

Optimizing the Configuration of Photovoltaic Plants to Minimize the Need for Storage

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Abstract—This article explores the application of optimizing tilt of photovoltaic (PV) plants as a statewide strategy to best match the California statewide load over the year and thus minimize storage requirements for a carbon-free grid. Through a simple cost model and energy balance model examining PV + storage in isolation, we show that, even though horizontal trackers produce the lowest cost electricity when the timing of generation is ignored, high-tilt PV plants have the potential to reduce overall system cost substantially by reducing the required storage capacity and by better utilizing surplus electricity. California should consider tilted PV configurations in capacity expansion planning and consider PV electricity pricing or incentives that encourage new PV installations that better match the seasonal load to reduce storage requirements.

Index Terms—Capacity planning, photovoltaic (PV), storage, tilt.

I. INTRODUCTION

THE need for action globally to address human-driven climate change is urgent. The State of California is an international leader in implementing measures to encourage clean technology and decarbonize its grid, with a legally mandated 100% carbon-free electric grid by 2045 [1]. The California mandate in particular, and more generally the worldwide recognition of the urgent need and emerging realistic prospect of decarbonizing electricity production, have spurred widespread research on the approaches and economics in recent years. Early work for the case of California has shown that, for its expected heavily solar-dominated future grid, the most challenging period for meeting the demanded load is in the winter months when solar and wind energy are comparatively scarce [2], [3].

Photovoltaics (PV) has emerged over the last decade as a major source for new electricity generation and has now become the cheapest option for new daytime generation in much of the world. The rapid growth in utility-scale PV has been mostly in the form of systems with 1-axis zero tilt (horizontal) trackers. These systems have added costs compared to fixed orientation

mounting, but the additional cost is more than offset by increased energy yield on an annual basis.

The annual generation profile of PV plants can be shaped by choice of the orientation of modules. To first order, modules tilted southward at the latitude angle relative to horizontal (“latitude-tilt”) maximize annual generation by minimizing the overall cosine loss imposed by the sun’s elevation change through the year. Greater tilt increases winter generation at the expense of summer generation, and conversely, a tilt less than the latitude angle favors summer over winter generation. Today’s commercial trackers with horizontal orientation sacrifice some winter electricity generation through simple cosine loss to favor electricity generation through the summer months when the grid needs the generation most due to summer air conditioning loads. Thus, the summer-dominated generation of 1-axis zero tilt tracking PV systems has until now been viewed as a benefit, but in a future grid with resource adequacy most challenged in the winter, the cost/benefit tradeoff may be revisited.

Before the emergence of cost-competitive PV at the utility scale, PV served niche markets, and particularly in situations requiring power in remote areas where a diesel generator was impractical. Stand-alone PV systems with batteries have been in use since at least the 1970s to serve remote loads, for example, in telecommunication applications [4], [5]. As a result, there is a body of practical experience designing systems that must operate without fossil fuel backup. Might there be any lessons from this long experience that can inform the transition to a fossil-free electricity system on a global scale?

One key design practice for stand-alone PV-battery systems is to examine the annual patterns of both the load to be served and the available solar resource and choose the orientation of the PV modules to generate as much power as possible during the periods where the load to solar resource ratio is highest [6]. In the era before widespread access to computers, the National Renewable Energy Laboratory (NREL) produced a handbook called the “Redbook” that provided monthly solar resource estimates around the United States as a function of the type of collector (flat plate versus concentrator) and orientation (tracking versus stationary, and tilt axis angle) [7]. The data provided in the Redbook enabled quick and reasonably optimized solar array sizing for stand-alone systems. Indeed, there is an IEEE standard for sizing of stand-alone PV systems [8] that describes this procedure and still references the NREL Redbook in its 2021 revision.

Manuscript received December 10, 2021; revised February 10, 2022 and March 1, 2022; accepted March 4, 2022. This work was supported in part by the California Energy Commission under Grant EPC-19-060. (*Corresponding author: Russell K. Jones.*)

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Color versions of one or more figures in this article are available at <https://doi.org/10.1109/JPHOTOV.2022.3157565>.

Digital Object Identifier 10.1109/JPHOTOV.2022.3157565

For stand-alone PV-battery systems with relatively constant loads (e.g., remote telecommunications equipment), the design process generally identifies winter as the challenging case and recommends PV module orientation optimized for winter generation. In practice, this means an elevation tilt angle of $\sim\text{latitude}+15^\circ$, which maximizes solar generation well throughout the winter, matching the sun elevation at noon roughly on October 30 and February 8, and with a cosine loss of only $\sim 1.1\%$ of the direct irradiance on the \sim December 21 winter solstice (in practice the total loss is less than 1.1% because some of the irradiance is diffuse). Tilt at latitude $\pm 15^\circ$ has long been recognized as good design for PV systems optimized for generation in the winter or summer and are included in the Redbook tables for this reason.

In this article, a shorthand convention is employed to refer to PV configurations consistent with the Redbook tables, as follows:

- 1) Tr0: 1-axis tracking zero tilt (horizontal axis)
- 2) TrL-15: 1-axis tracking summer tilt (latitude-15°)
- 3) TrL: 1-axis tracking latitude tilt
- 4) TrL+15: 1-axis tracking winter tilt (latitude+15°)
- 5) FxL-15: fixed south-facing summer tilt (latitude-15°)
- 6) FxL: fixed south-facing latitude tilt
- 7) FxL+15: fixed south-facing winter tilt (latitude+15°)

Many other authors are performing detailed studies that explore the design choices for a future carbon-free grid. To date, those studies have not explicitly considered the effect of PV configuration choices on the resulting imposed storage (or “clean firm power”) requirements. Thus, we anticipate that a study of PV orientation and resulting storage demand could be useful to those more comprehensive models by pointing to a lower cost carbon-free solution.

To address this opportunity and to see how the prior industry experience might apply to the future carbon-free grid, we examine the interrelationships between PV orientation (configuration), PV plant capacity, PV capital cost, and storage required to serve the load, considering PV and storage in isolation from other influences (e.g., other generation technologies, imports, exports, or transmission constraints). We consider the potential for reduction in required seasonal storage that can be achieved from a given amount of perfectly dispatchable energy from another source, as well as the availability and practicality of excess PV energy that may be put to other uses.

II. SURVEY OF CURRENT MODELING PRACTICE

A survey of recent publications regarding capacity planning studies along with their assumptions about the configuration of solar collectors is shown in Table I and shows that none of them have considered the orientation of PV collectors as a capacity planning variable. Many models consider only one orientation for all utility-scale solar installations, typically Tr0. This is no doubt because Tr0 systems are the dominant configuration in large-scale utility PV plants today.

Some of the models have different orientations assumed for utility-scale PV plants versus residential and commercial installations. Results from these studies do not explore the impact

TABLE I
TREATMENT OF SOLAR TILT ORIENTATION IN CAPACITY PLANNING MODELS

Lead author	Model name or description	Solar collector orientation
E3 Consulting [9]	RESOLVE linear optimization optimal capacity expansion and dispatch model	Utility: Tr0; distributed: existing mix
Hidalgo-Gonzalez [10]	SWITCH linear optimization optimal capacity expansion and dispatch model	Utility: 20° tilt single-axis tracking; distributed: FxL
Abido[3]	Statewide energy balance model	Existing mix
Mai[11]	NREL Resource Planning Model	Utility: Tr0; distributed: fixed 25° tilt
Ho[12]	Regional Energy Deployment System (ReEDS) Model	Utility: Tr0; distributed: FxL
Sun[13]	Electrification Futures Study (uses ReEDS)	Utility: Tr0; distributed: FxL
Cole[14]	Study of potential and challenges to reach 100% renewable grid (uses ReEDS)	Utility: Tr0; distributed: FxL
Mills[15]	Marginal economic valuation of PV capacity versus penetration	Unknown
Jacobson [16]	LOADMATCH grid integration model	Utility: Tr0 and fixed optimized tilt; distributed: optimized tilt
Frew[17]	POWER linear programming model	unknown
Dowling[18]	Macro energy model (MEM) for long duration energy storage	Tr0
Baik[19]	Capacity expansion and dispatch model, urbs	Existing mix (inferred)
Budischak [20]	Regional Renewable Electricity Economic Optimization Model (RREEM)	FxL
Sepulveda [21]	GenX electric power system investment and operations model	FxL
Ziegler[22]	Optimization of wind-solar-storage mix for minimum cost of electricity	TrL
Mileva[23]	SWITCH linear optimization optimal capacity expansion and dispatch model	utility: TrL; distributed: FxL
Breyer[24]	LUT Energy system model, linear optimization	Tr0 and fixed optimal tilt

of changing PV orientation exactly because other factors such as the installed cost or accessible capacity constraints differ significantly between utility-scale and small-scale systems.

None of these capacity planning studies cited from the literature have addressed the potential of changing the collector orientation as a means of reducing storage demand at all, but instead, explore alternative approaches to minimize cost. For example, Frew [17] considered cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle as sources of flexibility in a renewable grid. The study by Cole *et al.* [7] extensively considered sensitivity analyses of 23 different parameters in 100% renewable energy scenarios but differing PV generation profiles via orientation changes were not considered. This study uses the NREL Regional Energy Deployment System model [12] and shows a deficiency of solar generation in winter as the main driver for firm generation capacity. In this and other studies, the cost of storage is the biggest driver in 100% renewable energy scenarios, and some firm generation capacity greatly reduces overall cost to satisfy the last few percent of the load.

Mills [15] showed that the overall economic value of adding PV to the grid declines as penetration grows, to almost zero above about 30% penetration, because the variability of solar generation (of which seasonal variation is a major part) results in diminishing displacement of firm generation capacity. Sepulveda [21] also shows that firm generation capacity needs are driven by periods of low variable renewable resource availability.

The Dowling study [18] modeled the need for long-duration storage on an inter-seasonal and even inter-annual basis. They found that seasonal storage is mostly discharged in summer, in contrast to other studies, due to reduced availability of wind resources in summer.

Both Jacobson [16] and Breyer [24] have used a more in-depth optimization of tilt angles in their capacity planning studies. In those supporting studies, Jacobson [25] assessed optimum tilt angles globally for fixed tilt and azimuth tracking collectors, accounting for meteorological conditions that affect the direct versus diffuse resource. Breyer [26] similarly performed a global optimization for fixed tilt collectors in combination with a leveled cost of energy (LCOE) model. Both studies have been aimed at determining the optimum orientation to maximize energy production annually, rather than the optimum to serve the load that is the subject of this article.

III. METHODOLOGY

We use a statewide energy-balance approach, using a representative statewide generation profile for each of the PV plant configurations considered, and using the shape of the statewide electrical load based on historical data of the California Independent System Operator (CAISO) [27]. For clarity, the quantities are normalized: the PV generation is normalized to 1 W_{DC} capacity, cost is normalized per W_{DC} capacity, and load is normalized to an average of 1 W (i.e., the total normalized annual load is 8760 Wh, but has the “shape” of the actual statewide load in California).

A. Statewide PV Generation Profiles

The PV generation profiles were calculated using SAM’s PVWATTS v7 model, implemented in Python using SAM API calls [28]. The PV system parameters used (in common for all the configurations) are as follows.

- 1) DC/AC ratio: 1.3.
- 2) Module quality: 1 (monocrystalline).
- 3) Bifaciality: 0.7.
- 4) System losses: 14.07%.
- 5) Inverter efficiency: 96%.

For fixed tilt configurations, the ground coverage ratio was calculated according to criteria for inter-row spacing given by the Arizona Solar Center [29], which provides for no direct beam shading in mid-winter when the sun is above its noon elevation angle, capturing about 90% of the available energy. For tilted tracking configurations, row-to-row (inter-row) shading is ignored by PVWATTS, and the ground coverage ratio refers to shading of adjacent trackers within a row (intra-row shading); a ground coverage ratio of 0.4, a typical value for horizontal trackers, was used for all the tracking configurations. In reality,

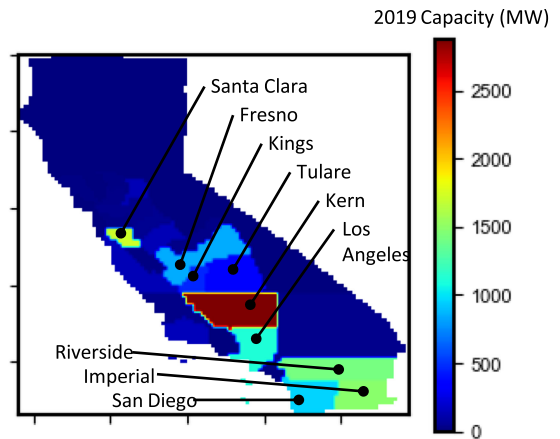


Fig. 1. Solar capacity in California by county for 2019. Statewide PV generation profiles were created by spatially averaging solar resources in each county and computing generation in each county using PVWATTS.

the shading in inclined-axis tracker fields is rather complex, with both inter-row and intra-row shading, and often with staggered placement of rows.

Statewide utility-scale PV generation profiles were developed for a simplified analysis by first developing spatially averaged solar resource files for each county in California, and then simulating the PV configurations for each county, and finally weighting the resulting PV generation in each county in proportion to the actual generation that existed in that county in 2019 [30]. Thus, the statewide profiles assume that future PV capacity growth in the state will follow what has already occurred, as illustrated in Fig. 1. The resulting capacity-weighted “average” PV system is located at 35.2° latitude.

The spatially averaged solar resource files were created using 2019 data downloaded from the National Solar Radiation Database [31], again on a $0.1^\circ \times 0.1^\circ$ grid throughout California, by averaging the irradiance values (as well as temperature and wind speed) from each location in each county. This procedure results in smoothing of the irradiance due to geographic diversity, realistically approximating the actual aggregated PV generation while still preserving the essential differences in performance of different PV configurations with latitude, with a PV generation time series for each of the 58 California counties, for each of the configurations considered. The generation profiles are for the year 2019, consistent with the CAISO data used for load. Fig. 2 shows the daily energy generation for each of the configurations modeled, for example, day in summer, spring/autumn, and winter.

B. PV Cost Model

The PV capital expense (Capex) is modeled based on an NREL study [32] that is the basis for the costs reflected in the 2021 NREL Annual Technology Baseline [33]. The NREL study benchmarked both fixed-tilt and one-axis tracking on ground-mounted racking systems using driven-pile foundations, using actual reported project costs and a U.S. carbon steel pricing index. Fig. 3 shows the baseline costs for both fixed latitude tilt

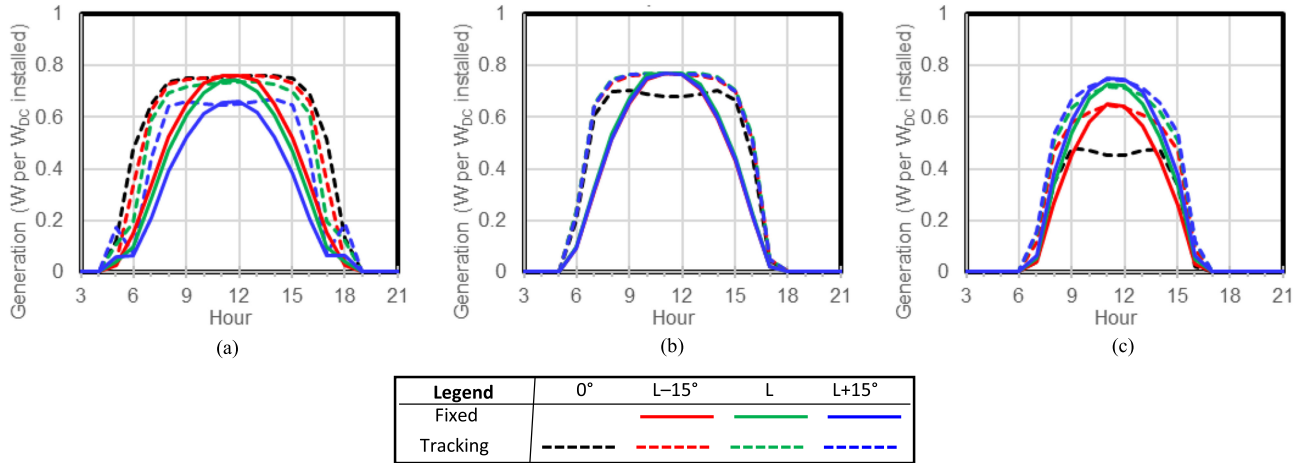


Fig. 2. Daily solar generation for different collector configurations in summer, autumn, and winter (spring is similar to autumn). (a) June 30. (b) September 21. (c) December 21.

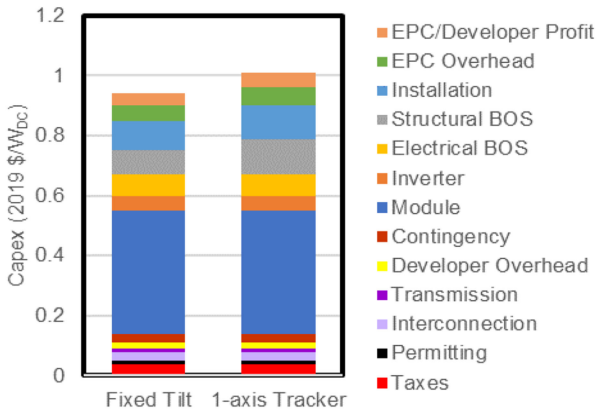


Fig. 3. Q1 2020 US benchmark utility-scale PV total cost, 2019 USD/W_{DC} (reproduced from data in [19]).

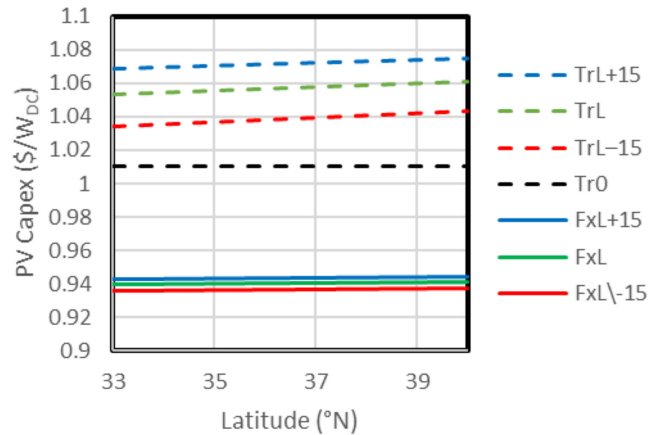


Fig. 4. Modeled cost of PV system as a function of latitude.

TABLE II
COST RELATIONSHIPS USED TO ESTIMATE PV CAPEX (θ IS THE TILT ANGLE)

Cost component	Fixed	Tracking
Structural BOS	NREL Structural BOS \times $\left[67\% + 33\% \frac{1 + \sin(\theta)}{1 + \sin(\text{lat})} \right]$	NREL Structural BOS \times $[34\% + 66\%(1 + \sin(\theta))]$
All other	Per Fig. 3	Per Fig. 3

and 1-axis zero tilt PV systems from the NREL study for 100 MW systems. Note that land cost is treated as an operational expense (Opex) in the form of lease payments, rather than as a Capex cost.

Table II shows how the NREL study was used to estimate PV Capex as a function of tilt angle. Changing the inclination of the PV generators has two effects on the total cost: 1) a change in the cost of structural balance of system (BOS) cost and 2) a change in the land use. Because there is no significant commercial presence

of inclined axis trackers on a scale comparable to that of horizontal trackers, it is difficult to say what cost might be achieved with volume and innovation. After discussions with suppliers of fixed-tilt and 1-axis tracking components, we assumed that for fixed tilt systems 33% of the structural BOS cost varies with the tilt angle θ in proportion to $(1 + \sin(\theta))$. For example, the racking on which modules are mounted depends only on module size, not inclination angle, but height (and possibly depth) of foundation posts is affected by θ . For trackers, we assume 66% of the structural BOS is affected by θ . The structural BOS is a small portion of the overall Capex in both cases, with the result that the modeled Capex cost is a rather weak function of latitude as shown in Fig. 4. The same capacity-weighting procedure by county used to develop the representative statewide PV generation profiles was also applied to establish statewide PV Capex cost, with a statewide weighted-average latitude of 35.2°.

The resulting statewide estimate of the PV capacity factor, statewide estimated PV Capex (per W_{DC} installed), and ratio

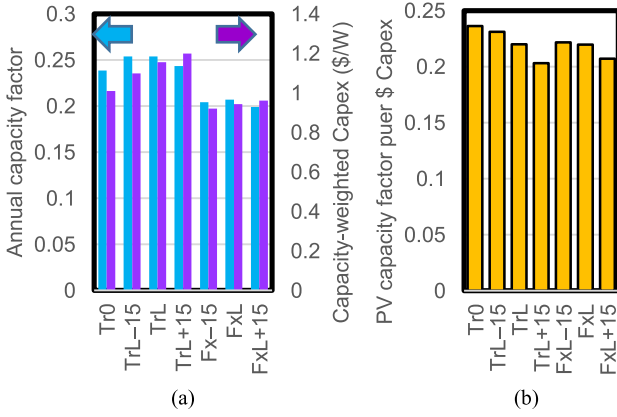


Fig. 5. Statewide analysis of PV cost-effectiveness without regard to the timing of energy delivery. Capacity factors were calculated from the statewide capacity-weighted PV generation profiles. Cost is based on Fig. 4 and a capacity-weighted latitude of 35.2°. (a) Capacity factor and Capex. (b) Capacity factor per \$ Capex.

of capacity factor to Capex are shown in Fig. 5. Here capacity factor is defined as [annual AC generation]/[nameplate capacity \times 8760] and nameplate capacity is the total dc rating of the modules in the system, consistent with the definitions used by SAM. The ratio of capacity factor to Capex is a measure of “bang for the buck” for each configuration. The Tr0 configuration increases the Capex per W_{DC} by $\sim 7\%$ but increases the capacity factor by $\sim 20\%$ compared to the FxL+15 configuration, and has the highest ratio of all the configurations considered, so it is to be expected that the vast majority of utility-scale PV systems being installed use the Tr0 configuration, as is the observed reality [18], since under current power purchase agreement (PPA) pricing schemes there is no preference for when energy is generated.

C. Statewide Energy Balance

The analysis of energy balance considers only the PV generator configurations and the statewide load profile in isolation, with the 2019 CAISO statewide load profile normalized to an average demand of 1 W (and thus 8760 Wh per year); as a result, the computed PV generation and PV capacity are also normalized per watt of average load. There is no attempt to account for any other generation such as from wind, hydro, biomass, etc., but rather, the analysis presented here just considers purely the ability of the various PV configurations to serve the load (with the hourly shape observed in California) with varying amounts of storage. The storage is also treated on a statewide basis, with no constraints related to transmission or congestion.

For each hour t the storage charge state s_t is calculated from the hourly generation G_t and load L_t with the following formulation (here C_s is the storage capacity, η_c and η_d are the efficiency of charging and discharging, and r_{sd} is the self-discharge rate). Charging occurs when $G_t > L_t$ according to the following:

$$s_t = \begin{cases} C_s & \text{if } \eta_c (G_t - L_t) + s_{t-1} (1 - r_{sd}) > C_s \\ s_t (1 - r_{sd}) + \eta_c (G_t - L_t) & \text{otherwise} \end{cases} \quad (1)$$

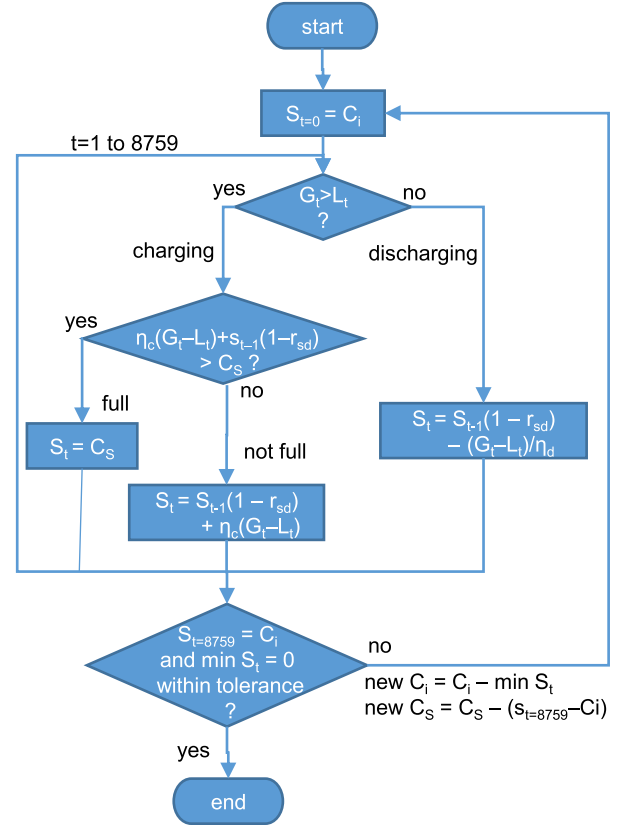


Fig. 6. Storage capacity calculation flowchart. The storage capacity C_s and initial charge state C_i are calculated iteratively until the minimum charge state is zero and the ending charge state $S_{t=8759}$ is equal to C_i within a tolerance.

whereas for discharging, when $G_t \leq L_t$,

$$s_t = s_{t-1} (1 - r_{sd}) - (L_t - G_t) / \eta_d. \quad (2)$$

At $t = 0$, $s_t = C_i$, the initial charge.

The charging and discharging efficiency are each assumed to be 90% (for a round-trip efficiency of 81%), and the self-discharge rate is assumed to be 0.2% per day. These values could be representative of batteries, but could also represent pumped hydro storage, or other types of storage. The values of the initial charge state and storage capacity are then solved iteratively as illustrated in Fig. 6 to determine the storage capacity, with the constraints that the final charge is equal to the initial charge (equivalent to assuming all years are identical to this one) and that the minimum charge is zero (whereas in reality, most energy storage technologies have a maximum permissible depth of discharge beyond which service is disrupted, sometimes with permanent damage to the storage system). The excess of any net generation that results in full storage is treated as curtailment or as available for a possible secondary use.

The storage holding time required was probed by aggregating the generation and load to successively longer intervals and recalculating the charge state and required capacity for each successive interval. Each such calculation expresses the total imbalance between generation and load over the aggregation interval; for example, aggregating over 10 h at each hour shows

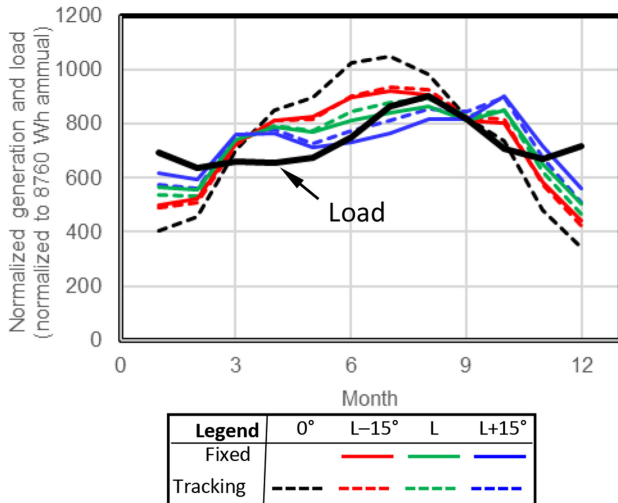


Fig. 7. Monthly solar statewide generation profile versus the statewide load for 2019 (based on the capacity-weighted generation by county).

the total imbalance that persists over that 10-h interval or more, but does not show imbalances over shorter intervals. Over a sufficiently long aggregation interval, the imbalance (load – generation) must be negative if the annual generation exceeds the load + losses, and the storage requirement is zero for that interval or longer. Although the CAISO data are over 5-min intervals, this analysis was limited to intervals of at least 1 h because the solar resource data used are on an hourly basis. Thus, the calculated storage requirements omit any storage that might be needed for balancing on subhourly intervals.

IV. RESULTS

Fig. 7 shows the annual statewide generation profiles aggregated on a monthly basis compared to the 2019 California statewide load (generation and load profiles are normalized to a sum of 8760 for the year). The load does exhibit an increase in summer months driven by air conditioning loads, but it is apparent that the inclined configurations (winter tilt or latitude tilt) provide an improved overall match.

A. Relationship of Storage Requirement to PV Capacity and Capex

Storage size is the minimum necessary to satisfy the load with perfect dispatch, calculated according to the formulation in Section III-C in every case. The interrelationship between the PV orientation and the storage required to serve the load is examined in Figs. 8–10. Fig. 8 shows the state of charge over the year calculated for the minimum PV capacity necessary to satisfy the 1 W average load as indicated in the inset of Fig. 8. Since the load is normalized to 8760 Wh/year, then by definition a PV nameplate capacity equal to the reciprocal of the capacity factor provides generation equal to the load. However, this is not enough: most of the generation is first stored and later retrieved, rather than serving the load directly. If all of the generated energy passes through storage, only the

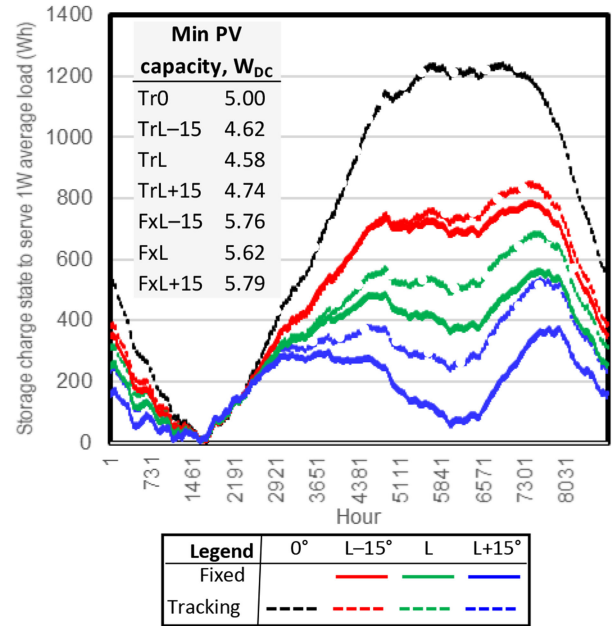
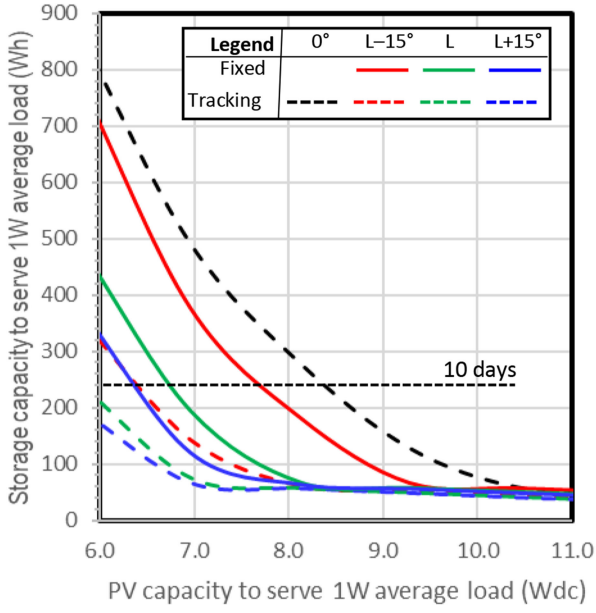


Fig. 8. Charge state throughout the year for the minimum PV capacity required to serve 1 W average load for each configuration (minimum capacity and storage required jointly satisfy the constraints that minimum charge=0, starting charge=ending charge, and no surplus electricity).

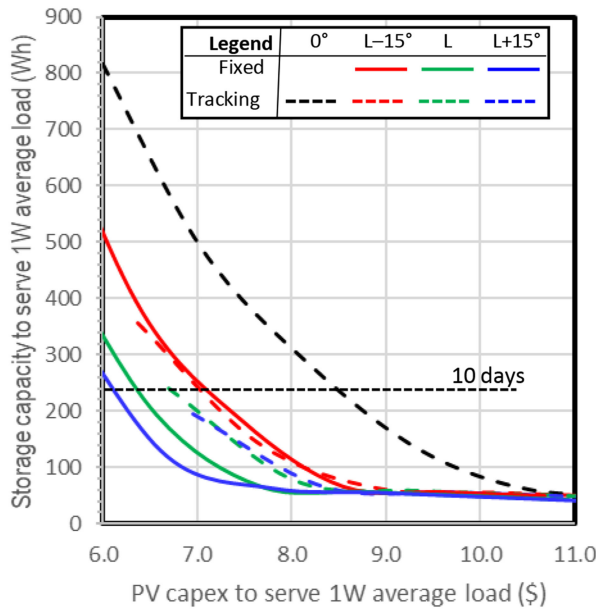
generation \times round-trip efficiency can be supplied to the load. There is thus a maximum storage requirement associated with the minimum PV capacity, such that the total energy supplied directly to the load, plus the total energy that is passed through storage before being supplied to the load, just equals the load, with no surplus energy generated. The inset table in Fig. 8 shows the PV nameplate capacity (in W_{DC}) corresponding to each charge state curve. Each of the fixed orientation configurations require more nameplate capacity than their tracking counterparts to satisfy the load. The fact that tracking systems have almost no generation advantage over fixed orientation at the same tilt angle when the sky is heavily overcast means that the long decline in charge state from November through February is greater for the lower-capacity tracking systems, resulting in a higher peak storage requirement to compensate.

Fig. 9(a) shows how the storage capacity (peak value of the charge state) is affected by adding PV capacity. Added capacity has two effects: first, the rate at which storage is depleted between November and February is reduced; and second, the stored charge state necessary at the start of that depletion is reduced. Thus, the required storage is reduced, but more PV energy has been generated, and the excess is curtailed (or is surplus available for a secondary use). Fig. 9(b) translates the PV capacities to PV capex (required to serve the 1 W average load) using the cost model of Fig. 4. Although the tracking configurations (TrL and TrL+15) have the least storage required per unit capacity, their cost premium means that the fixed orientations (FxL and FxL+15) have the lowest capex for a given storage requirement.

Fig. 9(a) and (b) shows horizontal lines of equal storage capacity at 10 days (240 h at a 1 W average load). Considering just FxL+15 and Tr0 configurations, Fig. 5(a) shows that the capacity factor of Tr0 is 20% greater than that of FxL+15 collectors,



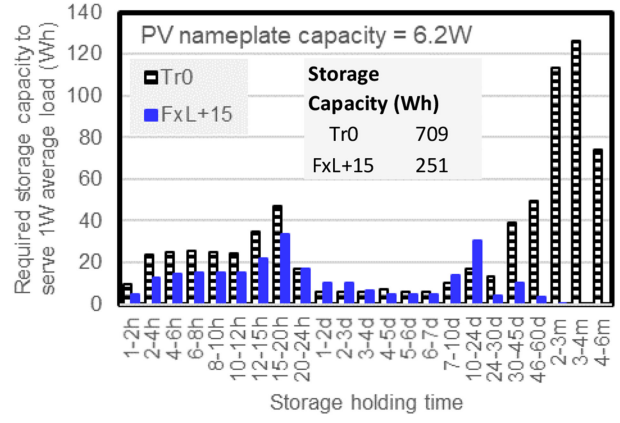
(a)



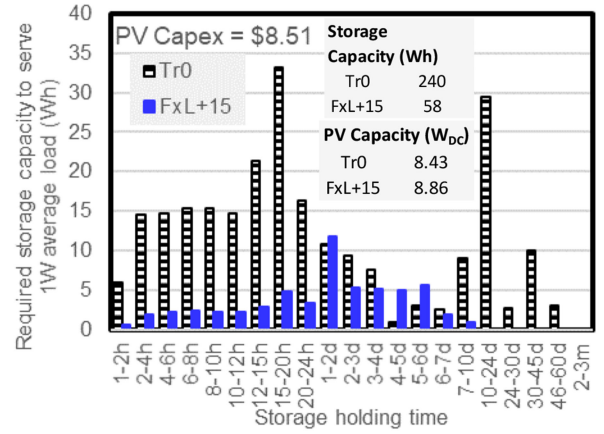
(b)

Fig. 9. Reduction of required storage to serve 1W average load as the PV capacity is increased (added PV capacity results in both reduced storage needed and surplus electricity exceeding the storage capacity). (a) Storage required as a function of PV capacity. (b) Storage required as a function of PV capex.

but Fig. 9(b) shows that the capex required to serve the load is $\sim 40\%$ greater for Tr0 than for FxL+15 collectors for the case of 10-day storage. This is a remarkable result: whereas Fig. 5 shows clearly that Tr0 is the most cost-competitive configuration and FxL+15 is the least competitive when the timing of generation is ignored, Fig. 9(b) shows the opposite is true if the objective is to serve the whole load throughout the year, unless either storage is extremely cheap (well under $\$0.01/\text{kWh}$), enabling the load to be satisfied with Tr0 at capex less than the minimum feasible capex for FxL+15, or else PV is so overbuilt that both configurations



(a)



(b)

Fig. 10. Distribution of energy storage holding time for Tr0 versus FxL+15 configurations. The holding time is the maximum energy charged and discharged annually over the indicated interval. (a) Storage holding time for equal PV nameplate capacity. (b) Storage holding time for equal PV Capex.

have essentially equal storage requirements. Conversely, vertical lines in Fig. 9(b) represent constant PV Capex, and we see that for a given Capex, Tr0 collectors require more storage capacity than FxL+15 collectors. These conclusions hold regardless of the cost of storage.

Fig. 10 shows the distribution of energy holding time in storage through two comparisons, using the progressive aggregation procedure described in Section II-C, now focusing just on the comparison between Tr0 and FxL+15 configurations. In Fig. 10(a), the holding time distribution is shown for systems of equal nameplate capacity of $6.2W_{DC}$, and reveals that for this case, not only is the total storage requirement for Tr0 much greater than for FxL+15 (2.8 times greater) but additionally, most of the increased storage needed is interseasonal storage of 1–6 months holding time. Fig. 10(b) compares systems of equal PV Capex (higher overall capacity than in Fig. 10(a) as indicated in the inset table in Fig. 10(b); this Capex corresponds to that needed for Tr0 to serve the 1 W average load with 10 days of storage) and shows an even greater penalty (4.1 times greater) in storage required for Tr0, again with some of the storage requiring longer hold times.

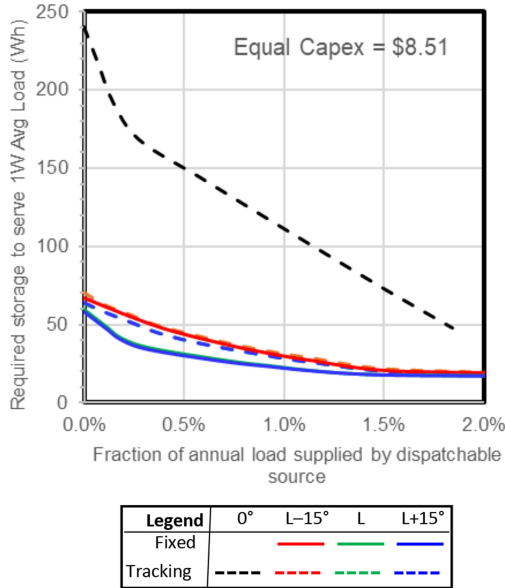


Fig. 11. Reduction of required storage by use of a dispatchable energy source (e.g., natural gas turbine, hydrogen turbine or fuel cell). It is assumed that the dispatchable source is optimally dispatched, i.e., each Wh of energy is supplied with the storage charge state at its minimum.

B. Effect of Supplementary Dispatchable Energy on Storage Requirement

Since the storage requirement is driven by episodes of extended low solar resource compared to the load, a useful question is how much the storage requirement can be reduced by the use of a dispatchable generation source such as a gas or hydrogen turbine or hydrogen fuel cell. This question has been addressed in some of the prior studies. For example, the Electrification Futures Study [13] forecasted that winter peak demand will be largely met by generation from the natural gas-combined cycle, and wind solar resource availability is lower in winter than in summer, and more so in high electrification scenarios. Cole [14] proposed combustion turbines using renewable fuels as a lower cost alternative to conventional storage.

Fig. 11 shows the reduction in storage needed as a function of the amount of supplemental energy from a dispatchable source, assuming it is optimally dispatched (as described in Section II-C). Even a very small amount of energy dispatched at the right time can significantly reduce the storage needed. The curves shown are for a case of equal capex for all the PV configurations, corresponding to the \$8.51 capex needed to serve the 1 W average load and achieve 10 days storage for the Tr0 configuration, and clearly illustrate that a given storage target can be met with significantly less dispatchable energy (fuel burn in the case of a turbine) for FxL+15 compared to Tr0 plants.

C. Effect of PV Configuration on Energy Available for Secondary Uses

There is an emerging consensus that cost-effective decarbonization of the electric grid must incorporate cross-sector coupling of electric generation (to serve newly electrified loads in transportation, heating, hydrogen electrolysis, and synthetic fuel

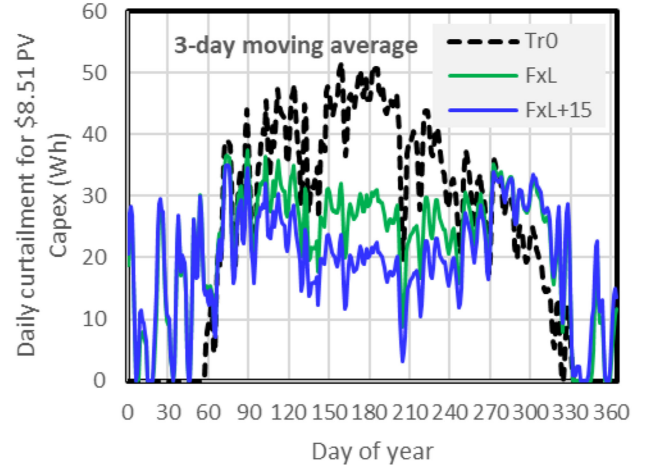


Fig. 12. Daily curtailed energy of Tr0, FxL, and FxL+15 generators of equal Capex for normalized CAISO load.

production) [34]. All the configurations considered above have some degree of excess generation that must be lost to curtailment, or preferably, supplied to secondary loads for cross-sector use cases. Such use cases include electrolysis for intermittent generation of hydrogen, or intermittent generation of thermal energy that is stored for process heat.

Fig. 12 shows the daily surplus electricity (a 3-day moving average is shown for visual clarity) for FxL+15, FxL, and Tr0 systems for the case of equal Capex of \$8.51 (again, the capex that results in ten days of storage for Tr0). Deploying cross-sector uses of this intermittent surplus electricity partially offsets the cost of the power system through revenues earned from those uses.

Whatever the nature of the cross-sector use, the surplus electricity must be supplied to some type of equipment whose capacity to use the electricity represents an investment. Ordinarily, facilities expect input electricity to be available 100% of the time, but the electricity in Fig. 12 is what is left over after meeting 100% of the loads of ordinary facilities. A facility using the surplus electricity must suffer a loss of productive capacity due to the intermittent supply of electricity, in addition to any losses it may incur from other causes such as failures or maintenance.

If the equipment can use at most C units of daily surplus electricity E , then on any given day the equipment will use C units if $E > C$, or E units if $E < C$. In Fig. 13, this equipment utilization factor is expressed in terms of the maximum electricity input it can utilize, and the resulting equipment utilization factor shown is the fraction of time the secondary use equipment receives energy at its rated capacity (analogous to capacity factor, but for the availability of input electricity rather than equipment capability). At lower levels of secondary use equipment capacity (measured in Wh of peak daily electric demand), the achievable equipment factor is far higher with FxL+15 or FxL PV generators compared to Tr0. In this case, for the same \$8.51 Capex, the FxL+15 generator not only reduces required storage by $\sim 75\%$ but also allows cross-sector use to operate at higher utilization factor (and thus cost-effectiveness).

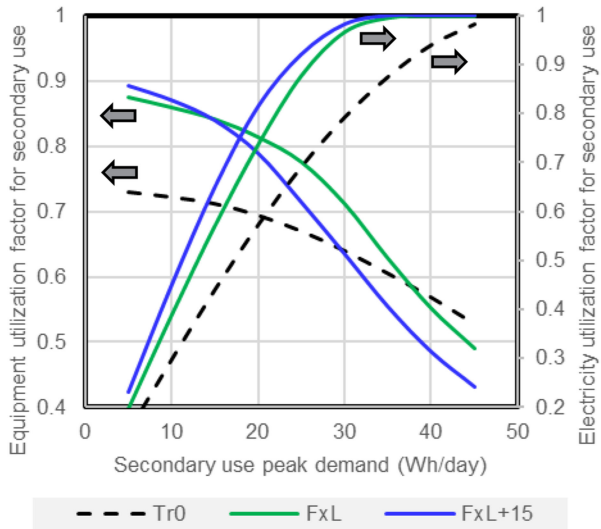


Fig. 13. Surplus electricity and equipment utilization factor for secondary use versus secondary use peak energy demand, for PV generators with equal Capex=\$ 8.51 serving 1 W primary load. The secondary use equipment is assumed to be able to use at most the indicated peak demand per day.

Conversely, the secondary axis of Fig. 13 shows the effectiveness of utilizing the surplus electricity and shows that the FxL and FxL+15 PV generators also enable higher utilization of the available surplus electricity compared to Tr0 generators. By producing surplus electricity more evenly throughout the year, the inclined collectors furnish a more reliable supply to the secondary equipment with lower losses of the available surplus.

V. DISCUSSION

The results are consistent with the findings of most of the prior studies in highlighting a large imbalance between winter load and winter generation using Tr0 PV plants, necessitating large amounts of interseasonal storage (or alternatively, comparatively large amounts of fuel burn in winter). Winter-oriented collectors greatly reduce this need but do not eliminate it entirely.

As stated previously, the analyses presented here consider only the shapes of the PV generation and the California load in isolation. It is therefore not representative of the California grid: it considers California as an island with no energy imports or exports and makes no accounting of transmission or congestion constraints. A realistic representation of the grid would obviously include future growth of on-shore and off-shore wind generation, anticipated changes in the load from electric vehicles or electrification of heating loads, and the potential for energy imports and exports. A realistic grid model would also include a diversity of PV generator and storage technologies, each with their own unique performance and cost metrics. On the other hand, the analysis has used fairly well-understood PV costs based on historical data and shows that the system (PV + storage) cost may be minimized by using inclined axis PV collectors, even though they are clearly more expensive when considered independently of storage on an annual cost per kWh basis. This insight is perhaps useful. The extent to which the renewable generators themselves can be tailored to reduce the

storage has not been widely recognized. The above analyses show a clear potential to accomplish this with PV, and analogous opportunities may exist with wind generators as well (choosing sites with high winter winds that might be seen as uneconomical when considered in isolation [35]). Although the FxL+15 configuration is the most cost-effective when considered in isolation, it may not be when these other generation sources are included in the analysis.

As mentioned previously, land costs are treated as Opex. Including Opex in this analysis would necessitate a complete LCOE assessment that is beyond the scope of this study. Land use is strongly affected by inclined axis tracking, since trackers must be spaced in two dimensions to avoid shading; the land use for fixed tilt systems is closer to that of horizontal tracking systems, requiring increased spacing with increased tilt in only one dimension. Thus, the effect of including Opex would be to make inclined axis trackers less attractive than their fixed-tilt counterparts to a greater degree than shown here. In any case, Opex generally has a rather small impact on the LCOE of PV systems.

It is worth noting also that the assumed dc:ac ratio of 1.3 means that some PV energy is being lost at the inverter, and effectively assumes all the storage is ac-driven. But modern battery charge controllers are often designed to use dc coupled power precisely to avoid this loss, and other storage technologies may be able to make use of dc energy as well, if collocated with the PV plant. Inclusion of this energy would result in reduced storage requirements for all configurations and would likely further favor FxL+15 systems since they have more incremental dc energy to capture in the winter than the other configurations.

The analyses are based solely on the loads as they existed in 2019. However, there is reason to believe that winter loads will increase in the coming years due to electrification of heating loads (mostly in the winter) and electric vehicle charging (year-round). On the other hand, summer cooling loads will increase due to climate change. It is difficult to predict how the load shape will evolve, and load shape changes may well change the optimal PV generation mix. Latitude tilt systems may best prepare for uncertain future load scenarios by just maximizing overall generation and balancing winter and summer performance.

Given the common practice in PPA contracts of setting a single price for all electricity delivered through the year, it is worth considering how buyers of utility PV might adjust contracting terms to favor inclined collectors with better winter generation. Solar PPAs have many creative pricing terms, and seasonal adjustments are uncommon but not unprecedented [36]. For example, the electricity price could have a premium for delivery in the winter months. In that case, using the generation and Capex figures in Fig. 9, and premium pricing for electricity delivered over the 12 weeks centered on the Dec. 21st winter solstice, we find the result shown in Table III: a winter price premium of 240% is needed for Tr0 and FxL+15 plants to have equal revenue per dollar of Capex. Table III uses a base price of 2.5¢/kWh as an example, but presumably, this price would be the main PPA negotiating point. In this example, the annual revenue equates to a simple payback interval of 14.9 years.

TABLE III
WINTER GENERATION INCENTIVE TO EQUALIZE REVENUE PER UNIT CAPEX
FOR Tr0 AND FxL+15 PV PLANTS

Parameter	Tr0	FxL+15	Δ
Capex (\$ per W_{DC})	\$1.01	\$0.96	
Annual generation (Wh per W_{DC})	2090	1814	15%
Winter generation (Wh per W_{DC})	257	316	23%
Base price per kWh (for example)		\$0.025	
Premium for winter delivery		240%	
Annual revenue/\$ Capex	\$0.067	\$0.067	0

VI. CONCLUSION

The results show that, at least for the case of the California load, and considering solar and storage in isolation, selecting PV plants with winter-optimized tilt versus horizontal tracking plants results in the following.

- 1) Lower total PV Capex required for a given amount of storage capacity.
- 2) Lower storage capacity required for a given amount of PV Capex.
- 3) Generally reduced storage holding time.
- 4) Reduced storage for a given fraction of the total load supplied by firm generation.
- 5) Reduced curtailment that is more evenly distributed through the year.

When PV is optimized to serve the load, the total cost of PV + storage is consequently reduced, which should enable PV to play a bigger role in the future grid.

The use of PV orientation to tailor the annual generation profile to best match the load is perhaps a case of knowledge that is “well-known to those who know it well,” namely to PV specialists, but maybe not to utility system planners and policymakers. One of the aims of this article has been to show that the same principles guiding the design of stand-alone PV systems in past years are applicable to the whole grid as we seek to rid it of carbon emissions. In effect, the future carbon-free grid driven by renewable energy is a stand-alone system, only bigger.

The simplified assumptions used in the analyses here make any quantitative assessment of cost savings achievable through optimized system-wide PV orientation doubtful, but the analytical results nevertheless clearly point to significant savings in total capital costs that should therefore motivate planners working with more robust and complete models for optimal capacity expansion and dispatch to include PV orientation options in their list of design choices for system planning.

Our results should also alert state policymakers and utility buyers to the need to consider how best to ensure PV plants procured in the coming years help to optimize the whole system for lowest cost through contract requirements and remuneration schemes. Remuneration of PV plants on the simple basis of kWh produced regardless of the timing of production will simply serve to ensure growth of generation at times it is not needed, at the expense of generation that is lacking when it is needed most.

ACKNOWLEDGMENT

The authors acknowledge Dr. R. Sinton for his review and thoughtful feedback. This work was prepared as a result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees, or the State of California. The Energy Commission, the State of California, its employees, contractors, and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this document; nor does any party represent that the use of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the Energy Commission nor has the Energy Commission passed upon the accuracy of the information in this report.

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