Title

Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States - 2019 Edition

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Installed Price Trends for Distributed Photovoltaic Systems in the United States - **2018 Edition**

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2018 Edition

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Executive Summary

Lawrence Berkeley National Laboratory (LBNL)'s annual *Tracking the Sun* report summarizes installed prices and other trends among grid-connected, distributed solar photovoltaic (PV) systems in the United States.[1] The present report focuses on systems installed through year-end 2017, with preliminary trends for the first half of 2018. As in years past, the primary emphasis is on describing changes in installed prices over time and variation in pricing across projects. New to this year, however, is an expanded discussion of other project characteristics in the large underlying data sample. Future editions will include more of such material, beyond the report's traditional focus on installed pricing.

Installed pricing trends presented within this report derive primarily from project-level data reported to state agencies and utilities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. Refer to the text box to the right for several key notes about the data. In total, data were collected and cleaned for more than 1.3 million individual PV systems, representing 81% of U.S. residential and non-residential PV systems installed through 2017. A public version of this dataset is available at trackingthesun.lbl.gov. The analysis of installed pricing trends in this report is based on a subset of roughly 770,000 systems with available installed price data.

Key Points on the Data in This Report

Installed price data presented in this report:

- Represent the up-front price paid by the PV system owner, prior to receipt of incentives
- Are self-reported by installers and customers
- Differ from the underlying cost borne by the developer and installer
- Are historical and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects
- Exclude those third-party owned (TPO) systems for which reported installed prices represent appraised values, but include other TPO systems (see Text Box 2 in the main body of the report for further details)

Key findings from this year's report are as follows, with all numerical results denoted in real 2017 dollars and direct current (DC) Watts (W):

Installed Prices Continued to Decline through 2017 and into 2018. National median installed prices in 2017 were \$3.7/W for residential systems (a \$0.2/W or 6% decline from the prior year), \$3.1/W for "small" non-residential systems ≤500 kW (a \$0.4/W or 11% decline), and \$2.2/W (a \$0.1/W or 5% decline) for "large" non-residential systems >500 kW. Similar rates of decline are observed among most major state markets, and are driven primarily by trends among host-owned systems, which make up a disproportionate share of the analysis sample. Preliminary data for the first half of 2018 show an additional drop of \$0.1/W for residential and small non-residential systems, and effectively no change for large non-residential systems. These recent trends are generally consistent with the pace of price declines since 2014, and mark a slowing from the years immediately preceding (2009-2013) when prices fell by roughly \$1/W per year. That slowing rate of decline is primarily a function of the underlying trajectory of module prices, though also reflects other dynamics in the industry (e.g., changes in installer mix and business strategies, saturation of

[1] In the context of this report "distributed PV" includes both residential as well as non-residential rooftop systems and ground-mounted systems smaller than 5 MW_{AC}. An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector, which includes ground-mounted PV systems larger than 5 MW_{AC}.

early adopters in some markets, solar loan fees, and potentially diminishing opportunities for further cost savings and efficiency gains as the "low hanging fruit" are increasingly picked).

Installed Price Declines Reflect Reductions in Both Hardware and Soft Costs. Over the long-term, roughly 46% of the decline in residential installed prices is associated with falling module prices, 12% to reductions in inverter prices, and the remaining 42% to the collective assortment of other balance of systems (BoS) costs and "soft" costs (e.g., customer acquisition, installation labor, installer margins, loan fees, etc.). Of the long-term decline in BoS and soft costs, just over 40% could be attributed to growth in residential system sizes and module efficiencies (growth in system sizes being the more dominant effect of the two). Over the last year of the analysis period, from 2016 to 2017, the reduction in aggregate hardware costs for residential PV equates to roughly half of the decline in national median installed prices for residential PV systems in the LBNL dataset, implying that the remainder is associated with falling soft costs.

Installed Price Declines Have Been Partially Offset by Falling Incentives. Cash incentives (i.e., rebates and performance-based incentives) provided through state and utility PV incentive programs have fallen substantially since their peak a decade ago, and have been largely phased-out in many key markets. This trend has been partly a *response* to installed price declines and the emergence of other forms of incentives, though it has no doubt also helped to motivate further cost and price reductions within the industry. From the customer-perspective, however, declining incentives have offset, to varying degrees, installed price reductions over the same time period. Among the five largest residential state PV markets in our sample, for example, the long-term decline in cash incentives has offset between 67% and 100% of the corresponding drop in installed prices.

National Median Installed Prices Are Relatively High Compared to Other Recent Benchmarks. Median installed prices of systems in the LBNL dataset are high compared to many other recently published PV pricing and cost benchmarks, including those based on bottom-up cost models. These apparent discrepancies can be traced to a variety of differences in underlying data, methods, and conventions. Many of the other published benchmarks, instead, align more closely with 20th percentile pricing levels observed within the LBNL data, and may more closely represent "best in class" or "turnkey" projects and/or relatively low cost markets.

Installed Prices in the United States Are Higher than in Most Other Major National PV Markets. Compared to median U.S. prices, installed prices reported for a number of other key national solar markets are substantially lower. In Australia, for example, typical pricing for residential systems was reported to be around $1.8/W in 2017 (i.e., half the median price observed within the LBNL dataset), while prices in Germany were even lower, at $1.5/W. Though data comparability across countries is imperfect and may overstate the differences to some degree, numerous other studies have shown that soft costs, in particular, tend to be considerably higher in the U.S. than in most other markets.

Installed Prices Vary Widely Across Individual Projects. Among residential systems installed in 2017, 20% were priced below $3.0/W (the 20th percentile value), while 20% were above $4.5/W (the 80th percentile). Non-residential systems also exhibit wide pricing variability, with the 20th-to-80th percentile ranging from $2.4/W to $4.1/W for smaller (≤500 kW) projects and from $1.8/W to $2.8/W for larger (>500 kW) projects. This pricing variability has persisted over time, despite continuing maturation of the U.S. PV market, and reflects a broad array of factors, including differences in project characteristics and installer attributes, as well as various aspects of the broader market, policy, and regulatory environment. This report explores a subset of those factors, using relatively simple comparisons, while a number of other studies that LBNL has conducted with academic partners explore these factors using more complex statistical methods.

Clear Economies of Scale Exist Among Both Residential and Non-Residential Systems. Among residential systems installed in 2017, median prices were roughly $1.3/W lower for the largest systems (>12 kW) compared to the smallest systems (≤2 kW). Among non-residential systems, which span an even wider size range, median prices were $1.6/W lower for systems >1,000 kW, compared to the smallest non-residential systems ≤10 kW. Both residential and non-residential systems exhibit diminishing returns to scale with system size, though even lower installed prices would be expected for utility-scale systems, which are outside the scope of this report.

Installed Prices Vary Widely Among States, with Relatively High Prices in Some Large State Markets. State-level median installed prices in 2017 ranged from $2.6/W to $4.5/W for residential systems, from $2.2/W to $4.0/W for small non-residential systems, and from $2.1/W to $2.4/W for large non-residential systems. Three of the largest state markets (California, Massachusetts, and New York) are relatively high-priced, pulling overall U.S. median prices upward. These cross-state pricing differences reflect both idiosyncratic features of particular states as well as more-fundamental differences in market and policy conditions.

Prices that Installers Receive for Third-Party Owned Residential Systems Tend to Be Lower than for Host-Owned Systems. This report does not evaluate lease terms or power purchase agreement (PPA) rates for TPO systems, and therefore does not speak to the relative economics of TPO vs. host-owned systems *from the host-customer perspective*. However, it does include data on the installed price of TPO systems sold by installation contractors to customer finance providers, and therefore allows for some comparison of the relative economics *from the installer perspective*. For residential systems, the median installed price of TPO systems in 2017 was $0.5/W lower than for host-owned systems, consistent with recent years. These trends likely reflect some combination of greater buying power on the part of third-party financiers, more-standardized or turnkey installations in the TPO segment, customer acquisition managed or performed by the financier, and loan-financing fees rolled into the prices reported for many host-owned systems. In contrast, for non-residential systems, no consistent differences exist between prices reported for TPO and host-owned systems.

Wide Pricing Variability Exists Across Major Residential Installers. Among the 100 installers with the greatest number of host-owned residential installations in the dataset in 2017, installer-level median prices ranged from $2.1/W to $9.6/W, with most installers below $4.0/W. Installer-median prices for the top-100 TPO installers ranged from $1.1/W to $5.5/W, with most installers below $3.5/W. While the extremities of these ranges likely reflect anomalous price reporting by a few installers (particularly at the high end for host-owned systems and at the low-end for TPO systems), they nevertheless demonstrate the substantial variation in installer pricing behavior. The likely causes of that variation include attributes of the installers themselves, for example firm size and experience, as well as features of the broader markets in which installers operate, such as labor and permitting costs specific to particular states or regions.

Installed Prices Are Substantially Higher for Systems with "Premium Efficiency" Modules. Module efficiencies vary widely among systems in the dataset, from roughly 15% to 21% and above, for systems installed in 2017. Systems with "premium efficiency" modules at the upper end of this range (20% and above) consistently have higher installed prices than those with efficiencies below that threshold. Among residential systems installed in 2017, the differential in median prices was $0.6/W for residential systems and $0.8/W for small non-residential systems. This difference reflects the higher costs of premium efficiency products. Though increased module efficiency can yield savings on BoS and soft costs (e.g., by allowing for a smaller footprint system), it is clear that any such savings are more than offset by the higher cost of the modules. Those premium modules, however, may offer improved performance characteristics or longer warrantees (both of which are relevant to any full economic comparison).

Residential New Construction Offers Significant Installed Price Advantages Compared to Retrofit Applications. Within California, residential systems installed in new construction have been consistently lower-priced than those installed on existing homes. The disparity in 2017 was especially pronounced, with a median price of $2.3/W for systems in new construction, compared to $3.9/W for residential retrofits. That particular result is driven by several installers with large numbers of especially low-priced systems in new construction. Earlier years show smaller, though still significant, price advantages for new construction (e.g., a difference in median prices of $0.5/W in both 2015 and 2016). These trends likely reflect some combination of economies of scale in new construction (where PV is typically installed across multiple homes in new housing developments), economies of scope (where certain costs and activities can be shared between the PV installation and home construction), and reduced customer acquisition costs.

Installed Prices Are Generally Higher for Systems at Tax-Exempt Customer Sites than for Systems at Commercial Sites. Roughly 20% of non-residential systems in the 2017 data sample were installed at tax-exempt site hosts, including schools, government facilities, and non-profit organizations (such as churches). Systems installed for tax-exempt customers have been consistently higher priced than those for their commercial counterparts. These differences are most pronounced among the larger class of >500 kW non-residential systems, where median prices were roughly $0.5/W higher for tax-exempt customers than for commercial customers in 2017. The differentials are even greater if comparing only among host-owned systems. Higher prices at tax-exempt customer sites potentially reflect higher incidence of prevailing wage/union labor requirements, domestically manufactured components, and shade or parking structures. Many tax-exempt site hosts may also have lower borrowing costs, in turn enabling higher-priced systems to pencil-out.

1. Introduction

The market for solar photovoltaics (PV) in the United States has been driven in part by various forms of policy support for solar and renewable energy. A central goal of many of these policies has been to facilitate and encourage cost reductions over time. The U.S. Department of Energy's Solar Energy Technologies Office, for example, has sought to reduce costs to $1.50/W for residential systems and $1.25/W for commercial systems by 2020, and by an additional 50% by 2030.[2] Others have argued that even deeper cost reductions may be needed over the longer-term, given the declining value of solar with increasing grid penetration (Sivaram and Kann 2016). As public and private investments in these efforts have grown, so too has the need for comprehensive and reliable data on the cost and price of PV systems, in order to track progress towards cost reduction targets, gauge the efficacy of existing programs, and identify opportunities for further cost reduction. Such data are also instrumental to cultivating informed consumers and competitive markets, which are themselves essential to achieving long-term cost reductions.

To address these varied needs, Lawrence Berkeley National Laboratory (LBNL) initiated the annual *Tracking the Sun* report series to summarize historical trends in the installed price of grid-connected, distributed PV systems in the United States.[3] It is produced in conjunction with several other ongoing National Lab research products that also address PV system costs and pricing, including a companion LBNL report focused on trends in the utility-scale solar market (see text box to the right).

This edition of *Tracking the Sun* describes installed price trends for projects installed through 2017, with preliminary data for the first half of 2018. The report is intended to provide an overview of both long-term and more-recent trends, highlighting a number of key drivers underlying these trends. The report also discusses in some depth *variability* in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics. Other LBNL research products have also explored pricing variability using more complex statistical methods. Beyond its primary focus on installed prices, this year's edition of *Tracking the Sun* also includes an expanded discussion of other characteristics of projects in the data sample. Future

Related National Lab Research Products

Tracking the Sun is produced in conjunction with several related and ongoing research activities:

- *Utility-Scale Solar* is a separate annual report series produced by LBNL that focuses on utility-scale solar (ground-mounted projects larger than 5 MW_{AC}) and includes trends and analysis related to project cost, performance, and pricing.
- *In-Depth Statistical Analyses* of PV pricing data by researchers at LBNL and several academic institutions seek to further explore PV pricing dynamics, applying more-advanced statistical techniques to the data collected for *Tracking the Sun*. These and other solar energy publications are available here.
- *The Open PV Project* is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL), which incorporates the *Tracking the Sun* dataset.
- *PV System Cost Benchmarks* developed by NREL researchers are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (for example, see Fu et al. 2017).

[2] The 2020 cost targets are denominated in real 2010 dollars.
[3] In the context of this report "distributed PV" includes both residential as well as non-residential rooftop systems and ground-mounted systems less than 5 MW_{AC}.

editions will include more of such material, beyond the report's traditional focus on installed pricing.

The trends presented in this report are based primarily on project-level data provided by state agencies, utilities, and other entities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. The full dataset underlying this year's report consists of more than 1.3 million grid-connected, distributed PV systems installed through year-end 2017, representing roughly 81% of the total U.S. market. A public version of this data file is available at trackingthesun.lbl.gov and is also incorporated into NREL's Open PV data portal. LBNL applies a substantial degree of quality control and undertakes numerous steps to clean these data. The analysis of installed price trends is based on a subset of approximately 770,000 systems, for which installed price data are available and represent a valid transaction price.

Essential to note at the outset are several important aspects of the installed price data described within this report. These reported prices represent the up-front price paid by the system owner, prior to receipt of incentives; such prices may differ from the underlying costs borne by the developer or installer, for a variety of reasons. The data are also self-reported, and therefore may be subject to inconsistent reporting practices (e.g., in terms of the scope of the underlying items embedded within the reported price or whether the administrator validates reported prices against invoices). Furthermore, these data are historical, and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects. Finally, as noted above (and explained more fully later in the report), the installed prices are intended to reflect actual transaction prices and therefore exclude the subset of third-party owned (TPO) systems installed by companies that perform both installation and customer financing, as the prices reported for those systems generally represent an appraised value.

The remainder of the report is organized as follows. Section 2 summarizes the data sources, key methodological details, and the sample size relative to the U.S. and individual state distributed PV markets. Section 3 described key characteristics of the full data sample, including system size trends, third-party ownership, customer segmentation, module efficiencies, use of module-level power electronics, and the prevalence of ground-mounting and tracking. Section 4 presents an overview of long-term, installed-price trends, focusing on median values drawn from the large underlying data sample. The section illustrates and discusses a number of the broad drivers for those historical installed-price trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. The section also compares median installed prices for systems installed in 2017 to a variety of other recent U.S. benchmarks, and to prices in other international markets. Section 5 describes the variability in installed prices within the dataset, and explores a series of specific sources of installed pricing differences across projects, including: system size, state, installer, host-owned vs. TPO, residential new construction vs. retrofit, for-profit commercial vs. tax-exempt site host, module efficiency level, and rooftop vs. ground-mounted with or without tracking. Finally, Section 6 offers brief conclusions. The appendix provides further details on data sources and the data cleaning process.

2. Data Sources, Methods, and Market Coverage

The trends presented in this report derive from data on individual distributed PV systems. This section describes the underlying data sources and the procedures used to standardize and clean the data, with further information provided in the Appendix. The section then describes the sample size over time and by market segment, comparing the data sample to the overall U.S. PV market and to individual state markets, highlighting any significant gaps in market coverage.

Data Sources

The data are sourced primarily from state agencies, utilities, and other organizations that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes (see Table B-1 in the Appendix for a list of data providers and associated sample sizes).

The data sources for this report series have evolved over time, particularly as incentive programs in a number of states have expired. In these instances, data collection has often continued to occur through other administrative processes, such as interconnection or SREC registration. One significant data gap that did emerge, albeit temporarily, was in California, where the state's primary incentive began to wind down in 2013. Data collection responsibilities were eventually transitioned to the investor-owned utilities' (IOUs') interconnection processes; however, in the intervening period, installed pricing data was unavailable for a sizeable fraction of the California market. Further discussion of this issue, and its impact on the trends presented in this report, are provided below.

Text Box 1. Customer Segment Definitions

This report segments trends according to whether the site host is residential or non-residential, and among non-residential systems into those that are ≤500 kW_{DC} and >500 kW_{DC}.

***Residential**:* Includes single-family residences and, depending on the conventions of the data provider, may also include multi-family housing.

Non-Residential: Includes non-residential rooftop systems regardless of size, and ground-mounted systems up to 5 MW_{AC}.

Both categories consist mostly, but not exclusively, of systems installed behind the customer meter. Ground-mounted systems larger than 5 MW_{AC} are considered **utility-scale**, regardless of whether they are installed on the utility- or customer-side of the meter. The size threshold for utility-scale is denominated in AC capacity terms, as is more common for utility-scale systems. Those systems are not covered within this report, but are instead addressed in LBNL's companion *Utility-Scale Solar* annual report.

These customer segment definitions may differ from those used by other organizations, and therefore some care must be taken in comparisons.

Data Standardization and Cleaning

Various steps were taken to clean and standardize the raw data. First, all systems missing data for system size or installation date, as well as any utility-scale PV systems or duplicate systems contained in multiple datasets, were removed from the raw sample. The remaining data were then cleaned by correcting text fields with obvious errors and by standardizing the spelling of installer names and module and inverter manufacturers and model names. Using module and inverter names, each PV system was then classified as building-integrated PV or rack-mounted; module technology type and efficiency were added to the dataset based on manufacturer spec sheet data; and systems with microinverters or DC optimizers were flagged. Finally, all price and incentive data were converted to real 2017 dollars (2017$), and if necessary system size data were converted to direct current nameplate capacity under standard test conditions (DC-STC). Further details on these steps, as well as other elements of the data cleaning process, are described in Appendix A. The resulting dataset, following these initial steps, is referred to hereafter as the ***full sample*** and is the basis for the public data file (which differs only in the exclusion of confidential or sensitive data).

For the purpose of analyzing installed prices, several other categories of systems were then removed from the data. The most significant group of excluded systems are those where reported prices are assumed to represent an appraised value, rather than a transaction price (see Text Box 2 below). Also excluded from the analysis are systems with missing installed price data, systems with battery-back up, self-installed systems, and systems with installed prices less than $1/W or greater than $20/W (assumed to be data entry errors). The resulting dataset, after these various additional exclusions, is denoted hereafter as the ***analysis sample*** and is the basis for all installed price trends presented in the report, unless otherwise indicated.

Text Box 2. Treatment of Third-Party Owned Systems in the Data Sample and Analysis

Third-party ownership of customer-sited PV systems through power purchase agreements and leases is prevalent in many state markets, though its dominance has been waning in recent years. The presence of TPO systems in the dataset creates certain complications for the tracking of installed prices. The nature of these complications, however, depends on whether the company providing the customer financing also performs the installation (i.e., an “integrated” TPO provider) or instead procures the system through an independent installation contractor.

For systems financed by integrated TPO providers, reported installed price data generally represent *appraised values*, as no sale of the individual PV system occurs from which a price is established. For some integrated TPO providers, reported prices for host-owned systems also appear to be appraised value. To the extent that appraised-value systems could be identified, they were removed from the analysis sample. Further details on the number of excluded appraised-value systems are provided below, and details on the procedure used to identify those systems are described in Appendix A, along with data on installed prices reported for those systems.

In contrast, systems financed by non-integrated TPO providers were retained in the analysis sample. The installed price data reported for these systems represent an actual transaction price: namely, the price paid to the installation contractor by the customer finance provider. That said, important differences may nevertheless exist between these prices and those reported for host-owned systems. Later sections compare installed prices reported for non-integrated TPO systems and host-owned systems, in order to discern whether those differences are potentially significant.

Sample Size

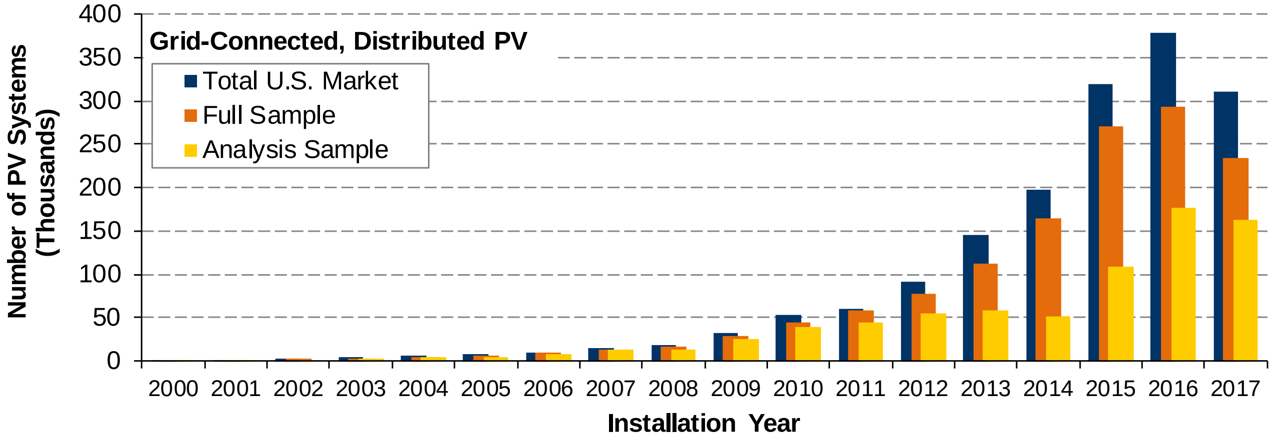
The ***full sample*** includes the majority of all U.S. grid-connected residential and non-residential PV systems. In total, it consists of roughly 1.3 million individual PV systems installed through year-end 2017, including more than 230,000 systems installed in 2017 (Table 1 and Figure 1). This represents 81% of all U.S. residential and non-residential systems installed cumulatively through 2017 and 75% of installations in 2017. As discussed further in the next section, coverage within most of the largest state markets is relatively high, and much of the sample gap is associated with smaller and mid-sized state markets either missing or under-represented in the sample.

The ***analysis sample***, following removal of appraised-value and all other excluded systems, consists of roughly 770,000 systems installed through year-end 2017 (57% of the full sample and 47% of all U.S. systems) and more than 160,000 systems installed in 2017 (69% of the full sample and 52% of all U.S. systems installed in that year). The gap between the full and final data samples consists primarily of appraised-value systems (approximately 380,000 systems) and systems missing installed price data (approximately 230,000 systems). The latter includes all systems from several states for which installed price data are wholly unavailable (as noted below), as well as a sizeable number of California systems installed from 2013 through 2015, during which time the collection of installed pricing data lapsed as the state's incentive program was winding down and the new data collection process had not yet been fully implemented. As shown in Figure 1, the gap between the full and final data samples narrowed considerably in 2016, and again in 2017. This is primarily due to the increased availability of installed price data for California, but also reflects the diminishing market share of appraised-value systems (and TPO systems more generally), which are otherwise culled from the analysis sample.

Table 1. Full Sample and Analysis Sample by Installation Year and Market Segment

Installation Year	**Full Sample**				**Analysis Sample**			
	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*
1998	27	1	0	***28***	9	0	0	***9***
1999	203	8	0	***211***	112	4	0	***116***
2000	183	3	0	***186***	104	2	0	***106***
2001	1,178	28	0	***1,206***	916	15	0	***931***
2002	2,305	125	1	***2,431***	1,866	72	0	***1,938***
2003	2,965	224	3	***3,192***	2,543	154	3	***2,700***
2004	4,950	363	5	***5,318***	4,450	258	5	***4,713***
2005	5,146	456	8	***5,610***	4,630	325	7	***4,962***
2006	8,598	569	22	***9,189***	7,835	400	19	***8,254***
2007	13,367	806	30	***14,203***	11,918	588	25	***12,531***
2008	15,234	1,497	76	***16,807***	12,877	1,217	60	***14,154***
2009	27,363	1,977	105	***29,445***	23,699	1,662	62	***25,423***
2010	40,812	3,724	189	***44,725***	35,688	3,155	103	***38,946***
2011	51,583	6,279	427	***58,289***	39,789	4,968	294	***45,051***
2012	71,114	6,115	406	***77,635***	49,834	4,613	284	***54,731***
2013	106,769	4,705	424	***111,898***	54,890	3,012	296	***58,198***
2014	158,604	5,499	413	***164,516***	48,270	2,524	227	***51,021***
2015	265,382	5,275	483	***271,140***	104,840	3,242	290	***108,372***
2016	286,274	6,819	674	***293,767***	171,470	5,029	483	***176,982***
2017	228,139	5,723	741	***234,603***	157,037	4,783	608	***162,428***
Total	***1,290,196***	***50,196***	***4,007***	***1,344,399***	***732,777***	***36,023***	***2,766***	***771,566***

Notes: See Text Box 1 for an explanation of the three customer segments used in this table and throughout the report.



Notes: Total U.S. distributed PV installations are based on data from IREC (Sherwood 2016) for all years through 2010 and from GTM Research and SEIA (2018) for each year thereafter.

Figure 1. Comparison of the Data Sample to the Total U.S. Distributed PV Market

State-Level Sample Distribution and Market Coverage

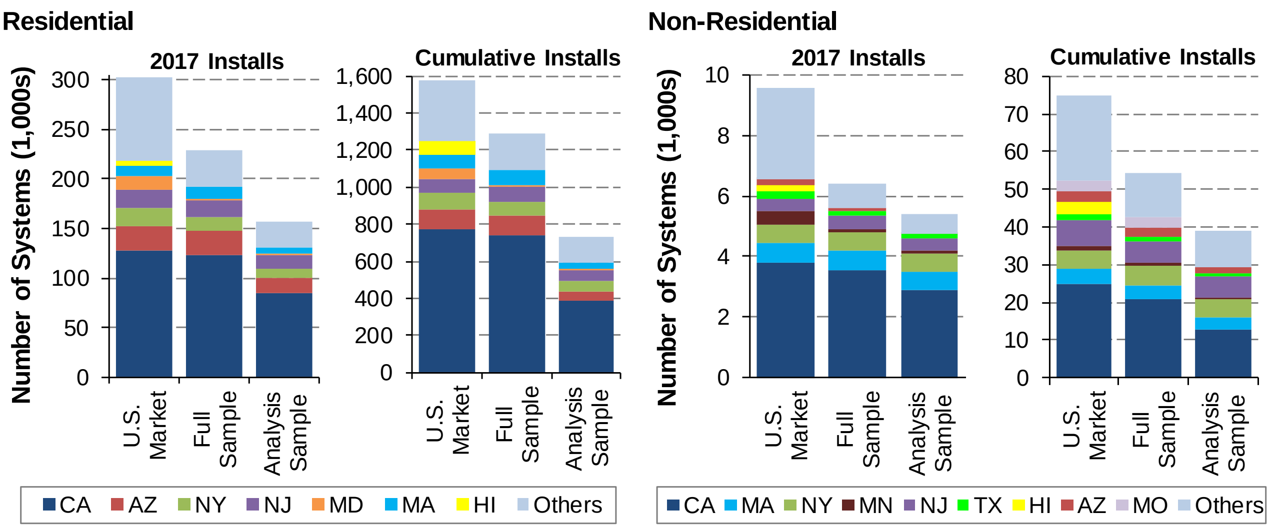
The full sample includes systems installed across 29 states, winnowed down to 25 states in the analysis sample, which excludes four states (DC, KS, MO, and OH) wholly lacking installed price data. Though the analysis sample has fairly broad geographic representation, it is nevertheless concentrated in a relatively small number of state markets, consistent with the broader U.S. market. This is illustrated in Figure 2, which shows the state-level market coverage and geographic distribution of the data sample, compared to the overall U.S. distributed PV market. Further details on sample sizes by state and data provider are also contained in Table B-1 in the Appendix.

California is, by far, the largest state in the sample—in terms of both 2017 installations and cumulative installations, for both residential and non-residential systems. The most prominent other states in the residential sample are Arizona, Massachusetts, New Jersey, and New York; while Massachusetts, New Jersey, and New York make up the bulk of the remaining non-residential sample. These states comprise a disproportionately large share of the sample (particularly for non-residential systems), relative to their share of the overall U.S. market. This has implications for the aggregate, national trends presented in this report, as discussed in later sections.

As a general matter, coverage within most of the major state markets is relatively strong, though several notable gaps do exist. Hawaii, which has historically been a large market for both residential and non-residential systems (though less so in recent years), is wholly absent from the sample. Maryland, one of the top-5 residential markets in 2017, is included in the sample but has relatively low market coverage. Finally, Minnesota was a top-5 non-residential market in 2017, but much of that growth consisted of community solar projects, which are largely absent from the data collected for this report. Other than those states, however, the full data sample includes at least 80% or more of systems installed in all of the larger state markets, as defined in Figure 2. Much of the gap between the full sample and total U.S. market is instead associated with smaller and mid-sized state markets (denoted as "Others" in the figure) either missing or under-represented in the sample.[4] As

[4] Within that catch-all group of states, the most notable gaps in the 2017 residential sample are from Florida, South Carolina, Pennsylvania, and Washington, which are largely or wholly missing from the 2017 sample, as well as roughly half the installations in Texas and Utah. Within the 2017 non-residential sample, the largest gaps from the "Others"

also evident in the figure, coverage within the non-residential sector is somewhat lower than for residential systems; this partly reflects the more diffuse nature of the non-residential market, as well as the fact that non-residential systems are more likely to be installed outside of incentive programs, such as those that contribute data to this report.



Notes: Data for total U.S. market are from GTM Research and SEIA (2018) which defines non-residential systems based on the off-taker (any entity other than a homeowner or utility) rather than the site-host. The figure explicitly identifies states that are among the top-5 in each segment in terms of either 2017 installations or cumulative installations, in either the U.S. market or data sample. The figure consolidates non-residential systems rather than distinguishing between the two size classes used elsewhere in the report, as U.S. market data are available only for non-residential systems as a whole. See Table B-1 in the appendix for additional details, including sample sizes for states included in "Others".

Figure 2. State-Level Market Coverage in the Data Sample

group are Iowa, South Carolina, Illinois, Florida, and Virginia, which are largely or wholly missing from the sample, and roughly 60% of the systems from Connecticut and Utah.

3. Sample Characteristics

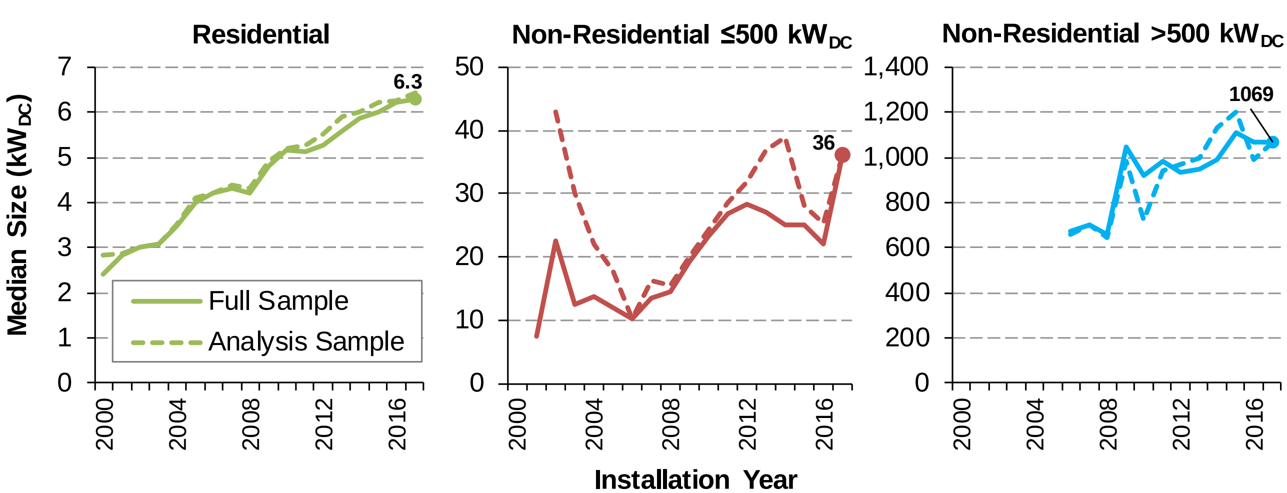
Characteristics of the data sample help to illustrate trends within the broader U.S. distributed PV market, and provide important context for understanding installed price trends presented later in this report. To that end, we describe below key characteristics of the data sample, including: the evolution of system sizes over time, the distribution between host-owned and TPO systems, the composition of non-residential site hosts, module efficiencies, the use of module-level power electronics, and the prevalence of ground-mounting and tracking equipment. We focus here primarily on characteristics of the *full data sample*, but also selectively note trends among the *analysis sample*, in order to highlight any differences (or lack thereof) and to provide additional context for the later discussions of installed price trends.

System Size

System sizes for residential systems in the data sample have grown steadily over time, rising from a median of 2.4 kW per system in 2000 to 6.3 kW in 2017, as shown in Figure 3. To the extent that residential system sizing is constrained by available roof area, increasing system sizes partly reflect steady increases in module efficiencies, as discussed in much more depth below. More significantly, though, increasing residential system sizes simply reflect the declining cost and increasing affordability of solar PV.

System sizes within the class of non-residential systems ≤500 kW have followed a somewhat irregular trajectory. Most important to note is simply that the vast majority of these systems are well below the 500 kW mark, with a median size of 36 kW among 2017 systems in the data sample. As such, this customer segment is often described in the report as "small" non-residential systems.

Finally, system sizes for the >500 kW (i.e., "large") non-residential class have also generally risen over time, reaching 1,069 kW in 2017, reflecting an increasing prevalence of multi-MW rooftop systems and "baby ground-mount" systems in the 1-5 MW range. As noted previously, this group consists of roof-mounted systems larger than 500 kW (with no upper size limit), as well as ground-mounted systems sized between 500 kW_{DC} and 5,000 kW_{AC} (ground-mounted systems larger than 5,000 kW_{AC} are covered in Berkeley Lab's *Utility-Scale Solar* report).

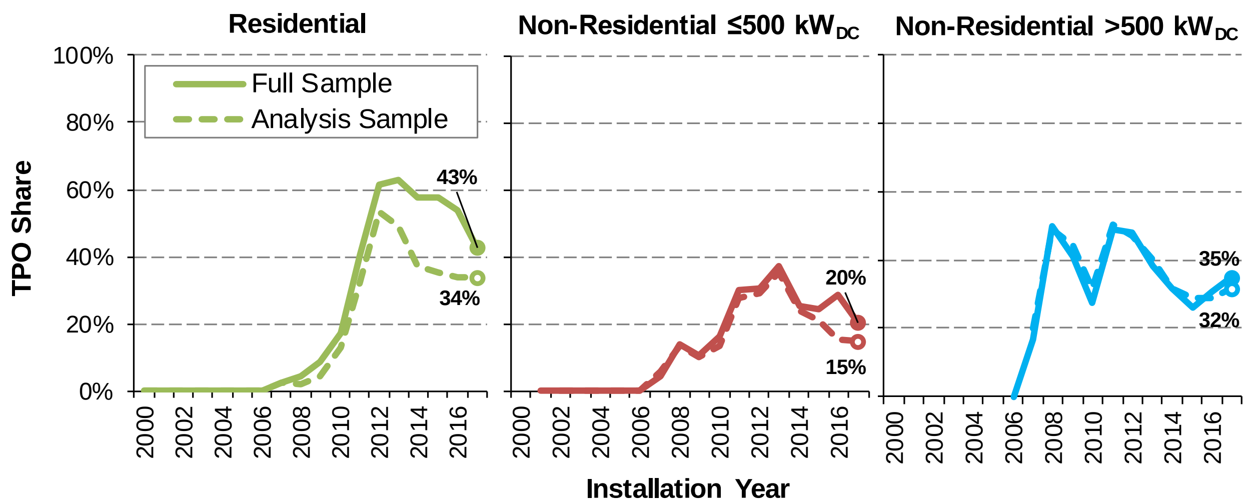


Notes: Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 3. Median System Size over Time

Third-Party Ownership

The composition of the data sample reflects the growth, and more recent decline, of third-party ownership. As shown in Figure 4, the TPO share among residential systems in the full data sample grew dramatically from 2007 to 2012, but has been falling in recent years, consistent with broader market trends. Among 2017 residential systems, TPO represented 43% of the full sample and 34% of the analysis sample—the difference between the two partly reflecting integrated TPO systems culled from the analysis sample. The trends differ within the non-residential sample, in several key respects. First, the overall TPO percentages are lower: 20% of the full sample for the sub-500 kW class in 2017 and 35% for the >500 kW class. As discussed in the section below, a disproportionately large share (roughly half) of the TPO systems in the non-residential sample are at tax-exempt customer sites. Second, integrated TPO systems represent a much smaller share of all non-residential TPO systems, and thus relatively few non-residential TPO systems were excluded from the analysis sample. For that reason, the TPO share within the non-residential segments are fairly similar between the full sample and analysis sample.



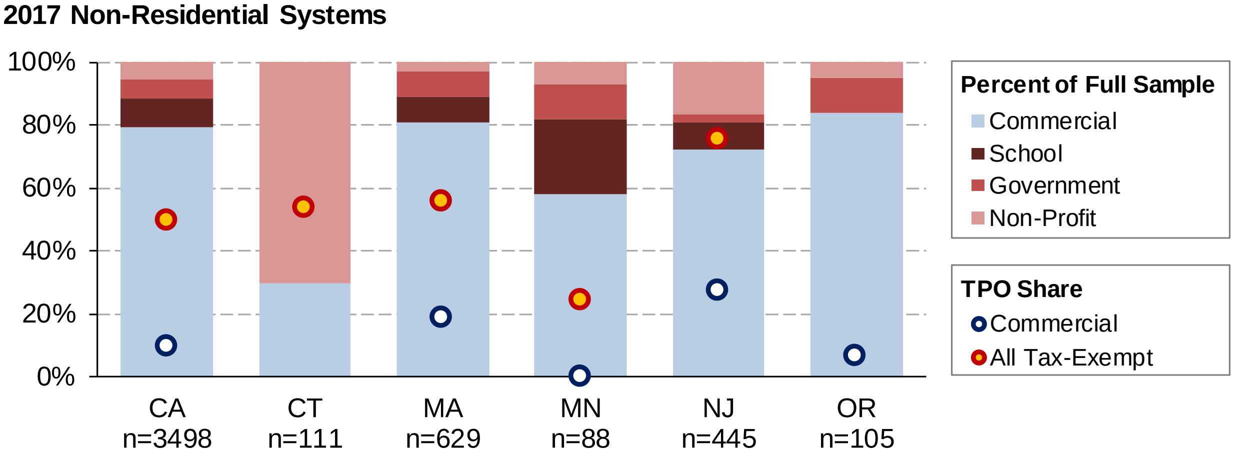
Notes: Summary statistics shown only if at least 20 observations are available for a given year and customer segment. Systems for which ownership is unknown or could not be readily inferred are excluded from the figure.

Figure 4. Sample Distribution between Host-owned and TPO Systems

Non-Residential Customer Segmentation

The non-residential solar sector is diverse in terms of the composition of the underlying base of customer site hosts, consisting of not only for-profit commercial entities, but also a sizeable contingent of systems installed at schools, government buildings, and non-profit organizations. That latter set we collectively refer to as “tax-exempt” customers. In 2017, systems at tax-exempt customer sites comprised 21% of all non-residential systems in the LBNL dataset (based on the sub-set of the sample with data on the specific type of site host). As shown in Figure 5, that percentage varies somewhat across states—though the three largest non-residential markets in the 2017 sample (California, Massachusetts, and New Jersey) all exhibit a fairly similar distributions between tax-exempt and commercial sites.

One critical distinction between commercial and tax-exempt customers is the prevalence of TPO. As shown in Figure 5, TPO is considerably more common among tax-exempt customers, as these customers are generally unable to directly monetize tax benefits, and therefore rely on third-party owners to capture (and pass on) those benefits. In aggregate across all non-residential systems in the sample, 52% of systems at tax-exempt sites were TPO in 2017, compared to 12% of systems at commercial customer sites (though, again, these percentages can vary by state).



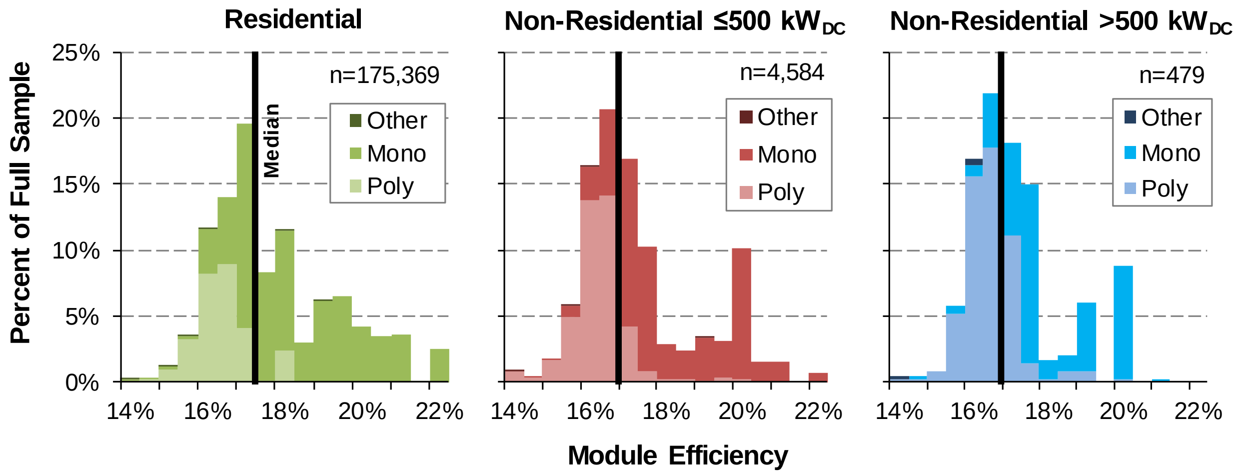
Notes: The figure includes only those states for which the available data consistently identify specific non-residential customer types and with meaningful sample sizes. TPO Share is omitted in several cases where fewer than 20 observations were available with known TPO status for the given state and customer grouping.

Figure 5. Non-Residential Customer Segmentation and TPO Shares

Module Efficiencies

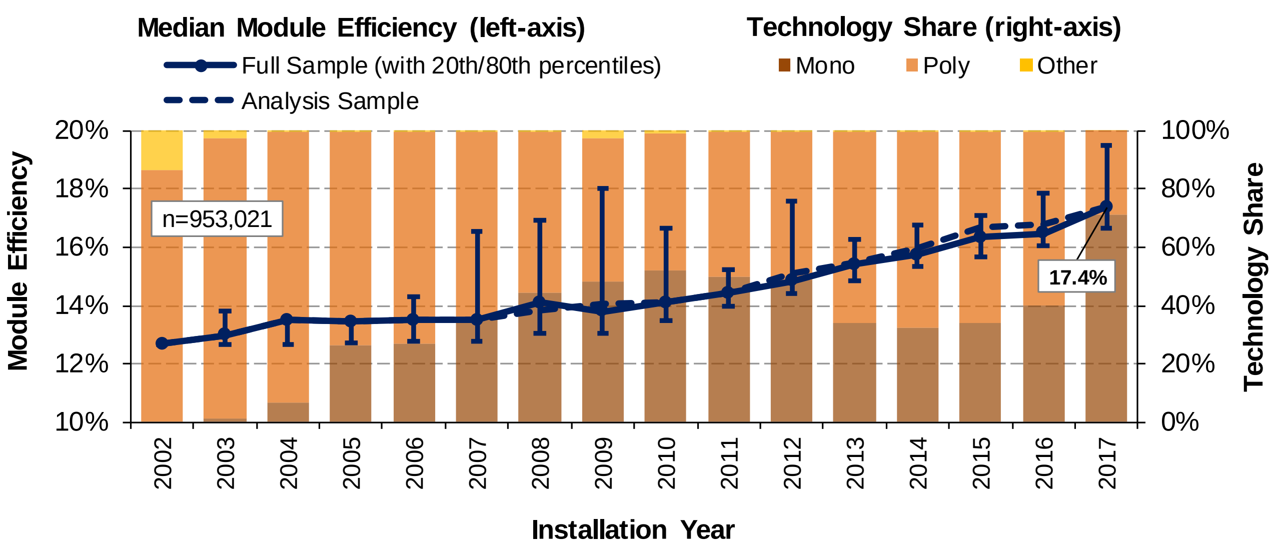
The conversion efficiency of commercially available PV modules varies considerably, depending on module technology and manufacturer. Among 2017 systems in the data sample, those using poly-crystalline silicon modules have efficiencies typically ranging from 15.5% to 17.5%, as shown in Figure 6. Systems with mono-crystalline modules span a wider range, from about 16% to greater than 22%, depending in part on whether they utilize p-type (lower efficiency) or n-type (higher efficiency) cells. Higher efficiency modules are slightly more prevalent among residential systems, which had a median module efficiency of 17.5% in 2017, compared to 17.0% for both small and larger non-residential systems. The modestly greater usage of high-efficiency modules in residential applications may reflect greater space constraints and potentially less price-sensitivity.

Module efficiency levels across technologies have steadily grown over time. Within the full data sample, median module efficiencies rose from 12.7% in 2002 to 17.4% in 2017, as shown in Figure 7. Within just the last year of the analysis period, median module efficiencies rose by almost a full percentage point, from 16.5% in 2016 to 17.4% in 2017. That dramatic rise may partly reflect the correspondingly sharp increase in the share of mono-crystalline modules in the dataset, from 40% to 70% in that year. Over the long-term, however, it is clear that module efficiencies have been climbing, irrespective of the fluctuating market share of mono-crystalline modules, reflecting continuous improvements in both mono- and poly-crystalline technologies.



Notes: Module efficiencies were determined by matching reported module manufacturer and model names for each system with module spec sheet data compiled by SolarHub.com and the California Energy Commission.

Figure 6. Module Efficiency Distributions for Systems Installed in 2017



Notes: This figure begins with 2002, the first year with module efficiency data for at least 20 systems.

Figure 7. Module Efficiency Trends over Time in the Data Sample

Module-Level Power Electronics

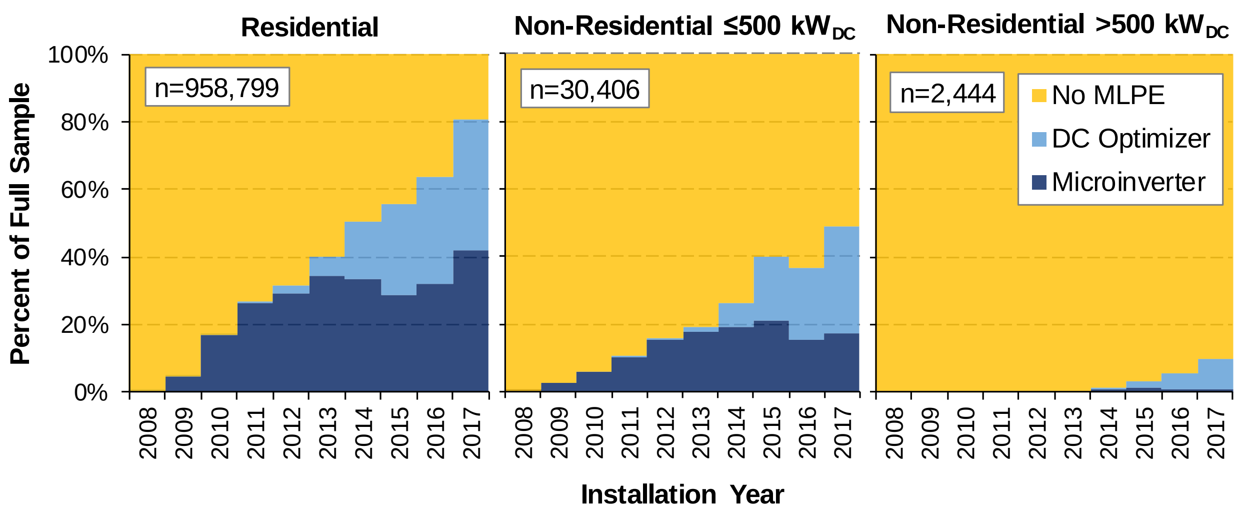
Microinverters and DC power optimizers, collectively known as module-level power electronics (MLPEs), offer a number of potential advantages over standard string inverters, including higher performance levels, longer warrantees, and ready-compliance with National Electrical Code (NEC) rapid-shutdown requirements.[5] MLPEs generally sell for a premium over standard inverters, but that price differential has narrowed in recent years—to roughly \$0.15/W for microinverters and \$0.10/W

[5] Deline et al. (2012) estimate 4-12% greater annual energy production from systems with microinverters. Such performance gains are associated primarily with the ability to control the operation of each panel independently, eliminating losses that would otherwise occur on a string of panels when the output of a subset of the panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string.

for DC optimizers in 2017 (Fu et al. 2017, GTM Research and SEIA 2018)—leading to steady gains in MLPE market share.

This is reflected in the data sample, as shown in Figure 8. MLPE growth has been most pronounced in the residential segment, reaching 80% of all systems in the sample installed in 2017, split roughly in half between DC optimizers and microinverters. As evident in the figure, virtually all of the growth since 2013 has been from DC optimizers, with the microinverter-share remaining fairly flat over that period. The same basic trends apply among small non-residential systems in the sample, albeit with lower overall MLPE penetration rates (roughly 50% of 2017 installations in the sample), and a heavier emphasis on DC power optimizers among those systems (roughly two-thirds of the 2017 systems with MLPEs). Among large non-residential systems in the sample, MLPE penetration is substantially lower than in the other two segments, with less than 10% of all 2017 systems including MLPEs (DC optimizers in virtually all cases).

Differences in MLPE penetration across customer segments in the sample partly reflect the nature of the performance benefits provided by MLPEs. Those benefits arise mostly in cases where PV systems are partially shaded or consist of multiple arrays with differing orientations: conditions that are naturally more likely to occur in residential applications (with multiple roof planes and more-constrained space) than in non-residential applications (where systems are often installed on flat rooftops with uniform orientation and potentially greater flexibility in terms of layout).

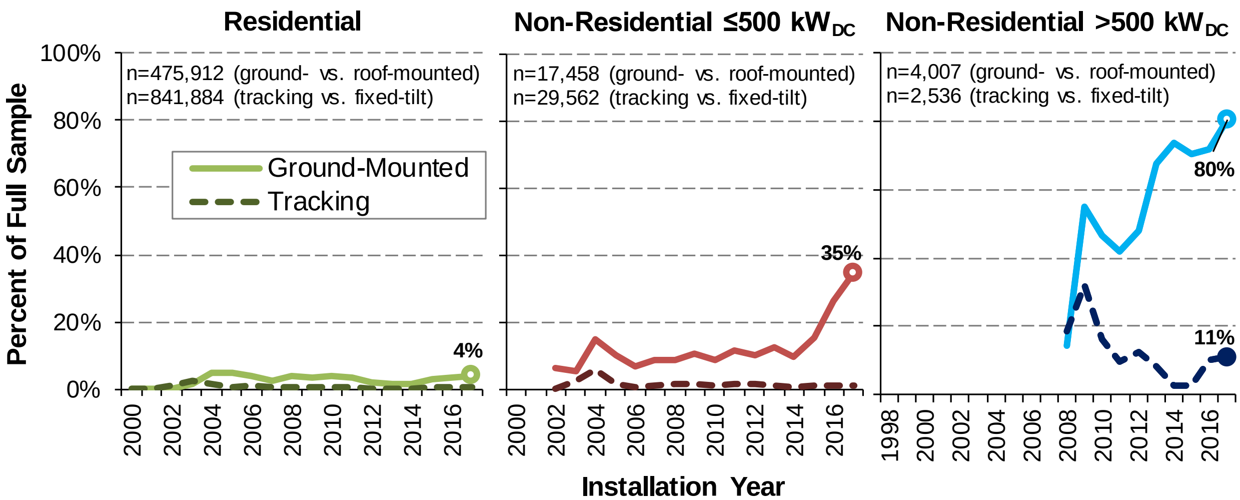


Notes: Use of MLPEs was determined by matching reported inverter manufacturer and model names for each system with inverter spec sheet data compiled by SolarHub.com and the California Energy Commission. The DC Optimizer share consists of only systems with SolarEdge inverters and may therefore understate the actual share of power optimizers in the data sample.

Figure 8. Penetration of Module-Level Power Electronics within the Data Sample

Ground-Mounting and Use of Tracking Equipment

Though distributed PV is most typically fixed-tilt, roof-mounted arrays, a subset of the systems in the sample are ground-mounted (which includes parking structures), and a portion of those use tracking equipment, as shown in Figure 9. As to be expected, residential systems are almost entirely roof-mounted and fixed-tilt (just 4% of residential systems in 2017 were ground-mounted, and virtually none had tracking). In contrast, 35% of small non-residential systems and 80% of large non-residential systems were ground-mounted in 2017, and those percentages have grown substantially over time. Use of tracking equipment, however, is confined primarily to just the larger non-residential systems, with 11% using tracking in 2017. Many of what are referred to within this report as large non-residential systems might thus be classified elsewhere as small utility-scale systems (keeping in mind that ground-mounted systems in this sample are limited to systems under 5 MW_{AC}, while larger ground-mounted systems are covered in LBNL's companion annual report on utility-scale solar).



Notes: Each line in the figure is based on the sub-set of systems in the sample with data for the associated attribute (ground-mounted vs. roof-mounted and tracking vs. fixed tilt). Summary statistics for any given year are shown only if at least 20 observations are available.

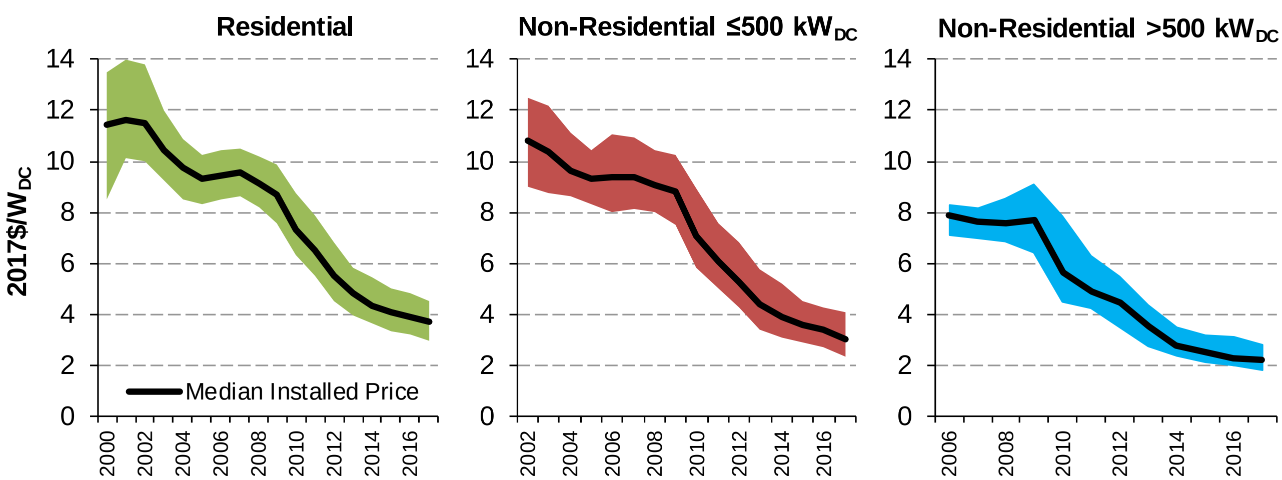
Figure 9. Mounting Configuration among Systems in the Data Sample

4. Historical Trends in Median Installed Prices

This section presents an overview of both long-term and more-recent historical trends in the installed price of residential and non-residential PV, based on *median values* derived from the large underlying data sample. It begins by describing the installed price trajectory over the full historical period of the data sample through 2017, along with preliminary data for the first half of 2018. The section then discusses a number of broad drivers for those historical trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. It then compares median installed prices for systems installed in 2017 to other recent benchmarks for the installed price or cost of PV, and finally compares installed prices between the United States and other international markets.

Installed Price Trends: 2000-2017

National median installed prices in 2017 were \$3.7/W for residential systems, \$3.1/W for small non-residential systems, and \$2.2/W for large non-residential systems. As evident in Figure 10, installed prices across all three segments have fallen dramatically over time. Over the full duration of the available time series, median installed prices fell by roughly \$0.5/W per year on average, for each of the three customer segments shown, equating to an average annual percentage drop of 6% per year for residential, 8% for small (≤500 kW) non-residential systems, and 11% for large (>500 kW) non-residential systems. These trajectories, however, have not been smooth. Prices fell rapidly in the early years through 2004, followed by little price movement over the 2004-2008 period, and then a resumption of price declines in 2009. Price declines from 2009 were initially quite steep—falling by roughly \$1/W each year, on average, over the 2009-2013 period—but have tapered off considerably since then. Over the last year of the analysis period, median prices fell by \$0.2/W (6%) for residential systems, by \$0.4/W (11%) for small non-residential, and by \$0.1/W (5%) for large non-residential systems. Those decline are largely in line with the pace of price decline since 2014.



Notes: Solid lines are median prices, and shaded areas are 20th-to-80th percentile ranges. Statistics shown only if at least 20 observations are available for a given year and customer segment. See Table 1 for annual sample sizes.

Figure 10. Installed Price Trends over Time

The slowing rate of installed price declines in recent years, relative to the rapid declines of the 2009-2013 period, reflects a number of broad trends. First and foremost is the underlying trajectory of module prices. As discussed further in the next section, the rapid installed-price declines that began in 2009 were fueled primarily by a correspondingly rapid drop in global module prices. As module-price declines began to slow in 2013, so too did the decline in system-level pricing. On the non-hardware side, cost declines in the residential sector have been dampened by higher customer acquisition costs, as early adopters are converted, and by a greater emphasis on profitability by large installation firms (GTM and SEIA 2018). More generally, opportunities for cost reductions across the PV value chain may be diminishing as the market matures and the easiest opportunities for efficiency gains are exploited. Residential loan products have also become more prevalent, whereby various fees are often embedded in the installed prices paid by customers and reported to PV incentive program administrators. PV systems are also increasingly bundled with other products, and though we attempt to exclude such systems from our data sample in cases where a single price is reported for both PV and other items, that screening is undoubtedly incomplete.

Trends in aggregate, national median installed prices are, in effect, a composite of trends among the largest state markets in our dataset. Later comparisons will show that installed prices can and do differ across states, in absolute magnitude. As shown in Figure 11, however, the year-over-year (YoY) *changes* in median installed prices across large state markets are generally well aligned with one another and with national trends. Within the residential and small non-residential segments, national trends are heavily driven by California, given that it represents more than half the analysis sample in both segments, but most other state markets show similar YoY price declines. Cross-state trends for large non-residential systems are also well-aligned with one another. This broad similarity across state markets gives confidence that recent national trends, in terms of YoY price declines, are not unduly driven by peculiarities within any individual state.

National installed price trends are also a composite of trends among host-owned and TPO systems. Later sections will highlight differences in installed prices between host-owned and TPO systems, also presenting time trends for these two market segments (see Figure 23, later in the report). Those results will not be repeated here, but rather we simply note that, because host-owned systems comprise the majority of the analysis sample (disproportionately so, given that integrated TPO systems are excluded from that sample), aggregate national installed trends tend to align most closely with changes in the installed price of host-owned systems. As those later results will show, installed prices for both TPO and host-owned systems have fallen over time, with a somewhat greater decline in the last year for residential host-owned systems, compared to residential TPO.

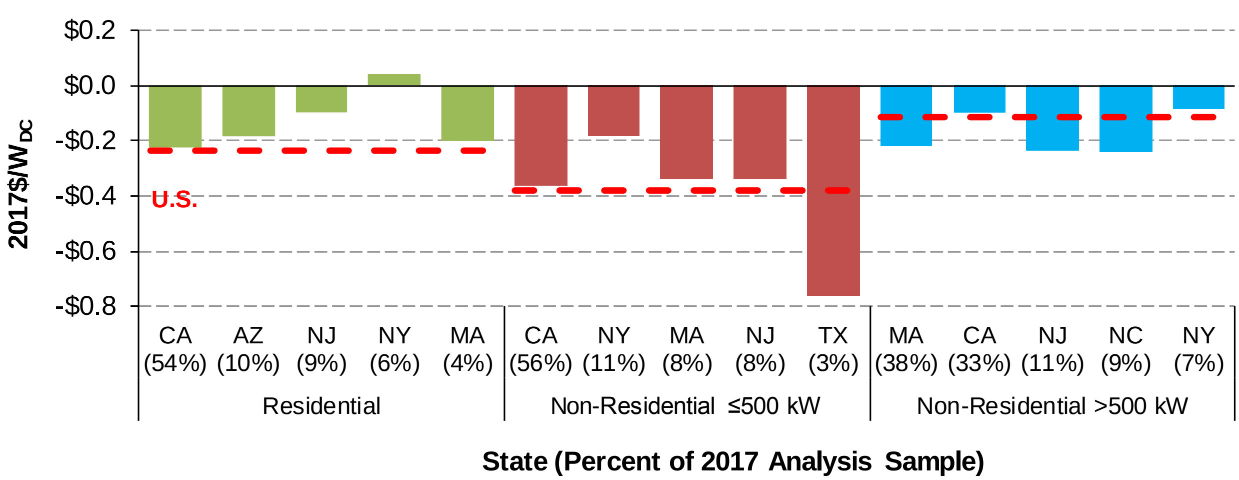
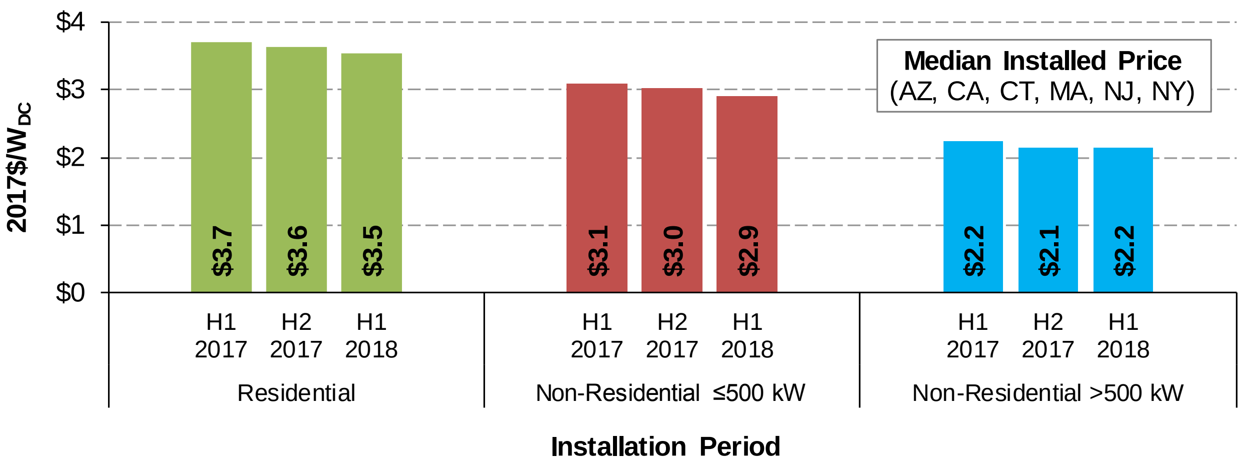


Figure 11. YoY Change (2016-2017) in Median Installed Price for Largest State Markets

Installed Price Trends: Preliminary Data for 2018

Preliminary data for the first six months of 2018, based on the largest state markets in the sample, show a continuing but modest decline in national median prices—at least for the residential and small non-residential segments. As shown in Figure 12, median installed prices for the first half (H1) of 2018 fell by an additional \$0.1/W for both the residential and small non-residential segments, relative to the second half (H2) of 2017, while median prices for large non-residential systems remained effectively flat (notwithstanding the apparent rise in the figure, due to rounding).



Notes: The figure is based on a subset of states and data sources used for the larger dataset, and therefore cannot be directly compared to Figure 10.

Figure 12. Median Installed Prices for Systems Installed in 2017 and the First Half of 2018

Underlying Hardware and Soft Cost Reductions

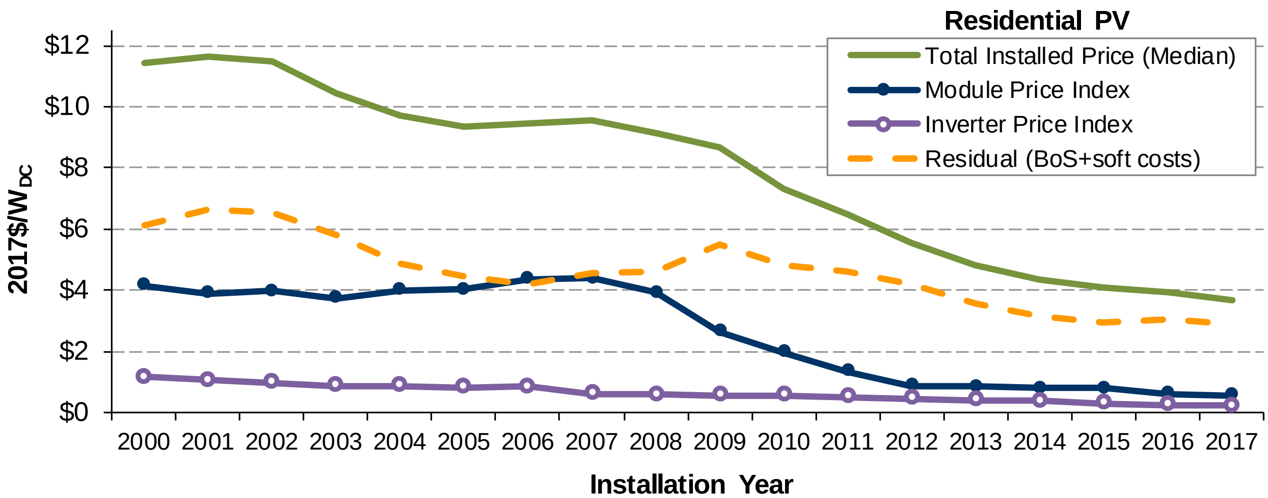
Long-term installed-price declines reflect the combined effect of reductions in both hardware and non-hardware costs. Among hardware costs, PV modules have been, far and away, the largest single driver for system-level installed-price declines. Since 2000, module prices have fallen by roughly \$3.6/W, equating to 46% of the total decline in residential-system installed prices over that period. As shown in Figure 13, most of that drop occurred between 2008 and 2012, when total installed prices fell more or less in tandem (albeit with some lag). Second in significance among hardware cost reductions are inverters, which have fallen by roughly \$0.9/W since 2000, representing 12% of the long-term decline in residential system prices.[6]

The remaining \$3.2/W or 42% of the long-term drop in residential-system installed prices is thus due to other balance of systems (BoS) costs, such as wiring and racking, and the wide assortment of "soft" costs, which include marketing and customer acquisition, system design, installation labor, permitting and inspection costs, installer margins, and loan-related fees in some cases. That amalgam of BoS and soft costs is captured by the residual term in Figure 13, which has declined in a somewhat undulating manner over time.[7]

[6] Long-term, time-series data for other hardware elements are not available. For residential racking equipment, data published by GTM Research and SEIA (2018) suggest roughly a \$0.3/W reduction from 2012 to 2017.

[7] This residual term has risen at various points in time. Though some soft costs, such as customer acquisition and installer margins, indeed may have risen, these apparent "spikes" likely result primarily from a lag between changes in component prices and total installed prices.

Installed-price reductions over the last year of the analysis period, from 2016 to 2017, also reflect some combination of reductions in hardware and soft costs. Based on residential PV component cost data published by GTM and SEIA (2018), average annual hardware costs for a typical residential system fell by just over $0.1/W from 2016 to 2017 and equate to 54% of the total decline in national median installed prices over that period. Though the two quantities cannot be precisely compared, they suggest that roughly half the decline in national median installed prices is attributable to hardware costs and, by extension, the remaining half to soft costs.



Notes: The Module Price Index is the U.S. module price index published by SPV Market Research (2018). The Inverter Price Index is a weighted average of residential string inverter and microinverter prices published by GTM Research and SEIA (2018), extended backwards in time using inverter costs reported for systems in the LBNL data sample. The Residual term is calculated as the Total Installed Price minus the Module Price Index and Inverter Price Index.

Figure 13. Installed Price, Module Price Index, Inverter Price Index, and Residual Costs over Time for Residential PV Systems

Long-term declines in soft costs reflect a wide diversity of underlying drivers—some related to the broader policy and market environment (e.g., maturation of the industry, declining incentives, etc.) and others more-technical in nature. Two specific technical factors, noted previously, are the steady and significant increases over time in both residential system sizes and module efficiencies. Increasing system sizes reduce BoS and soft costs on a per-watt basis by allowing fixed project costs (e.g., permitting and customer-acquisition) to be spread over a larger base of installed watts, while increasing module efficiencies reduce BoS and soft costs by, in effect, allowing system sizes to increase with less-than-a-proportional increase in the physical footprint of the system, thereby reducing area-related costs (e.g., racking and installation labor) relative to what would have occurred with lower efficiency modules.

Relying on modeled residential PV cost relationships developed by Fu et al. (2017), we can estimate the effects of increases in system size and module efficiency on residential BoS and soft over time. Over the full analysis period, the growth in residential system sizes reduced those costs by roughly $1.1/W, while increasing module efficiencies reduced BoS plus soft costs by $0.3/W.[8] Together, these two factors equate to 18% of the drop in residential installed prices over that period,

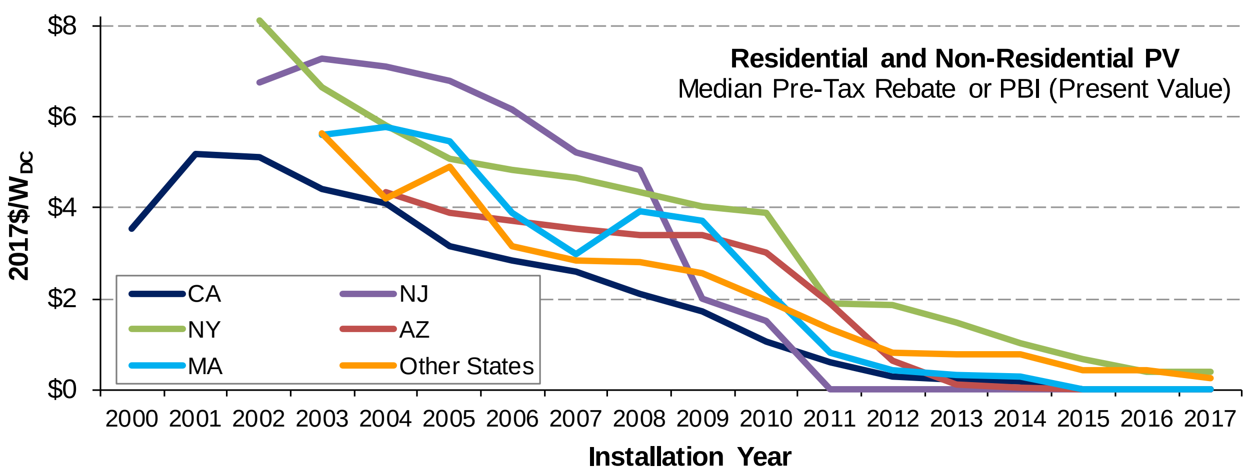
[8] These estimates represent only the *marginal* effect, given all other sources of cost reduction that occurred over the corresponding time span. Had other cost reductions not occurred (e.g., no change in installation labor efficiency or reduction in permitting costs), the effects of system size and module efficiency growth would be greater.

and 42% of the total drop in implied BoS and soft costs (i.e., the residual term in Figure 13). Within just the last year of the analysis period, from 2016 to 2017, increases in system size and module efficiency reduced BoS plus soft costs by $0.03/W and $0.05/W, respectively, a combined effect equivalent to 34% of the drop in residential installed prices, and 50% of the drop in total BoS and soft costs. Thus, while these two factors are, by no means, the sole or even primary source of installed price declines, they have nevertheless been important contributors—and have become somewhat more significant in recent years, given the waning effects of other drivers.

Declining State and Utility Cash Incentives

Financial incentives provided through utility, state, and federal programs have been a driving force for the PV market in the United States. For residential and non-residential PV, those incentives have—depending on the particular place and time—included some combination of cash incentives provided through state and/or utility PV programs (rebates and performance-based incentives), the federal investment tax credit (ITC), state ITCs, revenues from the sale of solar renewable energy certificates (SRECs), accelerated depreciation, and retail rate net metering.

Focusing *solely* on direct cash incentives provided in the form of rebates or performance-based incentives (PBIs), Figure 14 shows how these incentives have declined steadily and significantly over the past decade across the individual state markets. At their peak, most programs were providing incentives of $4-8/W (in real 2017 dollars). Over time, however, direct rebates and performance-based incentives have been largely phased-out in most of the larger state markets—including Arizona, California, Massachusetts, and New Jersey—and have diminished to below $0.5/W in most other locations. This continued ratcheting-down of incentives is partly a response to the steady decline in the installed price of PV and the emergence of other forms of financial support (for example, SRECs, as discussed in Text Box 3). At the same time, incentive declines have also likely helped to motivate further costs and price reductions. The continued ratcheting down of incentives has thus likely been both a cause and an effect of long-term installed price reductions.



Notes: The figure depicts the pre-tax value of rebates and PBI payments (calculated on a present-value basis) provided through state and utility PV incentive programs.

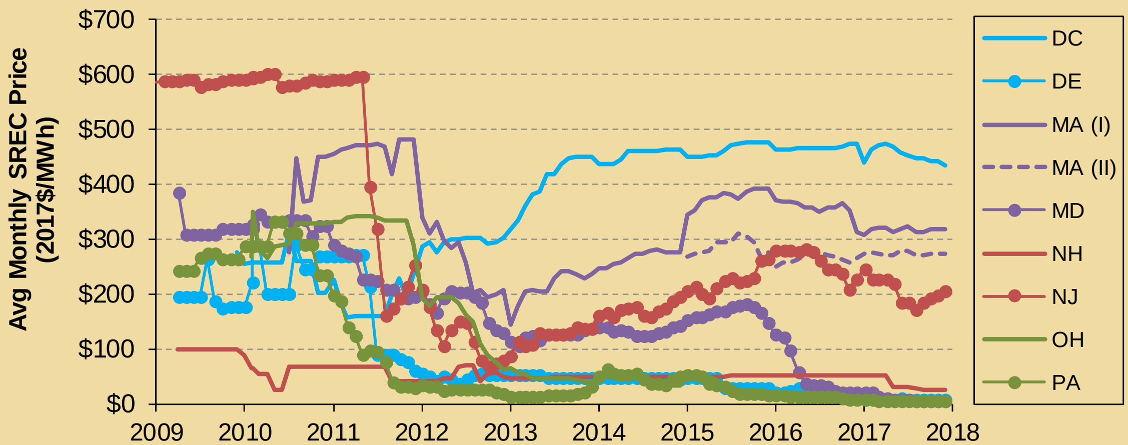
Figure 14. State/Utility Rebates and PBIs over Time

From the perspective of the customer-economics of PV, however, one thing is clear: the steady reduction in cash incentives has offset reductions in installed prices to a significant degree. Among the five state markets profiled in Figure 14, the decline in incentives from each market's respective peak is equivalent to anywhere from 67% to 100% of the drop in installed PV prices over the corresponding time period. Of course, other forms of financial support have simultaneously become more lucrative over this period of time—for example, the increase in the federal ITC for residential solar starting in 2009 and the emergence of SREC markets—and new financing structures have allowed greater monetization of existing tax benefits. And while net metering rules and rate design for solar PV customers have come under greater scrutiny, most of the large state markets have yet to make any substantial changes to those structures. The customer economics of solar in many states thus has likely improved, on balance, over the long-term, but the decline in state and utility cash incentives has nevertheless been a significant counterbalance to falling installed prices.

Text Box 3. SREC Price Trends

Eighteen states plus the District of Columbia have enacted renewables portfolio standards (RPS) with a solar or distributed generation set-aside (also known as a "carve-out"), and many of those states have established solar renewable energy certificate (SREC) markets to facilitate compliance. An SREC represents the solar "attribute" created by 1 MWh of solar-electricity generation, and can be transacted separately from the underlying electricity for purposes of facilitating compliance with RPS obligations or voluntary green energy goals. PV system owners in states with RPS solar carve-outs, and in some cases neighboring states, may sell SRECs generated by their systems, either in addition to or in lieu of direct cash incentives received from state/utility PV incentive programs. Many solar set-aside states have transitioned away from standard-offer based incentives, particularly for larger and non-residential systems, and towards SREC-based incentive mechanisms with SREC prices that vary over time.

Prior to 2011, SREC prices in most major RPS solar set-aside markets ranged from $200 to $400/MWh, topping $600/MWh in New Jersey (see Figure 15). Starting around 2011 or 2012, SREC supply began to outpace demand in these markets, leading to a steep drop in SREC pricing. As with the broader decline in solar incentives, this contraction in SREC pricing served as a source of further downward pressure on installed prices. Since then, SREC prices in several key markets have risen or stabilized, relieving some of that downward pressure on installed prices. In other states, low SREC prices have persisted, as local RPS solar carve-out markets remain over-supplied.

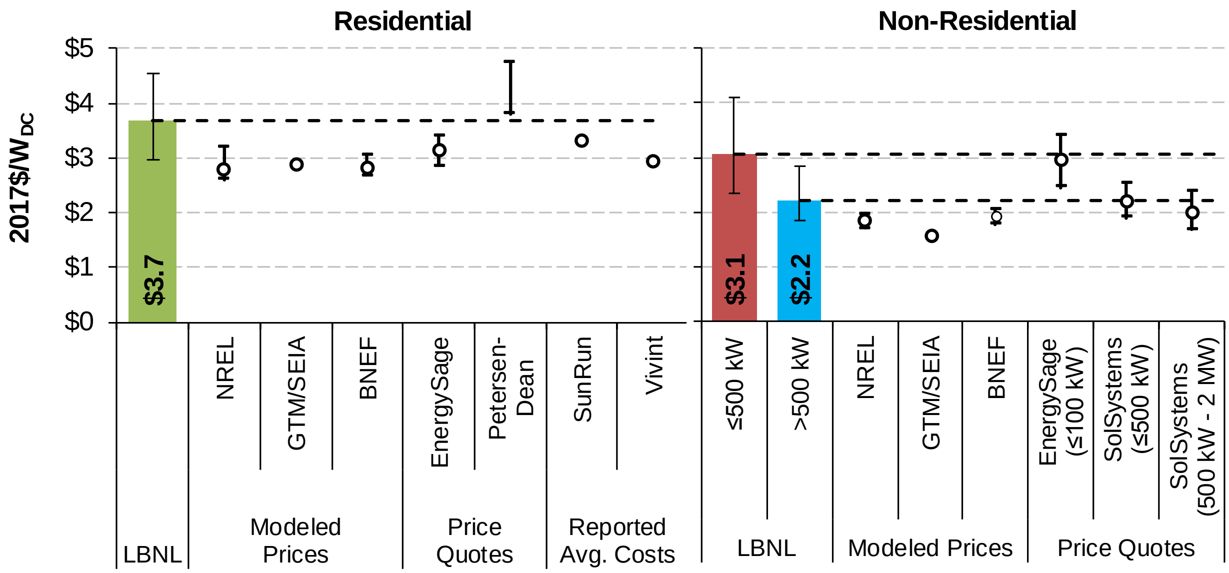


Notes: Data sourced from Marex-Spectron, SRECTrade, and Flett Exchange (data averaged across available sources). Plotted values represent SREC prices for the current or nearest future compliance year traded in each month. MA (I) and MA (II) refer to prices in the SREC I and SREC II programs, respectively.

Figure 15. Monthly Average SREC Prices for Current or Nearest Future Compliance Year

Comparison to Other U.S. PV Cost and Pricing Benchmarks

National median prices can provide a useful metric for characterizing aggregate trends, but may not provide the most relevant benchmark for system prices in all contexts. To provide a broader view of PV system pricing, Figure 16 compares median installed prices from the LBNL data sample, for systems installed in 2017, to a diverse set of other recent PV price and cost benchmarks. These other benchmarks include modeled PV system prices, price quotes for prospective PV systems, and average costs reported directly by several major residential installers, as described further in the figure notes.



Notes: ***LBNL*** *data are the median and 20th and 80th percentile values among projects installed in 2017.* ***NREL*** *data represent modeled turnkey costs in Q1 2017 for a 5.7 kW residential system (range across system configuration and installer type, with weighted average) and a 200 kW commercial system (range across states and national average) (Fu et al. 2017).* ***GTM/SEIA*** *data are modeled turnkey prices for Q1 and Q4 2017; their residential price is for a 5-10 kW system with standard crystalline modules, while the commercial price is for a 300 kW flat-roof system (GTM Research and SEIA 2018).* ***BNEF*** *data are estimated PV capex with developer margin in 2017 (US averages and range across states/regions) (BNEF 2018).* ***EnergySage*** *data are the median and 20th and 80th percentile range among price quotes issued in 2017, calculated by Berkeley Lab from data provided by EnergySage; quote data for non-residential systems are predominantly from small (<100 kW) projects.* ***Petersen-Dean*** *data are online price quotes for 3.4 to 8.4 kW systems in CA, queried from the company website by Berkeley Lab in May 2017.* ***SunRun*** *and* ***Vivint*** *data are the companies' reported average costs (in the case of SunRun, for cash-sale systems only), inclusive of general administrative and sales costs, for Q1 and Q4 2017.* ***SolSystems*** *data are averages of the 25th and 75th percentile values of "developer all-in asking prices" published in the company's monthly Sol Project Finance Journal reports throughout 2017.*

Figure 16. Comparison to Other Installed Price or Cost Benchmarks

Not surprisingly, the various benchmarks differ from one another, in some cases considerably so, reflecting underlying differences in data, methods, and definitions. In general, national median prices drawn from the LBNL dataset are higher than the other PV pricing benchmarks, for reasons such as those discussed in Text Box 4. For residential systems, the national median price from the LBNL dataset is $3.7/W. In comparison, most of the other residential benchmarks fall below $3.4/W, though they collectively span a relatively wide range, from $2.6/W to $4.7/W. The median price of small (≤500 kW) non-residential systems in the LBNL dataset is $3.1/W, above most of the other non-residential benchmarks but within their broader range of $1.6/W to $3.4/W and reasonably well-aligned with the EnergySage quote data. The larger non-residential systems >500 kW in the LBNL dataset, with a median price of $2.2/W, are less discrepant with the other benchmarks, though still higher than the various modeled values.

Notwithstanding the differences noted above, many systems in the LBNL dataset exhibit prices well-aligned with the other PV pricing and cost benchmarks. Indeed, the 20th percentile pricing levels for both residential systems ($3.0/W) and large non-residential systems ($1.8/W) fall squarely in the range of the other benchmarks. Later sections of this report further explore the wide spread in the data, and show that prices observed in many contexts—i.e., for certain states, installers, module technologies, and TPO systems—are substantially below the national median, and correspond more closely to the other pricing benchmarks in Figure 16.

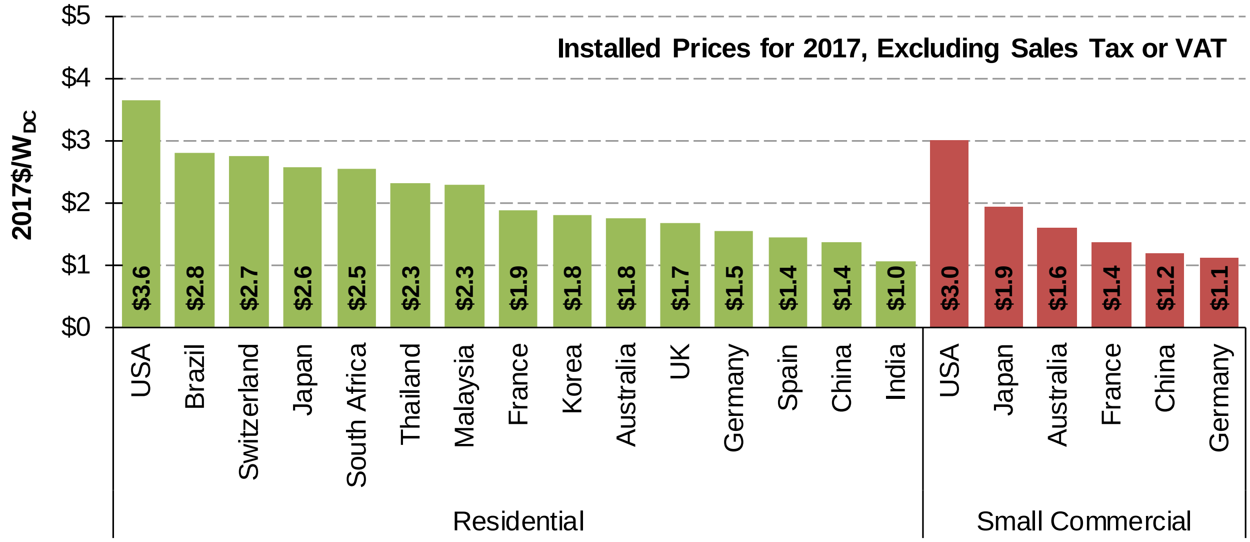
Text Box 4. Reasons for Differences between LBNL National Median Prices and Other Benchmarks

Variation across the benchmarks shown in Figure 16 arise for a number of reasons, and help to explain why median values drawn from the LBNL data sample tend to be higher than the other benchmark values:

- *Timing*: The LBNL data in Figure 16 are based on systems installed in 2017. A number of the other benchmarks cited in the figure are instead based on price quotes issued in 2017, which may precede installation by several months to even a year or more (especially for non-residential projects).
- *Price versus cost:* The LBNL data represent prices paid by PV system owners to installers or project developers. In contrast, the data points drawn from SunRun's and Vivint's publicly available financial reports represent costs borne by those companies, which exclude profit margins and, for a variety of other reasons, may differ from the prices ultimately paid by PV system owners.
- *Value-based pricing*: Benchmarks may reflect developer/installer margins based on some minimally sustainable level, as may occur in highly competitive markets. In contrast, the market price data assembled for this report are based on whatever profit margin developers are able to capture or willing to accept, which may exceed a theoretically competitive level in markets with high search costs and/or barriers to entry.
- *Location:* As noted earlier, statistics derived from the LBNL dataset are dominated by several high-cost states that constitute a large fraction of the sample (and of the broader U.S. market). Other benchmarks may instead be representative of lower-cost or lower-priced locations.
- *System size and components*: A number of the benchmarks in Figure 16 are based on standard, turnkey project designs. The LBNL data instead reflect the specific sizes and components of projects in the sample. For example, a sizeable contingent of systems in the sample use premium efficiency modules (which, as shown later, are associated with significantly higher installed prices than systems with standard efficiency modules), and most of the non-residential systems in the ≤500 kW class are, in fact, smaller than 40 kW.
- *Scope of costs included*: The set of cost components embedded in the installed price data collected for this report undoubtedly varies across projects, and in some cases may include optional add-ons, such as extended warranties or monitoring and maintenance services, as well as items such as re-roofing costs or loan-related fees that typically would not be included in other PV pricing benchmarks (though, from the customer's perspective, are nevertheless part of the price of "going solar").
- *Installer characteristics*: Finally, the LBNL data reflect the characteristics and reporting conventions of the particular installers in the sample, many of which are relatively small or regional firms. Moreover, by excluding appraised-value systems, the LBNL dataset excludes several of the largest U.S. residential installers. Other benchmarks in Figure 16 may instead be more representative of large installers.

Comparison to Other National Markets

Notwithstanding the significant installed price reductions that have already occurred in the United States, international experience suggests that much greater reductions are theoretically possible. Figure 17 compares median installed prices for residential and sub-500 kW non-residential systems installed in the United States in 2017 to system prices for a number of other countries, in all cases excluding sales tax or value added tax (VAT). For both segments, U.S. median prices are higher than all other countries shown—in many cases, more the double the averages reported elsewhere.



Notes: Installed prices for countries other than the United States are primarily from IRENA (2018) and refer to average prices in either Q1 or Q2 2017; the one exception is the value reported for small commercial systems in France, which comes from de L'Epine-Hespul (2018) and is an annual number for all of 2017.

Figure 17. Comparison of Installed Prices in 2017 across Countries (Pre-Sales Tax/VAT)

To be sure, these data are not perfectly comparable. For example, the U.S. prices are based on median values across a large data sample of system-level reported prices, while prices for other countries are based on a more-varied set of underlying data sources and, in some cases, may be indicative prices representative of "turnkey" systems. Nevertheless, the comparison paints a consistent picture, even when considering the broader set of U.S. benchmarks presented in the previous section, which are typically lower than the median values from the LBNL dataset but still higher than the other international pricing data reported in Figure 17.

Though module and inverter prices differ modestly between the U.S. and other countries, those differences are by no means the primary cause of the much larger gap in system-level prices.[9] By extension, differences in total system prices must therefore be attributable primarily to soft costs. Indeed, installer surveys in Australia, Japan, and Germany have found substantially lower soft costs in those countries compared to the United States, including lower costs for customer acquisition, installation, and permitting and interconnection (Seel et al. 2014; Ardani et al. 2012; Friedman et al. 2014; RMI and GTRI 2013, 2014). Those three countries all have larger distributed PV markets than the Unites States, at least in terms of cumulative per-capita capacity, and thus the lower soft

[9] For example, average module selling prices in the United States were roughly $0.1/W higher than the global-average in 2017 (SPV Market Research 2018).

costs may be partially due to greater experience and economies of scale. However, many of the countries shown in Figure 17 represent much smaller distributed PV markets than the United States; other factors beyond market size are therefore clearly also at play. These include, for example, differences in: incentive levels and incentive design, solar industry business models, demographics and customer awareness, building architecture, systems sizing and design, interconnection standards, labor wages, and the level of standardization and streamlining within permitting and interconnection processes. Further research into the role of these and other factors may be warranted, given the persistently higher installed prices observed in the United States.

5. Variation in Installed Prices

While the preceding section focused on trends in national median installed prices, this section highlights the substantial *variability* in installed prices and explores some sources of that variability. The section begins by describing the overall distribution in installed prices across the dataset as a whole. It then examines pricing differences according to system size, state, installer, host-owned vs. TPO, residential new construction vs. retrofit, tax-exempt vs. commercial site hosts, module efficiency, and rooftop vs. ground-mounted systems with and without tracking. These comparisons provide a richer characterization of installed pricing trends and help to explain observed pricing variability, but do not fully isolate the effects of any individual pricing driver, as doing so would require a more complex set of statistical methods.

Overall Installed Price Variability

Considerable spread exists within the pricing data and has persisted over time, despite continuing maturation of U.S. PV markets. This is evident in Figure 10, presented earlier, which shows the 20^{th}-to-80^{th} percentile installed-price range for each customer segment over time. Those percentile bands have shifted downward over time as prices have fallen, but the overall spread in pricing has remained relatively unchanged. Figure 18 provides further detail on the pricing distribution for systems installed in 2017. Among residential systems, roughly 20% were installed at prices below $3.0/W (the 20^{th} percentile value) and 20% were above $4.5/W (the 80^{th} percentile), with the remaining systems distributed across the wide range in between. Non-residential systems in the sub-500 kW class exhibit a similar spread, with 20^{th} and 80^{th} percentile values of $2.4/W and $4.1/W, respectively. The distribution for >500 kW non-residential systems is narrower, with a 20^{th}-to-80^{th} percentile band of $1.8/W to $2.8/W.

The potential underlying causes for this persistent pricing variability are numerous, including differences in project characteristics and installer attributes, as well as various aspects of the broader market, policy, and regulatory environment (e.g., degree of competition, incentive levels, electricity rates, permitting and interconnection processes, labor wages, and taxes, among others). Some of these pricing drivers are explored throughout the remainder of this report using simple descriptive methods, while others have been assessed through a series of econometric studies that LBNL and its collaborators have undertaken—select findings from which are summarized in Text Box 5.

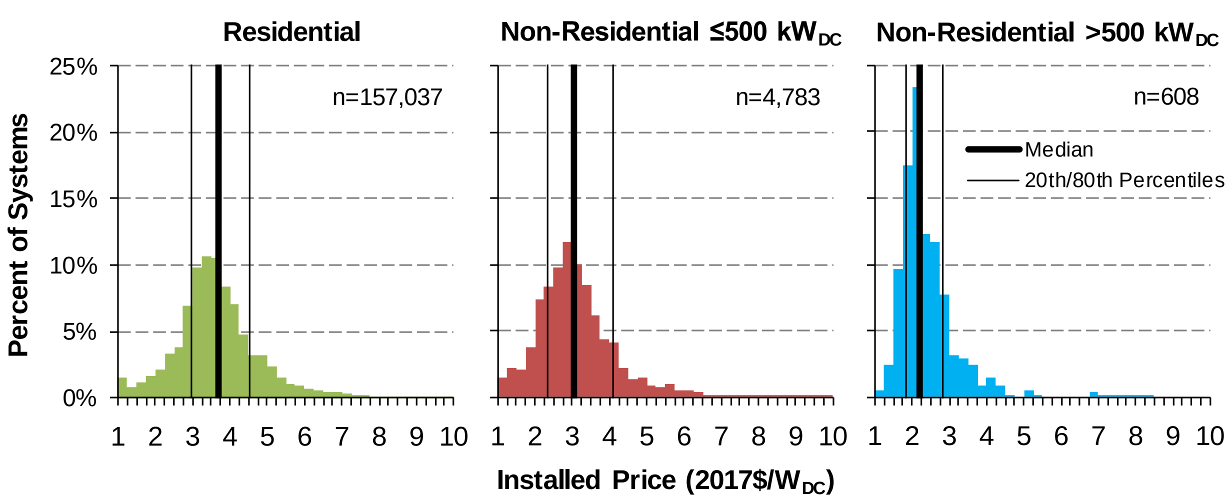


Figure 18. Installed Price Distributions for Systems Installed in 2017

Text Box 5. Findings from Recent In-Depth Analyses of PV Pricing Dynamics

In collaboration with researchers from Yale University, University of Wisconsin, and University of Texas at Austin, LBNL and NREL have engaged in a series of in-depth analyses to better understand PV pricing dynamics. These studies leverage the dataset assembled for Tracking the Sun in conjunction with other data sources, and apply a variety of statistical and econometric methods to explore PV pricing issues. To date, a number of studies in this series have been completed.

O'Shaughnessy (2018) studied how different characteristics of local installation industries affect PV prices. The study shows that PV prices tend to be lower in markets where experienced installers hold higher market shares, suggesting that installers "learn" to reduce costs. However, the study shows that prices increase again if experienced installers hold very high market shares, suggesting that the price-reducing effects of installer experience can be offset by a lack of competition.

Nemet et al. (2017) analyzed price dispersion in U.S. residential PV installations. The study found that price dispersion—defined as the variability in prices among systems installed within a given county and quarter—has increased over time. It further found that factors that increase consumer access to information—such as neighbors who have recently installed PV and the availability of third-party quotes—are associated with less price dispersion. These results provide support for the importance of efforts to enhance access to price information, especially in nascent PV markets where access to experiences of neighbors is unavailable.

Nemet et al. (2016a) sought to identify characteristics of the lowest priced systems (e.g., the lowest 10th percentile). That study found that low-priced systems are associated with experienced installers; customer ownership; larger system size; retrofits rather than new home construction; and thin-film, low-efficiency, and Chinese modules. The analysis also found that low-priced systems are much more likely to occur in some states than in others, and are more likely to occur in the presence of higher incentives, at least in California. Follow-up work by Nemet et al. (2016b) found that many of the same factors appear to drive low-priced systems to be even lower priced.

Gillingham et al. (2014) examined a broad range of potential drivers for PV pricing variability among residential systems installed during 2010 to 2012. Of the various factors considered, the single-largest contributor was system size ($1.5/W effect). The study also found that installed prices were lower in markets with the greatest density of installers ($0.5/W effect), potentially due to greater competition, and that prices were lower for systems installed by the most-experienced companies ($0.2/W effect). The study also found evidence that rich incentives can lead to higher prices ($0.4/W effect). That latter finding may reflect value-based pricing, though it may also simply be the natural result of high demand for solar enabling higher-cost installers and higher-cost systems.

Other studies in the series have focused on narrower issues related to the installed price of residential PV. Two of these studies have examined the impact of local permitting processes on residential PV pricing. Dong and Wiser (2013) found that cities in California with the most-favorable permitting practices had installed prices $0.3/W to $0.8/W lower than in cities with the most-onerous practices. Examining a broader geographical footprint, Burkhardt et al. (2014) found that variations in local permitting procedures lead to differences in average residential PV prices of approximately $0.2/W across jurisdictions; when considering variations not only in permitting practices, but also in other local regulatory procedures, price differences grew to $0.6/W to $0.9/W between the most-onerous and most-favorable jurisdictions.

Another study, Dong et al. (2014), examined incentive pass-through – i.e., the degree to which installers pass through the value of incentives to consumers – in California's statewide rebate programs. This analysis included two wholly distinct modeling approaches, and in both cases found average pass-through rates ranging from 95% to 99%. These finding thus indicate that installers in California have not artificially inflated their prices as a result of available rebates, though the findings do not rule out the possibility of value-based pricing more generally, for example associated with utility bill savings or tax incentives.

Variation by System Size

Larger PV installations benefit from economies of scale by spreading fixed project and overhead costs over a larger number of installed watts, and potentially by enabling volume purchases of materials. These scale economies are evident in the preceding figures that show lower installed prices for non-residential systems than for residential systems. They also arise within each customer segment, contributing to the observed pricing variability.

Among residential systems in the dataset, system sizes range from less than 2 kW to 12 kW and above. As shown in Figure 19, median prices at the upper end of that range are roughly $1.3/W less than at the lower end. Price declines taper off with increasing size, indicative of diminishing returns to scale. These trends also comport well with the econometric analysis by Gillingham et al. (2014) noted in the preceding text box (which found a price difference of $1.5/W between the smallest and largest residential systems evaluated), and with modeled system-cost relationships developed by Fu et al. (2017).

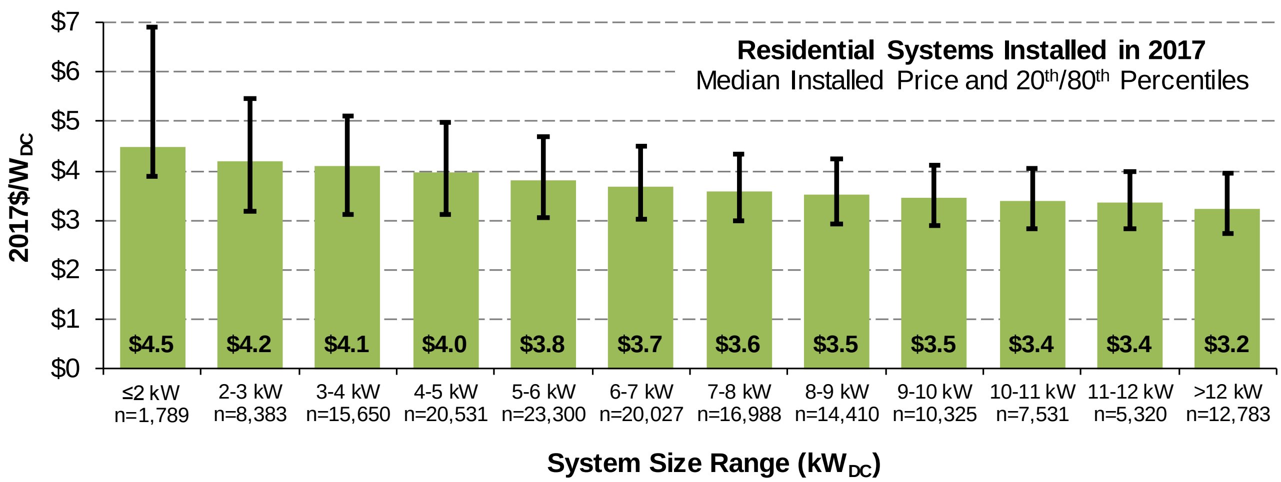
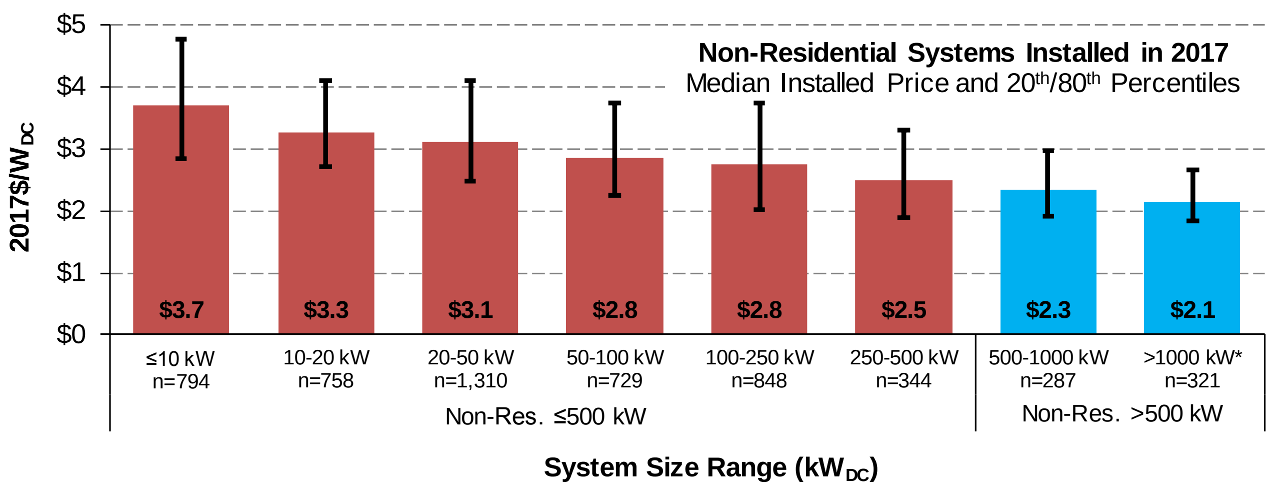


Figure 19. Installed Price of 2017 Residential Systems by Size



* *See Text Box 1 for details on the size range of non-residential systems, as defined for this report.*

Figure 20. Installed Price of 2017 Non-Residential Systems by Size

For non-residential systems (Figure 20), which span a wide range of system sizes, pronounced economies of scale also occur. Among systems installed in 2017, median installed prices were $1.6/W lower for the largest class of non-residential systems >1,000 kW in size than for the smallest non-residential systems ≤10 kW. Non-residential systems also exhibit diminishing returns to scale, though this is somewhat obscured in the figure, as the bin intervals become progressively wider at larger system sizes. Notwithstanding those diminishing returns to scale, even lower installed prices would be expected when moving from large non-residential systems to utility-scale systems, though the latter are outside the scope of this report.

Variation across States

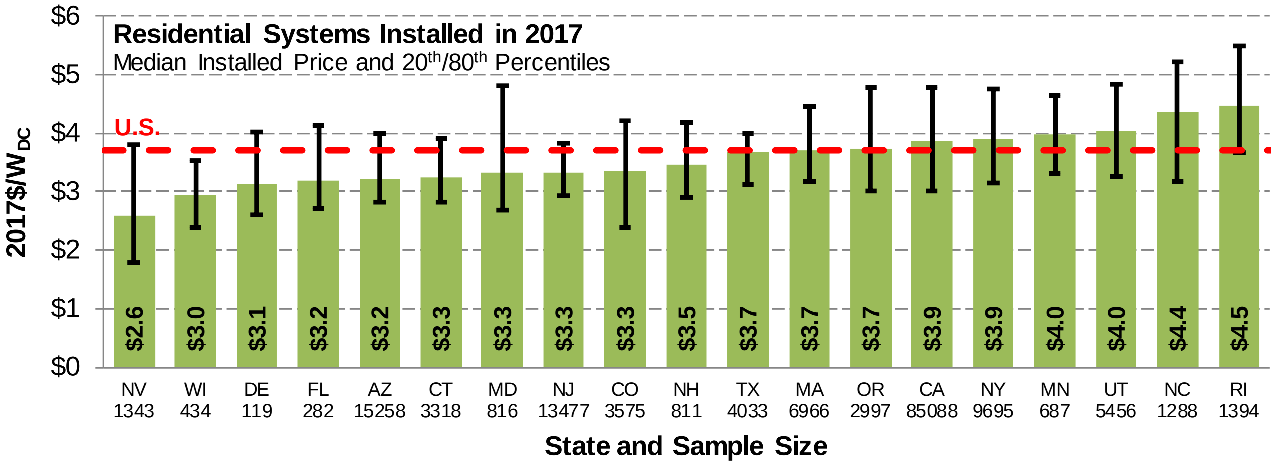
The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Figure 21 and Figure 22 focus, in particular, on state-level differences among systems installed in 2017, while also highlighting pricing variability *within* each state. As shown, installed prices vary substantially across states. Among residential systems installed in 2017, median installed prices range from a low of $2.6/W in Nevada to a high of $4.5/W in Rhode Island. Pricing for non-residential systems ≤500 kW similarly varies across a wide range, from $2.2/W in Wisconsin to $4.0/W in Minnesota. For larger non-residential systems >500 kW, the cross-state comparisons are somewhat less telling, given the limited set of states for which sufficient data are available. Among this small set of states, median installed prices vary across a relatively narrow range, from $2.1/W in California to $2.4/W in Massachusetts.

Of particular note is that, for both the residential and small non-residential segments, three of the largest state markets (California, Massachusetts, and New York) are relatively high-priced. This naturally tends to pull overall U.S. median prices upward, but as evident in the figures, pricing in many states is below—in some states, well below—the aggregate national median.

Installed-price differences across states reflect a diversity of factors. Some of the observed differences may simply be the result of peculiarities in the underlying data—particularly for states with relatively small sample sizes where prices reported by a single large installer can significantly impact the statewide median. Indeed, the two bookends of the residential comparison, Nevada and Rhode Island, are both heavily impacted by single installers comprising large shares of each state's 2017 installations (in Nevada, an installer with exceptionally low prices, and in Rhode Island, one with unusually high prices). Other factors may be highly state-specific; for example, most of the data for Minnesota come from the state's "Made in Minnesota" program, which requires the use of in-state manufactured products, likely leading to the relatively high prices observed there.

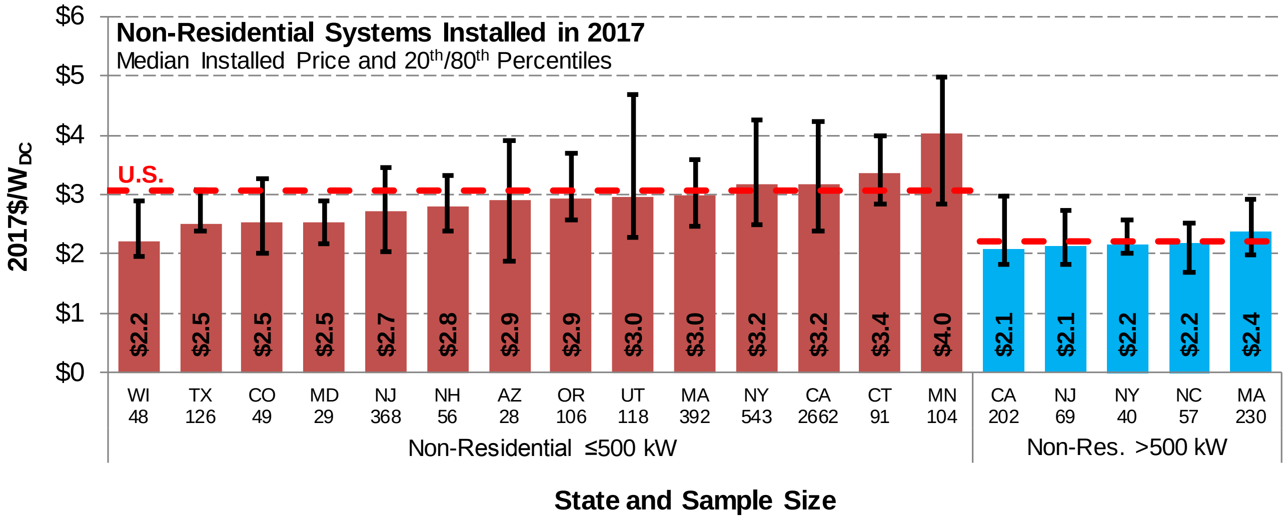
System design characteristics can also vary across states, contributing to the observed installed price variations. For example, residential system sizes vary from a median of 5.0 kW to 8.6 kW across the states in the analysis sample (perhaps due to differences in average household electricity consumption levels). The prevalence of "premium" efficiency modules (with efficiencies >20%) also varies considerably across states, which can significantly impact installed prices, as shown later. California, New York, and Massachusetts all have at least a 20% share of systems with premium efficiency modules, compared to just 9% in other states. Racking costs can also vary across states, depending on typical roofing materials and on wind and snow loading.

Finally, as noted previously, differences in market and policy conditions can impact installed prices, and those differences can correlate to varying degrees with state boundaries. As one relatively straightforward example, we estimate that varying sales tax rates and sales tax exemptions for PV systems in some states can lead to installed price differences of as much as $0.2/W from one state to another. Other market and policy effects—such as those related to incentive levels, installer market competition, and permitting processes—are generally more difficult to measure, though many of those effects have been explored—and found to be significant—through the studies highlighted in Text Box 5.



Notes: Median installed prices are shown only if at least 20 observations are available for a given state.

Figure 21. Installed Price of 2017 Residential PV Systems by State



Notes: Median installed prices are shown only if at least 20 observations are available for a given state.

Figure 22. Installed Price of 2017 Non-Residential PV Systems by State

Host-Owned vs. TPO Systems

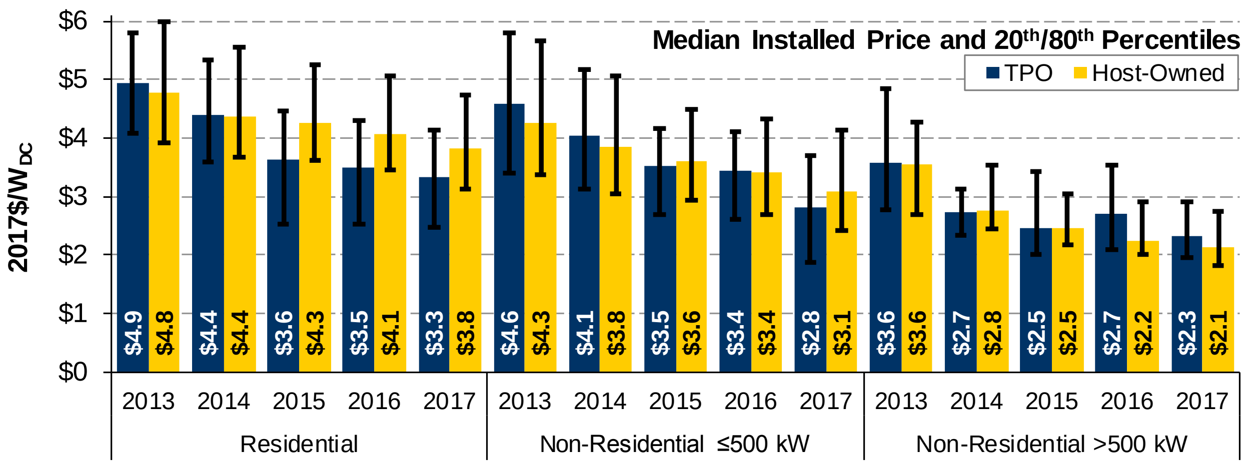
As described previously in Text Box 2, systems financed and installed by *integrated* TPO firms are excluded from the analysis, while those financed by *non-integrated* firms are retained.[10] Installed prices reported for those TPO systems retained in the sample represent the price paid to an

[10] For reference, installed prices reported by integrated TPO providers, otherwise excluded from the analysis presented in this report, are summarized in Appendix A and compared to prices reported for non-integrated TPO systems.

installation contractor by a customer finance provider; in some cases, the entity reporting those prices may be the installation contractor, while in other cases it may be finance provider.[11]

In principle, prices reported for the retained TPO systems could be either lower or higher than for host-owned systems. On the one hand, installers selling systems to TPO firms may face incremental transaction costs or a more-complicated customer sales process, which could elevate system prices. On the other hand, TPO finance providers likely also have greater leverage in negotiating prices with installation contractors, and may have a preference towards relatively standardized system designs, tending to push pricing lower compared to host-owned systems. In addition, customer acquisition and project development functions for some TPO projects may be performed by the financier or some other entity, besides the installer, in which case the reported price may reflect only hardware and direct installation labor costs. Finally, a growing share of host-owned systems may include interest-rate buydown or other loan-related fees in the installed price paid by the site host.

On balance, the data in Figure 23 indicate that TPO systems in the residential sector have tended to be lower priced than host-owned systems, at least over the past several years. Among systems installed in 2017, median prices were roughly $0.5/W lower for TPO than for host-owned systems, though both sets of systems show considerable spread in the data.[12] As noted above, the generally lower prices for TPO systems likely reflects some combination of greater buying power on the part of third-party financiers, more-standardized or turnkey installations in the TPO segment, customer acquisition performed by the financier, and loan-financing fees included in the prices reported for some host-owned systems. In contrast, non-residential systems (both small and large) exhibit no clear or persistent pricing differential between TPO and host-owned systems. This is not entirely surprising, as the aforementioned factors are arguably less applicable in the non-residential sector.



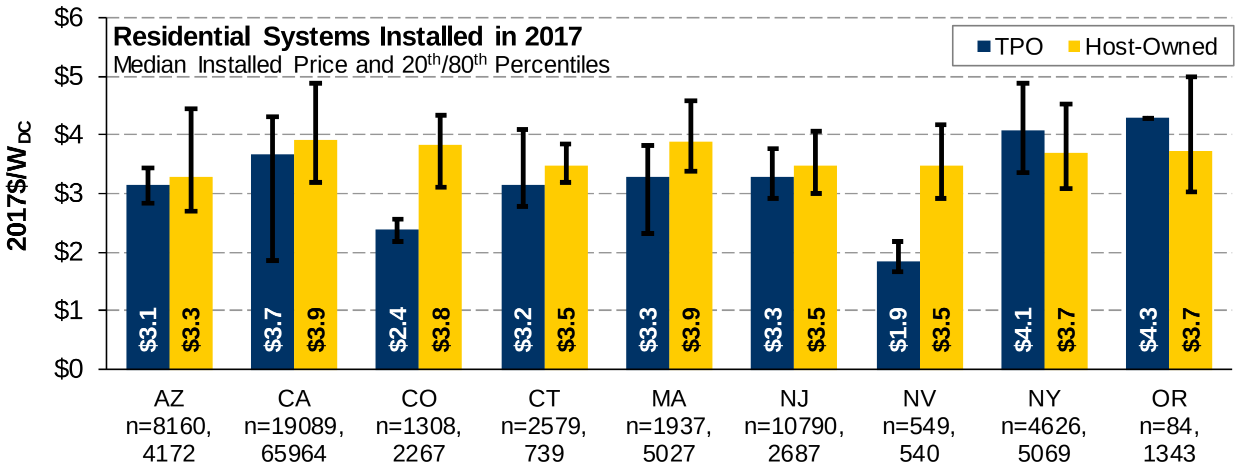
Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded.

Figure 23. Installed Prices Reported for Host-Owned vs. TPO Systems over Time

[11] It is worth noting that, in the case of TPO systems, what matters *to the host customer* is not the installed price, but rather the monthly lease payment or PPA rate—which is partly a function of the installed price paid by the financier for the system, but is also impacted by financing costs and numerous other factors.

[12] This recent trend among residential systems marks a departure from years prior to 2015, when median prices were generally higher for TPO than for host-owned residential systems.

Comparing TPO and host-owned residential systems at the state-level (see Figure 24) generally shows similar trends—namely, lower prices for TPO systems—though differences vary considerably from state to state, and several exceptions do exist. As noted previously, pricing trends at the state level, especially for TPO systems, can be heavily impacted by the pricing behavior of individual installers. This explains, for example, the especially low median price for TPO systems in Nevada ($1.9/W, driven by a single installer with a large number of TPO systems priced between $1.5/W and $2.0/W). It also explains why TPO systems are higher-priced than host-owned systems in New York, where roughly one-third of the 2017 TPO systems in the dataset have premium-efficiency modules—which, as discussed later, are associated with higher-priced systems.



Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded. The figure includes only those states with at least 20 observations for both TPO and host-owned systems in 2017.

Figure 24. Installed Prices Reported for Host-Owned vs. TPO Residential Systems by State

Variation across Installers

The U.S. PV market is serviced by a large number of installers of varying size, experience, and business models. Although the residential market, in particular, has historically been dominated by several large national companies, a great many regional firms and smaller "mom-and-pop" shops operate throughout the country. In total, the data sample assembled for this report includes more than 4,000 companies that installed PV systems in 2017, primarily in the residential sector. Most of those residential installers exclusively, or primarily, installed host-owned systems. A much smaller subset was active in the TPO space.

To illustrate how installed prices vary across installers, Figure 25 and Figure 26 show installer-level median prices for, respectively, host-owned and TPO residential systems in 2017, focusing in each case on the 100 installers with the most installations in that sub-segment. Among host-owned systems, installer-median prices ranged from $2.1/W to $9.6/W, though the upper end of that range almost certainly reflects data reporting anomalies by a few individual installers.[13] Ignoring the extremes at either end of this range, installer-median prices for host-owned systems otherwise ranged from roughly $3.0/W to $5.0/W, with about half of these installers falling below the $4.0/W threshold. Among TPO systems, the range in installer-medians is less extreme, though still

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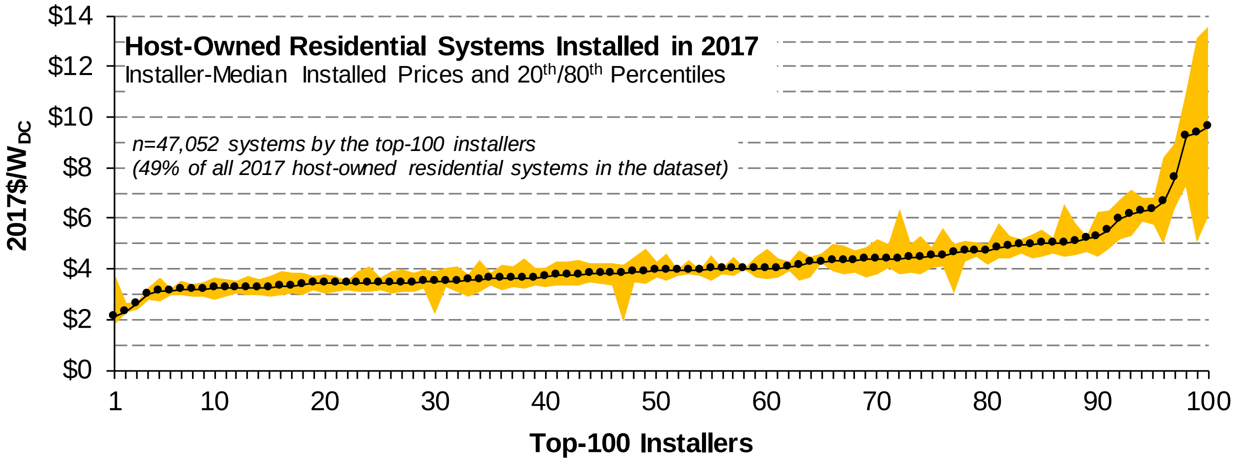
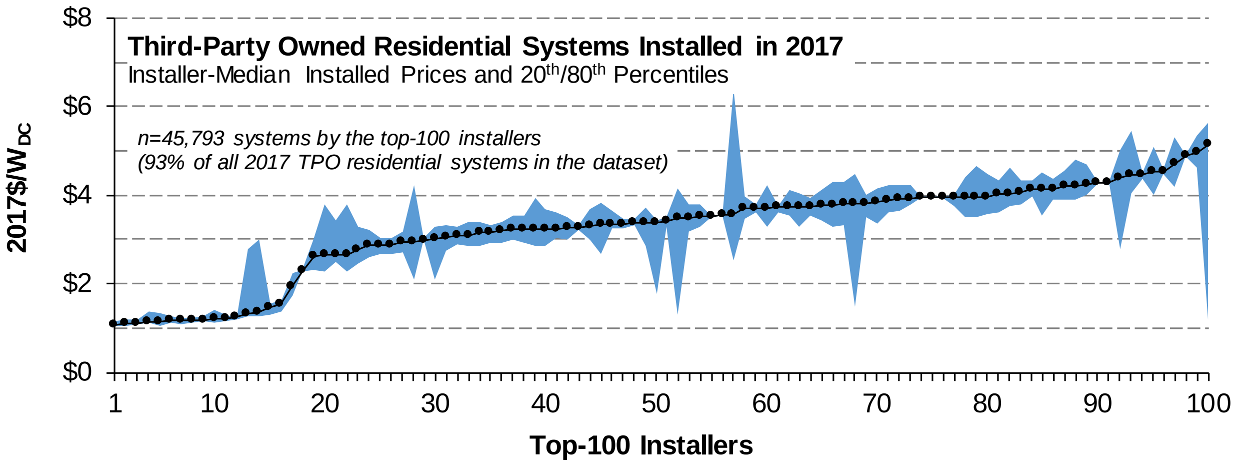
[13] For example, these exceptionally high-priced installers may be bundling PV with other measures and reporting the total installed price for all measures combined. To be sure, these extreme cases represent an inconsequential share of the overall data sample (i.e., several hundred systems out roughly 100,000 host-owned residential systems in 2017).

substantial, varying from \$1.1/W to \$5.1/W, with most installers below \$3.5/W. The contingent of TPO installers with median prices below \$1.5/W is particularly notable, both for their exceptionally low median prices as well as the uniformity of each installer's pricing. These are likely firms performing turnkey installations for financing partners and may be reporting prices that reflect only a portion of the overall cost of the systems.



Notes: Each dot represents the median installed price of an individual installer, ranked from lowest to highest, while the shaded band shows the 20th to 80th percentile range for each installer.

Figure 25. Installer-Level Pricing for Host-Owned Residential Systems in 2017



Notes: See Figure 25 notes.

Figure 26. Installer-Level Pricing for Third-Party Owned Residential Systems in 2017

The overall pricing variation across installers reflects a number of factors. Some of those factors relate to characteristics of the installers, for example firm size and experience. Some studies suggest that installers "learn" to reduce costs and as they grow, indicating that larger installers may be able to offer lower prices (Gillingham et al. 2014, O'Shaughnessy 2018). Other studies show that installers with large market shares tend to offer higher prices, suggesting that any returns to installer learning are diminishing (Mauritzen 2017, O'Shaughnessy and Margolis 2017). Installers may also vary in skill level and licensing, which may impact costs and pricing. In addition, some installers may specialize in systems with premium components or may undertake more-complex or customized installations, while others may tend toward more-standardized projects. Other drivers of installer-level pricing differences may, instead, relate to geographical factors—for example, whether the installer operates primarily in relatively low- or high-cost areas or in areas with greater or lesser degrees of competition. Parsing out the impacts of these various drivers is beyond the scope of this report but is a fruitful area for further exploration.

Variation by Module Efficiency

As described earlier in Section 3, module efficiencies vary widely across systems in the dataset, which can affect installed prices in several, opposing ways. On the one hand, premium-efficiency modules tend to be more expensive than standard efficiency modules. For example, among a subset of major module brands, PVInsights (2018) reports current retail prices for PV modules varying by more than $0.4/W, partly reflecting differences in efficiency level. On the other hand, higher efficiency modules reduce area-related BoS costs by shrinking the footprint of the system (or, alternatively, by allowing for a greater number of installed watts within a given footprint, thus spreading fixed project costs and area-related costs over a larger number installed watts). Premium-efficiency modules may offer other performance benefits, such as lower degradation rates or longer warrantees, which improve LCOE and are thus relevant to a more complete economic comparison.

Capturing the net effect of these varied drivers, Figure 27 compares installed prices based on module efficiency, focusing on residential and sub-500 kW non-residential systems installed in 2017. As shown, median installed prices are fairly level up until module efficiency levels of 19-20%, but are appreciably higher for systems with "premium efficiency" modules above 20%. Among residential systems, those with module efficiencies >20% had a median price $0.6/W higher, overall, compared to systems with module efficiencies below that level. For small non-residential systems, the differential was $0.8/W. The data in Figure 28 show similar differentials in prior years as well. Thus, at least among the specific mix of modules and systems within this data sample, the price premium for high-end modules with >20% efficiency has generally outweighed any corresponding reduction in BoS and soft costs (though, as noted, those modules may offer performance benefits that would also need to be considered in any LCOE comparison).

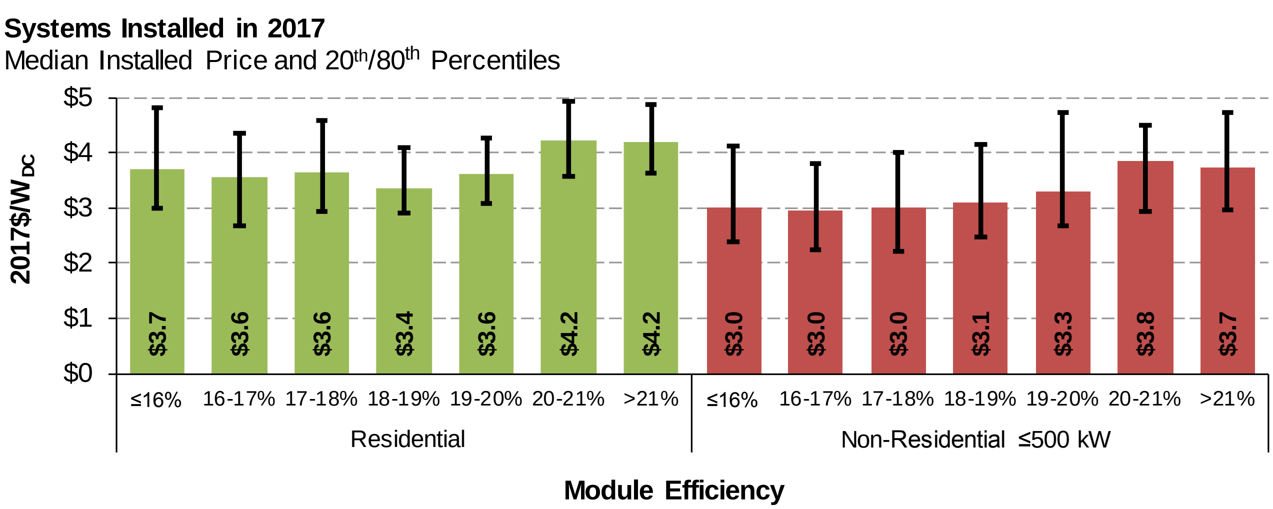


Figure 27. Installed Price Differences Based on Module Efficiency

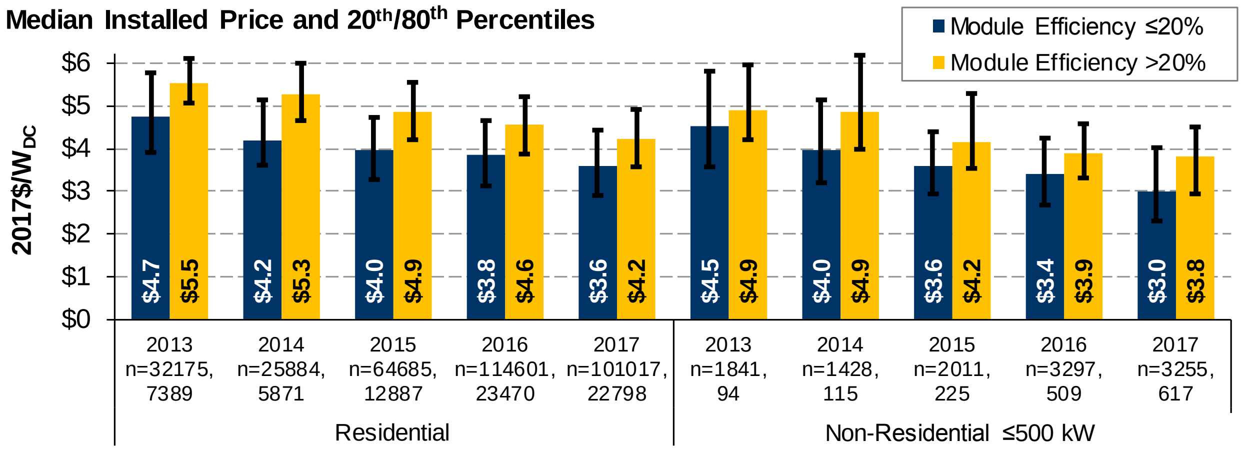


Figure 28. Installed Price Differences Based on Module Efficiency over Time

Residential New Construction vs. Retrofits

Though the vast majority of residential systems are installed as retrofits on existing homes, some are installed in new construction—often in large housing developments, as either a standard or optional feature. Within the data assembled for this report, the most comprehensive and consistent identification of PV in residential new construction is for California, where such systems have been funded through a long-standing incentive program (the California Energy Commission's "New Solar Homes Partnership" program). Based on participation in that program, roughly 3% of all residential systems installed in California in 2017 were in new construction.

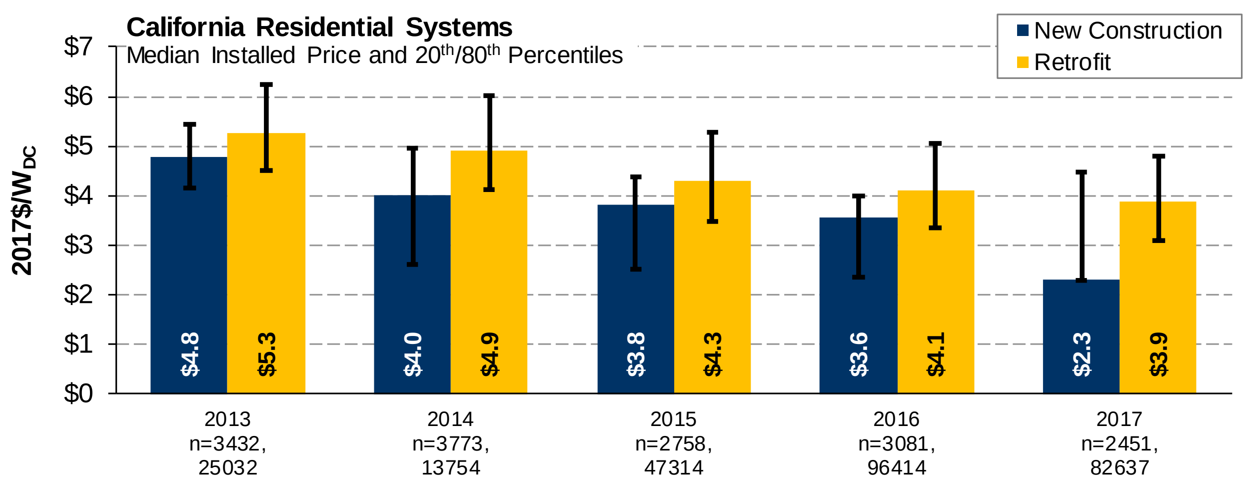


Figure 29. Installed Price of Residential Retrofit vs. New Construction in California

As shown in Figure 29, residential new construction systems in California have been consistently lower priced than residential retrofits. The disparity in 2017 was especially pronounced, with a median price of \$2.3/W for systems in new construction, compared to \$3.9/W for residential retrofits. These particular results are exaggerated by a large contingent of new construction systems in 2017 (roughly 1500 out of a total of 2500 systems) with installed prices all reported as \$2.3/W (which is also why the median and 20th percentile values are the same).[14] However, earlier years—which have more well-behaved distributions—also show significant, albeit smaller, installed price differences (e.g., a difference of $0.5/W in 2015 and 2016) between new construction and retrofits.

Lower installed prices for new construction systems reflect a number of underlying features. First and foremost is that most new construction systems are installed in large new housing developments with multiple solar homes, and therefore benefit from scale economies in installation and bulk purchasing that reduce unit costs. Customer acquisition costs for these systems are also likely minimal. New construction systems may also benefit from economies of scope, where certain labor or materials costs can be shared between PV installations and other elements of home construction. Conversely, some installers have reported more complex scheduling and logistics for new construction that might conceivably boost costs. Systems installed in new construction also tend to be considerably smaller: within our dataset, the median size of residential new construction systems in 2017 was just 3.0 kW, compared to 6.1 kW for residential retrofits in California.

Tax-Exempt vs. For-Profit Commercial Sites

As discussed earlier in Section 3, roughly 20% of non-residential systems in the data sample are installed at tax-exempt customer sites (i.e., schools, government buildings, and non-profit organizations, such as churches). As shown in Figure 30, installed prices are consistently higher for tax-exempt host customers than for commercial customers. These differences are most pronounced among the larger class of >500 kW non-residential systems, where median prices were roughly $0.5/W higher for tax-exempt customers than for commercial customers in 2017. Similar price differentials occurred in prior years as well. For the smaller size class of non-residential systems, the differential between tax-exempt and commercial site hosts was just $0.1/W in 2017.

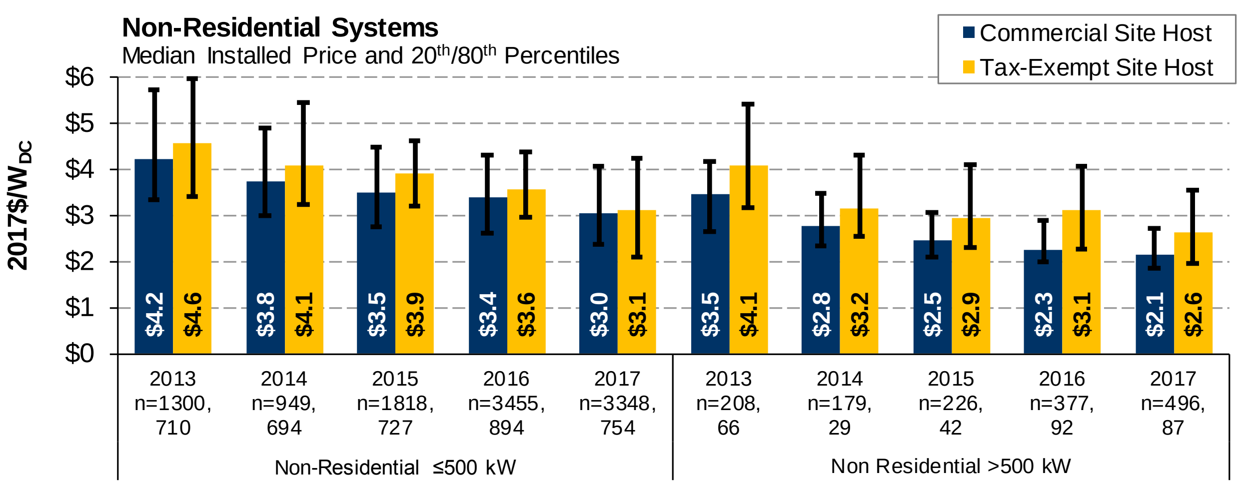


Figure 30. Installed Prices for Tax-Exempt vs. Commercial Site Hosts over Time

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[14] Several issues with the installed price data for new construction systems are worth noting. First, we commonly observe that identical prices are reported for all systems within a given development, presumably because the developer purchases the set of systems as a bulk order. This is a smaller scale issue than what we observe in the 2017 dataset, where several large installers report all or most of their systems at the same price. Second, to the extent that certain costs are shared between the PV installation and other aspects of home construction (e.g., roofing and electrical work), the entities reporting installed-price data may have some discretion in terms of how those shared costs are allocated to the PV system, which can create difficulties in making a true apples-to-apples comparison with retrofit systems.

One complicating factor in this comparison is the fact that TPO is considerably more prevalent among tax-exempt site hosts (40% of systems in the analysis sample in 2017) than among commercial site hosts (10% of systems). In order to control for these differences, Figure 31 separately compares installed prices between tax-exempt and commercial customers for host-owned systems and for TPO systems. As shown, the observed premium for tax-exempt customers is most pronounced and applicable in the case of host-owned systems, with a differential of $0.5/W in the ≤500 kW size class and $1.4/W in the >500 kW size class. Higher prices at tax-exempt customer sites may reflect a number of underlying factors, including prevailing wage/union labor requirements, preferences for domestically manufactured components, a high incidence of shade and parking structure PV arrays, and lower borrowing costs that allow higher-priced projects to pencil-out. The comparison for TPO systems in the ≤500 kW size class show the opposite relationship, with median prices for tax-exempt customers lower than for commercial customers. Those results, however, appear to be the exception to the rule, as they are driven primarily by two TPO installers with a large number of especially low-priced tax-exempt systems in 2017. Though not included here, the trends in prior years show consistently higher prices at tax-exempt sites, for both TPO and host-owned systems.

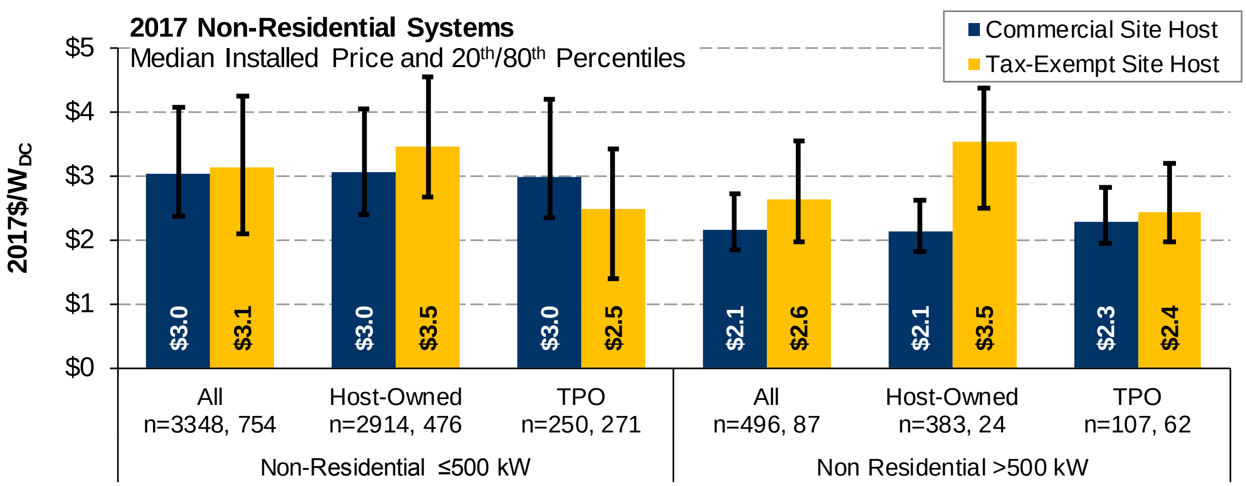
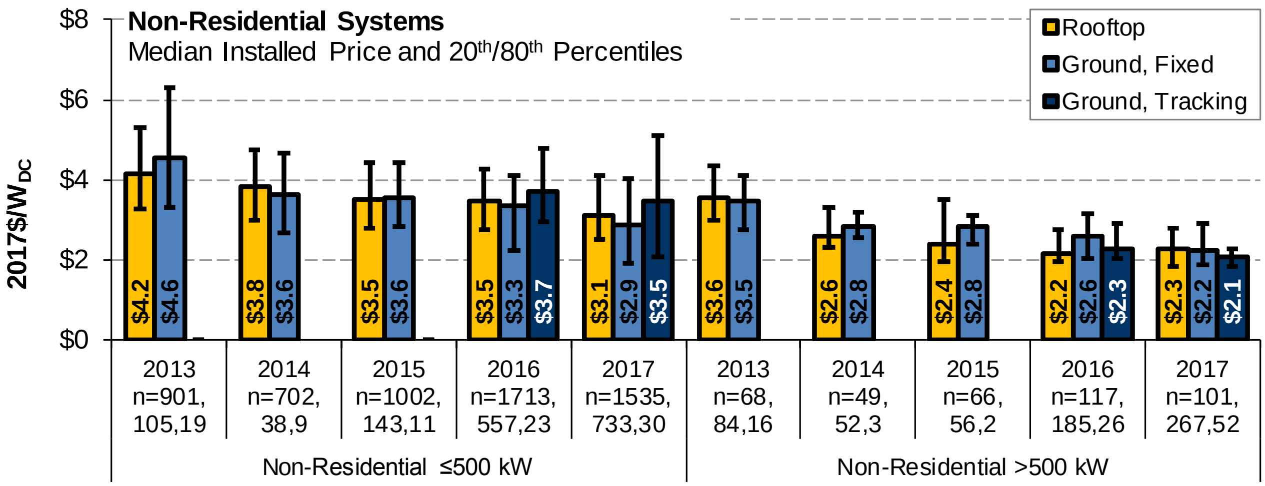


Figure 31. Installed Prices for Tax-Exempt vs. Commercial Site Hosts in 2017, by System Ownership

Variation by Mounting Configuration

As described previously, a sizeable fraction of non-residential systems in the dataset are ground-mounted, and roughly 10% of large non-residential systems also have tracking. Naturally, the relative economics of different mounting configurations—especially the choice between tracking and fixed-tilt—depend on both differences in up-front installed price as well as differences in performance. With respect to installed prices, tracking equipment obviously entails some additional up-front cost, and thus one might anticipate systems with tracking to have higher installed prices (though the cost of tracking equipment has generally decline over time). The price implications of ground-mounting vs. roof-mounted are less clear-cut, though ground-mounted systems may incur some additional costs associated with foundations, trenching, and permitting.

As shown in Figure 32, installed price differences across mounting configurations are generally quite small (and also fairly erratic, as a result of the small underlying sample sizes). Among systems installed in 2017, for example, fixed-tilt ground-mounted systems had slightly lower prices than roof-mounted systems in both size classes, and systems in the >500 kW size class with tracking had slightly lower price still—the exact inverse of what one might expect. In the sub-500 kW class, systems with tracking were (as to be expected) higher-priced than fixed-tilt systems, in both 2016 and 2017. Given the limitations of the data, in this case, the comparisons shown in Figure 32 serve largely just to demonstrate that, while differences in mounting configuration may impact installed prices, those effects are clearly not among the primary drivers for installed pricing variability in the non-residential sector.



Notes: The figure is derived from the relatively small subsample of systems for which data were available specifying whether the system is roof- or ground-mounted and whether or not it has tracking. Summary statistics for any given year are shown only if at least 20 observations are available.

Figure 32. Installed Price of Non-Residential Systems by Mounting Configuration over Time

6. Conclusions

The number of PV systems installed in the United States has grown at a rapid pace in recent years, driven both by declining costs and supportive policies. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage further cost reductions over time through increased deployment. Research and development (R&D) efforts within the industry have also focused on cost reductions, led by the U.S. DOE's Solar Energy Technologies Office, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020, and by an additional 50% from the 2020 goal by 2030.

Available evidence confirms that the installed price of PV systems (i.e., the up-front cost borne by the PV system owner, prior to any incentives) has declined substantially since 2000, though both the pace and source of those cost reductions have varied over time. Following a period of relatively steady and sizeable declines, installed price reductions began to stall around 2005, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Beginning in 2008, however, global module prices began a steep downward trajectory, and those module price reductions were the driving force behind the decline in total system prices for PV from 2009 through 2013. Since then, installed prices have continued to fall, but at a much slower pace, reflecting continued reductions in both hardware and soft costs.

Given the limits to further reductions in module and other hardware component prices, continued reductions in soft costs will be essential to driving further deep reductions in installed prices. Unlike module prices and other hardware component costs, which are primarily established through global and national markets, soft costs may be more readily affected by local policies—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. The heightened focus on soft cost reductions within the solar industry and among policymakers has spurred a flurry of initiatives and activity in recent years, and the continued decline in installed prices suggests that these efforts have begun to bear fruit.

Nevertheless, lower installed prices in other major international markets, as well as the wide diversity of observed prices within the United States, suggest that broader soft cost reductions are possible. Although such cost reductions may accompany increased market scale, it is also evident that market size alone is insufficient to fully capture potential near-term cost reductions. Achieving deep reductions in soft costs thus likely requires a broad mix of strategies, including both broader efforts that aim to foster efficiency and competition within the delivery infrastructure, as well as more targeted research and development efforts aimed at specific soft costs.

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Appendix A: Data Cleaning, Coding, and Standardization

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

Conversion to 2017 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2017 dollars (2017$). Data provided by PV program administrators in nominal dollars were converted to 2017$ 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 data providers directly provide system capacity in units of DC-STC; however, several did not. In those cases, PV system DC-STC capacity could generally be calculated from the nameplate rating of the modules and module quantity.

Identification and Treatment of Duplicate Systems: For a number of states (California, Florida, Massachusetts, and Oregon), data provided by multiple different entities contain overlapping sets of systems. In order to avoid double-counting, duplicate observations were merged or eliminated. These duplicate observations were identified using, wherever possible, a common ID number across datasets or customer street address. In cases where neither of those pieces of information are available, more-aggressive measures were taken to identify and eliminate duplicates. For systems within the California investor-owned utilities' service territories, the California Public Utilities Commission's Currently Interconnected Dataset was used as the base data sample, and additional data for those systems were incorporated from the various incentive program datasets (CSI, NSHIP, SGIP, and ERP) based on CSI ID numbers and street addresses.

Incorporating Data on Module and Inverter Characteristics. The raw data provided by PV incentive program administrators generally included module and inverter manufacturer and model names. We cross-referenced that information against public databases of PV component specification data (namely, the CSI eligible equipment lists[15] and SolarHub[16]) to characterize the module technology efficiency, module technology (e.g., mono-crystalline vs. poly-crystalline, building-integrated PV vs. rack-mounted systems), and inverter technology (microinverter vs. DC optimizer vs. standard string/central inverter). All systems with SolarEdge inverters were assumed to also be equipped with DC power optimizers.

Identification of Customer Segment: Almost all programs provided some explicit segmentation of host customers, at least into residential and non-residential customers. In the rare cases where even this minimal level of segmentation was not provided, systems less than or equal to 20 kW in size were assumed to be residential, and those larger than 20 kW were assumed to be non-residential. The choice of this threshold was based on an inspection of data where customer segmentation was available, and is roughly the value that minimizes the error in these assignments to customer segments.

Identification of Host-Owned vs. TPO Systems: Most programs explicitly identify the ownership type of each system as either host-owned or TPO. Where such data were not provided, however, systems were assumed to be host-owned under any of the following conditions: (a) the system was installed in a state where TPO was not allowed at the time of installation, (b) the system was installed in a state where TPO is technically allowed but actual market activity is known to be quite low, or (c) the PV incentive program providing data is not available to TPO systems.

[15] http://www.gosolarcalifornia.ca.gov/equipment/
[16] http://www.solarhub.com/

Identification and Removal of Appraised Value Systems: A total of 249,910 systems were removed from the final data sample, on the grounds that installed prices reported for these systems were appraised values, rather than transaction prices. The vast majority of these systems were identified simply based on reported installer name and system ownership type. Specifically, prices reported for TPO systems installed by integrated TPO providers—SolarCity/Tesla, Sungevity/Horizon, and Vivint—were assumed to be appraised values and removed from the final data sample. Upon inspection of the data, prices reported for *host-owned* systems installed by SolarCity/Tesla were also deemed likely to be appraised values and were thus also removed from the data sample.

If data on installer name were not available, appraised-value systems were identified using a "price clustering" approach. The logic for the price clustering approach is founded on the observation that identical prices are reported for large clusters of systems installed by individual integrated TPO providers. These prices may reflect, for example, the average per-kW assessed fair market value of a bundle of systems sold to tax equity investors. The first step in the price clustering analysis was to identify price clusters among the systems explicitly identified in the dataset as TPO and installed by an integrated TPO provider (all of which are categorically assumed to be appraised-value). Then, for systems where installer name data were unavailable, reported prices were assumed to be appraised value if they fell within the aforementioned set of price clusters and the system was not explicitly identified as host host-owned. A separate price clustering approach was used for several states where installer name data was wholly or largely unavailable. For those states, we also flag as appraised value systems where at least 20% of systems installed in any given year have an identical price. In practice, this only impacted our dataset for Colorado.

For reference, Figure 33 compares the reported installed prices for appraised-value systems (consisting primarily of systems installed by integrated TPO providers) to prices for other, non-integrated TPO systems. As shown, installed prices reported for appraised-value systems in 2010 and 2011 were dramatically higher than for non-integrated TPO systems. For many integrated TPO systems, the appraised values used as the basis for reported installed prices are an assessed "fair market value", often based on the discounted cash flow from the project (or a bundle of projects). Starting in 2012, at least one major integrated TPO provider changed its installed price reporting methodology for PV incentive programs. Following that, the disparity between installed prices reported for integrated and non-integrated TPO systems disappeared in 2012, but then reemerged and grew over time as integrated TPO prices remained essentially flat from 2013-2016. Among systems installed in 2017, prices for appraised-value systems were about $1.0/W higher than for the non-integrated TPO systems retained in the dataset.

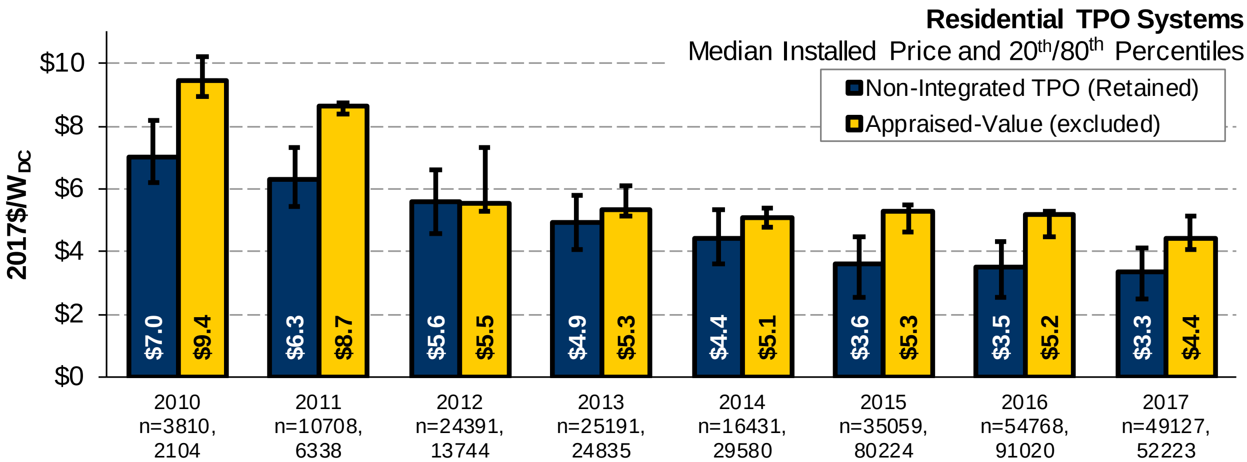

Figure 33. Installed Prices Reported for Non-Integrated and Integrated Residential TPO Systems

Identification of Self-Installed Systems: Self-installed systems were identified in several ways. In some cases, these systems could be identified based on the reported installer name (e.g., if listed as "owner" or "self"). In addition, all systems installed by Grid Alternatives or Habitat for Humanity were treated as self-installed, as these entities rely on volunteer labor for low-income solar installations.

Calculation of Net Present Value of Reported PBI Payments: A number of PV incentive programs in the data sample provided performance-based incentives (PBIs), paid out over time based on actual energy generation and a pre-specified payment rate, to some or all systems. In order to facilitate comparison with up-front rebates provided to the other systems in data sample, the net present value (NPV) of the expected PBI payments were calculated based on an assumed 7% nominal discount rate.

Appendix B: Additional Details on LBNL Data Sample

Table B-1. Sample Summary by Data Provider

State	Data Provider	2017 Systems		All Years	
		Full Sample	Analysis Sample	Full Sample	Analysis Sample
AR	Arkansas Energy Office	0	0	105	97
AZ	Ajo Improvement Company	0	0	3	3
	Arizona Public Service	18,426	12,203	74,910	33,534
	Duncan Valley Electric Coop.	0	0	7	0
	Mohave Electric Coop.	30	30	253	252
	Morenci Water & Electric	0	0	3	3
	Navopache Electric Coop.	0	0	141	129
	Salt River Project	1,294	1,247	17,446	9,320
	Sulpher Springs Valley Electric Coop.	288	254	888	793
	Trico Electric Coop.	166	84	596	467
	Tucson Electric Power	3,656	1,469	17,012	7,913
	UniSource Electric Services	617	0	2,970	1,541
CA	California Center for Sustainable Energy (Bear Valley Electric)	0	0	123	36
	California Center for Sustainable Energy (Pacific Power)	2	2	205	169
	CPUC and CEC (Currently Interconnected Dataset, CSI, NSHP, ERP, SGIP) [a]	118,804	84,449	700,270	370,087
	City of Palo Alto Utilities	8	0	940	564
	Imperial Irrigation District	100	35	4,162	1,437
	Los Angeles Dept. of Water & Power	4,433	3,447	31,252	20,415
	Sacramento Municipal Utility District	3,753	19	19,765	4,954
CO	Xcel Energy	5,837	3,624	40,714	24,829
CT	Clean Energy Finance and Investment Authority	4,036	3,410	24,373	16,605
DC	Washington D.C. Public Service Commission	634	0	3,431	0
DE	Department of Natural Resources and Environmental Control	126	126	2,681	2,416
FL	Florida Energy & Climate Commission[b]	0	0	1,258	1,201
	Gainesville Regional Utilities[b]	54	52	571	553
	Orlando Utilities Commission[b]	0	0	1,207	1,146
IL	Dept. Commerce and Economic Opportunity	82	0	158	0
MA	Massachusetts Clean Energy Center and Dept. of Energy Resources[c]	11,724	7,588	79,036	43,091

State	Data Provider	2017 Systems		All Years	
		Full Sample	Analysis Sample	Full Sample	Analysis Sample
MD	Maryland Energy Administration	1,523	845	11,563	8,945
ME	Efficiency Maine	0	0	555	550
MN	Dept. of Commerce	432	431	1,828	1,624
	Xcel Energy	706	599	2,684	2,232
MO	Ameren	146	0	3,935	0
	Kansas City Power and Light	316	0	3,319	0
NC	NC Sustainable Energy Association	1,388	1,360	7,387	6,870
NH	New Hampshire Public Utilities Commission	993	867	4,640	4,316
NJ	New Jersey Board of Public Utilities	18,544	13,914	87,715	61,813
NM	Energy, Minerals & Natural Resources Dept.	0	0	7,679	7,283
	Public Service Company of New Mexico	3,492	0	7,958	0
NV	NVEnergy	2,769	1,361	24,143	10,283
NY	New York State Energy Research and Development Authority	13,584	10,278	78,322	58,160
OH	Ohio Public Utilties Commission	143	0	2,483	0
OR	Energy Trust of Oregon[d]	1,783	1,457	12,339	8,932
	Oregon Dept. of Energy[d]	1,952	1,637	4,262	3,549
	Pacific Power	9	9	831	534
PA	Dept. Community and Economic Development	0	0	54	49
	Dept. of Environmental Protection	0	0	7,078	7,041
	Sustainable Development Fund	0	0	201	200
RI	National Grid	1,852	1,413	3,964	2,622
TX	Austin Energy	972	812	6,786	6,549
	CPS Energy	3,366	3,293	10,478	10,228
	Clean Energy Associates (El Paso Electric)	0	0	369	347
	Clean Energy Associates (Entergy)	0	0	57	57
	Clean Energy Associates (Oncor Electric Delivery Company)	0	0	908	867
	Clean Energy Associates (Sharyland Utilities)	3	3	6	5
	Clean Energy Associates (Southwestern Electric Power Company)	0	0	39	39
	Clean Energy Associates (Texas Central Company)	31	31	209	203
	Clean Energy Associates (Texas New Mexico Power Company)	0	0	23	23
	Clean Energy Associates (Texas North Company)	20	20	95	95

State	Data Provider	2017 Systems		All Years	
		Full Sample	Analysis Sample	Full Sample	Analysis Sample
UT	Rocky Mountain Power	6,027	5,577	19,177	17,879
VT	Vermont Energy Investment Corporation	0	0	3,956	3,913
WI	Focus on Energy	482	482	4,876	4,803
Total		***234,603***	***162,428***	***1,344,399***	***771,566***

[a] Data for California's three large investor owned utilities (PG&E, SCE, and SDG&E) are developed by merging the CPUC's Currently Interconnected Data Set with data from the various incentive programs that have been or are currently offered in the utilities' service territories. See Appendix A for more details on this merging process.

[b] A small number of PV systems that received an incentive through the Florida Energy & Climate Commission (FECC)'s statewide solar rebate program also participated in one of the Florida utility programs. Those systems were retained in the data sample for the utility programs and removed from the sample for FECC's program. The values shown here for FECC reflect the residual sample, after overlapping systems were removed.

[c] Separate datasets, consisting of largely overlapping sets of systems, were provided by the Massachusetts Clean Energy Center (MassCEC) and the Dept. of Energy Resources (DOER). These two datasets were merged, with overlapping systems identified based primarily on the PTS ID numbers provided in the two datasets.

[d] Oregon systems that received incentives through both the Oregon Dept. of Energy's tax credit program and the Energy Trust of Oregon were retained in the data sample for the Energy Trust and removed from sample for the Dept. of Energy. The values shown here for the Oregon DOE reflect the residual sample, after overlapping systems were removed.

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