Utility-Scale Solar

Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States

2019 Edition

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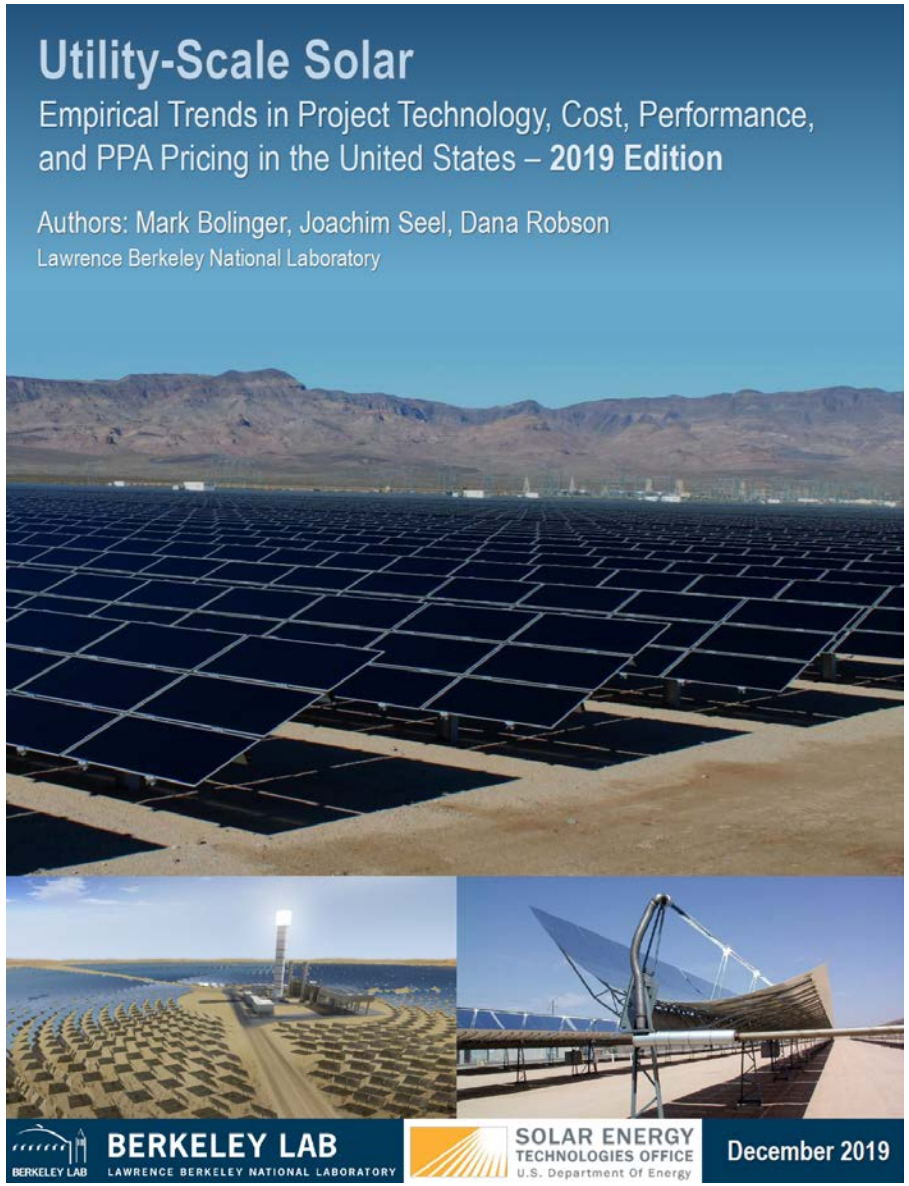


Presentation Outline

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

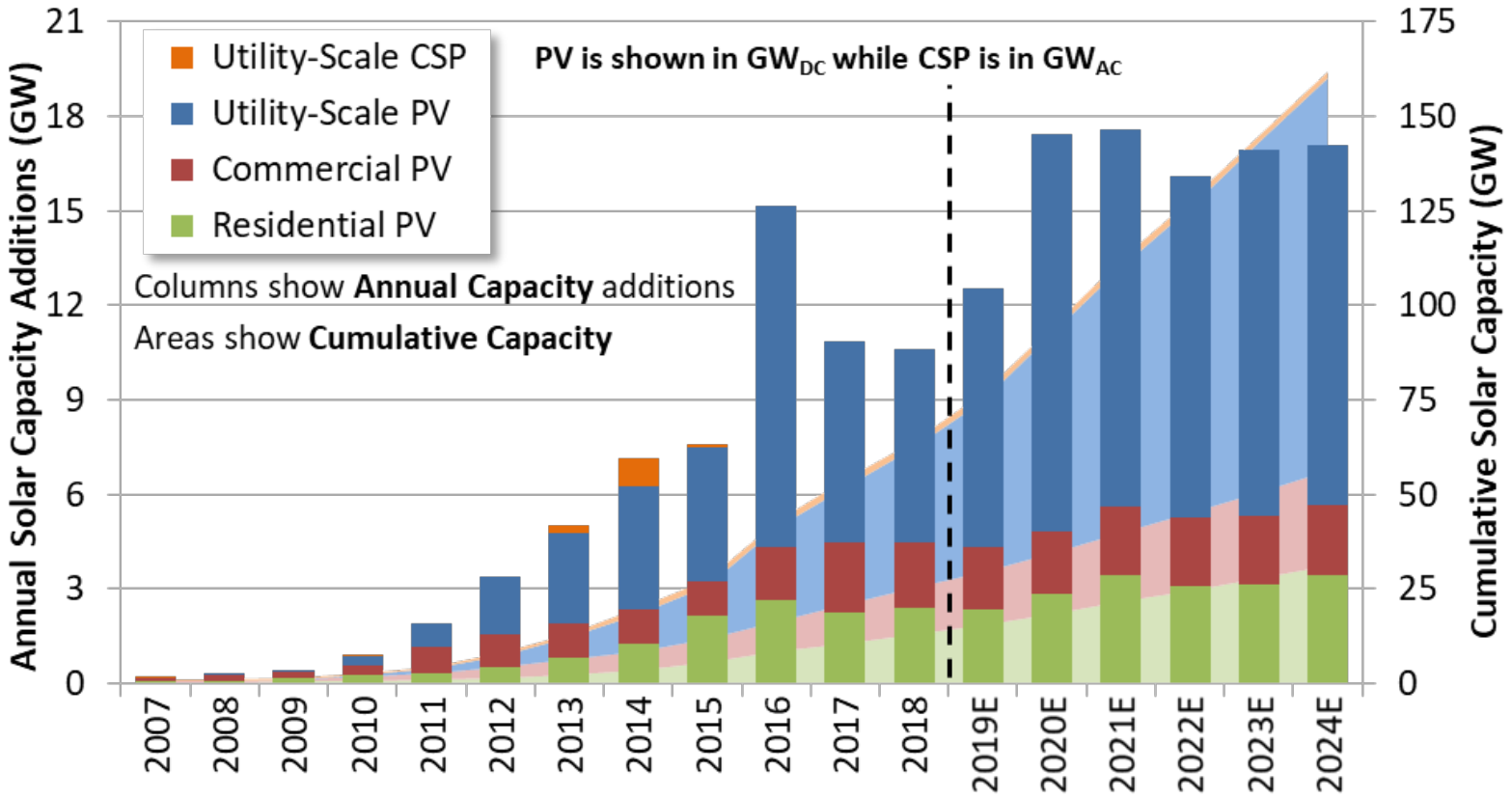
1. Solar deployment trends (and utility-scale's relative contribution)

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 and levelized cost of energy ("LCOE")
7. Wholesale market value

8. Future outlook

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



Sources: *Wood Mackenzie/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)

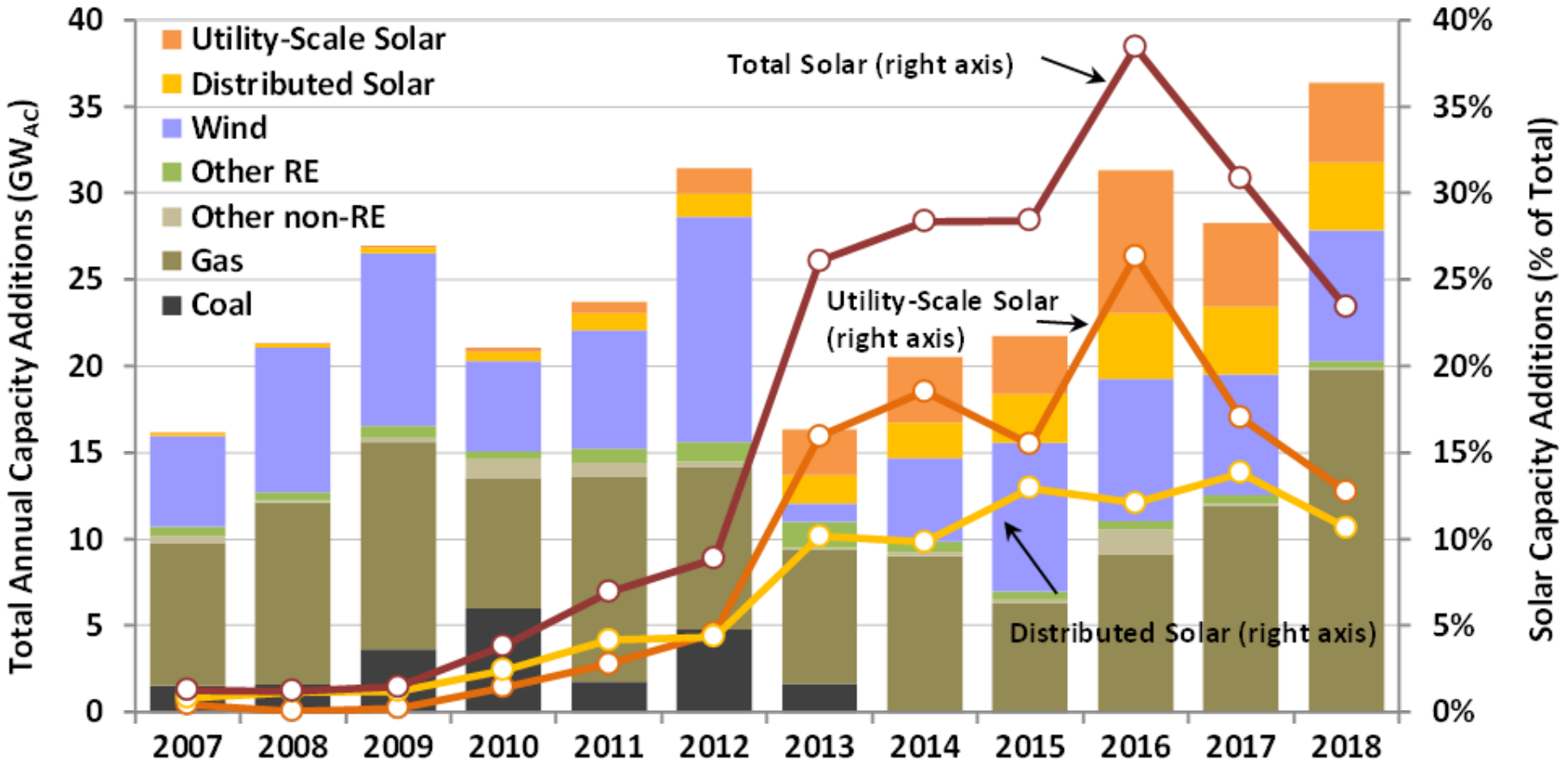
The utility-scale sector accounted for 6.2 GW_{DC} or **58% of all new** solar capacity added in 2018 and **60% of cumulative** solar capacity at the end of 2018.

Capacity additions declined slightly as a number of projects were pushed from end of 2018 to 2019.

Our data sample analyzes all projects larger than 5MW_{AC} that were completed by the end of 2018:

- **2017**: 152 new projects totaling 3.9 GW_{AC} (5.2 GW_{DC})
- **2018**: 93 new projects totaling 4.0 GW_{AC} (5.4 GW_{DC})

Solar power was the second largest source of U.S. electricity-generating capacity additions in 2018



Led by the utility-scale sector, solar power has comprised >20% of all generating capacity additions in the United States in each of the past six years.

In 2018, solar made up 23% of all U.S. capacity additions (with utility-scale accounting for 13%), behind natural gas (55%) but ahead of wind (21%).

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

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

Solar penetration rates top 19% in California and exceed 10% in five other states

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	19.0%	12.8%	15.8%	10.7%
Nevada	12.7%	11.5%	13.7%	12.4%
Hawaii	11.2%	1.9%	13.3%	2.3%
Vermont	11.0%	5.7%	4.9%	2.6%
Massachusetts	10.7%	4.3%	6.1%	2.5%
Arizona	6.5%	4.5%	9.6%	6.6%
Utah	6.4%	5.4%	8.4%	7.1%
North Carolina	5.4%	5.2%	5.2%	5.1%
New Mexico	4.7%	3.9%	6.4%	5.4%
New Jersey	4.2%	1.7%	4.3%	1.7%
Rest of U.S.	*0.7%*	*0.5%*	*0.8%*	*0.5%*
TOTAL U.S.	**2.3%**	**1.6%**	**2.5%**	**1.8%**

Source: EIA's Electric Power Monthly (February 2019)

Solar penetration rate varies considerably depending on whether it is calculated as a percentage of generation or load (e.g., see Vermont).

In 2018, five states achieved solar penetration levels >10% based on generation share. Three states had >10% based on load share.

Contribution of utility-scale also varies (a minority in Northeast states and Hawaii, a majority in Southwest states and overall).

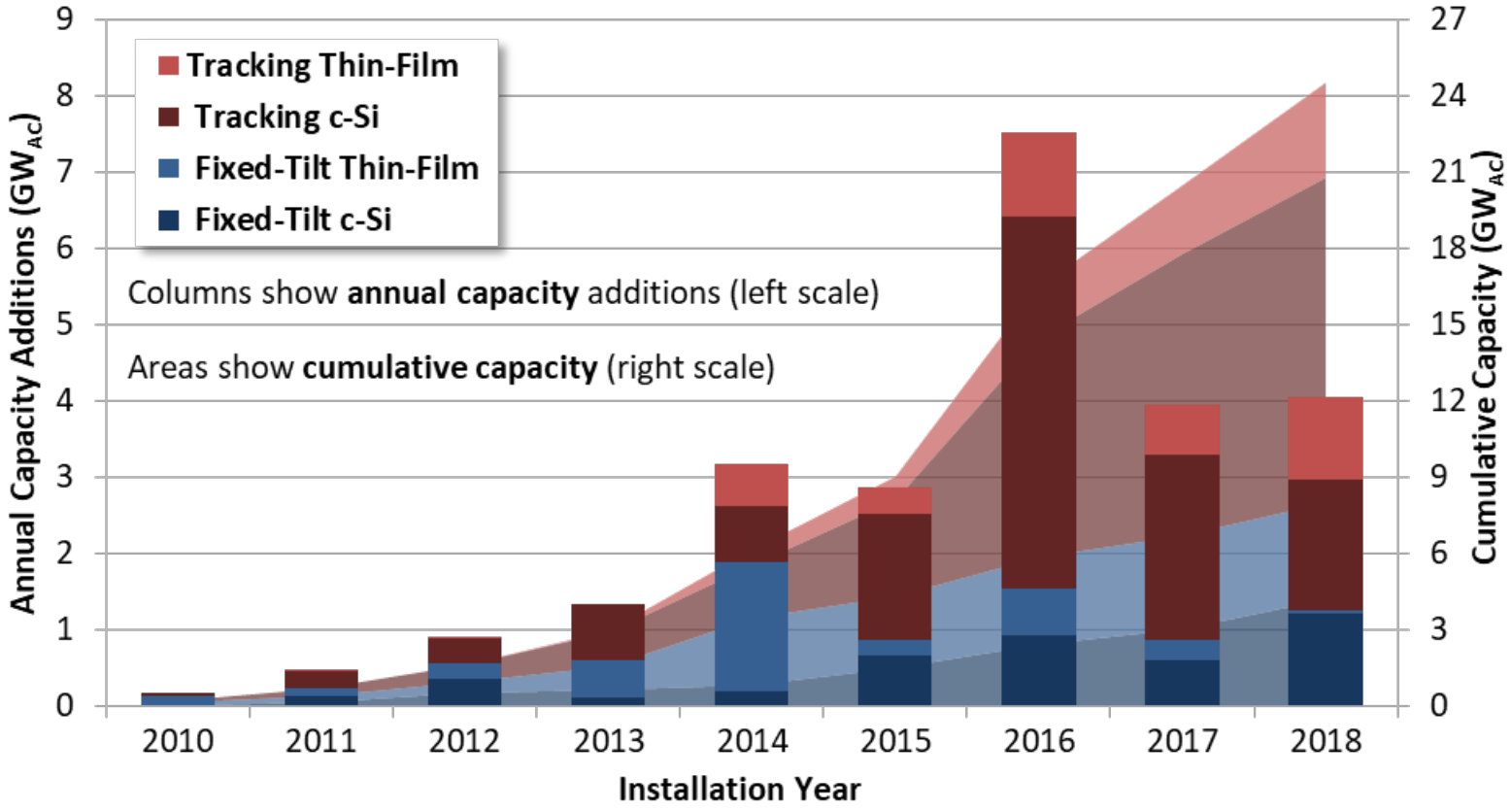
Note: In this table, "utility-scale" refers to projects ≥ 1 MW_{AC}, rather than our typical 5 MW_{AC} threshold.

Utility-Scale Photovoltaics (PV)

Photo Credit: Lawai Solar and Energy Project 20MW$_{AC}$, 100MWh storage Hawaii, AES

Projects with tracking technology dominated 2018 additions; c-Si modules led thin-film

PV project population: 690 projects totaling 24,586 MW_{AC}



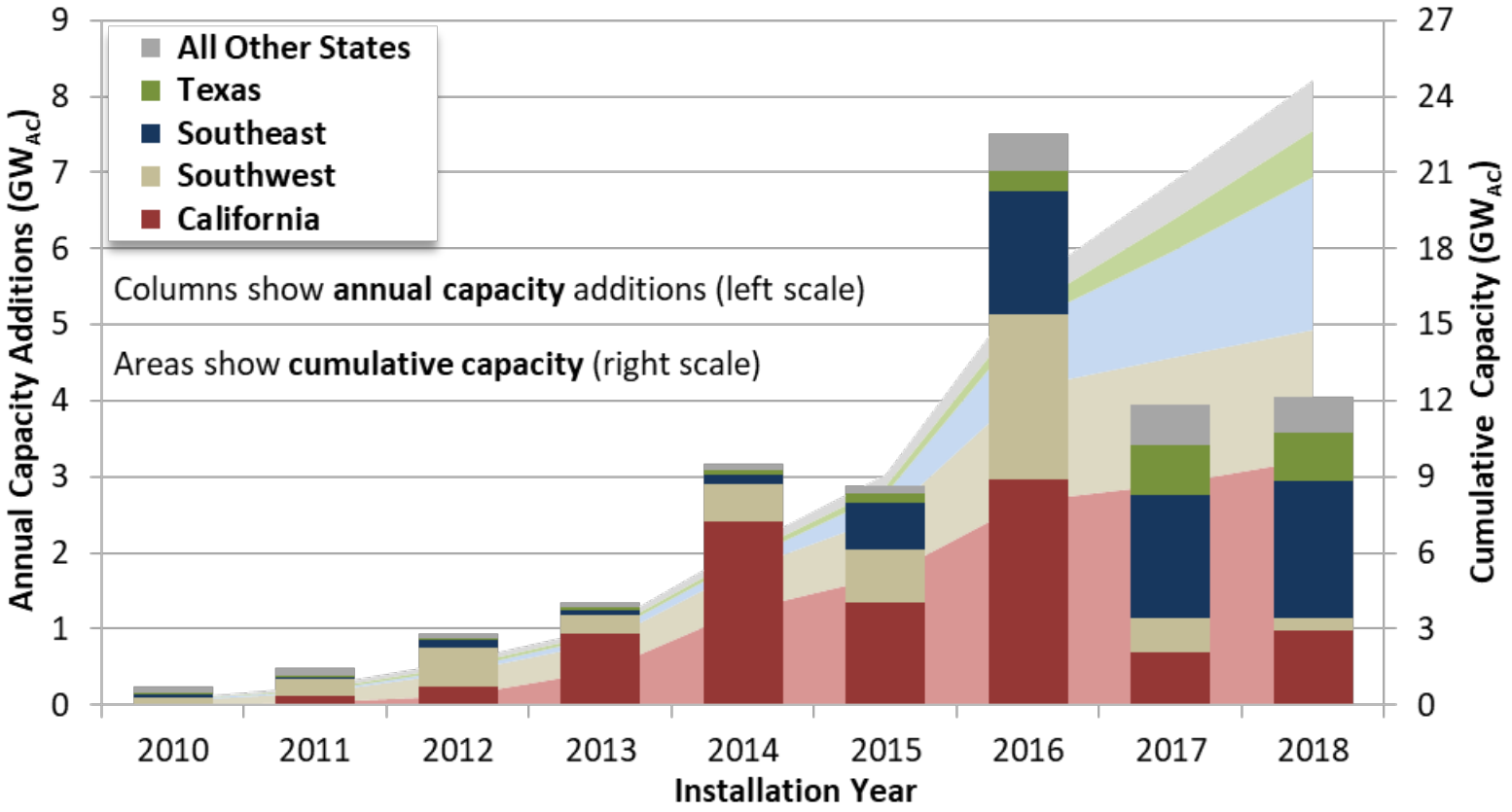
Continued dominance of **tracking** projects (69% of newly installed capacity) relative to **fixed-tilt** projects (31%). Thin-film projects are nearly exclusively using tracking now.

c-Si modules continue their clear lead (72% of newly installed capacity) relative to **thin-film** modules (28%).

Hanwha had the highest market share among c-Si modules in our sample, followed by Jinko, and Canadian Solar. First Solar provided 85% of all thin-film modules in 2018, the remainder supplied by Solar Frontier.

Florida is the new national leader in utility-scale solar growth

PV project population: 690 projects totaling 24,586 MW_{AC}



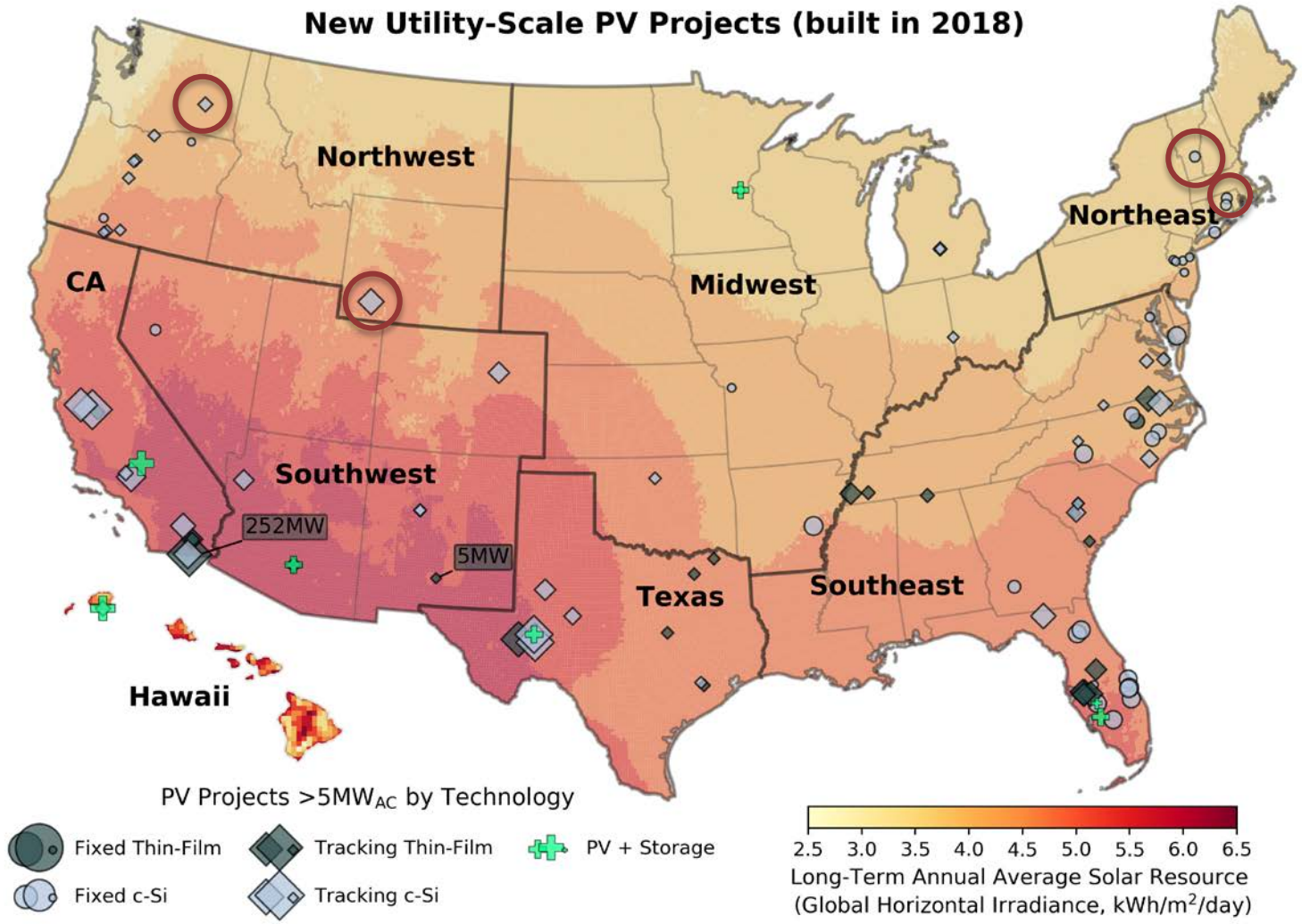
The **Southeast** is the new growth engine of the US utility-scale solar market. It is led by **Florida**, now the largest annual market at 1010 MW_{AC} or 25% of national additions. Established player **North Carolina** added 472 MW_{AC}.

For the first time since 2011, **California** is not the state with the most capacity growth (981 MW_{AC}). But it still accounts for 40% of the cumulative installed capacity of the country.

Texas continues its solar growth with another year of ~650 MW_{AC} and is the state with the third-most additions in 2018.

The **Southwest** only added 160 MW_{AC} in 2018, and was surpassed by new installations in the **Northwest** (181 MW_{AC}).

Florida is the new national leader in utility-scale solar growth



Florida's growth was driven by the regulated utilities FPL and TECO, which added many fixed-tilt projects ( ).

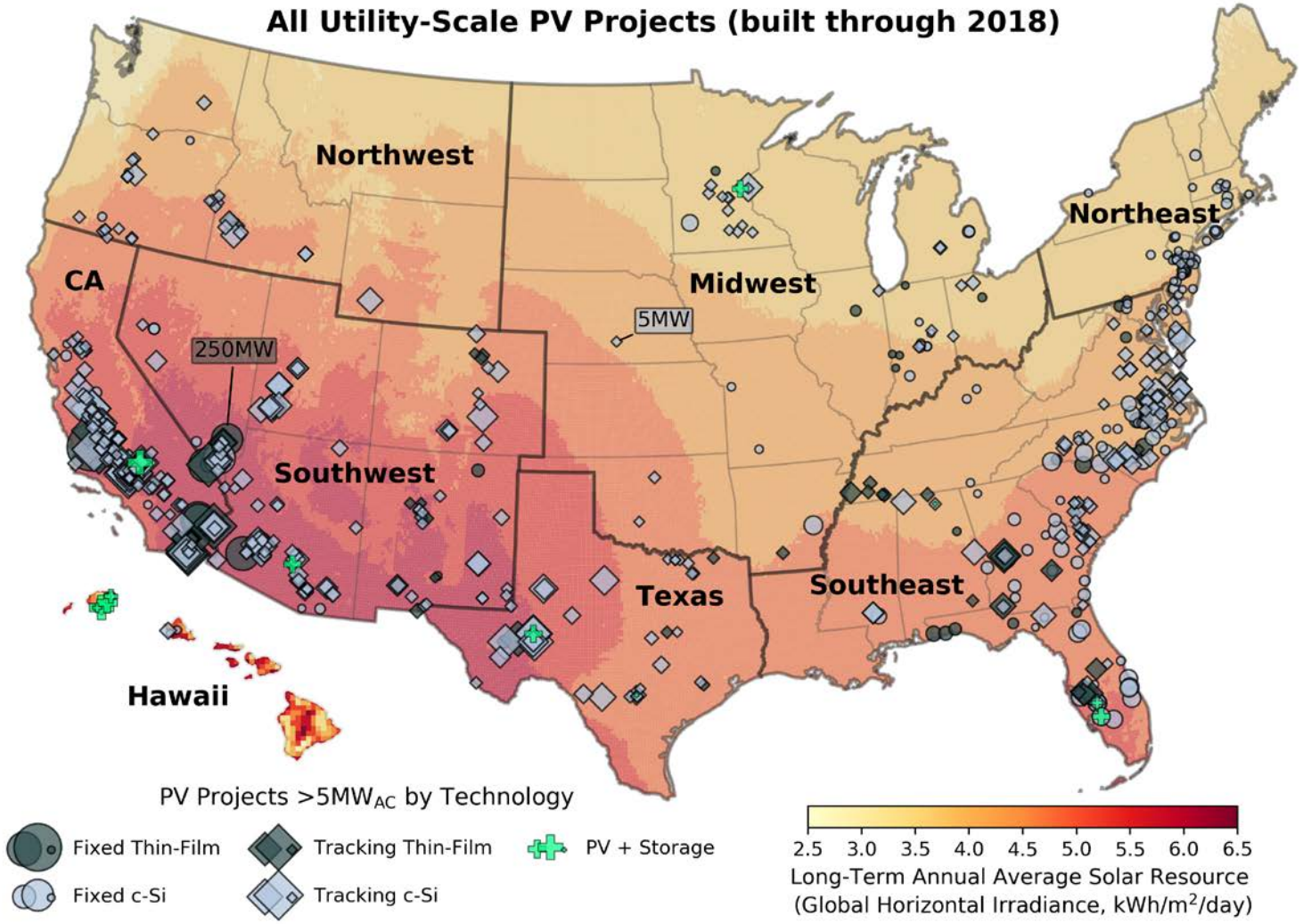
California only completed 10 projects, but these were large (up to 252 MW$_{AC}$) and added a respectable 981 MW.

Northwestern additions in 2018 were predominantly tracking projects ( ).

In 2018, storage ( ) was added to already existing (3) and new (4) PV projects. 6 of these were built in high penetration/transmission-constrained regions in HI, CA, AZ and TX, while the 7th is in relative newcomer state MN.

4 new states added their first utility-scale PV projects: **Connecticut**, **Vermont**, **Washington** and **Wyoming.**

Utility-Scale Solar has become a growing source of electricity in all regions of the United States

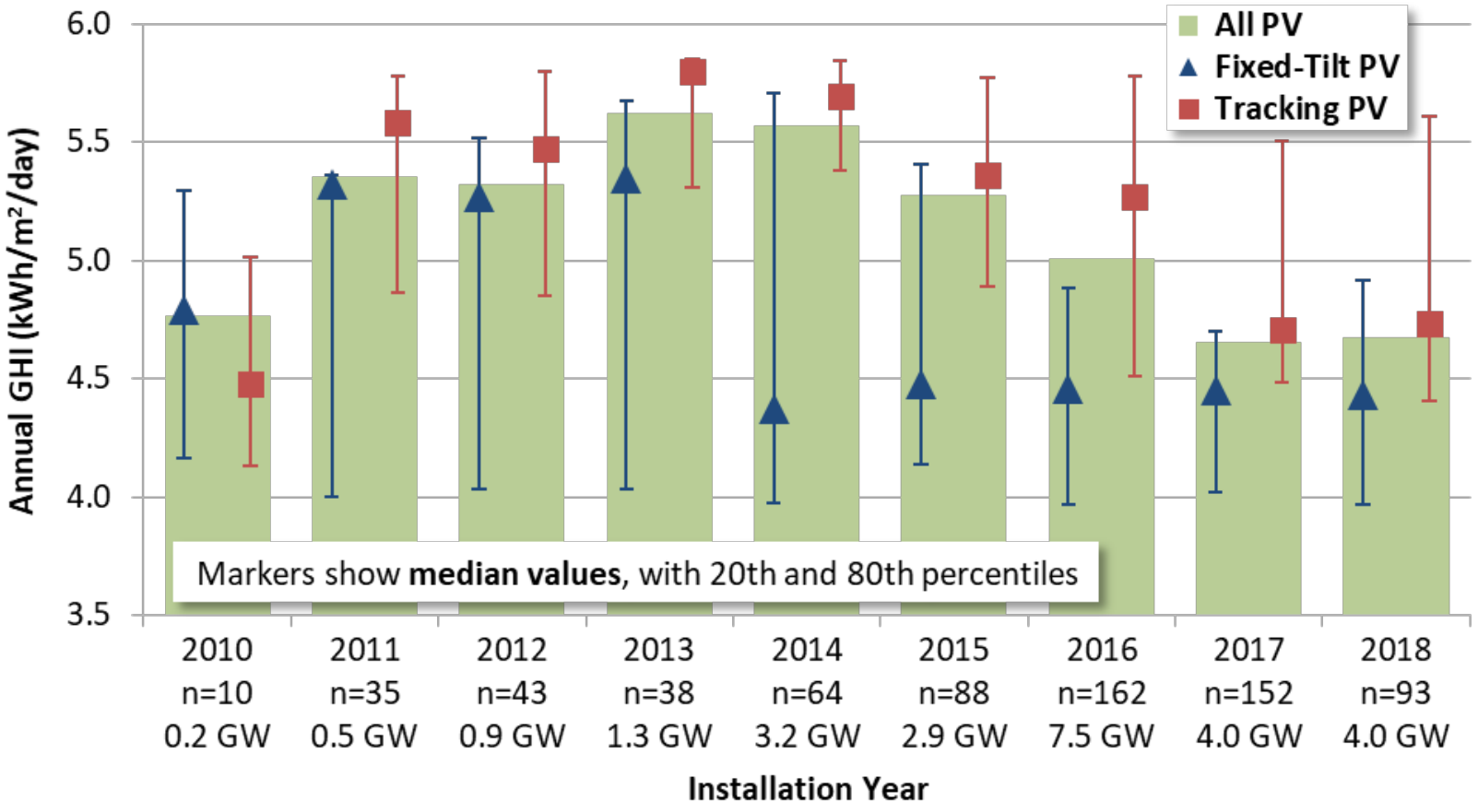


Utility-Scale PV is now well-represented throughout the nation with the exception of Midwestern states in the "wind belt."

Fixed-tilt projects (in particular c-Si) have been built in lower-insolation regions, primarily along the east coast.

Tracking projects ( ) started out in the Southwest but have increasingly spread throughout the country, north to Washington, Idaho, and Minnesota, and northeast to Virginia.

Utility-Scale Solar is increasingly built at lower-insolation sites



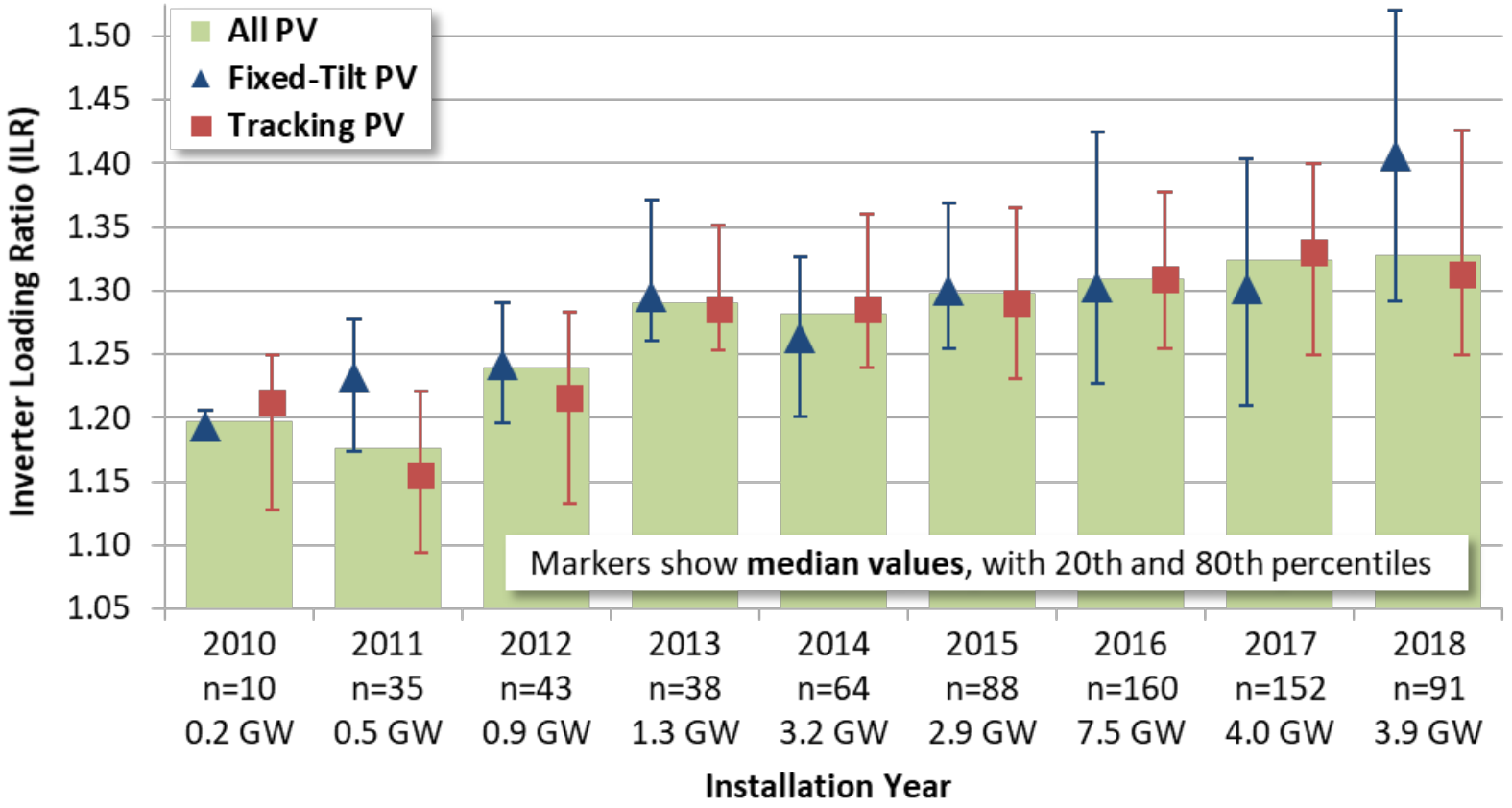
The median solar resource (measured in long-term global horizontal irradiance—**GHI**) at new project sites has decreased since 2013 as the market expands to less-sunny states but stabilized in 2018.

Fixed-tilt PV is increasingly relegated to lower-insolation sites (note the decline in its **80th percentile**), while tracking PV is pushing into those same areas (note the decline in its **20th percentile**).

Exceptions are fixed-tilt installations in either windy regions (Florida) or on brown-fields / landfill sites.

All else equal, the buildout of lower-GHI sites will dampen sample-wide capacity factors (reported later).

The median inverter loading ratio (ILR) continued to climb, especially for fixed-tilt projects



As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity to enhance revenue and reduce output variability.

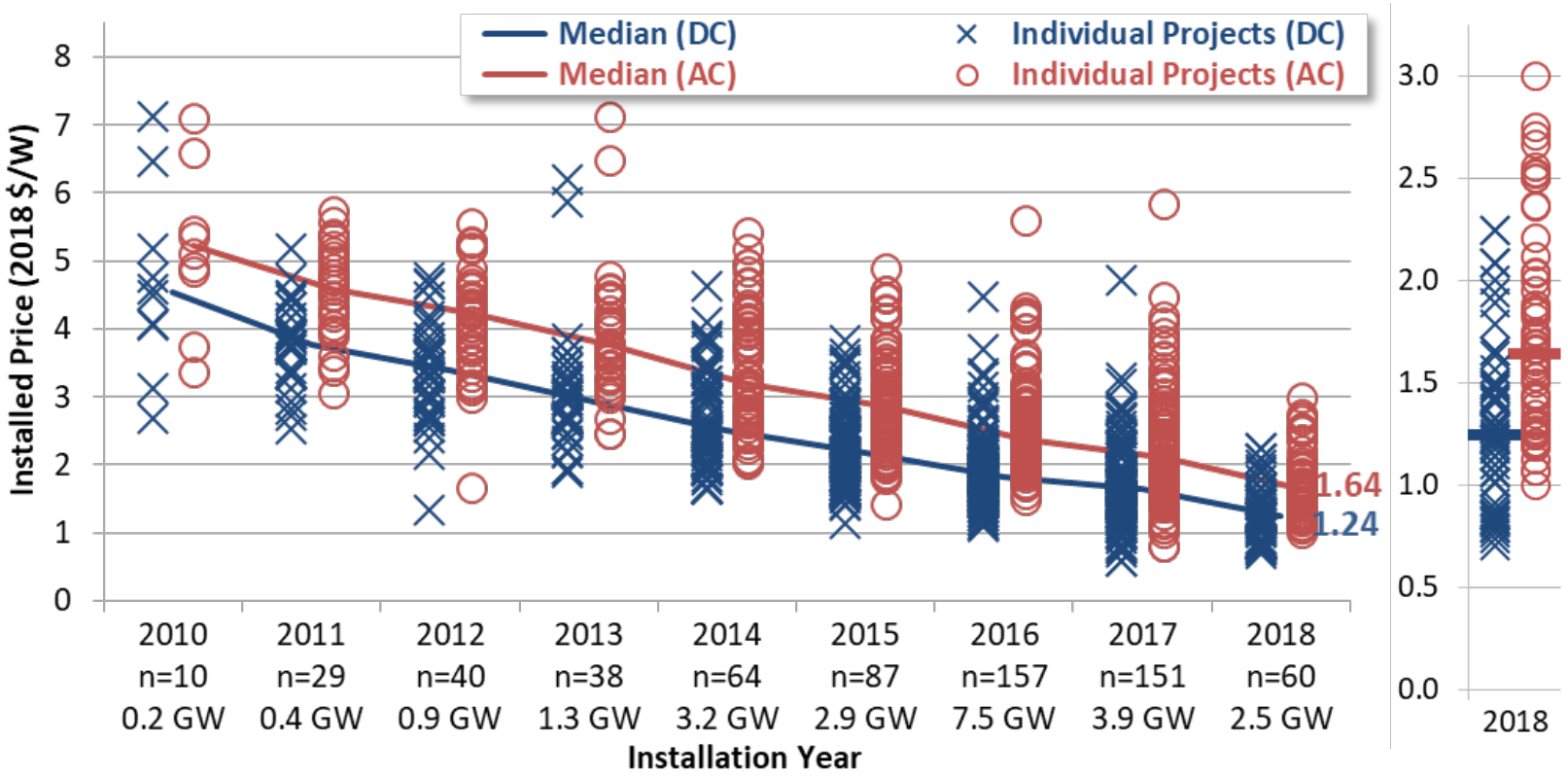
The median inverter loading ratio (**ILR** or DC:AC ratio) increased to 1.33 in 2018, though considerable variation remains (ranging from 1.14 to 1.59).

Fixed-tilt PV has more to gain from a higher ILR than does tracking PV, and 2018 showed a new record lead for fixed-tilt installations (1.41 vs. 1.31 - driven by high ILR projects in Florida, CT, and MD).

All else equal, a higher ILR should boost capacity factors (reported later).

Median installed price of PV has fallen by nearly 70% since 2010, to \$1.6/W_{AC} (\$1.2/W_{DC}) in 2018

PV price sample: 641 projects totaling 22,886 MW_{AC}



The lowest 20th percentile of project prices fell from \$1.7/W_{AC} (\$1.3/W_{DC}) in 2017 to \$1.3/W_{AC} (\$0.9/W_{DC}) in 2018.

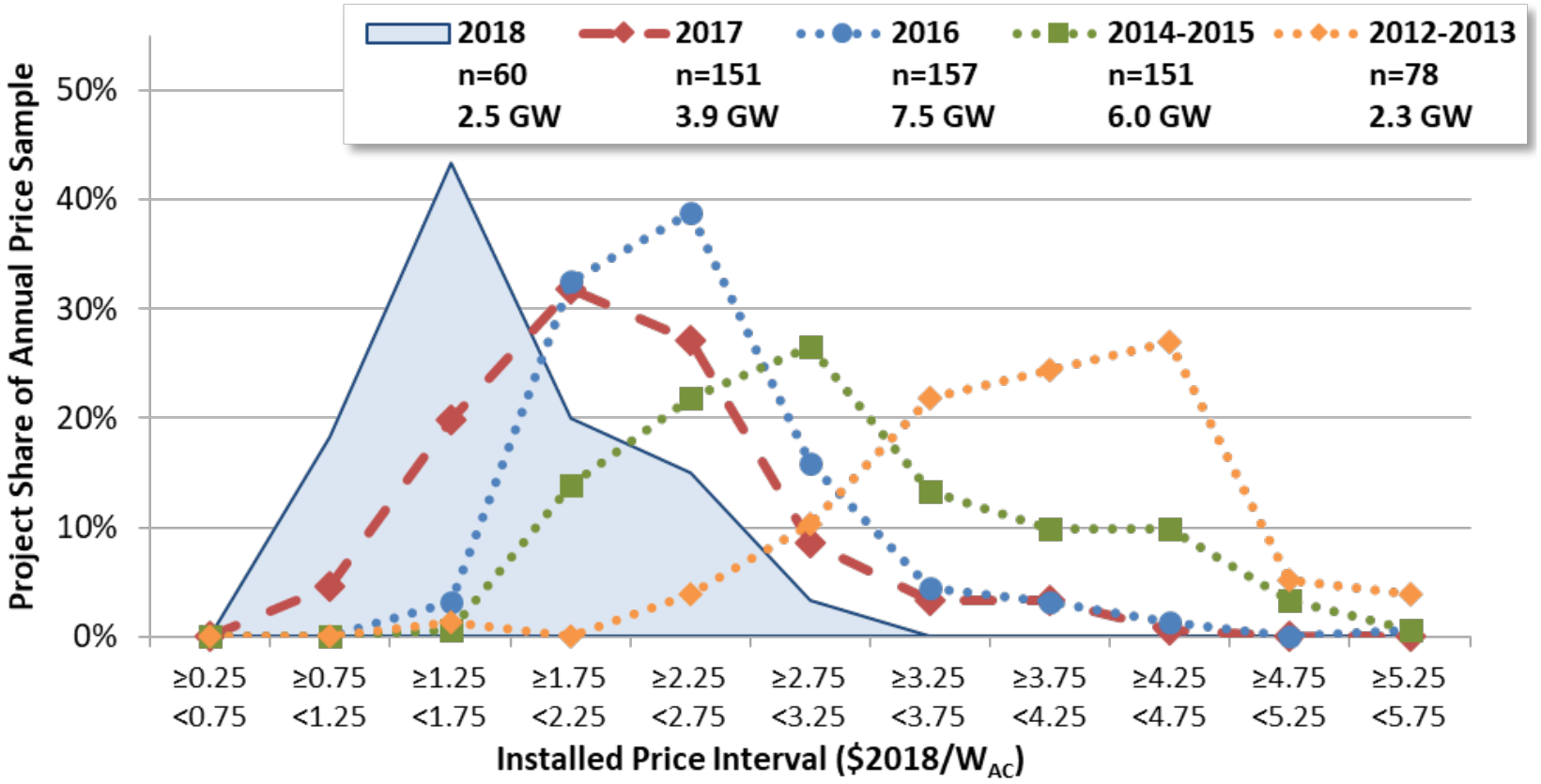
The lowest projects among the 60 data points in 2018 was \$1.0/W_{AC} (\$0.7/W_{DC}).

Historical pricing sample is robust (99% of installed capacity through 2017). 2018 data covers 64% of new projects or 62% of new capacity.

This sample is backward-looking and does not reflect the price of projects built in 2019/2020.

Pricing distributions have narrowed and continuously moved towards lower prices over the last 7 years

PV price sample: 641 projects totaling 22,886 MW_{AC}



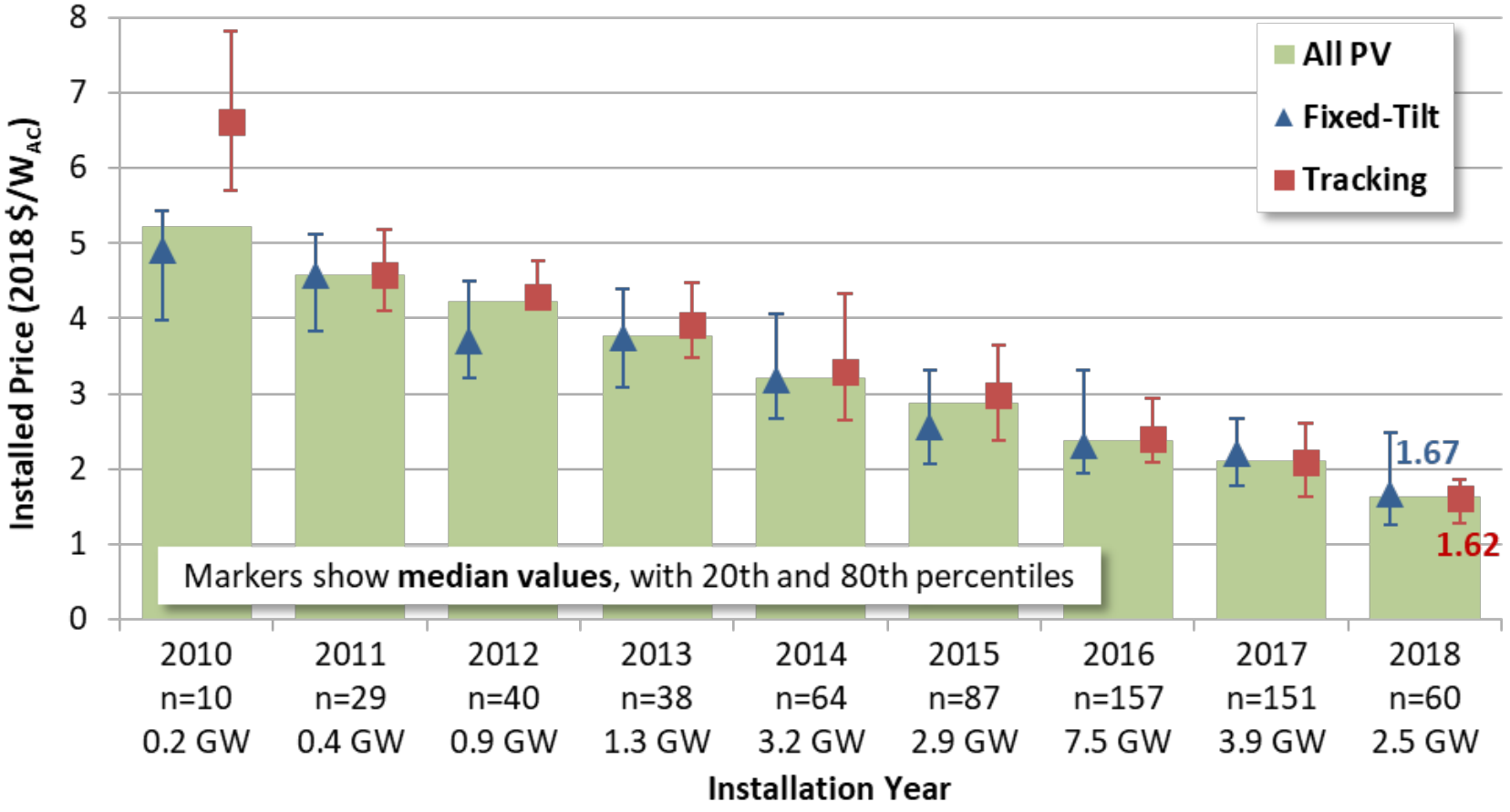
Both medians and modes have continued to fall (i.e., shift towards the left) each year.

Share of relatively high-cost systems decreases steadily each year while share of low-cost systems increases.

Price spread is the smallest in 2018, pointing to a reduction in underlying heterogeneity of prices across all installed projects.

Within our sample, projects with trackers now have lower average upfront costs than fixed-tilt projects

PV price sample: 640 projects totaling 22,880 MW_{AC}



Through 2016, projects with tracking were regularly more expensive (though by varying amounts) than fixed-tilt projects in our sample on average.

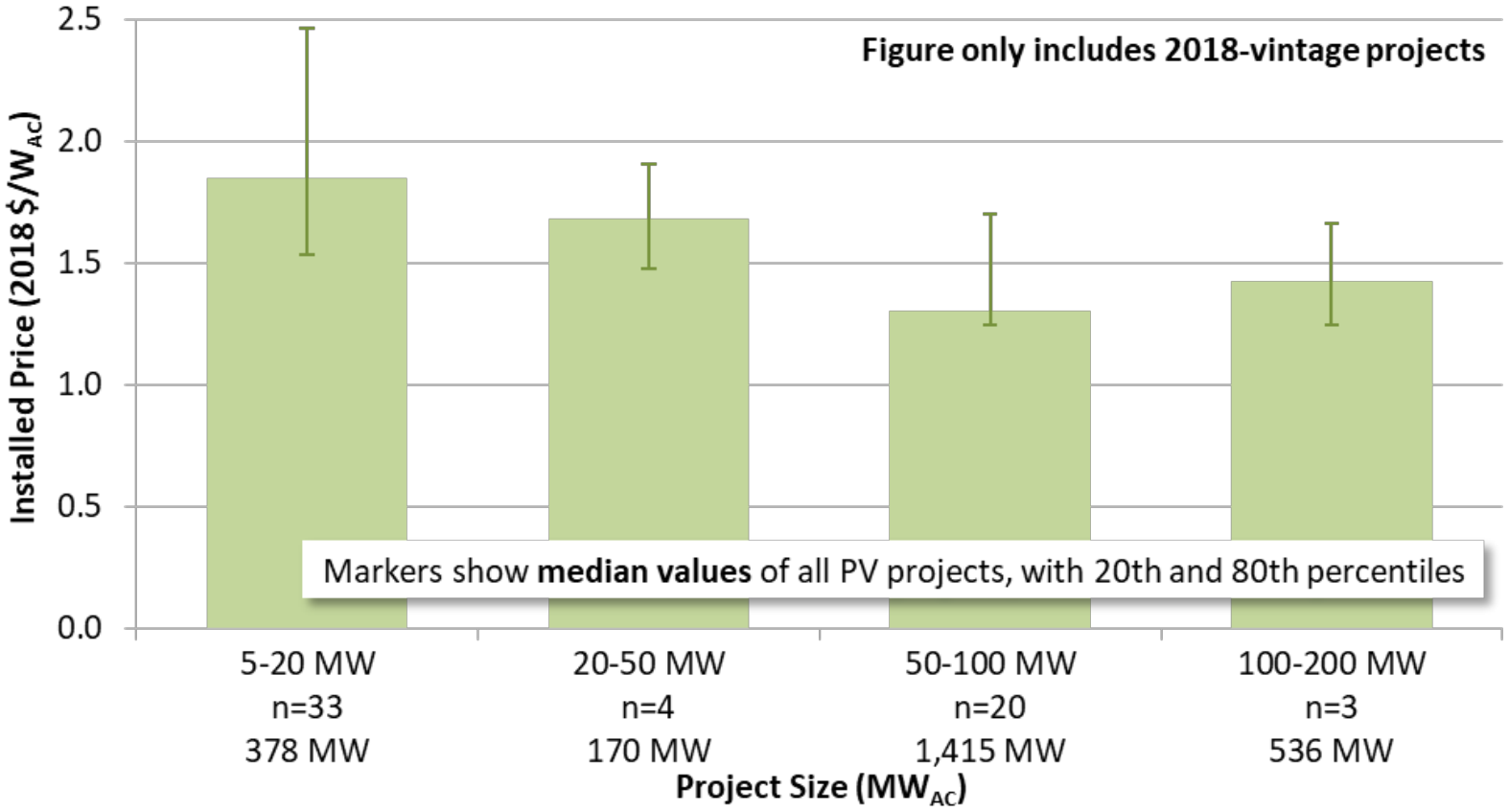
But in both 2017 and 2018, this historical relationship seemingly reversed, with average pricing in 2018 at \$1.7/W_{AC} (\$1.3/W_{DC}) for fixed-tilt projects vs. \$1.6/W_{AC} (\$1.2/W_{DC}) for tracking projects.

This apparent reversal may be driven by challenging construction environments for fixed-tilt projects (e.g., high wind loads, sensitive brown-field sites) as well as sampling issues. However, for any ***individual*** project, using trackers still likely has a higher CapEx than mounting at a fixed-tilt.

Trackers can sustain some amount of higher upfront costs because they deliver more generation.

Within our 2018 sample, large projects enjoy a 30% cost advantage over smaller projects

PV price sample for 2018: 60 projects totaling 2,499 MW_{AC}



Differences in project size could potentially explain pricing variation – we focus only on 2018 for this analysis.

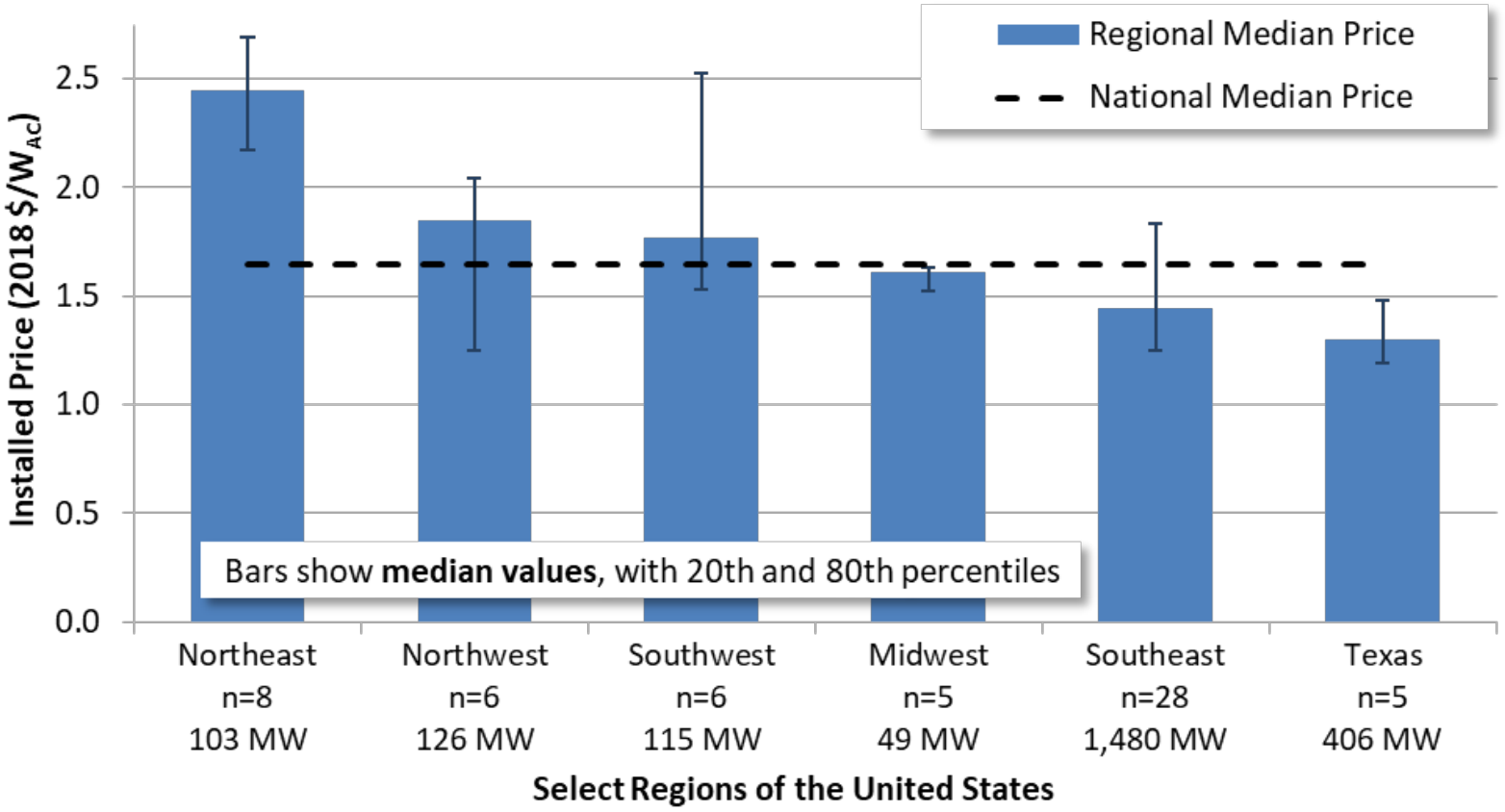
Median price for the first and second size bin (5-50MW_{AC}) is larger than for third and fourth size bin (50-200MW_{AC}) - \$1.74/W_{AC} vs. \$1.32/W_{AC}.

In \$/W_{DC} terms cost decline is even more obvious over first three bins:

- \$1.42/W_{DC} for 5-20MW
- \$1.21/W_{DC} for 20-50MW
- \$1.04/W_{DC} for 50-100MW

Project prices vary by region, newcomers have lower prices

PV price sample for 2018: 60 projects totaling 2,499 MW_{AC}



Note: The regions are defined in the earlier slides with a map of the United States

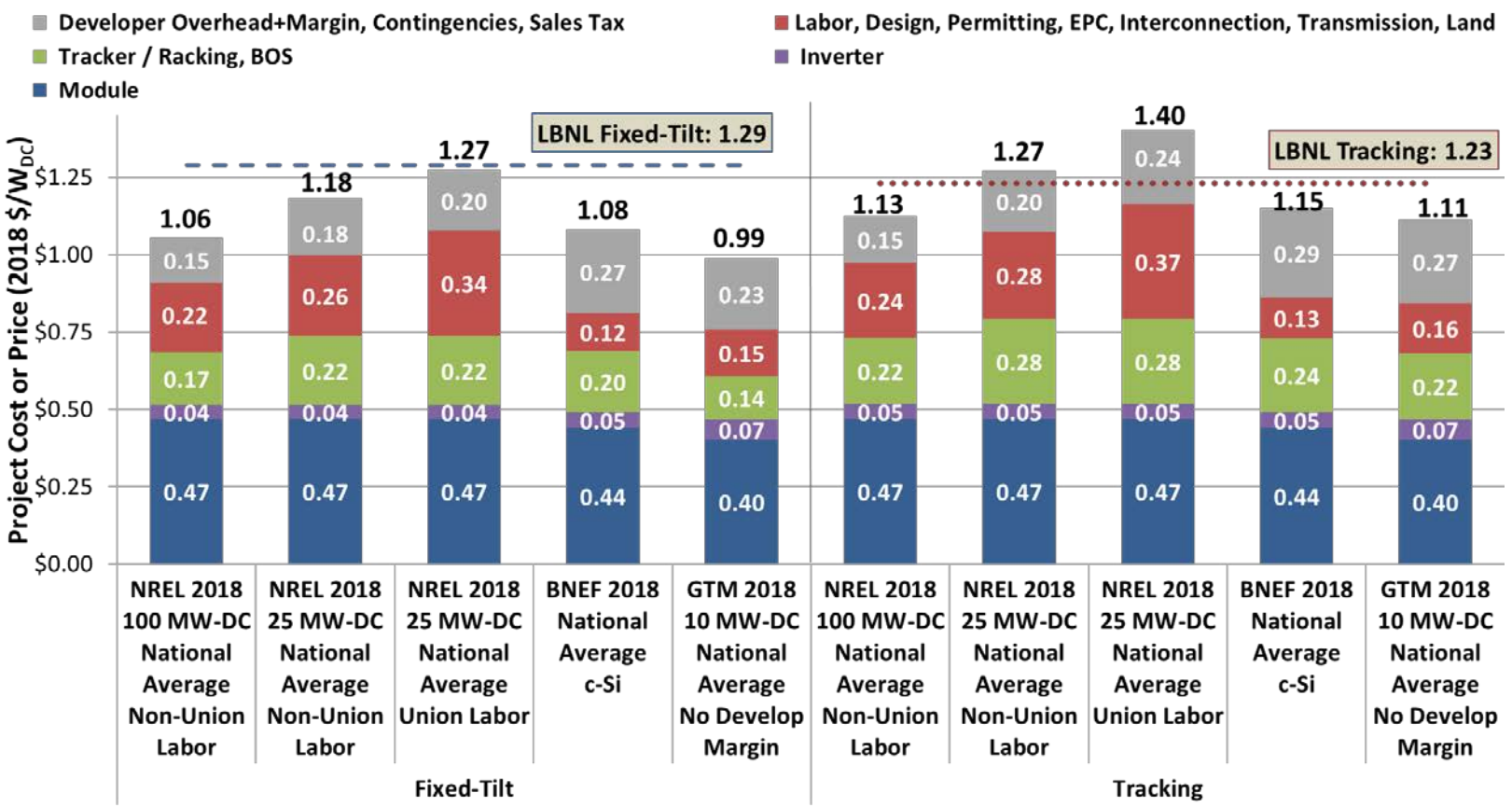
Price differences could be driven in part by technology ubiquity; other factors may include labor costs and share of union labor, land costs, terrain, soil conditions, snow and wind loads, and balance of supply and demand.

The Northeast, Northwest and Southwest seem to be priced above the national median, while the Midwest, Southeast and Texas appear to be lower priced.

Sample size outside of Southeast is very limited (Hawaii and California are excluded due to few observations), so these rankings should be viewed with some caution.

Bottom-up models estimate lower prices than all-in cost reports

PV price sample for 2018: 60 projects totaling 2,499 MW_{AC}



Note: Prices are presented in $/$W_{DC}$ to enable comparison with estimates by NREL, BNEF, and GTM

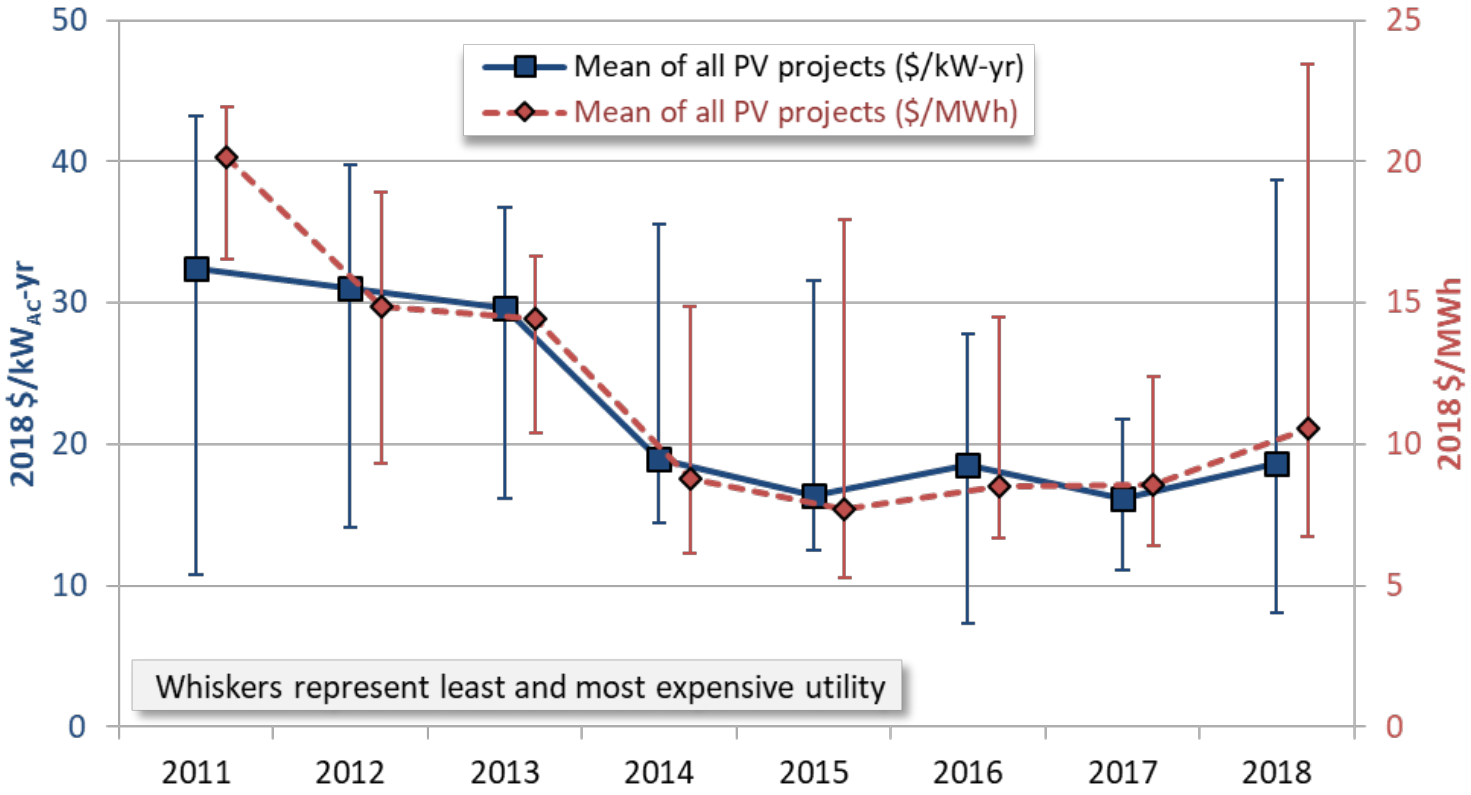
LBNL's top-down estimates reflect a mix of union and non-union labor and span a wide range of project sizes and prices ($0.7-$2.3/W_{DC}).

The median of our fixed-tilt price sample is higher than other price estimates, whereas the median of our tracking price sample falls within the range of other estimates.

Some of the price delta may be due to differences in the defined system boundaries and time horizon (e.g. under construction vs. operation date). For example, GTM (Wood Mackenzie) represents only turnkey EPC costs and excludes interconnection, and transmission costs, as well as developer overhead, fees, and profit margins.

Operation and Maintenance (O&M) costs broaden in range

O&M Cost sample: 48 projects totaling 919 MW_{AC}



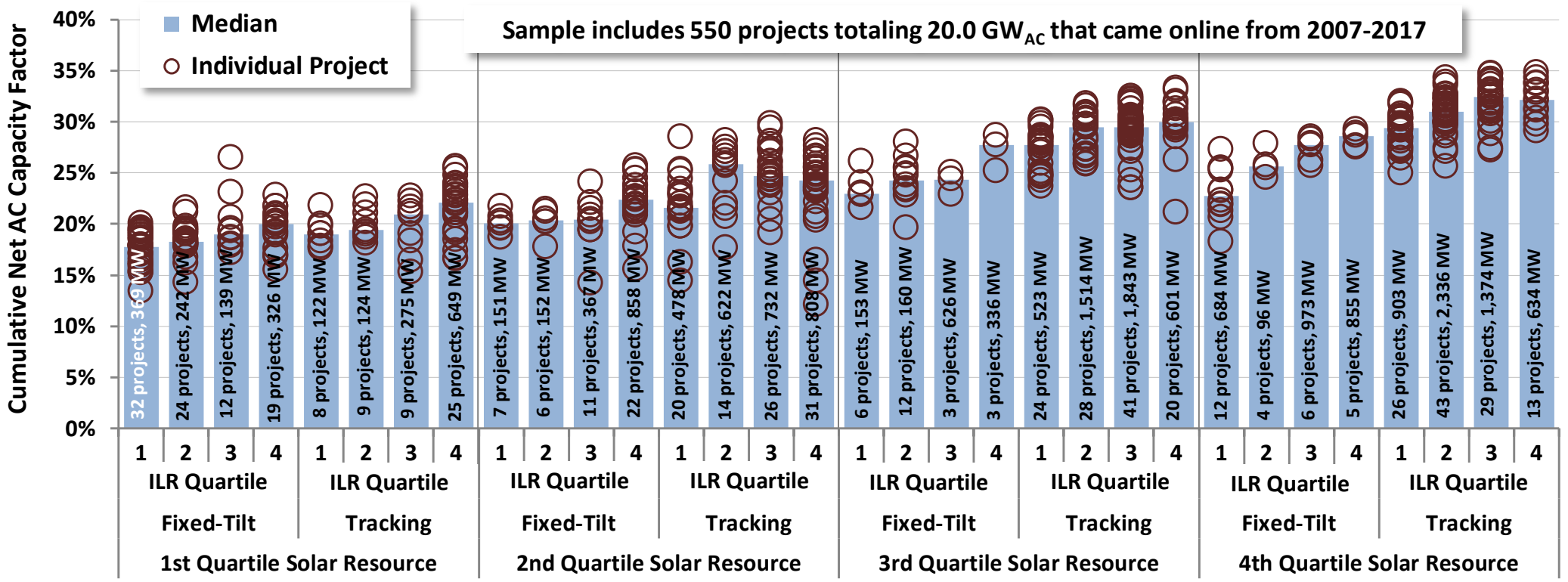
Cost Scope (per guidelines for FERC Form 1):
- Includes supervision and engineering, maintenance, rents, and training
- Excludes payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead

11 utilities report solar O&M costs for projects with ≥1 full operational year by 2018 and a mix of technologies (tracking vs. fixed tilt, module type).

Average O&M costs for the cumulative set of PV plants have declined from about \$32/kW_{AC}-year (or \$20/MWh) in 2011 to about \$18/kW_{AC}-year (\$10.6/MWh) in 2018.

Overall cost range among utilities has spread relative to earlier years as our sample has grown in 2018, perhaps reflecting different reporting practices by utilities.

25.0% average sample-wide PV net capacity factor (cumulative), but with large project-level range from 12.1%-34.8%

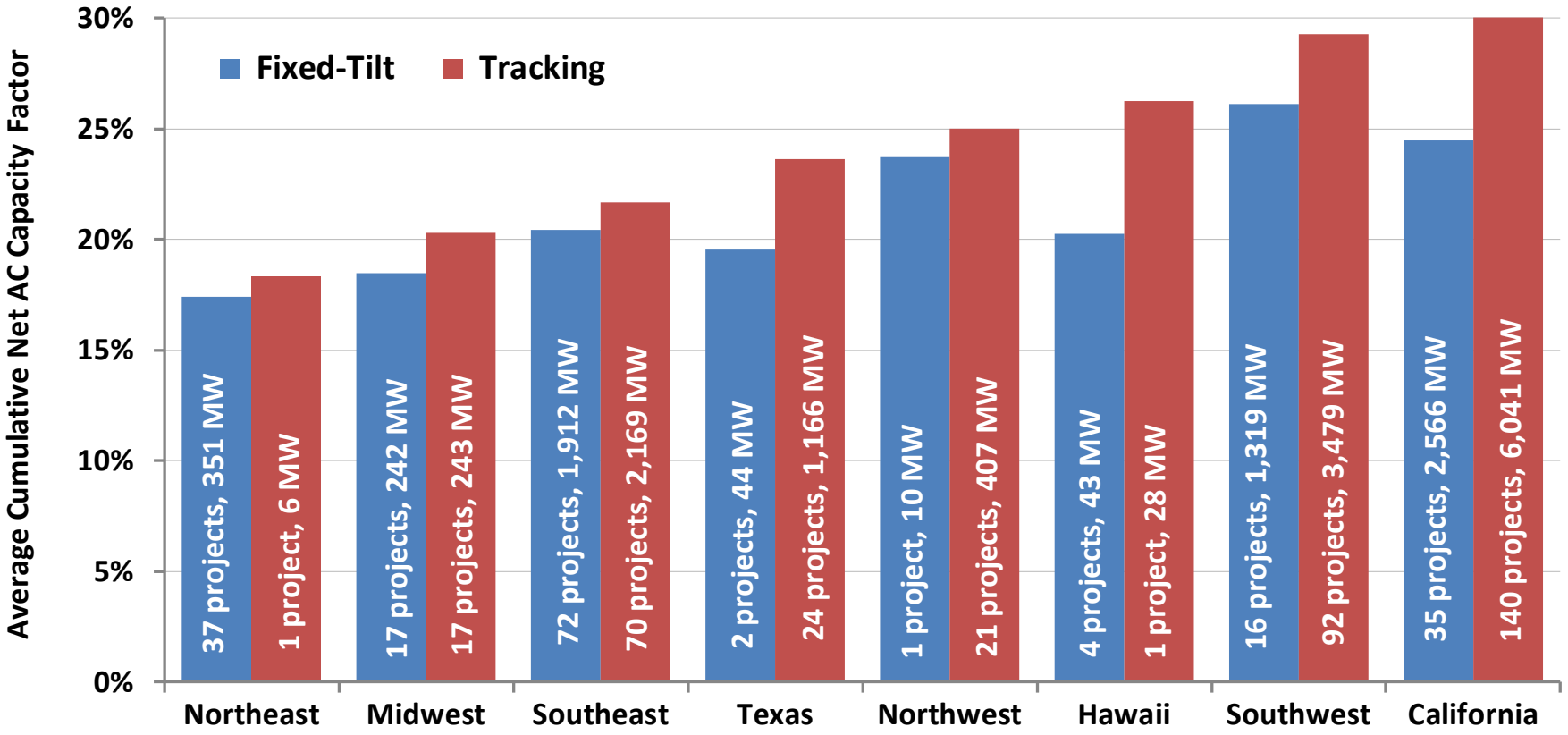


Project-level variation in PV capacity factor driven by:

- **Solar Resource (GHI)**: Strongest solar resource quartile has a ~9 percentage point higher capacity factor than lowest resource quartile
- **Tracking**: Adds 2-5 percentage points to capacity factor on average, depending on solar resource quartile
- **Inverter Loading Ratio (ILR)**: Highest ILR quartiles have on average ~3 percentage point higher capacity factors than lowest ILR quartiles

Tracking boosts net-capacity factors by up to 5% in high-insolation regions

PV Performance sample: 550 projects totaling 20,024 MW_{AC}

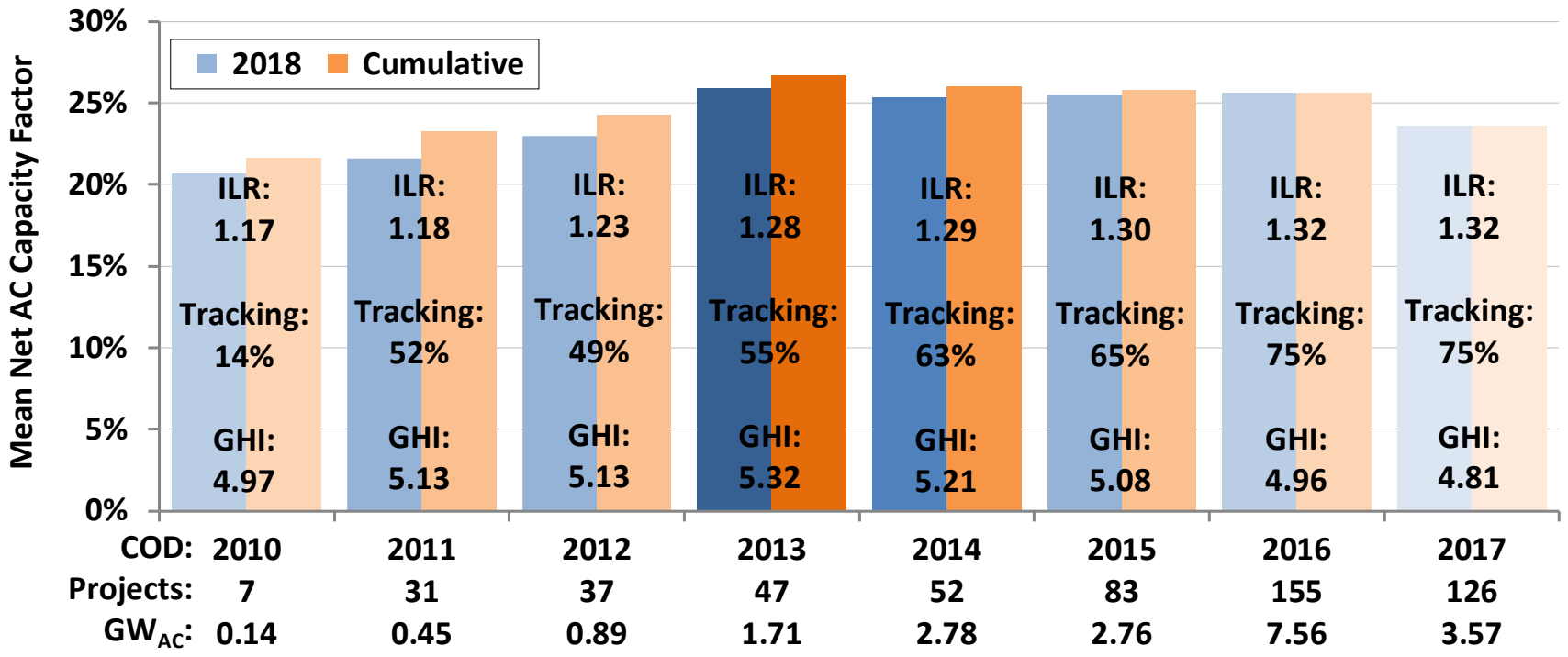


Not surprisingly, capacity factors are highest in California and the Southwest, and lowest in the Northeast and Midwest.

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.

Note: The regions are defined in the earlier slides with a map of the United States

Since 2013, competing drivers have gradually reduced average capacity factors by project vintage



Recent flat-to-declining trend is not necessarily negative, but rather a sign of a market that is expanding geographically into less-sunny regions
(as indicated by changes to GHI, portrayed both numerically and via shading intensity)

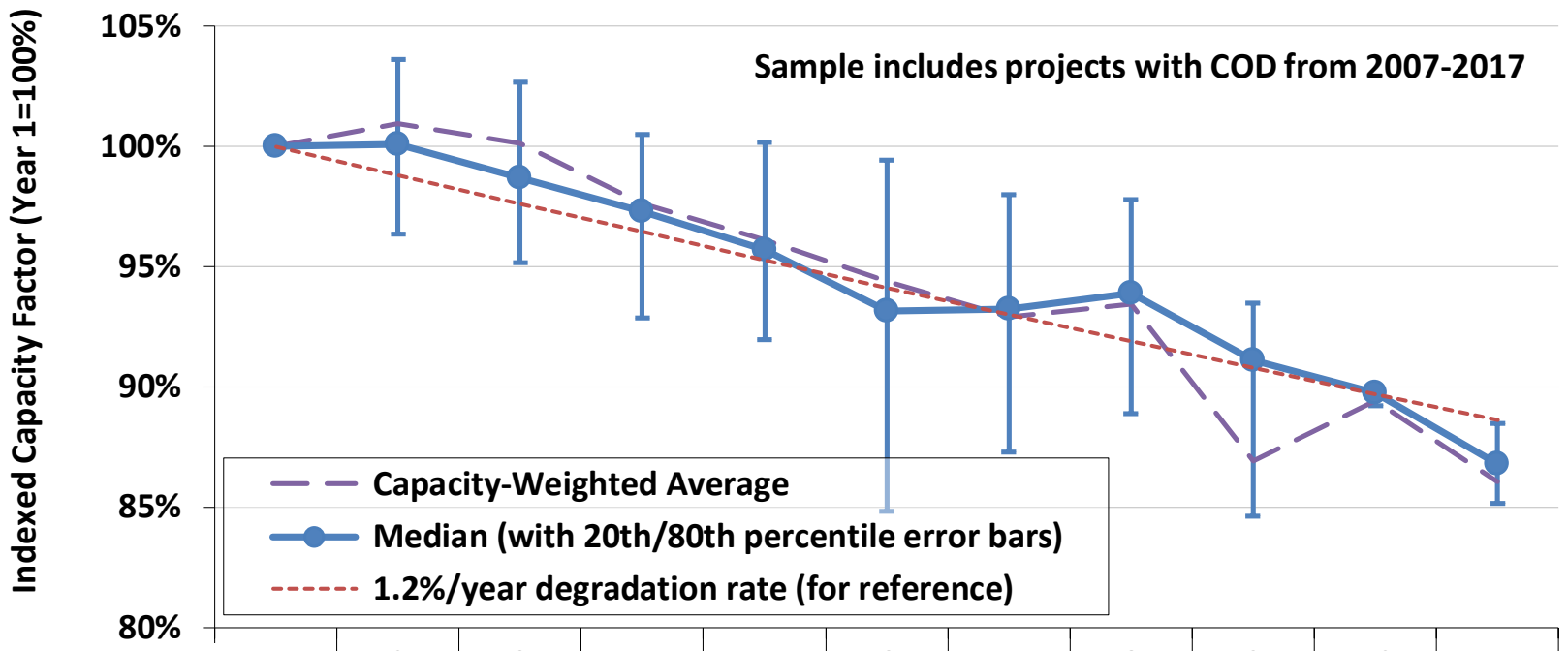
Average capacity factors increased from 2010- to 2013-vintage projects due to an increase in:

- ILR (from 1.17 to 1.28)
- tracking (from 14% to 55%)
- average site-level GHI (from 4.97 to 5.32 kWh/m^2/day)

But trends in tracking and GHI were at odds from 2013- to 2016-vintage projects, resulting in capacity factor stagnation (on average)

2017-vintage projects match 2016-vintage on both ILR and tracking, but GHI has declined further, resulting in a 2 percentage point drop in average capacity factor (from 25.6% down to 23.6%)

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



Years post-COD:	1	2	3	4	5	6	7	8	9	10	11
Sample projects:	541	411	262	181	128	81	44	13	6	3	2
Sample MW_{AC}:	19,876	16,256	8,757	6,070	3,278	1,567	675	227	83	29	19

Graph shows indexed capacity factors in each full calendar year following COD. Capacity factors have been normalized to correct for inter-year resource variation.

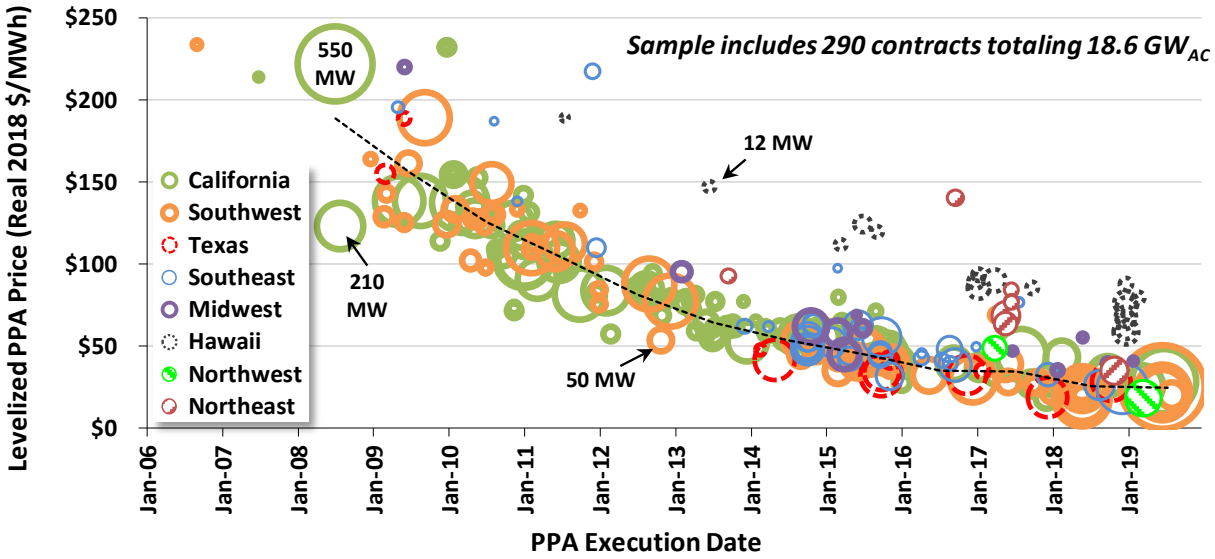
Weather-corrected fleet-wide degradation appears to be running at ~1.2%/year—i.e., higher than commonly assumed.

However, other important factors are not properly controlled for here:

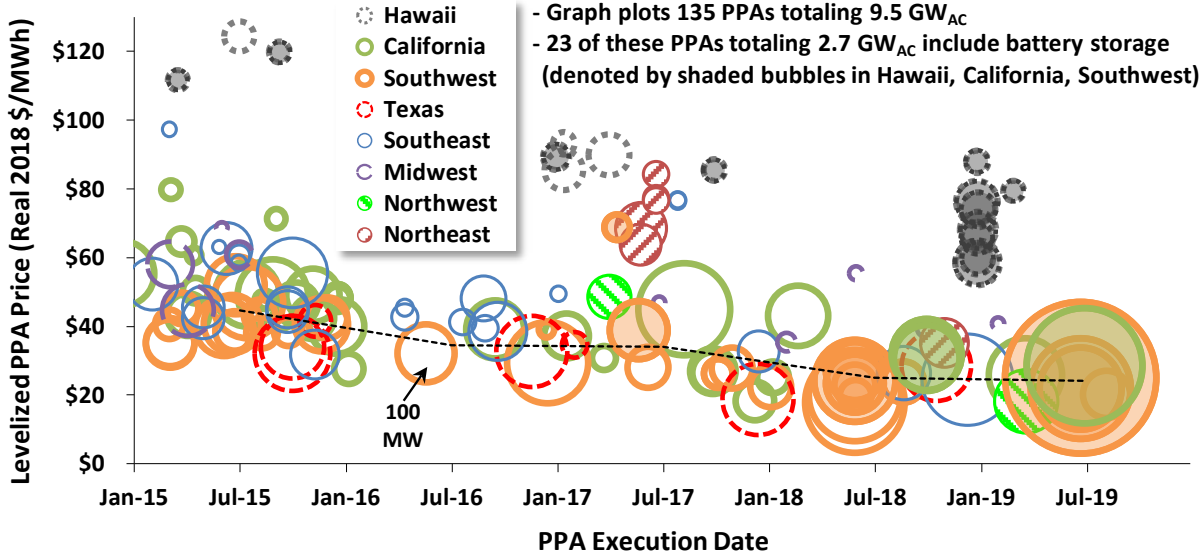
- **curtailment** (1.2% in California and 6.7% in Texas in 2018—see later slides)
- **an inconsistent sample** (which drops off quickly in each successive year)

PPA prices have fallen dramatically, in all regions of the country

Full sample:

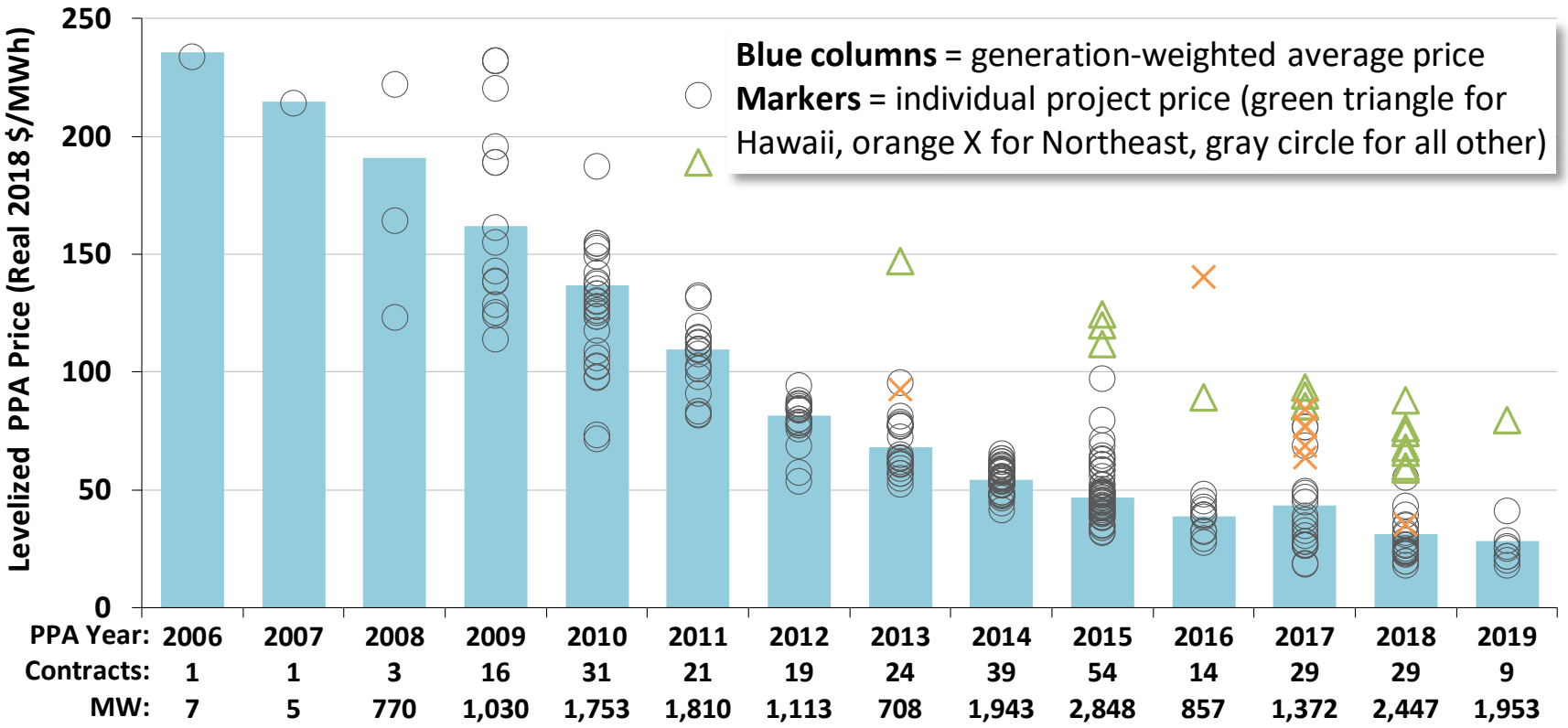


Focus on post-2014 period:



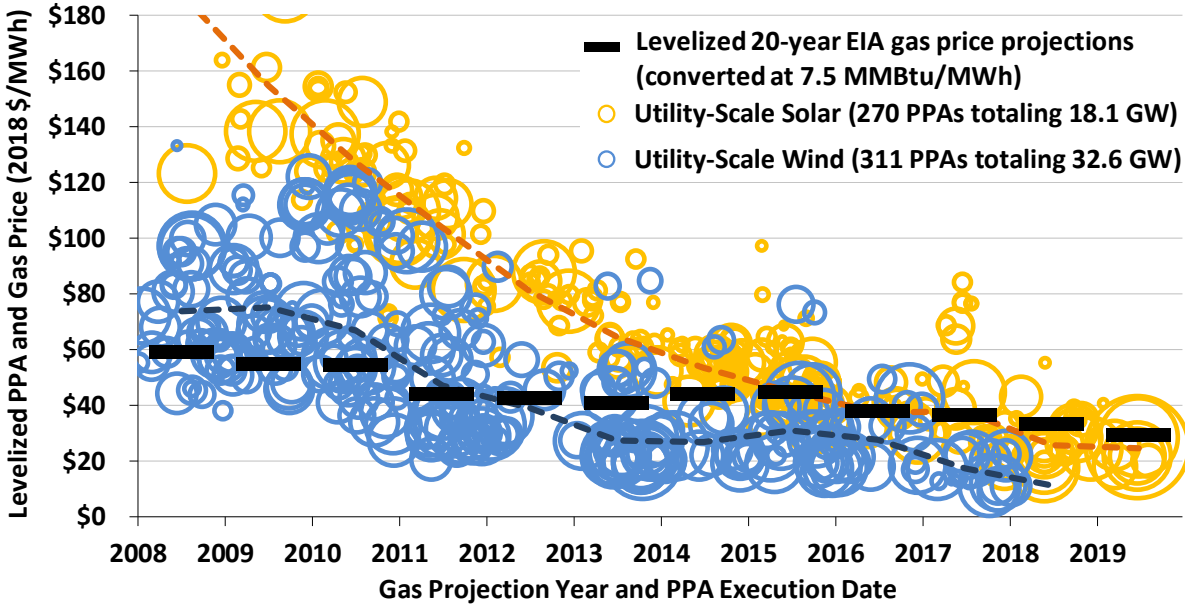
- Power Purchase Agreement (PPA) prices are **levelized** over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors, and are shown in real 2018 dollars
- 27 of 38 post-2017 PPAs in our sample are <$40/MWh, with 21 <$30/MWh and 4 even <$20/MWh (all levelized, in 2018 dollars)
- 23 PPAs featuring PV plus medium-duration battery storage (4-5 hour, shaded in right graph) do not seem to be priced at much of premium to their PV-only counterparts
- Hawaii projects show a consistent and significant premium of ~$40/MWh over the mainland
- Smaller projects (e.g., 20-50 MW) are seemingly no less competitive
- >80% of the sample is currently operational

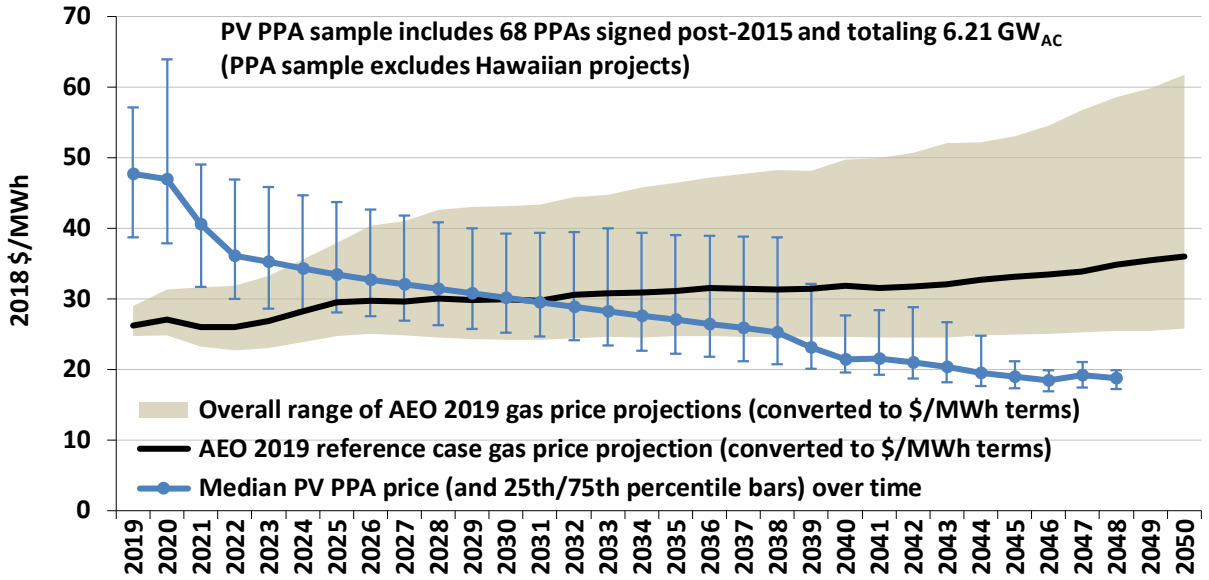
On average, levelized PPA prices have fallen by >80% since 2009



- This figure presents the same data as the previous slide, but in a different way: each marker is an individual contract, and the blue columns show the average levelized PPA price each year
- Green triangles are Hawaiian projects and orange x's are Northeastern projects (both tend to be higher cost)
- Steady drop in the average PPA price over time
  - 2017 reversal due to a prevalence of Hawaii and Northeast PPAs
  - Decline resumed in 2018

Despite record-low PPA prices, solar faces stiff competition from both wind and natural gas

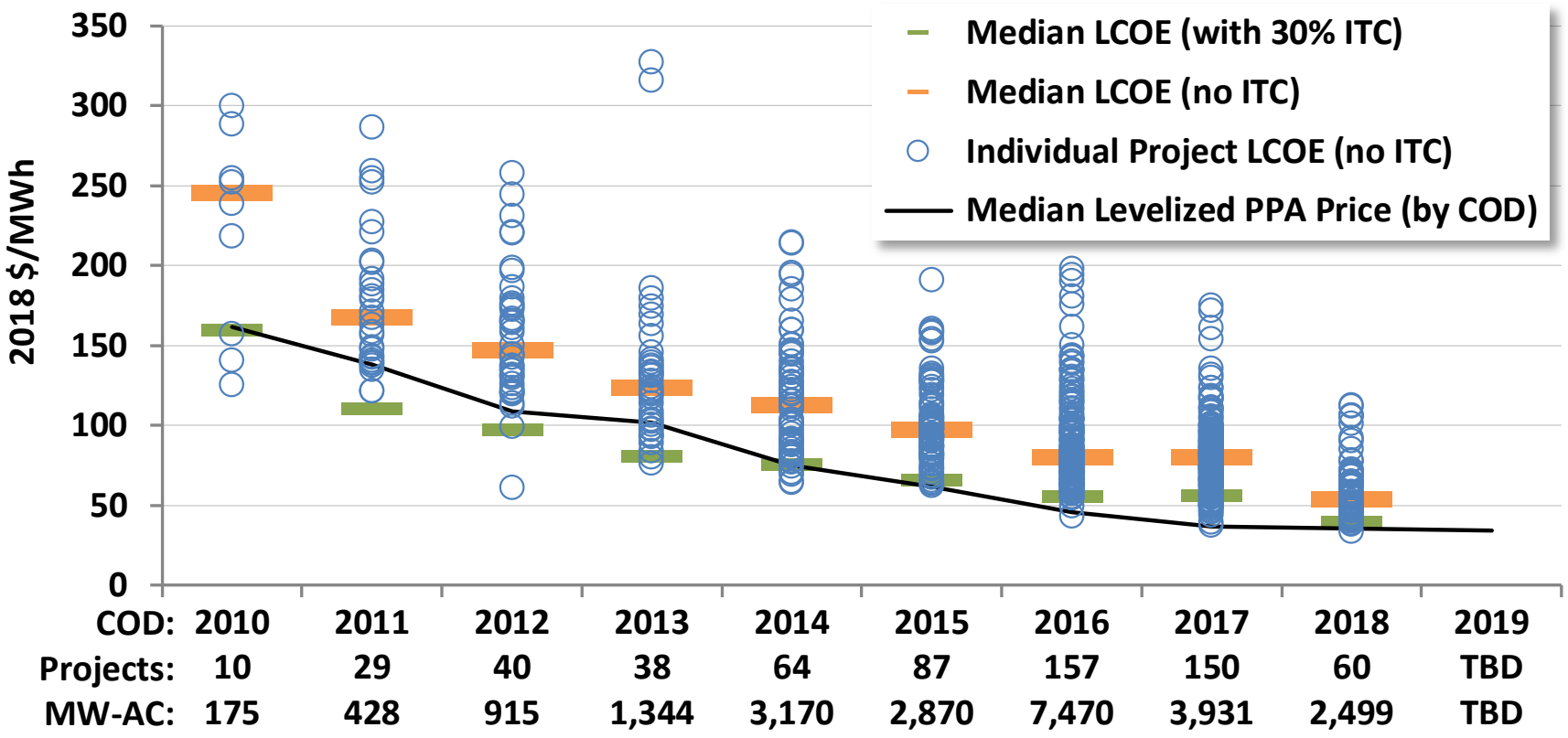




- Left graph shows that solar PPA prices have nearly closed the gap with wind, and both are competitive with levelized gas price projections
- Right graph compares recent solar PPA prices to range of gas price projections from AEO 2019. Although solar PPAs signed post-2015 are priced higher than the cost of burning fuel in an ***existing*** combined-cycle natural gas unit (NGCC), over longer terms PV is potentially more competitive (depending on what happens to the price of natural gas), and can help protect against fuel price risk.
- PV PPAs are priced to recover *both* capital *and* other ongoing operational costs (for an NGCC, this would add another ~$21-$50/MWh to fuel costs). With declining battery costs, PV+storage is becoming a serious competitor to new gas-fired peaker plants (that have higher heat rates and thus higher fuel costs than those depicted in the right graph).

Levelized PPA prices track the LCOE of utility-scale PV

LCOE sample: 640 projects totaling 22,876 MW_{AC}



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.

Median estimates of LCOE track median PPA prices (shown here by COD rather than by execution date) reasonably well, suggesting a fairly competitive PPA market.

PV + battery projects have proliferated within our PPA price sample

State	Project Name	Project Sponsor	Project Offtaker	Actual or Expected COD (PV/Wind/Battery)	Capacity (MW-AC) PV	Capacity (MW-AC) Wind	Capacity (MW-AC) Battery	Battery Storage Hours	Battery Storage MWh	Battery:PV Capacity Ratio	Levelized PPA Price (2018 $/MWh)
AL	Redstone Arsenal	SunPower	Redstone Arsenal	Dec-17	10	0	1	2.0	2	10%	?
AR	Searcy	NextEra	Entergy (owner)	Dec-21	100	0	30	?	?	30%	#N/A
AZ	Pinal Central	NextEra	SRP	Apr-18	20	0	10	4.0	40	50%	68.9
AZ	Wilmot	NextEra	TEP	Dec-19	100	0	30	4.0	120	30%	40.7
AZ	Redhawk(?)	First Solar	APS	Jun-21	65	0	50	2.7	135	77%	?
CA	Desert Harvest II	EDF-RE	SCPPA	Dec-20	70	0	35	4.0	140	50%	LMP plus $15.25
CA	RE Slate 2	ReCurrent	MBCP and SVCE	Jun-21	150	0	45	4.0	180	30%	≤31.8
CA	BigBeau	EDF-RE	MBCP and SVCE	Dec-21	128	0	40	4.0	160	31%	≤30.9
CA	?	NextEra	Kaiser Permanente	Dec-20/Dec-21/Dec-21	131	50	110	?	?	84%	?
CA	Sonrisa	EDPR	SJCE & EBCE	Dec-22	200	0	40	4.0	160	20%	?
CA	Raceway	sPower	EBCE	Dec-22	125	0	80	2.0	160	64%	?
CA	Eland	8minute Solar	LADWP/Glendale	Dec-23	400	0	300	4.0	1200	75%	28.5
FL	Babcock	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	10	4.0	40	13%	#N/A
FL	Citrus	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	4	4.0	16	5%	#N/A
FL	Manatee	NextEra/FPL	FPL (owner)	Dec-16/NA/Dec-21	74.5	0	409	2.2	900	549%	#N/A
HI	Kapaia	Tesla	KIUC	Apr-17	13	0	13	4.0	52	100%	119.8
HI	Lawai	AES	KIUC	Oct-18	20	0	20	5.0	100	100%	89.4
HI	Kekaha	AES	KIUC	Sep-19	14	0	14	5.0	70	100%	85.5
HI	West Loch	HECO	HECO (owner)	Oct-19	20	0	20	4.0	80	100%	#N/A
HI	Waikoloa Solar	AES	Hawaiin Electric	Jul-21	30	0	30	4.0	120	100%	59.8
HI	Kuihelani Solar	AES	Hawaiin Electric	Jul-21	60	0	60	4.0	240	100%	58.5
HI	West Oahu	AES	Hawaiin Electric	Sep-21	12.5	0	12.5	4.0	50	100%	79.5
HI	Hoohana Solar 1	174 Power Global	Hawaiin Electric	Dec-21	52	0	52	4.0	208	100%	76.3
HI	Mililani I Solar	Clearway	Hawaiin Electric	Dec-21	39	0	39	4.0	156	100%	68.0
HI	Waiawa Solar	Clearway	Hawaiin Electric	Dec-21	36	0	36	4.0	144	100%	74.0
HI	Hale Kuawehi	Innergex	Hawaiin Electric	Jun-22	30	0	30	4.0	120	100%	65.8
HI	Paeahu	Innergex	Hawaiin Electric	Jun-22	15	0	15	4.0	60	100%	87.9
MN	Ramsey/Athens	Engie/NextEra	Connexus	Dec-18	10	0	15	2.0	30	150%	?
NV	Battle Mountain	Cypress Creek	NV Energy	Jun-21	101	0	25	4.0	100	25%	22.3
NV	Dodge Flat	NextEra	NV Energy	Dec-21	200	0	50	4.0	200	25%	23.1
NV	Fish Springs Ranch	NextEra	NV Energy	Dec-21	100	0	25	4.0	100	25%	25.9
NV	Townsite	Capital Dynamics	Munis/Co-op	Dec-21	180	0	90	4.0	360	50%	?
NV	Arrow Canyon	EDF-RE	NV Energy	Dec-22	200	0	75	5.0	375	38%	21.8
NV	Southern Bighorn	8minute Solar	NV Energy	Sep-23	300	0	135	4.0	540	45%	21.9
NV	Gemini	Quinbrook/Arevia	NV Energy	Dec-23	690	0	380	3.8	1460	55%	25.1
OK	Skeleton Creek	NextEra	WFEC	Dec-23/Dec-19/Dec-23	250	250	200	4.0	800	80%	?
OR	Wheatridge	NextEra	PGE	Dec-21/Dec-20/Dec-21	50	300	30	4.0	120	60%	?
TX	Castle Gap	Luminant	Luminant (owner)	Jun-18/NA/Dec-18	180	0	10	4.2	42	6%	#N/A

Table includes metadata on 38 PV hybrid projects in 11 states totaling 4.3 GW_{AC} of PV and 2.6 GW_{AC} of battery capacity (all with 2-5 hours of storage)

- ❑ <10 of these projects are currently online
- ❑ These 38 projects are just a small fraction of the >55 GW of PV hybrid projects that were in the interconnection queues at the end of 2018

Most projects in the table are greenfield projects, but there are 3 retrofits, with many more to come

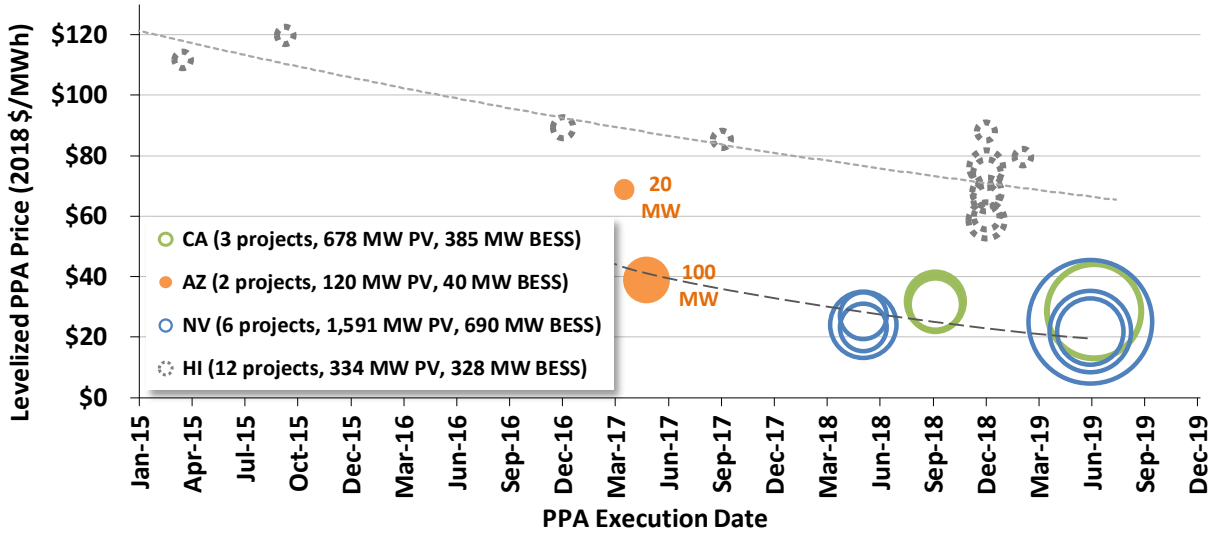
Three projects include wind power

The ratio of battery-to-PV capacity varies widely, reflecting specific circumstances of each project

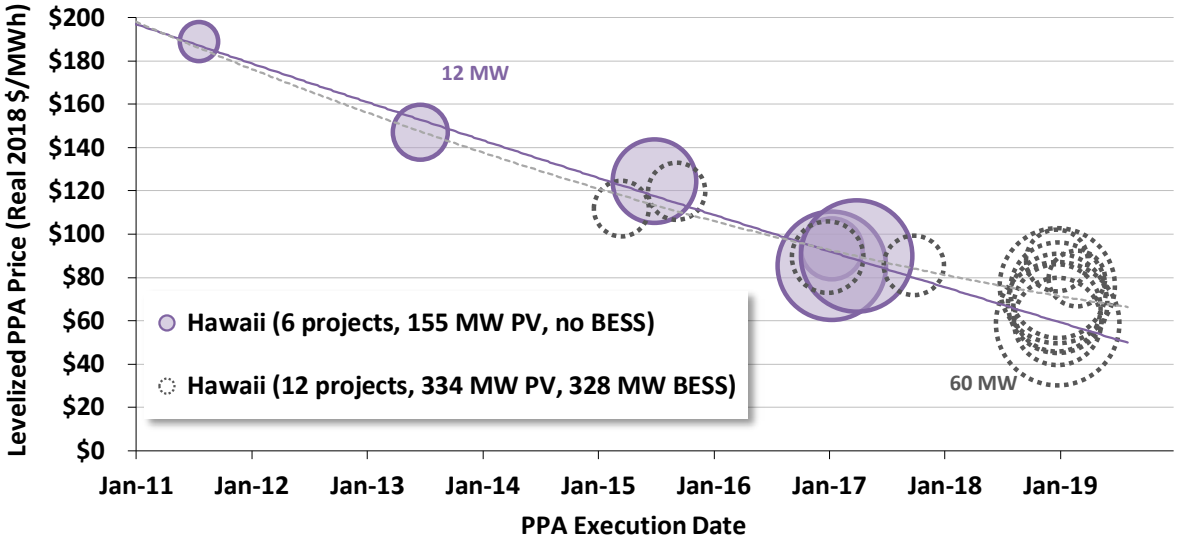
- ❑ For example, Hawaii is at 100% in all 12 cases, reflecting an isolated island grid with high solar penetration

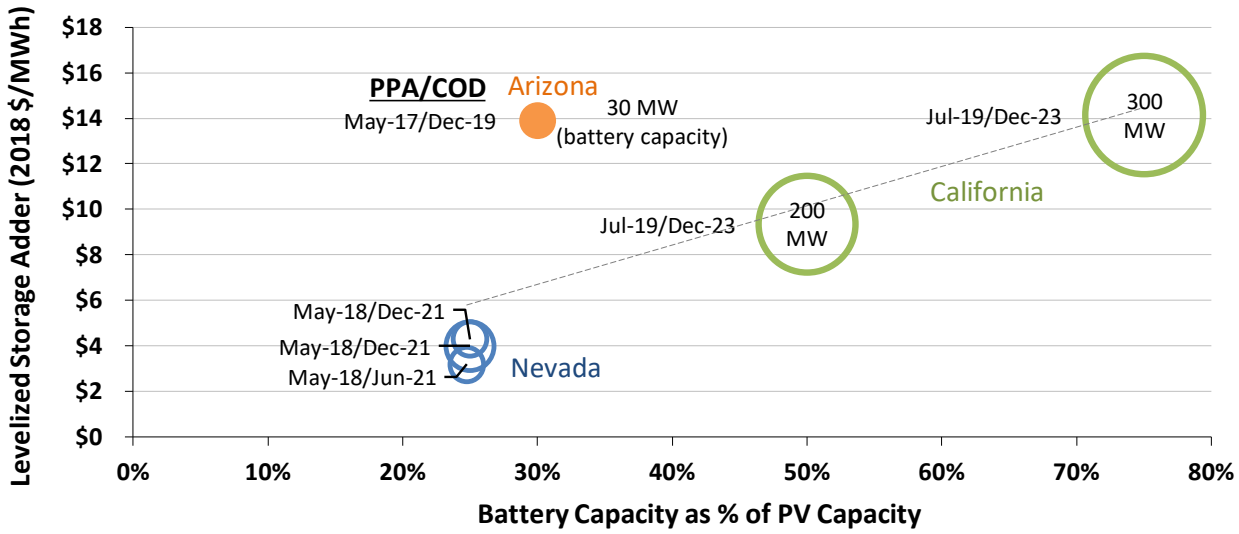
Among the sub-sample of 32 hybrid projects with PPAs, storage is compensated in several different ways (i.e., no consensus yet)

PPA price details from sample of 23 PV hybrid projects

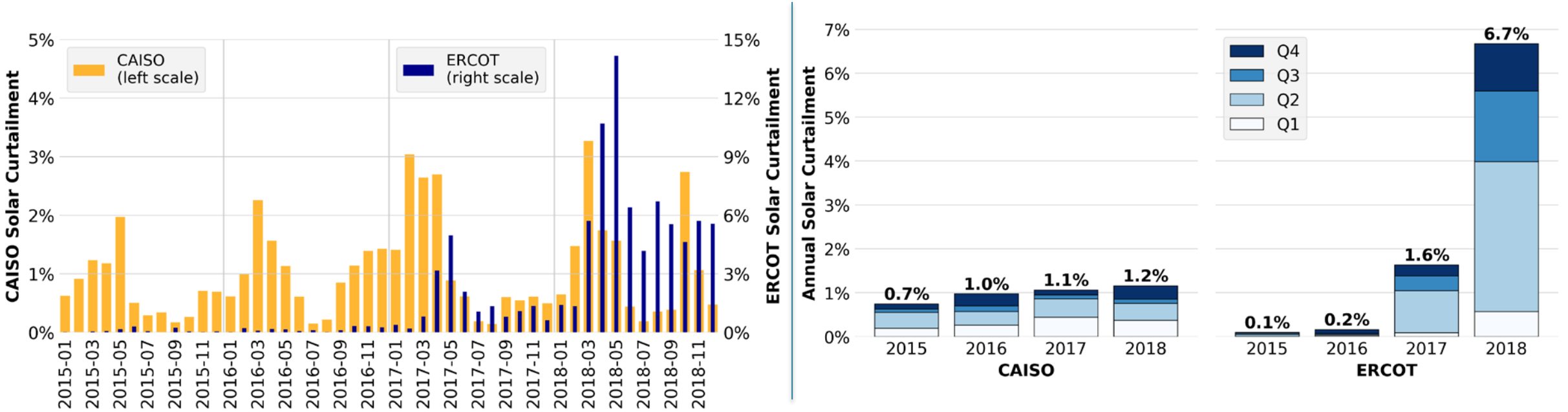


- Top left graph shows levelized PPA prices from just the 23 PV hybrid projects for which we have data
- Notable premium for Hawaii projects (top left) seems to be general rather than related to storage (bottom left)…
- …particularly given that the storage price adder (below) increases linearly with the battery-to-PV capacity ratio (which is high in Hawaii, at 100%)





Only two of the seven ISOs currently report solar curtailment: CAISO and ERCOT

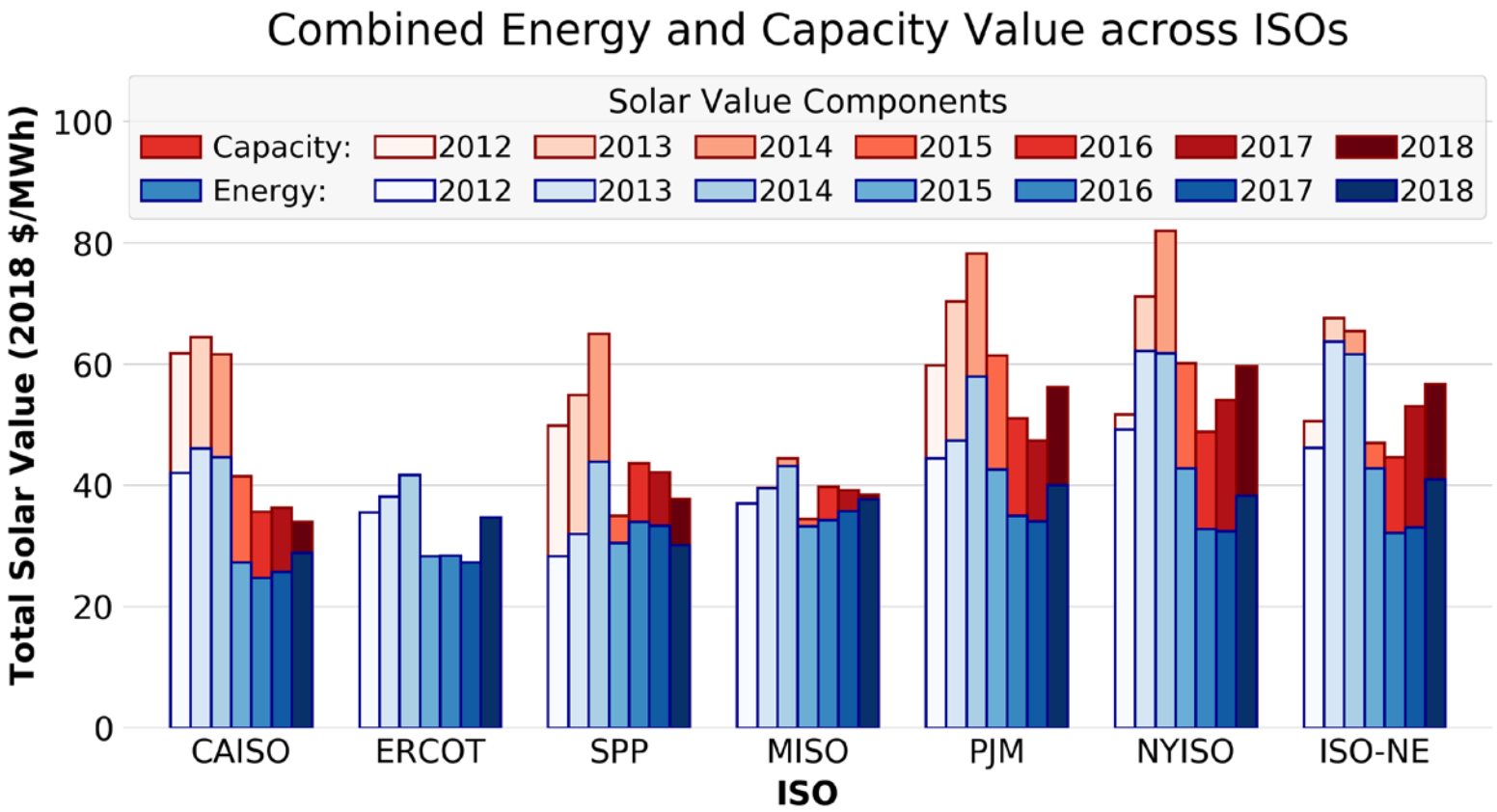


CAISO: 432 GWh of solar curtailed in 2018, equivalent to the annual output of a hypothetical 173 MW_{AC} PV project operating at an average CA capacity factor of 28.5% (which would have been 29.0% if not for curtailment).

ERCOT: 278 GWh of solar curtailed in 2018, equivalent to the annual output of a hypothetical 142 MW_{AC} PV project operating at an average TX capacity factor of 22.3% (which would have been 24.9% if not for curtailment).

Much higher *rate of curtailment* in ERCOT (6.7%) than in CAISO (1.2%) in 2018, even though solar's penetration rate is far lower in ERCOT (~1%) than CAISO (~16%). The curtailment in ERCOT is concentrated among just a few projects caught on the wrong side of transmission congestion in West Texas.

Market value: the other side of the coin



In 2018, market value was lowest in CAISO ($34.1/MWh) and highest in PJM ($56.8/MWh).

Energy value is the product of hourly solar generation and hourly wholesale energy prices in each year.

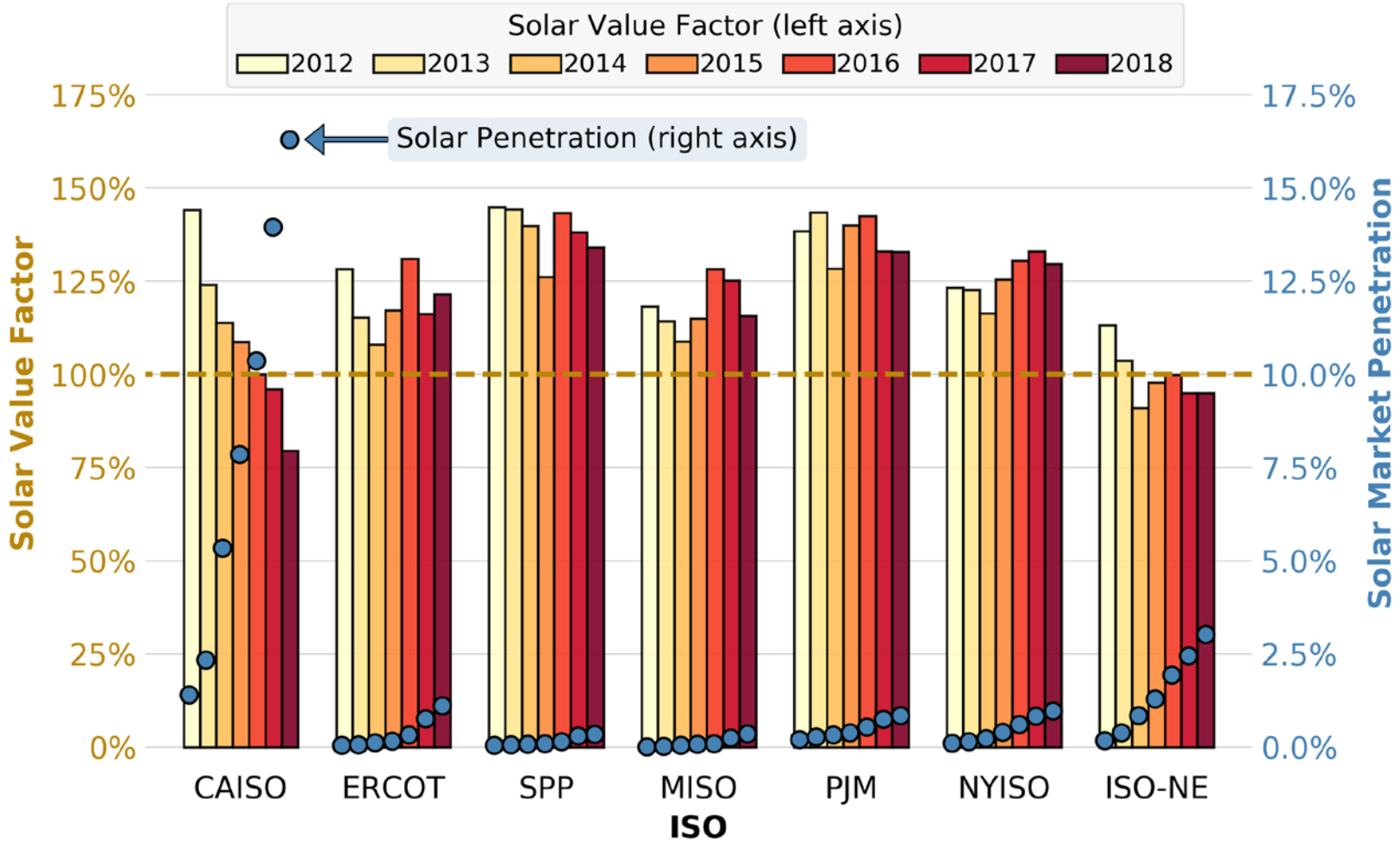
Capacity value uses the same hourly generation to calculate solar's "capacity credit" (according to market rules in place at the time), which is then multiplied by capacity prices .

Total market value is the sum of energy and capacity value (we ignore potential additional value from the sale of RECs and/or ancillary services)

Energy value makes up the bulk of total market value, but capacity value is significant in eastern markets in particular.

Fluctuations across years mostly reflect fluctuations in wholesale power prices, but in CAISO, the visible decline in value over time also reflects increasing solar penetration.

Solar provides above-average value in five of seven ISOs



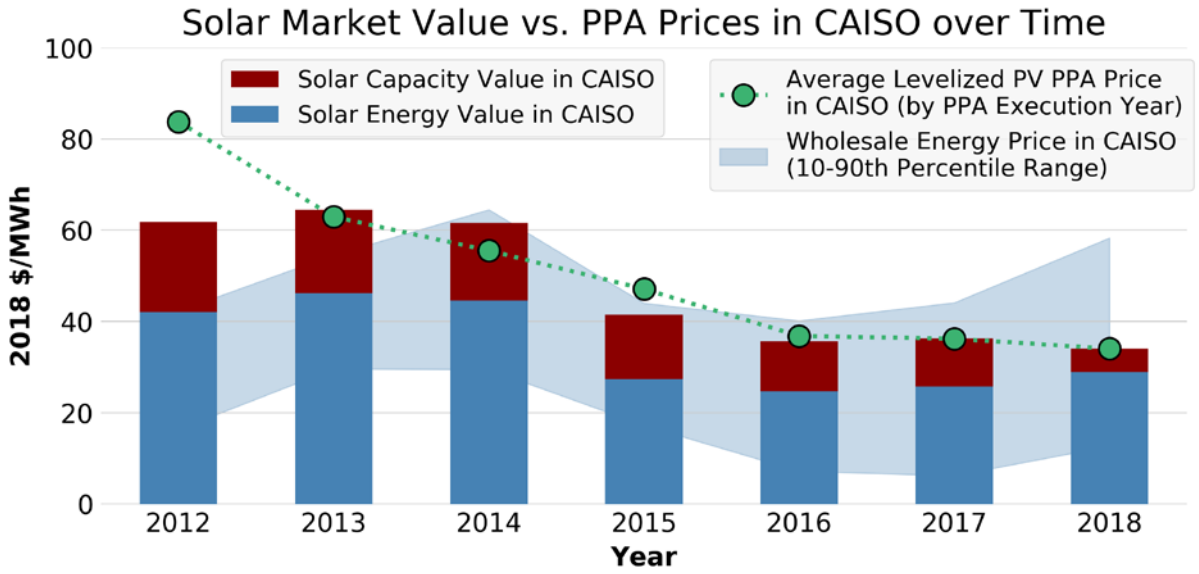
The "Value Factor" is defined as the ratio of solar's total market value (both energy and capacity) to the market value of a "flat block" (i.e., a 24x7 block) of power.

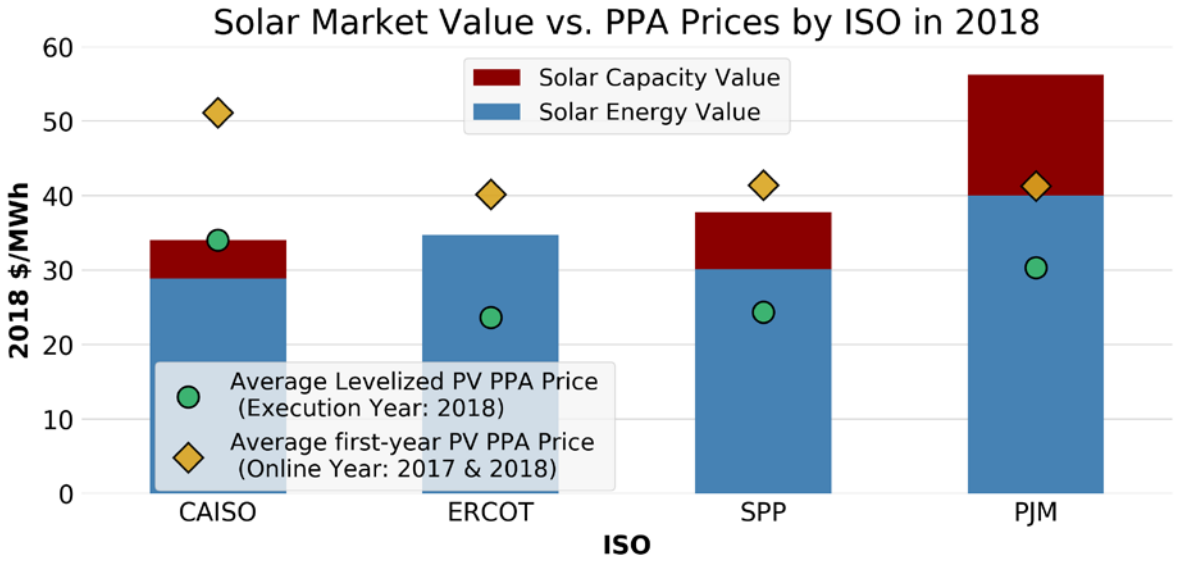
It indicates whether the total revenue captured by solar is higher (>100%) or lower (<100%) than the average wholesale price across all hours.

It controls for fluctuations in energy and capacity prices across years (and across ISOs), and focuses instead on the impact of solar's generation profile (and penetration) on value.

In CAISO and ISO-NE—the two markets with the highest solar penetration rates—solar's Value Factor has dipped below 100% in recent years (and down to 80% in CAISO in 2018).

Reduced by the ITC, solar PPA prices are generally comparable to solar's market value (focusing on energy and capacity value only)





Though solar's market value within CAISO has declined over time, falling PPA prices have largely kept pace since 2013, more or less maintaining solar's competitiveness.

Note: The comparison shown above is imperfect because the PPA prices are forward-looking and levelized over many future years, while the market value estimates are historical and for a single year.

In 2018, ERCOT, SPP, and PJM generally offered higher solar market value than in CAISO, yet with similar or even lower PPA prices, resulting in a superior cost/value tradeoff. This may be one reason why, for the first time ever, California was deposed as the largest solar market in the United States in 2018.

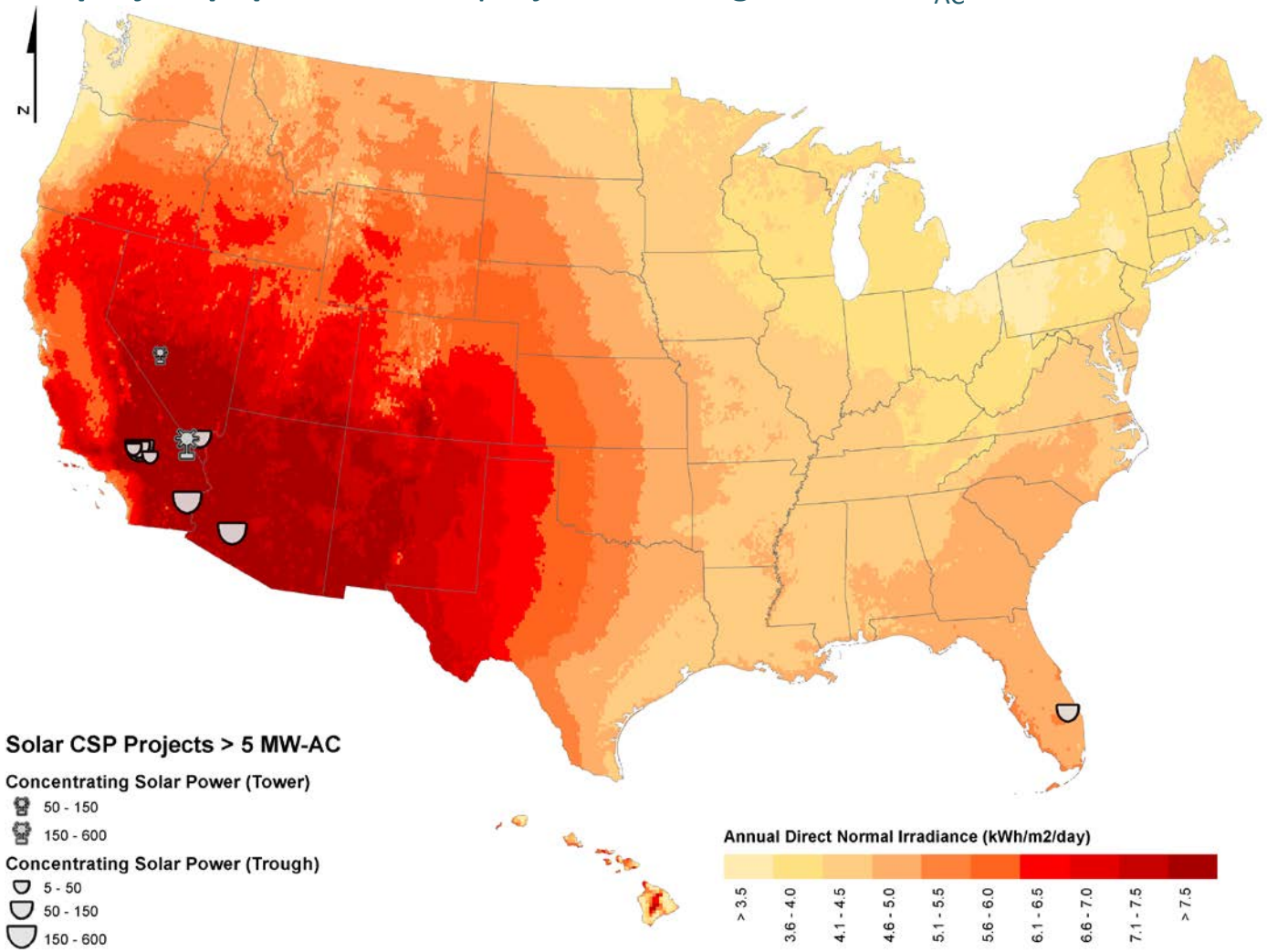
Note: The green PPA price markers in the right graph attempt to address the levelization mismatch (discussed to the left) by showing the average first-year PPA price among projects that came online in 2017 or 2018 (i.e., by comparing single-year prices to single-year value).

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}).

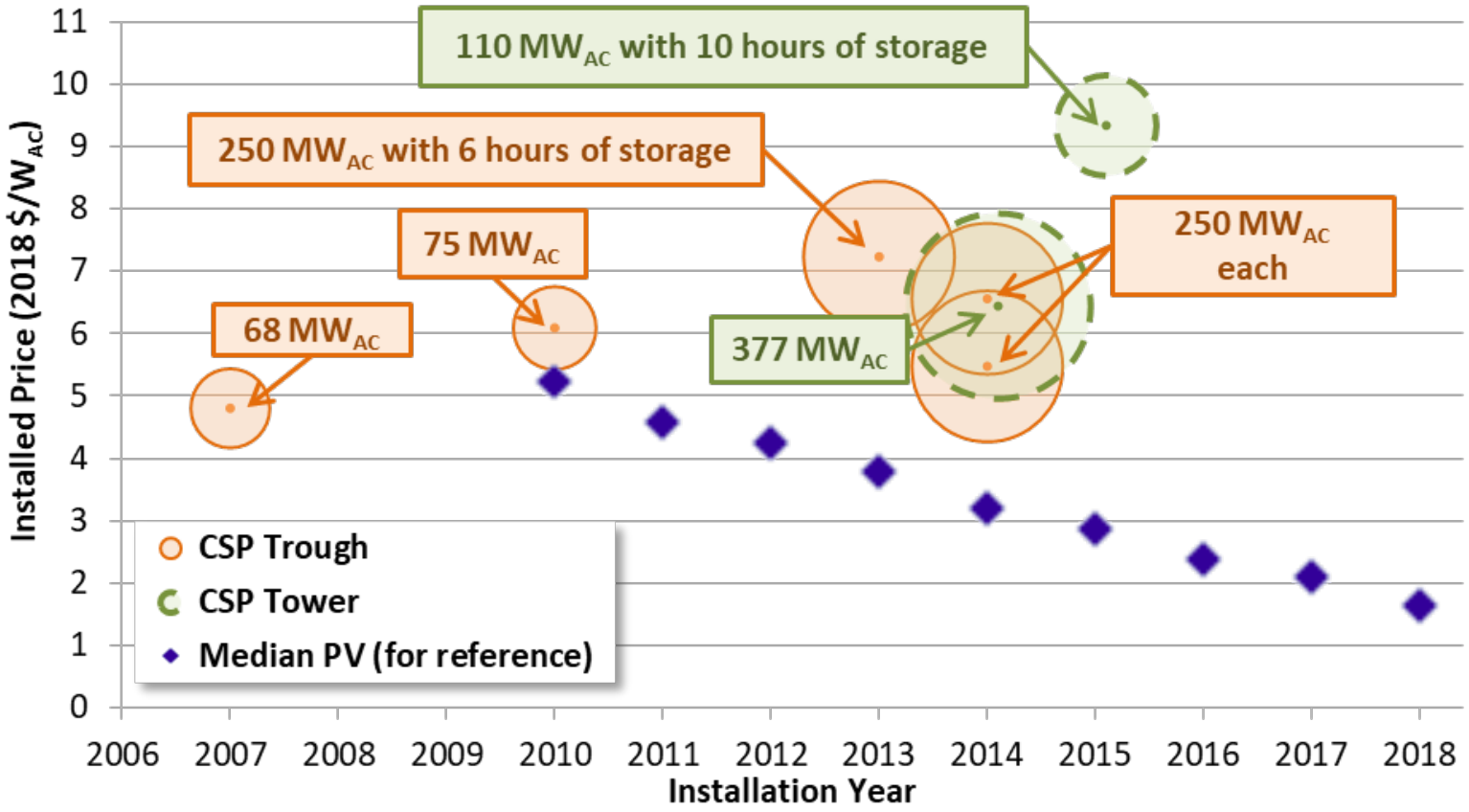
Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors.

The five 2013-2015 projects include:

- 3 parabolic troughs (one with 6 hours of storage) totaling 750 MW_{AC} (net) and
- 2 "power tower" projects (one with 10 hours of storage) totaling 487 MW_{AC} (net).

Not much movement in the installed price of CSP

CSP price sample: 7 projects totaling 1,381 MW_{AC}

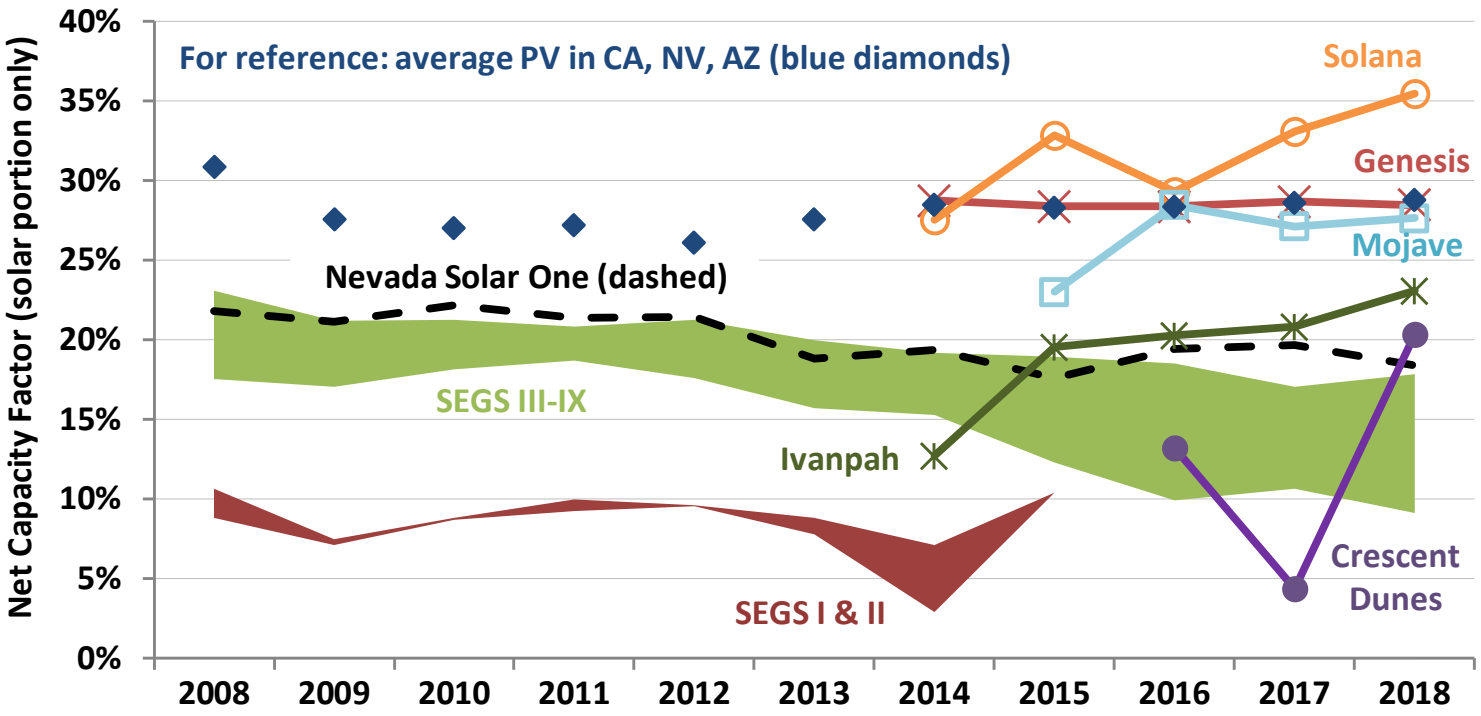


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

PV prices have continuously declined and are now far below the historical CSP prices. While international projects seem to be more competitive with PV, no new CSP projects are currently under active development in the U.S.

Despite improvements, most newer CSP projects continue to underperform relative to long-term expectations

CSP performance sample: 13 projects totaling 1,654 MW_{AC}



2018 was the best year yet for the 2 "power tower" projects, yet they continued to perform below long-term expectations (of ~27% for Ivanpah and ~50% for Crescent Dunes)

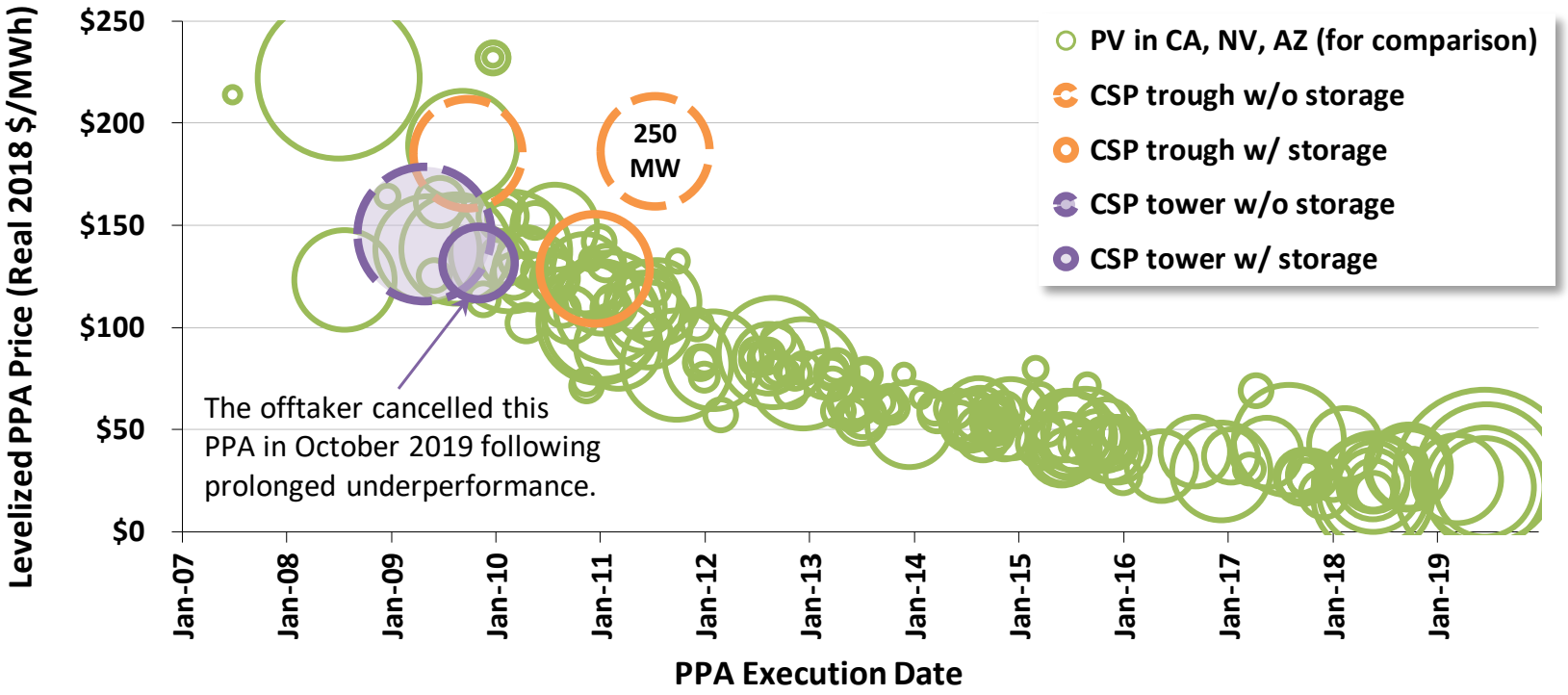
Solana (250 MW solar trough project with 6h thermal storage) also had its best year yet, but was still below long-term expectations of >40%

The two newer trough projects without storage (Genesis and Mojave) matched expectations and performed better than the eight older (25+ years old) trough projects SEGS III-IX, and the 2007 Nevada Solar One trough project

Since 2016, Solana, Genesis, and Mojave have all matched or exceeded the average capacity factor among utility-scale PV projects across California, Nevada, and Arizona. All other CSP projects have not been able to match average PV performance.

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

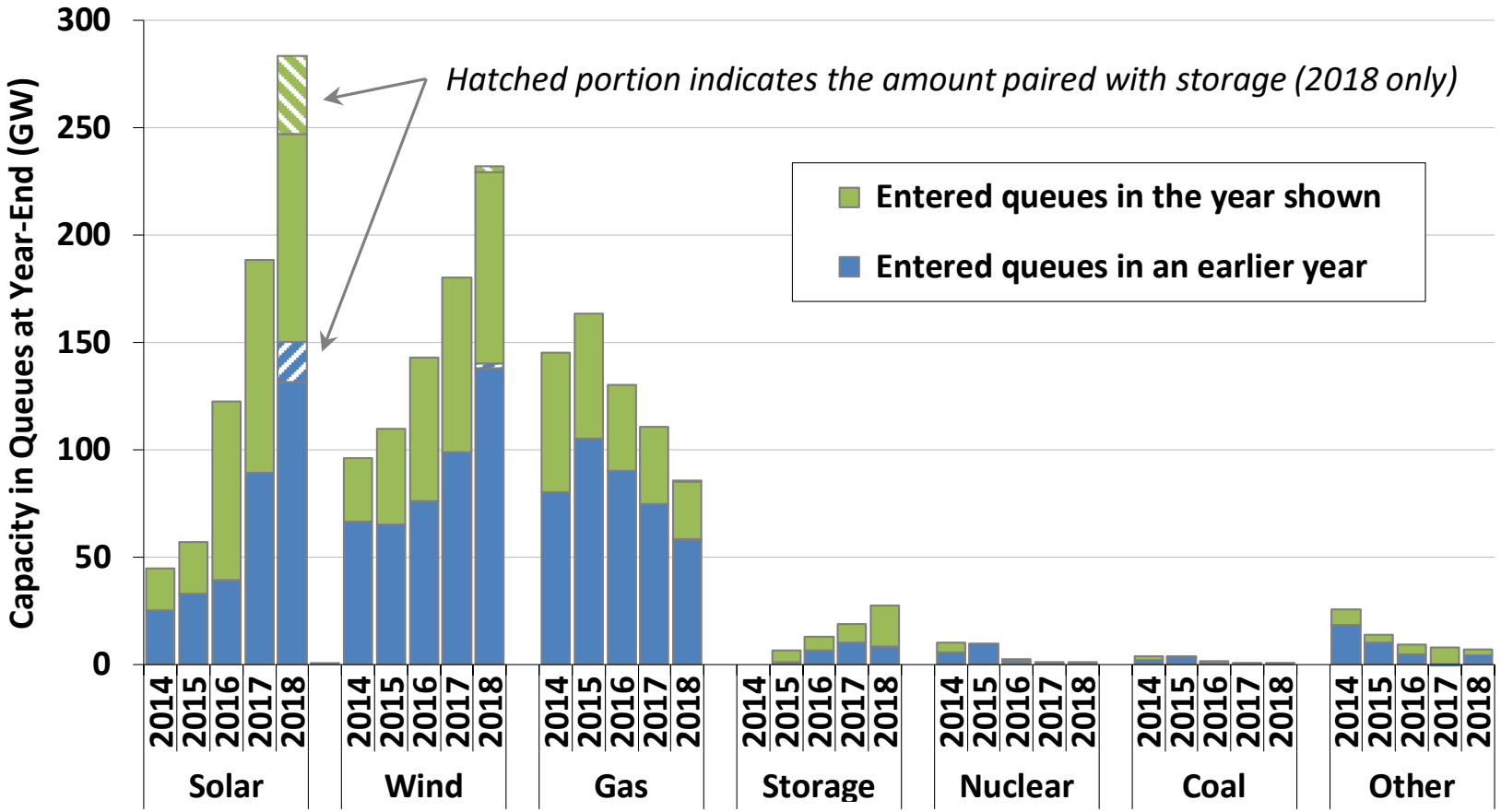
CSP PPA sample: 6 projects totaling 1,301 MW_{AC}



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: Strong growth in the utility-scale solar pipeline



Graphs show solar and other capacity in 37 interconnection queues across the U.S.
Not all of these projects will ultimately be built!

284 GW of solar was in the queues at the end of 2018—more than any other resource, and more than 10x the installed solar capacity at the end of 2018

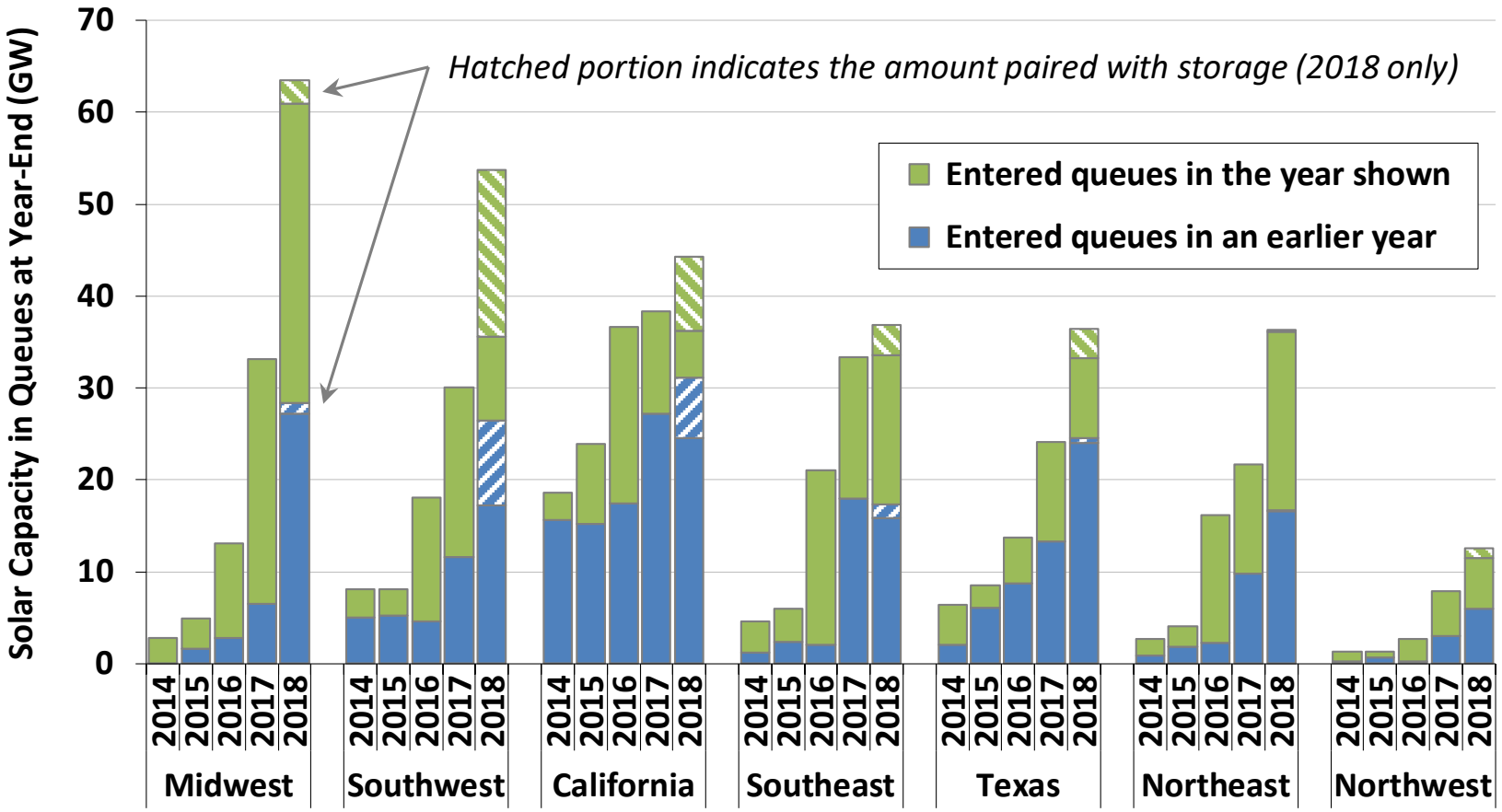
133 GW of solar capacity entered the queues in 2018 – the most ever

At least 55 GW of the 284 GW of solar in the queues includes a battery in a PV hybrid configuration

- ❑ >10x the 5 GW of wind hybrid projects in the queues

Standalone storage capacity in the queues grew to 28 GW at the end of 2018, accounting for about 4% of total queue capacity and ranking a distant fourth behind solar, wind, and gas

Looking ahead: Significant broadening of the market



Graphs show solar capacity in 37 interconnection queues across the U.S.
Not all of these projects will ultimately be built!

Very strong solar growth in all regions, but especially in the Midwest, which ranked next-to-last in 2016, but two years later is leading the pack (having added a record 33 GW in 2018 alone)

Solar capacity in the queues is now much more evenly distributed across the country than it was just three years ago

>75% of the 55 GW of PV hybrid capacity in the queues at the end of 2018 is in the Southwest (49%) and California (26%)—two high-penetration regions that are grappling with "duck curve" issues that can be at least partly alleviated by battery storage

Questions?

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

http://utilityscalesolar.lbl.gov

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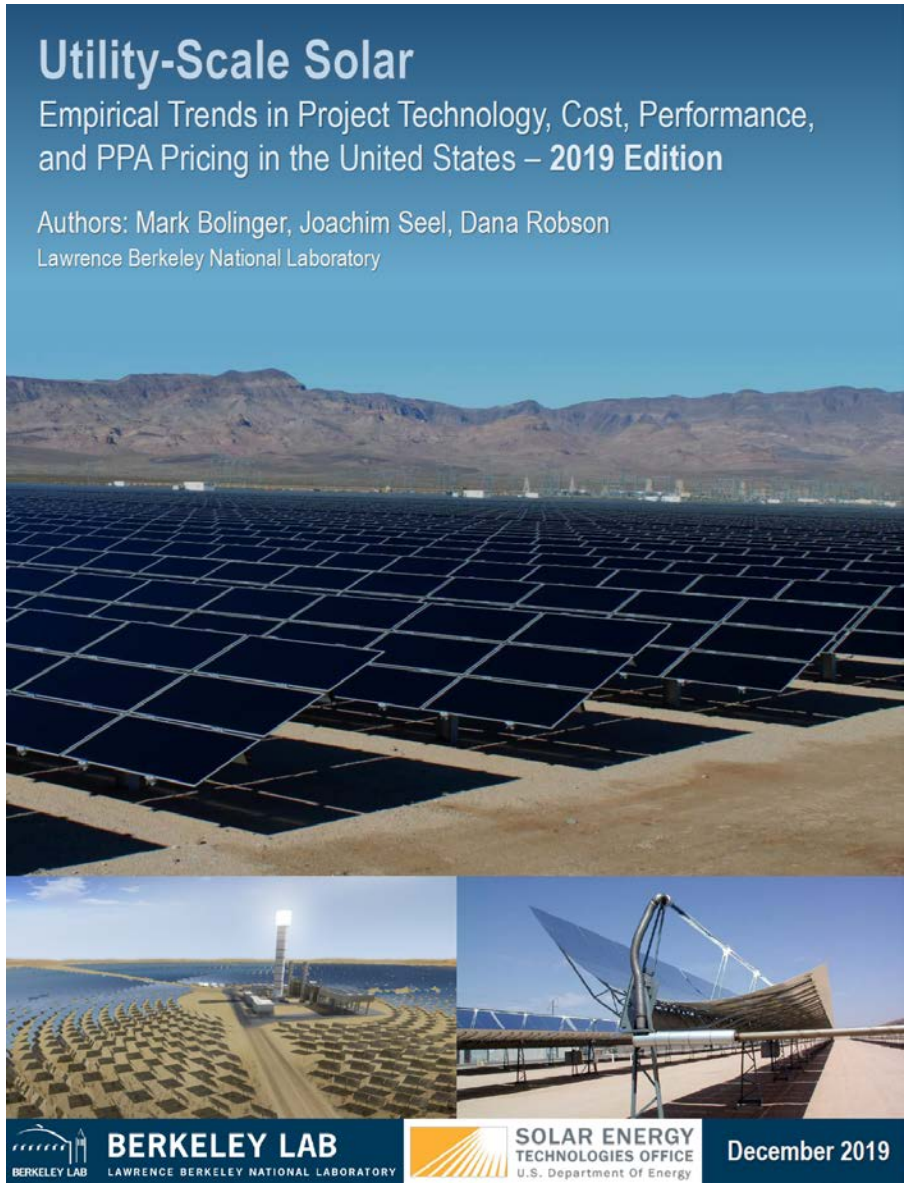
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