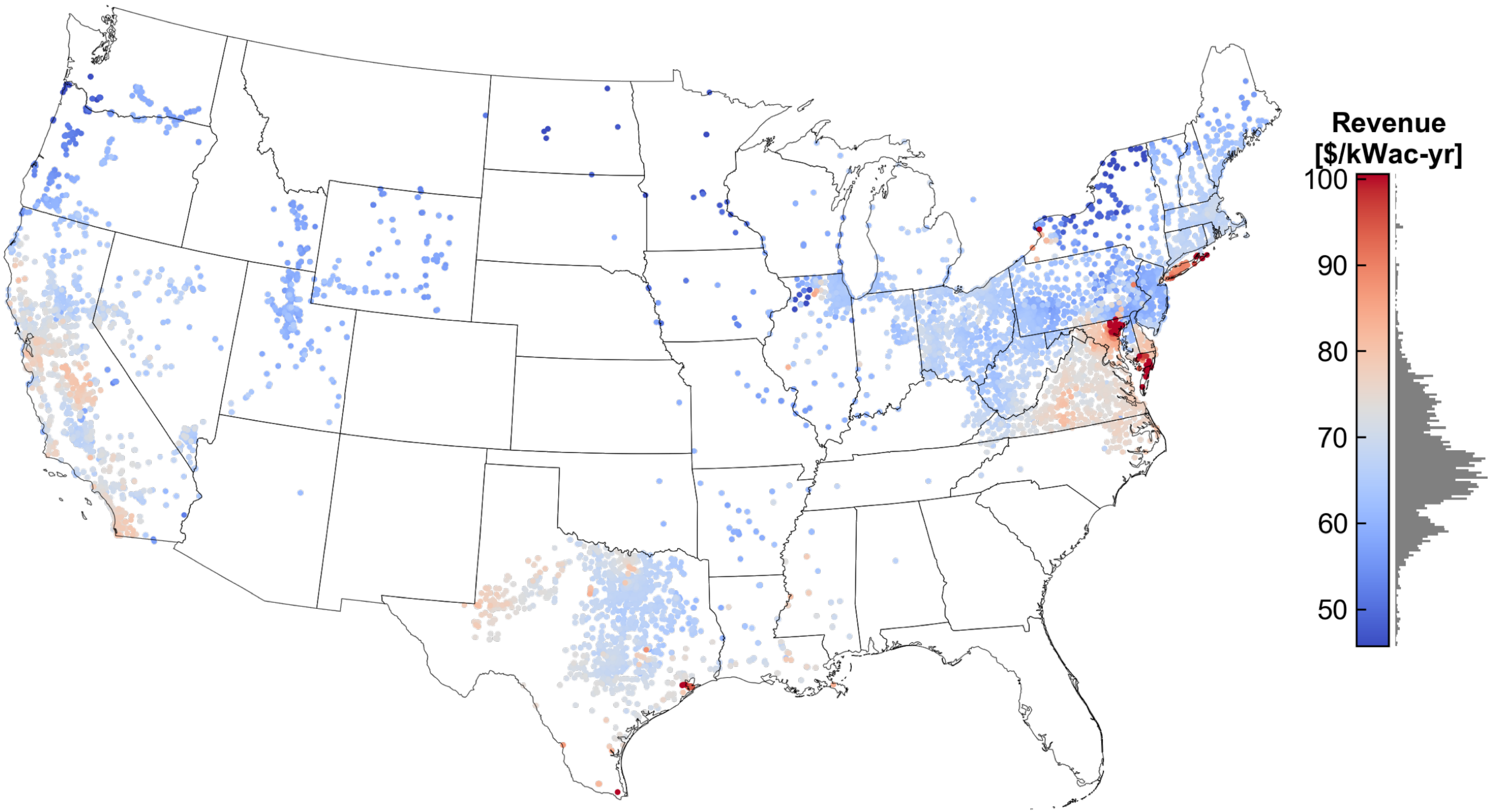
Spatial, Temporal, and Technological Variation in the Value of Solar Power across the U.S.



Patrick R. Brown

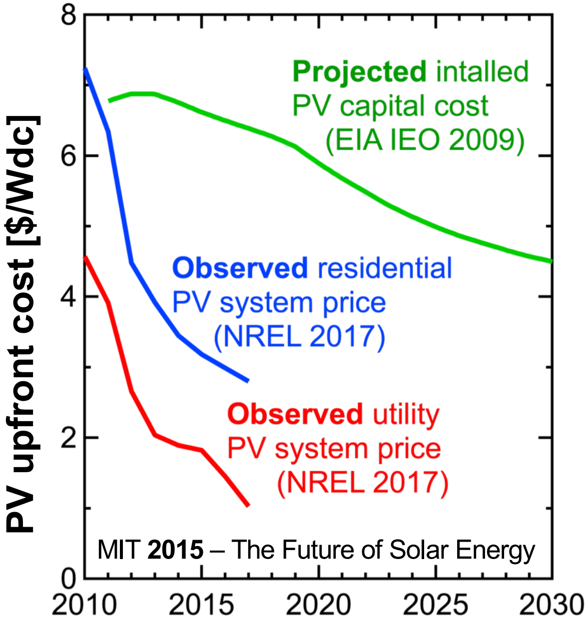
prbrown@mit.edu
2019-05-14

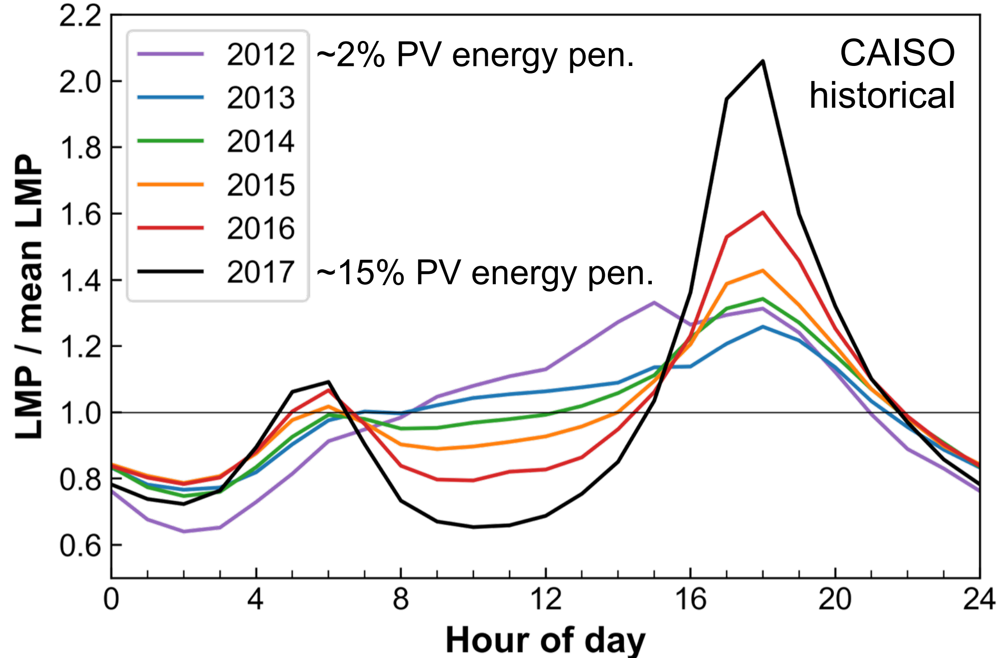
MIT Energy Initiative

U.S. DEPARTMENT OF ENERGY

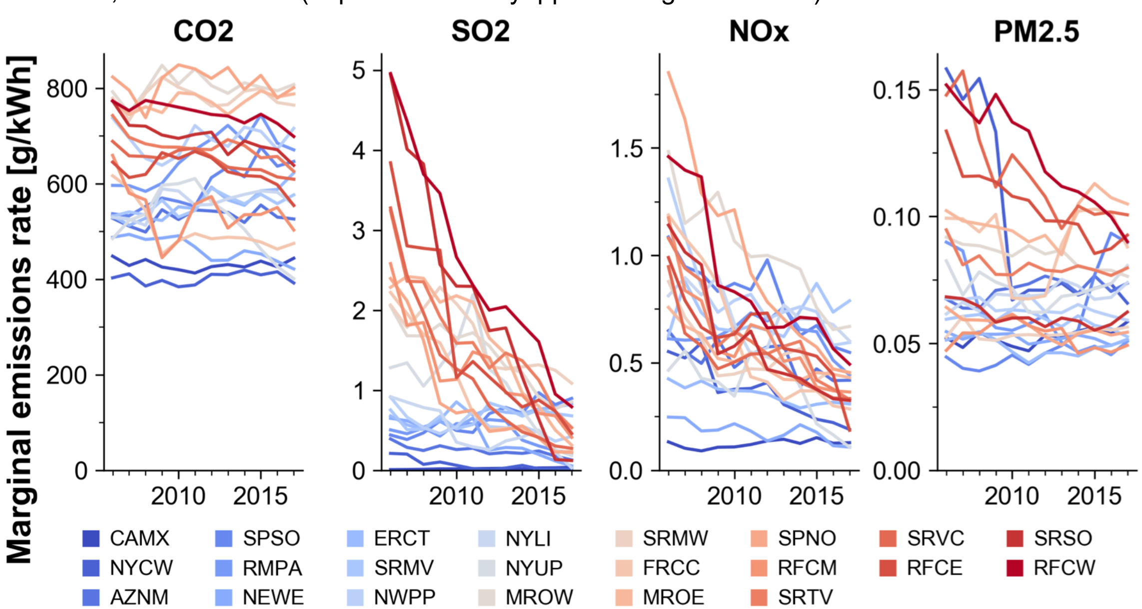
Energy Efficiency & Renewable Energy

PV value (not just cost) declines with penetration





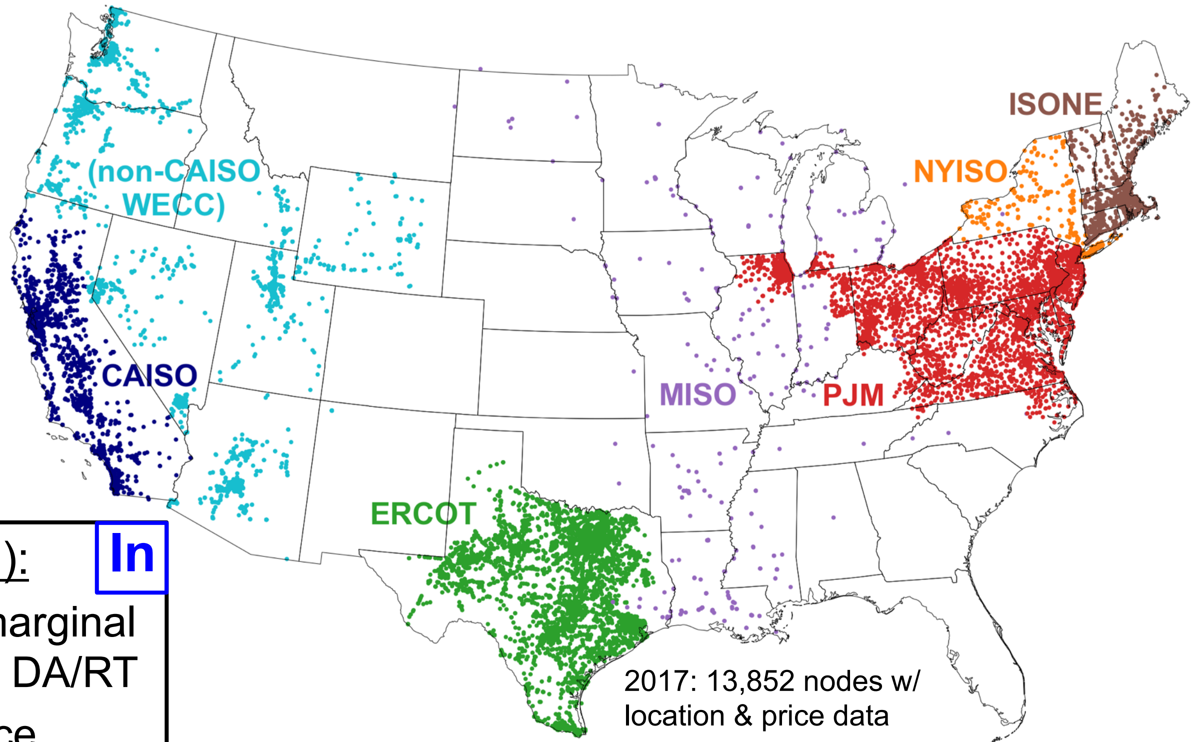
Azevedo, I.L. et al. **2017** (https://cedm.shinyapps.io/MarginalFactors/)



→ “Grid parity” is a moving target

- What is the value of solar **today** across the U.S.?
- What **cost target** is required for solar to stay competitive?
- How can **PV system design** be optimized for solar value?

Our approach: Nodal exploration of solar value



Prices, node locations:
CAISO, ERCOT, MISO, PJM, NYISO, ISONE

Weather:
NSRDB PSM

Emissions:
CMU CEDM

Simulation:
Sandia PVLIB

In

Market (5-60min):

- Locational marginal price (LMP), DA/RT
- Capacity price

Power system (60min):

- Demand
- Emissions rates

Weather (4km, 30min):

- DNI, DHI
- Surface air temp.
- Surface wind speed
- Location, datetime → solar position

In

Model variables:

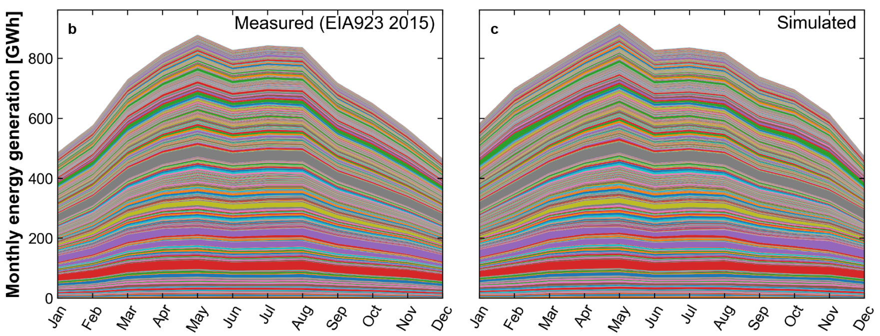
- Tracking strategy (fixed or 1-ax track) [1-ax track]
  - Max angle [60°]
  - Ground coverage ratio [0.33]
  - Backtracking [True]
- Axis tilt, azimuth [0°, 180°]
- DC/AC ratio [1.3]
- System losses [14%]
- Inverter losses [4%]
- AR coating index [1.3]
- Temperature coefficient [-0.4%/°C]
- Ground albedo [0.2]
- Diffuse sky model [Reindl]

Out

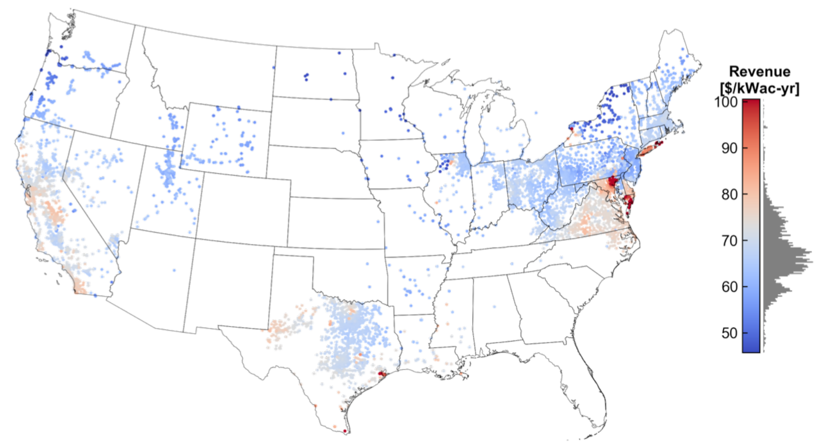
$$\text{Revenue} = \Sigma_t \left(P_{AC}(t) \times \text{value}(t)\right) \quad [\$/kW_{AC}\text{-yr}]$$

Outline

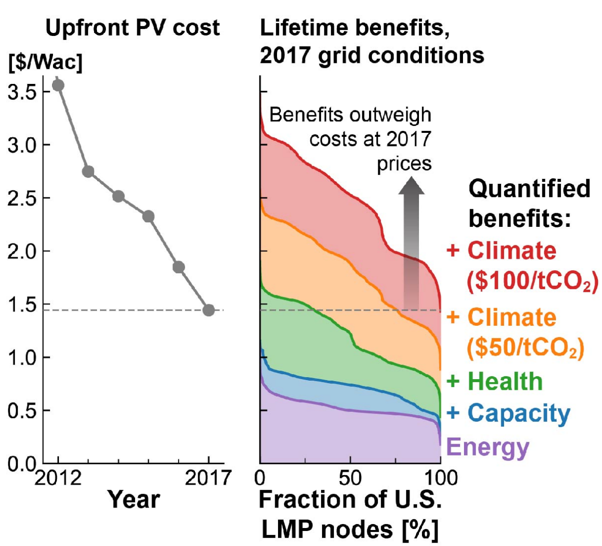
1. PV model validation
   - Monthly (vs. EIA)
   - Hourly (vs. NREL PVDAQ)



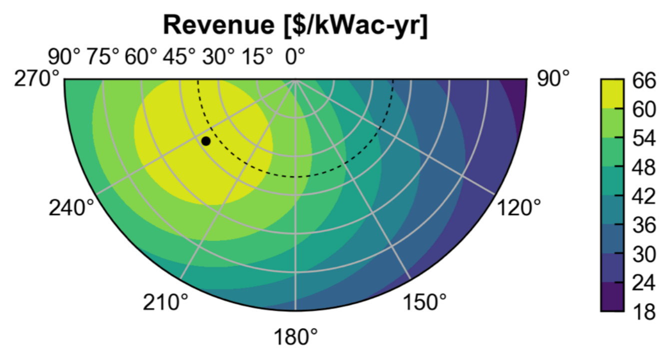
2. PV value across U.S. markets
   - Energy (locational marginal price)
   - Capacity (resource adequacy)
   - Public health (SO_2, NO_x, $PM_{2.5}$) and climate (CO_2)



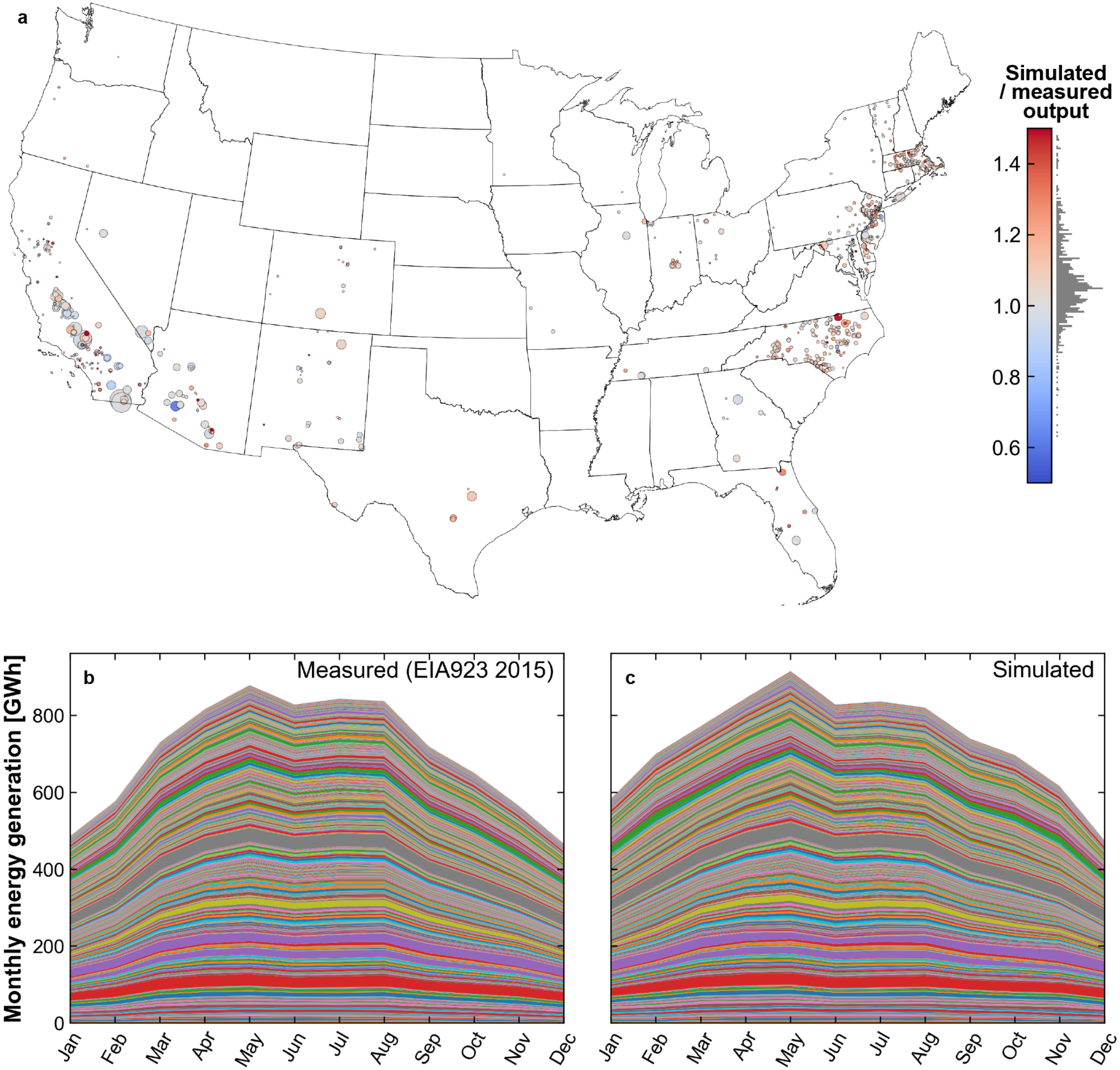
3. PV breakeven costs



4. Temporal shaping of PV output for energy value



Model validation: Monthly simulated output vs EIA 860/923



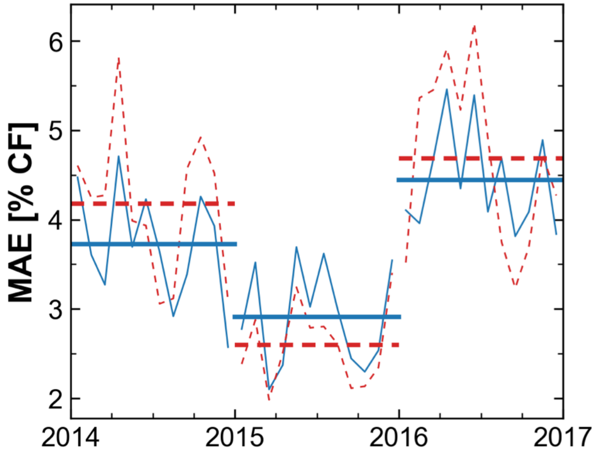
- EIA Form 860:
  - Plant latitude & longitude
  - Module technology (c-Si, CdTe, CIGS)
  - Tilt angle
  - Tracking
  - DC & AC capacity
- EIA Form 923:
  - Monthly generation
- Hundreds of plants:
  - 2014: 542 plants
  - 2015: 800 plants
  - 2016: 1170 plants

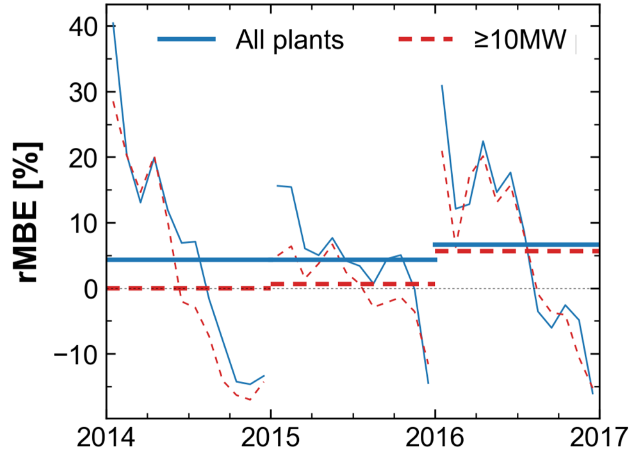
Monthly validation: Plant size

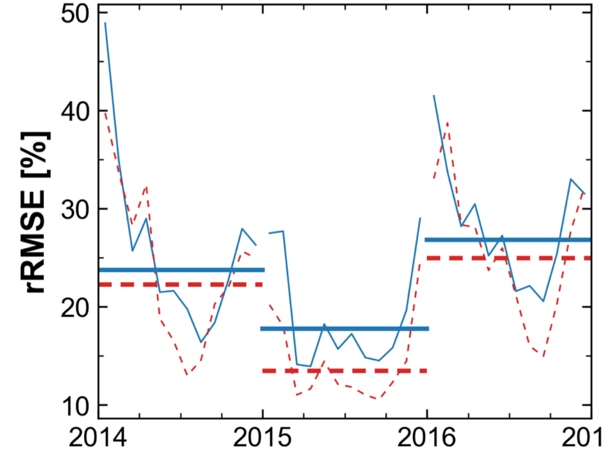
$$\mathrm{MAE} = \frac{1}{n}\sum |x_{sim} - x_{meas}|$$

$$\mathrm{rMBE} = \frac{\sum (x_{sim} - x_{meas})}{\sum x_{meas}}$$

$$\mathrm{rRMSE} = \sqrt{\frac{\sum (x_{sim} - x_{meas})^2}{\sum x_{meas}^2}}$$

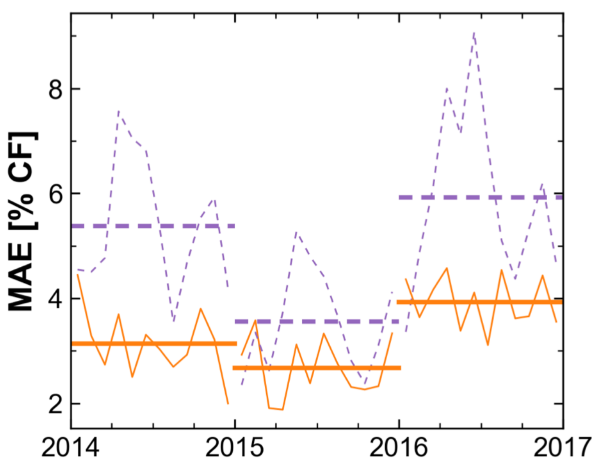


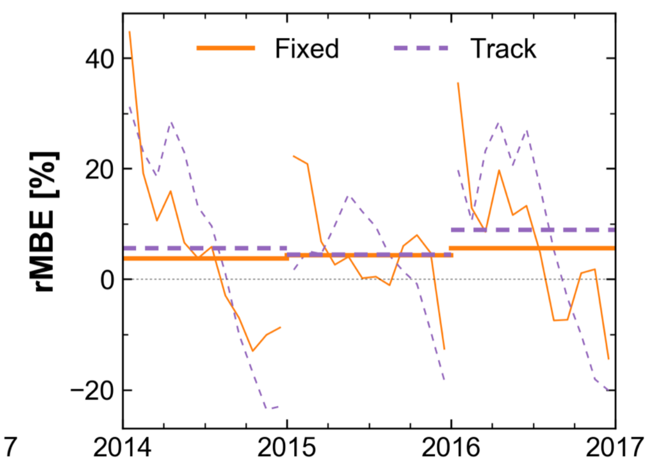


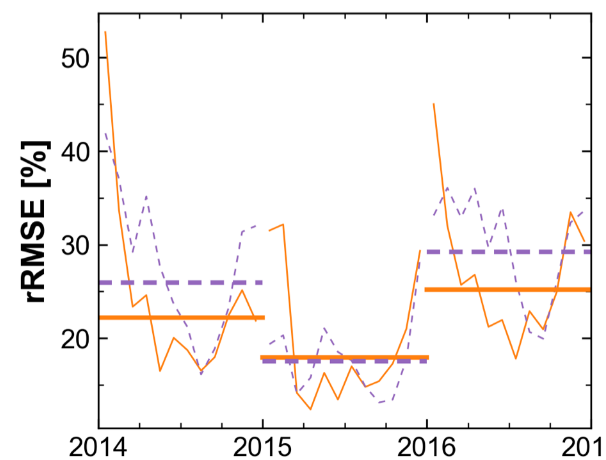


Lower bias in summer than winter

Lower bias for large (≥10 MW) plants







Better match for fixed-tilt than 1-axis tracking

Error rates comparable to NSRDB (rMBE ±5% for GHI, ±10% for DNI)

Habte, A. et al. 2017, "Evaluation of the National Solar Radiation Database (NSRDB): 1998-2015"

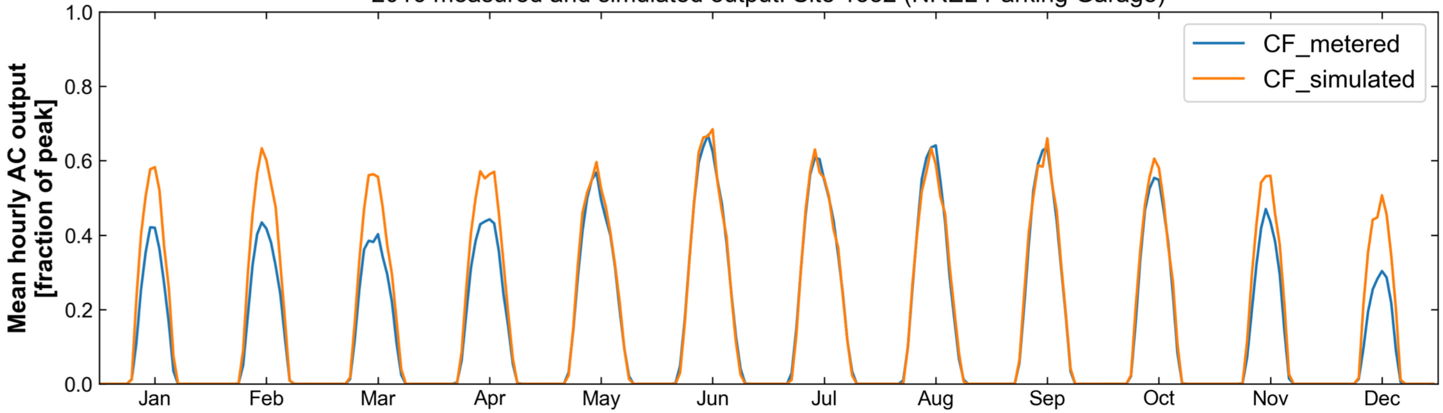
Model validation: Hourly simulated output vs. PVDAQ

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

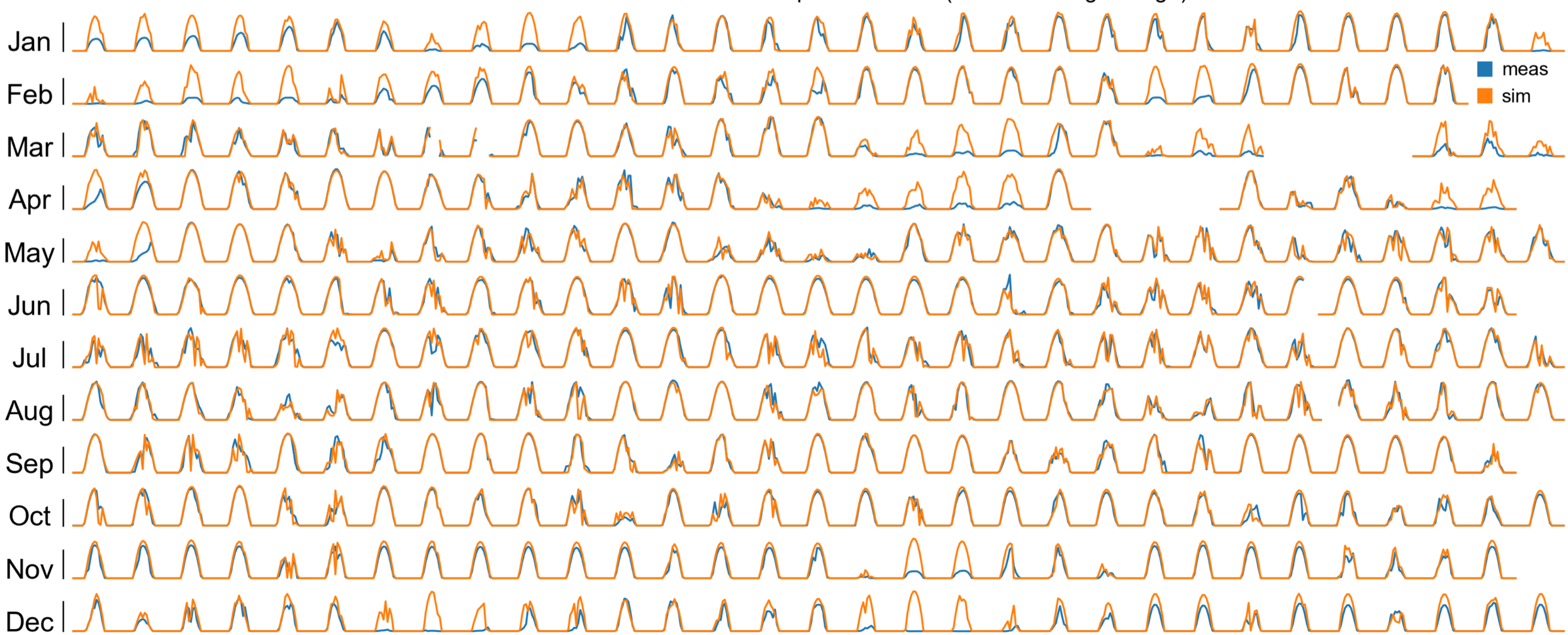
1.14 MWac, 16.8° tilt
1.02 DC/AC ratio

NREL PVDAQ (https://developer.nrel.gov/docs/solar/pvdaq-v3/)

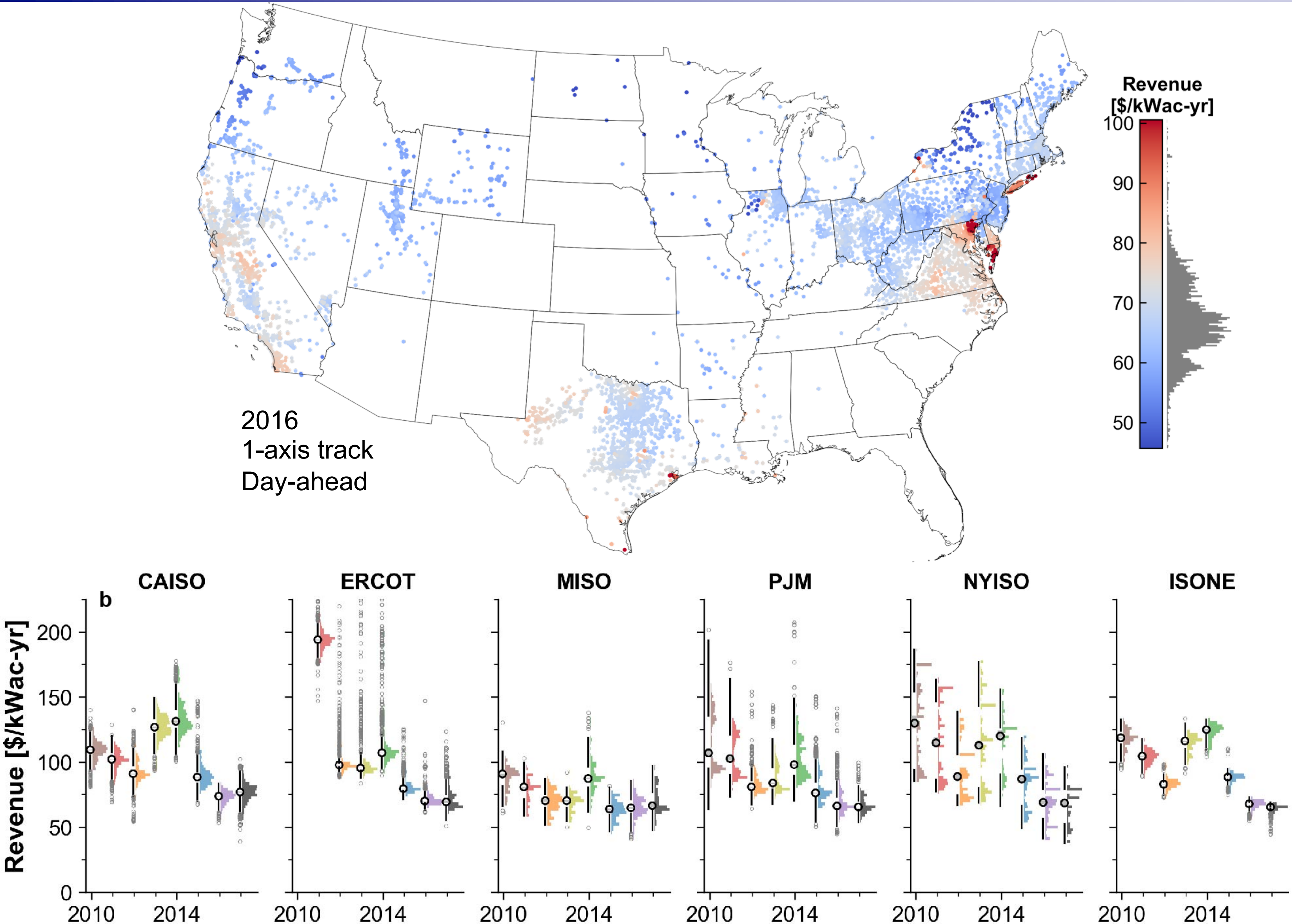
2016 measured and simulated output: Site 1332 (NREL Parking Garage)



2016 measured and simulated output: Site 1332 (NREL Parking Garage)



Spatial & temporal variation in energy revenue



PV capacity value

Market clearing prices for capacity by ISO capacity zone

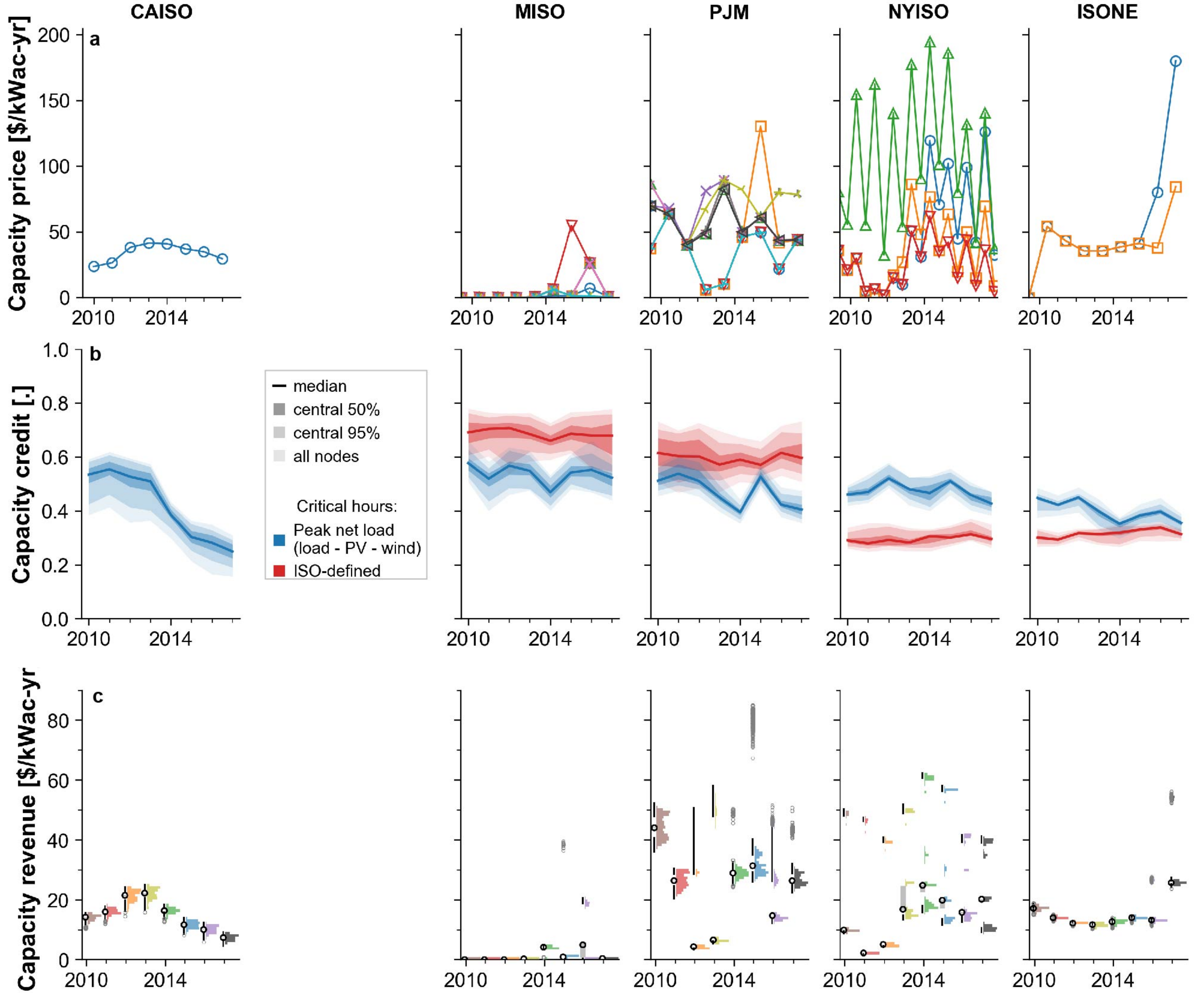
×

Calculated PV capacity credit

- Net load = (ISO load) – (wind generation) – (simulated utility-scale PV generation)
- Capacity credit = CF during peak net load hours (top 7%) or ISO-defined hours

=

Calculated PV historical capacity revenue



Public health and climate benefits

Marginal emissions data: Azevedo, I.L. et al. **2017** (https://cedm.shinyapps.io/MarginalFactors/)
EASIUR: Heo, J. et al. *Atmospheric Environment* **2016**, *137*, 80; (https://barney.ce.cmu.edu/~jinhyok/easiur/)

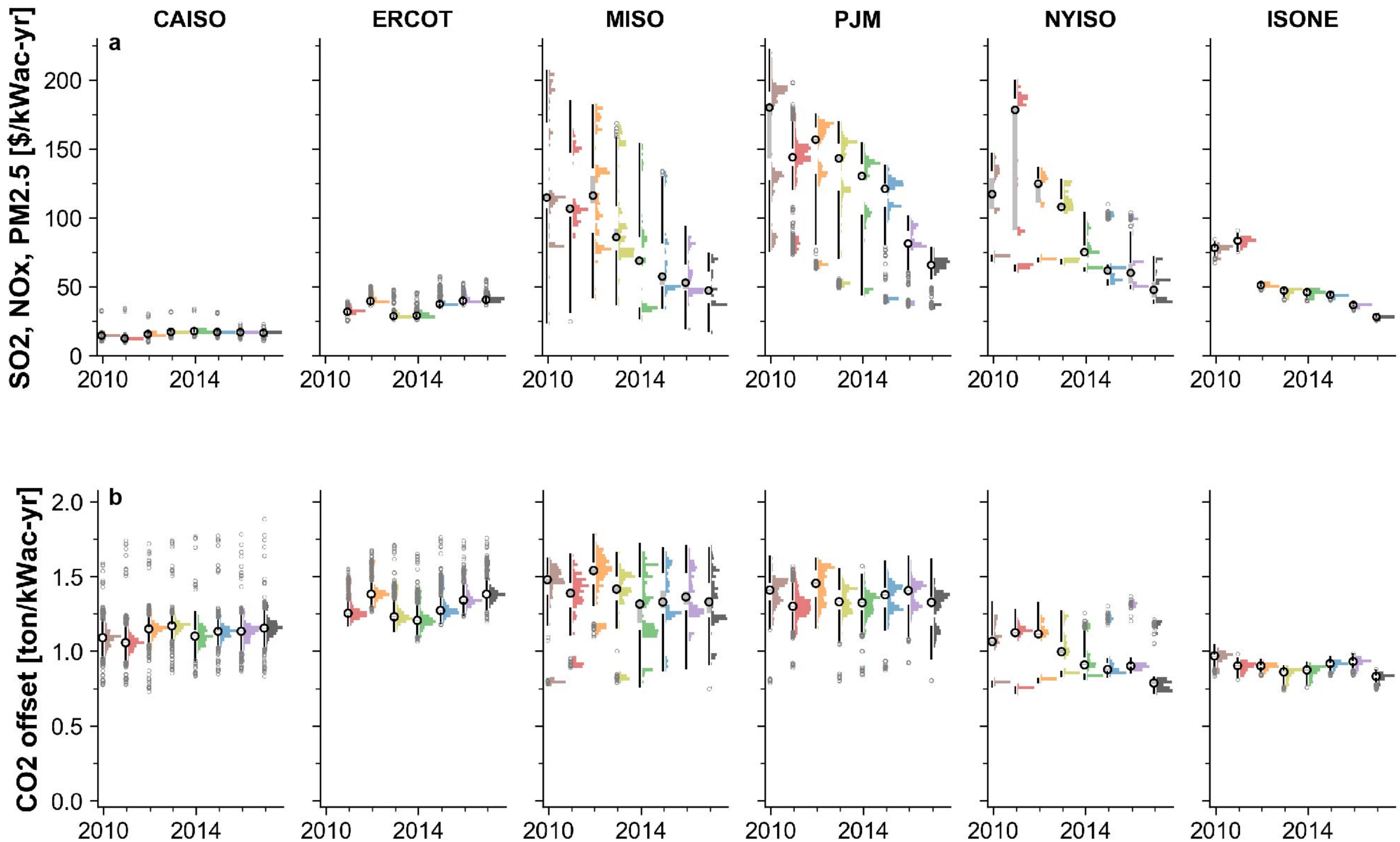
Air pollution damages

- Historical marginal emissions factors
- EASIUR model for monetized health impacts by eGRID region

+

CO_2 offset

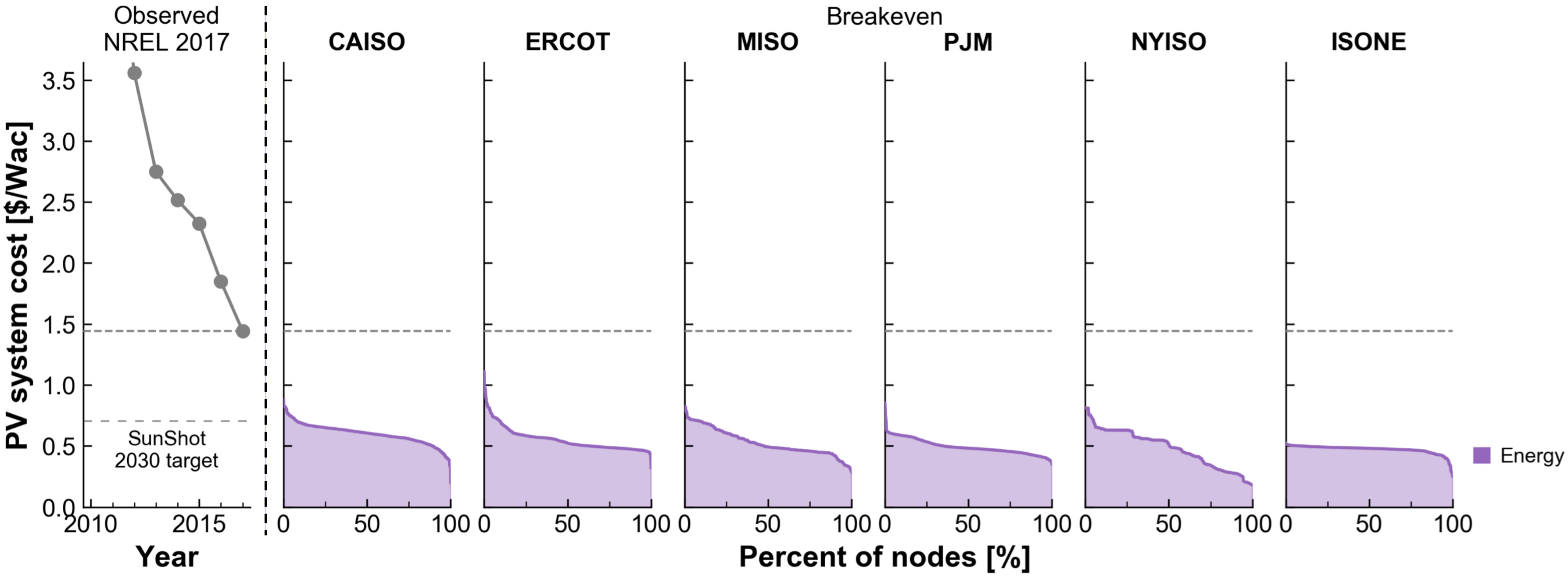
- Multiply by chosen carbon price (subtract cap & trade clearing price if applicable)



- Marginal public health benefits from PV are declining as emissions-control measures are adopted, but are still substantial in 2017
- CO_2 offset has not changed substantially

PV breakeven cost with full value stack, 2017

2017 data

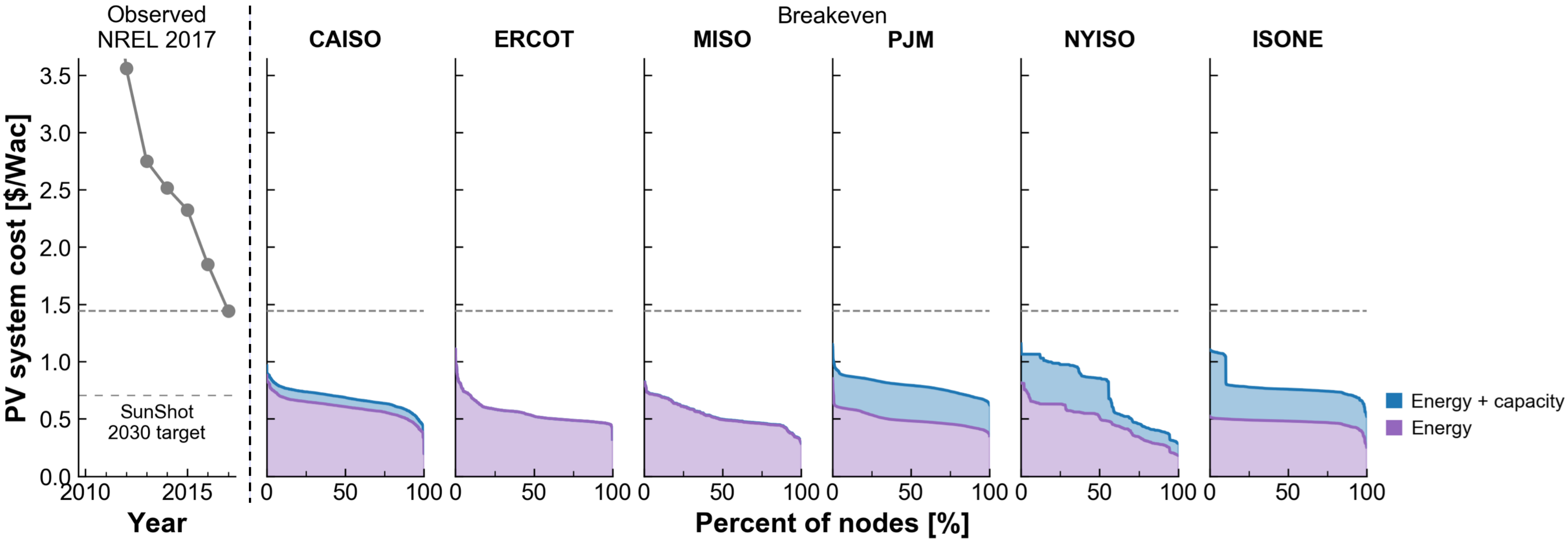


$$NPV = \sum_{t=1}^{L} \frac{\left(\left(R + C_{CO_2} M_{CO_2}\right)(1-d)^t - C_{OM}\right)(1-T) + \frac{D_t}{(1+i)^t} C_{PV} T}{(1+\rho)^t} - C_{PV}$$

NPV = net present value [$/kWac]	→ 0	C_{OM} = O&M cost [$/kWac-yr]	20
L = system lifetime [yr]	30	T = corporate tax rate [%]	28%
R = yearly revenue [$/kWac-yr]	(~100)	D_t = 5-yr MACRS depreciation [%]	(..)
C_{CO2} = CO_2 price [$/ton]	0,40,80	i = inflation rate [%]	2.5%
M_{CO2} = CO_2 offset [ton/kWac-yr]	(~1)	ρ = weighted ave. cost of capital [%]	7%
d = degradation rate [%/yr]	0.5%	C_{PV} = upfront cost [$/kWac]	→ solve

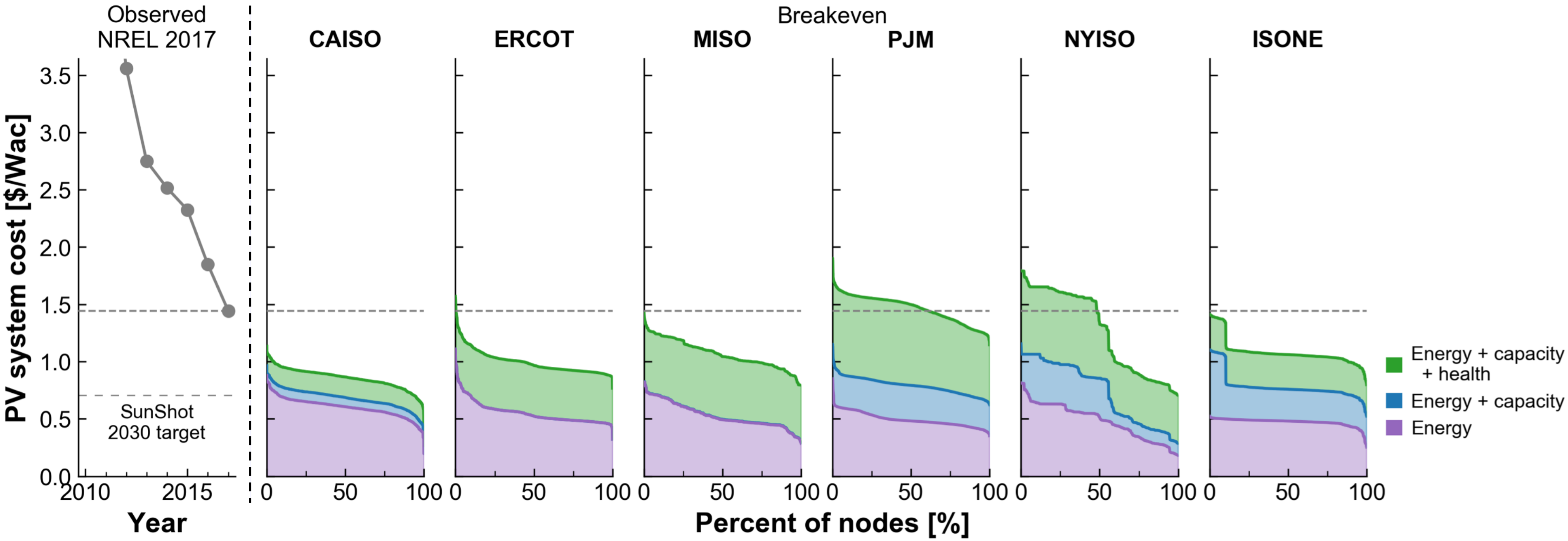
PV breakeven cost with full value stack, 2017

2017 data



PV breakeven cost with full value stack, 2017

2017 data

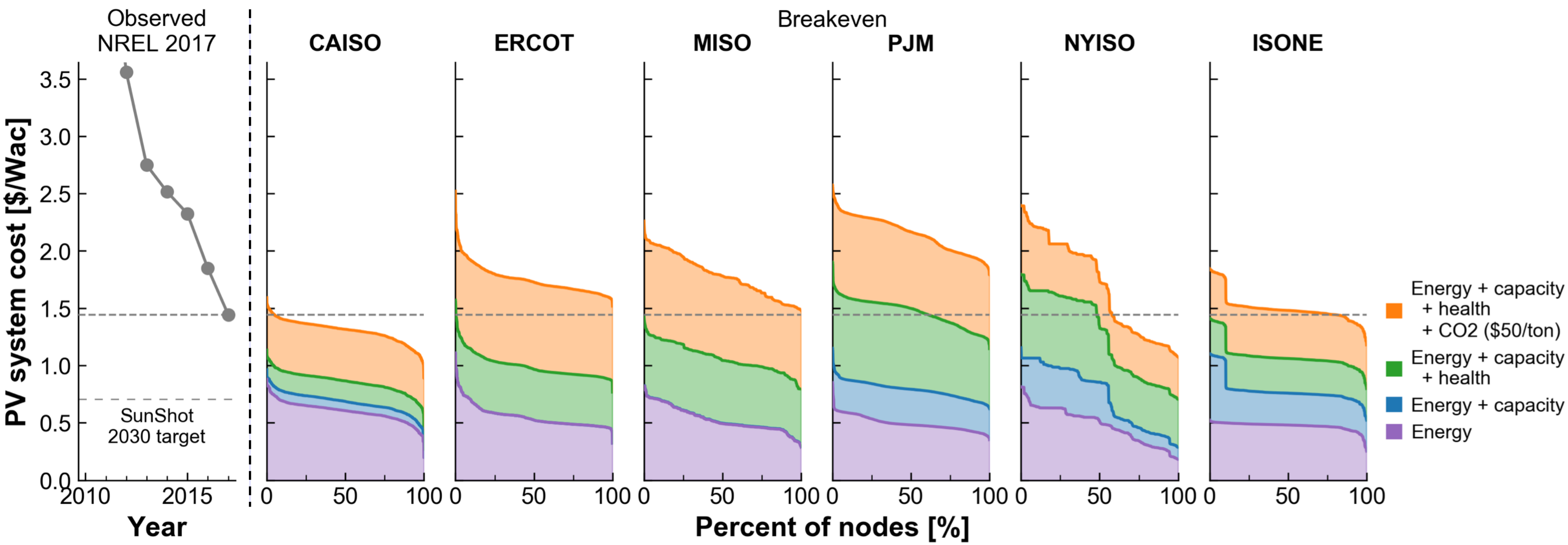


Utility-scale PV is competitive in 2017 at today's upfront cost…

- based on energy, capacity, and health benefits alone in ~60% of PJM, 50% of NYISO

PV breakeven cost with full value stack, 2017

2017 data

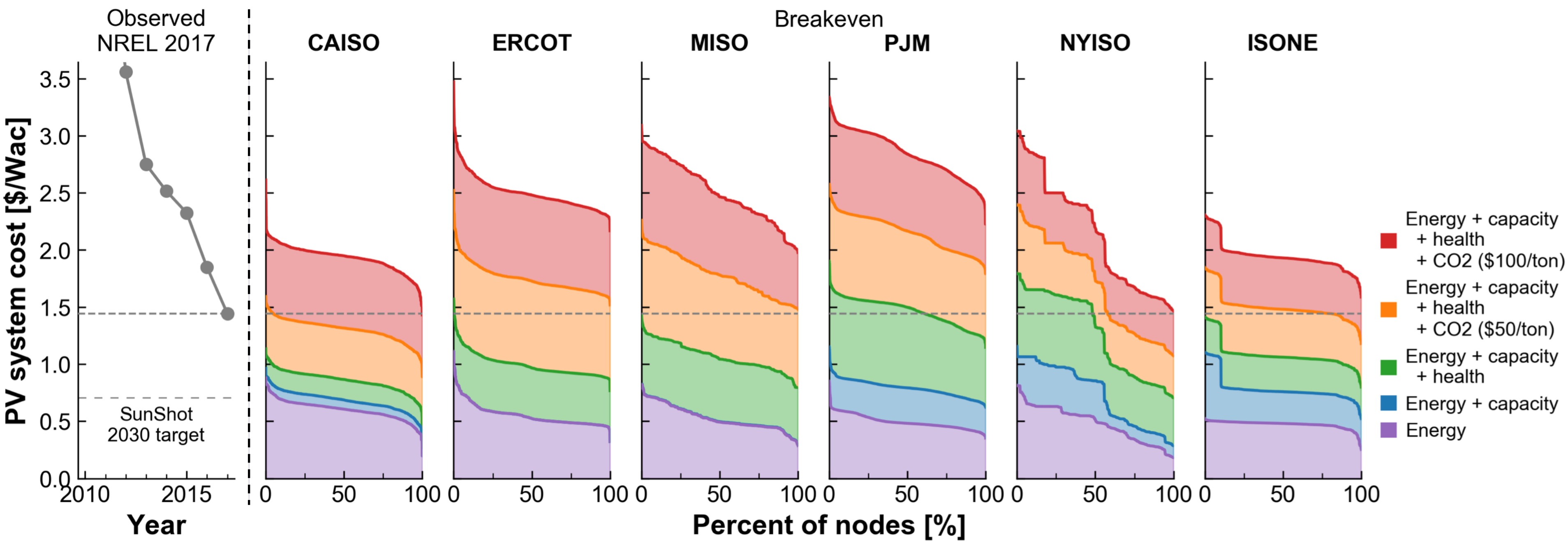


Utility-scale PV is competitive in 2017 at today's upfront cost…

- based on energy, capacity, and health benefits alone in ~60% of PJM, 50% of NYISO
- including a $50/ton-$CO_2$ price in 100% of ERCOT, MISO, PJM; ~60% of NYISO; 85% of ISONE

PV breakeven cost with full value stack, 2017

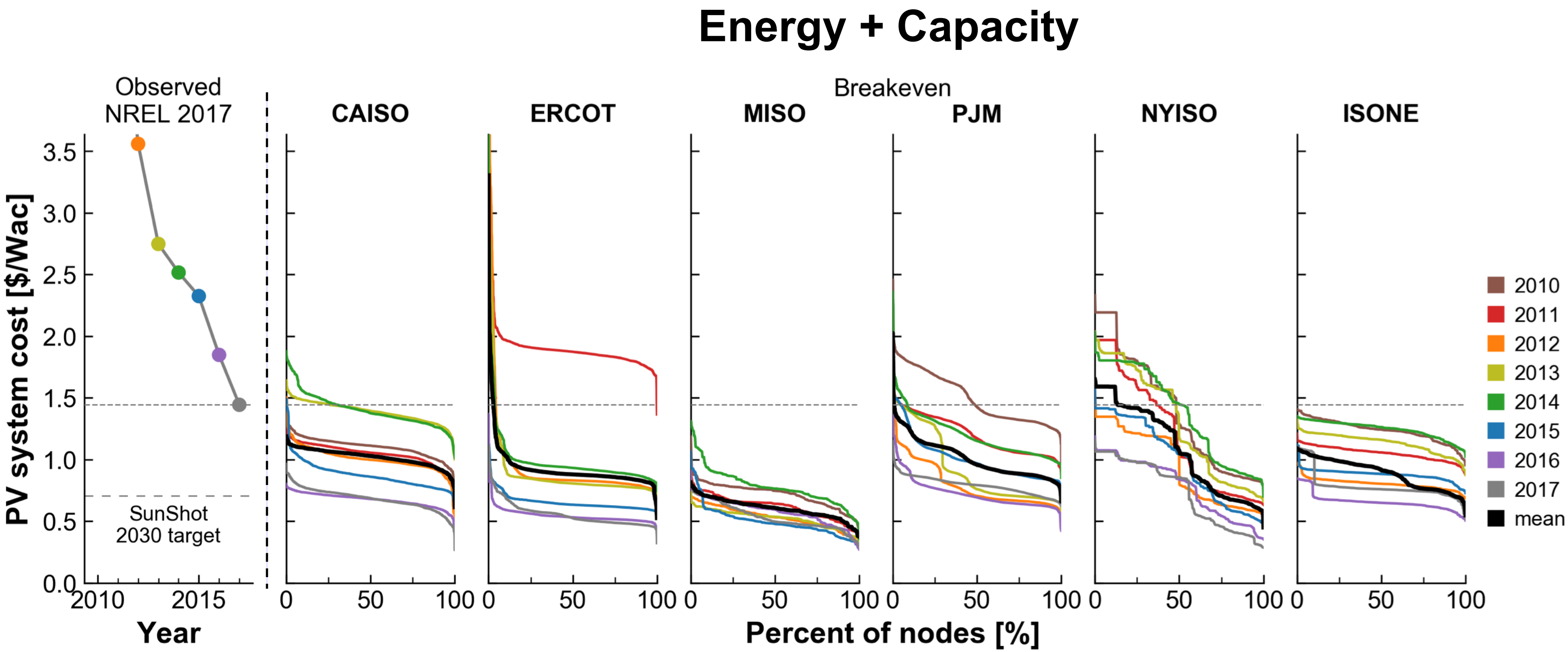
2017 data



Utility-scale PV is competitive in 2017 at today's upfront cost…

- based on energy, capacity, and health benefits alone in ~60% of PJM, 50% of NYISO
- including a \$50/ton-CO_2 price in 100% of ERCOT, MISO, PJM; ~60% of NYISO; 85% of ISONE
- including a \$100/ton-CO_2 price at 100% of nodes in all ISOs

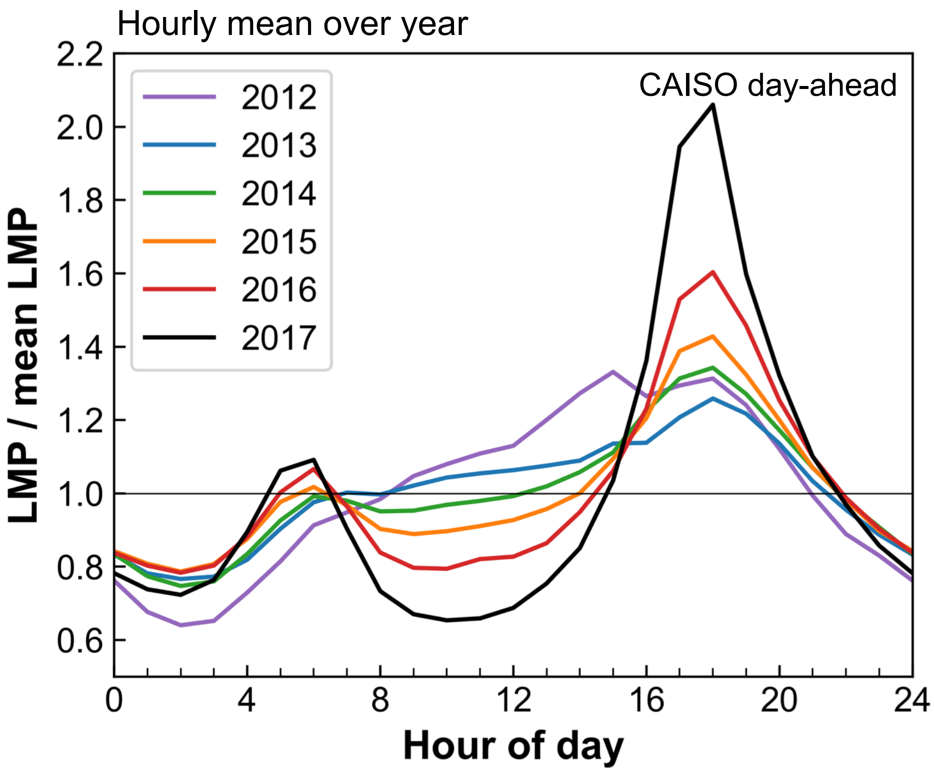
PV breakeven cost with market value alone

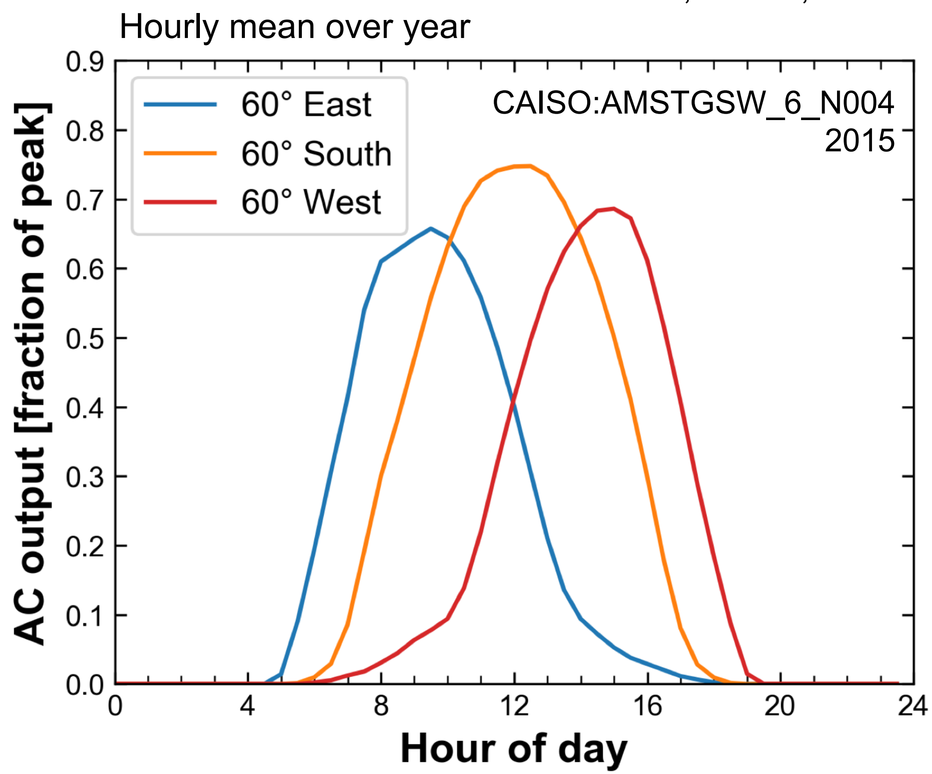


- Significant interannual variability (primarily driven by natural gas price variation)
- Based on market revenues alone, median unsubsidized breakeven costs over 2010–2017 range from ~$0.70/Wac in MISO to ~$1/Wac in NYISO, CAISO
- Long Island and parts of ERCOT and PJM demonstrate highest profitability

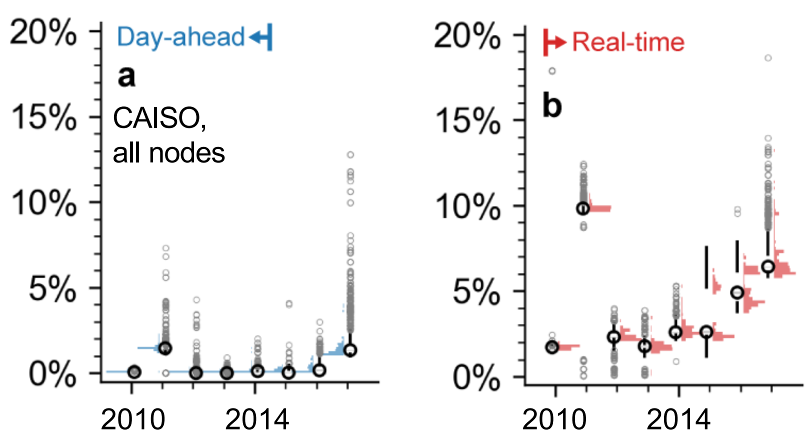
Optimizing for solar value: Orientation

Data; CAISO, NSRDB





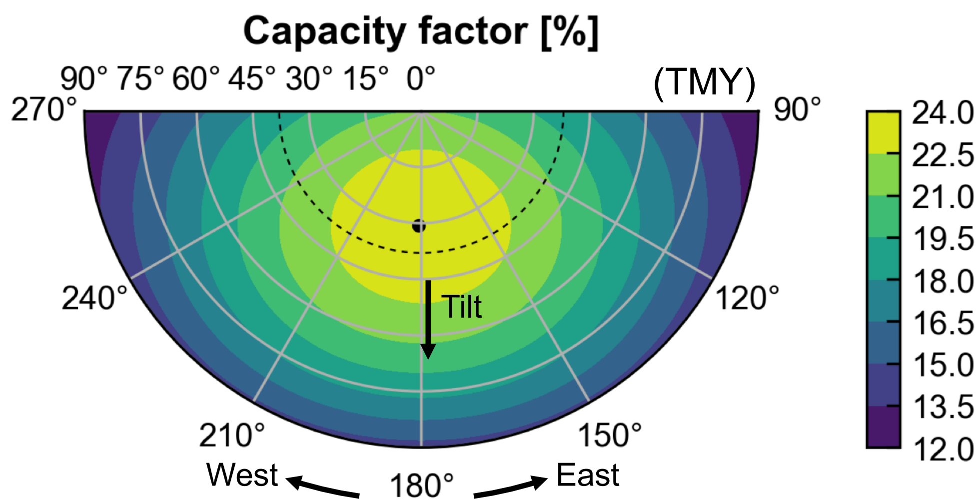
Fraction of time with negative LMP

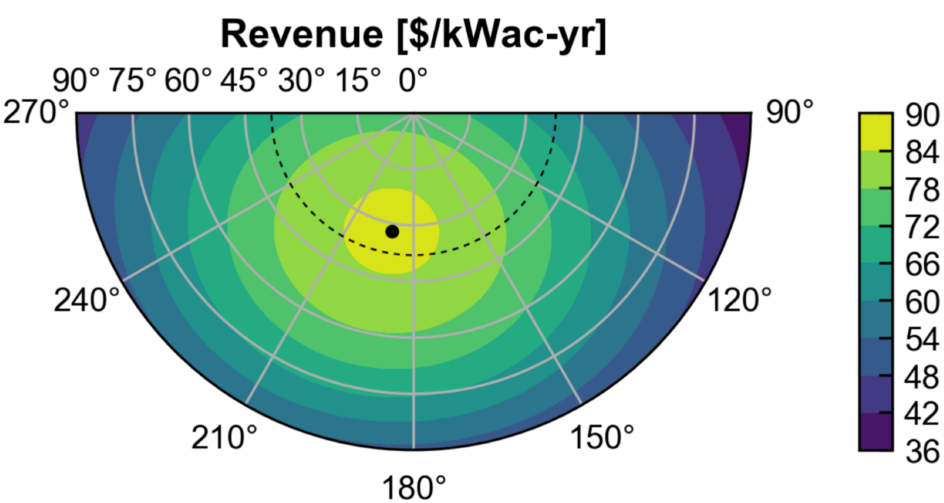


Is the observed change in price profile in California enough to change the way a PV system should be designed and operated?

PV orientation: CF-optimized vs. Revenue-optimized

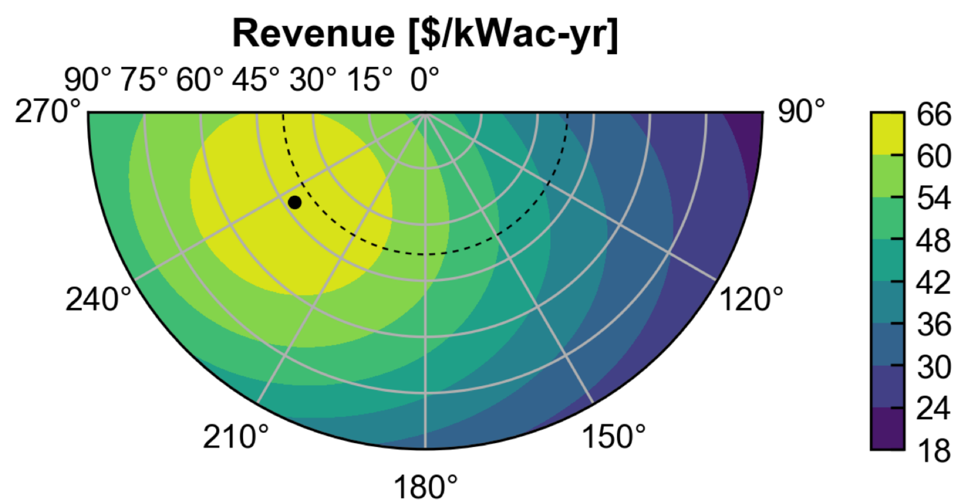
CAISO:STCKTNAR_6_N001 (Real-time, non-curtailable)





2010

PV capacity ~ 1.7%
of peak demand

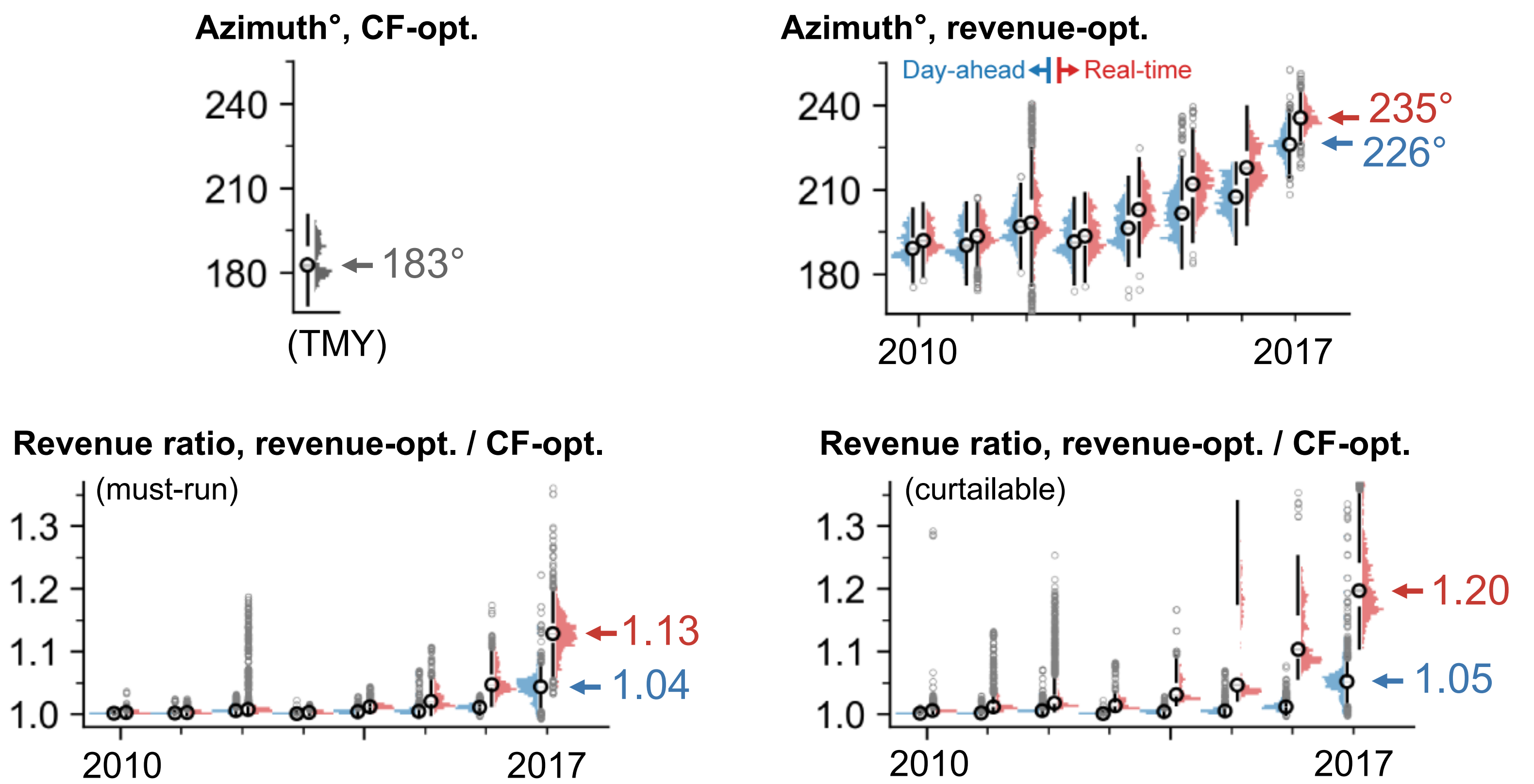


2017

PV capacity ~ 28%
of peak demand

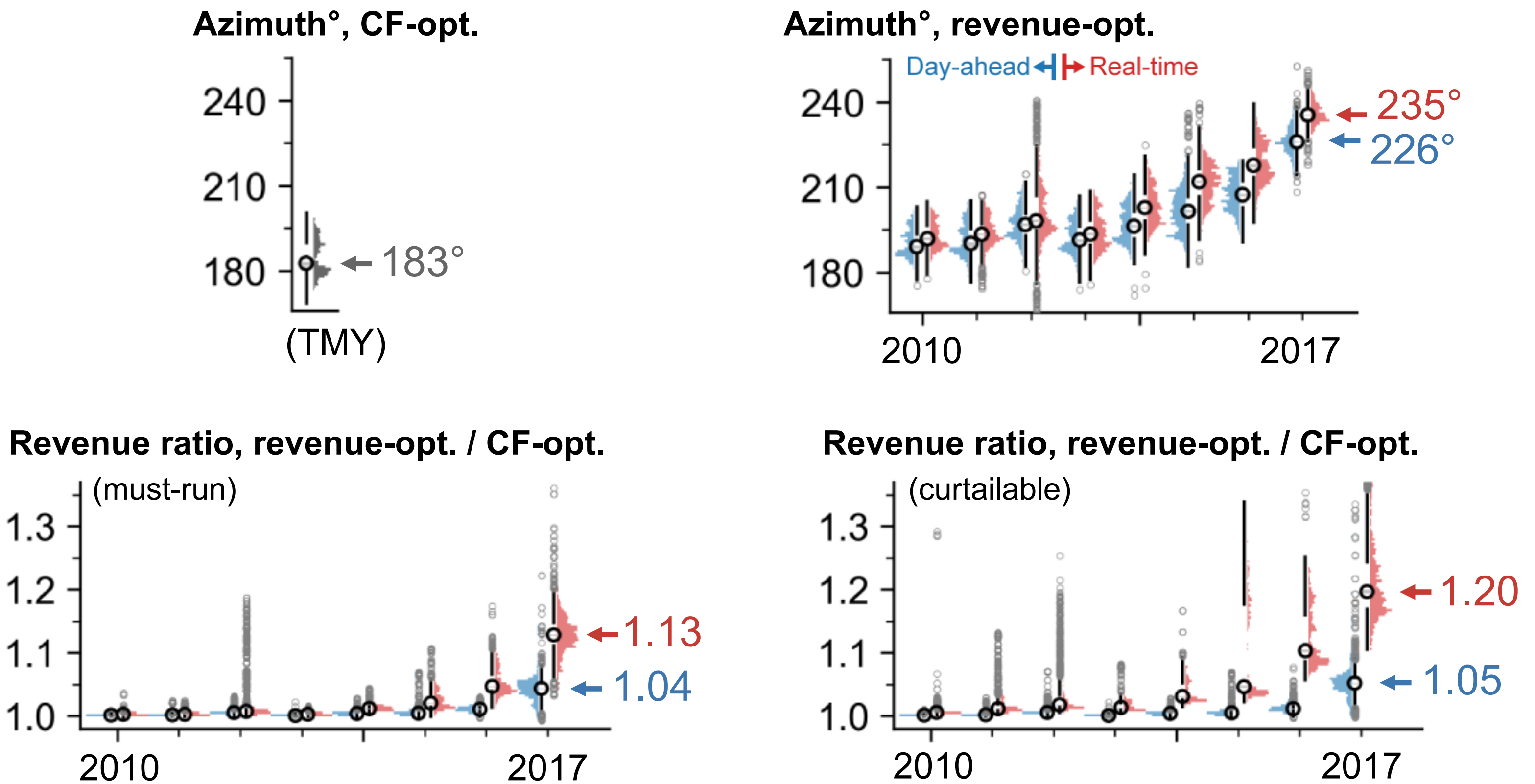
Optimal azimuth tending west in CAISO

CAISO system:

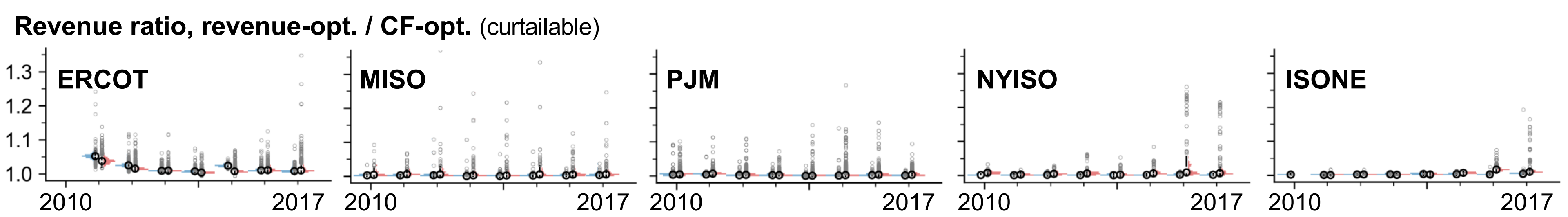


Optimal azimuth tending west in CAISO

CAISO system:



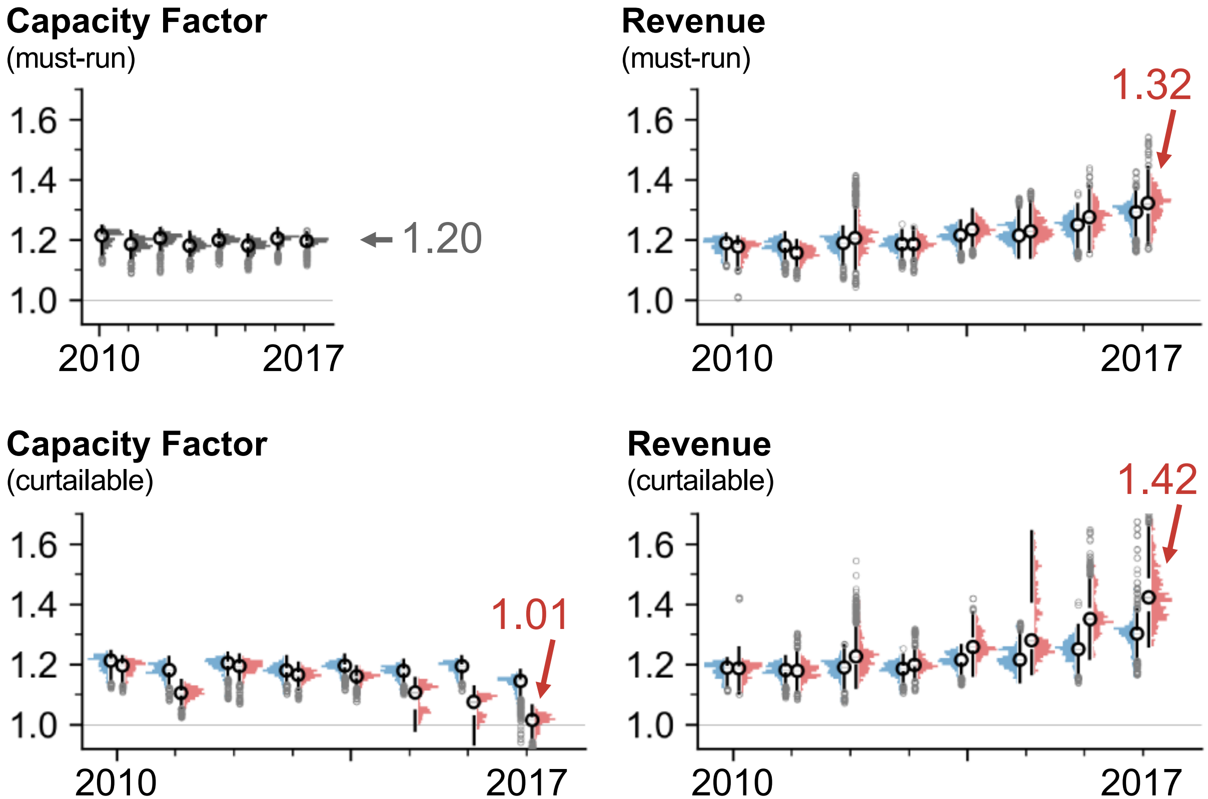
Effect is most pronounced in CAISO real-time market:



1-axis tracking: Revenue benefit outweighs CF benefit in CAISO

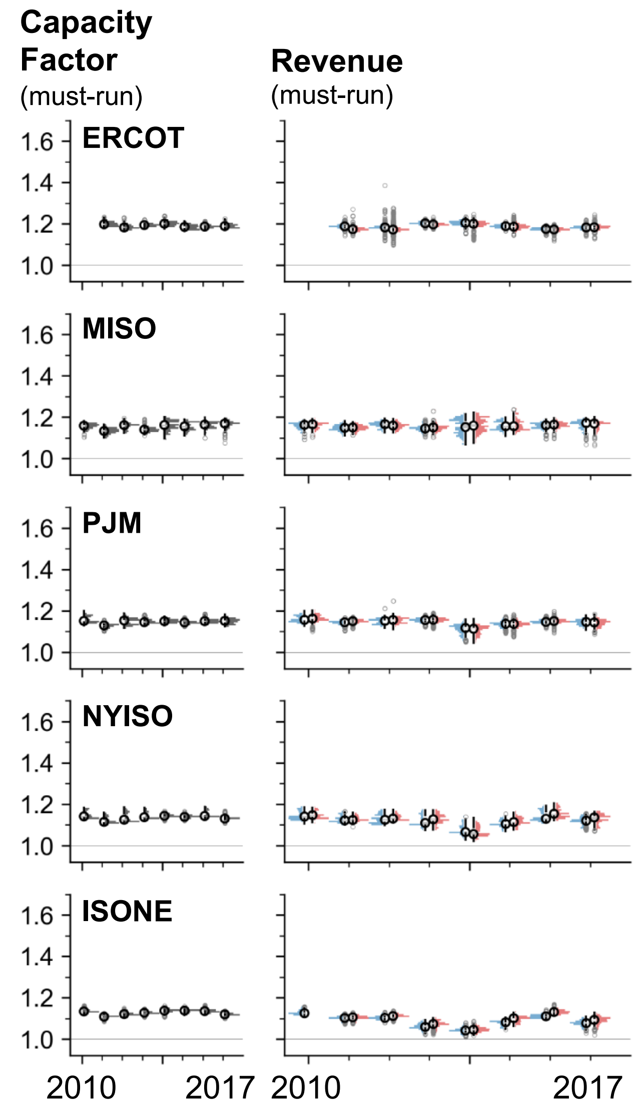
CAISO system:

Ratio, 1-axis-track / fixed [fraction]



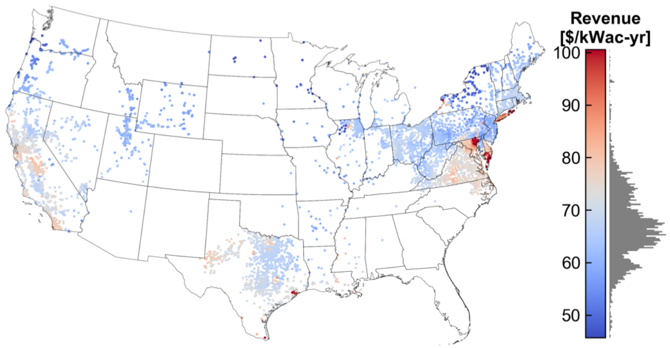
- Revenue benefit from tracking is increasing with PV penetration in CAISO, beyond the CF benefit
- With curtailment, CF benefit is erased but revenue benefit is increased

Revenue benefit is ≤ CF benefit in other ISOs:

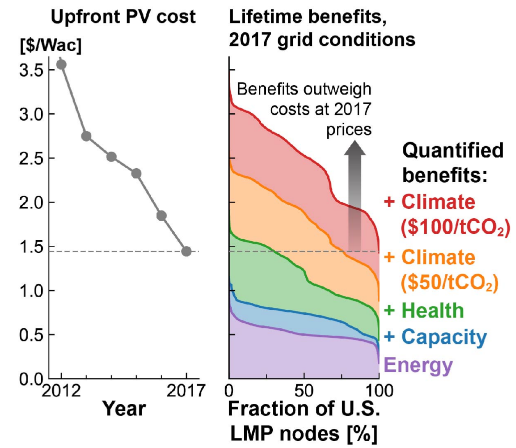


Conclusions

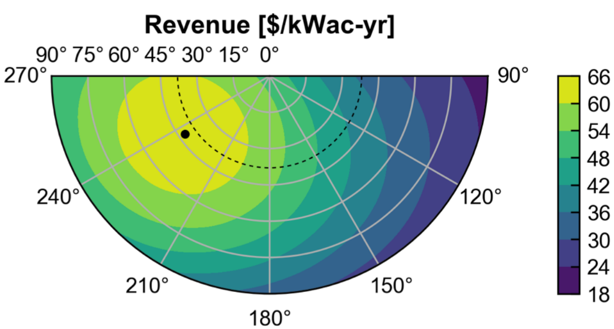
- Spatial variation in the value of PV, even at transmission level, can be significant
  - LCOE and capacity factor give an incomplete picture



- Utility-scale PV breaks even on the basis of market, public health, and climate benefits at the majority of nodes at today's cost
  - Cost declines have outrun value declines (so far)



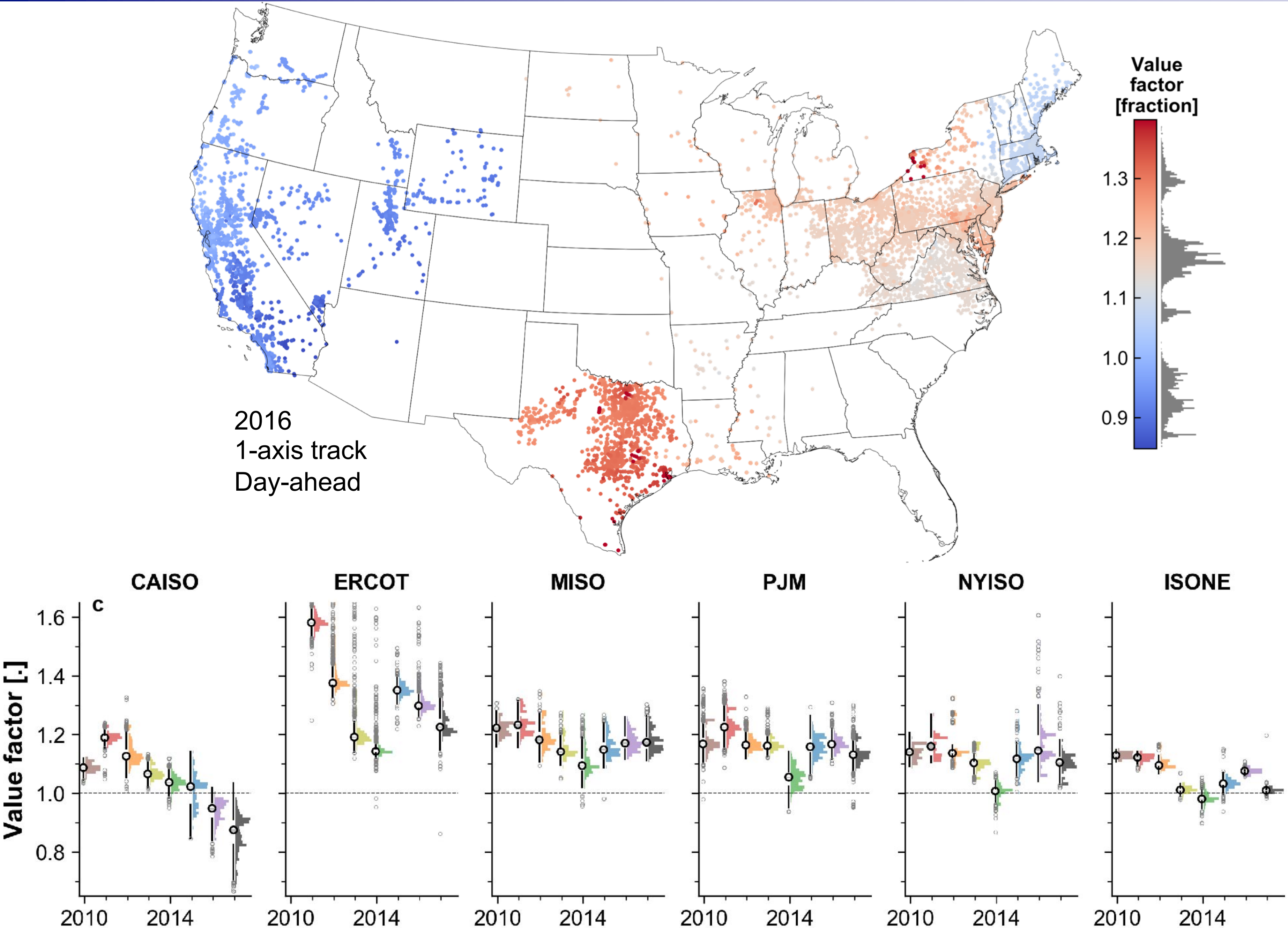
- The optimal PV system design changes as solar penetration increases
  - Appropriate system design and siting choices can mitigate some of the decline in solar value



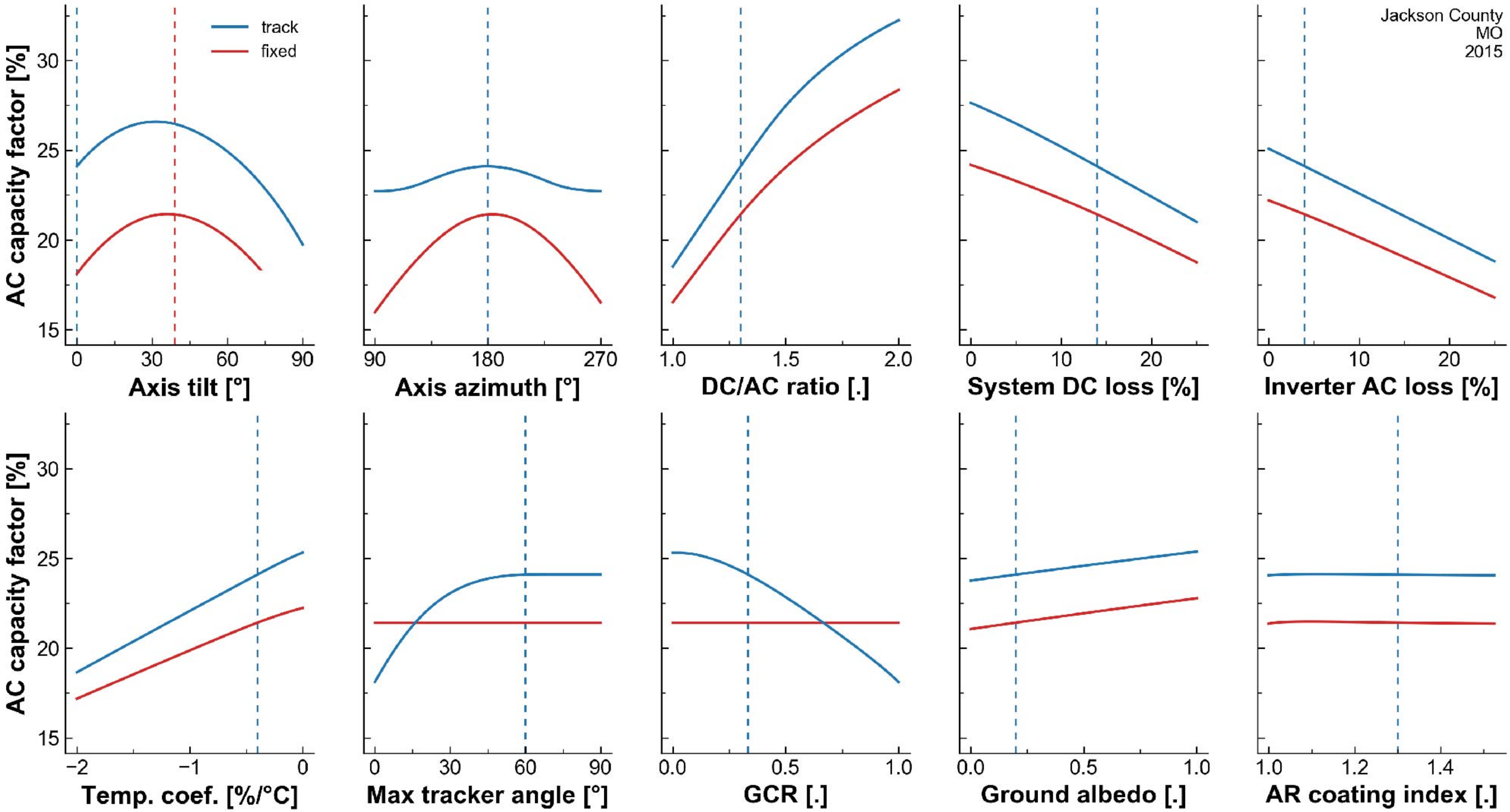
Brown, P.R.; O'Sullivan, F.M. "Spatial and temporal variation in the value of solar power across United States electricity markets". **2019**. http://ceepr.mit.edu/publications/working-papers/705

Brown, P.R.; O'Sullivan, F.M. "Shaping photovoltaic array output to align with changing wholesale electricity price profiles". *Applied Energy* **2019**, *in press*

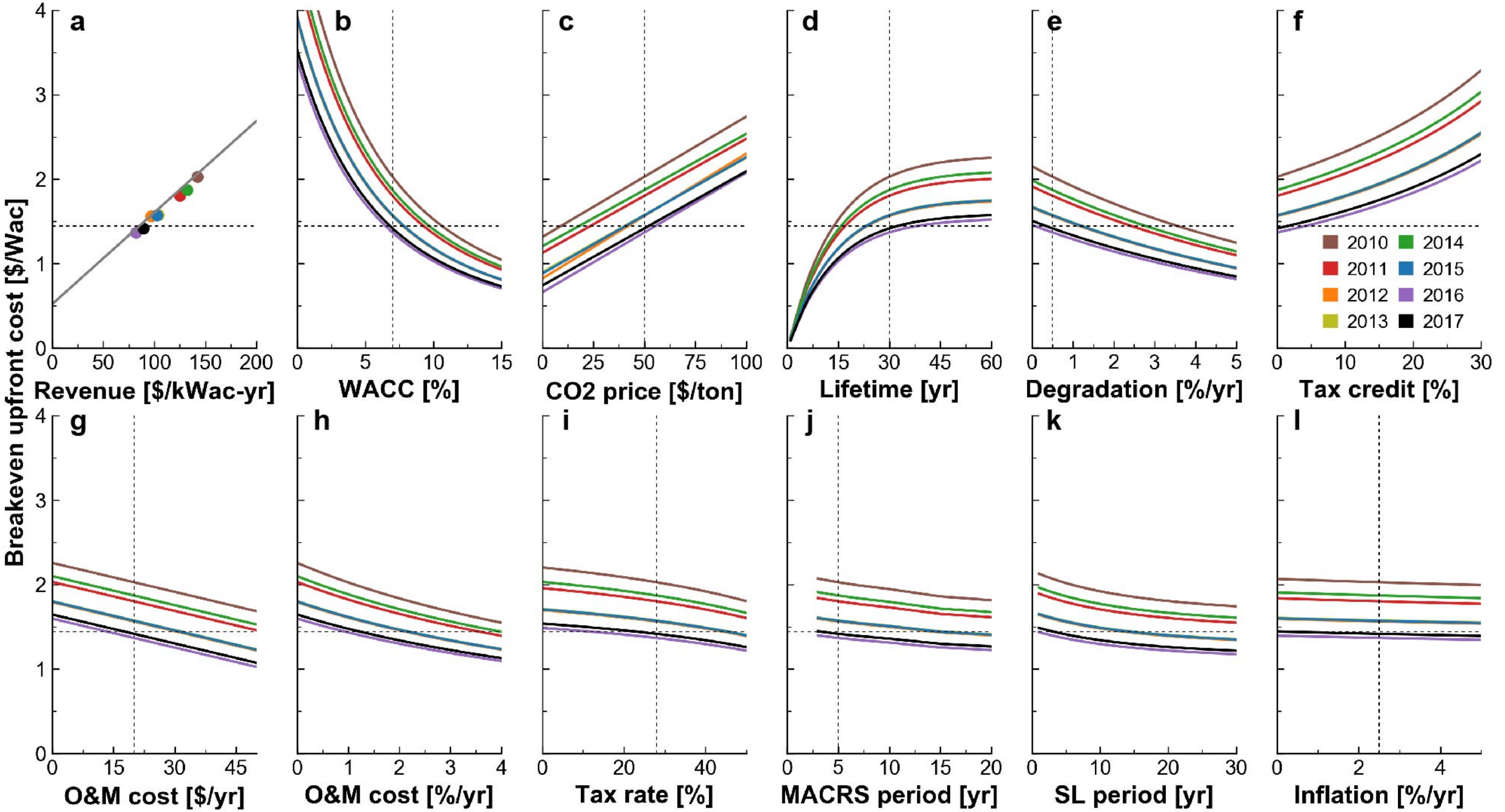
Spatial & temporal variation in PV value factor



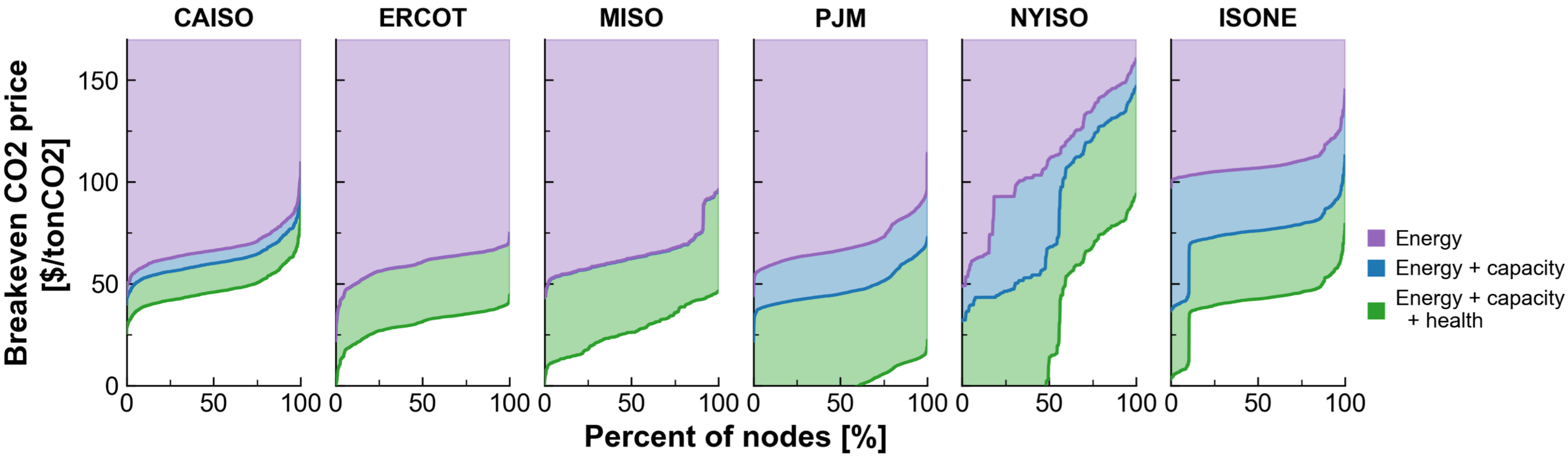
Sensitivity: PV capacity factor



Sensitivity: Financial assumptions



Alternative formulation: Breakeven CO_2 price



PV breaks even at most nodes with a moderate carbon price