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Empowering Local Grids: How Energy Communities Can Enable Variable Renewable Integration

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Executive summary

The aim of our research was to identify and measure the beneficial effects of community energy initiatives[1] on the electricity grid, particularly regarding the integration of solar power plants. Additionally, we aimed to identify a set of regulatory incentive tools that can effectively support community energy projects in expanding their efforts in ways that benefit the overall energy system.

In the initial phase of the research, a network modeling was conducted to examine 16 distinct scenarios, each reflecting various energy community roles and alternative network solutions. The impacts were analyzed using two different low-voltage network models: one model simulated a low-voltage transformer circuit representative of conditions in Hungary, while the other utilized the Cigré international benchmark model, representing the residential section of a European low-voltage circuit.[2]

<u>Conclusions drawn from the modeling results</u>

- By optimally positioning production units within the network community energy projects can enhance the PV hosting capacity of the LV district. Furthermore, a centrally located PV system is not necessarily more effective than decentralized PV systems, provided the latter are optimally placed.
- Scenarios exploring the use of community battery storage revealed that these systems are highly effective for integrating PVs. Storage not only boosts the local PV capacity that can be accommodated but also reduces the load spreading to the higher voltage levels. Furthermore, results indicate that there is no significant difference between centralized and decentralized storage arrangements in terms of network impact; both configurations can be beneficial. The key factor, however, is the control strategy governing storage use. If a shared "behind-the-meter" storage system is managed with a centralized optimization approach, rather than individual optimizations, PV hosting capacity can be significantly increased, and the load spreading to the higher voltage levels reduced. Notably, even a partial application of centralized optimization alongside individual optimization yields these positive effects.
- Demand-side response (DSR) can offer benefits comparable to storage in facilitating PV integration, and it presents a significantly more cost-effective solution than installing storage systems.
- Modeling of combined scenarios highlights the importance of integrating multiple community energy activities. Incentive and support systems should therefore encourage community energy projects to undertake diverse activities for maximum impact.
- The electrification scenario revealed that while integrating weather-dependent renewables is the current priority, and can be also aided by alternative network technologies, the rise in

[1]As explained in chapter I. of the study, the terms community energy projects and energy communities are used here as synonyms, knowing that citizen energy communities and renewable energy communities are actually specific community energy organizations according to the regulations.
[2]The modeling is presented in detail in the Technical Report of the research.

consumption due to electrification demands nearly immediate network upgrades. Community energy activities proved effective in supporting the integration of weather-dependent generation also under increased electrification. Additionally, energy communities can mitigate peak demand through DSR and storage, helping to reduce and delay the network expansion needs associated with electrification.

To enable community energy activities that benefit the electricity network, effective coordination within the community is essential. This coordination can only be feasible if shared use of locally produced or stored energy does not incur higher costs than individual "behind-the-meter" usage. In other words, network charges for shared energy need to be minimal—ideally zero—to provide adequate incentive for community coordination.

Consequently, we analyzed the relationship between the system benefits generated by community energy activities and the network charges for the shared part of energy. This assessment aimed to determine how much of a discount on network charges for shared electricity can be reasonably justified with the generated benefits.

<u>Cost-benefit analysis</u>[3]

Our calculations are based on two main types of benefits associated with PV integration. First, the benefit of addressing local voltage issues arising from increased PV capacity was estimated based on the costs incurred by the distribution system operator when employing alternative network devices—such as OLTC transformers and line replacements—for voltage management. Second, the benefit of reducing the load on the underlying network was approximated by the costs of network expansion investments driven by new PV capacities, calculated using the indirect connection costs from the Technical Economic Documents issued in the connection allocation procedure in the Summer of 2023 in Hungary. These quantified PV integration benefits from community energy activities can offset between 18-48% of the total necessary tariff discount on shared energy, depending on the scenario.

In addition to the PV integration benefits, community energy projects offer two other significant, measurable system benefits. One is the reduction of network losses achievable through supplying consumption from local production. The other is the reduction of peak consumption loads achieved through DSR, which helps avoid, mitigate, or defer network expansion needs.

When these additional benefits are factored in, community energy activities involving storage and DSR can offset between 52-85% of the total needed network tariff discount on shared energy. While these benefits are substantial, they do not entirely cover the tariff discount needed for members to favor community-based optimization over individual optimization.

[3] The cost-benefit analysis is based on Hungarian data, making this aspect specific to Hungary. However, the conclusions drawn are broadly applicable and can be generalized beyond this context.

Specific tariff system

To reconcile the tension between cost recovery and incentivization we propose an alternative approach to the prevailing international practice, which typically involves applying a discount to the existing network tariff on the shared energy. Instead, we recommend establishing a dedicated energy community tariff system specifically designed to support energy sharing. The key components of the proposed tariff system include:

- A zero energy-based tariff component for the shared part, to incentivize community-level optimization over individual optimization.
- For withdrawals other than shared energy, introducing a time-of-use energy-based component to incentivize shifting consumption away from peak periods as much as possible.
- A key component of the tariff is the fixed charge element, designed to offset the loss of tariff revenue from the shared part while considering the positive system benefits of local community energy projects. According to the modeling results, this fixed fee element should recover a maximum of 15–48% of the discount provided on energy sharing.
    - This fixed fee is further differentiated based on the extension of the network used during energy sharing. Since network benefits vary based on the extent of energy sharing, projects with a broader network extension yield smaller positive effects and therefore require higher fixed fees.

  For community energy projects that extend beyond an HV/MV area, we recommend excluding the application of this specific energy community tariff system.

Incentive framework

We propose the following additional measures to enhance the support scheme and regulatory framework for community energy projects:

CAPEX Subsidies

- Support for Local Community Energy Projects:
    - Subsidies should focus on projects which are local from a network point of view, and where the majority of produced renewable energy is consumed locally, requiring a minimum threshold for local consumption, e.g., 80%.
- Integration of Demand-Side Response (DSR):
    - Special focus should be on providing support for establishing the necessary IT, cabling, and communication infrastructure that enables DSR for flexible load appliances of community members.

- Storage Support:
    - Require a minimum 4-hour storage capacity instead of the current 2-hour standard.
    - Neither centralized or decentralized storage systems should be favoured; both should be treated equally.
    - Storage installations should include systems for optimal control of decentralized storages or centralized storage and associated production and consumption sites.
        - Specific targeted support could be provided for communities to establish the necessary control and IT infrastructure for community usage optimization of already built decentralized storage facilities.

Distribution level flexibility markets

- It is advisable to set up distribution level flexibility markets at congested LV areas, and pilot test the effects of community energy activities within them. Targeted support for building the flexibility capabilities of these communities is also recommended.

Support in the connection process

- During the connection process, it is worth exploiting the opportunities in community energy projects, for example in the following forms:
    - A new type of flexible connection option, under which the community undertakes that no electricity will be exported from the area of the community energy project to the underlying network during the periods indicated by the network operator
    - Prioritization of community solar power plants and storages in the connection application procedure, if the community undertakes to participate in the DSO flexibility market, offering the flexibility capabilities of the solar power plant, storage, and DSR through aggregation.

Introduction

Community energy organizations offer many opportunities, for example the involvement of decentralized capital from consumers to meet the significant investment needs necessary for the implementation of the green transition, the promotion of social acceptance of renewable energy-based power plants, and the increased awareness of households regarding their energy consumption. In addition to these valuable roles, community energy formations can also have a positive effect on the operation of the electricity network, contributing to the mitigation of challenges caused by weather-dependent renewable energy production in the electricity system.

Our research focuses on mapping this latter possible role. Its purpose is to examine the impact of community energy projects based on renewable energy production on the electricity system. To identify the extent to which a community energy project can contribute to the system integration of weather-dependent electricity production and explore what positive effects these community activities can have on the electricity system.

The first part of the research contains the technical modeling of community energy activities, which is summarized in the Technical Report. Through modeling, the benefits that communities can provide to the system become quantifiable, and thus become comparable to network development and other means of increasing flexibility potential. Based on the results, it can be determined which types of community energy activities should be incentivized through regulation, as well as the extent, form and source of this incentive to ensure that they are cost-effective.

Based on the technical modeling results, this study develops regulatory proposals for the support of community energy activities in the electricity system. The study first presents the regulatory framework that determines the discounts that can be granted to community energy projects, and then lists the international examples for each type of support, based on which a support toolkit is drawn up. Afterwards, we perform an economic evaluation of the technical results. We identify the community energy activities to be incentivized, and then compare their results with alternative network development solutions. We perform a cost-benefit analysis regarding the benefits provided by community energy activities and the discounts to be provided for them to achieve these benefits. Finally, based on the analysis, we prepare a regulatory proposal for the development of regulations incentivizing the network-friendly operation of community energy projects.

I. Regulatory background

One of the priority objectives of the Clean Energy Package (CEP)[4] was to empower and place consumers in the center of the energy markets. It introduced the concept of Renewable Energy Communities and Civil Energy Communities, and defined additional roles based on active consumer cooperation, such as active users and collective self-consumers. There are many studies on the categorization of these organizations, what activities they can perform, what kind of legal organization they require, and how they differ. What they have in common is that consumers gather together and jointly carry out energy market activities related to their own supply of energy consumption.

Out of the many possible community energy formations our study focuses on those that are organised around electricity supply and aim to supply (part of) the community's own electricity consumption from locally installed renewable energy generation.

The basis of the operation of such community energy organizations in the electricity market is energy sharing, which is the transfer of locally produced electricity to a consumption placed at another connection point. Sharing as an energy community activity is mentioned in the Clean Energy Package, but it did not include a definition or detailed rules on it, so the Member States began to implement community energy organizations and the related sharing activity in different ways, which is illustrated in the following section summarizing the experiences of the Member States. This gap began to be filled by the new electricity market package, EMD[5], announced on June 26 2024, which complemented CEP's Electricity Market Directive[6] with a definition and an article detailing energy sharing. The EMD states that those active users who own or jointly own, lease or rent a production or storage equipment on-site or off-site may share their surplus renewable energy production with themselves, among themselves, or with other users, and thus those also become active users. The consequence of this rule is that it is no longer necessary to create a formal energy community to be able to share energy through the public network, all active users who are included in the eligible user group will have the right to do so. The EMD limits the range of users with the right to share to households, SMEs and public institutions, but gives the possibility for the member states to extend sharing to other final consumers[7]. Regarding the geographical limitation on sharing, according to the EMD, sharing can be done within one bidding zone, but the Member State can also define a more limited geographical area.

In accordance with the EMD, the community energy organization examined in our study is based on the cooperation of active users, including households and SMEs, the members are located in

[4] The Clean Energy Package is the comprehensive legislative package of the European Union, which includes a number of regulations and directives, including Regulation 2019/943 and Directive 2019/944 on the electricity market (IEMD), as well as the Renewable Energy Directive 2018/2001 (RED II)

[5] EMD (Electricity Market Design): The EMD consists of two pieces of legislation, Regulation 2024/1747 and Directive 2024/1711 amending the CEP Regulation and Directive.

[6] Directive 2019/944 of the European Parliament and of the Council (June 5, 2019) on common rules for the internal market in electricity and amending Directive 2012/27/EU

[7] Provided that where this other user is larger than an SME, the capacity of the generation facility associated with the energy sharing activity shall be no more than 6 MW and the energy sharing shall take place within a local or geographically limited area, to be defined by the Member State.

a limited area in terms of network topology (within a low-voltage district) and share the locally produced (and in some cases stored) surplus renewable electricity with each other through the public network We do not deal with the legal form and framework in which the organization operates, whether it satisfies, for example, the definition of a Renewable Energy Community or not. Thus, in the followings we will use the terms community energy organization and energy community as synonyms.

Our analysis focuses on the question of which community energy activities can have a positive effect on the electricity system, and how energy communities can be incentivized to carry out activities that result in more significant positive effects for the system. Most of the modeled community energy activities are realized through energy sharing between members, so the legal requirements regarding energy sharing are decisive for the effectiveness of community energy activities.

As far as incentives are concerned, one of the incentives for energy sharing can be that if the consumer receives production from the community through sharing, they can get a more favorable product price than if buying from their supplier. However, a community can realize this advantage in terms of product price also if it sells the production of the generation unit on the market and distributes the resulting income after deducting costs among the members. This purely producer energy community activity is much simpler than sharing in the electricity system, it does not require continuous coordination, scheduling, measurement, monitoring, and even control of the community's production and consumption points. Therefore, the communities will share if, in addition to the product fee, they can realize discounts on the system usage and other fee items on the shared part.

In relation to network tariff discounts, the EU regulations lay down the general tariff principles, such as to be transparent, non-discriminatory and cost-based, and it is also important to state that the fees cannot be dependent on distance, they must reflect the costs and must take into account the use of the distribution system by the users, including the active users.[8]

In addition, the parts of the Clean Energy Package concerning the Renewable Energy Community and Civil Energy Community also contain clauses for determining the fee on sharing. According to the Electricity Market Directive [9]:

> Article 16 (1) e) *"citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system."*
>
> Furthermore, sub-paragraph (3) e) lays down that the Member States shall ensure that *within the citizen energy community members "are entitled to arrange the sharing of*

[8]Regulation 2019/943 of the European Parliament and of the Council (June 5, 2019) on the internal market for electricity Article 18

[9]Directive 2019/944 of the European Parliament and of the Council (June 5, 2019) on common rules for the internal market for electricity and amending Directive 2012/27/EU Article 16

electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers. For the purposes of point (e) of the first subparagraph, ***where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority*****.**

In RED II,[10] similar conditions were laid down for Renewable Energy Communities:

> Article 22 (4) *"Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that:" ... "d) " renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and* ***cost-reflective network charges****, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost sharing of the system* ***in line with a transparent cost-benefit analysis of distributed energy sources developed by the national competent authorities****;"*

The EU legislation thus explicitly addressed the network charges applicable to electricity sharing and stated that the fact of sharing does not exempt the payment of network and other charges, which are levied according to the general tariff-setting rules.

The general rules require, on the one hand, that the fees must reflect the costs and take into account the network usage of active users. These criteria can provide a basis for the fact that if the energy sharing within the community is local, thus uses the network infrastructure to a much lesser extent since it is not necessary to transport the electricity through all the voltage levels to get from the production to the point of consumption, then a lower system charge can be applied to the consumption of the shared part.

However, according to the other general criterion, network charges cannot be distance-dependent, which can even be interpreted as that the tariff system cannot differentiate according to whether production and consumption points are close to each other or not. The Hungarian Energy and Public Utility Regulatory Authority (MEKH), which is also responsible for determining network tariffs, used to formulate its opinion referring to this criterion, that there cannot be a network charge discount regarding sharing just because it does not exceed a network level, for example remains within a LV district. On the other hand, as the next chapter shows, many member states do not interpret this distance-dependence prohibition in this way, since they apply tariff discounts on energy sharing based on its network extent. We recommend that this prohibition on distance dependence be interpreted more narrowly in Hungary, for example that the system usage fee cannot be based on km.

[10] Directive 2018/2001 of the European Parliament and of the Council (11 December 2018) on the promotion of the use of energy from renewable sources

EMD provisions on sharing

The EMD also provided additional guidance regarding the application of network charges on sharing:[11]

> *"Member States shall ensure that active users participating in energy sharing:*
>
> *a) are entitled to have the shared electricity injected into the grid deducted from their total metered consumption within a time interval no longer than the imbalance settlement period and without prejudice to applicable non-discriminatory taxes, levies and cost-reflective network charges;"*

Therefore, the settlement of the sharing must be 15 minutes in accordance with the domestic imbalance settlement period, and therefore our study divides the modeling of the sample days into 15-minute time intervals. Furthermore, the new EU regulation says that the sharing settlement must be carried out without prejudice to applicable non-discriminatory taxes, levies and cost-reflective network charges. In order to interpret this clause, it is important to note that in the initial version of the EMD[12], which was published on March 14, 2023, this section read "*without prejudice to applicable taxes, duties and network charges*". That is, the "non-discriminatory" indicator for taxes and duties, as well as the *"cost-reflective"* indicator for network charges included in the final accepted version have an important meaning. With regard to network charges, this can be interpreted as if the cost of the active user's system usage during sharing is different from the usual network cost of supplying consumption, then this can be reflected in the network charges, and if it is lower, a discount can be given on the shared part.

In other words, the latest EU regulation allows the network tariff for sharing to differ from the fees otherwise applied, if the difference is based on cost. For this cost-based approach, it is necessary to determine the extent to which a community energy organization based on decentralized renewable energy production and sharing will use the network. The Clean Energy Package cited above requires that the network fees paid on sharing must be in line with *"the transparent cost-benefit analysis of the distributed energy resources developed by the competent national authority."* In other words, the national regulatory authority, MEKH must prepare a cost-benefit analysis for decentralized production, based on which any kind of discount regarding sharing can be established.

The regulatory authority has not carried out such analysis so far. Our study aims to remedy this shortcoming, and based on the technical modeling results and the cost-benefit analysis, we propose a network tariff system. In addition, we do not only focus on network charges, but also make recommendations regarding the broader regulatory and incentive framework affecting community energy activities.

[11]Directive 2024/1711 of the Eruopean Pairlament and pf the Council (13 June 2024) part of the EMD complements the IEMD with article 15.a., the cited legislation is a subsection of Article 15.a. paragraph (4)
[12]EMD proposal of 14 March 2023: https://eur-lex.europa.eu/legal-content/HU/TXT/HTML/?uri=CELEX:52023PC0148

II. Incentive Toolkit

Drawing on international best practices, below we will explore the range of incentive mechanisms available to support the operation of community energy projects.[13] Beyond the critically important network tariff reductions, we will also examine additional tools that can be considered, along with key factors that should be taken into account when designing and implementing these measures.

II.1. Network tariff discount

Across the international landscape, network tariff discounts are most commonly used to promote greater energy sharing and local consumption among members of energy communities. In many countries, eligibility for these discounts is tied to specific conditions, such as limitations on the geographical scope and the capacity of the production facilities. **In Austria,** a discounted tariff is applied for energy sharing within a 15-minute time interval within the renewable energy community. Consumers of renewable energy communities must either be connected to the low-voltage network (local level) or to the medium-voltage level (regional level). Sharing of electricity from production or storage equipment to consumption points is not permitted at a level above the HV/MV transformer station.

The discount on the variable part of the network fee varies according to which parts of the network are used during the energy sharing activity:

- If, for example, energy sharing only occurs at a local level, a 57% reduction is applied to the variable tariff element
- if the renewable energy community covers not only the local but also the regional level, the discount rate is lower, 28% for the local level, and 64% for the regional level

Civil Energy Communities do not benefit from a specific tariff discount as opposed to Renewable Energy Communities, because for this type of organization, the regulations do not require the production unit and the members of the community to be located close to each other, so in this case it is possible that the members of the community use several distribution or transmission network elements.

In the Brussels region of Belgium Sibelga DSO introduced a tariff system that applies incentives for electricity shared within 15-minute periods. The underlying principle of the tariff discount is that fees for network segments not utilized during energy sharing do not need to be paid. The amount of the discount depends on where the members participating in the sharing are located in relation to each other, thus, which section/sections of the network they use. The same fee or discount is applied uniformly to all members of the community. Consequently, if even a single member is connected to a higher-voltage section of the network, the entire community will only be eligible for a reduced discount. Accordingly, Sibelga defines four different cases:

[13] The country examples are based on information from the Energy Community Repository, REScoop, and various country-specific publications, as detailed in the References section.

• if all members of the community are in the same building (the network tariff is the most favorable in this case)

• if all the members of the community are under the same transformer district, at medium or low voltage level

• if the members of the community are located behind a single transmission point

• or if the members of the community are located upstream of a transmission feeder, in which case no tariff discount is granted

In Italy, the sharing activity of energy communities is also incentivized through the use of specific tariff system. The national regulatory authority, ARERA, determines which elements of the network tariff energy community members are exempted from. Civil and Renewable Energy Communities are only entitled to claim back the transmission fee per kWh based on the amount of energy produced and consumed behind the same transformer station, and if the community is limited to the level of a single apartment building, they can also claim back the fee element for medium and high voltage network losses. Similar to the Brussels system, the tariff discount is based on the logic that charges for network levels not affected by sharing are waived. The sharing is settled in 1-hour time intervals. Energy shared between community members is not subject to tax obligations. The size of the production equipment was previously limited to 200 kW, which was increased to 1 MW in 2021. The regulation states that any consumer can be a member of a Renewable Energy Community, including vulnerable and low-income households.

In Germany, in the case of energy sharing within an apartment building, consumers participating in the activity are exempt from certain fee elements, primarily taxes.

In Spain, several measures incentivize the local consumption of energy from renewable sources, including a specific tariff system (which does not apply exclusively to Renewable Energy Communities): electricity from renewable energy sources, waste or cogeneration consumed locally is exempted from taxes, transmission and distribution network fees. The sharing is settled in 1-hour time intervals. Previously, there was a geographical restriction of 500 m, but due to negative feedback this was extended to 2 km in 2022. Autonomous Communities such as Valencia, Andalusia or Extremadura, also apply specific tariff on energy sharing, among other measures to support energy communities.

in Portugal, the elements of the network tariff that are related to the costs of energy policy, sustainability and general economic interests can be partially or fully deducted on an annual basis by government decree, for the self-consumption of renewable energy communities and prosumers after the amount of electricity they feed into the grid. If the government does not issue a relevant decree, it is the task of the regulatory authority to determine which of these network tariff elements can be deducted. Since the introduction of the measure in 2020, a full exemption from these costs has been applied to the shared part in the case of collective self-consumption, as well as Renewable Energy Communities based on a 15-minute time interval. Individual prosumers received a 50% discount on the above-mentioned tariff elements. At different voltage levels, different territorial restrictions have been defined for Renewable Energy Communities and collective self-consumption: a maximum of 2 km at the low voltage level, 4 km at the medium voltage level, 10 km at the high voltage network, and

20 km at very high voltage level. On a case-by-case basis, the National Licensing Authority may authorize a larger area.

In Greece, community self-consumption is incentivized through a net balancing system, with monthly settlement and monthly adjustable ratios. The provisions regarding territorial restrictions are the most permissive here: previously, the regulations only required that if the producer's equipment is connected to the low-voltage network, the consumption points must also be there, if the producer is at medium voltage, then only consumers connected at the MV level can participate. Since 2023, consumers connected at the high-voltage level can also participate, regardless of where the production equipment is located. Regarding the participants, the regulation states that only non-profit organizations can be part of community self-consumption. The total capacity of production equipment was previously limited to 1 MW, which was increased to 3 MW.

In Denmark, two forms of energy sharing are distinguished: on the one hand, behind-the-meter sharing, which is limited to the level of a single building, and energy sharing which uses the public network. In the case of the latter, there has not been a network charge discount until now, but a newly introduced regulation enables the implementation of local-level, specific tariff systems for energy sharing.

In Slovenia, sharing within the same apartment building is supported by net settlement, provided that the capacity of the production equipment does not exceed 80% of the aggregated consumption load. Net settlement can also be used in the case of local consumption of electricity produced locally by Renewable Energy Communities, if the participants are located behind the same low-voltage transformer station.

In France, three cases of community self-consumption can be distinguished: the condominium case, the standard extended model and the regional extended model. In the case of the standard extended model, within the low-voltage network, a maximum production capacity of 3 MW and a maximum distance of 2 km are the main criteria. On a case-by-case basis, with the approval of the Ministry, the energy sharing activity can be extended to a maximum geographical extent of 20 km, only in the case of projects that are implemented in an isolated area with low population density. A separate legal entity must be created to organize community self-consumption, which can be a REC or something else.

The regulatory authority has developed a specific tariff system for community self-consumption. Members participating in self-consumption can choose between paying the specific or the general tariff. The former will only be favorable if the rate of self-consumption is sufficiently high, since the specific tariff is designed in such a way that for local consumption within the community it is lower than in the base case but sets a higher price for injection and withdrawal from outside the community.

II.2. Feed in tariff/ premium

In several countries, the establishment and activities of energy communities are incentivized through a feed-in tariff or market premium paid for the electricity produced by the Renewable/Civil Energy Community, but not consumed locally. Accordingly, community energy projects are exempted from the tendering process within the renewable energy support systems. Although this measure supports the establishment of energy communities, it does not encourage local consumption or network-friendly operation. Therefore, in some countries a cap is set for the amount of electricity fed into the grid by the community, above which the feed-in premium does not apply. The aim of this cap is to incentivize local consumption.

In Austria, Renewable Energy Communities receive a market premium for up to 50% of the electricity produced but not locally consumed.

In Italy, the surplus produced by the energy communities fed into the grid is purchased by GSE[14]. In the case of PV systems, if the amount consumed locally reaches 70% of the production, the remaining amount of electricity can be freely sold by the community on the market. However, if local consumption does not reach 70%, a price ceiling of EUR 0.08/kWh applies to its sales price, incentivizing energy communities to increase local consumption.

In Germany, community energy projects are exempt from tendering (onshore wind power projects up to 18 MW installed capacity, and PV projects up to 6 MW) if the community has not established a generation unit in the specific technology and capacity category in the last three years. In the case of community energy projects where the capacity of the production equipment is below 100 kW, a separate feed-in tariff applies to the excess electricity fed in, and a guaranteed market premium is applied to the production equipment below 1 MW.

In Ireland a feed in premium supports the operation of energy communities: projects with production equipment that has a capacity between 6 and 50 kW can benefit from the so-called Clean Export Premium for 15 years for the electricity fed into the network. The community receives the premium from the supplier, its value in 2022 was 0.135 EUR/kWh. In order to incentivize self-consumption, the application of this premium was capped at 80% of the electricity produced by the community. However, in the framework of the new renewable energy support system, RESS3, this upper limit has been abolished, and the community can benefit from a premium for any amount of electricity fed into the grid. Since 2021, a separate category for community energy projects has been created within the renewable energy support system. This requires that all profits and dividends achieved by the community must be returned to the operation of the community.

In France, renewable energy communities are not exempted from tendering, but the tender selection criteria includes among others an aspect that takes into account the share of the capital owned by the local residents and the local authority in the given project.

II.3. Simplified connection procedure

In Ireland Community Preference Category was established in 2021 for projects in which the production equipment has a capacity between 0.5-5 MW, and which is 100% owned and managed by a Renewable Energy Community. Projects that fall into this category are entitled to a simplified

[14] the GSE is responsible among others for supporting renewable electricity generation in Italy.

connection procedure, which means less administrative burden and the community does not need to submit a Bid Bond or Performance Security to apply for grid connection.

In Spain, projects aimed at local consumption of energy from renewable sources - including energy community organizations - are subject to a separate connection procedure. In the case of projects located in urban areas, projects up to a maximum capacity of 15 kW are exempted from the obligation to obtain a connection permit.

II.4. Other

In Italy, a specific premium applies to encourage real-time, on-site consumption by energy communities and participants in community energy sharing. A project is entitled to receive the premium if the production equipment has an installed capacity of no more than 1 MW, and the electricity is produced and consumed under the same medium voltage substation. The amount of the premium paid by GSE for 20 years is 110 EUR/ MWh, regardless of the production technology, but depending on the geographical location of the project, an additional "insolation compensation" is available: in the northern areas of the country, it is an additional 10 EUR/ MWh, in the central areas 4 EUR/ MWh. This premium of 110 EUR/ MWh is approximately the same as if the members of the energy community were exempted from all network charges.

An energy sharing premium is also applied **in Germany**, if the activity covers a single apartment building: the owner of the communal production equipment receives a premium of 23.7-37.9 EUR/ MWh for the electricity consumed locally (the amount of the premium depends on the capacity of the PV).

II.5. Investment subsidies

Renewable energy communities can apply for investment support in many EU member states.

In Austria, a support of up to EUR 1 million can be used by Renewable Energy Communities for the establishment of renewable electricity and gas generation units. Civil Energy Communities are also entitled to a subsidy, which can be used for the establishment, expansion or modernization of PV, wind turbines, storage, water and biomass power plants. The installed capacity of PVs, wind power plants and storage facilities may not exceed 1 MW.

In the Brussels region of Belgium, several loan programs have been established to support the establishment of energy communities, which can primarily be used for the installation of solar power plants. A separate loan program has been announced for condominium solar projects in 2023, in addition to small and medium-sized enterprises and social housing companies, especially for the establishment of solar power plants.

In Denmark, the Danish Energy Agency has been supporting local communities in the implementation of renewable energy projects since 2022. The support can be used, among other things, for the implementation of production, storage, flexibility and energy efficiency projects, as well as for projects aimed at disseminating related knowledge. The program also aims to support projects that demonstrate how energy communities can contribute to reducing the load on the grid, as well their additional climate, environmental and social benefits.

In Germany, a grant scheme was created in 2022 to support Citizen Energy Companies. The grant can be used for the preparation of the establishment of onshore wind farms of up to 25 MW (for example the preparation of feasibility studies), covering up to 70% of the costs, or up to a maximum amount of EUR 200,000 per project. If the project is successfully implemented, the subsidy must be repaid. In Germany, several banks and financial institutions provide low-interest loans for the establishment of community renewable energy projects (among others, the Kreditanstalt drill Wiederaufbau [KfW], or the Agency for Agricultural and Rural Development). In addition, several federal states, including the governments of Schleswig-Holstein and Thuringia, provide start-up financing to community energy projects through state-owned support banks or community energy funds created specifically for this purpose, which can significantly reduce project risks.

The **Portuguese** government announced a support system in 2022, with the aim to incentivize renewable energy communities and community self-consumption. The support can be used, among other things, for the establishment of renewable energy generating equipment (even with storage), for the preparation of feasibility studies or for consulting, as well as for the creation of softwares and smart platforms. The intensity of the support depends on the type of building it is used for (residential buildings 70%, commercial 50%, public buildings 100%). The grant is capped at EUR 500,000 per community initiative, and EUR 200,000 per production equipment. The criteria for evaluating the applications include the number of community members, the ratio of investment to energy savings achieved (EUR/toe), the self-sufficiency ratio (how much of local consumption is covered by local production), and the volume of energy sharing.

Spain allocates a total of EUR 100 million to support community energy projects. A part of this ('CE-Planifica ') can be used in the initial phase of Renewable Energy Community projects (for the costs of feasibility studies, legal and technical services). Another pillar of support ('CE- Implementa') is for community projects whose activities are related to renewable energy, thermal energy, energy efficiency or e -mobility. Support can be applied for up to 60% of the project costs. When selecting the supported communities, aspects such as innovation, social participation, social benefits achieved by the project, or the fight against energy poverty are taken into account, among others.

In Italy renewable energy communities are also supported through interest-free public loans, which can cover up to 100% of the costs. In addition, a EUR 2.2 billion program was created to finance energy communities and community self-consumption projects created by settlements with a population of no more than 5,000 people. Individual regions can independently create support systems to encourage energy communities. In Sicily and Campania for example a support is provided for the costs of feasibility studies and legal advice.

II.6. Summary: incentive toolkit

International examples clearly show that the establishment and operation of community energy projects can be supported through a variety of mechanisms. Many member states already offer targeted support to community energy organizations, either through investment grants or interest subsidies. This support often extends beyond the production units themselves, covering the development of storage facilities, the preparation of feasibility studies, legal advisory services, as well as software and platforms that facilitate organization and operation.

In addition to direct financial assistance, there are also electricity system-level instruments designed to promote the operation of community energy projects in ways that benefit the broader energy system.

Discounts on network charges

Many countries apply a network charge discount for the locally shared part. In fact, some countries, such as Greece and Slovenia, have extended the very favorable monthly net metering system to community energy projects beyond rooftop solar panels. However, in most countries that offer such discounts, in line with the Electricity Market Design (EMD), the tariff reduction applies only to the amount of energy that is produced and consumed within the community through sharing during the balancing settlement period. This period is 15 minutes in some countries (such as Portugal, Belgium, and the Brussels region), while in others — for the time being — it remains at 1 hour (such as in Spain and Italy).

The underlying logic of the discount is consistent across countries: the smaller the portion of the network utilized for community self-consumption through energy sharing, the lower the fee that must be paid. In all Member States, network tariffs are generally applied according to a cascade system, meaning that users connected at lower voltage levels also contribute to the costs of higher voltage networks.[15] This structure reflects the traditional model of electricity supply, where power generated at higher voltage levels is transmitted by network operators to consumers connected at lower voltage levels. Consequently, supplying a consumer on a low-voltage network still requires the use of higher-voltage infrastructure. In a cost-reflective tariff system, therefore, users must pay not only for the construction and operation of the network at their own voltage level but also for the use of higher-voltage networks.

The fee reductions applied to electricity sharing represent a rethinking of the traditional cascade system. In line with the cascade logic, distributed generation and local supply through sharing generate system usage costs based on the extent of local consumption — but now in the reverse direction (a "reverse cost cascade"). The experience from countries applying tariff reductions for energy sharing clearly reflects this principle: greater discounts are granted for community self-consumption that remains within lower voltage levels, compared to sharing that also involves higher voltage levels.

[15]See: ACER (2023): Report on Electricity Transmission and Distribution Tariff Methodologies in Europe

Typically, the discounts are structured so that network charges for unused higher-voltage levels are waived.

ACER's latest tariff report also mentions this practice and states that considering that some system users, such as energy communities only have a small need to use other network levels, an exception to the (traditional) cascade system may be justified.[16]

In other words, both, practice and ACER's findings support the fact that it is not contrary to EU law to provide a tariff discount on the basis of the extent of sharing, the distance dependency prohibition should not be interpreted in this sense.

Regarding the extent, some countries link the limits to the network topology (e.g., Austria, Italy, Belgium – Brussels region), while others, such as Spain and France, define the limits based on distance in kilometers. There are also hybrid approaches, like in Portugal, where both network topology and distance criteria are combined. It is also important to note that, in order to encourage communities to establish decentralized generation for their own consumption, some countries link the possibility of sharing — and the associated discount — to the size of the production unit. This can be done either relatively, by tying it to the amount of consumption involved (as in Slovenia), or by setting a specific capacity limit (as seen in Italy, France, and Greece).

Finally, while in most countries participants in community energy projects remain subject to the traditional tariff system and simply receive a discount on the shared portion, there is an example of a different approach in France. There, a separate tariff system has been developed specifically for community energy projects, designed to incentivize a high self-consumption ratio. However, if the self-consumption ratio is low, participants may actually end up paying more compared to the general network fee.

Other energy-based charges

The international examples also show that some countries (e.g. Germany, Spain) also grant a rebate from items beyond the system charges on the shared part, such as taxes, funds for green subsidies, etc. These items vary from country to country both in content and size. Consideration of their removal or reduction is not linked to the cost-reflective nature of system use, but to public policy considerations, e.g. the positive social benefits of community self-consumption of renewable energy communities.

Production subsidies

In several countries, power plants established by communities benefit from more favorable procedures within renewable energy support schemes — for example, they may be exempt from participating in competitive tenders or receive preferential treatment during the evaluation process. This approach is primarily justified by the fact that, unlike market-based projects, the production

[16]See: ACER (2023): Report on Electricity Transmission and Distribution Tariff Methodologies in Europe

profits of community-owned plants are returned directly to consumers, benefiting the community as a whole.

Additionally, there is a growing trend whereby smaller community power plants receive specially subsidized feed-in tariffs for the portion of their production that is not consumed locally. However, this support is often conditional: if the level of local consumption does not reach a high threshold, a price cap is imposed on the electricity sold, even when only a part of the production qualifies for a premium. These measures aim to provide production support while simultaneously encouraging higher levels of local self-consumption.

In addition, there are countries that specifically pay a premium for production consumed locally by the community (Germany, Italy).

Benefits during the connection process

Finally, there are currently only a few examples of community energy projects receiving priority during the grid connection process — for instance, in Ireland and Spain, where such projects are entitled to a simplified connection procedure. In our view, as grid connection becomes an increasingly critical bottleneck, it will be important to recognize the positive network impacts of community energy projects already at the connection stage, and to promote network-supportive operation through targeted incentives. We present a proposal on this topic in Chapter 5.3.

III. Economic evaluation of technical results

The summary above outlined the incentive schemes currently in place internationally for supporting community energy projects. While the applied discounts generally assume that these projects provide benefits to the electricity system, only a few Member States conducted quantitative assessments when introducing these incentives — and even in those cases, the analyses were not based on detailed network modeling. [17]

The technical modeling carried out within the framework of our project aimed to identify and quantify potential positive impacts. A detailed description of the modeling approach and results can be found in the Technical Report. For the purposes of the economic evaluation, we first summarize and interpret the network modeling results below.

III.1. Brief description of the technical modeling

The modeling is based on network simulation, utilizing a three-phase load -flow calculation implemented in the Python programming language. The technical modeling assessed the network impact of 16 different scenarios—including various energy community functions, their combinations, and alternative network configurations (see Table 1)—under two distinct low-voltage network conditions. One of the models, referred to as the 'R' network, represents Hungarian conditions and simulates an entire transformer area (comprising four circuits) within the network of a prosperous urban agglomeration. The other model is based on the international CIGRÉ benchmark, representing the residential section of a typical European low-voltage circuit.In the first run—the base case—the analysis evaluated how much PV capacity could be integrated into each modeled district and how this capacity would impact the underlying network in the absence of any energy community activities. The maximum allowable PV capacity was determined based on the limiting conditions specified in the DSO network code.[18] "In the following, the individual energy community scenarios are evaluated using three key indicators. The first indicator assesses the extent to which the PV hosting capacity of each district can be increased through the specific community activity. The other two indicators evaluate the impact on the underlying network beyond the district: one measures the annual power flow through the transformer station (in both directions), while the other captures the ratio of local consumption to local production. These two indicators provide complementary insights into the level of self-sufficiency and local energy utilization within the district. An improvement in their values indicates that the underlying network is being alleviated, whereas a decline suggests that increased PV integration within the district imposes additional burdens on the broader network, signaling potential negative externalities. Additionally, two alternative network solutions—the use of an OLTC transformer and line upgrading—were also examined to determine whether they could achieve comparable PV hosting capacities and similarly reduce the load on the underlying network, as observed in the energy community scenarios.

[17]See the cost-benefit analysis of the Brussels region, presented in IV.2.2.

[18] If certain conditions are met, the given district becomes closed, which means that new PV capacity can only be connected without injection capacity.

Table 1: Description of the examined scenarios

serial number	name	description
1.	Base case	With current EV, HP HWP penetration, how much distributed PV capacity can be allowed on the examined districts without any energy community functions
1.1	Central PV	In addition to 30% of the distributed PV capacity determined in the base case (10% on Cigré), how much **central** PV capacity can be allowed on the grid if it is installed near the transformer
1.2	Concentric PV	How much PV capacity can be allowed on the network if all PVs are **distributed**, butthey are placed concentrically starting from the transformer, with the same size (10 kW)
2.1	Central storage	In addition to 30% of the distributed PV capacity determined in the base case (10 % on Cigré), how much additional distributed PV capacity can be allowed on the network if **central** storage is operating in the district, with **community optimization**.
2.2	Distributed storage with community optimization	In addition to 30% of the distributed PV capacity resulting from the base case (10% on Cigré), how much additional distributed PV capacity can be allowed on the network if **distributed** storage is operating in the district, with **community optimization**.
2.3	Distributed storage with individual optimization	In addition to 30% of the distributed PV capacity resulting from the base case (10% on Cigré), how much additional distributed PV capacity can be allowed on the grid, if **distributed** storage operates in the district, with **behind-the-meter** consumption **optimization**.
2.4	Distributed storage, with half community, half individual optimization	In addition to 30% of the distributed PV capacity resulting from the base case (10% on Cigré), how much additional distributed PV capacity can be allowed on the network, if **distributed** storage operates in the network, with **half-individual, half-community optimization**.
3.	DSR	Compared to the base case, by how much can PV penetration be increased if part of the consumption of the flexible consumption equipment on the network (boilers, EV chargers, HPs) is rescheduled for periods of solar power production?
4.	DSR + reactive power control	Compared to the base case, by how much can PV penetration be increased if a part of the consumption of the flexible consumption equipment on the network (boilers, EV chargers, HPs) is rescheduled for periods of solar power production, and in addition the inverters of the PVs perform reactive power absorption?
5.1	DSR + distributed storage with community (or half individual) optimization	First, part of the flexible consumption is rescheduled for periods of solar power production, and then distributed storage is introduced, with community or half community-half individual optimization. How much distributed PV power can be allowed on the investigated districts?
5.2	DSR + central storage	This scenario differs from the above 5.1. scenario, in that there is a central storage with community optimization in this case.

6.	Electrification base	How much PV capacity can be allowed on the network if a new large consumer and at 10% of the households additional EV chargers and heat pumps are added to the investigated network district? (run only on the *R network)*
6.1	Electrification + central storage	How much PV capacity can be allowed on the network if, in addition to the above-mentioned electrification scenario, a central storage operating with community optimization is installed in the investigated network area? (run only on the *R network)*
6.2	Electrification + DSR	How much PV capacity can be allowed on the network if, in addition to the electrification scenario, part of the flexible consumption is rescheduled to periods of PV production through DSR? (run only on the *R* network*)*
7.	OLTC	Is it possible to install the same PV capacity as resulting from the energy community functions, if OLTC is installed instead of the MV/LV transformer on the examined district?
8.	Line upgrading	Is it possible to install the same PV capacity as resulting from the energy community functions, if lines with a larger cross-section are installed in the examined area? (Run only on the *R* network, as Cigré was already equipped with lines of the largest available cross section)

The table below, using the three key indicators, describes how the defined energy community activities, their combinations, and alternative network solutions affect the PV hosting capacity of the examined districts and the load on the underlying network.

Table 2: Results of runs for the 'R' and the international Cigré benchmark network models

scenarios	R network						Cigré benchmark network					
	PV hosting capacity			Tr. Max load (%)	Tr. Self-consump	Self Producti	PV hosting capacity			Tr. Max load (%)	Tr. Self-consump	Self Producti
	kW	Increase	%				kW	Increase	%			
Base case	535		70%	100	905 MWh	49%	348		24%	86%	1374 MWh	91%
Central PV	583	9%	76,50%	113%	5%	45%	645	85%	44%	88%	9%	63%
Concentric PV	720	35%	94%	143%	18%	39%	630	81%	43%	88%	8%	66%
Central Storage	596	11%	78%	87%	-20%	62%	537	54%	37%	88%	-11%	88%
Distributed storage community optimization	596	11%	78%	87%	-21%	62%	536	54%	37%	88%	-11%	88%
Distributed storage individual optimization	580	8%	76%	90%	-9%	56%	435	25%	30%	86%	-9%	94%
Distributed storage 50% individual 50% community optimization	580	8%	76%	107%	-32%	70%	463	33%	32%	88%	-10%	93%
DSR	580	8%	76%	93%	-12%	57%	348	0%	24%	88%	0%	92%
DSR + reactive power control	664	24%	87%	110%	-5%	52%	652	87%	45%	85%	7%	68%
DSR + distributed storage community (or 50% individual) optimization	596	11%	78%	90%	-38%	73%	464	33%	32%	86%	-11%	93%
DSR+central storage	617	15%	81%	72%	-30%	68%	536	54%	37%	86%	-11%	88%
Electrification base	535	0%	70%	98%	33%	52%	-	-	-	-	-	-
Electrification + central storage	603	13%	79%	85%	5%	69%	-	-	-	-	-	-
Electrification + DSR	535	0%	70%		4%	74%	-	-	-	-	-	-
OLTC	596	11%	78%	126%	6%	46%	464	33%	32	88%	1%	80%
Line replacement	596	11%	78%	114%	6%	45%	-	-	-	-	-	-

Below, we present and interpret these findings, and then draw conclusions about how we can effectively incentivize communities to engage in such activities.

III.2. Placement of PVs

Scenarios 1.1 and 1.2, which focus on PV allocation, aim to assess the extent to which network PV hosting capacity and other system parameters can be improved compared to the base case by planning the placement of solar panels—and the balance between centralized and decentralized (rooftop) PV systems—at the community level. In the base case, solar panel placement was driven by consumption levels, with PV systems installed at connection points with higher annual electricity usage. This approach partially reflects real-world practice, as it is generally more economical to install solar panels where electricity consumption is significant. However, in reality, a consumer's income plays a major role in whether a household with high consumption can actually afford to install a PV system. This socioeconomic factor, however, could not be incorporated into the modeling. III.2.1. Central vs. distributed

III.2.1. Centralised vs. decentralised

Scenario 1.1 investigates the impact of distributed versus centralized PV deployment. In the base case, all PV systems are distributed across the network in proportion to local consumption levels. In contrast, Scenario 1.1 assumes that only 30% of the PV capacity from the base case is distributed on the R network, and 10% on the CIGRÉ network, while the remaining capacity is installed centrally near the transformer—an arrangement that is optimal from the perspective of maintaining network voltage levels. Then the R network results show that:

- PV hosting capacity increases by 9% (535 kW -> 583 kW and PV penetration 70% -> 76.5%)
- However, the load on other parts of the network increases, and a significant part of the excess PV production will not be consumed locally, as shown by the values of the two indicators below:
    - the flow through the transformer increases by 5%
    - the export of local production also increases by 4 percentage points

The results of the CIGRÉ network show a similar trend, but the positive effect is much stronger here:

- The hosting capacity can be increased by 85% compared to the base case
- The flow passing through the transformer will increase by 9%, and the export of production by 28 percentage points.

<u>In other words, local PV hosting capacity can be significantly increased by deploying a central power plant and carefully selecting its location. However, the resulting excess generation places additional stress on the broader network. Therefore, if the higher voltage levels of the network are already nearing their limits, this energy community strategy alone offers only a partial solution for the system integration of PVs.</u>

III.2.2. Allocation

The next scenario (1.2) explores the impact of the placement of decentralized PV systems. It assesses how much network performance can be improved by strategically selecting the locations of rooftop PV units within a low-voltage district, compared to a baseline where all PVs are sited according to local consumption levels. In Scenario 1.2, all generation capacity remains decentralized, but is optimally distributed around the transformer in a concentric pattern — an arrangement intended to minimize adverse network effects. Then the R network results show that:

- The PV hosting capacity increases by 35%, more than in all other scenarios (535 kW -> 720 kW and PV penetration 70% -> 94%)
- However, the load on other parts of the network increases, a significant part of the excess PV production will not be consumed locally, as shown by the values of the following two indicators:
    - flow through the transformer increases by 18%
    - the export of local production also increases by 10 percentage points

The results of the CIGRÉ network show a similar trend:

- The PV hosting capacity also increases significantly in this case—by 81%—but compared to the central PV scenario, where the increase was 85%, the impact of the concentric design is slightly smaller.
- The flow passing through the transformer increases by 8%, and the export of production by 25 percentage points.

Conclusion regarding placement:

It is clear that the placement and concentration of PV systems can have a significant impact on the PV hosting capacity of the LV district. Notably, the concentric configuration demonstrated the greatest improvement (in the case of the R network), highlighting that decentralized PV systems, when optimally located, can sometimes outperform centralized installations. However, while strategic siting can improve local voltage conditions and thereby increase local hosting capacity, this additional generation cannot be fully absorbed by local consumption, thus the rest of the grid is burdened by the increased generation level. Therefore, such energy community strategies are only beneficial if the higher-voltage parts of the grid are not already near saturation and can handle the reverse power flow without issues. Otherwise, additional measures are required to better coordinate local generation with local consumption—this will be discussed later.

<u>Conclusions on incentivizing optimal placement:</u>

- For the community to be incentivized to optimize for PV hosting capacity rather than individual behind-the-meter self-supply when siting generation units, energy sharing must come at no or only minimal additional cost compared to self-consumption. In particular, volume-based network fee components charged on shared energy should be low—ideally close to zero.
- However, while optimized siting increases local PV hosting capacity, it also places a greater burden on the upstream network. Therefore, it is advisable to link tariff reductions on energy sharing to a cap on local generation capacity. For instance, the discount could be granted only up to the point where the installed PV capacity equals the combined peak load of the energy community members. This limitation is recommended in cases where the community lacks storage or significant demand-side response (DSR) capabilities.

III.3. Inclusion of storage

Four storage scenarios were analyzed. In the first, the energy community uses a central storage system, which is optimized to store surplus electricity produced within the community and discharge it during peak demand periods to meet community consumption needs. Additionally, three distributed storage cases were defined. In the first of these, there is no community-level coordination—each member's behind-the-meter (BtM) storage operates independently, optimizing for individual self-consumption. In the second distributed case, full community coordination is applied: BtM storage units are optimized collectively to align community-wide generation and consumption, rather than individual needs, similarly to the central storage scenario. In the third distributed case, a hybrid approach is used—half of the BtM storage units optimize for individual self-consumption, while the other half are coordinated at the community level.

Regarding storage sizing, the capacity was aligned with the highest transformer load observed during the modeled quarter-hour intervals throughout the year. Initially, both two-hour and four-hour storage durations were analyzed. However, as the two-hour storages demonstrated a more limited impact compared to the four-hour systems, the focus of the modeling shifted toward the latter. A key finding of the analysis is that for community energy projects, four-hour storage sizing is recommended over the currently more common two-hour approach. This longer duration is more effective in capturing surplus generation during sunny periods and enabling its local use at a later time.

The following section presents the results of the four storage scenarios and outlines the regulatory implications that can be derived from them.

III.3.1. Central storage (2.1.)

R network results:

Compared to the base case, central storage increased PV hosting capacity by 11% — from 535 kW to 596 kW. This improvement exceeds that achieved through the application of central PV alone but remains slightly below the gains observed with the concentric decentralized PV allocation. Importantly, this increase in hosting capacity was achieved while reducing the power flow through the transformer by 20%, and raising the share of locally consumed production by 13 percentage points—from 49% to 62%.

Moreover, when comparing the central storage results with alternative solutions typically implemented by DSOs to reach similar levels of PV hosting capacity—such as on-load tap-changing (OLTC) transformers or line upgrades—central storage proves more effective in alleviating stress on the upstream network:

- in the case of OLTC application (7), the energy flowing through the transformer increases by 6% compared to the base case, and the local consumption of local production decreases by 3 percentage points
- and in the case of line upgrading (8), the flow through the transformer also increases by 6%, and the local consumption of local production decreases by 4 percentage points

Cigré network results:

- In this case as well, central storage significantly increases PV hosting capacity—by 54%. However, this impact is still smaller than that achieved through the optimal allocation of PV systems. (Naturally, the magnitude of the effect also depends on the storage capacity.)
- The stress on the upstream network also improves: despite the substantially higher generation compared to the base case, the power flow through the transformer decreases by 11%, while the share of generation consumed locally drops by only 3 percentage points.

To conclude, the positive impact of storage on PV integration is evident. Storage systems also prove to be significantly more effective than OLTC transformers or line upgrades, which offer only localized solutions and cannot prevent the export of excess generation to higher voltage levels in the network.

III.3.2. Distributed storage - with community optimization (2.2)

If the energy community opts not to install a shared central storage system, but instead equips members with behind-the-meter (BtM) storage — or integrates existing BtM units into the community — and these are centrally controlled to optimize production and consumption at the community level, the outcome is nearly equivalent to that of a central storage solution, with the primary difference being in network losses.

The R network results:

- The PV hosting capacity increases by 11% compared to the case of central storage.
- The flow passing through the transformer is even lower as compared to the case of central storage by 1%, and the proportion of locally consumed production is the same as in the case of central storage.

Results on the Cigré network:

- PV hosting capacity is only 1 kW (within 1%) lower than in the central storage scenario, yet it still represents a 54% increase compared to the base case.
- The power flow passing through the transformer and the share of locally consumed production change nearly identically to that observed with central storage.

These results demonstrate that in the case of storage installation, there is no real difference between the effect of a large central storage and multiple behind the meter storage units, if the control principle is the same: it optimizes for energy balance at the community level.

III.3.3. Distributed storage – individual optimization (2.3)

In this scenario, the distributed storage units operate independently without coordination at the energy community level. They optimize solely for behind-the-meter consumption and production and are not functionally integrated into the energy community.

Then the R network results show that:

- Compared to community-level optimization, the increase in PV hosting capacity is more limited — 8% versus 11% relative to the base case.
- Similarly, the impact on the upstream network is more modest: the power flow through the transformer is reduced by 9% compared to the base case (versus 20–21% with community optimization), and the share of locally consumed production increases by 7 percentage points, whereas the improvement was 13 percentage points under community optimization.

The results are similar for the Cigré network:

- In this case, the PV hosting capacity increases by less than half as much as in the case of central optimization.
- The energy flow through the transformer is reduced by 9%, slightly less than the 11% reduction achieved through central optimization. The share of locally consumed production increases by 3 percentage points compared to the base case. While this appears numerically better than the 3 percentage point *decrease* seen in the central optimization case, it's important to note that total generation increased by less than half as much. As a result, the storage systems had an easier task in managing the smaller surplus. Therefore, in relative terms, even this 3 percentage point improvement is less effective than the outcome achieved with central optimization.

In summary, the comparison of the two distributed storage scenarios clearly illustrates the significant additional benefits that community-level coordination alone can provide to the network. Even without deploying new storage capacities, simply shifting the operation of existing behind-the-meter (BtM) storage units to a community-optimized strategy delivers network advantages that cannot be achieved through OLTC transformers or line upgrades. Therefore, any mechanism that incentivizes community-level optimization over individual optimization of BtM storage contributes tangible value to the broader energy system.

III.3.4. Distributed storage - 50% community 50% individual optimization (2.4)

Finally, we examine the intermediate case of distributed storage, when half of the capacity of a BtM storage operates with community optimization, while the other half with individual optimization.

Then the results for network R are the following:

- PV hosting capacity increased by the same amount as in the individual optimization scenario (8%), indicating that the impact of partial community-level optimization was limited.
- However, the load-related indicators of the underlying network are more favorable in this mixed scenario than in both the purely community and purely individual optimization cases: it shows the greatest reduction in transformer power flow and the highest share of local consumption of local production among all cases. In other words, partial community coordination improved the local use of increased PV generation, thereby further easing the load on the upstream network.

Results for the Cigré network:

- PV hosting capacity increased by an amount falling between the results of the individual and full community optimization scenarios—33% compared to 25%–54%—indicating that partial community optimization also had a measurable impact on hosting capacity in this network model.
- Similarly, the transformer power flow and the share of local consumption from local production also fall between the two extremes: transformer flow was reduced by 10% (compared to 9%–11%), and local consumption reached 93% (versus 88%–94%).

In summary, the analysis of the storage scenarios confirms that storage units are highly effective tools for integrating PV systems. They not only enable a higher PV hosting capacity but also reduce the load on the upstream network. Furthermore, the results show that there is no significant difference between centralized and decentralized storage configurations in terms of network impact — both can be beneficial. What clearly makes a difference, however, is the control strategy governing storage use. When the same storage capacity is operated under a community-level optimization approach, rather than individual optimization, PV hosting capacity increases significantly, and network stress is further alleviated. Notably, even partial application of community-level coordination alongside individual optimization yields measurable improvements. Finally, for effective local coordination of production and consumption, a four-hour storage sizing is recommended over the two-hour sizing commonly used in current practice.

<u>Conclusions on incentivizing the deployment and community level optimization of storages:</u>

- For communities to be incentivized to invest in storage systems and operate them using a community-optimized approach—or to begin coordinating existing behind-the-meter (BtM) storages accordingly—it is essential that this mode of operation does not incur higher charges than individual optimization. Currently, when energy is not stored behind the meter but instead used for community purposes, system charges and other energy-based fee components are applied twice: once during battery charging and again during withdrawal for consumption. This double cost creates a financial disincentive for community optimization, despite its clear benefits to the grid.
- This anomaly can only be resolved by exempting energy flows related to community storage — both when storing shared production and when supplying consumption from storage — from volumetric charges. In other words, no network tariffs or other energy-linked charges should be applied to these internal community flows. Distribution system operators (DSOs) do not receive network tariff payments under individual optimization either; however, compared to individual use, community optimization improves network conditions and can reduce the need for future grid reinforcement investments.
- As four hour storage systems proved to be significantly more efficient in supporting the network than two hour storages, it is recommended that future storage subsidy programs for small consumers either require four-hour storage capacity, offer higher subsidy rates for four-hour systems, or specifically cover the cost difference between two-hour and four-hour storage solutions.

III.4. Demand side Response

One of the key strengths of community energy projects lies in their ability to actively engage consumers. Because these initiatives are driven by the consumers themselves, they have far greater potential to mobilize demand-side response (DSR) than programs led by DSOs, aggregators, or traders. To model the potential impact of DSR within energy communities, we examined scenarios (3.) where part of the consumption of flexible household devices — such as boilers, electric vehicle chargers, and heat pumps — was shifted to align with periods of solar energy production.
In the case of the CIGRÉ benchmark network, this scenario had no effect on PV hosting capacity, as there is not enough flexible consumer device on this network. Therefore, there are only results for the R network:

- Through DSR, the PV hosting capacity can be increased by 8%.
- Meanwhile, even with the increased production, the energy flow passing through the transformer can be reduced by 12% compared to the base case and the local consumption of local production can be increased by 8 percentage points.

In other words, demand-side response can provide benefits comparable to those of storage when it comes to PV integration. It not only increases local PV hosting capacity but also reduces the load on the underlying network. The magnitude of these effects is similar to what was observed in the storage scenarios. This suggests that DSR may be a more effective tool for PV integration than traditional network reinforcements such as OLTC transformers or line upgrades, which do not alleviate network load. Moreover, DSR represents a far more cost-effective solution — it requires significantly lower investment than storage systems and can be implemented more flexibly. As such, from both a technical and economic standpoint, DSR stands out as the most efficient option for enhancing PV integration. Therefore, promoting DSR should be a key priority for policymakers seeking to support cost-effective and scalable energy transition strategies.

Key Conditions for Unlocking the Demand-Side Response (DSR) Potential in Energy Communities:

- To encourage consumers to shift flexible electricity use to periods of local solar generation — or to permit automated control over this shift — they must be offered a clear financial benefit. This means making electricity consumption during solar generation hours more affordable than during other times.
- While energy cost reductions are already addressed through community settlement mechanisms, further incentives should be introduced through discounts on network tariffs and other energy-based charges applied to shared electricity. This could include a zero network tariff during peak solar generation hours, when surplus energy would otherwise be exported, and a reduced tariff for the remaining sunny hours. Conversely, higher network tariffs could be applied during peak consumption periods that do not coincide with solar generation, reinforcing the economic signal for flexible load shifting.

- The deployment of the control systems needed to enable automated DSR should be supported through targeted subsidies or investment programs, recognizing the enabling role these technologies play in grid optimization.
- To further encourage DSR investments, additional revenue streams should be made available. These could include the possibility to participate in the distribution flexibility market, governed by rules that can be met by demand-side response. Similarly, it is important to create opportunities for small DSR players to participate in balancing energy and capacity markets.

III.5. Joint application of community energy activities

In the scenarios above, we examined the network impacts of various community energy activities individually. However, in practice, energy communities tend to expand their portfolios in multiple directions, either from the outset or progressively over time. Therefore, the modeling also included the combined effects of different activities. The combined use of the two most impactful tools — storage and DSR — was evaluated in two configurations: one with distributed storage and one with central storage. In the case of the CIGRÉ benchmark network, DSR could not be modeled due to the absence of flexible consumer devices. As a result, the outcomes of these combined scenarios were identical to those of scenarios 2.1 and 2.2, where storage was deployed without the inclusion of DSR.

III.5.1. DSR + distributed storage (50% community + 50% individual) (5.1.)

In the combined modeling scenario, demand-side management (DSM) and storage were applied sequentially: first, a portion of flexible consumption was shifted to align with solar PV generation periods, followed by the deployment of decentralized storage units operated under mixed control—50% community-optimized and 50% individually optimized.

Based on the results for the R network:

- PV hosting capacity increased by 11% compared to the base case—a greater improvement than when DSM or storage were applied individually (both at 8%). While this is less than the sum of the individual effects, it matches the result of the fully community-optimized storage scenario.

- The impact on the upstream network was even more pronounced: this scenario produced the largest reduction in transformer flow, at 38%. For comparison, the reductions were 12% with DSM alone and 32% with storage alone, despite lower overall PV generation in this combined scenario. The share of local consumption from local PV production increased by 24 percentage points relative to the base case, indicating a significant improvement in local energy use efficiency.

III.5.2. DSR + central storage (5.2.)

In the scenario combining DSR with central storage, the key difference compared to the previous mixed-control case is that the central storage operates under full community-level optimization.

The results for network R show the following:

- PV hosting capacity increased by an additional 4% compared to the previous combined scenario with 50% community-controlled decentralized storage.
- However, the network-related benefits were slightly reduced: transformer flow decreased by 30%, and the share of local consumption from local production reached 68%. These figures are lower than in the previous case, suggesting that while full community control enabled a higher level of PV generation, the system lacked sufficient flexibility to absorb the surplus locally.

In conclusion, the modeling of combined scenarios clearly demonstrates that integrating multiple community energy activities—such as DSR, storage, and coordinated operation—delivers stronger results than applying them individually. Therefore, policy and support frameworks should actively incentivize energy communities to adopt a combination of complementary measures, rather than focusing on single interventions in isolation.

III.6. Electrification scenario

Finally, a scenario was modeled in which the network impacts of community energy projects were assessed not under current grid conditions, but under projected future conditions resulting from widespread electrification. In this electrification scenario, the increase in electricity demand quickly led to a rise in periods of voltage limit violations. In fact, the CIGRÉ benchmark network could not accommodate any additional consumers, while the R network was only able to integrate a single large consumer—representing 10% of the annual baseline consumption—along with additional distributed loads from electric vehicles and heat pumps in 10% of households."

In this electrification base case (Scenario 6), PV hosting capacity did not increase. However, the share of local PV production consumed locally rose by 3 percentage points due to the higher overall consumption. At the same time, the increased load significantly raised the power flow through the transformer—by 33%—highlighting the added stress on the distribution network under future electrification conditions.

In the electrified system, if an energy community installs a central storage unit and operates it under community-level optimization (Scenario 6.1), PV hosting capacity can be increased by 15%. Additionally, transformer power flow is significantly reduced—by 28 percentage points compared to the electrification base case—bringing the overload from +33% down to just +5%. The share of local PV production consumed locally also improves, increasing by 17 percentage points.

The newly introduced electrification-related consumer devices—such as electric vehicles and heat pumps—are inherently more flexible than traditional loads, making them particularly well-suited for participation in demand-side response (DSR) programs. Electrification strategies often place high expectations on leveraging this new, large-scale flexibility to stabilize and optimize the electricity system. In light of this, a DSR-focused scenario was also modeled (Scenario 6.2) to assess the potential of these flexible loads under community coordination.

Based on the results, applying demand-side response (DSR) through energy community coordination does not increase PV hosting capacity compared to the electrification base case. However, its impact on the underlying network is significantly positive: transformer power flow is reduced by 29 percentage points, and the share of local consumption from local production increases by 22 percentage points. Nonetheless, since these improvements are achieved alongside a lower level of PV generation compared to the central storage scenario, it cannot be concluded that DSR delivers a greater network benefit than central storage. Rather, the results highlight that while DSR offers meaningful flexibility and grid relief, it is most effective when combined with other measures such as storage.

In summary, the electrification scenario underscores that, while the integration of weather-dependent renewable generation is currently a key challenge for the electricity system—and one that can be partially addressed through alternative network technologies—the sharp increase in consumption driven by electrification will necessitate grid upgrades almost immediately. However, even under these intensified conditions, community energy initiatives proved effective in supporting the integration of variable renewable energy. Moreover, through demand-side response (DSR), energy communities can help reduce peak consumption, thereby alleviating pressure on the grid. As a result, they have the potential not only to ease integration challenges but also to moderate or delay the costly network reinforcements that electrification would otherwise demand.

IV. Cost-benefit analysis

In this section, the benefits that community energy activities can deliver to the electricity system are quantified based on the modeling results. These quantified impacts can serve as a foundation for determining the appropriate level of discounts and subsidies needed to incentivize energy communities to engage in activities that provide measurable value to the grid.

IV.1. PV integration benefits

The modeling results revealed that while some community energy activities primarily support increased PV hosting capacity within a district, others provide broader system-level benefits—most notably, reducing the load on the upstream network. In contrast, conventional grid reinforcement measures commonly used to facilitate PV integration, such as OLTC transformers or line upgrades, can indeed expand local hosting capacity but do not reduce reverse power flows or alleviate stress on the underlying network. As a result, even after implementing such measures, further upstream investments may still be required. These additional costs, however, could be avoided, mitigated, or at least deferred through well-targeted energy community activities.

As far as costs are concerned, based on consultation with a DSO, the installation of OLTC transformers in the given modeled case would take approximately 6-12 months and would require a one-time HUF 6 million cost. According to our own estimate, with more sophisticated instrumentation, measurements, and data collection, this cost could increase to HUF 9 million. It is also important to note that DSOs can carry out only a limited number of such transformer replacements each year due to the scarcity of required resources.[19]

Line upgrades aimed at increasing conductor cross-sections typically require an average of two years to complete, at an estimated cost of 18 million HUF per intervention. Moreover, the number of such upgrades that can be carried out annually is limited by resource and capacity constraints.[20]

In comparison, community energy activities—if sufficiently incentivized—can be deployed in nearly any district following the initial investments in PV systems, storage, and demand-side response (DSR), which typically have a lead time of approximately one year.

To assess the financial implications of such incentives, we calculated the potential costs to both the tariff community (which funds the development and operation of the distribution network) and the state (through reduced tax revenues).

In the context of network price regulation, the regulatory authority first establishes the allowed revenue required for the network operator to cover its infrastructure development and operational costs. This allowed revenue is then recovered through network charges paid by the system users — the tariff community. The regulator allocates this revenue requirement across the tariff community based on various factors, including the principle of cost causation. When a discount is granted on network charges (such as for energy sharing within a community), the resulting revenue shortfall must still be recovered by the DSO — typically through increased charges to the rest of the tariff

[19]See the Technical Report of the research.

[20]See the Technical Report of the research.

community—unless the discounted activity reduces the overall network costs and, by extension, the allowed revenue itself.

Therefore, we quantify both the financial burden that a tariff discount on shared energy would impose on the tariff community and, in parallel, the cost savings that incentivized community energy activities would generate for that same group. This comparative analysis forms the basis for assessing whether the proposed discount structure delivers a net benefit to the overall electricity system.

The calculations were conducted for consumers purchasing electricity under the universal service framework. In this case, apart from the 27% value-added tax (VAT), no additional taxes or surcharges are applied to their energy tariffs, allowing for a clear assessment of the net effect of tariff discounts and corresponding system impacts.

Table 3: Annual amount of network discounts and relevant tax reductions from the universal service household electricity tariff for locally shared electricity, under different discount categories, for network R

	All energy-based network charge elements are waived, Ft		Energy-based network charges of higher voltage level network parts are waived, Ft		Energy-based network charges of the TSO are waived Ft	
	Tariff community	State	Tariff community	State	Tariff community	State
Base	3 905 928	1 054 601	2 390 294	645 379	1 135 056	306 465
1.1 Central PV	5 566 018	1 502 825	3 406 212	919 677	1 617 475	436 718
1.2 Concentric PV	5 458 752	1 473 863	3 340 570	901 954	1 586 304	428 302
2.1 Central Storage	6 192 202	1 671 894	3 789 416	1 023 142	1 799 443	485 850
2.2 Distributed storage community (	6 192 202	1 671 894	3 789 416	1 023 142	1 799 443	485 850
2.3 Distributed storage individual op	5 211 648	1 407 145	3 189 350	861 125	1 514 496	408 914
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	4 584 691	1 237 867	2 177 088	587 814
3. DSR	4 560 192	1 231 252	2 790 682	753 484	1 325 184	357 800
4. DSR+Q(U)	3 542 573	956 495	2 167 933	585 342	1 029 466	277 956
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	4 403 916	1 189 057	2 091 245	564 636
5.2 DSR+central storage	6 410 383	1 730 803	3 922 935	1 059 193	1 862 846	502 969

As shown in Table 3, exempting shared electricity from the full energy-based network tariff for use through the public grid would impose an annual cost on the tariff community that is only slightly less than the investment cost of a single OLTC transformer installation. Similarly, the cost of a line replacement is equivalent to approximately three years' worth of such tariff discounts. If the exemption is applied only to the energy-based tariff component associated with the highest grid level, then the investment cost of an OLTC or a line upgrade would cover 6 to 12 years of discounts. It is also worth noting that, while the tariff discount represents an ongoing cost, infrastructure investments like OLTCs and line upgrades have significantly longer lifespans.

Therefore, if improving local voltage conditions were the sole requirement for increasing PV hosting capacity, incentivizing community energy projects through tariff discounts would not be cost-effective. In such cases, deploying alternative grid devices—such as OLTC transformers or line upgrades—would represent a more efficient use of resources. However, it is important to note that the number of areas that can be upgraded is severely constrained by time and capacity limitations.

A higher level of network tariff discount may be justified in cases where the load on the underlying network has reached a point that necessitates substantial infrastructure development to accommodate additional weather-dependent generation. At this stage, the required investments are significantly larger and typically involve implementation timelines of up to four years. To estimate the development costs associated with the underlying network, we reference the indirect cost components outlined in the Terms of Connection Documents (MGT) [21] issued to solar and hybrid (solar plus storage) projects during last year's connection process.

Following the amendment of 10/2016 (XI.14.) Decree of the Hungarian Energy Regulatory Authority, effective from April 1, 2021, connection applicants in Hungary are now required to bear a larger share of the infrastructure costs needed to connect to the grid. The regulatory framework has shifted from a 'shallow' connection charge model — where applicants were responsible only for the direct connection costs — to a 'deep' connection charge model, under which applicants must also cover a proportional share of system-level, indirect grid development costs based on their connection capacity. As a result, the indirect fee components quoted in the most recent connection charge documents reflect the actual cost of the upstream grid upgrades necessary to integrate additional PV capacity.

The following table summarizes the average unit costs — specifically, the indirect cost per 1 MVA — based on the size categories of projects seeking connection to the medium- and high-voltage grids for both solar-only and hybrid (solar plus storage) projects.

As shown in Table 4, unit costs decrease as project size increases. However, the community energy projects analyzed in this study are most comparable in scale to projects with connection requirements below 0.5 MVA. Therefore, the relevant cost range is 34.7 to 43.2 million HUF per MVA. For the purposes of our calculations, we base our estimates on the upper end of this range—43.2 million HUF/MVA—corresponding to hybrid solar-plus-storage projects.

Table 4: Evolution of average unit indirect costs in the final round of the Terms of Connection Document (MGT) offered in the connection allocation procedure in summer 2023

		Average unit indirect cost
		Second round MGT
Below 0.5 MVA	individual	34.7
	hybrid	43.2
0.5 to <5 MVA	individual	26.3
	hybrid	25.3
5 - < 50 MVA	individual	17.2
	hybrid	16.3
50 MVA -	individual	-
	hybrid	9.2

Source: Kaderják -Szolnoki-Lengyel (2024) Table 2, page 32

In the analyzed scenarios, the load relief on the underlying network achieved through community energy activities is quantified by calculating the reduction in exported local PV production beyond the district, relative to the base case. This reduction in export is then translated into an equivalent amount of PV capacity that would otherwise require upstream network reinforcement. The resulting PV

[21] This document is the connection offer of the DSOs/TSO containing the technical and economic terms of the given required connection.

capacity figure is multiplied by the unit cost of indirect network development — 43.2 million HUF per MVA — to estimate the value of avoided infrastructure investment.

Table 5: Value of avoided indirect network development, R network

	PV hosting capacity, kW	Share of selfconsumption	Load reduction, kW	Avoided indirect investment
Base	535	49%	0,0	0,0
1.1 central PV	583	45%	0,2	0,0
1.2 Concentric PV	720	39%	18,7	0,8
2.1 Central storage	596	62%	107,4	4,6
2.2 Distributes storage community opt	596	62%	107,4	4,6
2.3 Distributed storage individual opt	580	56%	62,7	2,7
2.4 Distributed storage 50-50 opt	580	70%	143,9	6,2
3. DSR	580	57%	68,5	3,0
4. DSR+Q(U)	664	52%	83,1	3,6
5.1 DSR+distributed storage 50-50	596	73%	172,9	7,5
5.2 DSR+central storage	617	68%	157,4	6,8

As demonstrated, the cost of avoided upstream network investments is comparable to the annual value of the energy-based tariff reductions, though it remains lower when compared to the full value of total network tariff rebates. It is important to emphasize that these underlying network investments cannot be avoided through traditional grid solutions such as OLTC transformers or line replacements. Therefore, the value of avoided local investments and avoided indirect (upstream) investments should be considered cumulatively.

In the tariff framework, these types of infrastructure investments are accounted for through two components: annual depreciation, based on the asset's useful life (e.g., 30 years for OLTCs and 40 years for line replacements), and the recognized capital cost applied to the remaining regulatory asset base after depreciation. As a result, a direct comparison between annual network charge discounts and the total value of avoided investments is not possible.

However, due to the complexity and partial confidentiality of the full price regulation methodology, this study does not attempt to model the entire tariff calculation process. Instead, a simplified approach is used to derive an estimated annual investment value from the total investment amount. This provides a reasonable proxy for comparison within the context of this research.

Tables 6 and 7 present the annual value of the total network tariff discount required to ensure that community-level optimization is not financially less advantageous than individual optimization for energy community projects. The tables also include the estimated value of avoided network investments resulting from various incentivized community energy activities across different scenarios. Furthermore, they show the proportion of the network tariff discount that could be offset by these avoided infrastructure costs, providing insight into the economic justification for offering such incentives.

As shown, even with a simplified approach, the avoided infrastructure investments could offset between 18% and 48% of the energy-based component of the network tariff discount for shared energy. The exact percentage depends on the type of investment being avoided (e.g., OLTC or line replacement) and the extent to which the specific community activity reduces the burden on the underlying network.

Based on the modeling results, this suggests that a network tariff discount of at least 18% can be justified purely from a cost-avoidance perspective. However, it is important to note that such a discount is unlikely to be sufficient to make community-level optimization more attractive than individual optimization in most cases. Even a 48% discount does not appear adequate to incentivize, for example, the use of storage systems under community control. Therefore, while these levels of discount may offer partial incentives, they are not enough on their own to drive a significant shift in behavior toward system-beneficial community optimization

Table 6: The annual level of the energy-based tariff component discount and the network development costs avoided through the activities incentivized by the discount, if line replacement is avoided, R network

	Total rebate on energy-based tariff components		Cost of avoided line replacement	Value of avoided indirect investment	Sum of avoided investments	Annual value of total avoided investment	What discount could be covered by the avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	18 000 000	0	18 000 000	1 890 907	34%
1.2 Concentric PV	5 458 752	1 473 863	18 000 000	805 680	18 805 680	1 974 596	36%
2.1 Central storage	6 192 202	1 671 894	18 000 000	4 638 384	22 638 384	2 377 030	38%
2.2 Distributes storage community opt	6 192 202	1 671 894	18 000 000	4 638 384	22 638 384	2 377 030	38%
2.3 Distributed storage individual opt	5 211 648	1 407 145	18 000 000	2 706 480	20 706 480	2 174 180	42%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	18 000 000	6 214 320	24 214 320	2 542 504	34%
3. DSR	4 560 192	1 231 252	18 000 000	2 957 040	20 957 040	2 200 489	48%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	18 000 000	7 470 576	25 470 576	2 674 410	37%
5.2 DSR+central storage	6 410 383	1 730 803	18 000 000	6 800 112	24 800 112	2 604 012	41%

Table 7: The annual level of the energy-based tariff component charge discount and the network development costs avoided through the activities incentivized by the discount, if OLTC installation is avoided, R network

	Total rebate on energy-based tariff components		Cost of OLTC	Value of avoided indirect investment	Sum of avoided investments	Annual value of total avoided investment	What discount could be covered by the avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	9 000 000	0	9 000 000	1 020 907	18%
1.2 Concentric PV	5 458 752	1 473 863	9 000 000	805 680	9 805 680	1 104 596	20%
2.1 Central storage	6 192 202	1 671 894	9 000 000	4 638 384	13 638 384	1 507 030	24%
2.2 Distributes storage community opt	6 192 202	1 671 894	9 000 000	4 638 384	13 638 384	1 507 030	24%
2.3 Distributed storage individual opt	5 211 648	1 407 145	9 000 000	2 706 480	11 706 480	1 304 180	25%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	9 000 000	6 214 320	15 214 320	1 672 504	22%
3. DSR	4 560 192	1 231 252	9 000 000	2 957 040	11 957 040	1 330 489	29%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	9 000 000	7 470 576	16 470 576	1 804 410	25%
5.2 DSR+central storage	6 410 383	1 730 803	9 000 000	6 800 112	15 800 112	1 734 012	27%

IV.2. Additional benefits in terms of network operation

Up to this point, our analysis has focused solely on the network-related benefits of community energy organizations in facilitating the integration of weather-dependent renewable generation capacities. However, community energy projects can deliver two additional, quantifiable system-level benefits. First, by increasing the share of local production consumed locally, they can reduce network losses — an efficiency gain that translates into both economic and operational value. Second, through the engagement of demand-side response (DSR), community energy projects can help mitigate peak consumption loads. This reduction in peak demand can, in turn, support the deferral, reduction, or complete avoidance of costly network development investments.

IV.2.1. Network loss reduction

By supplying a portion of local consumption from local production, energy communities reduce the amount of electricity that must be transported across the grid, and thus they can lower network losses — a significant component of the operating costs incurred by distribution system operators (DSOs). While precise quantification of the cost savings associated with reduced losses from local energy sharing would require access to detailed, non-public data, we provide an approximate estimate. In Hungary, until April 2021, the network tariff structure included a separate 'DSO loss fee' component, explicitly designed to cover the cost of energy losses at various network levels. This DSO loss fee element at different network levels was structured in the following way.

Table 8: The DSO network loss fee and energy-based fees in effect in January 2021

	DSO network loss fee HUF/kWh	Sum of energy-based distribution network fee elements HUF/kWh	Share of DSO network loss fee in the total distribution network tariff
High-voltage connection	0,22	0,32	69%
High/Medium-voltage connection	0,35	0,80	44%
Medium-voltage connection	1,19	2,23	53%
Medium/Low-voltage connection			
profiled	2,28	8,72	26%
not profiled	2,28	4,15	55%
Low-voltage connection			
profiled	3,54	13,50	26%
profiled, controlled	2,64	6,51	41%
not profiled	3,54	6,66	53%

Source: MEKH

As shown in Table 8, the lower the voltage level at the consumption point, the higher the network losses—and consequently, the higher the corresponding fee—due to the greater distance electricity must travel and the inherently higher losses at lower voltage levels. This is why the DSO network loss fee for a low-voltage, profiled connection was more than 16 times higher than that for a high-voltage connection point under the former tariff structure.

Since April 2021, however, the regulatory authority has ceased publishing separate DSO loss fee components, replacing them with a single aggregated volumetric network charge. As a result, the exact current share of network loss-related charges is no longer publicly known. To approximate this value, we refer to the 2021 structure, where 26% of the energy-based fee component was allocated to cover DSO network losses. Applying this proportion to the current rate of 23.4 HUF/kWh, we estimate that approximately 6.14 HUF/kWh represents the cost of covering network losses.

In the modeled community energy scenarios, a greater share of local consumption is supplied directly from local production, thereby reducing the volume of electricity transported through the broader grid and minimizing associated network losses. We estimate the value of this operational benefit using the 6.14 HUF/kWh loss cost benchmark. The resulting cost savings reflect a measurable reduction in DSO operating expenses—and therefore in the burden placed on the tariff community—which are detailed in the following tables.

Table 9: Annual investment costs saved through community energy activities (in case of avoiding line replacement) and the value of saved network loss, network R

	Total rebate on energy-based tariff components		Annual value of total avoided investment	Annual value of avoided network loss	Sum of avoided annual costs	Discount on sharing induced by avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	1 890 907	1 474	1 892 381	34%
1.2 Concentric PV	5 458 752	1 473 863	1 974 596	137 413	2 112 010	39%
2.1 Central storage	6 192 202	1 671 894	2 377 030	791 102	3 168 132	51%
2.2 Distributes storage community opt	6 192 202	1 671 894	2 377 030	791 102	3 168 132	51%
2.3 Distributed storage individual opt	5 211 648	1 407 145	2 174 180	461 605	2 635 786	51%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	2 542 504	1 059 887	3 602 390	48%
3. DSR	4 560 192	1 231 252	2 200 489	504 340	2 704 829	59%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	2 674 410	1 274 148	3 948 559	55%
5.2 DSR+central storage	6 410 383	1 730 803	2 604 012	1 159 797	3 763 809	59%

Table 10: Annual investment costs saved through community energy activities (if OLTC is avoided) and the value of saved network loss, network R

	Total rebate on energy-based tariff components		Annual value of total avoided investment	Annual value of avoided network loss	Sum of avoided annual costs	Discount on sharing induced by avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	1 020 907	1 474	1 022 381	18%
1.2 Concentric PV	5 458 752	1 473 863	1 104 596	137 413	1 242 010	23%
2.1 Central storage	6 192 202	1 671 894	1 507 030	791 102	2 298 132	37%
2.2 Distributes storage community opt	6 192 202	1 671 894	1 507 030	791 102	2 298 132	37%
2.3 Distributed storage individual opt	5 211 648	1 407 145	1 304 180	461 605	1 765 786	34%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	1 672 504	1 059 887	2 732 390	36%
3. DSR	4 560 192	1 231 252	1 330 489	504 340	1 834 829	40%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	1 804 410	1 274 148	3 078 559	43%
5.2 DSR+central storage	6 410 383	1 730 803	1 734 012	1 159 797	2 893 809	45%

It is important to note that, unlike avoided investment costs — which are one-time capital expenditures — network loss reductions represent annual operating cost savings. When the estimated annual DSO operating cost savings are added to the the annualized value of avoided investment costs, the total savings generated by community energy activities can cover between 37% and 59% of the network tariff discount on energy sharing, particularly in scenarios that involve storage or demand-side response (DSR) activities.

IV.2.2. Decreasing peak consumption

In most countries where community energy activities are supported through tariff discounts, these initiatives are mostly recognized for the positive impact they have on consumption patterns—such as flattening the load curve and reducing peak demand. As electrification progresses, the anticipated surge in electricity consumption will require substantial network development. [22] This need was clearly reflected in our technical modeling results: no further consumption could be added to the CIGRÉ network, and only a limited amount to the R network, before technical limits were reached.

Peak consumption is the primary driver of network development requirements linked to rising demand. Community energy projects — particularly those involving demand-side response — can mitigate peak loads by shifting a portion of consumption from high-demand periods to times of high

[22] See, for example, Eurelectric's fresh Grid s for Speed study , according to which investments in the distribution network must be increased from the current 36 billion euros per year on average to 67 billion euros between 2025 and 2050 to allow for the mass electrification of transport, heating and industry, the integration of renewable energy sources, and to be resilient to extreme weather conditions and cyber threats.

solar generation. This not only improves system efficiency but can also defer, reduce, or eliminate the need for costly grid upgrades, yielding measurable financial savings for both DSOs and the tariff community.

To date, the only published cost-benefit analysis in this topic has been released by the regulatory authority of the Brussels Capital Region, BRUGEL. [23] The study, conducted by the consultancy Schwartz & Co, was based on a 20-year forecast period from 2023 to 2042. Among the potential benefits of community energy organizations, the analysis focused exclusively on the reduction of annual peak load resulting from energy sharing.

Drawing on data from existing pilot projects, the study examined two impact scenarios. In the 'high' impact scenario, each participant in an energy sharing initiative contributes 1 kW to peak load reduction, while in the 'low' scenario, the contribution is 0.5 kW per participant. Additionally, three growth trajectories for the adoption of energy sharing were modeled:

- Scenario 1: Very limited uptake, with 1% of consumers participating by 2042
- Scenario 2: Moderate uptake, reaching 5% participation by 2042
- Scenario 3: Ambitious growth, with 20% consumer participation by 2042

Based on these assumptions, the study calculated the projected reduction in peak electricity demand across the three growth scenarios, illustrating the potential system-wide benefits of widespread energy sharing.

The benefits related to peak consumption reduction were interpreted as the annual investment costs avoided by the distribution network operator (DSO) due to the contribution of energy sharing. However, since the local DSO, Sibelga, was unable to quantify these avoided investments directly, an approximation method was agreed upon. Under this simplified approach, the annual benefit from peak reduction was estimated by multiplying the network costs of year n by the ratio of the total estimated peak reduction from energy sharing to the network's total synchronous peak. This assumes that the reduction in peak demand translates proportionally into avoided investment costs, and uses historical investment data as a proxy for future cost avoidance.

In terms of costs, the analysis also included the DSO's investment expenditures required to support energy sharing projects. These included the installation of smart meters and IT infrastructure, as well as recurring annual operating costs related to system maintenance and the administration of energy sharing activities.

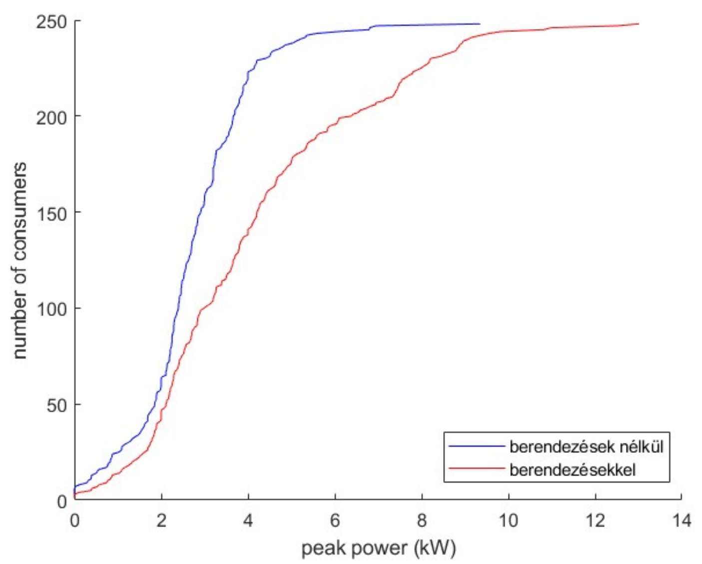
According to the results, in Scenario 1 (1% consumer participation), the estimated costs exceeded the benefits from energy sharing. However, in Scenario 2 (5% participation), benefits outweighed costs in the 'high' case, where each participant contributed 1 kW to peak reduction. In Scenario 3 (20% participation), even the 'low' case with a 0.5 kW contribution per participant proved cost-effective, justifying DSO support for energy sharing initiatives.

[23]BRUGEL (2023): Projet d'étude (BRUGEL-Etude-20230425-45) Coûts-avantages relative aux communautés d'énergie et au partage d'électricité

With this study, BRUGEL supports the network tariff discount scheme outlined in Section II.1., which bases the level of discount on the relative location of the production unit and the participants in energy sharing within the network. The closer the consumers are to each other and to the generation source, the higher the tariff discount they receive. Four levels were defined: the most favorable tariff applies to sharing within a single building, while at the other extreme — if the participants in energy sharing are located upstream of a transmission feeder — the full network charge must be paid.

Building on the logic of this study, we also perform a simplified calculation to estimate how much annual savings the domestic tariff community could achieve through peak load reduction enabled by energy sharing within community energy projects. As a first step, we determine the amount of peak load reduction that can be realized in the modeled scenario for the R network. The figure below illustrates the development of peak consumption on the R network — modeled using real consumer measurement data — with and without the contribution of flexible consumer appliances (boilers, electric vehicle chargers, and heat pumps).

Figure 1: Peak consumption of consumers on network R with (red) and without (blue) flexible consumer appliances



As shown in the figure, peak consumption without the involvement of flexible appliances typically remains below 4 kW, while with flexible appliances it rises but still remains mostly below 8 kW. Based on this observation, we calculate the peak load reduction only for consumer points equipped with flexible loads and assume a conservative individual contribution of 0.5 kW. This results in a total estimated peak reduction of 55.5 kW across the modeled community.

To estimate the associated financial benefit for the tariff community, we approximate the annual distribution system operator (DSO) investment cost using the combined value of depreciation and capital costs recognized by the regulatory authority for 2024, which amounts to HUF 193,195 million.[24] The total procured capacity used in the tariff calculation is 9,041,917 kW. [25] Based on this simplified

[24] MEKH Decree : Determination of electricity network tariffs applicable from January 1, 2024 Page 91 Table 60

[25] MEKH Decree : Determination of electricity network tariffs applicable from January 1, 2024 Page 94 Table 61

approach, the 55.5 kW peak reduction achieved through energy sharing in the modeled community corresponds to an estimated annual avoided investment cost of approximately HUF 1.2 million for the tariff community.

The peak reduction effect becomes even more significant in the context of electrification, where network development is increasingly driven by rising consumer demand. As demonstrated in the electrification modeling, we are approaching critical capacity limits: no additional consumption could be accommodated on the CIGRÉ network, and only a small increase was possible on the R network.

When this peak reduction benefit is combined with the other advantages community energy activities offer to the tariff community — particularly in scenarios involving DSR and decentralized storage — the total network cost savings become substantial. In these scenarios, the savings from avoided investments and reduced operational costs can cover between 52% and 85% of the total tariff discount provided for energy sharing.

Table 11: The annual level of network tariff discount, the annual savings on DSO network loss costs, and the annual value of investment cost savings from peak consumption reduction, and from the system integration of weather dependent renewables (in case of avoiding line replacement), network R.

	Total rebate on energy-based tariff components		Annual value of total avoided investment related to weather dependent renewable	Annual value of avoided network loss	Annual value of avoided investment due to decreased peak consumption	Total annual costs saved	Discount on sharing induced by avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	1 890 907	1 474		1 892 381	34%
1.2 Concentric PV	5 458 752	1 473 863	1 974 596	137 413		2 112 010	39%
2.1 Central storage	6 192 202	1 671 894	2 377 030	791 102		3 168 132	51%
2.2 Distributes storage community opt	6 192 202	1 671 894	2 377 030	791 102	1 185 846	4 353 979	70%
2.3 Distributed storage individual opt	5 211 648	1 407 145	2 174 180	461 605	1 185 846	3 821 632	73%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	2 542 504	1 059 887	1 185 846	4 788 237	64%
3. DSR	4 560 192	1 231 252	2 200 489	504 340	1 185 846	3 890 675	85%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	2 674 410	1 274 148	1 185 846	5 134 405	71%
5.2 DSR+central storage	6 410 383	1 730 803	2 604 012	1 159 797	1 185 846	4 949 655	77%

Table 12.: The annual level of network tariff discount, the annual savings on DSO network loss costs, and the annual value of investment cost savings from peak consumption reduction, and from the system integration of weather dependent renewables (in case of avoiding OLTC), network R

	Total rebate on energy-based tariff components		Annual value of total avoided investment related to weather dependent renewable integration	Annual value of avoided network loss	Annual value of avoided investment due to decreased peak consumption	Total annual costs saved	Discount on sharing induced by avoided investments
	Tariff community	State	Tariff community	Tariff community	Tariff community	Tariff community	
1.1 central PV	5 566 018	1 502 825	1 020 907	1 474		1 022 381	18%
1.2 Concentric PV	5 458 752	1 473 863	1 104 596	137 413		1 242 010	23%
2.1 Central storage	6 192 202	1 671 894	1 507 030	791 102		2 298 132	37%
2.2 Distributes storage community opt	6 192 202	1 671 894	1 507 030	791 102	1 185 846	3 483 979	56%
2.3 Distributed storage individual opt	5 211 648	1 407 145	1 304 180	461 605	1 185 846	2 951 632	57%
2.4 Distributed storage 50-50 opt	7 491 744	2 022 771	1 672 504	1 059 887	1 185 846	3 918 237	52%
3. DSR	4 560 192	1 231 252	1 330 489	504 340	1 185 846	3 020 675	66%
5.1 DSR+distributed storage 50-50	7 196 342	1 943 012	1 804 410	1 274 148	1 185 846	4 264 405	59%
5.2 DSR+central storage	6 410 383	1 730 803	1 734 012	1 159 797	1 185 846	4 079 655	64%

IV.3. Summary, conclusions on network operation effects

As demonstrated above, certain community energy activities can generate significant benefits for the tariff community. These benefits could be reached by incentivizing energy communities through tariff discounts on energy sharing, most effectively by applying a full tariff reduction. However, while the identified savings are substantial, they do not fully justify a complete exemption from volumetric network charges.

It is also essential to recognize that network development is not solely a financial issue—it also requires time, labor, and material resources, all of which are limited. As the modeling results show, the challenges of integrating weather-dependent renewable energy sources and managing rising peak consumption cannot be solved through grid expansion alone, even if it were the most cost-efficient solution. For this reason, complementary measures — such as those offered by community energy projects — will remain necessary. These decentralized, participatory approaches provide practical, scalable support to the electricity system and should therefore be integrated into future grid planning and incentive frameworks.

To reconcile the tension between cost recovery and incentivization, it is not sufficient to simply apply a cost-benefit reflective network tariff discount to the shared energy within the existing tariff framework. Instead, a dedicated tariff should be developed for system users participating in energy sharing schemes.

In designing this special tariff, it is crucial that the energy-based fee components applied to shared energy — whether delivered directly from producer to consumer or via storage — are set close to zero. This is necessary to create a strong financial incentive for community-level optimization, as opposed to individual optimization. At the same time, the volumetric network fee applied to any excess consumption not covered by sharing should be set higher than in the standard tariff. This adjustment serves two purposes: it partially offsets the network revenue lost on the shared energy portion, and it further encourages active participation in energy sharing.

In parallel, the role of fixed network charges should be significantly increased. This approach is in line with recent guidance from the European Union Agency for the Cooperation of Energy Regulators (ACER) [26], which recommends a transition from predominantly energy-based tariff structures to fixed and capacity-based models in the evolving electricity system. A stronger fixed component allows network operators to recover a stable portion of their revenue, even as energy-based fees are discounted for shared consumption, ensuring financial sustainability while supporting the growth of community energy initiatives.

The annual fixed fee component in the proposed energy community tariff must be set such that the total amount paid by each community offsets the difference between the value of the tariff discount provided on sharing and the measurable system benefits generated by the community's activities.

It is also important to acknowledge, as highlighted in the Belgian BRUGEL study, that supporting energy sharing through community energy projects imposes additional costs on distribution system operators (DSOs). These include expenses for replacing conventional meters with smart meters, operating IT systems, and managing organizational and administrative tasks. However, this study does not separately calculate these DSO costs. As outlined in Section I, the new EU Electricity Market Design package mandates that Member States enable energy sharing. Specifically, Article 15.a (6) requires

[26] ACER (2023): ACER Report on Electricity Transmission and Distribution Tariff Methodologies in Europe

that 'Member States shall ensure that the relevant transmission system operators or distribution system operators or other designated bodies... monitor, collect, validate and communicate metering data related to the shared electricity with relevant final customers and market participants at least every month, and in accordance with Article 23, and for that purpose, put in place the appropriate IT systems.'[27]

This requirement means that the necessary infrastructure for enabling energy sharing—such as smart metering and supporting IT systems—must be developed regardless of the incentives introduced or the realized benefits of community energy projects. Therefore, in the context of this study, which focuses specifically on incentivizing community-level optimization, we do not treat these DSO-related expenditures as part of the cost-benefit calculation. That said, these costs can reasonably be incorporated into the fixed fee component of the proposed energy community tariff.

IV.4. Additional social benefits

Finally, beyond the benefits related to network operation, community energy activities also generate important social benefits. As shown in the preceding tables, the tariff discount granted for energy sharing leads to a corresponding reduction in VAT, which — particularly for consumers under the universal service scheme — translates into a fiscal impact at the level of public finances. In the modeled scenarios, this effect represents a cost of approximately HUF 1.5–2 million annually.

At a broader societal level, community energy initiatives offer several additional advantages. These include the mobilization of decentralized capital, the enhancement of consumer awareness, the strengthening of local communities, and increased public acceptance of renewable energy technologies.

Among the various social benefits, the most quantifiable is the increase in PV hosting capacity enabled by community energy activities, which leads to additional renewable electricity generation and a corresponding reduction in carbon dioxide emissions from the domestic electricity mix. In practice, the newly installed solar capacity displaces natural gas-based electricity generation, which typically operates at the margin of the merit order. As a result, the carbon intensity of domestic power production decreases.

Based on international benchmarks, natural gas-based electricity generation emits approximately 368 kg CO_2 per MWh. In the modeled scenarios, the additional PV production made possible through community energy actions directly reduces this emission. To quantify the financial value of this environmental benefit, a CO_2 price is applied. For this purpose, we use the price of European Union Allowance (EUA) units traded on the EU Emissions Trading System (ETS). While current EUA futures prices on the ICE exchange range between 62 and 68 EUR/ton depending on the product, the average EUA value observed during 2024 was around 80 EUR/ton. [28]

[27]EMD 2024/1711 Directive Article 2, Article 5, which supplements the IEMD with Article 15a, Paragraph 6 is quoted

[28]ICE EUA Futures price quotations

Based on these assumptions, the modeled energy community activities enable measurable carbon dioxide emission reductions by replacing natural gas-based electricity generation with solar power. This results in avoided carbon quota costs at the societal level. Depending on the EUA price applied—ranging from the current market levels (62–68 EUR/ton) to the 2024 average of 80 EUR/ton—the value of these avoided emissions falls between HUF 480,000 and HUF 2.6 million annually.

With the exception of a few specific cases—such as the concentric PV allocation scenario, where a disproportionately high share of new PV production is integrated—the social benefit derived from reduced CO_2 emissions typically amounts to approximately one-half to one-third of the value of the VAT reduction associated with the tariff discount on energy sharing.

Table 13: The social benefit associated with the reduction of CO_2 emissions and the loss of VAT due to tariff discount

	PV hosting capacity, kW	Additional renewable generation, MWh	Avoided CO2, tons	Value of avoided CO2, HUF (with a price of 60 EUR/tons)	Value of avoided CO2, HUF (with a price of 80 EUR/tons)	VAT loss in case of full energy-based tariff discount, HUF
Base	535	-				
1.1 central PV	583	58	21,1968	508 723	678 298	1 502 825
1.2 Concentric PV	720	222	81,696	1 960 704	2 614 272	1 473 863
2.1 Central storage	596	73	26,9376	646 502	862 003	1 671 894
2.2 Distributes storage community opt	596	73	26,9376	646 502	862 003	1 671 894
2.3 Distributed storage individual opt	580	54	19,872	476 928	635 904	1 407 145
2.4 Distributed storage 50-50 opt	580	54	19,872	476 928	635 904	2 022 771
3. DSR	580	54	19,872	476 928	635 904	1 231 252
4. DSR+Q(U)	664	155	56,9664	1 367 194	1 822 925	1 943 012
5.1 DSR+distributed storage 50-50	596	73	26,9376	646 502	862 003	1 730 803
5.2 DSR+central storage	617	98	36,2112	869 069	1 158 758	1 730 803

If the specific energy sharing network tariff system outlined above were implemented, members of the modeled energy communities — being residential users — would also pay VAT on the fixed fee component. As a result, the total VAT revenue loss would be lower than in the baseline case presented here, where the energy-based fee element is simply waived on the shared portion of electricity.

V. Proposal for a support scheme and regulatory framework for community energy projects

In the following, we summarize our findings on the incentive scheme that should be applied to community energy projects in order to ensure that they engage in activities that support the PV integration capacity of the electricity system.

V.1. Subsidies

In many countries, including Hungary, community energy projects were initially launched with investment support provided through state-funded tenders. In exchange, beneficiary communities were required to meet various conditions, such as engaging a minimum percentage of the local population and installing specific technologies (e.g., photovoltaic systems, energy storage, electric vehicle chargers, etc.).

Based on our modeling results, the integration of energy storage and demand-side response (DSR) has the most beneficial impact on the grid and can significantly reduce stress on the underlying network infrastructure. Therefore, we recommend that future subsidy schemes focus on the installation of both energy storage systems and DSR capabilities,

- Implementing DSR Control for Flexible Loads
    - The establishment of DSR control systems could be supported as a standalone subsidized activity. For example, a dedicated funding call could be launched specifically for this purpose.
- Recommendations for Supporting Energy Storage Deployment
    - A minimum storage duration of 4 hours should be required, replacing the current 2-hour standard.
    - No preference should be given to centralized or decentralized storage solutions — both should be considered equally valid depending on project context.
    - Storage deployment should be accompanied by the development of a control system capable of optimizing the operation of either a central or multiple decentralized storage units, along with associated generation and consumption points. A separate support mechanism should be considered for this purpose.
        - A specific focus could be the targeted support of community groups formed around already placed decentralized storages.

Geographical Scope and Network Impact Considerations

From the modeling results, it is evident that community energy projects intended to support PV integration should be geographically localized—ideally within a defined area such as a low-voltage transformer district. Projects developed within such districts demonstrate the most beneficial impact on the electricity network and should therefore receive the highest level of support.

While national-level community energy projects may also be valuable for other policy goals, their contribution to local grid stability and PV integration is significantly lower. If enhancing network performance is a key policy objective, then geographical localization should be established as a requirement for funding eligibility.

To ensure that community energy projects are oriented toward local self-consumption rather than oversized production, it is advisable to introduce a minimum local self-consumption rate, such as 80%, as a funding condition.

V.2. Feed in tariff

International examples show that several countries provide targeted support for community renewable energy production, either through benefits embedded in renewable support schemes or through additional incentives specifically tied to local consumption—such as bonuses based on the local consumption rate or the absolute volume of locally consumed energy.

However, traditional renewable support mechanisms — such as feed-in tariffs or premiums — do not effectively incentivize community energy projects to contribute to PV integration, as the electricity generated is typically exported to the grid rather than used locally.

To address this, we recommend the introduction of a premium-type subsidy for local energy communities situated within low-voltage (LV) districts or areas served by HV/MV transformer stations. This premium would apply specifically to the surplus production remaining after local consumption, and its disbursement should be conditional upon achieving a high rate of community self-consumption—for example, at least 80% on a monthly basis.

This approach would provide a strong incentive for maximizing local consumption, as communities that meet the consumption threshold would receive a premium price for their remaining production—higher than its typical market value. In practice, this functions as a performance-based bonus, rewarding communities for aligning production with local demand. Furthermore, such a system would discourage oversizing of production assets and promote a more balanced and sustainable approach to capacity planning.

V.3. Connection

In Hungary, several pilot energy community projects have stalled during the grid connection process. Many of these initiatives planned to install generation capacities just as the domestic electricity system reached saturation with weather-dependent sources, resulting in a halt in new connection permits. For nearly three years, no new connection permits were issued for medium- and high-voltage networks. Even for those solar power plants that received conditional approval under the revised procedure, an additional four-year delay before grid connection was imposed.

Projects aiming to connect to the low-voltage (LV) network also encountered serious barriers. Entire LV districts were closed, meaning behind-the-meter PV installations were prohibited from exporting electricity to the grid. This effectively made the development of energy communities unfeasible in many areas.

However, modeling results indicate that PV generation coordinated through community-based frameworks places significantly less strain on the network compared to standalone PV systems. Based on these findings, we recommend that PV installations operated under community energy projects be granted priority access in the connection procedure.

Importantly, this preferential treatment should not be based merely on formal incorporation as an energy community, such as through corporate registration documents. Instead, eligibility should be determined by specific technical and operational criteria that demonstrate the project's expected contribution to network efficiency and stability. These criteria could include, for example:

- Both the community-operated PV system and the associated storage unit could be connected to the grid each under flexible connection agreements, whereby these assets agree not to inject electricity into the grid during time periods specified by the distribution system operator.
- A new type of flexible connection agreement could be established at the community level rather than the individual unit level. Under this arrangement, the community energy project would commit to ensuring that no electricity is exported from the community's geographic area to the underlying network during specific periods defined by the network operator.
- An additional condition could be imposed on community solar power plants, storage systems, and DSR equipment, requiring them to participate in the distribution-level flexibility market organized by the DSO. In return, these projects would be granted prioritized or earlier access to grid connection.

These measures would ensure that only projects providing tangible benefits to the grid are prioritized.

V.4. Creation of flexibility markets, inclusion of small actors

To address local grid issues — such as voltage problems and congestion — caused by weather-dependent renewable energy sources, EU regulations identify the development of local flexibility markets as the primary solution. In Hungary, the construction of such distribution-level flexibility markets is already underway through pilot projects, and it is anticipated that within the next two to three years, these markets will become standard tools for voltage control and congestion management.

Local energy communities can also contribute to the integration of weather-dependent generation capacities by participating in these DSO-managed flexibility markets. This, however, requires two key developments:

- On one hand, communities need to develop flexibility capabilities by setting up control and monitoring systems and integrating flexibility-enabling appliances such as storage units, electric vehicle chargers, heat pumps, boilers, and PV systems.

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- On the other hand, it is essential that the market rules are adapted to allow the participation of small-scale assets. These must not be discriminated against in the market design. The Demand Response Network Code currently being developed at the EU level aims, among other goals, to ensure this principle across all Member States.

In these markets, energy communities will aggregate and offer the flexibility potential of their assets, acting as aggregators. Therefore, developing the regulatory and technical framework for independent aggregators is also critical. While some progress has been made, Hungary still lacks a comprehensive regulatory structure to support the independent aggregator model effectively.

Additionally, to ensure that DSOs rely on flexibility markets—instead of traditional, potentially more costly grid reinforcements—to meet their system needs, Hungary's DSO tariff and incentive scheme must also be revised. The current regulatory framework does not yet sufficiently encourage DSOs for the use of flexibility as a primary grid management tool.

In summary, although the strategic direction has been clearly defined by EU policy, significant regulatory work remains to be done to enable implementation. In the meantime, and in line with our recommendations in Section V.1., targeted support should be provided to help local energy communities develop flexibility capabilities. For example:

- Introducing dedicated subsidies for communities located in closed LV districts, where grid access is currently restricted.
- Launching pilot flexibility markets in the closed districts to solve local congestion and voltage problems, and encouraging local energy communities to participate
    - Supporting the formation of local energy communities in closed districts by requiring that new PV installations in those areas become part of an energy community

V.5. Tariff system

International practices show that many EU Member States apply network charge discounts to community energy sharing, depending on the geographical scope of the activity. The underlying logic is that charges related to higher voltage levels — those not affected by local sharing — are waived. In contrast, the French community energy tariff system offers a more sophisticated approach. It not only provides network fee reductions, but is also structured to strongly incentivize local self-consumption. Under this system, if community self-consumption is low, the cost of using the grid becomes higher than under the standard tariff, thereby pushing communities to optimize for local use.

As part of our modeling and cost-benefit analysis, we examined the magnitude of the positive grid impact resulting from community energy activities located within low-voltage (LV) network areas, and explored what type of network tariff system could best incentivize such behavior while also assessing associated costs and benefits. Based on the findings, we recommend that—rather than simply providing a discount on the energy-based component of the existing tariff for shared volumes—a dedicated energy community tariff should be introduced for users participating in energy sharing. This tariff structure should include the following key elements:

- Zero energy-based network tariff for the shared volume, in order to incentivize community-level optimization over individual strategies.
- For non-shared consumption, the introduction of a time-of-use (ToU) energy-based component is recommended. This would encourage consumption to be shifted away from peak periods.
- Finally, an important element of this special tariff system is the fixed fee element, which compensates for the network revenue loss resulting from waived energy-based charges on shared volumes. This fixed fee should be calibrated based on the system-wide benefits provided by local community energy projects. Modeling results indicate that only 15–48% of the discount granted on the shared volume needs to be recovered through this fixed fee to maintain revenue neutrality.
    - This fixed fee should be differentiated by the network extent of the energy sharing. The larger the geographic scope of the energy community (e.g., extending across multiple network levels), the smaller the local grid benefit, and thus, the higher should be the fixed fee.
- For community energy projects that extend beyond a HV/MV transformer district, we do not recommend eligibility for this specific energy sharing tariff system.

In summary, we recommend that instead of providing a simple tariff discount on sharing, it is necessary to create a specific energy community tariff system that supports energy sharing. With tariff discounts, individual optimization will continue to be more attractive compared to community optimization. Community optimization will be more attractive only with a zero energy-based fee component, which, as the modeling results showed, can also ensure a much more efficient use of the existing infrastructure.

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