Tracking the Sun III

The Installed Cost of Photovoltaics in the U.S. from 1998-2009

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Executive Summary

As the deployment of grid-connected solar photovoltaic (PV) systems has increased, so too has the desire to track the installed cost of these systems over time and by location, customer type, system characteristics, and component. This report helps to fill this need by summarizing trends in the installed cost[1] of grid-connected PV systems in the United States from 1998 through 2009 (updating two previous reports with data through 2007 and 2008, respectively), and providing preliminary cost trends for systems installed in 2010.[2] The analysis is based on installed cost data for approximately 78,000 residential and non-residential PV systems, totaling 874 megawatts (MW) and representing 70% of all grid-connected PV capacity installed in the United States through 2009.

Key findings of the analysis are as follows:[3]

- The capacity-weighted average installed cost of systems completed in 2009 – in terms of real 2009 dollars per installed watt (DC-STC)[4] and prior to receipt of any direct financial incentives or tax credits – was $7.5/Watt, virtually unchanged from 2008, and $0.3/W below the averages in 2006 and 2007. From 1998-2009, capacity-weighted average installed costs declined by about 3.2% (or $0.3/W) per year, on average, starting from $10.8/W in 1998.
- Preliminary cost data suggest that a significant decline in average installed costs occurred in 2010, with the average cost of systems installed through the California Solar Initiative (CSI) program declining by $1.0/W during the first ten months of 2010 relative to 2009, and the average cost of systems installed in New Jersey declining by $1.2 /W during the first six months of 2010 compared to 2009.
- Installed costs lagged wholesale PV module price movements from 2007-2009. Over this period, wholesale PV module prices declined by $1.3/W (based on Navigant Consulting's Global Power Module Price Index), while total installed costs declined by only $0.2/W. The preliminary 2010 cost data cited above, however, suggests that the drop in wholesale module prices during the preceding years translated into a large reduction in installed costs in 2010.
- Both module and non-module costs have declined significantly over time. From 1998-2009, wholesale module prices dropped by $1.9/W (40%), while from 1998-2007, implied non-module costs (which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and installer profit) fell by $2.5/W (40%).[5]

[1] It should be noted that, in focusing specifically on *installed cost*, this report does not address performance improvements or other factors that may influence the *levelized cost of electricity* from PV.

[2] The primary data sample is based on systems funded through state and utility PV incentive programs, and therefore does not include either utility-owned or utility-scale PV systems; however, cost data from a select sample of multi-megawatt systems is separately summarized within the report. Also note that, while the report is intended to portray national trends, the overall sample is heavily skewed towards systems in California and New Jersey, where the vast majority of PV systems in the United States have been installed.

[3] Unless otherwise noted, the results reflect all system types represented within the sample (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, thin-film, etc.).

[4] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs is the nameplate capacity of the PV modules, which is reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout the present report

[5] Implied non-module costs are calculated as the difference between total installed cost and Navigant's wholesale module price index. This approach cannot distinguish between actual non-module costs as paid by PV system owners and a lag between wholesale module prices and retail module costs. To characterize the long-term historical reduction in module costs, we therefore focus on the period up to 2007, as wholesale module prices were relatively flat during the

- The year-on-year trend in average installed cost varied among system size ranges. From 2008 to 2009, the average cost of systems in the 5-10 kW and 10-100 kW size ranges declined by \$0.4/W and \$0.3/W, respectively, but remained flat for systems <5 kW and 100-500 kW in size, and rose by \$0.3/W for systems >500 kW.
- The distribution of installed costs within a given system size range narrowed significantly from 1998 to 2005, with high-cost outliers becoming increasingly infrequent, indicating a maturing market. However, little if any further narrowing of the cost distribution occurred from 2005 through 2009.
- PV installed costs exhibit significant economies of scale, with systems ≤2 kW completed in 2009 averaging \$9.9/W, while >1,000 kW systems averaged \$7.0/W (or about 29% less). Two multi-MW, utility-scale PV systems installed in 2009 that are not included in the primary data sample, but for which cost data were obtained through public sources, had significantly lower installed costs (\$2.5/W and \$5.1/W) than the >1,000 kW systems in the primary data sample.
- Component-level cost data for systems installed in 2009 indicate that module and inverter costs were relatively invariant across system sizes, while the remaining set of other costs were \$0.5-0.6/W lower for 10-100 kW systems than for either smaller or larger systems. This contrasts with trends from the preceding two years, when average module costs were lower for larger systems.
- International experience suggests that greater near-term cost reductions may be possible with increased market scale in the United States, as the average installed cost of 3-5 kW residential PV installations in 2009 (excluding sales/value-added tax) was significantly lower in both Germany (\$4.7/W) and Japan (\$5.9/W) than in the United States (\$7.7/W).
- Average installed costs vary widely across states; among ≤10 kW systems completed in 2009, average costs range from a low of \$7.1/W in Texas to a high of \$9.6/W in Minnesota. This variation in average installed cost across states suggests that, in addition to absolute market size, other state and local factors (e.g., permitting requirements, labor rates, and sales tax exemptions) strongly influence installed costs.
- The average installed cost of residential systems installed in 2009 was lower than that of other *similarly sized* systems. Compared to commercial systems, for example, residential systems had average installed costs that were lower by approximately \$0.5/W within both the 5-10 kW and 10-100 kW size ranges. In contrast, public sector systems installed in 2009 had relatively high average installed costs, exceeding the average installed cost of commercial systems by \$0.7/W for systems in the 10-100 kW size range and by \$0.8/W for systems in the 100-500 kW size range.
- The new construction market offers significant cost advantages for residential PV; among 1-3 kW residential systems funded through two California programs (the New Solar Home Partnership Program and the California Solar Initiative) and installed in 2009, PV systems installed in residential new construction cost \$1.6/W less than comparably-sized residential retrofit systems (or \$1.9/W less if focused exclusively on rack-mounted systems).
- PV systems with thin-film modules had higher average installed costs in 2009 than comparably-sized crystalline systems (\$0.8/W higher among ≤10 kW systems and \$0.4/W less among 10-100 kW systems).

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preceding two years, and thus the module price lag effect in 2007 is likely to be relatively small. Discerning trends in non-module costs after 2007 using this method will require waiting for some stabilization in wholesale module pricing.

- Average installed costs were lowest for systems with mid-range module efficiencies in 2009. Among systems ≤10 kW, for example, systems with module efficiencies of 15-16% had an average installed cost of $7.4/W, compared to $8.2/W for systems with module efficiencies ≤12% and $8.3/W for systems with module efficiencies >18%.
- Among ≤10 kW systems installed in 2009, those with tracking (either single- or double-axis) had average installed costs $1.7/W (or 21%) higher than fixed-axis systems (both roof-mounted and ground-mounted).[6] This cost differential may reflect both the additional cost of tracking equipment, as well as the increased cost associated with ground-mounting, which is more prevalent among tracking systems than fixed-axis systems.[7]
- The average cash incentive provided by the state/utility PV incentive programs in the sample ranged from $1.2-$2.2/W for systems installed in 2009, depending on system size. This represents up to a $0.3/W decline from 2008 and a $2.0-$3.3/W decline from the peak in 2002.
- In 2009, the average combined *after-tax* value of state/utility cash incentives *plus* state and federal investment tax credits (ITCs) – but excluding revenue from the sale of renewable energy certificates or the value of accelerated depreciation – was $3.9/W for both residential and commercial PV.[8] This represents roughly a 37% increase for residential PV relative to 2008, and is a consequence of the lifting of the dollar cap on the federal residential ITC for residential systems installed after January 1, 2009. In contrast, the combined after-tax incentive for commercial PV in 2009 remained effectively unchanged from the year prior and was slightly below its peak of $4.2/W in 2006.
- In 2009, the average *net installed cost* faced by PV system owners – that is, installed cost minus after-tax incentives – stood at $4.1/W for residential PV and $4.0/W for commercial PV. For residential PV, this represents an historic low, and is $1.3/W (or 24%) below the 2008 average, reversing the trend of the preceding several years during which average net installed costs had been slowly rising. For commercial PV, the average net installed costs in 2009 was virtually unchanged from the preceding two years, and was up slightly (by $0.4/W or 10%) from the all-time low of $3.6/W in 2006.
- Financial incentives and net installed costs diverged widely across states in 2009. Among residential PV systems completed in 2009, the combined after-tax incentive ranged from an average of $3.5/W in California to $5.9/W in New York, and net installed costs ranged from an average of $2.4/W in Texas to $5.5/W in Minnesota. Incentives and net installed costs for commercial systems varied similarly across states.

[6] Among 10-100 kW systems installed in 2009, tracking systems had average installed costs $3.5/W higher than fixed-axis systems; however, this comparison is based on only seven tracking systems.

[7] The data provided by PV program administrators do not identify whether systems are ground-mounted or roof-mounted. A more meaningful comparison, if the data were available, would be among tracking-systems, ground-mounted fixed-axis systems, and roof-mounted fixed-axis systems.

[8] Throughout this report, the terms “residential PV” and “commercial PV” refer, respectively, to PV systems sited at residential and commercial customer facilities.

1. Introduction

Installations of solar photovoltaic (PV) systems have been growing at a rapid pace in recent years. In 2009, approximately 7,500 megawatts (MW) of PV were installed globally, up from approximately 6,000 MW in 2008, consisting primarily of grid-connected applications.[9] With 435 MW of grid-connected PV capacity added in 2009, the United States was the world's fourth largest PV market in 2009, behind Germany, Italy, and Japan.[10] Despite the significant year-on-year growth, however, the share of global and U.S. electricity supply met with PV remains small, and annual PV additions are currently modest in the context of the overall electric system.

The market for PV in the United States is driven by national, state, and local government incentives, including up-front cash rebates, production-based incentives, requirements that electricity suppliers purchase a certain amount of solar energy, and federal and state tax benefits. These programs are, in part, motivated by the popular appeal of solar energy, and by the positive attributes of PV – modest environmental impacts, avoidance of fuel price risks, coincidence with peak electrical demand, and the possible deployment of PV at the point of use. Given the relatively high cost of PV, however, a key goal of these policies is to encourage cost reductions over time. Therefore, as policy incentives have become more significant and as PV deployment has accelerated, so too has the desire to track the installed cost of PV systems over time, by system characteristics, by system location, and by component.

To address this need, Lawrence Berkeley National Laboratory initiated a report series focused on describing trends in the installed cost of grid-connected PV systems in the United States. The present report, the third in the series, describes installed cost trends from 1998 through 2009, and provides preliminary cost data for systems installed in 2010.[11] Importantly, in focusing on *installed cost*, this report does not address other factors that may also influence the *levelized cost of electricity* from PV, such performance improvements and financing costs.

The analysis is based on project-level cost data from approximately 78,000 residential and non-residential PV systems in the U.S., all of which are installed at end-use customer facilities (herein referred to as "customer-sited" systems).[12] The combined capacity of systems in the data sample totals 874 MW, equal to 70% of all grid-connected PV capacity installed in the United States through 2009 and representing one of the most comprehensive sources of installed PV cost data for the U.S.[13] The report also briefly compares recent PV installed costs in the United States to those in Germany and Japan. Finally, it should be noted that the analysis presented here focuses on descriptive trends in the underlying data, serving primarily to summarize the data in tabular and

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[9] SolarBuzz. 2010. *MarketBuzz 2010*. http://www.solarbuzz.com/Marketbuzz2010-intro.htm.

[10] Sherwood, L. 2010. *U.S. Solar Market Trends 2009*. Interstate Renewable Energy Council. http://www.irecusa.org.

[11] To be clear, the report focuses on installed costs *as paid by the system owner*, rather than the costs born by manufacturers or installers. It is possible, especially over the past several years, that cost trends diverged between manufacturers and installers, or between installers and system owners.

[12] The dataset used in the present report consists of many of the same systems included in the National Renewable Energy Laboratory's OpenPV Mapping Project (http://openpv.nrel.gov). However, the results presented within this report may differ somewhat from the summary installed cost data provided through OpenPV, both because of differences in the underlying data sample, as well as potential differences in the data cleaning and processing protocols.

[13] In addition to the primary dataset, which is limited to data provided directly by PV incentive program administrators and only includes customer-sited systems, the report also summarizes installed cost data obtained through public data sources for 11 multi-MW grid-connected PV systems in the U.S. (several of which are installed on the utility-side of the meter). These additional large systems represent a combined 108 MW, bringing the total dataset to 982 MW, or 78% of all grid-connected PV capacity installed in the U.S. through 2009.

graphical form; later analysis may explore some of these trends with more-sophisticated statistical techniques.

The report begins with a summary of the data collection methodology and resultant dataset (Section 2). The primary findings of the analysis are presented in Section 3, which describes trends in installed costs prior to receipt of any financial incentives: over time and by system size, component, state, system ownership type (customer-owned vs. third party-owned), host customer segment (residential vs. commercial vs. public-sector vs. non-profit), application (new construction vs. retrofit), and technology type (building-integrated vs. rack-mounted, crystalline silicon vs. thin-film, and tracking vs. fixed-axis). Section 4 presents additional findings related to trends in PV incentive levels over time and among states (focusing specifically on state and utility incentive programs as well as state and federal tax credits), and trends in the net installed cost paid by system owners after receipt of such incentives. Brief conclusions are offered in the final section, and several appendices provide additional details on the analysis methodology and additional tabular summaries of the data.

2. Data Summary

This section briefly describes the procedures used to collect, standardize, and clean the data provided by individual PV incentive programs, and summarizes the basic characteristics of the resulting dataset, including: the number of systems and installed capacity by PV incentive program; the sample size relative to all grid-connected PV capacity installed in the United States; and the sample distribution by year, state, and project size.

Data Collection, Conventions, and Data Cleaning

Requests for project-level installed cost data were sent to state and utility PV incentive program administrators from around the country, with some focus (though not exclusively so) on relatively large programs. Ultimately, 27 PV incentive programs provided project-level installed cost data from 16 states. [14] To the extent possible, this report presents the data as provided directly by these PV incentive program administrators; however, several steps were taken to standardize and clean the data, as briefly summarized here and described in greater detail in Appendix A.

In particular, two key conventions used throughout this report deserve specific mention:

1. All cost and incentive data are presented in real 2009 dollars (2009$), which required inflation adjustments to the nominal-dollar data provided by PV programs.
2. All capacity and dollars-per-watt ($/W) data are presented in terms of rated module power output under Standard Test Conditions (DC-STC), which required that capacity data provided by several programs that use a different capacity rating be translated to DC-STC.[15]

The data were cleaned by eliminating projects with clearly erroneous cost or incentive data, by correcting text fields with obvious errors, and by standardizing identifiers for module and inverter models. To the extent possible, each PV system in the dataset was classified as either building-integrated PV or rack-mounted and as using either crystalline or thin-film modules, based on a combination of information sources. Finally, data on market sector (e.g., residential, commercial, government, non-profit) were not provided for roughly 40% of the systems in the final dataset; for the purpose of calculating the value of state and federal investment tax credits and net installed costs, systems ≤10 kW were assumed to be residential, and systems >10 kW were assumed to be commercial, if not identified otherwise.[16]

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[14] All data provided to LBNL was in the form of Excel spreadsheets. A number of PV incentive program within the sample use PowerClerk, a commercial database tool specifically designed for PV incentive program tracking. We acknowledge that the use PowerClerk and any other similar products has likely increased both the quantity and quality of data available for this analysis.

[15] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs is the total nameplate capacity of the PV modules in direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout this report. Alternatively, PV system sizes may be denominated in terms of DC watts under PVUSA test conditions (PTC), or in terms of alternating current (AC) watts under either STC or PTC.

[16] 10 kW is a common, albeit imperfect, cut-off between residential and commercial PV systems. Among the approximately 46,300 systems in the dataset for which market sector data were provided, 95% of systems (and 94% of capacity) ≤10 kW are residential, while 34% of systems (and 64% of capacity) >10 kW are commercial. If the same distribution applies to the entire dataset, a total of 10% of all systems in the sample (and 9% of the total capacity) would be misclassified by using 10 kW as the cut-off between residential and commercial systems.

Sample Description

The final dataset, after all data cleaning was completed, consists of approximately 78,000 grid-connected, residential and non-residential PV systems, totaling 870 MW (see Table 1).[17] This represents approximately 70% of all grid-connected PV capacity installed in the United States through 2009, and about 63% of 2009 capacity additions (see Figure 1). The largest state markets missing from the primary data sample, in terms of cumulative grid-connected PV capacity installed through 2009, are: Colorado (4.7% of total U.S. installed capacity), Hawaii (2.1%), and North Carolina (1.0%).

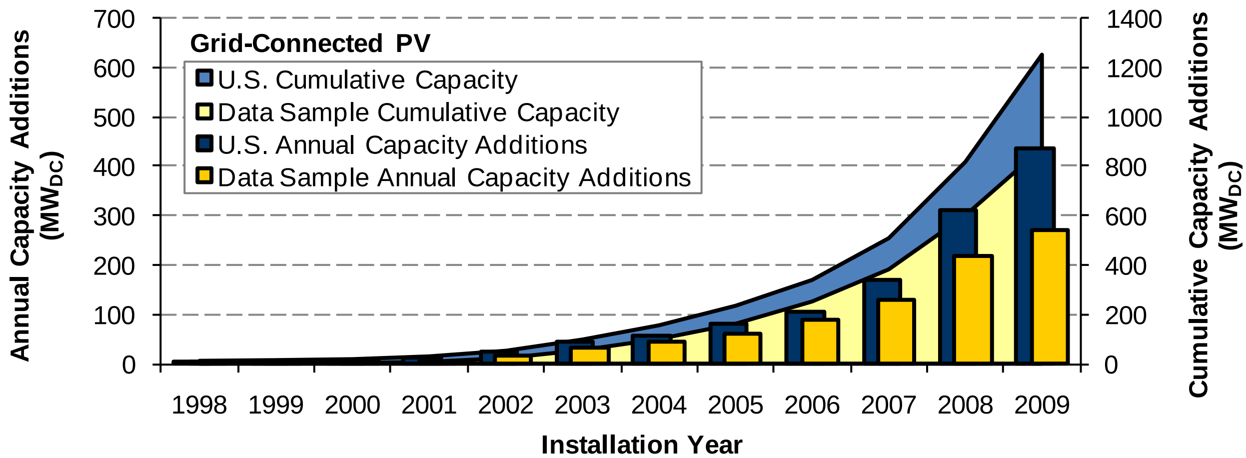
Table 1. Data Summary by PV Incentive Program

State	PV Incentive Program	No. of Systems	Total MW_{DC}	% of Total MW_{DC}	Size Range (kW_{DC})	Year Range
AZ	APS Solar & Renewables Incentive Program	2,291	15.0	1.7%	0.4 - 255	2002 - 2009
	SRP EarthWise Solar Energy Program	1,039	7.4	0.9%	0.7 - 502	2005 - 2009
CA	CEC Emerging Renewables Program (ERP)	27,947	146.4	16.8%	0.1 - 670	1998 - 2008
	CEC New Solar Homes Partnership (NSHP)	2,597	8.3	0.9%	1.2 - 154	2007 - 2009
	CPUC California Solar Initiative (CSI)	25,074	326.0	37.3%	1.1 - 1,308	2007 - 2009
	CPUC Self-Generation Incentive Program (SGIP)	806	148.6	17.0%	34 - 1,266	2002 - 2009
	LADWP Solar Incentive Program	2,199	22.9	2.6%	0.3 - 1,176	1999 - 2009
	SMUD Residential Retrofit and Commercial PV Programs	368	2.5	0.3%	1.2 - 172	2005 - 2009
CT	CCEF Onsite Renewable DG Program	117	13.6	1.6%	1.6 - 570	2003 - 2009
	CCEF Solar PV Program	829	4.9	0.6%	0.8 - 19	2005 - 2009
FL	FEO Solar Energy System Incentives Program	372	2.8	0.3%	1.1 - 123	2009 - 2009
MA	MassCEC Small Renewables Initiative*	577	4.6	0.5%	2.0 - 1,016	2006 - 2009
MD	MEA Solar Energy Grant Program	1,990	20.3	2.3%	0.2 - 502	2002 - 2009
MN	MSEO Solar Electric Rebate Program	546	2.2	0.2%	0.5 - 45	2005 - 2009
NH	NHPUC Renewable Energy Rebate Program	198	0.8	0.1%	0.5 - 40	2002 - 2009
NJ	NJCEP Customer Onsite Renewable Energy Program	189	0.5	0.1%	0.4 - 5.0	2008 - 2009
	NJCEP SREC Registration Program	3,859	74.5	8.5%	0.8 - 2,372	2004 - 2009
	NJCEP Renewable Energy Incentive Program	134	26.9	3.1%	0.7 - 1,650	2007 - 2009
NV	NPC/SPPC RenewableGenerations Rebate Program	641	5.6	0.6%	0.6 - 50	2009 - 2009
NY	NYSERDA PV Incentive Program	499	2.9	0.3%	0.4 - 99	2004 - 2009
OR	ETO Solar Electric Program	1,990	13.9	1.6%	0.7 - 79	2003 - 2009
PA	DEP Sunshine Solar PV Program (and other state agency programs**)	1,321	12.3	1.4%	0.4 - 859	2003 - 2009
	SDF Solar PV Grant Program	164	0.7	0.1%	1.2 - 12	2002 - 2008
TX	Austin Energy Power Saver Program	1,072	4.8	0.5%	0.2 - 28	2004 - 2009
	IOU Solar Incentive Programs (AEP, Entergy, Oncor, SWEPCO, TNMP)	154	1.2	0.1%	0.7 - 236	2009 - 2009
VT	RERC Small Scale Renewable Energy Incentive Program	365	1.3	0.2%	0.2 - 38	2004 - 2009
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	614	3.3	0.4%	0.5 - 47	2002 - 2009
	Total	***77,952***	***874.1***	***100%***	***0.1 - 2,372***	***1998 - 2009***

* Included within the totals shown for MassCEC's Small Renewables Initiative are systems funded through predecessor PV incentive programs offered by the Massachusetts Technology Collaborative.

** Pennsylvania state agencies have offered various grant and rebate programs for renewable energy systems; for simplicity, these programs are summarized in aggregate. Of these programs, the largest funding source for PV systems through 2009 has been the Department of Environmental Protection (DEP)'s Sunshine Program.

[17] There may be a modest level of double-counting of systems between programs, as some systems funded by LADWP and SMUD may have also received incentive funding through the CEC's Emerging Renewables Program. Some other large systems funded by LADWP and SMUD also received funding through the CPUC SGIP; however, those systems were removed from the SGIP dataset, in order to eliminate double-counting.



Data source for cumulative and annual U.S. grid-connected PV capacity additions: Sherwood, L. 2010. U.S. Solar Market Trends 2009. Interstate Renewable Energy Council.

Figure 1. Data Sample Compared to Total U.S. Grid-Connected PV Capacity

Table 2. Data Sample by Installation Year

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
No. of Systems	39	180	217	1,308	2,478	3,474	5,589	5,587	8,684	12,635	14,108	23,653	***77,952***
% of Total	*<0.5%*	*<0.5%*	*<0.5%*	*2%*	*3%*	*4%*	*7%*	*7%*	*11%*	*16%*	*18%*	*30%*	***100%***
Capacity (MW_{DC})	0.2	0.8	0.9	5.4	15	33	45	62	90	130	219	272	***874***
% of Total	*<0.5%*	*<0.5%*	*<0.5%*	*1%*	*2%*	*4%*	*5%*	*7%*	*10%*	*15%*	*25%*	*31%*	***100%***

The primary sample consists only of data provided by PV incentive program administrators, which consist entirely of customer-sited systems. The report separately describes the installed cost of 11 multi-MW grid-connected PV systems not included in the primary dataset, including the three largest PV systems installed in the United States through 2009.[18] Cost data for these projects were compiled from press releases and other publicly available sources. The data for these 11 projects bring the total PV capacity for which cost data are presented to 982 MW, equal to 78% of all grid-connected PV capacity installed in the United States through 2009.

The PV systems in the primary dataset were installed over a twelve-year period, from 1998 through 2009. Given the dramatic expansion of the U.S. solar market in recent years, however, the sample is skewed towards projects completed during the latter years of the study period, with approximately half of the PV systems and more than half of the total capacity in the sample installed in 2008 and 2009 (see Table 2). See Appendix B for annual installation data (number of systems and capacity) disaggregated by PV incentive program and by system size range.

Among the 27 PV incentive programs from which data was provided, the great majority of the sample is associated with the four largest PV incentive programs in the country to-date: California's Emerging Renewables Program (ERP); California's Self-Generation Incentive Program (SGIP); the California Solar Initiative (CSI) Program; and New Jersey's Customer Onsite Renewable Energy (CORE) Program. As such, the sample is heavily weighted towards systems installed in California and New Jersey, as shown in Figure 2. In terms of installed capacity, these two states represent

[18] These three PV systems are the 30 MW_{DC} DeSoto Next Generation Solar Energy Center installed in 2009 in Arcadia, FL; the 25.2 MW_{DC} system installed in 2009 in Blythe, CA; and the 14.2 MW_{DC} system installed in 2007 at Nellis Air Force base in Nevada.

75% and 12% of the total data sample, respectively. Arizona, Massachusetts, Connecticut, Oregon, and New York each represent 1.6-2.6% of the sample, with the remaining nine states (Florida, Nevada, New Hampshire, Maryland, Minnesota, Pennsylvania, Texas, Wisconsin, and Vermont) comprising 2.9% in total.

The size of the PV systems in the primary dataset spans a wide range, from as small as 100 W to as large as 2.3 MW, but almost 90% of the projects in the sample are ≤10 kW (see Figure 3). In terms of installed capacity, however, the sample is considerably more evenly distributed across system size ranges, with systems >100 kW comprising 47% of the total installed capacity, and systems ≤10 kW comprising 35%.

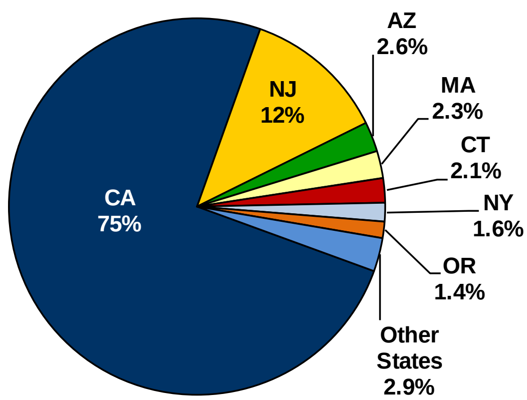


Figure 2. Data Sample Distribution among States (by Cumulative MW)

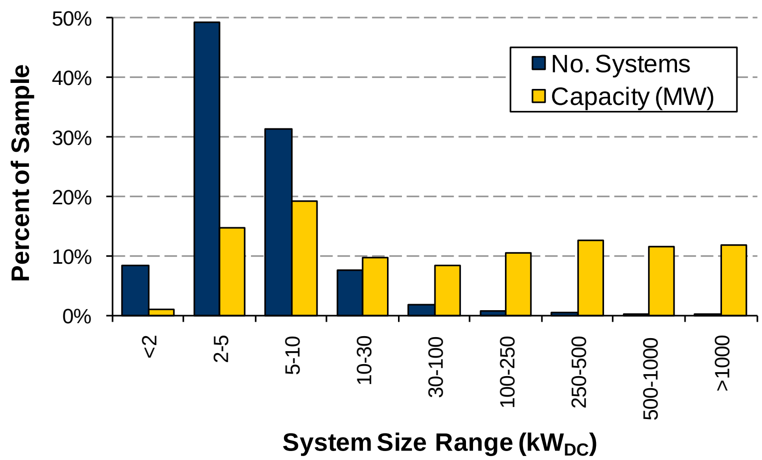


Figure 3. Data Sample Distribution by PV System Size

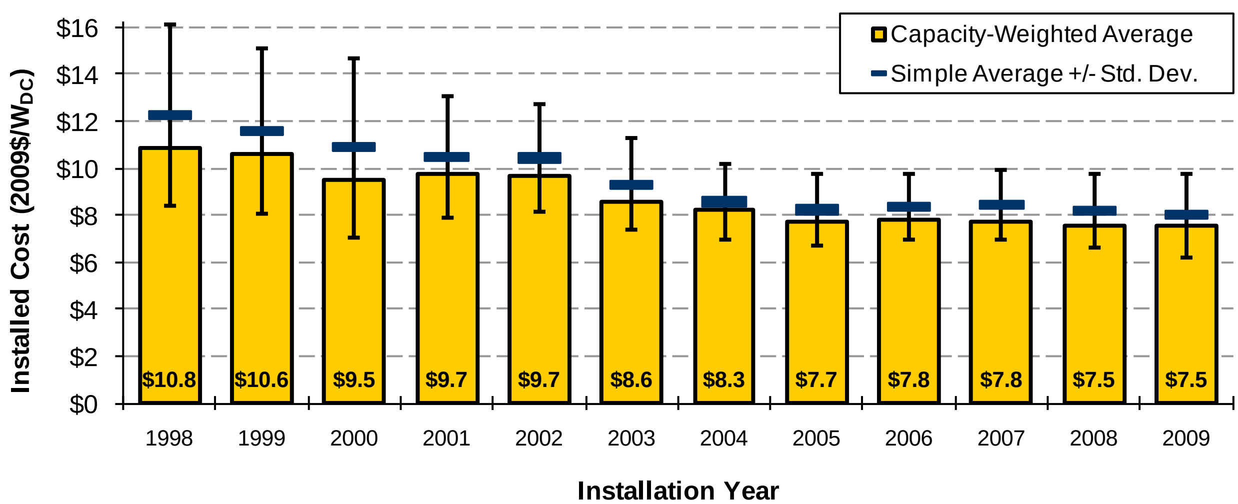
3. PV Installed Cost Trends

This section presents the primary findings of the report, describing trends in the average installed cost of grid-connected PV based on the dataset described in Section 2. It begins by presenting the trends in installed costs over time; by system size; by component; between the United States, Germany, and Japan; among individual states; between customer-owned and third party-owned systems; and among customer types (residential, commercial, public sector, and non-profit).[19] It then compares installed costs among several specific types of applications and technologies – specifically, residential new construction vs. residential retrofit, BIPV vs. rack-mounted systems, systems with thin-film modules vs. those with crystalline modules, and tracking vs. fixed-axis systems. To be clear, the focus of this section is on installed costs, as paid by the system owner, prior to receipt of any financial incentives (e.g., rebates, tax credits, etc.).

Overall Average Installed Costs Remained Flat from 2008 to 2009

Figure 4 presents the average installed cost of all projects in the primary sample completed each year from 1998-2009. Over the entirety of the twelve-year period depicted in the figure, capacity-weighted average installed costs declined by a total of \$3.3/W (30%), or \$0.3/W (3.2%) per year, on average. This cost decline occurred primarily during the period 1998-2005, after which average costs declined by only a modest amount (\$0.2/W total from 2005-2009).

Focusing specifically on the cost trend from 2008 to 2009, the capacity-weighted average annual installed cost for the entire data sample remained unchanged at \$7.5/W, while the simple (arithmetic) average installed cost fell by \$0.2/W, from \$8.2/W to \$8.0/W. This trend stands in stark contrast to the widely reported decline in wholesale module prices during 2009. One potential cause for this discrepancy is that the cost of many projects installed in 2009, as paid by the final system owner, may have been based on contracts signed and inventory stocked at a time when wholesale module prices were higher than at the date of system installation. This hypothesis is consistent with the preliminary 2010 cost data presented in Text Box 1, which show that average installed costs declined significantly from 2009 to 2010.



Notes: See Table 2 for sample size by installation year

Figure 4. Installed Cost Trends over Time

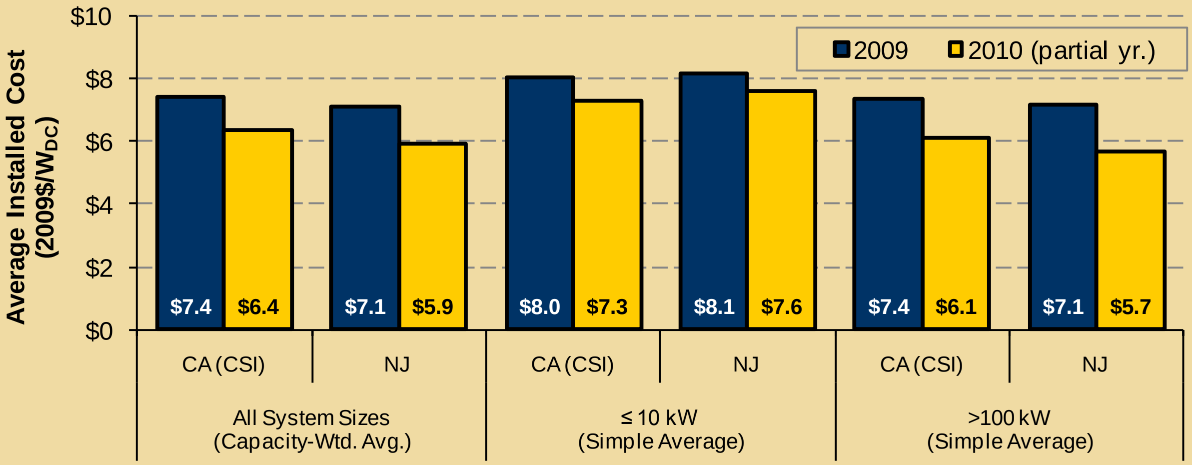
[19] Unless otherwise noted, the reported results are based on all system types in the data sample.

Text Box 1. Preliminary Installed Cost Trends for 2010

The dramatic and widely reported decline in *wholesale* module prices that began in 2008 and continued through 2009 and into 2010 would suggest that *retail* installed costs for PV systems should decline as well. Although the data presented in Figure 4 show that installed costs did not noticeably decline from 2008 to 2009, preliminary cost data for projects installed in 2010 indicate a significant drop in average installed costs between 2009 and 2010.

Figure 5 compares the average cost of projects installed in 2009 to the cost of projects installed during the first 6-10 months of 2010, with results presented separately for California's CSI program, based on data through November 10, 2010, and New Jersey, based on data from all statewide incentive programs through June 30, 2010. Among the California systems, the capacity-weighted average cost of all projects installed during the first ten months of 2010 was \$1.0/W below the average in 2009. Similarly, for New Jersey, the capacity-weighted average installed cost of systems installed during the first six months of 2010 was \$1.2/W below the average of all systems installed in 2009.

In both California and New Jersey, the decline in average installed costs was significantly greater for large systems than for smaller systems. Specifically, among CSI systems in California, average costs dropped by \$1.3/W for systems >100 kW and by \$0.7/W for systems ≤10 kW. Similarly, in New Jersey, average costs dropped by \$1.4/W for systems >100 kW and by \$0.5/W for systems ≤10 kW.



Notes: CA data are for the CSI program only, while NJ data include systems installed through the CORE Program, Renewable Energy Incentive Program, and SREC Registration Program. The 2010 partial year data extend through November 10, 2010 for CA systems and through June 30, 2010 for NJ systems.

Figure 5. 2009 and Preliminary 2010 Installed Costs for California and New Jersey

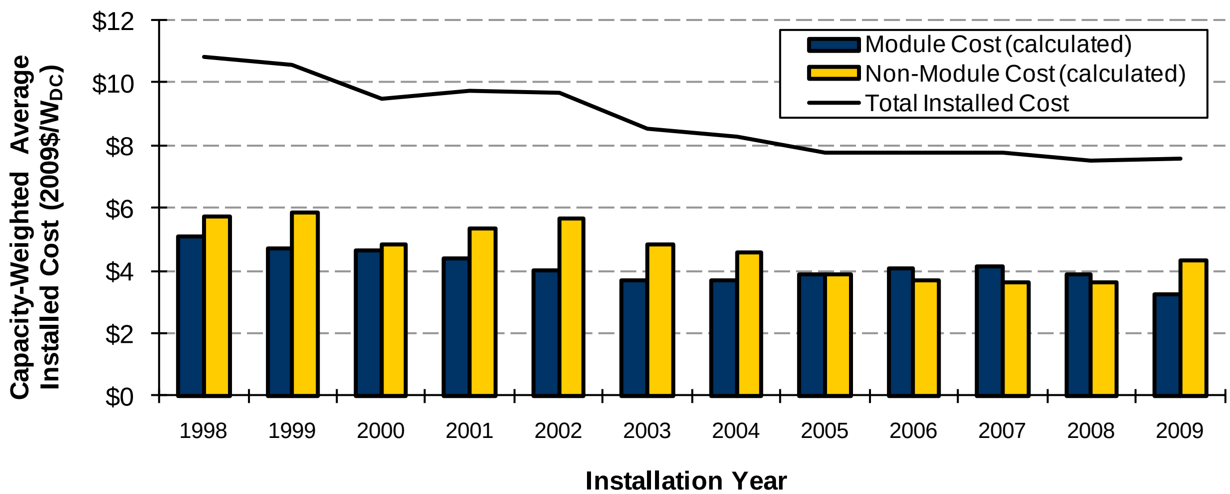
A Decline in Average Module Costs from 2008 to 2009 Was Offset by an Apparent Increase in Non-Module Costs

Figure 6 disaggregates average annual installed costs into average module and non-module costs. Because many programs did not provide component-level cost data, this figure relies on Navigant Consulting's Global Power Module Price Index, which reflects wholesale module prices. In order to roughly approximate the lag between movements in wholesale module prices and retail installed costs for PV systems, the module price index values shown in Figure 6 are equal to the average of the current and prior years' Global Power Module Price Index.[20] The non-module costs shown in

[20] The rationale behind this approach is to roughly approximate a six-month lag between the time that the PV installation contract is signed and the time that the system is installed. We acknowledge, however, that this is an imperfect approximation.

Figure 6 (which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and installer profit) were then calculated as the difference between the average total capacity-weighted installed cost and the "lagged" module price index in each year. Given the approximations inherent in this method, caution is warranted in interpreting these results.

Notwithstanding that caveat, Figure 6 clearly shows that both module and non-module costs declined significantly over the twelve-year period from 1998-2009, with module costs falling by $1.9/W and non-module costs falling by $1.4/W. Within the last two years of the data series, from 2008-2009, module costs (which, again, represent the average of the current and prior years' wholesale index price) declined by $0.7/W.[21] In contrast, non-module costs, as calculated according to the method described above, *increased* by approximately $0.7/W from 2008-2009. This apparent increase in non-module cost may, in part, reflect increased installer profit margins, capacity constraints in the delivery infrastructure, or higher penetrations of tracking systems or emerging technologies that increase installed costs while improving system performance. It is also possible, however, that the method used to calculate module and non-module costs for Figure 6 does not fully account for the lag between wholesale module price movements and PV system installations, and could therefore overstate the increase in non-module costs from 2008-2009.



Notes: Module costs are equal to the average of the current and prior years' global module price index, developed by Navigant Consulting. Non-module costs are calculated as the reported total installed costs minus the averaged module index.

Figure 6. Module and Non-Module Cost Trends over Time

Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV programs. Unlike module prices, which are primarily established through global markets, non-module costs consist of a variety of cost components that may be more readily affected by local programs – including deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. Thus, the fact that non-module costs have fallen over time, at least until 2005, suggests that state and local PV programs may have had some success in driving down the installed

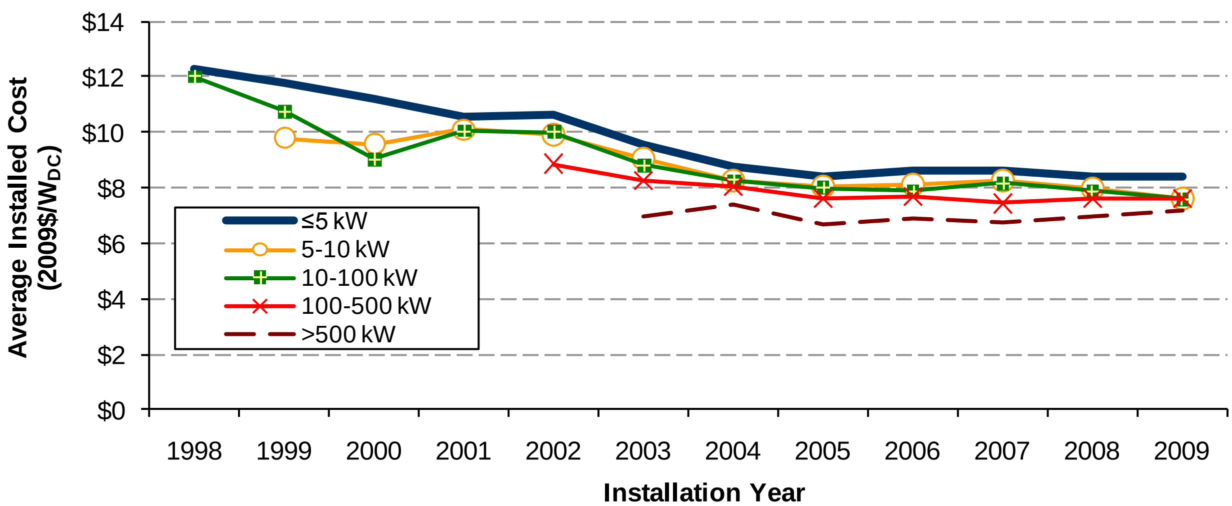
[21] By comparison, the SolarBuzz retail module price index indicates that average retail module prices in the United States declined by approximately $0.4/W from 2008 to 2009 (http://www.solarbuzz.com/Moduleprices.htm). As presented later in this report, data on component-level costs provided by a sub-set of the programs in the sample show that, from 2008-2009, average module costs declined by $0.1/W. Reported retail module costs, however, likely include a mark-up over the wholesale module purchase price, and therefore are not strictly comparable to the Navigant Index.

cost of PV. At the same time, the relatively flat trend in non-module costs from 2005-2009 suggests either that state and local programs have become less effective at driving down non-module costs, or that other drivers (e.g., constraints in the delivery infrastructure, permitting and incentive application costs, or installer profit margins) have put increasing upward pressure on non-module costs borne by PV system owners.

Average Installed Costs Fell Moderately in 2009 for Systems 5-100 kW, while Remaining Flat or Rising for Other System Sizes

Although average installed costs remained relatively flat across all size ranges from 2008 to 2009, small differences can be observed among the size classifications shown in Figure 7.[22] Specifically, average costs declined by \$0.4/W and \$0.3/W, respectively, for systems in the 5-10 kW and 10-100 kW size ranges, but remained flat for systems <5 kW and 100-500 kW in size, and rose by \$0.3/W for systems >500 kW. As noted previously in Text Box 2, however, preliminary cost data for 2010 indicates that significant cost reductions occurred between 2009 and the first six to ten months of 2010, with the greatest cost reductions occurring among larger systems.

Over the entirety of the historical analysis period, cost reductions are most evident for smaller system sizes. From 1999-2009, the average installed cost of systems ≤5 kW dropped by \$3.4/W, from \$11.8/W to \$8.4/W, while the average cost of systems in the 5-10 kW and 10-100 kW size ranges dropped by \$2.2/W and \$3.1/W, respectively. It is less apparent to what extent larger systems experienced cost reductions over the 1999-2009 period, given limited data availability for the early years of the analysis period. Over the historical periods for which sufficient data is available, the average cost of systems 100-500 kW declined by \$1.2/W (2002-2009), while the average cost of systems >500 kW increased by \$0.2/W (2003-2009).[23]



Notes: Averages shown only if five or more observations were available for a given size category in a given year. For sample sizes, refer to Table B-2 in the Appendix.

Figure 7. Installed Cost Trends over Time, by PV System Size

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[22] As with many of the trends presented in this report, small differences in averages between years or between groups of systems may, in some cases, reflect idiosyncrasies of the data, rather than fundamental market drivers.

[23] The data sample for >500 kW systems consists of ten or fewer systems each year through 2005; thus, the average costs shown for systems in this size range installed from 2003-2005 may have limited significance.

The Distribution of Installed Costs Narrowed from 1998 to 2005, but No Further Narrowing Occurred through 2009

As indicated by the standard deviation bars in Figure 4, the distribution of installed costs has narrowed considerably over time. This trend can be seen with greater precision in Figure 8 and Figure 9, which present frequency distributions of installed costs for systems less than and greater than 10 kW, respectively, installed in different time periods. Both figures show a marked narrowing of the cost distributions occurring between 1998 and 2005, although this trend largely subsided from 2005 through 2009. This convergence of prices, with high-cost outliers becoming increasingly infrequent, is consistent with a maturing market characterized by increased competition among installers and module manufacturers and by better-informed consumers.

The two figures also show a *shifting* of the cost distributions to the left, as would be expected based on the previous finding that average installed costs have declined over time. For example, in both figures, the cost distributions for 2008-2009 are shifted to the left relative to the distributions for 2006-2007. This is consistent with Figure 4, which shows that the simple average (i.e., arithmetic average) installed cost in 2008 and 2009 was lower than in 2006 and 2007.

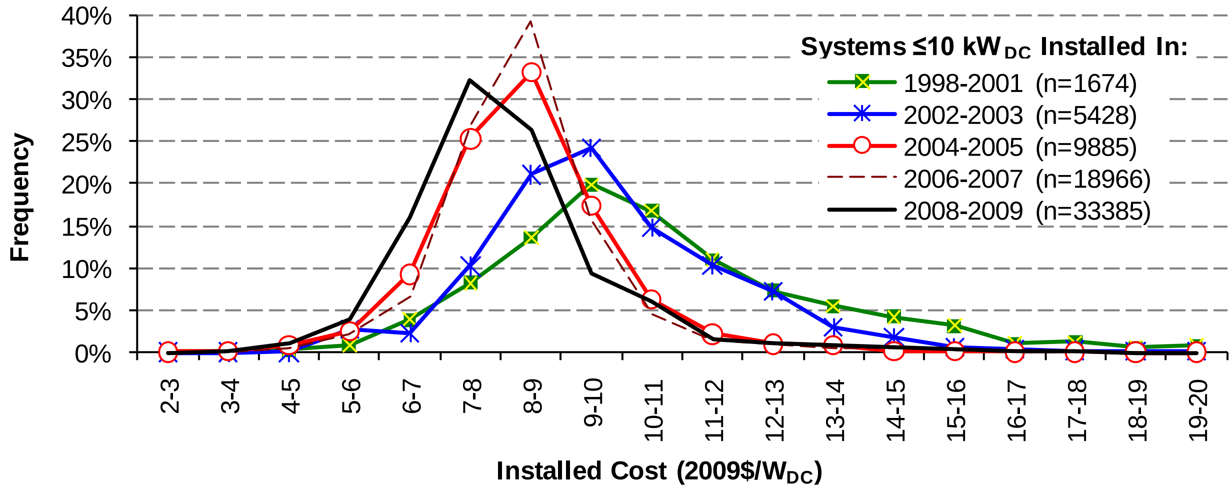


Figure 8. Distribution of Installed Costs for Systems ≤10 kW

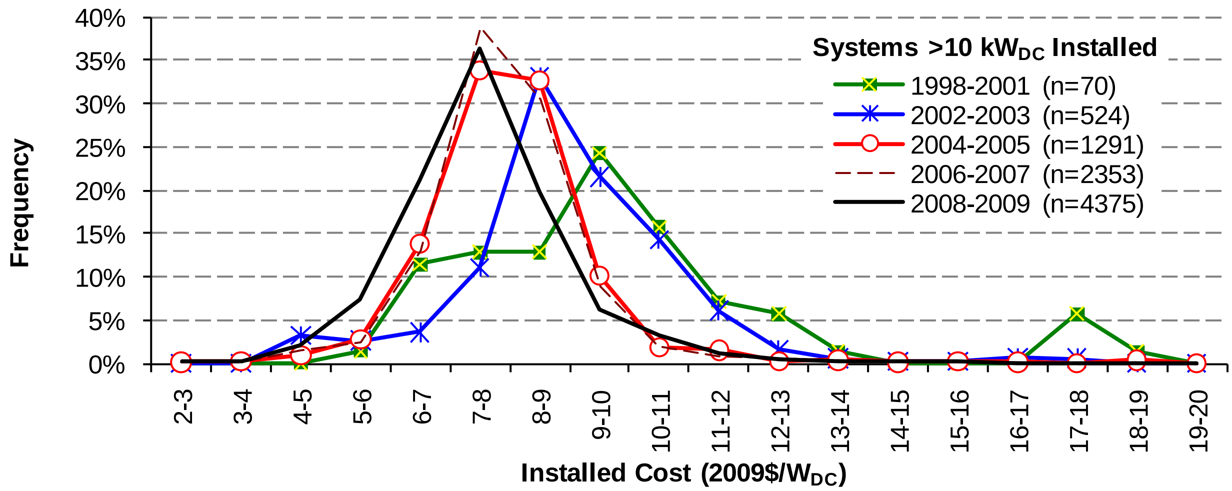


Figure 9. Distribution of Installed Costs for Systems >10 kW

Installed Costs Exhibit Economies of Scale

Large PV installations may benefit from economies of scale through price reductions on volume purchases of materials and the ability to spread fixed costs and transaction costs over a larger number of installed watts. This expectation has generally been borne out in experience, as indicated by Figure 10, which shows the average installed cost according to system size, for PV systems completed in 2009. The smallest systems (≤2 kW) exhibit the highest average installed cost ($9.9/W), while the largest systems (>1000 kW) have the lowest average cost ($7.0/W, or about 29% below the average cost of the smallest systems). Interestingly, economies of scale do not appear to be continuous with system size, but rather, most strongly accompany increases in system size up to 10 kW, and increases in system size above 250 kW. In contrast, the data do not show evidence of significant economies of scale within the 30-250 kW size range, and in fact, they indicate that average installed costs *increase* somewhat with system size between 10 kW and 250 kW. This latter trend may reflect a lower level of standardization as system size increases and/or increased permitting costs, which could counteract scale economies within certain system size ranges.

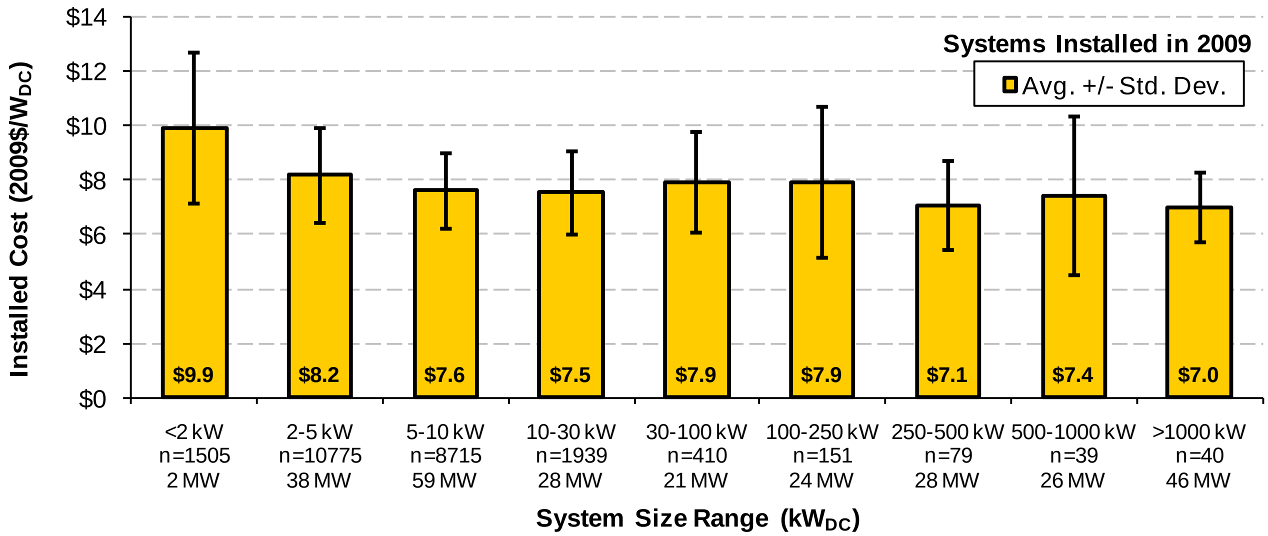


Figure 10. Variation in Installed Cost According to PV System Size

The primary dataset underlying the results shown in Figure 10 consists only of data provided by the 27 PV program administrators in our sample. Not included in this dataset are a number of large, multi-MW PV systems, several of which are installed on the utility-side of the meter. Installed cost data for 11 of these projects have been reported in press releases and other public sources, and are summarized in Table 3.[24] As shown, the installed costs of these projects vary considerably. The two projects completed in 2009 have reported installed costs of $5.1/W and $2.5/W, which are significantly below the average for systems >1,000 kW shown in Figure 10 ($7.0/W). Also note that a number of the systems in Table 3 have tracking systems, and are therefore likely to attain higher performance (and thus lower *levelized* costs on a $/MWh basis, even if the up-front installed costs are higher) than the large projects in the primary dataset, which are mostly fixed-axis systems.

[24] Table 3 only includes systems ≥2 MW that are not in the primary dataset and for which installed cost data (or proxies thereof) could be found. Note, though, that the sources of these cost data vary in quality, and therefore these data are less certain than the data in the primary sample.

To the extent that the economies of scale described above have persisted over time, they partially explain the temporal decline in average installed costs highlighted earlier, as the average size of PV systems has grown over time. As shown in Figure 11, the average size of ≤10 kW systems grew from 2.7 kW in 1998 to 4.7 kW in 2009, while the average size of systems >10 kW rose from 25 kW to 65 kW over the same time period.[25]

Table 3. Installed Cost of Large (≥ 2 MW) Out-of-Sample PV Systems

Location	Year of Installation	Plant Size (kW_{DC})	Installed Cost ($2009\$/W_{DC}$)	Tracking System Design
Arcadia, FL	2009	30,000	5.1	single axis
Blythe, CA	2009	25,200	2.5	none (fixed-axis)
Boulder City, NV	2008	12,600	3.2	none (fixed-axis)
Fairless Hills, PA	2008	3,000	6.6	none (fixed-axis)
Fontana, CA	2008	2,400	4.2	none (fixed-axis)
Riverside, CA	2008	2,000	6.5	none (fixed-axis)
Nellis, NV	2007	14,200	7.3	single axis
Alamosa, CO	2007	8,220	7.6	fixed, single axis, and double axis
Fort Carson, CO	2007	2,000	6.5	none (fixed-axis)
Springerville, AZ	2001-2004	4,590	6.1	none (fixed-axis)
Prescott Airport, AZ	2002-2006	3,388	5.6	single axis and double axis

Notes: Cost for Springerville is for capacity added in 2004. Cost for Prescott is for single-axis capacity additions in 2004.

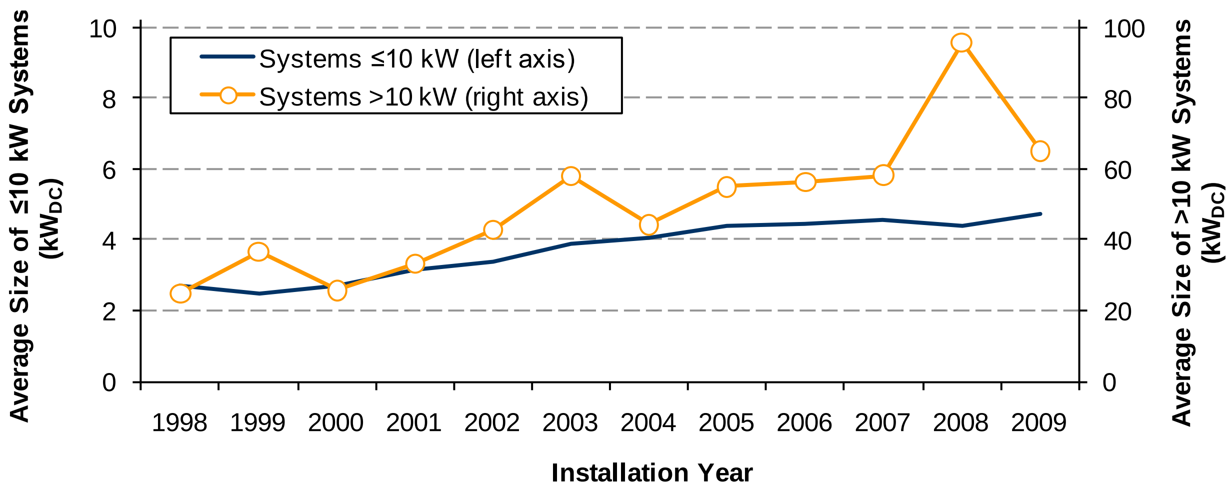


Figure 11. PV System Size Trends over Time

Non-Module/Non-Inverter Costs Were Lowest for Mid-Sized Systems in 2009

The average module and non-module costs presented in Figure 6 were estimated based on a wholesale module price index. This approach was necessitated, in part, by the fact that many of the PV incentive programs in our data sample did not provide component-level cost data. However, three programs[26] did provide component-level cost data (even if at a fairly coarse level of detail),

[25] Customer segment data are available for approximately 60% of the systems in the data sample. Among those systems for which customer segment data was provided, the average size of residential systems rose from 2.1 kW in 1999 to 5.5 kW in 2009, and the average size of non-residential systems rose from 4.6 kW in 1999 to 43.9 kW in 2009.
[26] These three programs – California Solar Initiative, Minnesota's Solar Electric Rebate Program, and the Wisconsin Focus on Energy Cash-Back Rewards Program – represent 56% of the systems in the dataset installed in 2009.

and these data provide a moderate level of additional detail on the composition of total system costs and the variation in component-level costs across system sizes.

Figure 12 summarizes the component-level cost data provided by PV incentive programs in our data sample, for systems installed in 2009. As shown, average module costs ranged from $4.1/W to $4.2/W, representing 52% to 56% of total installed costs, across the three size ranges. On average, inverter costs comprised 6-9% of the total cost, while other costs (e.g., mounting hardware, labor, overhead, installer profit, etc.) made up the relatively substantial remaining 36-42%.

Comparing across system size ranges, Figure 12 indicates that average module costs were relatively invariant across system size in 2009. This contrasts with the preceding two years, as shown in Table 4, when reported module costs were lower for larger systems (e.g., $3.9/W for systems >100 kW installed in 2008, compared to $4.5/W for systems 10-100 kW and $4.6/W for systems ≤10 kW). "Other" (non-module/non-inverter) costs vary with system size, and tend to be lowest for systems in the 10-100 kW size range. Among systems installed in 2009, for example, other costs were $2.7/W for 10-100 kW systems, compared to $3.2/W for ≤10 kW systems and $3.3/W for >100 kW systems. This trend mirrors the trend shown in Figure 10, which demonstrated that economies of scale reduced average costs for systems up to 30 kW, but total installed costs increased somewhat for systems within the 30-250 kW size range.

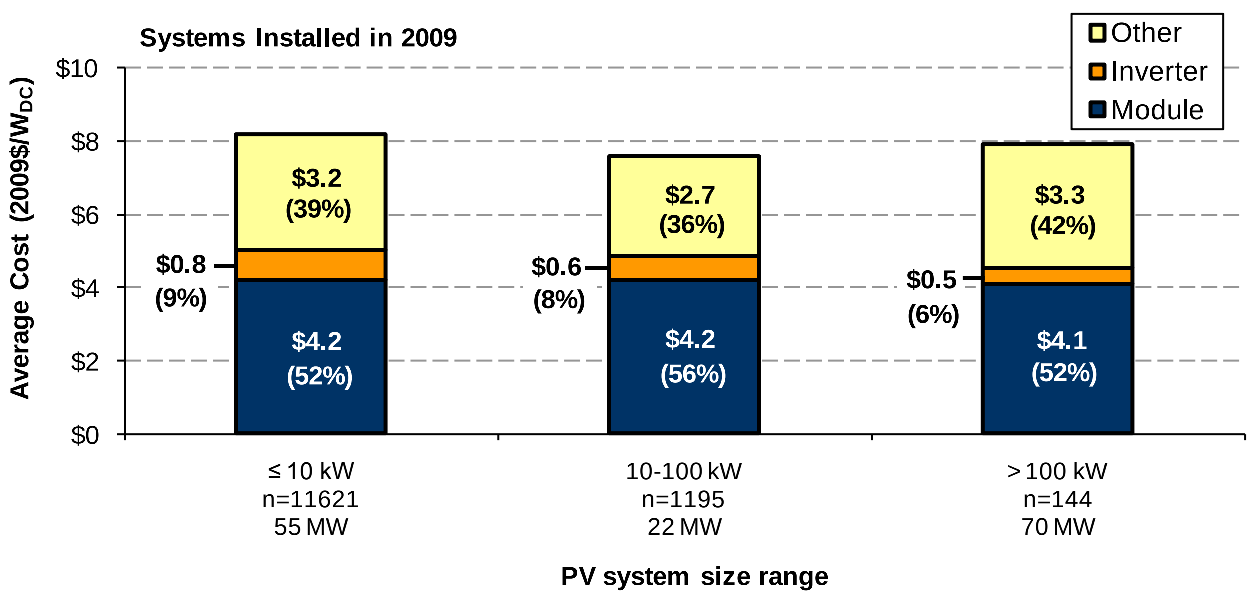


Figure 12. Module, Inverter, and Other Costs

Table 4. Module, Inverter, and Other Costs over Time

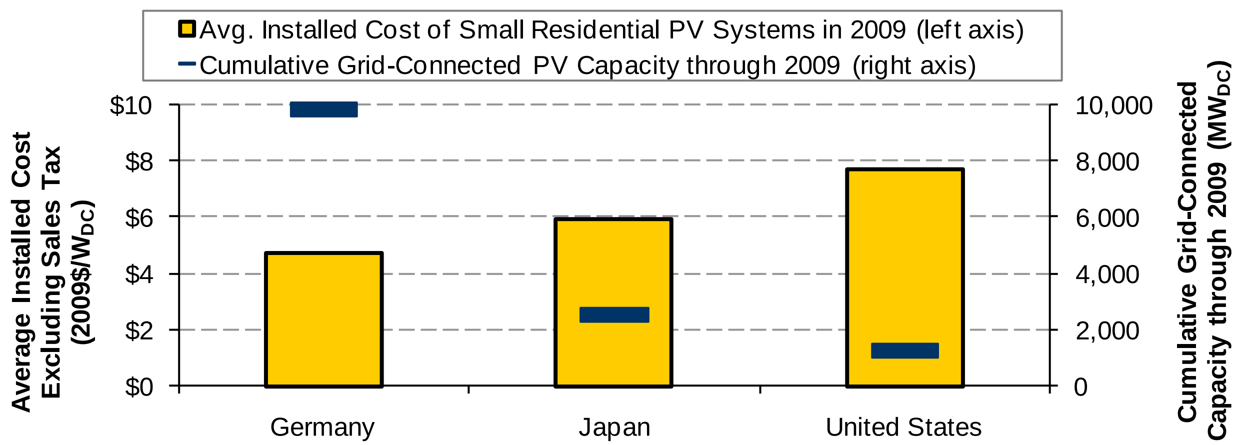
Installation Year	All System Sizes (capacity-weighted average)			≤ 10 kW			10-100 kW			>100 kW		
	Mod.	Inv.	Oth.	Mod.	Inv.	Oth.	Mod.	Inv.	Oth.	Mod.	Inv.	Oth.
2007	$4.3	$0.6	$2.8	$4.8	$0.7	$2.9	$4.7	$0.7	$2.7	$3.8	$0.4	$3.0
2008	$4.1	$0.5	$2.9	$4.6	$0.7	$2.9	$4.5	$0.6	$2.6	$3.9	$0.5	$3.0
2009	$4.0	$0.6	$3.0	$4.2	$0.8	$3.2	$4.2	$0.6	$2.7	$4.1	$0.5	$3.3

Notes: The results presented in this table are based on component level cost data provided by the California Solar Initiative, Minnesota's Solar Electric Rebate Program, and the Wisconsin Focus on Energy Cash-Back Rewards Program.

Table 4 also illustrates recent temporal trends in component level costs, among the three programs that reported such information. Across all system sizes, the capacity-weighted average reported module cost declined by \$0.1/W from 2008 to 2009. However, when segmented by system size, average module costs declined only among ≤10 kW systems (by \$0.4/W) and 10-100 kW systems (by \$0.3/W), but increased by \$0.2/W among >100 kW systems. "Other" (non-module/non-inverter) costs increased from 2008-2009 across all size ranges (by \$0.1/W for all systems, by \$0.3/W for ≤10 kW systems and >100 kW systems, and by \$0.1/W for 10-100 kW systems).

Average Installed Costs for Residential Systems Are Lower in Germany and Japan than in the United States

Notwithstanding the significant cost reductions that have already occurred in the United States, international experience suggests that greater near-term cost reductions may be possible. Figure 13 compares average installed costs, excluding sales or value-added tax, in Germany, Japan, and the United States, focusing specifically on *small* residential systems (either 2-5 kW or 3-5 kW, depending on the country) installed in 2009. Among this class of systems, average installed costs were substantially lower in Germany and Japan (\$4.7/W and \$5.9/W, respectively) than in the United States (\$7.7/W). These differences may be partly attributable to the much greater cumulative grid-connected PV capacity in Germany and Japan (about 10,000 MW and 2,500 MW, respectively, at the end of 2009), compared to approximately 1,300 MW in the United States. That said, larger market size, alone, is unlikely to account for the entirety of the differences in average installed costs among countries.[27]



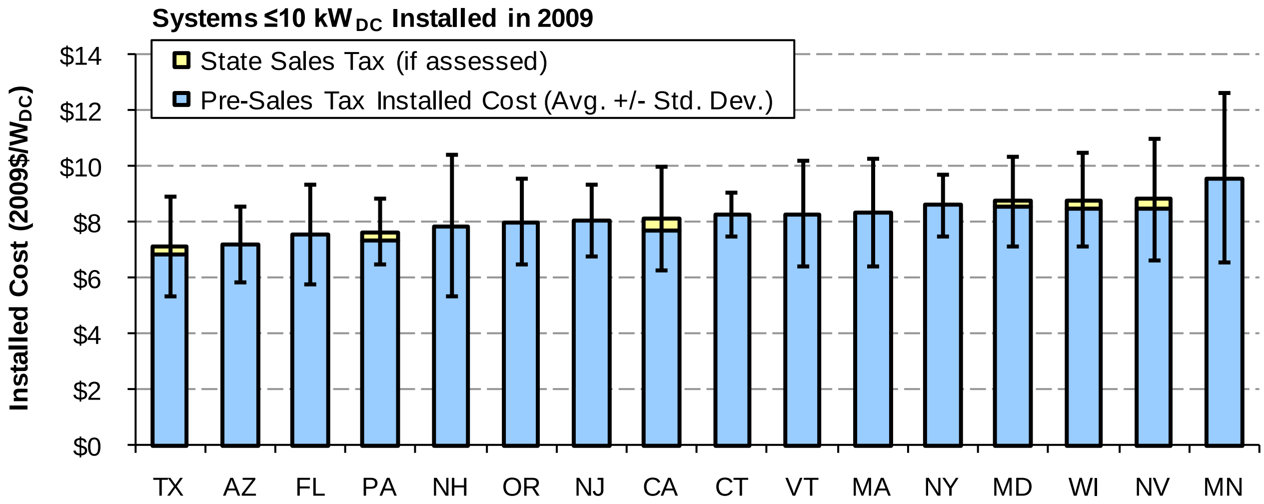
Notes: The Japanese and U.S. cost data are for 2-5 kW systems, while the German cost data are for 3-5 kW systems. Source for Japanese price and cumulative installed capacity data: Yamamoto, M. and O. Ikki. 2010. National Survey Report of PV Power Applications in Japan 2009. *Paris, France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems. Source for German price and cumulative installed capacity data: Wissing, L. 2010.* National Survey Report of PV Power Applications in Germany 2009. *Paris: France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems.*

Figure 13. Comparison of Average Installed Costs (Pre-Sales Tax/VAT) for Small Residential PV Systems in Germany, Japan, and the United States

[27] Installed costs may differ among countries as a result of a wide variety of factors, including differences in: module prices, technical standards for grid-connected PV systems, installation labor costs, procedures for receiving incentives and permitting/interconnection approvals (i.e., "paperwork burden"), foreign exchange rates, the degree to which components are manufactured locally, and average system size.

Installed Costs Vary Widely Across States

The United States is clearly not a homogenous PV market, as evidenced by Figure 14, which compares the average installed cost of systems ≤10 kW completed in 2009, across the 16 states in our dataset. Among systems in this size class, average costs range from a low of $7.1/W in Texas to a high of $9.6/W in Minnesota. Table 5 presents the same data in tabular form, along with comparative data for other system size ranges and groupings.



Notes: State Sales Tax and Pre-State Sales Tax Installed Cost were calculated from 2009 sales tax rates in each state (local sales taxes were not considered). Sales tax was assumed to have been assessed only on hardware costs, which, in turn, were assumed to constitute 65% of the total pre-sales-tax installed cost.

Figure 14. Variation in Installed Costs among U.S. States

The variation in average installed costs across states may partially be a consequence of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and hence greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. It is not surprising, therefore, that the two largest PV markets in the country (California and New Jersey) have relatively low average costs. This fact lends some credence to the premise behind state and local policies and programs that seek to reduce the cost of PV by accelerating deployment.

That said, the lowest cost states (Texas, Arizona, and Florida) are relatively small markets, illustrating the potential influence of other state- or local factors on installed costs.[28] For example, administrative and regulatory compliance costs (e.g., incentive applications, permitting, and interconnection) can vary substantially across states, as can installation labor costs. Installed costs also vary across states as a result of differing sales tax treatment; eight of the 16 states shown in Figure 14 exempted residential PV systems from state sales tax throughout the entirety of 2009, and Oregon and New Hampshire have no state sales tax. Assuming that PV hardware costs represent approximately 65% of the total installed cost of residential PV systems (an assumption supported by the component-level cost data presented previously), state sales tax exemptions effectively reduce the post-sales-tax installed cost by $0.2-0.4/W, depending on the specific state sales tax rate that would otherwise be levied. Average installed costs may also differ among states due to differences

[28] Although Texas and Arizona are both relatively small statewide PV markets in absolute size, the data from these two states largely come from programs with relatively high local concentrations of PV system installations.

in the proportion of systems that are ground-mounted or that have tracking equipment, both of which will tend to increase total installed cost.[29] Finally, as discussed further in Text Box 2, apparent differences in installed costs among states may also be an artifact of inconsistencies in how the installed cost of third-party owned systems is reported to PV incentive program administrators, although the available evidence does not suggest that this issue has significantly skewed the results.

Table 5. Average Installed Cost ($\$/W_{DC}$) by State and PV System Size Range

State	**All Reported Yrs.** Capacity-Weighted Average Cost (all sizes)		**2009 Systems**									
			Capacity-Weighted Average Cost (all sizes)		Simple Average Cost							
					0 - 10 kW_{DC}		10 - 100 kW_{DC}		100 - 500 kW_{DC}		>500 kW_{DC}	
AZ	$7.2	(n=3330)	$7.1	(n=2048)	$7.2	(n=1858)	$6.9	(n=187)	*	(n=3)	*	(n=0)
CA	$7.7	(n=58991)	$7.6	(n=15376)	$8.1	(n=13882)	$7.5	(n=1326)	$8.1	(n=106)	$7.2	(n=62)
CT	$7.9	(n=946)	$7.6	(n=306)	$8.3	(n=226)	$8.1	(n=61)	$7.3	(n=19)	*	(n=0)
FL	$7.5	(n=577)	$7.5	(n=575)	$7.6	(n=536)	$7.3	(n=38)	*	(n=0)	*	(n=1)
MA	$8.1	(n=1990)	$7.4	(n=860)	$8.4	(n=740)	$8.0	(n=92)	$6.8	(n=26)	*	(n=2)
MD	$9.0	(n=546)	$8.6	(n=316)	$8.8	(n=307)	$8.4	(n=9)	*	(n=0)	*	(n=0)
MN	$9.1	(n=198)	$9.3	(n=54)	$9.6	(n=49)	$9.6	(n=5)	*	(n=0)	*	(n=0)
NH	$7.6	(n=189)	$7.5	(n=157)	$7.9	(n=157)	*	(n=0)	*	(n=0)	*	(n=0)
NJ	$7.7	(n=4634)	$7.4	(n=1292)	$8.1	(n=964)	$7.9	(n=253)	$7.5	(n=62)	$7.2	(n=13)
NV	$8.7	(n=499)	$8.2	(n=183)	$8.8	(n=167)	$8.8	(n=16)	*	(n=0)	*	(n=0)
NY	$8.7	(n=1990)	$8.4	(n=779)	$8.6	(n=654)	$8.3	(n=125)	*	(n=0)	*	(n=0)
OR	$7.9	(n=1321)	$7.3	(n=473)	$8.0	(n=385)	$7.7	(n=76)	$6.9	(n=11)	*	(n=1)
PA	$7.9	(n=536)	$7.4	(n=372)	$7.7	(n=305)	$7.4	(n=66)	*	(n=1)	*	(n=0)
TX	$7.0	(n=1226)	$6.7	(n=459)	$7.1	(n=406)	$6.4	(n=51)	*	(n=2)	*	(n=0)
VT	$8.4	(n=365)	$7.9	(n=139)	$8.3	(n=134)	$7.2	(n=5)	*	(n=0)	*	(n=0)
WI	$8.7	(n=614)	$8.6	(n=264)	$8.8	(n=225)	$8.6	(n=39)	*	(n=0)	*	(n=0)

* Cost data are omitted if the sample size (n) is less than five.

[29] For example, in Wisconsin, a relatively high-cost state, approximately 20% of the systems in the sample have tracking equipment.

Text Box 2. Reported Installed Costs for Customer-Owned vs. Third Party-Owned Systems

Third party ownership of customer-sited PV systems, through power purchase agreements and leases, has become increasingly common for PV systems of all sizes. Under such arrangements, the transaction between the host customer and the system owner typically consists of a series of payments over time, rather than a single up-front payment for the purchase of the PV system. The structure of the retail transaction therefore provides some discretion to third party PV system owners in terms of how they report installed cost to PV incentive program administrators. In some cases, the reported installed cost may include financing costs that are bundled into the payments made by the customer over time. Although customer-owned systems may also entail financing costs (e.g., if the customer finances some portion of the up-front payment through a home equity loan), those financing costs are incurred separate from the purchase of the PV system and therefore are not included in the installed cost data reported to PV incentive program administrators. Thus, to the extent that the installed cost of third party-owned systems reported to PV incentive program administrators includes financing costs or other costs unrelated to the installation of the PV system (e.g., maintenance or warranty services), it may obscure the underlying trends in PV installed costs.

To gain some insight into the potential significance of this issue, Figure 15 compares the reported installed cost of customer-owned and third party-owned systems in the California Solar Initiative (CSI) program. As shown, installed costs reported for third party-owned systems were, on average, higher than for customer-owned systems. Among all CSI systems installed in 2009, the capacity-weighted average installed cost reported for third party-owned systems was \$0.4/W higher than for customer-owned systems. A similar price differential is evident for systems ≤10 kW, while for systems in the 10-100 kW size range, the average reported installed cost of third party-owned systems was \$1.2/W higher than for customer-owned systems. Figure 15 also identifies the average reported installed cost for all systems (both customer-owned and third party-owned). As shown, the higher reported cost for third party-owned systems – which represented about 13% of the CSI systems installed in 2009 – did not significantly affect the average cost data for all CSI systems. It therefore does not appear likely that any inconsistencies between how installed costs are reported for third party-owned and customer-owned systems significantly skewed the installed cost trends presented in this report. However, to the extent that third party ownership becomes a larger portion of the overall market, issues associated with consistent reporting of cost data could become more significant over time. It should also be noted that third party-owned systems may legitimately entail higher installed costs, if performance-enhancing equipment (e.g., tracking systems or advanced power electronics) or high-precision metering are more prevalent among those systems.

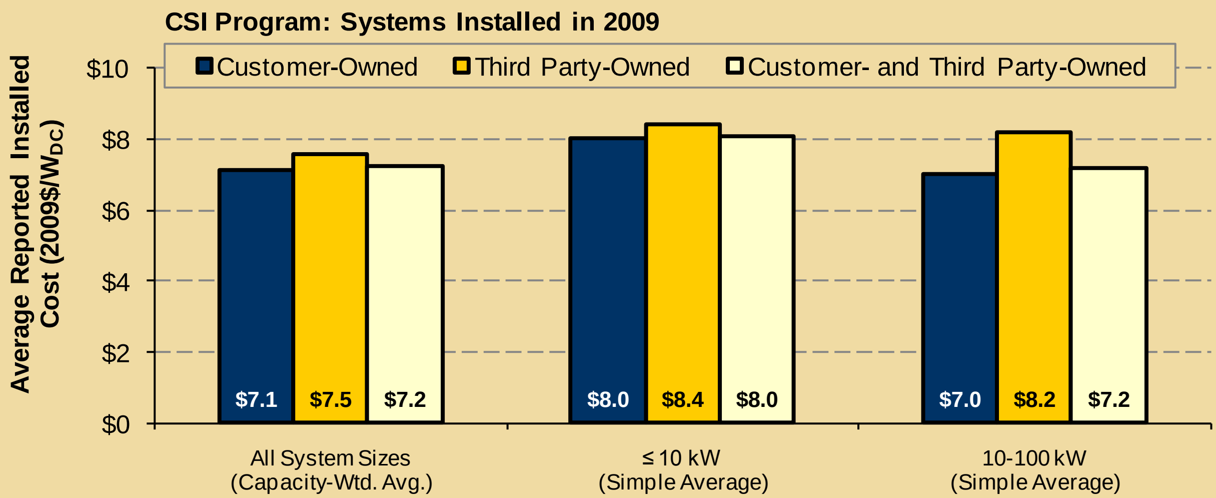


Figure 15. Comparison of Reported Installed Costs between Customer-Owned and Third Party-Owned Systems in the CSI Program

Installed Costs Are Generally Lowest for Residential Systems and Highest for Public Sector Systems, Compared to Other Similarly Sized Systems

Figure 16 compares average installed costs across four customer segments: residential, commercial, non-profit, and public sector (i.e., government and schools). We focus on systems installed in 2009 for which customer segment data was provided, splitting those data into three size categories: 5-10 kW, 10-100 kW, and 100-500 kW.[30] The figure shows fairly consistent trends across all three system size ranges, in terms of the relative installed cost of PV systems among market segments. In general, installed costs tend to be lowest for residential systems compared to other similarly sized systems. Specifically, within the 5-10 kW size range, residential systems have an average installed cost ($7.6/W) that is $0.5/W less than commercial customers ($8.1/W), $1.2/W less than non-profit customers ($8.8/W), and $1.1/W less than public sector customers ($8.7/W). Consistent, though somewhat smaller, cost differentials are evident for systems in the 10-100 kW size range.

Figure 16 also indicates that public sector systems tend to have higher installed costs than similarly sized commercial systems. Specifically, the average installed cost of public sector systems exceeds that of commercial systems by $0.6/W within the 5-10 kW system size range ($8.7/W vs. $8.1/W), by $0.7/W in the 10-100 kW size range ($8.6/W vs. $7.9/W), and by $0.8/W in the 100-500 kW size range ($8.1/W vs. $7.3/W). Non-profit systems also tend to have higher costs than similarly sized commercial systems, though the sample of non-profit systems in each size range is fairly limited.

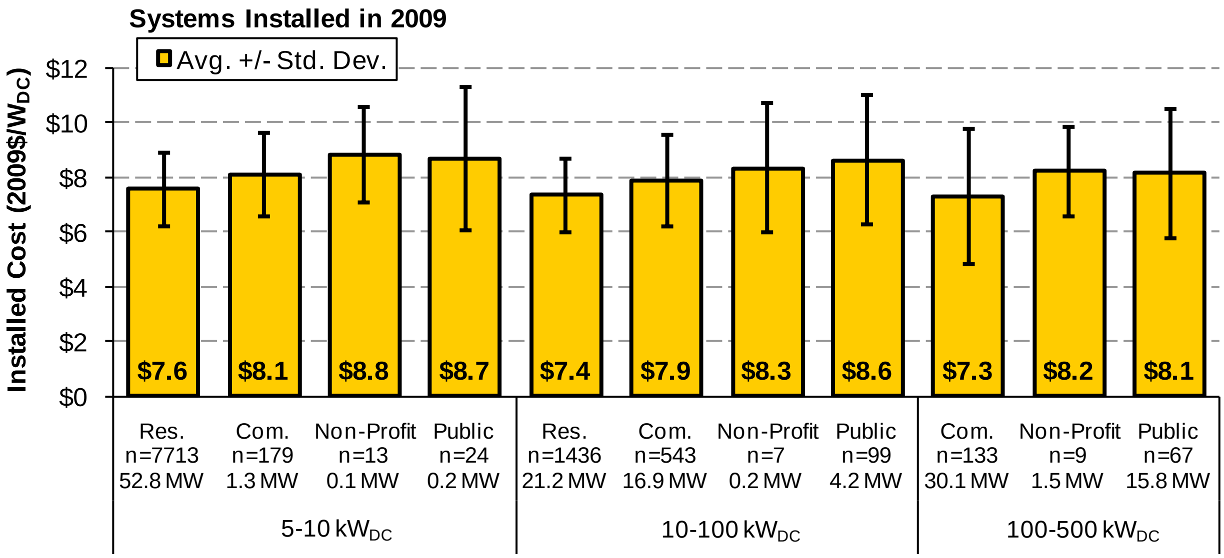


Figure 16. Variation in Installed Costs among Customer Sectors

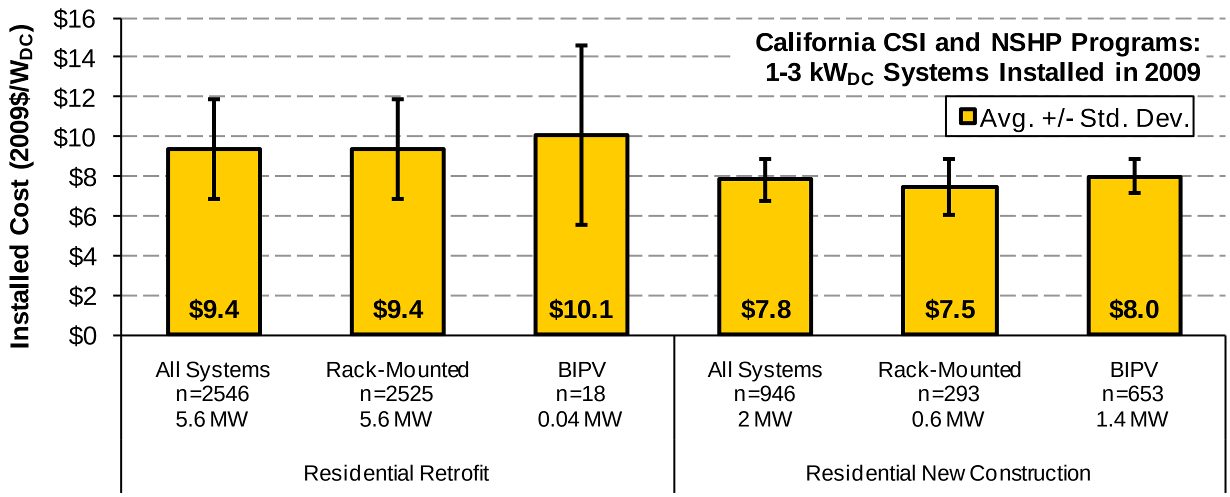
[30] Customer segment identifiers were provided by PV incentive programs for approximately 92% of all 2009 installations within the dataset. We focus on the 5-10 kW, 10-100 kW, and 100-500 kW size ranges, as these are ranges for which the sample size in each relevant customer segment is sufficiently large. There were no residential systems in the 100-500 kW size range, however.

The New Construction Market Offers Significant Cost Advantages for Residential PV, Despite the Higher Cost of BIPV Relative to Rack-Mounted Systems

Figure 17 compares the average installed cost of PV systems installed residential new construction and residential retrofit applications funded through two California programs (the CSI and New Solar Homes Partnership [NSHP] programs[31]), focusing in particular on 1-3 kW systems installed in 2009.[32] Among this group of PV systems, those installed in residential new construction cost $1.6/W less, on average, than comparably-sized residential retrofit systems ($7.8/W compared to $9.4/W), a cost advantage of approximately 16%.

However, simply comparing the overall average cost of all residential new construction and all residential retrofit systems masks the fact that a much larger proportion of new construction systems are building-integrated PV (BIPV), which tend to have somewhat higher costs than rack-mounted systems, though the higher installed costs may be partially offset by avoided roofing material costs. Systems within the data sample were identified as BIPV or rack-mounted based on module manufacturer and model data provided by the PV incentive program administrators. As shown in Figure 17, BIPV systems in the two California programs cost $0.5/W more, on average, than rack-mounted systems installed in residential new construction (i.e., $8.0/W vs. $7.5/W).

To make an apples-to-apples comparison between residential new construction and residential retrofit applications, one can compare the average cost of rack-mounted systems installed in the two applications, as also shown in Figure 17. This comparison suggest a somewhat greater cost advantage for new construction than implied by the overall averages, with rack-mounted systems installed in residential new construction averaging $1.9/W less than residential retrofit systems ($7.5/W compared to $9.4/W).



Note : The number of rack-mounted systems plus BIPV systems may not sum to the total number of systems, as some systems could not be identified as either rack-mounted or BIPV.

Figure 17. Comparison of Installed Costs for Residential Retrofit vs. New Construction

[31] The NSHP program exclusively targets residential new construction, and thus all systems in that program were assumed to be residential new construction, and all residential systems within CSI were assumed to be retrofit.
[32] Of the 1,221 NSHP systems within the dataset installed in 2009, 77% are within the 1-3 kW size range.

Systems with Thin-Film Modules Had Higher Installed Costs than Those with Crystalline Modules

A number of countervailing factors may influence the relative cost of systems employing thin-film[33] and crystalline modules. Thin-film modules are typically lower-cost than crystalline modules but are less efficient, which would tend to engender higher balance of system costs. In addition, greater uncertainty in the long-term performance of thin-film modules on the part of consumers and potentially faster degradation rates would tend to drive down the price of thin-film systems relative to crystalline systems. However, some thin-film technologies have higher energy yields (annual kWh per installed kW) than crystalline modules, due to better performance at high temperatures or under diffuse irradiance, which would tend to increase the price that customers are willing to pay for thin-film systems.

To understand the net effect of these cost drivers, Figure 18 compares the average installed cost of crystalline and thin-film systems, focusing specifically on rack-mounted (i.e., not BIPV) systems installed in 2009.[34] Individual systems within the dataset were identified as employing either thin-film or crystalline modules based on module manufacturer and model data provided by the PV incentive programs. As shown, thin-film systems in both of the size ranges shown had average installed costs higher than comparably-sized crystalline systems ($0.8/W higher among ≤10 kW systems and $0.4/W higher among 10-100 kW systems).[35]

To examine the relationship between total installed cost and module efficiency more directly, Figure 19 compares the average installed cost of all rack-mounted systems installed in 2009, according to module efficiency. Within both of the two system size ranges shown, average installed costs were lowest for systems with modules of mid-range efficiencies (14-16%), although the differences in installed cost across module efficiencies are relatively small. Among systems ≤10 kW, for example, average installed costs were lowest ($7.4/W) for systems with module efficiencies of 15-16%, compared to $8.2/W for systems with module efficiencies ≤12% and $8.3/W for systems with module efficiencies >18%.

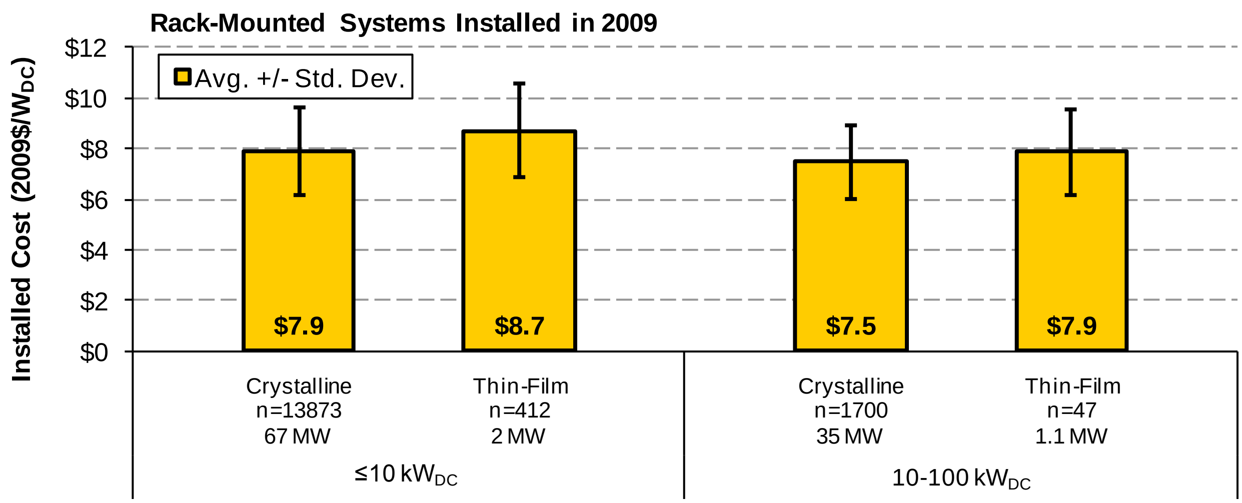


Figure 18. Comparison of Installed Costs for Crystalline vs. Thin-Film Systems

[33] Thin-film systems include both amorphous silicon and non-silicon modules.

[34] We limit the comparison to rack-mounted systems, in order to eliminate any distortion associated with the higher incidence of thin-film modules among BIPV systems.

[35] Although not included in the figure due to insufficient sample size, the average installed cost of the eight thin-film systems >100 kW identified within the dataset was $1.2/W higher than the crystalline systems in this size range.

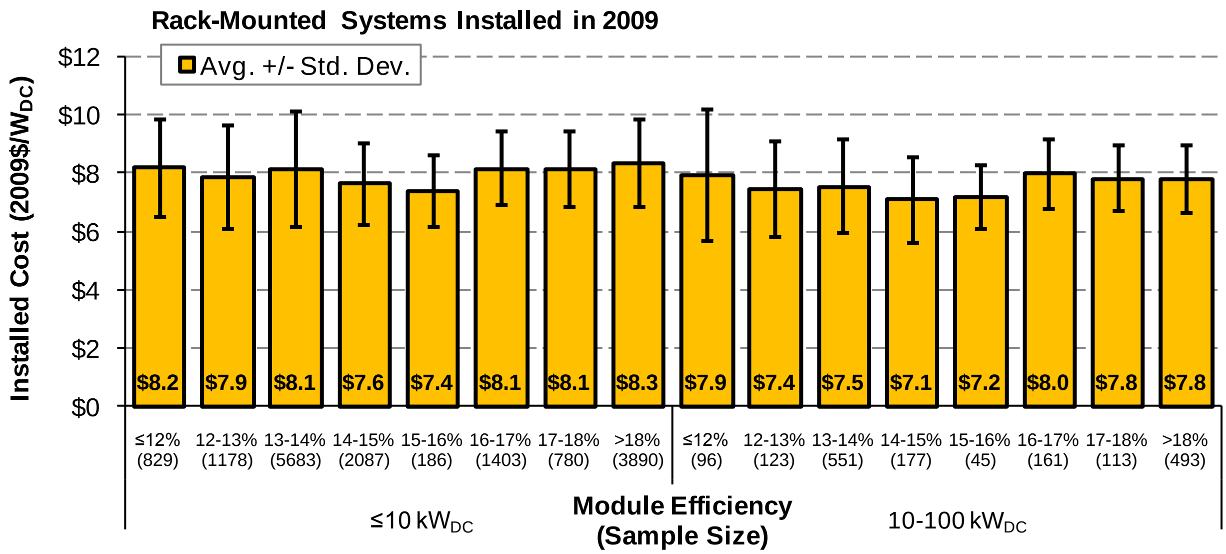


Figure 19. Variation in Total Installed Cost by Module Efficiency

Tracking Systems Had Higher Installed Costs than Fixed-Axis Systems

Data indicating whether or not PV systems had tracking equipment were provided for a relatively small percentage of systems in the sample (14% of systems and 18% of capacity installed in 2009). Based on the limited data available, Figure 20 compares the average cost of PV systems with tracking (including both single- and double-axis tracking) to those with fixed mounting, focusing on rack-mounted systems (both roof- and ground-mounted) installed in 2009.[36] As shown, tracking systems had higher installed costs within both size categories, as would be expected, given the additional cost associated with the tracking equipment and ground-mounting.[37] Among systems ≤10 kW, tracking systems had average installed costs $1.7/W (or 21%) higher than fixed-axis systems. This comports reasonably well with component-level cost data from Wisconsin's Focus on Energy Renewable Energy Cash-Back Rewards Program, which show that, among systems installed in 2009, those with tracking systems had "rack" costs $1.3/W higher than fixed-axis systems.[38] Among the 10-100 kW systems summarized in Figure 20, tracking systems had average installed costs $3.5/W (or 44%) higher than their fixed-axis counterparts; however, given the small number of tracking systems in this size range, caution is warranted in generalizing from these results.

[36] A more meaningful comparison would be to compare tracking systems, ground-mounted fixed-axis systems, and roof-mounted fixed-axis systems. However, the data provided by PV program administrators do not identify whether systems are ground-mounted or roof-mounted.
[37] Tracking systems increase the energy yield of the PV systems, which will tend to offset some of the increase in the up-front cost.
[38] This is the only PV incentive program that provided separate component-level cost data for the "rack" element of each PV system.

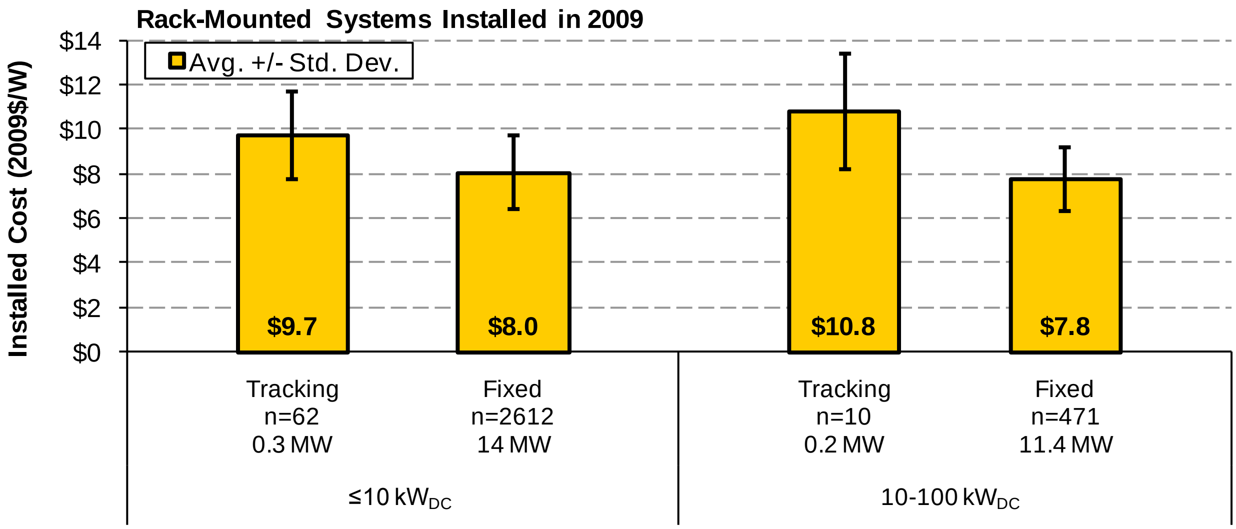


Figure 20. Comparison of Installed Costs for Tracking vs. Fixed-Axis Systems

4. PV Incentive and Net Installed Cost Trends

Financial incentives provided through utility, state, and federal programs have been a major driving force for the PV market in the United States. For any individual system, these incentives potentially include some combination of cash incentives provided through state or utility PV incentive programs, federal and/or state investment tax credits (ITCs)[39], revenues from the sale of renewable energy certificates (RECs), and accelerated depreciation of capital investments in solar energy systems. This section describes trends in incentive levels (focusing specifically on state/utility cash incentives and state/federal ITCs) and net installed costs (i.e., installed costs after receipt of financial incentives) over time, by system size, and among states.

Two important caveats should be noted at the outset:

- First, the set of incentives addressed in this section are necessarily limited in scope, accounting only for the direct cash incentives provided through the specific state/utility PV incentive programs in the dataset, plus state and federal ITCs. The analysis does not account for the incentive for commercial PV provided through accelerated depreciation,[40] nor for any additional incentives that projects may have received from state/utility incentive programs outside of the PV incentive program covered in this report. The results presented in this section also do not account for revenue from the sale of RECs, although the potential magnitude of this revenue stream is briefly discussed in general terms (see Text Box 3). As such, the results presented in this section exclude New Jersey's SREC Registration Program (which is included in previous sections of this report), as that program provides incentives solely in the form of solar RECs, the price of which varies over time according to market conditions.
- Second, this section marks a departure from Section 3 by going beyond a simple reporting of data provided by program administrators. In particular, a variety of assumptions, as documented within this section and described further in Appendix C, were required in order to estimate the value of federal and state ITCs for each project and to determine the net installed cost on an after-tax basis.

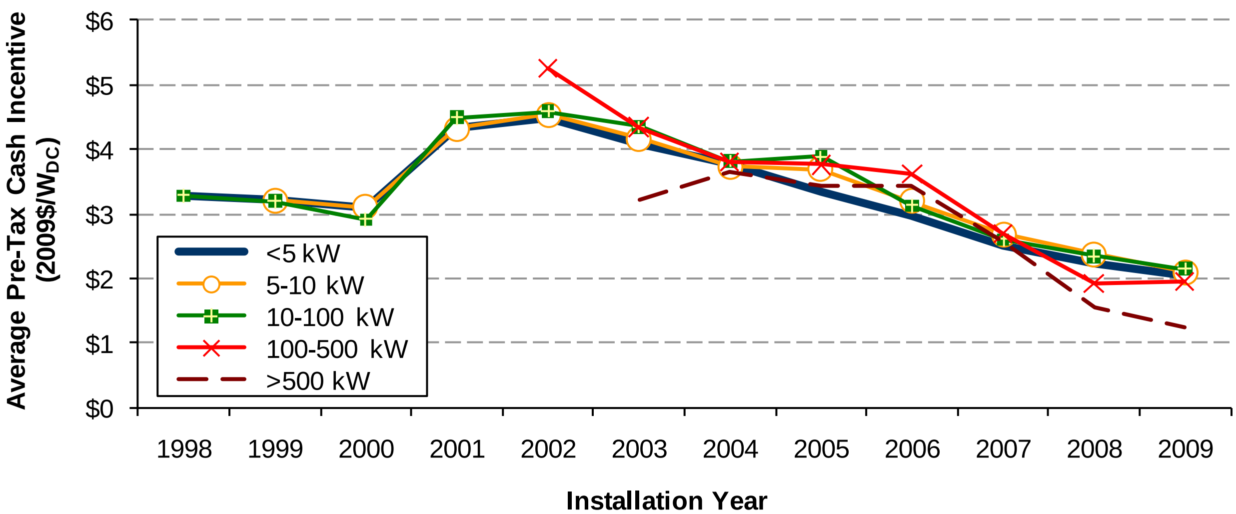
State/Utility Cash Incentives Continued Their Decline in 2009

The PV incentive programs represented within the dataset provide cash incentives of varying forms. Most provide up-front cash incentives (i.e., "rebates"), based either on system capacity, a percentage of installed cost, or a projection of annual energy production. Several programs, instead, provide performance-based incentives (PBIs), which are paid out over time based on actual energy production, as either a supplement or an alternative to an up-front rebate.[41] Figure 21 shows the average cash incentive received by the PV systems in the dataset, over time and according to system

[39] Starting in 2009 and for a limited period, the federal ITC for commercial PV could be converted to a cash grant of equal value from the U.S. Treasury.
[40] For tax purposes, commercial PV owners are allowed to depreciate PV systems using an accelerated 5-year schedule. The net present value of this accelerated depreciation schedule, relative to a 20-year straight-line schedule, is equal to 12% of installed costs. See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.
[41] PBI payments were reported by PV incentive program administrators on a $/W basis, based on estimated energy production. For the purpose of the present analysis, these reported $/W incentive amounts were discounted at a 10% nominal discount rate, based on the number of years over which the PBI payments are made.

size. These data are presented on a *pre-tax* basis – that is, prior to assessment of state or federal taxes that may be levied if the incentive is treated as taxable income.[42] Note also that the figure does not necessarily provide an accurate depiction of the size of incentives *offered* in each year, as there is typically some lag between the time that a project reserves its incentives and the time that it is installed.

As shown in Figure 21, average cash incentives for systems installed in 2009 ranged from $1.2/W - $2.2/W across the system size categories shown, and were up to $0.3/W lower than the incentive levels in the preceding year. Incentive levels in 2009 were 37-47% of their peak in 2002 and 2003, declining at an average rate of about $0.3-0.4/W per year over the intervening period. These trends largely reflect changes in incentives received by systems funded by California's ERP, Self Generation Incentive Program (SGIP), and CSI program, and by New Jersey's Customer Onsite Renewable Energy (CORE) program, which together represent 79% of all of the systems in the data sample. To some extent, the trends in Figure 21 also reflect the increasing geographic diversification of the sample over time, with a progressively larger percentage of the sample consisting of systems funded by programs other than the three aforementioned California programs. In general, these other programs have tended to offer higher incentives, counteracting to some degree the declining incentives within the California programs. That said, average incentives among all PV incentive programs in the sample have generally declined over time (see Table B-3 in Appendix B).



Notes: Averages shown only if five or more observations were available for a given size category in a given year. For sample sizes, refer to Table B-2 in the Appendix.

Figure 21. Pre-Tax State/Utility Cash Incentive Levels over Time

[42] Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. Cash incentives for residential PV, however, are exempt from Federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Text Box 3. Revenue from the Sale of RECs

PV system owners may be able to sell RECs generated by their system, adding to any direct incentives received from state/utility PV incentive programs and Federal or state ITCs (provided that REC ownership is not automatically transferred to the state/utility as a condition of providing a direct cash incentive). Projecting the value of REC sales over the lifetime of each individual PV system in our dataset would be a highly speculative task, and therefore was not undertaken for this study. Based on recent REC prices, however, the revenue potential in most states is relatively modest, compared to the value of direct cash incentives received through state/utility PV incentive programs and to the value of the Federal ITC.

In general, the potential REC revenue for customer-sited PV depends on where the system is located, and consequently, what types of REC markets are available.

- *Voluntary REC Markets*. In most states, RECs generated by PV systems may be sold to individuals, businesses, or government agencies that are voluntarily seeking to support renewable energy. Given the elective nature of these transactions, prices in voluntary REC markets have historically been quite modest. For example, voluntary RECs traded through Spectron, a brokerage firm, averaged about \$1.4/MWh in 2009. If extrapolated over 20 years, revenue from REC sales at this price would be equivalent to an up-front, pre-tax incentive of just \$0.02/W_{DC} on a present value basis (assuming a 10% nominal discount rate, an AC capacity factor of 20%, and DC-to-AC losses of 20%).
- *General RPS Markets*. In some states, RECs generated by PV systems may be sold to electricity suppliers for compliance with state renewables portfolio standards (RPS). These markets may offer greater REC revenue potential than in voluntary markets, though REC prices in RPS markets have historically varied quite substantially across states and over time. For PV, the most critical issue typically is whether the state RPS has a specific solar requirement (i.e., a solar "set-aside" or "carve-out"). In "general" RPS markets without a solar set-aside (in which case RECs from PV systems may be used to satisfy the total renewable electricity compliance obligation), the highest average REC prices in 2009 occurred in Massachusetts, where REC prices for compliance with the state's Class I RPS requirement averaged approximately \$30/MWh (again, based on REC trades through Spectron). If extrapolated over a 20-year period, using the same assumptions as before, revenue from REC sales at this price would be equivalent to an up-front, pre-tax payment of \$0.40/W_{DC}.
- *RPS Solar Set-Aside Markets*. Substantially greater REC revenue potential may be available in RPS states with a solar (or distributed generation) set-aside. During 2009, the highest solar REC (or SREC) prices occurred for compliance with New Jersey's solar set-aside, with SREC prices averaging \$542/MWh over the year. Extrapolating this revenue stream over a 15-year period (as PV systems in New Jersey can sell SRECs only for up to 15 years) yields the equivalent of an up-front, pre-tax payment of \$6.4/W, which is significantly larger than the direct cash incentives offered in most states.

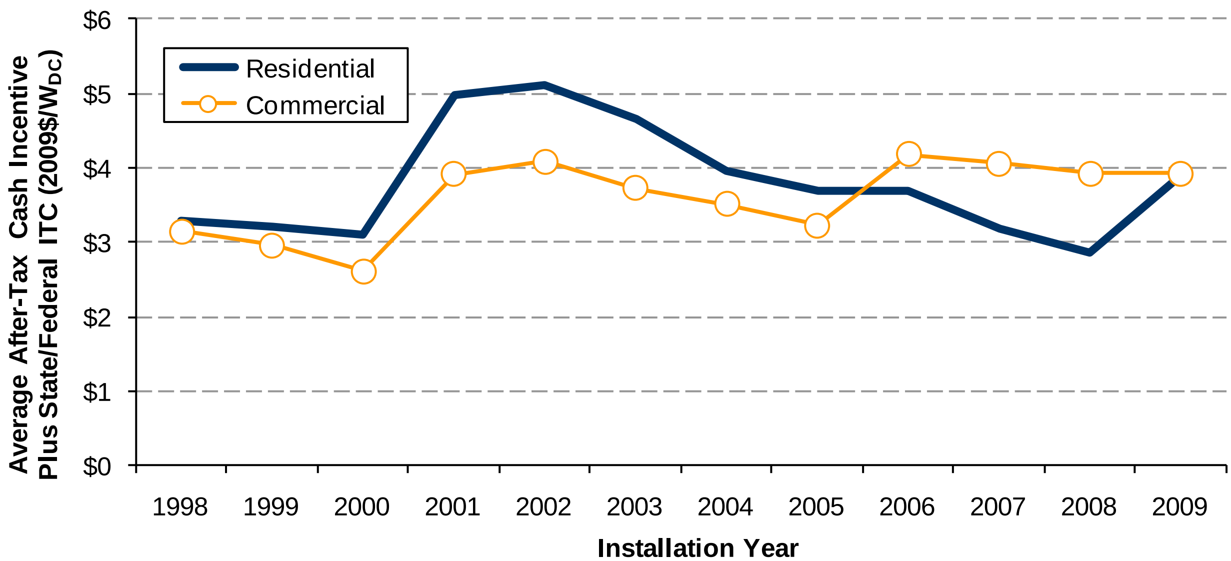
In 2009, the Combined Value of Federal & State ITCs Plus Direct Cash Incentives Was Near Its Peak for Commercial PV, and Up Significantly for Residential PV

Although direct cash incentives received from state and utility PV programs have, on average, declined over time, other sources of financial incentives have become more significant. Most notably, starting January 1, 2006, the federal ITC for commercial PV systems rose from 10% to 30% of project costs, and a 30% ITC (capped at \$2,000) was established for residential PV. [43] The

[43] The *American Recovery and Reinvestment Act*, signed into law in 2009, provides commercial PV projects the option, for a limited period of time, to receive an up-front cash grant from the Treasury Department of equal value to the federal ITC. For the purpose of the present analysis, we assume that the Treasury grant has the same economic value as the

Energy Improvement and Extension Act of 2008 subsequently lifted the $2,000 cap on the residential ITC for systems installed on or after January 1, 2009. In addition to the federal tax credits, a number of states have, at various times, offered state ITCs for PV, although these tax credits have generally been smaller and/or available to a more-restricted set of projects than the federal tax credit (see Appendix C for details on the ITCs for PV offered by the states in our dataset).

Figure 22 illustrates the combined effect of changes over time in state and federal ITCs (assuming that all customers take advantage of available tax credits) *plus* changes to the cash incentives provided through the state and utility PV incentive programs in the dataset, expressed here on an *after-tax* basis.[44] As noted previously, this assessment ignores potential revenues from the sale of RECs, though for most of the states in our dataset (other than New Jersey), such revenues would likely add only marginally to the overall incentive received (see Text Box 3).



Notes: We assume that all systems ≤10 kW are residential and all systems >10 kW are commercial (unless indentified otherwise). For residential systems, we assume that state/utility cash incentives are non-taxable and reduce the basis of the federal ITC. For commercial systems, we assume that state/utility cash incentives are taxed at a federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 22. After-Tax State/Utility Cash Incentives plus State & Federal ITCs (Calculated)

Figure 22 depicts a discernibly different trend than Figure 21, reflecting the introduction and subsequent increases in the federal ITC, occurring at different times for residential and commercial systems. Among residential PV systems, the decline in average aggregate incentive levels temporarily abated in 2006 when the federal ITC was extended to these systems, though the effect through 2008 was relatively small due to the $2,000 cap on the residential credit. After the cap on

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federal ITC for commercial PV. For a more thorough comparison of the relative value of the cash grant to the ITC, see: Bolinger, M., R. Wiser, and N. Darghouth. 2009. *Preliminary Evaluation of the Impact of the Section 1603 Treasury Grant Program on Renewable Energy Deployment in 2009*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-3188E.

[44] By expressing the incentives on an after-tax basis, we account for state and Federal income taxes that may be levied on direct cash incentives, as well as any reduction in the federal ITC tax basis associated with direct cash incentives. For further details, please refer to Appendix C.

the residential ITC was lifted in 2009, the average aggregate incentive for residential PV rose substantially to $3.9/W, approximately a 37% increase over the average in 2008.

For commercial PV systems, the decline in the aggregate after-tax incentive that began in 2002 abruptly reversed course in 2006, when the federal ITC for commercial PV increased from 10% to 30% of project costs. The aggregate commercial incentive has subsequently declined slowly over time as cash incentives have been reduced; as of 2009, the average aggregate after-tax financial incentive received by commercial PV systems was $3.9/W, virtually unchanged from the prior year and slightly below its peak of $4.2/W in 2006.[45] The fact that, over the 2005-2008 timeframe, combined after-tax incentives rose substantially for commercial PV while declining for residential PV may partially explain the shift towards the commercial sector within the U.S. PV market over that period. With the lifting of the cap on the federal ITC for residential PV in 2009, however, some movement back towards the residential sector has begun to occur.[46]

Net Installed Costs Dropped Sharply in 2009 for Residential PV, while Remaining Flat for Commercial PV

In 2009, average *net installed costs* – that is, installed costs minus the combined after-tax value of state/utility cash incentives and state/federal ITCs – stood at $4.1/W for residential PV and $4.0/W for commercial PV. For residential PV, the average net installed cost in 2009 represents an historical low, and was $1.3/W (or 24%) below the 2008 average, reversing the trend of the preceding several years during which average net installed costs for residential PV had been slowly rising. As discussed in Section 3, average pre-incentive installed costs remained relatively stable from 2005 to 2009, while average state/utility cash incentives were declining. The net effect of these two trends, as illustrated in Figure 23, is that the net installed cost of residential PV rose by approximately $0.7/W from 2006 to 2008. The dramatic reversal of this trend in 2009 is attributable to the lifting of the dollar cap on the federal ITC for residential PV installations beginning in that year. Given the expectation that state/utility cash incentives will continue to be ratcheted down, future reductions in the net installed cost of residential PV will require that reductions in pre-incentive installed costs keep pace with declining cash incentives.

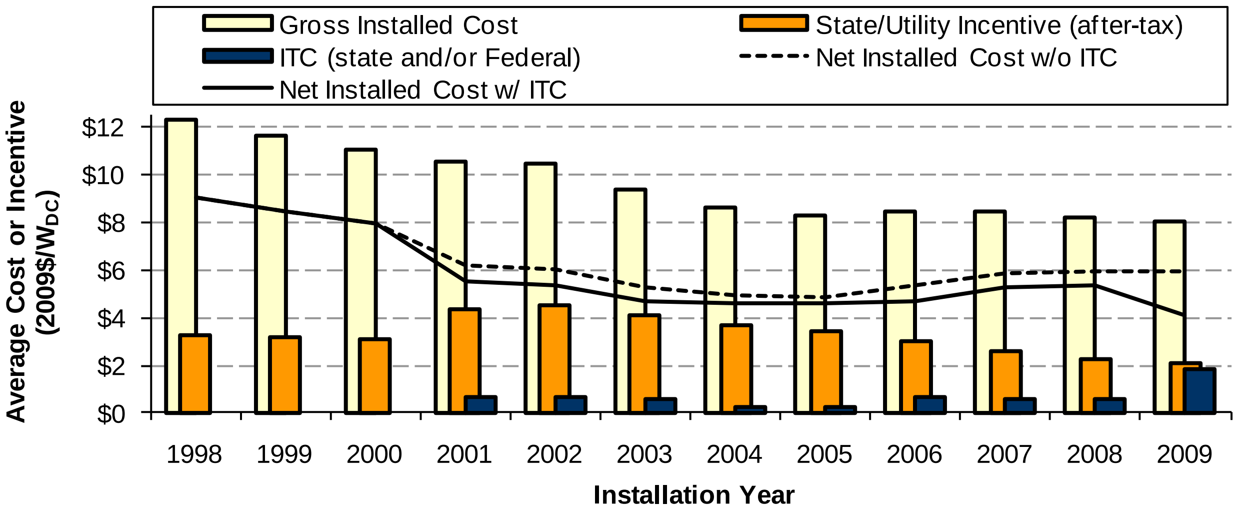
For commercial PV, the average net installed costs in 2009 was virtually unchanged from the preceding two years, and was up slightly (by $0.4/W or 11%) from the all-time low of $3.7/W in 2006. The long-term trend for commercial PV differs from the trend for residential PV, by virtue of the fact that commercial PV systems had access to the full, uncapped federal ITC beginning in 2006. Like residential PV, however, future reductions in average net installed costs will require that reductions in pre-incentive installed costs keep pace with expected future reductions in state/utility cash incentives.

Finally, Figure 23 and Figure 24 also illustrate the potential impact of incentive levels on gross (i.e., pre-incentive) installed costs. A previous Berkeley Lab report found a statistically significant

[45] Two trends exhibited in Figure 21 – that aggregate after-tax incentives for commercial PV in 2009 were virtually unchanged from the prior year and were slightly greater than aggregate after-tax incentives for residential PV in 2009 – appear on fist glance to be inconsistent with Figure 20, which indicates that state/utility cash incentives declined from 2008 to 2009, and that they were generally smaller for larger systems. The reason for this apparent inconsistency is that, from 2008 to 2009, commercial PV installations in the data sample shifted disproportionately toward PV incentive programs with relatively high incentive levels.

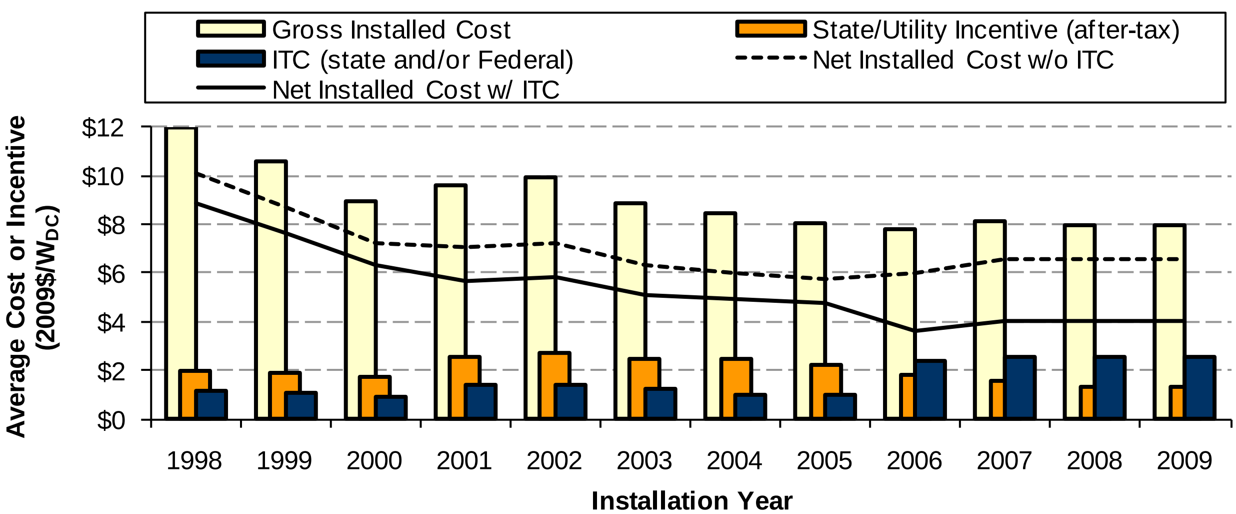
[46] Perhaps as one sign of movement back towards the residential sector, roughly 44% of all customer-sited PV capacity installed in 2009 consisted of residential systems, compared to 32% in 2008.

correlation between pre-incentive installed costs in California and incentive levels under the state's two major PV incentive programs operating from 1998-2005 (ERP and SGIP).[47] Evidence of this correlation can be seen in Figure 23 and Figure 24 (not surprisingly so, given the dominance of ERP and SGIP systems within the dataset). Most visibly, the decline in gross installed costs that had occurred during prior years ceased in 2001-2002, coinciding with a substantial increase in incentive levels under ERP and SGIP.



Notes: We assume that all systems ≤10 kW are residential , unless identified otherwise, and that state/utility cash incentives for residential PV are non-taxable and reduce the basis of the federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 23. Net Installed Cost of Residential PV over Time (Calculated)



Notes: We assume that all systems >10 kW are commercial, unless identified otherwise, and that state/utility cash incentives for commercial PV are taxed at a federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 24. Net Installed Cost of Commercial PV over Time (Calculated)

[47] Wiser, R., M. Bolinger, P. Cappers, and R. Margolis. 2006. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. LBNL-59282. Berkeley, California: Lawrence Berkeley National Laboratory.

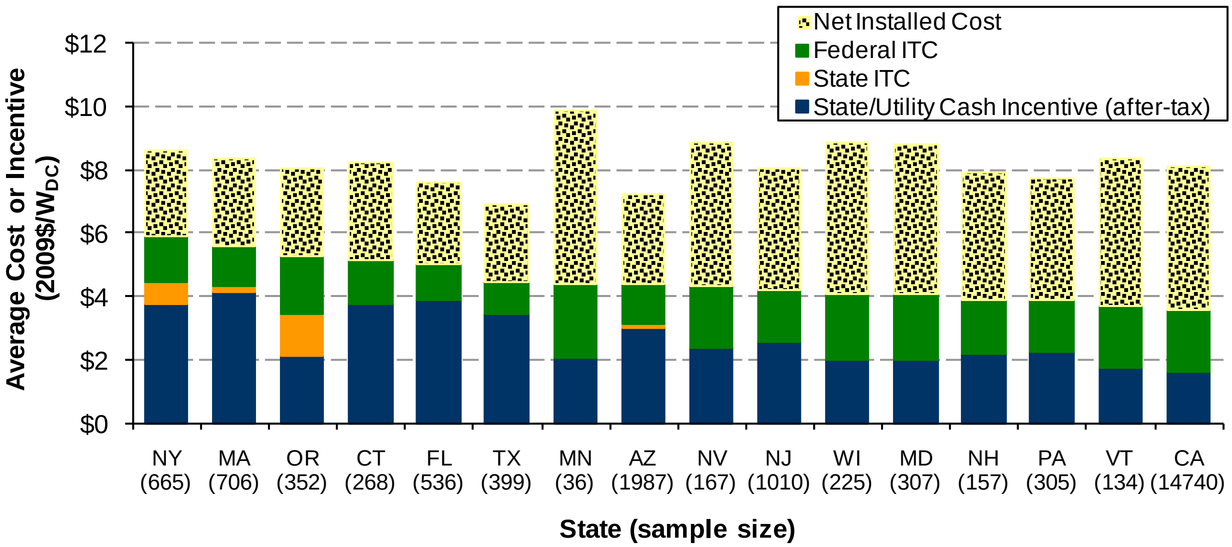
Incentives and Net Installed Costs Differ Widely Across States

The preceding incentive-related trends are drawn from the entire dataset and are therefore dominated by the PV incentive programs in California and New Jersey. Incentives and net installed costs, however, vary significantly across all the states in the sample. Figure 25 and Figure 26 compare average incentive levels and net installed costs across states in 2009, for residential and commercial PV systems, respectively.[48] Again, note that this analysis does not capture all types of financial incentives that may be available to PV systems in each state (e.g., incentives offered by PV incentive programs outside of those included in the data sample, or revenue from the sale of RECs). In addition, systems participating in New Jersey's SREC Registration program are excluded from the analysis in this section, and the New Jersey results presented in Figure 25 and Figure 26 are based solely on data from the state's Customer Onsite Renewable Energy (CORE) program and its successor, the Renewable Energy Incentive Program (REIP).[49] New Jersey's position within this analysis – especially among commercial PV systems – could look substantially different if systems funded through the SREC Registration Program were included, and if the value of SRECs (which have significant value in New Jersey, as discussed in Text Box 3) were included.

Among residential systems installed in 2009 (Figure 25), average after-tax incentives (i.e., direct cash incentives from state/utility PV incentive programs plus state and federal ITCs, but excluding revenue from sale of RECs) ranged from a low of $3.5/W in California to a high of $5.9/W in New York. Average net installed costs for residential PV were lowest in Texas ($2.4/W), which had relatively lucrative incentives and the lowest average pre-incentive installed cost among the 16 states. At the other end of the spectrum was Minnesota, with an average net installed cost for residential PV equal to $5.5/W in 2009.

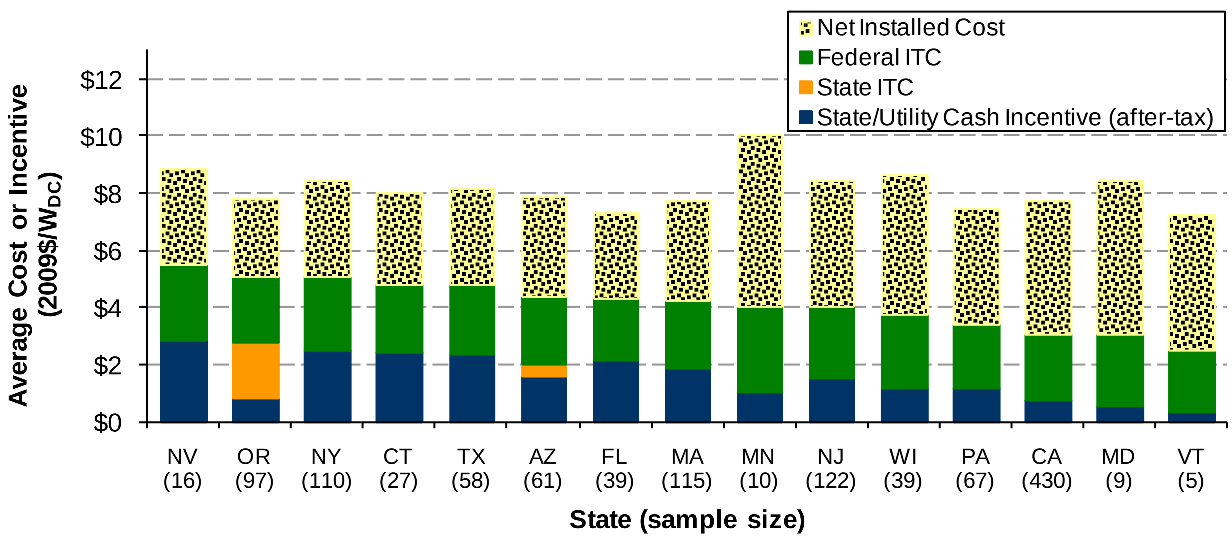
For commercial PV (Figure 26), average after-tax incentive levels and net installed costs also varied considerably across states in 2009. Average after-tax incentives were lowest in Vermont ($2.5/W) and were highest in Nevada ($5.5/W). Average net installed costs for commercial PV in 2009 was lowest in Oregon ($2.1/W), owing to its relatively lucrative incentives combined with relatively low pre-incentive installed costs, while Minnesota had the highest average net installed cost ($6.0/W), as a result of relatively low cash incentives and high pre-incentive installed costs.

[48] See Appendix B for data on the average annual cash incentive for each of the PV incentive programs in the dataset.
[49] Within the data sample, the CORE and REIP programs represents the vast majority (99%) of New Jersey residential PV systems installed in 2009. Among commercial PV systems installed in New Jersey in 2009, however, the CORE and REIP programs represent 68% of the systems, and only 17% of the capacity, with the remaining commercial systems funded through the SREC Registration program.



Notes: We assume that all systems ≤10 kW are residential unless identified otherwise, and that direct cash incentives for residential PV are non-taxable and reduce the basis of the federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE and REIP programs.

Figure 25. Comparison of Incentive Levels and Net Installed Cost across States for Residential PV Systems Installed in 2009 (Calculated)



Notes: We assume that all systems >10 kW are commercial unless identified otherwise, and that direct cash incentives for commercial systems are taxed at a federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE and REIP programs. NH is excluded from the figure, as the NH PV systems in the dataset are exclusively residential.

Figure 26. Comparison of Incentive Levels and Net Installed Cost across States for Commercial PV Systems Installed in 2009 (Calculated)

5. Conclusions

The number of photovoltaic systems installed in the United States. has been growing at a rapid pace in recent years, driven in large measure by government incentives. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage cost reductions over time. Out of this goal arises the need for reliable information on the historical installed cost of PV. To address this need, Lawrence Berkeley National Laboratory initiated a series of reports focused on describing trends in the installed cost of grid-connected PV systems in the United States. The present report, the third in the series, describes installed cost trends from 1998 through 2009, based on project-level data for approximately 78,000 grid-connected systems deployed across 16 states.

Available evidence confirms that the installed cost of customer-sited PV systems has declined substantially since 1998, though both the pace and source of those cost reductions have varied over time. Prior to 2005, installed cost reductions were associated primarily with a decline in non-module costs. Starting in 2005, however, cost reductions began to stall, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Starting in 2008 and continuing into 2010, wholesale module prices began a steep downward trajectory, in response to expanded manufacturing capacity and the global financial crisis. These reductions in module prices, however, did not translate into a noticeable reduction in average installed costs for PV systems in 2009, perhaps reflecting a natural lag between the time that PV system installation contracts are signed and when systems are installed. Preliminary evidence does suggest, though, that average installed costs for PV systems installed in 2010 will be substantially lower than in 2009. Those trends will be more fully explored in the next edition of this report.

The historical trend towards declining installed costs, along with the narrowing of cost distributions, suggests that PV deployment policies have achieved some success in fostering competition within the industry and spurring improvements in the cost structure and efficiency of the PV delivery infrastructure. Moreover, the fact that states with the largest PV markets also appear to have somewhat lower average costs than most states with smaller markets lends credence to the premise that state and utility PV deployment policies can affect local costs. However, even lower average installed costs in Japan and Germany suggest that deeper near-term cost reductions may be possible. Indeed, further cost reductions will be necessary if the PV industry is to continue its expansion in the customer-sited market, given the desire of PV incentive programs to ratchet down the level of financial support offered to PV installations.

Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents the data as provided directly by PV incentive program administrators; however, several steps were taken to clean the data and standardize it across programs, as described below.

Projects Removed from the Dataset: The initial data sample received from PV incentive program administrators consisted of 80,824 PV systems installed through 2009. To eliminate presumably erroneous numerical data entries, systems were removed from the dataset if the reported installed cost was less than $2/W (641 systems) or greater than $30/W (545 systems), or if the incentive amount was zero (57 systems) or greater than $30/W (236 systems). For the California Self Generation Incentive Program, systems receiving incentives from other subsidy programs were dropped (106 systems). In addition, systems missing installed cost data (1,545 systems), incentive data (929 systems), or system size data (278 systems) were removed from the dataset. Finally, 158 systems with battery back-up were removed from the dataset. In total, 2,872 systems from the initial sample were removed from the dataset as a result of these filters, yielding a final sample of 77,952 systems.

Manual Data Cleaning: Module manufacturer/model and inverter manufacturer/model data were reviewed in order to correct obvious misspellings and misidentifications, and to create standardized identifiers for individual module and inverter models.

Completion Date: The data provided by several PV incentive programs did not identify the system completion date. In lieu of this information, the best available proxy was used (e.g., the date of the incentive payment or the post-installation site inspection).

Identification of Residential New Construction and Residential Retrofit Systems: Section 3 compares the cost of systems installed in residential new construction to those installed in residential retrofit applications, focusing specifically on 1-3 kW systems installed through two California programs in 2009: the California Energy Commission (CEC)'s New Home Solar Partnership (NHSP) program and the California Solar Initiative (CSI). All systems installed through NHSP are assumed to be residential new construction, while all residential systems installed through CSI are assumed to be retrofit.

Identification of Building-Integrated and Rack-Mounted Residential Systems: The comparison between residential new construction and residential retrofit systems funded through NHSP and CSI is further differentiated between building-integrated PV (BIPV) and rack-mounted systems. The raw data provided by PV incentive program administrators did not include explicit identifiers for these categories; thus, systems were identified as either BIPV or rack-mounted by cross-referencing data provided on the module manufacturer and model for each system with the California Solar Initiative (CSI)'s List of Eligible Modules, which identifies whether modules are BIPV or rack-mounted.[50] Based on this procedure, 3,486 of the 3,492 applicable systems in the dataset (i.e., 1-3 kW systems funded through NHSP and CSI and installed in 2009) were identified as either BIPV or rack-mounted.

Identification of Crystalline and Thin-Film Systems: Section 3 compares the installed cost of systems with thin-film modules to those with crystalline modules. The raw data provided by PV program administrators generally do not include explicit identifiers for these categories. Thus, systems were categorized as crystalline, thin-film, or hybrid by cross-referencing data provided on module manufacturer and model with the CSI's List of Eligible Modules, which identifies whether modules are crystalline, thin-film, or hybrid. Based on this procedure, 21,497 of the 23,653 systems installed in 2009 were identified as employing either thin-film, crystalline, or hybrid modules.

[50] http://www.gosolarcalifornia.org/equipment/pvmodule.php

Conversion to 2009 Real Dollars: Installed cost and incentive data are expressed throughout this report in real 2009 dollars (2009$). Data provided by PV program administrators in nominal dollars were converted to 2009$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to Direct Current (DC) Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most programs directly provided data in units of DC-STC; however, four programs (the CEC's Emerging Renewables Program and the New Solar Home Partnership program, the CPUC's Self-Generation Incentive Program, and SMUD's Residential Retrofit and Commercial PV Programs) provided capacity data only in terms of the California Energy Commission Alternating Current (CEC-AC) rating convention. The CEC-AC rating represents peak AC power output at PVUSA Test Conditions (PTC). Capacity data from these four programs were converted to DC-STC, according to the procedures described below.

CEC Emerging Renewables Program (ERP), CEC New Solar Home Partnership (NSHP) Program, and SMUD Residential Retrofit and Commercial PV Programs: The data provided for these programs included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC ratings were identified for most modules by cross-referencing the information provided about the module type with the CSI's List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through these programs. The DC-STC rating for each module was then multiplied by the number of modules to determine the total DC-STC rating for the system, as a whole. This approach was used to determine the DC-STC capacity rating for all of the systems in the NSHP and SMUD datasets, and for 86% of the systems in the ERP dataset. For the remaining systems in the ERP dataset, either the module data fields were incomplete, or the module could not be cross-referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.200 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the averages for other systems in the ERP dataset.

CPUC Self-Generation Incentive Program (SGIP): The data provided for SGIP included data fields identifying module manufacturer and model (but not number of modules), and inverter manufacturer and model. DC-STC module ratings and DC-PTC module ratings (i.e., DC watts at PVUSA Test Conditions) were identified by cross-referencing the reported module type with the CSI's List of Eligible Photovoltaic Modules. Similarly, the rated inverter efficiency for each project was identified by cross referencing the reported inverter type with the CSI's List of Eligible Inverters, which identifies inverter efficiency ratings for most of the inverters used within the systems funded through SGIP.[51] These pieces of information (module DC-STC rating, module DC-PTC rating, and inverter efficiency rating), along with the reported CEC-AC rating for the system, were used to estimate the system DC-STC rating according to the following:

$$\text{System}_{DC\text{-}STC} = (\text{System}_{CEC\text{-}AC} / \text{Inverter Eff.}) * (\text{Module}_{DC\text{-}STC} / \text{Module}_{DC\text{-}PTC})$$

In cases where data on module manufacturer and model either was not provided or could not be matched with the CSI module list, then the DC-STC rating was calculated using the median ratio of module DC-STC to DC-PTC ratings for systems installed in the same year (0.88-0.90 $W_{DC\text{-}STC}/W_{DC\text{-}PTC}$). In cases where data on inverter manufacturer and model either was not provided or could not be matched with the CSI's inverter list, the inverter efficiency was stipulated based on the average inverter efficiency of systems in the SGIP dataset installed in the same year and for which inverter efficiency ratings could be identified. If neither the module nor inverter data were provided, then the DC-STC rating was calculated directly from the reported

[51] http://www.gosolarcalifornia.org/equipment/inverter.php

CEC-AC rating, using the median annual ratio of module DC-STC rating to system CEC-AC rating (1.19-1.22 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$).

Appendix B: Detailed Sample Size and Program-Level Summaries

Table B-1. Program-Level Annual Installation Data, Based on Final Study Sample

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
AZ	APS Solar & Renewables Incentive Program	*No. Systems*	-	-	-	-	4	10	42	73	183	231	369	1,379	***2,291***
		MW	-	-	-	-	0.0	0.1	0.2	0.4	1.1	1.4	3.0	8.9	***15.0***
	SRP EarthWise Solar Energy Program	*No. Systems*	-	-	-	-	-	-	-	27	124	107	112	669	***1,039***
		MW	-	-	-	-	-	-	-	0.1	0.5	0.6	1.6	4.8	***7.4***
CA	CEC Emerging Renewables Program (ERP)	*No. Systems*	39	178	213	1,238	2,246	2,964	4,540	3,862	6,117	5,862	688	-	***27,947***
		MW	0.2	0.7	0.9	4.8	9.8	15.1	22.4	20.4	34.2	34.3	3.6	-	***146.4***
	CEC New Solar Home Partnership (NSHP)	*No. Systems*	-	-	-	-	-	-	-	-	-	241	1,135	1,221	***2,597***
		MW	-	-	-	-	-	-	-	-	-	0.7	3.1	4.5	***8.3***
	CPUC California Solar Initiative (CSI)	*No. Systems*	-	-	-	-	-	-	-	-	-	3,549	8,297	13,228	***25,074***
		MW	-	-	-	-	-	-	-	-	-	33.3	136.7	156.0	***326.0***
	CPUC Self-Generation Incentive Program (SGIP)	*No. Systems*	-	-	-	-	16	71	147	191	143	141	87	10	***806***
		MW	-	-	-	-	2.3	11.6	17.3	26.9	29.5	33.4	24.6	2.9	***148.6***
	LADWP Solar Incentive Program	*No. Systems*	-	2	4	70	201	224	42	79	136	308	415	718	***2,199***
		MW	-	0.1	0.0	0.5	3.0	5.0	0.9	1.0	1.2	1.7	3.5	5.9	***22.9***
	SMUD Residential Retrofit and Commercial PV Programs	*No. Systems*	-	-	-	-	-	-	-	19	29	56	65	199	***368***
		MW	-	-	-	-	-	-	-	0.1	0.2	0.4	0.5	1.3	***2.5***
CT	CCEF Onsite Renewable DG Program	*No. Systems*	-	-	-	-	-	1	2	2	7	14	53	38	***117***
		MW	-	-	-	-	-	0.0	0.0	0.0	0.3	1.6	5.9	5.7	***13.6***
	CCEF Solar PV Program	*No. Systems*	-	-	-	-	-	-	-	32	89	168	272	268	***829***
		MW	-	-	-	-	-	-	-	0.1	0.4	0.9	1.7	1.8	***4.9***
FL	FEO Solar Energy System Incentives Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	-	372	***372***
		MW	-	-	-	-	-	-	-	-	-	-	-	2.8	***2.8***
MA	MassCEC Small Renewables Initiative*	*No. Systems*	-	-	-	-	-	-	-	-	1	-	1	575	***577***
		MW	-	-	-	-	-	-	-	-	0.0	-	0.0	4.6	***4.6***
MD	MEA Solar Energy Grant Program	*No. Systems*	-	-	-	-	1	70	127	91	258	214	369	860	***1,990***
		MW	-	-	-	-	0.0	0.3	0.6	0.8	1.8	1.6	2.8	12.4	***20.3***
MN	MSEO Solar Electric Rebate Program	*No. Systems*	-	-	-	-	-	-	-	7	43	45	135	316	***546***
		MW	-	-	-	-	-	-	-	0.0	0.2	0.1	0.5	1.4	***2.2***
NH	NHPUC Renewable Energy Rebate Program	*No. Systems*	-	-	-	-	1	8	23	12	24	39	37	54	***198***
		MW	-	-	-	-	0.0	0.0	0.1	0.0	0.1	0.2	0.1	0.3	***0.8***
NJ	NJCEP Customer Onsite Renewable Energy (CORE) Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	32	157	***189***
		MW	-	-	-	-	-	-	-	-	-	-	0.1	0.5	***0.5***
	NJCEP SREC Registration Program	*No. Systems*	-	-	-	-	-	-	287	727	849	677	744	575	***3,859***
		MW	-	-	-	-	-	-	2.0	9.9	18.0	15.2	14.0	15.5	***74.5***
	NJCEP Renewable Energy Incentive Program (REIP)	*No. Systems*	-	-	-	-	-	-	-	-	-	2	56	76	***134***
		MW	-	-	-	-	-	-	-	-	-	0.0	8.4	18.5	***26.9***

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
NV	NPC/SPPC RenewableGenerations Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	-	641	***641***
		MW	-	-	-	-	-	-	-	-	-	-	-	5.6	***5.6***
NY	NYSERDA PV Incentive Program	*No. Systems*	-	-	-	-	-	-	1	62	75	94	84	183	***499***
		MW	-	-	-	-	-	-	0.0	0.3	0.4	0.5	0.4	1.3	***2.9***
OR	ETO Solar Electric Program	*No. Systems*	-	-	-	-	-	44	122	113	191	332	409	779	***1,990***
		MW	-	-	-	-	-	0.2	0.5	0.6	1.1	2.0	2.9	6.5	***13.9***
PA	DEP Sunshine Solar PV Program (and other state agency programs**)	*No. Systems*	-	-	-	-	-	56	134	85	130	206	237	473	***1,321***
		MW	-	-	-	-	-	0.3	0.6	0.3	0.6	1.0	3.5	6.0	***12.3***
	SDF Solar PV Grant Program	*No. Systems*	-	-	-	-	3	17	28	23	54	21	18	-	***164***
		MW	-	-	-	-	0.0	0.1	0.1	0.1	0.2	0.1	0.1	-	***0.7***
TX	Austin Energy Power Saver Program	*No. Systems*	-	-	-	-	-	-	49	145	145	171	257	305	***1,072***
		MW	-	-	-	-	-	-	0.1	0.6	0.5	0.7	1.1	1.8	***4.8***
	IOU Solar Incentive Programs (AEP, Entergy, Oncor, SWEPCO, TNMP)	*No. Systems*	-	-	-	-	-	-	-	-	-	-	-	154	***154***
		MW	-	-	-	-	-	-	-	-	-	-	-	1.2	***1.2***
VT	RERC Small Scale Renewable Energy Incentive Program	*No. Systems*	-	-	-	-	-	-	33	15	24	61	93	139	***365***
		MW	-	-	-	-	-	-	0.1	0.0	0.1	0.2	0.4	0.5	***1.3***
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	*No. Systems*	-	-	-	-	6	9	12	22	62	96	143	264	***614***
		MW	-	-	-	-	0.0	0.0	0.0	0.1	0.2	0.5	0.8	1.6	***3.3***
Total		*No. Systems*	***39***	***180***	***217***	***1,308***	***2,478***	***3,474***	***5,589***	***5,587***	***8,684***	***12,635***	***14,108***	***23,653***	***77,952***
		MW	***0.2***	***0.8***	***0.9***	***5.4***	***15.2***	***32.6***	***44.9***	***62.0***	***90.4***	***130.4***	***219.3***	***272.2***	***874.1***

* Included within the totals shown for MassCEC's Small Renewables Initiative are systems funded through predecessor PV incentive programs offered by the Massachusetts Technology Collaborative that targeted residential and small non-residential PV systems.

** Pennsylvania state agencies have offered various grant and rebate programs for renewable energy systems; for simplicity, these programs are summarized in aggregate. Of these programs, the largest funding source for PV systems through 2009 has been the Pennsylvania Department of Environmental Protection (DEP)'s Sunshine Program.

Table B-2. Sample Size by Installation Year and System Size Range

System Size Range	Installation Year												Total
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	
No. Systems													
0-5 kW	31	156	180	1,108	1,877	2,258	3,490	3,176	4,982	7,200	8,139	12,280	**44,877**
5-10 kW	3	13	24	159	428	865	1,548	1,671	2,706	4,078	4,252	8,715	**24,462**
10-100 kW	5	10	12	36	152	308	508	637	882	1,206	1,363	2,349	**7,468**
100-500 kW	0	1	1	5	18	37	36	93	92	117	273	230	**903**
>500 kW	0	0	0	0	3	6	7	10	22	34	81	79	**242**
Total	*39*	*180*	*217*	*1,308*	*2,478*	*3,474*	*5,589*	*5,587*	*8,684*	*12,635*	*14,108*	*23,653*	***77,952***
Capacity (MW)													
0-5 kW	0.1	0.3	0.4	3.0	5.0	6.4	10.0	9.5	15.5	23.1	25.5	40.0	**138.8**
5-10 kW	0.0	0.1	0.2	1.0	2.8	5.8	10.5	11.8	18.7	28.3	29.1	59.2	**167.5**
10-100 kW	0.1	0.3	0.2	0.6	2.5	6.6	11.7	14.9	17.9	25.0	31.3	49.1	**160.1**
100-500 kW	0.0	0.1	0.1	0.8	3.2	8.5	7.5	18.4	20.6	27.0	65.9	51.5	**203.6**
>500 kW	0.0	0.0	0.0	0.0	1.7	5.3	5.1	7.4	17.7	27.1	67.5	72.3	**204.2**
Total	*0.2*	*0.8*	*0.9*	*5.4*	*15.2*	*32.6*	*44.9*	*62.0*	*90.4*	*130.4*	*219.3*	*272.2*	***874.1***

Table B-3. Annual Average Installed Cost and Direct Cash Incentives, by PV Incentive Program and System Size

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
AZ	APS Solar & Renewables Incentive Program	≤10 kW	No. Systems	-	-	-	-	4	9	40	68	173	219	331	1266
			Avg. Cost	-	-	-	-	*	12.7	8.7	8.6	8.6	7.9	7.2	7.2
			Avg. Incentive	-	-	-	-	*	4.4	4.3	4.2	3.9	3.2	2.9	3.0
		10-100 kW	No. Systems	-	-	-	-	-	1	2	5	9	11	34	112
			Avg. Cost	-	-	-	-	-	*	*	11.3	8.4	9.0	6.8	7.0
			Avg. Incentive	-	-	-	-	-	*	*	3.6	4.1	3.6	2.8	2.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4	1
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*	*
AZ	SRP EarthWise Solar Energy Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	27	122	103	96	592
			Avg. Cost	-	-	-	-	-	-	-	7.6	8.4	7.4	7.1	7.2
			Avg. Incentive	-	-	-	-	-	-	-	3.4	3.2	3.1	3.0	2.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	2	4	14	75
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.4	6.8
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	2.9	2.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	2	2
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	*	*
CA	CEC Emerging Renewables Program (ERP)	≤10 kW	No. Systems	34	168	200	1201	2107	2728	4184	3519	5498	5203	595	-
			Avg. Cost	12.3	11.6	11.0	10.5	10.5	9.3	8.5	8.2	8.3	8.4	8.1	-
			Avg. Incentive	3.3	3.2	3.1	4.3	4.3	3.9	3.5	2.9	2.6	2.4	2.3	-
		10-100 kW	No. Systems	5	9	12	33	135	234	356	343	619	659	93	-
			Avg. Cost	12.0	11.2	9.0	10.1	10.0	8.7	8.0	7.6	7.7	8.0	7.8	-
			Avg. Incentive	3.3	3.2	2.9	4.3	4.4	4.0	3.5	2.9	2.6	2.4	2.3	-
		>100 kW	No. Systems	-	1	1	4	4	2	-	-	-	-	-	-
			Avg. Cost	-	*	*	*	*	*	-	-	-	-	-	-
			Avg. Incentive	-	*	*	*	*	*	-	-	-	-	-	-
CA	CEC New Solar Home Partnership (NSHP)	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	239	1120	1166
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.1	8.0	7.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.3	2.3	2.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	15	53
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	6.7	7.3
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	2.3	2.4
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	2
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	*

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
CA	CPUC California Solar Initiative (CSI)	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	3253	7301	11872
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.4	8.2	8.1
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.0	1.7	1.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	267	781	1202
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.1	7.7	7.5
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.0	1.7	1.4
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	29	215	154
			Avg. Cost	-	-	-	-	-	-	-	-	-	7.1	7.4	7.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	1.6	1.3	1.1
CA	CPUC Self-Generation Incentive Program (SGIP)	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
		10-100 kW	No. Systems	-	-	-	-	10	44	108	107	72	53	31	4
			Avg. Cost	-	-	-	-	9.8	8.1	8.4	7.9	7.7	7.5	7.1	*
			Avg. Incentive	-	-	-	-	4.4	3.8	4.0	3.8	3.3	2.6	2.4	*
		>100 kW	No. Systems	-	-	-	-	6	27	39	84	71	88	56	6
			Avg. Cost	-	-	-	-	8.0	7.0	7.9	7.5	7.5	7.2	7.4	9.5
			Avg. Incentive	-	-	-	-	4.0	3.3	3.8	3.7	3.4	2.7	2.4	2.2
CA	LADWP Solar Incentive Program	≤10 kW	No. Systems	-	1	4	66	184	194	37	70	126	276	385	655
			Avg. Cost	-	*	*	11.0	10.8	9.6	8.8	8.0	8.7	8.8	8.4	8.4
			Avg. Incentive	-	*	*	5.7	6.4	5.9	3.7	3.2	3.5	3.7	3.6	3.5
		10-100 kW	No. Systems	-	1	-	3	6	17	3	6	7	32	25	60
			Avg. Cost	-	*	-	*	9.5	9.8	*	7.2	7.9	8.5	8.0	8.0
			Avg. Incentive	-	*	-	*	6.1	6.2	*	3.1	3.1	3.5	3.5	3.3
		>100 kW	No. Systems	-	-	-	1	11	13	2	3	3	-	5	3
			Avg. Cost	-	-	-	*	9.5	10.3	*	*	*	-	6.9	*
			Avg. Incentive	-	-	-	*	6.3	6.2	*	*	*	-	3.0	*
CA	SMUD Residential Retrofit and Commercial PV Programs	≤10 kW	No. Systems	-	-	-	-	-	-	-	16	27	53	63	189
			Avg. Cost	-	-	-	-	-	-	-	8.6	8.6	8.3	8.0	8.5
			Avg. Incentive	-	-	-	-	-	-	-	2.8	2.4	2.1	2.0	1.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	3	2	2	-	7
			Avg. Cost	-	-	-	-	-	-	-	*	*	*	-	8.0
			Avg. Incentive	-	-	-	-	-	-	-	*	*	*	-	1.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	2	3
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*	*

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
CT	CCEF Onsite Renewable DG Program	≤10 kW	No. Systems	-	-	-	-	-	1	1	1	1	2	10	2
			Avg. Cost	-	-	-	-	-	*	*	*	*	*	8.4	*
			Avg. Incentive	-	-	-	-	-	*	*	*	*	*	5.3	*
		10-100 kW	No. Systems	-	-	-	-	-	-	1	1	5	8	23	17
			Avg. Cost	-	-	-	-	-	-	*	*	8.8	8.5	8.2	8.5
			Avg. Incentive	-	-	-	-	-	-	*	*	4.8	4.6	4.3	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	4	20	19
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.7	7.3
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	4.2	3.8
CT	CCEF Solar PV Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	32	88	162	243	224
			Avg. Cost	-	-	-	-	-	-	-	9.0	9.2	9.2	8.7	8.3
			Avg. Incentive	-	-	-	-	-	-	-	5.0	4.7	4.4	4.2	3.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	6	29	44
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.5	8.3	8.0
			Avg. Incentive	-	-	-	-	-	-	-	-	*	3.8	4.1	3.6
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
FL	FEO Solar Energy System Incentives Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	305
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.7
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	2.2
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	66
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.4
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	2.0
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	*
MA	MassCEC Small Renewables Initiative	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	1	-	1	536
			Avg. Cost	-	-	-	-	-	-	-	-	*	-	*	7.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	-	*	3.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	38
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.3
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	3.5
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	*

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
MD	MEA Solar Energy Grant Program	≤10 kW	No. Systems	-	-	-	-	-	65	118	74	241	200	327	740
			Avg. Cost	-	-	-	-	-	10.5	9.2	9.3	9.5	9.3	8.6	8.4
			Avg. Incentive	-	-	-	-	-	4.9	5.0	5.0	4.2	4.2	3.8	4.0
		10-100 kW	No. Systems	-	-	-	-	1	5	9	17	14	12	38	92
			Avg. Cost	-	-	-	-	*	13.0	10.9	10.3	10.5	9.8	8.6	8.0
			Avg. Incentive	-	-	-	-	*	15.2	8.5	11.1	8.3	7.3	4.1	4.3
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	3	2	4	28
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*	6.8
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*	3.4
MN	MSEO Solar Electric Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	7	42	44	131	307
			Avg. Cost	-	-	-	-	-	-	-	11.4	11.7	10.7	9.3	8.8
			Avg. Incentive	-	-	-	-	-	-	-	1.3	1.6	1.5	1.8	2.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4	9
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*	8.4
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*	0.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
NH	NHPUC Renewable Energy Rebate Program	≤10 kW	No. Systems	-	-	-	-	1	8	23	12	24	37	36	49
			Avg. Cost	-	-	-	-	*	9.3	7.8	9.5	8.6	9.4	9.9	9.6
			Avg. Incentive	-	-	-	-	*	2.3	2.2	2.2	2.1	2.1	2.0	2.1
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	1	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*	9.6
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*	2.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
NJ	NJCEP Customer Onsite Renewable Energy (CORE) Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	32	157
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	8.7	7.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	2.4	2.1
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
NJ	NJCEP SREC Registration Program**	≤10 kW	No. Systems	-	-	-	-	-	-	267	592	706	570	596	398
			Avg. Cost	-	-	-	-	-	-	9.2	8.7	8.6	8.6	8.4	8.4
			Avg. Incentive	-	-	-	-	-	-	6.2	5.9	5.4	4.8	4.2	3.7
		10-100 kW	No. Systems	-	-	-	-	-	-	19	119	108	81	130	148
			Avg. Cost	-	-	-	-	-	-	9.5	8.5	8.5	8.9	8.3	8.1
			Avg. Incentive	-	-	-	-	-	-	5.4	5.6	5.1	4.5	4.0	3.4
		>100 kW	No. Systems	-	-	-	-	-	-	1	16	35	26	18	29
			Avg. Cost	-	-	-	-	-	-	*	7.5	7.4	7.3	8.1	8.2
			Avg. Incentive	-	-	-	-	-	-	*	4.3	4.0	3.5	3.2	2.6
NJ	NJCEP Renewable Energy Incentive Program (REIP)	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	21	11
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.0	7.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	15	19
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	7.5	7.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	20	46
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	6.9	6.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
NV	NPC/SPPC RenewableGenerations Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	555
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	1.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	86
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.6
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	1.3
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
NY	NYSERDA PV Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	1	55	69	89	80	167
			Avg. Cost	-	-	-	-	-	-	*	9.4	9.0	9.6	9.2	8.8
			Avg. Incentive	-	-	-	-	-	-	*	5.1	3.8	3.1	2.8	2.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	7	6	5	4	16
			Avg. Cost	-	-	-	-	-	-	-	13.6	9.4	8.1	*	8.8
			Avg. Incentive	-	-	-	-	-	-	-	5.3	4.2	3.4	*	4.4
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
OR	ETO Solar Electric Program	≤10 kW	No. Systems	-	-	-	-	-	38	113	97	170	306	362	654
			Avg. Cost	-	-	-	-	-	9.7	10.5	9.8	9.2	9.1	8.8	8.6
			Avg. Incentive	-	-	-	-	-	5.0	6.4	5.7	4.3	4.2	4.0	3.8
		10-100 kW	No. Systems	-	-	-	-	-	6	9	16	21	26	47	125
			Avg. Cost	-	-	-	-	-	9.5	8.5	8.3	9.3	9.3	8.8	8.3
			Avg. Incentive	-	-	-	-	-	5.6	5.4	4.5	4.4	4.1	4.1	3.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
PA	DEP Sunshine Solar PV Program (and other state agency programs)	≤10 kW	No. Systems	-	-	-	-	-	54	132	82	123	191	193	385
			Avg. Cost	-	-	-	-	-	8.1	7.4	7.8	8.6	8.9	8.7	8.0
			Avg. Incentive	-	-	-	-	-	4.7	4.1	3.2	2.1	2.0	1.9	2.1
		10-100 kW	No. Systems	-	-	-	-	-	1	1	3	7	15	36	76
			Avg. Cost	-	-	-	-	-	*	*	*	7.4	9.2	9.5	7.7
			Avg. Incentive	-	-	-	-	-	*	*	*	1.2	1.5	1.3	1.4
		>100 kW	No. Systems	-	-	-	-	-	1	1	-	-	-	8	12
			Avg. Cost	-	-	-	-	-	*	*	-	-	-	8.2	6.8
			Avg. Incentive	-	-	-	-	-	*	*	-	-	-	1.3	1.0
PA	SDF Solar PV Grant Program	≤10 kW	No. Systems	-	-	-	-	3	17	28	23	53	21	16	-
			Avg. Cost	-	-	-	-	*	10.7	12.3	10.4	9.4	9.5	9.8	-
			Avg. Incentive	-	-	-	-	*	6.6	5.8	5.6	5.2	4.9	3.9	-
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	-	2	-
			Avg. Cost	-	-	-	-	-	-	-	-	*	-	*	-
			Avg. Incentive	-	-	-	-	-	-	-	-	*	-	*	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
TX	Austin Energy Power Saver Program	≤10 kW	No. Systems	-	-	-	-	-	-	49	135	141	162	240	270
			Avg. Cost	-	-	-	-	-	-	7.4	7.2	7.2	7.3	7.6	6.8
			Avg. Incentive	-	-	-	-	-	-	5.2	5.1	4.3	4.3	4.3	3.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	10	4	9	17	35
			Avg. Cost	-	-	-	-	-	-	-	6.8	*	9.1	7.6	6.4
			Avg. Incentive	-	-	-	-	-	-	-	5.2	*	4.5	4.0	4.0
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2009
TX	IOU Solar Incentive Programs (AEP, Entergy, Oncor, SWEPCO, TNMP)	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	136
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	7.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	2.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	16
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	6.5
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	2.3
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	2
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	*
VT	RERC Small Scale Renewable Energy Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	33	15	24	60	88	134
			Avg. Cost	-	-	-	-	-	-	8.9	9.5	9.2	9.3	9.4	8.3
			Avg. Incentive	-	-	-	-	-	-	2.9	2.6	2.1	1.8	1.7	1.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	5	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.8	7.2
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	0.7	0.6
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	≤10 kW	No. Systems	-	-	-	-	6	9	12	22	59	86	124	225
			Avg. Cost	-	-	-	-	12.6	10.8	9.3	10.0	8.7	9.3	9.4	8.8
			Avg. Incentive	-	-	-	-	3.1	2.5	2.5	2.7	2.6	2.0	2.1	2.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	3	10	19	39
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.2	8.5	8.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	2.2	1.9	2.0
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-	-

* Average cost and incentive data are omitted if there are fewer than five systems.

** The NJ SREC-Only Pilot does not provide any direct cash incentive, but instead, provides financial support solely though the sale of solar renewable energy certificates based on solar energy production.

Appendix C: Calculating After-Tax Cash Incentives and State and Federal Investment Tax Credits

Section 4 presents trends related to combined after-tax financial incentives (direct cash incentives from state/utility PV incentive programs plus state and federal ITCs) and net installed costs after receipt of these incentives. Calculating this value required that several operations first be performed on the data provided by PV program administrators, as described below.

1. **Segmenting Systems as Residential, Commercial, or Tax-Exempt.** Data provided by many of the programs did not explicitly identify whether the PV systems were owned by residential, commercial, or tax-exempt entities. Unless otherwise identified, we classified all systems ≤10 kW as residential and all systems >10 kW as commercial.

2. **Estimating the After-Tax Value of Cash Incentives from State/Utility Incentive Programs.** Although the Internal Revenue Service (IRS) has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered federally-taxable income. As such, the cash incentives provided for systems in the dataset identified as commercial PV were assumed to be taxed at a federal corporate tax rate of 35%. The taxation of cash incentives for commercial PV at the state level may vary by state; for simplicity, we assume that all commercial PV systems are taxed at the "effective" state corporate tax rate, which accounts for the fact that state corporate taxes reduce the incentive-recipient's federally-taxable income. The effective state corporate tax rate applied to the cash incentive is equal to 65% (i.e., 1 minus 35%) of the nominal state corporate tax rate in 2009, which ranged from 0% to 9.99% among the 16 states in our dataset.[52]

   Cash incentives paid to residential PV system owners are exempt from federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." Notwithstanding this uncertainty, we assume that cash incentives provided to all systems in the dataset identified as residential PV are exempt from federal income taxes. The taxation of cash incentives for residential PV at the state level may vary by state, but for simplicity, we assume that all residential PV systems are also exempt from state income tax.

3. **Estimating the Value of Federal ITCs.** Projects in the dataset identified as residential PV and installed between January 1, 2006 and December 31, 2008 were assumed to receive a federal ITC equal to the lesser of 30% of the tax credit basis or $2,000; residential PV systems installed after December 31, 2008 were assumed to receive the full 30% ITC. Projects in the dataset identified as commercial PV are assumed to receive a federal ITC equal to 10% of the tax credit basis if installed prior to January 1, 2006, or 30% of the tax credit basis if installed after that date. Commercial PV systems installed in 2009 may have opted for the Treasury grant, in lieu of the ITC; for the purpose of this analysis, however, we assume that the economic value of the grant is equal to that of the ITC.

   The tax credit basis on which the federal ITC is calculated depends on whether cash incentives received by a project are federally-taxable. If the cash incentives are federally-taxable, as assumed for all commercial PV, then the federal ITC is calculated based on the full installed cost of the system. If, on the other hand, the cash incentives are not federally-taxable, as assumed for all

[52] http://www.taxadmin.org/fta/rate/corp_inc.html

residential PV, then the federal ITC is calculated based on the installed cost minus the value of the tax-exempt cash incentives.

4. **Estimating the Value of State ITCs.** We identified five of the 16 states in our dataset as having offered a state ITC for PV at some point from 1998-2009. Based on the information contained in Table C-1, we determined whether each project in the dataset was eligible for a state ITC, and if so, estimated the amount of the tax credit. In three states (California, New York, and Massachusetts), we assumed that the basis for the state ITC was reduced for any direct cash incentives ("rebates") and/or for the federal ITC. In addition, we accounted for the fact that state tax credits are financially equivalent to federally taxable income, because they increase the recipient's federally-taxable income by an amount equal to the size of the state tax credit. The net value of state ITCs was therefore reduced by the assumed federal income tax levied on the increased income. For commercial customers, we assumed a federal income tax rate of 35%. For residential customers, we assumed that the increased income would be taxed at the marginal rate applicable to a married couple filing jointly with federally taxable income of $150,000 (e.g., 28% in 2009).[53]

Table C-1: State ITC Details

<table>
<tr><th>State</th><th>Applicable Customers</th><th>System Size Cap</th><th>Applicable Period</th><th>Tax Credit Amount</th><th>Cap</th></tr>
<tr><td rowspan="2">AZ</td><td>Residential</td><td>None</td><td>1995-indefinite</td><td>25% of pre-rebate installed cost</td><td>$1,000</td></tr>
<tr><td>Non-Residential and Tax-Exempt</td><td>None</td><td>2006-2018</td><td>10% of pre-rebate installed cost</td><td>$25,000</td></tr>
<tr><td rowspan="2">CA</td><td>All</td><td>200 kW</td><td>2001-2003</td><td>15% of net installed cost after state rebate and federal ITC</td><td>None</td></tr>
<tr><td>All</td><td>200 kW</td><td>2004-2005</td><td>7.5% of net installed cost after state rebate and federal ITC</td><td>None</td></tr>
<tr><td>MA</td><td>Residential</td><td>None</td><td>1979-indefinite</td><td>15% of net installed cost after federal ITC</td><td>$1,000</td></tr>
<tr><td rowspan="2">NY</td><td>Residential</td><td>10 kW</td><td>1998-9/1/2006</td><td>25% of net installed cost after rebate</td><td>$3,750</td></tr>
<tr><td>Residential</td><td>10 kW</td><td>9/1/2006-indefinite</td><td>25% of net installed cost after rebate</td><td>$5,000</td></tr>
<tr><td rowspan="3">OR</td><td>Residential</td><td>None</td><td>11/4/2005-indefinite</td><td>$3/W based on rated capacity (DC-STC)*</td><td>$6,000 up to 50% of pre-rebate installed cost**</td></tr>
<tr><td>Non-Residential and Tax-Exempt</td><td>None</td><td>1981-2006</td><td>35% of pre-rebate installed cost</td><td>$10,000,000</td></tr>
<tr><td>Non-Residential and Tax-Exempt</td><td>None</td><td>2007-2017</td><td>50% of pre-rebate installed cost (up to maximum eligible cost***)</td><td>$10,000,000</td></tr>
</table>

* Tax credit paid out over multiple years, with an annual limit of $1,500/yr. To calculate the after-tax value of the tax credit, the stream of credits was discounted at a 10% nominal discount rate.

** For systems installed after August 13, 2010, the cap on the Oregon state tax credit for residential PV is based on *net* installed cost after deducting the value of any up-front cash incentives and the federal ITC. This provision, however, does not affect the systems within the data sample, all of which were installed prior to 2010.

*** The maximum eligible cost varies by system size and date of installation. The tax credit is paid out over five years. To calculate the after-tax value of the tax credit, the stream of credits was discounted at a 10% nominal discount rate.

[53] http://www.taxfoundation.org/taxdata/show/151.html

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