Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition

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Technical Report
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Executive Summary

This report presents results from the second U.S. Department of Energy (DOE) sponsored, bottom-up data-collection and analysis of non-hardware balance-of-system costs—often referred to as "business process" or "soft" costs—for U.S. residential and commercial photovoltaic (PV) systems. Annual expenditure and labor-hour-productivity data are analyzed to benchmark 2012 soft costs related to (1) customer acquisition and system design and (2) permitting, inspection, and interconnection (PII). We also include an in-depth analysis of costs related to financing, overhead, and profit.

The second annual survey of U.S. PV installers was deployed from September 2012 to May 2013, focusing on customer acquisition and PII costs for the study period of January 1 to June 30, 2012. We gathered data from 55 residential PV installers, representing 4,260 residential installations and approximately 27 MW of residential capacity installed during the first half of 2012. We cleaned the data for outliers, yielding sample sizes ranging by cost category from 47 to 53. We also gathered data from 22 commercial PV installers, representing 269 commercial PV installations during the 6-month study period for a total of 66 MW of capacity.

According to our analysis, the soft costs accounted for a significant portion of total installed PV system prices in the first half of 2012: 64% of the total residential system price, 57% of the small (less than 250 kW) commercial system price, and 52% of the large (250 kW or larger) commercial system price.

In contrast to the first edition of this report, in this second edition we have unpacked the "other soft cost" category using a detailed "bottom-up" cost-accounting framework into five categories: transaction costs, indirect corporate costs, installer/developer profit, supply chain costs, and sales tax. Specifically, we model a third-party ownership structure, capturing the costs of doing business that have not been previously quantified, such as engineering, procurement, and construction (EPC), developer and finance department staff and overhead, professional/legal services, capital costs during construction, and other costs that may not be attributable to specific PV projects. The detailed breakdown of soft and hard costs are shown in Figure ES-1.

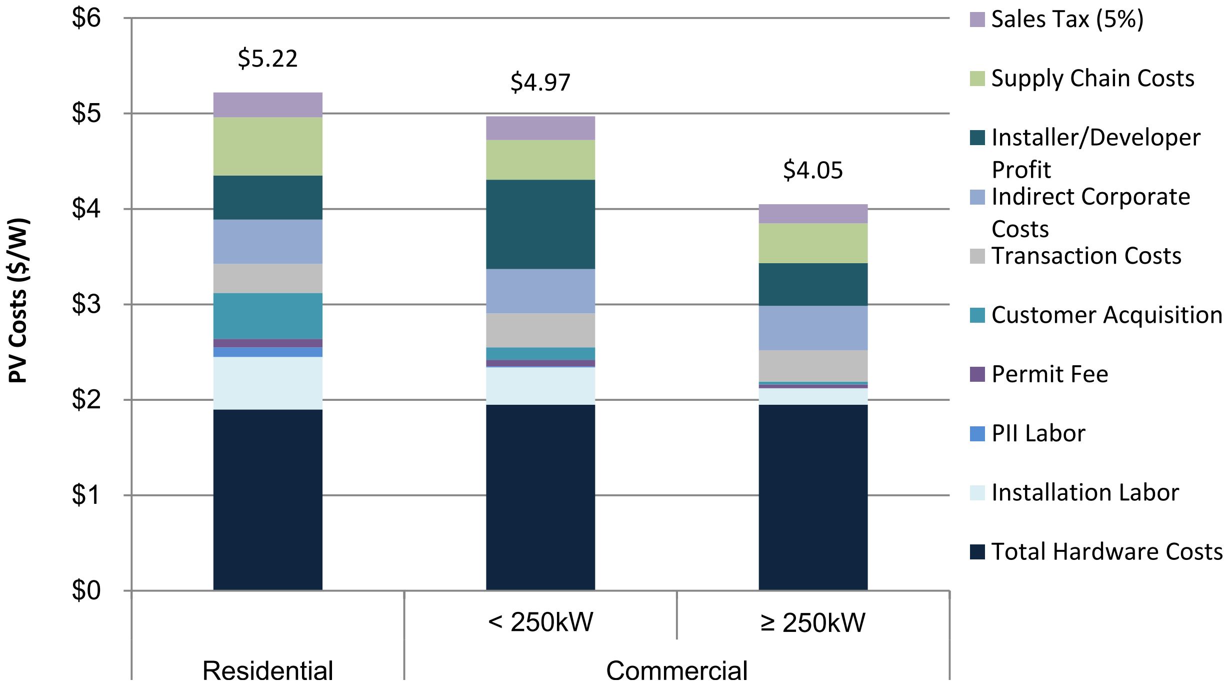

Figure ES-1. Total PV system price, by sector and system size (first half of 2012)

The plotted values are derived from our survey, modeling, and calculations (installation labor, PII labor, customer acquisition, transaction costs, indirect corporate costs, and installer/developer profit); Barbose et al. (2013) and Feldman et al. (2013-a) (total soft costs, which helped determine installer/developer profit); Feldman et al. (2013-a) (sales tax and supply chain costs); and assumptions based on Vote Solar (2011), Sunrun (2011), Newick (2012), and internal analysis (permit fee). Residential systems are assumed to be 5kW. Note that each value relies on various specific assumptions as well as the specific method used to generate it; thus the results should be interpreted as an estimate of one possible set of soft costs rather than the soft costs for specific systems in the first half of 2012. At this early stage of benchmarking soft costs, it is necessary to draw values from different sources and methods, as different soft-cost categories lend themselves to different approaches.

As shown in Figure ES-1, we find that economies of scale helped reduce soft costs, particularly when comparing the residential and small commercial systems with the large commercial systems. Among the individual soft-cost categories we characterized, supply chain costs, indirect corporate costs, transaction costs, and installer/developer profit are dominant contributors, followed by installation labor, sales tax, and customer acquisition. PII contributes relatively little cost when measured in terms of dollars per watt but presents a market barrier that can deter project completion entirely. It is difficult to know for certain how many projects are deterred in this way each year, but the issue underscores the importance of considering market barriers and other market factors, rather than limiting soft-cost analysis to installed costs. Our analysis suggests that customer acquisition and PII costs decreased from 2010 to 2012.

The SunShot Initiative aims to reduce the installed-system price contribution of all soft costs to approximately $0.65/W for residential systems and $0.44/W for commercial systems by 2020, in 2010 dollars (DOE 2012).[1] The soft costs we characterized contributed $3.19/W for residential systems, $2.90/W for small commercial systems, and $2.02/W for large commercial systems, in 2010 dollars.

[1] The SunShot Initiative's total installed price targets are $1.50/W for residential systems and $1.25/W for commercial systems.

Soft costs for residential and large commercial systems declined in the United States between 2010 and 2012, while small commercial soft costs increased. This second benchmarking effort characterizes all PV soft costs—which the previous edition did not—and represents the most granular analysis to date that measures progress toward the SunShot soft-cost-reduction targets.

Soft costs are both a major challenge and a major opportunity for reducing PV system prices and stimulating SunShot-level PV deployment in the United States. The data and analysis in this series of benchmarking reports are a step toward the more detailed understanding of PV soft costs required to track and accelerate these price reductions.

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1 Summary of Survey Results

In 2012, soft costs accounted for more than half of total system prices for residential, small commercial and large commercial photovoltaic (PV) installations (Figure 1).[2] We used our various data sources and methods to attribute all these soft costs to specific categories in the first half of 2012 (Figure 1 and Table 1). For residential systems, the greatest soft costs were supply chain costs ($0.61/W), installation labor ($0.55/W), customer acquisition ($0.48/W), and indirect corporate costs ($0.47/W). For small commercial systems, the largest soft costs were developer/installer profit ($0.94/W), indirect corporate costs ($0.47/W), supply chain costs ($0.42/W), and transaction costs ($0.36/W). For large commercial systems, the largest soft costs were indirect corporate costs ($0.47/W), supply chain costs ($0.42/W), and transaction costs ($0.33/W).[3]

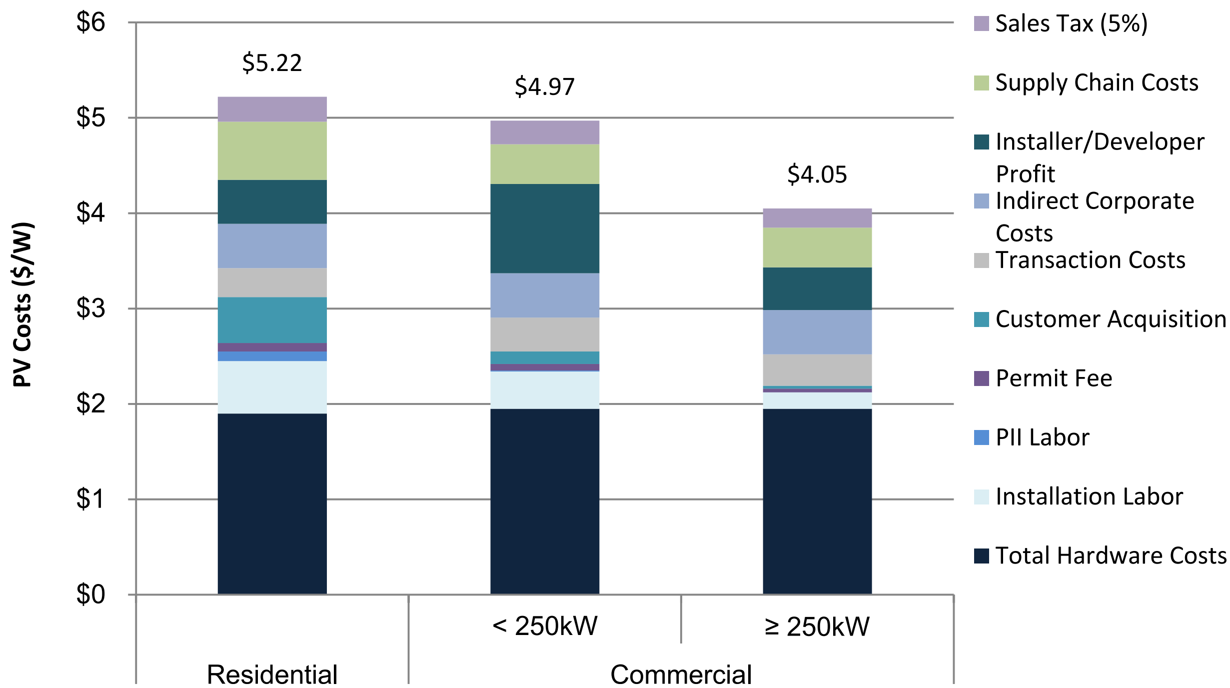

Figure 1. Total PV system price, by sector and system size (first half of 2012)

The plotted values are derived from our survey, modeling, and calculations (installation labor, PII labor, customer acquisition, transaction costs, indirect corporate costs, and installer/developer profit); Barbose et al. (2013) and Feldman et al. (2013-a) (total soft costs, which helped determine installer/developer profit); Feldman et al. (2013-a) (sales tax and supply chain costs); and assumptions based on Vote Solar (2011), Sunrun (2011), Newick (2012), and internal analysis (permit fee). Residential systems are assumed to be 5kW. Note that each value relies on various specific assumptions as well as the specific method used to generate it; thus the results should be interpreted as an estimate of one possible set of soft costs rather than the soft costs for specific systems in the first half of 2012. At this early stage of benchmarking soft costs, it is necessary to draw values from different sources and methods, as different soft-cost categories lend themselves to different approaches.

[2] The total average system prices are based on the average installed prices cited by Barbose et al. (2013) for PV systems of comparable size installed in 2012. The value for total soft costs is then calculated as the difference between total average installed price and the sum of all hardware-related costs for 2012 PV systems (Feldman et al. 2013a).
[3] Given that the majority of respondents are based in California, it should be noted that costs may be skewed upward of national averages, given the generally higher fixed costs and electricity prices in California.

Table 1. Residential and Commercial PV System Soft Costs (first half of 2012)

Soft-Cost Category	Residential Systems		Small Commercial Systems (< 250 kW)		Large Commercial Systems (≥ 250 kW)	
	Cost (2012$/W)	Proportion of System Price	Cost (2012$/W)	Proportion of System Price	Cost (2012$/W)	Proportion of System Price
Customer acquisition (surveyed)	0.48	9.2%	0.13	2.6%	0.03	0.7%
Installation labor (calculated)	0.55	10.5%	0.39	3.8%	0.17	4.7%
Permitting, inspection, and interconnection (surveyed)	0.10	1.9%	0.01	0.2%	0.00	0.0%
Transaction costs (modeled)	0.30	5.8%	0.36	7.1%	0.33	8.1%
Indirect corporate costs (modeled)	0.47	8.9%	0.47	9.4%	0.47	11.5%
Installer/developer profit (modeled)	0.46	8.8%%	0.94	18.8%	0.45	11.1%
Supply chain costs (Feldman et al. 2013-a)	0.61	11.7%	0.42	8.4%	0.42	10.3%
Sales tax, 5% (Feldman et al. 2013-a)	0.26	5.0%	0.25	5.0%	0.20	5.0%
Permitting fees (assumed)	0.09	1.7%	0.07	1.4%	0.04	0.7%
All characterized soft costs	**3.32**	**63.5%**	**3.01**	**56.7%**	**2.10**	**52.0%**
Total hardware costs	1.90	36.4%	1.95	39.2%	1.95	48.1%
Total Costs	**5.22**	**100%**	**4.97**	**100%**	**4.05**	**100%**

Individual values may not add up to totals owing to rounding.

In the United States, residential photovoltaic (PV) hardware costs declined from approximately $3.30/W in 2010 to $1.83/W in 2012 (in 2010 dollars), with wholesale module prices widely reported at well under $1/W.[4] Over the same period, the capacity-weighted average of residential U.S. PV system prices declined from $6.60/W to $5.02/W in 2010 dollars (Barbose et al. 2013).[5] Thus, similar to the period of 2005–2010, non-hardware balance-of-system (BOS) costs—often referred to as "business process" or

[4] The $3.30/W hardware cost estimate for 2010 is from Goodrich et al. (2012). The $1.83/W hardware cost estimate for 2012 is from Feldman et al. (2013a), adjusted to 2010 dollars. All other cost and price figures in the report refer to 2012 dollars.
[5] The value of $5.02/W was derived by converting the $5.22/W value in Barbose et al. (2013) to 2010 dollars for comparison with 2010 benchmarks.

“soft” costs—continued to account for an increasing portion of average installed residential PV system prices in the United States: from approximately 50% ($3.30/W) of total installed price in 2010 to approximately 64% ($3.19/W) in 2012. Commercial PV system costs followed similar trends.

The U.S. Department of Energy’s (DOE’s) SunShot Initiative aims to reduce the installed-system price contribution of all soft costs to approximately $0.65/W for residential PV systems and $0.44/W for commercial systems by 2020, in 2010 dollars (DOE 2012).[6] This is the second report in the National Renewable Energy Laboratory’s (NREL’s) benchmarking series established to track and analyze the rapidly evolving price structures of PV systems, with a particular focus on soft costs.

A number of previous analyses have examined non-module PV system hardware costs, including the costs of power electronics and other BOS hardware elements. Several other analysts have examined soft costs, which include permitting and commissioning, profit, overhead, installation labor, customer acquisition, and financing. Few have attempted to understand what has sometimes been called the “other” soft-cost category. Our analysis provides current benchmarks for a fuller scope of residential and commercial PV system costs. Unlike hardware costs, which can be benchmarked readily with data from equipment manufacturers and purchasers (and for which a variety of available indexes already exist), quantifying soft costs requires detailed tracking of the time and resources needed to complete the various stages of a PV system sale and installation. To accomplish this, we fielded our second annual survey of U.S. PV installers, collecting data on labor hours required per installation as well as aggregate expenditures for customer acquisition and system design. As in our first benchmarking study (Ardani et al. 2012), we translate labor-hour requirements per installation into dollars per watt using system size, labor class and composition assumptions, and fully burdened wages.[7] Our survey data and analysis focus on soft costs related to (1) customer acquisition and system design and (2) permitting, inspection, and interconnection (PII). In conjunction with our soft-cost modeling, we are able to unpack the “other soft cost” category by attributing all soft costs to specific categories.

Concurrent with our installer survey, we conducted a series of in-depth interviews with members of financing departments at large PV installation companies on the subjects of third-party financing and overhead costs, and we collected data from industry participants’ corporate public filings. These interviewees vetted a first-of-its-kind, bottom-up model that attempts to capture previously opaque cost values. This includes the first effort to articulate overhead that can be layered across the downstream value chain, including costs associated with bundling systems for investors. The model was developed for both residential and commercial third-party-owned installations. The remainder of this report is structured as follows. Section 2 briefly describes the existing soft-cost literature. Section 3 describes our survey and analysis methodology. Section 4 describes the residential PV system data collection and results, and Section 5 does the same for commercial PV systems. Section 6 goes into depth on costs related to third-party financing and overhead, and Section 7 discusses the study’s limitations. Section 8 summarizes the soft-cost reductions during the period between the two benchmarking studies (2010 and 2012 benchmarks) as well as the differences and similarities between the two datasets. Finally, Section 9 draws conclusions and outlines areas for potential future work. Appendix A contains our installer survey

[6] The SunShot Initiative’s total installed price targets are $1.50/W for residential systems and $1.25/W for commercial systems. For more information on the SunShot Initiative and SunShot soft-cost targets, visit www.eere.energy.gov/solar/sunshot.

[7] Burdened labor rates include worker’s compensation insurance, 6.4%; federal and state unemployment insurance, 6.2%; Social Security taxes (FICA), 7.65%; builder’s insurance, 0.44%; and public liability insurance, 2.02% (RSMeans 2010).

instrument. Throughout the report, all values are in 2012 dollars unless otherwise specified; in particular, Section 8 compares the 2010 and 2012 analyses and the SunShot targets in 2010 dollars.

2 Existing Literature

Recent studies of soft costs and their impact on PV markets provide new insights into specific soft-cost components, most notably on the topic of permitting. Most of the existing literature analyzes the general barriers to large-scale U.S. PV deployment due to high soft costs, whereas our analysis disaggregates soft costs further and provides benchmarks for progress toward the SunShot Initiative's soft-cost targets.

A number of recent and ongoing studies examine soft costs broadly. Greentech Media (GTM) published a proprietary, comprehensive BOS cost study that includes detailed cost and market data by global region as well as BOS cost forecasts out to 2016 (Smith and Shiao 2012). The Rocky Mountain Institute (RMI) analyzed U.S. BOS costs, focusing on commercial and utility-scale systems of up to 20 MW in capacity (Bony et al. 2010). Additional efforts to estimate soft costs are available via subscription from Photon Consulting, Bloomberg New Energy Finance, and other consulting organizations.

A substantial body of literature focuses on the effects of permitting processes on PV installations (Brooks 2011; Rose et al. 2011; Varnado and Sheehan 2009; Pitt 2008). Clean Power Finance (CPF) found that 36% of residential PV installers avoid operating in certain jurisdictions because of onerous permitting requirements (Tong 2012). Lawrence Berkeley National Laboratory (LBNL) found that streamlining city-level permitting processes could reduce the average price of 4-kW residential PV systems in California by $1,000 or more and cut development time by roughly 1 month; permitting processes caused differences in average PV installed prices among cities of up to $0.27–$0.77/W (Wiser and Dong 2013). PV installer Sunrun indicated that local permitting and inspection adds as much as $2,516 per installation to residential costs (up to $0.50/W) for a 5-kW system (Sunrun 2011). The Sierra Club reports permitting fees across California jurisdictions, gathered through an ongoing survey process (Mills and Newick 2011). Vote Solar has expanded on these California fee data to include permitting information, and it has published the data online through its Project Permit Initiative (Vote Solar 2011). Taken together, these studies suggest that the heterogeneity of permitting processes among various jurisdictions and the relative inexperience with PV requirements among many local officials continue to be significant market barriers.

Comparative studies of PV installation costs in other countries are also informative. In Germany, residential soft costs are only 10% of those in the United States (Guccione et al. 2013). Australia is another example of a country that is implementing effective soft-cost-reduction strategies (Chan et al. 2013).

There are also a number of studies that examine PV system pricing more generally.[8] For example, LBNL produces a series of reports aggregating historical price data sourced primarily from state and utility PV incentive programs, such as the California Solar Initiative (Barbose et al. 2013). This top-down approach, however, cannot identify component-level costs beyond the broad categories of module, inverter, and other.[9] In contrast, Goodrich et al. (2012) use a bottom-up modeling methodology to benchmark PV system prices and report detailed component costs such as installation materials, electrical labor, installation labor, supply chain costs, permitting and commissioning, and installer overhead. Although this work is among the most granular available in the existing literature, soft costs remain relatively aggregated—a limitation that our work aims to address.

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[8] "Price" here means the price paid by the end user.

[9] Barbose et al. (2013) use the category "other" to capture all costs other than module and inverter costs.

3 Methodology

From September 2012 through May 2013, we disseminated a 17-question online survey to U.S. residential and commercial PV installers to benchmark the average time and cost of business processes for PV systems installed in the first half of 2012. Appendix A shows the complete survey instrument. We distributed and followed-up on the survey through a multi-pronged strategy that included telephone interviews covering the survey questions, webinars, outreach at conferences, social media, and e-mails to distribution lists held by NREL, DOE, the Solar Energy Industries Association, Solartech, Vote Solar, and others.

The survey collected PII-related labor hour data, and we translated these hours per installation into dollars per watt using assumed system size (for residential systems), actual average system sizes of individual installers (for commercial systems), and assumptions about labor class, proportional share of labor, and fully burdened labor rates. Table 2 depicts the labor-related assumptions used to calculate labor costs (U.S. Bureau of Labor Statistics 2011). We assumed flat permitting fees for residential and commercial installations (as described in Sections 4.2.2 and 5.2.2). In addition, total expenditure data were collected in the areas of customer acquisition and system design. Annual expenditures were translated into dollars per watt, for each cost category, based on the reported number of installations and assumed (for residential systems) and average (for commercial systems) PV system size.

The cost categories included in our 2012 survey are similar to those included in the 2010 survey (Ardani et al. 2012), with a few key differences as described in Section 8. Importantly, the 2012 survey did not include questions on installation labor that were included in the 2010 survey. Instead, an efficiency improvement assumption of 7% was applied to the 2010 installation labor cost benchmarks as described in Section 8.

Table 2. Labor Class and Wage Assumptions Used to Calculate Labor Costs

Soft-Cost Category	Occupation (labor class)	Share of Labor Used (%)	Burdened Wage ($/h)
Permit preparation	Permit procurement	70	36.69
	Administrative staff	30	19.56
Permit submission	Permit procurement	30	36.69
	Administrative staff	70	19.56
Inspection	Installer (roofer)	70	40.49
	Administrative staff	30	19.56
Interconnection	Permit procurement	30	36.69
	Administrative staff	70	19.56
Incentive application process	Installer (roofer)	30	40.49
	Administrative staff	70	19.56

Source: U.S. Bureau of Labor Statistics (2011).

To gain a better understanding of the costs associated with running a PV installation business, we modeled a third-party financing business structure to capture fully the indirect costs of residential and commercial installations. We modeled a third-party financing structure because this business model is currently the most common in the marketplace (Kann 2013). During the survey period, we conducted a series of in-depth interviews with members of financing departments at large PV installation companies on the subjects of third-party financing and overhead costs. We also collected data from industry participants' corporate public filings, which enabled us to refine the model.

4 Residential PV System Data Collection and Results

4.1 Sample Market Representation and Characterization

From September 2012 through May 2013, we gathered data from 55 residential PV installers, representing 4,260 residential installations and approximately 27 MW of residential capacity installed during the first half of 2012. We cleaned the sample for outliers on a per-question basis by eliminating the highest 5% and lowest 5% of cost-per-watt values and obviously erroneous responses. The cleaned sample sizes range by cost category from 47 to 53. The sample is predominantly composed of small-volume installers, with only 12 respondents completing more than 100 installations during the study period and three respondents completing 600 or more. The three largest-volume installers in the sample combined to complete approximately 2,500 installations, about 60% of the total number of systems in the sample.[10]

4.2 Residential Results

We assumed an average system size of 5 kW when calculating cost per watt for all soft-cost categories examined at the residential scale. The residential survey results are reported below in terms of the average cost per watt (in 2012 dollars), across respondents, weighted by total number of installations per respondent.

4.2.1 Customer Acquisition

Customer-acquisition activities can add considerable time and cost to PV installations, perhaps especially in states with less-mature markets where perceived technology risk and unfamiliarity with PV might increase bid-failure rates. Expenses related to customer acquisition—such as lead generation, bid and pro-forma preparation, contract negotiation, and system design—increase the cost of doing business. Our survey asked installers to provide their total expenditures on customer-acquisition activities for residential PV installed in the first half of 2012, segmented into two cost categories: system design and all other customer-acquisition costs.[11] Following the methodology explained in Section 3, these annual dollar amounts were translated into dollars per watt. Average installer expenditures on customer-acquisition activities totaled $0.48/W for a typical 5-kW residential PV installation: $0.08/W for system design and $0.40/W for all other customer-acquisition costs (Table 3).

Table 3. Customer-Acquisition Costs for Residential PV Installers

Cost Component	Cost ($/W)
System design	0.08
All other customer-acquisition costs	0.40
Total	**0.48**

In contrast to the 2010 survey results, the 2012 results provide limited, anecdotal evidence of economies of scale associated with customer-acquisition costs: two of the three largest installers surveyed had customer-acquisition costs of less than half of the median surveyed value of $0.26/W.

[10] The potential for skewed sample effects are discussed in detail in Section 7.

[11] "All other customer acquisition costs" include marketing and advertising, sales calls, site visits, travel time to and from the site, contract negotiation with the system host/owner, and bid/pro-forma preparation—but exclude system design.

Figure 2, however, indicates that customer-acquisition costs varied significantly among the low-volume installers surveyed, with six reporting costs of $1.00/W or more and 33 reporting costs of $0.25/W or less. For illustrative purposes, in Figures 2 and 3 we have excluded extreme outliers as indicated in the graphic insets.[12]

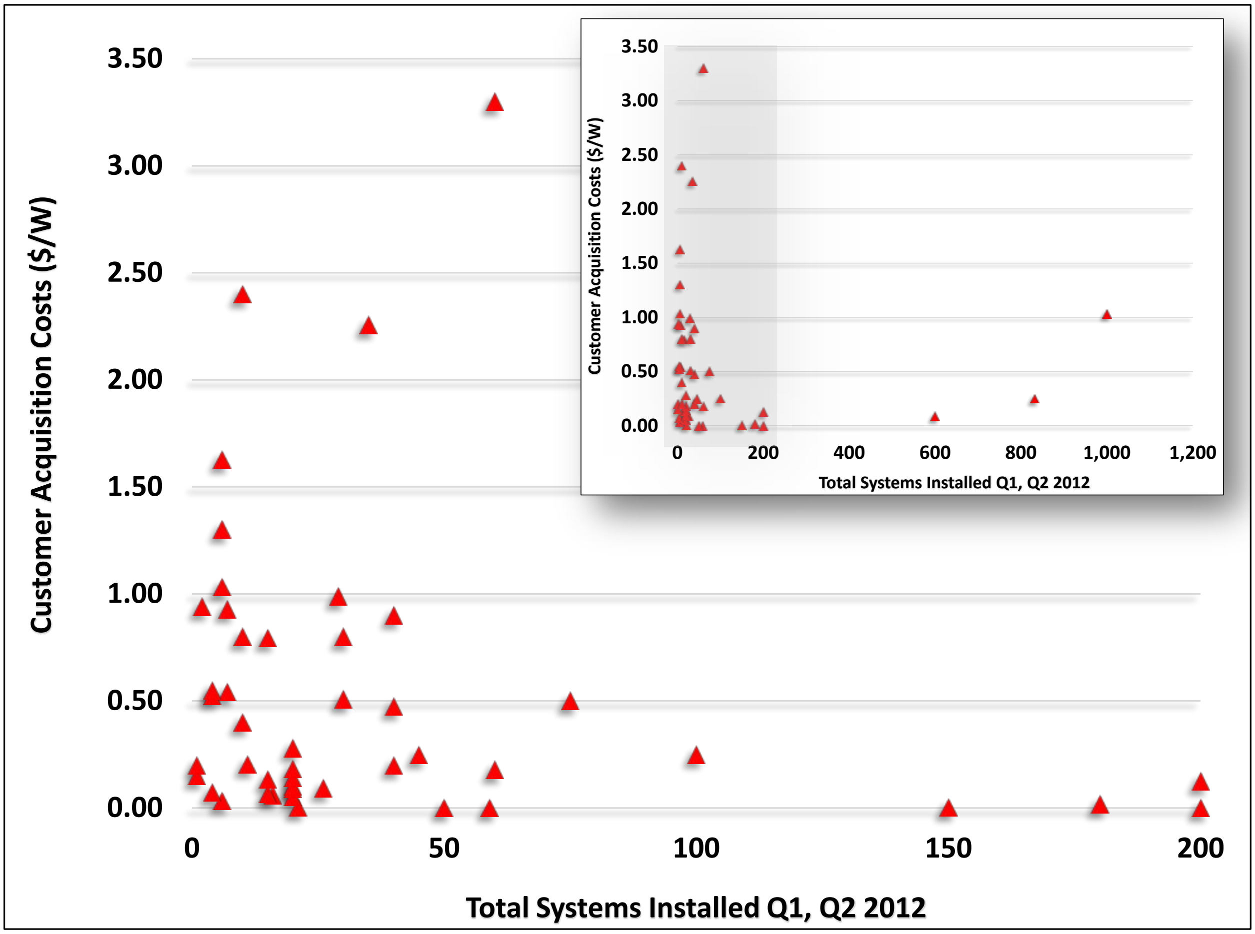

Figure 2. Reported customer acquisition costs for residential installers

4.2.2 Permitting, Inspection, and Interconnection

Regulatory requirements and permitting processes for U.S. PV installations are often burdensome and costly compared with those in leading PV nations such as Germany (Langen 2010). Installers expend significant resources on paperwork completion and compliance. Additionally, the lack of standardization in permitting and interconnection requirements and fees across more than 18,000 authorities having jurisdiction (AHJs), in addition to more than 5,000 utilities, impedes installers' ability to deploy PV rapidly across numerous jurisdictions (for example, cities and counties) and utility service territories. Permitting processes vary widely across AHJs and usually involve two distinct agencies (and as many as five), each with different processes (Tong 2012). Incentive application procedures add to these

[12] For the purpose of visual clarity in the scatter plot graphic presentations, we provide a magnified view of the shaded portion of the datasets, in which those datapoints not within the shaded area are excluded. The insets depict the entire dataset, including points within and not within the magnified view.

requirements and costs. In some jurisdictions and utility service territories, cumbersome permitting and interconnection requirements deter PV development entirely. More than one in three installers avoid operating in an average of 3.5 jurisdictions owing to associated permitting hurdles, which limits the overall growth of the residential PV market.

Our analysis of PII labor requirements includes the following elements:

- **Permit Preparation**—determination of a jurisdiction's permitting requirements, travel time to site, drawing of system plans, structural calculations, zoning application, and delays
- **Permit Package Submittal**—travel time to and from the permitting office and wait time at the permitting office
- **Permitting Inspection**—paperwork, travel time to and from the site, wait time for inspector, and physical inspection
- **Interconnection Process**—paperwork, travel time to and from the site, wait time for representative from utility, and physical interconnection
- **Financial Incentive Application Process**—determination of eligibility, paperwork, travel time to and from the site when inspection required, wait time for inspector, and physical inspection.

The estimated labor costs associated with completing these PII procedures totaled $0.10/W on average. More than half the installers in our survey reported PII labor hours per installation within the range of 8–22 hours. The three largest installers (with 600 or more installations) provide limited, anecdotal evidence of economies of scale: two of the three reported permitting times below the median of 20 hours per install. Figure 3 shows total PII labor hours per installation by installer volume. Table 4 shows PII weighted average labor costs by category, plus an assumed permitting fee of $430.[13] Although not surveyed for this study, typical U.S. residential permitting fees are approximately $200–$450 per installation (Vote Solar 2011; Sunrun 2011).

Of the five PII processes examined, installers reported the greatest labor-hour requirements for permit preparation, with 31% (17 of 55) reporting 10 or more labor hours per installation. Only 6% of installers reported 10 or more labor hours per installation for permit submittal, 4% for inspection, 12.5% for interconnection, and 19% for the financial incentive application process. These figures are approximately consistent with 2010 benchmarks. Figure 4 details the labor-hour requirements for the five PII processes analyzed. Note that labor class and wage assumptions as well as labor hours affect labor costs. For example, labor class and wage assumptions make inspection-related labor more costly on an hourly basis than labor related to financial incentive application (Table 2).

[13] The average is weighted by total number of completed installations.

Table 4. Average Total Residential Permitting, Inspection, and Interconnection Costs

Cost Component	Cost ($/W)
Permit preparation	0.04
Permit submittal	0.01
Inspection	0.03
Interconnection	0.01
Financial incentive application process	0.01
Assumed permitting fee ($430)	**0.09**
Total	**0.19**

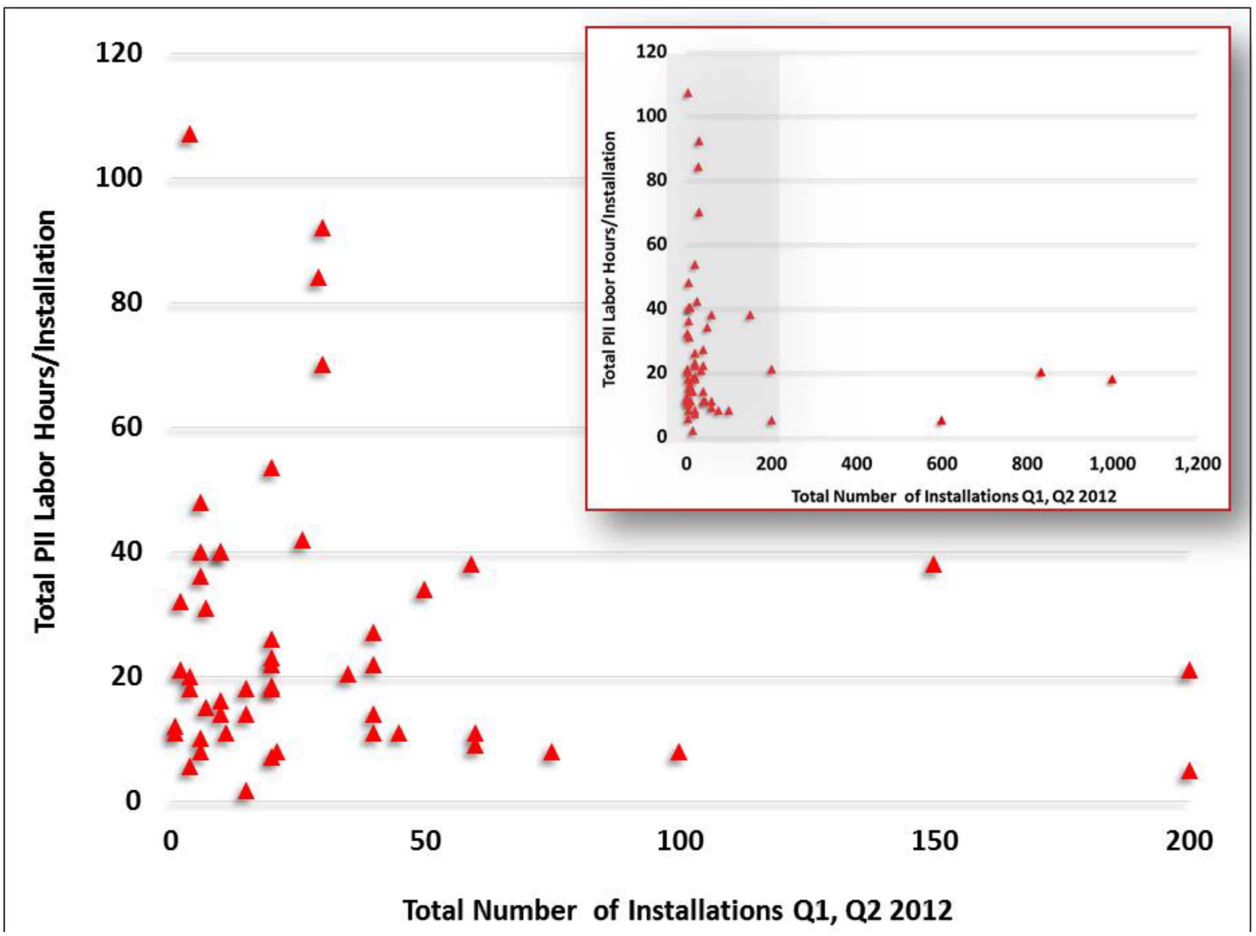

Figure 3. Total permitting, inspection, and interconnection labor-hour requirements per installation for each residential installer surveyed (all data)

To supplement these data, we examined the data in the CPF permitting study (Tong 2012). Although that study does not break out permitting “preparation,” “submittal,” and “inspection,” the total for all three of these PII subcategories is an average of 14.25 hours per installation. Our survey respondents reported a comparable average of 13 hours for those three subcategories. Focusing on the roughly one-third (89 of 273) of the projects in the CPF study that were installed during our study period (January 1 to June 30, 2012), and eliminating the top and bottom 5% of responses as outliers, yields a weighted average of 23 hours per installation. When we combine these 89 installations (at 23 hours per installation) with the 53 installations for which we have the three subcategories of PII survey data (at 13 hours per installation), we obtain an overall weighted average of approximately 21 hours or \$0.13/W—substantially higher than the \$0.08/W for these three subcategories obtained in our survey.[14]

CPF also found that 84% of installations required a site inspection from the local utility, and 81% required a site inspection from the local city or town, with most requiring inspections from two different AHJs.[15] This is consistent with our responses; all of our respondents reported an inspection from at least one of these types of AHJs. Our survey did not specifically address project delays caused by AHJ permitting process times, which the CPF study estimates at 8 weeks. It is unclear how much installer time is actually spent waiting for AHJ inspectors. Because project activities are often concurrent, it is difficult to ascertain a “net” wait time figure (Tong 2012).

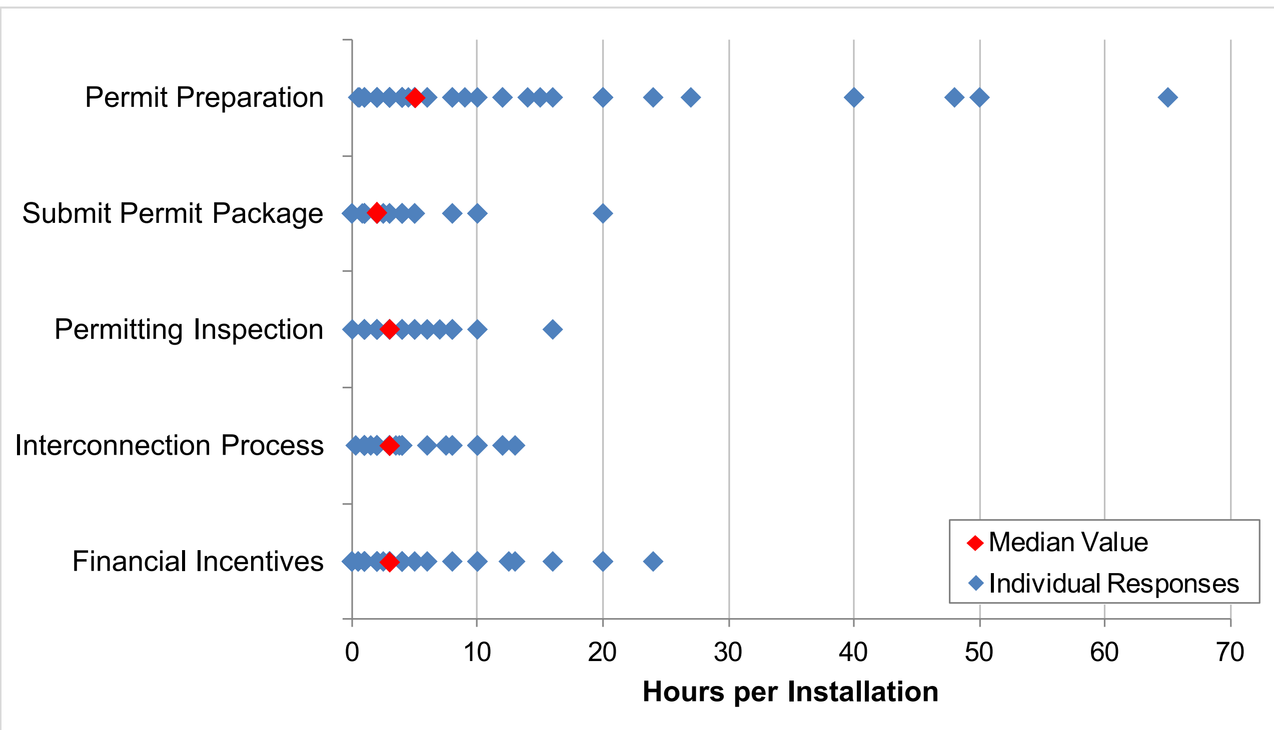

Figure 4. Hours per installation for residential permitting, inspection, and interconnection (all data)

[14] Given the confidentiality of the CPF respondents’ identities, there is no way to eliminate any potential installations or installers that may have been included in both surveys.

[15] CPF also found that AHJs often function under strained budgets and that, in many cases, PV installations are unfamiliar enough to inspectors that they are commonly unaware of potential problems or best practices.

5 Commercial PV System Data Collection and Results

5.1 Sample Market Representation and Characterization

In all, 22 commercial PV installers responded to the survey. These installers reported completing 269 commercial PV systems during the 6-month study period, totaling 66 MW. Unlike our treatment of the larger residential sample, we did not remove any extreme commercial values as outliers in our calculations of median values. Given the small sample size for the commercial survey, caution should be exercised when generalizing from the findings. The sample primarily consists of relatively small to mid-volume commercial installers. Three of the 22 respondents completed 20 or more commercial systems in the first half of 2012, and 10 respondents completed 10 or more. Of the 22 respondents, 11 reported average system sizes of 250 kW or larger and 11 reported average system sizes of less than 250 kW. Figure 5 and Figure 6 characterize our sample of commercial respondents.

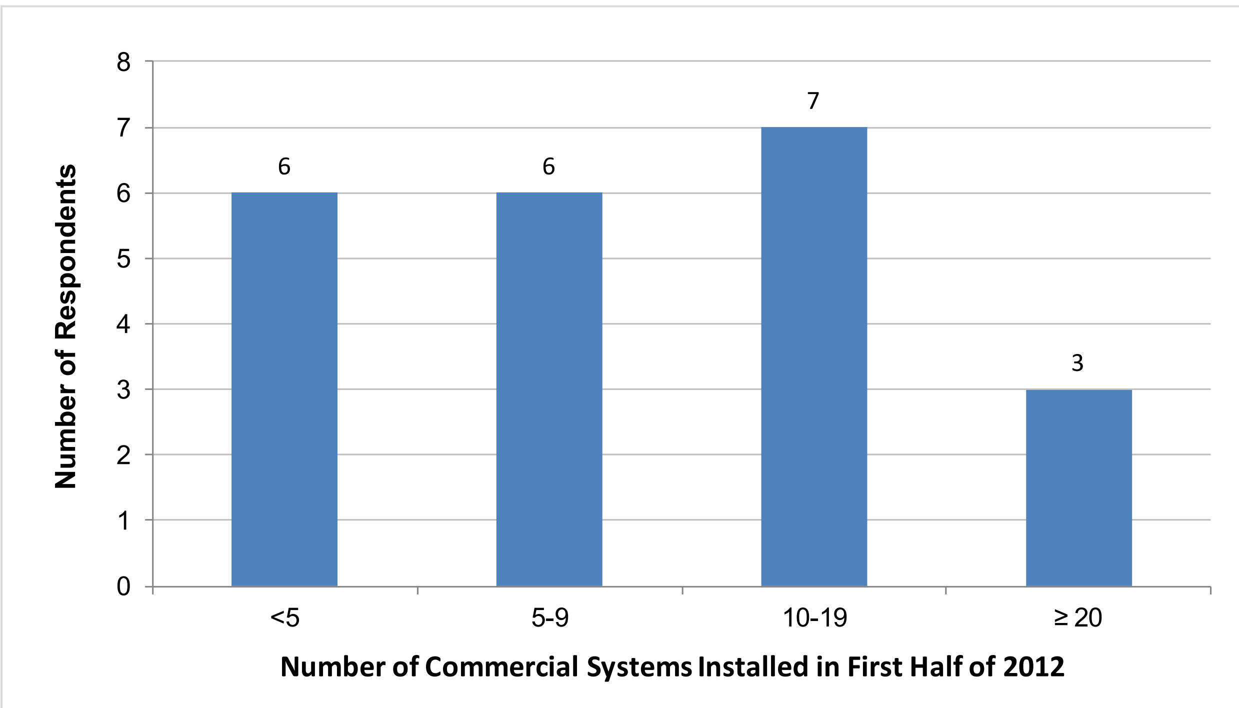

Figure 5. Number of respondents by number of commercial systems installed

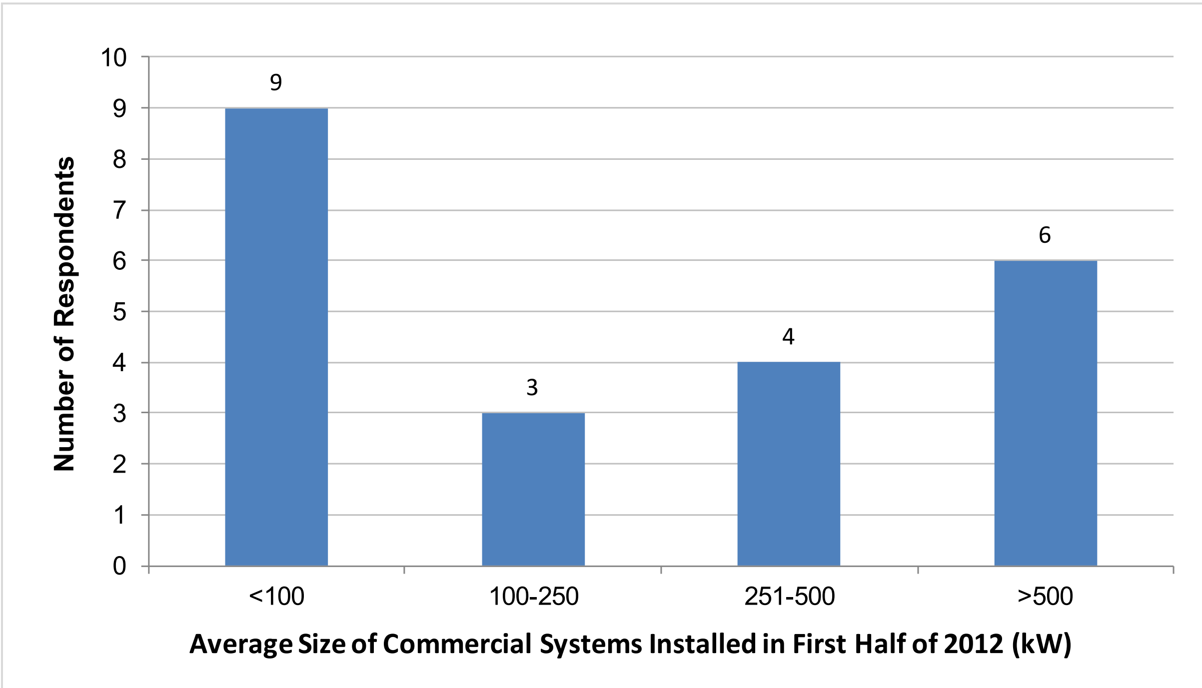

Figure 6. Number of respondents by average commercial system size installed

5.2 Commercial Results

Survey responses for commercial installers are summarized here in terms of the median value across respondents. Given the relatively small sample of commercial installers, the median was deemed more meaningful than an average weighted by the number of completed installations (as was used for residential PV). To illustrate how soft costs for commercial PV may differ depending on the size of the system installed, we separately report median values for installers with an average system size smaller than 250 kW and for those with an average system size of 250 kW or larger.

5.2.1 Customer Acquisition

The survey asked installers to provide their total expenditures on customer-acquisition activities for commercial PV systems installed in the first half of 2012, segmented into two cost categories: system design and all other customer-acquisition costs. Following the methodology explained in Section 3, these annual dollar amounts were translated into dollars per watt.

Across commercial PV installers with average system sizes smaller than 250 kW, median customer-acquisition costs totaled \$0.13/W: \$0.04/W for system design and \$0.09/W for all other customer-acquisition costs (Figure 7). Almost all respondents reported total customer-acquisition costs of less than \$0.20/W on average (Figure 8 and Figure 9). Customer-acquisition costs appear to exhibit strong economies of scale. Across commercial PV installers with average system sizes of 250 kW or larger, median customer-acquisition costs totaled \$0.03/W: \$0.01/W for system design and \$0.02/W for all other customer-acquisition costs (Figure 7). Also of note is the gap between these commercial results and the residential customer-acquisition costs reported in the previous section ($0.48/W). For illustrative purposes in Figures 8 and 9, we have excluded extreme outliers as indicated in the graphic insets.[16]

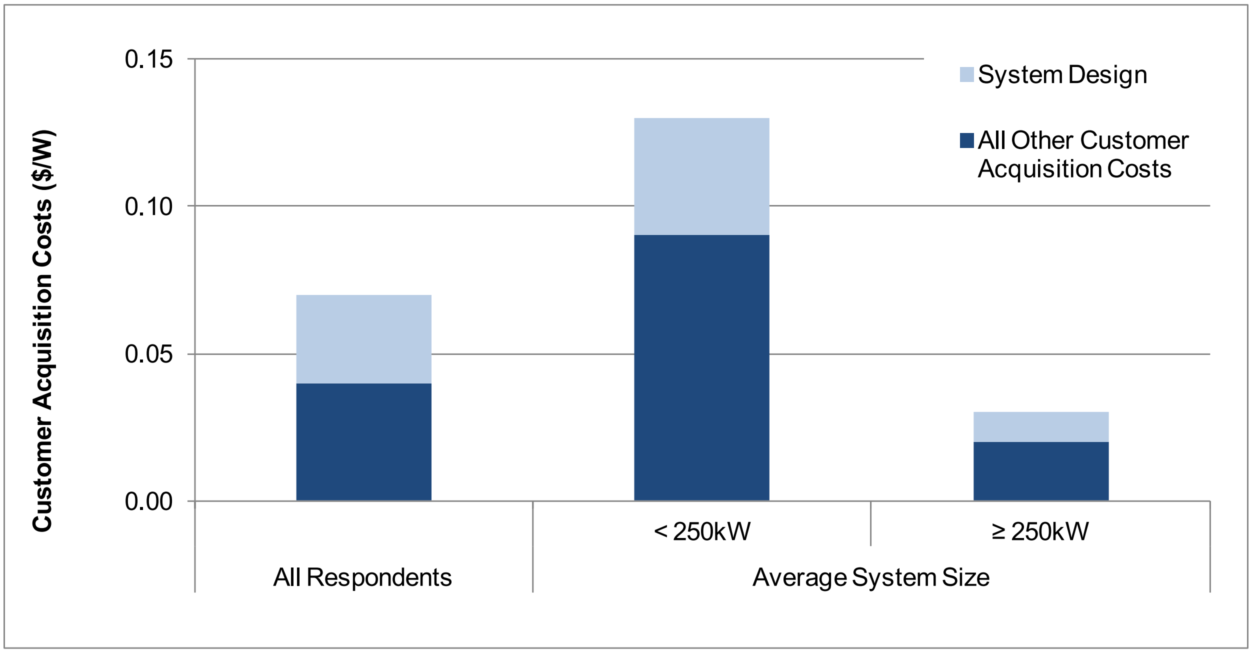

Figure 7. Median customer-acquisition costs for commercial PV installers

[16] For the purpose of visual clarity in the scatter plot graphic presentations, we provide a magnified view of the shaded portion of the datasets. The insets depict the entire dataset, including points within and not within the magnified view.

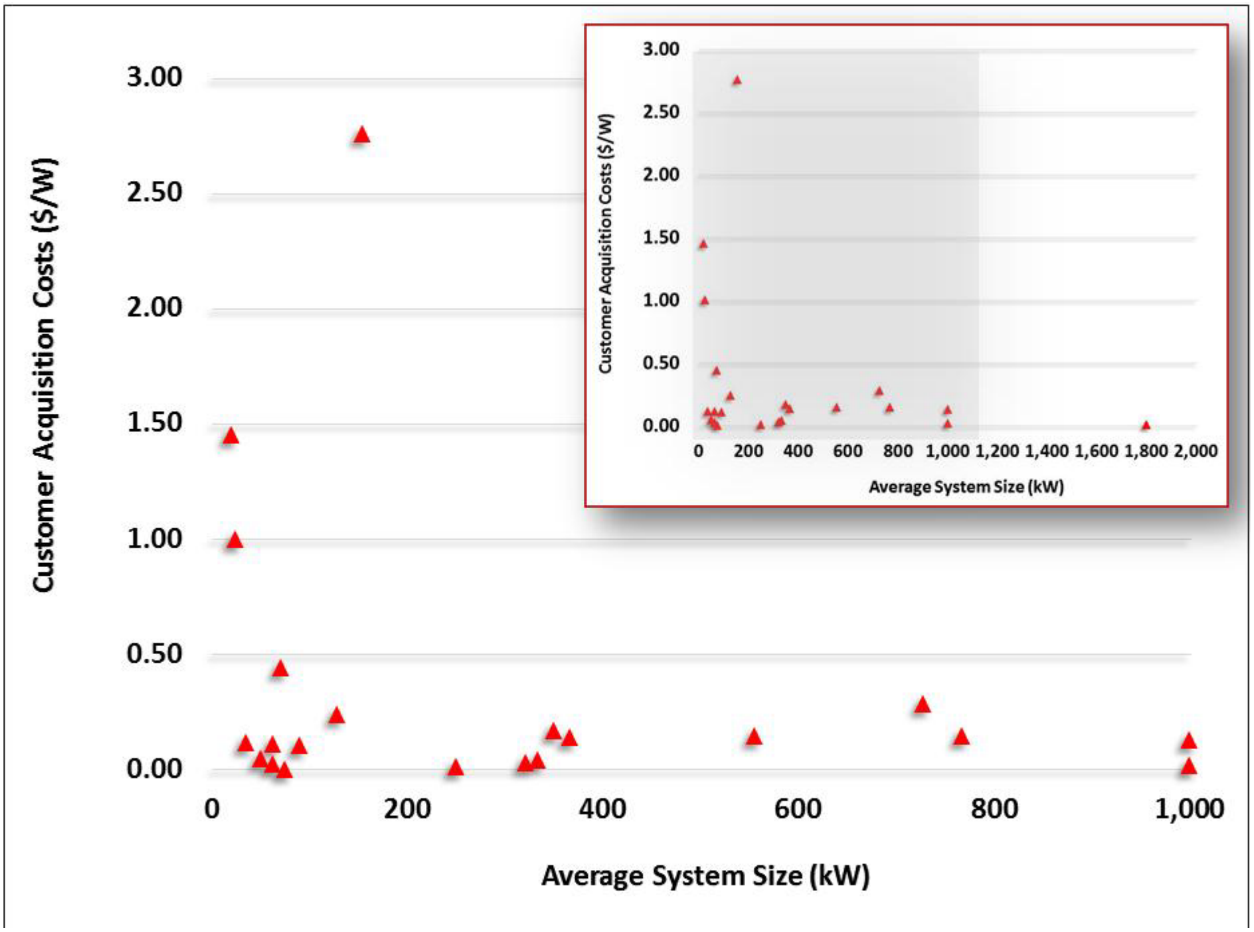

Figure 8. Reported customer acquisition costs for each commercial installer surveyed, relative to average system size

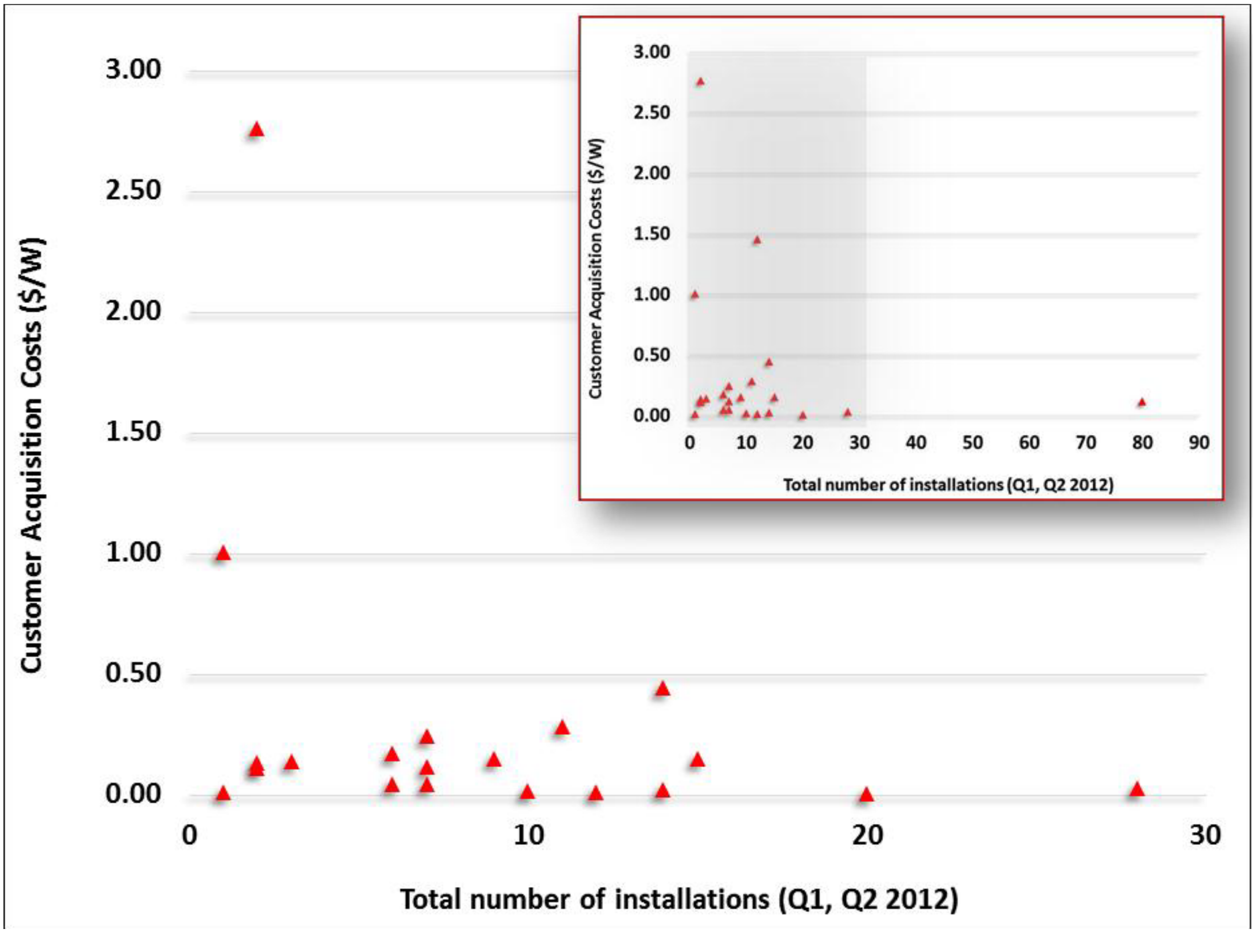

Figure 9. Reported customer acquisition costs for each commercial installer surveyed, relative to total number of installations

5.2.2 Permitting, Inspection, and Interconnection

The survey asked commercial installers for the average number of labor hours per installation associated with PII processes, segmented into the five activities described in Section 4.2.2. As shown in Figure 10, the reported average number of labor hours for all five PII activities varied widely across installers, ranging from 4 to 1,350 hours per system, with a median response of 31 hours. PII labor requirements were typically higher for larger systems; the median for installers with average system sizes of 250 kW or larger was 30 hours per system, compared with 33 hours per system for installers with average system sizes smaller than 250 kW. This difference is to be expected given the generally greater complexity of PII processes for larger systems.

Based on assumed labor rates and each installer's average system size, median PII labor costs amount to less than $0.01/W across the full set of commercial installers surveyed, with permit preparation constituting the largest cost (Figure 11). Although more labor hours are required for larger commercial PV systems, the associated costs on a per-watt basis are lower because the absolute dollar costs are spread across a larger number of installed watts.

The PII labor costs reported here for commercial PV do not include the cost of permitting or interconnection fees that may significantly exceed the direct PII labor costs. At the writing of this report, while limited commercial PV permitting fee data is available, no comprehensive cost data exists for commercial PV interconnection studies and fees that could significantly add to total PII costs or deter project completion entirely. Anecdotally, interconnection study costs are reported to vary substantially—from $2,500 to more than $30,000—depending on PV penetration rates in a given utility service territory and system size (Ardani 2013). Collecting comprehensive interconnection study cost and fee data for commercial PV systems remains an area for future research. For this report, we assume a $5,000 permitting fee for systems smaller than 250 kW and a $25,000 fee for systems of 250 kW or larger.[17] This equates to an additional $0.07/W for our small commercial systems (assuming a system size of 70 kW, the average size among this group) and $0.04/W for our large commercial systems (assuming a system size of 679 kW, the average size among this group). For illustrative purposes in Figures 10 and 11, we have excluded extreme outliers as indicated in the graphic insets.[18]

[17] The $5,000 value approximates the average permitting fee for 131-kW systems in California as of March 2012 (Newick 2012); the fees in this report range from $0 to more than $46,000, with relatively few higher than $25,000. Our internal analysis suggests $25,000 is a reasonably representative fee for large commercial systems.

[18] For the purpose of visual clarity in the scatter plot graphic presentations, we provide a magnified view of the shaded portion of the datasets. The insets depict the entire dataset, including points within and not within the magnified view.

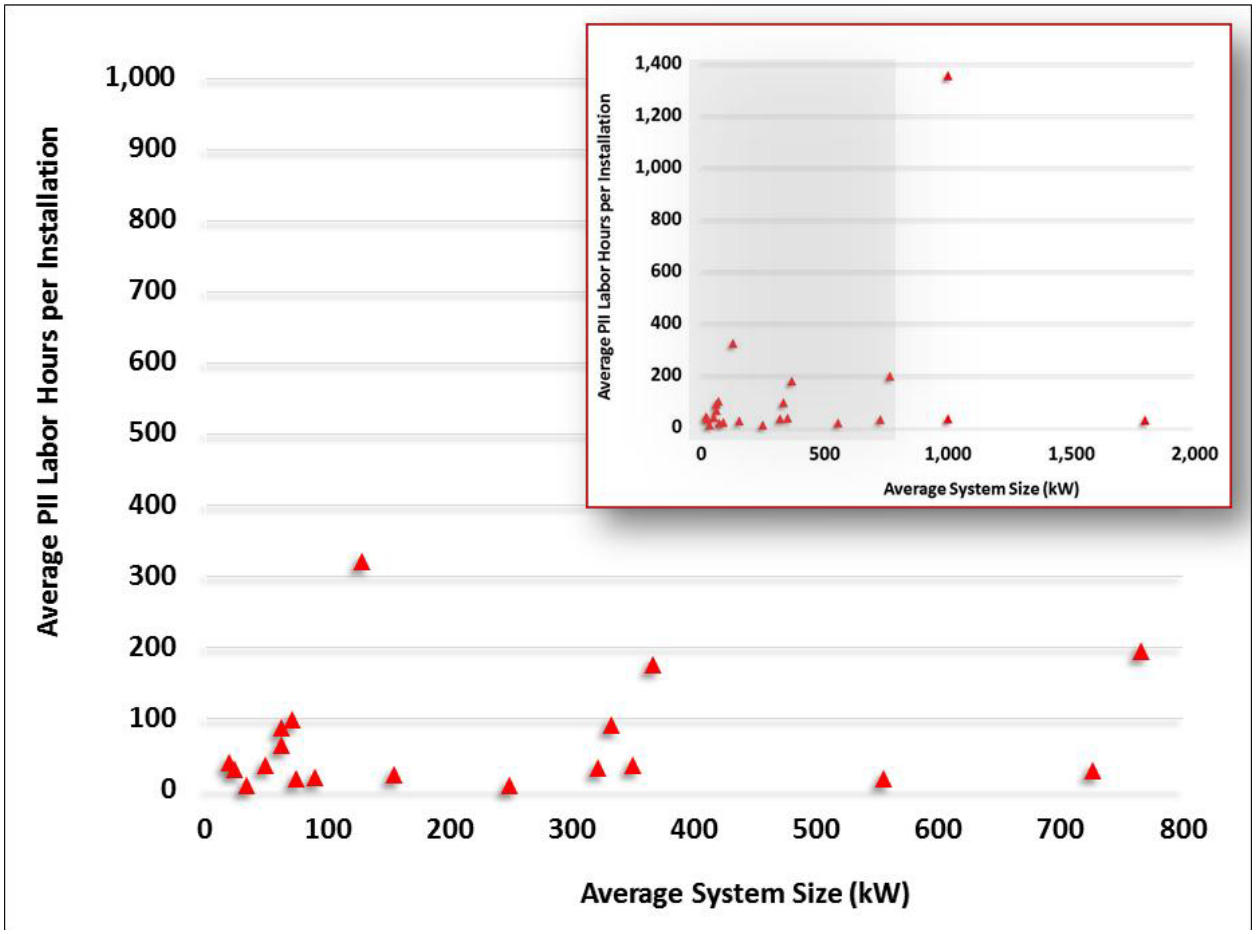

Figure 10. Hours per commercial installation for permitting, inspection, and interconnection processes, relative to average system size

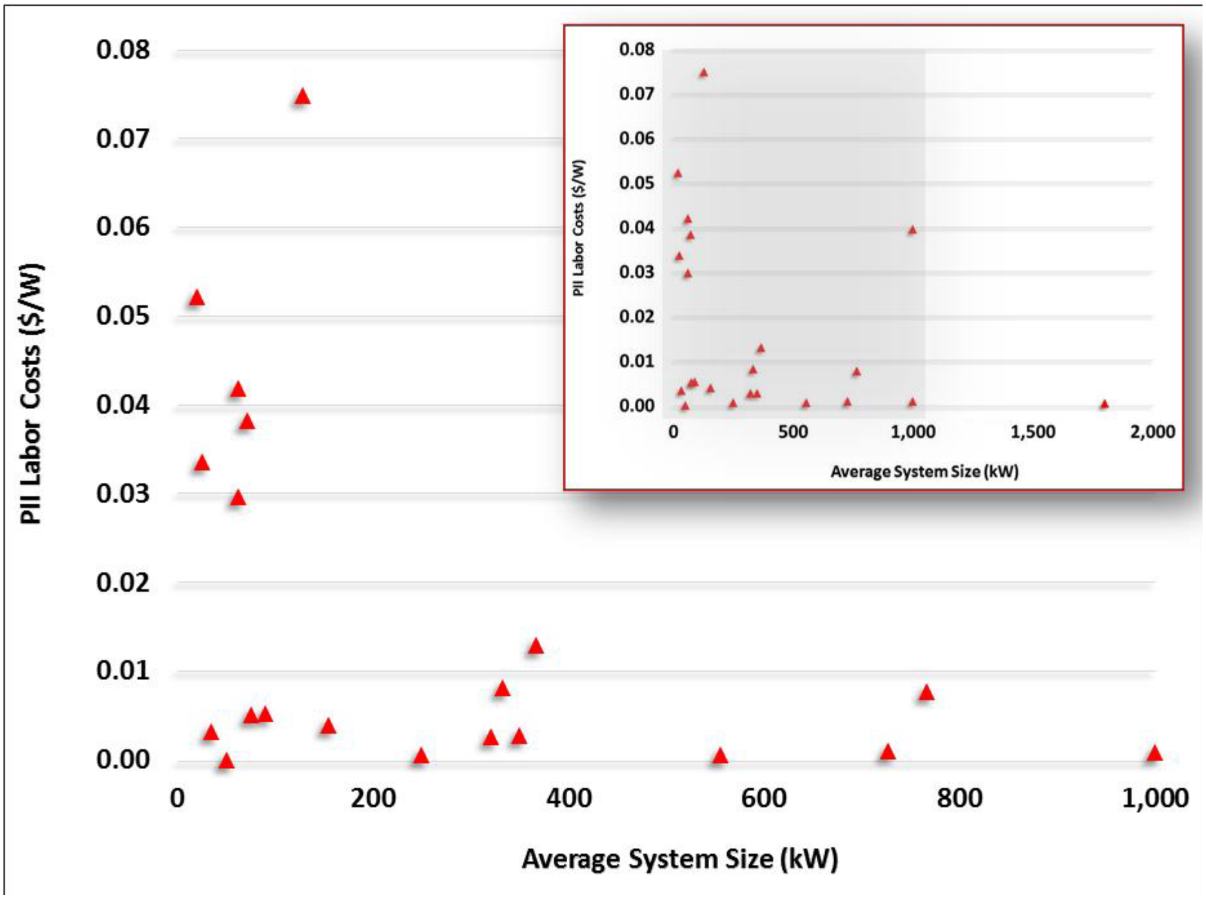

Figure 11. Total permitting, inspection, and interconnection labor costs for each commercial installer surveyed, relative to average system size

6 Financing, Overhead, and Profit Costs

After incorporating the surveyed soft cost information with total hardware costs, supply chain costs, and sales tax, PV system prices still include a category consisting of undifferentiated "other" soft costs ranging from $1.23/W to $1.76/W (Figure 12). This section seeks to explain this gap by better quantifying the cost areas of financing, overhead, and profit for residential and commercial PV installations. These categories can become particularly complicated when systems are financed through a third party, such as through solar leases and power purchase agreements (PPAs), in which there are more parties involved in the transaction than are involved in a direct sale. Because third-party financing has become the dominant business model in much of the United States [responsible for approximately 68% of all U.S. residential systems installed during 2012 (Kann 2013)], it is even more important to understand these costs.

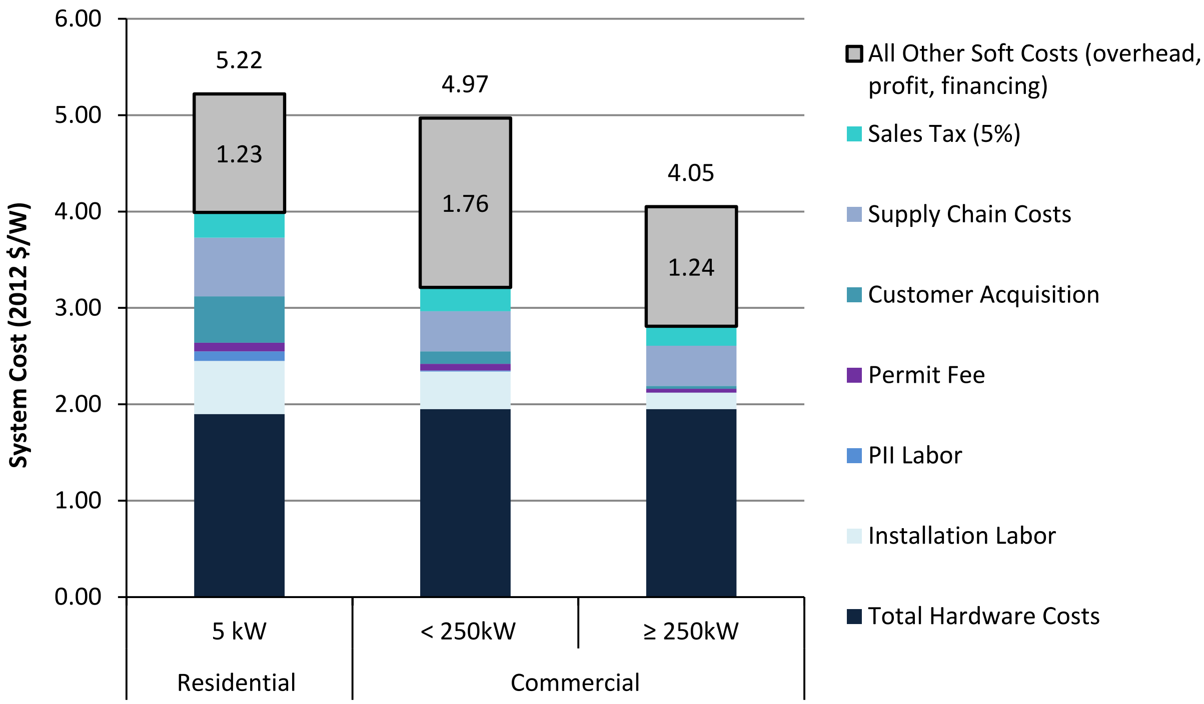

Figure 12. Breakout of total 2012 PV system prices with "other" soft costs highlighted

The plotted values are derived from our survey (installation labor, PII labor, and customer acquisition); Barbose et al. (2013) and Feldman et al. (2013a) (total system costs and total soft costs); Feldman et al. (2013-a) (sales tax and supply chain costs); and assumptions based on Vote Solar (2011), Sunrun (2011), Newick (2012), and internal analysis (permit fee).

The survey-based benchmarking analysis in this report generally includes all costs directly associated with building a PV system by an engineering, procurement, and construction (EPC) installer; financing, overhead, and profit do not typically fit into these categories, as described below:

Financing: In the case of third-party ownership, a project developer must arrange financing with equity and, sometimes, debt providers. There are associated transaction costs between parties.

Overhead: The costs calculated in the customer-acquisition and PII sections of this report (Sections 4.2.1, 4.2.2, 5.2.1, and 5.2.2) generally include EPC installer corporate expenditures directly associated with projects, such as from their sales and engineering departments. However, these companies have additional costs they must bear to operate a business. In the case of third-party financing, when the developer owns (or is leasing) and operates the projects as well, its overhead cost increases.

Profit: Finally, companies are expected to earn a profit on top of their costs to achieve a return on investment to their equity holders.

A more detailed explanation of these costs is in the accompanying publication, *Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing* (Feldman et al. 2013b).[19]

Briefly, to quantify the abovementioned costs, we modeled a third-party financing business structure to fully capture direct and indirect costs of residential and commercial installations. There are many different business models in the PV marketplace, but we chose the business structure in Figure 13 to demonstrate a model that is currently common in the marketplace.

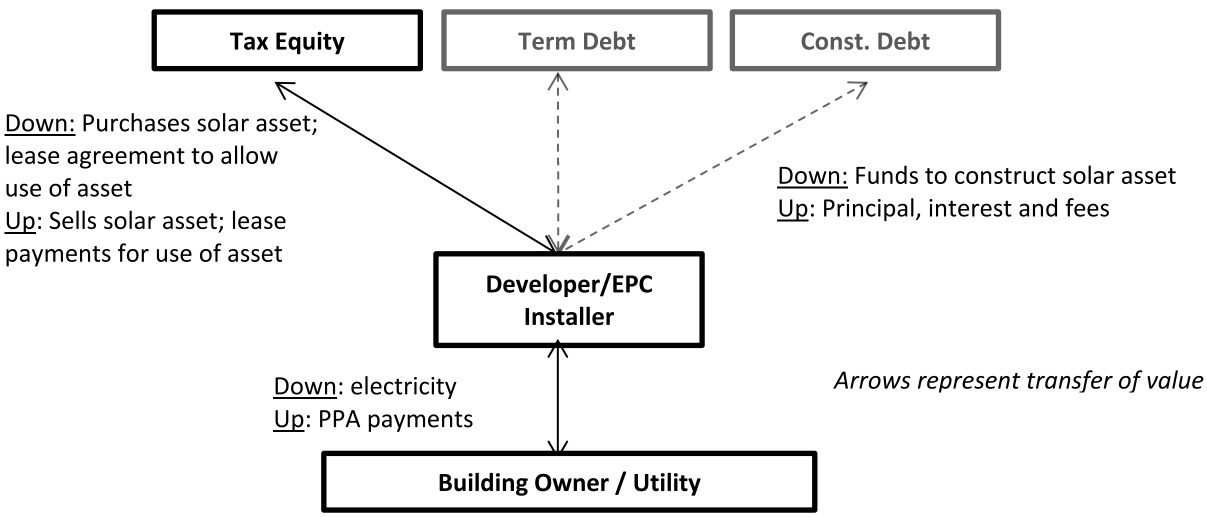

Figure 13. Organization chart of benchmarked business model[20]

In this business structure, the developer/EPC installer, as a company installs 70 MW of projects per year, signs a PPA with a building owner, constructs the system, and finances a portfolio of systems (we assume 10 MW of residential, small commercial, or large systems) through a sale-leaseback arrangement with a tax-equity investor. For non-residential projects, a separate financier may be brought on to fund construction of these assets before they are sold to the tax-equity investor at the projects'

[19] The costs discussed in Section 6 of this report were derived from the analysis summarized in Feldman et. al. (2013b). The fundamental difference between the reports is that Feldman et al. (2013b) is a bottom-up benchmarking analysis, which uses individual cost assumptions to derive a total system price. In this report, total system price is the 2012 total average installed price as reported by Barbose et al. (2013). "Other soft costs" are calculated by subtracting hardware costs, as reported in Feldman et al. (2013b) and soft costs determined in Sections 1–5 of this report, from the total system price. Further, "Transaction cost" assumptions in this report are identical to those in Feldman et al. (2013b), however results may vary due fees based on total system costs, which are different between reports. "Indirect corporate costs" in this report are based on developer indirect corporate overhead as reported in Feldman et al. (2013b). However, staff costs which were determined to be captured in Sections 1–5 of this report, such as design and engineering, and sales and marketing, were excluded. Finally, profit in Feldman et al. (2013b) is determined by analyzing gross margins within the industry, while in this report, profit is the remainder between total system price and all calculated costs.

[20] The labels "up" and "down" represent the direction in which the benefits flow between the relevant two parties. This report simplifies the organization chart in Feldman et. al. (2013b) by combining the EPC installer and developer into one entity.

placed-in-service dates. Further, non-recourse term-debt may be raised to fund part of the portfolio, depending largely upon the tax equity investor's minimum investment size threshold; in other words, the debt must not exceed an amount that would reduce the tax equity portion to a level below that threshold. Inputs to and design of this model are based on discussions from multiple industry participants involved in third-party PV financing as well as data from corporate public filings and vetting and review by external stakeholders. Table 5 summarizes the transaction costs associated with this structure, and Table 6 details the corporate overhead costs of the EPC installer/system developer. The results should be treated as representative of general trends and not specific to any company. The following subsections detail the costs listed in the tables.

Table 5. Transaction Costs Breakdown

		Residential ($/W)	Small Commercial Systems (< 250 kW) ($/W)	Large Commercial Systems (≥ 250 kW) ($/W)
Average transaction size (MW)		10	10	10
Professional Services	*$/Portfolio*			
Developer legal fees	$250,000	$ 0.03	$ 0.03	$ 0.03
Tax-equity legal fees	$250,000	$ 0.03	$ 0.03	$ 0.03
Auditor (for residential only)	$10,000	$ 0.00	N/A	N/A
Accountants	$25,000	$ 0.00	$ 0.00	$ 0.00
Independent engineering (for commercial only)	$75,000	N/A	$ 0.01	$ 0.01
Subtotal: Professional Services		***$ 0.05***	***$ 0.06***	***$ 0.06***
Financier Expenses				
Fees from term debt	2.5% fee on loan amount (40% of system price)	$ 0.05	$ 0.05	$ 0.04
Fees from construction debt / revolving line of credit (for commercial only)	1% fee on loan amount (90% of system price to developer)	N/A	$ 0.02	$ 0.02
Interest on loan / line of credit (during construction, for commercial only)	5% interest rate on loan for 6 months	N/A	$ 0.05	$ 0.05
Subtotal: Financier Expenses		***$ 0.05***	***$ 0.12***	***$ 0.10***
Additional Costs				
Inverter warranties (20 years)		$ 0.10	$ 0.09	$ 0.09
System production guarantees		$ 0.02	$ 0.01	$ 0.01
Construction insurance	0.3% fee on system price to developer	$ 0.01	$ 0.01	$ 0.01
Debt service reserve	Reserve of 5% interest rate on term loan for six months (40% of total system price)	$ 0.05	$ 0.05	$ 0.04
O&M reserve	6 month reserve of O&M costs ($23.5/kW, per year)	$ 0.01	$ 0.01	$ 0.01
Subtotal: Additional Costs		***$ 0.20***	***$ 0.18***	***$ 0.16***
Subtotal: Transaction Costs		**$ 0.30**	**$ 0.36**	**$ 0.33**

Table 6. EPC Installer/Developer Corporate Costs

Business Expenses				$/year	$/W
Rent (98 sq ft/person)	$28.92/sq ft			$1,519,262	$0.02
Office expenses (equipment, supplies, maintenance, phones)	$5,000/person			$2,689,928	$0.04
Corp. professional service (accountants, lawyers, consultants, recruiting, lobbying)				$2,826,972	$0.04
Insurance				$30,000	$0.00
Other (business taxes, bank fees)				$20,000	$0.00
Vehicle fees (lease, gas, insurance)				$913,172	$0.01
Dues and memberships				$20,000	$0.00
Billing system (prorated over 5 years)				$100,000	$0.00
Staff Expenses	**Base Salary (unburdened) / Person**	**# of Employees**	**Employees per MW Installed**	**(Base Salary + Benefits)**	
Corporate - senior (c-level, HR & legal)	$185,000	22.5	0.32	$5,611,798	$0.08
Corporate - junior (c-level, HR & legal)	$75,000	13.8	0.20	$1,400,033	$0.02
Finance - senior (treasury, project finance, accounting, and compliance)	$185,000	10.4	0.15	$2,590,061	$0.04
Finance - junior (treasury, project finance, accounting, and compliance)	$75,000	34.6	0.49	$3,500,082	$0.05
Software/IT	$85,000	49.3	0.70	$5,656,103	$0.08
Project management	$75,000	42.5	0.61	$4,302,309	$0.06
Customer service	$75,000	17.0	0.24	$1,720,924	$0.02
Subtotal: employees		190.0	2.71	$24,781,309	$0.35
Benefits, FICA, bonus (added to base salary)	35%				
Total indirect corporate costs (staff + business expenses)				**$32,551,803**	**$0.47**
Employee divisions pertaining to previous soft cost benchmarking (excluding installation labor)					
Design and engineering		66.4	0.95		
Supply chain		6.9	0.10		
Rebate/interconnection		20.4	0.29		
Sales		182.6	2.61		
Marketing		27.7	0.40		
EPC sales management		43.9	0.63		
Total company employees (excluding installation labor)		**538.0**	**7.69**		
MW installed by developer per year		**70**			

6.1 Transaction Costs

Structuring financing for a PV asset involves arranging, negotiating, and contracting agreements between two or more parties. These transactions are designed to allocate the benefits of a PV system to entities that can use them at the lowest possible cost. The tax-equity investor is brought into the deal to utilize the investment tax credit and depreciation benefits; debt is raised to fund a portion of the project at a lower cost than the rate of return required for equity; and, in the case of commercial systems with long construction timelines, construction debt is raised to minimize risk to the tax-equity investor during construction. All of these companies' services have a purpose, but they come at a cost.

Before an arrangement can be put in place, the purchasers of the assets (tax equity) must validate what they are buying from the developer. It was assumed that an auditor is hired to assess the residential portfolio; in a portfolio of commercial systems, independent engineers are assumed to be used. Lawyers on both sides of the transaction (tax equity and developer) are needed to negotiate the necessary contracts, although the developer typically pays both fees. Accountants are also often necessary to validate the financial records of a project and/or developer. These professional service costs, summarized in for a 10-MW portfolio of financed assets, were modeled at $0.05/W for residential and $0.06/W for small and large commercial.

Banks that offer term debt typically charge a fee to set up the transaction. In addition, in the case of construction debt for commercial projects, an arranging fee is charged as well as interest on the loan during construction (which can be added to the cost basis of a project for tax purposes). The debt fees (and interest), summarized in Table 5 for a 10-MW portfolio of financed assets, were modeled at $0.05/W for residential, $0.12/W for small commercial, and $0.10/W for large commercial.

There are also provisions that developers must make to minimize the risk to investors and PPA customers in the transaction. The value of extended inverter warranties that last the life of the contract, liability insurance during construction, and system production guarantees made to the end-user, which are all often necessary for third-party ownership, come at a cost.[21] Finally, debt providers often require that money is set aside to cover payments (debt service reserve), in case of revenue variability, and tax-equity investors often require that developers set aside money to cover O&M costs (O&M reserve). These reserves are not eligible for inclusion in a project's cost basis, but funds are still necessary. The additional costs, summarized in Table 5 for a 10-MW portfolio of financed assets, were modeled at $0.20/W for residential, $0.18/W for small commercial, and $0.16/W for large commercial.

In total, the transaction costs to set up a 10-MW residential portfolio, a 10-MW small commercial portfolio, and a 10-MW large commercial portfolio, summarized in Table 5, were modeled to be $0.30/W, $0.36/W, and $0.33/W, respectively.

6.2 Developer/EPC Installer Indirect Corporate Costs

Developer costs were modeled using feedback from developer interviews. The developer is assumed to install 70 MW of residential or commercial PV systems per year. Like a typical EPC installer, office rent, equipment and supplies, insurance, taxes, vehicles, dues, and memberships, as well as corporate professional service, such as accountants and lawyers, are estimated as corporate overhead. However, it is also assumed that consultants, recruiters, and lobbyists are necessary as well as the cost of purchasing a billing system, which is prorated over a 5-year period.

There are also significantly more operational requirements at the corporate level for a developer than for a typical EPC installer. In addition to a larger corporate staff of executives, HR, and a legal team, there is also a finance team, which handles corporate treasury duties, project finance arrangements, compliance, and accounting. Certain departments were assumed to have already been benchmarked in the customer-acquisition and PII sections of this report (Sections 4.2.1, 4.2.2, 5.2.1, and 5.2.2). These

[21] Some of these costs, particularly construction insurance, are also borne when the system is sold directly to the end user.

include the sales, marketing, and EPC sales management teams that develop PPA customer portfolios, the design and engineering department, the supply chain management, and rebate interconnection team, which shepherd the PV projects from design, procurement of equipment, and construction of project to system interconnection to the grid. Because EPC costs have already been measured, we only estimated their headcounts to determine their contribution to rent and office expenses. However, a project management department, which also helps in development, was included. Finally, once the PV projects are in operation, the software/IT department (which also handles general corporate needs and customer acquisition) and the customer service department monitor, bill, and interact with customers. A 35% increase is added to salaries to account for benefits, FICA, and salary bonuses. These costs, summarized in Table 6, total $32.6 million (or $0.47/W) for both commercial and residential systems.

6.3 Summary

Of the $1.23/W to $1.76/W of "other soft costs" estimated, $0.77/W to $0.82/W can be attributed to financing-related transaction costs and indirect corporate costs (overhead) as outlined above. Assuming that all costs incurred by the developer and installer have been accounted for, the remaining $0.45/W to $0.94/W, or 9% to 19% of total system price, can be attributed to profit (14).[22]

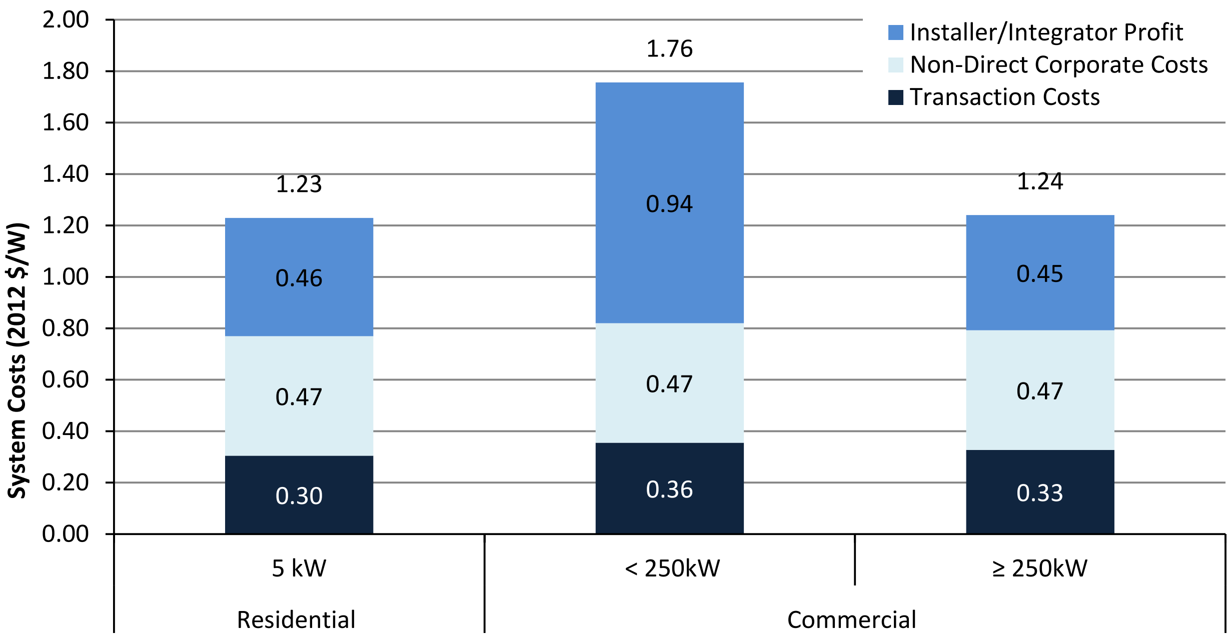

Figure 14. Breakout of "other soft costs" based on model

Because many of the financing and overhead costs are fixed, the cost per watt is determined in large part by sales volume. Therefore, differences in a particular company's sales volume can have a large impact on its indirect costs.[23] This may partially explain the differences in estimates of system pricing. For

[22] As stated, unlike other cost categories, profit is calculated as a remainder, and is a result of comparing this particular business model with average reported pricing. See the accompanying report, *Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing* (Feldman et al. 2013b) for more discussion on profit.

[23] Sales volume can also impact direct costs through stronger purchasing power.

example, the accompanying report, *Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing* (Feldman et al. 2013b), estimates that, in 2012, the installed price of a residential system was $4.72/W, compared to the median reported price of $5.22/W calculated by the LBNL annual report, *Tracking the Sun VI*, which is based on installer-reported system prices (Barbose et al. 2013). If the EPC installer and system developers that contributed information to *Tracking the Sun VI* have median sale volumes that are lower than those in the model, but have the same costs, they would have higher costs per watt. Due to these higher costs, EPC installers and system developers may need to charge higher prices.

7 Study Limitations

This report summarizes the soft costs that PV installers incurred when completing residential and commercial projects in the first half of 2012. However, the analysis has limitations. First, the sample size of installers across the United States is small—up to 53 installer responses per cost category for residential (after eliminating the top and bottom 5% of responses) and up to 22 for commercial[24]—potentially magnifying the effect of response error. Second, when assessing bottom-up cost structures, the inability to identify whether some questions may be inapplicable or only marginally applicable to respondents that serve primarily as subcontractors to EPC firms may result in an underestimation of costs. Third, the dataset could be enhanced with increased geographic variability. The sample representation is heavily weighted toward installers based in California, with the exception of a few large-scale installers from the East Coast. This lack of geographic representation could misrepresent costs on a national basis, given the differences in market maturity across states.

There is risk of double-counting costs in multiple categories in certain cases, most notably between system design costs and permit preparation costs, since there are business activities that could apply to both, such as drawing system plans and preparing structural calculations. Although the survey specifically identified these as permit preparation tasks, the definitions of and potential overlap between these terms inevitably reside, to some extent, in the interpretation of each individual respondent. There is also potential ambiguity in the necessary process of relating bottom-up reported soft costs to the reported system prices published in LBNL's *Tracking the Sun VI* (Barbose et al. 2013). In a perfectly efficient market, operating margins are limited to overhead and profit, but in a relatively immature market like the U.S. PV market, inherent gray areas emerge between operating margins, overhead, and cost subcategories. These may or may not be reported within and attributable to system prices. In particular, this is a potential issue with residential systems that are third-party owned under a power purchase or lease agreement, for which there is no competitive price bidding that would help clarify costs associated with specific projects; approximately 68% of all U.S. residential systems installed during 2012 were third-party financed (Kann 2013). For example, third-party leases might be associated with higher direct costs, but some subcategories of customer acquisition costs for third-party-owned projects encompass both direct costs and overhead.

Last, it should be noted that the installed cost metric has its limitations as an indicator of progress towards SunShot goals. For example, we have noted that there are projects deferred or not pursued because of cumbersome or inconsistent permitting and interconnection requirements, highlighting the importance of examining market barriers and their impact on deployment levels. In addition, installed costs do not capture the costs of maintaining a system over its lifetime. Levelized cost of energy (LCOE), which is not part of this analysis, would more accurately capture such costs.

[24] Sample size and representation vary by cost category.

8 Comparison of 2010 and 2012 Benchmarks

This section compares the 2012 results presented in this report to the results presented in our survey of 2010 PV soft costs (Ardani et al. 2012) and to the SunShot soft-cost targets (DOE 2012). To make this comparison, we converted the 2012 results (in 2012 dollars) to 2010 dollars.[25] **Thus the 2012 values presented here in 2010 dollars are different than those presented elsewhere in the report**. We present the 2010 survey results and SunShot targets in their original, 2010-dollar values.

Several methodological differences between the 2010 and 2012 surveys affect the results, including modifications to the 2010 survey instrument—made principally to reduce the response time required of installers—and correction for potential double-counting and/or definitional inconsistencies (see Study Limitations, Section 7). First, with respect to survey modifications, the 2012 survey did not include questions on installation labor that were included in the 2010 survey. Instead, an efficiency improvement assumption of 7% was applied to the 2010 installation labor cost benchmarks. As a result, inflation-adjusted installation labor amounted to $0.53/W for residential installations in 2012 (compared with $0.59/W in 2010), $0.38/W for small commercial installations (compared with $0.42/W in 2010), and $0.16/W for large commercial installations (compared with $0.18/W in 2010). Second, whereas the 2010 survey distinguished between marketing and advertising and "all other customer-acquisition costs," the 2012 survey did not. Rather, the 2012 survey asked for each sector (residential and commercial), "What was the total cost of customer-acquisition activities in Q1 and Q2 of 2012? (including marketing and advertising, sales calls, site visits, travel time to and from the site, contract negotiation with system host/owner, and bid preparation, but excluding system design)," from which a $/W value was calculated. As with the 2010 analysis, 2012 system design costs were examined separately. However, for both 2010 and 2012, all these costs are rolled up into a single customer-acquisition category in this section. Finally, the transaction costs, indirect corporate costs, and installer/developer profit modeling we performed for 2012 is new; along with the sales tax and supply chain cost values from Feldman et al. (2013a), this modeling enabled us to attribute all soft costs to specific categories in 2012, rather than leaving a large "other" soft-cost category as in 2010.

For reference, Figure 15 shows total PV system costs in 2010 and 2012, separated into hardware costs and soft costs, compared with the 2020 SunShot targets. As system costs declined between 2010 and 2012, the proportion of total costs attributable to soft costs increased.

Soft-cost details are presented in Figure 16 (residential), Figure 17 (small commercial), and Figure 18 (large commercial). In each case, the proportion of total soft costs categorized as "other" was eliminated between 2010 and 2012 owing to the new cost data, analysis, and categorization in 2012. Aside from those new values, customer-acquisition costs showed a large change for residential PV systems, declining 31% between 2010 and 2012. Customer-acquisition costs for small commercial systems also decreased substantially (32%), but the largest change in previously categorized costs was an 80% reduction in the assumed permitting fee. The previously categorized costs for large commercial systems remained largely unchanged.

[25] The inflation conversion was made using the Areppim Current to Real Dollars Converter, http://stats.areppim.com/calc/calc_usdlrxdeflator.php.

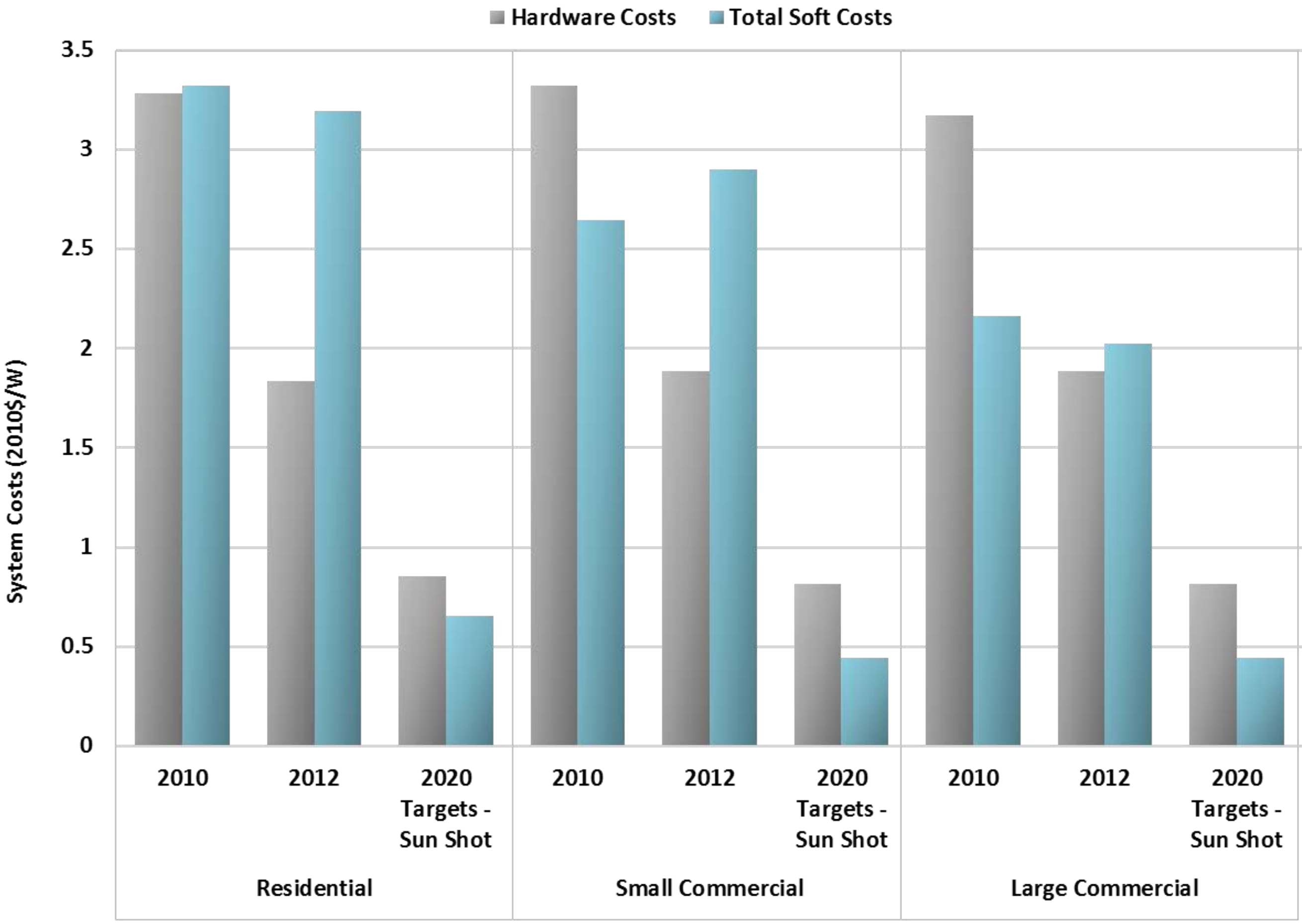

Figure 15. Total PV system hardware and software prices: 2010, 2012, and 2020 SunShot targets

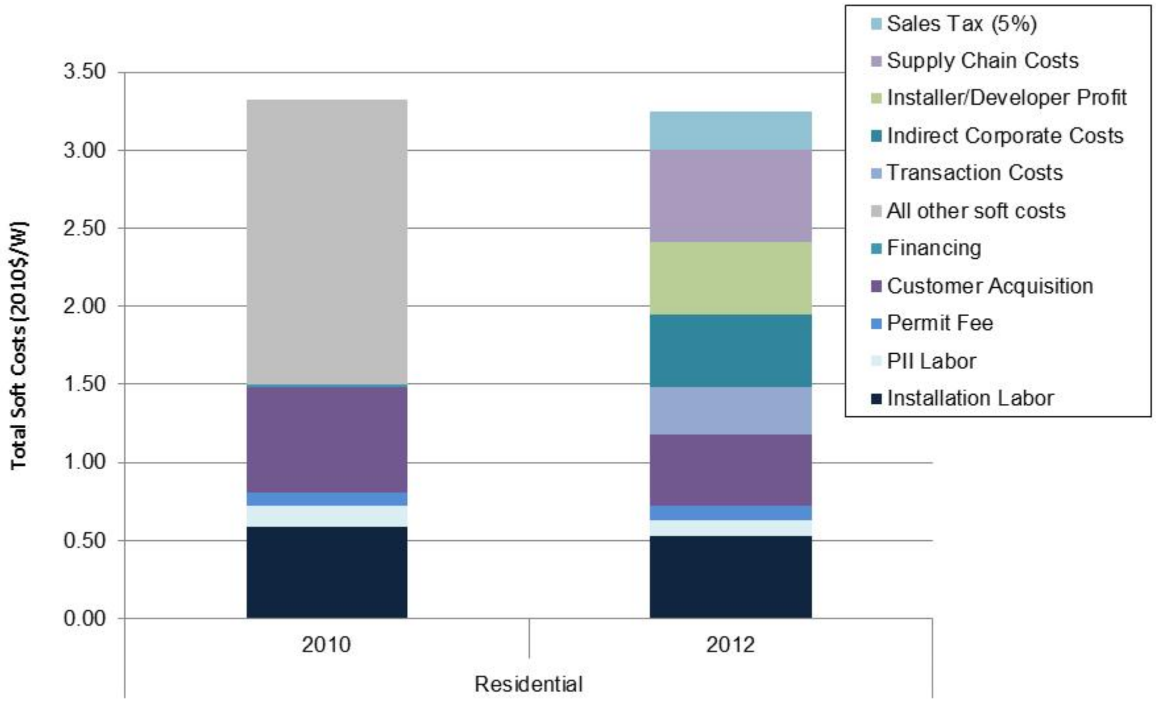

Figure 16. Comparison of 2010 and 2012 residential PV soft costs

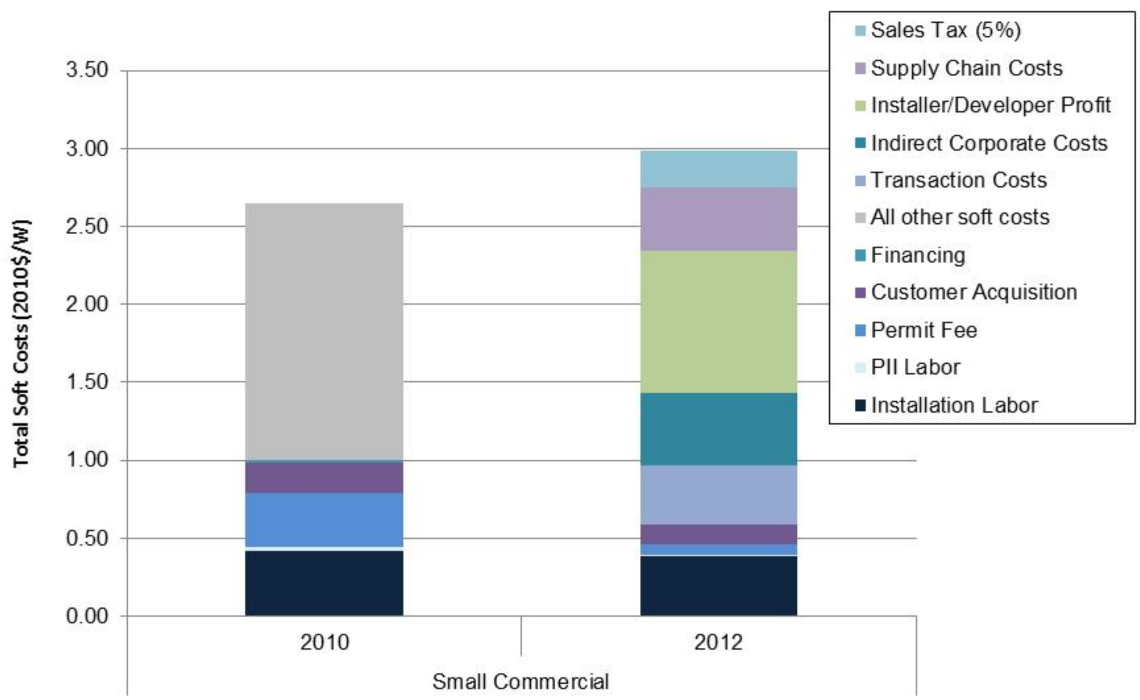

Figure 17. Comparison of 2010 and 2012 small commercial PV soft costs

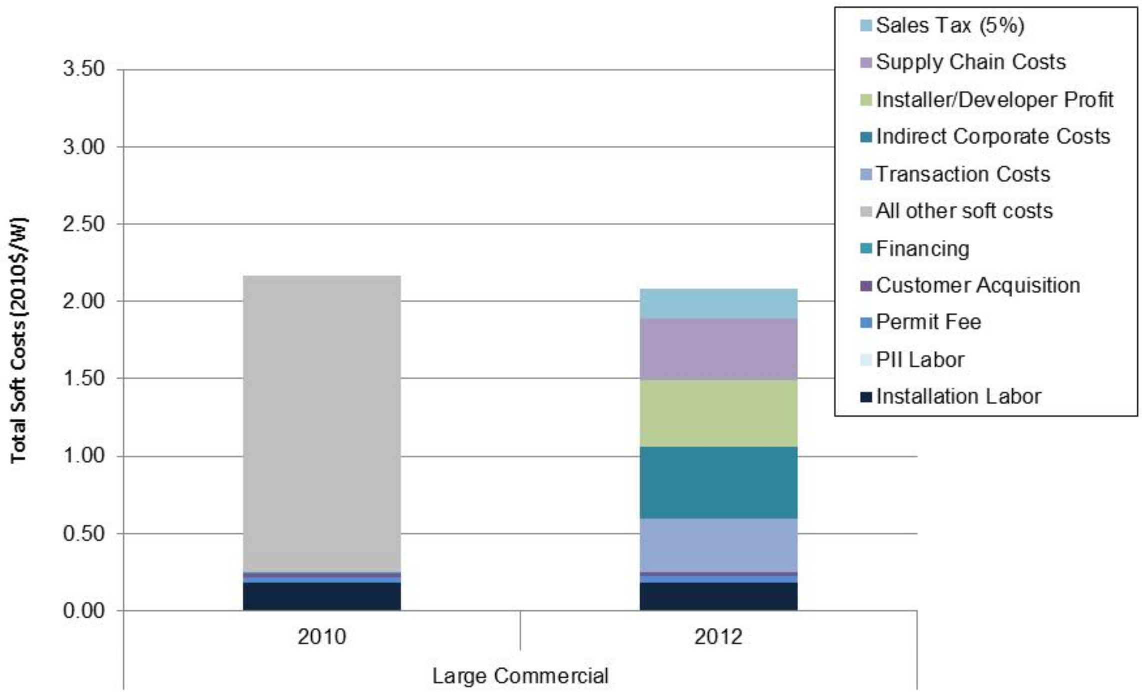

Figure 18. Comparison of 2010 and 2012 large commercial PV soft costs

9 Conclusions and Future Work

As PV system prices continue to decline owing to module and hardware cost reductions, accurately quantifying soft costs is increasingly important for explaining PV system price dynamics across various U.S. and international markets. This report presents results from a bottom-up, survey-data and model-driven analysis of soft costs in the areas of customer acquisition, financing, PII, and installation for the first half of 2012. This work continues the effort started with Ardani et al. (2012) to benchmark soft costs for residential and commercial PV with the objectives of tracking costs over time, identifying opportunities for cost reductions and informing the development of policies and practices aimed at reducing cost inefficiencies. The soft costs detailed in this report constitute a significant portion of total installed PV system prices. The soft costs we characterized—which accounted for all soft costs—constituted 64% of the total residential system price, 57% of the small commercial system price, and 52% of the large commercial system price in the first half of 2012.

Clearly, economies of scale help reduce these soft costs, particularly when comparing residential and small commercial systems with large commercial systems. Among the individual soft-cost categories we characterized, supply chain costs, indirect corporate costs, transaction costs, and installer/developer profit are dominant contributors, followed by installation labor, sales tax, and customer acquisition. With some form of sales tax exemption for solar PV equipment in place in 20 U.S. states plus Puerto Rico (DSIRE 2013), sales tax represents an area of potentially straightforward cost reductions for the remaining states. PII contributes relatively little cost when measured in terms of dollars per watt but presents a qualitative market barrier that can deter project completion entirely. Our analysis suggests that customer acquisition and PII costs decreased in general from 2010 to 2012.

The SunShot Initiative aims to reduce the installed system price contribution of all soft costs to approximately \$0.65/W for residential systems and \$0.44/W for commercial systems by 2020, in 2010 dollars (DOE 2012).[26] The soft costs we characterized (including assumed permitting fees) contribute \$3.19/W for residential systems, \$2.90/W for small commercial systems, and \$2.02/W for large commercial systems, in 2010 dollars. Soft costs for residential and large commercial systems declined in the United States between 2010 and 2012, while small commercial soft costs increased. Because this second benchmarking effort characterized all PV soft costs—which the previous edition did not—it represents a step forward in measuring progress toward the SunShot soft-cost-reduction targets. This improvement resulted from capturing transaction costs, indirect corporate costs, and installer/developer profit using our newly developed model along with the sales tax and supply chain cost values from Feldman et al. (2013a). Improving our model and our understanding of related costs will be a focus of future work.

In general, our future work will continue to improve the accuracy and comprehensiveness of PV soft-cost analysis—providing data-derived metrics in support of private and public soft-cost-reduction efforts. For example, more work is required to distinguish the cost of goods sold from operating margins. In addition, customer-acquisition costs are increased by potential PV customers' lack of access to credible, standardized PV performance data and by installers' need to visit potential PV sites to develop preliminary system designs and prepare bids. Future work in these areas could include benchmarking the specific cost contributions of these barriers and estimating the cost-reduction potential

[26] The SunShot Initiative's total installed price targets are \$1.50/W for residential systems and \$1.25/W for commercial systems.

of solutions, such as web-based dissemination of third-party-verified PV consumer data and remote PV site assessment.

Strategies for reducing installation-labor costs are also important, such as the development of "plug and play" PV systems and widespread implementation of PV installer training and certification programs. Developing more accurate, granular analysis of installation-labor costs would enable the effectiveness of such strategies to be evaluated and optimized. Understanding the cost of system operations and maintenance over its lifetime is another area for future research, not only from an installed cost perspective but also from an LCOE perspective. Interconnection delays represent yet another significant area where true costs may not be fully understood.

Finally, understanding the location-dependent variability of soft costs throughout the United States is important. Our future work will seek to expand both the geographic scope of our soft-cost analysis and the geographic specificity of the results.

Soft costs are both a major challenge and a major opportunity for reducing PV system prices and stimulating SunShot-level PV deployment in the United States. The data and analysis in this series of benchmarking reports are a step toward the more detailed understanding of PV soft costs required to track and accelerate these price reductions.

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Appendix A: Survey Instruments

We surveyed installers via online surveys, which dynamically performed calculations (averages, sums, etc.) for the quantitative questions (the survey was scripted in Microsoft Excel). Four almost-identical surveys were administered, two for residential installers (one for New York installers and one for all others) and two for commercial installers (one for New York installers and one for all others). To eliminate repetitiveness, only the generic residential survey is reproduced below.

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Residential Soft Costs Data Collection 2012

The objective of this data collection effort is to benchmark and track the soft costs (i.e., costs of red-tape, non-hardware, excess overhead and delays) associated with deploying photovoltaic (PV) systems. The information you provide below will help identify regulatory and other processes that may be streamlined or standardized to reduce cost burdens. Please provide information for Q1 and Q2 of 2012 (January 1 - June 30, 2012). The input you provide will be used to generate auto-calculated values, to better assist you in gauging the accuracy of your responses. Responses will be accepted until June 1, 2013. Thank you for your important contribution.

Company Profile

Company Name	
Address	
City	
State	
Zip Code	
Your Name	
Position	
Phone	
Email	

Section A: Number of PV Systems Installed

For the following customer segments, please provide the number of PV systems and the total number of megawatts installed.

	Q1,Q2 TOTAL
Residential # of Systems	
Residential MW	
Commercial # of Systems	
Commercial MW	
Other (utility-scale and off-grid installations) # of Systems	
Other (utility-scale and off-grid installations) MW	
Total # of Systems	*0*
Total MW	*0*

Average System Size

Residential	0	kW
Commercial	0	kW
Other	0	kW

	Q1,Q2 TOTAL
What percent of your total residential installations were leased systems?	

Number of Leased Systems Installed

Residential	0	#

Section B: Residential Customer Acquisition

What was the total cost of residential customer acquisition activities in Q1 and Q2 of 2012? (include marketing and advertising, sales calls, site visits, travel time to and from the site, contract negotiation with system host/owner, and bid preparation, but exclude system design)

	Q1,Q2 Total
Total Customer Acquisition Costs [$]	
Customer Acquisition Cost/Installation [$]	*0*

For residential PV systems, what was the total system design budget in Q1 and Q2 of 2012?

	Q1,Q2 Total
Total System Design Costs [$]	
System Design Cost/Installation [$]	*0*

Check all that apply to your business operations

- ☐ Use lead referral service (e.g., Global Solar Center, 1BOG)
- ☐ Act as a contractor for a seller or finance firm
- ☐ Offer third-party financing through third-party provider
- ☐ Provide own third-party financing

Do you typically use remote site assessment techniques or google maps prior to an initial site visit?

- ○ Yes
- ○ No

Section C: Residential Permitting, Inspection, and Interconnection

Based on the average system size calculated above (Section A), how many labor hours (both full-time employees and contract labor) per residential PV installation were spent on the following?

	Labor Hours/Installation
a) Preparing a permit package (including determining a jurisdiction's permitting requirements, travel time to site/verification, drawing system plans, structural calculations, zoning application)	
b) Submitting the permit package (including travel time to and from the permitting office and wait time at the permitting office)	
c) Completing the permitting inspection (including paperwork, travel time to and from the site, wait time for inspector, and physical inspection)	
d) Completing the interconnection process (including paperwork, travel time to and from the site, wait time for representative from utility, and physical interconnection)	
e) Applying for and receiving all local, state, and federal financial incentives (including determining eligibility, paperwork, travel time to and from the site, wait time for inspector, and physical inspection)	
Total hours per installation	*0*

Section D: Conclusion

Please provide any additional feedback that would be helpful in better understanding the soft costs associated with PV installation and the PV business process.

Submit