Utility-Scale Solar Technology Update 2025 Edition

Growth Through Headwinds:
Costs, Value, and the Storage Shift

Draft
Final Results May Deviate From This Presentation

Joachim Seel

Julie Mulvaney Kemp, Anna Cheyette, Will Gorman, Naim Darghouth,
Dana Robson, Joe Rand

Lawrence Berkeley National Laboratory
Energy Markets and Policy Department

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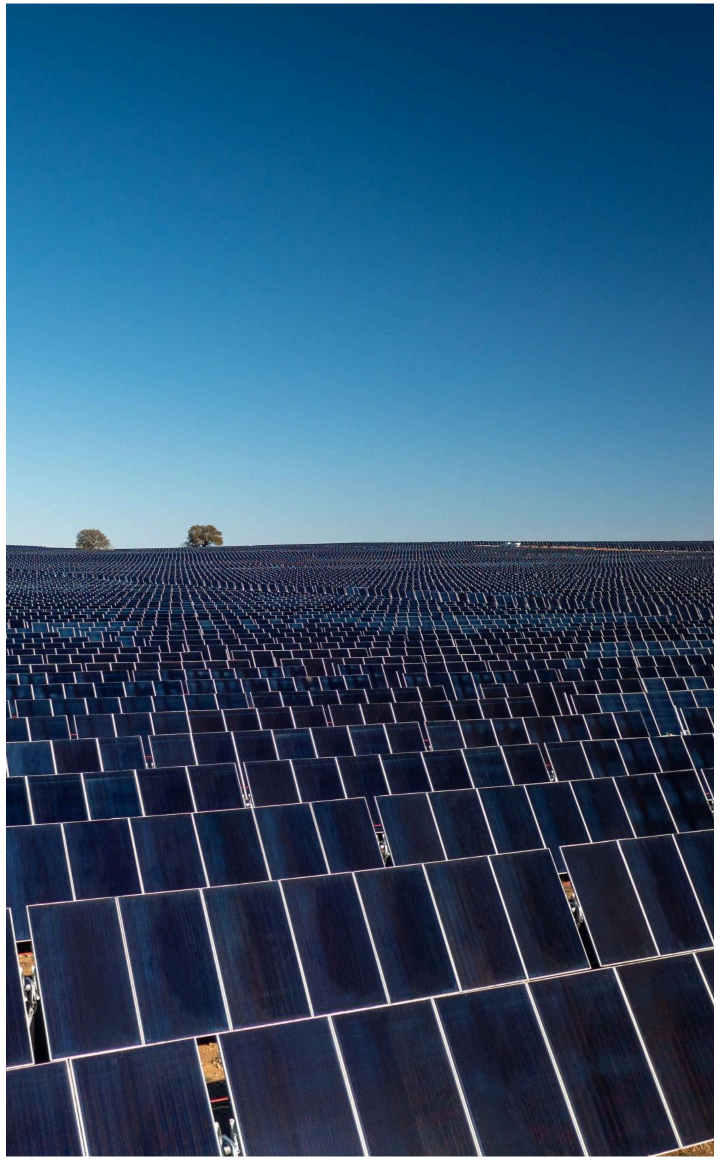

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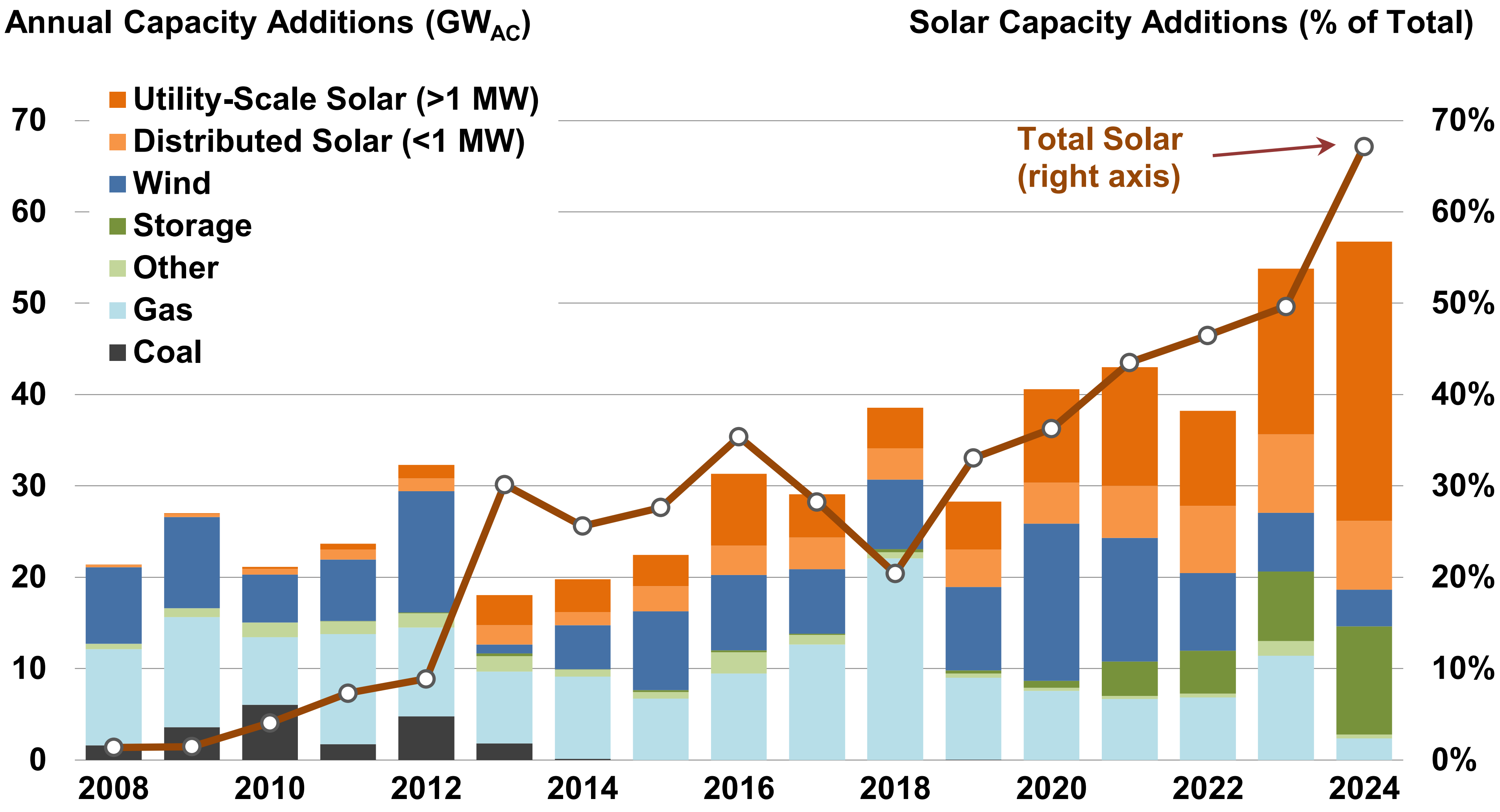
Photo credit:
Intersect Power's 415 MW_{DC}/320 MW_{AC} Radian solar facility, completed in 2023.

More than 50% of new U.S. grid capacity came from utility-scale solar in 2024



Bars represent annual capacity additions in GW_{AC} (left axis),
Line represents solar's capacity share of annual additions (right axis)

Utility-scale (54%) and distributed (13%) solar accounted for a combined 67% of all capacity added to U.S. grids in 2024.

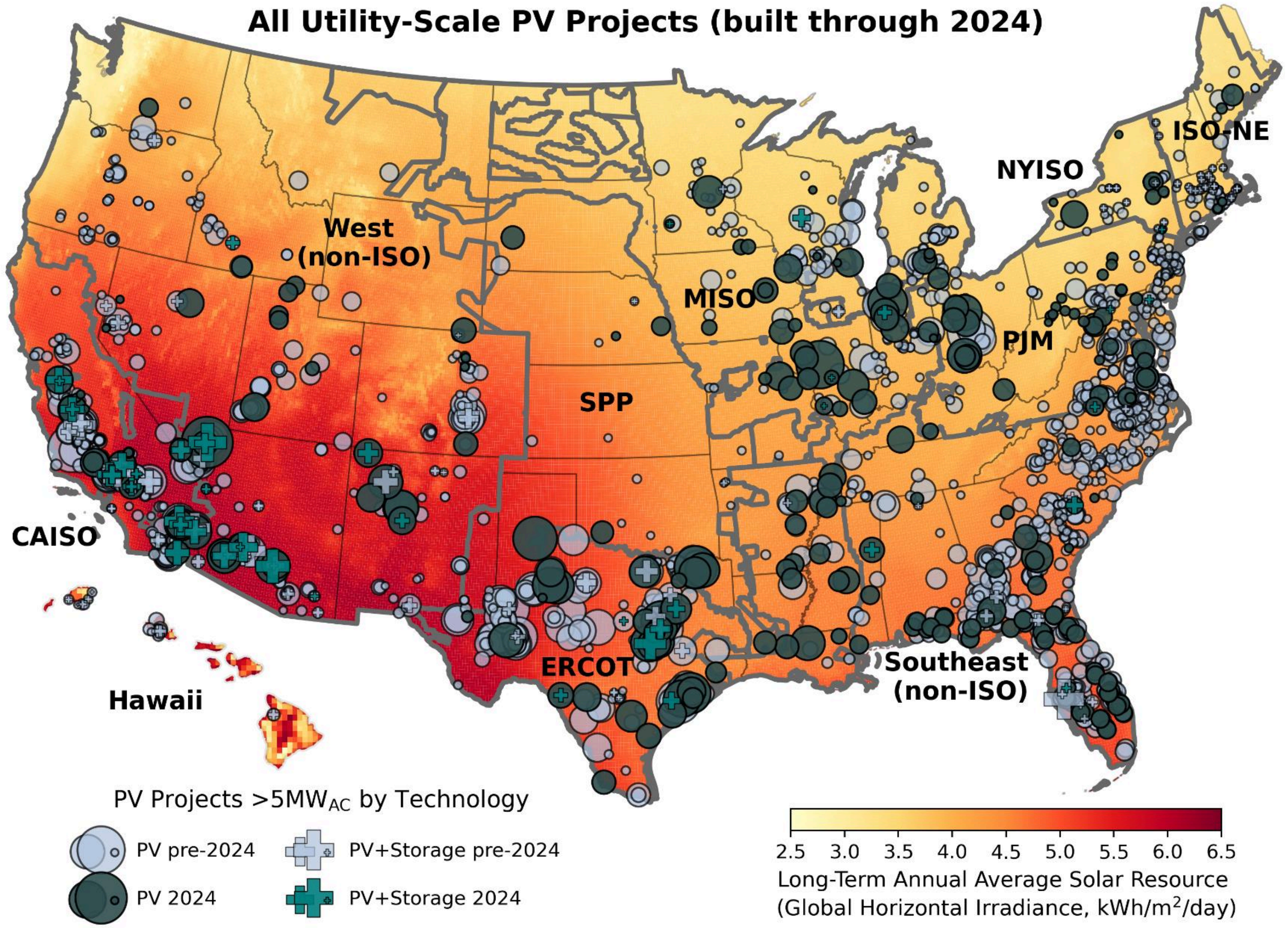
It is the first year that solar made up 2/3 of new US grid capacity.

Solar has added more capacity than any other fuel since 2021, contributing >40% of capacity additions each year, >30% in 8 of the last 9 years, and >20% in each of the last 12 years.

Storage continues to expand as well: 11.8 GW of storage were added to U.S. grids in 2024, up from 7.6 GW in 2023.

Note: Graph above shows utility-scale solar as >1 MW_{AC} while most of this report uses >5 MW_{AC}.

Utility-scale solar has been built throughout the United States



Utility-scale PV is well-represented throughout the nation, with the exception of the central "wind belt" states in SPP, Montana, and Wyoming.

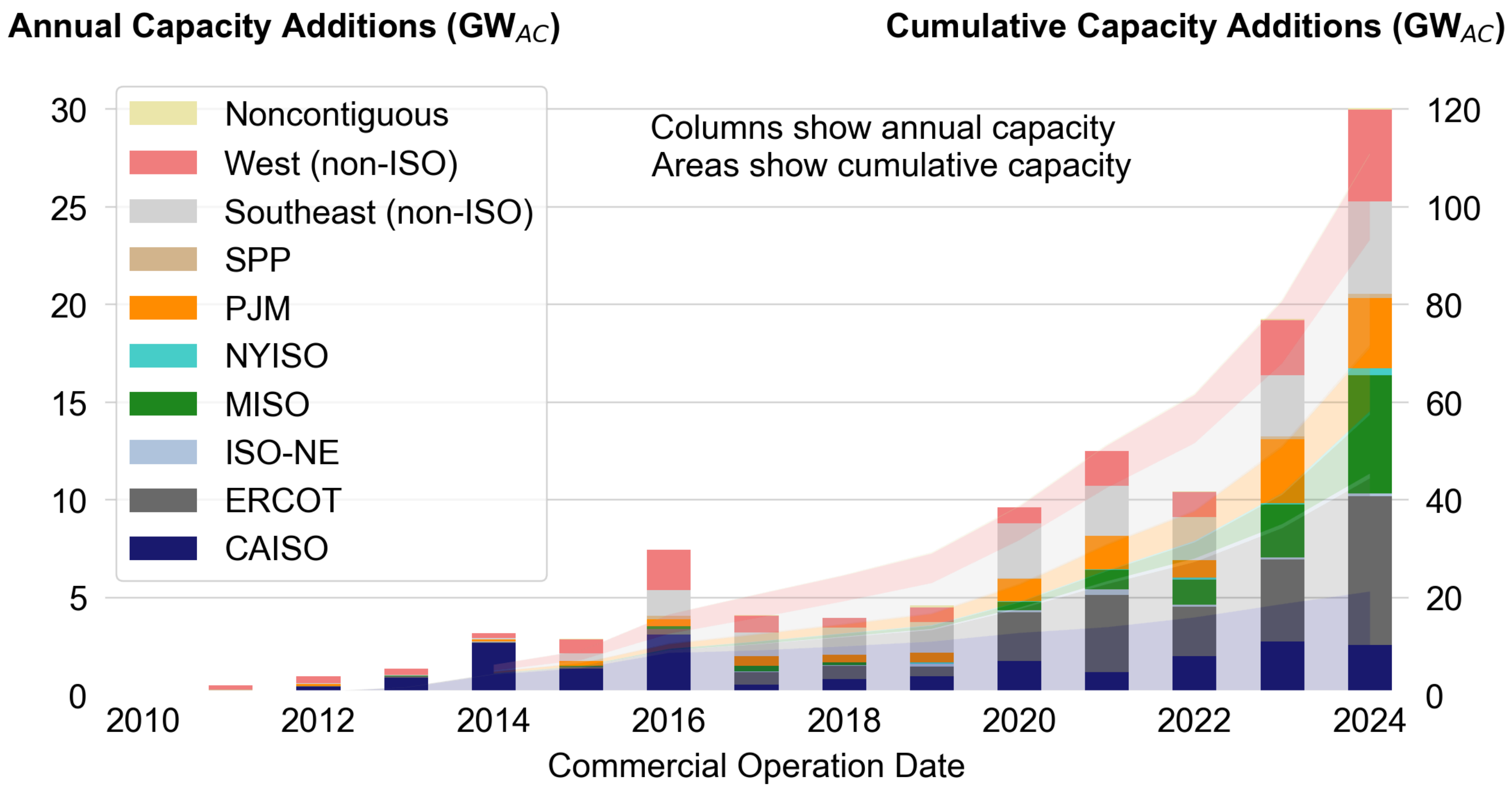
West Virgina had their first large solar projects (6-80 MW) in 2024. 14 states more than doubled their solar capacity in 2024, led by Missouri, Nebraska, Oklahoma, Kentucky. Only North Dakota and New Hampshire still await their first utility-scale solar projects in our sample.

In 2024, storage ( ) hybrid projects hit the ground in record numbers. Batteries were added to already existing (14) and new (35) PV projects. Solar-rich non-ISO West added the most solar-coupled storage capacity (1,905 MW), followed by CAISO (1,465 MW).

You can explore this data interactively at https://emp.lbl.gov/technology-trends

ERCOT and the MISO added the most utility-scale solar capacity in 2024. ERCOT and the Southeast have overtaken CAISO in total deployment.

PV project population: 1,759 projects totaling 111 GW_{AC}



Utility-scale solar deployment set new records in 2024, with multiple GW of additions in ERCOT (7.6 GW_{AC}), MISO (6 GW_{AC}), the non-ISO Southeast and West (both 4.7 GW_{AC}), PJM (3.6 GW_{AC}), and CAISO (2.6 GW_{AC}).

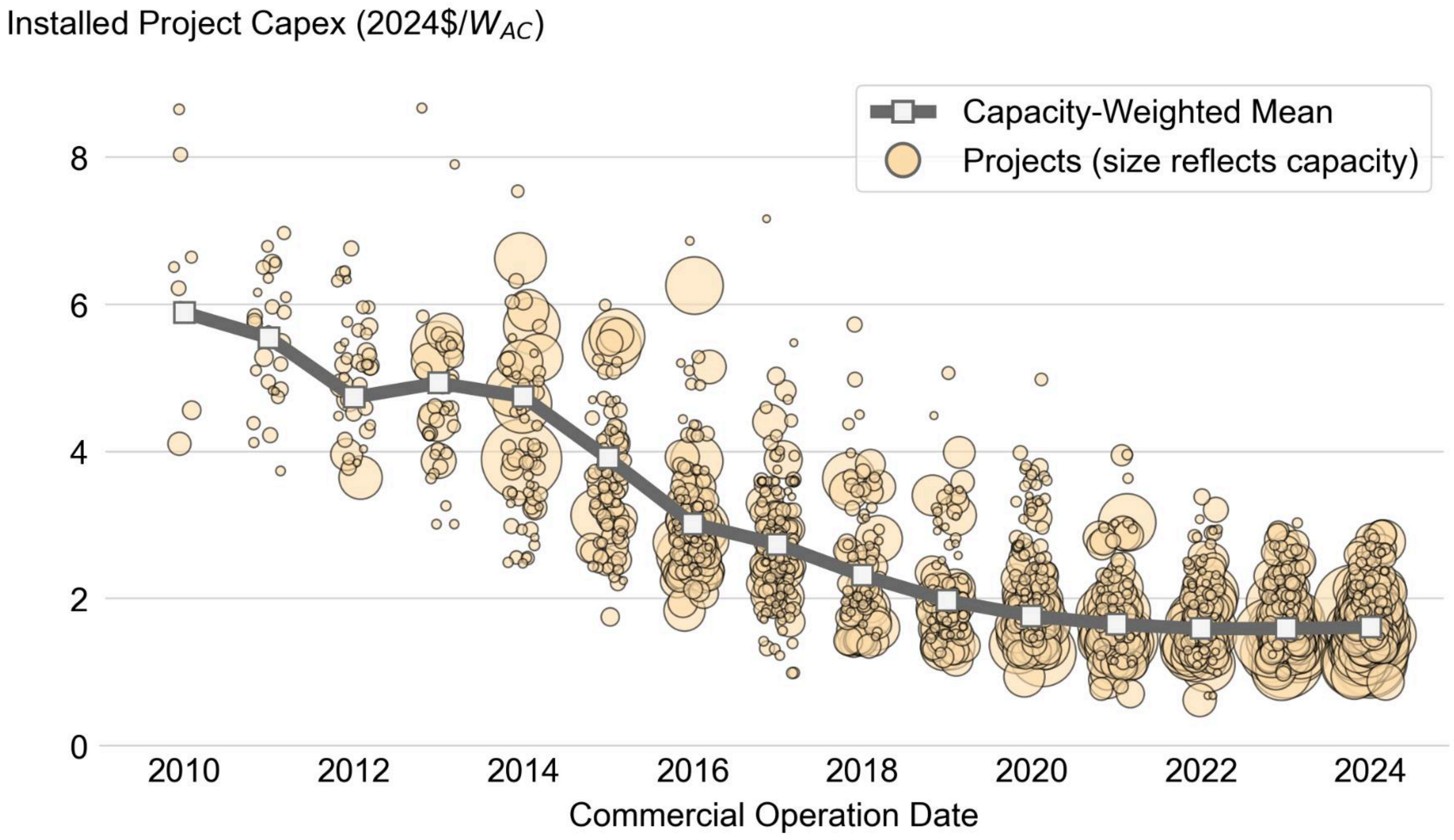
Taking a state perspective, **Texas** led the nation with 7.7 GW_{AC} followed by **Florida** (3.2 GW_{AC}), **California** (2.5 GW_{AC}), **Illinois** (1.6 GW_{AC}) and **Ohio** (1.5 GW_{AC}) scored 3rd to 5th place. 9 states added more than 1 GW_{AC} of new capacity.

In cumulative deployment, ERCOT (23 GW_{AC}) and the non-ISO Southeast (21 GW_{AC}) have finally overtaken CAISO in 2024 (also 21 GW_{AC}). The non-ISO West (17 GW_{AC}) is following closely.

You can explore this data interactively at https://emp.lbl.gov/capacity-and-generation-state

Installed costs of PV have increased for the first time to $1.61/W_{AC}$ ($1.22/W_{DC}$) in 2024

Sample: 1,629 projects totaling 104 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Costs for installed utility-scale PV have fallen by 73% between 2010 and 2022 but increased slightly since then in real dollar terms in a high inflation environment.

Capacity-weighted means (reflecting the average costs of solar capacity) increased from $1.59/$W_{AC}$ in 2023 to $1.61/$W_{AC}$ in 2024.

Medians (reflecting typical project costs) increased from $1.64/$W_{AC}$ in 2023 to $1.70/$W_{AC}$ in 2024.

The lowest 20th percentile of project costs rose in real terms from $1.39/$W_{AC}$ ($1.05/$W_{DC}$) in 2023 to $1.44/$W_{AC}$ ($1.09/$W_{DC}$) in 2024.

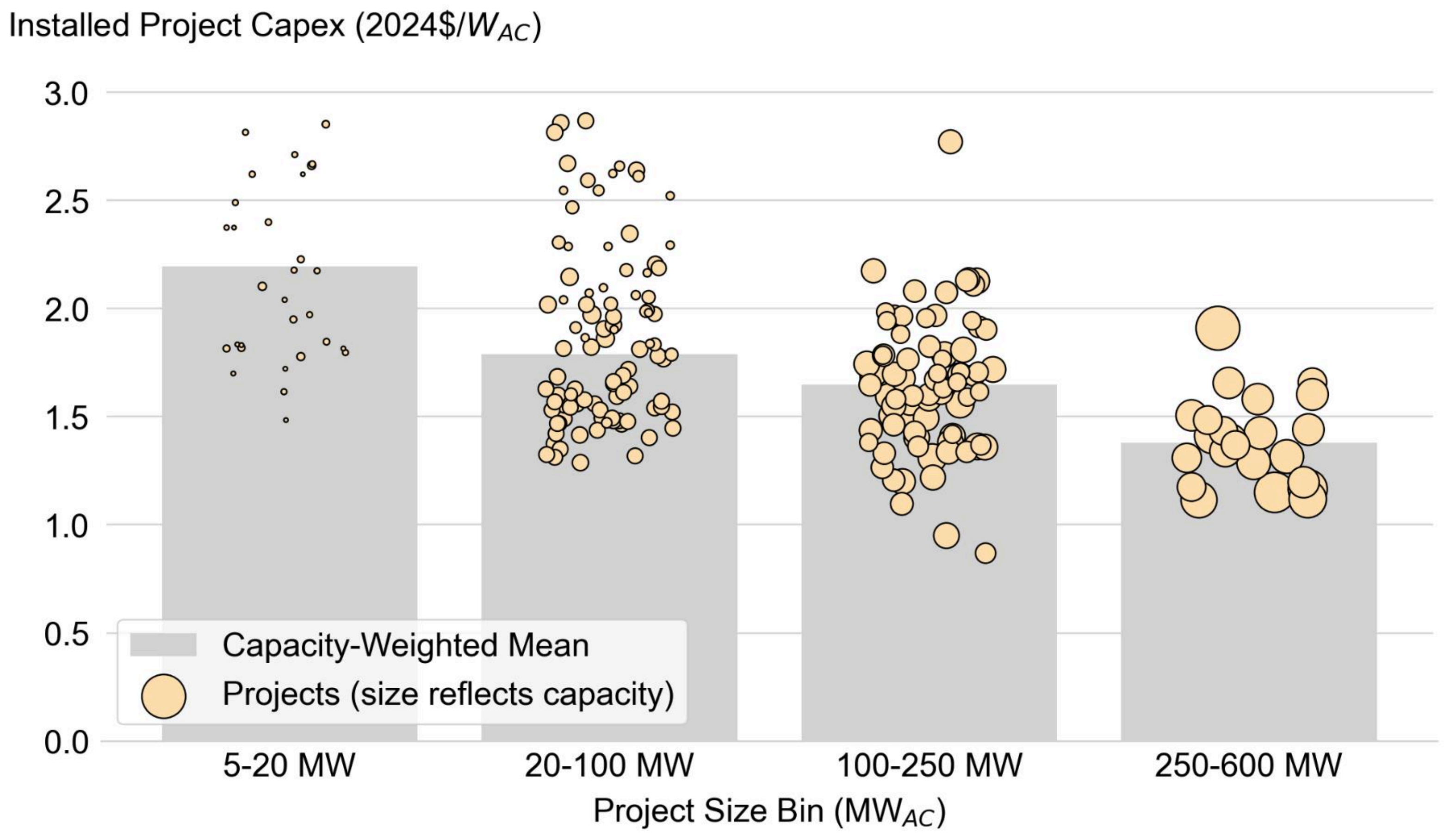
Our sample is robust (covering 93% of installed capacity through 2024). 2024 data covers 92% of new projects (227) or 88% of new capacity (26.4 GW_{AC}).

Data presented here refers only to PV costs. Additional storage costs of hybrid projects are discussed on later slides.

Detailed statistics in $/$W_{DC}$ are shown in the accompanying data workbook.

Larger solar projects (>250 MW) cost 37% less than smaller (5-20 MW) per MW of installed capacity in 2024

Sample in 2024: 227 projects totaling 26 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Differences in project size are one major driver in explaining cost variation—we focus only on 2024 for this slide. The apparent economies of scale are likely one reason why average project sizes have grown by a factor of 5 since the 2017.

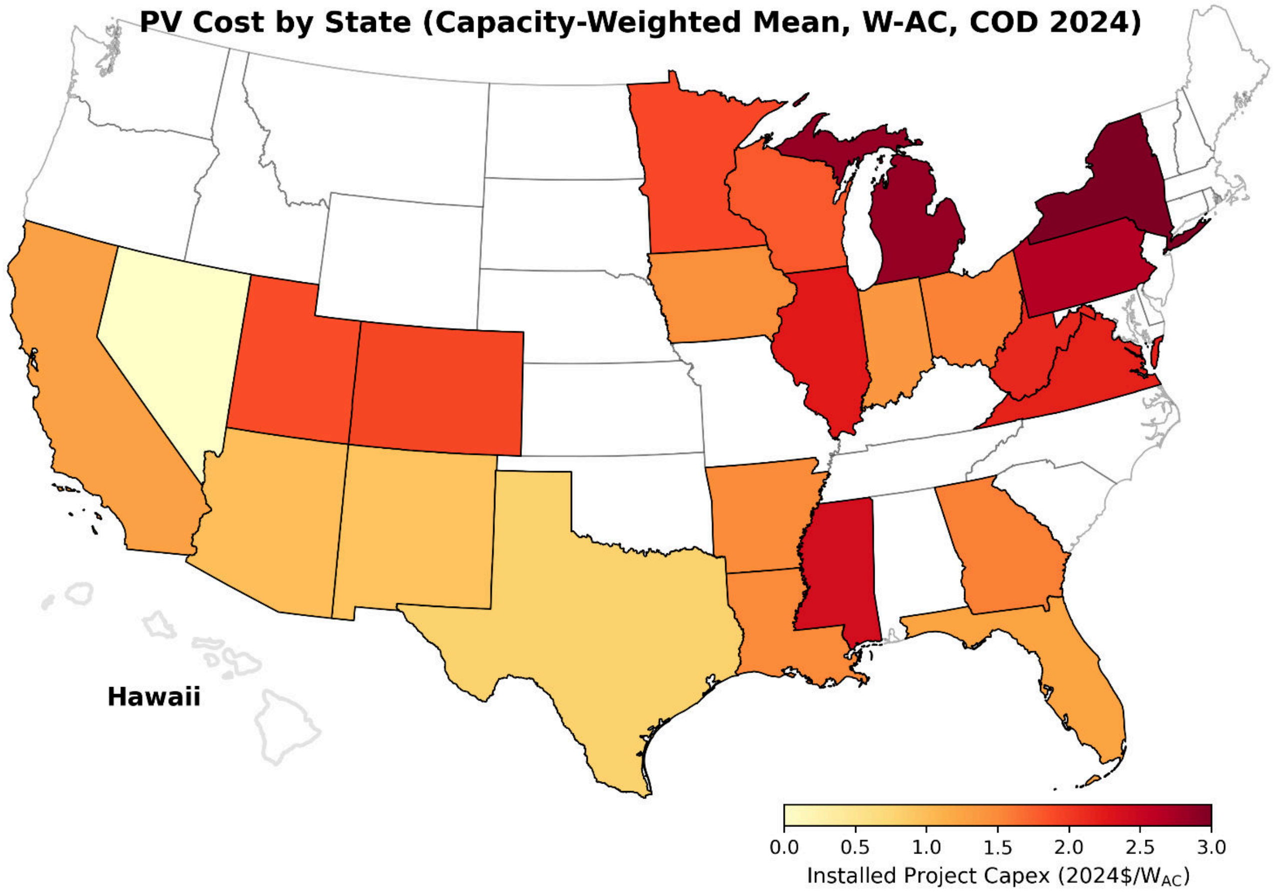
Cost savings seem to occur especially in projects larger than 250 MW_{AC} at \$1.38/W_{AC} vs. \$2.19/W_{AC} for smaller projects.

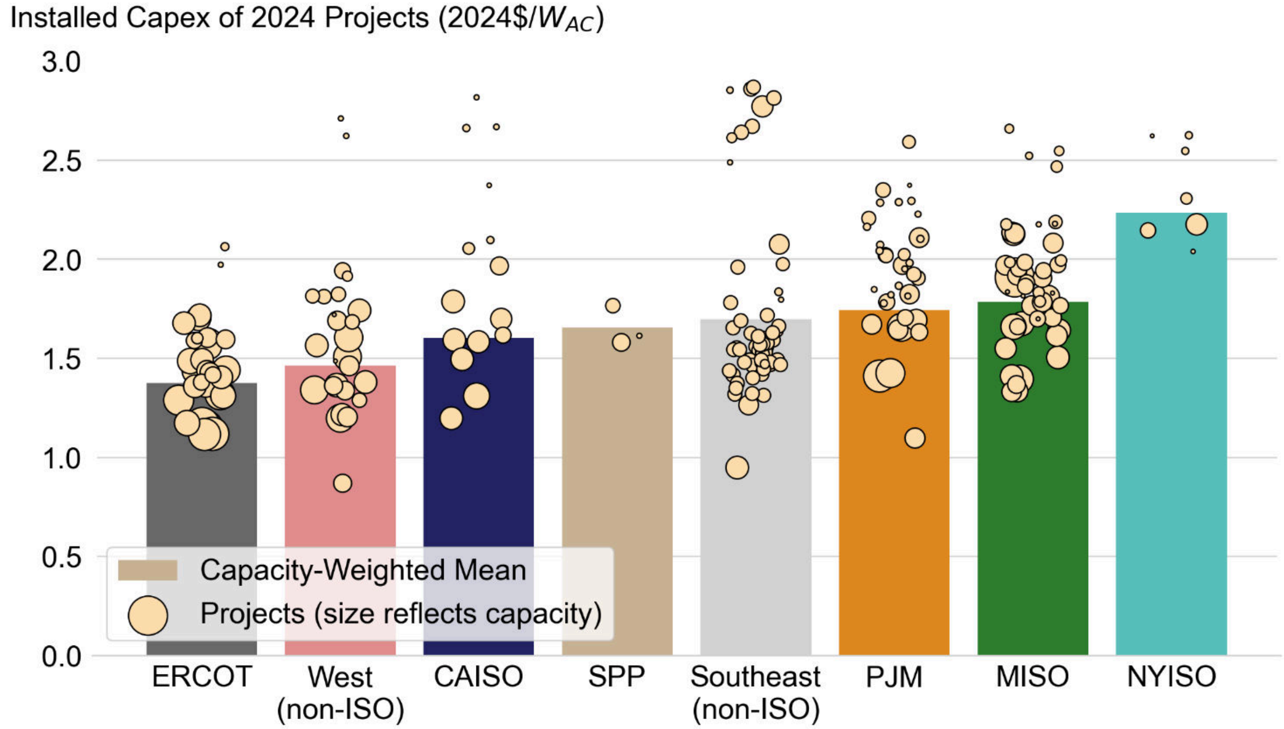
In \$/W_{DC} terms, prices seem to decline especially among projects larger than 100MW_{DC}:

- \$1.62/W_{DC} for 5-20 MW
- \$1.53/W_{DC} for 20-100 MW
- \$1.28/W_{DC} for 100-25 MW
- \$1.10/W_{DC} for 250-800 MW

Solar projects in ERCOT and the Southwest are cheaper than in the Northeast.

Sample in 2024: 227 projects totaling 26 GW_{AC}





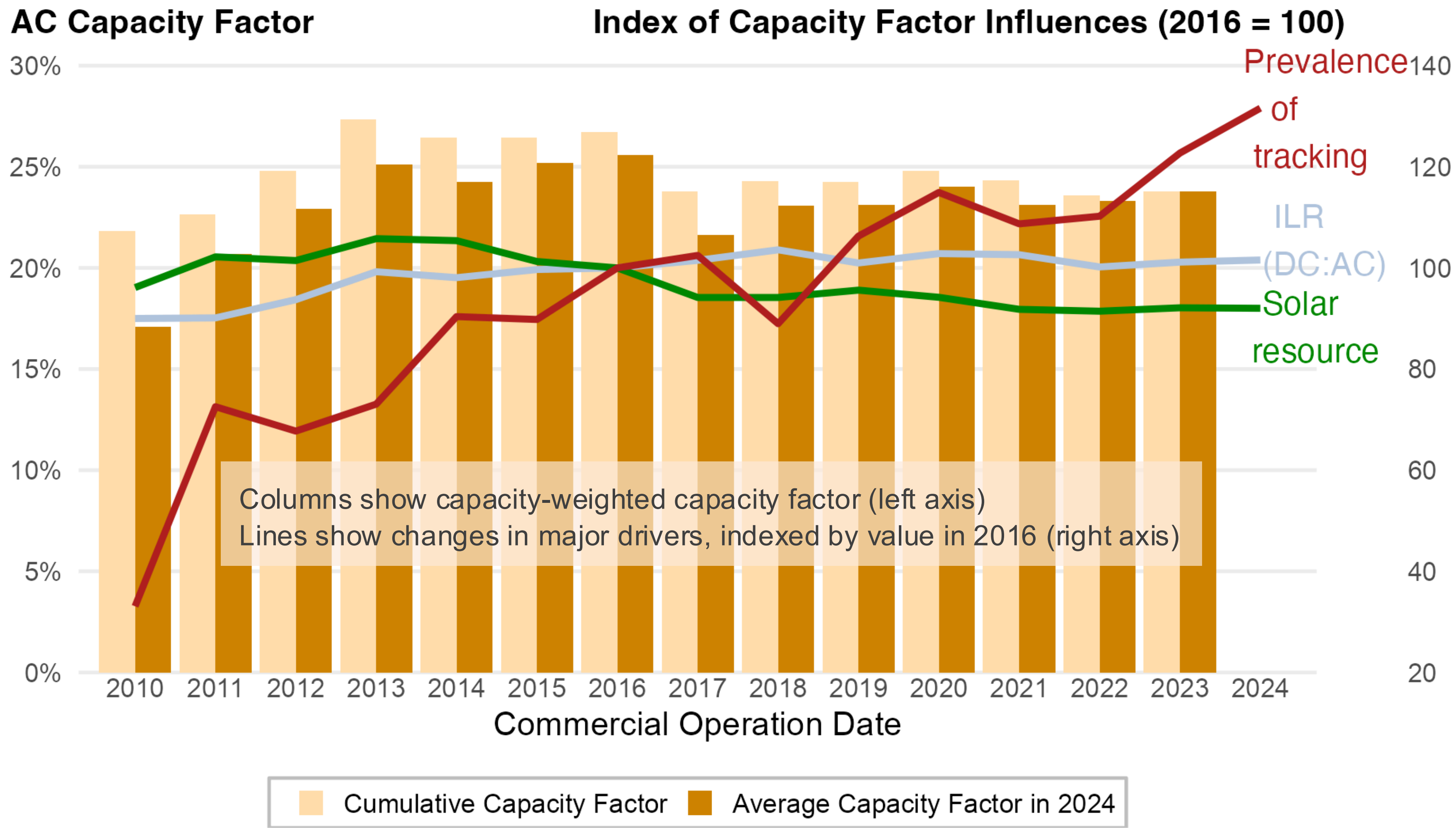
Utility-scale solar project costs also vary region, driven in part by the previously discussed economies of scale, but also due to land availability, prevailing labor rates and transmission network upgrade costs. Projects in ERCOT ($1.38/$W_{AC}$ or $1.06/$W_{DC}$) and the non-ISO West have lower costs than the northeastern U.S.

Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Detailed statistics in $/$W_{DC}$ are shown in the accompanying data workbook.

Since 2013, competing drivers have caused average capacity factors by plant vintage to stabilize

Sample: 1,462 plants totaling 79.7 GW_{AC}



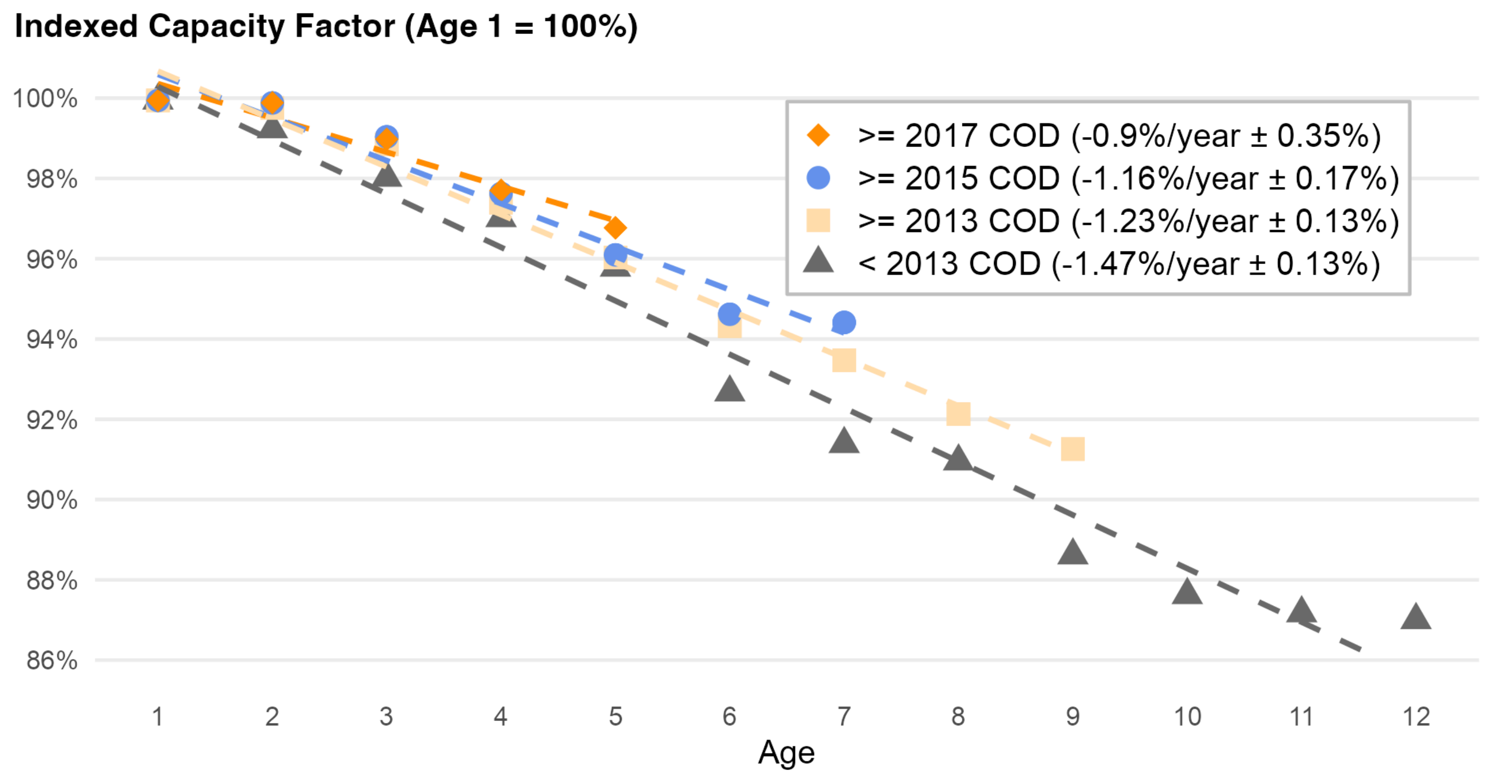
Cumulative capacity-weighted capacity factors improved for projects from 2010 to 2013 due to increased DC-oversizing, adoption of single-axis tracking, and better solar resources.

Since 2013, capacity factors have declined and stagnated due to mixed factors: while tracking has become widespread (53% to 95%) and ILR has seen minor growth, new projects have expanded into less sunny regions (average site GHI decreased from 5.30 to 4.61 kWh/m²/day).

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Plant output declines with age, but the performance of newer projects has fallen at a slower rate compared to older projects

Sample: 905 plants totaling 37.4 GW_{AC}



Note: Sample includes plants built through 2020 (model requires two years of performance with weather data available through 2022). All four slopes are statistically significant, but commercial operation date (COD) $\geq$ 2015 is not statistically different from COD $\geq$ 2013 or $\geq$ 2017.

Annual system-level performance degradation varies by cohort, with newer plants degrading 0.9% per year compared to 1.47% for older plants.

Fixed effects regression model defined by:

$$CF_{f,t}^{actual} = CF_{f,t}^{ideal} + S_f + A_T + \epsilon_{f,t}$$

where:

$CF_{f,t}^{actual}$ = Actual capacity factor of plant f at time t (raw empirical data, but grossed up for curtailment in CAISO and ERCOT)

$CF_{f,t}^{ideal}$ = "Ideal" capacity factor of plant f at time t, estimated based on physical plant characteristics and solar resource at the site

S_f = Site-level fixed effects of plant f to control for differences in capacity factor across plants

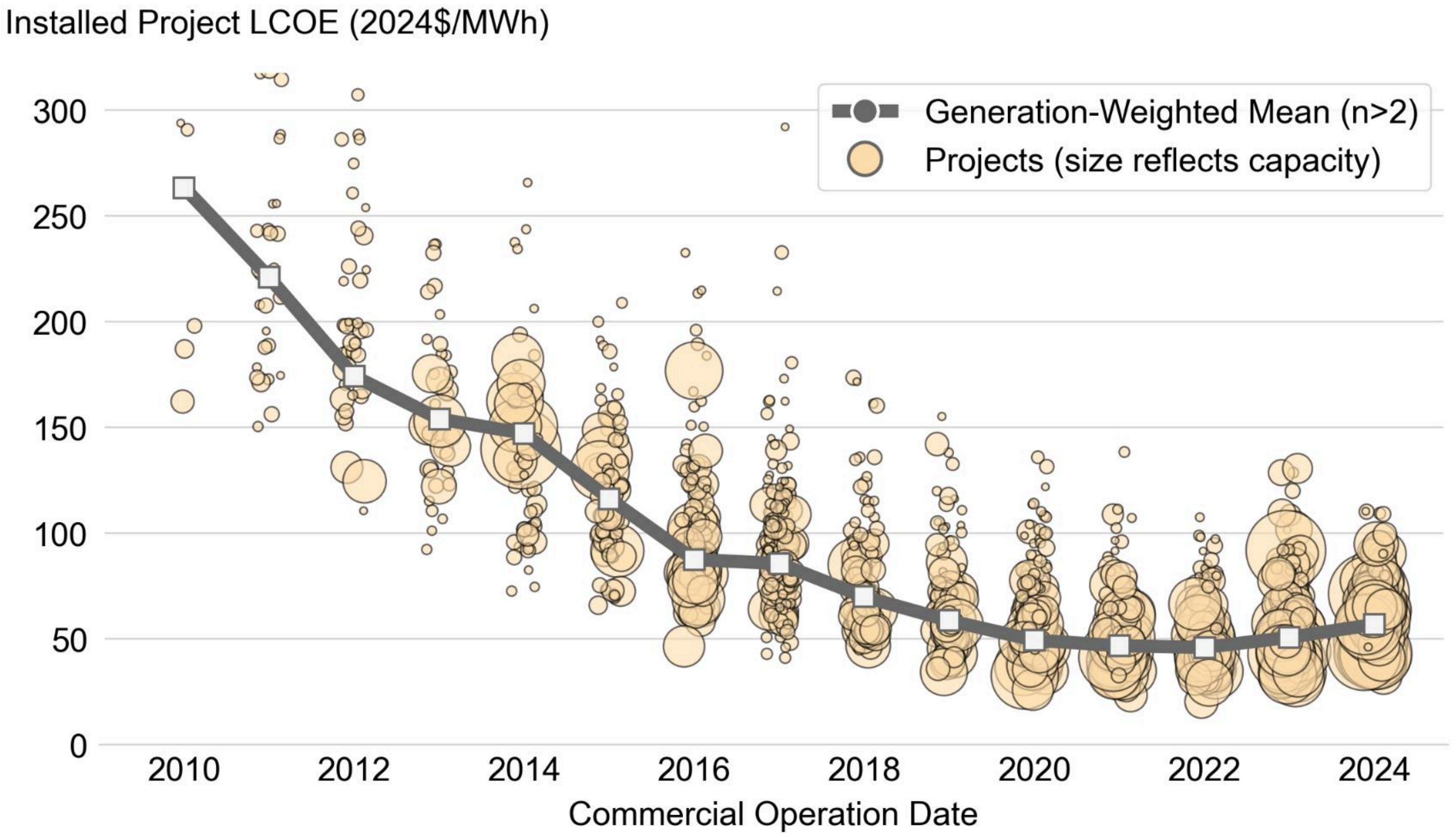
A_T = Age fixed effects at time t to control for differences in capacity factor within plants

$\epsilon_{f,t}$ = Residual of plant f at time t

Note: For greater detail on methods, see Bolinger et al. (2020) System-level Performance and Degradation of 21 GW_{DC} of Utility-Scale PV Plants in the United States.

Average LCOE (without the ITC/PTC) has increased 24% since 2022

Sample: 1,624 projects totaling 104 GW_{AC}



Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2024.
Findings may shift as more final EIA Capex and project-specific performance data become available.

Utility-scale PV's average LCOE has fallen by 83% between 2010 and 2022 to $46/MWh, driven by lower capital costs and operating expenses, as well as increased project design life.

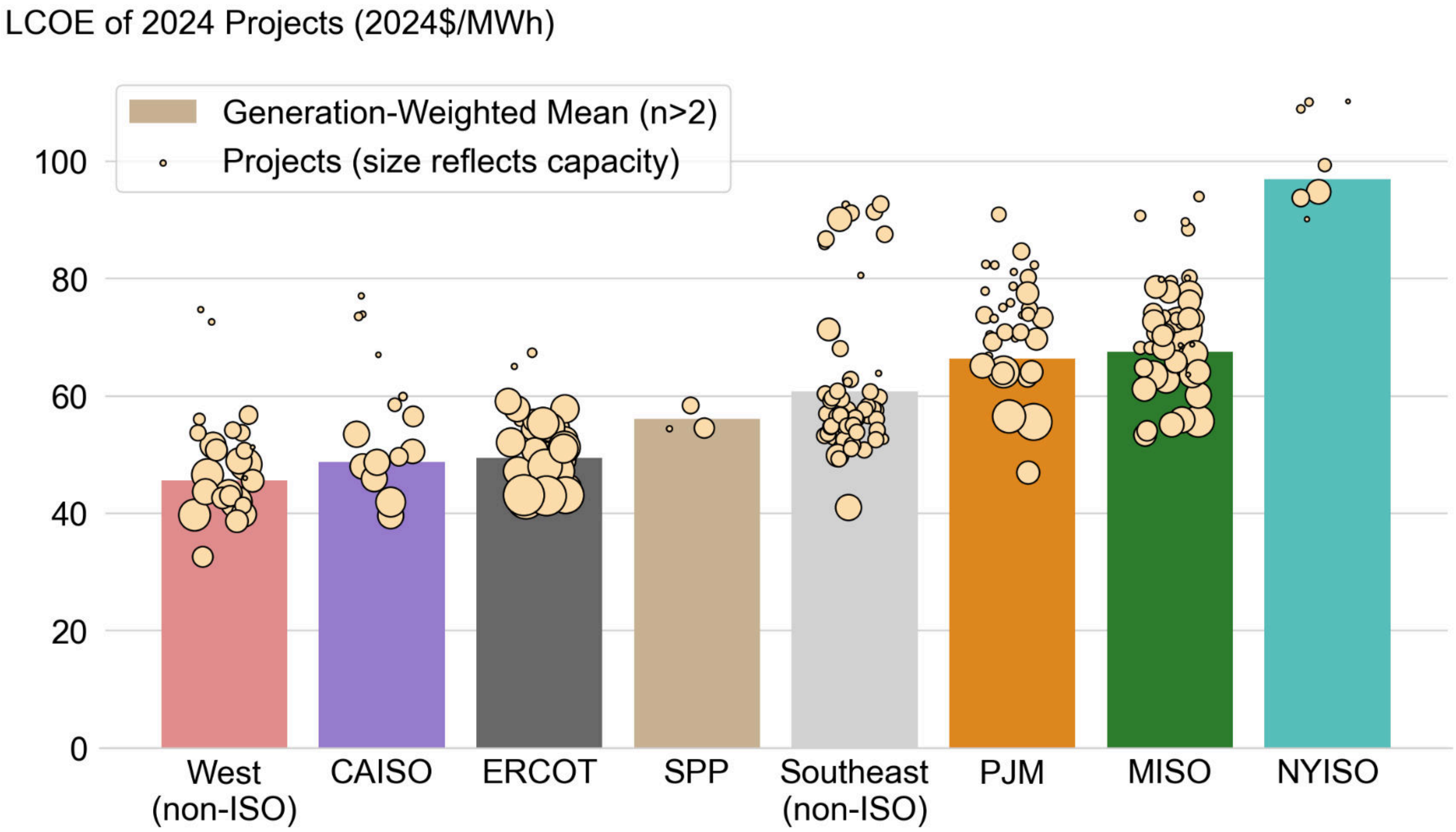
Counteracting these beneficial longer-term trends are falling national average capacity factors since 2016 and less favorable financing terms since 2020.

Average LCOE (not including any tax credits) increased by 24% since 2022 to $57/MWh in 2024.

See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

LCOE varies between regions due to differences in solar resource quality, project costs, and system size

Sample: 227 projects totaling 26.4 GW_{AC}



Lower-insolation regions (NYISO, MISO, PJM) will always have higher LCOEs than higher-insolation regions (ERCOT, CAISO, the non-ISO West and Southeast), but the difference has narrowed over time.

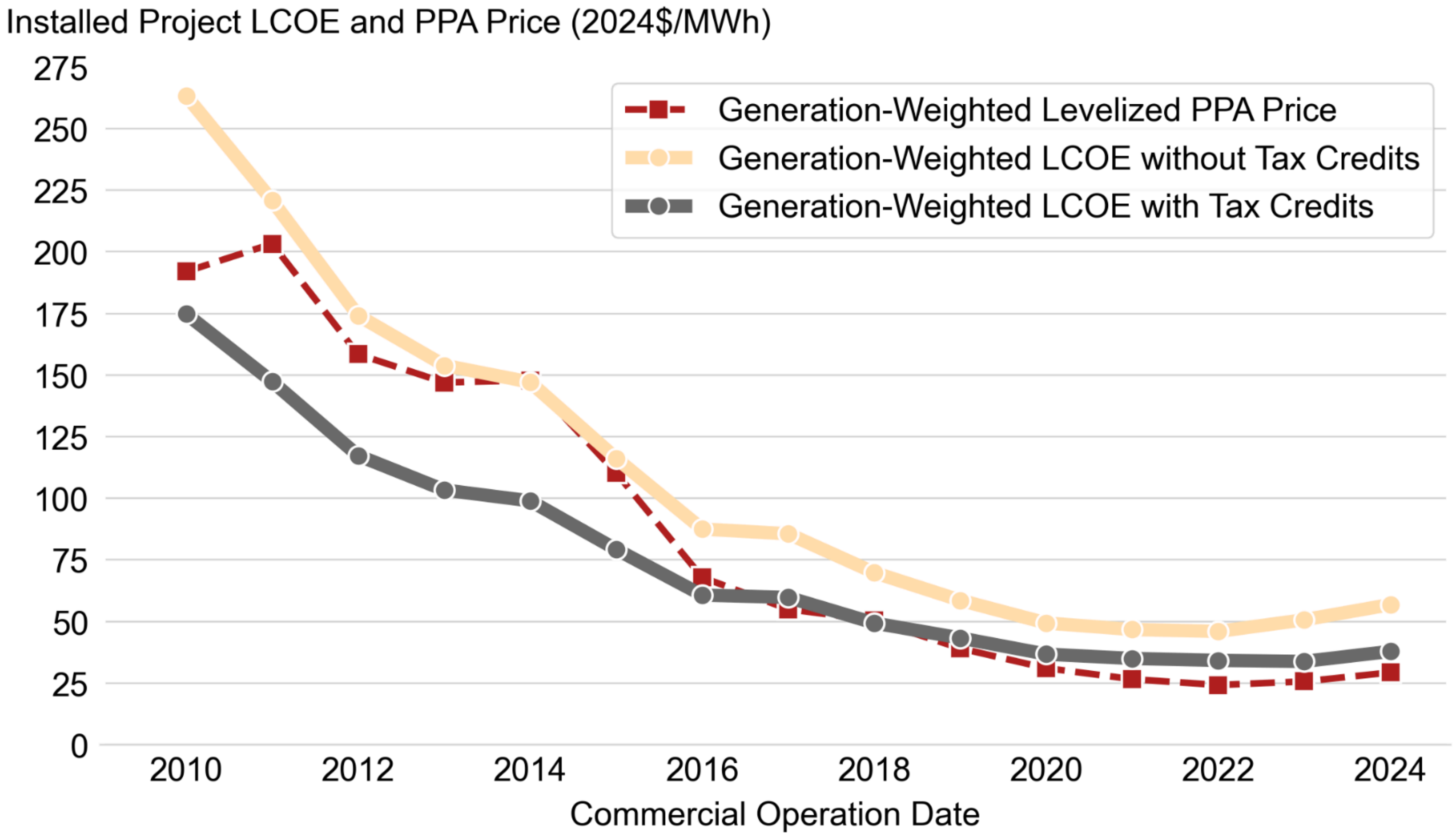
Among projects coming online in 2024, large projects in the non-ISO West, CAISO, and ERCOT had the lowest cost ($46 and $49/MWh for both), while smaller projects in NYISO had the highest cost in our sample $97/MWh).

Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2024.
Findings may shift as more final EIA Capex and project-specific performance data become available.

See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

Since 2022, levelized PPA prices have tracked the LCOE accounting for tax credits of utility-scale PV

Sample: 1,629 projects totaling 104 GW_{AC}



This graph contrasts solar LCOE with and without tax credits - choosing either PTC or ITC for each project that results in lowest cost (not including Domestic Content adder).

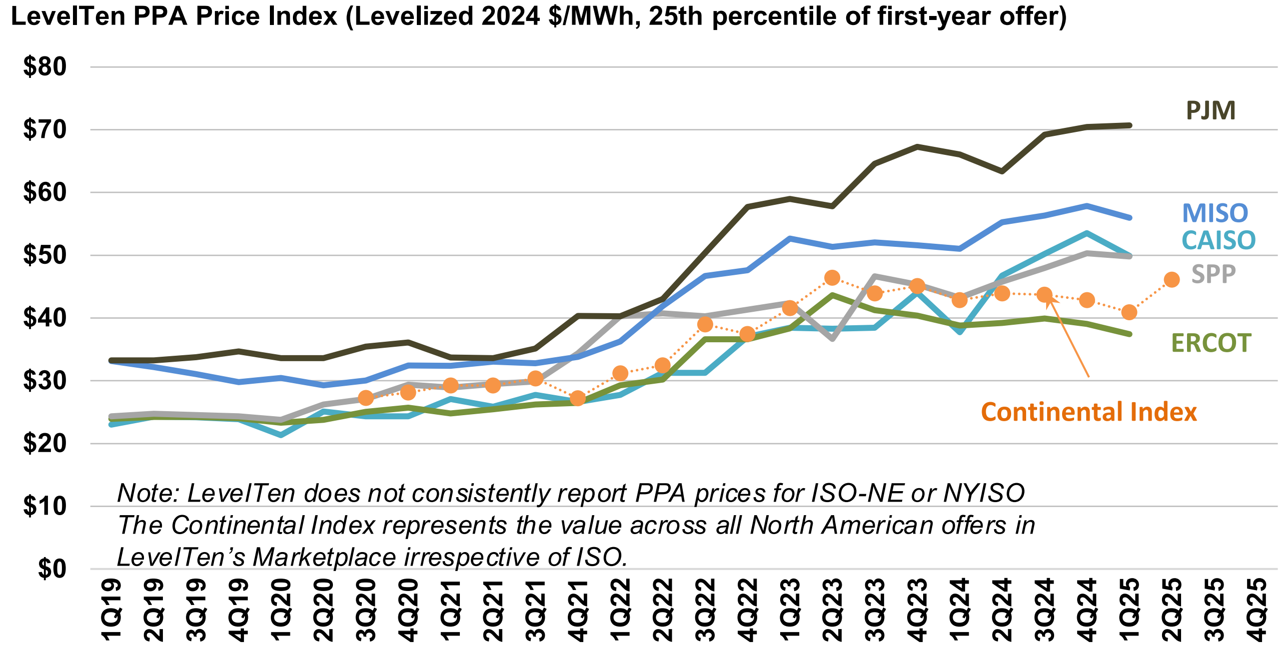
While generation-weighted average LCOE increased slightly since 2022 before the application of tax credits ($57/MWh in 2024 vs. $46 in 2022), post-credit LCOE only rose modestly ($38/MWh vs. $34/MWh).

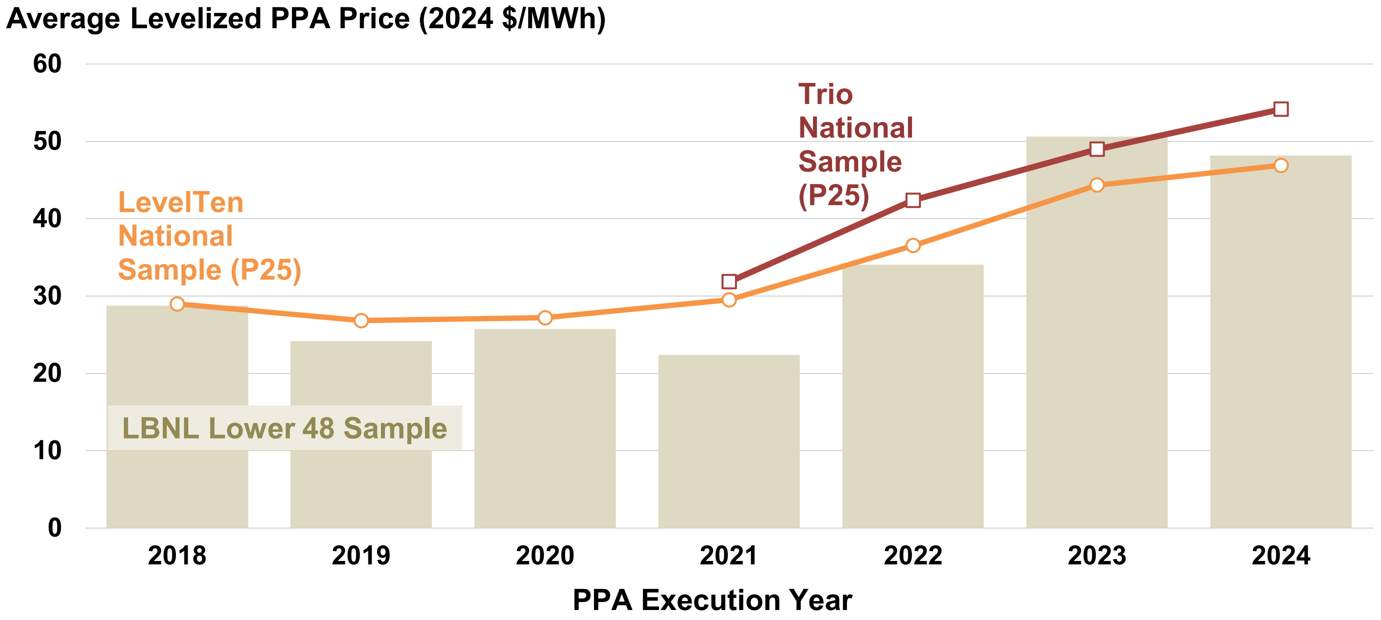
Since 2016, levelized PPA prices charted by plant COD have closely tracked or hovered slightly below the LCOE with tax credits. This suggests a pass-through of these tax credits and a competitive PPA market.

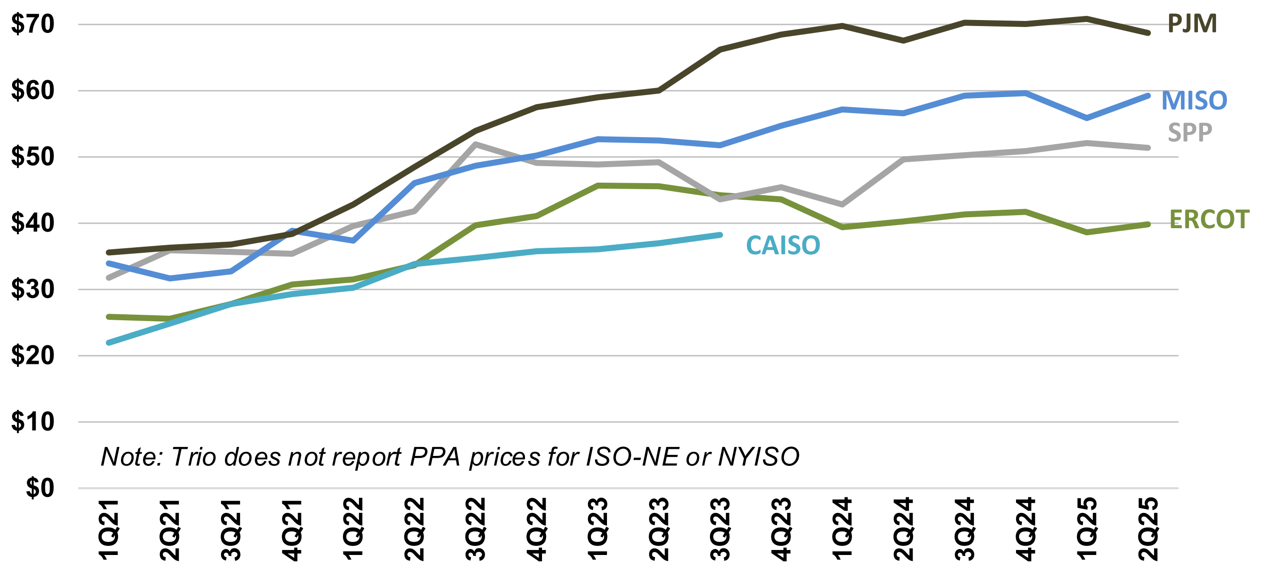
Note that the PPA sample is smaller than the LCOE sample, potentially explaining some of the gap.

Note: Only preliminary data is available for new solar projects coming online in 2024. Findings may shift as more final EIA Capex and project-specific performance data become available.

LevelTen Energy and Trio's utility-scale PV PPA price indices match the increasing trend seen in the LBNL sample since 2021





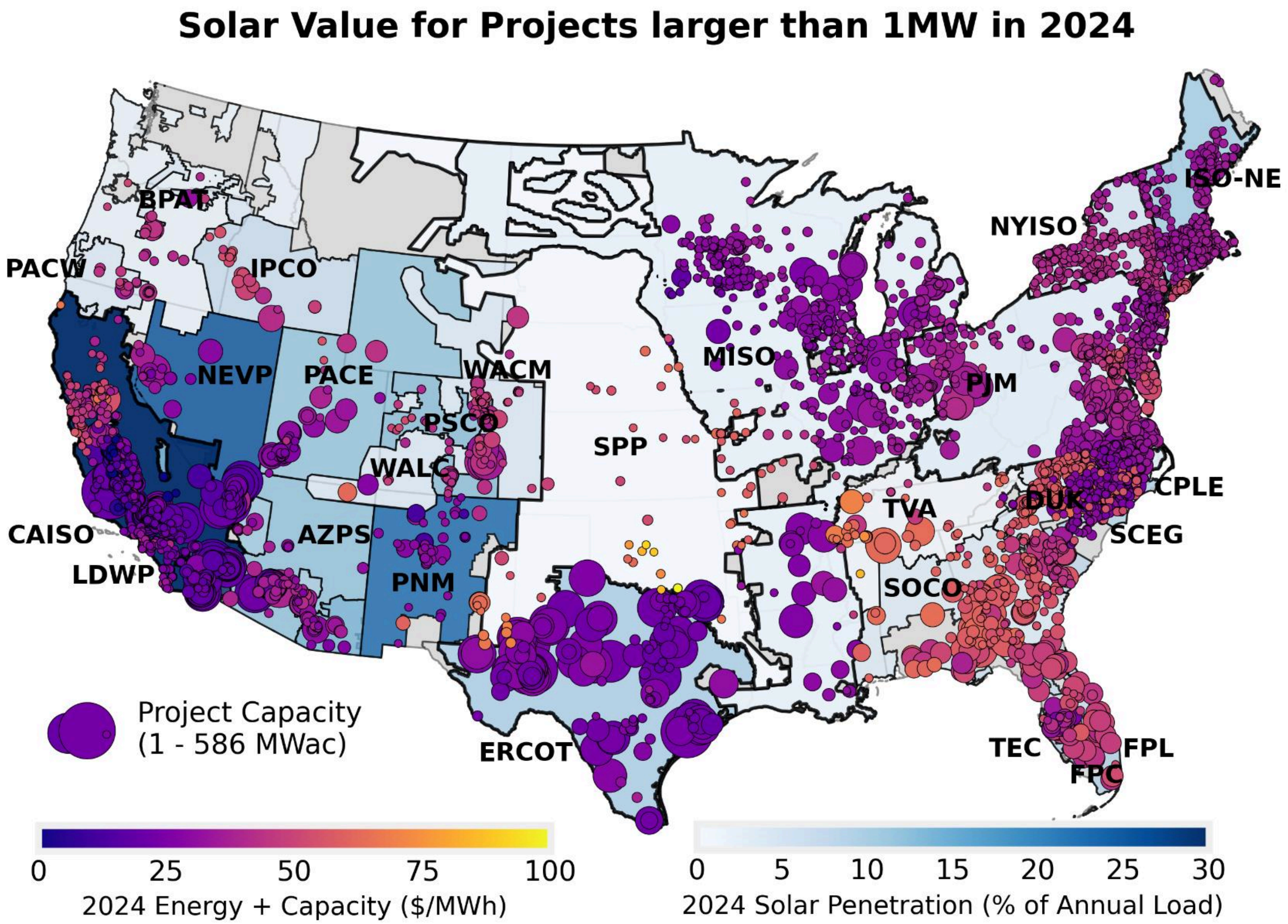


To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we present LevelTen Energy and Trio's PPA price indices.

Drivers of PPA price increases in recent years include:

- High interest rates leading to higher financing costs
- Long lead times for high- and medium-voltage equipment
- Supply constraints by these equipment lead times and long interconnection and permitting timelines
- High demand from corporations and utilities in advance of 2025 and 2030 emissions targets

Solar's energy and capacity value varied by location



Note: Marker size shows project capacity while marker color shows market value.

We estimate solar wholesale market value for 5571 projects in 30 Balancing Authorities (subset shown on the left map).

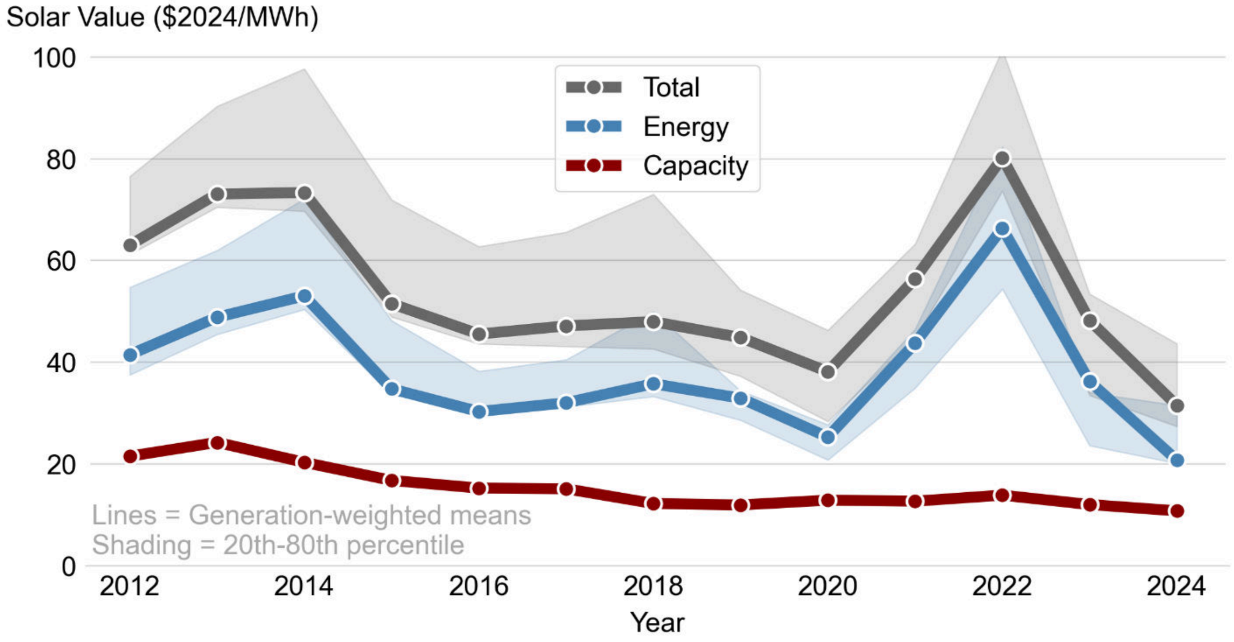
Value varies both between and within regions, driven by generator supply curves, transmission congestion, solar resource quality or differing use of technology like trackers.

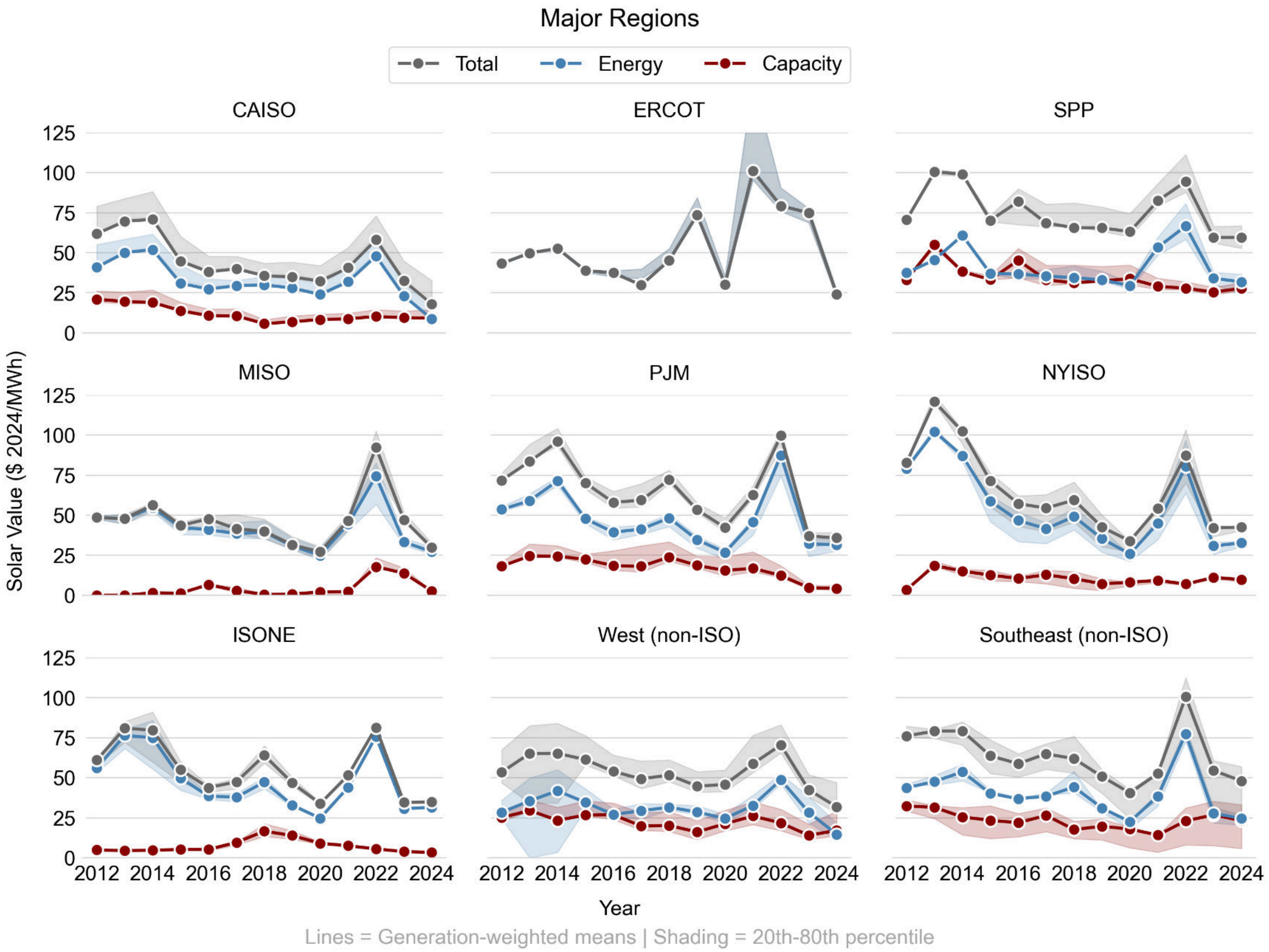
For example, in CAISO the northern zone has typically higher average values than the southern zone. Similarly solar in southern SPP and NYISO was much more valuable than solar in the north of the ISOs.

Other markets like ISO-NE show very little variation in annual average value between projects (10^{th} vs. 90^{th} percentile had a difference of less than $2/MWh).

You can explore this data interactively at https://emp.lbl.gov/utility-scale-solar-value

Solar's energy and capacity value declined to record low $32/MWh in 2024



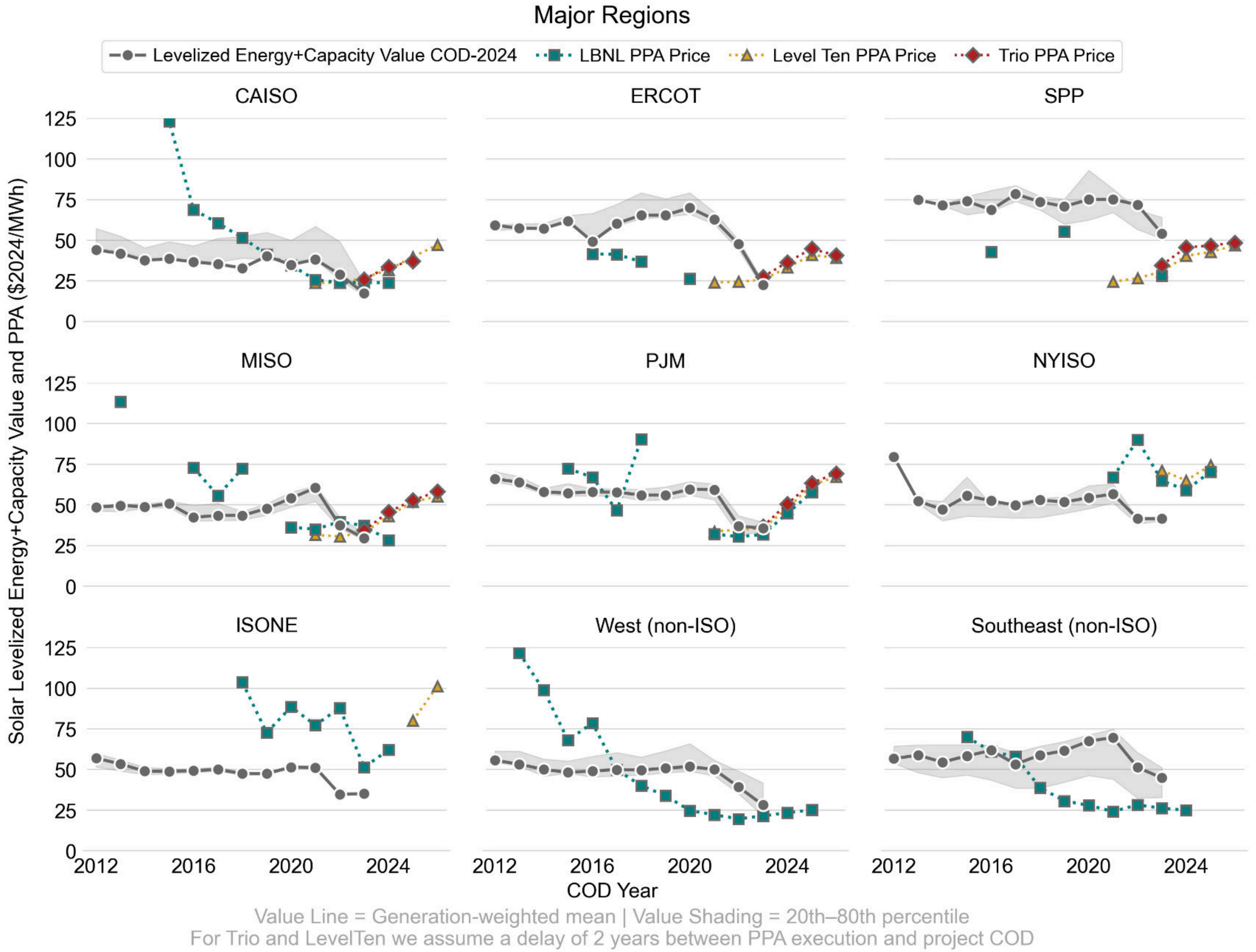


Driven by declining natural gas prices, fewer summer heat waves, and increasing penetration, solar's average market value decreased from $48/MWh in 2023 to only $32/MWh in 2024.

CAISO had the lowest standalone solar value at $18/MWh, while high capacity value supported solar in SPP ($60/MWh) and many southeastern BAs.

Note: The data shows generation-weighted average annual market value of all large-scale (1 MW+) solar projects in select Balancing Authorities. Non-ISO BA results are shown in the accompanying data file.

Market Value vs. PPAs: Rising prices for new PPAs exceed falling wholesale market value in some regions in 2024



PPAs provide the power purchaser a hedge value for price fluctuations over 10 to 20 years. A true benefit accounting should span the length of the PPA contract. We do not project future revenue and simply levelize wholesale market revenue between COD and 2024 as a proxy. PPA prices are influenced by solar's generation costs, solar's wholesale market "replacement costs", and broader supply and demand dynamics.

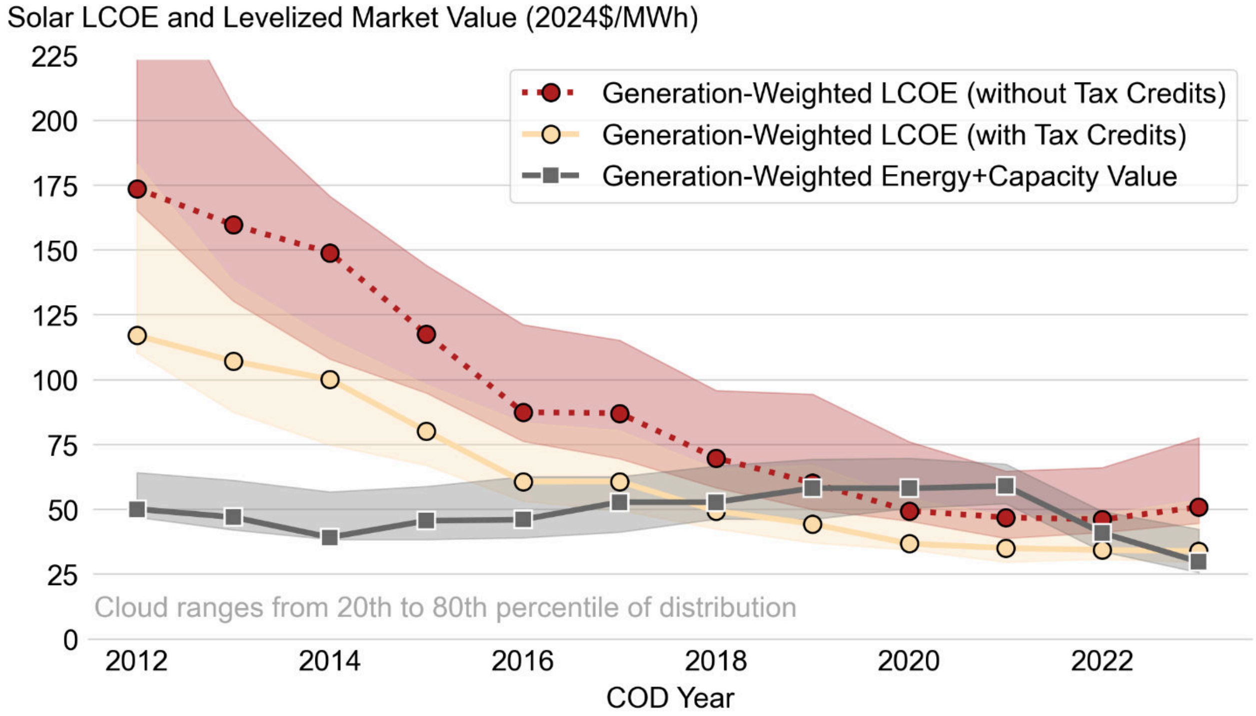
Falling PPA prices had largely kept pace with falling market value until PPAs started rising in 2021.

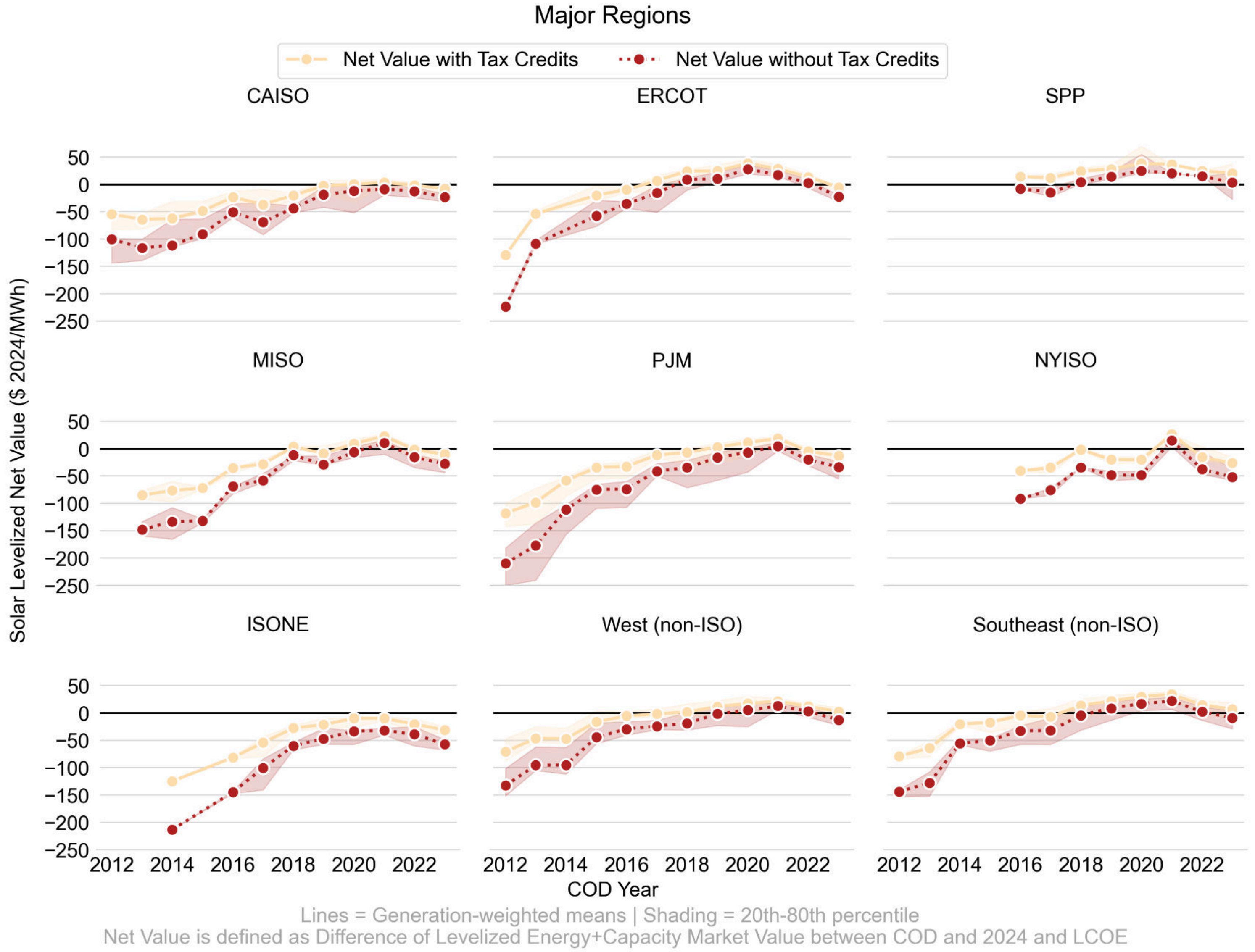
Temporarily high energy prices in 2022 more than compensated for emerging PPA price increases, but PPAs have begun to exceed wholesale market value in multiple regions (CAISO, ERCOT, MISO, PJM, NYISO and ISO-NE).

In contrast, solar offered greater value than what it is paid for in PPAs in SPP and many non-ISO BAs in 2024.

Note: We do not have sufficient PPA data to present robust trends for every balancing authority. PPAs are indexed here by Commercial Operation Date and span a longer time than the wholesale market estimates.

Market Value vs. LCOE (with tax credits): Solar projects coming online in 2018-2022 had on average greater value than generation costs





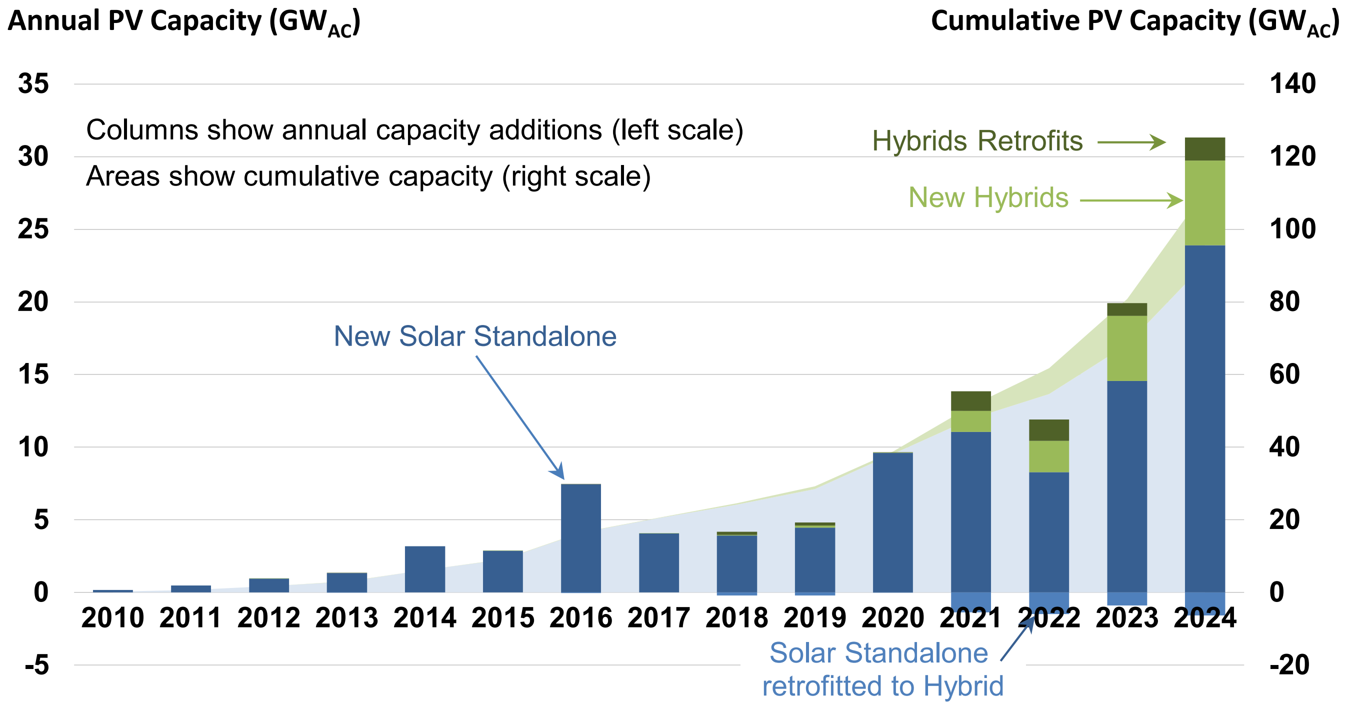
National average net value for 2023 COD solar standalone projects is slightly negative (-$4/MWh) even after accounting for tax credits.

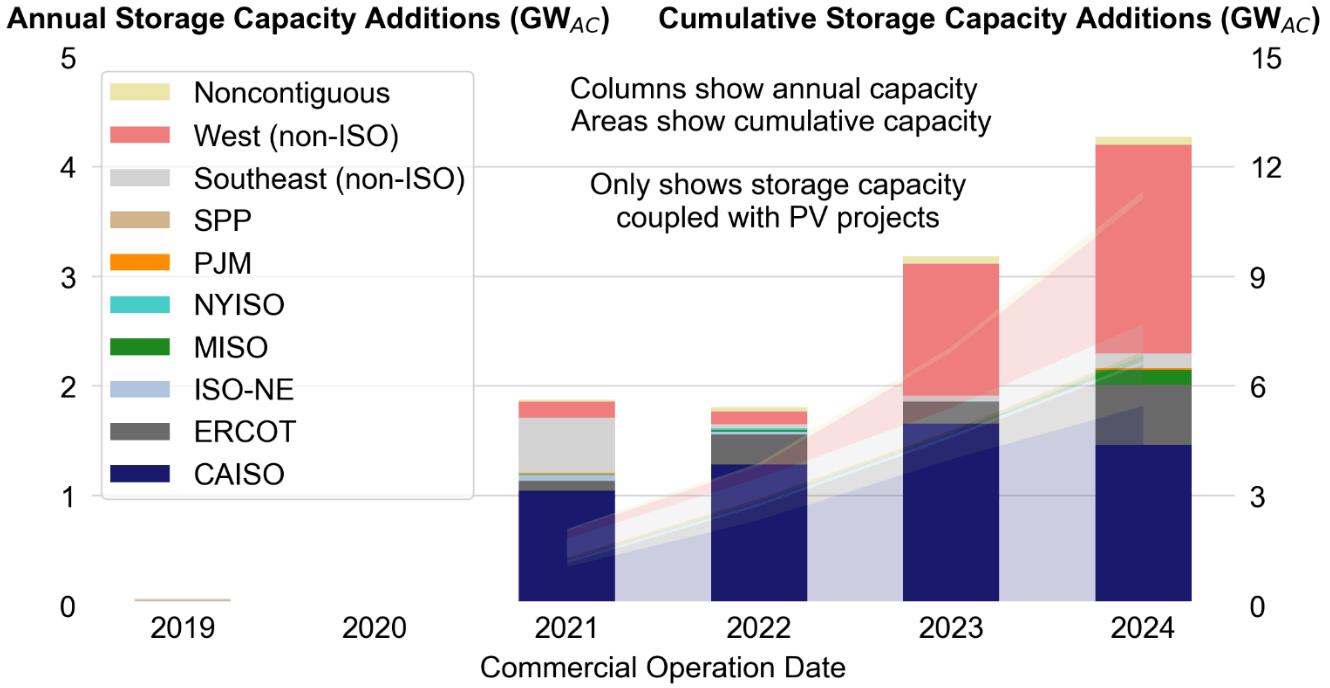
Net value varies by region from -$31/MWh in ISONE to $20/MWh in SPP. 10 out of 30 BAs still have positive net values

Note: For greater detail on methods and impacts, see Wiser et al (2024) Grid Value and Cost of Utility-Scale Wind and Solar: Potential Implications for Consumer Electricity Bills.

Deployment of PV-battery hybrid plants set a record with 7.4GW$_{AC\text{-}PV}$ greenfield and retrofit capacity in 2024

Sample: 201 projects totaling 19.9 GW$_{AC}$ of PV, 11.4 GW$_{AC}$ of battery capacity, and 36.3 GWh of battery energy

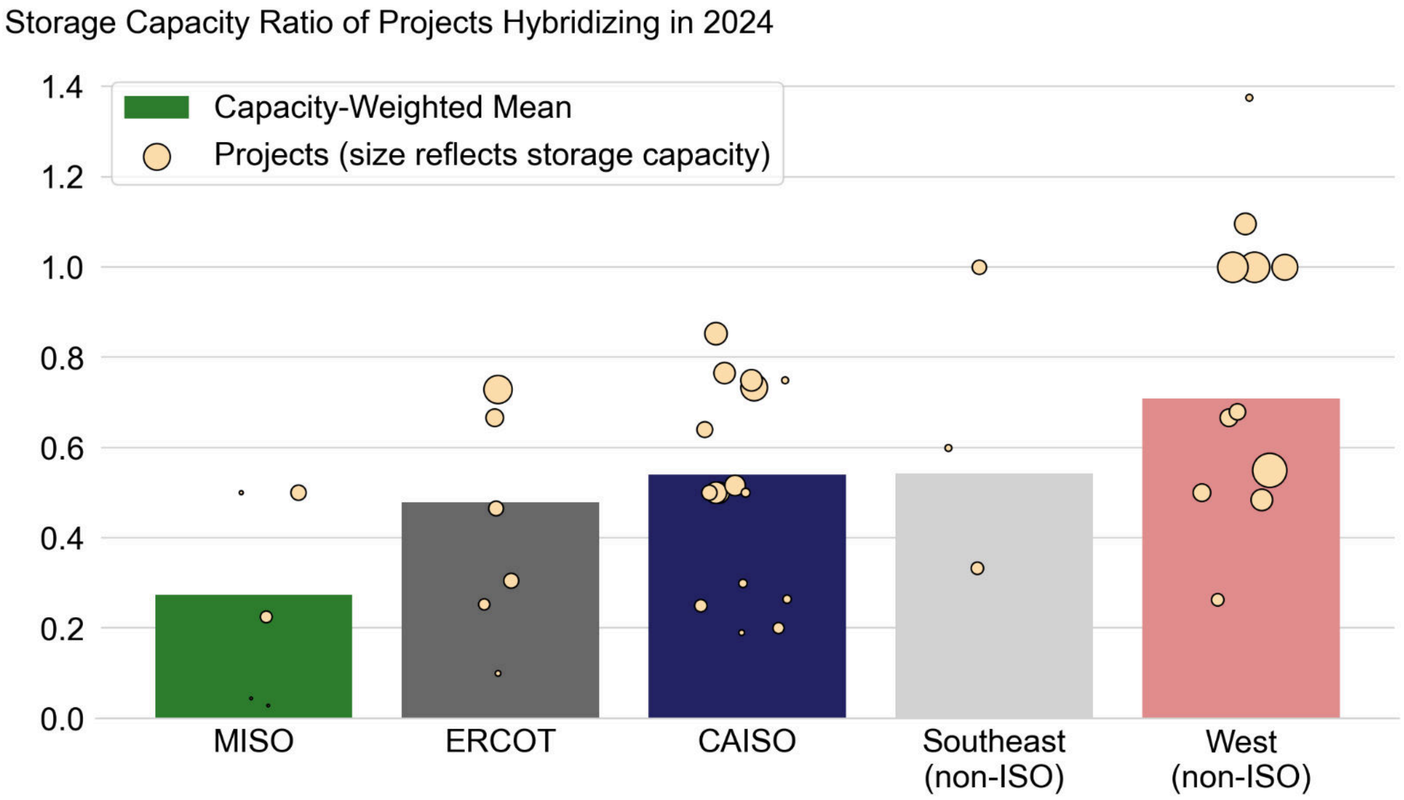


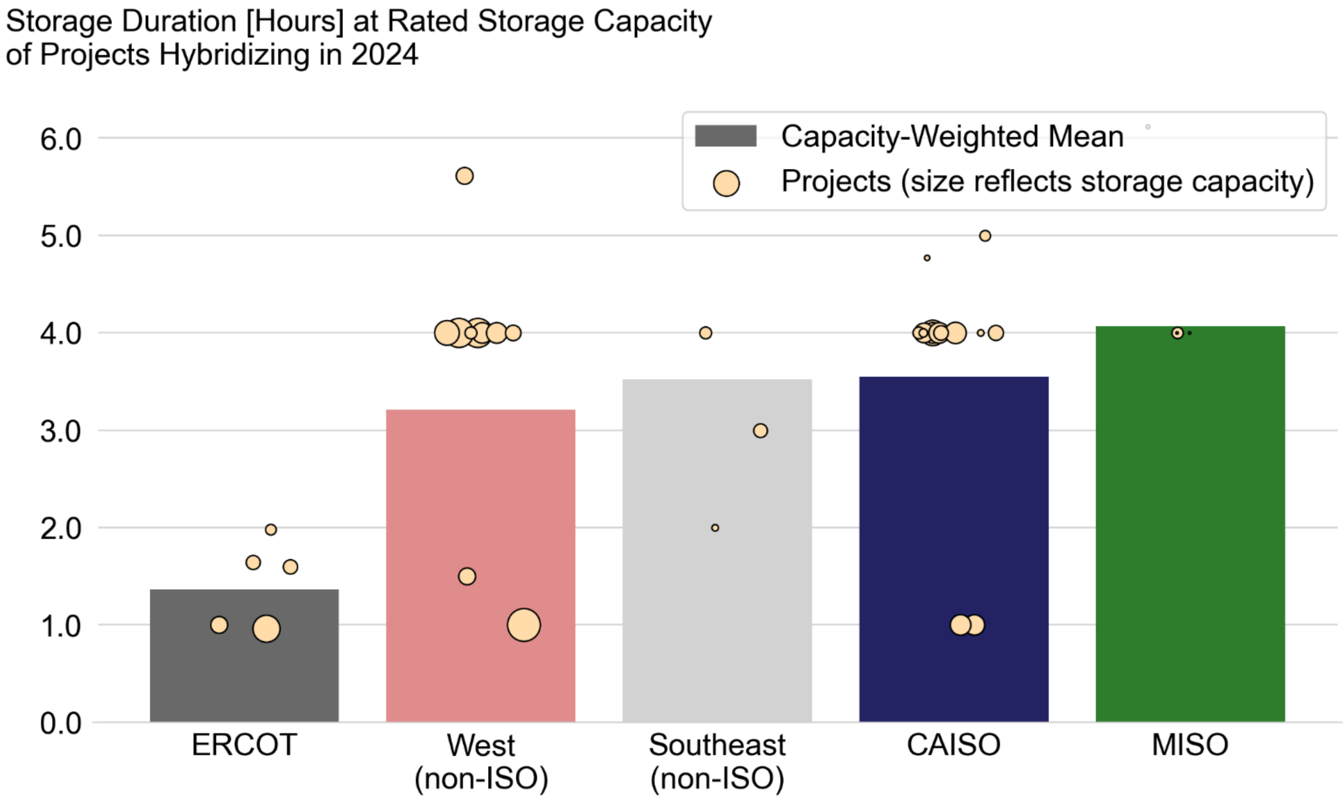


The large-scale PV+battery hybrid market started in earnest in 2021 with 39 hybrid installations. 2024 was another record year both for newly built hybrids (33 plants, 5.8 GW$_{AC\text{-}PV}$) and storage retrofits to existing stand-alone solar projects (14 plants, 1.6 GW$_{AC\text{-}PV}$).

Most of the new hybrid storage was built in the solar-rich non-ISO West (13 plants, 1.9GW$_{Storage}$) followed by CAISO (16 plants, 1.5 GW$_{Storage}$). ERCOT grew rapidly (6 plants, 0.5 GW$_{Storage}$) and MISO had its first larger deployment (5 plants, 0.1GW$_{Storage}$).

National Storage Capacity Ratio grew to 0.57 with 3.3h of duration in 2024



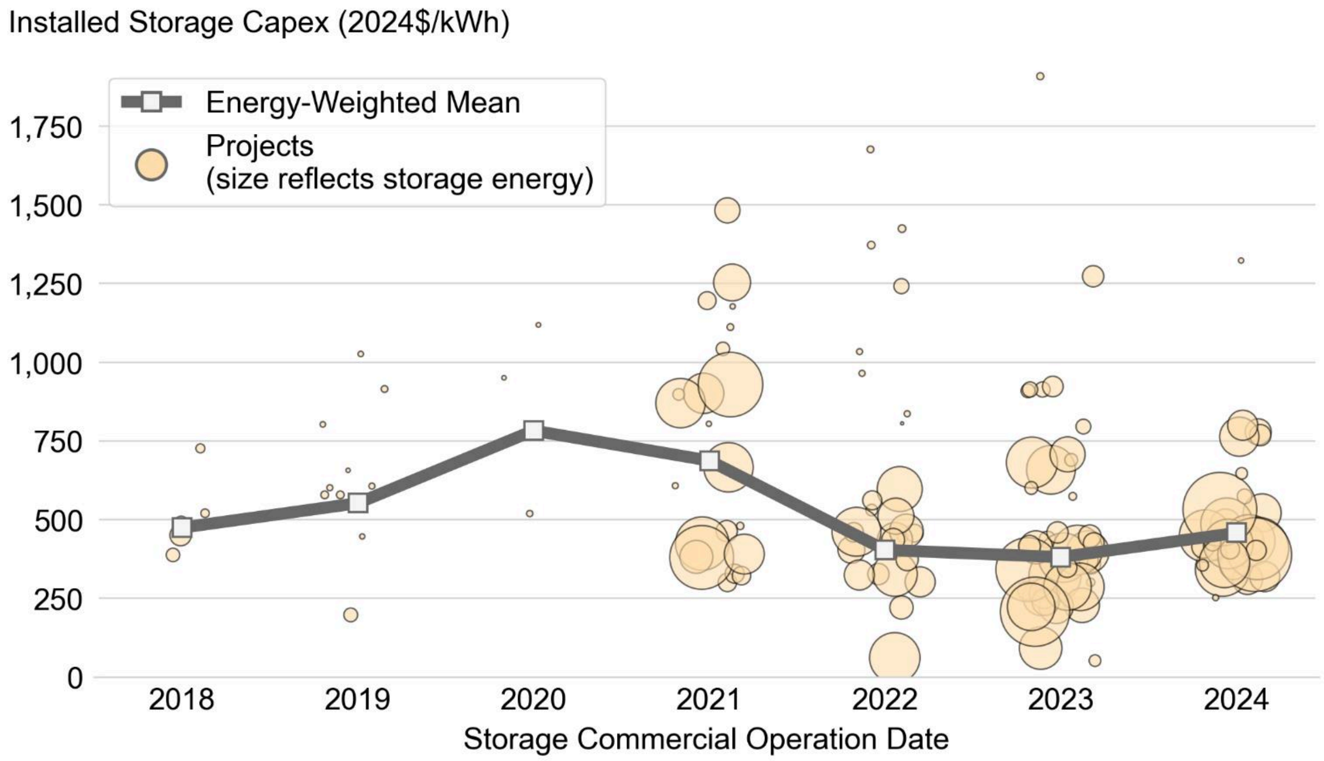


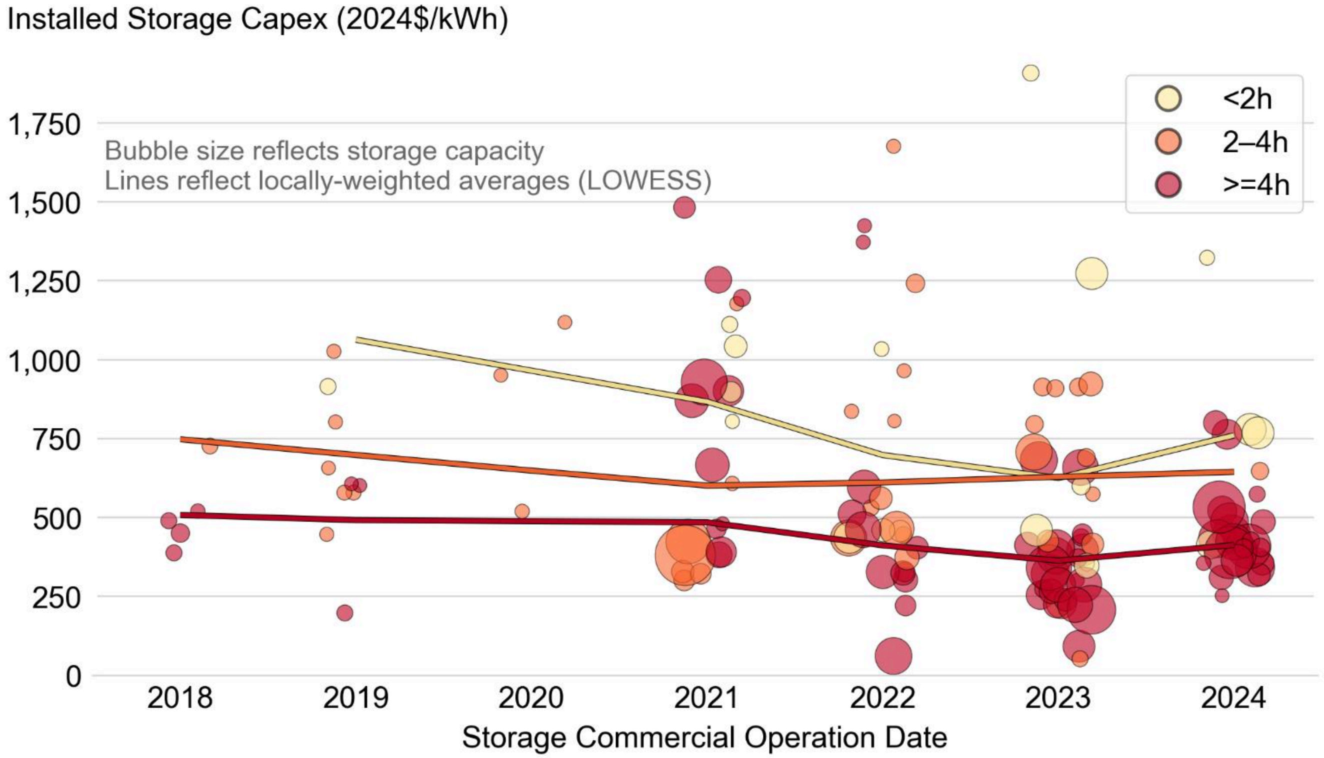
Storage Capacity Ratio describes the battery size relative to solar capacity (MW_{AC}). In 2024 it is greatest in the non-ISO West and lowest in PJM and MISO.

Storage duration at full rated capacity is shortest in ERCOT (even decreasing over the past few years) and often above 3h in the rest of the country.

Costs of co-located storage has increased slightly in $/kWh terms in 2024

Sample: 138 projects totaling 8.5 GW and 29.5 GWh of batteries



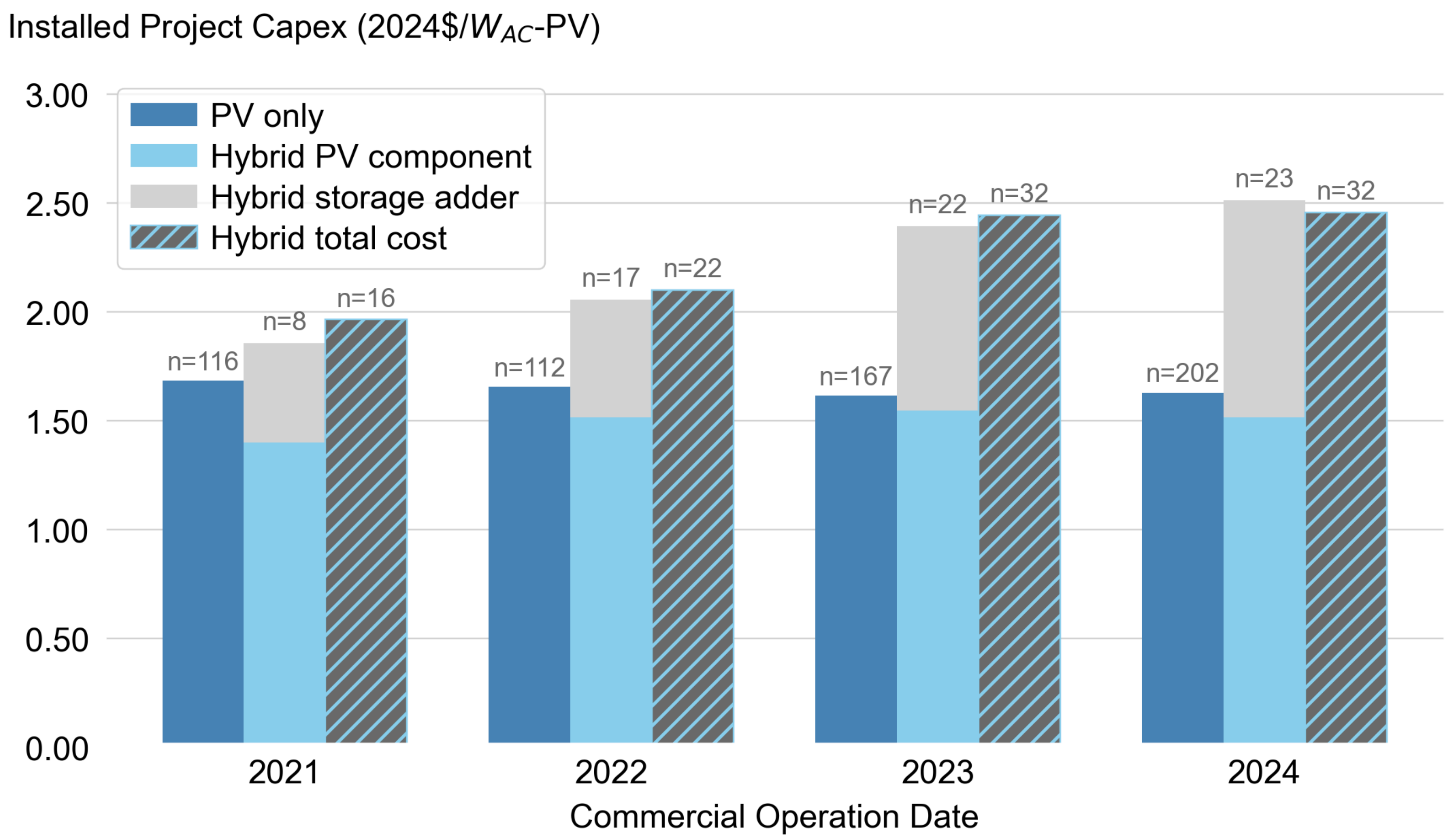


Capacity-weighted average costs increased from $381/kWh in 2023 to $458/kWh in 2024. Costs are lowest in MISO ($351/kWh) and greatest in the non-ISO Southeast ($473/kWh).

Longer duration storage is cheaper on a per kWh basis than shorter duration storage, indicating economies of scape.

Costs of PV-storage hybrids remained stable are $2.46/W$_{AC\text{-}PV}$ in 2024

Sample: 102 greenfield plants totaling 12.4 GW$_{AC}$ of PV and 6.6 GW / 23.1 GWh of batteries

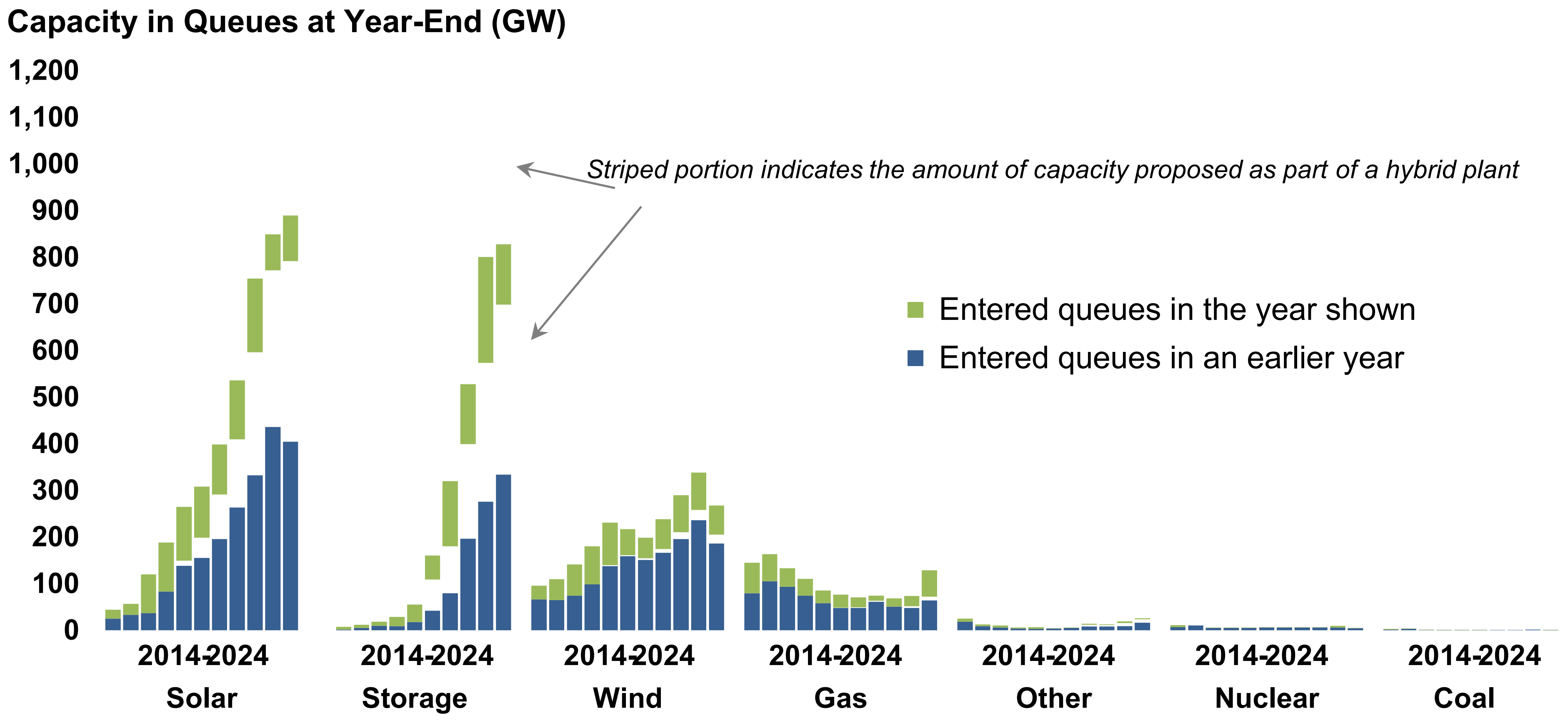


Focusing only of greenfield hybrid developments (excluding retrofits), average cost of PV components of a co-located project are slightly lower than for a PV-standalone project (due to shared infrastructure like inverter for DC-coupled installations or other factors like economies of scale).

For some hybrid projects we lack component-level costs and can only report total system costs (hatched).

Looking ahead: Strong growth in the utility-scale solar pipeline

Sample: Active bulk-power interconnection requests from 51 interconnection queues.



953 GW of solar was in the queues at the end of 161 GW of this total entered the queues in 2024 (the remainder entered in earlier years and remain active).

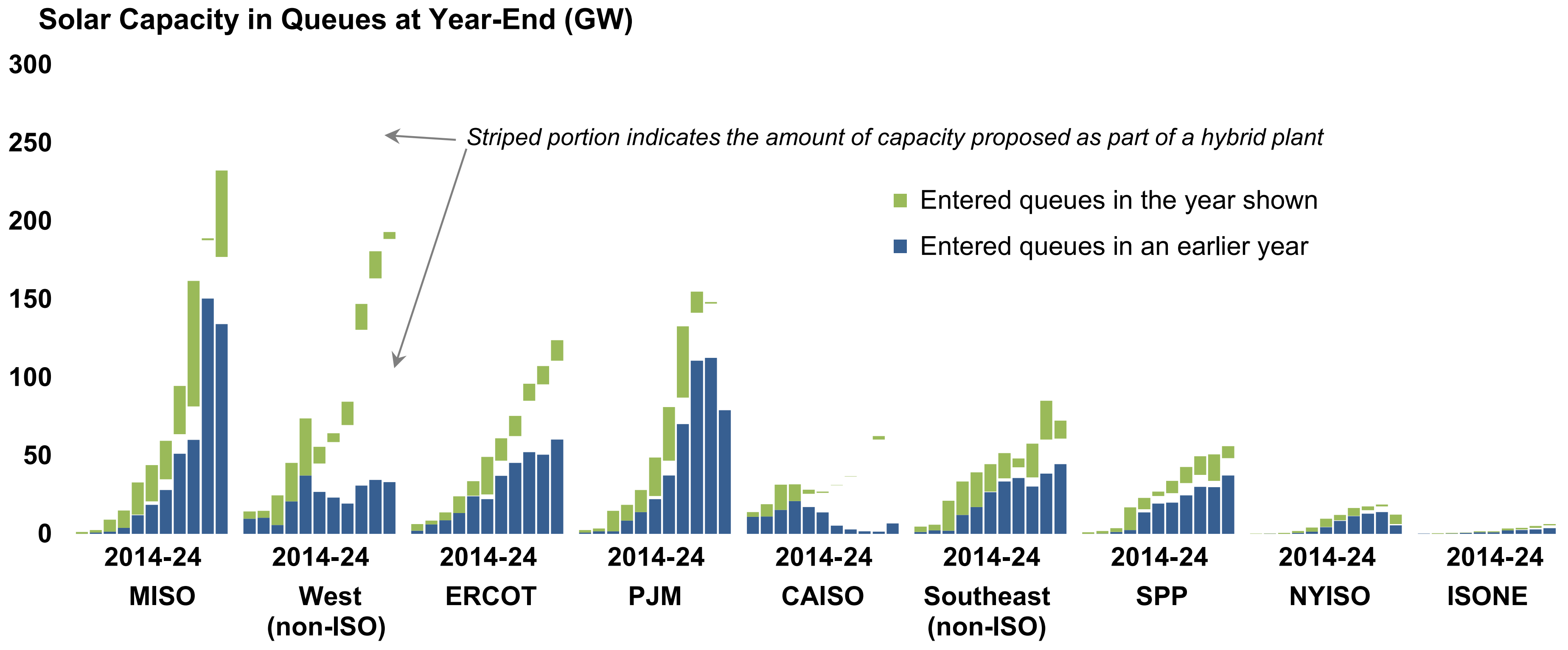
450 GW of the 953 GW of solar in the queues (47%) includes a battery in a PV hybrid configuration.

Solar (both in standalone and hybrid form) is the largest resource within these queues, followed closely by storage, with wind and gas a distant 3rd and 4th. (All other resources are negligible in comparison.)

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

Looking ahead: Continued broadening of the market

Sample: Data from 51 interconnection queues across the U.S.



Most regions of the country saw growth in the amount of queued solar, with MISO and the non-ISO West leading the way in 2024

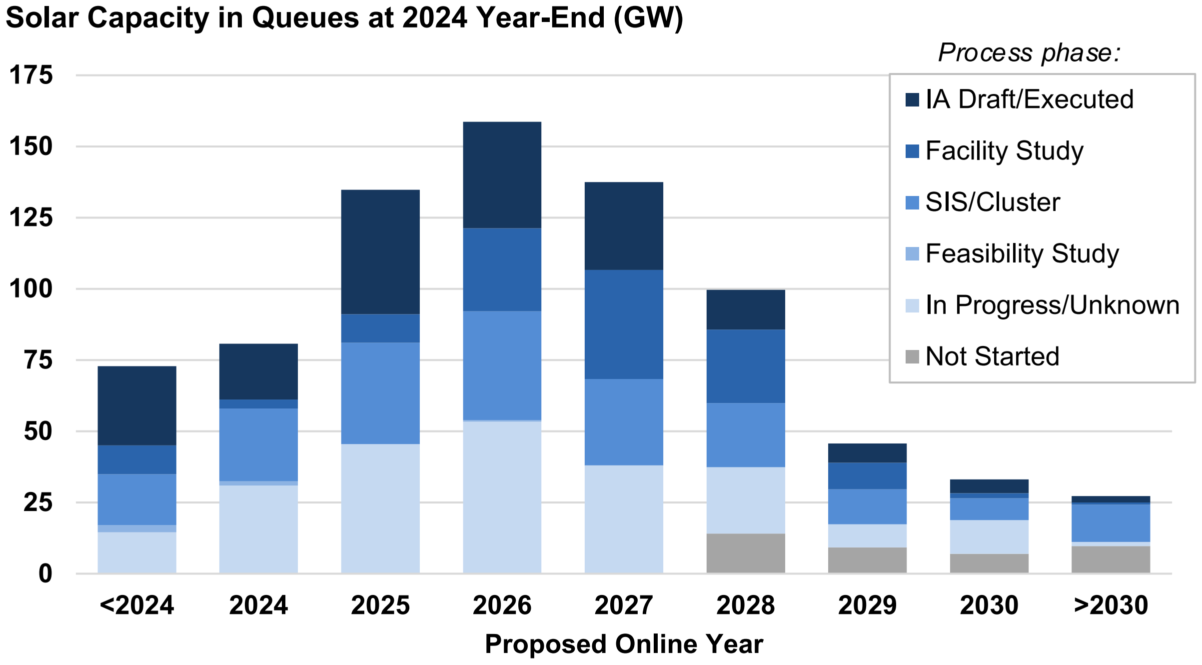
- CAISO and PJM did not accept new interconnection requests in 2024, so all solar in those queues entered in an earlier year

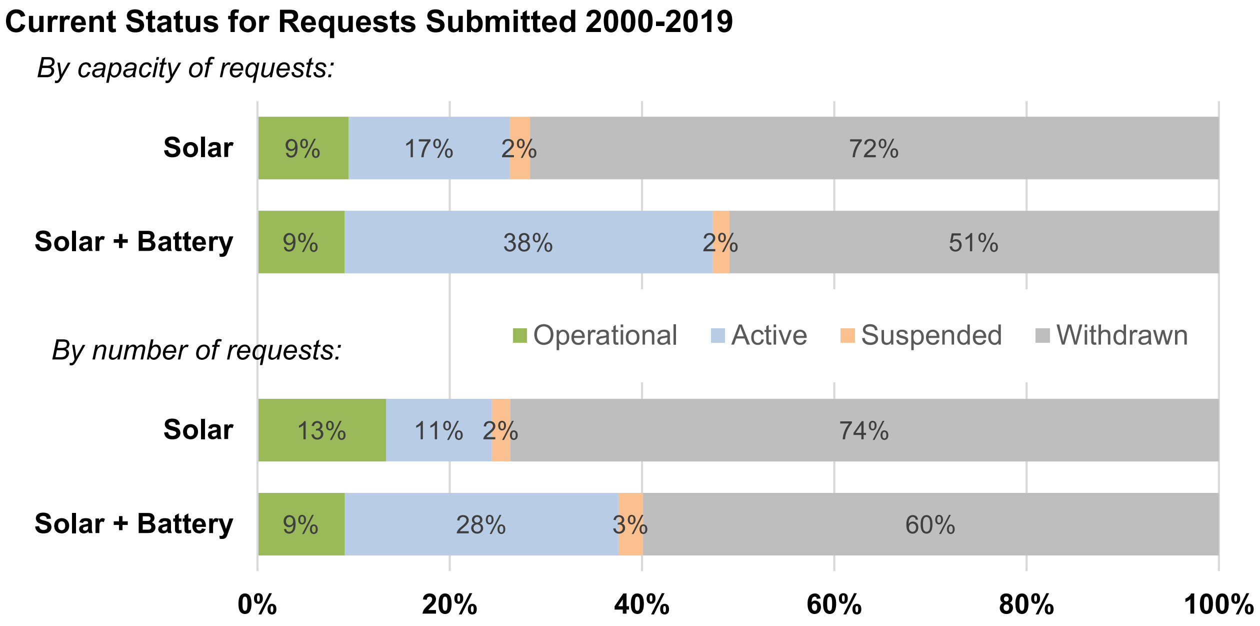
93% of the solar capacity in CAISO's queue at the end of 2024 was paired with a battery; in the non-ISO West, that number was also high, at 83%

- Both regions are grappling with "duck curve" issues due to solar's relatively high market share

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

Most active solar proposes to be online by 2028, but the historical completion rate for solar projects requesting interconnection is low





- Few solar projects have requested interconnection with a proposed online date of 2029 or later
- Proposed online dates are included in the developer's original interconnection request and may differ from actual online date
  - 154 GW of active solar requests were already past their proposed online date at the end of 2024
- 187 GW of solar capacity have an interconnection agreement (either draft or executed) – these projects are the most likely to be completed

- If historical patterns persist, only ~9% of solar capacity requesting interconnection will ultimately get built and become operational
- Developers withdraw interconnection requests for myriad reasons:
  - Some reasons are based in the interconnection process, such as high cost to interconnect and study delays
  - Some reasons arise outside of the interconnection process, such as failure to secure financing or an offtaker, permitting issues, or insufficient resources to complete all proposed projects

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

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For more information

Explore this report deck, a written technical brief, an extensive workbook with all underlying data, and interactive visualizations: http://utilityscalesolar.lbl.gov

For questions or technical assistance requests, contact:

Joachim Seel (JSeel@lbl.gov)
Julie Mulvaney Kemp (JMulvaneykemp@lbl.gov)

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Appendix

Presentation Contents

Deployment and Technology Trends

Capital Costs (CapEx) and Operation & Maintenance (O&M) Costs

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Wholesale Market Value and Net Value

PV+Battery Hybrid Plants

Capacity in Interconnection Queues

Deployment and Technology Trends: data and methodology

Deployment Trends Data: National and state-level deployment data are sourced from the Energy Information Administration (EIA), the American Clean Power Association (ACP), Wood Mackenzie/SEIA Solar Market Insight Reports, and Berkeley Lab datasets.

Technology Trends Data: Project-level metadata are sourced from a combination of Form EIA-860, FERC Form 556, state regulatory filings, interviews and websites of project developers and owners, and news and trade press articles. We independently verify much of the metadata—such as project location, fixed-tilt vs. tracking, azimuth—via satellite imagery.

Methods: Because we collect data from a variety of unaffiliated and incongruous sources, the data must be synthesized and cleaned in multiple steps before becoming useful for analytic purposes. In some cases, we essentially create new data by piecing together various snippets of information that are of less consequence on their own.

Capital and Operation & Maintenance Costs: data and methodology

CapEx Data:

- Project-level capital expenditure (CapEx) estimates are sourced from a combination of Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, and trade press articles.
- CapEx estimates for projects built from 2013-2024 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement. Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA. Berkeley Lab did not include all preliminary data points after a data review and will provide revised estimates at a later update.

CapEx Methods:

- We present data in $/$W_{AC}$ terms to facilitate cost comparison between generators of multiple fuel types. The accompanying data file on our project website also provides detailed data in $/$W_{DC}$ terms. CapEx is adjusted from nominal to real $ using BEA's implicit GDP price deflator (Table 1.1.9).
- We define cost scope in close alignment with EIA's 860 Schedule 5B (p29) to include:
  - construction costs (civil and structural costs, equipment and installation, electrical and instrumentation, indirect costs (incl. overhead and profits) and owner costs (incl. tie-in and potential transmission network upgrades)). For a detailed analysis of interconnection costs of utility-scale solar see https://emp.lbl.gov/interconnection_costs.
  - construction finance costs.
- We first show costs for PV standalone projects (or PV component costs of hybrid projects). Storage costs are discussed later in the hybrid section.

O&M Data:

- Plant-level operation and maintenance costs, capacity, net generation, and construction year are sourced from FERC Form 1 Annual Reports, which are filed by major electric utilities.

O&M Methods:

- We exclude O&M cost observations from the year a plant was constructed to avoid data based on a partial year of operations.
- We also exclude projects ≤5 MW in size, consistent with our definition of utility-scale.
- We present data for combined operations and maintenance costs in $/k$W_{AC}$ (capacity denomination) and $/MWh (generation denomination) terms.

PV performance analysis: data and methodology

Net generation data are sourced largely from EIA Form 923. These data reflect net generation and thus exclude energy used by the plant itself. They also exclude energy that was curtailed (for economic or system stability reasons). Outliers and low-quality data are dropped from the analysis. We exclude observations from the first calendar year of the plant's operation.

Net Capacity Factors (AC) measure a plant's performance, representing the ratio of its actual annual generation delivered to the grid to the maximum possible annual output if it operated continuously every hour of the year.

$$Annual\ Net\ Capacity\ Factor = \frac{Annual\ Net\ Generation\ (MWh)}{Capacity\ (MW_{AC}) * number\ of\ hours\ in\ year}$$

We use MW_{AC} capacity terms in our capacity factor calculations to facilitate comparisons with other bulk system generator types.

Annual generation can vary based on weather and climate variability, system degradation, system uptime, or curtailment. We thus present primarily **cumulative net capacity factors**, which represent the average capacity factor over the lifetime of a project up until the most recent reported period (i.e., no future modeled generation data).

LCOE analysis: data sets and methodology

Methods:

- For our project-level LCOE estimates of solar projects we follow the formula published in NREL's Annual Technology Baseline.
- We use LCOE as proxy for generation costs in later parts of this presentation. It is important to note that additional integration costs (transmission needs beyond what is captured via interconnection costs and LMP congestion components or ancillary service costs) are not fully accounted for here.

Data and Assumptions:

- LCOE will be presented first without and then later with inclusion of federal tax credits (assuming labor requirements for ITC and PTC are met, including Energy Community adders where applicable, but assuming no Domestic Content adders).
- Project-level variation:
  - **Capex:** LCOE is only calculated for projects with empirical cost estimates, only costs of solar components are used for PV-battery projects.
  - **Net Capacity Factor:** We use empirical annual NCF estimates based on EIA 923 data when available. For missing and future years we assume annual degradation rates ranging between 1.47% (pre-2013) and 0.9% (post-2016). For projects without any reported generation (e.g., most recent COD cohort) we use the regional average NCF of recent projects. NCF is levelized over the project design life.
- Cohort-level variation:
  - **OpEx** is levelized and declines from \$50/kW$_{DC}$-yr in 2007 to \$25/kW$_{DC}$-yr in 2024 (in 2024\$, based on prior LBNL and NREL Benchmarks)
  - **Project design life** increases from 21.5 years in 2007 to 35 years in 2021 and thereafter (prior LBNL research).
  - **Weighted average cost of capital (WACC):**
    - based on a constant 70%/30% debt/equity ratio and time-varying market rates.
    - Combined income tax rate of 38.25% pre-2018 and 24.95% post-2017.
    - 5-yr MACRS; forward-looking annual inflation expectations range from -0.2% (early Covid pandemic) to 4.2%.
    - Real WACC for 2024 COD projects is 3.26%.

Power Purchase Agreement (PPA) price analysis: data sets and methodology

PPA prices are from utility-scale solar plants built since 2007 or planned for future installation, and include:

- 472 PV-only contracts totaling 36.8 GW_{AC}
- 104 PV+battery contracts totaling 13.0 GW_{AC} of PV capacity and 7.8 GW_{AC} / 30.9 GWh of battery capacity (presented in a later section)
- 5 concentrating solar thermal power (CSP) contracts totaling 1.2 GW_{AC} (presented in a later section)

PPA prices reflect the bundled price of electricity and RECs as sold by the project owner under the PPA

- Dataset excludes merchant plants, projects that sell renewable energy certificates (RECs) separately, and most direct retail sales
- PPAs are priced to recover both capital and other ongoing operational costs while accounting for the receipt of state and federal incentives (e.g., the ITC) and, as a result, do not simply reflect solar generation *costs.* Ultimately PPA prices reflect marketplace conditions, including the supply of ready-to-build plants, cost of capital, and demand for energy, capacity, and RECs.

Data collection

- We gather PPA price data from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, and trade press articles. We prioritize data quality over quantity in this process. That is, we only include a PPA within our sample if we have high confidence in all of the key variables such as execution date, starting date, starting price, escalation rate (if any), time-of-day factor (if any), and term.
- To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we also compile LevelTen Energy[1] and Trio[2] data on PPA offers (25^{th} percentile). These often reflect shorter contract durations and target voluntary and corporate offtakers, though fewer contract specifics are known relative to the PPA data we collect directly.

Levelization methodology

- We deflate the nominal dollar price series to 2023 dollars using a GDP deflator (actual deflators historically, along with projected future deflators), and then levelize the resulting price series using a 4% real discount rate.
  - For PPA prices we collect, prices are levelized over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors.
  - For LevelTen Energy and Trio, we assume the reported prices are for 12-year, flat-priced (in nominal dollars) PPAs that commence in the following calendar year.

[1] https://www.leveltenenergy.com/ppa
[2] https://www.trioadvisory.com/publications

Wholesale market value analysis: data sets and methodology I

We estimate the wholesale market value for each utility-scale PV project larger than 1 MW (as reported on Form EIA-860). Each project-level estimate may be prone to some biases - greater emphasis should thus be placed on the aggregate generation-weighted averages which we calculate for all seven ISOs and ten additional balancing authorities.

We draw from project-level modeled hourly solar generation (using NREL's System Advisor Model and site- and year-specific insolation data from NREL's National Solar Radiation Database and NOAA's High Resolution Rapid Refresh Model) and de-bias the generation by leveraging ISO-reported aggregate solar generation and plant-level reported generation by Form EIA-923. Hourly curtailment data is either derived from plant-level reports (ERCOT: HSL minus MW) or allocated from ISO-level reports (CAISO and SPP).

Energy value is the product of hourly solar generation by plant or county and concurrent wholesale energy prices

- Plant-level debiased hourly solar generation
- Real-time energy price from
  - nearest LMP node (ISOs, CAISO's + SPP's EIM/EIS BAs)
  - FERC Lambda for some BAs without ISO connection

$$Energy\ Value = \frac{\sum Postcurtailment\ Generation_h * Wholesale\ RT\ Energy\ Price_h}{\sum Precurtailment\ Generation_h}$$

Capacity value is the product of a plant's or county's capacity credit and capacity prices

- Capacity credit based on plant-level profile; varies by month, season, or year
- Capacity prices from respective ISO region; prices vary by month, season, or year
- Estimate bilateral capacity prices for regions without organized capacity markets
- Focus on annual value of solar for projects with a full calendar year of operation
- Calculate capacity value for all solar, even if some solar does not participate in capacity markets

$$Capacity\ Value = \frac{\sum Capacity\ Credit_T * Nameplate * Capacity\ Price_T}{\sum Precurtailment\ Generation_T}$$

For more information, see Berkeley Lab's publication: "Solar-to-Grid: Trends in System Impacts, Reliability, and Market Value in the United States with Data Through 2020." https://emp.lbl.gov/publications/solar-grid-trends-system-impacts-0

Wholesale market value analysis: data sets and methodology II

- **Total wholesale market value** is simply the sum of solar’s energy and capacity value
  - It represents the “replacement costs” of what an offtaker would have to pay in the wholesale market had they not procured solar generation. Revenues for a solar project owner are set by their PPA terms and may differ from our estimate. However, in a market with little friction, we expect long-term convergence.
  - It does not include any potential additional revenue streams (ancillary service (AS) revenues, renewable energy credits, infrastructure deferral, or resilience that are not already internalized in wholesale energy and capacity markets).
  - It is based on the real-time LMP market and thus reflects the marginal solar value. It does not fully consider sub-hourly variability and forecast errors.
  - It excludes broader sectoral impacts such as merit-order effect on power prices or reduced natural gas demand and associated price declines.

- **Generation costs** are approximated by LCOE (with and without tax credits), but do not include:
  - Full integration costs (AS) or transmission needs (beyond LMP congestion components and interconnection network upgrade costs).
  - The full cost to the Treasury of federal investment and production tax credits.
  - Other costs and benefits to local communities and ecosystems.

- The **Value Factor** is defined as the ratio of solar’s total market value to the market value of a 'flat block' of power (i.e., a 24x7 block).
  - It indicates whether solar’s total revenue is above or below the average wholesale revenue, with generators delivering electricity during high-value hours achieving a value factor above 100%.“
  - 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.

Other recent publications from our team related to utility-scale solar

Annual Reports

[Queued Up: 2024 Edition]

Berkeley Lab's annual report documents the growing backlog of new power generation, particularly solar, wind, and storage, seeking transmission connections.

[Hybrid Power Plants: 2024 Edition]

This annual briefing tracks existing hybrid plants in the U.S. while also synthesizing data from PPAs and interconnection queues to shed light on future growth.

[U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update]

This report provides a status update on state renewable portfolio and clean electricity standards.

[U.S. Large-Scale Solar Photovoltaic Database]

In collaboration with the USGS, the USPVDB creates an accurate, comprehensive, and publicly accessible national large-scale PV database of large-scale PV facilities.

Siting and Community Engagement

[Developer Practices and Perspectives on Community Engagement for Utility-Scale Renewable Energy in the United States]

A survey of professionals shows that renewable developers use community engagement strategies but favor limited public input, falling short of full citizen empowerment.

[Laws in Order: An Inventory of State Renewable Energy Siting Policies]

This report outlines state and territorial authorities responsible for siting and permitting large-scale wind and solar projects, alongside an interactive map for exploring state-specific information.

[Perceptions of Large-Scale Solar Project Neighbors]

A survey of residents living near large-scale solar projects provides insights into local perceptions that can inform future large-scale solar deployment.

Value of Renewable Energy

[The Renewables and Wholesale Electricity Prices (ReWEP) Tool]

The ReWEP tool allows users to explore trends in nodal wholesale energy pricing and their relationship to renewable generation.

[Grid Value and Cost of Utility-Scale Wind and Solar: Potential Implications for Consumer Electricity Bills]

This research quantifies the market value of wind and solar over time, exploring how contractual and market structures influence consumers' ability to benefit from cost savings.

[Renewable-Battery Hybrid Power Plants in Congested Electricity Markets]

Berkeley Lab's analysis of hybrid renewable-battery plants in congested U.S. regions reveals optimal energy and capacity value for solar and wind hybrid projects.

[Solar and Storage Integration in the Southeastern U.S.]

This study evaluates how varying levels of solar and storage would affect electricity system costs, reliability, and operations in the Southeast U.S. by 2035.

Join our mailing list to receive notice of future publications: https://emp.lbl.gov/mailing-list

Deployment and Technology Trends

Solar generation's market share was 6.9% across the U.S. in 2024, but reached >30% in California and Nevada

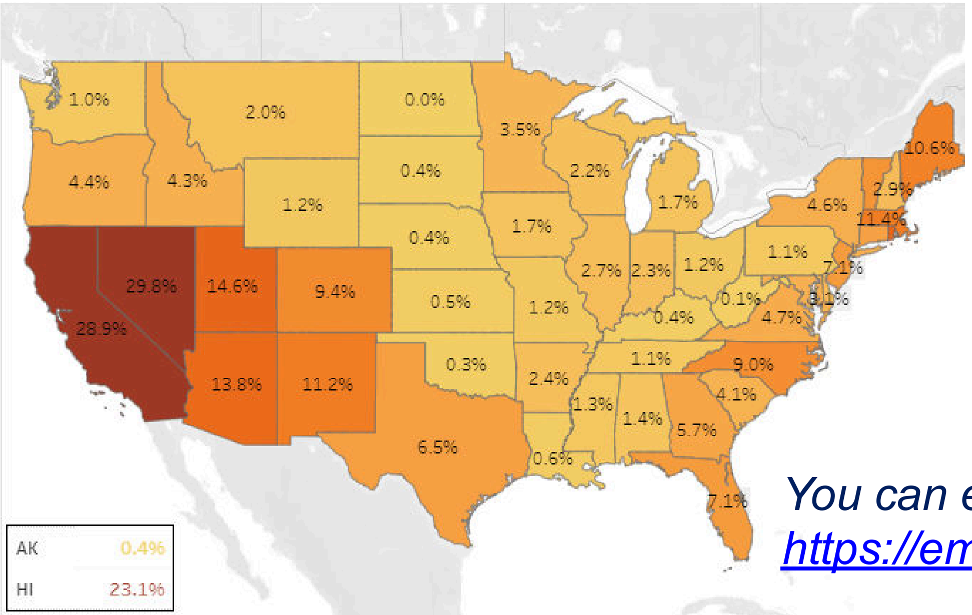
State	Preliminary 2024			
	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	32.4	19.5	28.8	17.3
Nevada	30.5	26.2	34.0	29.2
Massachusetts	25.6	9.1	11.8	4.2
Hawaii	21.5	6.8	22.1	7.0
Vermont	16.8	8.0	8.2	3.9
Utah	16.6	13.8	16.7	13.9
Maine	14.2	7.3	17.1	8.8
Arizona	13.3	8.9	17.0	11.3
Rhode Island	13.1	6.1	16.4	7.7
New Mexico	12.5	10.5	16.4	13.9
Colorado	11.5	8.1	11.9	8.4
North Carolina	9.7	9.0	9.6	8.9
Florida	8.6	6.9	9.0	7.2
New Jersey	8.0	2.8	6.8	2.3
Virginia	7.8	6.8	5.9	5.1
Texas	7.8	7.0	8.9	7.9
Delaware	7.5	3.4	3.2	1.4
Maryland	7.0	3.0	4.3	1.8
Idaho	6.9	5.4	4.9	3.8
Georgia	6.6	6.2	6.3	5.9
TOTAL U.S.	**6.9**	**5.0**	**7.5**	**5.4**

Solar market share can vary considerably depending on whether it is calculated as a percentage of total generation or load (e.g., Vermont).

As a percentage of in-state generation, California's solar market share reached 32% in 2024, while Nevada, Massachusetts, Hawaii, Vermont, and Utah all surpassed 15%.

The utility-scale sector's contribution varies by state: a minority in the Northeast and Hawaii, a majority elsewhere in the U.S.

Percentage of In-State Electricity Sales and Generation from Solar PV, as of 2023



You can explore this data over time at https://emp.lbl.gov/capacity-and-generation-state

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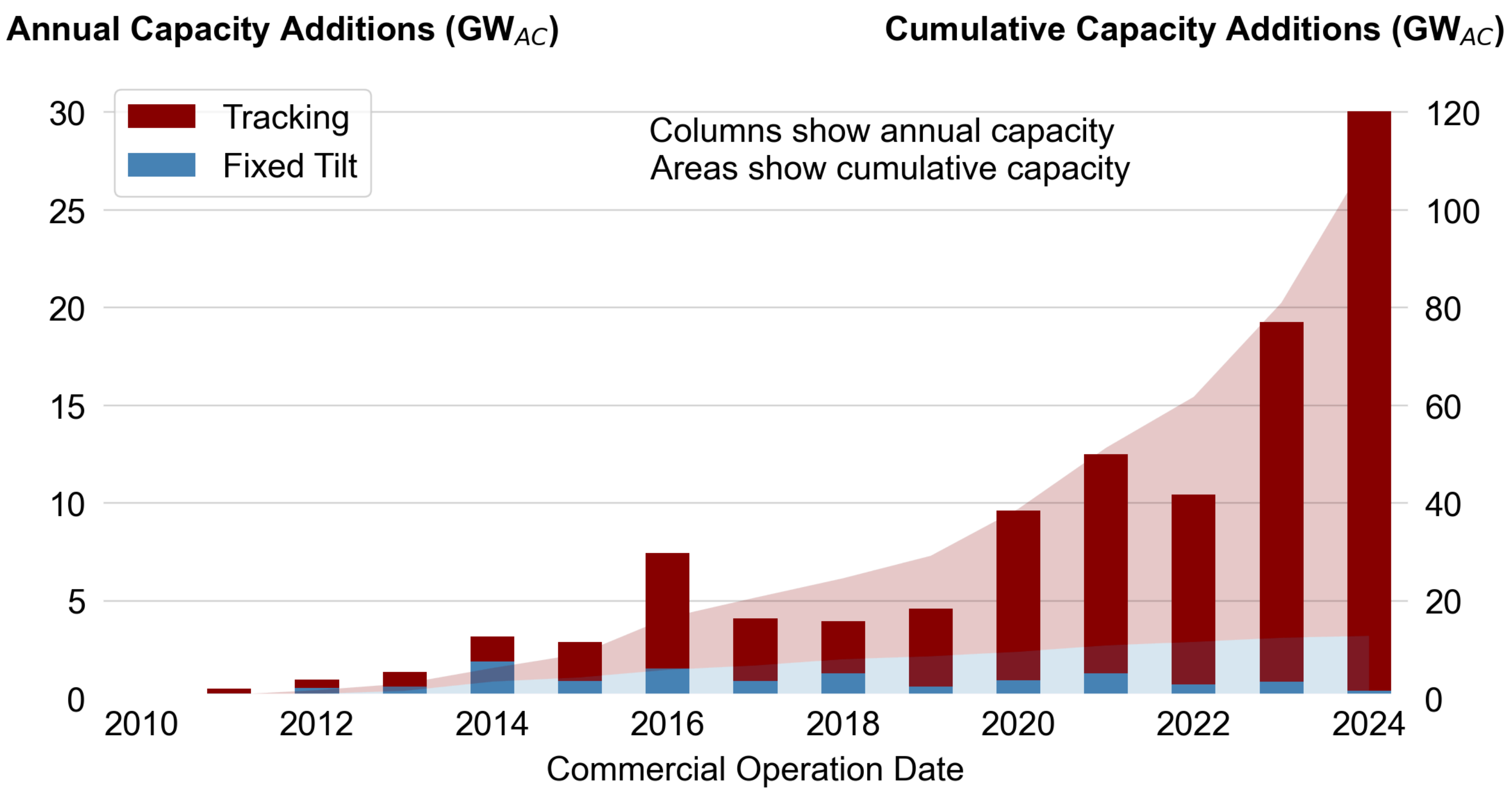
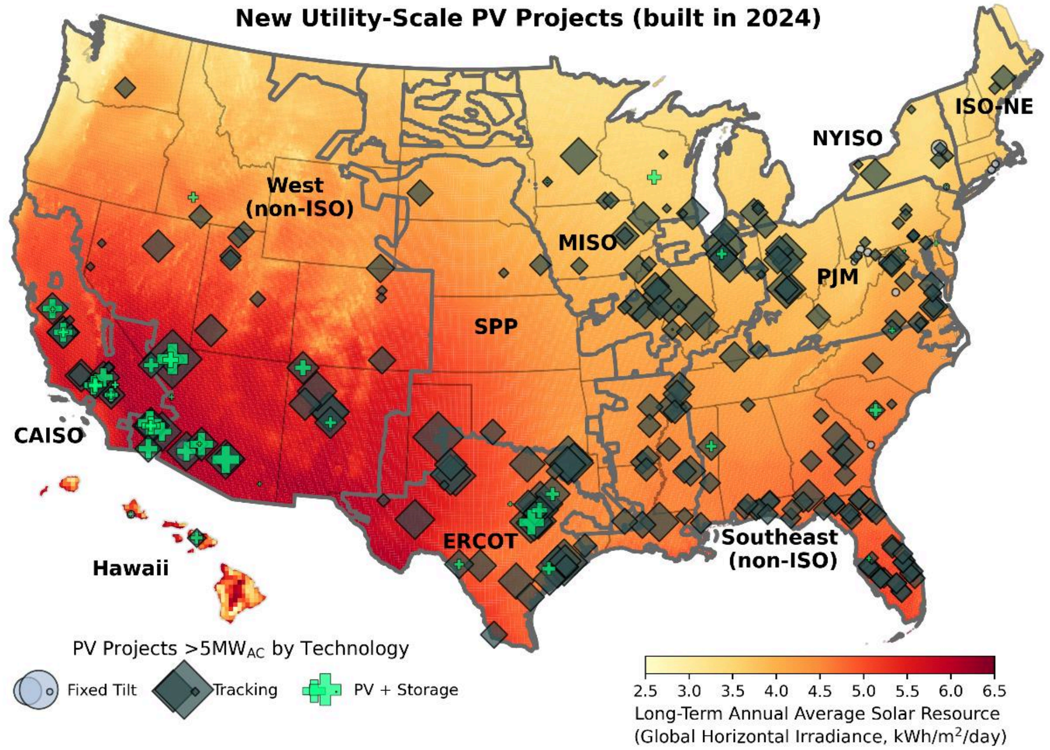
Note: Table above shows utility-scale solar as >1 MW_{AC} (most of this report uses >5 MW_{AC}). Percentages represent annual averages. Data is based on an early EIA data for 2024, findings may be revised with final data.

99% of new projects chose single-axis tracking over fixed-tilt racking

PV project population: 1,757 projects totaling 111 GW_{AC}

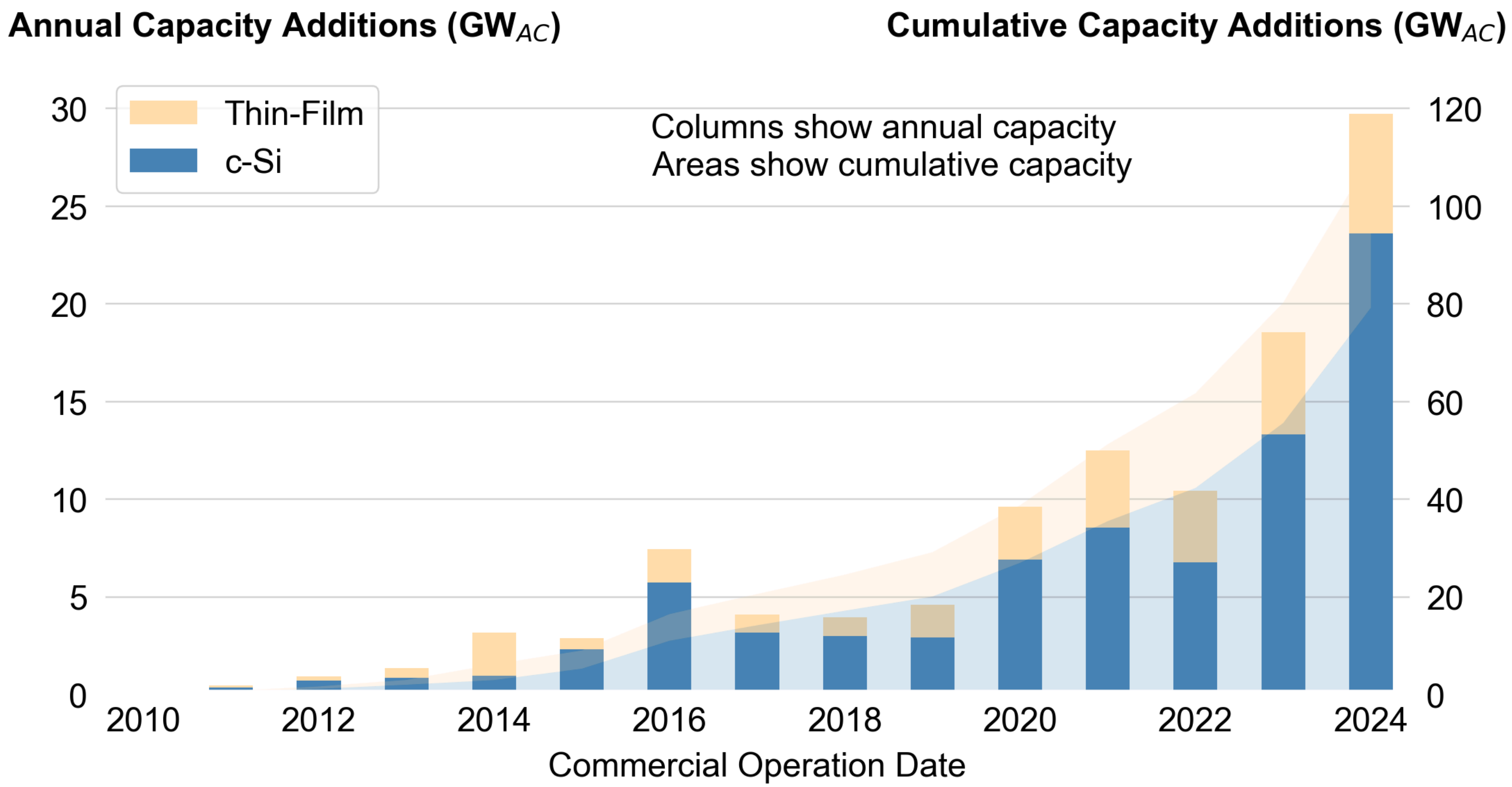


An original coming upfront cost premium for **trackers** eroded over time resulting favorable overall economics. **Fixed-tilt** installations are now only chosen in a few edge cases (challenging terrain or wind loading).



Use of c-Si modules grew again in 2024 to 79%

PV project population: 1,747 projects totaling 110 GW_{AC}



c-Si modules have been the dominant module technology at large-scale solar projects in the US since 2015. After a temporary decline in relative growth in 2022, c-Si modules expanded their market share again in 2024 to 79% of newly installed capacity.

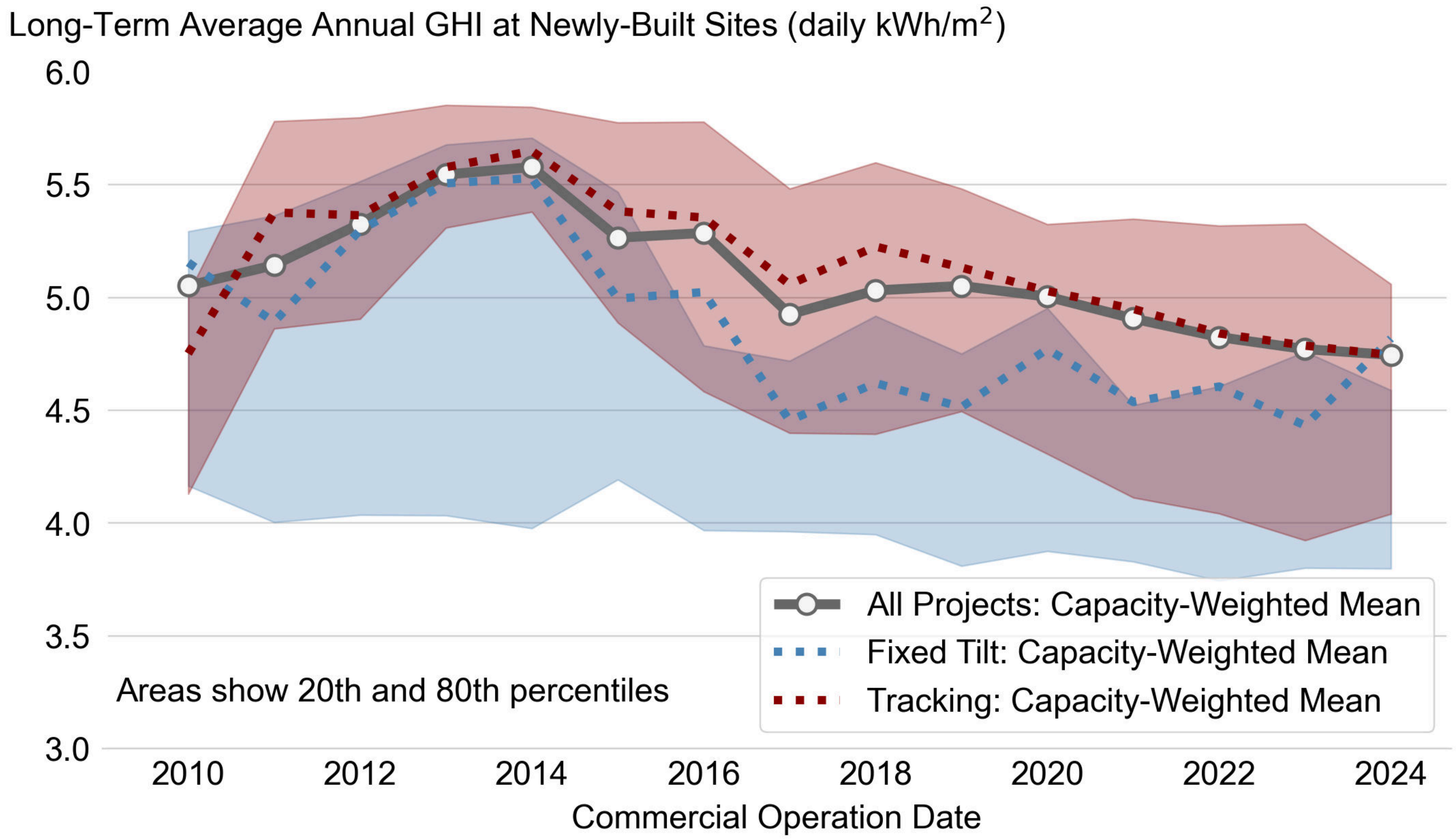
Thin-film modules grew in popularity between 2018 and 2021 as they were not subject to Section 201 import tariffs. In 2024 they reached a new record annual deployment of 6 GW_{AC}.

Note: The 2024 sample includes 2 projects (0.3GW_{AC}) without conclusive module type data which are excluded from the graph above

You can explore this data interactively at https://emp.lbl.gov/technology-trends

Solar projects built were built in very solar rich areas in the early 2010s. Project locations and associated resource quality have become much more diverse since then.

PV project population: 1,758 projects totaling 111 GW_{AC}



The capacity-weighted average long-term global horizontal irradiance (**GHI**) at newly built sites declined since 2014 as the market expanded to less-sunny states to 4.75 kWh/m^2/day.

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

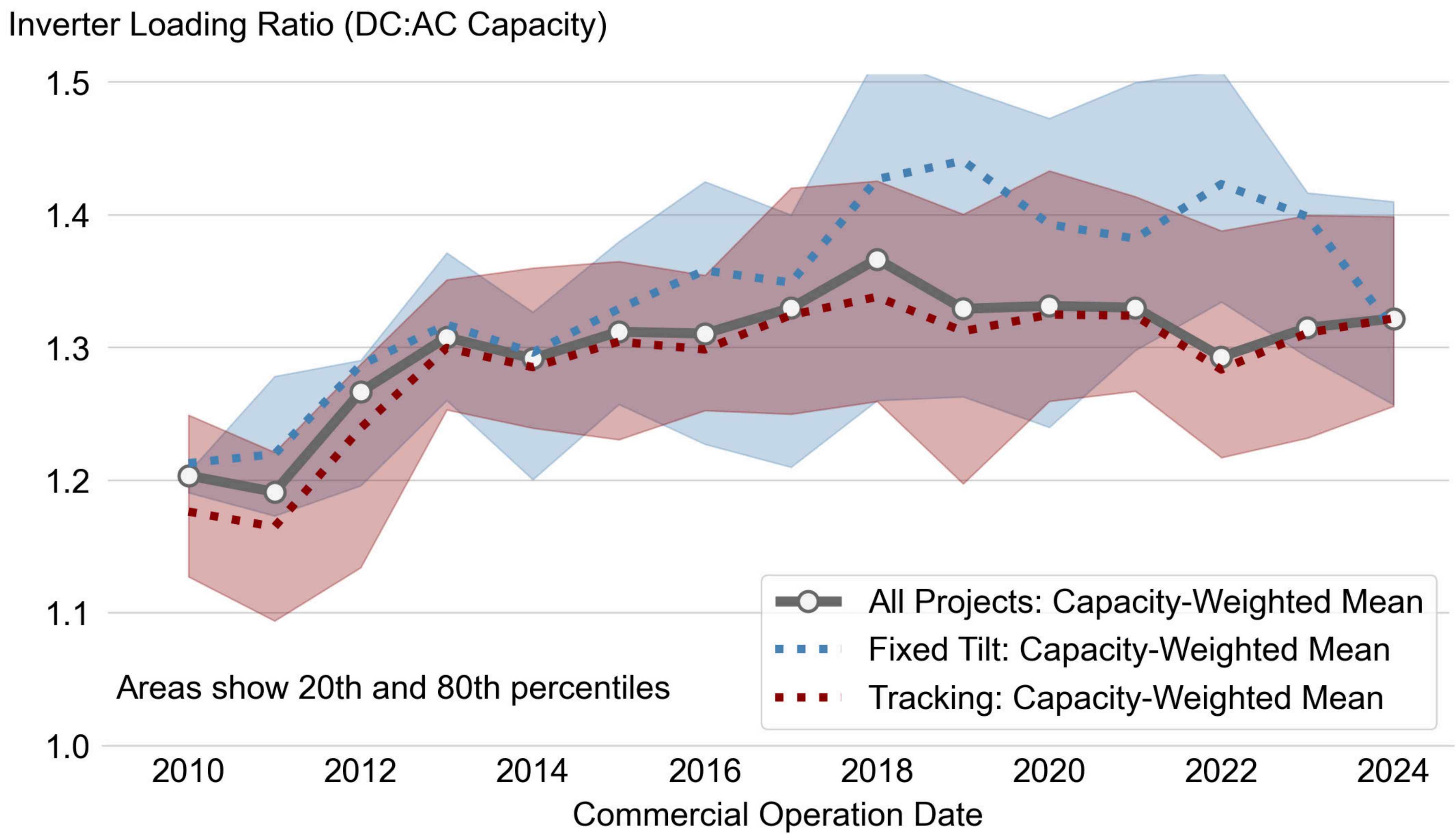
Exceptions are fixed-tilt installations in windy regions (Florida), on brownfields and landfill sites, and on particularly challenging terrain. Only 2 out of 13 of these new 2024 projects have a south-western orientation to maximize evening production.

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

Note: We use NREL's NSRDB to estimate long-term solar resource quality for each new USS project.

The average inverter loading ratio (ILR) has held steady since 2017

PV project population: 1,726 projects totaling 107 GW_{AC}



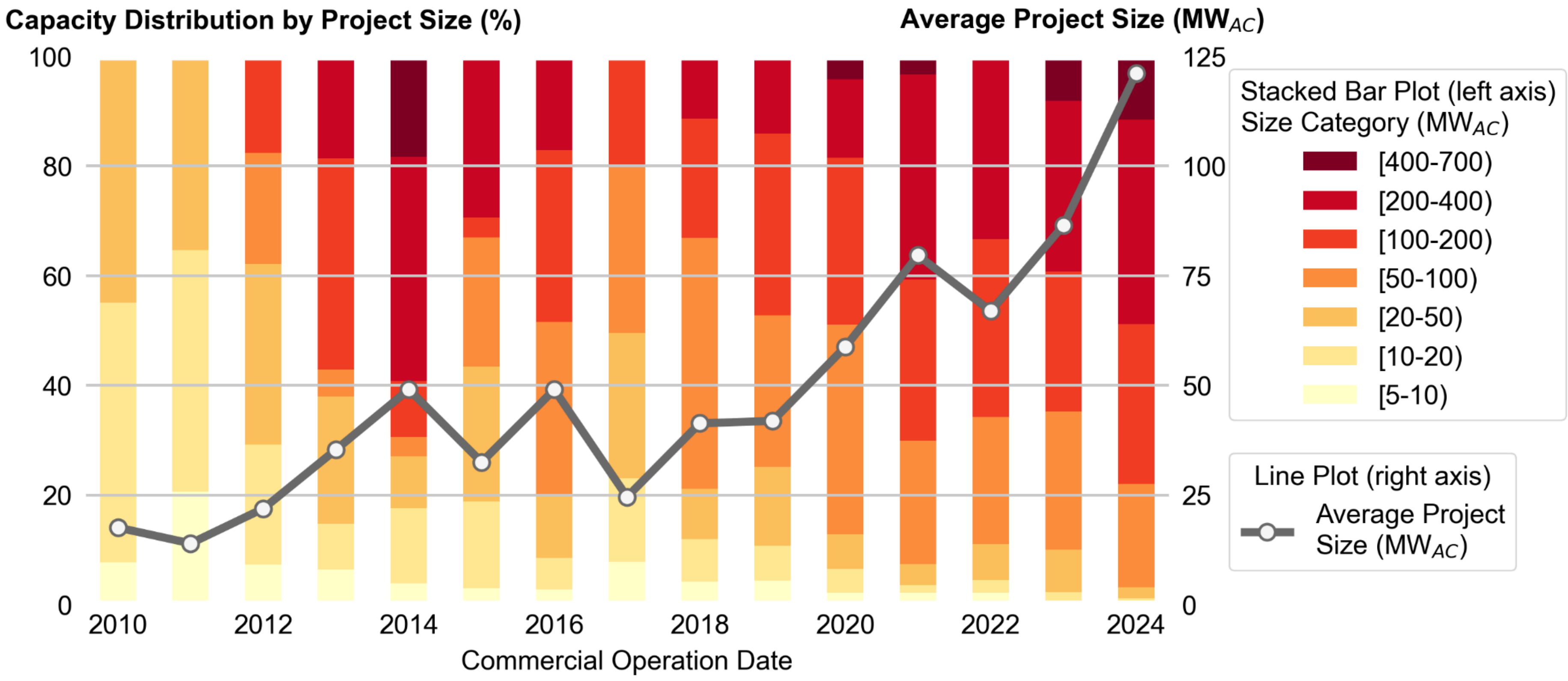
As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity to enhance revenue and reduce output variability.

In 2024, the capacity-weighted average inverter loading ratio (**ILR:** MW_{DC} to MW_{AC} ratio) did not differ meaningfully between fixed-tilt installations and tracking projects.

All else equal, a higher ILR should boost capacity factors (denominated in AC terms and discussed later in the report).

New solar projects are much larger than in the 2010s

PV project population: 1,759 projects totaling 111 GW_{AC}



Average project size has grown 7x since 2010 to 120MW_{AC} (~480 acres land-use, providing electricity for 24k households). 2024 saw 52 projects >200MW_{AC} come online.

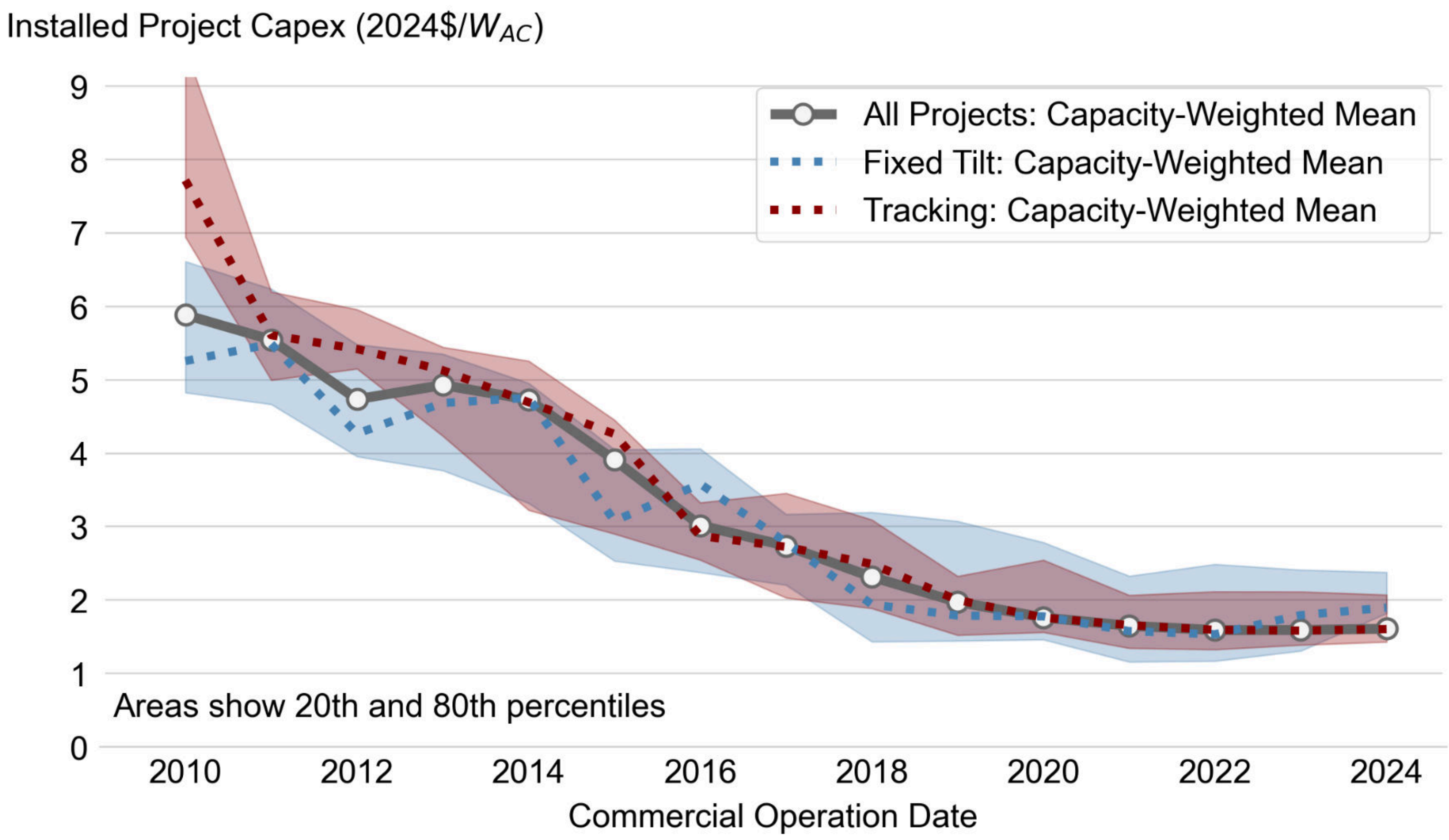
The Gemini Solar project (690MW_{AC}) built in 2024 in NV is the largest to date.

Multiple projects larger than 1GW_{AC} are in the pipeline. Greater projects size are likely spurred by slow-moving interconnection queues and economies of scale.

Capital Costs (CapEx)
and
Operation & Maintenance (O&M) Costs

2024 Tracking projects cost less than fixed-tilt projects

Sample: 1,629 projects totaling 104 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

We focus here on cost differences between projects using tracking and fixed-tilt mounting. The graph shows capacity-weigthed average costs by mounting type across our sample but does not control for other factors that influence total project costs (equipment, labor, land, grid interconnection, project size…).

Trackers can sustain some higher upfront costs because they deliver more energy per installed capacity. Over time tracking projects have often been more expensive, at least on average across our sample, but the cost premium has fluctuated and at times even reversed (like in 2016 and now in 2024).

Beginning in 2020, tracker installations boomed. By 2024, 99% of all new capacity used trackers, and fixed-tilt has only been used in particularly challenging sites.

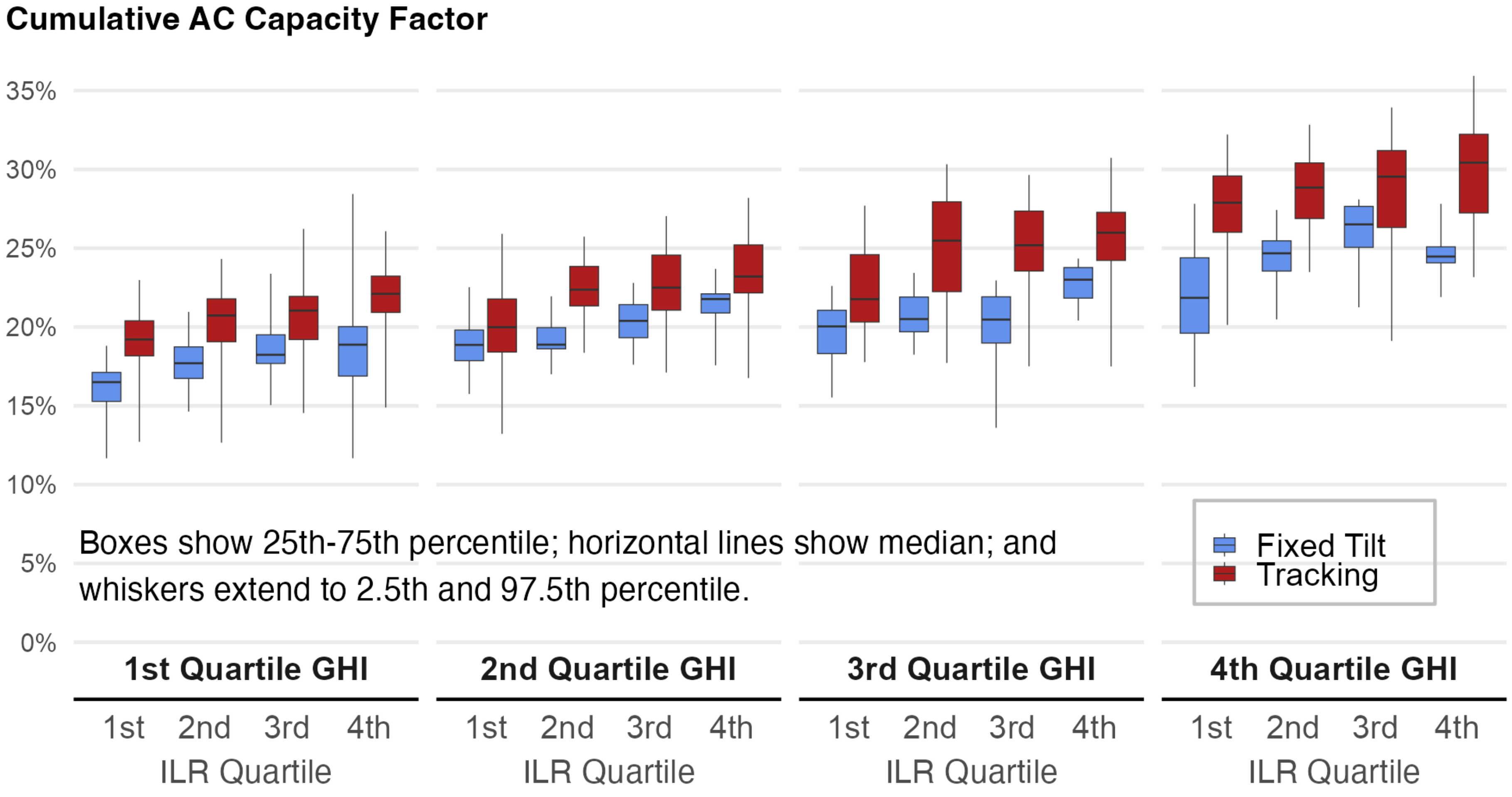
Tracking projects ($1.61/$W_{AC}$ or $1.22/$W_{DC}$) were less expensive than fixed-tilt projects ($1.90/$W_{AC}$ or $1.35/$W_{DC}$) in 2024.

Detailed statistics in $/$W_{DC}$ are shown in the accompanying data workbook.

Performance (Capacity Factors)

PV performance varies widely among projects, driven by resource availability and project design choices

Sample: 1,461 plants totaling 79.3 GW_{AC}



The cumulative net capacity factor is typically around 25% but ranges from 7% to 37% among all projects in our sample.

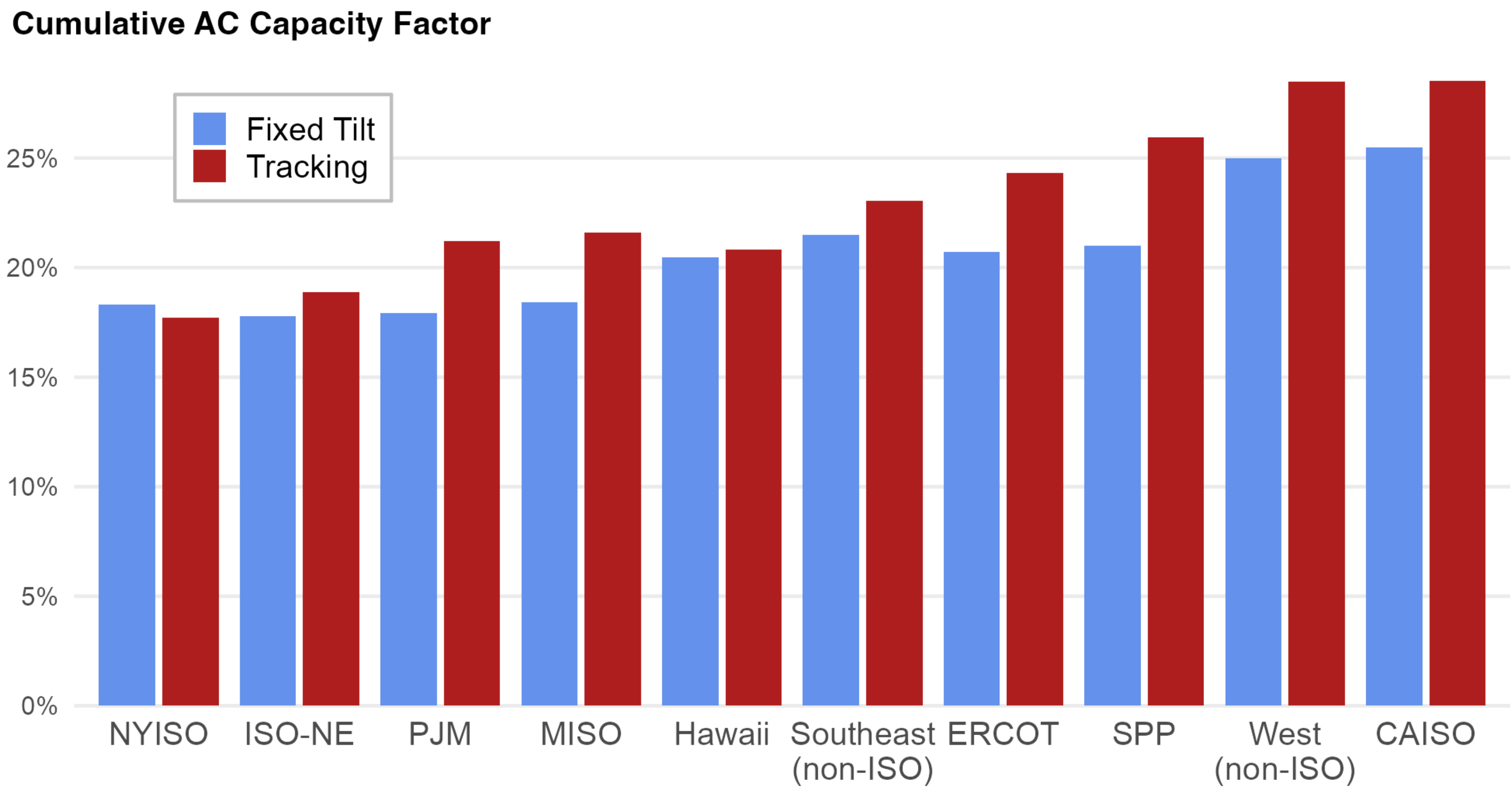
Project-level variation in PV capacity factor is driven by:

- **Solar Resource (GHI)**: Strongest solar resource quartile has ~9 percentage point higher capacity factor than lowest resource quartile
- **Tracking**: Adds ~5 percentage points to capacity factor on average, with improvement from tracking more pronounced in higher solar resource areas
- **Inverter Loading Ratio (ILR)**: Highest ILR (DC/AC ratio) quartiles have on average ~1 percentage point higher capacity factors than lowest ILR quartiles

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Tracking boosts capacity factors by roughly 5 percentage points in high-insolation regions

Sample: 1,465 plants totaling 79.9 GW_{AC}



Not surprisingly, capacity factors are highest in California and the non-ISO West, and lowest in the Northeast (ISO-NE and NYISO). Tracking yields more benefits compared with fixed-tilt installations in regions with strong solar resources, leading to a greater proportion of tracking projects in those regions.

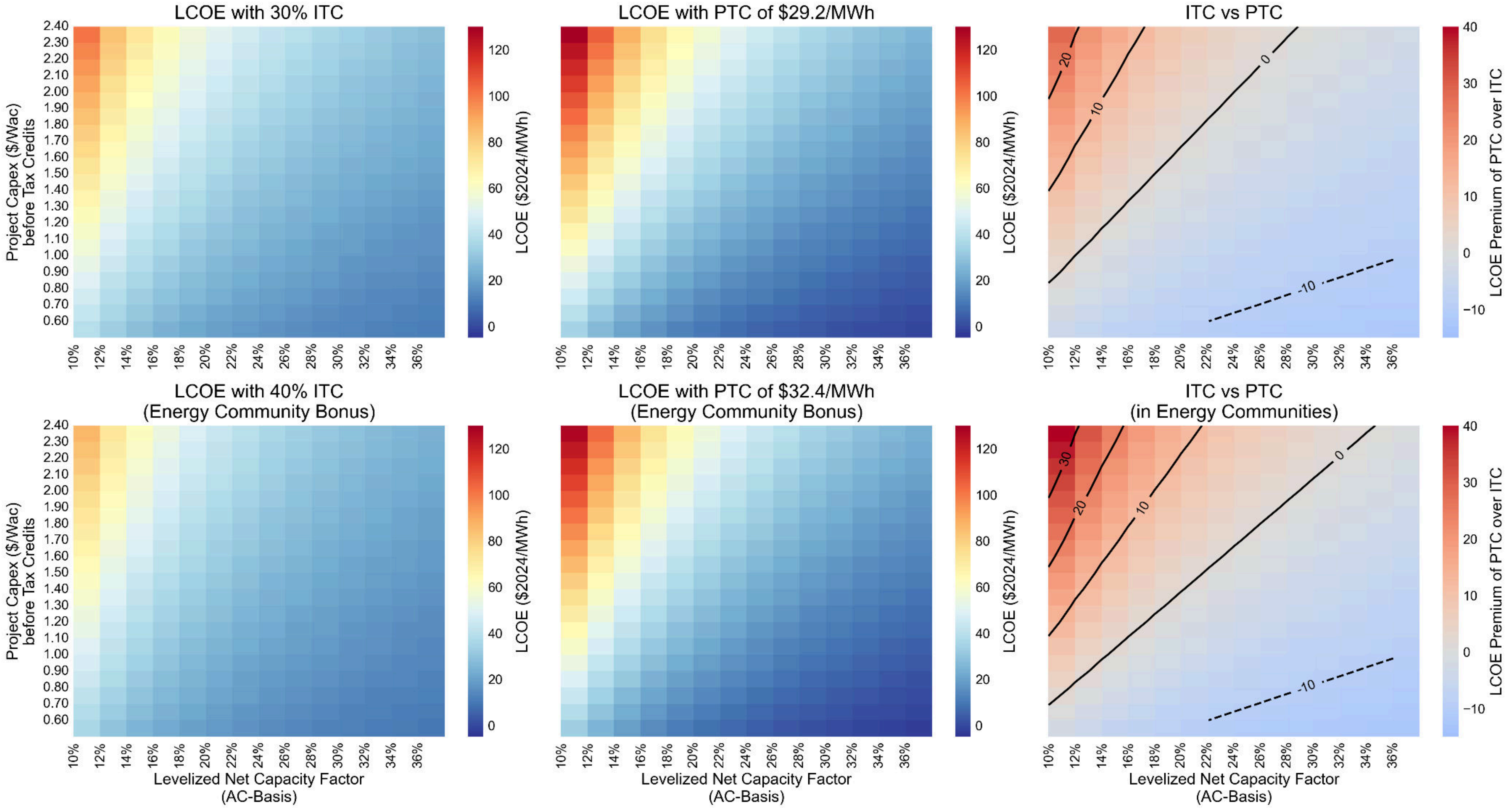
Region	Proportion of Projects with Tracking	Proportion of Capacity with Tracking
ERCOT	98.3%	99.7%
SPP	84.0%	93.3%
MISO	79.8%	92.6%
West (non-ISO)	90.5%	91.3%
PJM	61.1%	86.5%
CAISO	86.0%	82.9%
Hawaii	56.3%	78.0%
Southeast (non-ISO)	64.3%	68.4%
NYISO	28.1%	27.7%
ISO-NE	16.2%	19.7%

Notes: Capacity factors represent weighted means by capacity (MW_{AC}) across all years of data. The one utility-scale solar project in Alaska is excluded from this plot.

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Levelized Cost of Energy (LCOE) and Power Purchase Agreement (PPA) Prices

About half of all of projects seem to benefit more from the Production Tax Credit than the Investment Tax Credit



Available federal tax credits lower the effective LCOE shown on the previous slides. The graphs show post-incentive LCOE variation by project capex and performance, both for the Investment Tax Credit (ITC, left) and the new Production Tax Credit (PTC, center). Introduced by the Inflation Reduction Act, the PTC is paid for the first 10 years ($29.2/MWh and rising with inflation) – levelized over a 35-year project lifetime it reduces LCOE by ~$15.8/MWh.

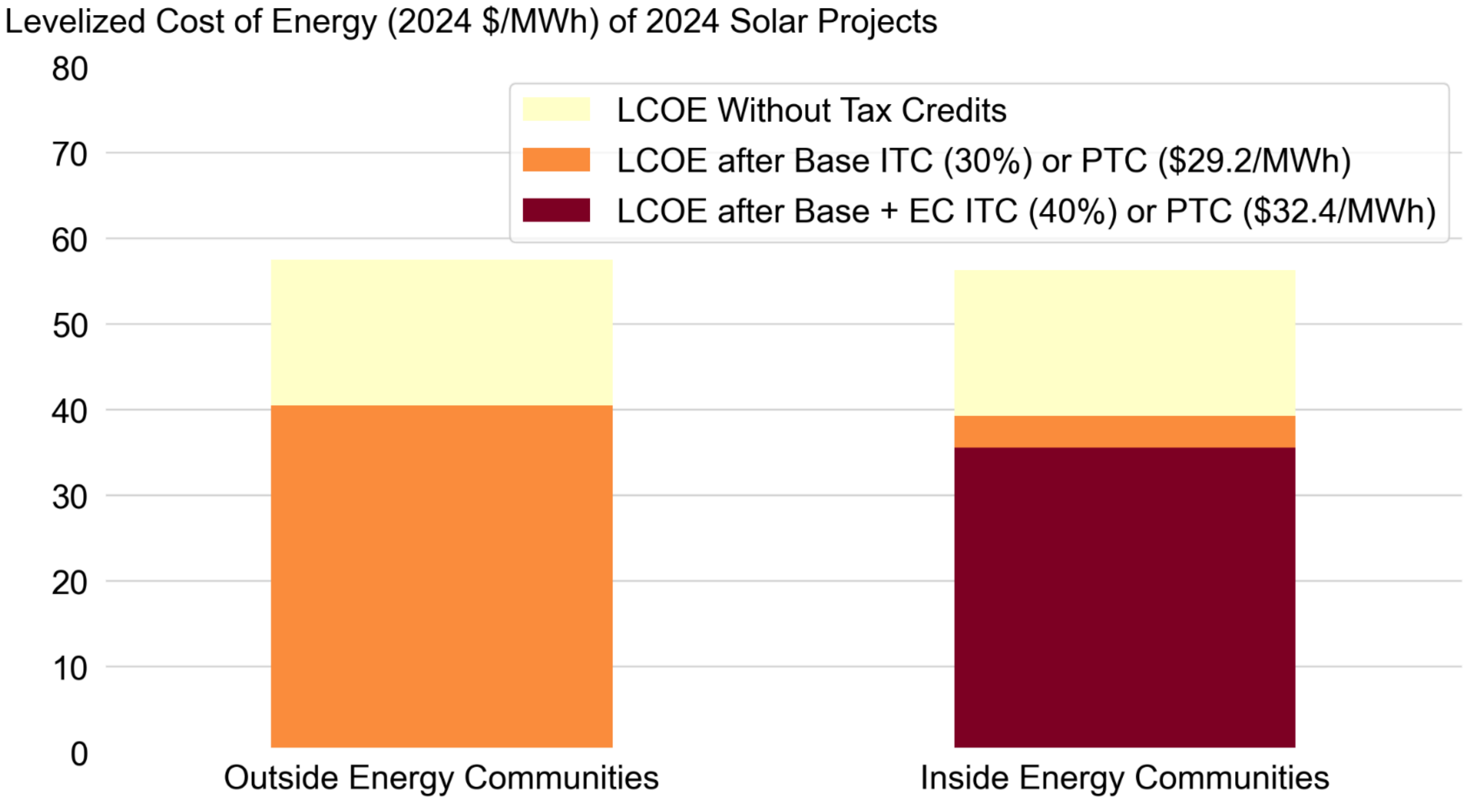
The right column compares the benefit of each tax credit, with red squares showing where the ITC results in a lower LCOE (higher-cost, lower-performing projects) and the blue squares showing where the PTC is preferable (lower-cost, higher-performing projects).

For the 2023 and 2024 COD cohort, preliminary data indicates that about half projects (233 out of 424) would benefit more from the Base PTC than the ITC (although the PTC comes with some challenges such as greater performance risk that we do not account for in this comparison).

The lower column repeats the analyses but includes the bonus adder available for projects sited in Energy Communities (more details on the next slide).

2024 solar projects in Energy Communities have an average after-tax credit LCOE of $36/MWh, compared to $40/MWh in the rest of the country

Sample: 227 projects totaling 26.4 GW_{AC} (92 EC projects, 13.9 GW_{AC})



Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2024. Findings may shift as more final EIA Capex and project-specific performance data become available.

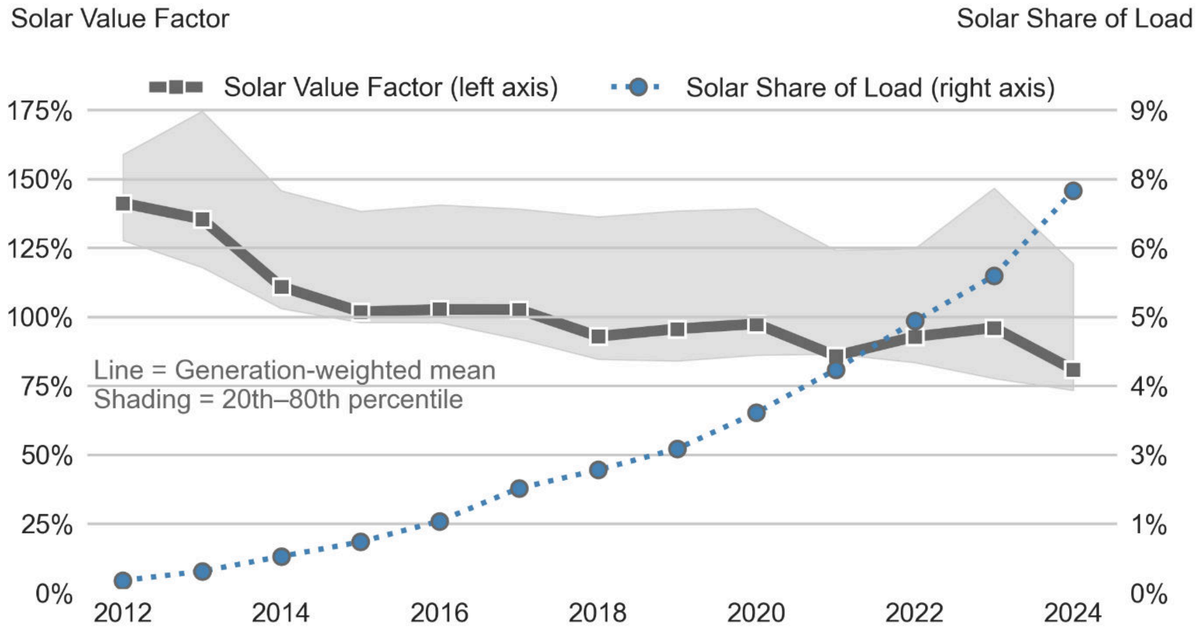
About 40% of all new utility-scale solar capacity in 2024 qualifies for the Energy Community Tax Credit Adder. Not considering potential Domestic Content adders, these project are eligible for a 40% ITC or a $32.4/MWh PTC over the first 10-years ($2024) – equivalent to $17.6/MWh levelized over a project's lifetime.

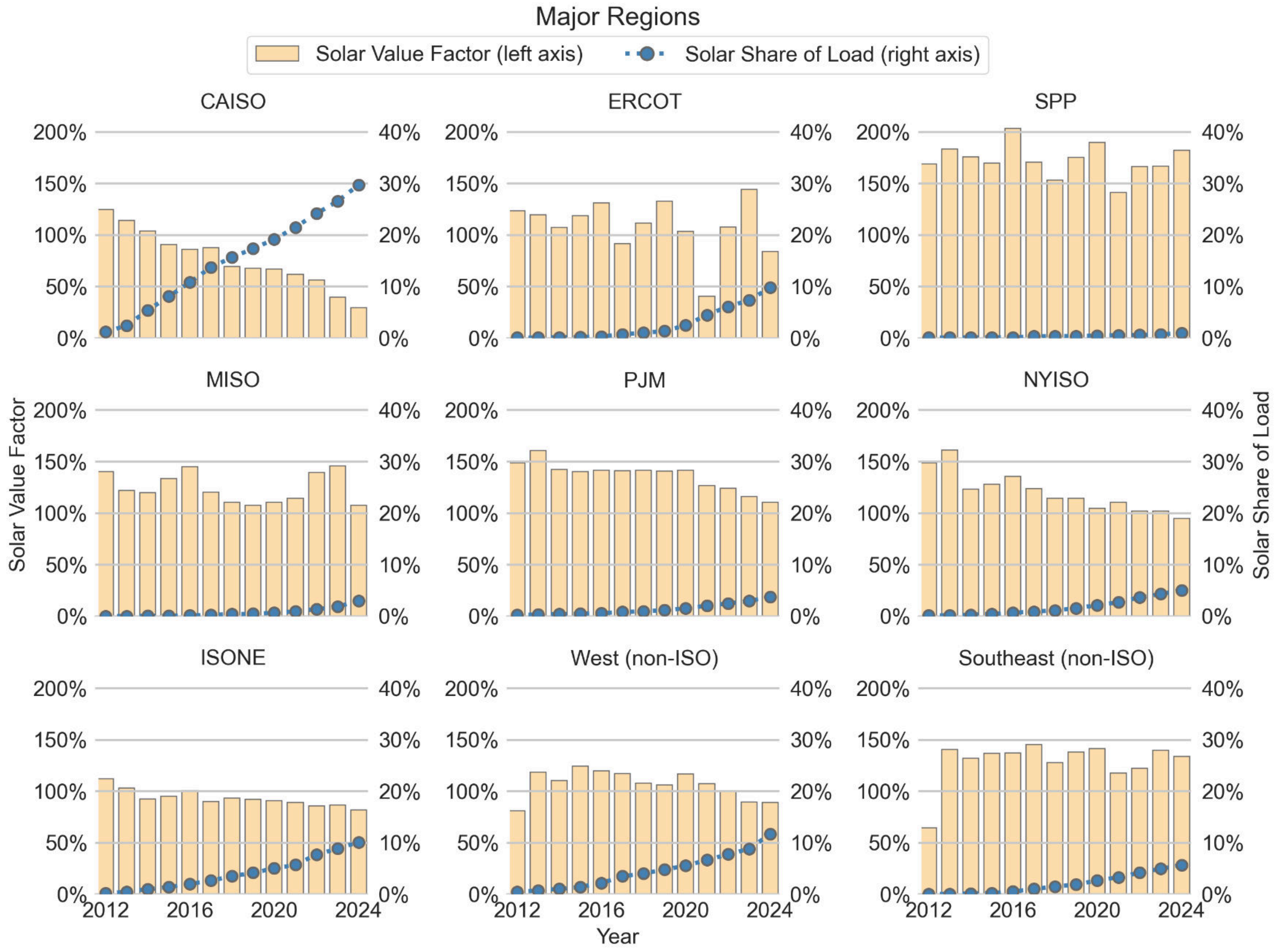
Pre-incentive LCOE do not vary significantly between projects inside or outside of Energy Communities. Post-incentive LCOE is $36/MWh inside Energy Communities and $40/MWh outside.

The ITC benefit over the PTC increases if additional adders (like Energy Community or Domestic Content) are available for a project, but even among our 92 projects in Energy Communities, 25 have a lower LCOE with the PTC than the ITC.

Wholesale Market Value and Net Value

Solar's value factor declines as solar serves a higher share of a region's load and fell to 80% in 2024

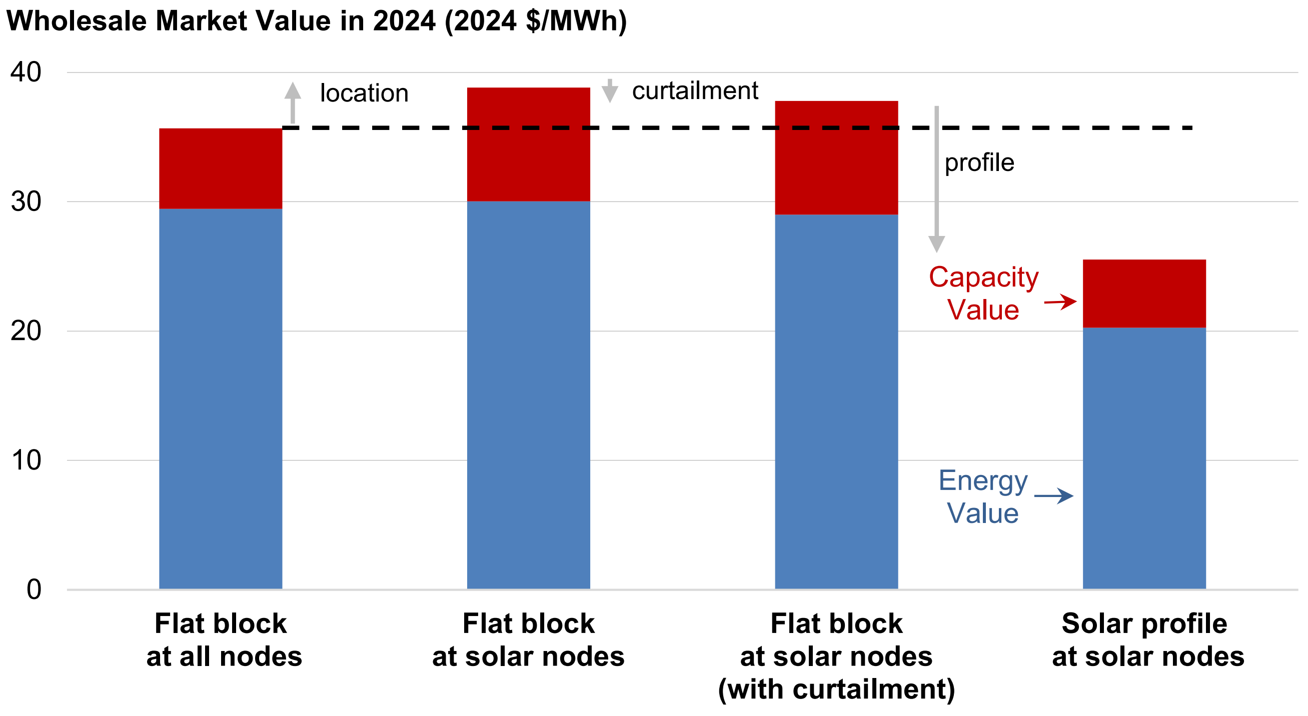


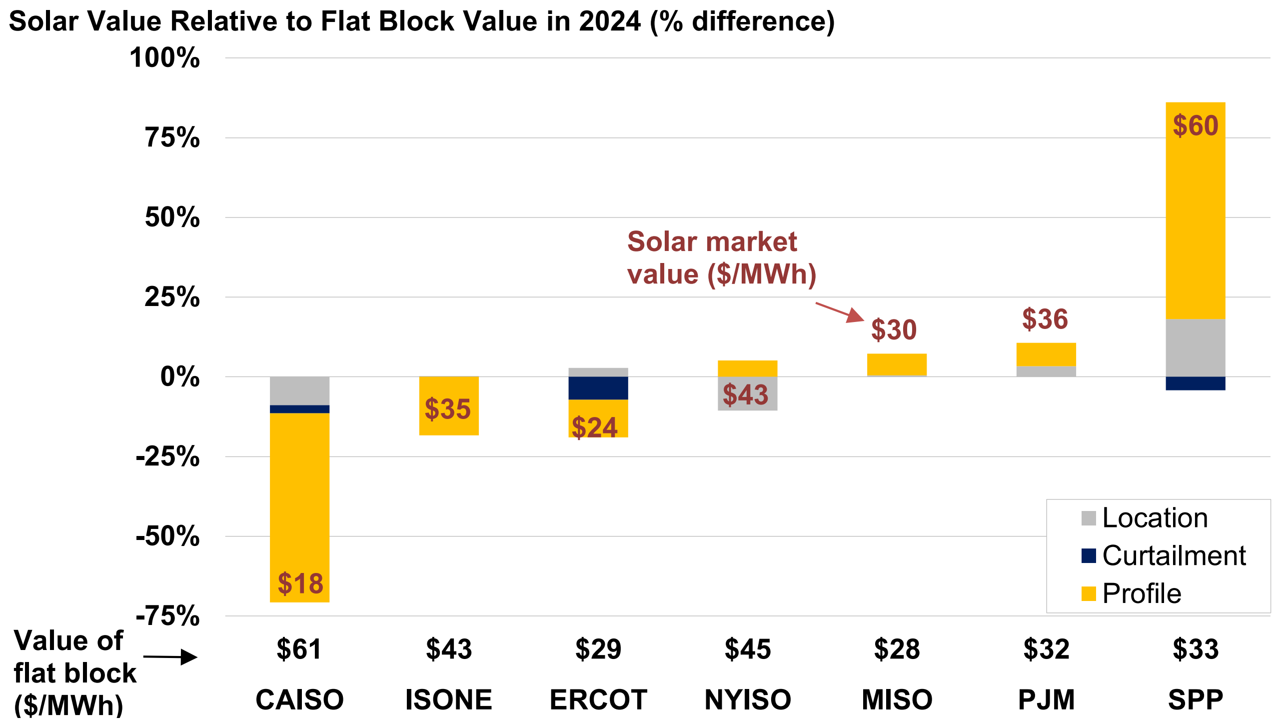


Solar's value factor has fallen over time as solar serves a greater share of load and reached 80% on across the nation in 2024. It is lowest at 30% in CAISO (at 30% penetration) and NEVP (49%). The value factor is highest 181% in SPP (at 1% penetration) and is still above 100% in MISO, PJM, BANC, WALC, PSCO, WACM and most southeastern BAs.

Note: Solar market share in those years only reflects contribution of distributed PV. Non-ISO BA results are shown in the accompanying data workbook.

Solar's generation profile was the largest source of value differences between solar and a flat block in 2024





Across the seven ISOs, solar projects were usually sited at locations with above average energy values. The large amount of solar deployed in areas with lower relative value (particularly CAISO) yields a value factor of 72% across all solar projects in the ISOs.

Solar's generation profile has the largest impact and either hurts (in CAISO, ISO-NE, ERCOT) or helps (in SPP, PJM, MISO, and NYISO) solar's value relative to a flat block. Curtailment is primarily an issue for solar in ERCOT.

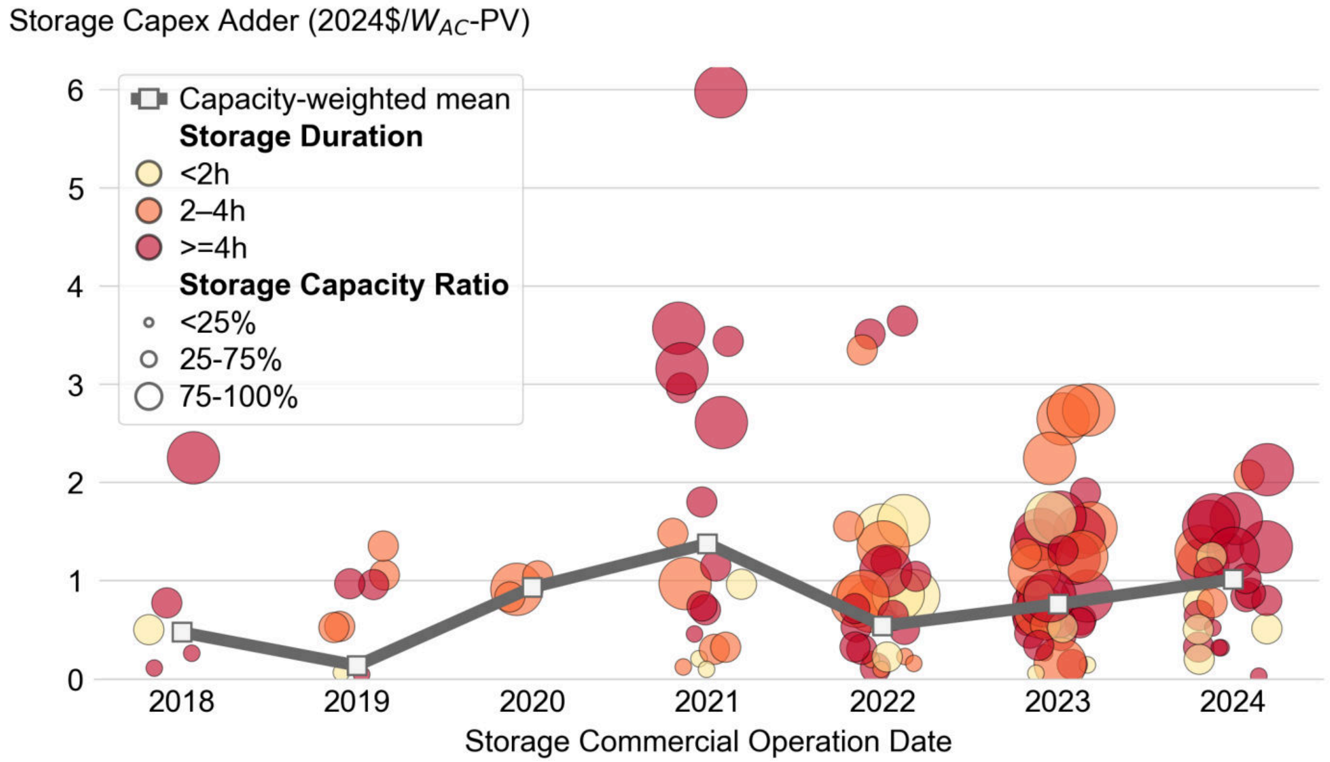
Note: Numbers and figures shown here only reflect market value in the year 2024 in the seven ISOs and do not include data from other years or non-ISO regions.

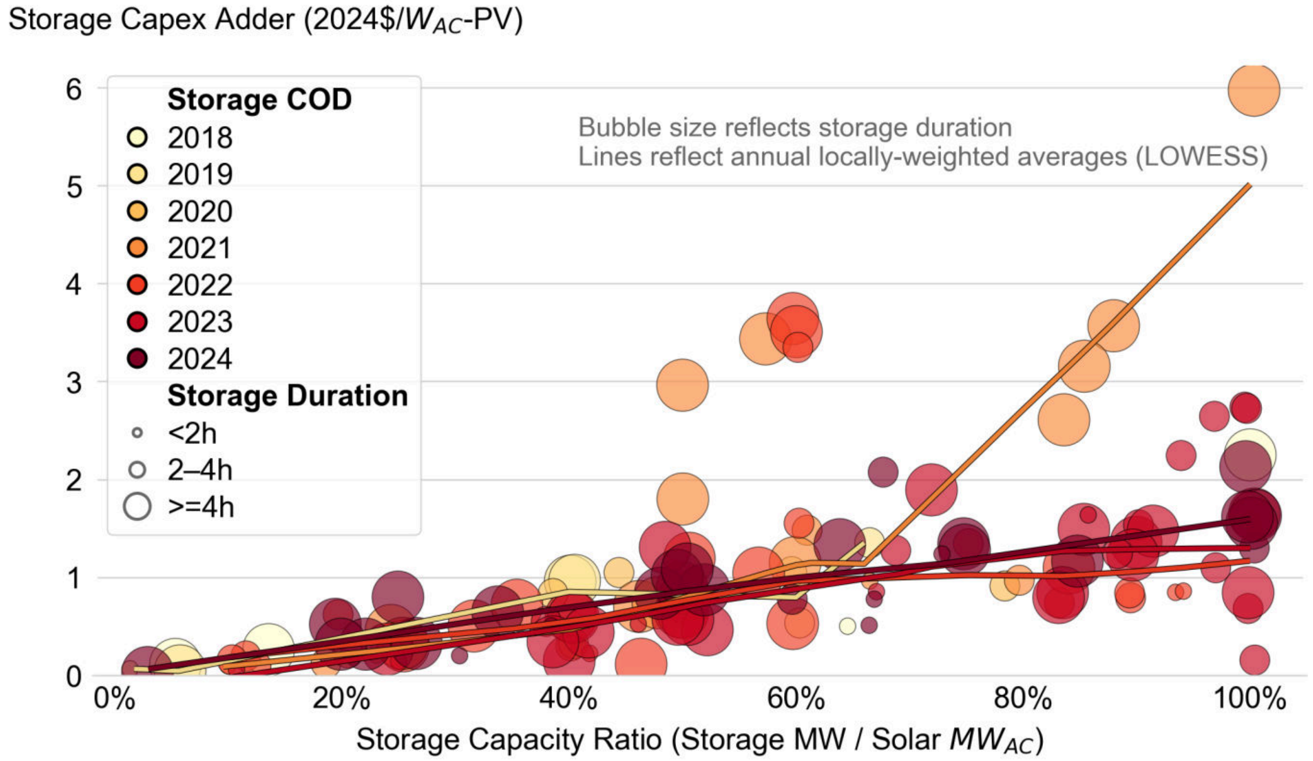
PV+Battery Hybrid Plants

(for more of Berkeley Lab’s analysis of hybrid power plants, see https://emp.lbl.gov/hybrid)

The storage capex adder to PV projects depends on capacity ratio and duration

Sample: 131 projects totaling 8 GW and 27.4 GWh of batteries

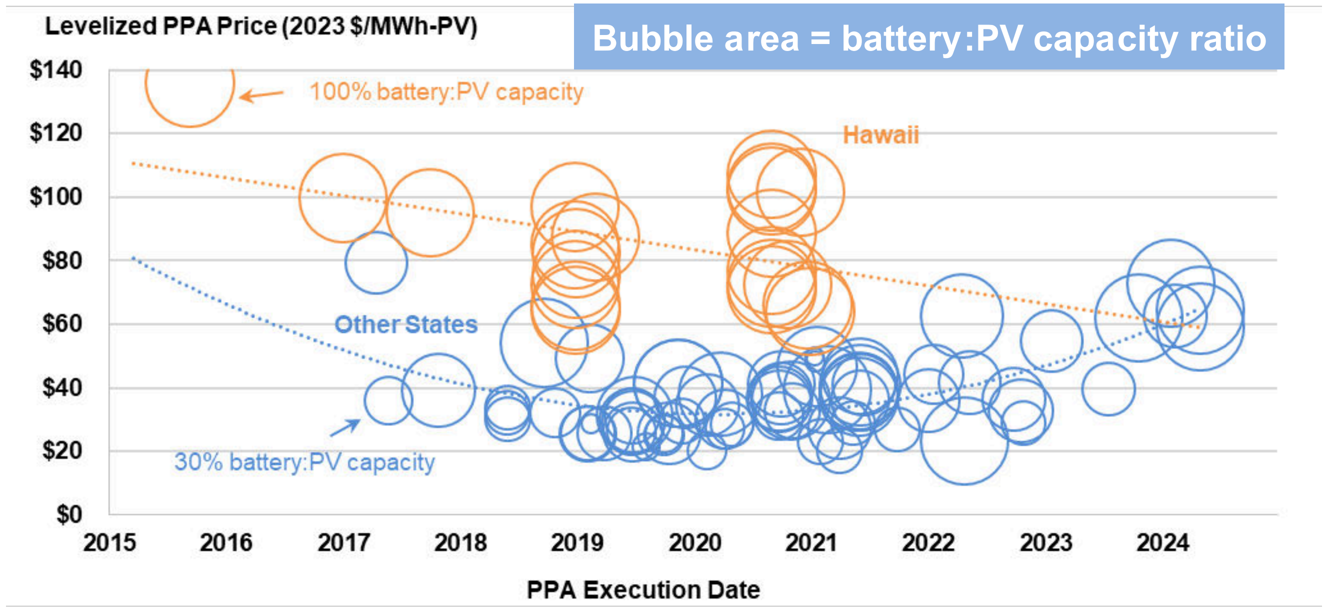


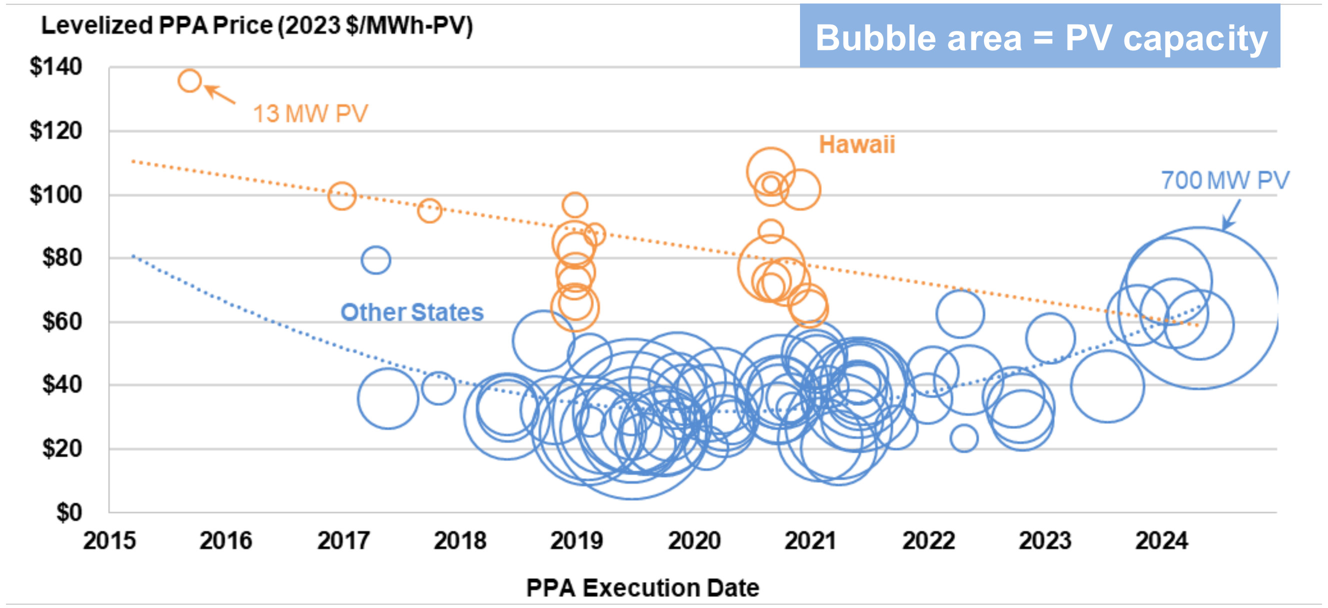


Storage cost adder has grown to $1.00/$W_{AC\text{-}PV}$ in 2024, driven in part by longer duration and greater capacity ratio.

Accounting for storage capacity ratio variations, 2024 storage adders are greater than in the past (but also have longer duration).

PPA prices for PV+battery have approximately doubled since 2019/20 lows; Hawaii historically at a premium

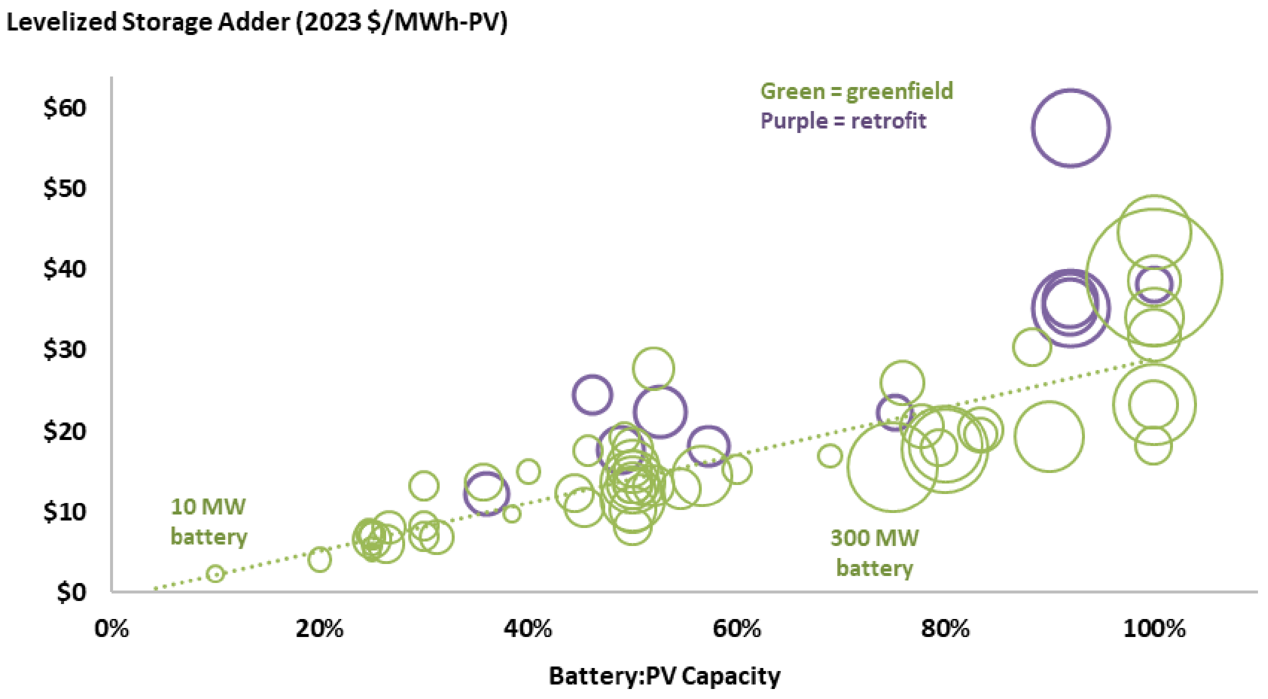


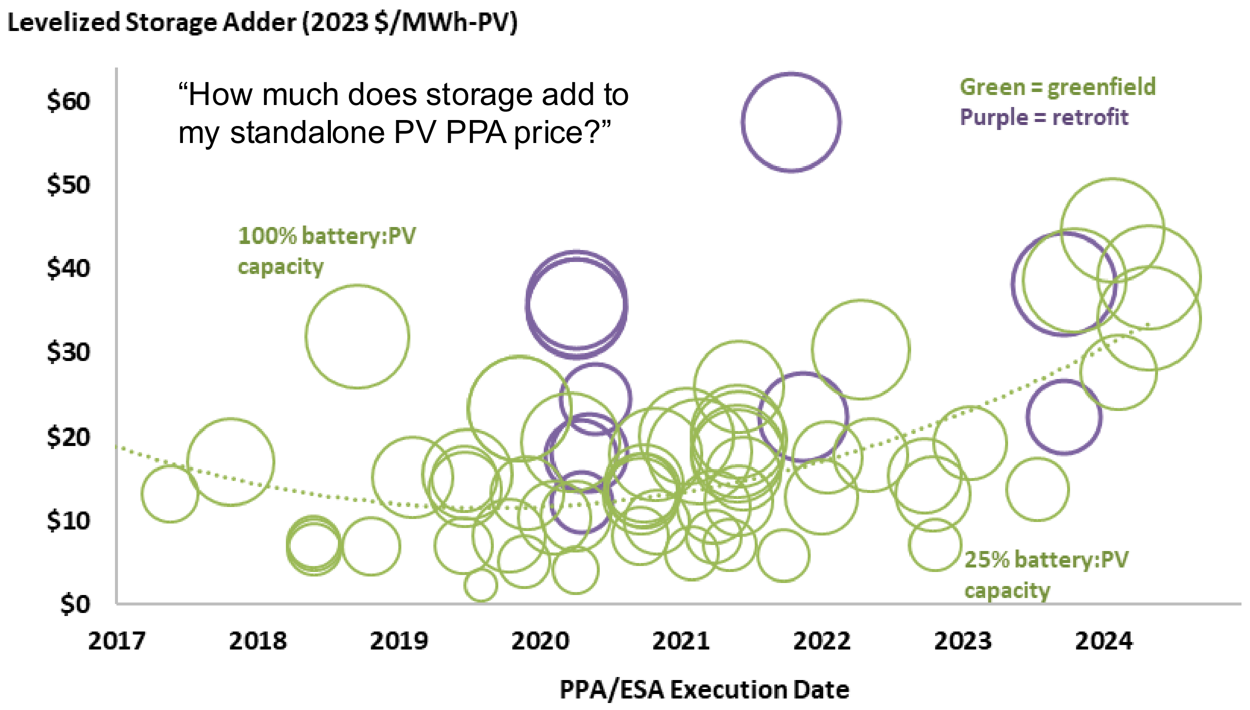


- Both graphs show same data from sub-sample of 93 plants (retrofits not included); the only difference is what the bubble size represents
  - Hawaii (orange): 22 plants, 0.8 GW_{AC} PV, 0.8 GW_{AC} battery (third round of Hawaii PPAs expected soon)
  - Other States (blue): 71 plants, 10.5 GW_{AC} PV, 5.8 GW_{AC} battery
  - Storage duration ranges from 2-8 hours; 80 plants have 4-hr duration (the other 13 are 5x2 hr, 1x2.5, 1x3, 1x3.7, 4x5, and 1x8 hr)
- Upward price trend among PPAs on the mainland, with prices in 2024 approximately twice typical prices in 2020
  - Rate of hybrid PPA price growth exceeds that of stand-alone solar, which saw increases of ~50-65% since 2020/2021 (see previous “LCOE & PPA Prices” section)

PPAs that price the PV and storage separately enable us to calculate a "levelized storage adder," which has increased in recent years

Graph Sample: 66 PV hybrid projects with 5.9 GW_{AC} of batteries (all 4h duration) in CA (35), NV (16), NM (11), AZ (3) and OR (1)





A larger capacity battery adds more to a PPA price than a smaller battery, when normalized for the PV plant size. This relationship between "levelized storage adders" and Battery-to-PV capacity ratios is roughly linear.

Retrofits tend to have higher "levelized storage adders" than greenfield projects.

Increased PPA prices for the battery component explain some, but not all, of the recent increase in hybrid PPA prices. Levelized price increase since 2020 ($2023):

- Hybrid PPAs: ~$30/MWh-PV (see prior slide)
- Storage Adder: ~$23/MWh-PV
- All PV PPAs (not just hybrid): ~$10/MWh-PV

Capacity in Interconnection Queues