

# Identifying Barriers to Solar and Storage Hybrids

Modeled vs. empirical wholesale market value and net-value for co-located solar + storage projects

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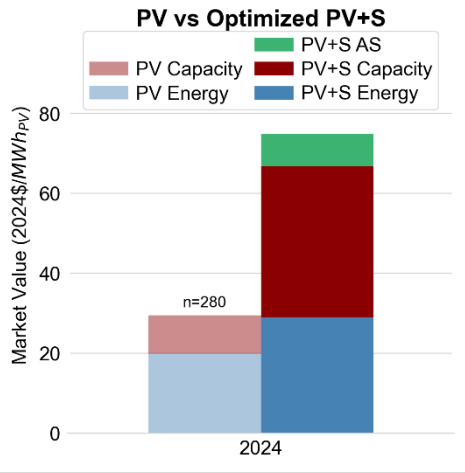
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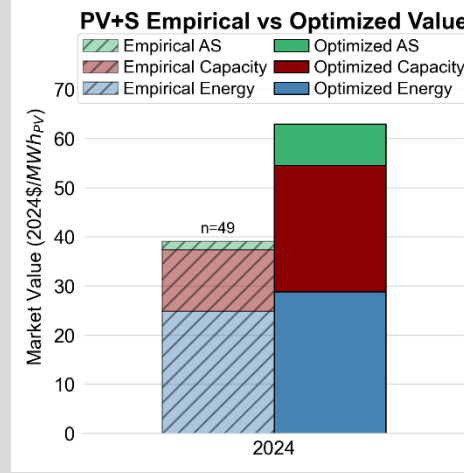
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# Key Valuation Findings of PV+Storage (PV+S) Projects Based on Empirical and Optimized Operation

With perfect price foresight, battery additions could increase solar's national average market value from \$29/MWh to \$75/MWh in 2024



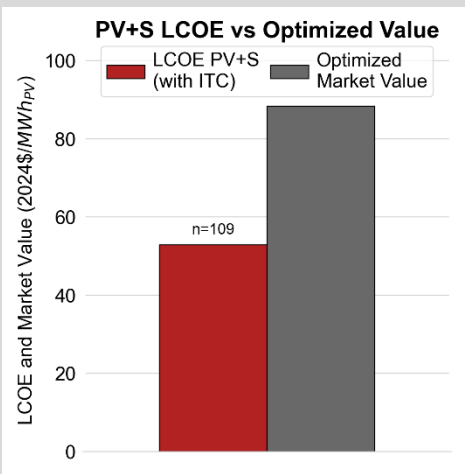
Empirical PV+S operations captured \$39/MWh or 62% of modeled optimized value in 2024



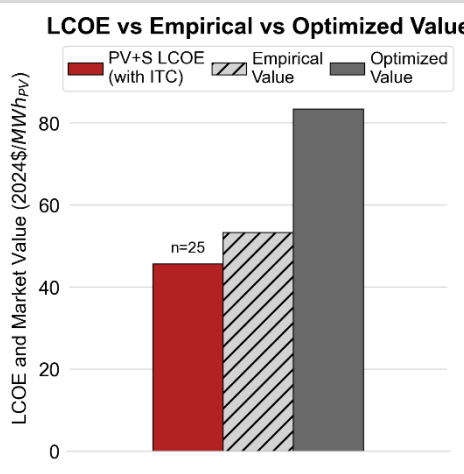
## Barriers to greater PV+S bulk power value:

- Under-participation in wholesale markets, including still-lucrative ancillary services.
- Restrictions on grid charging under earlier ITC rules for older projects.
- Fixed dispatch strategies (delivery obligations of tolls, PPAs, or state incentive programs; rule-of-thumb operations).
- Limited response to negative prices because of volume targets or hub-based settlement.
- Imperfect price forecasting tools used by asset operators result in suboptimal dispatch.
- Lack of AS markets + weak energy/capacity value signals in non-ISO regions.

National optimized PV+S market value in 2020-2024 exceeded LCOE by \$35/MWh



Despite shortfalls, national empirical PV+S market value in 2020-2024 still exceeded LCOE by \$8/MWh



# Overview of Research Project

## □ Background:

- Co-located PV+storage (PV+S) deployment has been concentrated in regions with high standalone solar penetration. One possible explanation is that standalone solar market value declines as penetration rises, increasing the incentive to pair solar with storage.
- Because PV+S can earn revenue from energy, capacity, and ancillary services, its valuation is complex and requires detailed modeling.
- Understanding how PV+S operates and contributes to the bulk power system is important for both private investment and long-term system planning.
- Yet public operating data for PV+S remain scarce, making independent validation of modeled behavior uncommon.

## □ Objectives and contributions:

- Quantify the optimal wholesale market value of PV+S relative to standalone PV.
- Assess whether the wholesale market value premium alone justifies the additional generation cost of adding storage.
- Compare modeled and empirical value where possible and identify barriers that prevent projects from realizing their full potential.

## Outline:

- Executive Summary
- Sample + Methods
- Results
  - Optimized Value Premium of PV+S over PV Standalone
  - Comparison of Value Premium with Cost Premium
  - Comparison of Modeled with Empirical Data
- Discussion of Barriers
- Appendix
  - Sensitivity Cases
  - Storage Value in \$/kW-yr
  - Additional Comparisons of Empirical and Optimized Storage Value Premium

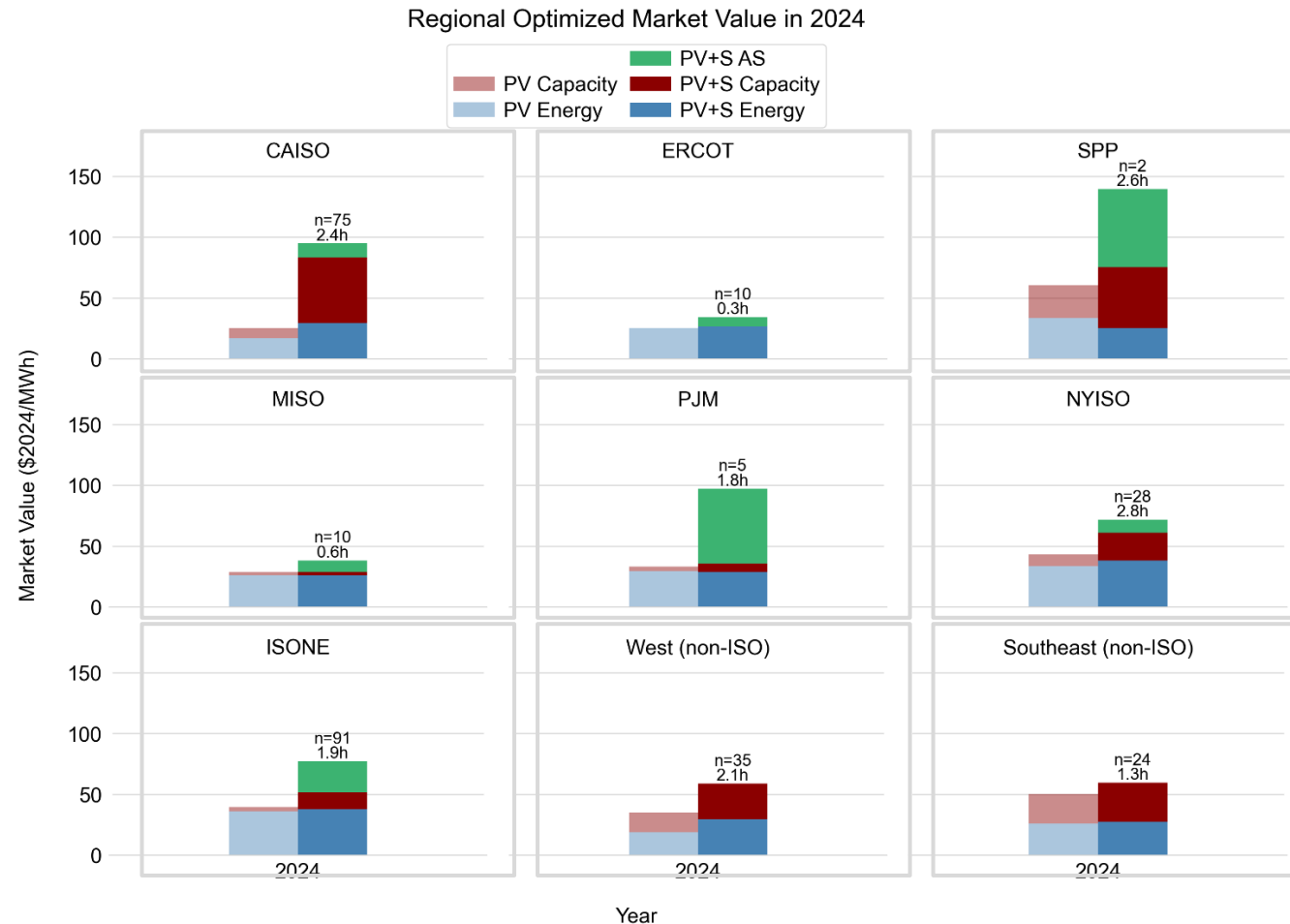
# Executive Summary



# With perfect price foresight, battery additions could increase solar's national average market value from \$29/MWh to \$75/MWh in 2024

- We modeled how storage co-located with large-scale PV projects would be optimally dispatched to maximize wholesale market value. In this analysis, we assumed that operators had perfect foresight of energy and ancillary service prices, as well as of the hours during which their capacity contributions would be assessed.
- In 2024, installed co-located batteries had the potential to increase the national generation-weighted average wholesale market value from \$29/MWh for standalone solar to \$75/MWh for PV+S. This value increase is driven primarily by higher capacity value (\$38/MWh, or 3.8x standalone solar), followed by energy value (\$29/MWh, or 1.5x standalone solar) and ancillary services value (\$8/MWh).
- Added value varies with both battery sizing and market dynamics.
  - ▣ Value increases are strongest where the marginal standalone value of solar is low, for example because of high solar penetration (for example, lower solar energy and capacity value in the Southwest)
  - ▣ Batteries can also unlock additional ancillary services (AS) revenue, especially in markets where relatively few other batteries are already active, such as SPP, PJM, and ISO-NE.

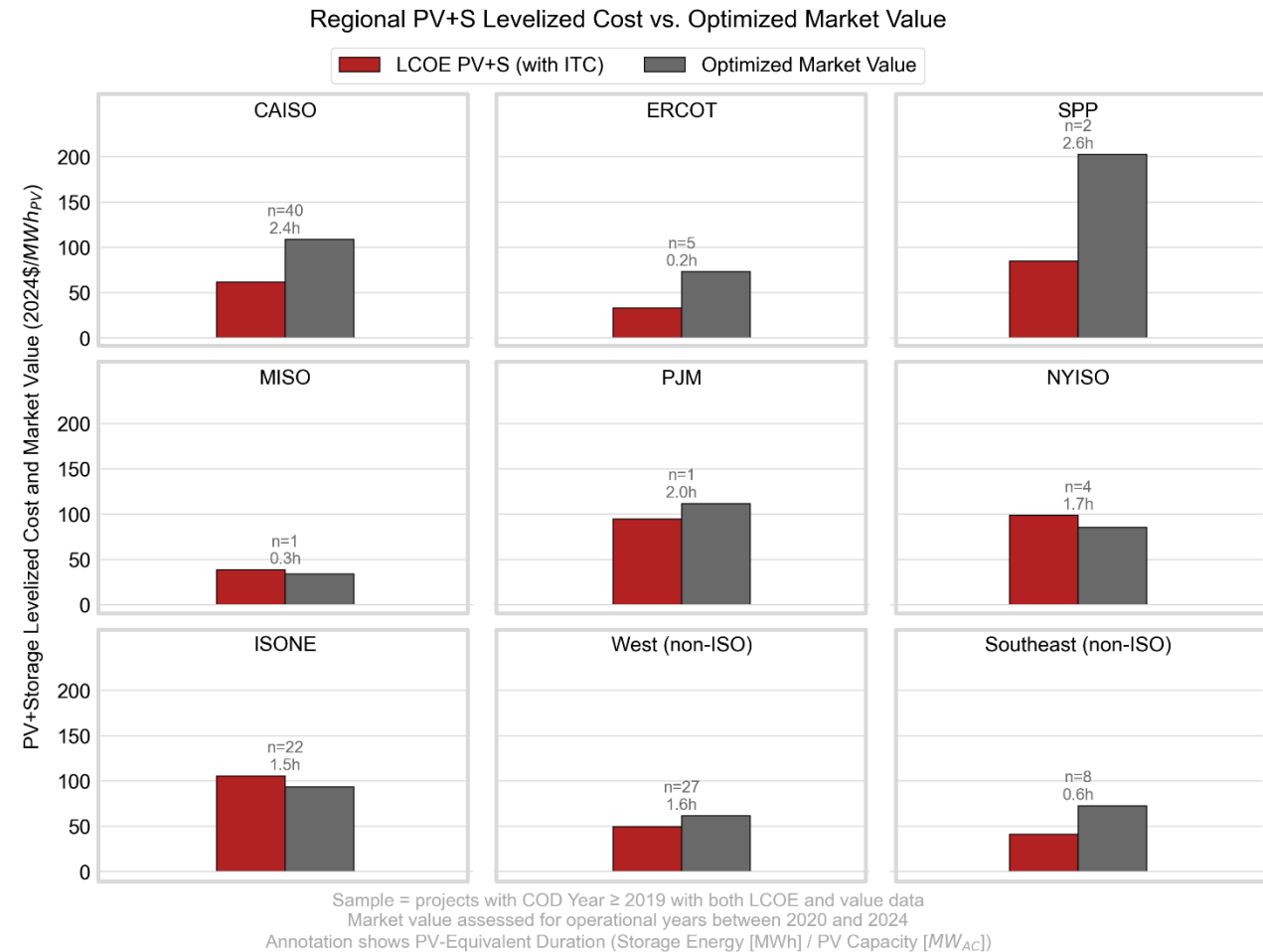
Sample: 280 projects totaling 12.6 GW<sub>PV</sub>, 7.3 GW<sub>Bat</sub>/23.7GWh



# On a national average basis, optimized PV+storage market value exceeded LCOE from 2020–2024 by nearly \$30/MWh

- For 39% of recent PV+storage plants, project-specific capex data were available, allowing us to estimate long-term generation costs using the levelized cost of energy (LCOE).
- From 2020 to 2024, the optimized wholesale market value exceeded LCOE on a national average basis, both with investment tax credits (net value of \$35/MWh) and without them (net value of \$16/MWh).
- The net value proposition varied by region.
  - It was especially strong in the established CAISO and ERCOT markets, as well as in the non-ISO Southeast. High potential ancillary services value for the two projects in SPP drives the greatest regional net value. In the non-ISO West, projects where storage was retrofit tend to have costs above their value potential, while greenfield projects typically have positive net value, resulting in a small net positive for the region.
  - In regions with less sunshine such as ISO-NE and NYISO PV+S generation costs are greater than the optimized market value between 2020 and 2024. This analysis does not account for potential additional revenue from RECs, tolling agreements, or state incentive programs that may underwrite these projects.

**Sample:** 110 projects totaling 10.1 GW<sub>PV</sub>, 5.1 GW<sub>Bat</sub>/18.0GWh

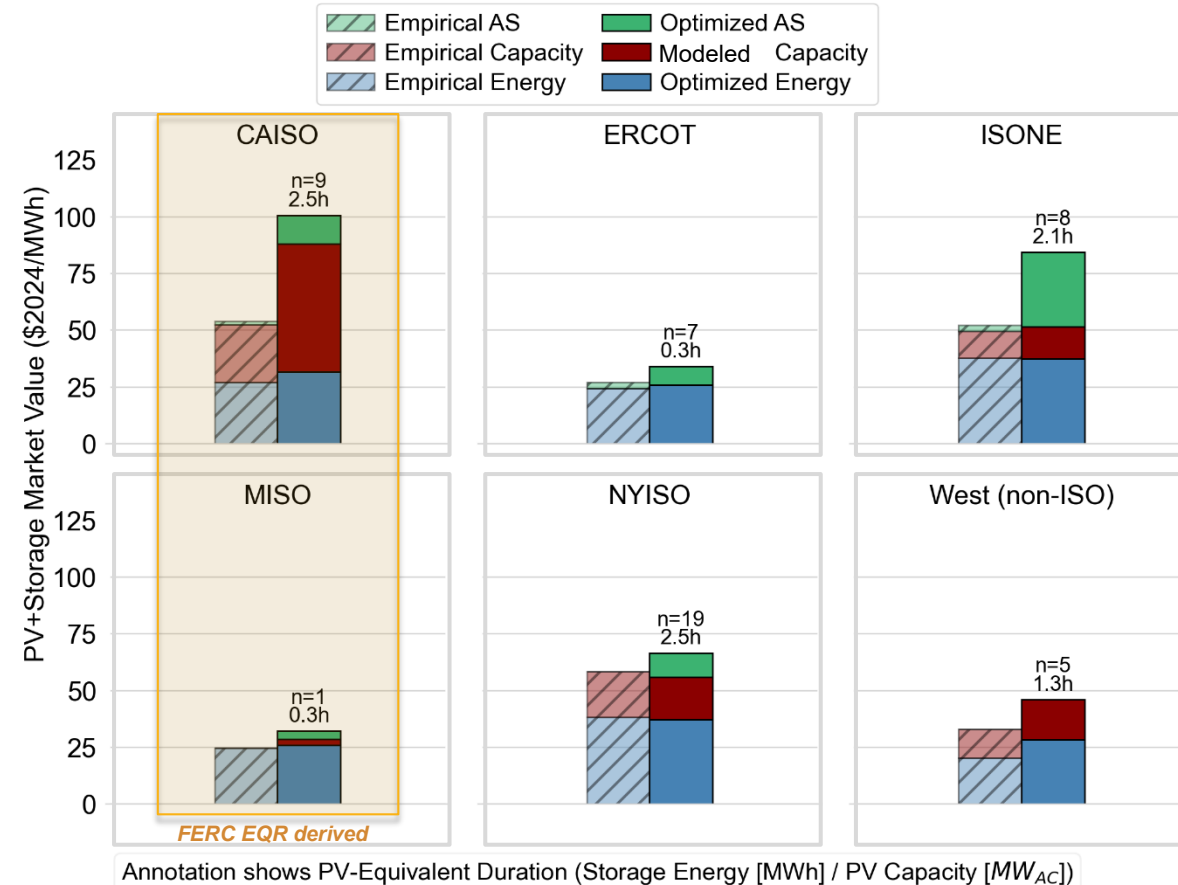


# In 2024, actual PV+storage operations realized \$39/MWh of market value, 62% of the optimized value potential.

- We collected empirical operating data for 18% of the modeled projects and compared observed with optimized dispatch.
- On a national average basis in 2024, projects in this subsample increased wholesale market value from \$25/MWh for standalone PV to \$39/MWh for combined PV+S output.
- The empirical value fell well short of the optimized result of \$63/MWh, achieving only 62% of modeled value. This gap was driven mainly by:
  - Lower realized storage value, as the implied storage value adder was \$14/MWh under empirical operations, compared with \$36/MWh under optimized dispatch (38%).
  - Lower reported ancillary services revenue, often driven by under-participation in still lucrative markets.
  - Lower capacity revenue in CAISO compared to our modeled estimates, possibly due to incomplete capacity revenue reporting in FERC EQR or lower realized capacity prices. The modeled values are the product of design-driven capacity credits and zonal capacity prices reported by the CPUC that may not have been accessible by the sampled projects.
- Performance also varied by region.
  - In ISO-NE, NYISO, and ERCOT, the largest shortfall relative to the optimum came from lower AS value.
  - Lower realized capacity and energy value was the main reason optimized value was higher in CAISO and the non-ISO West.

**Sample:** 49 projects totaling 4.2 GW<sub>PV</sub> , 1.6 GW<sub>Bat</sub>/5.3GWh

Regional Empirical vs. Optimized Market Value in 2024

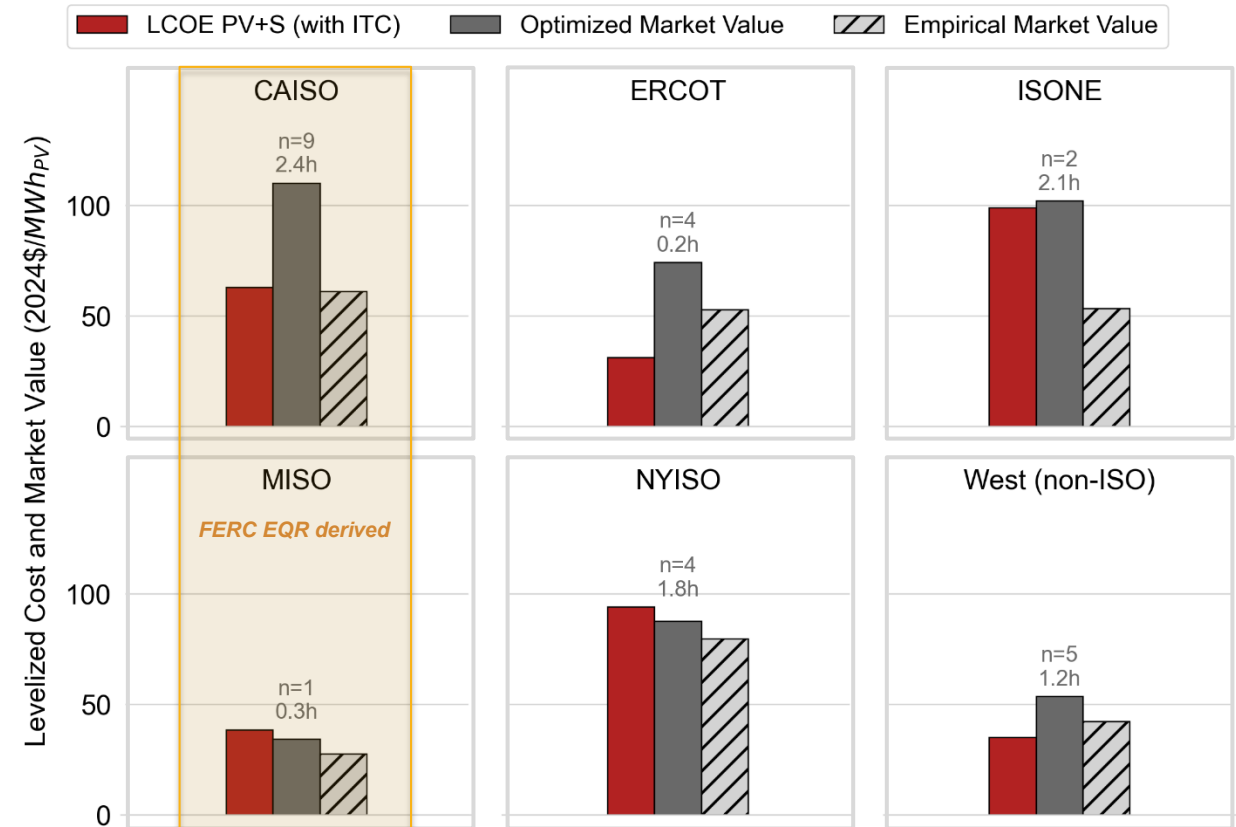


# Despite operational shortfalls, empirical PV+storage value still exceeded LCOE nationally by \$8/MWh in 2020–2024

- For the 9% of projects in our total sample for which both empirical operating data and cost data were available, we compared empirical and optimized market value over 2020–2024 with long-term generation costs and found that the national average empirical value exceeded LCOE by \$8/MWh with tax incentives.
- The net-value proposition varied by region:
  - Empirical wholesale market value exceeded LCOE in ERCOT, and the non-ISO West, where PV+storage deployment has been strongest. In ISO-NE, projects could have achieved positive net value under optimized operations but fell short in practice, in part because projects barely participated in the highly remunerative ancillary services market.
  - In NYISO and MISO, projects in this small subsample did not earn enough wholesale market value to exceed generation costs (not including additional value streams like RECs or state incentives).
  - In CAISO reported EQR revenue across energy, capacity, and AS products is roughly the same as LCOE.

**Sample:** 25 projects totaling 3.5 GW<sub>PV</sub>, 1.3 GW<sub>Bat</sub>/4.8GWh

Regional PV+S Levelized Cost vs. Optimized and Empirical Market Value



Sample = projects with COD Year ≥ 2019 with both LCOE and value data  
 Levelized optimized market value assessed for operational years between 2020 and 2024  
 Levelized empirical market value may be assessed over a smaller subset of years based on data availability  
 Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

# Multiple operational and organizational barriers limit the value that PV+S systems could offer the bulk power system

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Barriers to increasing PV+S market value include:

Under-participation in wholesale markets, including still-lucrative ancillary services in less mature markets.

Restrictions on grid charging under earlier ITC rules for older projects

Limited response to negative prices because of volume targets or hub-based settlement

Dispatch strategies tied to out-of-market considerations including fixed delivery obligations under tolls, PPAs, REC markets or state incentive programs

Rule-based operation, such as charging at midday and discharging in the evening regardless of price conditions

Imperfect price forecasting

In non-ISO regions, additional value is constrained by the lack of organized ancillary services markets and by weak energy price signals.

- Even utilities in regional imbalance markets may prioritize balancing within their own BA rather than dispatching against imbalance market prices.
- In the Southeast, available FERC system lambda data are a poor proxy for nodal price volatility, understating the value that PV+storage could provide.



# Sample and Methods



## Sample sizes vary by analysis based on data availability



- **1) Largest sample:** modeled PV+S projects operating in 2024 across 7 ISO/RTOs and 19 additional balancing authorities. We compare optimized standalone PV and PV+storage wholesale market value.
  - ▣ **2) Cost-data subset:** projects with available capital expenditure data. We estimate levelized generation costs (LCOE) and compare them with optimized market value from 2020–2024 to assess net value.
- **3) Empirical-dispatch subset:** projects with observed PV+S operating data across 7 regions. We compare empirical with optimized wholesale market value project by project.
  - ▣ **4) Empirical net-value subset:** projects with both empirical operating data and cost data. We compare PV+S net value under optimized and empirical dispatch for available years from 2020–2024.

# Modeled sample covers 280 PV+storage projects and 95% of the U.S. operational PV+storage fleet

**Sample:** 280 projects totaling 12.6 GW<sub>PV</sub>, 7.3 GW<sub>Bat</sub>/23.7GWh

We define PV+S as co-located PV and storage located behind, or associated with, a common point of interconnection.

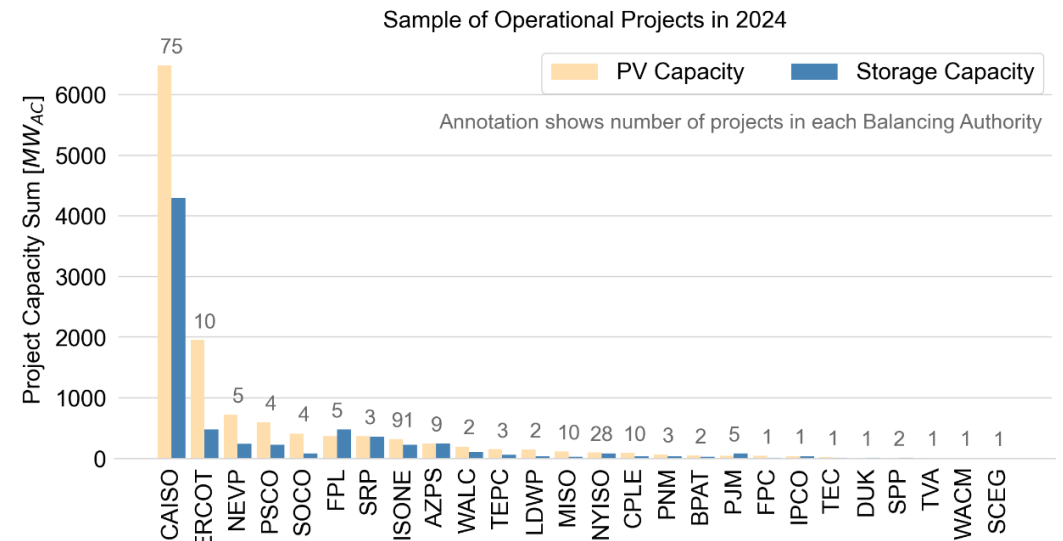
Not all modeled projects participate in practice in wholesale markets. Those that do may operate as separate PV and storage resources, co-located resources, or hybrid resources.

## Project selection criteria

- Project locations and technical design are derived from EIA Form 860.
- Both the PV and storage components had at least one full calendar year of operation in 2024
- PV capacity exceeds 1MW<sub>AC</sub>

## Grid charging and ITC treatment

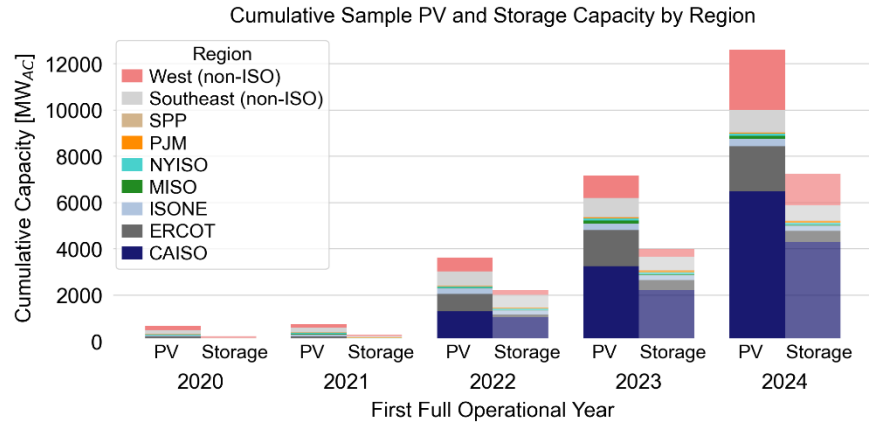
- 23% of batteries were eligible for the standalone ITC, which does not restrict grid charging. These projects were concentrated in the non-ISO West (57% of regional capacity), CAISO (36%), and the non-ISO Southeast (29%).
- For the remaining projects, ITC eligibility depends on charging primarily from the paired solar asset.



## Geographic distribution

- Location in 7 ISO/RTOs and 19 additional Balancing Authorities (BAs) that have non-negligible utility-scale solar capacity
- The sample is unevenly distributed across regions and varies substantially in total capacity, average project size, and project configuration.
- CAISO contains the most capacity, with 6.5 GW of PV across 75 projects.
- ISONE and NYISO have many projects (91 and 28) but relatively small average PV project sizes of about 3.5 MW.
- 14 BAs have three or fewer PV+S projects.

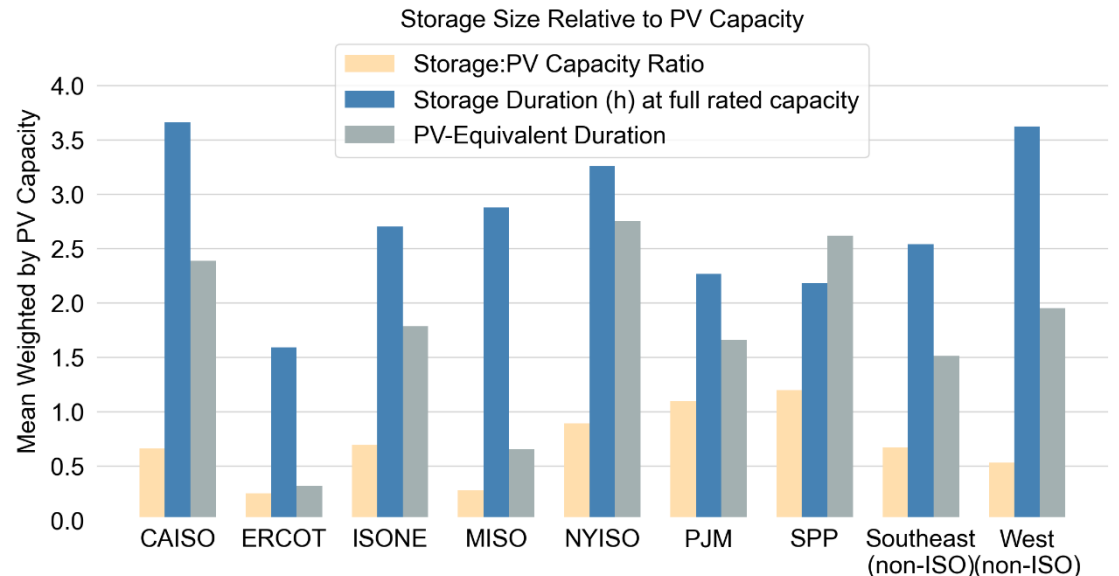
# PV+S fleet grew dramatically over the 2020-2024 analysis period and shifted toward configurations with larger storage components



The analyzed fleet expands from 44 projects in 2020 to 280 in 2024 as additional projects came online.

- Newer systems have greater battery capabilities: PV-equivalent duration of 1.9h in 2024 vs. 0.6h in 2020
- PV-Equivalent Duration (h) is the battery energy capacity expressed as “theoretical battery hours at PV max output.” It combines the storage:PV capacity ratio and storage duration and will be used as proxy for battery size.

$$PVED = \frac{E_{\{bat\}}}{P_{\{PV\}}} = \left( \frac{E_{\{bat\}}}{P_{\{bat\}}} \right) \left( \frac{P_{\{bat\}}}{P_{\{PV\}}} \right)$$



# Project-specific hourly solar generation profiles were modeled and calibrated to observed data

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Comprehensive, project-specific, high-resolution generation profiles for utility-scale solar projects are not publicly available outside ERCOT, where 60-day SCED and day-ahead market disclosure reports provide limited plant-level information. We therefore model these profiles.

## Modeling process:

1. We estimate hourly solar generation using NLR's System Advisor Model (SAM), combining
  - ▣ site- and year-specific irradiance data from NLR's National Solar Radiation Database and NOAA's High-Resolution Rapid Refresh model with
  - ▣ project-specific technical design data from EIA Form 860, augmented by LBNL's Utility-Scale Solar dataset.
2. We then de-bias the modeled profiles<sup>1</sup> using:
  - ▣ ISO-reported aggregate hourly solar generation,
  - ▣ plant-level annual generation reported in EIA Form 923, and
  - ▣ hourly curtailment estimates derived either from plant-level data in ERCOT (HSL minus MW) or allocated from ISO-level curtailment reports in CAISO and SPP.

<sup>1</sup> The methods are based on Mills, A., Seel, J., Millstein, D., Kim, JK., Jeong, S., Warner, C., and Gorman, W., 2021. *Solar-to-Grid: Trends in System Impacts, Reliability, and Market Value in the United States*. LBNL. <https://emp.lbl.gov/publications/solar-grid-trends-system-impacts-0>

# Calculation of wholesale electricity market value (1/5)

2 optimized value cases per project across 3 value streams in different scenarios

	PV Standalone	PV + Storage
	Hypothetical plant with only PV component and \$0 marginal cost	Two components are jointly operated as a single resource
Value streams	Energy	✓
	Capacity	✓
	Ancillary Services	✓

## Interpretation

- Wholesale market value represents the short-term procurement cost an offtaker avoids by purchasing output from a PV+S project rather than from wholesale markets.
- Actual project revenues depend on contract terms and may differ from these estimated market values.
- These estimates exclude additional value streams and costs not captured in wholesale energy and capacity markets, such as renewable energy credits and certain transmission or distribution cost impacts.
- Market value is reported at annual resolution in 2024 dollars and normalized by pre-curtailment solar generation (MWh), using BEA's GDP price deflator.

Scenario	Energy sales	AS participation	Grid charging
<b>Base case</b>	<i>ISO/RTOs</i> : Day-ahead (DA) market <i>non-ISO BAs</i> : either real-time regional imbalance markets (WEIM, WEIS) or hourly FERC system lambda data (southeastern BAs)	Regulation and reserve products in ISO/RTOs	Unrestricted for storage that came online after 2022 or have been operational for more than 5 years (based on ITC), disallowed otherwise
<b>Sensitivity</b>	<i>ISO/RTOs</i> : Real-time (RT) market <i>non-ISO BAs</i> : no change from base case	No AS participation	Full grid charging allowed for all storage

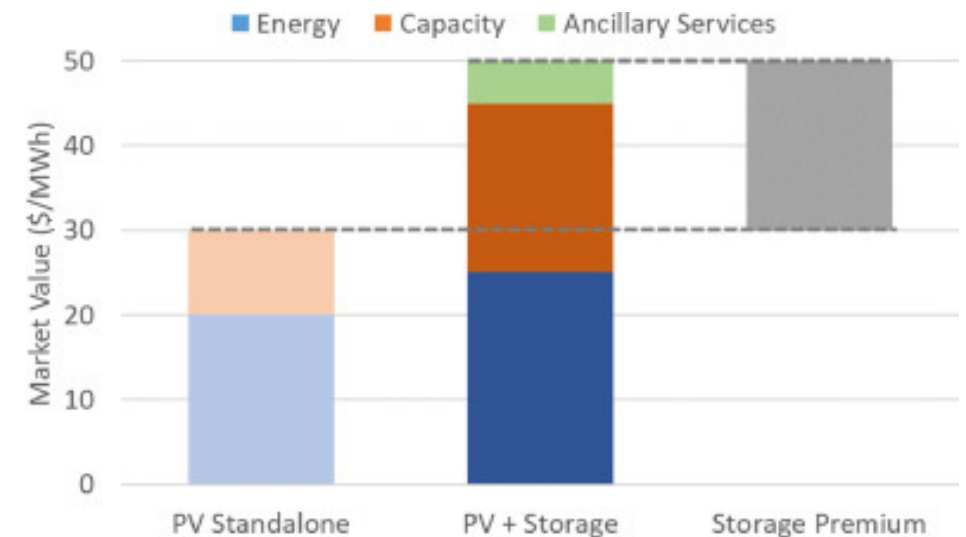
All results correspond to the base case unless a sensitivity is specified

# Calculation of wholesale electricity market value (2/5)

## Storage Premium: The incremental value of PV+S over standalone PV

### Sources of PV+storage value premium relative to standalone PV:

- **Energy Value** can increase when solar output is shifted into higher-priced hours or when the battery performs energy arbitrage through grid charging. Total energy exports from PV+storage are generally lower than from standalone PV because of battery efficiency losses, except when DC-coupled batteries capture otherwise clipped energy or when storage reduces curtailment.
- **Capacity Value** can increase substantially because PV+storage projects typically receive higher capacity credit, reflecting the added reliability contribution of storage, especially in markets with high solar penetration.
- **Ancillary Service Value** is assumed to be available only to PV+storage projects, not to the hypothetical standalone PV case, consistent with current U.S. market rules.



# Calculation of wholesale electricity market value (3/5)

## Energy value assumptions

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- In the optimal dispatch analysis, solar generation is assigned zero marginal cost. As a result, modeled curtailment during negative-price periods may exceed real-world curtailment, where PTC incentives, PPA terms, or RPS obligations can imply effective marginal costs below zero.

$$\text{Energy Value} = \frac{\sum \text{Postcurtailment PV}(+\text{Storage Dispatch})_h * \text{Energy Price}_h}{\sum \text{Precurtailment PV Generation}_h}$$

- Energy prices:
  - **ISOs:** hourly locational marginal prices (LMPs) at the nearest node.
  - **Non-ISO BAs:**
    - either LMPs from regional imbalance markets (WEIM, WEIS), or
    - hourly FERC system lambda data for southeastern balancing authorities, intended to approximate marginal operating costs.

# Calculation of wholesale electricity market value (4/5)

## Capacity value assumptions

$$\text{Capacity Value} = \frac{\sum PV(+Storage) \text{ Capacity Credit}_T * \text{Nameplate} * \text{Capacity Price}_T}{\sum \text{Precurtailment PV Generation}_T}$$

- Capacity prices:
  - ISO-reported zonal capacity market prices (ISO-NE, NYISO, PJM, MISO) or
  - bilateral capacity payment proxies:
    - For CAISO we use the 85<sup>th</sup> percentile of zonal system capacity prices reported by the CPUC<sup>1</sup> to estimate marginal capacity value. As the data is published with significant delay, we use 2023 prices when evaluating delivered capacity in 2023 and 2024. PV+S projects in California may not be able to access these prices in practice.
    - For SPP and non-ISO balancing authorities we use regional capacity-weighted mean prices from capacity transactions reported in FERC EQR.
  
- Capacity accreditation:
  - ISOs other than ERCOT: published accreditation rules, which vary by zone and by month or season.
  - ERCOT: no explicit capacity value.
  - Non-ISO balancing authorities: average contribution during the top 100 net-load hours over the previous three years. We add 1/100<sup>th</sup> of annual capacity value to each of the top 100 net-load hours during the optimization to incentivize dispatch during these hours.
  
- The point-of-interconnection (POI) limit is assumed to equal  $\max(\text{Capacity}_{PV}, \text{Capacity}_{Storage})$

<sup>1</sup> Draghi, Z. et al, 2025. *2023 Resource Adequacy Report*. Table 8. RA Capacity Prices by Month and Path 26 Zone. p27. <https://www.cpuc.ca.gov/RA/>

# Calculation of wholesale electricity market value (5/5)

## Ancillary Services (AS) value assumptions

- Optimal dispatch assumes AS participation for all ISO PV+S projects, but no AS value for non-ISO BAs (*though CAISO may allow AS bids from EIM participants with dynamic scheduling*) or stand-alone PV
- Includes both **award** and **deployment** (real-time energy) revenue for each Ancillary Service k:

$$AS\ Value = \frac{\overbrace{\sum AS\ Capacity_{h,k} * AS\ Price_{h,k}}^{Award} + \overbrace{\sum AS\ Capacity_{h,k} * Deployment\ to\ Award\ Ratio * RT\ Energy\ Price_h}^{Deployment}}{\sum\ Precurtailment\ PV\ Generation_h}$$

### Regulation Awards

Assuming 30% deployment-to-award ratio<sup>1</sup>

- ISOs (except ERCOT) pay for awarded capacity and performance
- We assume the performance payments are **in addition to energy market compensation**

$$Award\ Revenue = Capacity_{Reg} * (P_{Capacity_{Reg}} + \rho * \Delta_{Mileage} * P_{Mileage})^2$$

Where:

- Performance or accuracy score ( $\rho$ ): 0.9 in PJM and otherwise assumed to be 1
- Mileage ( $\Delta_M$ , sum of absolute values of regulation signal movements per MW):
  - We use ISO-level average mileage values, except in PJM, where we use the hourly mileage ratio
- In CAISO and SPP we differentiate between regulation up and down prices

### Non-Regulation Awards

Assuming 2% deployment-to-award ratios<sup>1</sup>

- All Markets:
  - Spinning/online reserve
  - Non-spinning/offline reserve
- SPP: Uncertainty reserve + Supplemental reserve
- ERCOT : ERCOT contingency reserve service
- MISO: Stored energy reserve

<sup>1</sup> Kim, J.H., Kahrl, F., Mills, A., Wiser, R., Montañés, C.C., Gorman, W., 2023. *Economic evaluation of variable renewable energy participation in U.S. ancillary services markets*. Utilities Policy 82, 101578. <https://doi.org/10.1016/j.jup.2023.101578>

<sup>2</sup> Xu, B., Dvorkin, Y., Kirschen, D.S., Silva-Monroy, C.A., Watson, J.-P., 2016. *A comparison of policies on the participation of storage in U.S. frequency regulation markets*, 2016 IEEE Power and Energy Society General Meeting (PESGM), pp. 1-5. <https://doi.org/10.1109/PESGM.2016.7741531>

# AS assumptions: example prices for regulation (up/down or combined)

ISO	$P_{Cap}$ (\$/MW) 2024 avg	$P_{Mileage}$ (\$/MW) 2024 avg	Hourly mileage $\Delta_M$ ( $\Delta MW/MW$ )	Performance Score ( $\rho$ )	Combined Price (\$/MW) 2024 avg [10 <sup>th</sup> , 90 <sup>th</sup> percentile]
CAISO (day-ahead)	5.52 (down), 2.98 (up)	0.00113 (down), 0.00086 (up)	7 (down), 4 (up) <sup>1</sup>	1	5.52 [3.1, 8.0] (down), 2.98 [0.2, 5.0] (up)
MISO (real-time)	12.8	0.610	7.2 <sup>2</sup>	1	17.2 [9.2, 23.8]
SPP (real-time)	NA	NA	NA <sup>3</sup>	1	5.89 [1.3, 11.6] (down), 12.2 [2.6, 21.9] (up)
ISO-NE (real-time)	15.3	0.0848	8 <sup>4</sup>	1	16.0 [0, 41.9]
NYISO (real-time)	7.99	0.136	8 <sup>4</sup>	1	9.07 [4.0, 11.1]
PJM (real-time)	28.9	1.07	5.75 <sup>5</sup>	0.9 <sup>6</sup>	34.1 [8.4, 64.0]
ERCOT (day-ahead)	3.44 (down), 6.01 (up)	NA	NA	NA <sup>7</sup>	3.44 [0.5, 5.0] (down), 6.01 [1.0, 6.7] (up)

<sup>1</sup> From table on pg. 11 [here](#).

<sup>2</sup> From [Sandia paper](#) after equation (1): “Based on historical data, MISO uses an average market-wide value alpha = 0.6/5min (or 7.2/hour)”.

<sup>3</sup> Our understanding from the description given [here](#) is that SPP’s “service price” given in our data already includes the Mileage component. Thus, we only have the combined price, not the components.

<sup>4</sup> Use 8 for both ISO-NE and NYISO. 8 is NYISO’s uniform movement-to-capacity ratio used in scheduling, see pg. 295/A-113 of [2024 Market Monitor report](#). We do not have a source for this ratio for ISO-NE, so we use NYISO’s value for both.

<sup>5</sup> PJM provides the hourly movement ratio between RegD and RegA, which we use instead of one common movement multiplier.

<sup>6</sup> Value based on the table on pg. 48 [here](#) for batteries following RegD.

<sup>7</sup> ERCOT does not have mileage or performance scores. The combined price = the capacity price.

# Optimization for PV+S dispatch

- **Modeling perspective:** asset owner who is a price-taker with *perfect foresight into generation and price conditions* seeking to maximize market value while considering battery degradation.
- **Implementation:** Linear model optimizing operation of battery and solar curtailment to maximize value (energy and AS revenue, including hourly capacity price adders for regions where accreditation is profile-dependent) less costs at an hourly resolution.

Equality Constraints	Inequality Constraints
PV power balance	SOC bounds
Storage power balance	Charge/discharge power limits
AC bus power balance	Export/import limit at POI
Battery State of Charge (SOC) transition	AS awards limited by storage power and energy capacity according to varying market rules
AS deployment rate assumption	Total awards limited by energy availability: We require enough SOC to fulfill all AS awards each hour, even though the assumed deployment rate is <100%

- **Modeled costs**
  - PV marginal generation cost = \$0/MWh
  - Storage degradation proxied by linear throughput cost of \$10/MWh → minimum economic sale price for energy charged at a price (or opportunity cost) of  $\$P/MWh$  of  $P \left( \frac{1}{\eta} - 1 \right) + 10 \frac{1+\eta}{\eta} \approx 0.11P + 21.08\$/MWh$  using combined battery and inverter one-way efficiency of  $\eta = 0.9$
- **Leverages project-specific technical design information:** modeled PV input profile, DC/AC coupling with battery, battery max capacity and energy, POI limit. Assumes instantaneous ramping and constant battery and inverter efficiency.

# Project-level cost data allow estimation of PV+storage LCOE

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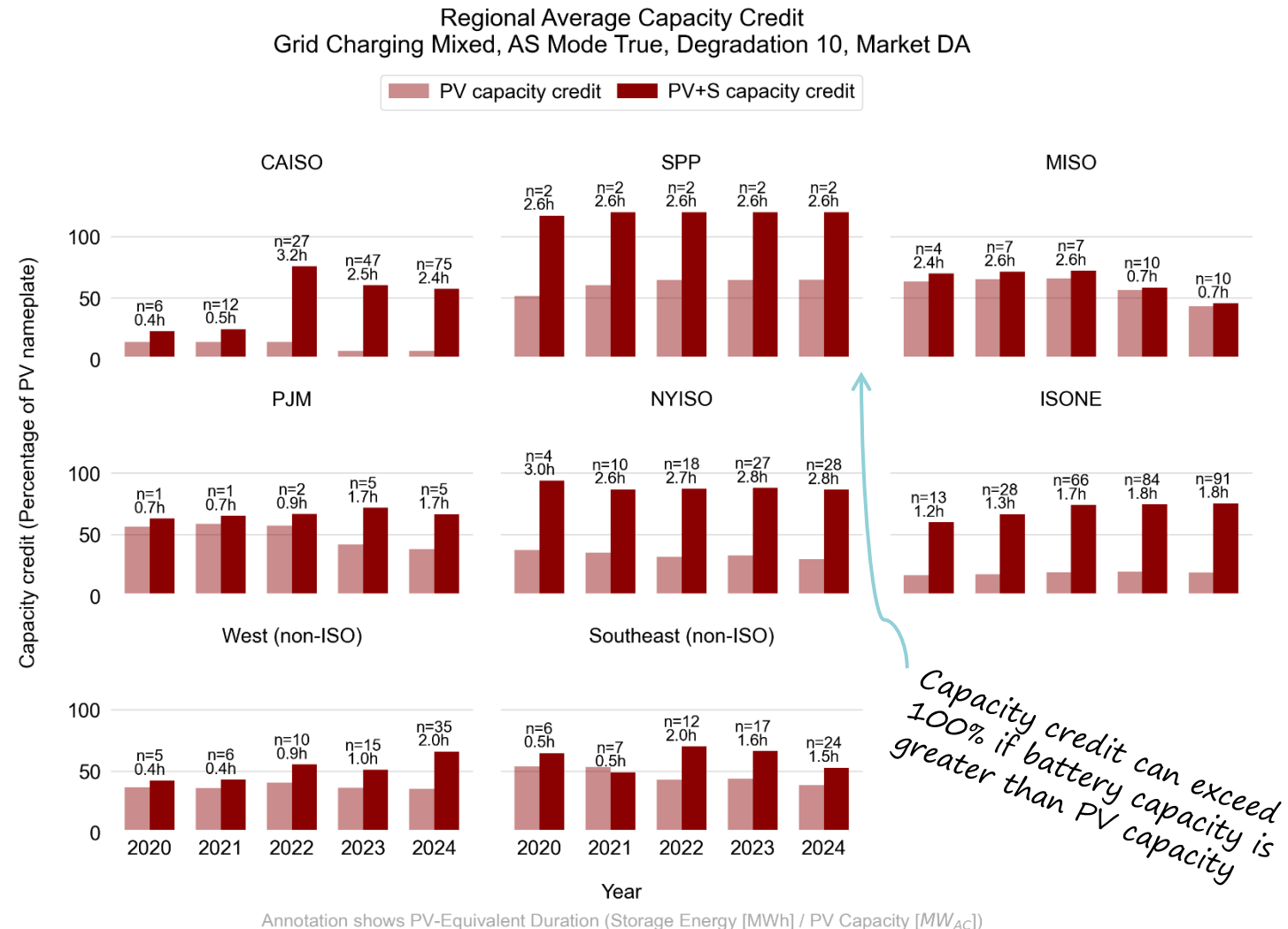
- For 114 projects with PV capacity above 5 MW<sub>AC</sub>, we estimate project-specific Levelized Cost of Energy (LCOE) as a proxy for direct generation cost. These estimates exclude broader system costs not fully internalized in market prices, such as additional transmission, resource adequacy, congestion, and ancillary service needs.
- We follow NLR's [ATB](#) methods to estimate lifetime cost per MWh with and without federal tax credits. We include the ITC, including Energy Community adders where applicable, but exclude Domestic Content adders and do not model the PTC or any additional state incentives.
- Project-level variation
  - CapEx from confidential EIA-860 data and FERC Form 1 including overhead/profits, tie-in and potential transmission upgrades costs
  - Empirical annual net capacity factors from EIA-923, adjusted for curtailment where available
  - Levelized net capacity factors for missing and future years using size-based degradation assumptions
- Cohort-level variation
  - Time-varying OpEx, design life, inflation, tax, and financing assumptions
  - One battery replacement after 15 years for hybrid projects
  - Real WACC for 2024 COD projects: 3.26%
- Retrofit PV+S projects have higher average LCOEs because their PV components were built in earlier, higher-cost years.

# Optimized Value Premium over PV Standalone

Value Premium in Sensitivity Cases is covered in Appendix

# Batteries can increase firm capacity contributions from 18% to 60% of PV nameplate capacity with optimal dispatch in 2024

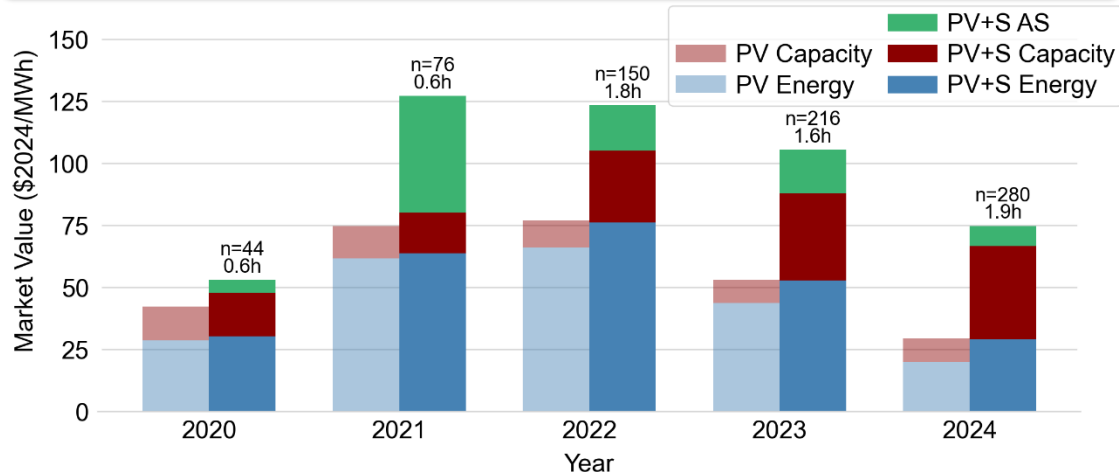
- PV+S systems have greater capacity credit than the same PV component would have as a standalone resource. The gap is widest in
  - ▣ high solar penetration regions where standalone PV capacity credits have declined sharply (e.g., CAISO)
  - ▣ systems with high-need periods in the winter (e.g., ISONE)
  
- Methods reminder:
  - ▣ For ISOs we follow official accreditation rules by delivery year
  - ▣ For non-ISO BAs we use top 100 net-load hour contributions. Battery dispatch during these hours was incentivized with a capacity price adder that would not be visible to real-world market participants.



# Optimized national market value of PV+storage projects was \$75/MWh in 2024 (250% of standalone PV)

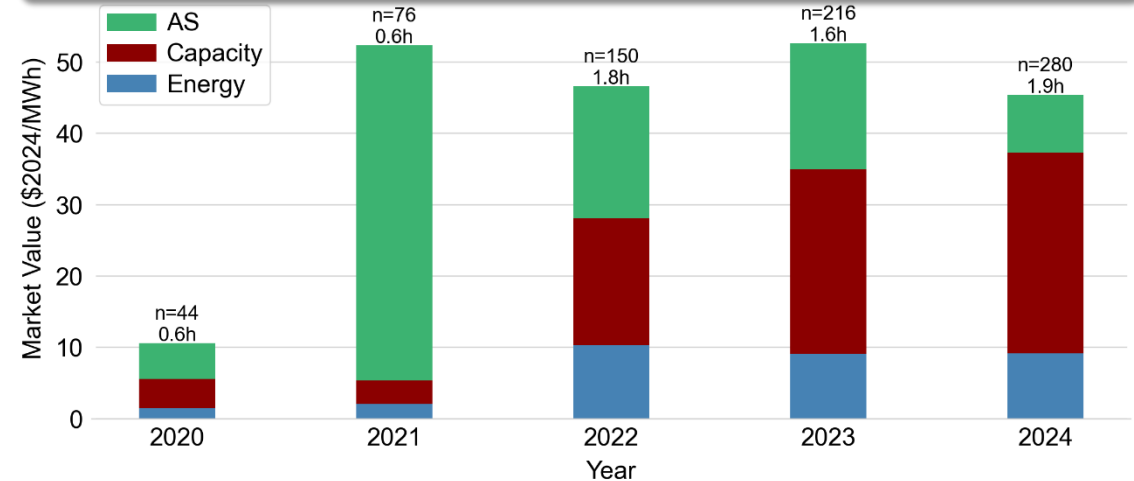
Sample: 280 projects totaling 12.6 GW<sub>PV</sub>, 7.3 GW<sub>Bat</sub>/23.7GWh

## Total Market Value Potential



Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

## Storage Premium Potential



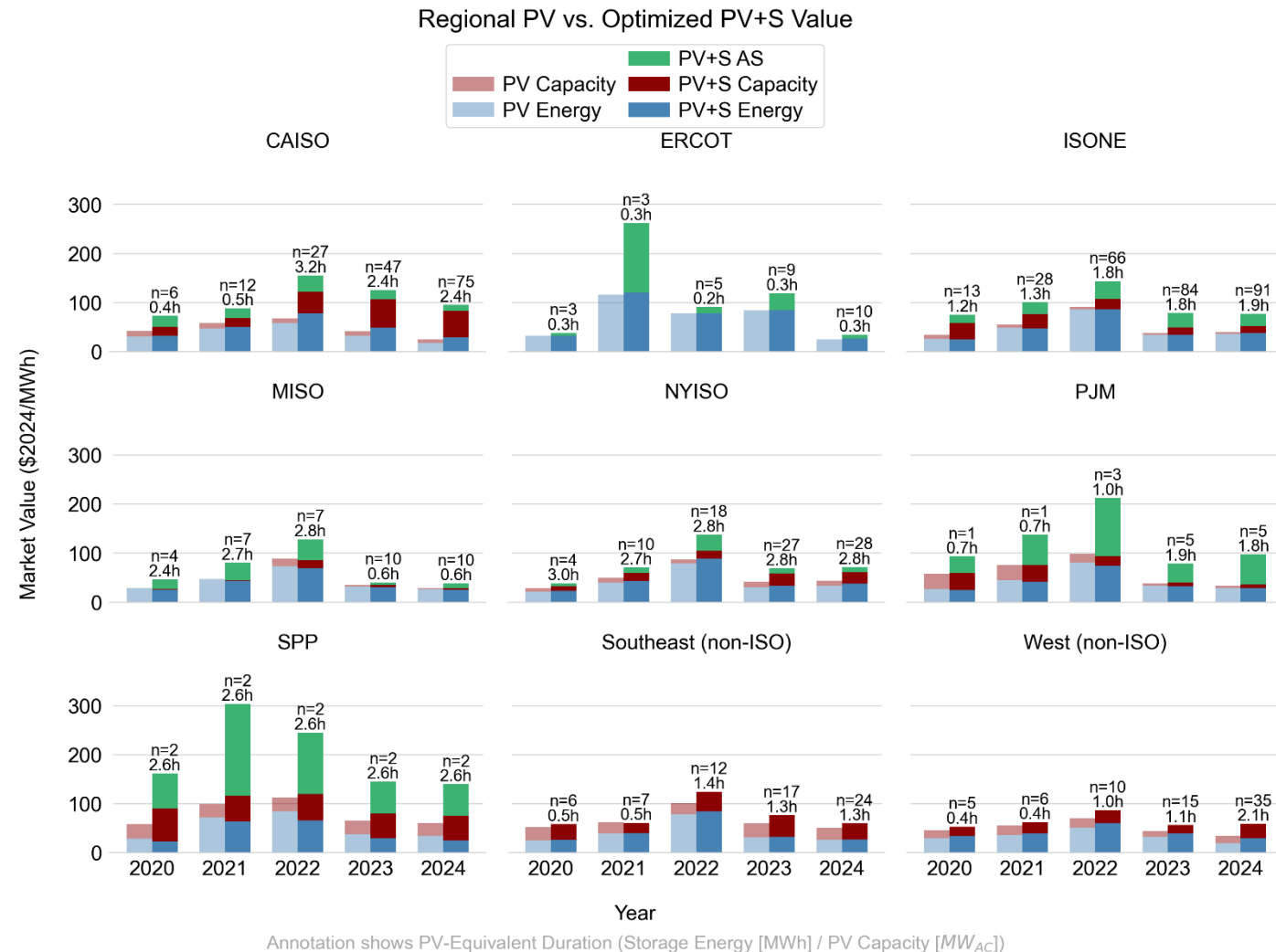
Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

- National average wholesale market value has declined since 2021/22 for both standalone PV (~\$75 → \$29/MWh) and optimized PV+S (\$127 → \$75/MWh) as
  - ▣ Energy and AS prices declined
  - ▣ PV+S deployment expanded into non-ISO markets without AS markets and less price volatility

- The addition of batteries with optimized dispatch enables a national average (in 2024) of:
  - ▣ \$28/MWh more capacity value (total PV+S value of \$38/MWh)
  - ▣ \$9/MWh more energy value (total of \$29/MWh)
  - ▣ \$8/MWh of AS revenue (higher in ISO regions)

# Optimized PV+storage value varied widely across regions in 2024, driven by differences in ancillary services and capacity value

- Regional differences in optimized PV+S value streams were large in 2024.
  - **Energy** value ranged from \$25/MWh in SPP to \$38/MWh in NYISO, while **capacity** value ranged from just \$3/MWh in MISO to about \$54/MWh in SPP and CAISO. **AS** value showed the widest spread, from \$8/MWh in ERCOT to \$64/MWh in SPP.
- These differences translated into large variation in **total PV+S value**.
  - SPP had the highest total value (\$140/MWh), driven mainly by AS, while ERCOT had the lowest (\$34/MWh), reflecting smaller batteries and lower AS value.
  - Non-ISO projects, which generally lack access to organized ancillary services markets, also clustered near the lower end of the distribution at roughly \$60/MWh.
- The **storage premium** likewise varied by region.
  - In most ISOs, it was driven mainly by AS revenue. In CAISO and in the non-ISO West and Southeast, by contrast, the premium was driven primarily by capacity value uplift.



# Net-Value based on Optimized Operations

# Project-level optimized market value and long-term generation cost

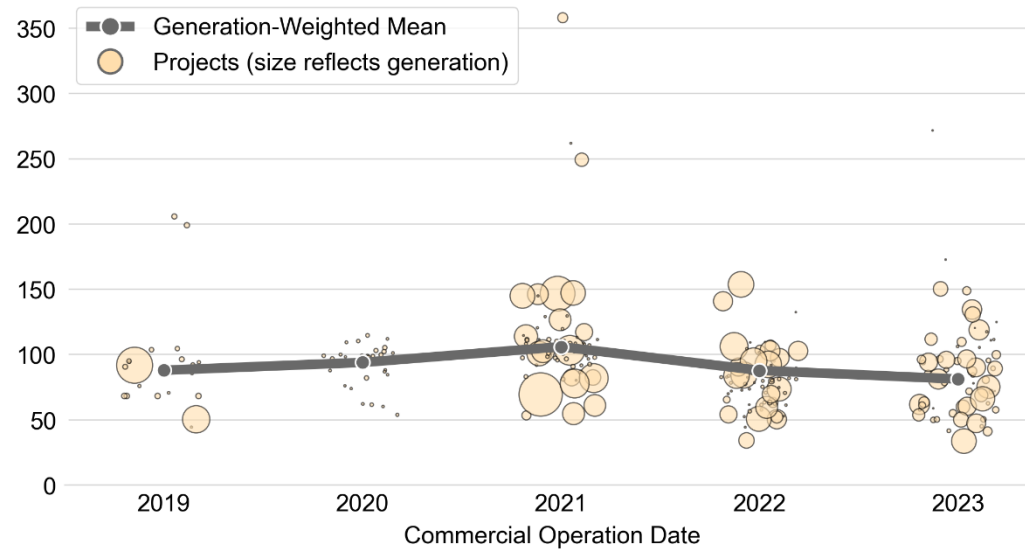
- The following slides compare, at the project level, optimized wholesale market value for PV+storage with long-term generation cost, measured as LCOE.
  - To make this comparison, we levelize annual market values over 2020–2024 for the years in which each project was operating and convert them into a single metric using a cohort-specific weighted average cost of capital (WACC) that varies by commercial operation date (COD). These levelized value estimates are still preliminary, as they are based on only the first years of project operation and will evolve as more years of asset life are observed.
  
- Initial Value sample
  - We exclude 22 projects with COD in 2013–2018 because we do not estimate market value for their earlier operating years.
  - We retain 22 projects for which storage capacity exceeds 120% of PV capacity.
  
- LCOE sample
  - LCOE can be estimated only for a subset of projects with value data.
  - We focus on projects with COD after 2019 and PV capacity above 5 MW<sub>AC</sub>.
  - The sample includes both greenfield projects and 36 retrofit projects; for retrofits, the storage retrofit year is treated as the COD.
  - Here and in the net-value section we exclude 4 projects for which storage capacity exceeds 120% of PV capacity.

If levelized optimized market value exceeds long-term generation cost, the PV+S project could provide cost-effective bulk power system services and increase overall welfare. How that value is divided between the project owner and the offtaker depends on contract structure. If many projects were able to capture similar value, additional market entry would likely compress margins, as value and cost tend to converge in a long-run equilibrium.

# The levelized value based on optimized operations (2020-2024) has been \$80-\$100/MWh<sub>PV</sub>, resulting on average in positive net values, even without tax credits

**Value Sample:** 258 projects, 12.3 GW<sub>PV</sub>, 7.1 GW<sub>Bat</sub>/23.5GWh

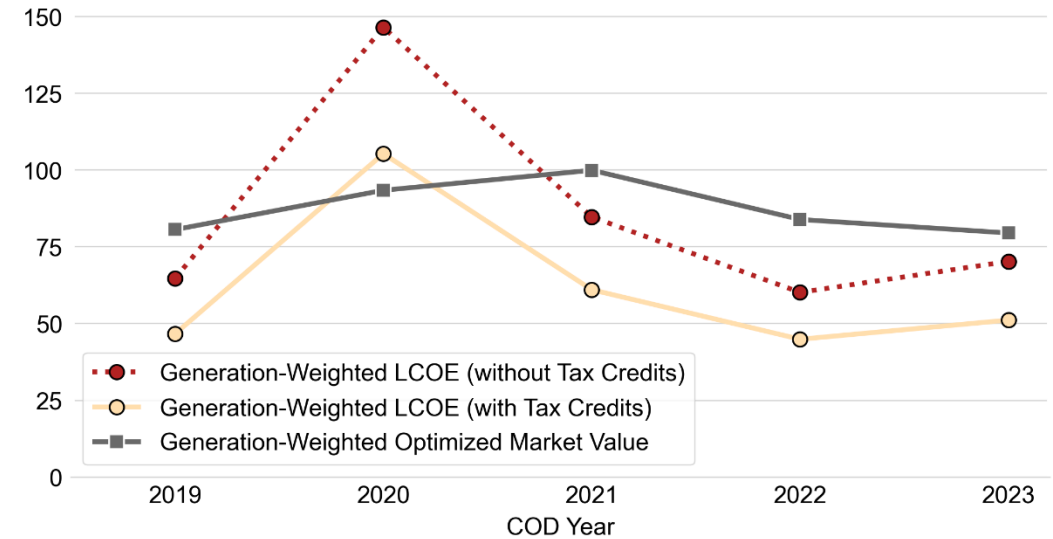
Levelized Total Hybrid Value 2020-2024 (2024\$/MWh<sub>PV</sub>)



- Levelized value has wide range for any given cohort.
- The generation-weighted average tended to decrease from a peak in 2021 as later projects could not capture high electricity prices in 2022 or benefit high priced early AS markets in CAISO and ERCOT.

**Net Value Sample:** 110 projects, 10.1 GW<sub>PV</sub>, 5.1 GW<sub>Bat</sub>/18GWh

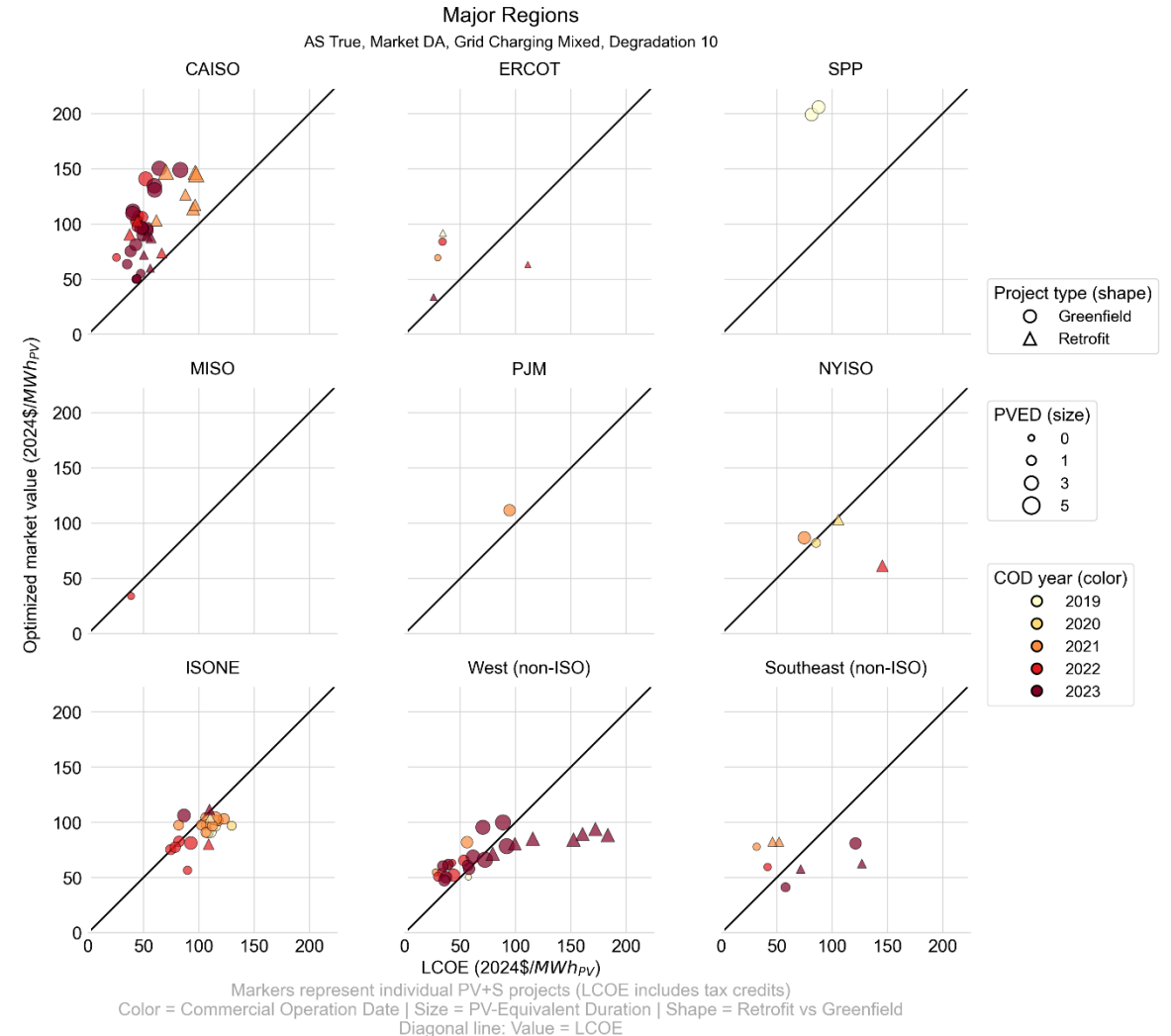
Solar PV+Storage LCOE and Levelized Optimized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)



- On national level, average optimized value was greater than LCOE in most years
  - 2020 PV+S projects had atypically high LCOE due to small project sizes (no economies of scale) and low capacity factors (deployment in the northeast with lower quality solar resource)

# Optimized net value with tax credits is positive for 83% of recent (COD 2022/23) greenfield PV+S projects (56% without tax credits)

- CAISO and older SPP projects have consistent positive net value
  - Some projects in TVA/Duke Progress East struggle with little energy price spreads in FERC Lambda data.
- Greenfield projects often show greater net value, as retrofits have older, more expensive PV components driving up LCOE.
  - Nonetheless, some regions have retrofits with positive optimized net value (e.g., CAISO).
- Larger batteries relative to PV capacity (PVED) have higher optimized net value. Although LCOE increases with greater batteries, we observe economies of scale with decreasing marginal costs. Optimized value gains of larger batteries seems to outpace LCOE penalties.
- Projects with earlier COD benefited more from higher energy (especially 2022) and AS prices than later years but had to contend with higher battery capex. Time trend is inconclusive.



# Empirical data comparison



# Empirical Operations Data Sample

## Number of projects analyzed

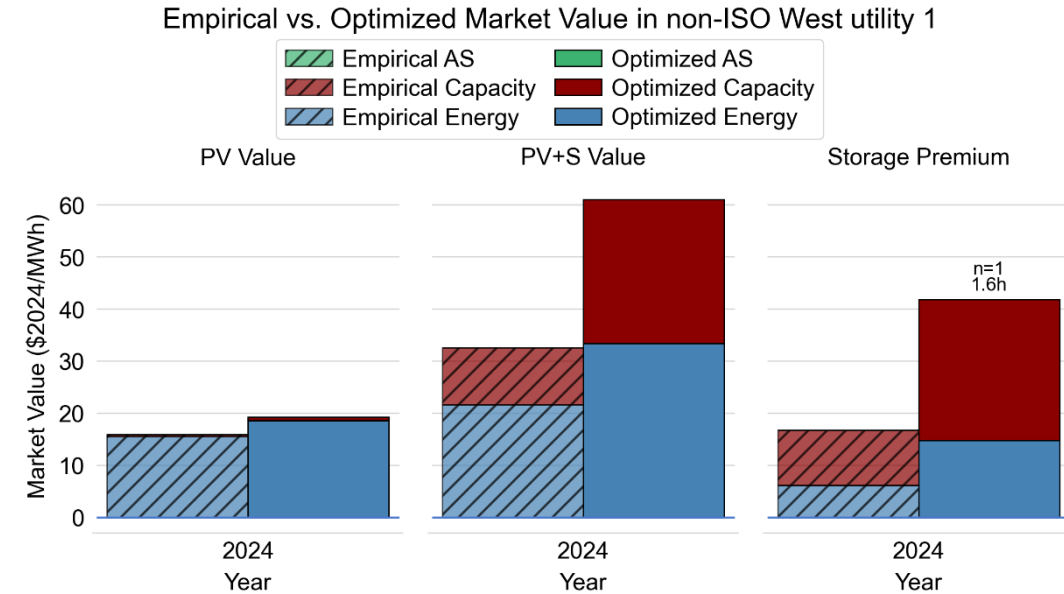
BA	Optimized Value	Net Value	Empirical Value	Notes	Adjustment for missing or dropped data
ERCOT	10	5	7	Reliable data starts in 2022 for projects >10MW, some projects have storage dispatch data quality issues	Some empirical dispatch data had quality issues and was excluded (e.g., data with monthly storage round-trip efficiency <30% or >100%, driven by asymmetric charge or discharge data availability). To mitigate biases from data exclusion we “crop” the optimized dispatch to the same hours as the clean empirical data.
ISONE	91	22	8	Includes AS and capacity revenue. Some projects report PV+S combined profiles, other only storage profiles or separate PV and storage profiles. Only 2024 data.	
NYISO (via NYSERDA)	28	4	21	Many projects lack storage operational data for 50% of year. Minimum inclusion criteria is 2000h.	
Non-ISO West 1	3	3	1	Separate PV and storage profiles available	
Non-ISO West 2	5	5	4	Separate PV and storage profiles available	
CAISO (via FERC EQR)	75	40	9	Mostly annual combined PV+S revenue	
MISO (via FERC EQR)	10	1	1	Mostly annual combined PV+S revenue, no capacity value included	
<b>Total</b>	<b>222</b>	<b>80</b>	<b>51</b>		

For comparison we show the optimized and net-value sample for each of the 7 regions with empirical data

# Utility 1 in non-ISO West

2024 empirical dispatch produces a \$17/MWh storage premium, 40% of the optimized potential, for a total realized PV+S market value of \$33/MWh

- Empirical data description:
  - 1 project with full 2024 generation data (battery has ~50% capacity ratio relative to PV and a 4h duration, eligible for grid-charging)
  - Additional projects will be included in next study iteration
  
- In its first full calendar year of operation, this PV+S project created \$33/MWh of empirical market value, with 67% from energy and 33% from capacity.
  - Storage created incremental value primarily by delivering power during the utility's top 100 net load hours (capacity value) which had little overlap with PV production
  - The optimized dispatch suggests substantially greater upside for potential capacity value (2.5x the realized level), and energy arbitrage.
  
- Potential reasons for empirical value gap:
  - A mismatch between the utility's operational priorities and our valuation framework, which emphasizes performance during the top 100 net-load hours.
  - 2024 was the first full operational year of the project (and also the broader fleet of this utility's hybrid projects) → continued learning may shift value in the future
  - Solar curtailment may reflect incentives not captured in the optimization, such as REC value.
  - Real-world dispatch does not benefit from perfect price foresight.



Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [ $MW_{AC}$ ])

	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	33	61	17	42
Capacity	11	28	11	27
Energy	22	33	6	11

Tables will summarize the total PV+S and Storage Premium Value for both empirical and optimized dispatch for the year 2024 for each analyzed region

# Utility 1 in non-ISO West

## Comparison of optimized and empirical dispatch: drivers of value differences

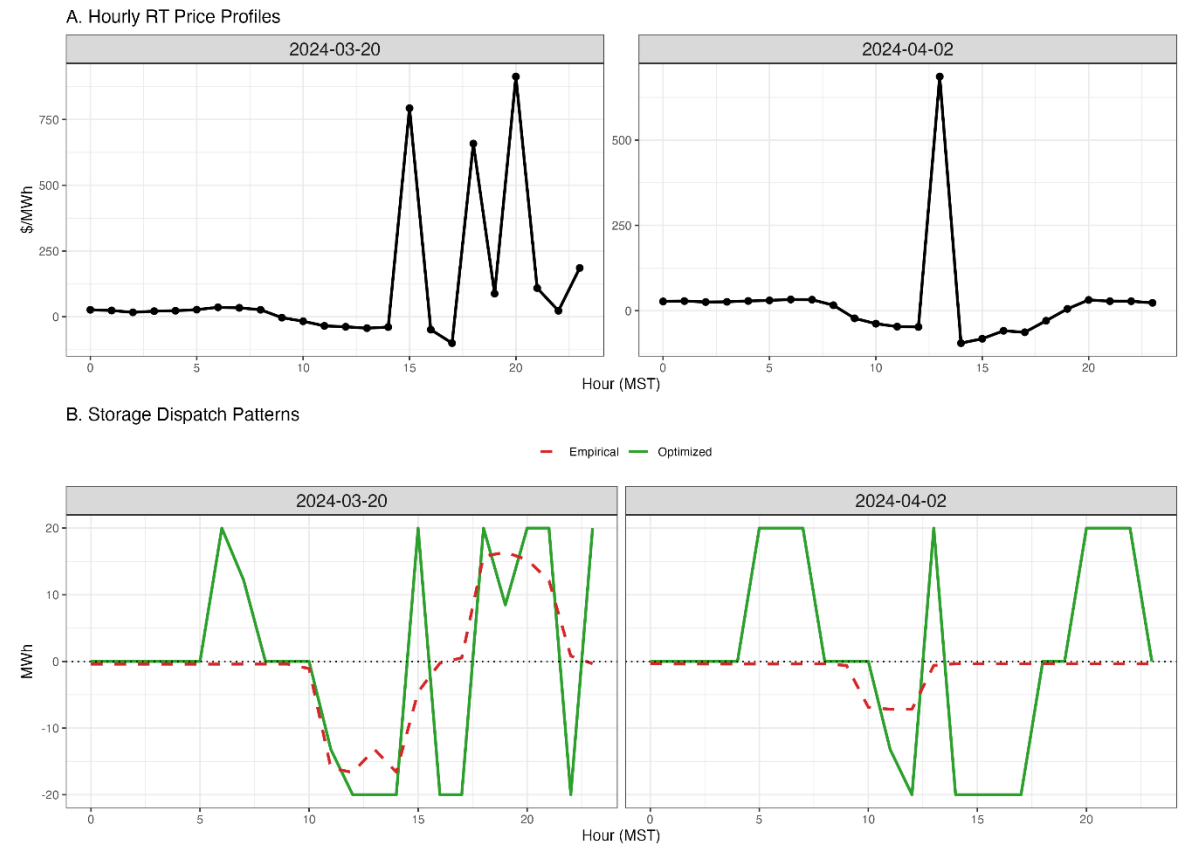
- Optimized dispatch curtails solar and charges battery from the grid during negative price hours

### Driver 1: Negative Price Curtailment - Empirical Exports, Optimizer Curtails



- Optimal storage dispatch responds to energy price volatility

### Driver 2: Diurnal Arbitrage Opportunities - Optimizer Exploits RT Price Spreads



# Utility 2 in non-ISO West

2024 empirical dispatch produces a \$7/MWh storage premium, 46% of the optimized potential, for a total realized PV+S market value of \$33/MWh

Empirical data description:

- 4 projects that were operational for full year 2024. Storage often sized to ~25% of PV capacity with 4h duration. Sample will increase to 8 for 2025.

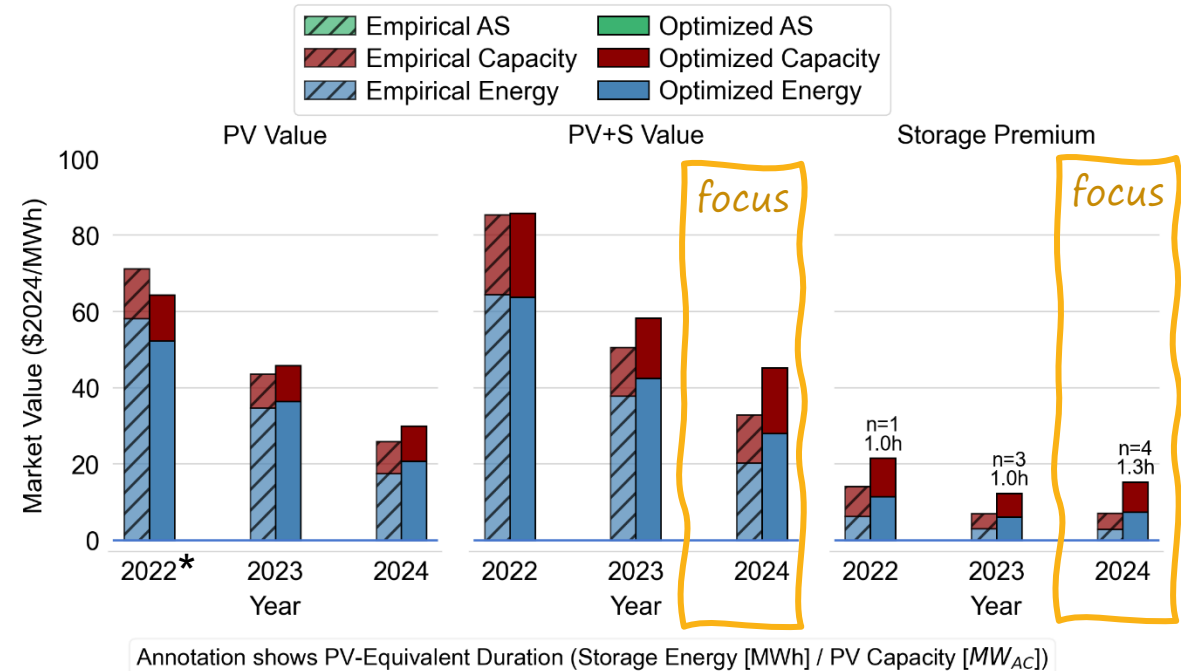
In 2024, these PV+S projects created \$33/MWh of empirical market value. Both energy and capacity value were important components, though in 2023 energy was a much greater share.

- The added storage value was balanced between the two value streams.
- The optimized profile yielded 1.4x the realized PV+S value and 2.3x the storage premium due to differences in both energy and capacity value.

Potential reasons for lower empirical value:

- Less responsive to imbalance market prices than internal scheduling and operational “rules-of-thumb”, results in missing morning price peak
- Different incentives for curtailing solar, e.g., renewable energy certificate (REC) values that aren’t accounted for in the optimized dispatch
- A mismatch between the utility’s operational priorities and our valuation framework, which emphasizes performance during the top 100 net-load hours.

Empirical vs. Optimized Market Value in non-ISO West utility 2



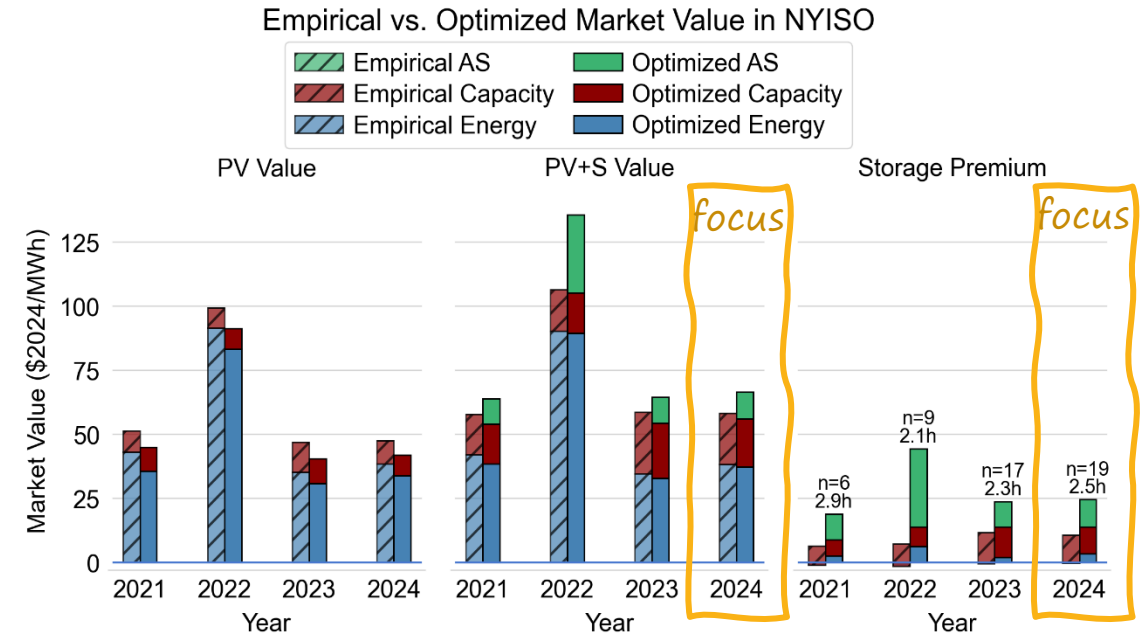
	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	33	45	7	15
Capacity	13	17	4	8
Energy	20	28	3	7

\* Note: 2022 values are just driven by 1 project with solar production issues in first half of the year → empirical and modeled solar profiles are misaligned, leading to higher empirical PV value. Later years have more robust sample with better alignment of solar profiles.

# New York State Energy Research and Development Authority (NYSERDA)

2024 empirical dispatch produces an \$11/MWh storage premium, 44% of the optimized potential, for a total realized PV+S market value of \$58/MWh

- Empirical data description:
  - ▣ 21 small projects (1-5 MW<sub>PV-AC</sub>) with solar and storage dispatch data
  - ▣ NYSERDA data capture physical dispatch only. We require >2,000h/y valid observations, which leaves year-long gaps for some projects.
  - ▣ These projects were compensated mainly under New York's Value of Distributed Energy Resources (DER) tariff rather than through the NYISO wholesale markets analyzed here.
  - ▣ Wholesale participation by DERs is only emerging through NYISO's DER participation model and FERC Order 2222 implementation by end of 2026.
  
- In 2024, these PV+S projects created \$58/MWh of empirical market value: \$38/MWh from energy and \$20/MWh from capacity.
  - ▣ Based on discussions with program administrators, these projects likely did not provide ancillary services. → The optimized storage premium is higher because it assumes NYISO ancillary services participation.
  - ▣ Results for 2023 were similar.
  
- Potential reasons for lower empirical value:
  - ▣ NYISO participation pathways for DERs in ancillary services were still under development.
  - ▣ Retail program incentives differ from wholesale market signals and likely led to different dispatch behavior.



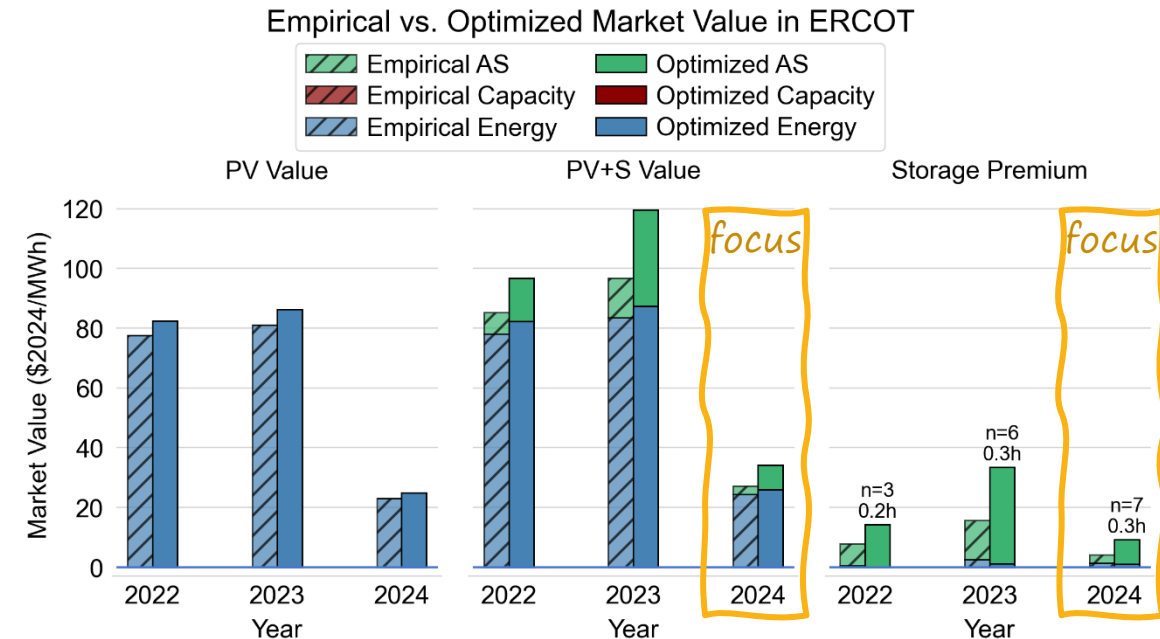
Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	58	67	11	25
AS	-	11	-	11
Capacity	20	19	11	11
Energy	38	37	0	3

# ERCOT

2024 empirical dispatch produces a \$4/MWh storage premium, 44% of the optimized potential, for a total realized PV+S market value of \$27/MWh

- Empirical data description:
  - ERCOT has many operating batteries, but only 7 projects with available data were co-located with solar (with varying degrees of usable data of 2,208 to 8,784 h/year).
  - Reliable data begin in 2022. Smaller PV+S projects were online earlier, but ERCOT's 60-day disclosures exclude storage  $\leq 10$  MW, so this sample does not capture 2021 and the unusually high value opportunities during Winter Storm Uri.
  - Batteries in the sample are small: PV-equivalent duration of 0.3h in 2024.
- In 2024, these projects produced \$27/MWh of empirical market value, about 90% of it from energy value.
  - The realized storage premium, driven mainly by ancillary services, was less than half of the optimized potential.
  - Values were higher in 2022 and 2023, but the gap to the optimized ancillary services value remained similar.
  - This base case values energy using day-ahead prices. Many projects likely transact in real time, where we find a [similar storage premium](#) but lower standalone PV value. The analysis does not include DA-RT arbitrage.
- Potential reasons for lower empirical value:
  - Suboptimal mix of AS products
  - Limited ability to forecast price spikes.



Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [ $MW_{AC}$ ])

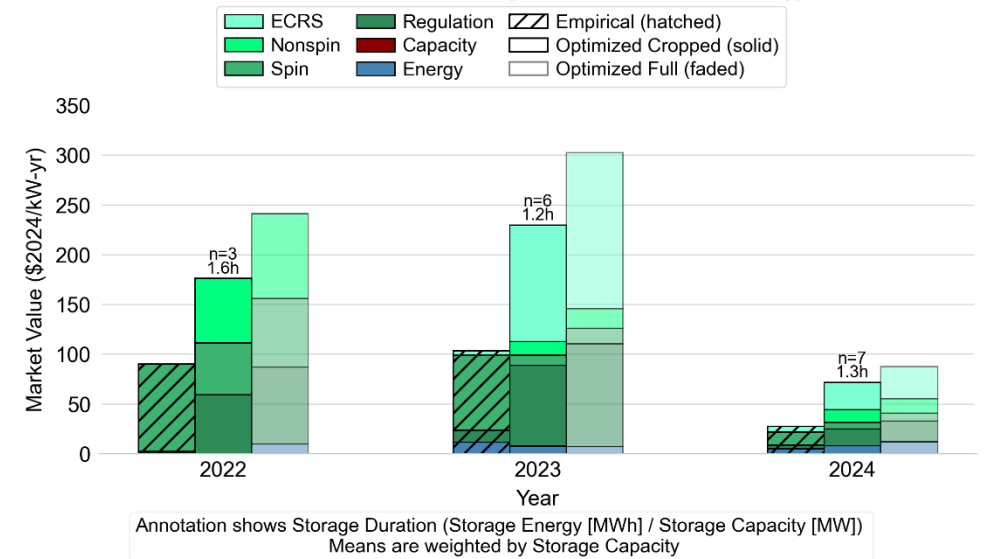
	2024	PV+S		Storage Premium	
		Empirical	Optimized	Empirical	Optimized
<b>Total</b>		<b>27</b>	<b>34</b>	<b>4</b>	<b>9</b>
AS		3	8	3	8
Energy		24	26	1	1

# ERCOT

## Optimized 2024 dispatch results in 2.6x greater storage value in \$/kW-yr terms

- Storage standalone value
  - Analogous to the standalone PV value metric, we estimate a standalone storage value for the battery portion of each project, reported in standard industry units of \$/kW-yr.
  - This metric is more sensitive than our other results to whether optimized dispatch is aligned to missing or excluded empirical observations. We therefore report both “optimized cropped” and “optimized full” values.
- ERCOT results
  - For the 2024 PV+S sample, empirical cropped storage revenue was \$28/kW-yr, slightly below Modo’s<sup>1</sup> estimate for the broader ERCOT storage fleet, which has longer average battery duration than these seven projects.
  - Optimized non-cropped storage revenue fell by 70% in 2024, to \$88/kW-yr, reflecting lower ancillary services prices. This aligns with the range assumed by Ascend Analytics<sup>2</sup> for optimized ERCOT storage operations (\$60–\$105/kW-yr, depending on region).
- Value drivers
  - In both 2023 and 2024, ECRS was the largest storage value driver in the optimized case, contributing \$32/kW-yr in 2024. By contrast, empirical dispatch focused mainly on Spin products.
  - As ancillary services markets become more saturated, energy arbitrage is increasing in relative importance.

Empirical vs. Optimized (Cropped and Full) Storage Value in ERCOT, Energy DA market, AS Detail



1: Modo Webinar on State of Market in ERCOT, Oct 21<sup>st</sup> 2025, <https://modoenergy.com/>  
2: Ascend Analytics Webinar on SmartBidder values in ERCOT, Feb 13<sup>th</sup> 2025, <https://www.ascendanalytics.com/>

# ERCOT

## Example of value divergence between empirical and optimized operations in RT energy market

Sensitivity case

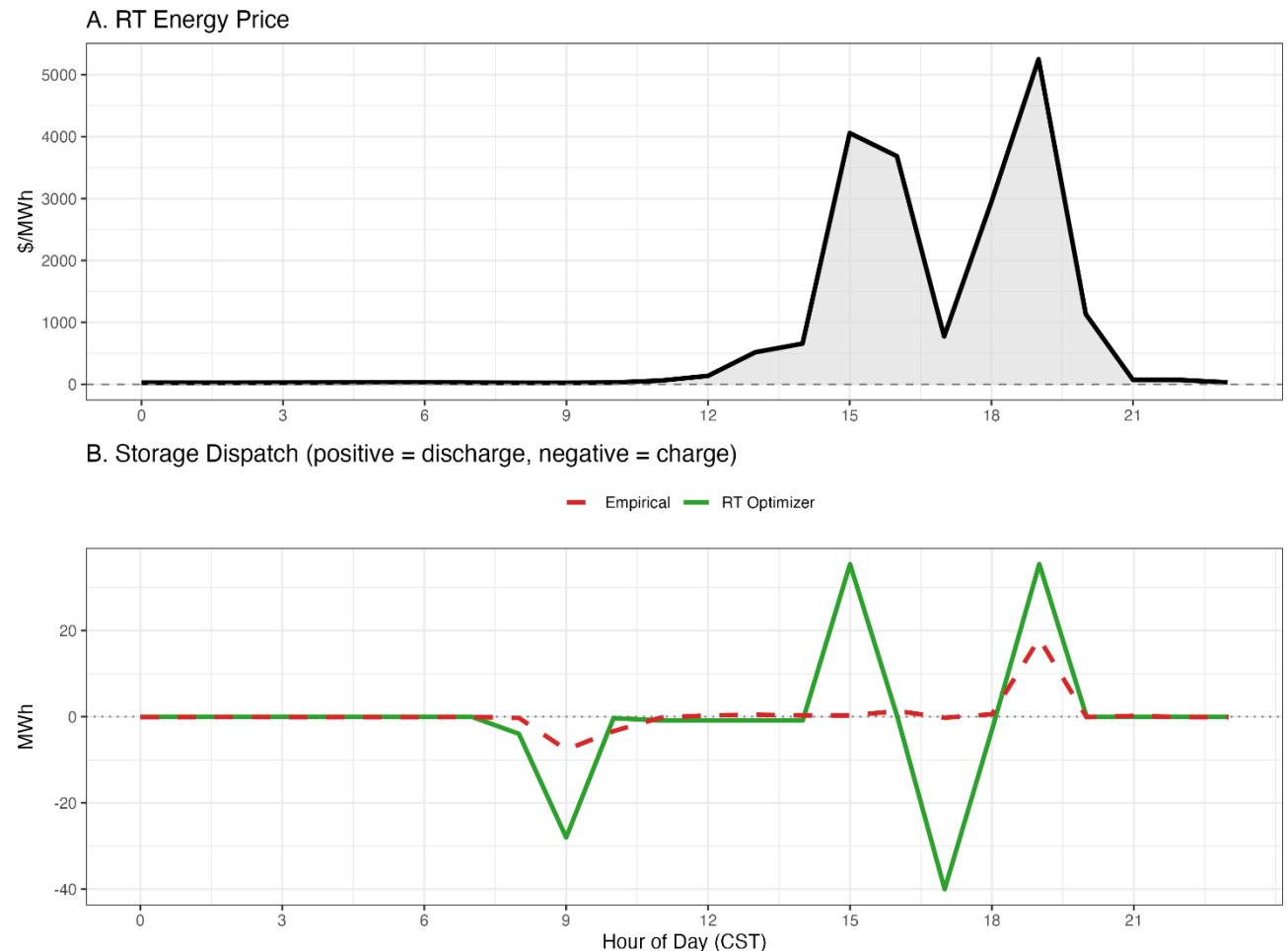
- ERCOT's energy market allows for high price spikes through the Operating Reserve Demand Curve (ORDC) adder. These spikes drive battery revenue potentials disproportionately.
  - Batteries with short duration are especially challenged to accurately predict these rare events and ensure that they have sufficient state of charge to cash in.

### Example:

- On Sept 9<sup>th</sup>, 2023, ERCOT endured a September heat record, causing two extreme price spikes at the 2W Permian Solar project - first in the afternoon and then in the evening. The optimizer with perfect price foresight can cycle to participate with full capacity in both events (green line), while the empirical project (red dashed line) only discharged during the second price spike, missing out on significant revenue.

### Diurnal Arbitrage Opportunity — 2023-09-06

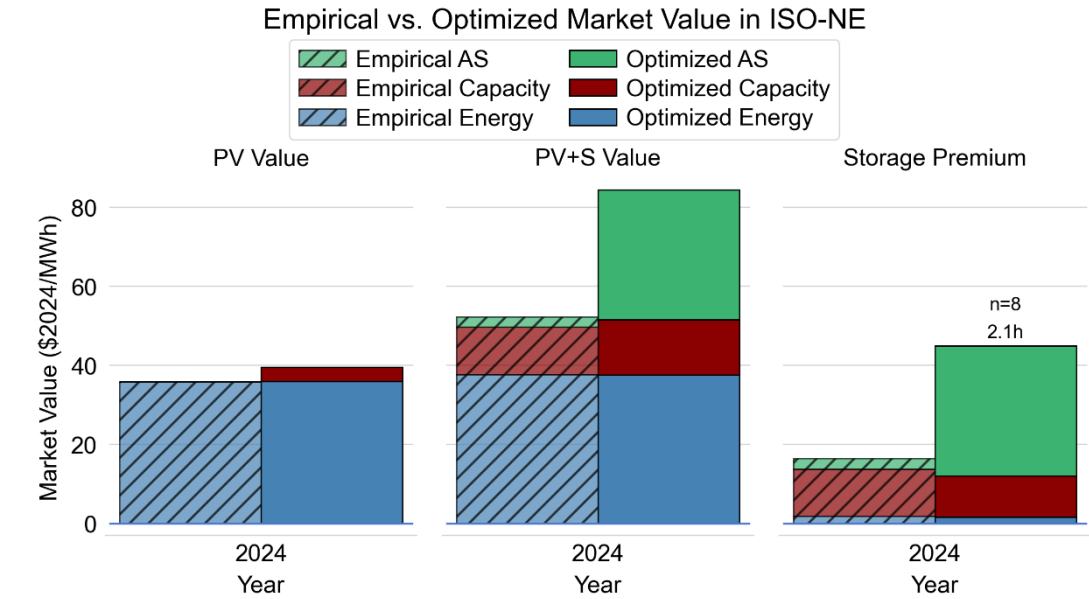
RT price spread: \$5227/MWh (min \$24 at hour 9, max \$5251 at hour 19)



# ISO-NE

## 2024 empirical dispatch produces a \$16/MWh storage premium, 36% of the optimized potential, for a total realized PV+S market value of \$52/MWh

- Empirical data description:
  - 8 projects in Massachusetts, some of which report PV+S combined profiles, others only storage profiles or separate PV and storage profiles. This sample is based on projects willing to share data.
  - Massachusetts' SMART program has driven broad deployment of relatively small PV+S projects, but only a small share actively participate in ISO-NE wholesale markets. For many projects, state programs, including the Clean Peak Standard, remain the primary revenue source.
  
- In 2024 these PV+S projects created \$52/MWh of empirical market value.
  - The data show no capacity revenue for standalone PV but confirm our modeled capacity value for PV+S, which was the primary empirical value driver for storage.
  - The optimized case suggests substantial additional upside from ancillary services which is more than 10x the empirical AS value. However, ISO-NE's AS market is shallow, so this modeled upside would likely be smaller if battery participation increased materially.
  - With little diurnal energy price variation, energy arbitrage did not play a large role.
  
- Potential reasons for lower empirical value:
  - Under-participating in still-lucrative ancillary services, perhaps due to lack of experience or less sophisticated controls technology
  - Operations focused on state program compliance vs wholesale markets



Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [ $MW_{AC}$ ])

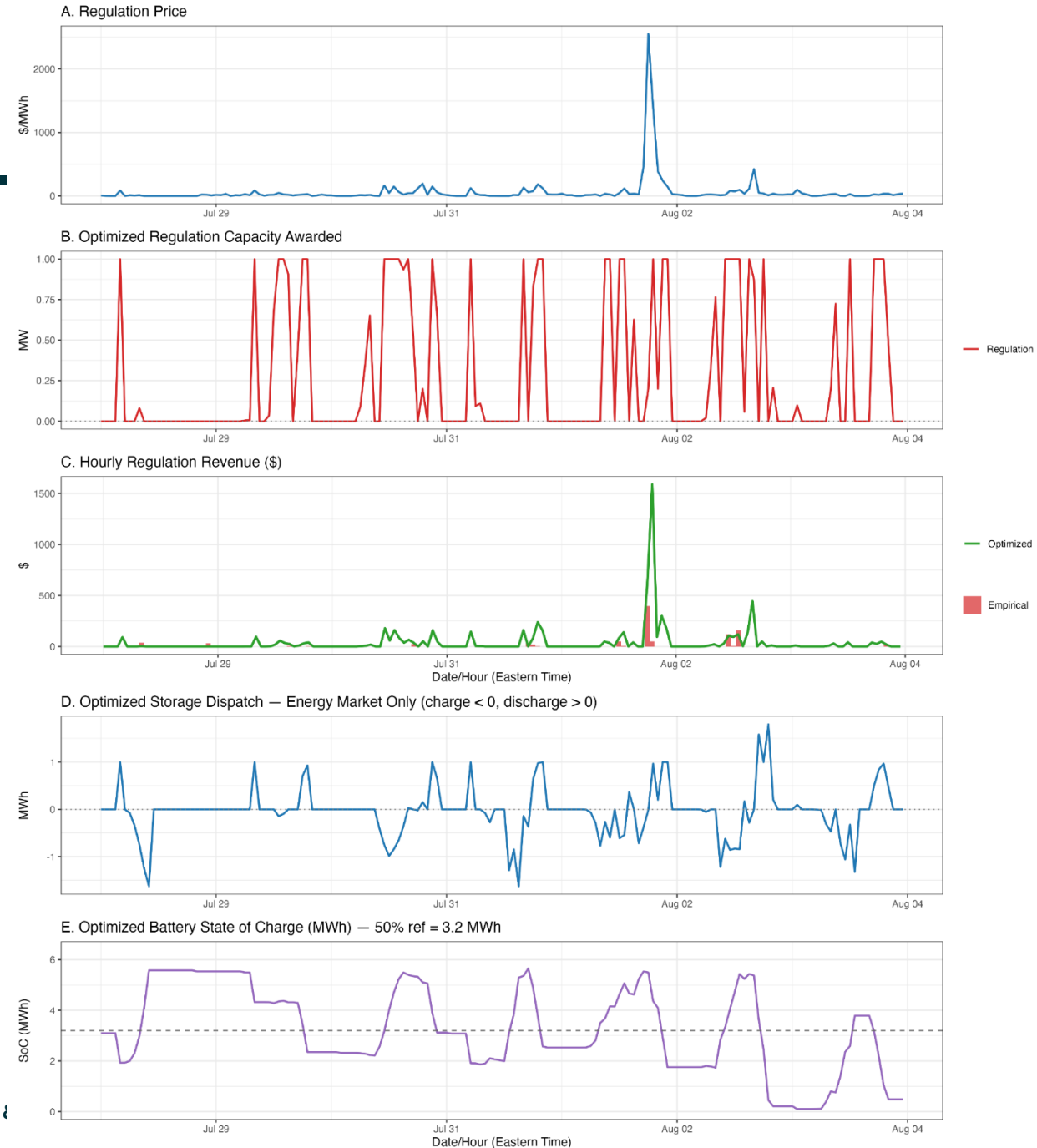
	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	52	84	16	45
AS	3	33	3	33
Capacity	12	14	12	10
Energy	38	38	2	2

# ISO-NE

## Example of Regulation Participation

- Selected week has the highest optimized revenue in 2024
- The optimized dispatch results in more frequent and larger regulation awards than the plant had empirically (panel C).
  - ▣ While both optimized and empirical dispatch earn during a regulation price spike on August 1<sup>st</sup> (panel A), the optimized battery earns 6.6x the revenue over this example week.
  - ▣ In the [sensitivity case with unrestricted grid charging](#), the AS value potential is even greater.
- Assumptions:
  - ▣ Battery needs sufficient SOC to comply with a full regulation award over the next hour.
  - ▣ Actual AS deployment for the single regulation product is symmetric for up/down regulation.
    - As consequence, little net-energy is expended by the battery, allowing for multiple AS awards per day. If the battery was allowed to charge from the grid we would see near constant AS awards in many of the single product markets (ISO-NE, SPP, NYISO, and MISO).

Optimizer reg revenue: \$6517 | Empirical reg revenue same week: \$983



# FERC Electric Quarterly Reports (EQR)

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- FERC EQR transaction data are challenging to use:
  - ▣ They only include total asset sales and do not allow for separate solar/battery dispatch profiles
  - ▣ Some transaction data are “lumpy” with apparent monthly aggregation instead of hourly
  - ▣ Some reported data are incomplete, possibly missing for example capacity contract or AS revenue
  
- Annual revenue based on reported values for energy (energy + energy imbalance), capacity, and AS
  - ▣ “Other” product type is discarded it may refer to FTRs, RECs, etc. that go beyond our revenue streams
  - ▣ We divide annual revenue by modeled PV production to have comparable denominator to the optimized value.
  - ▣ Revenue reported for project clusters (e.g. Gaskell 2-5, Edwards Sanborn) is excluded.
  
- Storage premium estimated as the delta between FERC EQR derived PV+S value and modeled optimized PV standalone value.
  - ▣ This approach may underestimate empirical storage premium as the PV standalone value is based on perfect curtailment
  - ▣ If FERC EQR has little capacity revenue, we exclude the PV-only capacity value to avoid negative storage premiums.

# CAISO (using FERC EQR data)

2024 empirical dispatch produces a \$27/MWh storage premium, 37% of the modeled potential, for a total realized PV+S market value of \$54/MWh

Empirical data description:

- 9 projects in 2024 with PV-Equivalent Duration of 2.5h

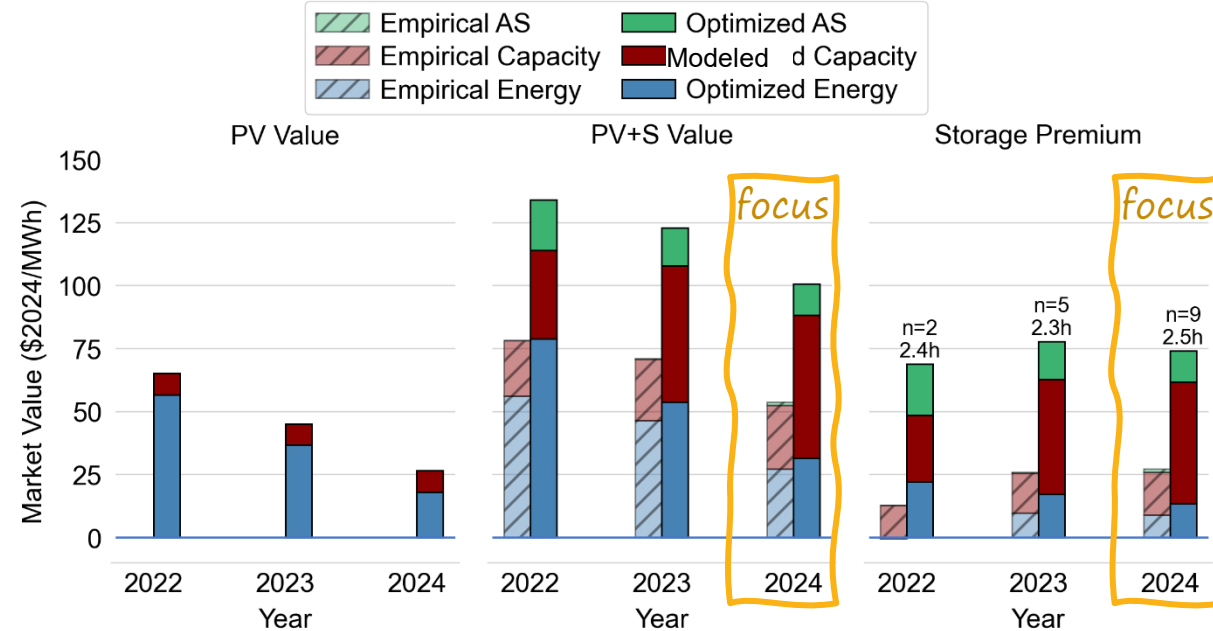
In 2024, these PV+S projects created \$54/MWh of empirical market value, \$27/MWh more than we would expect from the same set of PV standalone projects.

- Relative to the modeled value, projects provide much less capacity, AS, and energy value.
- The CA resource adequacy market is bilateral. While the average EQR-derived capacity value is 44% of the modeled value, we observe projects with both higher and lower capacity prices in their EQR contracts than what we modeled.
  - Our model of capacity value uses 85<sup>th</sup> percentile zonal system RA prices, specifically 2023 capacity prices as CPUC has long delay in reporting. Newer [reports](#) indicate even higher capacity prices for 2024.
  - Example: Desert Harvest II reported ~\$35/kW<sub>Battery</sub>-mo or \$84/MWh in capacity revenue – we estimated \$51/MWh).

Potential reasons for lower empirical value:

- Under-participation or under-reporting in ancillary services.
- Sample is skewed towards cheaper-than modeled capacity contracts.
- Aggressive curtailment of optimized PV generation during negative price events may understate empirical energy value premium from batteries.

Empirical vs. Optimized Market Value in CAISO



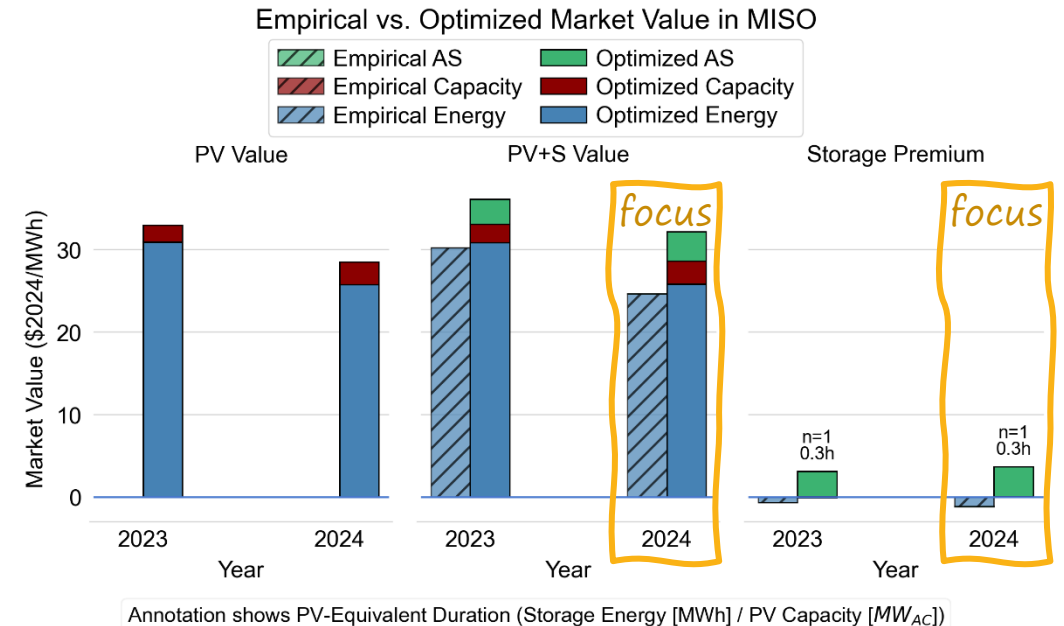
Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	54	101	27	74
AS	1	13	1	13
Capacity	25	57	17	48
Energy	27	32	9	13

# MISO (using FERC EQR data)

## 2024 empirical dispatch supposedly results in value loss relative to standalone PV and yields a total realized PV+S market value of \$25/MWh

- Searcy Solar Hybrid characteristics:
  - PV: 100 MW, Battery: 10 MW, 30 MWh (0.3h PV-equivalent duration)
  - Utility-owned (Entergy, Arkansas) with original project expenses being rate-based; no PPA, COD of 2022 (assuming no grid charging)
  - Primary purpose is to “be charged and discharged daily to maximize the value of the solar energy for the benefit of customers” ([Entergy](#))
  
- In 2024, the \$24/MWh of empirical PV+S value is below the modeled stand-alone PV value with or without capacity value, implying a negative storage premium.
  - While it likely contributes to Entergy’s RA obligations there is no arms-length transaction reported in FERC EQR for capacity revenue
  - The project is registered with MISO as an Dispatchable Intermittent Resource (DIR) that is ineligible to provide AS. However, the DC-coupled battery could instead register as co-located ESR to access AS markets as modeled in our optimized case.
  
- Potential explanations for counterintuitive storage premium result:
  - Mismatch between debiased modeled PV profile and (unobserved) empirical PV profile
  - Under-participating in still-lucrative ancillary services



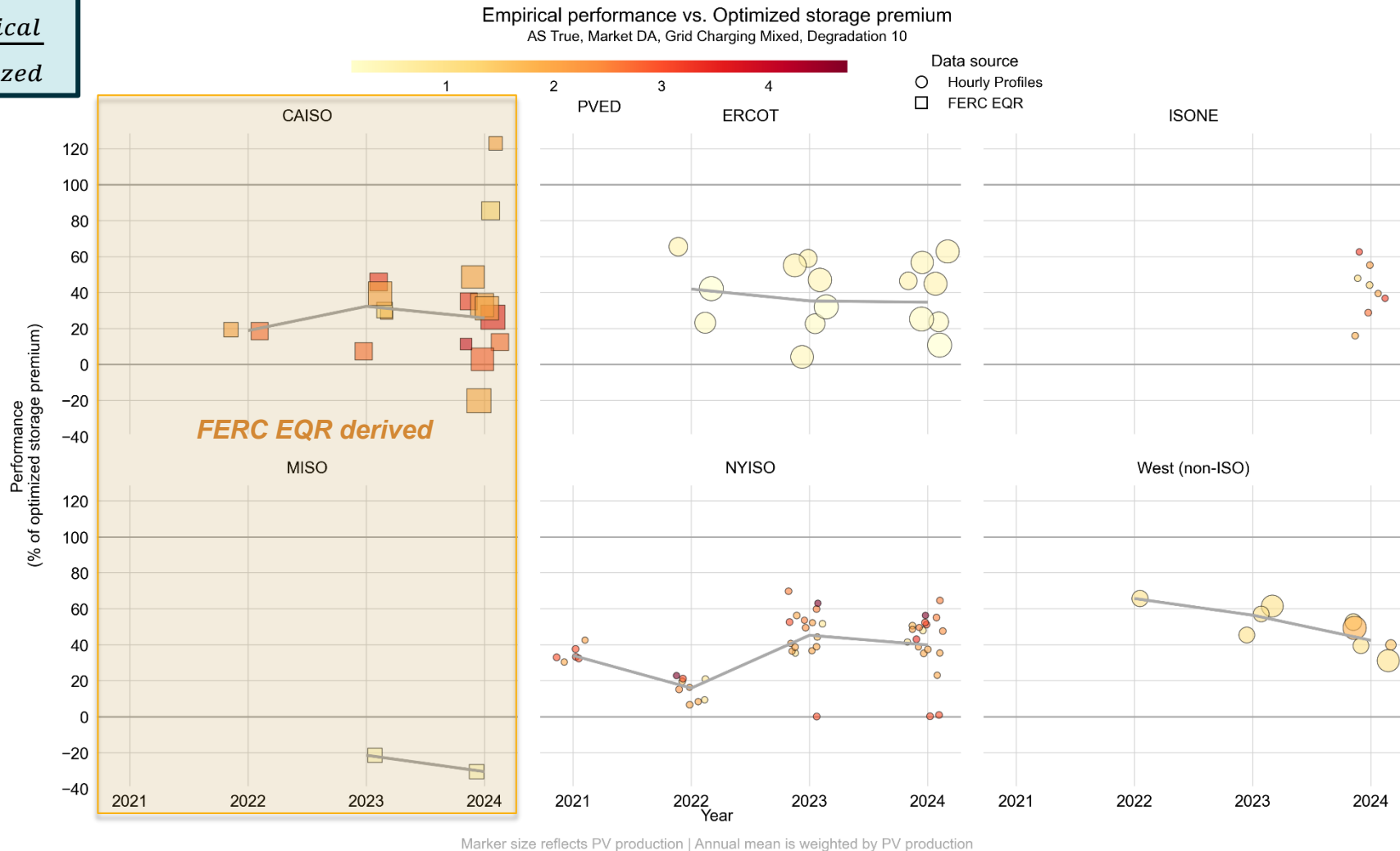
	PV+S		Storage Premium	
	Empirical	Optimized	Empirical	Optimized
2024 Total	25	32	-1	4
AS	-	4	-	4
Capacity	-	3	-	-
Energy	25	26	-1	-

\$/MWh<sub>PV</sub>

# Plant-level analysis show wide distribution of performance relative to optimized value premium with average of 37% in 2024

$$\text{Performance} = \frac{\text{Storage Premium Empirical}}{\text{Storage Premium Optimized}}$$

- Empirical values in MISO and CAISO were derived from FERC EQR reported revenues, following a different methodology than using hourly dispatch data.
- Across all plants, generation-weighted performance remained relatively stable between 2021 and 2024.
- Performance score has a wide distribution with annual regional averages ranging from -31% to 66%
  - In 2024, CAISO, ERCOT, ISONE, NYISO, and non-ISO West had average regional performance in the 35-42% range

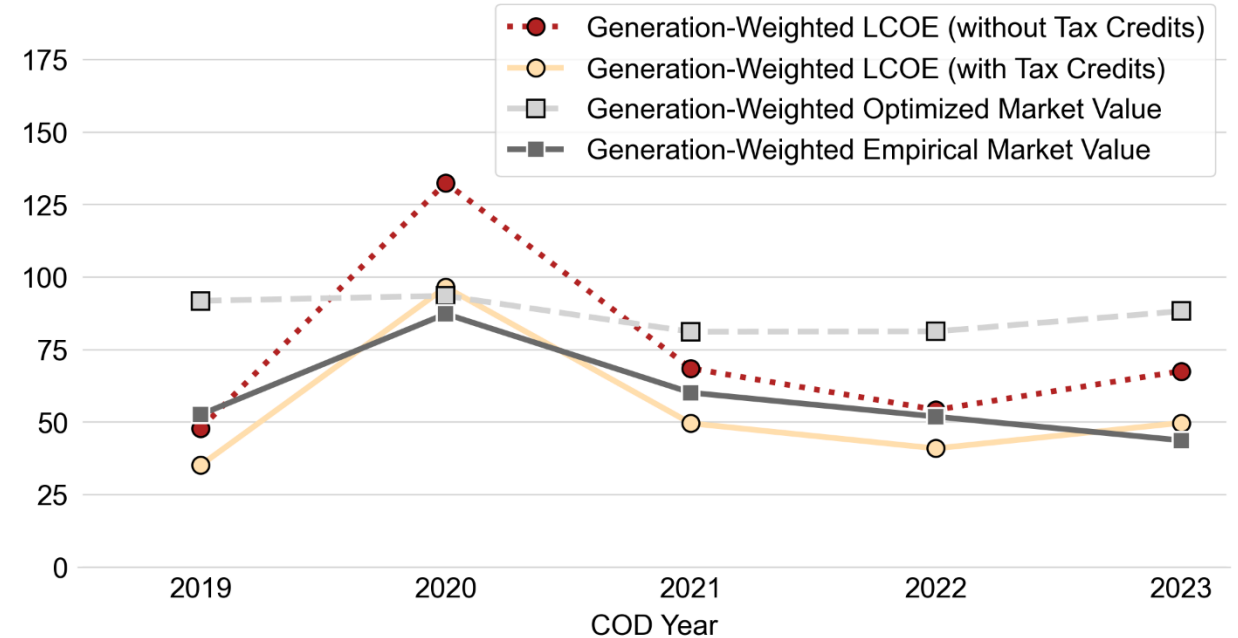


# Average national net-value remains positive using empirical dispatch, though often only with ITC.

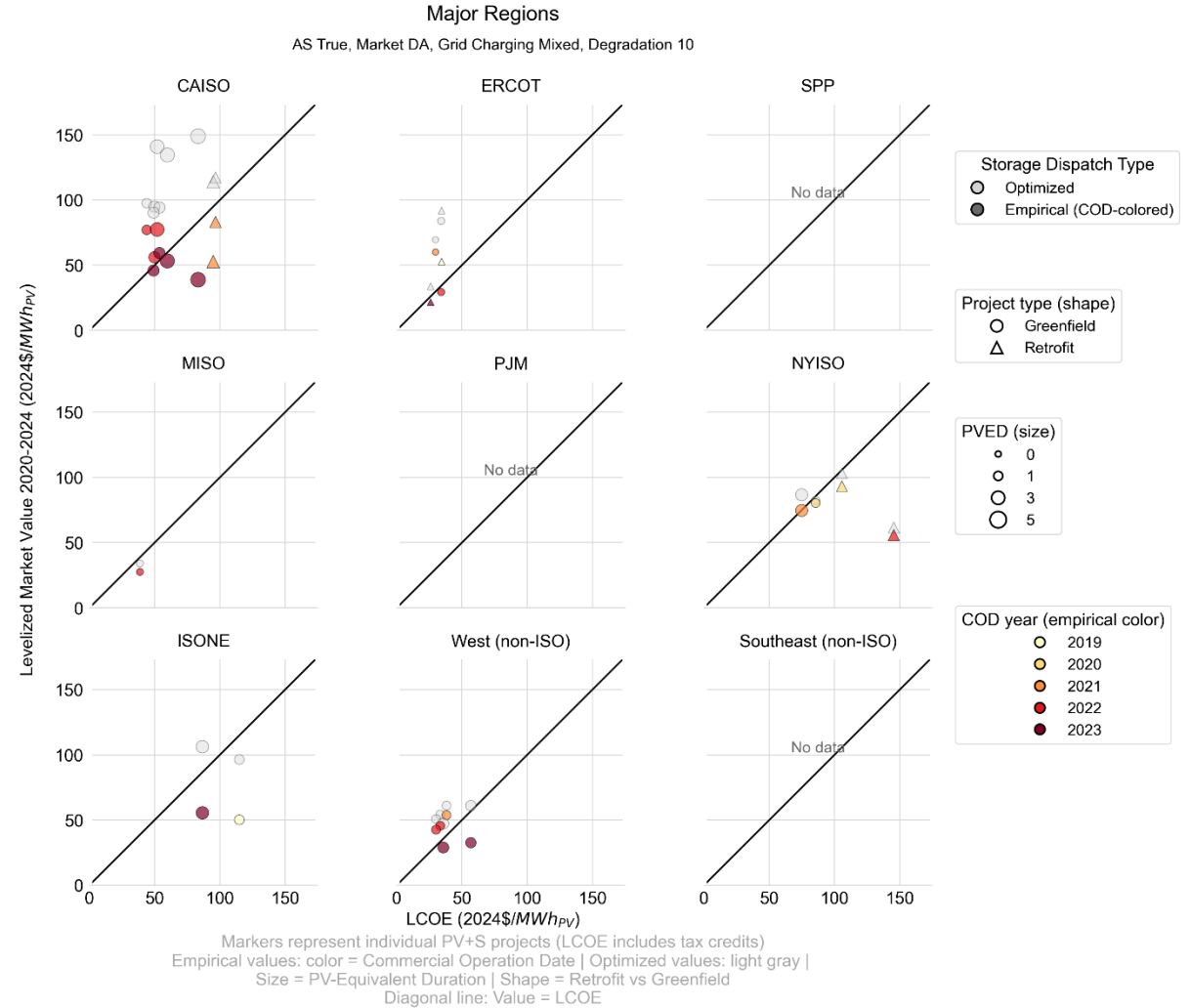
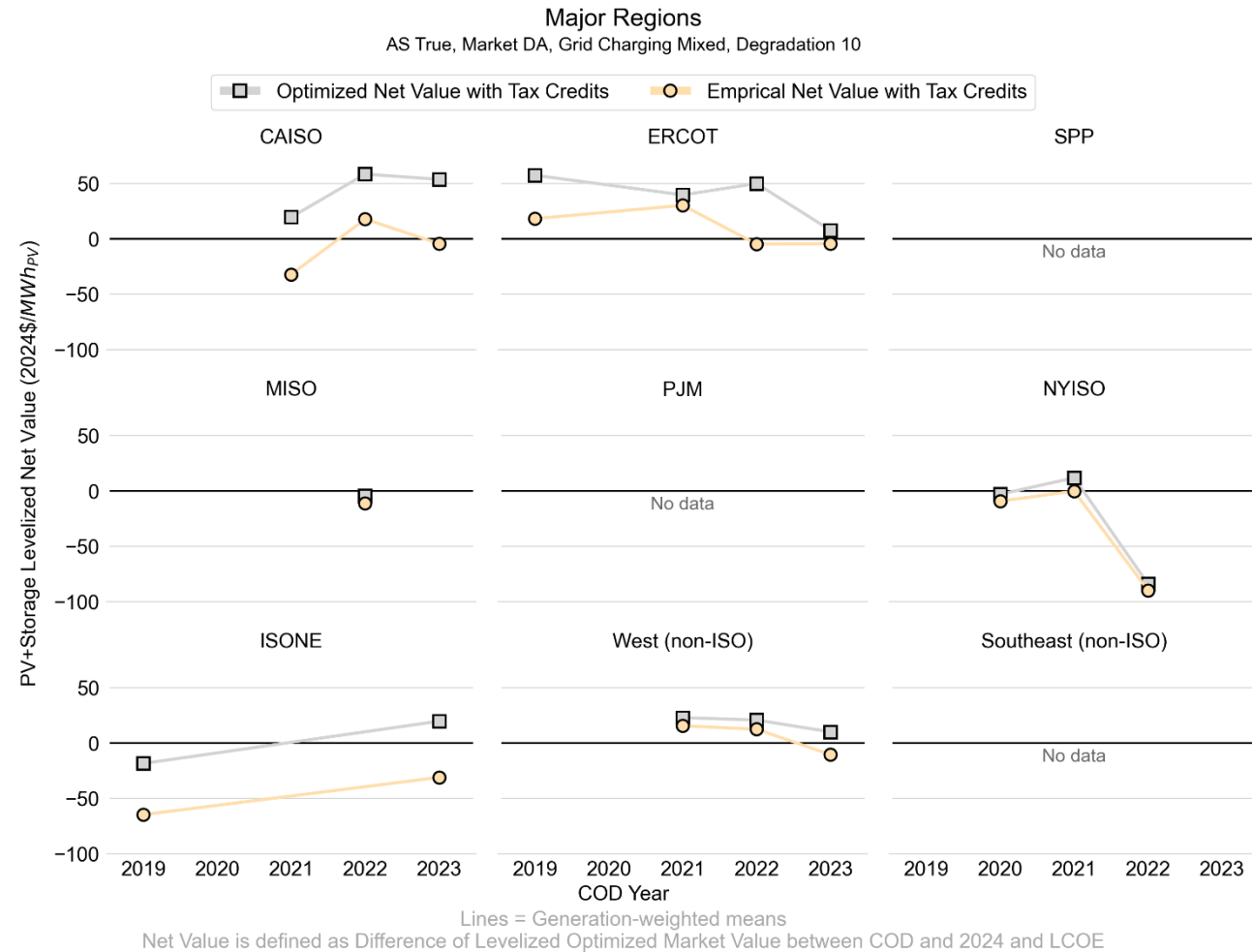
- CapEx availability limits net-value analysis to ~50% of projects with empirical dispatch data. Compared to the modeled PV+S sample, the following pages represent just 9% of projects and 28% of hybridized PV capacity.
- Average empirical market value across all projects is \$8/MWh greater than generation costs accounting for the ITC that was available at the project's COD. Not all cohorts are net-positive without ITC. Projects built in 2023 have on average \$6/MWh lower value than costs, even after accounting for the ITC.
  - Projects may have access to additional revenue beyond the modeled wholesale value (RECs, tolling/PPA, state incentives...).
  - LCOE numbers already include returns for investors using WACC.
  - Most projects have only operated a few years and may be working through teething issues. Most of their life-time revenue will be earned over the coming years and may differ from the values observed so far.

**Net Value Sample:** 25 projects, 3.5 GW<sub>PV</sub>, 1.3 GW<sub>Bat</sub>/4.8GWh

Solar PV+Storage LCOE and Levelized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)  
AS True, Market DA, Grid Charging Mixed, Degradation 10



# Net-values using empirical dispatch data are positive for most greenfield projects in major markets of CAISO and non-ISO West but negative elsewhere



# Discussion and Conclusion

# Discussion of divergence between modeled optimized and empirical storage dispatch

---

## □ Modeling Artifacts:

- Real-world cycling “costs” / warranty limitations / roundtrip efficiencies / POI limits are project-specific and differ from modeling assumptions.
- Grid charging capability of DC-connected projects is unclear.
- In non-ISO regions, capacity price adder in top 100 net-load hours provides strong dispatch incentives to earn capacity credit. Utilities’ views of resource adequacy contributions likely differ from our proxy of energy delivered in the top 100 net load hours.
- In CAISO, our model of capacity value uses system RA price + broad zonal adders applied to the project attributes. Yet, the CA resource adequacy market is bilateral and local factors and online dates affect contract prices.
- Ancillary services deployment modeled as constant scalar multiple of corresponding award.
- In NY, wholesale market value is theoretical, as projects are DERs that are not yet full participants in the wholesale market.

## □ “Messy” empirical data:

- Incomplete empirical data series lead to misalignment with optimized data and incorrect value assessment
- Empirical solar profiles differ from Berkeley Lab’s modeled profiles with cascading effects on storage operations, total PV+S value and implicit storage value premium.
- FERC EQR transaction data only include total asset sales and do not allow for separate solar/battery dispatch profiles. Further, some transaction data are “lumpy” with apparent monthly aggregation.

# Multiple operational and organizational barriers limit the value that PV+S systems could offer the bulk power system

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Barriers to increasing PV+S market value include:

Under-participation in wholesale markets, including still-lucrative ancillary services in less mature markets.

Restrictions on grid charging under earlier ITC rules for older projects

Limited response to negative prices because of volume targets or hub-based settlement

Dispatch strategies tied to out-of-market considerations including fixed delivery obligations under tolls, PPAs, REC markets or state incentive programs

Rule-based operation, such as charging at midday and discharging in the evening regardless of price conditions

Imperfect price forecasting

In non-ISO regions, additional value is constrained by the lack of organized ancillary services markets and by weak energy price signals.

- Even utilities in regional imbalance markets may prioritize balancing within their own BA rather than dispatching against imbalance market prices.
- In the Southeast, available FERC system lambda data are a poor proxy for nodal price volatility, understating the value that PV+storage could provide.

## For more information

**Explore** this briefing and underlying data: <https://emp.lbl.gov/utility-scale-storage>

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**Read** about our other work on utility-scale generators and storage: <https://emp.lbl.gov/utility-scale-generation-storage>

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## Acknowledgements

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The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

## Appendix

- **Optimized PV+S Value in \$/MWh for Sensitivity Cases**
- **Optimized Storage Value in \$/kW-yr**
- **Optimized Net Value for Sensitivity Cases**
- **Comparison of Empirical and Optimized Storage Value Premium**



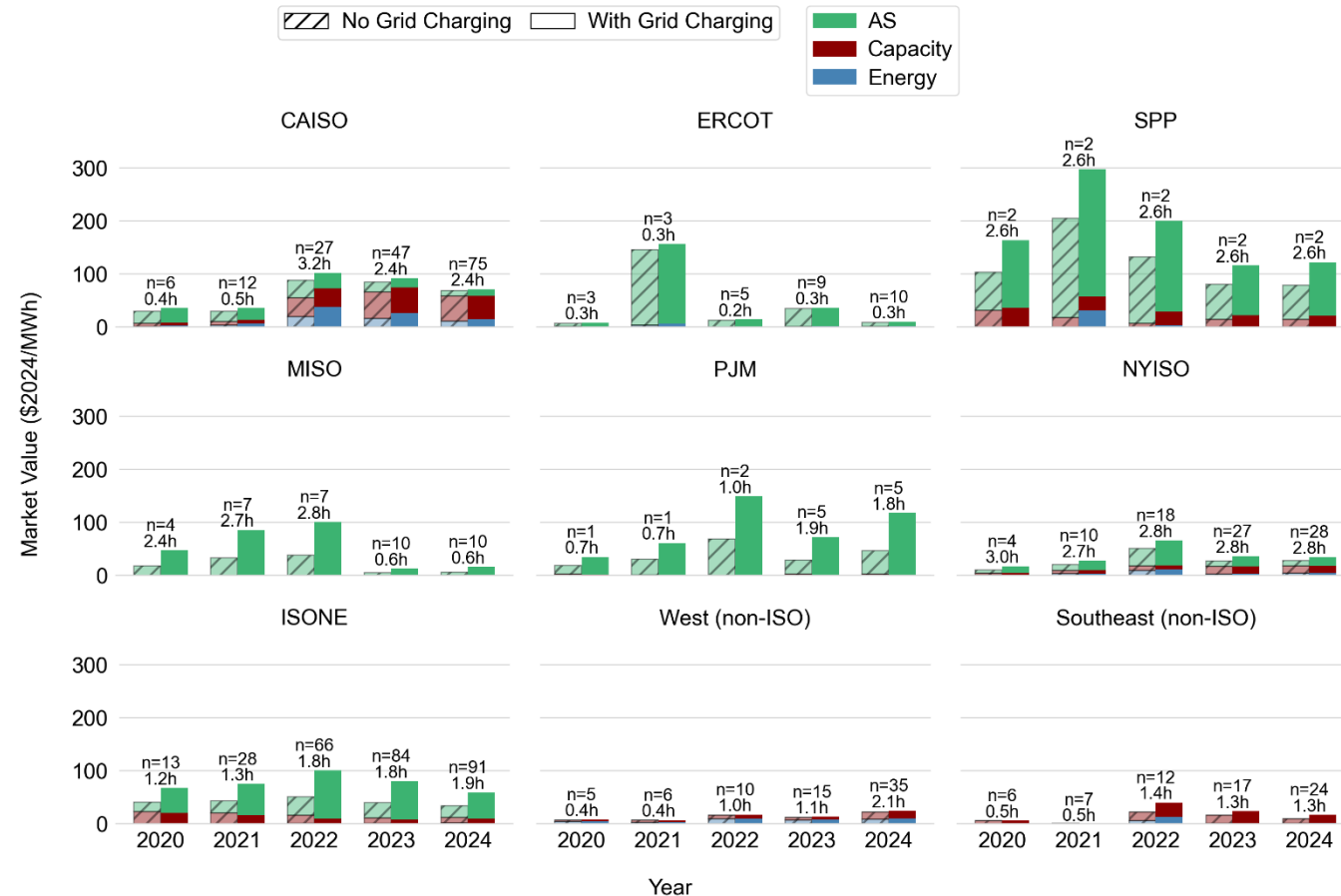
# Sensitivity Analysis Charging Constraints:

## Grid charging increases ancillary services value in many regions

Sensitivity case

- 77% of batteries face grid-charging constraints in 2024:
  - Before 2023, storage qualified for the Investment Tax Credit (ITC) only if it was treated as part of a solar energy property and met a minimum solar-charging requirement during its first five years of operation.
  - Batteries charging up to 25% from the grid faced a proportional reduction in ITC eligibility. When charging more than 25% they could trigger recapture of the unvested portion of the credit.
  - These tax-driven operating constraints should no longer matter after 2027. In the base case, we therefore apply a mixed treatment based on the storage unit's commercial operation date.
- Allowing grid charging materially increases the potential storage premium.
  - AS value** declines sharply when regulation-down service cannot be provided through grid charging and instead must be offered only by reducing energy output. In that case, regulation provision is effectively limited to hours when the battery is already discharging. This effect is especially important in PJM, SPP, ISO-NE, and in earlier years in MISO.
  - Capacity value** declines in the non-ISO Southeast when grid charging is not allowed, because battery state of charge is then often insufficient to contribute during all top net-load hours used for capacity accreditation.
  - Energy value** changes little outside CAISO in 2022. Under our degradation proxy, cycling generally requires an energy price spread greater than \$20/MWh to be economic. In addition, many hours suitable for grid charging already coincide with solar production, especially in high-solar-penetration regions.

Regional Average Storage Premium: Impact of Grid-Charging  
AS Mode True, Degradation 10, Market DA



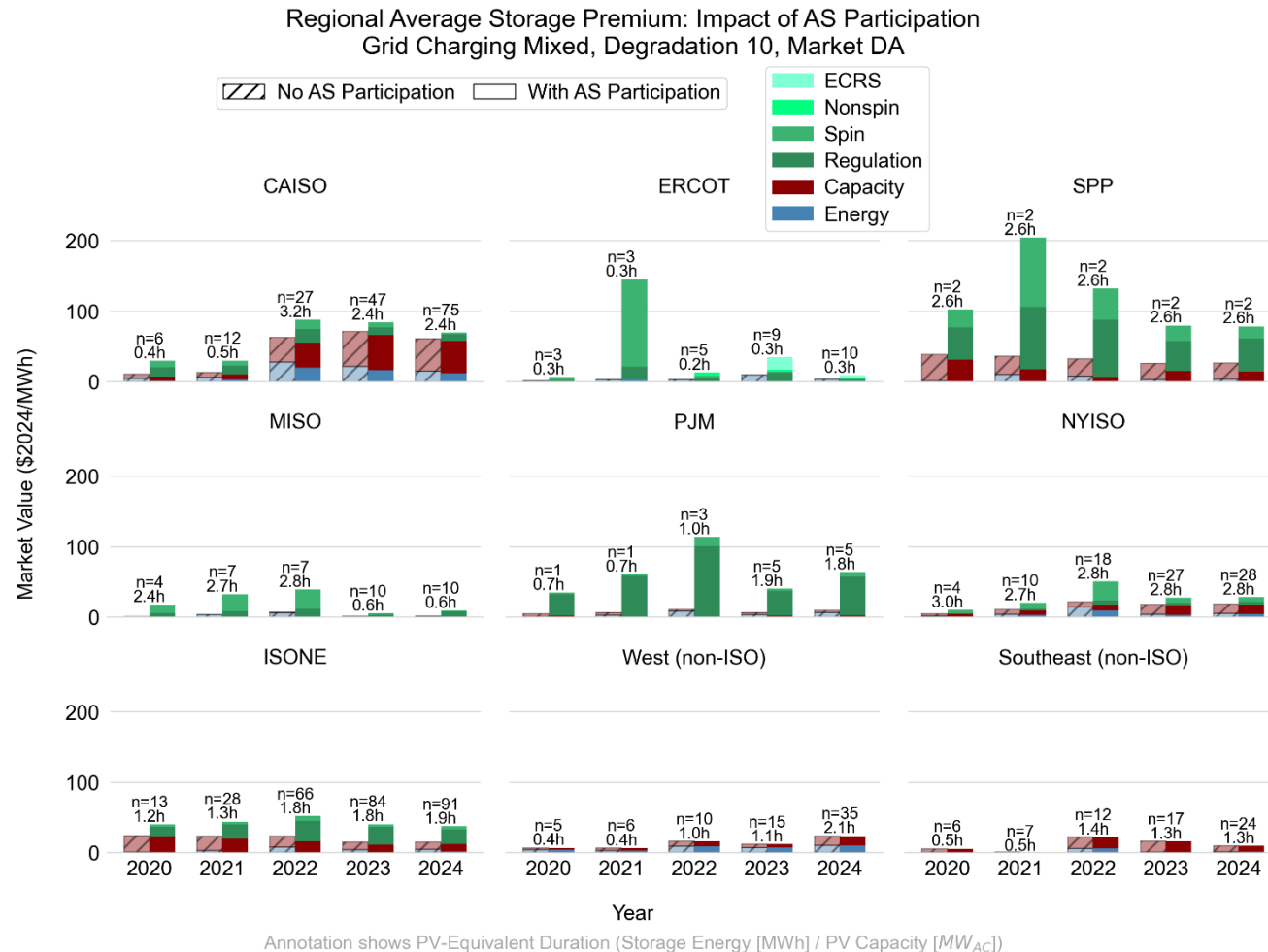
Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW<sub>AC</sub>])

# Sensitivity Analysis AS:

## AS value is material, but its importance varies strongly by market maturity

Sensitivity case

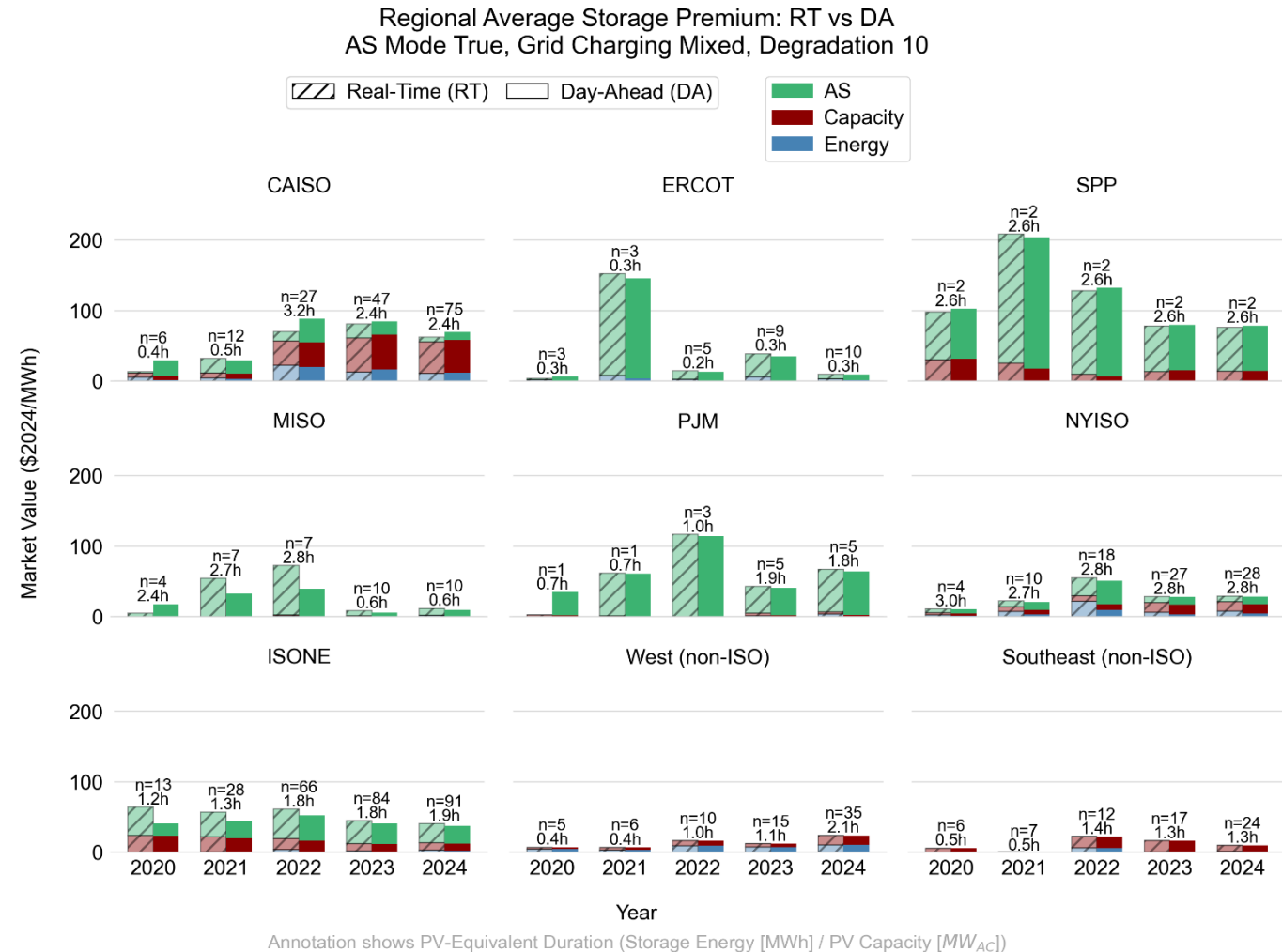
- AS are an important component of the modeled storage value premium, but their weight varies substantially across markets. The largest AS-driven gains appear in markets with limited existing battery participation, where AS prices remain relatively high. In more mature hybrid markets, especially CAISO, storage value is driven more by energy and capacity value, and the incremental upside from AS participation is smaller.
  - Excluding AS revenues reduces total storage value most strongly in less saturated markets such as PJM, SPP, and ISO-NE. Without access to AS markets, batteries shift more toward energy arbitrage, but the resulting revenue gains are usually small.
  - In CAISO, by contrast, AS participation still adds only little value.
  - Most AS revenue comes from capacity awards rather than from actual deployment, which we assume is compensated at real-time energy prices. In 2024, deployment accounted for only 13% of total AS revenue.
  - Regulation is the dominant AS product in most markets, followed by spinning reserve. In ERCOT, non-spin and ECRS also contribute.
- Our model assumes price-taking behavior and perfect foresight. In practice, greater battery participation tends to reduce AS prices, as already observed in CAISO and ERCOT. Similar price compression would likely occur in other ISOs if battery participation scaled up.



# Sensitivity Analysis Day-Ahead vs. Real-Time Energy Market Participation: Energy market timing mattered little in 2024

Sensitivity case

- This sensitivity compares dispatch against either DA or RT energy prices only. The model currently does not allow DA-RT arbitrage; in each case, storage participates in a single energy market with perfect price foresight. Because resource adequacy obligations and some capacity market participation often require day-ahead scheduling, we use the DA case as the central scenario. To preserve comparability with the core valuation framework, the RT case still includes estimated capacity value. It should therefore be interpreted as an RT energy-price sensitivity, not as a case in which projects participate exclusively in RT markets for all revenue streams.
- Under the base case, which includes ancillary services and COD-dependent grid-charging logic, modeled market value differences between DA and RT are generally small in 2024.
- In non-ISO regions, we use only RT-based price proxies (WEIM, WEIS, and FERC system lambda), so DA-RT differences do not arise there.





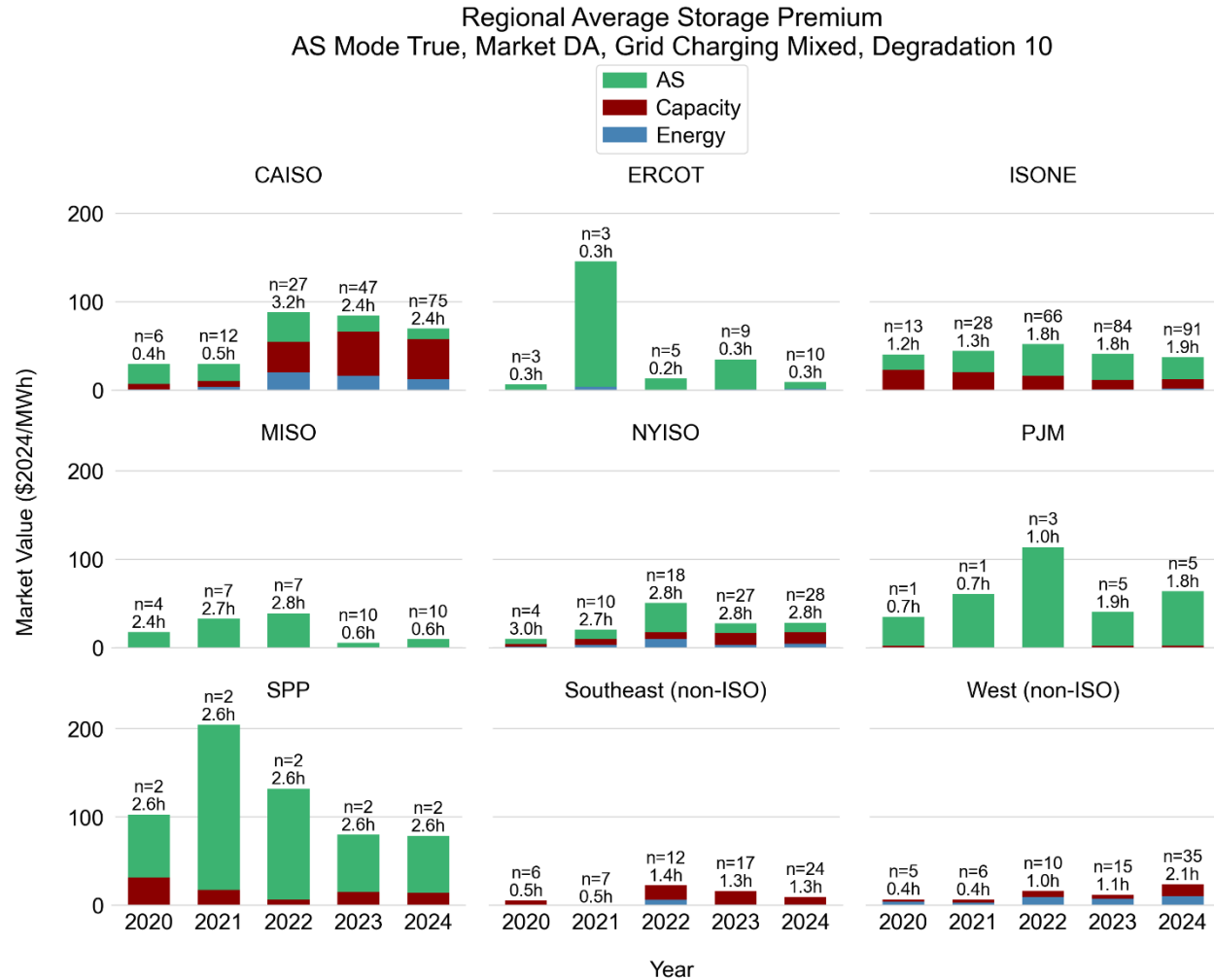
## Appendix

- Optimized PV+S Value in \$/MWh for Sensitivity Cases
- **Optimized Storage Value in \$/kW-yr**
- Optimized Net Value for Sensitivity Cases
- Comparison of Empirical and Optimized Storage Value Premium



# Appendix: Optimized Wholesale Market Value

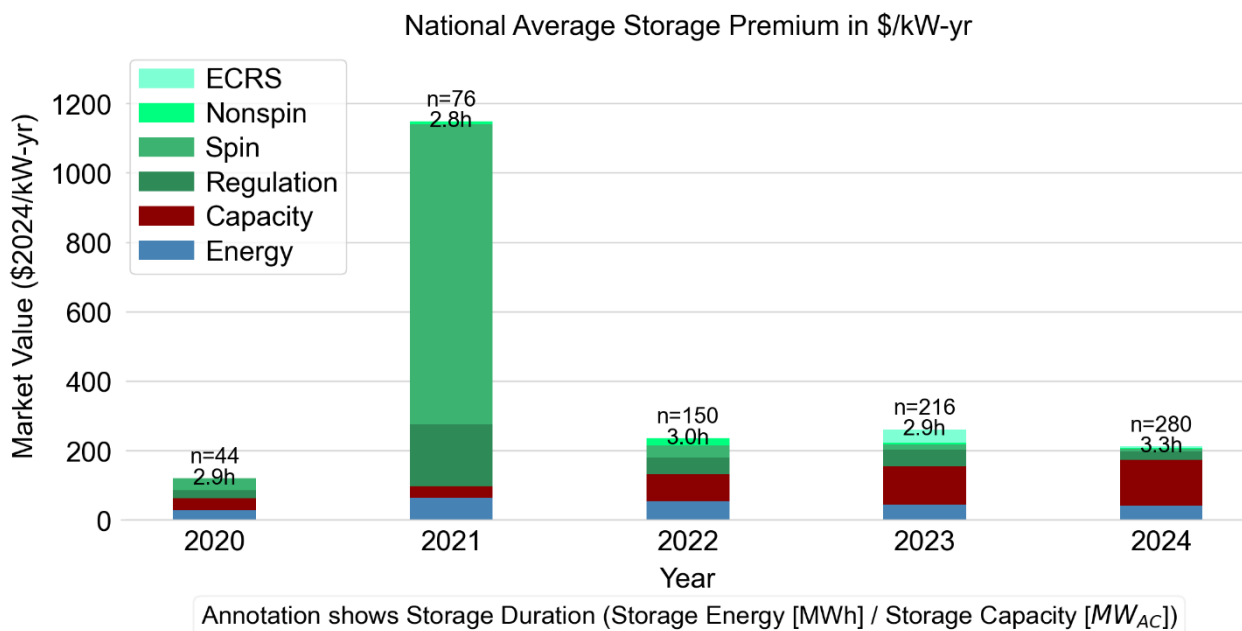
## Base Scenario: Regional Storage Premium in \$/MWh<sub>PV</sub>



Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [ $MW_{AC}$ ])

# Appendix: Optimized Wholesale Market Value

## Base Scenario: National Storage Value in \$/kW-yr



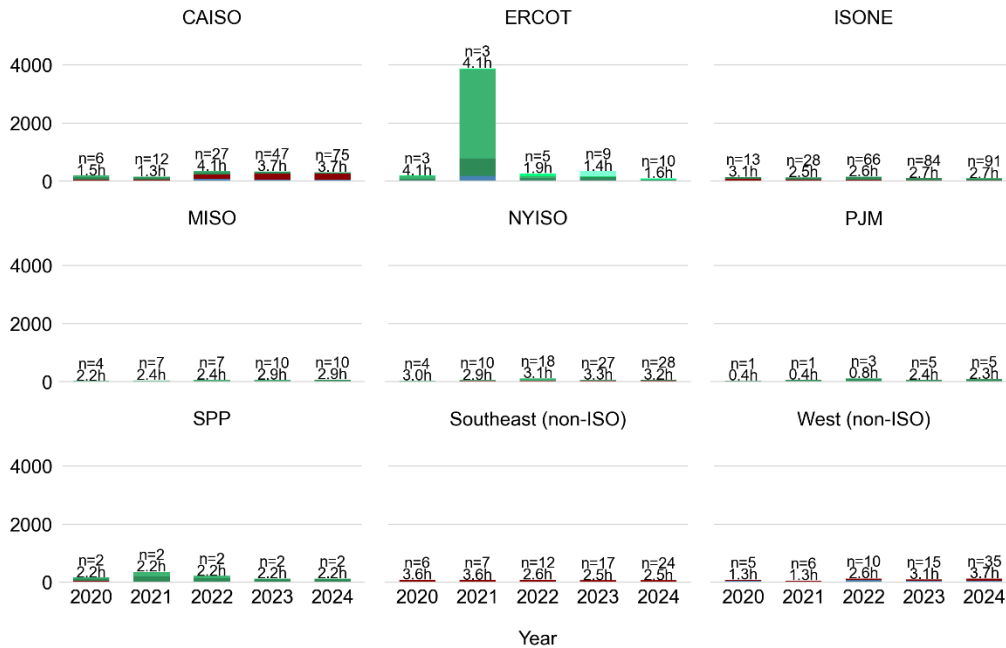
- Difficult to compare storage value when expressed in  $\$/MWh_{PV}$  terms with official storage value reports
  - ▣ → switching to  $\$/kW_{Bat-yr}$
  - ▣ Duration now refers just to storage duration, not PVED
  - ▣ Weighted average based on plant PV generation
  
- 2021 was breakout storage value year in ERCOT, otherwise national average  $\$210-260/kW-yr$  with perfect foresight. Usually, regulation is most valuable AS product except in 2021
  
- Capacity value takes on bigger role (but also skewed by expanding sample that includes more non-ISO BAs)
  - ▣ Overstating full premium as depicted values show storage standalone value. Especially with capacity value there are some minor derates due to POI limits when using sum-of-part methods

# Appendix: Optimized Wholesale Market Value

## Base Scenario: Regional Storage Value in \$/kW-yr

Zoomed out

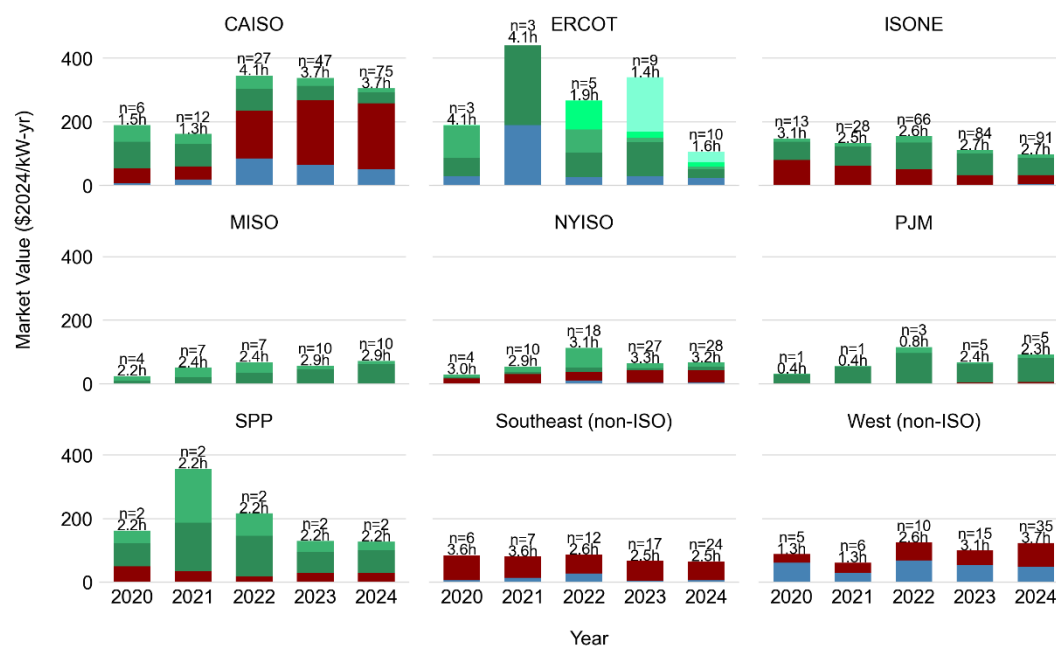
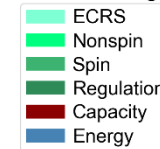
Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market DA, Grid Charging Mixed, Degradation 10



Annotation shows Storage Duration (Storage Energy [MWh] / Storage Capacity [MW<sub>AC</sub>])

Zoomed in

Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market DA, Grid Charging Mixed, Degradation 10



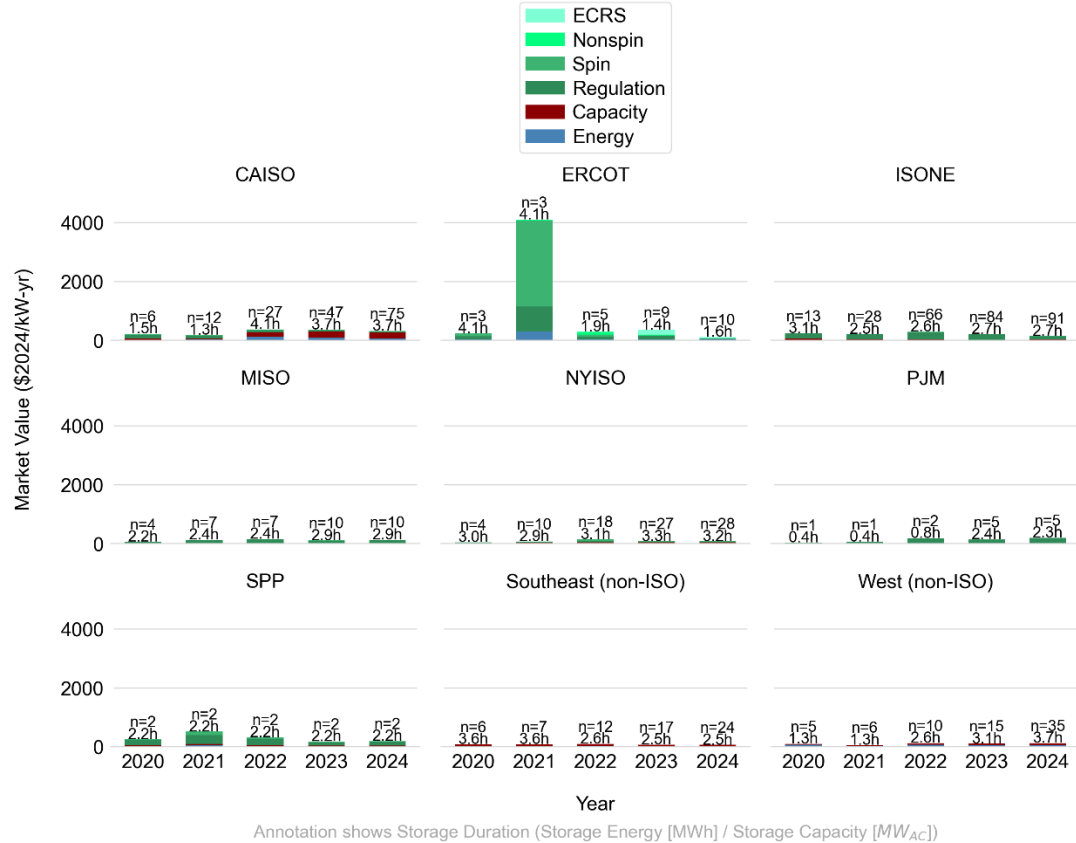
Annotation shows Storage Duration (Storage Energy [MWh] / Storage Capacity [MW<sub>AC</sub>])

- ERCOT 2021 AS value is so great at close to \$4000/kW-yr that other regions are difficult to see → right graph caps y-axis at \$450
- Capacity value may be overstated as POI limits for sum-of-parts are not considered

# Appendix: Optimized Wholesale Market Value Sensitivity Scenario with Grid-charging: Regional Storage Value in \$/kW-yr

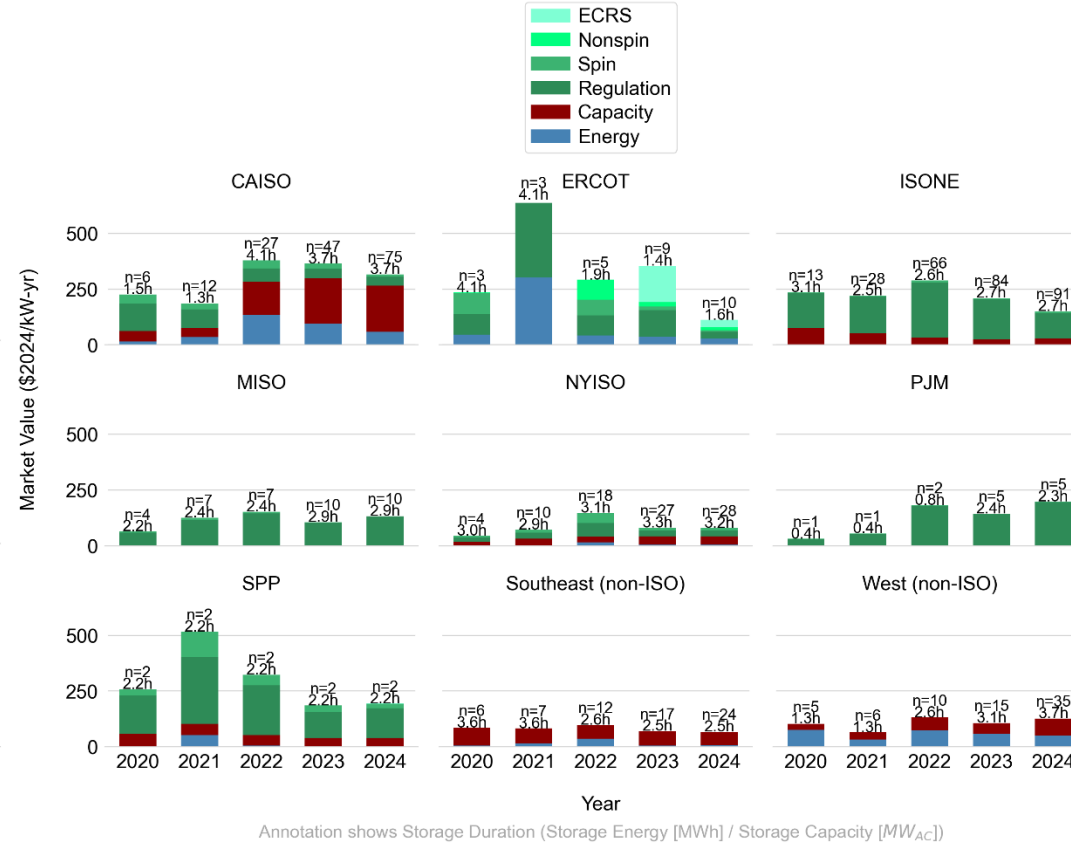
Zoomed out

Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market DA, Grid Charging True, Degradation 10



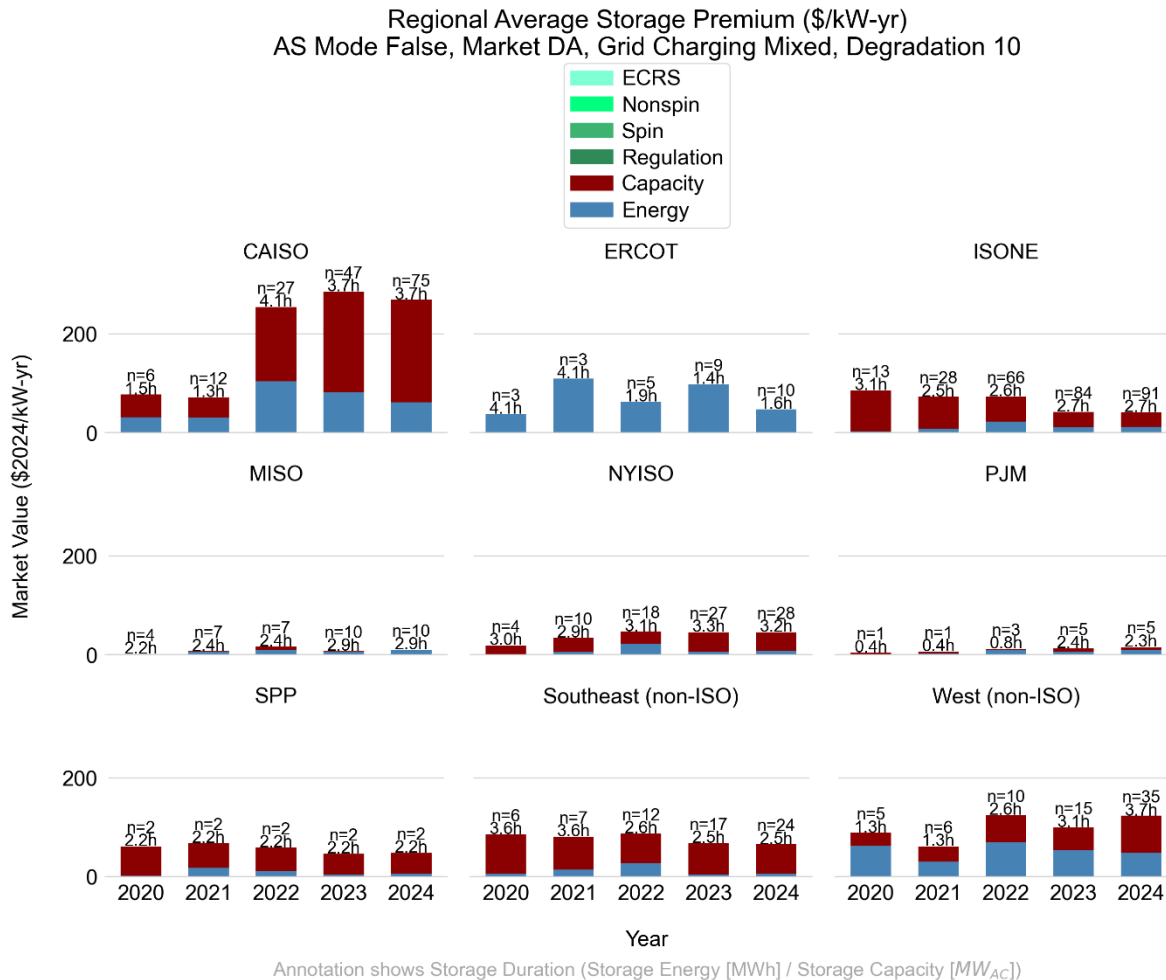
Zoomed in

Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market DA, Grid Charging True, Degradation 10



- ERCOT 2021 AS value is so great at close to \$4000/kW-yr that other regions are difficult to see → right graph caps y-axis at \$650
- Capacity value may be overstated as POI limits for sum-of-parts are not considered

# Appendix: Optimized Wholesale Market Value Sensitivity Scenario without AS: Regional Storage Value in \$/kW-yr

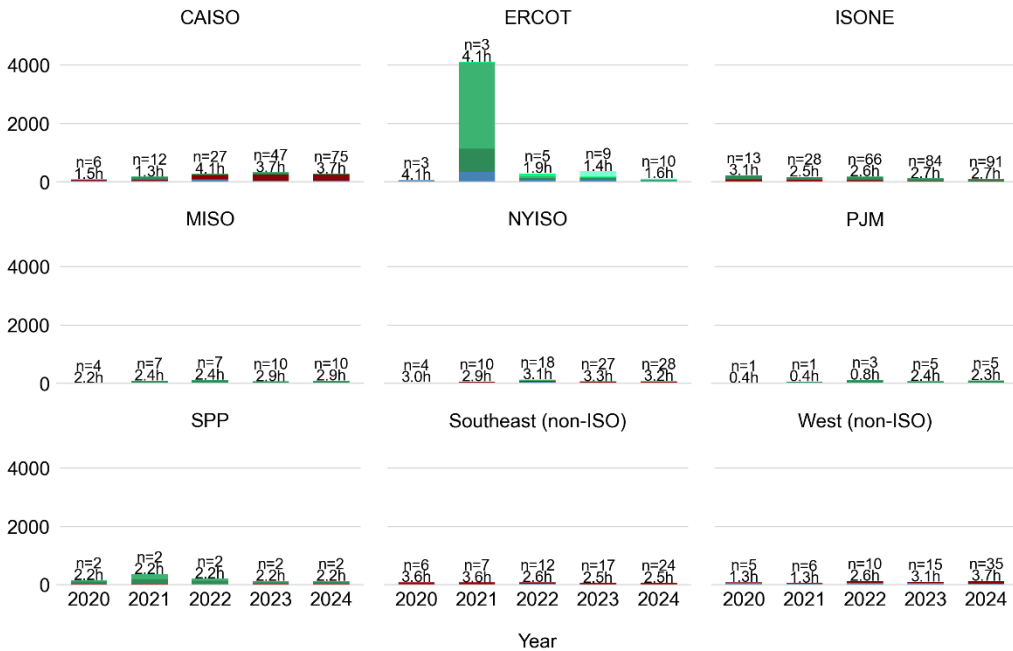


□ Capacity value may be overstated as POI limits for sum-of-parts are not considered

# Appendix: Optimized Wholesale Market Value Sensitivity Scenario RT Energy Market: Regional Storage Value in \$/kW-yr

Zoomed out

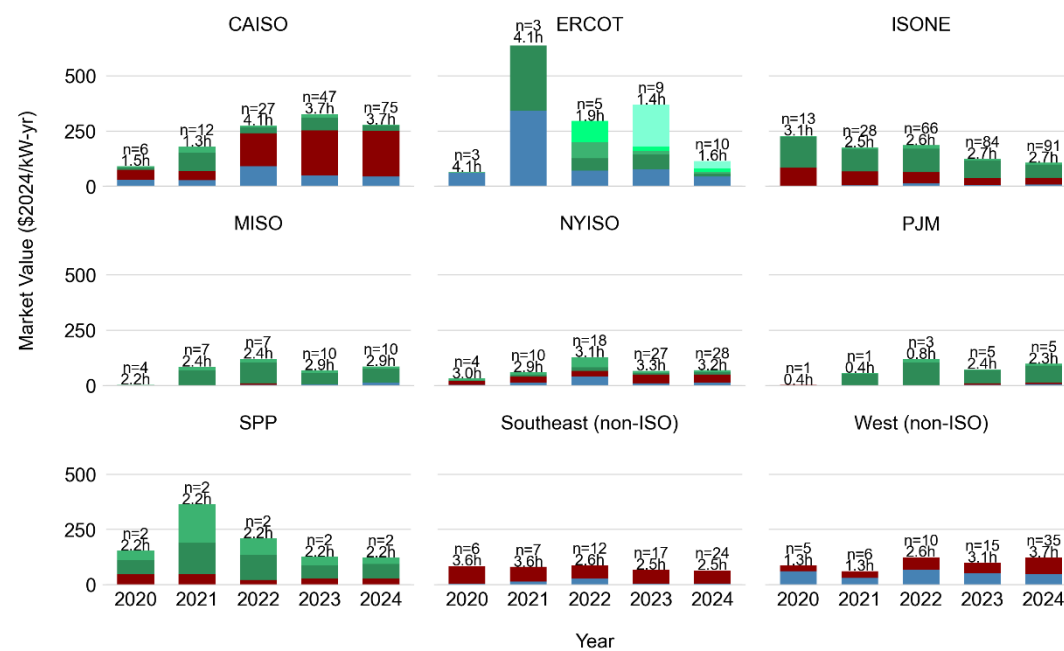
Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market RT, Grid Charging Mixed, Degradation 10



Annotation shows Storage Duration (Storage Energy [MWh] / Storage Capacity [MW<sub>AC</sub>])

Zoomed in

Regional Average Storage Premium (\$/kW-yr)  
AS Mode True, Market RT, Grid Charging Mixed, Degradation 10



Annotation shows Storage Duration (Storage Energy [MWh] / Storage Capacity [MW<sub>AC</sub>])

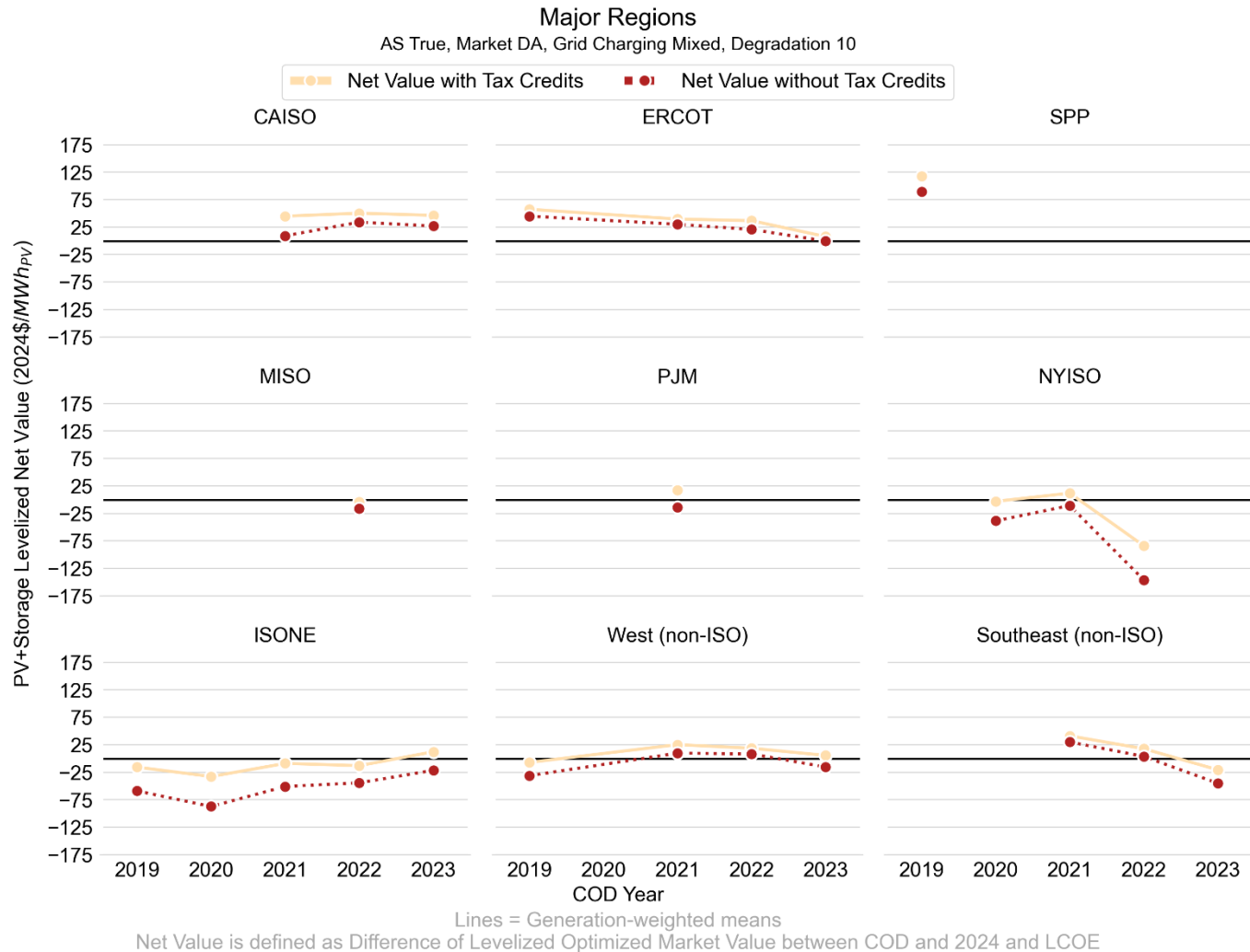
- ERCOT 2021 AS value is so great at close to \$4000/kW-yr that other regions are difficult to see → right graph caps y-axis at \$450
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## Appendix

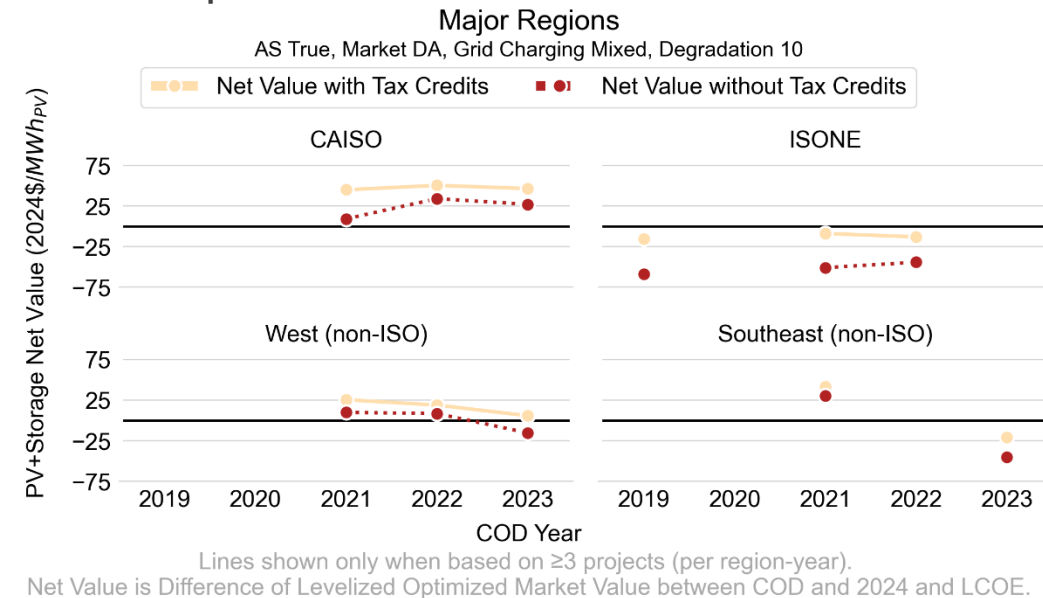
- Optimized PV+S Value in \$/MWh for Sensitivity Cases
- Optimized Storage Value in \$/kW-yr
- **Optimized Net Value for Sensitivity Cases**
- Comparison of Empirical and Optimized Storage Value Premium



# Optimized net value varies by region and is positive with investment tax credits in CAISO, ERCOT, ISONE, and non-ISO West for recent projects



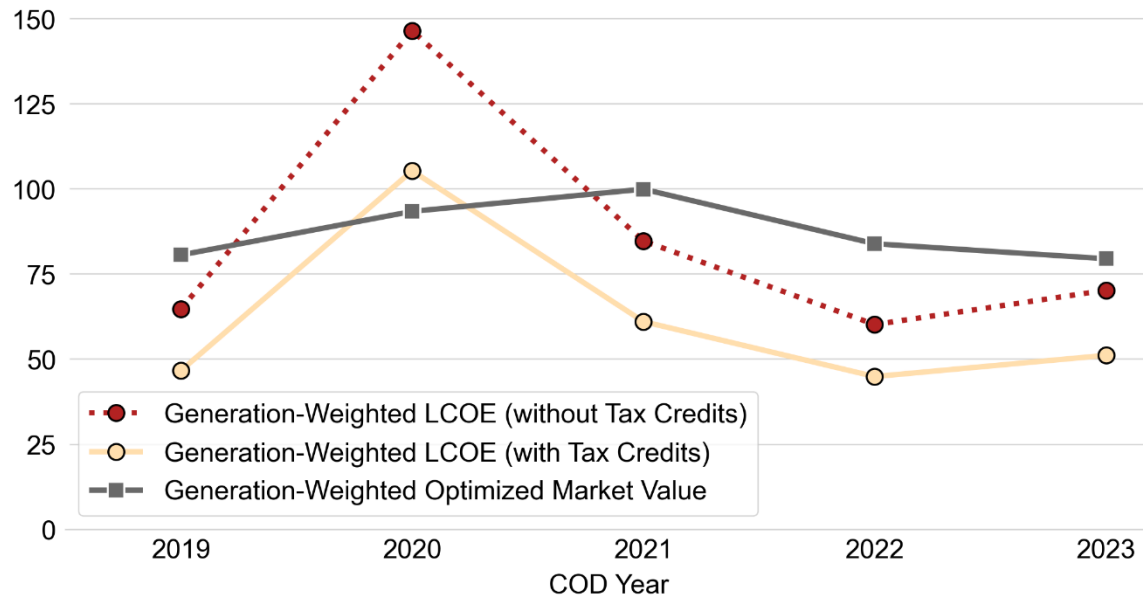
- Data becomes sparse once we differentiate by region and commercial operation year. More recent projects tend to have lower net-values as they did not capture high 2022 electricity prices and are more exposed to value cannibalization (mature AS markets).
- Robust sample with  $n \geq 3$  for each data point:



# Recent (COD 2021-2023) PV+S projects achieve on average positive net value under optimized dispatch, even without AS and without tax credits

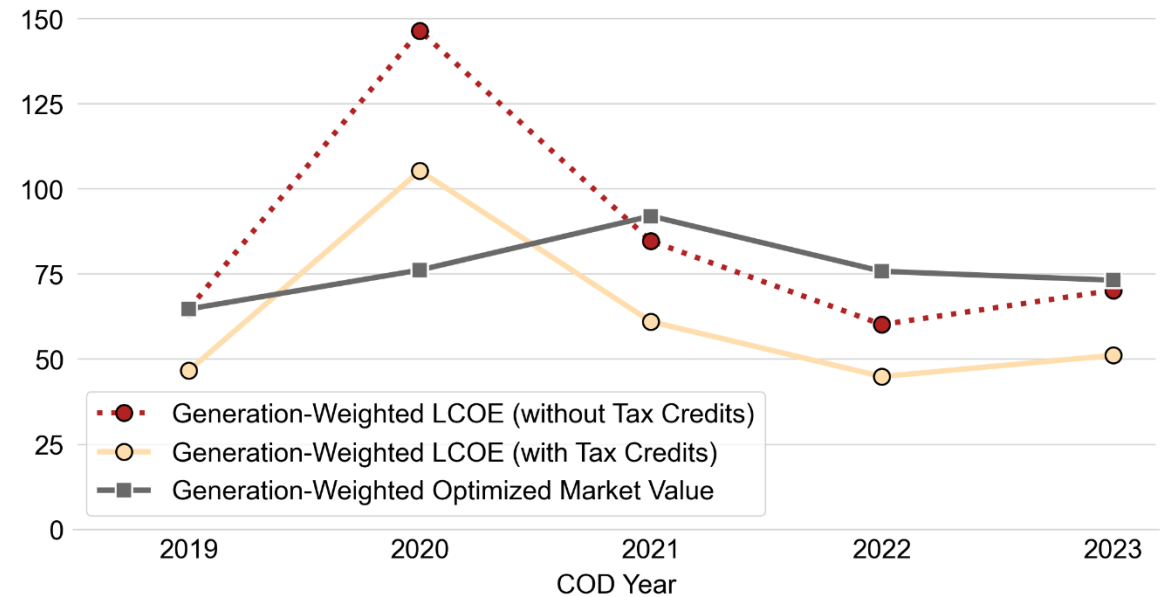
## Base Scenario: With AS in ISOs

Solar PV+Storage LCOE and Levelized Optimized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)  
AS True, Market DA, Grid Charging Mixed, Degradation 10



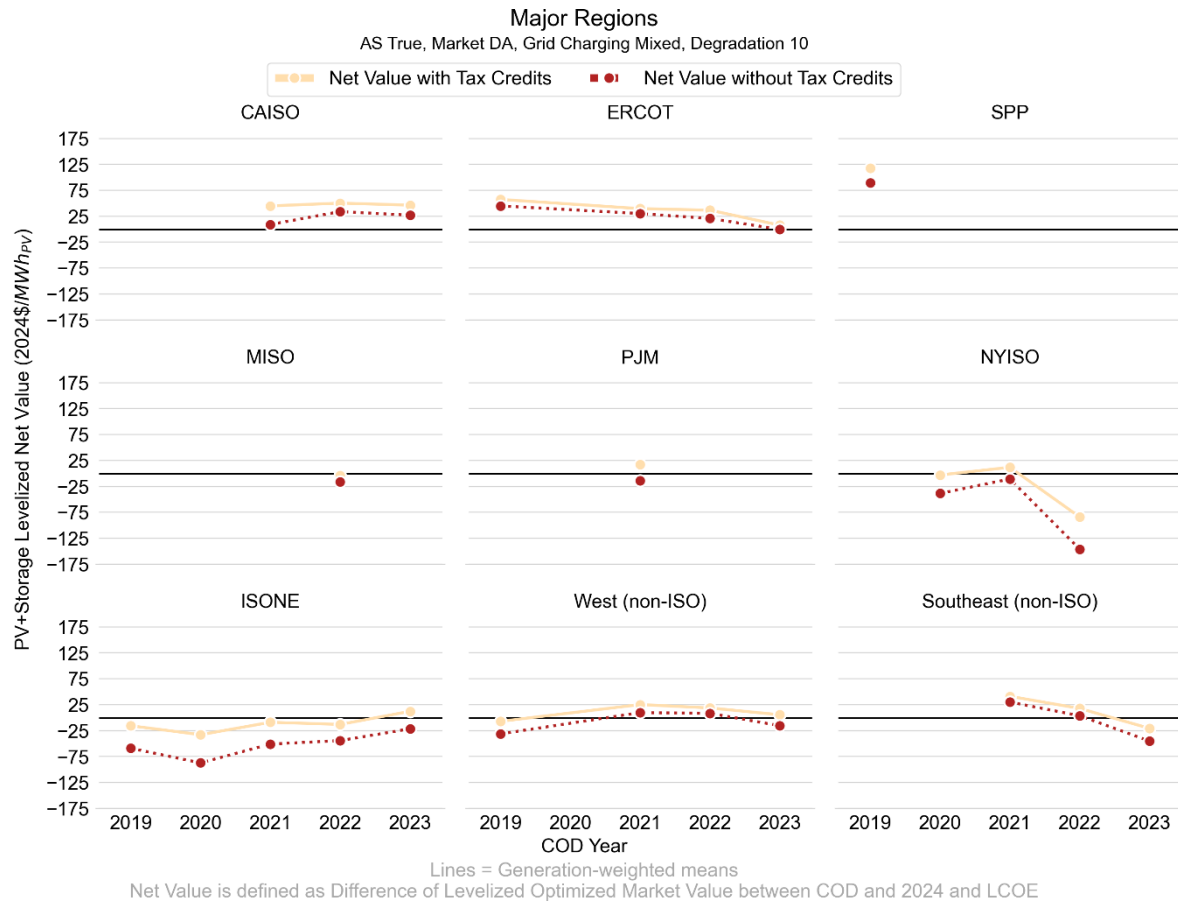
## Sensitivity Scenario: Without AS in ISOs

Solar PV+Storage LCOE and Levelized Optimized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)  
AS False, Market DA, Grid Charging Mixed, Degradation 10

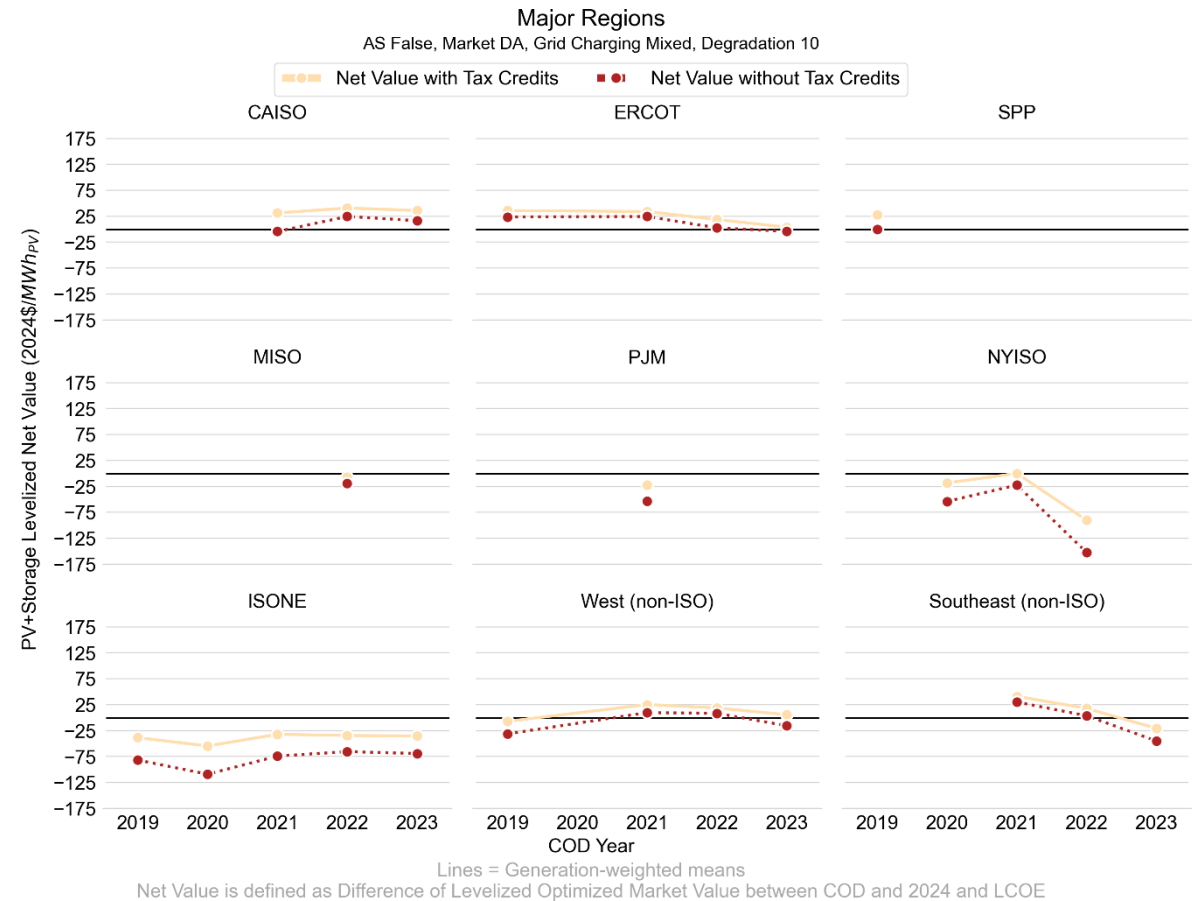


# Recent projects in CAISO, ERCOT (and non-ISO West) retain average positive optimized net value without AS, ISO-NE turns negative

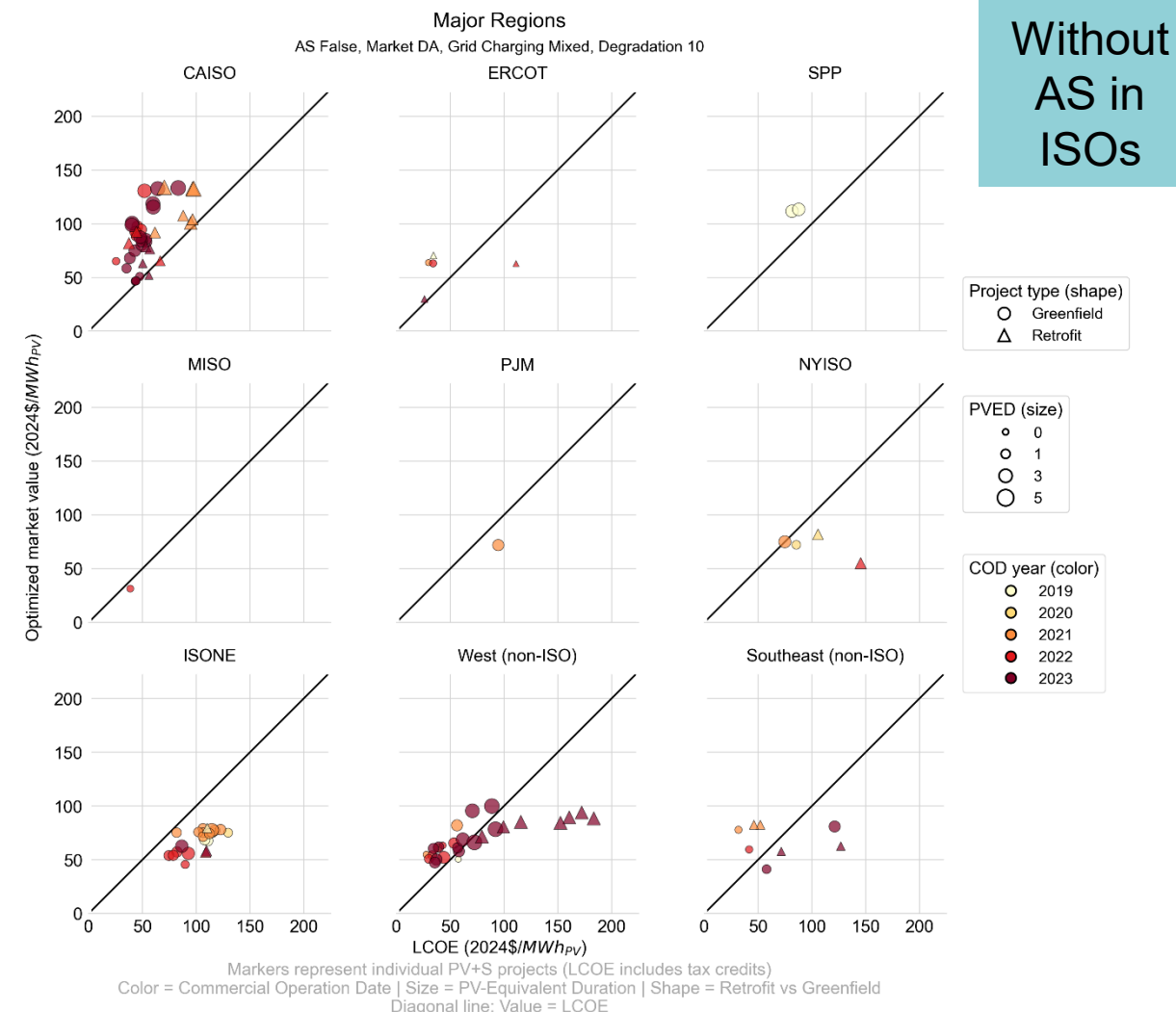
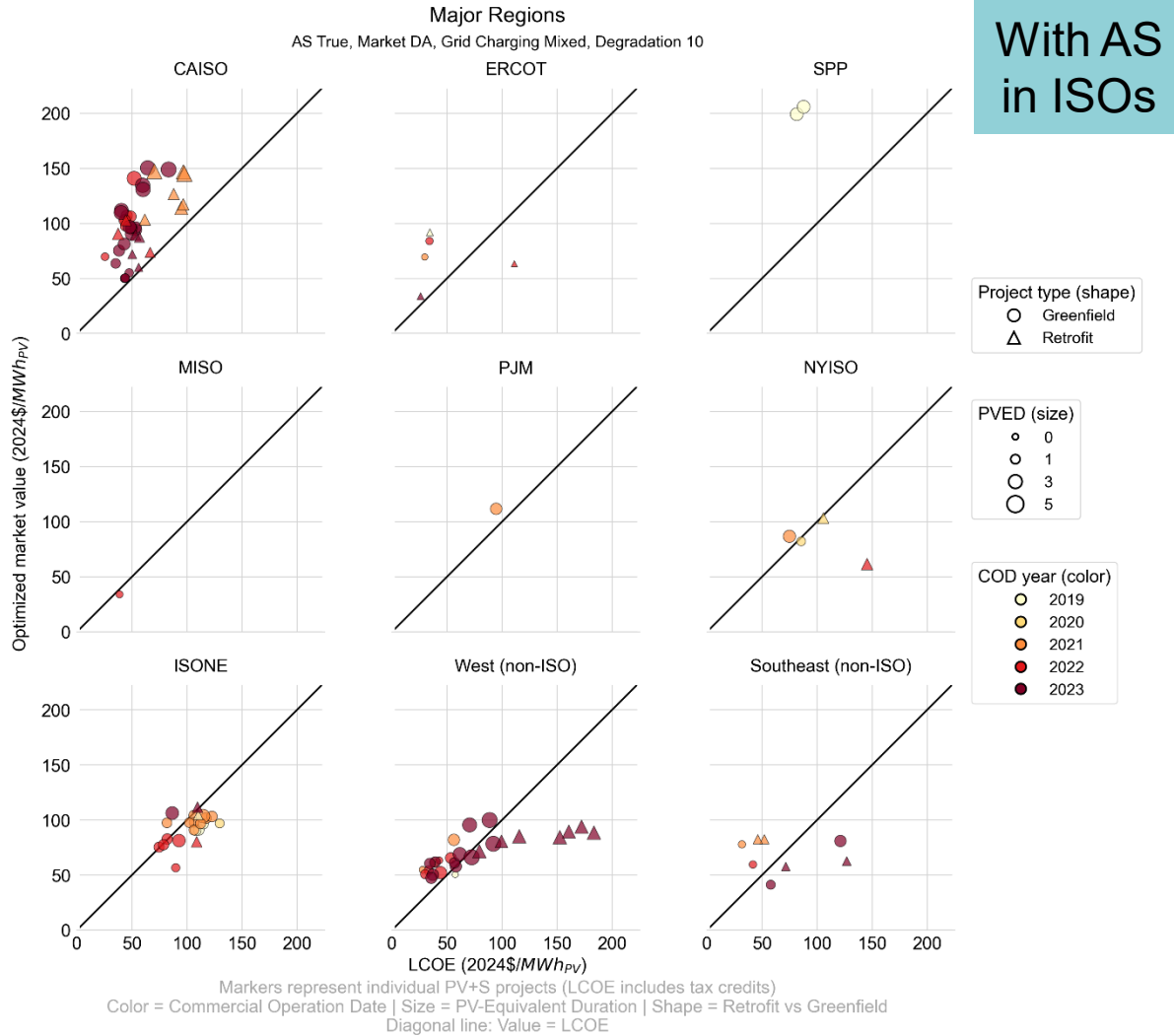
## Base Scenario: With AS in ISOs



## Sensitivity Scenario: Without AS in ISOs



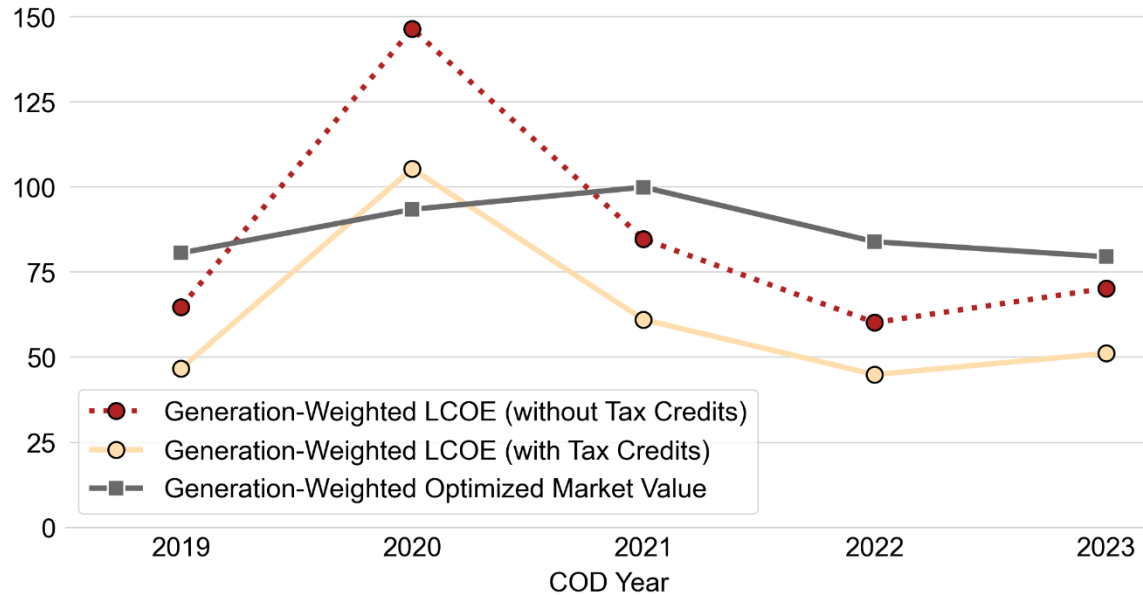
# Recent projects in CAISO, ERCOT (and non-ISO West) retain average positive optimized net value without AS, ISO-NE turns negative



# Allowing for grid charging increases wholesale market value for 2019-2022 projects

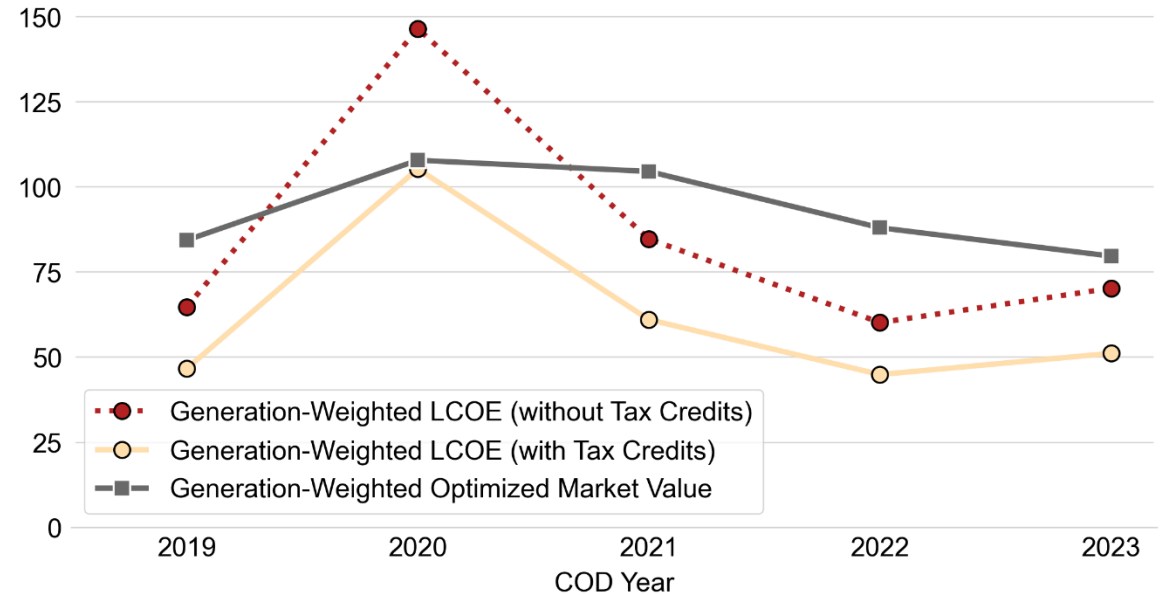
## Base Scenario: Mixed Grid-Charging

Solar PV+Storage LCOE and Levelized Optimized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)  
AS True, Market DA, Grid Charging Mixed, Degradation 10



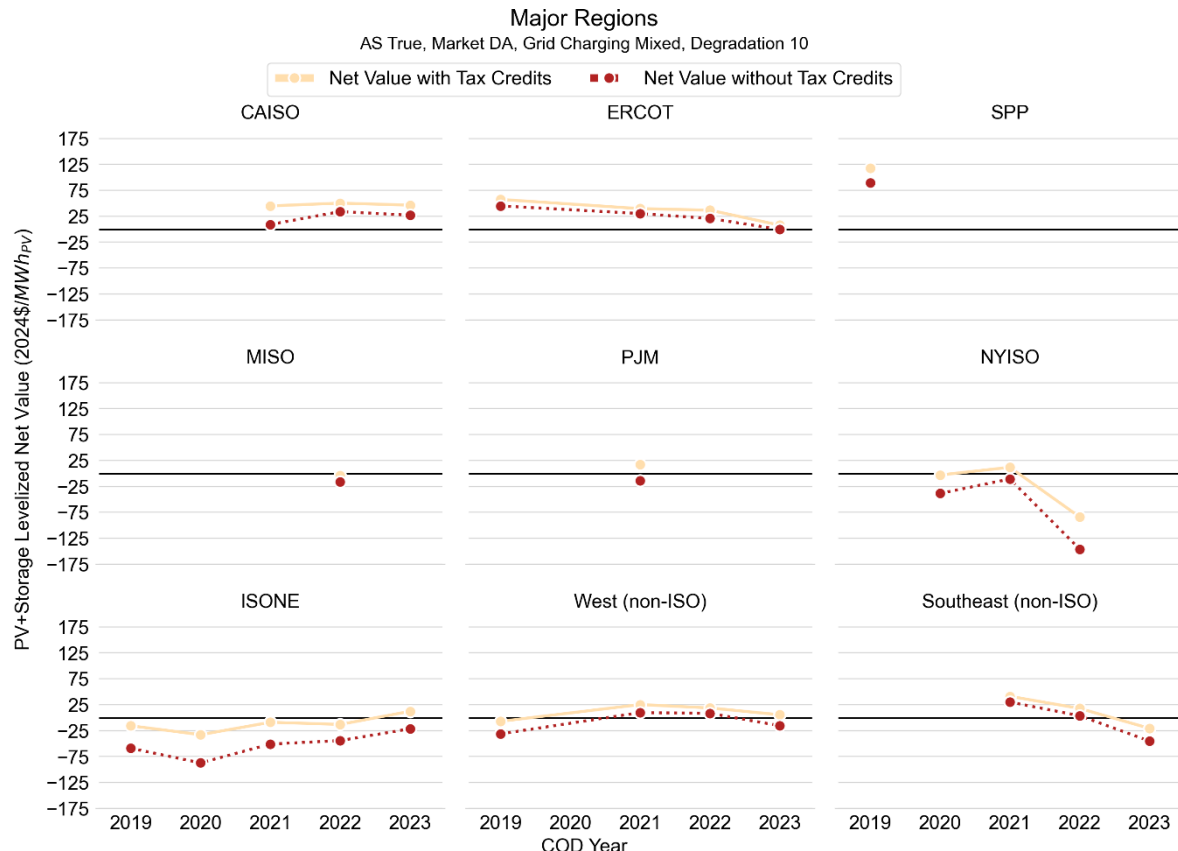
## Sensitivity Scenario: Full Grid-Charging

Solar PV+Storage LCOE and Levelized Optimized Market Value 2020-2024 (2024\$/MWh<sub>PV</sub>)  
AS True, Market DA, Grid Charging True, Degradation 10

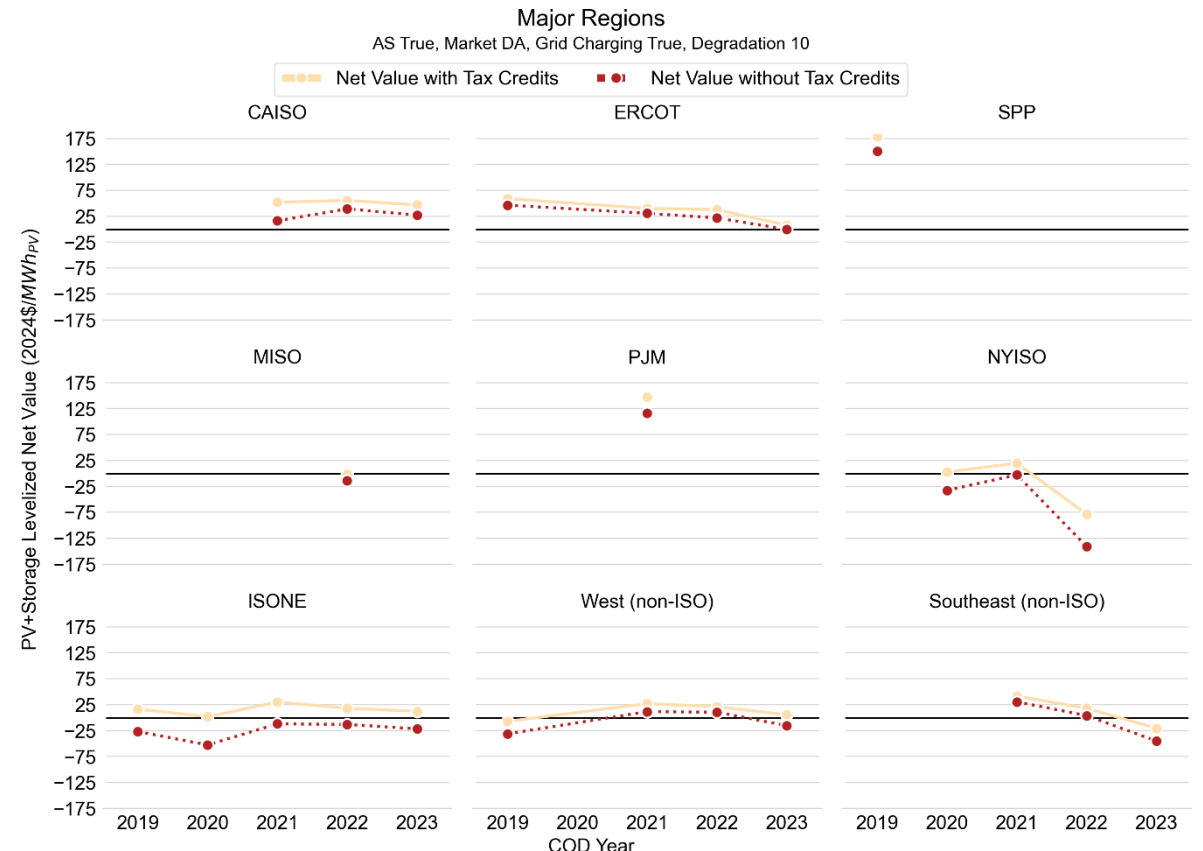


# Allowing for grid charging raises net-value especially for older projects in SPP and ISO-NE

## Base Scenario: Mixed Grid-Charging



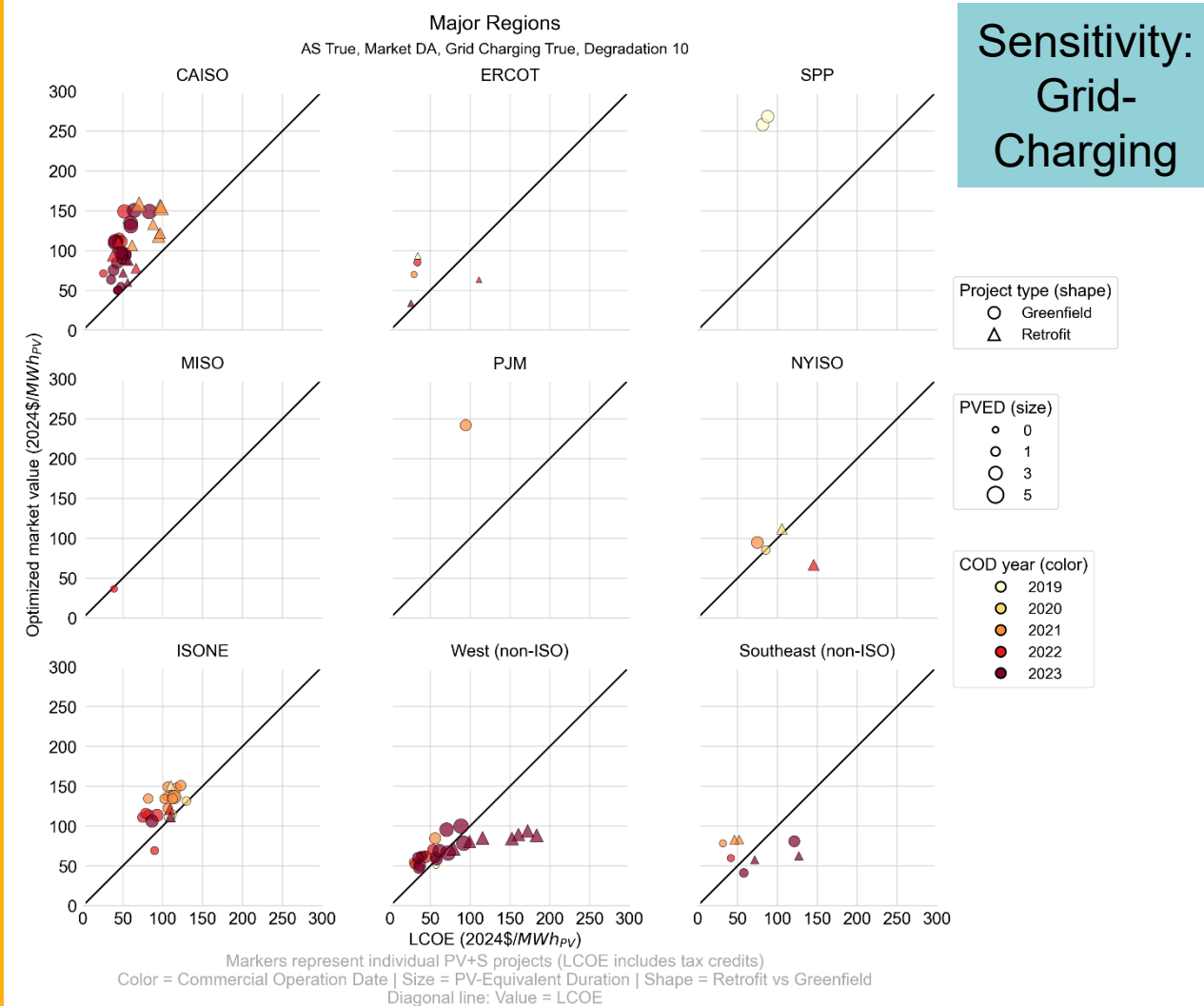
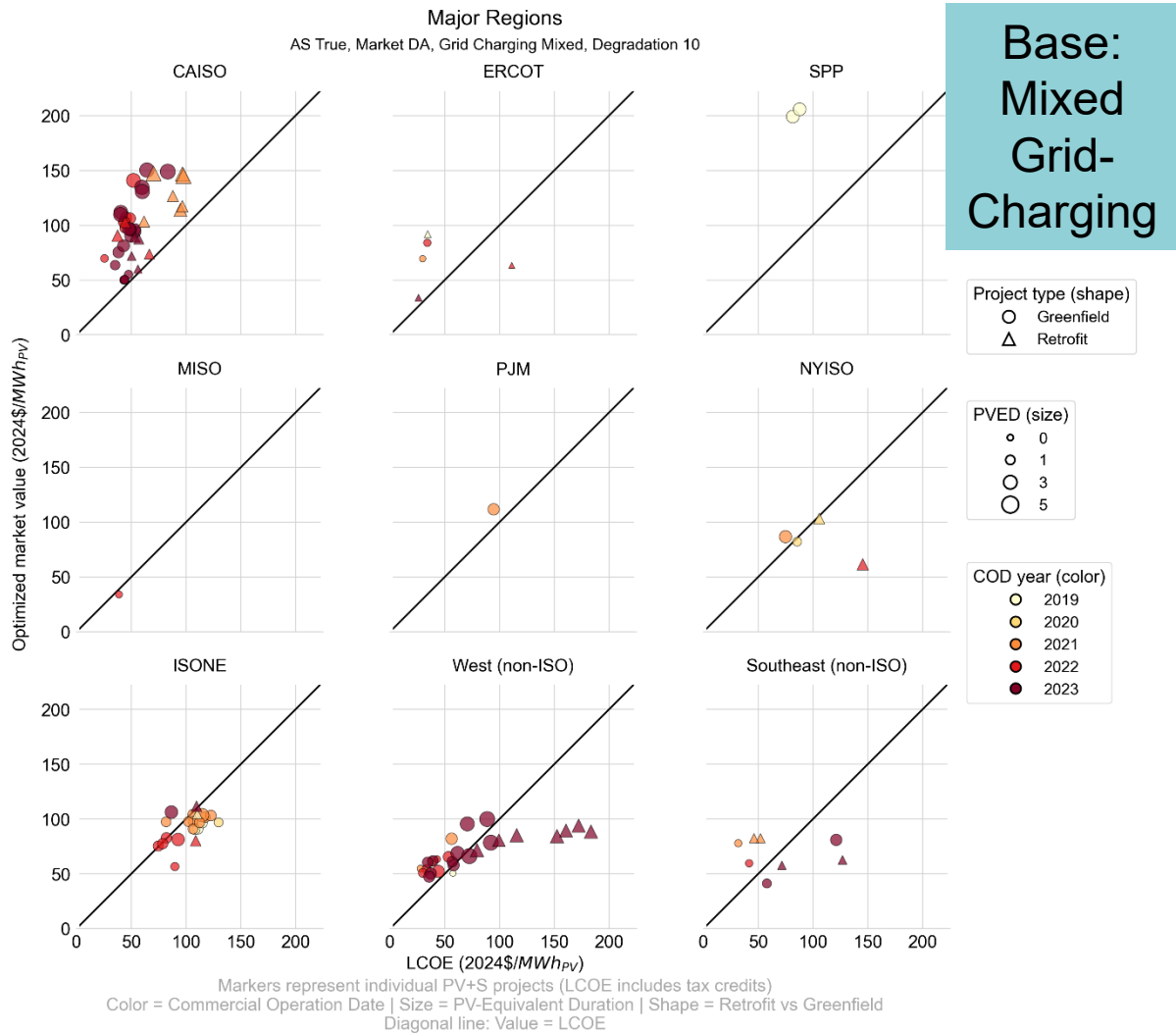
## Sensitivity Scenario: Full Grid-Charging



Lines = Generation-weighted means  
Net Value is defined as Difference of Levelized Optimized Market Value between COD and 2024 and LCOE

Lines = Generation-weighted means  
Net Value is defined as Difference of Levelized Optimized Market Value between COD and 2024 and LCOE

# Older projects in SPP and ISO-NE gain in net-value with full grid-charging driven by higher AS revenue



## Appendix

- Optimized PV+S Value in \$/MWh for Sensitivity Cases
- Optimized Storage Value in \$/kW-yr
- Optimized Net Value for Sensitivity Cases
- **Comparison of Empirical and Optimized Storage Value Premium**

# Project-level comparison of storage premiums shows wide variation between empirical and optimized values

- Storage Premium in  $\$/MWh_{PV}$  terms depends on
  - ▣ design choices (battery size relative to PV) and operational strategy success
    - low absolute premiums are not an indicator of bad performance
- ERCOT:
  - ▣ Consistent underperformance across value spectrum (higher optimized value is not correlated with lower performance)
- ISO-NE, NYISO, non-ISO West:
  - ▣ Few ISO plants captured AS value in empirical operations. Value deviation large for plants that had high optimized value.
- CAISO:
  - ▣ CAISO values were derived from EQR reported values and thus by a different method compared to other regions. One project exceeds optimized value due to rich bilateral capacity contract
- MISO:
  - ▣ Single project has negative empirical premium (no empirical capacity and little AS revenue reported in FERC EQR)

