**Building-
Integrated
Photovoltaics
(BIPV)—Analysis
and US Market
Potential**

**Report to
US Department of Energy
Office of Building
Technologies**

February 1995

Arthur D. Little, Inc.
Acorn Park
Cambridge, Massachusetts

Reference 44513

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED *pw*

MASTER

This publication was reproduced from the best available camera-ready copy submitted by the subcontractor and received no editorial review at NREL.

NOTICE

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, makes 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.

Available to DOE and DOE contractors from:
Office of Scientific and Technical Information (OSTI)
P.O. Box 62
Oak Ridge, TN 37831
Prices available by calling (615) 576-8401

Available to the public from:
National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
(703) 487-4650

DISCLAIMER

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

**Building-Integrated Photovoltaics (BIPV):
Analysis and US Market Potential**

Prepared by

Lisa Frantzis, David Friedman, Sarah Hill, and Peter Teagan

**Arthur D. Little, Inc.
20 Acorn Park
Cambridge, MA 02140-2390**

Arthur D. Little Reference No. 44513

and

Steven and Marilyn Strong

**Solar Design Associates
252 Old Littleton Road
Harvard, MA 01451-0242**

for

**Building Equipment Division
Office of Building Technologies
U.S. Department of Energy
Project Managers: Bob Hassett (DOE), Chuck Kutscher (NREL),
Sheila Hayter (NREL)
Contract No. DE-AC01-90CE23821**

February 1995

Acknowledgements

The information in this report required the expertise of many individuals and companies actively involved with integrating photovoltaics in buildings. We gratefully acknowledge the significant contributions made by these professionals, and we appreciate their enthusiasm and time in providing support to this BIPV effort. Their opinions, data, and feedback were critical to successfully completing this project.

Our special thanks to our DOE program management, Mr. Bob Hassett and NREL program management, Doug Dahle (at project initiation), Chuck Kutscher, and Sheila Hayter for their reviews and comments throughout this effort. In addition, we would like to thank Ascension Technology, Inc. and the BIPV Steering Committee: Renewable Energy Consultants (Fred Morse); National Association of Home Builders (Joe Wiehagen and Burt Goldberg); Kiss, Cathcart, Anders Architects (Gregory Kiss); Solar Energy Industries Association (Keith Durand); ERG International (Norm Weaver); NREL (Roger Taylor and Ren Anderson); Alternate Energy & Design Consulting (Alan Paradis) and SAIC (Bob Lorand).

Lisa Frantzis
Program Manager

Table of Contents

Executive Summary	E-1
1.0 Background	1-1
1.1 What Is BIPV	1-1
1.2 Study Objectives	1-1
1.3 Project and Report Organization	1-2
2.0 BIPV Costs With Conventional Mounting Techniques: 1994 - 2010 ..	2-1
2.1 Retrofit Buildings	2-1
2.1.1 Commercial Buildings	2-1
2.1.2 Residential Buildings	2-7
2.2 New Construction	2-10
2.3 References	2-11
3.0 Cost Reduction Options	3-1
3.1 Roof-Integrated Concepts (New Construction/Reroofing)	3-1
3.1.1 Technology Description	3-1
3.1.2 Potential Impact on Installed BIPV System Costs	3-1
3.1.3 References	3-1
3.2 Ballasted Roof Mount at Low Tilt Angle	3-5
3.2.1 Technology Description	3-5
3.2.2 Potential Barriers	3-8
3.2.3 Potential Impact on Installed BIPV System Costs	3-8
3.2.4 References	3-11
3.3 Curtainwall Applications	3-15
3.3.1 Technology Description	3-15
3.3.2 Potential Impact on Installed BIPV System Costs	3-16
3.3.3 References	3-19
3.4 The AC Photovoltaic Module	3-20
3.4.1 Technology Description	3-20
3.4.2 Potential Impact on Installed BIPV System Costs	3-22
3.4.3 References	3-25
4.0 BIPV Building Analysis and Economics	4-1
4.1 Analytical Approach	4-1
4.1.1 Commercial Building Assumptions and Analysis	4-1
4.1.2 Residential Building Assumptions and Analysis	4-3
4.2 Annual Energy Cost Savings - Commercial	4-5
4.2.1 Roof Mount BIPV Impact on Demand and Energy Charges ..	4-5
4.2.2 Economics of Commercial Roof Mount BIPV - Consumer Perspective	4-7
4.2.3 Curtainwall BIPV Impact on Demand and Energy Charges ..	4-11
4.2.4 Economic Analysis of Curtainwall BIPV	4-11
4.2.5 Impact of IRP Benefits	4-11
4.3 Annual Energy Cost Savings - Residential	4-15
4.3.1 Impact on Energy Savings	4-15
4.3.2 Economic Analysis of Residential BIPV	4-17
4.3.3 Impact of IRP Benefits - Residential	4-17

Table of Contents (continued)

4.3.4 References	4-20
5.0 BIPV Potential Impact on National Energy Savings	5-1
5.1 PV Market Model Assumptions	5-1
5.1.1 Orientation and Module Output	5-4
5.1.2 PV System Performance	5-4
5.1.3 Roof Area Available for PV	5-4
5.1.4 Wall Area Available for Curtainwall Applications	5-5
5.1.5 BIPV System Prices and Contractor Markups	5-5
5.1.6 Utility Rate Structures	5-6
5.1.7 Demand Charge Savings	5-8
5.1.8 Capacity Credits	5-9
5.1.9 T&D Avoided Costs	5-10
5.1.10 Environmental Externality Credits	5-12
5.1.11 Market Penetration Curves	5-13
5.2 Potential BIPV Impact - With Energy Savings Only	5-15
5.2.1 Single Family	5-15
5.2.2 Multifamily	5-16
5.2.3 Commercial Rooftop	5-17
5.2.4 Curtainwall	5-18
5.3 Potential BIPV Impact - With Demand Charge Savings	5-19
5.3.1 Multifamily	5-19
5.3.2 Commercial Rooftop	5-19
5.3.3 Curtainwall	5-19
5.4 Upper Bound - With Demand Charges, IRP, and Externality Benefits	5-20
5.4.1 Single Family	5-20
5.4.2 Multifamily	5-23
5.4.3 Commercial Rooftop	5-23
5.4.4 Curtainwall	5-23
5.5 Advanced BIPV Module Technology	5-23
5.6 BIPV Near-Term, Niche Applications	5-24
5.6.1 BIPV Skylights, Atriums, and Awnings	5-26
5.6.2 Limitations	5-29
5.6.3 Market Analysis	5-30
5.7 Innovative Rate Analysis	5-33
5.8 References	5-34
6.0 DOE Program Recommendations	6-1
6.1 Background/Summary	6-1
6.1.1 Installation Costs/Building Physical Interface	6-1
6.1.2 Utility Impacts and Rate Structures	6-1
6.1.3 Single vs. Multiple Impacts	6-1
6.2 Program Development Criteria	6-2
6.2.1 PV Technology	6-2
6.2.2 Installation Cost Reduction	6-2
6.2.3 Utility Interface	6-3
6.2.4 Program Leverage	6-3
6.3 Program Plan Outline	6-3

Table of Contents (continued)

6.3.1 Program Element 1: Installation Cost Reductions	6-5
6.3.2 Program Element 2: BIPV/Utility Interface	6-6
6.3.3 Program Element 3: Supporting Analysis	6-7

Appendix A: Accelerating the Development of BIPV, Workshop Summary

A.1 Themes	A-2
A.2 Reflections On State-of-the-Art	A-3
A.3 Major Challenges	A-4
A.4 Essentials for Expanding the Marketplace	A-4
A.5 Next Steps	A-4
A.6 References	A-5

Appendix B: An Overview of Worldwide Development Activity in BIPV

Appendix C: Glossary of Terms and Abbreviations

Samples of Arthur D. Little Market Model Analyses

List of Figures

Figure 1.2-1	Project Organization	1-3
Figure 2.1-1	PV Mounting Types	2-2
Figure 2.1-2	Schematic of PV Rack Mounted System on Flat Roof	2-3
Figure 2.1-3	Typical Array Support Structure for Rack Mount Systems	2-4
Figure 2.1-4	Engineering Design for PV Roof Penetration	2-5
Figure 3.2-1	Ballasted Roof Mount	3-6
Figure 3.2-2	Roof Material Market Shares for New Roofing	3-7
Figure 3.2-3	EPA2 Ballasted Roof System Configuration for 18kW Project ..	3-11
Figure 3.2-4	Location of Participating Utilities for EPA Rooftop PV	3-14
Figure 3.4-1	The AC Module Concept	3-20
Figure 4.1-1	PV/Building Analysis Methodology	4-2
Figure 4.1-2	Impact of Orientation on Curtainwall Array Output	4-4
Figure 4.2-1	Impact of PV Orientation on Office Building Peak (kW) Loads ..	4-6
Figure 4.2-2	Impact of PV Orientation on Retail Building Peak (kW) Loads ..	4-6
Figure 4.2-3	Impact of PV on Albuquerque Office Building Hourly Electricity Use	4-8
Figure 4.2-4	Impact of PV on Albuquerque Retail Building Hourly Electricity Use	4-8
Figure 4.2-5	Impact of PV Orientation on Office Building Electric Energy Consumption (kWh)	4-9
Figure 4.2-6	Impact of PV Orientation on Retail Building Electric Energy Consumption (kWh)	4-9
Figure 4.2-7	Impact of Curtainwall PV System on Office Building Peak (kW) Loads	4-12
Figure 4.2-8	Impact of Curtainwall PV on Albuquerque Office Building Hourly Electricity Use	4-12
Figure 4.2-9	Impact of Curtainwall PV on Office Electric Consumption	4-13
Figure 4.2-10	Impact of IRP and Externality Benefits on Commercial Building Allowable System Price - 5 Year Payback	4-14
Figure 4.2-11	Impact of IRP and Externality Benefits on Curtainwall Office Building Allowable System Price - 5 Year Payback	4-14
Figure 4.3-1	Impact of PV Sizing and Utility Buyback on Annual Single Family Building Electric Consumption	4-16
Figure 4.3-2	Impact of PV on Monthly Single Family Building Peak Load ...	4-16
Figure 4.3-3	Impact of IRP and Externality Benefits on Residential Building Allowable System Price - 5 Year Payback	4-18
Figure 5.1-1	BIPV Market Penetration Methodology	5-2
Figure 5.1-2	Electricity Consumption By Building Type (1989)	5-7
Figure 5.1-3	Market Penetration Curves Characteristic of Energy Saving Technologies (From the Customers Perspective)	5-14
Figure 5.4-1	Commercial Building Paybacks by Region (1995)	5-21
Figure 5.4-2	Commercial Building Payback Periods for the Pacific Southwest	5-22
Figure 5.5-1	Commercial Building Paybacks With Aggressive Module Pricing	5-25
Figure 5.6-1	Large Area PV Skylights	5-27
Figure 5.6-2	Sloped PV Skylight System	5-28
Figure 5.6-3	Double-Glazed PV Atrium Roof	5-30
Figure 5.6-4	Paybacks for Crystalline Silicon Atriums/Skylights	5-32

List of Figures

Figure 5.6-5	Paybacks for Atriums/Skylights Using Advanced Thin-Film Modules	5-31
Figure 6.2-1	Communication Coordination for BIPV Program	6-4

List of Tables

Table 2.1-1	Average PV Prices for Retrofit, Flat Roof, Commercial Buildings With Hard Connection (Roof Penetration) 30kW (1994\$/Wpac)	2-6
Table 2.1-2	Average PV Prices for Standoff, Retrofit Residential Buildings - 4kW (1994\$/Wpac)	2-9
Table 3.1.1	Building Integral PV Installations	3-2
Table 3.1-2	Average PV Prices for New Construction, Flat Roof, Commercial Buildings, Rack Mount - 30kW (1994\$/Wpac)	3-3
Table 3.1-3	Average PV Prices for New Construction Residential Buildings, Integral System - 4kW (1994\$/Wpac)	3-4
Table 3.2-1	Ballasted Mount Weight (lbs/ft ²)	3-5
Table 3.2-2	Summary of Key Concerns With Ballasted Mount Systems	3-9
Table 3.2-3	PV Prices for Retrofit/New Construction Commercial Buildings At 15 Degree Tilt For A Flat Roof, Ballasted System - 30kW	3-12
Table 3.2-4	Price Summary for EPA1 Projects (Primarily Ballasted Mount)	3-13
Table 3.3-1	Opaque Wall Materials Used With Curtainwalls	3-16
Table 3.3-2	Average Prices for Crystalline PV Curtainwall Applications - New Construction, Commercial Buildings (1994\$/Wpac)	3-18
Table 3.4-1	PV AC Module Prices	3-22
Table 3.4-2	Projected Costs of Three Inverter Types (\$/Wpac)	3-23
Table 3.4-3	Average PV Prices for Standoff, AC Module on Retrofit Residential Buildings - 4kW (1994\$/Wpac)	3-23
Table 3.4-4	Average PV Prices for AC Module, Integral System, New Construction Residential Buildings - 4kW (1994\$/Wpac)	3-24
Table 3.4-5	Average PV Prices for an AC Module Mounted on a Flat Roof, Retrofit or New Construction Commercial Building at 15 Degree Tilt, Ballasted System (1994\$/Wpac)	3-24
Table 3.4-6	Prices for Crystalline PV Curtainwall Applications Using AC Module (1994\$/Wpac)	3-25
Table 4.1-1	Commercial Building Characteristics	4-1
Table 4.1-2	Single Family Building and Electricity Consumption Characteristics	4-3
Table 4.2-1	Impact of PV on Office Building Annual Electricity Costs	4-10
Table 4.2-2	Impact of PV on Retail Building Annual Electricity Costs	4-10
Table 4.2-3	Impact of Curtainwall PV on Office Annual Electricity Costs	4-13
Table 4.3-1	Impact of PV on Single Family Residence Annual Electricity Costs	4-18
Table 5.1-1	PV System Performance and Size Assumptions	5-1
Table 5.1-2	BIPV System Price Assumptions	5-3
Table 5.1-3	IRP Assumptions	5-3
Table 5.1-4	Percent Correlation Between Utility Peak and PV Output	5-8
Table 5.1-5	Commercial Sector Capacity Credits	5-9
Table 5.1-6	Multifamily Capacity Credits	5-10
Table 5.1-7	Examples of T&D Annual Benefits Calculated for Various Utilities	5-11
Table 5.1-8	Regional SO ₂ , NO _x , and CO ₂ Emissions in lbs/kWh	5-12
Table 5.1-9	Regional Externality Values in \$/lb of Emissions	5-12
Table 5.1-10	Average Regional Externality Values in \$/kWh	5-13

List of Tables (continued)

Table 5.2-1	Residential Sector Electricity Rates (\$/kWh)	5-16
Table 5.2-2	Multifamily Sector Electricity Rates (\$/kWh)	5-17
Table 5.2-3	Commercial Sector Electricity Rates (\$/kWh)	5-18
Table 5.4-1	Upper Bound BIPV Market Penetration With and Without IRP Benefits	5-20
Table 5.5-1	Advanced Module BIPV Market Penetration With and Without IRP Benefits	5-24
Table 5.6-1	Rule of Thumb Estimates for Material Credits	5-29
Table 5.6-2	Advanced Thin-Film Module, Atrium Roof, System Prices and Efficiencies - Before Material Credits	5-31

Executive Summary

Arthur D. Little, Inc., in conjunction with Solar Design Associates, conducted a study for the US Department of Energy (DOE), Office of Building Technologies (OBT) to determine the market potential for grid-connected, building-integrated photovoltaics (BIPV). This study defines BIPV as two types of applications: 1) where the PV modules are an integral part of the building, often serving as the exterior weathering skin, and 2) the PV modules are mounted on the existing building exterior. Both of these systems are fully integrated with the energy usage of the building and have potential for significant market penetration in the US. Off-grid building applications also offer a near-term market for BIPV, but are not included in the scope of this study.

BIPV Cost Reduction Options

This report initially discusses various cost reduction options for BIPV such as ballasted roof mount, curtainwall applications, AC modules, and other integral systems to evaluate their economic attractiveness in US residential and commercial buildings. Cost data are provided for modules, inverters, wiring, installation, and other indirect costs for the years 1994, 1995, 2000, 2005, and 2010, and for various types of BIPV systems for new and retrofit applications. These data are then input into the *ADL PV Market Penetration Model* to estimate potential national energy savings.

BIPV Building Analysis/Economics

The impact of BIPV on residential and commercial building load profiles were evaluated and the resulting economic savings that can be achieved by implementing BIPV were calculated. Information on the BIPV system's orientation, tilt, and performance characteristics were input into the *ADL PV Performance Model*, a simulation model developed by Arthur D. Little. The data were then coupled with hourly building load data to simulate the impact of the BIPV system on a given building's load profile. This approach evaluated the benefits of BIPV from the building/customer perspective.

The building runs conducted for commercial (retail and office) buildings indicate that BIPV without storage or load management in some cases may not reduce a building's peak significantly if the building load peaks longer than coincident PV output. This is most evident in retail facilities where building loads commonly extend into the evening. Office buildings, by contrast, show a greater potential for building peak demand reduction as their loads do not extend as long into the evening. Demand charge savings for BIPV on office buildings in areas that have high demand charges, ~\$20/kW in New York for example, are almost as large as the savings based on BIPV energy displacement (kWhs).

Current rate schedules for demand charges typically reflect an 11-12 hour on-peak period where premium demand charge rates are imposed on the end-user Monday through Friday from about 8AM to 7- 8PM. Demand charges are currently calculated based typically on the highest 15 minute peak during a given month. This creates an

important barrier to achieving demand charge savings from the customer perspective. Public Utility Commissions, utility companies, and the PV industry need to assess the basis for these demand charge schedules and determine how modifications to rate structures can be made that more accurately reflect the premium cost of generating electricity during critical peak cooling load hours during the middle and late afternoon of the day, and that will more accurately capture the benefits of many BIPV systems to the utility. Although individual building loads may peak longer than coincident BIPV output, there may be substantial correlation of BIPV systems with utility peak load profiles. This analysis is discussed in the following section of this executive summary. In addition, operational strategies for BIPV need to be investigated to further enhance the value of BIPV systems.

Commercial Office Building - Rooftop

The Southwest orientation/latitude tilt ($\pm 10^\circ$) is one of the more favorable configurations for BIPV to reduce power demand (kW) for an office building. The model run conducted for the prototypical office building shows that on the peak building load day, the building load can be reduced by 44% of the theoretical maximum peak reduction (i.e., the rated capacity of the PV system) without any battery storage or load management such as cycling off of AC loads.

Commercial Office Building - Curtainwall

Office building load profiles with a vertical BIPV curtainwall system resulted in a demand reduction of approximately 25% of the rated capacity of the system without storage and cycling off of AC loads. The annual energy savings from a curtainwall system are 34% less than a BIPV with a latitude tilt, true south orientation. During summer months, which are often utility peak months, the curtainwall BIPV system monthly building electricity savings are ~50% less than a BIPV with a latitude tilt, true south orientation. This loss in energy performance is somewhat compensated for by material credits associated with displacement of Spandrel glass and other curtainwall materials.

Residential Rooftop

Residential building loads tend to be low during the day when BIPV output is greatest. Residential customers therefore need to export their power to the utility to improve the economics of the BIPV system. The ability of a residential customer to sell BIPV power to the utility at or near the customer cost of power is critical for their economic viability. BIPV systems in areas with shorter cooling seasons such as Albuquerque, Figure E-1, have the greatest need to sell their excess power back to the utility, if they do not have storage, to be more economical.

BIPV Allowable System Price Without IRP Benefits

The BIPV annual energy cost savings were used to determine a maximum allowable system price for BIPV, assuming a five-year payback period. Both residential and commercial customers typically use some form of simple payback consideration (e.g. rather than a more formal rate of return or cost of capital type analysis) to assess the economic value of energy saving technologies. Based on field interviews, consumer surveys, and analyses of market experience with a variety of energy saving technologies, Arthur D. Little has developed curves that relate market penetration rates to economic performance from the consumer perspective. These curves show that

Figure E-1 Impact of BIPV Sizing and Buyback Potential on Single Family Electricity Savings

the threshold payback period (i.e. upper limit) required for significant market penetration is four to five years. This analysis therefore used a five year payback to estimate an allowable system price that customers most typically would be willing to pay for BIPV.

The "allowable BIPV system prices" were determined initially from the building/customer perspective. Arthur D. Little, however, did evaluate several scenarios. One of the scenarios showed some benefits of BIPV from the utility perspective and used data provided by the State University of New York at Albany (SUNYA) to show BIPV correlation with utility loads. Effective Load Carrying Capability (ELCC) values were derived for nine regions of the US for which the *ADL Market Model* was developed, Table E-1. ELCC, as defined by SUNYA, is the effective increase in a utility's installed capacity due to the added resource, at a constant loss of load probability. Using the value of these correlations can potentially increase the allowable system price for BIPV systems, as shown in Table E-2.

Table E-1 BIPV ELCC Correlations

Region	Capacity Correlation (%) (ELCC) ¹	Representative Utility
New England (Boston)	50	NEES
Middle Atlantic (New York)	60	LILCO
East North Central (Chicago)	60	NSP
West North Central (Minneapolis)	60	NSP
South Atlantic (Miami)	45	FP&L
East South Central (Birmingham)	55	SES
West South Central (Dallas)	65	TU
Pacific Southwest (Los Angeles)	70	PG&E
Pacific Northwest (Olympia)	20	Relative to all northwest

¹ ELCC—Effective Load Carrying Capability. A statistical measure of effective capacity—the effective increase in a utility's installed capacity due to the added resource, at a constant loss of load probability. These percentages assume 2% PV penetration on the considered grid. If 10% PV penetration is assumed, then the above ELCC percentages would be 3–5% less.

Source: Telephone interview with Richard Perez at SUNYA, August 1994.

Table E-2 Average Allowable BIPV System Prices for the Southwest US - Without IRP Benefits¹

Building Type	Allowable System Price Customer Perspective (\$/kW)	Allowable System Price Adjusted for Utility ELCC ² (\$/kW)
Office	~\$1,150	~\$1,300
Retail	~\$750	~\$1,500

¹Using current utility rates and assuming a five year payback and 10% federal tax credit. Allowable prices could be higher for niche applications, such as in strained areas of the grid where T&D benefits would be higher.

²ELCC - Effective Load Carrying Capability.

Impact of IRP Benefits on BIPV Economics

The most favorable BIPV analysis assumes energy savings, potential demand charge savings, and Integrated Resource Planning (IRP) benefits. IRP benefits include environmental externality benefits (correlated with kWh savings), transmission and distribution deferred costs, and capacity credits (correlated with coincident kW savings).

This study has shown that IRP benefits, if properly assigned, can increase significantly the allowable BIPV system price for commercial buildings, as shown in Table E-3 for an analysis that used existing utility rates. These IRP benefits are potentially very important to the cost-effectiveness of BIPV systems and can increase the allowable installed system price approximately 50-80% - if benefits gained by the utility for the BIPV systems are passed on to the consumer in some form of rebates or "cash incentives".

If the industry does not move to encourage utility groups and Public Utility Commissions to value these benefits, the market for BIPV in the US will be more limited based on economics.

Table E-3 Average Allowable BIPV System Prices for the Southwest US¹

Building Type	Allowable BIPV System Price - No IRP Benefits and Adjusted for Utility ELCC (\$/kW)	Allowable BIPV System Price - With IRP Benefits and Adjusted for Utility ELCC ² (\$/kW)
Office Rooftop	~\$1,300	~\$2,000
Office Curtainwall	~\$1,000	~\$1,600
Retail Rooftop	~\$1,500	~\$2,300
Single Family Rooftop	~\$1,350	~\$1,800

¹Using current utility rates and assuming a five year payback and 10% federal tax credit. Allowable prices could be higher for niche applications, such as in strained areas of the grid where T&D benefits would be higher.

²ELCC - Effective Load Carrying Capability.

Impact of BIPV on National Energy Savings

Four ADL PV Market Models were used to assess the potential impact of BIPV on national energy savings for single family, multifamily, and commercial buildings. Separate models for rooftop and curtainwall systems were used to evaluate commercial building applications. The models used existing and forecast data for utility rates, BIPV system performance, installed system pricing with BIPV cost reduction options, and potential IRP benefits to determine consumer payback, consequent market penetration, and the resulting energy savings potential.

As discussed above, the incorporation of IRP benefits results in shorter payback periods and significantly better economics. The value of these potential IRP benefits, for example, in the Pacific Southwest in the year 2005 for rooftop commercial building applications, can reduce the payback period from 16 years with no IRP benefits to 11 years with IRP benefits, Figure E-2.

The addition of IRP benefits, which increases market penetration, results in an annual US market between 600–700 MW/yr by the year 2010 for building applications. If IRP benefits are not assigned, this market size is less than 5 MW/yr (based strictly on an economic analysis and not including demonstration programs).

Aggressive module cost reductions can also have a significant impact on the market penetration of BIPV systems. Many projections have been made by module manufacturers that advanced thin-film PV module materials can achieve direct manufacturing costs below \$1/Wpac by the year 2005. Adding appropriate profit margins for manufacturers still results in significant BIPV cost reductions. These aggressive module cost reductions, along with the BIPV cost reduction options identified in this study, can further improve BIPV economics. The same payback period discussed above for the year 2005 in the Pacific Southwest would be 13 years without IRP benefits and nine years with IRP benefits, Figure E-3.

Advanced thin-film module materials combined with BIPV cost reduction options can therefore result in significant annual markets in the 2005–2010 time period. Even a small fraction of building penetration results in relatively large markets because of the magnitude of the building sector. The potential BIPV market penetration for the US could reach 600-700 MW/yr by 2005 and 1300–1600 MW/yr by 2010 if IRP benefits are incorporated along with very aggressive module and installed BIPV cost reduction options. Without IRP benefits, BIPV market penetration will likely be less than 30 MW/yr in the US by 2005, based strictly on an economic analysis from the customer perspective.

To achieve large market penetration values, the industry must promote activity that focuses on reducing installation costs, and provide supporting data to show the BIPV/utility interface benefits. Currently, IRP benefits are not given to BIPV systems. Although the BIPV output may not correlate well with some building load profiles, the utility should acknowledge the BIPV system output correlation with their overall peak load. The PV industry, DOE and Public Utility Commissions (PUCs) need to promote the value of BIPV until the customer receives rebates or cash incentives that more accurately reflect the IRP benefits to the utility.

Figure E-2 Impact of IRP Benefits and ELCC on Payback Periods

- Scenario A: PV with Energy Charge Savings (no additional benefits)
 Scenario B: Scenario A with Demand Charge Savings ¹
 Scenario C: Scenario B with IRP Benefits (T&D and Capacity Credits included) ²
 Scenario D: Scenario C with Environmental Externalities included ²

Assumptions: All scenarios represent a 30 kW AC module system at a south-facing, 15-degree tilt and with a ballasted mount on a flat roof. Total system installed costs are, including one-step distribution (15% markup) and a 10% federal tax credit, \$7.10/Wpac (1995), \$5.30/Wpac (2000), \$4.00/Wpac (2005), and \$3.50/Wpac (2010).

Figure E-3 Impact of IRP Benefits and ELCC on Payback Periods Using Aggressive Module Pricing

- Scenario A: PV with Energy Charge Savings (no additional benefits)
 Scenario B: Scenario A with Demand Charge Savings ¹
 Scenario C: Scenario B with IRP Benefits (T&D and Capacity Credits included) ²
 Scenario D: Scenario C with Environmental Externalities included ²

Assumptions: All scenarios represent a 30 kW AC module system at a south-facing, 15-degree tilt and with a ballasted mount on a flat roof. Total system installed costs are, including one-step distribution (15% markup) and a 10% federal tax credit, \$3.25/Wpac (2005), and \$2.60/Wpac (2010).

Notes for Figures E-2 and E-3

- ¹ Assumes a percentage of system capacity is recovered through demand charge savings. This ELCC percentage varies by region.
² T&D avoided costs and environmental externality benefits assume utilities will pass on "cash incentives" to consumers. To date, monetized values have not been offered for these benefits.

Conclusions

- For residential systems, it is essential that BIPV systems be able to sell back to the utility at or near the customer cost of power, rather than at the utility avoided cost. Sell back to the utility at these rates ensures more favorable economics.
- Variations in commercial electric rate structures are as important in defining BIPV economics as variations in insolation.
- The basis for utility demand charge rate schedules need to be reviewed and modified, if appropriate, to more accurately reflect the BIPV benefit to the utility.
- There are high-value, niche markets for BIPV systems that can be cost-effective in the near-term such as strained areas of the utility grid or selected sloped glazing and skylight systems where premium material credits are combined with optimal PV performance.
- The ability to obtain utility IRP benefits, combined with projected BIPV system cost reductions, can potentially result in large BIPV market penetrations from the customers economic perspective.
- The industry, DOE, and the PUCs should work together to properly value BIPV benefits. Proper assignment of capacity credits, T&D avoided and deferred costs, and environmental externalities can accelerate the BIPV market penetration and result in significant energy savings.

1.0 Background

1.1 What Is BIPV

There is a growing consensus that distributed photovoltaic (PV) systems will be among those applications to first reach widespread commercialization in the generation of power on the utility grid. Chief among these distributed applications are PV power systems for individual buildings. Interest in building-integrated photovoltaics (BIPV) is growing worldwide. This report defines BIPV as basically two types of grid-connected applications: 1) where the PV modules actually become an integral part of the building, often serving as the exterior weathering skin, and 2) PV modules installed over the existing building exterior. Both of these systems are fully integrated with the energy usage within the building and have potential for significant market penetration in the US. Off-grid building applications also offer a near-term, niche market for BIPV, but are not included in the scope of this study.

There are many advantages to BIPV systems. An architecturally clean, well-integrated system is aesthetically pleasing, which significantly increases acceptance on the part of design professionals, building owners, and the general public. In addition, when a BIPV system is an integral part of the building, BIPV components displace conventional building materials and labor, potentially reducing the installed system cost of the PV system.

BIPV are typically grid-connected and can displace electricity on the customer side of the meter at the retail rate, whereas centrally located PV plants displace conventional fuels at the utilities avoided cost. In addition, these BIPV systems avoid or dramatically reduce the costs and losses in the transmission and distribution of electricity from central power plants, which in some utility systems can approach 10-15%.

1.2 Study Objectives

Arthur D. Little conducted this study for the US Department of Energy (DOE), Office of Building Technologies (OBT) to determine the market potential for BIPV. The DOE OBT manages a broad spectrum of multi-disciplinary programs that address all aspects of energy-related issues and technology development for the building sector. Within the OBT resides DOE's expertise and knowledge in:

- energy efficient building design and analysis;
- building energy systems and materials technology development;
- building renewable energy systems development and integration;
- Federal building energy management and building technology application test beds;
- building codes and standards, appliance standards, equipment certification and test procedures; and
- prior BIPV activities in the late 1970s and early 1980s.

DOE OBT has worked integrally with and is very knowledgeable of the building industry and associated infrastructure supporting design, construction and servicing of commercial and residential buildings.

This study was initiated within OBT with the main objective of assessing the potential national energy savings that could be realized from BIPV applications by the year 2010.

1.3 Project and Report Organization

This project initially brought together over 55 builders, contractors, PV manufacturers, utility companies, architects/engineers, and government agencies to discuss the status of BIPV technology and determine ways to accelerate their development into the marketplace. Arthur D. Little, Inc., with Solar Design Associates, the National Renewable Energy Laboratory (NREL), and DOE, organized a two day meeting to ensure that the project participants were familiar with the key issues and barriers potentially facing the industry, and to work toward accelerating the needed development of BIPV. The participants also provided feedback on market assumptions that were to be used in Arthur D. Little's market penetration analysis.

After the meeting, comments from the participants were incorporated into a new statement of work. The first task was to establish a baseline of current installed costs of BIPV systems for retrofit and new building applications. Once this baseline was established, key cost reduction options and their potential for reducing installed system costs to levels that would make PV more cost-effective for residential and commercial buildings were determined. Using the most cost-effective building integration techniques, BIPV economics were calculated. Arthur D. Little developed residential and commercial building load models, along with Lawrence Berkeley Laboratory, that were used to determine the potential annual energy cost savings of implementing BIPV for roof mounted systems at various tilt angles and curtainwall (vertical tilt) applications. The potential for reducing utility demand charges was also estimated based on the hourly load profiles of the building relative to the PV output. These annual cost savings, along with the total installed system price with the cost-reduction techniques, guided the market penetration model development and analysis for single family, multifamily, and commercial buildings. An overall project organization is provided in Figure 1.2-1.

The National Association of Home Builders (NAHB), under a separate contract to DOE, evaluated the technical and non-technical barriers for implementing PV in buildings. A report summarizing their results can be obtained from Oak Ridge National Laboratories.

This report is organized into six sections. Section 1.0 provides a brief introduction to the overall report. BIPV costs for both new and retrofit buildings for various types of mounting systems are presented in Section 2.0. The cost structure of PV is currently too expensive to have significant penetration in the building market. In addition to module cost reduction, many efforts have been made to reduce balance of system (BOS) costs. Section 3.0 discusses several cost reduction options and strategies. The option with most significant cost reduction potential is later applied to the market penetration models to determine their ultimate impact on national energy savings.

Section 4.0 presents the BIPV building analysis and economics. This section shows the correlation of PV output to single family, office and retail building electrical loads. The annual cost savings for both residential and commercial buildings are included, discussing the impact of energy savings alone, potential demand charges savings (for the commercial sector), and Integrated Resource Plan (IRP) benefits.

The assumptions used in the market analysis and the potential impact of BIPV on national energy savings are discussed in Section 5.0. Based on the energy savings potential, the feedback from the Boston Workshop, and findings during the course of the cost-reduction analysis, Section 6.0 provides DOE with recommendations for future BIPV program plans.

Arthur D. Little conducted a market study for the Electric Power Research Institute (EPRI) entitled, The Market for Solar Photovoltaic (PV) Technology, March 1993. This study for the US DOE supplements the EPRI study and addresses issues in more depth for building applications of PV. Detailed costs and various BIPV cost reduction options are discussed, specifically analyzing building loads and their correlation to PV output at various tilt angles and orientations. In addition, new data were available at the time of this DOE study to assess with more accuracy the details of PV output correlation to utility peak loads in nine regions of the US. This data was taken from a study conducted by the State University of New York, Albany (SUNYA), and was applied to more accurately determine what portion of capacity credits, T&D benefits, and other demand related savings could potentially be passed on to the consumer from benefits gained by the utility for the implementation of BIPV. Details of the analyses are provided in Sections 4.0 and 5.0.

As mentioned above, DOE sponsored a two-day workshop on "Accelerating The Development of BIPV" in Boston. A workshop summary is provided in Appendix A. This contract also supported US attendance at two International Energy Administration (IEA) Task 16 meetings. Appendix B provides an overview of worldwide development activity in BIPV. Appendix C provides a glossary of terms and abbreviations to facilitate reader understanding of terms commonly used in the BIPV industry.

Sample outputs from the Arthur D. Little BIPV Market Penetration Models are shown following Appendix C.

2.0 BIPV Costs With Conventional Mounting Techniques: 1994 - 2010

This section discusses approaches and costs associated with installing PV on new and retrofit commercial and residential buildings. The four generic PV mounting types that have been used for placing PV on buildings are: rack; standoff with *Roof-Jacks*; direct; and integral, Figure 2.1-1. Newer and more cost-effective techniques such as a ballasted mounting system for commercial flat roof buildings utilizing steel trays or precast concrete blocks along with *Roof-Jacks* or aluminum struts have also recently been used. These newer approaches, offering substantial cost-reductions, are presented in Section 3.0, "Cost Reduction Options".

2.1 Retrofit Buildings

2.1.1 Commercial Buildings

Retrofit commercial buildings have typically used rack mount techniques due to the fact that most commercial buildings have a flat vs. sloped roof construction. A study by Jet Propulsion Laboratory estimated that approximately 80% of the total commercial roof square footage area is low slope - with a pitch of 3:12 or less.¹ A rack mounted design on a flat roof building allows one to mount the PV module at an optimum tilt angle. A rack mounted system in commercial buildings also provides flexibility in the location of the PV system and ease of maintenance. The mounting structure and labor costs for installation associated with this type of system are extremely costly for flat roof commercial buildings. The installer must locate the building structure and penetrate the roof membrane to make strong connections to secure the PV module to the building.

The structural costs for the supports increase as the height and mounting angle of the modules increase due to resistance to dead loading and wind uplift. For a 20kW ballasted roof mount (no roof penetration), PV system installed by Integrated Power at the New York Transit Authority in Queens, upward wind loads on panels were calculated at 14 pounds per square foot (psf) of panel, applied in a upward direction and perpendicular to the panel plane. This was in accordance with State of New York Code Title 9 Table VI-803.² Winds can also result in downward forces of 90-100 psf on a module, as shown in Figure 2.1-2 for a roof penetration type of mounting system.

Building codes require costly structural requirements to penetrate the roof of existing buildings for adequate structure support and to prevent leaks from roof penetration. An engineering design showing the stub-ups, pitch pockets, I-beam, and steel structure are presented in Figures 2.1-3 and 2.1-4. Table 2.1-1 presents a breakdown of the current and projected costs that are incurred with this type of hard connection, roof penetration system.

The high costs presented in Table 2.1-1 are associated with the need for structural stub-ups through the roof every 16-20 feet at a cost of about \$300 per point and associated costs of making leakproof roof penetrations. A 20kW amorphous silicon array, for example, with seven rows 84 feet long and six panels per row would require 98 roof penetrations. Each panel requires two roof penetrations and an extra pair of penetrations are needed at the end of each row. This results in a cost of \$29,400 or about \$1.80/Wpac. The stub-ups and pitch pockets required must also be installed in good weather conditions to avoid roof leakage.¹⁰

Rack

**Stand-off
Roof Jack**

*** Direct Mount**

Integral

*No longer widely applied with thicker crystalline modules. Shows potential with thin-film materials.

Figure 2.1-1: PV Mounting Types

Figure 2.1-2 Schematic of PV Rack Mounted System on Flat Roof

Source: Solar Design Associates, January 1994

Figure 2.1-3 Typical Array Support Structure for Rack Mount System

Source: Solar Design Associates, January 1994

Figure 2.1-4 Engineering Design for PV Roof Penetration

Table 2.1-1 Average PV Prices for Retrofit, Flat Roof, Commercial Buildings With Hard Connection (Roof Penetration) - 30kW (1994\$/Wpac)¹

Component	1994	1995	2000	2005	2010
Mounting Structure ²	3.25	3.25	2.80	2.45	2.45
PCU/Aux. Equipment ³	1.10	.90	.70	.50	.40
Module Installation ⁴	.15	.15	.10	.05	.05
Wiring and Electricals ⁵	.30	.30	.25	.25	.20
Other Indirect ⁶	.50	.50	.40	.30	.25
Sub-Total BOS	5.30	5.10	4.25	3.55	3.35
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	9.70	9.35	7.25	5.75	5.35
Total System Price (15% Markup)	11.15	10.75	8.35	6.60	6.15

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings). Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Includes cost of stub-ups, pitch pockets or membrane flashing, I-beam and steel structure, half the cost of the crane (\$.15/Wpac) and labor. Single, nonvolume mounting structure costs for comparison are \$4.30/Wpac (1994, 1995), \$3.75/Wpac (2000), \$3.25/Wpac (2005, 2010).

³Based on 15kVa Abacus Controls Sunverter Model 7158-4-200 three phase power inverters (\$.90/Wpac). Ground fault detection will be part of unit in 1995. Price includes isolation transformer and EMI/RFI filters in unit, and labor/electrical supplies (\$.20/Wpac). Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$.70-.85/Wpac for commercial size units.

⁴Includes the cost of labor and half the cost of crane and vehicles (\$.15/Wpac total cost). Other half of crane cost and vehicles associated with mounting structure.

⁵Outdoor conduit @ \$3.56/ft for 1.5" conduit, schedule 40 PVC with labor. Stranded copper wire (#12THHN) @ \$.36/ft. with 10 conductors for 300ft run = \$2,160 for array to equip. room. Module to module connections and mounting of electrical equip. such as string combiner box. Master electrician and helper 1wk of time = \$4,000. Misc. equip (fasteners, conductor clips etc.) = \$1,000.

⁶Includes insurance, packing (\$.10/Wpac), shipping (\$.10/Wpac), local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

Source: Arthur D. Little estimates, based on discussions with Abacus Controls, Solar Engineering, SMUD, Solar Design Associates, and Ascension Technology, January 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wiring prices.

Other costs associated with a rack mounted, roof penetration mounting structure include: I-beams, steel structures, and bolts and fasteners. The structural members, depending on the module tilt can range from \$.50- \$1.00/Wpac. The material cost to attach a 4" pipe stub to the existing roof structure is about \$100. Associated labor and welding costs can vary significantly depending on the type of roof structure and roof condition. A single membrane roof, for example, will have very different costs than a built-up, tar and gravel roof mounting system. Additional labor is needed for welding the attachment to the structure and to deal with local building code authorities. A structural analysis of the building is often required to determine if the building can carry the load of the PV system. If this information is not available, additional engineering costs are incurred.¹⁰

Insurance and roof warranty policies may be compromised with the installation of BIPV mounting systems that penetrate the roof. This issue has negatively impacted the installation of PV on commercial buildings. Insurance companies and building code officials must be well educated about the installation and maintenance of a PV system to facilitate these types of installations in the future.

2.1.2 Residential Buildings

Retrofit residential buildings typically use standoff or direct mount techniques as the roof slope of residential buildings provides adequate tilt and support, thereby eliminating the need for a rack mount system. Standoffs separate the modules from the roof to allow air and water to pass beneath the module. This space facilitates cooling of the PV modules and therefore slightly improves overall module efficiency. Standoffs have an advantage over direct mount in that the angle of the modules can be slightly more flexible and not rely completely on the pitch of the roof. Direct mount systems have been investigated for residential retrofit applications. Modules with these systems are directly attached to the roof, eliminating some structural supports. The modules are typically placed on a waterproof membrane, therefore the back surface is not exposed for electrical connections and no cooling airflow is possible. Direct mount systems are rarely applied for these reasons with thicker crystalline modules.

The *Roof-Jack* mounting system was developed at the Massachusetts Institute of Technology (MIT) in 1985 for more efficient application of standoff mounting. The mounting system has subsequently been refined by Ascension Technology. The cost of materials and labor for an installation on a retrofit residential pitched roof was below \$.50/Wp in 1985.⁵ This system uses "L"-shaped brackets that have a slot to support PV modules at four points. The modules have four pin assemblies that protrude from two sides of the panel. The pins from the module slide into the *Roof-Jack* slot where they sit in place. No tools are needed to attach the modules to the *Roof-Jack* system.⁴ *Roof-Jacks* are secured to the roof with lag-screws that are driven through the roofing material and into the wood sheathing. Sealants and washers are used to ensure no leakage at the attachment points.⁶

Modules for a *Roof-Jack* system are mounted on two aluminum channels that are preassembled and electrically interconnected before being shipped to the installation site. The modules are then prewired with panel-to-panel jumpers equipped with

connectors to minimize field installation labor costs. Large area modules eliminate the need for this preassembly and wiring to further reduce costs.⁶

As shown in Table 2.1-2, the prices associated with a residential retrofit application are significantly less expensive than a flat roof commercial building using traditional mounting techniques. System prices direct from the manufacturer are on average \$7.05/W_{pac} compared to \$9.70/W_{pac} for flat roof commercial buildings with roof penetrations, assuming volume installations.

The power conditioning unit (PCU) price is based on a unit sold by Omnion Power Engineering Corporation. It is a Series 2200 static power converter designed to maximum power track PV arrays for 200 to 250Vdc and produce up to 33.4Aac into a standard 120V, 60Hz ac circuit. The price shown in Table 2.1-2 is for a 4kW unit priced at about \$3,600 for volume purchases of 100 units. These inverters operate at about 90% efficiency. In 1994 and 1995 ground fault detection has been added bringing the total price to \$4,560 to meet National Electric Codes (NEC). It is expected that ground fault detection will not be required in the next revision to the NEC.⁶ However, building inspectors need to see Underwriters Laboratories (UL) approval of the inverters to facilitate the BIPV system installations.^{4,11}

Some inverter units manufactured by Abacus Controls are expected to include the ground fault detection as part of their basic unit by 1995. The Abacus 5kW Sunverter Model 753-4-200 and two 15kVa Model 7158-4-200 (for the commercial 30kW size) were used for the analysis of commercial size inverter prices. Future price reductions will likely be a result of state-of-the-art electronics such as Insulated Gate Bipolar Transistors - IGBTs, which are now used in some inverter systems, and the manufacture of more standard systems from major suppliers vs. specialty manufacturers. This latter issue will likely be the outcome of volume production. One inverter manufacturer claimed that inverter prices of \$.40/W_p could be achieved today if volume quantities were sold.⁷

Pricing Assumptions. All prices shown in Sections 2.0 and 3.0 have been converted to \$ per net system output based on PVUSA Test Conditions (PTC) in constant 1994 dollars. PV system prices at standard test conditions (STC) of 1000W/m² irradiance and 25 degrees Celsius cell temperature are divided by .80 to determine system prices that account for cumulative DC to AC losses such as module mismatch, wiring, and diode losses, inverter losses (8-10%), and temperature derating of array power. Peak STC costs can also be multiplied by 1.25 to achieve the same \$ per net system output (ac) given the following PTC assumptions:^{8,9}

- Plane of Array: 1000W/m²
- Ambient Temperature: 20 degrees C
- Cell Temperature: 50 degrees C
- Wind Speed of 1 m/s

Table 2.1-2 Average PV Prices for Standoff, Retrofit Residential Buildings - 4kW (1994\$/Wpac)¹

Component	1994	1995	2000	2005	2010
Mounting Structure ²	.60	.55	.50	.45	.40
PCU/Aux. Equipment ³	1.20	1.00	.80	.60	.40
Module Installation ⁴	.15	.15	.10	.05	.05
Wiring and Electrical ⁵	.30	.30	.25	.25	.20
Other Indirect ⁶	.40	.40	.30	.25	.25
Sub-Total BOS	2.65	2.40	1.95	1.60	1.30
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	7.05	6.70	4.95	3.80	3.30
Total System Price (15% Markup)	8.10	7.70	5.70	4.35	3.80

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings). Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Includes cost of Roof-Jack system and labor. Heavy weight EPDM, if needed, adds \$.30/Wpac.

³Based on Omnion Power Engineering Series 2200 static power converter with ground fault detection used in SMUD units (\$4,560). Price also includes manual AC and DC disconnect, and source circuit combining circuitry. Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$2.50/Wpac for residential units.

⁴Includes the cost of labor and half the cost of crane and vehicles (\$.15/Wpac total cost). Other half of crane cost and vehicles associated with mounting structure.

⁵Outdoor conduit @ \$3.56/ft for 1.5" conduit, schedule 40 PVC with labor. Stranded copper wire (#12THHN) @ \$.36/ft. with 6 conductors for 100ft run = \$572 for array to equip. room. Module to module connections and mounting of electrical equip. such as string combiner box. Master electrician and helper \$300. Misc equip. = \$150.

⁶Includes insurance, packing (\$.10/Wpac), shipping (\$.10/Wpac), local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

Source: Arthur D. Little estimates, based on discussions with Omnion Power Engineering, SMUD, Solar Engineering, and Ascension Technology, January 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wire prices.

1993-1994 no volume/one kind EPA Roof-Jack, stand-off installations for comparison were:

Residential (4kW)

AZ - \$8.95/Wpac

CA/E - \$8.85/Wpac*

CA/B - \$8.75/Wpac*

Commercial (4kW)

NJ - \$8.85/Wpac

* Does not include panel shipping (about \$.10/Wpac)

The low end of the price range that was shown in Table 2.1-1, illustrates system prices direct to the end-users from the manufacturer with volume purchases and installation for a typical installation. This direct distribution results in installed system prices of \$9.70/Wpac (Watts peak alternating current) for volume installations of between 400-500kW. *There are, however, a wide variety of commercial building roof types and age of the existing inventory which can impact commercial BIPV installation prices significantly for flat roof buildings.*

Assuming distribution mark-ups, single installations can result in costs of up to \$12.50/Wpac. A typical electrical contractor or systems house mark-up adds approximately 15% to the installed system price, and a general contractor would result in an additional overall markup of approximately 25%.³

2.2 New Construction

Most new construction applications of BIPV have been integrated into upscale homes with total installed costs of approximately \$9-10/Wpac for residential applications and \$12-14/Wpac for single installations of flat roof commercial buildings with roof penetrations. The PV support structure can be planned and installed during building construction, so the installer of commercial, flat-roof building does not have to open up an existing roof for a hard connection. Engineering costs can be lower because structural design becomes part of the overall building design. In some cases, the costs can be incorporated into the overall mortgage of the building, further enhancing the economics of the BIPV system. Mounting structure costs can also be eliminated for new construction residential applications.

Detailed costs for new construction are presented in Section 3.0, "Cost Reduction Options". Section 2.2 does not go into detail about new construction applications of PV because there are very limited, site specific data available for the US. The data that does exist are for upscale homes and would not apply to the majority of new construction buildings. Many representatives of the PV industry, however, acknowledge that the initial PV applications in new construction are likely to be for systems where the end-user is willing to pay a premium for the PV system for a "green" public relations image, or for environmental and/or political reasons.

This analysis assumes that most new construction applications, excluding isolated custom installations for "green" public relations or political applications, will occur in the near future when economics will help to drive the purchase and installation decision. When economic attractiveness begins to play more of a role in the building integration marketplace, there will be a significant impact on national energy savings. The near-term will also incorporate added features for cost reduction which are discussed in Section 3.0.

2.3 References

1. Jet Propulsion Laboratory, Commercial/Industrial Photovoltaic Module and Array Requirement Study, Prepared for US Department of Energy, DOE/JPL/955698--81/1, December 1981.
2. Integrated Power, "NREL Operation and Maintenance Manual", 1993.
3. Turner Construction Company, New York, Interview, October 1993.
4. Ascension Technology, Inc. and US EPA Air and Energy Engineering Research Laboratory, "US EPA's Photovoltaic Demand-Side Management Project", Presented to the International Solar Energy Society, Solar World Congress, 1993, Budapest, Hungary.
5. Russell, M.C. and E.C. Kern, Stand-Off Building Block Systems for Roof-Mounted Photovoltaic Arrays, Sandia National Laboratories, SAND85-7020, June 1986.
6. Ascension Technology, Inc. and US EPA Air and Energy Engineering Research Laboratory, "EPA's Photovoltaic Demand-Side Management Cost-Shared Demonstrations", Presented to the American Solar Energy Society, Solar 93 Conference, Washington, DC., 1993.
7. Abacus Controls, Somerville, N.J. Interview, January, 1994.
8. Ascension Technology, Interview based on monitored data of installed PV systems. January, 1994.
9. Pacific Gas & Electric, Alpha Real AG, and Siemens Solar, "Comparison of Selected Economic Factors For Large Ground-Mounted Photovoltaic Systems With Roof-Mounted Photovoltaic Systems in Switzerland and The USA", Proceedings of the 11th European PV Conference, October 1992.
10. Interview with private consulting engineer for Integrated Power, Jeff Shingleton, February 1994.
11. Omnion Power Engineering, Interview, January 1994.
12. Paul Wormser, ASE Americas, Interview, February 1994.

3.0 Cost Reduction Options

3.1 Roof-Integrated Concepts (New Construction/Reroofing)

3.1.1 Technology Description

Roof-integrated BIPV for new construction or reroofing applications offer significant potential for cost reduction relative to conventional retrofit stand-off mounting schemes. There are many approaches to integrating PV directly into the roof structure of a building which have already been implemented, as shown in Table 3.1-1. A recent study by the Florida Solar Energy Center, Evaluation of Roof-Integrated PV Module Designs and Systems, discusses in detail the pros and cons of these various approaches.¹ Many companies are developing unique concepts for incorporating PV directly into new construction or retrofit applications. For example, United Solar Systems Corporation are developing a flat, roof shingle to replace conventional roof shingle materials for residential and light commercial applications. The cost structures discussed below illustrate the approximate costs associated with some of these typical roof-integrated PV systems applied to new construction or reroofing applications.

3.1.2 Potential Impact on Installed PV System Costs

Commercial Buildings. PV installed in commercial new construction and reroofing applications offer potential for cost reduction relative to retrofit applications. For example, most commercial buildings have flat roofs which may require a rack mounting structure in order to provide a tilt angle for the PV system. Since the PV support structure can be planned and installed during building construction or reroofing, the installer does not have to open up an existing roof. Engineering costs are also lower because structural design becomes part of the overall building design. Most of the other costs associated with retrofit systems are the same. Integrating the module with the building structure would result in the installation costs shown in Table 3.1-2 for new construction/reroofing, flat-roof building applications.

Residential Buildings. Residential new construction can be slightly cheaper than retrofit residential applications by eliminating some mounting structure costs. PV modules used as an integral part of the building have to be constructed to standard building tolerances. The modules must withstand all live and dead loads of a conventional roof. The costs for an integral system for new construction or reroofing are shown in Table 3.1-3.

3.1.3 References

1. Florida Solar Energy Center, Evaluation of Roof-Integrated PV Module Designs and Systems, Draft Report Prepared for the National Renewable Energy Laboratory, FSEC-CR-496-92, July 1992.

Table 3.1-1 Building Integral PV Installations

Date	Location	Who	What
1973	Newark, Delaware	Boer	Delaware PV House U. of Delaware
1974	Los Alamos, NM	LANL	Integrated Thermal Collector
1978	Pasadena, CA	JPL	Integrated Roof Test Bed
1978	Pasadena, CA	Boeing	PV Solar Dome
1980	Phoenix, AZ	John Long	Long House Direct-Mount PV
1980	Woburn, MA	Solenergy	Clay PV Shingle
1981	Carlise, MA	Strong	Track Stand-off
1982	Las Cruces/Boston	GE	Hexagonal PV Shingles
1982	Las Cruces/Phoenix	ARCO	Direct Batten and Seam
1982	Las Cruces/Boston	TSC	Vented Batten and Seam
1982	Las Cruces/Boston	WST	Sheathing Panels
1982	Las Cruces/NM	ARTU	Stand-off Sheathing
1982	Georgia	GPC	Future I Batten and Seam
1983	Cape Canaveral, FL	SERES	Prototype 2 Sheathing
1983	Cape Canaveral, FL	SERES	Prototype 3 Batten and Seam
1983	Las Cruces, NM	Mobile	Photobuilding 10 Sheathing
1983	Germany	Melchior	PV Cooling Channel Tile
1983	Stuttgart, Germany	Bopp	Greenhouse Integral-Roof
1984	Brookline, MA	Strong	Integral Batten and Seam
1984	Japan	Sanyo	PV Curved Tile
1984	Georgetown, DC	Hughes	PV Sheathing
1986	Miami/Charleston	GE	PV Channel Sheathing
1986	Santa Maria	GE/SANDIA	PV Sheathing Panels
1986	Boston/Madison	GE/SANDIA	PV Shingles
1986	Tennessee	TVA	Integral-Roof
1986	California	Laaly	PV Single-Ply Roof Membrane
1986	Baltimore, MD	SPIA	PV Membrane
1986	Milton Keynes, UK	Dichler	Conservatory Greenhouse
1986	Germany	Hullmann	Greenhouse Integral-Roof
1987	Japan	Sanyo	PV Flat Tile
1991	Germany	Flachglas	PV Glass Window
1992	New York State	State	Future PV Roofs
1993	Lausanne, Switzerland	USSC, Siemens, APS, Solarex	Integrated Roof Demos
1993	Geneva, Switzerland	Atlantis Energy	Digital Equipment Pyramid
1993	Bern, Switzerland	Atlantis Energy	PV Shingle Roof
1993	Fairfield, CA	APS	Skylights, Curtainwall, Awnings
1994	Fort Davis, TX	USSC	Integrated Roof Recreation Area
1994	Kansas City, MO	USSC	Batten and Seam Integrated Roof

Source: Florida Solar Energy Center, 1992, and Arthur D. Little, Inc. 1994.

Table 3.1-2 Average PV Prices for New Construction, Flat Roof, Commercial Buildings, Rack Mount - 30kW (1994\$/Wpac)¹

Component	1994	1995	2000	2005	2010
Mounting Structure ²	2.25	2.00	1.75	1.50	1.40
PCU/Aux. Equipment ³	1.10	.90	.70	.50	.40
Module Installation ⁴	.10	.10	.10	.05	.05
Wiring and Electrical ⁵	.30	.30	.25	.25	.20
Other Indirect ⁶	.40	.40	.30	.25	.25
<i>Sub-Total BOS</i>	<i>4.15</i>	<i>3.70</i>	<i>3.10</i>	<i>2.55</i>	<i>2.30</i>
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	8.55	7.95	6.10	4.75	4.30
Total System Price (15% Markup)	9.85	9.15	7.00	5.45	4.95

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings).

Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Reduces cost of stub-ups, pitch pockets or membrane flashing, I-beam, steel structure, labor and crane.

³Based on 15kVa Abacus Controls Sunverter Model 7158-4-200 three phase power inverters (\$.90/Wpac). Ground fault detection will be part of unit in 1995. Price includes isolation transformer and EMI/RFI filters in unit, and labor/electrical supplies (\$.20/Wpac). Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$.70-.85/Wpac for commercial size units.

⁴Includes the cost of labor and half the cost of crane and vehicles (\$.15/Wpac total cost). Other half of crane cost and vehicles associated with mounting structure.

⁵Outdoor conduit @ \$3.56/ft for 1.5" conduit, schedule 40 PVC with labor. Stranded copper wire (#12THHN) @ \$.36/ft. with 10 conductors for 300ft run = \$2,160 for array to equip. room. Module to module connections and mounting of electrical equip. such as string combiner box. Master electrician and helper 1wk of time = \$4,000. Misc. equip (fasteners, conductor clips etc.) = \$1,000.

⁶Includes insurance, packing (\$.10/Wpac), shipping (\$.10/Wpac), local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

Source: Arthur D. Little estimates, based on discussions with Abacus Controls, SMUD, Solar Engineering, Solar Design Associates, and Ascension Technology, January 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wire prices.

**Table 3.1-3 Average PV Prices for New Construction Residential Buildings, Integral System - 4kW
(1994\$/Wpac)¹**

Component	1994	1995	2000	2005	2010
Mounting Structure ²	.10	.10	.10	.05	.05
PCU/Aux. Equipment ³	1.20	1.00	.80	.60	.40
Module Installation ⁴	.50	.50	.40	.30	.30
Wiring and Electrical ⁵	.25	.25	.20	.20	.15
Other Indirect ⁶	.40	.40	.30	.25	.25
<i>Sub-Total BOS</i>	<i>2.45</i>	<i>2.25</i>	<i>1.80</i>	<i>1.45</i>	<i>1.15</i>
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	6.85	6.50	4.80	3.65	3.15
Total System Price (15% Markup)	7.85	7.50	5.50	4.20	3.60

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings).

Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Eliminates cost of conventional roofing, conventional roof deck, and Roof-Jacks. Includes cost of horizontal aluminum extrusion, module Battens, glazing tapes and fasteners, and misc. roof flashing.

³Based on Omnion Power Engineering series 2200 static power converter with ground fault detection used in SMUD units (\$4,560). Price also includes manual AC and DC disconnect, and source circuit combining circuitry. Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$2.50/Wpac for residential size units.

⁴Includes labor, vehicles, and crane (Cost varies significantly depending on location)

⁵Romex #10 wire, 3 conductor @ \$.50/ft. -with labor @ \$1.95/ft. #12 wire/3 @ \$.35/ft and \$1.67 with labor. 100ft run roof array to equip. room. Master electrician and helper \$400. Misc. equip. \$150.

⁶Includes insurance, packing (\$.10/Wpac), shipping (\$.10/Wpac), local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

Source: Arthur D. Little estimates, based on discussions with Omnion Power Engineering, Ascension Technology, Solar Design Associates, SMUD, and Solar Engineering, January 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wire prices.

3.2 Ballasted Roof Mount At Low Tilt Angle

3.2.1 Technology Description

Ascension Technology, located in Waltham, MA, has developed a ballasted mounting system for flat roof retrofit commercial buildings. A "ballasted" system has shallow tilt collectors essentially weighted down with gravel or some other material to resist wind loads. The ballasted mounting system used by Ascension Technology utilizes steel trays in combination with the *Roof-Jack* technique used for residential buildings. The steel trays, as shown in Figure 3.2-1, are placed on a flat roof and covered with gravel or other ballast to hold the trays in place. The modules are held in place at tilt angles of 15 - 25 degrees to reduce wind loading, allow for more installed capacity on roofs with limited available area due to reduced shading from modules, and to increase PV output during summer months when summer-peaking utility loads are largest.

The weight of the steel and one inch of gravel is approximately 12 psf, not including the PV module. The depth of gravel can be varied depending on wind loading requirements and the structural integrity of the roof. Table 3.2-1 shows the weight of each component of a ballasted mount system. The ballasted systems are currently being designed for 7.5 psf of steel tray component with the PV module and 7.5 psf of gravel or rocks.^{2,3} There is currently, however, no uniform design guidance as to what values are appropriate for different roof types and different locations of the US.⁶

Table 3.2-1 Ballasted Mount Weight (lbs/ft²)

Component	Weight in PSF
Steel tray	3.5-4
1" of gravel/ballast	7.5
PV module	4
TOTAL	15-16

The steel trays can be carried by two people. A layer of ethylene-propylene diene monomer (EPDM) rubber or insulating board are placed under the trays. Ten of these systems are currently being tested on the Environmental Protection Agency (EPA) PV Demand-Side Management (DSM) project installations. Improvements have been made to the design to facilitate use of the ballasted mounting system for a wide variety of roof types, such as built-up (layers of felt material, fiberglass mats, and hot-mopped asphalt), standing seam metal roofs, modified Bitumen (a single layer of mat material with hot asphalt), and low density concrete. Standing seam metal roof installations have been mechanically attached to the metal roof seam, thus eliminating the steel tray and ballast cost. As shown in Figure 3.2-2, built-up, metal (as represented in "other"), low density concrete (also in "other"), and single ply EPDM roofs represent the majority of roofing material types in the US for new or retrofit roofing. Other single ply roofs (a rolled sheet of mat fastened with ballast, mechanical fasteners, or adhered to with an adhesive) such as PVC/PVC alloys (plastics) and Hypolon/CPE (plastics) are other roofing materials not currently being used with ballasted roof mount PV systems.

Roofing gravel is added as ballast to hold the trays in place.

Roof-jack slots are designed to mate with PV panel pin assemblies.

Figure 3.2-1: Ballasted Roof Mount

Source: Ascension Technology, 1993.

Figure 3.2-2 Roofing Material Market Shares for New Roofing

3.2.2 Potential Barriers

Several potential barriers have been highlighted by Endecon Engineering, a firm that has installed the ballasted mount system as part of EPA Project One.⁴ These issues and potential mitigation measures are presented in Table 3.2-2.

Interviews with building inspectors have confirmed the concern with adding weight to roofs. Snow drifts around the panels is an additional weight concern, as it is with the placement of any new structure on an existing roof. Added weight margins are built in around heating, ventilation and cooling (HVAC) equipment during design and construction specifically to deal with potential snow drift loads.

Building inspectors will need to evaluate data on building wind load impacts to facilitate implementation and acceptance of ballasted mounts. The ballasted system, in spite of these near-term research areas, has the potential to be very cost-effective. In addition, there is a well established and reliable track record for mounting other equipment on rooftops such as satellite dishes and HVAC equipment that should help to mitigate some concerns for ballasted roof mounting of PV.⁶

There may be potential for the BIPV ballasted system to offset some of the live loads. Most building rooftops are designed with a live load requirement of about 20-100 psf to allow for walking, placement of construction materials, etc. A close-to-flat mounted PV module would not be able to be walked on or have material placed on top, which could potentially take credit for some of the 20 -100 psf. This issue however, needs to be researched further and ultimately depends on the local building inspector's analysis of the situation.^{5,6}

3.2.2 Potential Impact on Installed BIPV System Costs

If the above mentioned concerns can be mitigated, the ballasted mount at a low tilt angle will offer significant cost reduction potential. An 18kW PV system, similar to those used on the EPA2 projects, requires 90 4' x 6' panels with a total dimension of 71' x 66', Figure 3.2-3. The array size, not including space between the PV panels if the system is in multiple rows, is 2,343ft². Including space between panels would make the total area 4,686ft². This size system would require 99 steel trays and 99 *Roof-Jacks*, nuts, plugs, and conduit body for a total direct mounting structure material cost of \$13,590 (\$.85/Wpac). A 15%- 20% mark-up would result in a total price of \$15,600 - 16,300 (~\$1/Wpac). Adding half the total cost of vehicles and a crane at \$.15/Wpac (the other half is associated with the module installation), and labor at \$.80/Wpac for roof preparation and mounting structure installation brings the total cost to \$1.75/Wpac for a single, non-volume installation with no experience installation crew. Adding the cost of 60 mil, heavy weight Carlisle Walkway EPDM would cost an additional \$.30/Wpac, but this is not a typical specification.

Experience installing the EPA projects has indicated that local crew costs vary significantly from site to site. For volume purchases and installation of about .5MW, however, it is expected that the total cost can be reduced to \$8-10/ft² or about \$1.00/Wpac.³ Details of the total system cost for this system mounted on a commercial building for 1994 and projected to 2010 are presented in Table 3.2-3 for volume

Table 3.2-2 Summary of Key Concerns With Ballasted Mount Systems

Concern	Description	Rating	Potential Mitigation Measure
NEC Sect. 90	All electrical equipment installed in/on a residential, commercial, or industrial building must be listed by a nationally recognized testing lab.	Minor	UL listing has been obtained for all system components, including the Mobil Solar modules, Omnion inverters, and ATI Source Circuit Protectors.
UBC (1991), Sect. 2336	Structures and their attachments must be designed to resist local design seismic forces. Attachments shall include anchorages and required braces. Friction from gravity loads is not considered to provide resistance to seismic forces. UBC applies to approximately 40% of the US building population.	Major	Seismic requirements are most significant along the California coast region, which has the highest seismic zone factor in the US. Use of the ballasted mount in this region may not be appropriate. Addition of a seismic tether at one of the EPA project sites resulted in an added cost of \$.75/Wpac, including installation. ³ In other regions, this barrier is less significant. The gulf coast and many northern states have seismic zone factors of zero, and the BOCA National Building Code, the major code for the eastern US, does not appear to prohibit the use of friction as resistance.
Roof Type	Built-up and graveled tar roofs may not be appropriate for installation of ballasted mount systems. Most roofs in the West are one of these two types. <i>Built up:</i> water that builds up under the steel tray will rot the roofing material. <i>Graveled tar:</i> even small pieces of gravel under the steel tray may pierce the tar and cause leaks.	Moderate	Ballast system originally developed for EPDM roof. Built-up and modified bituminum roof manufacturers have been receptive to this type of installation and claim that they would maintain roof warranties. Must be approved on a roof by roof basis by licensed roofer of manufacturer. Mounting system is still in R&D.
Design Wind Pressure	There is no uniform guidance for the development of wind pressures to be used for design of rooftop systems.	Major	Collect and evaluate existing studies on this issue (including those from Europe and Australia). Review other codes and design standards to develop uniform guidelines. Coordinate with code writing officials to develop uniform guidelines.

Table 3.2-2 Summary of Key Concerns With Ballasted Mount Systems (continued)

Concern	Description	Rating	Potential Mitigation Measure
Structural Loading	Contractors have stated that dead weight additions over 5-8 psf may not be acceptable for approximately 70% of flat roof, retrofit buildings. ¹ In addition, many commercial building roofs are designed with low margin load carrying capability relative to building codes.	Moderate to Major*	Use of ballast material already present on roof, such as gravel, results in minimal additional loading and reduces material costs. If configured as shown in Figure 3.2-3, the mounting structure impact is reduced to 8 psf. Roof areas over building columns can be loaded more heavily.

• This issue is very location specific. Some regions of the country have roof weight margins to accommodate snow loads etc. But, even within a less favorable region of the country such as the Pacific Southwest, there are likely to be buildings that are suitable for the ballasted mount PV system.

Source: Arthur D. Little, based on interviews with Endecon Engineering, Ascension Technology, Jeff Shingleton, and Southern Building Code Congress International, 1994.

installations. For comparison, actual EPA project experience with Roof-Jack systems are shown in Table 3.2-4 for single installations. Prices shown are for flat roof and pitched roof commercial buildings. The locations of these various BIPV installations are shown in Figure 3.2-4.

3.2.3 References

1. Innovative Design, Interview, October, 1993.
2. Ascension Technology, Inc. and Air and Energy Engineering Research, "US EPA's Photovoltaic Demand-Side Management Project", Presented to the International Solar Energy Society, Solar World Congress, 1993, Budapest, Hungary.
3. Ascension Technology, Inc., Interview, January 1994.
4. Endecon Engineering, Interview, July 1994.
5. Southern Building Code Congress International, Birmingham, AL and Building Officials & Code Administrators (BOCA), Country Club Hills, IL., Interviews, January 1994.
6. Interview with private consulting engineer for Integrated Power, Jeff Shingleton, January 1994.

Figure 3.2-3 EPA2 Ballasted Roof System Configuration for 18kW Project

**Table 3.2-3 PV Prices for Retrofit or New Construction Commercial Buildings At 15 Degree Tilt
For A Flat Roof, Ballasted System - 30kW (1994\$/Wpac)¹**

Component	1994	1995	2000	2005	2010
Mounting Structure ²	1.00	.90	.80	.70	.60
PCU/Aux. Equipment ³	1.10	.90	.70	.50	.40
Module Installation ⁴	.10	.10	.10	.05	.05
Wiring and Electricals ⁵	.30	.30	.25	.25	.20
Other Indirect ⁶	.40	.40	.30	.25	.25
Sub-Total BOS	2.90	2.60	2.15	1.75	1.50
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	7.30	6.85	5.15	3.95	3.50
Total System Price (15% Markup)	8.40	7.90	5.90	4.55	4.00

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings).

Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Eliminates cost of stub-ups, pitch pockets or membrane flashing, I-beam and steel structure. Includes cost of steel trays @ \$85 ea. and Roof-Jacks @ \$40ea.

³Based on 15kVa Abacus Controls Sunverter Model 7158-4-200 three phase power inverters (\$.90/Wpac). Ground fault detection will be part of unit in 1995. Price includes isolation transformer and EMI/RFI filters in unit, and labor/electrical supplies (\$.20/Wpac). Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$.70-.85/Wpac for commercial size units.

⁴Includes the cost of labor, and half the cost of crane and vehicles (\$.15/Wpac total cost). Other half of crane cost and vehicles associated with mounting structure.

⁵Outdoor conduit @ \$3.56/ft for 1.5" conduit, schedule 40 PVC with labor. Stranded copper wire (#12THHN) @ \$.36/ft. with 10 conductors for 300ft run = \$2,160 for array to equip. room. Module to module connections and mounting of electrical equip. such as string combiner box. Master electrician and helper 1wk of time = \$4,000. Misc. equip (fasteners, conductor clips etc.) = \$1,000.

⁶Includes insurance, packing (\$.10/Wpac), shipping (\$.10/Wpac), local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

Source: Arthur D. Little estimates, based on discussions with Abacus Controls, SMUD, and Ascension Technology, January 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wire prices.

1993-1994 no volume/one kind EPA Roof-Jack, ballast installations for comparison were:

12kW SCE: \$9.20/Wpac*

12kW PGE: \$10.00/Wpac**

8kW APS: \$9.15/Wpac

4kW NYPA: \$10.05/Wpac

12kW COA: \$9.25/Wpac

4kW NU: \$10.25/Wpac

*Includes Roof-Jack, but not steel tray (mechanically attached to Butler building)

**With seismic tether. Price would be \$9.05 without tether

Table 3.2-4 Price Summary for EPA1 Projects (Primarily Ballasted Mount Systems)

Project/kW	Array +	Installation	Shipping	Total Price	\$/Wpac
NYSEG/12#	\$85,062	\$15,351	\$1,500	\$101,913	\$9.69
NU/4#	28,354	7,113**	500	35,967	\$10.26
ACE/4*	26,974	3,804	320	31,098	\$8.87
ACE/12^	85,063	NA	1,180	NA	NA
NYPA/4#	28,354	6,280	560	35,194	\$10.04
APS/4*	26,974	4,069	301	31,344	\$8.94
APS/4#	28,354	NA	318	NA	NA
APS/8##	56,708	6,177	1,302	64,187	\$9.15
WPS/4*	26,974	NA	257	NA	\$8.91
WPS/12#	85,062	NA	1,359	NA	\$9.60
COA/12^	85,062	10,890	1,566	97,518	\$9.27
NSP/4^	28,345	NA	600	NA	NA
PG&E/12^	85,062	~18,000	2,024	~105,466	~\$9.99
SCE/4*	26,974	3,788	NA	NA	\$8.77
SCE/4*	26,974	4,100	NA	NA	\$8.86
SCE/12++	81,651	14,825	-	96,480	\$9.18
PSO/18#	122,815	16,998	2,223	142,036	\$7.89
NEES/8*	NA	NA	NA	NA	NA

#Ballasted mount on flat roof that already had ballast

##Ballasted mount on flat roof with concrete

^Ballasted mount on flat roof where ballast had to be added

++Not ballasted mount. Clip-on to flat roof Butler building

*Roof-Jack, stand-off system on pitched roof

+Includes price of modules, inverters, and mounting structure

** Details of installation include: \$1,015 for EPDM, \$491 for electrical supplies, \$881 for vehicles and crane, \$95 for misc, and \$4,631 for labor.

Source: Ascension Technology, EPA Phase I Draft Report, January 1994 and interview with Ascension Technology, August 1994.

Phase I Participating Utilities

Arizona Public Service (APS)
 Atlantic City Electric (ACE)
 Austin Power and Light (AUS)
 New England Electric System (NEES)
 New York Power Authority (NYPA)
 New York State Electric & Gas Corp. (NYSEG)
 Northeast Utilities (NU)
 Northern States Power (NSP)

Pacific Gas and Electric (PG&E)
 Southern California Edison (SCE)
 Wisconsin Public Service (WPS)

Phase II Participating Utilities

Arizona Electric Power Cooperative (AEPCO)
 Atlantic City Electric (ACE)
 Boston Edison Company (BECO)
 Consolidated Edison Company of New York (CONED)

Florida Power Corporation (FPC)
 Idaho Power Company (IPC)
 Los Angeles Department of Water and Power (LADWP)
 Nevada Power Company (NPC)
 New York State Electric & Gas Corp. (NYSEG)
 Public Service Company of Colorado (PSCO)
 Public Service Company of Oklahoma (PSO)

Figure 3.2-4 Location of Participating Utilities for EPA Rooftop PV Systems

Source: Solar Industry Journal, Fourth Quarter 1993.

3.3 Curtainwall Applications

3.3.1 Technology Description

PV modules can be substituted for spandrel (nonvision) glass in curtainwalls for mid- to high-rise commercial buildings. As a substitute for other glass, PV modules would achieve some credit for the displaced conventional glass and could use the curtainwall structure as the mounting system. Electricity produced by the BIPV system would serve as part of the building's needs through integration with the regular utility grid network, similar to roof-mounted BIPV systems.

Curtainwalls are nonload bearing wall systems used principally in mid- to high-rise office buildings. A curtainwall typically has an aluminum framework anchored to structural floor members in the building itself. This aluminum frame holds clear and tinted glass panel in vision areas and a variety of panels in nonvision areas. This opaque spandrel material can be glass, metal, or metal/plastic panels, stone, and various composite materials.

Approximately 30% of the total wall area in commercial buildings is considered nonload bearing wall usage (curtainwall). Of this total, 20% is vision glass and 10% is opaque material.²

Curtainwalls are primarily used in visible (over 3-story) structures designed by architects. Consequently, selection of curtainwall materials is based upon a combination of:

- aesthetics;
- material cost;
- installation simplicity and cost; and
- design simplicity.

New materials are carefully reviewed prior to serious acceptance in order to insure in-field longevity and successful performance. Many new products have failed to perform up to expectations. Thus, designers, contractors, and owners will not accept any product without extensive testing and in-field trial. Noneconomic questions needing resolution before serious acceptance include:

- breakage patterns/experience;
- replacement availability;
- availability with tempered or other nonstandard glass substrate;
- color availability, consistency, and stability;
- glass panel size (typical horizontal mullion spacing is about 4 ft. with varying height requirements of between 5-7ft. There currently are no monolithic modules as large as 4ft. by 5ft.).¹

In particular, color availability will be a factor in selection, including complimentary colors for non-electricity producing building faces. Architects want flexibility and choices of color, as aesthetics are a key driving factor in their selection. In the near-

term when PV materials replace spandrel glass, PV modules will have to complement the color of the vision glass and other building facade colors. Some architects claim that there may be a preference to use thin-film PV materials that have a more uniform color than polycrystalline or crystalline materials. Modules that still have yellowing problems may not be appropriate for curtainwall applications.

A report by Kiss, Cathcart, Anders Architects, identified two technical areas needing further development. "There are two basic curtainwall framing systems in common use: pressure plate and structural silicon glazing. In pressure plate systems, the glazing unit is mechanically held from the front by a plate with an extruded cover or 'cap'. Structural silicon glazing glues some or all of the glazing edges to the framing system, leaving no framing visible on the outside. In PV applications of pressure plate systems, the mullion cap depth must be kept to a minimum to avoid adverse shadowing on the PV cells. Alternatively, flush application of a structural silicon seal between PV glazing units eliminates shadowing effects, but increases weatherseal and durability problems for PV panel edges."¹

3.3.2 Potential Impact on Installed BIPV System Cost

The primary opaque material used for curtainwall applications is spandrel glass, which represents approximately 20% of the curtainwall market, Table 3.3-1.² PV systems would primarily replace this material, or potentially patterned glass or reflective glass.³ These latter two material types are not as common as spandrel glass. The following analysis of potential cost savings from incorporating PV into a curtainwall have therefore focused on the spandrel glass market. Some critiques claim that BIPV could replace more costly curtainwall building materials such as granite and marble facades. In these instances commercial building owners are typically paying for the "expensive appearance" and may not be willing to sacrifice that facade for a PV material.

Table 3.3-1 Opaque Wall Materials Used With Curtainwalls

Material	Percent of New Construction
Spandrel Glass	20
Metal Plastic Laminates	19
Plates (typically aluminum)	19
Marble, granite, other masonry	14
Honeycomb (aluminum/aluminum matrix)	8
Porcelain	8

Source: American Architectural Manufacturers Association.

Spandrel glass material currently costs approximately \$5.90/ft², or \$7.45/ft² including overhead and profit. A 10% increase in the price of this material is expected by the year 2000, based on discussions with a major US glass manufacturer.⁶ The material credit

from using PV as a curtainwall material that replaces spandrel glass is therefore \$.75/Wpac in 1994 and 1995, \$.80/Wpac in 2000, and \$1.00/Wpac by 2010, assuming a crystalline technology and increases in the price of spandrel glass over time. Thin film technologies with lower efficiencies would result in material credits larger than those shown for crystalline technologies due to the larger cost per square foot.

Architects with some experience installing BIPV curtainwalls claim that there is no cost premium over the installation cost of spandrel glass. The installation costs however, do assume that the installation can be done by iron workers. BIPV installations requiring other building trades, such as electrical workers, would increase installation prices.

The primary added cost is for additional wiring and electrical work. There is very little data available on BIPV curtainwall costs. Kiss, Cathcart, Anders Architects have done one installation of an APS system. Based on their experience, the wiring and electrical work required for a curtainwall system should not be anymore than a rooftop application for new construction applications. A recent application indicates that wiring and electrical prices would be close to \$3.00/ft² or about \$.30/Wpac for a 13% module.⁷

The above price for wiring and labor can potentially be reduced further due to the current non-optimized electrical system design in existing curtainwalls for PV integration. More standard conduit features in curtainwalls in the future to accommodate PV systems will reduce wiring and associated installation further. This assumes that curtainwall framing in the future will have conduit channels to facilitate wiring and electrical work. The price will progressively decrease with more wiring experience associated with BIPV curtainwall systems.⁶

Given the above assumptions, the installed BIPV system prices can be reduced considerably with curtainwall systems, as shown in Table 3.3-2. The prices shown are for a crystalline material which can reduce the overall installed system price to approximately \$6.15/Wpac, if direct from the manufacturer. Thin-film materials with more uniform color and typically larger monolithic panels (2.5' x 5' for the current Advanced Photovoltaic System module) are potentially more conducive to curtainwall applications, but this material may have a negative impact on the overall installed system price. Thin-film materials currently have much lower efficiencies and therefore require more spandrel glass area replacement for the same power output. This will gain in material credit per Wpac, but not in overall \$/ft². Given that the BIPV area is likely to be fixed, the overall costs associated with a thin-film material would be greater. The analysis in this report shows the economic scenario using a crystalline or higher efficiency material.

Although BIPV system costs can be reduced with the material credit gained from the curtainwall material used, PV output is significantly reduced with a vertical tilt, as discussed in Section 4.1.

Table 3.3-2 Average Prices for Crystalline PV Curtainwall Applications - New Construction, Commercial Buildings (1994\$/Wpac)¹

Component	1994	1995	2000	2005	2010
Mounting Structure ²	0	0	0	0	0
PCU/Aux. Equipment ³	1.10	.90	.70	.50	.40
Module Installation ⁴	0	0	0	0	0
Wiring and Electricals ⁵	.30	.30	.25	.25	.20
Other Indirect ⁶	.50	.50	.40	.30	.25
Sub-Total BOS	1.90	1.70	1.35	1.05	.85
Modules ⁷	4.40	4.25	3.00	2.20	2.00
Material Credits ⁸	(.75)	(.75)	(.80)	(.90)	(1.00)
Total System Price (Direct From Manuf)	5.55	5.20	3.55	2.35	1.85
Total System Price (15% Markup)	6.40	6.00	4.10	2.70	2.10

¹Prices shown include installation and are for volume purchases of .5MW. Prices are represented in \$ per net system output based on PVUSA Test Conditions (20% loss from STC DC module ratings). Price reductions, except for PCU, are primarily a result of module efficiency and manufacturing improvements from 13% in 1994 for crystalline technologies to 20% in 2010.

²Eliminates cost of stub-ups, pitch pockets or membrane flashing, I-beam and steel structure, half the cost of the crane and labor.

³Based on 15kVa Abacus Controls Sunverter Model 7158-4-200 three phase power inverters (\$.90/Wpac). Ground fault detection will be part of unit in 1995. Price includes isolation transformer and EMI/RFI filters in unit, and labor/electrical supplies (\$.20/Wpac). Manual outdoor lockable fused disconnect is <\$.04/Wpac. Other utilities with less operational experience may require metering, remote control, data acquisition, and extra protection packages for up to an additional \$.70-.85/Wpac for commercial size units.

⁴Zero premium assumed over spandrel glass, assuming iron workers can do installation. Retrofit installation prices would be higher due to access difficulties.

⁵Conduit channels being built into curtainwalls in the future may help to reduce costs further. Module efficiency improvements reduce wiring costs beyond 1995. 1/2" rigid conduit, PVC @ \$.32/ft materials, \$1.26/ft labor (\$1.58/ft total). Stranded copper wire (#12THHN) @ \$.36/ft.

⁶Includes insurance, packing, shipping, local permits, engineering, project management, and overhead.

⁷Ex-plant module prices include: direct materials and labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes, and interest and profit. Assumes large area panels > 20ft². Panelization would add \$.65/Wpac.

⁸Assumes replacement of Spandrel glass material: \$7.45/ft² for 1/4" thick, standard colors, over 2000 ft² with 26% overhead and profit.

Source: Arthur D. Little estimates, based on discussions with Abacus Controls; Kiss, Cathcart, Anders Architects; Libbey Owens Ford; and Advanced Photovoltaic Systems, January and February 1994. National Construction Estimator, 1993. ISBN 0934041-768 for wiring prices and Means Concrete and Masonry Cost Data, 1994 for Spandrel glass prices. Forecast of glass prices from LOF, 1994.

After the year 2000, PV modules could potentially replace vision glass materials, but it is unlikely that BIPV materials will ever be completely transparent. BIPV materials in the future may be manufactured with optic performance similar to some of the darkest solar absorbing glass products. However, greater light transmission is also likely to decrease module efficiencies below acceptable levels.⁸ The primary material currently used in the vision glass area is 1" thick, double glazed, 1/4" float, tinted, insulating glass.⁴ This material costs \$9.55/ft², or \$11.95/ft² including overhead and profit.⁵

3.3.3 References

1. Kiss, Cathcart, Anders Architects, Building-Integrated Photovoltaics, Prepared for the National Renewable Energy Laboratory, January 1993.
2. American Architectural Manufacturers Association, Interview, February 1994.
3. Advanced Photovoltaics Systems, Interview, February 1994.
4. Kawneer Company, Interview, February 1994.
5. R.S. Means Company, Inc. Means Interior Cost Data 1994, Kingston, MA, 1994.
6. Libbey-Owens Ford, Interview, February, 1994.
7. Kiss, Cathcart, Anders Architects, Interview, February, 1994.
8. Alternative Energy & Design Consulting, Alan Paradis, Interview, October 1994.

3.4 The AC Photovoltaic Module

3.4.1. Technology Description

The utility grid and everything connected to it functions on alternating-current (AC) electricity. PV cells and conventional modules produce direct-current (DC) electricity. One of the major sources of PV system costs and complexity is in making the DC output of a BIPV system compatible with AC power.

BIPV systems presently must employ DC array output circuits, DC circuit string combiners, DC-rated disconnects, a separate power conditioning unit and, in some cases, DC ground-fault protection. These DC circuits and components are more costly than equivalent AC-rated equipment, often require specialized engineering, and are unfamiliar to many electricians and code officials.

An AC PV module is being developed by several companies to address these issues. The AC module integrates a large-area PV module with a dedicated, integrally-mounted, DC to AC power inverter, whose electrical output is 60 Hz AC power which is fully compatible with the utility grid, Figure 3.4-1. The AC module's output will be connected directly to the building's AC distribution system without need for any DC wiring, string combiners, DC ground-fault protection or additional power conditioning equipment.

Figure 3.4-1 The AC Module Concept

The AC module is nominally 4 x 6 feet (24 square feet) in size and designed for direct building integration into the vertical facades and sloped-roof construction of residential, commercial and institutional buildings, replacing the traditional building skin. A framed version of the AC module is also being developed for systems employing rack and tracker mounting.

A module-integrated inverter also eliminates all DC circuit design costs and other DC related components as these become embedded in the PV/inverter assembly. The PV module and inverter together become an AC appliance.

The AC module has the potential to become the first PV power "building product" as it can be marketed as a complete, packaged solution requiring minimal design, for the emerging residential rooftop and commercial demand-side-management markets.

In addition, the standardization offered by small, mass-produced inverters with a common, approved interface has the potential to eliminate most, if not all, of the problems presently associated with utility interconnection.

The benefits of AC PV modules are:

- The minimum system-size of one AC module provides a low barrier to market entry.
- The minimum array-increment of one AC module and the elimination of balance of system equipment allows for maximum system flexibility and simple array expansion.
- AC modules from different manufacturers and with different power ratings are compatible because all of them use a common 120V, 60Hz bus.
- There are no constraints on module or array orientation, shading or solar exposure. Unlike series-connected DC arrays which must have the same orientation and exposure. Each AC module maximum-power tracks by itself and can therefore allow for differing orientation or shading.
- String mismatch losses from long DC series strings are eliminated.
- No special string combiners, blocking diodes or DC wiring are needed.
- A significant reduction in manufacturing costs should be possible with mass production of the modular inverters because far greater numbers will be produced for a given market.
- Design and installation costs can be reduced through product standardization.

- A communications capability can be added to the inverter which is capable of module level system diagnostics, monitoring and control.
- AC modules are inherently suited to utility interactive systems which have the advantage of not wasting energy as stand-alone systems do when the load is less than PV generating capacity and storage is full.
- AC modules are inherently safer than conventional, high voltage DC PV systems.
- PV systems employing AC modules are less complex than standard UI systems and will likely receive easier acceptance by code and utility officials.

3.4.2. Potential Impact on Installed BIPV System Costs

Table 3.4-1 compares the estimated costs of utility-interactive BIPV systems designed in three ways:

- AC module with 250W integrated modular inverter,
- 4 kW blocks, and
- 100 kW central systems.

A PV system costing model for the years 1995 - 2010 was prepared in spreadsheet form. The projections for PV module pricing (at wholesale) and US market size are:

Table 3.4-1 PV AC Module Prices

Year	1995	2000	2005	2010
PV Module Cost (\$/Wpac)	4.25	3.00	2.20	2.00
Total PV Sales (MW)	2	5	10	25
Unit Sales 250W	8000	20000	40000	100000
Unit Sales 4000W	500	1250	2500	6250
Unit Sales 100 kW	20	50	100	250

The unit sales prices in Table 3.4-1 assume that the entire annual market is the single inverter type. Even with this assumption in 2010, with a 25 MW per year market, only a few (<250, 100 kW) inverters would be needed. There is, therefore, little potential for economy of production in large, central inverters.

When using 4 kW blocks, in the short term, only hundreds of units would be made per year. For comparison, total world sales for UI inverters are currently less than 1000 units per year.

The cost of inverter manufacturing was estimated using a component breakdown such as enclosure, circuit cards, power switches, magnetics, and assembly. An overhead and profit of between 60% and 100% was added, with the larger overhead being applied for smaller production 4 and 100 kW units. The 60% estimate for the modular inverter used through 2010 is somewhat conservative. When production volumes reach tens of thousands of units, this estimate could be lower. The projected costs by year for the three inverter types are shown in Table 3.4-2.

Table 3.4-2 Projected Costs of Three Inverter Types (\$/Wpac)

	1995	2000	2005	2010
Modular 250 W	\$0.90	\$0.65	\$0.50	\$0.40
Central 4000 W	\$0.80	\$0.55	\$0.40	\$0.35
Central 100 kW	\$0.85	\$0.75	\$0.65	\$0.60

When the inverters are installed in working systems, the modular inverter becomes the least expensive option. The design costs associated with the AC module are minimal, and the balance-of-system consisting of AC wiring and standard AC distribution panels will also be lower. Price estimates for complete utility-interactive PV systems are presented in Tables 3.4-3 through Table 3.4-7 using the 250W modular inverter.

Table 3.4-3 Average PV Prices for Standoff, AC Module on Retrofit Residential Buildings - 4kW (1994\$/Wpac)

Component	1994	1995	2000	2005	2010
Mounting Structure	.60	.55	.50	.45	.40
PCU/Aux. Equipment	1.10	1.10	.80	.55	.45
Module Installation	.15	.15	.10	.05	.05
Wiring and Electrical	.20	.20	.15	.12	.10
Other Indirect	.30	.30	.25	.20	.20
Sub-Total BOS	2.35	2.30	1.80	1.35	1.20
Modules	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	6.75	6.55	4.80	3.55	3.20
Total System Price (15% Markup)	7.75	7.55	5.55	4.10	3.70

Table 3.4-4 Average PV Prices for AC Module, Integral System, New Construction Residential Buildings - 4kW (1994\$/Wpac)

Component	1994	1995	2000	2005	2010
Mounting Structure	.10	.10	.10	.05	.05
PCU/Aux. Equipment	1.10	1.10	.80	.55	.45
Module Installation	.15	.15	.10	.05	.05
Wiring and Electrical	.50	.50	.40	.30	.30
Other Indirect	.30	.30	.25	.20	.20
Sub-Total BOS	2.20	2.20	1.70	1.25	1.10
Modules	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	6.60	6.45	4.70	3.45	3.10
Total System Price (15% Markup)	7.60	7.40	5.40	3.95	3.60

Table 3.4-5 Average PV Prices for an AC Module Mounted on a Flat Roof, Retrofit or New Construction Commercial Building at 15 Degree Tilt, Ballasted System (1994\$/Wpac)

Component	1994	1995	2000	2005	2010
Mounting Structure	1.00	.90	.80	.70	.60
PCU/Aux. Equipment	1.10	1.10	.80	.55	.45
Module Installation	.10	.10	.10	.05	.05
Wiring and Electrical	.20	.20	.15	.12	.10
Other Indirect	.30	.30	.25	.20	.20
Sub-Total BOS	2.70	2.60	2.10	1.65	1.40
Modules	4.40	4.25	3.00	2.20	2.00
Total System Price (Direct From Manuf)	7.10	6.85	5.10	3.85	3.40
Total System Price (15% Markup)	8.15	7.85	5.85	4.45	3.90

Table 3.4-6 Prices for Crystalline PV Curtainwall Applications Using AC Module (1994\$/Wpac)

Component	1994	1995	2000	2005	2010
Mounting Structure	0	0	0	0	0
PCU/Aux. Equipment	1.10	1.10	.80	.55	.45
Module Installation	0	0	0	0	0
Wiring and Electrical	.20	.20	.15	.12	.10
Other Indirect	.30	.30	.25	.20	.20
Sub-Total BOS	1.60	1.60	1.20	.90	.75
Modules	4.40	4.25	3.00	2.20	2.00
Material Credit	(.75)	(.75)	(.80)	(.90)	(1.00)
Total System Price (Direct From Manuf)	5.25	5.10	3.40	2.20	1.75
Total System Price (15% Markup)	6.05	5.85	3.90	2.55	2.05

The reduction in installed system costs using the AC module approach is approximately \$.30/Wp. Although this is currently not a significant market driver, only representing 5% of the 1994 total system cost, it becomes more significant as PV module prices in the future drop and volume grows. The economy of mass-production is a key element.

The key market drivers for the AC module concept are more than a reduction in installed system price. The ability to purchase just one AC module for a residence reduces the minimum entry level cost from the \$15,000 to the \$1,000 range. This lower barrier to market entry will help to increase PV sales. Other benefits such as enhanced system reliability and reduced O&M costs are not captured in the installed system price, but add to the value of the AC module concept.

Many development teams around the world are working to bring the AC module to the market. It is very likely that this concept will play a large role in utility-interactive PV systems worldwide in the near future.

3.4.3 References

1. Assessment by Solar Design Associates, under subcontract to PV:BONUS, June 1994.

4.0 BIPV Building Analysis and Economics

4.1 Analytical Approach

The purpose of this section is to evaluate the impact of BIPV on residential and commercial building load profiles and to calculate the resulting economic savings that can be achieved by implementing BIPV. Sections 2.0 and 3.0 presented information on various costs of BIPV systems. Using the most attractive cost reduction options, Arthur D. Little input information on the systems design and performance characteristics into the *ADL PV Performance Model*, a PV array simulation developed by Arthur D. Little, Inc. This simulation combines weather data and PV system characteristics to determine the hourly output for various sized and oriented arrays.

Analyses were conducted of BIPV performance, impact of the BIPV system on building loads, and resulting energy cost savings. Figure 4.1-1 illustrates the analysis methodology.

4.1.1 Commercial Building Assumptions and Analysis

Two commercial buildings were selected for analysis: a medium retail building and a large office facility. The details of these building types are presented in Table 4.1-1. To determine the impact of BIPV on commercial and residential buildings, hourly electrical consumption profiles were created using the DOE-2.1D building simulation package developed by the Simulation Research Group at Lawrence Berkeley Laboratory (LBL). This program simulates heating, cooling and electric loads based on weather conditions, lighting/equipment schedules and physical building characteristics. The weather data used in the simulations were Typical Meteorological Year (TMY) files for Chicago and Weather Year For Energy Calculation (WYEC) files for Albuquerque and Miami.

Table 4.1-1 Commercial Building Characteristics*

Building Type	Total Feet (000 ft ²)	Floors (#)	Roof Area (Flat Roof) (000 ft ²)	Wall Area (000 ft ²)	Peak Load (kW)	Elect. Use (kWh/yr)
Retail	66	2	40	22	225	1,000,000
Office	142	7	24	40	600	2,000,000

*Characteristics are consistent with buildings of the same types in the southwestern US. The building electric loads are determined as the sum of the lighting, HVAC (air handling and conditioning), and miscellaneous equipment (elevators, televisions, etc.) loads.

The DOE-2 simulations were conducted for Albuquerque; an area well suited to BIPV, and Chicago; an area with moderate insolation. The BIPV output in these areas was then simulated using the *ADL PV Performance Model*.

Roof-Mounted Analysis. For the analysis of roof mounted BIPV, a 165 kWpac array was chosen for the retail building, given a roof area availability of 50% and 13% PV

Figure 4.1-1 PV/Building Analysis Methodology

module efficiency. The office building assumed a 100 kWpac roof-mounted array. The sizing of the arrays is a result of the fact that, as discussed in Section 5.2, commercial building rooftops have HVAC equipment, weight restrictions, shading, and other barriers limiting the roof area available for PV systems. On a national average, retrofit flat-roof commercial buildings have roughly 30% of the total roof area available for BIPV. This lower percentage is used in Section 5.0 to evaluate National Energy Savings potential. For the building analysis presented here, retail and office buildings are assumed to be optimal applications, with 50% of the roof area available for solar. These BIPV systems are also assumed to have no battery storage.

Curtainwall Analysis. For the curtainwall BIPV analysis, a 145 kWpac array with a 13% module efficiency was assumed. As shown in Figure 4.1-2, South, East and West facing walls have the largest PV output. Three walls of a building were therefore assumed to be the most economically viable for BIPV curtainwall applications.

The space available for curtainwall BIPV is reduced due to shading and requirements for vision glass. A high rise office building for example, is estimated to have approximately 15% of its available area eliminated by shading. An additional 25% is eliminated due to vision glass requirements.¹ This analysis therefore assumed that only 60% of the three walls of a high-rise building (or 45% of the total wall area) would be available for BIPV. This wall area analysis is specific to a high rise office building, which is the most common curtainwall application.

BP Solar and APS both manufacture a glass on glass module specifically designed for curtainwalls that do let some light through between cells. The ability of PV to be completely transparent for use as vision area glass, however, is not feasible at this time. This study therefore assumed a small PV penetration of the vision glass area for the market penetration analysis presented in Section 5.2.

4.1.2 Residential Building Assumptions and Analysis

The single family residential building chosen for this study is a 1,400 ft² single story house typical of the Southern US. Electric loads in the building include lighting, air conditioning, and miscellaneous loads, but do not include electric heat or the short duration peaks that result from the operation of washing machines, dryers, etc. Details on the electricity use assumptions are shown in Table 4.1-2.

Table 4.1-2 Single Family Building and Electricity Consumption Characteristics

Location	Total Feet (ft ²)	Floors (#)	Annual Elect. Use (kWh/yr)	Building Peak Load (kW)
Albuquerque	1,400	1	8,000	2
Miami	1,400	1	11,000	3

Figure 4.1-2 Impact of Orientation on Curtainwall Array Output

Both 2 kW and 4 kW arrays were simulated in order to incorporate the full range of typical PV sizes for single family residential applications. As with the commercial buildings, no battery storage was assumed for the residential PV arrays.

4.2 Annual Energy Cost Savings - Commercial

This section evaluates the potential to reduce energy costs using roof mount and curtainwall BIPV in the commercial sector. The energy savings potential for roof mount applications was estimated using the *ADL PV Performance Model* for both office and retail buildings. The energy savings potential of curtainwall BIPV was determined only for high rise office buildings, as these are the most common applications of curtainwalls. The annual energy cost savings were then used to determine the maximum allowable system cost for each application, assuming a five-year payback period. Consumers typically use some form of simple payback considerations (e.g. rather than a more formal rate of return, or cost of capital type of analysis) in assessing the economic value of energy saving technologies. Based on field interviews and consumer surveys Arthur D. Little developed curves which relate market penetration rates to economic performance (payback period) as viewed by parties making purchase decisions. These curves, shown in Section 5.0, show that a payback period of *at least* five years is required for significant market penetration. For the economic analysis, a five year payback was therefore used to determine the allowable system price of BIPV systems.

In addition to energy savings, commercial building applications could also benefit from Integrated Resource Plan (IRP) credits. Capacity credits, transmission and distribution (T&D) credits, and environmental externalities have the potential, if implemented, to improve the economics of BIPV. Section 4.2.6 considers the impact that IRP benefits could have on allowable system costs for BIPV applications.

4.2.1 Roof Mount BIPV Impact on Demand and Energy Charges

BIPV can potentially reduce a commercial consumer's electricity bill in two areas: demand savings and energy savings. Demand savings are captured through the ability of the PV array to reduce the monthly peak power requirement of the building. This is determined by the degree of coincidence of the PV output and the building peak demand. Energy savings are a function of the total output of the array and the coincidence of that output with net building electric loads. The ability of BIPV to capture savings in these two areas is influenced by both the orientation and tilt angle of the array. The *ADL PV Performance Model* was used to determine which orientation and tilt angle best capture the potential savings.

Demand Reduction. Figures 4.2-1 and 4.2-2 demonstrate the impact of the various orientations on reducing the building peak load. The Southwest orientation/latitude tilt combination shows the most promise for peak reductions. As illustrated in Figure 4.2-1, the peak demand at this orientation is, at best, reduced by 44% of the theoretical maximum peak reduction (100 kW for the office building).

Figure 4.2-1 Impact of PV Orientation on Office Building Peak (kW) Loads

Figure 4.2-2 Impact of PV Orientation on Retail Building Peak (kW) Loads

The main reason that the PV array cannot significantly reduce building peak demand is that the peak building load extends later in the day than coincident PV output as illustrated in Figures 4.2-3 and 4.2-4.

Energy Reduction. Figures 4.2-5 and 4.2-6 demonstrate the impact of the PV orientation and tilt on the total building electric load (kWh). The true south orientation/latitude tilt results in the largest energy savings. By comparison, reducing the tilt to 15 degrees does not have a significant negative impact on electricity savings, on an annual basis. A ballasted roofing system, therefore, with a low tilt PV system will only result in a loss in PV output of 4% relative to latitude tilt, true south orientation.

The analysis also shows that the impact is relatively the same among building types when normalized as energy savings per kW of installed PV capacity. Because the kWh/kW values are similar for all commercial buildings, our analysis of the National Energy Savings potential presented in Section 5.0 does not differentiate between commercial building types.

4.2.2 Economics of Commercial Roof Mount BIPV - Consumer Perspective

The economic savings attainable to the consumer from BIPV depends on the utility rate structure and the actual demand and energy reductions. Tables 4.2-1 and Table 4.2-2 demonstrate that, due to differences in demand charges, an area with moderate insolation and high demand charges, such as Chicago, can potentially obtain greater dollar savings than an area with high insolation and lower demand charges, such as Albuquerque.

The results of the economic analysis, Table 4.2-1, show that an office building (given current utility rates and assuming a five year payback and 10% Federal tax credit) provides for an allowable PV installed system price of \$1,150/kWp. The five year payback criteria was selected based on experience with HVAC purchase criteria requirements. Commercial/industrial users will rarely consider a new technology if the equipment has a payback greater than five years. In fact, experience and interviews with end-users indicate that most commercial building applications require two to three year paybacks. Similarly, as shown in Table 4.2-2, the retail building has an allowable system cost of \$725/kWp. The \$400/kWp difference between the two is a result of the inability of the array to reduce the retail peak by the same amount as the office peak. In both cases, the allowable system cost could be increased to over \$1800/kWp in favorable areas if, through storage or some other means, the building peak could be reduced by the full capacity of the PV array.

Figure 4.2-3 Impact of PV on Albuquerque Office Building Hourly Electricity Use

Figure 4.2-4 Impact of PV on Albuquerque Retail Building Hourly Electricity Use

Figure 4.2-5 Impact of PV Orientation on Office Building Electric Energy Consumption (kWh)

Figure 4.2-6 Impact of PV Orientation on Retail Building Electric Energy Consumption (kWh)

Table 4.2-1 Impact of PV on Office Annual Electricity Costs (No IRP Benefits)

Location	Orientation ¹	Without PV			With PV ⁴				
		Annual Energy Cost (\$)	Annual Demand Cost (\$)	Total Annual Cost (\$) ³	Annual Energy Savings (\$/kW)	Annual Demand Savings (\$/kW)	Allowable System Price (\$/kW) ³	Allowable System Price w/ELCC (\$/kW) ^{3, 6}	Maximum Allowable System Price (\$/kW) ^{3, 5}
Albuquerque (LA Rates)	South	179,664	49,909	231,262	176	31	1,140	1,290	1,425
	Southwest ²				164	40	1,130	1,220	1,360
New York (NYC Rates)	South	97,985	127,971	254,546	60	56	720	1,170	1,729
	Southwest ²				54	64	730	1,135	1,690

1 Latitude Tilt

2 40° West of True South

3 Includes taxes and monthly service charge. Assuming 5 year payback and a 10% federal tax credit.

4 100 kWpac PV system on 7 story office building

5 Due to maximum theoretical demand savings, assuming monthly peaks reduced by 100% of PV peak output. This is unlikely to be achieved without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

6 Using Effective Load Carrying Capability (ELCC) of PV, derived by SUNYA. Values are 70% for Albuquerque and 60% for New York.

Table 4.2-2 Impact of PV on Retail Building Annual Electricity Costs (No IRP Benefits)

Location	Orientation ¹	Without PV			With PV ⁴				
		Annual Energy Cost (\$)	Annual Demand Cost (\$)	Total Annual Cost (\$) ³	Annual Energy Savings (\$/kW)	Annual Demand Savings (\$/kW)	Allowable System Price (\$/kW) ³	Allowable System Price w/ELCC (\$/kW) ^{3, 6}	Maximum Allowable System Price (\$/kW) ^{3, 5}
Albuquerque (LA Rates)	South	91,256	21,056	113,516	126	5	725	1,500	1,830
	Southwest ²				114	7	670	1,430	1,795
New York (NYC Rates)	South	54,500	58,570	128,253	60	17	490	1,160	1,720
	Southwest ²				54	14	430	1,130	1,675

1 Latitude Tilt

2 40° West of True South

3 Includes taxes and monthly service charge. Assuming 5 year payback and a 10% federal tax credit.

4 165 kWpac PV system on 2 story retail building

5 Due to maximum theoretical demand savings, assuming monthly peaks reduced by 100% of PV peak output. This is unlikely to be achieved without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

6 Using Effective Load Carrying Capability (ELCC) of PV, derived by SUNYA. Values are 70% for Albuquerque and 60% for New York.

4.2.3 Curtainwall BIPV Impact on Demand and Energy Charges

The results of the curtainwall analysis show that a reduced BIPV system cost is necessary to compensate for the lower PV output because of the typically vertical module (90 degree) tilt.

Demand Reduction. Figure 4.2-7 shows that, at best, 24% of the theoretical maximum possible peak reduction is attainable with the use of the curtainwall system on the office building. This is about half that of the optimal roof mounted system with a latitude tilt. The peaks are shifted by one to two hours and therefore, as with latitude tilt roof mounted systems, demand charge savings are minimal.

The reason for the low impact on the office building load is seen in Figures 4.2-7 and 4.2-8. While the PV output and building electrical loads are well matched with the curtainwall system, the overall output of the array is significantly lower than its designed peak output due to the vertical tilt angle.

Energy Reduction. The impact of the curtainwall system on electricity consumption in the office building is demonstrated in Figure 4.2-9. In Albuquerque, electricity consumption is reduced about 8% annually. Due to lower insolation, electricity consumption in Chicago is reduced by only 6% annually. As compared to latitude tilt BIPV systems, there is 34% less energy savings from a curtainwall system.

4.2.4 Economic Analysis of Curtainwall BIPV

The five-year payback economics of the curtainwall BIPV reflect the reductions in output due to the orientation of the three walls. Table 4.2-3 shows that the allowable system price, including the 10% federal tax credit, is approximately \$700/kWp. While this allowable system price is not as favorable as the roof mounted office building systems, the economics are comparable to the roof mounted retail building systems. If the maximum demand savings could be realized, with battery storage, cycling off of AC loads, and/or BIPV system design optimization Table 4.2-3 suggests that the allowable system price could reach \$1600/kWp. This is quite favorable compared to the roof mounted systems.

Some curtainwall applications of BIPV can potentially be justified by means other than economics. This study focussed on the economic attractiveness of BIPV. The potential for BIPV curtainwall applications to be purchased as a result of "green marketing" (i.e., a company chooses to install BIPV for public relations purposes to demonstrate their environmental concern) was outside the scope of this study.

4.2.5 Impact of IRP Benefits

Integrated Resource Plan (IRP) benefits such as capacity credits, environmental externalities, and T&D avoided costs can increase significantly the allowable BIPV system price as shown in Figures 4.2-10 and 4.2-11. These IRP benefits are potentially very important to the cost-effectiveness of the BIPV system and can increase the allowable installed cost approximately 50-80% if full values were given to BIPV system. To date, T&D avoided cost benefits and capacity credits are not given to BIPV systems. But, as discussed in Section 5.0, a study by Richard Perez

Figure 4.2-7 Impact of Curtainwall PV System on Office Building Peak (kW) Loads

Figure 4.2-8 Impact of Curtainwall PV on Albuquerque Office Building Hourly Electricity Use

Figure 4.2-9 Impact of Curtainwall PV on Office Building Electric Consumption (kWh)

Table 4.2-3 Impact of Curtainwall PV on Office Annual Electricity Costs (No IRP Benefits)

Location	Without PV			With PV ⁴				
	Annual Energy Cost (\$)	Annual Demand Cost (\$)	Total Annual Cost (\$)	Annual Energy Savings (\$/kW)	Annual Demand Savings (\$/kW)	Allowable System Price (\$/kW) ³	Allowable System Price w/ELCC (\$/kW) ^{3,5}	Maximum Allowable System Price (\$/kW) ^{3,4}
Albuquerque (LA Rates)	179,664	49,909	231,262	100	20	664	980	1,166
New York (NYC Rates)	97,985	127,971	254,548	33	36	430	1,000	1,550

1 90° Tilt (Curtainwall); South, East and West wall orientation.

2 145 kWpac PV system on 7 story office building

3 Includes taxes and monthly service charge. Assuming 5 year payback and a 10% federal tax credit.

4 Due to maximum theoretical demand savings, assuming monthly peaks reduced by 100% of PV peak output. This is unlikely to be achieved without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

5 Using Effective Load Carrying Capability (ELCC) of PV, derived by SUNYA. Values are 70% for Albuquerque and 60% for New York.

¹ Peak is reduced by 100% of peak PV output. This is the maximum theoretical potential which is unlikely without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

² Using Effective Load Carrying Capability (ELCC) of PV, derived by SUNYA. Values are 70% for Albuquerque and 60% for New York.

Figure 4.2-10 Impact of IRP and Externality Benefits on Commercial Building Allowable System Price—5 Year Payback

¹ Peak is reduced by 100% of peak PV output. This is the maximum theoretical potential which is unlikely without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

² Using Effective Load Carrying Capability (ELCC) of PV, derived by SUNYA. Values are 70% for Albuquerque and 60% for New York.

Figure 4.2-11 Impact of IRP and Externality Benefits on Curtainwall Office Building Allowable System Price—5 Year Payback

at the State University of New York Albany (SUNYA) shows that there is significant correlation between the PV output and utility load profiles.² Although the PV output may not correlate well with some building load profiles, the utility should still acknowledge the BIPV system output correlation with their load peaks. As discussed more in Section 6.0, Recommendations, the PV industry, DOE and Public Utility Commissions need to promote the value of PV so the BIPV customer receives appropriate rebates or cash incentives that more accurately reflect the IRP benefits to the utility.

4.3 Annual Energy Cost Savings - Residential

4.3.1 Impact on Energy Savings

In single family residential applications, BIPV has the potential to reduce a consumer's electricity bill through energy consumption reductions and/or energy production. Energy consumption reduction is achieved by using a PV array sized near the building peak load with a PV output that nearly matches the building load. The energy production scenario utilizes an oversized array and takes advantage of a utility's willingness to run their meters backward. Many utilities throughout the US will allow reverse metering for systems less than 50kW in size. These two scenarios were investigated using the *ADL PV Performance Model* to simulate 2kW and 4kW arrays. A latitude tilt and true south orientation were chosen for the analysis because these orientations, as shown earlier in Figures 4.2-5 and 4.2-6, had the largest energy savings.

Figure 4.3-1 shows both the impact of the energy reduction and energy production scenarios. If the utility will not buy back the excess electricity, the 2 kW array shows greater savings per kW, and therefore has a higher allowable system cost. If the utility offers reverse metering, doubling the array size would only marginally increase the savings and therefore should result in only a slight decrease in payback period.

Figures 4.3-1 and 4.3-2 highlight the impact of the length of the cooling season. Because Miami requires more cooling than Albuquerque, less energy is available to sell back to the utility. This reduces the impact of the electric consumption which occurs during times of low (or zero) PV output. As a result, the advantage of reverse metering is reduced. The impact in Albuquerque would be similar if electric resistance or heat pumps were used to heat the residence.

Figure 4.3-1 Impact of PV Sizing and Utility Buyback on Annual Single Family Building Electric Consumption

Figure 4.3-2 Impact of PV on Monthly Single Family Building Peak Load

4.3.2 Economic Analysis of Residential BIPV

The economic impact of BIPV for residential systems can be significant. Figure 4.3-1 shows that, if reverse metering is allowed for the 4 kW array, electricity for the residence can be fully supplied by the BIPV system. Areas with year round electricity demands would realize a cost reduction of over 50%, but these savings would only be accessible after the payback period has elapsed.

Assuming a five year payback, allowable BIPV system prices from the customer perspective, range from \$500/kW to \$1300/kW for residential applications, given current utility rates. They are higher in Albuquerque due to the ability of the array to produce excess electricity and sell it back to the utility. Table 4.3-1 further illustrates that savings for the 2 kW systems are actually larger per kW than the 4 kW systems. This would seem to contradict the findings in Figure 4.3-1, but the difference is due to the block structure of the utility rates used in the analysis. Most of the savings for the 2 kW system occur because energy consumption is concentrated in a less expensive block. The savings from the 4 kW system are due mainly to the selling back of electricity at the lower block cost. As a result, the reduction of the more expensive blocks for the 2 kW system results in greater savings per kW.

4.3.3 Impact of IRP Benefits - Residential

IRP benefits can substantially add to the allowable system price for BIPV systems in the residential sector, as shown in Figure 4.3-3. Discussions with industry representatives have indicated that utilities should provide some IRP incentives or rebates to customers who install BIPV systems. Most residential customers do not currently have demand charges. As a result, a technology such as BIPV that is within a region that has a stressed feeder or substation does not currently incur any credits or rebates from the utility for reducing the utility peak demand. At the time of an Electric Power Research Institute (EPRI) PV marketing study, an assumption was made that most BIPV systems installed on residential rooftops would be located in a region served by a feeder or substation with primarily residential load profiles. In general, residential load profiles tend to peak much later in the day than utility peak loads. Therefore no credit was given in the EPRI study for residential T&D support or capacity credit savings.³

Further analysis has shown that indeed installation of BIPV on residential buildings should receive some T&D avoided costs and capacity credits, as output from these systems in locations with feeders or substations served by both residential and commercial customers would benefit from the BIPV system located on a residential building. As shown in Figure 4.3-3, the capacity credits and T&D benefits can add approximately 50-80% to the allowable system price of a residential system, if the theoretical maximum potential could be obtained from the full capacity of the BIPV system.

Table 4.3-1 Impact of PV on Single Family Residence Annual Electricity Cost

Location	PV Capacity (kW)	Without PV	With PV (Buyback Scenario) ¹		Allowable System Price ² (\$/kW)
		Total Annual Electricity Cost (\$)	Total Annual Electricity Savings (\$)	Total Annual Electricity Savings (\$/kW)	
Albuquerque ³ (L.A. Rates)	2	976	529	264	1,320
	4		945	236	1,180
Miami (Miami Rates) ⁴	2	810	191	96	480
	4		379	95	475

1 True South orientation, Latitude Tilt

2 Assuming 5-year payback

3-4

	Southern California Edison Company ³	Florida Power & Light Company ⁴
Customer Charge	0.0000	5.6500
Minimum Charge	3.4500	5.6500
Energy Cost Adjustment	0.00000000	0.03426000
Tax Rate	\$0.0000	10%
Surcharge	\$0.00057000	\$0.00000000
No. of Energy Blocks	2 (summer: 2)	2
Block 1 Size	315 (summer: 393)	750
Block 2 Size	>315 (summer >393)	> 750
Block 1 Energy Charge	0.10855000	0.03922000
Block 2 Energy Charge	0.14464000	0.04922000

Source for rates: GRI, *Electric and Gas Rates for Residential, Commercial, and Industrial Sectors: 1993*, GRI-93/0368, October 1993.

* Peak is reduced by 100% of peak PV output. This is the maximum theoretical potential which is unlikely without battery storage, cycling off of AC loads, and/or optimization of PV system configuration.

Figure 4.3-3 Impact of IRP and Externality Benefits on Residential Building Allowable System Price—5 Year Payback

4.4 References

1. American Architectural Manufacturers Association, Interview, December 1993.
2. Perez, R., R. Seals, and R. Stewart, Solar Resource - Utility Load-Matching Assessment, Prepared by State University of New York Albany for the National Renewable Energy Laboratory, NREL/TP-411-6292, March 1994.
3. Cody, A. and L. Frantzis, The Market for Solar Photovoltaic (PV) Technology, Prepared by Arthur D. Little for the Electric Power Research Institute, EPRI TR-102290, March 1993.

5.0 BIPV Potential Impact on National Energy Savings

Four *ADL PV Market Models* were used to assess the potential impact of BIPV on National Energy Savings for single family, multifamily, and commercial buildings. Commercial buildings were evaluated using separate models for both rooftop and curtainwall applications. The models use existing and forecast data for utility rates, PV system performance, installed system pricing, and potential IRP benefits to determine consumer paybacks, consequent market penetration, and the resulting energy savings potential. Figure 5.1-1 illustrates the BIPV market potential methodology used for this section's analysis.

Section 5.1 presents the assumptions used in the *ADL PV Market Model* analyses, and the remaining sections discuss the potential for National Energy Savings under three different scenarios. The first scenario is based on energy savings alone, the second includes demand charge reductions, and the third includes IRP and externality benefits.

5.1 PV Market Model Assumptions

The overall market model assumptions are shown in Tables 5.1-1, 5.1-2, and 5.1-3, and are described in the following sections.

Table 5.1-1 PV System Performance and Size Assumptions

Entry	Assumptions/Outputs	Sources
Orientation A. Latitude tilt (+/- 10°) B. 15 degree tilt C. Vertical, True South D. Vertical (average of South, East, and West facing facades)	Affects system prices and annual solar output A. 0% loss (baseline) B. 4% loss from latitude tilt C. 34% loss from latitude tilt D. 43% loss from latitude tilt	SNL, PV FORM, 1986 <i>ADL PV Performance Model</i>
PV <u>System</u> Performance	80% of module efficiency ¹ 85% of module eff. after 2000 O&M: \$.008/kWh; \$.007/kWh in 2005; \$.006/kWh in 2010	Ascension Technology and PG&E, 1994 and 1992.
Roof Area Available for PV	30% for retrofits 45% for new construction	See Section 5.1.3
Wall Area Available for PV (Curtainwall analysis)	9% of total exterior wall area (National Average - all bldgs.)	See Section 5.1.4

¹Includes cumulative DC to AC losses such as module mismatch, wiring, and diode losses, inverter losses (8-10%), and temperature derating of array power at ambient temperatures. An Ascension Technology analysis based on monitored data in 1993. The PG&E, Alpha Real AG, and Siemens Solar paper, "Comparison of Selected Economic Factors For Large Ground-Mounted PV Systems With Roof-Mounted PV Systems in Switzerland and the USA," *Proceedings of the 11th European PV Conference*, 1992.

Figure 5.1-1 BIPV Market Penetration Methodology

Table 5.1-2 BIPV System Price Assumptions

Entry	Assumptions	Sources
PV System Prices ¹	A. Commercial retrofit, new, and multifamily B. Curtainwall (new) C. Residential retrofit D. Residential new	A. Table 3.4-5 B. Table 3.4-6 C. Table 3.4-3 D. Table 3.4-4
Contractor Mark-ups	0 step: Direct from manuf. 1 step: 15% mark-up (Typical of an Electrical Contractor) 2 step: 25% mark-up (Typical of an Electrical and General Contractor mark-up)	Turner Construction Company, Interview 1993.

¹The commercial building model assumes PV system prices using a ballasted roof mount for flat roof buildings. The installed system prices for both new and retrofit applications are very similar for ballasted systems, and cheaper than rack-mounted designs. The model therefore used these more favorable system prices to assess the more favorable scenario. Residential models used the integrated PV system prices for new construction and Roof-Jack, stand-off systems for retrofit buildings.

Table 5.1-3 IRP Assumptions

Entry	Assumptions	Sources
Capacity Credits	Varies by region	ADL, based on existing rebates ¹
T&D Avoided Costs	\$50/kW/yr	ADL ^{1,2}
Environmental Externality Credits	\$.002 - .03/kWh (1990s) \$.012 - .026/kWh (2000+) Total for SO _x , NO _x , CO ₂	ADL, based on EIA, <u>Supplement to the Annual Energy Outlook, 1993</u> ; EPRI, <u>DSM Proceedings</u> ; PUCs 1993.

¹Values assumed for capacity credits and T&D avoided costs are further modified based on capacity correlation data provided by Richard Perez at SUNYA, 1994. See Section 5.4.6.

²ADL estimates, based on studies by Decision Focus, Potential Benefits of Battery Storage to SDG&E, prepared for SNL and SDG&E, January 1992 and Potential Benefits of Battery Storage to Chugach Electric, April 1992. Other data sources: EPRI Journal, April/May 1992; Freeman, Sullivan & Co. "Grid-Support Photovoltaics: Summary of Case Studies" Prepared for PG&E, August 1994; and Zaininger Engineering Company, The Integration of Renewable Energy Sources into Electric Power Distribution Systems, Prepared for ORNL, ORNL-6775/V2, June 1994. The \$50/kW/yr value represents a National Average number. Areas within a given utility can have values significantly higher than this value. An interview with H. W. Zaininger supports the \$50/kW/yr national average number, August 1994.

5.1.1 Orientation and Module Output

PV system output varies with adjustments in module orientation. The *ADL PV Market Models* utilize average annual insolation data (kWh/ft²) developed by Sandia National Labs PVFORM (1986), which assume latitude tilt orientation in various cities throughout the US. Annual solar output from the BIPV system is then determined, based on system efficiency and annual insolation. The residential model assumes latitude tilt for all rooftop applications. The commercial model allows for either latitude tilt or 15-degree tilt orientation. Annual solar output in kWh is reduced by 4% if the module is placed at a 15-degree tilt. For curtainwall applications, output losses are estimated at an average of 43%, assuming a 90-degree tilt orientation with BIPV applied to the South, East and West facades. This percentage was calculated using the *ADL PV Performance Model*.

5.1.2 PV System Performance

System performance is assumed to be 80% of module efficiency through 2000. At that time, system performance is expected to rise to 85% of module efficiency. These system performances include cumulative DC to AC losses such as module mismatch, wiring and diode losses, inverter losses, and temperature derating of array power at ambient temperatures. These assumptions are based on an Ascension Technology analysis of monitored data in 1993, a PG&E, Alpha Real AG, and Siemens Solar paper titled, "Comparison of Selected Economic Factors For Large Ground-Mounted PV Systems With Roof-Mounted PV Systems in Switzerland and the USA," and Proceedings of the 11th European PV Conference, 1992.

5.1.3 Roof Area Available for PV

Commercial Buildings. To assess the availability of flat commercial roof area, personnel within the buildings division of the National Renewable Energy Laboratory (NREL), building code officials, and architects were contacted and interviewed. Based on these interviews, Arthur D. Little estimated that approximately 15% of a typical flat roof commercial building is occupied by heating, ventilation, and air conditioning (HVAC) equipment, vents, and louvers. This estimate provided by building code officials is even higher for smaller commercial buildings. An additional 20% of the roof would not be available for BIPV due to shading from parapets, which often go around the perimeter at least one foot above the roof line, trees, HVAC equipment, and other buildings. Zoning restrictions or code barriers which limit weight on rooftops, especially given wind and snow loading, and areas such as California which restrict equipment placement due to earthquake concerns will also limit the roof area available for BIPV.

One architect estimated that the above issues could restrict the available commercial roof area by 70%. A more liberal estimate of 45% assumes that potentially some live loads can be offset by the ballasted weight and/or that new anchoring techniques will be developed to ameliorate this issue. Given that the restrictions mentioned above are not necessarily additive, this DOE analysis assumed that 30% of existing commercial building roof area, and that 45% of new commercial building roof area would be available for PV installations.

Residential Buildings. For existing residential buildings, 30% are estimated to have adequate solar access. This estimate considers buildings with a roof slope less than or equal to 45 degrees of true south and roof tilts within 10 degrees of latitude as having adequate solar access.⁶ To assess the percent of new residential buildings that are BIPV-accessible, personnel within the buildings division of the National Renewable Energy Laboratory (NREL) were contacted. Based on these discussions, Arthur D. Little estimates that approximately 45% of new residential buildings will have adequate solar access. This increase assumes that practical consideration of building energy management issues during the design phase will be more common in the future.⁷

5.1.4 Wall Area Available for Curtainwall Applications

To determine the maximum number of walls that are viable for installation of curtainwall systems, the *ADL PV Performance Model* was used to simulate various BIPV orientations. Figure 4.1-1, shown in the previous section, illustrates that South, East and West facing walls would produce approximately 70% of the maximum possible PV output for a curtainwall array. The North facing wall would only produce about 30% of the maximum BIPV output and would therefore not be cost-effective. As a result, three walls were assumed to be used for curtainwall BIPV arrays while the fourth was assumed to be covered with a surface that would simulate the appearance of a BIPV array.

To further delineate the surface area available for curtainwall PV systems, a report by the American Architectural Manufacturers Association was reviewed and updated through Arthur D. Little interviews. The findings indicate that 30% of the total wall area is non-load bearing. Of this, 20% is typically vision glass and 10% is non-vision material. The *ADL PV Market Models* assume that all of the non-vision area and 25% of the vision glass area is available for curtainwall PV applications. An additional 15% is assumed lost due to shading, leaving only 9% of total wall area PV-accessible.^{8,9} Although this percentage appears low, it reflects the total commercial wall space available for PV on a national average. There are specific commercial building types, however, such as high rise office buildings, that would be particularly appropriate for curtainwall applications because a larger percentage of wall space would be available. The *ADL PV Performance Model* was used to simulate a high rise curtainwall application as discussed in Section 4.1.

5.1.5 BIPV System Prices and Contractor Markups

Sources and assumptions related to BIPV system prices are detailed in Sections 3.0 and 4.0 of this report. Distribution markups are assumed to be 15% for a one-step distribution (typical of an electrical contractor) and 25% for a two-step distribution (typical of a general contractor).¹⁰ Currently, each component of the PV system is marked up differently. For example, some PV system integrators may mark up the module by only 15%, while the inverter mark-up may be closer to 30%. The *ADL PV Market Models* provide the user with options to select the distribution steps required based on likely mark-ups once the technology becomes marketed through more typical distribution networks.

5.1.6 Utility Rate Structures

Utility rates vary significantly in the nine regions selected for evaluation in the residential and commercial market models. Arthur D. Little selected one utility to represent each region, and then examined rates offered by that utility to determine the most appropriate rate structure for each sector.¹ The regions and their representative city and utility are presented below.

Region	City	Utility
New England	Boston	Boston Edison
Middle Atlantic	New York	Consolidated Edison
East North Central	Chicago	Commonwealth Edison ²
West North Central	Minneapolis	Northern States Power
South Atlantic	Miami	Florida Power and Light
East South Central	Birmingham	Alabama Power
West South Central	Dallas	Texas Utilities Electric Co.
Pacific Northwest	Olympia	Puget Sound Power and Light
Pacific Southwest	Los Angeles	Southern California Edison

Although time-of-use (TOU) rates are offered by most utilities, general service rates were selected because they reflect the most common choice of residential and commercial customers.

To calculate the rates, an average energy use (without electric heat) of 700 kWh/month was assumed for the residential sector, which is typical of a single family home. This load was derived from work being conducted by Lawrence Berkeley Laboratory for the US DOE to develop prototypical building load profiles.³ An average demand of 300 kW/month and an energy use of 90,000 kWh/month was assumed for the commercial sector, representing a typical office building. The commercial loads were developed from the DOE2 building load model that was based on DOE's energy conservation standards.

Typical demand loads for other types of commercial buildings range from <300 kW for educational facilities, to 1000 kW for hotels, and 2500 kW for hospitals. Although 300 kW appears to be a low mean, office buildings consume 31% (781 trillion Btu) of total electricity used in the commercial sector. As shown in Figure 5.1-2, this represents the largest commercial building electricity consumption. Mercantile and service represent the next largest building sector for electricity consumption at 550 trillion Btu. Office building loads were selected to represent the most common building electricity use load profile for commercial buildings as they are the largest electricity consumer in the US.⁴

Rate projections for 1995, 2000, 2005 and 2010 were calculated by applying annual regional growth factors to 1993 rates for both sectors. The growth factors were based on EIA's reference scenario projections for 2000 and 2010.⁵

(1) Site energy

Source: Energy Information Administration, *Commercial Buildings and Expenditures*, 1992

Figure 5.1-2 Electricity Consumption By Building Type (1989)

5.1.7 Demand Charge Savings

The *ADL PV Market Models* assume a percentage of the PV system size is recovered through demand charge reductions, if this option is selected. This percentage varies by region as shown in Table 5.1-4. For example, a 100 kW system on a commercial building in Boston is assumed to reduce monthly demand by 50 kW. These data are based on a detailed analysis conducted by Richard Perez, et. al., at the State University of New York at Albany (SUNYA) that compares the correlation between utility peak load profiles and PV output for 20 US utilities nationwide.

Table 5.1-4 Percent Correlation Between Utility Peak and PV Output

Region	Capacity Correlation (%) (ELCC) ¹	Representative Utility
New England (Boston)	50	NEES
Middle Atlantic (New York)	60	LILCO
East North Central (Chicago)	60	NSP
West North Central (Minneapolis)	60	NSP
South Atlantic (Miami)	45	FP&L
East South Central (Birmingham)	55	SES
West South Central (Dallas)	65	TU
Pacific Southwest (Los Angeles)	70	PG&E
Pacific Northwest (Olympia)	20	Relative to all northwest

¹ELCC - Effective Load Carrying Capability. A statistical measure of effective capacity - the effective increase in a utility's installed capacity due to the added resource, at constant loss of load probability. These percentages assume 2% PV penetration on the considered grid. If 10% PV penetration is assumed, then the above ELCC percentages would be 3-5% less.

Source: Telephone interview with Richard Perez at SUNYA, August 1994.

Customer demand charges are normally calculated based on the highest demand during any 15-minute to 1-hour period for a given month. Commercial office building loads typically begin by 9:00 am and continue through 5:00 pm, as compared to peak output from the PV system, which will occur at midday. For retail buildings, the load will often continue into the evening hours. As shown in Section 4.0, if PV output is measured against actual building loads and existing rate structures, the actual demand savings realized by the customer may reflect an even smaller percentage of the rated capacity of the system. By using the percent capacity correlation between the utility peak and PV output to estimate demand charge savings, the true value of the system to the utility is more closely approximated. Although no such valuation exists today, this analysis assumes that in the future, the utility may provide the customer with demand savings equal to the true capacity benefit.

5.1.8 Capacity Credits

Arthur D. Little assumed an average capacity credit of \$150/kW for residential and multifamily applications, and \$200/kW for commercial and curtainwall applications. As with the demand charge reductions, these credits are adjusted by a percentage to reflect the correlation between system output and utility peak load profiles. These credits are assumed to be a one-time rebate that will be offered by utilities for BIPV system installation, and are applied in the model as an up-front reduction in system price.

At the present time, capacity credits are not offered by utilities for BIPV installations. The assumed credits are based on rebates offered for other means of demand reduction, such as high efficiency lighting, motors, and chillers, Table 5.1-5. Table 5.1-6 summarizes the potential capacity credits for multifamily buildings.

Table 5.1-5 Commercial Sector Capacity Credits

Utility	Rebates Offered for Demand Reduction (\$/kW)	Average Capacity Credit Potentially Applicable to Solar (\$/kW)
Consolidated Edison	\$200-1250/kW high efficiency lighting in new construction \$10-80/ton electric AC	\$250
Detroit Edison	\$250/kW fluorescent, MH, HPS lighting \$25-500 for 1-200 hp motors	\$250
Florida Power & Light	\$250/kW major lighting modifications \$80/kW minor lighting modifications \$250/kW thermal storage off summer peak \$35/ton for heat pumps; plus \$5/ton each additional .1 SEER/EER improvement over minimum.	\$200
Southern California Edison	\$100-150/kW lighting \$75/ton evaporative cooling \$21/ton chillers	\$100

Sources: *Energy User News*, April 1993, interviews with utilities, and Delmarva Power, "Identification of the Potential of PV in the Utility DSM Market: A Study of 21 US Utilities," December 1992.

Table 5.1-6 Multifamily Capacity Credits

Region	Rebates Offered in Equivalent (\$/kW) ¹
Northeast	\$100
Northcentral	\$100
South	\$200
West	\$150

112,000 Btu/ton conversion used in calculations

Sources: Delmarva Power, "*Identification of the Potential of PV in the Utility DSM Market: A Study of 21 US Utilities*," December 1992.

5.1.9 T&D Avoided Costs

To assess the annual T&D benefit (\$/kW/yr) that could be realized through distributed BIPV, the findings of several assessments conducted for specific utilities were compared. These data are presented in Table 5.1-7. Based on the range in values for the several utilities reviewed and through an interview with Zaininger Engineering Company (who recently conducted case studies for seven utilities throughout the US), the *ADL PV Market Models* assume a national average T&D benefit value of \$50/kW/yr. Values for T&D benefits, however, vary significantly, as shown in Table 5.1-7. Some of the associated T&D benefits include:

- the value of deferring a substation and other distribution investments;
- the savings in losses achieved by locating generation closer to customer loads;
- the value of transmission capacity freed up by the distributed PV;
- the value of being able to partially solve minimum load problems; and
- improved reliability from being able to shorten the duration of outages.¹⁵

The value of \$50/kW/yr was viewed as a value that could be applied to all buildings in the US on a national average. It should be noted however, that the values used in the model are the best judgement of Zaininger Engineering Company and Arthur D. Little given the limited data available.^{14, 15}

At the present time, T&D benefits are not passed on to BIPV owners by utilities. Arthur D. Little acknowledges that T&D savings will vary considerably among utilities, and that they are very site specific, even within a single utility network. For this analysis the T&D benefits are applied to all building types except single family. According to a number of utility personnel and reviewing the building load profile model runs, residential loads tend to peak later in the day when BIPV output is low, compared to mid-afternoon. As cited in an Arthur D. Little report for the Electric Power

Research Institute, "In utility districts where substations serve primarily residential customers, distributed power applications using BIPV, either at or near the substation location or on building rooftops, are less beneficial to a utility that needs additional power delivery capacity. A number of utility substations serve a mix of residential and commercial loads. In these areas, BIPV may offer potential benefits in a distributed power configurations for avoiding or deferring T&D investments, but insufficient data are available to determine the exact mix of distribution substation customer classes and residential load profiles at the time of system peak by utility." This DOE analysis assumes that multifamily buildings are more likely than single family buildings to be located near a substation location served also by commercial loads where the BIPV output would coincide well with the maximum stress on distribution feeders and substations. Very limited data is currently available to assess the true benefit of BIPV at the distributed feeder or substation level. The Utility Photovoltaic Group (UPVG) and others are encouraging more utility analyses of T&D costs and BIPV savings.¹⁶

Table 5.1-7 Examples of T&D Annual Benefits Calculated for Various Utilities

Utility	T&D Annual Benefit (\$/kW/yr)
San Diego Gas & Electric	\$10-200
CEA (Alaska)	\$3-27
LA Department of Water and Power ¹	\$6-37
Central and Southwest Corporation ¹	\$9-68
City of Austin (STECK-1 feeder)	\$5-11
Arizona Public Service (highest benefit - Cocopah substation)	\$245
Southern California Edison	~\$70
Green Mountain Power (Vermont)	~30
Salt River Project (Wilkins distribution area)	\$136-196
Plains Electric Coop. (Cibecue feeder)	\$578-735
Oglethorpe Power Corporation ¹	\$8-25
Pacific Gas and Electric (Kerman) ²	\$380

¹ Calculated using a 60% capacity factor

² Includes estimates of \$205/kW/yr for reliability; \$28/kW/yr for minimum load; and \$47/kW/yr for transmission which still need to be validated.

Sources: Decision Focus, Potential Benefits of Battery Storage to SDG&E, Prepared for SNL and SDG&E, January 1992 and Potential Benefits of Battery Storage to Chugach Electric, April 1992; EPRI Journal, April/May 1992; Freeman, Sullivan & Co. "Grid-Support Photovoltaics: Summary of Case Studies, August 1994; and Zaininger Engineering Company, The Integration of Renewable Energy Sources Into Electric Power Distribution Systems, June 1994.

5.1.10 Environmental Externality Credits

The monetization of externalities has only been conducted by a handful of utilities and PUCs, with a wide range of values assigned for SO₂, NO_x and CO₂. The assumed externality values (\$/kWh) in this study were derived using EIA data characterizing regional emissions (lbs/kWh), and applying externality values (\$/lb) where available. As shown in Table 5.1-8, an EIA report evaluated SO₂, NO_x and CO₂ emissions (lbs/kWh) in various regions of the US, based on average utility fuel mix for each region. These emissions data were then converted to \$/kWh by applying the monetized values shown in Table 5.1-9. For regions without externality values, the lowest values developed in other regions were applied. The *ADL PV Market Models* assume the externality values (\$/kWh) shown in Table 5.1-10.¹³

Table 5.1-8 Regional SO₂, NO_x, and CO₂ Emissions in lbs/kWh

Region	1990			2000		
	SO ₂	NO _x	CO ₂	SO ₂	NO _x	CO ₂
Northeast (NY/NJ Region)	.005	.002	0.86	.003	.002	0.64
Northcentral (Midwest Region)	.021	.007	1.68	.008	.005	1.59
South (South Atlantic Region)	.013	.005	1.40	.007	.004	1.36
West (West Region)	.001	.003	0.90	.001	.003	0.85

Source: Arthur D. Little analysis using utility generation mix data from Energy Information Administration, *Supplement to the Annual Energy Outlook*, 1993. DOE/EIA-0554(93).

Table 5.1-9 Regional Externality Values in \$/lb of Emissions

Region	SO ₂	NO ₂	CO ₂
Northeast (NY Energy Office) (MA DPU)	0.43	2.10	0.037
	0.75	3.25	0.012
	Average: 0.59	Average: 2.68	Average: 0.025
Northcentral (Wisconsin)	0.43 ¹	0.98 ¹	0.008
South	0.43 ¹	0.98 ¹	0.004 ¹
West (SDG&E) (Nevada PSC) (PG&E)	10.13	13.56	0.004
	0.78	3.40	0.011
	2.24	0.98	0.004
	Average: 4.38	Average: 5.98	Average: 0.006

¹ No PSCs have ordered externalities to date. These values are based on the lowest values presented in other regions.

Source: EPRI, Proceedings: *6th National Demand-Side Management Conference*, TR-102021, March 1993. Interviews with Public Service Commissions in each region, June 1993.

Table 5.1-10 Average Regional Externality Values in \$/kWh

Region	1990				2000			
	SO ₂	NO _x	CO ₂	Total	SO ₂	NO _x	CO ₂	Total
Northeast	.003	.005	.022	.030	.002	.005	.016	.023
Northcentral	.009	.007	.013	.029	.003	.005	.013	.021
South	.005	.005	.006	.016	.003	.004	.005	.012
West	.004	.017	.005	.026	.004	.017	.005	.026

Source: Arthur D. Little estimates, June 1993.

5.1.11 Market Penetration Curves

Consumers typically use some form of simple payback consideration (e.g. rather than a more formal rate of return or cost of capital type analysis) in assessing the economic value of energy saving technologies. Based on field interviews, consumer surveys and analyses of market experience with a variety of energy saving technologies, Arthur D. Little has developed curves which relate market penetration rates to economic performance as viewed by parties making purchase decisions, Figure 5.1-3.

It is recognized that there is always a significant level of uncertainty in estimating markets for the building sector energy products, given the complex decision making processes involved and the variety of building ownership modes. In order to help quantify this procedure, Arthur D. Little developed market penetration curves shown in Figure 5.1-3 which should be viewed as providing guidance on basic trends rather than being quantitatively precise. Assumptions used in the BIPV market models include:

- the threshold payback period (i.e. upper limit) required to initiate a significant market penetration is on the order of four (4) to five (5) years;
- large market penetrations require payback periods of three (3) years or less if the analysis is viewed from the customer perspective. The utility perspective is more in the range of seven (7) years;
- it takes five to ten years for large markets to develop due to the natural inertia in the decision making process (equipment replacement schedules, annual budget processes, etc.) and the requirements on many purchasers to rely on the extended experience of others before making a commitment to a new energy technology.

For the residential, multifamily, and commercial rooftop markets, the one year curve was used from 1994-2000. The one year curve represents a technology curve for systems that are commercially viable - showing a positive life-cycle cost. BIPV is not likely to meet this criteria until around the year 2000 for limited regions of the US such as the Pacific Southwest or areas with large demand charges. The five year curve was used for the 2005 and 2010 time periods because commercial viability of BIPV is weak in some regions of the US even in the 2005 time period.

Data Points:

- Desiccant dehumidifiers five years following introduction
- ◆ Gas engine driven rooftop packages one year following introduction
- Desiccant dehumidifiers one year following introduction
- Ground source heat pumps five years following introduction
- Ground source heat pumps one year following introduction
- △ High efficiency central A/C systems three years following introduction
- ▲ High efficiency gas furnaces ten years following introduction

Source: Arthur D. Little estimates, based on HVAC penetration experience

Figure 5.1-3 Market Penetration Curves Characteristic of Energy Saving Technologies (from the customers perspective)

For the curtainwall markets, the one year curve was used for the time period 1994-2000, and the five year curve for 2005-2010. The distinction between curves for each of the applications makes very little difference until the five year level of payback is achieved. In this analysis of BIPV, the five year payback was never achieved.

Using these curves, market penetration has been projected for BIPV at different installed system prices and for nine different regions of the US. Economic considerations often are not the only purchase criterion; other factors such as noise, reliability, product perception, and reduced emissions may also be important factors. When other factors are important in the purchase decision, these market penetration curves can still be used as a guideline for market penetration estimates.

5.2 Potential BIPV Impact - With Energy Savings Only

The first analysis determines payback period and resulting market penetration for the nine regions, assuming only energy savings. It is important to note throughout this study that this analysis is from the customer perspective. If utility companies were to own and lease BIPV systems, for example, their payback requirements are less strict and almost twice that of residential or commercial customers, as shown earlier in Figure 5.1-2. As a result, BIPV market penetration would potentially be higher.

The analysis was repeated for single family, multifamily, commercial, and curtainwall building applications.

5.2.1 Single Family

As shown in Table 5.2-1, Boston, New York, Chicago, and Los Angeles have the highest residential energy charges. Although New York rates are the highest overall, the annual solar output (kWh/ft²) in the Middle Atlantic region is significantly lower than that of the Pacific Southwest. Because of this, the Pacific Southwest is the only region showing payback periods within the range of market penetration (<12 years).

Assuming a one-step distribution, paybacks in the Pacific Southwest are just over 12 years, so no market penetration is indicated by the model. Assuming direct distribution from the manufacturer, BIPV costs are sufficiently low to achieve market penetration by 2005. This scenario results in an energy savings potential in the Pacific Southwest of 10 MW/yr in 2005, and 95 MW/yr in 2010.

Table 5.2-1 Residential Sector Electricity Rates (\$/kWh)¹

Region	1993	1995	2000	2005	2010
New England (Boston)	0.111	0.116	0.126	0.124	0.122
Middle Atlantic (New York)	0.140	0.137	0.131	0.133	0.134
East North Central (Chicago)	0.107	0.109	0.115	0.115	0.115
West North Central (Minneapolis)	0.077	0.078	0.080	0.082	0.084
South Atlantic (Miami)	0.070	0.069	0.066	0.066	0.066
East South Central (Birmingham)	0.069	0.068	0.065	0.065	0.066
West South Central (Dallas)	0.075	0.076	0.080	0.082	0.084
Pacific Northwest (Olympia)	0.056	0.059	0.067	0.069	0.070
Pacific Southwest (Los Angeles)	0.127	0.126	0.124	0.124	0.123

¹ 1993 rates: GRI, assuming a monthly load of 700 kWh. Projections calculated using growth factors based on Energy Information Administration, *Annual Outlook for Electric Power*, 1991. All rates reflect average annual \$/kWh.

5.2.2 Multifamily

With the exception of New York and Chicago, none of the major utilities in the nine regions evaluated offer special rates for multifamily buildings. This analysis therefore used residential general service rates for all regions except the Middle Atlantic (New York) and East North Central (Chicago). Some market penetration occurs in the single family analysis for the Pacific Southwest, but commercial BIPV prices are assumed for multifamily building applications, Table 5.2-2. Commercial system prices are somewhat higher than residential prices due to additional BOS costs, and this price differential appears to hold payback periods for multifamily applications at 13 years, even in the Pacific Southwest. This is beyond the payback required for significant market penetration. Therefore, assuming a one-step distribution, no market penetration is expected in this sector based on energy charge savings alone.

Assuming direct distribution, BIPV prices result in paybacks of 11 years in the Pacific Southwest by 2010. This allows for market penetration and potential energy savings of 40 MW/yr.

Table 5.2-2 Multifamily Sector Electricity Rates ¹

	1993	1995	2000	2005	2010
Region	Energy Charges (\$/kWh)				
New England (Boston)	0.111	0.116	0.126	0.124	0.122
Middle Atlantic (New York)	0.050	0.050	0.049	0.049	0.049
East North Central (Chicago)	0.056	0.056	0.056	0.057	0.058
West North Central (Minneapolis)	0.077	0.078	0.080	0.082	0.084
South Atlantic (Miami)	0.070	0.069	0.066	0.066	0.066
East South Central (Birmingham)	0.069	0.068	0.065	0.065	0.066
West South Central (Dallas)	0.075	0.076	0.080	0.082	0.084
Pacific Northwest (Olympia)	0.056	0.059	0.067	0.069	0.070
Pacific Southwest (Los Angeles)	0.127	0.126	0.124	0.123	0.123
	Demand Charges (\$/kW)				
New England (Boston)	0.00	0.00	0.00	0.00	0.00
Middle Atlantic (New York)	25.24	25.24	25.24	25.24	25.24
East North Central (Chicago)	11.13	11.13	11.13	11.13	11.13
West North Central (Minneapolis)	0.00	0.00	0.00	0.00	0.00
South Atlantic (Miami)	0.00	0.00	0.00	0.00	0.00
East South Central (Birmingham)	0.00	0.00	0.00	0.00	0.00
West South Central (Dallas)	0.00	0.00	0.00	0.00	0.00
Pacific Northwest (Olympia)	0.00	0.00	0.00	0.00	0.00
Pacific Southwest (Los Angeles)	0.00	0.00	0.00	0.00	0.00

¹ 1993 rates: GRI. Projections calculated using growth factors based on Energy Information Administration, "Annual Outlook for Electric Power," 1991. All rates reflect average annual costs.

5.2.3 Commercial Rooftop

Commercial energy rates, Table 5.2-3, are considerably lower than those offered to the residential sector for all utilities. Boston and Los Angeles have the highest energy rates at approximately \$0.06-0.09/kWh. At these rates, assuming a one-step distribution, energy charge savings allow for PV system paybacks in Boston and LA of 41 and 18 years, respectively. Even if the PV systems were distributed directly from the manufacturer, the paybacks are insufficient to allow market penetration. No market penetration is expected in this sector based on energy charge savings alone.

Table 5.2-3 Commercial Sector Electricity Rates ¹

	1993	1995	2000	2005	2010
Region	Energy Charges (\$/kWh)				
New England (Boston)	0.066	0.068	0.074	0.070	0.067
Middle Atlantic (New York)	0.060	0.059	0.058	0.058	0.059
East North Central (Chicago)	0.039	0.039	0.038	0.039	0.040
West North Central (Minneapolis)	0.034	0.033	0.032	0.031	0.031
South Atlantic (Miami)	0.050	0.049	0.047	0.047	0.047
East South Central (Birmingham)	0.061	0.060	0.058	0.057	0.057
West South Central (Dallas)	0.044	0.045	0.046	0.046	0.047
Pacific Northwest (Olympia)	0.049	0.051	0.054	0.055	0.057
Pacific Southwest (Los Angeles)	0.094	0.093	0.091	0.089	0.087
	Demand Charges (\$/kW)				
New England (Boston)	14.30	14.30	14.30	14.30	14.30
Middle Atlantic (New York)	20.31	20.31	20.31	20.31	20.31
East North Central (Chicago)	12.20	12.20	12.20	12.20	12.20
West North Central (Minneapolis)	7.33	7.33	7.33	7.33	7.33
South Atlantic (Miami)	6.94	6.94	6.94	6.94	6.94
East South Central (Birmingham)	4.88	4.88	4.88	4.88	4.88
West South Central (Dallas)	7.36	7.36	7.36	7.36	7.36
Pacific Northwest (Olympia)	6.12	6.12	6.12	6.12	6.12
Pacific Southwest (Los Angeles)	6.35	6.35	6.35	6.35	6.35

¹ 1993 rates: GRI. Assuming 90,000 kWh and 300 kW per month. Projections calculated using growth factors based on Energy Information Administration, "Annual Outlook for Electric Power," 1991. All rates reflect average annual costs.

5.2.4 Curtainwall

Curtainwall BIPV systems were assumed to be installed as part of new construction. Using the same commercial rates used for the commercial rooftop analysis (Section 5.2.3), paybacks are not within a range that allows for market penetration based on energy cost savings alone. The paybacks are slightly better than the rooftop systems (Boston: 35 yrs, LA: 16 yrs), even though annual solar output (kWh/ft²) is reduced by 43% for curtainwall applications (Section 4.2). This improvement in payback is a function of lower system cost per square foot for curtainwall BIPV systems, and highlights the importance of reducing BIPV system costs.

5.3 Potential BIPV Impact - With Demand Charge Savings

The second analysis assumes a percentage of the BIPV system size is recovered through demand charge savings. The percentage varies by region as discussed in Section 5.1.7. This assumption is based on the correlation between PV output and utility peak loads that was identified through a detailed analysis conducted at SUNYA by Richard Perez. As demand charges are not part of residential rate structures, this discussion includes only multi-family, commercial, and curtainwall building applications.

5.3.1 Multifamily

Demand charge savings are not relevant to multifamily buildings in most regions. The majority of multifamily buildings have separate meters for individual apartments, and consequently single family residential rates would apply. Discussions with Southern California Edison's rate department indicate that virtually every apartment in greater Los Angeles has a separate meter.¹¹ Only two of the utilities selected in this study offer multifamily building rates that include demand charges: Consolidated Edison (New York) and Commonwealth Edison (Chicago). Residential rates were used for the remaining regions, and consequently the outcome of the analysis is the same for those regions as described in Section 5.2.2 (market potential of 40 MW/yr in the Pacific Southwest in 2010). Assuming either one-step or direct distribution, the payback periods do not reach a level that allows for market penetration in New York or Chicago based on demand charge savings.

5.3.2 Commercial Rooftop

This analysis suggests that demand charge savings in this building sector are not sufficient to reduce the payback period below 12 years, which would allow for market penetration.

5.3.3 Curtainwall

Using the same commercial rates described in Section 5.2.3, curtainwall applications appear to have market potential by 2010. Though penetration is noted in this analysis, the overall potential for energy savings is relatively low (1 MW/yr in 2010 for a one-step distribution, 3 MW/yr in 2010 for direct distribution). This is due in part to the assumption that curtainwalls will be used only for new construction, and also because of the minimal wall area that is actually available and appropriate for PV systems on a national average (see assumptions, Section 5.1.4).

A consideration that has not been factored in to the curtainwall analysis is consumer reluctance. The standard market penetration curve that is used for this and other building applications may not be appropriate for the curtainwall analysis. Although the market penetration curve that is utilized in these models is intended to reflect consumer acceptance of new technologies, they assume that the technology is well commercialized. Curtainwall applications are unique in that they require the consumer to replace two items that are available and reliable: building materials and grid electricity. For this reason, curtainwall applications may need to demonstrate extended

reliability before they will actually realize standard market penetration potential as a new technology.

5.4 Upper Bound—With Demand Charges, IRP, and Externality Benefits

The final analysis determines payback periods for the nine regions under the most favorable scenario. This scenario assumes energy savings, potential demand charge savings, IRP and externality benefits. Table 5.4-1 summarizes the market potential for this upper bound scenario. Figure 5.4-1 shows the relative payback periods for commercial building for each region and scenario. Figure 5.4-2 illustrates the trend in paybacks periods for the Pacific Southwest. The values assumed for IRP and externality benefits were discussed in Section 5.1.

Table 5.4-1 Upper Bound BIPV Market Penetration With and Without IRP Benefits^{1,2}

	Single Family	Multifamily ³	Commercial Rooftop	Curtainwall	Total ³ (MW/yr)
2000 System Price (\$/Wpac)	\$5.40	\$5.30	\$5.30	\$3.50	
2000 MW/yr Without IRP	0	0	0	0	0
2000 MW/yr With IRP	0	0	0	0	0
2005 System Price (\$/Wpac)	\$3.95	\$4.00	\$4.00	\$2.30	
2005 MW/yr Without IRP	0	0	0	0	0
2005 MW/yr With IRP	90	35	85	3	~175-210
2010 System Price (\$/Wpac)	\$3.60	\$3.50	\$3.50	\$1.80	
2010 MW/yr Without IRP	0	0	0	3	~3
2010 MW/yr With IRP	290	115	300	6	~595-710

¹Assuming one-step distribution (15% markup), 10% Federal Investment Tax Credit (all but single family), and demand charge savings. SF prices are for new construction.

²Based on economics alone. Some BIPV installations are likely from demonstration systems or other utility encouraged programs.

³Ownership issues for multifamily might limit the high-end market penetration shown (see Section 5.4.2)

5.4.1 Single Family

For the residential sector, this analysis includes all but demand charge savings. The addition of IRP and externality benefits significantly accelerates the adoption of PV systems. The first market penetration is seen for single family homes in 2005 in the Pacific Southwest, where 8-yr paybacks are realized by 2010. This region is the only one to exhibit market potential for the residential sector within the timeframe of this

- Scenario A: PV with Energy Charge Savings (no additional benefits)
 Scenario B: Scenario A with Demand Charge Savings ¹
 Scenario C: Scenario B with IRP Benefits (T&D and Capacity Credits included) ²
 Scenario D: Scenario C with Environmental Externalities included ²

Note: All scenarios represent a 30 kW AC module system at a south-facing, 15-degree tilt. Total system installed cost in 1995, including one-step distribution (15% markup) and a 10% federal tax credit, is \$7.10/Wpac for a ballasted mount system on a flat roof.

¹ Assumes a percentage of system capacity is recovered through demand charge savings. This percentage varies by region as shown in Table 5.1-4.

² T&D avoided costs and environmental externality benefits assume utilities will pass on "cash incentives" to consumers. To date, monetized values have not been offered for these benefits.

Figure 5.4-1 Commercial Building Paybacks by Region

Scenario A: PV with Energy Charge Savings (no additional benefits)

Scenario B: Scenario A with Demand Charge Savings ¹

Scenario C: Scenario B with IRP Benefits (T&D and Capacity Credits included) ²

Scenario D: Scenario C with Environmental Externalities included ²

Note: All scenarios represent a 30 kW AC module system at a south-facing, 15-degree tilt and with a ballasted mount on a flat roof. Total system installed costs are, including one-step distribution (15% markup) and a 10% federal tax credit, \$7.10/Wpac (1995), \$5.30/Wpac (2000), \$4.00/Wpac (2005), and \$3.50/Wpac (2010).

¹ Assumes a percentage of system capacity is recovered through demand charge savings. This percentage varies by region as shown in Table 5.1-4.

² T&D avoided costs and environmental externality benefits assume utilities will pass on "cash incentives" to consumers. To date, monetized values have not been offered for these benefits.

Figure 5.4-2 Commercial Building Payback Periods for the Pacific Southwest

analysis. The Middle Atlantic region approaches reasonable payback periods in 2010, and may see some market penetration beyond that time. Assuming a one-step distribution, this analysis indicates that the total energy savings potential from PV installations on single family homes is 90 MW/yr in 2005, and 290 MW/yr in 2010, all of which will be installed in the Pacific Southwest. Direct distribution could result in total energy savings potential as high as 275 MW/yr in 2005, and 290 MW/yr in 2010.

5.4.2 Multifamily

The addition of IRP and externality benefits for multifamily buildings appears to bring about market penetration as early as 2005. Assuming one-step distribution, market penetration is seen in the Pacific Southwest that would result in energy savings of 35 MW/yr in 2005 and 115 MW/yr in 2010. Assuming direct distribution, early market penetration is exhibited, resulting in savings of 30 MW/yr in 2000, 130 MW/yr in 2005 and 220 MW/yr in 2010.

It should be noted, however, that the issue of ownership in the multifamily sector presents a significant obstacle to market penetration as viewed from the consumer perspective. As discussed in Section 5.3.1, most apartments in multifamily buildings have a separate meter. Given that many apartment dwellers are short-term residents who pay their own electric bills, there is no long-term focus and little incentive for installing a BIPV system. Similarly, because the building owner is not responsible for electric utility bills, there is little incentive to reduce consumption. For this building sector, it appears that the incentive would have to be on the supply side as a distributed power source.

5.4.3 Commercial Rooftop

The addition of IRP and externality benefits to commercial buildings reduces the payback period to an acceptable level in 2005. Assuming a one-step distribution, the total energy savings potential is estimated to be 85 MW/yr in 2005 and 300 MW/yr in 2010. Direct distribution would result in an increase in potential energy savings to 260 MW/yr in 2005 and 390 MW/yr in 2010.

5.4.4 Curtainwall

The implementation of IRP and externality benefits appears to bring about market penetration as early as 2005 for curtainwall applications. By 2010, penetration is seen in both the Middle Atlantic and Pacific Southwest. However, as discussed in section 5.3.3, the relative energy savings potential is low, with 3 MW/yr in 2005, and 6 MW/yr in 2010. If direct distribution is assumed, these savings rise to 3 MW/yr in 2005 and 9 MW/yr in 2010.

5.5 Advanced BIPV Module Technology

A much greater market potential could result if many current R&D activities in advanced BIPV technologies can achieve their cost reduction and manufacturing targets. Advanced thin-film module materials are under development with claims to achieve direct manufacturing costs of below \$1/Wp by 2005. These direct manufacturing costs would result in the installed system prices and payback periods

shown in Figure 5.5-1, assuming appropriate profit margins for manufacturers. In addition, many claims have been made that if significant market volumes of BIPV could be achieved, inverter prices could be reduced even sooner. The technology is well established, but the volumes are needed to help drive the costs down. The prices in Table 5.5-1 and resulting potential market penetration are a result of these two additional cost reduction factors.

Table 5.5-1 Advanced Module BIPV Market Penetration With and Without IRP Benefits^{1,2}

	Single Family	Multifamily³	Commercial Rooftop	Curtainwall	Total³ (MW/yr)
2000 System Price (\$/Wpac)	\$5.00	\$4.50	\$4.50	\$2.85	
2000 MW/yr Without IRP	0	0	0	0	0
2000 MW/yr With IRP	0	28	0	1	~0-30
2005 System Price (\$/Wpac)	\$3.60	\$3.25	\$3.25	\$2.10	
2005 MW/yr Without IRP	0	30	0	0	~0-30
2005 MW/yr With IRP	275	125	350	3	~625-750
2010 System Price (\$/Wpac)	\$2.90	\$2.60	\$2.60	\$1.60	
2010 MW/yr Without IRP	0	140	100	3	~105-245
2010 MW/yr With IRP	475	310	810	9	~1290-1600

¹Assuming one-step distribution (15% markup), 10% Federal Investment Tax Credit (all but single family), and demand charge savings. SF prices are for new construction.

²Based on economics alone. Some BIPV installations are likely from demonstration systems or other utility encouraged programs.

³Ownership issues for multifamily might limit the high-end market penetration shown (see Section 5.4.2)

Even the most aggressive scenario of Table 5.5-1 highlights the importance of IRP benefits. If the industry does not work to ensure that the true value and benefits of BIPV are recognized, market penetration into the building sector may be significantly limited.

5.6 BIPV Near-Term, Niche Applications

Previous sections of this report focussed on BIPV markets with potential for large national energy savings, a major objective for the US Department of Energy (DOE). Rooftop systems offer the greatest potential for national energy savings, primarily because they can access the retrofit market which significantly increases available roof

Scenario A: PV with Energy Charge Savings (no additional benefits)

Scenario B: Scenario A with Demand Charge Savings ¹

Scenario C: Scenario B with IRP Benefits (T&D and Capacity Credits included) ²

Scenario D: Scenario C with Environmental Externalities included ²

Note: All scenarios represent a 30 kW AC module system at a south-facing, 15-degree tilt and with a ballasted mount on a flat roof. Total system installed costs are, including one-step distribution (15% markup) and a 10% federal tax credit, \$3.25/Wpac (2005), and \$2.60/Wpac (2010).

¹ Assumes a percentage of system capacity is recovered through demand charge savings. This ELCC percentage varies by region.

² T&D avoided costs and environmental externality benefits assume utilities will pass on "cash incentives" to consumers. To date, monetized values have not been offered for these benefits.

Figure 5.5-1 Commercial Building Paybacks Assuming Aggressive Module Pricing

area relative to new construction. There are however, near-term, niche applications that may also be attractive markets for BIPV, but may not have as significant an impact on national energy savings. These applications were outside the scope of this project as other DOE contractors have addressed these markets in detail. This section does however, provide a brief overview.

BIPV applications such as atrium roofs, skylights, and awnings offer value for near-term market entry. Although these high-value, niche applications are not economically viable at present, they are attractive from a "green marketing" perspective. Applications with an angled surface can also offer better BIPV system output than curtainwall applications, which have similar "green marketing" appeal. The following sections will discuss the various applications, their limitations, and estimated market potential, based on a limited analysis by Arthur D. Little.

5.6.1 BIPV Skylights, Atriums, and Awnings

Several studies have examined BIPV skylights, atriums, and awnings in detail. A report by Kiss Cathcart Anders Architects, "Building-Integrated Photovoltaics: A Case Study," examines several of these niche BIPV rooftop applications. Currently, a number of these systems have been installed worldwide, as shown in Table 3.1-1. This section briefly describes BIPV skylights, atriums, and awnings, based on a review of available data.

BIPV Skylights^{17,18} A semi-transparent standard laminated glass-to-glass module or a high performance double-glazed module can be used as large-area skylights, as shown in Figure 5.6-1. If existing thin-film technologies are used, a standard glass-to-glass module will be 5% transparent, which is adequate to allow for daylighting.

The laminated glass-to-glass module does not appear to be a viable alternative compared to a conventional flat insulated roof due to poor energy performance. Without an insulated roof, the building requires more energy to meet increased heating and cooling demand. The double-glazed module provides insulating value which improves overall energy performance, but as mentioned above, less light is available, and supplemental lighting may be required on cloudy days.

Figure 5.6-2 shows a skylight system similar to the one installed by Advanced Photovoltaic Systems (APS) at their Fairfield, CA production facility. This system alternates insulated clear glazing units with BIPV glazing units and captures daylight benefits in addition to PV power.

Semi-Transparent PV Roof

- Poor thermal performance results in building energy consumption more than twice that of better insulated alternatives analyzed.
- Wide extremes of building loads require oversized HVAC systems, increasing capital cost.

Semi-Transparent, Double Glazed, PV Roof

- Good overall energy performance despite low thermal insulation value, due to daylighting contribution.
- Tendency to over- and under-light space below; supplemental lighting may be required on cloudy days.
- Insulated glazing PV unit not yet available as product; potentially expensive.

Source: Kiss Cathcart Anders Architects, 1994.

Figure 5.6-1 Large Area PV Skylights

Sloped Glazing and Skylight Systems

Facade and Spandrel Panels

Source: Solar Today, May/June 1994

Figure 5.6-2 Sloped PV Skylight System

BIPV Atriums A double-glazed (or single glazed) module can also serve as an atrium roof, Figure 5.6-3. For new construction, a significant material credit (\$21/ft²) could apply if the system displaces insulated atrium safety glass. This credit is offset, however, by the cost of double glazing the PV module (\$18/ft²)¹⁷. The overall energy performance for this system would depend on the characteristics of the atrium walls, but a BIPV roof would generally be more energy efficient than a traditional atrium roof.

BIPV Awnings BIPV awnings can be designed using either thin-film or crystalline silicon modules to provide shading over window areas. These systems can be designed for optimum tilt to maximize BIPV output, and do not require additional insulation as do BIPV skylights and atriums because the structure extends outside of the building facade. An additional benefit is reduced heat gain during summer months when air conditioning demand is high. A BIPV awning system installed at the Fairfield, CA APS production facility reportedly reduces heat gain by 77%.¹⁸

It is important to note that ancillary benefits such as daylighting and shading could be obtained using conventional skylights, atriums and awnings, and are therefore not appropriate for inclusion in an economic analysis of BIPV systems.

5.6.2 Limitations

The primary limitation for atrium, skylight, and awning applications is that they are restricted to new construction. Material credits, which are critical to the economic viability of these applications, are not captured in a retrofit application unless the structure required replacement. As shown in Table 5.6-1, material credits can range from \$1-\$20/ft², depending on the material being replaced. This range is reasonably consistent with the material credits applied by Kiss Cathcart Anders Architects in their case study (\$4 - \$23/ft²). However, material credits apply only if the use of BIPV avoids the purchase of another material, and not if an existing structure is replaced solely for the purpose of installing a BIPV system.

Table 5.6-1 Rule of Thumb Estimates for Material Credits

Material Credit	Material Avoided by BIPV Installation
\$1/ft ²	Asphalt shingle roof, monolithic glazing
\$5/ft ²	Laminated glass with coatings, metal roofing/cladding
\$10/ft ²	Roofing slates, clay tile, high performance glazings
\$20/ft ²	Stainless steel, photochromic glass

Source: Advanced Photovoltaic Systems, Interview, August 1993.

Semi-Transparent Double Glazed PV Atrium

- Replaces a traditional atrium roof.
- Not as much daylight as traditional atriums - would be a more comfortable environment to occupy for long periods.
- Much more energy efficient than a traditional atrium roof.

Source: Kiss Cathcart Anders Architects, 1994.

Figure 5.6-3 Double Glazed PV Atrium Roof

In addition, replacement of existing glass atriums with BIPV can be problematic from a technical standpoint. First, the BIPV panel would have to be custom made to accommodate the existing structure, a costly undertaking that few manufacturers are willing to pursue. Running the wiring for a retrofit application poses additional problems. Each module requires an interconnect that would be exposed under the atrium. Alternatively, the wires could be run internally, but this would require drilling into the mullions, which would compromise their structural integrity.³ For these reasons, the market for BIPV atriums is largely limited to new construction. This significantly reduces the overall potential market size, as new construction represents only ~1% of the total building inventory in any given year. A brief analysis of the resulting market potential is provided in 5.6.3.

5.6.3 Market Analysis

An interview with Kiss Cathcart Anders Architects confirmed that skylights, atriums, and awnings are best suited to offices, retail buildings, schools, and hotels. To approximate the potential market for atriums and skylights, Arthur D. Little conducted a preliminary analysis using the *ADL PV Market Model* for commercial buildings.

For crystalline silicon atriums, this analysis assumed the prices shown in Table 3.4-4 for an AC integrated module. Installed system prices and efficiencies assumed for an advanced thin-film module are shown in Table 5.6-2. A material credit of \$6.30/ft² was applied, which reflects the cost of 1/4" laminated, tinted glass which can be used for atrium and skylight applications.¹⁷ To estimate the total surface area available, Arthur D. Little assumed that 20% of all new commercial buildings would include an atrium and/or skylight, and that the surface area of the atrium/skylight system would equal one sixth of the total roof area. This estimate should be viewed as liberal, given that offices, retail buildings, schools, and hotels represent only ~60% of the total commercial building market.²⁰

Table 5.6-2 Advanced Thin-Film Module, Atrium Roof, System Prices and Efficiencies (before material credits) - A Most Favorable Scenario

	1995	2000	2005	2010
Module Price (\$/Wpac)	\$3.50	\$2.50	\$1.75	\$1.50
BOS Costs (\$/Wpac)	\$2.20	\$1.70	\$1.25	\$1.10
Module Efficiency	5%	9%	11%	12%

Source: Arthur D. Little estimates, 1994

Figures 5.6-4 and 5.6-5 show the paybacks for New England, the Mid Atlantic and Pacific Southwest, three regions exhibiting the most favorable economics. Assuming IRP and externality benefits are included, the crystalline silicon unit achieves a seven year payback in the Pacific Southwest in 2010. The advanced thin-film atrium roof shows a slightly lower payback, reaching five years in the same region.

Figure 5.6-4 Paybacks for Crystalline Silicon Atriums/Skylights

Figure 5.6-5 Paybacks for Atriums/Skylights Using Advanced Thin-Film Modules

This is because the lower efficiency associated with this system is offset by its lower cost per square foot when combined with the material credit.

Favorable payback periods for atrium and skylight applications may result in a market penetration within the range of 1 MW per year by 2005. Although this market size is small, it does offer near-term niche opportunities for BIPV applications in buildings. In addition, these applications offer increased near-term BIPV visibility and hands-on experience relative to building integration issues for the industry and building officials.

5.7 Innovative Rate Analysis

General service rates were used for the BIPV market model analysis of national energy savings potential because they apply to the majority of utility customers. Other innovative rates that could be more favorable for BIPV are offered by some utilities. Because of the uncertain potential of BIPV to capture demand charge savings, a rate structure that incorporates demand charges into the energy charge, resulting in a high \$/kWh, could be more economically attractive for BIPV systems.

Kiss Cathcart & Anders selected an innovative commercial rate offered by Pacific Gas & Electric for a case study presented in Building-Integrated Photovoltaics: A Case Study.¹² Because San Francisco is not one of the cities chosen to represent any of the nine regions of this study, Arthur D. Little has examined the impact this rate would have on BIPV economics if it were offered in the Pacific Southwest, which has the most favorable insolation.

Using commercial general service rates, the payback period in 1994 for the Pacific Southwest, assuming one-step distribution and energy savings only (no demand charges or IRP benefits), is 35 years. If PG&E's innovative rate structure (Schedule A-6) is applied in this region, the payback period is reduced to 19 years. With IRP benefits included, the payback is further reduced to 15 years, almost half of the General Service rate analysis.

While high energy charges might improve BIPV economics, the impact of such rate structures on the customer's total bill requires further analysis. Innovative rate structures, such as time of use, often require more careful load management than is expected, and customers typically find their monthly bills are lower using general service rates. An interview with the rate department at PG&E revealed that 95% of their commercial customers subscribe to Schedule A-1, a general service rate, while only ~5% use Schedule A-6. Further, these rates are not offered by all utilities, and are therefore not considered appropriate for an analysis of national energy savings.

These rates are however, extremely relevant to an assessment of niche applications.

5.8 References

1. Casazza, Schultz & Associates, Electric and Gas Rates for the Residential, Commercial, and Industrial Sectors: 1993, Volumes 1 and 2, Prepared for the Gas Research Institute, GRI-93/0368, October 1993.
2. GRI rates for Commonwealth Edison were modified to reflect 6% reductions as per a telephone interview with Commonwealth Edison Rate Department, December, 1993.
3. Joe Huang, Lawrence Berkeley Laboratory, Interview, Winter 1993.
4. Energy Information Administration, Commercial Buildings Energy Consumption and Expenditures, 1989, DOE/EIA--0318(89), April 1992.
5. Energy Information Administration, Supplement to the Annual Energy Outlook, 1993, Tables 41-62.
6. Massachusetts Institute of Technology, Residential Solar Photovoltaic Systems, MIT Energy Laboratory, 1986.
7. National Renewable Energy Laboratory, Buildings Division, Interview, Spring 1993.
8. American Architectural Manufacturers Association, Study of the Nonresidential Window and Skylight Markets, 1987.
9. American Architectural Manufacturers Association, Interview, Winter 1993.
10. Turner Construction Company, New York, Interview, October 1993.
11. Southern California Edison, Rate Department, Interview, March 1994.
12. Kiss Cathcart Architects, P.C. and Ove Arup & Partners New York, Building-Integrated Photovoltaics: A Case Study, Prepared for the National Renewable Energy Laboratory, Draft Report, April 29, 1994.
13. ERG, Inc., Environmental Externalities: An Issue Under Critical Review, Prepared for the Edison Electric Institute, April 1994.
14. Zaininger Engineering Company, The Integration of Renewable Energy Sources into Electric Power Distribution Systems, Prepared for Oak Ridge National Laboratory, ORNL-6775/V2, June 1994.
15. Freeman, Sullivan & Co., "Grid-Support Photovoltaics: Summary of Case Studies", Prepared for Pacific Gas & Electric, August 1994.

16. Cody, A. and L. Frantzis, The Market for Solar Photovoltaic (PV) Technology, Prepared by Arthur D. Little for the Electric Power Research Institute, EPRI TR-102290, March 1993.
17. Kiss Cathcart Anders Architects, "Building-Integrated Photovoltaics: A Case Study," Draft Report, Prepared for the National Renewable Energy Laboratory, January 1995.
18. Paradis, A. and D. Shugar, "Photovoltaic Building Materials," Solar Today, May/June 1994.
19. Alan Paradis, former Architectural Department Manager for Advanced Photovoltaic Systems, Interview, November 1994.
20. Dodge, F.W., "Construction Potentials," 1990-1992.
21. Gregory Kiss, Kiss Cathcart Anders Architects, Interview, January 1995.

6.0 DOE Program Recommendations

6.1 Background/Summary

The prior sections of this report have identified the key performance, cost, and institutional issues impacting the economics and market for BIPV. The conclusions and associated programmatic implications are summarized below.

6.1.1 Installation Costs/Building Physical Interface

As a result of government and industry programs, it is projected that the cost of PV modules will decrease significantly over the next decade to a manufacturing cost below \$1.50/Wp. The largest cost factors associated with system installation will increasingly be physically installing the panels on the buildings and associated balance -of-system costs consistent with building physical integrity, safety considerations, codes, and aesthetics. The review of past practice indicated that these costs would need to be greatly reduced to result in acceptable installed costs. Several promising strategies for reducing costs have been identified and need to be further evaluated via a combination of cost analyses, building practice/code assessments, and focussed field demonstrations.

6.1.2 Utility Impacts and Rate Structures

The economic analyses showed conclusively that the widespread use of BIPV in commercial buildings will require that the PV systems provide IRP benefits to the utilities which are reflected in some combination of reduced demand charge costs (which are built into the rate structures), capacity credits, T&D credits, and environmental externality credits. The impact of the BIPV system on demand charges is of critical importance since such charges are built into all electric utility rate structures. The preliminary analyses undertaken in this report suggests that the ability of PV systems to impact on demand charges is still uncertain and will require special attention in system design/operational strategies which are likely to be building, location, and utility rate schedule specific. Data available from a study conducted by SUNYA, however, does show some correlation of the PV output with utility loads. Limited field data and analyses have been conducted on this subject area - a fact that the DOE program will endeavor to correct via a focussed combination of analytical and field monitoring activities.

6.1.3 Single vs. Multiple Unit Impacts

All analyses undertaken in this study and by others, as reported in the literature, focus on the impact of a single PV system on building and utility loads. If PV is successfully commercialized, a given utility will have hundreds or thousands of BIPV systems distributed throughout the service area. The utility impact of these systems is NOT merely a multiple of that from a single unit due to such factors as:

- Building orientation and building load profiles;
- Local variations in cloud cover; and
- Location of the PV system in the grid.

An example is the case where a cloud bank moves across a service area such that every single PV unit is out of service for one half hour. In such cases, most utility rate structures would result in ZERO credit for demand charge savings even though the population of PV systems operated with over 90% availability. Such factors will work to the disadvantage of PV given current utility rate structure requirements. A combination of analytical and field testing activities will be needed to adequately address this issue.

The recommended program plan outlined below was designed to address the above and other technical, cost, and utility interface issues which are central to developing PV systems with large market potential.

6.2 Program Development Criteria

The BIPV program within the DOE Office of Building Technologies is designed to supplement ongoing programs being undertaken within the DOE Office of Utility Technologies, industry, and utility-supported programs with a focus on issues specific to building applications. The resultant criteria used in developing a recommended program plan are:

6.2.1 PV Technology

The BIPV program does not intend to support basic advances in PV technology via such activities as improved materials and panel production techniques. These functions are covered by the DOE Office of Utility Technologies, National Renewable Energy Laboratory, and industry programs. The recommended DOE Office of Building Technologies program will provide flexibility to support modification of PV panel designs. DOE will engage traditional construction product manufacturers as prime contractors as the expertise for structural balance of system and interface with construction systems resides within the building sector. In addition, the same group of building product suppliers has immediate market access. DOE will focus on facilitating the installation of panels on buildings thereby providing some combination of cost reduction, improved aesthetics, and code compliance that are critical to building markets.

6.2.2 Installation Cost Reduction

The focus of the technology oriented efforts will be to lower the installation costs associated with installing PV panels in buildings and providing the needed electric utility and building load interfaces. The program will address both commercial and residential buildings so that multiple technology strategies will be pursued, such as curtainwalls in commercial buildings and PV roofing shingle strategies in residential buildings.

DOE Office of Building Technologies will also try to engage trade groups in education and training programs for the installation of BIPV. In particular, project cost estimates for BIPV needs support as construction estimates for new construction BIPV installations usually incorporates a multiplier of two to three times what the estimate should be due to unfamiliarity with the technology and perceived risks. Most trade groups have guidelines to assist in estimation costs for specific materials, systems or appliances. This needs to be generated for BIPV to provide contractors with a means to reduce BIPV bid prices in new construction.

6.2.3 Utility Interface

The recommended DOE Office of Building Technology program will address the multifaceted issues of how BIPV does and could impact utility operations. The program will also address how PV system utility rate structures should be applied to PV so both the PV system owners and the electric utilities can receive benefits for implementing a BIPV system. The issue of how PV systems can be designed and operated to increase the utility related benefits as measured by such factors as reducing demand charge costs will be developed under this program.

6.2.4 Program Leverage

The ongoing industry and government supported programs are resulting in the installation of several hundred PV installations on residential and commercial buildings over the next few years. The BIPV program will work cooperatively with these ongoing programs in multiple modes. For example, the recommended program will:

- Utilize data developed via designing and operating the systems to help refine the BIPV data base and provide a stronger basis for program planning;
- Work with specific projects to modify the monitoring/evaluation systems to ensure specific data needed for the building program are developed;
- Fund a portion (20-30%) of a demonstration or experimental program to obtain necessary information about the impacts and benefits of BIPV;
- Share analyses, models, databases, and experimental results.

The cooperation and communication with other program initiatives such as PV:BONUS, EPA Utility Projects, and Utility Photovoltaic Group (TEAM-UP Program) will ensure that the relatively modest resources of the BIPV program are focussed on building specific technical/cost issues which are not being addressed through other program initiatives. To ensure this communication, the program recommends a yearly meeting, as shown in Figure 6.2-1, that would bring together inputs from one or two key contacts from each of the national PV programs to help guide future program needs and a focussed and productive output from the BIPV program.

6.3 Program Plan Outline

The program plan resulting from the above considerations has three primary programmatic elements:

1. Installation Cost Reduction
2. BIPV/Utility Interface (Utility Benefits Maximization)
3. Supporting Analyses

These are discussed briefly in the following sections.

Figure 6.2-1 Communication Coordination for BIPV Program

6.3.1 Program Element 1: Installation Cost Reductions

Monitor/Define System Cost Structures Definitive cost data for past PV installations is often rather sparse and incomplete. It often applies to "one of a kind" installations and includes various design and engineering costs which do not reflect economies which might occur in a more mature industry. The objective of this subtask will be to collect and evaluate cost structure data resulting from ongoing activities which clearly define such factors as the:

- cost structure with a focus on the elements associated with system installation for curtainwall, flat roof, and/or pitched roof buildings;
- impact on the system design and cost structure of meeting local code requirements;
- potential for cost reduction assuming replication of the system on multiple buildings; and
- skill level and special training needs for installation personnel.

Some of this data has been gathered as part of this BIPV project effort. However, as other projects and demonstrations systems are installed, targeted data should be retrieved to ensure an updated database.

Identify Cost Reduction Strategies The results of the "monitoring/define current system cost structures" subtask will be combined with the results of industry inputs and cost structure analyses to identify cost reduction strategies for both residential and commercial buildings. These should apply to installation:

- on flat roof commercial buildings with greatly reduced structural costs as compared to current common practice;
- on or as part of curtainwall systems on commercial buildings; and
- on or as an integral part of slanted roof structures associated with most residential construction.

This report identifies cost reduction strategies applied to both new and retrofit construction. The impact of zoning and/or weight restrictions, and code requirements such as UL listing of electrical components however may dictate an alternative PV system design or configuration. As information unfolds, the database of information in this report must be updated and refined.

Cost Reduction Verification A program will be developed to verify the potential of the cost reduction strategies through an appropriate series of field demonstration units. Field testing will focus on filling "gaps" in technology and monitoring which are not being covered by other ongoing programs and will specifically address building integration issues.

6.3.2 Program Element 2: BIPV/Utility Interface (Utility Benefits Maximization)

Model Refinement and Expansion Preliminary analyses suggest that the potential impact of BIPV on building loads and utility costs will vary significantly by building type and service, location (insolation), PV system design/operating strategy, and utility rate structures. The analytical models used to estimate the economics of PV systems will be refined and applied to a broad range of buildings, utility rates, and locations to:

- Better quantify the impact of PV systems on utility loads and consumer costs;
- Provide an analytical tool that can be used to evaluate specific building installations for comparison with measured field results; and
- Provide a database and evaluation tool that can be used for interviews with electric utilities. This dialog will help to determine if rate structures can be modified to more accurately reflect the real economic impacts of BIPV for the utility. In addition, the utility interview will focus on the rates or incentives that should be passed on to the consumer to more accurately reflect the utility cost savings from BIPV and under what conditions BIPV should qualify for IRP benefits (capacity credits, demand charge savings, etc.)

Identify Favorable Design/Operational Strategies The output of the models combined with extensive interaction with electric utilities will be used to identify PV system design and operational strategies that show promise of improving economic performance by capturing demand charge savings and/or qualifying for IRP credits. The strategies could include:

- Preferential orientation of BIPV arrays to better coincide with building and/or utility peak loads;
- Utilizing BIPV to manage one or more dedicated loads to reduce peaks in an integrated fashion;
- Inclusion of a small amount of energy storage to maximize demand charge savings;
- Working with local utilities and Public Utility Commissions to modify rate structures to account for the special characteristics of PV, while providing benefits to both the user and the utility

Field Verification of Building/Utility/PV System Design Strategies It is imperative to develop field data that verifies the IRP and demand charge savings potential for properly designed and operated BIPV systems. This will be done with monitoring of field systems and will focus on measuring those parameters that will determine:

- The extent to which the systems reduce demand charge savings and how this varies by application, utility rate structures, and season; and

- The PV system impact on actual utility peaks and the associated potential to qualify for capacity credits or T&D credits

It is expected that the field verification monitoring will be executed via several routes:

- Gaining access to the data being developed as part of other DOE/NREL, EPA, utility, and industry programs;
- Supporting focussed field demonstrations which include design/operational strategies that have been identified through a combination of the aforementioned modelling efforts, interactions with electric utilities, and suggestions by PV industry representatives.

6.3.3 Program Element 3: Supporting Analyses

It is important that the BIPV program develop a strong analytical base for both its program planning functions and in its support of the PV industry, utilities, policy makers, and other parties having an interest in the market and national impacts of BIPV systems. The activities undertaken in this program element could include, but are not restricted to:

- Developing "user friendly" models that estimate BIPV system technical and economic performance as impacted by building loads, PV system design, etc.;
- Assessing a statistically weighted impact of a large number of BIPV systems in a utility service area when there are microvariations due to intermittent cloud cover;
- Updating on a regular basis the market potential for PV technology in the building sector as influenced by such factors as system cost, energy costs, government policy (for example, tax credits), and other factors;
- Developing a database on system cost structures, local and state codes, and regulations impacting PV costs, building loads and inventories which will be needed by DOE and industry in assessing technology needs and markets;
- Assessing the impacts of new technology developments on application economics and market potential;
- Preparing information and analyses packages for use by Public Utility Commissions, environmental groups, utilities, and other interested parties that would include information such as the impact of BIPV on Integrated Resource Plans (IRP);
- Determining the potential impacts of utility deregulation on BIPV economics and markets; and
- Ensuring the communication among all PV programs for the dissemination of important databases, analyses, models, and results related to BIPV issues.

The US DOE OBT, with support from Arthur D. Little, Inc., Solar Design Associates, Brookman-King, and NREL, initiated a meeting to explore approaches on accelerating the market place for BIPV. Over 55 people participated. The industry was represented by four sectors:

- PV manufacturers,
- building sector representatives,
- architects and engineers, and
- utility solar program or Demand-Side Management (DSM) staff.

These individuals met to address the basic issues that impede accelerating the BIPV market place. Over the course of this two day meeting that took place in Boston, European and American experts described the state-of-the-art in:

- manufactured products,
- design, and
- cross-sectoral partnerships

which they had found successful in advancing the industry and BIPV applications. The experts also detailed major barriers, and then identified strategies for overcoming those barriers.

The meeting was designed to encourage free-flowing discussions. Both small and large groups were used to foster the dialogue and successfully reveal the differing perspectives among the four sectors. The discussions produced an appreciation for the complexity of integrating PV into buildings. Participants emerged with a shared sense of the tremendous potential of the BIPV market place. They also acknowledged the hurdles that hinder broad market penetration.

In post-meeting evaluations, 83% of the participants rated the meeting as either excellent or good. The meeting brought together representatives from the various stakeholder groups for the first time to discuss BIPV. This gave individuals a chance to get to know one another and provided an opportunity to better understand the different sectors, their needs, and the potential benefits of working together.

This Workshop Summary captures, in bulleted format, the highlights from the meeting, presented in the following categories:

- Themes,
- Reflections on the State-of-the-Art,
- Major Challenges,
- Essentials for Expanding the Market Place, and
- Next Steps.

Table A-1 summarizes some of the key issues discussed during the workshop.

Table A-1 Accelerating the Development of BIPV - Workshop Summary Key Issues

Major Challenges	<ul style="list-style-type: none"> • Reduce installed costs. • Make a true building material, not just a PV module. • Educate crafts and trades people, and promote efforts that reach across BIPV industry sectors. • Create analytical tools that consider BOS trade-offs.
Essentials for Expanding the BIPV Market	<ul style="list-style-type: none"> • Reduce costs by supporting government partnerships/incentives and equipment standardization. • Integrate PV both architecturally and aesthetically to expand the BIPV market potential. • Demonstrate a proven technology with empirical performance data and testimonials to back-up claims. Achieve U.L. standards and certification. • Develop partnerships among PV manufacturers, architects & engineers, utilities and builders to help accelerate large-scale market adoption. • "Keep it simple", using conventional construction methods, and educating trades people and inspectors for successful implementation and acceptance.
Next Steps	<ul style="list-style-type: none"> • Use government seed money as a catalyst. Target a few barriers where government funding can have a significant impact. • Work with policy makers to promote use of "green energy". • Develop BIPV demonstration projects, including demonstration buildings, utility sponsored school projects, and government buildings. The projects should be designed as test-beds for strategies to break down barriers and provide cross-sectoral education. • Develop needed analytical tools. • Coordinate the various PV programs to avoid duplication of efforts, streamline the use of funding, and provide a more cohesive effort to develop the BIPV market. • Work to maximize the US involvement in IEA Task 16.

A.1 Themes

- Collaborative approaches are key to advancing the market place: PV manufacturers, architects & engineers, utilities and builders must work together. "Partnerships" may hold the key to large-scale market adoption.
- Significant educational efforts need to occur in all four sectors. This will enable the industry to realize its market potential. The educational efforts must extend beyond the building trades and code officials. A concerted effort that includes all sectors attending the Boston meeting is required.

- The OBT PV program should find its own niche. This niche should not duplicate the efforts of other existing PV programs. The office should work closely with the PV industry and other key groups to maximize the effectiveness of OBT's program.
- Coordination among the different PV programs is lacking or non-existent. Coordination would be an effective use of resources. Some of the perceived benefits are non-duplication of activities, better education programs, and a more cohesive effort to develop the market place.
- In trying to define "building integrated", the group learned first-hand the challenge of bringing cross-sectoral and divergent approaches to market applications. Some participants defined "building integrated" as a PV application where the PV materials are a structural part of the building skin, architecturally integrated, and attractive. Others thought that stand-alone modules which could be installed over the building exterior weathering skin should also qualify.

There was general agreement that there are two distinctly different approaches to building-integrated applications which hold large market potential.

- The Europeans have created collaborative approaches which include significant subsidies and government participation in leadership roles. Limitations on space and consistently funded (subsidized) programs have enabled advanced architectural integration of PV in Europe.

A.2 Reflections On State-of-the-Art

Experts and innovators from Europe and the US shared their challenges, lessons learned and strategies used for successful BIPV applications.

- The building industry was identified as "quite conservative", and therefore the recommendation was to "keep it simple":
 - Use conventional methods in construction.
 - Educate trades people and inspectors for successful implementation and acceptance.
- The building industry has learned that skilled trades people are proficient at installing PV panels.
- Successful projects employed with a customer focus by developing the product design with the customer. For example, metal roofing manufacturers were brought in to help create integrated, structural roofing panels.
- Both cost and risk sharing are an important element to the success of a PV project.
- Architectural and engineering integration is necessary. It is essential to work with architects and engineers to find ways to develop BIPV applications that work

aesthetically. These alliances produce designs that directly fit into standard building specifications.

A.3 Major Challenges

- Reduce installed costs.
- Make a true building material, not just a PV module.
- Provide architecturally enhancing design solutions.
- Educate crafts and trades people.
- Promote education efforts that reach across industry sectors.
- Create analytical tools that consider BOS trade-offs.

A.4 Essentials for Expanding the Marketplace

Expert presenters identified key requirements for accelerating the market and advancing BIPV:

- Reduce costs by supporting government partnerships/incentives and standardization of equipment.
- Integrate PV both architecturally and aesthetically to expand the BIPV market potential.
- Demonstrate a proven technology with empirical performance data and testimonials to back-up claims. One important enhancement would be to achieve U.L. standards and certification.

A.5 Next Steps

- Continue the dialogue started in Boston.
- Use government seed money to act as a catalyst:
 - Choose a few barriers where government funding can make a real difference.
- Work with policy makers to increase use of "green energy".
- Work to maximize the US involvement in IEA Task 16.
- Develop needed analytical tools.
- Develop BIPV demonstration projects now, including demonstration buildings, utility sponsored school projects, and Federal sector buildings. The projects should

be designed as test-beds for strategies to break-down barriers. Specifically, the projects should:

- Demonstrate to the mainstream building industry how BIPV fits into production and construction -- not just an "add-on",
- Demonstrate PV modules as construction materials,
- Develop a broader range of options/prototypes of BIPV applications as construction materials,
- Acquire U.L. certification, and
- Fix code, standards and insurance problems by getting the right people involved before a project begins.

A.6 References

1. Brookman - King Collaborative Solutions and the BIPV Planning Committee, Accelerating the Development of BIPV - Executive Summary, Fall 1993.

Appendix B: An Overview of Worldwide Development Activity in BIPV

This contract funded the US participation in two International Energy Administration (IEA) Task 16 meetings, in Japan and Amsterdam. As shown in Table B-1, there are several BIPV activities being undertaken by countries other than the US. The status and development of these programs helped guide the focus of the BIPV cost-reduction options identified in this DOE BIPV study. A discussion of these international activities are provided in this Appendix B.

Table B-1 BIPV Activities of Countries Outside the U.S.

Japan <ul style="list-style-type: none"> • PV roofing materials -shingles, ceramic tiles • Rokko Island BIPV test site (200kW of ~ 2kW sized systems) • Large area modules with 30% light transmissivity • Subsidy by Ministry of International Trade and Industry (MITI) for residential rooftop BIPV systems. Goal of 62,000 systems totalling 185MW over 7 years.
Germany <ul style="list-style-type: none"> • "1,000 roofs" program (each 2kW+) for residential and commercial applications. Now targeted for 3,000 rooftop installations. • Development of an a-Si curtainwall PV module
Switzerland <ul style="list-style-type: none"> • Goal of 50MW by 2000 • 5,910,000 ECU (~\$7.3 million) allocated by Swiss Federal Energy Office for development of BIPV • Demonstration site for testing and evaluation of BIPV systems at Lausanne. Eight test systems are complete to date (roof and facade construction) • 333 grid-connected PV systems each at 3kW with specially arranged private, long-term financing. Constructed by Alpha Real, located in Zurich. • Solutions AG and Atlantis-Energie AG fielded several BIPV - office bldg. facades • Roof tiles prototyped by Alpha Real (30Wp each)
United Kingdom <ul style="list-style-type: none"> • Goal of 1,000MW/yr by 2000 from all renewables set by the government in the 1989 UK Electricity Act - "Non-fossil Fuel Obligation" • British government funding BIPV curtainwall analyses
Austria <ul style="list-style-type: none"> • Government and utility assistance program modeled after German "1,000 roofs". Promotes BIPV for 200 buildings • Development of glass-on-glass roof tile. Prototype successfully fielded in Gleisdorf in 1991
Italy <ul style="list-style-type: none"> • Development of large area, glass substrate PV modules for BIPV applications
The Netherlands <ul style="list-style-type: none"> • Smaller scale German "1,000 roof" program
Sweden <ul style="list-style-type: none"> • Development of DC/AC inverters and battery control regulators • Demonstration of 3.5kW grid-connected system
Norway <ul style="list-style-type: none"> • ~8,000 installations per year of vacation cottages
Canada <ul style="list-style-type: none"> • BIPV software development for performance monitoring and improved system design • 14 BIPV systems are being monitored
Spain <ul style="list-style-type: none"> • Fielded several grid-connected BIPV systems • Focus on system design, utility interface, demonstration monitoring and testing
Finland <ul style="list-style-type: none"> • Three year plan that includes the demonstration of PV/hydrogen systems and BIPV

Japan

Interest in building-integrated PV has been growing steadily in Japan over the past decade and the government has funded a number of R&D contracts which address this area. For example, Sanyo has developed and prototyped two types of a-Si PV roof modules for residential roof integration. Both are direct-mounted on a sloped roof surface over the roof deck. The first was a curved tile similar to the traditional Japanese ceramic roof tiles. This curved tile measured 305 mm square, was quite elegant and blended well with the traditional Japanese roof tile system but, with an output of only 2.7 Wp per tile, was very expensive to produce and install.

The second Sanyo effort introduced a larger-area, flat-panel shingle measuring approximately 1.1 m by .54 m with an active area of approximately .5 sq. m. It did not integrate as well with the traditional Japanese architectural style but the results were pleasing and it was far more cost effective to produce and install. The concept is very similar to the rectangular roof shingle developed in the US using single-crystal cells in the early 1980's by General Electric.

A-Si technology appears to be a better choice for direct-mounted roof applications when compared to thick-crystal technologies because it is far less sensitive to the higher operating cell temperatures resulting from reduced module cooling. The first generation of the Sanyo PV roof shingle is shown in Figure 1. The traditional roofing material in Japan has been tile. However, an asphalt-based roof shingle similar to that produced in the US is now being used increasingly on new residences because of cost. Sanyo has recently revised their flat-panel shingle, changing its scale to better integrate with these new conventional roofing materials. The latest version, shown in Figure 2, is approximately 90 cm wide by 35 cm high with an exposed area of about 15 cm high.

Fig. 1. Sanyo PV shingles under test

Fig. 2. Latest Sanyo glass a-Si PV Shingle

The module is a-Si on a glass superstrate and small plug-in connectors are employed to facilitate module-to-module interconnection. Installation is direct-mount over the structural roof deck. A test house employing this new Sanyo roof shingle has been completed at the Japanese PV test site at Rokko Island operated by Kansai Electric. This house is shown in Figure 3.

Sanyo is also working on a-Si-on-glass modules for commercial curtain wall applications. Their vertical facade PV element is a semi-transparent a-Si glass panel with uniformly-spaced, laser-cut microscopic holes, using a process developed at Sanyo in 1986. This technology, which generates electricity while allowing 30% light transmission, is well suited for auto windows and sunroofs as well as residential windows and commercial curtain wall construction. The integration of the semi-transparent a-Si PV into a conventional building curtain wall reduces glare from direct sun while also reducing the building's cooling demand from unwanted solar gain. Companion opaque (full power) a-Si panels could be installed on the non-view surfaces of the building.

Module construction employs: glass cover, EVA, glass, a-Si thin film with microscopic holes, EVA and a clear plastic back sheet. Prototype modules measure 1.22 m by .370 m by 9 mm thick and weigh 6.4 kg. All modules are custom order. In addition to commercial curtain wall view panels, many other varied applications such as individual skylight units, sloped glazing systems and residential window units are possible with this versatile product.

Fig. 3. Kansai Electric's PV demo house

Following the classic Japanese model for market entry, Sanyo began marketing this transparent a-Si technology to automotive companies first for see-through PV sunroofs which are a high-value-added product, while working to develop a market for building integrated power products which is potentially a very large market when unit costs are lowered. Sanyo is the largest Japanese PV manufacturer, reportedly producing 6.5 MWp in 1992.

Fig. 4. Sanyo a-Si PV facade

Recently, Sanyo has fielded several prototype installations of its a-Si curtain wall modules in commercial buildings including their own office building and a building for Hokuriku Electric Power Company. A building for the Tsukasa Electric Industry Company, shown in Figure 4, features a full south facade of Sanyo a-Si PV with opaque modules used in the non-view areas and see-through modules used as view glass.

Other Japanese companies are gearing up for the domestic market for distributed PV systems in Japan. Misawa has built a demonstration called the Eco Energy House which is shown in Figure 5. The home features a PV roof employing custom glass-superstrate polycrystalline PV modules from Solarex and an innovative framework of extrusions which provide physical clamping and a weather seal to create an integral PV roof over a sloped residential roof deck.

The Japanese government subsequently sponsored another effort for "The development of a (low-cost) roof-mounted PV array for existing Japanese residences". The prime contractor for this effort is Kandenko Co., Ltd. The program involved an assessment of existing Japanese housing stock and resulted in the development of a new large-area, single- and poly-crystal PV module 1.3 m by .650 m and a stand-off mounting system to install the arrays above the existing roof. The results are quite similar to the 30 residential systems fielded in the US by Solar Design Associates in 1985 for New England Electric in Gardner, Massachusetts..

Fig. 5. Misawa PV demonstration house

The Japanese government is also funding participation in the IEA Task 16, Photovoltaics in Buildings. In addition to representatives from the Japanese MITI, the Government Research Institute and Project Sunshine, PV professionals from Sanyo, Kandenko and the

Central Research Institute of Electric Power (Japan's EPRI) are representing Japan in this multi-country development effort.

In 1993, the Japanese government invested 206 million yen in component development, 45 million yen in standards and 1,224 million yen on PV demonstrations. Another area of interest has been the development of combined PV/thermal systems for buildings in Japan. Figure 6 shows a prototype combined PV/T system developed for residential applications. This system employs hybrid collectors using polycrystalline PV cells backed by a thermal absorber to produce 3.2 kWp of electricity and 25 kW of thermal energy.

Fig. 6. Japanese PV/T test residence

At their Rokko Island test site, the Japanese have some 500 kWp of small, distributed PV systems under test. Most of these systems are 2 kWp. Some are mounted on test houses as shown in Figure 7, while others are ground-mounted and all are connected to the same distribution feeder through a complex of switchgear that allows simulation of any possible combination of events. When representatives of Solar Design Associates visited Rokko Island, Mr. Kitamura, the Program Manager, stated that:

- Distributed PV systems are safe and reliable and will be encouraged in Japan
- The issues surrounding "islanding" and power quality have all been technically resolved
- All utilities must follow the same national uniform interconnection standards
- All utilities must provide Net Metering, two-way power flow connections to small power producers
- Utilities are 'encouraged' to offer a 10% premium for renewables for the good of the country

These statements were later confirmed and elaborated on in various presentations at the 7th PVSEC held in Nagoya in November, 1993 in a special session entitled: "PV Residences Now Ready". The Japanese have concluded that distributed PV systems on buildings are the most attractive way to field photovoltaics and appear ready to dive into this market and make it happen to the direct benefit of their country and their PV manufacturers and the indirect benefit of the rest of the world.

Fig. 7. 2 kW PV test systems at Rokko Island

To get things started, the Japanese Ministry of International Trade and Industry (MITI) announced a domestic program, in January 1994, to subsidize distributed, utility-interactive PV systems for residential roof-top applications. The subsidy, of up to 2.7 million yen (~US\$27,000), is meant to cover only up to 1/2 of the price of the PV systems up to 3 kWp per house.

At least 700 residential installations are planned for 1994, the first year of the program; 1,500 in 1995, 2,000 in 1996 and so on, building toward a total of 62,000 and 185 MWp over seven years. The 1/2 subsidy will remain for the first three years of the program and then step down to zero after seven years. The subsidy is proposed to be paid to the PV system supplier, not the homeowner.

Germany

In the aftermath of the disastrous nuclear plant meltdown at Chernobyl, the “Green political revolution” gained a strong following momentum all across Europe as environmental consciousness grew. The German government has lead the way in the acceleration of its renewable programs, allocating about 300 million DM in FY 1993. Out of this, 100 million was set aside for PV.

Fig. 8. PV residence in '1000 Roofs Program'

With the implementation of the “1,000 Roofs” program, the German government assumed a leadership role in supporting distributed PV systems for buildings in Europe. In this program, grid-connected PV systems sized at 1-5 kWp are fielded on residential roof tops with up to 70% cost-sharing from the German government.

Figure 8 shows a typical PV installation under the 1,000 Roofs Program. This residence in Helmstedt received a 4 kWp array of 80 standard (frameless) Siemens M-50 modules integrated into the roof using off-the-shelf aluminum profiles from the German facade company

Schüco, replacing the traditional red-clay tile roof. Shortly after the program was started in the fall of 1990, it was expanded to include some 2,500 roof-top installations. By the spring 1994, over 4 MWp of roof-top PV systems had been installed on 1- and 2-family homes across Germany.

In 1993, the headquarters of the Bavarian Environment Ministry received a building-integrated facade of amorphous silicon modules and sun-controlling “eyebrows” over the south-facing windows using mono-crystalline PV modules. This installation, shown in Figure 9, was engineered and supplied by Deutsche Aerospace, (now a partner with RWE in the new German PV joint venture ASE), and provide a total of 53.4 kWp of capacity.

Germany's strong commitment to distributed PV systems for buildings has spurred considerable activity in the development of PV modules specifically for building-integrated applications. Phototronics Solartechnik (PST) of Putzbrunn (near Munich and also now a part of ASE) is developing an a-Si commercial curtainwall module approximately 1 m by .6 m with 6% efficiency. These modules were used on the PV facade at the Bavarian Environment Ministry.

The PST line includes custom-made modules on thin glass superstrates of 1mm to 3mm thick and 1 m by .6m in size. Larger modules can be made up of multiple a-Si panels on a larger sheet of face glass. The maximum output claimed is 60 Watts / sq. m. Both opaque and semi-transparent panels are available. Power reduction for semi-transparent panels is said to be only 15%.

Fig. 9. PV on the Bavarian Ministry

This product is designed for vertical facades of commercial and residential buildings. Four basic product approaches are offered for vertical building facades: opaque PV panels for "cold" facades, opaque PV panels backed by thermal insulation, semi-transparent PV panels for view windows within an insulated glass sandwich and a hybrid combined PV/thermal panel incorporating semi-transparent PV panels for view windows within an insulated glass sandwich with warm-air heat recovery. All orders are custom. A roofing tile is also available which fits into standard tile roof systems with an a-Si glass module top surface measuring .6m by 1.0m.

Fig. 10. STAWAG PV Facade

Telefunken System Technik (TST) and Nukem (both now part of ASE) have each developed large-area, glass-on-glass, frameless modules using thick-crystal cells for vertical wall and sloped roof integrated applications. Nukem, which is wholly-owned by the German electric utility RWE, offers a full line of PV modules including special custom large-area frameless modules.

Modules are available with either CZ or polycrystalline cells in sizes up to 1.5 m by 2.5 m at up to 360 Wp. Module construction is glass-on-glass lamination with a poured and cast methyl methacrylate resin as the cell encapsulation and lamination adhesive. Large-area module voltage and current parameters can be configured to suit project requirements. ASE also recently acquired the assets of Mobil Solar Energy Corporation in the US and will be marketing an unframed version of Mobil's large-area 300 Wp module to the building-integrated market.

Flachglas Solartechnik (Flagsol) in Köln, a subsidiary of Flachglas, a major producer of architectural glass in Europe, has embarked on an ambitious development program for both thick-crystal and thin-film commercial curtain wall applications and is looking at semi-transparent thin-film curtain wall modules similar to those produced by Sanyo in Japan. Flachglas sees PV as a means to add additional value to their glass products.

In May 1991, Flachglas installed a prototype 4.2 kWp, 50m² array in the south facade of the administration building of the Stadtwerke Aachen AG (STAWAG), a local municipal utility in Aachen, Germany. The facade, shown in Figure 10, employs 10 x 10 cm polycrystalline cells laminated between two sheets of 4mm glass backed by an air space and two more panes of glass (3mm and 4mm).

Four different size panels were specified by the architect to provide balanced daylighting for the stair hall while creating a pleasing design pattern. The interior of the STAWAG PV facade is shown in Figure 11. The system is utility-interactive. Flachglas provides complete system design and integration as desired by the client and recently received a contract for design and construction of a 300 kWp utility-interactive PV roof to be installed at the Science Park Gelsenkirchen near the Essen, Germany. This

Fig. 11. STAWAG PV facade interior

system will cover some 2,130m² making it the largest building-integrated PV system in Europe.

Other German companies have also developed innovative approaches to building integration. The commercial building shown in Figure 12 features a facade of "structural glazing" elements which incorporate PV modules and operable view glass in a prefabricated assembly. Close design collaboration between the architect, (Planerwerkstatt Hölken and Berghoff of Vörstetten), the PV system engineers, (Solare Systemtechnik of Freiburg) and the construction contractor, (Greschbach of Karlsruhe), allowed the entire building facade to be installed in half a day. The combined capacity of the PV facade and the roof-top array is 18.5 kWp. The building was completed in 1993.

Fig. 12. Structural PV Glazing in Freiburg

The Institut für Solare Energieversorgungstechnik (ISET) in Kassel is also developing and refining methods of mechanical and electrical integration of PV elements into commercial building facades as well as working on other 'balance-of-system' issues for building-integrated PV including small, modular, DC-to-DC maximum-power-point tracking devices and DC-to-AC power converters.

The Fraunhofer Institute for Solar Energy Systems in Freiburg has active research efforts underway in a number of areas related to PV-in-buildings and has recently completed the design and construction of an energy autonomous house in Freiburg which incorporates PV, active solar thermal, passive solar gain, super insulation and a hydrogen system consisting of an electrolyzer, storage and a fuel cell. This house is shown in Figure 13.

Fig. 13. The Fraunhofer Energy-autonomous House

Under the leadership of Dr. Jürgen Schmid, who realized very early on the many benefits of PV-in-Buildings, Germany took the lead in establishing the IEA Task 16, Photovoltaics in Buildings and is the operating agent. In addition to representatives from the Government's Federal

Energy Office, PV professionals from several government-funded research institutes, universities and PV companies are representing Germany in this multi-country development effort.

The immediate future for building-integrated PV in Germany will certainly be affected by the current budget strain on all branches of government due to the enormous costs of the re-unification of east and west Germany. PV is said to still be an important priority but things like housing, schools, etc. are first in line. Program managers say the best they are hoping for is level funding but some budget reductions seem certain in the near term as the country struggles to accommodate the fiscal burden of re-unification.

Switzerland

Political fallout from the nuclear disaster at Chernobyl has also had a very significant impact on Swiss policy making. The Swiss declared a 10-year moratorium on new nuclear plant construction in mid-1990 and, shortly thereafter, announced a dramatic increase in support for photovoltaics and other renewable energy sources with the pledge to field 50 MWp of PV by the year 2000.

Fig. 14. Integrated PV facade by Schweizer at the Swiss Demo Site

Large areas of flat, open land are not common in Switzerland and, accordingly, activity in photovoltaics for buildings has increased significantly. A substantial amount of funding (6,100,000 SF) has been allocated by the Swiss Federal Energy Office to support the development of building-integrated PV, including component and systems development, systems integration issues, utility interface, demonstration projects, and education / information dissemination.

As a part of the Swiss Federal PV in buildings program, the Solar Energy Laboratory at the Swiss Federal Institute of Technology (EPFL) in Lausanne has recently dedicated a demonstration site for the testing and evaluation of building-integrated PV systems. At present, some twelve demonstration pavilions are complete, presenting different approaches to roof and facade construction.

Figure 14 shows an innovative integration of PV into a commercial building facade on display at the 'Demo Site'. The system, developed by the Swiss firm of Ernst Schweizer in Hedingen, places the PV elements at 20° to the vertical, creating a sun-controlling overhang for the floor below.

Sponsors of the Demo Site envision it as an "international center for the architectural integration of PV" in support of the IEA Task 16. A sort of 'shopping market' where architects, engineers and building owners can go to see a variety of working building-integrated PV systems on display. Sites for additional systems are still available and manufacturers the world over are invited to participate.

In addition to the Demo Site, the EPFL has a number of innovative installations of PV on their campus. Figure 15 shows the integration of PV elements into daylighting roof monitors on the EPFL Administration Building. The PV modules are fabricated with a clear back skin and a slight spacing between the cells to allow in a gentle pattern of direct sunlight while the primary daylighting comes from the north-facing clerestories.

Engineers at the EPFL's Laboratoire d' Energie Solaire (LESO) have designed other PV systems

Fig. 15. Integral PV / Daylighting monitors at EPFL

for new and existing buildings on the campus including PV elements used as sun shades, retrofits of existing roof monitors, a novel flat roof system and a facade retrofit.

A privately funded program started before the German "1,000 roofs" program was instituted to install a megawatt of capacity in distributed roof-top PV systems. Using specially-arranged private, long-term financing with low interest rates and volume purchases, 333 grid-connected PV systems, each rated at 3kWp, have been constructed by the Zurich company Alpha Real.

Alpha Real is also developing a novel PV roof tile system in collaboration with Plaston LTD. (Widnau) with funding from the Swiss Federal government. These tiles have an active area of about .25 sq. m and employ 24 10 x 10 cm silicon cells to produce approximately 30 Wp each.

Quick-connect, plug-in connectors are employed. The tile design is very clever in that they integrate directly into the system of conventional tiles as shown in Figure 16 and are thus appropriate for both retrofit as well as new construction. Several prototype residential installations have been fielded.

Fig. 16. Plaston's PV roof tile replaces clay tiles

With well over 90% of the sloped roofs in Switzerland and most of the rest of central Europe constructed with clay tile, the potential market for new and retrofit installations of PV roof tiles is very large across Europe and in other countries such as Japan where clay tiles are also the traditional roofing.

The Swiss government has embarked upon an ambitious nation-wide educational program on photovoltaics. The program goal is to inform the Swiss people of the virtues and benefits of solar electricity. The program includes public information (including the Swiss DemoSite) and technical seminars and workshops for electricians, roofing craftsman, architects and building engineers. In an effort to reach all segments of the population, PV systems have been fielded on Swiss school buildings as a way to acquaint the next generation with photovoltaics.

Fig. 17. PV roof and facade integration at Fenster AG

Solution AG fur Solartechnik (Härkingen) has developed a line of large-area, glass-superstrate PV modules custom made to project specifications which employ either single-crystal or polycrystal silicon cells. Modules can be made up to 1.7 m long by 1.3 m wide. Combined PV / thermal hybrid designs have also been produced using air to scavenge heat from the back of the modules and deliver it to storage or a load.

Working in collaboration with Atlantis-Energie AG (Berne), Solution has fielded several demonstration projects with building-integrated PV arrays. Figure

17 shows a new industrial plant and office building in Arisdorf (CH) completed in 1991 for window

Fig. 18. Swiss PV facade at Scheidegger Metallbau

manufacturer Aerni Fenster, AG where Solution installed a 62 kWp grid-tied system. 9 kWp of modules were integrated into the office building's facade and 53 kWp of modules were integrated into the roof of the production facility on the south side of north-facing daylighting clerestories.

Another significant project realized by Solution and Atlantis is the new office and manufacturing building for Scheidegger Metallbau in Kirchberg, shown in Figure 18. Completed in 1992, the south-facing facade of the building incorporates a multifunctional PV system employing PV elements for sun shading and facade cladding with reflector augmentation in the spandrel areas, while scavenging thermal energy from the center section to temper the stairhall. The system peak output is 18 kWp.

The Swiss government is also heavily involved in the IEA Task 16, Photovoltaics in Buildings. In

addition to representatives from the Government's Federal Energy Office, PV professionals from several government funded research institutes, universities and PV companies are representing Switzerland in this multi-country development effort.

The immediate future for building-integrated PV in Switzerland looks very promising. With generous government incentives to underwrite the cost of introducing a new technology, Swiss architects and engineers have responded with very innovative concepts in the design of building-integrated PV.

They have also fielded some innovative systems integrated with other "built forms" such as the system shown in Figure 19 which is integrated with the sound barrier along highway N13 south of Chur. Other PV systems have been fielded along rights of way of the Swiss railroads which are, of course, electric.

Fig. 19. PV integrated with highway sound barrier

A number of Swiss companies have begun to produce custom PV modules to meet special design requirements with some even producing custom triangular modules to architect's specifications. In addition, the country has instituted net metering and uniform interconnection policies on a national basis which, in itself, represents a major national commitment to PV since Switzerland has over one thousand individual electric utility companies.

The Netherlands

Interest in PV and distributed systems for buildings has also grown in the Netherlands just as it has across the rest of Europe. Recent R&D activities have concentrated on improvements in the development of PV building elements and improved power conditioning. Government funds have been appropriated for a pilot program of grid-connected, distributed PV systems with building-integrated PV arrays. In the next 4 years, some 1,000 homes will be built with roof-integrated PV systems. In this effort, the Dutch will study the influences of PV on architecture, town planning, home financing and ownership.

Figure 20 shows a 10-unit multi-family housing development in Heerhugowaard, a town 50 km north of Amsterdam, where a roof-integrated 25 kWp utility-interactive PV system was installed as a demonstration of building-integrated PV applications.

Financed largely by the Dutch regional utility PEN with additional support from the Netherlands Office of Energy and Environment, (NOVEM), the PV system uses standard polycrystalline PV modules from R&S (Netherlands), integrally mounted with off-the-shelf aluminum profiles adapted from a greenhouse glazing system. Each individual unit has its own 3 kW power inverter.

The Dutch PV program has provided funding for the development of building integration techniques for both residential and commercial buildings. In addition to the multi-family housing demonstrations, a number of detached, single-family homes have received roof-integrated PV systems such as the home shown in Figure 21 in Lekkerkerk which features an integral 3kWp array of glass-superstrate crystalline silicon PV roof tiles from Switzerland.

A PV-powered, energy autonomous demonstration house was constructed in Woubrugge, a small village between Amsterdam and Rotterdam. The PV array incorporates standard (unframed) polycrystalline modules in a roof-integrated mount using aluminum profiles similar to those employed in the Heerhugowaard project. Space and domestic water heating are provided by solar thermal collectors. As would be expected, the house is heavily insulated and employs high-efficiency glazings and appliances.

The Dutch have also explored other methods of integrating PV into their lives, including the use of PV on-board the hundreds of house boats that line the canals in and around Amsterdam as well as on cargo barges so important for the shipment of goods. Figure 22 shows a "roof-top" PV system atop the wheelhouse of a Dutch canal barge. The PV system provides power for lights and communications equipment allowing the Captain to shut down the ship's diesel when the vessel is not underway.

Similar PV systems on the roofs of Dutch houseboats allow boat owners to live independent of the utility mains without operating an on-board generator. Nearly all PV systems on watercraft are installed flat because of variable orientation. The first of these systems were fielded by ECOFYS (Utrecht) as demonstrations. Now that they have been shown to be reliable and cost-effective, boat owners are installing these systems themselves. As might be expected, the Dutch government has long ago instituted a program to power the thousands of aids to water navigation with PV.

Fig. 22. PV atop the wheelhouse of a canal barge

In the interest to further integrated PV solutions that utilize existing aperture area and available structural elements, the Dutch have also developed PV for highway soundbarriers. Figure 23 (below left) shows a prototype section of a pre-cast concrete soundbarrier element with integrated PV. The Dutch government will complete the first 80 kWp demonstration in 1994. Also being considered are the rights-of-ways along the Dutch railroads, where a recent assessment has shown that PV placed in the available area would provide enough capacity to completely power the rail system.

The Dutch government has announced plans for a large-scale PV-in-buildings project on 100 units of new housing to be constructed in Nieuw Sloten, a new city district of Amsterdam. The project is being funded by the Energy Company of Amsterdam (the electric utility), as part of its Environmental Action Plan, in cooperation with NOVEM and EU-Thermie. Plans call for PV to be installed on some 70 buildings using roof integration and facade integration techniques, resulting in a total capacity of 250 kWp. Other future plans call for up to 600 kWp of roof-top PV to power a new, large-scale housing development in Amersfoort with construction scheduled to start in 1995.

The Netherlands is actively involved in the IEA Task 16 program with participation by NOVEM and ECOFYS. The Dutch coordinated the first world-wide design competition on PV-in-buildings sponsored by IEA Task 16 and Novem. The competition was open to A&E professionals as well as students. 100 entries from all around the world were received and awards were presented at the 12th EC PV conference in Amsterdam in April, 1994. A book of the most creative designs has been published and is available from NOVEM.

The prospects for advancement of building-integrated PV in the Netherlands look very promising. Budgets and research activity are increasing and significant demonstrations are planned over the next few years. The Dutch see PV as a significant part of their 20-year National Environmental Policy Plan and, if the Dutch program goal of fielding 250 MWp of PV by the year 2010 is to be achieved, there will surely be thousands of PV-powered buildings.

Austria

Interest in distributed PV applications has increased in recent years in Austria along with the rest of Europe. The Austrian government has announced a comprehensive plan to reduce CO₂ emissions and PV is seen as an important part of this effort. Over the past ten years, Austria has fielded a number of stand-alone and grid-connected PV systems totaling some 800 kWp including a 30kWp utility-interactive system at Mount Loser, high in the Alps and a 40 kWp U.I. system along the A1 motorway.

In May 1992, the Austrian government announced a distributed roof-top PV demonstration program modeled after the German "1,000 roofs" effort. This program will initially include some 200 kWp of PV systems financed with support from the government and the electric utilities. In addition, several local district authorities have offered additional funding of up to 50% of the systems cost.

A good example of the Austrian roof-top PV program can be seen in the energy-efficient, private, single-family residence constructed in 1992 in Gleisdorf, a small town in southern Austria. The house was designed as a 'low-energy' house and, as such, incorporates solar thermal collectors for domestic water heating, extra-heavy insulation, high-quality glazings, passive solar gain and state-of-the-art high-efficiency appliances. The home's detached garage, shown in Figure 24, incorporates a 2 kWp roof-integrated PV array employing frameless Siemens laminates. The array has provisions for free air flow behind the modules to provide back-surface cooling.

In 1993 another 'low-energy' house was completed near Vienna. With support from the local electric utility, Wiener Stadtwerke Wienstrom, and the Austrian Roof-top PV Program, a 3 kWp PV system was installed with approximately one half the capacity mounted on the roof and the remainder integrated into the south facing facade. The house also incorporates solar thermal collectors for domestic water heating. The utility is monitoring the output of the energy systems to determine the amount of possible reduction in CO₂ from large-scale use of PV and solar thermal systems.

Within the first five months of the Austrian roof-top PV program, over 160 kWp of systems were committed with significant cost-sharing from the homeowners. Many of these systems are building integrated. Nearly all of the systems under the first 200 kWp roof-top program are presently complete and in operation, and discussions are now underway to expand the program by another 100 kWp.

Fig. 24. 2 kWp roof-integrated PV array on Austrian home

As in most of Europe, tile is the traditional material for sloped roofing in Austria. In an effort to make residential PV arrays compatible with the majority of existing roofs, a flat-glass roof tile using single-crystal technology has been prototyped in Villach, Austria by a private group headed by a Dr. Kroner. The tiles are a glass-on-glass laminate with silicon gel used as the encapsulant. Each tile measures approximately 12" wide by 9" high in active area and incorporates twelve 3 inch square cells to deliver

about 12 Wp. A prototype residential roof system, shown as Figure 25, was successfully fielded in Gleisdorf and the group is now looking for development capital.

With much of Austria alpine, efforts have been made to utilize other available sites for PV in addition to buildings. In 1992, the Austrian electric utility Oberösterreichische Kraftwerke AG, (OKA) completed a 40 kWp PV system atop the existing soundbarriers along the southern motorway A1 near Salzburg.

The system, shown in Figure 26, incorporates standard Siemens modules preassembled into subarrays and lifted into place with a light crane reducing field labor. An advanced IGBT pulse-width-modulated inverter feeds system output directly into the OKA distribution feeder.

Fig. 25. Austrian PV Roof Tile

Fig. 26. 40 kWp PV System along Austrian Motorway

OKA fielded the first utility-interactive PV system in Austria in 1988 and has since taken a lead role in the promotion of PV in Austria for both stand-alone and grid-tied applications. The utility is studying the potential benefits provided by the PV system they installed along the motorway for line support as it is located near the end of their distribution line.

Austria has also initiated work in PV facade integration in commercial

buildings with the recent construction of the 13 kWp system on an office building in Innsbruck shown in Figure 27. The building was an existing structure which was scheduled for extensive renovation. During the reconstruction process, the idea was proposed to incorporate a PV array on the south facade as a sun screen to limit unwanted sun-driven summer cooling loads from direct solar gain through the glazing.

The grid-connected system employs large-area single-crystal PV modules manufactured by DASA in Germany (now ASE). The system's output is estimated at 10,370 kWh per year and will be monitored as part of the programme of the Austrian Utilities Association (TIWAG).

Austria supports IEA Task 16 effort with representation from the Technical University at Wien and OKA participating.

Fig. 27. Austrian commercial building with 13 kWp PV array

United States

Photovoltaics was born in the US with the invention of the silicon solar cell at Bell Labs in the early 1950's. With the first world oil shock in 1973, interest blossomed in terrestrial applications of PV and, a conference was held at Cherry Hill, NJ where experts in all aspects of PV convened to plan the best strategy for the development of the PV industry. As a result of the Cherry Hill meeting, the United States embarked on a comprehensive, multi-level program of research, development and demonstration of PV for large-scale terrestrial power use.

Many major corporations including US industrial giants such as Atlantic Richfield, Exxon, Texaco, Shell, General Electric, Westinghouse, Boeing, and Martin Marietta, jumped in, investing hundreds of millions of dollars in PV research and development and the race was on! With its considerable resources, focused program and federal government leadership, the US quickly became the acknowledged world leader in the development of PV. After just five years, costs had been reduced dramatically and efficiencies had improved significantly.

Fig. 28. DOE's Southwest Residential Experiment Station

In the late 1970s, a well-planned program of development of distributed PV was established by the US Department of Energy (DOE) at MIT which included the design and demonstration of many different approaches to building integration. A number of hardware and building designs were commissioned and three demonstration sites were established across the country where prototype building-integrated PV systems were

fielded for evaluation under different climate conditions. The DOE's Southwest Residential Experiment Station (SWRES) constructed at New Mexico State University in Las Cruces, NM to test PV systems in the hot, dry, desert climate is shown in Figure 28.

Working under contract to the US DOE, Solar Design Associates developed the first building-integrated PV system employing large-area .9m x 1.8m PV modules and, in 1979, constructed prototype residential roofs for testing and evaluation at the DOE-sponsored residential experiment stations. Based on the results at the residential experiment stations, the US DOE and MIT commissioned Solar Design Associates to design the energy-efficient, passive solar residence powered by photovoltaics, shown in Figure 29.

The 'Carlisle House', as it became known, was constructed in 1980 in Carlisle, MA with participation from MIT and the US DOE. The residence features passive

Fig. 29. The Carlisle House

solar heating and cooling, super-insulation, internal thermal mass, earth-sheltering, daylighting, a roof-integrated solar thermal system and a 7.5 kWp PV array of polycrystalline modules from Solarex. The home is heated and cooled by a high-efficiency, dual-compressor heat pump system, needs no fossil fuel and shares its surplus power with the utility via a net metering connection. This first residence ever to be powered by a utility-interactive PV system received world-wide attention.

Fig. 30. The Solarex 'Breeder' with 200 kWp PV Roof

In 1982, Solarex Corporation made a most significant commitment to PV-in-Buildings by powering their new manufacturing plant with their own solar modules. The facility, located in Frederick, MD, was designed specifically to receive a 200 kWp array as the entire south roof. A large bank of storage batteries provides a UPS capability for critical plant systems. The 'Solarex Breeder', as the plant became known, was the vision of Solarex founder Joseph Lindemeyer and is shown in Figure 30.

In 1983, the Boston Edison Company commissioned Solar Design Associates to design the Impact 2000 residence as a demonstration of future trends in energy technology and design that would be commonplace early in the next century. The house, shown in Figure 31, features passive solar heating and cooling, super-insulation, internal thermal mass, earth-sheltering, daylighting, a roof-integrated solar thermal system and a 4.5 kWp PV array of large-area modules, each 2.5m^2 , integrated as the finished weathering skin of the roof. Heating and cooling are supplied by a high-efficiency, ground-coupled heat pump system and no fossil fuel is required on site. Like the Carlisle house before it, this house shares its surplus electricity with the Boston Edison grid via a net metering connection. The building of the house was the subject of a national TV series on energy-efficient construction.

Fig. 31. The Impact 2000 House

In 1984, a significant commercial-scale building-integrated PV system was completed at Georgetown University in Washington D.C. The project, sponsored by the US DOE, integrated a 300 kWp PV array of Solarex polycrystalline modules into the stepped south roof of the new Intercultural Center. The project architect worked closely with the PV system engineers to design the building specifically to receive the PV array. The electricity generated serves the building's loads and the surplus is used to support the campus utility grid. The Georgetown Intercultural Center is shown in Figure 32.

In 1985, Solar Design Associates fielded 100 kWp of distributed, roof-top PV systems in a demonstration sponsored by the New England Electric System which includes the world's first PV-powered neighborhood, in the central Massachusetts town of Gardner. Following the NEES pioneering

example, far-sighted utilities, such as the Sacramento Municipal Utility District (SMUD) in California, are now beginning to install distributed PV systems on buildings to support their grid, helping to meet their peak demand while reducing dependence on traditional sources of power and improving the environment.

According to SMUD board Chairman Edward Smeloff, their multi-year program will field some 850 kWp of distributed PV systems in 1993 with 1 MWp in 1994 and another 1 MWp in 1995. Southern California Edison has also recently announced plans for a distributed, roof-top PV program and other utilities such as Niagara Mohawk (NY), Delmarva Power and Light (DE), the New York Power Authority and the City of Austin (TX) Electric are also fielding PV-powered buildings.

Fig. 32. Georgetown University 300 kWp Roof

Fig. 33. APS PV cube and entry canopy

In 1992, Advanced Photovoltaics Systems (APS) completed its new manufacturing plans in Fairfield, CA. APS produces a-Si glass modules measuring .75m by 1.5m in size and asked New York architect Gregory Kiss to integrate these modules into their new building. His design incorporates a cubic control room for the production facility clad with APS modules. The cube, shown in Figure 33, also has a skylight fitted with both clear glass and PV modules. The building's front entry canopy also incorporates PV modules above the curved metal elements.

In June of 1993, the US DOE and the National Renewable Energy Laboratory (NREL) awarded 5 contracts for a 5-year, \$25M program called: "Building Opportunities in the U.S. for Photovoltaics" ("PV:BONUS") to encourage development of building-integrated PV systems. Specific products include a PV element for architectural curtain walls by Solarex and large-area integral roofing modules from Energy Conversion Devices.

The US PV program was invited to join the IEA Task 16 development effort in PV systems for buildings and, in January 1994, the US DOE's Office of Building Technology accepted this invitation. The potential market for building-integrated PV systems in the US is enormous and many companies are beginning to work at the development and commercialization of building-integrated PV components and systems. If consistent government support can be assured, this potential will be realized.

Fig. 34. The US National Renewable Energy Laboratory's new SERF building features a 15 kWp PV system

United Kingdom

Until recently, the UK PV industry has concentrated on traditional export markets for remote PV power systems. In 1990, a review for the UK Department of Energy (now part of the Department of Trade and Industry or DTI) indicated that the status of PV had moved from a 'long-shot' to a 'medium term' solution as an energy resource for the UK. This conclusion was based on the decreasing costs of PV devices and perceived advantages of applying this technology to commercial buildings.

The report concluded that daytime loads of commercial buildings are a good match for PV power systems and commercial building facades are often clad with expensive materials - such as marble or stone - which can be replaced by the PV panels in an integrated structure. These factors together with avoided costs of land and array support structure could make building-integrated PV systems cost effective in the UK within 10 years for optimum designs.

An initial two years of studies have looked at the potential resource; feasibility of building integration; grid interconnection guidelines and practical roof integration. A recent white paper (R62) has formalized PV as a technology requiring R & D support within the Government Renewable Energy Research, Development, Demonstration and Dissemination Programme. This strategy for PV started in 1994 and builds on the previous studies to assist industry to develop a capability in building-integrated PV systems and then field demonstration systems. This segment of the PV programme will look at technical and non-technical barriers to market development in the following areas:

- Resource studies
- Cladding and roof integration methodologies
- Technical issues for grid interconnection
- Examples of building integrated PV system types

Fig. 35. PV 'Recladding' of UK Building Facade

Many of these topics were examined during the realization of the UK's first commercial PV curtain wall facade at the University of Northumbria at Newcastle. This project, shown in Figure 35, is a refurbishment of an existing university building and incorporates 40 kWp of high-efficiency BP Solar PV laminates into a new rainscreen overcladding spandrel system which also provides integrated sun shading on the south face of the building. The project was realized under the direction of Professor Robert Hill and received support from the local regional electricity company (REC) and other members of the electricity supply industry in addition to DTI and EU THERMIE demonstration programmes.

Although residences are not expected to be the first cost-effective application for building-integrated PV systems in the UK, there is a growing interest from domestic consumers and there are some projects completed or under construction which use PV in grid-connected application. Another demonstration project will incorporate a 10 kWp array into the roof of a visitor center at the Center for Alternative

Technology in Wales. Significant attention is being paid to the combination of PV with passive design principles to optimize daylighting, heating and PV power use.

The UK PV community is discussing options for market stimulation with the UK Government. One strategy would be to include PV in the legal requirement for RECs to buy Renewable Energy at a premium rate (the Non-Fossil Fuels Obligation - NFFO). The 1989 UK Electricity Act created a special "non-fossil fuel obligation" (NFFO) requiring the 12 English and Wales regional electric utilities to produce or purchase a specified portion of their capacity from renewable sources. This has created the vitally-important "market pull" needed to introduce renewables to the utility community. The initial goal of 102 MWp was easily reached and the government has set a target of 1,000 MWp by the year 2000. This initiative has helped to increase interest and activity in photovoltaics in the UK.

On the technology side, BP Solar International LTD. now has working prototype modules using cadmium telluride technology with efficiencies approaching the 10% range. BP also has single crystal modules in the 17% range using high-efficiency, laser-grooved cell processes developed by Martin Green at the University of New South Wales in Australia. BP has established a manufacturing plant in Spain (BP Solar Espana) and plans to look at large area module fabrication of the CZ modules and the use of its CdTe thin film materials in modules developed specifically for building facades. Initially, modules of .5 m by 1.0 m are planned with CdTe technology and CdTe module selling prices in the area of US\$1.00 - 2.00 /Wp are forecast by the end of the decade.

The British government has funded a comprehensive evaluation of the potential of building-integrated PV systems in the UK. The study, conducted by Professor Robert Hill and his colleagues at the Newcastle PV Applications Centre, was initially only to include the south-facing facades but was expanded to include all building surfaces regardless of orientation and concluded there were 111 Gigawatts of potential generating capacity available from distributed PV systems on buildings. Another related study now underway is investigating the various types of curtain wall systems for commercial buildings. It is expected that a follow-on study will pursue the development of specific PV products designed for building integration.

The British government is also funding participation in the IEA Task 16, Photovoltaics in Buildings. In addition to UKDOE personnel, PV professionals from BP Solar and IT Power are representing the UK in this multi-country development effort.

Finland

Activity in Finland relative to distributed PV applications has also increased in recent years along with the rest of Europe. Finland has recently embarked on a three-year plan which includes the development of improved load management systems, demonstration of PV / hydrogen systems with hydrogen storage and the fielding of distributed, grid-connected PV demonstration systems on buildings.

There are over 400,000 vacation cottages in Finland and about half of them are located off the grid where PV systems are an ideal source of power. Today there are some 20,000 summer houses around Finland powered by small PV systems. A typical system is designed to meet lighting, home electronics, water pumping and refrigeration needs from April to September.

Figure 36 shows a Finnish summer cottage with a 2.4 kWp roof-top array of a-Si modules from NAPS France. This system was installed in 1992 and includes a battery bank and stand-alone 2.5 kW DC/AC inverter to power lighting, refrigeration, home electronics and small appliances, vacuum cleaner, washing machine and dishwasher. The house is located some 260 km north of Helsinki at 62°N and 26°E.

Fig. 36. Finnish summer cottage with 2.4 kW PV array

Since 1991, the Fins have retrofitted 10 residences with PV power systems. Five are stand-alone and five are grid-connected. R&D programs underway are presently investigating the development of building-integrated PV systems and engineers from NESTE have fielded two demonstration projects.

Fig. 37. Southwest facade of NESTEhaus with PV sunshades

The first, shown in Figure 37, is a demonstration house designed and constructed by NESTE as an experimental house incorporating many building components and materials made of plastic. The house features see-through a-Si modules as window glass and crystal-Si sun shades on the south facade to reduce summer cooling loads. The house is located 35 km east of Helsinki in Porvoo, 60°N and 25°E.

The second, shown in Figure 38, is a private house located in Pietarsaari, Finland 63.5°N and known as the Pietarsaari low energy house. This residence features a roof-integrated 2.4 kWp PV array of a-Si modules along with a 10m² array of solar thermal collectors. The PV array is mounted using novel custom designed profiles of glass fibre which have nearly the same expansion coefficient as glass. The house is a demonstration of energy-efficiency and solar design and serves as the Finnish IEA demonstration house. It was completed in 1994.

Finland has also joined the IEA Task 16 effort with representatives from Helsinki University and the engineering firm NESTE OY participating.

Fig. 38. Finnish PV-powered low-energy demonstration house.

Spain

Spain's interest in distributed PV applications has also increased in recent years along with the rest of Europe. The potential market for remote PV applications in isolated areas of Spain is considered the most significant in the European Community.

Spain has already fielded hundreds of stand-alone and grid-connected PV systems totalling well over 5 Megawatts in capacity including a 1 Megawatt central plant under construction at Toledo.

Spain has a number of PV R&D and manufacturing activities underway including the production facility of BP Solar and ISOFOTON. Spain's recent activity has focused on systems design, utility interface, demonstration monitoring and testing. The area of building integration of PV is beginning to receive research and development attention.

Spain has joined the IEA Task 16 PV-in-Buildings development effort and was the host of the second meeting of the Experts' working group held in Madrid at CIEMAT in February 1992.

Figure 39 shows the Spanish Task 16 demonstration house which is a four-plex incorporating 4 roof-integrated PV arrays of 2.2 kWp each. The systems are utility

interactive. There are thousands of PV-powered off-grid residences in remote areas of Spain and utility-interactive PV systems are now starting to be installed on residences with the cooperation and support of Spanish utilities. Additional building-integrated PV projects are now in the planning stages.

Sweden

In Sweden, as well as in Norway and Finland, PV is often employed to power remote vacation cottages. There are now over 20,000 such PV powered cottages in Sweden and the market is increasing rapidly with over 5,000 new installations every year. In addition, several hundred lighthouses along remote stretches of the Swedish coast are now powered with PV.

Sweden's activity in distributed PV has increased along with that of other European countries. Present program activities include both stand-alone and grid-connected distributed PV systems. Development and testing of DC-AC inverters and battery charge control regulators is being undertaken. PV research and development activities in Sweden are concentrated at the Royal Institute of Technology and the University of Uppsala for cell research and, Catella Generics AB and Vattenfall Utveckling AB (the largest utility in Sweden) for systems.

In 1990, a 3.5 kWp grid-connected demonstration was completed on a single residence in Linköping

Fig. 40. 10 kWp PV system in Stockholm

approximately 200 km south of Stockholm.

A Swedish company called GPV has recently started manufacturing PV modules. The modules are of standard construction with a glass top skin and tedlar back and come in sizes up to 100Wp. The company has expressed an interest in participating in the development of PV modules for direct building integration.

In 1993, the Swedish utility, Stockholm Energi AB, installed a 10 kWp utility-interactive PV system on an existing apartment building in downtown Stockholm. The system, shown in Figure 40, serves as the IEA Task 16

demonstration building and features three parallel arrays of 3.3kWp each with its own inverter. Sweden has also joined the IEA Task 16 effort with representatives from the Swedish National Testing Institute and Catella Generics representing the county's effort.

Italy

Italy's federal funding has increased significantly for PV in recent years and interest in building-integrated PV applications is growing in Italy along with the rest of Europe. As a result of growing environmental concerns and the dependence of Italy on foreign oil, the government has launched a program to field some 25 Megawatts of PV by 1996. Italy's National Agency for New Technology Energy and the Environment (ENEA) will be responsible for research and development and the National Electrical Board, ENEL will be responsible for implementation of the demonstration program and construction of the plants.

Fig. 41. PV Parking Structure near Rome

The Italian PV program includes plans for a number of building-integrated PV demonstrations. One of the first is a PV parking structure in Rome shown in Figure 41. Others include an innovative 30 kW integrated PV roof for the Eurosolare factory of Nettuno near Rome shown in Figure 42 which combines PV with daylighting, a 20 kW terrace at the German School of Rome and a 4 kW shading structure at ENEL headquarters in Rome. A second series of 10 systems is planned for 1995 with cost-sharing from the Thermie Project. These will include ENEL offices, training and information centers and parking structures.

Fig. 42. Integrated PV factory roof

Mr. Robert Vigotti of ENEL is a very strong proponent of

PV and its use in buildings and has considerable influence on the development of the government's policy to promote the technology. Italy has recently joined IEA Task 16 and appointed an architect from Rome to represent the country. Italy has also sent a representative from ENEL to participate in IEA Task 16 meetings as well as in the new IEA PV Task 5.

Canada

Interest in PV has increased in Canada in recent years even though conventional energy resources are plentiful and inexpensive. Present activities within the Canadian R&D program center on improved system design and performance modeling. Projects underway include further software development for system optimization and simulation including modeling of battery storage characteristics. Over a dozen PV systems are being monitored, and codes and standards for PV systems are being developed.

PV powered buildings are also beginning to be fielded such as the stand-alone residence in Saskatchewan shown in Figure 44. The Canadian Department of Energy, Mines and Resources (CANMET) has installed a 30 kWp array atop their research laboratory near Montreal. The system, shown in Figure 43, works as a building peak shaver while providing PV power to support research efforts in power conditioning development and system simulation modeling.

In Toronto, the Canadian utility Ontario Hydro, in collaboration with the Canadian Energy Diversification Research Laboratory (EDRL), has fielded a 75 kWp

roof-top PV system at the McMillian Rehabilitation Center as a demand-side management measure to help shave the hospital's summer air conditioning peak.

Canada has also joined the IEA Task 16 effort. Representatives from the University of Ottawa, PV systems companies and the government (EDRL-CANMET) are representing Canada in Task 16.

Ontario Hydro was influential in the installation of PV on the "Innova House", a low-energy demonstration home in Ottawa which is shown in Figure 45. This system, which features a 2.7 kWp array, is the first grid-connected PV residence in Canada and has been selected as an IEA Task 16 demonstration house.

Norway

Norway has long had a strong market for small distributed residential PV systems with the large number of vacation cottages located off the power grid. There are presently over 50,000 PV-powered vacation homes in Norway with over 8,000 new installations completed every year.

A substantial part of the energy R&D activities in Norway has been allocated to medium-scale hybrid power generation plants for isolated communities along the coast. Wind/diesel systems of 50 kW installed power have been developed and are being commercialized. The integration of PV in such stand-alone systems is being investigated and development of supervisory control systems for short-term scheduling of diesel start/stops has received much of the R & D attention in the last 5 years.

A demonstration low energy row-house with 3 apartments has been constructed in Hamar to provide housing for foreign journalists at the 1994 Winter Olympics. The project, shown in Figure 46,

Fig. 46. Low-energy Row House with PV in Hamar

established a new level of integrated design incorporating passive solar, super insulation, air-tight construction with controlled ventilation, active solar water heating, high-efficiency heat pumps for backup space and water heating as well as non-toxic building materials.

The center apartment gets its electricity from a 2.2 kWp / 27m² roof-integrated, utility-interactive PV system. The array incorporates standard Siemens modules mounted over a watertight membrane. A detail of the PV array installation is shown as Figure 47. The project supports Norway's work in IEA Tasks 13 (Low-energy Buildings) and Task 16 (PV-in-Buildings) and will serve as a model for new building codes to be introduced in 1995 incorporating very high energy efficiency standards.

As Norway has introduced a deregulated electricity market with spot-pricing, utilities are interested in testing electronic meters with 2-way communication for remote metering of small and medium size customers. The impact on this market regime from all kinds of local generation by new renewable energy sources, along with equipment reliability and power quality issues are subject to increasing interest by the distribution utilities in Norway.

Fig. 47. PV array installation in Hamar

Interest in distributed, grid-connected applications has increased along with that of other countries in Europe. As a result, Norway has increased its program involvement in this area and participates in the IEA Task 16 effort. Representatives from the Norwegian Institute of Technology and SINTEF are representing Norway in Task 16.

Appendix C: Glossary of Terms and Abbreviations

BIPV - Building-Integrated Photovoltaics.

BOS - Balance of System.

Capacity - The numerical measure used to indicate "size." For generating stations, the measurement is in megawatts (MW) or kilowatts (kW).

Capacity Factor - Percentage of total annual hours in operation.

CO₂ (Carbon Dioxide) - A colorless gas produced by the complete combustion of carbon, by the actions of acids on carbonates, by the thermal decomposition of carbonates (e.g., lime burning) and during fermentation. It is one of the gases known to contribute to the greenhouse effect.

Demand - The power and energy that must be generated to meet customer needs; includes delivery losses.

Demand-Side Management (DSM) - Measures taken by utilities to influence the amount and timing of customer electricity demand.

DOE OBT - Department of Energy, Office of Building Technologies.

Ex-Plant Module Price - Includes direct materials, direct labor, indirect manufacturing labor, depreciation on equipment, rent or depreciation on facilities, fringes, utilities, property taxes and insurance, G&A, R&D, selling costs, marketing, corporate taxes and interest, and profit.

Global Insolation - The total solar radiant energy incident upon unit area of a horizontal surface during a specified time period (units as for direct insolation). Global Insolation = Direct Insolation (horizontal) + Diffuse Insolation (horizontal) for the same time period.

IEA - International Energy Agency.

Independent Power Producers (IPPs) - Non-utility or unregulated utility subsidiary companies that obtain financing, construct, and operate wholesale power generation facilities under contract with regulated utilities, the wholesale price to those utilities is regulated by the Federal Energy Regulatory Commission (FERC) - a US government agency.

IRP - Integrated Resource Plans.

Appendix C: Glossary of Terms and Abbreviations (continued)

Kilowatt (kW) - A unit of electrical power equal to 1,000 Watts.

Kilowatthour (KWh) - A unit of electrical energy or work, equal to that done by one kilowatt acting for one hour.

Load - Electricity (peak power and energy) consumed to meet customer electricity needs; synonymous with customer load.

MW (Megawatts) - One million watts or 1,000 kilowatts. It is a means of indicating the power rating of equipment (e.g., electrical power of a generator or thermal power of a nuclear reactor).

NAHB - National Association of Home Builders.

NO_x (Nitric Oxide) - A gas formed in great part from atmospheric nitrogen and oxygen when combustion takes place under high temperatures and pressures, as in internal combustion engines. NO_x is not itself a pollutant. However, in the ambient air, it converts to nitrogen dioxide (NO₂), a major contributor to photochemical smog or ozone. Forms of NO_x are precursors to acid rain and greenhouse gases.

NREL - National Renewable Energy Laboratory.

Off-Peak - Power use outside of high demand (peak) periods.

psf - Pounds per square foot.

Peak/Peaking - The highest average load during a time interval of specified duration, e.g., 20 minutes, occurring during a given period of time, e.g., in a day.

Photovoltaic (PV) System - An installed aggregate of solar arrays generating power for a given application. A system may include the following sub-systems:

- Photovoltaic array,
- Support foundation,
- Power conditioning and control equipment,
- Battery storage,
- Land, security system, and building,
- Wiring, and
- Instrumentation.

PUC - Public Utility Commission

Rated or Peak Power (Wp) - The power output of a photovoltaic generator at a specified operating voltage under Standard Test Conditions (W).

Appendix C: Glossary of Terms and Abbreviations (continued)

Renewable Resource - A source of energy that is not measurably depleted when used to generate thermal or electric energy (e.g., wind, solar radiation, hydroelectric).

SUNYA - State University of New York Albany.

Standard Test Conditions (STC) - Cell junction temperature, as measured at the front contact: $25 \pm 2^\circ\text{C}$. Irradiance, as measured with a reference solar cell: $1,000 \text{ W/m}^2$. Standard solar spectral energy distribution: AM 1.5 direct irradiance normalized to give $1,000 \text{ W/m}^2$.

SO₂ (Sulphur Dioxide) - A heavy, pungent, colorless gas primarily formed by the combustion of fossil fuels. SO₂ can damage the mammalian respiratory tracts, as well as vegetation and materials. It is a major pollutant resulting from fossil fuel (mainly coal) combustion and a precursor to acid rain.

T&D - Transmission and Distribution.

UL - Underwriters Laboratory

Watt (W) - A measure of electrical power, i.e., a 100-Watt light bulb. When measured as the peak output of a photovoltaic system, it is referred to as Watts peak or Wp.

ADL Market Model Analyses

**Energy Savings, Demand Charge Reduction,
IRP/Externalities**

Payback Analysis for Photovoltaic System (Volume Discount / Utility Incentive Case)					
Single Family Application					
USER OPTIONS					
Distribution Steps (0, 1, or, 2):	1				
Desired PV System Size of (kW):	4				
Requires PV Square Footage of:	481	446	346	310	294
Externality Credit: (0=no, 1=yes)	1				
Capacity Credit (0=no, 1=yes)	1				
COSTS (Retrofit)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.35	\$2.30	\$1.80	\$1.35	\$1.20
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$7.76	\$7.53	\$5.52	\$4.08	\$3.68
PV Installed Cost (\$/ft2)	\$75.08	\$78.46	\$74.18	\$61.32	\$58.18
Total Selling Price	\$36,096	\$35,026	\$25,668	\$18,984	\$17,112
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Capacity Credit (\$150/kW, w/ 60%ELCC)	\$360	\$360	\$360	\$360	\$360
Net Selling Price	\$35,736	\$34,666	\$25,308	\$18,624	\$16,752
COSTS (New Construction)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.20	\$2.20	\$1.70	\$1.25	\$1.10
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$7.59	\$7.42	\$5.41	\$3.97	\$3.57
PV Installed Cost (\$/ft2)	\$73.41	\$77.26	\$72.64	\$59.59	\$56.36
Total Selling Price	\$35,294	\$34,491	\$25,133	\$18,449	\$16,577
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Capacity Credit (\$150/kW, w/ 60%ELCC)	\$360	\$360	\$360	\$360	\$360
Net Selling Price	\$34,934	\$34,131	\$24,773	\$18,089	\$16,217
PV PERFORMANCE					
Module Efficiency(%)	13.00%	14.00%	17.00%	19.00%	20.00%
System Efficiency(%)	10.40%	11.20%	14.45%	16.15%	17.00%
Average Annual Insolation (kWh/ft2) 1					
New England (Boston)	136	136	136	136	136
Middle Atlantic (New York)	137	137	137	137	137
East North Central (Detroit)	138	138	138	138	138
West North Central (Omaha)	172	172	172	172	172
South Atlantic (Miami)	196	196	196	196	196
East South Central (Birmingham)	161	161	161	161	161
West South Central (Dallas)	180	180	180	180	180
Pacific Northwest (Great Falls)	168	168	168	168	168
Pacific Southwest (Albuquerque)	235	235	235	235	235
Annual Solar Output (kWh/ft2) 2					
New England (Boston)	14.1	15.2	19.7	22.0	23.1
Middle Atlantic (New York)	14.2	15.3	19.8	22.1	23.3
East North Central (Detroit)	14.4	15.5	19.9	22.3	23.5
West North Central (Omaha)	17.9	19.3	24.9	27.8	29.2
South Atlantic (Miami)	20.4	22.0	28.3	31.7	33.3
East South Central (Birmingham)	16.7	18.0	23.3	26.0	27.4
West South Central (Dallas)	18.7	20.2	26.0	29.1	30.6
Pacific Northwest (Great Falls)	17.5	18.8	24.3	27.1	28.6
Pacific Southwest (Albuquerque)	24.4	26.3	34.0	38.0	40.0

Solar Output (kW/ft2) 3	0.008	0.009	0.012	0.013	0.014
Electricity Prices (\$/kWh) 4					
New England (Boston)	0.111	0.116	0.126	0.124	0.122
Middle Atlantic (New York)	0.140	0.137	0.131	0.133	0.134
East North Central (Chicago)	0.107	0.109	0.115	0.115	0.115
West North Central (Minneapolis)	0.077	0.078	0.080	0.082	0.084
South Atlantic (Miami)	0.070	0.069	0.066	0.066	0.066
East South Central (Birmingham)	0.069	0.068	0.065	0.065	0.066
West South Central (Dallas)	0.075	0.076	0.080	0.082	0.084
Pacific Northwest (Olympia)	0.056	0.059	0.067	0.069	0.070
Pacific Southwest (Los Angeles)	0.127	0.126	0.124	0.123	0.123
O&M Cost (\$/kWh)	0.008	0.008	0.008	0.007	0.006
Annual Electricity Cost Savings (\$/ft2)					
(Including O&M Costs)					
New England	\$1.46	\$1.64	\$2.33	\$2.58	\$2.69
Middle Atlantic	\$1.88	\$1.99	\$2.44	\$2.78	\$2.99
East North Central	\$1.42	\$1.57	\$2.13	\$2.40	\$2.55
West North Central	\$1.24	\$1.35	\$1.78	\$2.07	\$2.27
South Atlantic	\$1.26	\$1.33	\$1.64	\$1.87	\$2.02
East South Central	\$1.02	\$1.07	\$1.32	\$1.51	\$1.63
West South Central	\$1.25	\$1.37	\$1.87	\$2.19	\$2.40
Pacific Northwest	\$0.84	\$0.96	\$1.44	\$1.67	\$1.82
Pacific Southwest	\$2.90	\$3.10	\$3.94	\$4.42	\$4.67
Annual Externality Credit Savings (\$/ft2) 5					
New England	\$0.42	\$0.46	\$0.45	\$0.51	\$0.53
Middle Atlantic	\$0.43	\$0.46	\$0.46	\$0.51	\$0.54
East North Central	\$0.42	\$0.45	\$0.42	\$0.47	\$0.49
West North Central	\$0.52	\$0.56	\$0.52	\$0.58	\$0.61
South Atlantic	\$0.33	\$0.35	\$0.34	\$0.38	\$0.40
East South Central	\$0.27	\$0.29	\$0.28	\$0.31	\$0.33
West South Central	\$0.30	\$0.32	\$0.31	\$0.35	\$0.37
Pacific Northwest	\$0.45	\$0.49	\$0.63	\$0.71	\$0.74
Pacific Southwest	\$0.64	\$0.68	\$0.88	\$0.99	\$1.04
Payback for Retrofit (yrs)					
New England	39	37	26	20	18
Middle Atlantic	32	32	25	18	16
East North Central	40	39	29	21	19
West North Central	42	41	32	23	20
South Atlantic	47	46	37	27	24
East South Central	58	57	46	33	29
West South Central	48	46	33	24	21
Pacific Northwest	57	53	35	25	22
Pacific Southwest	21	21	15	11	10
Payback for New Construction (yrs)					
New England	38	36	26	19	17
Middle Atlantic	31	31	25	18	16
East North Central	39	38	28	20	18
West North Central	41	40	31	22	19
South Atlantic	46	45	36	26	23
East South Central	57	56	45	32	28
West South Central	47	45	33	23	20
Pacific Northwest	56	53	35	25	22
Pacific Northwest	56	53	35	25	22

Pacific Southwest	21	20	15	11	10
SF Existing Units (000's) 6					
New England	3,260	3,445	3,638	3,861	4,062
Middle Atlantic	8,649	9,027	9,387	9,784	10,163
East North Central	11,587	12,375	13,040	13,741	14,459
West North Central	5,385	5,738	6,046	6,374	6,704
South Atlantic	11,857	13,425	15,111	17,016	18,735
East South Central	4,343	4,666	4,948	5,234	5,530
West South Central	7,532	8,036	8,580	9,236	9,804
Pacific Northwest	2,934	3,228	3,491	3,782	4,065
Pacific Southwest	10,214	11,178	12,224	13,414	14,480
SF Existing Units w/ PV Access (000's) 7					
New England	978	1,034	1,091	1,158	1,219
Middle Atlantic	2,595	2,708	2,816	2,935	3,049
East North Central	3,476	3,713	3,912	4,122	4,338
West North Central	1,616	1,721	1,814	1,912	2,011
South Atlantic	3,557	4,028	4,533	5,105	5,621
East South Central	1,303	1,400	1,484	1,570	1,659
West South Central	2,260	2,411	2,574	2,771	2,941
Pacific Northwest	880	968	1,047	1,135	1,220
Pacific Southwest	3,064	3,353	3,667	4,024	4,324
SF Existing Penetration (000's)					
New England	0.00	0.00	0.00	0.00	0.00
Middle Atlantic	0.00	0.00	0.00	0.00	0.00
East North Central	0.00	0.00	0.00	0.00	0.00
West North Central	0.00	0.00	0.00	0.00	0.00
South Atlantic	0.00	0.00	0.00	0.00	0.00
East South Central	0.00	0.00	0.00	0.00	0.00
West South Central	0.00	0.00	0.00	0.00	0.00
Pacific Northwest	0.00	0.00	0.00	0.00	0.00
Pacific Southwest	0.00	0.00	0.00	20.12	64.86
SF Units New Construction (000's)					
New England		185	193	223	201
Middle Atlantic		378	360	397	379
East North Central		788	665	701	718
West North Central		353	308	328	330
South Atlantic		1,568	1,686	1,905	1,719
East South Central		323	282	286	296
West South Central		504	544	656	568
Pacific Northwest		294	263	291	283
Pacific Southwest		964	1,046	1,190	1,066
SF New Units w/ PV Access (000's) 8					
New England	0	83	87	100	90
Middle Atlantic	0	170	162	179	171
East North Central	0	355	299	315	323
West North Central	0	159	139	148	149
South Atlantic	0	706	759	857	774
East South Central	0	145	127	129	133
West South Central	0	227	245	295	256
Pacific Northwest	0	132	118	131	127
Pacific Southwest	0	434	471	536	480

SF New Penetration (000's)					
New England	0.00	0.00	0.00	0.00	0.00
Middle Atlantic	0.00	0.00	0.00	0.00	0.00
East North Central	0.00	0.00	0.00	0.00	0.00
West North Central	0.00	0.00	0.00	0.00	0.00
South Atlantic	0.00	0.00	0.00	0.00	0.00
East South Central	0.00	0.00	0.00	0.00	0.00
West South Central	0.00	0.00	0.00	0.00	0.00
Pacific Northwest	0.00	0.00	0.00	0.00	0.00
Pacific Southwest	0.00	0.00	0.00	2.68	7.20
Total PV Penetration (000's)					
New England	0.00	0.00	0.00	0.00	0.00
Middle Atlantic	0.00	0.00	0.00	0.00	0.00
East North Central	0.00	0.00	0.00	0.00	0.00
West North Central	0.00	0.00	0.00	0.00	0.00
South Atlantic	0.00	0.00	0.00	0.00	0.00
East South Central	0.00	0.00	0.00	0.00	0.00
West South Central	0.00	0.00	0.00	0.00	0.00
Pacific Northwest	0.00	0.00	0.00	0.00	0.00
Pacific Southwest	0.00	0.00	0.00	22.80	72.05
Total PV Penetration by Region (MW/YR)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	91	288
TOTAL (MW/YR)	0	0	0	91	288
1- For a south facing latitude tilt. Sandia National Labs- PVFORM, 1986					
2- Assuming latitude tilt for residential sector					
3- Peak Insolation derived from ASHRAE, "Procedure for Determining Heating and Cooling Loads for Computerizing Energy Calculations," 1976. Peak Insolation includes clearness factor to account for local atmospheric conditions (e.g. smog)					
4- 1993 rates: GRI, assuming monthly load of 800 kWh. Projections calculated using growth factors based on Energy Information Administration, "Annual Outlook for Electric Power," 1991. Includes relevant taxes and surcharges.					
5- Externality values are based on regional utility generation mix data (lbs/kWh) from EIA, Supplement to Annual Energy Outlook, 1993, and values assigned by PSCs (\$/lb). For regions that have not assigned externality values, the lowest value from other regions has been used.					
6- Existing inventory, 1990 US Census Bureau, "1990 Census of Housing". New construction, ADL estimates based on 1991-1993 US Census "Housing Starts".					
7- Assumes 30% of existing units have solar access					
8- Assumes 45% of new units have solar access					

Payback Analysis for Photovoltaic System (Volume Discount / Utility Incentive Case)					
Multifamily Building Application					
USER OPTIONS					
Module Orientation (0=latitude tilt, 1= 15 degree tilt):	1				
Distribution Steps (0, 1, or, 2):	1				
Desired PV System Output (kW):	30				
Requires PV Square Footage of:	3606	3348	2595	2322	2206
Externality Credit: (0=no, 1=yes)	1				
Demand Charge Credit: (0=no, 1=yes)	1				
Capacity Credit (0=no, 1=yes)	1				
T&D Credit: (0=no, 1=yes)	1				
COSTS (Retrofit)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.70	\$2.60	\$2.10	\$1.65	\$1.40
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$8.17	\$7.88	\$5.87	\$4.43	\$3.91
PV Installed Cost (\$/ft2)	\$79	\$82	\$79	\$66	\$62
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$8	\$8	\$8	\$7	\$6
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$1	\$1
Net Selling Price (\$/ft2)	\$71	\$74	\$71	\$60	\$56
COSTS (New Construction)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.70	\$2.60	\$2.10	\$1.65	\$1.40
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$8.17	\$7.88	\$5.87	\$4.43	\$3.91
PV Installed Cost (\$/ft2)	\$79	\$82	\$79	\$66	\$62
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$8	\$8	\$8	\$7	\$6
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$1	\$1
Net Selling Price (\$/ft2)	\$71	\$74	\$71	\$60	\$56
PV PERFORMANCE					
Module Efficiency(%)	13.00%	14.00%	17.00%	19.00%	20.00%
System Efficiency(%)	10.40%	11.20%	14.45%	16.15%	17.00%
Average Annual Insolation (kWh/ft2) 2					
New England (Boston)	136	136	136	136	136
Middle Atlantic (New York)	137	137	137	137	137
East North Central (Detroit)	138	138	138	138	138
West North Central (Omaha)	172	172	172	172	172
South Atlantic (Miami)	196	196	196	196	196
East South Central (Birmingham)	161	161	161	161	161
West South Central (Dallas)	180	180	180	180	180
Pacific Northwest (Great Falls)	168	168	168	168	168
Pacific Southwest (Albuquerque)	235	235	235	235	235

Annual Solar Output (kWh/ft2) 3					
New England (Boston)	13.6	14.6	18.9	21.1	22.2
Middle Atlantic (New York)	13.7	14.7	19.0	21.2	22.4
East North Central (Detroit)	13.8	14.8	19.1	21.4	22.5
West North Central (Omaha)	17.2	18.5	23.9	26.7	28.1
South Atlantic (Miami)	19.6	21.1	27.2	30.4	32.0
East South Central (Birmingham)	16.1	17.3	22.3	25.0	26.3
West South Central (Dallas)	18.0	19.4	25.0	27.9	29.4
Pacific Northwest (Great Falls)	16.8	18.1	23.3	26.0	27.4
Pacific Southwest (Albuquerque)	23.5	25.3	32.6	36.4	38.4
Solar Output (kW/ft2) 4	0.008	0.009	0.012	0.013	0.014
Electricity Prices (\$/kWh) 5					
New England (Boston)	0.111	0.116	0.126	0.124	0.122
Middle Atlantic (New York)	0.050	0.050	0.049	0.049	0.049
East North Central (Chicago)	0.056	0.056	0.056	0.057	0.058
West North Central (Minneapolis)	0.077	0.078	0.080	0.082	0.084
South Atlantic (Miami)	0.070	0.069	0.066	0.066	0.066
East South Central (Birmingham)	0.069	0.068	0.065	0.065	0.066
West South Central (Dallas)	0.075	0.076	0.080	0.082	0.084
Pacific Northwest (Olympia)	0.056	0.059	0.067	0.069	0.070
Pacific Southwest (Los Angeles)	0.127	0.126	0.124	0.123	0.123
Annual Demand Charges (\$/kW/mo) 5					
New England (Boston)	0.00	0.00	0.00	0.00	0.00
Middle Atlantic (New York)	25.24	25.24	25.24	25.24	25.24
East North Central (Chicago)	11.13	11.13	11.13	11.13	11.13
West North Central (Minneapolis)	0.00	0.00	0.00	0.00	0.00
South Atlantic (Miami)	0.00	0.00	0.00	0.00	0.00
East South Central (Birmingham)	0.00	0.00	0.00	0.00	0.00
West South Central (Dallas)	0.00	0.00	0.00	0.00	0.00
Pacific Northwest (Olympia)	0.00	0.00	0.00	0.00	0.00
Pacific Southwest (Los Angeles)	0.00	0.00	0.00	0.00	0.00
O&M Cost (\$/kWh)	0.008	0.008	0.008	0.007	0.006
Annual Electricity Cost Savings (\$/ft2)					
(Including O&M Costs)					
New England	\$1.40	\$1.57	\$2.23	\$2.47	\$2.58
Middle Atlantic	\$0.57	\$0.61	\$0.77	\$0.89	\$0.97
East North Central	\$0.66	\$0.71	\$0.91	\$1.07	\$1.17
West North Central	\$1.19	\$1.29	\$1.71	\$1.99	\$2.18
South Atlantic	\$1.21	\$1.28	\$1.57	\$1.80	\$1.94
East South Central	\$0.98	\$1.03	\$1.27	\$1.45	\$1.56
West South Central	\$1.20	\$1.32	\$1.80	\$2.10	\$2.30
Pacific Northwest	\$0.81	\$0.92	\$1.38	\$1.60	\$1.75
Pacific Southwest	\$2.78	\$2.98	\$3.78	\$4.24	\$4.48

Environmental Externality Savings (\$/ft2) 6					
New England	\$0.41	\$0.44	\$0.43	\$0.48	\$0.51
Middle Atlantic	\$0.41	\$0.44	\$0.44	\$0.49	\$0.51
East North Central	\$0.40	\$0.43	\$0.40	\$0.45	\$0.47
West North Central	\$0.50	\$0.54	\$0.50	\$0.56	\$0.59
South Atlantic	\$0.31	\$0.34	\$0.33	\$0.36	\$0.38
East South Central	\$0.26	\$0.28	\$0.27	\$0.30	\$0.32
West South Central	\$0.29	\$0.31	\$0.30	\$0.33	\$0.35
Pacific Northwest	\$0.44	\$0.47	\$0.61	\$0.68	\$0.71
Pacific Southwest	\$0.61	\$0.66	\$0.85	\$0.95	\$1.00
Annual Demand Charge Savings (\$/ft2) 7					
New England	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Middle Atlantic	\$1.51	\$1.63	\$2.10	\$2.35	\$2.47
East North Central	\$0.67	\$0.72	\$0.93	\$1.04	\$1.09
West North Central	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
South Atlantic	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
East South Central	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
West South Central	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Pacific Northwest	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Pacific Southwest	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Annual Avoided T&D Costs (\$/ft2) 8					
New England	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Middle Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
South Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Northwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Southwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Payback for Retrofit (yrs)					
New England	32	30	22	17	15
Middle Atlantic	24	24	18	14	12
East North Central	33	32	25	19	16
West North Central	34	32	25	19	16
South Atlantic	37	36	29	21	19
East South Central	43	42	34	25	22
West South Central	37	36	27	19	17
Pacific Northwest	43	40	28	20	18
Pacific Southwest	19	18	14	10	9
Payback for New Construction (yrs)					
New England	32	30	22	17	15
Middle Atlantic	24	24	18	14	12
East North Central	33	32	25	19	16
West North Central	34	32	25	19	16
South Atlantic	37	36	29	21	19
East South Central	43	42	34	25	22

West South Central	37	36	27	19	17
Pacific Northwest	43	40	28	20	18
Pacific Southwest	19	18	14	10	9
Existing Roof Area (million sq.ft) 9					
New England		435	440	446	451
Middle Atlantic		1,234	1,248	1,259	1,271
East North Central		1,185	1,247	1,298	1,355
West North Central		414	441	462	487
South Atlantic		1,537	1,662	1,775	1,892
East South Central		357	379	398	418
West South Central		814	865	918	969
Pacific Northwest		304	335	363	394
Pacific Southwest		1,502	1,601	1,692	1,785
Roof Area w/ PV Access (million sq.ft) 10					
New England	0	131	132	134	135
Middle Atlantic	0	370	374	378	381
East North Central	0	356	374	389	407
West North Central	0	124	132	139	146
South Atlantic	0	461	499	533	568
East South Central	0	107	114	119	125
West South Central	0	244	260	275	291
Pacific Northwest	0	91	101	109	118
Pacific Southwest	0	451	480	508	536
Existing Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	3	8
New Construction Roof Area (million sq.ft) 9					
New England		1	1	1	1
Middle Atlantic		3	2	2	3
East North Central		13	9	11	12
West North Central		5	4	5	5
South Atlantic		24	20	25	23
East South Central		5	3	4	4
West South Central		9	9	12	10
Pacific Northwest		6	5	6	6
Pacific Southwest		19	16	20	18
New w/ PV Access (million sq.ft) 10					
New England	0	0	0	0	0
Middle Atlantic	0	1	1	1	1

East North Central	0	6	4	5	5
West North Central	0	2	2	2	2
South Atlantic	0	11	9	11	10
East South Central	0	2	1	2	2
West South Central	0	4	4	5	5
Pacific Northwest	0	3	2	3	3
Pacific Southwest	0	9	7	9	8
New Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	-0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	0	0
Total PV Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	3	9
Total PV Penetration by Region (MW)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	37	116
TOTAL (MW/YR)	0	0	0	37	116
1- Assumes an average capacity credit for multifamily buildings of \$150/kW, based on existing rebates given for other DSM options. Energy User News, April 1993, Interviews with utilities, and Delmarva Power, "Identification of the Potential of PV in the Utility DSM Market: A Study of 21 US Utilities," Dec 1992.					
2- For a south facing latitude tilt. Sandia National Labs- PVFORM, 1986					
3- Assuming 4% loss for 15-degree tilt. Sandia National Labs, PVFORM, 1986					
4- Peak Insolation derived from ASHRAE, "Procedure for Determining Heating and Cooling Loads for Computerizing Energy Calculations," 1976. Peak insolation includes clearness factor to account for local atmospheric conditions (e.g. smog). (Clear day = 93 W/ft2; Adjusted for local conditions = 80 W/ft2) Insolation times PV system efficiency.					
5- 1993 rates: GRI. Projections calculated using growth factors based on Energy Information Administration, "Annual					

Outlook for Electric Power," 1991.						
6- Externality values are based on regional utility generation mix data (lbs/kWh) from EIA, Supplement to Annual Energy Outlook, 1993, and values assigned by PSCs (\$/lb). For regions that have not assigned externality values, the lowest value from other regions has been used.						
7- Assumes that a percentage (20-70%) of PV output is recovered through demand charge savings. This percent varies by region, and is based on %ELCC values developed by Perez at SUNYA, 1994.						
8- Assumed average national T&D Credit is \$50/kW/Yr. From Decision Focus, "Potential Benefits of Battery Storage to SDG&E," prepared for Sandia National Laboratory and SDG&E, Jan 1992, "Potential Benefits of Battery Storage to Chugach Electric," Apr 1992, and EPRI Journal, April/May 1992. Interview with Zaininger Engineering, Aug 1994.						
9- Existing inventory and new construction estimates are based on "Commercial Building Characteristics 1989," DOE/IEA-0246(89) and FW Dodge, "Construction Potentials" 1990-1992.						
10- Assumes 30% of roof area is available for existing buildings; 45% for new construction.						

Payback Analysis for Photovoltaic System (Volume Discount / Utility Incentive Case)					
Commercial Building Application					
USER OPTIONS					
Module Orientation (0=latitude tilt, 1= 15 degree tilt):	1				
Distribution Steps (0, 1, or, 2):	1				
Desired PV System Output (kW):	30				
Requires PV Square Footage of:	3606	3348	2595	2322	2206
Externality Credit: (0=no, 1=yes)	1				
Demand Charge Credit: (0=no, 1=yes)	1				
Capacity Credit (0=no, 1=yes)	1				
T&D Credit: (0=no, 1=yes)	1				
COSTS (Retrofit)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.70	\$2.60	\$2.10	\$1.65	\$1.40
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$8.17	\$7.88	\$5.87	\$4.43	\$3.91
PV Installed Cost (\$/ft2)	\$79	\$82	\$79	\$66	\$62
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$8	\$8	\$8	\$7	\$6
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$2	\$2
Net Selling Price (\$/ft2)	\$70	\$73	\$70	\$58	\$54
COSTS (New Construction)					
	1994	1995	2000	2005	2010
PV Ex-Plant Module Price (\$/Wpac)	\$4.40	\$4.25	\$3.00	\$2.20	\$2.00
PV BOS Costs (\$/Wpac)	\$2.70	\$2.60	\$2.10	\$1.65	\$1.40
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$8.17	\$7.88	\$5.87	\$4.43	\$3.91
PV Installed Cost (\$/ft2)	\$79	\$82	\$79	\$66	\$62
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$8	\$8	\$8	\$7	\$6
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$2	\$2
Net Selling Price (\$/ft2)	\$70	\$73	\$70	\$58	\$54
PV PERFORMANCE					
Module Efficiency(%)	13.00%	14.00%	17.00%	19.00%	20.00%
System Efficiency(%)	10.40%	11.20%	14.45%	16.15%	17.00%
Average Annual Insolation (kWh/ft2) 2					
New England (Boston)	136	136	136	136	136
Middle Atlantic (New York)	137	137	137	137	137
East North Central (Detroit)	138	138	138	138	138
West North Central (Omaha)	172	172	172	172	172
South Atlantic (Miami)	196	196	196	196	196
East South Central (Birmingham)	161	161	161	161	161
West South Central (Dallas)	180	180	180	180	180
Pacific Northwest (Great Falls)	168	168	168	168	168
Pacific Southwest (Albuquerque)	235	235	235	235	235

Annual Solar Output (kWh/ft2) 3					
New England (Boston)	13.6	14.6	18.9	21.1	22.2
Middle Atlantic (New York)	13.7	14.7	19.0	21.2	22.4
East North Central (Detroit)	13.8	14.8	19.1	21.4	22.5
West North Central (Omaha)	17.2	18.5	23.9	26.7	28.1
South Atlantic (Miami)	19.6	21.1	27.2	30.4	32.0
East South Central (Birmingham)	16.1	17.3	22.3	25.0	26.3
West South Central (Dallas)	18.0	19.4	25.0	27.9	29.4
Pacific Northwest (Great Falls)	16.8	18.1	23.3	26.0	27.4
Pacific Southwest (Albuquerque)	23.5	25.3	32.6	36.4	38.4
Solar Output From PV System (kW/ft2) 4	0.008	0.009	0.012	0.013	0.014
Electricity Prices (\$/kWh) 5					
New England (Boston)	0.066	0.068	0.074	0.070	0.067
Middle Atlantic (New York)	0.060	0.059	0.058	0.058	0.059
East North Central (Chicago)	0.039	0.039	0.038	0.039	0.040
West North Central (Minneapolis)	0.034	0.033	0.032	0.031	0.031
South Atlantic (Miami)	0.050	0.049	0.047	0.047	0.047
East South Central (Birmingham)	0.061	0.060	0.058	0.057	0.057
West South Central (Dallas)	0.044	0.045	0.046	0.046	0.047
Pacific Northwest (Olympia)	0.049	0.051	0.054	0.055	0.057
Pacific Southwest (Los Angeles)	0.094	0.093	0.091	0.089	0.087
Annual Demand Charges (\$/kW/mo) 5					
New England (Boston)	14.30	14.30	14.30	14.30	14.30
Middle Atlantic (New York)	20.31	20.31	20.31	20.31	20.31
East North Central (Chicago)	12.20	12.20	12.20	12.20	12.20
West North Central (Minneapolis)	7.33	7.33	7.33	7.33	7.33
South Atlantic (Miami)	6.94	6.94	6.94	6.94	6.94
East South Central (Birmingham)	4.88	4.88	4.88	4.88	4.88
West South Central (Dallas)	7.36	7.36	7.36	7.36	7.36
Pacific Northwest (Olympia)	6.12	6.12	6.12	6.12	6.12
Pacific Southwest (Los Angeles)	6.35	6.35	6.35	6.35	6.35
O&M Cost (\$/kWh)	0.008	0.008	0.008	0.007	0.006
Annual Electricity Cost Savings (\$/ft2)					
(Including O&M Costs)					
New England	\$0.79	\$0.88	\$1.24	\$1.34	\$1.36
Middle Atlantic	\$0.71	\$0.75	\$0.95	\$1.09	\$1.18
East North Central	\$0.42	\$0.45	\$0.58	\$0.69	\$0.77
West North Central	\$0.44	\$0.46	\$0.57	\$0.65	\$0.71
South Atlantic	\$0.82	\$0.87	\$1.07	\$1.22	\$1.30
East South Central	\$0.85	\$0.90	\$1.11	\$1.25	\$1.33
West South Central	\$0.65	\$0.71	\$0.95	\$1.10	\$1.20
Pacific Northwest	\$0.69	\$0.77	\$1.08	\$1.26	\$1.38
Pacific Southwest	\$2.02	\$2.15	\$2.71	\$2.99	\$3.10

Environmental Externality Savings (\$/ft2) 6					
New England	\$0.41	\$0.44	\$0.43	\$0.48	\$0.51
Middle Atlantic	\$0.41	\$0.44	\$0.44	\$0.49	\$0.51
East North Central	\$0.40	\$0.43	\$0.40	\$0.45	\$0.47
West North Central	\$0.50	\$0.54	\$0.50	\$0.56	\$0.59
South Atlantic	\$0.31	\$0.34	\$0.33	\$0.36	\$0.38
East South Central	\$0.26	\$0.28	\$0.27	\$0.30	\$0.32
West South Central	\$0.29	\$0.31	\$0.30	\$0.33	\$0.35
Pacific Northwest	\$0.44	\$0.47	\$0.61	\$0.68	\$0.71
Pacific Southwest	\$0.61	\$0.66	\$0.85	\$0.95	\$1.00
Annual Demand Charge Savings (\$/ft2) 7					
New England	\$0.71	\$0.77	\$0.99	\$1.11	\$1.17
Middle Atlantic	\$1.22	\$1.31	\$1.69	\$1.89	\$1.99
East North Central	\$0.73	\$0.79	\$1.02	\$1.13	\$1.19
West North Central	\$0.44	\$0.47	\$0.61	\$0.68	\$0.72
South Atlantic	\$0.31	\$0.34	\$0.43	\$0.48	\$0.51
East South Central	\$0.27	\$0.29	\$0.37	\$0.42	\$0.44
West South Central	\$0.48	\$0.51	\$0.66	\$0.74	\$0.78
Pacific Northwest	\$0.12	\$0.13	\$0.17	\$0.19	\$0.20
Pacific Southwest	\$0.44	\$0.48	\$0.62	\$0.69	\$0.73
Annual Avoided T&D Costs (\$/ft2) 8					
New England	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Middle Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
South Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Northwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Southwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Payback for Retrofit (yrs)					
New England	30	29	21	16	15
Middle Atlantic	25	25	19	14	12
East North Central	36	34	27	20	17
West North Central	39	38	31	23	20
South Atlantic	38	37	29	22	19
East South Central	39	38	30	22	20
West South Central	38	37	28	21	18
Pacific Northwest	42	40	29	21	18
Pacific Southwest	20	19	15	11	10
Payback for New Construction (yrs)					
New England	30	29	21	16	15
Middle Atlantic	25	25	19	14	12
East North Central	36	34	27	20	17
West North Central	39	38	31	23	20
South Atlantic	38	37	29	22	19

East South Central	39	38	30	22	20
West South Central	38	37	28	21	18
Pacific Northwest	42	40	29	21	18
Pacific Southwest	20	19	15	11	10
Existing Roof Area (million sq.ft) 9					
New England		1,224	1,308	1,393	1,471
Middle Atlantic		4,110	4,308	4,505	4,692
East North Central		4,376	4,726	5,077	5,410
West North Central		2,104	2,233	2,361	2,485
South Atlantic		4,264	4,663	5,078	5,472
East South Central		1,703	1,822	1,940	2,054
West South Central		3,250	3,499	3,760	3,992
Pacific Northwest		889	975	1,058	1,140
Pacific Southwest		3,590	3,982	4,389	4,776
Roof Area w/ PV Access (million sq.ft) 10					
New England	0	367	392	418	441
Middle Atlantic	0	1,233	1,292	1,352	1,408
East North Central	0	1,313	1,418	1,523	1,623
West North Central	0	631	670	708	746
South Atlantic	0	1,279	1,399	1,523	1,642
East South Central	0	511	547	582	616
West South Central	0	975	1,050	1,128	1,198
Pacific Northwest	0	267	293	317	342
Pacific Southwest	0	1,077	1,195	1,317	1,426
Existing Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	7	21
New Construction Roof Area (million sq.ft) 9					
New England		16	17	16	16
Middle Atlantic		38	40	37	37
East North Central		69	71	67	67
West North Central		25	26	25	25
South Atlantic		76	83	79	79
East South Central		23	24	23	23
West South Central		47	53	46	46
Pacific Northwest		17	17	16	16
Pacific Southwest		77	81	77	77

New w/ PV Access (million sq.ft) 10					
New England	0	7	8	7	7
Middle Atlantic	0	17	18	17	17
East North Central	0	31	32	30	30
West North Central	0	11	12	11	11
South Atlantic	0	34	37	35	35
East South Central	0	11	11	10	10
West South Central	0	21	24	21	21
Pacific Northwest	0	8	8	7	7
Pacific Southwest	0	34	36	35	35
New Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	0	1
Total PV Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	7	22
Total PV Penetration by Region (MW/YR)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	87	298
TOTAL (MW/YR)	0	0	0	87	298
1- Assumes an average capacity credit for commercial buildings of \$200/kW, based on existing rebates given for other DSM options. Energy User News, April 1993, interviews with utilities, and Delmarva Power, "Identification of the Potential of PV in the Utility DSM Market: A Study of 21 US Utilities," Dec 1992. Modified per Perez, 1994.					
2- For a south facing latitude tilt, Sandia National Labs- PVFORM, 1986. Daily insolation levels converted to kWh/ft2 from kWh/m2 using 0.093 conversion factor.					

3- Assuming 4% loss for 15-degree tilt. Sandia National Labs, PVFORM, 1986					
4- Peak insolation derived from ASHRAE, "Procedure for Determining Heating and Cooling Loads for Computerizing Energy Calculations," 1976. Peak insolation includes clearness factor to account for local atmospheric conditions (e.g. smog). (Clear day = 93 W/ft ² ; Adjusted for local conditions = 80 W/ft ²) Insolation times PV system efficiency.					
5- 1993 rates: GRI. Projections calculated using growth factors based on Energy Information Administration, "Annual Outlook for Electric Power," 1991.					
6- Externality values are based on regional utility generation mix data (lbs/kWh) from EIA, Supplement to Annual Energy Outlook, 1993, and values assigned by PSCs (\$/lb). For regions that have not assigned externality values, the lowest value from other regions has been used.					
7- Assumes that a percentage (20-70%) of PV output is recovered through demand charge savings. This percent varies by region, and is based on %ELCC values developed by Perez at SUNYA, 1994.					
8- Assumed average national T&D Credit is \$50/kW/Yr. From Decision Focus, "Potential Benefits of Battery Storage to SDG&E," prepared for Sandia National Laboratory and SDG&E, Jan 1992, "Potential Benefits of Battery Storage to Chugach Electric," Apr 1992, and EPRI Journal, April/May 1992. Interview with Zaininger Engineering, Aug 1994.					
9- Existing inventory and new construction estimates are based on "Commercial Building Characteristics 1989," DOE/IEA-0246(89) and FW Dodge, "Construction Potentials" 1990-1992.					
10- Assumes 30% of roof area is available for existing buildings; 45% for new construction.					

Payback Analysis for Photovoltaic System (Volume Discount / Utility Incentive Case)					
Curtainwell Application					
USER OPTIONS					
Module Orientation: Vertical Tilt					
Distribution Steps (0, 1, or 2):	1				
Desired PV System Output (kW):	30				
Requires PV Square Footage of:	3606	3348	2595	2322	2206
Externality Credit: (0=no, 1=yes)	1				
Demand Charge Credit: (0=no, 1=yes)	1				
Capacity Credit (0=no, 1=yes)	1				
T&D Credit: (0=no, 1=yes)	1				
COSTS (Retrofit)					
	1994	1995	2000	2005	2010
PV Ex-Plant System Price (\$/Wpac)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
PV Installed Cost (\$/ft2)	\$0	\$0	\$0	\$0	\$0
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$0	\$0	\$0	\$0	\$0
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$2	\$2
Net Selling Price (\$/ft2)	(\$1)	(\$1)	(\$1)	(\$2)	(\$2)
COSTS (New Construction)					
	1994	1995	2000	2005	2010
PV Ex-Plant System Price (\$/Wpac)	\$5.25	\$5.10	\$3.40	\$2.20	\$1.75
Distributor Mark-up	15%	15%	15%	15%	15%
PV Installed Cost (\$/Wpac)	\$6.04	\$5.87	\$3.91	\$2.53	\$2.01
PV Installed Cost (\$/ft2)	\$58	\$61	\$53	\$38	\$32
Utility Rebate	\$0	\$0	\$0	\$0	\$0
Federal Tax Credit (10%)	\$6	\$6	\$5	\$4	\$3
Capacity Credit (\$/ft2) 1	\$1	\$1	\$1	\$2	\$2
Net Selling Price (\$/ft2)	\$53	\$55	\$47	\$34	\$29
PV PERFORMANCE					
Module Efficiency(%)	13.00%	14.00%	17.00%	19.00%	20.00%
System Efficiency(%)	10.40%	11.20%	14.45%	16.15%	17.00%
Average Annual Insolation (kWh/ft2) 2					
New England (Boston)	136	136	136	136	136
Middle Atlantic (New York)	137	137	137	137	137
East North Central (Detroit)	138	138	138	138	138
West North Central (Omaha)	172	172	172	172	172
South Atlantic (Miami)	196	196	196	196	196
East South Central (Birmingham)	161	161	161	161	161
West South Central (Dallas)	180	180	180	180	180
Pacific Northwest (Great Falls)	168	168	168	168	168
Pacific Southwest (Albuquerque)	235	235	235	235	235

Annual Solar Output (kWh/ft2) 3					
New England (Boston)	8.1	8.7	11.2	12.5	13.2
Middle Atlantic (New York)	8.1	8.7	11.3	12.6	13.3
East North Central (Detroit)	8.2	8.8	11.4	12.7	13.4
West North Central (Omaha)	10.2	11.0	14.2	15.8	16.7
South Atlantic (Miami)	11.6	12.5	16.1	18.0	19.0
East South Central (Birmingham)	9.5	10.3	13.3	14.8	15.6
West South Central (Dallas)	10.7	11.5	14.8	16.6	17.4
Pacific Northwest (Great Falls)	10.0	10.7	13.8	15.5	16.3
Pacific Southwest (Albuquerque)	13.9	15.0	19.4	21.6	22.8
Solar Output (kW/ft2) 4	0.008	0.009	0.012	0.013	0.014
Electricity Prices (\$/kWh) 5					
New England (Boston)	0.066	0.068	0.074	0.070	0.067
Middle Atlantic (New York)	0.060	0.059	0.058	0.058	0.059
East North Central (Chicago)	0.039	0.039	0.038	0.039	0.040
West North Central (Minneapolis)	0.034	0.033	0.032	0.031	0.031
South Atlantic (Miami)	0.050	0.049	0.047	0.047	0.047
East South Central (Birmingham)	0.061	0.060	0.058	0.057	0.057
West South Central (Dallas)	0.044	0.045	0.046	0.046	0.047
Pacific Northwest (Olympia)	0.049	0.051	0.054	0.055	0.057
Pacific Southwest (Los Angeles)	0.094	0.093	0.091	0.089	0.087
Annual Demand Charges (\$/kW/mo) 5					
New England (Boston)	14.30	14.30	14.30	14.30	14.30
Middle Atlantic (New York)	20.31	20.31	20.31	20.31	20.31
East North Central (Chicago)	12.20	12.20	12.20	12.20	12.20
West North Central (Minneapolis)	7.33	7.33	7.33	7.33	7.33
South Atlantic (Miami)	6.94	6.94	6.94	6.94	6.94
East South Central (Birmingham)	4.88	4.88	4.88	4.88	4.88
West South Central (Dallas)	7.36	7.36	7.36	7.36	7.36
Pacific Northwest (Olympia)	6.12	6.12	6.12	6.12	6.12
Pacific Southwest (Los Angeles)	6.35	6.35	6.35	6.35	6.35
O&M Cost (\$/kWh)	0.008	0.008	0.008	0.007	0.006
Annual Electricity Cost Savings (\$/ft2)					
(Including O&M Costs)					
New England	\$0.47	\$0.52	\$0.74	\$0.79	\$0.81
Middle Atlantic	\$0.42	\$0.45	\$0.56	\$0.65	\$0.70
East North Central	\$0.25	\$0.27	\$0.35	\$0.41	\$0.46
West North Central	\$0.26	\$0.28	\$0.34	\$0.39	\$0.42
South Atlantic	\$0.49	\$0.52	\$0.64	\$0.72	\$0.77
East South Central	\$0.50	\$0.53	\$0.66	\$0.74	\$0.79
West South Central	\$0.39	\$0.42	\$0.56	\$0.65	\$0.71
Pacific Northwest	\$0.41	\$0.46	\$0.64	\$0.75	\$0.82
Pacific Southwest	\$1.20	\$1.28	\$1.61	\$1.77	\$1.84

Environmental Externality Savings (\$/ft2) 6					
New England	\$0.24	\$0.26	\$0.26	\$0.29	\$0.30
Middle Atlantic	\$0.24	\$0.26	\$0.26	\$0.29	\$0.31
East North Central	\$0.24	\$0.26	\$0.24	\$0.27	\$0.28
West North Central	\$0.30	\$0.32	\$0.30	\$0.33	\$0.35
South Atlantic	\$0.19	\$0.20	\$0.19	\$0.22	\$0.23
East South Central	\$0.15	\$0.16	\$0.16	\$0.18	\$0.19
West South Central	\$0.17	\$0.18	\$0.18	\$0.20	\$0.21
Pacific Northwest	\$0.26	\$0.28	\$0.36	\$0.40	\$0.42
Pacific Southwest	\$0.36	\$0.39	\$0.50	\$0.56	\$0.59
Annual Demand Charge Savings (\$/ft2) 7					
New England	\$0.71	\$0.77	\$0.99	\$1.11	\$1.17
Middle Atlantic	\$1.22	\$1.31	\$1.69	\$1.89	\$1.99
East North Central	\$0.73	\$0.79	\$1.02	\$1.13	\$1.19
West North Central	\$0.44	\$0.47	\$0.61	\$0.68	\$0.72
South Atlantic	\$0.31	\$0.34	\$0.43	\$0.48	\$0.51
East South Central	\$0.27	\$0.29	\$0.37	\$0.42	\$0.44
West South Central	\$0.48	\$0.51	\$0.66	\$0.74	\$0.78
Pacific Northwest	\$0.12	\$0.13	\$0.17	\$0.19	\$0.20
Pacific Southwest	\$0.44	\$0.48	\$0.62	\$0.69	\$0.73
Annual Avoided T&D Costs (\$/ft2) 8					
New England	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Middle Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West North Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
South Atlantic	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
East South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
West South Central	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Northwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Pacific Southwest	\$0.42	\$0.45	\$0.58	\$0.65	\$0.68
Payback for Retrofit (yrs)					
New England	-1	-1	-1	-1	-1
Middle Atlantic	0	0	0	0	0
East North Central	-1	-1	-1	-1	-1
West North Central	-1	-1	-1	-1	-1
South Atlantic	-1	-1	-1	-1	-1
East South Central	-1	-1	-1	-1	-1
West South Central	-1	-1	-1	-1	-1
Pacific Northwest	-1	-1	-1	-1	-1
Pacific Southwest	0	0	0	0	0
Payback for New Construction (yrs)					
New England	29	27	18	12	10
Middle Atlantic	23	22	15	10	8
East North Central	32	31	22	14	11
West North Central	37	36	26	17	13
South Atlantic	38	37	26	17	13

East South Central	39	38	27	17	14
West South Central	36	35	24	15	12
Pacific Northwest	43	42	27	17	13
Pacific Southwest	22	21	14	9	7
Existing Wall Area (million sq.ft) 9					
New England					
Middle Atlantic					
East North Central					
West North Central					
South Atlantic					
East South Central					
West South Central					
Pacific Northwest					
Pacific Southwest					
Wall Area w/ PV Access (million sq.ft) 10					
New England		0	0	0	0
Middle Atlantic		0	0	0	0
East North Central		0	0	0	0
West North Central		0	0	0	0
South Atlantic		0	0	0	0
East South Central		0	0	0	0
West South Central		0	0	0	0
Pacific Northwest		0	0	0	0
Pacific Southwest		0	0	0	0
Existing Penetration (million sq.ft)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	0	0
East North Central	0	0	0	0	0
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	0	0
New Construction Wall Area (million sq.ft) 9					
New England		21	24	21	21
Middle Atlantic		50	56	52	52
East North Central		93	100	93	93
West North Central		36	38	36	36
South Atlantic		107	122	113	113
East South Central		34	36	33	33
West South Central		65	75	65	65
Pacific Northwest		23	24	23	23
Pacific Southwest		104	117	109	109

New w/ PV Access (million sq.ft) 10					
New England		2	2	2	2
Middle Atlantic		5	5	5	5
East North Central		8	9	8	8
West North Central		3	3	3	3
South Atlantic		10	11	10	10
East South Central		3	3	3	3
West South Central		6	7	6	6
Pacific Northwest		2	2	2	2
Pacific Southwest		9	11	10	10
New Penetration (million sq.ft)					
New England	0.00	0.00	0.00	0.00	0.03
Middle Atlantic	0.00	0.00	0.00	0.07	0.12
East North Central	0.00	0.00	0.00	0.00	0.04
West North Central	0.00	0.00	0.00	0.00	0.00
South Atlantic	0.00	0.00	0.00	0.00	0.00
East South Central	0.00	0.00	0.00	0.00	0.00
West South Central	0.00	0.00	0.00	0.00	0.00
Pacific Northwest	0.00	0.00	0.00	0.00	0.00
Pacific Southwest	0.00	0.00	0.00	0.15	0.25
Total PV Penetration (million sq.ft)					
New England	0.00	0.00	0.00	0.00	0.03
Middle Atlantic	0.00	0.00	0.00	0.07	0.12
East North Central	0.00	0.00	0.00	0.00	0.04
West North Central	0.00	0.00	0.00	0.00	0.00
South Atlantic	0.00	0.00	0.00	0.00	0.00
East South Central	0.00	0.00	0.00	0.00	0.00
West South Central	0.00	0.00	0.00	0.00	0.00
Pacific Northwest	0.00	0.00	0.00	0.00	0.00
Pacific Southwest	0.00	0.00	0.00	0.15	0.25
Total PV Penetration by Region (MW)					
New England	0	0	0	0	0
Middle Atlantic	0	0	0	1	2
East North Central	0	0	0	0	1
West North Central	0	0	0	0	0
South Atlantic	0	0	0	0	0
East South Central	0	0	0	0	0
West South Central	0	0	0	0	0
Pacific Northwest	0	0	0	0	0
Pacific Southwest	0	0	0	2	3
TOTAL (MW/YR)					
	0	0	0	3	6
1- Assumes an average capacity credit for commercial buildings of \$200/kW, based on existing rebates given for other DSM options. Energy User News, April 1993, Interviews with utilities, and Delmarva Power, "Identification of the Potential of PV in the Utility DSM Market: A Study of 21 US Utilities," Dec 1992.					
2- For a south facing latitude tilt. Sandia National Labs- PVFORM, 1986					
3- Assuming 34% loss for vertical/true south. Sandia National Labs, PVFORM, 1986					