BERKELEY LAB

ELECTRICITY MARKETS & POLICY

Solar-to-Grid

Trends in System Impacts, Reliability, and Market Value in the United States with Data Through 2019

Andrew D. Mills, Joachim Seel, Dev Millstein, James Hyungkwan Kim, Mark Bolinger, Will Gorman, Yuhan Wang, Seongeun Jeong, Ryan Wiser

February 2021

This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under the Solar Energy Technologies Office Award Number 34170 and Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

ENERGY TECHNOLOGIES AREA | ENERGY ANALYSIS AND ENVIRONMENTAL IMPACTS DIVISION | ELECTRICITY MARKETS & POLICY

SEE PROJECT PAGE FOR MORE INFORMATION: https://emp.lbl.gov/renewable-grid-insights

Disclaimer

Copyright Notice

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)

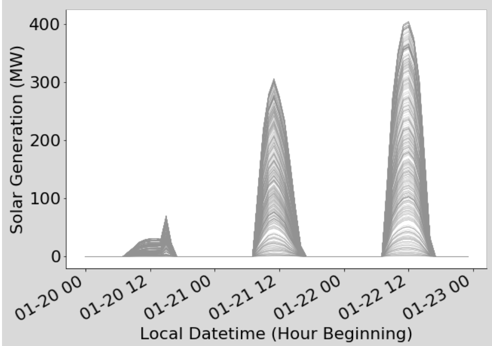
Distributed PV (DPV)

Residential and Non-Residential

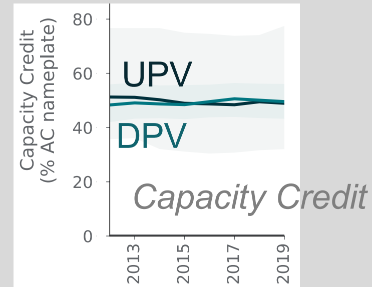
EIA Form 861 by State (<1 MW)

Hourly Solar Generation Profiles

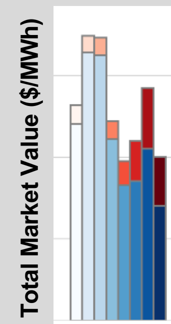
Solar Generation at Individual Plants



Contribution to Reliability



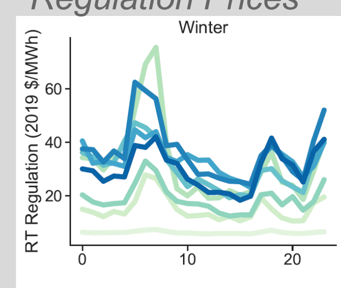
Market Value



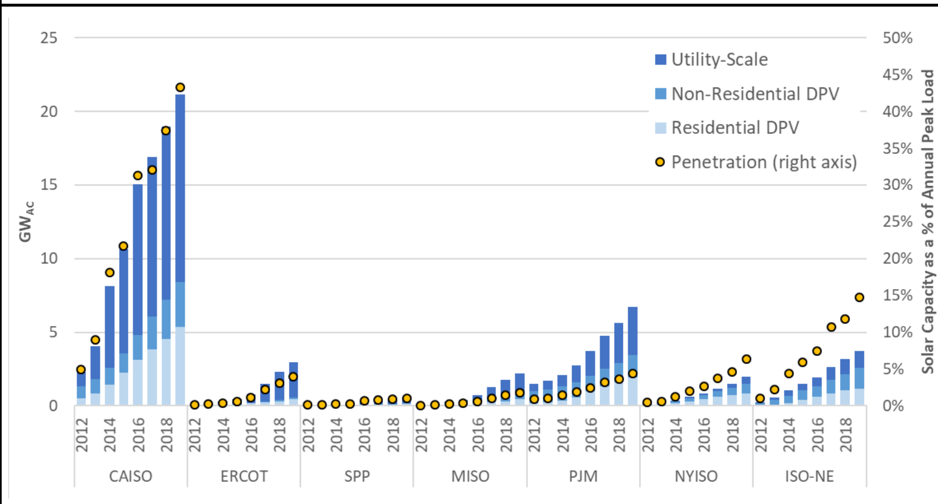
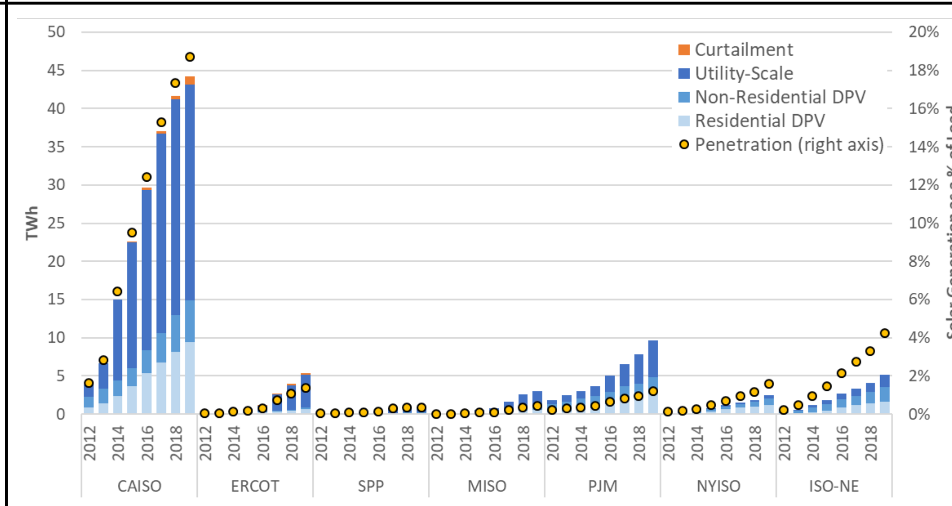
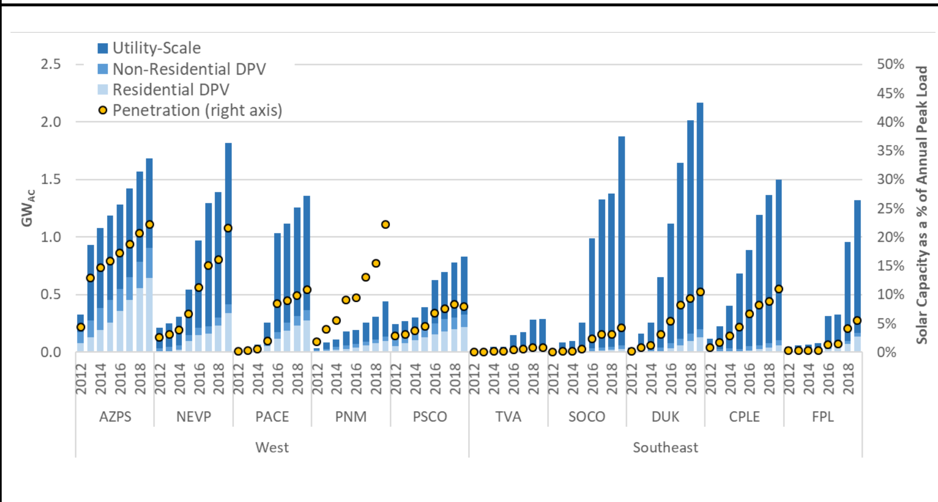
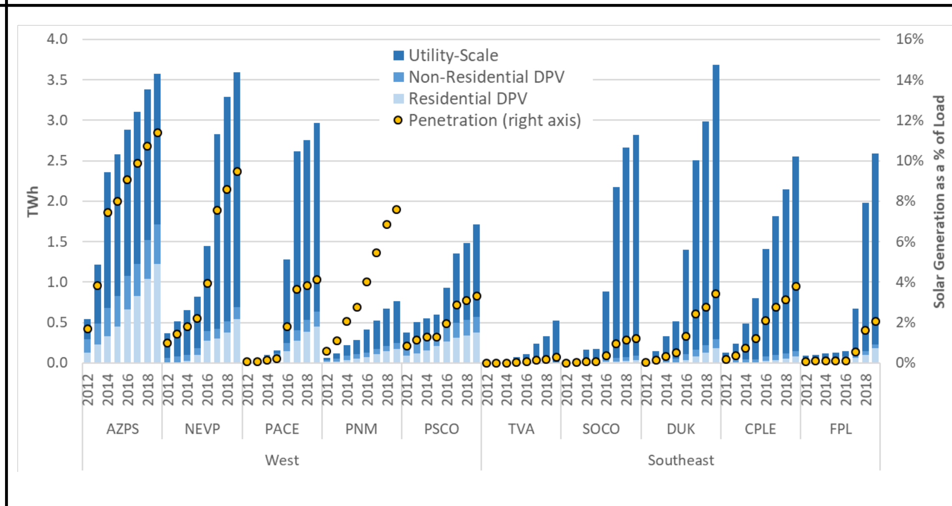
Capacity and Energy Value

Bulk System Impacts

Regulation Prices



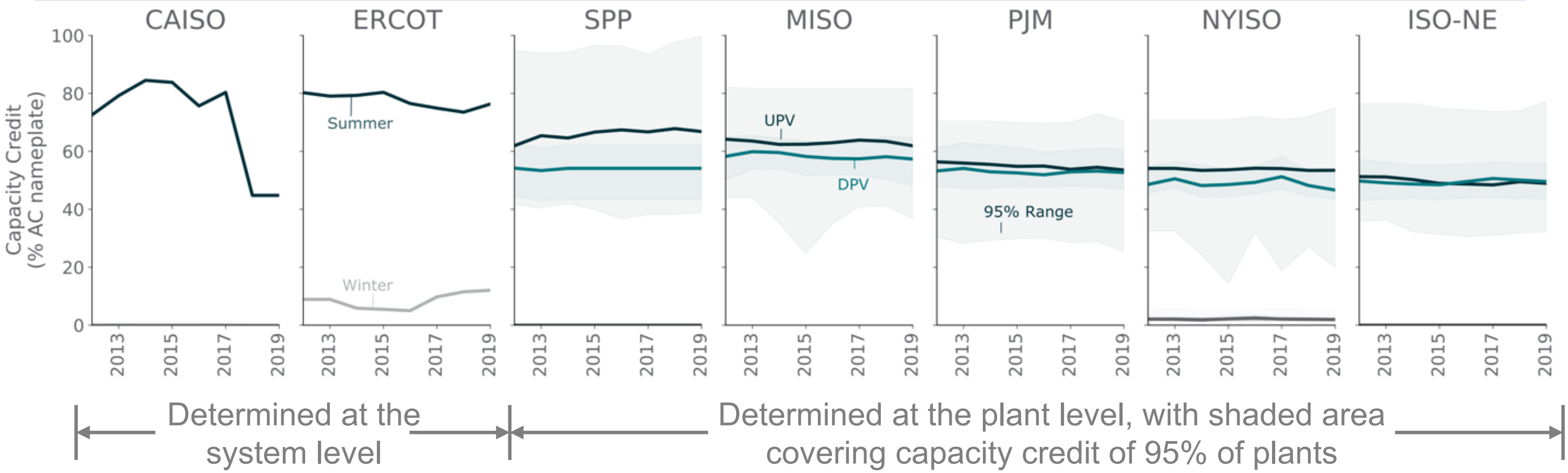
Solar deployment in CAISO far exceeds the level in other ISOs

	Capacity	Generation
ISOs		
Select Utilities		

Capacity credit of solar

Average summer capacity credits in 2019 range from 45–76%, 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 filed with FERC to do the same in 2021.



	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

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

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

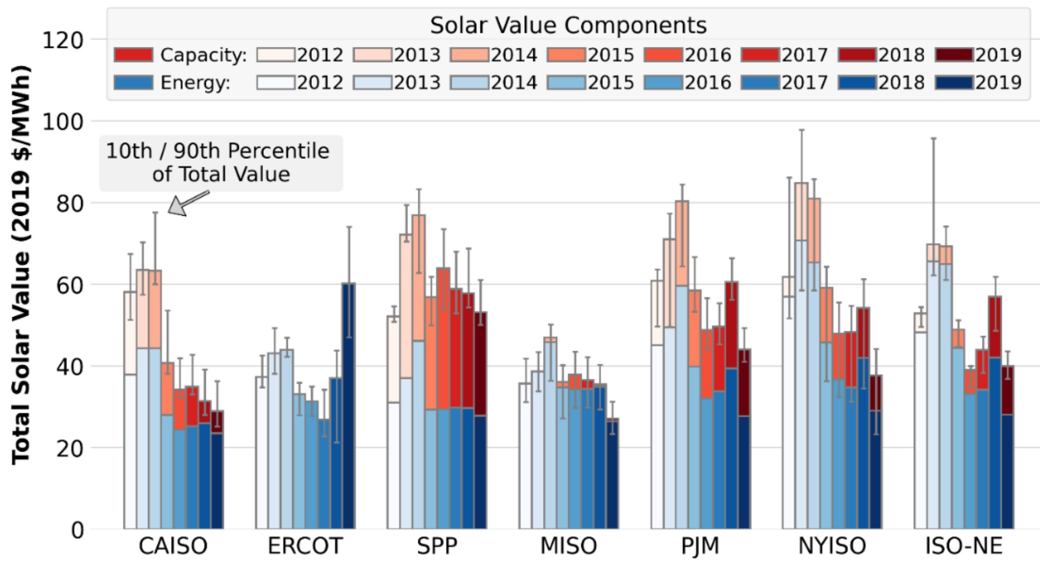
Capacity Value

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

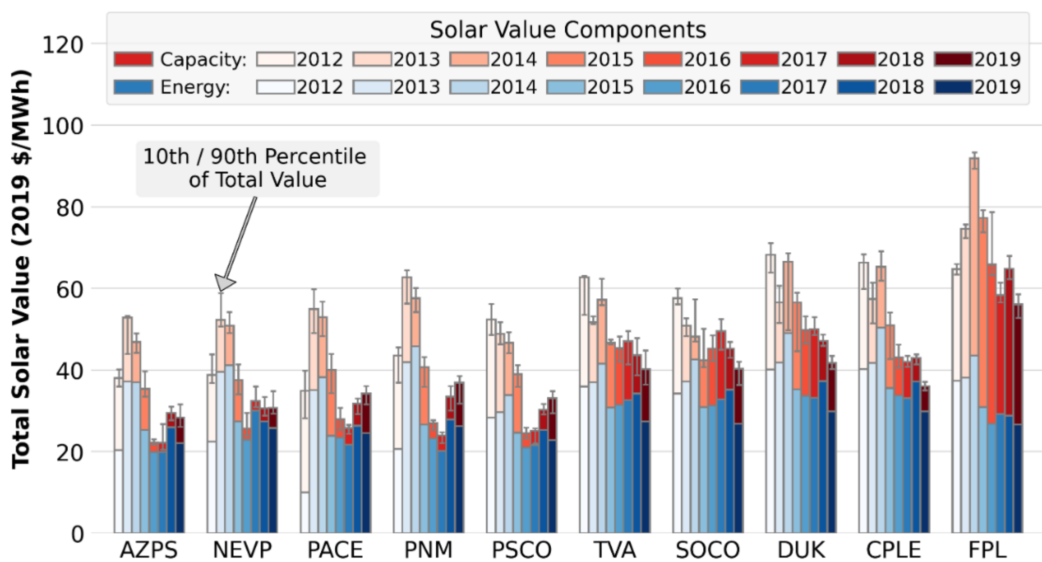
- Capacity credit based on plant-level profile; varies by month, season, or year
- Capacity prices from respective ISO region; prices vary by month, season, or year
- Estimate bilateral capacity prices for regions without organized capacity markets
- Focus on annual value of solar from all sectors
- 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

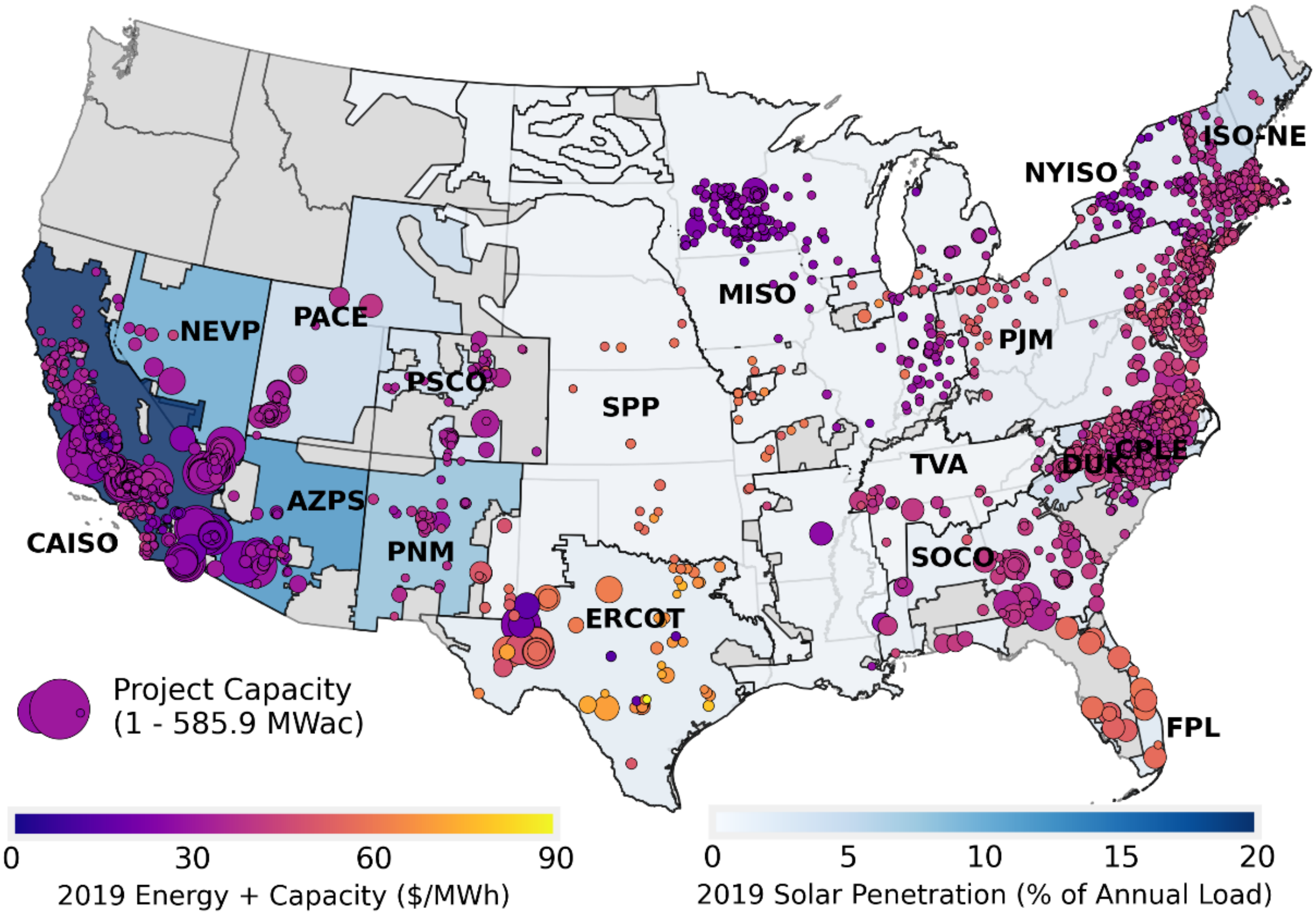
Variations in average energy and capacity prices largely drive differences in the market value of solar



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

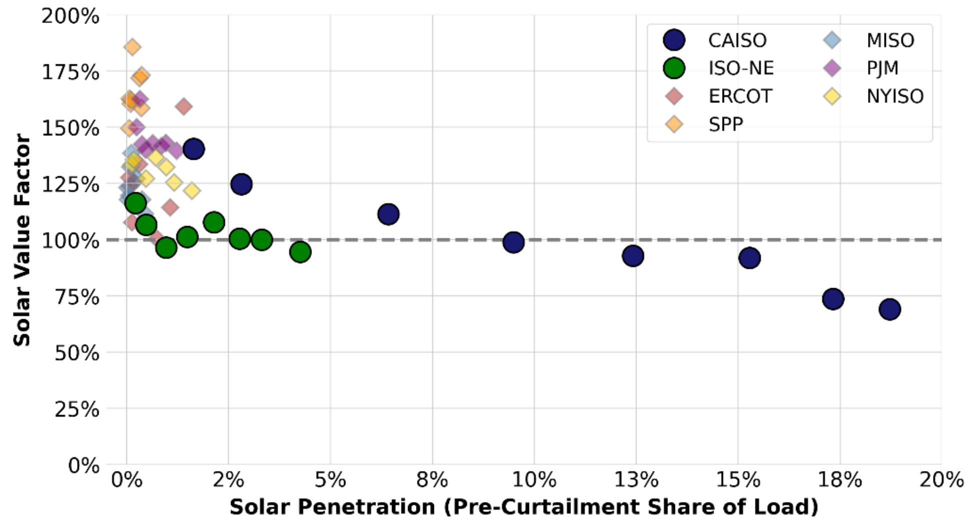


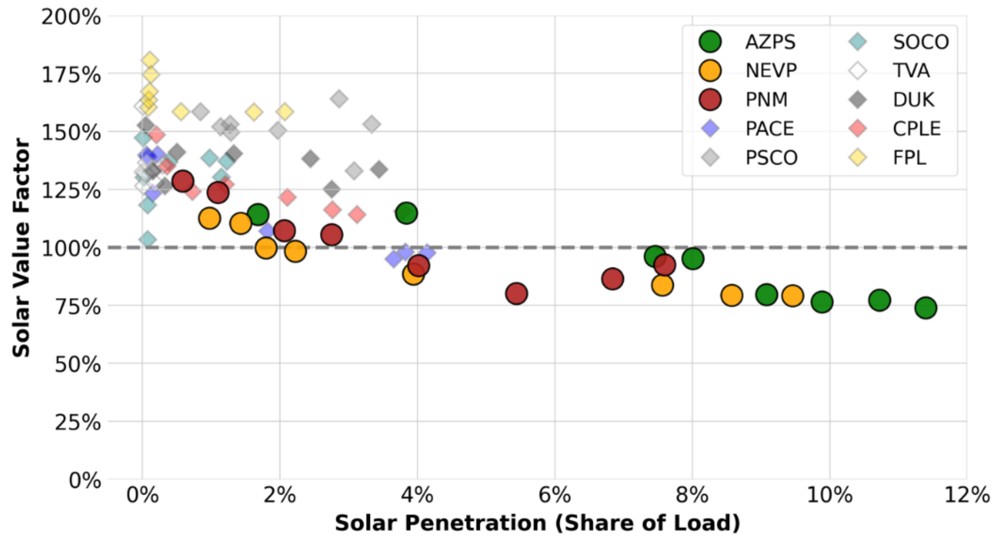
Wholesale market value of solar, by plant in 2019



Note: Only plants larger than 1 MW are shown

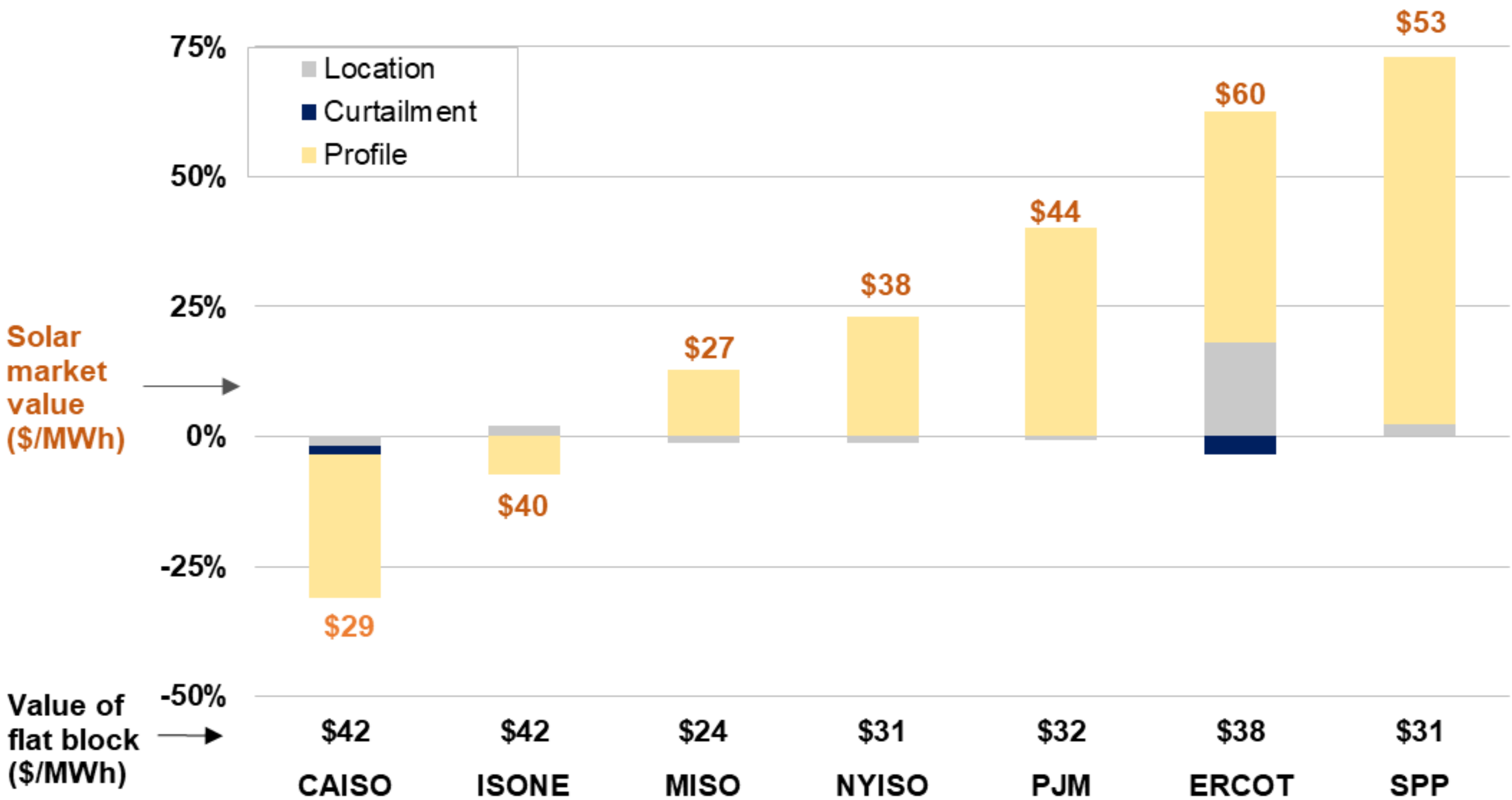
Market value of solar declines with higher solar penetration relative to average prices





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

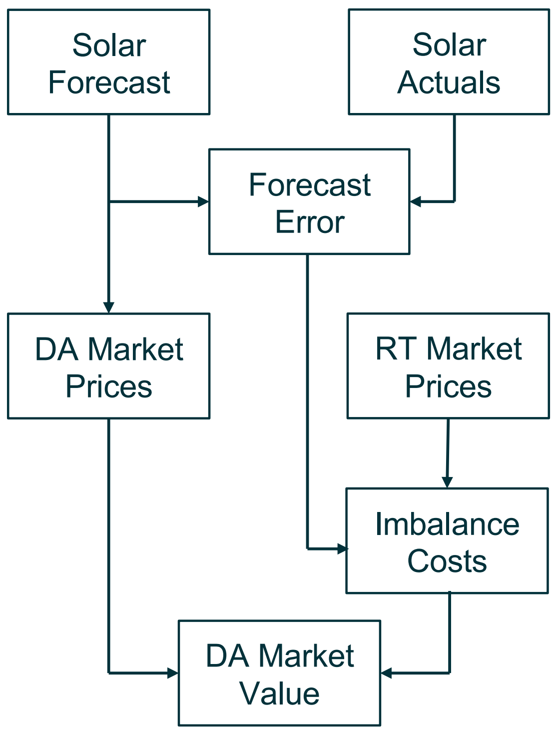


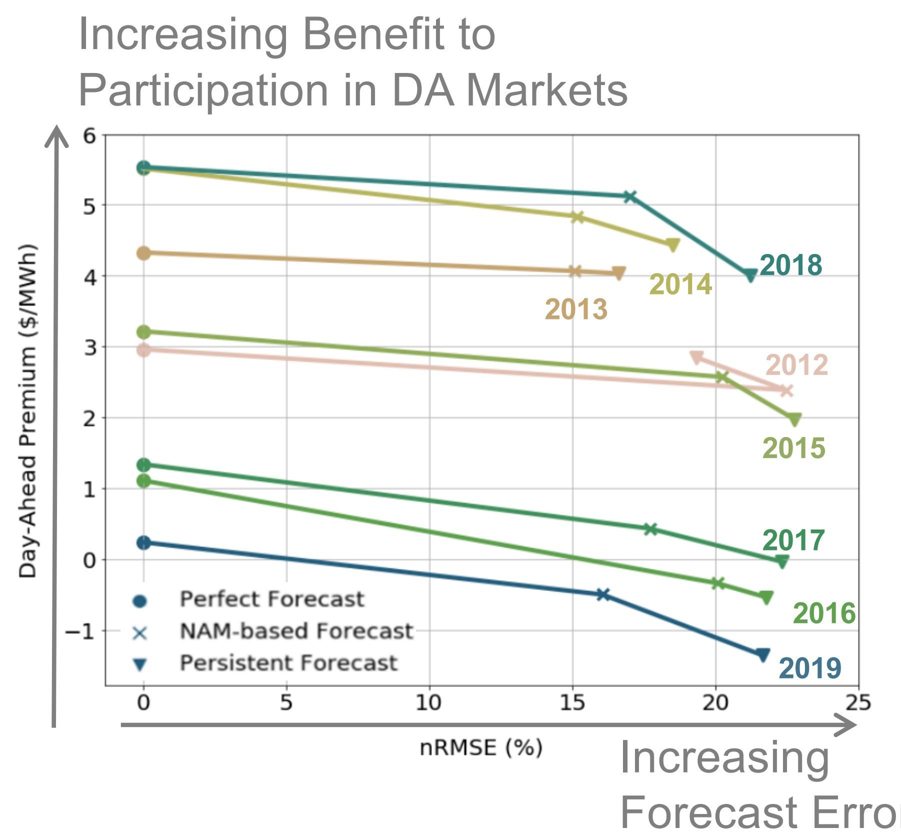
Note: Flat block is 24x7 average price across all pricing nodes in region

Benefit of participating in day-ahead (DA) markets is insensitive to forecasting skill

Only RT Market

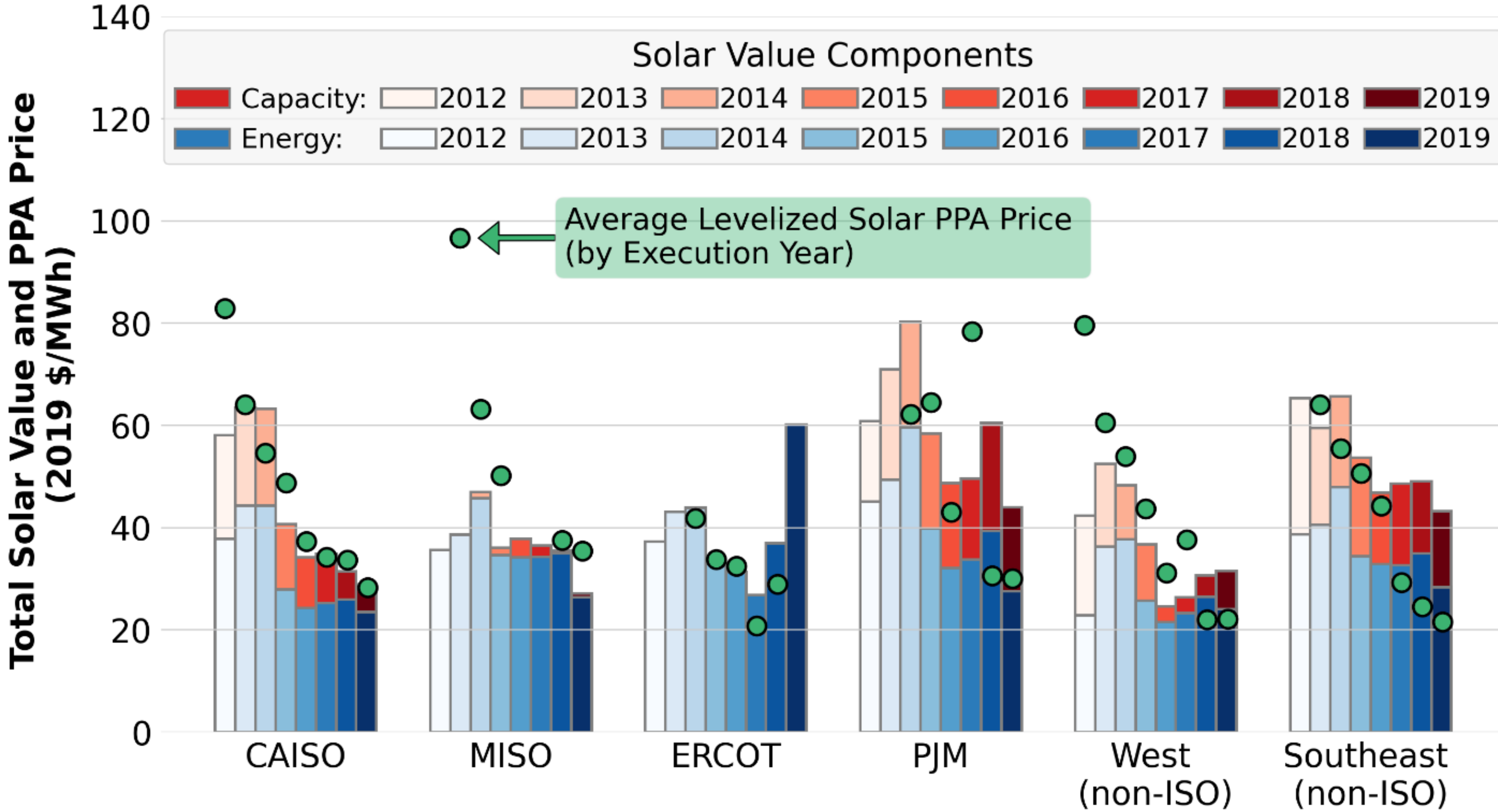
DA Market Participant





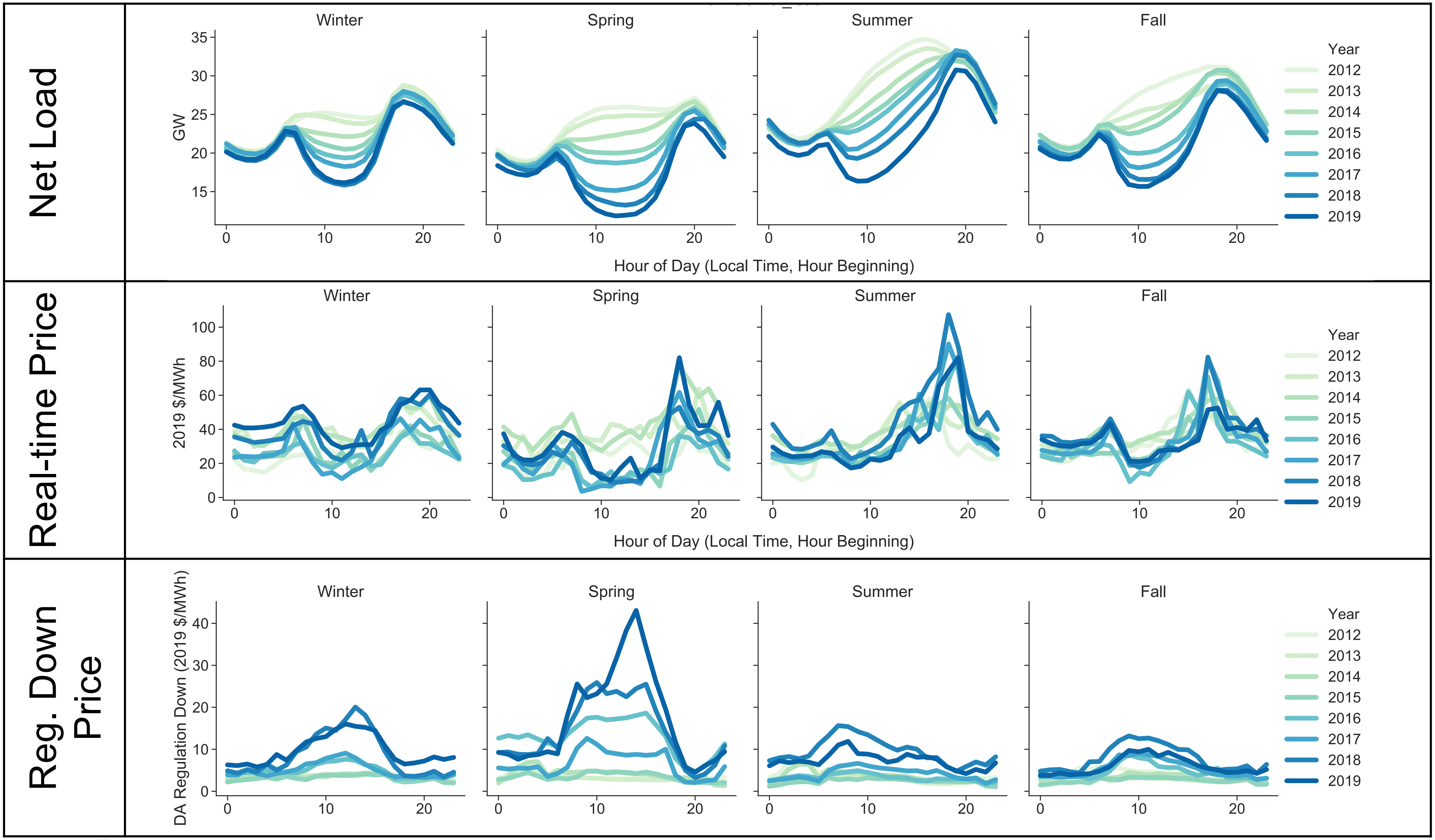
Note: Previous energy value results were based on real-time market value. Participation in the day-ahead market decreased value by $0.50/MWh in 2019 when using the NAM-based forecasts.

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



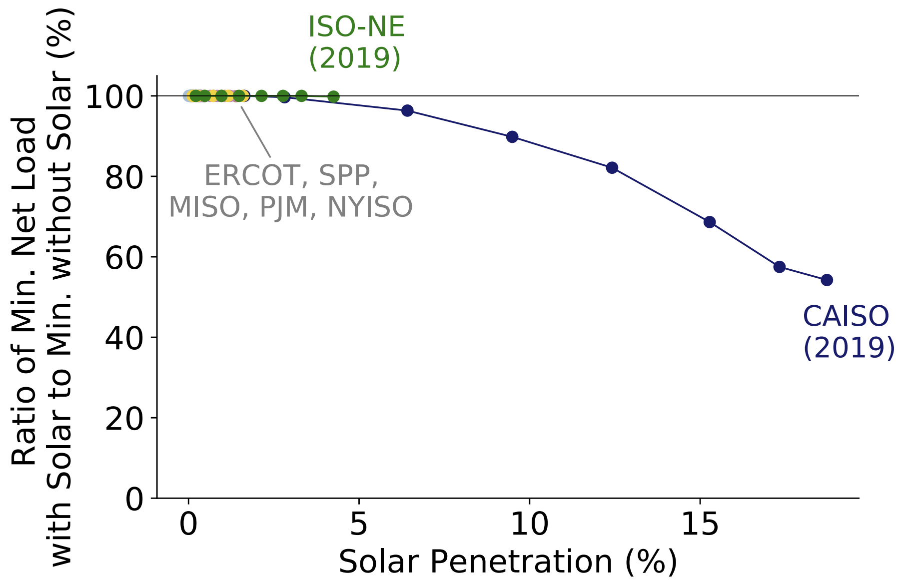
Impact of solar on the bulk power system

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

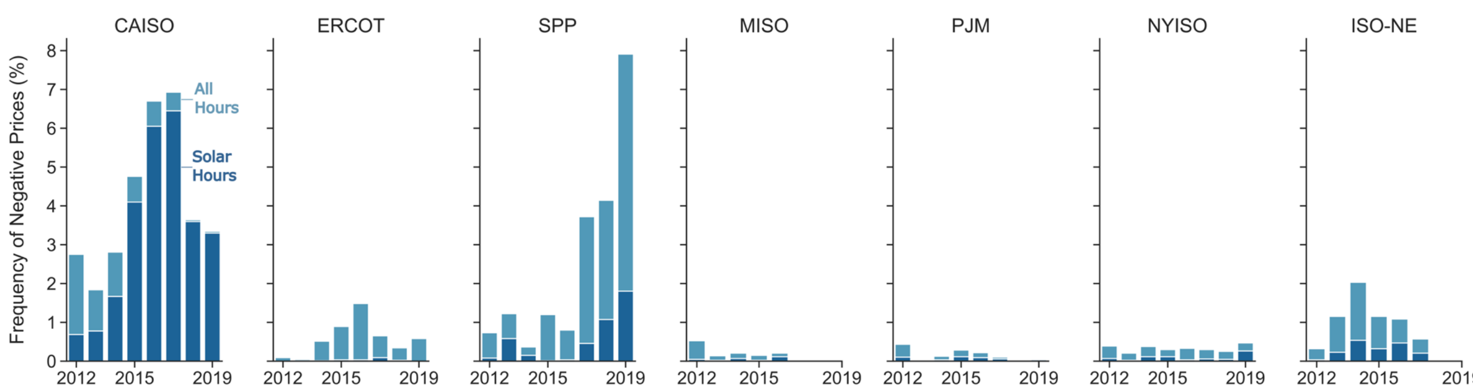


Lower minimum net load due to solar contributes to negative prices in CAISO

Lower minimum net load in CAISO

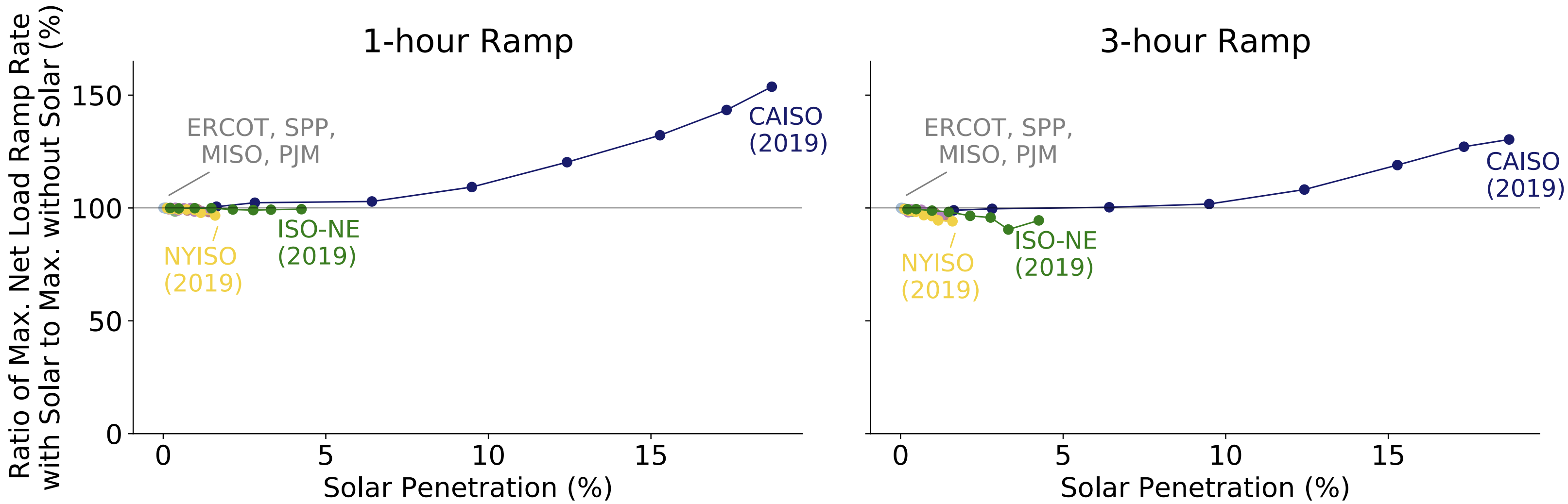


Negative prices occur during solar hours in CAISO

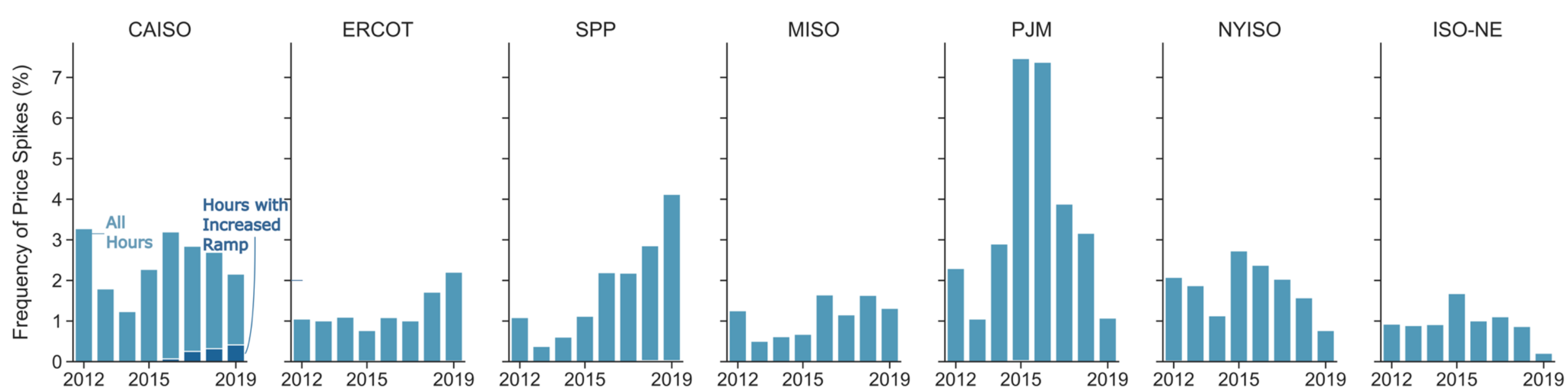


Higher net load ramps due to solar are beginning to contribute to price spikes in CAISO

Higher net load ramp rates in CAISO

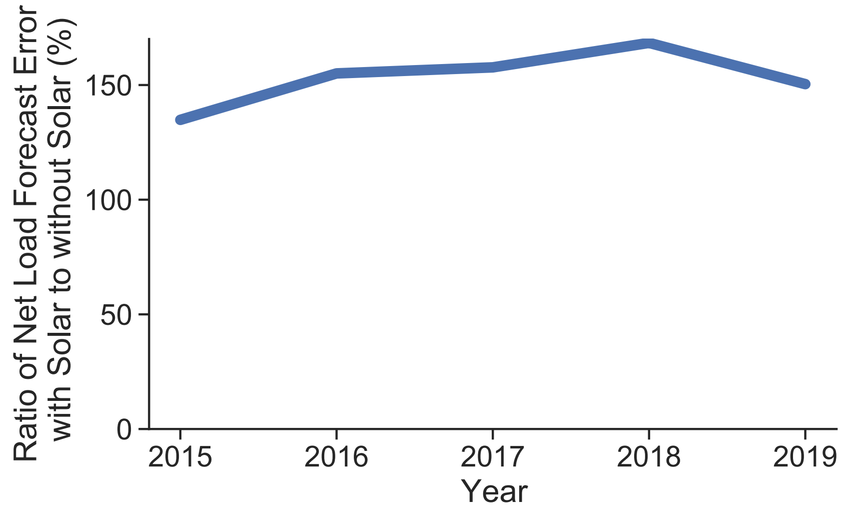


Price spikes beginning to occur at times of high solar ramps in CAISO

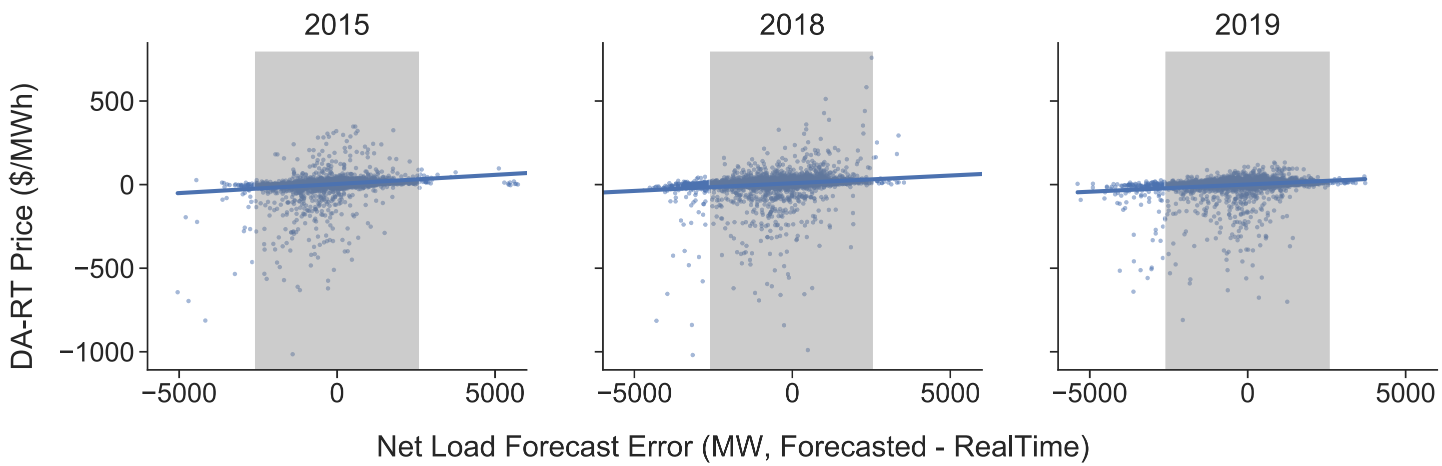


Solar forecast errors increase uncertainty between day-ahead market real-time markets in CAISO, though price impacts are limited

Higher day-ahead forecast errors due to solar in CAISO

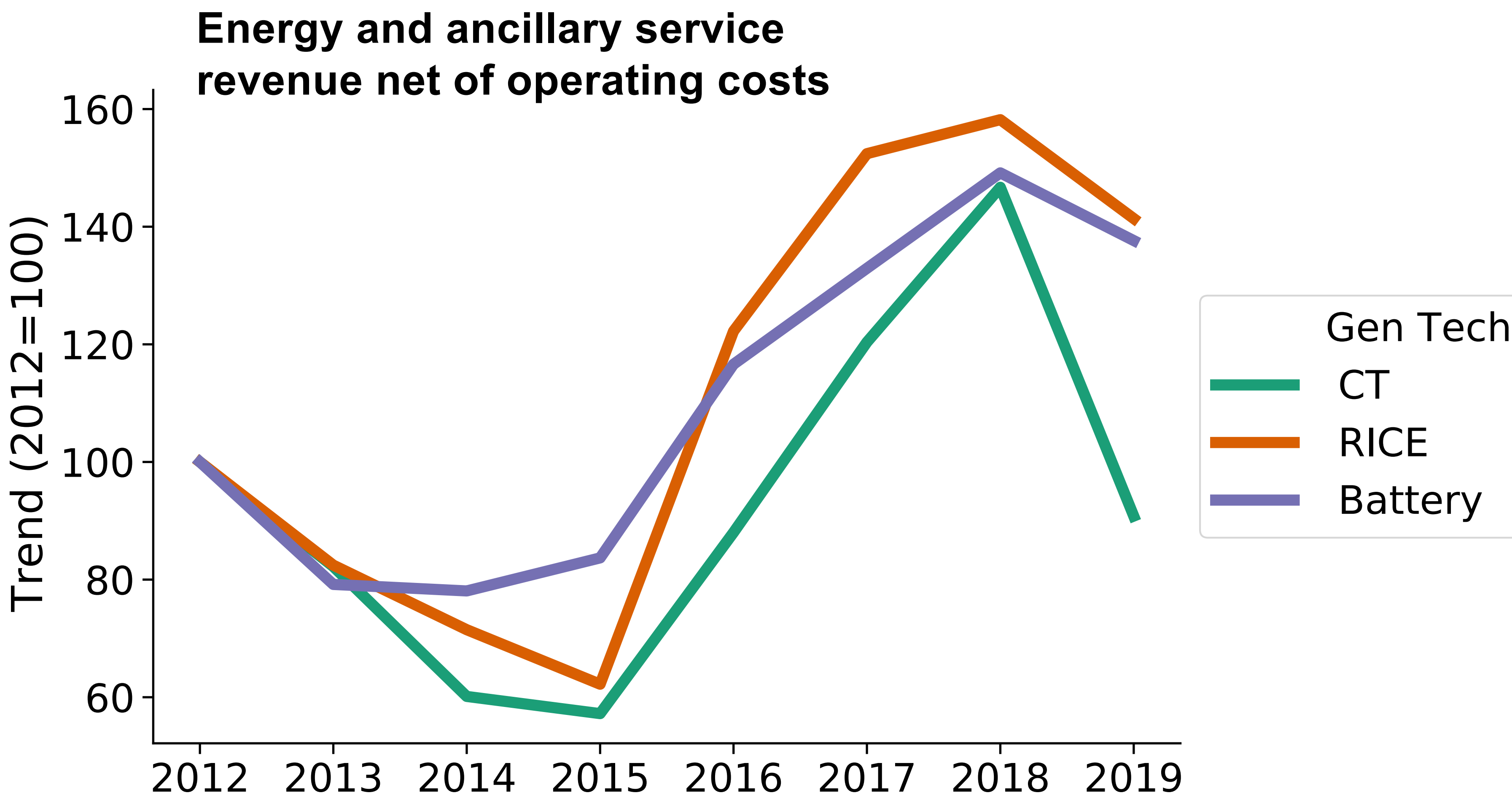


Little evidence that abnormally high net load forecast errors consistently drive extreme differences in the DA and RT prices



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

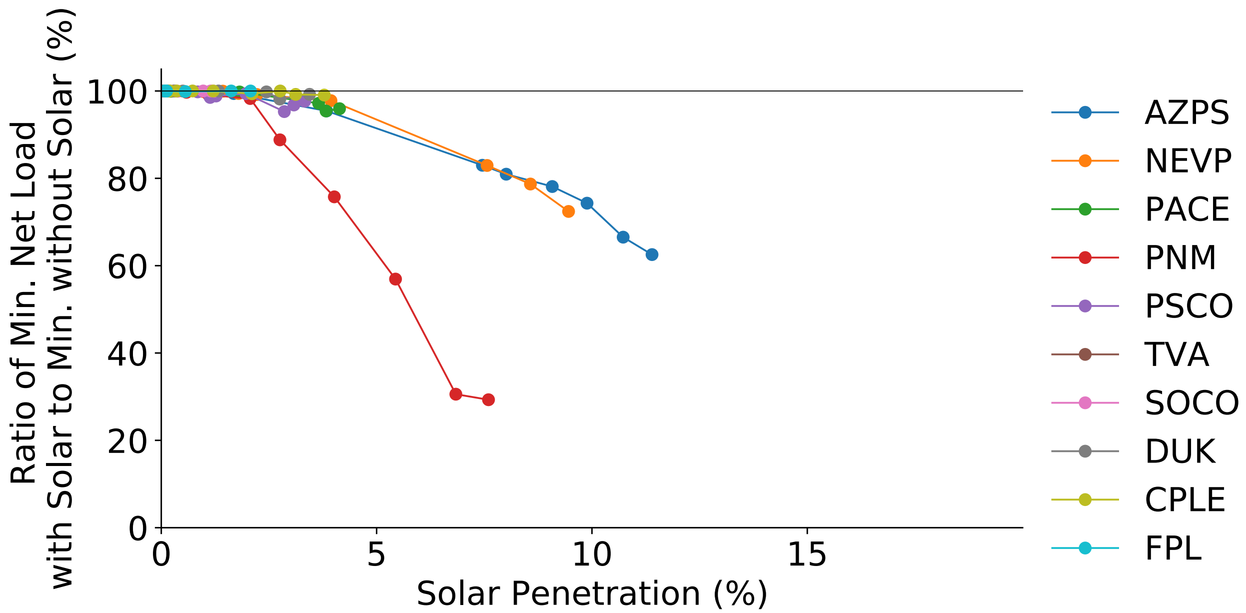


Note: Chart shows the trend in net revenue for each technology indexed to its level in 2012

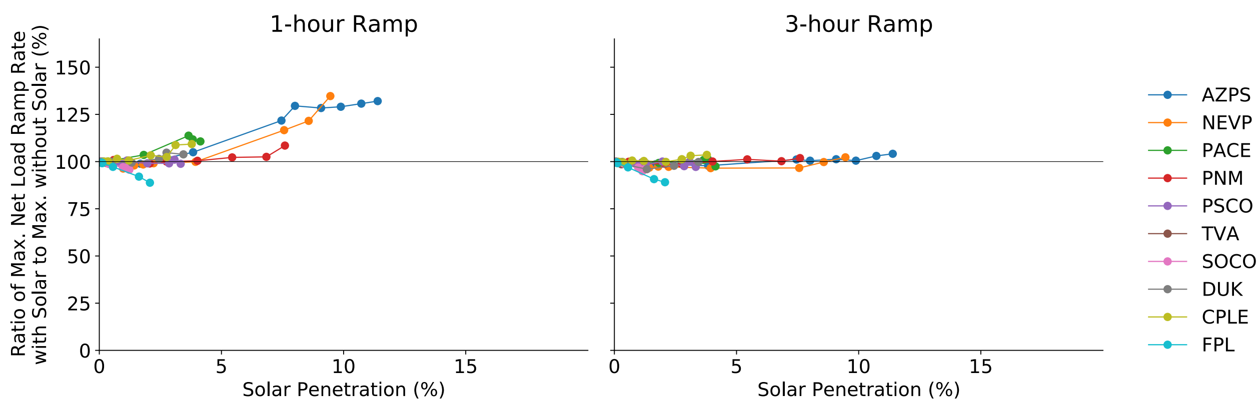
Solar is increasing the need for flexibility in some utilities outside of ISO/RTO regions

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
Summer	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	1.1	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	1.1	1.0	1.1	0.8	0.7	0.7
	Severe Weather	3.06	2016-08-11					1.1		
Other Seasons	Polar Vortex	11.14	2014-01-07		0.9			1.6		
	Polar Vortex	8.02	2014-01-06		0.8			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	1.1						
	Winter Storm Riley	4.22	2018-03-02						0.1	0.1
	Winter Storm Grayson	4.06	2018-01-02		0.4	1.0	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

Contacts

Andrew D. Mills: ADMills@lbl.gov , 510-486-4059
Joachim Seel: jseel@lbl.gov, 510-486-5087

For more information

Visit the project page to download the report, a briefing deck, and underlying data: https://emp.lbl.gov/renewable-grid-insights

Download other publications from the Electricity Markets & Policy: https://emp.lbl.gov/publications
Sign up for our email list: https://emp.lbl.gov/mailing-list
Follow the Electricity Markets & Policy on Twitter: @BerkeleyLabEMP

Acknowledgements

This work was funded by the Solar Energy Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.We especially thank Michele Boyd and Ruchi Singh for supporting this work and helpful guidance from Cynthia Bothwell. We also appreciate early feedback, review, and data provided by external advisors on this work, including: Julia Matevosjana, Connor Anderson, Clayton Stice, Julie Jin (ERCOT), Arvind Jaggi (NYISO), Ken Schuyer (PJM), James Okullo (MISO), Clyde Loutan (CAISO), Ryan Quint (NERC), John Sterling (First Solar), and Christopher Rauscher, Rachel McMahon (Sunrun).