DOE/FC36-CH10569.01

R
FEB 0 (1996
OSTI

DELMARVA POWER & LIGHT COMPANY

DEVELOPMENT OF A DISPATCHABLE PV PEAK SHAVING SYSTEM

PV:BONUS PROGRAM - PHASE 1 REPORT

VOLUME 1

PREPARED FOR THE US DEPARTMENT OF ENERGY
COOPERATIVE AGREEMENT NO. DE-FC36-93CHI0569

October 1995

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

TABLE OF CONTENTS

VOLUME 1

Executive Summary

INTRODUCTION

This report summarizes the work performed by Delmarva Power & Light and its subcontractors in Phase 1 of the US Department of Energy's PV:BONUS Program. The purpose of the program is to develop products and systems for buildings which utilize photovoltaic (PV) technology. Beginning with a cooperative research effort with the University of Delaware's Center for Energy and Environmental Policy Research, Delmarva Power developed and demonstrated the concept of Dispatchable PV Peak Shaving. This concept and the system which resulted from the development work are unique from other grid-connected PV systems because it combines a PV, battery energy storage, power conversion and control technologies into an integrated package.

Phase 1 began in July 1993 with the installation of a test and demonstration system at Delmarva's Northern Division General Office building near Newark, Delaware. Following initial testing throughout the summer and fall of 1993, significant modifications were made under an amendment to the DOE contract. Work on Phase 1 concluded in the early spring of 1995.

Significant progress towards the goal of commercializing the system was made during Phase 1, and is summarized below. Based on progress in Phase 1, a proposal to continue the work in Phase 2 was submitted to the US DOE in May 1995. A contract amendment and providing funds for the Phase 2 work is expected in July 1995.

TECHNICAL DEVELOPMENT

The concept of combining PV and energy storage is not new. In fact, for years small PV systems have provided power for numerous applications at sites remote from utility service. Storage capacity for these off-grid applications is typically large in comparison to the PV array capacity. This permits the user to "ride out" long periods with little or no sun. During the Summer of 1992, Delmarva Power and the University of Delaware Center for Energy and Environmental Policy (CEEP) investigated the use of small PV arrays combined with thermal storage. Results of the research indicated that a relatively small amount of storage could have a profound effect on the value of energy from a PV array. This additional value is derived from the fact that most summer-peaking utilities experience their peak loads well after the output of a PV array peaks. This initial research at the University of Delaware, combined with solar resource/utility load coincidence studies at SUNY Albany, resulted in three significant conclusions:

1. Utility loads during the summer months are positively correlated with the availability of the solar resource in most areas of the United States;

2. A relatively small amount of energy storage permits the output of a PV array to be stored until it is most needed, usually during the late afternoon hours; and,

3. Storage also allows a significant "leveraging effect" in which the output of the system at the time of peak can be as much as two times the rated capacity of the PV array.

Later analysis indicated that PV systems which included storage (hence Dispatchable PV Peak Shaving System) are considerably closer to economic break-even than "non-dispatchable" PV systems for grid-connected applications, based purely on the value of capacity and energy. When employed as "dual purpose" systems (e.g., to provide both peak shaving and emergency power), the economic value can increase substantially (see Appendix B). The relationship between the utility and customer can also have a significant impact on the economic value of the system. Alternative service arrangements, in which both the utility and customer may realize economic benefits, can be developed to help commercialize grid-connected PV systems (see Appendix C).

To demonstrate and develop the Dispatchable PV Peak Shaving System, Delmarva installed a system consisting of a 15 kW PV array, 25 kWh of battery energy storage, and a 32 kW inverter. The battery storage and inverter components were provided as an integrated package. Throughout the Summer of 1993, the system was dispatched consistently during peak periods, and verified the association between the availability of solar energy and utility peak loads. The demonstration system also provided a test bed for hardware development. System testing and evaluation resulted in considerable enhancements to the system's controls, operational flexibility, packaging and safety. A "user friendly" interface eliminated the need for a dedicated, external control computer. PV array conversion efficiency was enhanced by installing a DC-to-DC converter at the array/battery module interface. Finally, a proposed modular roof-mounting system was designed for application with future units.

Phase 2 of the PV:BONUS Program will deploy four of the refined Dispatchable PV Peak Shaving Systems at host sites across the country for additional testing and evaluation. These systems will provide the pre-commercial operating experience necessary to move forward with an expanded commercialization effort.

MARKET OVERVIEW

Applied Energy Group, Inc. was contracted to analyze the potential market for the Dispatchable PV Peak Shaving System among electric utility commercial customers. This was accomplished primarily through surveys of customer and trade groups to evaluate potential barriers, and a quantitative analysis of market potential. The details of the market research are explained in a confidential attachment, Appendix A. Not surprisingly, the analyses indicated that the most significant barrier to acceptance is the very long payback period for systems at today's prices. However, a small but significant market currently exists among "early adopters." If this market could be consolidated in the United States, there is probably sufficient volume to drive the Dispatchable PV System's production costs down substantially. A preliminary analysis of the international market also revealed applications for the system in areas with high electricity costs. In several cases in the international market, the system already appears to be cost-effective.

Overall, the potential domestic market for the Dispatchable PV Peak Shaving System among commercial customers is very large. Approximately 14 percent of commercial customers (roughly 800,000 buildings) have characteristics indicating a high adoption potential at break-even system costs. Obviously, actual market penetration will be less, depending on a number of technical, commercial and marketing issues.

Several other potential markets exist, but were not examined in detail in Phase 1. These include off-grid applications, such as village power and remote residential systems, and various emergency power and back-up systems. These markets require an adaptation of the basic Dispatchable PV Peak Shaving System which will be accomplished during Phase 2. Larger versions of the basic unit can also be used in utility distributed generation applications at substations and along heavily loaded feeders.

BUSINESS DEVELOPMENT OVERVIEW

The overall goal of the program is the formation of a sustainable business around the development, integration, distribution and servicing of the Dispatchable PV Peak Shaving System and its derivatives. Substantial progress has been made towards securing alliances, entering early markets and identifying the necessary resources. These are discussed in a confidential attachment, Appendix D.

Introduction

The conceptual design of the Dispatchable PV Peak Shaving System was initially developed by Delmarva Power and the Center for Energy and Environmental Policy (CEEP) in late 1992. The concept evolved from research done throughout the Summer of 1992 on the use of PV as a demand-side management (DSM) tool. This research indicated that PV, combined with energy storage, was of greater economic value than PV alone for grid-interactive systems. This increased economic value is derived from the ability to control the output of a PV system with storage, allowing its use at the time of utility system peaks, local substation or distribution peaks and/or customer peaks.

While the design of the system described in this report utilizes ***battery*** energy storage, the overall concept of a dispatchable PV system is not linked intrinsically to battery technology. In fact, the original research conducted by CEEP and Delmarva Power utilized a combination of PV and hot water storage to demonstrate the concept.

By the time the PV:BONUS contract was awarded to Delmarva Power in July 1993, the original concept had been developed to the point of deploying a test and demonstration system utilizing battery energy storage. Because the design, installation and operation of the test system had a major influence on subsequent work, this report begins by describing the work performed under Task 4 of the original PV:BONUS Statement of Work.

Task 4 - Test System Deployment and Testing

The major work items under this task were the installation of the test system, an accounting of the performance and costs of the system, a summary of the technical issues resulting from the testing of the system and recommendations for Phase 2 development and testing.

PROJECT DESCRIPTION

Design and Construction Overview

Delmarva Power constructed a dispatchable photovoltaic (PV) test and demonstration facility at the Northern Division General Office Building (NDGO) near Newark, Delaware during the early summer of 1993. The purposes of this facility were to:

1. Gain experience with PV technology;
2. Gather solar resource data;
3. Explore the potential uses of photovoltaics and battery energy storage for dispatchable building peak shaving systems; and

4. Serve as the test-bed for the development of modular, dispatchable PV systems for buildings under the Department of Energy's PV:BONUS Program.

The system was later modified to incorporate some of the improvements identified during early testing. Detailed engineering for the project began in January 1993 in a collaborative effort which included Delmarva Power, Ascension Technology of Waltham, Massachusetts and AstroPower of Newark, Delaware. The system design phase was followed by the award of separate contracts for system integration, electrical installation, mechanical installation, and data acquisition system equipment. Site construction began with preliminary electrical installation in June 1993. Installation of the rooftop array was completed on July 1 and 2, 1993. System electrical work was completed on July 15, 1993. Start up and functional check out were completed on July 16, 1993.

Conceptual Design and Operation

The conceptual design of the original system, which is illustrated in Figure 1, shows its most important components -- the PV arrays, DC interface, battery/inverter module and control computer.

The system at NDGO was designed for summer peak shaving using the combined output of the PV array and energy in short-term battery storage. Based on data taken during the Summer of 1992 in tests at the University of Delaware, and data collected during system testing from July through September 1993, clouds are practically non-existent on the summer days in which Delmarva experiences system peaks. On days like this, the output of the PV array is evenly divided between morning and afternoon, peaking at solar noon (approximately 1:00 PM, EDT). However, Delmarva's need for capacity, like many other utilities, is skewed towards the afternoon hours. To overcome this problem, the array's output during the morning hours was used to charge a battery bank. This stored energy, minus storage losses, was combined with the array's output in the afternoon, when it is most needed, and fed into the building's distribution grid. The system's capacity is dependent on the amount of energy stored prior to dispatch, and the duration of the dispatch period.

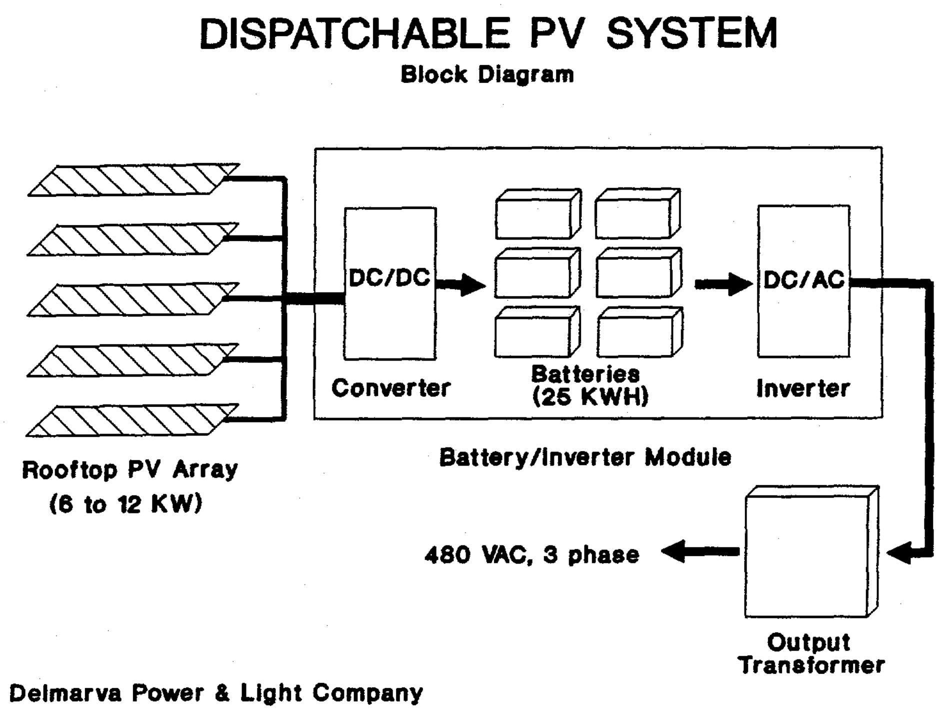

FIGURE 1

Site Description

The PV array is installed on the roof of NDGO above the main entrance area. This building location was chosen because it has a clear southern exposure and allowed great flexibility in the final array configuration. The battery/inverter module is located in the switchgear room above the engine-generator room. The DC output of the array is routed to the battery/inverter module via two conduits running across the roof of the building. Once the DC output from the array and batteries are converted to AC, the output is fed into the building's electrical system through an existing 480 VAC distribution panel.

Photovoltaic Arrays and Mounting Structure

The PV array is nominally rated at 14.5 kW at PV-USA Test Conditions (PTC).[1] The array was originally configured for a design open circuit voltage of 880 VDC. The high array voltage was necessary to match the high DC voltage of the battery string (48 twelve-volt batteries in series) in the battery/inverter module. The array is divided into two subarrays, nominally rated at 7.25 kW DC, each consisting of five parallel strings. Subarray open circuit voltage is approximately 440

1. PV-USA Test Conditions are defined as 1,000 Watts/sq. meter plane of array insolation, 20 °C ambient temperature and less than 1 meter/second wind speed.

VDC. The subarrays were originally series-connected with a center tap neutral at the input terminals of the battery/inverter module to achieve the necessary input voltage.

The modules used in the array were manufactured by AstroPower. The modules are rated at 61 Watts each at PTC and consist of single-crystal silicon PV cells encapsulated in EVA (ethyl vinyl acetate). A glass-aluminum frame is used for mechanical protection. A total of 240 modules are used in the NDGO array.

The arrays are mounted on ballasted roof jacks. This mounting system is unique because it does not require roof penetrations or additional structural steel. Each roof jack is bolted to a galvanized steel tray. The first step in the installation of the roof jacks was the removal of existing roof ballast. An additional layer of rubber roofing material was placed inside the cleared area, and the ballast trays were placed in their proper locations. Once in place, the ballast was restored to each tray and the PV panels were mounted on the roof jacks. The ballasted roof jack system is suitable for existing open roof areas where an additional dead load of 7 to 10 pounds per square foot can be supported by the roof structure.

Battery/Inverter Module

The battery/inverter module manages the energy produced by the PV array by operating in one of three primary modes -- battery charging, peak shaving or simple grid-connected operation. The unit originally installed at NDGO was adapted for this purpose from an AC Battery Module, manufactured by the AC Battery Corporation of East Troy, Wisconsin. The AC Battery module was originally designed for utility load leveling and peak shaving using batteries alone. In its original configuration, the batteries are charged using off-peak energy from the utility system, and discharged to help manage short-duration peaks at substations. The AC Battery Module was developed jointly by the Omnion Power Engineering Corporation, the Delco Systems Division of General Motors and Sandia National Laboratory. For the purpose of using an AC Battery Module on the dispatchable PV system, the necessary modifications included addition of a DC input port to permit battery charging from the PV array, and changes to the system control software.

The module is designed to provide nominally 25 kWh of energy storage when discharged over approximately 4 hours. Conversion from DC to AC is accomplished using a 31 kW solid state inverter, which also permits the use of the unit for reactive power (VAR) compensation. Because of the developmental nature of the PV charging software, the grid charging and static VAR compensation features were not incorporated.

With the configuration represented in Figure 1, the PV array operating voltage was determined by the battery float voltage, which was set at 621 VDC. The system output is 3 phase, 60 Hertz at 480 VAC. The inverter output is matched to the building's electrical distribution system through a step up transformer. The inverter incorporates standard overcurrent, undervoltage and frequency protection. The inverter will also isolate itself in the event of a loss of external power. This will prevent "backfeeding" the grid during utility outages.

The original batteries used for this application were 48 Delco 2000 twelve Volt heavy-duty truck/marine batteries. The batteries incorporate conventional maintenance-free, lead-acid technology. Although not traditionally used in PV or stationary power applications, these batteries were chosen because they are mass-manufactured. Since they are also packaged into an easily replaced module, a favorable trade-off results between initial capital costs and battery replacement costs.

Data Collection and Analysis

A significant amount of data is being collected on ambient conditions, PV system performance and building system performance. Ambient data includes insolation, temperature, humidity, and wind speed and direction. PV system performance parameters include array voltage, current, and temperature, as well as the system's AC power output. Building system performance parameters include the loads on the four primary feeders, engine generators, four chillers, and four HVAC motor control centers. All of this data is logged at 15 minute intervals.

The data collection equipment and software were provided by Ascension Technology. Data is downloaded via telephone line to a PC for monitoring and analysis.

The data analysis presented in this report focuses on component performance and resource assessment. Specifically, the data is being analyzed to:

1. Evaluate the PV array performance relative to ambient temperature and insolation;

2. Evaluate battery storage capacity vs. discharge rate;

3. Evaluate system losses and inefficiencies; and,

4. Compare Delmarva summer group loads to insolation.

PROJECT COST SUMMARY

Capital Budget

A total project capital budget of $275,000 was established in Delmarva Power CBID Number 93-D-93. In addition, $55,000 of R&D funds were used to support the development of the hardware and software for PV battery charging, and the data acquisition system. A breakdown of project capital expenditures is shown in Table 1.

Table 1

NDGO PHOTOVOLTAICS PROJECT CAPITAL COST COMPARISON

CONTRACTOR/VENDOR	ITEM	COST
AstroPower[2]	PV Arrays and Balance of System Equipment	$186,653
WSMW	Rooftop Installation	7,500
Tri-M	Electrical Construction	18,083
Bruce Industrial	Access Stairs and Roof Shelter	25,444
Miscellaneous Materials		423
Total Owner's Costs	Payroll, Loadings and Miscellaneous	32,432
PROJECT TOTAL		$270,535

Because the NDGO dispatchable PV peak shaving system is the first of its kind, caution must be used in comparing its capital costs to other PV systems. it is difficult to compare the capital costs to other PV systems. The installed costs of grid-connected PV systems without storage range widely from about $6,500/kW to $11,000/kW and higher, excluding owner's costs, special access and data acquisition. The upper end of this range represents custom-designed, roof-mounted systems.[3] When owner's costs, access stairs, and data acquisition system electrical installation costs are excluded from the NDGO Project, the total capital cost is reduced to $208,000 (approximately $14,500/kW). If battery storage is eliminated, the cost is reduced to approximately $157,000, or about $10,800/kW.

For comparison, it is more expensive to increase the size of the array in lieu of using some storage. Since Delmarva's peak loads occur at about 5 PM during the summer, a fixed plate PV array ***without*** storage could only be credited with about half of its nameplate capacity. If a 15 kW

2. AstroPower's contract included the purchase of electrical design services and miscellaneous hardware from Ascension Technology, and the purchase of the AC Battery Module.

3. Recent mass purchases of small, roof-mounted PV systems for residential applications have been reported at approximately $6,600/kW. Larger, "one-of-a-kind" systems are considerably more expensive because of increased engineering and installation costs.

credited capacity is required over a three hour period from 3:00 PM to 6:00 PM, a PV array of at least 30 kW would be required, which would cost in excess of $300,000. This should be compared to the installed hardware cost of the system ***including*** storage of about $208,000. For peaks occurring later in the day, the cost of a PV system without storage would be even higher to assure a specified capacity level. While tracking could offset some of the added array cost, significant additional costs would be incurred in modifications to the roof structure necessary to accommodate tracking hardware and additional wind loadings.

PERFORMANCE OF THE ORIGINAL SYSTEM

PV Arrays

Immediately following initial installation, several modules were replaced. One failed when the glass on the module shattered, probably due to improper handling or frame misalignment. Three modules were replaced after measurements detected open-circuit voltage levels below specifications.

The AstroPower Model AP-5107 modules used in the PV array are nominally rated at 61 Watts DC at PTC. The output of the entire array, which consists of 240 modules, should be 14,500 Watts DC at PTC, corresponding to an array "maximum power operating point" at 696 Volts DC and 20.8 Amps. In the original configuration, the array operating voltage was determined by the battery bus voltage. The actual operating point at PTC was therefore 621 Volts and approximately 22 Amps, or 13,700 Watts DC. AstroPower's performance warranty states that the DC power output will be within 10 percent of the predicted output. For a predicted output of 13,700 Watts, the minimum guaranteed output is 12,330 Watts. Actual array output at the operating point is approximately 11,600 Watts, or about 6 percent below the minimum guaranteed level.

The array output deficiency is probably caused by several modules in the east subarray which are suspected of performing below specifications. AstroPower has acknowledged that a deficiency exists, and has resolved the warranty claim.

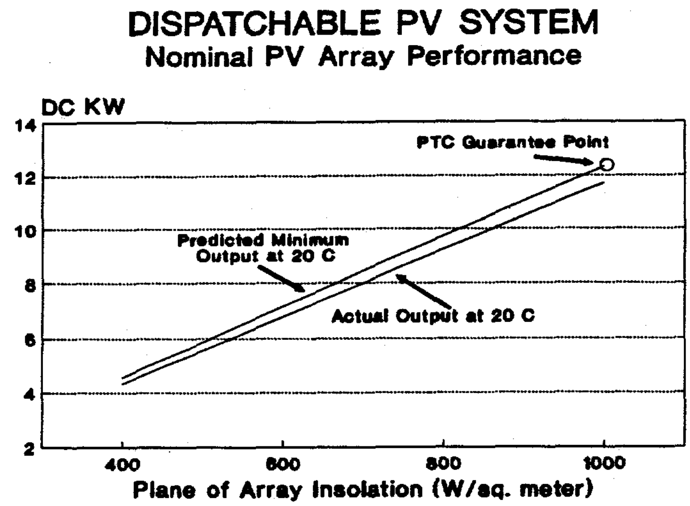

FIGURE 2

Figure 2 shows the predicted performance of the PV array compared to actual performance at 20 degrees Celsius for varying insolation levels. The line which represents actual performance at 20 degrees Celsius is based on a regression of measured performance data.

AC Battery Module

The two most important performance parameters for the AC Battery Module are inverter efficiency and energy storage capacity. In addition, overall inverter and control system reliability and power quality are also discussed briefly.

The inverter, which is a modified version of Omnion's 3200 Series PV inverter, has performed well since start up. This is significant because inverters have historically been troublesome in grid-connected PV systems. The inverter's output has been tested across its operating range, with no observed problems even at maximum output. Although the inverter is designed and manufactured to comply with IEEE 519 for current and voltage harmonic distortion, no measurements have been taken to date to verify its performance in the field. Measurements taken in the factory indicate that the unit is in compliance with the IEEE standards in effect at the time of manufacture.

The guaranteed inverter efficiency point is 93 percent at its rated output of 31.25 kW. This efficiency is determined by measuring the AC output power upstream of the system step-up transformer and dividing by the DC input power. Inverter efficiency is a function of output, and measured efficiencies show that the inverter operates at 93 percent or higher beginning at approximately 12 kW. Efficiency from 6 to 12 kW increases nearly linearly from about 90 to 93 percent. Efficiencies increase logarithmically from approximately 60 percent at 1 kW to 90 percent at 6 kW. In the original design a significant inefficiency was introduced by the step up transformer. The idling losses incurred by this transformer are 2 percent of its rated capacity, which corresponds to a 620 Watt continuous loss whenever the unit is connected to the grid. This problem was addressed with later modifications.

The amount of energy delivered from battery storage to the inverter of the AC Battery Module is a function of battery discharge rate. Table 2 shows the expected module storage capacity for full discharges of 1, 4 and 8 hours duration.

Table 2

Expected Battery Storage Capacity

Time	Energy from Storage	Energy from Storage	Discharge Rate
Minutes	DC kWh	DC Amp-hours	DC Amps *
60	20	35	35.4
240	25	44	11.1
480	30	53	6.6

*Discharge current is based on an average battery string voltage of 565 VDC during discharges.

Figure 3 shows the measured battery capacity for twenty full battery discharges from July through October. Many more partial discharges were done during the same period, but do not provide information about total battery capacity. When comparing energy delivered from storage versus discharge time the overall trend is a characteristic logarithmic curve. The corresponding discharge rates are also shown. There are two explanations for the significant amount of "scatter" in the data. First, most of the points shown in Figure 3 were derived from data collected by the data acquisition system at 15 minute intervals, which results in relatively poor resolution. Second, 15 of the data points represent ***system*** dispatches, which included energy from the PV array combined with the battery. Because these discharges were at fixed output levels with declining PV input, they are characterized by large changes in battery discharge rate.

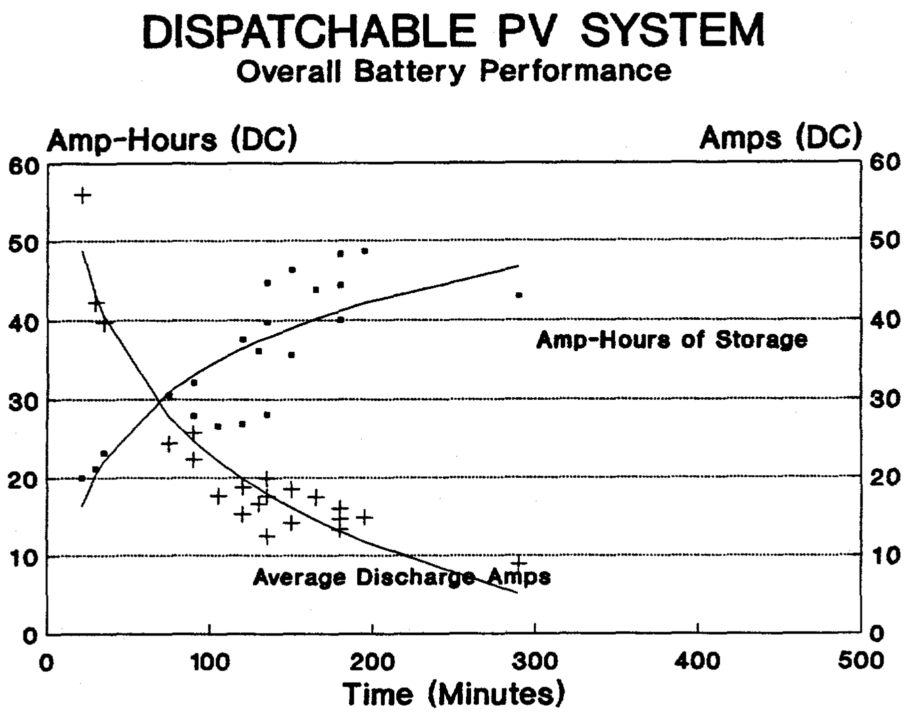

FIGURE 3

To provide a basis for comparison, five "controlled discharges" using only energy stored in the batteries were done to exclude the influence of the PV array, and to more precisely measure the elapsed time to full discharge and total energy released from storage. The trend for these discharges is shown in Figure 4, and compared to the expected capacity curve and the overall capacity when PV energy is included.

When expected capacity is compared to measured capacity in controlled discharges, the data trend for the amount of energy actually available from storage indicates that about 20 percent less energy is recovered from storage than expected for short, high power discharges. For longer periods, however, the amount of energy recovered from storage was closer to what is expected, although still about 10 percent less. Battery capacity data points for discharges ***with*** PV input are also shown for comparison.

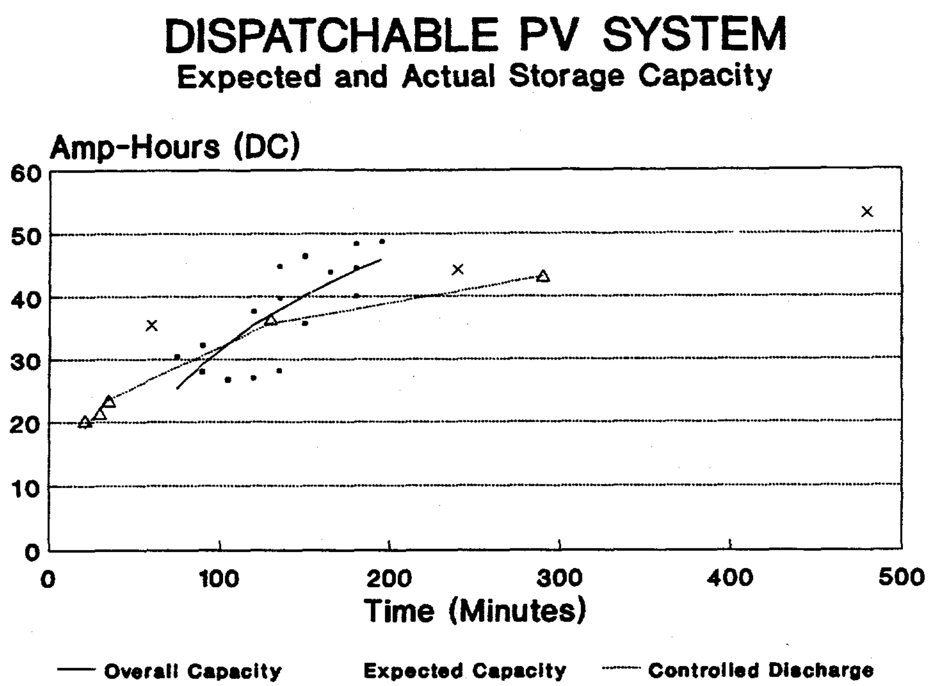

FIGURE 4

The AC Battery control system accounted for most of the difficulties encountered during the 1993 test period. The system control algorithms for charging, dispatch and float operating modes reside in software on a PC-based controller. This controller was "off board" the AC Battery module. A separate controller in the inverter was used primarily for regulating the DC bus voltage. This voltage level is critical for proper charge and discharge control. Several minor communications problems were observed in which the PC lost the ability to communicate over the RS-232 link with the control board in the inverter. These were easily reset with no ill effects.

Voltage regulation on the DC bus was also a problem. Because an RS-232 serial communications port was used, the speed of communications was relatively slow. This made it difficult to stabilize the DC bus voltage, especially when the batteries were fully charged and the bulk of the PV array's energy was exported to the grid. This caused an oscillation in the DC bus voltage and rapid system power output fluctuations under these conditions, although there were no adverse effects on the system hardware. The last problem with the control system was an unexplained software error which occasionally caused the system to shut down. An error message was always present, although the root cause was not determined.

At least part of the storage shortfall may have been due to the charge control software. AC Battery believes that the control software may have prematurely terminated the battery charge cycle, resulting in battery undercharging. Other causes of the shortfall may be due to battery cell reversal, or other battery-related problems.

Although the control and software problems were troublesome they did not prevent the system from functioning for test purposes. Future generations of this system will have "on board" controllers, which should eliminate communications and voltage regulation problems.

System Dispatch Performance

The primary purpose of the NDGO system was to test the practicality of dispatchable PV systems. The system was dispatched a total of 27 times from July through late September 1993. An example of a "back-to-back" dispatch is shown in Figure 5. This represents the most difficult design condition for the unit, because it requires the batteries to be fully charged in time for the peak on successive peak days. In the mid-Atlantic region, system peaks usually occur in the late afternoon. Therefore, battery charging takes place during the morning and early afternoon hours. The ability to be reliably dispatched on successive days is a function of the availability of solar energy for battery charging on system peak days. This is explained in greater depth in the section on system sizing.

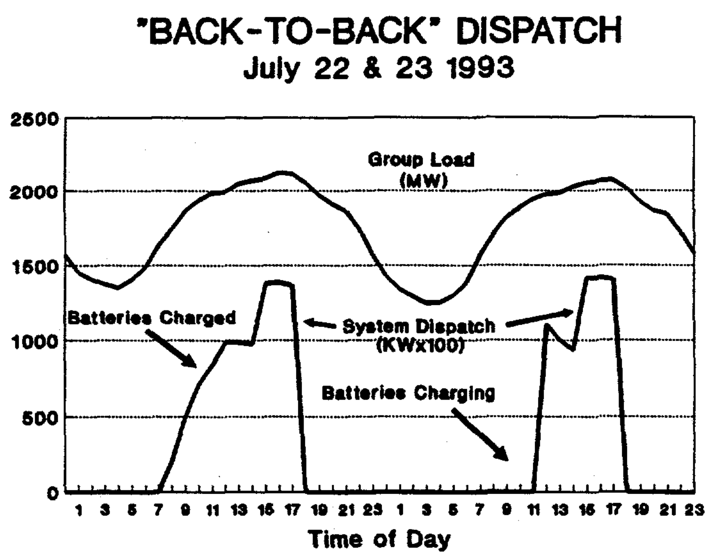

FIGURE 5

The performance of the system during dispatches and charging cycles helped to highlight a few of the problems associated with hardware components (i.e., control system, battery storage capacity, and PV array performance), but also established the soundness of the basic concept. This is a major step forward, simply because this type of system was never actually tested before the Summer of 1993. Refinements will be necessary before a commercially viable system is available.

Tasks 1 & 2 - Conceptual Design Refinement

Tasks 1 and 2 of the original Statement of Work were identified respectively as System Conceptual Design and Building Conceptual Design, and were intended to provide the basis for system refinements in Phase 2. This was accomplished through the experience accumulated during the design, installation and operation of the test and demonstration system. Several of the earliest proposed refinements were later included in a Phase 1 contract modification.
Tasks 1 and 2 were originally conceived as stand-alone activities. As work progressed, it became apparent that these two tasks were more closely tied together. The results of the work performed in Tasks 1 and 2 are therefore combined in this report.

FUNDAMENTAL DESIGN GOALS

A relatively simple system design was used to demonstrate the conceptual and technical feasibility of dispatchable PV systems. While this simple design was adequate for the purpose of demonstration and data collection, it was not intended to represent a refined, commercially available system. Before a refined design could be completed, a set of fundamental design goals had to be established. These goals reflect a combination of the designers' experiences and market preferences (see Task 3, Market Research).

1. *Modularity:* The design of a dispatchable PV system should be modular. Modularity applies to the design of sub-system components, as well as to the modular nature of the integrated "units." The use of modular sub-system components permits rapid design turn-around, and simplifies component sourcing, assembly, installation and maintenance. A modular "unit" design permits flexibility in sizing systems (consisting of one or more units) for particular applications. Modularity also emphasizes the use of a controlled, factory assembly environment for sub-system components, and minimizes the amount of field labor required to install systems.

2. *Functional Flexibility:* A variety of functions should also be inherent in the design of a dispatchable PV system. Functional flexibility is required to accommodate diverse customer requirements, and is already a common feature of many conventional building systems, ranging from HVAC to emergency back-up systems. A key advantage of functional flexibility is that it adds value to the system. It is not a requirement that ***every*** dispatchable PV system be capable of performing ***every*** envisioned function, but that it should at least be easily modified during or after assembly.

3. *Design Flexibility:* As the market for PV systems evolves, it is certain to become more sophisticated and demanding. In addition, new design standards will evolve which will require changes. The designers' responses to new market demands and design standards must be timely, otherwise product and system offerings will simply be uncompetitive. A system with high design flexibility permits rapid responses to new demands without the need for complete re-design.

The combined features of modularity, functional flexibility and design flexibility will ultimately help make dispatchable PV systems more economically competitive. By emphasizing modularity and flexibility in products for the early market, system designs and features will not be fixed prematurely. Another characteristic of an evolving PV market will likely be the rapid introduction of new components, processes and applications. Design flexibility in an older product or system may not help it compete against newcomers, but it helps foster the institutional flexibility necessary to smooth the transition between "old" and "new" technologies.

SYSTEM DESIGN ISSUES

With the above goals in mind, many system design issues were identified during the initial design, installation and operation of Delmarva's dispatchable PV system. Design issues are categorized by sub-system, and are subsequently addressed in the Phase 1 contract modification and/or Phase 2 planning.

PV Array

The PV array is the primary source of energy for the dispatchable PV system. The widespread introduction of PV arrays to the commercial building market must account for the requirements of building owners and tenants, code officials, and those responsible for facility maintenance and operation.

1. ***UL Listing***: One of the main criteria used by code officials in determining the suitability of electrical equipment for a given application is a listing by Underwriters' Laboratories. Presently, many manufacturers of PV modules do not list their products with the UL. While some code officials may be flexible regarding the requirement for UL listings in "experimental" systems, it is preferable in the long-term to have PV modules listed with the UL to minimize liability and code compliance problems.

2. ***Array Open Circuit Voltage:*** The open circuit voltage of the PV array determines the National Electric Code voltage classification of downstream equipment as well as system electrical design. The threshold between "low" voltage and "high" voltage is nominally 600 Volts. The array open circuit voltage level encompasses safety, design and construction issues. The demonstration system's array open circuit voltage, which was determined by the input voltage necessary for the AC Battery Module, was approximately 880 Volts DC. Electrical equipment classified for high voltage DC service is nearly unavailable. This problem was addressed by using a center-tapped array configuration in which two separate array source circuits were installed operating at nominally 440 Volts DC. While this solved the immediate problem, it required redundant cable, conduits, disconnects, junction and pull boxes.

3. ***Lightning Protection:*** Lightning protection is required on many commercial buildings. The design and installation of lightning protection systems must be done by certified lightning protection contractors. In many cases, especially retrofits, simply connecting the

PV array to an existing lightning protection grid is not sufficient. Although the demonstration system did include lightning protection, different requirements may apply to alternative structures.

4. ***Small vs. Large-Area Modules:*** The demonstration system utilized AstroPower AP-5107 modules. The dimensions of these modules are 21 inches wide by 46 inches long. Six modules are assembled into a panelized assemblies on aluminum channels. Ultimately, panelized assemblies of small PV modules will be inefficient. Each assembly requires interconnecting wiring, junction boxes and structural supports. To the extent that large-area modules can be substituted for panelized modules, factory assembly costs should be reduced. The elimination of parts, especially electrical connectors, should also enhance array reliability and reduce field maintenance and troubleshooting costs.

5. ***PV Array Electrical Connections:*** Individual PV modules were electrically connected in the factory prior to shipment. Once at the site, panelized assemblies were interconnected using "quick" connectors, and finally terminated in row junction boxes to create sub-array source circuits. The row junction boxes were then interconnected for each sub-array. The demonstration system required the electrical sub-contractor to install a considerable amount of the interconnecting cable and conduit. In part, the arrangement of the electrical connections was dictated by the use of a ballasted roof mounting system. For future installations, the number of electrical interconnections requiring the use of a field contractor should be minimized.

6. ***Building-Integrated PV Materials:*** Although the Phase 1 development work concentrated on the use of crystalline silicon PV arrays, thin-film PV arrays, or PV roofing and glazing can also be used in dispatchable systems. The main issue, in this case, is the standardization of PV source circuit designs.

PV Array Support Structures

Many engineering, installation and operational issues are encountered in the design of PV array support structures. Additional complications arise when the ages and types of buildings and roofing systems are considered. The Phase 1 work concentrated on support structure options for PV arrays mounted on low-rise, flat-roof commercial buildings. Table 3 summarizes the main issues.

TABLE 3

SUMMARY OF SIGNIFICANT ISSUES - ROOFTOP PV INSTALLATION METHODS

Category	New Structure	Retrofit Structure	Ballasted Roof Jack
Engineering/Design	Architects and builders are not used to allowing for the installation of PV support structures. Codes, standards and procedures are not well defined. Coordination with architect and overall project timing are critical.	The capacity to resist additional wind loading forces and moments on building structural members may limit the PV array size. Interferences with other rooftop equipment (HVAC, etc.) make array layout difficult.	Additional ballast required to resist uplift may exceed the dead-load design limits of the roof. Interferences with other rooftop equipment (HVAC, etc.) may make layout difficult. Rooftop drainage requirements may require a less than optimal layout. Seismic design criteria may preclude the use of ballasted system in parts of the country. Tie-downs or other fastening methods may be required.
Installation		Rooftop penetrations will probably be required, adding cost to the overall installation. Field structural modifications may be required	
Operations/ Maintenance		Roof warranty may be altered as a result of making penetrations.	PV system must be removed for roof replacement or repairs. Roof warranty may be altered.
Others		A retrofit structure may affect building aesthetics and architectural integrity.	

AC Battery Module

A primary goal of the PV:BONUS product development effort is to reduce design and field installation costs by incorporating factory-produced, standardized sub-systems. Although the original design of the AC Battery Module was not intended for use in a dispatchable PV system, one of its chief advantages is its modularity. The unit as it was originally configured had several shortcomings. These were:

1. ***Operating Voltage***: The operating voltage of the PV system had to be in excess of 600 VDC in order to charge the batteries. DC electrical equipment suitable for this voltage level is virtually unavailable. This requires a bipolar array design with duplicate disconnects, cable and conduit, resulting in higher equipment and field installation costs.

2. ***DC Interface***: A DC contactor was used to connect the PV array to the AC Battery Module. This forces the PV array to operate at the battery bus voltage instead of the PV

array maximum power point. The addition of a DC to DC converter will permit maximum power tracking and allow the array operating voltage to be reduced.

3. *Controls*: The AC Battery Module was controlled by a stand-alone desktop computer. While this was acceptable for test purposes, it is not viable in production units located in commercial buildings.

4. *PCS Optimization*: At this time, the optimum combination of equipment for a production "unit" includes a PV array between 6 and 12 kW at PTC (depending on design conditions), 25 kWh of battery energy storage and a 15 kW PCS. The current PCS is optimized for 32 kW. A DC to DC converter will permit the PCS to operate at its optimum voltage (600 VDC) while halving the PCS current. This will result in reduced PCS production costs.

5. *Flexible Charging*: The unit is presently not capable of being charged from the utility grid. The ability to charge the batteries from either the PV array or the utility grid will help optimize battery life and enhance flexibility.

Contract Modification to Address Early Design Issues

Delmarva Power's original PV:BONUS proposal included the installation and testing of a dispatchable PV peak shaving system. The intent of this task was to prove the technical feasibility of dispatchable PV systems and to identify areas requiring additional technical development. As a result of testing throughout the second half of 1993, two major development areas were identified. The first area of development is the refinement of the Battery/Inverter Module for the dispatchable PV system. The second area is in the development and testing of cost-effective roof mounting structures. The Department of Energy requested an expansion in Delmarva's scope of work to address improvements to the battery/inverter module. Work on roof structures will be incorporated into Phase 2..

In order to address the specific technical issues associated with the AC Battery Module, the unit was disconnected and returned to the manufacturer in March 1994. AC Battery incorporated features which considerably improve its performance and enhance its commercial viability. At the end of the Phase 2 development and testing effort, only minor modifications should be necessary to field commercial prototypes.

PERFORMANCE OF THE MODIFIED SYSTEM

In order to address the shortcomings of the original system, several modifications were completed as part of a contract amendment.

PV Arrays

The high operating voltage of the PV array, which originally operated in excess of 600 Volts DC, was addressed by a reconfiguration. Originally, the two subarrays were configured in series to create a bipolar, center-tapped array. This was done to accommodate the high operating voltage necessary to properly charge the battery/inverter module. With the reconfiguration of the battery/inverter module, high array operating voltages were no longer necessary. The subarrays were reconnected in parallel, resulting in a monopolar array configuration. The operating voltage of the array is now less than 600 Volts DC.

The array reconfiguration and reduced array operating voltage was made possible by the addition of a DC to DC converter to the battery/inverter module. By adding the DC to DC converter, it is also now possible to employ PV array maximum power tracking. Based on data taken shortly after the system modifications in December 1994, PV array performance improved by about 10 percent as a result of maximum power tracking. This is shown in Figures 6 and 7, which show regression lines for the PV array output as a function of Plane of Array Insolation for December 1993 and December 1994. While this improvement is representative of performance during the winter months, when the array tends to operate at lower temperatures and higher voltage levels, the overall annual improvement is expected to be about 5 percent.

ARRAY OUTPUT
WITHOUT MAX POWER TRACKING
December 1993

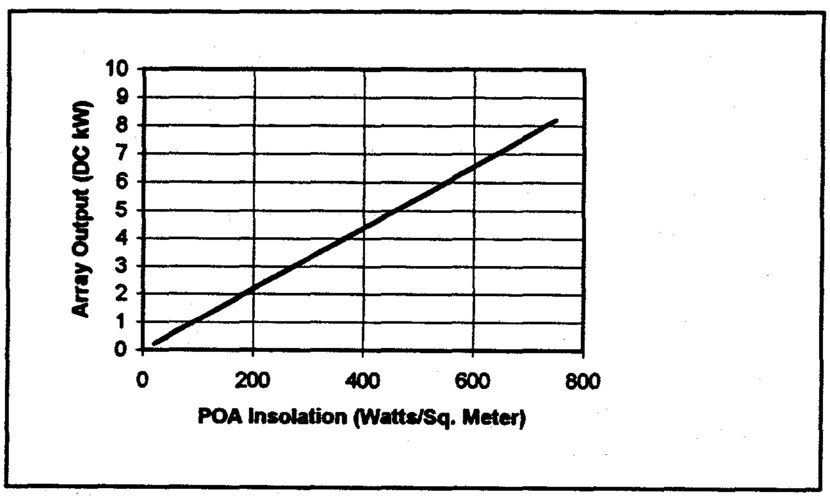

FIGURE 6

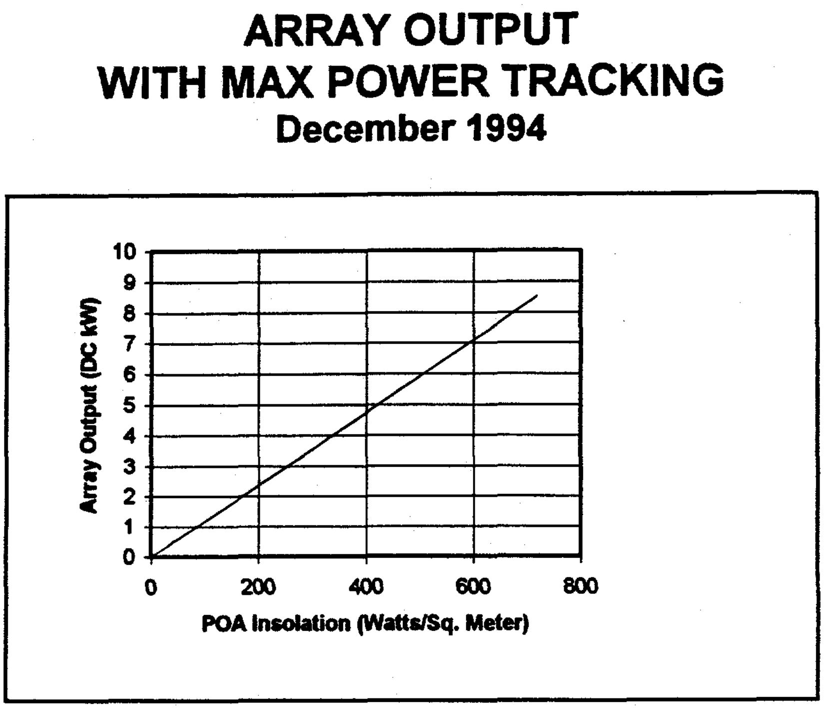

FIGURE 7

AC Battery Module

Significant changes were made to the battery/inverter module by the AC Battery Corporation. The first significant alteration was the addition of the DC-to-DC converter. The converter serves as the interface between the PV array and the battery/inverter module. As previously described, the converter permits the PV array to operate below 600 Volts DC and permits maximum power tracking, while simultaneously allowing the battery string voltage to be maintained at optimal levels.

The original control hardware configuration was also completely changed. The stand-alone PC-based control system was replaced by an on-board control computer with a keypad user interface. These improvements move significantly towards a commercially viable system by making the unit more self-contained and "user friendly." In addition to changing control hardware, control software was also changed. The new software, developed to optimize the operation of the battery/inverter module with PV, has exhibited none of the problems and errors associated with the earlier software versions.

The combined modifications of the battery/inverter module have added several capabilities, including the ability to charge the batteries from the PV array or grid, automatic "wake-up" and shutdown, remote dispatch control via a building energy management or SCADA system, and the ability to pre-set charge/dispatch schedules.

Overall DC to AC conversion efficiency is slightly lower than before the modifications, primarily because of the addition of the DC-to-DC converter. Although the converter accounts for some additional conversion losses, these are offset by the ability to operate the PV array at its maximum power point. Figure 8 shows the DC-to-AC conversion curve for the modified system.

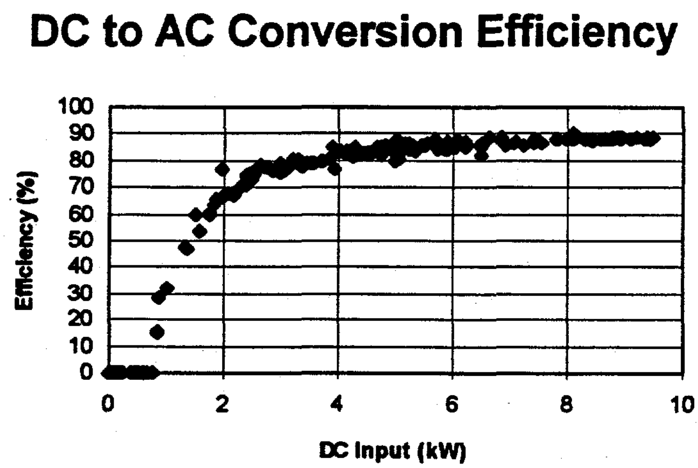

FIGURE 8

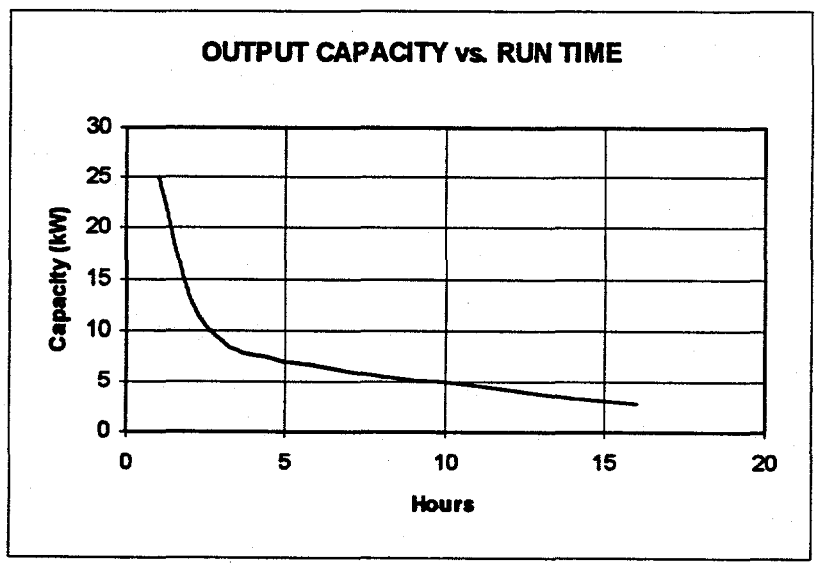

FIGURE 9

System Dispatch Performance

Based on preliminary tests following system reconfiguration, the expected battery capacity is shown in Figure 9 for an 80 percent depth of discharge. This figure does not include the contribution of energy from the PV array (as would normally be expected), and therefore shows the minimum time the unit should run at a given output level.

RESOURCE AND SYSTEM SIZING ANALYSIS

Resource Availability

Solar resource availability on system peak days is an important factor in the operation of the dispatchable PV system. Because the system uses storage, it is not critical that the solar resource and load coincide exactly. In Figure 10, the coincidence between ***Group Load*** and ***Global Horizontal Irradiance*** is shown for the highest hourly loads during the month of July 1993. Although the coincidence is good for about the ten highest load hours, it drops quickly. This is because there are very few hours when peak loads and solar energy precisely coincide, and is due to Delmarva's late afternoon peak. The main implication is that the effective load carrying capability of a PV array without storage in this region is significantly lower than the nameplate rating for all but a few hours.

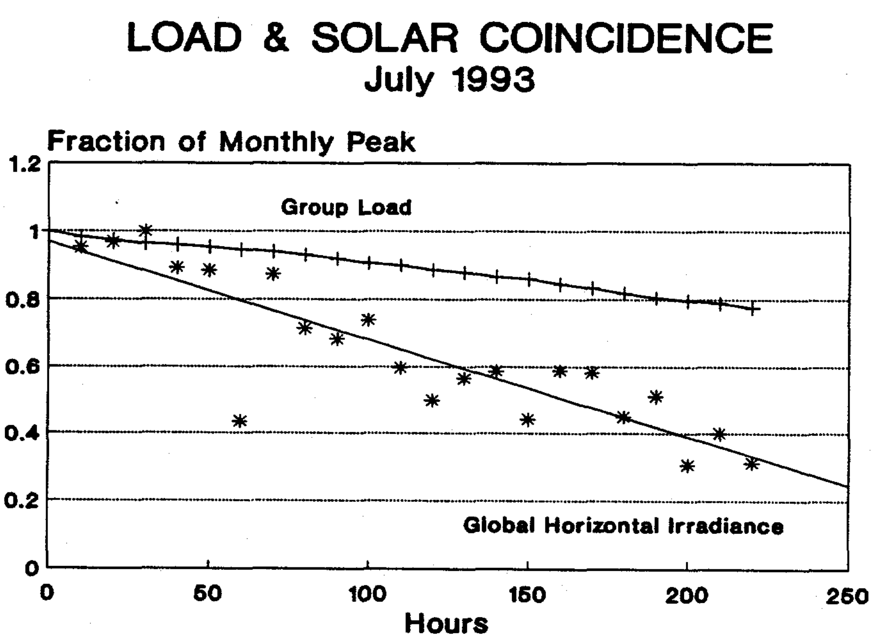

FIGURE 10

Figure 11 shows the coincidence between ***Total Daily Solar Energy Availability*** (expressed as kWh/day/sq. meter) and ***Daily Peak Loads*** for weekdays from July through September 1993. Because the trends shown are nearly parallel, this figure indicates that, for about the 20 highest summer peak loads, there is a high and relatively predictable level of solar energy available ***on those days***. Because the hottest days in the region are also quite humid, the amount of solar energy actually available is somewhat lower than clear, cooler, low humidity days. For lower utility loads, the data indicates less predictability. This is because cooler summer days in the mid-Atlantic region (also days in which utility loads are lower) are a mixture of cloudy and very clear sunny days. This figure has a direct impact on the design of dispatchable PV systems because it indicates the relative quantity of solar energy available for collection and storage on peak days.

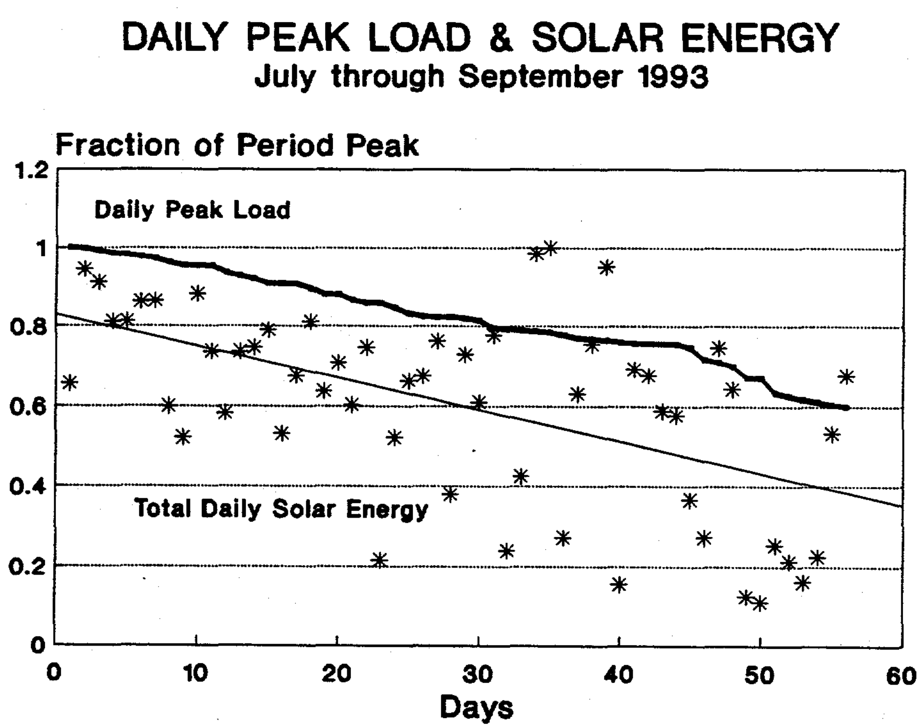

FIGURE 11

A similar analysis was completed in May 1995 to determine the coincidence between solar energy and Delmarva Power feeder and substation loads. The outcome of the analysis indicates, in general, that a larger number of feeders are candidates for dispatchable PV systems than for non-dispatchable systems. This analysis will help quantify the potential "distributed benefits" of dispatchable PV systems.

System Sizing Methodology

The combination of component performance and resource availability data, along with reasonable design assumptions can be used to help size dispatchable PV peak shaving systems. The following steps describe the methodology.

1. Establish the number of times peak shaving is required during the peak period.

2. Using daily peak load and energy coincidence data, establish the array "design day" conditions, i.e., insolation values and ambient temperatures.

3. Calculate a PV array output curve representative of the "design day" conditions.

4. Set the time of day, duration and output level for the system.

5. Calculate the proportions of energy which must be supplied from the PV array and storage.

6. Calculate the size of the storage block and PV array, accounting for storage round-trip energy losses, and ambient temperature derating of the PV array.

7. Using battery storage curves and fixed array size, determine the dispatch output of the system for different times of day.

The above methodology is used in a simple spreadsheet analysis to predict the performance of dispatchable PV systems, and the relationship between PV array size and battery storage. Figure 12 shows examples of the relationship for "design days" with insolation peaks at 650 and 1,000 Watts/sq. meter. 650 Watts/ sq. meter is derived from analysis of the data shown in Figure 11. If it is determined that the system must be dispatched during the highest 20 peak loads, then the insolation profile on the twentieth day will peak at about 650 Watts/sq. meter. This establishes the insolation profile and the minimum amount of energy available to the system. For sizing the PV array properly, it is assumed that the ambient temperature on these days will be around 100 ^{O}F (38 ^{O}C).

Figure 12 shows the relationship between the PV array size, dispatch capacity for a range of hours and the available AC Battery storage capacity. In this figure, the utilization of the battery storage is maximized for each dispatch duration, with the size of the PV array determined by the energy necessary to fully charge the batteries prior to dispatch. In this example, all of the dispatches are assumed to end at 6:00 PM, daylight time. Array size is nearly a linear function of dispatch duration, ranging from 4 kW to about 12 kW DC at PTC. Dispatch capacity decreases from 15 kW to about 10 kW AC over the same range of dispatch duration.

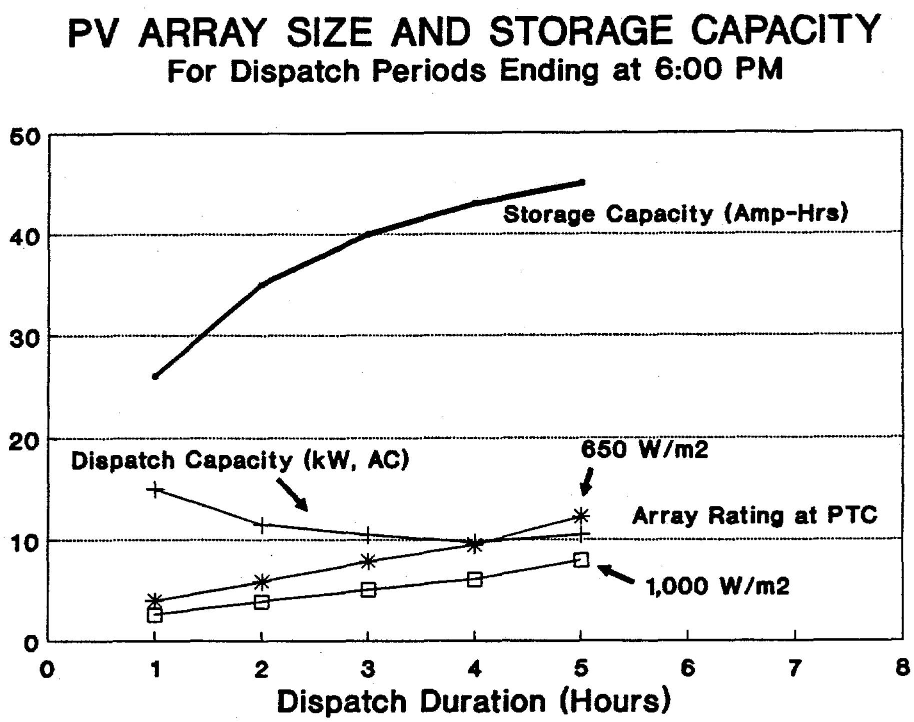

FIGURE 12

The effect of a better insolation profile is to reduce the size of the PV array in relation to the dispatch capacity. For example, if the peak insolation is 1,000 Watts/sq. meter, the array size in Figure 12 ranges from less than 3 kW to about 8 kW DC at PTC. If this is used as a design condition in the mid-Atlantic region, it also reduces the number of peak loads for which the system can be dispatched.

Demand and Energy Impacts of the Dispatchable PV System

The technical impacts the dispatchable PV peak shaving system can be subdivided into ***energy*** and ***demand*** components. The energy (kWh) output of the system results in a simple decrease in the electricity purchased or generated from conventional sources. Because the system is also dispatchable, it can be used to shave peaks, and effectively help to reduce the maximum demand (kW) for power. The impact of peak shaving is dependent on the end user's load shape. End users with relatively flat load profiles will experience less "flattening" or peak shaving than end users exhibiting more pronounced peaks. The AEG market research helped to identify categories of end users which have characteristics more favorable to the use of dispatchable PV systems.

The magnitudes of the energy and demand impacts are roughly proportional to the number of modular units necessary to achieve design objectives. The impacts of a single modular unit located in different areas of the country are shown in Table 4 for five cases. This table shows the approximate annual energy output of the system (a function of average annual insolation), credited demand reduction and the benefit/cost ratios from both a utility and customer perspective, and for both dispatchable and non-dispatchable systems. The calculations for these cases were done using a spreadsheet model under development by CEEP.

TABLE 4

IMPACTS OF A MODULAR DISPATCHABLE PV PEAK SHAVING UNIT (1)

Case	Approximate Annual Energy Output (kWh)		Credited Demand Reduction (kW)		Customer Benefit/Cost Ratio		Utility Benefit/Cost Ratio	
	Non-Dispatch-able	Dispatch-able	Non-Dispatch-able	Dispatch-able	Non-Dispatch-able	Dispatch-able	Non-Dispatch-able	Dispatch-able
Delmarva Power	16,800	16,800	4.3	14.9	0.63	0.76	0.48	0.66
Sacramento Municipal Utility District	20,100	20,100	3.2	17.2	0.62	0.73	N/A	N/A
City of Austin	19,000	19,000	4.9	15.3	0.63	0.75	N/A	N/A
ECUU (2)	16,400	16,400	4.4	12.2	0.74	0.98	0.51	0.52
Niagara Mohawk (3)	15,300	15,300	0.7	4.5	0.61	0.69	0.40	0.41

Source: Byrne, et. al., 1995, *Photovoltaics for Demand-Side Management Utility Markets: A Utility/Customer Partnership Approach*

(1) The results of the analysis presented in the table assume that a 10 kW PV array is used, for both dispatchable and non-dispatchable systems. Dispatchable systems assume the use of a single AC Battery module.
(2) ECUU refers to a confidential study case for an East Coast urban utility.
(3) Niagara Mohawk is a winter-peaking utility, which results in the significantly lower credited capacity and benefit/cost ratios.

Calculating the economic impacts of the dispatchable PV system are complex because they are dependent on system ownership, tax treatment, utility rates and costs. A considerable amount of work in this area has been done by CEEP. Starting from the perspective of a utility ***customer***, the primary economic benefit derived from the use of a dispatchable PV system is a reduction in demand and energy charges. A utility customer would be expected to maximize benefits based on load shape and electric rates. Depending on the rate structure, the highest economic impact may not coincide with the greatest peak reductions. For example, the owner of an office building with electric heat pumps may have higher demand in the winter than in the summer. However, higher demand charges may result in higher bills during the summer. The CEEP analysis shows that dispatchable PV systems have a significant cost-benefit advantage over conventional non-dispatchable grid-connected PV systems, based solely on customer bill savings.

From the perspective of a ***utility***, the primary economic benefit is the revenue collected as a result of the sale of capacity and energy from the utility system. The maximum benefit to the utility is achieved when the capacity and energy are available for sale at the time they are of highest value (usually at the time of system peak loads). In addition, utilities can use dispatchable PV systems as distributed generating units. In this role, the systems may be able to defer a larger capital investment. The CEEP analysis shows that the dispatchable PV system once again has a significant cost-benefit advantage over conventional PV systems. The advantages for utilities are not as great as they are for customers, primarily because of tax benefits which cannot be claimed by utilities.

The CEEP analysis does not assume that there is good coincidence between commercial customer peaks and utility peaks. In fact, because the customer's peak demand is not necessarily coincident with the utility's peak load, the utility may still be faced with the need to invest in incremental generating, transmission and/or distribution capacity, and still lose a portion of the customer's revenue. Traditionally, the ownership of PV systems has been restricted to either the utility or the customer, although recent work by CEEP has also explored various utility-customer partnership arrangements which help to overcome some of the economic and institutional barriers. For example, it is possible to create an arrangement between the utility and customer which allows the use of the system by the utility for peak shaving purposes. In this way, both the customer and the utility can benefit from the installation of the system.

PHASE 2 SYSTEM CONCEPTUAL DESIGN

The conceptual design of the dispatchable PV system is based on the experience gained in Phase 1, particularly from the deployment and testing of the demonstration system. Basically, two types of systems evolved from this work - small units for modest commercial applications and large pad-mounted systems for bigger commercial and utility applications. Supplemental market research also revealed that off-grid versions of the dispatchable PV system could have great potential for village power and remote power systems. The features of the systems are described in the following sections.

PV Array Design

The development of the dispatchable PV system is not restricted to the use of a single manufacturer's PV modules. A disadvantage of this approach is that it makes standardization of arrays and source circuits much more difficult.

The standard PV array source circuit design must be based on a ceiling voltage level of 600 VDC (open circuit) at STC conditions. This level was chosen to stay within the design and safety requirements of the National Electric Code for systems at or below 600 Volts at Standard Test Conditions. Based on manufacturers' performance information, "standard" monopolar PV string arrangements are shown for several manufacturers in Table 5. The minimum ***array*** size for a dispatchable PV system is the same as the minimum ***string*** size for any manufacturer's modules.

TABLE 5

MONOPOLAR PV SOURCE-CIRCUIT STRING ARRANGEMENTS

Manufacturer	Model	Modules per String	Open circuit Voltage at STC	kW per String
Solarex	MSX-64	24	497	1.5
Siemens	M-53	24	521	1.3
AstroPower	AP-67	24	494	1.6
ASE Americas	GP-50	6	372	1.7

Smaller PV modules (Solarex, Siemens, AstroPower) would be panelized into larger sections. Large area modules will not have to be panelized prior to shipment. In some cases, the panelized sections or large area modules can be mounted onto shop fabricated structures and pre-wired before shipment. The final configuration of pre-assembled arrays and structures will depend on shipping size limitations.

Support Structure Options and Configurations

The PV array support structure is an important component in the overall system design and installation. The design of the support structure is closely linked to the configuration of the PV array. The design of cost-effective rooftop structures for PV arrays has been an elusive goal because of the lack of standardization and relatively limited experience. The diversity of residential and commercial rooftop materials and structural configurations, as well as building code requirements, has only compounded the difficulties of developing cost-effective designs. It is unreasonable to expect that a single design could be capable of satisfying all structural design, building code and performance criteria across the country. The approach taken by the development team is to offer flexible options which can satisfy a range of requirements, can be easily modified and are inherently simple. Two options are available for systems deployed in Phase 2. These are described below.

1. ***Ballasted Roof Jacks***: Ascension Technology has developed and installed numerous ballasted roof jack mounting systems. This system utilizes a series of galvanized steel "trays" filled with ballast to anchor the PV arrays. Each tray is fitted with a roof jack which is designed to accept panelized or large area modules. Ascension Technology has developed array drawings and electrical interface drawings for Solarex, AstroPower and

ASE Americas PV modules. The ballasted roof jack mounting system is best suited to retrofit applications.

The ballasted roof jack mounting system can be used on flat roofs with the capability of carrying between 7 and 14 pounds per square foot of additional dead load.

2. *Pre-fabricated Support Structure*: The alternative to the Ascension ballasted roof jack system is a pre-fabricated steel support structure, suitable for both retrofit and new construction applications. The PV array support structure will be a "monotube" structure consisting of a single 30 foot section of 10 or 12 inch Schedule 40 steel pipe. Crossarms will be used to support the panelized PV modules. Each structure will support a total of about 3 kW of PV modules. The support structure would be used in cases where :

   a. Ballasted supports cannot be used due to roof loading limitations, or local code restrictions;
   b. Other interferences require an elevated array;
   c. An array would be installed on a new building; or
   d. A new roof is being installed.

The design of the proposed structure emerged from an investigation of steel structures for one to three story, low-rise commercial buildings. These buildings are typically designed with column bay spacings ranging from 20 to 30 feet. For arrays with moderate tilt angles (10 to 20 degrees above horizontal) modifications to structural framing are usually not required if the loads are transferred directly to the building columns. Based on this finding, each pre-fabricated structure can be mounted to two simple stanchions welded to the building columns. There are currently some limitations on this design:

1. Generally, each structure must be installed over two separate columns, i.e., two PV support structures cannot share a common center column. This is because the center column(s) will experience twice the loading of the outboard columns. While such installations are not necessarily excluded, they must be analyzed case-by-case.

2. Because the structural attachments require cutting through the roof and welding, installation of the attachments must generally take place when the building is unoccupied. The potential for roof leaks exists, although this can be controlled through the use of qualified contractors.

This structure utilizes low cost, readily available steel components, and requires only simple fabrication techniques. A sketch of the proposed structure is shown in Figure 13. Because the structure can be shop assembled and pre-wired, field labor is minimized. The design of this structure also lends itself to variations which can be used in parking lots and other open areas.

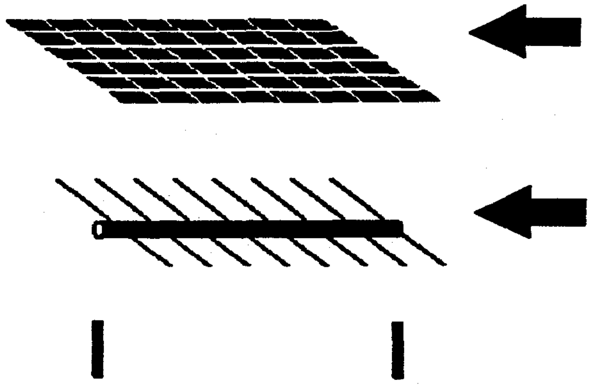

FIGURE 13

AC Battery Module Design and Functional Specifications

The AC Battery module used in the demonstration system required several modifications to make it better suited to commercial applications. An improved version of the AC Battery module for dispatchable PV applications was completed under a contract amendment. Several new features which address the shortcomings of the original unit are described below.

1. The nominal AC Battery performance characteristics are 25 kWh of energy storage over a 4 hour discharge period. These overall specifications will be retained, although improved batteries will be used (Delco AES 2010 in lieu of the original AES 2000). The unit's inverter capacity is presently set at 32 kW. An inverter with less capacity may be better matched with the battery and PV array, resulting in lower inverter costs. This will be determined later, once more operational data is available

2. Each AC Battery module will be configured with a DC-to-DC converter capable of up to about 14 kW input. An option for a 7 kW DC-to-DC converter is under consideration.

3. The AC Battery module control system will include all protective and control system functions, and can be remotely dispatched by either the utility or a building management system. The operator interface will be a simple keypad located on the module instead of the microcomputer used originally.

4. The unit will also be capable of charging from either the PV array, the utility grid, or a combination of both sources. This will assure that battery charging is always accomplished in a controlled manner, which will help extend battery life.

System Packaging

The dispatchable PV system developed under this program will consist of modular "building blocks." A typical building block, shown schematically in Figure 14, includes a PV array which can range in size from 6 to 12 kW (depending on the local solar resource), and a battery/inverter module. The battery/inverter module includes 25 kWh of battery energy storage, a 32 kW inverter, and system controls. Because these units are modular, they can be combined as necessary to meet specified peak shaving requirements. For larger installations, building block units can be containerized. Each container is capable of storing up to 150 kWh of energy, with a maximum output of 192 kW. Modularity also reduces the amount of field labor required for installation.

There are two basic units requiring installation -- the PV array and the battery/inverter module. If a rooftop PV array installation is desired, either the ballasted tray system or the pre-fabricated structure can be used.

Individual battery/inverter modules would normally be installed in a service room inside a building. The unit is virtually self-contained, requiring a small vent port, and electrical connections to the PV array and the building or utility electrical distribution system. Containerized systems would normally be provided as outdoor, pad-mounted units. Containerized systems include HVAC for temperature control. The typical system output voltage is 480 VAC, 3 phase, 60 Hz, although other output specifications can be accommodated. Installation of a complete system is expected to take several days from the arrival of the equipment.

Because the system is modular, a wide range of output specifications can be met without difficulty. One of the advantages of the containerized system is that it can be used to provide peak shaving service to individual buildings, or on utility distribution feeders. In this way, the system can be considered a distributed generation unit.

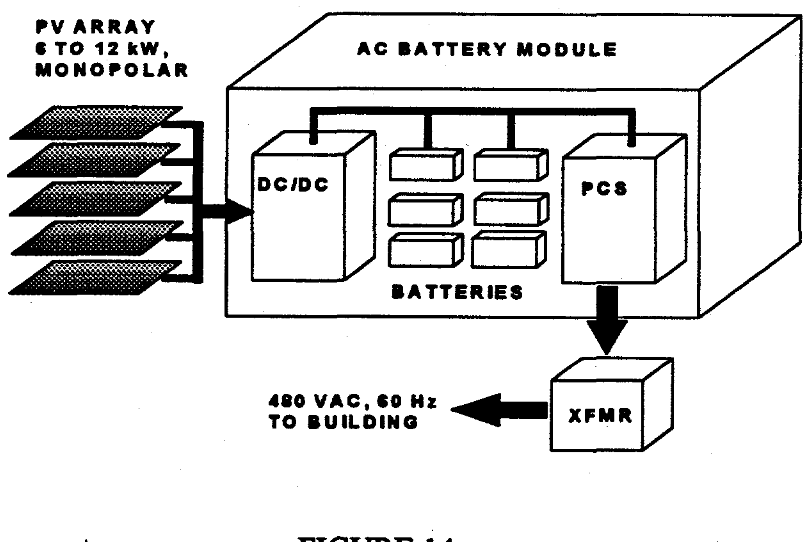

FIGURE 14

Near-Term and Mid-Term Cost Estimates

Market assessment work performed by the Applied Energy Group, as well as work performed by CEEP and others have helped to establish the value of the dispatchable PV system under different ownership, electric rate and payback scenarios. As expected, there is a very wide range of values for the system. Table 4, which summarizes the benefit/cost ratios for several case studies, shows that in areas where electric rates are high, the system cost is near the break-even point already for utility customers. In areas with more moderate electric rates, the benefit/cost ratio is lower. For benefit/cost ratios ranging from approximately 0.5 to 1.0, the implied system values range from approximately $50,000 to $100,000 per unit. Assuming that 10 kW PV arrays are used as proposed in Phase 2, this translates to a range of $5,000 to $10,000/kW. This range is important because it helps to set the targets for the cost of producing dispatchable PV units for the domestic market. Table 6 presents cost estimates for fully installed units now and in the near future. These estimates are, of course, sensitive to production levels, which can change significantly if units are sold overseas. In certain areas of the world, the cost of PV-generated electricity is already competitive with conventionally generated electricity. If a significant number of units are sold outside of the domestic market, the cost of production could be much lower in the near-term.

TABLE 6

DISPATCHABLE PV SYSTEM COST ESTIMATES

Time Frame	System Cost Range ($/kW)	PV Module Cost Range, PTC ($/kW)	Balance of System Cost Range ($/kW)
Base (1994)	10,000	4,300	5,700
1996	8,500-9,500	3,900-4,200	4,600-5,300
1997	7,000-8,000	3,200-3,600	3,800-4,400
1998	5,500-6,500	2,500-3,000	3,000-3,500

The estimates above are based on an internal study of PV module suppliers and trends in the PV market. Based on recent announcements of manufacturing expansions and technology improvements, the projected costs of PV modules are reasonable and may be conservative. Future balance of system costs are more difficult to estimate, although as PV manufacturing accelerates, it is reasonable to expect that the various BOS component costs will also decrease. A major uncertainty is the response of the international marketplace. As demand for PV systems and components increases around the world, short-term prices may actually increase until manufacturing capacity catches up to demand. In general, the projected costs for the dispatchable PV system are achievable.

Task 3 - Market Assessment

The major work items under this task are to assess the local, regional and national markets for the dispatchable PV peak shaving system, assess competing alternatives, and to assess market entry options. Market assessment work was done with the assistance of the Applied Energy Group (AEG). A draft of the final market research report was submitted on April 27. A final version, incorporating Delmarva comments, was submitted in early June. In addition to the market assessment work performed by AEG, the University of Delaware's Center for Energy and Environmental Policy (CEEP) examined the economics of "multiple-use" systems in which the dispatchable PV system could be used for emergency and back-up power.

APPLIED ENERGY GROUP MARKET RESEARCH

A summary of the results of the AEG market research is provided in this report. In general, all of the customer groups surveyed saw considerable merit in both PV technology and the system as configured by Delmarva. Based on AEG's research, there are virtually no concerns among potential Delmarva customers that PV technology will work, mainly because of its inherent simplicity. The modularity of the system was attractive because it can be useful to a wide range of utility customers. Nearly all of the customers and trade groups interviewed agreed that peak shaving is a good application of PV technology because it offers an environmentally "friendly" way to control utility bills. In addition, utility endorsement of any energy technology used on customer premises, including PV, is important. To utilities, the system can also be used for distributed generation. However, for the vast majority of Delmarva's own commercial customers (and probably the customers of other utilities), a 2 to 5 year payback period is still the primary criteria for making decisions about investments in energy systems and equipment. The cost of the technology therefore remains as the most significant barrier to its adoption.

A quantitative analysis helped to identify the size of the potential market. The market quantification analysis did not attempt to take early adopters into account. Instead, the basic approach was to examine the highest value of the dispatchable PV system based on building load shapes, electric rates and weather. This analysis focused on commercial business types (based on SIC codes) in three geographic tiers - Delmarva's service territory, the mid-Atlantic region, and the entire country. The primary result of this analysis is an estimate of the number of commercial buildings in each of the three tiers with the highest potential to adopt the system for economic reasons. Table 7 summarizes these results below.

As shown in Table 7, the size of the potential market for the dispatchable PV system is very large within the U.S. commercial sector. Assuming a relatively low penetration rate of 5 percent of all of the high-potential adopters to account for technical limitations (inappropriate building orientation, unsuitable structure, shading, etc.) and other market acceptance factors, the market is still substantial. At a 5 percent penetration, approximately 40,000 systems would be installed, requiring a minimum of about 400 MW of PV modules. In order to approach these figures, the installed cost must be reduced to between $3,100 and $7,700/kW. The upper end of this range is probably achievable by about 1998.

TABLE 7

SUMMARY OF MARKET RESEARCH RESULTS

Region	Total Number of Buildings	High Potential Adopters	Percentage
Delmarva	27,520	1,980	14
Mid-Atlantic	1,157,405	215,003	19
Nation	5,876,079	818,317	14

Not withstanding efforts to reduce the cost of the system, the cost barrier can be overcome initially by increasing the value of the system and/or by seeking out "early adopters." These approaches are described in greater detail below, in conjunction with additional information in Appendices A and B.

COMPETING TECHNOLOGIES AND VALUE-ADDED FUNCTIONS

As part of its scope of work under the PV:BONUS contract, the University of Delaware's Center for Energy and Environmental Policy (CEEP) studied the value added to the dispatchable PV system when its use is expanded to include emergency lighting and backup power. Depending on the application and the cost of competing alternatives, the value of a multi-functional system can be as much as three times higher than a dispatchable PV system alone. The methodology employed and the detailed results are contained in Appendix B.

This result has important implications for additional system development and market entry strategies. One of the highest valued service functions is emergency power for computers. Based on the costs of today's UPS systems, the current cost of dispatchable PV systems is nearly competitive. However, if a dual purpose PV system capable of being used for peak shaving and emergency service is to be made available, then considerable work is necessary to understand this market niche, along with the product requirements. While the system may be competitive with other emergency/backup systems, such as emergency lighting and UPS systems, it is not presently competitive with conventional engine-generators. This means that wherever brief service interruptions can be tolerated prior to starting an engine-generator, the engine generator will probably be the preferred option.

Task 5 - Product Development and Testing Plan

The major work items under this task are to develop manufacturing flows, assess technical and institutional milestones and to develop cost and other resource estimates for scaled up manufacturing.

DEPLOYMENT AND TESTING PLANS FOR PHASE 2

Objectives of Phase 2 Work

Phase 2 of the PV:BONUS Program is an important step in refining and commercializing the Dispatchable PV Peak Shaving System. There are several technical and business objectives which establish the foundation of the Phase 2 Statement of Work. These overall objectives are summarized below:

1. Install and measure the performance of at least four Dispatchable PV Peak Shaving units to validate both the conceptual and hardware designs on a larger scale;

2. Identify technical improvements and further cost reductions necessary for commercial introduction in Phase 3;

3. Identify and analyze economic and policy strategies which facilitate the commercial introduction of the system;

4. Develop the strategic alliances, manufacturing and support infrastructure necessary for production and installation; and,

5. Acquire the market knowledge and develop the marketing plans necessary to focus on "early adopters."

These objectives form the basis of specific tasks listed in the following summary of the Phase 2 Statement of Work.

TASK 1a - Installation of Prototype Systems

Delmarva Power, with Ascension Technology and the AC Battery Corporation, will furnish the equipment and engineering services necessary for the installation of at least four (4) Dispatchable PV Peak Shaving Systems. Initial contacts have already been made with prospective customers. Although final sites have not been selected, it is highly probable that at least three of the systems will be installed at facilities outside of the Delmarva Power service territory.

For each system, the following equipment and services will be provided to the purchasers:

Equipment	10 kW PV Array AC Battery Module Roof Jack or Structural PV Array Support System Monitoring Equipment Miscellaneous Electrical Hardware
Services	System Performance Analysis System Design and Installation Package Installation Supervision and Checkout

TASK 1b - Development of a Grid-Independent Prototype System

In addition to the deployment of four dispatchable prototypes, a fifth grid-independent version of the system will be developed. This is in response to the market research analysis, which showed that significant demand exists for packaged off-grid systems. While the largest share of this market is overseas, a significant domestic market also exists. The basic hardware developed under this task can also be used for multi-function systems, capable of operating in either grid-connected or grid-independent modes. Systems such as these could be deployed as UPS or emergency power systems.

TASK 2 - Refined Policy Analysis

Refined economic and policy analyses are needed to help efficiently focus future resources in the commercialization effort. As a result of work in progress at the University of Delaware's Center for Energy and Environmental Policy it is now possible to model the economic performance of Dispatchable PV Peak Shaving Systems under different ownership and policy scenarios. In addition, the results of Phase 1 work indicated the importance of capturing "multiple use" benefits.

Under contract to Delmarva Power, the Center for Energy and Environmental Policy at the University of Delaware will perform a more comprehensive analysis of the economic value of a Dispatchable PV Peak Shaving System with multi-function capabilities to utilities and customers including emergency lighting, and other back-up functions CEEP will also perform a cash flow analysis from the perspectives of the utility and customer using a spreadsheet analysis tool developed by CEEP.

TASK 3 - Refined Market Research

The Phase 1 market research revealed significant potential "early adopter" market segments. A detailed understanding of these early adopter segments is very important to the successful commercialization of the Dispatchable PV Peak Shaving System. Penetration of the early adopter markets will help to build sales volume and reduce the production costs of the Dispatchable PV System - two critical steps necessary before entering the broader market. These segments include Federal facilities (especially those managed by the General Services Administration), "near offshore" island electric utilities, and "green firms."

Quantitative analysis done during Phase 1 using secondary data sources also indicated significant long-term market potential. Direct market research data will help to refine the preliminary market estimates, and to focus on the most important segments.

Additional market research performed under Phase 2 will include a telephone survey of 100 potential "green firms" with follow-up visits to the top candidates to identify financing options, pricing requirements, contractual requirements and other remaining barriers. In addition, 500 telephone-mail-telephone surveys will be administered in the mid-Atlantic region to identify the non-cost benefits to a broader range of potential customers of the Dispatchable PV Peak Shaving System

TASK 4 - Solar Resource, Building and System Performance Data Analysis

Because it is likely that the systems deployed in Phase 2 of PV:BONUS will be in areas outside of Delmarva Power's service territory, additional solar resource, building and system performance data will need to be collected and analyzed. Using equipment installed under Task 1, data will be collected, analyzed and stored at a central location.

TASK 5 - Battery/Inverter Sub-system Data Analysis and Development

Similar to Task 4, additional data must be collected and analyzed to evaluate the performance of the battery/inverter system. Other enhancements to the battery/inverter module are also anticipated in Phase 2. Finally, the resources necessary to scale up module assembly for the Dispatchable PV Peak Shaving System must be identified. Under contract to Delmarva Power, the AC Battery Corporation will analyze battery/inverter module data to provide a complete sub-system performance profile, including PV array size vs. PCS size, chopper performance, battery storage capacity vs. discharge rate, and other performance parameters.

TASK 6 - Development of System Integration, Marketing and Service Capability

The development of system integration, marketing and service capabilities are important milestones in commercializing the Dispatchable PV Peak Shaving System. This task addresses several commercial and technical issues related to specifying, sourcing, assembling and marketing the system. The proposed sub-tasks will be performed in parallel with Task 1 in order to assure that input from early customers is incorporated. These tasks include the development of array specifications, investigation of PV module manufacturers and technologies and the local development of one or more assemblers. In addition, a refined marketing plan will be developed.

The total estimated cost for the new work proposed in Phase 2 is approximately $1,300,000

APPENDICES

APPENDIX B

EMERGENCY POWER AS AN ADDITIONAL VALUE FROM DISPATCHABLE PV PEAK SHAVING

EMERGENCY POWER AS AN ADDITIONAL VALUE FROM DISPATCHABLE PV PEAK SHAVING

John Byrne, Contractor
Chandrasekhar Govindarajalu
Willett Kempton
Young-Doo Wang

Center for Energy and Environmental Policy
University of Delaware

Prepared for PV-BONUS, Phase I Project:
Ralph Nigro, Delmarva Power
Principal Investigator

July, 1994

Contents

1. Introduction

The Dispatchable Photovoltaic Peak Shaving (DPV-PS) system configuration includes battery storage to assure its dispatchability while maximizing its power at load peak. The battery storage component of a DPV-PS system could additionally provide customers with on-site power for critical functions in the event of grid power failure. Most commercial buildings now purchase some form of emergency power, typically, emergency lighting. Since DPV-PS could potentially obviate or reduce the need for that purchase, it can increase the value of DPV-PS systems to building customers.

Three emergency power options are reviewed below. All are widely used in the commercial sector. Each case examines typical system configurations and the value provided by current systems to customers. The functions of emergency power options are as follows:

1. Emergency lighting, especially lighting in corridors and stairways, to permit exit from a building. Emergency lighting systems (ELS) are designed to switch on automatically during power outages, or during any local problem in the building that interrupts power.
2. Uninterruptable power supplies (UPS) for computer operations. Most of these are sized to provide only enough energy storage to ride out short outages (approximately 10 to 30 minutes) or to permit orderly shutdown of network and file services.
3. Power for continued commercial operations. Emergency power systems may be purchased in order to allow normal operations, for example cash register sales or transaction processing, to continue throughout a power outage.

These three types of systems differ in the nature of customer needs being met, technical requirements, value, and economic cost. Metrics are developed for measuring the costs and value of each service and evaluating the possibilities of DPV-PS meeting these needs, including relative costs and potential opportunities or barriers as seen by customers.

2. Customer needs for emergency power

This section considers three emergency power applications in detail. The value of each application is defined and the characteristics a DPV-PS must meet to satisfy customer needs are delineated.

A. Emergency lighting Commercial buildings are required by code to provide lighting for safe occupant exit in the case of power loss, primarily in halls and stairways. BOCA code requires that this lighting operate at least one hour, although available systems provide from 1.5 to 4 hours. Typically, these are self-contained modular units, with charger, battery and lamps in one box. Some systems have centralized batteries with conduit to the lighting. The centralized systems would be more adaptable to DPV-PS systems, which would have centralized batteries. Due to the need for cabling, centralized systems are most economical if designed into the buildings initially. But DPV-PS systems could also replace modular units under certain circumstances.

Three vendors were contacted (Brite-Lite, Lighting Design Center and United Electric Supply).

B. Computer UPS We consider both a PC-sized unit and the less common but higher-value, larger sized UPS systems for minicomputer or data center users.

Computer UPS can supply either a few minutes of power, intended to allow a rational shutdown, or much longer, to allow continuing computer operations throughout a power outage. UPS systems are rated by load, number of minutes runtime, and switchover time (from grid failure to emergency power activation). Protection from surges or spikes is another service advertised and provided by many of the UPS units. Such protection may be required by only a minority of customers, for example those in more rural areas.

Vendors contacted for this paper (American Power Conversion and Controlled Power Company) advertise very short switchover times (2-8 milliseconds). Advertisements from one vendor claim that "sensitive" electronic equipment can be shut down by an 8 msec blackout, but AC Battery's research finds that almost all computers and electronic equipment can tolerate 5-8 lost cycles (that is, 80-130 msec).

Some UPS systems come with software to shut down the computer system automatically. Some units are integrated, with a single box enclosing plugs and switches, battery charger and inverter, and the batteries themselves. Others have power conditioning and plugs in one box, and batteries in a separate box.

C. Power for continued commercial operations. High-volume stores, or those providing emergency services, may invest in emergency power for business reasons. We examine in detail the case of a retail grocery, whose investment in emergency power is justified by the high-volume, high-turnover nature of the business, and by the high costs incurred (in labor, loss of perishables and customer satisfaction) if customers are forced to leave the store without ringing up their purchases. In the case examined, emergency power was provided by a natural-gas fueled generator. This provides emergency power at lower capital cost than batteries, but requires up to several minutes to switch over to emergency power. A several-minute delay is acceptable in this case, as cashiers (and customers) wait briefly, then resume operations.

The Appendix provides more detail on the technology of each application, and quantitative analysis of the characteristics and costs.

3. Comparison metrics

Each system we analyze is rated by kW and kWh. Whereas power generation equipment, including PV, is typically compared on a $/kW basis, the cost of storage is rated by capacity. Thus, $/kWh is a good metric. The kWh ratings here are different than those of conventional power units, as they are based on the required energy storage of the unit per emergency use.

The required design energy storage depends upon the time during which the equipment is intended to operate. For example, if a retail store has a 10 kW generator with a fuel tank capable of running the generator 24 hours, but the store's policy is to shut down after 3 hours of power-off to protect against customers buying spoiled food, we calculate that energy system at 10 kW x 3 hours (30 kWh), not its technical capacity of 10 kW x 24 hours (240 kWh). This required storage rating dictates the size of the battery component a DPV-PS system must include to provide equivalent service.[1]

This approach allows us to compare different systems meeting divergent needs on comparable metrics of kW, kWh, and capital cost per kW and per kWh. The following table compares the different types of systems and, within the emergency lighting type, compares several different brands of emergency lighting. O&M costs for some units amounts to 30% of the O&M costs. Data and assumptions are spelled out in the more detailed cases discussed in the Appendix.

TABLE 1
Comparison of Energy Storage Costs for Emergency Power

Type	System cost ($)	O&M cost ($/yr)	Power (kW)	Design duration (Hrs)	kWh per Use	Switch-over time	Capital cost $/kW	Capital cost $/kWh
Emergency Lighting (High)	35	5.8	0.0054	3	0.016	0.1-10 sec	6,480	2,160
Emergency Lighting (Low)	67	12.0	0.0120	3	0.036	0.1-10 sec	5,580	1,861
Computer UPS (PC)	799	103	0.315	0.33	0.105	2 msec	2,536	8,590
Computer UPS (mini)	24,144	1,170	10	0.45	4.5	< 8 msec	2,414	5,365
Generator	11,869	100	20.0	3	60.0	1-15 min	593	198

Note: See Appendix for details.

The summary table indicates that current markets place a premium value on in-building emergency power, far above values common in utility calculations. There is also more than a ten-to-one difference in prices charged within the emergency power market (admittedly, for very different functions). The largest difference in cost is between a back-up combustion generator, at roughly $600 kW, and battery-based systems, at $2,500 - $6,000 /kW. The cheaper generator technology is only possible at larger scales, and when a several-minute interruption is permissible. The more expensive battery-based systems are required for small units (modular

[1] Actually, DPV-PS battery storage may be sized above the required storage rating of an emergency power application to assure the system's ability to satisfy multiple objectives and/or to optimize storage from the PV component.

emergency lighting) and in applications requiring fast switchover time (computer UPS and, to a lesser degree, emergency lighting). Within the computer UPS and modular lighting categories, price differences are smaller, and primarily related to the size of the unit.

4. Comparison to DPV-PS

Can DPV-PS meet some or all of the functions of emergency power? There are both equipment and marketing issues. Delmarva Power's current PV-BONUS 1A unit can be modified according to the manufacturer of the AC Battery module to serve the functions described here.[2] If it were modified, there are still questions from the customer's perspective, as to whether the DPV-PS package provides equivalent service at a competitive price.

One sizing issue is that the reservoir of usable power in a DPV-PS configuration fluctuates. For example, lead-acid battery electrochemistry limits depth of discharge in order to prolong battery life. The amount of energy which can be drawn without any battery damage is called usable energy, and the total amount available if battery damage is acceptable is called available energy. Normal operation of the DPV-PS unit anticipates discharging to a baseline discharge. Even at this level, some usable energy remains for emergency power applications.[3] Since emergencies would not typically occur at the lowest state of charge, the typical emergency energy available would be much greater than the minimum guaranteed energy. Also, if emergency power were needed at just the time of maximum discharge of DPV-PS batteries, added cost would accrue to the DPV-PS in the form of reduced battery life.

If maintenace of the DPV-PS system is provided as part of the total package, it offers an additional advantage. All dedicated emergency power systems require some form of maintenance. Battery-based systems require regular battery testing and battery replacement approximately every 4 to 5 years. Bundling this testing and maintenance requirment into the DPV-PS system would be desirable to the building customer.[4]

5. Relevance to Product and Marketing Decisions for DPV-PS

All three emergency power functions reviewed here could potentially provide added

---

[2] Robert Flemming, AC Battery, personal communication, June 1994.

[3] This terminology and information was provided by AC Battery.

[4] Economic analyses conducted to date on the peak-shaving application designed by the Center for Energy and Environmental Policy and Delmarva Power has assumed utility maintenance. See, e.g., Byrne et al., 1993, "Commercial Building Demand-Side Managment Tools: Requirements for Dispatchable Photovoltaic Systems," in *The Conference Record of the Twenty Third IEEE Photovoltaic Specialists Conference*, Louisville, Kentucky and Byrne et al., 1994, "PV-DSM as a Green Investment Strategy, *Proceedings of the Fifth National Conference on Integrated Resource Planning*, National Association of Regulatory Utility Commissioners, Washington, DC.

opportunities for marketing DPV-PS. Some of the marketing advantages are identified below.

A. Emergency Lighting. Modular ELS units are sold at the same high costs as computer UPS systems, but are very easy to install and maintain. Furthermore, their distributed nature makes them robust even to major building disruptions (e.g., fire in the service room). On the other hand, modular installations require battery testing and replacement for a dispersed set of lighting units. This can add considerably to the O&M cost. DPV-PS can be modular in operation by distributing at least a portion of the battery bank to different sites in a building and connecting the dispersed storage to separately wired PV panels.

However, a centralized emergency lighting system would seem to be a more logical match for DPV-PS. Such a system would have centralized battery storage with conduit to individual lights. However, this would be most economical in buildings for which the DPV-PS system is being offered during the design phase, or a replacement of an existing centralized ELS. Retrofitting a centralized DPV-PS-powered lighting system to a building already fitted with modular units could be difficult.

Marketing an ELS function as an added benefit of DPV-PS seems the most straight forward of the three emergency power applications investigated here. ELS does not involve complex design or service criteria, as computer UPS does (see Appendix), and has an established market because it is mandated by all states. Service guarantee could be similar to that provided by current manufacturers.

Market potential can be rated as promising.

B. Computer UPS. This is a high-value application which can be met by the DPV-PS system (with minor equipment changes).

The dual demands of power from DPV-PS—for peak-shaving and emergency power—will require further thought and testing with customers. However, potentially it could be sold under a guarantee of supplying sufficient power (e.g., 1-5 minutes) to permit orderly shutdown. In many cases, it should be possible for computer UPS service from DPV-PS to allow continuous operations for extended periods during a power outage. It may be worthwhile to conduct an analysis of the timing of commercial power outages compared with peak shaving needs, to arrive at a figure for the probability that only minimum storage would be available at the time of an outage. More complex controls could be built in; for example, overriding the peak-shaving mode of operation when a UPS order is given by a customer. Similarly, the customer might have an override switch allowing the DPV-PS system to use all available battery power, at the cost of reduced battery life or even battery damage, in order to meet extended emergency computer UPS needs. Such options would increase the value of the DPV-PS system by providing additional emergency power when the customer is willing to pay for it, an option not provided by separate UPS systems.

Another issue may be vendor credibility. Network administrators or MIS managers (Management Information Systems) may perceive a company which specializes in UPS to be more credible than a vendor of a PV power unit. It would help if the vendor were conspicuously identified as a division of the electric utility, since electric utilities generally have high credibility in such technical matters. This is certainly a solvable problem, since some utilities have already entered the business of selling or leasing UPS systems to their customers.[5]

Market potential is probably less strong than ELS but well worth additional investigation.

C. Power for Continued Commercial Operations. The case we examined was a retail grocery using an internal-combustion generator. As long as the customer can tolerate the longer switchover times, the generator option is inexpensive and offers long duration for continued operations (energy is stored more economically in fuel than batteries). Therefore, the DPV-PS would offer little added value if it replaced a generator.

Nevertheless, the market for continued commercial operations is diverse. Some potential customers would not want a generator due to noise, pollution, hazard to employees from rotating machinery, etc. As with computer UPS systems, for this function some customers might find it attractive that they were guaranteed a certain minimum period of power supply, but that a longer time would be available in most cases.

More generally, customer functions which would benefit from having uninterruptible power should be further investigated as part of a DPV-PS marketing strategy. These may include services not now provided, and that the customer may not have considered to this point. Uninterruptible power can be a clear benefit that increases the value of DPV-PS systems and which can draw support from additional managers in a customer's organization.

Further study is needed before market potential of this category of emergency power can be fairly assessed.

[5] In Florida, Tampa Electric has leased over 100 UPS units to its customers. Baltimore Gas and Electric is currently providing UPS systems to its customers.

APPENDIX

CASE I: Battery Powered Emergency Lighting Systems

We describe the characteristics of two types of emergency lighting systems, centralized and modular. Lighting costs can be accurately estimated from manufacturer data for modular systems but not for centralized ones, so we provide cost data only for modular units.

Case IA: Centralized Emergency Lighting Systems

Centralized emergency lighting systems have a centralized battery and charger. The lighting load is powered by this unit in case of power outages. The emergency lighting requirement itself is determined based on the building layout. Costs can be established only with reference to a specified building design. The centralized battery and inverter capacity of the emergency lighting system could be replaced by the battery and power conditioning unit which form a part of the DPV-PS system.

Case IB: Modular Emergency Lighting Systems

Emergency lighting systems are also available as independent units comprised of lamps, battery and charger unit. Typically, these modular units are rated at 6V and 12V and have two 6 W lamps as light sources. 12 V units are typically used in industrial establishments. In case of power failure, this system is designed to provide light for about 3-4 hours. Data collected from various retailers is tabulated below. The capital cost comparisons per kWh are based on the costs paid for typical usage time capacity of 3 hrs. We estimate operating and maintenance costs as a $ 25 expenditure once every five years for battery replacement. The batteries usually carry a 3 year warranty.

TABLE A-2
Cost Comparisons of Modular Emergency Lighting Systems

Manufacturer	System Cost($)	Bulb Wattage(W)	Capital Cost in $/kWh	Capital cost in $/kW	Design hours of use
Brite-Lite 6V	49.0	6 W	2,722.0	8,160.0	3 hrs
Brite-Lite 12V	75.0	25 W	1,077.0	3,000.0	3 hrs
Lighting Design Center	67.0	12 W	1,861.0	5,580.0	3 hrs
United Electric Supply	35.0	5.4 W	2,160.0	6,480.0	4 hrs.

CASE II: Uninterruptable Power Supply for Computers (UPS)

We consider two size ranges of computer UPS systems: PC or network server, and minicomputer. These span a 300 W to 20 kW range (one that is likely to be met by a DPV-PS system of the type now contemplated).

Case IIA: Personal Computers or PC Network Servers

A PC-size UPS can be purchased when any single office worker performs computer functions that are considered critical. Considering an office building as a whole, a typical size might be 50 PCs on network and 3 PC-type file and print servers. In the PC-size market, American Power Conversion is the largest manufacturer. The example building could be fitted with three UPS units—three American Power Conversion "Smart-UPS 900" systems (no UPS on individual workstations) and a criterion of twenty minutes of emergency power before shutdown.

We assume that the DPV-PS battery and power conditioning completely replaces the UPS system, rather than using the battery of the DPV-PS in conjunction with the UPS power-conditioning and switching. This means that the DPV-PS system would have to be capable of fast switchover, and the DPV-PS vendor would have to convince the customer that the system would reliably provide "uninterruptibility".

Our contact manufacturer provided no guarantee on uninterruptible power. It was stated that there was no way to distinguish customer errors (e.g. overloading) from failures of UPS equipment. They did provide a $25,000 guarantee if customer equipment was damaged by surges or spikes.

Unit specification: APC Smart-UPS 900[6]

- List price $799 (discounts available)
- Three units typically installed for servers on a 50 PC network
- Each unit powers a single IBM PS/2 80 file server
- Units draw 3/10 amp, 36 watts, standby (without charging) (at $0.09/kWh, running costs are $30/year)
  (larger battery unit increases only to 0.45 amp)
- Maximum AC output 630W @ 0.7 power factor (900 VA) can run 7 minutes
- Half power, 315W @ 0.7 power factor can run 20 minutes (note that the relationship between runtime and power output is nonlinear)
  (thus, 0.074 kWh of energy at max, 0.105 kWh at half power)
- Batteries in 900 unit: 4 x 6V, 10 amp-hour batteries; $77 replacement cost for set of 4 (thus, 0.24 kWh total battery storage per unit—more than twice the output energy)

Alternative unit specification: APC SmartCell External Battery Supplement

- To increase storage, one can add external battery packs (chain up to 10)

---

[6] Data from manufacturer (dominant in PC UPS market): American Power Conversion, West Kingston, RI (800) 800-4272. Information also from technician at 1-800-788-2409.

- Each single external battery pack is 4 cells, 12V, 17 amp-hour, total cost $599 list
- Thus, cost per kWh DC is $737 for smart cell, more than twice the cost of 900 battery.

Operating and maintenance costs, single 900 unit:

- Manufacturer states 3.5 - 4 years to replace battery, we take 4
- Battery cost at $77, plus 1 hour time of system manager ($20), total $97 or $24/year
- Standby electricity is 36 watts; if always plugged in, 315 kWh/year @ $0.07/kWh = $22/year
- Assume one unit failure per 7 years, requiring $400 repair = $57/year
- Thus, total O&M cost is $103/year (battery replacement represents 20% of O&M)

Summary for a single UPS 900:

Key assumptions: running at 1/2 load; 20 minutes available at 315W
Power: 0.315 kW
Emergency Power Time: 20 minutes
Delivered energy: 0.105 kWh
O&M cost: $103/year (estimated from battery+repairs+electricity)
System cost: $7609/kWh; $2536/kW
Battery cost: $733/kWh; $244/kW

Case IIB: UPS for Larger Computer

Larger computer UPS systems would be sized for machines such as a VAX or small IBM mainframe, or for a data center including a central computer and peripheral equipment. The manufacturer contacted for this case (Controlled Power Company) has a complete line of large computer UPS systems. Their single-phase units range from 2.17 kW to 20 kW. We review both ends of this range here. They also have a line of three-phase systems, 120/208 volt output, ranging up to 500 kVA.[7]

For this manufacturer, we estimate O&M costs based on the cost of a five-year service contract; this is the equivalent of out-sourcing O&M. Of the variety of service contracts offered, the ones quoted here are comprehensive; they are priced on a five-year basis and include battery replacement when needed. This manufacturer provides no guarantee to compensate for data loss, only repair or replacement of their equipment within the warranty period.

The next larger commercial systems would use different technology: pulse-width modulated, double-conversion (input is always converted to DC and back to AC, even during normal power conditions). These systems are available in the 10 kVA to 500 kVA range, single

[7] Information from Controlled Power Company, 1955 Stephenson Hwy, Troy, MI 48083, 1-800-642-9624.

and three-phase.[8]

Regarding technical specifications, they advertise switchover time as less than one-half cycle (8 msec). They advertise "high" AC to AC efficiency of "up to 95%". Since the power to the computer always runs through the UPS, we assume that this represents a 5% loss during computer operations. To calculate the ongoing energy costs, we assume that the computer load is 1/2 the maximum UPS load rating, electricity is 8 ¢/kWh with no demand charge, and that minicomputers or mainframes would be operational 24-hours a day, 365 days per year. If these assumptions are correct, for the two larger systems, the energy costs of UPS are significant--40% as much as the O&M costs.

The table compares three models, spanning the range of sizes of single-phase units. Calculations of cost per energy unit are based on half-load usage, since running these units at full load dramatically shortens time available (for example, the HV14000 runs 16 minutes at half load, but only 6 minutes at full load, so the half-load condition provides 33% more energy).

TABLE A-1
Cost Comparisons of Single-Phase Computer UPS Systems

Model	Full load kW	Minutes @ 1/2 load	Capital cost	O&M $/year	Energy cost $/year	Capital cost $/kW	Capital cost $/kWh
MD3100	2.17	32 min @ 1.08kW	$3,695.	$190.	$38	3,421.	6,415.
HV14000	10	16 min @ 5 kW	$11,470.	$430.	$175	2,294.	8,602.
HV25000	20	27 min @ 10 kW	$24,144.	$820.	$350	2,414.	5,365.

[8] Manufacturers for the larger commercial UPS systems are Liebert (Columbus, Ohio) and Exide Electronics (Raleigh, North Carolina). Industrial applications use even larger uninterruptable power supplies, for example, for control rooms or maintaining processes. A manufacturer of these systems is Weiss Instruments in Philadelphia (1-610-647-4650).

CASE III: Emergency Power for Continued Retail Operations

The commercial establishment used as an example for this application is a grocery store (Acme) of 1,500 square meters, having 11 cash registers. The main electrified end-uses in this store are refrigeration, air conditioning and lighting.

The store is assumed to have a natural gas-based emergency backup system, which automatically switches on in case of power failure. It is assumed to take several minutes to start up. This system can supply 20 kW (three-phase) or 13 kW (single-phase) load at 60 Hz and 0.8 power factor. It is sized to meet the energy requirements of cash registers and lighting systems. There is no energy backup for refrigeration and air conditioning systems.

The manager of the store was not aware of the capital cost or operating costs of the generator. During the past year, the generator was used only two times, once for one hour and once for two hours. When asked about use of PV systems for meeting emergency requirements of the store, he felt it would depend on the system's cost-effectiveness.

The generator set consists of a multi-fuel capability engine (natural gas or gasoline), a brushless AC alternator, a control panel, voltage regulating system, a cooling system and a base. The automatic transfer switch which could be used along with the generator set has a utility-to-generator option that enables retransfer of load in 0-30 minutes.[9] This time delay is not sufficient to maintain power to computers achieved by UPS systems.

Specifications of the internal-combustion generator set
Make: Onan
W Capacity: 20 W
Design hours of use: 3(estimated)
Delivered Energy: 60 kWh (based on 3 hours)
Cost of generator plus switch : $ 11,869.00
Operation and maintenance costs: estimated $100/year maintenance and fuel consumption of 9.0 m^3/hr when running, no fuel or electric use when not operating
Capital Cost: $ 198/kWh, $ 593/kW

[9] Contact for data on technical and economic characteristics of the gas generator: Eastern Generators, 1-800-397-1983.

APPENDIX C

ASSESSMENT OF POLICY, REGULATORY AND INSTITUTIONAL BARRIERS TO THE COMMERCIALIZATION OF A DISPATCHABLE PV PEAK SHAVING SYSTEM

ASSESSMENT OF POLICY, REGULATORY AND INSTITUTIONAL BARRIERS TO THE COMMERCIALIZATION OF A DISPATCHABLE PV PEAK-SHAVING SYSTEM

John Byrne, Sub-Contractor
Young-Doo Wang
Willett Kempton
Thulasi Kumar

Center for Energy and Environmental Policy
University of Delaware

Prepared for PV-BONUS, Phase I Project
Ralph Nigro, Delmarva Power
Principal Investigator

July 1994

Table of Contents

This paper identifies typical barriers hindering the commercialization of a dispatchable PV peak-shaving system (hereafter DPV-PS) and describes options for overcoming those barriers. A utility-customer partnership is argued to be a major tool for speeding commercialization under existing constraints.

I. Typical Barriers[1]

Major institutional issues bearing on the commercialization of utility DPV-PS systems include financing issues, owner-tenant differences, technical risks and uncertainties, building code problems, aesthetic concerns, the lack of a DPV-PS system infrastructure, and the lack of information by many of the parties involved. These issues are briefly reviewed below.

- DPV-PS involves high capital costs which increase the purchase price of a new building in which it is installed. Builders, and especially those building for speculative sale, seek to minimize construction costs and may, therefore, judge DPV-PS uneconomical. DPV-PS as a retrofit building technology may, likewise, face financial hurdles. Buldings tenants are unlikely to be willing to shoulder the long-term debt represented by an investment in DPV-PS, and building owners reap few benefits unless demand (kW) elements of their electricity operating costs are significant and borne by them (rather than passed onto, for example, tenants in the building.

- Interest rates charged by existing lending institutions on loans for building euipment are typically higher than those charged for new construction or building purchase. The unavailability of low-interest loans is a disincentive to purchase and install a PV-DSM system with a higher front end cost, even though it could lower operating costs in the long run.

- A major barrier to DPV-PS commercialization is the demand, often, for high rates of return by commercial customers (typically, 5 year paybacks or less are sought for efficiency investments-- see Arthur D. Little, 1993; Greely, Harris and Hatcher, 1990). Additionally, energy costs are in many cases a small fraction of operating costs for businesses. Only high rates of return justify, in such instances, attention to what will be comparatively modest gains to the firm.

---

[1]Detailed discussion of barriers to renewable energy and DSM options can be found in Nadel (1993), Moskovitz (1992 and 1993), Arthur D. Little (1993) and Hirst and Brown (1990).

- Most commercial utility customers are tenants. But investment in energy efficiency is from two to five times more likely when the utility customer is the building owner (Hines, 1990). Furthermore, high turnover rates among tenants are a problem. A survey of 143 commercial sites found 45 changes of occupancy over a two year period, representing 16% per year (Peterson, 1990). Sometimes a building owner refuses to let a tenant install energy-saving equipment even though the tenant would pay 100% of the cost due to a concern that maintenance workers would not be able to work with the new equipment.

- Investing in new PV-DSM systems may be perceived as risky. Users of DPV-PS systems cannot be sure whether these systems will perform as projected without major maintenance problems. Such concerns have been found to be very important to decision makers in all end-use sectors. Risk aversion can affect customer participation in utility DPV-PS programs and might be more important to some than the technology's costs and benefits.

- Building codes and standards are mostly concerned with health, safety and reliability. End-use efficiency is seldom addressed. The efficiency advantage of DPV-PS must therefore compete with mandated building equipment and improvements for customer investment. When building owners must carry out mandated actions, the available capital for discretionary investments (such as efficiency upgrades) is reduced and, consequently, opportunities for DPV-PS are diminished.

- DPV-PS investments are affected by code and standard requirements which relate to height and wind loads, resulting in higher design and mounting structure costs (Arthur D. Little, 1993).

- The spatial requirements for PV energy collection can raise aesthetic questions that impact DPV-PS commercialization. Physical limits on collector area and location for some buildings may also narrow the market potential for this technology. Additionally, basic questions surrounding solar access remain unsolved. This places DPV-PS at an institutional disadvantage in the building investment market.

- The scale of commercialization of DPV-PS technology will almost certainly be limited in the near term by the modest number of firms and professionals skilled in the design, system integration, engineering, financing, operations and maintenance, and construction of DPV-PS systems. In addition, competence and expertise in the manufacture, distribution, and servicing of DPV-PS systems is weak at this time. In general, DPV-PS infrastructure problems are likely to hamper rapid, large-scale commercialization of the technoogy at least for the next 2-5 years.

- Credible information on the performance of DPV-PS technologies is very limited. Such information is critical to those who decide on the commercial deployment and adoption of this new technology, including investors, regulators, building owners/tenants and utilities. In particular, information regarding the technical and economic viability of PV-DSM technologies is often scarce, and the absence of such data can be a barrier to the adoption of such systems.

II. Options for DPV-PS Commercialization

By enhancing the overall economic competitiveness of renewable energy, the commercialization of DPV-PS can be promoted. To bolster private investment in DPV-PS, federal, state or local governments could reduce private risk or increase private returns through tax incentives, energy-efficiency building codes, regulatory reforms, and investment in R&D and procurement. Likewise, reduction in subsidies to conventional energy sources[2] and the recognition of social and environmental costs in conventional energy prices would establish a more accurate market in which DPV-PS would have to prove its competitiveness.

The Public Utility Regulatory Policies Act (PURPA) of 1978 and the Energy Policy Act (EPACT) of 1992 constitute the basic policy framework for renewable energy development in the U.S. Key elements of this framework include: the requirement that utilities evaluate demand- and supply-side options at their avoided costs; the institutionalization of integrated resource planning; the provision of tax credits for renewable energy investment; and regulatory consideration of social and environmental costs of electricity consumption. While these and other policy milestones have been put in place, these are unlikely to mobilize an open and competitive market for DPV-PS systems (see Appendix for regulatory and policy reforms related to DPV-PS applications). The barriers identified in the previous section will continue to thwart efforts at early development of DPV-PS. But new technologies have often had to compete on an uneven playing field. The central question at this juncture is whether and under what conditions PV applications have the best chance of overcoming these barriers.

Not only domestic (U.S.) but also international energy markets have important roles to play in DPV-PS commercialization. European and Japanese manufacturers and markets are major influences on PV development. Multilateral lending organizations, including the World Bank and regional development banks, are and will play a significant role in shaping energy efficiency and renewable energy use in developing countries. These international efforts could open up PV markets, reduce PV system costs and, consequently, enhance PV commercialization.

---

[2]One estimate places the federal subsidy to U.S. energy industries at more than $44 billion as of 1984 (Flavin and Lenssen, 1992).

In general, assessments of the near- to mid-term prospects of PV commercialization are positive. A typical, optimistic view is that of the Worldwatch Institute (1990) which notes that PV cost was 339¢/kWh in 1980, 30¢/kWh in 1988, and estimated to be 10¢/kWh in 2000 and 4¢/kWh in 2030. A less optimistic, but nevertheless positive assessment was recently rendered by Arthur D. Little (1993) which specifically identified utility applications as among the most promising.

PV's future is clearly filled with opportunity,[3] but the current cost of 20-25¢/kWh underscores the challenge to effective commercialization. PV technology needs to gather momentum through innovative market penetration strategies. The commercialization of DPV-PS can be accelerated either through a decline in unit costs and/or a targeting of high-value applications. By penetrating high-value niche markets, PV-entreprenuers will be better able to compete while also contributing to the expansion of PV production facilities. In turn, expanding production capacity drives down costs to open up broader PV markets.[4]

Given current PV costs and technical constraints and under the present regulatory and institutional constraints, the most plausible marketing strategy for dispatchable peak-shaving PV is to form a utility-customer partnership and target the non-residential building sector as the "early" market. The arrangement typical of partnerships appears to fit well with the conditions that are necessary for the promotion of PV in the utility sector. The reasons are as follows: 1.) neither customers nor utilities can justify investing in DPV-PS systems because costs exceed benefits (Hoff and Wenger, 1992); 2.) if the combined benefits of dispatchable peak-shaving capacity to utilities and moderation of electricity costs to customers during the peak-demand period are weighed against system costs, DPV-PS is much closer to cost-effectiveness than expected (Byrne et al., 1994); and 3.) commercial building sector applications offer high value to utilities and customers because the electricity market of this sector is highly sensitive to peak demand costs.

This section focuses on partnership arrangements which foster a closer relationship between customers and utility than typical DSM programs. In the case described below, building owners who are also utility customers are targetted to avoid the frequent turnover rates and owner-tenant conflicts discussed above. The two parties enter into a partnership to share the costs and capture the benefits of DPV-PS applications. Four basic forms of partnership are examined: 1.) a partnership stimulated by a rate adjustments package offered by a utility; 2.) a shared savings partnership in which the benefits of peak shaving are shared between utilities and their customers; 3.) lease-to-own strategy which allows partners to share risks until one party

---

[3]The current world market for PV is around 50 MW, growing 20 to 30% annually in which the United States supplies one-quarter of total production (Kozloff and Dower, 1993).

[4]The Utility Photovoltaic Group (UPVG) has adopted the concept of forward pricing in its TEAM-UP Proposal to the U.S. Department of Energy. The strategy follows the logic of developing high-value markets in order to stimulate increased production and, hopefully, lower unit costs.

is prepared to own and operate the system themselves; and 4.) a Green Partnership which utilities and customers share costs and benefits via a utility-managed limited partnership.

II-1. Rate Adjustment Option

Electric utilities across the country seek to induce customers to participate in specific DSM programs by offering them incentives often in the form either of rebates or lower electric rates. Customers must undertake specific actions to improve end-use efficiency such as the installation of higher SEER-rated HVAC equipment, in order to qualify for utility incentives. The electric utility may provide a rebate on the purchase of such equipment or reclassify the customer making them eligible for a lower electric rate. Rate adjustments can include: lower energy charges, lower demand charges, or demand charges based on the peak demand reduced by the DSM system. In almost all cases the customer is responsible for providing most of the necessary investment and has ownership and responsibility for the maintenance of the equipment.

The adjustment of rates or the provision of rebates frequently is targetted to commercial and industrial customers. An increasingly common focus of these programs is to stimulate faster purchase of load shifting or peak load shaving equipment. In return for the long-term benefits at reduced risk provided the customer through rate adjustments or rebate, the utility expects the customer to contribute a portion of the capital cost of the system.[5] DPV-PS could be encouraged by this mechanism. But its high initial cost may narrow the number of commercial customers who would invest in the technology on this basis.

II-2. Shared Savings Option

Often, consumers might be able to improve the energy efficiency of their operations through investment but are either unable or unwilling to undertake the necessary capital expenditure. This can be due to the relatively high cost of capital to the customer (compared to, for example, a utility), higher perceived risk, lack of information, or other factors. In such cases, shared savings partnerships with an energy service company (ESCO) can be attractive. Typically, these partnerships involve the energy service provider financing all, or most, of the capital investment for energy efficiency improvements. This investment is then recovered, with a profit, by the investor receiving a portion of the energy bill savings of the customer. In many cases, these ESCOs are non-regulated subsidiaries of electric utilities.[6]

The primary determining factor for many shared savings contracts appears to be the size of the initial investment. Small investments typically require shorter periods for their recovery (3-5 years), requiring a smaller percentage of the bill savings received by the investor (30-50%).

---

[5]The maximum customer's contribution would be equal to the net present value of the stream of benefits (at lower risk) accrued during the useful life of the equipment.

[6]A notable development in this area is that the regulatory environment is evolving to allow utilities to enter into such partnerships (Eto et al., 1992).

Large investments typically have recovery periods from 15 to 20 years and 50 to 80 percent of bill savings may be needed by the investor to justify such a high outlay of capital.

The shared savings can overcome the high first-cost problem of PV-DSM, especially if the utility is the investor. This is because the utility has direct access to bill savings and already has a well-established service relationship with the customer. The likely arrangement would be for a utility to propose to purchase the majority of the necessary investment and offering to share a portion of the resulting bill savings on the basis of the marginal benefits it derives from using PV-DSM instead of a generation option. The payback period would probably be the expected life of the equipment, and the share ratio (proportion of savings withheld) would be between 70 and 80 percent at current PV prices. This would require a long-term relationship with the customer which a utility would be capable of. But customers may prefer arrangements which do not presume long pay backs.

II-3. Lease-to-Own Option

To address the long payback issue, shared savings contracts can specify that the customer or utility has the option to buy out the interest of the other after a certain period. Contracts could stipulate that the customer or utility receives ownership of the equipment by paying a specified amount from a schedule that is based upon the number of years that the contract has been in effect. This would create the basis for a lease-to-own partnership. In this partnership, the customer eventually can become the sole owner after a period of time, allowing the initial investor (the utility) to recover its capital contribution by being paid a lump sum. In its application to DPV-PS, the lump sum transfer from customer to utility reflects the remaining value of the utility's initial investment.

II-4. Green Partnership

The Green Parternership[7] is an innovative investment strategy in which customers and utilities contribute to a green investment fund for the purpose of purchasing a DPV-PS system 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 parties (Moskovitz, 1992 and 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.

In green pricing, the customer agrees to pay a premium rate in order to enable more utility investment in renewable energy sources. The Green Partnership asks customers to transfer to an investment fund most of the potential bill savings from the DPV-PS system and

---

[7]For further information on this strategy see Byrne et al. (1994). "PV-DSM As a Green Investment Strategy." *Proceedings of Fifth National Conference on Integrated Resource Planning*. Kalispell, Montana. May 15-18, 1994.

most of the tax savings from the investment. The remaining cash savings might be small, but it may be attractive to customers who are interested in promoting the environment or high-technology as part of their corporate image. The highly-visible nature of this investment may, for some customers, be more important than the magnitude of the economic return.

Under the Green Partnership, the utility would contribute an amount equal to the capacity and distribution benefits that it would derive from the dispatch of a peak-shaving PV system. Typically, these benefits would take the form of avoided costs; i.e., postponed capacity additions and/distribution upgrades. For the utility to contribute its avoided costs, though, it must be possible to sell the capacity and energy freed up by the operation of the DPV-PS system. If no market exists for the freed capacity and energy, the utility might decline to contribute its avoided costs to the partnership in order to avoid potential lost revenues (namely, the revenues it would have earned by selling electricity before the DPV-PS system was put into place). This in all likelihood would limit utility participation to those companies experiencing capacity constraints.

In this arrangement, the customer transfers to the Green Partnership a percentage of the tax and bill savings that could be realized from the operation of the PV-DSM system. In addition, the utility contributes its avoided costs for the credited capacity of the system.[8]

There is, however, a necessary condition of regulatory reform for the successful implementation of the Green Partnership. Typically, state regulators utilize a Total Resource Cost (TRC) test to evaluate utility-sponsored DSM programs.[9] Under this test, transfers between utilities and their customers are generally not counted as benefits.

In the case of the Green Partnership, this would mean that the tax and bill savings contributed by the customer would not figure into the cost-benefit analysis. Our suggestion is that such savings should be recognized as partnership transactions outside the established cost-of-service regulatory framework. In effect, the Green Partnership could be treated as an unregulated affiliate transaction, in which case only the avoided cost calculation and its contribution to the Partnership by the utility would be subject to regulatory assessment. If such treatment were extended to the proposed Green Partnership, technology would be more likely to achieve market penetration in the near term.

---

[8]This does not represent double-counting if 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 <u>not</u> under a utility dispatch requirement (i.e., non-peak days). The Partnership incurs the debt associated with the purchase of the DPV-PS system.

[9]There are several approaches used by electric utilities and regulators to estimate the cost-effectiveness of utility-sponsored DSM programs. These approaches differ mainly in terms of the costs and benefits considered in the calculation of net present values or benefit-cost ratios. These tests are commonly defined in terms of their impacts on participants, non-participants, the utility, and society (Krause and Eto, 1988).

III. Conclusion

DPV-PS systems face a wide array of policy, regulatory and institutional barriers that disadvantage the technology in the electricity market place. But many of these barriers are similar in form to those that affected adversely the economics of earlier innovative technologies. Which reforms in the regulatory and policy areas are appropriate and useful to assuring a fair market evaluation of DPV-PS systems, there are specific options that can be implemented by utilities to spur commercialization in the absence of reforms.

These options involve investment partnerships between utilities and selected customers that utilize already established contractual relations (e.g., the Rate Adjustment and Shared Savings Partnership discussed above). But in addition, new partnerships options (especially, the Green Partnership) offer utilities and selected customers the opportunity to be early developers of this technology by spreading risks and pooling benefits. When reforms subsequently occur, these early adopters will be ideally positioned to take advantage of this promising PV market.

IV. References

Byrne, John, Steven Letendre, Ralph Nigro and Young-Doo Wang. 1994. "PV-DSM As a Green Investment Strategy." *Proceedings of Fifth National Conference on Integrated Resource Planning*. Kalispell, Montana. May 15-18, 1994.

Center for Environmental Legal Studies (Pace University). 1990. *Environmental Costs of Electricity* (New York: Oceana Publications).

Eto, J., A. Destribats and D. Schultz. 1992. *Sharing the Savings to Promote Energy Efficiency*. Lawrence Berkeley Laboratory, Energy and Environment Division.

Flavin, Christopher and Nicholas Lenssen. 1992. "Policies for a Solar Economy." *Energy Policy* 20(3).

Greely, Kathleen M., Jeffrey P. Harris and Ann M. Hatcher. 1990. "Measured Energy Savings and Cost-Effectiveness of Conservation Retrofits in Commercial Buildings." *Proceedings of ACEEE 1990 Summer Study on Energy Efficiency in Buildings* 3: 95-108.

Hines, V. 1990. "Study Shows Conservation Trends in D.C. New Construction." *Energy User News* 15(10): 4.

Hirst, Eric and Marilyn Brown. 1990. *Closing the Efficiency Gap: Barriers to the Efficient Use of Energy, Resources, Conservation and Recycling*. Oak Ridge National Laboratory.

Hoff, Tom and Howard J. Wenger. 1992. *Photovoltaics as a Demand-Side Management Options: Concept Development* (San Ramon: Pacific Gas and Electric Company).

Kilmarx, Mary and Peter Wallis. 1991. "DSM LCP." *DSM Quarterly*. Fall: 22-25.

Kozloff, K. Lee and Roger C. Dower. 1993. *A New Power Base: Renewable Energy Policies for the Nineties and Beyond* (Washington, DC: World Resources Institute).

Krause, Florentin and Joseph Eto. 1988. *Least-Cost Utility Planning Handbook for Public Utility Commissioners* (Washington, DC: National Association of Regulatory Utility Commissioners).

Little, Arthur D. 1993. *The Market for Solar Photovoltaic (PV) Technology*. EPRI TR-102290. March.

Moskovitz, David. 1992. *Renewable Energy: Barriers and Opportunities; Walls and Bridges*. A paper for the World Resources Institute. The Regulatory Assistance Project.

Moskovitz, David. 1993. *Green Pricing: Experience and Lessons Learned.* The Regulatory Assistance Project.

Nadel, Steven M. 1993. "Utility Demand-Side Management Experience and Potential: A Critical Review." *LBL Advance IRP Seminar.* Vol.1.

Nadel, Steven M., Michael W. Reid and David R. Wolcott (eds.). 1992. *Regulatory Incentives for Demand-Side Management* (Washington, DC: ACEEE).

Peterson, Frances J. 1990. "Remodel and Tenancy Changes: Threats to the Reliability of Commercial Conservation Savings." *Proceedings of ACEEE 1990 Summer Study on Energy Efficiency in Buildings* 3: 165-172.

Rowe, John. 1990. "Making Conservation Pay: The NEES Experience." *The Electricity Journal* 3.

U.S. Congress. 1992. *Energy Policy Act.*

V. Appendix

As of 1991, U.S. electric utilities were spending nearly $2 billion per year, representing approximately 1% of their revenues, on demand-side management (DSM) investments. Some utilities were investing 7% of their gross revenues in DSM (Kilmarx and Wallis, 1991). Such a DSM commitment is stimulated to a large degree by policy and regulatory changes. More than 20 states have adopted or experimented with regulatory reforms since 1989 to promote DSM oppotunities.

The passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 was a major contributor to changes in the regulatory environment. Integrated Resource Planning (IRP), also called Least-Cost Planning (LCP), grew out of PURPA and is now well-established in many utilities as an alternative to traditional supply-side planning. The nature of conventional regulation had created a bias in favor of traditional supply-side resources. IRP creates a level playing field in the acquisition of DSM and supply-side resources. The federal reform of utility regulation with PURPA stimulated a variety of state-level reforms.

State-level DSM reforms date back to at least 1980 when Washington State legislation directed that utilities be granted a 2% bonus rate of return on the equity portion of DSM investments and allowed utilities to submit conservation program expenditures as investments, similar to supply-side investments. ERAM, the Electric Revenue Adjustment Mechanism, was proposed in 1981 in California as a means of decoupling the link between base revenue and the level of sales. In 1986, the Wisconsin Public Service Commission adopted a performance-based incentive scheme.[10]

Togehter, these federal and state policy activities established an institutional basis for a DSM market. Without these actions, it is difficult to imagine DSM as having achieved anything like its current market status. Additional federal and state initiatives are identified below which underscore the importance of policy/regulatory reform and the focus and direction of the electricity market.

V-1. Energy Policy Act of 1992

The 1992 Energy Policy Act (EPACT) has several provisions promoting utility DSM programs (including DPV-PS when it effectively acts as an efficiency upgrade to a building's operations-- see Hoff and Wenger). EPACT promotes IRP and also includes such provisions addressing DSM incentives, energy-efficient mortgages, performance contracts and the commercialization of energy-efficient products to enhance energy end-use efficiency of the electricity sector. Key provisions of EPACT are summarized below:

---

[10]The mechanism was designed in such a way that one percentage point additional return on the equity portion of DSM would be received for each 125 MW of demand reduction.

- States must conduct hearings on the merits of requiring electric utilities to employ IRP, a process that would include comparing the life-cycle costs of conventional power plants, energy conservation and efficiency, power purchases and renewable energy sources. [§111(a),(d)]

- States must consider establishing rate structures for regulated electric utilities to encourage investments in "appropriately monitored" energy efficiency, conservation and demand-side management. [§111(a)]

- DOE is authorized to grant up to $250,000 to state regulatory authorities to encourage electricity DSM measures, including conservation, efficiency and load management, and DSM for meeting natural gas supply needs. [§112]

- National Energy Policy Plans submitted by the President in 1993 and afterward shall include a least-cost energy strategy prepared by DOE. The strategy is to set goals and priorities that promote energy efficiency, renewable energy and other energy technologies that reduce greenhouse gas emissions. [§1602]

- Competitive DOE grants totaling $10 million for FY94 and $50 million for FY95 are authorized for helping federal agencies meet the Act's energy efficiency requirements. Agencies are permitted and encouraged to participate in utility incentive programs for gas, electricity, and water conservation, and to negotiate incentives with utilities. [§153]

- DOE is authorized to particioate in the development of revolving funds for energy efficiency projects in state and local government buildlings (up to $1 million per state). To qualify, a state must have "demonstrated a commitment to improving energy efficiency," by, for example, adopting energy codes (specified in Subtitle A) or by raising at least 75 percent of the fund's capital from non-federal sources. [§141(a)]

- If appropriations are available, DOE is directed to make payments of 1.5 ¢/kWh, adjusted for inflation after 1993, for electricity produced by new qualified renewable energy facilities. Facilities eligible for the payment are state-owned generation plants or electrical cooperatives, and must begin operating within the next 10 fiscal years, and each facility may receive payments for only 10 fiscal years after starting operation. [§1212]

- Beginning on January 1, 1993, incentives given to residential customers by regulated public utilities for installing energy conservation measures is excluded from gross income for tax purposes. "Energy conservation measures" are defined by reference to the National Energy Conservation Policy Act of 1978 (P.L. 95-619). For utility incentives to commercial and industrial customers, the exclusion begins on January 1, 1995, and is limited to 40 percent of the incentive for 1995, 50 percent for 1996, and 65 percent after 1996. [§1912]

- The 10 percent business tax credit for solar and geothermal equipment is extended indefinitely. The credit for solar and geothermal equipment was introduced in 1978 as part of President Carter's National Energy Plan. [§1916]

- The Departments of Housing and Urban Development (HUD) and Agriculture (USDA) are to issue energy efficiency standards for residential buildings financed through federal mortgage programs. New buildings must satisfy these standards to receive federal financing assistance. [§101(c)]

- EPACT promotes homogeneous building energy efficiency codes by requiring states to begin upgrading their residential and commercial building energy efficiency codes [§101(d)].[11]

- A task force on energy efficiency and private mortgages, established in 1990 by the Cranston-Gonzalez National Affordable Housing Act, is to make recommendations on notifying potential home buyers about energy-efficient mortgages (EEMs), which are designed to provide incentives for purchases of residences with major energy efficiency measures installed. HUD must implement and promote a pilot five-state EEM program for existing residences. The pilot program must be expanded to new construction and the remaining states within two years, unless HUD reports to Congress why expansion would be impractical. [§105, §106]

- Federal agencies are permitted to enter into multiyear energy-savings performance contracts, subject to certain specified requirements. Under such contracts, private firms may pay to install energy-saving equipment in federal buildings in return for a share of the future energy cost savings. DOE is to establish procedures for use by agencies based on specified criteria. [§155]

- DOE is to establish a program to install energy conservation measures in federal facilities and federally assisted housing. Agencies may submit proposals for funding under this program. DOE is to study the potential of using federal purchasing power to promote the development and commercialization of energy efficient products, and study potential cost-effective energy savings achievable in federal buildings. [§152(h)]

[11]For residential buildings, states must certify that their code meets or exceeds the 1992 Council of American Building Officials (CABO) Model Energy Code (MEC). For commercial buildings, states must certify that their code meets or exceeds ASHRAE/IES Standard 90.1-1989 (Standard 90.1).

V-2. Regulatory Reforms

Several regulatory reforms made thus far for utility DSM programs can contribute to DPV-PS systems as well. These include:[12]

- Decoupling utility profit from sales through such mechanisms as the Electric Revenue Adjustment Mechanism (ERAM)[13] has been an important regulatory reform for removing existing disincentives against utility DSM investments, thereby encouraging the successful implementation of IRP.

- Some utilities are allowed to recover from customers the revenue losses associated with approved DSM measures. In other cases, like New England Power, the rates are determined annually and demand-side activities are accounted for explicitly in future-test-year forecasts, all but eliminating the problem of lost revenues.

- Currently, prudent supply-side resource costs can be fully recovered in utility rates. To promote utility investments in DSM, some utilities are allowed to recover DSM costs on terms equivalent to those for the recovery of supply-side costs. In other cases, participating customers pay the full cost of utility-sponsored DSM programs through a surcharge.

- Removing disincentives to DSM is a necessary, but not sufficient condition to make DSM attractive to at least some utilities. For some utilities, performance-based incentives have been offered with impressive results (Rowe 1990).[14]

- Shared-savings incentives have been approved in 13 states[15] and the District of Columbia. Shared-savings incentives are usually accompanied by guarantees of program cost recovery and by a decoupling mechanism that remove disincentives associated with reduced sales.

---

[12]See Nadel et al., eds. 1992. *Regulatory Incentives for Demand-Side Management* for a more detailed discussion of several of these items.

[13]ERAM adjusts base rates to ensure that an electric utility collects its full authorized revenue requirement, despite its level of sales. ERAM was mainly intended to remove a perceived anti-DSM bias.

[14]In the case of New England Electric System (NEES), DSM incentives have been successful, giving the incentives movement new credibility. In 1991, NEES allocated a greater portion of its budget to DSM than any other investor-owned utilities in the country, about 5% of revenue.

[15]These states include California, Georgia, Idaho, Indiana, Maine, New Hampshire, New Jersey, New York, Ohio, Oregon, Rhode Island, Vermont and Wisconsin.