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Impact of energy communities on the distribution network: An Italian case study

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ABSTRACT

In this paper, a methodology for evaluating the potential impact of Energy Communities (ECs) on medium-voltage (MV) distribution networks is presented. To account for the various configurations and scenarios of ECs, a stochastic approach has been developed; it is based on a Monte Carlo simulation that generates a variety of EC configurations, varying the size and number of new generators, points of common coupling, and primary energy sources in the generation mix (wind, hydro, photovoltaics). The procedure proposed has the aim of evaluating all the possible configurations that could impact the grid's infrastructure. Following the execution of an hourly load flow procedure for the entire year for each configuration, output variables are processed obtaining analytical results to identify trends in losses, line and transformer loading, as well as voltage violations. The proposed methodology was applied to two case studies based on real MV networks. The first is relevant to an urban area with a high energy demand but limited generator capacity, while the latter is related to a mountainous, sparsely populated area with low energy demand and an abundance of renewable energy production. The results show that promoting coupling between loads and generators is a key factor for ensuring grid compliance (i.e. minimizing the grid impact) in the development of ECs.

1. European energy strategy and energy communities

The commitment of the European Union (EU) toward climate and energy is embedded into the fundamental Treaties that shaped the EU in its founding. First of all, the Treaty on European Union commits the EU to "work for the sustainable development of Europe, aiming at full employment and social progress, and a high level of protection and improvement of the quality of the environment" (Art 3) [1]. Moreover, the Treaty of Functioning of the European Union highlights the importance of the environmental protection in the Union' s policy, affirming that its "requirements must be integrated into the definition and implementation of the Union's policies and activities, in particular with a view to promoting sustainable development" (Art 6). The same Treaty states that energy and environment are areas in which the Union shares competence with the Member States (Art 4) and affirms that "Union policy on energy shall aim, in a spirit of solidarity between Member States, to promote energy efficiency and energy saving, and the development of new and renewable forms of energy" (Art 194) [2]. Driven by these strong regulatory commitments, throughout the years the EU has set objectives for increasing the share of renewables in the energy mix, as well as promoting energy efficiency. An important step in this direction was made in 2010, when the European Commission, headed by Jose Manuel Barroso, proposed the "Europe 2020" strategy to restart after the financial crisis. In the field of climate and energy, the strategy set the well known "20-20-20" target. The commitment to these targets led to the adoption of a set of binding legislation that includes the Directive 2009/28/EC on the promotion and use of energy from renewable sources (the first Renewable Energy Directive — RED), Directive 2010/31/EU on improving energy performance in buildings, and Directive 2012/27/EU on energy efficiency. In November 2014, the European Commission, headed by Jean-Claude Juncker, set among its top 10 priorities "a resilient energy union with a forward-looking climate change policy" and, in February 2015, launched its "European Energy Union Strategy" [3]. One of the main results of this strategy has been the presentation from the European Commission, on 30 November 2016, of a package of proposals, called the "Clean Energy for all Europeans Package" or "Clean Energy Package" for short (CEP) [4]. The proposal led to the adoption of eight legislative acts between 2018 and the first half of 2019, with which the European Union has reformed its energy policy framework. Among them there is the recast Renewable Energy Directive 2018/2001, also known as REDII, and the Directive on common rules for the internal market for electricity 2019/944, also known as Electricity Market Directive (EMDII). It is within this context, and specifically in Directive 2018/2001 (REDII) and

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Directive 2019/944 (EMDII), that the Energy Communities (ECs) are officially defined for the first time in the European Legislation. With reference to these legislations, the Energy Communities considered within this paper represent the Renewable Energy Communities defined within the REDII vision, rather than Citizen Energy Communities defined within the EMDII framework. Recently, the European Commission, formed in 2019 and headed by Ursula von der Leyen, announced the implementation of the "European Green Deal" [5], a set of policies with the ambitious purpose of making the EU carbon-neutral by 2050 through measures that include the massive decarbonization of the energy sector and improvement of energy efficiency in buildings. It is evident that achieving these challenging objectives can be highly intricate, and ECs are supposed to be one of the means at our disposal to accomplish them. Therefore, it is crucial to thoroughly evaluate the most effective methods for their design and raising awareness among the general public, as well as to assess their impact on existing infrastructures, to effectively steer their implementation. In this context, the aim of the paper is to present an accurate modeling of ECs and to evaluate their impact on the electric grid. While the focus of this work is primarily on modeling the ECs within the Italian framework, the proposed procedure for grid impact assessment has been designed to be as general as possible. It is worthwhile clarifying that in the Italian context, ECs are not isolated microgrids, and the energy produced is shared among community members using public infrastructures that are already in place. This approach is consistent with the REDII vision, which regards ECs as a group of consumers and generators who share energy in a local area on the public grid, typically on the local distribution grid. Therefore, achieving complete autarky is not a technical requirement, and self-sufficiency is not mandatory. With that being said, given the close relationship between ECs and energy sharing, incentive schemes are generally based on self-consumption, providing direct stimulus among the participants to aim for its maximization. Similarly, given the utilization of the public infrastructure for energy sharing among the EC members, analysis evaluating the impact on the electric grid are critical to assure future system reliability and develop effective policies.

The remainder of the paper is structured as follows: Chapter 2 discusses how the impact of ECs on the grid could be evaluated and identifies gaps in the literature that motivate this paper. Chapter 3 presents the proposed algorithm, while Chapter 4 provides real-life study cases that were used to validate the approach proposed. Chapter 5 describes how ECs have been sized using the proposed stochastic approach, which simulates a wide range of realistic scenarios. Chapter 6 presents the numerical results obtained from the simulations conducted, while Chapter 7 details the main conclusions drawn from the analyses.

2. Energy communities' impact on the distribution grid

Energy communities may have a key role in the decentralization of the energy system and in the exploiting of local renewable energy, although they may also pose certain challenges for the energy system [6]. The additional generation on the distribution networks could impact the quantity and price of the energy on the electricity market, as well as the operation of transmission and distribution networks. In the literature, several papers investigated the optimal sizing of ECs, ranging from the city districts to the single building level. [7] proposed a framework for establishing an EC in a city district. The aim of the paper is to quantify the advantages of optimizing the technology portfolio of ECs regarding cost and carbon emission reduction. The EC is modeled as a multi-energy system with the restriction of satisfying needs for electricity and heat of an energy system. [8] investigated the option of urban building clustering as a small-scale smart community solution. The participants cooperate by utilizing an Internet of Things (IoT)-based platform, in order to increase their energy self-sufficiency, and to decrease the city's CO2 emissions. Despite the significant number of papers that have focused on ECs, only a small portion have evaluated their impact on the electric grid. In [9], the potential impact of Renewable Energy Communities on the electric distribution grid was examined. The study proposed a Linear Programming optimization model to size the energy community's photovoltaics (PVs) and Energy Storage System (ESS). However, the impact on the grid was evaluated using a deterministic approach for a highly simplified CIGRE distribution grid model. Specifically, generators and energy storage apparatus were deployed using simplified assumptions, such as connecting them in predefined nodes at the beginning or end of the feeder. In [10] a mixed-use, all-electric community located in Denver, Colorado, was analyzed as a case study. The community was modeled using a physics-based urban energy modeling platform, which allowed the evaluation of the impact of PV, Electric Vehicles (EVs), and ESS on the community's energy usage, carbon emissions, and peak demand. However, similar to many studies in the literature, the grid impact was evaluated only with respect to the energy balance, i.e. as a reduction in the power peak injected and absorbed by the grid. A similar limitation is found in the approach proposed in [11], where a detailed appliances model is used for a given set of domestic houses, while the grid impact is limited to the estimation of the transformers' loading. In a similar vein, the study presented in [12] provides a detailed techno-economic analysis based on high-resolution real-world demand data from 3594 households. The study aims to evaluate how the configuration of a solar EC impacts its economic and technical performance. However, the evaluation of the grid impact is limited to the estimation of the maximum import and export power flowing through the transformer over the year for different energy community configurations. Other approaches have investigated the impact of ECs on a large scale, such as [13], which explores the effects of widespread medium-scale EC development across Europe on the European electricity and heating system. The focus is on the response of the capacity expansion of cross-border transmission and national generation and storage within the system, with and without ECs in selected European countries. However, these approaches often overlook the proper modeling of the grid and rely on evaluating only the net transfer capacity between virtual nodes, which are modeled to represent a given area, typically a country. In this paper, the impact that an EC could have on the planning and operation of the distribution network is evaluated. According to the Joint Research Centre of the European Commission "at the distribution network level, energy communities may improve quality of service (by reducing network losses) and reduce or postpone network investments (by increasing hosting capacity and improving flexibility)" [6]. In principle, it is possible to agree with this observation, nonetheless it has to be verified and a metric is required to quantify this theoretical benefits; to the best of the authors' knowledge, this presents a gap in the literature, motivating the present work. In particular, to properly evaluate EC's impact on the distribution grid, well consolidated approaches for investigating the impact of Distributed Generation (DG) are proposed as a proxy. Obviously, the main factors that differentiate the generators of an EC from a singular DG have to be considered. As a general definition, a DG "is an electric power source connected directly to the distribution network or on the customer site of the meter" [14]. However, despite all the environmental, economical and social benefits, it has an important impact on the operation of electrical grids. Increasing penetration of DGs could cause issues both, in normal operation mode (such as bidirectional power flow, voltage rise,

Table 1
Main differences between classical DG and new generation from ECs.

	Classical DG		Energy community
Purpose	Self-consumption	Sell energy	Energy sharing
Generation portfolio	Optimized for single user's consumption	Driven by market request and presence of incentives	Optimized for EC members' aggregated consumption
ESS	Behind the meter application (intra-POD balancing)	Price arbitrage	Collective storage (inter-PODs balancing)

overloading), as well as in faulty conditions (protection coordination and unwanted islanding). Several research activities have been carried out using statistical, deterministic, and heuristic approaches to ensure that the electrical network remains within the acceptable operational ranges when a given amount of DG is connected to the distribution grid [15]. The ability of the grid to accommodate new generators is commonly referred to as Hosting Capacity (HC), and various algorithms have been proposed for its evaluation [16–18].

Among the approaches used in the HC evaluation problem, it is possible to identify at least two classifications: a nodal HC evaluation or a global (grid-scale) approach. Moreover, HC computation could be based on deterministic [19,20] or stochastic models. Examples of HC evaluation can be found in literature, both for the nodal [21], as well as the global one [22–24]. In the literature, stochastic approaches are adopted for various goals closely related to the topic of ECs; obtaining load profiles [21], siting of generators [22,25] and simulating generators' profiles [23,24,26]. In Italy, studies to evaluate the nodal HC in MV and Low Voltage (LV) grids have been also commissioned by the National Energy Authority [27,28]. As previously mentioned, activating an EC from the grid's perspective can be simplified as deploying one or more generators on the distribution network, leading to an increase in the penetration of dispersed generation. However, there are some characteristics that are unique to ECs, and therefore the study of hosting capacity differs in some ways. The main differences between a classical DG and new generation for the purpose of EC participation are presented in Table 1. The main factor that distinguishes these forms of generation is the purpose that drives their installation. The proliferation of DG has two primary economic drivers: in one case, the installation's purpose is the internal usage of the energy produced (self-consumption), while in the other, it is to sell the entire production, often due to incentives for renewable energy production. The primary difference in generators installed from an EC perspective is that they are sized and controlled to maximize self-consumption within the community for an economic benefit. Furthermore, when discussing the difference from the electric grid's point of view, the main distinction is the correlation obtained in the results. Mainly, in studies assessing the impact of DG on the grid, the goal is to assess the impact as a function of the injection of power, whereas in the EC paradigm, the goal is to assess the impact on the grid as function of the number of users participating in an EC. This is made possible by first optimizing the generation portfolio for the specific EC. Given the steep rise of EC adoption nowadays, the authors feel like this type of analysis is crucial to properly assess potential grid inadequacy issues. Similarly, when discussing ESS resources from the grid's perspective, in a classical DG approach, usually the objective is smoothing of the grid's power profiles. On the contrary, using an ESS to maximize the energy shared within an EC is a novelty, and it affects the distribution grid diversely.

3. Proposed methodology

A stochastic methodology based on Monte Carlo simulations is proposed to evaluate the impact of an EC on the distribution network. This approach has mainly been inspired by those previously formulated to quantify the HC [15–18]. The considered EC model is based on the possibility for users, supplied by the same High Voltage (HV)/MV substation, to form an EC and share energy utilizing the public MV distribution network. It is worth noting that the HV/MV substation constraint aligns with the Regulatory Framework in place in Italy, Resolution Arg/elt 727/2022 [29], which governs the local characteristics of energy communities. This type of regulatory framework justifies the self-consumption incentives by the reduction in losses on the HV grid. Similarly, the local nature of ECs is a goal in other countries within the European Union as well, albeit with proximity constraints typically expressed in a more simplified manner, such as imposing a maximum aerial distance between loads and generators participating in the EC. Examples of this type of legislations include Germany [30], France [31], Greece [32], Portugal [33]. This means that the direct replicability is conditioned by the possibility to share energy under the same HV/MV substations, whereas imposing an aerial distance constraint would require an update in the logic for localization of generation units. The EC will install a Distributed Energy Resources (DER) portfolio based on its preferences regarding size and location of the generation portfolio, and this will have an impact on the operation of the grid. The portfolio may consist of one or more generators, based on different energy sources, and possibly a centralized ESS.

The following sets of elements are used for modeling the problem.

- U^{LV}_{Area}: Low voltage passive users fed by the MV grid (through a MV/LV substation);
- U^{MV}_{Area}: Medium voltage passive users connected to the MV grid;
- G_{Area}: Generators connected to the local distribution grid;
- U^{LV}_{EC}: Low voltage passive users, members of the EC;
- U^{MV}_{EC}: Medium voltage passive users, members of the EC;
- G_{EC}: Generators of the EC connected to the local distribution grid.

The evaluation of the impact is based on four main steps, which are briefly introduced here and detailed in the following sub-sections.

- **Loads**. The members of the EC are a subset of the passive users in the area. They can be either MV users directly connected to the considered network or LV users fed through MV/LV transformers.

$$\begin{cases} U^{LV}_{EC} \subset U^{LV}_{Area} \\ U^{MV}_{EC} \subset U^{MV}_{Area} \end{cases} \tag{1}$$

- **Generators**. The ECs under investigation will install a set of new generators, G_{EC}, according to an optimal generation portfolio that is based on the energy needs of the members and limited by the availability of local sources. The definition of the EC's generation portfolio is optimized according to specific objective functions, such as minimizing the exchanges of the EC with external actors or maximizing the economic value of the investment. The generators connected to the MV network will be the sum of those already connected in the base case, as well as those resulting from the optimization of the EC portfolio.

$$G = G_{Area} \cup G_{EC} \tag{2}$$

- **Energy storage system**. An energy storage system, ESS_{EC}, can be installed to maximize the energy shared within the EC and reduce the exchanges with external actors who are not members of the EC. The shared energy is defined as the minimum value between production and consumption in the same hour.
- **Electrical analysis**. The energy flows are evaluated on the MV grid for a duration of one year with hourly time steps. The topological limits of the network correspond to the nodes fed by the same HV/MV substation.

For each scenario, the loads participating in the EC are defined and their generation portfolio is optimized, following which the impact on the grid is evaluated by solving a yearly AC load flow using the Newton–Raphson method. The proposed Monte Carlo procedure consists in executing each step in the previously defined list until a convergence has been reached, defined from the analysis of output parameters defined further on. The pseudocode of the entire procedure is demonstrated in Algorithm 1, with each step being furtherly described in the following.

Algorithm 1 Monte Carlo procedure

repeat
  Define the EC loads -> U^{LV}_{Area},U^{MV}_{Area} **[Chapter 3]**
  Compute the EC's yearly load profile $EC_{load}(t)$, $\forall t \in [1, 8760]$ **[Chapter 3.1]**
  Optimize the generation portfolio $P_{j,opt}$, $\forall j \in Types$ **[Chapters 3.2.1 and 3.2.2]**
  for $j \in Types$ **do** **[Chapter 3.2.3]**
    $P_{j,tot} = 0$
    while $P_{j,tot} < P_{j,opt}$ **do**
      select $node$ =random.uniform$\{Nodes_j\}$
      select $Power$ =random.uniform$[P_{min,j,node}, P_{max,j,node}]$
      $P(t) = prod_j(t) * Power \quad , \forall t \in [1, 8760]$
      $P_{j,tot} += Power$
    end while
  end for
  select $node_{bat}$ =random.uniform$\{Nodes_{bat}\}$ **[Chapter 3.3]**
  select ESS_{cap} =random.uniform$[ESS_{min}, ESS_{max}]$
  Execute yearly load flow
  Evaluate $convergence$ $(\Delta\mu_{Loss}, \Delta\sigma_{Loss})$ **[Chapter 3.4]**
until $convergence$

3.1. Energy community loads

The EC model used in this study is detailed down to each individual MV node of the grid. As a result, the concept of participation in the EC for LV customers is shifted from the individual user to a single secondary substation, assuming that LV users will either join or not join the EC. This means that LV feeders are not modeled in the proposed model. To address this issue, the probability that low voltage users will participate in the energy community is introduced. For each single secondary substation, the power profile of the LV users $EC^{LV}_{load}(t)$ is evaluated as:

$$EC^{LV}_{load}(t) = \sum_{i \in U^{LV}_{EC}} load_i(t) \tag{3}$$

where $load_i(t)$ is the power profile of the user i and U^{LV}_{EC} is the set of LV users within the EC. U^{LV}_{EC} is defined starting from the entire set of LV users of the area and considering for each user u_i the probability $Prob_{LV}$ to participate to the EC.

$$\begin{cases} u_i \in U^{LV}_{EC} & \text{if } x_i \le Prob_{LV} \\ u_i \notin U^{LV}_{EC} & \text{if } x_i > Prob_{LV} \end{cases} \text{where} \begin{cases} x_i = random(0, 100) \\ Prob_{LV} \in (0, 100) \end{cases} \tag{4}$$

The set of MV users that joins the EC is defined in a similar way. In this case there are no simplifications and all the passive MV users are considered singularly. The subset of MV users that are members of the EC is defined based on the probability to take part to an energy community $Prob_{MV}$. The total power profile of the MV users of the community $EC^{MV}_{load}(t)$ is evaluated as:

$$EC^{MV}_{load}(t) = \sum_{i \in U^{MV}_{EC}} load_i(t) \tag{5}$$

where $load_i(t)$ is the power profile of the user i and U^{MV}_{EC} is the set of MV users within the EC. U^{MV}_{EC} is defined starting from the entire set of MV users of the area and considering for each user u_i the probability $Prob_{MV}$ to participate to the EC.

$$\begin{cases} u_i \in U^{MV}_{EC} & \text{if } x_i \le Prob_{MV} \\ u_i \notin U^{MV}_{EC} & \text{if } x_i > Prob_{MV} \end{cases} \text{where} \begin{cases} x_i = random(0, 100) \\ Prob_{MV} \in (0, 100) \end{cases} \tag{6}$$

The parameters $Prob_{LV}$ and $Prob_{MV}$ are generated for each scenario of the Monte Carlo procedure and have an impact each scenario's EC penetration. The overall load profile of the community $EC_{load}(t)$ is computed as the sum of the loads of LV and MV users, and it will be used in the next step to size the EC's generation portfolio.

$$EC_{load}(t) = EC^{LV}_{load}(t) + EC^{MV}_{load}(t) \tag{7}$$

The yearly energy request of the EC is computed in order to have a relative penetration of the EC with respect to the overall local load. The EC's penetration ($EC_{penetration}$) is computed as the ratio between the yearly energy request of the EC and the yearly energy request of the entire set of users connected to the MV network.

$$EC_{penetration} = \frac{\sum_t EC_{load}(t)}{\sum_t Area_{load}(t)} \cdot 100 \tag{8}$$

where

$$Area_{load}(t) = \sum_{i \in U^{LV}_{Area}} load_i(t) + \sum_{i \in U^{MV}_{Area}} load_i(t) \tag{9}$$

3.2. Energy community generators

The optimal generation portfolio for the EC is evaluated according to a predefined objective function. This optimization is a key element of the procedure since it reflects the behavior and preferences of the EC. The objective function can be based on energy balances, where the EC's goal is to reduce the power and energy exchanged with external generators and loads, but it can also be based on other objectives such as economic gain or minimizing the environmental impact. The result of the optimization is a vector that contains the optimal rated power $P_{j,opt}$ for each considered energy source j. The installation of the optimal portfolio leads to a production profile equal to $EC_{gen}(t)$, which is given by the sum of the energy produced by each generator. A normalized production profile $prod_j(t)$ is obtained for each energy source j, so that the total production of can be evaluated as:

$$EC_{gen}(t) = \sum_{j \in Types} prod_j(t) \cdot P_{j,opt} \tag{10}$$

where $Types$ is the set of different sources considered (e.g. PV, Hydroelectric, Wind, Biomass...), $prod_j(t)$ is the normalized production profile for each source j and $P_{j,opt}$ is the overall rated power for the generators of type j.

In order to optimize the generators portfolio, two strategies have been investigated.

3.2.1. Strategy 1

Using the first strategy, the EC generates the same amount of energy consumed by its members throughout the year, without considering the synchronicity between production and consumption. The power generation portfolio is entirely composed of PV generators (which are expected to be the most widely used in Italian ECs) and is sized to achieve a net-zero balance over the year through the installation of PV power plants. Strategy 1 is proposed as a means to simulate the uncoordinated development of renewable distributed generators.

$$\sum_{t \in year} EC_{load}(t) = \sum_{t \in year} EC_{gen}(t) \tag{11}$$

3.2.2. Strategy 2

The second strategy aims to minimize the energy exchange with the external grid, which enables the EC to reduce its dependence on external suppliers. Additionally, this strategy aims to avoid injecting energy into the grid when it is not required by the community members, thereby maximizing self-consumption.

$$EC_{exchanges} = \sum_{t \in year} |EC_{load}(t) - EC_{gen}(t)| \tag{12}$$

A maximum threshold is established for new generation capacity for each potential energy source, taking into account the availability limits of each resource. The addition of this constraint within this methodology allows the consideration of both, resource availability and political objectives in a given study area. The restricted availability of sources is considered through a specific set of constraints that limit the installed power, P_j, to the maximum available, P_j^{max}.

$$P_j \leq P_j^{max} \tag{13}$$

3.2.3. Generator's placement on the grid

For both investigated strategies, the optimal portfolio specifies a total rated capacity, which is then divided among a set of generators, G_{EC}, that are connected to different nodes of the grid. Each source, j, is considered individually, and the size of the generators is selected from a uniform distribution probability, ranging from a minimum of 200 kW to a maximum of 10 MW. These limits are consistent with the Italian scenario and have been established to encompass the entire range of generator sizes that could potentially be connected to the MV network, according to the Italian Authority [34]. Subsequently, each generator, k, is connected to a randomly selected (uniform distribution) MV node of the grid. In the selection process, a separate list of available nodes $\{Nodes_j\}$ is created for each Type j based on constraints related to historical areas, land space that can host certain technologies (such as wind turbines and PV) or proximity to necessary resources (such as hydro). Moreover, the size of a generator of type j installed in node n is constrained in a given range($P_{min,j,n}$, $P_{max,j,n}$). Similarly to the list of available nodes, this is also performed by analyzing the availability of resources. Additional generators are added in the same manner until the total capacity for that source is installed. The sum of the rated power of the generators that exploit source j is equal to the optimal overall rated power defined in the portfolio ($P_{j,opt}$).

$$P_{j,opt} = \sum_{k \in G_{EC}^{j}} P_k \tag{14}$$

where P_k is the rated power of generator k and G_{EC}^{j} is the subset of generators of the community that exploit the source j.

3.3. Energy storage systems

An ESS is considered in order to maximize the energy shared within the EC and reduce the exchanges with others market actors. The control logic of the ESS charges the storage when there is a surplus of energy (EC's production higher than its consumption) and discharges it when there is a deficit. The power request to the ESS P_{ESS} is consequently defined as the difference between the EC request EC_{load} and production EC_{gen}. In terms of sign terminology, positive values indicates that the storage is injecting energy in the grid, while negative values refer to consumption.

$$P_{ESS}(t) = EC_{load}(t) - EC_{gen}(t) \tag{15}$$

The state of charge is updated considering the power exchanged:

$$SOC(t+1) = \begin{cases} SOC(t) - \frac{P_{ESS}(t)}{\eta \cdot ESS_{cap}} \cdot 100 & \forall\ t \text{ s.t. } P_{ESS}(t) \geq 0 \\ SOC(t) - \frac{P_{ESS}(t) \cdot \eta}{ESS_{cap}} \cdot 100 & \forall\ t \text{ s.t. } P_{ESS}(t) < 0 \end{cases} \tag{16}$$

The model of the ESS has constrains that limit minimum and maximum State Of Charge (SOC).

$$SOC_{min} \leq SOC(t) \leq SOC_{max} \quad \forall t \in \text{year} \tag{17}$$

Another constrain is defined in order to consider the limitation of the maximum power exchange of the ESS.

$$\begin{cases} P_{ESS}(t) \leq P_{max}^{dis} & \forall\ t \text{ s.t. } P_{ESS}(t) > 0 \\ -P_{ESS}(t) \leq P_{max}^{ch} & \forall\ t \text{ s.t. } P_{ESS}(t) < 0 \end{cases} \tag{18}$$

where P_{max}^{dis} is the maximum discharging power and P_{max}^{ch} is the maximum charging power of the ESS.

3.4. Convergence criterion

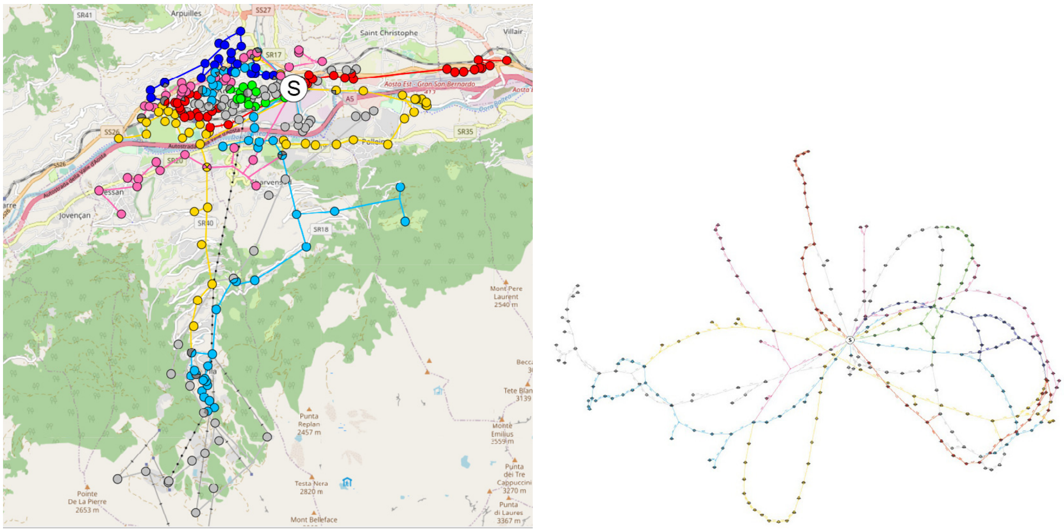
The proposed convergence criterion is based on the results of the quasi-dynamic load flow evaluation, specifically on the grid losses. A two-fold check is adopted, and convergence is considered achieved when both the mean value and the standard deviation of the losses are stable within a tolerance limit. After each iteration, i, the mean value of the grid losses, $\mu_{Loss}(i)$, and their standard deviation, $\sigma_{Loss}(i)$, are evaluated, considering all previous iterations. From the second iteration onward, the differences between the most recent values and the ones resulting from the previous iteration are computed. These differences are evaluated as a percentage, as detailed in Eqs. (19) and (20). Convergence is considered achieved when these variations are smaller than a limit, ϵ, for a specified number of consecutive iterations, N_{conv}.

$$\Delta\mu_{Loss}(i) = \frac{\mu_{Loss}(i) - \mu_{Loss}(i-1)}{\mu_{Loss}(i-1)} \cdot 100 \tag{19}$$

$$\Delta\sigma_{Loss}(i) = \frac{\sigma_{Loss}(i) - \sigma_{Loss}(i-1)}{\sigma_{Loss}(i-1)} \cdot 100 \tag{20}$$

4. Study cases

The methodology proposed was implemented in a software framework based on two different modules: the overall Monte Carlo procedure, scenario generation and results processing, is coded in python environment, whereas the load flow analysis is executed in DIgSILENT PowerFactory. The communication between the modules is done through an API, effectively automatizing the procedure. In particular, in order to have a realistic estimation of the ECs' impact on the distribution grid, two real-life distribution networks were selected and modeled. The criterion for the choice of the networks to be analyzed was the need for



(a) Geographic view (b) Single-diagram view

Fig. 1. Test Grid 1 (City of Aosta).

evaluating both, the rural context, as well as the urban one. In general, in the rural network there is higher RES availability but lower loads, while in the urban one the concentration of loads is higher but the energy sources are scarce. The power flows on the grids in the base scenario (i.e. without energy communities) are evaluated for each hour of the year, based on real measurement collected in 2019 [35]; in a second step, ECs have been simulated consequently to the proposed procedure. The main characteristics of the test grids are detailed in the following paragraphs.

4.1. Test grid 1 - Urban network

The first test grid is relevant to the city of Aosta, a small town located in northern Italy. The geo-spatial representation, as well as the single-line diagram can be seen in Fig. 1, in which the various colors represent the different feeders originating from the primary substation. The grid mainly extends through the city center, although a few lines reach the southern rural periphery, which consists of small mountain villages. The HV/MV substation has two 25 MVA transformers that feed a large number of feeders (17) with an average length of 8 km. The yearly energy requested by MV/LV substations (i.e. low voltage users) is 95.7 GWh, while the yearly energy requested by MV users is 58.6 GWh. This load is only partially satisfied with local production (29.6%), since the injection into the MV grid is only 45.6 GWh, resulting in a local deficit of 108.7 GWh per year. On the other hand, energy produced locally is entirely consumed within the MV network, and there is no energy surplus. In Fig. 3(a), the hourly profiles of power injections and requests are shown. It can be observed that the request is consistently higher than the injection on an hourly basis. As mentioned earlier, there is always an energy deficit, and an energy surplus never occurs. It is worth noting the distinctive shape of the injections, which have lower production levels from June to October. This is due to an important Combined Heat and Power (CHP) generator that feeds the district heating of the city, which is switched off during the summer. Looking at this graph, it is evident that there is a deficit of energy that could be easily reduced by installing new generation units. Load flow analysis was used to evaluate power profiles over one year with an hourly granularity. The yearly losses amounted to 1,770 MWh, with HV/MV transformer losses equaling 1,029 MWh and line losses equaling 741 MWh. The line losses per km of line were 5.43 MWh. The maximum loading of each branch was also investigated, with only two elements reaching a particularly high maximum loading (higher than 70%). These were due to the already mentioned CHP generator (which has an electrical power of 7 MW and a dedicated connection to the MV busbar of the primary substation and is normally operated around 70%–75% of the nominal capacity). All other branches of the system had a maximum loading lower than 47%, with an average value of 14.3%.

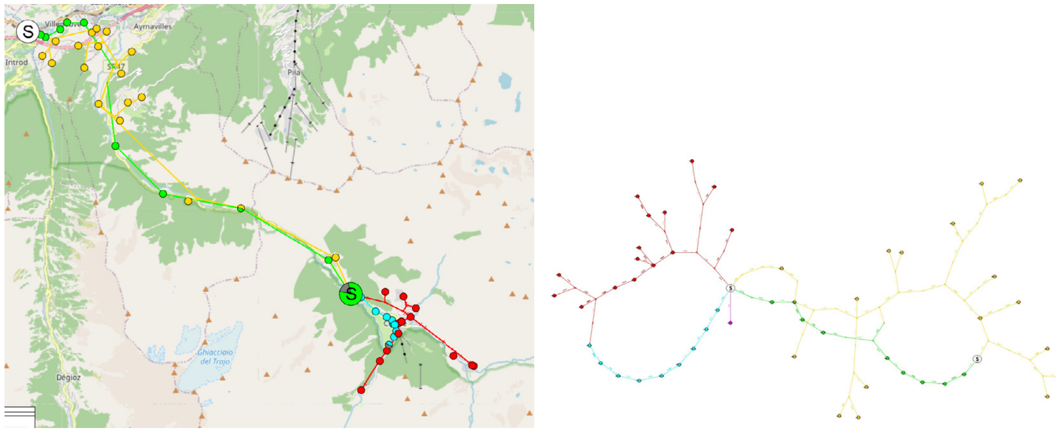
4.2. Test grid 2 - Rural network

The second grid considered is located in the valley of Cogne, a rural and dispersed village in the north of Italy, with the geographic and single-diagram schemes shown in Fig. 2. Similar to the case of the urban network, each radial feeder has a unique color. The network is characterized by longer feeders, which are 61% longer than those in test grid 1, and a greater prevalence of overhead lines, accounting for 49.3% of the total length compared to 29.5% in Aosta. Another significant difference is the low presence of MV loads, which amount to 1.0 GWh/year, and the high presence of MV active users, which account for a production of 12.2 GWh/year. This results in a surplus of energy that causes a reverse power flow in the HV/MV substation, meaning that in several periods, the system injects energy into the HV transmission grid. This is due to the significant presence of hydroelectric power plants whose production is concentrated in the summer months. As a result of this overproduction, which is concentrated in a short period, only 70.6% of the energy injected into the MV network is consumed locally.

Load flow analysis shows that the yearly losses are 312 MWh. A detailed comparison between the test grids is reported in Table 2.

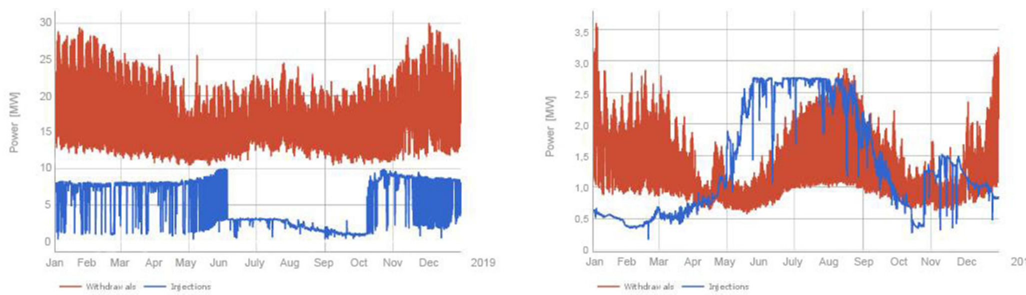
4.3. Energy sources availability

As explained in Section 3.2, the optimal generation portfolio is defined according to two possible objective functions named Strategy 1 and Strategy 2. In the latter case, the limits on the availability of local sources must be quantified. In this study, the power limits for new renewable energy generators were defined in accordance with the regional energy authority of the Aosta Valley region [36]. These limits are based on the availability of energy resources in the area and to requests for new generation facilities



(a) Geographic view (b) Single-diagram view

Fig. 2. Test Grid 2 (Valley of Cogne).

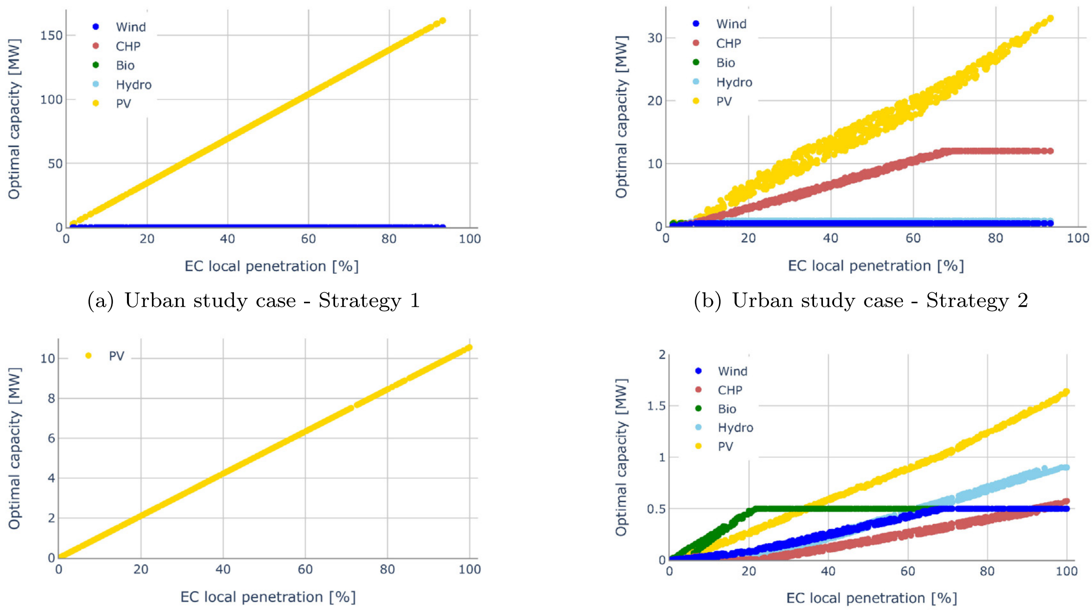


(a) Urban (b) Rural

Fig. 3. Hourly injections (blue) and withdrawals (red) for the test grids.

Table 2
Comparison between the two real-life test grids.

	Urban test grid	Rural test grid
Grid name	Aosta	Cogne
Grid type	Urban	Rural
Number of feeders	17	5
Total line length	136.4 km	64.3 km
- Cable	- 106.9 km (78.4%)	- 32.6 km (50.7%)
- Overhead line	- 29.5 km (21.6%)	- 31.7 km (49.3%)
Mean feeder length	8.0 km	12.9 km
Number of secondary substations	225	45
Number of LV users	27 768	3717
Yearly LV users' consumption	95.7 GWh	11.0 GWh
Average yearly consumption per LV user	3447 kWh	2951 kWh
Number of MV users	70	11
- Passive	- 59	- 6
- Active	- 11	- 5
Yearly MV users' consumption	58.6 GWh	1.0 GWh
Yearly MV users' injection	45.6 GWh	12.2 GWh
Deficit	108.7 GWh	3.4 GWh
Energy produced and consumed locally	45.6 GWh	8.6 GWh
Surplus	0 GWh	3.6 GWh
Locally produced energy (% of local consumption)	29.6%	71.6%
Locally consumed energy (% of local production)	100%	70.6%
Yearly losses	1770 MWh	312 MWh
Yearly losses lines/km	5.43 MWh/km	2.61 MWh/km
Loading max (max)	76.6%	47.7%
Loading max (avg)	14.3%	8.50%
Maximum voltage (max)	1.005 p.u.	1.039 p.u.
Minimum voltage (min)	0.950 p.u.	0.964 p.u.



(a) Urban study case - Strategy 1

(b) Urban study case - Strategy 2

(c) Rural study case - Strategy 1

(d) Rural study case - Strategy 2

Fig. 4. Optimal portfolios variation with respect to EC penetration in the local energy system.

Table 3
Assumptions on the energy sources availability in the two study cases.

Energy source	Test grid 1	Test grid 2
Photovoltaics	96 MW	15 MW
Hydroelectric	0.9 MW	10 MW
Wind	0.5 MW	0.5 MW
CHP	12 MW	6 MW
Biogas	0.5 MW	0.5 MW

Table 4
Convergence of the Monte Carlo simulations.

Test grid	Strategy	Iterations	μ_{Loss}	σ_{Loss}	$\Delta\mu_{Loss}$	$\Delta\sigma_{Loss}$
Urban grid	Strategy 1	536	2620.2	831.5	0.036%	0.059%
Urban grid	Strategy 2	579	2138.0	520.7	0.018%	0.071%
Rural grid	Strategy 1	589	504.0	214.0	0.048%	0.048%
Rural grid	Strategy 2	567	375.0	65.0	0.008%	0.082%

collected by the relevant authorities in past years. Specifically, five different energy sources were considered according to the local source availability. The values are reported in Table 3. For each source, a normalized production profile was computed based on the average production of the monitored power plants already in place in the area, as measured from the local Distribution System Operator(DSO) data.

From the point of view of maximizing self-consumption, it is clear that the ESS should be as large as possible. However, the main limitation is the cost of the system. In the Monte Carlo simulation, we have introduced a cap on the ESS capacity, resulting in an upper bound of ESS_{max}, which is assumed to be 200 MWh for test grid 1 and 20 MWh for test grid 2. These limits were selected after discussing with regional stakeholders and the local DSO, as they are considered a realistic upper bound for possible utility-scale storage solutions in the investigated areas.

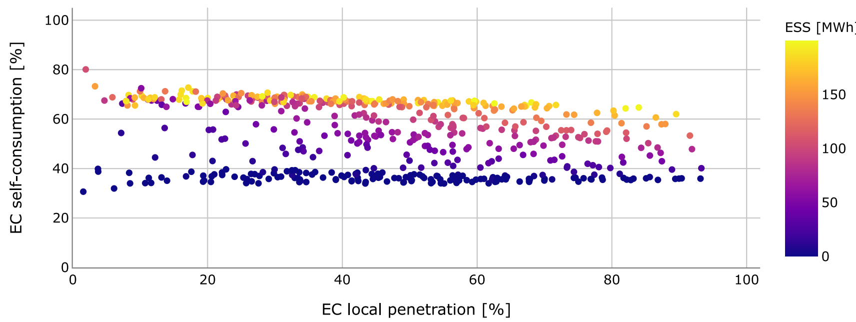
5. Tests and results

5.1. Convergence

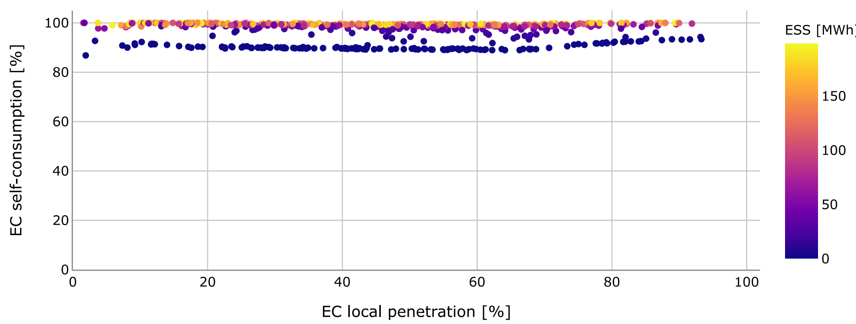
To test various potential EC scenarios, the proposed Monte Carlo procedure was utilized. The convergence criterion detailed in Section 3.4 was applied to both the test grids and optimization strategies, resulting in four distinct scenarios. The tolerance value ϵ was set at 0.1%, and the number of consecutive iterations in which this tolerance had to be respected was set at 25. Monte Carlo simulations were conducted for each of the four scenarios, and the convergence criterion was met after a number of iterations ranging from 536 to 589. It is worth clarifying that each iteration pertains to a yearly simulation with hourly samples. Table 4 provides information on variables related to the convergence, including the number of iterations required, the mean value of losses μ_{Loss}, their standard deviation σ_{Loss} at the end of the simulation, marginal variation of losses, and the standard deviation in the last step.

5.2. Optimal portfolio

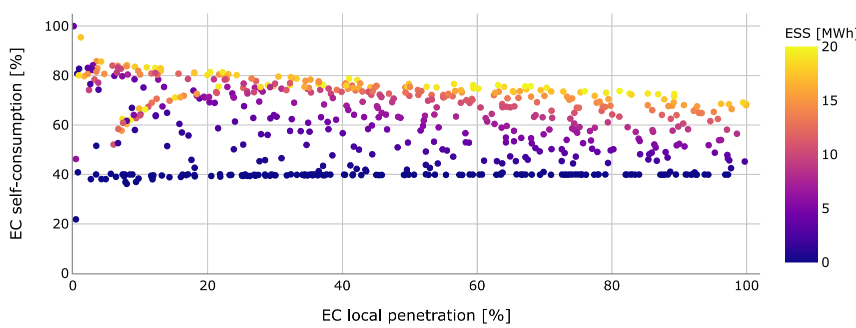
The optimal portfolio for the four cases considered is shown in Fig. 4. Specifically, the optimal capacity for each portfolio source is plotted against the $EC_{penetration}$ (i.e., the proportion of local energy needs included in the EC — see Eq. (8)). For the first strategy, installed capacity is proportional to $EC_{penetration}$ since production must match energy demand. For the second strategy, the portfolio includes various energy sources. In the urban case study, CHP provides a significant contribution and is included in the optimal portfolio up to the source limits of 12 MW. Hydroelectric, biogas, and wind are also selected in the optimal portfolio, but their availability in the area is limited to a few hundred kW, resulting in limited shares in the portfolio. It is worth noting that different portfolios may be selected for the same EC penetration. Indeed, two or more ECs with the same annual energy consumption can be composed of different sets of members, each with its own load profile. As a result, with the load profiles of the ECs being different, the optimization procedure selects the most appropriate generation portfolio on an individual case basis. In the Strategy 2 simulations, this leads to a dispersion of samples, as clearly shown in Fig. 4.



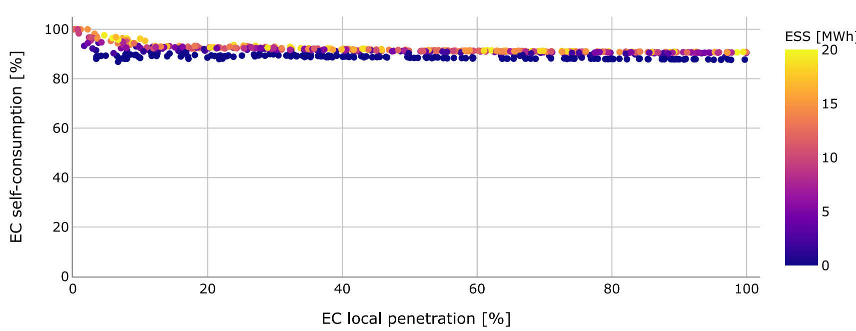
(a) Urban study case - Strategy 1



(b) Urban study case - Strategy 2



(c) Rural study case - Strategy 1



(d) Rural study case - Strategy 2

Fig. 5. Energy community self-consumption.

5.3. EC energy balance

The paradigm adopted is that energy generated by the EC's generators can be shared directly with the members of the community if they require it. Otherwise, the energy can be stored in the ESS or injected into the external grid. The hourly ratio of energy produced and consumed within the EC was evaluated for each iteration, and the results are shown in Fig. 5. The self-consumption index of the EC is evaluated as:

$$EC_{SC} = \frac{EC_{gen} - EC_{surplus}}{EC_{gen}} \tag{21}$$

where EC_{gen} is the EC yearly production and $EC_{surplus}$ is the EC yearly surplus [MWh]. When examining a generation portfolio strategy, comparable patterns in terms of self-consumption can be observed between the urban and rural case studies. In the first scenario, as demonstrated in Fig. 5(a and c), the existence and size of the energy storage system (ESS) greatly influence self-consumption. Without storage, the average self-consumption index is 36.0% for the urban case and 39.6% for the rural case, and is not influenced by the level of EC penetration. However, with an ESS, the self-consumption index can increase up to 80%. It should be noted that the effectiveness of the ESS is affected by the level of EC penetration, with a higher EC penetration necessitating a larger ESS capacity to effectively manage energy self-consumption. When examining the second strategy, as depicted in Fig. 5(b and d), the self-consumption index is significantly higher. Even in scenarios without an ESS, the minimum values are on average 90.2% for the urban case and 88.6% for the rural case. This is due to the balanced generation portfolios that generate distributed energy production throughout the year, day and night. While the presence of storage increases the self-consumption value, its marginal contribution is less significant than in the first strategy. For the urban case, an ESS with a capacity smaller than 100 MWh is sufficient to achieve 100% self-consumption for each penetration level. However, for the rural case, it is not possible to achieve 100% self-consumption within the defined constraints, as a larger ESS would be required.

In the figures, each dot corresponds to a yearly scenario simulated using the Monte Carlo procedure. The colors of the dots are proportional to the size of the simulated ESS.

5.4. Impact of EC on the distribution grid

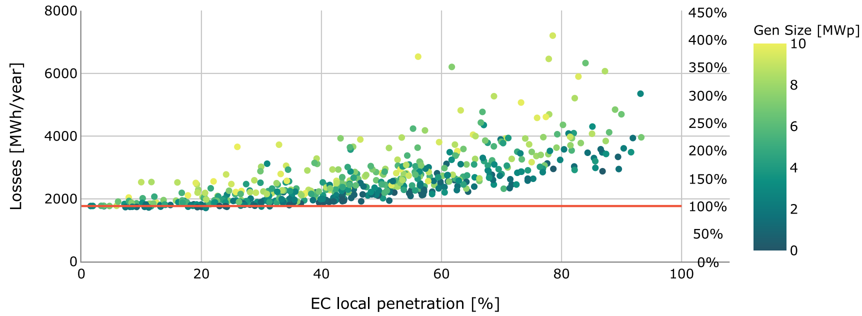
The main scope of this paper is to assess the effect of the ECs on the distribution grid. To achieve this objective, three indices were employed: the first is related to the annual losses in the grid, the second is associated with the loading of each branch, and the last is focused on the voltage profile. These three parameters were selected because they are the most representative indicators on the grid's operation and have been well-established in both the scientific literature and the grid operation procedures of DSOs [37]. All Monte Carlo scenarios were evaluated in order to provide a broad-spectrum probabilistic analysis of the potential impact of ECs on the grid.

5.4.1. Impact on energy losses

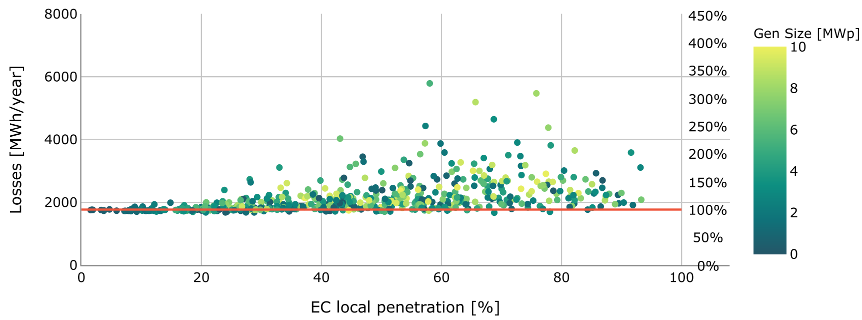
Among the variables of interest, grid losses are a key parameter to evaluate. The analysis show that the energy losses on the MV grid show an increasing trend as the EC expands in most of the simulated cases, as depicted in Fig. 6. Moreover, looking at the color legend in Fig. 6, a general correlation can be made between the losses and the size of the largest plant. The losses are evaluated for different EC penetration levels (i.e., the share of the area's energy needs covered by the EC). Furthermore, different scenarios have been evaluated with respect to the maximum nominal power of the generators included in the EC. In the colored scale adopted in the pictures, light green points refer to scenarios with large generators, while dark green ones correspond to scenarios with a higher number (i.e. the overall energy inject for a given $EC_{penetration}$ is constant) of small-scale generators. When considering the first strategy, the increment of losses is more significant, reaching a maximum increment of +307% for the urban case and +363% for the rural case, compared to the base case. For the second strategy, the increment is lower, and the maximum values are respectively 227% and +112%. In some cases, for the urban case, it is possible to have a marginal reduction of network losses, mainly when the EC installs generators with low rated power. Designing ECs using the proposed Strategy 1, the losses reductions only occur in cases of penetration lower than 40.2%, while adopting Strategy 2, it is possible to have a reduction also for higher penetration levels. Over the simulated scenarios, the minimum value of losses corresponds to a reduction of 5.54%. Whilst, for the rural area, the probability that the EC reduces the losses is negligible, happening only in few cases, and for a maximum value of 0.1%. The analysis of both study cases indicates that Strategy 2 performs significantly better than Strategy 1, demonstrating that a well-designed EC with a focus on maximizing self-consumption also results in a reduced impact on the grid. Similarly, the performed stochastic simulation demonstrates that an EC based on a significant number of small generators has a lower impact compared to an EC based on large generators.

5.4.2. Impact on the maximum loading of the MV branches

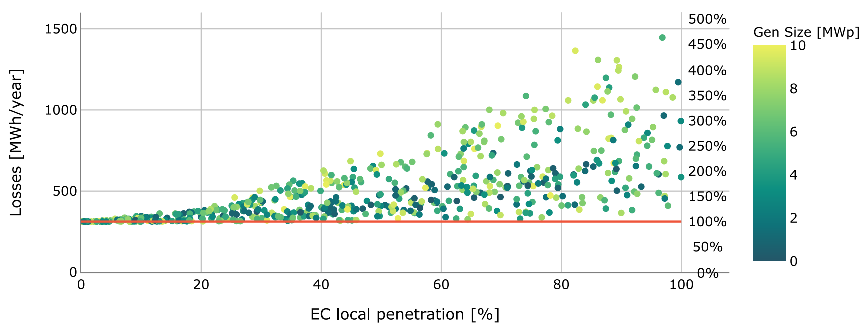
Another important electrical aspect is the loading of the MV branches. This parameter was evaluated with two variables: the maximum loading registered on the network and the number of overloaded elements (i.e. with a loading higher that 100%). In Fig. 7, the maximum loading detected in each scenario is reported in the form of a boxplot, evaluated for different level of the EC penetration. The maximum loading for the base cases are the ones detailed in Table 2: 76% for the urban case and 47.7% for the rural one. It can be noticed that, considering Strategy 1, for the urban case the overloading problem can be more severe and the maximum loading can reach theoretical values of 513%. For the rural one, applying the same strategy, the maximum loading is limited to 217%. The overloading appears to be significantly less critical when ECs are designed adopting Strategy 2. In this case, the maximum loading for the urban case is limited to 254% while for rural one no overloading occurs (maximum value 86.2%). Clearly, such violations are not acceptable in the operation of the grid, i.e. ECs would be limited in size, in order to respect the grid constraints. The cases with loading higher than 100% of the nominal current are reported solely for quantitative comparison purposes and are not feasible in real-life conditions. The results demonstrate a significantly lower grid impact for strategy 2 compared to strategy 1, which is an important factor when designing the legislation that incentivizes the ECs. Those cases would require grid reinforcements to enable the implementation of an EC with such a high penetration share. It is important to note that the maximum loading does not provide a comprehensive description of the issue. This information does not reveal whether only one element is consistently overloaded or if a bigger set of branches are overloaded. With the aim of furtherly analyzing this issue, the total number of overloaded branches is considered. This information is reported in Fig. 8, in the same form of a boxplot already adopted for the maximum loading. It can be observed that for the urban case the impact is more severe than for the rural one. Considering Strategy 1, overloading occur in all the penetration range and affects, in the worst case, 79 elements (24% of the entire grid). Similar to the previous results, with Strategy 2 the impact is more limited: the overloading starts from a penetration of 21%–30% and affect a maximum of 26 elements (8.0% of the grid). For the rural case the problem is more contained, overloading violation occur only when considering Strategy 1, starting from a penetration of 31%–40% and they are limited to 15 (14.7% of the grid) elements. Adopting Strategy 2 no elements are overloaded. The difference between urban and rural scenarios is clearly correlated with the base case, or starting scenario. In the urban case, due to higher energy density, a higher average line loading is detected, resulting in a lower margin for deploying new resources. Therefore, the need for a criteria capable of designing the EC is even more significant in urban areas, requiring approaches similar to the



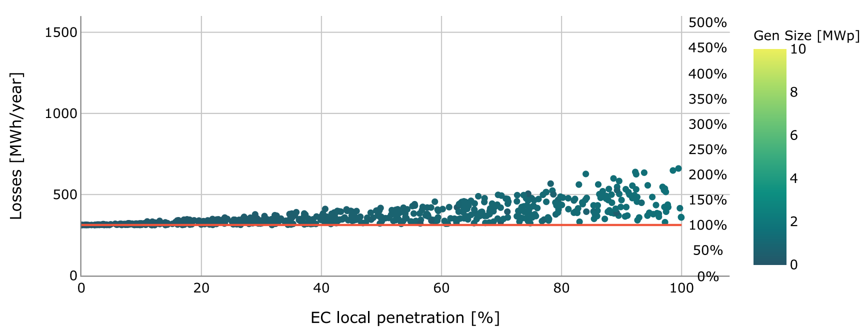
(a) Urban study case - Strategy 1



(b) Urban study case - Strategy 2



(c) Rural study case - Strategy 1



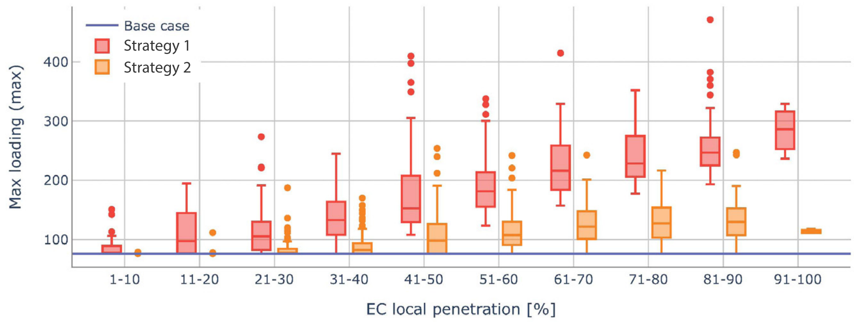
(d) Rural study case - Strategy 2

Fig. 6. Yearly losses computed in the Monte Carlo simulation.

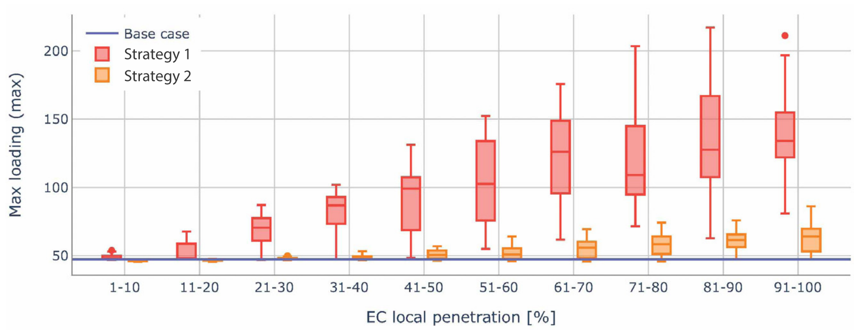
proposed strategy 2. To summarize, loading of MV branches was found to be a major issue in the evolution of ECs, requiring a proper evaluation of the problem. Even when adopting the better performing Strategy 2, the maximum penetration of EC in the urban case study could only reach 20% (i.e., 20% of the local energy demand could be supplied by local generators); once the EC penetration exceeds this threshold, grid reinforcement becomes mandatory. On the other hand, overloading of transformers was found to be a negligible problem due to the general over-sizing of primary substations.

5.4.3. EC impact on the MV feeders voltage profile

With respect to voltage levels, the most interesting results pertain to the maximum voltage reached during the simulated year.

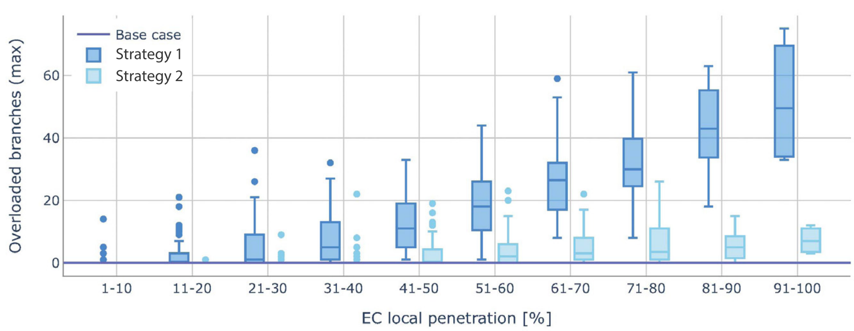


(a) Urban study case - Strategy 1 and 2

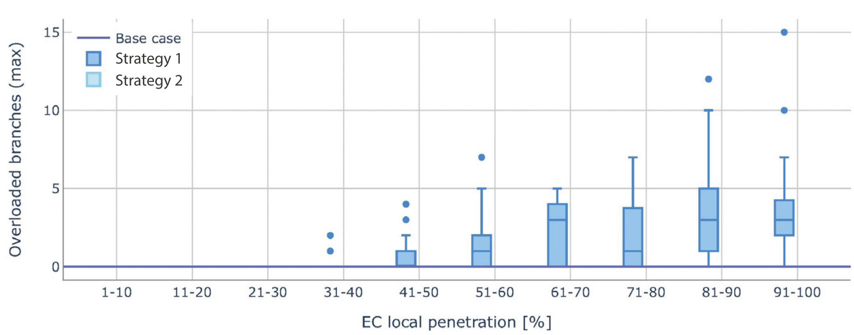


(b) Rural study case - Strategy 1 and 2

Fig. 7. Maximum loading of MV branches versus EC penetration.



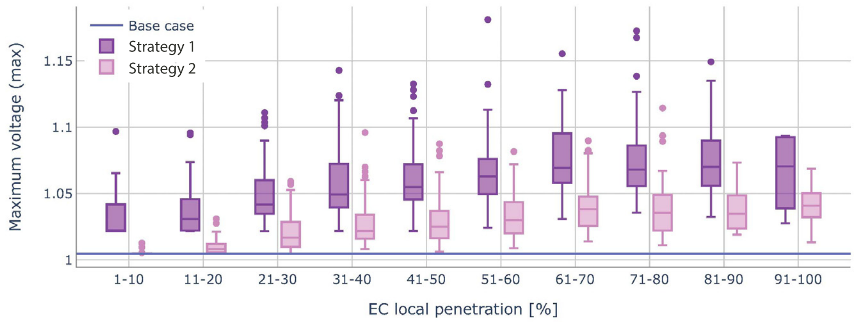
(a) Urban study case - Strategy 1 and 2



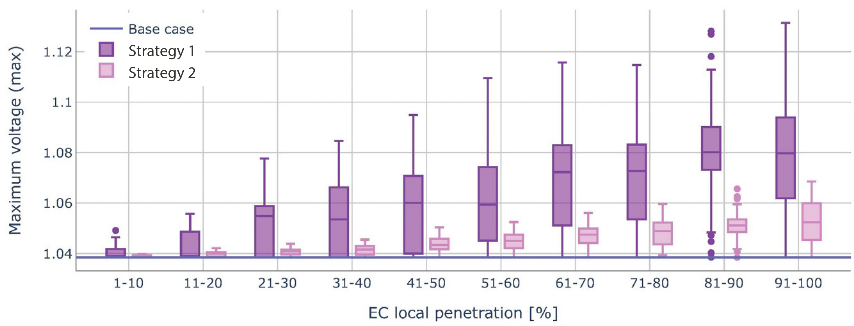
(b) Rural study case - Strategy 1 and 2

Fig. 8. Maximum number of overloaded branches versus EC penetration.

This is because, as it is well-known, adding generators to the MV feeders leads to a rise in the steady-state voltages. The boxplot in Fig. 9, similar to the one introduced for overloading, illustrates the distribution of the maximum nodal voltage obtained for each Monte Carlo iteration. Values greater than 1.1 p.u. are considered overvoltages. According to Italian power quality requirements which follow the technical norm CEI EN 50160, the voltage at the point of delivery must be within ±10% of the nominal voltage.



(a) Urban study case - Strategy 1 and 2



(b) Rural study case - Strategy 1 and 2

Fig. 9. Maximum voltage versus the EC local penetration.

It is interesting to note that overvoltage issues are less severe than overloading issues. For both test grids, overvoltages occurred only when considering Strategy 1. It is worthwhile to mention that there are possible strategies that have not been considered in this simulation, which could reduce voltage issues. Among the most important are tap changing in the primary substation and the implementation of specific operating rules for DGs, such as reactive power control. Since the voltage profile was not a limiting factor in the simulation performed, these controls were not implemented. Of course, the limiting technical factor in the development of ECs is impacted by the structure of the underlying passive network.

In Table 5 a final comparison of the penetration limits obtained considering overloading and overvoltage issues is proposed. The penetration limit is defined as the maximum level at which the acceptable values are not exceeded (100% for loading and 1.10 p.u. for voltages). The limit is considered as respected until the higher whisker of the boxplot exceeds it, whereas dots are considered as outliers. Comparing the two study cases, the urban and the rural ones, and the two EC design strategies (strategy 1: S1 and strategy 2: S2), it is clear that strategy 2 results in a significantly lower impact on the grid. It is worth noting that, despite the higher energy density and energy needs, the urban scenario presents a lower feasibility of integrating a high share of EC given the physical limits of the existing infrastructure. In other words, new lines and transformers would be required in case EC penetration increases. On the contrary, the electric grid in the rural scenario is more adequate to host more ECs. Generally, loading limits proved to be a much more critical issue compared to the potential for overvoltages.

Table 5
ECs acceptable penetration levels, based on overloading and overvoltages.

	Urban-S1	Urban-S2	Rural-S1	Rural-S2
Overloading	0%	21%–30%	21%–30%	91%–100%
N. of overloaded elements	1%–10%	31%–40%	31%–40%	91%–100%
Overvoltages	21%–30%	91%–100%	41%–50%	91%–100%

5.4.4. EC impact versus the siting of generators

The last analyzed point refers to the distribution of loads and generators of the EC on the network. A coincidence factor is evaluated for each feeder as the percentage of energy produced by the EC's generator located on the feeder, and the total energy request by the users located on the same feeder.

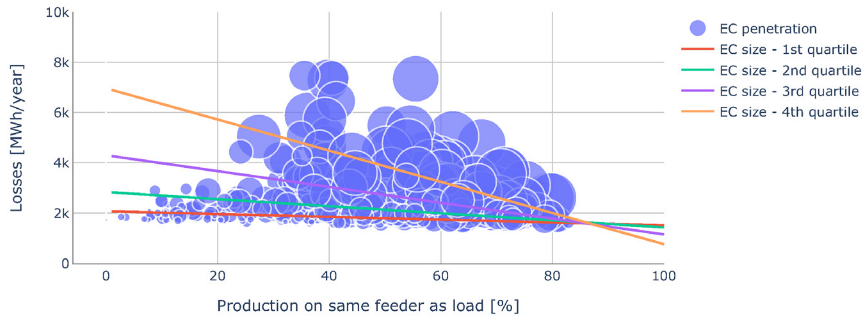
$$SF_f = \frac{E^f_{gen}}{E^f_{LV} + E^f_{MV}} \cdot 100 \tag{22}$$

where E^f_{LV} is the Yearly energy request from LV users on the feeder f [MWh], E^f_{MV} is the Yearly energy request from MV users on feeder f [MWh] and E^f_{gen} is the Yearly energy production for each source j on feeder f [MWh].

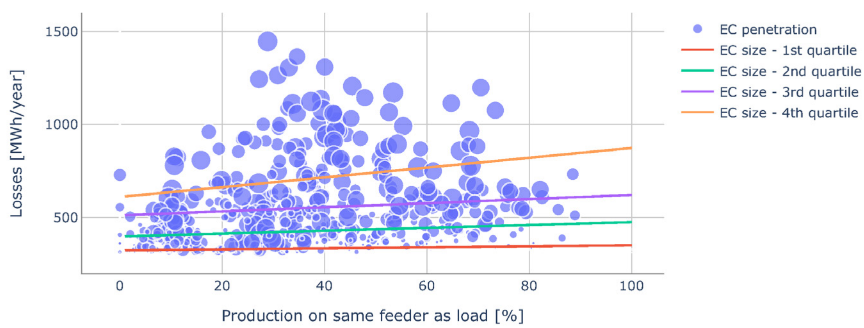
A global index SF_{CE} related to the entire grid is then computed as:

$$SF_{CE} = \sum SF_f \tag{23}$$

In Fig. 10, the correlation between losses and the index SF_{CE} is reported in the form of a bubble plot. The size of each bubble corresponds to the EC penetration (i.e. to the size of the EC). Considering the urban case, a decreasing trend can be identified for both strategies. This means that, if generators and loads are distributed in a balanced way among the feeders, the increase of the losses can be avoided. Moreover, it is worth to notice that this trend is strongly dependent on the size of the community; if an EC is big, the importance of having a high value of SF_{CE} is crucial. To show this, the regression lines have been computed for each of the quartiles defined by the EC size. For the 1st quartile (small EC), the slope is negligible, but it becomes more and more important moving toward the 4th quartile. The results for the rural area



(a) Urban



(b) Rural

Fig. 10. Losses dependency to the EC distribution among the feeders.

Table 6
Computational time for the scenarios considered.

	Urban str1	Urban str2	Rural str1	Rural str 2
Total time	93.6 h	75.3 h	14.3 h	13.0 h
Number of iterations	536	579	589	567
Time per iteration	10.48 min	7.80 min	1.46 min	1.38 min

do not show the same trend; instead, there is a slightly positive slope. This behavior can be explained by the peculiar topology of the network. In the rural area, most of the loads are located on the feeders in the upper part of the valley. Therefore, placing generators on the same feeder as the loads means placing them in the farthest nodes from the primary substation. Furthermore, in the rural case, many feeders already have a generation power higher than the loads require. Adding new generators results in an increase in power fluxes.

5.5. Computational time

The proposed methodology requires an important computational effort, mainly due to the yearly quasi-dynamic load flow computation; nevertheless it is viable with respect to the requirements of a planning procedure. The execution times for the considered scenarios are reported in Table 6. The procedure has been executed on a workstation equipped with an Intel® Core™i9-10980XE CPU @3 GHz (18 core) and 128 GB of RAM.

6. Conclusion

In this paper, two real-life networks, an urban and a rural distribution grid, are analyzed with the aim of evaluating the impact of ECs on the electric system. Starting from the already-in-place scenario, a Monte Carlo procedure is adopted in order to simulate various EC configurations. The EC generation portfolio is simulated using two approaches: in Strategy 1 the yearly energy production equals the consumption of the EC (obtaining a net-zero energy balance), whereas Strategy 2 minimizes the power exchange between the EC and the external grid for each individual time stamp. In the latter approach, the goal is to maximize energy self-consumption within the EC. The impact of the EC is evaluated adopting the common indicators in general grid planning studies: energy losses, steady-state voltages and thermal loading of lines. The simulations performed clearly demonstrated that the impact of ECs on the grid is not a minor issue. In particular, the grid could suffer from increased losses, a worsen voltage profile, and an increased loading of the lines. The latter problem results to be the most critical one, motivating a proper modeling of the distribution grid. On the contrary, this is typically underinvestigated in the scientific literature. Energy storage solutions were found to be only partially effective, with a large energy storage capacity necessary to manage a real-life distribution grid. In this case, the addition of a ESS requires a clear cost–benefit analysis. To minimize the impact of the EC on the grid, numerical results have demonstrated that self-consumption criteria (i.e., Strategy 2) should be a primary target in the design of EC. Consequently, this suggests that maximizing self-consumption should be considered a mandatory requirement in regulatory frameworks that propose incentives. Furthermore, the impact of the location of new Energy Community (EC) generators has been investigated, revealing that in urban areas, deploying generators and loads on the same feeder leads to lower grid impact. However, implementing such an arrangement in the Regulatory Framework would be difficult, as Distribution System Operators (DSOs) and generators are separate entities with different objectives. Moreover, a completely different behavior was detected in the rural area, demonstrating that each single grid could have a different trend.

Further research analyzing the impact of ECs on the electric grid could focus on the inclusion of the economic factor within the design phase of the EC itself, for the sizing of both, the generators and the BESS. Moreover, the temporal dimension of the electric loads could be included to analyze the evolution of the ECs and the future impact on the grid. Finally, the Monte Carlo approach could be altered with a different logic for constraining the localization of generators in order to investigate the impact of ECs on the grid in case of other known EC legislation frameworks. However, it should be noted that the case of allowing the installation on the same MV network is more severe in terms of impact on the electric infrastructure compared to the imposition of aerial distance as a constraint.

CRediT authorship contribution statement

Aleksandar Dimovski: Software, Writing – review & editing, Validation. **Matteo Moncecchi:** Conceptualization, Methodology, Software, Writing – original draft. **Marco Merlo:** Writing – review & editing, Supervision, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The authors do not have permission to share data.

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