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Optimized market value of alpine solar photovoltaic installations

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ABSTRACT

Solar photovoltaic (PV) is the most rapidly expanding renewable resource worldwide. Yet, its full potential may be hindered by mismatches with market demand and correlated production profiles. In this research, we explore a case study of innovative PV placements in alpine regions using two, soft-linked optimization models of Switzerland's electricity system. Using Swissmod, an electricity dispatch and load-flow model, and OREES, an electricity system model employing evolution strategy to optimize PV placement, we simulate market prices of optimized PV placements given multiple years of weather data, various CO2 prices, and considering future electricity infrastructure developments across Europe. Mountain placements result in higher market value and less required area relative to lower-altitude PV placement strategies. The higher market value is driven by better alignment with demand, particularly during winter when demand is highest. We found that optimized alpine placements offer revenues of panel capacity (EUR/kW/year) that are on average 20% higher than revenues from urban PV installations. Furthermore, the Swiss mountains could host more than 1 GW of capacity with even greater revenues (33%). Alpine PV installations, with their higher market values and increased value factors, can potentially be very profitable investments and are also valuable from a system perspective.

1. Introduction

The Paris Agreement and legislative climate policy packages such as the European Commission's “Fit-for-55” package call for energy systems to decarbonize by 2050 [1]. The electricity sector will play leading roles both directly and indirectly in decarbonizing energy systems worldwide. First, countries will replace fossil-fuel generation technologies with renewable generation technologies in their electricity systems, accounting for a large direct reduction in carbon emissions. Second, once the electricity sector has been decarbonized, other sectors historically relying on fossil fuels (e.g., transportation and heating) will be decarbonized through electrification, further reducing CO_2 emissions.

Countries have already begun expanding their share of renewable technologies in the electricity sector. The International Energy Agency expects that solar photovoltaic (PV) panels will make the largest contribution to expanding global renewable capacities in the coming decades [2]. Indeed, PV is being installed at the highest rate of all renewable technology options [3] due to its rapidly falling investment costs that are expected to decrease further [4]. Solar power is now less expensive than coal and gas in most countries, according to IEA estimates [2].

However, there are two challenges that arise at high levels of installed PV: a temporal mismatch between electricity demand and PV production (within the day and seasonally), and the so-called “cannibalization” effect (reduced market value induced by the introduction of more correlated PV generation in the market). In this paper, we explore the innovative PV placements proposed in Kahl et al. [5] and show how placing PV at higher altitudes can help address these issues, making PV potentially a more attractive investment opportunity.

Temporal mismatch within a day occurs because solar generation is highest around noon whereas electricity demand peaks at

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different times. Summer-peaking systems such as most North American power systems experience their demand peaks in the late afternoons, while winter-peaking systems such as the interconnected European power system experience their peaks in evening hours, both not matching the peak around noon of solar electricity generation. This results in electricity prices often being depressed in hours of peak solar infeed (as in the case of the Californian "duck curve" of summer electricity prices). Such daily mismatches can be addressed by short-term storage options such as batteries and pumped-storage hydropower, partly mitigating the cannibalization effect.

Seasonal mismatches occur where demand is highest in the colder, darker winter months[1] while solar generation is highest in the summer (Fig. 1). Seasonal mismatch requires seasonal storage options, grid expansion, other generation options (e.g., wind power) to compensate for PV production shortfalls during winter months.

PV cannibalization is when the market value of PV production declines as more PV comes online because the production of PV panels are correlated one with another. Cannibalization in turn depresses PV investment. However, PV cannibalization can also be addressed to some degree by storage options, which will however never fully compensate the effect due to the costs of storage investments and the energetic losses in storage operation.

Besides storage, innovative PV placements and configurations proposed in Kahl et al. [5] are another, promising way of dealing with cannibalization and the temporal mismatch of demand and production, particularly in places where storage options or public acceptance of alternative generation are limited. Kahl et al. [5] propose PV panel placements in locations that facilitate higher winter production. Using Switzerland as a case study, they show that PV panels placed at higher elevations can take advantage of higher winter irradiance, ground-reflected radiation from snow, and greater tilt angles to improve winter yield, all resulting in more electricity generation during the peak winter demand, and generation that is less correlated to pre-existing PV installations. Furthermore, Kahl et al. quantify the solar potential for Switzerland with these previously dismissed locations and find a more

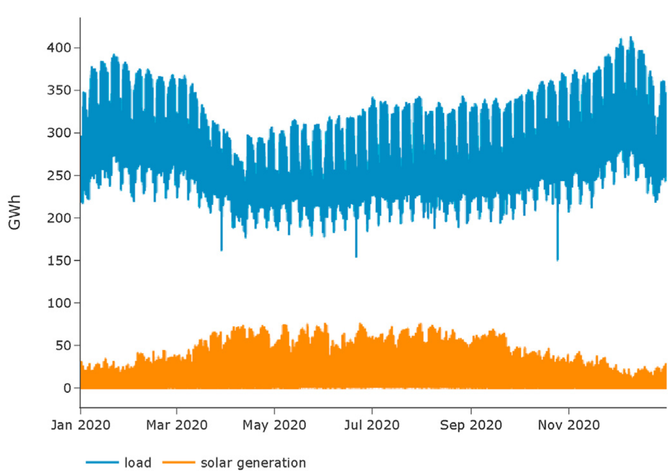

Fig. 1. Hourly solar power generation and load in EU-28 in 2020 [6].

[1] This is the case for example in Northern and Central European countries such as Germany, France or Switzerland. Warmer countries such as Italy or Spain, but also in parts of the US including California, have their peak in summer.

optimistic potential, rising from previous estimates between 7 and 19 TWh/year to more than 25 TWh/year. These results are exciting for mid-latitude regions like Switzerland; however, it remains to be seen whether there is an economic case for such placements.

In this paper, we use the market value approach (see e.g. Refs. [7,8] for the approach and [9–13] for more recent applications) to estimate the market viability of innovative PV panel placements and geometries proposed by Kahl et al. [5]. Following [7], we define market value as the average market price per MWh of output (EUR/MWh) over all hours. In doing so, we account for the fact that the value of electricity depends on the time and location of the production and that generation profiles can be correlated through their dependence on weather patterns [e.g., 7] (insights that the traditional Levelized Cost of Electricity (LCOE) approach cannot capture). We also consider average panel revenue, a measure of the financial viability of new capacities (EUR/kW/year). To this end, we couple two complementary numerical models to explore economically viable placements of PV, both allowing and forbidding alpine locations. Our soft-linked models find optimal placements given local variations in the climate; electricity production and consumption; power transmission capacity; and market prices.

Switzerland is an interesting case study for a few reasons. First, in 2017 the Swiss passed a new Energy Strategy (ES 2050) [14] that requires the share of renewable generation to expand dramatically as the country phases-out nuclear generation. Second, Switzerland has significant potential for solar power (much more than its potential for other renewables [15]) and will continue to invest heavily in expanding this capacity. To date, the vast majority of solar panels are installed on rooftops of private homes and commercial buildings. Third, the Swiss electricity market exhibits similar seasonal patterns to other markets in Europe; therefore, these results are relevant for other countries. Switzerland has an additional constraint and advantage: its large share of hydropower generation (56%) in the electricity mix. In spring and summer, the country is a net exporter due to increased hydro production from snow melt. In fall and winter, it is a net-importer.

We proceed with this paper as follows: In Section 2, we outline the relevant literature. In Section 3, we explain our modeling method, scenario framework, and associated input data. In Section 4, we present our results. Finally, in Section 5, we discuss our results in context and discuss their broader policy implications.

2. Literature review

In order to value the in-feed from intermittent energy sources more equitably, researchers and policymakers have turned away from levelized-cost comparisons to market value estimations [8]. Market value is particularly important for estimating the financial viability of renewable energy sources with intermittent in-feed because market value acts as a proxy for the time-varying energy system balance: Higher prices at time t indicate that additional in-feed will benefit the system; lower prices indicate that additional in-feed is not as beneficial to the system at that time. Borenstein [16] uses simulated and historic wholesale market prices that incorporate average transmission losses and investment costs to quantify the cost-benefit market value comparison of a 10-kW solar installation in California. Comparing the time-varying value of solar to its constant counterfactual and considering the costs of investment and maintenance, he finds that PV did not have a compelling financial case in California, though he admittedly does not attempt to incorporate un-priced market externalities (e.g., environmental and social benefits) nor model the whole energy system.

Using different time and spatial resolutions, other researchers have used market value estimations to measure changes to both the supply and demand sides of energy systems. Hirth [7] uses an open market model to understand supply dynamics in the medium and long-term as the penetration of solar and wind increases and policy levers are adjusted. As the author increases solar and wind penetration in his model, the market value (value factor or value relative to a constant source of electricity) decreases for both solar and wind power, leaving both technologies noncompetitive. He also finds that changes in fuel prices, conventional capacity, interconnection investments, and CO_2 prices influence the value factors of these renewables, though not necessarily in intuitive directions. Winkler et al. [17] also show using econometric methods that fuel prices, conventional capacity, and CO_2 prices are some of the main drivers of changes in market value. Again, these drivers change in importance depending on the penetration rate: At lower shares of renewables, fuel prices, conventional capacity and CO_2 prices are most important while flexibility options become more important as penetration increases. Engelhorn and Müsgens [18] use historical in-feed data on existing wind installations to show the large variation in individual wind turbines' market value relative to the fleet; that is, even if the overall fleet does not have a high market value, individual turbines can have high market values. The author also quantifies the market value variation within Germany due to differences in in-feed price correlations and the consistency of the production yield, showing how regional production can vary significantly.

There are increasingly more studies considering alternative placements and orientations of renewables that could improve their market value prospects. Zipp [19] explores demand-oriented configurations, rather than orientations maximizing gross production, using historical data. He finds that solar orientations in Germany are largely driven by policies that do not consider market value. These results, and those in Ref. [16] that consider different panel orientations in California, suggest that load-response investment would improve market values of solar if supported by appropriate policies.

We contribute to the literature in several ways. First, we quantify the market value of placing solar PV panels in mountainous areas. Second, we endogenously consider feedback effects between electricity prices and solar placement to ensure that the resulting market values are not subject to cannibalization effects. Third, we optimize the market value of solar PV placements in alpine and non-alpine regions under different weather scenarios and CO_2 price scenarios.

3. Methods

To calculate the market value of PV placement strategies, we soft link two models: OREES (Optimized Renewable Energy by Evolution Strategy) [20,21] and Swissmod [22,23]. We couple the models to leverage the strengths of each and iterate one with the other until the prices and placements converge to an equilibrium (Fig. 2). For reasons detailed in 3.1.1 and 3.1.2, the two models cannot be combined into a unique entity.

We organize our analysis by comparing two main optimization scenarios (mountain and no-mountain placements) that we compare to a business as usual scenario. Both scenarios begin with the same initial conditions (step 1 in Fig. 2): time series of observed market prices [24]. Those time series are fed into the objective function of OREES that explores the feasible space of PV locations in Switzerland and identifies the placements that generate the most revenue given grid constraints. The optimization includes or excludes mountain locations, creating the two scenarios.

For each scenario, when the optimal PV placement is found (step 2), the corresponding power generation time series is used by Swissmod to compute resulting electricity prices as well as other

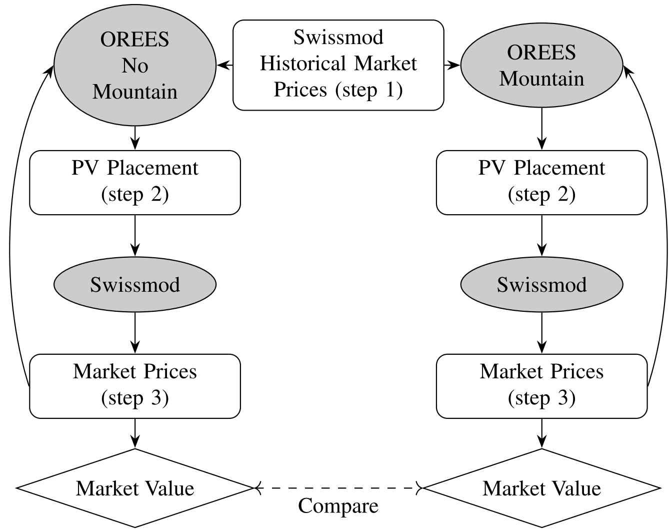

Fig. 2. Model iterations.

market related indicators (step 3). The new market prices are then used by OREES to optimize the PV placements once again. We repeat this process until the models converge: The PV placement and corresponding revenues reach an equilibrium and do not change significantly anymore between iterations.

3.1. Models

3.1.1. Swissmod

Swissmod [22,23] is an electricity market dispatch and load-flow model that represents the Swiss wholesale electricity market in a high spatial (nodal) and temporal (hourly) resolution. In its original formulation, Swissmod represents the entire transmission network of Switzerland (220 and 380 kV), the interconnections with Switzerland's neighboring countries as well as the cross-border connections in Europe (207 nodes and 450 lines) using a DC load flow approach [25,26].[2] In this paper, Swissmod is used as a zonal model in an aggregated way. Each country is represented by a single node, with commercial import-export structures between interconnected countries being limited by net transfer capacities (NTCs). This results in a single market clearance and a single price (compared to multiple nodal prices) per country, which better reflects the current design of electricity markets in Europe.

The objective of the model is to minimize total generation costs under given demand levels. The model is deterministic, assumes a perfectly competitive market with perfect foresight and considers a whole year in hourly resolution. Due to the high dependence of the Swiss electricity market on hydropower, the model contains a detailed hydropower operation model of individual hydro power plants (run-of-river, storage and pumped-storage) and their interaction within cascade structures (interconnection and water flow).

Swissmod is coded in GAMS (General Algebraic Modeling System) and solved using the IBM CPLEX solver and the Gurobi Optimizer. A detailed model description can be found in Refs. [22,23,27].

The advantage of using Swissmod in combination with the OREES model (see next section) is on the one hand that Swissmod allows the simulation of future price developments, which are

[2] In addition to Switzerland, the countries considered in Swissmod include Austria, Germany, France, Italy, Belgium, Denmark, Spain, Great Britain, Luxembourg, the Netherlands, Norway, Poland, Portugal, Sweden, Slovenia, Slovakia, the Czech Republic, Hungary and the United Kingdom.

needed to simulate revenue-maximizing PV placements under future conditions. On the other hand, Swissmod enables the consideration of possible feedback effects of PV placements on market prices.

3.1.2. OREES

OREES shares many features with Swissmod: the high-voltage transmission grid of Switzerland and connections with the neighboring countries, the distributed electricity consumption and production from hydropower facilities, and a representation of the water inflow into the hydropower infrastructure. OREES does not consider the electricity market and is thus much faster at simulating an entire year, which is essential for the optimization of PV placement described below. Like Swissmod, we run OREES with an hourly resolution for each considered year. The model uses spatially distributed hourly time series of electricity consumption, production from run-of-river plants and PV panels, water inflow into the hydroelectric reservoirs and the hydropower plants specifications. Bartlett et al. [21] describe in detail how these data are fed into the optimal power flow algorithm of the MATPOWER library [28].

OREES has an external optimization layer that allows to explore the feasible space for PV placements [20]. Based on evolution strategy, this layer successively generates PV placement scenarios of a specified total production; computes the corresponding spatially distributed production time series; and using the power flow model, simulates the behavior of the electric and hydropower systems given these choices of PV placements. Only solutions that are compatible with the grid infrastructure are allowed.

Concretely, the evolution strategy iteratively displaces fragments of the installed capacity of PV connected to each electric grid node, decreasing the amount on certain nodes and increasing it on others. Starting from a quasi-homogeneous distribution of installed capacities, the algorithm relocates them in order to maximize our objective function: the country-wide averaged market value of panel capacity. This evolution occurs across 169 electric nodes and on a spatial grid of 1.6×2.3 km which corresponds to the satellite-derived radiation data used in the SUNWELL model (details in 3.2.2). The total installed capacity varies at each optimization step to keep an annual production of 25 TWh. The local geometry of PV panels (tilt and azimuth in each grid cell) is optimized once and for all at the initialization phase. In each location, tilt and azimuth are chosen to maximize revenue, given the market prices provided by Swissmod. More detail concerning the panel geometry is provided in 3.2.

Dujardin et al. [20] used this optimization scheme to minimize the amount of required import in Switzerland by optimizing generation mix and location of PV and wind installations. In the present work, we only optimize PV location to maximize the average revenue of panel capacity under the constraint of a fixed total production of 25 TWh for each considered year.

3.2. Scenarios

3.2.1. Scenario setup

To quantify the impact of different PV placement strategies (business as usual BAU, No-Mountain, and Mountain) on the market value of PV, we apply the scenario setup shown in Table 1. Aside from differing the PV placement space, in each scenario setup we also take additional factors that can influence the market value of PV into account and do some robustness checks. That is, we consider changes to the European and Swiss electricity system, the price of carbon, and the weather (e.g., Ref. [7]). As a starting point, we consider the future European and Swiss electricity systems in 2025. In order to take into account the continuous change in generation structures as part of the energy transition (less conventional technologies, more renewables), we also analyzed the system in 2040. To account for the significant impact of the CO_2 prices on the marginal costs of fossil power plants and thus on the wholesale electricity price, we use the three CO_2 price scenarios described in 3.2.2. To consider the impact of weather on PV generation and the resulting impact on market values, the weather years 2013–2015 are analyzed. These years were chosen because they capture a range of weather conditions such that we feel confident in the robustness of our results. Since the model iteration process used in this paper is resource intensive, we do not calculate all possible cross-combinations (of system year, CO_2 price scenario and weather year). Furthermore, we do not account for the spatial variability in installation costs throughout the country. While alpine installations tend to be more expensive, the costs for individual sites vary strongly depending on availability of road access and existing grid connections.

Table 1
Scenario setup.

System	CO_2 price (EUR/t CO_2)	Weather	PV placement
2025	TYNDP Best Estimate (BE) (25.7)	2013	BAU No-Mountain Mountain
		2014	BAU No-Mountain Mountain
		2015	BAU No-Mountain Mountain
	TYNDP G2C scenario (56)	2015	BAU No-Mountain Mountain
	TYNDP GCA scenario (126)	2015	BAU No-Mountain Mountain
2040	TYNDP GCA scenario (126)	2015	BAU No-Mountain Mountain

3.2.2. Input data

In this paper, we consider the Swiss and European electricity system in 2025 and 2040 based on the TYNDP 2018 [29] “Best Estimate” (BE) and “Sustainable Transition” scenarios. Accordingly, in Swissmod, we base the generation capacities, in-feed (except PV in CH) and demand on TYNDP 2018. For Switzerland, we replace 25 TWh of nuclear generation (rounded 20-year average [30]) with the same amount of solar PV generation, for which we consider various placement scenarios from the OREES model. With regard to demand, in-feed profiles from renewable energies, and water inflows for Swiss hydropower, we run our models with three weather years: 2013, 2014, and 2015. These years represent average (2015), above-average (2013) and below-average (2014) years for Switzerland in terms of the annual electricity demand relative to the average over the last 10 years [30]. To generate the corresponding Swissmod data for the three weather years for the future system, we scale the profiles and relative annual differences for demand [31,32] and renewable in-feed (except for PV in CH) [33] for the years 2013, 2014 and 2015 to TYNDP 2018 [29] values. For Swiss PV, we use the simulated values from the SUNWELL/OREES models for the respective weather years (see below), and for the water inflows, we rely on the data generated by Ref. [23].

To limit cross-border trade in Swissmod, we use the NTC values for all European countries included in the model from TYNDP 2018 [29], matching to the closest available year in the source dataset. With regard to fuel and carbon prices, we also rely on the data from TYNDP, taking into account three sensitivities with respect to the

CO_2 price, a scenario where coal is before gas in the merit order (BE scenario, CO_2 price of 25.7 EUR/t CO_2 [29]), a scenario where gas is before coal in the merit order (G2C scenario, CO_2 price of 56 EUR/t CO_2 [34]) and a scenario in which "Global Climate Action" (GCA scenario, CO_2 price of 126 EUR/t CO_2 [29]) is undertaken.

We generated all input time series needed by OREES (solar radiation, hydropower, demand) using the procedure described in Refs. [21,35]. These data correspond to the historical data for 2013, 2014, and 2015. Power generation from PV panels is computed by the SUNWELL model [5], which models the direct, diffuse and ground reflected solar irradiance perpendicular to the surface of a solar panel of given tilt and azimuth angle at hourly resolution. SUNWELL uses Meteosat Second Generation [36] satellite imagery and employs the HelioMont [37] algorithm to derive solar irradiance incoming to the earth's surface on a 1.6 × 2.3 km grid. Solar energy production is computed in each grid cell and for each hour of the considered years given the (annual) optimal geometry OREES uses this grid for the optimization, choosing the amount of panel capacity installed in each grid cell. "Optimal geometry" refers to the panel tilt and azimuth angles that generate the highest revenue. The optimal geometry depends on the temporal patterns of electricity prices, on the regional weather patterns, and local topography. High production at times of high prices is desirable. Furthermore, azimuth angles deviating from south are advantageous if preferential cloud cover or shading persistently diminish the direct solar irradiance during some part of the day. The optimal tilt angle favors production during the time of the year that provides the most energy at times of highest electricity prices. Local conditions such as cloud cover and surface albedo (especially in the presence of snow) have a strong effect on this dynamic.

3.2.3. Mountain, No-Mountain and BAU scenarios

As mentioned in 3.1.2, OREES generates maps of installed PV capacity on a 1.6 × 2.3 km grid. The solution space we explore in the optimization is constrained by the maximum amount of PV panel area that can be installed in each grid cell. The Mountain and No-Mountain scenarios are created using different maps of available PV panel area.

For the Mountain scenario, we use the same map as the one described in Dujardin et al. [20]. This map was constructed with a Geographical Information System (GIS) analysis at 50 m resolution. Using datasets [38,39] from the Swiss Federal Office of Topography, we include locations that are: lower than 2700 m-above-see-level (m.a.s.l), at least 150 m away from slopes steeper than 30°, within 500 m of a road. We exclude the Swiss national park and north facing slopes and only consider the following surface cover types suitable (as defined by The Corine Land Cover inventory [40]): urban fabric; industrial or commercial units; non-irrigated arable land; permanently irrigated land; pasture; heterogeneous agriculture areas; natural grasslands; bare rocks; and sparsely vegetated areas. In each permitted location, we allow a maximum coverage of 5%, corresponding to a national potential PV area of 600 km^2. This high-resolution map of PV potential is then aggregated to the coarser 1.6 × 2.3 km grid.

For the No-Mountain scenario, we lower the elevation limit to 800 m.a.s.l, which reduces the PV potential area to 450 km^2. The PV potentials for both scenarios are depicted in Fig. 3.

In addition to optimizing PV installations for the Mountain and No-Mountain cases, we computed the market value generated by a business-as-usual (BAU) scenario in which PV installations are homogeneously distributed in urban areas (Fig. 4) and have a typical south-facing and 23°-tilt geometry. This third scenario does not need to be optimized by ORESS as the PV placements are predefined. Swissmod directly uses the time series of power generation by this particular constellation of PV to compute the associated market value. We consider BAU as representative of the conventional, currently adopted strategy of PV installation on rooftops and compare it to the optimized scenarios in the analysis.

We used the weather year 2015 for an initial and extended analysis of our 2-model approach. More specifically, we used the three different (CO_2) price scenarios from TYNDP (BE, G2C and GCA) and iterated the two models four times in order to validate the stability of the procedure. Between the first iteration of the 2-model approach and all consecutive iterations, the variations in market values and PV placements were smaller than 0.2%. The 2-model approach is thus stable and the changes in electricity generation from PV in Switzerland from one iteration to the next do not impact sufficiently the electricity market to require multiple iterations in order to reach an equilibrium. After only one iteration, a solution sufficiently close to the global optimum is reached. Consequently, for the weather years 2013 and 2014, we iterated the models only twice. Similar to 2015, only small variations of 0.1–0.4% were observed between those two iterations.

4. Results

In this section, we first present the results for the weather year 2015, given the three CO_2 price scenarios and the two system conditions (2025 and 2040) and then present the results for 2013 and 2014 for the BE price scenario and the system in 2025 only. Finally, we analyze the inter-annual variations and their link to weather patterns.

4.1. Increased market value

As shown in Table 2, the optimized scenarios (No-Mountain, Mountain) have higher market values than the BAU scenario. The increase in market value of energy is moderate (between 1.29% and 6.55%) and is due to a better alignment of production with demand, i.e. more production in winter when demand (and accordingly prices) is higher. The increase in market value of capacity is however quite large (between 8.10% and 21.98%) and can be explained by the higher yield of panels in alpine areas. We can also observe that the No-Mountain scenario is positioned between the BAU and alpine scenarios in terms of performance. Additionally, the generation of the targeted 25 TWh in 2015 requires 120.21 km^2 of PV panel area (considering an efficiency of 15%) or 18.03 GW_{peak} under the BAU scenario and 104.04 km^2 or 15.61 GW_{peak} under the mountain scenario (and BE prices). In general, our results show that the altitude constraint that limits our scenarios has a strong impact on the economic performance of the panels: the higher, the better.

Concerning the value factors, we can observe that PV has a market value below the average market price in all scenarios (value factor $<$ 1). However, the value factors increase with optimal placement of the panels, especially when alpine areas are also allowed. It is important to note that value factors can also be increased by more demand flexibility, reducing certain price peaks outside of solar generation hours. Accordingly, a better representation of demand side flexibility could result in value factors closer to 1.

Comparing the three CO_2 price scenarios for the system in 2025, the market values for energy and capacity increase as CO_2 prices (and consequently electricity prices) rise. The added value of PV in the mountains (compared to the BAU scenario) is greatest in the GCA scenario, the scenario with the highest CO_2 price. However, as shown for the market value of energy, a higher CO_2 price does not necessarily increase the added value of alpine PV. Comparing the G2C scenario and the BE scenario, the increase in the market value of energy by allowing alpine PV placement is higher in the BE scenario (although in a similar range). Looking at the value factors

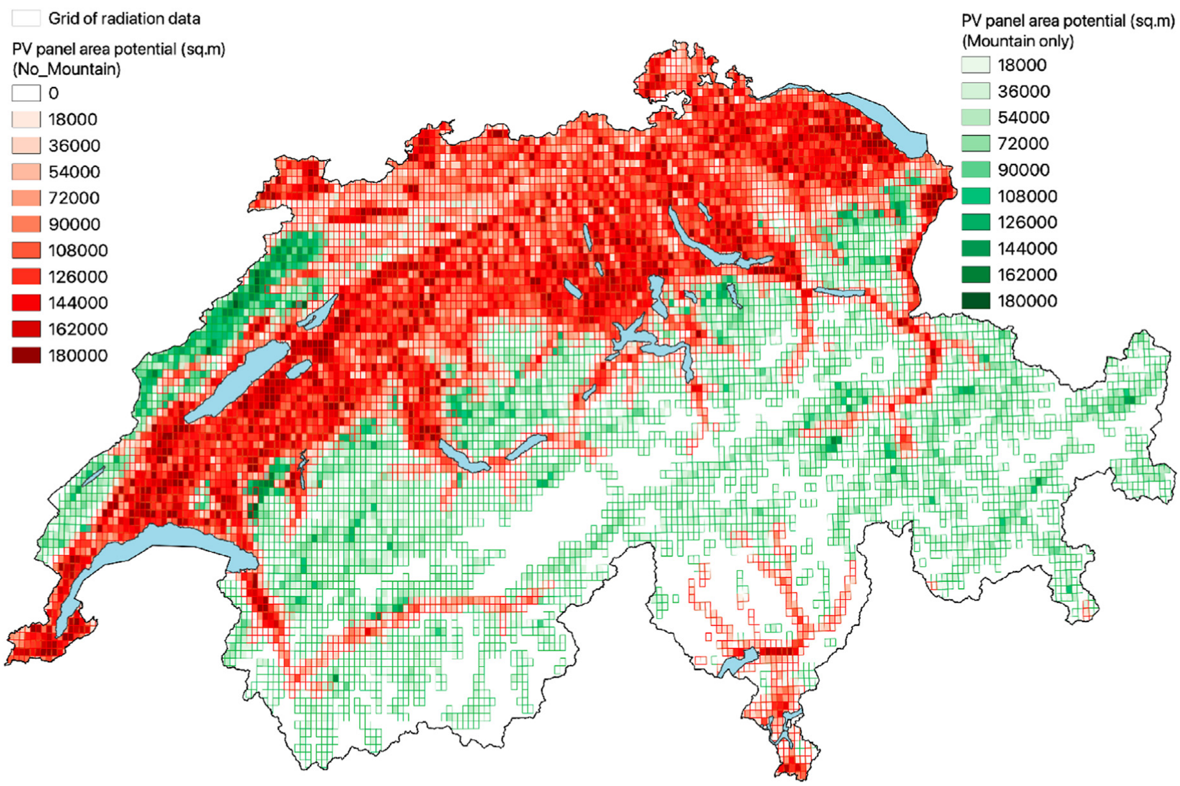

Fig. 3. Potential for PV installation in the Mountain and No-Mountain scenarios.

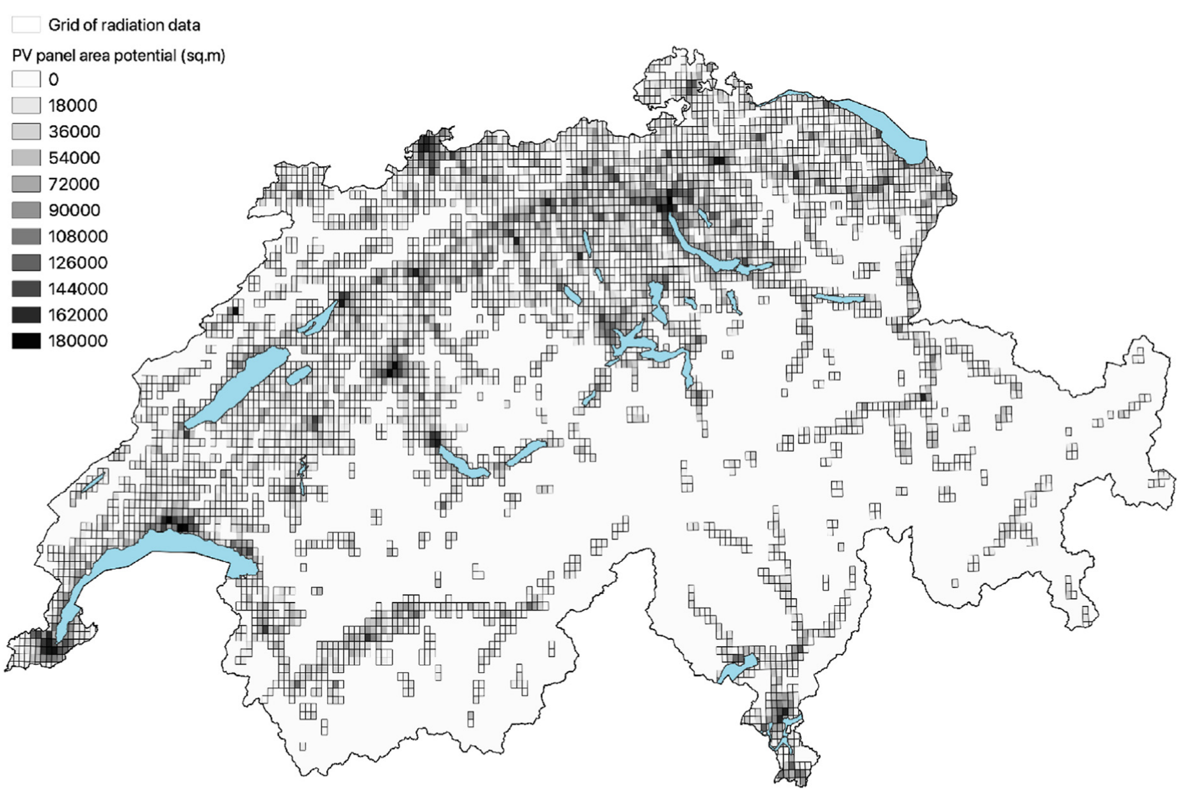

Fig. 4. PV panels installed in the Business As Usual scenario.

for the 2025 system, the highest increase compared to the BAU scenario is observed in the BE scenario, the scenario with the lowest CO_2 price. This suggests that the increase in the value factor is not driven solely by the electricity price level, but rather by the

Table 2
Market value of PV installations (weather year 2015) for the 3 placement scenarios, 3 CO_2 price scenarios and 2 system years.

CO_2 price/System	Placement scenario	Market value of energy from PV (EUR/MWh)	Value Factor	Market value of panel capacity (EUR/kW/yr)
BE/2025	BAU	43.55 (reference)	0.82 (reference)	60.37 (reference)
	No-Mountain	44.17 (+1.42%)	0.83 (+1.89%)	65.3 (+8.16%)
	Mountain	44.95 (+3.23%)	0.85 (+4.37%)	72.01 (+19.27%)
G2C/2025	BAU	60.89 (reference)	0.86 (reference)	84.42 (reference)
	No-Mountain	61.68 (+1.29%)	0.88 (+1.33%)	91.26 (+8.10%)
	Mountain	62.76 (+3.07%)	0.89 (+3.33%)	100.75 (+19.34%)
GCA/2025	BAU	96.25 (reference)	0.84 (reference)	133.44 (reference)
	No-Mountain	97.93 (+1.75%)	0.85 (+1.63%)	144.77 (+8.49%)
	Mountain	100.26 (+4.17%)	0.87 (+3.90%)	160.59 (+20.35%)
GCA/2040	BAU	55.42 (reference)	0.66 (reference)	76.84 (reference)
	No-Mountain	57.26 (+3.31%)	0.68 (+3.62%)	83.83 (+9.10%)
	Mountain	59.05 (+6.55%)	0.71 (+7.12%)	93.73 (+21.98%)

structure and dynamics of the underlying merit order (i.e., steepness [7]).

Comparing the system in 2025 and 2040 (for the GCA CO_2 price scenario), absolute market values fall in 2040. With less fossil plants (especially about 65% less coal generation) and more renewable generation (about +75%) in the system in 2040, the high CO_2 price is less relevant to market prices. More importantly, the high share of renewables lowers price levels, market values and value factors (also called “cannibalization effect”, e.g., Ref. [41]). However, allowing mountain PV in 2040 shows the highest relative increase in market values (and value factors) compared to the BAU scenario. In a system with more renewable energies, alpine PV has a higher value.

For the weather years 2013 and 2014, we optimized the location of PV panels only under the TYNDP Best Estimate CO_2 price scenario, which is more in line with the current market conditions. Similar to 2015, the market value of energy from PV is increased by 5.03% and 2.10% for 2013 and 2014 respectively, between the BAU and Mountain scenario (Table 3). This increase is of 24.54% and 13.90% for the market value of panel capacity. We can observe significant changes between each of the three years, with 2014 (the year with the lowest demand) showing the least improvement in the transition from an urban to a mountain placement scenario. The year 2013, which has the highest demand especially in winter, was the weather year with the biggest improvement. This result confirms the role of alpine PV for winter production.

4.2. Spatial distribution of PV installations

Fig. 5 depicts the spatially distributed results for the three considered years, for the Mountain and No-Mountain scenarios. The color gradient shows the market value of panel capacity in every grid cell, computed with the market price time series of the considered year and the local PV production time series computed by SUNWELL. The areas shaded in blue indicate the locations selected by OREES. As described in Dujardin et al. [20], in the region surrounding each electric grid node, OREES fills the best grid cells first (to their potential) until the optimal installed capacity connected to the node is reached. Consequently, the map of PV installations (surface area per grid cell) is equivalent to overlaying the blue areas of Fig. 5 with the installation potentials of Fig. 3. For this reason, we did not incorporate an additional figure. We can observe in Fig. 5 that some selected areas are common between the two scenarios, and throughout the three years: the Rhone Valley in the south-west and the south part of Ticino (populated Italian border) in the south. Both offer rather high market values and are located below our elevation threshold (800 m.a.s.l). The first benefits from particularly good weather conditions in winter, with the low-altitude clouds (stratus) being trapped further north on the Swiss plateau. The second exhibits a quasi-Mediterranean climate, also favoring high winter radiation (compared to the rest of the country).

Another important observation concerns the overall market value distribution across the country: The Alps exhibit high values compared to the Swiss plateau. Kahl et al. [5] showed that PV panels located in the Alps can produce much more electricity in winter than anywhere else in Switzerland. Higher winter solar radiation and higher ground reflection from snow can be exploited with steeper installations geometry to maximize winter production. In addition, the fact that market prices are higher in winter than in summer explains why the Alps show such high market values. In the Mountain scenario, OREES places as much PV as possible in the Alps, given the land availability and the grid constraints. In 2015, for the TYNDP Best Estimate CO_2 price scenario, 79% of the PV panels are located above 800 m.a.s.l, occupying 52.6% of the potential available above this elevation.

2014 shows the lowest market values of the three years and requires 114 km^2 and 121 km^2 of PV panel area for the Mountain and No-Mountain scenarios, respectively. Those values are 111 km^2 and 124 km^2 for 2013, and 104 km^2 and 113 km^2 for 2015. As described below, 2014 had an above-average cloudiness, especially in the Alps. More PV surface area is thus needed to reach the total production target. Despite the interannual change in PV capacity that is required to reach the desired production target, 78.9% of the installations are common between 2013 and 2015. This value is 75.2% between 2014 and 2015. This indicates that most installations are considered optimal for all years, and thus optimal for a range of weather situations.

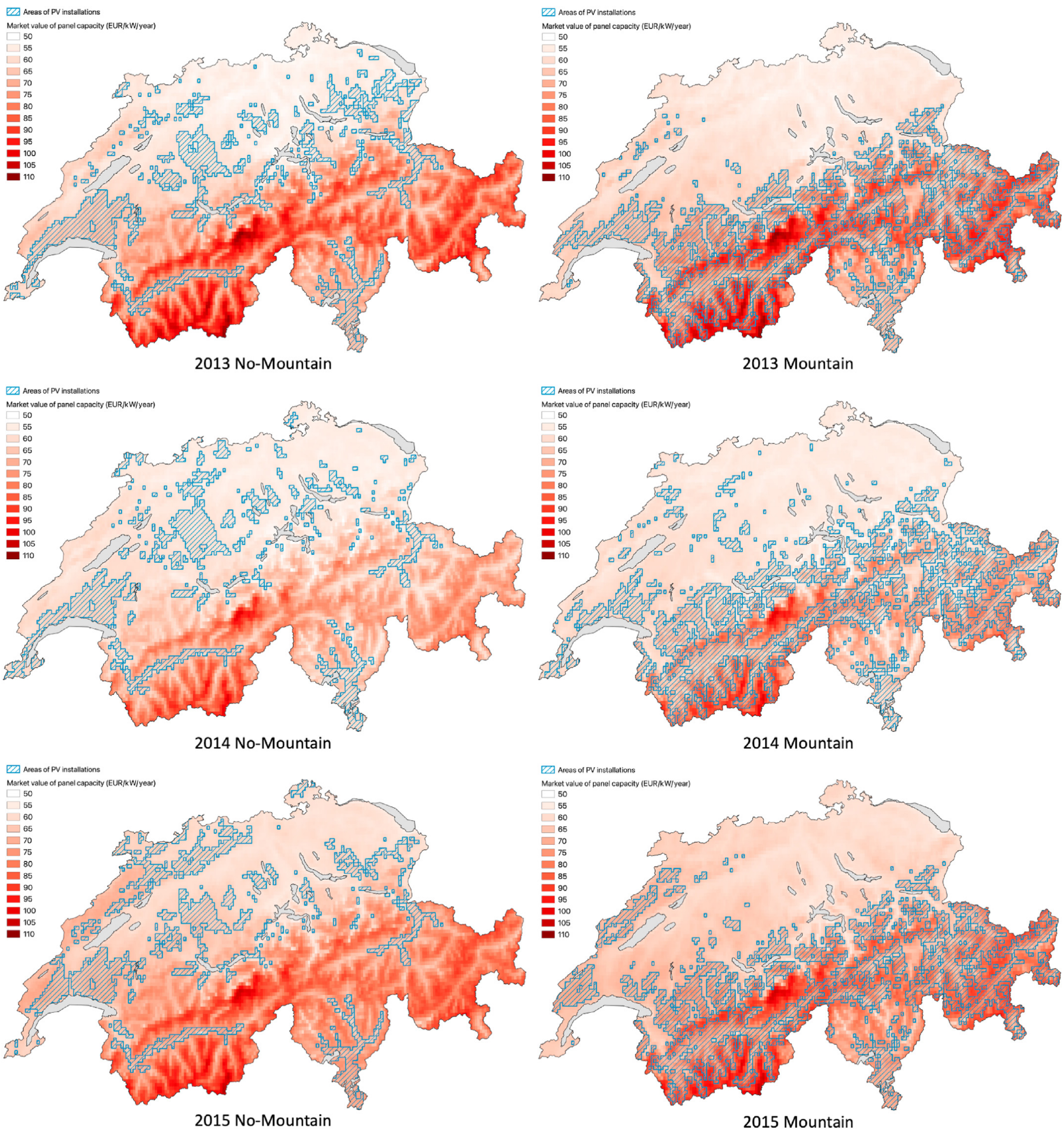

Fig. 5. Market value of panel capacity and optimized location for PV installations for the 3 considered years and the 2 placement scenarios.

We can summarize the PV placement dynamics as follows: The Alps offer the highest market values, independent of the inter-annual weather variations. If installations in certain high-altitude areas are not allowed, some specific valleys should be considered as alternatives. The region surrounding Lake Geneva offers a lot of installation potential and higher market values than other Swiss urban centers.

4.3. Weather driven performance

Of all three years, 2013 shows the biggest contrast in market value between alpine and non-alpine regions, as we can observe in Fig. 5. 2014 is characterised by overall lower values, across the entire country, with a more expressed decrease in the mountain regions. Finally, 2015 is characterized by overall high values in both regions. Those trends are confirmed in Fig. 6 which depicts a temporally more detailed picture of the weather conditions for our

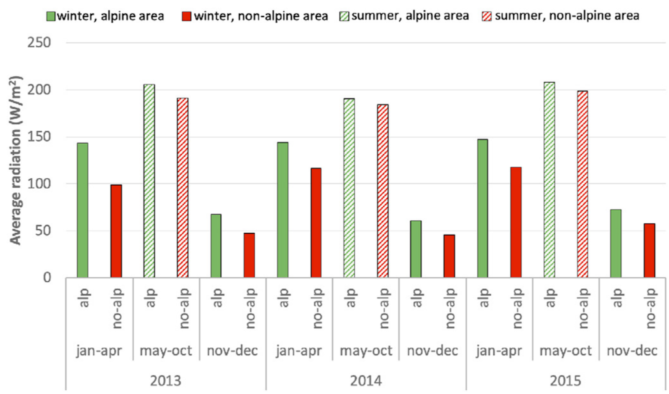

Fig. 6. Average horizontal solar radiation for alpine and non-alpine areas.

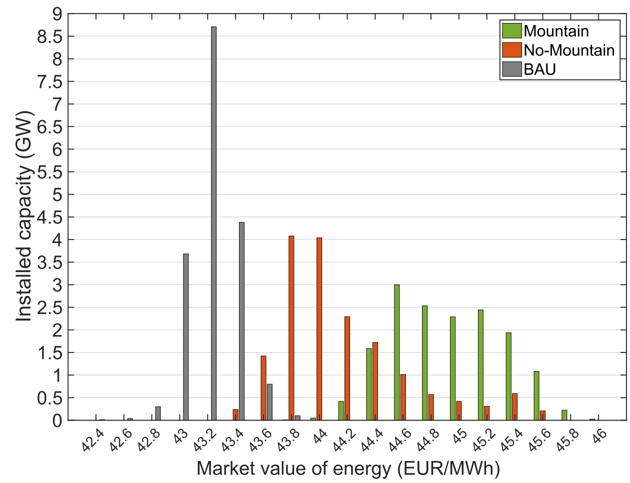

Fig. 7. Distribution of the market values of energy for the optimized PV placements of the three scenarios under the TYNDP Best Estimate CO_2 price for 2015.

considered period. The biggest differences between mountain and non-mountain areas occur in each season of 2013. The summer of 2014 and end of the year show particularly low radiation values. We can conclude that the market value of panel capacity is strongly driven by the weather patterns occurring on seasonal timescales and that our optimization of PV placements took advantage of the differences between regions to increase this market value.

4.4. Spatial heterogeneity of market value

Tables 2 and 3 show the average performances of the three scenarios. Figs. 7 and 8 depict a disaggregated view of these performances, with the distributions of the market value of all PV panels in 2015. The panels in the BAU scenario, represented in grey, show an almost Gaussian distribution of revenues, centered around 43.2 EUR/MWh and 61 EUR/kW/year. For the market value of energy, we can see a clear separation between the distributions of the three scenarios. The No-Mountain scenario exhibits a long tail, indicating that some panels have the same market value of energy as panels from the Mountain scenario. As already observed in Table 2, the relative differences between scenarios are small.

The distribution of market value of panel capacity for the Mountain scenario reveals an important piece of information. The long tail towards high revenues indicates that a considerable amount of installed capacity offers much higher revenues than the average value of the scenario, which is already 19.27% higher than the one from BAU. More than 1 GW of capacity offers revenues higher than 81 EUR/kW/year. This should be compared to the 61 EUR/kW/year that conventional urban PV panels offer during the same time.

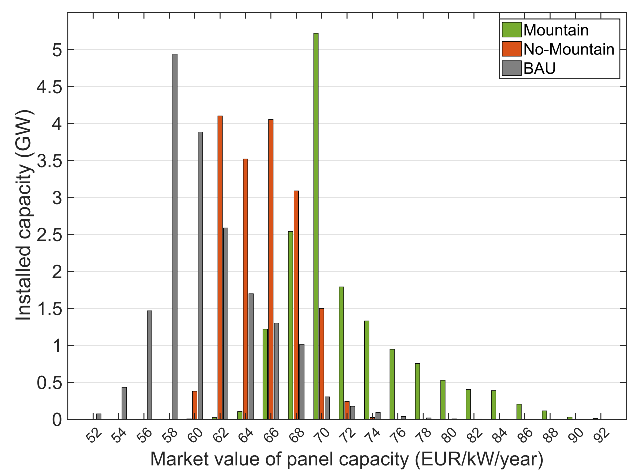

Fig. 8. Distribution of the market values of panel capacity for the optimized PV placements of the three scenarios under the TYNDP Best Estimate CO_2 price for 2015.

5. Discussion

Our results show that placing photovoltaic installations in alpine areas can increase the market value of the produced electricity. We therefore add to the literature that discusses measures to

Table 3
Market value of PV installations (weather year 2013 and 2014) for the 3 placement scenarios under the TYNDP Best Estimate CO_2 price scenario for the system in 2025.

Year	Placement scenario	Market value of energy from PV (EUR/MWh)	Value Factor	Market value of panel capacity (EUR/kW/yr)
2013	BAU	44.63 (reference)	0.82 (reference)	56.41 (reference)
	No-Mountain	45.59 (+2.14%)	0.84 (+2.49%)	61.27 (+8.63%)
	Mountain	46.88 (+5.03%)	0.87 (+5.74%)	70.25 (+24.54%)
2014	BAU	43.01 (reference)	0.82 (reference)	56.01 (reference)
	No-Mountain	43.16 (+0.33%)	0.82 (+0.42%)	59.25 (+5.77%)
	Mountain	43.92 (+2.10%)	0.84 (+2.48%)	63.80 (+13.90%)

increase the market value of renewable generation including alternative configurations for renewable generation technologies (such as weak wind turbines [9] and solar panel tilt [42]) or flexibility options in the power system (such as hydrogen production [43], storage [44], demand side management [45]) or a combination of the two [46]. Whereas we confirm the cannibalization effects seen in the literature for high renewable scenarios (see. e.g. Ref. [7]), we also show that the relative value of alpine PV placements is even higher in systems with high shares of renewable generation.

. One of the main limitations of our study is the limited representation of demand side flexibility. While improved demand side management will increase the value factor and thereby the system value of non-dispatchable generation, it will at the same time reduce some of the gains from alpine PV generation. Another limitation is that we do not allow for curtailment of PV when determining the optimal placement of PV panels. However, from an economic perspective, some degree of curtailment may be socially optimal (e.g., Ref. [47]). If we allowed for curtailment, the share of alpine PV would likely be even higher. Most of the load in Switzerland is in non-alpine areas whereas production is mostly concentrated in alpine areas (especially hydropower), thus production-related grid constraints are more binding in alpine areas than in non-alpine areas. Curtailment would allow larger capacities to be installed in the mountains before grid congestion occurs. Another limiting factor in our modeling approach is the rather coarse resolution (1.6 $\times$ 2.3 km) of the radiation data, which is not sufficient to accurately account for all the topographic shading in the Alps. This results in an underestimation of the potential in certain, well exposed, locations and in an overestimation in other locations that have strong shading. We expect that the overall performance of the scenarios remains essentially the same if higher resolution datasets would be available and used. However, with such resolution, the tail of the distribution of market value of panel capacity for the alpine placements (green in Fig. 8) is expected to be even longer, with some locations offering even higher revenues. Furthermore, for a holistic cost-benefit calculation of alpine PV, an important question remains: What is the additional investment cost of such installations? Such installation costs are difficult to calculate in a generic manner, especially in alpine environments. Road access and proximity to existing electric infrastructure, as well as project size, have a strong impact on the investment cost. Given the well-developed road and grid infrastructures in Switzerland, many locations could offer great competitiveness, but it remains to quantify such installation costs in a spatially distributed way. The advantage of alpine solar installations for the electric system as a whole was demonstrated through their increased value factor. Despite the intrinsic correlation between the various PV installations, and mismatch with demand peaks, alpine PV strongly reduces the need for storage. We applied the storage model described in Ref. [35] to the various time series used in the BAU and Mountain scenarios (2015, BE). While BAU needs 1.83 TWh of storage capacity and 12.60 GW of charging power, the mountain scenario requires 61% less storage (0.72 TWh) and the charging power is reduced to 10.76 GW. Hence, alpine PV might not strongly decrease power mismatch, but mitigates the need for large storage capacities. This advantage can counterbalance the increased installation costs of alpine PV, especially if the European electric grid is impacted by large amounts of correlated PV generation. The construction of PV plants in the Alps also raises the question of the social acceptance of such projects. However, at least for Switzerland, a relatively high level of social acceptance can be observed, whereby the environmental impact, ownership and design of the PV panels can have a major influence on social acceptance [48]. Furthermore, Switzerland's alpine areas are already impacted by civilization, offering considerable surface area where the addition of PV panels would not be the only “disturbance”.

6. Conclusion

We explore the market value of PV panels located in alpine regions of Switzerland. We show that placement at higher elevation can result in increases in average market value of panel capacity of up to 25% relative to non-alpine installations. We also show that for the first 1 GW of capacity revenues increase by 33% (TYNDP Best Estimate scenario). The future role for alpine PV looks promising based on our results since the highest increase in value factor can be observed for a system with a high share of renewable generation (2040 system).

Data availability

The data that support the findings of this study are available upon reasonable request from the authors.

Contributions

J.D. contributed to the research question, developed the version of the optimization model (OREES) for maximum revenues from PV panels, ran the model, analyzed the results and contributed to the writing of the paper.

J.S. contributed to the design of the study, development and model coding of the Swissmod model, result analysis and to writing of the paper.

I.S. contributed to the design of the study, development and model coding of the Swissmod model, and to writing of the paper.

M.S. contributed to the design of the study, the coding and running of the Swissmod model, and the writing of the paper.

A.K. developed the SUNWELL model, contributed to the research question and to writing the paper.

R.L.-P. contributed to the research question and to writing the paper.

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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