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Project developer options to enhance the value of solar electricity as solar and storage penetrations increase

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HIGHLIGHTS

- Photovoltaic (PV) project developers have a range of configuration options.
- Analyze more than ten strategies to preserve the marginal grid value of PV.
- Limited impact of shifting the timing of PV generation at the expense of total generation.
- Shifting the timing of generation becomes redundant when storage is added.
- At high penetrations, leading options add storage to configurations that maximize PV generation.

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ABSTRACT

Increasing the penetration of photovoltaics (PV) reduces the marginal grid value of PV electricity. The declining grid value of PV with higher penetration could limit the technology's economic attractiveness and future demand. Various strategies have been proposed for preserving this value. Using a consistent framework, we analyze the net value (accounting for both cost and grid value) of more than ten strategies in the United States. Here, grid value is estimated from coincident wholesale power market prices and PV generation using observed historical prices or modeled future prices with up to 30% PV penetration. We find that established and emerging strategies designed to shift the timing of standalone PV generation at the expense of total generation—including orienting monofacial PV modules west or bifacial modules vertically—result in minor net-value benefits or penalties. Adding energy storage to such systems magnifies the net-value loss, because configurations that change the timing of PV production become redundant when the energy-shifting capabilities of storage are added. The largest net-value gains come from strategies that maximize generation (solar tracking plus oversized PV arrays) in conjunction with storage, especially at high PV penetrations. PV systems are long-lived assets. Our results suggest that efforts to promote generation-maximizing strategies today may yield increasing net-value benefits as PV and storage deployments continue to accelerate in the United States over the coming decades.

1. Introduction

Solar photovoltaic (PV) deployment is increasing rapidly across the United States owing to favorable policies, technological advancement and related cost declines, and customer demand for clean energy. Adding a new power source avoids the need to dispatch or build other sources, which creates value for the grid system that can be compared to the investment cost to evaluate overall economic efficiency. In an ideal market, location- and time-specific wholesale power prices reflect this value such that grid value is equivalent to the revenue earned selling power into the market.

PV generation is driven by sunshine and thus often highly correlated over the course of a day within a region. Without the deployment of storage or an increase in price-responsive load, growth in PV capacity is accompanied by lower wholesale prices during sunny hours, leading to a decline in the marginal grid value of PV in markets across the world, including in the U.S. [1,2], in Europe [3], and Australia [4]. Empirical market data indicate the observed market value decline corresponds to

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expectations from previous models [5]. PV developers have largely been shielded from this value erosion by long-term, fixed-price power-purchase agreements. However, in some markets, utilities and other PV power purchasers have found themselves buying a product that is progressively less valuable. The declining grid value of PV with higher penetration could limit the technology's economic attractiveness and future demand.

PV can be made more grid-friendly through modifications to project configuration and operations. Grid-friendly PV, for the purposes of this study, refers to PV that maintains marginal grid value as PV penetration increases. Alternative PV system configurations can shift the timing of solar production, although many studies of this approach focus exclusively on plant costs without connecting the shifted production to changes in grid value [6–12]. More recent studies use wholesale market prices or power market simulation models with a limited set of standalone PV plant configurations— including changes to tilt, azimuth, and solar tracking device—to show that shifting production timing can marginally increase grid value [13–20]. Some of these studies conclude that the value-maximizing azimuths for PV are increasingly westward as solar penetration increases [18,19].

Solutions designed to preserve PV's grid value under historical conditions may be ill-suited to rapidly evolving energy landscapes. California—the U.S. leader in solar energy—reached a 16.3% solar electricity share in 2018 (from PV plus concentrating solar power), and it is targeting a 60% renewable electricity share by 2030. Other U.S. states and regions have set aggressive renewable energy targets as well [21]. As solar penetrations increase, net load profiles and electricity prices continue to evolve in ways that affect PV grid value under various PV configurations and operating strategies. At the same time, declining energy storage costs have raised interest in grid-connected standalone storage and hybrid solar + storage plants for shifting generation to higher-priced hours [22,23]. Widespread deployment of energy storage could have a game-changing effect on the design, operation, and economics of PV systems for grids with low or high solar penetrations.

This study offers a comprehensive analysis of the cost and value of multiple PV configurations under a range of grid conditions. The four primary contributions of this study relative to the existing literature are: (i) we consider a broader range of PV options in a unified framework, (ii) we evaluate configurations with and without energy storage, (iii) we quantify the benefits of PV participation in ancillary service (AS) markets, and (iv) we utilize a larger and more granular dataset on historical and projected wholesale prices with increased solar penetration. While most previous studies focus on one or two configuration options [6–17,20] and the more comprehensive studies assess a few configuration options [18,19], our analysis considers more than ten options. We compare existing PV plants with grid-friendly PV options ranging from simple tilt and azimuth adjustments to vertical bifacial modules, provision of ancillary services, and addition of energy storage. More broadly, much of the literature focuses on value enhancement, sometimes with less emphasis on the cost of the various options. We use a consistent framework to consider value and cost, ultimately calculating net value. The approach builds on insights from literature showing that standalone PV plant configurations affect costs and that shifting production timing can marginally increase grid value. Consistent with the literature, we show that among standalone PV options, plants with tracking systems provide the largest net-value gains. In addition, consistent with previous research [18,19], we show that the westward orientation of standalone PV plants can increase grid value relative to typical south-facing plants. However, we show that the modest net-value gains of this configuration at low solar penetrations, when west-facing PV production aligns with mid-afternoon peak prices, can disappear at higher solar penetrations. Increased deployment of PV can shift peak prices away from peak solar production hours even for west-facing PV.

Furthermore, while the literature assesses configuration options [9–23] and hybridized storage options [24,25], including at high penetrations in future markets [26], we are aware of no literature that joins the two to assess them in combination. By joining the two, we show how the attractiveness of adding storage to PV depends on the configuration of the PV subsystem. Among the many options to boost value, participation in AS markets is understudied, and we include AS in order to compare it to other methods to potentially boost value. Also, this study uses a comprehensive dataset across various solar penetrations associated with historical and projected U.S. wholesale power prices, while the previous studies often use snapshot data, unrelated to the solar penetration, or only used one of the historical or future datasets. Combining the comprehensive dataset and wide range of PV configuration options and energy storage enables this study to make the case that storage is much more effective at increasing value, and that value boost increases with solar penetration. Most importantly, the strategies that sacrifice production, like westward orientation, make the PV plant much worse off when storage is added. Existing knowledge suggests that westward orientation of PV panels can be an effective strategy for increasing the value of PV, even with increasing PV penetration. Therefore, a developer following the existing knowledge by deploying west-facing panels will potentially configure the plant in a way that is worse than simply maintaining a south-facing panel as storage is deployed.

More specifically, we calculate marginal grid value using wholesale market prices reflecting energy, capacity, and ancillary services and coincident solar output profiles. Marginal grid value is calculated as the annual wholesale market revenue of the PV plant per unit of solar energy produced on the AC side of the inverter. Prices from multiple regional organized wholesale markets are based on historical market outcomes between 2012 and 2018 and simulated future prices for 2030. Use of historical prices is important in this study since they are observed market outcomes whereas models are limited in their ability to reflect the full complexity of nodal electricity markets. Furthermore, forward looking models embed the analyst's expectations of the future. Nevertheless, we do expect wholesale prices, and therefore marginal grid value of PV, to change with increasing penetration and therefore supplement the historical market outcomes with forward-looking simulations. The scenario based future grid prices with current and higher (>30%) solar penetrations are from simulations of wholesale markets using commercial grid models for four regions. We model the impact of plant design alternatives on the generation profile using the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) with location- and year-specific insolation data. We populate a simple model of plant costs with component cost estimates from the existing literature to also consider the cost of the various grid-friendly options.

2. Methods

Grid-friendly options can increase the grid value of PV, but some can also increase PV costs. Choosing between alternative configurations requires balancing value against costs to optimize net present value. Wholesale market prices for grid services reflect the marginal grid value of services provided by PV. There are two important caveats regarding the use of wholesale prices to estimate value. First, wholesale prices reflect the grid value at the bulk power system level. Resources sited at the distribution level would have additional distribution grid impacts that are not included here. Also, when wholesale markets have externalities, such as the environmental and health impacts of pollution, grid value will not be the same as a social value. Second, wholesale prices indicate marginal values. The value of grid-friendly PV options represents the marginal value of the first increment of that configuration. As deployment increases, the grid-friendly options will impact wholesale prices and the marginal value of adding more will change. Levelized PV costs are primarily driven by upfront capital costs as well as total expected PV production, but are also impacted by operational costs, project lifetime, and the cost of finance. This section begins with an overview of the framework for evaluating the value and costs of grid-friendly options. It is followed by detailed descriptions of value calculations, costs calculations, and data and assumptions needed to evaluate each option.

2.1. Evaluating grid-friendly PV options

We compare grid-friendly PV options with a base PV plant in the same market and with similar underlying component costs. This relative approach avoids the complications of calculating absolute net present value, which is sensitive to fundamental dynamics affecting wholesale market prices, regional variation in market characteristics, and PV equipment costs. Assuming the base and grid-friendly PV plants are sized to provide equivalent energy, comparing net present value between them is equivalent to comparing value and cost changes in terms of dollars per unit of energy. If a grid-friendly option increases grid value more than it increases cost—relative to the base PV plant—then it has a higher net present value and is more attractive (Fig. 1). For each year of the analysis, we compare the value based on one year of revenue to the cost based on the annualized cost over the plant life.

This decision framework accounts for trends that equally affect the base and grid-friendly PV plants across different years and geographies. The alternative approach of comparing benefit-cost ratios across technology options, as in previous studies [22], does not as clearly differentiate the role of value from the role of costs in determining the relative attractiveness of options. By visualizing differences in value separately from differences in costs, we can highlight a particular trend that affects the value of options: the system-wide solar penetration level.

The base PV plant has a typical configuration with fixed, south-facing modules tilted at 31 degrees. The direct current (DC) rating of the PV modules is sized to 1.3 times the alternating current (AC) rating of the inverter capacity, giving the plant a DC:AC ratio, or inverter loading ratio (ILR), of 1.3 [27]. While inclusion of tracking has been increasingly common in recent years, our choice of fixed modules for the base PV plant enables the evaluation of a wide range of options that incrementally shift production profiles relative to a simple south-facing plant.

We evaluate a wide range of grid-friendly PV options available to developers (see Table 1). Relatively simple options revolve around the choice of geographic location (which impacts production profiles and correlations with local wholesale prices), panel tilt (tilting more towards south and less towards north along the meridian creates more winter production), and azimuth (westward orientation shifts production to later in the day). Developers can also vary ILR. A small AC inverter capacity relative to DC module capacity can lead to clipping of some midday production, thereby forgoing a portion of available PV generation, but it can also lower plant cost through savings on inverter equipment.

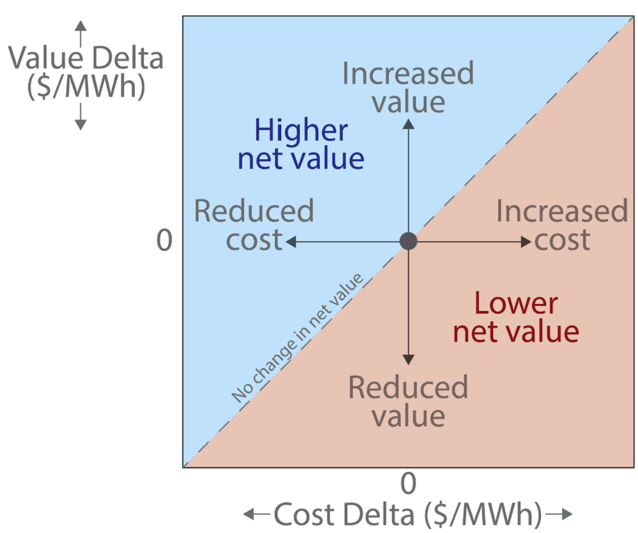

Fig. 1. Decision Framework for Evaluating the Attractiveness of a Grid-Friendly PV Plant Relative to a Base PV Plant. The change in value (vertical axis) depends on the wholesale price for grid services and the provision of those services from both plants. The change in value is calculated using market prices per unit of energy delivered by PV. The change in cost (horizontal axis) is similarly calculated per unit of energy delivered by PV. Cost changes are driven by changes in underlying capital equipment costs or changes in energy production. Grid-friendly PV plants that increase value by more than they increase costs have a higher net present value and are more attractive than the base PV plant.

Table 1
Configurations of the grid-friendly PV options in CAISO.

	ILR	Tilt	Azimuth	CF (%, 2018)[a]
Base	1.3	31	180	29.2
West-facing	1.3	31	270	23.5
Bifacial	1.3	31	180	30.3
Vertical Bifacial	1.3	90	270	24.4
Tracking[b]	1.3	0	180	36.0
Tilt-20 deg	1.3	11	180	27.5
Tilt + 20 deg	1.3	51	180	27.8
ILR 1.1	1.1	31	180	24.8
ILR 1.7	1.7	31	180	33.7
Base Hybrid (Base + Storage)	1.3	31	180	29.2
Location	Base configuration with weather and prices from other locations[c]			
Regulation Reserves	Base configuration with capability of following automatic generation control signal[c]			
Westward shift	Base configuration with weather from locations west of chosen pricing hub and additional interconnection cost			

[a] CF is the AC capacity factor of PV options using National Solar Radiation Database (NSRDB) weather in 2018. The CF of the underlying standalone PV configuration is used in the denominator of cost and value calculations.
[b] Single-axis tracking is employed only in the 'Tracking' configuration, all others use fixed modules.
[c] Fig. 2 summarizes the impact of PV plant location or provision of regulation reserves in CAISO in Section 3.1. Additional details for CAISO and other U.S. markets are in Section 3.2 "Options for Enhancing Grid Services without Shifting Production".

Several additional options are emerging. New bifacial modules absorb light on both sides of the module and enhance production, particularly during lower-insolation hours. One novel configuration is to orient bifacial modules vertically along a north–south axis so the east-facing side provides morning production and the west-facing side provides evening production. Increasingly, developers are incorporating battery storage into solar plant design, placing it on the DC-side of shared inverters (DC-coupled) or deploying it with its own inverter (AC-coupled). In the United States, storage assets charged from solar can receive the federal investment tax credit (ITC), reducing storage capital costs by up to 30%.

Two other options are more complex and/or not fully under developer control. A solar plant can be sited far west of the point of grid interconnection, which can shift production to later in the evening relative to load, but such a strategy would incur additional transmission costs. In contrast, the simple choice of geographic location, described above, delivers power to the local load without incurring additional transmission costs. Another option is for PV to provide ancillary services, such as frequency regulation. Providing this service, however, requires a clear participation model in wholesale markets, which is still under development in the seven organized U.S. wholesale markets.

2.2. Value

Values of the base PV plant and all grid-friendly PV options are calculated as the annual wholesale market revenue per unit of solar energy produced on the AC side of the inverter. Curtailments during negative-price hours are not considered. The market revenue is the product of the location-specific real-time market price and coincident solar production. Throughout the analysis, this study uses hourly averages of wholesale prices and solar production to estimate the marginal grid value of the first increment of different PV plant configurations.

The base PV plant is located at the centroid of solar capacity deployed up through 2018 in each organized wholesale market. Wholesale prices for the base plant are from the nearest major trading hub, such as the SP15 trading hub for CAISO. Although the historical prices are available in the public domain, we use the Velocity Suite data aggregator service from ABB to compile the data for more convenient data access. Scenario-based future prices are from a previous collaboration between Lawrence Berkeley National Laboratory and LCG Consulting using the commercially-available UPLAN market simulation software [28]. All future prices are non-negative based on the modeling assumptions used in that study.

Price profiles, both historical and future, include a capacity price adder. For historical years, the cost of capacity is assumed to be $50/kW-yr, similar to recent capacity prices in the forward capacity markets in PJM, NYISO, and ISO-NE [29] and bilateral capacity contracts in CAISO [30]. The assumption of a single annual capacity price is a simplification: actual historical capacity prices vary by location and year and, depending on the market, may vary by capacity zone, season, or even by month. Furthermore, prices have shifted over time with market design changes. We abstract from these complications with a simple uniform assumption of an annual capacity price. One exception is in ERCOT, where no capacity price is included, because it is the only region that does not impose a resource-adequacy requirement on load-serving entities. Future years use a scenario- and region-specific capacity cost of similar magnitude based on simulations where energy and capacity prices were found simultaneously [28].

This capacity cost is then evenly allocated to the highest 100 net load hours of the year. Net load is the independent system operator/regional transmission organization (ISO/RTO) reported load less the system-wide aggregate solar and wind generation profile, which is also from ABB Velocity Suite. For historical years, this capacity adder results in a $500/MWh increase in wholesale prices in the top 100 net load hours. We chose this approach rather than using ISO-specific approaches to estimate the capacity credit of solar plants for three reasons. First, in some regions, the ISO-specific capacity accreditation method applies a single capacity credit to all solar, irrespective of the generation profile of an individual solar plant (e.g., CAISO). Second, regions that do base capacity credit on individual plant production profiles use broad, static definitions of peak load periods. Using these historical definitions would not reflect solar-induced shifts in the net load peaks. Third, ISO-specific rules for capacity accreditation for hybrids are nascent or are still under discussion [31]. By allocating capacity costs to the peak net load hours, our analysis reflects variation in capacity contributions of different solar configurations and the changing timing of system needs in scenarios with higher solar penetration. Finally, previous studies that compare capacity credits based on detailed probabilistic resource assessments to simple peak net load approximations indicate the reasonableness of focusing on the top 100 net load hours [32,33].

The PV production profiles of standalone PV plants are modeled in NREL's SAM using the weather profile for the specific location and weather year from the National Solar Radiation Database [34,35]. Although the hourly solar insolation data is reported to have a normalized root mean square error of 10–20% [36], our analysis avoids some of this uncertainty by focusing on the change in value relative to a base PV plant using the same weather file. The SAM model itself was shown to achieve an hourly root mean squared error of less than 7% [37]. Hybrid solar + storage production profiles are generated from revenue-maximizing dispatch assuming storage self-schedules in the real-time market and assuming a storage degradation penalty on storage throughput of $5/MWh based on the analysis of He et al. [38]. The upper bound of the hybrid solar + storage dispatch assumes perfect foresight of real-time market energy prices and solar production. The lower bound of the hybrid dispatch is from a naive scheduling approach that schedules storage based on day-ahead prices and the previous day's actual solar production [39]. The lower-bound results are an implementable method that requires no proprietary forecasting skill. Advanced methods could improve on the lower bound, although results would remain somewhere between our upper and lower bounds. In all cases, storage is assumed to only charge from solar to ensure full eligibility for the 30% federal ITC.

2.3. Cost

Costs of the base PV plant and all grid-friendly PV options are calculated as the levelized cost per unit of solar energy produced on the AC side of the inverter (see Table 2). Following the assumptions and methods used in levelized cost calculations in NREL's 2019 Annual Technology Baseline [40], the levelized cost of energy (LCOE, Eq. (1)) is calculated by dividing an annualized capital cost per unit of AC capacity (CC_{-}) plus a fixed operations and maintenance (O&M) cost per unit of AC capacity ($20/kW-yr, FOM_{-}) by the average lifetime capacity factor (CF). The average lifetime capacity factor is based on the assumed PV degradation rate (d) of 0.7% per year over a plant lifetime (L) of 30 years (Eq. (2)). The first-year capacity factor is based on simulation of the plant in NREL's SAM [41] using the weather data for the particular location and historical weather year. Solar and storage annualized capital costs (CC_{-}) are reduced by 30%, assuming both are eligible for the 30% federal ITC.

$$LCOE = \frac{CC_{-} + FOM_{-}}{CF} \quad (1)$$

$$CF = \frac{CF_0}{L}\sum_{n=0}^{L}(1-d)^n \quad (2)$$

Again following the default assumptions in NREL's ATB [40], the annualized capital cost in Eq. (3) is based on the upfront capital costs per unit of AC capacity (CC) times a capital recovery factor (CRF), a project finance factor (PFF) that accounts for the post-tax benefits of accelerated

Table 2
Cost assumptions of the grid-friendly PV options.

	Parameter	Value	Unit	Applies to
Project Finance Factor	PFF	1.046		All
Construction Finance Factor	CFF	1.014		All
Real Weighted Average Cost of Capital	$WACC$	0.0271	yr^-1	All
Solar Annual Degradation Rate	d	0.007	yr^-1	All
Solar Lifetime	L_{PV}	30	years	All
Solar Fixed O&M	FOM_{-PV}	20	$/kW$_{ac}$-yr	All
Solar Field Capital Cost	CC_{field}	982	$/kW$_{dc}$	All
Solar Power Block Capital Cost	CC_{inv}	47	$/kW$_{ac}$	All
Solar Field Tracking Cost Adder	Add to CC_{field}	70	$/kW$_{dc}$	Tracking
Solar Field Bifacial Cost Adder	Add to CC_{field}	50	$/kW$_{dc}$	Bifacial, Vertical Bifacial
Solar Field Vertical Bifacial Cost Adder	Add to CC_{field}	32	$/kW$_{dc}$	Vertical Bifacial
Storage Lifetime	$L_{Storage}$	10	years	All Hybrids
Storage Fixed O&M	$FOM_{-Storage}$	10	$/kW$_{storage}$-yr	All Hybrids
Storage Power Block Capital Cost	$CC_{Storage: Power}$	280	$/kW$_{storage}$	All Hybrids
Storage Energy Capital Cost	$CC_{Storage: Energy}$	325	$/kWh$_{storage}$	All Hybrids
AC Hybridization Cost-reduction Factor	HCF	0.93		AC-Coupled Hybrids
DC Hybridization Cost-reduction Factor	HCF	0.92		DC-Coupled Hybrids

depreciation (1.046), and a construction finance factor (*CFF*) for plants that can be built in less than a year (1.014). The capital recovery factor (Eq. (4)) is based on the tax rate (26%), a real weighted-average cost of capital (WACC) accounting for taxes (2.71%), and the lifetime (*L*).

$$CC_{-} = CC \cdot CRF \cdot CFF \cdot PFF \tag{3}$$

$$CRF = \frac{WACC}{1 - \frac{1}{(1+WACC)\cdot L}} \tag{4}$$

The base PV plant capital cost (CC_{base}) includes the cost of the solar panel field (CC_{field}, \$982/kW_{dc}) and the cost of inverters (CC_{inv}, \$47/kW_{ac}), with both based on default assumptions for fixed-panel PV in NREL's SAM [41]. The *ILR* of the base PV plant is assumed to be 1.3, with the upfront capital cost calculated as in Eq. (5).

$$CC_{base} = ILR_{base} \cdot CC_{field} + CC_{inv} \tag{5}$$

2.4. Data and assumptions for simple alternatives

The simple alternatives (varying location, tilt, azimuth, ILR, and tracking) are all modeled in nearly the same manner as the base PV plant, with a few key modifications. Alternative locations use LMPs from the nearest pricing node in the value calculations. They also use the weather profile for the alternative location, which impacts both value and the first-year capacity factor used in the cost calculations (Eq. (2)). Modifications to tilt and azimuth are modeled through changes to the PV production profile from SAM. The only impact to cost of tilt and azimuth is the change in the first-year capacity factor in Eq. (2). Changes to the ILR and tracking are similarly modeled through changes to the PV production profile from SAM. On the cost side, changing ILR impacts both the first-year capacity factor in Eq. (2) and the capital cost of the plant in Eq. (5). The addition of tracking increases the capital cost of the solar field by \$70/kW_{dc} in Eq. (5) [42].

2.5. Data and assumptions for emerging alternatives

The emerging alternatives (bifacial modules, vertical bifacial configurations, and hybrid solar + storage configurations) all include changes to the plant production profile and the capital cost of the plant. The impact of bifacial modules on the PV production profile is modeled in SAM assuming a ground albedo of 20%. On the cost side, in addition to changing the first-year capacity factor, bifacial modules increase the capital cost of the solar field by \$50/kW_{dc} in Eq. (5) [43]. Vertical bifacial configurations are modeled in SAM by changing the tilt to 90 degrees and the azimuth to 270 degrees. The capital costs of the field are further increased by an additional \$32/kW_{dc} based on the assumption that the vertical bifacial plant will require more land to provide adequate spacing between modules to avoid self-shading. Due to the lack of significant market experience with this configuration, this cost adder is relatively uncertain. We base our cost adder assumption on the percent increase in land area from one study [44] and the cost of land for a typical PV plant from another study [42].

Hybrid solar + storage plants impact value through being dispatched in response to wholesale prices, as described earlier. All hybrid cases assume that the battery is sized to 50% of the AC nameplate capacity of the PV plant and that the duration, measured as the ratio of the battery energy capacity to the battery power capacity, is 4 h, which is a typical configuration in U.S. electricity markets [24]. The hybrid dispatch is managed differently depending on whether the hybrid is AC-coupled or DC-coupled. Based on collected data from EIA Form 860 and discussions with plant owners, most hybrid solar + storage systems in operation by the end of 2019 have an ILR of 1.3 and are AC-coupled, though examples of DC-coupled hybrid systems with higher ILRs are increasing.

AC-coupled hybrids assume that the PV plant and the storage plant share a point of interconnection with the grid that is limited to the AC capacity of the PV inverter. The hybrid dispatch model uses the solar plant output from SAM (measured as the AC power from the solar inverter) and dispatches storage through its own inverter. The round-trip efficiency of storage in the AC-coupled system is 81%, a value in line with round-trip efficiencies of lithium-ion batteries reported elsewhere in the literature [45].

The DC-coupled hybrids similarly have a point of interconnection that is limited to the AC capacity of the shared inverter. The DC solar field production (as opposed to the AC power from the inverter) is extracted as an intermediate calculation from SAM and used in the dispatch of the DC-coupled hybrid. In the DC-coupled configuration, the one-way efficiency of the storage is assumed to be 94%. The shared inverter imposes a one-way efficiency penalty of 4%, similar to the default inverter efficiency in SAM. Overall, the DC-coupled system is slightly more efficient than the AC-coupled system when storage is charged from solar. With these assumptions, 1 kWh_{ac} delivered to the grid from storage in an AC-coupled system requires 1.28 kWh_{dc} from the PV panels (i.e., losses occur in the battery and its inverter along with the solar panels and its inverter). Whereas 1kWh_{ac} delivered to the grid from storage in the DC-coupled system requires 1.18 kWh_{dc} from the PV panels (i.e., the only losses are in the battery and the shared inverter).

On the cost side, the cost of hybrids differs from the cost of standalone PV plants owing to the addition of the annualized storage capital cost and fixed O&M cost to the numerator in Eq. (1), followed by a hybridization cost-reduction factor (*HCF*), as in Eq. (6) (see Table 2). For the hybrid plants, the capacity factor used in the denominator is based on the energy that would be produced by the standalone PV plant, absent storage, which is consistent with the assumption used to calculate the value of hybrid plants.

$$LCOE_{hybrid} = \frac{\left(CC_{-PV} + FOM_{-PV} + CC_{-Storage} + FOM_{-Storage}\right) \cdot HCF}{CF_{PV}} \tag{6}$$

The hybridization cost-reduction factor is from shared costs between the PV and storage parts of the hybrid plant and differs between an AC-coupled hybrid (0.93) and DC-coupled hybrid (0.92). These parameters are estimated from bottom-up engineering estimates of the cost of solar + storage [25]. The annualized capital cost of the storage uses annualization parameters similar to the base PV plant's (including accelerated depreciation, which is also allowed for storage that is charged by PV), although the lifetime of the batteries is assumed to be only 10 years [46]. Based on recent storage capital costs [47], the capital cost of the 4-hour duration storage per unit of PV nameplate capacity is \$930/kW_{ac} when assuming that the batteries are sized to only 50% of the PV capacity. The fixed O&M cost of storage, again per unit of PV nameplate capacity when sized to 50% of the PV capacity, is \$5/kW_{ac}-yr [46].

2.6. Data and assumptions for more involved alternatives

The two alternatives that are more involved are the provision of ancillary services, regulation reserves in particular, and the westward shift of a PV plant relative to the point of interconnection with the grid.

Previous research demonstrates the ability of a PV plant to follow an automatic generation control signal sent to resources providing regulation reserves [48]. Relative to other types of grid services, regulation reserves are the most commonly considered grid service that can be provided by PV plant. Modern PV plants have the technical capabilities to contribute to regulation requirements through precise output control [49]. With this capability, PV plants can offer part of their capacity for regulation services, and system operators can elect to use PV resources in the day-ahead market to provide regulation reserves in the real-time market. The provision of these services requires the plant operator to maintain footroom for downward dispatch, and some services require the plant operator to maintain headroom for upward dispatch. More specifically, to follow a real-time control signal, PV plant operators must hold enough headroom and footroom to ensure that they can deliver the necessary regulation service in real time in light of the weather-driven nature of PV energy production and related forecasting challenges. In practice, in part as a consequence of these PV attributes, rules for PV participating in regulation markets across the United States are evolving, inconsistent, and unclear [50]. Given this lack of clarity, we make several simplifying assumptions related to the portion of nameplate capacity, headroom, and footroom required when PV plants participate in the regulation market; these assumptions are broadly in line with Loutan et al. [48], and they are described in more depth in Appendix A. We optimistically assume that a PV plant has the option of providing regulation reserves and can schedule those reserves with perfect foresight of regulation reserve prices, energy prices, and solar production.

The analysis of the westward shift of the plant posits a fixed PV plant that interconnects at a particular pricing node through a dedicated generator tie line. Achieving the westward shift of the plant while selling power at the eastward pricing node adds an additional interconnection cost. The potential advantage is that as the plant shifts westward from the pricing node, the timing of production shifts later into the day. The shift in production is modeled by selecting weather data from a site further to the west in SAM. The change in value is compared to the additional cost of transmission. Assuming a transmission cost of $870–$2,280/MW-km [51] and a latitude of 40 degrees north, the cost of a transmission line to move 1 degree of longitude west is $74,000–$194,000/MW-degree. Using the transmission cost levelization assumptions from Gorman et al. [51], the levelized cost of transmission for a PV plant is roughly $1.3–$3.5/MWh-degree.

3. Results

This section begins with an evaluation of options that impact the timing of production, focusing on results from California with different levels of solar penetration. Next, we examine alternative configurations that enhance the provision of grid services through changing the plant location or providing regulation reserves. Finally, we evaluate how the benefits of adding storage are impacted by PV production.

3.1. Options for shifting the timing of PV production

Here we evaluate the grid value and costs of grid-friendly PV options (Table 1) using wholesale market prices from a major trading hub in California (SP15), including the capacity price adder described in Section 2.2, near the center of existing PV deployment in California [52]. Prices are from different historical years with different levels of system-wide solar penetration. For example, 2012 corresponds to a solar penetration of 1.4%, whereas 2018 corresponds to a penetration of 16.3% in California. As the system-wide solar penetration increases from 1.4% to 16.3%, the grid value of the base PV plant decreases from $41.0/MWh to $25.2/MWh. Fig. 2 shows the cost and value of a subset of grid-friendly configurations relative to the base PV plant. Other alternatives—such as changing the tilt, lowering the ILR, and adding bifacial modules oriented in the same manner as the base PV plant—are not shown, because none of those changes significantly impacts cost or value. Details for all configurations considered are in Table 1.

As shown in Fig. 2, the largest increases in value relative to the base PV plant are achieved by better aligning the timing of production with high wholesale prices that signal times of greatest grid needs. Relative to the base plant, west-facing PV modules increase value by $5.2–$9.7/MWh, vertical bifacial modules increase value by $6.3–$7.8/MWh, single-axis tracking increases value by $2.7–$4.2/MWh, and 4-hour-duration AC-coupled storage sized to 50% of PV nameplate capacity increases value by $18.6–$25.7/MWh when dispatched with perfect foresight.

For all these alternatives except single-axis tracking, increased value is accompanied by increased levelized cost relative to the base PV plant. The west-facing option and vertical bifacial option produce less energy overall, with capacity factors that are 23.5% and 24.4%, respectively, compared to the 29.2% capacity factor of the base PV plant. Lower annual energy production (along with additional capital cost for the vertical bifacial option) increases the levelized cost of energy. This higher cost is more than offset by higher value for the vertical bifacial option at 16.3% solar penetration and for the west-facing option at 1.4% solar penetration. The increased value from adding storage to the base PV plant, on the other hand, is not high enough to offset the $27.7/MWh additional cost, even with the ITC and assuming perfect foresight in dispatching the storage. As detailed later, this conclusion changes if storage is added to different underlying configurations of the PV subsystem.

The value of the grid-friendly options relative to the base PV plant depends on system-wide solar penetration, which increases from 1.4% in 2012 to 16.3% in 2018. With higher solar penetration, the timing of the highest wholesale prices (inclusive of the capacity price adders) shifts from summer afternoons to summer evenings, whereas lowest prices occur midday in non-summer months. The impact of higher solar penetration on value added by a grid-friendly option depends on the way production is shifted by the option (Fig. 3). PV plants with tracking, the vertical bifacial configuration, or storage have greater value at 16.3% penetration than at 1.4% penetration because each option shifts solar production to higher-priced hours in the mornings and, especially, in late afternoons to evening, relative to the base PV plant. By far, the value boost from adding storage increases the most in response to higher system-wide solar penetration. In contrast, the increased value of west-facing PV is greater at 1.4% than at 16.3% solar penetration. At 1.4%

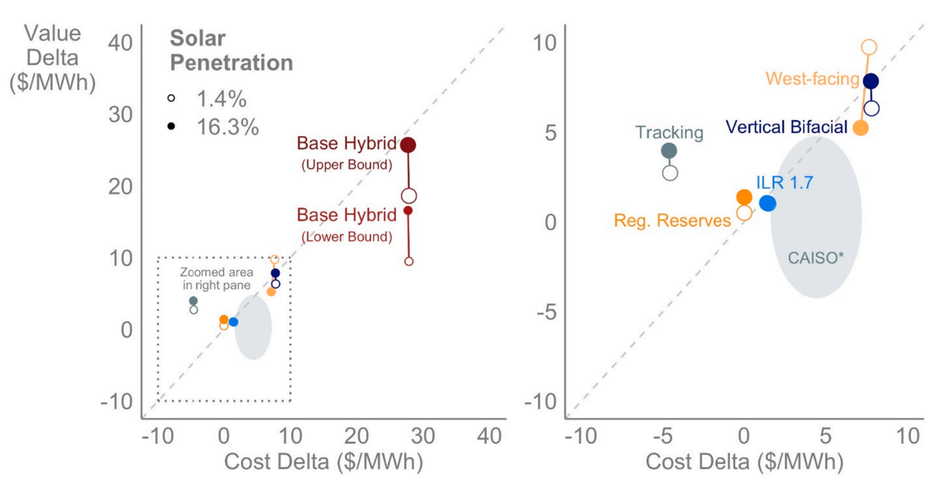

Fig. 2. Value and Cost of Grid-Friendly PV Options Relative to the Base PV Plant in California. Alternatives that increase value by more than they increase costs relative to the base PV plant are on the upper left side of the dashed line. Dots corresponding to 1.4% solar penetration are calculated using wholesale prices and weather files from 2012, whereas the 16.3% solar penetration dots use data from 2018. The gray oval marked "CAISO*" illustrates how value and cost vary with alternative locations across CAISO. The height of the oval shows one standard deviation away from the mean value, and the width shows one standard deviation in the cost of the alternative sites. The value of an AC-coupled hybrid plant is calculated assuming either perfect foresight of both real-time prices and production of the solar field (upper bound) or using imperfect forecasts of real-time prices and solar field production (lower bound). The configuration details of the grid-friendly options are in Table 1.

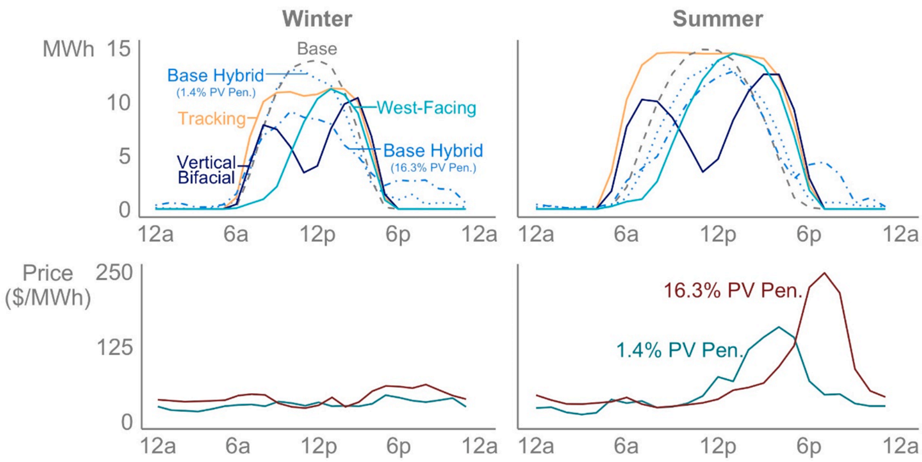

Fig. 3. Seasonal Average Hourly Profiles of Grid-Friendly PV Production (top) and Wholesale Prices (bottom). The wholesale prices shown, including a capacity value adder, are from CAISO's SP15 trading hub in years with a solar penetration of 1.4% (2012) and 16.3% (2018). The configuration details of the grid-friendly option are in Table 1. The presented grid-friendly PV options are selected because they show significant shifting of the PV production timing, which impacts value and, in some cases, cost.

penetration, westward orientation aligns peak PV production with peak wholesale prices in the summer, at around 2–3 pm. At 16.3% penetration, summer prices peak after 6 pm; westward orientation still increases grid value, but the increase is less than when penetration is 1.4%. This finding suggests limits on the effectiveness of west-facing PV for mitigating declining marginal grid value with higher solar penetration.

In the United States, CAISO is the organized wholesale market with the highest solar penetration. However, simulations of future wholesale market prices with increasing solar penetrations demonstrate similar trends in the Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), and New York Independent System Operator (NYISO) markets (see Supplementary Note 1).

Finally, moving the PV plant west of where power is delivered to the grid can shift solar production to later in the day, but the benefit is small. Shifting plants westward by up to 15 degrees of longitude increases the value of solar by at most \$3/MWh for both recent wholesale prices

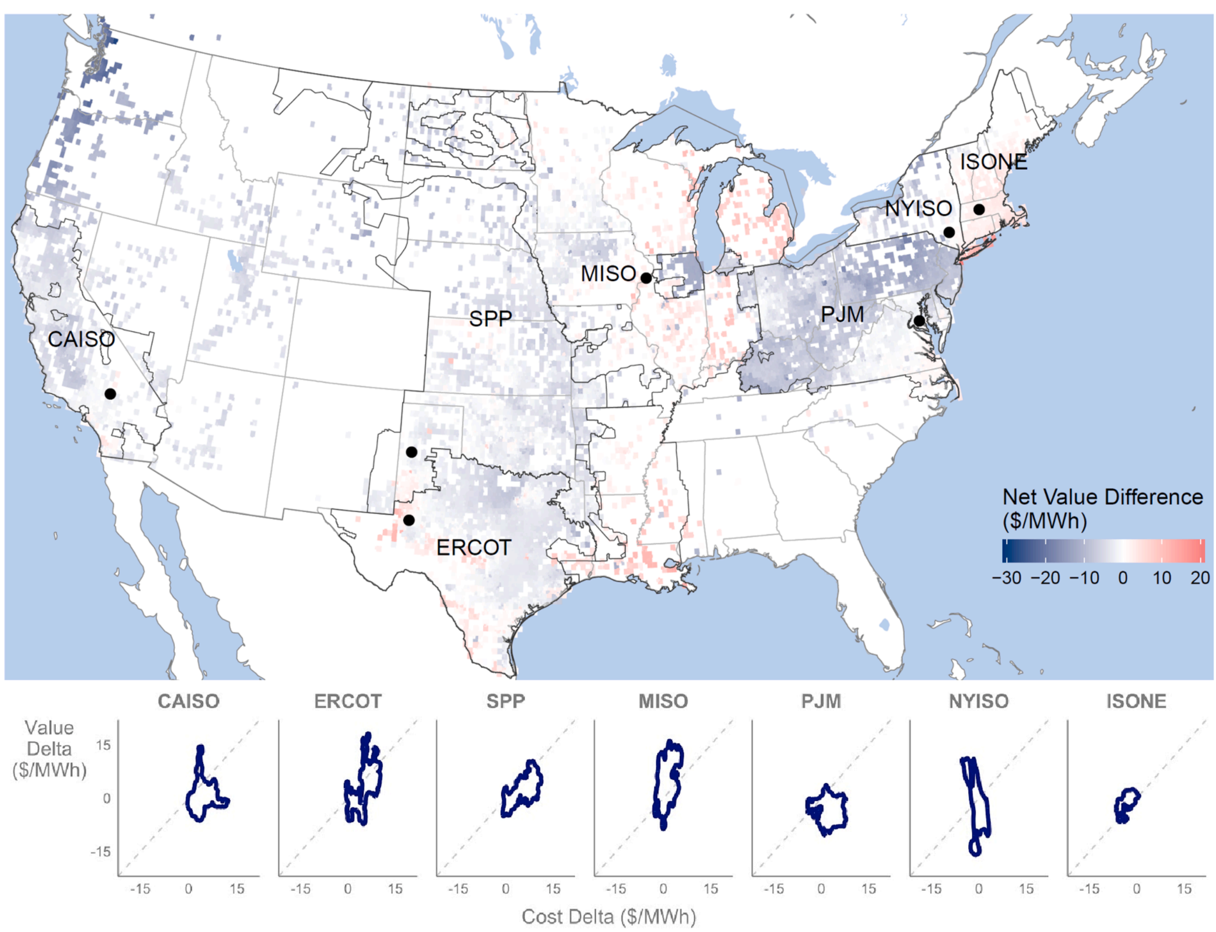

Fig. 4. Cost and Value of PV Plants at Alternative Locations Relative to the Cost and Value of the Base PV Plant. In each organized wholesale market, the base PV plant is located at the capacity-weighted centroid of currently deployed PV plants (black dots). Prices are from trading hubs close to the centroids. Using 2018 price data, value differs because of changes in locational marginal prices (LMPs) and solar production profiles. Costs differ only because of differences in solar resource quality. The bottom figures summarize individual location cost and value differences for each region, with a 95th percentile contour line.

(2018) and simulated high solar futures in 2030 for CAISO, ERCOT, SPP, and NYISO (see Supplementary Note 2). The cost of transmission to achieve a 15-degree westward shift would be $20–$53/MWh, based on assumptions described in Section 2.6.

3.2. Options for enhancing grid services without shifting production

Two options may increase the grid value of PV without fundamentally shifting the timing of production: using alternative PV locations and providing enhanced grid services through participation in ancillary service markets.

In all seven organized U.S. wholesale markets, the grid value of PV in some alternative locations is greater than the value of the base PV system sited at the capacity-weighted centroid of currently installed PV plants in each market. Grid value varies with location because the marginal cost of balancing supply and demand varies across the market. Locational prices are often higher close to major demand centers owing to the congestion caused by limited transmission capacity. If currently installed PV plants are not near these high-price regions, then an alternative site may have higher value.

More than half of all potential alternative sites in the Midcontinent Independent System Operator (MISO) territory, for example, have higher grid value than the base PV system located near the border of Iowa and Illinois, which is the centroid of currently installed PV plants in MISO. The alternative sites may have greater or lesser solar resource quality, which drives cost differences, but the range of cost differences across roughly 95% of the sites is only about $5/MWh, whereas the range of value deltas is about $25/MWh in MISO (Fig. 4). Most alternative sites in MISO, many located in the southern MISO region or Michigan, appear to have a higher net value than the base PV system. Similarly, existing plant locations in each of the market regions may be influenced by favorable community solar rules [53], eligibility for state incentives, qualification for state renewables portfolio standards, land costs, land availability, and interconnection cost—none of which are considered in this analysis. Year-to-year variability in location-specific wholesale prices may also confound the value increase from PV plant relocation.

Overall, the potential increased value at a large proportion of alternative sites clearly outweighs the costs associated only with solar resource quality at the sites in four of the market regions (without considering the local cost or policy elements). MISO is discussed above. In NYISO, attractiveness increases near New York City, largely due to high electricity demand and a congested transmission network. Nearly all locations away from the centroid of existing ISO New England (ISO-NE) PV plants in western Massachusetts are more attractive, though ISO-NE has the least overall regional variation. In ERCOT, west and south Texas sites are more attractive owing to higher-quality solar resources and higher demand, respectively. Localized value decline may also contribute to lower value near the centroid of existing PV plants, although without further analysis of localized grid conditions, it is unclear whether that issue contributes to these results. In the three other market regions, PJM, CAISO and SPP, most alternative locations are not as attractive as the base PV system.

Current PV technology can use advanced controls to provide ancillary services, although previous studies demonstrating these capabilities have not quantified impacts on grid value [54,55]. We analyze the value of PV providing the ancillary service of regulation reserves by responding to an automatic generation control signal from the system operator. The cost of adding controls is minor relative to the opportunity cost associated with curtailing PV production to create the headroom necessary for precisely following the signal. Assuming perfect PV foresight and controllability, providing regulation reserves in CAISO can increase the net value—after accounting for lost energy revenues—by $0.3/MWh (1.4% solar penetration) to $1.1/MWh (16.3% solar penetration) (see Fig. 2). The increased value associated with the provision of regulation reserves in all organized U.S. markets is highly sensitive to changes in market conditions (see Supplementary Note 3). A core challenge with this option is that market rules for solar participation in ancillary service markets are still under development and vary by region.

3.3. Maximizing the benefits of storage via high PV production

Our base hybrid PV system adds storage to a fixed-axis PV system with an ILR of 1.3, but storage can be added to any PV configuration. Storage can even be integrated directly into the DC side of an inverter, enabling it to capture PV energy that would otherwise be clipped by the inverter. In this section, we show that the attractiveness of adding storage to PV depends on the configuration of the PV subsystem (i.e., of the PV elements of the solar + storage system)—mostly because of cost differences rather than value differences. Also, the configurations of the PV subsystem that change the timing of PV production become redundant with the addition of the energy-shifting capabilities of storage.

Irrespective of the PV subsystem production profile, the output of solar + storage hybrid plants during the highest-priced summer evening hours is similar (Fig. 5). Storage acts as a buffer that can shift limited energy from any time during the day to the highest-priced hours in early evening; thus, hybrid performance during high-priced hours is largely independent of the PV subsystem production profile. On the other hand, PV subsystem differences lead to very different annual production levels over which the additional storage costs are allocated.

As a result, the range in increased value relative to the base PV across the various hybrid PV configurations is narrower ($11/MWh at 1.4% solar penetration and $19/MWh for 16.3% penetration) than the range in increased costs across the hybrid PV configurations ($27/MWh at 1.4% solar penetration and $31/MWh at 16.3% penetration); see Supplementary Note 4. In particular, PV subsystem configurations that sacrifice overall production to better align solar production with times of system need (such as the west-facing and vertical bifacial configurations) are less attractive with storage than options that increase annual production, such as the 1.7 ILR AC-coupled hybrid (Fig. 6). This result contrasts with our analysis of standalone PV configurations (Fig. 2), in which PV with a 1.7 ILR is no more attractive than the base PV plant. Configurations of the PV subsystem that change the timing of PV production become redundant with the addition of the energy-shifting capabilities of storage. Storage is more effective at shifting energy because the timing of the shift can dynamically change in response to overall grid system conditions. In contrast, the shift from different PV subsystem configurations is relatively static.

Further increasing production by combining a high ILR, tracking, and DC-coupled batteries results in the most attractive hybrid option. DC-coupling provides additional ability to capture clipped energy and brings modest additional cost synergies relative to the AC-coupled plant. Even with the lower-bound estimate of hybrid value, the net value of the DC-coupled, 1.7-ILR tracking configuration exceeds the net value of the standalone tracking PV plant in CAISO using wholesale prices from a year with high PV penetration (16.3%).

4. Discussion

Alternative photovoltaics (PV) plant design options can help maintain PV's grid value, but the net value (grid value minus system cost) of different choices varies with system-wide solar penetration. Consistent with previous research [18,19], these results show that westward orientation of standalone PV plants can increase grid value relative to typical south-facing plants, in some cases enough to outweigh the higher levelized costs associated with lower production. However, the modest net-value gains of this strategy at low solar penetrations, when west-facing PV production aligns with mid-afternoon peak prices, disappears at higher solar penetrations, which shift peak prices away from peak production even for west-facing PV. The grid value of standalone vertical-bifacial PV increases with higher solar penetration, but the net

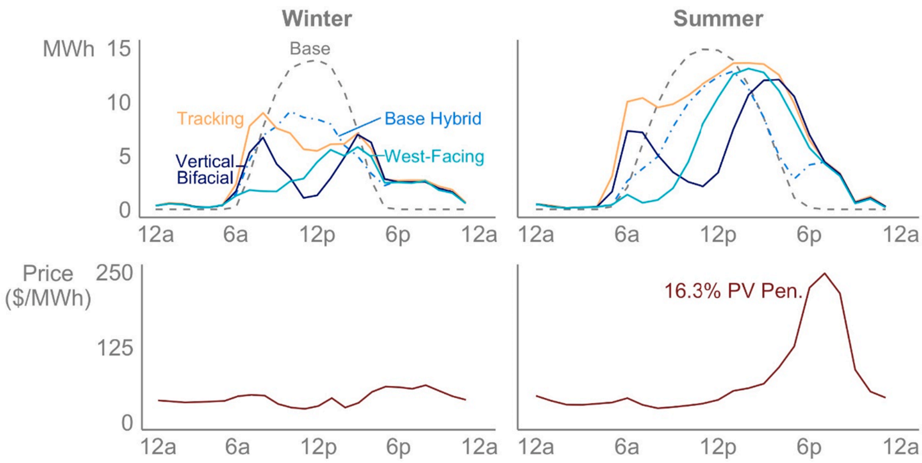

Fig. 5. Comparison of Solar + Storage Hybrid Production Profiles Across Different PV Subsystem Configurations. Each seasonal average profile results from the dispatch of a solar + storage plant with 4-hour duration, AC-coupled storage sized to 50% of the nameplate capacity of PV. The storage is dispatched with perfect foresight of wholesale prices and PV production from the solar field. Wholesale prices are from CAISO's SP15 trading hub, including a capacity value adder, in a year with a solar penetration of 16.3% (2018). To qualify for the full federal ITC, storage can only charge from the solar plant, not the grid. The configuration details of the grid-friendly options are in Table 1.

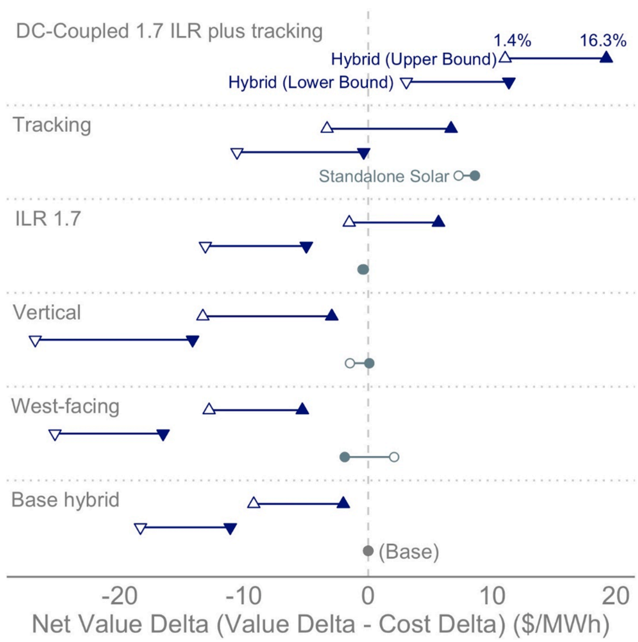

Fig. 6. Difference in Net Value of Standalone and Hybrid Grid-Friendly PV Options Relative to the Net Value of the Base PV Plant. Net value is the difference between the value of a configuration and its levelized cost relative to the base PV plant. The value of hybrid plants is calculated assuming either perfect foresight of real-time prices and solar field production (upper bound) or imperfect forecasts of real-time prices and solar field production (lower bound) using the wholesale prices, including a capacity value adder, from CAISO's SP15 trading hub in years with solar penetration of 1.4% (2012) and 16.3% (2018). Hybrid system cost and value are reported per unit of energy of the underlying standalone PV configuration. The configuration details of the grid-friendly options are in Table 1. The hybrid cases add storage to the underlying standalone PV (AC-coupled unless otherwise marked).

value added by this approach is modest at best. Among standalone PV options, plants with tracking systems provide the largest net-value gains, which increase slightly at higher solar penetration.

Adding energy storage to the various PV configurations alters the cost and value results dramatically. In all scenarios, strategies that shift the timing of PV generation at the expense of total generation—including west-facing and vertical-bifacial systems—result in net-value penalties, because these strategies become redundant when the energy-shifting capabilities of storage are added. Energy storage shifts PV production in very similar ways across PV subsystem configurations, making the value of solar + storage systems less sensitive to PV subsystem configuration, but levelized costs increase significantly as production declines.

By the same token, strategies that maximize PV generation—including solar tracking and oversized PV arrays—provide the largest net-value gains when combined with storage, especially at high PV penetrations. Under almost all the scenarios we analyze, a DC-coupled hybrid plant with a high ILR and single-axis tracking provides the most net value when the PV penetration is high. Solar penetration is expected to increase across the U.S. [56,57]. This finding aligns with the growing commercial interest in hybrid solar + storage plants: current U. S. hybrid capacity totals 4.6 GW, 14.7 GW are in the immediate development pipeline, and 69 GW are in the interconnection queues of wholesale electricity markets [24]. Based on our results, the rise of hybrid solar + storage plants fundamentally changes the design space for PV configurations.

Our results have broader implications as well. Previous work shows that investment in low-cost storage could make PV economics more attractive [41,58,59], even if the PV and storage are not co-located, which raises the possibility that siting storage closer to load could be more attractive than directly coupling storage with PV in hybrid solar + storage plants [24]. In addition, the PV net-value implications of adding storage anywhere in the grid system could be similar to the implications of adding storage via hybrid plants. As a result, PV configurations that shift energy production but sacrifice total production may be less attractive than generation-maximizing strategies, regardless of whether the plant incorporates storage directly.

5. Conclusions

Solar photovoltaic (PV) power plant developers have many different configuration options. Here we analyze the cost and grid value of more than ten strategies to identify those that enhance the net value as solar penetration increases. While it is possible to shift the timing of standalone PV generation to better align with high value times, including through strategies like orienting monofacial PV modules west or bifacial modules vertically, these result in minor net-value benefits or even penalties because of the cost associated with reductions in total generation. In contrast, adding energy storage to the PV plant alters the cost and value results dramatically. In this research, we find that the attractiveness of adding storage to PV depends on the configuration of the PV subsystem. Adding energy storage to west-facing or vertical bifacial PV subsystems with reduced energy production magnifies the net-value loss, because configurations that change the timing of PV production become redundant when the energy-shifting capabilities of storage are added. With high solar penetration, the largest net-value gains come from strategies that maximize generation (solar tracking plus oversized PV arrays) in conjunction with storage.

Future work could investigate whether grid-level strategies for mitigating value decline are more effective than PV design options that are under developer control. In addition, when wholesale market prices reflect the full social value and cost, technologies that have the highest net market value will achieve the highest net social value. But externalities can distort this alignment. Future work could investigate configuration options based on the social net value of PV and energy storage. More generally, this research compared a select set of configurations to the base PV plant. A full parametric sweep across the wide range of configuration options could yield the maximum net value hybrid solar + storage plant under different levels of solar penetration and at different locations. Finally, hybrid participation in ancillary service markets may further impact the choice of configuration, though it is important to recognize that ancillary service markets are relatively shallow, and attractive prices can diminish faster than in the energy market with the deployment of new sources of reserves.

PV systems are long-lived assets. Overall, our results suggest that efforts to promote generation-maximizing strategies today may yield increasing net-value benefits as PV and storage deployments continue to accelerate over the coming decades. These findings may aid stakeholders who are seeking to achieve (or simply understand the implications of) high solar penetration, from solar developers and investors to energy-sector planners and policymakers.

Author contributions

J.H.K. led the research execution. J.H.K. and A.D.M jointly designed the study and wrote the paper. A.D.M and R.W acquired the funding for this research. R.W. and M.B. provided overarching research direction and methodology design. W.G. and C.C.M. developed the hybrid dispatch model. E.O. assisted with visualization.

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.

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Appendix A

Here we present additional details on the data and assumptions for modeling the provision of regulation reserves from a standalone PV plant. In CAISO, regulation reserves are split into two products: regulation down and regulation up. To provide regulation down, the plant must maintain the ability to reduce its output by being dispatched down via an automatic generation control signal; depending on the signal, the plant generates less power than it could have otherwise produced (i.e., the plant is curtailed in response to the signal). To ensure that adequate capability is available, this study assumes that the PV plant can provide at most 10% of its nameplate capacity as regulation down and only when the average hourly generation level is greater than 20% of its nameplate capacity. The assumed amount of curtailment associated with regulation down, 30% of the amount of regulation down service, is based on the negative portion of the regulating reserve signal from PJM [60]. This study assumes that the plant provides regulation down as long as the regulation down price is greater than the energy price. Regulation up is similar to regulation down, except the plant must maintain adequate headroom to be able to dispatch up, therefore requiring pre-curtailment. To ensure that adequate capability is available, this study assumes that the PV plant can provide at most 10% of its nameplate capacity as regulation up and only when the average hourly generation level is greater than 20% of its nameplate capacity. This study assumes that curtailment from offering regulation up is 70% of the regulation up service provided. This study assumes that the plant provides regulation up as long as the regulation up price is greater than the energy price.

Regulation reserve products vary by wholesale market region. Similar assumptions are used in other wholesale market regions where regulation reserves are split between regulation up and regulation down: ERCOT, SPP, and MISO. The remaining markets—including PJM, ISO-NE, and NYISO—use a single regulation reserve product that includes both a regulation up and regulation down signal. This study assumes that if the PV plant provides 10% of its nameplate capacity toward a single regulation product then it must be able to increase its output by 10% or decrease its output by 10% in response to the regulation signal [61]. To ensure that adequate capability is available, we assume it can only provide regulation when the average hourly generation level is greater than 30% of its nameplate capacity. The reason for the higher threshold than for the two product markets is that the solar plant must be backed down from its available generation level to follow the up regulation signals while still maintaining room to further decrease output in response to down regulation signals. Consistent with the assumptions in the two-product market, this study assumes that curtailment is 50% of the regulation service provided and assumes the plant provides regulation when the regulation price is greater than the energy price.

Appendix B. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2021.117742.

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