Utility-Scale Solar 2016

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

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Presentation Outline

Strong growth of the utility-scale solar market provides increasing amounts of empirical project-level data that are ripe for analysis

1. Solar deployment trends (and utility-scale's relative contribution)

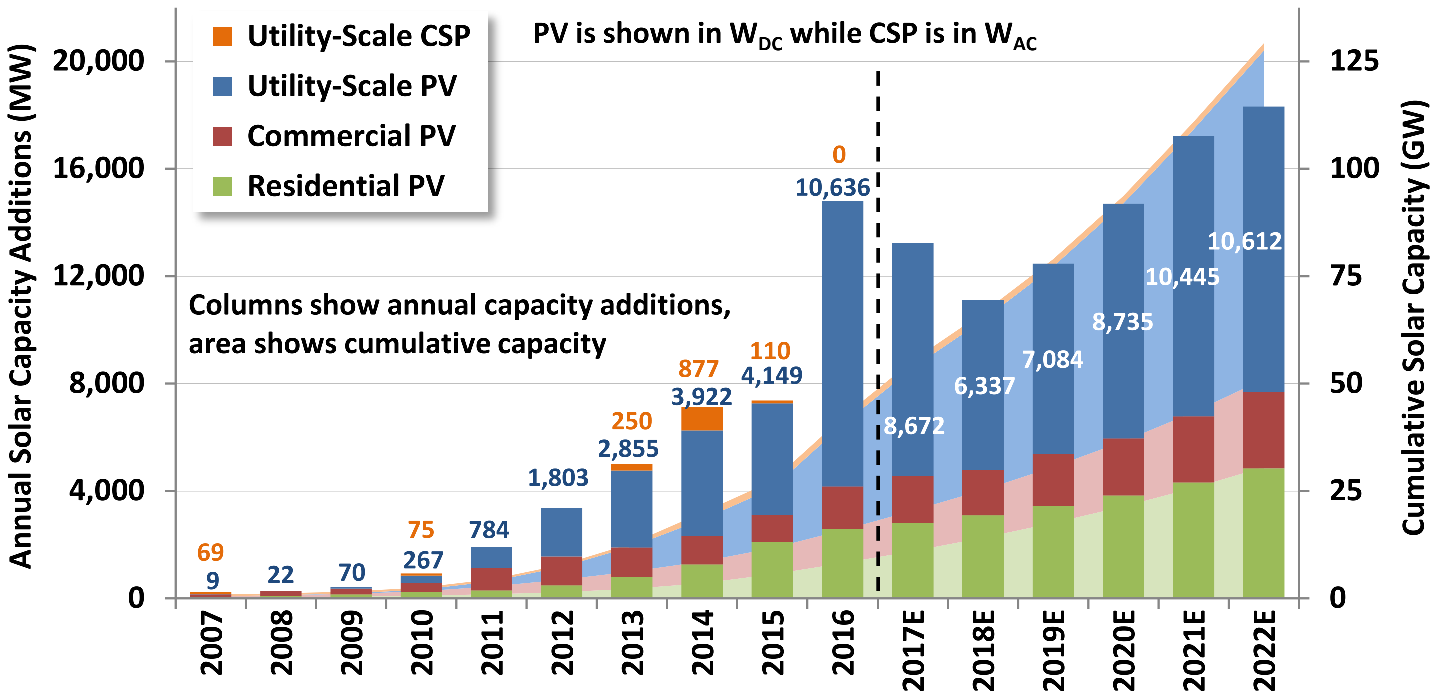
Key findings from analysis of the data samples *(first for* ***PV****, then for* ***CSP****):*

2. Project design, technology, and location
3. Installed project prices
4. Operation and maintenance (O&M) costs
5. Performance (capacity factors)
6. Power purchase agreement ("PPA") prices

7. Future outlook

Utility-scale projects have the greatest capacity share in the U. S. solar market

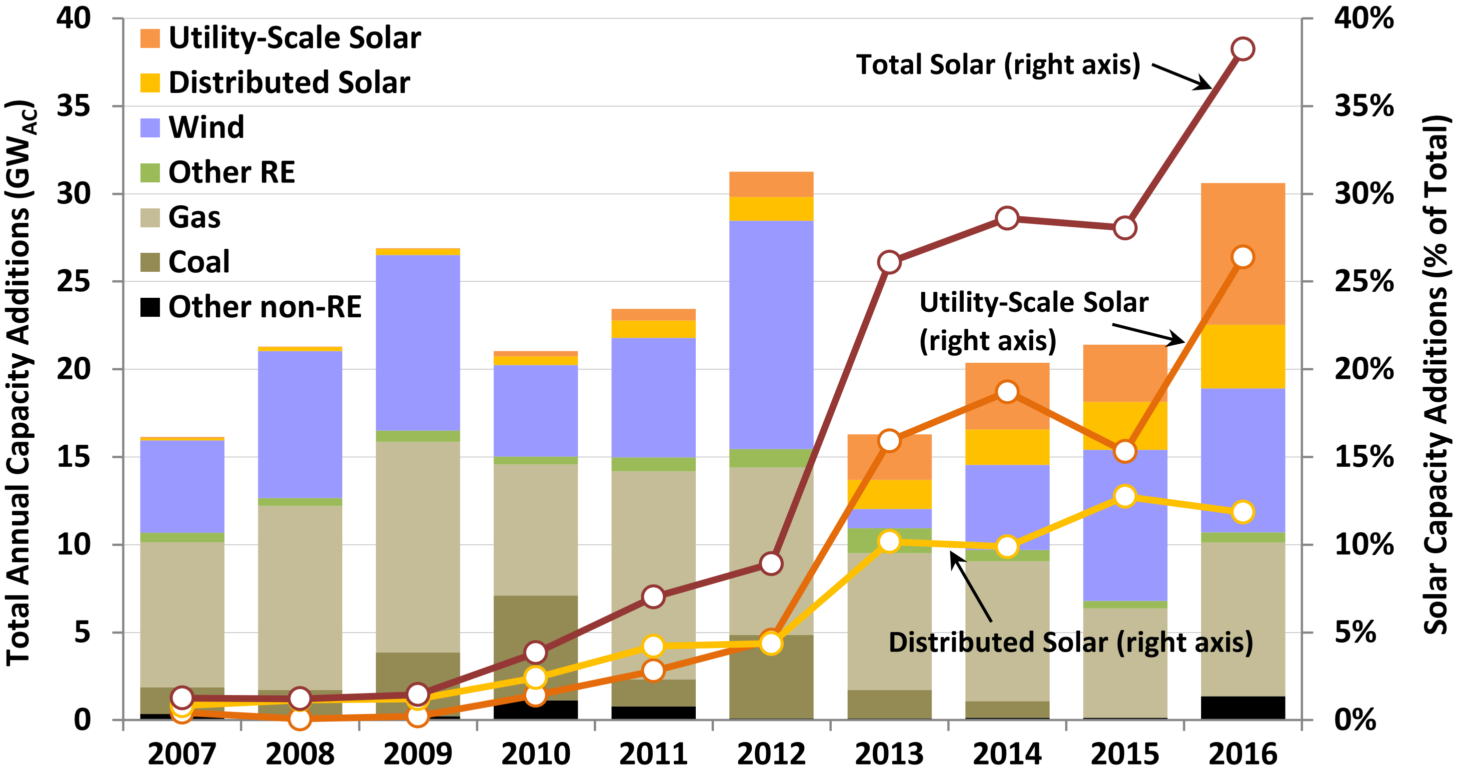
- The utility-scale sector accounted for 72% of all new solar capacity added in 2016 and 61% of cumulative solar capacity at the end of 2016



Sources: *GTM/SEIA Solar Market Insight Reports, Berkeley Lab*

We define "utility-scale" as **any ground-mounted project that is larger than 5 MW_{AC}**
Smaller systems are analyzed in LBNL's *"Tracking the Sun"* series (trackingthesun.lbl.gov)

Solar power was the largest source of U.S. electric-generating capacity additions in 2016



Note: This graph follows GTM/SEIA's split between distributed and utility-scale solar, rather than our 5 MW_{AC} threshold

Sources: *ABB, AWEA, GTM/SEIA Solar Market Insight Reports, Berkeley Lab*

- Led by the utility-scale sector, solar power has comprised >25% of all generating capacity additions in the United States in each of the past four years
- In 2016, solar made up 38% of all U.S. capacity additions (with utility-scale accounting for 26%), and was the largest source of new capacity, ahead of both natural gas and wind

Solar penetration rates approaching or exceeding 10% in several states

- Solar penetration rate varies considerably depending on whether calculated as a percentage of generation or load (e.g., see Vermont)
- Contribution of utility-scale also varies (a minority in northeast states and Hawaii, a majority in other states and overall)

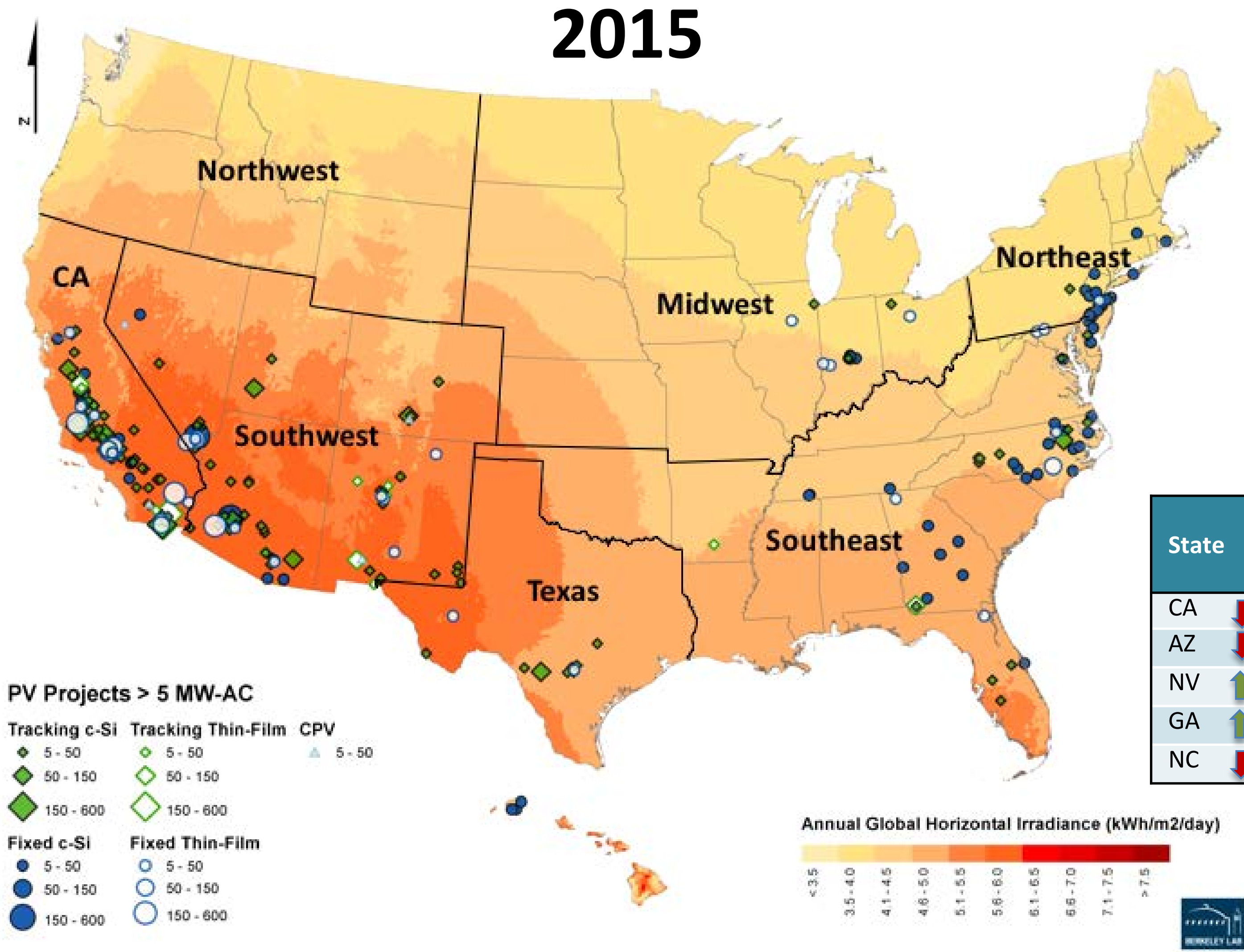
State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	12.6%	8.3%	9.8%	6.5%
Hawaii	8.5%	1.0%	8.7%	1.0%
Vermont	8.2%	4.0%	2.8%	1.4%
Nevada	6.8%	5.8%	7.4%	6.4%
Massachusetts	6.0%	2.2%	3.7%	1.4%
Arizona	4.4%	2.9%	6.1%	4.0%
New Jersey	3.5%	1.3%	3.7%	1.4%
North Carolina	3.1%	2.9%	3.0%	2.9%
New Mexico	3.0%	2.4%	4.2%	3.5%
Utah	2.7%	2.3%	3.4%	2.9%
Rest of U.S.	*0.3%*	*0.1%*	*0.3%*	*0.1%*
TOTAL U.S.	**1.3%**	**0.8%**	**1.4%**	**0.9%**

Source: EIA's Electric Power Monthly (February 2017)
Note: In this table, "utility-scale" refers to projects ≥1 MW_{AC} (which differs from the >5 MW_{AC} threshold used elsewhere in this report).

Utility-Scale PV

Photo Credit: Community Solar Amazon Solar Farm US East 1

Historically heavy concentration in the Southwest and mid-Atlantic, but now spreading to Southeast and Northwest



- Primarily fixed-tilt c-Si projects in the East
- Tracking (c-Si and, increasingly, thin-film) is more common in the Southwest

State		Cumulative Capacity MW-AC %	
		2016	2015
CA	↓	54%	56%
AZ	↓	9%	12%
NV	↑	8%	7%
GA	↑	6%	3%
NC	↓	5%	6%

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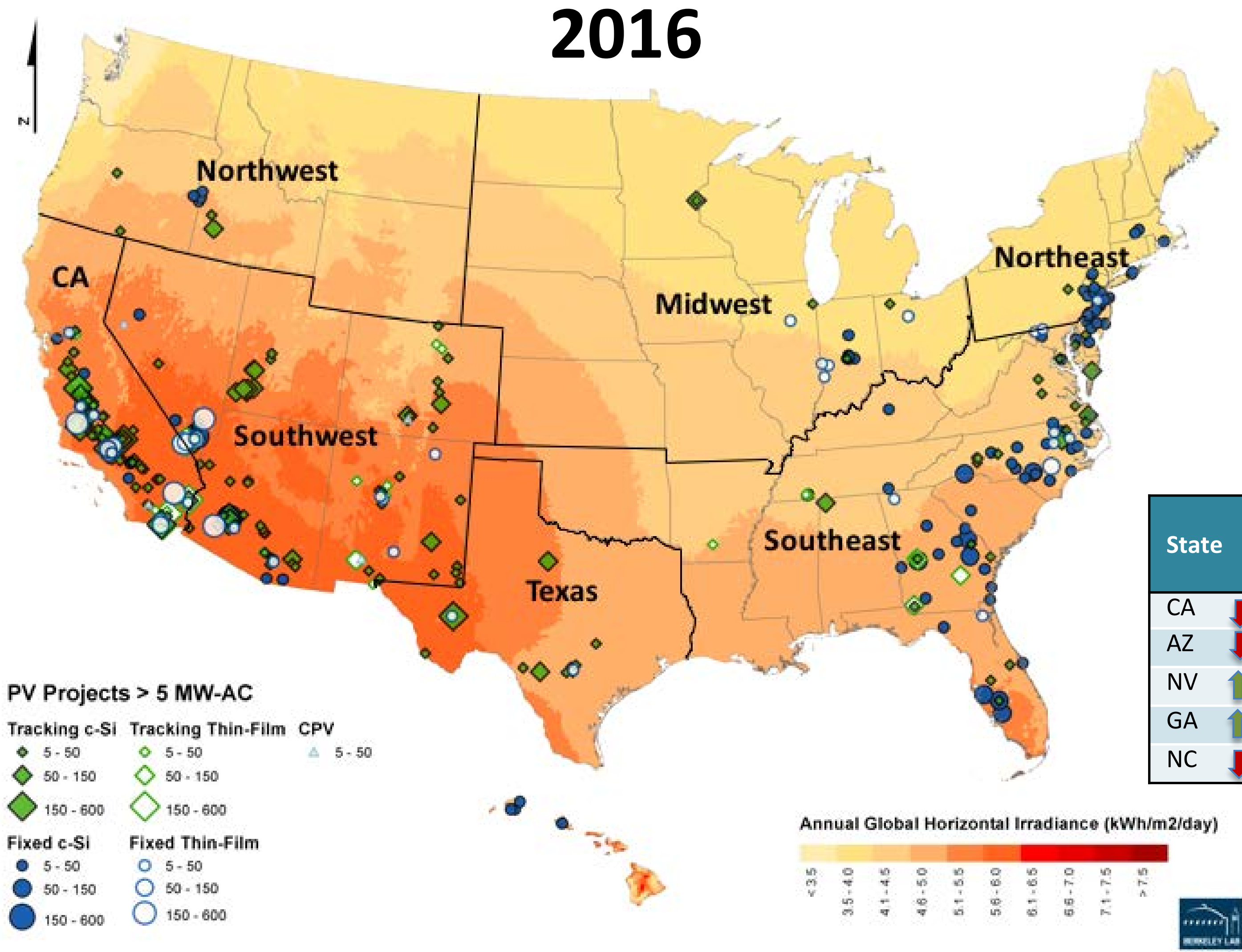

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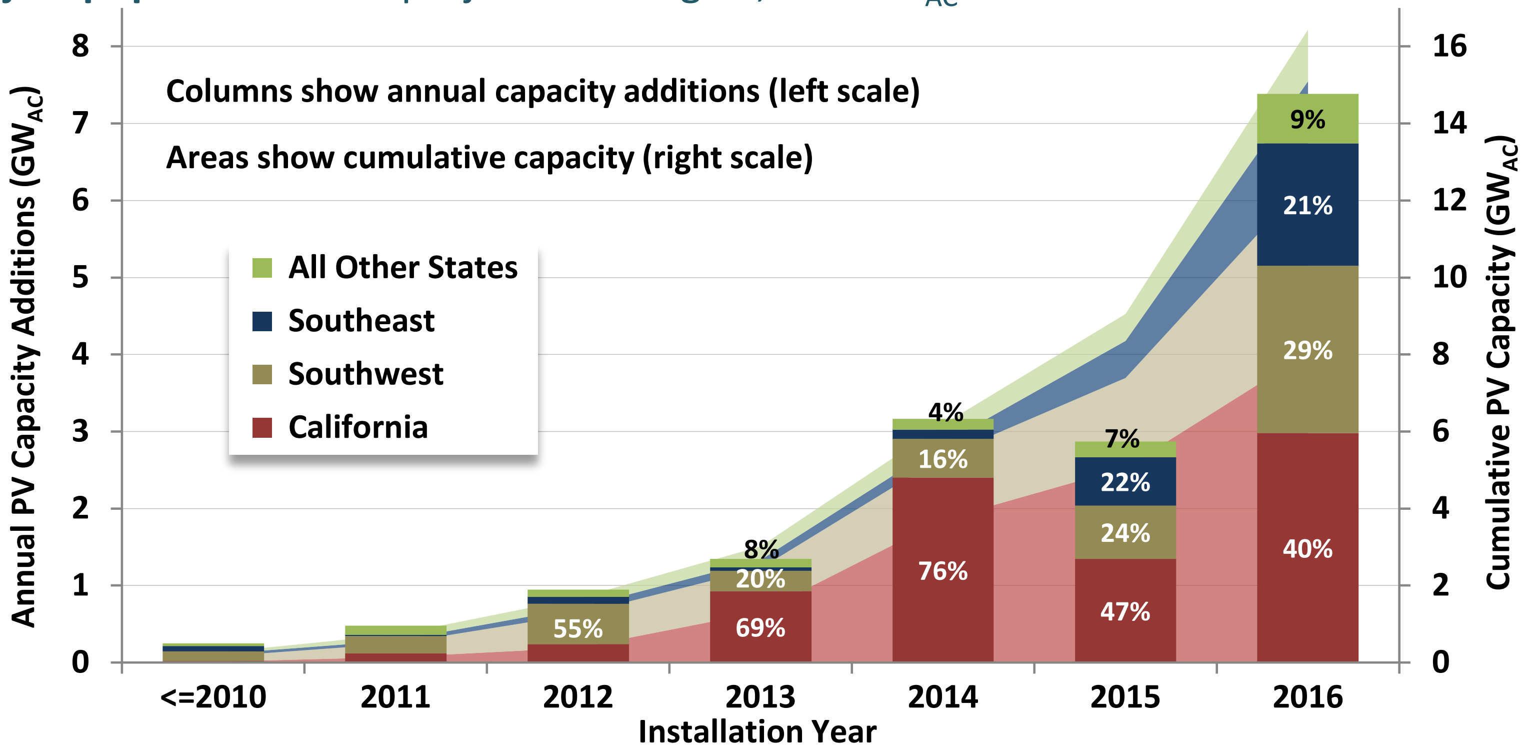
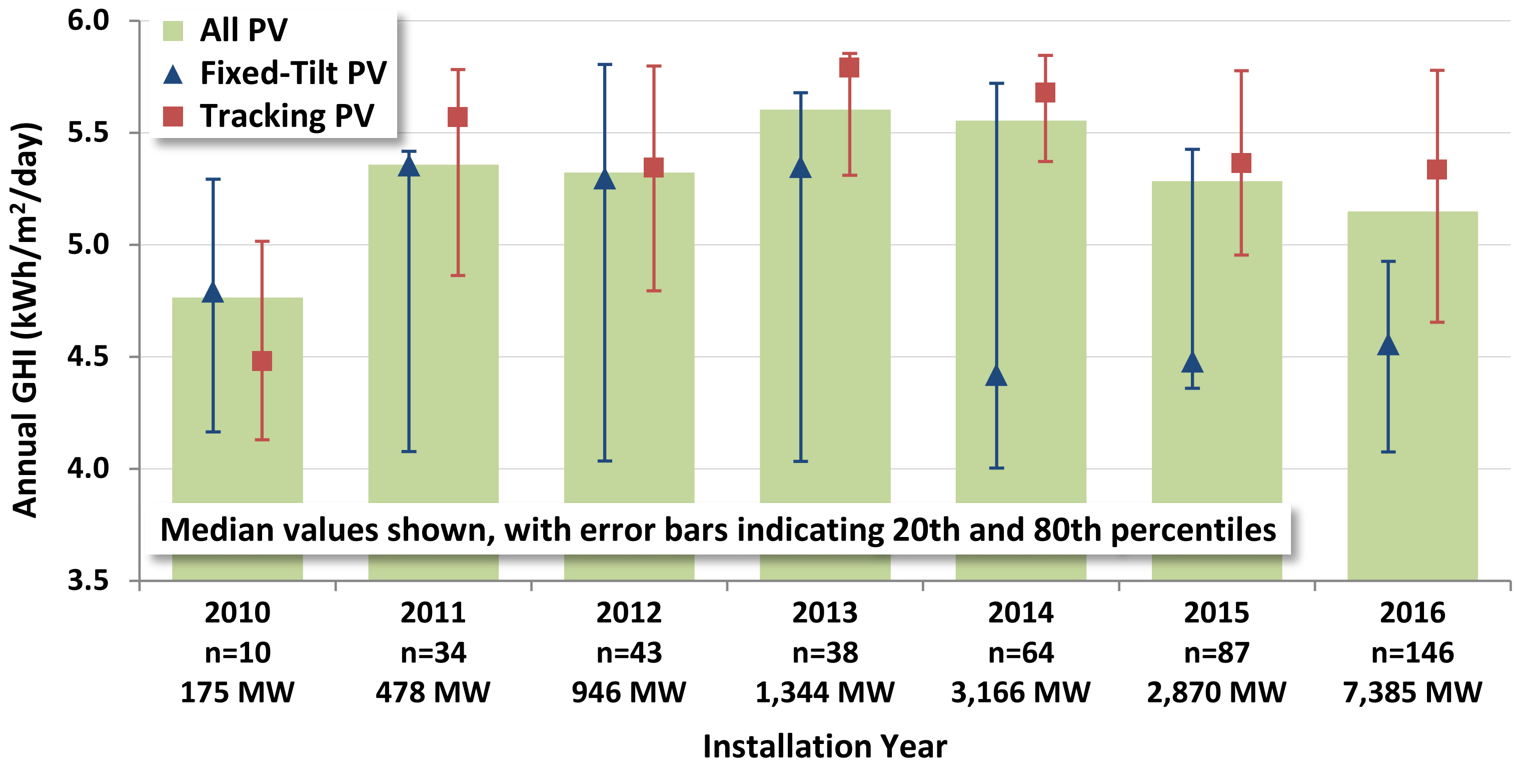
Utility-scale PV continues to expand beyond California and the Southwest

PV project population: 427 projects totaling 16,439 MW_{AC}



- Strong percentage growth outside the established markets:
  - 7 new states added their first utility-scale solar project: OR, ID, MN, VA, AL, KY, SC
  - Georgia added 726 MW_{AC} – the second-largest amount of new solar capacity among all states in 2016
  - Texas doubled its annual new capacity with 263 MW_{AC}
  - Florida started growth spree with 229 MW_{AC} – with substantially more planned for coming years

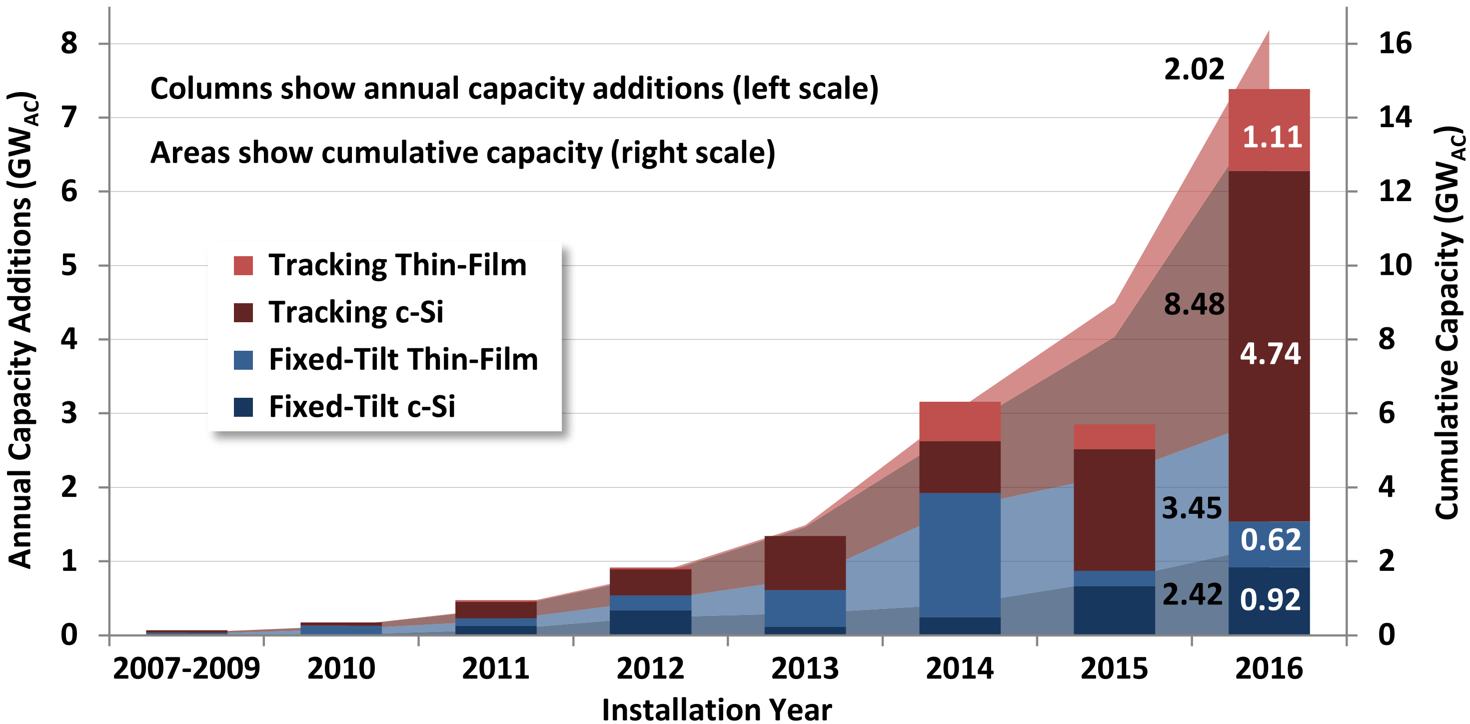
The eastward expansion is reflected in the buildout of lower-insolation sites



- 2016 was the 3rd year of declining median solar resource (measured in long-term global horizontal irradiance (GHI)) as the market expands to less-sunny states
- Fixed-tilt PV is increasingly relegated to lower-insolation sites (note the decline in its 80th percentile), while tracking PV is increasingly pushing into those same areas (note the decline in its 20th percentile)
- All else equal, the buildout of lower-GHI sites will dampen sample-wide capacity factors (reported later)

PV project population broken out by tracking vs. fixed-tilt, module type, and installation year

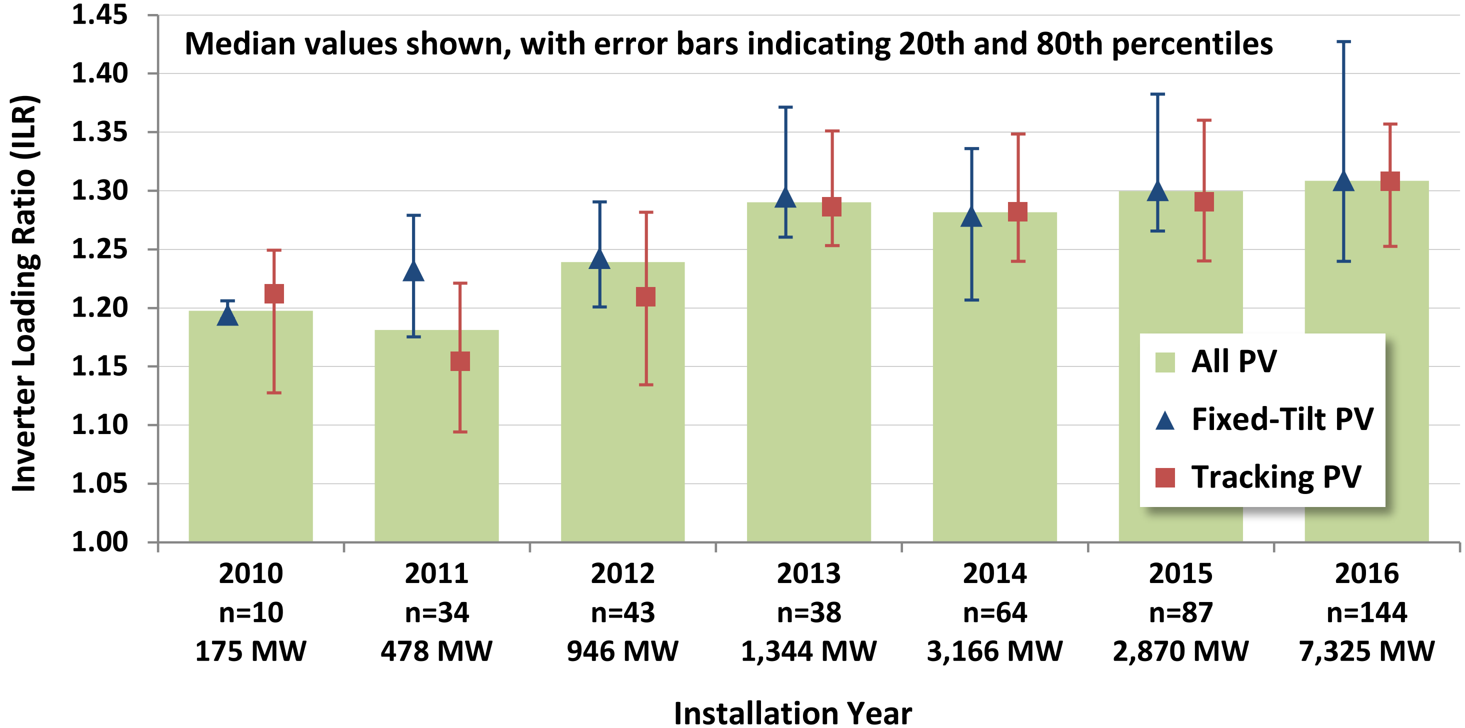
PV project population: 427 projects totaling 16,439 MW_{AC}



2016 Trends:

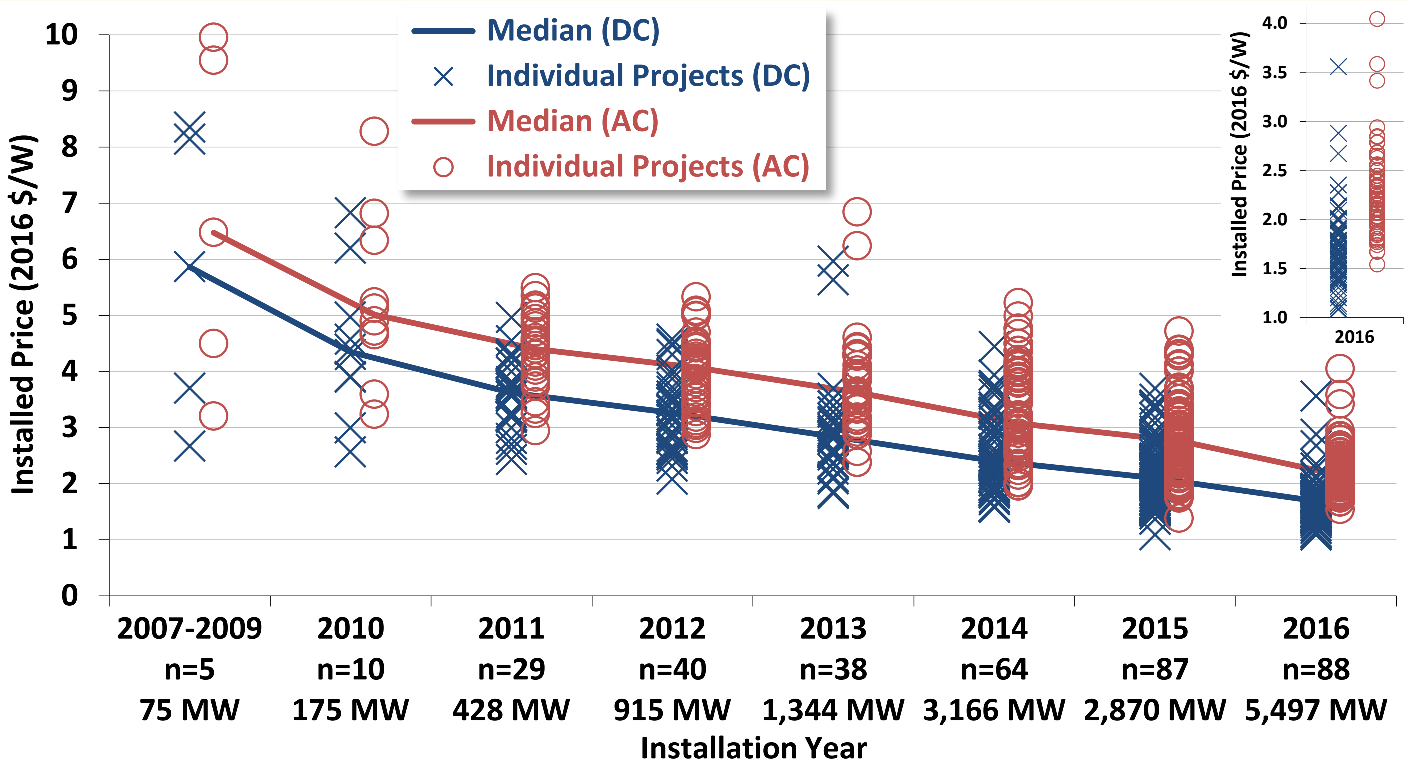
- Increasing dominance of tracking projects (79% of newly installed capacity) relative to fixed-tilt projects (21%)
- Continued strong growth in c-Si capacity (77%) relative to thin-film capacity (23%). Largest c-Si manufacturers are Trina (22%), and Jinko (14%), Canadian Solar (14%) and SunPower (8%), while the thin-film market is dominated by First Solar (97% of the installed capacity).

The median inverter loading ratio (ILR) has risen over time, though not much since 2013



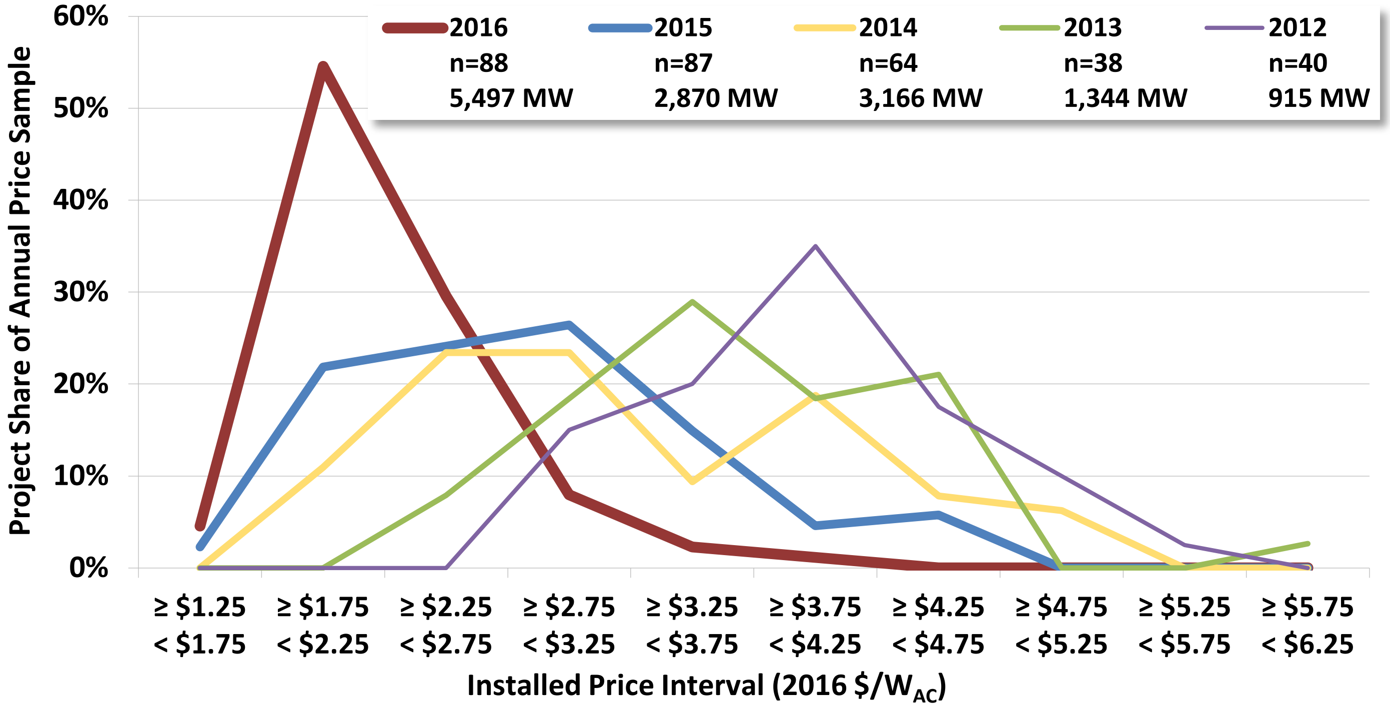
- As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity (i.e., the ILR) to enhance revenue
- The ILR (DC:AC ratio) seems to have stabilized around 1.3 on average, though considerable variation remains
- Fixed-tilt PV has more to gain from a higher ILR than does tracking PV; the highest ILR projects tend to be fixed-tilt
- All else equal, a higher ILR should boost capacity factors (reported later)

Median installed price of PV has fallen steadily, by over 65%, to around $2.2/W_{AC}$ ($1.7/W_{DC}$) in 2016



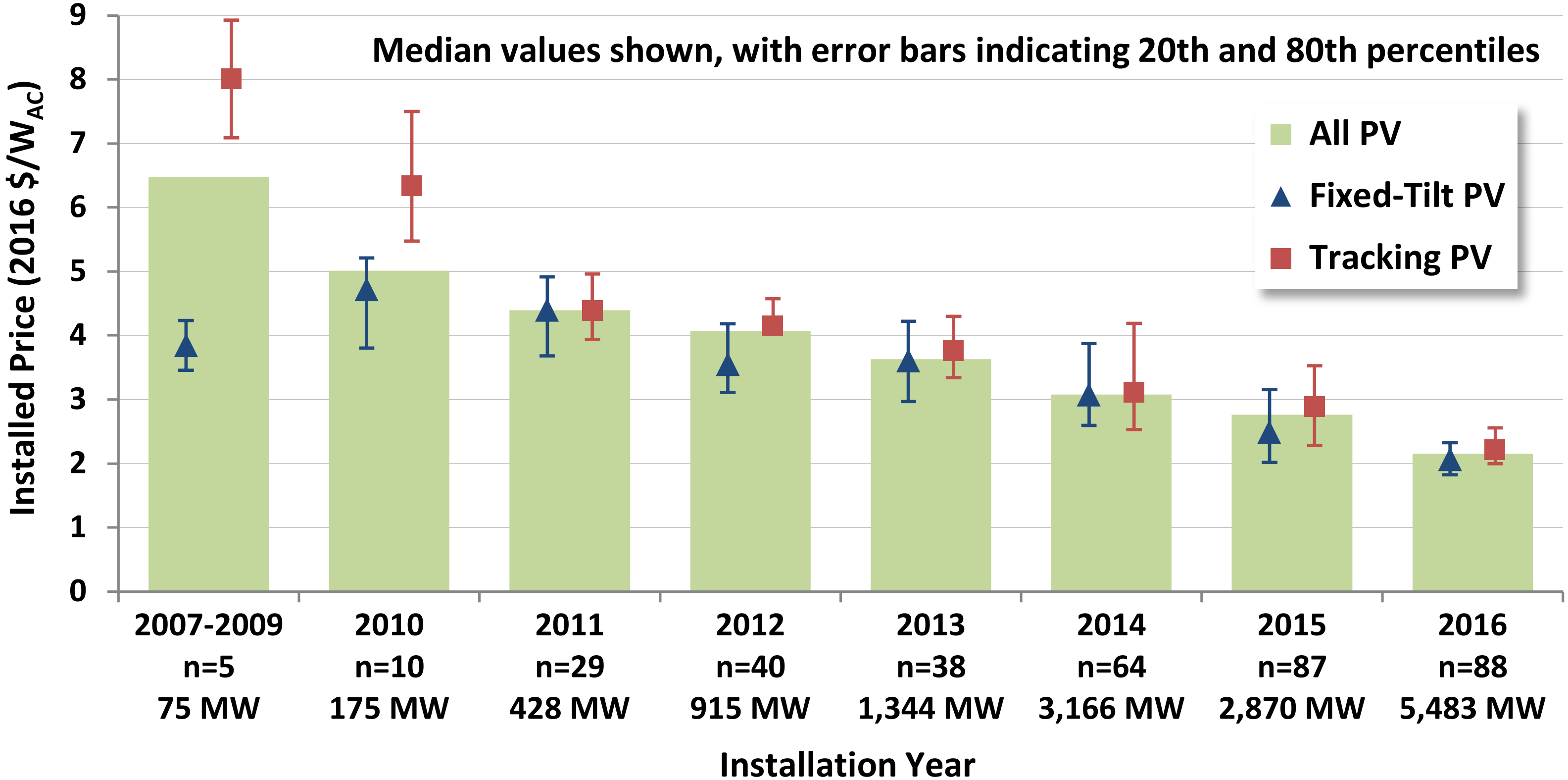
- Installed prices are shown here in both DC and AC terms, but because AC is more relevant to the utility sector, all metrics used in the rest of this slide deck are expressed solely in AC terms
- The lowest 20th percentile fell from $2.2/W_{AC}$ ($1.6/W_{DC}$) in 2015 to $2.0/W_{AC}$ ($1.5/W_{DC}$) in 2016
- Minimum price among our 88 projects in 2016 was $1.5/W_{AC}$ ($1.1/W_{DC}$)
- This sample is backward-looking and may not reflect the price of projects built in 2017/2018

Pricing distributions have continuously moved towards lower prices over the last 5 years



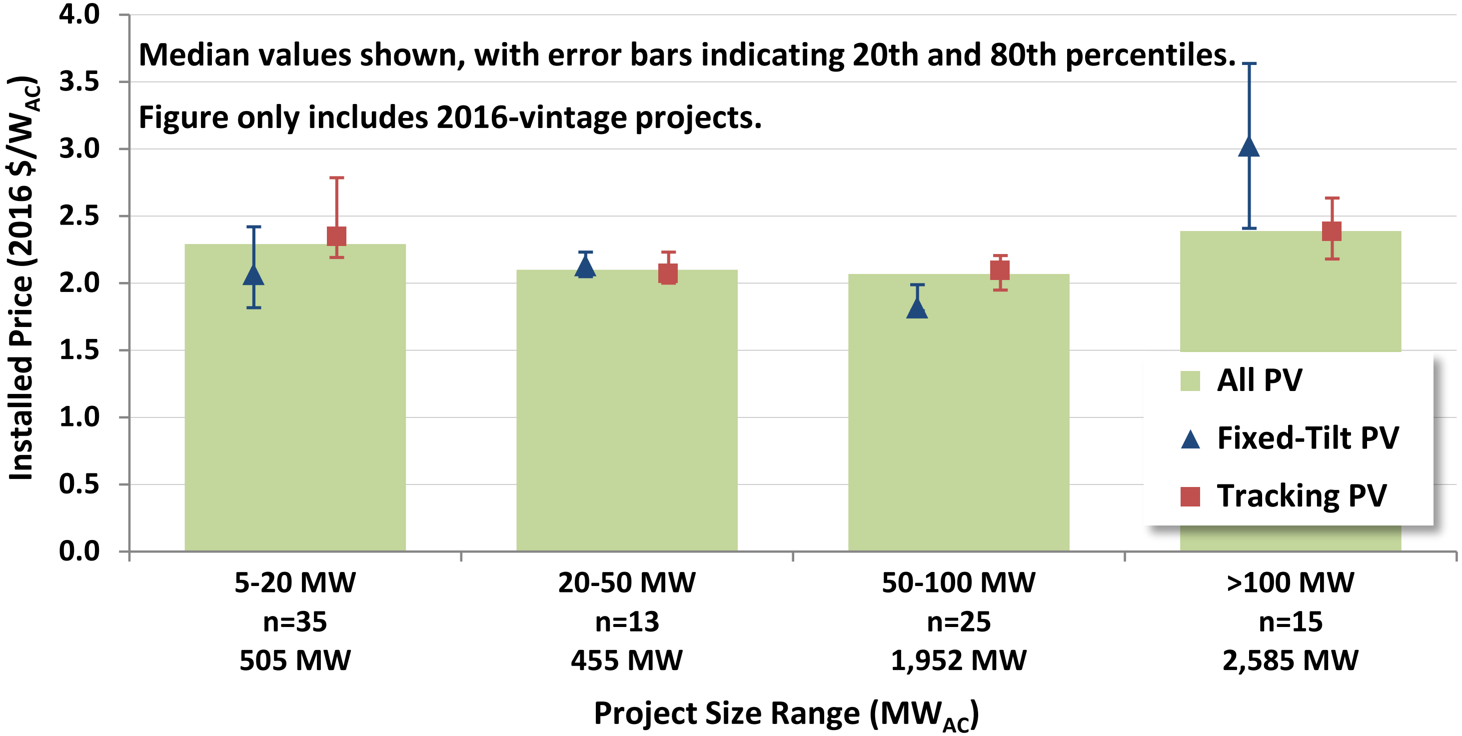
- Both medians and modes have continued to fall (moving towards the left) each year
- Share of relatively high-cost systems decreases steadily each year while share of low-cost systems increases
- Price spread is the smallest in 2016, pointing to a reduction in underlying heterogeneity of prices across all installed projects

Tracking projects were $0.15/W_{AC}$ more costly (at the median) than fixed-tilt projects in 2016



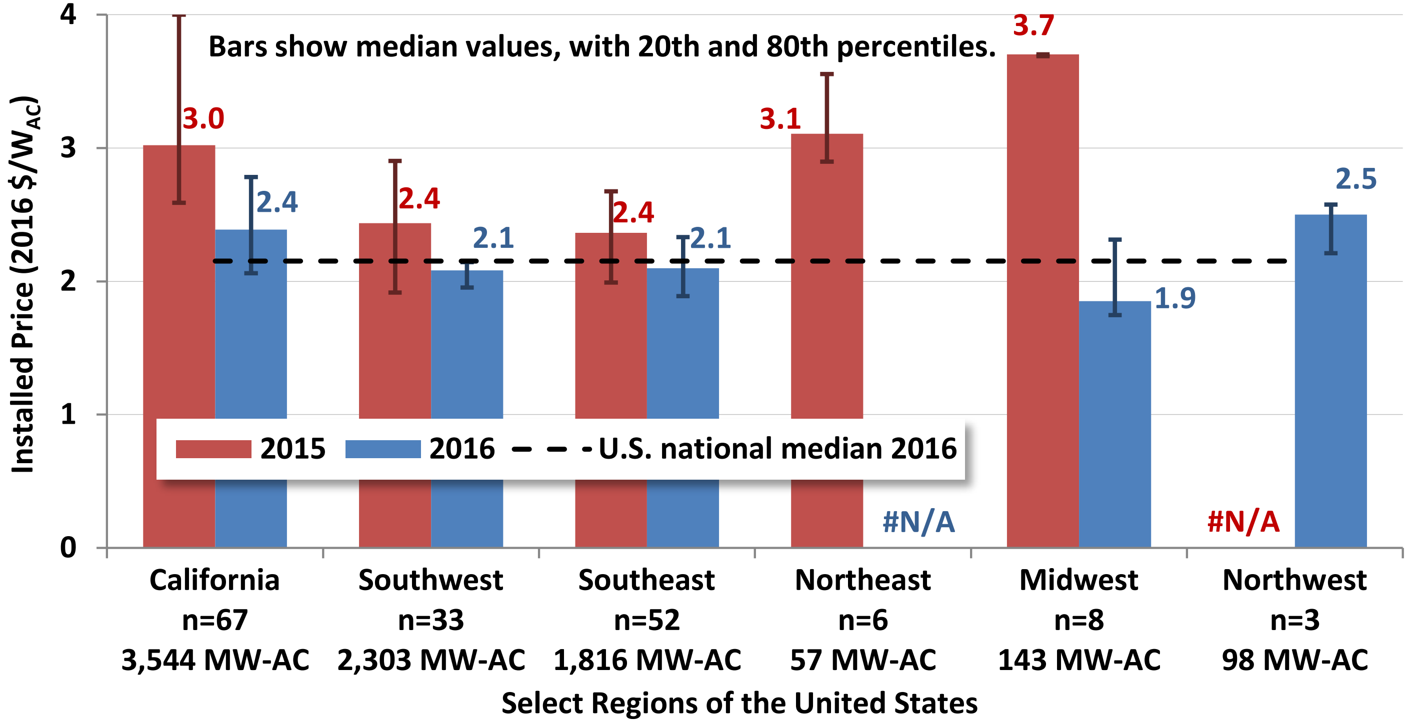
- Tracking's empirical cost premium has varied somewhat over time, but in general has declined considerably since 2010
- Upfront cost premium usually compensated by higher annual generation

2016 project sample hints at possible economies of scale (at least up to 100 MW)



- Modest economies of scale evident in the sample, from \$2.3/W_{AC} for projects smaller than 20MW_{AC} to \$2.1/W_{AC} for projects between 50 and 100MW_{AC}
- But higher costs for the 100+ MW projects, several of which have been under construction for several years, possibly reflecting a higher-cost past. In addition, larger projects may face greater development, regulatory, and interconnection costs that could outweigh any economies of scale.

Project prices vary by region



Southwest: NV, UT, CO, AZ, NM

Southeast: AR, AL, FL, GA, KY, MD, NC, SC, VA

Northeast: NJ, NY

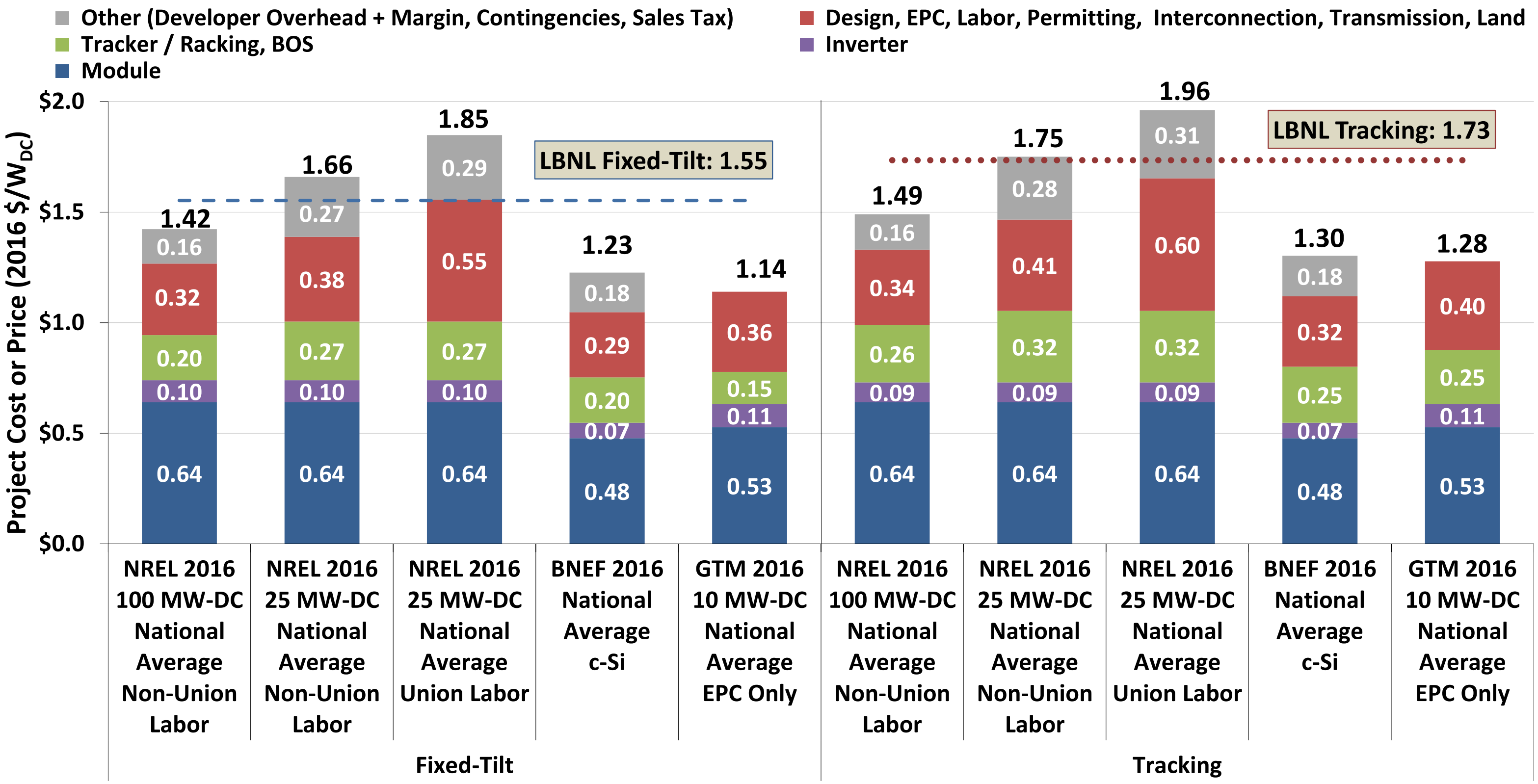
Midwest: IN, MN

Northwest: ID, OR

Not included: HI, TX

- Price differences driven in part by technology ubiquity (e.g., higher-priced tracking projects are more prevalent in the Southwest and California)
- Other factors may include labor costs and share of union labor, land costs, soil conditions or snow load, and balance of supply and demand

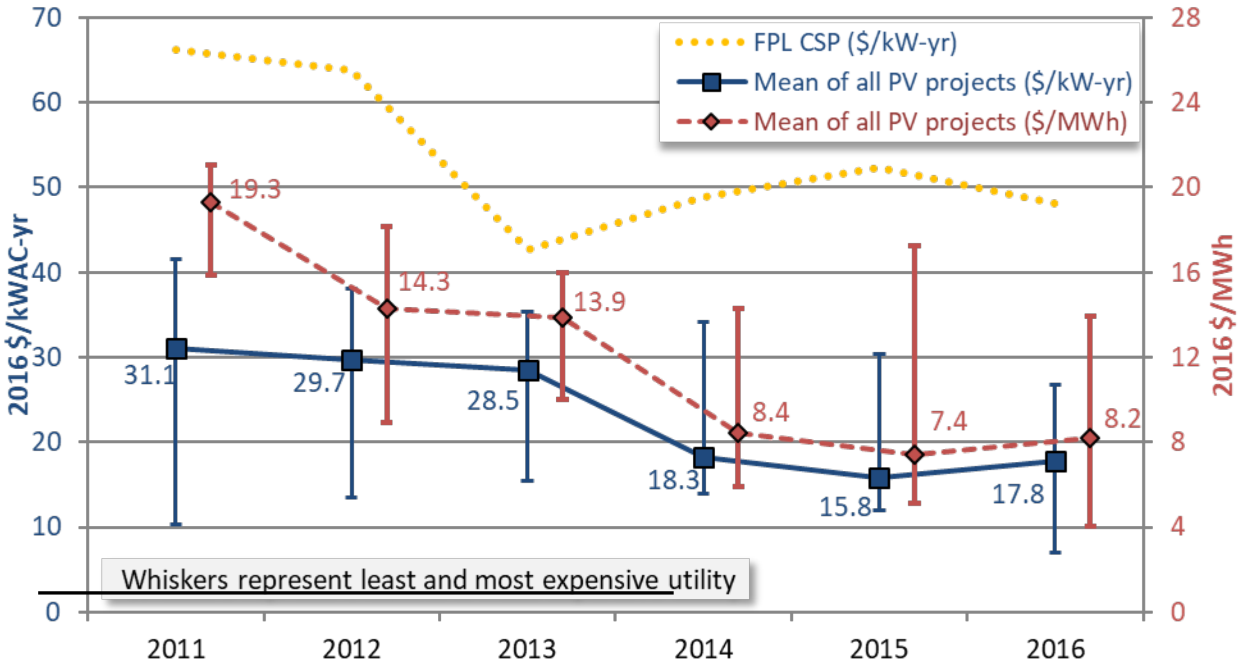
Bottom-up models roughly consistent with LBNL's top-down findings



Prices are presented here in $/W_{DC}$ for consistency with how they are presented by NREL, BNEF, and GTM

- LBNL's top-down empirical prices are fairly close to modelled bottom-up prices
- GTM project represents only turn-key EPC costs and excludes permitting, interconnection, transmission, developer overhead, fees, and profit margins
- Difficult to ensure consistency of scope in cost categories and time horizon (under construction vs. operation date)

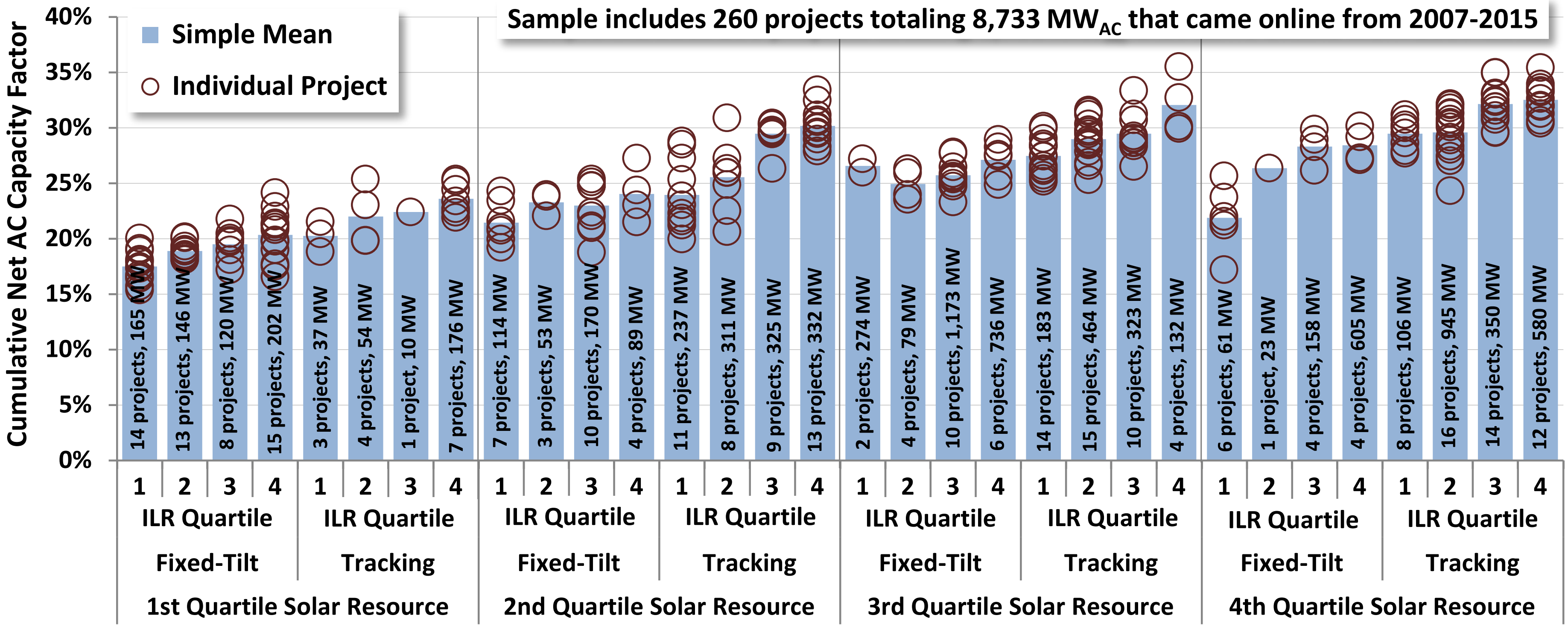
O&M cost data still very thin



- Only a few utilities report solar O&M costs, slow emergence of project-specific O&M costs
- O&M costs appear to be declining over time, to $17.8/kW-year and $8.2/MWh in 2016 (slight increase from 2015)
- Cost declines may reflect economies of scale
- Cost range among utilities continues to be large

Year	PG&E		PNM		Nevada Power		Georgia Power		APS		PSEG		FP&L	
	MW_{AC}	project #	MW_{AC}	project #	MW_{AC}	project #	MW_{AC}	project #	MW_{AC}	project #	MW_{AC}	project #	MW_{AC}	project #
2011	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	51	3	#N/A	#N/A	110	3
2012	50	3	8	2	#N/A	#N/A	#N/A	#N/A	96	4	#N/A	#N/A	110	3
2013	100	6	30	4	#N/A	#N/A	#N/A	#N/A	136	6	#N/A	#N/A	110	3
2014	#N/A	#N/A	55	7	#N/A	#N/A	#N/A	#N/A	168	7	#N/A	#N/A	110	3
2015	150	9	95	11	#N/A	#N/A	#N/A	#N/A	191	9	#N/A	#N/A	110	3
2016	150	9	95	11	16	1	36	2	237	10	44	3	110	3
predominant technology	Fixed-Tilt c-Si		4 Fixed-Tilt, 7 Tracking		Tracking c-Si		Fixed-Tilt c-Si		Tracking c-Si		Fixed-Tilt c-Si		mix of c-Si and CSP	

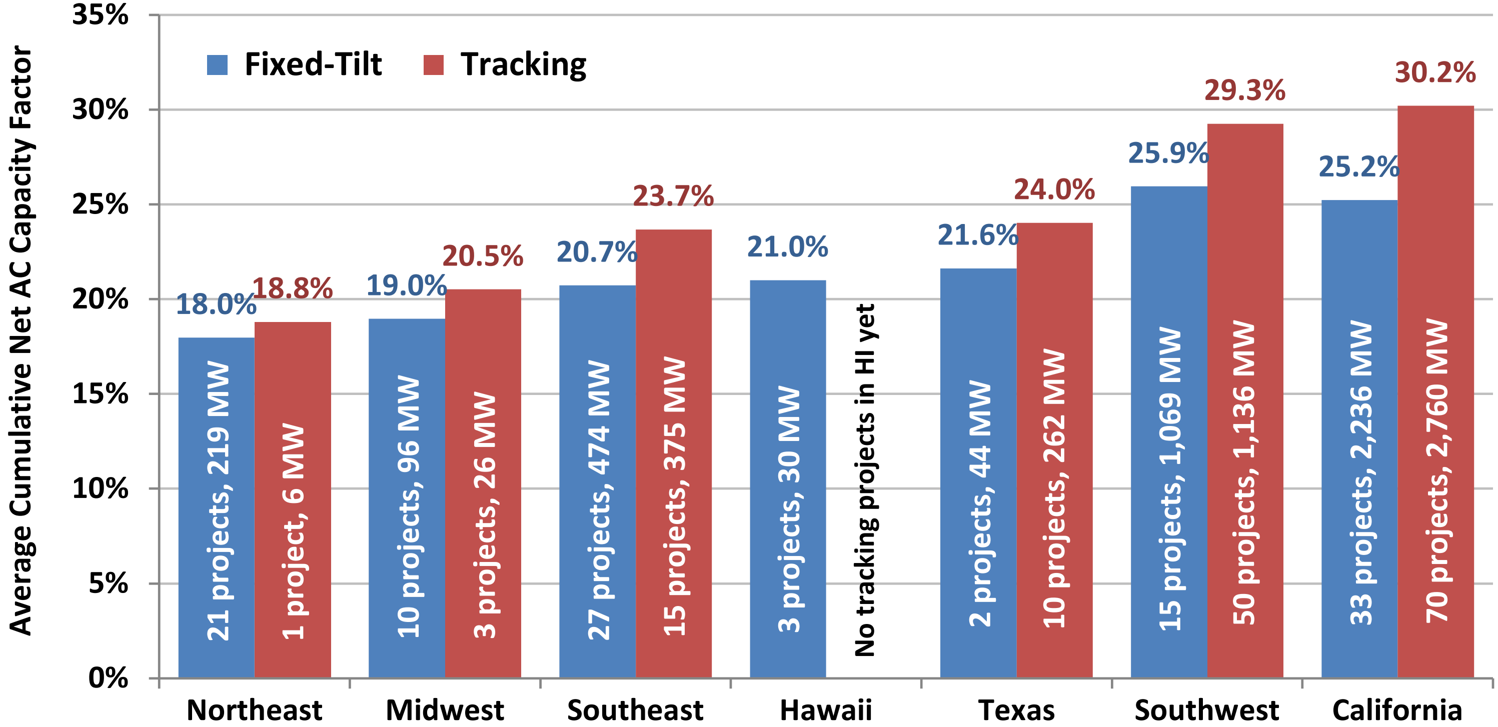
25.8% average sample-wide PV net capacity factor, but with large project-level range (from 15.4%-35.5%)



Project-level variation in PV capacity factor driven by:

- **Solar Resource (GHI):** Highest resource quartile has ~8 percentage point higher capacity factor than lowest
- **Tracking:** Adds ~4 percentage points to capacity factor on average across all four resource quartiles
- **Inverter Loading Ratio (ILR):** Highest ILR quartiles have ~4 percentage point higher capacity factor than lowest

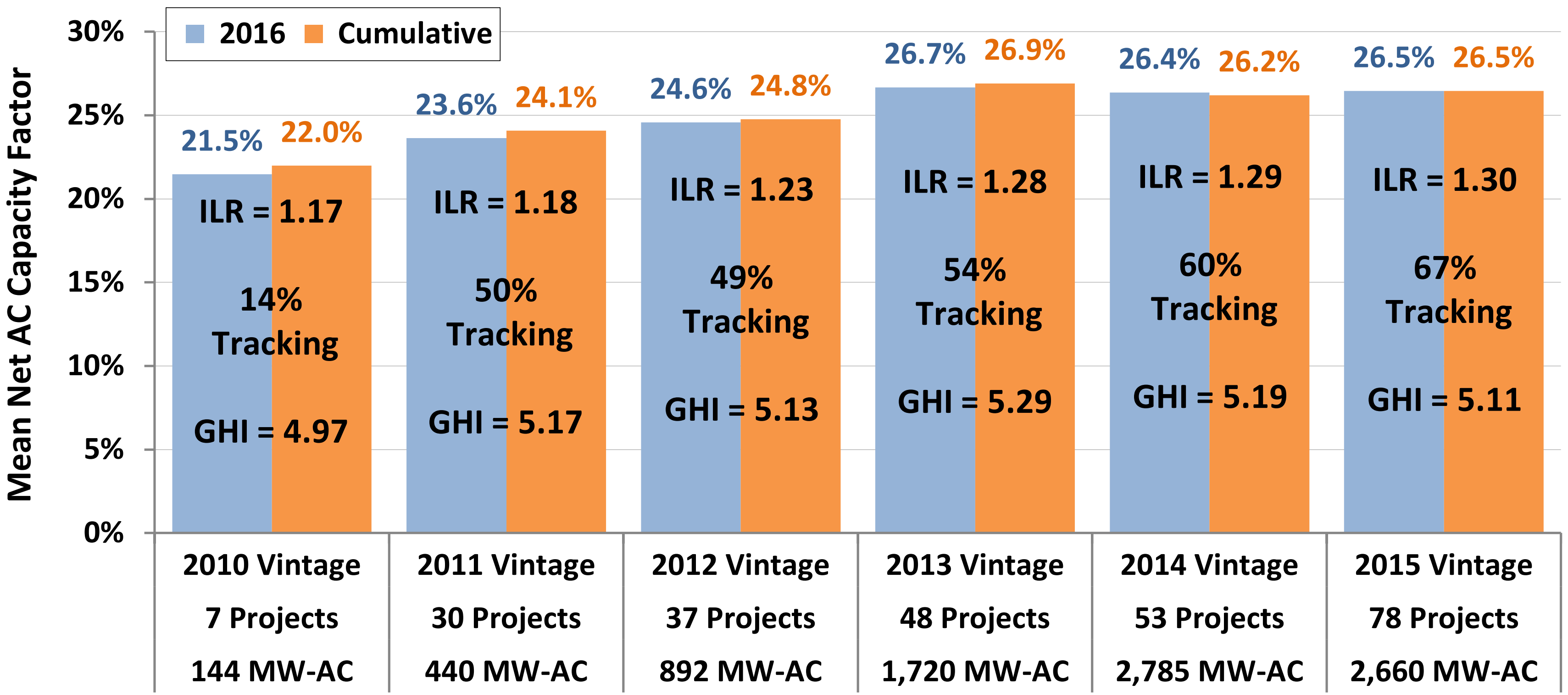
For those who prefer to think geographically rather than in terms of insolation quartiles…



Regions are defined in the map on slide 8

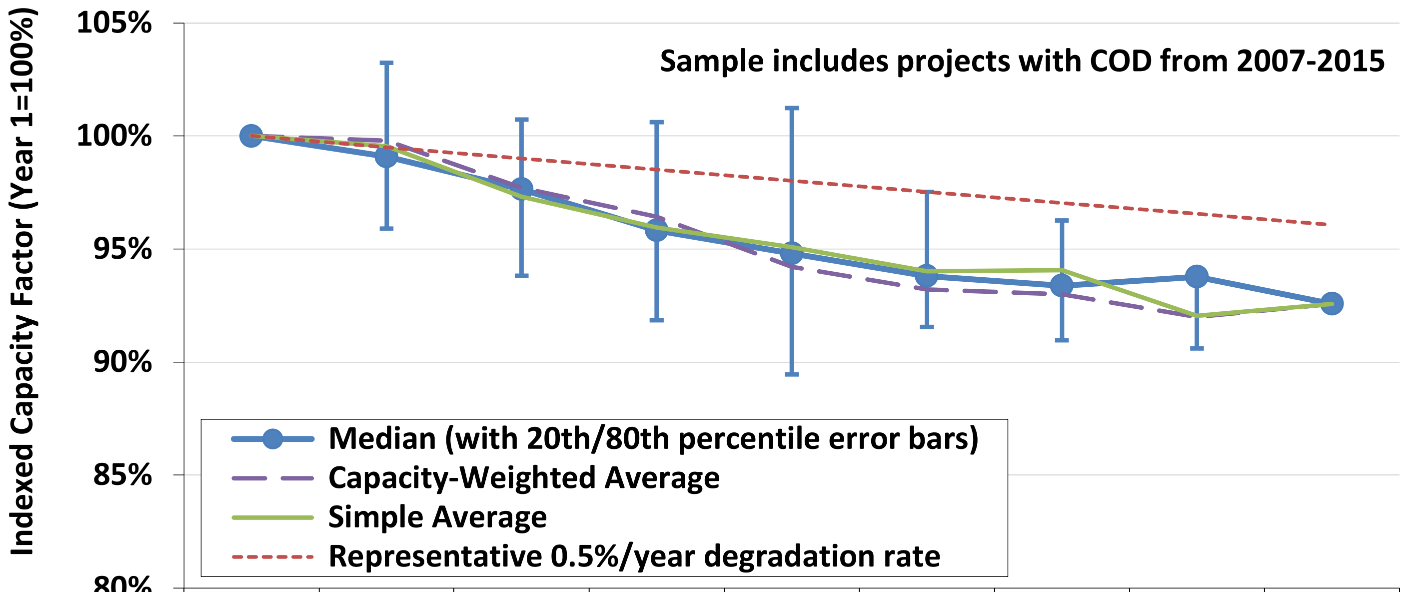
- Not surprisingly, capacity factors are highest in California and the Southwest, and lowest in the Northeast and Midwest
- Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions

More recent PV project vintages have higher capacity factors on average



- Average capacity factors driven higher from 2010- to 2013-vintage projects by an increase in ILR (from 1.17 to 1.28), tracking (from 14% to 54%) and average site-level GHI (from 4.97 to 5.29).
- But since 2013, average long-term site-level GHI has decreased while tracking has increased (with ILR roughly unchanged), leading to stagnation in capacity factors among 2014 and 2015 projects.

Performance degradation is evident, but difficult to assess and attribute at the project-level

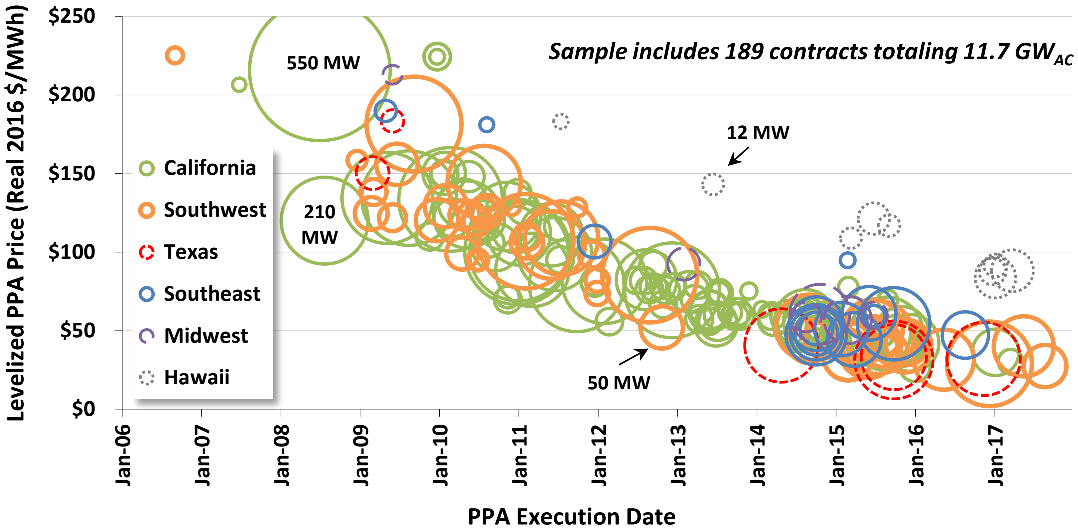


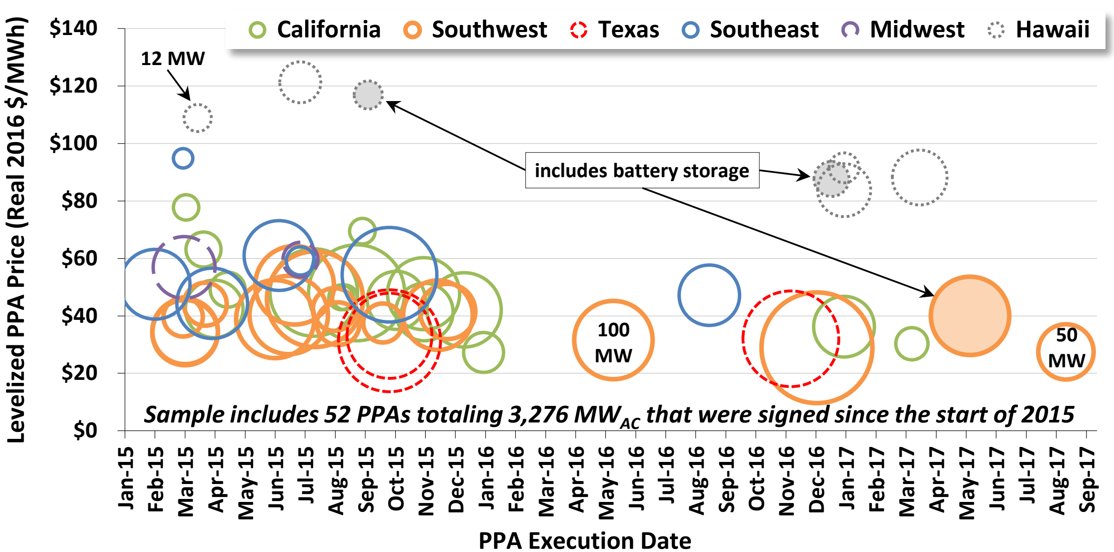
Years post-COD:	1	2	3	4	5	6	7	8	9
Sample projects:	260	182	129	81	43	13	6	3	1
Sample MW_{AC}:	8,733	6,073	3,288	1,567	667	227	83	29	7

Graph shows indexed capacity factors in each full calendar year following COD. No attempt has been made to correct for inter-year resource variation or other factors.

- Fleetwide degradation appears to exceed the 0.5%/year benchmark commonly assumed in PPAs and pro forma models
- Contributing factors (other than actual degradation) could include inter-year resource variability (e.g., several bad solar years in a row), curtailment (which has become an issue in California – the largest market), and an inconsistent sample (which drops off quickly) in each successive year

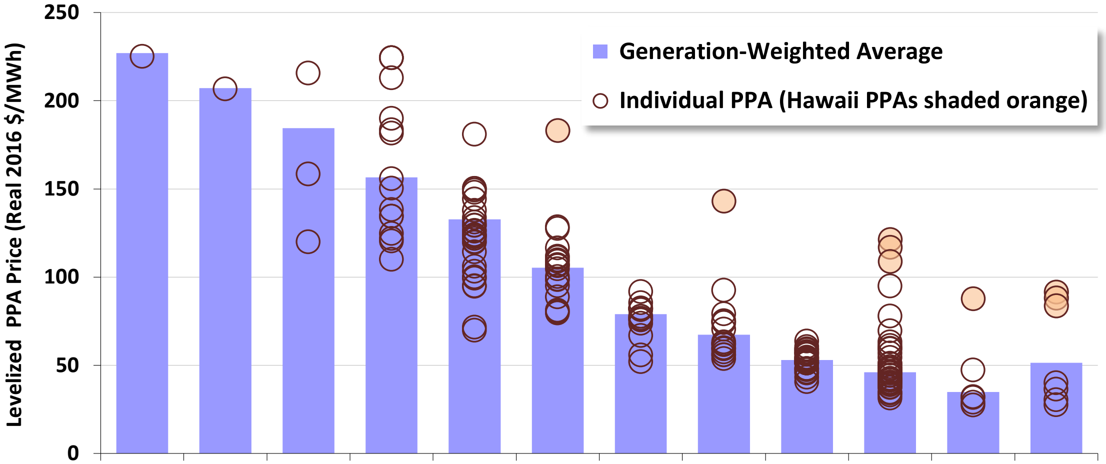
Combination of falling installed prices and better project performance enables lower PPA prices



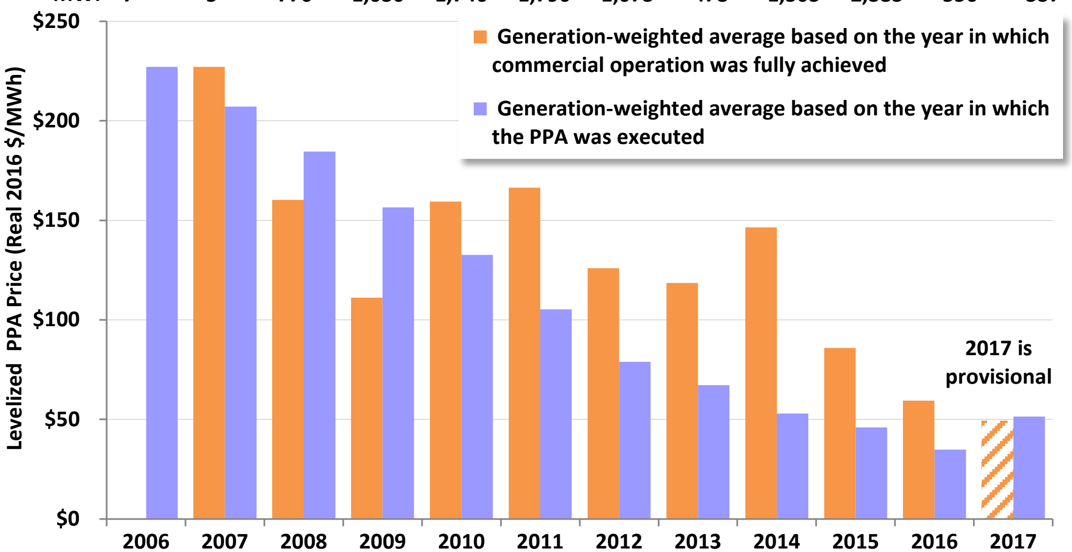


- PPA prices are levelized over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors, and are shown in real 2016 dollars
- Top graph shows the full sample; bottom graph shows a sub-sample of PPAs signed post-2014
- CA and the Southwest dominate the sample, but in recent years the market has expanded to other regions
- Hawaii projects (included here for the first time) show a consistent and significant premium over the mainland
- Three PPAs featuring PV plus long-duration battery storage do not seem to be priced at a prohibitive premium to their PV-only counterparts
- Smaller projects (e.g., 20-50 MW) are seemingly no less competitive
- >90% of the sample is currently operational

On average, levelized PPA prices fell by >75% from 2009 through 2016

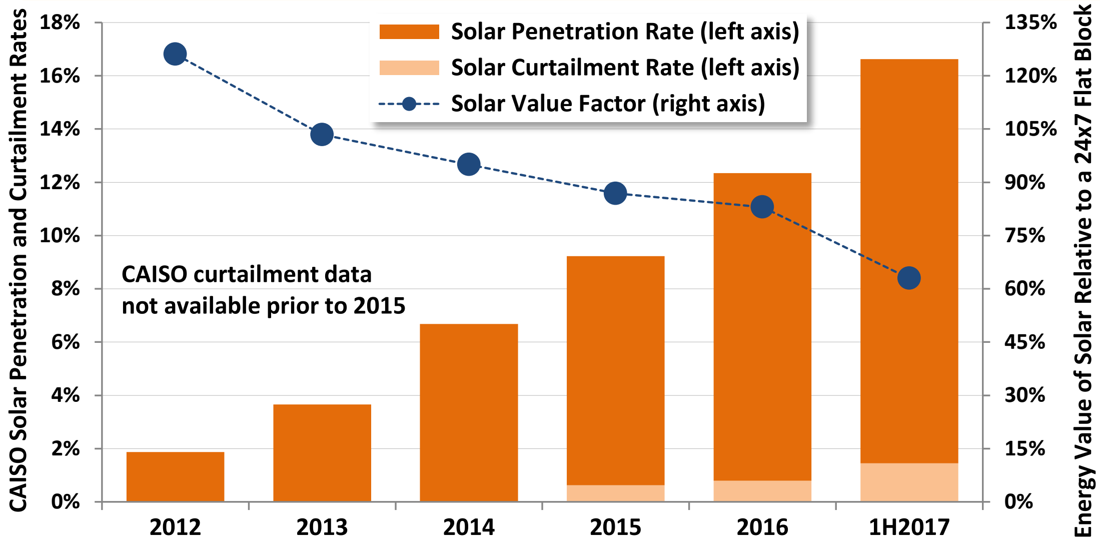


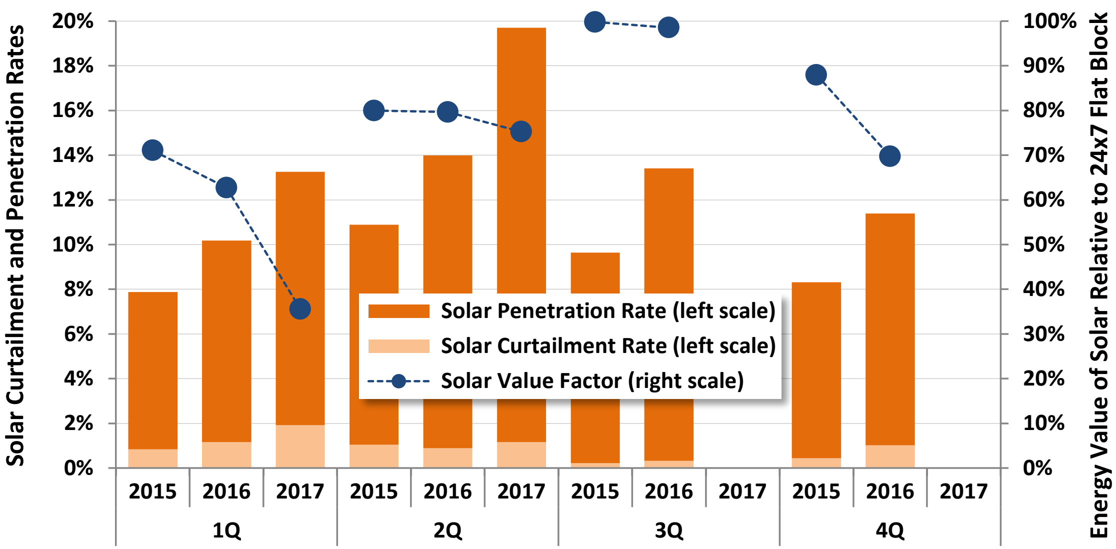
PPA Year:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Contracts:	1	1	3	16	30	20	17	19	30	39	6	7
MW:	7	5	770	1,030	1,746	1,790	1,073	478	1,503	2,383	556	337



- Top figure presents the same data as previous slide, but in a different way: each circle is an individual contract, and the blue columns show the average levelized PPA price each year
- Steady downward trend in the average PPA price over time has slowed in recent years as average prices approached and then fell below $50/MWh
- Price decline over time is more erratic when viewed by COD (orange bars in bottom graph) rather than by PPA execution date (blue bars)
- Though the average levelized price of PPAs signed in 2016 is ~$35/MWh, the average levelized PPA price among projects that came online in 2016 is significantly higher, at ~$60/MWh
- 2017 is provisional and currently reflects a very small sample and a high proportion of high-priced Hawaiian PPAs, plus several PPAs with long-duration battery storage

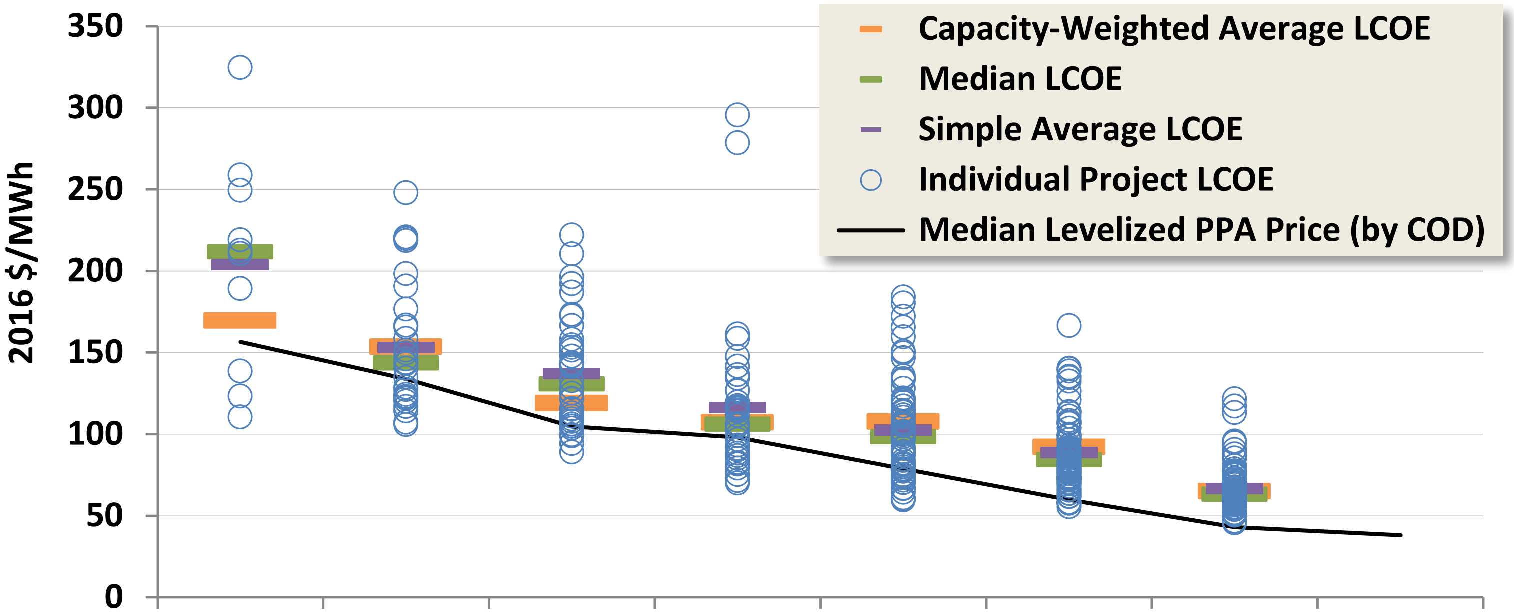
The value of solar has declined in America's largest solar market





- With increasing solar penetration in California, solar curtailment has increased and solar's wholesale energy value has declined
- In 2012, when solar penetration was ~2%, solar earned 126% of the average wholesale power price
- In 2016, with solar penetration at ~12%, solar earned just 83% of the average wholesale power price
- Based on data for the first half of the year, this value decline is likely to continue in 2017 (1Q17 was particularly bad – bottom graph)
- Most other markets are not yet facing this value decline, due to lower levels of solar penetration

Levelized PPA prices track the LCOE of utility-scale PV reasonably well

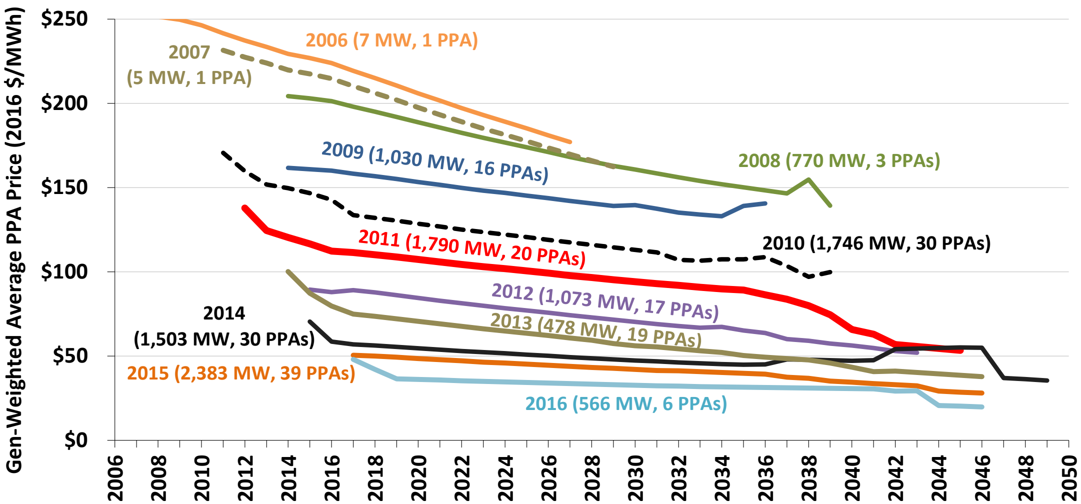


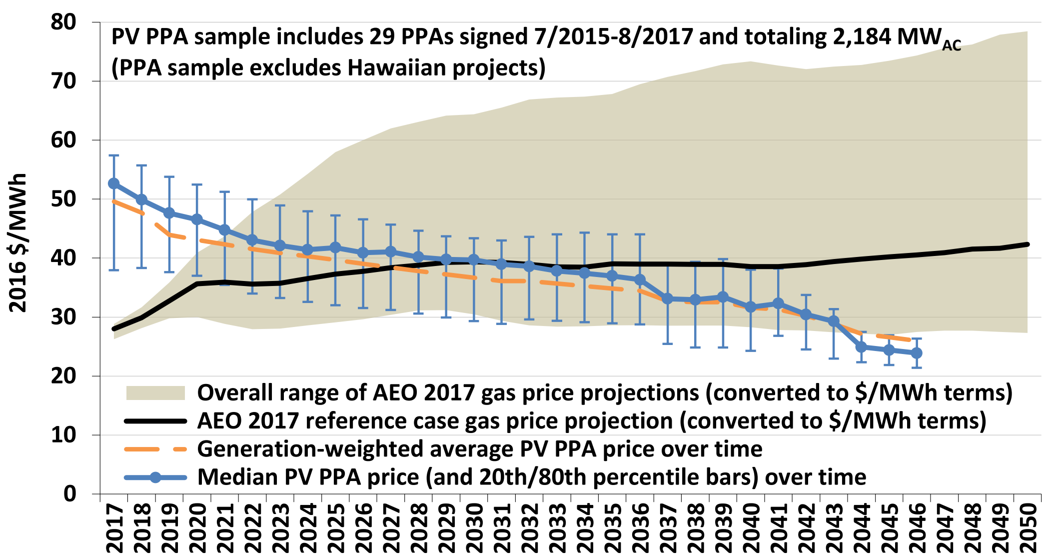
COD:	2010	2011	2012	2013	2014	2015	2016	2017
Projects:	10	28	38	38	63	86	83	TBD
MW-AC:	175	423	863	1,344	3,160	2,883	5,407	TBD

NOTE: LCOE calculations do NOT include the 30% ITC (whereas PPA prices do reflect the ITC, and perhaps also state-level incentives)

- Using empirical data from elsewhere in the report, along with a number of assumptions (e.g., about financing), we calculated project-level LCOEs for the entire sample of projects for which we have CapEx data (14.3 GW_{AC})
- Central estimates of LCOE track median PPA prices (levelized over 30 years in this case, and shown by COD rather than by execution date) reasonably well, suggesting a fairly competitive PPA market
- PPAs are lower than LCOEs because they reflect receipt of the 30% ITC and perhaps also state-level incentives

PV PPA prices generally decline over time in real dollar terms, in contrast to fuel cost projections





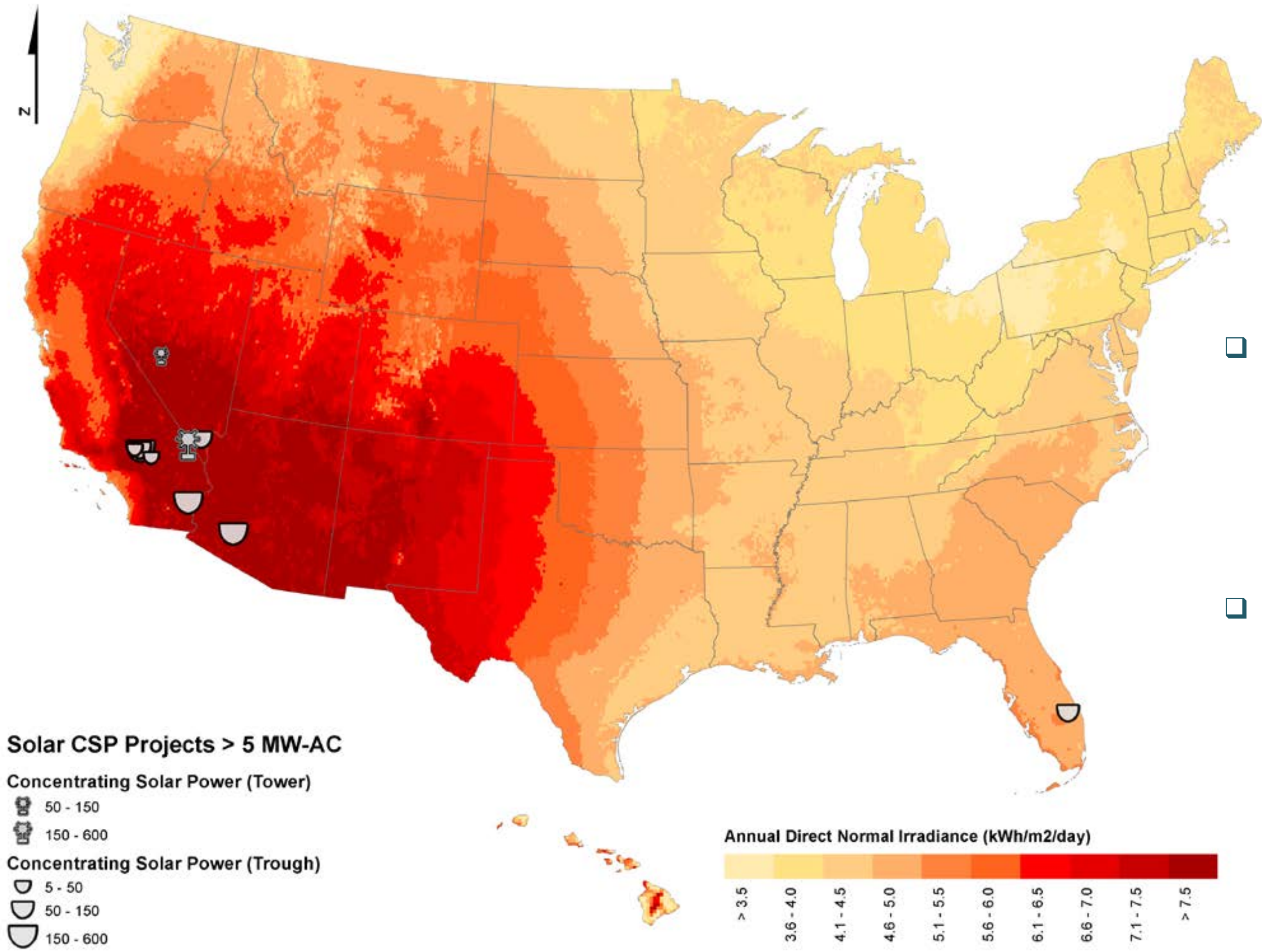
- Two-thirds of PV sample has flat annual PPA pricing (in nominal dollars), while the rest escalate at low rates
- Thus, average PPA prices tend to ***decline*** over time in real dollar terms (top graph)
- Bottom graph compares recent PPA prices to range of gas price projections from *AEO 2017*, showing that…
- …although PV is currently priced higher than the cost of burning fuel in a combined-cycle unit, over longer terms PV is perhaps likely to be more competitive, and can help protect against fuel price risk

Utility-Scale Concentrating Solar Thermal Power (CSP)

Photo Credit: Solar Reserve: Crescent Dunes

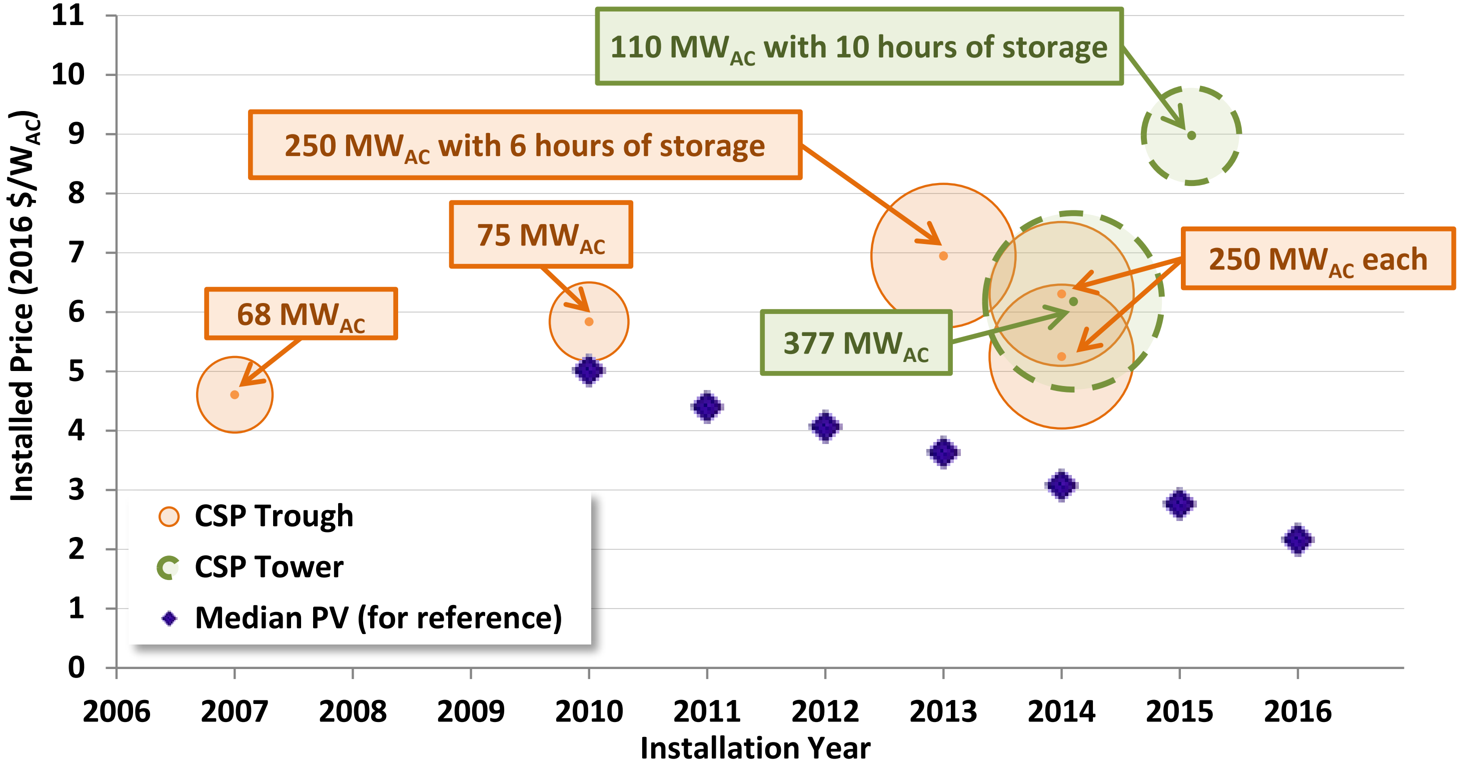
Sample description of CSP projects

CSP project population: 16 projects totaling 1,781 MW_{AC}



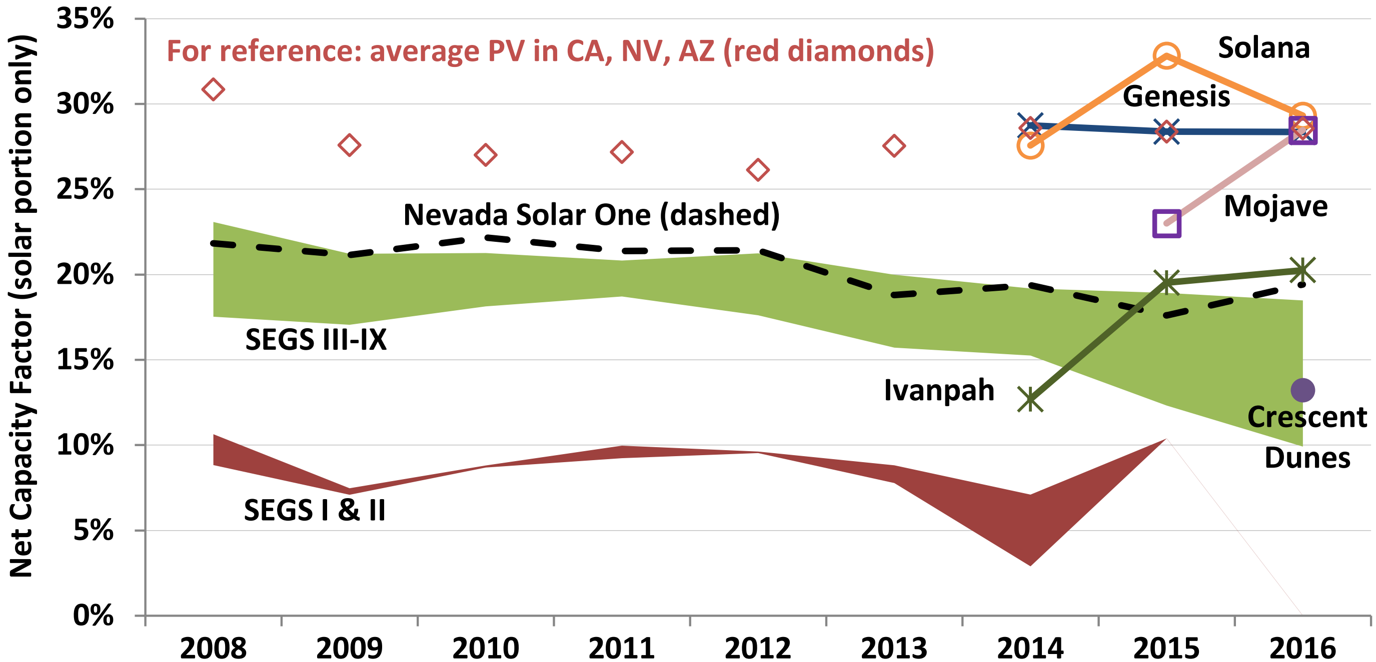
- After nearly 400 MW_{AC} built in the late-1980s (and early-1990s), no new CSP was built in the U.S. until 2007 (68 MW_{AC}), 2010 (75 MW_{AC}), and 2013-2015 (1,237 MW_{AC})
- Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors
- The five 2013-2015 projects include 3 parabolic troughs (one with 6 hours of storage) totaling 750 MW_{AC} (net) and two "power tower" projects (one with 10 hours of storage) totaling 487 MW_{AC} (net)

Not much movement in the installed price of CSP



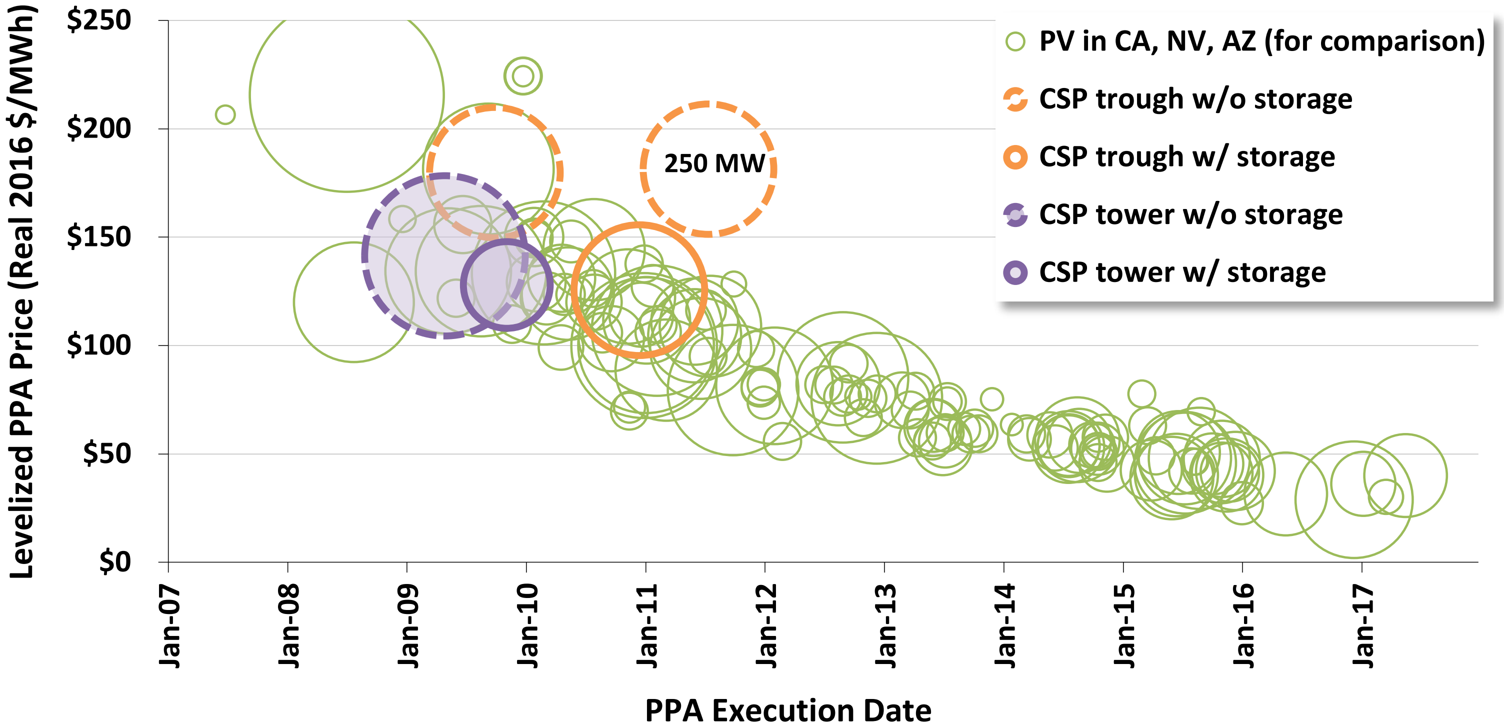
- Small sample of 7 projects (5 built in 2013-15) using different technologies makes it hard to identify trends
- That said, there does not appear to be much of a trend (in contrast to PV's steady downward trend)
- To be fair, newest projects are much larger, and include thermal storage and/or new technology (power tower) in some cases, making comparisons difficult

Several newer CSP projects continued to underperform relative to long-term expectations



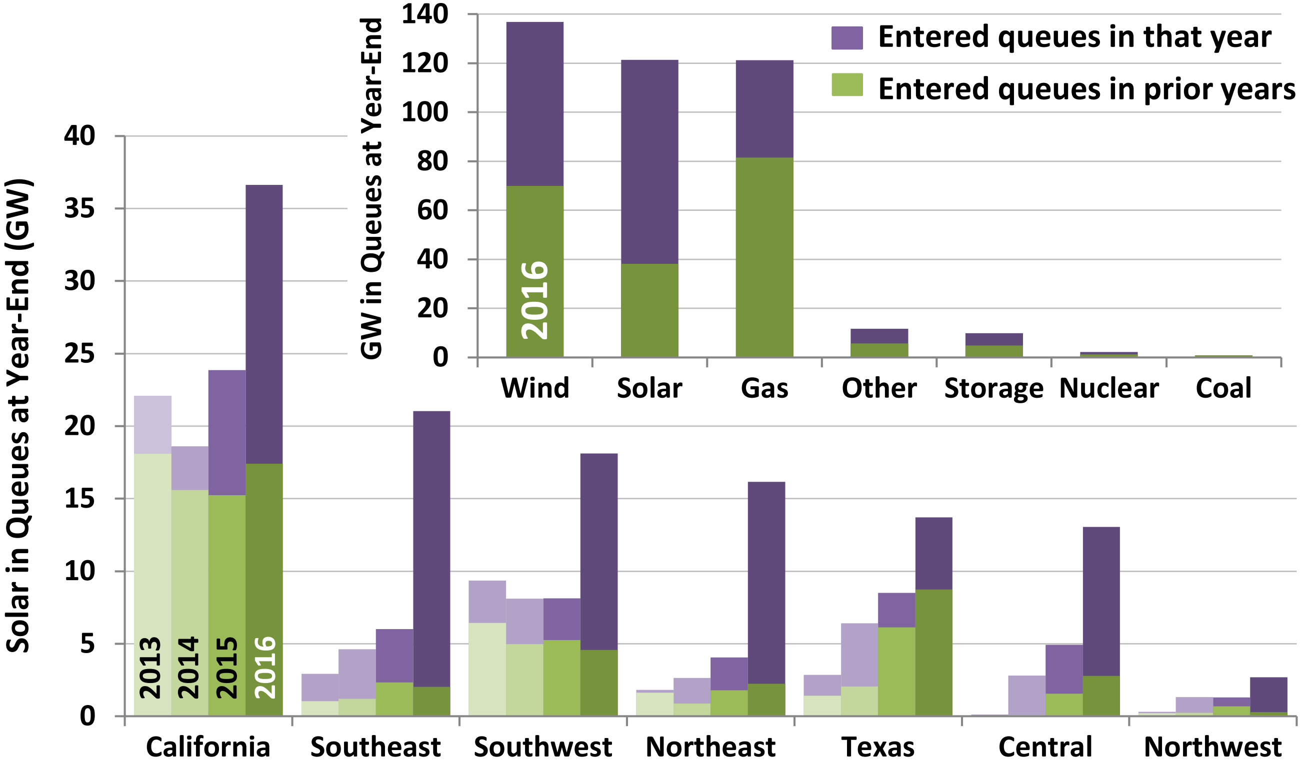
- The two "power tower" projects (Ivanpah and Crescent Dunes) were hit with closures in 2016 that negatively impacted capacity factors. The Crescent Dunes closure lasted into 2017.
- Solana was at reduced capacity for part of 2016 due to micro-burst storm damage, and for part of 2017 due to a transformer fire.
- Genesis and Mojave were both largely on target in 2016
- Most newer CSP projects generally performing better than older CSP projects, but not necessarily any better than (and in some cases worse than) local PV projects

Though once competitive, CSP PPA prices have failed to keep pace with PV's price decline



- When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they were still mostly competitive with PV
- But CSP has not been able to keep pace with PV's price decline
- Partly as a result, no new PPAs for CSP projects have been signed in the U.S. since 2011 – though the technology continues to advance overseas

Looking ahead: long-term ITC extension should support continued growth in the utility-scale solar pipeline



Graphs show solar and other capacity in 35 interconnection queues across the US:

- **Inset compares solar to other resources (2016 only)**
- **Main graph shows location of solar (2013-2016)**
- ***Not all of these projects will ultimately be built!***

- 121.4 GW of solar was in the queues at the end of 2016—up from 56.8 GW at end of 2015, and more than six times the amount of installed capacity at the end of 2016
- 83.3 GW of the 121.4 GW total first entered the queues in 2016
- Very strong solar growth in all regions, with the possible exception of the Northwest
- The Southeast moved ahead of the Southwest for the number two position behind California

Questions?

Download the full report, a data file, and this slide deck at:

http://utilityscalesolar.lbl.gov

Download all of our other solar and wind work at:

http://emp.lbl.gov/reports/re

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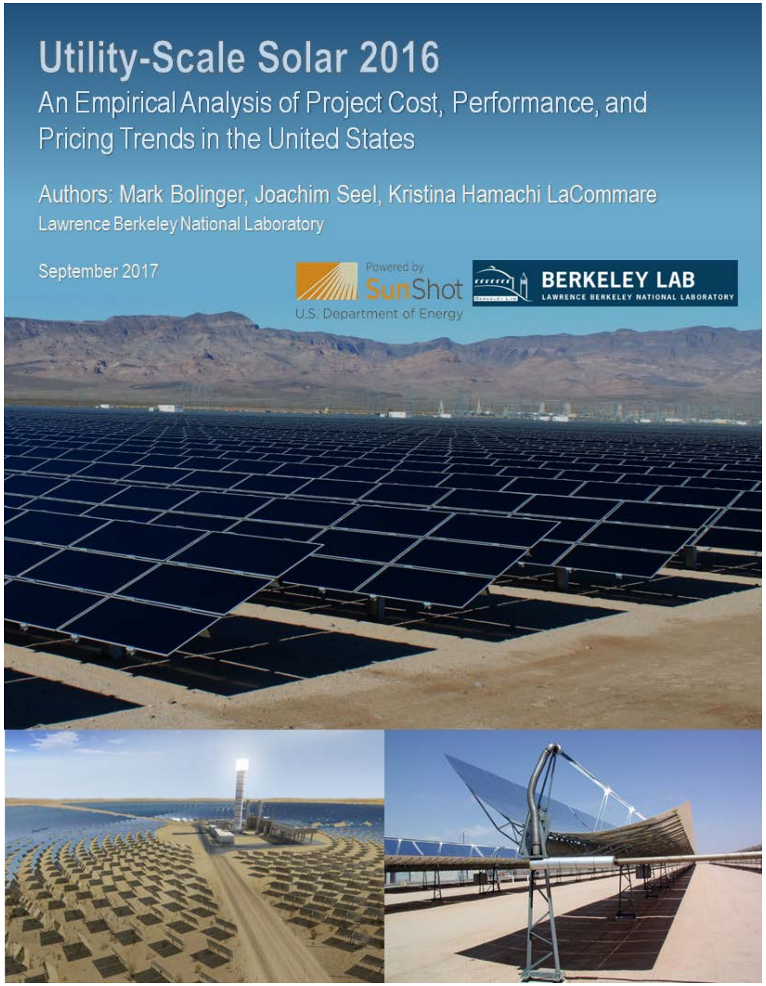

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