

Solar-to-Grid

Trends in System Impacts, Reliability, and Market Value in the United States with Preliminary Data Through 2020

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Goal: improve decision making through information on the observed market value and grid impacts of solar

Characteristics of Deployed Solar

Utility-Scale (UPV)

EIA Form 860 by Plant (>1 MW)

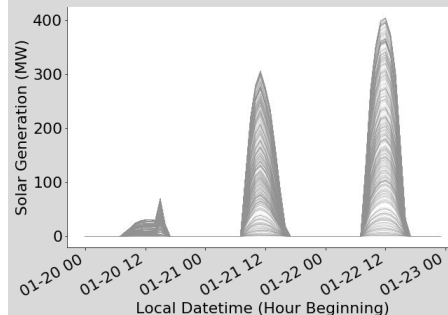
Distributed PV (DPV)

Residential and Non-Residential

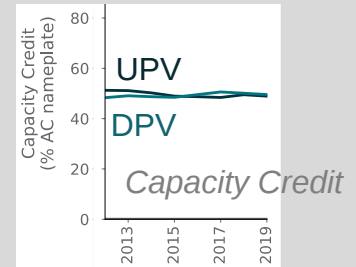
EIA Form 861 by State (<1 MW)

Hourly Solar Generation Profiles

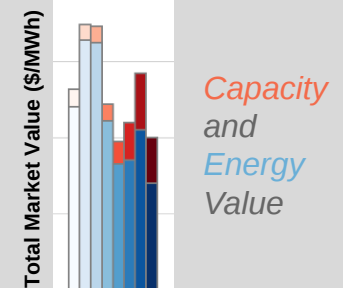
Solar Generation at Individual Plants



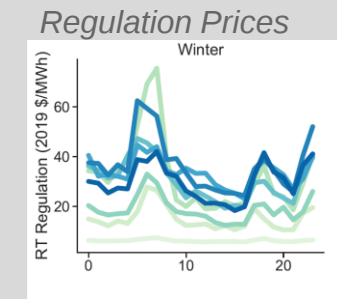
Contribution to Reliability



Market Value



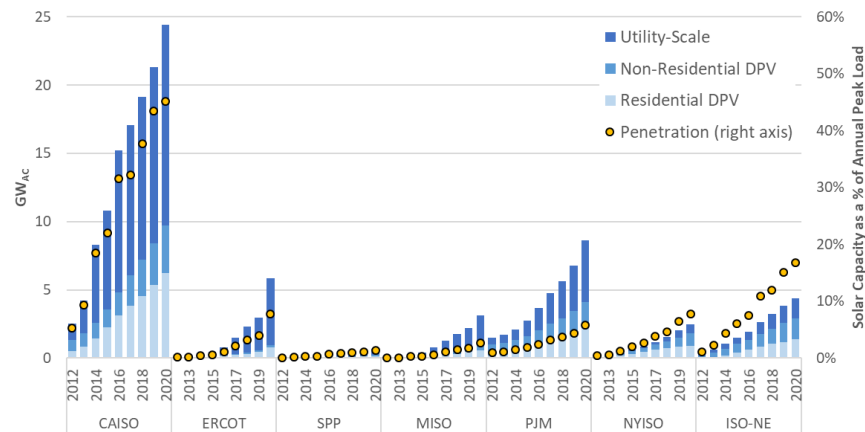
Bulk System Impacts



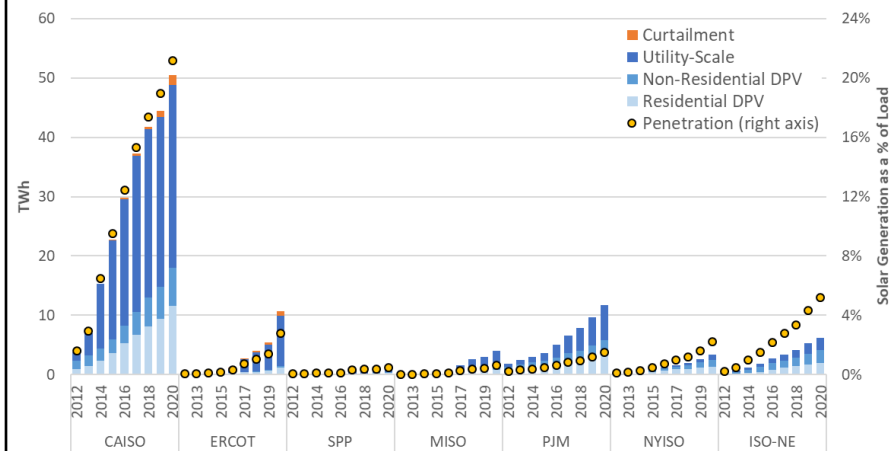
Solar deployment in CAISO far exceeds the level in other ISOs

ISOs

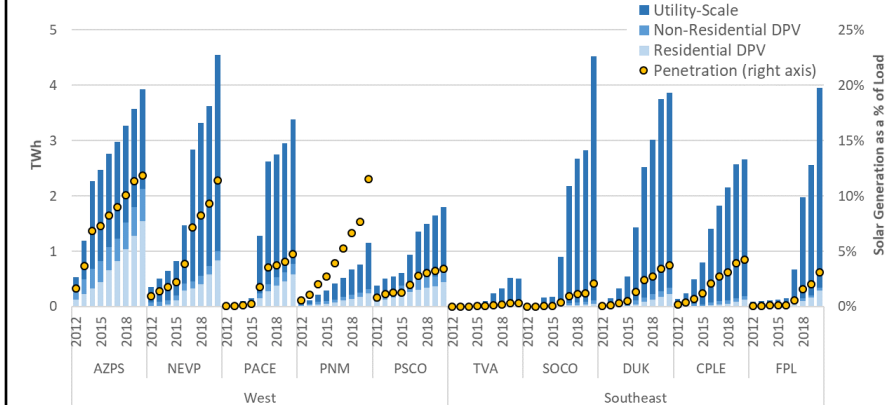
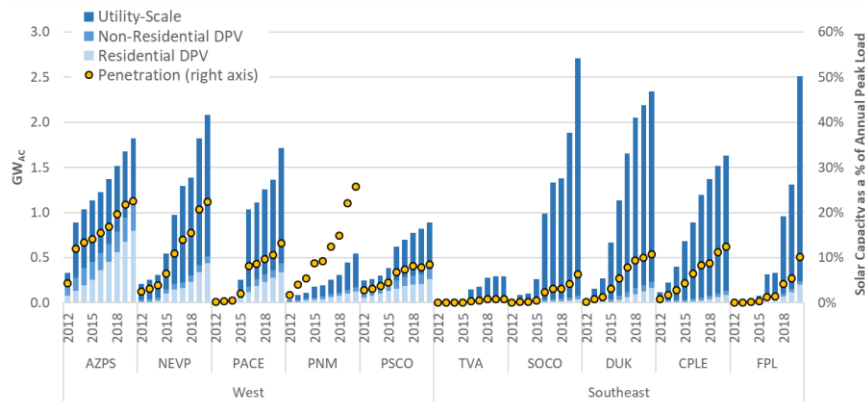
Capacity



Generation



Select Utilities

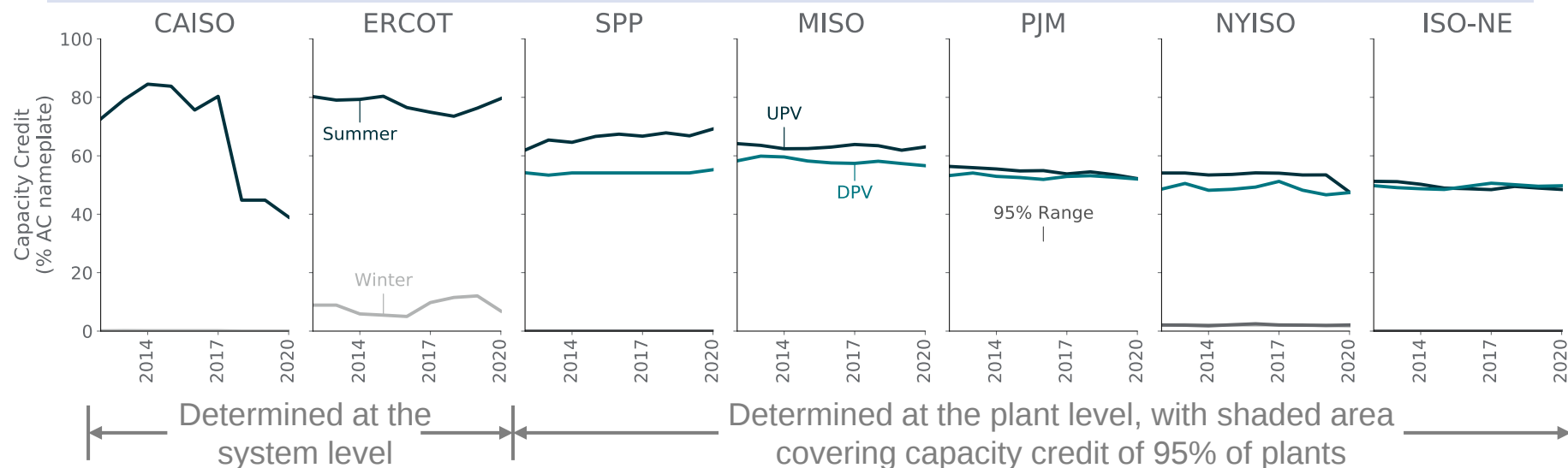


Capacity credit of solar



Average summer capacity credits in 2020 range from 39–80%, capacity credit is near zero in winter

Capacity credit of solar is calculated by methods used by each market. CAISO shifted to an “effective load carrying capability” method in 2018, PJM will do the same for 2023/24, SPP plans to shift in 2023.



	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Basis of measurement	ELCC	Average generation in top 20 peak hours	Generation exceedance level during top 3% peak hours	Average generation during peak period	Average generation during peak period	Average generation during peak period	Median generation during peak period
Frequency of measurement	Monthly	Summer, fall, winter, spring	Summer, winter	Summer	Summer	Summer, winter	Summer, winter
Credit varies for UPV vs. DPV?	No	No	Yes	Yes	Yes	Yes	Yes



Market value of solar



Market value approach and assumptions

Energy Value

$$\text{Energy Value} = \frac{\sum \text{Postcurtailment Generation}_h * \text{Wholesale RT Energy Price}_h}{\sum \text{Precurtailment Generation}_h}$$

- Plant-level debiased hourly solar generation
- Real-time energy price from nearest pricing node
- Focus on annual value of solar from all sectors

Capacity Value

$$\text{Capacity Value} = \frac{\sum \text{Capacity Credit}_T * \text{Nameplate} * \text{Capacity Price}_T}{\sum \text{Precurtailment Generation}_T}$$

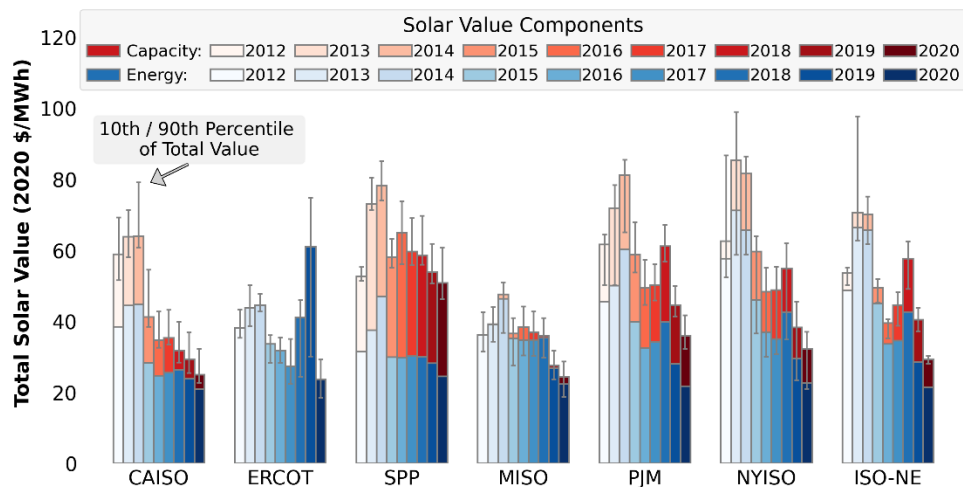
- Capacity credit based on plant-level profile; varies by month, season, or year
- Capacity prices from respective ISO region; prices vary by month, season, or year
- Estimate bilateral capacity prices for regions without organized capacity markets
- Focus on annual value of solar from all sectors
-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

- No AS value, REC value, wholesale price effects, or externalities included in market value
- Energy + capacity value represents the marginal value to the power system



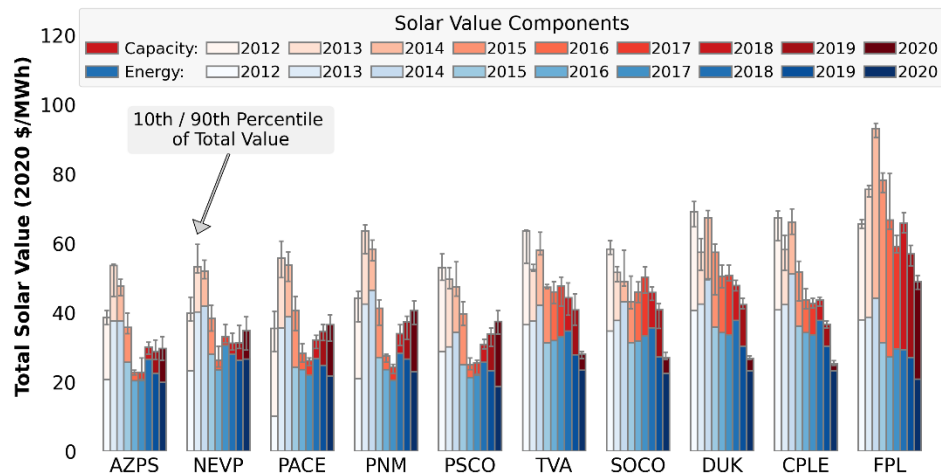
Variations in average energy and capacity prices largely drive differences in the market value of solar

ISOs

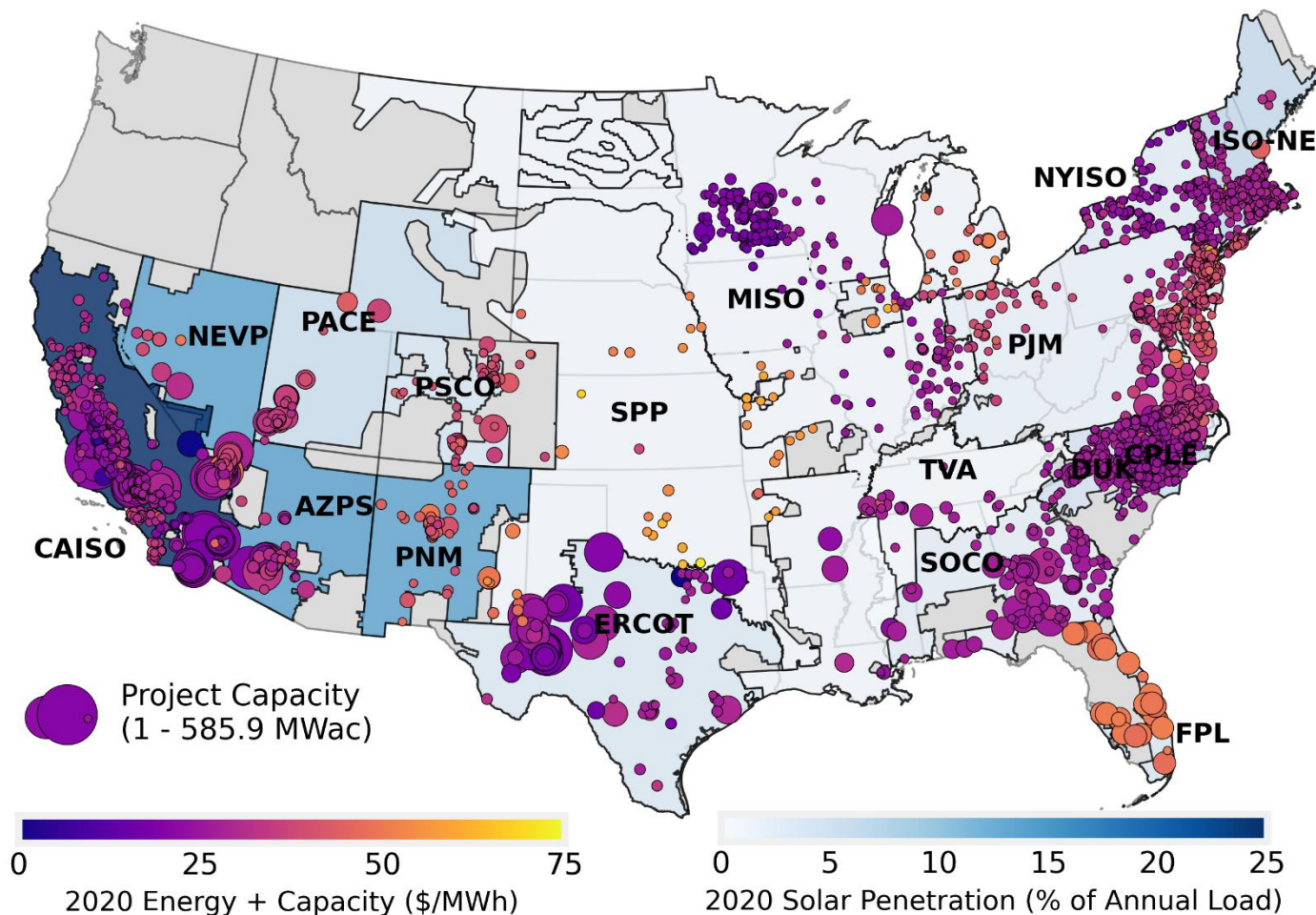


Note: ERCOT's solar market value spiked temporarily in 2019 due to scarcity prices during some summer afternoons

Utilities



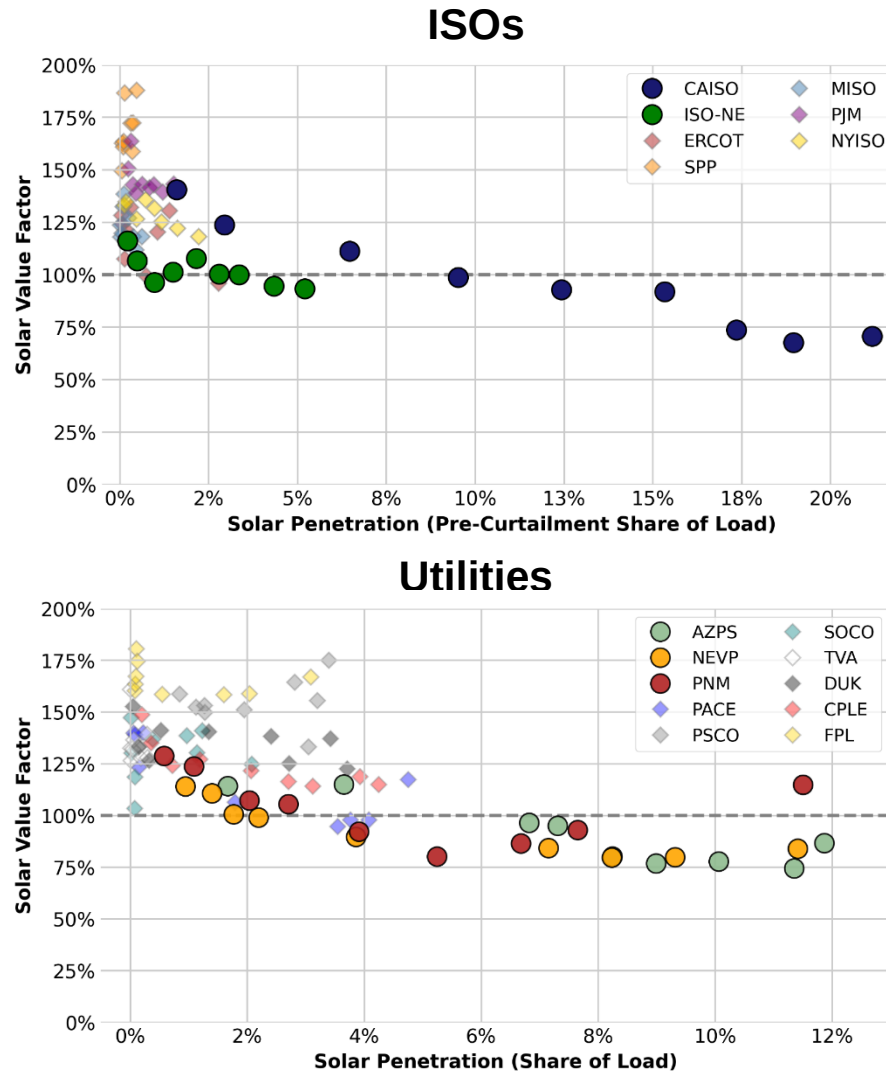
Wholesale market value of solar, by plant in 2020



Note: Only plants larger than 1 MW are shown



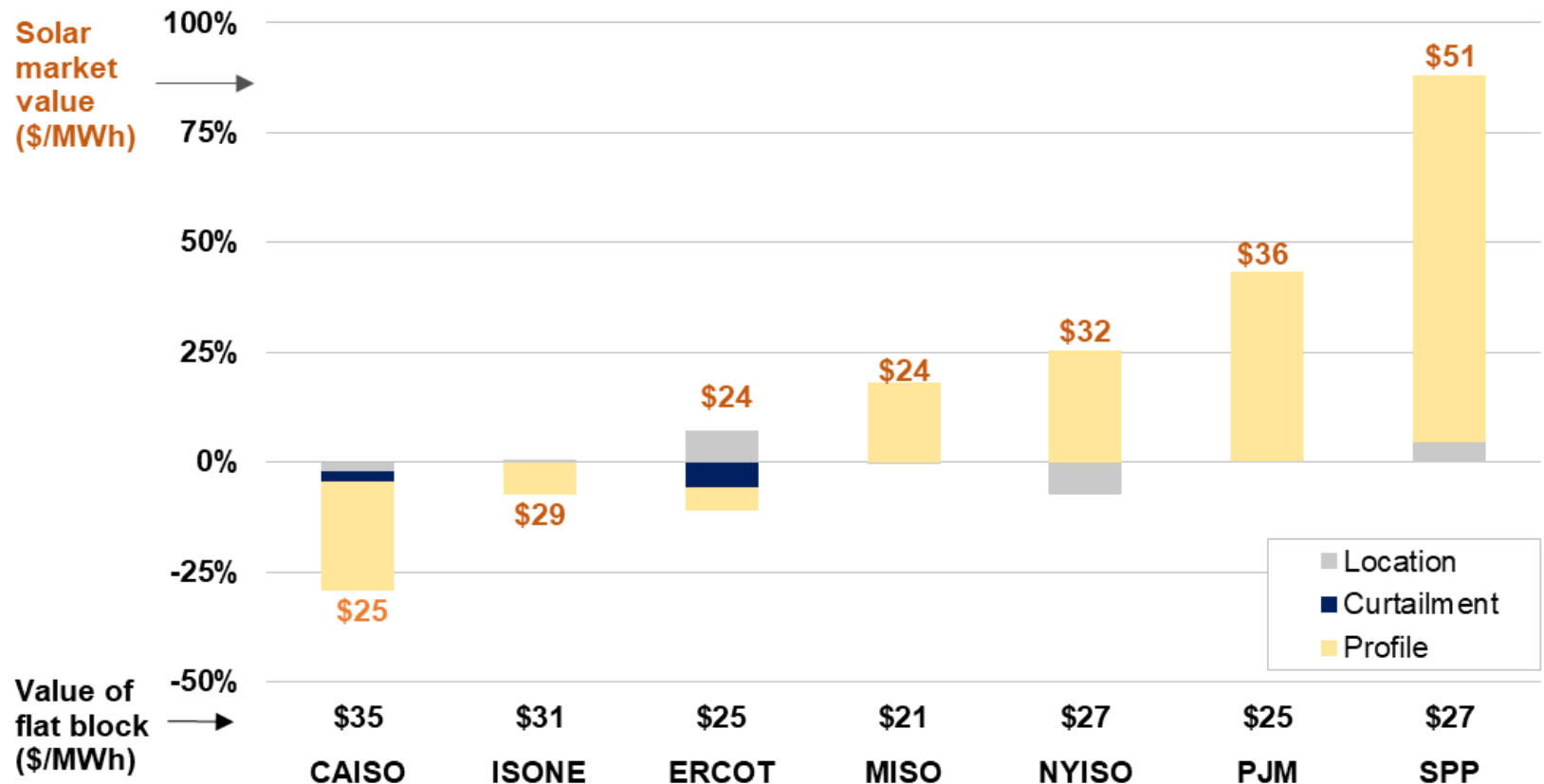
Market value of solar declines with higher solar penetration relative to average prices



*Solar value factor =
wholesale market value of
solar relative to generalized
flat block of power in region;
generalized flat block is
24x7 average price across
all pricing nodes in region*



Market value relative to a flat block is primarily due to the timing of the solar profile, rather than solar location

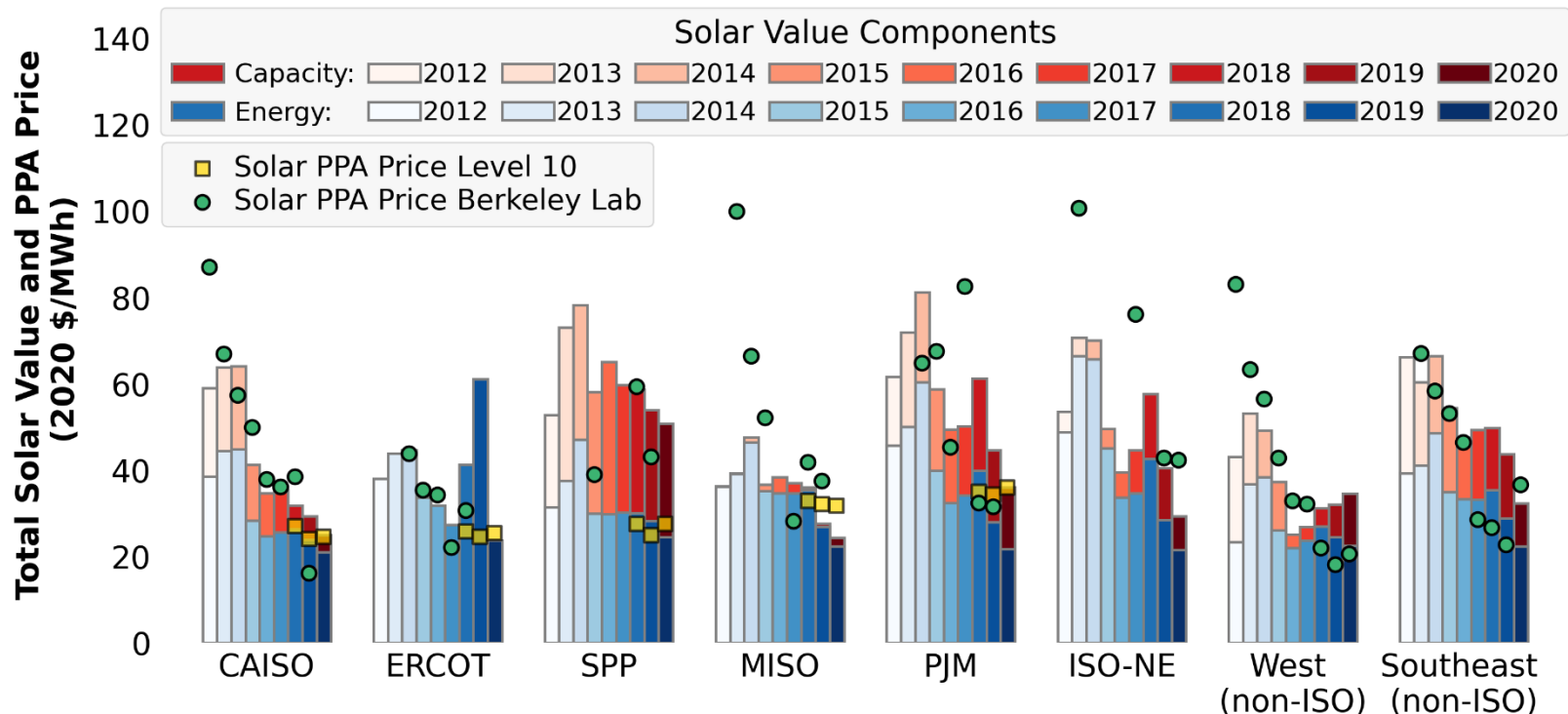


Note: Flat block is 24x7 average price across all pricing nodes in region



Falling costs have kept pace with declining solar value, more or less maintaining solar's competitiveness

Solar Market Value vs. PPA Prices over Time



Note:

- Berkeley Lab's PPA prices are the generation-weighted average levelized PPA prices in real \$ by execution date
- Level 10 PPA prices represent only the 25th percentile of all offers by offer date



Analysis of empirical PV+Storage dispatch show moderate wholesale market value premium of storage

PV+Storage business models are diverse and target many different value streams beyond those monetized in wholesale markets

- **Price signals:** Competitively-set market prices
- **Revenue:** Energy and ancillary services (AS) revenue

Merchant



- **Price signals:** Regulated peak-load pricing schedules
- **Revenue:** Lower transmission costs; potentially AS revenue

Peak-load reducer



- **Price signals:** Incentive program rules;
- **Revenue:** Feed-in tariff, renewable energy credits (RECs), tax credits, grants

Incentive participant

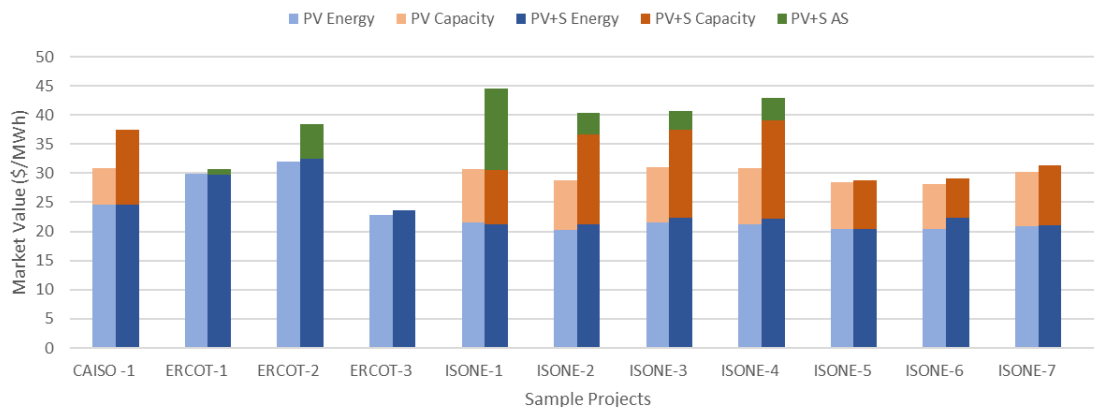


- **Price signals:** Regulated utility tariffs; private operating costs
- **Revenue:** Lower operating costs; resiliency benefits

Large end-user



Wholesale Market Value of PV and PV+Storage Generation in 2020
(Empirical Profiles)



Wholesale market premium for storage addition of PV hybrid projects ranges from \$1 to \$15/MWh.

Including non-wholesale market values streams can increase PV+Storage values substantially:

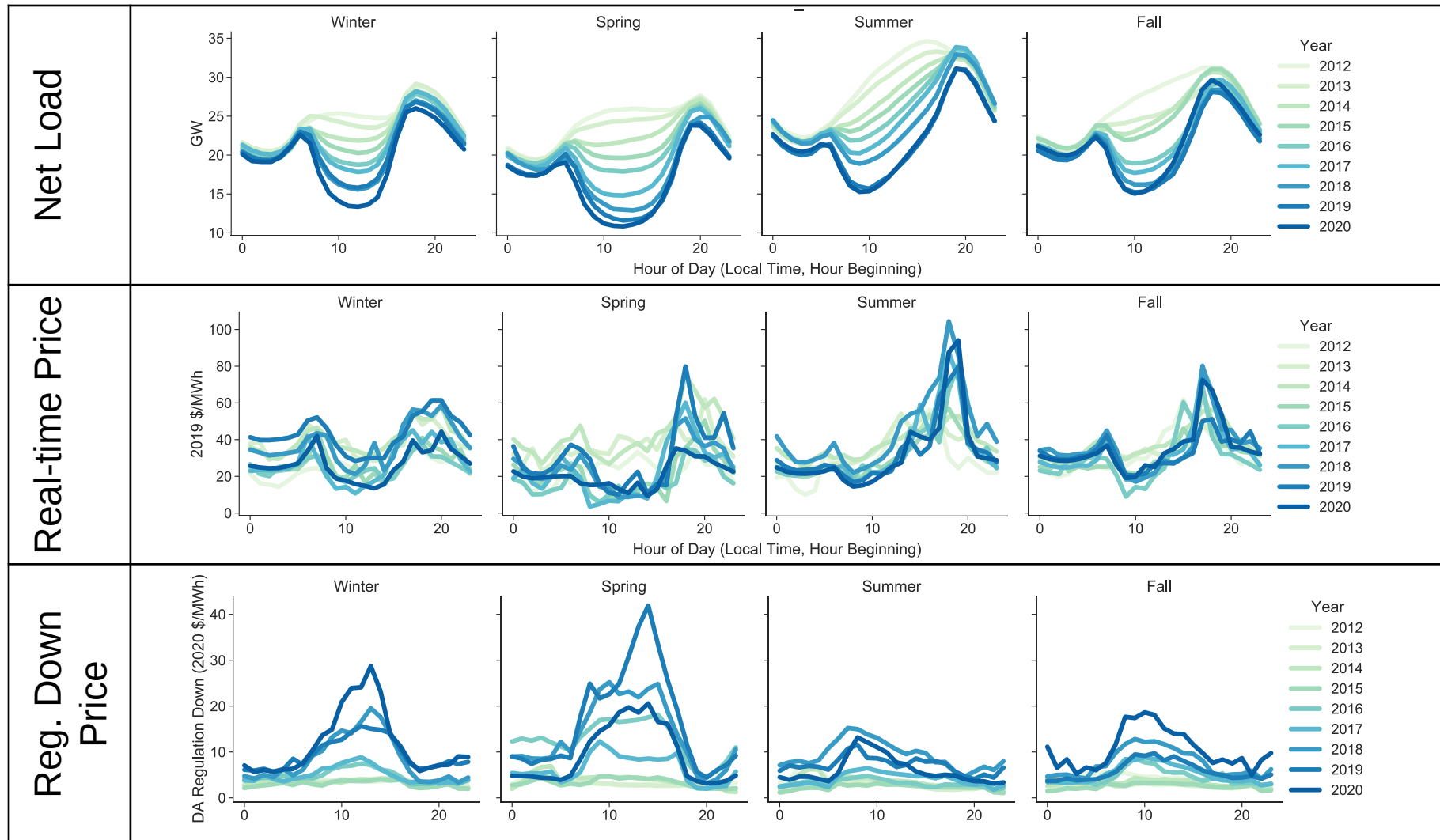
- Berkeley Lab modeling for ISO-NE suggests storage premiums \$100/MWh for peak-load reducers and \$30/MWh incentive participants.
- Total PV+Storage values can approach \$150/MWh in both cases.



Impact of solar on the bulk power system

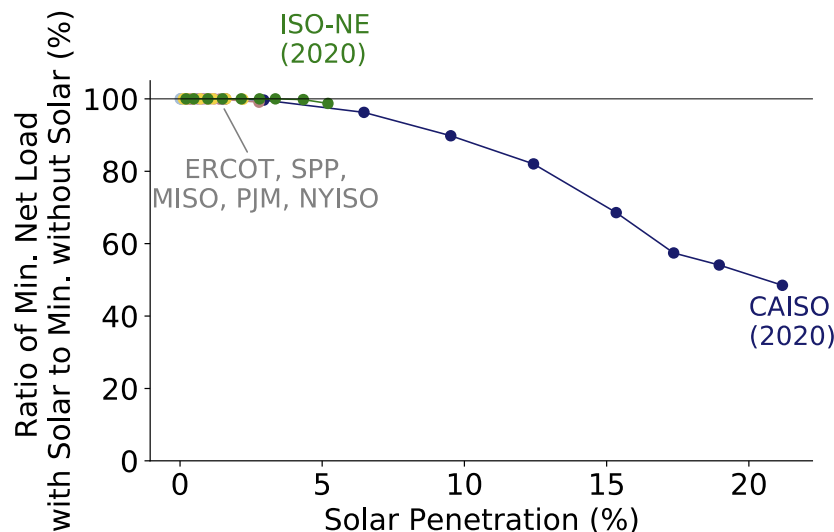


Obvious impacts of solar on CAISO net load and wholesale market prices

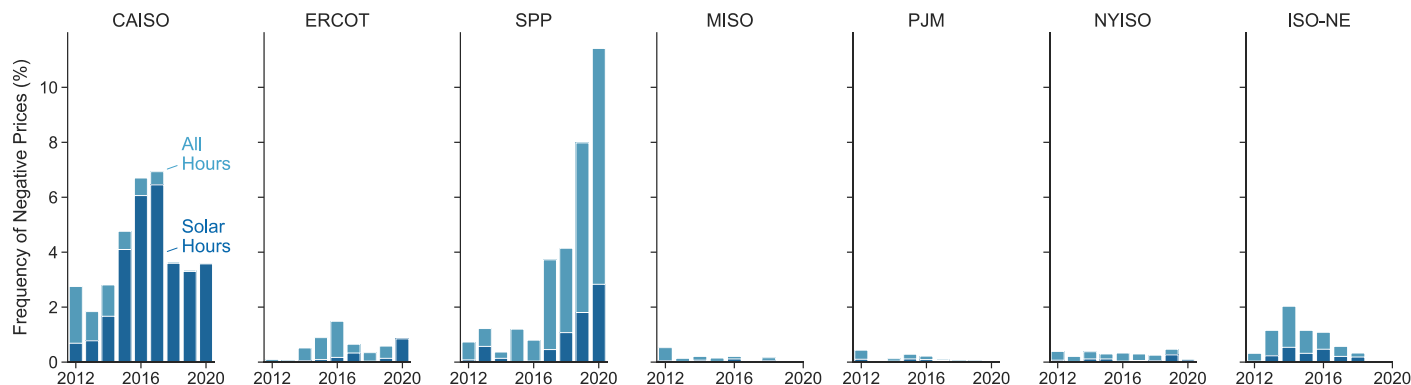


Lower minimum net load due to solar contributes to negative prices in CAISO

Lower minimum net load in CAISO

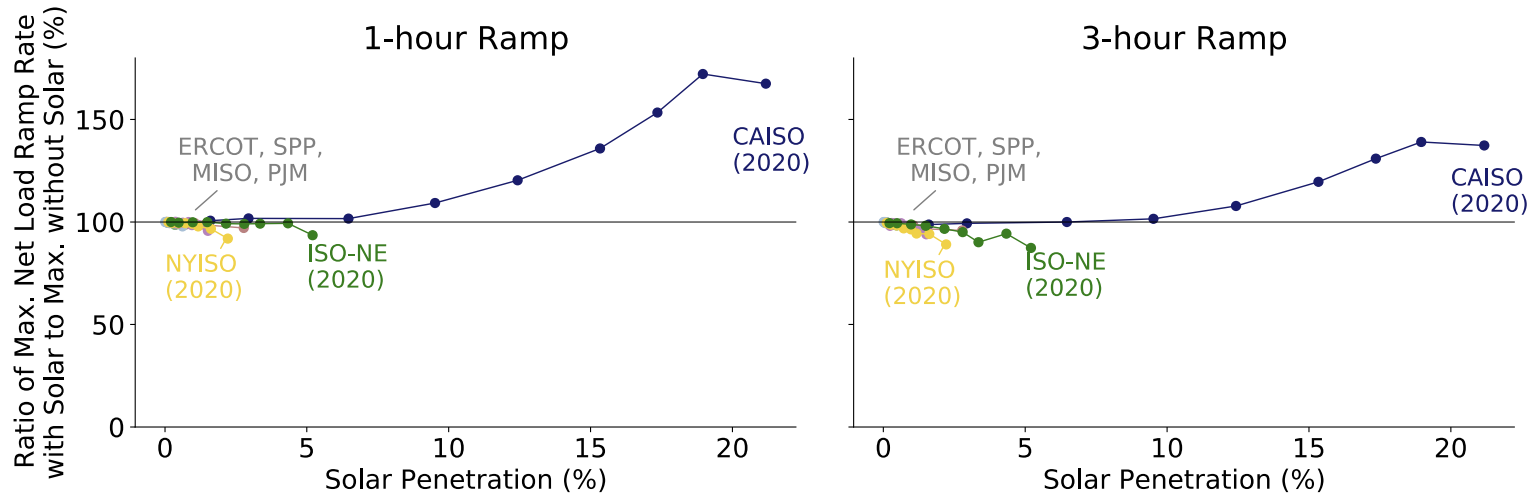


Negative prices occur during solar hours in CAISO

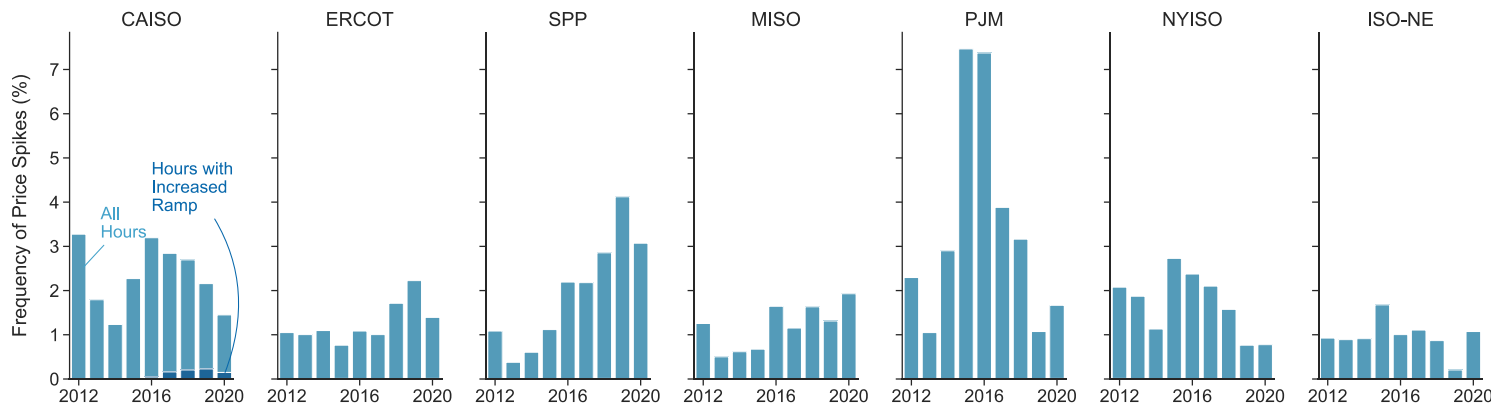


Higher net load ramps due to solar are beginning to contribute to price spikes in CAISO

Higher net load ramp rates in CAISO

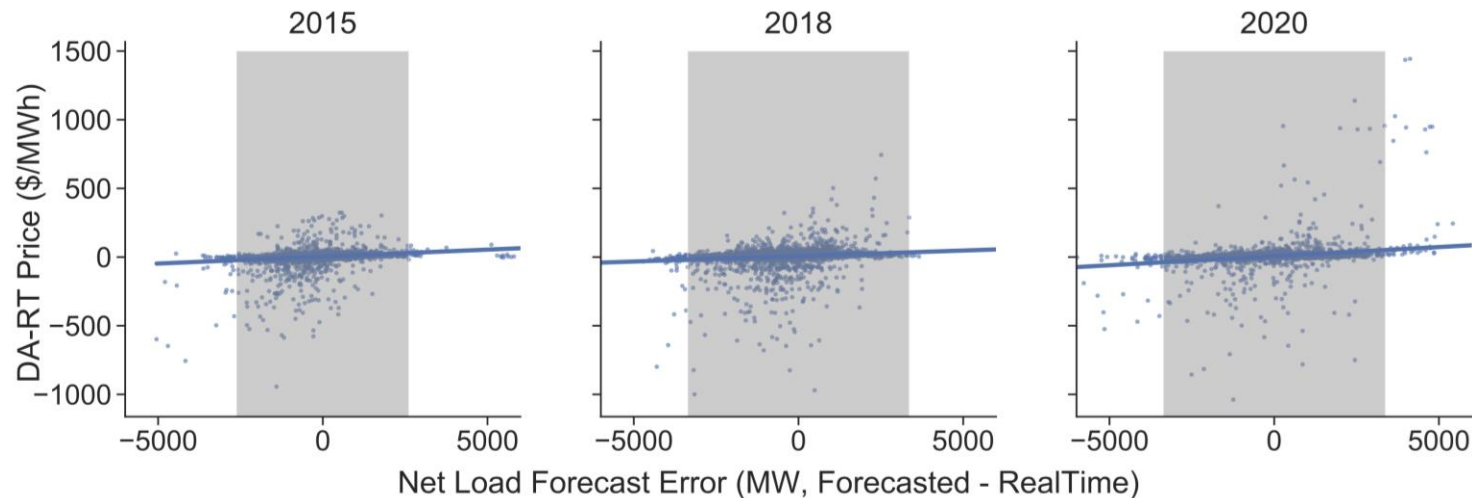
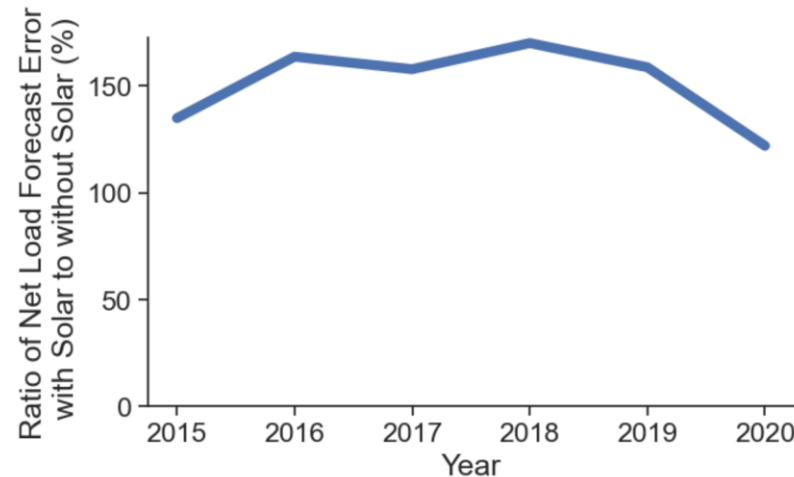


Price spikes beginning to occur at times of high solar ramps in CAISO



Solar forecast errors increase uncertainty between day-ahead market real-time markets in CAISO, though price impacts are limited

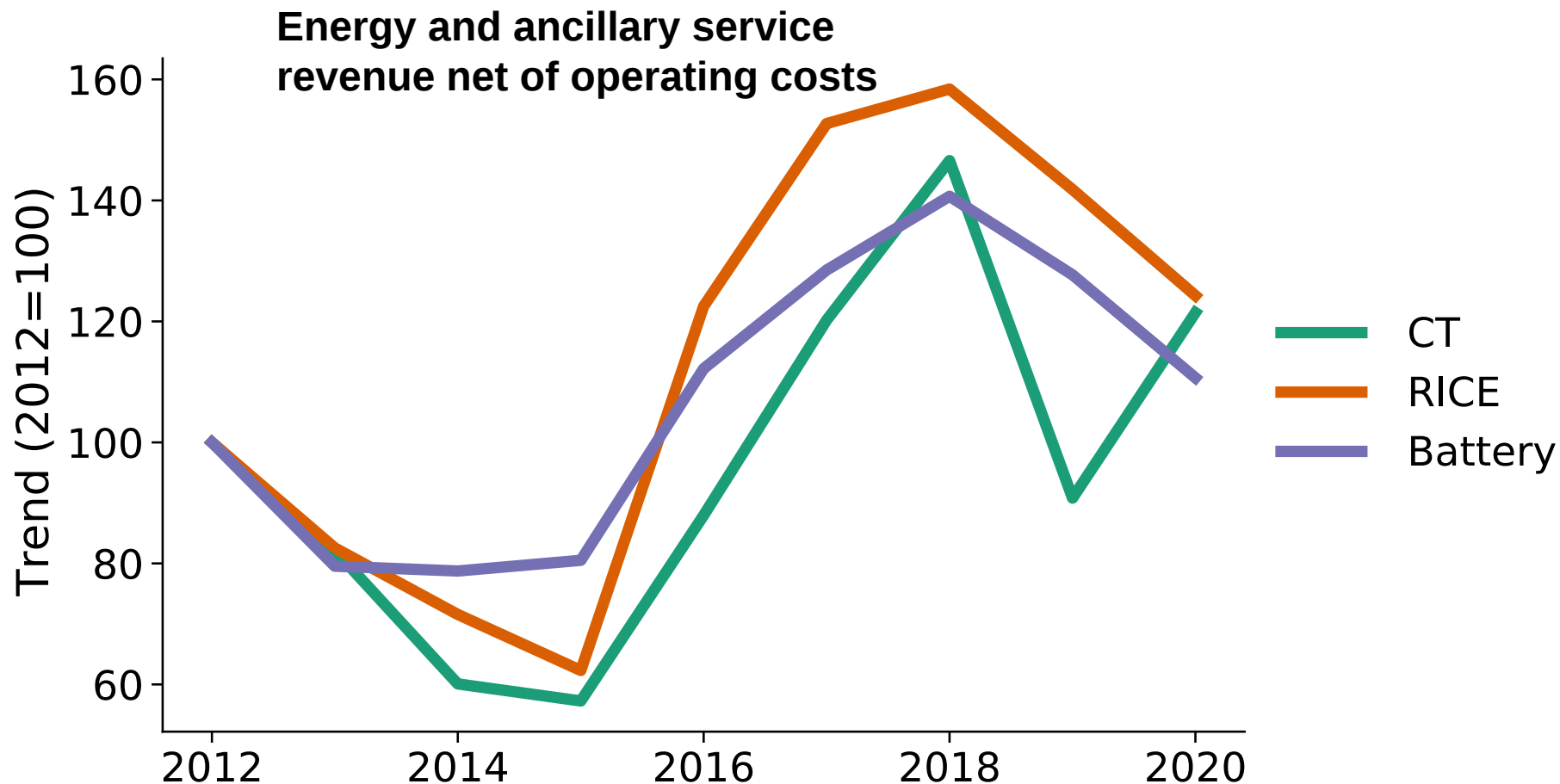
Higher day-ahead forecast errors due to solar in CAISO



Note: The gray-shaded regions include 99% of all net load forecast errors without solar



Incentives to invest in flexible resources in CAISO increased since 2012



Note: Chart shows the trend in net revenue for each technology indexed to its level in 2012

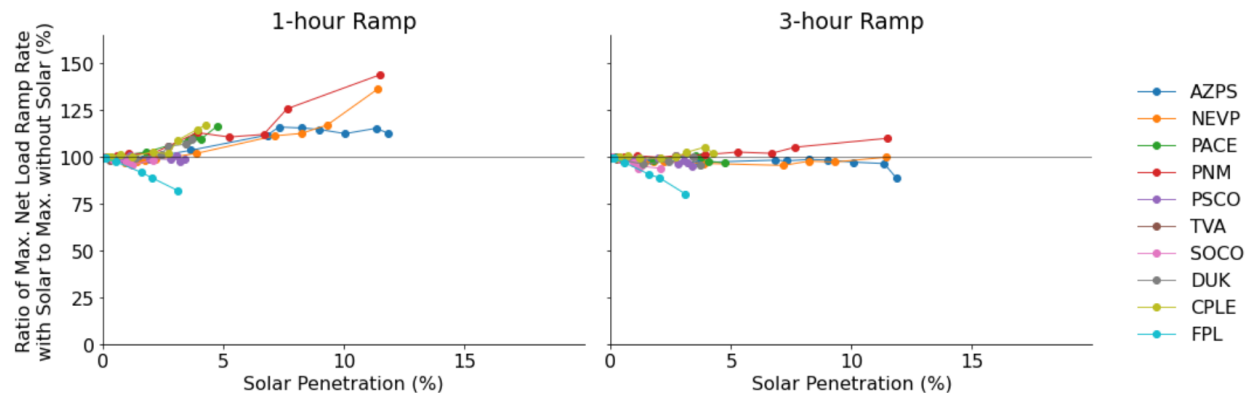
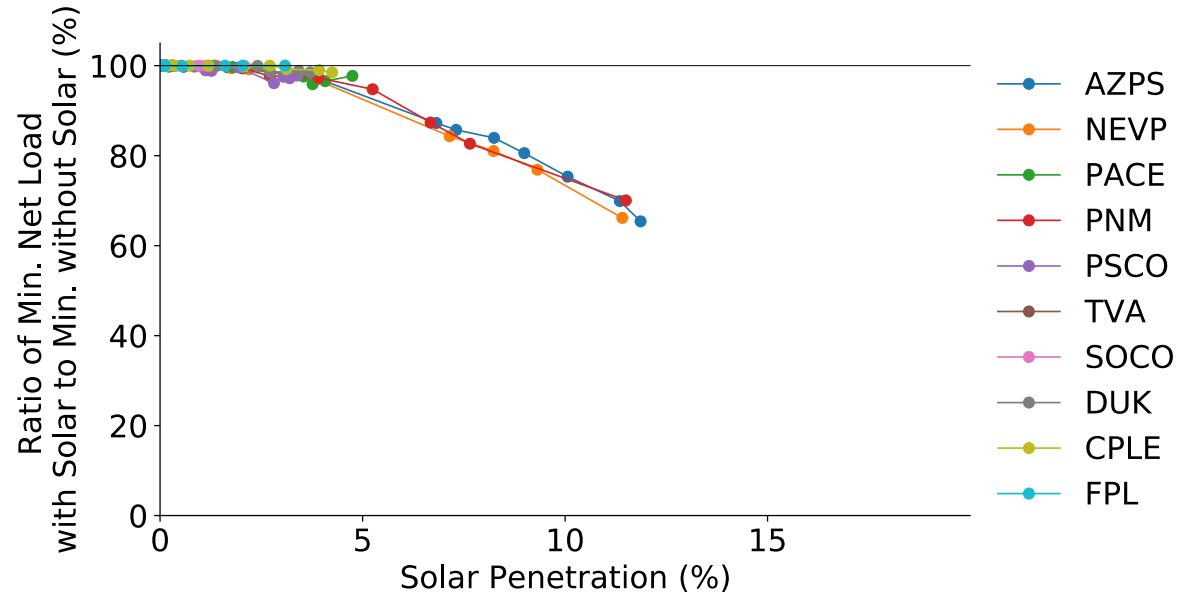


Solar is increasing the need for flexibility in some utilities outside of ISO/RTO regions

Lower minimum net load with solar in the Southwest

Solar growth shifted the minimum net load from nights to days in the spring and late fall

Higher net load ramp rates, especially in 1-hour net load ramps



Solar production on days of high risk of outages relative to average solar production in the same month

NERC System Risk Index (SRI): A high SRI indicates a day with severe challenges with generating and delivering power to U.S. loads

Event Type	SRI	Date	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Heatwave	TBD	2020-08-14	 0.9						
Heatwave	TBD	2020-08-15	 0.8						
Thunderstorm Derecho	8.87	2012-06-29				 0.9	 1.1	 1.1	 1.0
Severe Weather	4.40	2015-06-30	 0.8						
Coincidental Generator Outages	3.49	2016-06-20	 1.1		 0.7	 1.1	 1.2		
Severe Weather	3.38	2015-07-18	 0.5			 1.0			
Thunderstorms/Showers	3.30	2015-07-20	 0.8	 1.0	 0.9	 0.9	 1.1	 1.1	 1.0
Severe Weather	3.24	2015-06-23					 1.0	 0.9	 0.8
Severe Weather	3.20	2015-07-13					 0.9		
Summer Weather	3.10	2015-07-30	 0.8	 1.0	 1.0	 1.1	 0.8	 0.7	 0.7
Severe Weather	3.06	2016-08-11					 1.1		
Polar Vortex	11.14	2014-01-07		 0.9			 1.6		
Polar Vortex	8.02	2014-01-06		 0.7			 0.6		
Hurricane Sandy	7.17	2012-10-30						 0.5	 0.5
Hurricane Sandy	7.04	2012-10-29						 0.2	 0.2
Storm, Flooding, Straightline Winds	4.45	2015-11-17	 1.2						
Winter Storm Riley	4.22	2018-03-02					 0.1	 0.1	 0.1
Winter Storm Grayson	4.06	2018-01-02		 0.4	 0.9	 1.0	 1.4	 1.1	 1.0
Winter Storm Avery	4.05	2018-11-15					 0.1	 0.2	 0.4
Winter Storm Juno	3.86	2015-01-08						 1.3	 1.4
Excessive Rainfall, Thunder/Lightning Storm	3.79	2015-10-23		 0.5	 0.6				
Coincidental Generator Outages	3.61	2017-05-01					 0.8		
Winter Storm	3.34	2019-02-24					 0.4		
Winter Storm Jayden	3.29	2019-01-30			 1.3	 1.3	 1.6		
Saddleridge Fire	3.25	2019-10-11	 1.1						
Winter Storm Indra	3.20	2019-01-21					 1.7	 1.2	 1.1
Winter Storms Quiana and Ryan	2.93	2019-02-25					 1.8		

- Suggests solar, at least during daytime hours, mitigates stressful periods in the summer
- Contributions of solar in the non-summer months are more mixed depending on the event



Other impacts of solar on the bulk power system

Inverter performance during disturbances

- NERC identified potential reliability issues associated with bulk power system-connected PV resources and their inverter settings
- Noted loss of solar generating resources during disturbances to the bulk power system
- Includes both tripping-related challenges and response to large voltage disturbances

Maintenance of adequate frequency response

- CAISO identified challenges with maintaining adequate frequency response as the share of inverter-based renewables increases
- CAISO contracts with neighboring utilities to transfer a portion of its frequency response obligation, actions are not included in market prices

Visibility and representation of DPV in operations and planning

- NERC identified gaps in representing the potential impacts of DER on the bulk power system
- Recommendations include:
 - Modeling these resources explicitly in planning studies rather than netting them with load
 - Improving representation of the resources in power system models and sharing data across the transmission and distribution interface



Summary

- Effects of solar growth on net load, wholesale prices, and solar's market value can readily be seen in California; effects are small in other organized markets where solar penetrations are at (ISO-NE) or below 5%
- California has low net load during spring days and high ramps as the sun sets in the evening, with similar patterns in real-time prices
- Negative prices during solar hours, price spikes in solar ramping hours, and higher prices for regulation down reserves all suggest growing challenges with providing flexibility, though broader shifts in the system can mitigate some of these challenges
- The decline in solar's wholesale market value in California has been matched by reductions in the cost of solar, thus maintaining solar's overall net-value proposition
- In many markets outside California, costs have often declined faster than market value, maintaining solar's overall competitive position.
- Impacts on prices can also increase the attractiveness of storage and other flexible resources to meet early-evening net-load peaks and ancillary service requirements



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