7. The Role of Electric Utilities in the Photovoltaics Industry

Introduction

As the costs of photovoltaic (PV) modules have declined toward $3.50 per watt[120] and system costs toward $7.00 per watt, many utilities have taken a renewed look at PV systems for grid-interactive applications. Utility and nongovernment organization (NGO) partnerships, such as PVUSA (Photovoltaics for Utility-Scale Applications) and UPVG (Utility Photovoltaic Group), have been developed and expanded to demonstrate system performance and reliability, to lower costs, and to identify cost-effective applications. Currently, dozens of utilities are demonstrating PV systems at hundreds of sites across the country. Typical demonstrations include large-scale substation support,[121] residential and commercial rooftop installations, and power quality correction.[122]

The Sacramento Municipal Utility District (SMUD) is the industry leader in many areas of grid-interactive PV development. SMUD sponsors the PV Pioneers program for small-scale residential rooftop applications. SMUD also recently took over from Pacific Gas & Electric (PG&E) as the leader of the PVUSA program. SMUD hosts an important substation support demonstration at its Hedge substation, and PG&E hosts a similar demonstration at its Kerman substation. These demonstrations place PV technology in one of its highest valued grid-interactive applications. The benefits of substation support include such nontraditional benefits as local reliability enhancements, real and reactive energy loss savings, deferral of transformer replacement and maintenance, transmission capacity deferral, and power plant dispatch savings.

SMUD believes that domestic PV production and utility installation levels in the range of 50 to 100 megawatts per year are necessary for “sustained orderly development.” SMUD expectations are that in 5 years sustained orderly development could lead to PV price declines sufficient to make the technology economically competitive with conventional generating sources. This development could include such programs as substation support and residential or commercial rooftop applications. SMUD currently projects that delivered power costs can be reduced from more than 20 cents per kilowatthour in 1996 to 6 cents per kilowatthour in 2001 with sustained orderly development. The experience utilities across the country are now obtaining in areas such as reliability, maintainability, and systems interactions would then have significant commercial relevance. Continued NGO partnerships are considered a key to this development.

Utility Programs

The utility industry, in collaboration with the U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI), and others, has established three major PV programs: Photovoltaics for Utility-Scale Applications (PVUSA), the Utility Photovoltaic Group (UPVG), and Photovoltaics for Utilities (PV4U). Each program is discussed below. In addition, the two utility substation support demonstrations, SMUD’s Hedge substation and PG&E’s Kerman substation, are discussed. Other DOE and utility initiatives are also described.

PVUSA

History and Objectives

PVUSA was established in 1987 as a cooperative research effort by a dozen electric utilities, EPRI, and Federal and State government agencies, with the following objectives:

- Evaluate the performance, reliability, and cost of promising PV modules and balance-of-system components side-by-side at a single location

[120]In this chapter, photovoltaic capacities given in watts refer to “peak watts.”
[121]For large-scale substation support, a PV installation is used to supply power directly to a substation, in order to lessen the load on a generating station.
[122]Power quality correction operations make PV-generated power consistent with conventional transmission and distribution power requirements.

- Assess PV system operation and maintenance (O&M) costs in a utility setting
- Compare PV technologies in diverse geographic areas
- Offer U.S. utilities hands-on experience in designing, procuring, and operating PV systems
- Document and disseminate knowledge gained from the project.

The key commercial-scale, utility-sited PV system in the PVUSA program is at PG&E's Kerman substation. An additional nine systems at utilities, including one of the five systems at SMUD's Hedge substation, are also part of the program. As of the end of 1995, 19 PV arrays were being tested. The following discussion, excerpted from the *1995 PVUSA Progress Report*,[123] summarizes the status of the PVUSA program.

PVUSA consists of two types of demonstrations: (1) emerging module technologies (EMTs), which are state-of-the-art technologies in 20-kilowatt (nameplate) arrays located at Davis, California; and (2) utility systems, which represent more mature PV technologies in turnkey systems ranging from 200 to 500 kilowatts (nameplate). Table 21 lists the PVUSA Davis EMT systems, Table 22 lists the PVUSA Davis and Kerman utility systems, and Table 23 lists PVUSA host utility systems. Each table also shows 1994 and 1995 performance using PVUSA's performance index. The index, which is similar to a capacity factor, includes adjustments for irradiance, temperature, degradation, soiling, and balance-of-system performance. The performance indices for 1995 include a 5-percent increase in the delivered efficiency power conditioning unit (PCU)[124] low-load loss adjustment. This makes the 1995 results 5 percent higher than the 1994 results, all else being equal. The results

Table 21. PVUSA Emerging Module Technology Systems at Davis, California

Completion Date	Supplier	Module Technology	Direct Current System Efficiency (Percent)	Direct Current Power (Kilowatts)	Performance Index	
					1994	1995
01/89	Siemens Solar (ARCO)	Microgridded single-crystal silicon	11.1	18.7	88	92
06/89	Sovonics	Tandem-junction amorphous silicon	3.5	17.3	88	91
12/89	Utility Power Group	Tandem-junction amorphous silicon	3.3	15.7	95	91
10/90	Solarex	Bifacial polycrystalline silicon	8.6	15.7	90	83
03/91	ENTECH	22x linear concentrator, crystalline silicon	11.3	16.5	67	75
11/94	AstroPower	Thin-film polycrystalline silicon on ceramic	5.9	17.1	78	94
12/95	Solar Cells	Cadmium telluride	6.3	12.0	NI	99
12/95	Amonix	260x point-focus concentrator, crystalline silicon	TBD	[a]19.0	NI	NR

[a]Supplier's estimate.

NI = not installed. NR = not recorded. TBD = to be determined.

Notes: Efficiency and power were calculated at the time of initial acceptance, based on PVUSA test conditions and total module area. Test conditions were defined as 1,000 watts per square meter plane-of-array incidence, 20°C ambient temperature, and 1 mile per second wind speed. For concentrators, a direct normal irradiance of 850 watts per square meter was used. Direct current efficiency is reported because the emphasis is on comparing module performance. Start dates are staggered; therefore, some performance indexes are part-year.

Source: Pacific Gas & Electric Co., *1995 PVUSA Progress Report*, DOE/AL/82993-28, prepared for the U.S. Department of Energy under Cooperative Agreement DE-FC04-92-AL82993 (March 1996), pp. 1-5.

[123]Pacific Gas & Electric Co., *1995 PVUSA Progress Report*, DOE/AL/82993-28, prepared for the U.S. Department of Energy under Cooperative Agreement DE-FC04-92-AL82993 (March 1996).

[124]PCUs are used to convert direct current (d.c.) to alternating current (a.c.).

show both a significant number of solidly performing systems and several systems with low capacity factors, including Kerman in 1995 and Hedge in 1994.

Performance of PVUSA Systems

Performance highlights of PVUSA systems since 1989 can be summarized as follows:

- Cumulative output from 1989 through 1995 totaled 7.1 gigawatthours, of which 2.3 gigawatthours represented 1995 output (from systems shown in Tables 21, 22, and 23).
- System efficiencies ranged from about 3 percent for amorphous silicon modules to between 7 and 10 percent for single-crystal silicon modules.
- Only 4 of the 18 systems rated by PVUSA met or exceeded the supplier's efficiency estimates.
- Efficiencies of fielded arrays and systems appear to be degrading by an average of 2 percent per year.
- Annual capacity factors ranged from 7 to 21 percent. Monthly capacity factors for several systems exceeded 30 percent during the summer. Peak period capacity factors for several systems in PG&E's service territory were in the range of 50 to 66 percent.
- Panelized and factory-wired modules reduced field labor and costs. Integration of the module or panel supports into the array structure also reduced costs.
- Module reliability has been very good. The majority of failures at both Davis and Kerman were related to wiring and connections, tracking system misoperation, and power conditioning.

UPVG

UPVG was established in 1992 with support from EPRI, the American Public Power Association (APPA), the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association (NRECA). As of May 1996, 76 utilities were members of the group. Its objectives are to accelerate cost-effective PV applications, aggregate market demand, and demonstrate near-term uses. Among other projects, UPVG has published a six-volume analysis of PV status, opportunities, and markets and has developed a comprehensive action plan for stimulating demand in those markets.

With an estimated one-third financial support from DOE, UPVG sponsors TEAM-UP (Technology Experience to Accelerate Markets in Utility Photovoltaics). TEAM-UP is a $500 million, 6-year initiative to accelerate the demonstration of 50 megawatts of on-grid and

Table 22. PVUSA Utility Systems at Davis and Kerman, California

Completion Date	Supplier	System Technology	Alternating Current System Efficiency (Percent)	Alternating Current Power (Kilowatts)	Performance Index	
					1994	1995
Davis Systems						
9/92	Advanced PV Systems	Amorphous silicon, fixed tilt, APS PCU	4.2	479	83	73
6/93	Integrated Power Corp.	Ribbon silicon (MSEC EFG), one-axis active-tracking, KWI PCU	8.0	196	31	40
5/94	Siemens Solar	Single-crystal silicon, one-axis passive-tracking, Bluepoint PCU	[a]7.9	[a]67	60	57
Kerman System						
6/93	Siemens Solar	Single-crystal silicon, one-axis passive-tracking, Omnion PCU	9.8	498	85	51

[a]Based on 50 percent of the array.

Notes: Efficiency and power were calculated at the time of initial acceptance, based on PVUSA test conditions and total system area. Test conditions were defined as 1,000 watts per square meter plane-of-array incidence, 20^{o}C ambient temperature, and 1 mile per second wind speed. Alternating current efficiency is reported because the emphasis is on comparing system performance. Power conditioning unit (PCU) efficiencies of 90 to 95 percent account for almost all the difference between alternating current and direct current efficiencies. Start dates are staggered; therefore, some performance indexes are part-year.

Source: Pacific Gas & Electric Co., *1995 PVUSA Progress Report*, DOE/AL/82993-28, prepared for the U.S. Department of Energy under Cooperative Agreement DE-FC04-92-AL82993 (March 1996), pp. 1-5.

off-grid PV applications. Its first request for proposals (issued in December 1994 and accepted in 1995) resulted in cofunding of $32 million of utility proposals and 5.6 megawatts of PV applications in more than 340 installations at 25 utilities in 12 States. Table 24 highlights the awards for grid-connected systems. In second-round awards, announced in May 1996, 11 teams representing almost 50 electric utilities were awarded $4.5 million in Federal funds. These venture teams are expected to invest more than $16 million to install more than 1,000 new PV systems in as many as 25 States.

PV4U

PV4U is a loose confederation of State-level working groups that includes universities, PV manufacturers, State energy offices, and utilities. As of fall 1995, 15 States had PV4U working groups. Highlights of PV4U

Table 23. PVUSA Host Utility Systems

Completion Date	Host Utility Sponsor	Supplier	Technology	Efficiency (Percent)	Power (Kilowatts)	Performance Index	
						1994	1995
10/89	Maui Electric (HI)	Sovonics	Tandem-junction amorphous silicon, fixed tilt, DECC PCU	3.7 d.c.	18.5 d.c.	92	97
07/92	City of Austin (TX)	IPC	Ribbon silicon (MSEC EFG), one-axis active tracking, Omnion PCU	8.4 a.c.	17.9 a.c.	84	77
07/93	NREL, New York Power Authority (NY)	IPC	Tandem-junction amorphous silicon (USSC), fixed tilt, Omnion PCU	3.1 a.c.	12.9 a.c.	83	84
08/93	New York State Energy Research & Development Administration (NY)	IPC	Ribbon silicon (MSEC EFG), one-axis active tracking, Omnion PCU	8.4 a.c.[a]	17.9 a.c.[a]	66	38
04/94	Sacramento Municipal Utility District (CA)	UPG	Single-crystal silicon (SSI), one-axis active tracking, Omnion PCU	10.1 a.c.	207 a.c.	64	81
11/94	Central & Southwest (TX)	UPG	Single-crystal silicon (SSI), one-axis active tracking, Omnion PCU	9.6 a.c.	98 a.c.	NR	63
09/95	Central & Southwest (TX)	ENTECH	21x linear concentrator, crystalline silicon, Omnion PCU	11.0 a.c.	83 a.c.	78	NR
12/96	Dept. of Defense (AZ)	UPG	Single-crystal silicon (SSI), fixed tilt, Kenetech PCU	TBD	375 a.c.[a]	NI	NI
06/96	Public Service of Colorado (CO)	New World Power	Single-crystal silicon (AstroPower), one-axis active-tracking, Omnion PCU	TBD	22 a.c.[a]	NI	NI

[a]Estimate.

a.c. = alternating current. d.c. = direct current. NI = not installed. NR = not recorded. TBD = to be determined.

Notes: Efficiency and power were calculated at the time of initial acceptance, based on PVUSA test conditions and total area. Test conditions were defined as 1,000 watts per square meter plane-of-array incidence, 20°C ambient temperature, and 1 mile per second wind speed. For concentrators, a direct normal irradiance of 850 watts per square meter was used. Generally, emerging module technologies are rated on array d.c. output and utility systems are rated on a.c. output (determined by contract). Start dates are staggered; therefore, some performance indexes are part-year.

Source: Pacific Gas & Electric Co., *1995 PVUSA Progress Report*, DOE/AL/82993-28, prepared for the U.S. Department of Energy under Cooperative Agreement DE-FC04-92-AL82993 (March 1996), pp. 1-6.

activities and PV-related events in 1995 are summarized below.[125]

Arizona. Arizona Public Service Company (APS) is installing the 25-kilowatt PV/hybrid system at Carol Spring Mountain, testing four systems for its remote PV leasing program, developing a 50-kilowatt PV covered parking project, a 17-kilowatt home "green pricing" project, a 125-kilowatt tracking PV system to provide transmission and distribution support, and a 36-kilowatt high-concentration PV system. APS has a net metering rate schedule (EPR-3) and a remote PV leasing rate schedule (Solar-1). The Salt River Project is testing a PV-powered heat pump and is involved in a Solarex advanced amorphous-silicon PV project. Tucson Electric Power Company has installed a 500-watt grid-tied system at a local school district and has a grant to install a 5-kilowatt PV system at the University of Arizona Agricultural Station. Arizona Electric Power Cooperative, Inc., plans to install an 18-kilowatt PV system to serve one of its buildings.

California. SMUD is leading a nine-utility project to install PV systems at more than 200 residential, commercial, and industrial sites. Other California utilities in the project are Southern California Edison, the Northern California Power Agency, and the City of Anaheim. The second California project is a 5-megawatt central-station PV power plant in Imperial County. The total cost of the proposed Amoco/ENRON Solar Power Development joint venture is less than $2 per watt installed. The power will be sold to San Diego Gas & Electric.

Colorado. The UPVG TEAM-UP project awarded to Empire Electric and its partners funding for a 126-kilowatt PV system at the end of an unreliable transmission line in Mesa Verde National Park.

Delaware. Delmarva Power has installed a 15-kilowatt, grid-connected, rooftop PV system at its northern headquarters. The president of AstroPower has installed a 4-kilowatt rooftop PV system on his home in Newark,

Table 24. Utility Photovoltaic Group (UPVG) TEAM-UP Ventures, 1995

Lead Utility(s)	Key Objectives	Total Cost (Million Dollars)	TEAM-UP Funding (Millions Dollars)	Alternating Current Power (Kilowatts)
Niagara Mohawk	Power quality correction	2.40	0.30	100
Hawaii Electric	Evaluate attachment of modules to roofing insulation	0.20	0.06	15
Sacramento Utility District and eight other utilities	Rooftop, building-integrated, and transmission and distribution support	10.90	1.70	1,400
Arizona Public Service	Standardize rooftop systems for covered parking garages	[a]5.3	[a]0.9	50
Arizona Public Service	Tracking systems for transmission and distribution support	[a]5.3	[a]0.9	125
Arizona Public Service, Nevada Power, Central & Southwest	High-concentration (230x) systems	[a]5.3	[a]0.9	72
Eight utilities	Validate green pricing programs	3.10	1.40	350
Public Service of Colorado	Transmission and distribution support	0.25	0.06	22
Northern States Power	Dual-axis tracker, 22x concentration in a cold climate	0.04	0.01	2
UtilCorp United, Nevada Power	Power quality	0.34	0.16	40
Gainesville Regional Utility	Uninterruptible power supply, green pricing	0.20	0.04	10

[a]Denotes funding for all three Arizona Public Service Projects.
Source: "Utility Photovoltaic Group 1995 TEAM-UP Ventures," http:/www.paltech.com.ttc/upvg/pr_sep95.htm.

[125]Interstate Renewable Energy Council, "Reports from the PV4U State Working Groups," *PV4U Connections*, No. 3 (Fall 1995), web site www.eren.doe.gov/irec.

Delaware, as a prototype. Delmarva Power, the Delaware Electric Cooperative, the State government, and the Delaware Nature Society are installing a 1.5-kilowatt PV system on a State-owned building.

Hawaii. Hawaiian Electric proposes to install a grid-connected, 15-kilowatt commercial rooftop PV application in Kailua-Kona, which is located on the island of Hawaii.

Idaho. The Idaho Power Company (IPCo) is experiencing a flurry of activity in its PV tariff program. IPCo installed twice as many PV systems in the summer of 1995 as the total number of systems installed during the first 2 years of the program.

Maryland. Some utility projects under review include highway sign lighting, PV water pumping, rooftop PV, and a remote and relocatable PV service in a box for small 120-volt plug loads.

Massachusetts. Utilities continue to install and monitor residential, commercial, and street-lighting installations. Planned installations include a 2.5-kilowatt grid-connected system in Cambridge and a 2-kilowatt system in a State park. An additional 5 kilowatts of PV-assisted lighting will be installed by the Taunton Municipal Lighting Plant.

New York. Installation of a PV system at the Bennington Historic Site was expected in 1996.

Wisconsin. Wisconsin has 11 grid-connected PV systems that have been monitored by utilities for up to 6 years. In addition, about 20 small, grid-connected, non-utility PV systems have also been installed.

The SMUD Experience— Recent and Projected Cost Trends

The Sacramento Municipal Utility District (SMUD) is leading the utility industry in attempting to advance the development of low-cost, grid-connected PV applications. Two programs are of particular note: PV Pioneers and the Hedge substation.

PV Pioneers

In 1994, SMUD established a voluntary program called PV Pioneers through which the utility's participating customers permit SMUD to install 400 square feet of solar panels on the roofs of their homes. PV Pioneers agree to pay a 10-percent premium (approximately $4 per month) over their electric bill for 10 years. More than 700 homeowners volunteered for the first 100 available installations.

The most recent bidding for the PV Pioneers program was completed in the spring of 1996. SMUD received bids for modules in the range of $3.50 per watt (a.c.) and turnkey costs in the range of $5.50 per watt. Including program and other costs, SMUD estimates the modules to cost about $6.50 to $7.00 per watt. These costs translate into electricity costs of about 16.5 to 18 cents per kilowatthour. In comparison, costs for 1994 and 1993 for rooftop installations were about $7.13 per watt (20 cents per kilowatthour) and $8.78 per watt (23 cents per kilowatthour), respectively.[126]

For 2001, SMUD projects system costs of about $2.82 per watt and an electricity cost of about 7.4 cents per kilowatthour. Excluding costs for running the program, SMUD projects costs at 6.3 cents per kilowatthour by 2001. On a component-by-component basis, SMUD's estimates for cost reductions from 1996 to and 2001 are as follows (all in dollars per peak watt, a.c.):

- Modules—$3.80 to $1.74
- Power Conditioning—$0.66 to $0.23
- Non-inverter balance of system and installation—$0.60 to $0.40
- Panelization and engineering design and insurance—$0.40 to $0.10.

The valuation of the residential PV Pioneers systems is different from that of a utility-owned system or a distribution support system. Effective January 1, 1996, all California utilities are required to provide net metering of residential PV systems up to 10 kilowatts. Net metering means that the PV system is valued (by the customer) at the residential retail price of electricity, not the wholesale avoided cost of electricity. The retail price of electricity is typically several times greater than the avoided cost of electricity. Net metering is a potentially crucial method of obtaining customer acceptance. So long as the installed PV capacity billed on a net basis is small, the effective subsidy provided by the utility is not likely to affect utility system economics. The California law limits net metering for each utility to 0.1 percent of the utility's 1996 peak demand. For the California utilities as a group, this amounts to slightly more than 50 megawatts. While 50 megawatts is insignificant for the utilities as a group, it is significant in relation to the installed PV capacity base.

[126]D.E. Osborn and D.E. Collier, Sacramento Municipal Utility District, "Utility Grid-Connected Photovoltaic Distributed Power Systems," in *American Solar Energy Society (ASES) 96* (Asheville, NC, April 1996).

Hedge Substation

The Hedge substation plant is a series of PV installations at the Hedge substation for transmission and distribution support. SMUD started construction of the first PV system at Hedge in 1993 and completed installation of a 210-kilowatt ground-mounted, single-axis tracking system in 1994. This first Hedge system (which is part of the PVUSA program) had a turnkey cost of $7.70 per watt. Including a 23-percent increase in performance of tracking versus fixed-tilt technology, the effective turnkey cost was $6.26 per watt. Including SMUD's costs of $3.89 per watt, the total system cost was $10.15 per watt, or 32 cents per kilowatthour over 30 years.

In 1994, SMUD began the addition of three additional systems at Hedge with a total rating of 317 kilowatts. The three systems, completed in 1995, were each rated at just over 100 kilowatts. The two fixed-tilt systems had nominal costs of $6.68 per watt and $7.35 per watt. A third system, using a single-axis tracking system, had a nominal cost of $7.50 per watt and an equivalent power factor (EPF) cost of $6.10 per watt. In 1995, SMUD began construction of a 214-kilowatt (nominal), 263-kilowatt EPF tracking system. The system turnkey cost is $7.00 per watt (nominal) or $5.71 per watt (EPF).[127]

SMUD Cost Trends

Table 25 summarizes SMUD's PV cost improvement for 1993-95 for its substation and residential projects. SMUD believes that with a sustained, widespread collaborative effort, PV system prices could drop below $3 per watt by 2000. SMUD believes this would occur if utility orders and production increases moved quickly from a few megawatts a year to between 50 and 100 megawatts per year by the end of the 1990s. SMUD characterizes this scenario, in which PV system prices are expected to drop into the range of competitiveness with gas-fired generation, as "sustained orderly development."

PG&E—The Kerman Substation PV Plant

The Kerman PV plant on the PG&E system is the first and largest plant designed and built to measure the benefits of grid-support photovoltaics. The plant, designed at 500 kilowatts a.c. and rated by PVUSA at 498 kilowatts a.c., was completed in 1993. It is connected to a semi-rural 12-kilovolt (kilovolt-amperes) distribution feeder about 8 circuit-miles downstream from PG&E's Kerman substation. A 10.5-megavolt (megavolt-amperes) transformer bank at the substation maintains feeder voltage and supplies current to customers.

Traditional Benefits and Costs

Traditional benefits can be measured in terms of energy and capacity. Traditional costs (excluding capital costs) are for operations and maintenance.

Energy Value. During the 1993-94 12-month evaluation period, the Kerman PV plant (498 kilowatts capacity)

Table 25. Sacramento Municipal Utility District (SMUD) Photovoltaic System Cost Improvement, 1993-1995

Year	Project	Capacity Costs (Dollars per Watt)			30-Year Generation Costs (Cents per Kilowatthour)[c]
		Turnkey[a]	SMUD[b]	Total	
1993	Substation[d]	6.26	3.89	10.15	32
1994	Substation[e]	6.68	1.07	7.75	21
1994	Substation[d]	6.10	0.87	6.97	19
1995	Substation[d]	5.71	0.91	6.62	18
1993	Residential[e]	7.70	1.08	8.78	23
1994	Residential[e]	6.23	0.90	7.13	20
1995	Residential[d]	5.98	0.89	6.87	18

[a]Turnkey contract cost up to utility interconnection, without tax, bonding, or utility add-on costs.
[b]Includes interconnections, metering, site preparation, labor, administration, overheads, tax, bonding, AFUDC, and other costs.
[c]Preliminary estimate, including operation and maintenance, excluding DOE cost-sharing.
[d]Single-axis tracking system, includes Energy Production Credit factor of 1.23 compared to fixed tilt.
[e]Fixed, non-tracking (EPF = 1.0).

Source: D.E. Osborn and D.E. Collier, "Utility Grid-Connected Photovoltaic Distributed Power Systems," presented to the American Solar Energy Society (ASES) 1996 Conference (Asheville, NC, April 1996).

[127]D.E. Osborn and D.E. Collier, "Utility Grid-Connected Photovoltaic Distributed Power Systems."

generated 1,080 megawatthours.[128] This output corresponds to a capacity factor of about 25 percent. The value of the output depends on PG&E's avoided cost of energy, which varies from month to month. Since 1992, it has ranged from an annual average of 1.84 to 2.96 cents per kilowatthour ($18.40 to $29.60 per megawatthour). During 1995, it averaged approximately $18.40 per megawatthour.[129] Ordinarily, the avoided cost of energy is highest during the summer peaking season, when PV output is also highest. For the past few years, however, the value of energy during the summer peaking season in California has been historically low, due to surplus gas transmission capacity and low natural gas prices. The historically low value is likely to continue for some time with little or no increase. Thus, this value can be considered a constant-dollar lower bound.

During the summer of 1996, the price of nonfirm on-peak (6 a.m. to 10 p.m.) energy at the California-Oregon and California-Nevada borders was in the range of $15 to $20 per megawatthour. This is consistent with PG&E's avoided costs for most of the 1990s. Firm, on-peak energy was roughly $4 per megawatthour more.[130] At $20 per megawatthour, the value of the Kerman output from July 1993 through June 1994 (1,080 megawatthours) would have been about $21,600, or $43 per kilowatt per year.[131] At $25 per megawatthour, the value of the Kerman output for that period would have been about $27,300, or $55 per kilowatt per year.

During the mid- to late 1980s, the long-run avoided cost for on-peak energy was commonly expected to be in the range of $60 per megawatthour for most of the country. At that value, the energy from Kerman during the 1993-94 period would have been worth about $130 per kilowatt per year. Although an avoided cost of $60 per megawatthour appears unlikely in the near future, it may be a reasonable upper bound over a long period of time. This suggests a current, constant-dollar lower-bound value of Kerman energy (assuming a capacity factor of about 25 percent) of roughly $50 per kilowatt per year and a possible, though unlikely, constant-dollar upper bound of roughly $130 per kilowatt per year.

PVUSA estimates average system degradation at roughly 2 percent per year across all systems. For system economics based on a 30-year lifetime, 2-percent annual degradation is highly significant. It implies that output in the thirtieth year would only be about 55 percent of that in the first year. Degradation at this rate exerts continual downward pressure on system value and diminishes any real increases in value due to higher avoided costs.

Capacity Value. PG&E currently has no need for additional capacity. In fact, PG&E is under regulatory advisement to plan for no additional capacity (at least not nonrenewable capacity). Thus, the value of the capacity provided by the Kerman PV plant to PG&E is effectively zero. The off-system value of the Kerman plant (i.e., the surplus capacity it frees for off-system sale) depends on the need for capacity elsewhere in the region. In general, capacity value is established by the equivalent load-carrying capability of a plant at the value of the least-cost generic capacity, i.e., a combustion turbine. Combustion turbine capacity is typically available anywhere in the country at about $40 to $50 per kilowatt per year. In energy-equivalent units, this capacity value translates to roughly $4 per megawatthour. This translation is the reason the difference in price between firm and nonfirm on-peak energy at the California-Oregon border is roughly $4 per megawatthour. This value is likely to remain constant for the foreseeable future.

At Kerman's estimated 77 percent equivalent-load carrying capability[132] the value of displacing combustion turbine capacity is in the range of $30 to $40 per kilowatt per year, or about $3 per megawatthour. The extent to which PG&E can capture the value of Kerman capacity by selling other capacity off-system varies from time to time. Because of the current surplus of capacity in the western United States, the value of off-system capacity sales made possible by the existence of Kerman is low. If it is assumed that PG&E can capture the value of Kerman capacity via off-system sales of surplus capacity 50 percent of the time, Kerman's measured capacity value of $30 to $40 per kilowatt per year under a full capacity credit would be worth $15 to $20 per kilowatt per year to PG&E.

Operation and Maintenance (O&M) Costs. From June 1993 through 1995, the Kerman system had a cumulative O&M cost of $15 per megawatthour. Assuming

[128]H.J. Wenger, T.E. Hoff, and B.K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project," presented to the First World Conference on Photovoltaic Energy Conversion (Waikoloa, HI, December 1994).

[129]Calpine Corporation, *U.S. Securities and Exchange Commission Form S-4 Registration Statement* (Washington, DC, 1995).

[130]"DJ Electricity Prices," *The Wall Street Journal* (July and August 1996).

[131]Costs were calculated as follows: $20 per megawatthour × 1,080 megawatthour per year = $21,600 per year; $21,600 per year / 498 kilowatts = $43 per kilowatt per year. The additional value of Kerman output at distribution voltage at the substation (versus transmission voltage at the Oregon border) is captured in the section on nontraditional benefits.

[132]H.J. Wenger, T.E. Hoff, and B.K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project."

long-range costs at this level and performance at a 25-percent capacity factor, $15 per megawatthour is about equal to $8 per kilowatt per year. In general, module reliability has been good. The majority of failures were related to wiring and connections, tracking system misoperation, and power conditioning.

During 1995, maintenance costs at Kerman averaged $32 per megawatthour, consisting of roughly $10 per megawatthour for preventive maintenance and $22 per megawatthour for failure-related maintenance. O&M costs at Kerman were consistent with 1995 O&M costs for the three other utility system installations in the PVUSA program (all at Davis, California) of $27 to $57 per megawatthour (weighted average of $33 per megawatthour).[133] Expectations are that long-run O&M costs will trend back downward toward $15 per megawatthour from the unusually high 1995 values.

Total Traditional Benefits. Taken together, the traditional benefits from the Kerman PV system range from a constant-dollar low of about $65 per kilowatt per year to a constant-dollar high of roughly $170 per kilowatt per year. Assuming the continued surplus of natural gas in the West region, the excess of generating capacity, and the likelihood of 2 percent per year degradation in module efficiency, the value of Kerman will tend toward the low end of the range for the foreseeable future.

In 1995, the Kerman PV plant generated 572 megawatthours of electricity, or about a 13-percent capacity factor. System outages were disproportionately concentrated in the summer months. At a 13-percent capacity factor (annual average), the traditional benefits from the PV station would be reduced by about half from those stated above, as the long-term capacity factor has been 25 percent. Poor summer performance means an even greater reduction in value. Had capacity value represented a larger share of the station valuation, the poor 1995 performance would have reduced traditional benefits even more.

Evidence from the other PVUSA utility systems (Table 22) suggests that Kerman's 1995 performance was below par for the group. Although PVUSA did not calculate performance indexes prior to 1994, the total output from the utility systems installed before 1994 is consistent with performance indexes at about the 60 percent level for the Integrated Power Corporation's system and the 70 percent level for the APS system. Ironically, Kerman's best performance index would have been its part-year 1993 index, had that value been calculated. Overall, Kerman's poor 1995 performance should not be considered representative of its future performance. Accordingly, the estimated long-run, constant-dollar valuation for Kerman on a traditional evaluation basis is in the range of $55 per kilowatt per year to $160 per kilowatt per year.

Nontraditional Benefits

Nontraditional benefits consist of externalities from reduced fossil fuel use, local reliability enhancements, real and reactive energy loss savings, deferral of transformer replacement and load-tap-changer maintenance, transmission capacity deferral, and power plant dispatch savings. Table 26 summarizes the estimated value of these benefits. The table shows nontraditional benefits ranging from a low of $138 per kilowatt per year to a high of $214 per kilowatt per year.

Within the category of nontraditional benefits, it is useful to distinguish those benefits that can be captured by the utility and those benefits that may have value to society but cannot be captured by the utility. In Table 26, the row labeled "Externalities" indicates that about 95 percent of the emissions savings, valued at $31 to $34 per kilowatt per year, arise from reduced CO_2 and NO_x emissions. The SO_2 offset accounts for only 4 percent of the emissions value. Offsets of particulates account for 1 percent.

Currently, no market exists for offsets to CO_2 and only limited regional markets exist for offsets to NO_x (unlike the national market for SO_2 offsets). The development of a market for NO_x offsets depends on how the U.S. Environmental Protection Agency implements the Clean Air Act Amendments of 1990. Thus, while it may be beneficial to society to reduce emissions of CO_2 and NO_x, it is not necessarily the case that the utility can realize the CO_2 or NO_x offset benefits. This inability to realize the value of emissions offsets is particularly true for CO_2, which represents an estimated 39 percent of the emissions offset value. There is no legal, regulatory, or financial tradeoff of any type that relates to CO_2 offsets.

The other benefits shown in Table 26 arise from improvements to the PG&E system or its operations from the existence of a peaking generation source at distribution voltage near a high-stress substation. These benefits belong in all internal analyses of the value of the plant. Because of low energy costs, however, the current value from reduced transmission and distribution losses is perhaps only half the value shown in the table.

[133]Pacific Gas & Electric Co., *1995 PVUSA Progress Report*, pp. 4-12, 4-13, 11-5, and 11-6.

Table 26. Kerman Photovoltaic Plant Nontraditional Benefits
(1995 Dollars)

Benefit	Definition and Economics Driver	Technical Validation Results	Nominal Estimate (Dollars per Kilowatt per Year)	High Estimate (Dollars per Kilowatt per Year)
Externalities	Generation fuel mix and externality valuation	Offset 155 tons of CO_2 and 0.5 tons of NO_x each year	31	34
Reliability	Postpone planned reliability improvements	Voltage support of 3V per 120V base	4	4
Loss Savings	Reduce kWh and kVAR losses	Save 58,500 kWh and 350 kVAR each year	14	15
Substation	Reduced transformer upgrade expenditures	Transformer cooling increases capacity by 410 kW at peak; extend load-tap-changer maintenance by more than 10 years	16	88
Transmission	Marginal cost of transmission capacity	Increase of 450 kW on peak	45	45
Minimum Load	Marginal cost of keeping peak load-following units on line	90-percent coincidence with peak load-following unit dispatch	28	28
Total			**138**	**214**

Source: H.J. Wenger, T.E. Hoff, and B.K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project," *First World Conference on Photovoltaic Energy Conversion* (Waikoloa, HI, December 1994).

Combined Net Benefits

Combining traditional and nontraditional benefits, net of O&M costs, and adjusted for CO_2 and energy loss benefits, generates a value for the Kerman PV installation roughly in the range of $180 per kilowatt per year to $380 per kilowatt per year, assuming a 25-percent capacity factor. This range almost certainly encompasses possible increases in natural gas prices and possible module degradation over time. Even ignoring the poor 1995 performance at Kerman, PV system valuations are considerably lower than had been expected when the plant was conceived.[134] There are three reasons for this:

- Energy and capacity values are low due to low natural gas prices, surplus hydroelectric capacity, and a 1992 regulatory assumption that PG&E does not need capacity for the foreseeable future.
- Local reliability enhancement value is low because a capacitor bank could be added to the Kerman circuit and provide the same operational benefits at a lower cost than had been previously estimated.
- Substation transformer value is low because it is relatively easy to switch load in the Kerman area.

Breakeven Cost

The breakeven capital cost of the Kerman PV system (including balance-of-system costs, installation, and allowance for funds used during construction) can be estimated from the valuation described above. Using utility costs of capital, and excluding tax credits, the breakeven capital cost is roughly 9 times the constant-dollar valuation in net dollars per kilowatt per year. Since most PV costs are known and fixed at the time the plant is completed (i.e., there is no fuel cost and little likelihood of unusual escalation in O&M costs), the estimated constant-dollar valuation is likely to be very close to the actual, future value.

The most conservative valuation and the only allowable one—traditional benefits only and a continuation of current avoided energy and capacity costs—generates a valuation of about $55 per kilowatt per year or about $500 per kilowatt. For traditional benefits but upper-

[134]H.J. Wenger, T.E. Hoff, and B.K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project."

bound long-range avoided energy and capacity costs, the valuation is about $160 per kilowatt per year, or about $1,450 per kilowatt. The key difference between these two valuations is the difference between constant-dollar avoided energy costs at roughly $20 per megawatthour (current avoided energy costs) and roughly $60 per megawatthour (long-run upper bound). Combining traditional and nontraditional benefits generates a range of roughly $180 to $380 per kilowatt per year, or roughly $1,700 to $3,600 per kilowatt.

For the Kerman installation, the turnkey cost was $8,900 per kilowatt,[135] and the total plant cost, including utility costs, was about $11,000 per kilowatt. The cost of the Kerman system is thus about six times greater than the value of its current traditional and nontraditional benefits and about three times greater than an optimistic upper bound on long-run avoided costs for energy and capacity.

Other Grid-connected Activities

About half of the $87 million fiscal year 1996 budget of DOE's Office of Energy Efficiency and Renewable Energy is allocated for participation in three collaborative programs: UPVG (described above), PVMat (PV manufacturing process research), and PV:BONUS (development of PV products for integration into residential and commercial buildings). Of these, UPVG is the key program related to utility grid-interactive photovoltaics.

In late 1994, Enron (now Amoco/Enron) proposed a 1,016-megawatt solar park in Nevada that would include up to 175 megawatts of central station PV (later reduced to 100 megawatts). Amoco/Enron claims that it could produce power at a levelized cost of 5.5 cents per kilowatthour using nonconcentrating, advanced thin films. Amoco/Enron's solar park is in an early stage of consideration and cannot be evaluated for financial risk or investor requirements. The estimate of 5.5 cents per kilowatthour, however, is based on a cost of capital of 5 percent and assumes some type of tax-exempt financing, such as industrial revenue bonds issued by Nevada. In January 1996, Amoco/Enron was notified that it was one of four finalists for a DOE power purchase contract. As of the middle of 1996, no further announcement had been made.

Amoco/Enron Solar Power Development is also proposing to build a $7 million solar electric generation facility in Hawaii during 1997 with the aid of a $1.14 million award from UPVG. The facility will use 4 megawatts of PV modules produced by a thin-film manufacturing process at a new Solarex factory that began construction in October 1995 near Williamsburg, Virginia. Hawaiian Electric is slated to purchase the solar-generated electricity.

In 1996, Detroit Edison dedicated the first customer-supported, centralized PV generating facility in the United States. The system is supported in part by customers paying a supplemental "green rate" for renewable energy. A portion of the construction cost ($116,160) was supplied by The DOE/UPVG consortium. The 28.4-kilowatt station at the utility's Michigan Electric Power Coordination Center was built after nearly 200 Detroit Edison customers subscribed to its SolarCurrents program. Under the program, open only to residential customers, subscribers pay an additional $6.59 per month for each 100 watts of electricity. Each 100-watt block will provide a customer with about 140 kilowatthours of electricity per year. The system is expected to produce about 40.3 megawatthours annually (16.2 percent capacity factor) using 120 solar panels.

Utility-Scale PV Investment Under Industry Restructuring

Historically, a high-risk, high-return investment would be undertaken by independent power producers (IPPs) using leveraged, tax-favored financing. While this financial model is still valid in some cases, it has been adversely affected by current and proposed restructuring and deregulation of transmission and generation. In particular, the probable curtailment of power purchase agreements from unbundled transmission and distribution utilities and the prohibition by the Federal Energy Regulatory Commission (FERC) on wholesale purchases above avoided cost makes the competitive environment for high-risk IPPs much more difficult. Continued low-cost power from natural gas also reduces potential returns on PV projects.

Another major development under deregulation is the distinction between the cost of capital for generation investment and the cost of capital for transmission and distribution investment. Some studies have estimated increases of 3 to 5 percentage points in the cost of capital for generation investment and similar decreases in the cost of capital for transmission and distribution investment. Increases of this magnitude would effectively reduce the constant-dollar capitalized value rate for generation investment by roughly 15 to 20 percent. This change exceeds the value of benefits from existing tax credit and depreciation rules favoring nonregulated entities.

[135]D.E. Osborn and D.E. Collier, "Utility Grid-Connected Photovoltaic Distributed Power Systems."

At present, dozens of utilities are investing nominal amounts of time and money to explore the opportunities for grid-interactive PV installations on their systems. Increases in grid-interactive PV system installations are likely to arise mostly from collaborative programs, such as PVUSA, or pursuant to regulatory requirements, including portfolio standards. Because PV systems are uneconomical regardless of how traditional or nontraditional benefits are measured, the balancing act for utilities and State commissions is between creating incentives for more installed capacity and creating measurable adverse impacts on competitive pricing.

For municipal utilities (such as SMUD) and rural electric cooperatives, both of which report directly to ratepayers but not to shareholders or FERC, the ability to expend funds for photovoltaics may be greater than for investor-owned utilities. For States that are willing to mandate portfolio standards at retail, as California is considering, the desire of the taxpaying public for certain types of energy sources must be balanced against the desire of the public for low-cost electricity. For quantities that would make a difference to the utility industry and the PV industry (i.e., 50 to 100 megawatts a year), costs to the public would be negligible. Beyond that, however, or in connection with other preferred but uneconomical energy sources (i.e., other renewables), the costs could become significant. Ultimately, photovoltaics will have to be judged on standard economic criteria. At present, they fall short by a factor of perhaps 6, even if estimates of nontraditional benefits are included. If SMUD's plan for sustained orderly development is realized and costs for natural gas increase, photovoltaics could approach commercial competitiveness.

Niche Markets

The value of a PV system depends on the value of the energy and capacity it offsets and the nontraditional benefits it generates. These values differ widely from utility to utility and site to site. In general, systems that provide transmission and distribution (T&D) support, such as Kerman or Hedge, are worth roughly $100 to $200 per kilowatt per year more than central station systems that supply bulk power. The exact difference between a T&D support system and a central station system is highly sensitive to the characteristics of the T&D system, the costs of extending the distribution lines, and other line-specific factors.

The niche market that appears to have captured the public's imagination is rooftop PV. Rooftop systems have many of the attributes of T&D support systems, in that they reduce the load on distribution feeders and substations in essentially the same way as a centralized T&D support system. Rooftop PV systems also have no-cost land for siting. On the other hand, they have higher costs for utility overhead, marketing and administration, installation per kilowatt, and other scale diseconomies.

The key attribute of rooftop PV systems that makes them a potentially significant niche application is net metering. Under net metering, the customer's PV system offsets retail electric rates rather than wholesale avoided costs. Retail electric rates are typically several times greater than avoided costs. This difference creates considerable value for the residential customer at the expense of the utility. By valuing PV electricity at the retail offset (without a standby charge), the utility absorbs the costs above avoided cost. These costs include all the costs related to T&D capital and operations, generating capacity, system overheads, etc. If PV market penetration were to become substantial, utilities would not be able to subsidize PV net metering. As a means of penetrating the market, however, the provision of net metering may be critical. To the extent that the use of net metering advances the PV market without substantially impairing the competitive position of the utility, the tradeoff may be beneficial to the utility in the long run. Ultimately, however, penetration of net metered technologies shifts costs from net metered customers to other customers. In a competitive market, absorption of these costs can only occur by regulatory direction.

PV technologies require cost reductions or a combination of cost reductions and an increase in natural gas prices to become cost-competitive in most grid applications. Some obstacles slowing commercialization are technology-specific, while others are more general. The primary obstacle is that PV technologies cannot currently compete with conventional fossil-fueled technologies in most grid-connected applications. On the other hand, niche applications, such as photovoltaics for T&D support at the end of a fully loaded distribution line, have value above that of a new generating plant. Such applications may permit the technology to establish itself and benefit from economies of scale and learning effects.

Financial risk and uncertainty are also adversely affecting PV development. Because the technologies are costly and have high absolute capital costs per kilowatt of capacity, they are riskier than most conventional power plants. The risks are partially offset by the modularity of the plants and their short construction times, but their overall risk-adjusted cost of capital is high.

An associated obstacle to solar development is the way in which electric utilities conduct their resource planning. Planning and avoided-cost methods currently cannot consider nonmarket benefits and costs, understating the social benefits of PV energy. For instance, the environmental benefits of using the sun to produce electricity are not usually explicitly accounted for in the resource planning process. Because the environmental benefits of using cleaner technologies are dispersed and accrue to the general public, the decisionmaking utility has no direct incentive to take them into account. Therefore, even though solar energy technologies impose little or no pollution cost on society, that benefit is generally left out of the least-cost planning process.

Despite some obstacles, PV energy technologies continue to enjoy success in certain market niches. PV is a versatile power source, and PV technologies have some unique attributes that drive their use in situations where most conventional energy technologies are not cost-effective. PV modules, as opposed to systems, have no moving parts to wear or break down, and they can be used for extended periods of time without maintenance or intervention. PV systems, however, have experienced a system degradation of 2 percent per year.

Conclusion

PV prices and the delivered cost of PV energy have declined substantially in recent years. Major progress has been made in all areas of module performance, reliability, and cost. Competitiveness with conventional forms of generation has been constrained, however, by declines in the price of natural gas, the surplus of coal-fired energy, deregulation of generation, and other market factors. In most cases, PV systems are not currently economical for grid-interactive applications. Utilities are willing to invest money to develop a technical understanding of the technology and systems, and to respond to customer requests for “green” forms of energy. Given present uncertain market conditions, however, utilities are not willing to expend major investment funds to commercialize an uncompetitive technology at a utility plant scale.

As deregulation of generation increases and energy prices continue to decline, photovoltaics will face increasing competitive challenges. Utilities are mainly concerned with cost and price competition and customer retention. With increased competition, customer loyalty and retention are playing an increasingly important role in utilities’ decisionmaking. In some cases, a partial answer may be “green” pricing, in which consumers who choose to pay more for clean, renewable energy have the option to do so. In other cases, a partial answer may be portfolio standards. Under the portfolio standards approach, a utility that distributes at retail in a franchise service area is required to obtain part of its energy from renewable sources. Many jurisdictions, including California, are considering portfolio standards.

At current PV prices and levels of cost-competitiveness, public-private partnerships are the key to technology development. Partnerships such as UPVG and PVUSA combine the technical, economic, and regulatory expertise of many parties in ways that would not be financially feasible for the private sector alone. To a certain degree, the government role in these partnerships reflects the notion of societal benefits (reduced air emissions, reduced oil imports, etc.) that cannot be properly valued by electric utilities and nonutility generators. In the long term, photovoltaics must become more competitive in their own right—either through lower costs or through explicit recognition of the external costs of conventional energy supplies.