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Publication Date
2024-10-01

DOI
10.1016/j.renene.2024.121070

Energy Markets & Policy
BERKELEY LAB

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October 2024

This is a preprint version of an article published in *Renewable Energy*. DOI: https://doi.org/10.1016/j.renene.2024.121070

This work was supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) Wind Energy Technologies Office and Solar Energy Technologies Office under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

This document is a preprint version of an article that has now been published in the journal *Renewable Energy*. For the published version, see: https://doi.org/10.1016/j.renene.2024.121070.

Renewable-Battery Hybrid Power Plants in Congested Electricity Markets: Implications for Plant Configuration

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ABSTRACT

Examining coupled renewable-battery power plants ("hybrids") in congested areas provides insights into a future of increased wind and solar penetration. Our study focuses on two types of congested regions, Variable Renewable Energy (VRE)-rich Areas and Load Centers, and explores likely plant configuration choices for developers and transmission network planners. This paper examines how hybrid value, comprising energy and capacity value, varies by plant configuration and congested region type considering factors such as storage duration, battery degradation, and ability to charge from the grid. We select plant locations from across the seven main U.S. independent system operators (ISOs). Hybrid value for each configuration is computed based on profit-maximizing plant operation given perfect foresight, according to observed wholesale power market real time prices from 2018-2021. In VRE-rich Areas, the median increase in energy value from extending storage duration from one to four hours is 29.4% for solar and 26.8% for wind, assuming low battery degradation costs and storage sized to 100% of the plant's nameplate generation capacity. Increasing storage duration beyond four hours does not substantially increase its value from energy markets, even in VRE-rich Areas. We find that solar hybrids reach a 90% capacity credit with four hours of storage, while wind hybrids require eight hours of storage, based on the capacity factor of each hybrid during the top 100 net load hours.

KEYWORDS: Energy Storage, Renewable Energy, Hybrid Power Plants, Electricity Markets, Transmission Congestion.

1. Introduction

Increased deployment of renewable-battery hybrid power plants ("hybrids") is expected and evidenced by the rapid growth in their appearance in interconnection queues (Rand et al. 2021). Recent research has highlighted the potential benefits and trade-offs of pairing variable renewable energy (VRE) and battery energy storage in the same location (Gorman et al. 2021).

Given the continued deployment of VRE and potential benefits of co-located VRE and storage, it is important to study hybrid plant designs across a range of conditions, including in regions that face transmission congestion. This is especially true in cases where the share of VRE on the grid is expected to increase substantially, which would tend to increase congestion absent sizable increases in transmission capacity. By studying congested regions, we can better understand the nuances of how VRE, storage, and hybrids can interact with the power system and support a high-renewable future (Kim, Bolinger, et al. 2023).

However, many studies on integrating VRE and storage into power grids have not focused on transmission constraints (Braff, Mueller, and Trancik 2016; Denholm et al. 2020; Denholm and Mai 2019; Vejdan and Grijalva 2018; Kittner, Lill, and Kammen 2017). Transmission constraints can create congested regions within the power grid, leading to either higher or lower wholesale electricity prices depending on whether the congestion is caused by under- or over-supply of local generation relative to local load. Castillo and Gayme (2014) found that transmission constraints can lead to a decrease in the amount of renewable energy that can be integrated into the grid. Further, failing to consider transmission constraints can result in suboptimal deployment and integration strategies for VRE and storage systems, leading to less efficient use of these resources and higher integration costs (Wu and Jiang 2019).

"Congested regions" are locations where the flow of electricity on the grid is restricted due to transmission capacity limits, as identified by market prices that differ from regional averages. This study considers two types of congested regions: those with under-supply and those with over-supply of low-cost local generation relative to local load. As VRE resources continue to be deployed over time, especially in remote areas, local VRE over-supply is anticipated, leading to growing congestion and a decrease in value (Kim et al. 2021). Hybrid plants have been proposed (Gorman et al. 2022; Montañés et al. 2022; Kim et al. 2021) as a way to both reverse this value decline and ensure reliable electricity supply. Additionally, certain kinds of hybrids, especially solar-plus-storage, have been identified as a means of addressing congestion in load pockets, where local load otherwise exceeds local supply.

The objective of this paper is to identify which specific hybrid configurations drive the greatest hybrid project value in both types of congested areas of the electricity network. Understanding the relative value of different hybrid plant configurations in congested regions can provide valuable insight into configuration choices and how market policies should be designed. The insight into plant configurations can also be used to help design energy system models, where plant configurations must be set *a priori*. As renewable energy penetrations grow and existing thermal power plants retire, congested regions of both types may increase in prevalence. By focusing on areas that are already congested, this paper seeks to offer valuable insights into configuring hybrid plants for maximum value in different locations well into the future.

By examining how price profiles in congested areas influence the value of hybrid configurations and how variations in configuration impact hybrids' system value, our analysis fills a gap in current literature. With few exceptions (Kemp et al. 2023), previous research on the estimated value of hybrid plants has not investigated how geographic constraints, such as transmission line congestion, affect the value of coupling storage with generators (Kim et al. 2021; Montañés et al. 2022). Previous studies highlight the importance to system operators and utilities of considering the likely operational behavior of hybrid power plants in different geographic regions and their associated transmission line congestion levels (Glick and McNamee 2020). Because the operational behavior of hybrid power plants depends on their underlying design choices, it is important that independent system operators (ISOs) and regional transmission operators (RTOs), who plan the transmission network, understand which hybrid configurations will likely be deployed in congested areas in the near future (Montañés et al. 2022). Notably, our study did not consider the cost associated with optimal configurations, which future research should explore. A previous study (Montañés et al. 2022), which used a representative hybrid plant for each ISO/RTO in the U.S., found that the incremental value of hybrid plant revenues was capped after two hours of storage duration.

To quantify the electricity market value of hybrid projects in congested areas, we use real time market prices from seven U.S. ISO/RTOs and a linear optimization program. We focus on the system value and capacity contribution of hybrid plants and estimate how specific configurations impact electricity markets. In addition, we explore the role of hybrid plants in capacity markets to provide a comprehensive examination of their economic potential.

Our approach includes an important simplification, that of perfect foresight. Hybrid plants need to make decisions about when to charge and discharge their batteries, and our simplification assumes that these decisions are fully optimized given a time series of local, real time prices and generation from the attached wind or solar plant. In reality, hybrid plant operators have imperfect information about future generation and prices and thus make sub-optimal dispatch decisions. Gorman et al. (2022) explored the value of adding batteries to wind and solar plants in U.S. markets and found that optimizing dispatch with perfect foresight provided a substantial improvement in value versus a lower bound estimate of sub-optimal dispatch profile created without any forecasting (for example, the value of adding batteries increased by roughly 50% with perfect foresight in multiple regions and years). The values reported here, assuming perfect foresight, represent an upper bound of what could be achieved with high quality forecasting. While developing dispatch strategies given imperfect forecasts is an important topic, simplifying the scope with the assumption of perfect foresight allows this research to focus on evaluating value difference between plant configurations.

A second important simplification is to evaluate energy value based only on real time prices. This valuation approach does not necessarily represent the revenue a plant could earn (for example, many plants sign longer term contracts that reduce exposure to hourly prices), but instead represents the real time market cost of replacing generation from the plant. Plants that choose, or are required, to participate in day ahead markets face an additional complication that if their real time dispatch varies from their day ahead dispatch they will have to reconcile that difference at real time market prices. As above, forecasting can also help to minimize reconciliation costs (Wang et al. 2022), and this simplification was also chosen to facilitate our focus on plant configuration.

This study's findings can help system planners, system operators, utilities, developers, and policy makers better understand the factors affecting the value and performance of hybrid projects in congested areas, and consequently make more informed decisions about how these plants can best be deployed.

2. Background: Evaluating hybrid plant value in energy and capacity markets

Wholesale energy markets and capacity mechanisms are key revenue streams for generators – and, due to their locational and temporal variability, significant signals for investment and operational decisions – in many regions of the world. Energy markets provide a price per unit of energy, while capacity mechanisms incentivize generators to be available during peak-need periods to support reliability. Two other common locational investment signals are grid connection charges (e.g., in France, Sweden, Mexico, and the U.S.) and location-specific grid usage charges (e.g., in Australia, India, Norway, Sweden, and the UK) (Eicke, Khanna, and Hirth 2020). Since the former are not typically impacted by hybrid plant design choices behind the point of interconnection and the latter are not relevant to the regions studied here, this study focuses exclusively on energy and capacity market signals.

Price-taker models are one proven tool used to evaluate the economic performance of hybrid systems based on these market signals. In one line of research, these models define certain technical specifications, such as aggregate generation profiles (Couto and Estanqueiro 2021; Ziegler et al. 2019), performance parameters (Ross 2018), and reliability or availability thresholds (Ross 2018), and then identify the configuration that can meet the specifications at the lowest cost. Other tools and studies aim to identify the optimal plant design in an effort to maximize its value (Schleifer et al. 2022, Montañés et al. 2022, Castillejo-Cuberos et al, 2023). Price-taker models do not consider how their investment or operational decisions would impact the markets, which is a notable limitation.

The spatial granularity of market signals affects their ability to reflect congestion conditions in the transmission system. Wholesale electricity markets in the U.S. and Mexico reflect transmission constraints and losses through locational marginal prices (LMPs) defined at thousands of nodes. This fine spatial granularity reflects local, regional, and interregional congestion. In contrast, some markets (e.g., in India, Norway, and Australia) are only divided into a small number of zones – a coarse granularity that reflects congestion between, but not within, zones. In the absence of detailed grid modeling, the applicability of this research is limited in regions with a zonal model (Borowski 2020).

Our approach and geographic context allow us to incorporate spatiotemporal variation in estimates of system value while comparing hybrids located in differently congested areas in one consistent price-taker framework. This allows us to gain insights into the relative system value of hybrids in terms of geography and electricity markets.

3. Methods

In this study, we incorporate the signal of energy and, where applicable, capacity markets to analyze the value of multiple configurations of hybrid plants at each location of interest. We calculate "value" as the annual market revenue of power bought and sold at wholesale market prices.

This study does not consider ancillary services for three reasons. First, although ancillary services can be valuable today, the size of existing ancillary services markets is small, and they are quickly saturating with the first wave of storage deployments, for example, see trends in ERCOT (Mago 2023). Second, the geographic resolution of ancillary services pricing is generally too coarse to distinguish between the types of congested areas in scope here. Finally, ancillary service products and requirements vary considerably across markets, so variation in ancillary service revenues across plants may be more reflective of simply what market footprint the plant is in, as opposed to the congestion characteristics we set out to study.

Price data is sourced from Velocity Suite, which features more than 50,000 price nodes across the U.S. Plants are matched to the appropriate locational marginal price (LMP) nodes; usually these are assigned by Velocity Suite, or by selecting the closest node based on distance.

The study period covers the four years from 2018 through 2021. Each combination of plant location, configuration, and year provides a different value. Wind and solar hourly profiles are obtained from data that underlie two National Laboratory reports (Wiser et al. 2022; Bolinger et al. 2022).

A limited number (10) of congested regions are chosen for assessment based on historical pricing data and a comprehensive analysis of grid congestion patterns. Congested regions are divided into two types: (1) "Load Centers" are defined as areas with high electricity demand and higher prices, and a transmission constraint for bringing energy *into* the area; (2) "VRE-rich Areas" are those having abundant renewable energy resources and lower prices, and a transmission constraint for moving energy *out* of the area.

Figure 1 contains a map indicating the locations selected for the present analysis, whether they are Load Centers or VRE-rich Areas, and whether the renewable generation is wind- or solar-powered.

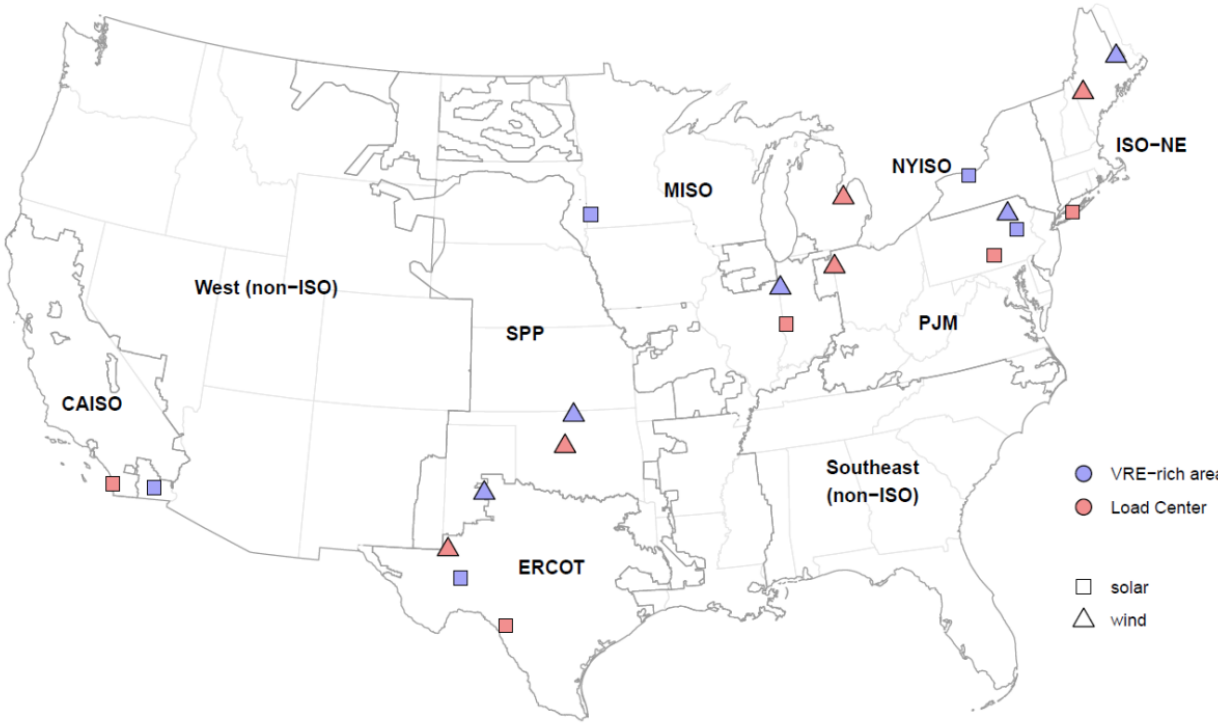

Figure 1: Geographic Distribution of Plant Locations by Category Across U.S. ISO/RTOs.

3.1 Hybrid dispatch

A linear optimization model is used to calculate hybrid plants' optimal dispatch. The model accounts for the location-specific output profiles of wind and solar projects, as well as battery storage capacity and duration. The model maximizes the annual market revenue of the hybrid plant based on the historical locational marginal prices (LMPs), which reflect the region's transmission constraints. The model also factors in capacity value, whose calculation is described in Section 3.3. Curtailment of wind and solar and their respective hourly generation profiles are also addressed in the model, which accounts for grid limitations and allows wind and solar plants to adjust their generation output in response to low or negative pricing conditions.

Hybrid dispatch in our modeling is constrained by several factors: the energy capacity of the battery, the power rating of the battery, the power from the renewable generator (modeled using historical hourly weather data), and the point of interconnection (POI) capacity. Additionally, a linear degradation penalty ($/MWh) is applied to battery charge and discharge. This functions as a hurdle rate to prevent the battery from being cycled for low-value opportunities and consequently influences dispatch decisions. Constraint parameters are adjusted depending on whether the battery is allowed to charge from the grid.

Calculations use the open-source optimization solver COIN-OR Linear Programming Interface, which was implemented using the Pyomo package in Python. Previous studies provide details of the optimization program (Gorman et al. 2022; Kim, Kahrl, et al. 2023).

3.2 Hybrid energy value

The annual energy market value of hybrid plants is calculated by multiplying hourly real-time wholesale power prices with the power from both the generator and battery that is delivered (or, in the case of battery charging, consumed) across the shared POI, and then summing the results over the year.

We focus on value rather than net value, as the latter is heavily dependent on the cost of the hybrid plant, which can vary significantly across regions and has been changing over time. This makes it difficult to assess the economic attractiveness of different configurations. Gorman et al. (2022) analyzed hybrid configurations with a net value framework that accounts for value and cost. The present work focuses solely on the value impacts of different power plant configurations, normalized by annual net power delivered (Eq. 1). By doing this, we provide a more generalizable comparison of the economic attractiveness of different configurations and allow a more accurate assessment of their economic viability. Assessments of costs will be considered in future research.

$$Energy\ Value\ = \frac{\sum_t P_t^{RT} \times G_t^{RT}}{E_{VRE}} \tag{Eq. 1}$$

Where:
P_{RT} = Real-time wholesale power price at time *t* ($/MWh)
G_{RT} = Net power delivered from the hybrid plant at time *t* (MWh)
E_{VRE} = Annual energy generation by the underlying VRE generator (MWh/yr)

3.3 Hybrid capacity value

We calculate capacity value as the product of a “capacity credit” and a “capacity price.” Specifically, the capacity factor of a hybrid plant during the highest 100 net load hours of the year serves as the basis for determining the capacity credit attributed to the plant (i.e., a fraction from 0.0 to 1.0). Importantly, the capacity price varies depending on the market in which the hybrid plant operates. For clarity, net load in each region is defined as the ISO/RTO reported load minus the system-wide aggregate solar and wind generation profile, obtained from Velocity Suite.

Though energy prices are typically high during the top 100 net load hours, energy price patterns alone do not ensure that a hybrid plant will maximize its potential discharge during these hours. To ensure each plant is providing its maximum possible contribution to capacity credit, we include a nominal hourly capacity price adder (set at $500/MWh) during the top 100 net load hours. This specific nominal adder was chosen based on empirical observations and sensitivity analysis, showing that it adequately emphasizes these peak load hours in the dispatch algorithm without unduly skewing the results (Kim et al. 2021). After hourly dispatch is calculated, we throw away the price adder so it is not counted as revenue for the plant; in other words, the adder is only used to drive the dispatch schedule. Empirical studies, including previous research and works such as Kim, Kahrl, et al. (2021), suggest that average production during peak net load hours can be a reliable proxy for estimating the reliability contribution of hybrid plants when benchmarked against probabilistic representations of power system reliability (Mills and Rodriguez 2020; Stephen, Hale, and Cowiestoll 2021).

Equation 2 describes how capacity value is calculated, with the first term on the right side representing the capacity credit.

$$Capacity\ Value\ = \left(\frac{\sum_{h \in top100hrs} Energy_h}{100 \times Max\ Capacity}\right) \times Capacity\ Price \tag{Eq. 2}$$

Where:

$\sum_{h \in top100hrs} Energy_h$ = Sum of the energy generated by the hybrid plant during the top 100 net load hours (MWh)

$Max\ Capacity$ = Maximum capacity of the hybrid plant (MW)

$Capacity\ Price$ = Market-specific capacity price ($/MW)

Capacity rules are complex and can differ by region. For hybrid projects, which are relatively new, capacity rules are still changing and under development in some regions (Energy Storage Association 2020). Because of this complexity, we employ the simple and uniform approach to calculating the capacity credit described above. Note that we do not calculate a capacity value in ERCOT because it is the only region where load serving entities (LSEs) are not required to procure resources to maintain a planning reserve margin.

The capacity prices used in this study are the same as those compiled for Wiser et al. (2022) and Bolinger et al. (2022). They are based on historical annual average capacity prices in each ISO/RTO, accounting for different capacity zones. Capacity prices from organized forward-capacity markets were used in MISO, PJM, NYISO, and ISO-NE. For SPP, the price of average short-term capacity transactions reported in Federal Energy Regulatory Commission (FERC) Electronic Quarterly Reports was used. The use of an annual capacity price is a simplification, as capacity prices can vary by season, or even by month, depending on the market.

3.4 Configuration choices and scenarios

We analyze the value of selected locations in the seven organized wholesale power markets in the U.S. The set of analyzed configurations focuses on design choices consistent with past literature and current market conditions, as well as choices that may yield important insight on design decisions in congested areas.

All hybrids considered in this study consist of a 100 MW (AC) wind or solar generator coupled with batteries of 100 MW capacities, both of which are typical in the U.S. The battery's energy-to-power ratio, or duration, is scaled in hourly increments between one and 10 hours. This enables an important assessment of how battery duration impacts hybrid value in congested areas. Solar hybrids are AC-coupled, with an inverter loading ratio of 1.3 (i.e., with a maximum solar output 30% larger than the inverter's capability, as is common). The batteries and generator each have their own inverter, connecting to the grid on the AC side through a common POI. Consistent with U.S. conditions, the capacity of the POI is 100 MW (the AC capacity of the VRE generator), so maximum battery discharge is not possible when the associated VRE plant is generating electricity. Figure 2, shows a simple schematic of the hybrid plants.

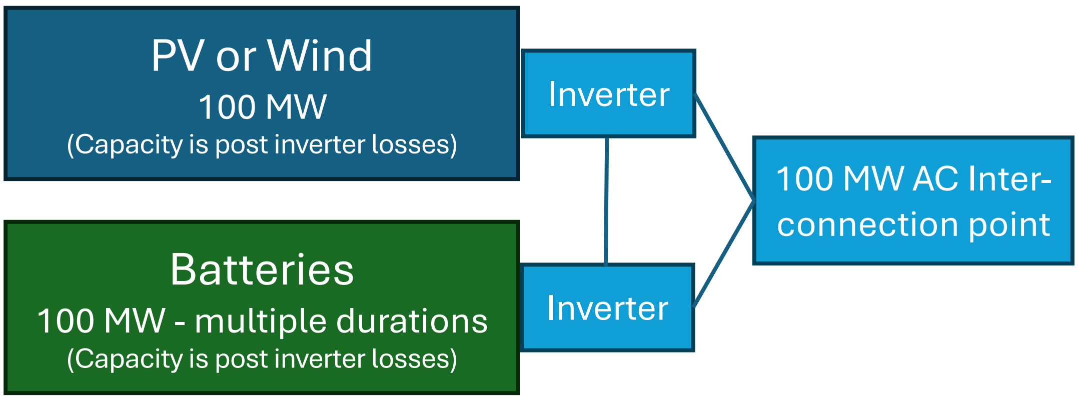

Figure 2: Schematic representation of the hybrid plants.

Several factors that are partly beyond a developer's control can affect hybrid value and the value of one configuration relative to another. In the Baseline scenario, we use a $5/MWh degradation penalty applied to battery charge and discharge when determining the dispatch of the hybrid plant (Montañés et al. 2022). We also assume perfect foresight of both real-time prices and VRE generation, and allow the battery to charge from the VRE generator or the grid. Beyond the Baseline scenario, we assess how imposing a higher degradation penalty ($25/MWh) and disallowing grid charging impact hybrid value. The results of this study should be interpreted within the context of the assumed conditions and parameters. The specific configuration options examined in this research are listed in Table 1.

Table 1. Hybrid configuration options

Configuration Choice	**Values**
Battery Duration (hour)	1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Degradation Penalty ($/MWh)	5, 25
Grid Charging	Allowed, Not allowed
System coupling	AC-coupled

Point of Interconnection Capacity (AC)	100 MW
Inverter Loading Ratio (solar)	1.3

3.5 Congested regions

As noted earlier, a limited number of congested regions were chosen for assessment, including both Load Centers and VRE-rich Areas. The specific approach used to select these locations is described in the literature (Kemp et al. 2023), and their locations are shown in Figure 1. Each location chosen for this study is the site of an existing wind or solar plant. The site was then modeled with the range of hybrid plant configurations described in the previous section, using wholesale market prices from a trading node near the plant location, accessed from Velocity Suite, as well as capacity prices and hourly net load as described earlier. More related details can be found in (Kim, Kahrl, et al. 2023).

3.6 Solar and wind profiles

To create solar PV generation profiles, we used historical weather data from the National Solar Radiation Database for each location and weather year, and then created PV profiles in NREL's System Advisor Model (SAM) assuming a single-axis tracking facility and an inverter loading ratio of 1.3.

Wind generation profiles were based on average power curves from Wiser et al. (2022) and wind speeds from the ERA5 weather data product of the European Centre for Medium-Range Weather Forecasts (ECMWF). To use the ERA5 data, we first removed long-term bias in the ERA5 wind speeds for individual plants. To debias wind speeds, we used generation records from existing wind plants' first two to five years of operation to find the implied average wind speed, and then scaled the ERA5 wind speeds to match this indicated average. We then applied a scaled ERA5 wind speed time series to our typical power curve to calculate hourly wind generation profiles for each location and weather year.

4. Results and discussion

We present our findings in two parts. The first part explores how hybrid plant energy value changes with varying configurations in congested areas. The second section examines the capacity contribution and capacity value of varying hybrid configurations in congested areas. Capacity value, in this context, not only refers to a plant's ability to provide generation during times of peak need, but also to its contribution to overall system reliability.

4.1 Hybrid configuration, location, and energy value

Comparing hybrid energy values across generator type and location type, we find that hybrids in Load Centers generally had higher value than hybrids in VRE-rich Areas; and solar hybrids generally had higher value than wind hybrids (Figure 3).[1] These findings were consistent with our hypotheses: we expected Load Centers to have higher prices due to constraints on building new generation and transmission, and we expected solar-plus-storage hybrids to be more aligned with high-price hours than wind-plus-storage hybrids, since wind generation often peaks at night. The value differentiation between solar and wind energy can also be influenced by various factors such as technological, geographical, and market dynamics (see, e.g., Bolinger et al. 2022; Wiser et al. 2022; Millstein et al. 2021).

We find that adding a one-hour battery to standalone solar and wind generators substantially increased the energy value of those plants (Figure 3). In Load Centers, converting standalone plants to hybrids with one-hour storage increased the value of those plants by 48.8%, from $33.8/MWh to $50.3/MWh. In VRE-rich Areas, this trend was even more pronounced: one-hour batteries increased solar and wind plants' median values by 80.5% and 81.1%, respectively.

We also find that extending storage duration from one to four hours provides substantial energy value (Figure 3). In Load Centers, replacing one-hour batteries with four-hour batteries increased hybrid plants' median values by 23.1%, from $50.3/MWh to $61.9/MWh. In VRE-rich Areas, we observed an even more substantial increase: median values rose by 31.7%, from $35.4/MWh to $46.6/MWh. (For solar hybrids specifically, the increase was a more muted 19%, up to $42.1/MWh.) Overall, in VRE-Rich areas, we find that the additional energy value of siting a four-hour battery sized to 100% of the plant's nameplate generation capacity is 29.4% for solar and 26.8% for wind.

Notably, we find low incremental value for storage durations beyond four hours in highly congested regions (Figure 3). Across both VRE-Rich and Load Centers, the median increase in energy market value from extending storage duration from one to four hours was 29.2% and 21.3% for solar and wind, respectively; by contrast, the increase from five to eight hours of duration was much smaller (7.3% and 6.1% for solar and wind, respectively). Most existing and in-development solar and wind hybrid plants in the U.S. have storage durations of four hours or less, but we anticipated a greater value boost from extending storage beyond four hours in the highly congested regions specifically selected for this study. Notwithstanding that expectation, these highly congested regions simply do not yet have price patterns that incentivize storage durations beyond four hours, at least in energy-only markets.

[1] For the sake of readability, Figure 3 omits hybrid wind plants located in ERCOT Load Centers, whose disproportionately high revenues would have visually compressed the data for other plants. ERCOT has volatile pricing patterns (Woo et al. 2011), which cause the higher energy revenues for ERCOT wind hybrids. For a comprehensive view by ISO/RTOs, including this data on ERCOT wind hybrids, please refer to Appendix B, which provides the complete dataset in a broader context.

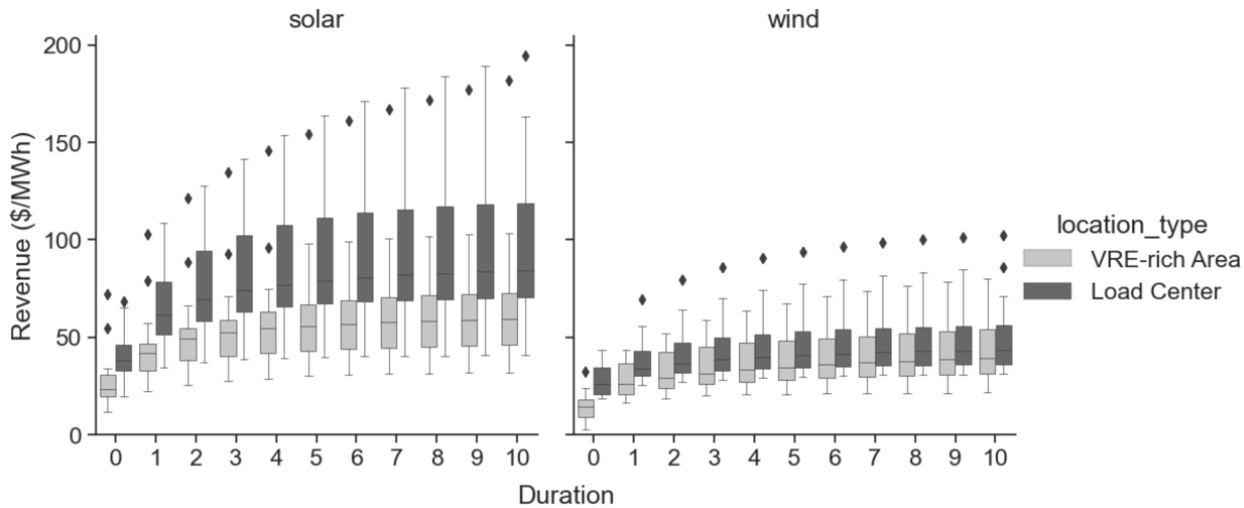

Figure 3: Annual hybrid plant energy revenues by plant type and location across all markets (excluding wind hybrids in ERCOT). Standalone wind and solar plants are reprsented by zero duration for comparison. Outliers, represented by diamond-shaped points, are data points that fall outside the range of 1.5 times the interquartile range.

The value of extending storage duration is sensitive to the cost of battery degradation. Figure 4 shows the relative increase in per-unit energy revenue that occurs when battery duration increases from one to four hours, given two parameterizations of battery degradation. For example, a value of 1.5 (on the y-axis) would indicate that the per-unit energy revenue of the hybrid with a four-hour battery is one and half times larger than the revenue derived from a one-hour battery. High degradation costs prevent hybrid plants from taking advantage of lower-margin cycles because battery degradation costs would outweigh the added revenue, whereas reducing battery degradation costs in our dispatch algorithm for hybrid plants allows for more frequent cycling. With baseline low degradation costs ($5/MWh), we find the median increase in value from extending storage duration from one to four hours in VRE-rich Areas is 29.4% for solar and 26.8% for wind, as noted earlier. With high degradation costs ($25/MWh), on the other hand, the median increase is only 20.3% and 19.1% for solar and wind, respectively.

Details about battery degradation costs are uncommon, and these costs are often treated quite simply; for example, plant operators may be primarily concerned with maintaining battery warranties, which often limit annual cycles (e.g., 365 cycles per year). But the sensitivity of hybrid plants’ annual value to battery degradation costs, as described above, suggests the importance of more carefully characterizing these costs during project planning and operation. Furthermore, to the extent that the highly congested conditions reflected in our modeling of VRE-rich Areas become more common over time with increased wind and solar deployment, the importance of reducing battery degradation costs may also increase.

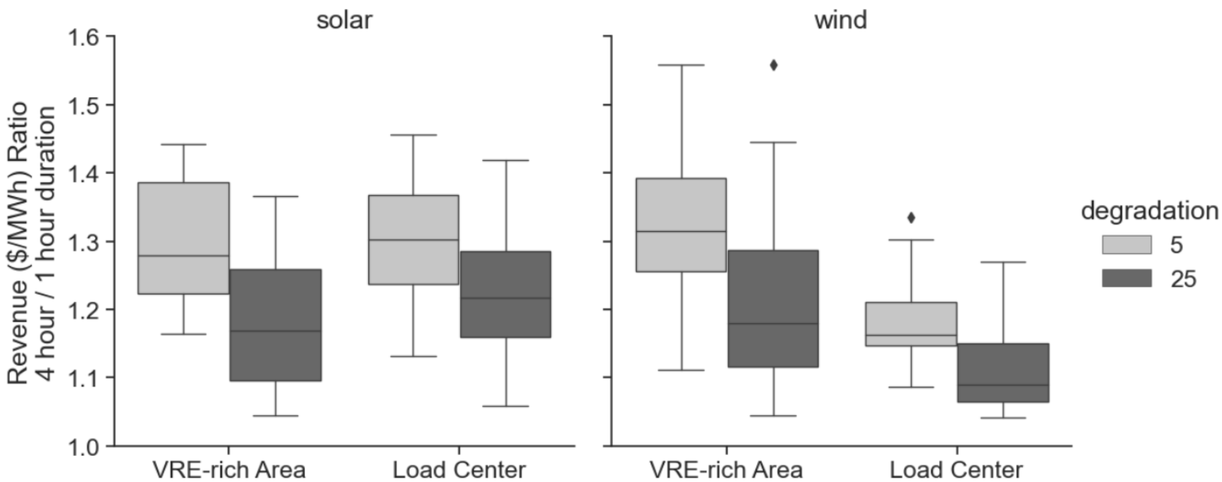

Figure 4: Revenue ratio ($/MWh) of hybrid plant energy by plant type and storage duration, categorized by low (5) and high (25) battery degradation costs. This figure illustrates how storage duration affects revenues, with separate analyses for solar and wind energy sources in VRE-rich areas and load centers

The ability to charge the energy storage system from the grid (i.e., “grid charging”) can increase hybrid plants’ energy revenues. In our baseline case with grid charging, for example, we found a median value of $65/MWh for energy revenues of solar hybrid plants with four hours of storage, which was $12/MWh greater than solar hybrids in an alternative case without grid charging. Without grid charging, solar hybrids’ revenue potential is limited by the daily cycle of solar generation; these plants can only use solar-generated electricity during the day and cannot benefit from energy storage arbitrage at night. Charging from the grid when solar is not available allows solar hybrids to access arbitrage for a longer period and more frequently and flexibly. The federal Investment Tax Credit (ITC) for solar in the U.S. has historically limited the use of grid charging of battery storage when paired with renewable generation, but recent changes under the Inflation Reduction Act have mitigated these limitations, facilitating greater utilization of grid charging. The ability to charge storage from the grid also increases the incentive for four-hour batteries over one-hour batteries: as shown in Figure 5, this value boost from grid charging appears more pronounced in VRE-rich Areas than in Load Centers.

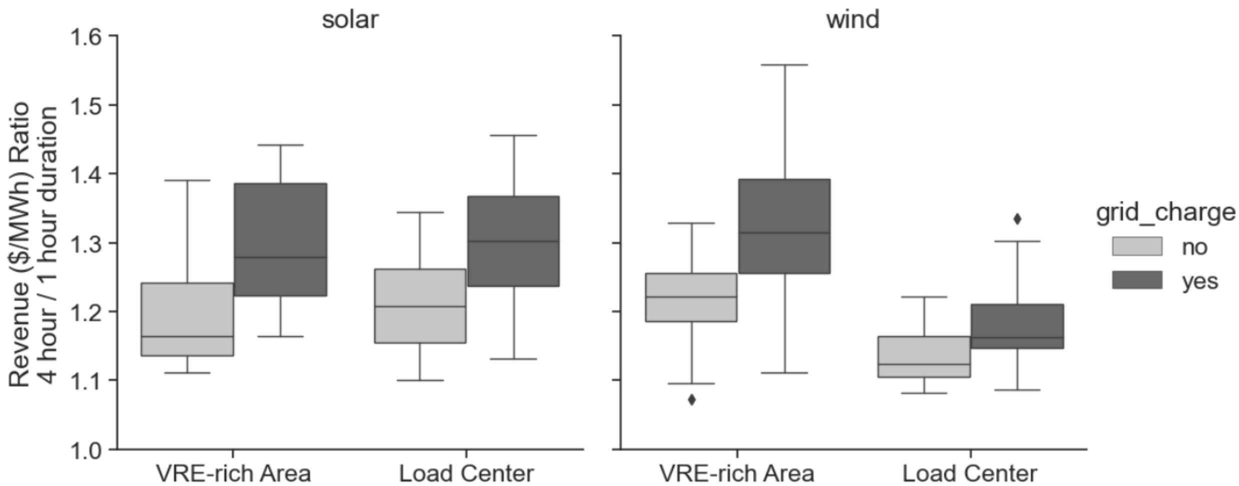

Figure 5: Revenue ratio ($/MWh) for hybrid plant energy by plant type and storage duration, segmented by the presence or absence of grid charging. The data compares solar and wind hybrid energy sources across VRE-rich areas and load centers, illustrating the effect of grid charging on revenue outcomes.

Finally, we explore how battery degradation costs can impact energy revenues across key configuration options – i.e., plant type (solar/wind), grid charging (allowed/not allowed), and battery duration (from one hour up to four hours) – in both Load Centers and VRE-rich Areas (Figure 6). The reduction in energy revenues due to higher battery degradation costs is approximately 11.4% for plants with one-hour storage across all cases. Higher degradation costs reduce median energy revenues for hybrid plants with four-hour storage and allowed grid charging by 7.7% in Load Centers and 11.3% in VRE-rich Areas. Grid charging for storage amplifies the penalizing effects of higher degradation costs; for example, when higher degradation costs are assumed, solar hybrids with four-hour storage in Load Centers experience a 15.5% decrease in energy revenues when they can charge from the grid, compared to only a 10.1% decrease for similar plants without grid charging. Solar hybrids in VRE-rich Areas with grid charging experience even greater revenue reductions from higher battery degradation costs, with a median decrease of 18.6%. The range of revenue outcomes described above highlights the importance of grid charging capability and battery degradation cost levels in determining the market value of solar and wind hybrid plants in congested areas.

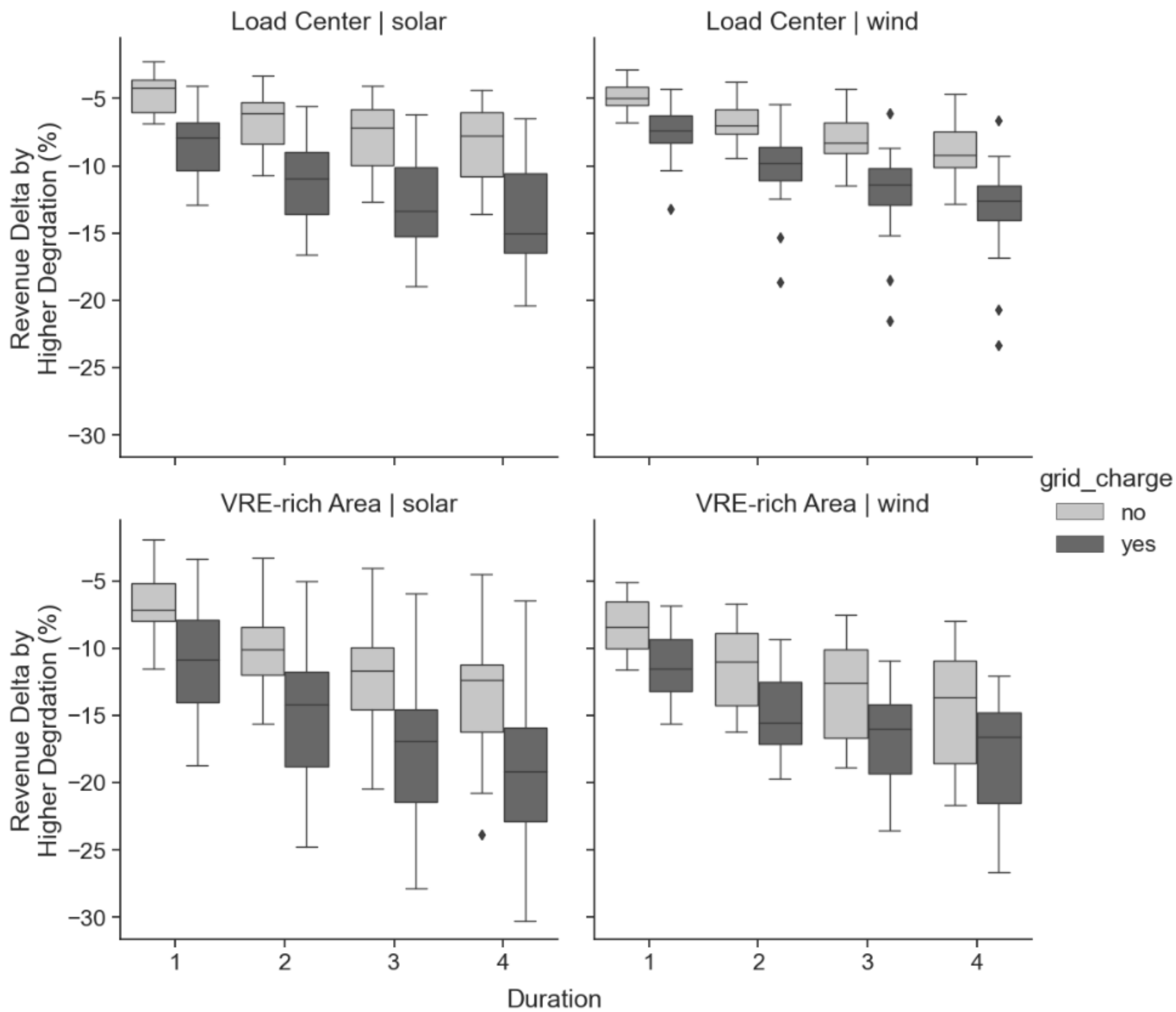

Figure 6: Differences in hybrid plant energy revenues by plant type, location, and storage duration, with low/high battery degradation costs, with and without grid charging.

4.2 Estimating the capacity value of hybrid plants

Capacity markets play an important role in ensuring that the electricity system has sufficient resources to meet peak demand and maintain reliability. For generators that can operate during high-load hours, capacity markets can provide an additional revenue stream beyond energy markets.

We found that inclusion of the capacity price adder across the top 100 net load hours in the optimization of plant dispatch (as described in Section 3.3) substantially increased the generation provided during those hours, compared to the optimization of energy prices alone. Thus, inclusion of the price adder into the optimized plant dispatch increased the capacity contribution of hybrid plants. This finding likely applies to non-congested regions as well the congested regions studied here. This finding was surprising in that we expected the 100 highest net load hours to have relatively high energy prices even in VRE-rich congested regions, and that these high energy prices would have a much greater effect on dispatch than the capacity price adder. The pronounced additional effect of the capacity price adder shows that it is important to explicitly account for capacity markets in dispatch algorithms when analyzing the potential capacity contribution of hybrid plants. We note that the capacity price adder provides dispatch incentives that serve the same purpose as capacity performance requirements that exist in certain market regions (for example, ISO-NE maintains Pay-For-Performance rules in capacity markets to ensure dispatch during scarcity hours). It also calls for a future study to assess the potential trade-offs between maximizing combined energy-plus-capacity value versus maximizing energy-only value.

Solar hybrid plants in congested regions reach a “capacity credit” (as described in Section 3.3) of 0.9 during the top 100 net load hours when combined with four-hour storage, whereas wind hybrid plants require longer-duration storage of approximately eight hours to reach the same capacity credit (Figure 7). This distinction in storage requirements for achieving high effective capacity credits holds implications for grid reliability and flexibility. Specifically, the ability of solar hybrid plants with four-hour storage to maintain a high output level during peak net load hours makes them highly adaptable to changes in demand or supply conditions; the need for wind to employ much longer-duration storage to achieve a similar capacity credit is also notable (Denholm, Cole, and Blair 2023).

As wind and solar penetration levels increase, the timing of peak net load becomes increasingly correlated with low wind or solar output, potentially leading to a drop in capacity credit. However, this trend does not apply uniformly across all regions, and one possible reason for the variance is the differing penetration levels of wind and solar. For instance, our study found high capacity credit for solar hybrids in California, despite high solar penetration levels. This may be attributed to the correlation of solar profiles with high demand periods, as well as the diurnal nature of solar energy, which pairs well with short-duration storage. In contrast, in most U.S. regions, solar is at a lower penetration level than wind, which could contribute to larger capacity credits for solar versus wind hybrids when equal storage is assumed. Additionally, the differing resource profiles of wind and solar – as evidenced by the fact that even one-hour storage solar hybrids tend to have a much larger capacity credit than their wind counterparts – should be considered when designing hybrid plants for optimal capacity value. These variations highlight the importance of region-specific analysis to assess the impact of wind and solar penetration levels and their respective underlying resource profiles on hybrid plants’ capacity credit.

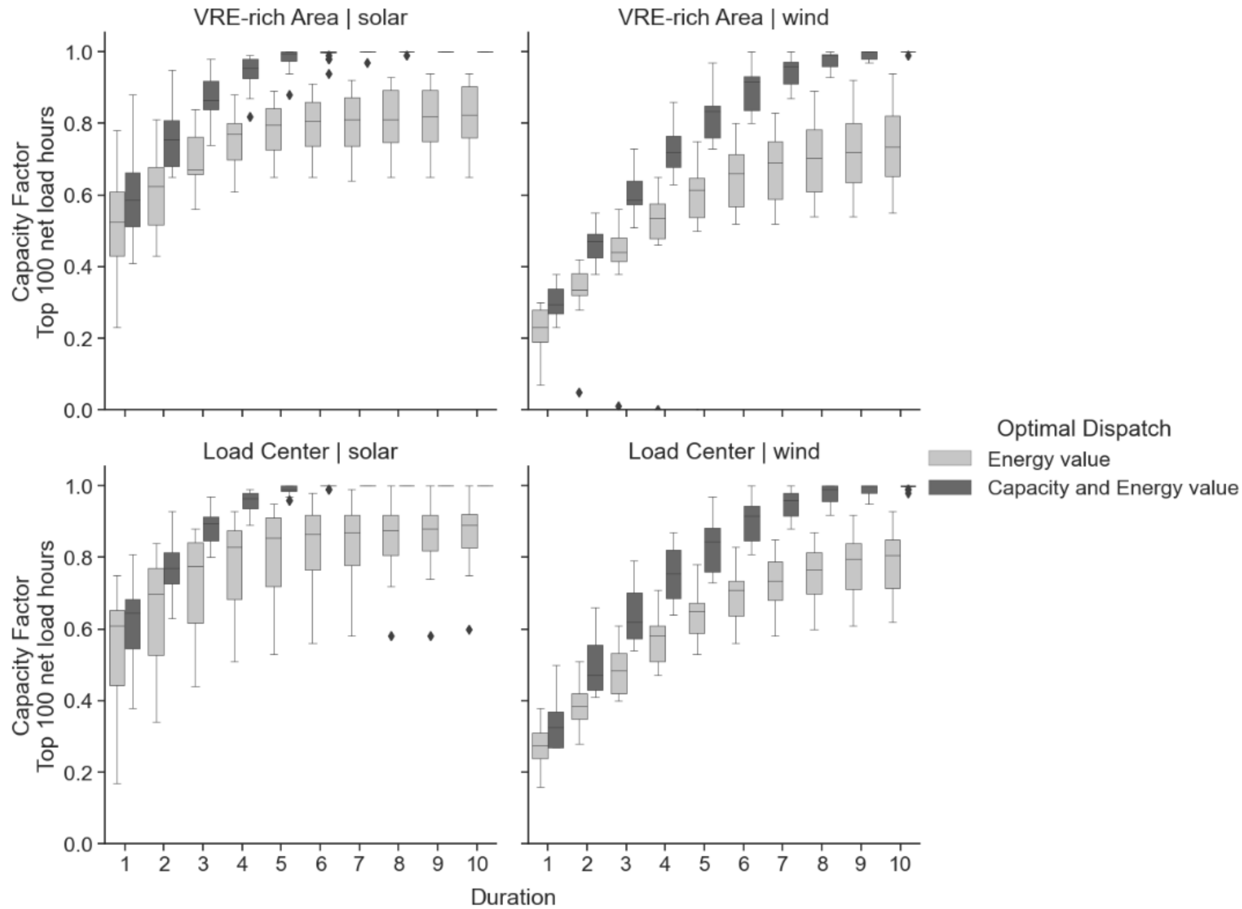

Figure 7: Capacity and energy values of hybrid plants by plant type, location, and storage duration during the top 100 net load hours.

After multiplying the capacity credits by regional capacity prices, overall capacity values were generally higher for solar hybrids than wind hybrids, in $/MWh terms. Capacity values also tended to be higher in Load Centers than in VRE-rich Areas, although the interquartile range of the capacity values in VRE-rich Areas was more substantial (Figure 8). This difference in capacity values between Load Centers and VRE-rich Areas is partially due to zonal capacity price differences. For instance, in New York, the capacity price in Long Island is substantially higher (2.3 times higher) than the capacity price further upstate. Additionally, some of the price differences between Load Centers and VRE-rich Areas could be attributed to the sample of plants across different ISO/RTOs. (For a comprehensive view by ISO/RTOs, please refer to Appendix C, which provides the complete dataset in a broader context.)

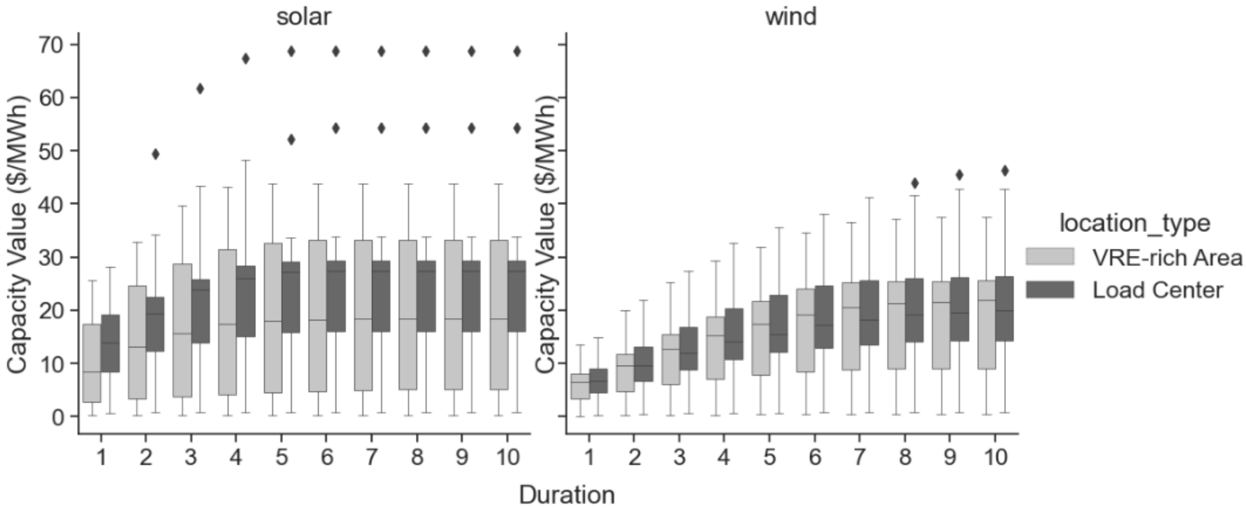

Figure 8: Distribution of hybrid plant capacity value for different durations of battery storage.

5. Conclusion

This paper investigates the impact of market price profiles in highly congested regions on the value of coupled renewable-battery projects in electricity markets. By using wholesale power market prices from 2018 through 2021 from the seven major U.S. independent system operators (ISOs), we find that value-enhancing configurations of hybrids differ between Load Centers and VRE-rich Areas, and based on several other external conditions.

Focusing on energy-only market revenue, we find that within Load Centers, increasing the duration of hybrid storage from one- to four-hour capacity provides, in the median case, a 23% increase in value ($50.3 per MWh to $61.9 per MWh). In VRE-rich Areas, the improvement in the median value of hybrid plants with the same increase to storage is larger at 31% ($35.4 per MWh to $46.6 per MWh). However, even in highly congested regions with high local penetrations of wind and solar, energy market prices provide little incentive for storage duration beyond four hours (for example, energy value increased by less than 5 percentage points when storage duration increased from 5 to 8 hours).

In highly congested regions, the value of hybridizing is sensitive to battery degradation; substantial value is lost when there are strict limits to battery cycling. We found that, with low degradation costs in VRE-rich Areas, the median increase in energy value from extending storage duration from one to four hours is 29.4% for solar and 26.8% for wind, assuming storage is sized to 100% of the plant's nameplate generation capacity. But with high degradation costs, the median increase is only 20.3% and 19.1% for solar and wind, respectively.

We find that solar hybrids need only four-hour storage to reach a 90% capacity credit during the top 100 net load hours, whereas wind hybrids typically need eight-hour storage to reach the same capacity credit. This may, in part, be a function of the underlying correlation of solar output with high demand periods. This finding suggests that longer-duration storage may be a better match for wind hybrids in congested regions than for solar hybrids in similar regions.

Limitations of our analysis include sampling only a limited number of plant locations; assessing value but not cost; assuming perfect foresight for hybrid operations; using a simplification for capacity credit calculation; and not accounting for ancillary services. Additionally, the findings may not generalize to systems with substantially different market designs than those in the U.S. today. Future research should build on our analysis by addressing these limitations and investigating the impact of specific factors, such as battery capacity costs, on the value of hybrid projects in congested regions.

Acknowledgments

The authors thank Seongeun Jeong for support creating Figure 1. This work was supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) Wind Energy Technologies Office and Solar Energy Technologies Office, Award Number 38444 under Lawrence Berkeley National Laboratory Contract no. DE-AC02-05CH11231. The US Government retains, and the publisher, by accepting the article for publication, acknowledges, that the US Government retains a non-exclusive, paid-up, irrevocable, world-wide license to publish or reproduce the published form of this manuscript, or allow others to do so, for US Government purposes.

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Appendix A: Glossary of Acronyms and Abbreviations

- AC-coupled – Alternating current-coupled
- CAISO – California Independent System Operator
- ERCOT – Electric Reliability Council of Texas
- ISO – Independent System Operator
- ISO-NE – Independent System Operator New England
- MISO – Midcontinent Independent System Operator
- MW – Megawatt
- MWh – Megawatt-hour
- NYISO – New York Independent System Operator
- PJM – PJM Interconnection (a regional transmission organization)
- POI – Point of interconnection
- RTO – Regional Transmission Organization
- SPP – Southwest Power Pool (a regional transmission organization)
- VRE – Variable Renewable Energy

Appendix B: Comprehensive Figure Showing Hybrid Plant Energy Values, Including ERCOT Wind Hybrids

This Appendix provides an in-depth view of the data set, including the hybrid wind plants located in ERCOT Load Centers that were omitted from Figures 1 and 2 in the main body of the paper. Including these outliers leads to visual data compression, as seen in Figure D.1.

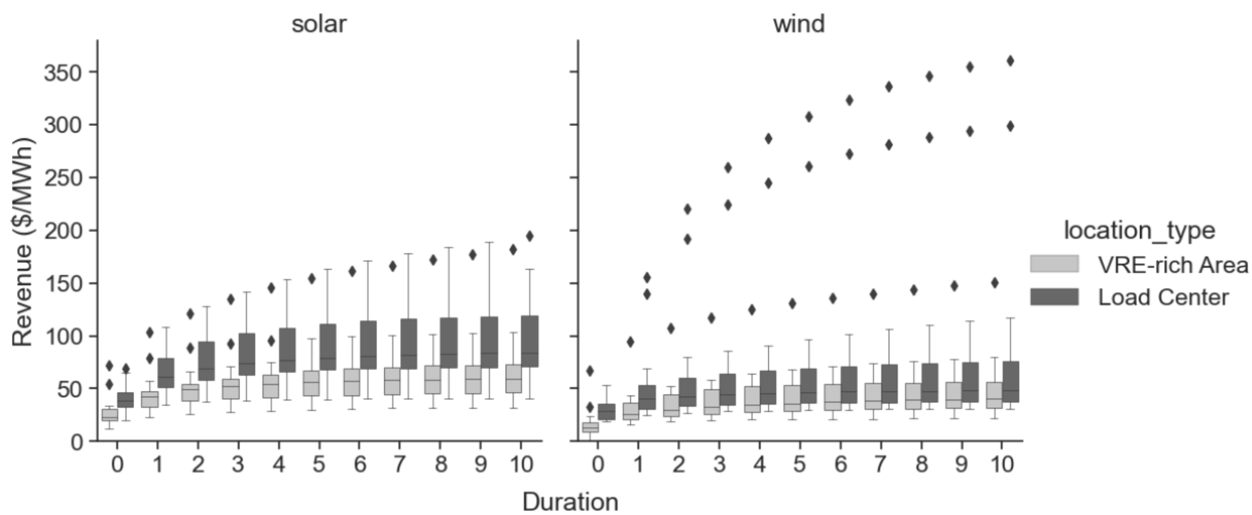

Figure B.1: Annual hybrid plant energy revenues by plant type and location across all markets, including wind hybrids in ERCOT. This figure includes the revenues of standalone wind and solar plants for comparison. Outliers, represented by diamond-shaped points, are data points that fall outside the range of 1.5 times the interquartile range.

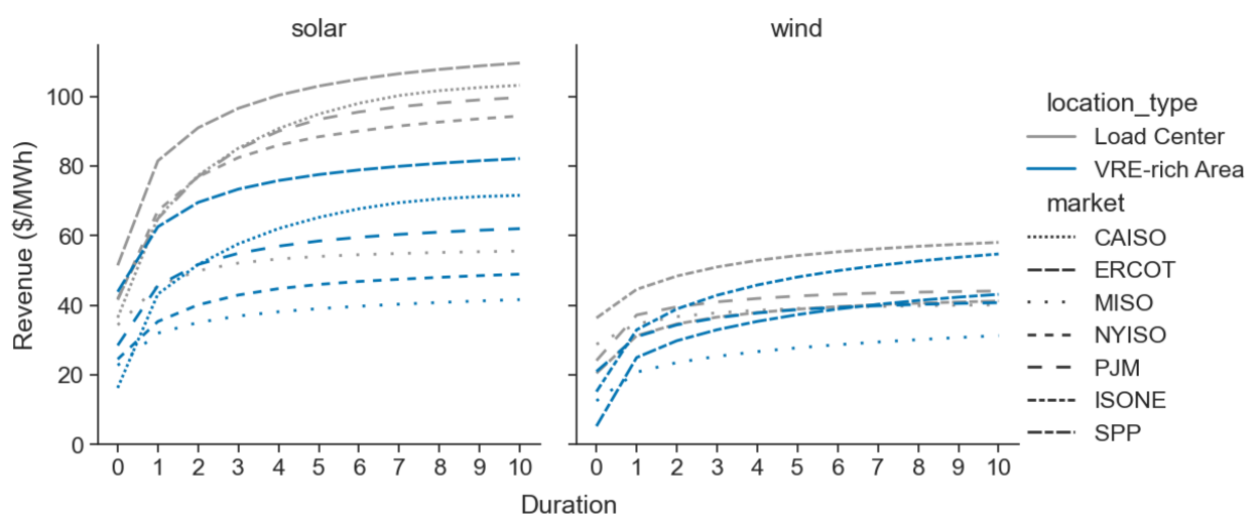

Figure B.2: Annual hybrid plant energy revenues by plant type and location in specific ISO/RTOs, *excluding* wind in ERCOT.

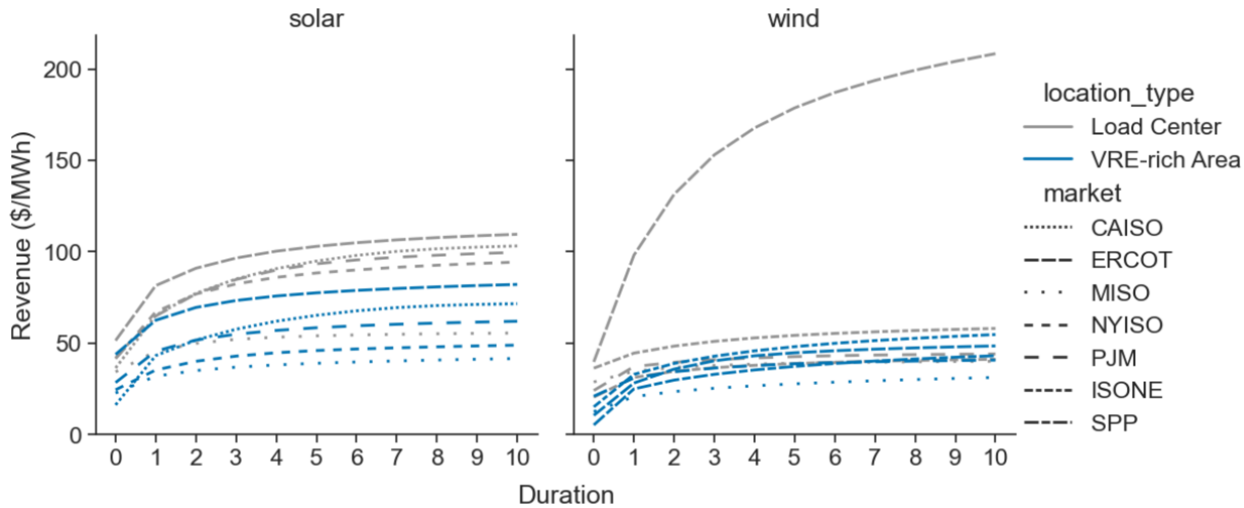

Figure B.3: Annual hybrid plant energy revenues by plant type and location in specific ISO/RTOs, *including* wind in ERCOT.

Appendix C: Comprehensive Figure Showing Hybrid Plant Capacity Values

This Appendix provides an in-depth view of the data set that were not included in Figure 8 in the main body of the paper. The aim is to present a comprehensive data analysis by ISO/RTO level.

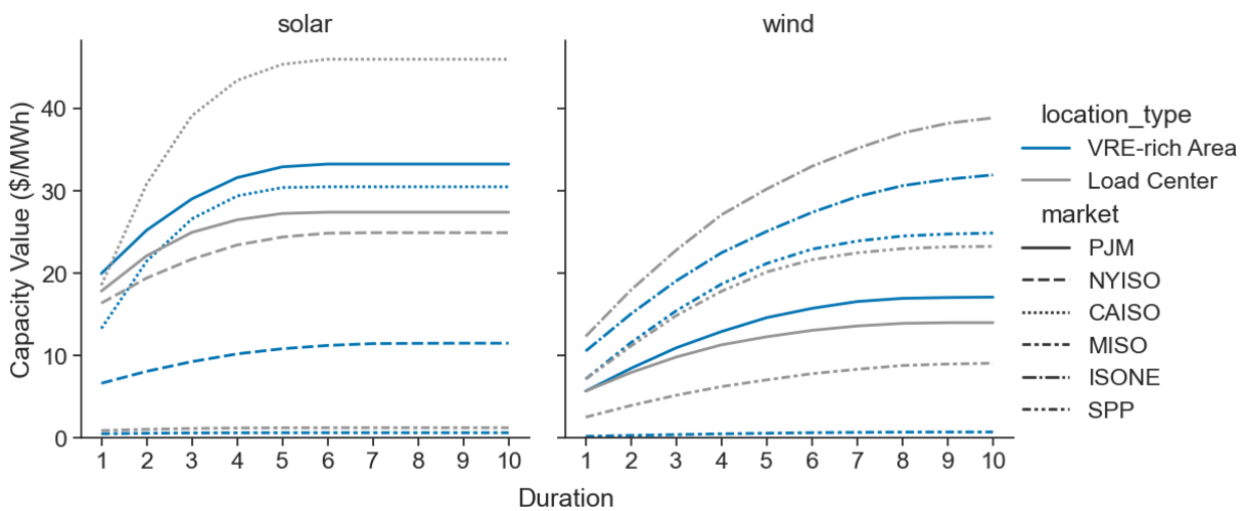

Figure C: Hybrid plant capacity values in specific ISO/RTOs. (ERCOT not shown due to absence of a capacity market.)