Tracking the Sun

Pricing and Design Trends for Distributed Photovoltaic Systems in the United States
2019 Edition

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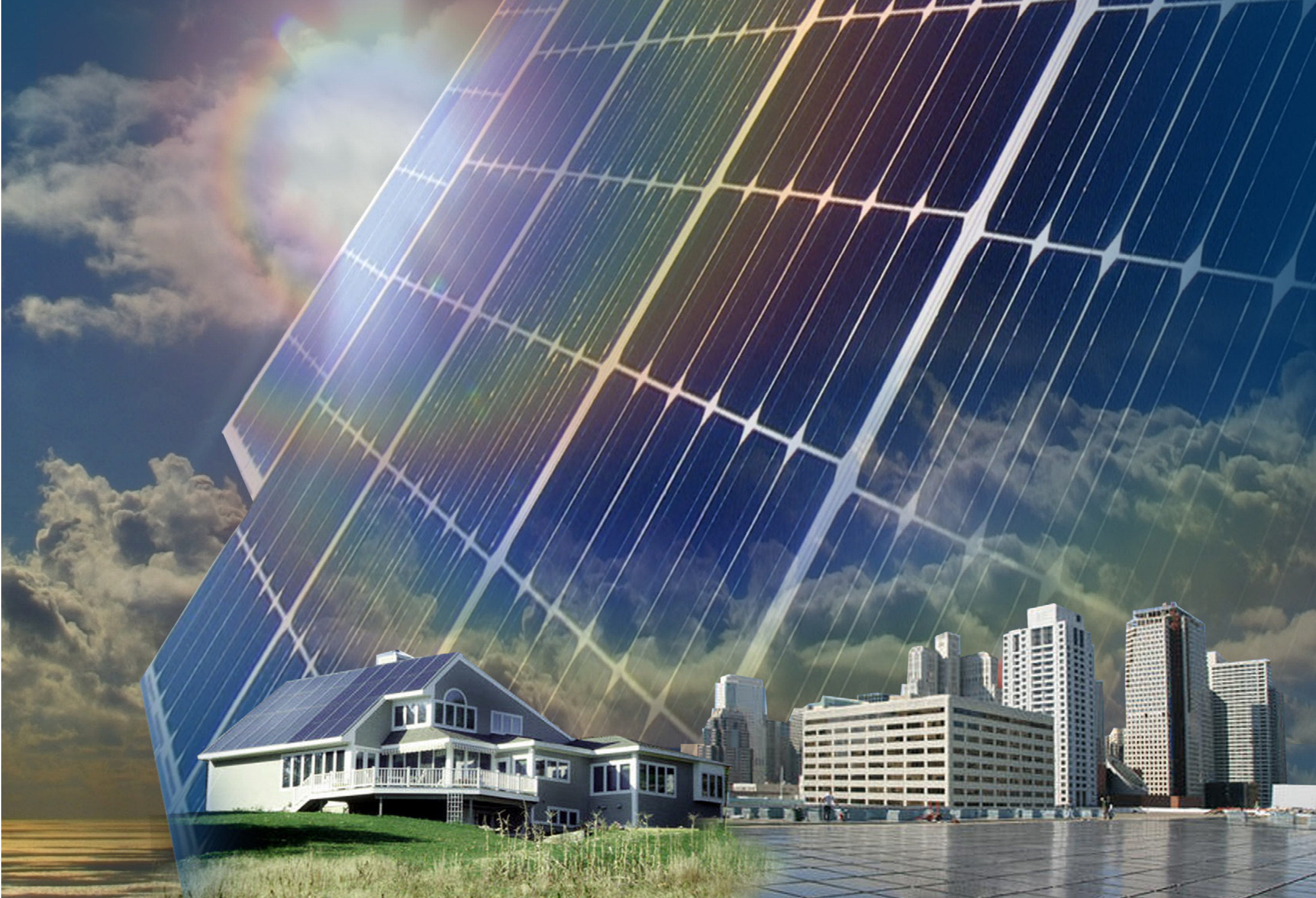

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Executive Summary 1

1. Introduction 4

2. Data Sources, Methods, and Market Coverage 6

Data Sources 6
Data Standardization and Cleaning 6
Sample Size and Market Coverage 7

3. PV System Characteristics 10

System Size 10
Module Efficiencies 11
Module-Level Power Electronics 12
Inverter Loading Ratios 13
Ground-Mounting and Use of Tracking Equipment 14
Orientation 14
Solar-Plus-Storage 15
Third-Party Ownership 16
Non-Residential Customer Segmentation 17

4. Temporal Trends in Median Installed Prices 18

Installed Price Trends: 2000-2018 18
Installed Price Trends: Preliminary Data for 2019 20
Underlying Hardware and Soft Cost Reductions 21
Declining State and Utility Cash Incentives 22
Comparison to Other U.S. PV Cost and Pricing Benchmarks 24

5. Variation in Installed Prices 26

Overall Installed Price Variability 26
Pricing by System Size 27
Pricing across States 28
Pricing across Installers 29
Pricing by Module Efficiency 30
Pricing by Inverter Type 31
Pricing for Residential New Construction vs. Retrofits 32
Pricing for Tax-Exempt vs. For-Profit Commercial Sites 33
Pricing by Mounting Configuration 34

6. Conclusions 36

References 37

Appendix A: Additional Details on the Data Sample 39

Appendix B: Data Cleaning and Standardization 42

Appendix C: Multi-Variate Regression Analysis of 2018 Residential System Prices 44

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] This edition focuses on systems installed through year-end 2018, with preliminary trends for the first half of 2019. As in years past, the primary emphasis is on describing changes in installed prices over time and variation across projects. This year's report also includes an expanded discussion of other key technology and market trends, along with several other new features, as noted in the text box below.

Trends in this report derive from project-level data reported primarily to state agencies and utilities that administer PV incentives, renewable energy credit (REC) registration, or interconnection processes. In total, data were collected and cleaned for 1.6 million individual PV systems, representing 81% of all U.S. distributed PV systems installed through 2018. The analysis of installed prices is based on the subset of roughly 680,000 host-owned systems with available installed price data, of which 127,000 were installed in 2018. A public version of the full dataset is available at trackingthesun.lbl.gov.

Numerical results are denoted in direct current (DC) Watts (W) and real 2018 dollars. Non-residential systems are segmented into small vs. large non-residential, based on a cut-off of 100 kW.

New Features in This Year's *Tracking the Sun*

- *Expanded Discussion of Project Characteristics*. This year's report includes additional trends related to distributed PV orientation, inverter loading ratios, and solar-plus-storage.
- *Focus on Host-Owned Systems for Installed Pricing Analysis*. In order to simplify the analysis and discussion, the report now excludes third-party owned systems from its analysis of installed pricing trends, though those systems are included when characterizing broader technology and market trends.
- *Multi-Variate Regression Analysis*. The report now includes an econometric model of installed pricing variation across residential systems installed in 2018 (see Appendix C), complementing the descriptive analysis.

Distributed PV Project Characteristics. Key technology and market trends based on the full dataset compiled for this report are as follows.

- PV systems continue to grow in size, with median sizes in 2018 reaching 6.4 kW for residential systems and 47 kW for non-residential systems. Sizes also vary considerably within each sector, particularly for non-residential systems, for which 20% were larger than 200 kW in 2018.
- Module efficiencies continue to grow over time, with a median module efficiency of 18.4% across all systems in the sample in 2018, a full percentage point increase from the prior year.
- Module-level power electronics—either microinverters or DC optimizers—have continued to gain share across the sample, representing 85% of residential systems, 65% of small non-residential systems, and 22% of large non-residential systems installed in 2018.
- Inverter-loading ratios (ILRs, the ratio of module-to-inverter nameplate ratings) have

[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} (or roughly 7 MW_{DC}). An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector, which consists of ground-mounted PV systems larger than 5 MW_{AC}.

generally grown over time, and are higher for non-residential systems than for residential systems. In 2018, the median ILR was 1.11 for residential systems with string inverters and 1.16 for those microinverters, while large non-residential systems had a median ILR of 1.24.

- Roughly half (52%) of all large non-residential systems in the 2018 sample are ground-mounted, while 7% have tracking. In comparison, 17% of small non-residential systems and just 3% of residential systems are ground-mounted, and negligible shares have tracking.
- Panel orientation has become more varied over time, with 57% of systems installed in 2018 facing the south, 23% to the west, and most of the remainder to the east.
- A small but increasing share of distributed PV projects are paired with battery storage, typically ranging from 1-5% in 2018 across states in our dataset, though much higher penetrations occurred in Hawaii and in a number of individual utility service territories.
- Third-party ownership (TPO) has declined in recent years, dropping to 38% of residential, 14% of small non-residential, and 34% of large non-residential systems in the 2018 sample.
- Tax-exempt customers—consisting of schools, government, and nonprofit organizations—make up a disproportionately large share (roughly 20%) of all 2018 non-residential systems.

Temporal Trends in Median Installed Prices. The analysis of installed pricing trends in this report focuses primarily on host-owned systems. Key trends in *median* prices, prior to receipt of any incentives, are as follows.

- National median installed prices in 2018 were \$3.7/W for residential, \$3.0/W for small non-residential, and \$2.4/W for large non-residential systems. Other cost and pricing benchmarks tend to be lower than these national median values, and instead align better with 20th percentile values (see Text Box 5 in the main body for further discussion of these issues).
- Over the last full year of the analysis period, national median prices fell by \$0.2/W (5%) for residential, by \$0.2/W (7%) for small non-residential, and by \$0.1/W (5%) for large non-residential systems. Those \$/W declines are in-line with trends over the past five years.
- Over the longer-term, since 2000, installed prices have fallen by \$0.5/W per year, on average, encompassing a period of particularly rapid declines (2008-2012) when global module prices rapidly fell. In many states, the long-term drop in (pre-incentive) installed prices has been substantially offset by a corresponding drop in rebates or other incentives.
- Preliminary and partial data for the first half of 2019 show roughly a \$0.1/W drop in median installed prices compared to the first half of 2018, though no observable drop relative to the second half of 2018. Those trends are based on a subset of states, consisting of larger markets, where price declines have recently slowed compared to other states.
- Installed price declines reflect both hardware and soft-cost reductions. Since 2014, following the steep drop in global module prices, roughly 64% of the total decline in residential installed prices is associated with a drop in module and inverter price, while the remaining 36% is due to a drop in soft costs and other balance-of-systems (BoS) costs. For non-residential systems, a slightly higher percentage of total installed price declines is attributable to BoS and soft costs.

Variation in Installed Prices. This report highlights the widespread variability in pricing across projects and explores some of the drivers for that variability, focusing primarily on systems installed in 2018. The exploration of pricing drivers includes both basic descriptive comparisons as well as a more formal econometric analysis. Key findings include the following.

- Installed prices in 2018 ranged from \$3.1-4.5/W for residential systems (based on the 20^{th} and 80^{th} percentile levels), from \$2.4-4.0/W for small non-residential systems, and from \$1.8-3.3/W for large non-residential systems.
- Installed prices within each customer segment vary substantially depending on system size, with median prices ranging from \$3.3-4.3/W for residential, from \$2.7-3.4/W for small non-residential, and from \$2.0-3.6/W for large non-residential systems, depending on size.
- Installed prices also vary widely across states, with state-level median prices ranging from \$2.8-4.4/W for residential, \$2.5-3.7/W for small non-residential, and \$1.7-2.5/W for large non-residential systems.
- Across the top-100 residential installers in 2018, median prices for each individual installer generally ranged from \$3.0-5.0/W, with most below \$4.0/W.
- Median prices are notably higher for systems using premium efficiency modules (>20%) and for systems with microinverters or DC optimizers. Comparisons between residential retrofits and new construction, and comparisons based on mounting configuration, are both less revealing, likely due to relatively small underlying sample sizes.
- The multi-variate regression analysis, which focuses on host-owned residential systems installed in 2018, shows relatively substantial effects associated with system size (a \$0.8/W range between 20^{th} and 80^{th} percentile system sizes) and with other system-level factors, including those related to module efficiency (+\$0.2/W for systems with premium efficiency modules), inverter type (+\$0.2/W for systems with either microinverter or DC-optimizers), ground-mounting (+\$0.3/W), and new construction (-\$0.5/W).
- In comparison, the regression analysis found relatively small effects for various market- and installer-related drivers—including variables related to market size (a \$0.2/W range between the 20^{th} to 80^{th} percentile values for market size), market concentration (a \$0.1/W range), household density (a \$0.2/W range), average household income (no effect), and installer experience (no effect).
- After controlling for various system-, market-, and installer-level variables, the regression analysis still found substantial residual pricing differences across states (a \$1.5/W range), indicating that other, unobserved factors significantly impact installed prices at the state- or local-levels.

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 (SETO), 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 1).

This edition of *Tracking the Sun* describes installed price trends for projects installed through 2018, with preliminary data for the first half of 2019. 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 depth observed *variability* in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics. The analysis of installed pricing variation includes both a descriptive component (comparing median prices across different types of systems, installers, and markets) as well as a multi-variate regression analysis that controls for correlations among individual pricing drivers. Finally, beyond its primary focus on installed prices, the report also describes a variety of other technology and market trends for distributed PV.

Text Box 1. Related National Lab Research

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.
- *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. 2018).
- *Other Derivative Works* that rely on the Tracking the Sun dataset include in-depth statistical analyses of PV pricing dynamics, solar-adopter demographics, impacts of solar on property value, and other topics. These and other solar energy publications are available here.

[2] The 2020 cost targets are denominated in real 2010 dollars. The data in this annual tracking report also informs the formulation of and tracking progress towards SETOs Government Performance and Reporting Act (GPRA) cost targets.
[3] 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} (or roughly 7 MW_{DC}).

The trends presented in this report are based 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 1.6 million grid-connected, distributed PV systems installed through year-end 2018, representing roughly 81% of the total U.S. market. A public version of this data file is available at trackingthesun.lbl.gov. 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 the subset of approximately 680,000 host-owned systems for which installed price data are available, of which 127,000 were installed in 2018.

Essential to note at the outset are several important aspects of the installed price data described within this report. First, as noted above, the analysis of installed prices focuses solely on host-owned systems and excludes third-party owned (TPO) systems, for reasons discussed in the main body of the report. Installed prices for host-owned systems represent the up-front price paid by the host customer, prior to receipt of incentives. These values 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. Last but not least, it is important to acknowledge that installed prices are but one aspect of evaluating the customer economics of distributed PV; a full evaluation also requires consideration of ongoing operating costs as well as system performance over time.

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 total U.S. and state distributed PV markets. Section 3 describes key characteristics of the full data sample, including system size trends, third-party ownership, customer segmentation, module efficiencies, use of module-level power electronics, inverter loading ratios, panel orientation, the prevalence of ground-mounting and tracking, and pairing of storage with distributed PV. 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 2018 to a variety of other recent U.S. benchmarks. Section 5 describes the variability in installed prices within the dataset, and explores installed pricing differences across projects, including those related to: system size, state, installer, module efficiency, inverter type, residential new construction vs. retrofit, for-profit commercial vs. tax-exempt site host, and mounting configuration. Finally, Section 6 offers brief conclusions. Appendices A and B provide further details on data sources and the data cleaning process, while Appendix C presents a new multi-variate regression analysis of residential system pricing in 2018, complementing the descriptive analysis in Section 5.

Additional supplementary materials are available online at http://trackingthesun.lbl.gov/, including a public version of the Tracking the Sun dataset, summary data tables containing the numerical values plotted in the figures throughout the report, a slide deck summary of the report, and a webinar recording.

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 for this report 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. In total, 67 entities spanning 30 states contributed data to this report (see Table A-1 in the Appendix). These data sources 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 the other types of administrative processes noted above. In some cases, gaps in data collection have occurred, such as in California, as discussed further below.

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 the cleaned module and inverter names, equipment spec sheet data were integrated into the dataset, including data on module efficiency and technology type and inverter power rating and technology type. Each system was also categorized as either residential, small non-residential, or large non-residential, per the definitions described in Text Box 2. Finally, all price and incentive data were converted to real 2018 dollars (2018$), and if necessary system size data were converted to direct-current (DC) nameplate capacity under standard test conditions (STC). 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. Most significantly, all TPO were removed, as prices

Text Box 2. Customer Segment Definitions

This report distinguishes among three customer segments:

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

Small Non-Residential: Includes all non-residential systems up to 100 kW_{DC}.

Large Non-Residential: Includes non-residential systems larger than 100 kW_{DC}, with no upper size limit for rooftop systems and a cap of 5,000 kW_{AC} (roughly 7,000 kW_{DC}) for ground-mounted systems.

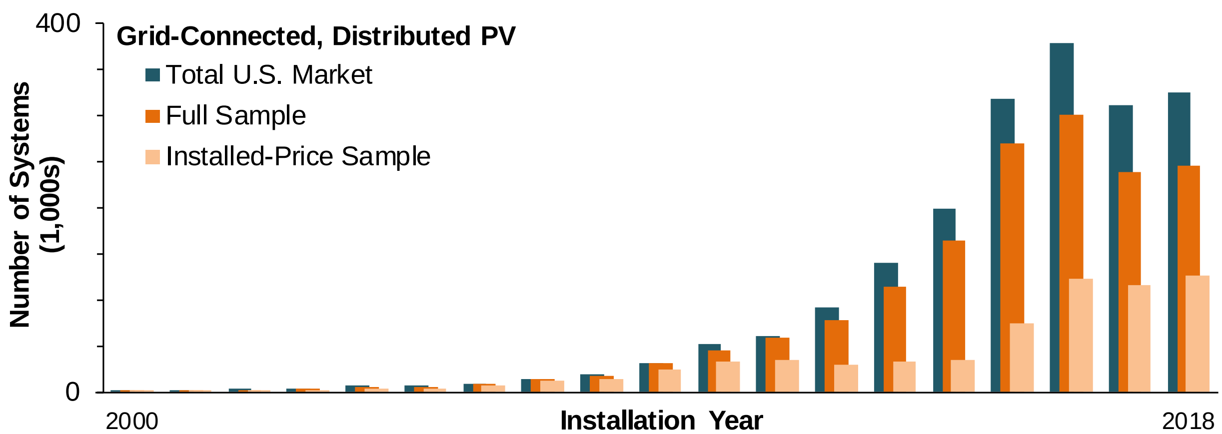
Ground-mounted systems larger than 5,000 kW_{AC} are considered **utility-scale** and are addressed separately in Berkeley Lab's companion *Utility-Scale Solar* annual report. Note that these various customer segment definitions may differ from those used by other organizations, and thus some care must be taken in comparisons.

reported for those systems cannot be meaningfully compared to those of host-owned systems (though, for reference, Text Box 3, presented later in the report, compares installed prices reported for TPO and host-owned systems). Host-owned systems installed by SolarCity/Tesla were also removed, as prices reported for those systems appear to represent appraised values, rather than transaction prices. Also excluded from the installed-price analysis are systems missing installed price data, systems with battery-back up, self-installed systems, and systems with prices less than $1/W or greater than $20/W (assumed data entry errors). The resulting dataset, after these various additional exclusions are applied, is denoted hereafter as the ***installed-price sample*** and is the basis for all installed price trends presented in the report, unless otherwise indicated. Further details on these steps and on other elements of the data cleaning process are described in Appendix B.

Sample Size and Market Coverage

The ***full sample*** includes the majority of all U.S. grid-connected residential and non-residential PV systems. In total, it consists of more than 1.6 million individual PV systems installed through year-end 2018, including roughly 250,000 systems installed in 2018 (Figure 1 and Table 1). This represents 81% of all U.S. residential and non-residential systems installed cumulatively through 2018 and 76% of installations in 2018. As discussed further below, coverage within 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 ***installed-price sample*** consists of roughly 680,000 systems installed through year-end 2018 and 120,000 systems installed in 2018. The gap between the full sample and the installed-price sample consists primarily of TPO systems (approximately 630,000 systems) and systems missing installed price data (approximately 270,000 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 sample and installed-price sample has narrowed in recent years, due to increased availability of installed price data for California and the diminishing market share of TPO systems.



Notes: Total U.S. distributed PV installations are based on data from IREC (Sherwood 2016) for all years through 2010 and from Wood Mackenzie and SEIA (2019) for each year thereafter.

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

Table 1. Full Sample and Installed-Price Sample by Installation Year and Market Segment

Installation Year	Full Sample (No. of Systems)				Installed-Price Sample (No. of Systems)			
	Residential	Small Non-Res.	Large Non-Res.	***Total***	Residential	Small Non-Res.	Large Non-Res.	***Total***
1998	25	1	1	***27***	8	0	0	***8***
1999	210	11	1	***222***	111	2	0	***113***
2000	201	11	1	***213***	115	8	0	***123***
2001	1,243	40	5	***1,288***	832	18	0	***850***
2002	2,294	163	27	***2,484***	1,554	80	3	***1,637***
2003	3,070	265	45	***3,380***	2,513	169	16	***2,698***
2004	5,189	434	38	***5,661***	4,451	297	24	***4,772***
2005	5,371	454	81	***5,906***	4,532	296	56	***4,884***
2006	8,958	549	102	***9,609***	7,852	357	74	***8,283***
2007	13,612	876	154	***14,642***	11,255	592	89	***11,936***
2008	15,843	1,552	378	***17,773***	12,344	1,176	178	***13,698***
2009	28,792	2,077	353	***31,222***	22,360	1,687	213	***24,260***
2010	41,188	3,565	713	***45,466***	30,657	2,883	438	***33,978***
2011	53,137	5,290	1,638	***60,065***	30,193	3,518	795	***34,506***
2012	71,819	5,423	1,741	***78,983***	25,946	3,414	827	***30,187***
2013	108,847	4,043	1,458	***114,348***	30,810	2,049	632	***33,491***
2014	159,394	4,763	1,375	***165,532***	33,256	1,716	646	***35,618***
2015	263,205	4,792	1,512	***269,509***	71,558	2,251	646	***74,455***
2016	293,410	5,748	2,311	***301,469***	118,625	3,491	1,199	***123,315***
2017	231,405	4,653	2,552	***238,610***	110,995	3,323	1,357	***115,675***
2018	239,477	4,390	2,210	***246,077***	122,404	3,151	1,145	***126,700***
Total	***1,546,690***	***49,100***	***16,696***	***1,612,486***	***642,371***	***30,478***	***8,338***	***681,187***

Notes: Text Box 2 for an explanation of the three customer segments used in this table and throughout the report.

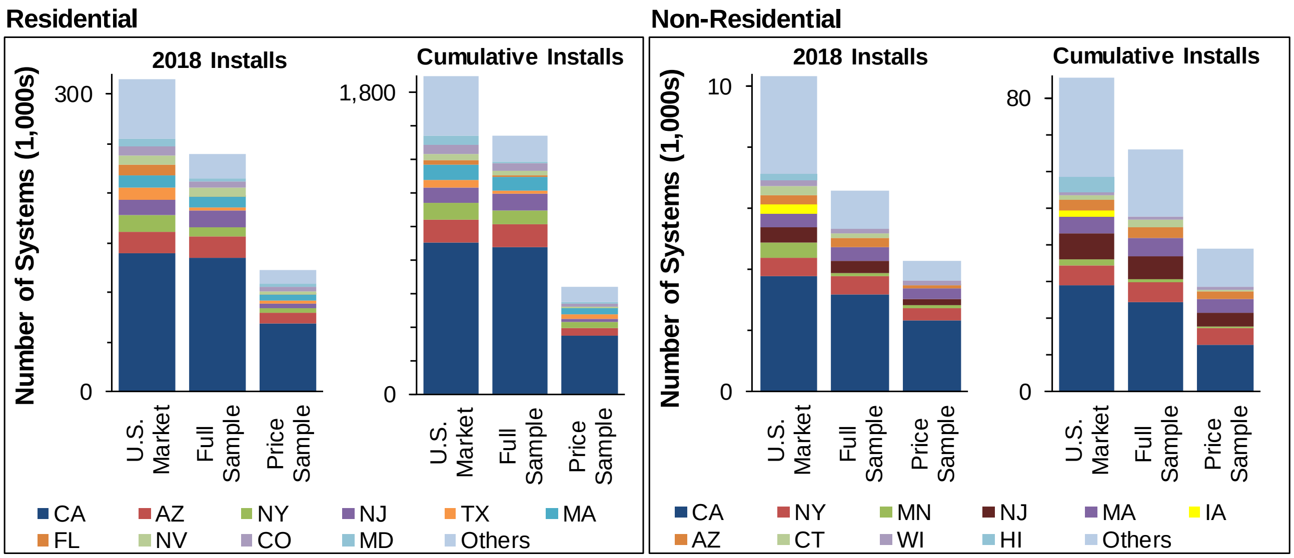
The full sample includes systems installed across 30 states, winnowed down to 26 states in the installed-price sample, which excludes four states (DC, KS, MO, and OH) wholly lacking installed price data. Though the sample has fairly broad geographic representation, it is nevertheless concentrated in 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 2018 installations and cumulative installations, for both residential and non-residential systems. Arizona, Massachusetts, New Jersey, and New York make up the bulk of the remaining sample, for both the residential and non-residential sectors. These five states comprise a disproportionately large share of the sample, relative to their share of the overall U.S. market, which may have 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. Within the residential sector, the biggest data gaps are in Texas, Florida, and Maryland; while the biggest data gaps in the non-residential sample are for Minnesota, Iowa, and Hawaii.[4] Outside of those states, however, the data sample includes at least 60%, and in

[4] For Texas and Florida, the data come mostly from large municipal utilities, but almost no data were provided by those states' investor-owned utilities. In Maryland, the data come from the state's rebate program, which has a limited annual budget and is open only to host-owned systems. For Minnesota, much of the recent growth in the non-residential

most cases more than 80%, of systems installed in each of the top-10 residential and non-residential states in 2018. More generally, where sample coverage tends to be weakest is among smaller state markets (denoted as "Others" in the figure) that are either missing or under-represented in the sample. As 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 the total U.S. market are from Wood Mackenzie and SEIA (2019). The figure identifies the top-10 states in each customer segment, based on total U.S. market installations in 2018. 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 individual states included in "Others".

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

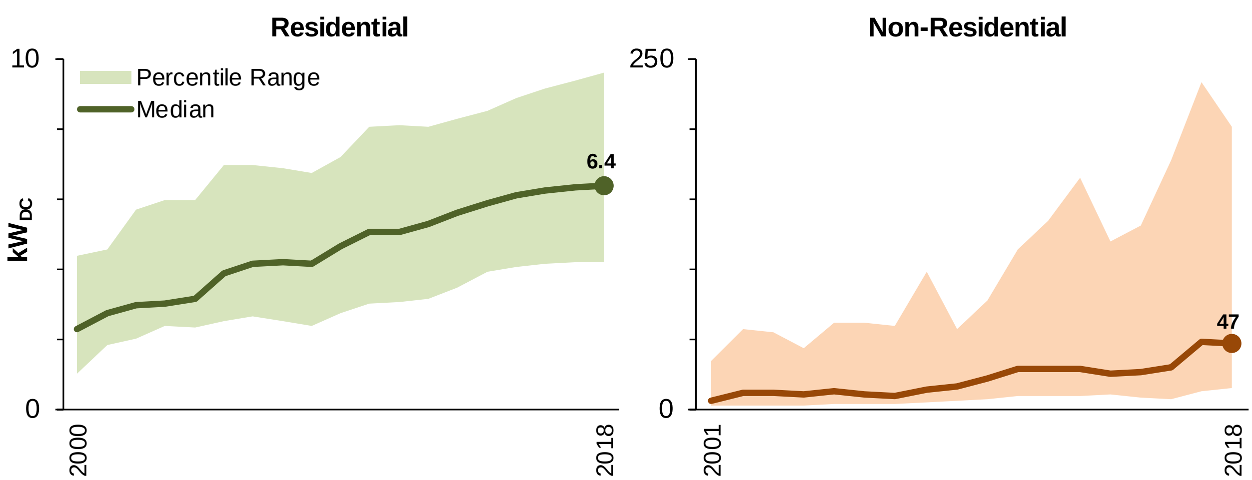
segment has been community solar, which is largely absent from the data collected for this report, and Iowa and Hawaii are both wholly missing from this report.

3. PV System Characteristics

Characteristics of the data sample help to illustrate trends within the broader U.S. distributed PV market, and provide context for understanding installed price trends presented later in this report. To those ends, we describe below key characteristics of the data sample, including: the evolution of system sizes over time, module efficiencies, the use of module-level power electronics, inverter loading ratios (ILRs), the prevalence of ground-mounting and tracking equipment, system orientation, the prevalence of solar-plus-storage, the distribution between host-owned and TPO systems, and the composition of non-residential site hosts. These trends are based on the *full data sample*, in contrast to the installed-price trends discussed later, which are based on the smaller *installed-price sample*, as described in Section 2.

System Size

As shown in Figure 3, both residential and non-residential system sizes have grown substantially over time. In the residential sector, median system sizes grew from 2.4 kW in 2000 to 6.4 kW in 2018. Those trends partly reflect increasing module efficiencies, as many residential systems are space-constrained based on available roof area. In the non-residential sector, median system sizes grew from 7 kW to 47 kW over the period shown, though the more pronounced trend is the growth at the upper end of the size spectrum, as indicated by the widening percentile bands in Figure 3. At the 80th percentile level, non-residential system sizes grew from 35 kW to 201 kW. Large non-residential systems, both rooftop and ground-mounted, have become increasingly prevalent as a broader set of non-residential customers become comfortable with the technology and as developers and investors seek out projects offering higher returns. It is partly because of this wide range in project sizes that this report elsewhere distinguishes between small and large non-residential systems.[5]



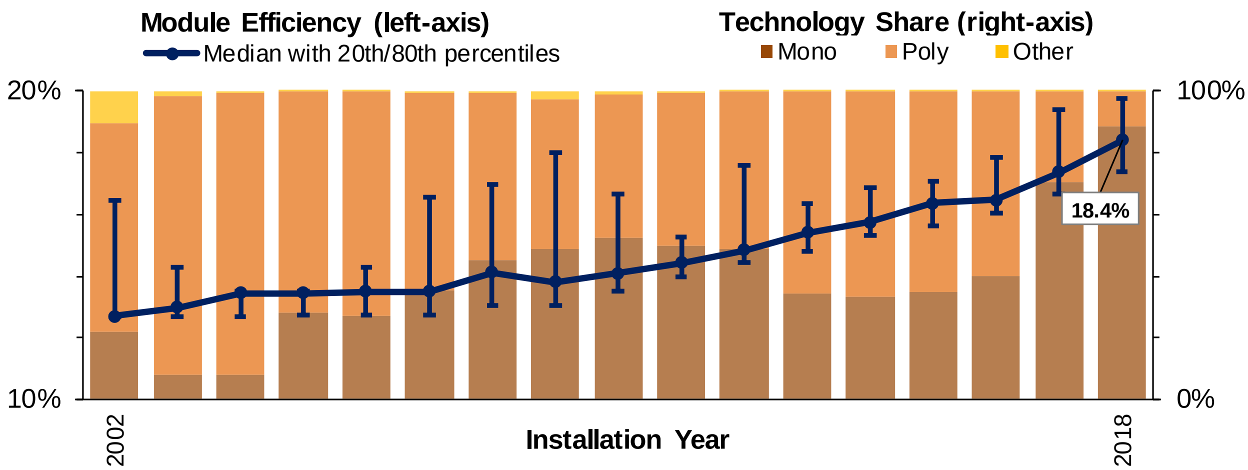
Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year. Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 3. System Size over Time

[5] As noted previously, ground-mounted systems larger than 5 MW_{AC}, or roughly 7 MW_{DC}, are covered in LBNL's companion *Utility-Scale Solar* report.

Module Efficiencies

Module efficiency levels have risen considerably over time, from a median of 12.7% in 2002 to 18.4% in 2018, as shown in Figure 4. These gains have been particularly pronounced over the past several years, with median efficiencies climbing by roughly one percentage point in both 2017 and again in 2018. Those recent gains reflect a correspondingly sharp increase in the share of mono-crystalline modules, from 40% of the sample in 2016 to almost 90% in 2018, as well as a steady increase in the use of passivated emitter rear-cell (PERC) technology. Over the long term, efficiencies for both mono- and poly-crystalline technologies have risen substantially, as manufacturing processes and cell architectures have steadily improved.



Notes: Median values prior to 2002 are omitted due to small sample sizes.

Figure 4. Module Efficiency Trends over Time

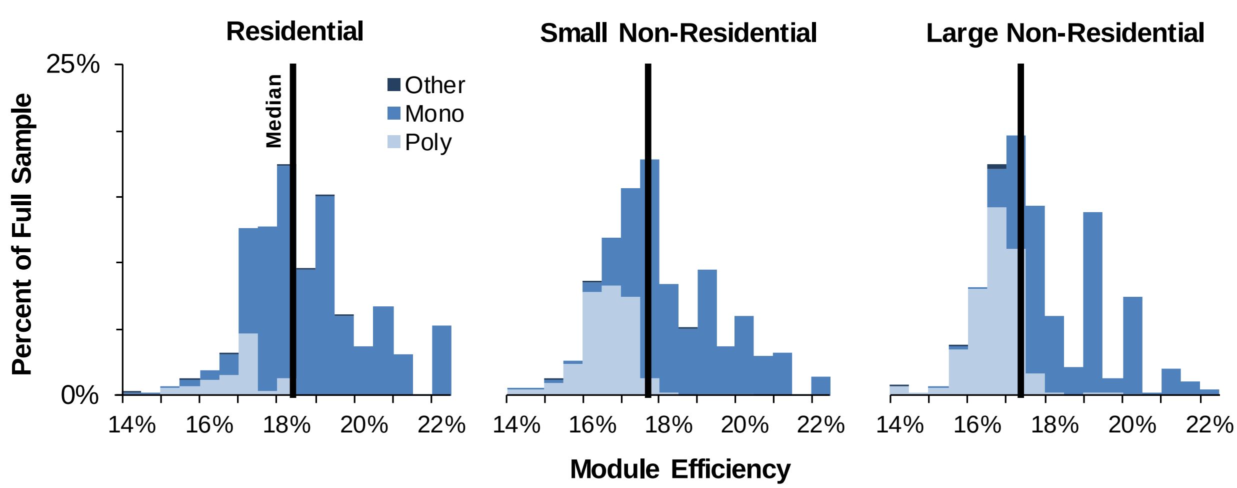


Figure 5. Module Efficiency Distributions for Systems Installed in 2018

Among 2018 systems in the data sample, module efficiencies range from less than 16% to more than 22%, as shown in Figure 5. Systems at the lower end of that range primarily use poly-crystalline silicon modules, which typically range from 16% to 17.5% efficiency. Systems with mono-crystalline modules are generally higher efficiency but span a wider range, from about 16.5%

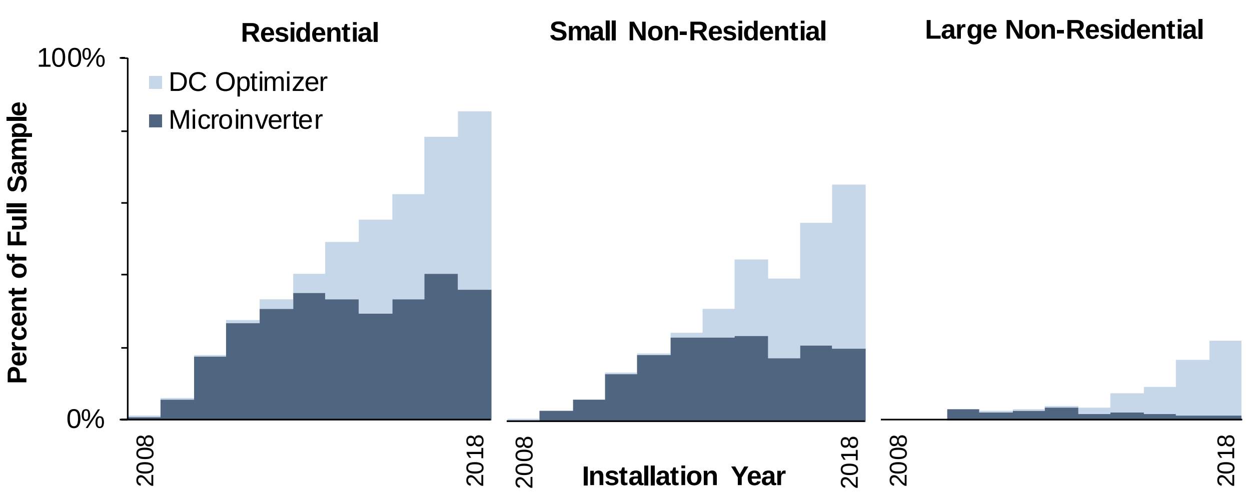
to 22%, depending in part on whether the cells use PERC and whether they are p-type or n-type.[6]

As evident in Figure 5, mono-crystalline modules dominate the residential sample (roughly 90% of 2018 installations), but represent progressively smaller shares of the small non-residential (70%) and large non-residential (60%) segments. Accordingly, residential systems had the highest median module efficiency in 2018 at 18.4%, compared to 17.7% for small non-residential systems and 17.4% for large non-residential systems. Differences in module technology choice among customer segments partly reflect greater space constraints in residential applications, as well as less price-sensitivity among residential customers compared to non-residential customers.

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.[7] MLPEs generally sell for a premium over standard inverters, but that price differential has narrowed in recent years (Fu et al. 2018, Wood Mackenzie and SEIA 2019), leading to steady gains in MLPE market share.

This is reflected in the data sample, as shown in Figure 6. MLPE growth has been most pronounced in the residential segment, reaching 85% of all systems in the sample installed in 2018, compared to 64% for small non-residential systems and 22% of large non-residential systems. As evident in the figure, virtually all of the growth in MLPE market share since 2013 has been from DC optimizers, with the microinverter-share remaining fairly flat over that period, and the entirety of MLPE adoption in the large non-residential segment consists of DC optimizers.



Notes: DC Optimizer share consists of only systems with SolarEdge inverters and may therefore slightly understate the actual share of power optimizers in the data sample.

Figure 6. Penetration of Module-Level Power Electronics within the Data Sample

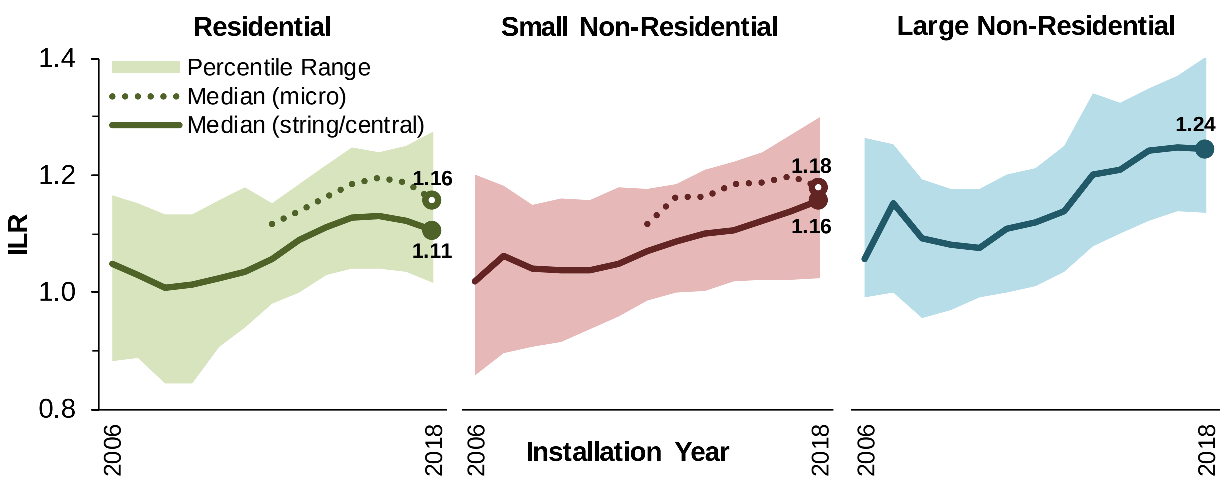
[6] P-type and n-type are two different ways to create impurities in the silicon crystals of PV cells (Neaman 2003). N-type cells allow higher efficiencies compared to p-type, but usually have higher costs related to the different chemical elements involved in their fabrication, and high volume manufacturing challenges.

[7] 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 when the output of individual panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string. Deline et al. (2012) estimate 4-12% greater energy production from systems with microinverters, which can offset the higher up-front cost of MLPEs.

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 tend to be more prevalent in residential applications (with multiple roof planes and more-constrained space) than in large non-residential applications (where systems are often installed on flat rooftops with uniform orientation and potentially greater flexibility in terms of layout).

Inverter Loading Ratios

The inverter loading ratio (ILR) is the ratio of a PV system's total module nameplate rating (in DC watts) to its total inverter nameplate rating (in AC watts), also sometimes called the DC-to-AC ratio. Most PV systems are designed with ILRs greater than 1.0, that is, with modules oversized relative to the inverter. In general, higher ILRs entail greater clipping of module output during hours of peak production, but can reduce inverter and other BoS costs for a given module array size. In sizing a system's ILR, installers may also consider module degradation, ambient temperatures, and other issues such as soiling and shading that reduce module output relative to its rated capacity.



Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year across all inverter types. Trends are shown starting in 2006, and for micro-inverters in 2012, as the trends for prior years tend to be erratic, partly due to small sample sizes.

Figure 7. Inverter Loading Ratios among Systems in the Data Sample

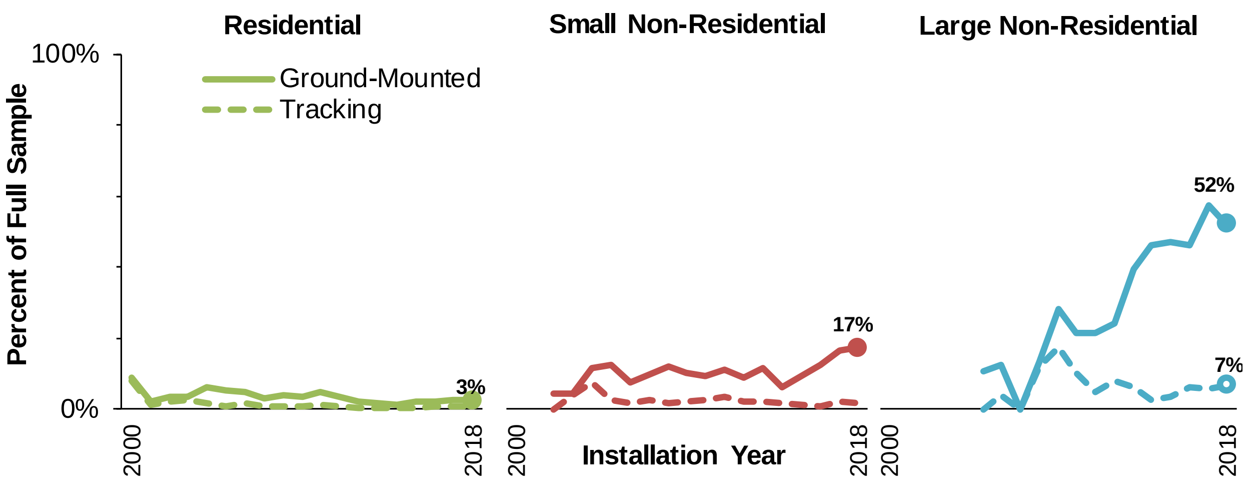
As shown in Figure 7, ILRs for distributed PV systems vary widely, with residential and small non-residential systems installed in 2018 typically ranging from roughly 1.0 to 1.3 and large non-residential systems from 1.1 to 1.4. Within those broad ranges, several specific trends can be seen. First, systems with microinverters tend to have higher ILRs than those with string inverters, though this depends on which microinverter brand is used. Systems with Enphase inverters, which comprise the majority of microinverter systems in the sample, had a median ILR of 1.26 in 2018, while those using SunPower modules with integrated microinverters, which make up most of the remainder, have much lower ILRs (a median of 1.08 in 2018), reflecting the higher module costs.

Second, ILRs have generally risen over time, across all sectors and inverter types. In part, this reflects the steady decline in module costs, which shifts project economics towards higher ILRs. In addition, string inverters are often sized based on the amperage of the customer's electrical service panel; as module efficiencies and PV system sizes have grown over time, ILRs have therefore grown as well. These trends appear to have reversed over the last several years, with median ILRs declining for microinverter systems and for residential string-inverter systems. In the case of microinverter systems, that apparent reversal is simply an artifact of the underlying mix of manufacturers, with low-ILR SunPower systems taking on a larger share relative to higher-ILR Enphase systems.

Finally, ILRs tend to be higher for large non-residential systems than for residential and small non-residential systems. In part, that may reflect a greater emphasis among large non-residential systems on minimizing LCOE, which may in turn steer system design towards greater oversizing of the arrays.

Ground-Mounting and Use of Tracking Equipment

Though residential PV systems are generally roof-mounted, many non-residential systems are ground-mounted, including shade structures. As shown in Figure 8, roughly half of all large non-residential systems installed in 2018 were ground-mounted, and that fraction has grown considerably over time in concert with the previously noted trend towards larger system sizes. These systems are still predominantly fixed-tilt, with just 7% of large non-residential systems in 2018 using tracking equipment. This stands in contrast to the utility-scale market, where more than two-thirds of systems in 2018 had tracking (Bolinger and Seel 2019). Within the small non-residential and residential customer segments, progressively smaller fractions of systems are ground-mounted, and negligible percentages (<1%) use tracking.



Notes: Summary statistics for any given year are shown only if at least 20 observations are available.

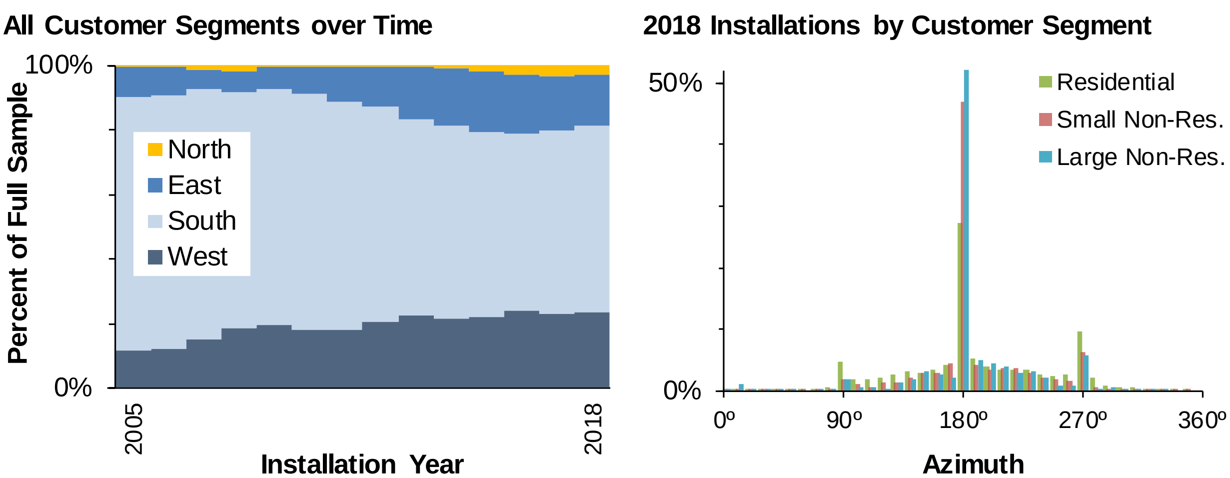
Figure 8. Mounting Configuration among Systems in the Data Sample

Orientation

PV panel orientation (azimuth and tilt) is a key determinant of PV energy production, with the greatest energy production for fixed-tilt systems typically occurring when panels are oriented due south and with tilt equal to the location's latitude. In some cases, however, PV panels may provide greater value to the utility system and potentially to the customer if oriented westward, so that the PV generation profile more closely matches the utility system load profile. That said, many rooftop applications may offer limited flexibility in terms of panel orientation, given existing roof planes.

As shown in the left-hand panel of Figure 9, just over half of PV systems in the 2018 sample are oriented southward (57%), and that fraction has declined over time. The trend toward more diverse panel orientations may reflect both falling rooftop PV costs, allowing systems to become economically viable even with sub-optimal orientations, as well as deeper market penetration in some regions, requiring installers to look beyond the low-hanging fruit of customers with ideally oriented rooftops. Some states and utilities have also begun requiring that rooftop PV customers take service under time-of-use (TOU) rates, which might encourage more westerly oriented systems if peak and off-peak rates sufficiently differ. However, we see little direct evidence of such an effect, as both west-facing and east-facing systems have become more prevalent, comprising 23% and 16% of 2018 installations, respectively. Though not shown in the figure, we also see no meaningful differences in orientation trends between markets with and without TOU rates.

As shown in the right-hand panel of Figure 9, residential and non-residential systems both tend to be oriented in the general southerly direction, though a significantly greater share of non-residential systems than residential systems face exactly due-south. This is likely due to the greater prevalence of both flat rooftops and ground-mounting in the non-residential sector, allowing for more-optimized system orientation. Also of note, the residential and non-residential distributions both exhibit relatively high concentrations of systems with panels facing exactly due-east and due-west; this likely reflects the fact that streets—and therefore houses and rooftops—tend to be oriented along cardinal compass directions.



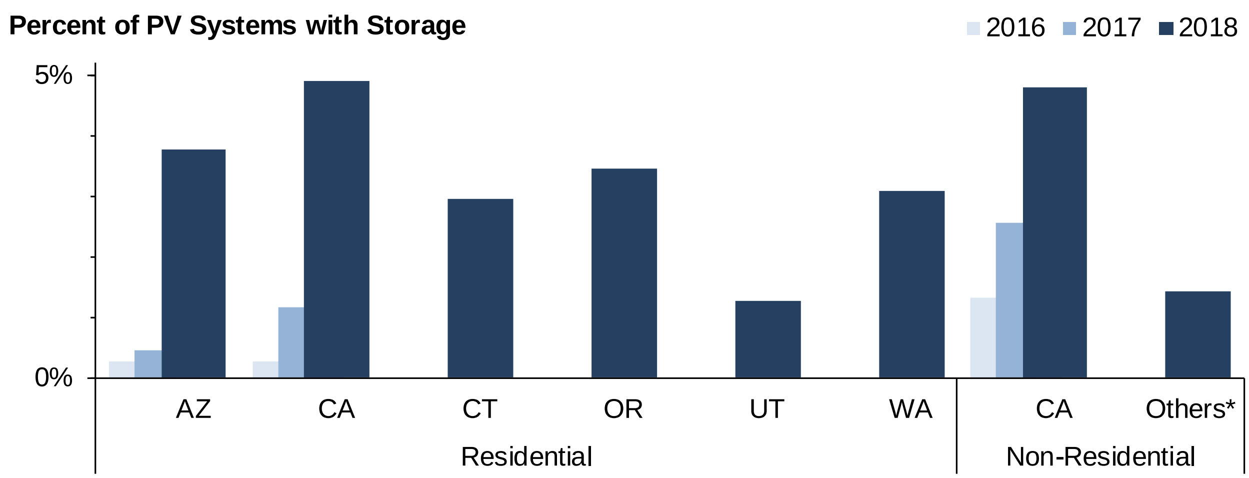
Notes: In the left-hand figure, azimuths are grouped according to cardinal compass directions ±45º (e.g., systems within ±45º of due-south are considered south-facing). Both figures exclude flat-mounted and tracking systems.

Figure 9. Orientation among Systems in the Data Sample

Solar-Plus-Storage

Pairing battery storage with distributed PV has become more common, as storage costs decline, as customers with high reliability needs seek to ride-through outages, and as utilities adopt incentives and implement rate designs that encourage storage adoption. Among those rate designs, net billing rates—an emerging successor to traditional net metering—provide lower levels of compensation for solar generation exported to the grid, thereby incentivizing customers to install storage in order to minimize grid exports (in essence, arbitraging between the grid export-rate and retail rates). Similarly, demand charge rates, which are common in the non-residential sector and have been implemented for residential solar customers in several jurisdictions as well, can provide a powerful impetus for solar-plus-storage (Gagnon et al. 2017, Darghouth et al. 2019).

Within the dataset assembled for this report, data identifying PV systems paired with storage are available for only a subset of states (primarily AZ, CA, CT, OR, UT, and WA), as summarized in Figure 10. Among this set of states, between 1-5% of both residential and non-residential PV systems included storage in 2018. Though still relatively small, these penetration rates have risen rapidly in both AZ and CA, where time series data are available. Within AZ, the highest rates of pairing occur within Salt River Project's service territory, where 20% of residential PV systems in 2018 included storage, due to the combination of a new storage incentive program and demand-charge rates for solar PV customers. Though not included in the Tracking the Sun dataset, HI has seen even greater storage penetration in its distributed PV market, as a result of changes to its compensation scheme for behind-the-meter PV that heavily discourage grid exports. In 2018, more than 60% of all permits issued for distributed PV on Oahu included storage (HI DBEDT 2019).



Notes: The figure includes only those states and years with sufficient sample size and coverage. For non-residential systems, all states other than California with sufficient data are grouped together.

Figure 10. Share of Annual PV Installations with Battery Storage

Third-Party Ownership

The composition of the full data sample reflects the growth, and more recent decline, of third-party ownership. As shown in Figure 11, the TPO share among residential systems in the data sample grew dramatically from 2007 to 2012, reaching nearly 60%. Consistent with broader market trends, however, that share has fallen in recent years, with TPO comprising just 38% of the full residential sample in 2018. That recent trend reflects the emergence of residential loan products as well as a move away from TPO by SolarCity/Tesla, previously the country's largest TPO provider. As noted previously, all TPO systems are removed from the sample for the purpose of analyzing installed-price trends.

TPO market-share within the non-residential sample differs in several respects. Among small non-residential systems, the initial TPO growth was less pronounced, though the recent drop-off is still notable. Among large non-residential systems in the data sample, the TPO share has vacillated over time, but shows no consistent decline. As discussed further below, many non-residential systems are installed at tax-exempt customer sites, which serves to sustain some continuing appetite for TPO in order to monetize tax benefits.

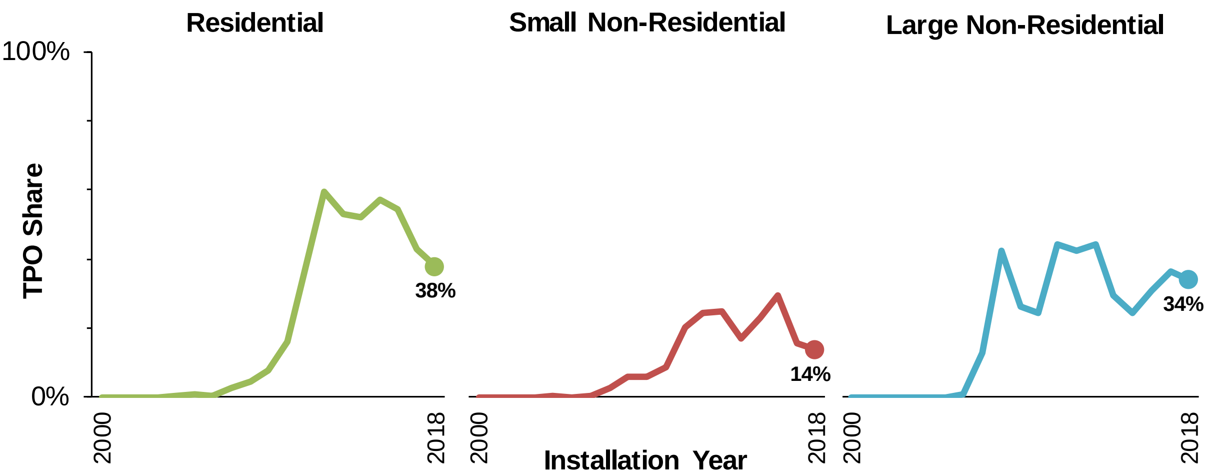


Figure 11. Sample Distribution between Host-owned and TPO Systems

Non-Residential Customer Segmentation

The non-residential solar sector consists of a diverse set of customer types, including for-profit commercial entities, as well as 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 2018, roughly 80% of all non-residential systems were installed at for-profit commercial sites, while the remaining 20% were at tax-exempt customer sites, and that overall mix is generally consistent across a number of the larger state markets shown in Figure 12. That 80/20 split is also consistent with analysis performed by Hoen et al. (2019), which examined non-residential PV addresses matched to proprietary datasets of property types.

In general, TPO is 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, 40% of systems at tax-exempt sites were TPO in 2018, compared to 14% at commercial customer sites. These percentages, however, can vary quite a bit from state to state; in Massachusetts and New Jersey, for example, 60-80% of systems at tax-exempt sites were TPO.

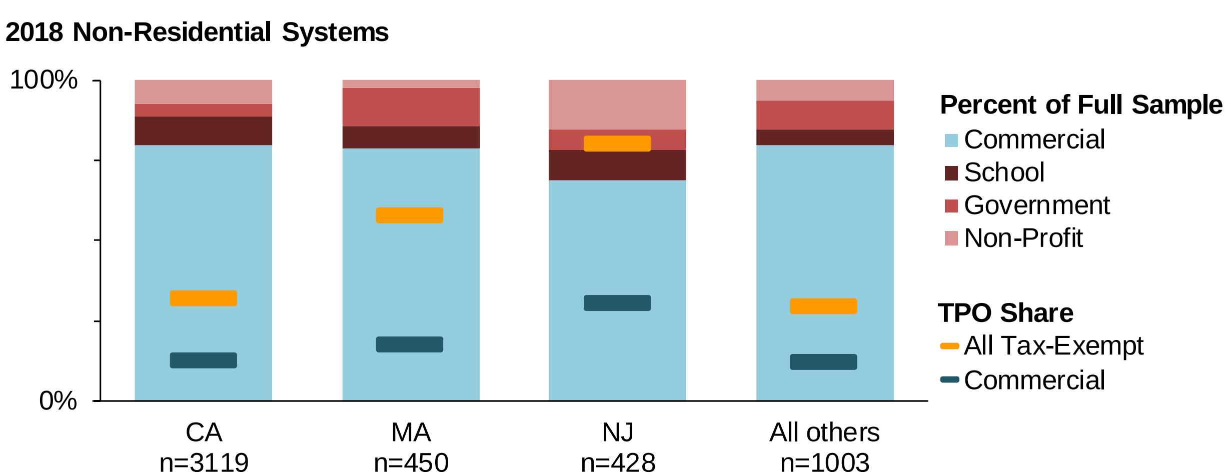


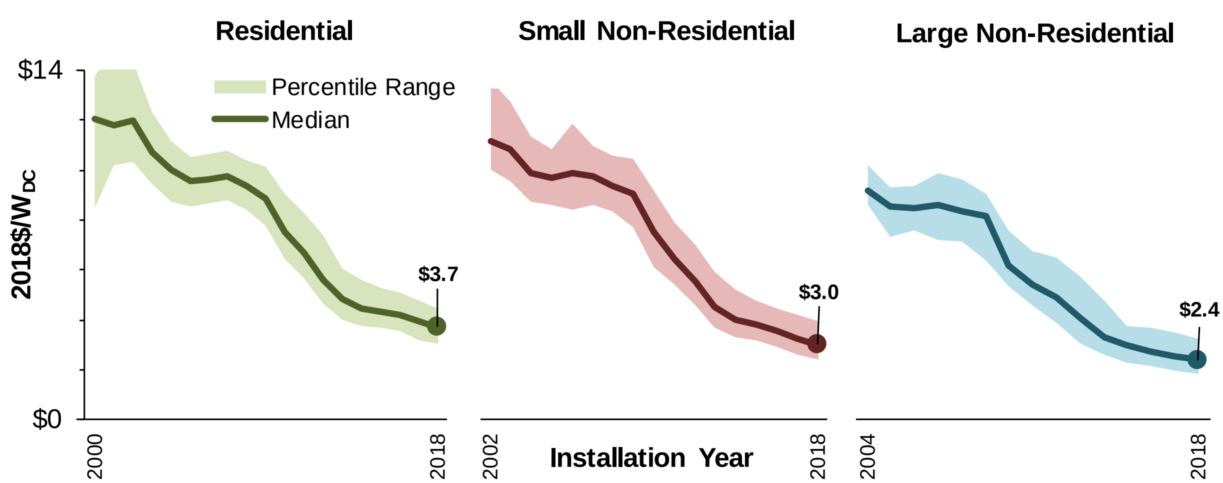
Figure 12. Non-Residential Customer Segmentation and TPO Shares

4. Temporal Trends in Median Installed Prices

This section presents an overview of both long-term and more-recent historical trends in the installed price of distributed PV, focusing on *national median prices* derived from the installed-price data sample described earlier. The section begins by describing the installed price trajectory over the full historical period through 2018, along with preliminary data for the first half of 2019. While the installed-price analysis otherwise focuses on host-owned systems, Text Box 3 compares prices for host-owned and TPO systems, as a point of reference. The section then discusses a number of broad drivers for those historical trends, including 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 between the LBNL dataset and other recent benchmarks for the installed price or cost of distributed PV.

Installed Price Trends: 2000-2018

National median installed prices for host-owned PV systems in 2018 were $3.7/W for residential systems, $3.0/W for small non-residential systems, and $2.4/W for large non-residential systems. As evident in Figure 13, installed prices across all three segments have fallen dramatically over time, though those trajectories have not been smooth. Following a period of particularly steep price declines from 2009-2014, the pace of installed price declines has tapered off. Over the last year of the analysis period, median prices fell by $0.2/W (5%) for residential systems, by $0.2/W (7%) for small non-residential systems, and by $0.1/W (5%) for large non-residential systems. Those declines are largely in line with the rate of price declines observed since 2014. By comparison, long-term annual price declines, over the full analysis timeframe, averaged roughly $0.5/W per year across all three customer segments.



Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year. Statistics shown only if at least 20 observations available for a given year and customer segment. See Table 1 for annual sample sizes.

Figure 13. Installed Price Trends over Time

The slowing pace of installed price declines in recent years, relative to the rapid rate over the 2009-2014 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 (albeit with some lag). 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. 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, wherein various fees are often embedded in the installed prices paid by customers and reported to PV incentive program administrators.[8] PV systems are also increasingly bundled with other products (such as battery storage), and though we attempt to exclude such systems from our data sample, that screening is undoubtedly incomplete.

Text Box 3. Installed Prices for Third-Party Owned Systems

As discussed in Section 2, TPO systems are excluded from the installed-price analysis in this report. Installed prices reported for TPO systems in some cases represent an appraised value or a fair-market value, as may be used as the basis for the federal investment tax credit. In other cases, installed prices reported for TPO systems may be the transaction price between an installation contractor and a third-party financier. Even in that case, however, the underlying goods and services conveyed under that transaction may vary greatly from one system to another. For example, customer acquisition and project development functions for some TPO systems may be performed by the financier or some other entity, rather than the installer, in which case the reported price may reflect only hardware and direct installation labor costs. It is for these various reasons that the installed-price analysis in this report focuses exclusively on host-owned systems.

For reference, Figure 14 compares reported installed prices for all TPO systems and host-owned systems over time. In recent years, median prices for TPO and host-owned systems have coincided quite closely. At earlier points in time, however, pricing for the two groups have diverged, particularly in the residential sector, where TPO prices have been notably higher than for host-owned systems. The convergence over time likely reflects, at least in part, changes in the reporting conventions of TPO companies. Excluding these systems from the installed-price analysis thus avoids any associated distortion in long term pricing trends.

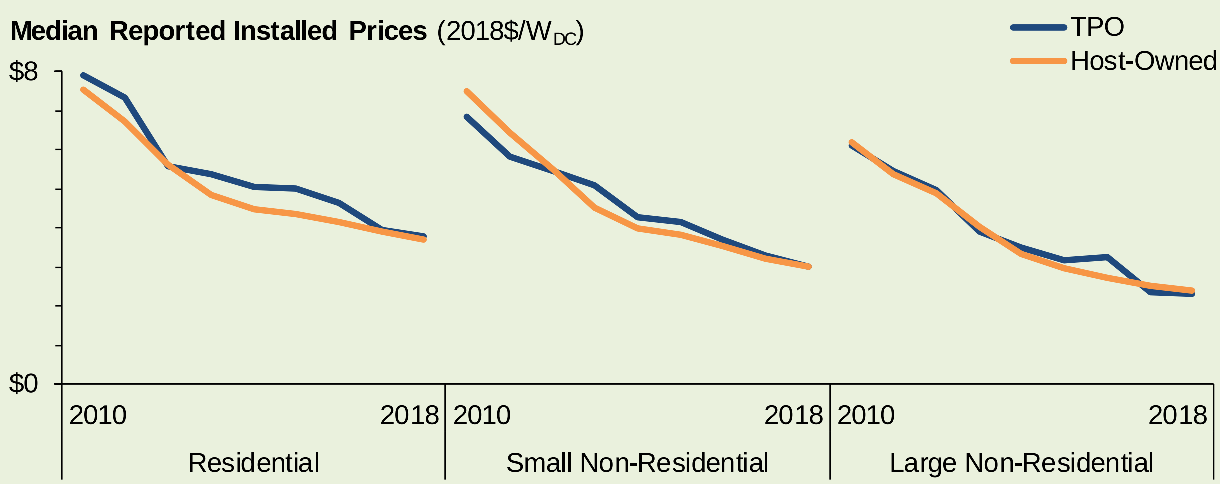


Figure 14. Comparison of Installed Prices between TPO and Host-Owned Systems

[8] Based on data from Wood Mackenzie (2019), roughly two-thirds of all host-owned residential systems installed in 2018 were loan-financed.

Trends in aggregate, national median installed prices are, in effect, a composite of trends among the largest state markets in the dataset. Within the residential segment, median prices fell year-over-year (YoY) by roughly $0.0-0.2/W across the five largest states in the dataset, as shown in Figure 15. Notably, all five saw lower annual price declines than the aggregate national drop. By extension, smaller markets saw larger declines, suggestive of the greater cost-saving opportunities that may exist in less mature markets. Among non-residential systems, YoY changes in median installed prices varied much more dramatically across states, as might be expected given the more-diverse set of projects and smaller sample sizes. For that reason, YoY changes in median prices for non-residential systems can be somewhat erratic, at both the state and national levels.

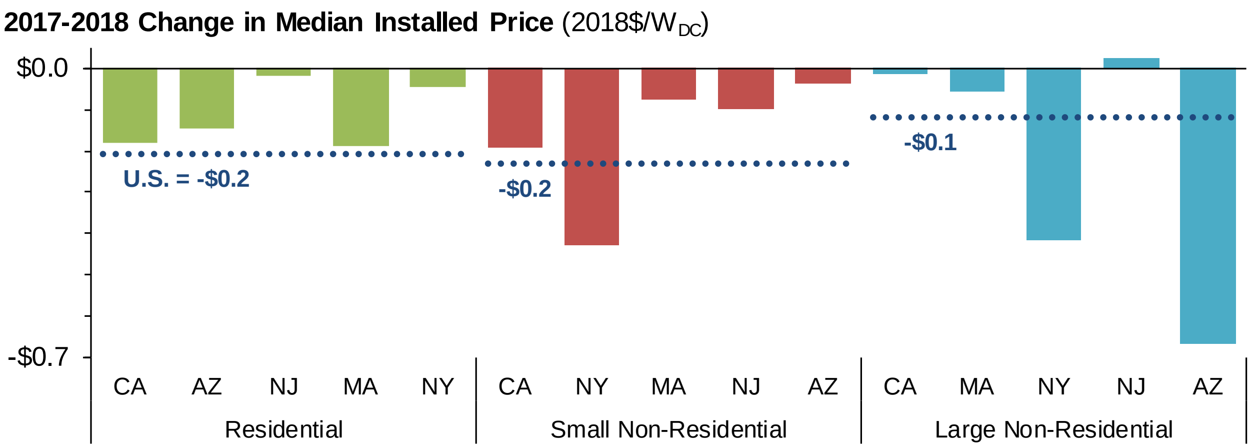


Figure 15. Annual Change in Median Installed Price for Largest State Markets in the Data Sample

Installed Price Trends: Preliminary Data for 2019

Preliminary data for the first six months of 2019, 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 large non-residential segments. As shown in Figure 16, median installed prices for the first half (H1) of 2019 fell by an additional $0.1/W for both the residential and small non-residential segments, relative to H1 2018, while median prices for small non-residential systems rose slightly. As noted previously, recent price declines in these state have been lower than in other, mostly smaller state-markets, and therefore the trends shown in Figure 16 may understate the drop in national median prices over the first half of 2019.

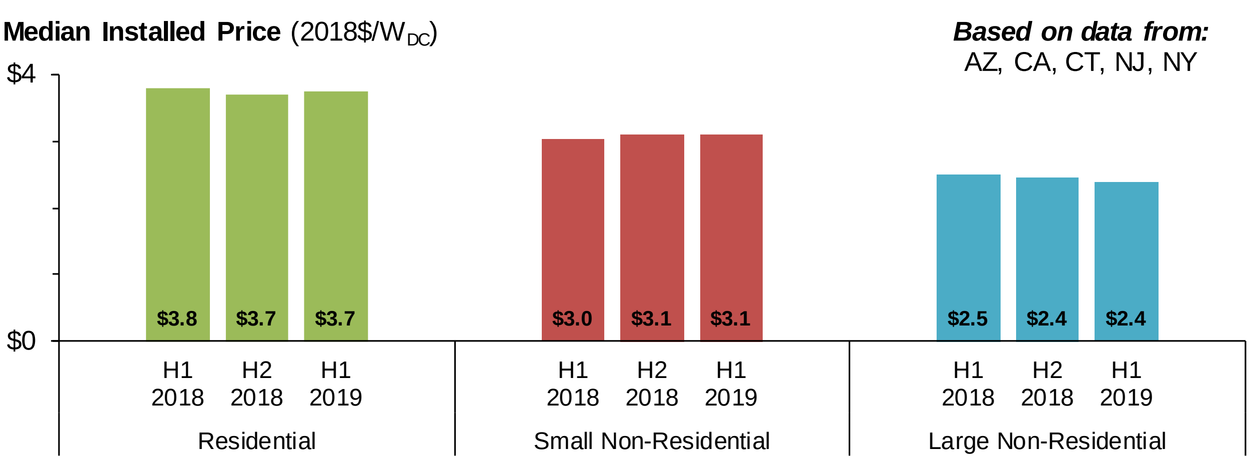


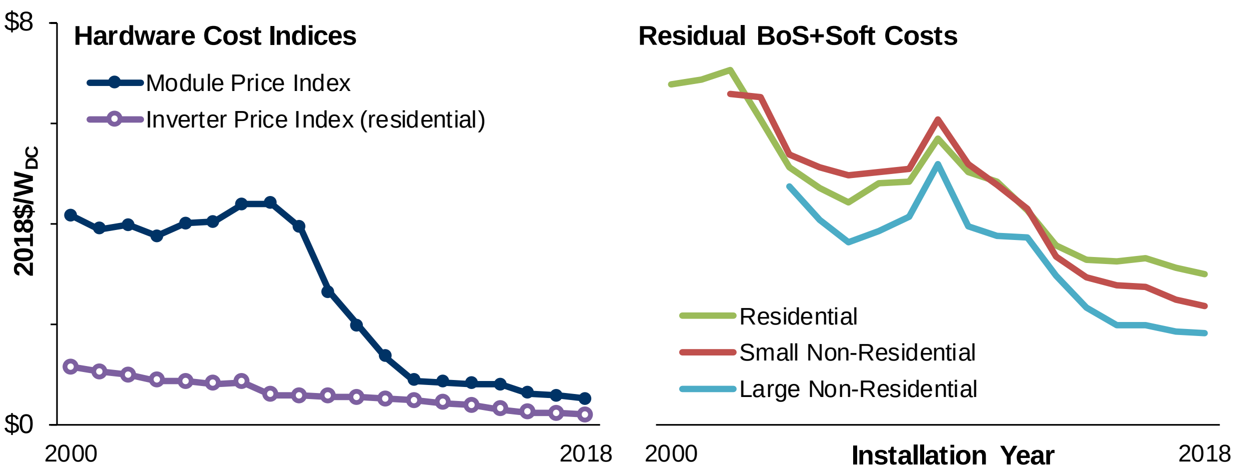
Figure 16. Median Installed Prices for Systems Installed in 2018 and the First Half of 2019

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 over the long term. Based on the indices shown in the left-hand panel of Figure 17, module prices have fallen by roughly $3.6/W since 2000—with most of that drop occurring over the 2008-2012 period—while inverter prices have fallen by roughly $0.9/W. Price reductions for these two primary hardware components equate to roughly 44% and 11% of the long-run decline in median residential system prices, and roughly similar proportions for both small and large non-residential systems.

The remaining long-term drop in installed prices is associated with other balance of systems (BoS) costs, such as racking and wiring, and the wide assortment of "soft" costs, which include customer acquisition, system design, installation labor, permitting and inspection costs, installer margins, and loan-related fees in some cases. While hardware costs are largely global in nature, soft costs can be more directly affected by local market conditions. BoS and soft costs are, together, captured by the set of residual terms shown in the right-hand panel of Figure 17. Those residual BoS+soft costs have declined significantly over time, constituting 45% of the long-term drop in median residential installed prices (and similar percentages for non-residential customers).[9]

Over the more recent term since 2014, following the steep drop in global module prices, installed price declines have continued to be driven by both hardware and soft-cost reductions. Based on the price indices in Figure 17, modules and inverters represent roughly 38% and 28%, respectively, of the decline in median residential system prices since 2014, with the remaining 36% associated with residual BoS and soft costs. For non-residential systems, installed price declines since 2014 have been more heavily driven by BoS and soft-cost reductions, representing roughly 55% of total installed price reductions.



Notes: The Module Price Index is the U.S. module price index published by SPV Market Research (2019). The Inverter Price Index is a weighted average of string inverter and microinverter prices published by Wood Mackenzie and SEIA (2019), based on the mix for each segment, extended backwards in time using inverter costs reported for systems in the LBNL data sample. The Residual term for each customer segment is calculated as the median installed price for that segment minus the Module Price Index and the corresponding Inverter Price Index for that customer segment.

Figure 17. Installed Price, Module Price Index, Inverter Price Index, and Residual Costs over Time

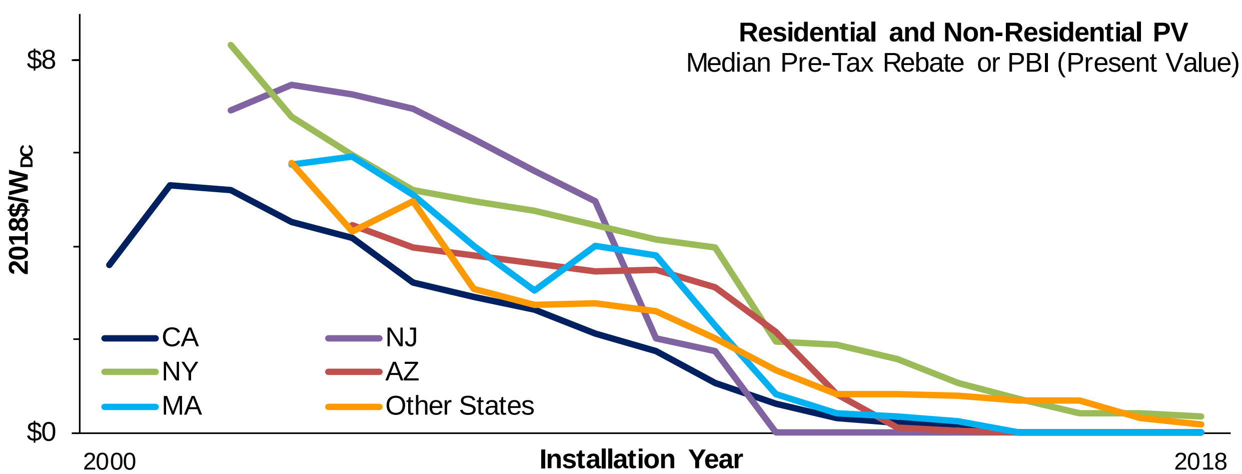
[9] The apparent "spike" in the residual BoS+soft cost term during the middle of the analysis period is a computational artifact associated with the lag between changes in global module prices and in total installed prices.

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, both described previously, are the steady and significant increases over time in both 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 a less-than-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.

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 18 shows how these incentives have declined steadily and significantly over the past decade. At their peak, most programs were providing incentives of \$4-8/W (in real 2018 dollars). Over time, direct rebates and performance-based incentives have been largely phased-out in 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 4). At the same time, incentive declines may have also helped to motivate further cost and price reductions, as installers were forced to cut costs to remain competitive. The steady 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.

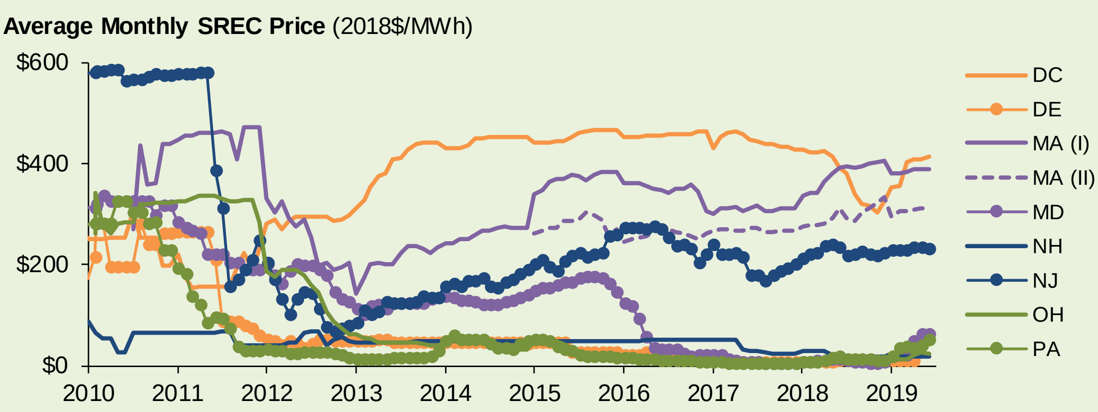
Figure 18. State/Utility Rebates and PBIs over Time

From the perspective of the customer-economics of PV, however, one thing is clear: the steady reduction in cash incentives has offset reductions in (pre-incentive) installed prices to a significant degree. Among the five state markets profiled in Figure 18, the decline in incentives from each market's respective peak is equivalent to anywhere from 66% 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 federal ITC for residential solar rose in 2009, and SREC markets emerged in many states; new financing structures have also 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 4. SREC Price Trends

Fifteen states plus the District of Columbia have 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 19). 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 (DC, MA, and NJ) have risen or stabilized, easing 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.



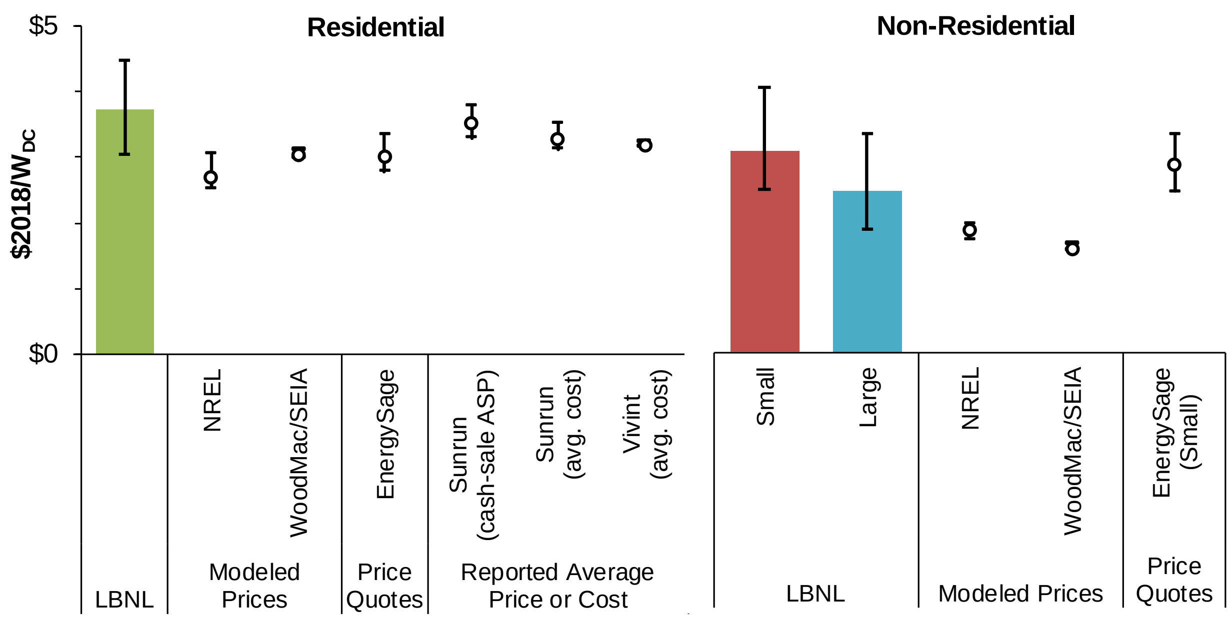
Notes: Data sourced primarily from Marex-Spectron. Plotted values represent SREC prices for the current or nearest future compliance year traded in each month. MA (I) and MA (II) refer to prices in the SREC I and SREC II programs, respectively.

Figure 19. Solar Renewable Energy Certificate Spot-Market Prices

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 20 compares median installed prices of 2018 systems from the LBNL data sample 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.

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 shown in the figure, for reasons such as those noted in Text Box 5. The other benchmarks are, instead, generally more closely aligned with 20th percentile pricing levels in the LBNL dataset, and may be representative of "best in class" or "turnkey" systems and/or relatively low cost markets. Later sections of this report further explore the wide spread in the LBNL data and show how prices observed in many contexts—e.g., for certain states, installers, and module technologies—are substantially below the national median, and may correspond more closely to the other pricing benchmarks in Figure 20.



*Notes: **LBNL** data are the median and 20th and 80th percentile values among projects installed in 2018. **NREL** data represent modeled turnkey costs in Q1 2018 for a 6.2 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. 2018). **WoodMac/SEIA** data are modeled turnkey prices for 2018 (the average, min, and max of quarterly estimates); 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 (Wood MacKenzie and SEIA 2019). **EnergySage** data are the median and 20th and 80th percentile range among price quotes issued in 2018, calculated by Berkeley Lab from data provided by EnergySage; quote data for non-residential systems are predominantly from small (<100 kW) projects. **Sunrun** and **Vivint** data are the companies' reported average selling prices or ASP (Sunrun only) or costs in 2018 (the average, min, and max of quarterly values).*

Figure 20. Comparison to Other Installed Price or Cost Benchmarks

Text Box 5. Reasons for Differences between LBNL National Median Prices and Other Benchmarks

Variation across the benchmarks shown in Figure 20 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 20 are based on systems installed in 2018. A number of the other benchmarks cited in the figure are instead based on price quotes issued in 2018, 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 cost data 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. Notably, though, Sunrun also reports average selling prices (ASPs) for its cash-sale systems, which are quite similar to the median prices drawn from the LBNL dataset.
- *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 20 are based on standard, turnkey project designs. The LBNL data instead reflect the specific sizes and components of projects in the sample.
- *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, particularly given the focus here on host-owned systems. Other benchmarks in Figure 20 may instead be more representative of large installers.

5. Variation in Installed Prices

While the preceding section focused on temporal trends in median installed prices, this section instead focuses on *variability* in installed prices observed among projects in the dataset—again, focusing on host-owned residential and non-residential systems. The section begins by describing the overall distribution in installed prices across the dataset as a whole. It then explores potential sources of this pricing variation, through a basic descriptive analysis comparing median prices for different groups of systems. This includes pricing differences based on: system size, state, installer, module efficiency, inverter technology, residential new construction vs. retrofit, tax-exempt vs. commercial site hosts, and mounting configuration. The descriptive analysis in this section is supplemented by a new multi-variate regression analysis in Appendix C, which seeks to further isolate the effects of individual pricing drivers.

Overall Installed Price Variability

The installed price data exhibits considerable spread, as evident in Figure 21, and that spread has largely persisted over time (as evident by referring back to Figure 13, presented earlier in the report). Among residential systems installed in 2018, roughly 20% were priced below \$3.1/W (the 20^{th} percentile value), while 20% were above \$4.5/W (the 80^{th} percentile). Non-residential systems exhibit similar spreads, with 20^{th}-to-80^{th} percentile bands of \$2.4/W to \$4.0/W for small non-residential systems and \$1.8/W to \$3.3/W for large non-residential systems. As shown, these distributions have relatively long right-hand tails, skewing the percentile values towards right. Thus, what might be deemed “typical” system pricing is closer to the 20^{th} percentile level than to the 80^{th}. Prices at the far right-hand end of these distributions may, in some cases, include additional items beyond the PV installation (e.g., re-roofing costs), but these distributions nonetheless illustrate the substantial variability in PV system pricing currently observed in the market.

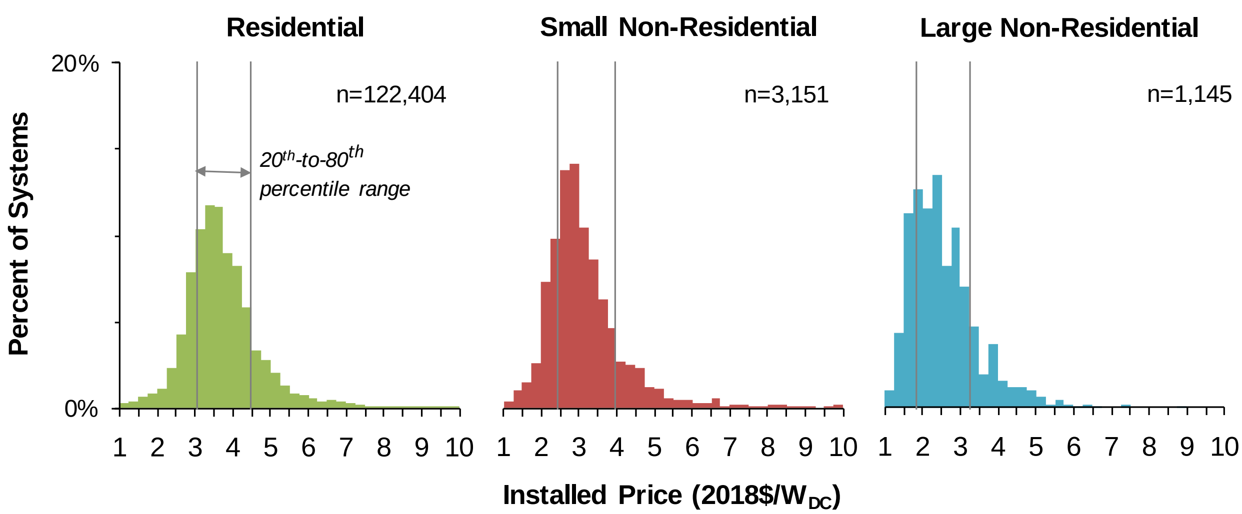


Figure 21. Installed Price Distributions for Systems Installed in 2018

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 distributed solar market, policy, and regulatory environment. The remainder of this report explores many of these potential drivers. This discussion adds to the growing body of literature on distributed PV pricing, much of which has drawn on the same data as described in this report (see, for example, Burkardt et al. 2014; Dong and Wiser 2013; Dong et al. 2014; Gillingham et al. 2014; Nemet et al. 2016a, 2016b, and 2017; and O'Shaughnessy 2018). For a broad review of the literature on PV pricing drivers, see O'Shaughnessy et al. 2019.

Pricing 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. These scale economies are evident when comparing between residential and non-residential systems. As shown in Figure 22 and Figure 23, they also arise within each customer segment, and, indeed, are one of the largest single drivers for observed pricing variability.

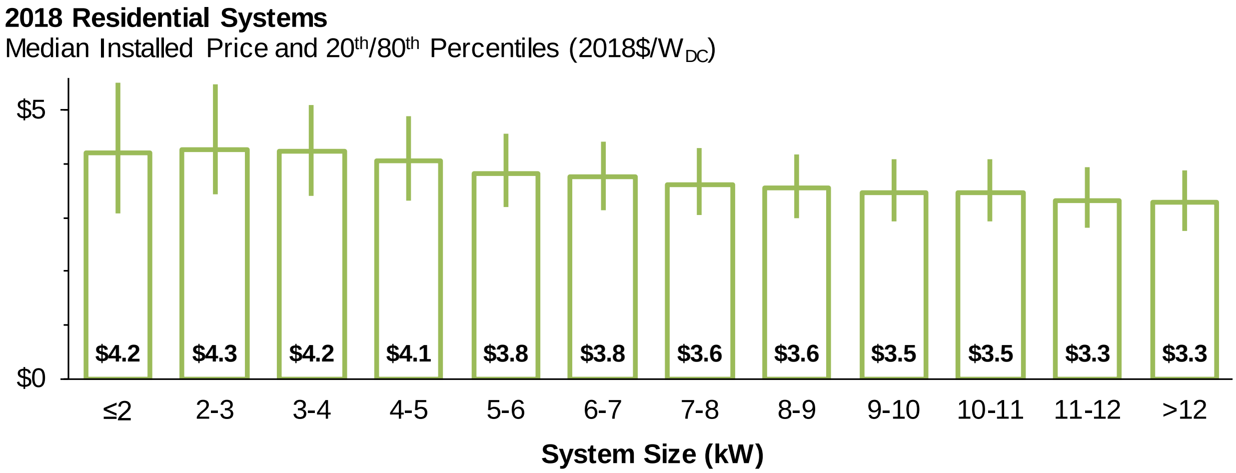
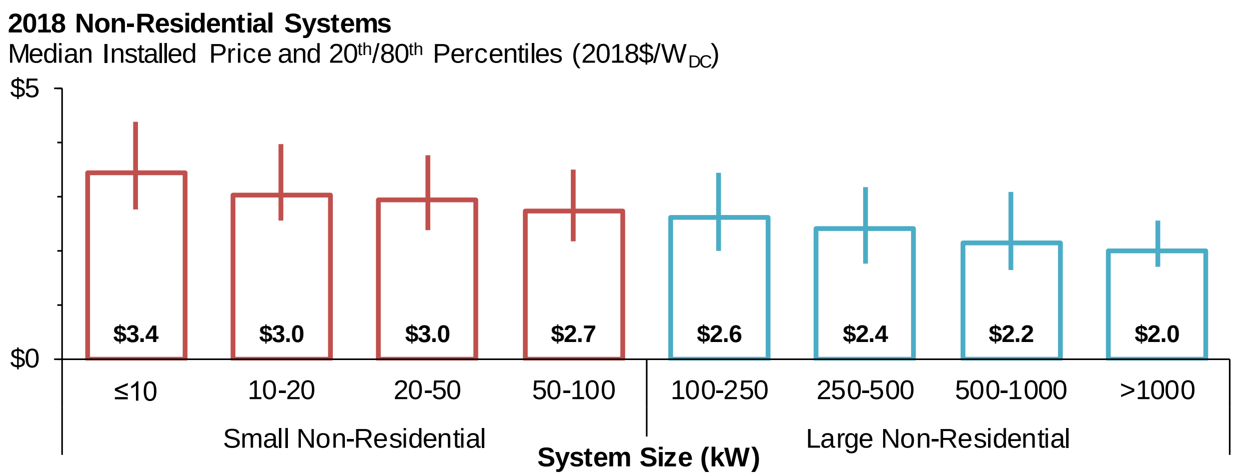


Figure 22. Installed Price of 2018 Residential Systems by Size



* *See Text Box 2 for details on the upper bound size of non-residential systems, as defined for this report.*

Figure 23. Installed Price of 2018 Non-Residential Systems by Size

Among residential systems installed in 2018, median prices at the far upper end of the size spectrum were roughly $1.0/W lower than at the lower end. Across the narrower range between the 20th and 80th percentile system sizes (4.2 kW and 9.6 kW), median installed prices differed by

$0.6/W. As evident in the figure, price declines taper off with increasing size, consistent with diminishing returns to scale. The regression analysis presented in Appendix C shows the same general pattern, but somewhat larger overall effects.

Economies of scale among non-residential systems are even more pronounced, given the order-of-magnitude larger range in system sizes. Among systems installed in 2018, median installed prices were $1.4/W lower for the largest class of non-residential systems >1,000 kW in size than for the smallest systems. Non-residential systems also exhibit diminishing returns to scale, though this is obscured in the figure, as the bin intervals become progressively wider at larger system sizes. Note again that ground-mounted non-residential systems in this report are capped at 5 MW_{AC}; larger systems are considered utility-scale and exhibit even lower prices (see Bolinger and Seel 2019).

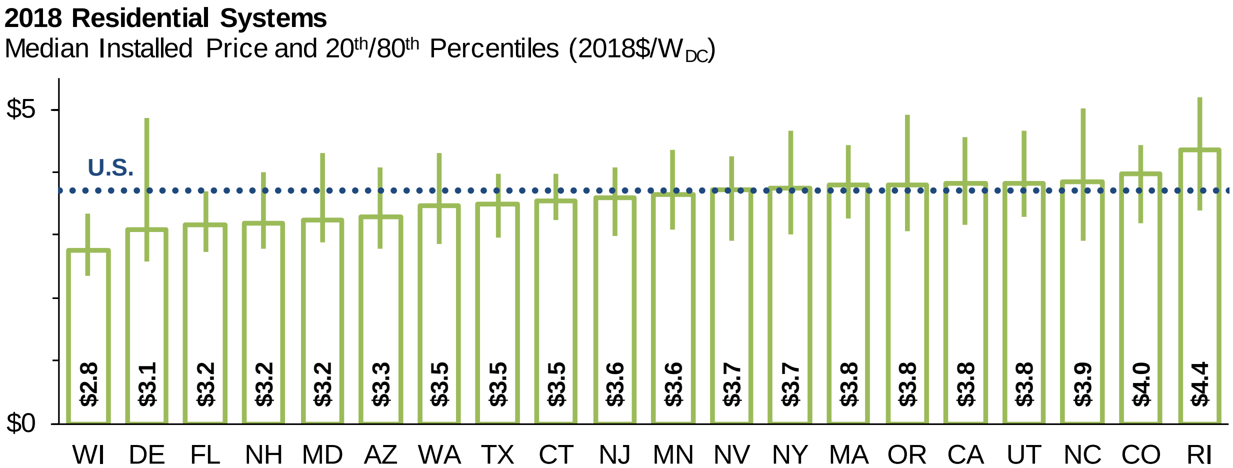
Pricing across States

The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Focusing on state-level differences, Figure 24 and Figure 25 compare median prices of residential and non-residential systems installed in 2018. Among residential systems, median prices ranged from a low of $2.8/W in WI to a high of $4.4/W in RI. Pricing for small non-residential systems varied across a similarly wide range, from $2.5/W in WA to $3.7/W in MN, while cross-state differences among large non-residential systems were somewhat smaller, ranging from a median of $1.7/W in CO to $2.5/W in CA. Some of these differences may simply be the result of peculiarities in the underlying data—particularly for states with relatively small sample sizes—but they also reflect other, more fundamental drivers.

State-level pricing differences stem, in part, from underlying market conditions, such as market size and competition. In particular, one might anticipate that larger state markets (in terms of number of installations) would tend to have lower prices. In fact, the descriptive results presented here would seem to suggest the exact opposite, as some of the largest state markets (CA, MA, and NY) are all relatively high-priced. The regression analysis in Appendix C, however, finds that larger markets are generally associated with lower prices; other confounding differences simply drown out those impacts in the figures below. Prices can also vary across markets based on competitive factors, as may be measured in terms of the number of installers operating in a market and/or the level of concentration among a small set of installers, as the later regression analysis and other studies (Gillingham et al. 2014, O'Shaughnessy 2019) show.

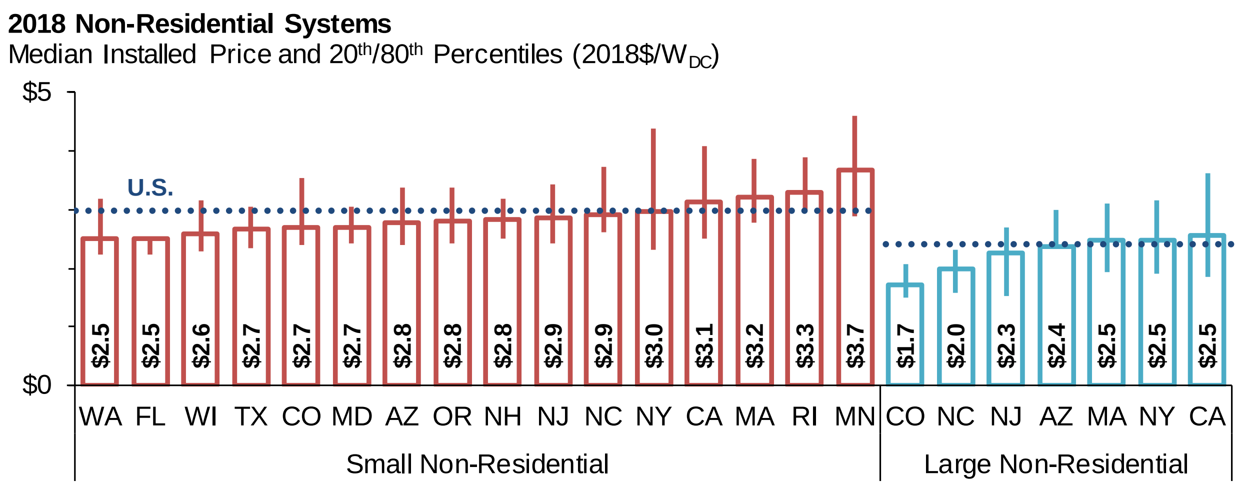
Policy differences across states can also impact installed prices. Many studies, for example, have evaluated the impacts of rate design and incentive levels on (pre-incentive) PV prices. Collectively, these studies have come to varying conclusions—in some cases finding significant effects (Gillingham et al. 2014, Borenstein 2017) and in others not (Dong et al. 2014). Local permitting, interconnection, and other regulatory processes can also impact PV pricing (Dong and Wiser 2013, Burkhardt et al. 2014). Those processes are typically defined at the local municipal or county level, but in aggregate, may impact state-level pricing. Sales taxes also vary across states, and many states exempt PV from sales tax, leading to as much as a $0.3/W difference in installed prices across states. Other unique state-level policy factors may also impact costs; 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.

Finally, state-level pricing differences also reflect systemic differences in PV system design, associated with climate or characteristics of the local building stock or building standards. For example, residential system sizes vary from a median of 5.3 kW in CO to 9.3 kW in WA, perhaps partly due to differences in solar irradiance levels. Racking costs can vary across states, depending on typical roofing materials and on wind and snow loading. In addition, many of the higher-priced states also have a particularly high share of systems with premium efficiency (>20%) modules, and as shown later, those systems tend to be considerably higher priced than others.



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

Figure 24. Installed Price of 2018 Residential PV Systems by State



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

Figure 25. Installed Price of 2018 Non-Residential PV Systems by State

Pricing across Installers

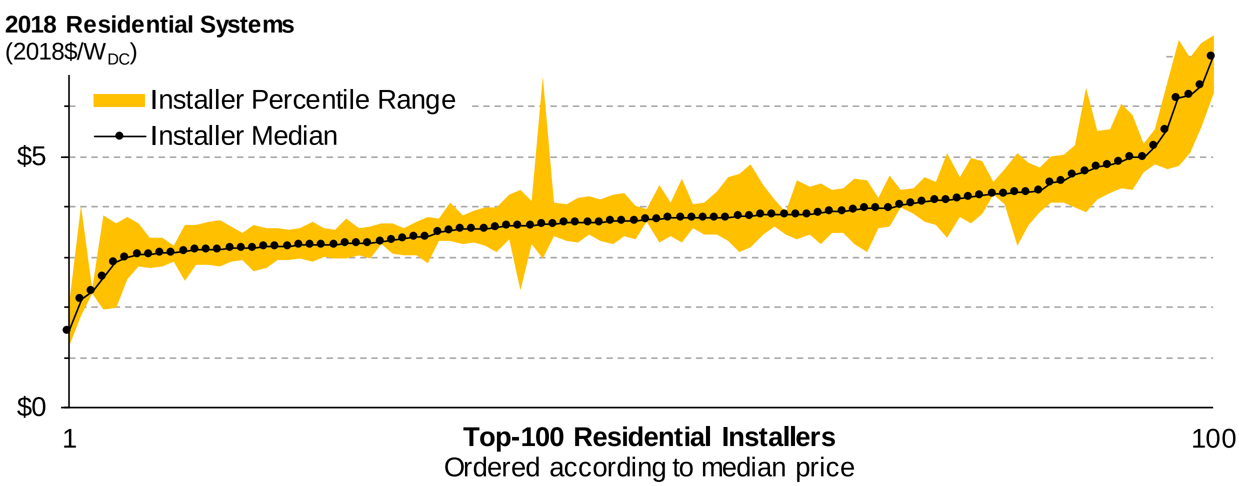
The U.S. PV market is serviced by a large number of installers of varying size, experience, and business models. Although the residential market, in particular, has historically been dominated by several large national companies, a great many regional firms and small local installers operate throughout the country. In total, the data sample assembled for this report includes roughly 4,000 companies that installed PV systems in 2018, primarily in the residential sector.[10] Of those, roughly

[10] The total number of firms in the dataset is likely inflated to some extent due to incomplete standardization of installer names.

two-thirds installed fewer than 10 systems over the course of the year, and just over 250 companies had more than 100 installs.

Pricing can and does vary considerably across individual installers, as shown in Figure 26, which focuses on the 100 residential installers with the most systems installed last year. These companies each installed between roughly 200 and 4500 host-owned systems last year, and collectively represent 45% of all systems in the installed-price dataset. Ignoring the tails of this curve, median prices across these installers ranged from roughly \$3.0/W to \$5.0/W, with most below \$4.0/W.[11]

To some extent, these pricing differences simply reflect each company's unique pricing strategy and the margin it is willing to accept. One might also expect pricing to vary according to firm size and experience. Though the later regression analysis shows no discernible effect related to installer experience, other studies have found that installers reduce costs as they grow, consistent with the broader literature on "learning by doing" (Gillingham et al. 2014, O'Shaughnessy 2018). Installers may also vary in skill level and licensing, which can 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. Lastly, some installer-level pricing differences may simply reflect attributes of the local markets they serve, which vary in terms of competition, permitting and interconnection processes, and the various other factors identified within the preceding discussion of state-level pricing differences.



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 26. Installer Pricing for 2018 Residential Systems

Pricing by Module Efficiency

Module efficiency can impact installed prices in countervailing ways. On the one hand, higher efficiency modules can help to reduce BoS costs, by shrinking the footprint of the system. At the same time, however, higher-efficiency modules can also be more expensive. For example, spot market prices reported through PVInsights in August 2019 were roughly \$0.05/W higher for mono-crystalline PERC modules versus standard poly-crystalline modules, while prices reported through

[11] The extremes at either end of the curve quite likely represent reporting anomalies by individual installers. For example, the exceptionally high-priced installers may be bundling PV with other measures and reporting the total installed price for all measures combined.

pvXchange were \$0.06/W higher for "high efficiency" than for "mainstream" modules (PVInsights 2019, pvXchange 2019). These differences are but a fraction of the much greater pricing variation among individual module brands and models. For example, among just six major brands reported on PVInsights, average weekly retail prices varied over a range of more than \$0.46/W from the lowest to the highest-price manufacturer—reflecting differences in not just efficiency, but other performance attributes, warranty terms, and aesthetics as well.

To illustrate the net impact on system-level prices, Figure 27 compares installed prices based on the efficiency of the modules used in each system. Differences in module efficiencies up to 20% appear to have minimal impact on net system-level pricing. Above 20%, however, system prices were markedly higher. Within the residential class, systems with module efficiencies >20% had a median price almost \$0.4/W higher than those with efficiencies below that threshold. That pricing premium was even greater in the non-residential sector (\$0.7/W for small non-residential and \$0.9/W for large non-residential). These system-level pricing differences partly reflect underlying module pricing, as almost all of the systems in the dataset with premium efficiency modules use either SunPower or LG models with n-type mono-crystalline cells, which often sell at a substantial premium over standard mono-crystalline modules. In addition, a relatively high proportion of systems with premium efficiency modules also have microinverters, which, as discussed below, are also associated with higher installed prices.

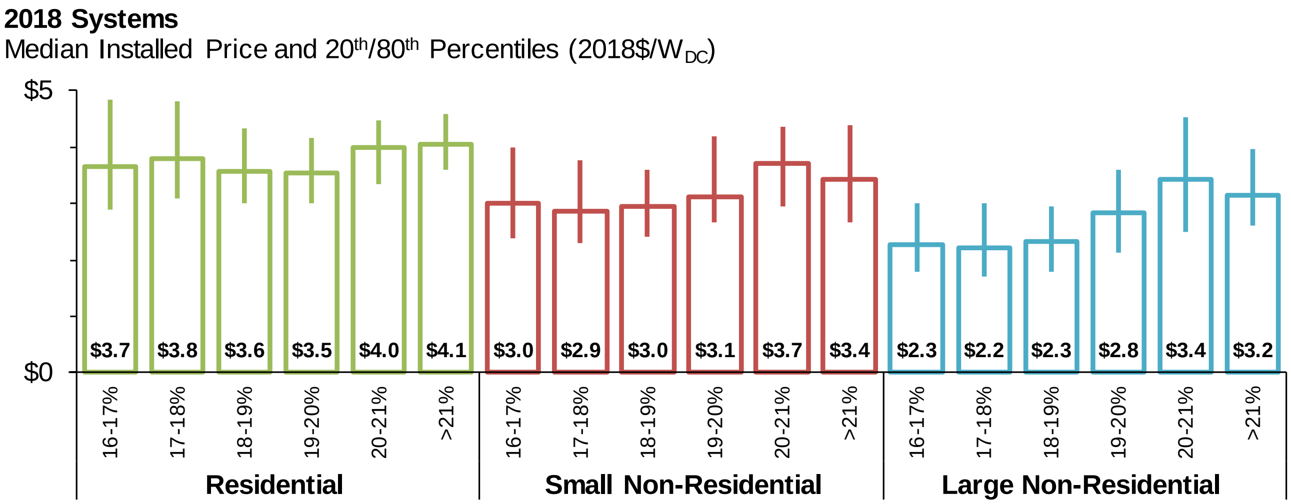


Figure 27. Installed Price Differences Based on Module Efficiency

Pricing by Inverter Type

MLPEs enhance system performance, but entail some higher up-front cost relative to standard string inverters. In 2018, prices for microinverters averaged \$0.2-0.3/W higher than for standard string inverters, while DC optimizers added roughly \$0.1/W (Fu et al. 2019, Wood MacKenzie and SEIA 2019). MLPEs may also affect installed prices indirectly, via impacts on installation labor, system design, and electrical balance-of-system costs.

As shown in Figure 28, installed-price differences between systems with and without MLPEs are relatively small and have not been altogether consistent over time. That said, installed-price difference in 2018 more-or-less coincide with cost premiums for each type of MLPE, noted above. Among residential systems, median installed prices for systems with microinverters were roughly \$0.3/W higher, while those with DC optimizers were roughly \$0.1/W higher, compared to systems with no MLPEs. Non-residential systems exhibit similar installed-price differences across inverter technologies. These results are generally consistent with the regression results presented later, though those show a slightly smaller premium for system with microinverters, and a somewhat larger one for systems with DC optimizers. These empirically estimated effects can also be compared to modeled PV cost benchmarks developed by Fu et al. (2018), which estimates roughly a $0.50/W premium for systems with microinverters—in large measure due to higher electrical BoS and installation labor costs—and a $0.05/W premium for systems with DC optimizers.

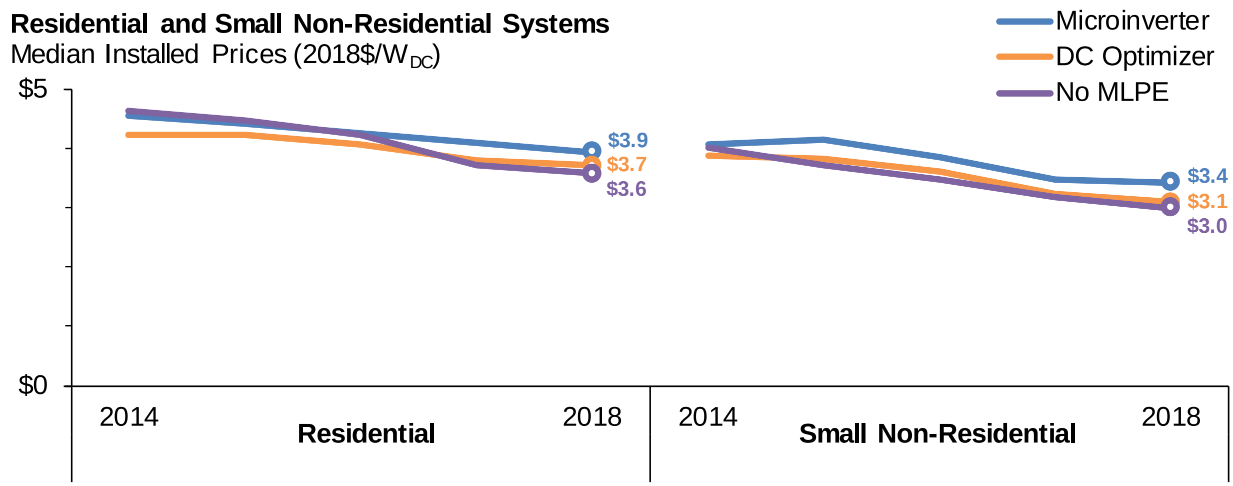


Figure 28. Installed Price Differences between Systems with and without MLPEs

Pricing for 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. Within the data assembled for this report, most of the residential new construction systems are in California, and have been funded through the state's *New Solar Homes Partnership* (NSHP) program. Those systems represent roughly 3% of all residential systems installed in California's investor-owned utilities' service territories in 2018. Going forward, that percentage is likely to rise, as a result of the state's solar home mandate that all new residential new construction starting in 2020 must include PV (subject to certain limitations).

Solar installed in new construction can benefit from economies of both scale and scope, potentially reducing its cost relative to retrofits on existing homes. Economies of scale occur specifically in the case of large new housing developments, where equipment and services can be procured in bulk, and system design and installation can be standardized and coordinated across large numbers of homes in close proximity. Customer acquisition costs for these systems may also be minimal, particularly if solar is installed as a standard feature on all homes in the developments. Economies of scope, instead, occur when particular labor or materials costs can be shared between PV installations and other elements of home construction, such as roofing and electrical work (Ardani et al. 2018).

In contrast, several other factors can lead to higher costs and prices for systems installed in new construction. First, PV systems on new homes tend to be relatively small. Within California's NSHP program, for example, the median system size in 2018 was just 3.0 kW, compared to 6.1 kW for retrofit systems in the state. New construction systems also disproportionately use premium efficiency modules (83%, compared to 25% for retrofits) and microinverters (98%, compared to 41% for retrofits), which, as the previous sections have shown, tends to increase installed prices.

On net, installed prices for new construction systems in California were higher in 2018 than for retrofit systems, as shown in Figure 29. This is true even when comparing only among 2-5 kW systems with premium efficiency modules and microinverters. These counter-intuitive results are driven by a single installer, representing more than 80% of the new construction systems, that reports prices of roughly $4.5/W for most of its systems.[12] In contrast, the regression analysis presented later, which controls for a wider set of confounding variables, finds that installed prices for new construction systems were, in fact, *lower* than for retrofits, by roughly $0.5/W on average.

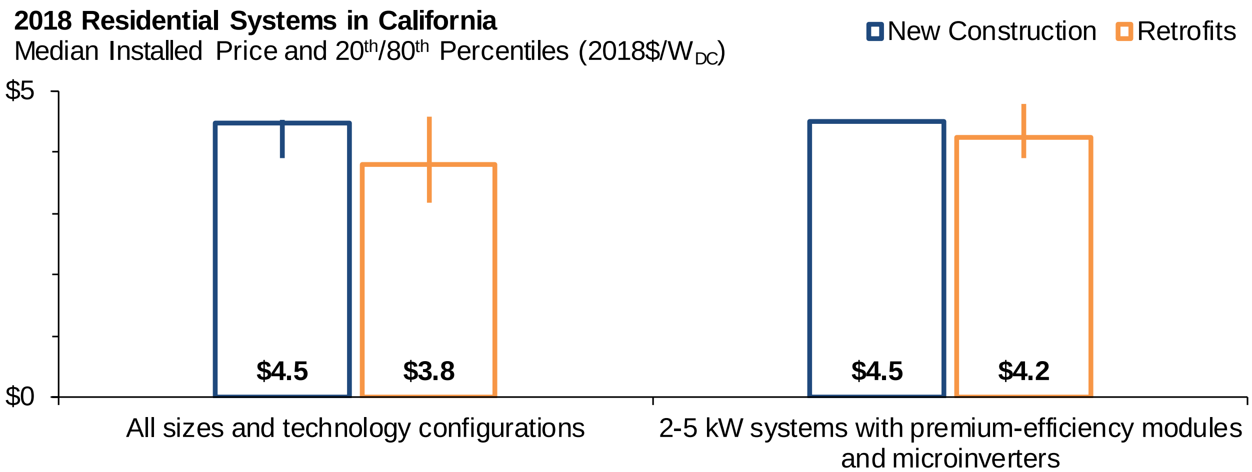


Figure 29. Installed Price of Residential Retrofit vs. New Construction in California

Pricing for Tax-Exempt vs. For-Profit Commercial Sites

As noted earlier, roughly 20% of the 2018 non-residential systems in the full data sample are at tax-exempt customer sites (i.e., schools, government buildings, and non-profit organizations, such as churches). That percentage is slightly lower in the installed-price sample (16%), given the exclusion of TPO systems, which are more prevalent among tax-exempt customers.

As shown in Figure 30, systems installed at tax-exempt customer sites are generally higher priced than those at commercial sites. These differences are consistent over time and are most pronounced among large non-residential systems. 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. Within the large non-residential segment, systems at tax-exempt sites also tend to be somewhat smaller than those at commercial sites; in 2018, for example, the former averaged roughly 1,100 kW in size while the latter averaged 1,800 kW.

[12] Two other issues with the installed-price data for new construction systems are also 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. 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.

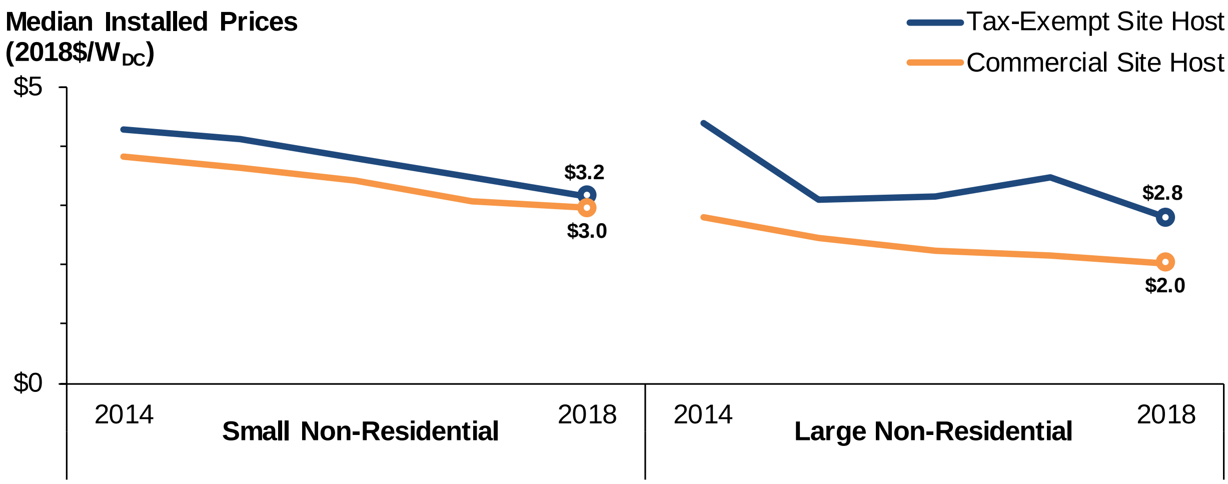
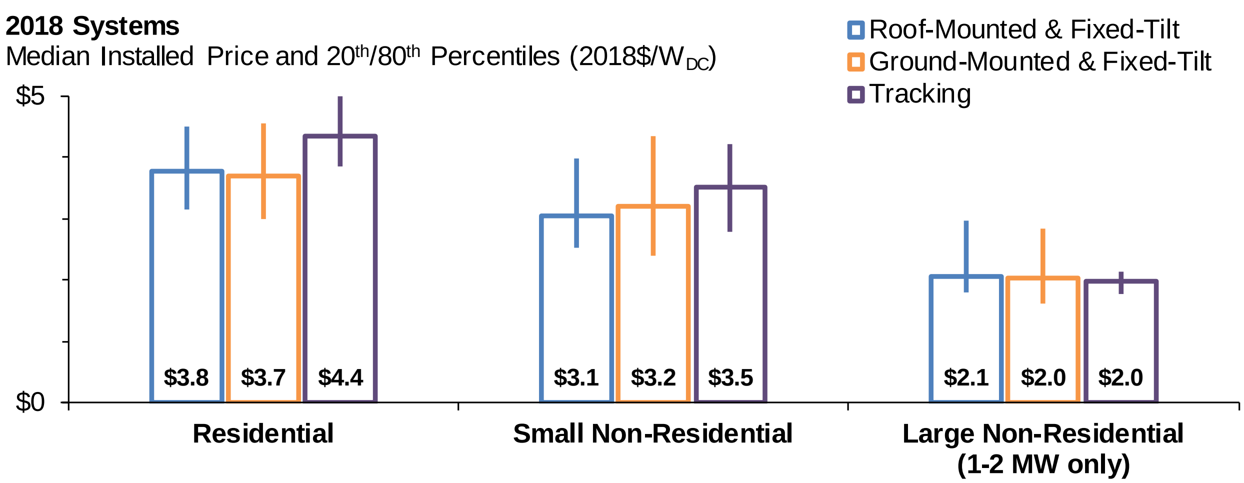


Figure 30. Installed Prices for Tax-Exempt vs. Commercial Site Hosts over Time

Pricing by Mounting Configuration

As described earlier in the report, the data sample consists mostly of roof-mounted systems, but some portion are ground-mounted, and a small fraction of those use tracking. These variations in mounting configurations may also lead to differences in up-front installed prices. This is most obvious in the case of tracking equipment, which represents an incremental hardware cost. Ground-mounting may also involve some additional up-front costs related to trenching and foundation-work, not present in the case of roof-mounted systems. To varying degrees, the additional up-front costs associated with both tracking and ground-mounting may be offset by performance gains (i.e., higher capacity factors) and, in the case of ground-mounting compared to roof-mounted systems, potentially lower ongoing maintenance costs.



Notes: The comparison among large non-residential systems focuses specifically on systems in the 1-2 MW size range, in order to maintain comparability across mounting configurations in this customer segment.

Figure 31. Installed Prices by Mounting Configuration

Focusing on just the up-front cost differences, Figure 31 compares installed prices across mounting configurations, for both residential and non-residential systems installed in 2018. The figure shows no clear or consistent difference between fixed-tilt ground-mounted and roof-mounted systems, though the regression analysis in Appendix C does find a fairly strong and statistically significant effect within the residential segment. The figure does show a distinct premium for systems with tracking equipment, at least within the residential and small non-residential segments, as one would anticipate. The lack of any apparent effect among large non-residential systems is likely just an artifact of the small underlying sample sizes and the presence of other, more significant confounding factors. As one point of reference, bottom-up engineering cost models of utility-scale PV generally suggest about a $0.1/W premium for systems with tracking (Fu et al. 2018, Wood Mackenzie and SEIA 2019).

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 distributed PV systems 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, but gradual, reductions in both hardware and soft costs. Widespread variability in installed pricing has also persisted over time, which may be indicative of the potential for further installed price declines.

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Appendix A: Additional Details on the Data Sample

Table A-1. Sample Summary by Data Provider

State	Data Provider	2018 Systems (No. of Systems)		All Years (No. of Systems)	
		Full Sample	Installed-Price Sample	Full Sample	Installed-Price Sample
AR	Arkansas Energy Office	0	0	105	97
AZ	Ajo Improvement Company	0	0	3	3
	Arizona Public Service	15,104	4,584	90,110	20,456
	Duncan Valley Electric Coop.	0	0	7	1
	Mohave Electric Coop.	36	36	645	643
	Morenci Water & Electric	0	0	3	3
	Navopache Electric Coop.	0	0	141	128
	Salt River Project	1,968	1,554	19,496	8,319
	Sulpher Springs Valley Electric Coop.	0	0	1,471	1,169
	Trico Electric Coop.	47	43	2,001	1,060
	Tucson Electric Power	4,533	3,671	21,656	11,738
	UniSource Electric Services	498	482	3,469	2,688
CA	California Center for Sustainable Energy (Bear Valley Electric)	0	0	123	25
	California Center for Sustainable Energy (Pacific Power)	0	0	205	130
	CPUC and CEC (Currently Interconnected Dataset, CSI, NSHP, ERP, SGIP) [a]	128,648	68,195	834,429	341,823
	City of Palo Alto Utilities	0	0	940	547
	Imperial Irrigation District	0	0	4,162	1,450
	Los Angeles Dept. of Water & Power	3,988	2,733	34,963	13,800
	Sacramento Municipal Utility District	4,611	0	24,368	4,171
CO	Xcel Energy	6,222	4,797	46,965	23,677
CT	Clean Energy Finance and Investment Authority	4,665	1,077	29,220	8,553
	Public Utilities Regulatory Authority	193	0	796	0
DC	Washington D.C. Public Service Commission	774	0	4,252	0
DE	Department of Natural Resources and Environmental Control	154	153	2,795	2,567
FL	Florida Energy & Climate Commission[b]	0	0	1,256	1,201
	Gainesville Regional Utilities[b]	108	105	679	658

	Orlando Utilities Commission[b]	458	356	1,200	1,009
IL	Dept. Commerce and Economic Opportunity	0	0	1,463	1,386
MA	Massachusetts Clean Energy Center and Dept. of Energy Resources[c]	10,805	5,751	90,037	39,284
MD	Maryland Energy Administration	2,435	2,416	13,984	11,034
ME	Efficiency Maine	0	0	531	526
MN	Dept. of Commerce	185	183	1,876	1,674
	Xcel Energy	659	642	2,636	2,287
MO	Ameren	76	0	4,012	0
	Kansas City Power and Light	283	0	3,760	0
NC	NC Sustainable Energy Association	2,528	2,449	9,957	9,336
NH	New Hampshire Public Utilities Commission	1,238	888	6,543	5,382
NJ	New Jersey Board of Public Utilities	16,263	4,240	104,650	24,148
NM	Energy, Minerals & Natural Resources Dept.	0	0	7,679	7,282
	Public Service Company of New Mexico	2,876	0	10,436	0
NV	NVEnergy	8,859	3,160	32,580	7,046
NY	New York State Energy Research and Development Authority	10,686	5,442	89,016	42,741
OH	Ohio Public Utilties Commission	67	0	2,666	0
OR	Energy Trust of Oregon[d]	1,778	1,430	14,384	9,643
	Oregon Dept. of Energy[d]	1	1	4,133	3,349
	Pacific Power	1	1	832	709
PA	Dept. Community and Economic Development	0	0	55	51
	Dept. of Environmental Protection	0	0	7,078	7,039
	Sustainable Development Fund	0	0	201	200
RI	National Grid & Rhode Island Commerce Commission	1,728	1,132	5,802	3,819
TX	Austin Energy	1,067	951	7,379	7,142
	CPS Energy	3,077	3,051	13,761	13,695
	Clean Energy Associates (El Paso Electric)	0	0	369	333
	Clean Energy Associates (Entergy)	0	0	57	55
	Clean Energy Associates (Oncor Electric Delivery Company)	0	0	908	692
	Clean Energy Associates (Sharyland Utilities)	0	0	6	6
	Clean Energy Associates (Southwestern Electric Power Company)	0	0	39	39
	Clean Energy Associates (Texas Central Company)	36	36	245	241
	Clean Energy Associates (Texas New Mexico Power Company)	0	0	23	21
	Clean Energy Associates (Texas North Company)	30	30	125	122

UT	Office of Energy Development	1,282	1,258	21,052	20,751
VT	Vermont Energy Investment Corporation & Energy Action Network	2,134	0	12,483	3,453
WA	Washington State University & Puget Sound Energy	5,134	5,010	12,231	7,784
WI	Focus on Energy	844	843	4,039	4,001
Total		**246,079**	**126,700**	**1,612,488**	**681,187**

(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.

Appendix B: Data Cleaning 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 2018 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2018 dollars (2018$). Data provided by PV program administrators in nominal dollars were converted to 2018$ 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. Of particular note, that latter procedure was applied to all systems in the CPUC's Currently Interconnected Dataset, as the DC system sizes reported in that dataset were determined to generally not reflect STC ratings (but, instead, may reflect DC output under PV-USA test conditions, which differ from STC). Where module manufacturer or quantity data were unavailable, utility-specific adjustment factors were applied to the reported DC ratings.

Identification and Treatment of Duplicate Systems: For a number of states (California, Florida, Massachusetts, Oregon, Rhode Island, and Vermont), data provided by multiple different entities contain overlapping sets of systems. In addition, data provided by some entities includes multiple records for the same address—for example, where individual arrays or project phases are each submitted under a separate application. In order to avoid double-counting, duplicate observations were merged or eliminated, and multi-phase projects were consolidated. These instances were identified using, wherever possible, a common ID number across datasets or customer street address. In cases where neither of those pieces of information were available, more-aggressive measures were taken to identify and eliminate duplicates.

California Data Integration: The CPUC's Currently Interconnected Dataset (CID) was used as the base dataset for California's investor-owned utilities, and additional data for those systems were incorporated from the various incentive program datasets (CSI, NSHP, SGIP, and ERP). Matching systems across datasets was based on a CSI ID numbers, if available; otherwise, street addresses were used. As a general rule, data from the CID were retained as-is, and data from the incentive programs were integrated only in instances where the CID was missing data within a particular field or simply did not contain that field. There were, however, several key exceptions to that general rule. The first, as noted previously, is that system sizes were re-calculated based on reported module models and quantities. The second exception occurred in the case of multi-phase projects, where the reported installed cost is assumed to reflect only the final project phase, but the system size reflects the sum total across all phases. In those instances, the installed cost is assumed to be unavailable within the CID. Finally, in cases where installed price is unavailable in the CID but available from one of the incentive program datasets, not only is the installed price data integrated from the incentive program (replacing a null value), but the system size and installation date are over-written as well, in order to maintain internal consistency across those three key fields.

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[13] and SolarHub[14]) to characterize the module efficiency, module technology type

[13] http://www.gosolarcalifornia.ca.gov/equipment/
[14] http://www.solarhub.com/

(mono-crystalline vs. poly-crystalline vs. thin-film), and inverter technology (microinverter vs. 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.

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 C: Multi-Variate Regression Analysis of 2018 Residential System Prices

The installed price comparisons across various sub-segments of the PV dataset, presented within the main body of the report, help to reveal some of the key drivers for PV pricing variation. As highlighted within that discussion, however, those comparisons can be obscured or distorted as a result of correlations among various pricing drivers. In order to better control for those correlations, this appendix presents the results of a multi-variate regression analysis that accounts for these inter-relationships and more accurately identifies the effects of individual installed-price drivers.

Data Sample and Model Description

We estimate the regression model based on 2018 residential systems from the installed-price dataset, though the full dataset is used to generate some of the variables. Among the 2018 residential systems from the installed-price dataset, systems were dropped from the regression analysis if missing data for any of the regression variables. The resulting data sample used for this regression analysis thus consists of 102,223 host-owned residential systems installed in 2018, across 15 states.

This statistical model is based largely on previous econometric analysis of the *Tracking the Sun* (TTS) dataset (Gillingham et al. 2014; Nemet et al. 2017; O'Shaughnessy 2019). The model can be summarized by the following equation:

$$p = \alpha + system\beta_1 + market\beta_2 + installer\beta_3 + S + Q + \varepsilon_i$$

where:

- p is the system price
- The terms *system*, *market*, and *installer* represent vectors of system-, market, and installer-level variables, respectively; the terms β represent the numeric effects of those variables on prices
- S is a state fixed effect; it measures the average price difference by state after controlling for all the other factors in the model
- Q is a quarterly fixed effect; it measures the average price difference by quarter after controlling for all other factors

Table C-1 identifies the individual regression variables and their sources. This selection of variables is based largely on other TTS-based models (Gillingham et al. 2014, Nemet et al. 2016b, and O'Shaughnessy 2019), and most are present in, or can easily be derived from, the TTS dataset.

HHI: Market concentration is the degree to which market shares are disproportionately held by an industry's large companies. A market where large companies hold a disproportionately high market share is said to be concentrated. The Herfindahl-Hirschman Index (HHI) is the most common metric for market concentration. HHI is equal to the sum of squared market shares over some defined time period. The most concentrated market is one where HHI = 1, which represents a monopoly. HHI approaches zero as market shares become more evenly distributed among a larger number of firms.

Our estimation of HHI follows the methodology developed in O'Shaughnessy (2019). For each system, the market is defined as the set of zip codes that fall within a 20 km radius around that system's zip code. Market shares are estimated for every installer that installed at least one system in that market in the 12-month period preceding the system's installation date. Note that the estimation of market shares is based on the full dataset, including all systems dropped for analysis purposes (e.g., TPO).

Market Size: Market size is equal to the aggregate number of systems installed in the customer's market based on the full dataset. The market is defined under the same approach as described for HHI: the set of zip codes falling within a 20 km radius around the customer's zip code (O'Shaughnessy 2019).

***Installer Experience*:** For a given system *i*, installer experience is equal to the aggregate number of systems installed by the installer associated with system *i* as of the date that system *i* was installed. Consistent with Gillingham et al. (2014), we assume that recent experience is more relevant than past experience and depreciate the experience variable at 20% per quarter.

***Premium Modules*:** The PV module market comprises a broad mix of products with various characteristics. The actual or perceived quality of certain modules may contribute to differences in system prices. Previous studies have used module efficiency as a proxy for module quality (Nemet et al. 2016b, O'Shaughnessy 2019). While module efficiency may indicate module quality, it is unlikely that a linear relationship exists between percentage points of efficiency and perceived or actual quality and their effects on prices. Anecdotal evidence suggests that high-efficiency modules also tend to have other premium characteristics such as longer warranties. As a result, we instead use a dummy variable for "premium" modules, where premium refers to any module with at least 20% efficiency.

Table C-1. Regression Variable Definitions and Sources

Variable	Definition	Source
System		
kW	System capacity in kW	TTS
kW^2	Squared term of system capacity	TTS
Premium modules	Dummy variable indicating whether system uses a premium-efficiency module	TTS
Microinverter	Dummy variable indicating whether system uses a microinverter	TTS
DC optimizer	Dummy variable indicating whether system uses a DC optimizer	TTS
Ground-mounting	Dummy variable indicating a ground-mounted PV system (groundmount=1, rooftop=0)	TTS
New construction	Dummy variable indicating if system was installed during new construction (new construction=1) or as a retrofit installation on an existing home (new construction=0)	TTS
Market		
HHI	Metric of the degree to which market shares are skewed toward larger firms	Calculated
HHI^2	Squared term of HHI	Calculated
Market size	Number of systems installed in the customer's market in 2018	Calculated
Household density	Number of households per square mile in customer's market	U.S. Census
Median income	Median household income in customer's zip code	U.S. Census
Installer		
Installer experience	Cumulative number of systems installed by the installer as a proxy for installer experience, depreciated at 20% per quarter	Calculated

There are two noteworthy limitations of TTS-based regression models, including the model presented in this report. First, the model is limited to observed variables as reported to TTS or derivable from other reliable sources such as U.S. Census data. There are numerous unobserved variables that affect system prices but are excluded from the model, such as rooftop characteristics and home electrical wiring characteristics. Second, the geographic representation of the model is limited to states and utility service territories that report data to TTS. As a result, the results do not necessarily represent price drivers in key markets such as Hawaii that do not report data to TTS.

Results and Discussion

Table C-2 presents the complete regression results, in terms of the coefficient and standard error for each variable. As shown, virtually all variables are significant at the 99% level. In general, these results are consistent with those from previous models in Gillingham et al. (2014) and O'Shaughnessy (2019).

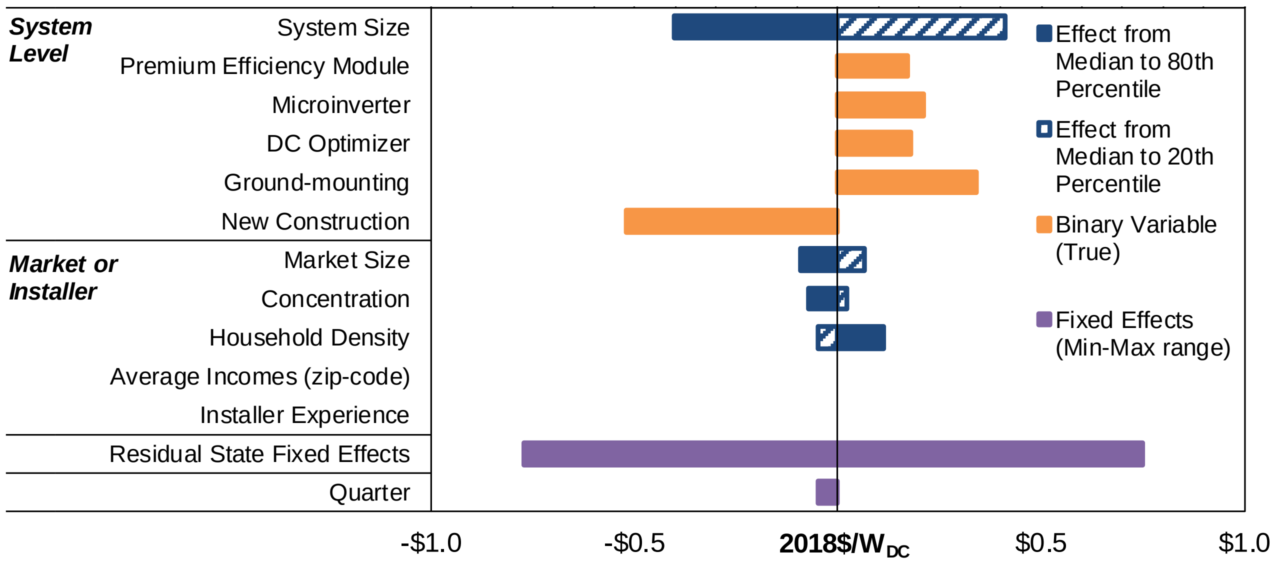
Table C-2. Complete Regression Results

Variable	Coefficient	SE
System size	-0.30*	0.01
System size squared	0.01*	0.00
Premium module	0.17*	0.01
Microinverter	0.21*	0.01
DC optimizer	0.18*	0.01
Groundmount	0.34*	0.02
New Construction	-0.52*	0.03
HHI	-1.44*	0.11
HHI^2	1.15*	0.15
Market size (x1000)	-0.09*	0.00
Installer experience (x1000)	0.00*	0.00
Households per sq. mi (x1000)	0.10*	0.00
Median income (x1000)	0.00*	0.00
AZ	-0.19*	0.01
CT	-0.27*	0.04
FL	-0.46*	0.06
MA	0.08*	0.02
MN	0.66*	0.10
NC	0.50*	0.03
NH	-0.26*	0.04
NJ	-0.18*	0.02
NV	-0.21*	0.02
NY	-0.01	0.02
OR	0.20*	0.03
RI	0.75*	0.04
TX	-0.34*	0.02
WI	-0.77*	0.05
Q2	-0.05*	0.01
Q3	-0.04*	0.01
Q4	-0.05*	0.01
Intercept	5.40*	0.03
R^2	0.15	

* Statistically significant at p<0.01

Figure 32 summarizes the regression results in a form that allows for more direct comparison of the relative contribution of each variable to overall pricing variability. As explained in the notes below the figure, the interpretation for each variable depends on whether it is a continuous variable (such as system size), a binary variable (such as module or inverter type), or a fixed-effects variable (state and quarter).

Focusing first on the system-level variables, the results show quite substantial effects related to system size, with roughly an $0.8/W difference in average prices between the 20th and 80th percentile values for system size. This is slightly larger than the $0.6/W difference in median prices shown in the earlier descriptive analysis. As with the descriptive analysis, the regression analysis also shows clear diminishing returns to scale. For example, based on the regression model coefficients in Table C-2, increasing system size from 5 kW to 10 kW would result in a price reduction of $0.75/W, but increasing system size further from 10 kW to 15 kW would result in just a $0.25/W price reduction.



Notes: For continuous variables, the figure shows the effect on system prices associated with moving from the median to the 20th and 80th percentile values of those variables. For binary variables, the figure shows the effect if that binary variable is true, and for fixed effects variables, the figure shows the range between the minimum and maximum effect of the variables in each set.

Figure 32. Impact of Modeled Variables on Installed Prices

The model results for the various component-related variables are all directionally consistent with the earlier descriptive analysis, though differ in magnitude. In particular, the model results suggest that prices are $0.2/W higher for systems installed with premium modules (vs. the $0.4/W difference from the simple comparison of medians), $0.2/W higher for systems with microinverters (vs. $0.3/W from the descriptive analysis), and $0.2/W higher for systems with DC optimizers (vs. $0.1/W from the descriptive analysis). The descriptive comparisons may be amplified due to strong overlap between systems with premium efficiency modules and microinverters, whereas the econometric model is able to separately parse out the incremental effects of each.

The coefficients for the system variables related to ground-mounting and new construction are both intuitive but contrast with the earlier descriptive comparisons. For ground-mounted systems, the model estimates that prices were $0.3/W higher, on average, than prices for rooftop systems. This effect is plausible, given the additional site preparation costs, but was not apparent earlier in Figure 31, when simply comparing median values between a relatively small number of residential ground-mounted systems and a vastly larger number of rooftop systems.

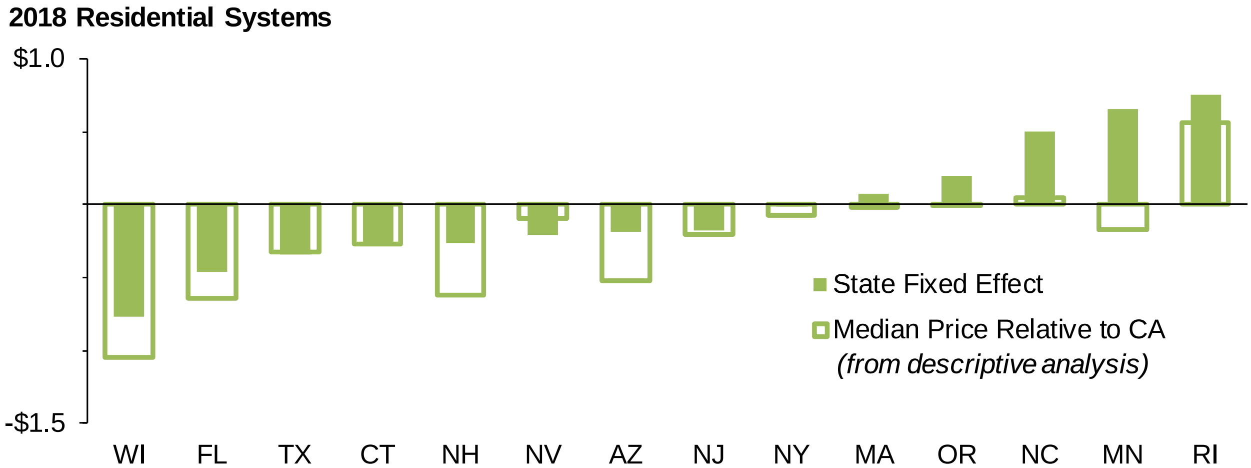
For systems installed in new construction, the econometric model estimates that prices were lower, by $0.5/W on average, compared to retrofit systems. This result is, again, intuitively plausible—given the economies of scope and scale that arise in new construction (Ardani et al. 2018, O'Shaughnessy and Margolis 2018)—but contrasts markedly with the descriptive results. Those earlier results showed that median prices for new construction systems were *higher* than for retrofits, by \$0.7/W overall and by \$0.3/W if comparing only among relatively small systems with premium efficiency modules and microinverters. In this case, the discrepancy between the simple descriptive comparison and the economic model is partly due to the additional controls included in the econometric model, but is also due to peculiar features of the underlying pricing distribution for new construction systems. That distribution has several large spikes, which result in a substantially higher median price (as used in the earlier descriptive analysis) than the average price (as used implicitly in the econometric model).

The results for the various market- and installer-level variables generally show relatively small impacts on system prices, compared to the effects of the system-level variables. That said, they nevertheless reveal some interesting, and potentially counterintuitive, results. Among other things, these results show that, after controlling for other factors, prices do tend to be lower in larger markets, which contrasts with the earlier descriptive results. Prices also tend to be higher in markets with greater housing density (e.g., in more urbanized areas, which often have a higher cost of living). The model results also show no statistically significant effect related to average incomes within a given market.

The results related market concentration and installer experience are both somewhat counterintuitive, but explainable. The results indicate that prices tend to be lower in more concentrated markets, whereas the general expectation might be for prices to be higher in those markets, due to greater market power. At the same time, the results also suggest that installer experience has no statistical impact on prices. This contrasts with previous studies (Gillingham et al. 2014 and O'Shaughnessy 2019), which show that installers with more experience tend to have lower prices, as a result of learning-by-doing and economies of scale. These seemingly counter-intuitive results reflect a competing dynamic between market concentration and installer experience, as more competition generally implies that installers operate at smaller scales, and small-scale installers tend to be less efficient. Prices therefore tend to be lowest in markets with some optimal balance of competition and installer scale. O'Shaughnessy (2019) provides a more comprehensive discussion of these competing effects.

Finally, the state-level fixed effects represent the "residual" pricing variation across states, after controlling for the various system- and market-level variables discussed above. As indicated by the results presented in Figure 32, those state-level effects are quite substantial, with roughly a \$1.5/W range across states. These residual pricing differences reflect other (unobserved) pricing drivers that vary across states but are not explicitly modeled—for example, differences related to permitting, interconnection, incentives, or housing stock.

Figure 33 provides additional detail on these state fixed-effects. The values refer to average pricing differences *relative to California*, after controlling for other pricing drivers. For example, the results indicate that, on average, systems are about \$0.8/W less expensive in Wisconsin and about \$0.8/W more expensive in Rhode Island, than in California. The figure also shows the difference in median prices between each state and California, based on the earlier descriptive analysis. In some cases, the descriptive results coincide quite closely with the results of the regression analysis, while in other cases, the two sets of results differ substantially. For example, the fixed-effects for New Hampshire and Arizona are considerably smaller than what the simple descriptive analysis showed, indicating that the difference in medians relative to California is largely related to other factors captured in the regression analysis. Conversely, in states such as North Carolina and Minnesota, the fixed effects are much larger (and may even point in a different direction) than the simple difference in medians, suggesting that other, un-modeled pricing drivers are dampening the apparent pricing differences across states.



Notes: A number of states contained within the larger data sample were omitted from the multi-variate regression analysis if missing one or more key data fields

Figure 33. State Fixed-Effects from Regression Analysis Compared to Descriptive Analysis

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