PROGRAM ON WATER GOVERNANCE

Site C Inquiry:

Submission #6 to the BC Utilities Commission

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This is the sixth submission by the University of British Columbia's Program on Water Governance to the BC Utilities Commission Inquiry Respecting Site C.

The Program on Water Governance (www.watergovernance.ca) is co-hosted by UBC's Department for Geography and Institute for Resources, Environment, and Sustainability. Dr. Karen Bakker, Professor and Canada Research Chair at the University of British Columbia, is the Co-Director of the Program.

The Program on Water Governance previously published five reports on Site C, which are available online (watergovernance.ca/projects/sitec/). In addition, several submissions have been made to the BCUC, including:

Document Title	BCUC ref number/ submission date	Suggested Reference
Reassessing the Need for Site C	F106-1 (August 2017)	Hendriks et al. (April 2017)
Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives	F106-1 (August 2017)	Hendriks (July 2016)
Submission to the British Columbia Utilities Commission regarding the Site C Hydroelectric Project	F106-2 (August 2017)	Raphals and Hendriks (August 2017)
An Updated Portfolio Present Value Cost Analysis of the Site C Project	F106-5 (October 2017)	Raphals and Hendriks (October 2017)
Policy Issues of Relevance to the Inquiry Respecting Site C	F106-6 (October 2017)	Hendriks and Raphals (October 2017a)
Comments on BC Hydro's Appendix M: "Flaws in Hendricks [sic] /Rafals [sic]/Baker [sic] ("UBC") Report"	F106-7 (October 2017)	Hendriks and Raphals (October 2017b)

In addition, two PowerPoint presentations were filed, following the authors' presentations at the Commission's Technical Conference on October 14, 2017:

Document Title	BCUC ref number/ submission date	Suggested Reference

Presentation: Policy Issues of Relevance to the Inquiry Respecting Site C	F106-8 (October 2017)	R. Hendriks (October 2017a)
Presentation: An Updated Portfolio Present Value Cost Analysis of the Site C Project	F106-9 (October 2017)	P. Raphals (October 2017a)

This current submission consists of two additional documents, prepared in response to the Commission's invitation (A-22):

Document Title	BCUC ref number/ submission date	Suggested Reference
Comments on the Commission's Draft Alternative Portfolio to Site C	F106-10 (October 2017)	R. Hendriks (October 2017b)
Alternative Portfolios with regard to the Site C Project	F106-11 (October 2017)	P. Raphals (October 2017b)

It should be noted that both documents of this current submission contain embedded spreadsheets.

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The authors are solely responsible for the report's contents. The report does not reflect the views of the University of British Columbia or of the funder.

Sincerely,

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Comments on the Commission's Draft Alternative Portfolio to Site C

Richard Hendriks

October 2017

ABOUT THE AUTHOR

Richard Hendriks is the director of Camerado Energy Consulting, an Ontario-based firm providing environmental assessment, energy planning, policy analysis, and research services to clients across Canada. For the past two decades, he has been engaged in the planning and assessment of several proposed large-scale hydroelectric developments, and provided testimony before regulatory bodies concerning their environmental effects, economic viability, socio-economic impacts and implications for Indigenous rights. Mr. Hendriks has played a key role in environmental assessment and negotiation processes regarding large hydroelectric and mining projects for several First Nations across Canada, including for the Innu Nation in Labrador with respect to the Lower Churchill Project, and for the Treaty 8 Tribal Association, with respect to the Site C Hydroelectric Project.

From 1999 to 2002, Mr. Hendriks was the environmental and engineering analyst for Innu Nation in relation to hydroelectric development proposals in Labrador. There, he participated in environmental assessment, negotiation of an environmental protection chapter of an impacts and benefits agreement in relation to the Lower Churchill Project, and technical and research support for negotiation of a compensation agreement for the existing Churchill Falls Project.

In 2003, Mr. Hendriks joined Chignecto Consulting Group as an Associate where he provided resource negotiation and environmental assessment support services to Indigenous groups across Canada. His work included negotiation of impacts and benefits agreements, regulatory interventions, and assessment of environmental, economic and social impacts and benefits related to hydroelectric, transmission and mining developments.

Since 2009, as director of Camerado Energy Consulting, Mr. Hendriks has conducted and managed environmental, technical and economic review of several large-scale proposed resource projects, including the Lower Churchill Hydroelectric Generation Project, the Labrador-Island Transmission Link, the Site C Clean Energy Project, the Côte Gold Project, and the proposed Slave River Hydro Project. He has also assessed the potential for compensation to Indigenous communities for historic and ongoing effects of hydroelectric and transmission development in Ontario, Labrador, Manitoba and the Northwest Territories.

In 2010, Mr. Hendriks testified before the Alberta Utilities Commission during its Inquiry on Hydroelectric Power Generation that was reviewing the policy, planning and regulatory context for additional hydroelectric development in that Province. The following year, Mr. Hendriks presented testimony on several economic and environmental matters before the Joint Review Panel for the Lower Churchill Project, who accepted many of his recommendations. More recently, Mr. Hendriks testified on several occasions before the Joint Review Panel for the Site C Project, who adopted several of his recommendations. In May 2014, the Manitoba Public Utilities Board qualified Mr. Hendriks as an expert in the policy and planning aspects of large-scale hydroelectric developments, including the socioeconomic implications and environmental consequences for Indigenous communities of these developments.

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1 Summary and introduction

This report aims to address the following items in the Commission's letter of October 11, 2017 concerning the alternative portfolio:

> **10. Energy and capacity Options**. The energy and capacity options included in the illustrative Portfolio Alternatives are: wind, energy efficiency DSM programs, capacity focused DSM programs, optional TOU rate, industrial curtailment rate, and batteries. It is acknowledged that there may be additional options that could reduce the cost of the Alternative Portfolios, such as codes and standards, Independent Power Producer (IPP) contract renewals, upgrade of existing BC Hydro assets, geothermal, solar, biomass, etc.
>
> **4. Size of the Alternative Portfolio**. The Alternative Portfolio has been sized to replace Site C energy and capacity used for domestic consumption. Specifically, the Alternative Portfolio does not include generation built for the purpose of export. The starting point is the "energy and capacity load resource balance after planned resources" from BC Hydro's F2017–F2019 RRA.

Section 2 of this report addresses item 10 above by exploring in detail the potential for solar PV to have much lower system costs and levelized costs than have been presumed to date. Specifically, this section explores information from the National Renewable Energy Laboratory (NREL) that was filed recently during the Site C Inquiry. The key findings of this section are as follows:

- **Economies of scale**. BC Hydro uses a 5 MW utility-scale solar project to represent all utility-scale solar. However, over the last four years a substantial gap has opened up such that a 100 MW facility is now 25% less expensive on a per watt basis than a 5 MW facility. **A cost of US$1.11/$W_{dc}$ or CA$1.39/$W_{dc}$ determined in this report is materially lower (i.e. 15%) than the CA$1.64/$W_{dc}$ that BC Hydro was requested to model in IR.2.47 in the Commission Preliminary Report**.
- **Utility-scale PV cost has declined**. The current estimated cost of developing a 100-MW solar facility in Cranbrook, BC is $79/MWh based on the most recent information provided by NREL for installations in the first quarter of 2017.
- **Residential solar costs projected to decline**. Though residential solar levelized costs are currently much higher than commercial and utility levelized costs, based on the projections reviewed by the NREL they are projected to decline much as costs have declined for commercial and utility-scale solar over the past 5 years.
- **Utility-scale solar becomes competitive with wind**. Solar PV becomes cost-effective with wind for use as an energy resource in the alternative resource portfolio based on

the wind decline scenario presented in Commission's Preliminary Report.[1]

- **Projected solar PV cost declines for BC**. Solar PV costs are projected to decline substantially to 2040 even under projections of small declines based on recent analyses carried out by NREL, and projected in this analysis for Cranbrook, BC.

Table 1: Summary of solar PV levelized costs for Cranbrook, BC

Year	Residential 5.7 kW ($/MWh)	Commercial 200 kW ($/MWh)	Commercial 1 MW ($/MWh)	Utility-Scale 5 MW ($/MWh)	Utility-Scale 100 MW ($/MWh)
2017	216	155	140	117	79
Small decline	50%	40%	40%	25%	25%
Large decline	60%	50%	50%	50%	50%
High in 2040	108	93	84	88	59
Low in 2040	86	78	70	58	39

Section 3 addresses item 4 above by examining the potential for an increase in solar PV self-generation, meeting a meaningful portion of future energy and capacity requirements. The effect of this generation would be to reduce the requirements for energy and capacity from the grid, effectively lowering the requirements that would need to be met by the alternative portfolio. The key findings of this section are as follows:

- **Residential solar**. Residential solar PV is projected to decline below the Tier 2 rates by 2025 in the regions of the Province having greater solar potential, including the East Kootenay (i.e. Cranbrook), the Peace Region and Selkirk (Kelowna). Adoption in the lower mainland, though not studied in this submission, is considered less likely given the much lower solar insolation in that region of the Province.
- **Commercial solar**. Commercial 200 kW PV is projected to decline in cost below MGS rates in the regions of the Province having greatest solar potential. The potential for more widespread adoption will likely depend on the future increases in electricity rates and the ultimate decline in the cost of solar PV.
- **Utility-scale solar**. Large industrial rates are low compared to the projected cost of 5 MW solar PV. As a result, the analysis does not suggest widespread development of 5 MW utility-scale solar, though larger facilities may prove economic in particular situations.

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[1] A-13, IR.2.46 which projects wind cost declines of 25% by 2025 and 45% by 2040.

2 Solar PV as an alternative resource

2.1 Introduction

In reviewing the alternative portfolios filed by the Commission, we noted that there was no allowance for use of solar photovoltaic (PV) resources. We analyzed the potential for the use of utility-scale solar PV as a cost-effective resource in the resource portfolios by making use of the following information:

- The National Renewable Energy Lab (NREL) most recent solar cost data for Q1 2017 ("NREL 2017"),[2] which is attached to this submission as Appendix A;
- The NREL solar cost data for Q1 2016 ("NREL 2016")[3] for comparative purposes and to assist in establishing cost trends over time;
- NREL solar radiation data manual for solar insolation values[4] for the generic locations used in NREL 2017 and NREL 2016;
- The NREL Annual Technology Baseline for utility-scale solar, commercial solar and residential solar; and
- NRCan photovoltaic potential and insolation dataset for Canadian municipalities[5] for solar insolation values for BC municipalities.

2.2 Current cost of solar PV

Since 2010, the NREL has maintained detailed data concerning the evolution of the solar PV industry in the U.S., and has published an annual cost benchmark of solar PV each of the previous two years, the most recent report having been released during the Site C Inquiry. Based on the information provided in NREL 2016 and NREL 2017, we have assembled detailed cost data for several sizes of solar PV installations, as summarized in Table 2 below.

The data in this table reflect the cost assumptions made in NREL 2017,[6] and the conditions and costs of solar PV in Kansas City, Missouri, the location that NREL uses as an average for the

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[2] NREL. August 2017. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. Available at: https://www.nrel.gov/docs/fy17osti/68925.pdf.

[3] NREL. August 2017. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. Available at: https://www.nrel.gov/docs/fy16osti/66532.pdf.

[4] NREL. Undated. Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors. Available at: http://rredc.nrel.gov/solar/pubs/redbook/. (See Missouri).

[5] NRCan. Photovoltaic and solar resource maps. Available at: http://www.nrcan.gc.ca/18366.

[6] NREL 2017, see Table 6 Residential, Table 8 Commercial, Table 10 Utility-scale.

entirety of the United States. All data in the this table are taken from NREL 2017,[7] with the exception of data for the year 2016 for 100 kW, 1 MW and 5 MW systems, which is from NREL 2016.[8,9] Shaded data have been interpolated based on the known cost data in the remainder of the table, particularly the cost differences between different sizes of systems in the years 2016 and 2017.

Table 2: NREL 2017 solar photovoltaic system costs (2017$US/Wdc)

Class =>	Residential	Commercial	Commercial	Utility-scale	Utility-scale
Size =>	5.7 kW	200 kW	1 MW	5 MW	1-axis 100 MW
Year	($US/Wdc)	($US/Wdc)	($US/Wdc)	($US/Wdc)	($US/Wdc)
2010	7.24	5.36	5.38	5.40	5.44
2011	6.34	4.97	4.89	4.78	4.59
2012	4.48	3.42	3.37	3.29	3.15
2013	3.92	2.78	2.70	2.59	2.39
2014	3.44	2.76	2.64	2.46	2.15
2015	3.18	2.27	2.21	2.12	1.97
2016	2.98	2.17	2.03	1.92	1.54
2017	2.80	1.85	1.74	1.49	1.11
3-yr decline	-19%	-33%	-34%	-39%	-48%
2-yr decline	-12%	-19%	-21%	-30%	-44%
1-yr decline	-6%	-15%	-14%	-22%	-28%

The table illustrates the following:

- **Recent data**. NREL 2017 includes cost data for systems deployed in the first quarter of 2017, making it the most recent data made available to the Site C Inquiry.
- **System cost declines**. Modelled PV costs across all sectors and sizes of solar PV systems, as they have for each year since 2010. System costs have declined to a greater extent for utility-scale solar compared to commercial solar, which in turn have declined more than residential solar.
- **Recent economies of scale**. In its 2013 IRP and again in its 2016 resource options update, BC Hydro uses a 5 MW utility-scale solar project to represent all utility-scale solar. As Table 2 illustrates, this assumption was appropriate until about 2013 as there

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[7] See NREL 2017, Figure 35, Figure 28 and Figure 20.

[8] See NREL 2016, Figure 16 and Figure 21.

[9] The analysis in NREL 2017 uses a more robust set of current and historical assumptions. Where there are discrepancies in reported data with NREL 2016, the most recent data are used.

was little cost difference between a 5 MW and 100 MW solar facility per watt of installed capacity. However, over the last four years a substantial gap has opened up such that a 100 MW facility is now 25% less expensive on a per watt basis than a 5 MW facility. **A cost of US$1.11/$W_{dc}$ or CA$1.39/$W_{dc}$ is materially lower (i.e. 15%) than the CA$1.64/$W_{dc}$ that BC Hydro was requested to model in IR.2.47 in the Commission Preliminary Report**.

System costs and not levelized costs are usually used to compare solar PV across jurisdictions due to different policy drivers and incentives, system location and production characteristics, cost of capital, debt-equity ratio and other factors. However, in the absence of a mature solar industry in BC from which to obtain installed system costs, we have applied the levelized cost assumptions used in NREL 2017 to estimate levelized costs for solar in various locations in BC.

NREL 2017 reports levelized cost of energy (LCOE) information for residential (5.7 kW), commercial (200 kW) and utility-scale (100 MW) solar. Specifically, NREL 2017 proceeds as follows in estimating LCOE at different locations:

> To estimate regional LCOEs across the United States, we combine modeled regional installed cost with localized solar irradiance and weather data, a PV performance model, and a pro forma financial analysis that models the revenue, operating expenses, taxes, incentives, debt structures, and cash flows for a representative PV system.[10]

Using this approach and the detailed design[11] and financial assumptions[12] presented in the study, NREL calculated the LCOE in Phoenix, Kansas City, and New York City, corresponding to higher, medium, and lower resource areas in the United States. This information is summarized in Table 3 along with estimated levelized costs for a 1 MW commercial project and a 5 MW utility-scale solar project by interpolating from the levelized costs for the 200 kW and 100 MW solar facilities presented in NREL 2017, and the differences in system costs for the different installed capacities presented in Table 2.

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[10] NREL 2017, p.46.

[11] NREL 2017, see Table 6 Residential, Table 8 Commercial, Table 10 Utility-scale.

[12] NREL 2017, see Table 7 Residential, Table 9 Commercial, Table 11 Utility-scale.

Table 3: NREL 2017 levelized cost of energy for various locations ($2017 CAD)[13]

Location	Residential 5.7 kW ($/MWh)	Commercial 200 kW ($/MWh)	Commercial 1 MW ($/MWh)	Utility-Scale 5 MW ($/MWh)	Utility-Scale 100 MW ($/MWh)
Phoenix	161	115	103	85	55
Kansas City	196	141	127	106	70
New York	209	150	135	113	76

The above table illustrates the degree to which solar PV levelized costs have declined across much of the United States. In locations such as New York City, with similar solar insolation to that of the best locations in BC, the cost of utility-scale solar is below $80/MWh in Canadian dollars.

In order to estimate the levelized costs in British Columbia of solar PV of different installed capacities, cost estimates were developed for Cranbrook, a representative location of high solar potential in the province. Lacking detailed cost information for actual solar developments in Cranbrook, costs were estimated from a ratio of the solar insolation for this location and that of New York. Considering the similar solar insolation for the two locations, this is considered to provide a reasonable approach for the purposes of developing estimated costs, recognizing that the assumptions used for system design and costing in NREL 2017 are also likely to differ somewhat from those that would apply in BC. Some of these assumptions could result in moderate cost increases, and others in moderate cost decreases. A procurement process would be necessary in order to firm up more precise cost estimates.

The following table presents the estimated costs of solar development in Cranbrook based on the NREL 2017 data.

Table 4: Estimated levelized costs for solar development in Cranbrook, BC ($2017CAD)

Location	Residential 5.7 kW ($/MWh)	Commercial 200 kW ($/MWh)	Commercial 1 MW ($/MWh)	Utility-Scale 5 MW ($/MWh)	Utility-Scale 100 MW ($/MWh)	Latitude Tilt Insolation ($kWh/m^2/day$)
Phoenix	161	115	103	85	55	6.50
Kansas City	196	141	127	106	70	4.90
New York	209	150	135	113	76	4.60
Cranbrook	216	155	140	117	79	4.45

[13] NREL 2017, Appendix B converted to 2017$CAD at USD = 1.25CAD.

The above table provides up-to-date information to the Commission concerning estimated levelized cost of solar energy from different sized facilities. In particular, during the Site C Inquiry, there was very limited discussion concern solar PV beyond a 5 MW utility-scale solar facility. This analysis provides an estimate of the cost of a large utility-scale solar PV development in BC, addressing the substantial declines noted by NREL in the cost of 100-MW facilities compared to 5-MW facilities. **The current estimated cost of developing a 100-MW solar facility in Cranbrook, BC is $79/MWh based on the information provided in NREL 2017.**

With respect to smaller utility-scale projects, this information updates BC Hydro's most recent resources options update for a 5 MW solar facility.[14] This estimate was based on solar PV system cost data up to 2014,[15] excluding more than two years of additional data used in NREL 2017. The findings of the resource options update are summarized below for a 5 MW single-axis tracker in Cranbrook compared to the current estimate in Table 4.

Table 5: BC Hydro 2016 resource options update 5 MW solar PV unit energy costs

Transmission Region	Site Location	Solar potential	UEC at POI (5% discount rate)	UEC at POI (7% discount rate)	Estimate based on NREL 2017
		(kWh/kW/year)	($/MWh)	($/MWh)	($/MWh)
East Kootenay	Cranbrook	1,510	$145	$171	$117

In evaluating the information in Table 5, it is important to note that the BC Hydro estimates are not inclusive of the substantial declines in system costs of both commercial and utility-scale solar PV noted by NREL, and summarized in Table 2. Indeed, to the extent that a 30% decline in system costs results in a comparable decline in levelized energy costs, BC Hydro's estimates would have declined from $145/MWh to $112/MWh (5% discount rate) and from $171/MWh to $132/MWh. The current estimate of $117/MWh is within this range of $112/MWh to $132/MWh.

2.3 Potential future cost declines

2.3.1 Utility-scale PV

NREL's Annual Technology Baseline provides up-to-date information on the NREL's review of utilty-scale, commercial and residential PV costs, including potential for future cost declines.

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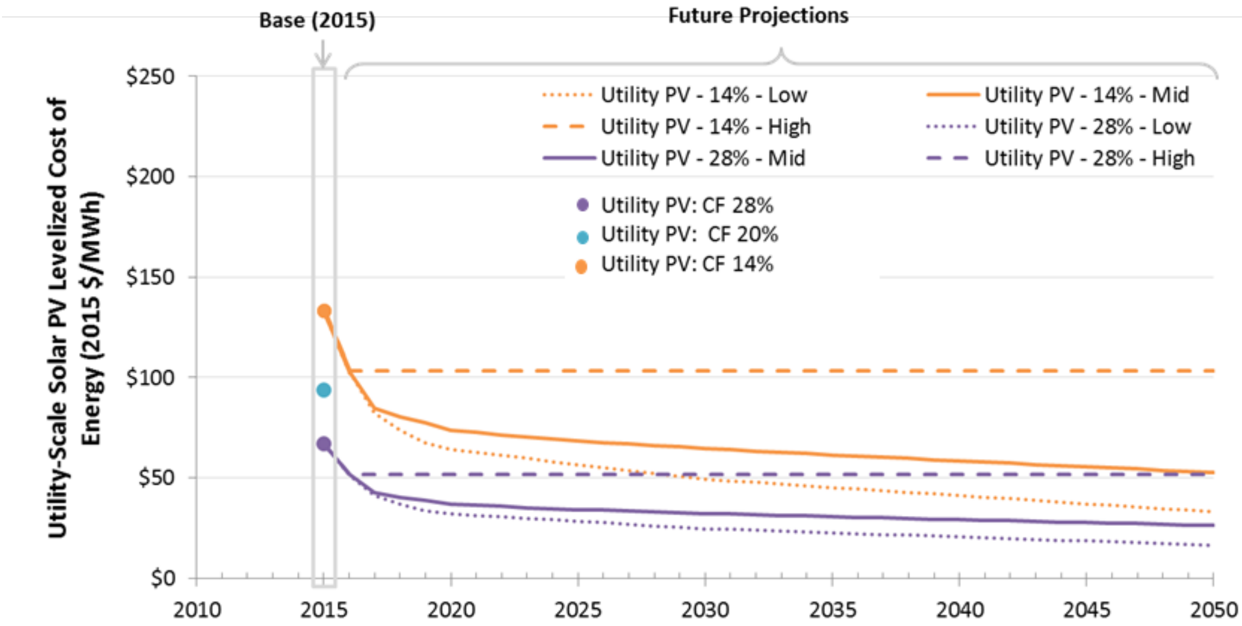
[14] BC Hydro. October 2016. Resource Options Update Result Summary.

[15] Compass Energy Consulting. June 2015. British Columbia Solar Market Update 2015. Final Report. Prepared for BC Hydro and FortisBC. Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf.

Figure 1 illustrates the NREL levelized cost of energy projections of 14 projections from separate institutions dating to 2015 and projecting out to 2050.

Figure 1: NREL summary of utility-scale PV levelized cost projections to 2050[16]



Utility PV plant LCOE projections based on current market conditions
Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), http://atb.nrel.gov

The current utility-scale levelized cost for Kansas City, the middle of the ranges reflected in the above figure, is US$56/MWh in 2017 as reported in NREL 2017, or CA$70/MWh as indicated in

[16] NREL. 2017. Annual Technology Baseline. Utility-scale PV Power Plants. Available at: https://atb.nrel.gov/electricity/2017/index.html?t=su.

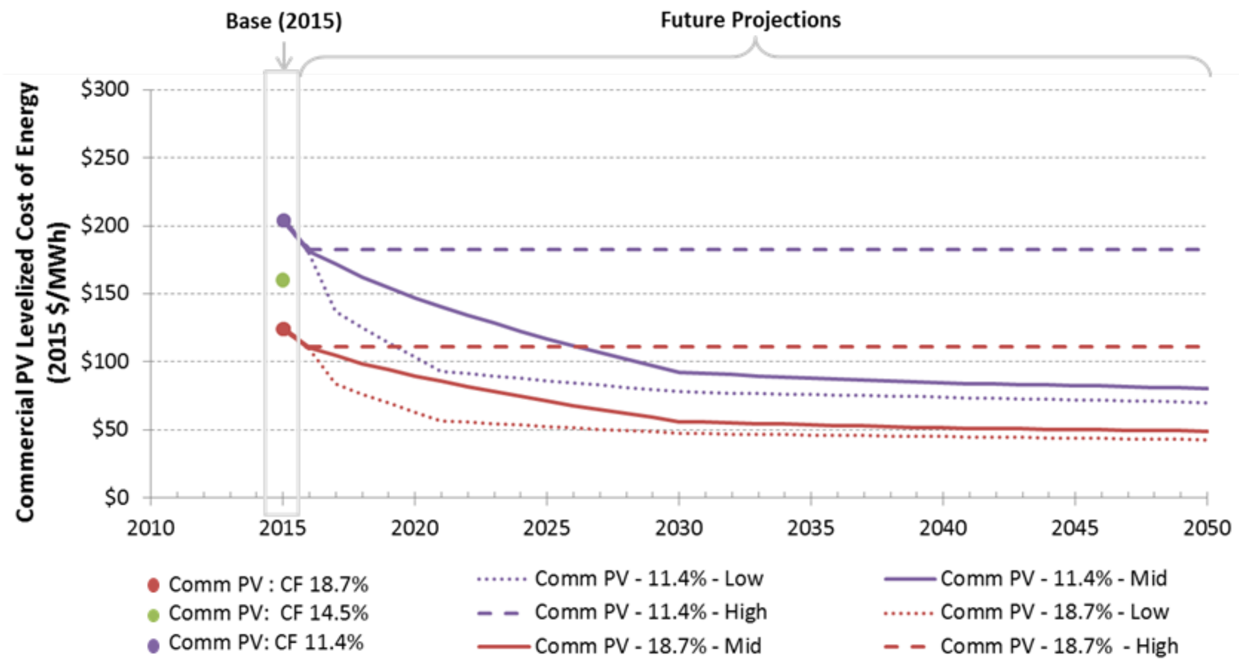
Table 3. In other words, the costs are tracking on both the mid and the low forecasts and well below the middle of the high forecast. Costs will average about US$40/MWh in 2040 if they follow the mid forecast, or a decline of about 25%. Costs will average about US$30/MWh if they follow the low forecast, a decline of nearly 50%. Based on these projections, we have modeled costs declines for utility-scale solar PV in BC based on two scenarios out to 2040: a decline of 25% and a decline of 50% from current costs based on NREL 2017.

2.3.2 Commercial solar PV

NREL has also summarized cost projections for commercial solar based on 10 system price projections from 5 separate institutions.

Figure 2 illustrates this analysis projecting levelized costs out to 2050. As for utility-scale solar PV, the high cost forecast has not materialized as the current levelized cost average is US$113/MWh, or CA$141/MWh as indicated in Table 3. Presuming costs decline on the mid cost forecast, they will average about US$65 in 2040, a decline of about 40%. In the event that they track along the low forecast, the will average about US$60 in 2040, a decline of 45%. Based on these projections, and since costs are currently tracking on the low forecast we have modeled costs declines for commerical solar PV in BC based on two scenarios out to 2040: a decline of 40% and a decline of 50% from current costs based on NREL 2017.

Figure 2: NREL summary of commercial PV levelized cost projections to 2050[17]



Commercial PV plant LCOE projections based on current market conditions
Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), http://atb.nrel.gov

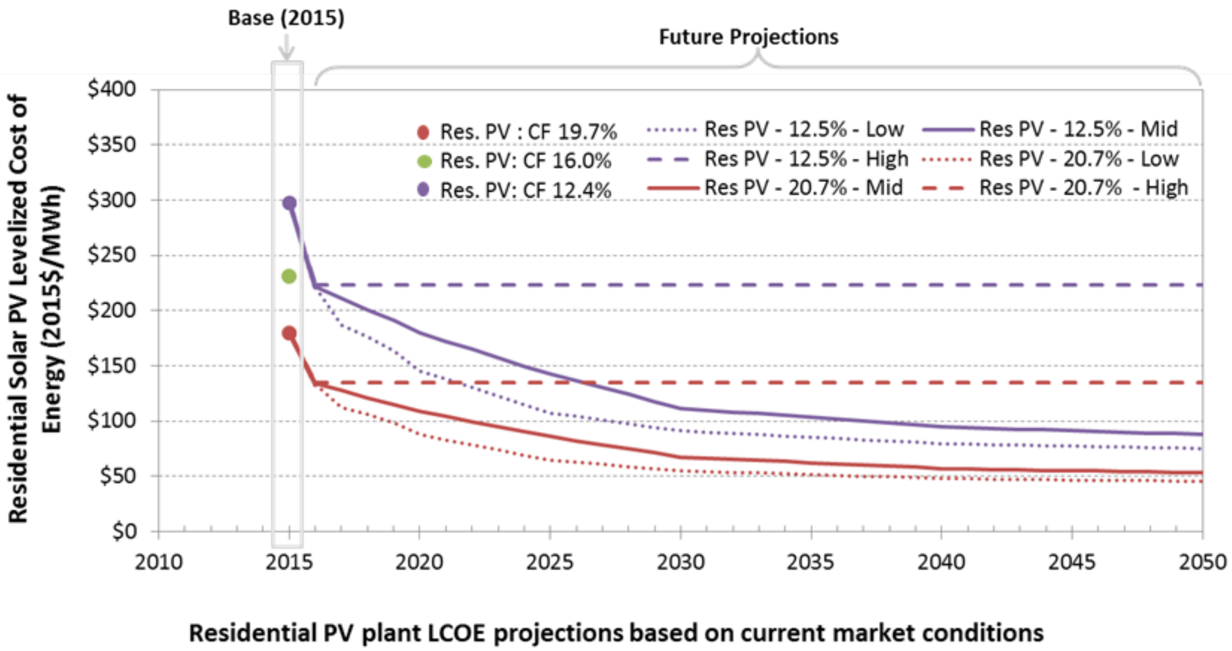
2.3.3 Residential solar PV

NREL summarized cost projections for commercial solar based on 11 system price projections from 7 separate institutions.

[17] NREL. 2017. Annual Technology Baseline. Commercial PV. Available at https://atb.nrel.gov/electricity/2017/index.html?t=sd.

Figure 3 illustrates this analysis projecting levelized costs out to 2050. Current average costs are US$157/MWh or CA$196/MWh as reported in Table 3. Once again, costs are tracking such that the high cost forecast appears unlikely to materialized. Presuming costs decline based on the mid cost forecast, they will average about US$75 in 2040, a decline of just over 50%. In the event that they track along the low forecast, they will average about US$60 in 2040, a decline of just over 60%. Based on these projections, we have modeled costs declines for residential solar PV in BC based on two scenarios out to 2040: a decline of 50% and a decline of 60% from current costs based on NREL 2017.

Figure 3: NREL summary of residential PV levelized cost projections to 2050



Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), http://atb.nrel.gov

2.4 Summary of future solar PV costs

Based on the discussion and analysis above, and the spreadsheets attached as Appendix B, future solar PV costs have been calculated for Cranbrook under the high and low future cost scenarios. These values are summarized in the table below.

Table 6: Detailed summary of solar PV levelized costs for Cranbrook, BC

	Residential	Commercial	Commercial	Utility-Scale	Utility-Scale
	5.7 kW	200 kW	1 MW	5 MW	100 MW
Year	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2017	216	155	140	117	79
Small decline	50%	40%	40%	25%	25%
Large decline	60%	50%	50%	50%	50%
High in 2025	146	101	91	89	59
High in 2030	127	95	86	88	59
High in 2035	115	93	84	88	59
High in 2040	108	93	84	88	59
Low in 2025	139	92	82	66	44
Low in 2030	114	84	75	60	41
Low in 2035	97	80	72	58	39
Low in 2040	86	78	70	58	39

Key observations from this table include the following:

- **Residential solar costs decline**. Though residential solar levelized costs are currently much higher than commercial and utility levelized costs, based on the projections reviewed by the NREL they are projected to decline much as costs have declined for commercial and utility-scale solar over the past 5 years, as shown in Table 2. Should this decline materialize, it may have implications for residential self-generation. This is discussed further below in section 3.2.
- **Utility-scale solar becomes competitive with wind**. Under the "small decline" scenario, utility-scale solar declines to $59/MWh by 2025, while under the large decline scenario it reaches $44/MWh by 2025 and below $40/MWh by 2040. Solar PV becomes cost-effective with wind for use as an energy resource in the alternative resource portfolio based on the wind decline scenario presented in Commission's Preliminary Report.[18]

3 Potential for self-generation using solar PV

3.1 Introduction

Based on the revised cost information for solar PV developed in section 2, this section explores the potential for BC Hydro customer self-generation either as a means to offset on-site generation or through participation in the standard offer program or other similar program developed in the future.

In addition to the information used in section 2 of this report, this section makes use of the following information

- BC Hydro's response to RRA information request IR.BCUC 2.203.1, which provides detailed information concerning energy consumption and customers by rate class;
- BC Hydro's response to RRA information request IR.BCUC 1.4.4, which provides additional information concerning energy consumption and customers by rate class; and
- BC Hydro's Electric Tariff, which presents rates by rate class.

The potential for BC Hydro customers to self-generate is a function of both the declining cost of solar PV and the increases in future electricity rates. As rates increase and solar PV costs decline, the latter may reach "price parity" with the former, incenting customers to offset a

[18] A-13, IR.2.46 which projects wind cost declines of 25% by 2025 and 45% by 2040.

portion of their consumption through self-generation. This form of generation is currently facilitated through BC Hydro's net metering program.[19]

In addition, self-generation may take the form of community, cooperative, corporate or other forms of collective generation of electricity from solar PV. This form of generation is currently facilitated through BC Hydro's Standing Offer Program (SOP) and its Micro-SOP for First Nations and Communities, both of which are currently suspended and under review.[20] As solar costs decline, evidence from other jurisdictions suggests that corporate solar and community solar would become much more common in British Columbia. [21,22]

3.2 Evaluating the potential for self-generation using solar PV

The approach to evaluating the potential for self-generation using solar PV involves the comparison of solar PV costs against electric rate for the various classes of BC Hydro customers. The rates used in this analysis are those from BC Hydro's Electric Tariff, inclusive of the 5% rate rider and 5% GST making them comparable to the estimates for the NREL levelized costs which also included an allowance for federal and/or state taxes.[23] Rates are analyzed under two scenarios, one with no real rate increases and the second with rate increases of 1% real per year.

Based on information filed by BC Hydro during the RRA, the average annual generation for several of the most common customer classes is presented in the table below.

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[19] BC Hydro. Generating your own electricity. Available at: https://www.bchydro.com/work-with-us/selling-clean-energy/net-metering.html?WT.mc_id=rd_netmetering.

[20] BC Hydro. Standing Offer Program. Available at: https://www.bchydro.com/work-with-us/selling-clean-energy/standing-offer-program.html.

[21] Reuters. June 21, 2017. America's hungriest wind and solar power users: big companies. Available at: https://www.reuters.com/article/us-usa-companies-renewables-analysis/americas-hungriest-wind-and-solar-power-users-big-companies-idUSKBN19C0E0.

[22] Greentech Media (GTM). February 6, 2017. America's Community Solar Market Will Surpass 400 MW in 2017. Available at: https://www.greentechmedia.com/articles/read/us-community-solar-market-to-surpass-400-mw-in-2017.

[23] NREL 2017, see Table 6 Residential, Table 8 Commercial, Table 10 Utility-scale.

Table 7: Annual energy consumption by rate class (2017 to 2019)[24]

	Residential – Tier 2	General Service - MGS	General Service - LGS	Large Industrial
	Average	Average	Average	Average
Year	(MWh/year)	(MWh/year)	(MWh/year)	(MWh/year)
F2017	4.08	209.28	1,583.46	71,575.27

As a proxy estimate of the size of solar facility that a given customer class might choose to develop, the average annual consumption presented in

[24] RRA, calculated from response to BCUC. 2.03.1

Table 7 was compared to the average annual generation of solar projects of the size investigated in section 2 above. These average annual generation values are presented in the following table.

Table 8: Annual energy generation by solar facility installed capacity

	Residential	Commercial	Commercial	Utility-Scale	Utility-Scale
	5.7 kW	**200 kW**	**1 MW**	**5 MW**	**100 MW**
Size (MW)	0.0057	0.2	1	5	100
Hours	8760	8760	8760	8760	8760
C.F.	0.15	0.15	0.18	0.18	0.18
(MWh/year)	**7**	**263**	**1,577**	**7,884**	**157,680**

Based on this information, a comparison of solar PV costs and electric rates was made for the following five pairings:

- Residential tier 2 rates : residential 5.7kW solar
- Medium General Service (MGS) : Commercial 200 kW solar
- Large General Service (LGS) : Commercial 1 MW solar
- Large industrial : Utility-scale 5 MW solar
- Large industrial : Utility-scale 100 MW solar

The four pairings match the consumption of the electricity customer and the generation of the solar resource quite closely with the possible exception of the final pairing. We included this pairing to evaluate the potential that large industrial customers may become concerned if their rates substantially exceed the cost of electricity generated from utility-scale solar.

The following five charts illustrate graphically the detailed information contained in Appendix B to this submission.

Figure 4: Residential rates compared to 5.7 kW solar

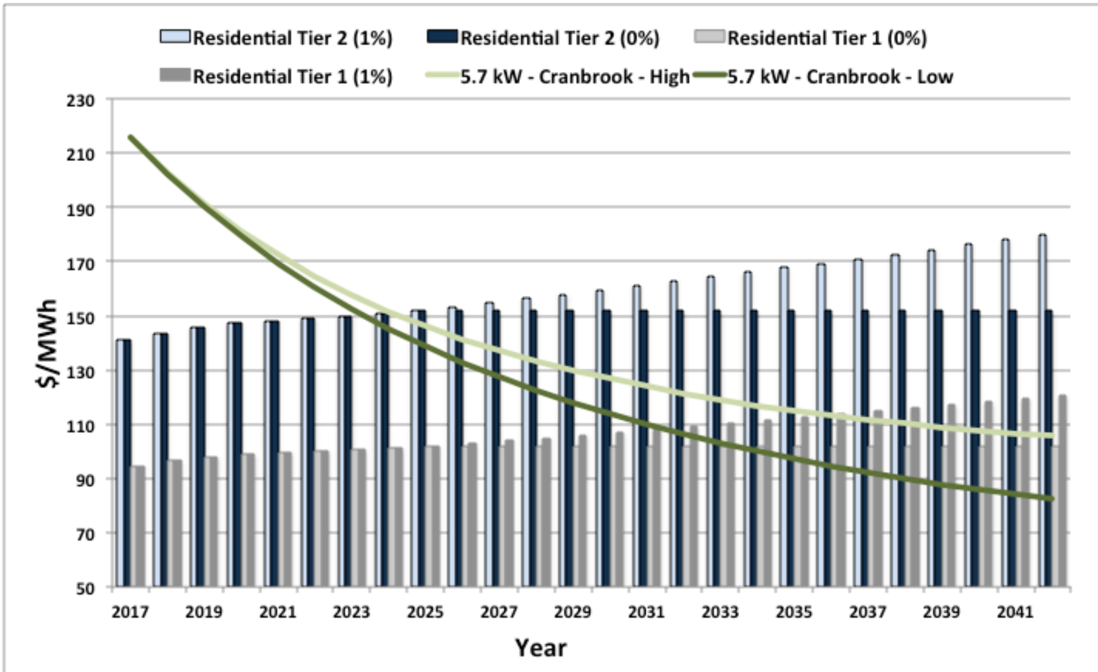


Figure 5: MGS rates compared to 200 kW solar

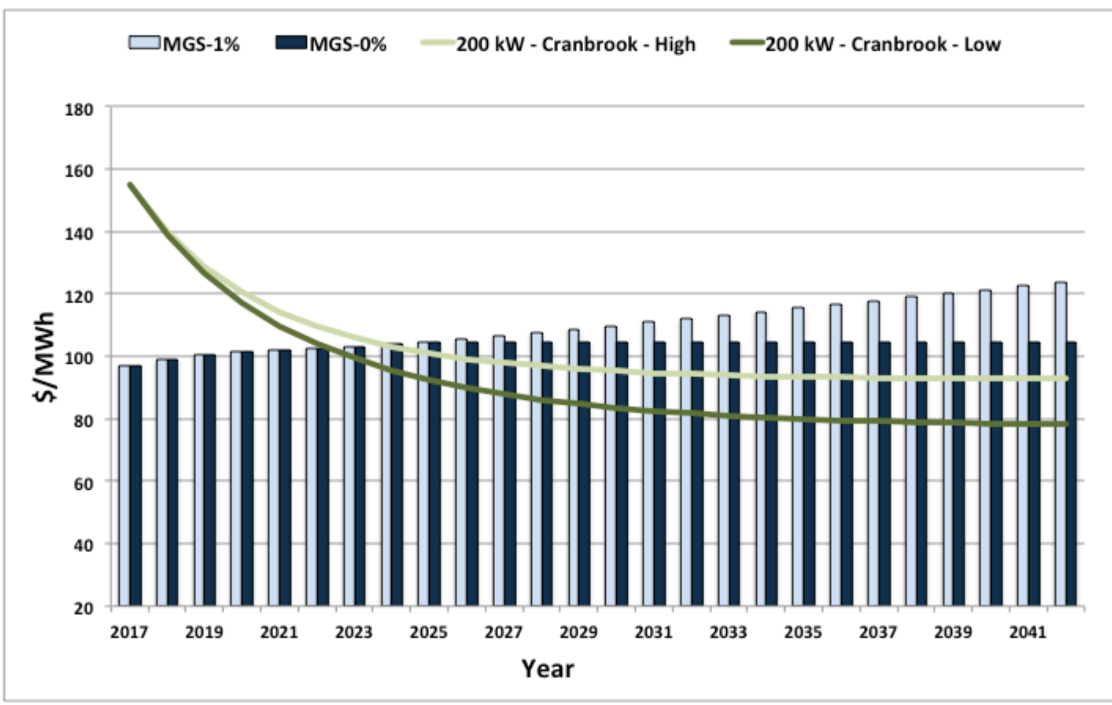


Figure 6: LGS rates compared to 1 MW solar

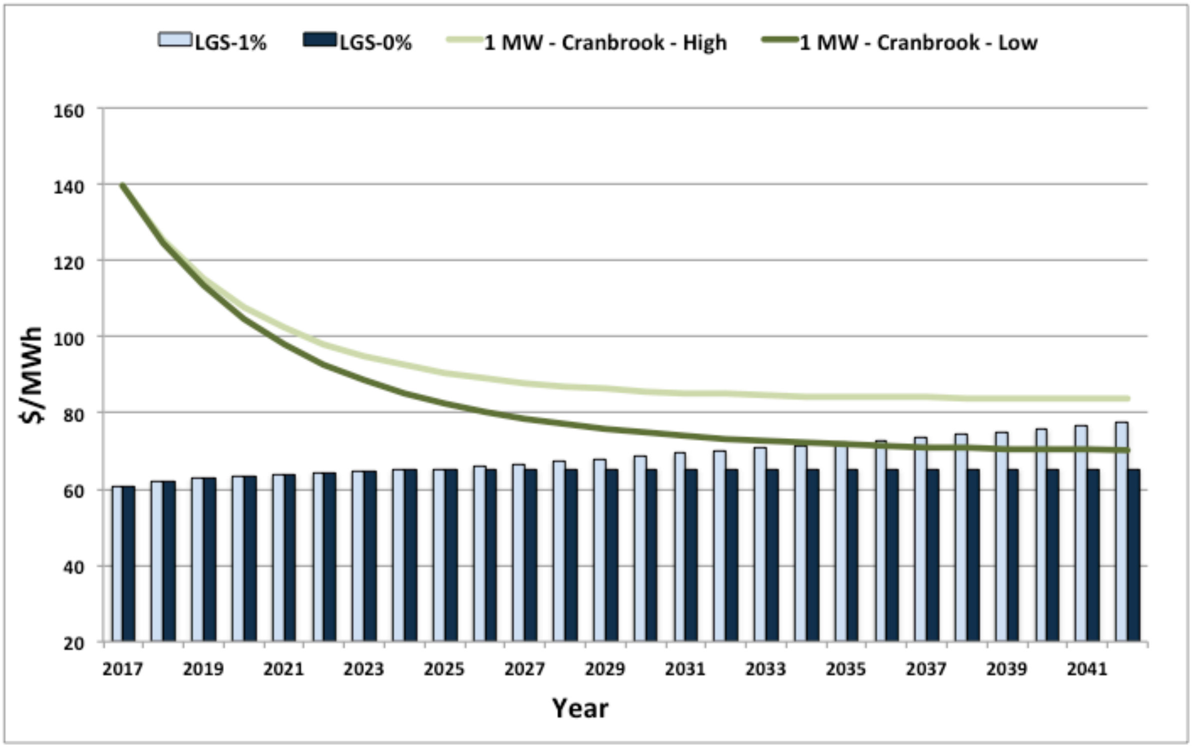


Figure 7: Large Industrial rates compared to 5 MW solar

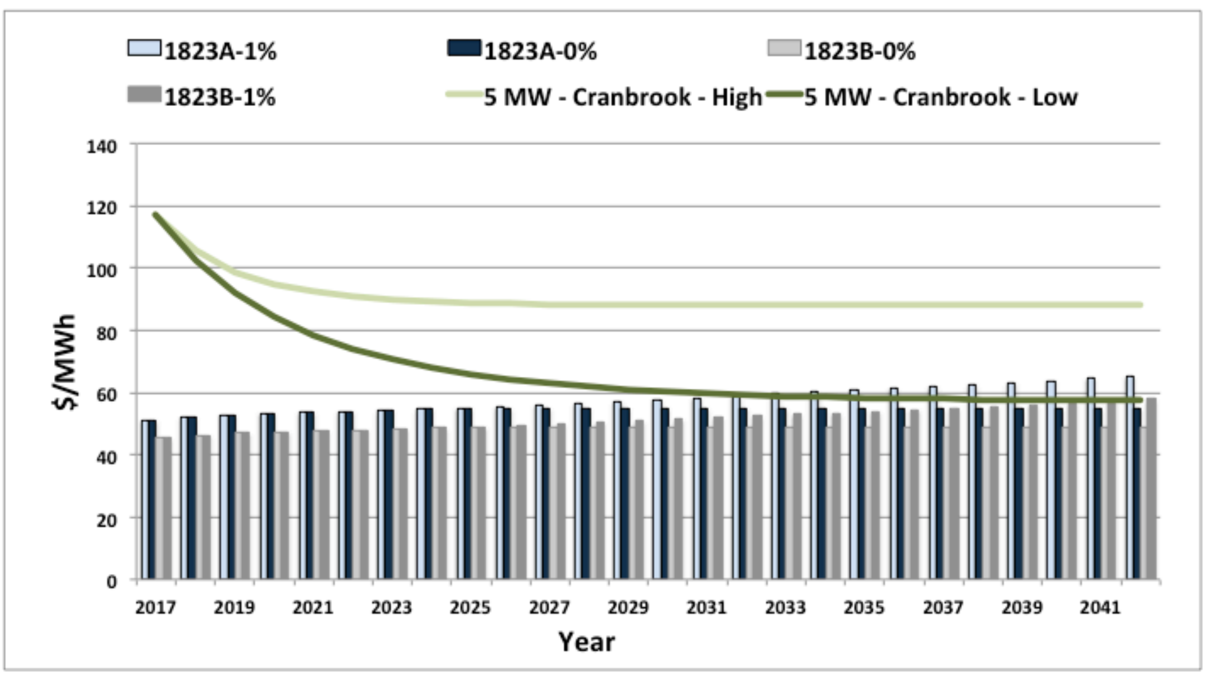
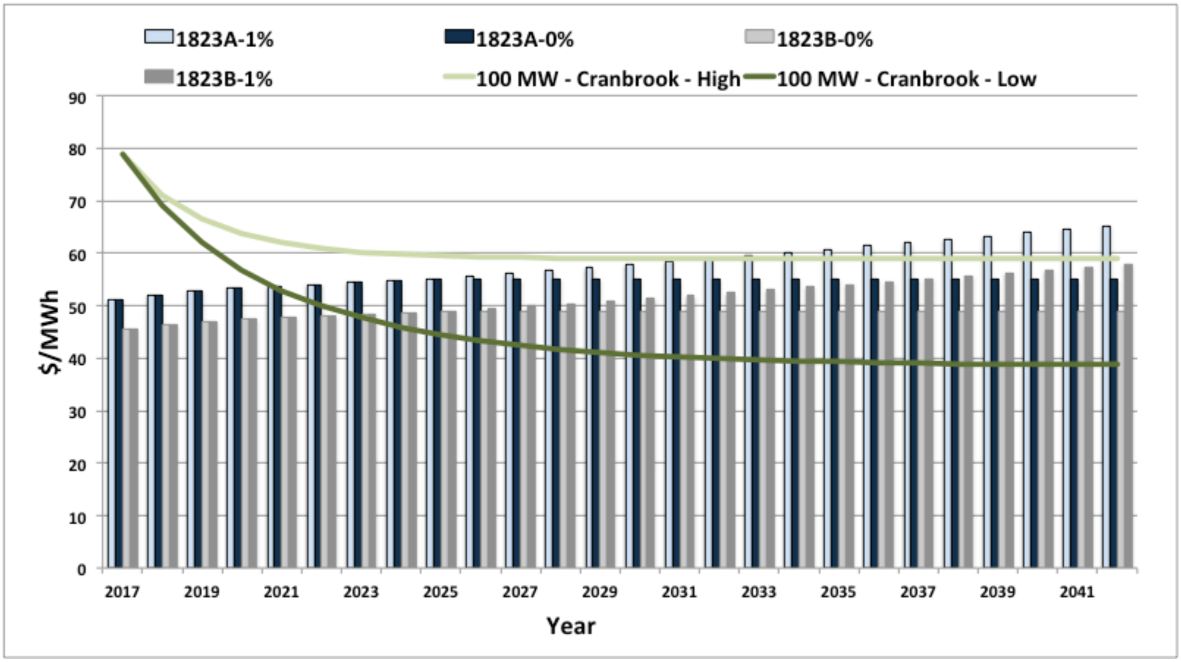


Figure 8: Large industrial rates compared to 100 MW utility-scale solar



These figures illustrate the following:

- **Residential : Residential 5.7 kW**. As a result of the NREL summary of projections showing substantial declines in residential solar levelized costs, coupled with relatively high Tier 2 electricity rates designed to promote conservation, residential solar PV is projected to decline below the Tier 2 rates by 2025 in the regions of the Province having greater solar potential, including the East Kootenay (i.e. Cranbrook), the Peace Region and Selkirk (Kelowna). Adoption in the lower mainland, though not studied in this submission, is considered less likely given the much lower solar insolation in that region of the Province.
- **MGS : Commercial 200 KW**. Similar to residential PV, Commercial 200 kW PV is also projected to decline in cost below MGS rates in the regions of the Province having greatest solar potential, including the East Kootenay (i.e. Cranbrook). The potential for more widespread adoption will likely depend on the future increases in electricity rates and the ultimate decline in the cost of solar PV.
- **LGS : Commercial 1 MW**. As a result of LGS rates being substantially lower than MGS rates and commercial 1 MW solar only marginally less costly than 200 kW solar, it is considered less likely that LGS customers would self-generate barring a decline in solar PV costs beyond expections, or rate increases above 1% real per year. This is not to say that isolate LGS customers will not develop larger-scale and more affordable ground-mounted solar PV under the appropriate conditions since there are economies of scale to building larger facilities.
- **Large industrial : Utility-scale 5 MW solar**. Similar to LGS rates, large industrial rates are low compared to the projected cost of 5 MW solar PV. As a result, the findings of this analysis do not suggest widespread development of 5 MW utility-scale solar, though

larger facilities may prove economic in particular situations, as discussed immediately below

- **Large industrial : Utility-scale 100 MW solar**. Only under the scenario of large declines in the cost of 100 MW utility-scale solar do levelized costs fall below rates for large industrial customers. Nonetheless, in the context of those rapid and large declines in the levelized cost of 100 MW utility-scale solar, costs in the regions of the Province having greatest solar potential, including the East Kootenay (i.e. Cranbrook), Peace and Selkirk, could drop below industrial rates prior to 2025. In such a circumstance, it is reasonable to conclude that industrial customers located in those regions would seek to avail of a solar resource that is less costly than electricity supplied from the grid.

In terms of the potential impact of increasing solar PV generation on BC Hydro's load forecast, this cannot be determined in detail without a more extensive analysis beyond the time available for commenting on the Alternative Portfolio. For context, the following information is potentially of relevance to the Commission in determining the potential impact of self-generation from solar PV and additional community solar generation:

- Ontario's feed-in tariff, which provided price support to solar development, resulted in the development of 2000 MW of embedded solar generation and an additional 500 MW of embedded wind generation, or about 3 TWh/year of annual generation over a 5 year period.
- The California Solar Initiative, which is geared at residential and small- to medium-sized businesses, has developed nearly 2000 MW of solar capacity over a 10-year period.[25]
- Washington State, with a coastal climate more similar to the Lower Mainland, installed 26.5 MW of solar in 2016 bringing its total to 101.3 MW, and has a total of 10,000 homes powered by solar. Comparable numbers for Oregon are 123.9 MW installed in 2016 for a total of

Where solar generation is cost effective, or has been advanced to cost competitiveness through enabling policy, it has been widely and rapidly adopted. Though adoption in BC may be slower since the major load centre in the Lower Mainland is an area of lower solar potential, adoption in the other areas of the Province would be expected to follow that of the other regions discussed above. Every 100 MW of embedded solar developed results in about 150 GWh/year of generation. Based on BC Hydro's domestic requirements of about 50,000 GWh/year, and growth rates of 1% per year or 500 GWh/year, the addition of 100 MW of solar per year would constitute a meaningful reduction in annual load growth.

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[25] Go Solar California. California Distributed Generation Statistics. Statistics and Charts: California Solar Initiative. Available at: http://californiadgstats.ca.gov/charts/csi.

APPENDIX A: NREL U.S. SOLAR PHOTOVOLTAIC SYSTEM COST BENCHMARK: Q1 2017

U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017

Ran Fu, David Feldman, Robert Margolis, Mike Woodhouse, and Kristen Ardani
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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NREL/TP-6A20-68925
September 2017

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Prepared under Task No. SETP.10308.03.01.10

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List of Acronyms

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

Executive Summary

This report benchmarks U.S. solar photovoltaic (PV) system installed costs as of the first quarter of 2017 (Q1 2017). 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,[1] 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 is 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. Table ES-1 summarizes the first order benchmark assumptions.

Table ES-1. Benchmark Assumptions

Unit	Description
Values	2017 U.S. dollars (USD)
System Sizes	In direct current (DC) terms; inverter prices are converted by DC-to-alternating current (AC) ratios.

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

Based on our bottom-up modeling, the Q1 2017 PV cost benchmarks are:

- $2.80 per watt DC (Wdc) (or $3.22 per watt AC [Wac]) for residential systems
- $1.85/Wdc (or $2.13/Wac) for commercial systems
- $1.03/Wdc (or $1.34/Wac) for fixed-tilt utility-scale systems
- $1.11/Wdc (or $1.44/Wac) for one-axis-tracking utility-scale systems.[2]

[1] Profit is one of the differentiators between “cost” (aggregated expenses incurred by a developer/installer to build a system) and “price” (what the end user pays for a system).
[2] This year, we use the same DC-to-AC ratio (1.3) for both fixed-tilt and one-axis-tracking utility-scale PV systems (see Section 2.5).

Overall, modeled PV installed costs declined, year over year, in Q1 2017 for all three sectors, as they have done each year since we began modeling PV system costs.

Figure ES-1 puts our Q1 2017 benchmark results in context with the results of previous NREL benchmarking analyses. When comparing the results across this period, it is important to note the following:

1. Values are inflation adjusted using the Consumer Price Index. 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.
3. The “Utility-Scale PV, One-Axis Tracker (100 MW)” consists of our previous bottom-up results (2010 and 2013–2016) and interpolation estimates for 2009 and 2011–2012.
4. A comparison of Q1 2016 and Q1 2017 is presented in Table ES-2.

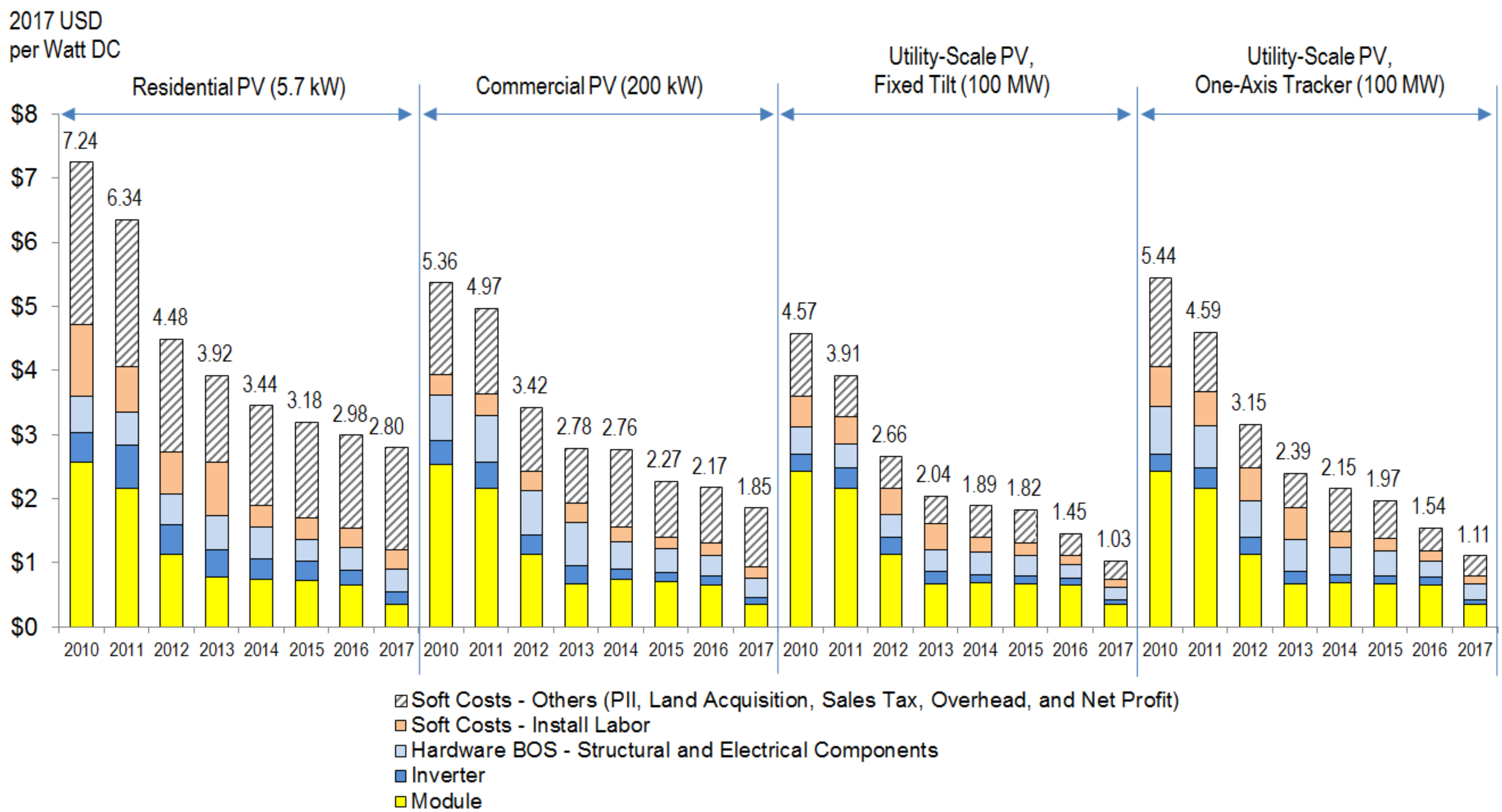

Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

The inflation-adjusted system cost differences between Q1 2016 and Q1 2017 are $0.18/Wdc (residential), $0.32/Wdc (commercial), and $0.42/Wdc (fixed-tilt utility-scale). Table ES-2 shows the benchmarked values for all three sectors and drivers of cost decrease and increase.

Table ES-2. Comparison of Q1 2016 and Q1 2017 PV System Cost Benchmarks

Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2016 Benchmarks in 2016 USD/Wdc	$2.93	$2.13	$1.42
Q1 2016 Benchmarks in 2017 USD/Wdc	$2.98	$2.17	$1.45
Q1 2017 Benchmarks in 2017 USD/Wdc	$2.80	$1.85	$1.03
Drivers of Cost Decrease	• Lower module price • Lower inverter price • Higher module efficiency • Lower electrical BOS commodity price • Higher small installer market share • Lower sales & marketing costs • Lower overhead (general & administrative)	• Lower module price • Lower inverter price • Higher module efficiency • Smaller developer team	• Lower module price • Lower inverter price • Higher module efficiency
Drivers of Cost Increase	• Higher labor wages • Higher advanced inverter adoption • More BOS components for rapid shutdown • Higher supply-chain costs	• Higher labor wages • Higher PII costs • Higher net profit to EPC/developer	• Higher labor wages • Higher net profit to EPC/developer

As Figure ES-1 shows, hardware costs—and module prices in particular—declined substantially in Q1 2017 owing to an imbalance in global module supply and demand. This has increased the importance of non-hardware, or "soft," costs.[3] Figure ES-2 shows the growing contribution from soft costs.[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. This trend has also reduced soft costs from direct labor and related installation overhead.

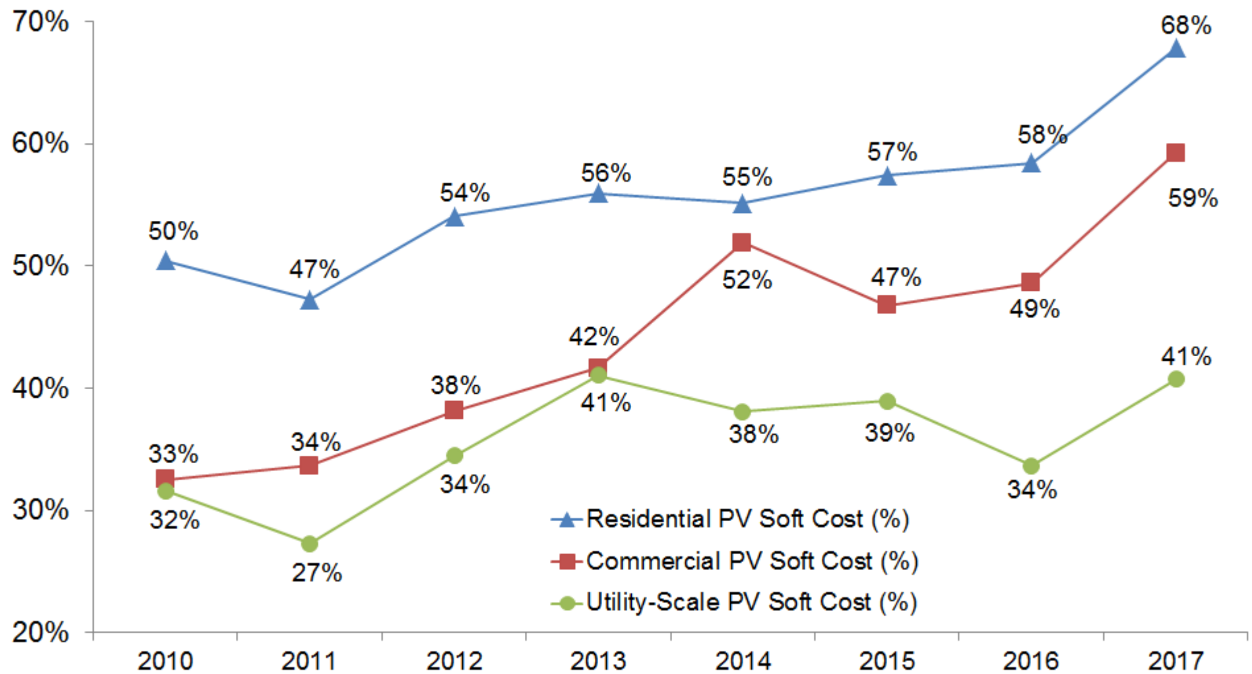

Figure ES-2. Modeled trend of soft cost as a proportion of total cost by sector, 2010–2017

Also, our bottom-up system cost models enable us to investigate regional variations, system configurations (such as 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). Different scenarios result in different costs, so consistent comparisons can only be made when cost scenarios are aligned.

Finally, the reductions in installed cost, along with improvements in operation, system design, and technology have resulted in significant reduction in the cost of electricity, as shown in Figure ES-3. U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.

[3] Soft cost = total cost - hardware (module, inverter, structural and electrical BOS) cost.

[4] An increasing soft cost proportion in Figure ES-2 indicates soft costs declined more slowly than did hardware costs; it does not indicate soft costs increased on an absolute basis.

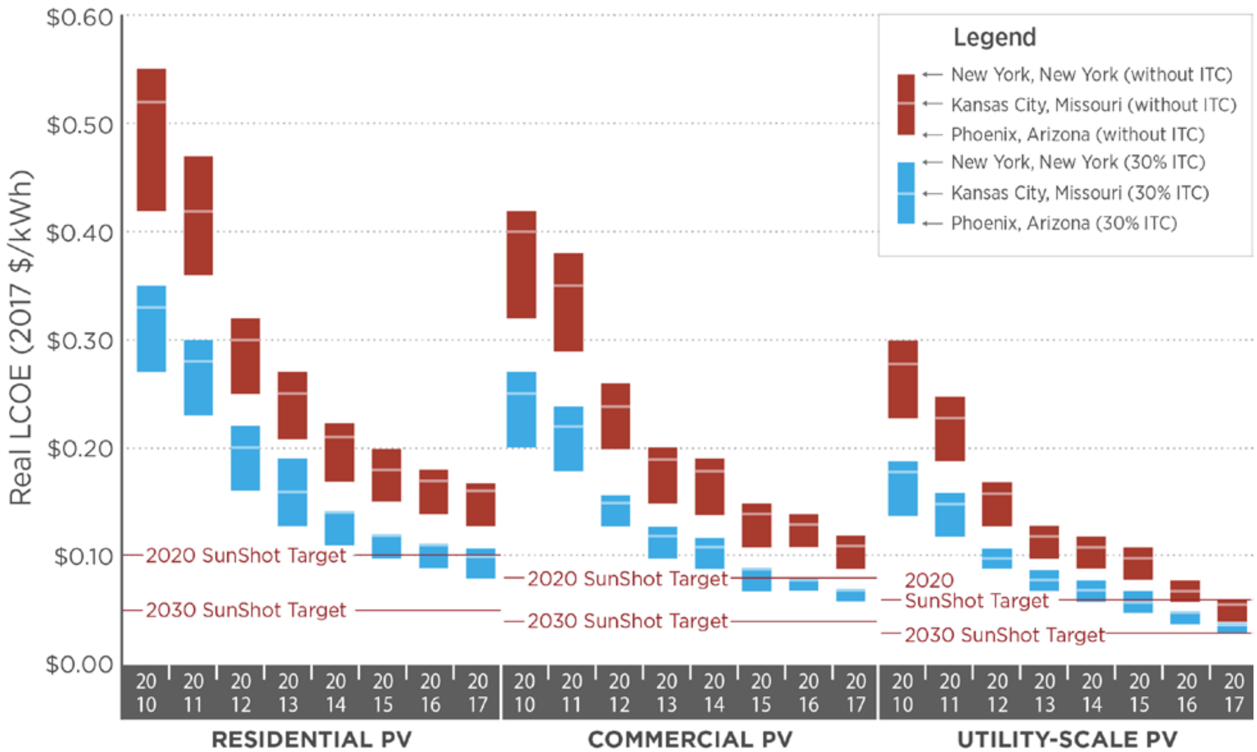

Figure ES-3. NREL PV LCOE benchmark summary (inflation adjusted), 2010–2017

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1 Introduction

Solar photovoltaic (PV) deployment has grown rapidly in the United States over the past several years. As Figure 1 shows, in 2016 new U.S. PV installations included 2.3 gigawatts (GW) in the residential sector, 1.1 GW in the commercial sector, and 10.2 GW in the utility-scale sector—totaling 13.7 GW across all sectors (Bloomberg 2017). At the same time, PV system costs have continued to decline. Previous modeling (Fu et al. 2016) by the National Renewable Energy Laboratory (NREL) shows system cost reductions of about 60%–80% across sectors between the fourth quarter of 2009 (Q4 2009) and Q1 2016.

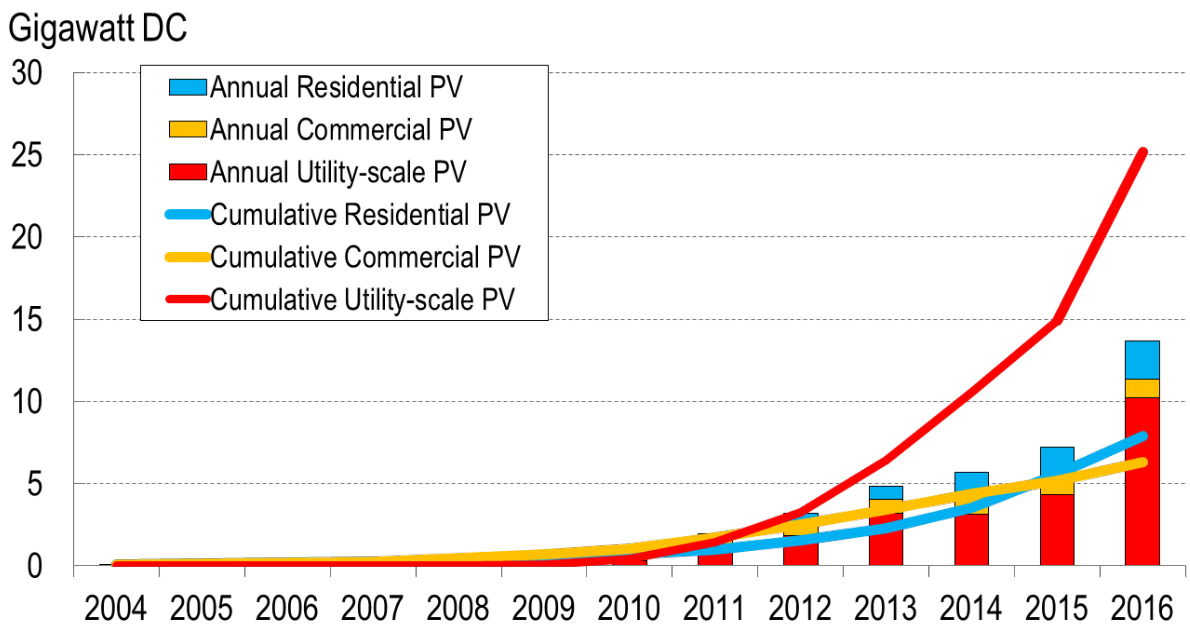

Figure 1. U.S. PV market growth, 2004–2016, in gigawatts of direct-current (DC) capacity (Bloomberg 2017)

This report continues tracking cost reductions by benchmarking costs of U.S. PV for residential, commercial, and utility-scale systems built in Q1 2017. It was produced in conjunction with several related research activities at NREL and Lawrence Berkeley National Laboratory, which are documented in Barbose and Darghouth (2016), Bolinger and Seel (2016), Chung et al. (2015), Feldman et al. (2015), and Fu et al. (2016).

Our methodology includes bottom-up accounting for all system and project-development costs incurred when installing residential, commercial, and utility-scale systems, and it models the Q1 2017 costs for such systems excluding any previous supply agreements or contracts. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective, and our benchmarks are national averages of installed capacities, weighted by state. The residential benchmark is further averaged across installer and integrator business models, weighted by market share. All benchmarks assume non-union construction labor, although union labor cases are estimated for utility-scale systems.

Our modeled costs can be interpreted as the sales price an engineering, procurement, and construction (EPC) contractor/developer might charge for a system before any developer fee or price gross-up. We use 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.

The remainder of this report is organized as follows. Section 2 describes our model inputs and sources. Sections 3, 4, and 5 show specific model inputs and outputs for the residential, commercial, and utility-scale PV sectors, including historical trends in system costs and the levelized costs of energy (LCOE). Section 6 includes three additional applications of our cost modeling: system cost reduction from economies of scale, module efficiency impacts, and regional LCOEs. Finally, Section 7 puts the results in context with each other and offers conclusions.

2 Model Inputs and Sources

This section describes our model inputs and sources. Section 2.1 describes our main data source, California's Net Energy Metering (NEM) Interconnection Applications Data Set. Sections 2.2 through 2.6 detail the inputs for the various components affecting PV system cost, and Section 2.7 describes how we allocated installations to installers versus integrators in the residential PV model.

2.1 California's NEM Interconnection Applications Data Set

Previous NREL analyses used the California Solar Initiative Data Set (CSI 2017), but, as that program has wound down, the number of new PV incentive applications—and consequently the data collection—has decreased substantially. As a result, in last year's report, we began using the more robust California NEM Interconnection Applications Data Set instead (Go Solar CA 2017). 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). We use the database to benchmark generic system characteristics, such as system size, module power and efficiency, and choice of power electronics. Although there are other databases for other markets, such as Massachusetts and New York, we use only the California NEM database to inform these general benchmark characteristics because of its higher granularity and greater consistency. Notably, 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.

As shown in Figure 2, the California NEM database captures most residential capacity in California (79% of installed capacity in 2015 and 80% in 2016) and a sizable portion of commercial capacity (91% of installed capacity in 2015 and 35% in 2016). Note that:

- We analyze only rooftop systems in the database for the residential and commercial sectors. We exclude ground-mounted systems.
- We exclude systems with only alternating-current (AC) power records.
- We exclude systems that were still in the validation phase.
- We use GTM (2017) data to represent total installed capacities.

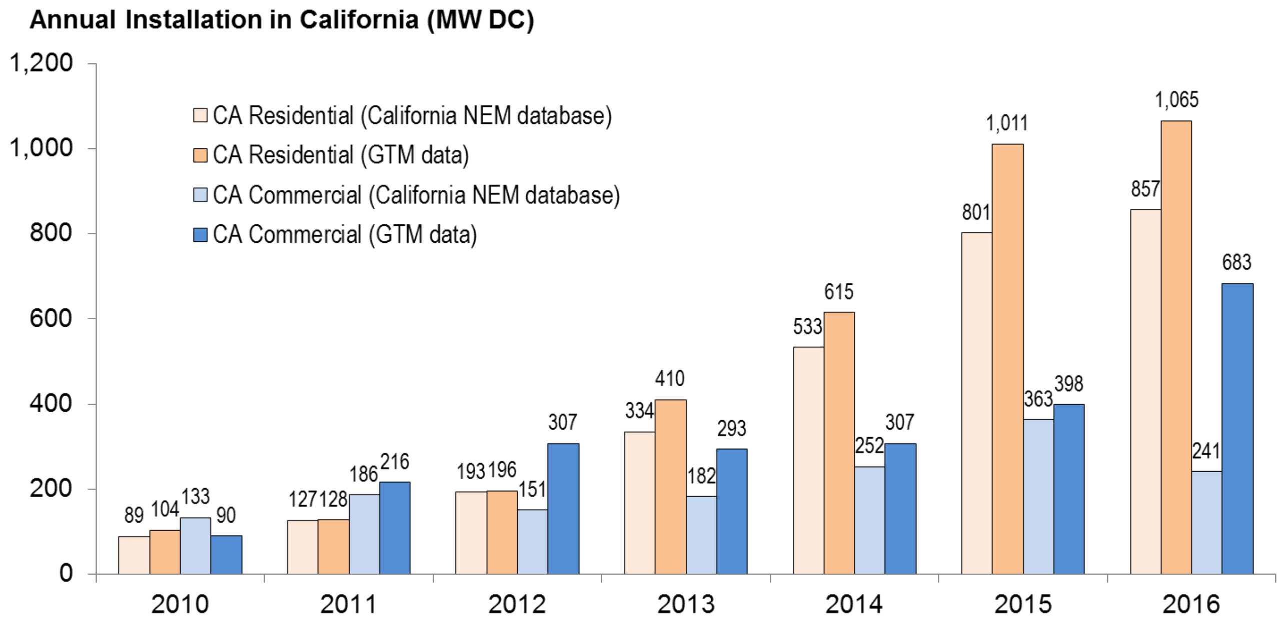

Figure 2. Installed capacities of residential and commercial PV systems covered by the California NEM database (Go Solar CA 2017) compared with GTM data (GTM Research 2017), 2010–2016

2.2 Module Power and Efficiency

Figure 3 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 16.2% (residential) and 17.5% (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.

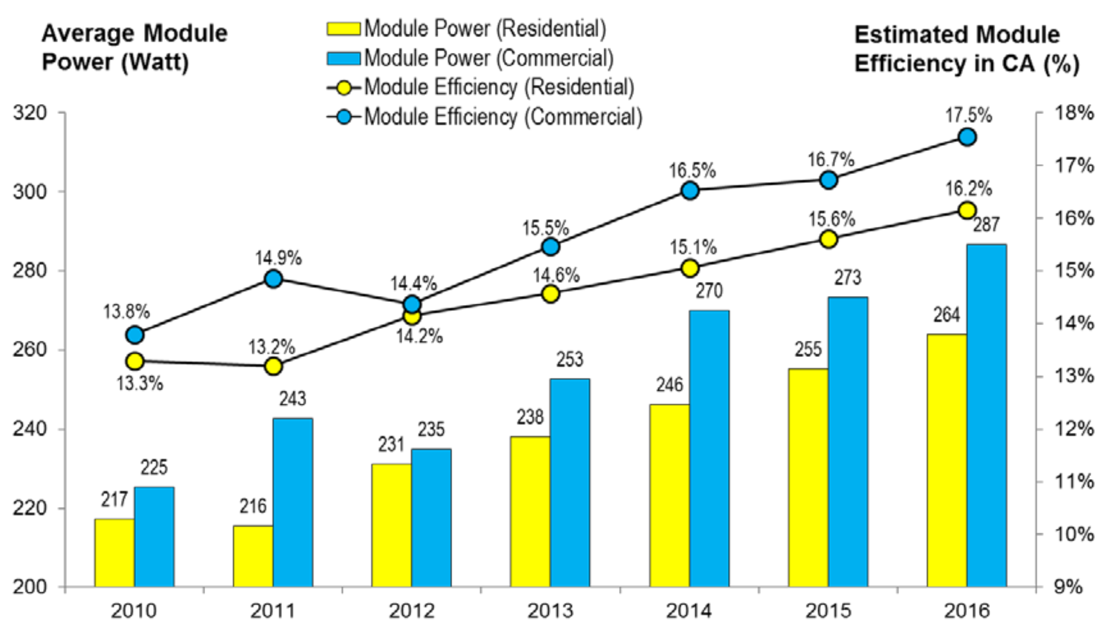

Figure 3. Module power and efficiency trends from the California NEM database (Go Solar CA 2017), 2010–2016

2.3 PV System Size

Figure 4 displays average system sizes from the California NEM database. Average residential system sizes have not changed significantly over the past 6 years. We use the 2016 value of 5.7 kW as the baseline case in our residential cost model. Conversely, 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. We use 200 kW as the baseline case in our commercial model.

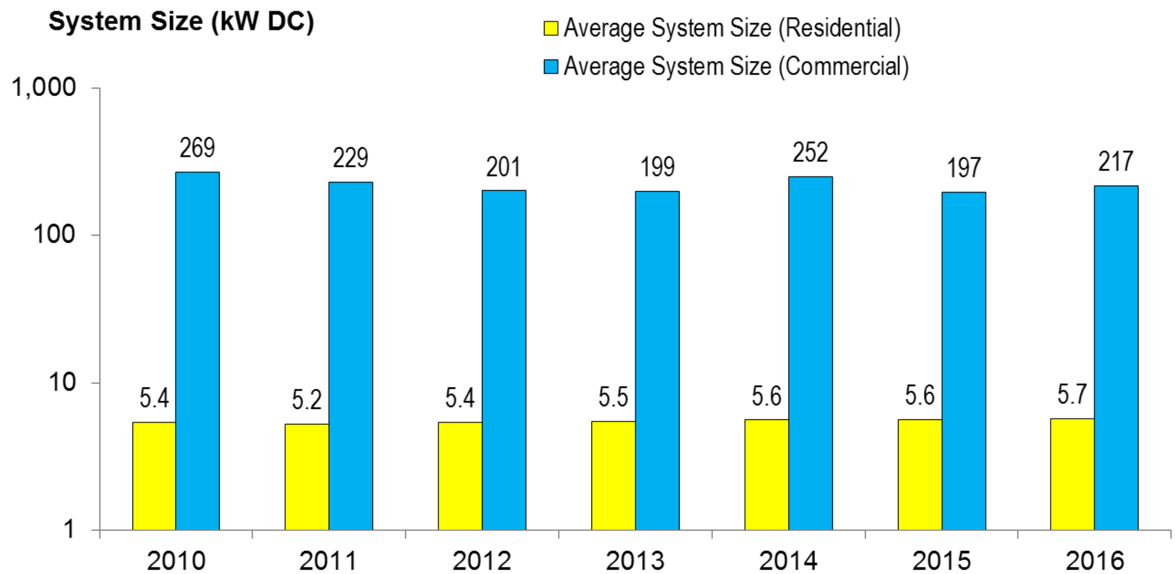

Figure 4. PV system size trends from the California NEM database (Go Solar CA 2017), 2010–2016

2.4 Module-Level Power Electronics

Microinverters and DC power optimizers are collectively referred to as module-level power electronics (MLPE). By allowing designs with different roof configurations (orientations and tilts) and constantly tracking the maximum power point for each module, MLPE provide an optimized design solution at the module level. Table 1 provides a brief comparison of traditional string inverters and MLPE.

Table 1. Comparison of Inverter Solutions: String Inverter, DC Power Optimizer, and Microinverter

	String Inverter	DC Power Optimizer	Microinverter
Function	PV modules are connected in parallel by one or multiple strings and then directly connected to the string inverter for DC-to-AC conversion. If one module is shaded, the whole string is impacted.	Each PV module has one power optimizer for DC-to-DC conversion, so the traditional junction box is replaced, and all modules are connected by string inverter for DC-to-AC conversion. Shading only impacts individual modules.	Each PV module has one microinverter for DC-to-AC conversion, and thus no string inverter is used. Shading only impacts individual modules.
Relative product price	Low (without rapid shutdown) Medium (with rapid shutdown)	Medium	High
Performance in shading	Poor	More efficient	More efficient
Performance in various directions or on irregular roofs	Low	Medium	High
Module-level monitoring and troubleshooting	No	Yes (e.g., SolarEdge Cellular Kit)	Yes (e.g., Enphase “Envoy + Enlighten”)
Improved energy yield from module mismatch reduction	No	Yes	Yes
Number of electronic components	Normal	Greater (thus may have some component risks)	Greater (thus may have some component risks)
Safety for installation	Normal	Safer; easier wiring work	Safest; use only AC cable with no high-voltage DC power

According to the California NEM database, market uptake of MLPE has been growing rapidly since 2010 in California’s residential sector (Figure 5). 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 2016, MLPE—represented by the combined share of Enphase and SolarEdge inverter solutions—reached 53% of the total California residential market share (Figure 5). Therefore, in our residential system cost model, string inverter, power optimizer, and microinverter options are modeled separately and their market shares (47%, 26%, and 27%) are used for the weighted average case. Conversely, MLPE growth (represented by Enphase and SolarEdge) has been slow in California's commercial sector, reaching a share of only 12% in 2016 (Figure 6). Thus, we do not include MLPE inverter solutions into our commercial model.

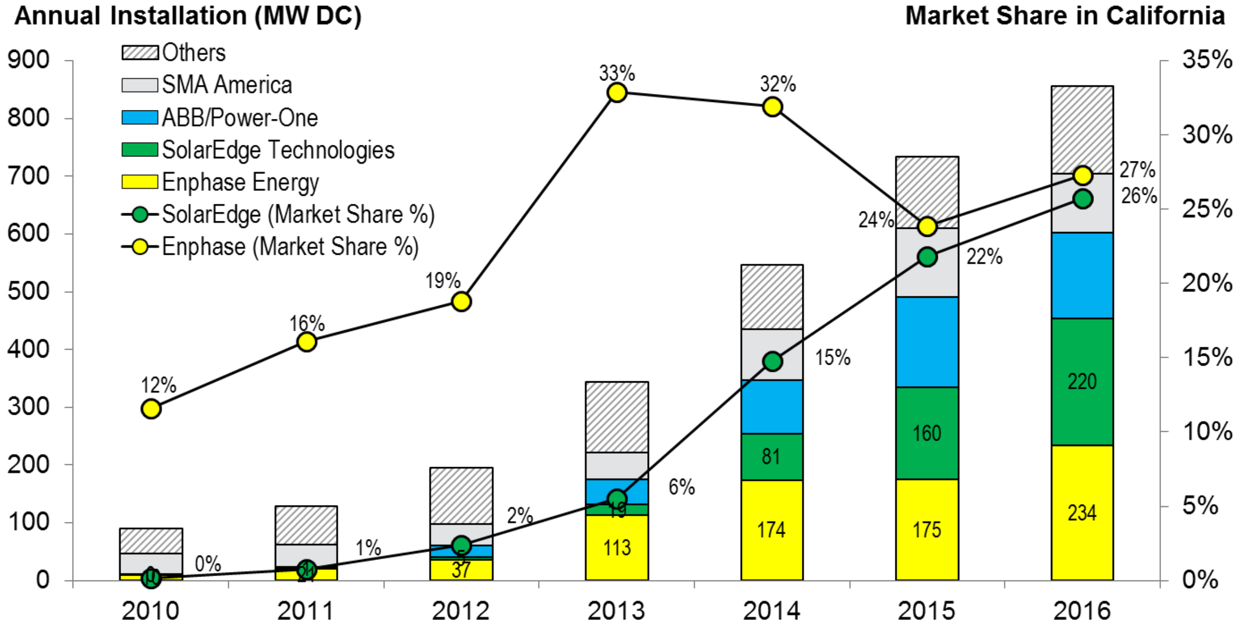

Figure 5. Residential inverter market in California from the California NEM database (Go Solar CA 2017), 2010–2016[5]

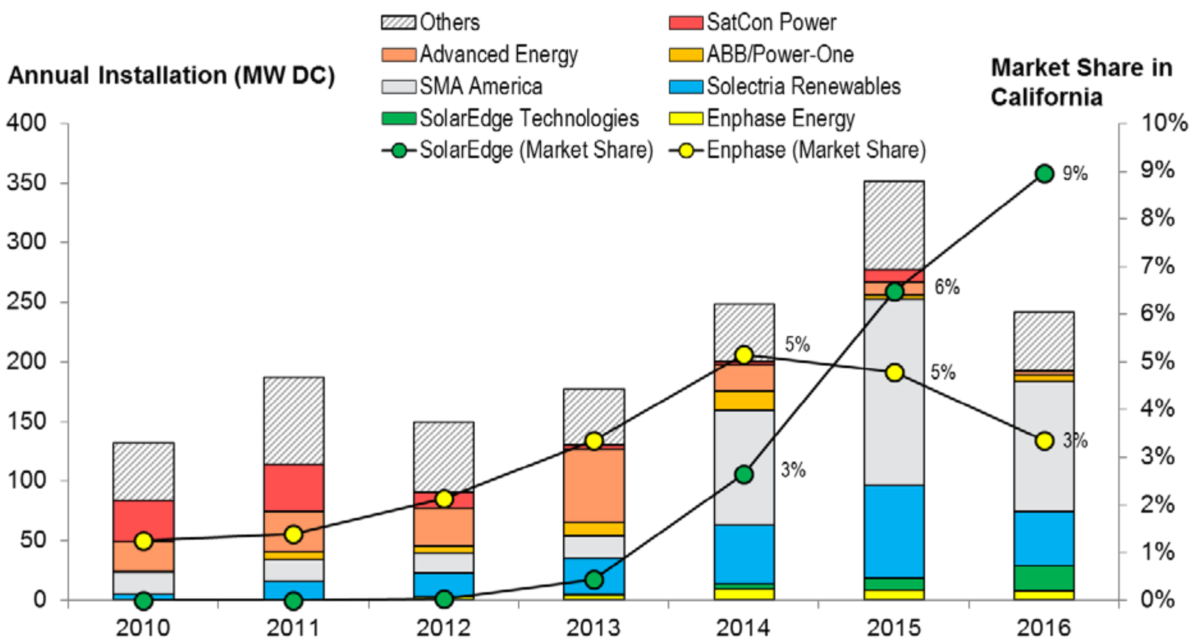

Figure 6. Commercial inverter market in California from the California NEM database (Go Solar CA 2017), 2010–2016

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[5] "Others" represents other companies with small market shares. Although some companies may also have MLPE-based inverter products, we assume that SolarEdge and Enphase represent MLPE inverter manufacturers.

For safety reasons, rapid-shutdown codes[6] are prevalent in most of the top residential PV markets, and they typically include language from NEC 2014 (Article 690.12).[7] As of January 1, 2017, the 2017 NEC rapid-shutdown code was in effect in one state, the 2014 NEC was in effect in 35 states, the 2011 NEC was in effect in five states, and the 2008 NEC was in effect in six states (Table 2). Our cost model uses the 2014 NEC, which is the most widely adopted version and includes the rapid-shutdown requirement. Table 3 presents the rapid-shutdown technical solutions and cost impacts for various inverter options. Because of the increase in rapid shutdown requirements, the cost difference between string inverter and power optimizer configurations became smaller this year.[8] The model for our Q1 2016 benchmark did not include rapid shutdown.

Table 2. Rapid-Shutdown Codes—Progress by State

Code	Rapid-Shutdown Requirement	State
2017 NEC	Yes	Massachusetts
2014 NEC	Yes	Alabama, Alaska, Arkansas, California, Colorado, Connecticut, Delaware, Georgia, Idaho, Iowa, Kentucky, Maine, Maryland, Michigan, Minnesota, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, West Virginia, Wyoming
2011 NEC	No	Florida, Louisiana, Virginia, Wisconsin, Nevada
2008 NEC	No	Hawaii, Illinois, Indiana, Kansas, Pennsylvania, Tennessee
No statewide NEC adoption	No	Arizona, Mississippi, Missouri

[6] During a power shutdown (e.g., during a building fire or utility power loss), DC conductors in each PV array string are most dangerous to first responders such as fire fighters because the DC side can still be energized even if the inverter is shut down. Rapid-shutdown codes require a set distance between PV system conductors and PV arrays, so the conductors are de-energized to a safe level and risks to first responders are reduced.

[7] For example, a segment of the NEC language that is used says, "Conductors more than 5 feet inside a building or more than 10 feet from an array will be limited to a maximum of 30 V and 240 VA within 10 seconds of shutdown." This only applies to PV system circuits "on or in buildings," thus ground-mounted systems are not required to have rapid-shutdown capability.

[8] The costs were $2.78/W (string inverter) vs. $2.94/W (power optimizer) in Q1 2016 when rapid shutdown was not included in our cost models, compared with $2.90/W (string inverter) vs. $2.95/W (power optimizer) if rapid shutdown is included in Q1 2016 benchmark.

Table 3. Rapid Shutdown—Different Inverter Solutions

	String Inverter	DC Power Optimizer	Microinverter
Solution for rapid-shutdown requirement	**A rapid-shutdown box** must be mounted directly to the PV mounting rail and fit under the PV modules. **A rapid-shutdown controller** must be mounted so it is visible and freely accessible to first responders.	**A rapid-shutdown cable** must be installed in the inverter box. No additional roof-mounted devices are required.	**Microinverters inherently meet rapid-shutdown requirements** without any additional electrical equipment, because the DC side (which has low voltage) is de-energized as soon as the grid or power from the grid is interrupted.
Additional balance-of-system (BOS) costs	Rapid shutdown box Rapid shutdown controller Cable between box and controller Total BOS increase = $0.08/W	One rapid shutdown cable in each inverter Total BOS increase = $0.01/W	None
Additional direct labor costs	Electrician for cabling between box and controller Common labor for racking box and controller Total labor increase = $0.01/W	Electrician for setting up internal cable in each inverter Total labor increase = $0.01/W	None
Q1 2016 – Benchmark (no rapid shutdown consideration)	$2.78/W	$2.94/W	$3.28/W
Q1 2016 – Benchmark (if rapid shutdown is considered)	$2.90/W	$2.95/W	$3.28/W
Cost change in 2016 models due to rapid shutdown only	0.12/W = 0.08/W (electrical BOS) + 0.01/W (direct labor) + 0.03/W (other related costs)	0.01/W = 0.01/W (electrical BOS and direct labor)	No change

2.5 Inverter Price and DC-to-AC Ratios

As shown in Figure 7, we source non-MLPE inverter prices from the PVinsights (2017) database, which contains typical prices between Tier 1 suppliers and developers in the market. For MLPE inverter prices, we use data from public corporate filings, shown in Figure 8 (Enphase 2017; SolarEdge 2017).[9] Enphase's Q1 2017 revenue was $0.40/Wac, which represents the typical microinverter price. SolarEdge's Q1 2017 revenue was $0.25/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 $0.08/Wac (GTM Research 2017), implying a string inverter and monitoring equipment price of $0.17/Wac. This is close to the Q1 2017 non-MLPE string inverter costs of $0.15/Wac shown in Figure 7 (assuming a $0.02–$0.03/Wac cost for monitoring equipment) (GTM Research and SEIA 2017).

We convert the USD/Wac inverter prices from Figure 7 and Figure 8 to USD per watt DC (Wdc) using the DC-to-AC ratios shown in Table 4. In our benchmark, we use USD/Wdc for all costs, including inverter prices.

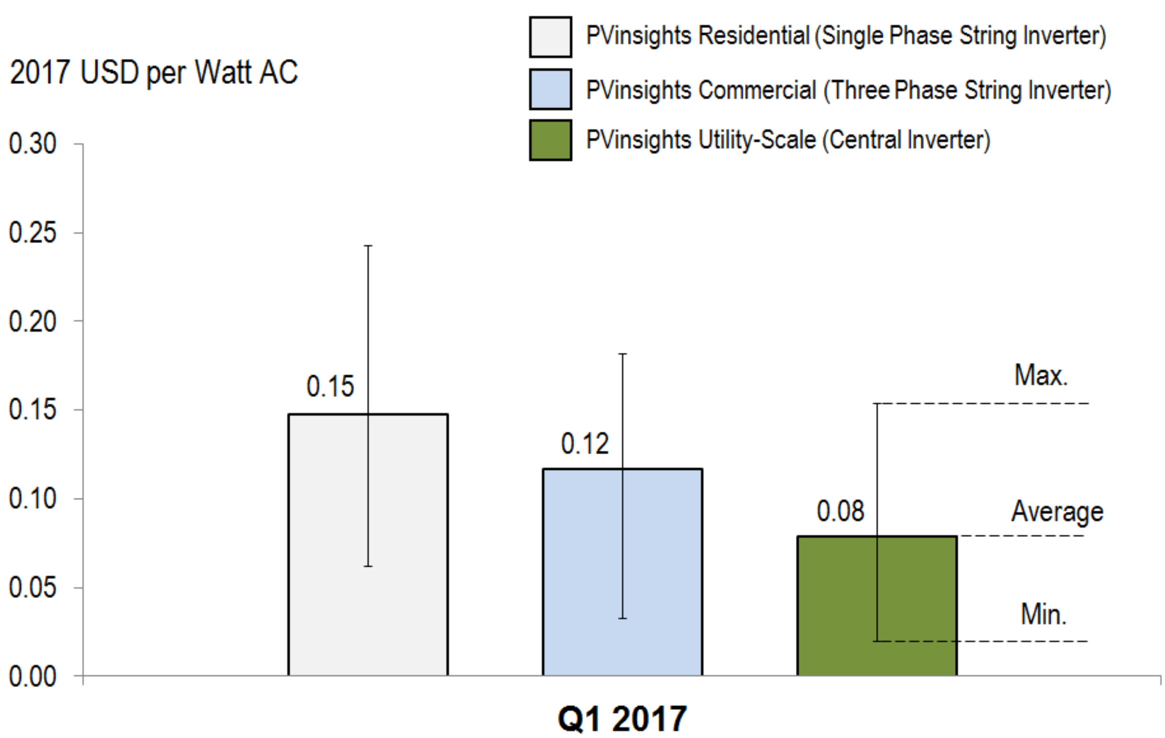


Figure 7. Non-MLPE inverter prices (USD/Wac) from PVinsights (2017), Q1 2017

[9] All sourced inverter prices are quoted in U.S. dollars (USD) per watt AC (Wac).

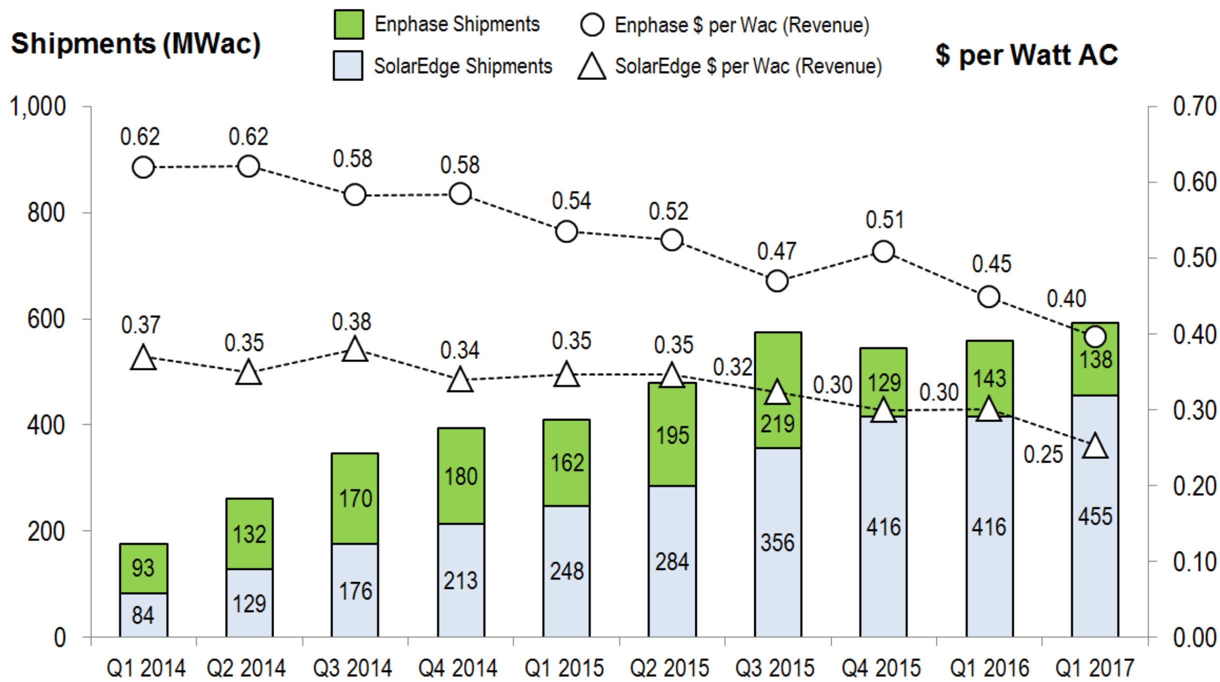


Figure 8. MLPE inverter shipments and prices (USD/Wac) from public corporate filings (Enphase 2017, SolarEdge 2017), Q1 2014–Q1 2017

Table 4. Inverter Price Conversion (2017 USD)

Inverter Type	Sector	USD/Wac	DC-to-AC Ratio[a]	USD/Wdc
Single-Phase String Inverter	Residential PV (non-MLPE)	0.15	1.15	0.13
Microinverter	Residential PV (MLPE)	0.40	1.15	0.34
DC Power Optimizer String Inverter	Residential PV (MLPE)	0.17	1.15	0.15
Three-Phase String Inverter	Commercial PV (non-MLPE)	0.12	1.15	0.10
Central Inverter	Utility-scale PV (fixed-tilt)	0.08	1.3 (oversized)[b]	0.06
Central Inverter	Utility-scale PV (1-axis tracker)	0.08	1.3 (oversized)	0.06

[a] We updated the central inverter DC-to-AC ratios using Lawrence Berkeley National Laboratory data (Bolinger and Seel 2017); for the other ratios, we use the estimates from our 2016 report (Fu et al. 2016) based on interview feedback (NREL 2017).

[b] A DC-to-AC ratio larger than one means that the PV array's DC rating is higher than the inverter's AC rating. This increases inverter utilization, although it also results in some PV energy curtailment, or "clipping," during the sunniest periods when PV output exceeds the inverter's capacity. PV module prices

have dropped more rapidly than inverter prices have, and many utility-scale PV developers have found it economical to oversize their PV arrays. The resulting AC-generation gains during periods of less-than-peak PV production more than offset the losses from occasional peak-period clipping (Bolinger and Seel 2016).

2.6 Module Prices

We use \$0.35/W—the spot price of U.S. crystalline-silicon modules in March 2017—to represent the ex-factory gate price between Tier 1 module suppliers and first buyers[10] in all sectors, based on Bloomberg (2017) data (Figure 9). Because we model ex-factory gate price in Q1 2017, actual market pricing may vary owing to previously signed supply agreements or installer/distributor inventory lags.[11] In addition, the actual market price may vary by market segment because of increased supply-chain costs as well as the price premium for small-scale procurement. Compared with module spot prices in 2016, module spot prices in 2017 have also been influenced by changes in currency exchange rates. The USD appreciated against the Chinese Yuan by approximately 6% between Q1 2016 and Q1 2017 (XE Currency Charts 2017).

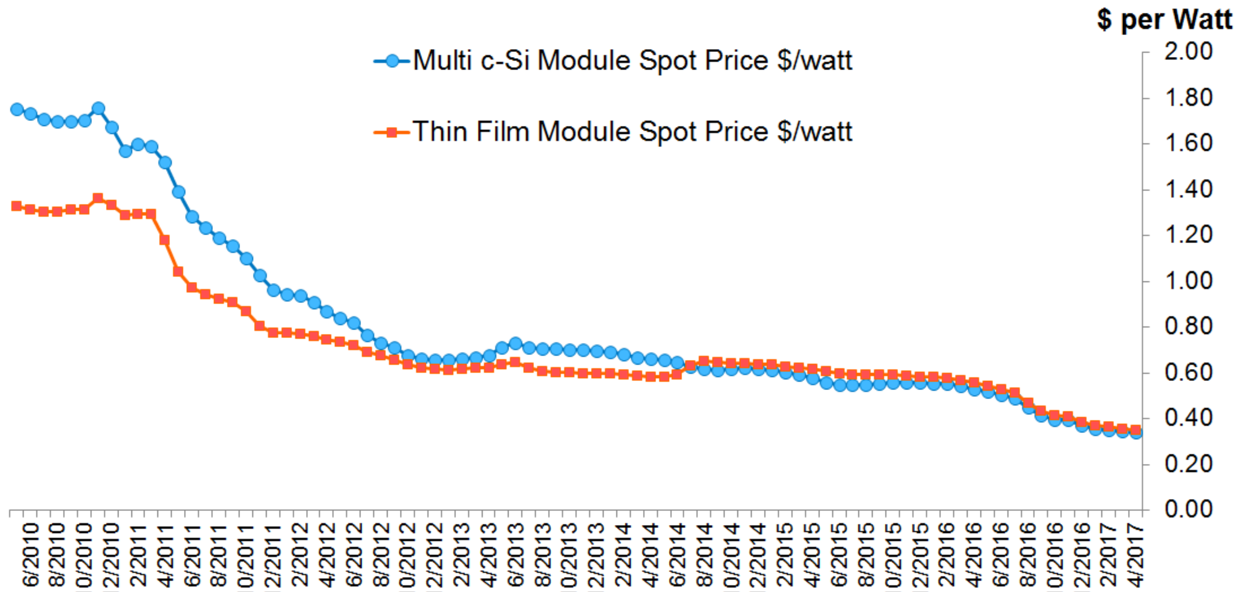


Figure 9. Ex-factory gate price (spot prices) for U.S. crystalline-silicon modules from Bloomberg (2017) data

Despite a \$0.35/W factory gate module price, additional module costs increase national integrators' total module costs to \$0.65/W (86% price premium) and small installers' total module costs to \$0.73/W (109% price premium). These additional costs in Figure 10 consist of shipping and handling (a 15% price premium above factory gate pricing for national integrators and small installers, respectively [NREL 2017]), historical inventory (a 60% price premium

[10] The first buyers of modules ex-factory gate can be developers, EPC contractors, installers, distributors, retailers, or other end users. In our cost model, first buyer price—that is, ex-factory gate price—is used as the "module price" component of the total system cost in the residential, commercial, and utility-scale sectors.

[11] The effect of inventory lags and previous supply agreements on system pricing in the latter half of 2016 and the first quarter of 2017 may be particularly high, because the actual market module price had not dropped so precipitously since 2011 and 2012.

above factory gate pricing [NREL 2017]), a sales-tax of 6.7%, and, for small installers, a 20% price premium above factory gate pricing due to small-scale procurement (Bloomberg 2017).

In Q1 2017 historical inventory represented the largest supply-chain cost for residential installers. While we do not include pre-existing supply agreements or other contracts into our benchmark, historical inventory is a necessary cost for residential installers. Because homeowners of residential rooftop PV systems have different preferences for module brand, both small installers and national integrators tend to diversify their module procurement. Furthermore, since rooftop PV system sizes are relatively small (5.7 kW in our benchmark), the various module brands procured may not be fully consumed and installed instantly. Thus, the historical inventory price creates 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.

From 2012 to mid-2016 this price lag did not create a large price premium because the average spot price of modules did not change dramatically. However, from mid-2016 to early-2017 module spot price dropped by approximately $0.25/W, or 41%, as shown in Figure 9. Thus, in the first quarter of 2017 residential installers must bear the costs of this $0.21/W historical inventory. It is likely that this price premium will be much smaller next year as analysts expect the spot price curve to become flatter. However, many things may change within the market (e.g., tariffs) and make it challenging for residential players to forecast module price. Without historical inventory, total module costs would be $0.43/W for national integrators and $0.52/W for small installers (potentially reducing total residential PV costs to $2.59/Wdc).

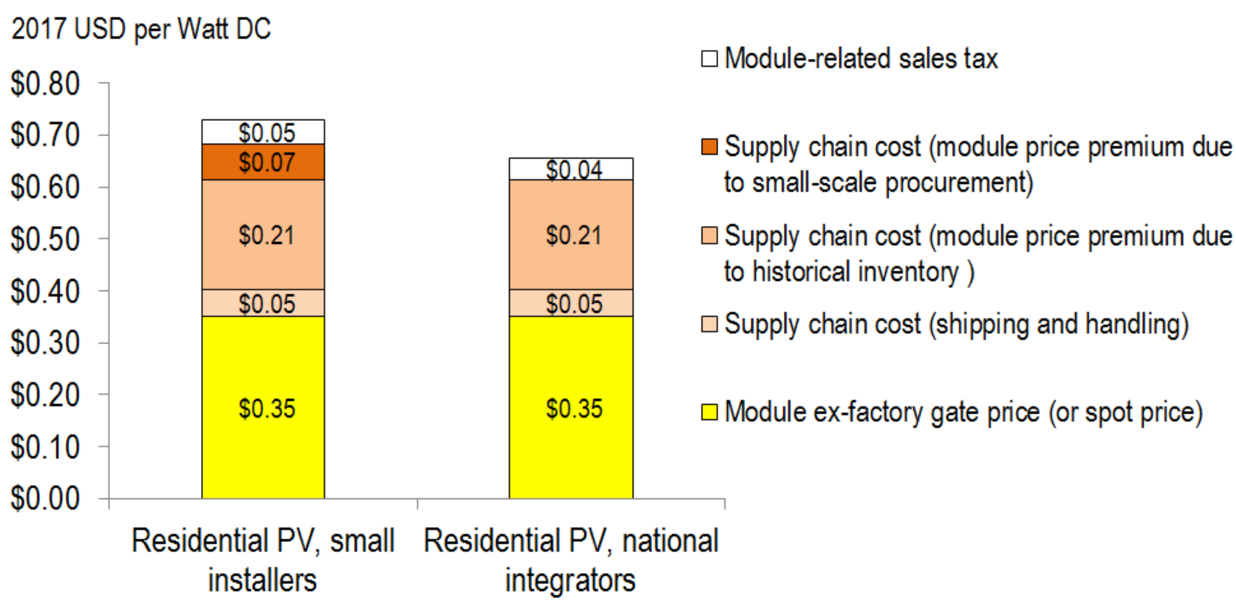


Figure 10. Actual market module prices (2017 USD)

Besides module spot price, actual module manufacturing cost is introduced here in order to demonstrate the technology improvement. We work across the spectrum of academic and national laboratory researchers, startup companies, and multinational corporations to understand the cost drivers and technology landscape of PV module production. Our bottom-up method entails an examination of each stage in the supply chain, including polysilicon, ingot, and wafer production, cell conversion, and module assembly. For each stage, we begin with the derivation of detailed technology-manufacturing process flows. Then we work with equipment and materials suppliers, as well as integrated manufacturers already engaged in production, to collect and verify the costs for each step of the process. Finally, we sum the individual process steps to generate total costs for the intermediate materials (polysilicon, ingots, wafers, and cells) and finished PV modules.

Figure 11 shows our most recent module manufacturing cost analysis, for passivated emitter and rear cells (PERC) and modules manufactured in Southeast Asia. The dark blue bars show the Q1 2017 cost contributions for each step: about $0.05/W for polysilicon, $0.05/W for ingot and wafer production, $0.08/W for cell conversion, $0.13/W for module assembly, and $0.03/W for an industry-average budget for research and development (R&D) plus sales, general, and administrative (SG&A). The all-in module manufacturing cost is about $0.35/W.

Figure 11 also illustrates the magnitude of cost reductions since our last detailed module manufacturing analysis in 2014 and the first half of 2015, when we calculated an all-in module manufacturing cost of about $0.63/W. This 45% reduction in costs over 2–3 years was enabled by improving silicon utilization (principally reducing kerf loss), converting from slurry-based wafer slicing to diamond-wire-based wafer slicing, and reducing costs for cell conversion and module assembly principally via improved efficiency and capital investment requirements (the depreciation expenses shown in the figure). In a forthcoming paper, we will detail additional technology-improvement opportunities that could lead to even lower costs in the future.

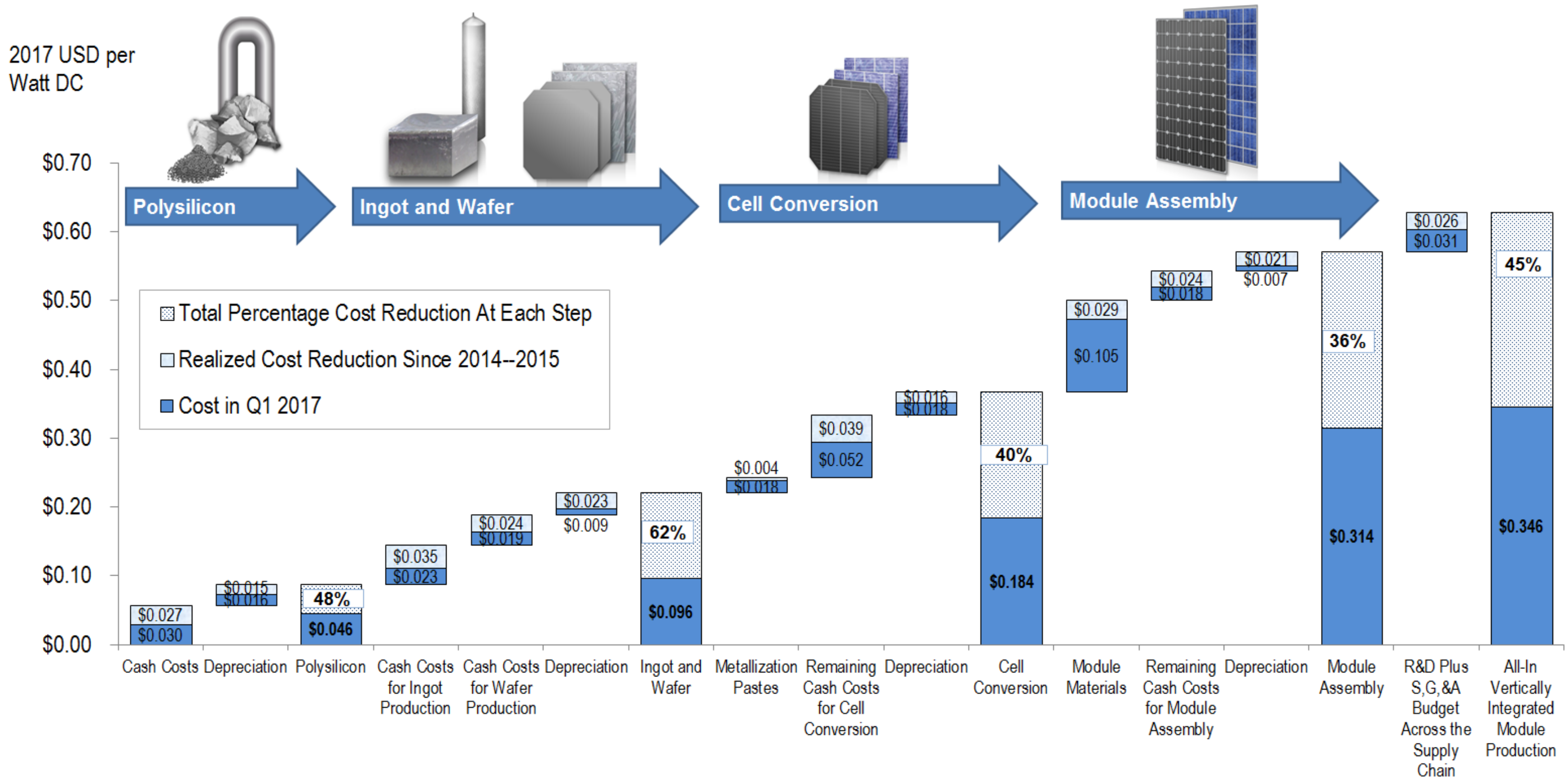


Figure 11. Updated bottom-up manufacturing cost model results for the full crystalline-silicon module supply chain from 2014/15 to Q1 2017[12]

[12] The results shown are for manufacturing PERC and modules in Southeast Asia.

2.7 Small Installers vs. National Integrators in the Residential PV Model

Our residential PV benchmark is based on two different business structures: "small installer" and "national integrator." We define small installers as businesses that engage in 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 is manifested 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 2017; Vivint Solar 2017) and GTM Research and SEIA (2017). As shown in Figure 12, small installers gained more market share than national integrators did during 2016, in part because the direct ownership business model, led by installers, remained more popular than third-party ownership. We use the 41% integrator and 59% installer market shares in our Q1 2017 model to compute the national weighted-average case in our residential PV model.

Table 5 summarizes overhead and sales and marketing costs for small installers and national integrators from our Q1 2016 and Q1 2017 reports. National integrators achieved lower per-watt sales and marketing and overhead costs in Q1 2017 compared with Q1 2016 because of lower reported total expenditures on those two categories. Small installers had higher total expenditures on sales and marketing and overhead as they prepared to grow their businesses in 2017, but they still achieved lower per-watt costs for sales and marketing in Q1 2017 compared with Q1 2016 because they installed more PV capacity in the later period.

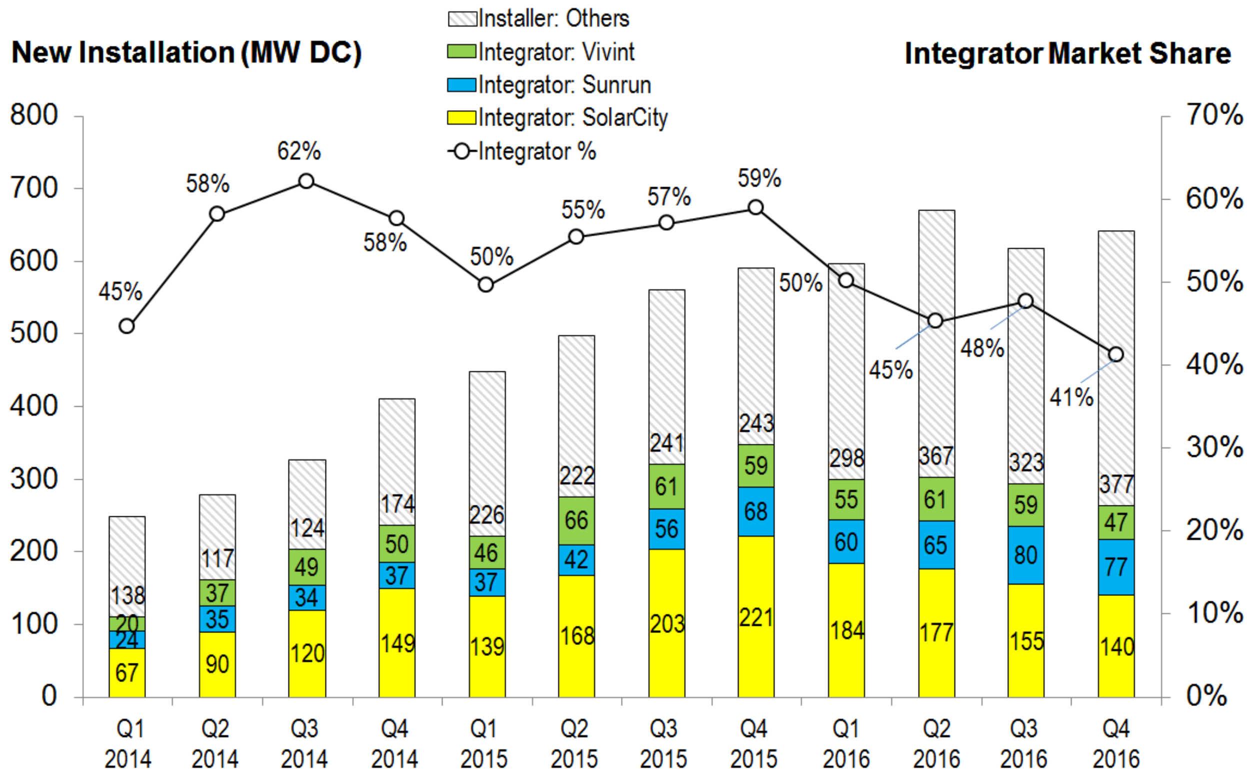


Figure 12. Residential PV market share: integrator vs. installer, Q1 2014–Q1 2016 (GTM Research and SEIA 2017; Sunrun 2017; Vivint Solar 2017)

Table 5. Installer and Integrator Cost Changes, Q1 2016–Q1 2017

	Q1 2016 Report	Q1 2017 Report
Sales & marketing (customer acquisition)	\$0.31/Wdc (small installer) \$0.43/Wdc (national integrator)	\$0.29/Wdc (small installer) \$0.42/Wdc (national integrator)
Overhead (general & administrative)	\$0.28/Wdc (small installer) \$0.38/Wdc (national integrator)	\$0.28/Wdc (small installer) \$0.35/Wdc (national integrator)

3 Residential PV Model

This section describes our residential model's structure, inputs, and assumptions (Section 3.1), output (Section 3.2), and differences between modeled output and reported costs (Section 3.3).

3.1 Residential Model Structure, Inputs, and Assumptions

We model a 5.7-kW residential rooftop system using 60-cell, multicrystalline, 16.2%-efficient modules from a Tier 1 supplier and a standard flush mount, pitched-roof racking system. Figure 13 presents the cost drivers and assumptions, cost categories, inputs, and outputs of the model. Table 6 presents modeling inputs and assumptions in detail.

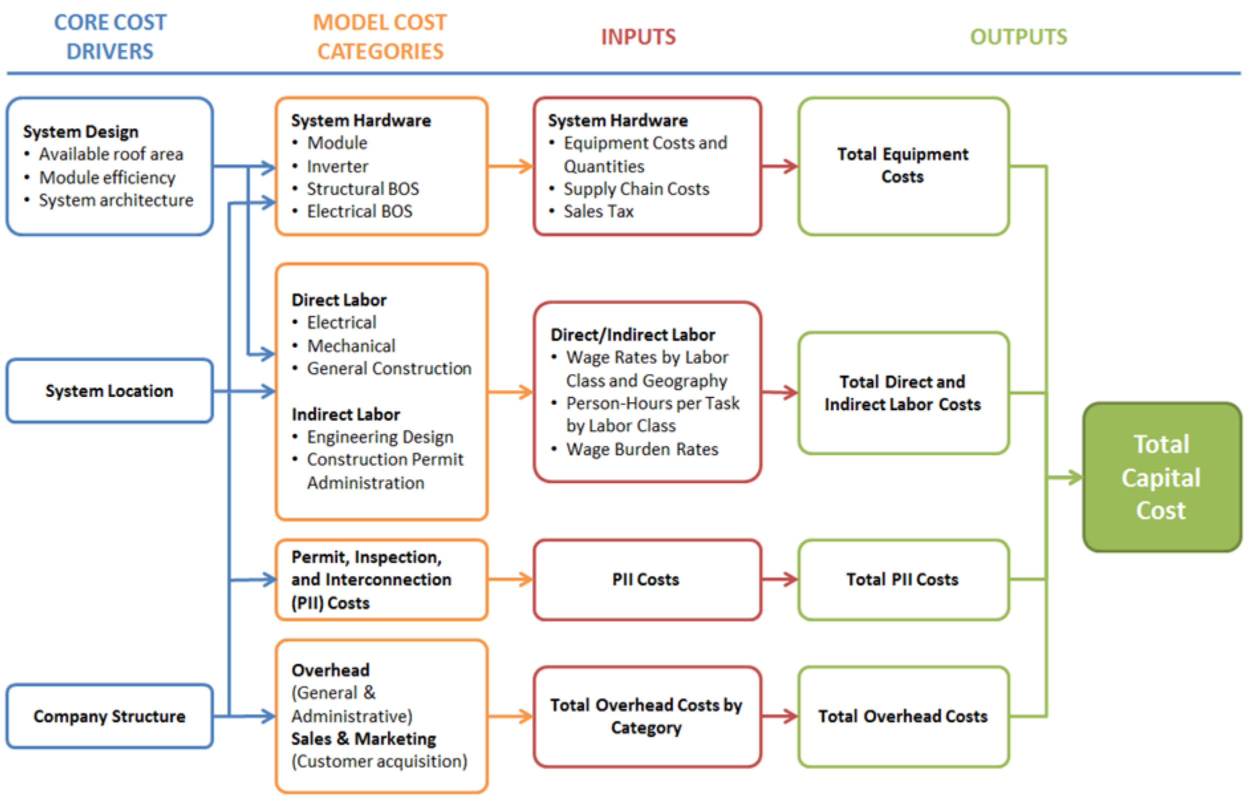


Figure 13. Residential PV: model structure

Table 6. Residential PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	5.7 kW	Average installed size per system	Go Solar CA (2017)
Module efficiency	16.2%	Average module efficiency	Go Solar CA (2017)
Module price	$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Single-phase string inverter: $0.13/Wdc DC power optimizer string inverter: $0.15/Wdc Microinverter: $0.34/Wdc	Ex-factory gate (first buyer) prices, Tier 1 inverters	Go Solar CA (2017), NREL (2017), PVinsights (2017), corporate filings (Enphase 2017; SolarEdge 2017)
Structural BOS (racking)	$0.11/Wdc	Includes flashing for roof penetrations	Model assumptions, NREL (2017)
Electrical BOS	$0.20–$0.33/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 (2017), RSMeans (2016)
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 80% (60% historical inventory + 20% small-scale procurement) for module-related supply chain costs for small installers and 60% (historical inventory) for national integrators Additional 20% for inverter-related supply chain costs for small installers and 10% for national integrators	NREL (2017), model assumptions (2017)
Sales tax	Varies by location	Sales tax on the equipment; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: $19.37–$38.22 per hour; Laborer: $12.64–$25.09 per hour; Varies by location and inverter option	Modeled labor rate depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)

Category	Modeled Value	Description	Sources
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 (2016)
Permitting, inspection, and interconnection (PII)	$0.10/Wdc	Includes assumed building permitting fee of $400 and six office staff hours for building permit preparation and submission, and interconnection application preparation and submission	NREL (2017), Vote Solar (2015), Vote Solar and IREC (2013)
Sales & marketing (customer acquisition)	$0.29/Wdc (installer) $0.42/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)	$0.28/Wdc (installer) $0.35/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 (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Profit (%)	17%	Applies a fixed percentage margin to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees	Fu et al. (2016)

3.2 Residential Model Output

Figure 14 presents the U.S. national benchmark from our residential model. The national benchmark represents an average weighted by 2016 state installed capacities. Market shares of 59% for installers and 41% 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 (47%, 26%, and 27%)[13] as weightings.

Small installers have lower total costs than do large integrators; although small installers pay more for hardware, they have much lower overhead and sales and marketing costs. Notably, the cost difference between installer and integrator became smaller in Q1 2017 than in Q1 2016 (see Table 5). Because of rapid-shutdown requirements, the cost difference between string inverters and power optimizers also became smaller in Q1 2017 than in Q1 2016 (see Table 3).

[13] This market share combination only reflects the California residential sector and may not reflect the actual national market shares.

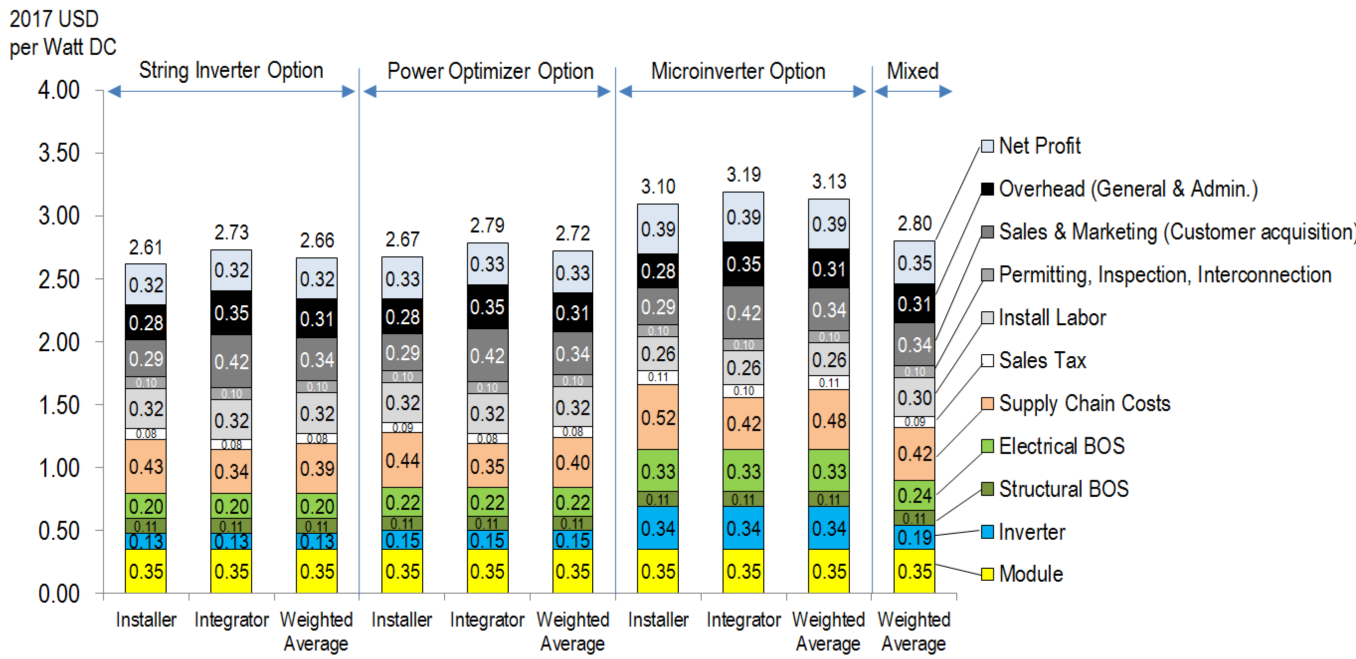


Figure 14. Q1 2017 U.S. benchmark: 5.7-kW residential system cost (2017 USD/Wdc)

Figure 15 presents the benchmark in the top U.S. solar markets (by 2016 installations), reflecting differences in supply chain and labor costs, sales tax, and SG&A expenses—that is, the cost of doing business (Case 2012).

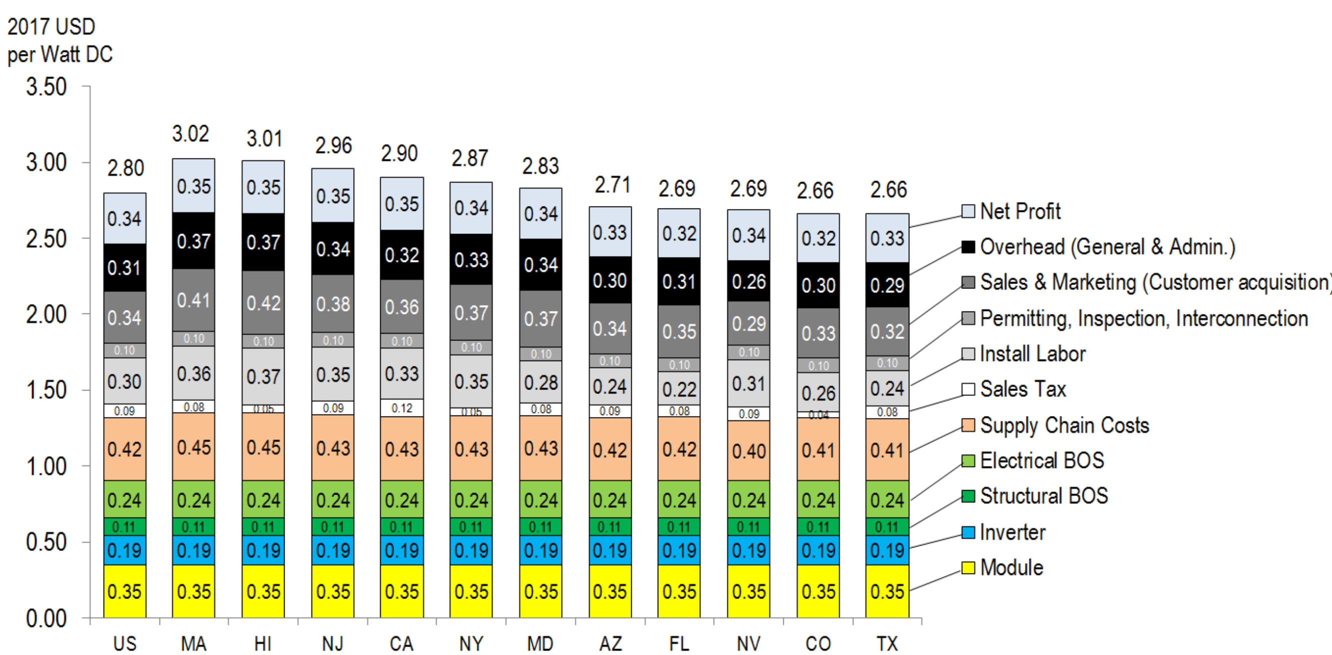


Figure 15. Q1 2017 benchmark by location: 5.7-kW residential system cost (2017 USD/Wdc)

3.3 Residential Model Output vs. Reported Costs

As shown in Figure 16, our bottom-up modeling approach yields a different cost structure than those reported by public solar integrators in their corporate filings[14] (Sunrun 2017; Vivint Solar 2017). 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 there are the corporate filings from Sunrun and Vivint Solar report system costs on a quarterly basis, the limited transparency in the public filings makes it difficult to determine the underlying costs as well as the timing of those costs. As indicated in Figure 16, our total modeled costs for national integrators are $0.40–$0.46/W below company-reported values. Because of the lack of transparency in the reported company costs, it is difficult to explain these differences entirely. Part of the difference in installation costs could come from integrators having preexisting contracts or older inventory that they used in systems installed in Q1 2017; this is particularly relevant owing to the rapid decline in module price in the second half of 2016. In addition, our sales and marketing costs are $0.08–$0.23/W below company-reported values, indicating either a difference in how costs are classified or additional costs not included in our model—a deeper exploration of this topic may prove valuable.

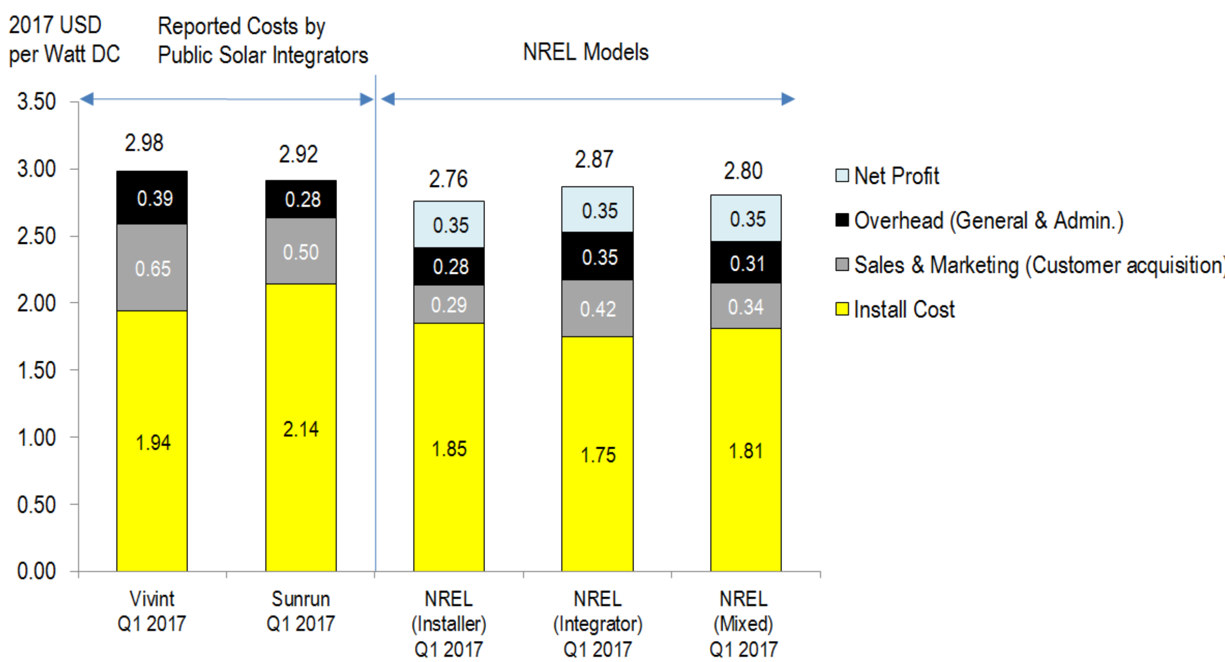


Figure 16. Q1 2017 NREL modeled cost benchmark (2017 USD/Wdc) vs. Q4 2016 company-reported costs

[14] Because of the acquisition of SolarCity by Tesla, the quarterly corporate filings from SolarCity are not available this year.

3.4 Residential PV Price Benchmark Historical Trends

NREL began benchmarking PV system costs in 2010 in order to track PV system energy costs against the U.S. Department of Energy's (DOE) SunShot Initiative targets, as well as examine cost reduction opportunities for achieving these goals.[15] Since that time NREL has produced seven additional benchmarks, including a historical Q4 2009 benchmark. Figure 17 summarizes the reduction in residential PV system cost benchmarks between 2010 and 2017.[16]

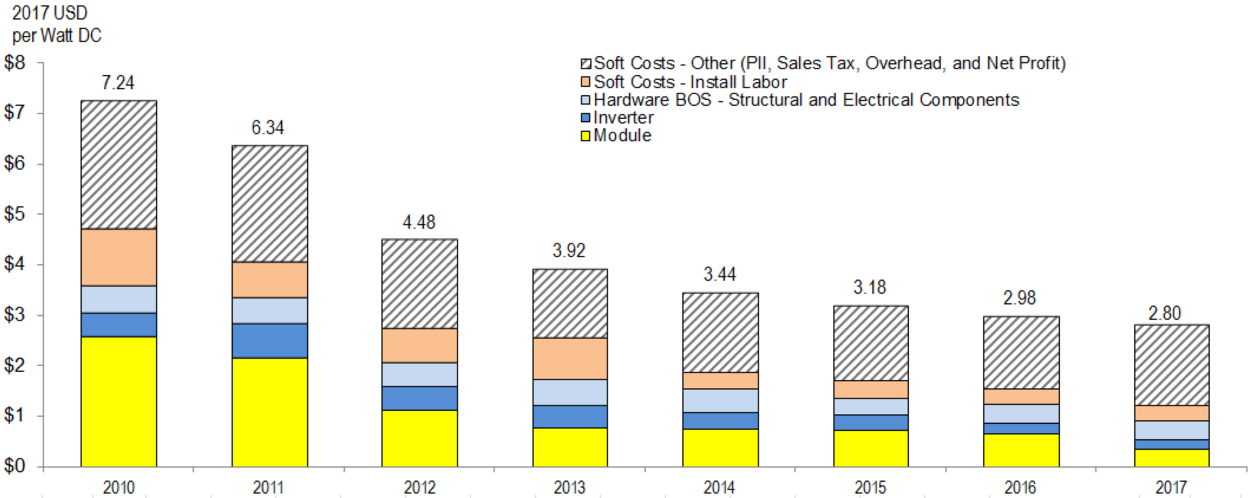


Figure 17. NREL residential PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2017

As demonstrated in Figure 17, from 2010 to 2017 there was a 61% reduction in the residential PV system cost benchmark. Approximately 61% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 18% can be attributed to labor, which dropped 73% over that time period, with the final 21% attributable to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 6% reduction in the residential PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by the increase in module supply chain costs discussed earlier (shown here in "soft costs – other").

[15] The original overarching 2020 goal of the SunShot Initiative was for solar to reach cost parity with baseload energy rates, estimated to be 6 cents/kWh without subsidies, or a system installed cost of $1/W. Commercial PV and residential PV were later separated to have their own goals of costs below retail rates, estimated to be 7 cents/kWh and 9 cents/kWh respectively, or system installed costs of $1.25/W and $1.50/W respectively (note: all 2020 targets are quoted in nominal USD). In recognition of the transformative solar progress to date and the potential for further innovation, in 2016 the SunShot Initiative extended its goals to reduce the unsubsidized cost of energy by 2030 to 3¢/kWh, 4¢/kWh and 5¢/kWh for utility-scale PV, commercial PV, and residential PV (note: all 2030 targets are quoted in nominal USD).

[16] Each year's PV system cost benchmark corresponds to the NREL benchmark calculted in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).

3.5 Residential PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 7, from Q4 2009 to Q1 2017 ([a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).[17]

Table 7. Residential PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$7.24	$6.34	$4.48	$3.92	$3.44	$3.18	$2.98	$2.80
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[c]	0.75%	0.75%
Inverter replacement price ($/W)	$0.41[a]	$0.36	$0.31	$0.26	$0.21	$0.15[c]	$0.14[e]	$0.13
Inverter lifetime (years)	10[a]	11	12	13	14	15[c]	15	15
O&M expenses ($/kw-yr)	$37[a]	$33	$30	$27	$24	$21[c]	$21	$21
Pre-inverter derate (%)	90.0%[a]	90.10%	90.20%	90.30%	90.40%	90.5%[c]	90.5%	90.5%
Inverter efficiency (%)	94.0%[a]	94.80%	95.60%	96.40%	97.20%	98.0%[c]	98.0%	98.0%
System size (kw-DC)	5.0[a]	5.0	5.1	5.1	5.2	5.2[c]	5.6[e]	5.7
Inverter loading ratio	1.1[a]	1.11	1.12	1.13	1.13	1.14	1.15[e]	1.15
Equity discount rate (real)[e]	9.0%[c]	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%[d]	6.9%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate[f]	5.5%[c]	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%[d]	4.8%
Debt fraction	34.2%[b]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

[17] In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

Other important assumptions: residential PV system LCOE assume a 1) system lifetime of 30 years[b], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a three month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a module tilt angle of 25 degrees, and an azimuth of 180 degrees, 9) debt with a term of 18 years[b], and 10) $1.1MM of upfront financial transaction costs for a $100MM TPO transaction of a pool of residential projects[d].

[e] In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

[f] The historical financial structure for a residential TPO system assumed in 2010 from Feldman and Bolinger 2016 does not assume a debt raise; however, the financial structure in 2016 from Feldman, Lowder, and Schwabe does assume back-leveraged debt. To make these assumptions uniform, the “debt interest rate” and “debt fraction” are taken from the utility-scale historical financial structure in Feldman and Bolinger 2016 that uses back-leveraged debt.

As demonstrated in Table 7, in addition to a 61% reduction in installed cost from 2010 to 2017, inverter replacement costs reduced 69%, O&M costs reduced 44%,annual degradation rates reduced 25%, the equity discount rate reduced 23%, the debt interest rate reducd 13%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 18.[18]

[18] Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

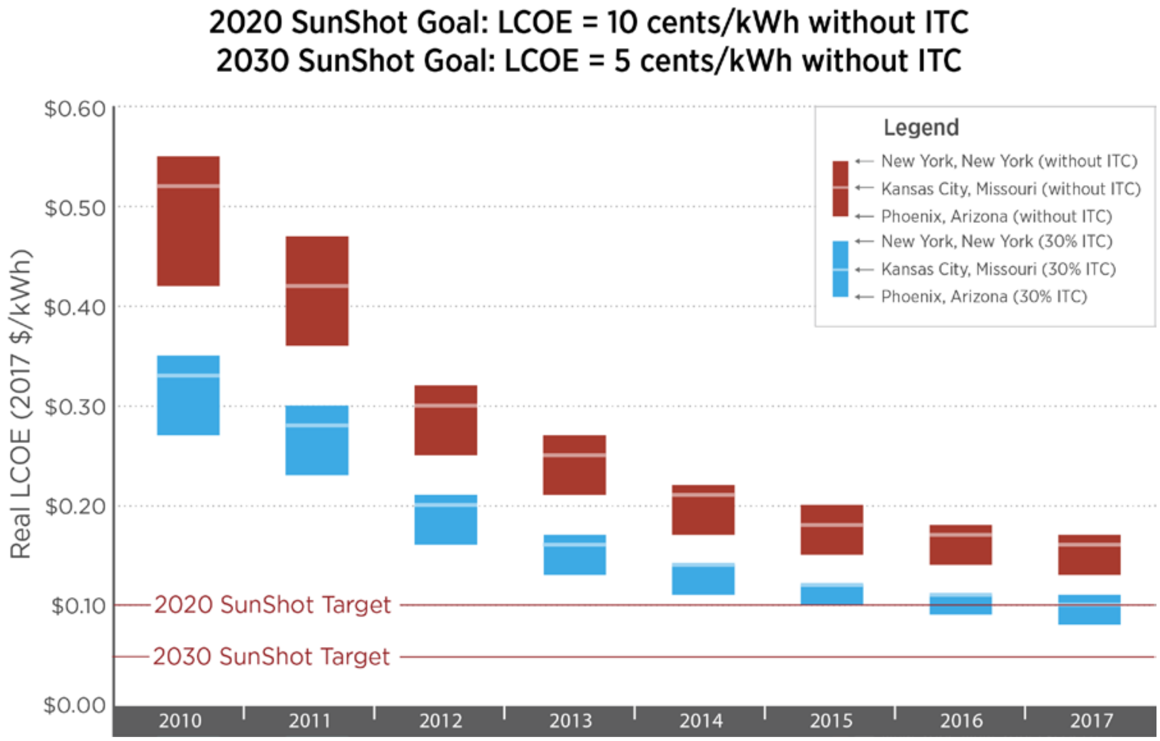


Figure 18. Levelized cost of energy for residential PV systems, by region and with and without ITC, 2010 –2017

As demonstrated in Figure 18, from 2010 to 2017 there was a 70% reduction in the residential PV system electricity cost benchmark (a 5% to 6% reduction was achieved from Q1 2016 to Q1 2017), bringing the unsubsidized LCOE between $0.13/kWh to $0.17/kWh ($0.08/kWh to $0.11/kWh when including the federal ITC). This reduction is 86% toward achieving SunShot's 2020 residential PV LCOE goal.[19]

[19] The SunShot 2020 target is adjusted from 2010 USD using the Consumer Price Index (CPI). A Summary of these values can be found in Appendix A and B. For LCOE Kansas City, MO, without ITC cases are $0.52/kWh in 2010 and $0.16/kWh in 2017 in 2017 USD from Appendix A and B. Thus, calculation is: (0.52 – 0.16)/(0.52 – 0.10) = 86%.

4 Commercial PV Model

This section describes our commercial model's structure, inputs, and assumptions (Section 4.1) and output (Section 4.2).

4.1 Commercial Model Structure, Inputs, and Assumptions

We model a 200-kW, 1,000 volts DC (Vdc), commercial-scale flat-roof system using multicrystalline 17.5%-efficient modules from a Tier 1 supplier, three-phase string inverters, and a ballasted racking solution on a membrane roof. A penetrating PV mounting system can have higher energy yield (kWh per kW) owing to wider tilt-angle range allowance. However, we do not model this system type, because its market share has declined owing to additional required flashing and sealing work, roof warranty issues, and the relative difficulty of replacing such a system in the future. Figure 19 presents a schematic of our commercial-scale system cost model. Table 8 presents the detailed modeling inputs and assumptions. We separate our cost estimate into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, and potentially achieve lower cost and pricing by reducing the total margin across functions, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

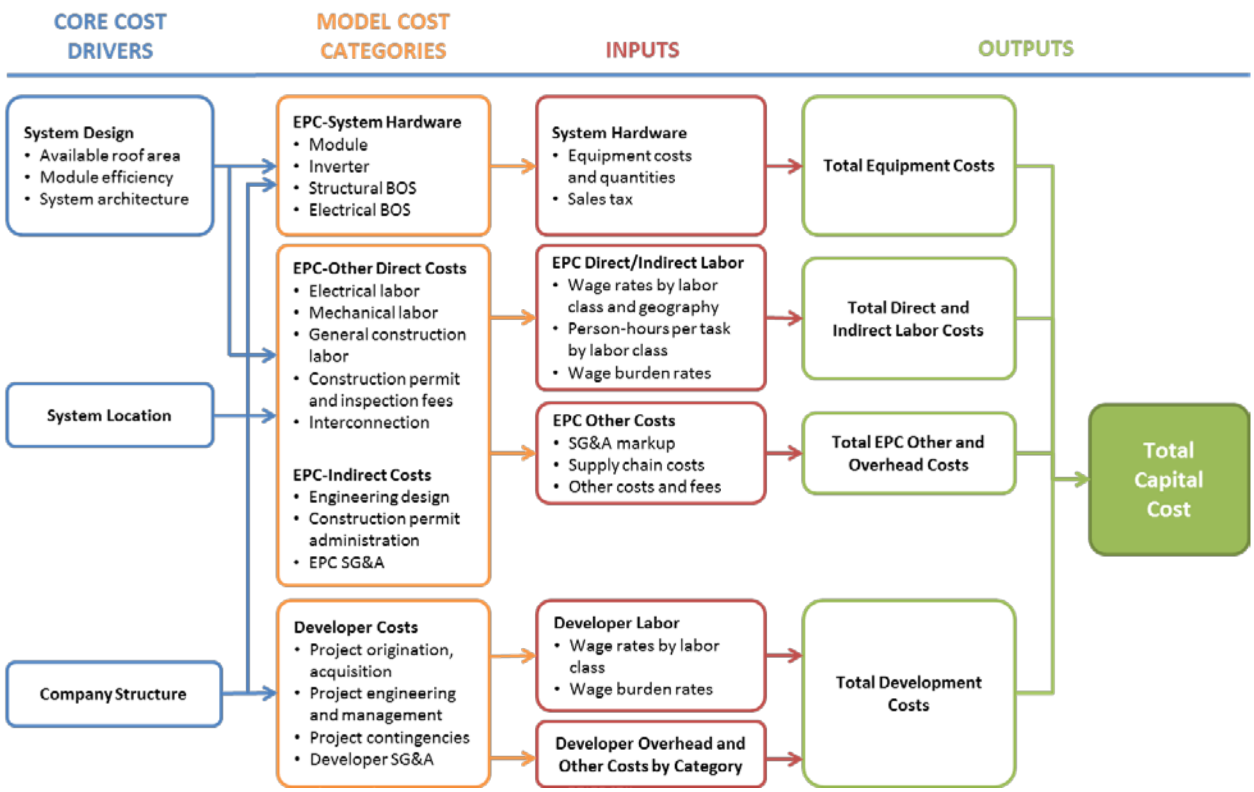


Figure 19. Commercial PV: model structure

Table 8. Commercial PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	10 kW – 2 MW	Average installed size per system	Go Solar CA (2017)
Module efficiency	17.5%	Average module efficiency	Go Solar CA (2017)
Module price	$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Three-phase string inverter: $0.10/Wdc	Ex-factory gate prices (first buyer) price, Tier 1 inverters	Bloomberg (2017), NREL (2017)
Structural components (racking)	$0.13–$0.28/Wdc; varies by location and system size	Flat-roof ballasted racking system	ASCE (2006), model assumptions, NREL (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, etc.	Model assumptions, NREL (2017), RSMeans (2016)
EPC overhead (% of equipment costs)	13%	Costs and fees associated with EPC overhead, inventory, shipping, and handling	NREL (2017)
Sales tax	Varies by location	Sales tax on equipment costs; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: $19.37–$38.22 per hour Laborer: $12.64–$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
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 (2016)
PII	$0.11–$0.16/Wdc	For construction permits fee, interconnection, testing, and commissioning	NREL (2017)
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 (2017)
Contingency	4%	Estimated as markup on EPC price; value represents actual cost overruns above estimated price	NREL (2017)
Profit	7%	Applies a fixed percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2017)

4.2 Commercial Model Output

Figure 20 presents the U.S. national benchmark from our commercial model. As in the residential model, the national benchmark represents an average weighted by 2016 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. Economies of scale—driven by hardware, labor, and related markups—are evident here. As system sizes increase, the per-watt cost to build them decreases. This holds even as we assume that a typical developer has 10 MW of system development and installation per year, and therefore has overhead on this 10 MW total capacity that does not vary for different system sizes. When a developer installs more capacity annually, the developer's overhead per watt in each system declines (shown in Figure 18 in our Q1 2015 benchmark report, Chung et al. 2015).

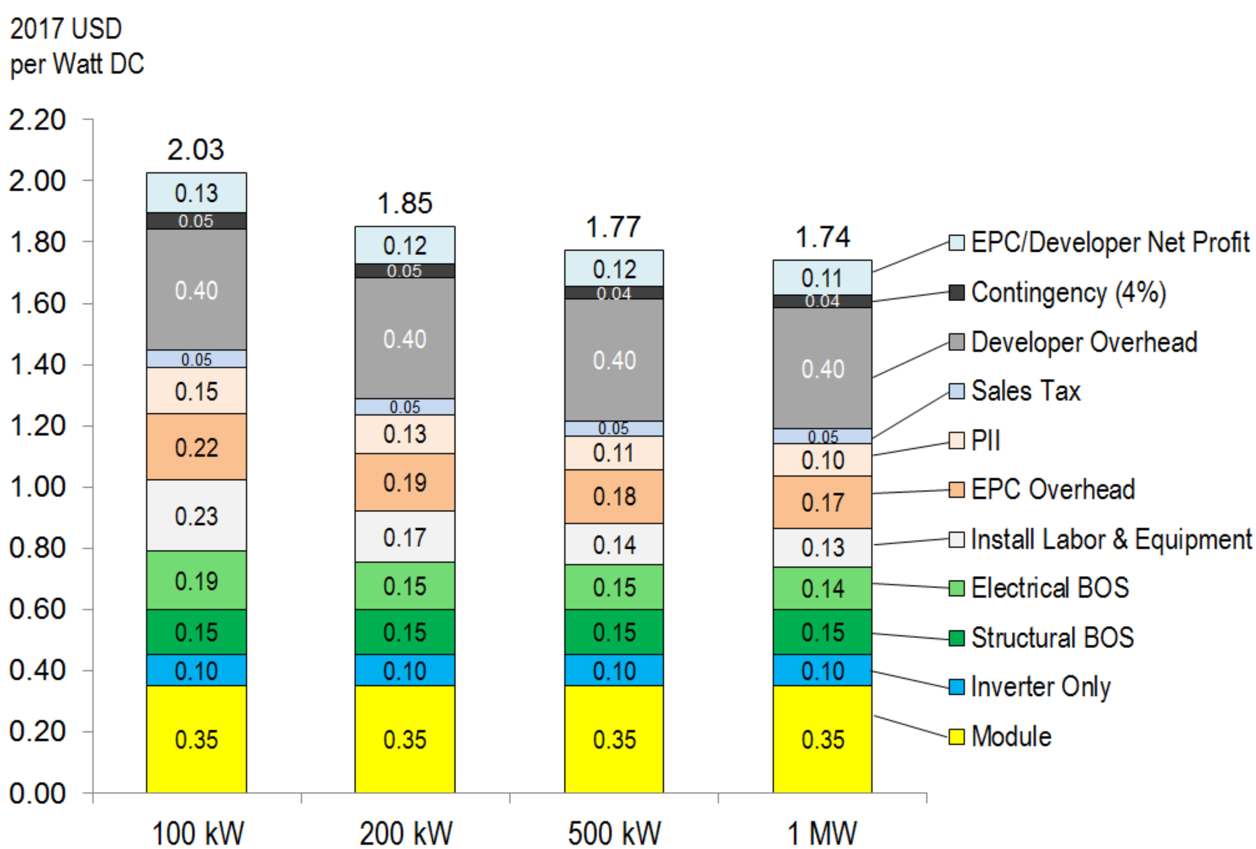


Figure 20. Q1 2017 U.S. benchmark: commercial system cost (2017 USD/Wdc)

The PII cost was higher in Q1 2017 than in Q1 2016, because the low-hanging fruit—such as ideal commercial building rooftops—have already been picked by Q1 2017. Thus, the associated PII time and fees were higher in Q1 2017 for commercial projects with more PII obstacles. Also, the higher net profit in Q1 2017—7%, compared with 2% in Q1 2016—indicates that the rapid module price reduction in 2016 enabled EPC firms and developers to retain a higher profit and still maintain a competitive project cost (NREL 2017).

Figure 21 presents the benchmark from our commercial model by location in the top U.S. solar markets (by 2016 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.

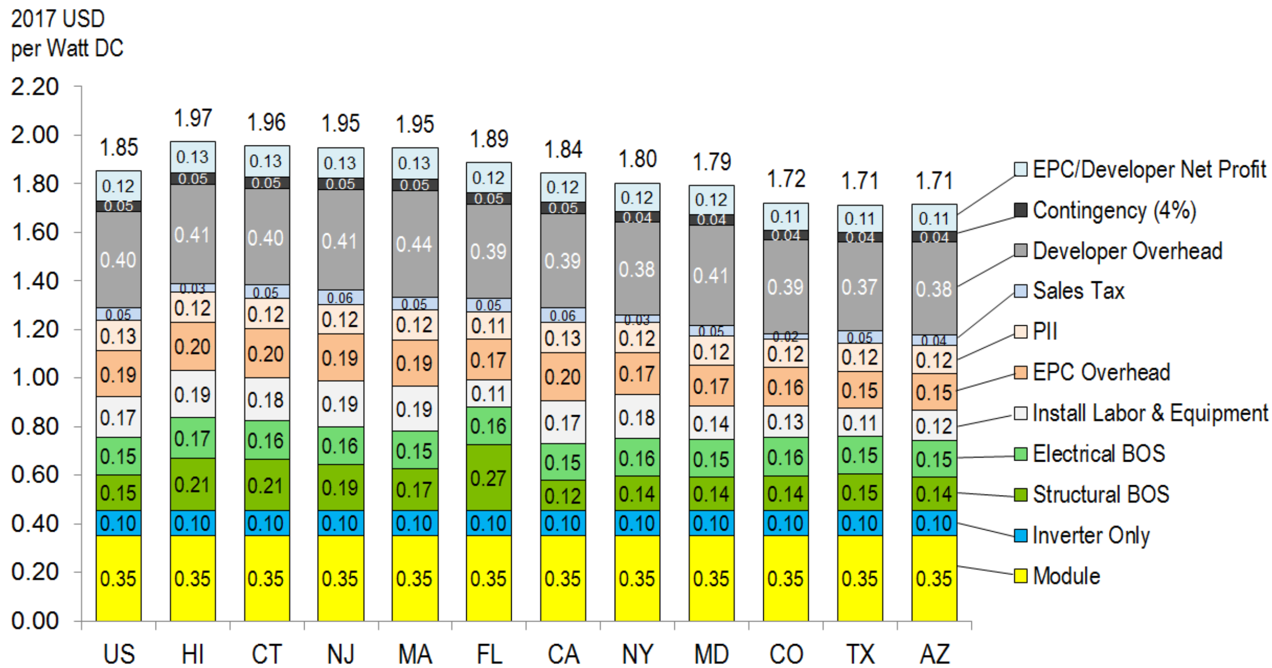


Figure 21. Q1 2017 benchmark by location: 200-kW commercial system cost (2017 USD/Wdc)

4.3 Commercial PV Price Benchmark Historical Trends

Figure 22 summarizes the reduction in commercial PV system cost benchmarks between 2010 and 2017.[20]

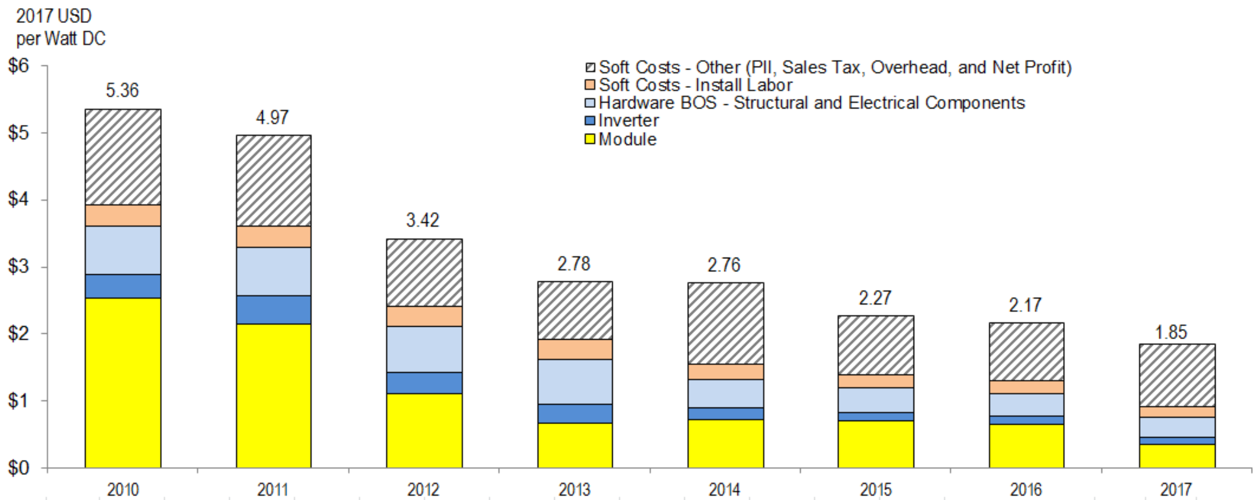


Figure 22. NREL commercial PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2017

As demonstrated in Figure 22, from 2010 to 2017 there was a 65% reduction in the commercial PV system cost benchmark. Approximately 82% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 4% can be attributed to labor, which dropped 47% over that time period, with the final 14% attibitubal to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 15% reduction in the commercial PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by an increase in PII and installer profit.

4.4 Commercial PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 9, from 2010 to 2017 ([a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).[21]

[20] Each year's PV system cost benchmark corresponds to the NREL benchmark calculted in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).

[21] In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

Table 9. Commercial PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$5.36	$4.97	$3.42	$2.78	$2.76	$2.27	$2.17	$1.85
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.24[a]	$0.22	$0.19	$0.17	$0.15	$0.12[b]	$0.11[e]	$0.10
O&M expenses ($/kw-yr)	$26[a]	$24	$22	$20	$18	$15[b]	$15	$15
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	95.0%[a]	95.60%	96.20%	96.80%	97.40%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.11	1.12	1.13	1.13	1.14	1.15[e]	1.15
Equity discount rate[e] (real)	9.0%[c]	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%[d]	6.9%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate[f]	5.5%[c]	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%[d]	4.8%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: commercial PV system LCOE assume a 1) system lifetime of 30 years[b], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a system size of 200 kW[a], 9) an inverter lifetime of 15 years[a], 10) a module tilt angle of 10 degrees, and an azimuth of 180 degrees, 11) debt with a term of 18 years[b], and 12) $1.1MM of upfront financial transaction costs for a $100MM TPO transaction of a pool of commercial projects[d].

[e] The financial assumptions in Table 7 assume a $100MM TPO transaction of a pool of commercial projects.

[f] The historical financial structure for a residential TPO system, assumed in 2010 from Feldman and Bolinger 2016 does not assume a debt raise; however, the financial structure in 2016 from Feldman, Lowder, and Schwabe does assume back-leveraged debt. To make these assumptions uniform, the “debt interest rate” and “debt fraction” are taken from the utility-scale historical financial structure in Feldman and Bolinger 2016 that uses back-leveraged debt.

As demonstrated in Table 9, in addition to a 65% reduction in installed cost from 2010 to 2017, inverter replacement costs reduced 58%, O&M costs reduced 41%, annual degradation rates reduced 25%, the equity discount rate reduced 23%, the debt interest rate reducd 13%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 23.[22]

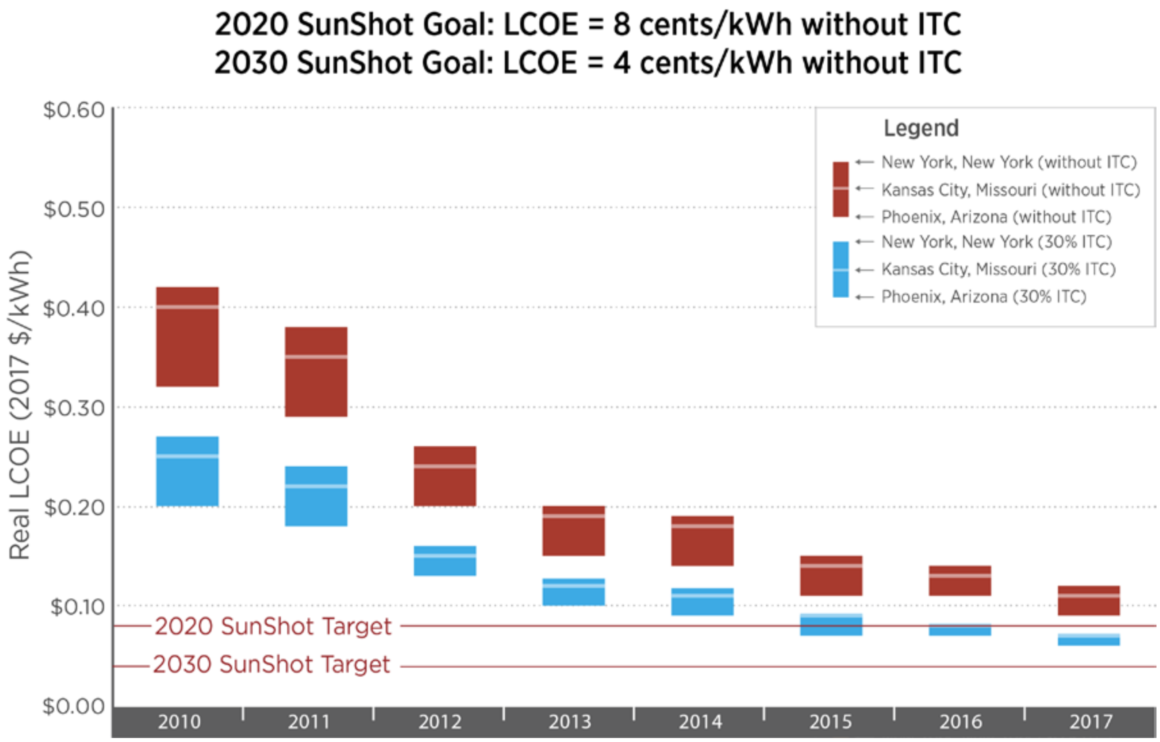


Figure 23. Levelized cost of energy for commercial PV systems, by region and with and without ITC, 2010 –2017

As demonstrated in Figure 23, from 2010 to 2017 there was a 71% - 72% reduction in the commercial PV system electricity cost benchmark (a 12% - 13% reduction was achieved from 2016 to 2017), 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 89% toward achieving SunShot's 2020 commercial PV LCOE goal.[23]

[22] Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

[23] The SunShot 2020 target is adjusted from 2010 USD using the CPI. A Summary of these values can be found in Appendix A and B. For LCOE Kansas City, MO, without ITC cases are $0.40/kWh in 2010 and $0.11/kWh in 2017 in 2017 USD from Appendix A and B. Thus, calculation is: (0.40 – 0.11)/(0.40 – 0.08) = 89%.

5 Utility-Scale PV Model

This section describes our utility-scale model's structure, inputs, and assumptions (Section 5.1) and output (Section 5.2).

5.1 Utility-Scale Model Structure, Inputs, and Assumptions

We model a 100-MW, 1,000-Vdc utility-scale system using 72-cell, multicrystalline 17.5%-efficient modules from a Tier 1 supplier and three-phase central inverters. We model both fixed-tilt and one-axis tracking on ground-mounted racking systems using driven-pile foundations. In addition, we separate our cost estimate into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

Figure 24 presents a schematic of our utility-scale system cost model, and Table 10 details its assumptions and inputs.

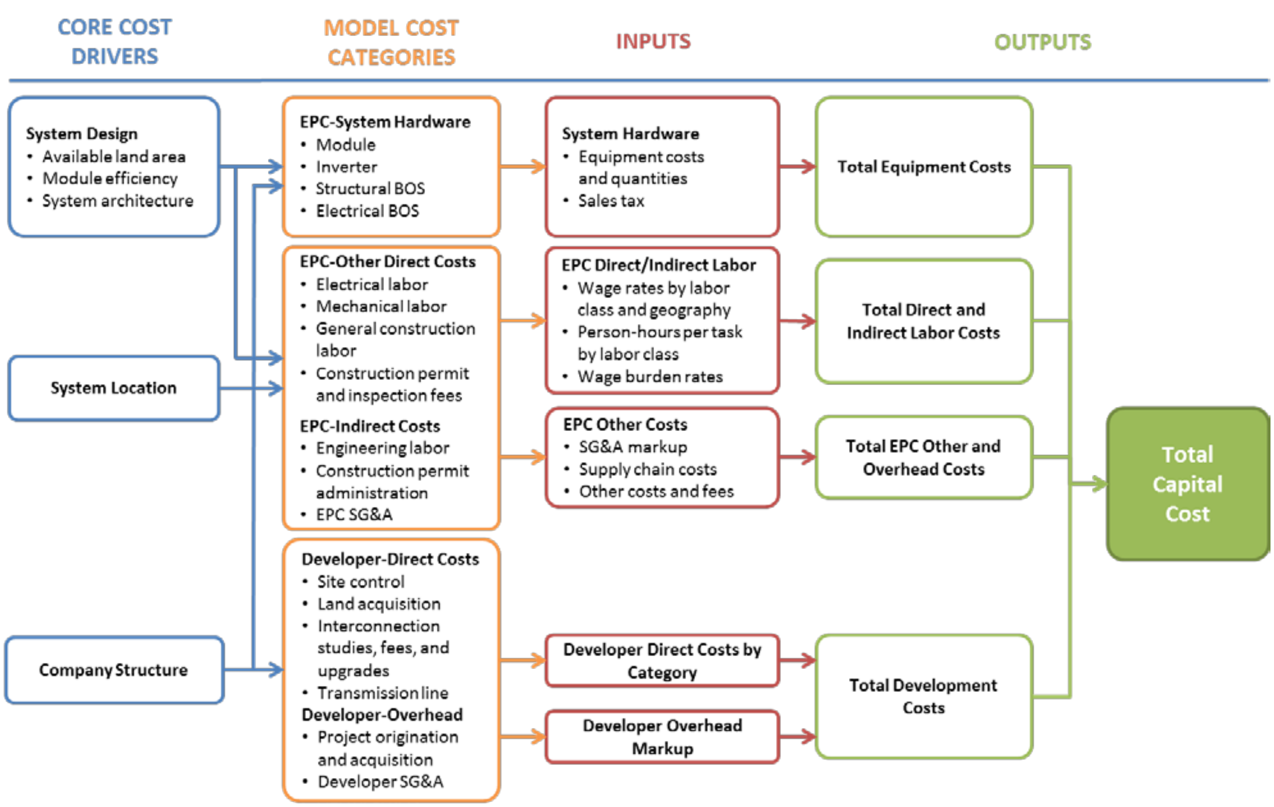


Figure 24. Utility-scale PV: model structure

Table 10. Utility-Scale PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	>2 MW	A large utility-scale system capacity	Model assumption
Module efficiency	17.5%	Average module efficiency	NREL (2017)
Module price	$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	$0.06/Wdc (fixed-tilt) $0.06/Wdc (one-axis tracker)	Ex-factory gate prices (first buyer) price, Tier 1 inverters DC-to-AC ratio = 1.3 for both fixed-tilt and one-axis tracker	Bloomberg (2017), NREL (2017), Bolinger and Seel (2017)
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 (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, onsite transmission, etc.	Model assumptions, NREL (2017), RSMeans (2016)
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 (2017)
Sales tax	Varies by location	National benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: $19.37–$38.22 per hour Laborer: $12.64–$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union and union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
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 (2016)

Category	Modeled Value	Description	Sources
PII	$0.03–$0.09/Wdc Varies by system size and location	For construction permits fee, interconnection, testing, and commissioning	NREL (2017)
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 (2017)
Developer overhead	3%–12% Varies by system size (100 MW uses 3%; 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 (2017)
Contingency	3%	Estimated as markup on EPC cost	NREL (2017)
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 (2017)

Figure 25 shows the percentage of U.S. utility-scale PV systems using tracking systems for 2007–2016. 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 2017). Cumulative tracking system installation reached 64% in 2016.

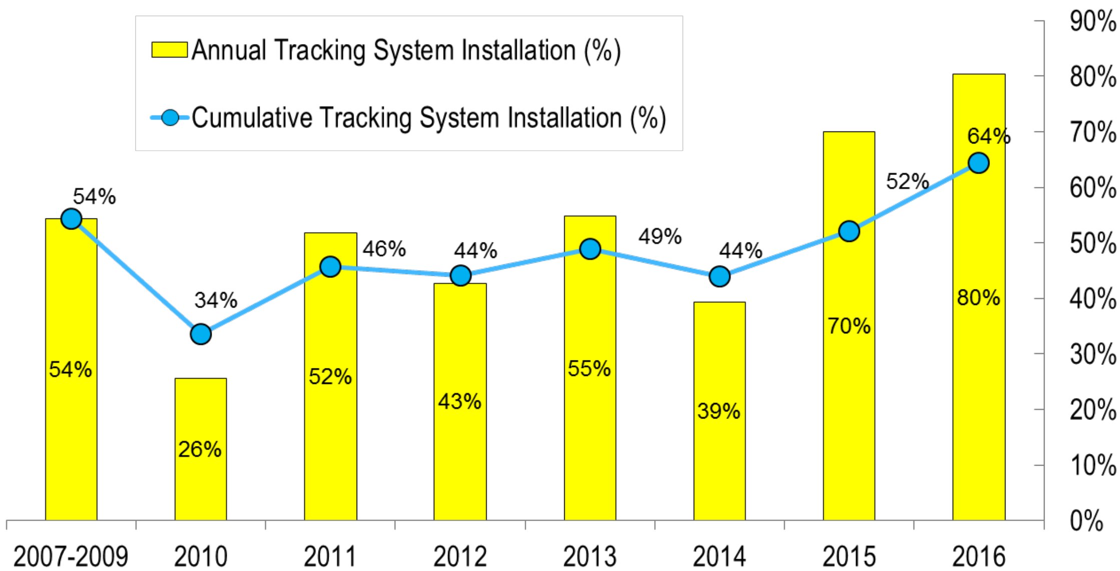


Figure 25. Percentage of U.S. utility-scale PV systems using tracking systems, 2007–2016 (Bolinger and Seel 2017)

Although EPC contractors and developers tend to employ low-cost, non-union labor (based on data from BLS 2017) 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. Figure 26 shows 2016 utility-scale PV capacity installed (GTM Research and SEIA 2017) and the proportion of unionized labor in each state (BLS 2017). 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 (Figure 27).

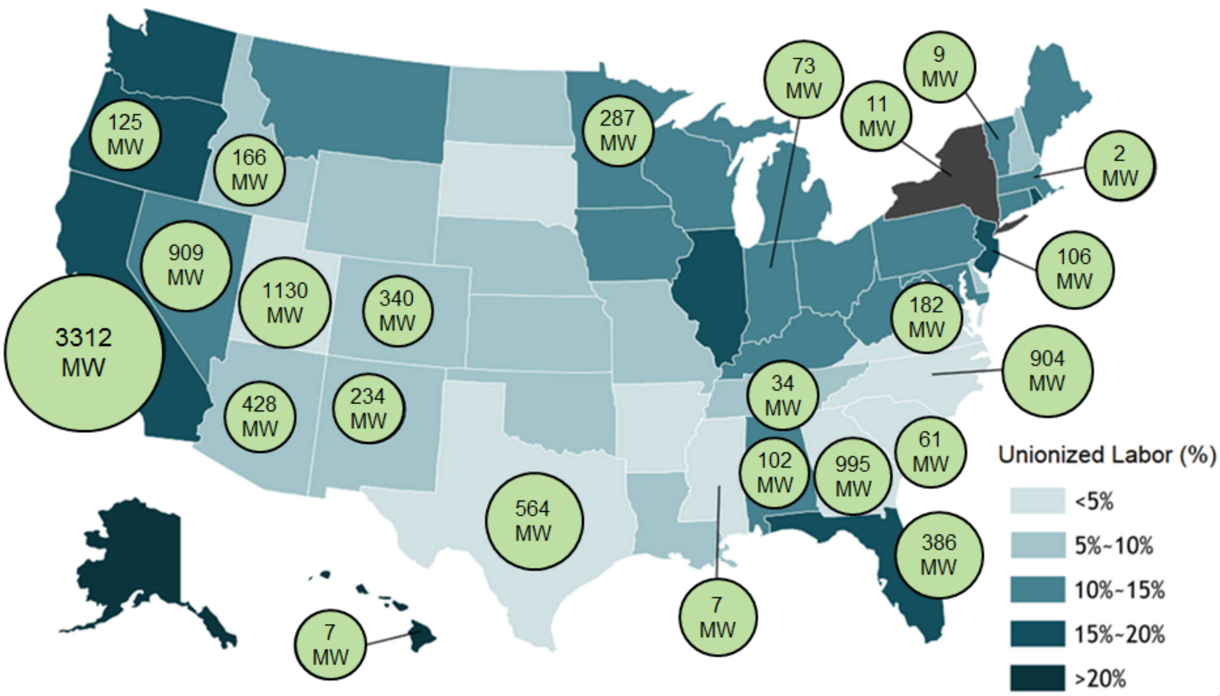


Figure 26. Utility-scale PV: 2016 capacity installed and percentage of unionized labor by state (BLS 2017; GTM Research and SEIA 2017)

5.2 Utility-Scale Model Output

Figure 27 presents the regional EPC benchmark from our utility-scale model, and Figure 28 presents the U.S. national benchmark (EPC + developer) for fixed-tilt and one-axis tracker systems, using non-union labor. In Figure 28, note the following:

1. The national benchmark applies an average weighted by 2016 installed capacities.
2. Non-union labor is used.
3. Economies of scale—driven by BOS, labor, related markups, and development cost—are demonstrated.

As in the commercial PV sector, the 7% net profit in Q1 2017 is higher than the 2% in Q1 2016, because the rapid module price reduction in 2016 enabled EPC firms and developers to retain a higher profit and still keep a competitive project cost bid.

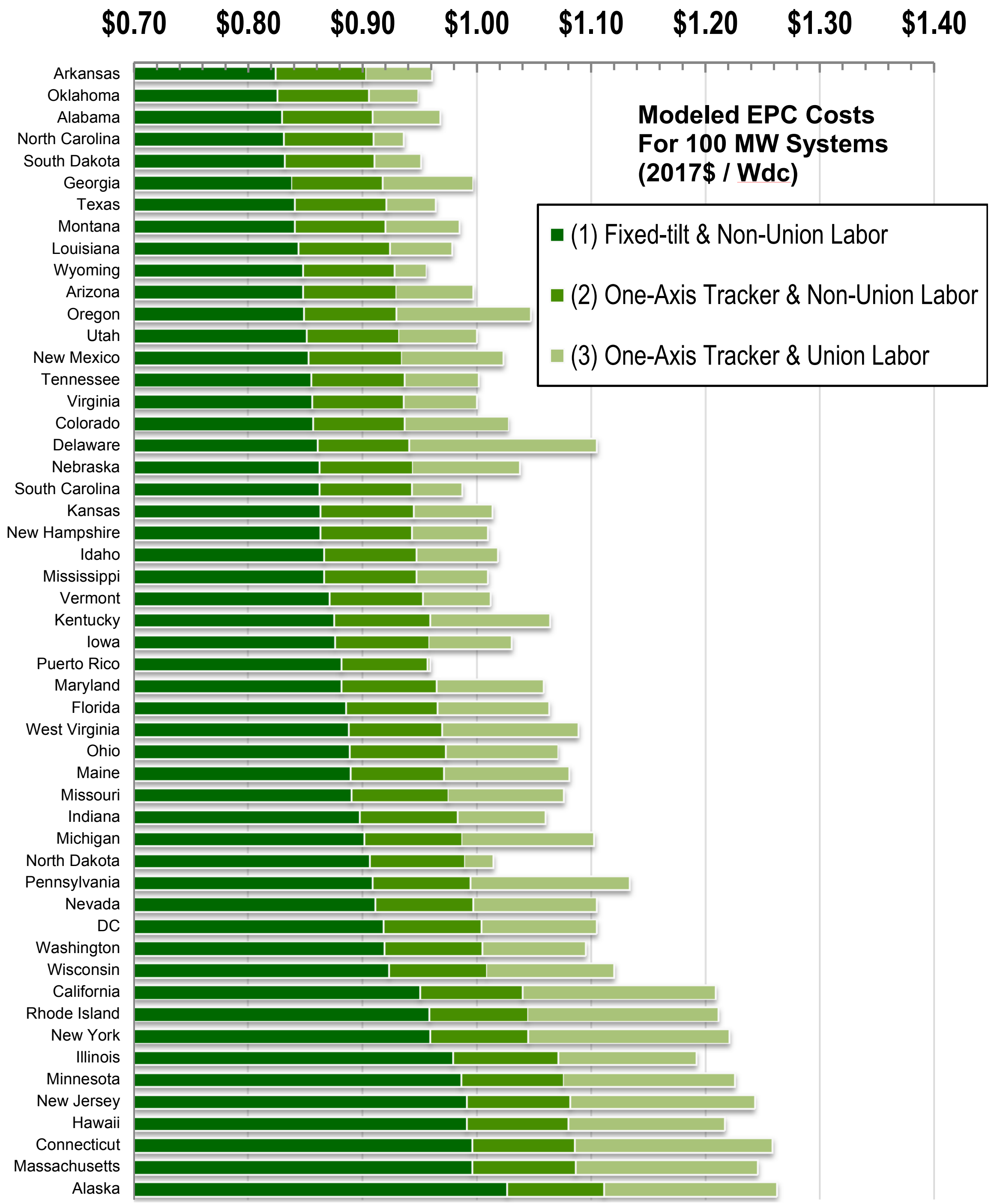


Figure 27. Q1 2017 benchmark by location: 100-MW utility-scale PV systems, EPC only (2017 USD/Wdc)[24]

[24] The fixed-tilt, non-union cost is always lowest, followed by the one-axis tracker, non-union cost and the one-axis tracker, union cost. Thus the bars are additive: the fixed-tilt, non-union cost is represented by the dark green bar alone; the one-axis tracker, non-union cost is the sum of the dark green and medium green bars; and the one-axis tracker, union cost is the sum of all three bars.

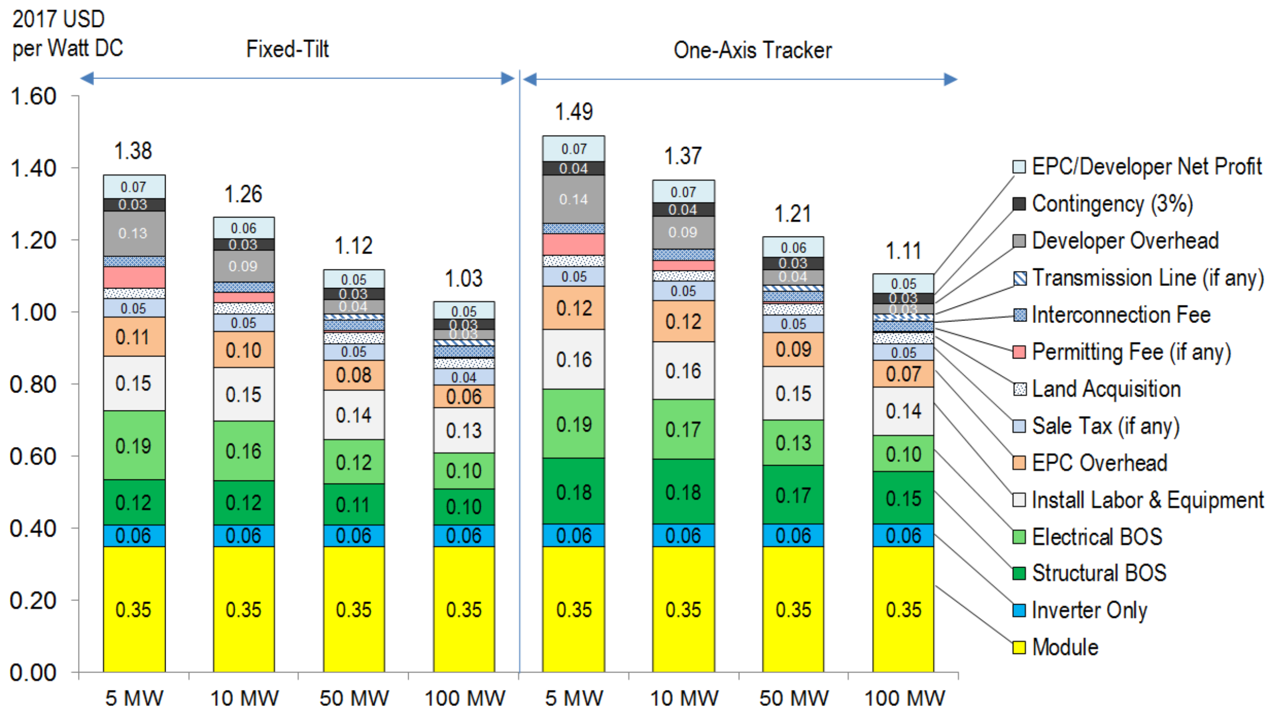


Figure 28. Q1 2017 U.S. benchmark: utility-scale PV total cost (EPC + developer), 2017 USD/Wdc[25]

[25] Although four different system sizes are shown in this figure, the actual national average system size in 2015 was 29 MW for fixed-tilt systems and 37 MW for one-axis tracker systems. Our model estimates $1.17/W for 29-MW fixed-tilt systems and $1.25/W for 37-MW one-axis tracker systems.

5.3 Utility-Scale PV Price Benchmark Historical Trends

Figure 29 summarizes the reduction in utility-scale PV system cost benchmarks between 2010 and 2017.[26]

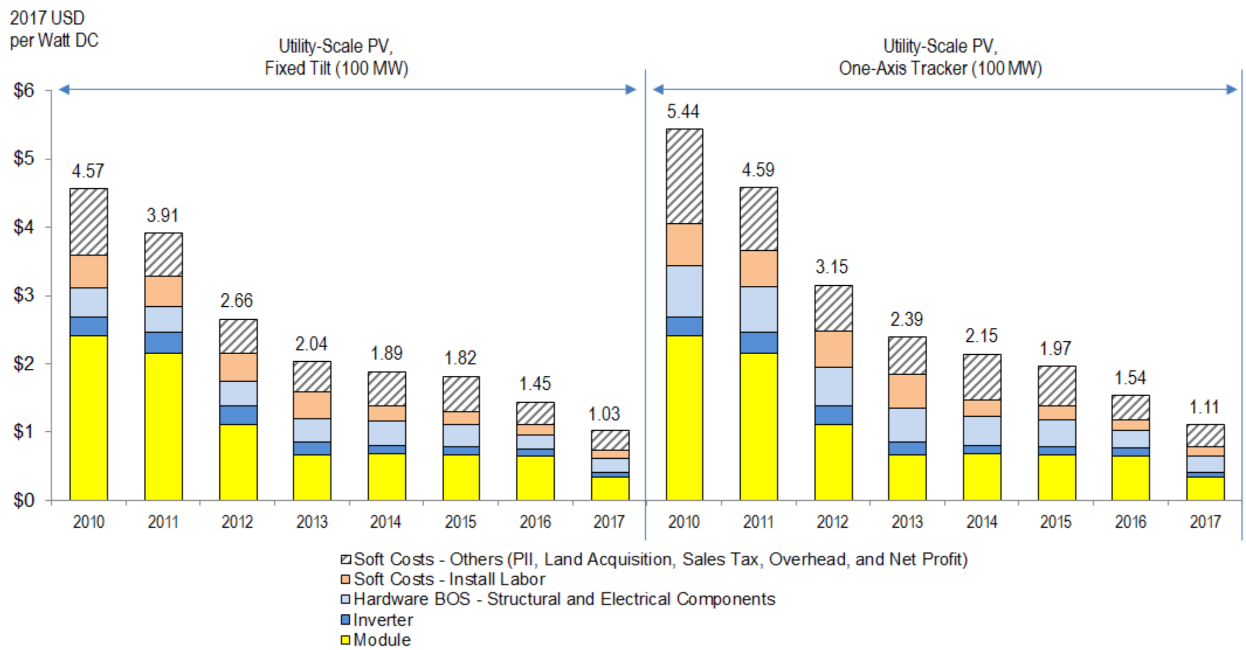


Figure 29. NREL utility-scale PV system cost benchmark summary (inflation adjusted), 2010–2017

As demonstrated in Figure 29, from 2010 to 2017 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 71% and 64% of that reduction can be attributed to total hardware costs (for fixed-tilt and one-axis systems respectively), as module prices dropped 86% over that time period. An additional 10% / 11% can be attributed to labor, which dropped 74% / 78% over that time period, with the final 19% / 25% attributabal to other soft costs, including PII, sales tax, overhead, and net profit (for fixed-tilt and one-axis systems respectively).

Looking at this past year, from 2016 to 2017 there was a 29% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 28% reduction in the utility-scale (one-axis) PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, and a 45% / 41% reduction in inverter factory gate price.[27]

[26] Each year's PV system cost benchmark corresponds to the NREL benchmark calculted in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).
[27] One-axis and fixed-tilt PV systems have different reductions in inverter factory gate price due to differing ILRs in 2016.

5.4 Utility-Scale PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 11 (next page), from Q4 2009 to Q1 2017 ([a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).[28]

As demonstrated in Table 11, in addition to a 80% reduction in installed cost of utility-scale (one-axis) systems from 2010 to 2017, inverter replacement costs reduced 68%, O&M costs reduced 17%, annual degradation rates reduced 25%, the equity discount rate reduced 14%, the debt interest rate reducd 18%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 30.[29]

[28] In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

[29] Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

Table 11. One-Axis Tracker and Fixed-Tilt Utility-Scale PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
One-Axis Tracker								
Installed cost	$5.44	$4.59	$3.15	$2.39	$2.15	$1.97	$1.54	$1.11
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.19[a]	$0.17	$0.15	$0.14	$0.12	$0.10[b]	$0.08[e]	$0.06
O&M expenses ($/kw-yr)	$22.2[a]	$21.5	$20.7	$20.0	$19.2	$18.5[b]	$18.5	$18.5
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	96.0%[a]	96.40%	96.80%	97.20%	97.60%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.12	1.13	1.15	1.17	1.18	1.20[e]	1.30
Equity discount rate (real)	7.4%[c]	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%[d]	6.3%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%[d]	4.5%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%
Fixed-Tilt								
Installed cost	$4.57	$3.91	$2.66	$2.04	$1.89	$1.82	$1.45	$1.03
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.19[a]	$0.17	$0.15	$0.14	$0.12	$0.10[b]	$0.08[e]	$0.06
O&M expenses ($/kw-yr)	$22.2[a]	$20.9	$19.5	$18.1	$16.8	$15.4[b]	$15.4	$15.4
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	96.0%[a]	96.40%	96.80%	97.20%	97.60%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.15	1.2	1.25	1.3	1.35	1.40[e]	1.3
Equity discount rate (real)	7.4%[c]	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%[d]	6.3%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%[d]	4.5%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: utility-scale PV system LCOE assume a 1) system lifetime of 30 years[a], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a system size of 100 MW[b], 9) an inverter lifetime of 15 years[a], 10) debt with a term of 18 years[b], and 11) $1.1MM of upfront financial transaction costs[d].

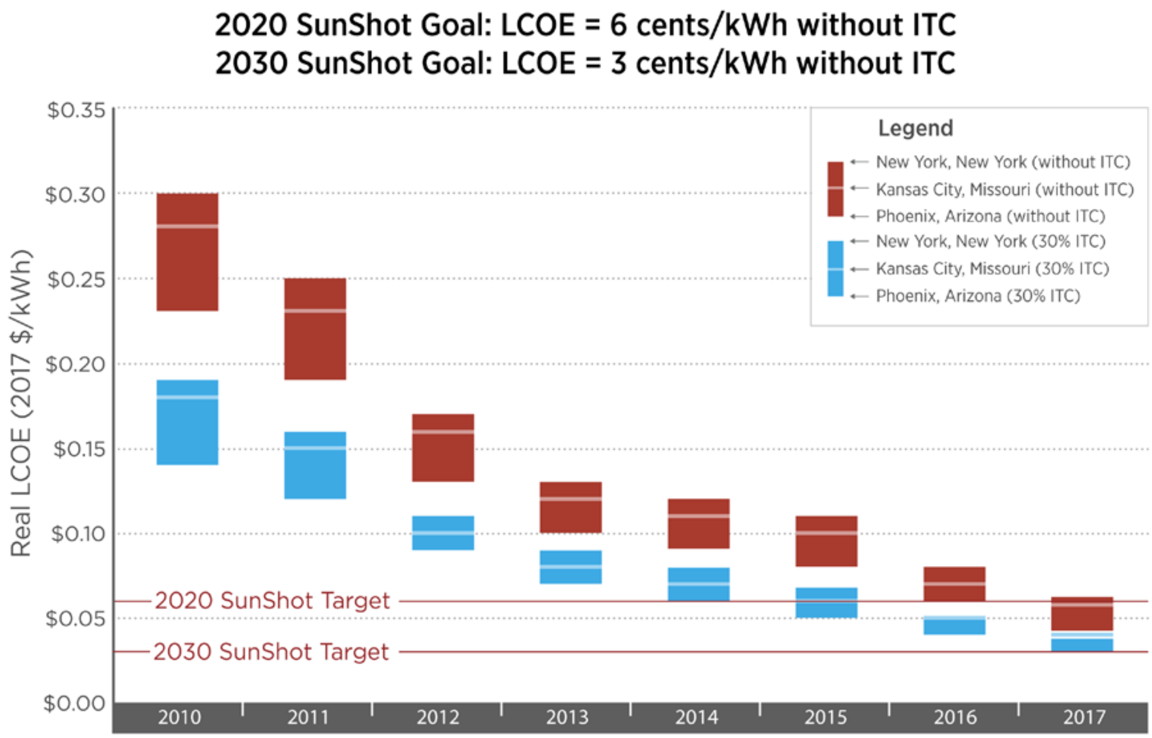


Figure 30. Levelized cost of energy for utility-scale PV systems, by region and with and without ITC, 2010–2017

We use the fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2017 to reflect the market share change in Figure 31. All detailed LCOE values can be found in Appendix A and B.

As demonstrated in Figure 30, from 2010 to 2017 there was a 78%–79% reduction in the utility-scale PV system electricity cost benchmark (a 20%– 23% reduction was achieved from 2016 to 2017), 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 SunShot's 2020 utility-scale PV goal.[30]

[30]The 2020 utility-scale goal is not adjusted for inflation as wholesale prices have been relatively flat, and in some cases gone down, from 2010-2017. A Summary of these values can be found in Appendix A and B.

6 Model Applications

This section includes three additional applications of our cost modeling: system cost reduction from economies of scale (Section 6.1), module efficiency impacts (Section 6.2), and regional LCOE (Section 6.3). The granularity of our bottom-up models enables us to determine the changes in particular cost drivers over time. Accordingly, the models can be used to predict future system cost-reduction opportunities based on particular market trends and technologies.

6.1 System Cost Reduction from Economies of Scale

Figure 31 demonstrates the cost savings from increased system size. Scaling up the system size from 10 MW to 100 MW reduces related costs in several ways: per-watt BOS costs because of bulk purchasing, labor costs that benefit from learning-related improvements for larger systems, and EPC overhead and developer costs that are spread over more installed capacity. Note that non-union labor is used in this figure.

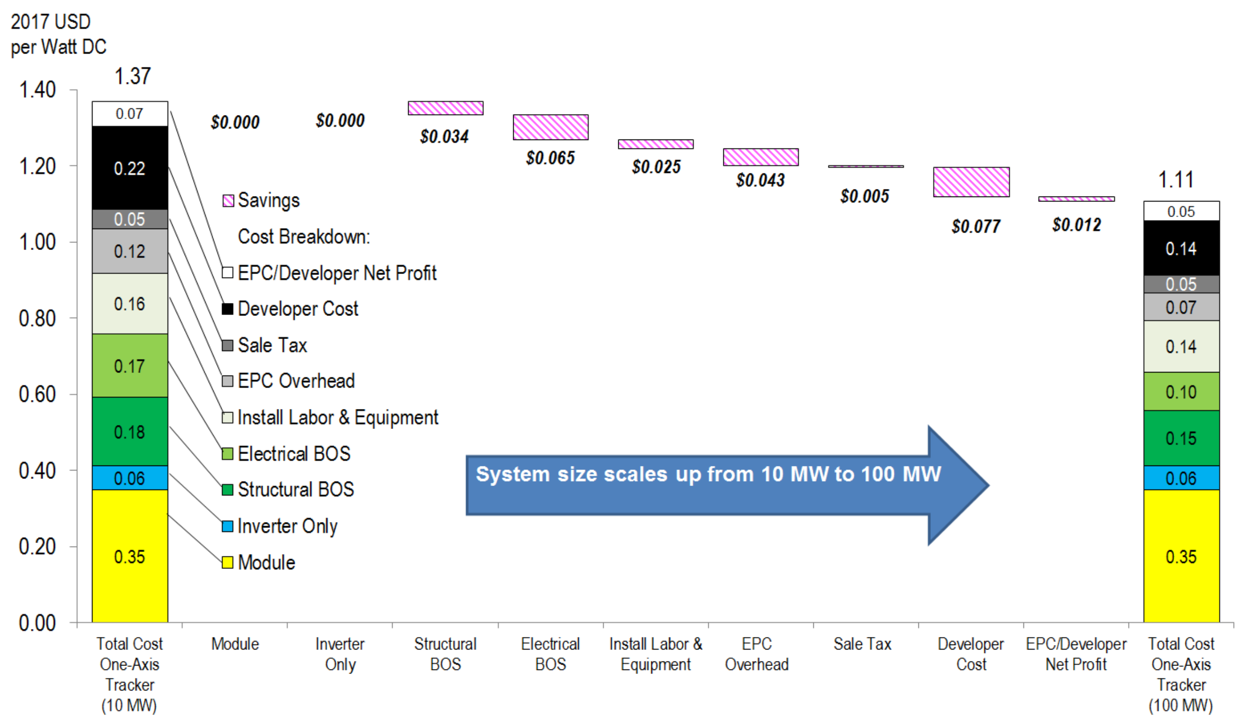


Figure 32. Model application: U.S. utility-scale one-axis tracking PV system cost reduction from economies of scale (2017 USD/Wdc)

6.2 Module Efficiency Impacts

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. Figure 32 presents the relationship 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 a fixed-tilt system is used in the utility-scale curve and a string inverter is used in the residential curve.

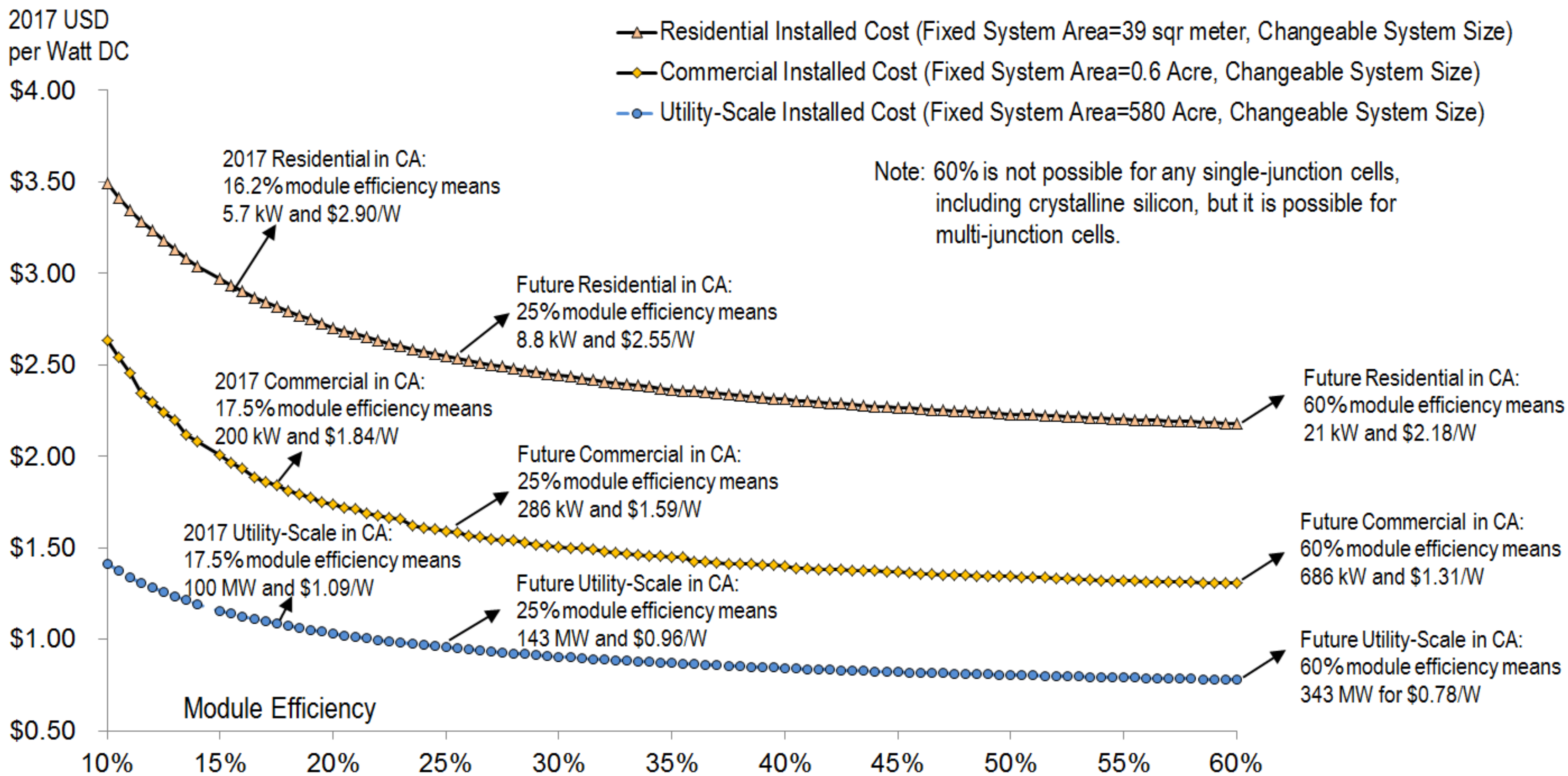


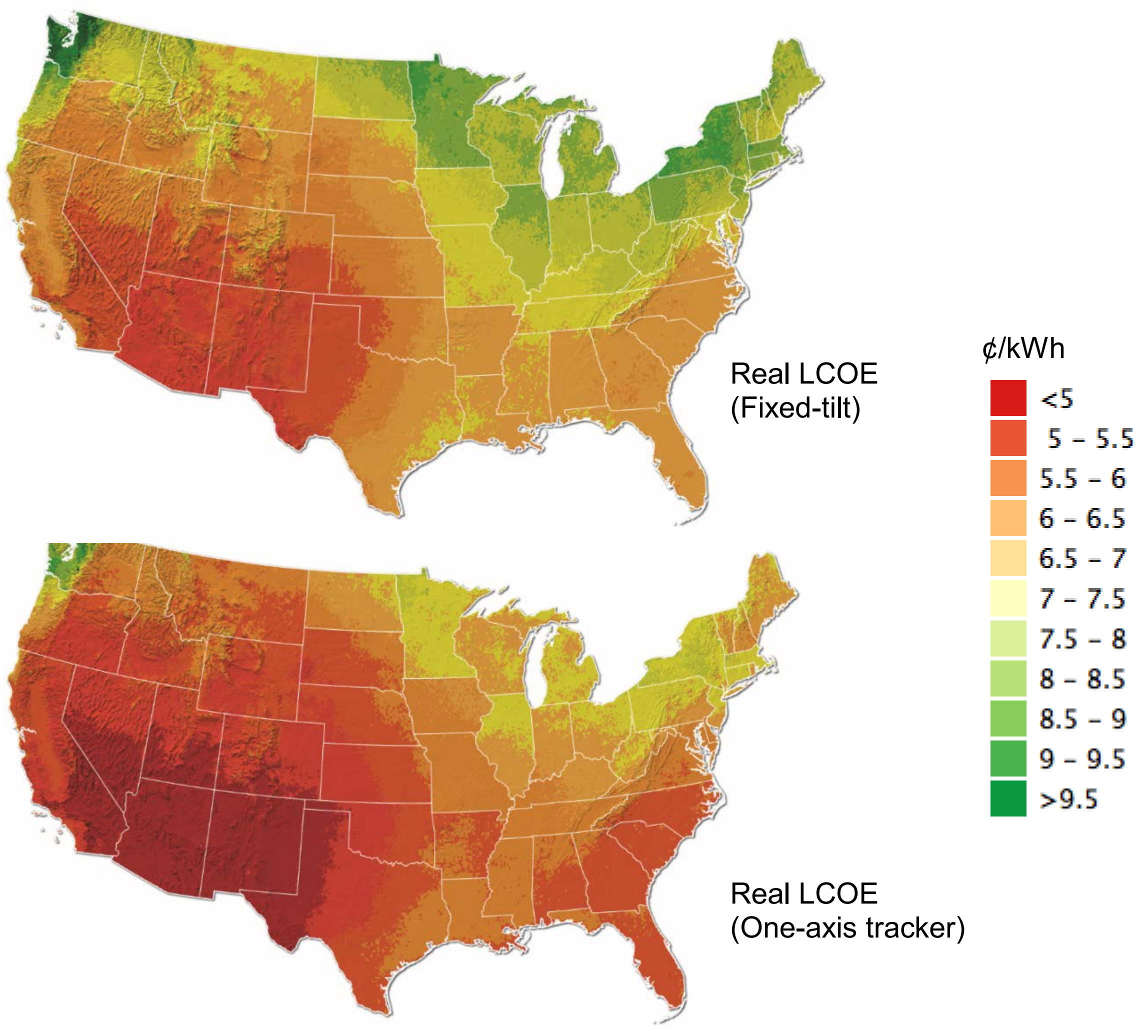
Figure 33. Modeled impacts of module efficiency on total system costs, 2017

6.3 Regional LCOE

To estimate regional LCOEs across the United States, we combine modeled regional installed cost with localized solar irradiance and weather data, a PV performance model, and a pro forma financial analysis that models the revenue, operating expenses, taxes, incentives, debt structures, and cash flows for a representative PV system. We use NREL's System Advisor Model (SAM), a performance and financial model,[31] to estimate location-specific hourly energy output over the PV system's lifetime and subsequently calculate the resulting real LCOEs (considering inflation) for each location. Figure 33 presents real LCOEs for a 100-MW utility-scale PV system with fixed tilt or one-axis tracking based on regional labor and material costs, wind speeds, snow loading, solar irradiance, weather data, and sales tax.[32] We assume the following:

- ITC = 0%, Real discount rate = 6.3%, IRR target = 6.46%, Inflation = Price escalator = 2.5%, Analysis period = 30-Yr, Degradation rate = 0.75% per year. System size = 100 MW utility-scale PV, Project debt = 40%, Debt interest rate = 4.5%.
- Fixed-tilt: DC-to-AC ratio = 1.3 and Fixed O&M cost = $15/kW per year. One-axis tracker: DC-to-AC ratio = 1.3 and Fixed O&M cost = $18.5/kW per year.

[31] See https://sam.nrel.gov/.
[32] The assumptions in this LCOE exercise are the same from those in Section 5.



2017 USD		Fixed-Tilt			One-Axis Tracker			One-Axis Tracker vs. Fixed-Tilt		
State	Location	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Installed Costs Premium (%)	Nominal LCOE Change (%)	Real LCOE Change (%)
CA	Bakersfield	1.09	7.26	5.68	1.18	6.44	5.04	8.26%	-11.29%	-11.27%
CA	Imperial	1.09	6.64	5.19	1.18	5.76	4.50	8.26%	-13.25%	-13.29%
AZ	Prescott	0.98	6.20	4.85	1.06	5.47	4.27	8.16%	-11.77%	-11.96%
AZ	Tucson	0.98	6.01	4.70	1.06	5.29	4.14	8.16%	-11.98%	-11.91%
NV	Las Vegas	1.05	6.33	4.95	1.13	5.54	4.33	7.62%	-12.48%	-12.53%
NM	Albuquerque	0.99	6.05	4.73	1.06	5.39	4.21	7.07%	-10.91%	-10.99%
CO	Alamosa	0.99	6.05	4.73	1.07	5.33	4.16	8.08%	-11.90%	-12.05%
NC	Jacksonville	0.96	7.25	5.67	1.03	6.56	5.13	7.29%	-9.52%	-9.52%
TX	San Antonio	0.97	7.11	5.56	1.04	6.55	5.12	7.22%	-7.88%	-7.91%
NJ	Newark	1.13	9.15	7.16	1.22	8.59	6.71	7.96%	-6.12%	-6.28%
FL	Orlando	1.02	8.47	6.63	1.09	7.51	5.87	6.86%	-11.33%	-11.46%
HI	Kona	1.14	8.08	6.32	1.22	7.41	5.79	7.02%	-8.29%	-8.39%

Figure 34. Modeled real LCOE (¢/kWh), ITC = 0%, for a 100-MWdc utility-scale PV system with fixed-tilt and one-axis tracking in 2017[33]

[33] The U.S. Department of Energy's SunShot Initiative uses Kansas City's insolation as the national average insolation to calculate LCOE (Woodhouse et al. 2016).

7 Conclusions

Based on our bottom-up modeling, the Q1 2017 PV cost benchmarks are $2.80/Wdc (or $3.22/Wac) for residential systems, $1.85/Wdc (or $2.13/Wac) for commercial systems, $1.03/Wdc (or $1.34/Wac) for fixed-tilt utility-scale systems, and $1.11/Wdc (or $1.44/Wac) for one-axis-tracking utility-scale systems. Overall, modeled PV installed costs continued to decline in Q1 2017 for all three sectors.

Figure 34 puts our Q1 2017 benchmark results in context with the results of previous NREL benchmarking analyses. When comparing the results across this period, note the following:

1. Values are inflation adjusted using the U.S. Bureau of Labor Statistics' Consumer Price Index. Thus, historical values from our models are adjusted and presented as real USD instead of as nominal USD.
2. Cost categories are aggregated for comparison purposes. "Soft Costs – Others" represents PII, land acquisition, sales tax, and EPC/developer overhead and profit.[34]
3. The "Utility-Scale PV, One-Axis Tracker (100 MW)" consists of our previous bottom-up results (2010 and 2013–2016) and interpolation estimates for 2009 and 2011–2012.
4. The comparison of Q1 2016 and Q1 2017 is presented in Table 12.

The inflation-adjusted system cost differences between Q1 2016 and Q1 2017 are $0.18/Wdc (residential), $0.32/Wdc (commercial), and $0.42/Wdc (fixed-tilt utility-scale). Table 12 shows the benchmarked values for all three sectors and drivers of cost decrease and increase.

As Figure 34 shows, hardware costs—and module prices in particular—declined substantially in Q1 2017 owing to an imbalance in global module supply and demand. This has increased the importance of non-hardware, or "soft," costs.[35] Figure 35 shows the growing contribution from soft costs.[36] 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. This trend has also reduced soft costs from direct labor and related installation overhead.

Also, our bottom-up system cost models enable us to investigate regional variations, system configurations (such as 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) are considered. Different scenarios result in different costs, so consistent comparisons can only be made when cost scenarios are aligned.

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[34] System cost categories in this report differ from previously published material, beyond inflation adjustments, to delineate profit from overhead for installers and integrators. Also, profit is added to the Q1 2015 commercial benchmark price; thus it is $0.06/W higher than in the 2015 publication ($0.05/W profit, $0.01/W inflation).

[35] Soft cost = total cost - hardware (module, inverter, structural, and electrical BOS) cost.

[36] An increasing soft cost proportion in Figure 35 indicates soft costs declined more slowly than did hardware costs; it does not indicate soft costs increased on an absolute basis.

Finally, the reduction in installed cost, along with improvements in operation, system design, and technology have resulted in significant reduction in the cost of electricity, as shown in Figure 36. U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.

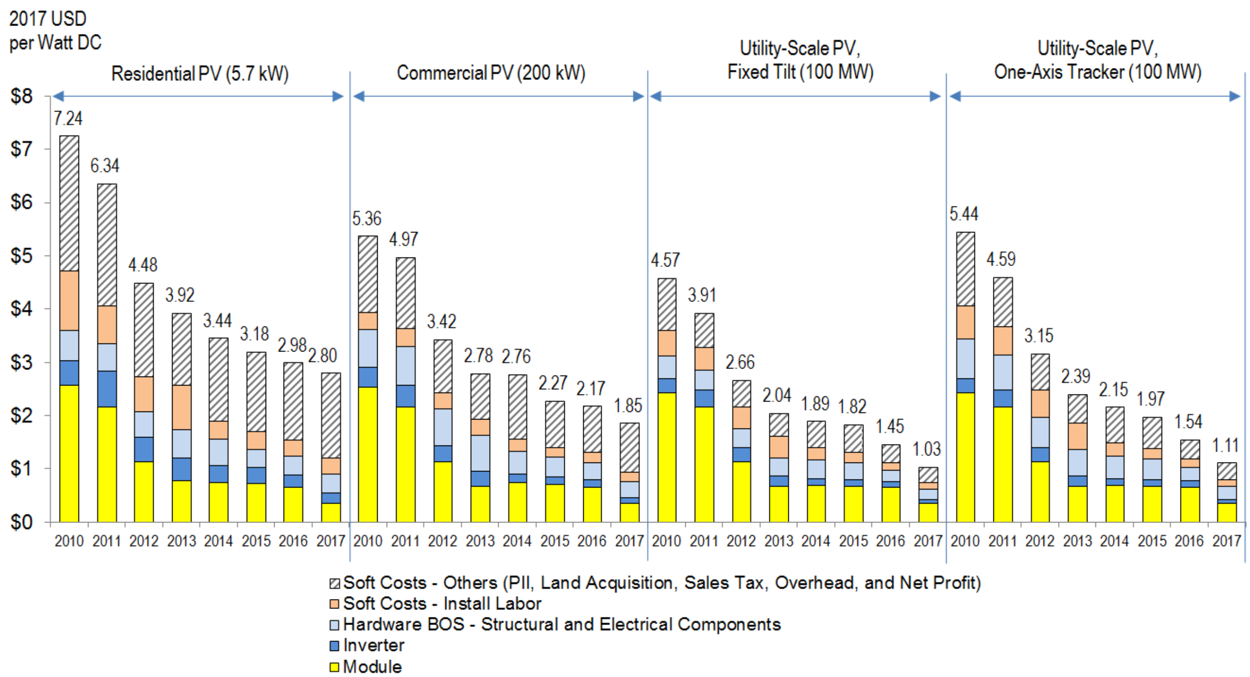

Figure 35. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

Table 12. Comparison of Q1 2016 and Q1 2017 PV System Cost Benchmarks

Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2016 Benchmarks in 2016 USD/Wdc	$2.93	$2.13	$1.42
Q1 2016 Benchmarks in 2017 USD/Wdc	$2.98	$2.17	$1.45
Q1 2017 Benchmarks in 2017 USD/Wdc	$2.80	$1.85	$1.03
Drivers of Cost Decrease	• Lower module price • Lower inverter price • Higher module efficiency • Lower electrical BOS commodity price • Higher small installer market share • Lower sales & marketing costs • Lower overhead (general & administrative)	• Lower module price • Lower inverter price • Higher module efficiency • Smaller developer team	• Lower module price • Lower inverter price • Higher module efficiency
Drivers of Cost Increase	• Higher labor wages • Higher advanced inverter adoption • More BOS components for rapid shutdown • Higher supply-chain costs	• Higher labor wages • Higher PII costs • Higher net profit	• Higher labor wages • Higher net profit

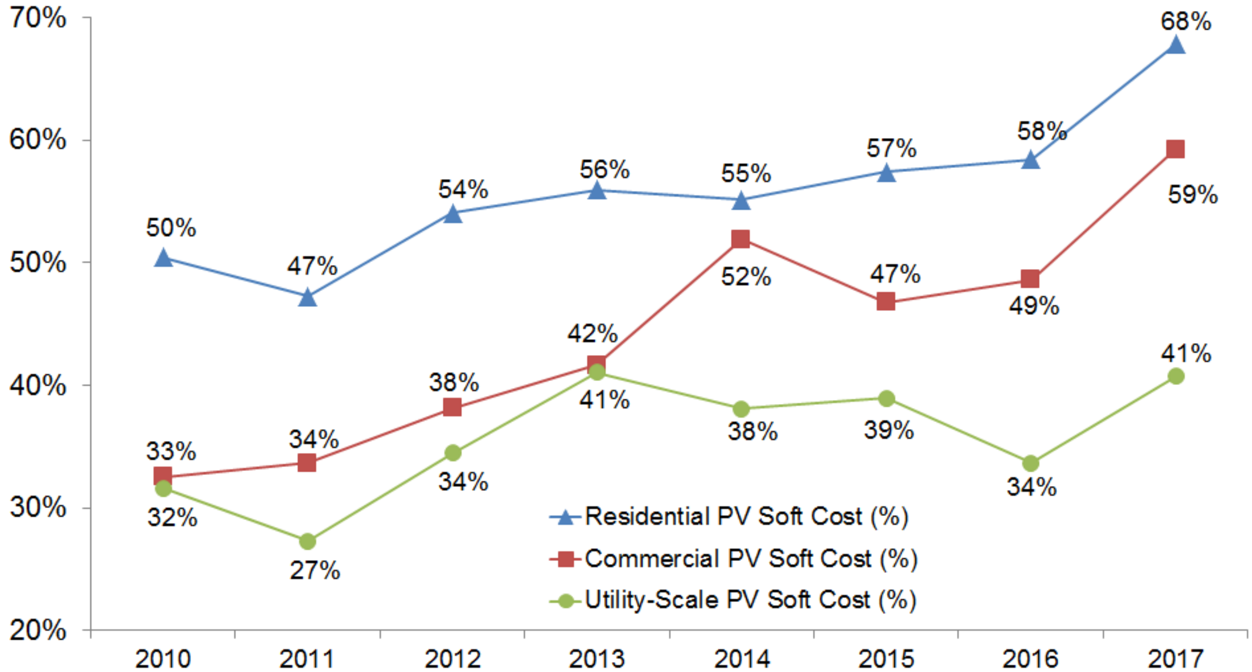

Figure 36. Modeled trend of soft cost as a proportion of total cost by sector, 2010–2017

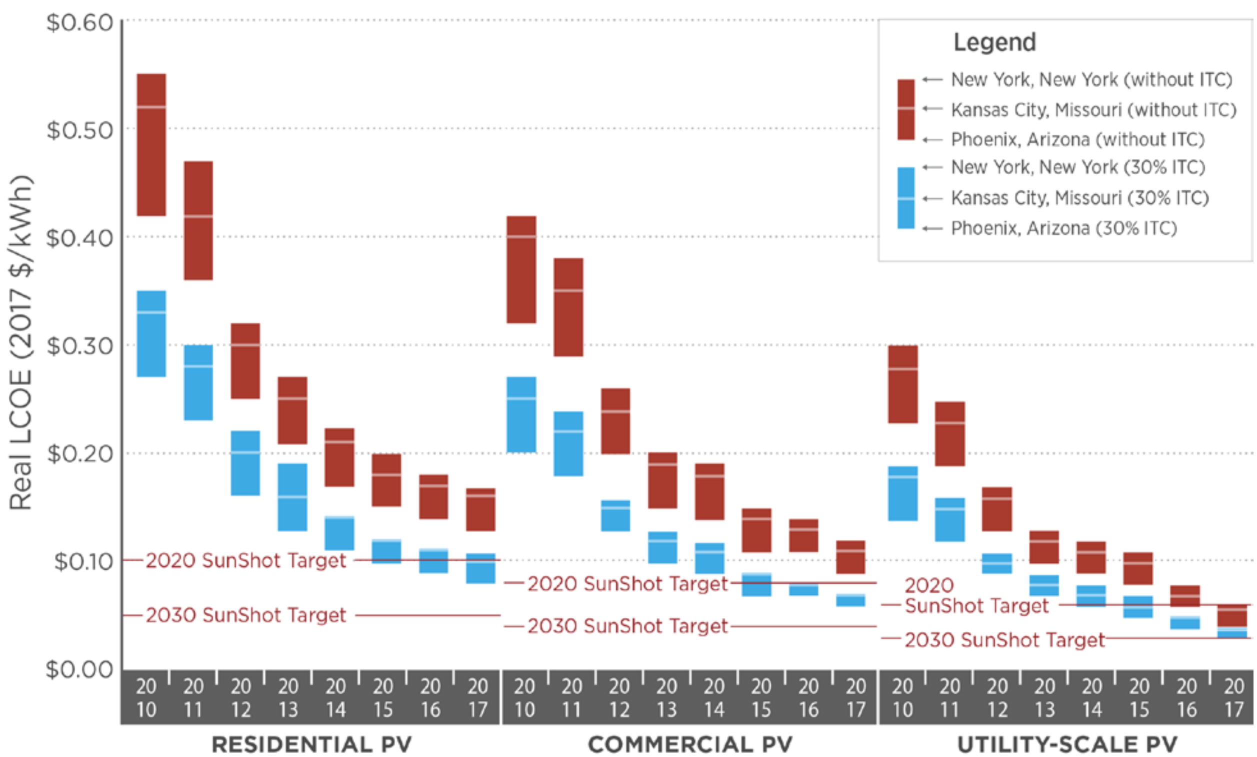

Figure 37. NREL PV LCOE benchmark summary (inflation adjusted), 2010–2017

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Appendix A. Historical PV System Benchmarks in 2010 USD

Table 13. NREL Residential PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	$2.26	$1.89	$0.98	$0.68	$0.65	$0.63	$0.57	$0.31
Inverter	$0.41	$0.60	$0.40	$0.38	$0.28	$0.26	$0.19	$0.17
Hardware BOS - Structural and Electrical Components	$0.49	$0.45	$0.42	$0.46	$0.42	$0.30	$0.33	$0.31
Soft Costs - Install Labor	$0.99	$0.62	$0.59	$0.73	$0.29	$0.30	$0.26	$0.27
Soft Costs - Others (PII, Sales Tax, Overhead, and Net Profit)	$2.22	$2.01	$1.54	$1.20	$1.37	$1.31	$1.26	$1.40
Total	**$6.36**	**$5.58**	**$3.94**	**$3.44**	**$3.02**	**$2.80**	**$2.61**	**$2.45**
Total Inverter Replacement Price ($/W)	$0.37	$0.32	$0.28	$0.23	$0.18	$0.14	$0.13	$0.12
O&M Expenses ($/kW-yr)	$33	$30	$27	$24	$21	$18	$18	$18
LCOE Phoenix, AZ, no ITC	$0.38	$0.32	$0.22	$0.19	$0.15	$0.13	$0.12	$0.12
LCOE Kansas City, MO, no ITC	$0.46	$0.39	$0.27	$0.23	$0.19	$0.16	$0.15	$0.14
LCOE New York, NY, no ITC	$0.49	$0.42	$0.29	$0.24	$0.20	$0.17	$0.16	$0.15
LCOE Phoenix, AZ, ITC	$0.24	$0.20	$0.14	$0.12	$0.10	$0.09	$0.08	$0.07
LCOE Kansas City, MO, ITC	$0.30	$0.25	$0.18	$0.15	$0.12	$0.10	$0.09	$0.09
LCOE New York, NY, ITC	$0.32	$0.27	$0.19	$0.16	$0.13	$0.11	$0.10	$0.10

Table 13. NREL Commercial PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	$2.23	$1.89	$0.98	$0.59	$0.64	$0.62	$0.57	$0.31
Inverter	$0.32	$0.37	$0.27	$0.24	$0.15	$0.12	$0.12	$0.09
Hardware BOS - Structural and Electrical Components	$0.63	$0.64	$0.60	$0.59	$0.38	$0.33	$0.29	$0.26
Soft Costs - Install Labor	$0.28	$0.28	$0.27	$0.26	$0.19	$0.17	$0.17	$0.15
Soft Costs - Others (PII, Sales Tax, Overhead, and Net Profit)	$1.25	$1.18	$0.88	$0.75	$1.06	$0.76	$0.76	$0.81
Total	$4.71	$4.36	$3.00	$2.44	$2.42	$1.99	$1.90	$1.62
Total Inverter Replacement Price ($/W)	$0.22	$0.19	$0.17	$0.15	$0.13	$0.11	$0.10	$0.09
O&M Expenses ($/kW-yr)	$24	$22	$20	$18	$16	$14	$14	$14
LCOE Phoenix, AZ, no ITC	$0.29	$0.26	$0.17	$0.14	$0.13	$0.10	$0.09	$0.08
LCOE Kansas City, MO, no ITC	$0.36	$0.32	$0.22	$0.17	$0.16	$0.12	$0.12	$0.10
LCOE New York, NY, no ITC	$0.38	$0.34	$0.23	$0.18	$0.17	$0.13	$0.12	$0.11
LCOE Phoenix, AZ, ITC	$0.18	$0.16	$0.11	$0.09	$0.08	$0.06	$0.06	$0.05
LCOE Kansas City, MO, ITC	$0.23	$0.20	$0.14	$0.11	$0.10	$0.08	$0.07	$0.07
LCOE New York, NY, ITC	$0.24	$0.21	$0.15	$0.12	$0.11	$0.08	$0.08	$0.07

Table 14. NREL Utility-Scale PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	$2.12	$1.89	$0.98	$0.59	$0.60	$0.59	$0.57	$0.31
Inverter	$0.24	$0.28	$0.24	$0.16	$0.11	$0.10	$0.10	$0.05
Hardware BOS - Structural and Electrical Components	$0.66	$0.58	$0.50	$0.43	$0.37	$0.34	$0.22	$0.22
Soft Costs - Install Labor	$0.54	$0.48	$0.45	$0.44	$0.21	$0.18	$0.14	$0.12
Soft Costs - Others (PII, Land Acquisition, Sales Tax, Overhead, and Net Profit)	$1.22	$0.81	$0.59	$0.48	$0.59	$0.52	$0.31	$0.27
Total	**$4.78**	**$4.03**	**$2.77**	**$2.10**	**$1.88**	**$1.73**	**$1.35**	**$0.97**
Total Inverter Replacement Price ($/W)	$0.17	$0.15	$0.14	$0.12	$0.11	$0.09	$0.07	$0.05
O&M Expenses ($/kW-yr)	$20	$19	$19	$18	$17	$17	$17	$17
LCOE Phoenix, AZ, no ITC	$0.19	$0.16	$0.11	$0.08	$0.07	$0.06	$0.05	$0.04
LCOE Kansas City, MO, no ITC	$0.24	$0.20	$0.14	$0.10	$0.09	$0.08	$0.06	$0.05
LCOE New York, NY, no ITC	$0.26	$0.22	$0.15	$0.12	$0.10	$0.09	$0.07	$0.06
LCOE Phoenix, AZ, ITC	$0.12	$0.10	$0.07	$0.05	$0.05	$0.04	$0.03	$0.03
LCOE Kansas City, MO, ITC	$0.15	$0.12	$0.09	$0.07	$0.06	$0.05	$0.04	$0.03
LCOE New York, NY, ITC	$0.17	$0.14	$0.10	$0.08	$0.07	$0.06	$0.05	$0.04

Appendix B. PV System LCOE Benchmarks in 2017 and 2010 USD

Table 16. NREL LCOE Summary (2017 cents/kWh)

Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2020[37] Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017		
Residential										
Phoenix, AZ, no ITC	42.1	35.7	24.9	20.7	17.3	15.0	13.6	12.9		
Kansas City, MO, no ITC	51.8	43.6	30.4	25.3	21.1	18.3	16.7	15.7	10.0	5.0
New York, NY, no ITC	55.2	46.5	32.4	26.9	22.4	19.5	17.7	16.7		
Phoenix, AZ, ITC	26.9	22.8	16.1	13.4	11.1	9.5	8.7	8.2		
Kansas City, MO, ITC	33.1	27.9	19.7	16.3	13.5	11.6	10.6	10.0		
New York, NY, ITC	35.3	29.7	21.0	17.4	14.4	12.3	11.3	10.7		
Commercial										
Phoenix, AZ, no ITC	32.3	28.6	19.5	15.4	14.4	11.2	10.5	9.2		
Kansas City, MO, no ITC	40.0	35.3	24.1	19.0	17.8	13.9	13.0	11.3	7.8	4.0
New York, NY, no ITC	42.4	37.5	25.6	20.2	18.9	14.8	13.8	12.0		
Phoenix, AZ, ITC	20.4	18.0	12.5	9.9	9.2	7.1	6.7	5.9		
Kansas City, MO, ITC	25.2	22.2	15.4	12.3	11.4	8.9	8.3	7.3		
New York, NY, ITC	26.8	23.6	16.4	13.0	12.0	9.4	8.8	7.7		
Utility-scale (one-axis tracking)										
Phoenix, AZ, no ITC	21.2	17.5	12.1	9.2	8.1	7.2	5.7	4.4		
Kansas City, MO, no ITC	26.8	22.1	15.3	11.7	10.2	9.1	7.2	5.6	6.0	3.0
New York, NY, no ITC	29.5	24.3	16.8	12.9	11.3	10.0	7.9	6.1		
Phoenix, AZ, ITC	13.4	11.0	7.8	6.0	5.3	4.7	3.8	3.0		
Kansas City, MO, ITC	16.9	13.9	9.8	7.6	6.7	5.9	4.8	3.8		
New York, NY, ITC	18.6	15.4	10.8	8.4	7.4	6.5	5.3	4.2		

[37] 2020 Residential and commercial SunShot goals are adjusted for inflation using the Consumer Price Index; the 2020 utility-scale goal was left unchanged as wholesale prices have been relatively flat, and in some cases gone down, from 2010-2017.

Utility-scale (fixed-tilt)										
Phoenix, AZ, no ITC	22.6	18.9	13.0	10.1	9.0	8.4	6.8	5.0		
Kansas City, MO, no ITC	27.7	23.1	15.9	12.3	11.0	10.2	8.3	6.1		
New York, NY, no ITC	29.6	24.7	17.0	13.2	11.8	10.9	8.8	6.6		
Phoenix, AZ, ITC	14.4	12.0	8.5	6.6	5.9	5.4	4.5	3.4		
Kansas City, MO, ITC	17.6	14.7	10.4	8.1	7.3	6.7	5.4	4.2		
New York, NY, ITC	18.9	15.8	11.1	8.7	7.8	7.1	5.8	4.4		
Residential										
Phoenix, AZ, no ITC	37.8	32.0	22.3	18.5	15.5	13.4	12.2	11.5		
Kansas City, MO, no ITC	46.4	39.1	27.3	22.7	18.9	16.4	14.9	14.1	9.0	5.0
New York, NY, no ITC	49.5	41.6	29.0	24.1	20.1	17.4	15.9	15.0		
Phoenix, AZ, ITC	24.1	20.4	14.5	12.0	9.9	8.5	7.8	7.4		
Kansas City, MO, ITC	29.7	25.0	17.7	14.6	12.1	10.4	9.5	9.0		
New York, NY, ITC	31.6	26.6	18.8	15.6	12.9	11.1	10.1	9.6		
Commercial										
Phoenix, AZ, no ITC	29.0	25.6	17.5	13.8	12.9	10.1	9.4	8.2		
Kansas City, MO, no ITC	35.8	31.7	21.6	17.0	16.0	12.5	11.7	10.1	7.0	4.0
New York, NY, no ITC	38.0	33.6	22.9	18.1	16.9	13.3	12.4	10.7		
Phoenix, AZ, ITC	18.3	16.1	11.2	8.9	8.2	6.4	6.0	5.3		
Kansas City, MO, ITC	22.6	19.9	13.8	11.0	10.2	8.0	7.4	6.5		
New York, NY, ITC	24.0	21.1	14.7	11.6	10.8	8.4	7.9	6.9		
Utility-scale (one-axis tracking)[38]										
Phoenix, AZ, no ITC	19.0	15.6	10.8	8.3	7.2	6.4	5.1	3.9		
Kansas City, MO, no ITC	24.0	19.8	13.7	10.5	9.2	8.1	6.4	5.0	6.0	3.0
New York, NY, no ITC	26.4	21.8	15.1	11.5	10.1	9.0	7.1	5.5		
Phoenix, AZ, ITC	12.0	9.9	7.0	5.4	4.7	4.2	3.4	2.7		
Kansas City, MO, ITC	15.1	12.5	8.8	6.8	6.0	5.3	4.3	3.4		

[38] LCOE benchmarks are highlighted in bold. As noted previously, we use the fixed-tilt systems for LCOE benchmarks from 2010-2015 and then switch to one-axis tracking systems from 2016 to 2017

New York, NY, ITC	16.7	13.8	9.7	7.6	6.6	5.9	4.7	3.7
Utility-scale (fixed-tilt)								
Phoenix, AZ, no ITC	20.3	16.9	11.6	9.0	8.1	7.5	6.1	4.5
Kansas City, MO, no ITC	24.8	20.7	14.3	11.1	9.9	9.2	7.4	5.5
New York, NY, no ITC	26.5	22.1	15.3	11.8	10.6	9.8	7.9	5.9
Phoenix, AZ, ITC	12.9	10.8	7.6	6.0	5.3	4.9	4.0	3.0
Kansas City, MO, ITC	15.8	13.2	9.3	7.3	6.5	6.0	4.9	3.7
New York, NY, ITC	16.9	14.1	9.9	7.8	7.0	6.4	5.2	4.0

APPENDIX B: SUPPORTING SPREADSHEETS