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U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018

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Introduction

NREL has been modeling U.S. photovoltaic (PV) system costs since 2009. This year, our report benchmarks costs of U.S. solar PV for residential, commercial, and utility-scale systems built in the first quarter of 2018 (Q1 2018).

We use a bottom-up methodology, accounting for all system and project-development costs incurred during the installation to model the costs for residential, commercial, and utility-scale systems. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective. Costs are represented from the perspective of the developer/installer, thus all hardware costs represent the price at which components are purchased by the developer/installer, not accounting for preexisting supply agreements or other contracts. Importantly, the benchmark also represents the sales price paid to the installer; therefore, it includes profit in the cost of the hardware, along with the profit the installer/developer receives, as a separate cost category. However, it does not include any additional net profit, such as a developer fee or price gross-up, which are common in the marketplace. We adopt this approach owing to the wide variation in developer profits in all three sectors, where project pricing is highly dependent on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, competitive environment, and overall project or deal structures. Finally, our benchmarks are national averages weighted by state installed capacities.

Introduction

This report builds on a number of previous publications from NREL and Lawrence Berkeley National Laboratory (LBNL):

- Fu, Ran, David Feldman, Robert Margolis, Mike Woodhouse, and Kristen Ardani. 2017. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20- 68925.
- Fu, Ran, Donald Chung, Travis Lowder, David Feldman, Kristen Ardani, and Robert Margolis. 2016. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-66532.
- Barbose, Galen, and Naïm Darghouth. 2016. *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory.
- Bolinger, Mark, and Joachim Seel. 2016. *Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Berkeley, CA: Lawrence Berkeley National Laboratory.
- Chung, Donald, Carolyn Davidson, Ran Fu, Kristen Ardani, and Robert Margolis. 2015. *U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64746.
- Fu, Ran, Ted James, Donald Chung, Douglas Gagne, Anthony Lopez, and Aron Dobos. 2015. *Economic Competitiveness of U.S. Utility-scale Photovoltaics Systems in 2015: Regional Cost Modeling of Installed Cost ($/W) and LCOE ($/kWh)*. IEEE 42nd Photovoltaic Specialist Conference, New Orleans, LA.
- Feldman, David, Galen Barbose, Robert Margolis, Mark Bolinger, Donald Chung, Ran Fu, Joachim Seel, Carolyn Davidson, Naïm Darghouth, and Ryan Wiser. 2015. *Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections*. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-64898.

Key Definitions

Unit	Description
Value	2018 U.S. dollar (USD)
System Size	In direct current (DC) terms; inverter prices are converted by DC-to-alternating current (AC) ratios.

Sector Category	Description	Size Range
Residential PV	Residential rooftop systems	3 kW – 10 kW
Commercial PV	Commercial rooftop systems, ballasted racking	10 kW – 2 MW
Utility-Scale PV	Ground-mounted systems, fixed-tilt and one-axis tracker	> 2 MW

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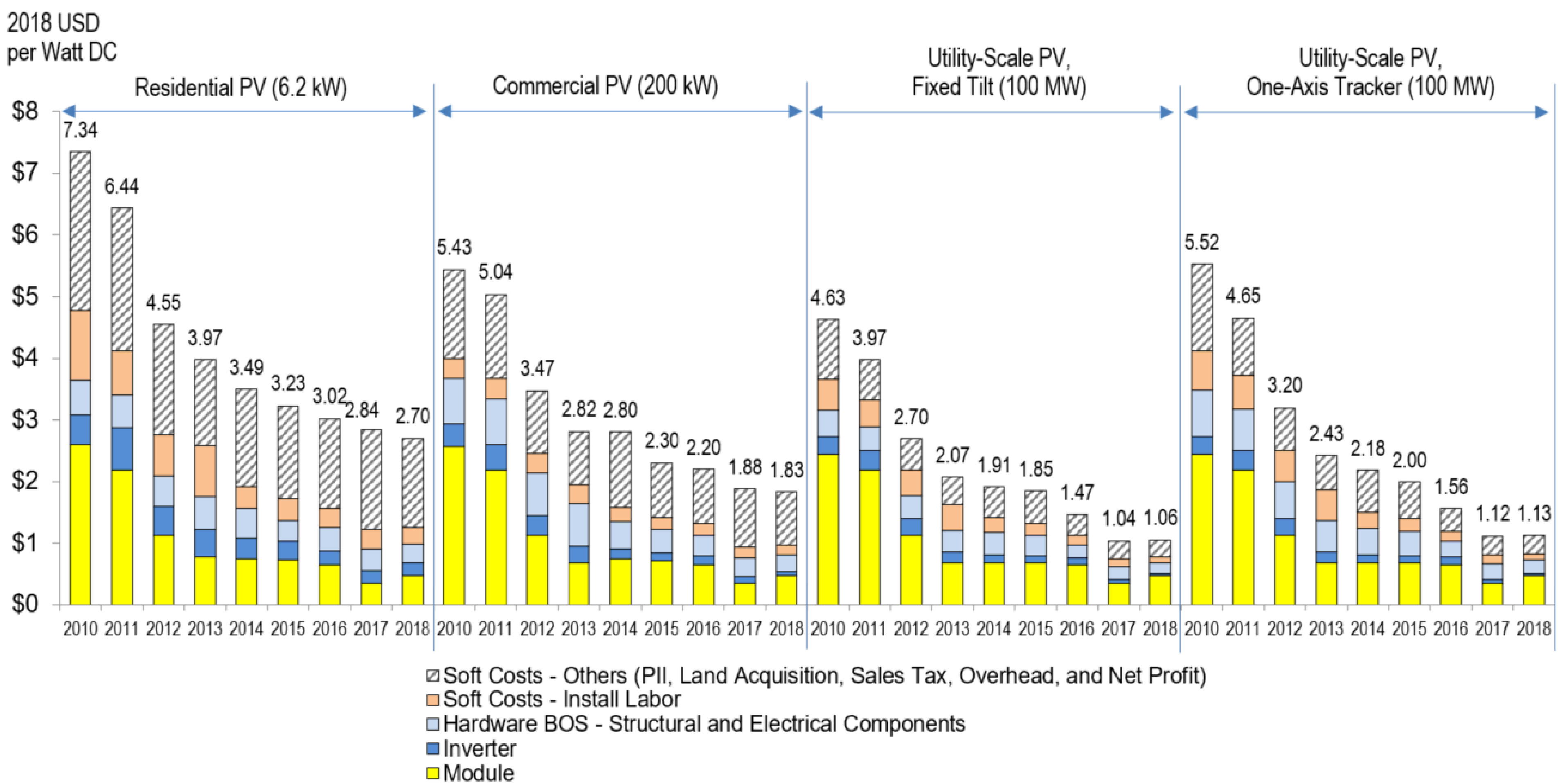
Overall Model Results (Total Installed Cost)

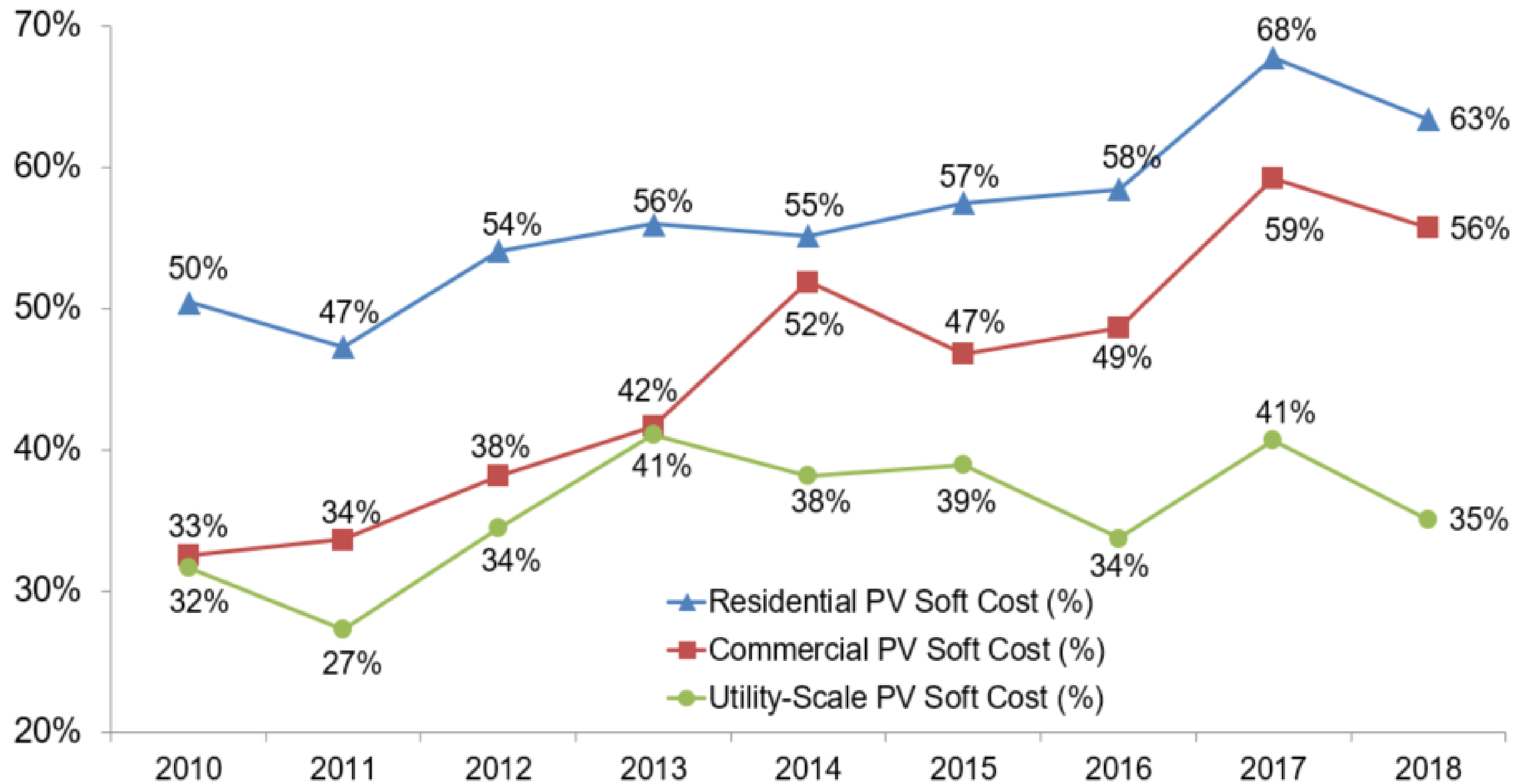


1. Values are inflation adjusted using the Consumer Price Index (2018). Thus, historical values from our models are adjusted and presented as real USD instead of nominal USD.
2. Cost categories are aggregated for comparison purposes. “Soft Costs – Others” represents permitting, inspection, and interconnection (PII); land acquisition; sales tax; and engineering, procurement, and construction (EPC)/developer overhead and net profit.

Overall Model Results (Q1 2017 vs. Q1 2018)

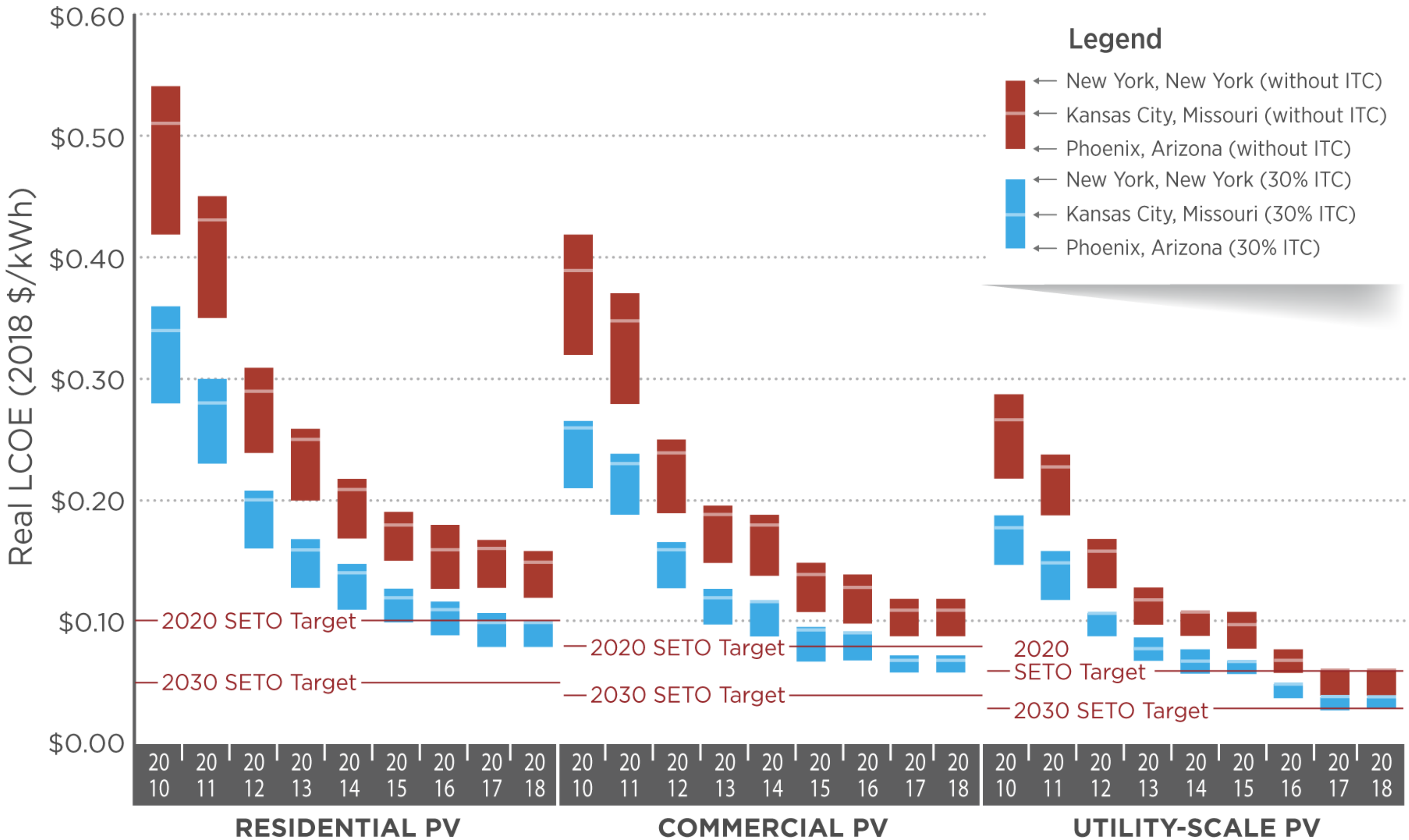
Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2017 Benchmarks in 2017 USD/W DC	$2.80	$1.85	$1.11
Q1 2017 Benchmarks in 2018 USD/W DC	$2.84	$1.88	$1.12
Q1 2018 Benchmarks in 2018 USD/W DC	$2.70	$1.83	$1.13
Drivers of Cost Decrease	• Higher module efficiency • Lower structural BOS commodity price • Lower electrical BOS commodity price • Higher labor productivity • Lower supply chain costs • Decrease in higher-cost module inventory • Higher small installer market share • Lower permitting cost	• Lower inverter price • Higher module efficiency • Smaller developer team • Lower permitting and interconnection costs	• Lower inverter price • Higher module efficiency • Optimized design coefficients for wind loads • 1,500 Vdc to replace 1,000 Vdc • Lower developer overhead
Drivers of Cost Increase	• Higher mixed inverter price due to higher advanced inverter adoption • Higher module price • Higher labor wages	• Higher module price • Higher labor wages	• Higher module price • Higher labor wages • Higher steel prices

Overall Model Results (Soft Cost)



1. "Soft Cost" in this report is defined as non-hardware cost—i.e., "Soft Cost" = Total Cost - Hardware Cost (module, inverter, and structural and electrical BOS).
2. In 2018, the decreased soft costs (%) of all three sectors are caused by the increased module prices.
3. Residential and commercial sectors have larger soft cost percentage than the utility-scale sector.
4. Soft costs and hardware costs also interact with each other. For instance, module efficiency improvements have reduced the number of modules required to construct a system of a given size, thus reducing hardware costs, and this trend has also reduced soft costs from direct labor and related installation overhead.
5. An increasing soft cost proportion in this figure indicates that soft costs declined more slowly than hardware costs; it does not indicate that soft costs increased on an absolute basis.

Overall Model Results (LCOE)



The reductions in total capital cost, along with improvements in operation, system design, and technology have resulted in significant reductions in the cost of electricity. U.S. residential and commercial PV systems are 89% and 91% towards achieving SETO's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SETO target three years early.

Note that we use the fixed-tilt systems for LCOE benchmarks from 2010-2015 and then switch to one-axis tracking systems from 2016 to 2018 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in Appendix.

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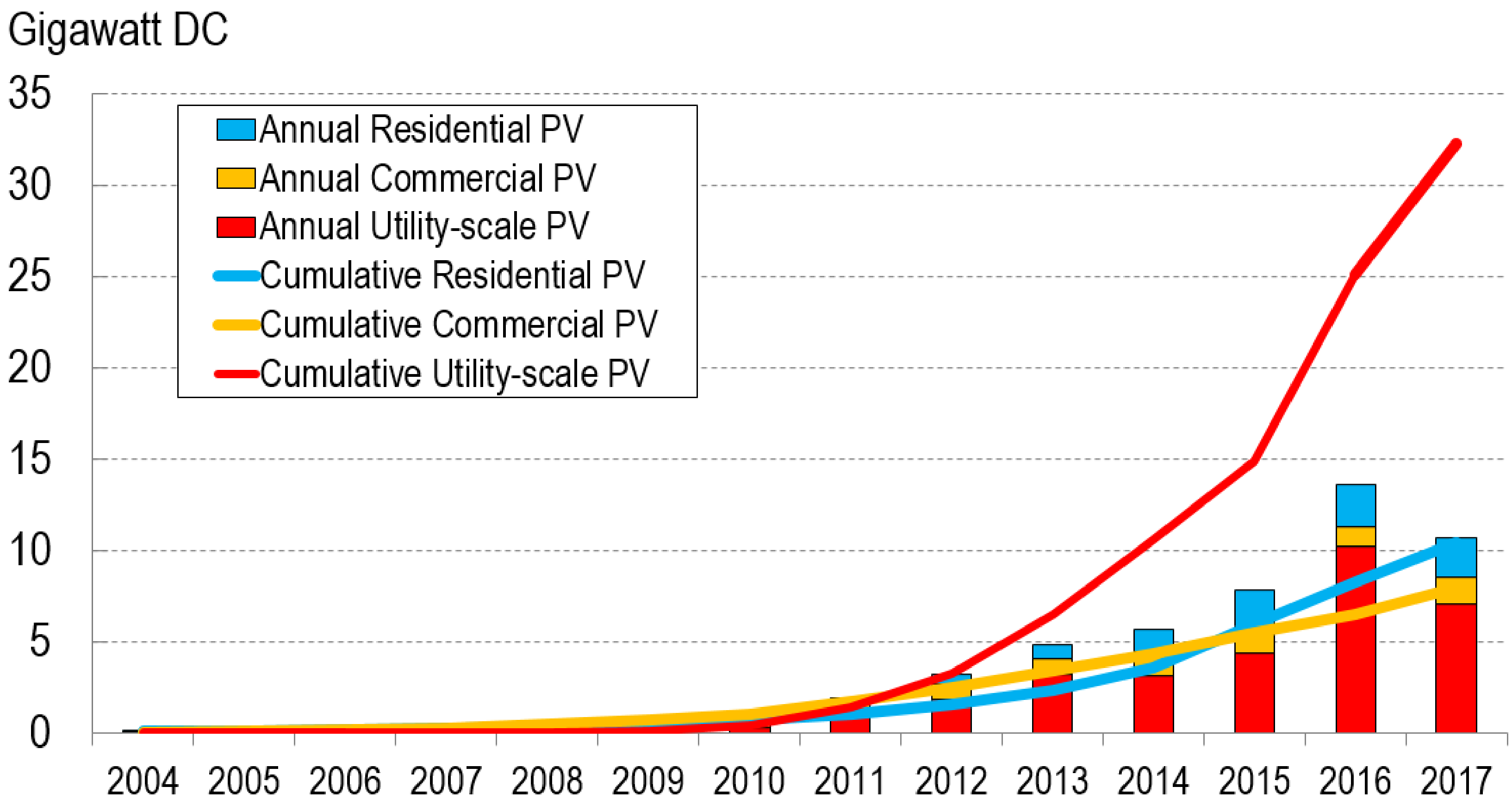
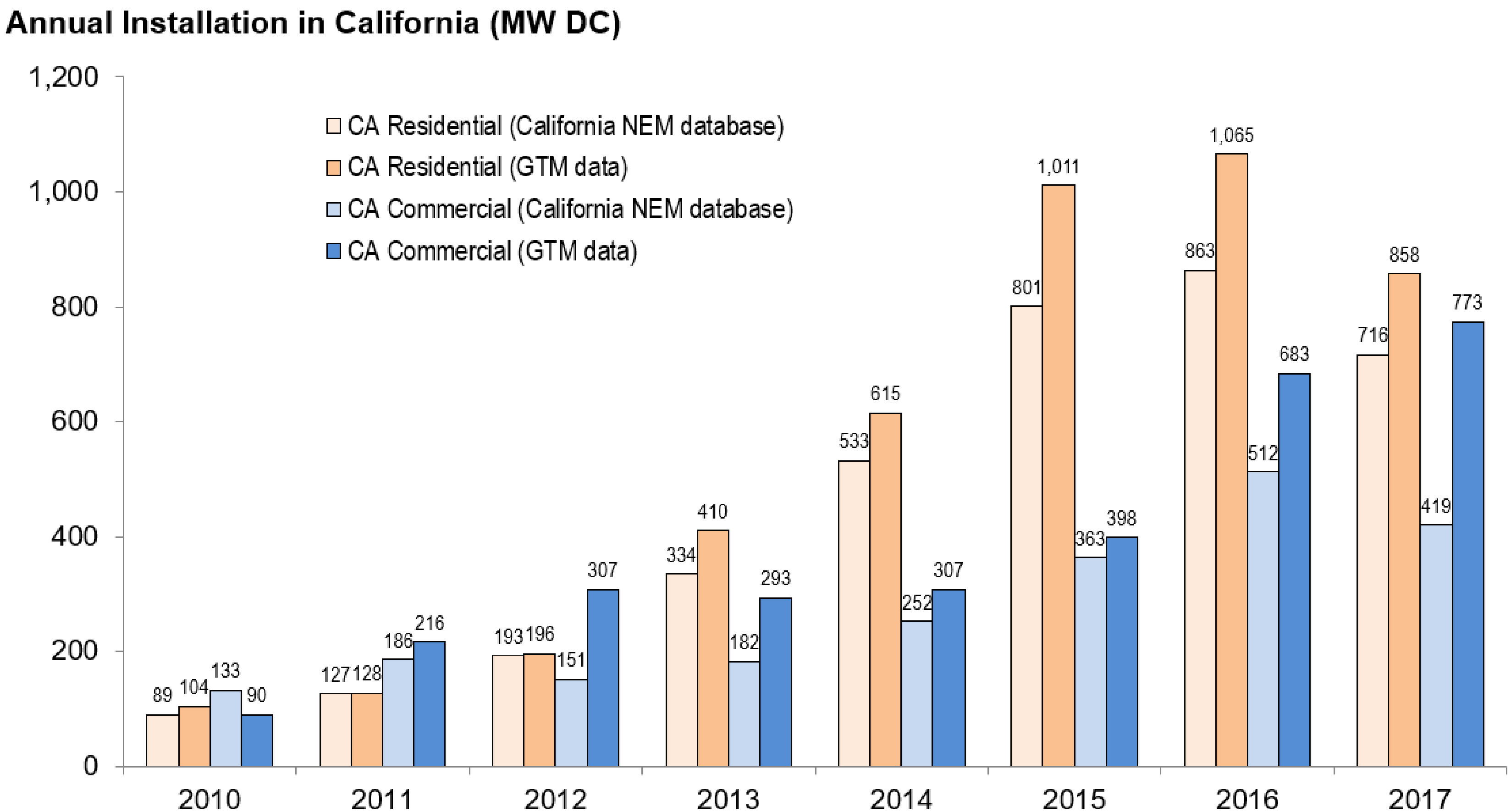
US Solar PV Market Growth



U.S. PV market growth, 2004–2017, in gigawatts of direct-current (DC) capacity (Bloomberg 2018)

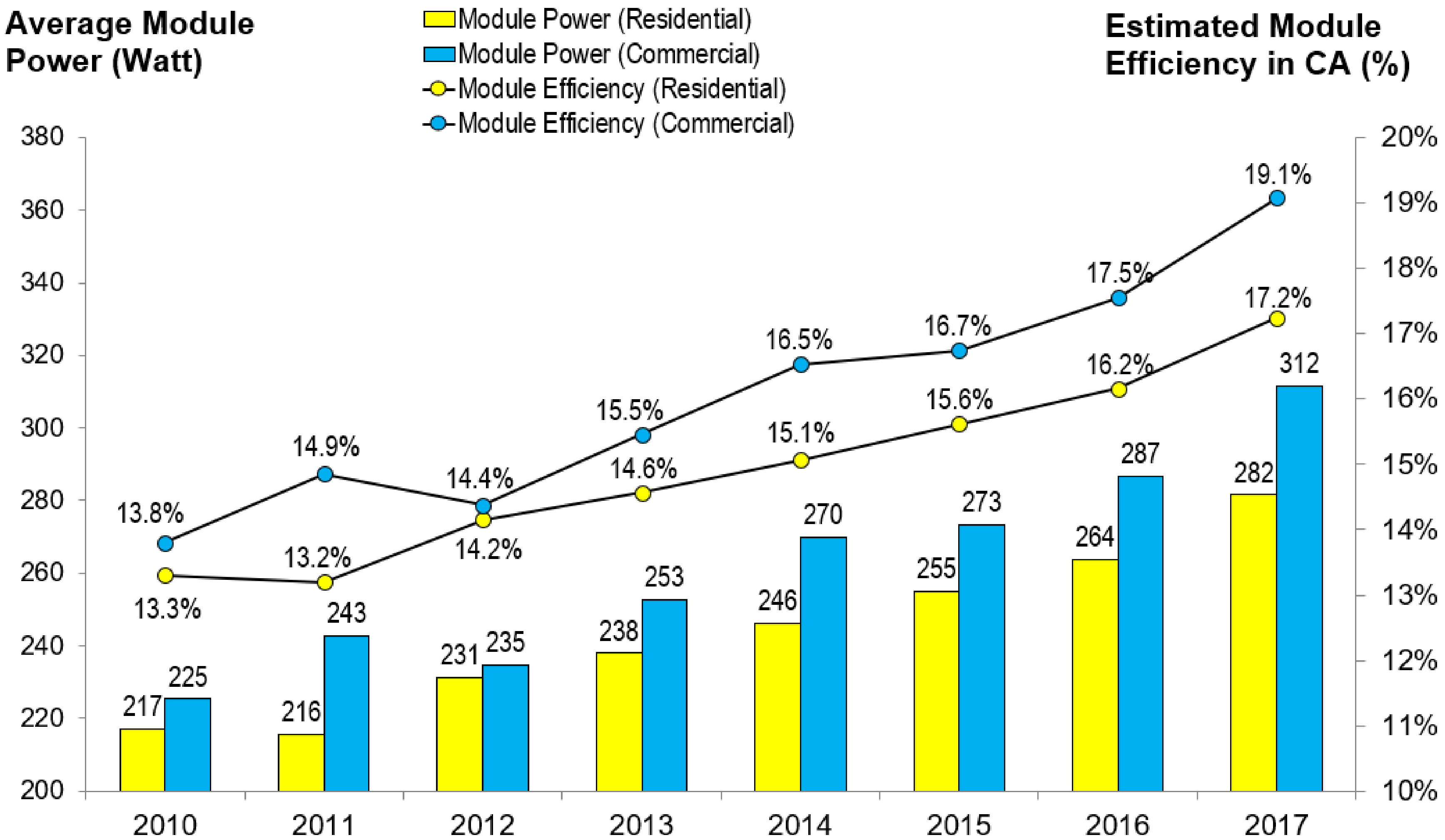
Solar photovoltaic (PV) deployment has grown rapidly in the United States over the past several years. As the figure shows, in 2017 new U.S. PV installations included 2.1 gigawatts (GW) in the residential sector, 1.5 GW in the commercial sector, and 7.1 GW in the utility-scale sector—totaling 10.7 GW across all sectors (Bloomberg 2018). Meanwhile, although commercial sector showed increased annual installation in 2017, compared to 2016, both residential and utility-scale sectors experienced the decreased installations in 2017 for the first time since 2004. The decreased installation in residential sector might be caused by the Net Metering reforms in some states. The decreased installation in utility-scale sector might be caused by the large volume of installations in 2016 when developers expected to fully leverage the 30% federal Investment Tax Credit (ITC).

Database for Residential and Commercial Sectors



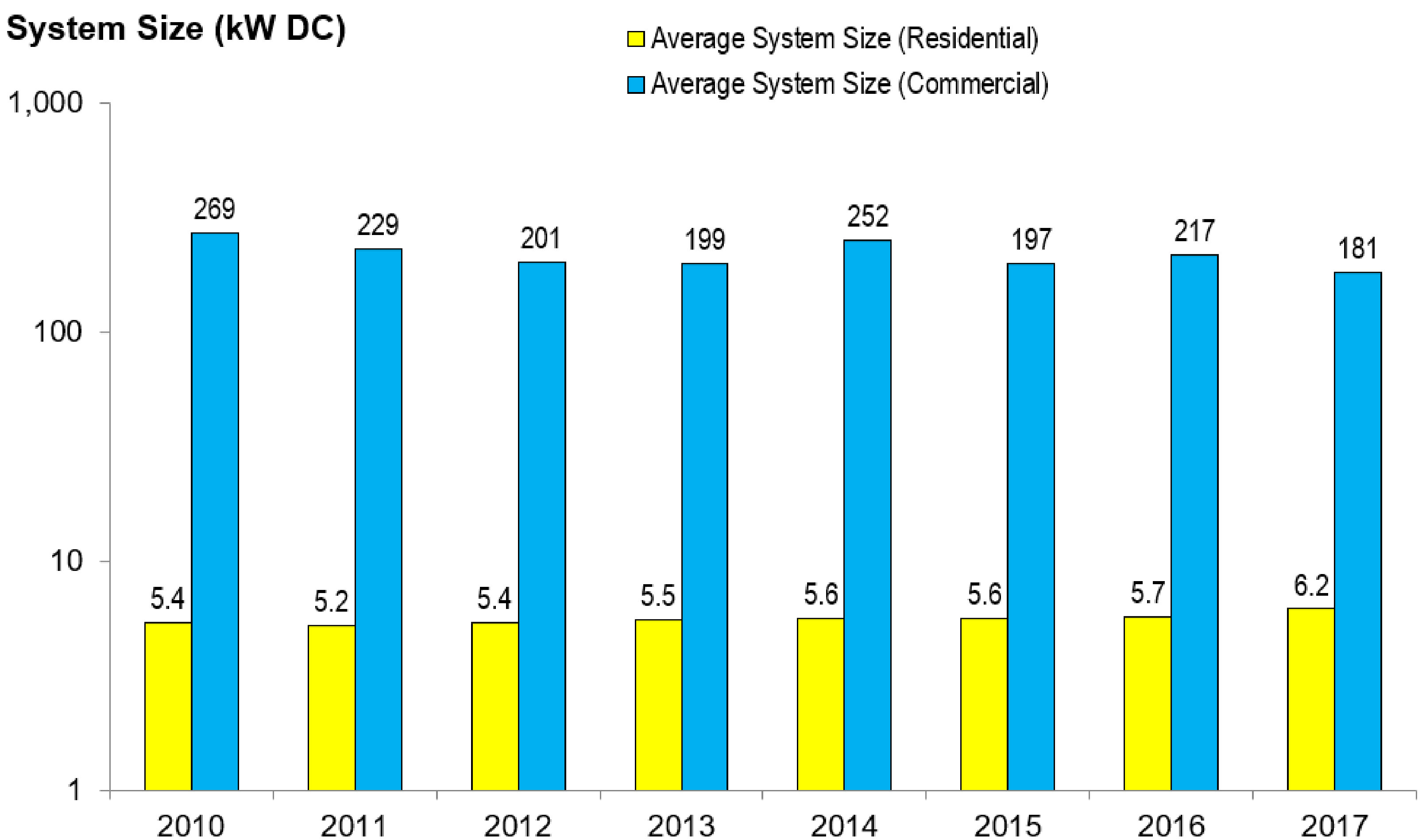
We use the California NEM Interconnection Applications Data Set (CSI 2018) to benchmark generic system characteristics, such as system size, module power and efficiency, and choice of power electronics. This database is updated monthly and contains all interconnection applications in the service territories of the state's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric). Although there are other databases for other markets, such as Massachusetts and New York, we use only the California NEM database because of its higher granularity and greater consistency. However, we do not use the California NEM database for regional cost analyses; inputs and sources for regional analyses are described in subsequent sections of this report.

Module Power and Efficiency Trend (California)



This figure displays module power and efficiency data from the California NEM database. Since 2010, module power and efficiency in both sectors have been steadily improving. We use the values of 17.2% (residential) and 19.1% (commercial and utility-scale) module efficiency in our models. Also note that since module selection may vary in different regions, the actual module efficiencies in other regions than CA may be different.

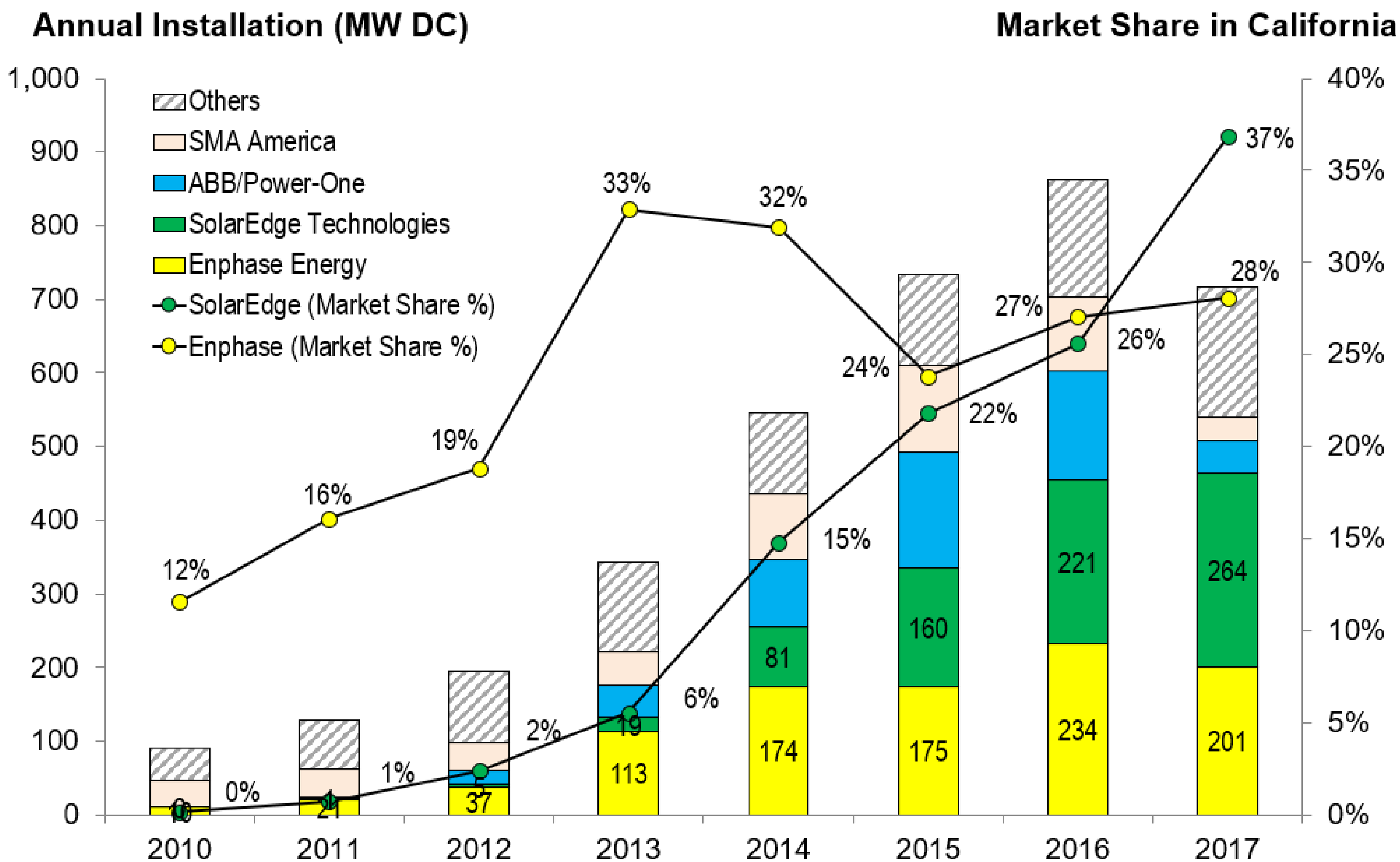
PV System Size Trend (California)



This figure displays average system sizes from the California NEM database. We use the 2017 value of 6.2 kW as the baseline case in our residential cost model to reflect the adoption of higher module efficiency.

Commercial system sizes have changed more frequently, likely reflecting the wide scope for “commercial customers,” which include schools, office buildings, malls, retail stores, and government projects. Thus, we use 200 kW as the baseline case in our commercial model.

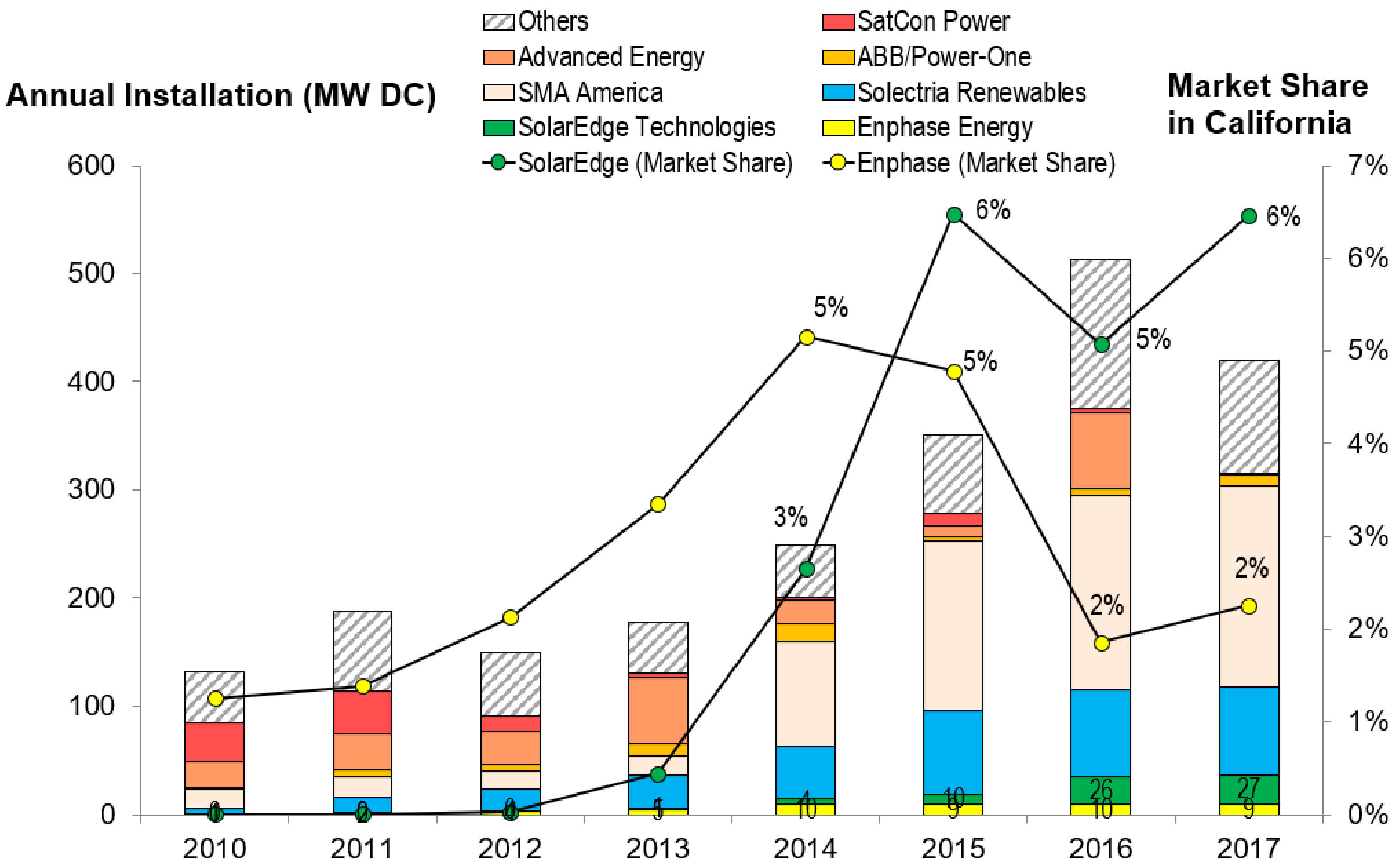
Inverter Market — Residential PV Sector (California)



According to the California NEM database, market uptake of MLPE has been growing rapidly since 2010 in California's residential sector. This increasing market growth may be driven by decreasing MLPE costs and by the "rapid shutdown" of PV output from buildings required by Article 690.12 of the National Electric Code (NEC) since 2014—MLPE inherently meet rapid-shutdown requirements without the need to install additional electrical equipment.

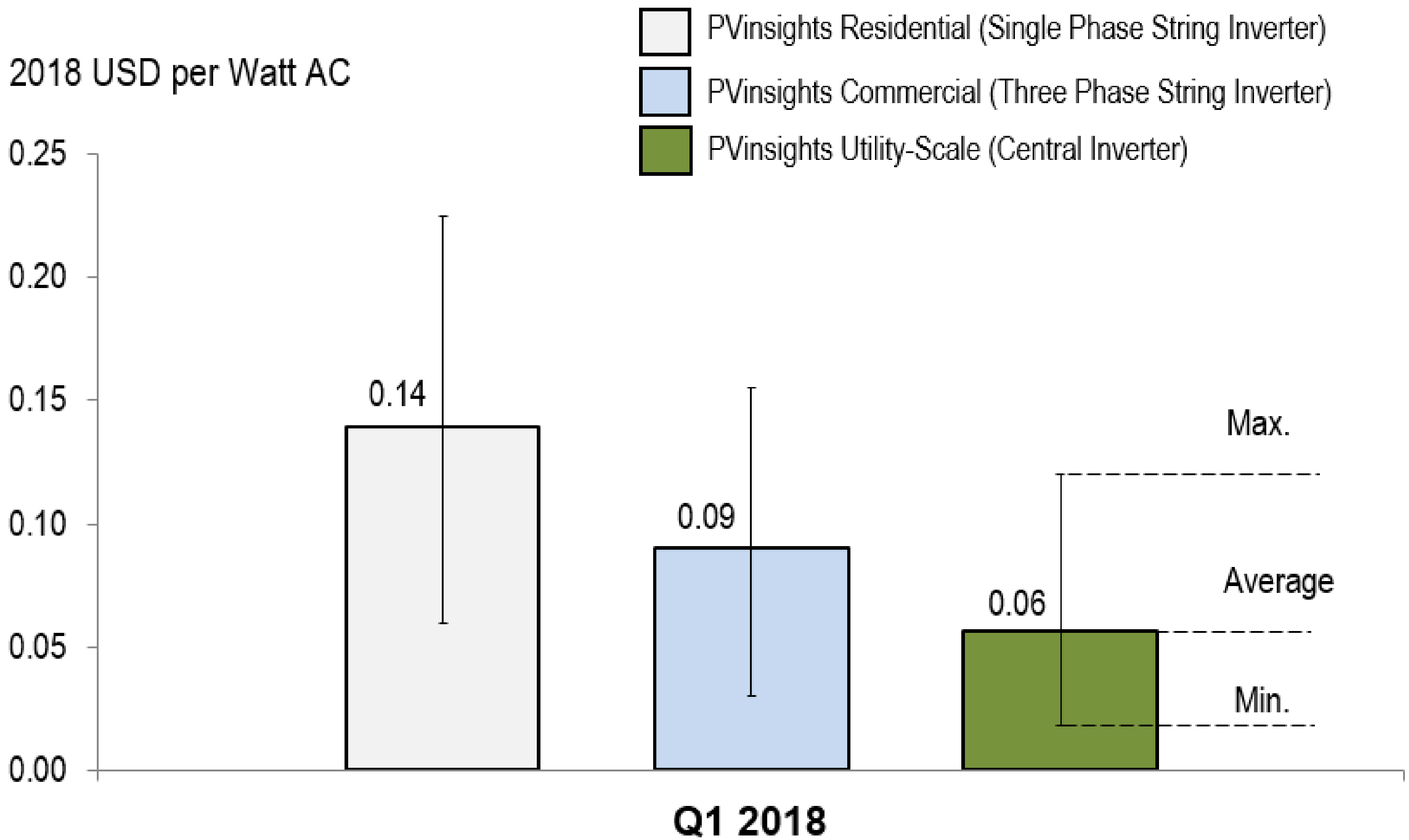
In 2017, MLPE—represented by the combined share of Enphase and SolarEdge inverter solutions—reached 65% of the total California residential market share. Therefore, in our residential system cost model, string inverter, power optimizer, and microinverter options are modeled separately and their market shares (35%, 37%, and 28%) are used for the weighted average case.

Inverter Market — Commercial PV Sector (California)



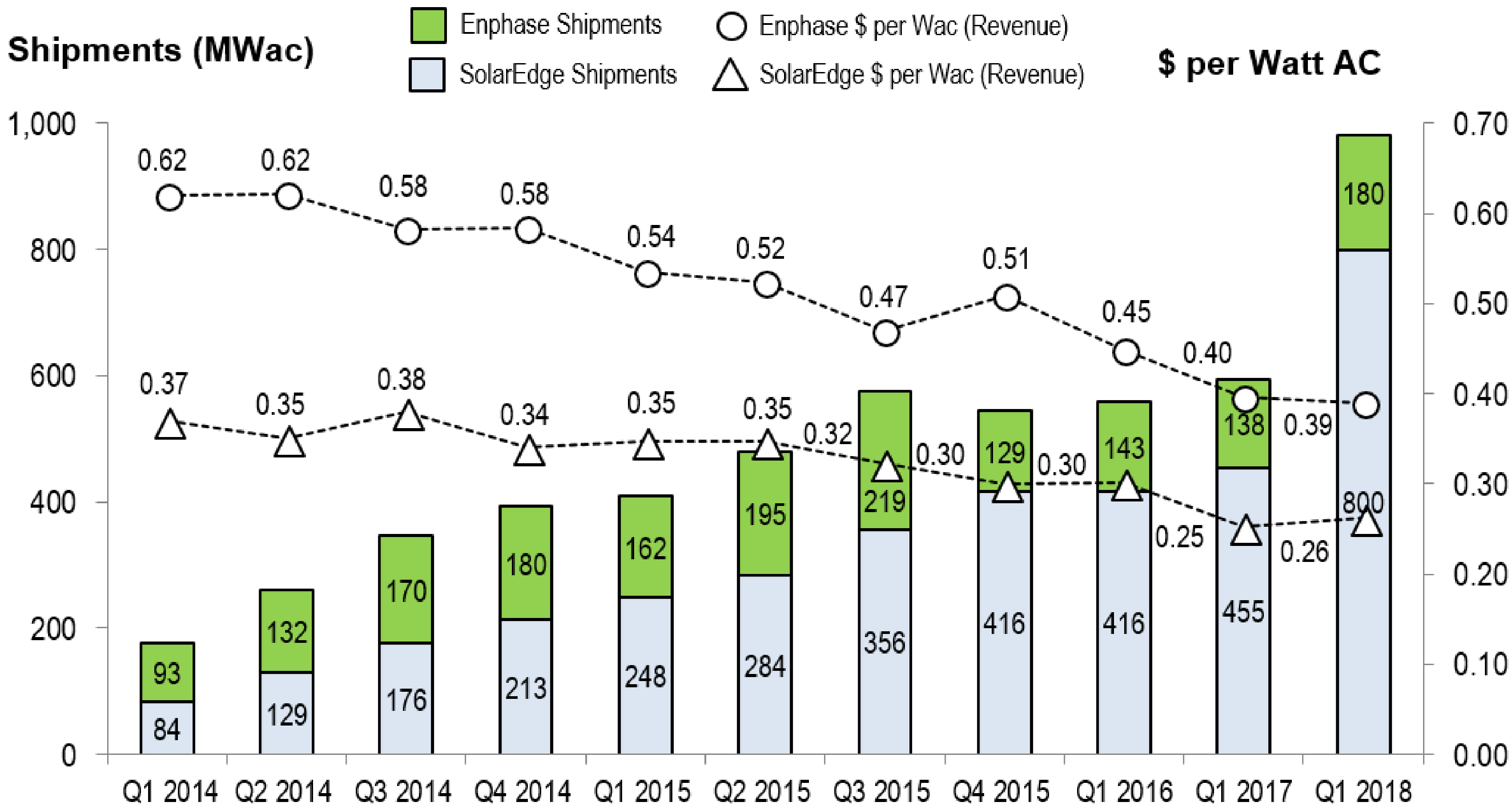
Conversely, MLPE growth (represented by Enphase and SolarEdge) has been slow in California's commercial sector, reaching a share of only 8% in 2017. Thus, we do not build MLPE inverter solutions into our commercial model.

Inverter Price for non-MLPEs



We source non-MLPE inverter prices from the PVinsights (2018) database, which contains typical prices between Tier 1 suppliers and developers in the market.

Inverter Price for MLPEs



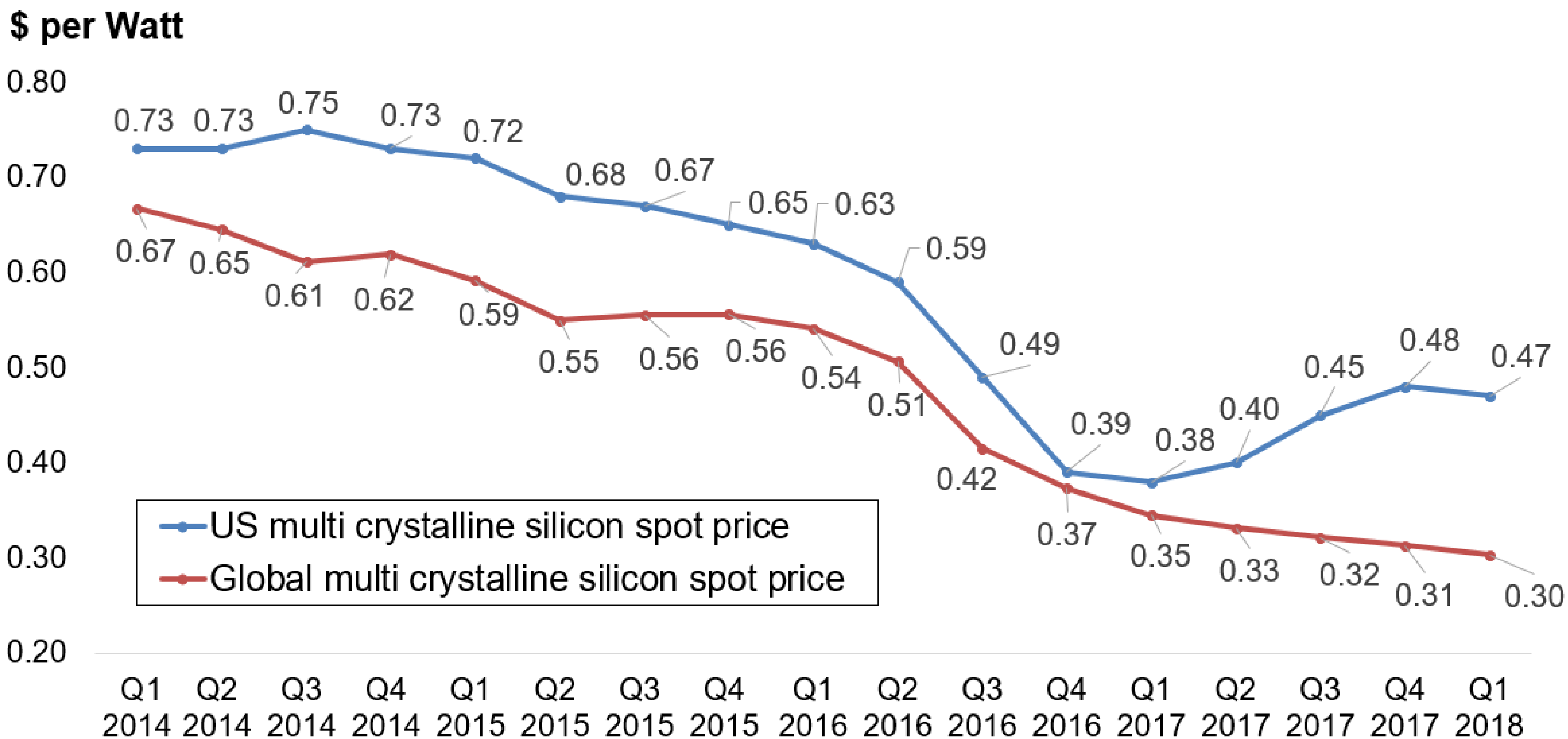
For MLPE inverter prices, we use data from public corporate filings, shown in this figure (Enphase 2018; SolarEdge 2018). Enphase's Q1 2018 revenue was $0.39/Wac, which represents the typical microinverter price. SolarEdge's Q1 2018 revenue was $0.26/Wac, including sales from DC power optimizers, string inverters, and monitoring equipment, which are typically included in one product offering. GTM Research estimates a DC power optimizer cost of $0.06/Wac (GTM Research 2018), implying a string inverter and monitoring equipment price of $0.20/Wac.

Inverter Price and DC-to-AC ratios

Inverter Type	Sector	$ per Watt AC	DC-to-AC Ratio	$ per Watt DC
Single Phase String Inverter	Residential PV (non-MLPE)	0.14	1.15	0.12
Microinverter	Residential PV (MLPE)	0.39	1.15	0.34
DC Power Optimizer String Inverter	Residential PV (MLPE)	0.20	1.15	0.18
Three Phase String Inverter	Commercial PV (non-MLPE)	0.09	1.15	0.08
Central Inverter	Utility-scale PV (fixed-tilt)	0.06	1.36 (Oversized)	0.04
Central Inverter	Utility-scale PV (1-axis tracker)	0.06	1.30 (Oversized)	0.05

We convert the USD/Wac inverter prices from previous inverter price figures to USD per watt DC (Wdc) using different DC-to-AC ratios (table below). In our benchmark, we use USD/Wdc for all costs, including inverter prices. Note that we updated the central inverter DC-to-AC ratios using Lawrence Berkeley National Laboratory data (Bolinger and Seel 2018); for the ratios in residential and commercial sectors, we use the estimates based on interview feedback (NREL 2018).

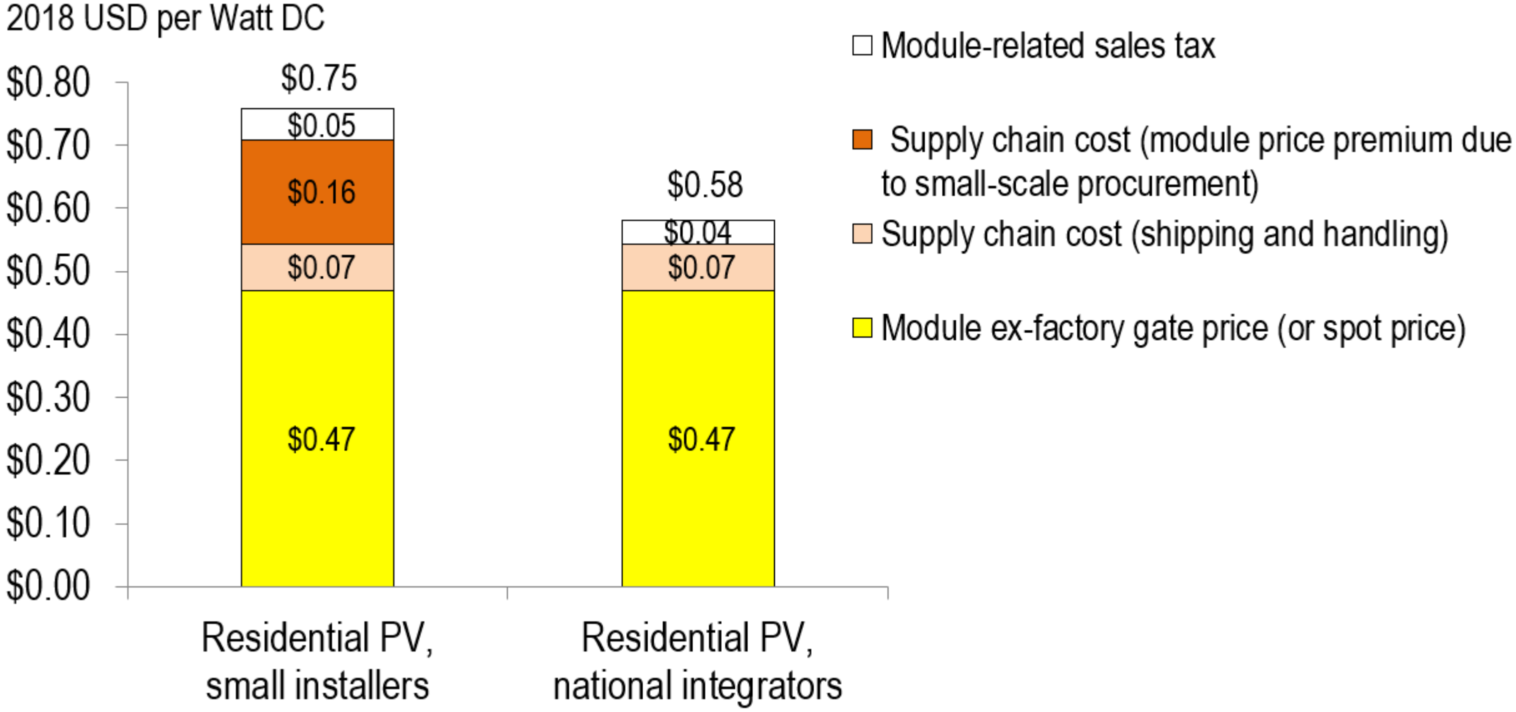
Module Price (US vs. Global)



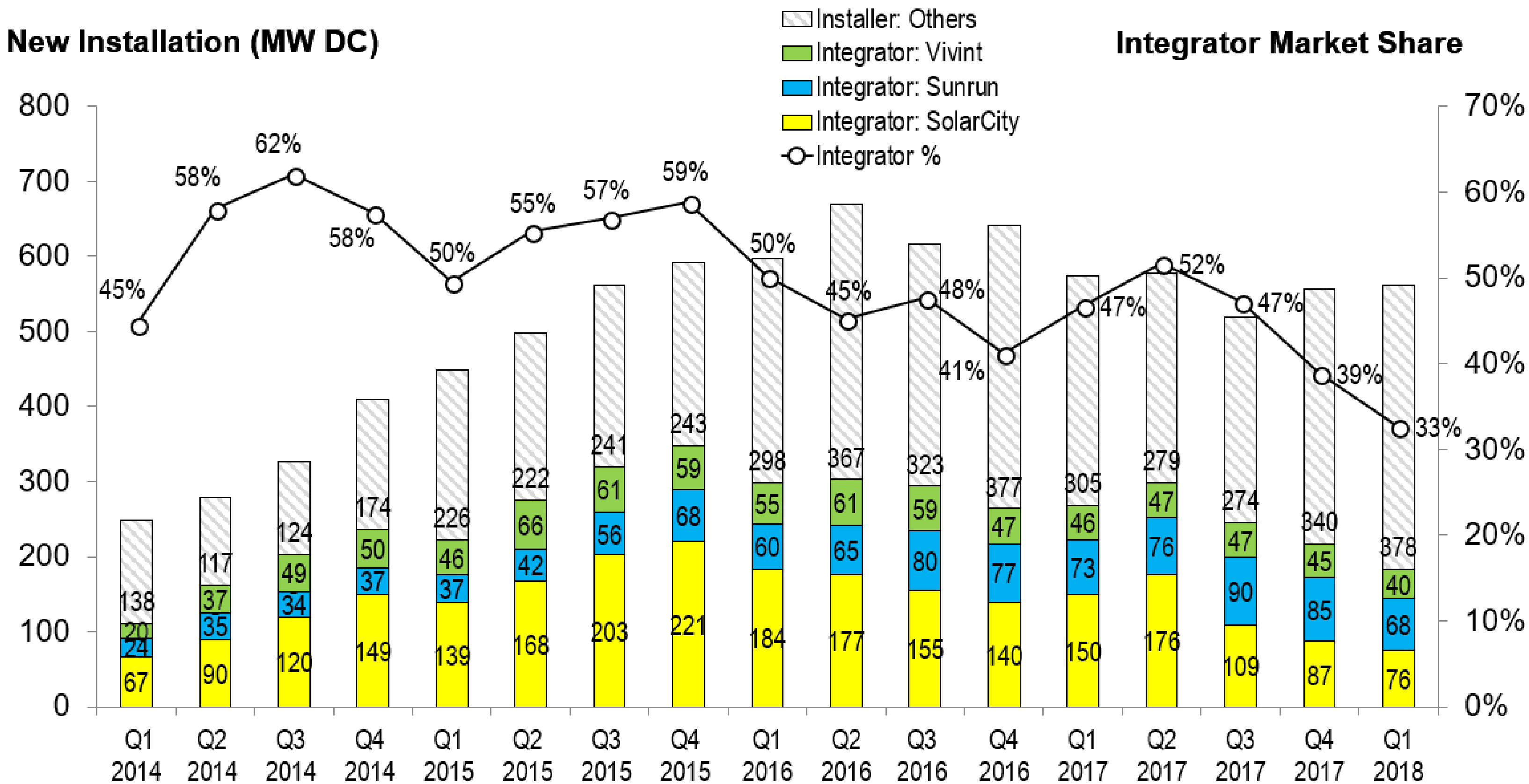
We assume an ex-factory gate (spot or first-buyer) price of $0.47/Wdc for Tier 1 crystalline-silicon PV modules in Q1 2018. As this figure shows, U.S. spot prices declined substantially between 2014 and 2016, approaching global spot prices. In 2017, however, U.S. spot prices rose as many commercial and utility-scale PV developers and residential installers purchased large quantities of modules owing to uncertainty about U.S. policy on imported modules (GTM/SEIA 2018). By the time U.S. tariffs on imported modules came into effect in 2018, U.S. spot prices had reached $0.47/Wdc—$0.17/Wdc above the global spot price—and appeared to be leveling off.

Module Price Inputs: Q1 2018

Although commercial and utility-scale PV developers typically can procure modules at or near the spot price, residential integrators and installers incur additional supply chain costs (figure below). Historical inventory price can create a price lag (approximately six months) for the market module price in the residential sector when the modules from previous procurement are installed in today's systems. In the Q1 2017 residential PV benchmark this supply chain cost represented $0.21/W – a 60% premium. Because US module ASP was lower than Q1 2018 pricing for much of 2017 we do not included this supply chain cost in the current benchmark. We assume that small installers and national integrators are both subject to a 15% ($0.07/W) premium on the spot price for module shipping and handling (NREL 2018), consistent with Q1 2017 residential PV benchmark. Small installers are subject to an additional 35% ($16/W) premium owing to small-scale procurement (Bloomberg 2018), increasing from an assumed 20% premium in the Q1 2017 residential PV benchmark. Both types of companies are also subject to 6.9% sales tax (weighted national average), bringing the small installer module cost to $0.76/W and the national integrator cost to $0.58/W (Bloomberg 2018).



Residential PV: Integrator vs. Installer



Our residential PV benchmark is based on two different business structures: "small installer" and "national integrator." We define small installers as businesses that lead generation, sales, and installation, but do not provide financing solutions. The national integrator performs all of the small installer's functions, and provides financing and system monitoring for third-party-owned systems. In our models, the difference between small installers and national integrators manifests in the overhead and sales and marketing cost categories, where the national integrator is modeled with higher expenses for customer acquisition, financial structuring, and asset management. To estimate the split in market share between small installers and national integrators, we use data compiled from corporate filings (Sunrun 2018; Vivint Solar 2018) and GTM Research and SEIA (2018). As shown in this figure, small installers have gained more market share than national integrators since 2016, because the direct ownership business model, led by installers, became more popular than third-party ownership.

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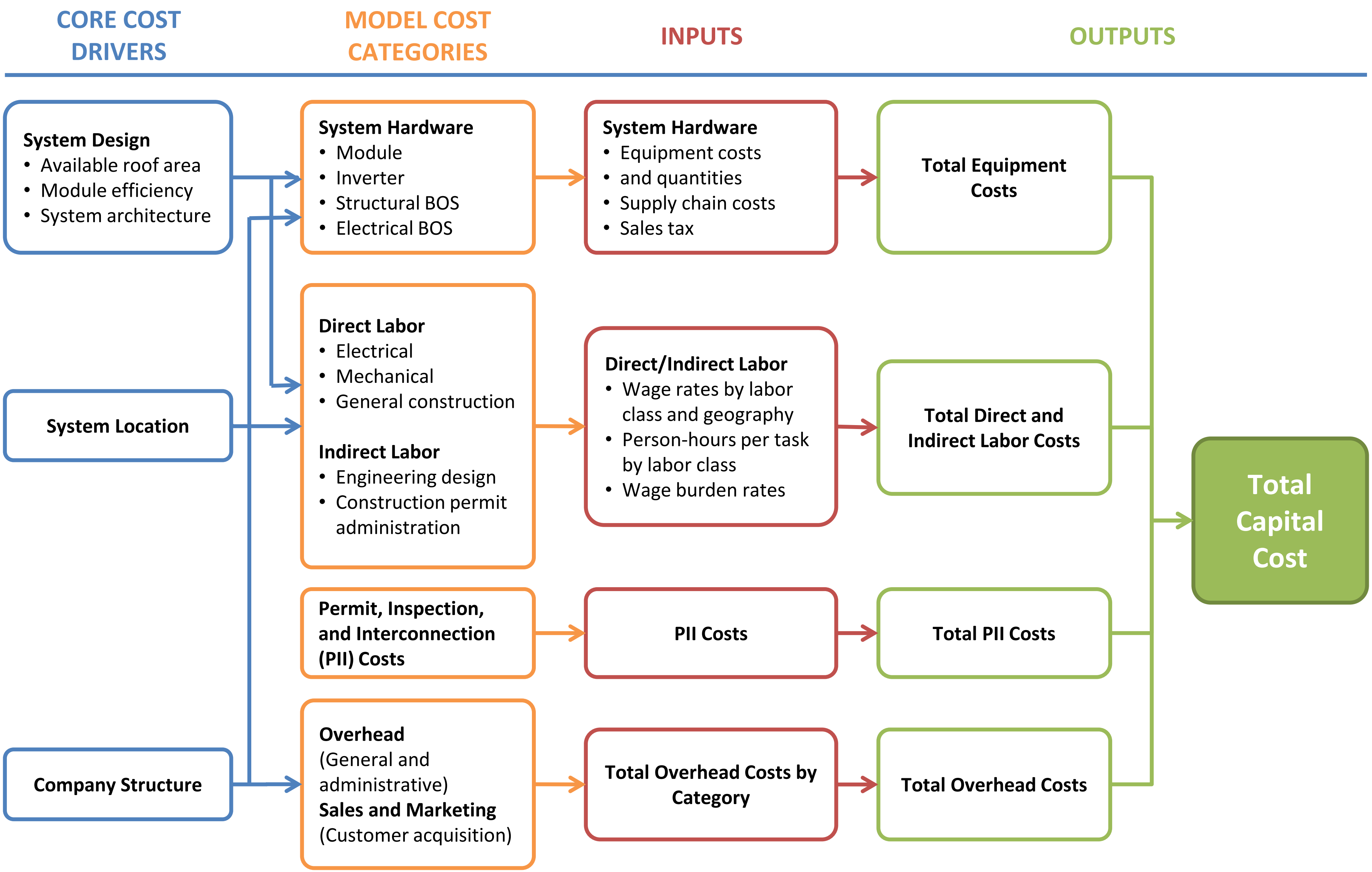
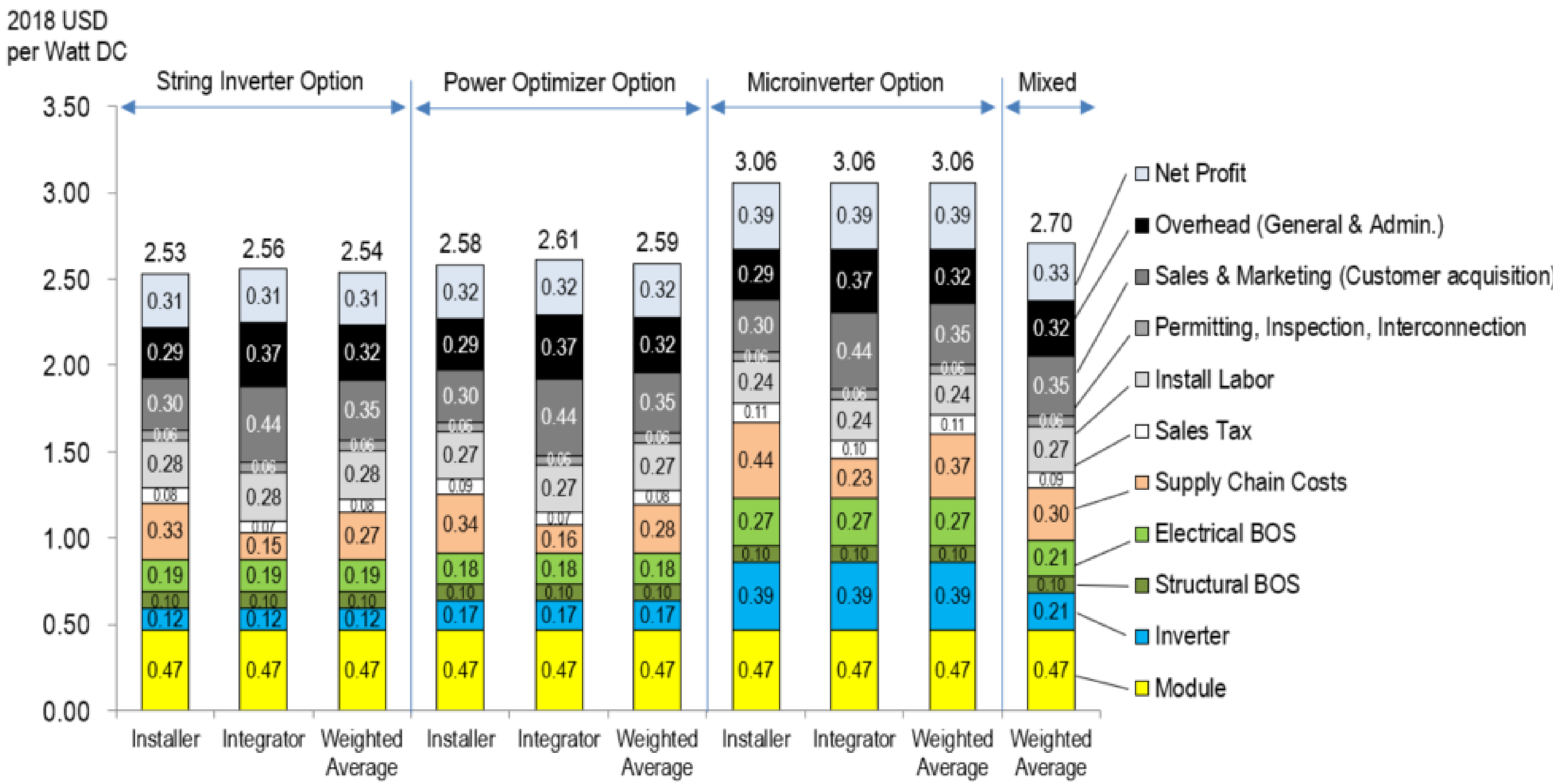
Residential PV: Model Structure



Residential PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	6.2 kW	Average installed size per system	Go Solar CA (2018)
Module efficiency	17.2%	Average module efficiency	Go Solar CA (2018)
Module price	$0.47/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	GTM and SEIA (2018), NREL (2018)
Inverter price	Single-phase string inverter: $0.12/Wdc DC power optimizer string inverter: $0.18/Wdc Microinverter: $0.39/Wdc	Ex-factory gate (first buyer) prices, Tier 1 inverters	PVinsights (2018), NREL (2018), corporate filings (Enphase 2018, SolarEdge 2018)
Structural BOS (racking)	$0.10/Wdc	Includes flashing for roof penetrations and all the rails and clamps	NREL (2018)
Electrical BOS	$0.19–$0.27/Wdc Varies by inverter option	Conductors, switches, combiners and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers	Model assumptions, NREL (2018), RSMeans (2017)
Supply chain costs (% of equipment costs)	Varies by installer type	15% costs and fees associated with shipping and handling of equipment multiplied by the cost of doing business index (101%) Additional 35% small-scale procurement for module-related supply chain costs for small installers. Additional 20% for inverter-related supply chain costs for small installers and 10% for national integrators	NREL (2018), model assumptions
Sales tax	Varies by location; weighted national average: 6.9%	Sales tax on the equipment; national benchmark applies an average (by state) weighted by 2017 installed capacities	RSMeans (2018), GTM and SEIA (2018)
Direct installation labor	Electrician: $19.74–$38.96 per hour; Laborer: $12.88–$25.57 per hour; Varies by location and inverter option	Modeled labor rate depends on state; national benchmark uses weighted average of state rates	BLS (2018), NREL (2018)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, Federal Insurance Contributions Act (FICA), builders risk, public liability	RSMeans (2018)
Permitting, inspection, and interconnection (PII)	$0.06/Wdc	Includes assumed building permitting fee of $200 and six office staff hours for building permit preparation and submission, and interconnection application preparation and submission	NREL (2018)
Sales & marketing (customer acquisition)	$0.30/Wdc (installer) $0.44/Wdc (integrator)	Total cost of sales and marketing activities over the last year—including marketing and advertising, sales calls, site visits, bid preparation, and contract negotiation; adjusted based on state “cost of doing business” index	NREL (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Overhead (general & administrative)	$0.29/Wdc (installer) $0.37/Wdc (integrator)	General and administrative expenses—including fixed overhead expenses covering payroll (excluding permitting payroll), facilities, administrative, finance, legal, information technology, and other corporate functions as well as office expenses; adjusted based on state “cost of doing business” index	NREL (2018), Feldman et al. (2013)
Profit (%)	17%	Fixed percentage margin applied to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees	Fu et al. (2017)

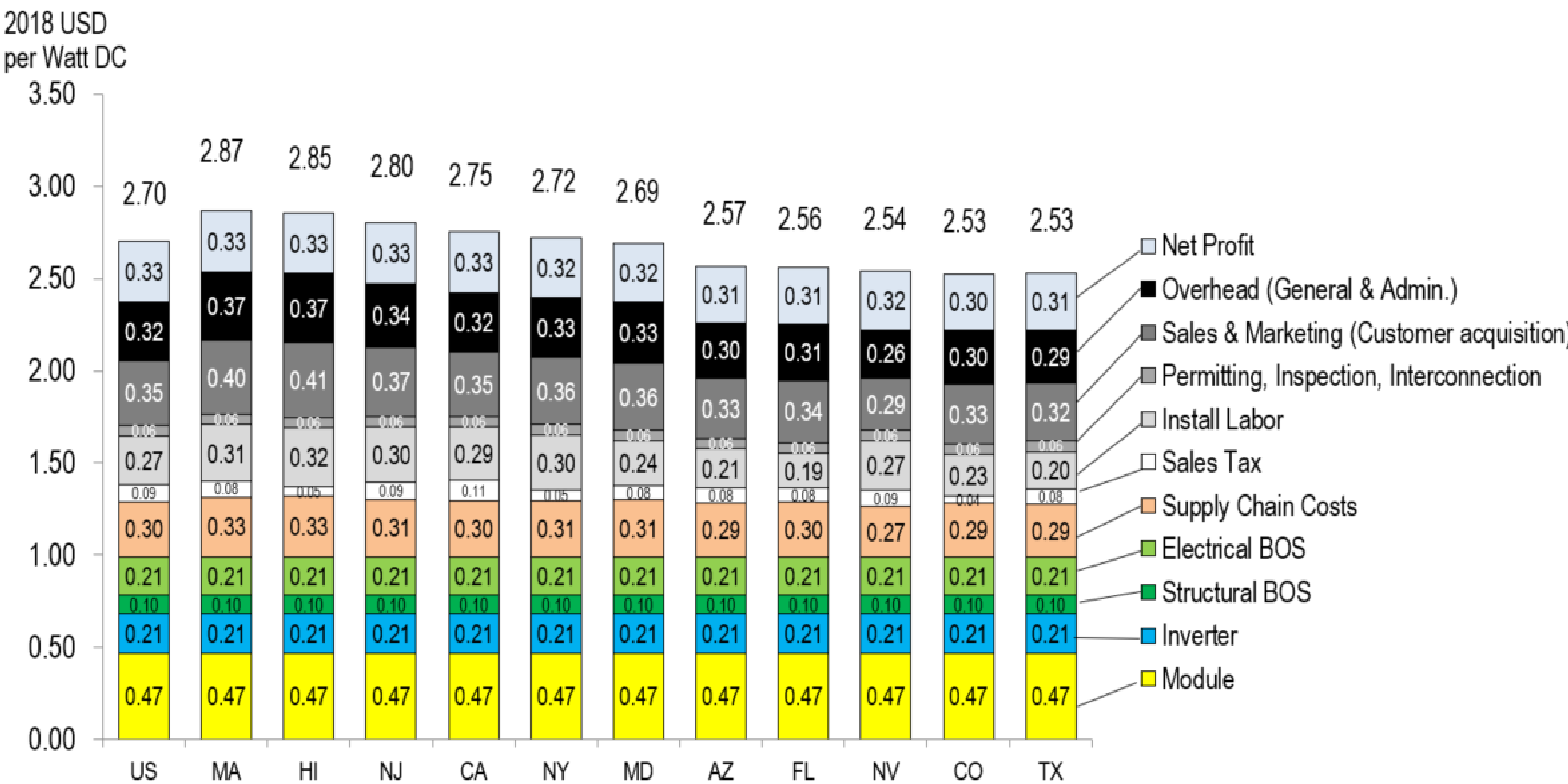
Residential PV: Model Outputs



Q1 2018 U.S. benchmark: 6.2-kW residential system cost (2018 USD/Wdc)

This figure presents the U.S. national benchmark from our residential model. The national benchmark represents an average weighted by Q1 2018 installed capacities. Market shares of 67% for installers and 33% for integrators are used to compute the national weighted average. String inverter, power optimizer, and microinverter options are each modeled individually, and the “mixed” case applies their market shares (35%, 37%, and 28%) as weightings.

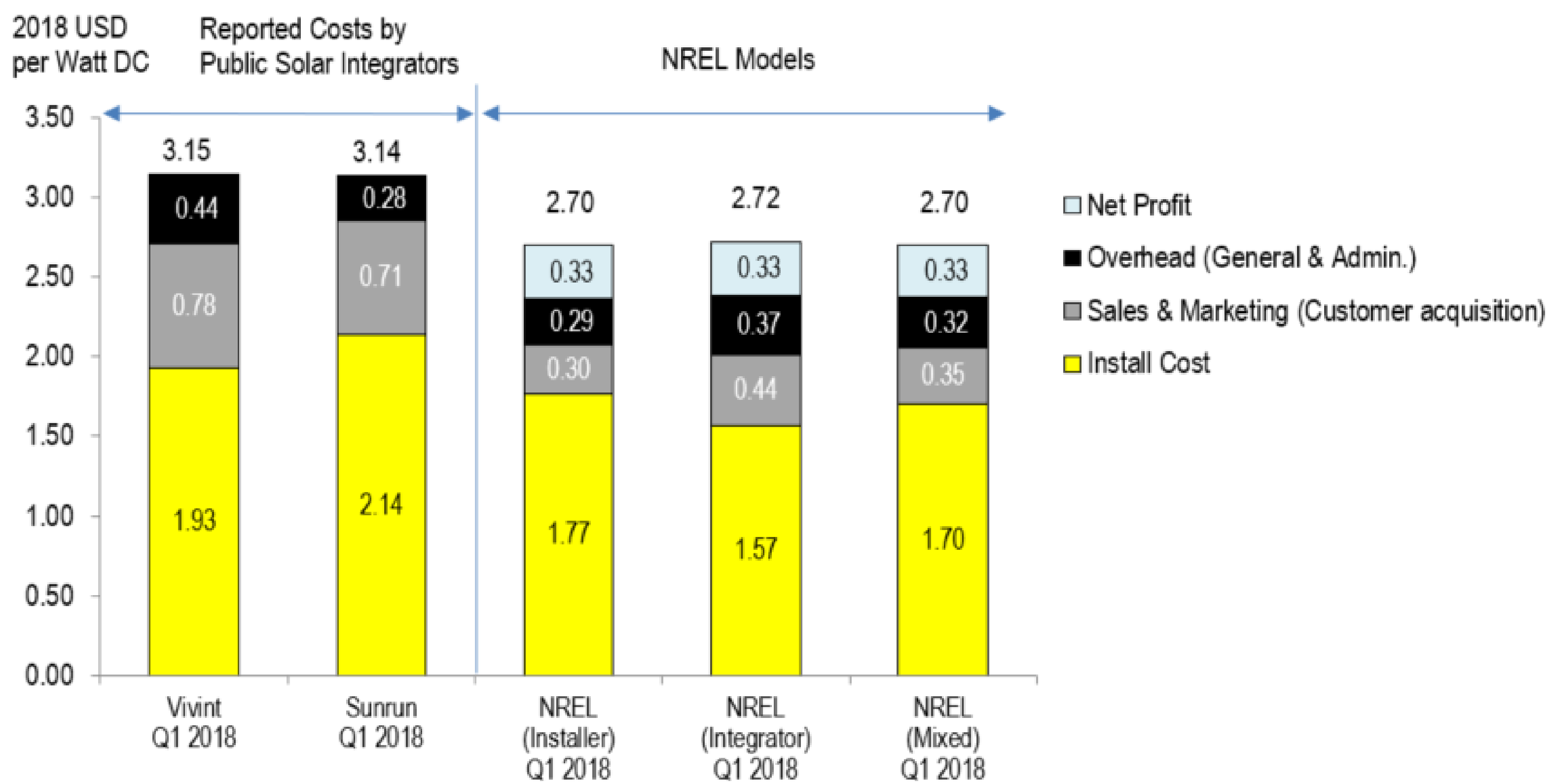
Residential PV: Model Outputs



Q1 2018 benchmark by location: 6.2-kW residential system cost (2018 USD/Wdc)

This figure presents the benchmark in the top U.S. solar markets (by 2017 installations), reflecting differences in supply chain and labor costs, sales tax, and SG&A expenses—that is, the cost of doing business (Case 2012).

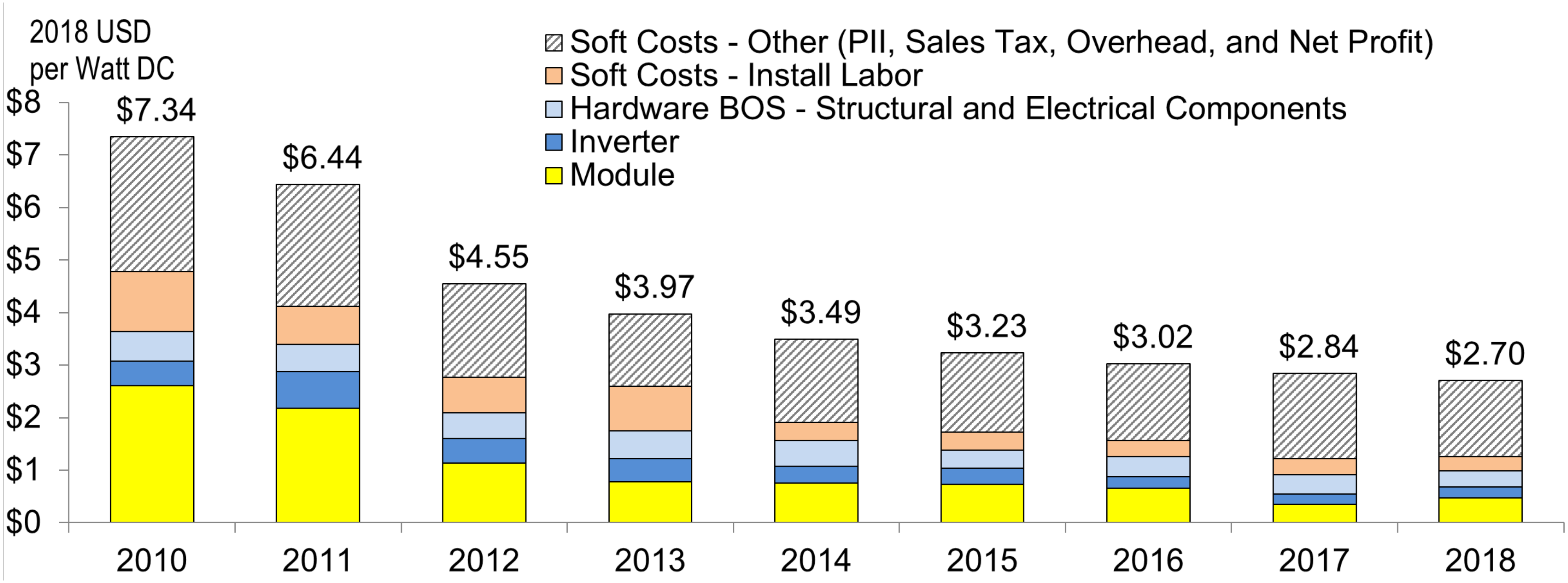
Residential PV: Model Outputs



Q1 2018 NREL modeled cost benchmark (2018 USD/Wdc) vs. Q1 2018 company-reported costs

Our bottom-up modeling approach yields a different cost structure than those reported by public solar integrators in their corporate filings (Sunrun 2018; Vivint Solar 2018). Because integrators sell and lease PV systems, they practice a different method of reporting costs than do businesses that only sell goods. Many of the costs for leased systems are reported over the life of the lease rather than the period in which the system is sold; therefore, it is difficult to determine the actual costs at the time of the sale. Although the corporate filings from Sunrun and Vivint Solar report system costs on a quarterly basis, the lack of transparency in the public filings makes it difficult to determine the underlying costs as well as the timing of those costs.

Residential PV: Capital Cost Benchmark Historical Trends



From 2010 to 2018 there was a 63% reduction in the residential PV system cost benchmark. Approximately 57% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 82% over that time period. An additional 19% can be attributed to labor, which dropped 77% over that time period, with the final 24% attributed to other soft costs, including PII, sales tax, overhead, and net profit.

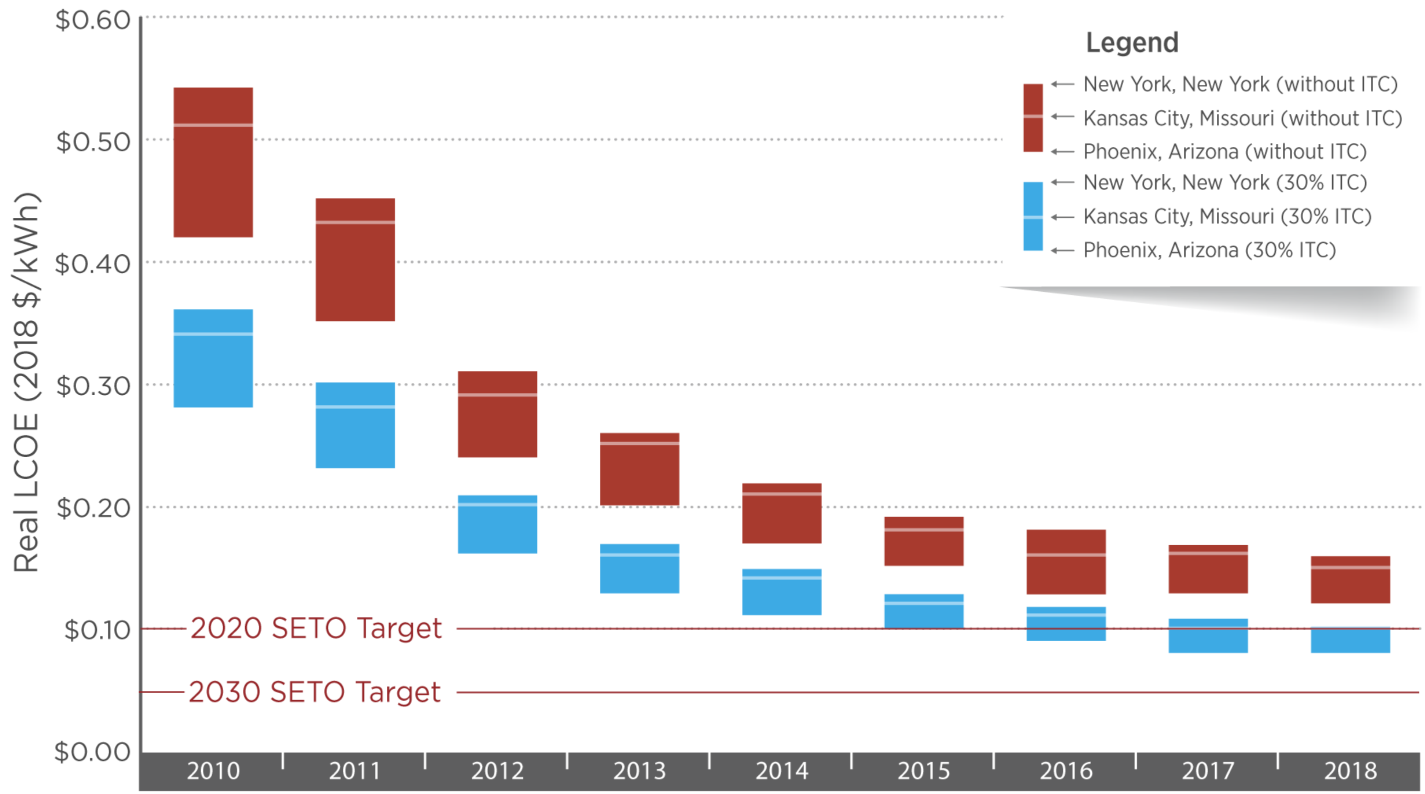
Looking at this past year, from 2017 to 2018 there was a 5% reduction in the residential PV system cost benchmark.

Residential PV: LCOE assumptions

2018 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017	2018
Benchmark report									
Installed cost ($/W)	7.34	6.44	4.55	3.97	3.49	3.23	3.02	2.84	2.70
System size (kw-DC)	5.0	5.0	5.1	5.1	5.2	5.2	5.6	5.7	6.2
Inverter loading ratio	1.10	1.11	1.12	1.13	1.13	1.14	1.15	1.15	1.15
Ongoing NREL benchmarking									
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kw-yr)	54	48	41	36	30	25	25	24	22
Pre-inverter derate (%)	90.0%	90.1%	90.2%	90.3%	90.4%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	94.0%	94.8%	95.6%	96.4%	97.2%	98.0%	98.0%	98.0%	98.0%
Equity discount rate (real)	9.0%	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%	6.9%	6.9%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%	4.8%	4.8%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40%

All 2010–2017 data are from Fu et al. (2017), adjusted for inflation. The inverter replacement line-item in Fu et al. (2017) is incorporated into O&M expenses in this edition to be consistent with the 2018 O&M benchmark. Other important assumptions: residential PV system LCOE assumes a 1) system lifetime of 30 years; 2) federal tax rate of 35% from 2010–2017, changing to 21% in 2018; 3) state tax rate of 7%; 4) MACRS depreciation schedule; 5) no state or local subsidies; 6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest of 1.75%); 7) a 3-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system; 8) a module tilt angle of 25 degrees, and an azimuth of 180 degrees; 9) debt with a term of 18 years; and 10) $1.1 million of upfront financial transaction costs for a $100 million TPO transaction of a pool of residential projects.

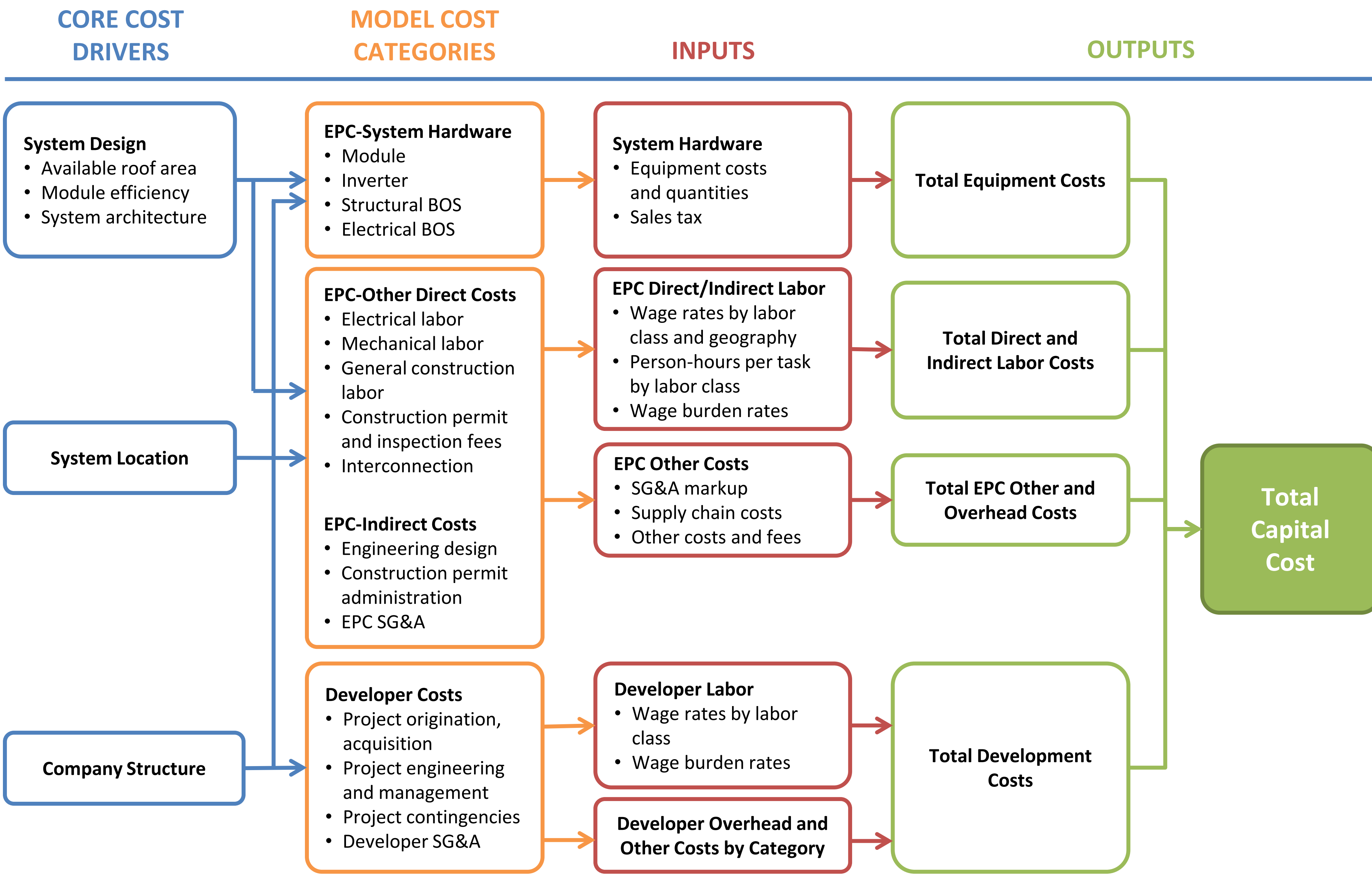
Residential PV: LCOE Benchmark Historical Trends



From 2010 to 2018 there was a 71% reduction in the residential PV system electricity cost benchmark (a 6% reduction was achieved from 2017 to 2018), bringing the unsubsidized LCOE between $0.12/kWh to $0.16/kWh ($0.08/kWh to $0.10/kWh when including the federal ITC). This reduction is 89% towards achieving SETO's 2020 residential LCOE goal, which is 10 cents/kWh in 2018 USD.
Note: For LCOE Kansas City, MO, without ITC cases are $0.51/kWh in 2010 and $0.15/kWh in 2018 (2018 USD); see also the Appendix. Thus, calculation is: (0.507 – 0.147)/(0.507 – 0.102) = 89%.

Contents

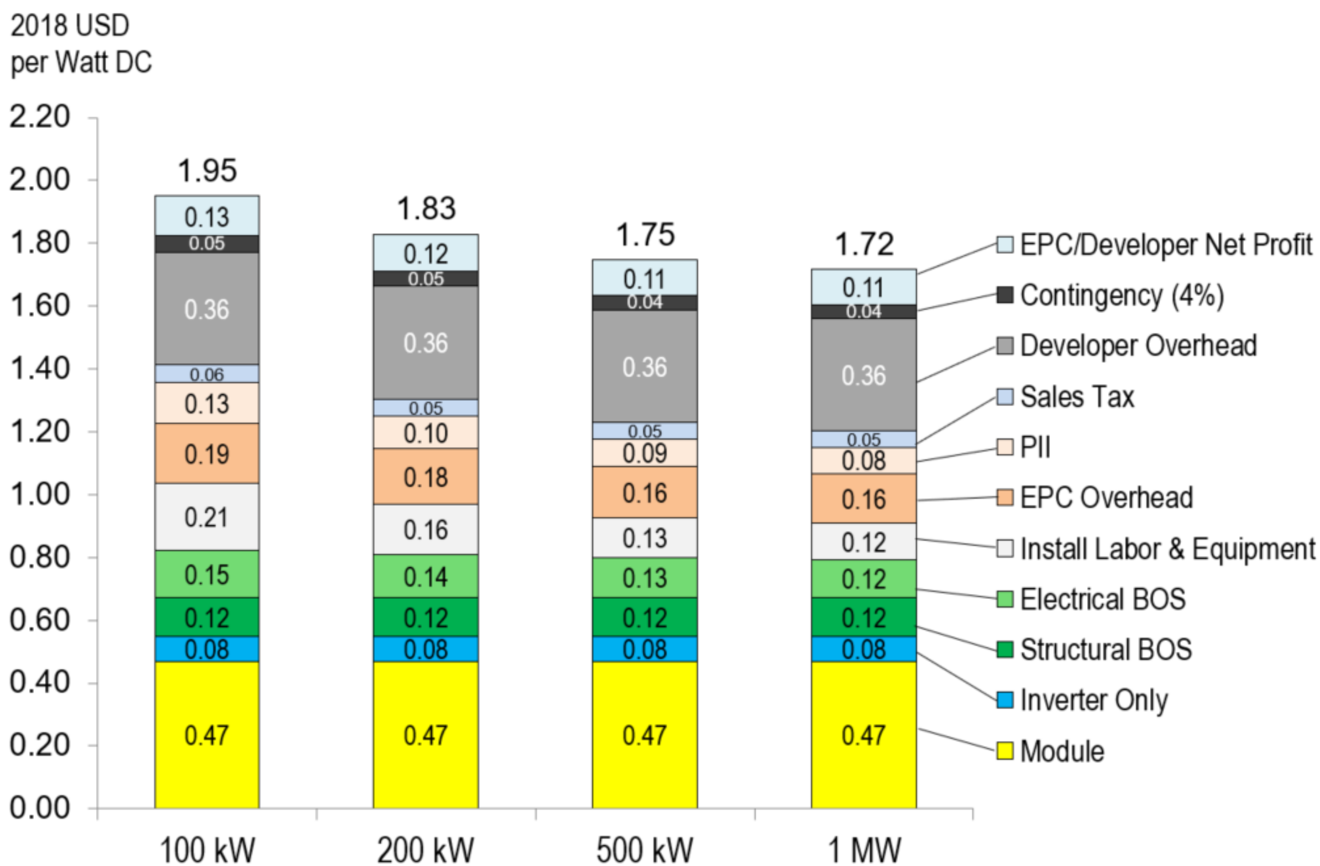
Commercial PV: Model Structure



Commercial PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	100 kW–1 MW	Average installed size per system	Go Solar CA (2018)
Module efficiency	19.1%	Average module efficiency	Go Solar CA (2018)
Module price	\$0.47/Wdc	Ex-factory gate (first buyer) ASP, Tier 1 modules	GTM and SEIA (2018), NREL (2018)
Inverter price	Three-phase string inverter: \$0.08/Wdc	Ex-factory gate prices (first buyer) ASP, Tier 1 inverters	PVinsights (2018), NREL (2018)
Structural components (racking)	\$0.10–\$0.22/Wdc; varies by location due to wind and snow loading	Ex-factory gate prices; flat-roof ballasted racking system	ASCE (2006), model assumptions, NREL (2018)
Electrical components	\$0.13–\$0.17/Wdc; varies by location due to cost of doing business	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, etc.	Model assumptions, NREL (2018), RSMeans (2018)
EPC overhead (% of equipment costs)	13%	Costs and fees associated with EPC overhead, inventory, shipping, and handling	NREL (2018)
Sales tax	Varies by location	Sales tax on equipment costs; national benchmark applies an average (by state) weighted by 2017 installed capacities	RSMeans (2018), GTM and SEIA (2018)
Direct installation labor	Electrician: \$19.74–\$38.96 per hour; Laborer: \$12.88–\$25.57 per hour; Varies by location	Modeled labor rate assumes non-union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2018), NREL (2018)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, FICA, builders' risk, public liability	RSMeans (2018)
PII	\$0.10/Wdc	For construction permits fee, interconnection study fees for existing substation, testing, and commissioning	NREL (2018)
Developer overhead	Assume 10-MW system development and installation per year for a typical developer	Includes fixed overhead expenses such as payroll, facilities, travel, insurance, administrative, business development, finance, and other corporate functions; assumes 10 MW/year of system sales	Model assumptions, NREL (2018)
Contingency	4%	Estimated as markup on EPC cost; value represents actual cost overruns above estimated cost	NREL (2018)
Profit	7%	Applies a fixed percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2018)

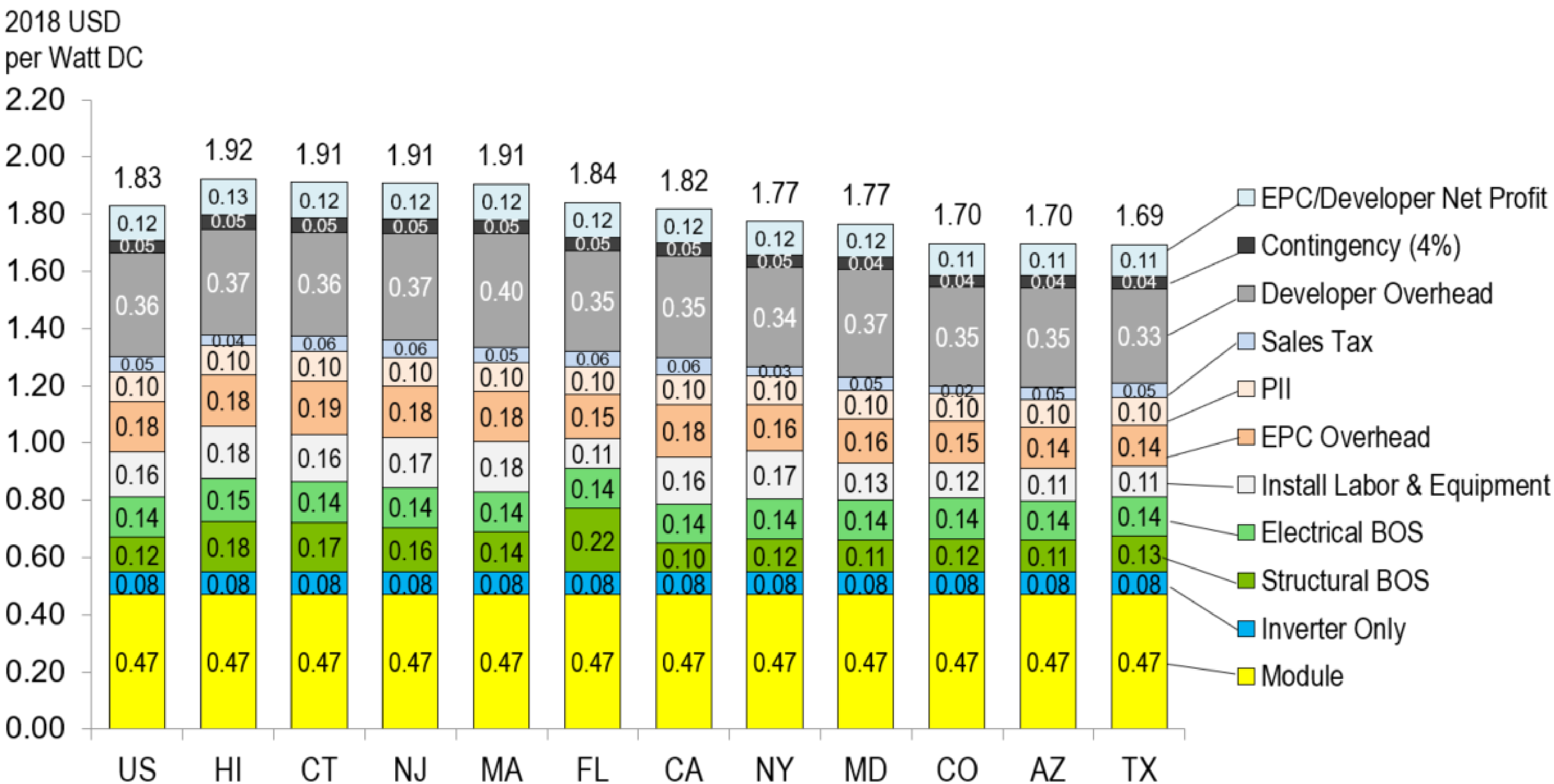
Commercial PV: Model Outputs



Q1 2018 U.S. benchmark: commercial system cost (2018 USD/Wdc)

As in the commercial model, the national benchmark represents an average weighted by 2017 state installed capacities. We model different system sizes because of the wide scope of the "commercial" sector, which comprises a diverse customer base occupying a variety of building sizes. Also, economies of scale—driven by hardware, labor, and related markups—are evident here. That is, as system sizes increase, the per-watt cost to build them decreases. Meanwhile, because we assume that a typical developer has 10 MW of system development and installation per year, the developer overhead on this 10 MW total capacity does not vary for different system sizes. When a developer installs more capacity annually, that developer's overhead per watt in each system declines (shown in Figure 18 in our Q1 2015 benchmark report, Chung et al. 2015).

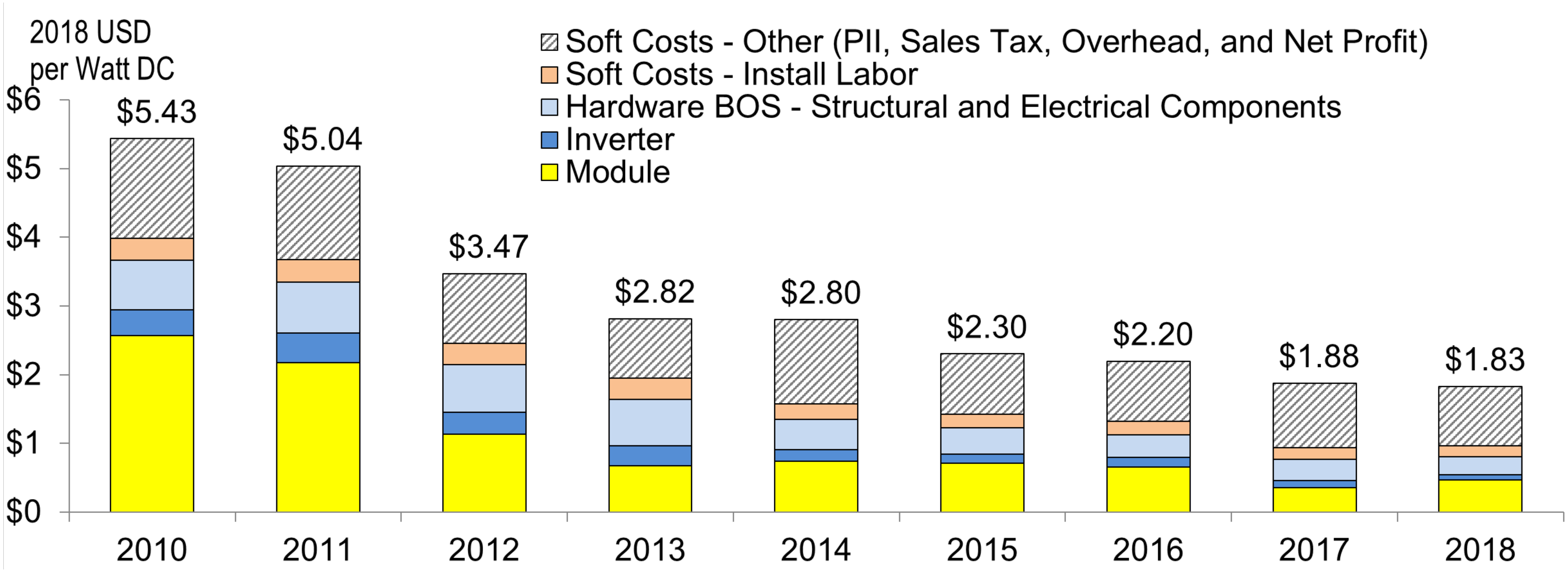
Commercial PV: Model Outputs



Q1 2018 benchmark by location: 200-kW commercial system cost (2018 USD/Wdc)

This figure presents the benchmark from our commercial model by location in the top U.S. solar markets (by 2017 installations). The main cost drivers for different regions in the commercial PV market are the same as in the residential model (labor rates, sales tax, and cost of doing business index), but also include costs associated with wind or snow loading.

Commercial PV: Capital Cost Benchmark Historical Trends



From 2010 to 2018 there was a 66% reduction in the commercial PV system cost benchmark. Approximately 79% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 82% over that time period. An additional 5% can be attributed to labor, which dropped 50% over that time period, with the final 16% attributable to other soft costs, including PII, sales tax, overhead, and net profit.

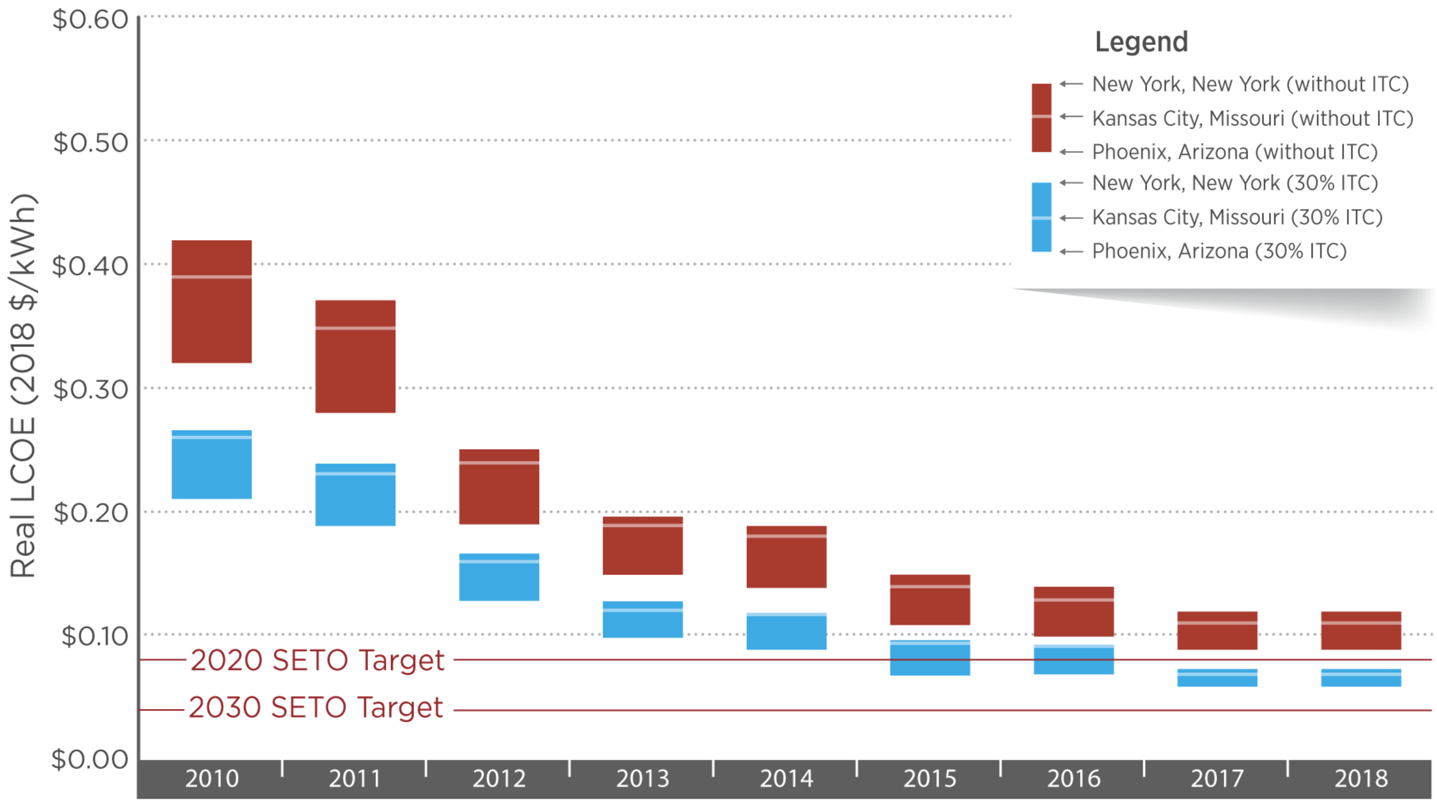
Looking at this past year, from 2017 to 2018 there was a 3% reduction in the commercial PV system cost benchmark. Cost reductions in most categories were moderated by a 32% increase in module spot price.

Commercial PV: LCOE assumptions

2018 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017	2018
Benchmark report									
Installed cost ($/W)	5.43	5.04	3.47	2.82	2.80	2.30	2.20	1.88	1.83
System size (kw-DC)	200	200	200	200	200	200	200	200	200
Inverter loading ratio	1.10	1.11	1.12	1.13	1.13	1.14	1.15	1.15	1.15
Ongoing NREL benchmarking									
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kw-yr)	33	30	28	25	22	19	19	18	18
Pre-inverter derate (%)	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	95.0%	95.6%	96.2%	96.8%	97.4%	98.0%	98.0%	98.0%	98.0%
Equity discount rate (real)	9.0%	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%	6.9%	6.9%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%	4.8%	4.8%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40%

All 2010–2017 data are from Fu et al. (2017), adjusted for inflation. The inverter replacement line-item in Fu et al. (2017) is incorporated into O&M expenses in this edition to be consistent with the 2018 O&M benchmark. Other important assumptions: commercial PV system LCOE assumes a 1) system lifetime of 30 years; 2) federal tax rate of 35% from 2010–2017, changing to 21% in 2018; 3) state tax rate of 7%; 4) MACRS depreciation schedule; 5) no state or local subsidies; 6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest of 1.75%); 7) a 6-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system; 8) a system size of 200 kW; 9) an inverter lifetime of 15 years; 10) a module tilt angle of 10 degrees and an azimuth of 180 degrees; 11) debt with a term of 18 years; and 12) $1.1 million of upfront financial transaction costs for a $100 million TPO transaction of a pool of commercial projects.

Commercial PV: LCOE Benchmark Historical Trends



From 2010 to 2018 there was a 72% reduction in the commercial PV system electricity cost benchmark (a 3% reduction was achieved from 2017 to 2018), bringing the unsubsidized LCOE between $0.09/kWh to $0.12/kWh ($0.06/kWh to $0.08/kWh when including the federal ITC). This reduction is 91% towards achieving SETO's 2020 commercial PV LCOE goal, which is 8 cents/kWh in 2017 USD.

Note: For LCOE Kansas City, MO, without ITC cases are $0.39/kWh in 2010 and $0.11/kWh in 2018 in 2018 USD from Appendix. Thus, calculation is: (0.393 – 0.107)/(0.393 – 0.079) = 91%.

Contents

Utility-Scale PV: Model Structure

CORE COST DRIVERS

System Design
- Available land area
- Module efficiency
- System architecture

System Location

Company Structure

MODEL COST CATEGORIES

EPC-System Hardware
- Module
- Inverter
- Structural BOS
- Electrical BOS

EPC-Other Direct Costs
- Electrical labor
- Mechanical labor
- General construction labor
- Construction permit and inspection fees

EPC-Indirect Costs
- Engineering labor
- Construction permit administration
- EPC SG&A

Developer-Direct Costs
- Site control
- Land acquisition
- Interconnection studies, fees, and upgrades
- Transmission line

Developer-Overhead
- Project origination and acquisition
- Developer SG&A

INPUTS

System Hardware
- Equipment costs and quantities
- Sales tax

EPC Direct/Indirect Labor
- Wage rates by labor class and geography
- Person-hours per task by labor class
- Wage burden rates

EPC Other Costs
- SG&A markup
- Supply chain costs
- Other costs and fees

Developer Direct Costs by Category

Developer Overhead Markup

OUTPUTS

Total Equipment Costs

Total Direct and Indirect Labor Costs

Total EPC Other and Overhead Costs

Total Development Costs

Total Capital Cost

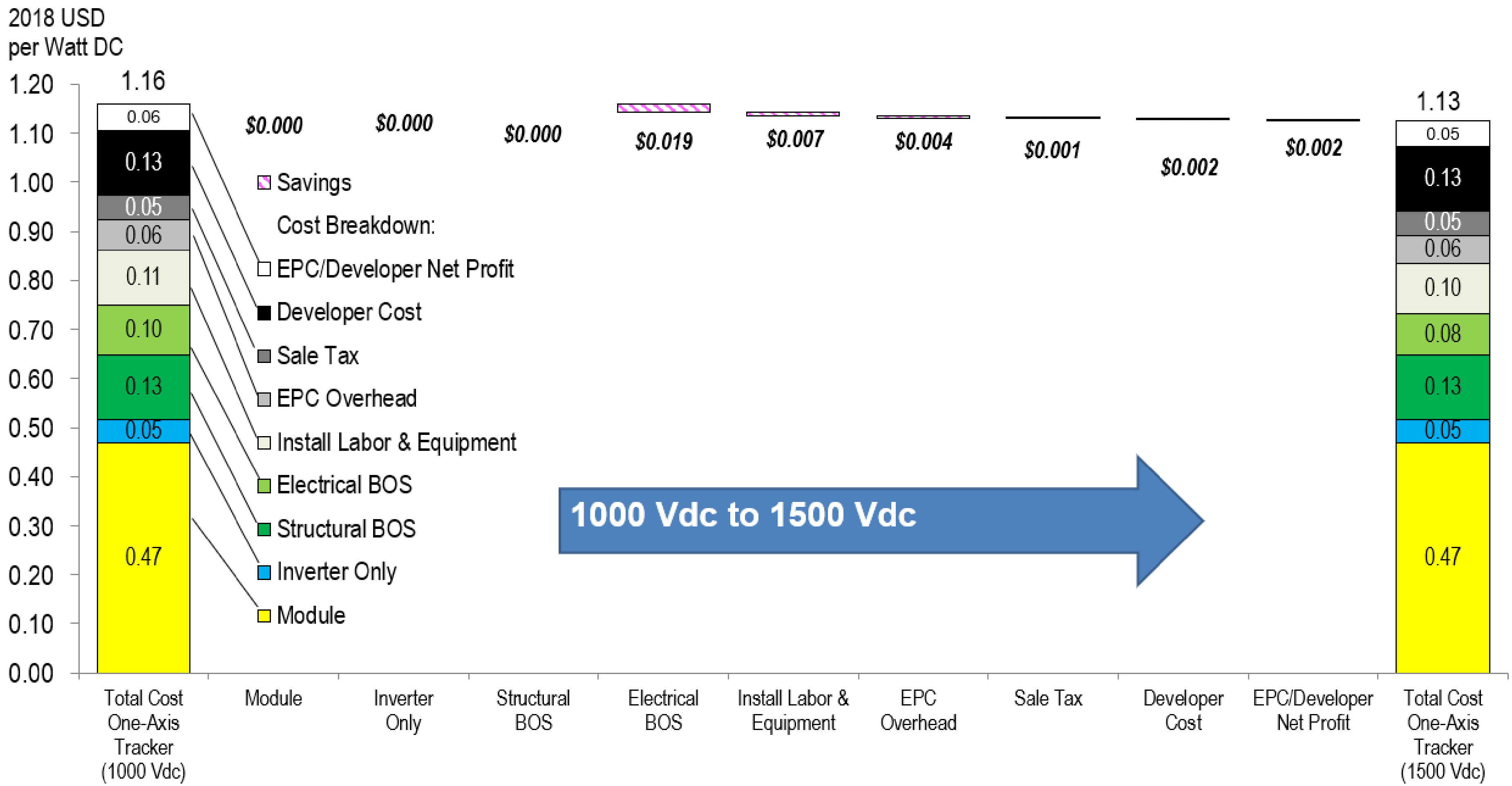
Utility-Scale PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	5-100 MW	A large utility-scale system capacity	Model assumption
Module efficiency	19.1%	Average module efficiency	NREL (2018)
Module price	$0.47/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	GTM and SEIA (2018), NREL (2018)
Inverter price	$0.04/Wdc (fixed-tilt) $0.05/Wdc (one-axis tracker)	Ex-factory gate (first buyer) price, Tier 1 inverters DC-to-AC ratio = 1.36 for fixed-tilt and 1.30 for one-axis tracker	Bloomberg (2018), Bolinger and Seel (2018), NREL (2018)
Structural components (racking)	$0.10–$0.21/Wdc for a 100-MW system; varies by location and system size	Fixed-tilt racking or one-axis tracking system	ASCE (2006), model assumptions, NREL (2018)
Electrical components	Varies by location and system size	Our model has been upgraded to 1,500 Vdc system, including conductors, conduit and fittings, transition boxes, switchgear, panel boards, onsite transmission, etc.	Model assumptions, NREL (2018), RSMeans (2018)
EPC overhead (% of equipment costs)	8.67%–13% for equipment and material (except for transmission line costs); 23%–69% for labor costs; varies by system size, labor activity, and location	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL (2018)
Sales tax	Varies by location	National benchmark applies an average (by state) weighted by 2017 installed capacities	RSMeans (2018), GTM and SEIA (2018)
Direct installation labor	Electrician: $19.74–$38.96 per hour; Laborer: $12.88–$25.57 per hour; Varies by location	Modeled labor rate assumes both non-union and union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2018), NREL (2018)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, FICA, builders' risk, public liability	RSMeans (2018)
PII	$0.03–$0.09/Wdc Varies by system size and location	For construction permits fee, interconnection, testing, and commissioning	NREL (2018)
Transmission line (gen-tie line)	$0.00–$0.02/Wdc Varies by system size	System size < 10 MW, use 0 miles for gen-tie line System size > 200 MW, use 5 miles for gen-tie line System size = 10–200 MW, use linear interpolation	Model assumptions, NREL (2018)
Developer overhead	2%–12% Varies by system size (100 MW uses 2%; 5 MW uses 12%)	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	Model assumptions, NREL (2018)
Contingency	3%	Estimated as markup on EPC cost	NREL (2018)
Profit	5%–8% Varies by system size (100 MW uses 5%; 5 MW uses 8%)	Applies a percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2018)

Utility-Scale PV: 1000 Vdc and 1500 Vdc

	1000 Vdc	1500 Vdc
Input Max. Voltage (Vdc)	1000	1500
Output Nominal AC Power (MVA, Mega Volt Amp)	0.792	4
Rated AC operating voltage (Vac)	356	550
Max. Efficiency	98%	98.4%
Reduce trenching	0%	33%
Reduce wiring and cables	0%	33%
Reduce the number of combiner boxes	0%	33%
Reduce the number power conversion station (inverter + transformer)	0%	64%
Reduce DC wiring loss from higher voltage	No	Yes
Reduce AC wiring loss from higher inverter efficiency	No	Yes
Power harvesting and system efficiency	Regular	Higher

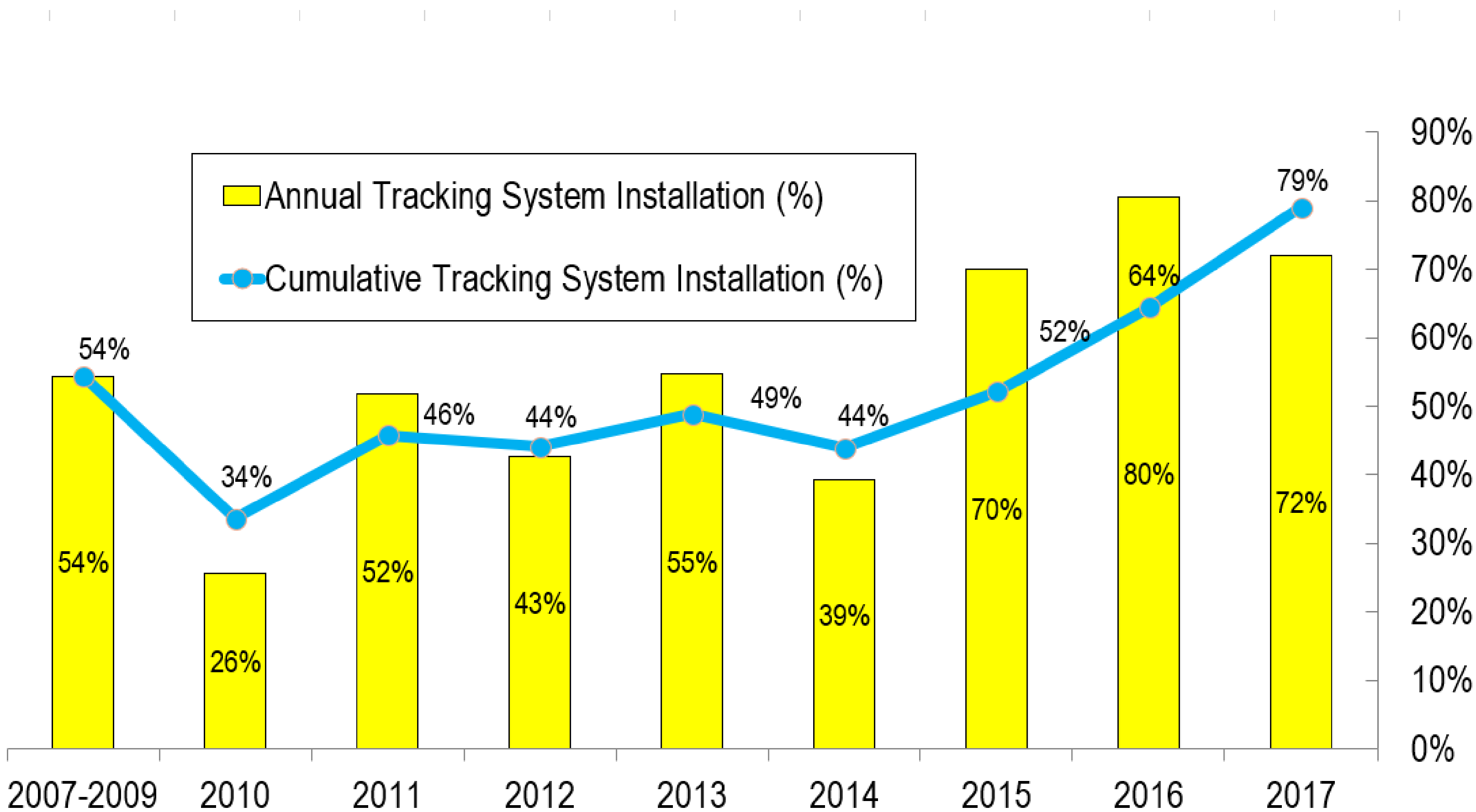
Utility-Scale PV: 1000 Vdc and 1500 Vdc



U.S. utility-scale one-axis tracking PV system cost reduction by upgrading from 1000 Vdc to 1500 Vdc (2018 USD/Wdc)

This figure demonstrates the cost savings from increased voltage from 1000 Vdc to 1500 Vdc. This change reduces the total cost by reducing trenching length, wiring and cable length, number of combiner boxes and power conversion station (inverter and transformer)

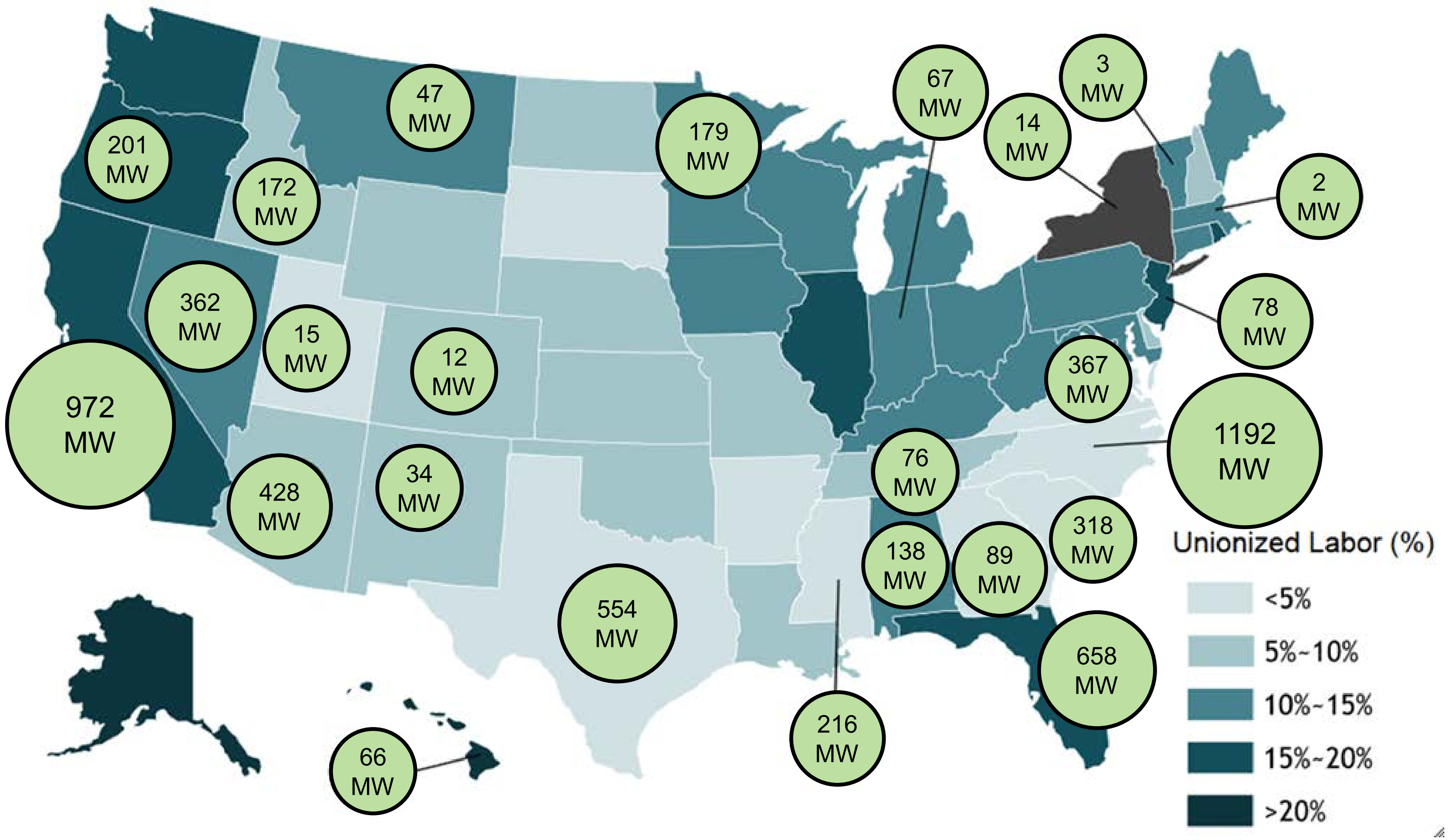
Utility-Scale PV: U.S. Fixed-Tilt vs. Tracking Systems



Percentage of U.S. utility-scale PV systems using tracking systems, 2007–2017 (Bolinger and Seel 2018)

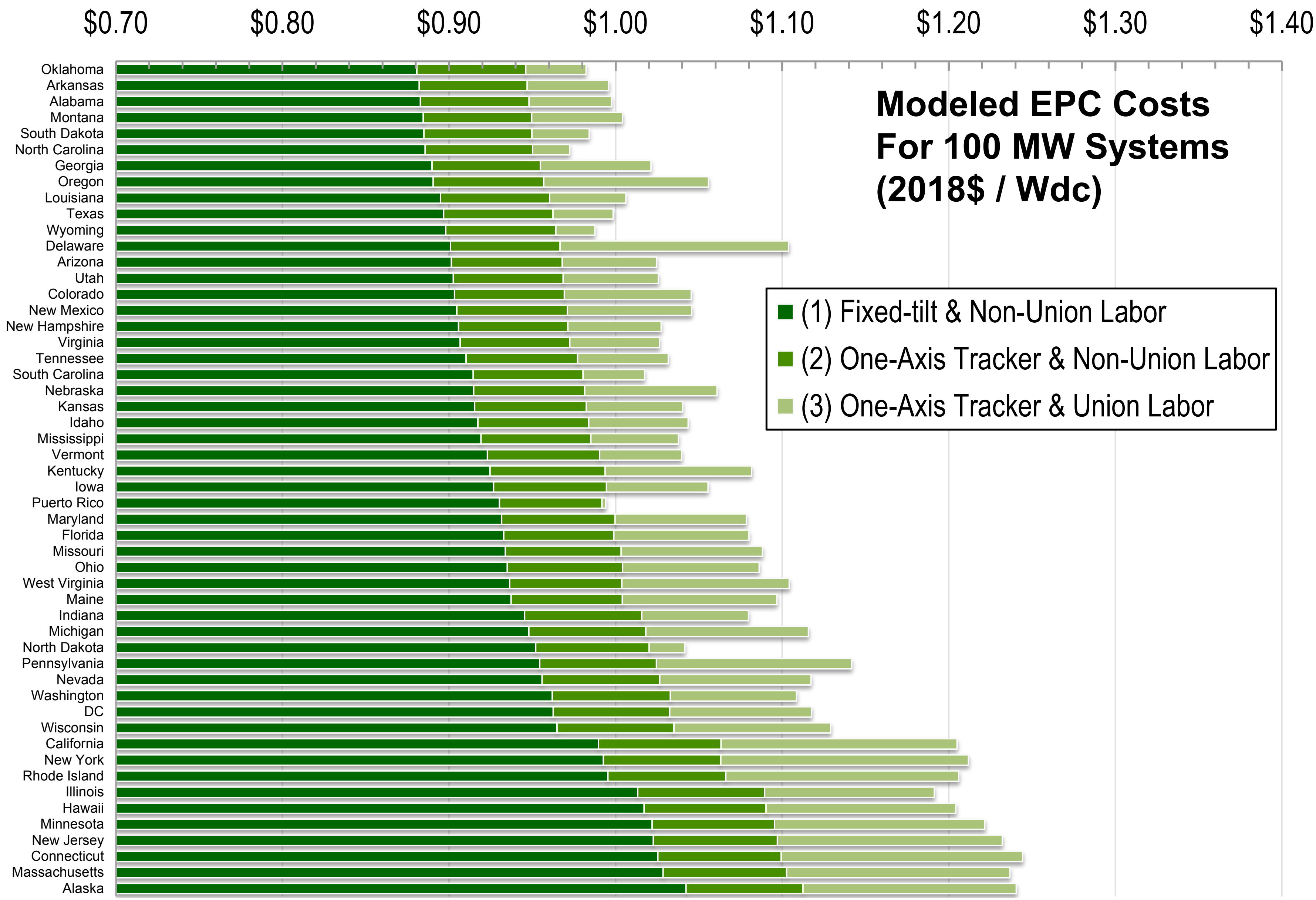
This figure shows the percentage of U.S. utility-scale PV systems using tracking systems for 2007–2017. Although the data include one-axis and dual-axis tracking systems in the same “tracking” category, there are many more one-axis trackers than dual-axis trackers (Bolinger and Seel 2018). Cumulative tracking system installation reached 79% by 2017.

Utility-Scale PV: Union Labor Case

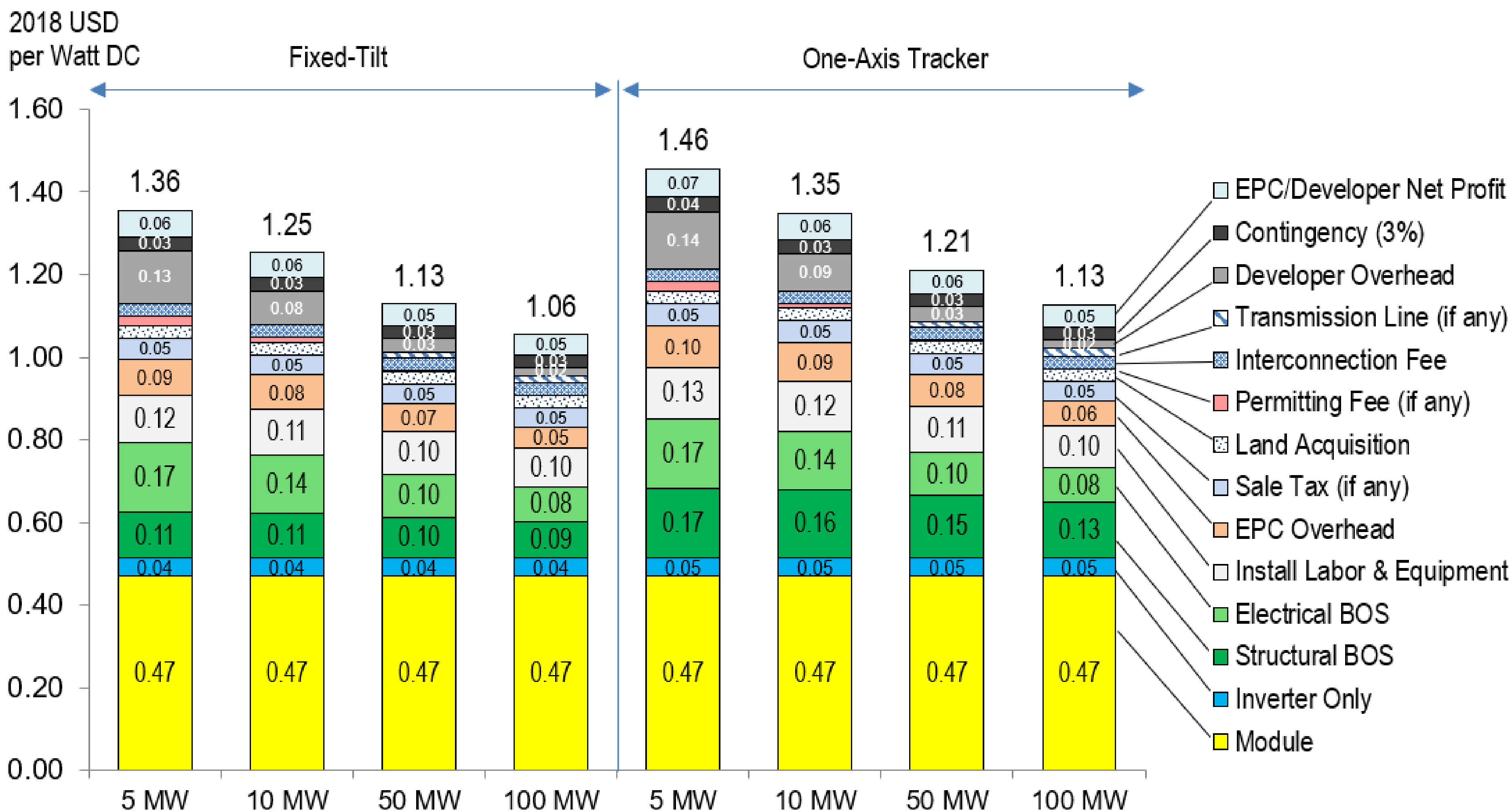


Although EPC contractors and developers tend to employ low-cost, non-union labor (based on data from BLS 2018) for PV system construction when possible, union labor is sometimes mandated. Construction trade unions may negotiate with the local jurisdiction and EPC contractor/developer during the public review period of the permitting process. This figure shows 2017 utility-scale PV capacity installed (GTM Research and SEIA 2018) and the proportion of unionized labor in each state (BLS 2018). The unionized labor number represents the percentage of employed workers in each state's entire construction industry who are union members. In our utility-scale model, both non-union and union labor rates are considered.

Utility-Scale PV: Model Outputs, EPC Only



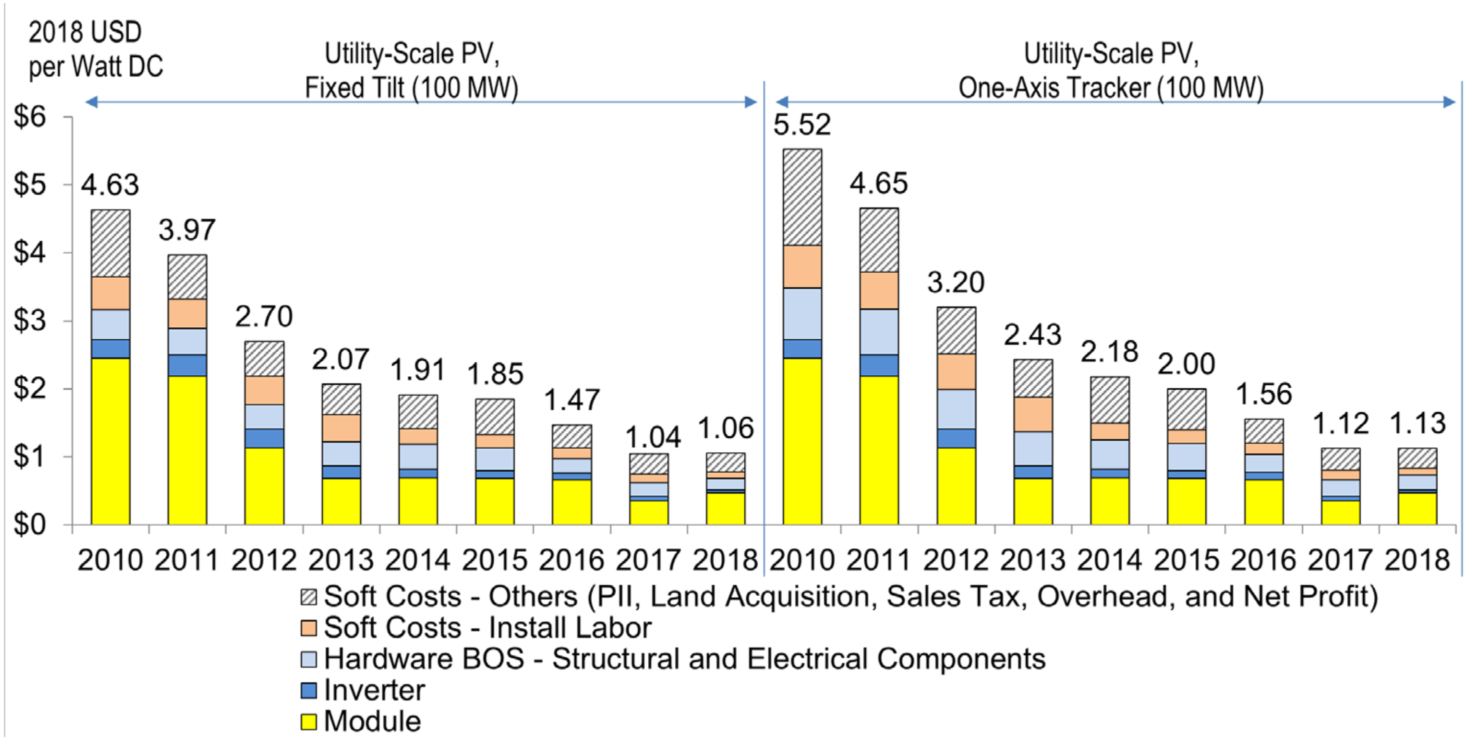
Utility-Scale PV: Model Outputs, EPC + Developer



Q1 2018 U.S. benchmark: utility-scale PV total cost (EPC + developer) 2018 USD/Wdc

(1) The national benchmark applies an average weighted by 2017 installed capacities.
(2) Non-union labor is used.
(3) Economies of scale—driven by BOS, labor, related markups, and development cost—are demonstrated.

Utility-Scale PV: Capital Cost Benchmark Historical Trends



From 2010 to 2018 there was a 77% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 80% reduction in the utility-scale (one-axis) PV system cost benchmark. Approximately 69% and 63% of that reduction can be attributed to total hardware costs (for fixed-tilt and one-axis systems respectively), as module prices dropped 81% over that time period. An additional 11%/12% can be attributed to labor, which dropped 81%/84% over that time period, with the final 20%/25% attributable to other soft costs, including PII, sales tax, overhead, and net profit (for fixed-tilt and one-axis systems respectively).

From 2017 to 2018, there was a 1% increase in the utility-scale (fixed-tilt) PV system cost benchmark, and a 0.4% increase in the utility-scale (one-axis) PV system cost benchmark. The majority of that increase can be attributed to the 32% increase in module spot price, which offset cost reductions in other areas.

Utility-Scale PV (One-Axis Tracker): LCOE assumptions

2018 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017	2018
Installed cost ($/W)	5.52	4.65	3.20	2.43	2.18	2.00	1.56	1.12	1.13
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kW-yr)	28	27	25	24	23	22	21	20	14
Pre-inverter derate (%)	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	96.0%	96.4%	96.8%	97.2%	97.6%	98.0%	98.0%	98.0%	98.0%
Inverter loading ratio	1.10	1.12	1.13	1.15	1.17	1.18	1.20	1.30	1.30
Equity discount rate (real)	7.4%	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%	6.3%	6.3%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%	4.5%	4.5%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40.0%

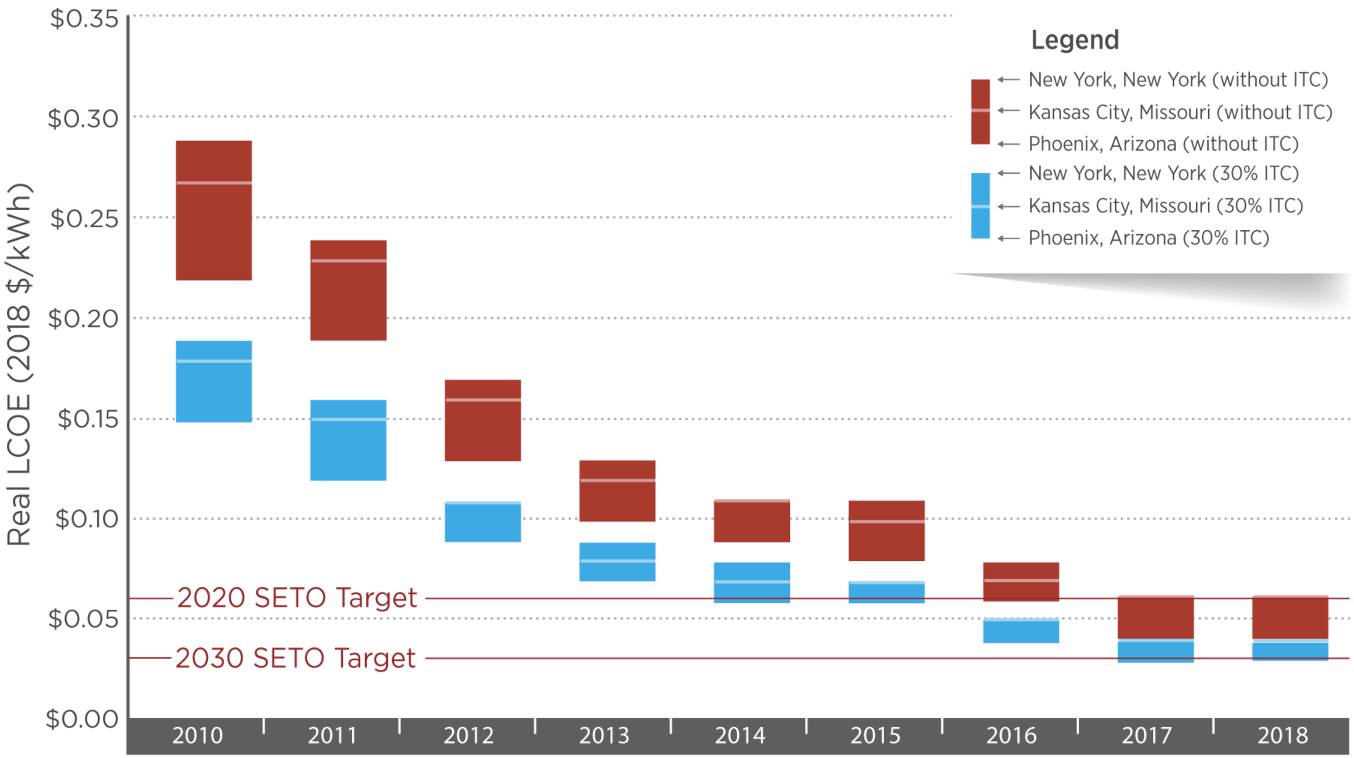
All 2010–2017 data are from Fu et al. (2017), adjusted for inflation. The inverter replacement line-item in Fu et al. (2017) is incorporated into O&M expenses in this edition to be consistent with the 2018 O&M benchmark. Other important assumptions: utility-scale PV system LCOEs assume a 1) system lifetime of 30 years; 2) federal tax rate of 35% from 2010–2017, changing to 21% in 2018; 3) state tax rate of 7%; 4) MACRS depreciation schedule; 5) no state or local subsidies; 6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning interest of 1.75%); 7) a 6-month construction loan with an interest rate of 4% and a fee of 1% of the cost of the system; 8) a system size of 100 MW; 9) an inverter lifetime of 15 years; 10) debt with a term of 18 years; and 11) $1.1 million of upfront financial transaction costs.

Utility-Scale PV (Fixed-Tilt): LCOE assumptions

2018 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017	2018
Installed cost ($/W)	4.63	3.97	2.70	2.07	1.91	1.85	1.47	1.04	1.06
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kW-yr)	28	26	24	22	20	18	18	17	13
Pre-inverter derate (%)	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	96.0%	96.4%	96.8%	97.2%	97.6%	98.0%	98.0%	98.0%	98.0%
Inverter loading ratio	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.30	1.36
Equity discount rate (real)	7.4%	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%	6.3%	6.3%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%	4.5%	4.5%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40.0%

All 2010–2017 data are from Fu et al. (2017), adjusted for inflation. The inverter replacement line-item in Fu et al. (2017) is incorporated into O&M expenses in this edition to be consistent with the 2018 O&M benchmark. Other important assumptions: utility-scale PV system LCOEs assume a 1) system lifetime of 30 years; 2) federal tax rate of 35% from 2010–2017, changing to 21% in 2018; 3) state tax rate of 7%; 4) MACRS depreciation schedule; 5) no state or local subsidies; 6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning interest of 1.75%); 7) a 6-month construction loan with an interest rate of 4% and a fee of 1% of the cost of the system; 8) a system size of 100 MW; 9) an inverter lifetime of 15 years; 10) debt with a term of 18 years; and 11) $1.1 million of upfront financial transaction costs.

Utility-Scale PV: LCOE Benchmark Historical Trends

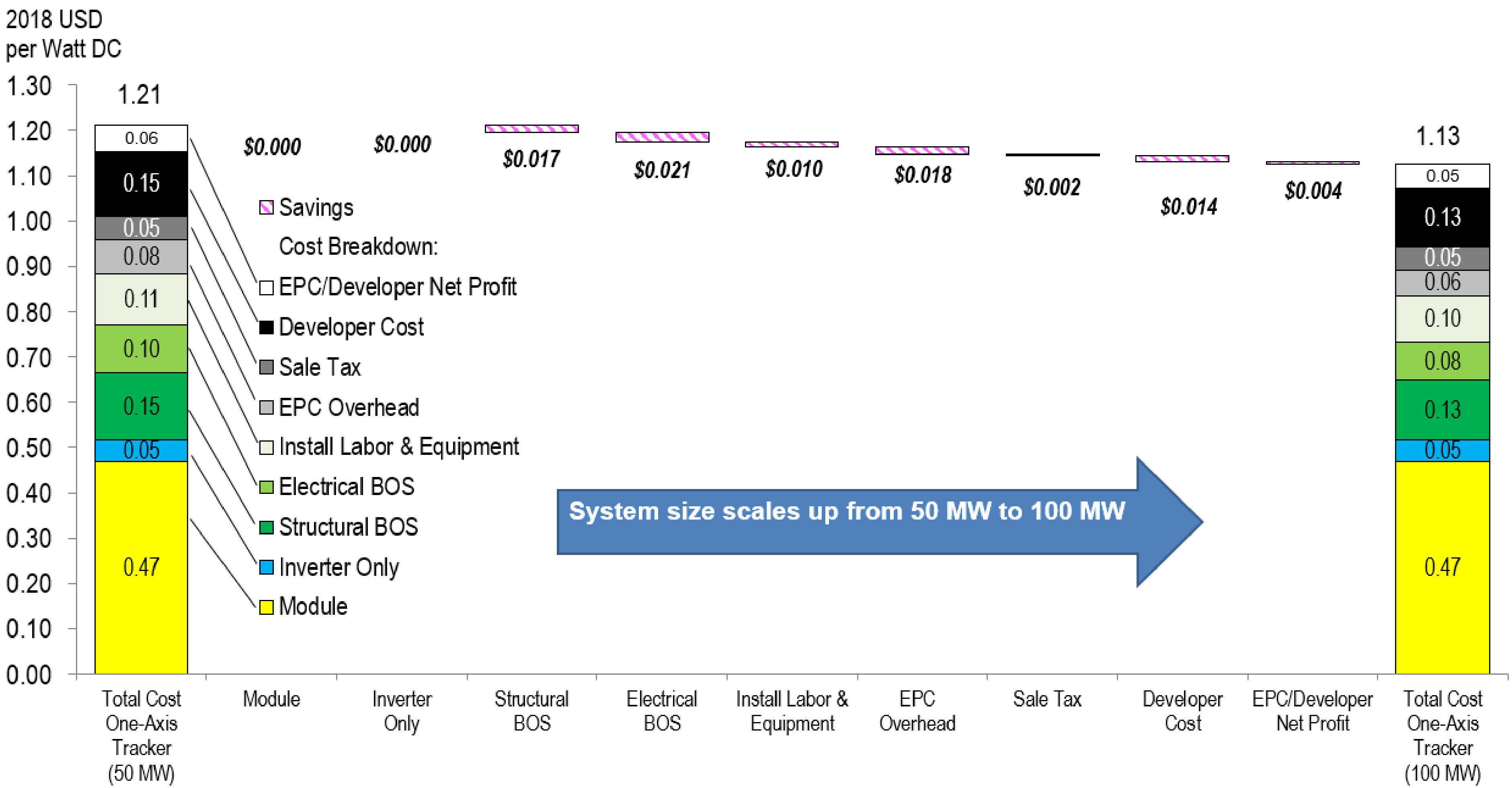


We use the fixed-tilt systems for LCOE benchmarks from 2010-2015 and then switch to one-axis tracking systems from 2016 to 2018 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in Appendix.

From 2010 to 2018 there was a 80%–82% reduction in the utility-scale PV system electricity cost benchmark (a 6%–9% reduction was achieved from 2017 to 2018), bringing the unsubsidized LCOE between $0.04/kWh to $0.06/kWh ($0.03/kWh to $0.04/kWh when including the federal ITC). This reduction signifies the achievement of SETO's 2020 utility-scale PV goal, which is 6 cents/kWh without subsidies.

Contents

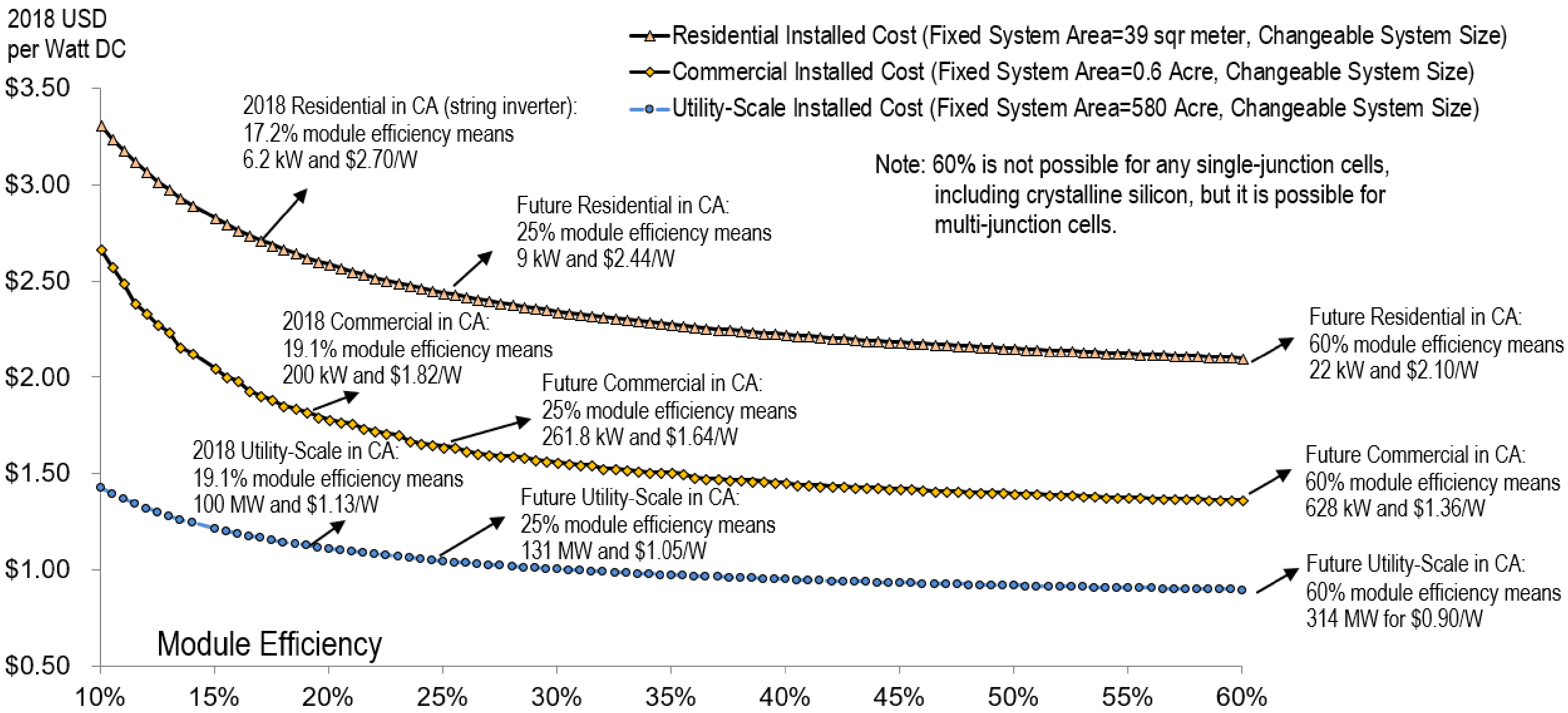
Model Application — Economies of Scale



Model application: U.S. utility-scale one-axis tracking PV system cost reduction from economies of scale (2018 USD/Wdc)

This figure demonstrates the cost savings from increased system size. Scaling up the system size from 50 MW to 100 MW reduces related costs in several ways: per-watt BOS costs because of bulk purchasing, labor costs because of learning-related improvements, and EPC overhead and developer costs because these fixed costs are spread over more installed watts. Note that non-union labor is used in this figure.

Model Application — Module Efficiency Impacts



Modeled impacts of module efficiency on total system costs (2018 USD/Wdc)

Our system cost models can also assess the economic benefits of high module efficiency. Because higher module efficiency reduces the number of modules required to reach a certain system size, the related racking or mounting hardware, foundation, BOS, EPC/developer overhead, and labor hours are reduced accordingly. This figure presents the relation between module efficiency and installed cost (with module prices held equal for any given efficiency) and demonstrates the cost-reduction potential due to high module efficiency. Note that fixed-tilt system is used in utility-scale curve and string inverter is used in residential curve.

Contents

Conclusions

(1) Based on our bottom-up modeling, the Q1 2018 PV cost benchmarks are $2.70/Wdc ($3.11/Wac) for residential systems, $1.83/Wdc ($2.10/Wac) for commercial systems, $1.06/Wdc ($1.38/Wac) for fixed-tilt utility-scale systems, and $1.13/Wdc ($1.54/Wac) for one-axis-tracking utility-scale systems. Overall, both modeled installed costs of residential and commercial PV systems continued to decline in Q1 2018. Meanwhile, modeled utility-scale PV system cost increased slightly.

(2) Lower inverter prices and higher module efficiencies continued contributing to these cost reductions across all three sectors. Increased module efficiency, smaller developer teams, lower structural and electrical BOS commodity prices, higher small installer market share, lower permitting cost, higher voltage configuration, and lower supply chain cost also contributed. On the other hand, higher module price, higher labor wages, higher advanced inverter adoption, and higher steel prices partially offset the cost reductions across the various sectors.

(3) Our bottom-up system cost models enable us to investigate regional variations, system configurations (such as 1500 Vdc vs. 1000 Vdc, MLPE vs. non-MLPE, fixed-tilt vs. one-axis tracker, and small vs. large system size), and business structures (such as installer vs. integrator, and EPC vs. developer).

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Appendix: PV System LCOE Benchmarks in 2018 USD$

Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2020 Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017	Q1 2018		
Residential											
Phoenix, AZ, no ITC	41.5	34.9	24.1	20.1	16.9	14.8	13.5	12.7	12.0		
Kansas City, MO, no ITC	50.7	42.6	29.4	24.6	20.6	18.0	16.5	15.5	14.7	10.2	5.1
New York, NY, no ITC	54.0	45.4	31.3	26.2	21.9	19.2	17.5	16.5	15.6		
Phoenix, AZ, ITC	27.6	23.1	16.1	13.4	11.2	9.8	8.9	8.5	7.9		
Kansas City, MO, ITC	33.7	28.3	19.7	16.4	13.7	11.9	10.9	10.3	9.7		
New York, NY, ITC	35.9	30.1	20.9	17.5	14.6	12.7	11.6	11.0	10.3		
Commercial											
Phoenix, AZ, no ITC	39.3	34.9	23.6	18.6	17.5	13.9	12.9	11.2	10.9		
Kansas City, MO, no ITC	41.6	37.0	25.0	19.7	18.6	14.7	13.7	11.9	11.5	7.9	4.1
New York, NY, no ITC	31.8	28.2	19.1	15.0	14.2	11.2	10.4	9.1	8.8		
Phoenix, AZ, ITC	25.9	23.0	15.7	12.4	11.6	9.2	8.6	7.5	7.3		
Kansas City, MO, ITC	27.5	24.3	16.6	13.1	12.3	9.8	9.1	7.9	7.7		
New York, NY, ITC	21.0	18.6	12.7	10.0	9.4	7.5	6.9	6.1	5.9		
Utility-scale (one-axis tracking)											
Phoenix, AZ, no ITC	26.7	22.0	15.1	11.5	10.1	9.0	7.1	5.5	5.2		
Kansas City, MO, no ITC	29.4	24.3	16.7	12.6	11.1	9.9	7.9	6.1	5.7	6.1	3.1
New York, NY, no ITC	21.1	17.4	12.0	9.1	8.0	7.1	5.6	4.4	4.1		
Phoenix, AZ, ITC	17.7	14.6	10.1	7.7	6.8	6.1	4.9	3.9	3.5		
Kansas City, MO, ITC	19.5	16.1	11.2	8.5	7.5	6.7	5.4	4.3	3.9		
New York, NY, ITC	14.0	11.6	8.0	6.1	5.4	4.8	3.9	3.1	2.8		
Utility-scale (fixed-tilt)											
Phoenix, AZ, no ITC	27.3	22.9	15.6	11.9	10.7	10.1	8.1	6.0	5.8		
Kansas City, MO, no ITC	29.2	24.4	16.7	12.7	11.5	10.7	8.6	6.4	6.2		
New York, NY, no ITC	22.4	18.7	12.8	9.7	8.8	8.3	6.7	4.9	4.8		
Phoenix, AZ, ITC	18.2	15.2	10.5	8.1	7.3	6.8	5.5	4.2	4.0		
Kansas City, MO, ITC	19.4	16.3	11.2	8.6	7.8	7.2	5.9	4.5	4.2		
New York, NY, ITC	14.9	12.5	8.6	6.6	6.0	5.6	4.6	3.4	3.2		

Acronyms and Abbreviations

AC	alternating current
BOS	balance of system
DC	direct current
EPC	engineering, procurement, and construction
FICA	Federal Insurance Contributions Act
GW	gigawatt
ILR	inverter loading ratio
ITC	investment tax credit
LCOE	levelized cost of energy
MACRS	Modified Accelerated Cost Recovery System
MLPE	module-level power electronics
NEC	National Electric Code
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PERC	passivated emitter and rear cells
PII	permitting, inspection, and interconnection
PV	photovoltaic(s)
Q	quarter
R&D	research and development
SAM	System Advisor Model
SG&A	sales, general, and administrative
TPO	third party ownership
USD	U.S. dollars
Vdc	volts direct current
Wac	watts alternating current
Wdc	watts direct current