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Techno-economic analysis of battery storage and curtailment in a distribution grid with high PV penetration

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ABSTRACT

Global solar PV capacity continues growing and this technology is a central solution for the global energy transition based on both economic growth and decarbonisation. PV technology is mainly being installed in distribution networks next to the consumption centres but it is an intermittent source which does not offer demand matching capability therefore calling for the redesign of distribution networks. In this study, battery storage and PV curtailment are compared as solutions for a residential area in Zurich (Switzerland) with large PV penetration from a techno-economic perspective. The techno-economic analysis focuses on the implications of the location (and related size) of battery storage and the type of curtailment control (fixed versus dynamic) for relevant stakeholders such as consumers and the distribution network operator. PV energy time-shift, the avoidance of PV curtailment and the upgrade deferral of the distribution transformer are the energy services provided by battery systems. Residential batteries offer more value for PV management than grid-scale solutions despite higher levelized cost but PV curtailment is the most cost-effective solution since only up to 3.2% of total PV electricity generation in energy terms should be curtailed for avoiding the transformer upgrading. We conclude that shared ownership models for PV curtailment could considerably improve its acceptance among consumers.

1. Introduction and literature review

Solar Photovoltaic (PV) technology is becoming a mature electricity supply option from a techno-economic perspective. The cumulative PV installed capacity has grown at an average rate of 49% p.a. for the last decade reaching a global capacity over 303.11 GW by 2016 [1]. The cost of PV systems has been divided by almost three in the last six years and by a factor of six in the case of the PV modules [2]. Another key characteristic of PV systems is their modularity, which makes them very attractive for small and medium installations in distribution grids. PV technology is projected to play a key role in achieving current and future decarbonisation targets across many countries. The roadmap made by the International Energy Agency (IEA) envisions a PV share of global electricity reaching 16% by 2050 [2]. In Switzerland, renewable electricity production is predominantly expected to increase through PV.

Several of the scenarios proposed by the Swiss Federal Office of Energy (SFOE) assume 7030 GWh by 2035 [3]. However, the increasing share of PV generation at regional and national scales brings technical and economic challenges related to the variability and uncertainty associated with PV generation. Battery energy storage systems (BESSs), active power curtailment, grid reinforcement, reactive power control (RPC) and on-load tap changers (OLTC) transformers are existing alternative solutions in order to guarantee grid stability in distribution areas with large PV penetration. Such strategies were already proposed for voltage control in low voltage grids with high penetration of PV technology in the previous literature [4–7].

In this study, we focus on battery storage and compare it with PV curtailment and grid reinforcement. BESSs are becoming very attractive for different stakeholders such as distribution system

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operators (DSOs) and consumers since they can be deployed to increase the value of PV generation, secure grid stability, improve asset utilisation and potentially reduce emissions. At the moment, lithium-ion (Li-ion) batteries are considered as the most relevant technology for distribution grids given their maturity level (in contrast to flow batteries and hydrogen fuel cells), modular design (in contrast to pumped storage hydropower and compressed air energy storage) and capability for both short-term (seconds-minutes) and mid-term (hours) applications (in contrast to super capacitors) [8]. Compared to lead-acid batteries, Li-ion batteries are advantageous due to its capability for charging and discharging efficiently at high power rates even with limited battery capacity [9]. Significant attention has been paid to batteries managing PV generation in distribution networks as well as other services such as demand load-shifting and ancillary services (e.g., frequency control) [10–12].

In our baseline scenario, PV curtailment is used to reduce the reverse power flow (electricity feed-in) at the medium to low voltage transformer. In particular, we include two different PV curtailment strategies, namely a fixed feed-in limit on each PV inverter (set as a percentage of the nominal AC power of each PV system) and a dynamic curtailment limit which is controlled by the instantaneous reverse power at the distribution transformer and transmitted to the distributed PV inverters. The third option comprises grid reinforcement which is the most traditional way of handling with new electricity supply and demand capacity.

We exclude both reactive power control (RPC) and on-load tap changers (OLTC) transformers for several reasons. Firstly, it has previously been demonstrated that RPC increases losses in the lines and we therefore do not explore this solution in this study [13]. Similarly, DSOs usually set the voltage level at the MV/LV transformers higher than 1 p.u. in order to prevent large voltage drops during the evening load peaks. However, when the distribution grid has high PV penetration, as in this case study, it is possible that the voltage suddenly rises during the midday PV peak. An OLTC transformer can adjust the secondary voltage level without disrupting the power flow, but the limitation for this solution is that this measure deals only with the voltage rise problem [14]. From an application perspective, a previous study demonstrated that the distribution area which is investigated for this study does not present voltage problems [15].

From a methodological perspective, recent publications focusing on battery storage have addressed, for example, novel control and schedule techniques [16,6], as well as optimal sizing and/or location in distribution networks [17]. Addressing voltage support and network losses minimisation, Nick et al. developed an optimal allocation method of BESSs providing ancillary services and balancing capability including both active and reactive power [16]. The novelty of this method lies in its velocity while ensuring a high level of detail by including several aspects such as network voltage deviation, line congestion and losses. In a second study, the same method was used to optimise the location and capacity of BESSs [18]. Voltage control was also studied by Crossland et al. with a heuristic planning tools based on a genetic algorithm, in particular the location and rating of distributed BESSs to solve voltage problems as a result of increased penetration of PV technology [19]. For voltage control, a single home battery (connected to a single phase) was found to be more efficient than a three-phase system installed in the neighbourhood. Moreover, it was concluded that the capital cost of a single BESS applied for voltage control is lower than network reinforcement. The sizing of a BESS to accommodate high penetration of variable generators for various time scales (from seconds to weeks) was resolved by Makarov using a discrete Fourier transformation to decompose the required balancing power [20]. Alternatively, sizing methods based on optimum cost-benefit simulation results were utilised in [21] and [17], for voltage regulation with demand peak shaving and demand load shifting respectively. However, the specific location within the distribution network as well as the related implications were not analysed. Likewise, optimal battery capacities have also been determined for particular locations such as single homes [9] and communities [11].

Although interesting studies have been published on BESSs for different applications (e.g., voltage control and demand peak-shaving) and different locations, little emphasis was paid to the implications, in terms of techno-economic benefits and ownership, of both the sizing and the location of distributed BESSs, namely grid-scale battery (next to the distribution transformer) or various smaller batteries within individual homes next to the PV generation and electricity consumption (behind the meter). To the best of our knowledge, only a few analyses have been made for grid planning in Germany and Austria [22,23]. This is a relevant research question since the location of a BESS not only has implications on the scale but also on the stakeholder ownership and related value proposition. Focusing on PV management in a distribution grid with large PV penetration, we compare the role of both consumers who decide to install a PV-coupled battery system and a DSO who is responsible for operating and ensuring the maintenance but also in charge of developing the distribution system across the energy transition. In particular, we address the following two research questions: (a) what are the techno-economic benefits of battery storage systems on distribution grids with high penetration of PV as a function of their size and location in the network, i.e. house level versus grid-scale and (b) how do battery storage systems compare with PV curtailment? Therefore, this paper gives insight into the relevant topic of managing PV generation by comparing the location, operation and control of two key solutions such as battery storage and PV curtailment. Our results are finally used to discuss trade-offs between battery ownership and/or PV curtailment control by consumers and DSOs and thus can inform various stakeholders interested in the deployment of battery storage for PV integration as well as policy makers. In order to investigate these two research questions, we base our analysis on a scenario with large PV penetration after the nuclear phase-out in Switzerland (planned by 2035). Our techno-economic analysis is based on the lifetime of battery systems without including the lifetime of existing PV systems since most of these installations were assumed to be previously installed and we particularly focus on how to better integrate and manage an existing PV capacity.

The paper is organized as follows: Section 2 introduces the methodology including a BESS model and the PV curtailment rationale, energy services and electricity prices. Section 3 describes the system under investigation and Section 4 then defines the different scenarios that have been considered for analysis. Section 5 explains the indicators we use to perform a techno-economic assessment. Section 6 summarizes the main results and Section 7 presents a discussion about the outcomes. Finally, we use our results to point out some policy and regulatory recommendations.

2. Methodology

2.1. Electricity prices

Our study is based on a future scenario after the phase-out of nuclear energy in Switzerland embedded in the Swiss Energy Transition and with large PV penetration. Since forecasting electricity prices is not straightforward, we use available data already published in Switzerland for both retail and wholesale electricity prices. Retails prices apply when dwellings import electricity and they are based on the projections from a study commissioned by SFOE in the context off the Swiss energy transition.

Based on this, a constant price of 0.5 CHF/kWh was used as input data [3], i.e. approximately twice the level of current prices [24]. It is assumed that dynamic pricing will apply after the phase-out of nuclear power but it is outside the scope of this study to evaluate the impact of alternative tariffs. We assume that PV generators sell their electricity to the wholesale market (as any other generator) when electricity is exported. Feed-in tariffs have been subject to regular reductions (almost 20% decrease p.a. in Switzerland) based on the technological progress and the degree of market maturity of PV technology. Furthermore, PV penetration targets established by the SFOE have been achieved and 34700 installations are waiting for being eligible for the feed-in tariff scheme at the moment. The Swiss government encourages all owners of new installations to use their PV electricity for self-consumption (i.e. consuming PV electricity on-site and therefore replacing electricity purchased from the grid at the higher retail price) and to sell the rest to the grid at the wholesale price.

Simulated wholesale electricity prices with 1 hr resolution for 2050 (average price equal to 173 CHF/MWh, i.e. four times more than in 2014 [25]) were utilised. We use the Swiss model developed by Schlecht and Weight for this purpose [26]. These wholesale prices assume a CO_2 price of 100 CHF/ton. A simplification of our input data is that the PV generation embedded in the distribution network of this study does not affect directly the wholesale electricity prices since both were modelled independently. This is however, a valid assumption since wholesale electricity prices are determined in a European market, i.e. at the continental level [27]; while PV generation is a local variable. A limitation of this assumption can occur however when PV generation is close to nominal conditions (clear sky conditions) across many countries in periods of anticyclone, this situation finally impacting the wholesale electricity market at the continental level.

2.2. Electricity services

Three services and related economic benefits are analysed in this study for batteries: PV energy time-shift (PVts) with an economic benefit referred to as $Benefit_{PVts}$ (CHF); the avoided cost associated with the energy losses of PV curtailment for the consumer, $Benefit_{PVCt}$ (CHF); and T&D upgrade deferral, i.e. potential avoidance of the transformer upgrading $Benefit_{T\&D}$ (CHF) which is relevant for a DSO (T&D refers to transmission and distribution). While a battery system can potentially benefit from all the three applications above, performing PV curtailment can only contribute to avoid the transformer upgrading, in particular when PV curtailment is centrally controlled by a DSO (referred to as dynamic curtailment in this study). We follow a simple approach and assume that the full cost of the new transformer could be avoided by the battery operation or PV curtailment. Although three different services have been identified, the final value associated with a BESS depends on its location and whether PV curtailment is avoided or not.

PVts consists of storing surplus PV energy (with respect to the electrical demand load) in order to supply it later if there is an economic driver, i.e. the electricity price associated with the discharge is higher than the electricity price associated with the instantaneous export of PV electricity. The benefit associated with PVts ($Benefit_{PVts}$) is calculated using Eq. (1) in which E_{char} (MWh) and E_{dis} (MWh) are the battery charge and discharge respectively; and P_i (CHF/MWh) and P_{ex} (CHF/MWh) are the import (purchase from the consumer perspective) and export (selling from the consumer perspective) electricity prices [9,11]. Two different purchase prices are utilised depending on the location of a BESS. For BESSs installed in singles homes, P_i refers to the electricity retail price (supplied by a utility company) while for a BESS installed at the distribution substation, P_i refers to the electricity wholesale price at the discharge time (i.e. it is assumed that a grid-scale BESS takes part in the wholesale market). Eq. (2) is derived from Eq. (1) after accounting for the definition of the battery's round trip efficiency, i.e. the ratio between E_{dis} and E_{char}. Secondly, battery storage could prevent (at least to a certain extent) that PV energy is curtailed therefore the value of the associated PV electricity is an avoided cost which could be translated into a benefit defined in Eq. (3). E_{PVCt} (MWh) refers to the PV generation which is charged to the battery and would be otherwise curtailed without the battery operation. From a battery perspective, the price associated with the battery discharge, P_i (CHF/MWh) is used across Eqs. (1), (2) and (3). However, we make the difference on the opportunity cost. While for PV energy time-shift the PV owner can get some alternative benefit by exporting to the grid (instead of charging the battery), for the avoidance of PV curtailment there is not benefit alternative. As a result, no term is subtracted in Eq. (3).

$$Benefit_{PVts} = E_{dis} \times P_i - E_{char} \times P_{ex} \tag{1}$$

$$Benefit_{PVts} = E_{char} \times P_i \times (\eta - \frac{P_{ex}}{P_i}) \tag{2}$$

$$Benefit_{PVCt} = E_{PVCt} \times \eta \times P_i \tag{3}$$

Regarding the transformer, its avoided replacement cost could also be internalised as an economic benefit, $Benefit_{T\&D}$ (CHF), when integrating BESSs and/or PV curtailment in the distribution network, therefore the transformer's lifetime is not used for the techno-economic analysis. A new nominal rating equal to 1.5 MW (the original rating is 1 MW) and larger than the maximum reverse power flow (1.31 MVA) is assumed for this upgrade which market price is assumed to be 20 kCHF (datum from 2015) [28]. From an internalization perspective, this service benefit can only be accrued in the case of a BESS owned by the DSO which is located next to the transformer and which is sized for avoiding any PV reverse power larger than the physical capability of the transformer. However, a consumer who purchases a PV-coupled battery system cannot profit from this service benefit despite its potential contribution.

Eq. (4) is used to calculate the total value associated with a BESS when it performs PVts and it is sized to avoid any PV curtailment (i.e. assuring the reverse PV power does not exceed the physical capabilities of the transformer). Otherwise, the T&D economic benefit is associated with PV curtailment. Table 2 is provided as a guide to understand the relationship between the location of a BESS and the value creation.

$$BESS_{value} = Benefit_{PVts} + Benefit_{PVCt} + Benefit_{T\&D} \tag{4}$$

2.3. Battery model and input data

This section provides the equations used to simulate the BESS' schedule depending on the location and number of services delivered. Except for the scenario in which a BESS is located next to the distribution transformer and sized to prevent any PV curtailment (scenario B2, see Table 2), the battery capacity is treated as a variable to be optimized. We consider an electricity demand profile described as $PL \in R^{n \times k}$, a PV generation profile depicted as $PV \in R^{n \times k}$ and an electricity price profile defined as $E_p \in R^{1 \times k}$, where n is the number of profiles and k is the number of measurements. Here, n is equal to 111 and k equals 35040 because measurements were taken with a time resolution of 15 minutes during 365 days. The difference between the generation (PV) and consumption (PL) at each bus i is calculated as follows.

$$P_{LV}(i,k) = PL(i,k) - PV(i,k), \quad i = 1,2,\ldots,n \tag{5}$$

and the power flow on the transformers $PG \in R^{1\times k}$ is equal to

$$PG = \sum_{i=1}^{n} P_{LV}(i,k) \cdot \tag{6}$$

A positive value $PG(k)$ represents a power flow from the medium voltage side towards the low voltage side i.e. the grid is providing electricity to the demand loads. A negative value $PG(k)$ represents a reverse flow in the transformers i.e. the excess power from the distribution system is fed back to the main grid.

2.3.1. Battery located next to the distribution transformer performing PV energy time-shift and the avoidance of PV curtailment

Here, a BESSs charges as soon as there is a reverse flow in the transformer $PG(k) < 0$ and there is free capacity in the battery $SoC_i(k) < Q_{i\_max}$, where Q_{i_max} is the maximum capacity and SoC_i the state of charge of the $i-th$ battery. Inversely, a BESSs discharges when the electricity demand is higher than the PV production $PG(k) > 0$ and the battery has energy stored $SoC_i(k) > 0$. This scenario is referred to as B1 in this manuscript and summarized in the following equation.

$$\begin{array}{llll} \text{if} & \mathrm{PG}(k) < 0 & \& & \mathrm{SoC}_i(k) < Q_{i\_max} \\ & P_{char}(k) = \mathrm{PG}(k), & & P_{dis}(k) = 0 \\ \text{else} & P_{char}(k) = 0, & & P_{dis}(k) = 0 \\ \text{if} & \mathrm{PG}(k) > 0 & \& & \mathrm{SoC}_i(k) > 0 \\ & P_{char}(k) = 0, & & P_{dis}(k) = \mathrm{SoC}_i(k) \\ \text{else} & P_{char}(k) = 0, & & P_{dis}(k) = 0 \end{array} \tag{7.1}$$

2.3.2. Battery located next to distribution transformer performing PV energy time-shift, avoidance of PV curtailment and T&D upgrade deferral

In this case, the capacity of the BESS is fixed to store any reverse power flow larger than the transformers capacity which is predefined as power limit (P_{lim}). The difference between the reverse power flow and the limit is used to charge ($P_{char} \in R^k$ in MW) a BESS as described below.

$$\begin{array}{lll} if & -PG(k) \le P_{lim} & \\ & P_{char}(k) = PG(k), & P_{dis}(k) = 0 \\ else & & \\ & P_{char}(k) = 0, & P_{dis}(k) = 0 \\ end & & \end{array} \tag{7.2a}$$

where $P_{dis} \in R^k$ is the discharge power in MW. Moreover, discharging is not allowed during these times to prevent charging and discharging at the same time. Finally, a *BESS* discharges only when the price of electricity in the market surpasses a predefined price during the day, defined as $E_p^{max}(k)$ in EUR/MWh. More details about this are given in Section 3. The discharging rule is then:

$$\begin{array}{ll} if & SoC(k) \ge 0 \ \& \ E_p(k) \ge E_p^{\max}(k) \\ & P_{char}(k) = 0, \quad P_{dis}(k) = P_{LV}(k) \\ else & \\ & P_{char}(k) = 0, \quad P_{dis}(k) = \min(SoC(k)\eta, P_{LV}) \\ end & \end{array} \tag{7.2b}$$

Note that discharging is limited to the storage capacity. This scenario is referred to as B2 in this manuscript.

2.3.3. Battery at each individual dwelling, performing PV energy time-shift

These BESSs follow a similar schedule to those in Section 2.3.1. The charge and discharge scheduling is as follows: a BESS charges as soon as there is a reverse flow at each consumer $P_{LV}(i,k) < 0$ and there is free capacity in the battery$SoC_i(k) < Q_{i_max}$. Inversely, a BESSs discharges when the electricity demand is higher than the PV production $P_{LV}(i,k) > 0$ and the battery has energy stored $SoC_i(k) > 0$.

$$\begin{array}{llll} \text{if} & P_{LV}(i,k) < 0 & \& & \mathrm{SoC}_i(k) < Q_{i\_max} \\ & P_{char}(k) = P_{LV}(i,k), & & P_{dis}(k) = 0 \\ \text{else} & P_{char}(k) = 0, & & P_{dis}(k) = 0 \\ \text{if} & P_{LV}(i,k) > 0 & \& & \mathrm{SoC}_i(k) > 0 \\ & P_{char}(k) = 0, & & P_{dis}(k) = \mathrm{SoC}_i(k) \\ \text{else} & P_{char}(k) = 0, & & P_{dis}(k) = 0 \end{array} \tag{7.3}$$

The state of charge ($SoC \in R^k$) of a BESS is calculated integrating the power charged and discharged every hour. The initial level of the *SoC* can be set by the user, e.g. the battery can be initially empty.

$$SoC(k) = \int_0^k (P_{char}(k) + P_{dis}(k)) \times \Delta t/60, \tag{8}$$

where Δt is the data sampling period measured in minutes.

From the cost perspective, a BESS comprises four different components, namely cell stack (storage medium), inverter cost, balance-of-plant (BoP) and maintenance. A novelty of this methodology is that the cost of a BESS does not change linearly with size. The reason is that the cell stack cost increases linearly with the battery capacity but the other three subcomponents are subject to economies of scale [29]. This is considered in this study by using a power relationship with a scaling factor equal to 0.7 as a first approximation (a detailed analysis of this relationship was outside the scope of this study). The main characteristics such as cell battery cost, round trip efficiency, cycle life, inverter cost, BoP cost and maintenance cost are given in Table 1 for Li-ion batteries. Previous reviews have pointed out that there is still important uncertainty in key battery parameters such as cost and maximum cycle life. The sensitivity of the techno-economic performance of Li-ion batteries has already been discussed in the previous literature and therefore it is not included in this study [30,31].

2.4. PV curtailment

Two PV curtailment options are considered for investigation. The first option is based on a fixed feed-in limit set in each inverter as a share of the nominal AC power (we refer to this strategy as scenario C2 later). Here, the nominal PV power at each node is

Table 1
Technical and economic characteristics assumed in this study for Li-ion battery energy storage systems (BESSs).

Parameter (Unit)	Li-ion BESSs
Round Trip Efficiency (%)	90
ΔSOC	0.8
Maximum SOC	0.9
Minimum SOC	0.1
Power Rating (kW)	Q
Cell cost (CHF/kWh)[a]	300
Battery inverter rating (kW)	Q
Battery inverter cost (CHF/kW)[b,c]	300
Balance-of-plant cost (CHF/kW)[c,d]	10
Maintenance cost (CHF/kW)[c,d]	10
Maximum cycle life (EFC)[e]	3000
Z (%/EFC)	0.0075
Maximum calendar life (years)[e]	22
Calendar losses (%/month) [e]	0.07

[a]Projected future battery cost [32].
[b]Future projected cost for inverters [33].
[c]This sub-cost was not assumed to increase linearly with the battery capacity but following a power function with 0.7 as scaling factor.
[d]Based on published data from the Department of Energy (DOE) [34].
[e]Equivalent full cycles (EFC) From available literature [35,36] and confirmed with manufacturers.

Table 2
Various scenarios and related implications for BESSs and curtailment strategies considered in this study regarding the location, stakeholder and control respectively.

Scenario	B1	B2	B3	C1	C2
Solution	BESS	BESS	BESS	Curtailment	Curtailment
Location	Substation	substation	Dwellings	Dwellings	Dwellings
Owner/Operated by	DSO	DSO	Consumer	DSO	EConsumer
Electricity price	Wholesale	Wholesale	Retail	Wholesale	wholesale
Size/Control	Optimised[a]	Fixed	Optimised	Dynamic	Fixed
Service benefits	PVts and PVCt	PVts, PVCt and T&D	PVts and PVCt	T&D	T&D
Economic benefits	PVts and PVCt	PVts, PVCt and T&D	PVts and PVCt	T&D	T&D

[a] Optimised refers to the battery capacity is a variable which is optimized using simulations.

estimated as the maximum of the PV generated power over the year (such feed-limit is currently set in Germany at 50% for households benefiting from subsidies for BESS installed in single dwellings). The second option, refer as scenario C1, assumes that PV production is curtailed dynamically to keep the transformer within its power limit. The PV penetration (given here by the ratio of yearly production to consumption at each node) varies in this study from 0 to more than 140% depending on the nodes. Fig. 1(a) shows the share of the PV production of each node that is self-consumed as a function of the PV penetration. Note that PV penetration is defined as the ratio of annual total production to annual total consumption at each node. Self-consumption decreases for increasing PV penetration. Almost all the PV generation is self-consumed for a PV penetration up to 20%. With a feed-in limit of 50%, excess power that would eventually lead to an overload of the transformer is curtailed at the PV system level and no overload is observed at any time. The curtailed energy varies from node to node as see on Fig. 1(b) and corresponds to a global energy curtailment of the PV production by 3.2%. This value is consistent, as seen in Fig. 1(b), with the PV global penetration of 51.7% determined for the entire grid under investigation. In comparison a dynamic curtailment (which would require some communication mean between the power value at the transformer site and all inverters) would result in a curtailment of the PV production of 1.3%.

3. System under investigation

The system under investigation and depicted in Fig. 2, is a residential area of the city of Zurich at the west side of its lake. This system offers an ideal case study to demonstrate the impact of PV penetration on distribution grids due to the combination of relatively low electricity demand load and large rooftops areas available. It is estimated that there are approximately 1300 inhabitants in this residential area and that there is a surface of around 0.4 km^2 available for PV installation (i.e. 308 m^2 per inhabitant approximately), according to Meteotest, the leading provider of land registry in Switzerland [37]. The distribution system is fed with two transformers with a total capacity of 1000 kVA MV/LV and it has a total of 254 nodes, of which 111 are house connections while the system is interconnected through 262 lines. Due to space limitations, the details of the meshed network topology of the system under investigation are omitted in Fig. 2. For more information about the system see previous references [15,38,39]. The location of the electricity demand loads and available PV measurements are known, thus there exist 111 individual demand loads and *PV* profiles. While the demand loads values represent physical measurements, PV productions has been simulated using the average of 288 real PV plants near Zurich. These profiles are distributed and scaled as a function of the available well oriented roof area assuming full coverage of the

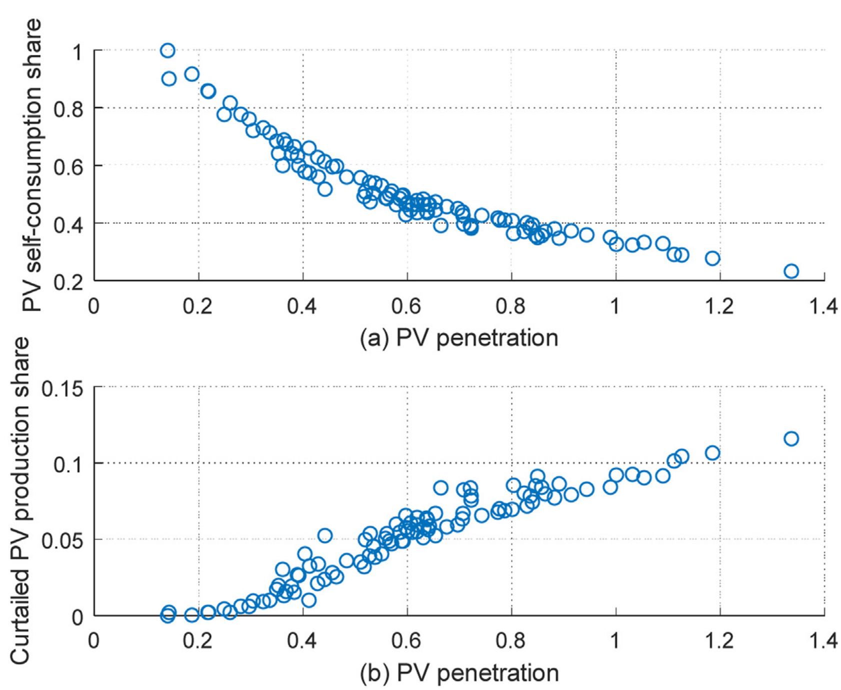

Fig. 1. (a) PV production that is self-consumed as a function of PV penetration at each node. (b) Energy curtailment at each node with a 50% fed-in limit as a function of PV penetration.

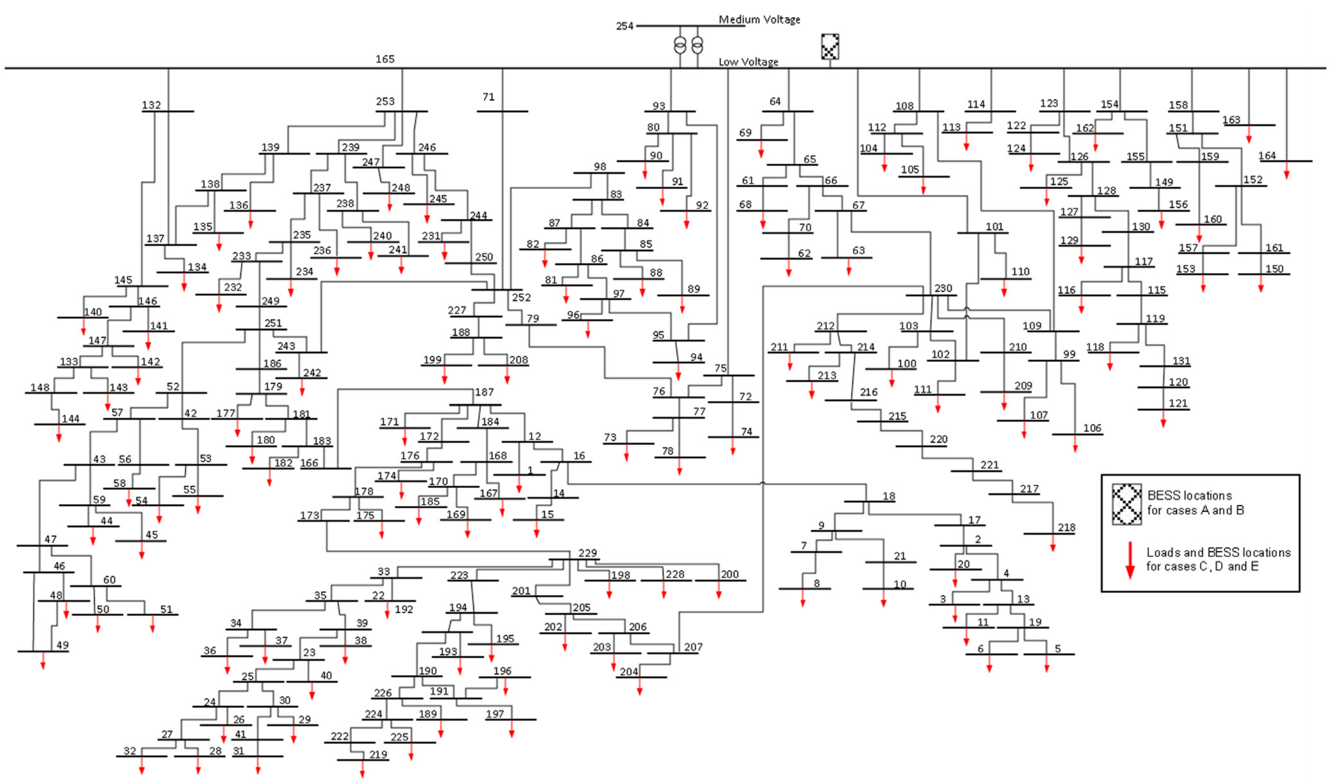

Fig. 2. Model of the distribution network with large PV penetration in Zurich (Switzerland).

modules. For this purpose the solar cadaster of the city of Zurich was used and only rooftops with the classification *good* and *very good* were considered with a total area of 18458m^2 (i.e. 14.2 per inhabitant). Fig. 3(a) shows the combination of the 111 individual profiles (PV production minus electricity demand) and the wholesale electricity price in Switzerland over one year with a resolution of 15 minutes and Fig. 3(b) depicts the average values per day, where E_{pday} is the electricity price limit per day calculated as follows:

$$E_{pday} = (E_{pday}^{\max} - E_{pday}^{\min}) \cdot (1 - \sigma) \tag{9}$$

Where E_{pday}^{max} and E_{pday}^{min} are the highest and lowest price of each day, respectively and σ is a variation from the mean value in percent defined by the DSO (45% in this case). From Fig. 3(a), it can be noticed that PV generation is considerably high during the summer as indicated by the larger picks on this trace. Fig. 4 shows the power flow on the transformers (also over one year). In this example, the maximum power flow through the transformers has been set to 100% of their nominal capacity. In Fig. 4, the plane shown in grey represents the maximum amount of active power allowed to flow towards the medium voltage side. As the figure indicates, the predefined limit is surpassed due to the large amount of power excess from March to September during a cumulated time of 233 h. The energy storage installation potential depends on various factors such as surplus PV generation and cost of the storage battery system. Other factors to be considered in a project would be the available physical space for the storage system and potential incentives from the regulatory context, which are not considered here. Finally, we note that the mesh network under investigation does not present voltage excursions out of accepted limits at any node even under full PV production and therefore the position of a BESS (distributed or centralised) can be chosen arbitrarily.

4. Application to the distribution system

Several scenarios are defined in order to compare battery technology versus PV curtailment from a cost and value perspective as well as the implications of the location and associated stakeholder involvement. Table 2 summarizes the key characteristics of each scenario considering that battery storage and PV curtailment are never combined across any scenario. Scenarios which focus on battery storage are referred with the letter B and scenarios which propose curtailment solutions are referred with the letter C. The scenarios on batteries differ on where the battery is located, the stakeholder operating the battery and the number of economic benefits associated with the battery performance. In particular, we compare a relatively large battery next to the distribution transformer (scenarios B1 and B2) with various small scale batteries located across the buses where the PV systems of consumers are installed (scenario B3). Batteries installed next to the distribution transformer deal with wholesale prices and are controlled by a DSO but we distinguish two different roles. In the first one which is referred to as scenario B1 (see Section 2.3.1), a BESS is located in the distribution substation and shifts any surplus PV generation across the distribution network but this strategy does not assure that the maximum reverse flow is always smaller than the physical capacity of the transformer. Therefore, the avoided cost related to the replacement of the transformer cannot be accrued in this case. In the scenario B2 in Table 2 (Section 2.3.2), we study a BESS with a capacity of 1.65 MWh which is able to store any reverse power larger than the nominal capacity of the transformer (i.e. avoiding any PV curtailment). This BESS can therefore gather all economic benefits given in equation (4) although the amount of PV energy managed is limited to the flow exceeding the transformer physical limit.

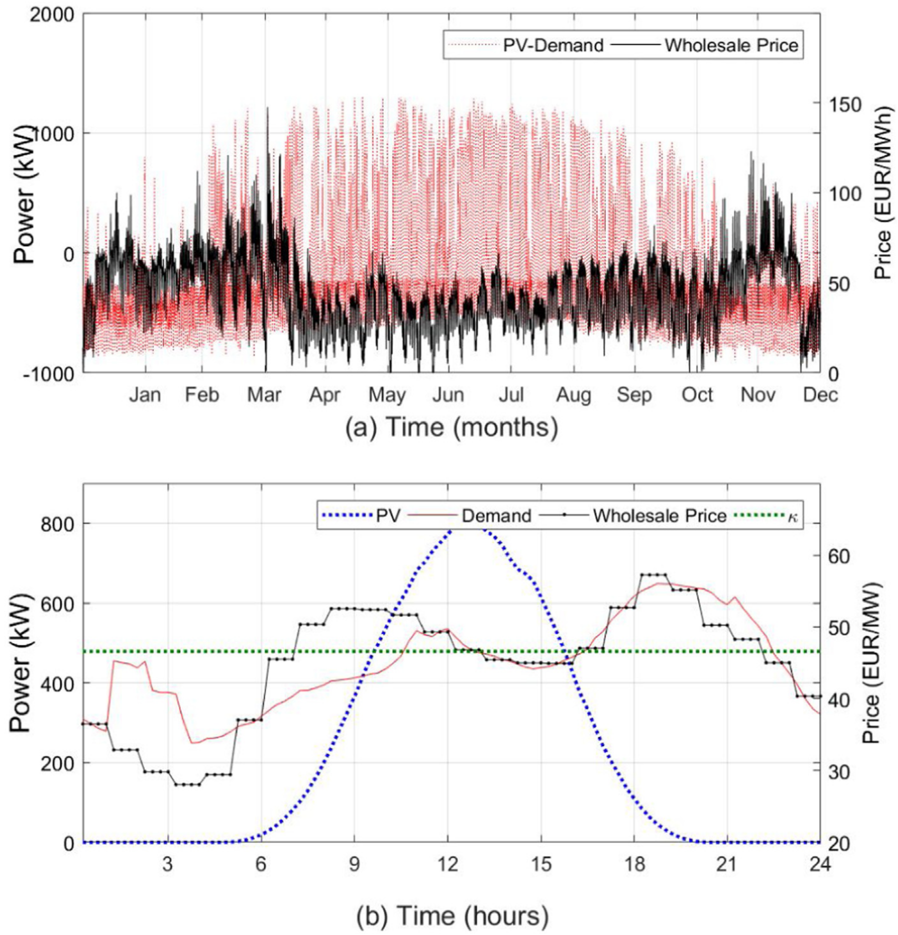

Fig. 3. (a) PV, electricity demand and electricity price during one year. (b) Average PV, electricity demand, electricity price and electricity price limit per day.

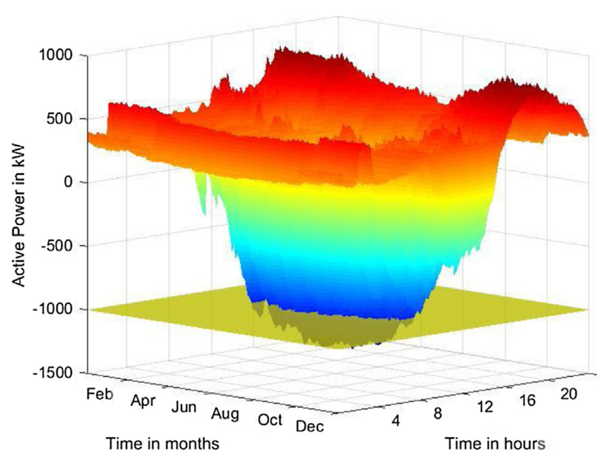

Fig. 4. Active power flows through the transformers.

The scenario B3 (Section 2.3.3) corresponds to batteries installed 'behind the meter' and we illustrate it with the bus 104 corresponding to a dwelling with the PV generation and demand data given in Table 3. Residential batteries manage local PV generation by performing PV energy time-shift which economic benefit is calculated with Eq. (2). The battery discharge replaces grid imports at retail price. Furthermore, consumers owning these batteries can also benefit from the avoidance of PV curtailment since these batteries avoid PV export (see Eq. (3)). However, they cannot economically benefit from T&D deferral despite the battery activity may avoid that the total reverse PV power in the area remains lower than the transformer limit since the transformer asset is owned by a different stakeholder, namely a DSO.

Scenarios C1 and C2 focus on PV curtailment but they differ on the type of control and stakeholder involved in the curtailment strategy (consumers versus a DSO). The scenario C1 assumes that PV curtailment is adjusted dynamically by the DSO whenever the PV reverse power flow exceeds the nominal total capacity of the distribution transformers (1 MVA 11 kV/400 V). On the other hand, PV curtailment is executed at a fixed threshold on injected power by consumers in the scenario C2 (for an explanation of both strategies, see Section 2.4).

Regarding battery storage and for scenarios B1 and B3, 10 different battery capacities, Q (kWh), are tested in order to understand the impact of the capacity on the techno-economic benefits brought by a BESS. This is referred to as optimized in Table 2, opposite to a fixed battery capacity for the scenario B2. The

Table 3
PV generation and electricity demand characteristics of the dwelling selected for the study of the residential battery system.

PV installed capacity	Peak electricity demand	Annual PV generation	Annual demand
4.9 kW	5.9 kW	5550 kWh	2900 kWh

battery capacity which is capable of absorbing any reverse power larger than the nominal capacity of the transformer (i.e. 1.65 MWh) is also used as maximum capacity in the scenario B1 (i.e. delimiting the search space of the optimization from the upper side). Similarly, a maximum battery capacity of 20 kWh is selected for the residential application (scenario B3) in agreement with other previous studies for single homes [11,9]. Our range therefore includes typical capacities available in the market between 4 and 10 kWh but goes beyond up to 20 kWh considering the characteristics of the dwelling give in Table 3. In particular, the annual PV generation (5550 kWh) significantly exceeds the electricity demand (2900 kWh) respectively. The minimum battery capacity as well as the capacity discretization is equal to a tenth of the maximum battery capacity in both scenarios B1 and B3.

5. Techno-economic assessment

BESS and PV curtailment are compared with two indicators: the levelized cost and levelized value. The levelized cost of a BESS, *LCOES* (CHF/MWh), is the ratio between the total cost of a BESS (including both capital and maintenance expenses) and the life cycle discharge throughout the project (a generic year is represented by k) considering the value of money time. It is defined by equation (10) and we use input data from Table 1 as well as the discharge resulting from the BESS operation. Likewise, the levelized value of energy storage, *LVOES* (CHF/MWh), measures the total revenues and benefits (e.g., avoided costs) defined by equation (4), with regard to the life cycle's BESS discharge as shown in equation (11). The type and number of economic benefits depend on the scenarios given in Table 2.

$$LCOES = \frac{CAPEX + \frac{OPEX}{(1+r)^k}}{\sum_{k=0}^{n} \frac{E_{dis}}{(1+r)^k}} \tag{10}$$

$$LVOES = \frac{\sum_{k=1}^{n} \frac{BESS_{value}}{(1+r)^k}}{\sum_{k=1}^{n} \frac{E_{dis}}{(1+r)^k}} \tag{11}$$

In the case of PV curtailment (regardless of whether it is based on a fixed or dynamic feed-in limit), the calculation of the levelized cost, *LCOCt* (CHF/MWh), and levelized value, *LVOCt* (CHF/MWh), are based on the PV energy which is curtailed, *EPVCt* (MWh), as given by Eqs. (12) and (13), respectively. The associated curtailment cost, *OPEXCt* (CHF), is based on the value of the PV generation which is curtailed, *PVCtE*, considering the wholesale prices as defined in Section 3.1, while the benefit is given by T&D upgrade deferral of the transformer. A discount rate equal to 4% is used accross this techno-economic analysis from a social perspective [40].

$$LCOCt = \frac{\frac{OPEX_{Ct}}{(1+r)^k}}{\sum_{k=0}^{n} \frac{E_{PVCt}}{(1+r)^k}} \tag{12}$$

$$LVOCt = \frac{\sum_{k=1}^{n} \frac{BESS_{T\&D}}{(1+r)^k}}{\sum_{k=1}^{n} \frac{E_{PVCt}}{(1+r)^k}} \tag{13}$$

Finally, we also use the NPV per unit of CAPEX to balance cost and value of batteries, given by equation (14). Here, CF_k refers to the cash flow of a year k considering economic benefits and costs.

$$NPV_{CAPEX} = \frac{\sum_{n}^{k=0} \frac{CF_k}{(1+r)^k}}{CAPEX} \tag{14}$$

6. Simulation results

Fig. 5 gives the levelized cost and levelized value as a function of the battery capacity for the various scenarios included in this analysis. We divide our results depending on the location where the solution (battery storage and PV curtailment) is applied, namely a substation in Fig. 5a (left side) and a dwelling in Fig. 5b (right side), and a total of 10 battery capacities are compared for scenarios B1 and B3 respectively. The levelized cost and levelized value are shown in the same figure allowing a direct examination of the economic attractiveness of the project: a solution is interesting when the levelised value is higher than the levelised cost. Finally, the levelized cost of PV curtailment, LCOCt (CHF/kWh), is given as a straight line in Fig. 5(a) and (b) but the levelized value of PV curtailment, LVOCt (CHF/kWh), is only indicated but not plotted because it is out of scale.

Focusing on a BESS connected to the distribution transformer of the substation, we distinguish whether curtailment is possible or

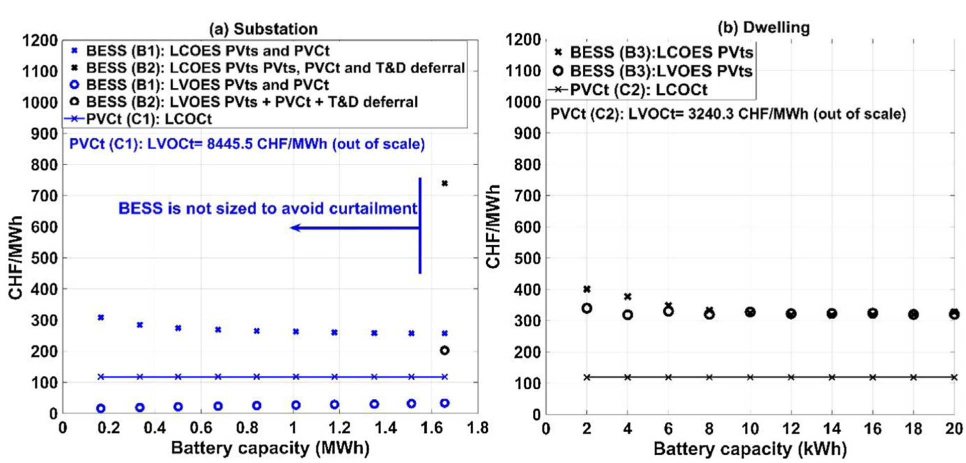

Fig. 5. (a) Levelized cost, LCOES (CHF/kWh), and levelized value, LVOES (CHF/kWh) for the scenarios corresponding to solutions implemented in the substation, namely B1, B2 and C1; and (b) scenarios corresponding to solutions located in an individual dwelling, namely B3 and C2. For the scenarios B1 (10 different capacities), B2 (a single battery capacity, 1.65 MWh) and B3 (10 different battery capacities) results are presented as a function of the battery capacity.

not. If PV curtailment is allowed (see scenario B1), a BESS is charged whenever there is surplus PV energy but the battery capacity is not designed to limit the maximum PV reverse power beyond the nominal capacity of the transformer. Therefore, we test 10 battery capacities, the largest having a capacity of 1.65 MWh (the same capacity as the BESS in the scenario B2 where the battery capacity is fixed to avoid any PV curtailment). Storing all surplus PV energy (beyond avoiding PV curtailment) increases the battery discharge and this has a positive impact in the levelized cost regardless the battery capacity but also, the levelized cost decreases with the capacity due to economies of scale assumed for the inverter, BoP and maintenance. For example, the levelized cost associated with a 0.2 MWh and 1.5 MWh BESS is 308.1 CHF/MWh and 257.1 CHF/MWh respectively. However, increasing the capacity beyond 1.5 MWh also increased the levelized cost (e.g., 257.1 CHF/MWh for a 1.7 MWh battery) since the reduction on EFC counterbalanced the economies of scale. For battery capacities much larger than 1.7 MWh, this trend becomes asymptotic. Furthermore, the levelized value associated with PV energy time-shift increased gently with the battery capacity from 15.7 CHF/MWh (0.2 MWh capacity) to 33.3 CHF/MWH (1.7 MWh BESS capacity), since larger capacities allow BESSs to discharge at higher value during the evenings.

If PV curtailment is not an option (see scenario B2), the levelized cost associated with the required BESS is significantly higher, equal to 740 CHF/MWh, the motive being twofold. Firstly, a large battery capacity (1.65 MWh) is required in order to guarantee that all PV power larger than the nominal transformer capacity (1 MW) is absorbed during the summer season. On the other hand, this large BESS implies that the full capacity is underused throughout the year except in summer. As a result, only 39 equivalent full cycles (EFC) were performed on a yearly basis. The total value associated with the BESS discharge is equal to 202.3 CHF/MWh, being the aggregation of the value associated with the deferral of the transformer cost (24.5 CHF/MWh), the avoidance of PV curtailment (144.5 CHF/MWh), and the selling of PV electricity in the wholesale market (33.3 CHF/MWh), see Fig. 6(a).

As the comparison of Fig. 5(b) and (a) shows, performing PV energy time-shift with a residential BESS offers 13 times more value (between 320-340 CHF/MWh) than with a BESS next to the distribution transformer (up to 33 CHF/MWh). The discharge of residential batteries replaces retail electricity prices (instead of wholesale prices) and this increases the value. However, the levelized cost of the residential batteries (the minimum equal 317 CHF/MWh for a 14 kWh BESS) is always higher than for the BESS connected to the distribution transformer. For residential BESS with a capacity ranging from 10-18 kWh, the value associated with the discharge is higher than its cost. Fig. 6(b) shows how residential batteries are the only case in reaching a slightly positive NPV per unit of CAPEX, i.e. allowing the investor to fully recover the investment and even earn some money (2% of CAPEX). Although it is not shown here, the NPV value of PV curtailment (both fixed and dynamic) is of several thousands indicating the profitability of implement these solutions in the distribution network.

To put our results into the current context using data from 2015, a well-designed PV-coupled battery system performing PV self-consumption in Switzerland could perform up to 250 EFC per year. As a result, the LCOES is around 400 CHF/MWh even with current battery cell prices of 500 CHF/kWh [41]. From a value perspective, current residential batteries can create up to 150 CHF/kWh but this value is expected to increase over time following the expected increase on retail prices across the energy transition [42]. At the utility scale and based on simulations using the current state-of-art, the levelized cost of batteries ranges between 120 CHF/MWh and 500 CHF/MWh depending on model efficiency, lifetime and value of electricity prices at charging time [43]. Furthermore, daily cycles (e.g., arbitrage) are more effective to reduce the levelized cost than short-term discharges (e.g., frequency control). On the other hand, short-term applications (also referred as power applications) can bring high value, even larger than the maximum value associated with electricity arbitrage in the wholesale market, around 200 CHF/MWh [44]. However, the annual average value of arbitrage reduces significantly, as proved in this study with PV energy time-shift at the utility scale.

For PV curtailment, the LCOES is totally borne by the PV producer as curtailment decrease the energy produced. The curtailment induced by the introduction of a 50% PV feed-in limit at each node (scenario C2) leads to a loss of only 3.2% of the PV production. The associated LCOCt (i.e. cost of the PV energy that cannot be sold to the wholesale market) is equal to 118.6 CHF/MWh. In contrast the LVOCt is very high (8445.5 CHF/MWh) as PV curtailment does not incur any capital cost but it avoids purchasing a new distribution transformer. However, PV curtailment only benefits the DSO. Another interesting situation for DSOs in countries where they also perform the role of utilities (e.g., Switzerland) would be to buy the PV surplus electricity (which is not self-consumed) at each node at the wholesale price and re-sell it locally to consumers of the same low voltage grid at retail price.

7. Discussion and conclusions

Although this study addresses a future Swiss scenario with large PV penetration, a transition from the current situation to the one under investigation seems likely if we attend to the current position of key stakeholders. Regarding consumers, the acceptance to PV by Swiss citizens have been demonstrated by various interviews and people almost unanimously hold a strongly positive

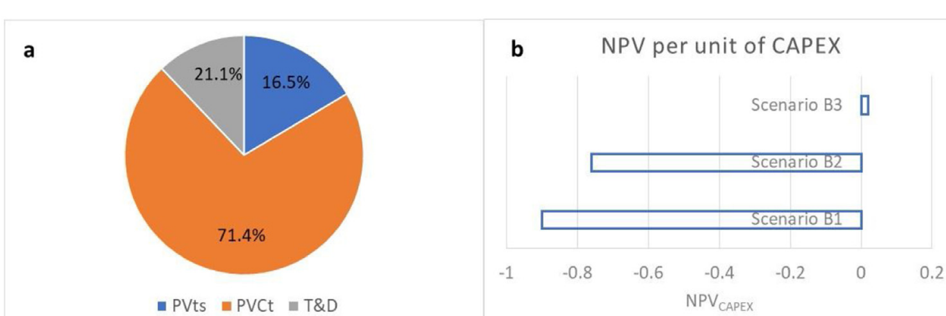

Fig. 6. (a) Breakdown of the value creation as percentage of the total (202.3 CHF/MWh) for the 1.6 MWh battery in the scenario B2 as a function of the applications incorporated in the value proposition, namely PV energy time-shift (PVts), avoidance of PV curtailment (PVCt) and T&D upgrade deferral (T&D); (b) Net present value per unit of CAPEX for the three different batteries scenarios (optimal batteries in scenarios B1 and B3).

imaginary of solar power [45]. PV panels, heat pumps and batteries are in this order the preferred energy technologies for consumers. Moreover, the Swiss citizens voted for the proposed Energy Strategy 2050, which requires the phase-out of nuclear and its replacement by RE technologies, mainly solar. Utility companies across Switzerland also have very important ambitious for PV energy. For example, the canton of Geneva and its local utility have set the goal to quadruple electricity generated from PV by 2025, while the canton of Zurich has targeted to increase a current PV consumption of 15% of the total consumption per person to a 50% by 2035 [46]. Finally, the Swiss Government was the first one to communicate its objectives after the Paris Agreement with 50% greenhouse gas emissions reduction by 2030 relative to 1990.

Following this trend, battery storage and PV curtailment have been analyzed and compared for a distribution grid in Zurich (Switzerland), with large PV penetration in a future scenario after the phase-out of nuclear power expected by 2035. This study considers two different scales for managing PV generation within the distribution grid: single dwellings and a centralized management by the DSO. Consumers and DSOs respectively are in charge of purchasing the equipment respectively. Managing PV energy with a BESS at the residential level increases both the levelized value and levelized cost of stored PV electricity compared to a centralized management by the DSO. Consumers should pay 23% more for the battery discharge from a life-cycle perspective but residential batteries allow them to replace retail electricity and this increases the value of the battery discharge markedly. This helps to create marginal economic cases for residential batteries with positive *NPV* results, i.e. *LVOES* values are slightly larger than *LCOES* values. Regarding DSOs, other systems benefits could be included by them related to PV management, namely avoidance of PV curtailment and distribution transformer upgrading, given their pivotal role and the central local of a BESS connected next to the distribution transformer. These two services increased the levelized value substantially (by 144.5 CHF/MWh and 24.5 CHF/MWh), but it remained still lower than the levelized cost. Limiting the battery charge to PV electricity exceeding the transformer rating increases the levelized cost up to 740 CHF/MWh reducing the economic attractiveness.

Regarding PV curtailment, we find that the marginal costs of lost PV production are much lower than the marginal costs of a distribution transformer. For fixed and dynamic control techniques, only up to 3.2% and 1.3% respectively of total PV electricity generation in energy terms should be curtailed for avoiding the transformer upgrading. Even for a PV penetration of 100%, curtailed electricity remains lower that 10% of the total PV production (see Fig. 1(b)). Acceptance by the PV producers of the losses associated with PV curtailment is however expected to be challenging. It may discourage PV deployment by introducing an additional economical risk, especially in the case of low feed-in limits or with dynamic curtailment (since it is more unpredictable from the PV producer side). Transformer upgrading would in theory allow for more PV hosting. However, for the present case study, the PV production is given by full coverage of well oriented roofs and does not allow for additional PV installations. Thus, there is no benefit in transformer upgrading. Given the very large gap between the LVOCt and the LCOCt, sharing of both costs and benefits of PV curtailment between PV producers and DSOs could much improve its acceptance. Possible schemes could comprise the purchase of PV electricity at a bonus price (with higher prices for lower feed-in limit) or a financial compensation (covering at least the curtailed electricity at retail price) in case of dynamic curtailment.

Residential batteries are becoming attractive for consumers due to reducing technology cost and increasing retail electricity prices. This study concludes than for Switzerland (and potentially for Europe due to similar ratio between wholesale and retail electricity prices), residential batteries are more attractive than centralized scales for PV management. Therefore, we anticipate that consumers will have a key role in driving the energy transition. Since the cost is the limiting factor for residential batteries, a possible strategy could be to develop community energy storage (CES) systems to reduce the capital expenditure and potentially the maintenance with some economies of scale. However, we can also argue that the system role of batteries managed by consumers is limited in comparison with the central position of DSO. On the other hand, the value yield by BESSs managing PV generation at the wholesale level is the weak spot. Therefore, DSOs should make use of their privileged position for battery deployment by considering other benefits which could be potentially provided to the energy system such as frequency control, arbitrage and voltage control. This is strongly the case for countries such as Switzerland where the electricity supply and the operation of distribution grids are vertically integrated. Our results suggest that the optimal performance of distribution networks requires both battery storage and curtailment. We therefore recommend that policymakers promote regulation which helps to create win-win situations for both consumers and DSOs considering both solutions. Interestingly, curtailment needs diminish as distributed battery installed capacity increases.

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