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Article

2021

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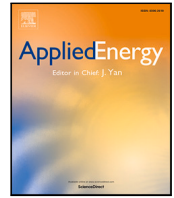
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### How to cite

GUPTA, Ruchi et al. Spatial analysis of distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating. In: Applied Energy, 2021, vol. 287, n° 116504. doi: 10.1016/j.apenergy.2021.116504

This publication URL: <https://archive-ouverte.unige.ch/unige:154422>

Publication DOI: [10.1016/j.apenergy.2021.116504](https://doi.org/10.1016/j.apenergy.2021.116504)



# Spatial analysis of distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating

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## ARTICLE INFO

### Keywords:

PV  
Heat pumps  
Electric vehicles  
Grid integration  
Decarbonization costs

## ABSTRACT

Rapid deployment of solar photovoltaics (PV), electric heat pumps (HP) and electric vehicles (EV) is needed to decarbonize the economy. However, the integration of these technologies into the power system creates challenges for the distribution grid infrastructure. It is therefore vital to analyse to which extent grid reinforcement is needed to enable decarbonization strategies while also studying alternative flexibility measures. In this GIS-based study, we model the impact of the deployment of PV, HP and EV on a low-voltage distribution grid network serving 170'000 households in Switzerland, and analyse scenarios for their penetration in the years 2035 and 2050. Using a detailed grid model in collaboration with a distribution system operator, we find that PV leads to 18.5% and 13.7% more voltage violation issues compared to HP and EV respectively, which on the other hand, cause slightly more line overloading, 0.5% and 2.5%, respectively. We also find that grid reinforcement costs markedly depend on the type of urban setting ranging between 51–213 CHF/kW<sub>p</sub>, 46–1'385 CHF/kW and 34–143 CHF/kW for PV, HP and EV, respectively, with the higher limit corresponding to rural areas. The total distribution grid reinforcement costs can amount up to 11 billion CHF until 2050 i.e. 2'900 CHF per household in Switzerland. Interestingly, we find that batteries, even with current costs, have the potential to defer grid reinforcement for up to 15% of the transformer stations with the highest specific grid reinforcement costs. Our study aims to inform various stakeholders about the required grid investments to enable the massive deployment of low carbon technologies.

## 1. Introduction

The energy system is undergoing a transformation from fossil fuels to renewable energy (RE) [1]. In 2018, RE technologies represented 84% of all the new electricity capacity added worldwide and already accounted for one third of the global power capacity [2]. At the same time, the decarbonization of the various demand sectors, namely mobility, heating and industry is resulting in additional electricity demand [3]. For instance, the global share of electricity in final energy use is projected to increase to 50% by 2050 compared with 20% in 2018 [1].

Switzerland committed itself to halve its greenhouse gas emissions by 2030 compared to 1990 levels, and to reach a reduction of 70%–85% by 2050 in the context of the Paris Agreement [4]. In view of the latest findings of the Intergovernmental Panel on Climate Change, the Swiss Federal Council took the decision in summer 2019 to tighten the targets and to reach net zero carbon emissions by 2050 [5]. To achieve these targets, Switzerland is taking steps to increase RE generation and

to curb CO<sub>2</sub> emissions from transport and heating sectors [6], which jointly contribute to 60% of all CO<sub>2</sub> emissions [7]. Solar photovoltaics (PV) is expected to become the prime RE technology, growing from an annual electricity generation of 2.2 TWh in 2019 to 34 TWh by 2050 [8]. For space heating, fossil-based heating systems are being replaced with electric heat pumps (HP) with significantly higher efficiency [9,10], reducing the final energy consumption in households by up to 70% [11,12]. A study by the Swiss heat pumps association estimated that the number of HP sold in Switzerland would increase from 20'000 p.a. in 2020 to 40'000 p.a. by 2030 [13]. Additionally, electric vehicles (EV) (both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV)) sales are markedly increasing relative to petrol and diesel vehicles [14–16]. It is estimated that the share of newly registered EV in Switzerland will reach 15% in 2022 (from 2.7% in 2017) [17]. EV are about 3–5 times more efficient than fossil-based vehicles and contribute to reducing urban pollution [18].

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<https://doi.org/10.1016/j.apenergy.2021.116504>

Received 26 October 2020; Received in revised form 19 December 2020; Accepted 8 January 2021

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### List of abbreviations

B CHF	Billion CHF (10 <sup>9</sup> CHF)
BEV	Battery electric vehicles
CAPEX	Capital expenditure
CIM	Common information model
CES	Community energy storage
COP	Coefficient of performance
DSO	Distribution system operator/s
ERA	Energy reference area
EV	Electric vehicle/s
GIS	Geographic information system
HP	Heat pump/s
IQR	Interquartile range
Li-ion	Lithium-ion battery
M CHF	Million CHF (10 <sup>6</sup> CHF)
MFH	Multi-family house/s
NMC	Nickel manganese cobalt oxide
NPV	Net present value
OPEX	Operational and maintenance expenditure
PHEV	Plug-in hybrid electric vehicles
PV	Solar photovoltaics
RE	Renewable energy
SFH	Single family house/s

The use of PV, HP and EV significantly modifies the load profile of the buildings where they are installed, both in energy and power terms. PV can create a reverse power flow in the distribution feeders, potentially resulting in voltage violations and overloading of the distribution lines [19–21]. The use of HP and EV, on the other hand, increases the peak electricity demand [14]. So far, these three technologies have been integrated into the distribution networks without reaching the limit ('hosting capacity'), i.e. with a limited impact on the existing grid infrastructure [22–25]. However, once the hosting capacity is reached after continued technology additions, upgrading or even a complete rebuilding of the existing transformer stations (also known as 'secondary substations') and reinforcement of the lines will be needed [3,22,26,27]. Thus, PV, HP and EV additions can lead to huge investments for distribution system operators (DSO), and finally affect the electricity bill of final consumers [3,25,28,29]. Therefore, DSO<sup>1</sup> need to carefully plan the deployment of PV, HP and EV to ensure a smooth and cost-effective energy transition [30]

The major steps involved in grid planning are: (i) electricity load and infeed forecast, (ii) analysis of grid adequacy for the future load, (iii) modelling of the future grid to allocate the new loads, and (iv) grid reinforcement [31]. Since estimates of grid reinforcement costs are seldomly reported by the distribution system operators and the data availability at high RE penetration is scarce [32], it is paramount to estimate the distribution grid impacts and reinforcement costs needed to enable increasing deployment of PV, HP, and EV charging in line with the net zero targets. Additionally, there are flexibility alternatives to grid reinforcement, such as active power curtailment [22,33], reactive power control [33], demand side management [3,34] and energy storage [24,35,36]. Battery storage systems are becoming very attractive since they can secure grid stability, improve asset utilisation and potentially defer grid reinforcements [35,37]. Our study provides distribution grid impacts and costs to inform DSO, regulators, policy makers, and new market actors and help them to navigate the energy transition.

<sup>1</sup> The same acronym is used both for singular and plural depending on the context.

### 1.1. Literature review and research objectives

Prior work focusing on the impact of PV generation, heating and transport electrification on distributed power systems has addressed various topics, namely: (i) quantification of the future electricity load, (ii) assessment of the grid adequacy and (iii) techno-economic analysis of potential flexibility options to enable the penetration of PV, HP and EV. In this section, we review the related work falling in each of these categories.

Luthander et al. assessed the impact of PV and EV on the Swedish distribution grid. They found that a fully electrified car fleet increases the electricity consumption by 9.3% and 17.1% during critical weeks in winter and summer, respectively. Also, 71% of the PV systems need to be curtailed during summer if PV generation equals electricity consumption throughout the year [38]. Another study analysed the impact of uncoordinated charging of EV on a distribution grid with 1200 nodes [39]. The authors reported an increase between approximately 60%–110% in the distribution transformer power load in case of 15%–30% EV penetration, respectively. The reason for this significant increase was attributed to the simultaneity of EV charging and the traditional peak residential demand occurring in the evening. Also, Rüdüsüli et al. studied the impact of the electric mobility and heating in Switzerland using a temporal resolution of 1 h, however, without considering spatial distribution of technologies [14]. It was shown that with an electrification share of 75% and 20% for heating and mobility, the annual electricity demand increases by 10 TWh and 3.7 TWh, respectively, which translates into a 25% increase in total electricity demand. However, the above-mentioned studies did not evaluate the impact of these new electricity demand loads on the distribution grids.

To assess grid adequacy, Salah et al. analysed the impact of EV charging on Swiss distribution substations under different penetrations and electricity tariffs [40]. This study found that with an EV penetration of 16% and under a flat electricity tariff, the existing substation capacity is adequate to integrate EV. However, beyond this limit, EV charging is expected to cause overloading of the substations. Another study shows that if 20% of households own a HP in the UK, the peak electricity load increases by 72% above the baseline, and that the transformers have to be reinforced [20]. PV penetration beyond 25%–30% would also require distribution grid reinforcements. Pillai et al. assessed the capability of three Danish distribution grids to incorporate EV for low (4 h) and peak demand (17 h) hours of a selected day. Their results show that depending on the robustness of the distribution grids, they can handle between 6% and 40% of EV loads for the peak and low hours, respectively [41]. While the above-mentioned studies quantify the grid impacts associated with the penetration of PV, HP and EV, they did not calculate the grid reinforcement costs needed to enable their penetration. In short, the studies on grid adequacy indicate that grid reinforcement is not needed with low diffusion of EV, HP and PV (e.g. up to 15%), with the exception of EV charged during peak hours, which however does become necessary for higher penetration levels.

Finally, several papers have already attempted to quantify and discuss the costs required for upgrading the distribution grids. Horowitz et al. carried out a detailed review on this topic and concluded that these costs are greatly case-dependent [25]. Pudjianto et al. quantified the cost of integrating PV for 11 countries in the EU and found that for a PV penetration between 2%–18%, the distribution reinforcement costs varies between –25 to 9 EUR<sup>2</sup>/MWh [28]. The cost is positive when PV deployment results in net additional cost for the distribution line upgrade compared to the base case, but it is negative when PV reduces the distribution network capacity due to positive correlation between PV generation and the peak demand. In a different study focusing only on the UK, the same authors simulated various scenarios for EV and HP in different distribution network topologies to determine

<sup>2</sup> 1 EUR = 1.0852 CHF (2019).

reinforcement costs up to 2050 [3]. Their results show that the electricity peak demand can increase by 2–3 times, requiring an investment of £36<sup>3</sup> billion by 2050. The study also emphasizes the role of smart EV charging and HP operation to reduce reinforcement costs. Fernández et al. found that, for an urban distribution network, investment costs could increase by up to 15% of the total actual investment costs in case of 60% EV penetration scenario [42]. Due to lack of publicly available grid data, Gupta et al. proposed an unsupervised method to investigate the PV hosting capacity of medium voltage grid for Switzerland and assessed the costs of battery storage to accommodate PV beyond the hosting capacity [43]. This study however neither assessed the cost of grid reinforcement nor the impact on the grid due to HP or EV charging deployment. Previous studies, therefore, typically focused on integration of the low carbon technologies, either on the supply or the demand side. However, since all the three technologies (PV, HP and EV) are needed to achieve the energy transition objectives, it is important to study the aggregated impact of their simultaneous deployment on the distribution grid. Only a recent study assessed the impact of PV, HP and EV on a distribution grid, but it was carried out for a medium sized town (population of 40'000) in Germany covering only the residential sector [44]. The authors simulated three different scenarios for combined HP and EV and one scenario considering only PV deployment. Their results show that the peak electricity load increases by a maximum of 74% for the combined HP and EV penetration scenarios, while the feed-in power due to PV (8.8 MW<sub>p</sub>) increases by 73% compared to the baseline decentralized generation. However, this study neither discusses the cost of grid reinforcement nor potential solutions to avoid grid reinforcement.

Against this background, our study aims to expand the existing body of literature by: (i) analysing a large-scale real distribution area covering 170'000 households located in the second-largest Swiss canton by both surface area and population, also distinguishing different urban settings, namely urban, suburban and rural; (ii) using a geographic information system (GIS)-based model to carry out long-term forecasting (for 2035 and 2050) of PV, HP and EV deployment; (iii) comparing the individual and aggregated impacts of PV, HP and EV based on different scenarios with a detailed low-voltage distribution grid model developed by the DSO; (iv) analysing the reinforcement costs as a function of technology and type of urban setting; and (v) analysing the potential of battery storage to defer distribution grid reinforcement. Finally, we scale up our results to the national level to evaluate the long-term grid impact of decarbonization in Switzerland. The proposed method developed and implemented in collaboration with one of the largest DSO in Switzerland allows to provide technical and regulatory recommendations which are important for DSO, regulators and policy makers to design a flexible electricity grid infrastructure including sector coupling. Furthermore, this methodology could be extended to other countries/regions to account for region-dependent capital and operational expenditures.

## 2. Input data and method

In this section, we give an overview of the input data including the electricity grid structure, scenarios for technology penetration and technology characteristics. Long-term forecasting of the electricity demand with geographical resolution is a challenging task since it depends on various economic, social, environmental and political factors [45]. We therefore use scenario analysis in this study.

### 2.1. Current structure of electricity grid in Switzerland

The Swiss electricity grid comprises different layers ranging from extra-high voltage (220 kV and 380 kV) to low voltage (400 V) as

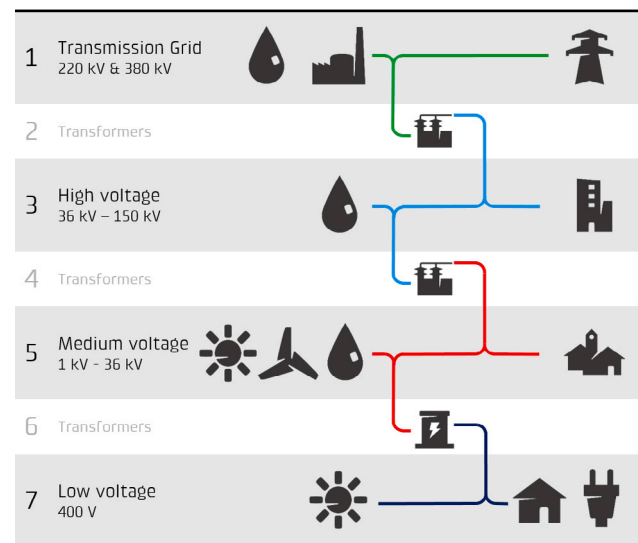


Fig. 1. Basic structure of the Swiss electricity grid. Our study focuses on the low voltage distribution grid depicted as level 6 and 7 in this figure.

illustrated in Fig. 1. The high voltage grid is operated in a meshed way and has a large capacity reserve, since each point is connected to more than one supply point. On the other hand, the medium and low voltage grids (the latter is referred to as **distribution grid** in this paper) are operated radially, where normally each point is connected to only one supply point and hence exposed to higher risks, in particular with the deployment of PV, HP and EV charging. Therefore, in this study, we focus on the low voltage distribution grid at the level of transformer stations (see level 6 and 7 in Fig. 1). We use a real distribution grid which is owned and operated by the utility, BKW<sup>4</sup>, in parts of the canton of Bern, Solothurn and Jura in Switzerland, referred to as **supply area** in this study. Fig. S.1 in the Supplementary Information (SI) shows the supply area.

### 2.2. PV deployment in Switzerland

In Switzerland, PV installations are so far limited to rooftops and this is expected to remain the same in the future [46]. Therefore, to assess the future PV deployment in Switzerland, we develop a method to select the rooftops with high PV potential. For this purpose, we use the Sonnendach database [47], which provides information on the solar potential of each building rooftop in Switzerland by taking into account its exposure to solar radiation, area, orientation, inclination and exposure to shade. The parameters used in this study for selecting the rooftops for future PV deployment are inclination, orientation and available surface area.

First, all rooftops within the supply area are categorized as flat ( $i = 0^\circ$ ) or non-flat ( $i > 0^\circ$ ), depending on their inclination angle ( $i$ ). Non-flat rooftops are further categorized on the basis of their orientation. We select rooftops receiving good annual solar radiation ( $\geq 1000$  kWh/m<sup>2</sup>/year) (grey shaded area in Fig. S.4 of the SI). This equals 271'249 non-flat rooftops oriented between  $-90^\circ$  and  $+90^\circ$  and 57'469 rooftops with flat inclination. On the other hand, all rooftops facing from northwest to northeast receive low and medium solar radiation ( $< 1000$  kWh/m<sup>2</sup>/year) and are therefore excluded from the analysis. Rooftops with an area smaller than 10m<sup>2</sup> are also excluded [48]. For the selected rooftops, we calculate the PV installed capacity,  $P_{PV}$  using Eq. (1) considering the area ( $A$ ), a typical PV production ( $O$ ) of 187.5

<sup>4</sup> BKW Energie AG is one of Switzerland's largest utilities companies serving mostly as a rural electricity distribution system operator.

<sup>3</sup> 1 GBP = 1.2739 CHF (2019).

$W_p/m^2$  [49] and the final assumption that only 70% of the rooftop area would be effectively available for PV installations [48].

$$P_{PV} = A \cdot O \cdot 0.7 \quad (1)$$

### 2.3. Heat electrification with heat pumps

In this study, we determine the demand for space heating and domestic hot water only for the residential sector, which is analysed with the Swiss Residential Building Stock (SwissRes) model, described in previous publications [50–52]. It is a bottom-up model which allows to calculate the monthly space heating demand based on the balance between energy gains and losses of the different building elements [51]. Input data are derived from a dataset of 50'000 Cantonal Energy Certificates for Buildings [53]. The residential stock is represented by archetype buildings which are defined by various categories together with their respective number of classes, which are given in brackets, as follows: construction period (9), building type (2, namely single-family houses (SFH) and multi-family houses (MFH)), urban setting (3, namely urban, suburban and rural) and heating system type (6) [50] (see Table S.1 in the SI). To account for the regional climate, the energy model uses daily mean temperature and daily global horizontal irradiance data with a high resolution of 1 km by 1 km for the base year of 2015 [54]. This allows to calculate the energy demand for each residential building that is then aggregated to 972 archetype buildings in the supply area.

Once the heating demand is calculated, the HP electrical nominal capacity is determined using Eq. (2) and the following method. Firstly, the specific annual useful heating demand,  $Q_{m^2}$  (kWh/m<sup>2</sup> p.a.), provided for the different archetypes by the SwissRes model is multiplied by the respective energy reference area, ERA (m<sup>2</sup>) for each building [55]. The nominal thermal capacity of a HP is derived from a regression with the useful heating demand extracted from more than 6000 energy certificates, resulting in a value ( $f_{power}$ ) of 4.58E–04 kW<sub>th</sub> per kWh of useful energy demand [56]. Finally, the nominal HP electrical capacity is calculated after dividing by the seasonal coefficient of performance (COP<sub>seasonal</sub>), assumed as 2.7 [57].

$$P_{HP} = \frac{(Q_{m^2} \cdot ERA) f_{power}}{COP_{seasonal}} \quad (2)$$

### 2.4. Electrification of mobility

EV are connected to the distribution grid network using charging stations. The number of EV sales over the total passenger car fleet until 2035 and the specific share of BEV and PHEV in Switzerland were determined in the former studies [58,59] (Table S.4 in the SI gives the current distribution of passenger vehicles in each canton of Switzerland).

The number of EV chargers is a function of the EV penetration. EV chargers are assumed to be deployed both in residential and public places. The residential sector is categorized into three main classes: one-unit SFH, two-unit SFH and MFH. We assume that every EV owner has access to one charger at home, in addition to the public chargers at various locations. We further assume that every MFH with EV owners has 2–5 chargers, depending on the EV penetration scenario. In addition, EV charges are located in the following public zones<sup>5</sup>: (1) zones for public use, (2) work zones, (3) tourism and leisure zones, (4) centre zones, (5) mixing zones, (6) traffic zones, and (7) further construction zones. We then assume for public areas a ratio of 1 EV charger per 10 EV in the stock [60]. Regarding the nominal capacity,

<sup>5</sup> The Swiss Federal Office of Spatial Development has divided areas in different zones. The definition of each construction zone is available at <https://www.are.admin.ch/are/fr/home/developpement-et-amenagement-du-territoire/bases-et-donnees/statistique-suisse-des-zones-a-batir.html>.

private charging stations at home are assumed to range from low power (7 kW) to high power (22 kW), whereas public chargers are assumed to be high power (22 kW). Table S.5 and S.6 of the SI show the distribution of nominal capacities of EV charging plugs for residential and public charging respectively [58]. Finally, the charging power depending on the type of EV model are illustrated in Table S.7 of the SI.

### 2.5. Scenarios

Various scenarios are built to determine the individual and aggregated nominal capacity of PV, HP and EV chargers for the years 2035 and 2050 as shown in Fig. 2. The scenarios refer to the supply area of BKW with 170'000 households and a total population of 379'100. The proposed scenarios consider different cases ranging from a highly pessimistic **least effort** scenario to the highly optimistic **heroic effort** scenario. The additional electricity load due to HP and EV charging as well as the maximum PV feed-in are aggregated at the level of transformer stations of the distribution grid. We do not consider PV self consumption and demand side management as this study deals with preparing the grid for the worst case scenarios. However, we consider simultaneity factors to calculate the contribution of HP and EV charging to the total electricity load at the transformer station level as follows. We simulate several PV-coupled HP systems in houses with different heating demand. Subsequently, we calculate the simultaneity factor among houses for a randomly selected pool of households, whose size varies from 2 to 100, with and without PV and with and without HP. This was repeated 1'000 times and we take the median results of the distribution. The simultaneity factor among houses is calculated as the ratio of the simultaneous maximum demand (with HP) of a group of consumers within 15-min, to the sum of their individual maximum demands (with HP) in the year (Eq. (1) in the SI). For EV, we use the simultaneity factors for EV charging from an open-source simultaneity factor tool [61] using the input data from our study, specifically, number of EV chargers, share of charging power (7 kW, 11 kW and 22 kW), share of EV class (BEV and PHEV) and their respective energy capacities (kWh). The different simultaneity factors used for HP and EV charging are detailed under Section 2 of the SI. To reflect the stochastic nature of spatial diffusion, the deployment of PV, HP and EV chargers are assumed to occur randomly in the future. However, to obtain more robust results, we perform several simulation tests to understand the sensitivity of grid reinforcement costs to spatial diffusion of technologies.

We investigate PV deployment under four different scenarios, mainly differentiated by the level of PV penetration. The **least effort** scenario assumes that the past trend of PV deployment would continue, corresponding to 20% of the best exhaustible PV potential in 2050. The **determined effort** scenario corresponds to 50% of the best exhaustible potential in 2050 and implies dedicated support of the government and commitments inline with the low carbon pathway. The **aggressive effort** scenario assumes a significant PV deployment which is ambitious, but achievable with aggressive efforts, accounting to 70% of the best exhaustible potential in 2050. Lastly, **heroic effort** scenario assumes that all the rooftops, oriented between –90° to +90° and with flat roof, have PV panels installed on them in 2050, which represents 100% of the best exhaustible potential. The PV installed capacity in 2035 and 2050 under each scenario is illustrated in Table 1. Further, we assume a linear PV deployment between 2020 and 2050. Fig. 3 shows a histogram of the PV installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

Future HP deployment in the residential sector is based on the replacement of the existing heating systems, as a function of their installation year and assuming a lifetime of 25 yr for the existing heating system [57], under three different scenarios which are shown in Table 2. The **least effort** scenario is based on historical and envisaged

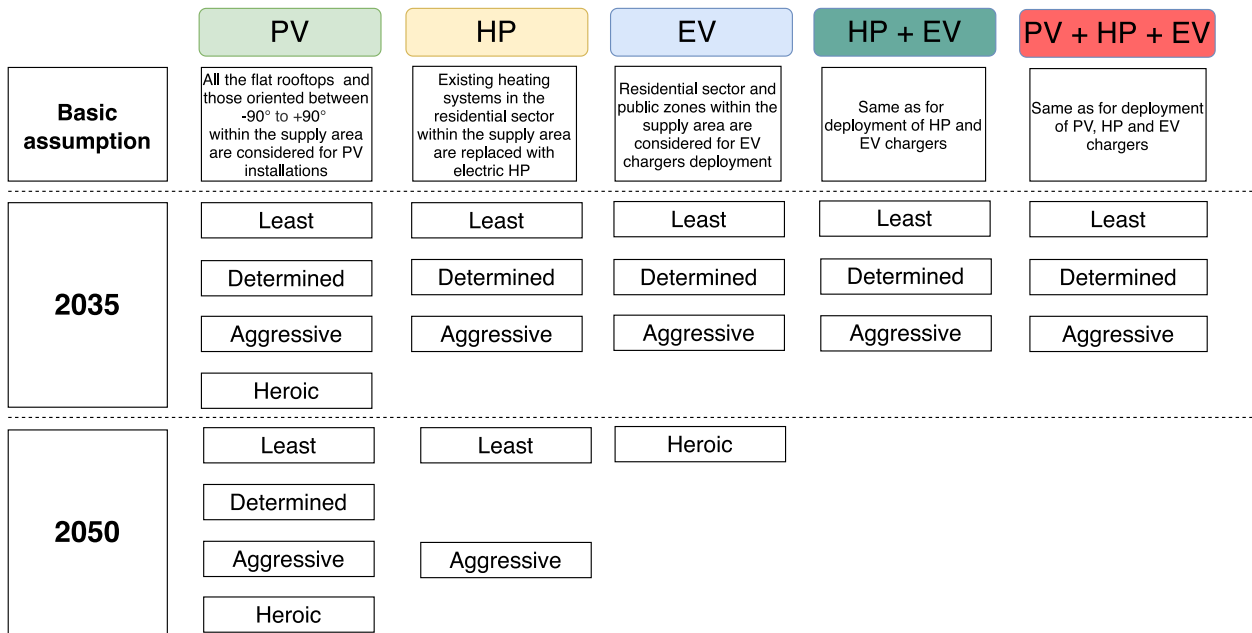


Fig. 2. Scenario development across different technologies and their combinations in 2035 and 2050.

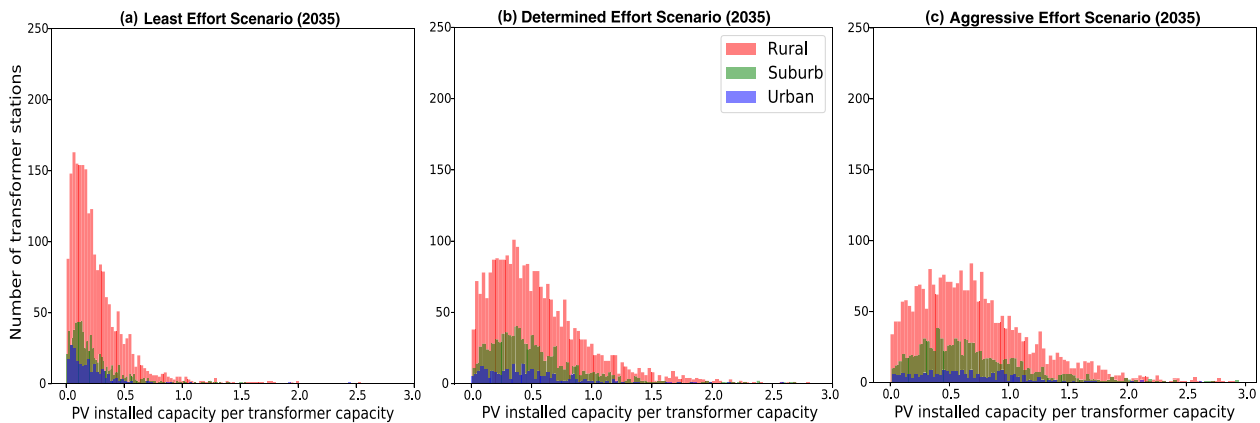


Fig. 3. Histogram of the PV installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

Table 1

Projected PV installed capacity addition for the supply area in 2035 and 2050 under four different scenarios.

Scenario	Projected PV Installed Capacity (MW <sub>p</sub> )	
	2035	2050
Heroic Effort	1'492	2'983
Aggressive Effort	1'044	2'088
Determined Effort	746	1'491
Least Effort	299	597

sales of HP in Switzerland (see Table S.3 in the SI) [13]. The **determined effort** scenario is driven by the new Energy Act in the canton of Basel-Stadt, which aims at replacing all the fossil-based heating systems at the end of their lifetime by renewable-based heating systems [62]. Here, we assume that all fossil-based heating systems are replaced by HP in 2035. Finally, all heating systems (including wood and direct electric) are replaced by HP in the **aggressive effort** scenario in 2050. Since, we consider deployment of HP only in the residential sector, we do not consider heroic effort scenario for HP. Fig. 4 shows a histogram of the HP installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

Under the **least effort** scenario, EV are envisaged to constitute only 15% of the total passenger vehicles fleet in Switzerland in 2035, whereas, this figure corresponds to 24% and 33% in case of **determined effort** and **aggressive effort** scenarios, respectively. In 2050, we base our analysis on a single scenario which assumes that 100% of the passenger cars will be electric (BEV or PHEV) (referred to as **heroic effort** scenario). Further, the total number of passenger cars are considered to remain unchanged between 2035 and 2050. Table 3 presents the number of EV charging stations deployed across the supply area in 2035 and 2050 for the various scenarios (for details refer to Subsection 1.4 of SI). Fig. 5 depicts a histogram of EV chargers installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

The installed capacities of technologies calculated for each house connection are aggregated at the level of transformer stations and plotted relative to the nominal capacities of their respective transformer stations in the form of a histogram presented in Figs. 3–5. While for the least effort scenario, the installed PV capacity only represents about half of the installed transformer capacity for most transformer stations, this ratio increases with the ambition level of the scenario (Fig. 3). For the aggressive effort scenario, for example, the installed PV capacity

**Table 2**

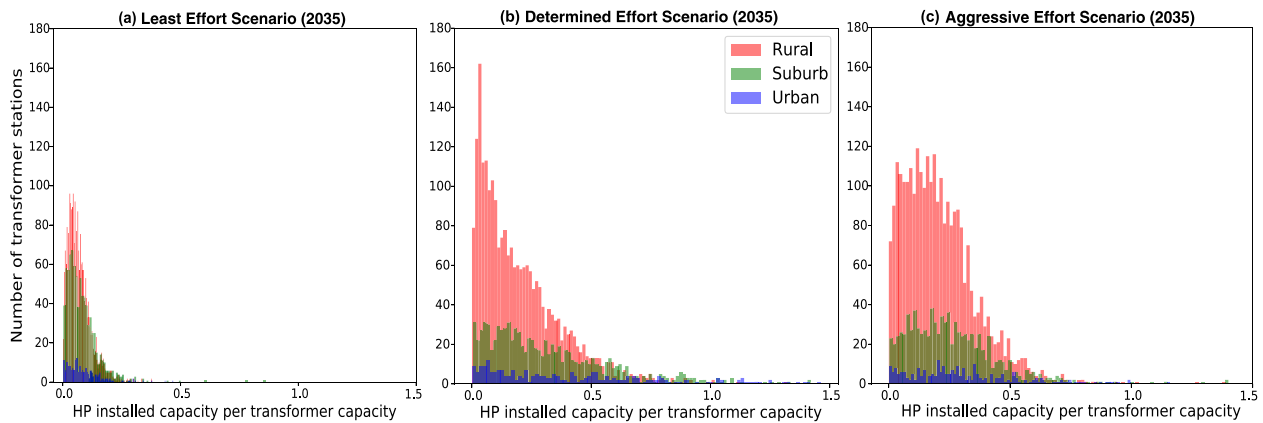
Projected number of existing heating systems replaced by HP and projected installed capacities addition of HP under three different scenarios for the supply area in 2035 and 2050.

Scenario	2035		2050	
	Number of heating systems replaced by HP	Projected HP installed capacity (MW)	Number of heating systems replaced by HP	Projected HP installed capacity (MW)
Aggressive Effort	69'830	350	111'210	570
Determined Effort	74'900	410	–	–
Least Effort	19'000	100	44'930	230

**Table 3**

Projected number of EV charging stations deployed and the total installed capacity (MW) under three different scenarios for the supply area in 2035 and 2050. The number of charging stations deployed are a function of the number of EV penetration.

Building Type	Power	Number of EV charging points and installed capacity addition			
		2035		2050	
		Aggressive Effort	Determined Effort	Least Effort	Heroic Effort
SFH (one-unit and two-unit)	7 kW	105'788	75'790	48'514	136'880
MFH	7 kW	6'059	4'335	2'816	160'695
	11 kW	41'161	29'549	18'952	0
	22 kW	2'666	1'998	1'300	0
Public	22 kW	26'700	19'129	12'243	75'587
<b>Total number of EV chargers</b>		<b>182'374</b>	<b>130'801</b>	<b>83'825</b>	<b>373'162</b>
<b>Total installed capacity (MW)</b>		<b>1'882</b>	<b>1'350</b>	<b>865</b>	<b>3'746</b>



**Fig. 4.** Histogram of the HP installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

represents more than 50% of the total transformer capacity for most transformers. The number of transformers for which the installed PV capacity exceeds the total transformer capacity (values  $> 1$  on x-axis) becomes significant, especially in rural areas. Similar patterns are found for HP (Fig. 4) and EV (Fig. 5), however with the difference that the HP capacity per transformer capacity remains relatively low (nearly always below 0.5 across the scenarios).

Further, the combination of HP and EV as well as PV along with HP and EV are analysed for least, determined and aggressive scenarios in 2035.

## 2.6. Distribution grid modelling

Table 4 displays various electric components within the supply area. Around 72% of the transformer stations within the supply area are in rural areas, 22% in suburban and 6% in urban areas. A large-scale distribution grid planning model with a high spatial resolution, developed and operated by the DSO (BKW), is used to calculate the required network investment for the different future levels of technology penetration according to the scenarios defined in Section 2.5. The model

consists of all electrical components of the low voltage grid, which are exported from BKW's GIS, starting at the medium to low voltage transformer (see level 6 Fig. 1) down to every house connection. During the export, the elements such as transformers and lines are enhanced with electrical parameters (resistance, reactance, technical limits etc.) according to their type. For lines and transformers, BKW maintains a library of technical parameters given by the relevant manufacturers. The model runs load flow calculations for various technology diffusion scenarios which allow us to determine the current and/or voltage limit violations, the subsequent reinforcement of the existing lines and transformers and the total reinforcement cost. The steps involved in the modelling process are illustrated in Fig. 6.

First, after the initial load flow calculation, the various grid elements (transformer or line) which are overloaded are replaced with elements of a higher capacity. An element is considered overloaded if its load exceeds its nominal capacity established by the manufacturer. Next, the load flow calculation is repeated to check any remaining voltage violations. The following cases are considered as voltage limit violations:

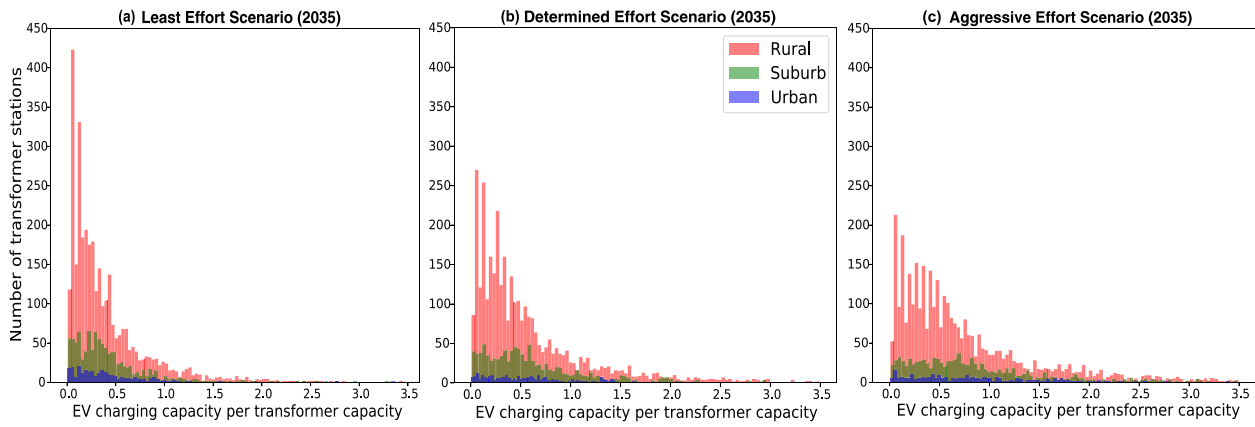


Fig. 5. Histogram of EV chargers installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

**Table 4**  
Key parameters of the current distribution grid within the supply area.

Parameter	Value
Number of transformer stations	5'879
Number of house connections	163'756
Total length of lines (km)	13'987
Estimated cumulative maximum load without considering simultaneity (GW)	4.2

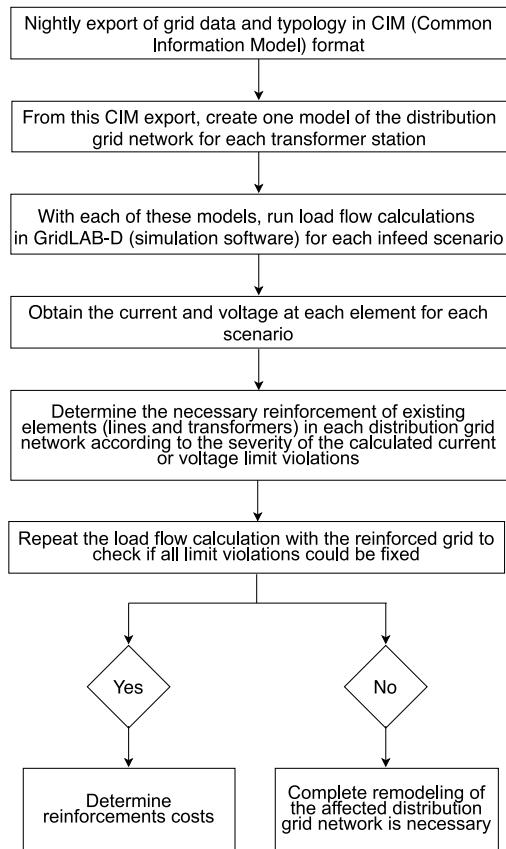


Fig. 6. Flowchart showing steps involved in modelling of the distribution grid.

1. A voltage increase of more than 3% due to PV power infeed compared to the situation without PV power infeed according to the DACHCZ technical rules for assessing network perturbations [63].

2. The voltage at any point in the distribution grid is lower than 90% of the nominal voltage for load simulations according to EN 50160 [63].

If there is any voltage violation, the grid is reinforced following a step-wise iterative approach. Once all violations are resolved, we determine the costs for these reinforcements. The reinforcement cost of a low voltage grid is zero if the aggregated load after deployment of technologies is lower than the nominal capacity of the transformer in the area and if there are no line overloading or voltage violation issues. Otherwise, grid reinforcement costs account for both upgrading and/or rebuilding of the transformer stations as well as reinforcing of the lines. We determine grid reinforcement costs using empirical values provided by the DSO. For example, for the reinforced lines, the unit costs contain average values for both the material and the installation of the new lines and dismantling costs for the existing lines. For cabling of the overhead lines, average civil engineering costs for new pipes are considered. For reinforced transformers, we consider the material and installation costs, as well as conversion or construction costs of the transformer station building which needs to be extended. The values primarily represent investment costs for the physical grid, whereas planning costs or the change in operational costs are not considered. If grid violations cannot be eliminated using a simple reinforcement (upgrading) of the grid elements, we assume a complete rebuilding of the affected part of the distribution grid network. This includes costs for an additional transformer station as well as for completely new low and medium voltage lines according to the size of this distribution grid network. We use average costs for rebuilding a complete low voltage grid based on existing projects of the DSO.

Grid reinforcement costs are affected by several factors, such as (i) the capacity of technologies installed (according to the scenarios above) vis-a-vis the capacity of the transformer stations, (ii) distribution of technologies across rural, suburban or urban areas, (iii) increase in electricity load at the transformer stations, (iv) number of house connections within the transformer station network undergoing voltage violation, (v) total segments and length of lines overloaded, and (vi) the ratio of the number of transformer stations requiring rebuilding to the number of transformer stations only requiring upgrade under different scenarios.

In case the load flow calculation in one part of the supply area does not converge (typically due to a significant PV reverse flow and/or a very high load in locations where the grid is very weak), we still assume a fixed reference reinforcement cost for that transformer station. To get a realistic cost estimate, we group the distribution grid networks into three different sizes (see Section 3 in the SI) and we assume for each a different fixed reference cost for remodelling the network. The transformer stations with convergence problems in the load flow calculations are filtered out when we calculate the specific grid reinforcement costs (CHF/kW).

### 2.7. Upscaling of results to the national scale

We scale-up our results from the supply area to the national level in order to estimate grid reinforcements costs for Switzerland. To do so, we extend the PV, HP and EV models and scenarios to the whole of Switzerland (see Sections 2.2–2.4). We use the results presented in the regression analysis (Section 3.5) per technology type (which is the output from our model described in Section 2.6) from the supply area. Thus, we assume that the specific grid reinforcement costs per urban setting from the DSO's supply area are representative for rest of the country. While this is a strong assumption, since grid costs are region dependent [28], this gives a first estimation of the range of grid reinforcement costs needed to promote the mass deployment of PV, HP and EV charging in Switzerland.

## 3. Results

We first present the grid reinforcement costs to enable the deployment of different technologies, both individually and in combination, for least, determined and aggressive effort scenarios within the supply area. This allows us to discuss the impact of various technologies on the distribution grid as well as the corresponding reinforcement costs needed to enable such deployments in the supply area. Since the heroic effort scenario is considered only in case of PV and EV, and not for HP nor the combination of technologies, their results are presented in Section 3.1 of the SI. We present the median values of the total grid reinforcement cost and their respective ranges from 12 simulation runs. Interestingly, the results from different runs show no significant variation. Furthermore, we compare the median grid reinforcement costs across all scenarios for PV, HP and EV charging in Fig. S.11 of the SI.

Secondly, specific grid reinforcement costs defined as the cost of grid reinforcement (CHF) per unit of technology installed (kW) are analysed at the level of transformer stations for different urban settings, namely rural, suburban and urban for the least and determined effort scenarios. The results of the aggressive effort scenario are presented in Section 3.2 of the SI. Furthermore, we examine battery storage as a flexibility option to defer grid reinforcement. Finally, the results are scaled up to the Swiss level.

### 3.1. Least effort scenario

Fig. 7(a) presents a boxen plot of the grid reinforcement costs needed to deploy PV, HP, EV and their combination for the least effort scenario in 2035 and 2050. The grid reinforcement costs depend on a number of factors as outlined in Section 2.6 and Figs. 7(b) to 7(g) compares the most relevant ones, i.e. percentage of house connections undergoing voltage violation, length of line overloaded as well as the share of transformer stations undergoing upgrade and rebuilding for 2035 and 2050. For 2035, we find that 5.8% of the house connections undergo voltage violation and around 222 km of lines are overloaded due to deployment of EV chargers (865 MW), compared to only 3.6% and 111 km for HP (100 MW) and 3.8% and 19 km for PV (299 MW<sub>p</sub>), respectively. Interestingly, HP leads to more line overloading compared to PV, despite the fact that HP installed capacity is one third

of PV capacity. This results in 27% of the transformer stations requiring upgrading in case of HP compared to 20% for PV. On the other hand, EV deployment results in 39% of transformer stations requiring an upgrade. These issues, overall, lead to a median grid reinforcement cost of 109M CHF (ranging between 108–109M CHF) for EV, as opposed to 79M CHF (ranging between 78–79M CHF) and 78M CHF (ranging between 76–82M CHF) for HP and PV, respectively, in 2035. Jointly, HP and EV increase the median cost of grid reinforcements to 113M CHF, while the addition of PV raises the total cost to 176M CHF (i.e., an increase of 63M CHF).

In 2050, the expected PV capacity in the least effort scenario is 597 MW<sub>p</sub> (100% higher than in 2035), causing a voltage violation in 11% of the house connections compared to only around 4% in case of HP (with a installed capacity of 230 MW in 2050). To enable this PV deployment, 8% of transformer stations should be rebuilt, which is a markedly higher percentage than for HP (only 1%). PV deployment in 2050 results in approximately doubled grid reinforcement costs compared to 2035, with a median value of 159M CHF (ranging between 153–165M CHF). This is significantly higher than for HP with a median value of 84M CHF (ranging between 84–86M CHF), representing less than 10% increase compared to 2035.

### 3.2. Determined effort scenario

For the grid reinforcement costs in the determined effort scenario (Fig. 8(a)), the following observations can be made. Contrary to the least effort scenario for 2035 where grid reinforcement for PV is least expensive, grid reinforcement costs for PV in the determined scenario for 2035 are most expensive, with a median value of 201M CHF (ranging between 195–206M CHF) as opposed to a median value of 129M CHF (ranging between 128–131M CHF) and 85M CHF for EV and HP respectively. This is despite the fact that installed capacity of EV chargers (1'350 MW) is much higher compared to PV (745 MW<sub>p</sub>) and HP (410 MW) in 2035. The reason is that PV causes voltage violation in 15% of the house connections compared to 7% and 4% in case of EV and HP respectively (see Figs. 8(b) to 8(g)). Overall, 10% of the transformer stations for PV need to be rebuilt, compared to only 1% and 2% for HP and EV respectively, thereby leading to higher costs. The combined deployment of HP along with EV results in a median grid reinforcement cost of 147M CHF (ranging between 145–148M CHF) in 2035. The simultaneous deployment of PV along with HP and EV leads to high grid reinforcement cost with the median value of 305M CHF (ranging between 301–310M CHF). Finally, doubling PV deployment in 2050, relative to 2035, leads to 34% of the house connections having voltage violations along with 104 km of lines overloading, resulting in a median grid reinforcement cost of 400M CHF (ranging between 395–406M CHF) in 2050.

### 3.3. Aggressive effort scenario

Fig. 9(a) shows the grid reinforcement costs needed to enable the deployment of PV, HP and EV and their combination under the aggressive effort scenario. First, in 2035, similar as in determined effort, PV deployment leads to relatively higher grid reinforcement costs with a median value of 282M CHF (ranging between 278–288M CHF) compared to a median value of 155M CHF (ranging between 154–156M CHF) and 90M CHF (ranging between 88–90M CHF) for EV and HP respectively. Although the deployment of HP and EV lead to a higher length of lines being overloaded compared to PV (422 km, 136 km and 72 km for EV, HP, and PV respectively), the cost related to PV-induced voltage violation issues becomes dominant. In particular, PV causes 23% of the house connections undergoing voltage violation compared to 9% and 4% for EV and HP respectively. As a result, 14% of the transformer stations should be completely rebuilt to allow PV penetration, compared to only 2% and 1% for EV and HP respectively, thereby resulting in higher reinforcements costs for PV (see Figs. 9(b)

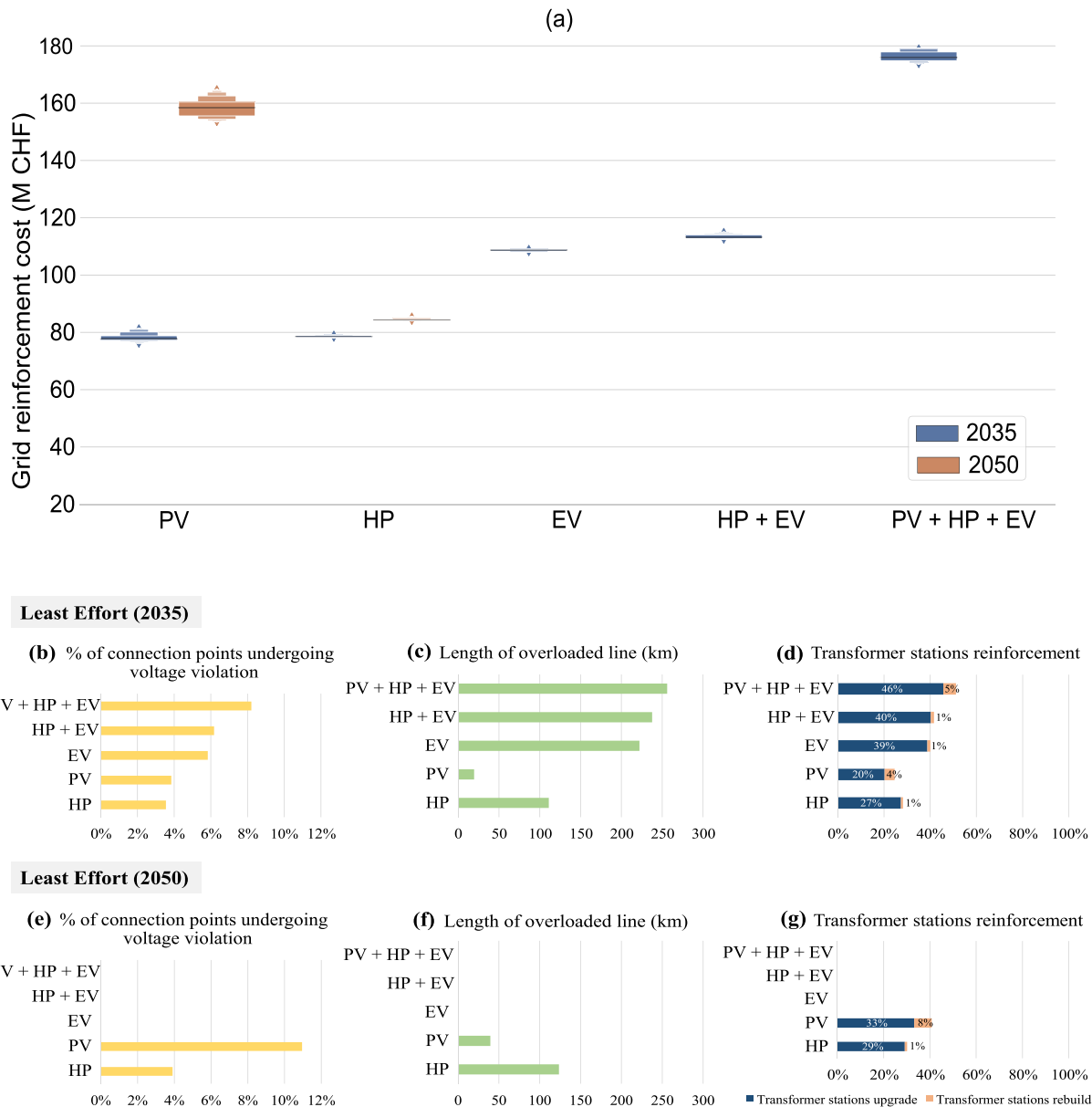


Fig. 7. Results for the least effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 (b) to (d)) and 2050 ((e) to (g)). Since, there is no least effort scenario for EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

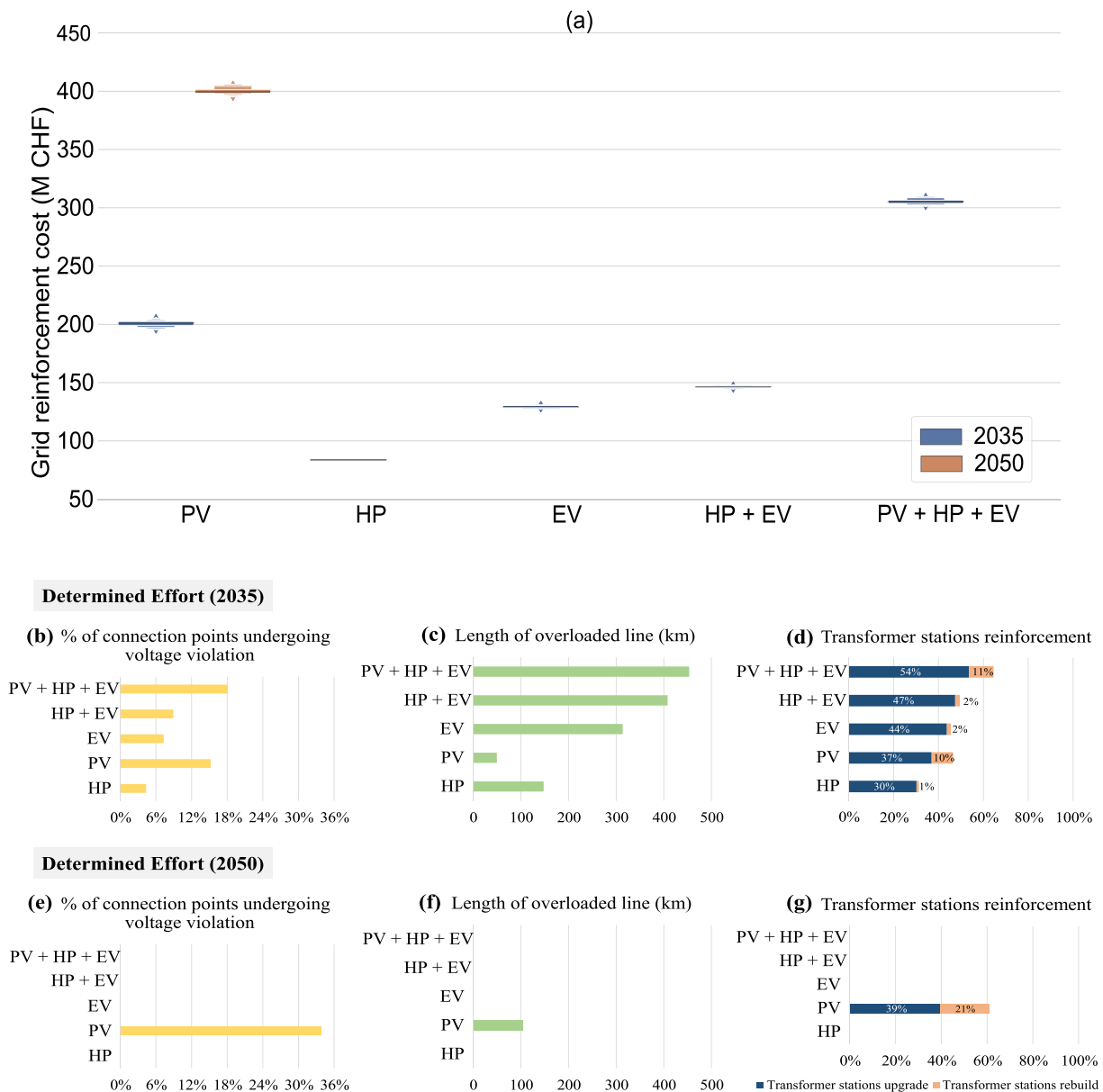
to 9(g)). Furthermore, the combined deployment of HP and EV results in grid reinforcement costs with a median value of 178M CHF (ranging between 177–179M CHF). However, the simultaneous deployment of PV along with HP and EV leads to a remarkable increase, with the median cost of around 405M CHF (ranging 399–407M CHF). In 2050, the grid reinforcement needed to deploy 2'088 MW<sub>p</sub> of PV is almost 5 times higher than to deploy 570 MW of HP. PV causes around 44% of the house connections undergoing voltage violation compared to only 5% for HP.

### 3.4. Grid reinforcement costs per urban setting

In this section, we analyse the specific grid reinforcement cost (CHF/kW) for deployment of PV, HP and EV chargers at the level of transformer stations under different urban settings (rural, suburban and urban). We present the medians and interquartile ranges (IQR) of

specific grid reinforcement costs while comparing different technologies, as the median values are less affected by the outliers than the mean and therefore a better measure of central tendency. Our random allocation together with the characteristics of the supply area result in the following distributions for various technologies in 2035: 59%, 31% and 10% of the total PV capacity is installed in rural, suburban and urban areas respectively across all scenarios: 50%, 36% and 14% of the total HP capacity is installed in rural, suburban and urban areas respectively, whereas, 61%, 29.5% and 9.5% of the total EV charging capacity is installed in rural, suburban and urban areas respectively.

Fig. 10 shows vertical boxplots of the specific grid reinforcement costs for PV, HP and EV in case of the least effort scenario for 2035. The following common observations can be made. First, the specific grid reinforcement costs are remarkably higher for rural areas compared to suburban and urban areas. For instance, the specific grid reinforcement costs for PV deployment in rural areas is around 170% and 290% higher than in suburban and urban areas, respectively. The reason for higher



**Fig. 8.** Results for the determined effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 (b) to (d)) and 2050 (e) to (g)). Since, there is no determined effort scenario for HP, EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

costs in rural areas is because the grid in rural area is generally weaker and more spread out. It is therefore more prone to voltage violation issues due to differences in length and strength of the grid network compared to the grid in urban area. For instance, HP results show that only 2% of the house connections in the urban areas undergo voltage violation compared to 12% in the rural areas. Second, the position of the median in all the boxes is closer to the lower quartile than the upper quartile. Also the whiskers (lines) on the bottom are much shorter than the whiskers on the top of the boxplots. This indicates that the specific grid reinforcement costs for various technologies is highly skewed to the right. The boxplots with outliers are presented in Section 3.2 of the SI.

While comparing specific grid reinforcement costs per urban setting across technologies, we find that the median for EV is lower than for HP and PV. In rural areas, the median (IQR values reported in brackets) specific grid reinforcement cost for EV is 143 (29 to 1'058) CHF/kW compared to 1'385 (280 to 6'413) CHF/kW and 201 (52 to

796) CHF/kW<sub>p</sub> for HP and PV respectively. For suburban areas, the median (IQR) specific grid reinforcement costs reduces substantially to 49 (16 to 150) CHF/kW, 199 (64 to 878) CHF/kW and 76 (24 to 259) CHF/kW<sub>p</sub> for EV, HP and PV respectively. The values reduce even further for PV, however, increase for HP and EV in urban areas, where the median (IQR) specific grid reinforcement costs are 63 (28 to 104) CHF/kW, 206 (81 to 397) CHF/kW and 51 (15 to 185) CHF/kW<sub>p</sub> for EV, HP and PV respectively. We also find that the IQR of the box for HP is larger than for PV and EV. This suggests that there is more spread or variation in the specific grid reinforcement cost values in case of HP. For the same grid reinforcement cost at the transformer station, the installed capacity of HP is low compared to EV for the least effort scenario, which leads to much higher and varied specific grid reinforcement costs for HP compared to EV.

Fig. 11 shows the specific grid reinforcement costs for PV, HP and EV deployment for the determined effort scenario for 2035. We find that, in rural areas, the median specific grid reinforcement costs for HP

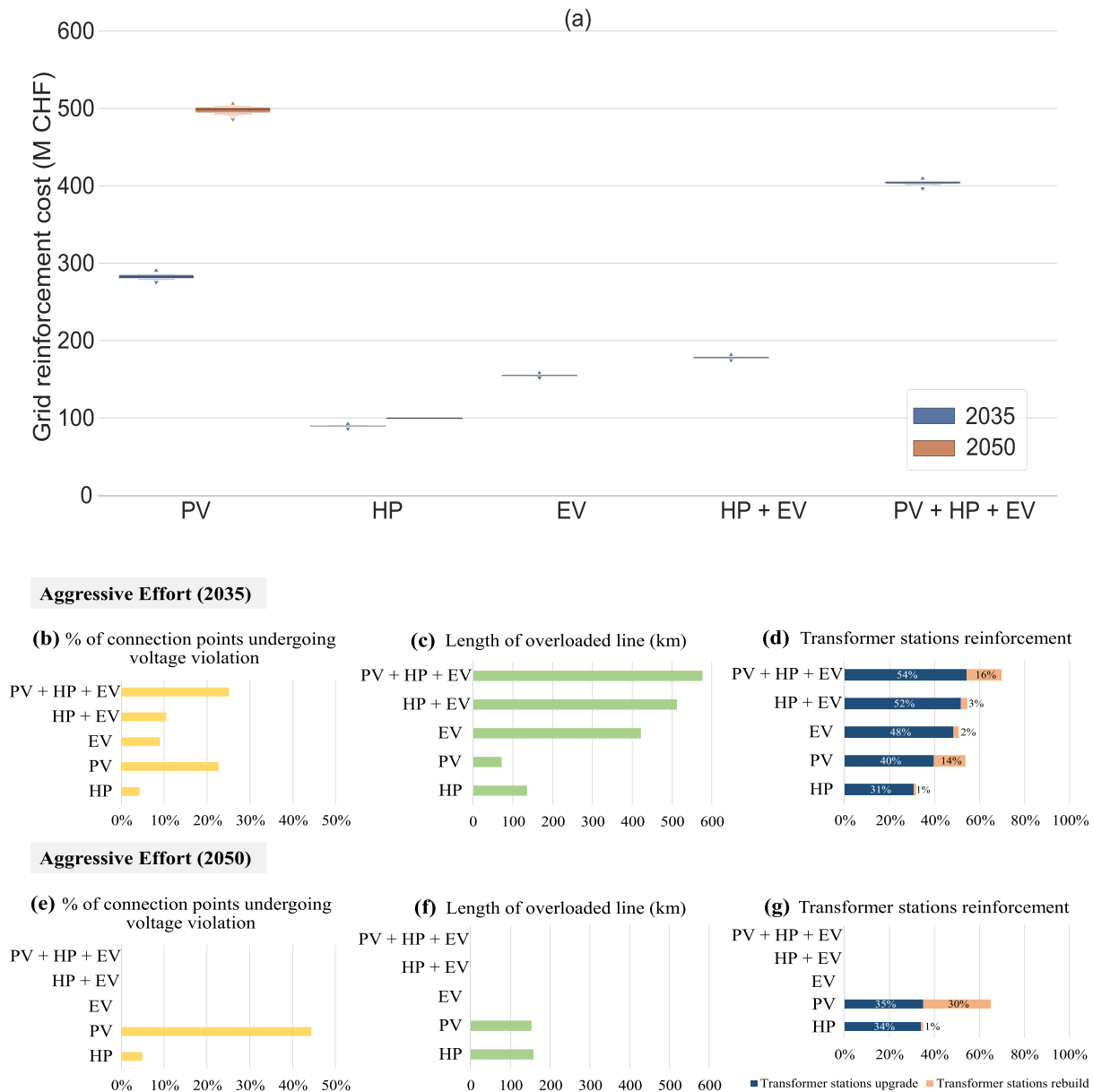


Fig. 9. Results for the aggressive effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 ((b) to (d)) and 2050 ((e) to (g)). Since, there is no aggressive effort scenario for EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

is higher compared to PV and EV, while it is the contrary for suburban and urban areas. The median (IQR values reported in brackets) specific grid reinforcement cost for HP in rural areas is 326 (66 to 2'607) CHF/kW, compared to 200 (65 to 619) CHF/kW<sub>p</sub>, and 95 (23 to 677) CHF/kW in case of PV and EV respectively. Compared to the least effort scenario, here we see that the difference is quite substantial in case of HP (median from 1'385 to 326 CHF/kW). This is due to the fact that for the same cost of grid reinforcement at several transformer stations, the installed capacity of HP is significantly higher in determined effort compared to the least effort scenario, thereby, resulting in relatively lower specific grid reinforcement costs for HP in determined effort. For suburban areas, the median (IQR) grid cost is 102 (36 to 276) CHF/kW, 46 (17 to 229) CHF/kW and 37 (14 to 111) CHF/kW for PV, HP and EV respectively. For urban areas, the median (IQR) grid cost is 72 (25 to 243) CHF/kW<sub>p</sub>, 57 (27 to 82) CHF/kW and 47 (25 to 77) CHF/kW for PV, HP and EV respectively. Similar to the least effort scenario, we

find that the specific grid reinforcement costs are higher in rural areas compared to suburban and urban areas.

### 3.5. Regression analysis

The relationship between the grid reinforcement costs and total technology capacity aggregated at the supply area level (results from Sections 3.1 to 3.3) is further analysed for each urban setting using linear regression as shown in Fig. 12. According to the regression analysis covering all urban settings and all scenarios, adding 1 kW<sub>p</sub> of PV increases the grid reinforcement costs by 248 CHF, 188 CHF and 166 CHF for rural, suburban and urban areas respectively. Interestingly, the last point on the PV graph showcasing the heroic PV penetration (1480 MWp) suggests a saturation (Fig. 12(a)). This implies that the linear dependency does not hold for very high PV capacities. We obtain a coefficient of determination, R<sup>2</sup> of 95%, 98% and 97% for PV in rural,

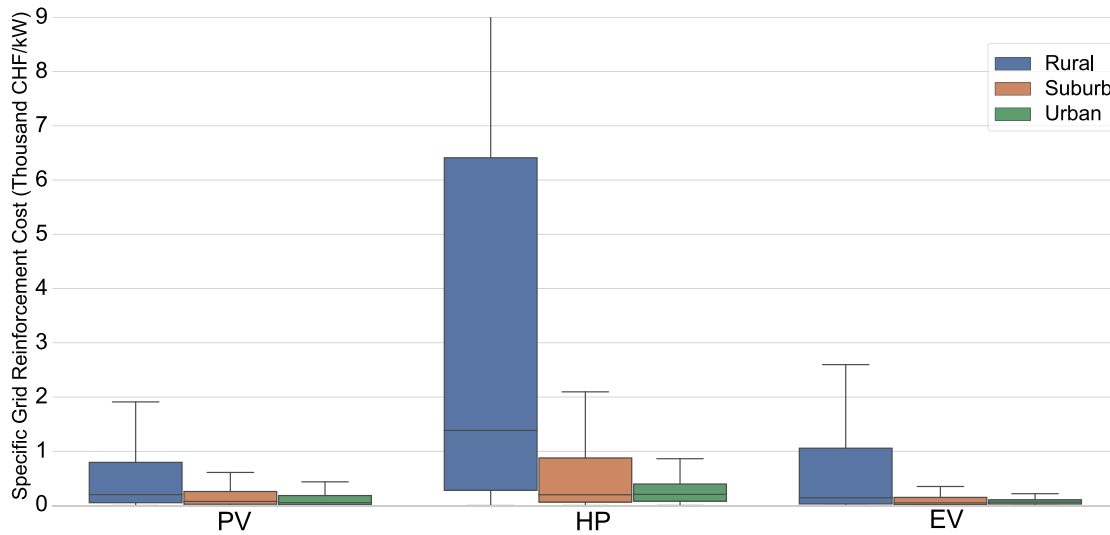


Fig. 10. Least effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035.

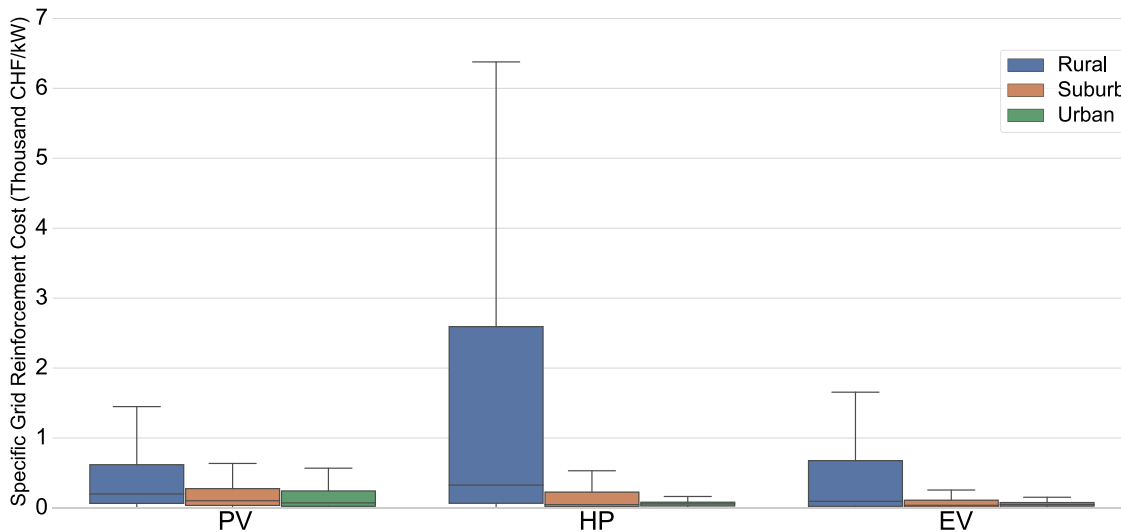


Fig. 11. Determined effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035.

suburban and urban areas, which implies a good fit (see Fig. 12(a)). The slope in Fig. 12(b) suggests that with each additional kW of HP capacity, the grid reinforcement cost increases by 178 CHF, 43 CHF and 33 CHF for rural, suburban and urban areas respectively and HP capacity explains the variance in grid reinforcement costs by  $R^2$  of 94%, 95% and 97% across rural, suburban and urban areas respectively. Fig. 12(c) for EV shows a similar trend where EV charging explains the variance in grid reinforcement costs by 99% ( $R^2$ ) across the three urban settings. Further, the slope suggests that adding 1 kW of EV chargers increases the grid reinforcement cost by 63 CHF, 46 CHF and 32 CHF for rural, suburban and urban areas respectively. For the three regressions, the independent variable (installed capacity) is significant at 1% level ( $p$ -value < 0.01), which means that grid reinforcement costs (dependent variable) can be explained very accurately by capacity additions of technologies (independent variable).

### 3.6. Battery storage to defer distribution grid reinforcement costs

Our results show that for some transformer stations, even very limited capacity addition can undermine the existing distribution grid capacity, in terms of peak load or voltage limits, which would then need to be replaced/reinforced. In this case, the model replaces the

line/transformer with one with higher capacity and then calculates the reinforcement cost. For some cases, the specific grid reinforcement costs (CHF/kW) is exceptionally high (e.g., by one order of magnitude), for example if the line is a long overhead line and requires new piping for reinforcement. DSO could filter out those transformer stations with extremely high specific grid reinforcement costs (CHF/kW) and consider other flexibility options such as energy storage. For instance, battery storage can be installed at the house connections within the distribution transformer, as an alternative to defer expensive grid reinforcement [24,35]. For our analysis, we select Li-ion batteries, since they are the benchmark technology for distributed applications [37,64, 65].

The size of the batteries is such that the power capacity is equal to the PV capacity whereas the energy capacity considers a discharge duration of 2.5 h which has been found to be sufficient to defer the upgrade of distribution assets [66]. The total battery cost is divided into capital expenditure (CAPEX) (assumed to be paid at the installation) as well as annual operational and maintenance expenses (OPEX) (see Section 4 of SI). The CAPEX considers the power-related (EUR/kW) and energy-related (EUR/kWh) cost components [67]. Furthermore, we use a scaling factor of 0.6 beyond an inverter capacity of 3 kW to model cost reduction with size [68]. Other costs such as labour expenses and

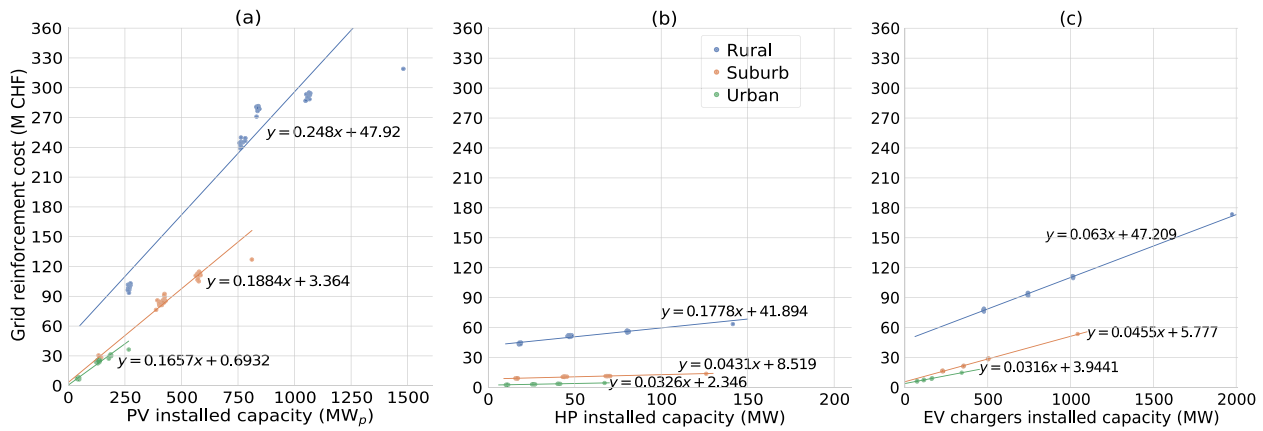


Fig. 12. Regression analysis between (a) PV and (b) HP (c) EV chargers installed capacity and grid reinforcement costs under different scenarios at the supply area level for both 2035 and 2050. Linear regression trend lines are marked in blue for rural, orange for suburban and green for urban. Regression equations are given against trend lines of each urban setting.

Table 5

Comparison between grid reinforcement and current battery costs to enable PV deployment. Costs are calculated as a function of the percentage of transformers stations with the highest specific grid reinforcement cost. Values in bold mark the amount of transformer stations, when the battery cost are still below the grid reinforcement cost.

Transformer stations (%)	PV Least 2035			PV Determined 2035			PV Aggressive 2035		
	PV capacity (MW <sub>p</sub> )	Grid reinforcement cost (M CHF)	Battery cost (M CHF)	PV capacity (MW <sub>p</sub> )	Grid reinforcement cost (M CHF)	Battery cost (M CHF)	PV capacity (MW <sub>p</sub> )	Grid reinforcement cost (M CHF)	Battery cost (M CHF)
1%	0.3	2.6	0.6	0.9	5.4	2.1	1.5	6.9	3.4
5%	2.5	11.8	5.4	9.1	<b>24.3</b>	<b>20.2</b>	13.8	<b>32.2</b>	<b>30.2</b>
10%	6.5	20.0	14.1	25.6	46.8	55.9	40.0	64.3	86.7
15%	12.8	<b>28.5</b>	<b>27.0</b>	48.9	69.3	106.0	70.5	90.9	151.3
20%	19.8	35.0	41.4	75.9	89.2	162.7	113.5	120.1	241.9
30%	37.1	45.0	75.5	136.9	119.4	289.2	203.1	163.8	428.8
40%	53.7	50.5	108.7	199.4	137.5	416.8	294.7	192.7	617.0
50%	73.1	54.4	145.0	265.4	149.9	550.2	403.0	215.6	835.6

land development expenses are not taken into account. To calculate the net present value (NPV) of the battery OPEX, we set the discount rate to 3.8% [69]. Finally, we consider the time period for distribution grid reinforcement deferral as 15 years, in agreement with the lifetime of a Li-ion battery based on Lithium Nickel Manganese Cobalt Oxide (NMC) technology [70], which is the baseline Li-ion chemistry at the moment. Table 5 compares grid reinforcement and battery costs for different PV scenarios. Considering the current costs, batteries are found to be more cost effective than grid reinforcement for 15% of the transformer stations with the highest specific grid reinforcement costs in the least effort scenario. However, as PV penetration increases, it becomes cheaper to reinforce the grid than to install batteries. For example, for the determined and aggressive effort scenarios, batteries are more competitive than reinforcement only for 5% of the transformer stations with the highest specific grid reinforcement costs. Beyond that, grid reinforcement becomes a more attractive flexibility option.

### 3.7. National distribution grid reinforcement costs

In this section, we make use of the results from the regression analysis (presented in Section 3.5) in order to estimate the total distribution grid reinforcement costs at the national level. Fig. 13 shows the resulting distribution grid reinforcement costs linked to the deployment of PV, HP and EV charging across Switzerland. For PV, the distribution grid reinforcement costs range between 0.9B CHF and 4.3B CHF in 2035, corresponding to 4.2 GW<sub>p</sub> (least effort 2035) and 21.1 GW<sub>p</sub> (heroic effort 2035) respectively. The cost increases to 8.6B CHF to enable the deployment of 42 GW<sub>p</sub> (heroic effort 2050) of PV in 2050.

Using 6.4 GW of HP (in electrical terms) to fully replace all the fossil-based heating systems in the Swiss residential sector (determined effort 2035), would imply a grid reinforcement cost of 0.5B CHF.

This value increases up to 0.7B CHF if also wood and direct electric heating systems are replaced in addition to ones based on fossil fuels, amounting to a nominal HP electrical capacity of 7.8 GW (heroic effort 2050). Finally, assuming a 7 kW charger for each EV (equally distributed in rural, suburban and urban) in a fully electrified passenger cars fleet in 2050, would add up to 35.4 GW (heroic effort 2050), requiring an investment of 1.7B CHF for grid reinforcement.

## 4. Discussion

In this study, we determine grid reinforcement costs required to enable the massive deployment of PV, HP, EV and their combinations as a function of the type of urban setting. The results show that the specific grid reinforcement costs are remarkably higher in rural areas compared to suburban and urban areas. For instance, across all scenarios presented in Section 3.4, the median specific grid reinforcement costs varies between 51–213<sup>6</sup> CHF/kW<sub>p</sub>, 46–1385 CHF/kW and 34–143 CHF/kW for PV, HP and EV respectively, with the higher limit corresponding to rural areas. These findings have important practical implications. For instance, a recent study on spatial diffusion patterns of PV projects shows that rural areas in Switzerland tend to be hot spots for PV installations compared to urban areas which have relatively less number of PV projects [71]. An important recommendation is to think of a policy framework which promotes more PV installations in urban areas and thereafter progressively in rural areas, while also considering other flexibility alternatives to grid reinforcement. Based on our result, we further confirm that the specific grid reinforcement

<sup>6</sup> See Fig. S.14 in SI for results of specific grid reinforcement costs in case of aggressive effort scenario.

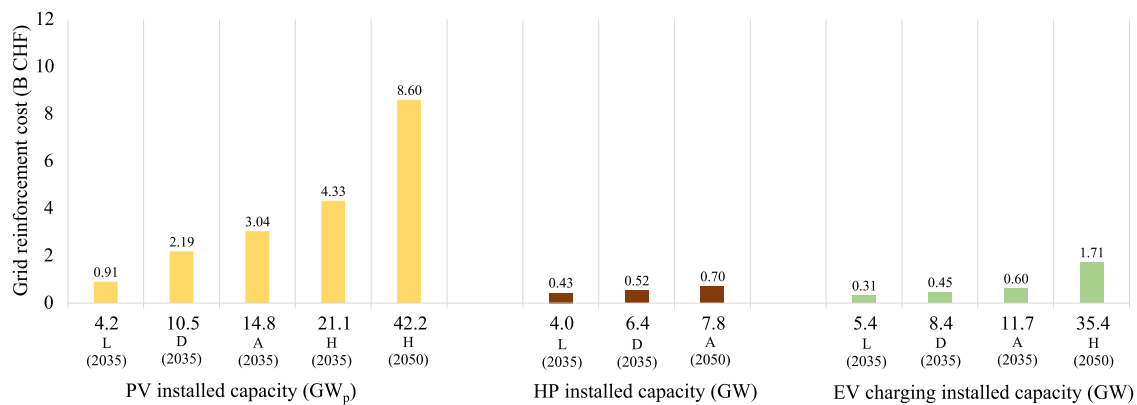


Fig. 13. Distribution grid reinforcement costs in B CHF for PV, HP and EV chargers deployment for whole of Switzerland. The abbreviations L, D, A and H represent least, determined, aggressive and heroic effort scenarios respectively.

cost is much lower for ambitious scenarios (determined and aggressive effort) than for low-ambition scenario (least effort), specifically in case of HP deployment (see Section 3.4). This is an important policy conclusion which suggests that replacement of *all* fossil-based heating systems with HP (determined effort) is more cost-effective for the grid than continuing with the current pace of HP deployment (least effort).

Additionally, we evaluate the application of battery storage as a potential alternative to defer grid reinforcement. Our results show that even with the current costs, batteries have the potential to defer grid reinforcement in up to 15% of the transformer stations with the highest specific grid reinforcement costs (CHF/kW) across different PV scenarios. Since the lifetime of grid reinforcement is usually considered between 40–50 yrs [55], the replacement of distribution grid reinforcement deferral is assumed to be more than 15 yrs. This would make batteries more costly than grid reinforcement. However, on the other hand, it is expected that the CAPEX of stationary Li-ion batteries will decrease by 54%–61% by 2030 [72], making batteries a good flexible solution to support distribution grid expansion. [24,35]. Moreover, batteries can provide up to 15 different services at the grid, generation and end-user level [73,74] and combining different applications (also referred to as benefit stacking) would substantially increase the value of batteries, and their profitability as shown by previous studies [75–77]. Community energy storage (CES) has also been suggested as a possible strategy to reduce the CAPEX and OPEX of batteries, regarding individual home systems [73,78]. Under different ownership models, batteries as CES could benefit both consumers and DSO, creating a win–win relationship [37,73,78]. The new regulatory context in the European Union and Switzerland states that the ownership and operation of energy storage is restricted for DSO, however, they could use tenders to engage market actors (like prosumers and aggregators) who own energy storage to provide grid services [79]. This is being already tested in the United States and Australia [80].

Our GIS-based method can be used to quantify the impacts of PV, HP and EV on the low voltage distribution grids and our results help to plan the distribution grid infrastructure including sector coupling. However, it is not without limitations, which in turn calls for future research. First, our model assumes that capacity additions and grid reinforcement occur all at once. However, in reality, technology capacity is added across the energy transition and thus could lead to higher cumulative reinforcement costs. Secondly, the assumed grid reinforcement costs for transformers and line correspond to average costs. Cost values can vary depending on the project characteristics and local circumstances. It is also important to note that other measures such as retrofitting of buildings can reduce the peak load of HP by 42%–73% [56,81] while local demand side flexibility can be used to decrease the grid impacts of all technologies [82]. This is not considered by our study, thus, our reinforcement costs correspond to extreme cases without inherent

behind-the-meter flexibility. While our study focuses on the analysis of grid impacts and reinforcement costs at the low voltage distribution grid level, future work should include the assessment of grid reinforcement costs at the various voltage levels. The redundancy is typically higher in the medium voltage/high voltage grid in Switzerland, and there are more reserves (higher hosting capacity) compared to the low voltage grid [83]. This means that it could accommodate more PV, HP or EV before it would need to be reinforced. However, once the hosting capacity of the medium/high voltage grid has been reached, the costs for grid reinforcement projects are much higher than for the low voltage grid. Therefore, with high penetration levels of PV, HP or EV, the grid reinforcement costs for medium/high voltage grid may exceed the cost established for the low voltage grid in this study. The total grid reinforcement cost is equal to the sum of cost for reinforcing the low, medium and high voltage grid. Finally, similar country-specific analyses are recommended as the grid impacts and reinforcement costs are highly region and grid dependent.

## 5. Conclusions

This study presents the low voltage distribution grid impacts and reinforcement costs required to enable a massive deployment of solar photovoltaics (PV), heat pumps (HP) and electric vehicles (EV) depending on the type of urban setting (namely, rural, suburban and urban). We develop a GIS-based method to map the technical potential and develop scenarios for rooftop PV, HP and EV charging deployment in 2035 and 2050, which is tested with a distribution grid model covering 170'000 households in Switzerland. Grid impacts are evaluated at the level of transformer stations, which serve several houses. The results are then upscaled to the national level. Overall, we calculate that the total distribution grid reinforcement cost for Switzerland in 2035 amounts to 5.4B CHF for a heroic effort scenario corresponding to a PV nominal capacity of 21.1 GW<sub>p</sub>, a HP nominal capacity of 6.4 GW (corresponding to the replacement of all the fossil-based heating) and 11.7 GW of EV charging. In 2050, the total cost amounts to 11B CHF when considering 42.2 GW<sub>p</sub>, 7.8 GW and 35.4 GW for PV, HP and EV charging respectively. With 3.8M households in Switzerland (assuming the same number as today), the cost of reinforcement would translate to around 1'440 CHF and 2'900 CHF per household in 2035 and 2050, respectively (1 Swiss Franc = 1 CHF ≈ 1 USD).

Based on a linear regression model, we explain grid reinforcement costs as function of the installed nominal capacity of various technologies (R<sup>2</sup> > 94%). Furthermore, we explain the sensitivity of grid reinforcement costs to the type of urban setting. We find that specific grid reinforcement costs are remarkably higher in rural areas compared to suburban and urban areas, in particular, by 150%, 410% and 90% for PV, HP and EV respectively, in an aggressive effort scenario.

Importantly, we also compare grid reinforcement with energy storage, assuming lithium-ion batteries, which are considered as a key flexibility option to enable further renewable energy penetration. Based on our results, we conclude that lithium-ion batteries are already attractive to defer grid reinforcement for up to 15% of the transformer stations with the highest specific grid reinforcement costs. The use of batteries as a distribution asset could be extended further considering future cost projections as well as benefit stacking and co-ownership models, if enabled by the regulatory environment. Considering the high relevance of PV, HP and EV for climate change mitigation and the challenges to integrate them in the existing grid infrastructure, this study aims to help various decision-makers such as the DSO, policy makers and regulators to better plan the future distribution grid infrastructure which maximizes renewable energy and sector coupling.

### CRedit authorship contribution statement

**Ruchi Gupta:** Conceptualization, Methodology, GIS-model and scenarios building, Formal analysis, Investigation, Visualization, Writing - original draft, Writing - review & editing. **Alejandro Pena-Bello:** Heat Pumps simultaneity factor data, Writing & review. **Kai Nino Streicher:** Heat demand simulation data, Writing & review. **Cattia Roduner:** Distribution grid modelling, Writing - review & editing. **David Thöni:** Electric vehicle charging location data, Distribution grid modelling. **Martin Kumar Patel:** Writing - review & editing, Supervision, Project administration, Funding acquisition. **David Parra:** Conceptualization, Writing - review & editing, Supervision, Validation, Project administration, Funding acquisition.

### 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.

### Acknowledgment

This research is part of the activities of Swiss Competence Center for Heat and Electricity Storage (SCCER HaE), which is financially supported by Innosuisse -Swiss Innovation Agency Grant number: 1157002526.

### Appendix A. Supplementary information

Supplementary material related to this article can be found online at <https://doi.org/10.1016/j.apenergy.2021.116504>.

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