Are coupled renewable-battery power plants more valuable than independently sited installations?

October 14th, 2021

ESIG Fall Technical Workshop

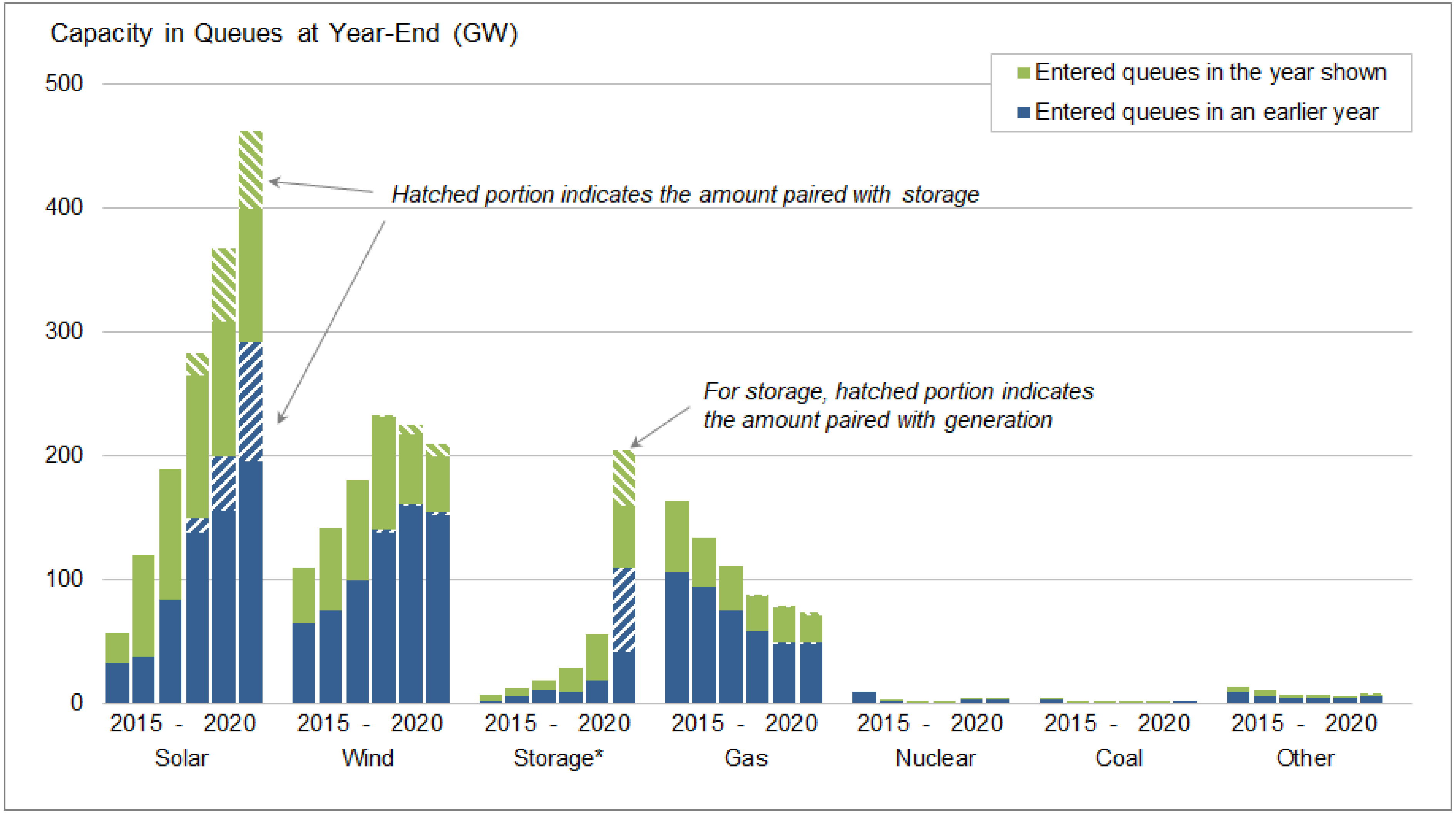
ESIG

Will Gorman

This work was funded by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

Table of Contents

Interconnection queues indicate that commercial interest in hybridization has grown



**Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data*

Storage capacity in hybrids was not estimated for years prior to 2020.

Note: Not all of this capacity will be built

Source: Berkeley Lab review of 37 ISO and utility interconnection queues

CAISO and the non-ISO west have dominate fraction of all proposed solar plants in hybrid configuration

Region	Percentage of Proposed Capacity Hybridizing in Each Region			
	Wind	Solar	Nat. Gas	Battery
CAISO	37%	89%	0%	64%
ERCOT	6%	21%	34%	37%
SPP	4%	22%	33%	38%
MISO	5%	18%	0%	n/a
PJM	1%	19%	1%	n/a
NYISO	0%	5%	6%	2%
ISO-NE	0%	12%	0%	n/a
West (non-ISO)	14%	69%	6%	n/a
Southeast (non-ISO)	0%	13%	1%	n/a
TOTAL	**6%**	**34%**	**6%**	**n/a**

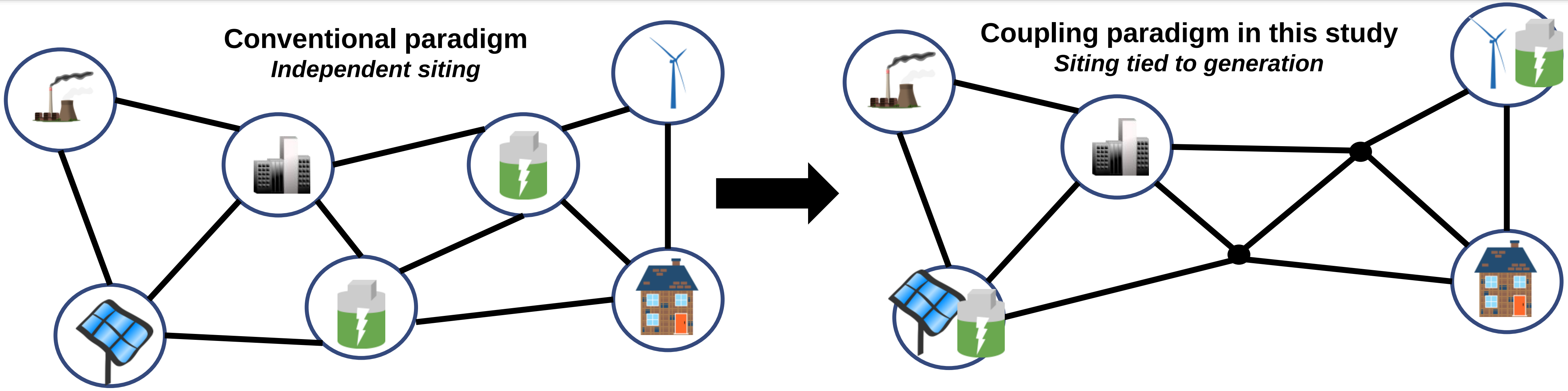
As of end of 2020

Source: Bolinger et al, Hybrid Power Plants: Status of Installed and Proposed Projects, LBNL

- **Solar** hybridization relative to total amount of solar in each queue is highest in CAISO (89%) and non-ISO West (69%)
- **Wind** hybridization relative to total amount of wind in each queue is highest in CAISO (37%), and significantly less in all other regions
- **Battery** development is dominated by hybrids only in CAISO, though data is not available in all ISOs to produce such a breakdown

Is the paradigm shifting on how to site power plants?

- Historically, the electricity paradigm involved Balancing Authorities using transmission network to **optimize geographically disperse** technologies
- Co-locating suggests **conventional wisdom might be changing**
  - Federal incentives?
  - Transmission constraints?
  - Operational/cost synergies?



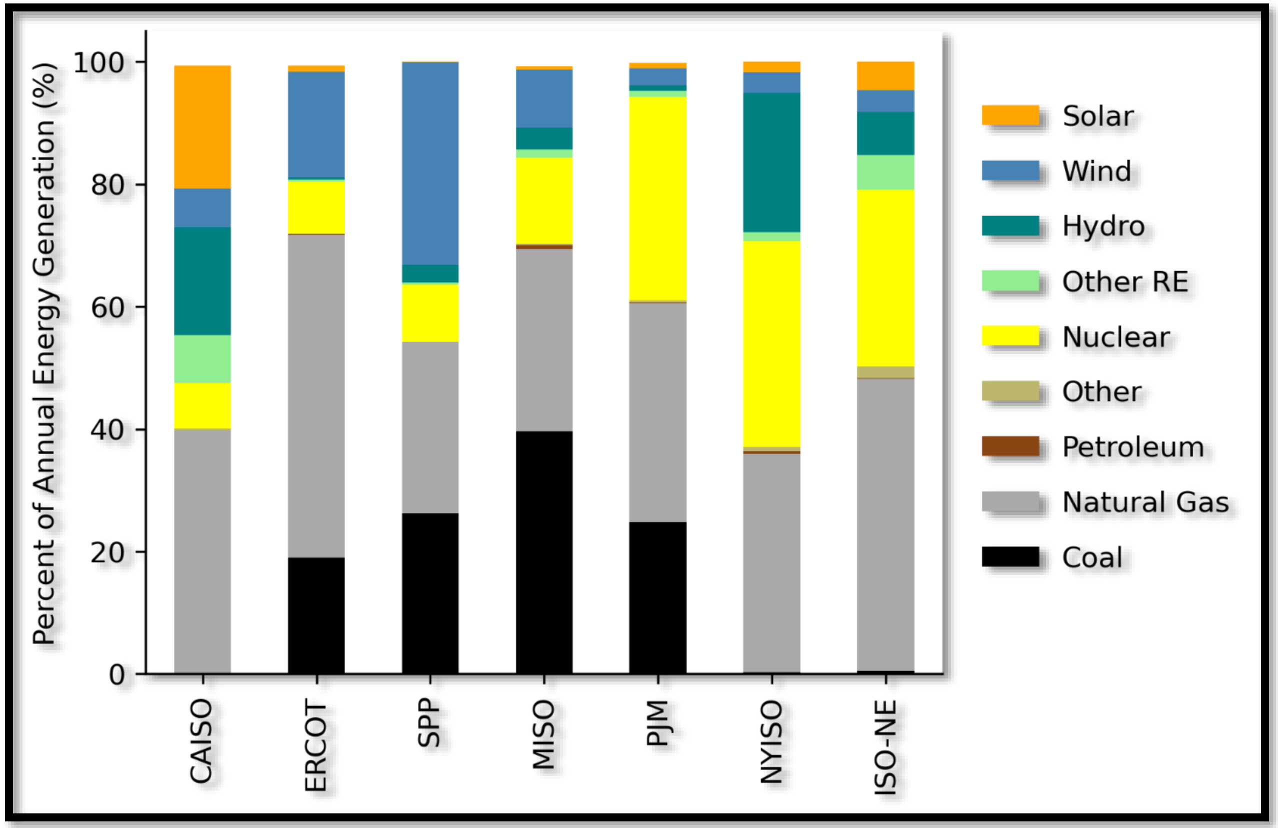
BERKELEY LAB

Table of Contents

Our analysis focuses on historical pricing data from the 7 nodal markets in the United States

- The seven markets are diverse in their ***resource mixes*** and market characteristics
- All operate day-ahead and real-time energy markets
- Use nodal LMPs reflecting ***transmission congestion***, unique compared to European counterparts

2019 Generation sources for ISOs in this study



BERKELEY LAB

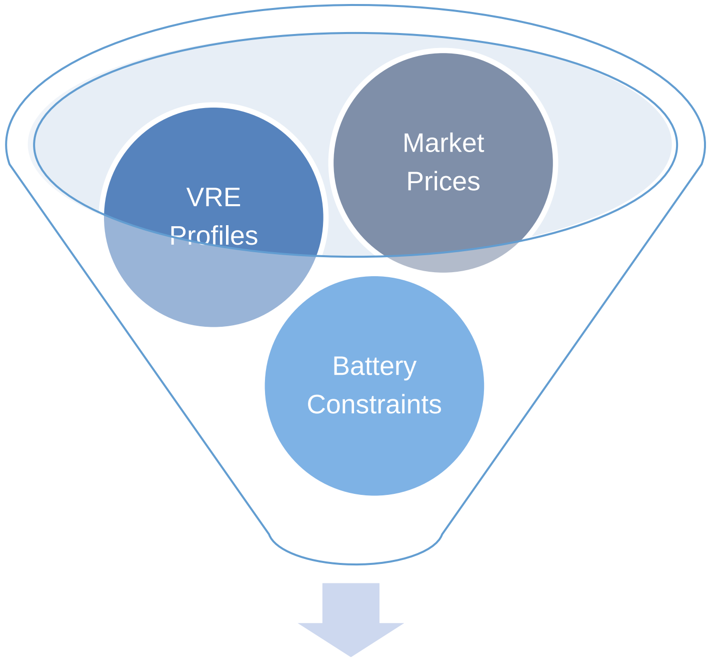
Calculation of value: price taker market optimization

Optimization

- Price taker analysis means resources do not impact marginal price
- **Optimistic:** maximizes real-time energy market revenue with perfect foresight
- **Pessimistic:** develop optimal schedule with day-ahead prices → realized revenue calculated from real-time energy market

Key Inputs

- **LMP prices** at nodes with utility-scale solar, wind, and high volatility
- Average annual capacity price allocated to production in **top 100 net load hours**
- Regulation prices at ISO zonal level *[used only as a sensitivity analysis]*
- PV profiles modeled from **weather data**, standard design assumptions
- Wind profiles modeled from **ERA5** weather data, standard wind power curve



Coupled Project Market Value

Key Outputs

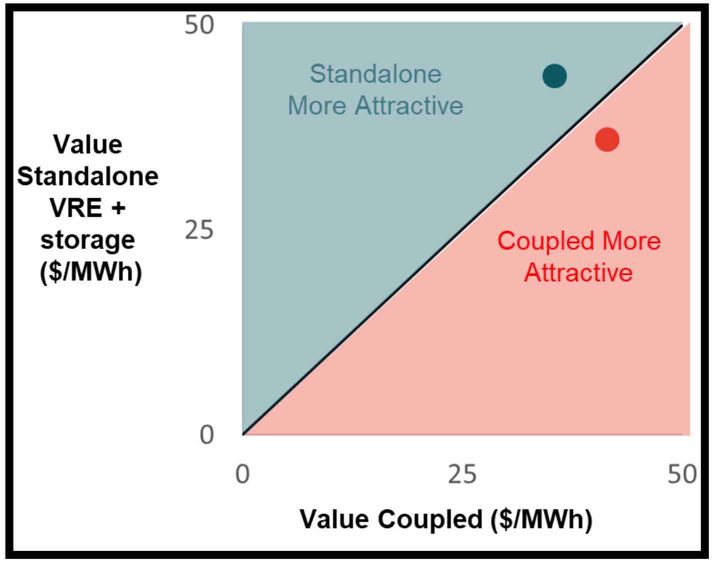
- Energy, capacity, regulation revenues (**levelized using generation from VRE**)

Coupling penalty metric evaluates constraints involved with co-locating batteries at the same VRE location

- Subtract the market value of a co-located generator from the market value of a standalone VRE generator and storage plant ***sited at different locations***

- Considers up to 3 constraints:
  1. Reduced ***geographic options*** for battery siting
  2. Increased operational constraints due to ***infrastructure sharing*** (i.e. inverter / POI)
  3. Restrictions on **grid charging**

Conceptual figure to frame coupling penalty



$$\boldsymbol{Coupling\ penalty} = \Big(\underbrace{[E_{VRE} + C_{VRE}]}_{\textbf{Standalone VRE}} + \underbrace{[E_S + C_S]}_{\textbf{storage value}}\Big) - \underbrace{(E_{CP} + C_{CP})}_{\textbf{coupling value}}$$

Standalone VRE + storage value - coupling value

BERKELEY LAB

Table of Contents

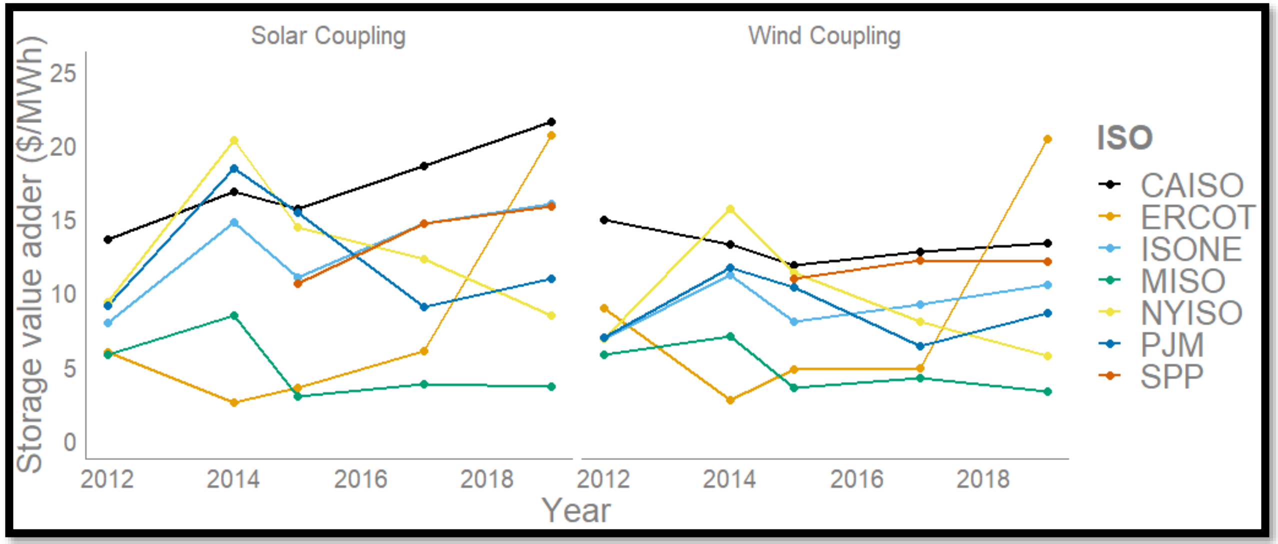
Storage value adder higher in ERCOT and CAISO in 2019

- High value in ***CAISO began to diverge*** from other markets in 2015

- Prior to 2019, ERCOT had a storage value adder that was the ***lowest of all ISOs***

- ***No significant change*** in the value adder between solar and wind couples, besides in CAISO

Aggregated storage value adder across markets

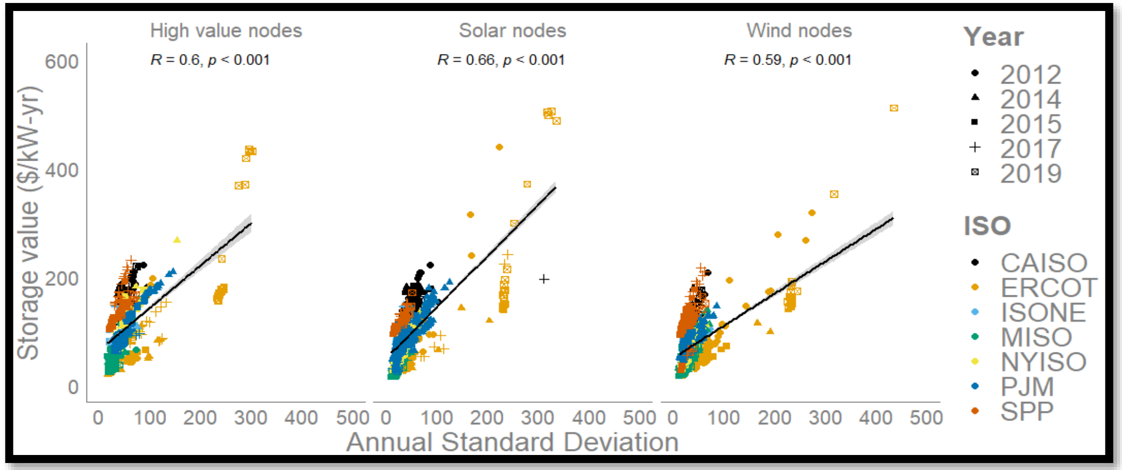


Our high volatility node selection resulted in additional storage value compared to solar and wind nodes

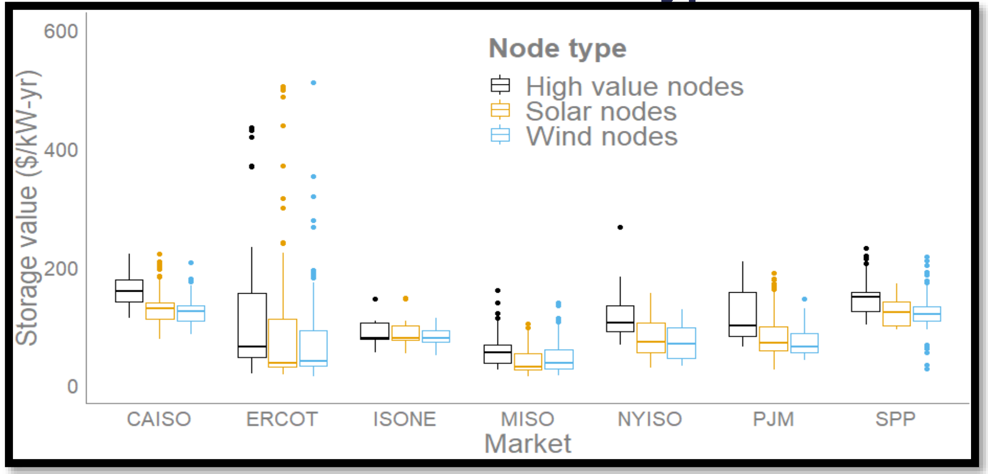
- ***Strong correlation*** between annual standard deviation and corresponding standalone storage value (top graph)

- Median storage value at high volatility nodes is higher than the corresponding value at wind and solar nodes but there is ***significant overlap*** (bottom graph)

Correlation between volatility and value



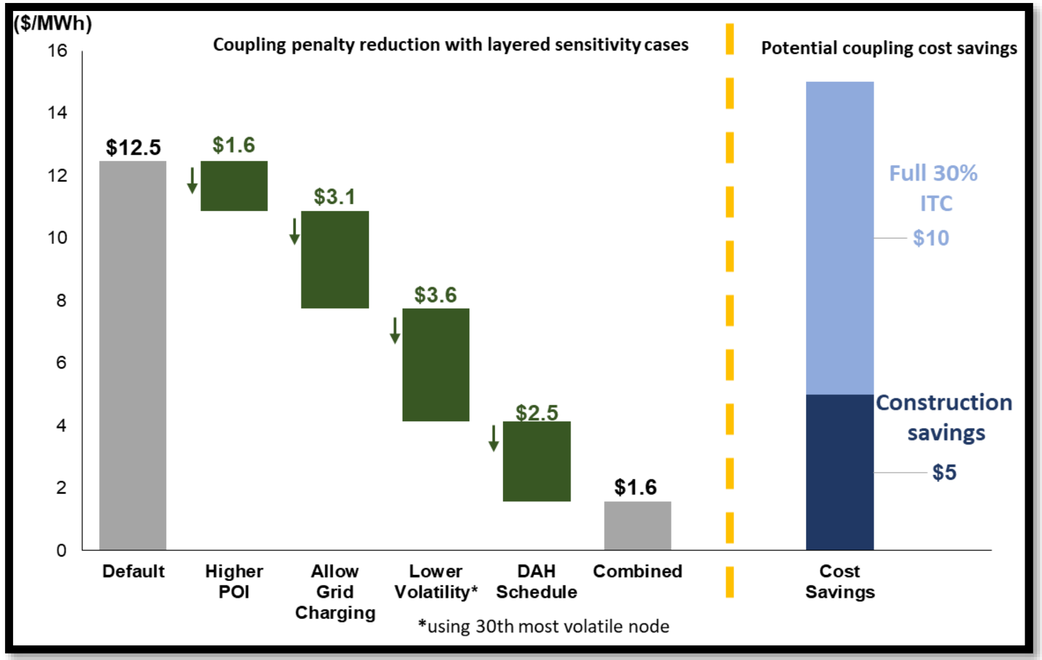
Storage value distribution across market and node type



BERKELEY LAB

Sensitivity cases significantly reduce coupling penalty

- While average coupling penalty is ***$12/MWh*** in default case, it is reduced to ***$1/MWh*** when using a relaxed POI/grid charging constraint, a less volatile node, and the day ahead scheduling algorithm
- Need to compare these penalties to ***potential cost savings of coupling*** including the investment tax credit and construction cost synergies.



Conclusions

- Commercial interest in coupled projects differs from ***convention of independently siting*** and operation of electricity facilities through cost-optimized dispatch via balancing authorities

- Using ***historical prices***, we find that coupled projects can significantly boost standalone VRE value across all markets in the U.S.
  - Value boost ranges from ***$5-$16/MWh,*** depending on sensitivity case
  - Biggest boost in CAISO, where coupled projects can offset value deflation

- Still, there is a penalty to restricting the location to a wind or solar node
  - Coupling penalty ranges from ***$1-$12/MWh,*** depending on sensitivity case
  - Future siting decisions will need to consider nodal volatility more deeply
  - Value of both the ITC (~$10/MWh) and project development cost reduction (~$5/MWh) could offset this penalty

Questions?

- Contact the presenters
  - Will Gorman (wgorman@lbl.gov)

- Additional project team at Lawrence Berkeley National Laboratory:
  - Andrew Mills
  - Cristina Crespo Montañés
  - James Hyungkwan Kim
  - Dev Millstein
  - Ryan Wiser

Download all of our work at:

http://emp.lbl.gov/reports/re

Follow the Electricity Markets & Policy Group on Twitter:

@BerkeleyLabEMP

This work is funded by the Office and Electricity and the Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy

Appendix

Prior paper outlined the pros and cons of hybridization

+ Cost Synergies
- Currently qualify for more financial incentives.
- Shared permitting, siting, equipment, interconnection, transmission, and transaction costs.

+ Market Value Synergies
- Policy driven market design rules may value hybrids more than standalone batteries.
- Batteries can capture otherwise "clipped" energy.
- Batteries can reduce wear and tear from thermal generator cycling.

- Operational and Siting Constraints
- Reduced operational flexibility.
- Potentially sub-optimal siting away from congested areas.

+/- Regulatory Uncertainty
- Market rules for standalone and hybrid batteries continue to evolve.
- Uncertainty related to the future availability of financial incentives (e.g., federal ITC).

Read more:

ELSEVIER

The Electricity Journal

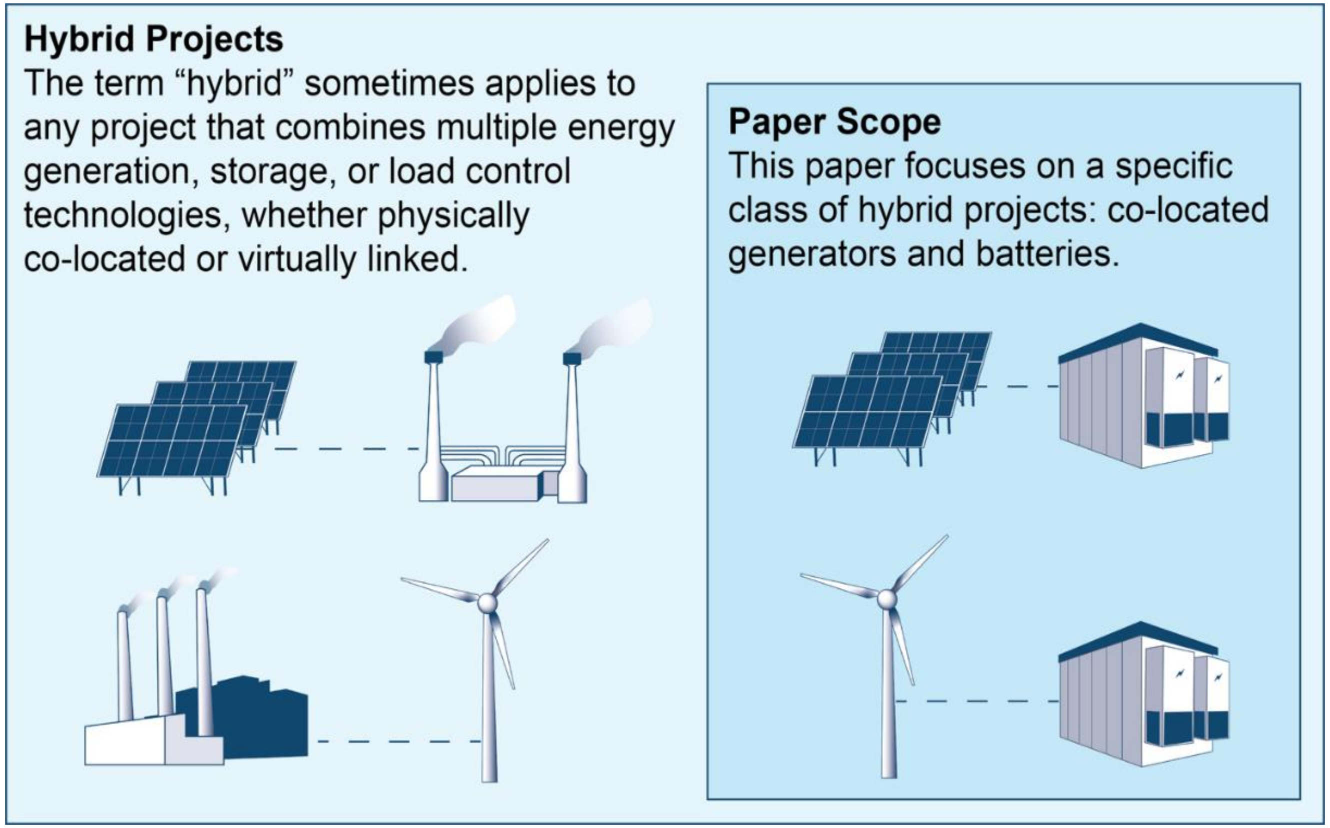
Volume 33, Issue 5, June 2020, 106739

Motivations and options for deploying hybrid generator-plus-battery projects within the bulk power system

- Economic arguments for hybridization (vs. standalone plants) focus on opportunities to reduce project costs and enhance market value
- Not all of these drivers reflect true system-level economic advantages, e.g., the federal ITC and some market design rules that may inefficiently favor hybridization over standalone plants
- Possible disadvantages of hybridization include operational and siting constraints
- If reduced operational flexibility is, in part, impacted by suboptimal market design then this too does not reflect true system-level economic outcomes

BERKELEY LAB

We only consider renewable-plus-battery hybrids due to current commercial interest in these applications



Out of scope examples:

(1) Multiple generation types (e.g. PV + wind)

(2) Alternative storage types (e.g. wind + pumped storage, concentrating solar power)

(3) Virtual hybrids with distributed technologies

(4) Full hybrids with operational synergies

Design decisions and parameters modeled

Parameter	Range	Effect on coupled value
Geospatial	1,763 pricing nodes	Price nodes with higher volatility will be more valuable for storage
Year	2012, 2014, 2015, 2017, 2019	Years with more renewable penetration become more valuable for storage
Dispatch algorithm	Perfect foresight; Day-ahead schedule	Perfect foresight leads to higher revenues through omniscient operation
Point of Interconnection (MW)	VRE capacity; VRE + battery capacity	• More interconnection capacity → more revenue • Potentially limited impact of constraint due to storage discharging at different times than renewable profile
Grid charging	Disallow grid charging; Allow grid charging	• Allowing grid charging increases arbitrage opportunities • Value depends on relationship of prices and renewable profile
Degradation penalty	\$5/MWh; \$25/MWh	Increasing penalty reduces lower value margin cycles, decreasing revenue but limiting degradation
Storage Size (%)	50% of generator capacity	More capacity → more revenue (though potentially diminishing returns)
Storage Duration (hrs)	4 hrs	More duration→ more revenue (though potentially diminishing returns)

BERKELEY LAB

Storage value adder metric used to understand value boost from adding battery to VRE

- Tracks both coupled project value and standalone VRE investment value ***at the same geographic location***

- Particularly helpful in understanding the potential for coupled projects to ***mitigate the value deflation*** that occurs for a VRE generator in regions with high VRE penetrations

$$\boldsymbol{Storage\ value\ adder} = \underbrace{(E_{CP} + C_{CP})}_{\textbf{Coupled value}} - \underbrace{(E_{VRE} + C_{VRE})}_{\textbf{Standalone VRE value}}$$

We consider a number of sensitivities to evaluate the robustness of our results

Default scenario:

- No ancillary services
- 1.3 ILR AC-coupled solar
- Perfect foresight algorithm
- Disallow grid charging for the coupled system
- VRE capacity for coupled POI limit
- $5/MWh degradation penalty
- 4 hr duration battery
- 50% battery to generation ratio

Six main sensitivities:

(1) Regulation reserves included in value

(2) 1.7 ILR DC-coupled solar

(3) Day-ahead schedule

(4) Allow grid charging

(5) VRE+storage capacity for coupled POI limit

(6) $25/MWh degradation penalty

N/A

N/A

BERKELEY LAB

Motivating Research Questions

1. Can ***market revenues*** explain higher commercial activity in the ***Western U.S***?

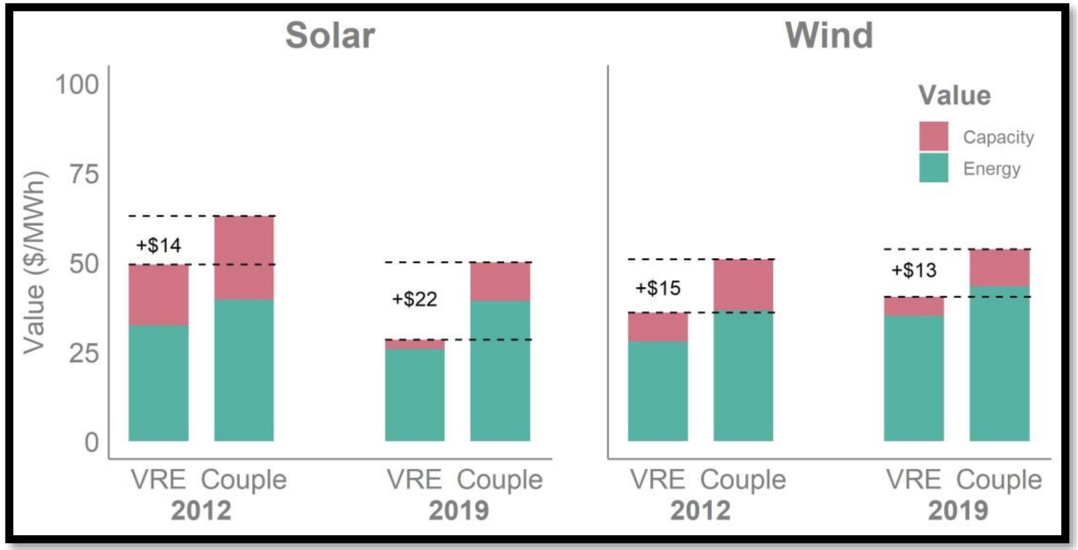
2. Can they explain why commercial activity is ***higher for solar than wind***?

3. Does the traditional concept of ***independently siting*** resources not apply to VRE and storage technologies?

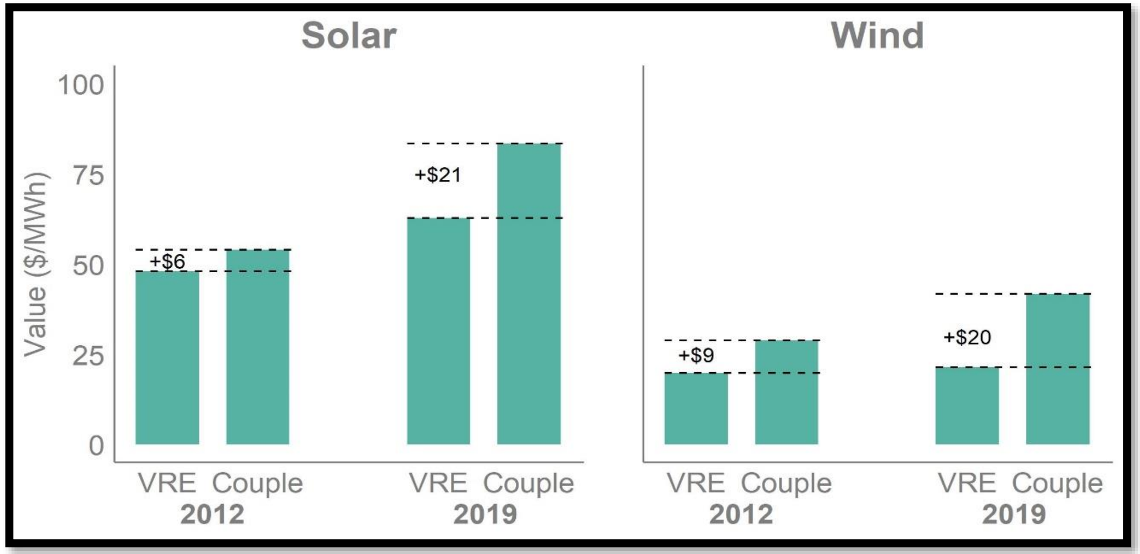
CAISO coupled projects help offset value deflation over the period between 2012 and 2019

- Value of standalone solar decreases significantly between 2012 and 2019 as solar penetration increases from ***2% to 19% of generation***.
- Coupled batteries ***almost offset*** this value decline
- ERCOT sees increase in ***both solar value and coupled value***

CAISO



ERCOT



Note: Value adder metric indicated by black number

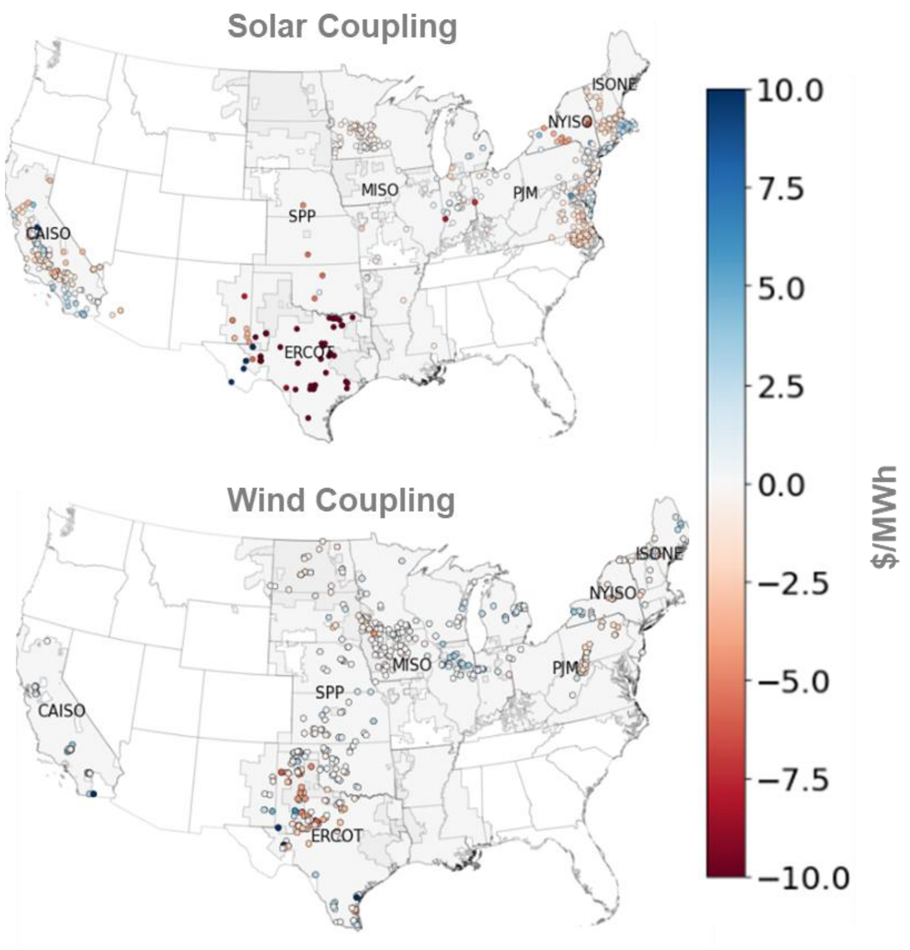
BERKELEY LAB

Results at individual nodes tend to follow the aggregated average in each ISO

- Suggests that results not driven by significant variation at the ***nodal level*** within a market

- ERCOT is a notable exception, where a few nodes in the west see substantially higher value

Geospatial differentiation of storage value adder across nodes

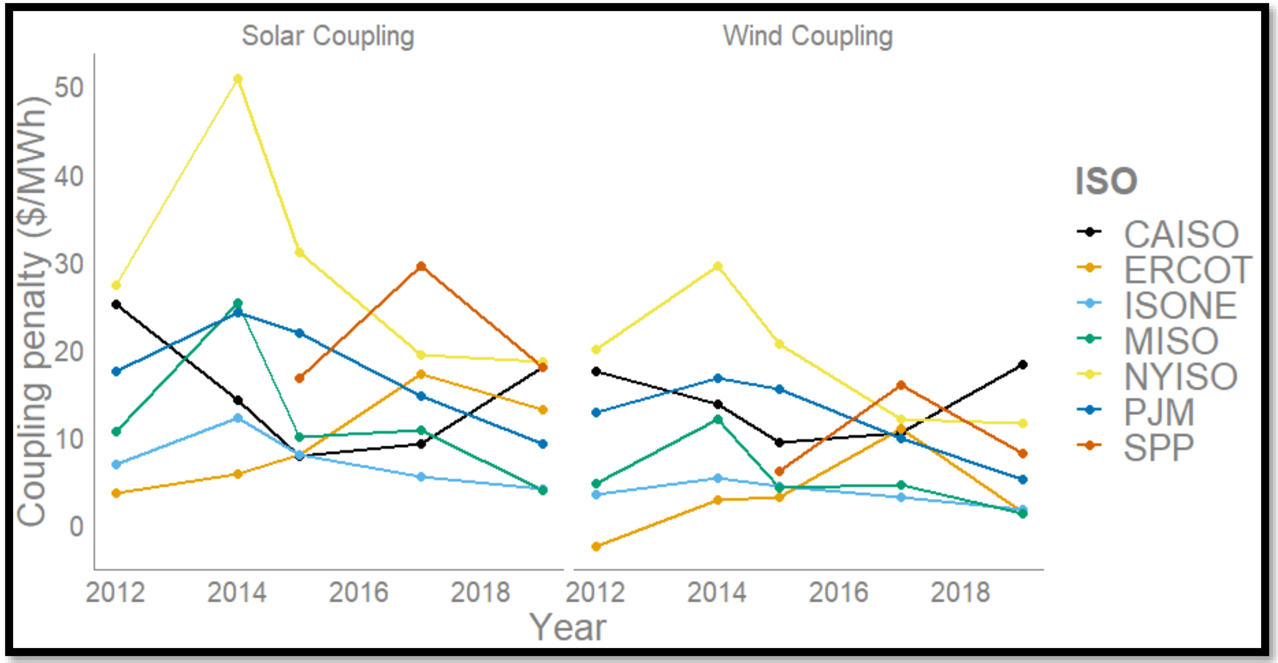


BERKELEY LAB

The value of standalone VRE and storage exceeds the value of coupled projects in our default case

- These results suggest ***significant penalties*** associated with co-locating VRE and battery technologies
- We did not find serious divergences between ISOs overtime
- NYISO is a ***notable exception*** where the penalty was higher than in other ISOs between 2012 and 2015

Aggregated coupling penalty across markets

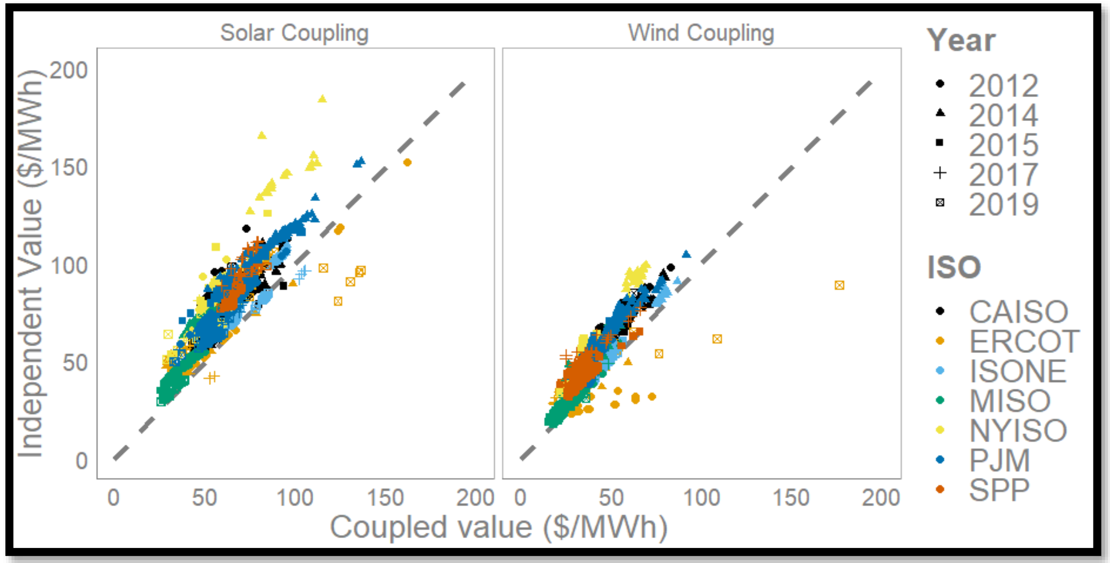


BERKELEY LAB

Only a few wind and solar locations had higher coupling value than standalone value

- Framework figure where dotted grey line represents a coupling penalty of $0/MWh
- The few negative penalties (right of dotted line), notably in ERCOT, illustrates the ***challenge of siting storage*** at high volatility locations for any specific year

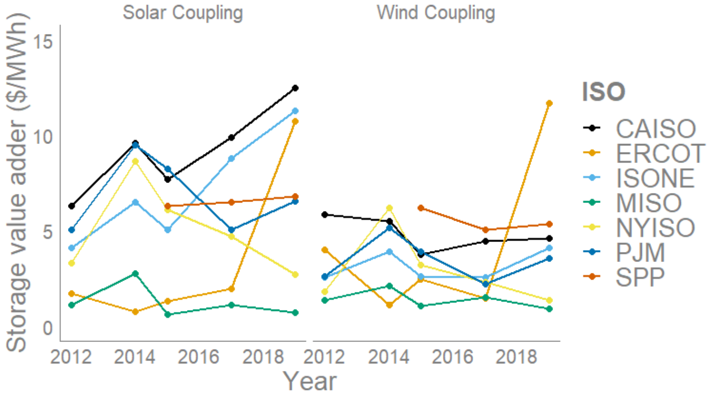
Individual node comparison of coupled and standalone value



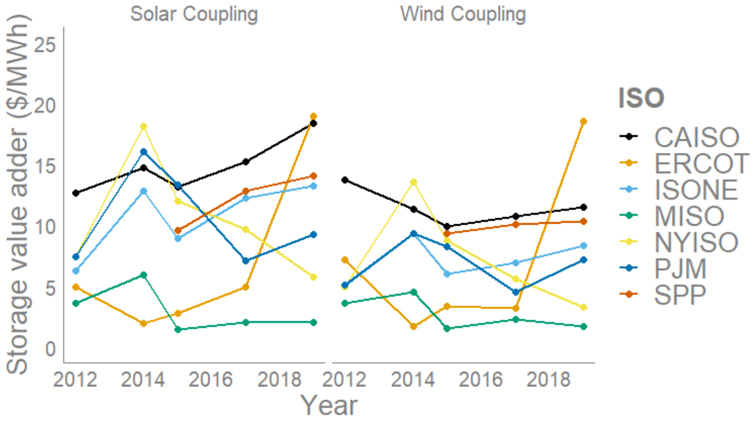
BERKELEY LAB

Sensitivities to storage value adder (absolute value)

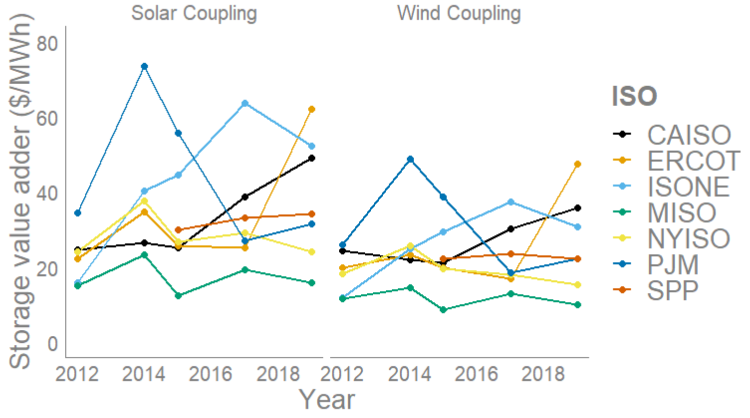
Day-ahead schedule



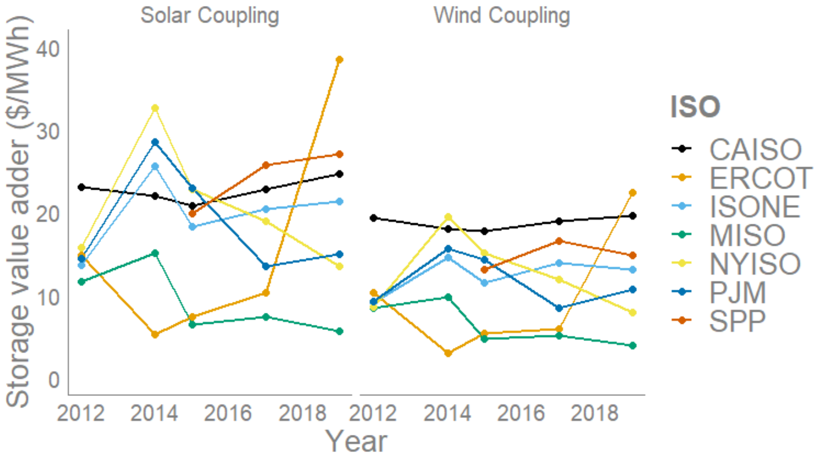
Higher degradation penalty



With regulation value



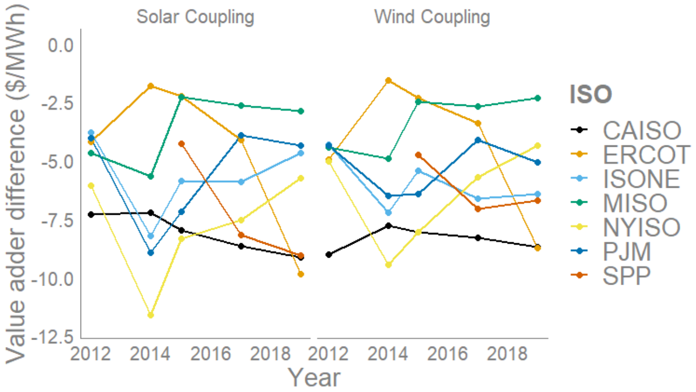
Grid charging / higher POI



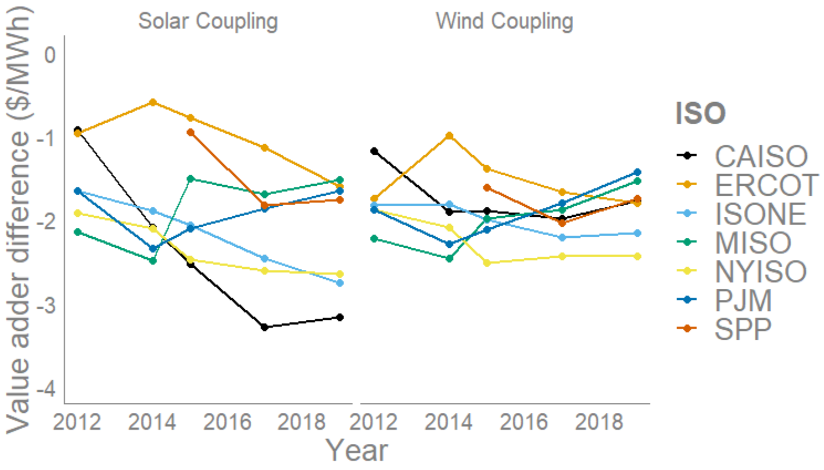
BERKELEY LAB

Sensitivities to storage value adder (differences)

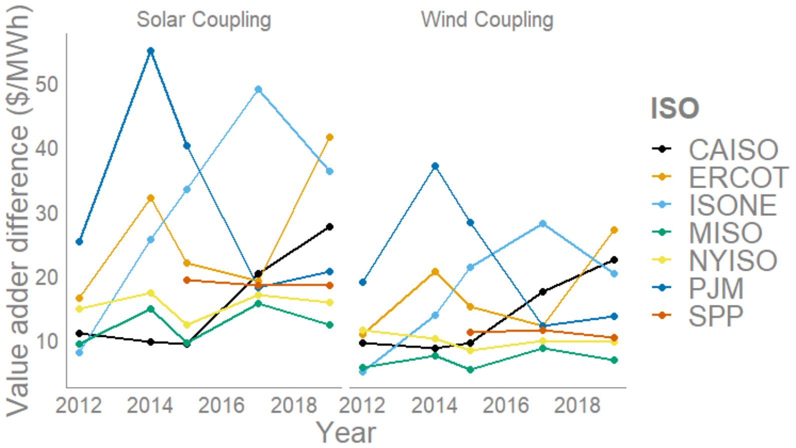
Day-ahead schedule



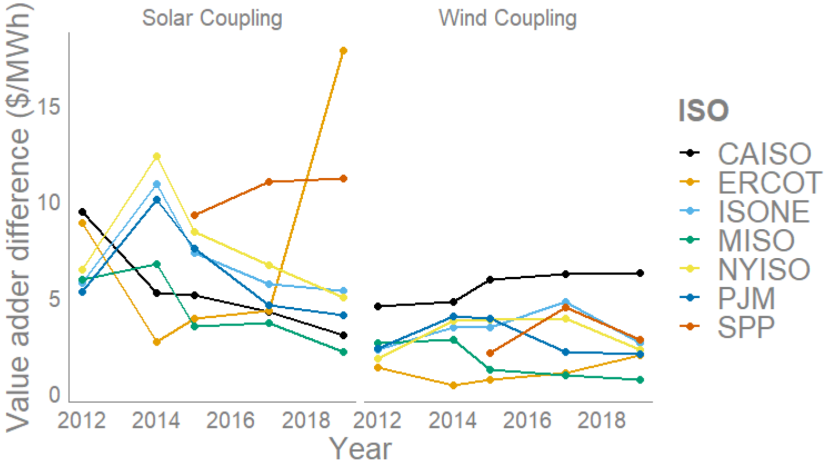
Higher degradation penalty



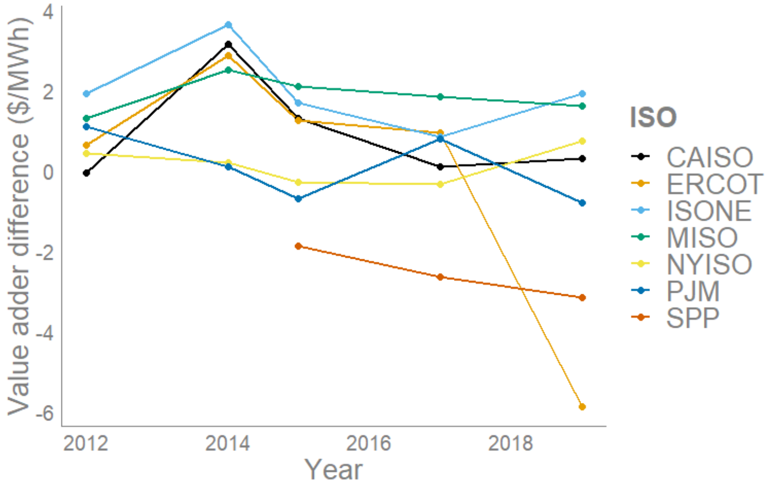
With regulation value



Grid charging / higher POI



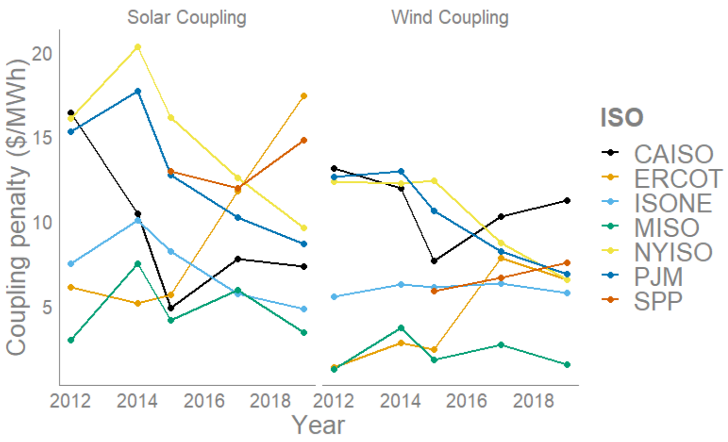
1.7 DC-coupled



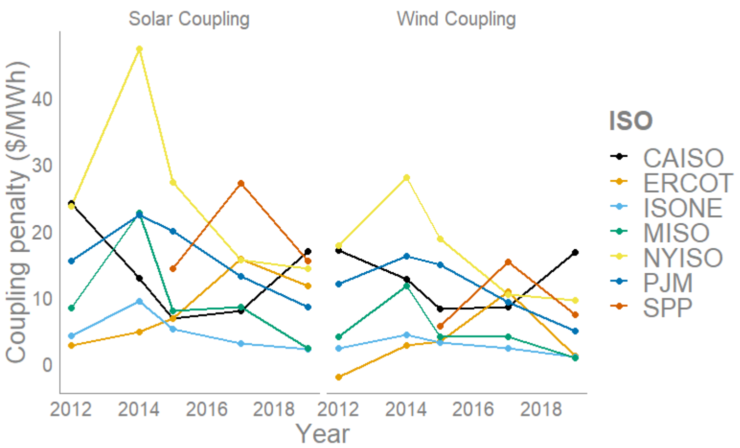
BERKELEY LAB

Sensitivities to coupling penalty (absolute value)

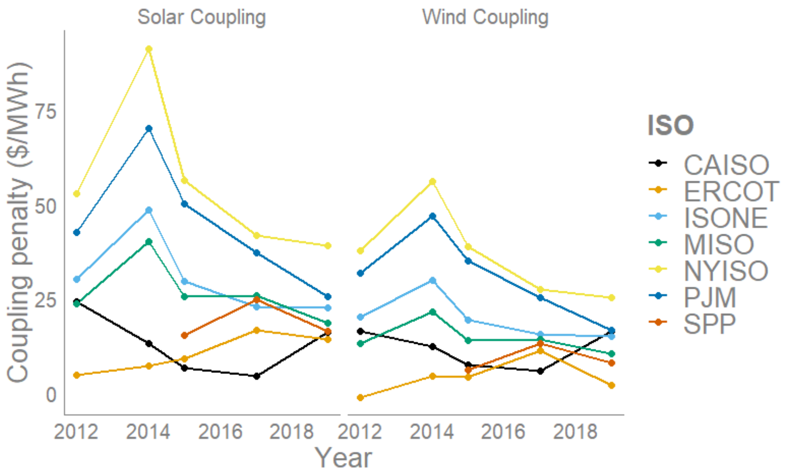
Day-ahead schedule



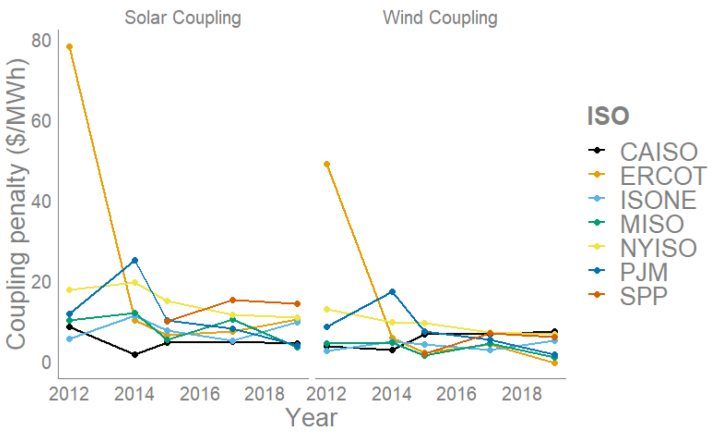
Higher degradation penalty



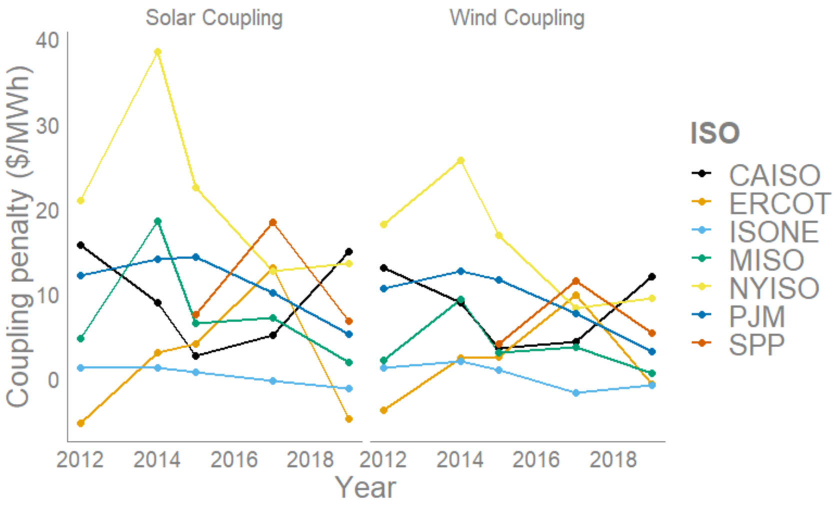
With regulation value



Less volatile nodes

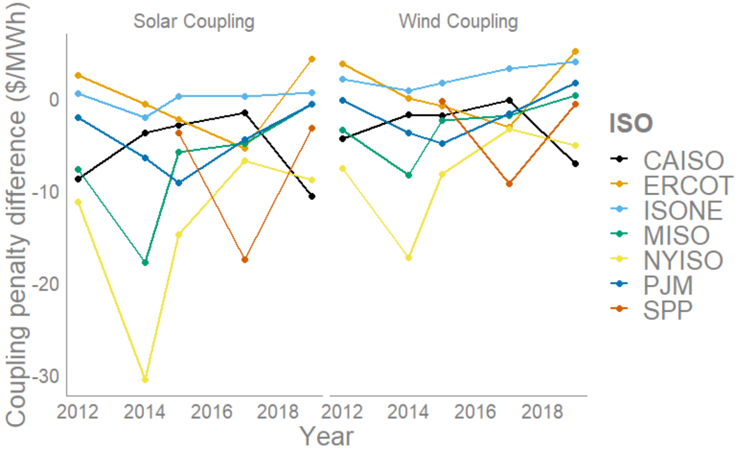


Grid charging / higher POI

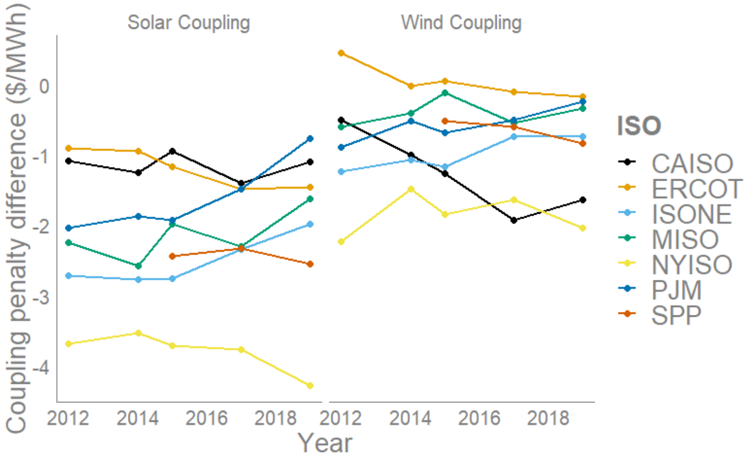


Sensitivities to coupling penalty (differences)

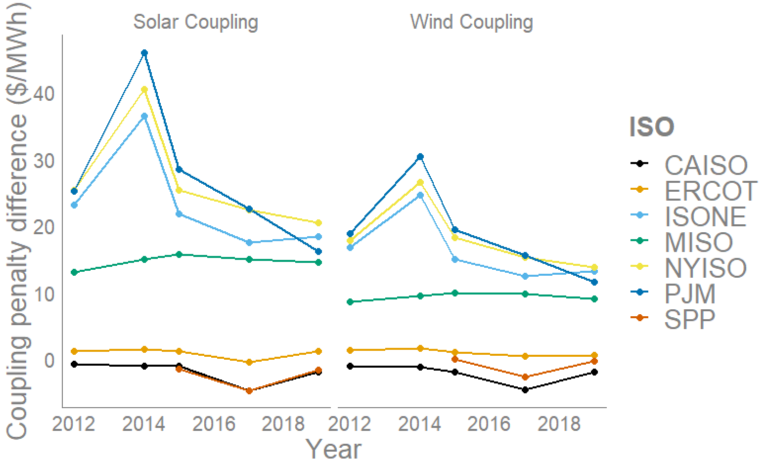
Day-ahead schedule



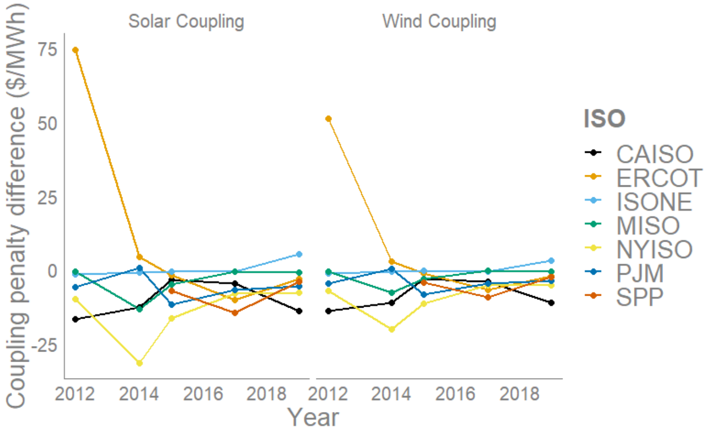
Higher degradation penalty



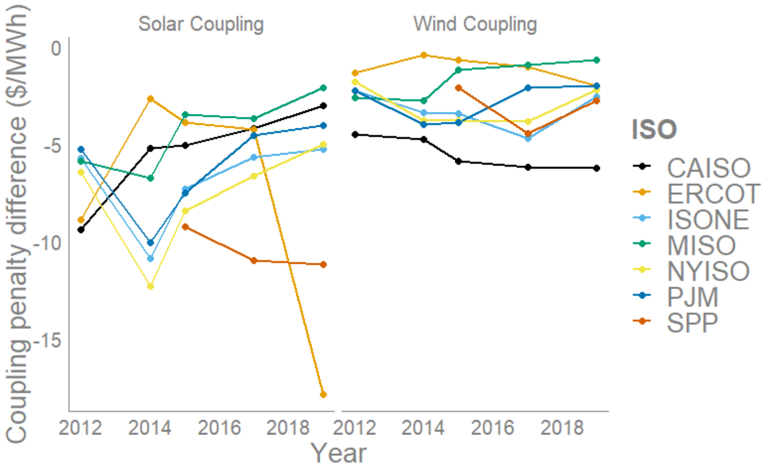
With regulation value



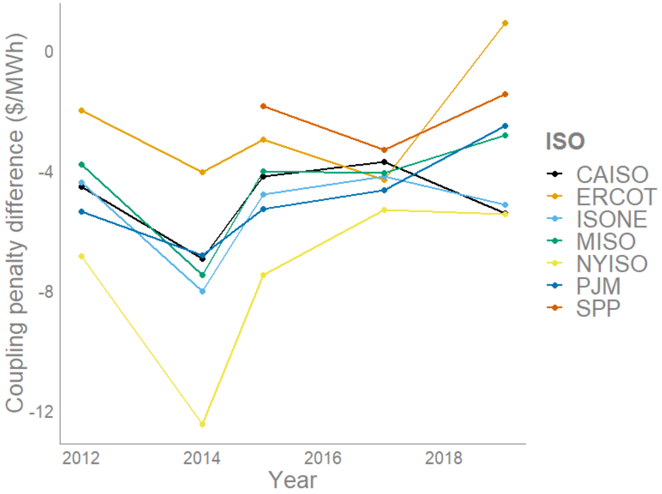
Less volatile nodes



Grid charging / higher POI

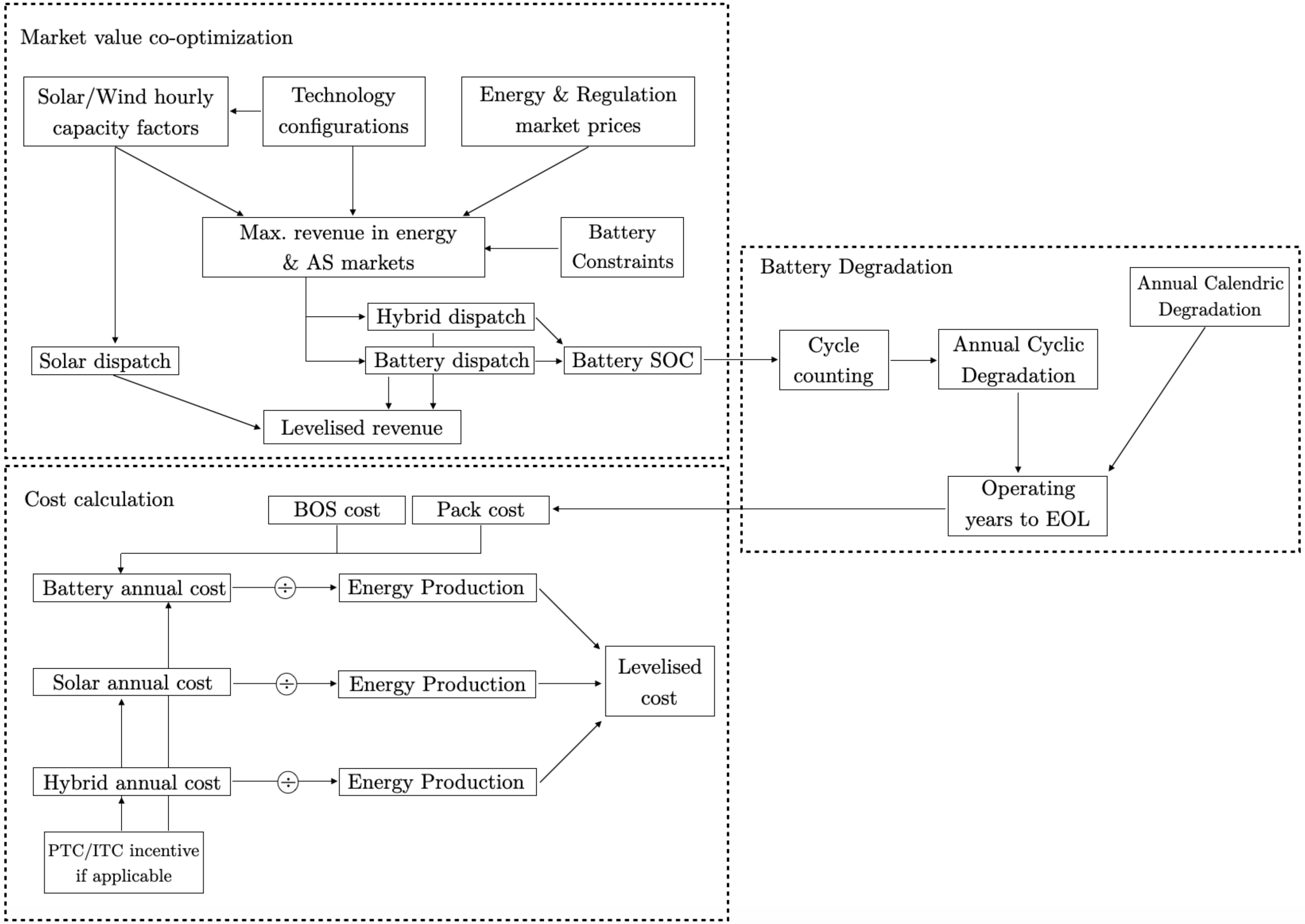


1.7 DC-coupled



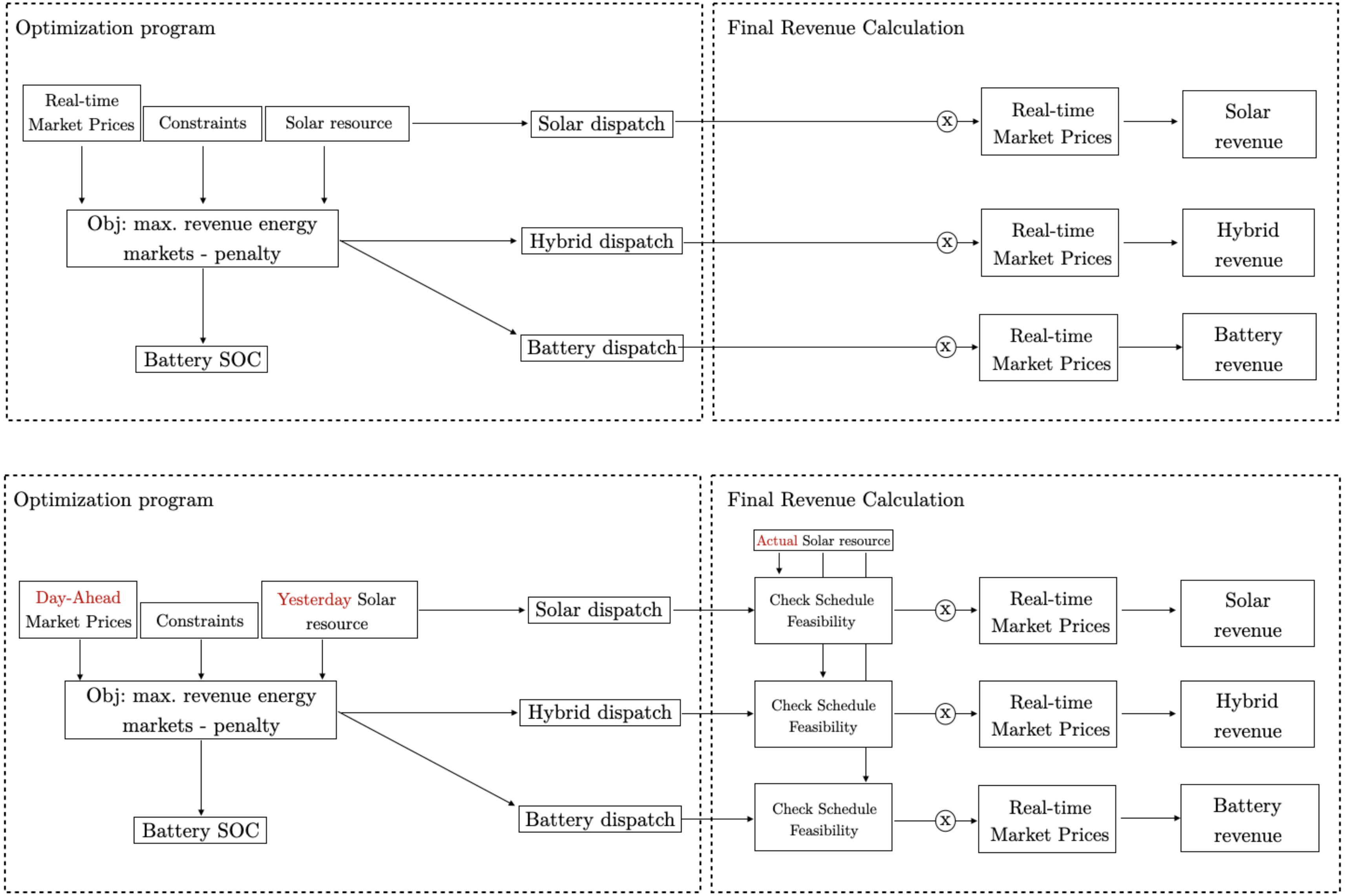
BERKELEY LAB

Overview of modeling framework



BERKELEY LAB

Comparison perfect forecast to Day-ahead schedule model



Base case optimization algorithm

Objective function:

$$Max \sum_1^{8760} [(P_{rt} + P_c/N * NL_m) * G_i] - [D_p * (B_d + B_c)]$$

Subject to:

Beginning state of charge: $S_0 = 0$

State of charge range: $0 \le S_k \le S_{max}$

Power in rate: $0 \le B_C(k) \le B_{max}$

Power out rate: $0 \le B_d(k) \le B_{max}$

Non-simultaneity rule: $B_d(k) + B_C(k) \le B_{max}$

Battery state of charge: $S_{k+1} = S_k + \left[\eta B_C(k) - \frac{B_d(k)}{\eta}\right]$

AC-grid limits: $-I_g B_{max} \le G_i(k) \le POI$

AC-grid balance: $G_i(k) = W(k) + B_d(k) - B_C(k)$

Curtailment allowance: $W(k) \le G_{VRE}(k)$

Where the decision variables are,
G_i = hourly net electricity profile of coupled or storage system (MWh)[10]
B_d = battery discharging (MWh)
B_c = battery charging (MWh)
S_k = battery state of charge at time step k (MWh)
W_k = power generated from renewable resource at time step k

Where the input parameters are,
P_{rt} = hourly real time electricity ($/MWh)
P_c = capacity price ($/MW)
NL_m = hourly indicator (0 or 1) for top N net-load hour for given market
N = number of top net-load hours, set to 100 in this analysis (h)
D_p = degradation penalty ($/MWh)
B_{max} = battery max power capacity (MW)
S_{max} = total energy capacity of battery (MWh)
η = battery one-way efficiency (%)
I_g = binary indicator to allow grid charging (1 allows grid charging, 0 restricts charging to available VRE)
POI = point of interconnection limit
G_{VRE} = standalone VRE generation profile

Ancillary service optimization algorithm

Expanded Optimization model with ancillary service value

Terms which are bolded in blue below represent the additional terms which are added to the original optimization formulation to take into account regulation reserve values.

Objective function:

$$Max \sum_{1}^{8760}[(P_{rt} + P_c * NL_m) * (G_i + \boldsymbol{\gamma R_i})] + [\boldsymbol{R_i * P_{as}}] - [D_p * (B_d + B_c + \boldsymbol{\gamma R_i})] \quad \text{(Eq. 1)}$$

Subject to:

Beginning state of charge: $S_0 = 0$ (Eq. 2)

State of charge range: $0 \leq S_k \leq S_{max}$ (Eq. 3)

Power in rate: $0 \leq B_C(k) \leq B_{max}$ (Eq. 4)

Power out rate: $0 \leq B_d(k) \leq B_{max}$ (Eq. 5)

Non-simultaneity rule: $B_d(k) + B_C(k) \leq B_{max}$ (Eq. 6)

Battery state of charge: $S_{k+1} = S_k + \left[\eta B_C(k) - \frac{B_d(k)}{\eta}\right]$ (Eq. 7)

AC-grid limits: $-I_g B_{max} \leq G_i(k) \leq POI$ (Eq. 8)

AC-grid balance: $G_i(k) = W(k) + B_d(k) - B_C(k)$ (Eq. 9)

Regulation constraint: $\boldsymbol{R_i + B_C(k) \leq B_{max}}$ **(Eq. 10)**

Regulation constraint: $\boldsymbol{R_i + B_d(k) \leq B_{max}}$ **(Eq. 11)**

Regulation AC constraint: $\boldsymbol{R_i + |G_i(k)| \leq}$ **POI** **(Eq. 12)**

Where,
P_{rt} = hourly real time electricity ($/MWh)
P_c = capacity price ($/MW)
NL_m = hourly indicator (i.e. 0 or 1) for top 100 net load hour for given market
G_i = hourly net electricity profile of hybrid or storage system (MWh)[12]
γ = regulation energy served fraction (%)
R_i = hourly regulation reserve profile of hybrid or storage system (MWh)
P_{as} = hourly regulation reserve price ($/MWh)
D_p = degradation penalty ($/MWh)
B_d = battery discharging (MWh)
B_c = battery charging (MWh)
B_{max} = battery max power capacity (MW)
S_k = battery state of charge at time step k (MWh)
S_{max} = total energy capacity of battery (MWh)
η = battery one-way efficiency (%)
I_g = binary indicator to allow grid charging (i.e. 1 allows grid charging, 0 restricts charging to available VRE)
POI = Point of interconnection limit
W_k = power generated from renewable resource at time step k

DC-coupled optimization algorithm

Expanded Optimization model for DC-coupled Hybrids

Terms which are bolded in blue below represent the additional/changed terms which are added to the original optimization formulation to take into account DC-coupling.

Objective function:

$$Max \sum_{1}^{8760}[(P_{rt} + P_c * NL_m) * G_{ac}] - [D_p * (B_d + B_c)] \qquad \text{(Eq. 13)}$$

Subject to:

Beginning state of charge: $S_0 = 0$ (Eq. 14)

State of charge range: $0 \leq S_k \leq S_{max}$ (Eq. 15)

Power in rate: $0 \leq B_C(k) \leq \frac{B_{max}}{\propto}$ (Eq. 16)

Power out rate: $0 \leq B_d(k) \leq \frac{B_{max}}{\propto}$ (Eq. 17)

Non-simultaneity rule: $B_d(k) + B_C(k) \leq \frac{B_{max}}{\propto}$ (Eq. 18)

Battery state of charge: $S_{k+1} = S_k + \left[\mu B_C(k) - \frac{B_d(k)}{\mu}\right]$ (Eq. 19)

AC-grid limits: $-I_g B_{max} \leq G_{ac}(k) \leq POI$ (Eq. 20)

Inverter-out: $\boldsymbol{G_{out-ac}(k) = G_{out-dc}(k) * \propto}$ **(Eq. 21)**

Inverter-in: $\boldsymbol{G_{in-ac}(k) = G_{in-dc}(k) * \propto}$ **(Eq. 22)**

DC-grid balance: $\boldsymbol{G_{in-dc}(k) = G_{out-dc}(k) + B_C(k) - W(k) - B_d(k)}$ **(Eq. 23)**

AC-grid balance: $\boldsymbol{G_{ac}(k) = G_{out-ac}(k) - G_{in-ac}(k)}$ **(Eq. 24)**

Where,
P_{rt} = hourly real time electricity ($/MWh)
P_c = capacity price ($/MW)
NL_m = hourly indicator (i.e. 0 or 1) for top 100 net load hour for given market
G_{ac} = hourly AC net electricity profile of DC-coupled hybrid system (MWh)
D_p = degradation penalty ($/MWh)
B_d = battery discharging (MWh)
B_c = battery charging (MWh)
B_{max} = battery max power capacity (MW)
α = inverter efficiency (%)
S_k = battery state of charge at time step k (MWh)
S_{max} = total energy capacity of battery (MWh)
μ = battery efficiency without inverter losses (%)
I_g = binary indicator to allow grid charging (i.e. 1 allows grid charging, 0 restricts charging to available VRE)
POI = Point of interconnection limit
G_{out-ac} = Energy out from the AC inverter (MWh)
G_{out-dc} = Energy out from the battery and/or PV system (MWh)
G_{in-ac} = Energy in from the AC inverter, that is the grid (MWh)
G_{in-dc} = Energy into the battery from the AC inverter and/or PV system (MWh)
W_k = DC power generated from solar resource at time step k