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Influence of business models on PV-battery dispatch decisions and market value: A pilot study of operating plants

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ABSTRACT

PV-battery hybrid projects dominate interconnection queues in some regions in the United States. But few large-scale projects have been in use long enough to assess how the hybrid capabilities may be used in practice and the existing literature scantly discusses observed operational strategies. We interview plant operators and analyze empirical dispatch data for eleven large-scale PV-battery hybrids in three organized wholesale markets in the United States. We estimate the market value of our sample hybrids in 2020. The empirical increase in market value of a PV-battery hybrid relative to a standalone PV plant varies by project and ranges from \$1 to \$48/MWh_{solar}, often aided by a large boost in capacity value. This premium is driven by market, location, technical characteristics of the PV and battery asset, and battery dispatch strategies. In contrast to the widespread assumptions in the PV-battery hybrid modeling literature, only three of the eleven project operators optimize battery usage for wholesale market revenue as merchant plants. Instead, load-serving entities target peak load reductions, incentive program participants focus on compliance with program requirements, and large energy consumers prioritize resiliency and utility bill minimization. These alternative business models can result in high revenues for the project operators, but do not optimize the storage dispatch from a grid perspective. Understanding real-world dispatch signals and aligning them closer with system-wide grid needs will be important for electric grid operators and system planners, and can increase the market value of PV-battery hybrids.

1. Introduction

Worldwide, the deployment of photovoltaic (PV) generators is growing rapidly. Empirical assessments show that in some regions, growth of PV is impacting wholesale power markets and altering the marginal market value of additional PV deployment [1,2]. Mitigating the decline in marginal market value is one of the motivations for the surge in commercial interest in co-locating battery storage with utility-scale solar PV plants ("PV-battery hybrids") both in the United States [3] and abroad [4]. While empirical assessments of the market value of PV can rely on readily observable data, such as satellite-derived insolation data, assessing the market value of adding battery storage to PV is hampered by a lack of publicly available data on battery dispatch decisions.

The technical characteristics of PV-battery hybrid configurations—including the battery power capacity and energy capacity relative to the PV capacity—establish a project's capability to alleviate the needs of the power system. The realized contribution, however, entirely depends on how the operator chooses to use the battery. Research is needed to understand how PV-battery hybrids are being used and dispatched, what drives PV-battery hybrid dispatch decisions, and to empirically confirm the benefits of adding batteries to PV plants ("storage value premium"). Such research is important to system planners who must make assumptions regarding the operation of batteries when assessing the impact of PV-battery hybrids on the bulk power system [5]. It is also important in the design of incentive programs, wholesale markets, regulated tariffs, or other policies supporting deployment of PV-battery hybrids to ensure programs and policies achieve their intended objectives.

Although empirical data to answer these questions are sparse, studies based on models are not. Carriere et al. [6] compare the potential increase in revenue from adding a battery to a PV system in France when used to either reduce imbalance charges or shift energy from low value to high value times of day, accounting for uncertainty. DiOrio et al. [7] develop a flexible model to evaluate the dispatch and design of PV-battery hybrid plants, including AC- or DC-coupled systems. Kim et al. [8] show that adding battery storage to a PV plant can be a much more effective strategy for enhancing the value of solar when the PV subsystem is designed to maximize generation rather than orienting the panels west to align PV generation with high prices. Gorman et al. [9] use historical wholesale market prices to estimate the storage value premium from adding storage to PV, similar to Byrne et al. [10], but expanding the analysis to all seven U.S. organized wholesale markets and contrasting

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Glossary

AC	alternating current
AS	ancillary service
CAISO	California Independent System Operator
CPUC	California Public Utility Commission
CPS	clean peak energy standard
DC	direct current
EIA	Energy Information Administration
ELCC	effective load-carrying capability
ERCOT	electric reliability council of Texas
ISO	independent system operator
ISO-NE–	Independent System Operator of New England
ITC	investment tax credit
MW	Megawatt
PV	photovoltaic
POI	point-of-interconnection
PV+*S*	photovoltaic + storage
RT	real-time
SMART	solar Massachusetts renewable target program

that value premium with the alternative of siting standalone storage at sites with the highest storage value. Schleifer et al. [11] evaluate how different coupling strategies of PV-battery hybrids compare under an evolving grid mix using projections of future prices. The storage value premium increases with the capacity of the battery relative to the PV generator and the storage duration [12]. Braff et al. [13] explore how a range of capital costs and optimal sizing of battery storage affect the storage premium. Kahrl et al. [14] use historical wholesale market prices in the U.S. to estimate the potential increase in revenue for providing ancillary services from a PV-battery hybrid plant, relative to only providing energy. One common thread in all these studies is that they model the PV-battery hybrid as being dispatched to maximize revenue from wholesale power markets. Studies focused on PV-battery hybrids sited behind the customer meter instead often model storage as being dispatched to maximize bill savings, which for some customers can include reducing customer demand charges [15].

None of these studies use empirical PV-battery hybrid dispatch data. As PV-battery hybrids are increasingly deployed, there is an opportunity to use actual dispatch data to confirm that storage additions increase the market value of PV. Empirical dispatch data allows estimating the market value of PV-battery hybrid directly without making assumptions about how operators make dispatch decisions. The underlying business models for the PV-battery hybrid owners are embedded in the empirical data, which may differ from the common assumption that they dispatch storage to maximize revenue in a wholesale power market.

A key contribution of this paper is that we directly calculate the increase in market value from adding storage to utility-scale PV plants using not modeled but measured PV-battery hybrid data for the year 2020. We use empirical data from eleven utility-scale installations sited in three U.S. organized wholesale market regions: one in the California Independent System Operator (CAISO), three in the Electric Reliability Council of Texas (ERCOT), and seven in the Independent System Operator of New England (ISO–NE). We rely on semi-structured interviews with the PV-battery hybrid project owners to understand their business models and how they in turn influence dispatch decisions.

The purpose of this paper is to bring empirical insights to the discussion of the market value of adding storage to PV plants. It is not intended to be a representative sample of all PV-battery hybrid facilities. It is also not a prediction of future value, as wholesale market prices patterns will evolve and dispatch strategies will be refined. While it provides useful context and a point of comparison, it is not meant to serve as a validation of previously developed modeling approaches. The study can, however, establish a foundation for further analysis as more projects come online and more data become available. Finally this paper also provides guidance for regulators and incentive program designers as we explore the motivation behind the various dispatch strategies in our sample and examine their degree of alignment with the dynamic grid needs.

Section 2 describes the methods for calculating the market value of PV-battery hybrids and describes the empirical dispatch data for the eleven plants. In Section 3, we map the individual plants to four business models that impact dispatch decisions. Section 4 describes the dispatch characteristics and Section 5 uses the dispatch and wholesale market prices to estimate the market value of each plant. In Section 6, we discuss in greater detail how differences in business models impact dispatch decisions, leading to variations in market value despite similar PV-battery hybrid equipment characteristics. Section 7 concludes and recommends further research.

2. Methods and data

2.1. Market value

We use empirical PV-battery hybrid dispatch data to compare the market value of PV-battery hybrid to standalone PV. In this paper, we define the marginal market value as the product of the provision of grid services with the wholesale market price for each grid service, summed over all intervals in the year and across all applicable services. Depending on the market and the products provided by a PV-battery hybrid, the grid services in this analysis can include energy (i.e., based on the real-time location-specific wholesale power market price, shown in Eq. (1)), capacity (i.e., based on the zonal forward capacity market price, Eq. (2)), and ancillary services Eq. (3)). In our sample, regulation reserve is the only ancillary service offered by a subset of projects. Based on this definition, the market value is equivalent to the total revenue that would be earned by selling output at the prevailing wholesale market price (or the sum of Eqs. (1)–((3). In all cases, we report the market value per unit of energy generated by the standalone solar system. We do not consider or include any other types of grid system-related value that solar hybrids might provide, such as minimization of incremental new transmission assets, resilience, energy security, wholesale price effects, or any other environmental or social values that are not already internalized in wholesale energy and capacity markets (e.g., via permit prices for pollution allowances). Instead, the value to the wholesale market is meant to be a proxy for the impact on the overall bulk power system. As will be discussed in later sections, the correspondence between the market value and the actual revenue earned by the plant depends on its business model, and should not be conflated. Various business models can involve transmission demand-charge offsets, incentive payments, or the sale of renewable energy credits that are not included in our simple definition of market value.

The energy value of each PV-battery hybrid represents the average product of real-time (RT) wholesale market energy prices and the coincident energy that is delivered to the grid (accounting for storage-related losses where applicable). The location-specific wholesale prices are based on matching a solar plant to the nearest wholesale pricing node. Eq. (1) summarizes a project's energy value, where the subscript h represents each of the hours of the year 2020:

$$\mathrm{V}_{Energy} = \frac{\sum \left(Delivered\,Energy_h \;*\; Wholesale\,RT\,Energy\,Price_h \right)}{\sum PV\,Generation_h} \tag{1}$$

The PV-battery hybrid projects contribute to the overall resource adequacy of the power system. The capacity value depends on the project's contribution to resource adequacy and the capacity price. We call the fraction of the nameplate capacity that is counted toward resource adequacy the "capacity credit". Eq. (2) summarizes a project's capacity value, where the subscript T represents seasons or months, depending on the region. To facilitate comparisons with a project's energy value we denominate the capacity value in \$/MWh terms as well, based on the PV generation of each project.

$$V_{Capacity} = \frac{\sum \left(Capacity\ Credit_T * Nameplate * Capacity\ Price_T \right)}{\sum PV\ Generation_T} \quad (2)$$

In regions with organized wholesale capacity markets such as ISO–NE the capacity credit reflects how much of a project's capacity can be bid in the capacity market auctions, while in CAISO it determines how much solar can count toward meeting a load-serving entity's required planning reserve margin. System planners in ERCOT estimate the capacity credit of PV and storage, but only as part of communicating expected overall system resource balances over the coming seasons to market participants. Load-serving entities in ERCOT are not required to meet a target planning reserve margin. For more details see [1].

ISO–NE has an organized capacity market, and we use the published forward capacity price for delivery in 2019/2020 and 2020/2021 corresponding to a project's generation and respective price zone. Average resource adequacy contributions of PV are assessed using its median generation-profile during a daily four-hour early afternoon peak window in the summer (June to September) and a daily two-hour early evening peak window in the winter (October to May). ISO–NE allows the capacity credit of PV-battery hybrids to be calculated in multiple ways, two of which we consider here. First, we simply evaluate the median output profile of the combined PV-battery project, like the method to estimate the capacity credit of standalone PV, with the exception that we now use the hybrid project's hourly net generation instead of the PV profile. We call this the profile-based capacity credit. The second alternative we consider uses a separate assessment of the capacity contributions of the PV and the battery resource (see configuration option 2 discussed in [16]), where the battery's capacity credit is defined as the maximum sustained discharge over a two-hour period. The capacity credit of the battery is added to the PV's capacity credit to yield a combined capacity credit, limited to the facility's point-of-interconnection (POI) limit. We assume that the POI capacity of the PV-battery hybrid is the highest observed net generation. We call this the design-based capacity credit, as the battery's technical design is a key determinant of the capacity credit.

Utilities in the CAISO region must show adequate resources to meet a planning reserve margin on a monthly basis, although utilities contract for this capacity on a bilateral basis rather than through a centralized forward capacity market. We estimate the monthly capacity price in CAISO based on the 85th percentile of bilateral capacity contracts reported by utilities to the California Public Utilities Commission (CPUC) [17]. The capacity credit is set administratively by the CPUC for all PV plants based on the effective load-carrying capability (ELCC) of the ISO's aggregate solar profile that is determined in a probabilistic reliability study. The capacity credit of batteries is calculated as the maximum sustained storage discharge over a four-hour period, and batteries with a duration of less than four hours receive a proportionally discounted credit. The capacity credit of the combined PV-battery hybrid plant is capped at plant's POI capacity. Even though CAISO's capacity credit is determined on a monthly basis, we facilitate comparisons by showing the capacity credit on a seasonal basis to match ISO–NE's seasonal definitions.

Because ERCOT does not require utilities to meet a planning reserve margin and does not operate a forward capacity market, we do not estimate a separate capacity value in this region. Instead, prices in the energy market are able rise to high levels (as high as $9000/MWh) to encourage utilities to enter into forward contracts to secure adequate generating resources. Based on ERCOT data, we include a wholesale price premium according to an administratively-set operating reserve demand curve, such that prices can rise when the risk of shortages is high. We do report the capacity credit of the PV-battery hybrids, using the capacity credit method in ERCOT, which is simply the average generation during the top 20 load hours in each season.

A subset of the PV-battery hybrid plants in our sample in ERCOT and ISO–NE provide regulating reserves in addition to energy and, in

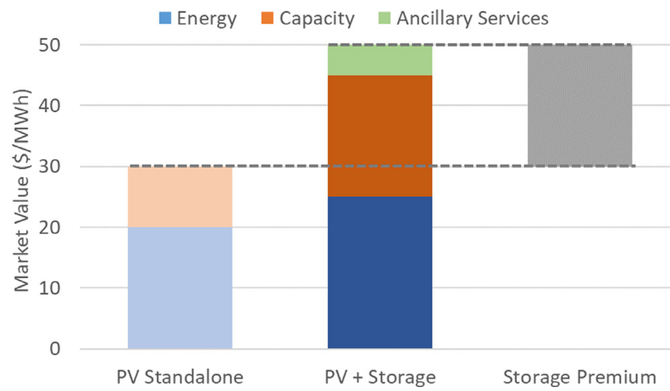

Fig. 1. Illustration of the storage premium definition.

ISO–NE, capacity, and we assess the ancillary service (AS) value only for those PV-battery hybrids. We leverage plant-level reported hourly AS awards by service type coupled with real-time hourly AS prices. We focus exclusively on AS capacity payments and disregard potential additional, but much smaller, mileage payments, as we did not consistently obtain the required plant-level information. Due to differences in market structure, PV-battery hybrid plants in ERCOT provide separate regulating reserve products in the up and down direction, while plants in ISO–NE provide a single bi-directional regulating reserve product. Eq. (3) summarizes a project's ancillary service value, where the subscript h represents each of the hours of the year 2020:

$$V_{AS} = \frac{\sum\left(AS\ Capacity\ Award_{\ h} * Wholesale\ AS\ Price_h \right)}{\sum^{P} V\ Generation_h} \quad (3)$$

We collect plant-level information with hourly resolution including the generation profile of the PV asset, charging and discharging activity of the battery asset, and the combined generation profile of the PV-battery hybrid. We use the PV generation profile – dubbed "PV Standalone" - to quantify the energy and capacity market value of the project as if it was not coupled with a battery. We contrast those results with the market value of the combined PV and storage profile – called "PV+S Empirical" – that includes ancillary service value estimates for the subset of projects that participate in AS markets. To facilitate a comparison of the two value estimates we denominate both in MWh terms of the PV standalone generation. As depicted in Fig. 1 and Eq. (4), we define the storage value premium as the difference of the PV+S value and the PV Standalone value:

$$Storage\ Premium = \left(V_{PV+S\ Energy} + V_{PV+S\ Capacity} + V_{PV+S\ AS} \right) - \left(V_{PV\ Energy} + V_{PV\ Capacity} \right) \quad (4)$$

2.2. Baseline market value

The storage premiums from the empirical dispatch vary across projects and their specific storage configurations, business models, and wholesale market locations. To assess the alignment of PV-battery hybrid dispatch with wholesale energy market signals, we develop a common "PV+S Baseline" against which we can compare each project. This hypothetical baseline dispatch uses the project-specific empirical PV generation profile, but it dispatches the battery to maximize profit based on the local wholesale energy revenue, building on the approach by Gorman et al. [9]. The baseline dispatch ignores any potential signals from the capacity and ancillary service market. Much like the approach of previous studies, we assume perfect foresight of PV generation and wholesale energy prices, and stipulate that the batteries need to be charged exclusively from the PV generation. We model the PV and battery as being coupled on the AC side of an inverter, which is similar to the configuration of nearly all projects in our sample. We define the POI limit as the project-specific maximum observed net-generation. We assume

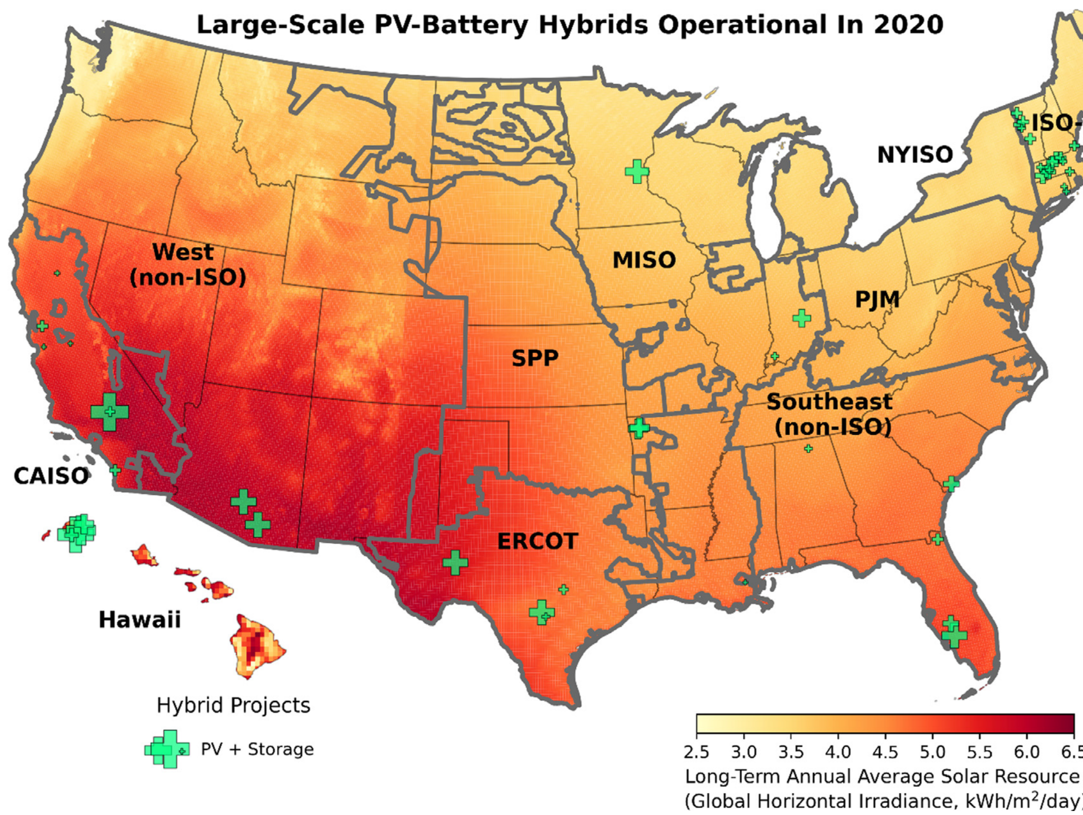

Fig. 2. Large-Scale PV-battery hybrid projects operational in 2020 in the United States.

an inverter efficiency of 96% and storage efficiency of 94%. To prevent too liberal use of the storage asset we incorporate a degradation penalty of $5/MWh [18]. We subsequently use the baseline PV-battery hybrid profile to calculate the baseline market value (inclusive of energy and capacity value) for each individual project using the same process described in Section 2.1. Because the dispatch of the baseline plant only maximizes energy revenue, the baseline market value does not include provision of any ancillary services.

2.3. Sample of PV-Battery hybrid plants

We began with identifying PV-battery hybrid plants included in EIA Form 860, which tracks all plants in the U.S. larger than 1 MW as shown in Fig. 2. We applied two additional criteria for including PV-battery hybrid plants in our sample. First, we wanted to conduct our analysis over the same year at all plants, requiring that the plant be in commercial operation for the duration of 2020. Second, we wanted to use transparent wholesale pricing data for grid services, requiring that the plant be in one of the seven U.S. organized wholesale market regions. The name and characteristics of each of the PV-battery hybrid plants that meet these criteria are listed in Appendix Table 2.

We then reached out to the plants' owners requesting access to the PV-battery hybrid dispatch data with at least hourly resolution. We arranged access to data necessary for the analysis from eleven plants, though with restrictions on identification of the plants and public access to the data. Using anonymizing identifiers, we summarize the characteristics of the plants in the sample in Table 1. Overall, the average characteristics of our eleven PV-battery hybrids are comparable to the larger sample of 46 plants in Appendix Table 2, although our sample projects have a slightly smaller battery to PV capacity ratio on average (0.56 vs. 0.78). Peak net generation levels can exceed the PV capacity if the interconnection limit allows for simultaneous PV and battery generation. On average, the maximum generation in excess of the nominal PV capacity is equal to 40% of the battery's nameplate capacity (as this number is based on empirical generation records we do not have a comparable statistic for all operational PV-battery hybrids). One of the eleven plants is configured such that the PV and battery units share the same inverter ("DC-coupled") whereas the other ten hybrid plants are AC-coupled [7].

The data we received from the eleven PV-battery hybrids contains 15-minute or hourly electricity meter readings for the plant's PV generation, battery generation, and the combined system's generation. Generation data for each meter can be negative if the PV or battery unit draws power from other plant components or the grid. For plants providing ancillary services, we also received hourly data on ancillary services awards. For the plants that provided 15 min metering data, we aggregate the meter readings up to the hourly level for consistency across the full sample. In some hours, a plant may be missing data. For these cases, we replace missing data with the average hourly meter reading for that month and verified with the corresponding plant operators that this approach was appropriate. After cleaning the empirical metering data, ten of the eleven plants have a full time-series dataset for the calendar year 2020. One plant contains missing PV data for the first month and missing battery data for the first four months of 2020; the storage value premium for that specific plant is thus smaller than if it operated for a full year as the stunted realized revenue gains are spread over a comparatively large amount of solar generation. The design-based capacity credit and baseline storage dispatch for this plant assume that the battery was operational since February 2020. For each of the plants in our sample, we conducted semi-structured interviews with the plant owners to verify data and understand the factors that affect the dispatch decisions for the PV-battery hybrid plants.

3. Asset owner business models

We document how operators of PV-battery hybrids in our sample combine distinct revenue streams to form an overarching operational strategy. In the context of PV-battery hybrids, we define a business

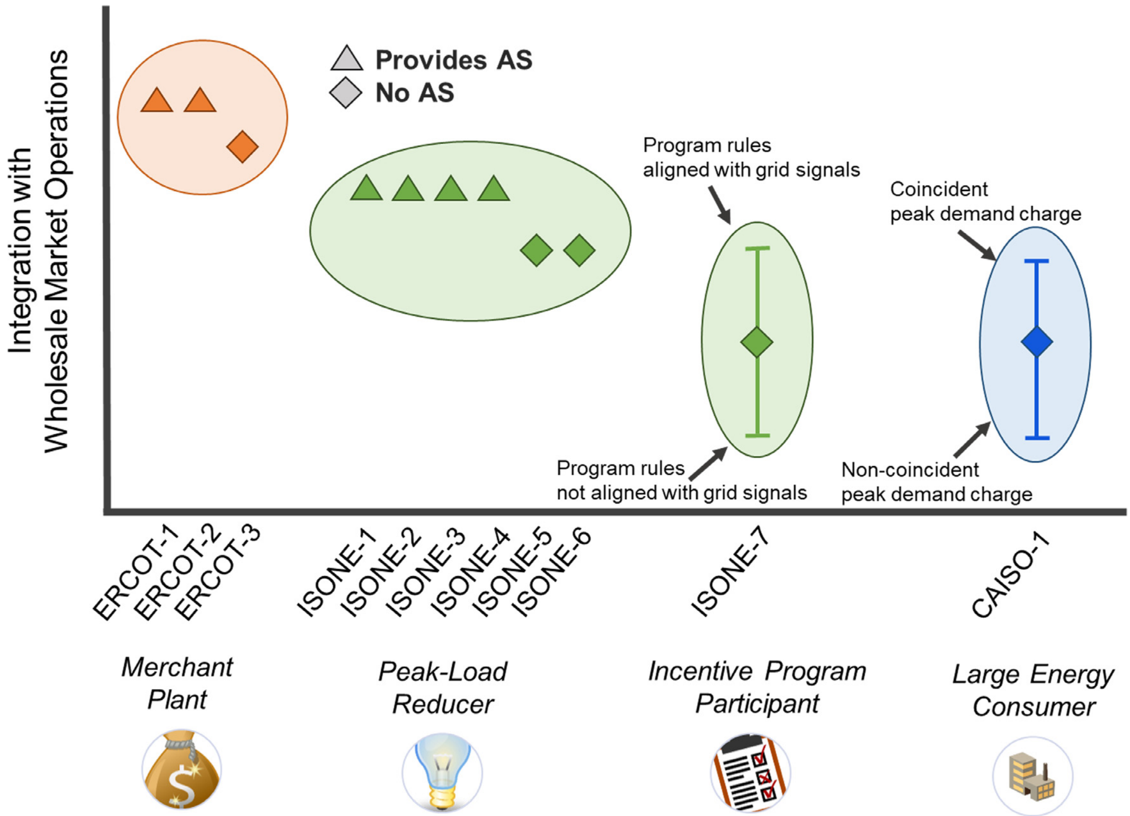

Fig. 3. Taxonomy of PV-battery hybrid business models for sample projects.

model as the strategy an owner of a hybrid plant relies on to justify the costs of building and operating the PV and storage asset. While the literature reviewed in the introduction discusses potential revenue sources, we classify hybrid plants by business model that we drive from semi-structured interviews with developers. This taxonomy of PV-battery hybrid business models is an important qualitative result of our study, and it builds the foundation for understanding why the empirical market value of such plants differs from the modeled baseline market value. The four business models, ordered from greatest to least responsiveness to organized wholesale power market price signals, are: merchant, peak-load reducer, incentive program participant, and large energy consumer. See Fig. 3 for a mapping of each of our eleven hybrid projects to one of these four business models.

3.1. Merchant plant

The most straightforward business model employed by PV-battery hybrid operators is the "merchant plant" business model. Under this strategy, the plant operator maximizes profit by responding directly to competitively set price signals in organized electricity markets. Only three of the eleven plants in our sample fit this merchant plant business model, and all three of these plants were located within ERCOT.

The merchant PV-battery hybrids earn revenue through energy arbitrage—charging the battery when wholesale electricity prices are low and selling when they are high [19]. Two of the merchant plants in ERCOT also provide regulation reserves. Among all four business models, the dispatch of the PV-battery merchant plant most closely follows competitively set wholesale electricity market prices. These prices are the best real-time reflections of electric power system conditions; thus the PV-battery merchant plant is expected to dispatch when the system needs it the most. Even if wholesale electricity market prices do not always reflect system needs precisely, they provide a more dynamic dispatch signal to plants than regulated tariffs or incentive program rules and requirements.

3.2. Peak load reducer

The "peak-load reducer" business model generates value by reducing the load of a load-serving entity during peak times. Unlike the merchant plant that earns wholesale market revenue from selling the output of the PV-battery hybrid, the peak-load reducer primarily uses the battery to lower load-serving entity costs. Six of the eleven plants in our sample fit this peak-load reducer business model, and all six of these plants are located within ISO–NE.

Utilities in ISO–NE typically pay for transmission service via a regulated peak-load pricing schedule and pay for capacity based on the forward capacity market price. As discussed later in Section 6, the avoided costs from lower transmission-related and capacity-related demand charges can be significant. The billing determinant for transmission service payments is the utility's peak demand during the regional monthly peak [20]. The billing determinants for system capacity is the peak demand during the system-wide annual peak, adjusted by the planning reserve margin. The peak-load reducer business model aims to forecast the peak hours each month and year when the demand charges will be assessed and then dispatch the PV-battery hybrid to reduce its reliance on the transmission network during those hours. In addition, any energy from the PV-battery hybrid can lower the energy charges for the load-serving entity, settled at the prevailing wholesale energy price. When not being utilized to lower peak load, four of the "peak-load reducer" plants also provide at times frequency regulation services. In this case, the services are sold directly to ISO–NE rather than indirectly reducing load-serving entity costs.

Unlike the merchant plant, the peak-load reducer does not primarily follow competitively set wholesale electricity market prices. Instead, the billing determinants, which are based on coincident peaks, become the primary dispatch signal. To the extent that system conditions coincide with the operator's expectations of the annual and twelve monthly peak load events, the dispatch signal is dynamically responsive to grid needs, though not as directly as the merchant plant.

3.3. Incentive program participant

Particularly while deployment of PV-battery hybrids is still nascent, one business model employed by plants is to earn revenue by participating in federal and state incentive programs. In contrast to merchant plants and peak-load reducers that are dispatched according to price signals (i.e., wholesale electricity prices, transmission- and capacity-related demand charges), the incentive program participant operates the PV-battery hybrid to comply with incentive program rules and regulations. One of the eleven PV-battery hybrids in our sample relies entirely on a state-incentive program for its revenue, while another seven have separate primary business models but also benefit from state or federal incentives.

The PV-battery hybrid that participates in the state incentive program is in ISO–NE and is part of the Solar Massachusetts Renewable Target Program ("SMART") and contributes to the Massachusetts Clean Peak Energy Standard ("CPS"). The CPS requires 1.5% of a retailer's annual electric sales in 2020 to come from clean peak energy certificates, increasing by 1.5% per year thereafter [21]. Three of the fourteen PV-battery hybrids in ISO–NE listed in Table 2 similarly participate in the SMART program, and another 40 PV-battery hybrid plants with battery storage capacity of roughly 90 MW are expected to be enrolled in SMART by the end of 2021 [22]. The SMART incentive program provides a feed-in tariff for PV projects. PV projects that are co-located with battery storage earn a higher feed-in tariff so long as the PV-battery hybrid satisfies certain technical characteristics and operational requirements [22]. PV-battery hybrids must either enroll in an ISO–NE demand-response program or discharge at least 52 complete cycle equivalents per year during a static peak window defined as 3:00 PM – 8:00 PM during the summer and 4:00 PM – 9:00 PM during the winter. Most PV-battery hybrids enrolled in the SMART program pick the second option. Following this dispatch signal results in an approximation of bulk power system needs, but it does not guarantee alignment with hours when the system is most stressed.

The Massachusetts CPS, on the other hand, provides both a static dispatch signal and a dynamic one for PV-battery hybrids. The static dispatch signal is based on pre-specified seasonal peak periods, similar to the SMART requirement. The dynamic signal comes from a credit multiplier that is awarded for generation coinciding with the monthly system peak, which must be predicted by the operator based on weather and resource availability, among other factors. Relative to the SMART feed-in tariff, CPS's inclusion of a static and dynamic dispatch signal provides a better reflection of times when the grid is most stressed. As these incentive rules can deviate from direct wholesale market signals, PV-battery hybrids that maximize revenue from such programs will be operated differently from merchant plants and will yield a lower market value, all the while still likely being privately profitable.

Seven of the eleven PV-battery hybrids in our sample reduce their upfront costs through the federal investment tax credit (ITC) that can offset federal tax obligations. It offers a private owner of a PV-battery hybrid a 30% federal tax credit for the battery storage investment if it charges 100% of the time from the co-located PV unit. Batteries charging 75–99% from PV generation earn a pro-rated ITC, and batteries charging less than 75% are not eligible [23]. Given the high capital costs of battery storage systems, the federal ITC plays an important role in determining the financial viability of deploying PV-battery hybrids [13,24]. However, the stipulation that qualifying batteries must charge at least 75% from the PV unit may limit the value these plants can provide to the grid [24]. A PV-battery hybrid operator may forgo charging from the grid—even if electricity costs are near-zero or negative—because doing so would reduce the share of the ITC the project can claim. Likewise, a PV-battery hybrid operator may choose not to provide regulation-down service outside of hours when the PV is generating because doing so could reduce its ITC eligibility.

3.4. Large energy consumer

With the "large energy consumer" business model, the dispatch of the PV-battery hybrid is determined primarily by private end-user characteristics and not bulk power system needs. Types of PV-battery hybrids falling under this description include ones located at military bases, jails, manufacturing facilities, water treatment plants, and oil and gas operations. Only one of the eleven plants in our sample, located in CAISO, fits this large energy consumer business model. The large energy consumer typically places a premium on the ability to ride out multi-day outages and shorter outages lasting several hours. To meet these criteria, the battery unit may be kept at full state-of-charge during most hours and cycled only infrequently in the event of an outage. This operating strategy does not straightforwardly benefit the electric grid, although it can provide significant benefits to the end-user and possibly the local community in the event of a natural disaster or other form of major outage.

Large energy consumers are typically enrolled in industrial electricity tariffs, and the PV-battery hybrid can reduce end-customer bills. Our large energy consumer faces a non-coincident peak demand charge and the PV-battery hybrid discharges to reduce its monthly maximum demand, irrespective of whether it lines up with system demand. Lowering customer demand can reduce local congestion along the utility's distribution system, but the dispatch of the PV-battery hybrid may provide less market value than if it directly responded to wholesale electricity market price signals. Industrial electricity tariffs may also include a coincident peak demand charge [25], which then provides a dispatch signal comparable to that of the peak-load-reducer business model.

4. Empirical dispatch characteristics

In this section, we describe the empirical metering data obtained for the eleven PV-battery hybrids operating in 2020.

As shown in Fig. 4, seven of the eleven PV-battery hybrids charge at least 75% of the battery's energy from the onsite PV generator, meeting or exceeding the ITC eligibility threshold. One of these hybrid plants is located in ERCOT, while the remaining six are located in ISO–NE. The sole ISO–NE hybrid plant charging less than 75% from the PV unit (ISO–NE 1) does so because it focuses primarily on providing regulation reserves, and high regulation reserve prices can often occur outside of PV generation hours. Likewise, the two ERCOT PV-battery hybrids under the 75% eligibility threshold provide regulation reserves.

The PV-battery hybrids differ in the typical battery discharge time, depicted in Fig. 5, which can be explained by their business models and timing of grid needs. For example, all seven ISO–NE plants are either peak-load reducers or incentive participants, and target peak loads or incentive program peak periods in the evening. All but one discharge at least 80% of the battery energy during these hours - the one that does not uses the battery to provide predominantly regulation reserves. Two of the ERCOT plants discharge primarily in the evening and afternoon: They are both merchant plants exposed to electricity prices that peaked in 2020 in the early afternoon hours. The ERCOT plant whose discharge is more evenly distributed throughout the day (ERCOT-1) uses the battery solely for regulation reserves, the incidental energy from the battery is only required to maintain the state of charge. CAISO-1 is a large energy customer that discharges more than 50% of the battery energy in early morning hours, as it is designed to lower the customer's utility bills and provide backup power. As discussed in the next section, the timing of this plant's discharge differs from CAISO's wholesale prices that tend to be highest in the early evening.

We also find variation in how often each plant is cycled, with some plants cycling about three times per week on average (150 times per

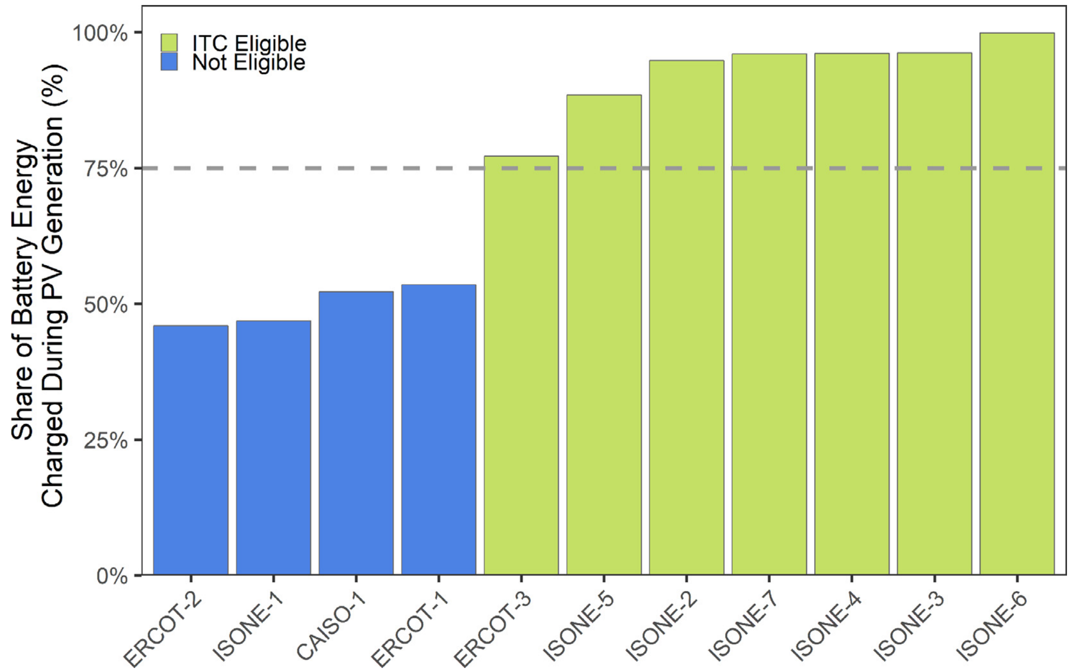

Fig. 4. Share of batteries' charge from PV generator.

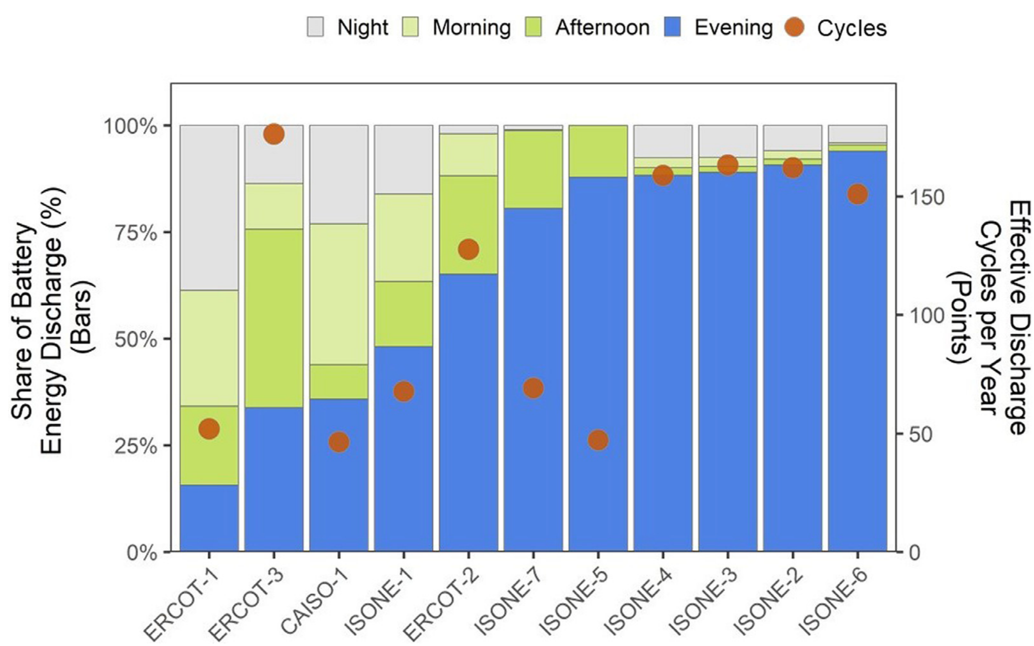

Fig. 5. Timing of battery discharge and amount of battery cycling
Note: The left axis indicates the time of day during which the battery is most commonly discharged (bars), the right axis shows how often each project cycles its battery over the course of a year (points). Morning is defined as 6:00 AM - 12:00 PM, afternoon as 12:00 PM - 5:00 PM, evening as 5:00 PM - 9:00 PM, and night as 9:00 PM - 6:00 AM.

year) and others cycling roughly once per week (52 times per year). We measure effective discharge cycles as the battery storage's total discharge over the course of the year divided by its rated energy capacity. More frequent cycling generates more market value and more revenue to the owner of the PV-battery hybrid, yet it comes at the expense of higher maintenance costs and an abbreviated asset lifetime. In addition, interviews with asset owners revealed that warranty policies for battery storage systems often only insure battery performance up to a certain number of cycles per year.

5. PV-Battery market value

This section examines the market value for the year 2020 of the standalone PV profiles, the empirical PV-battery hybrid dispatch data, and the hypothetical baseline dispatch that is optimized for wholesale energy market revenue. We first analyze the projects' contributions to meeting resource adequacy requirements, then detail energy, capacity and ancillary service value, and finally compare the empirical storage value premium to the baseline premium.

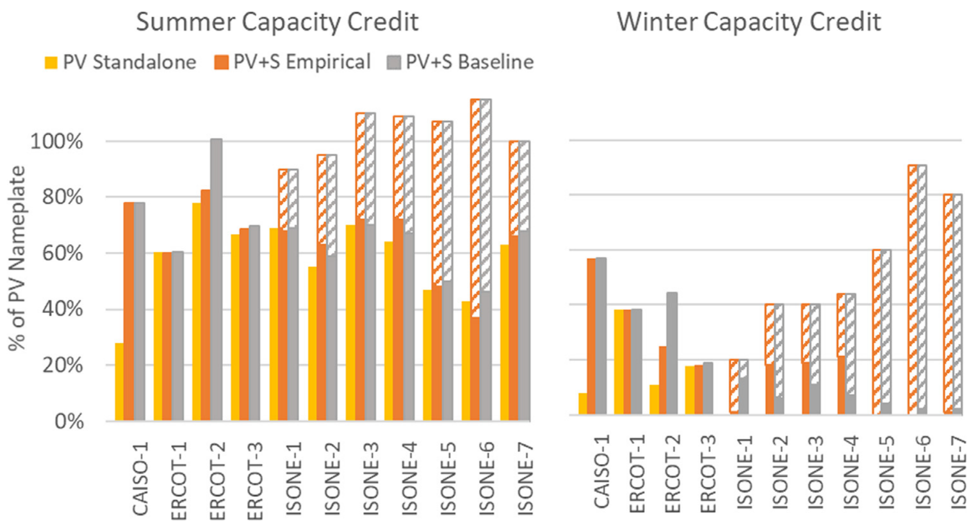

Fig. 6. Seasonal capacity credits of PV standalone, PV+S empirical and PV+S baseline profiles
Note: The solid-colored segment of the empirical and baseline PV+S bars reflect the profile-based credit for projects in ISO–NE. The hatched segment above depicts an adder to display the design-based credit (full bar height, not just hatched portion).

5.1. *Capacity credits of PV standalone and PV-Hybrid profiles*

For nearly all the projects in our sample, adding a battery leads to a higher capacity credit of the PV-battery hybrid than the standalone PV (Fig. 6). This result is obvious for CAISO-1 because the capacity credit rule in CAISO adds the battery capacity credit to the PV capacity credit, irrespective of how the battery is dispatched. The same is true for the ISO–NE hybrids when the design-based capacity credit is used. In contrast, when calculated with the profile-based approach, the capacity credit of the ISO–NE and the ERCOT hybrids depends on the battery dispatch. Across all ISO–NE projects, the battery dispatch only leads to minor changes to the empirical PV-hybrid profile relative to the standalone PV profile when assessed as the median generation over all hours of the seasonal peak windows. The profile-based capacity credit of the hybrid configurations increases by single-digit values in the summer, but gains can reach up to 20% for a few projects in the winter. For two hybrids (ISONE-1 and 6) the battery charges during the peak capacity windows, effectively shifting PV generation from the peak period to the off-peak period, leading to a capacity credit decline in the summer relative to standalone PV.

The capacity credit of the hypothetical baseline PV-battery profile is often similar to the capacity credit for the empirical PV-battery profile. Again, this result is obvious for cases where the capacity credit is based only on the design of the battery. The differences in the capacity credit of the baseline and empirical dispatch are more telling for cases where the capacity credit depends on the profile (i.e., in ERCOT and the ISO–NE profile-based capacity credits). ERCOT-2, which has large PV-battery capacity and PV-POI ratios, achieves a higher capacity credit with the baseline dispatch than with the empirical dispatch. The baseline dispatch can sometimes do worse than the empirical dispatch in ISO–NE—for example, ISONE-2 in both summer and winter or ISONE-3 and 4 in the winter— because it optimizes energy market revenue, whereas the capacity credit depends on median generation across all peak hours.

The greatest increases in the capacity credit from adding a battery occur in CAISO and ISO–NE when using the design-based capacity credit. The capacity credit for the CAISO project increases from 30% to nearly 80% in the summer and from less than 10% to nearly 60% in the winter. The capacity credit for ISONE-6, which has a high PV- battery capacity ratio and a greater than 1-hour duration battery, increases from 40% of the PV nameplate to over 100% of the PV nameplate in summer and from 0% up to 90% in the winter. A recent market monitoring report for ISO–NE suggests that this design-based approach may overvalue the true reliability contributions of a 2 h duration battery [26]. Even so, the lower 2 h battery capacity credits that they suggest as more reasonable (67% of the battery nameplate at low storage penetrations, declining to roughly 40% at higher penetrations) would still produce PV-battery hybrid capacity credits that exceed the profile-based capacity credits calculated here.

5.2. *Market value of PV standalone and empirical PV-Hybrid profiles*

The market value of the PV-battery hybrids in our sample, as calculated with the empirical dispatch data, exceeds the market value of standalone PV (Fig. 7). The majority of this increase is driven by capacity value (except for the ERCOT hybrids) and ancillary service value. In contrast, the energy values are usually very similar between both configurations. For a few projects the battery dispatch shifts overall hybrid generation into higher priced hours, but the energy value storage premium is always smaller than $2/MWh. For some projects the average energy value even decreases by a small amount relative to the standalone PV because of storage efficiency losses. These small energy premiums may be driven in part by energy prices that were unusually low due to pandemic-related demand reductions in the year 2020 [27].

The higher capacity credits discussed in the previous section result in a sizable increase in capacity value. Capacity value is higher for projects with large batteries relative to PV and multi-hour duration storage. The CAISO PV-battery hybrid can double its capacity value to $13/MWh. In ISO–NE, a profile-based capacity credit leads to a moderate capacity value gain for the hybrid projects (up to $7/MWh), whereas a design-based capacity credit can increase the capacity value by a factor of two to more than seven (from $8–10/MWh to $17–54/MWh). The effect is even greater for projects with modest capacity factors, because the capacity revenue rise is spread over few MWhs. No capacity values are shown for ERCOT, because the market relies only on the energy market and does not impose a resource adequacy obligation on load-serving entities.

Six projects in our sample participate in ancillary service markets. As standalone PV projects do not currently provide regulation reserves, we disregard AS value for the PV standalone profiles. The AS value of the PV+S empirical profiles in our sample range from $1 to $14/MWh depending on a variety of factors. The AS value for ERCOT-1 is modest because it has a small battery relative to the PV capacity. ERCOT-2 has a larger battery, leading to a higher AS value, but it only provided regulation reserves for the last three months of the year. Despite having similar battery sizes relative to the PV capacity, the AS value of ISONE-1 is more than double the AS value of ISONE 2–4 because ISONE-1 uses the full battery capacity to provide regulation reserves. In contrast, the other ISO–NE hybrids only offer upward biased regulation reserves to

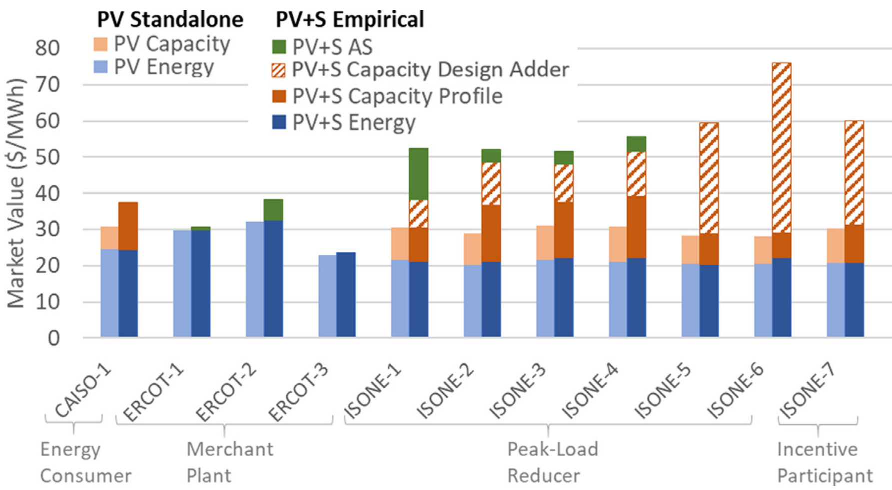

Fig. 7. Market value of PV standalone and PV+S empirical generation profiles in 2020
Note: The solid-colored segment of the empirical and baseline PV+*S* bars calculate capacity value with the profile-based capacity credit for projects in ISO–NE. The hatched segment above depicts an adder to get to the capacity value with the design-based capacity credit (full bar height, not just hatched portion).

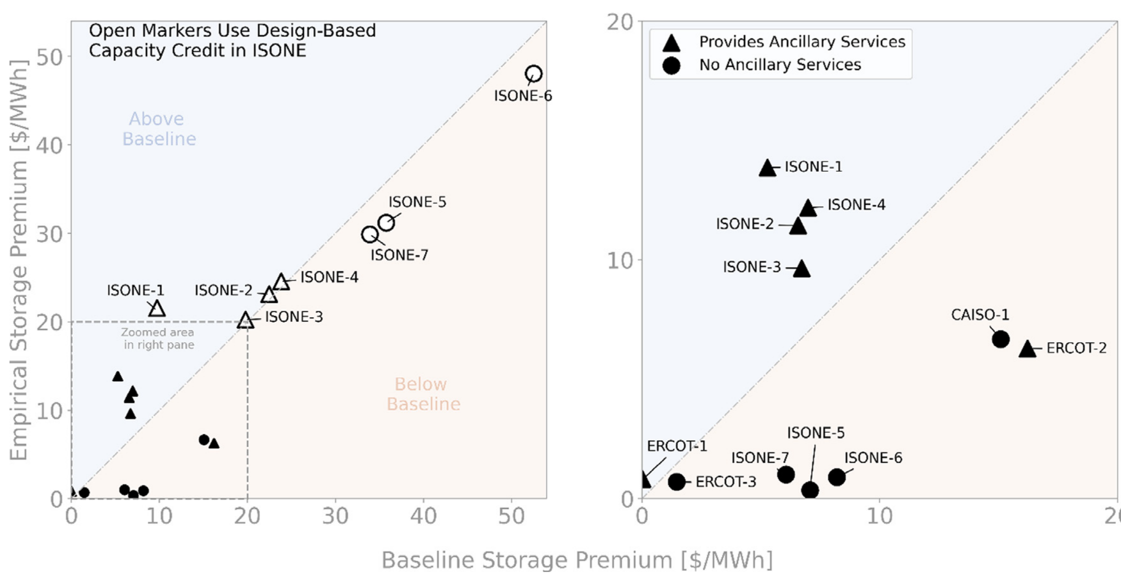

Fig. 8. Comparing storage premiums of empirical dispatch with hypothetical baseline dispatch.

comply with ITC stipulations that storage units shall not charge from the grid.

The storage value premium (across energy, capacity and AS products) with our empirical hybrid profiles ranges from $1/MWh for small battery systems in ERCOT to $45/MWh in ISO–NE with an average of $19/MWh.

5.3. Empirical storage value premium relative to baseline

Comparing the storage value premium across our sample is complicated by the fact that the premium varies in part because of the different technical characteristics of the plants and the different wholesale market environments. To better isolate the variation in storage value premium that is driven by differences in operational strategies, we juxtapose the empirical storage value premium of each PV-battery hybrid with that of a common baseline (Fig. 8). The baseline is the storage value premium that could hypothetically be achieved with the same technical capabilities and in the same location, but with the dispatch based on maximizing energy market revenue with perfect foresight. Empirical premiums that are the same as the baseline premium fall on the diagonal line of equal performance, whereas operational strategies that provide market value in excess of the baseline will be above the diagonal and operational strategies that provide less market value will be below the diagonal.

We find that the performance of the ISO–NE hybrids relative to the baseline greatly depends on whether the capacity value uses the design-based capacity credit or the profile-based capacity credit. With the design-based capacity credit, the ISO–NE hybrids are somewhat spread out along the line of equal performance (see the left side of Fig. 8). This indicates the empirical premium is similar to the baseline premium and that variation in the empirical premium between plants is based on differences in technical capabilities and locations within ISO–NE. On the other hand, the profile-based capacity credit clarifies the differences in storage value premiums related to operational strategies (see the right side of Fig. 8). Across all ISO–NE hybrids the baseline storage premium is between $5–8/MWh. The four ISO–NE hybrids that provide ancillary services outperform the baseline and achieve premiums of $10–14/MWh, while the other three underperform with premiums of less than $2/MWh. As discussed further in the next section, CAISO-1 and ERCOT-2 similarly underperform relative to the baseline.

6. The influence of business models on PV-Battery market value

We now discuss in detail the reasons why empirical storage premiums differ from the modeled baseline storage premiums. Two key reasons explain this gap. First, the lack of perfect foresight of real-time energy prices cause the plant to not realize its full market value from energy price arbitrage. Real-world actors can never replicate perfect foresight, which is more important for energy-limited batteries than conventional capacity-limited thermal plants. But we expect this effect to diminish over time, as operators overcome teething issues, gather experience dispatching the battery storage asset, and improve their predictive capabilities.

Second, the majority of our examined PV-battery hybrid plants in our sample (8 out of 11) employ business models whose objective is not to maximize wholesale market value alone, in contrast to the widely held assumption in the existing literature. Instead, their private profit-maximizing dispatch signals are often stronger than the price signals conveyed by wholesale energy markets. Absent larger reforms to tariff and incentive program structures, these deviations will likely persist and will continue to drive a wedge between the potential market value of PV-battery hybrids and what they contribute in practice. Thus, incorporating operator decisions into the PV-battery hybrid plant valuation framework is essential. Next, we briefly highlight why the empirical storage value premium for each plant in our sample differs from its baseline value, followed by a more detailed analysis of the business models of two specific hybrid plants in ISO–NE.

Beginning with ERCOT, Fig. 8 shows that ERCOT-2′s empirical market value in 2020 is about $9/MWh lower than what modeling would suggest. As a merchant plant, ERCOT 2′s primary goal is to maximize revenue from the wholesale market, so market-based and business-model dispatch signals should be closely aligned. However, lack of perfect foresight of real-time energy prices and early operational challenges lead to differences in modeled vs. realized values. Specifically, we found that ERCOT-2 was not delivering its maximum energy output to the grid during the highest-priced hours. Existing studies of PV-battery hybrid plants acknowledge this limitation of the perfect foresight assumption [11,28]. In contrast, ERCOT-1 and ERCOT-3′s empirical storage premiums do not deviate substantially from their baseline storage premiums. The difference between these plants and ERCOT-2 is that their battery storage capacities are small relative to their PV capacities, dampening the impact of operational decisions relative to a perfect foresight dispatch.

CAISO-1 and the ISO–NE PV-battery hybrids do not follow the merchant business model, and as a result their empirical and baseline storage premiums deviate more. Specifically, CAISO-1 is a large energy consumer and uses its battery primarily for resiliency and demand-charge reduction purposes, but not for energy arbitrage. It faces dispatch cues from an industrial retail electricity tariff with a summer non-coincident peak demand charge of about $25,000/MW of monthly billing demand [25]. As a morning-peaking end-user, this large price signal encourages dispatch in the morning instead of the evening when a merchant plant would be capturing arbitrage value (assuming the battery does not cycle multiple times per day). If participating in energy price arbitrage during the summer of 2020, CAISO-1 would earn about $4300/MW-month from the battery, much less than the avoided demand charge. Retail demand charge price signals, as documented for residential and commercial PV-battery hybrids in [15], lead to different operational decisions, explaining a gap of about $8/MWh in the empirical vs. baseline storage premiums.

6.1. Analyzing ISONE-5 and ISONE-7′s empirical and baseline dispatch

Next, we contrast how the differing business models of two similarly configured and located PV-battery hybrid plants in ISO–NE lead to key differences in their empirical and baseline dispatch. Given both plants are in moderate proximity to each other and share similarly-sized components, one would expect both to be dispatched in the same way and provide comparable market value. Yet, we find this is not the case in practice.

Starting with ISONE-7, the incentive program participant business model operates the battery to comply with the relevant program rules rather than optimizing for energy arbitrage. Complying with the SMART incentive program requires cycling the battery asset at least 52 times per year during the summer and winter peak periods. ISONE-7 earns a feed-in tariff of approximately $140/MWh, roughly $30–40/MWh more than the rate for a standalone PV system participating in the program [22]. Fig. 9 on the left shows that this incentive payment (panel c) is much higher than the price signal sent by real-time energy prices (panel a), which is why ISONE-7 favors incentive program participation over the merchant model. The SMART program incentive dispatch signal is strong, but it is much coarser than real-time energy prices and does not allow for dynamic responses to grid needs. As a result, ISONE-7′s empirical dispatch (panel c) yields a lower wholesale market premium than the baseline dispatch (panel a). ISONE-7 also participates in the CPS program that rewards generation during ISO–NE's twelve monthly system-wide peak demand hours, but when those hours occur is only known in hindsight. As shown in Fig. 9 panel c, ISONE-7 lacks perfect foresight and misses July's peak hour, dispatching instead only during the daily SMART peak period.

Like ISONE-7, ISONE-5 employs a business model that does not aim to maximize energy price arbitrage revenue. Instead, as a peak-load reducer, ISONE-5 only aims to minimize its peak load during the twelve hours when its use of the transmission network are determined and during the single annual hour when its portion of system-wide capacity costs are set. The load-serving entity faced a demand charge of roughly $12,000/MW-month [20] for its use of the transmission network and a charge of about $90,000/MW-year during ISO–NE's annual peak hour to compensate system capacity costs. Therefore, if the monthly transmission peak coincides with ISO–NE's annual peak, ISONE-5 can avoid a combined cost greater than $100,000/MWh during the annual peak, far greater than any wholesale energy price. Fig. 9 panel d demonstrates how ISONE-5 operates its battery according to this peak-load dispatch signal during the day of ISONE's system-wide peak and the days following. Comparing this with the real-time energy price at ISONE-5′s nearest node and ISONE-5′s baseline operation (panel b) illustrates how strong the peak-load reducer business model signal is compared to the merchant model. The peak-load reducer business model also discourages frequent cycling of the battery storage, leaving it idle for much of the time (panel d). Limiting the cycling of the battery only to the top peak hours of the year may provide the grid with important capacity value but misses an opportunity to alleviate daily stresses between peak and off-peak hours.

6.2. Estimated business model revenue for ISONE-5 and ISONE-7

We conclude with a comparison of the estimated revenue (or avoided cost) for both ISONE-5 and ISONE-7 if each had adopted the merchant, peak-load reducer, or incentive participant business model. Fig. 10 underscores that the business models can yield very different storage premiums, both for the empirical profiles (bars) and hypothetical profiles optimized for each business model (diamonds). For ISONE-5, dispatching the battery storage to avoid costly transmission and capacity demand charges produces a storage premium of approximately $85/MWh, which could rise by another $20/MWh if the operator had perfect foresight of peak-load hours. This premium dwarfs the storage premium it would earn via energy arbitrage and generation capacity payments ($31/MWh - assuming no changes in dispatch, or $36/MWh with perfect price foresight) that the merchant model targets. ISONE-7 instead pursued the incentive program participant business model and realized a storage premium of approximately $35/MWh, which is largely de-

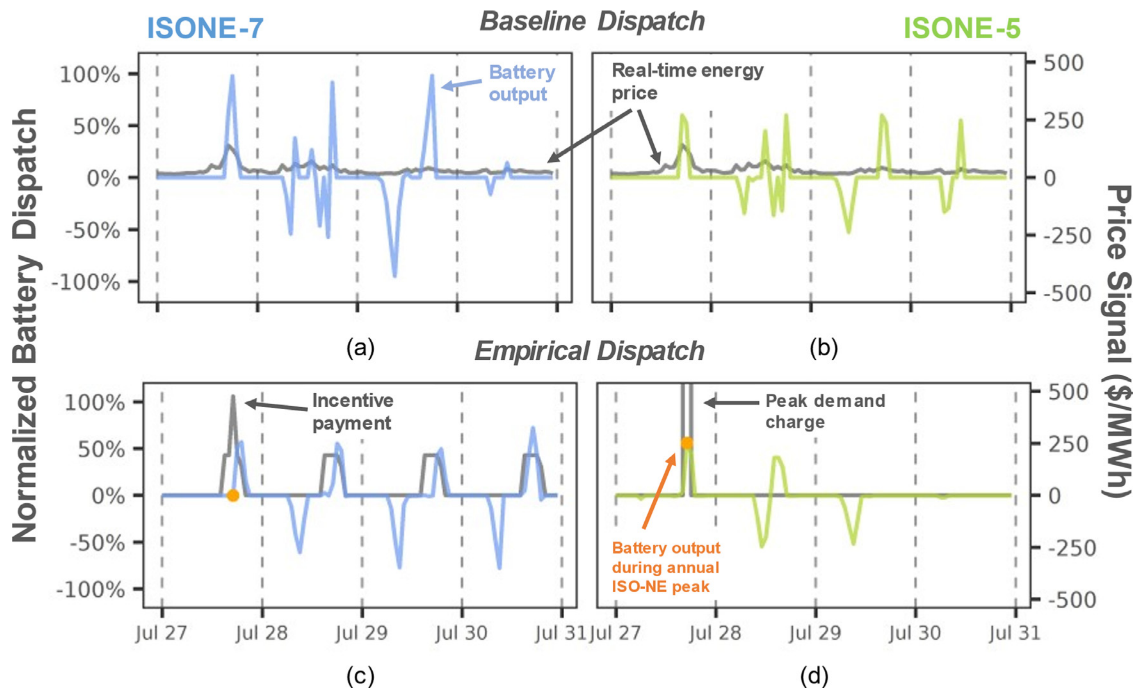

Fig. 9. Empirical (Bottom) vs. wholesale market optimized baseline dispatch (Top) and price signals for an incentive-participant (ISONE-7, Left) and peak-load-reducer (ISONE-5, right).

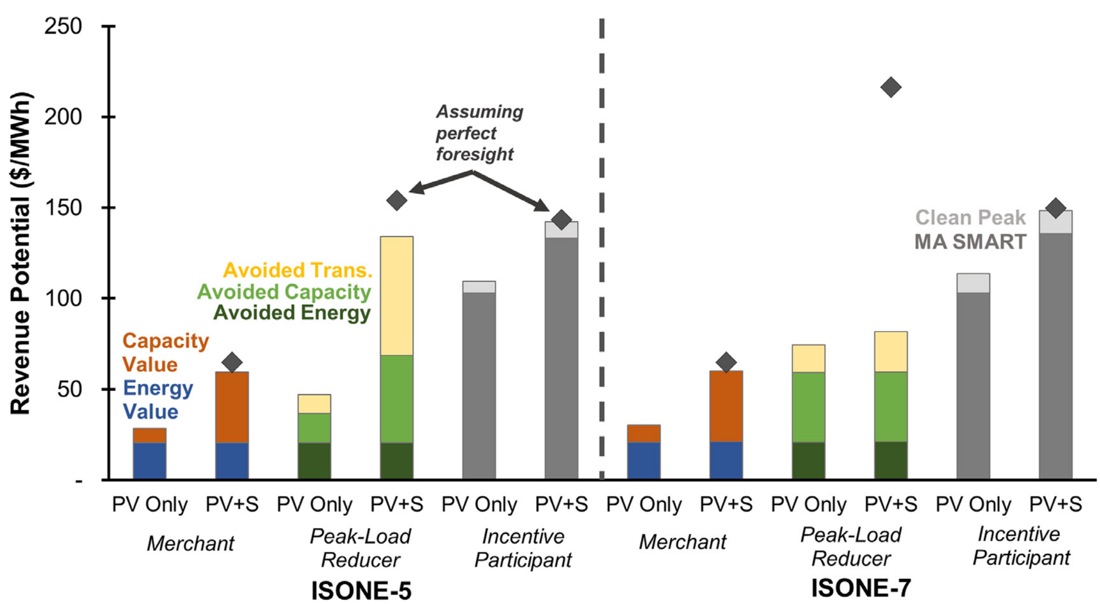

Fig. 10. Revenue potential across business models for PV standalone and PV+S configurations using two sample projects
Note: The merchant PV+*S* capacity value is calculated with the design-based capacity credit. ISONE-5 is a peak-load reducer and ISONE-7 is an incentive participant.

termined by the storage adder in the SMART incentive program. This realized storage premium slightly exceeds the storage premium of the merchant model ($30/MWh), but the incentive program provides much greater total revenue. ISONE-7 did not aim to reduce generation and transmission capacity charges, so its empirical profile performs poorly with the peak-load reducer business model. Its battery size and duration are slightly greater than ISONE-5′s, which means it could have yielded a bigger potential payout if it had targeted the peak-load hours with perfect foresight.

Overall, we find that there is no "right" dispatch signal for a PV-battery hybrid plant to follow other than the dispatch signal that provides it with the greatest source of revenue or avoided cost. Depending on the business model, adding storage to a standalone PV plant may or may not deliver significant value from a wholesale market perspective.

For a merchant plant, the dispatch is determined by differences between on-peak and off-peak energy prices (i.e., energy arbitrage) as well as capacity payments and sometimes ancillary services prices. For the load-serving entity acting as a peak-load reducer, the battery operation is driven by the prediction of the twelve monthly coincident peaks over which transmission costs are allocated and the annual system-wide peak. An incentive program participant, such as one enrolled in the MA

SMART program, will cycle their battery according to program rules, but not necessarily during the system-wide annual peak load hours. Finally, the large energy consumer minimizes its customer bill, which when faced with a non-coincident peak demand charge may produce significant local benefits to the distribution grid, but not necessarily system-wide benefits. Our use of empirical data reveals that understanding the business model choice of a PV-battery hybrid operator is key to understanding their operational incentives, which deliver varying amounts of market value.

7. Conclusions

PV-battery hybrid projects dominate interconnection queues in some regions in the United States, but few projects have been operational long enough to assess how the hybrid capabilities may be used in practice. With empirical dispatch data from eleven large-scale PV-battery hybrids in three organized wholesale markets in the United States we demonstrate that market value varies not only by location and technical design characteristics of PV and battery, but also by the project operator's business model. The empirical wholesale market storage premium of our project sample ranges from $1 to $48/MWh$_{solar}$ for the year 2020. These storage premiums should not be considered static, as they will evolve over time with greater PV-battery hybrid deployment and changing wholesale price dynamics – energy prices have for example already increased by $10-$25/MWh in 2021 compared to 2020 which may boost in turn the storage premium. A maturing market will also likely lead to more refined dispatch strategies, such that merchant projects with improved predictive capabilities will be able to capture an increasing share of our optimized baseline revenue. Finally, ISO rules that determine the contribution of hybrid projects to resource adequacy requirements are being refined in several markets, which will influence the capacity value of PV-battery hybrids.

In contrast to the widespread assumptions in the PV-battery hybrid modeling literature, only three of the eleven project operators optimize battery usage for wholesale market revenue as merchant plants. Instead, the majority of operators in our sample target alternate objectives which result in a lower market value than what could otherwise be achieved. Specifically, load-serving entities target peak loads reductions, incentive program participants target compliance with program requirements, and large energy consumers target resiliency enhancements and utility bill minimization. We have shown that operational signals associated with these business models deviate from market signals and can lead to a suboptimal PV-hybrid dispatch from a grid perspective. At the same time, they can result in much higher realized private revenue than what is offered by wholesale markets and what is commonly assumed by optimization models for PV-hybrids. Understanding those prevalent dispatch signals will be key for the grid system operators, and should be a focus of future research, especially as the hybrid projects will represent a more sizeable share of the overall generator portfolio. Regulators tasked with tariff design for generation and transmission capacity should ensure that entities who try to either increase their capacity credits or lower their demand-charge obligations do indeed contribute to overall grid needs. Incentive program designers may similarly want to verify that dispatch signals that are implicitly conveyed through program rules support the dynamic grid demands as expressed by wholesale market prices. Hybridizing PV with batteries has the potential to make their generation less weather-dependent and more responsive to grid system conditions. To fully realize this promise, policymakers will want to ensure that the incentive structures are properly aligned with grid needs, and consequently reward grid-supportive dispatch strategies.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Joachim Seel: Conceptualization, Methodology, Resources, Data curation, Software, Formal analysis, Visualization, Writing – original draft, Writing – review & editing. **Cody Warner:** Methodology, Resources, Data curation, Software, Formal analysis, Visualization, Writing – original draft, Writing – review & editing. **Andrew Mills:** Supervision, Funding acquisition, Conceptualization, Methodology, Writing – original draft, Writing – review & editing.

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We are grateful to the 20 developers of PV-battery hybrid projects who agreed to be interviewed about their business models. We especially thank the owners of the 11 projects that comprise our sample who shared hourly dispatch information with us and without whom this research project would not have been possible – for confidentiality reasons we will abstain from naming them here. We further thank our Berkeley Lab collaborators who gave feedback to our study, in particular James Hyungkwan Kim who provided assistance with the baseline dispatch optimization tool. Finally we appreciate the review of this work by Will Lauwers, Michael DeSocio, Julian Kuhlmann, Jan Porvaznik, Will Gorman, Ryan Wiser, and Ken Schuyler. Of course, any omissions or errors that remain are solely the responsibility of the authors.

Appendix

Using EIA data, we identified 46 PV-battery hybrid plants larger than 1 MW$_{AC}$ that were operational prior to 2020 [29]. Table 2 lists all PV-battery hybrids online prior to 2020 in terms of their DC and AC capacities as well as the power and energy capacities of their battery storage. While four PV-battery hybrids in our sample feature PV units larger than 100 MW$_{AC}$ and six feature battery energies of 40 MWhs or greater, we find that the median PV-battery hybrid is much smaller. Overall, the median PV-battery hybrid consists of a 5.0 MW$_{AC}$ PV generating unit and a battery storage system with a power capacity of 2.5 MW and an energy capacity of 4.8 MWh. In terms of geography, ISO New England is home to the most PV-battery hybrids (30%) but makes up a small share of total hybrid PV capacity (8%) and hybrid battery energy capacity (12%). ERCOT accounts for the largest share of hybrid PV capacity (31%), and Hawaii leads in hybrid battery energy capacity (40%). Looking ahead, interconnection queues suggest significant PV-battery hybrid growth in California, Texas, Nevada, and Hawaii [30].

Table 1
Sample characteristics of PV-battery hybrid plants compared to other major plants operational in 2020.

Plant ID	Inverter Loading Ratio	Battery: PV Capacity Ratio	Storage Duration (hr)	Peak Generation > PV Capacity (% of Storage Capacity)	PV (hours with data)	Storage (hours with data)	Ancillary Service Notes
CAISO-1	1.2–1.4	0–0.5	1–2	0–25%	8784	8784	None
ERCOT-1	1.2–1.4	0–0.5	0–1	0–25%	8784	8784	Reg Up + Down
ERCOT-2	1–1.2	1–2	0–1	25–50%	8784	8784	Reg Up + Down
ERCOT-3	1.2–1.4	0–0.5	2–4.5	25–50%	8784	8784	None
ISONE-1	1.2–1.4	0–0.5	2–4.5	25–50%	8784	8784	Regulation
ISONE-2	1.2–1.4	0–0.5	2–4.5	75–100%	8784	8784	Regulation
ISONE-3	1.2–1.4	0–0.5	2–4.5	75–100%	8784	8784	Regulation
ISONE-4	1.4–1.6	0–0.5	2–4.5	75–100%	8784	8784	Regulation
ISONE-5	1–1.2	0.5–1	1–2	25–50%	8784	8784	None
ISONE-6	1.2–1.4	0.5–1	1–2	0–25%	8784	8784	None
ISONE-7	1.4–1.6	0.5–1	1–2	0–25%	8039	5543	None
Sample Mean	1.31	0.56	2.68	40%	–	–	–
All Plant Mean	1.29	0.78	2.30	N/A			

Table 2
Catalog of PV+battery plants larger than 1 MW in commercial operation prior to 2020.

		PV Capacity			Battery Storage			
Plant Name	Region	MW_{DC}	MW_{AC}	ILR	MW	MWh	Duration	Battery-PV%
Castle Gap Solar Hybrid	ERCOT	234.0	180.0	1.30	10.0	42.0	4.2	6%
Springbok 3 Solar Farm Hybrid	non-CA-West	121.0	90.0	1.34	1.5	1.5	1.0	2%
Babcock Solar Energy Center Hybrid	Southeast	114.7	74.5	1.54	10.0	40.0	4.0	13%
Citrus Solar Energy Center Hybrid	Southeast	114.7	74.5	1.54	4.0	16.0	4.0	5%
Beacon BESS 1	non-CA-West	63.9	56.0	1.14	36.0	18.0	0.5	64%
OCI Alamo Solar I Hybrid	ERCOT	49.5	40.7	1.22	1.0	0.3	0.3	2%
Pinal Central Energy Center Hybrid	non-CA-West	30.9	20.0	1.55	10.0	40.0	4.0	50%
AES LAWAI SOLAR Hybrid	HI	28.2	20.0	1.41	20.0	100.0	5.0	100%
KIUC Kapaia PV and BA Storage Project	HI	17.0	13.0	1.31	13.6	57.1	4.2	105%
AES Kekaha Solar, LLC Hybrid	HI	19.3	14.0	1.38	14.0	70.0	5.0	100%
KRS I Anahola Solar Hybrid	HI	14.5	12.0	1.21	6.0	4.6	0.8	50%
Redstone Arsenal Hybrid	Southeast	12.5	10.0	1.25	1.0	2.0	2.0	10%
Athens BESS	MISO	8.8	6.6	1.33	9.0	18.0	2.0	136%
Port Allen Solar	HI	7.2	5.8	1.25	3.0	2.0	0.7	52%
MCRD Parris Island PV Hybrid	Southeast	6.7	6.0	1.12	4.0	4.0	1.0	67%
Commerce ESS	ERCOT	5.9	5.0	1.18	10.0	10.0	1.0	200%
Noland Wastewater Treatment Plant	SWPP	5.8	5.0	1.16	6.0	13.1	2.2	120%
Westside Wastewater Treatment Plant	SWPP	5.8	5.0	1.16	6.0	13.1	2.2	120%
GMP Solar/Storage-Milton Hybrid	ISO–NE	7.0	5.0	1.40	2.0	8.0	4.0	40%
GMP Solar/Storage-Ferrisburgh Hybrid	ISO–NE	6.3	5.0	1.26	2.0	8.0	4.0	40%
Happy Hollow CSG Hybrid	ISO–NE	7.1	5.0	1.43	3.3	6.6	2.0	66%
Imeson Solar	Southeast	9.0	5.0	1.80	2.0	4.0	2.0	40%
Middleton Solar Park	ISO–NE	6.0	5.0	1.20	3.0	6.6	2.2	60%
GMP Solar - Panton Hybrid	ISO–NE	4.9	4.9	1.00	1.0	4.0	4.0	20%
Syncarpha Blandford Hybrid CSG	ISO–NE	7.1	4.9	1.45	3.9	7.9	2.0	80%
Genentech-Oceanside Hybrid	CAISO	4.8	4.5	1.07	2.0	2.0	1.0	44%
UC Merced Solar Hybrid	CAISO	5.4	4.5	1.20	0.5	0.9	1.8	11%
Mt. Tom Solar Project Hybrid	ISO–NE	5.8	5.0	1.15	3.0	6.0	2.0	60%
GMP Solar/Storage-Essex Hybrid	ISO–NE	6.8	4.5	1.51	2.0	8.0	4.0	44%
CMEEC - Norwich Stott St Solar Hybrid	ISO–NE	4.8	3.5	1.37	0.8	3.0	3.8	23%
CMEEC - Polaris Park Solar Hybrid	ISO–NE	4.8	3.5	1.37	0.8	3.3	4.1	23%
Hampshire College Hybrid	ISO–NE	4.6	3.4	1.35	0.5	0.5	1.0	15%
Anoka BESS	MISO	4.6	3.4	1.35	6.0	12.0	2.0	176%
Kearsarge Amesbury Hybrid	ISO–NE	4.5	3.3	1.36	1.6	3.8	2.4	48%
HMV Minster Energy Storage System	PJM	4.3	3.0	1.43	7.0	7.0	1.0	233%
Kingsberry Energy Storage System	ERCOT	3.1	2.6	1.19	1.5	3.0	2.0	58%
Stafford Hill Solar Hybrid	ISO–NE	2.0	2.0	1.00	2.0	3.4	1.7	100%
Iron Horse Battery Storage Hybrid	non-CA-West	2.5	2.0	1.25	10.0	10.0	1.0	500%
Volkman Road Solar Array Hybrid	MISO	2.7	2.0	1.35	1.0	4.6	4.6	50%
Camp Atterbury Microgrid Hybrid	MISO	2.8	2.0	1.40	5.0	5.0	1.0	250%
Sierra Nevada Brewing Co Hybrid	CAISO	2.0	1.5	1.33	0.5	1.0	2.0	33%
Santa Rita Jail Hybrid	CAISO	1.7	1.5	1.13	2.0	4.0	2.0	133%
Gavilan District College Solar Project	CAISO	1.4	1.4	1.00	0.5	0.5	1.0	36%
Panasonic Carport Solar Hybrid	non-CA-West	1.6	1.3	1.23	1.0	2.2	2.2	77%
New Orleans Solar Power Plant	MISO	1.3	1.1	1.18	0.5	0.5	1.0	45%
MA Solar Storage 1 Hybrid	ISO–NE	1.4	1.1	1.27	1.0	2.0	2.0	91%
Mean		21.3	15.9	1.29	5.0	12.6	2.3	78%
Median		5.9	5.0	1.29	2.5	4.8	2.0	51%
Max		234.0	180.0	1.80	36.0	100.0	5.0	500%
Min		1.3	1.1	1.00	0.5	0.3	0.3	2%

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