Strategic PV expansion and its impact on regional electricity self-sufficiency: Case study of Switzerland

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A B S T R A C T

Solar photovoltaics (PV) will play an important role in decarbonising the energy system. To date, most assessments of PV transition pathways focus on least-cost aspects, without neither considering the time needed to achieve a substantial PV deployment, nor the impacts on regional electricity supply equality. In this work, we propose two alternative PV expansion strategies for Switzerland: The first strategy prioritises the most productive roofs and reaches national PV targets by exploiting the minimum number of rooftops, while the second strategy aims at maximising regional self-sufficiency as proxy of PV supply equality. Both strategies are assessed for several PV expansion scenarios using real hourly PV potential data for the entire Swiss building stock. The scenarios are compared to hourly electricity demand profiles for the residential and service sector. Results suggest that when employing the first strategy, at least 46% of suitable rooftops – mostly large roofs with low tilt angles – are needed to reach Switzerland’s 2050 PV expansion target of 35 TWh. For the projected electricity demand in 2050, this leads to annual electricity self-sufficiency in about 40% of Swiss districts. This percentage can be increased to over 70% by following strategy two to maximise self-sufficiency – which may feature several economic and societal advantages – at the cost of covering 86% of suitable rooftops with PV. The findings may support policy makers and local utilities to find efficient and equitable pathways for a decentralised PV expansion, while at the same time reaching the ambitious national renewable energy targets within due time.

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1. Introduction

In many countries without large wind potentials, such as in Switzerland, solar photovoltaics (PV) will play – along with hydro power – a crucial role in the decarbonisation of the energy systems. This decarbonisation is vital to reach the targets set out in international and national energy strategies such as the “Paris Agreement” (COP21) [1] or the “European Green Deal” [2]. At the national level, Switzerland’s “net zero” strategy aims at increasing its domestic PV electricity generation from 2 TWh [3] to about 35 TWh by 2050 [4]. This would amount to around 40% of its future total electricity generation.

Small-scale, decentralised PV feature a higher social acceptance than other renewable technologies such as wind [5], as PV can be well-integrated in buildings and even used as architectural design elements [6]. Large rooftops on buildings feature hereby the largest potential for such large-scale deployment of additional PV [7]. However, as the absolute PV potential of individual rooftops may vary by several orders of magnitude depending on their available area and irradiation profile [8,9], a non-strategic (i.e. random) expansion may become too slow to reach the national targets in time. Therefore, PV expansion must be pursued in a strategic manner such that the required timely increase in absolute installed capacities can be achieved.

Realising such a rapid PV expansion raises several challenges, on the one hand for national policy makers and on the other hand for regional electricity grid operators (utilities). As the expansion of rooftop PV will take place in a decentralised manner at a regional (local) scale, policy makers need to develop context-specific strategies to account for small-scale socio-technological regimes [10], while electricity grids have to be shaped and sized according to local demand and supply requirements [11].

These challenges cover environmental, technical, economic as well as social aspects. To date, environmental and techno-economic aspects have been the main focus in the literature [12,13]. However, social aspects have gained in attention in recent years, putting the social acceptance of PV expansion as well as regional electricity supply equality at the centre of the research [14-16]. These studies argue that a purely cost-driven PV expansion would result in an uneven allocation of PV related investments, jobs, etc. across a country, thus making some regions “winners” and some regions “losers” of the national energy transition strategy [14,15]. Consequently, in regions that benefit less from the national PV expansion strategy, there may be less of an overall acceptance and support for that strategy. In contrast, a regionally equitable PV expansion features, despite higher costs [16], several advantages as “benefits” and “burdens” are distributed more evenly across regions [17].

These advantages include – among others – a more resilient PV electricity generation on the national scale, due to more variability and hence a lumped risk towards regional weather conditions. On the regional scale, an equitable PV expansion catered to local needs in terms of demand and transmission capacities can increase local grid stability and reduce costly grid reinforcement [18]. In this context, Gupta et al. [19] proposed a method to estimate the PV generation hosting capacity of medium voltage grids and how to extend it through energy storage systems (e.g. batteries). Drechsler et al. [20] and Pfenninger et al. [21] could even show that an equitable PV expansion may result in a higher overall system efficiency due to lower costs for storage and transmission. Eventually, regions with high local PV integration benefit from lower electricity prices in times of global energy scarcity since more market-independent [22], low-price PV electricity can be generated and does not have to be auctioned at the wholesale market at substantially higher prices [23].

Motivated by these needs for a rapid, strategic and regionally equitable PV expansion, this paper assesses different deployment pathways for the use case of Switzerland, with a focus on regional self-sufficiency – as proxy of regional electricity supply equity – and the impact of local flexibility options on demand-supply mismatches. Findings may, however, readily be transferred to other countries with similar energy transition challenges and strategies.

1.1. Related literature

In the existing literature, most large-scale assessments of regional mismatches between electricity demand and supply in highly renewable energy systems assess PV in combination with other renewables such as wind or hydro power. These assessments are performed for a country as a whole [24,25], for clusters of different energy-use patterns [26], or for pixels covering an entire region like Europe [27]. Furthermore, electricity grid constrains are modelled in several studies, primarily at the high-voltage transmission grid level [28-30]. Only Gupta et al. [19] modelled distribution grids, which will play a key role for integrating distributed rooftop PV. Despite providing valuable insights regarding potential future power mismatches, these studies all assess PV integration from a techno-economic point of view and do not account for socio-political factors that may also influence PV adoption.

To anticipate where future PV deployment is most successful, an increasing body of literature assesses existing spatial and socio-economic patterns of PV deployment, by identifying typical predictor variables for PV diffusion [31,32] or spatial PV adoption patterns [33,34]. While these studies look retrospectively at past trends, Heymann et al. [35] use a technology adoption model to predict future PV distribution patterns, which are assessed with respect to cost and regional (in)equity. The concept of “regionally equitable” PV deployment has also been assessed and compared to least-cost-based approaches at national [16,36] and European [37] scales. These studies argue that a simple cost-minimisation is insufficient to assure an effective transition towards renewable energy systems, and identify PV as the key technology to enable regionally equitable electricity generation [16].

To date, self-sufficiency has primarily been addressed in individual building energy models [38], which may also be applied at regional scale [39]. Self-sufficiency assessments based on actual (i.e. current) demand and PV potentials have been proposed at city scale [40]. A national-scale study for German districts (NUTS-3) uses scenarios to analyse potential grid reinforcement needs [18]. While these studies assess the total PV capacity and storage required to achieve the modelled self-sufficiency, they do not investigate the number of required installations, their distribution across different urban typologies (urban, suburban, rural) and the magnitude of local excess generation.

Most of the reviewed national-scale studies on PV integration further use a fixed PV panel orientation and tilt angle or normalised production curves based on normal-distribution panel arrangements [41]. While this normal distribution approximation may be suitable for largescale PV generation modelling, it may not hold for modelling more local aspects of PV deployment on an existing building stock as this would systematically increase model errors [41]. National-scale PV potential assessments, which are available for an increasing number of countries [42-45], allow using actual PV potentials in studies of self-sufficiency and flexibility, thus making the results directly relatable to the existing building stock. Assessments of energy self-sufficiency that account for actual PV panel orientation have to date been carried out conceptually for hypothetical systems [46] and at district [47] or city scale [40,48].

1.2. Contributions and novelty

This study aims at closing the research gap between (a) national-scale assessments of PV deployment strategies based on standard PV systems, and (b) regional-scale studies of self-sufficiency for the existing building stock, using Switzerland as a use case. To this end, we propose a novel approach to identify typical patterns of PV deployment and regional self-sufficiency depending on the evolution of the regional electricity demand and supply, the total number of roofs equipped with PV as well as the region’s topology (urban, suburban, rural).

By targeting a rapid PV deployment in line with national and international renewable energy objectives, we propose two PV deployment
strategies: The first strategy prioritises PV deployment on the most productive roofs. This way the number of roofs equipped with PV can be substantially reduced compared to a non-strategic (i.e. random) expansion. In contrast to existing literature, we hereby focus not only on the national PV targets for 2050, but also consider three intermediate expansion targets. The second proposed PV deployment strategy aims at maximising regional self-sufficiency while still prioritising rooftops with high yields, such as to enable a rapid and equitable deployment of rooftop PV from a regional point of view.

To generate PV expansion scenarios for the two strategies, we employ specific hourly PV generation profiles of each individual roof (more than 5 million roofs in total) adapted from a previous work [8]. We show which roofs should be equipped first and how these roofs are spatially distributed over the country. In a next step, we assess how this strategic PV expansion would affect regional self-sufficiency at different temporal and spatial scales. Regional PV supply is hereby compared to the regional electricity demand for a current and a future state with a large electrification of the regional heat and transport sectors.

The comparison of the two strategies provides novel insights into the potential consequences of future PV expansion pathways and allows us to formulate concrete policy recommendations, based on three main research questions addressed in this work:

1. To which extent can a prioritisation of the most productive roofs accelerate the expansion of PV capacities in Switzerland?
2. How would such a strategic PV expansion impact the electricity supply–demand-balance and regional self-sufficiency?
3. By how much can a self-sufficiency-focused strategy reduce regional electricity supply equality, and what are the implied trade-offs?

While a quantitative socio-economic analysis is beyond the scope of this study, the economic feasibility, environmental impact and implications of the proposed strategies for social acceptance and regional equity of PV supply are discussed.

2. Methods and data

To assess a strategic expansion of rooftop PV in Switzerland, we generate (i) hourly PV generation profiles and (ii) electricity demand profiles for the entire Swiss building stock. The hourly PV generation profiles are adapted from an existing large-scale study for Switzerland [8], by proposing a novel method to arrange solar PV panels on flat roofs and integrating the estimation of real hourly PV generation potentials. The methodology to estimate electricity demand profiles combines annual demand models for the Swiss building stock with spatial and temporal resolution. Regional PV supply is hereby compared to the national PV targets for 2050, but also consider three intermediate (more than 5 million roofs in total) adapted from a previous work [8]. Based on the 33% and 90% quantiles of the potential PV generation for the considered years with the lowest (2010) and highest (2011) annual PV yield, to account for the stochasticity of solar radiation patterns. PV panels on flat surfaces are hereby modelled as alternating east and west-facing rows with a tilt angle of 15°, whereby all roofs with a tilt angle below 10° are considered as flat. A comparison with measurement data has shown that this arrangement corresponds well to the current installation practice for PV systems on flat roofs [50]. A summary of the main assumptions for the PV solar yield calculation is provided in Appendix A.

2.1. Hourly PV generation profiles

The potential hourly PV generation is estimated for all existing roofs in Switzerland (building reference year 2018). We adopt the method proposed by Walch et al. [8], which enables the estimation of PV potentials at national scale. The primary inputs to the method in Walch et al. [8] are a dataset of rooftop geometries for Switzerland [9], as well as recorded solar radiation data from satellites for 2004–2015 [49] as average monthly-mean-hourly (MMH) profiles. These MMH profiles contain one long-term mean hourly curve (24 h) for each month.

In this work, we further compute the actual hourly profiles of potential PV generation for the considered years with the lowest (2010) and highest (2011) annual PV yield, to account for the stochasticity of solar radiation patterns. PV panels on flat surfaces are hereby modelled as alternating east and west-facing rows with a tilt angle of 15°, whereby all roofs with a tilt angle below 10° are considered as flat. A comparison with measurement data has shown that this arrangement corresponds well to the current installation practice for PV systems on flat roofs [50]. A summary of the main assumptions for the PV solar yield calculation is provided in Appendix A.

2.1.1. Roof suitability

Based on the hourly PV generation profiles, we classify the suitability of the roofs for PV installation. This classification provides insights into which roof types are most relevant for different PV expansion scenarios. In this study, the suitability of rooftops is based on their specific annual PV yield, which accounts for both the solar irradiation and the available area for PV installation [8]. The specific annual PV yield is defined as the total annual electricity generation (in kWh) of the roof, divided by the total roof area (in m²roof). The total roof area does not only include roof parts eligible for PV installations, but also superstructures such as dormers, chimneys and other areas that are unsuitable for PV panels. Based on the 33% and 90% quantiles of this specific annual PV yield, roofs are classified as “moderate/poor”, “good” and “top”. We also distinguish between “North” (90° < azimuth < 270°) and “South/flat” (90° ≥ azimuth ≥ 270°) facing roofs.

2.2. Electricity demand profiles

The electricity demand profiles modelled in this work include the demand of residential and service sector buildings, as well as the future electricity demand of electric passenger vehicles (EV). Due to the lack of a coherent method for estimating such demand profiles at hourly temporal resolution across an entire country, we propose to combine several energy demand models for Switzerland and calibrate these based on national energy statistics, as summarised below. This approach allows us to model current and future electricity demand, accounting for electric appliances and processes as well as the electricity consumption of electric heaters, current and future heat pumps (HP) as well as future EV. As the electricity demand will be aggregated to municipality scale for the demand scenarios (Section 2.3.2), the proposed approach yields long-term mean electricity demand profiles.

Other means of electric transport (e.g. buses, heavy-duty trucks, trains, etc.) as well as the industrial sector are excluded, as there are no reliable and homogeneous databases available to create hourly electricity demand profiles for these sectors. To study the strategic integration of rooftop PV, the limitation to the residential, service and EV transport sectors is justified by the fact that other sectors are typically not connected to the same distribution (low-voltage) grid levels as rooftop PV.

2.2.1. Building electricity demand

The electricity demand model of the residential sector follows a bottom-up approach, estimating the demand as a function of building
typology (single vs. multi-family homes), construction period, urban typology (rural, suburban, urban) and local climate, based on the Swiss registry of buildings and dwellings (RBD) [51]. While the demand of electric appliances is directly derived from Yilmaz et al. [52], the electricity demand for space heating (SH) and domestic hot water (DHW) combines (i) the energy reference area (ERA), (ii) the annual heat demand [53,54], (iii) the hourly heat demand profile [55], and (iv) the electricity demand per unit of heat demand [56].

The demand model of the service sector follows a top-down approach, which estimates the electricity demand per employee from the Swiss annual energy demand in the industrial and service sectors [57] and hourly demand curves [55,56]. The dis-aggregation of the national demand to the electricity demand per (physical) employee is performed based on the Swiss Structural Business Statistics (SBS) [59]. We differentiate hereby between 6 service sub-sectors (trade, hospitality, offices, schools, hospitals, other services) following Bundesamt für Energie (BFE) [57]. All further details required to reproduce the results are provided in the Supplementary Materials.

2.2.2. Electric vehicles

The hourly EV charging demand is derived from the annual electricity demands for different electromobility scenarios at the Swiss municipality scale, developed by EBP [60], and hourly EV charging profiles estimated by Rüdisüli et al. [61].

The electromobility scenarios project the market penetration of EV such as to reach net zero greenhouse gas emission targets in Switzerland by 2050 [60,62,63]. To this end, the penetration of EV is modelled by a cohort-based fleet and mileage model EBP [60] with mobility data from the national passenger transport model 2017 and the micro-census on transport and mobility (MZMV) [64]. To account for regional differences, socio-demographic factors from a model of an evolving synthetic Swiss population (SynPop [65]) have been combined with data on the vehicle stock and travelled distance (mileage) for each municipality [66] (see Appendix B for further details).

The hourly recharging profiles of EV are also based on MZMV and derived according to the methodology described in Rüdisüli et al. [61] and Pareschi et al. [67]. The resulting hourly recharging profile is linearly scaled to the annual electricity demand per municipality from above.

2.3. Scenario design

The hourly profiles derived as described above are aggregated at municipality scale to assess two PV deployment strategies. For the first strategy, which prioritises the most productive roofs, we simulate four PV expansion scenarios and two electricity demand scenarios, as shown in Table 1. These electricity demand scenarios are used to derive two expansion scenarios for the second strategy, which aims at maximising annual regional self-sufficiency.

2.3.1. PV expansion scenarios (Strategy 1)

The four PV expansion scenarios for strategy 1 represent a national total PV generation of 5, 15, 25 and 35 TWh, respectively. The first scenario (5 TWh) hereby corresponds roughly to a doubling of the currently installed PV generation capacity (2.2 TWh in 2020) [3], and can be considered as a near-term goal for PV expansion. The scenarios of 15 TWh and 25 TWh represent the planned phase-out of nuclear power in Switzerland, whereby 15 TWh would cover the annual generation of Switzerland’s largest nuclear power plants (Leibstadt, Gösgen) and 25 TWh corresponds to a phase-out of all nuclear power [24]. Finally, the 35 TWh scenario represents the target of the Swiss energy perspectives for 2050 [4] and would also partially cover the additional electricity demand from the electrification of the heat and transport sectors.

To obtain the potential hourly PV generation for each of the 2198 Swiss municipalities and each scenario, 5.1 million suitable roofs are ranked according to their annual yield (in kWh) based on their monthly-mean-hourly profiles. The roofs with the highest yield are selected, such that the cumulative sum equals the respective PV expansion scenario. Physical or economic considerations such as structural restrictions or installation costs are out of scope for this assessment. The selected roofs are then aggregated for the analysis in Section 3 in two ways: (i) per super-ordinate district (Bezirk/county), and (ii) per urban typology (rural, suburban, urban). The urban typologies are obtained by applying the mapping proposed in Streicher et al. [53] to the typologies of Swiss municipalities [68].

2.3.2. Electricity demand scenarios

We consider two electricity demand scenarios: (i) a reference scenario representing the current electricity demand (reference year 2020), and (ii) a target scenario representing an electricity demand scenario for 2050 based on the targets of the “Swiss Energy Perspectives 2050+” [4]. The reference scenario is based on the estimation of the current demand (see Supplementary Materials). The target scenario is derived from these through the following assumptions:

1. The annual space heating demand in the residential and service sectors is reduced by 30% and 50% respectively (w.r.t. 2020), owing to building retrofit, renovation, climate change, etc. This is in line with the Swiss targets for space heating demand by 2050 in Bundesamt für Energie (BFE) [4] and EBP [60].
2. 60% of the target SH demand and 70% of the target DHW demand is delivered from heat pumps (HP), in addition to the heat demand already covered by HPs and electric resistive heaters. The remaining heat demand is delivered otherwise, i.e. from biomass, solar thermal or fossil sources. This HP expansion scenario is adopted from Rüdisüli et al. [24].
3. Future HPs are assumed to have an annual COP (or efficiency) of 3.5, which corresponds to the COP of state-of-the-art air-water HPs [24].
4. The electricity demand of a future EV passenger cars fleet is modelled as described in Section 2.2.2, adding a total of 11 TWh of annual EV electricity demand [60]. No EV charging is included in the reference scenario as it does not represent a significant demand to date.
5. Demand for electrical appliances, processes and space cooling (service sector) remains unchanged. This is justified by the expected offset of energy savings by population and economic growth, digitalisation, etc.

2.3.3. Scenarios for increased district self-sufficiency (Strategy 2)

The second proposed PV expansion strategy aims at increasing regional self-sufficiency to as close to 100% as possible, while still minimising the number of required rooftops. To this end, PV is deployed in each district until an (annual) self-sufficiency of 100% is reached (if possible) — starting from the most productive roofs. As this second strategy aims to maximise PV installations as a function of demand, we obtain one resulting PV expansion scenario for both the reference and target electricity demand scenario.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>PV production</th>
<th>Reference (2020)</th>
<th>Target (2050)</th>
</tr>
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<tbody>
<tr>
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<td>5 TWh</td>
<td>PV5-2020</td>
<td>PV5-2050</td>
</tr>
<tr>
<td>15 TWh</td>
<td>PV15-2020</td>
<td>PV15-2050</td>
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<td>25 TWh</td>
<td>PV25-2020</td>
<td>PV25-2050</td>
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<tr>
<td>35 TWh</td>
<td>PV35-2020</td>
<td>PV35-2050</td>
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<tr>
<td>2</td>
<td>Max. self-sufficiency</td>
<td>maxSS-2020</td>
<td>maxSS-2050</td>
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</table>
3. Results and discussion

3.1. Estimated electricity generation and demand

The estimation of the total annual PV potential on all 5.1 million roofs investigated in this study lies at 41.7 TWh, considering all roof tilts and orientations. The roofs with “top” suitability are primarily south-facing/flat roofs, while “moderate/poor” roofs are dominated by north-facing surfaces (see Fig. 1a). These findings are in line with Walch et al. [8], who identify high PV yields in particular for large rooftops of up to 20° tilt angle. Fig. 1b further shows the suitability of roofs for the municipality typologies (rural, suburban, urban). The “rural” and “suburban” typologies account for the highest share of rooftops, while “urban” municipalities represent only around 10% of the roofs. Urban areas also contain an over-proportional amount of “moderate/poor” roofs, likely caused by a high building density and complex roof shapes consisting of many small surfaces with a rather low available area for PV installation.

These numbers show that the targets of the Swiss Energy Strategy of 35 TWh of electricity generation are well within reach, but reaching these targets requires leveraging the potential of sub-urban and rural areas. Urban areas only play a secondary role in the scope of a large-scale expansion of PV. Focusing the expansion of PV outside of urban areas may also benefit the social acceptance, as for example large industrial roofs or agricultural sheds have generally a lower visibility and relevance to the general public.

Expanding PV capacities primarily in suburban and rural areas also anticipates the expected increase in electricity demand due to the electrification of the heat and transport sectors, as shown in (see Fig. 2). In rural municipalities the combined effect of the electrification will – on average – double their annual electricity demand, while it will only increase by about 50% in more urban areas. In some rural municipalities, the electricity demand will even triple compared to their current situation. Such an increase in demand would put substantial additional strain on the local electricity systems, which may be reduced by an increase in local electricity generation from PV.

However, the additional electricity demand of HPs takes place in winter, when the local electricity supply from renewables such as PV is lowest [69]. This seasonal mismatch of electricity demand and supply has to be taken into account when decentralised PV expansion is pursued. Quantifying the spatial and temporal patterns of these mismatches and assessing different ways to reduce them by technological or strategic means will be the main objectives of the following sections.

3.2. Strategy 1: Prioritising the most productive roofs

The comparison of a strategic to a random expansion of PV capacities shows that the number of required rooftops can be drastically reduced with the proposed strategy 1, which prioritises the most productive roofs (see Fig. 3). With a random expansion (red labels in Fig. 3), on average, 84% of all roofs are needed to reach 35 TWh. In turn, if the proposed strategic expansion prioritising the most productive roofs is pursued (blue labels in Fig. 3), only 46% are needed. For lower targets such as 15 TWh, differences between the strategic and random pathway become even larger with 36% vs. 4% of roofs, respectively. In this initial phase of the strategic expansion almost exclusively “top” and “good” roofs are used, leaving roofs with “moderate/poor” suitability to the last stage of the expansion. In other words, if a strategic PV expansion is pursued, a substantial PV yield can be reached with a relatively low number of well-suited roofs.

The drastic reduction in number of rooftops shown in (Fig. 3) has real impacts on the economic and environmental cost of the PV expansion. Economies of scale reduce the cost of installation if fewer but larger PV systems are installed. Furthermore, many of the most productive roofs are flat (see Appendix C.1), which facilitates the
installation of PV systems, as these roofs are more accessible and the PV arrangement can be freely (and optimally) chosen. In addition, prioritising the most productive roofs ramps up the PV capacity much faster. This has a multiplicative effect on the long-term CO\textsubscript{2} emissions, as it avoids the emissions that existing systems would cause before being replaced by PV in case of a slower expansion [70].

To leverage the full potential of these most productive roofs, we need suitable policies and business models [71]. Such policies should also account for regional differences in the rooftop PV potential. For example, reaching the 35 TWh target requires to exploit nearly all roofs in some municipalities, even if overall only 46% of roofs are needed (see Appendix D for details). Putting these municipalities at the centre of efforts to promote PV installation allows policy makers to assign the required resources (human, materials, planning, etc.) geographically, which may allow for a more effective realisation of PV projects.

3.2.1. Electricity supply peaks and load shifting
The nationally aggregated comparison of the monthly-mean-hourly (MMH) PV generation to the electricity demand (Fig. 4) shows substantial PV supply peaks around noon for the 25 and 35 TWh scenarios from March to September, and consistent PV supply deficits in January and December. This means in turn that a large share of PV supply could immediately be consumed during the winter months (October

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**Fig. 2.** Percentage increase of the electricity demand from additional heat pumps (HP) and battery electric vehicles (BEV) as well as their combined effect compared to the current electricity demand distinguished by urban topologies.

**Fig. 3.** Number of roofs needed to reach a predefined PV expansion target (e.g. 5, 15, 25, 35 TWh) with a “strategic” (blue labels) and “random” (red line and labels) expansion.
to February), particularly if accounting for the increased electricity demand from heat pumps in the 2050 demand scenario. However, as the electricity demand from mobility is highest in the evening, this additional demand does not immediately reduce PV surpluses.

The PV surpluses are even more pronounced if real hourly data and a higher spatial resolution (district scale) is considered, with supply peaks that exceed the demand by a factor of $1 - 5$ for the PV35-2050 scenario (see Appendix E). But even during a much earlier phase of the PV expansion, substantial excess PV generation could occur in several districts, which may harm the stability of local electricity grids. This diurnal mismatch of demand and PV supply can be partly offset by means of load shifting, for example through demand side management (DSM), flexible charging of EVs using vehicle-to-grid (V2G) or short-term electricity storage (e.g. batteries).

Our results suggest that an ideal load shifting across 24 h may reduce regional supply peaks by over 60% on average (median). These results, presented in Fig. 5 for each municipality (top row) and district (bottom row), have been obtained through the temporal aggregation of PV supply and electricity demand by a moving sum of a particular number of hours (i.e. time window). Without load shifting (i.e. time window = 1 h) and for the PV35-2050 scenario, the maximum hourly surplus at the municipality scale (top row) is, on average (median, dashed red line), 8.6 times larger than the corresponding hourly demand. In one municipality, this factor is as high as 64. By means of a 24 h load shifting (i.e. time window = 24 h), this maximum hourly surplus can be reduced to a median factor of 3.2. If there is a spatial aggregation from municipality to district scale, the corresponding maximum hourly surplus can be further reduced to a median of 2.5.

These findings underline that load shifting will play a key role in future electricity systems with high shares of PV. Nonetheless, the numbers presented above suggest that despite an ideal 24-h load shifting, several regions may generate substantial surplus electricity. To avoid the curtailment of this excess PV supply – resulting in an effective loss of the generated electricity – long-term solutions such as seasonal storage and sector coupling (power-to-X) must complement effective short-term load shifting strategies [69].

### 3.2.2. Regional self-sufficiency

The remaining surplus and deficit in PV supply, which cannot be offset by load shifting, is the result of the seasonal and regional mismatch of PV generation and electricity demand. This seasonal mismatch, a proxy of the (seasonal) self-sufficiency, varies considerably between municipalities of different urban typologies (rural, suburban and urban), as shown in Fig. 6 for the highest PV scenario (35 TWh). While around half of the rural municipalities reach annual self-sufficiency in the PV35-2050 scenario, not a single urban typology is close to self-sufficiency in this scenario. During the summer season, these differences are even more extreme, with the majority of municipalities (i.e. the entire interquartile range) exceeding 100% annual self-sufficiency (red dashed line in Fig. 6) in rural areas, and remaining entirely below 100% self-sufficiency in urban areas. The future electrification of heating and transport hereby reduces the self-sufficiency of municipalities by roughly one third.

In addition to these differences, the outliers in Fig. 6 show some particularly high surplus generation factors. The seasonal PV surplus of some rural municipalities may exceed their demand up to a factor of 15 in summer and a factor of 5 in winter in the 35 TWh PV scenario of 2050. Over the whole year, this surplus factor for some municipalities can have a maximum of about 5 to 10 depending on the demand scenario.

While this excess generation could be reduced through spatial aggregation to some extent (see Fig. 5), these outliers nonetheless point at significant regional imbalances in the future energy supply. Such a situation would likely be beneficial for local economies in regions with large PV surplus, driving business and creating jobs in the planning and installation of PV systems and the development of energy storage and sector coupling.

However, such large imbalances may also have negative impacts, as they would require costly investments in future grid infrastructure to reinforce regional grid connections. Furthermore, the economic benefits of the PV expansion would be unequally distributed between regions, profiting some and leaving others behind. This may harm the social acceptance of such a centrally-driven strategy.
Fig. 5. Influence of using local flexibility (load shifting) on the maximum surplus generation per municipality and district (rows) in all four PV expansion scenarios (columns) for the target (2050) demand scenario. Load shifting is simulated as a temporal aggregation (in hours) of PV supply and demand over a moving time window with a given duration. Each line represents the maximum surplus factor (PV supply/demand) for one municipality or district as a function of this time window (x-axis).

Fig. 6. Seasonal difference in PV supply and electricity demand per municipality typology and per demand scenario (2020 and 2050) for the 35 TWh PV expansion. Values are obtained as the ratio of total PV generation to electricity demand. The columns show the aggregated mismatch annually (Year), in winter and summer. The red dashed line represents an annual/seasonal demand-supply-equality. NOTE: Outliers above 8 are discarded.

3.3. Strategy 2: Maximising regional annual self-sufficiency

To reduce regional imbalances and their potential negative impacts on electricity supply equality, the second PV expansion strategy (Section 2.3.3) aims at maximising annual self-sufficiency at the district scale. Following this strategy 2, at least 52% and 86% of all roofs need to be equipped with PV to reach optimal (annual) self-sufficiency based on the reference (2020) and target (2050) demand scenarios. These scenarios yield a total national PV generation of 32.5 TWh and 39.6 TWh at a national self-sufficiency of 81% and 70%, respectively.

As shown in Fig. 7, this second strategy implies that some of the PV capacity of districts with low electricity demands (red lines in Fig. 7a) remains unused, while the PV potential in districts with high electricity demand is fully exploited. This results in a self-sufficiency near 100%
Fig. 7. (a) Annual PV supply to maximise self-sufficiency per district (yellow bars), for the electricity demand scenarios of 2020 and 2050 (red lines), and (b) number and share of roofs per district (including their suitability as colours) equipped with PV panels to supply that amount of PV electricity. Each bar represents one district. Fully self-sufficient districts are marked with a red “x”.

Table 2
Percentage of self-sufficient, deficit and surplus districts (rows) for each PV expansion scenario (5−35 TWh, strategy 1) and for each electricity demand scenario (strategies 1 and 2). Self-sufficient districts can cover their annual demand from PV (±20%), deficit districts cover <80% and surplus districts cover >120% of the annual demand from PV. Percentages are relative to 148 districts.

<table>
<thead>
<tr>
<th>Districts</th>
<th>5 TWh</th>
<th>15 TWh</th>
<th>25 TWh</th>
<th>35 TWh</th>
<th>Strategy 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>0</td>
<td>0</td>
<td>8.1</td>
<td>31.1</td>
<td>10.8</td>
</tr>
<tr>
<td>2050</td>
<td>100</td>
<td>100</td>
<td>91.2</td>
<td>52.7</td>
<td>87.8</td>
</tr>
<tr>
<td>Self-sufficient (%)</td>
<td>0</td>
<td>0</td>
<td>8.1</td>
<td>31.1</td>
<td>10.8</td>
</tr>
<tr>
<td>Deficit (%)</td>
<td>100</td>
<td>100</td>
<td>91.2</td>
<td>52.7</td>
<td>87.8</td>
</tr>
<tr>
<td>Surplus (%)</td>
<td>0</td>
<td>0</td>
<td>7.0</td>
<td>16.2</td>
<td>1.4</td>
</tr>
</tbody>
</table>

in many (rural and suburban) districts, while self-sufficiency remains often not attainable in (urban) areas with a large electricity demand. Strategy 2 further implies that many roofs of moderate/poor quality are used (see Fig. 7b), which are primarily small or steeply north-facing (see Appendix C.2). Exploiting such roofs comes at an economic cost, as these roofs are less productive and often more difficult to exploit, for example if they have complex roof shapes that require highly customised solutions.

3.3.1. Comparison to strategy 1
A comparison of the two PV expansion strategies shows that strategy 2 significantly increases the percentage of self-sufficient districts — even compared to the 35 TWh scenario of strategy 1 (see Table 2). The large increase in self-sufficient district is mainly due to avoiding surplus PV generation, as well as a reduction in the number of deficit districts due to the deployment of many small roofs in districts with high electricity demand.

While significantly increasing self-sufficiency, strategy 2 comes at the cost of reduced productivity of PV installations. For the reference demand (2020), this means that slightly more rooftops are exploited as in the 35 TWh scenario of strategy 1 (52% vs. 46%), but the PV yield lies around 2.5 TWh lower. By contrast, the target scenario (2050) of strategy 2 requires almost twice as many rooftops (>85%) to increase the percentage of self-sufficient districts from 41% to 72%, through nearly 40 TWh of PV supply.

3.3.2. Trade-offs between PV generation and self-sufficiency
The above comparison suggests that a combination of the two strategies may be desirable, as it can integrate the advantages of both methods. Such a combined approach may (i) avoid surplus generation in districts with low demand (primarily rural) and (ii) avoid the exploitation of many small roofs in districts with high demands (primarily urban). This may be achieved by exploiting the most productive roofs first (strategy 1), but only if the cumulative PV generation of the respective district does not exceed its annual demand (strategy 2), up until a target PV generation is reached.

For the previously discussed target of 35 TWh of PV supply and the projected electricity demand for 2050, such a strategy would require half the rooftops to be covered, while reaching self-sufficiency in 83 districts (56% of districts, see Fig. 8). As a trade-off for only 4% of more roofs, the number of self-sufficient districts can therefore be increased by 15% compared to strategy 1. Compared to strategy 2, the PV generation and district self-sufficiency is slightly reduced, but the number of required rooftops reduces drastically by 1.8 million (36% of suitable roofs).

The exponential increase in the required number of rooftops for very high PV expansion targets is shown in Fig. 8 for this combined approach (blue line), which is explained by the exploitation of small and north-facing surfaces. This exponential increase contrasts the noticeable increase in the number of self-sufficient districts as the national PV production increases. These curves represent an important trade-off between PV generation and district self-sufficiency beyond a PV generation of around 33 TWh. In other words, if self-sufficiency is to be increased significantly beyond around half of the Swiss districts,
then many poorly suitable rooftops should be exploited. This also has economic implications, as the marginal cost to realise such a PV expansion strategy would likely increase in a similar exponential fashion, becoming more and more costly as less suitable roofs are exploited.

4. Discussion

4.1. Policy recommendations

Findings from this study have direct implications on policy makers and local utilities. We show that the national targets for PV expansion can be achieved even with a relatively low number of roofs, if first the most productive roofs are equipped with PV. In other words, policy makers and local utilities should prioritise the installation of PV on those roofs with the highest absolute solar yield over roofs with high specific yields per area. Such prioritisation may be achieved for instance by paying additional subsidies (feed-in tariffs) to highly productive yet not optimally oriented roofs (i.e. with a lower PV yield per area).

In addition, it is important that owners of such highly productive roofs are encouraged to install PV on their entire available roof area, instead of just meeting their own electricity demand. Otherwise, there will be a gap between the total potential and the actually realised PV supply, resulting in an under-exploitation of the national rooftop PV potential [71].

In order not to jeopardise local electricity infrastructure, the herein proposed rapid strategic PV expansion must take into account local electricity demand and grid structures. This includes the future electrification of the local heat and transport sectors, which will become a substantial additional load in particular on smaller (i.e. rural) grids.

Although quantitative economic assessments are beyond the scope of this study, our analysis suggests that an equitable and at the same time rapid PV expansion strategy would likely increase in a similar exponential fashion, becoming more and more costly as less suitable roofs are exploited.

Policy support, or other economic benefits may result in lower public acceptance of new technologies and increase policy maker’s risks [37].

In order to locally integrate PV at an equitable manner, the use of local flexibility in the demand and supply of electricity becomes essential. This may be achieved both by exploiting temporal and spatial flexibility potentials. Exploitation of temporal flexibility in this respect can be achieved by the employment of short-term electricity storage (i.e. batteries) as well as load shifting and demand side management (DSM) including optimally designed control strategies such as fuzzy cooperative control mechanisms to prevent cascading failure (i.e. through vehicles-to-grid) [72–74] or model predictive control (MPC) for forecasting the dynamic nature of load profiles [75,76]. In turn, spatial flexibility can be exploited by taking into account neighbouring municipalities including their own demand and supply structures such as to take advantage of regional synergies and trade-offs (e.g. common grids and storage infrastructure).

It must be noted, however, that even with an ideal temporal (1 h to 24 h) and spatial (municipalities to districts) exploitation of all flexibility, remaining regional surpluses from PV in some particularly days (mainly in summer) and in some regions are still large (in this study sometimes more than 5-times higher than the corresponding regional demands) and additional measures (e.g. long-term (seasonal) storage and sector coupling/power-to-X) are needed.

4.2. Limitations and future work

While this study comprehensively addresses the technological potential of an equitable rooftop PV expansion at high spatio-temporal resolution, several other aspects that are relevant for such a PV expansion are deliberately excluded within the scope of this work. These aspects include other surfaces than roofs (e.g. facades, open fields, etc.) as well as economical aspects such as local feed-in tariffs, subsidies as well as costs such as for construction and labour. Another deliberately omitted aspect is the combined optimal design of PV systems and decentralised batteries (incl. vehicles-to-grid/building) to maximise the economic viability [77]. Sociological aspects such as the acceptance and willingness-to-pay (affinity) for PV as well as legal (local policies) and structural (roof strength) aspects are not considered. Moreover, no competition for roof areas with other technologies such as solar thermal collectors, etc. are considered. These aspects may be taken into account in future work. Moreover, a least-cost optimisation of self-sufficiency per municipality as well as a detailed study on local grid aspects such as voltage stability and an optimisation to select the rooftops with the maximum power may be conducted. Quantification of the effects of

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Fig. 8. Percentages of exploited rooftops (blue), national (annual) self-sufficiency (orange), districts reaching self-sufficiency (green, 80 – 120% of demand covered by PV) and districts with a deficit (red), as a function of total annual PV production.
the recommended large PV deployment on the decarbonisation of the energy system in terms of costs per avoided CO₂ could be achieved by detailed modelling of the energy system. This could be done in further studies to enhance the impact of the study towards policy makers.

5. Conclusion

This paper presents a novel assessment of PV deployment strategies for Switzerland, aimed at (i) enabling a rapid integration of PV by minimising the number of roofs to be equipped with PV, and (ii) maximising self-sufficiency at the regional scale (administrative districts), such as to reduce supply-demand-mismatches. Based on the national renewable energy targets, four PV deployment scenarios and two electricity demand scenarios for the residential and service sector have been generated at an hourly resolution, based on individual rooftop characteristics of the entire Swiss building stock. To avoid surplus electricity generation in (primarily rural) districts, a second PV deployment strategy is proposed, which maximises annual self-sufficiency at the district level.

We come to the following main conclusions:

First, prioritising the most productive roofs reduces the number of required rooftops from over 80% (random expansion) to less than 50% to reach the national target of 35 TWh of electricity generation from PV, whereby large flat roofs should be exploited first. For intermediate PV expansion targets, this reduction in the number of rooftops is over-proportionally higher, requiring <5% of roofs to reach 15 TWh of PV generation.

Second, the generation of 35 TWh of electricity from PV will cause large generation peaks, in particular during noon from March to September. By load shifting across 24 h, for example through electricity storage or flexible charging of electric vehicles, these generation peaks can be reduced by over 60%. Despite such load shifting, several regions may generate substantial surplus electricity, which could cause strain for local electricity grids.

Third, the proposed strategy to maximise regional self-sufficiency reduces this surplus electricity, while significantly increasing the percentage of potentially self-sufficient districts (±20% of annual demand covered by PV) from around 40% to over 70% for the projected demand in 2050. However, this scenario requires the exploitation of over 85% of the roofs. A combination of the two strategies could achieve annual self-sufficiency in more than half of the Swiss districts, by generating 35 TWh of electricity and exploiting half of the rooftops.

Findings from this study can inform policy makers as well as electricity providers in the design and planning of a large-scale deployment of PV, which is necessary to replace current fossil and nuclear power generation, while achieving the decarbonisation goals of the national energy strategy.

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Appendix A. Assumptions for the PV potential estimation

In Walch et al. [50], the hourly PV yield is computed from the tilted radiation received by each rooftop at each time step, the available area for PV installation, the PV panel efficiency and the system performance factor.

To compute the tilted radiation, the method in Walch et al. [8] accounts for the roof tilt and aspect angles, shading effects, sky visibility and surface reflectance (albedo). The available area for PV installation is obtained by virtually installing PV panels of size 1 × 1.6 m² on each roof. To account for roof superstructures such as chimneys and dormers, the area covered by virtual panels is then corrected using a Machine Learning (ML) approach [8]. In contrast to Walch et al. [8], PV panels on flat roofs are installed in this work as alternating east and west-facing rows with a tilt angle of 15°, whereby all roofs with a tilt angle below 10° are considered as flat.

The PV panel efficiency is derived for each roof surface from the tilted radiation and the ambient temperature, assuming all PV panels are mono-crystalline panels with a nominal power of 285 Wp [8]. The performance factor combines the inverter efficiency and other losses of 14% accounting for example for soiling, degradation, wiring losses etc. Furthermore, all roofs with less than 8 m² of available area for PV panel installation are excluded, as these are considered as not relevant for PV installation [8].

Appendix B. Electromobility scenarios

In the electromobility scenarios developed by EBP [60], introduced in Section 2.2.2, the market penetration of EV occurs via new vehicle registrations such as to reach net zero greenhouse gas emission targets in Switzerland by 2050 [60,62,63]. The penetration of EV is modelled by a cohort-based fleet and mileage model EBP [60] including typical survival rates per vehicle category and age. For data on mobility behaviour, the national passenger transport model 2017 and the micro census on transport and mobility (MZMV) [64] are used. The resulting total annual electricity demand of these EV will be 11 TWh by 2050.

The regionalisation of this EV electricity demand at the municipality level is then determined by taking into account socio-demographic factors such as the level of income, education and urbanisation. To this end, a model of an evolving synthetic Swiss population (Syn-Pop [65]) including households and companies is employed. In addition to current mobility patterns from the MZMV, vehicle data records [66] to know the vehicle stock and travelled distance (mileage) for each municipality are used. By updating socio-demographic factors of this synthetic population as well as the modal split, the mileage per vehicle and the vehicle occupancy in each municipality, the degree of motorisation (number of vehicles per inhabitants) and thus the electricity demand of the future EV fleet per municipality is obtained.

CRediT authorship contribution statement

Alina Walch: Methodology, Software, Data curation, Investigation, Writing – original draft, Writing – review & editing. Martin Rüdisüli: Conceptualization, Formal analysis, Visualization, Investigation, Writing – original draft, Writing – review & editing.

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.

Data availability

Data will be made available on request.
Appendix C. Occupied roof types for all PV expansion scenarios

C.1. Strategy 1

An investigation of the roof size, tilt and orientation of the expansion scenario of strategy 1 (Fig. C.9) shows that large roofs with tilt angles $< 20^\circ$ are exploited first, followed by medium roofs at tilt angles up to $50^\circ$. Following the findings from Fig. 1, south-facing roofs are preferred over north-facing surfaces. Noticeably, only in the 35 TWh scenario a significant amount of small roofs is exploited. To reach the PV expansion targets as fast as possible, medium and large, flat and south-facing roofs should hence be the focus of PV deployment.

C.2. Strategy 2

The increase in the number of rooftops for strategy 2, compared to strategy 1 (see Section 3.3), is primarily attributed to an increased number of small roofs of $< 100 \text{ m}^2$, as shown in Fig. C.10. In contrast to the 35 TWh scenario in Fig. C.9, the number of large and medium-sized flat roofs is reduced, but a substantial number of small roofs at tilt angles of $20 - 40^\circ$ is added. These small roofs are primarily located in urban districts in which all their PV potential should be exploited based on this second expansion strategy, whereas parts of the large and medium-size flat roofs – which typically have higher PV yields – are unused as they are located in rather rural districts with lower demand.

Appendix D. Spatial patterns of PV scenarios

To show how the PV expansion from Section 3.2 is distributed across the country, Fig. D.11 shows the spatial patterns of PV expansion for each scenario as a function of roof suitability. Hereby, the 5 and 15 TWh scenarios add primarily “top” roofs. “Good” roofs are added primarily in the 25 and 35 TWh scenarios. In the latter, also some “moderate/poor” roofs would be exploited. Noticeably, the PV expansion first takes place in the most densely inhabited areas in the Swiss plateau in the Northern part of the country and the large mountain valleys, where both industrial and large residential buildings are located. Reaching 35 TWh of PV generation however requires a dense deployment of PV across the entire country, even if the most productive roofs are exploited first and less than half of all available roof surfaces (see Fig. 3) are exploited.

The percentage of all roofs in each municipality (only inhabitable areas) equipped with PV is displayed in Fig. D.12 for all targets of 5, 15, 25 and 35 TWh. To reach 5 TWh, only a low percentage (< 20%) of roofs in each municipality is needed. This percentage gradually increases to almost 100% in several municipalities in the 35 TWh case, although according to Fig. 3 only 46% of all roofs are needed.

While this spatial distribution is relatively homogeneous across Swiss municipalities, some “hot spots” and “cold spots” can be identified. A particularly high percentage of PV exploitation occurs in some municipalities in the centre of the Swiss Central Plateau (Mittelland) in the northern part of the country and around Lake Geneva in western Switzerland. A high share of industrial and commercial areas, which often contain buildings with large flat surfaces, likely explain these “hot spots”, which are particularly visible for the 5 TWh scenario. “Cold spots” with a low percentage of exploited PV potential are found in rural municipalities in the Swiss mountains (Alps), which have lower building densities and smaller buildings in general.

Appendix E. Real hourly maximum surplus PV supply

With regard to the impacts of a substantial PV expansion on the capacity of existing electricity grids, the hourly maximum surplus PV supply is important. If this peak surplus PV supply is too high, grid
failure and consequently costly grid reinforcements may occur. Based on actual hourly data from 2010, a year with overall low PV yield, we find that the peak PV supply for the 35 TWh scenario at the district scale may exceed the target (2050) demand in most districts and days by a factor of $1 - 5$ in summer (see Fig. E.13). In winter it roughly matches the demand around noon. However, Fig. E.13 also shows that large supply peaks are not only a challenge for scenarios with vast PV deployment. Even for the 15 TWh scenario, PV supply peaks of up to 5 times the electricity demand may be expected for some districts from spring to autumn months.

Appendix F. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.apenergy.2023.121262.
Fig. D.12. Percentage of roofs per municipality (only inhabitable areas) needed to reach the predefined national PV generation targets of 5, 15, 25 and 35 TWh according to the strategic expansion pathway in Fig. 3.

Fig. E.13. Hourly self-sufficiency (PV supply/demand) based on the actual 2010 PmV supply profile at the district level for each PV expansion target distinguished by season. The demand profile is 2050 aggregated from weekday and weekend values.

References

