D 2.4: Recommendations for local markets

BEYOND | Work Package 2, Task 2.6

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Blockchain based ElectricitY trading for the integration Of National and Decentralized local markets

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ERA-Net Smart Energy Systems

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Contents

1. Introduction

The BEYOND project investigates different market designs for local energy markets and their integration in central electricity markets. Different concepts of peer-to-peer trading and tariff design are studied and the emerging regulatory framework facilitating local energy trading is evaluated. BEYOND demonstrates and validates local market designs in pilot sites across three different countries (Austria, Ireland and Norway).

The purpose of this Document is to evaluate different market designs that are developed in WP2 for the individual demo sites using tailor-made simulation and optimization models. Furthermore, general recommendations are derived from the findings of the individual demo investigations. The considered Use Cases and Business Models are listed in Table 1 and described in detail in deliverable D1.3 and deliverable D2.2, respectively. A comprehensive discussion of regulatory aspects in a European context is provided in deliverable D2.1.

Table 1: Overview of BEYOND use cases

ID	Type	Country	Short description
BUC IE01	Business	Ireland	Maximize consumption of local energy
BUC NO01	Business	Norway	Demand response as a measure against uncertain local generation
BUC AT01	Business	Austria	Local energy tariff
BUC AT02	Business	Austria	Local grid tariff
BUC AT03	Business	Austria	Portfolio investment optimization
SUC IE01	System	Ireland	Optimizing individual and community strategy
SUC NO01	System	Norway	

The document is organized as follows. Chapter 2 provides the analyses and findings from the individual use cases on an operational level. This includes simulations of different trading algorithms and market designs for local electricity markets and the analysis of different tariff design options as well as their impact on total electricity cost for Energy Community members, local self-consumption, CO2 emissions and the load on distribution grids.

In Chapter 3 several business models on top of these operational local energy market concepts are investigated in detail. This analysis considers investment costs of technologies required for the novel concepts, such as ICT infrastructure and evaluates the economic efficiency of the Business Models more comprehensively from a longer-term perspective.

Finally, Chapter 4 summarizes the key findings from the individual local energy market concepts and provides general recommendations for the implementation of Energy Communities and related local electricity trading concepts.

2. Recommendations for local markets in the use cases

2.1. Ireland

2.1.1. BUC IE: Maximize consumption of local energy

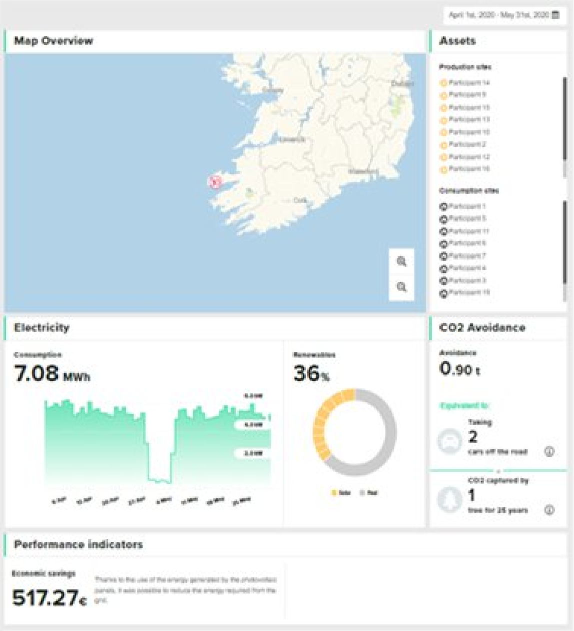
Description of test scenarios

The pilot site, where the use case will be tested, is situated in the Dingle peninsula in southwest Ireland. Irish distribution system operator, ESB Networks, is working towards building Dingle as a smart energy community (EC). Irish demo-site under BEYOND project has been involved with twenty residential customers within the community engaging in local market based on collective self-consumption (CSC) mechanism. The premise of the collective self-consumption concept allows the local generation to be shared among customers in near to real-time or over a billing period. The local generation facility can be on a community scale, e.g. large, community-scale solar PV facility or can be distributed among customers, e.g. roof-top solar PV. For the former case, the installation, investment and operation are conducted on behalf of the community, and the sharing of energy and profits are collectively performed. Whereas, in the latter case, prosumers with surplus electricity, after meeting onsite demand, are shared among the community.

Out of the 20 customers considered in the study, 10 of these customers are acting as prosumers with their roof-top PV facilities with a capacity in the range of 2-2.2 $\boldsymbol{kWp}$. Though the PV facilities are distributed, each prosumers' generation and demand have been measured separately on the demo site. Hence, it is possible to consider the generation from distributed PV facilities as aggregated. This paper considers the PV solar facilities as aggregated community facilities located at different locations. The aggregated generated electricity is then allocated in real-time among 20 customers in the demo site as per deployed allocation mechanism (discussed in detail in section 3.3). Under such consideration, the prosumers and consumers are treated equally, and prosumers have not benefitted from having the facility on their roof-top. This assumption is valid when the investment in the PV facilities is made through community-scale rather than the individual. On a different note, the residential homes having a PV facility behind the meter can share only the surplus PV with other community members after meeting their own demands. In this case, the investment is individually driven, and the profit-sharing model needs to consider the aforementioned fact.

System architectures

The real-life data which is utilised in the Irish demo site is received from meters installed at each participant's house and records the solar PV production (in case participant has solar roof-top PV), consumption separately for each individual pro-/consumers. The measurement frequency is on hourly resolution. The measured data are now stored in a cloud database which will be accessed and further processed by FlexiDAO's software "RESpring" (Figure 1 shows a snapshot) to use blockchain technology for energy communities. RESpring is a scalable and flexible community energy management software that connects renewable energy producers, from small roof-top PV systems up to large wind farms, with energy consumers, enabling real-time traceability of energy flows and accounting of CO_2 emissions and economic savings.



Thanks to the use of the energy generated by the photovoltaic panels, it was possible to reduce the energy required from the grid.

Figure 1: "RESpring" dashboard

All the real-time energy measurements are recorded on blockchain - i.e. tokenisation according to the Ethereum standard specifically for the tokenisation of energy metering data. Smart contracts are used to manage assets and contractual relationships among stakeholders. By creating a digital twin of the asset, it is possible to automatically establish a smart contract. RESpring software executes the real-time matching of generation and consumption according to the predefined agreements and records every peer-to-peer transaction on the blockchain. Blockchain automatically avoided double-counting, ensuring the trustless and fair allocation and matching generation with consumption without needing a third-party overviewing of the process. The overall system architecture is illustrated in Figure 2 in a simplified manner. One integrated API works across utilities, grid operators and hardware vendors to collect generation and consumption data. This allows for seamless, flexible integration with customers' meters. The user interface is designed to provide a simple visualisation and management dashboard for consumers and stakeholders, allowing them to control, edit and modify users, assets, and agreements and retrieve the results.

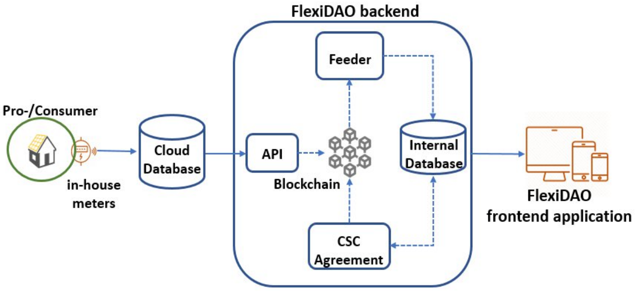


Figure 2: System architecture for Irish demo site

Matching algorithms

As soon as consumption and production data are received through API, a matching mechanism is immediately triggered, which performs matching per the algorithm defined in the software. The matching algorithm has the following rules based on which the CSC is being performed for Irish EC.

- The matching is being executed in real-time. This means that the generation and demand must happen in the same hour to be matched.
- All the consumers have equal priority. Hence, the solar generation is allocated among the consumers equally, with each of the consumers receiving a fixed, equal percentage of generated electricity. The percentage is determined based on the number of consumers within the community. For example, suppose the allocated generation of certain customers exceeds the consumption at a particular hour. In that case, the additional, allocated generation is redistributed equally among the consumers, not been fully covered yet.
- The matching algorithm also ensures that all the consumers are under the same MV/LV substation where the PV generation facilities are installed. This rule is critical for the calculation of economic savings to be used for the study.

Since Ireland does not have any regulatory framework yet, this study has considered the Italian economic savings model, known as ARERA (Pezzaglia, 2020). Till now, it is one of the leading regulatory frameworks across the EU. This paper only presents the part of the economic savings, which reflects in the monthly energy bill and does not consider the investment stage. Italian regulatory framework is based on providing a refund to the EC in terms of economic savings on their shared energy within EC. Calculation of total economic savings, ES_{EC} for the community can be expressed as follows:

$$ES_{EC} = \alpha_{Net} \times \sum_t E_{sh,t} + \left(\beta_{Loss} \times \sum_t E_{sh,t} \times P_{spot} \right) + \gamma_{inc.} \times \sum_t E_{sh,t} \quad (1)$$

The shared energy, $E_{sh,t}$ at hour, t refers to the energy shared among EC members generated from local RES facilities through CSC scheme. It must be mentioned that the economic savings are calculated over the monthly billing period and reflected as discounts in the monthly electricity bill. The details of the terms in eq. (1) is as follows-

- The first term refers to the refunded volumetric component of the network tariff. α_{Net} is usually the transmission network tariff for the EC, sharing energy through the public network.
- The second term accounts for avoided network loss due to the energy shared locally. β_{Loss} refers to the avoided network loss coefficient indicating the loss in the superordinate network voltage level to the voltage level in which energy sharing happens. The refunded network loss charge is calculated by multiplying the loss coefficient with shared energy volume and monthly averaged spot price, P_{spot} from the day-ahead market.
- The third term refers to the explicit incentives awarded for the volume of shared energy under CSC where $\gamma_{inc.}$ is the volumetric incentive tariff in €/$kWhr$, applicable to shared energy in EC.

This paper has used this formulation, but the parameters' values are taken from the Ireland tariff system. Considering the fact, Table 2 presents different factors used in the study.

Table 2 Values used in the study of the Irish demo site (CRU, 2021)

Parameters	Values
Refunded network tariff, α_{Net}	3.45 $c€/kWhr$
Avoided network loss coeff., β_{Loss}	0.036 (3.6 %)
Explicit incentives, $\gamma_{inc.}$	11 $c€/kWhr$

Economic savings of EC member i is as follows,

$$ES_i = \frac{\sum_t LEC_{i,t}}{\sum_t E_{sh,t}} \times ES_{EC} \tag{2}$$

where, $LEC_{i,t}$ is the energy consumption of EC member i from total shared energy in EC, $\sum_t E_{sh,t}$ over the monthly billing period. However, the energy is allocated to individual EC members in accordance matching algorithm on hourly resolution. Hence, the $E_{sh,t}$ and $LEC_{i,t}$ are summed up over the month to calculate individual economic savings.

2.1.2. Simulation Results

Benefits to the energy community

Based on the real-life data from the Irish pilot, the local market implemented ensured the local consumption of the locally generated electricity. Figure 3 depicts the self-consumption rate of the EC across the year. EC has an upper level of self-consumption rate from mid-Spring until mid-Autumn month ranging from 20% to 35%. May has shown the highest level of self-consumption rate and December being vice versa. This is because of low demand and high generation in the months showing higher self-consumption rate and vice-versa for other months. This is evident in the Figure 4, which shows monthly consumption and local generation of EC across the year 2020. It can be noted that EC has only rooftop PV as available local generation facilities; hence, the generation availability in EC strongly correlates with the seasonality. One important note from the study is that the matching between generation and consumption occurs in real-time. This implies that the matching algorithm encourages the simultaneous consumption of EC members at the time of solar PV generation. This time dimension in the matching ensures local balancing under local market benefiting the grid operator.

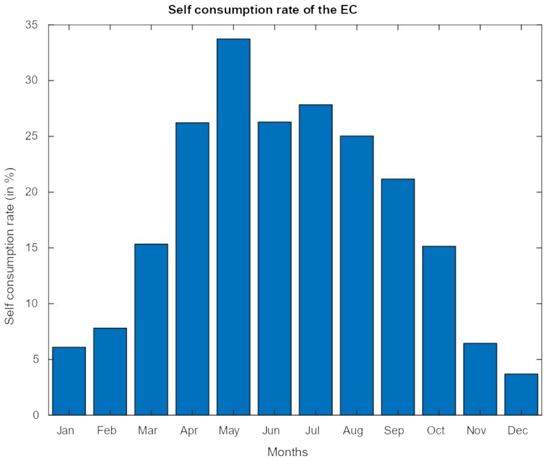


Figure 3: Self consumption rate in the EC

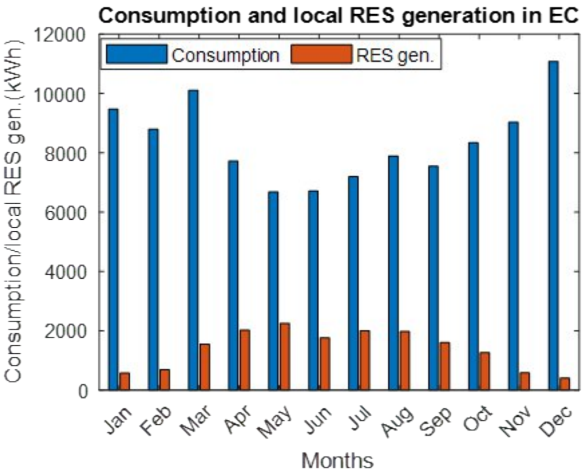


Figure 4: Consumption and local RES generation of EC

As the amount of shared energy through CSC is the only variable in the economic savings calculation of the EC as expressed in Eq. (1), this is likely to result in higher economic savings for months with higher shared energy in EC, i.e. higher local RES consumption. Figure 5 shows the monthly economic savings which are almost analogous to the self-consumption rate of the EC presented in Figure 3.

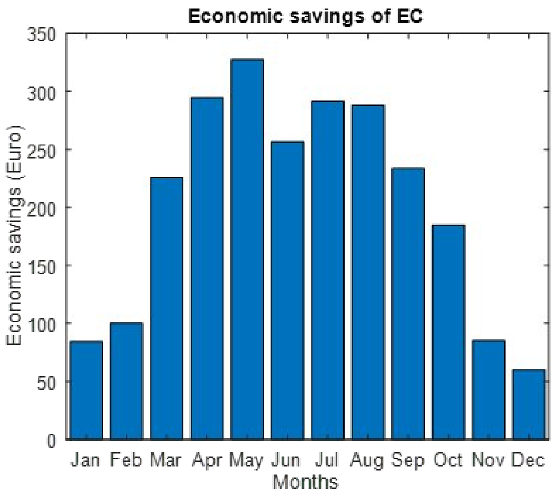


Figure 5: Economic savings of entire EC

The participation of EC members in CSC results in local RES consumption in EC and hence, avoidance of CO_2 emissions. In the absence of CSC, the entire energy will be supplied from the pool-based central electricity market resulting in higher CO_2 emissions. Figure 6 shows the impact of CSC on CO_2 emissions reduction. The blue bars indicate the CO_2 emissions if the entire EC's consumption is supplied from the grid and no CSC is taking place. Whereas the red bars indicate the CO_2 emissions from EC after a certain portion of consumption is met from local RES generation. It can be mentioned that the calculation is based on the annual CO_2 the intensity of electricity of the year 2020 in Ireland depends on the fuel mix used for electricity generation. Irish electricity generation has significantly reduced CO_2 emissions within the last decade with CO_2 emission fell down from 0.636 $kgCO_2/kWhr$ in 2005 to 0.296 $kgCO_2/kWhr$ in 2020 (SEAI, 2021). As locally shared electricity is mostly coming from RES having zero carbon emission, estimation of CO_2 emissions reduction shown in Figure 6 depends on very much on the fuel mix used in the particular year and their carbon intensity.

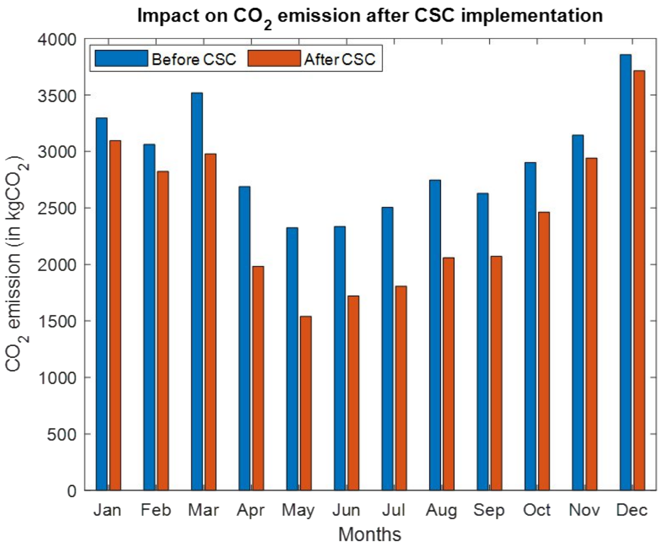


Figure 6: Impact of CSC on carbon emission

Benefits to energy community members

As outlined in the previous sections, the EC is not fully self-sufficient and relies on the retail energy market for meeting its deficit energy. Therefore, the electricity cost of individual customers depends upon the retail electricity pricing. The retail electricity pricing usually constitutes energy price and network tariffs, taxes and levies. The two main components of retail electricity pricing, which can have dynamism in price variation across time, are energy price and network tariff. The former reflects variation in the wholesale electricity market price, and the latter is related to energy delivery cost through distribution and transmission networks. The national energy regulatory body determines the network tariff for residential households to recover the cost of energy delivery by the network operators. This tariff also comprises of three components: energy (per kWhr), power (per kW) and fixed (per year). Historically, retail electricity pricing schemes include fixed-price, static time-of-use (SToU) price, dynamic time-of-use price, etc. (Defeuilley, 2009). In Ireland, fixed-price and static time-of-use (SToU) price are the two retail pricing schemes in place. The distinctness between these two retail pricing is the later one has financial incentives for customer to engage in demand response. As our Irish pilot case has not considered any assets capable of demand response. The analysis of the Irish pilot case is based on with fixed-price retail electricity pricing scheme. Yearly electricity cost of individual customers in the analysis is presented as per three components:

- Energy components: This is the cost associated with the procurement of energy which includes international fuel costs and the impact of exchange rates, capacity and fixed costs of operating generators and market operator costs. It is a volumetric component and charged for each consumed unit of energy.
- Network tariff components: This cost is passed on to the customers as cost of transmission and distribution of electricity which covers investment and maintenance of the network infrastructure. Only volumetric, energy component (per kWhr) of the network tariff has been considered in the analysis. This is regulated by energy regulatory authority which is Commission for Regulation of Utilities (CRU) in Ireland.
- Tax and Levies: Taxes and levies are determined by the State and paid electricity customers. This includes Public Service Obligation (PSO) levy charged on the customer to support subsidies scheme to achieve national renewable energy objectives. Value Added Tax (VAT) is paid by the customer on the total electricity bill.

The analysis does not include retailer's supply cost in the analysis, as it is the operating cost of the electricity retailer and set by retailers themselves as a part of their market strategy in retail market competitiveness. Table 3 presents the different parameters under the cost components used in the study.

Table 3 Parameters relevant to cost components in Irish demo site

Parameters	Values
Unit price under fixed-price scheme	18.5 $c€/kWhr$
Network tariff	4.9 $c€/kWhr$
PSO levy	3.76 $€/Month$
Value Added Tax (VAT)	13 %

Figure 7 illustrates the electricity cost of individual customers (EC members) segregated into the key retail pricing cost components. It is well visible in the Figure 7 is that the retail pricing components are proportional, especially the energy and network components as these two components are volumetric in nature and tax is percentage on overall electricity bill. Therefore, the yearly electricity cost is highly influenced by the electricity demand of the EC members from retail energy market.

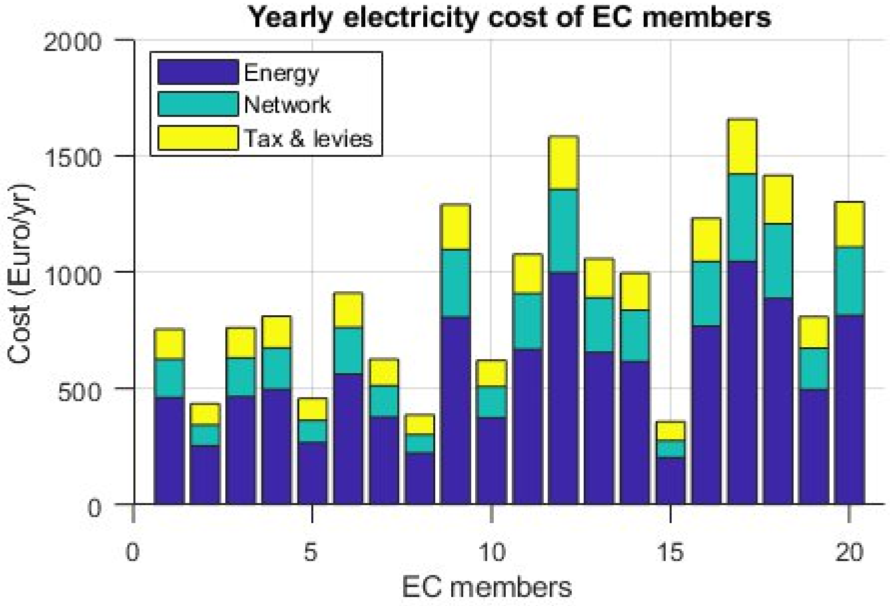


Figure 7: Yearly electricity cost of EC members segregated on key retail pricing components

It needs to be clearly mentioned that the CSC considered for the study works in a way where the EC members pay for the energy demand withdrawn from the grid and charged in accordance with contract with energy retailer. Afterwards, the EC members receives refund from the total economic savings of EC for the shared energy through the CSC scheme. Therefore, the total electricity cost for each EC members depends on the demand of EC members, which is actually withdrawn from the grid and the shared energy through CSC is only reflected in the economic savings, which is accounted separately as a refund. It can be seen in the Figure 8 that the demand curve and yearly electricity cost curve are identical.The amount of shared energy through CSC is the only variable in the economic savings calculation of the EC as expressed in Eq. (1), this is likely to result in higher economic savings for months with higher shared energy in EC, i.e. higher local RES consumption.

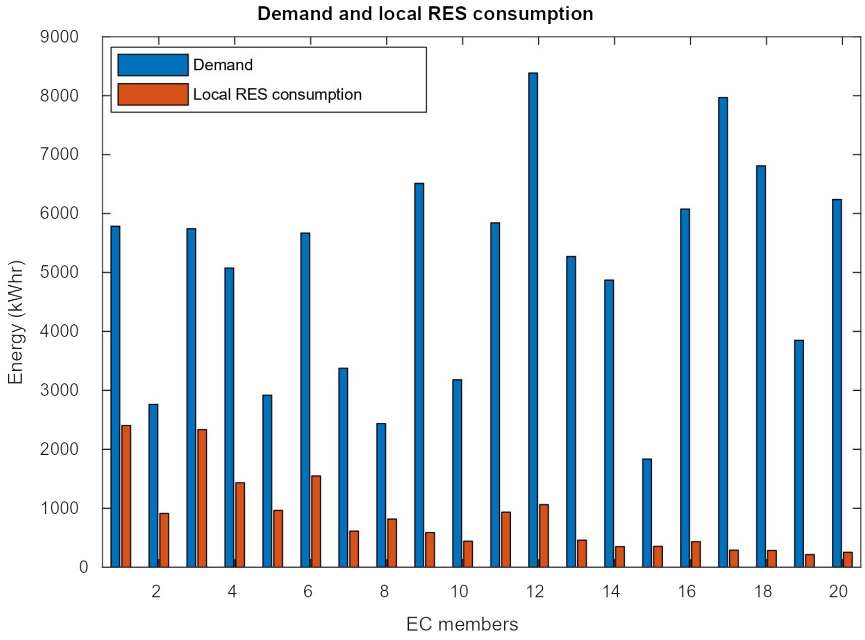


Figure 8: Demand and local RES consumption of EC members

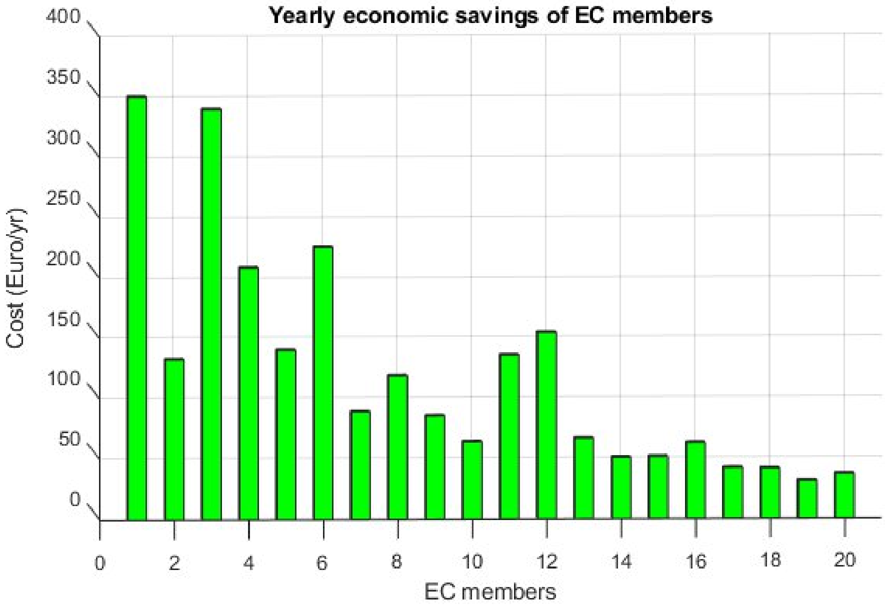


Figure 9: Yearly economic savings of EC members

The distribution of the economic savings among EC members has been considered in the study based on the local RES consumption rate of individual customers, as expressed in Eq. (2). Hence, the distribution of economic savings among EC members, as shown in Figure 9, is identical to the local RES consumption, as shown in the Figure 8. As the local RES allocation among EC members are executed on real-time. It means that the generation and demand must happen in the same hour to be matched. The economic model thus incentivises the EC members who have high consumption at the time of high local generation.

As the local generation is RES in nature, the local consumption of the EC member is also analogous to the local RES consumption. Hence, the local consumption of EC member is also causing the avoidance of CO_2 emission, as the source of energy is zero-carbon generation. This results in the EC member with higher local RES consumption rate has higher rate of CO_2 emission avoidance. Figure 10 depicts the avoided CO_2 emission of EC members along with the remainder CO_2 emitted after EC engages in CSC scheme. This suggests that the CO_2 emission without CSC will be summation of both columns for each EC member.

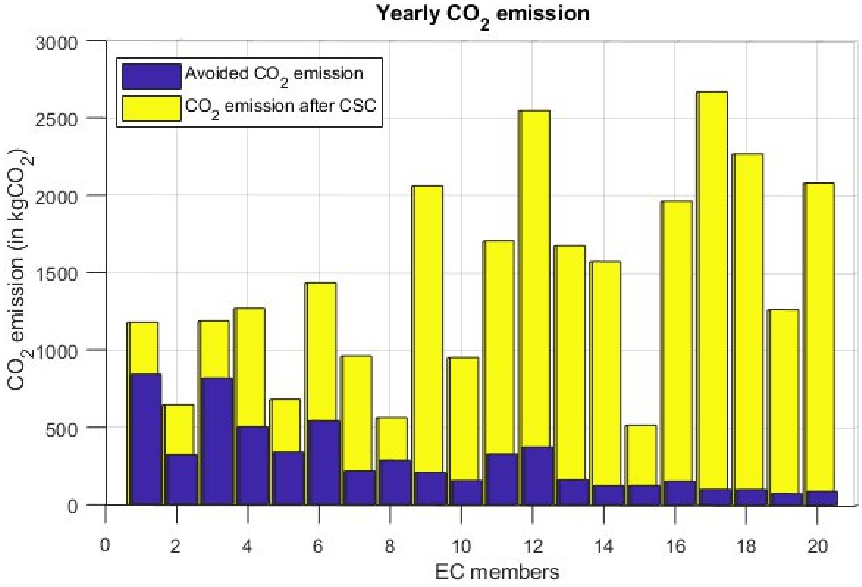


Figure 10: Yearly carbon emission of EC members

One important note from the study is that the matching between generation and consumption occurs in real-time. This implies that the matching algorithm encourages the simultaneous consumption of EC members at the time of RES generation, solar PV generation for this study. Therefore, the time dimension in the matching is crucial in determining local consumption rate of the EC members reflecting its impact on economic savings and CO_2 emission.

2.2. Norway

2.2.1. Use Case 1: Decentralized versus Centralized local energy markets

Local energy markets (LEMs) aim to make optimal use of locally generated energy and encourage the active participation of prosumers who both produce and consume electricity. LEMs can be divided into three market design categories: Full P2P market, community-based market, and hybrid P2P market. In a full P2P market, peers can negotiate directly with each other. In contrast, in the community-based market, a community manager is responsible for trading activities to achieve the optimal outcome from the community's perspective. Lastly, a hybrid P2P market is a combination of the two previously mentioned markets. By participating in a LEM, prosumers and consumers are less affected by volatile and increasing wholesale prices or supply problems of the main grid. LEMs not only provide benefits for the prosumers and consumers but can also bring significant benefits to the system and other market participants. To further explore the potential of LEMs, it is important to reflect on how to organize LEMs, how the internal market should function, and how the price will potentially be settled between diverse players with different selling and buying price willingness. This section explains how a centralized (community-based market) works. It then focuses on decentralized models with different trading algorithms, namely Peer-to-peer (P2P) and Multi Unit Double Auction (MUDA).

- Centralized models

The objective of such models is, for example, to minimize the total cost for the community, subject to constraints such as energy balance and the other operational limitation of assets like energy storage units. The community manager determines the operation plan of the community members by solving the described optimization problem.

- Decentralized models

This section explains the double auction algorithms MUDA and P2P in local electricity trading. Double auction is a collective term for various auction mechanisms in which multiple sellers and buyers come together to sell and buy goods. The algorithms are used to simulate competitive behavior in the LEM. It is worth mentioning that, in this section, it is assumed that self-consumption has priority over trading. This means that prosumers first consume their own electricity before placing an offer to the trading hub and selling their surplus energy. In case of a power deficit, consumers submit a bid to buy electricity. The trading algorithms (in this case, P2P or MUDA) clear the market for the whole period, one time-step at a time.

Multiple-unit double auction (MUDA) trading algorithm:
The MUDA algorithm was introduced to create an economically efficient (EE) trading algorithm that is at the same time individually rational (IR), budget balanced (BB), and incentive compatible (IC). The algorithm first creates two sub-markets, a left, and a right sub-market. The bids and offers are then divided between two sub-markets with a probability of 0.5. After that, the market equilibrium price is calculated on each sub-market with an aggregated demand and supply curve. Subsequently, each sub-market trades with the market equilibrium price of the other sub-market. Consequently, the bids and offers of the left sub-market trade at the market prices of the right sub-market and vice versa. For successful matching, the bid must be higher (or equal) and the offer must be lower (or equal) than the market equilibrium price. MUDA does not prevent an imbalance between supply and demand in each sub-market. The algorithm can

lead to greater demand or supply (long side) in the sub-markets. While the short side can trade all bids or offers, bids or offers from the long side remain. There are different variations of MUDA on how to deal with the excess on the long side. In this paper, we use "Vickrey"-MUDA. Here, the bids or offers with the highest profit are selected first (highest bids or lowest offers). In the next step, the selected traders must pay a trading fee. The trading fee is determined by the potential profits of the traders who are pushed out of the market. With MUDA, participants cannot manipulate the price through strategic reporting since bids and offers are traded at an exogenously determined market price. Consequently, they only have an incentive to submit their true value, and therefore, the trading algorithm fulfills the IC requirement. Moreover, the agents do not lose through their participation, so the algorithm is IR. Furthermore, the "Vickrey"- MUDA is weakly budget balanced as the market-maker can make profits through trading fees but never losses. Finally, MUDA approximately optimizes the economic efficiency in sufficiently large markets. Figure 11 presents a simplified illustration of the MUDA algorithm.

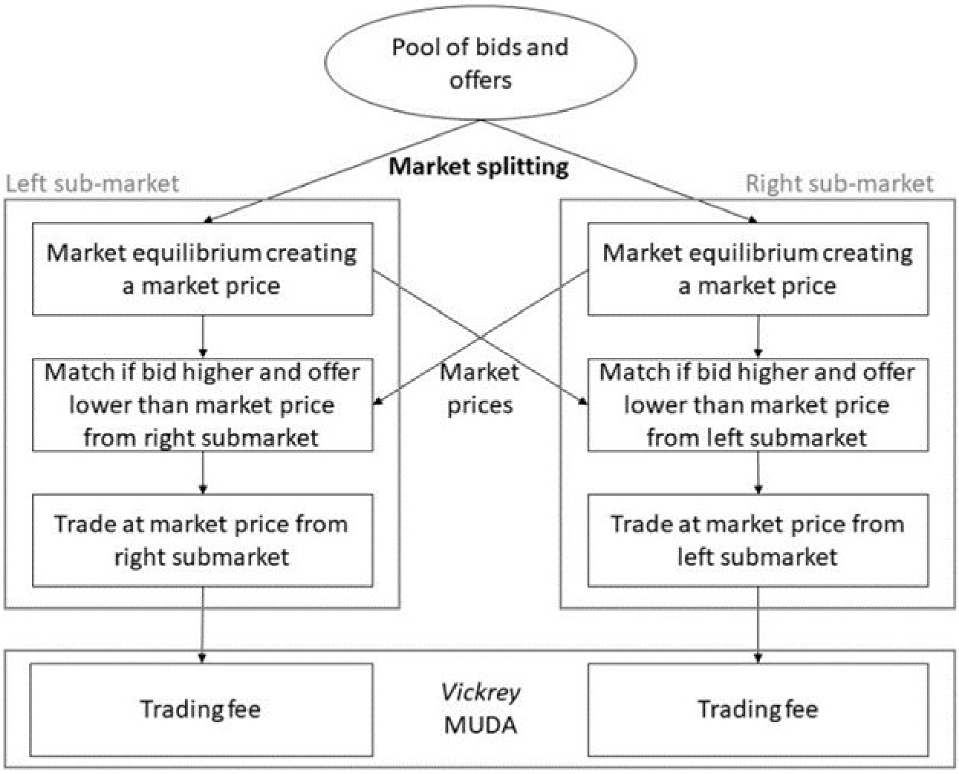


Figure 11 Graphical illustration of the MUDA algorithm

Peer-to-Peer (P2P) trading algorithm:

Similarly to MUDA, the P2P trading algorithm works by peers submitting bids and offers into a central trading hub. These bids are then randomly paired and matched if the bidding price is higher than the offer price. The trading price for each match is determined by the following Equation, and thus depends on the price coefficient, k. If k = 1 all profit goes to seller, if k = 0 all profit goes to buyer.

$$p_{p2p}^{(t)} = p_b^{(t)}.k + p_s^{(t)}.(1-k) \quad k\in[0,1]$$

Since all bids might not be matched in the first run, the algorithm does several iterations, as illustrated in Figure 12. This means that if a peer's bid or offer is not matched in the first iteration, or not all quantity is traded, they will participate in the next iteration. These iterations will go on until all unmatched participants either trade all their quantity or no available pairs are left in the trading hub.

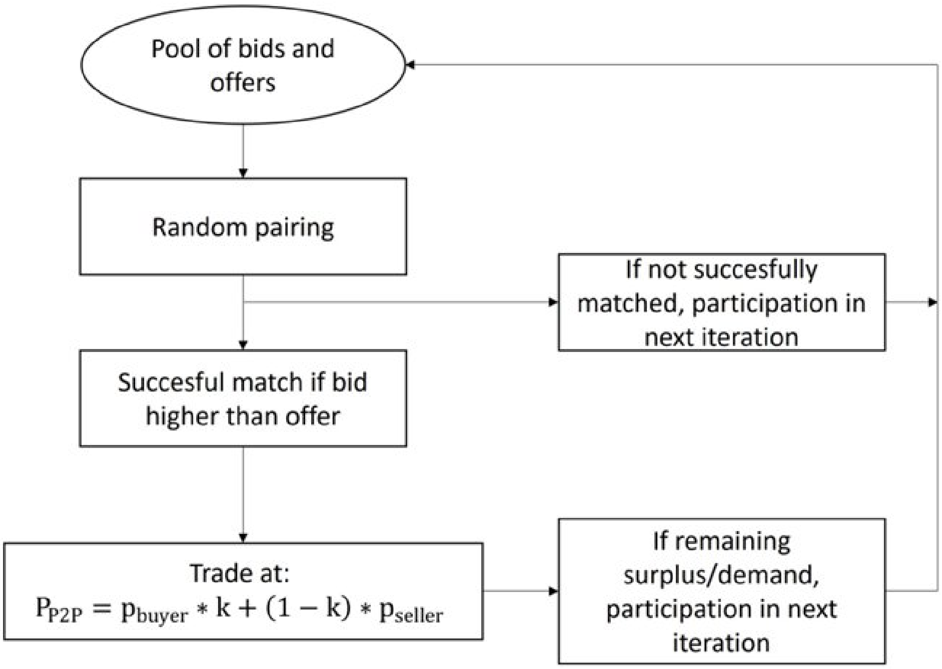


Figure 12 Graphical illustration of the P2P algorithm

An important characteristic of this algorithm, and possibly a drawback, is the price and quantity variations. Since all trades have an individual price, instead of a market price, different peers can end up with largely different prices for the same quantities in the same time-step. This means the algorithm can be perceived as unfair to some participants. However, the P2P trading algorithm does not provide incentives to manipulate bids and offers. On the one hand, buyers try to bid as low as possible, but they must not bid too low to find a trading partner. Otherwise, they have to buy more costly electricity from the grid. Sellers, on the other hand, try to drive the price up, but they need an even higher buying price. So their offer should also not be too high.

Result:

To analyze the MUDA and P2P trading algorithms and determine their efficiency a case from Steinkjer, Norway is examined. This case includes 54 households connected through a distribution network, which in turn is connected to the main grid. 35 households are equipped with PV systems of varying capacities. Additionally, 10 households are equipped with wind turbines of the Siemens SWT 2.3 82 model. Although the turbine model originally had a higher capacity and hub height, the data is realistic at the house level as we scaled down the capacity to 2.3 kW.

Table 4 provides KPIs for centralized, MUDA and P2P algorithms. The results of the P2P algorithm are relatively close to the solution of centralized optimization. The KPIs of the MUDA algorithm, in contrast, have a greater gap than the centralized optimization. Accordingly, the traded energy when using MUDA is lower compared to using P2P. This results in higher curtailment with MUDA as less electricity is distributed between the households. Consequently, using MUDA gives a lower self-consumption, and more electricity must be imported from the main grid. Finally, a higher grid import results in higher system costs when using MUDA.

Table 4: Comparison of KPIs for centralized, MUDA and P2P - Steinkjer case

KPI	Centralized	MUDA	P2P
System cost [NOK]	27037	28091	27229
Grid import [kWh]	39553	41073	39829
Self-consumption [kWh]	22388	20868	22112
Curtailment [kWh]	615	2135	891
Energy traded [kWh]	2506	986	2230

2.2.2.Use Case 2: Virtual energy communities

Extending the definition of local or ‘communal’ energy market to notions of virtual consumer-prosumer markets would facilitate: i) the participation of a larger pool of end-users beyond geographical limitations, ii) more opportunities to trade or share RES at a better price, and iii) accelerate the decentralization and democratization of energy. A formation of a virtual LEM would allow new visions on integrating end-use flexibility and open new business model ideas for LEM. Figure 13 visualizes this idea. A community of 25 houses with different characteristics might belong to a neighborhood where a ‘Dynamic-P2P’ market pairs prosumer and consumers to form virtual LEMs. In this example, for a particular day, five clusters (virtual LEMs) are formed. Here the value of EV flexibility complements the P2P-cluster formation by charging from surplus RES and by selling it back (discharging) to consumers based on day-night load patterns. In other words, a set of consumer and prosumers engage in the formation of virtual LEMs. The (upper) virtual layer coordinates the formation of dynamic P2P clusters based on a pool of participants from a community or district (lower layer). LEMs matches EV flexibility with the allocation (best match) of consumers and prosumers profiles.

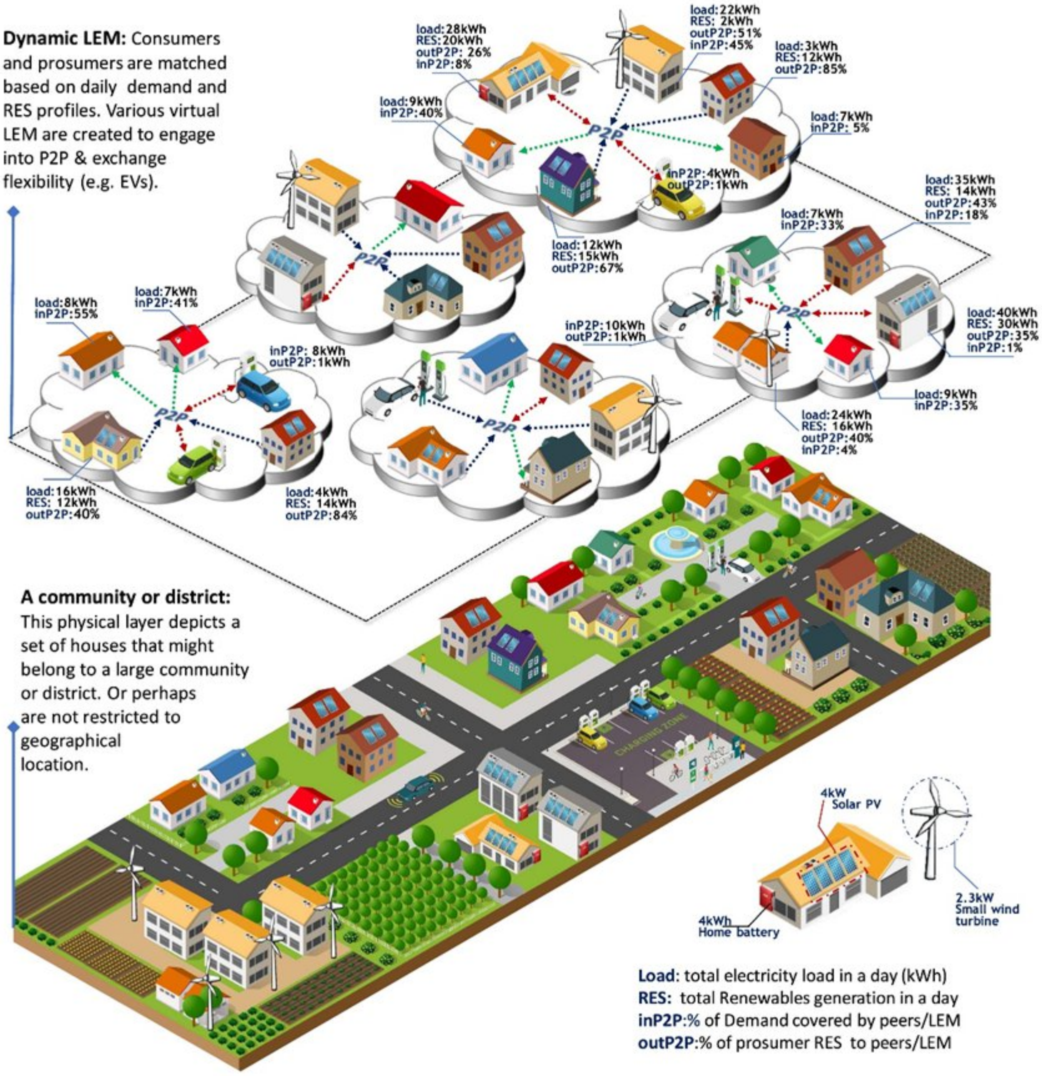


Figure 13: Virtual energy communities

2.3. Austria

2.3.1. Use Case 1: Distance-dependent electricity prices

The optimization model describes a market model for a local energy community (LEC) in which the prosumer sells his surplus energy to the nearest consumer. Based on a Mixed-integer linear programming (MILP) model, the energy flows are calculated. In the second stage of the algorithm, the costs for each participant in the energy community are calculated. In addition, the deployment of energy storage systems and their influences on the LEC are considered.

The energy market in the LEC is modelled using a MILP formulation and subsequently solved for different market configurations (e.g., different grid tariffs or distance metrics). The exact model formulation is presented in the following.

Let P be the set of households selling energy to the global grid at price p_{feed} at a certain time step t. Let C be the set of households buying energy from the grid at price p_{grid} at the same time step t. Let T be the set of all time steps of the simulation. Hence, the price p_{ij} for locally traded energy must fulfil in equation (1) so that there are no arbitrage possibilities, where $i \in C$ and $j \in P$.

$$p_{feed} \leq p_{ij} \leq p_{grid} \qquad (1)$$

The local energy trading is formulated as a linear optimization problem, with the objective to minimize the energy costs (2) for the consumers. Based on this basic assumption it is secured that the local energy is bought first and at the same time the prosumer gets the higher price for their energy consumption.

$$min\left(\sum_i \sum_j \sum_k p_{ij} L_{ijk} + \sum_i \sum_k p_{Grid} L_{ik}^{grid}\right) \qquad (2)$$

Here p_{ij} is the energy price for the i-th consumer for energy which was produced by j-th prosumer. In (2) L_{ijk} denotes the local energy flows and L_{ik}^{grid} denotes the energy flows from the global grid to the customers, for the time step k . The constraints in this problem formulation are based on the law of energy conservation.

$$D_{ik} - SOC_{ik}^{discharge} + SOC_{ik}^{charge} = \sum_j L_{ijk} + L_{ik}^{grid} \;\forall\; i \in C \qquad (3)$$

The balance for the energy production is modelled by the following equation.

$$P_{jk} = \sum_i L_{ijk} + P_{jk}^{grid} \;\forall\; j \in P \qquad (4)$$

Here P_{jk} is the production of the j-th prosumer at time step k. In equation (13) P_{jk}^{grid} denotes the excess energy which is sold to the global grid. The price distribution over the distance is modelled using the sigmoid function. The energy price p_{ij} from the j-th prosumer to the i-th consumer is described by the following equation (5).

$$p_{ij}\left(x_{ij}\right) = \left(p_{feed} + p_{spread}\frac{1}{1+e^{\alpha_j\left(x_{ij}-\overline{x}_j\right)}}\right)(1-\delta_{ij}) \qquad (5)$$

Here x_{ij} is the distance between the i-th consumer to the j-th prosumer. In (5) δ_{ij} stands for the Kronecker delta which is in this case identical with the identity matrix. p_{spread} denotes the difference between the energy procurement and the feed in price of the energy provider.

$$p_{spread} = p_{grid} - p_{feed} \qquad (6)$$

The median distance $\bar{x}_j$ is the median of the set of the euclidean distances X_j for all consumers to the prosumer j.

$$\overline{x}_j = med\left(X_j\right) \qquad (7)$$

The parameter α_j is used to scale the change in price over distance and is chosen such that the first quartile of the price is $p_{feed} + \frac{p_{spread}}{4}$.

$$\alpha_j = \frac{-1}{\left(x_{j,0.25} - \overline{x}_j\right)ln(3)} \qquad (8)$$

Since the recording of data only started with the project, simulated PV data and consumption data had to be used for the first simulations. In the simulated energy community, 22 consumers and 5 prosumers were assumed. Figure 14 shows the energy distribution for prosumer p3. It can be seen that energy is procured from the grid as long as there is no electricity production. As soon as the sun rises and the PV system produces energy, the energy procured from the grid is reduced to zero. The PV production is first used to cover the own demand and the remaining surplus energy is sold to consumers of the LEC. If the total production in the energy community exceeds the total demand, the surplus is sold to the grid operator.

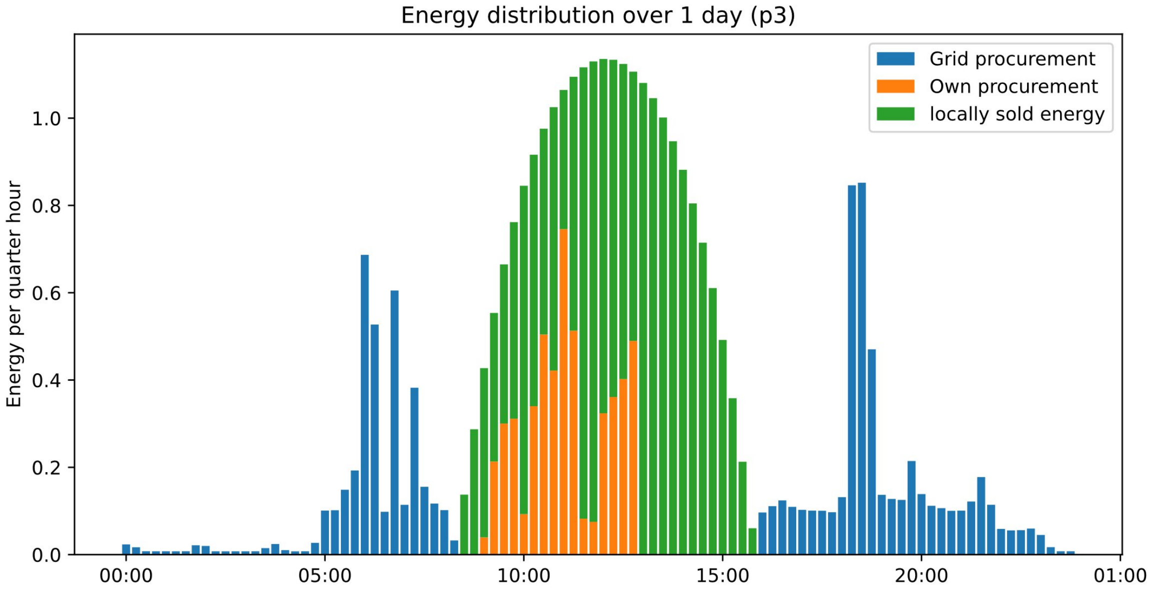


Figure 14 Energy mix for prosumer p3 over 1 day

In another optimization run, each consumer was expanded to include electricity storage. And the resulting local electricity trading volume is shown in Figure 15, the left heatmap shows the results for a LEC without storage, the right heatmap shows the results for a LEC with storage. In Figure 15 the x- and y-axis show the prosumers and consumers of the LEM, respectively. The right plot in Figure 15 depicts the results for the scenario with ESS. In the lower part of the heatmaps where the prosumers are shown, the recognizable diagonal structure results from the self-consumption of the individual prosumers. Furthermore, it can be seen that consumer c20 can massively increase its locally purchased electricity from prosumer p1 based on the ESS, the same is true for consumer c22. A similar case can be seen for the trade between consumer c15 and prosumer p2. The increase of locally traded energy based on electricity storage can also be found in the trading relationship between prosumers p3 and p5. An interesting outcome of the computational studies is that the distribution of energy in the local electricity market is limited to fewer market participants due to the use of electricity storage. The data indicates that effect in the area of energy sold by prosumer p2 to consumers c13-c15. This is because the use of ESS increases the amount of c15 purchased and at the same time decreases the amount of c13 and c14 purchased. The advantage of consumer c15 is certainly due to the fact that it is closest to prosumer p2 ($47.9m$ in contrast to c13 with $105.6m$ and c14 with $121.3m$). In this scenario, it is now clear that the surplus energy is distributed to fewer consumers. This is mainly due to the fact that the individual consumer now also includes his ideal future electricity consumption for the whole year in the energy purchases. What is remarkable here is that through the use of storages in the entire energy community, the share of energy that prosumers sell to the grid operator is reduced to zero.

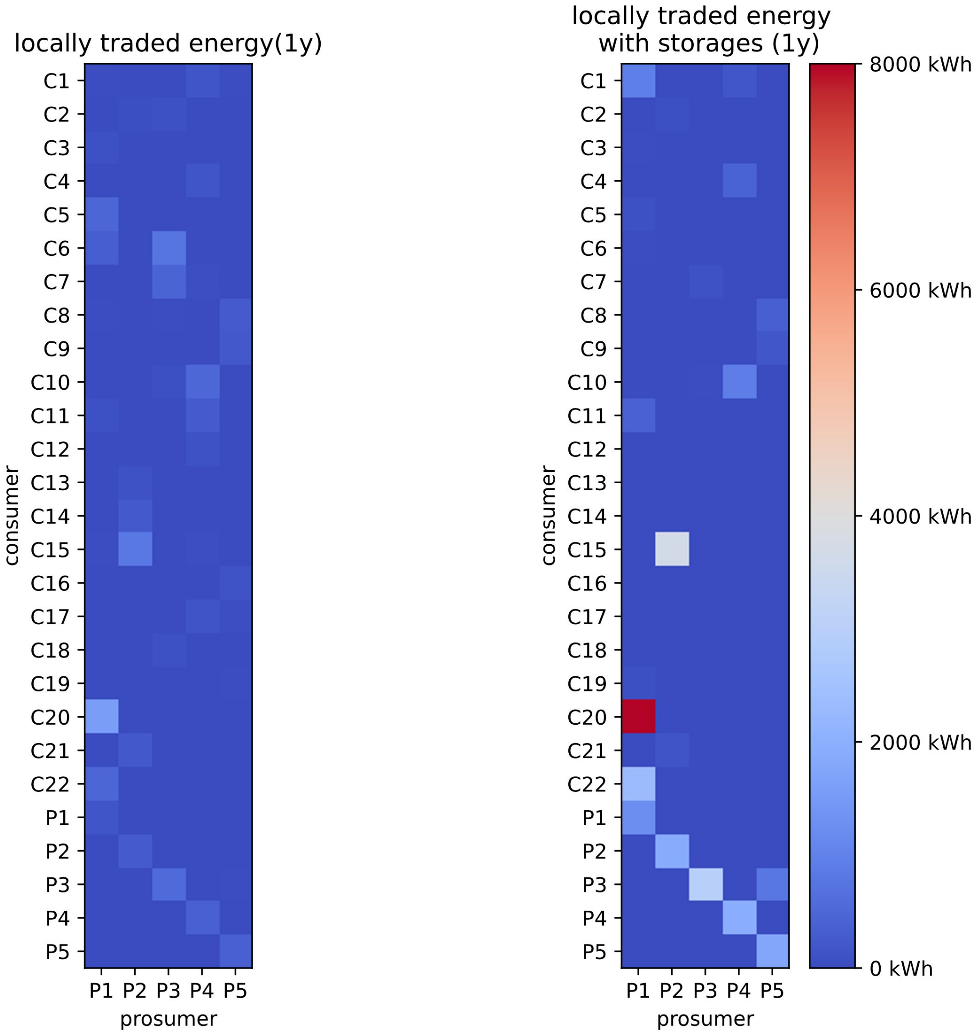


Figure 15 Comparison of the trading volume wih a storage available and without a storage available

2.3.2.Use Case 2: Local grid tariff

The Austrian Use Case 2 investigates the impact of a local grid tariff as proposed in the draft bill for renewable extension EAG[1] by the Austrian Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology.

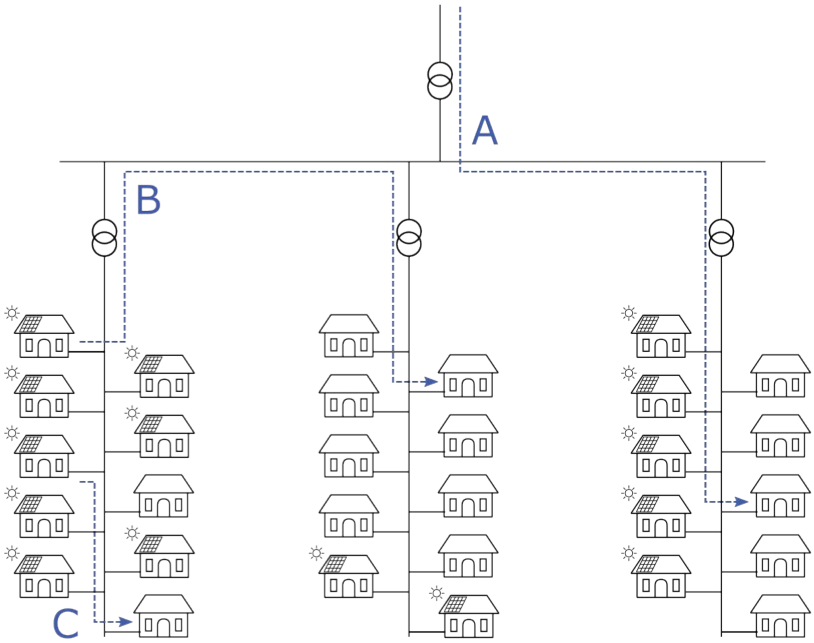


Figure 16: Overview of Use Case 2 Local grid tariff.

With this grid tariff design electricity purchases from outside the community (A in Figure 16) are charged the regular grid tariff. Trades within the community using grid level 5 (B in Figure 16) are charged a reduced tariff that excludes the tariff components for grid levels 1-4. For community trades within the same low voltage grid branch (C in Figure 16) consumers have to pay an even lower tariff that only considers the grid tariff component for grid level 7.

Table 5 shows the assumptions for the grid tariff, fees and energy prices chosen for the analysis conducted for Use Case 2. This lists the grid tariff and fees for non-metered customers. The community price in the last columns shows the price for trades among community members. It is determined in a way that both the selling and the buying party benefit equally from the community trade compared external sales to and purchases from the supplier.

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[1] Erneuerbaren-Ausbau-Gesetz (EAG) online available at https://www.bmk.gv.at/service/presse/gewessler/20210317_eag.html (accessed on 23.03.2021)

Table 5: Grid tariff, fees and price assumptions for non-metered customers

	Unit	Grid tariff[2]	Fees & surcharges[3]	Supplier price buy[4]	Supplier price sell4	Community price
Fix component	EUR/a	64.80	19.97	49.90		
Energy component regular	EUR/MWh	46.53	26.75	83.00	45.00	64.00
Energy component reduced (grid level 5-7)	EUR/MWh	40.23				67.15
Energy component reduced (grid level 7)	EUR/MWh	31.63				71.45

The grid tariff, fees and prices for metered customers are shown in Table 6. The supplier and community prices are the same as for non-metered customers. However, the grid tariff and fees have an additional power component that is charged for the highest load throughout the year in EUR/kW$_{peak}$. In return the fix component and the energy component of the grid tariff and fees are lower than for non-metered customers.

Only external purchases from the supplier are considered in the determination of the peak load for the reduced grid tariff's power component. Internal trades among community members are neglected.

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[2] Source: Systemnutzungsentgelte-Verordnung 2018 online avaialable at https://www.ris.bka.gv.at/GeltendeFassung.wxe?Abfrage=Bundesnormen&Gesetzesnummer=20010107 (accessed on 21.06.2021)

[3] Sources:

- Ökostromgesetz 2012 online available at https://www.ris.bka.gv.at/GeltendeFassung.wxe?Abfrage=Bundesnormen&Gesetzesnummer=20007386 (accessed on 21.06.2021)
- Verordnung über die Bestimmung des Ökostromförderbeitrags für 2020 online available at https://www.ris.bka.gv.at/Dokumente/Begut/BEGUT_COO_2026_100_2_1694894/BEGUT_COO_2026_100_2_1694894.html (accessed on 21.06.2021)
- KWK-Gesetz 2014 online avalailable at https://www.ris.bka.gv.at/Dokumente/Bundesnormen/NOR40164194/NOR40164194.html (accessed on 21.06.2021)
- Elektrizizätsabgabegesetz 1996 online available at https://www.ris.bka.gv.at/GeltendeFassung.wxe?Abfrage=Bundesnormen&Gesetzesnummer=10005027 (accessed on 21.06.2021)

[4] Source: eFriends tariff online available at https://www.efriends.at/images/besserer-strom/EFR_Besserer_Tarif2020-06-20_k.pdf (accessed on 21.06.2021)

Table 6: Grid tariff, fees and price assumptions for metered customers

	Unit	Grid tariff2	Fees & surcharges3	Supplier price buy4	Supplier price sell4	Community price
Fix component	EUR/a	28.80	12.25	49.90		
Energy component regular	EUR/MWh	37.63	22.11	83.00	45.00	64.00
Energy component reduced (grid level 5-7)	EUR/MWh	31.33				67.15
Energy component reduced (grid level 7)	EUR/MWh	22.73				71.45
Power component	EUR/kW_{peak}	30.00	10.76			

To investigate the effects of different grid tariff designs on the operation and trading within energy communities and on the annual electricity procurement cost of its members an example community has been set-up. It consists of thirty households. Each ten households are connected to the same low voltage grid branch. The annual load profiles for the households were generated with the LoadProfileGenerator[5] v10.5. Fifteen of the customers are assumed to be prosumers with a PV system. PV production data was collected from Renewable.ninja[6] for Austria and the year 2020.

Measured data for the residual load of eFriends customers for a full year has been provided as well. However, it has been decided to use generated data, because the measured residual load data cannot be disaggregated into consumption and production, and consequently no statements on the impact on self-consumption rates can be made.

The annual consumption, PV production and self-consumption of each household with the gathered input data is illustrated in Figure 17.

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[5] LoadProfileGenerator online available at https://www.loadprofilegenerator.de/ (accessed on 21.06.2021)

[6] Renewables.ninja online available at https://www.renewables.ninja/ (accessed on 21.06.2021)

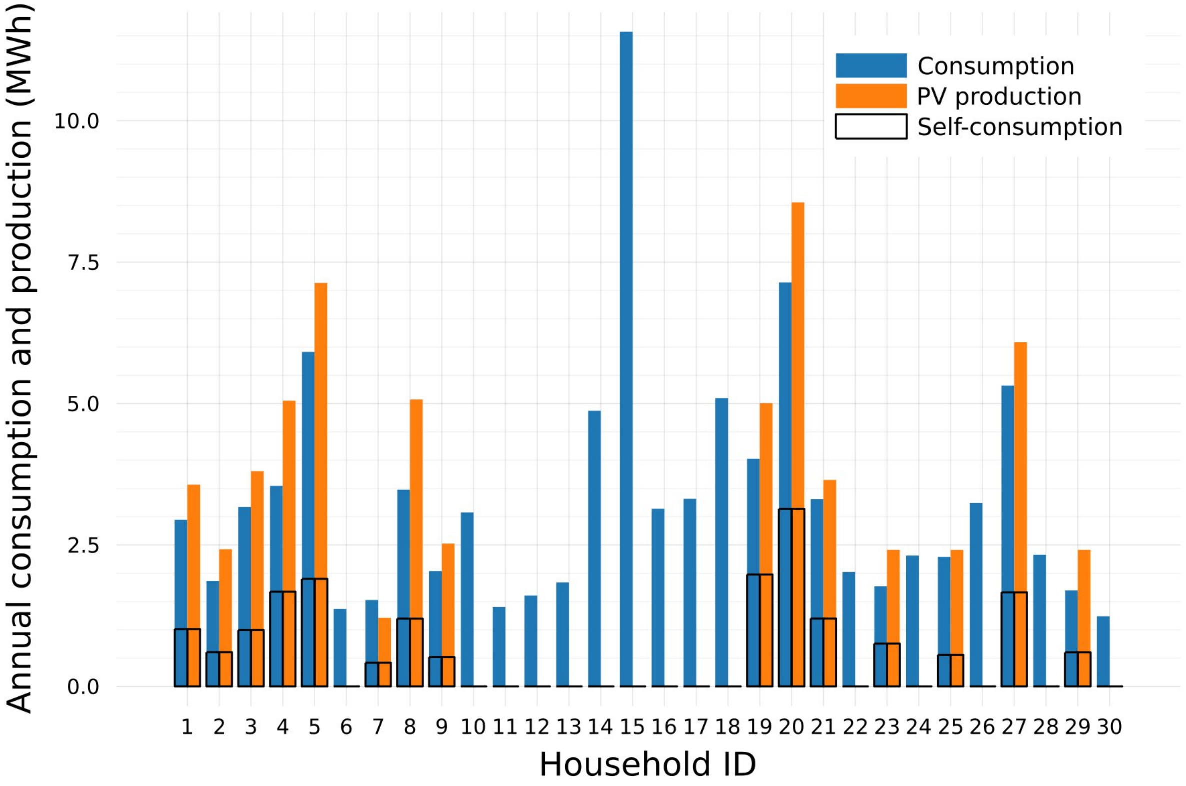

Figure 17: Annual consumption and PV production of the 30 households considered for the community.

To evaluate the effects of introducing energy communities and of reduced local grid tariffs three different simulation models are set-up:

- **No Community:** Each household is optimized individually and there is no possibility to trade electricity with other households.
- **Community:** The households are optimized together and electricity can be traded among community members. Optimal trades are determined by an optimization model minimizing the total annual cost of all community members, including energy prices, grid tariff and fees for trades with the supplier and for internal trades. In this setup all purchases are charged the regular grid tariff.
- **Community Reduced:** This is the same as the **Community** setup. However, internal trades among community members are charged the reduced grid tariffs.

Inflexible Community

In a first step, the effects of the local grid tariff on a community of thirty households without any flexibility options is investigated. Figure 18 provides an overview of the community setup.

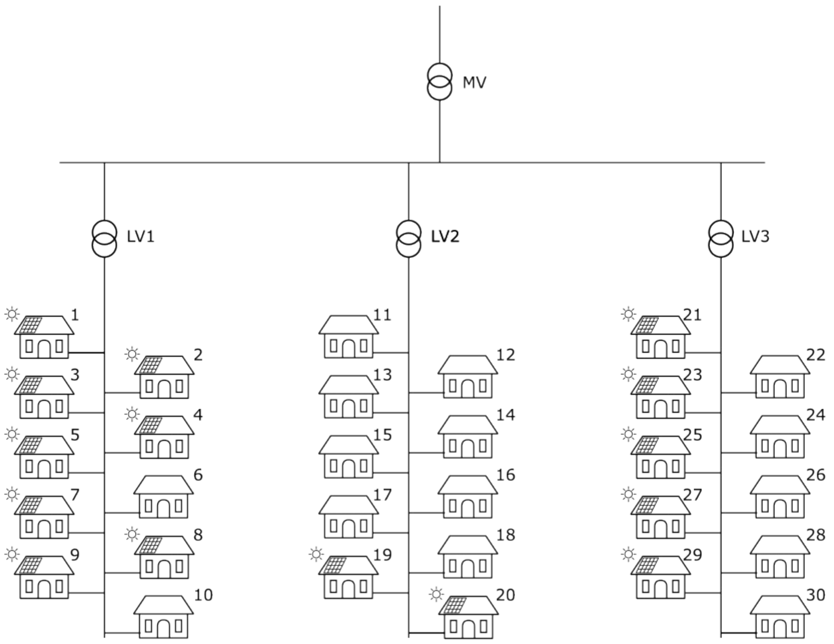

Figure 18: Inflexible community setup

Results with grid tariff for non-metered customers

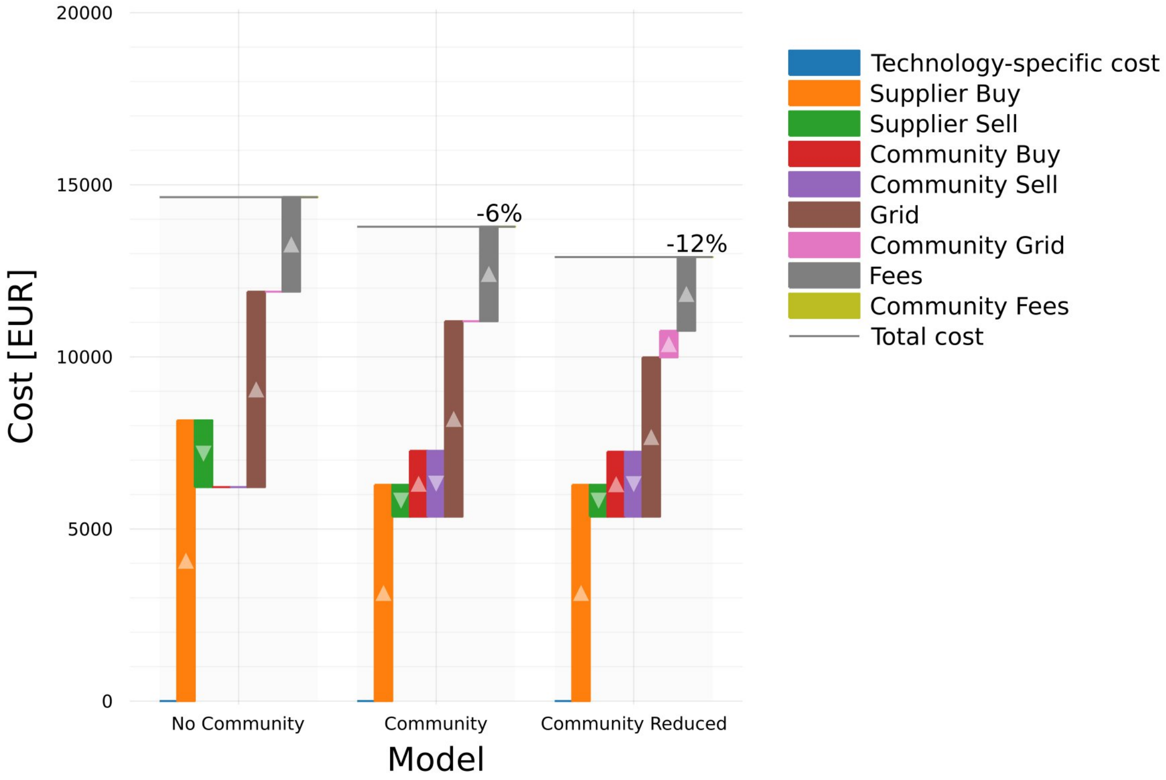

Figure 19: Total annual cost for an inflexible Community with the grid tariff for non-metered customers

The annual total community cost for non-metered households is illustrated in Figure 19. Forming a community results in a total cost reduction of about 6 % or 860 EUR. This cost reduction is achieved through avoidance of the spread between supplier buying and selling price only.

With a reduced local grid tariff the implementation of a community results in a total cost reduction of about 12 % or 1740 EUR. The additional cost reduction compared to the **Community** setup is caused by the lower grid tariffs for internal trades among community members.

Table 7 lists the mean cost reduction of all households and grouped by different customer types. On average, prosumers achieve a higher cost reduction than consumers. The individual cost reductions per end user are illustrated in Figure 20.

Table 7: Average cost reductions for different customer groups for inflexible households with the grid tariff for non-metered customers

Customer group	Unit	Community	Community Reduced
All	EUR	28.60	58.00
Consumers	EUR	26.10	49.20
Prosumers	EUR	31.10	66.80

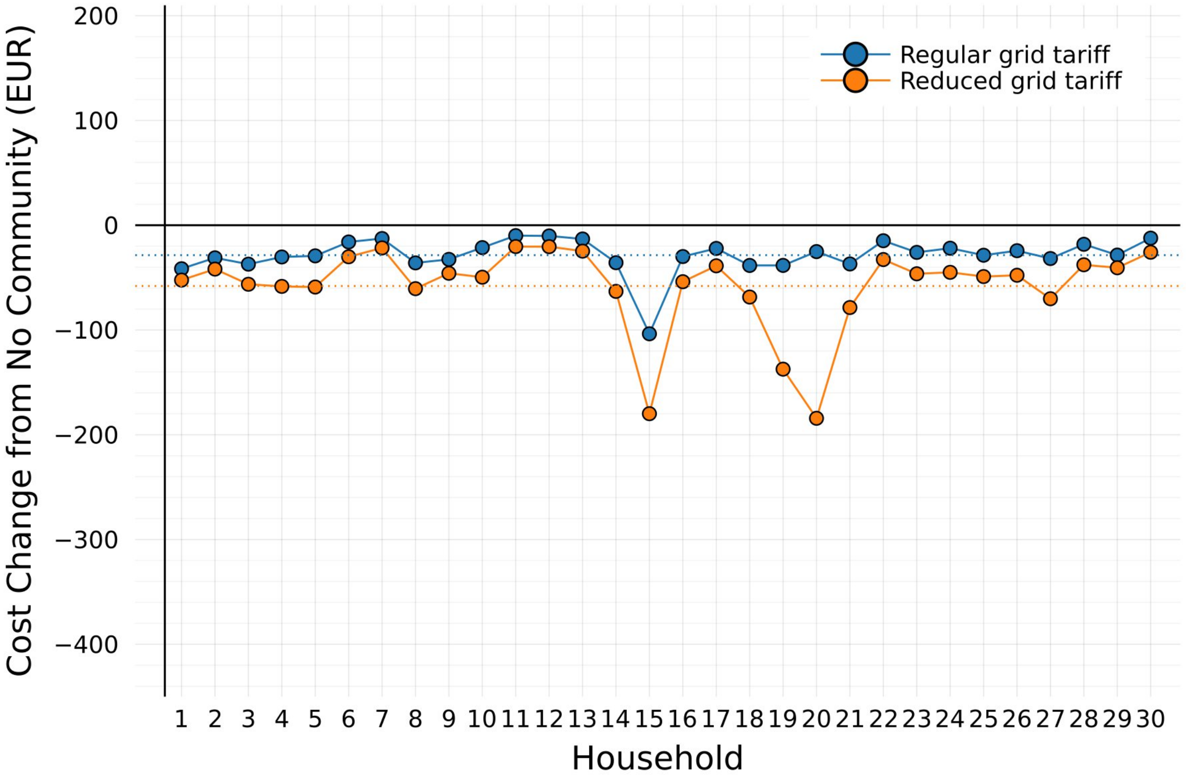

Figure 20: Individual household cost change compared to the No Community case for the inflexible community setup with the grid tariff for non-metered customers.

Figure 21 illustrates the trades among community members in the **Community** setup. The rows in the heatmap plot indicate the selling and the columns the buying household. The amount of traded energy is illustrated by the colour of each rectangle.

Analogously, Figure 22 shows the trades among community members in the **Community Reduced** setup. It can be observed that the reduced local grid tariff provides incentives to focus community trades within the three diagonal blocks, which correspond to trades within the same low voltage grid branch.

Figure 21: Community trades with the regular grid tariff

Figure 22: Community trades with the reduced grid tariff

Figure 23 shows the self-consumption, the local consumption within the same low voltage grid branch, the regional consumption within the community and the external feed-in of local PV production. This corresponds to the self-consumption at the household level, at the low voltage transformer level and at the medium voltage transformer level. Since no flexibility options are assumed here, different simulation setups do not affect PV usage.

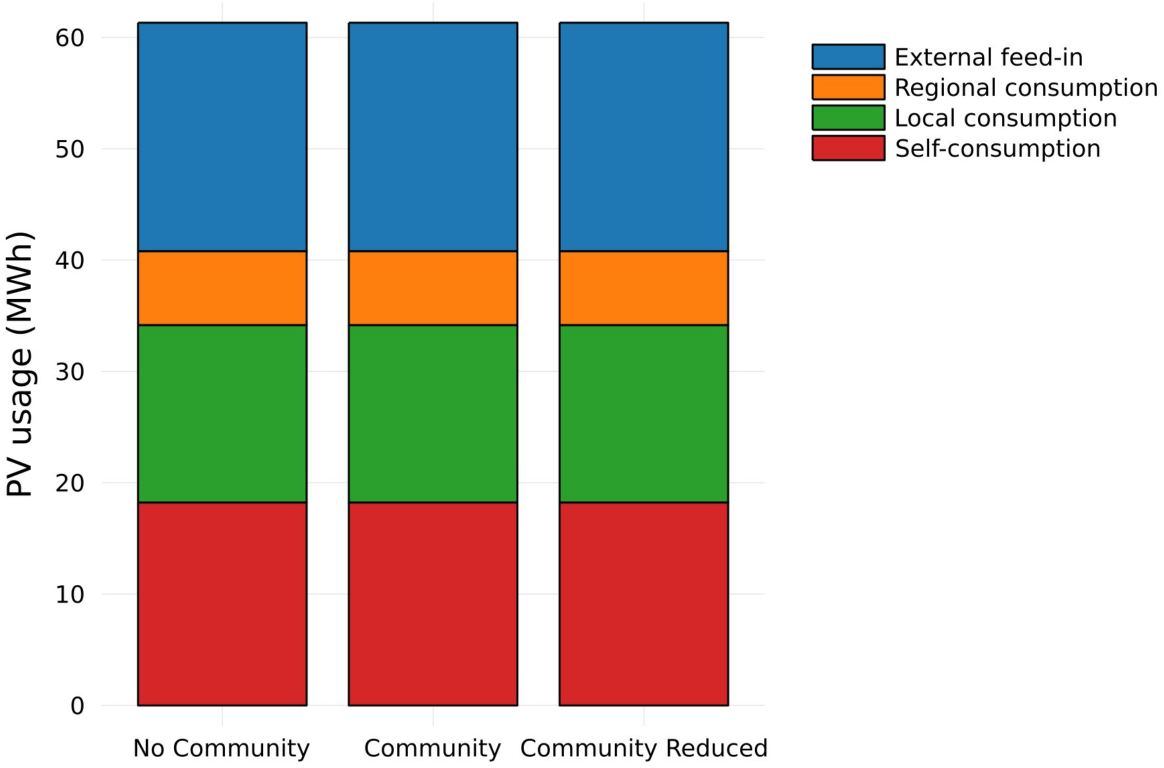

Figure 23: Usage of local PV production for the inflexible community setup with the grid tariff for non-metered customers

Without any flexibility options the community trades do not affect the residual loads at the transformer substations either. This can be also observed in Table 8 showing the maximal load and feed-in values at the transformer stations.

Table 8: Maximal load and feed-in values at the transformer stations

	Unit	No Community	Community	Community Reduced
Maximal load MV	kW	45.74	45.74	45.74
Maximal load LV1	kW	19.63	19.63	19.63
Maximal load LV2	kW	22.87	22.87	22.87
Maximal load LV3	kW	19.60	19.60	19.60
Maximal feed-in MV	kW	30.51	30.51	30.51
Maximal feed-in LV1	kW	17.36	17.36	17.36
Maximal feed-in LV2	kW	6.34	6.34	6.34
Maximal feed-in LV3	kW	9.22	9.22	9.22

Results with grid tariff for metered customers

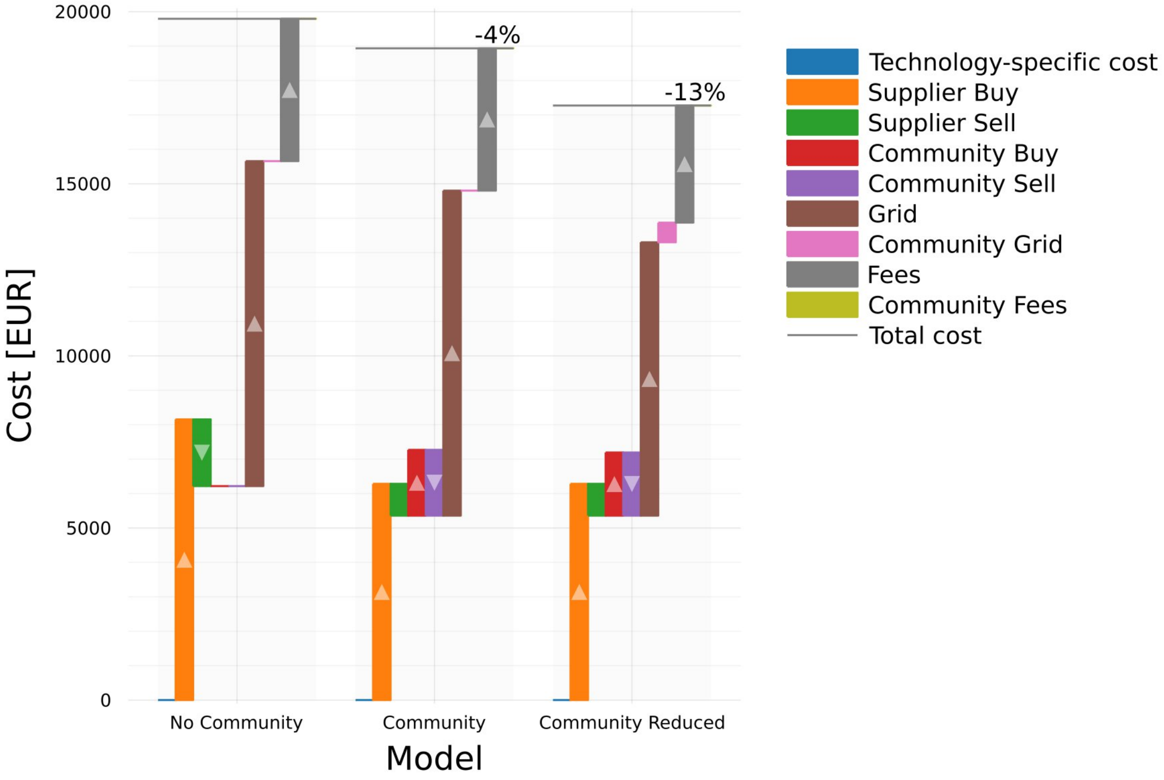

Figure 24: Total annual cost for an inflexible Community with the grid tariff for metered customers

The cost-related results for an inflexible community with a grid tariff for metered customers are illustrated in Figure 24. First, it can be observed that the grid tariff for metered customers yields significantly higher costs for the community in all three setups. The volumetric component of the grid tariff is lower for metered customers. However, the increase of the power-dependent component of the grid tariff and fees from 43.72 EUR/year to 40.76 EUR/kW/year has a greater impact.

For metered customers the implementation of a community results in a total annual cost reduction of 4 % or about 860 EUR. This corresponds to the cost reduction for non-metered customers. This is expected, because no reduced grid tariff is considered in the **Community** setup and cost reductions only stem from the spread between supplier buying and selling price.

In the **Community Reduced** the grid tariff reduction is the same as for non-metered customers in the volumetric component. In addition, community trades are excluded from the peak load calculation for the power component. This yields a further benefit and results in a total cost reduction of 13 % or about 2520 EUR.

Table 9: Average cost reductions for different customer groups for inflexible households with the grid tariff for metered customers

Customer group	Unit	Community	Community Reduced
All	EUR	28.60	84.00
Consumers	EUR	26.10	75.20
Prosumers	EUR	31.10	92.80

Table 9 shows the mean cost reductions per customer for the entire community and grouped by different customer types. On average, prosumers benefit more than consumers.

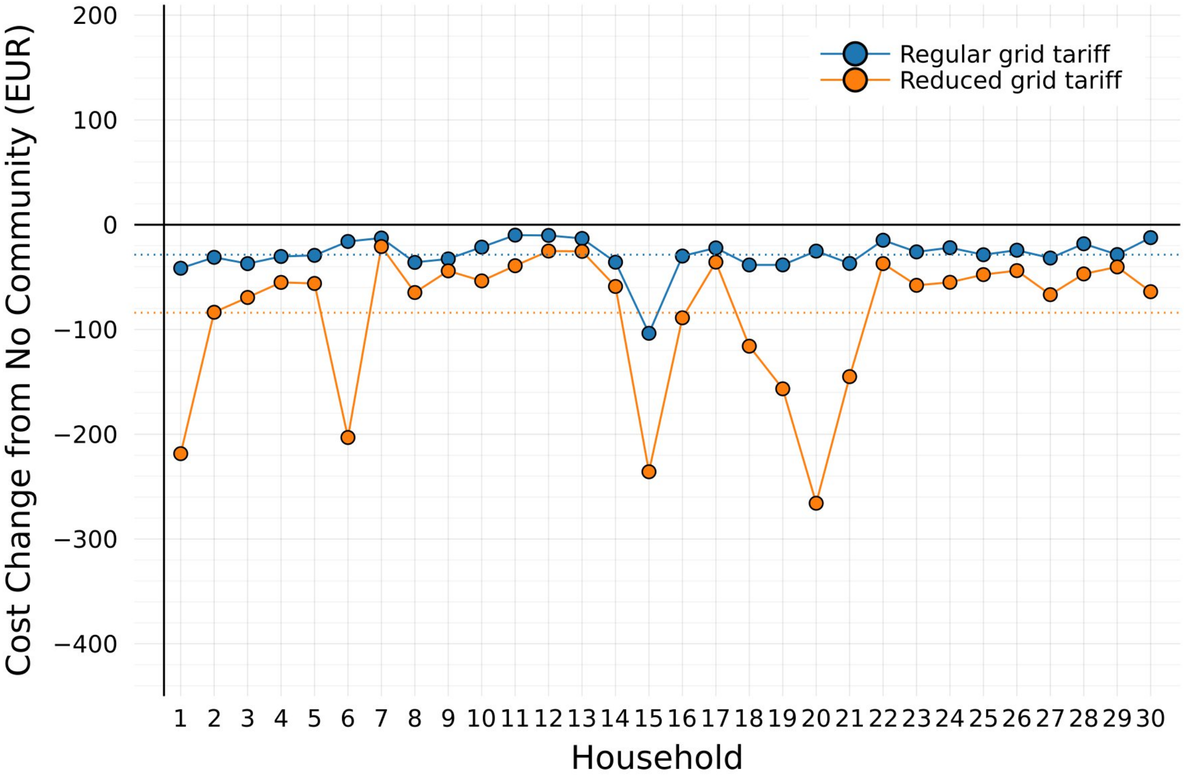

Figure 25: Individual household cost change compared to the No Community case for the inflexible community setup with the grid tariff for metered customers.

Figure 25 shows the cost change of individual customers for an inflexible community with the grid tariff for metered customers. The average cost reduction through a community implementation with the regular grid tariff amounts to 28.60 EUR and with reduced grid tariffs to 71.30 EUR.

Again, prosumers benefit more with a mean cost reduction of 33.10 EUR in the **Community** setup and 81.20 EUR in the **Community Reduced** setup. For consumers, the average cost reduction is 26.10 EUR and 60.40 EUR, respectively.

Figure 26 and Figure 27 illustrate the energy trades within the community showing very similar results to the case with grid tariffs for metered customers. The investigated scenario still has no flexibility options, so the results for PV usage and transformer station loads remain unchanged and can be observed in Figure 23 and Table 8.

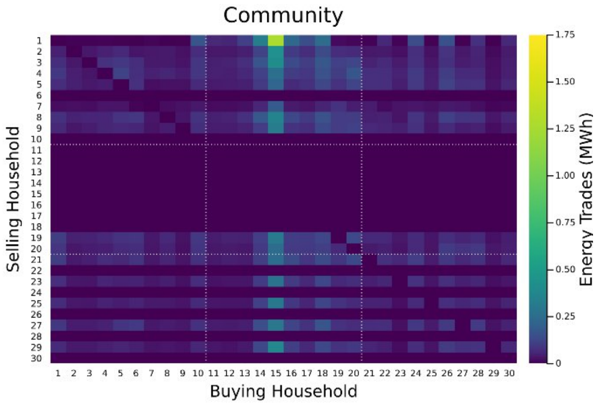

Figure 26: Community trades with the regular grid tariff

Figure 27: Community trades with the reduced grid tariff

Community with individual batteries

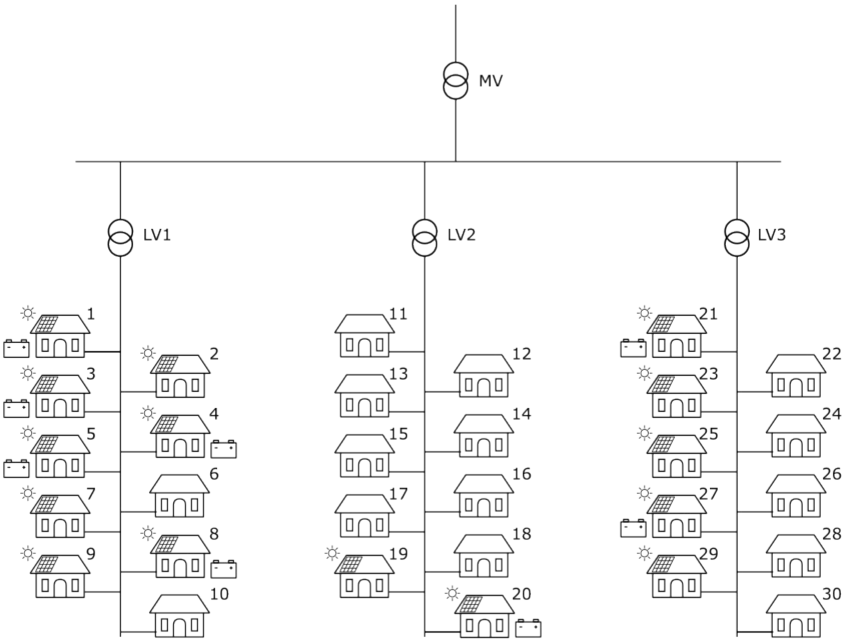

Figure 28: Community with individual batteries setup

Next, a community with flexibility options is considered. For this purpose, eight households (1, 3, 4, 5, 8, 20, 21 and 27) are equipped with batteries as illustrated in Figure 28.

Results with grid tariff for non-metered customers

The annual total community cost for non-metered households is illustrated in Figure 29. Due to battery usage to maximize self-consumption the baseline cost in the No Community setup are lower than for inflexible households. Hence, the economic benefits achieved by community implementations are also lower. Forming a community results in a total cost reduction of about 5 % or 730 EUR. With a reduced local grid tariff the implementation of a community results in a total cost reduction of about 11 % or 1580 EUR.

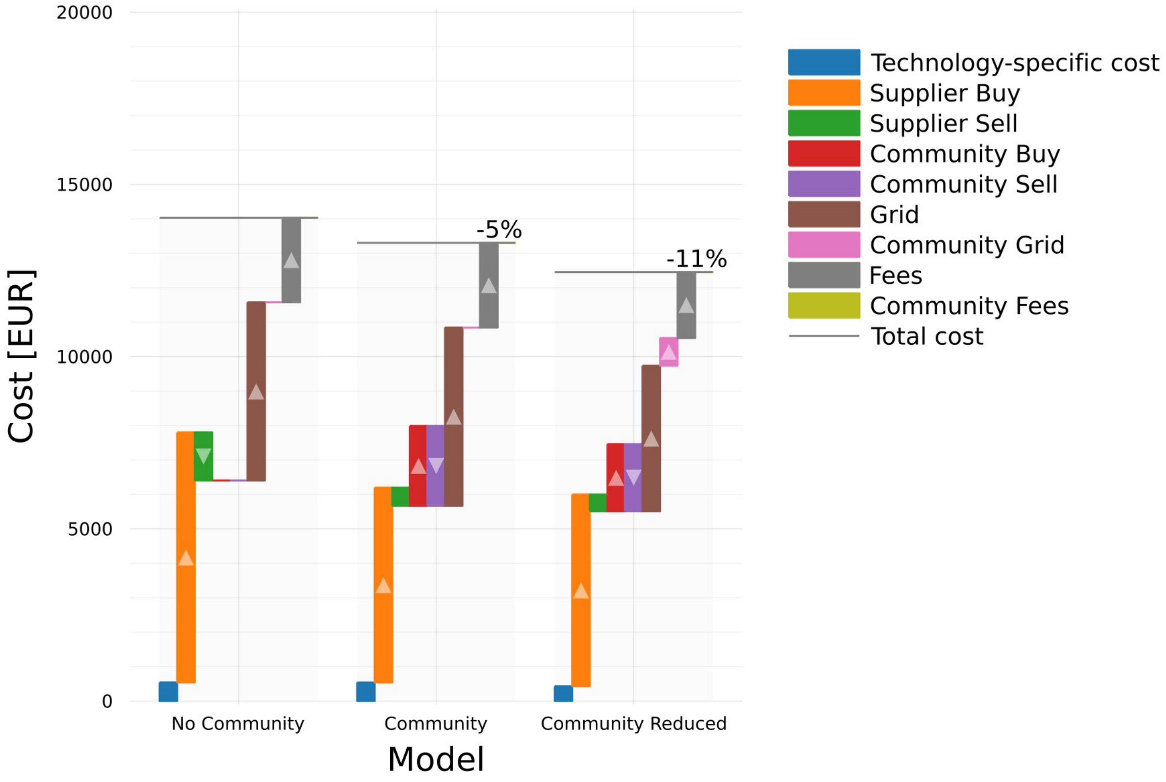

Figure 29: Total annual cost for a Community with batteries with the grid tariff for non-metered customers

The average cost reductions per customer group are listed in Table 10. Prosumers include customers with PV only and prosumagers represent customers with PV and battery. In both setups prosumagers benefit least, because they share battery flexibility with other community members. Otherwise, they would have used this flexibility to maximize self-consumption.

Table 10: Average cost reductions for different customer groups

Customer group	Unit	Community	Community Reduced
All	EUR	24.40	52.70
Consumers	EUR	29.30	50.10
Prosumers	EUR	28.10	61.80
Prosumagers	EUR	11.90	49.50

The individual cost reductions for each household are illustrated in Figure 30. With the **Community** setup there is one customer with PV and battery with higher cost than in the **No Community** setup.

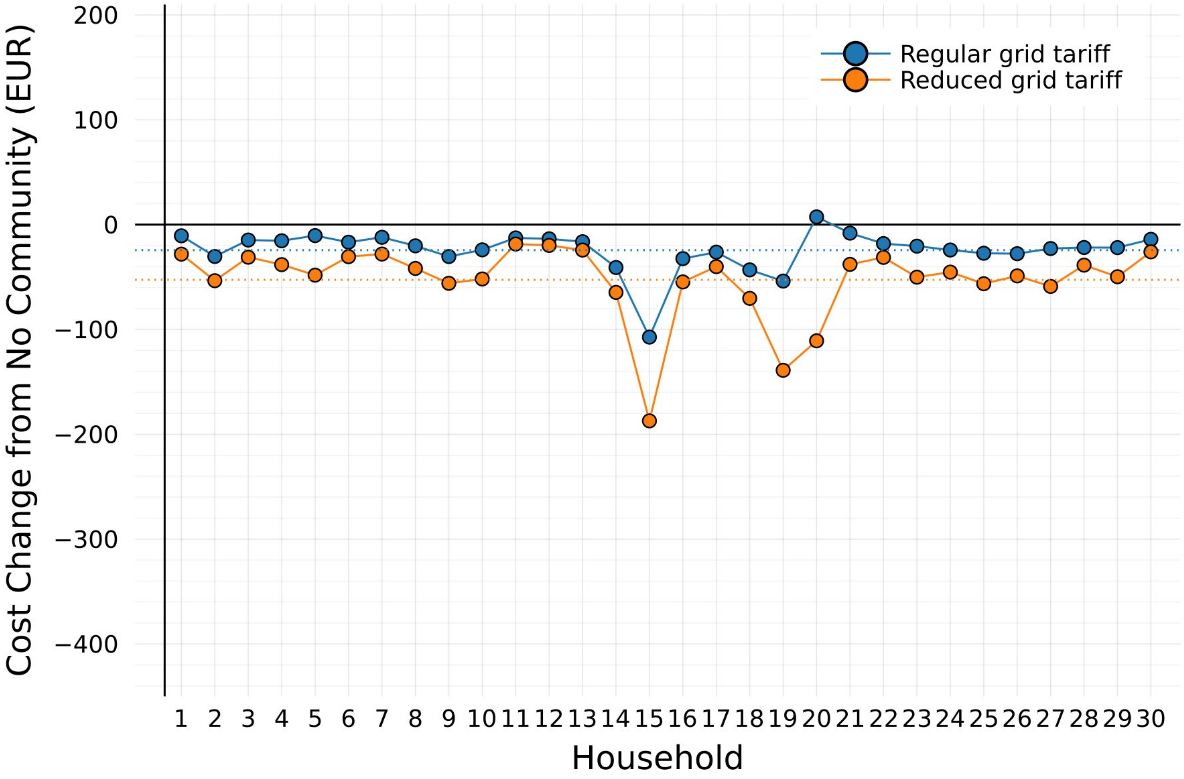

Figure 30: Individual household cost change compared to the No Community case for the battery community setup with the grid tariff for non-metered customers.

The trades among community members are illustrated in Figure 31 and Figure 32.

Figure 31: Community trades with the regular grid tariff

Figure 32: Community trades with the reduced grid tariff

The usage of local PV production is illustrated in Figure 33. It can be observed that the introduction of a community increases regional consumption of PV production. With reduced grid tariffs self-consumption is slightly reduced. However, more PV production is used locally, i.e. within the same low voltage grid branch. Hence, the reduced grid tariffs provide incentives to operate batteries differently in order to reduce export of PV production beyond the regional level.

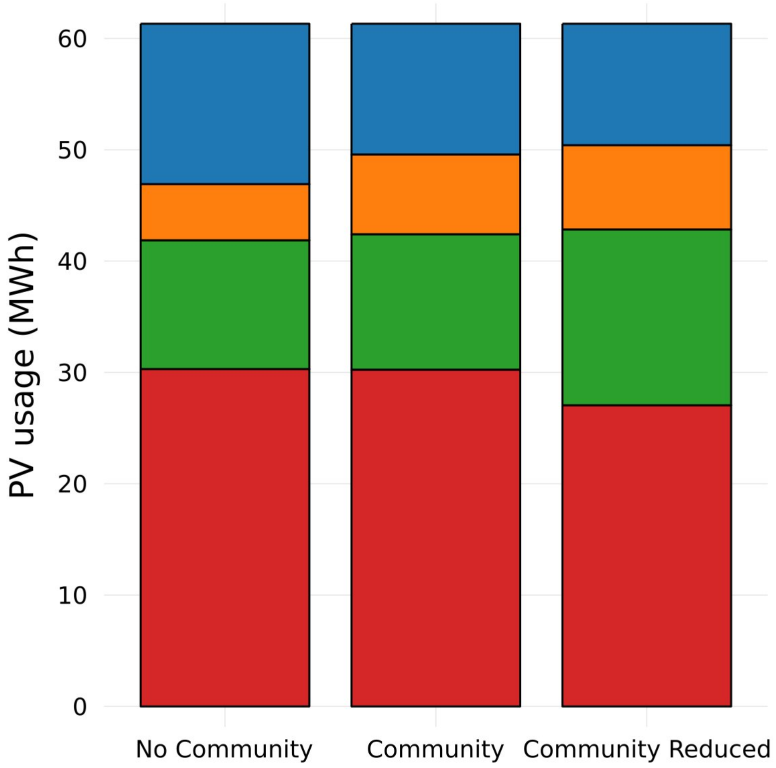

Figure 33: Usage of local PV production for the flexible community setup with the grid tariff for non-metered customers

The maximal load and feed-in values at the transformer stations are listed in Table 11. The introduction of a community does not affect these values in this case. However, with reduced local grid tariffs the maximal feed-in values are reduced and the maximal loads are increased.

Table 11: Maximal load and feed-in values at the transformer stations

	Unit	No Community	Community	Community Reduced
Maximal load MV	kW	39.69	39.69	42.65
Maximal load LV1	kW	18.83	18.83	18.83
Maximal load LV2	kW	22.87	22.87	22.87
Maximal load LV3	kW	17.87	17.87	17.87
Maximal feed-in MV	kW	30.51	30.51	27.83
Maximal feed-in LV1	kW	17.36	17.36	17.36
Maximal feed-in LV2	kW	6.34	6.34	6.07
Maximal feed-in LV3	kW	9.22	9.22	9.22

Results with grid tariff for metered customers

Figure 34 shows the total cost of the community with batteries and metered grid tariffs in the different Community setups. It can be observed again, that the total electricity purchase cost of all households is higher with the grid tariff for metered customers. The cost reduction caused by community peer-to-peer trading is similar to the case with non-metered customers. However, with the reduced community grid tariff a significant cost reduction of 32 % can be achieved in total. Here, the flexibility of the battery is used to minimize load peaks of community members, because internal trades are not considered in peak-load-pricing.

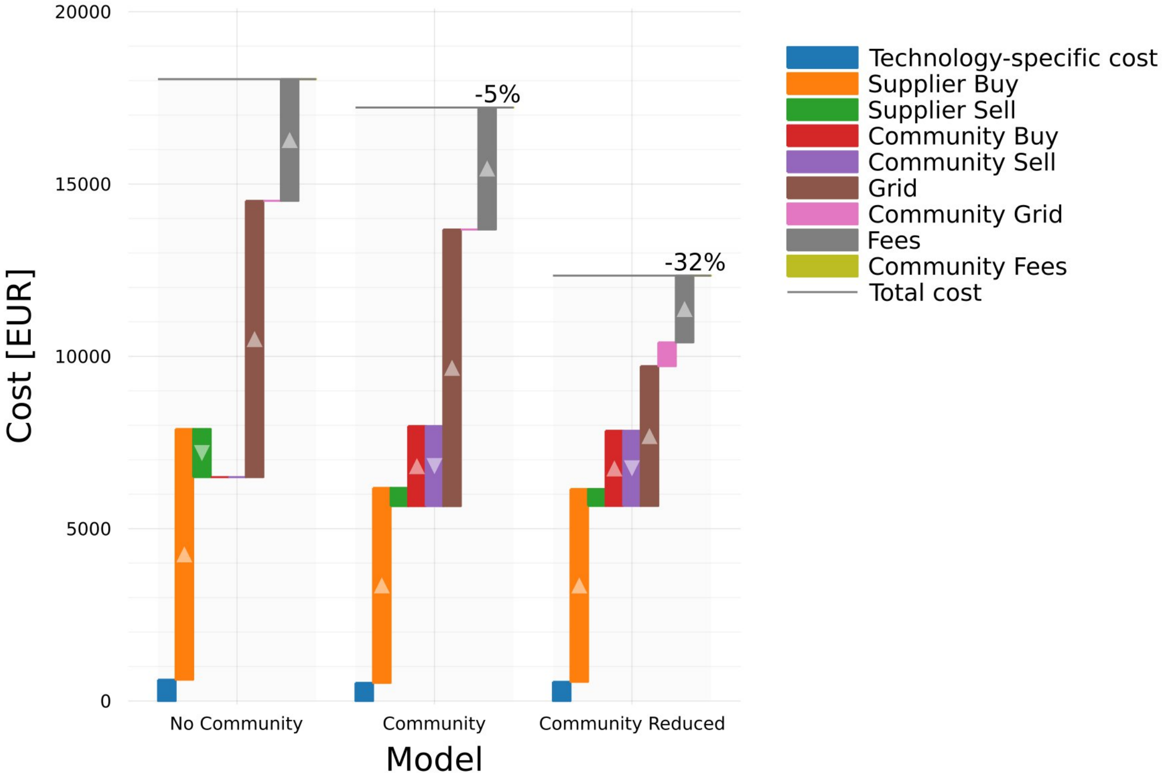

Figure 34: Total annual cost for a Community with batteries with the grid tariff for metered customers

Table 12 lists the average cost reductions per customer group. Similar to the case with grid tariffs for non-metered customers, prosumagers benefit least. This difference in cost reductions is specifically significant for the reduced local grid tariff. Here, the batteries of flexible customers are used to reduce the peak-load-pricing cost of other customers. This is possible, because internal community trades are not considered for determining the peaks that are used in the peak-load-pricing calculation with local community grid tariffs.

Table 12: Average cost reductions for different customer groups

Customer group	Unit	Community	Community Reduced
All	EUR	27.50	190.00
Consumers	EUR	29.40	210.40
Prosumers	EUR	27.80	260.80
Prosumagers	EUR	23.60	91.80

Figure 35 shows the cost change per individual household. It can be observed that for both the Community and the Community Reduced setup all customers achieve economic benefits compared to the individual optimization.

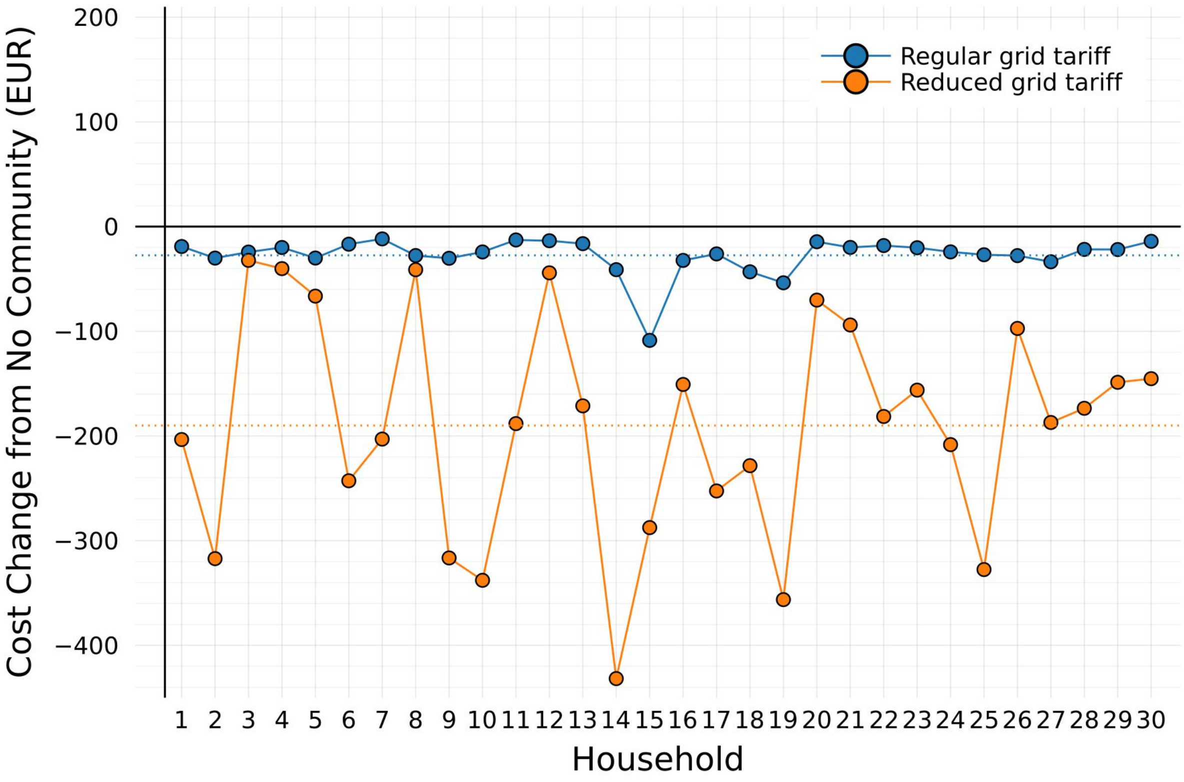

Figure 35: Individual household cost change compared to the No Community case for the battery community setup with the grid tariff for metered customers.

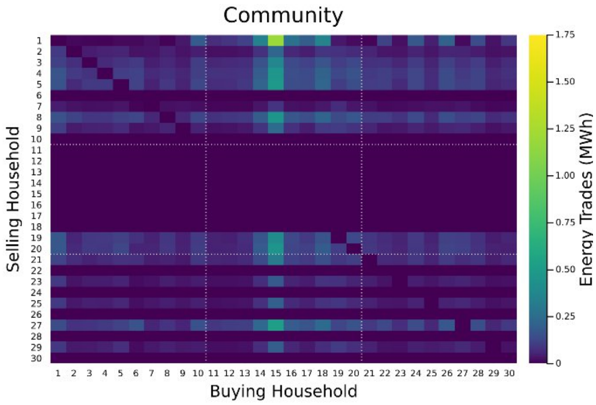

Figure 36: Community trades with the regular grid tariff

Figure 37: Community trades with the reduced grid tariff

The reduced grid tariff provides incentives to use locally produced electricity locally. This can be observed when comparing the community trades with a regular grid tariff in Figure 36 to the community trades with a reduced grid tariff in Figure 37. In the latter case significantly more electricity is traded locally and significantly less regionally.

Furthermore, the reduced grid tariff results in lower individual self-consumption of local PV production, but in higher local and regional self consumption and less external feed-in than the regular grid tariff. This is illustraded in Figure 38.

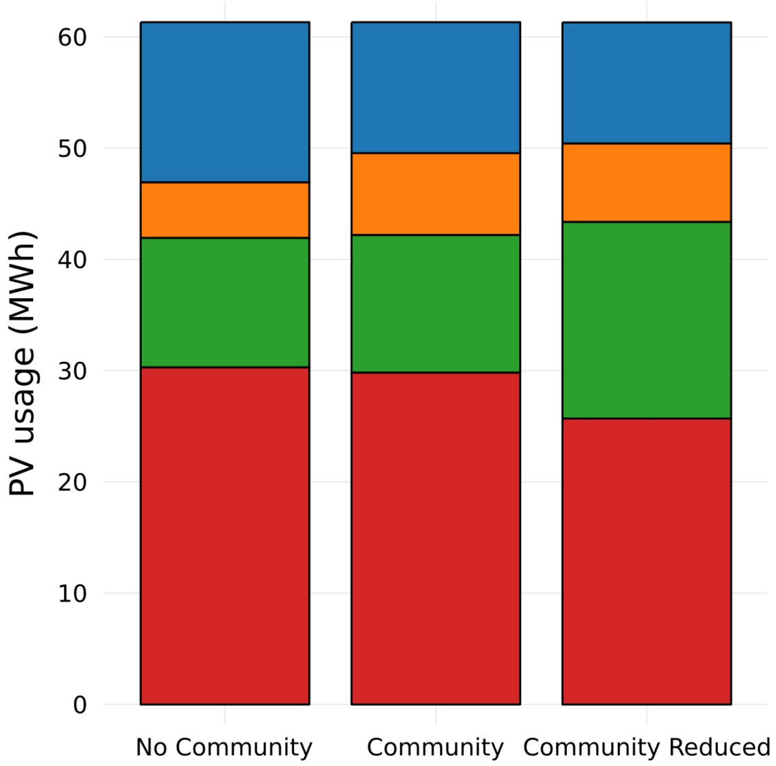

Figure 38: Usage of local PV production for the flexible community setup with the grid tariff for metered customers

Table 13 lists the maximal load and feed-in values on different low voltage grid branches and on the medium voltage grid. Compared to the regular grid tariff, the reduced grid tariff provides lower maximal load and feed-in values on almost all grid branches, except for the maximal load on LV3.

Table 13: Maximal load and feed-in values at the transformer stations

	Unit	No Community	Community	Community Reduced
Maximal load MV	kW	36.39	36.51	27.96
Maximal load LV1	kW	15.66	17.02	15.9
Maximal load LV2	kW	21.19	20.65	21.22
Maximal load LV3	kW	16.15	17.1	15.08
Maximal feed-in MV	kW	30.51	30.51	16.01
Maximal feed-in LV1	kW	17.36	17.36	15.87
Maximal feed-in LV2	kW	6.34	6.34	4.4
Maximal feed-in LV3	kW	9.22	9.22	8.42

2.3.3.Use Case 3

In the Austrian Use Case 3, a location in the city of Klagenfurt with six companies of different size and expertise is considered. The aim of the use case is, to investigate potential investments into sustainable technologies like a photovoltaic system or battery storages by the companies. Thereby, different cost assumptions for the technologies and the formation of an energy community between the companies, and moreover their impact on investments, are examined. Furthermore, costs savings due to technology investments and energy community formation are analysed. The idea and the set-up of the use case are presented in the following figure.

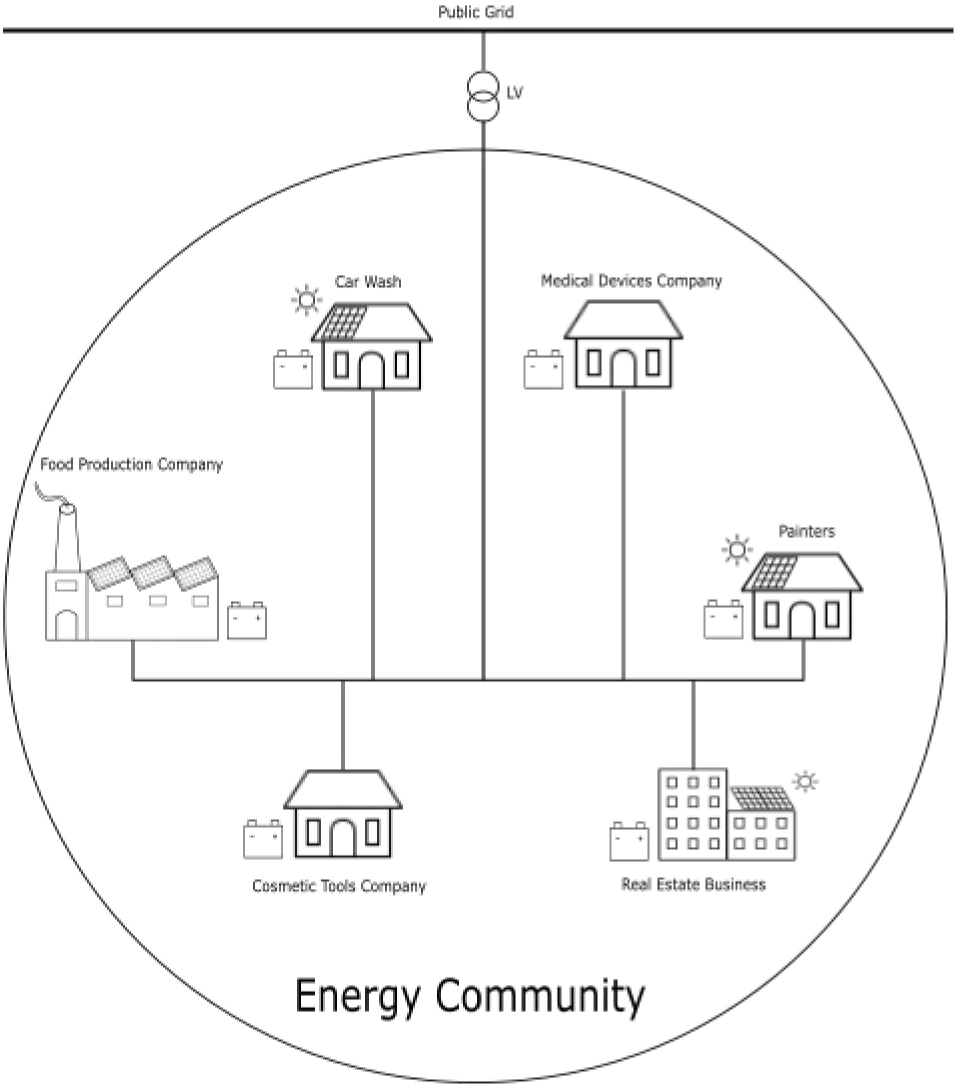

Figure 39 Use Case 3 Set-Up

Various assumptions must be made for the execution of the investment decisions. These are presented in Table 14. In further investigations, investment subsidies for the technologies are considered as well. For the PV feed-in tariff, it is differed between a basic scenario with remuneration via day-ahead prices (mean value over the year) and an additional scenario with remuneration via subsidized feed-in tariffs. Additionally, the investment costs for PV systems are assumed depending on the size of the PV system. Based on the rooftop areas, a large-scale PV system can be considered for the food production company, a medium-sized PV system for the real estate business, and small-scale systems for all other companies.

Table 14 Use Case 3 Assumptions

Parameter	Value	Unit
Electricity Price[7]	8.77	cent/kWh
Feed-In Tariff Day Ahead[8]	3.32	cent/kWh
Feed-In Tariff subsidized[9]	7.00	cent/kWh
Power price grid[10]	56.4	€/kW
Grid fees for community trading10	2.87	cent/kWh
PV costs large-scale	1000	€/kWp
PV costs medium-sized	1250	€/kWp
PV costs small-scale[11]	1500	€/kWp
Battery Costs[12]	740	€/kWh

The overall goal in the use case is to minimize the total costs of all six companies together. In order to make a distinction between different set-ups, three major investigations are carried out for each cost and configuration scenario.

- **Grid Consumption:** It is not possible to build a PV system or invest into PV systems. The electricity can only be purchased from the public grid, so the total costs are only composed of grid purchase cost. Thus, this is the scenario without any additional investments into PV, while investment in batteries would, however, be possible.
- **No Community:** The only difference to the previous scenario is the PV investment opportunity. Excess energy can be fed into the grid or stored in batteries.
- **Community:** As additional flexibility option, electricity can be traded locally to other companies in the community. In this scenario, various assumptions are made in the investigations, such as reduced grid charges or exemption of the green energy flat rate. As an additional difference, the power prices are not charged individually for each consumer (with subsequent cost summation), but are applied to the maximum power within the community.

As the electricity consumption of the food production company is significantly higher than the consumption of the other companies in the community, investment decisions for the food production company alone and for the energy community without this industrial partner are carried out as well.

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[7] Strompreise für die Industrie in Österreich von 2009 bis 2020 online available at https://de.statista.com/statistik/daten/studie/287849/umfrage/strompreise-fuer-industrielle-verbraucher-in-oesterreich/ (accessed on 10.09.2021)

[8] ENTSOE Day Ahead Prices online available at https://littleearthling.owncube.com/index.php/s/gBPp2iSWyTP2YdL (accessed on 10.09.2021)

[9] Tarifförderung Photovoltaik online https://www.oem-ag.at/de/foerderung/photovoltaik/tariffoerderung/ (accessed on 10.09.2021)

[10] Netznutzungsentgelt online https://www.e-control.at/marktteilnehmer/strom/netzentgelte/netznutzungsentgelt (accessed on 10.09.2021)

[11] Kosten von Photovoltaikanlagen online https://www.dachgold.at/photovoltaik-kosten/ (accessed on 10.09.2021)

[12] IRENA Electricity Storage online https://www.irena.org/costs/Electricity-Storage (accesse on 10.09.2021)

Base Scenario

In the base scenario, the costs of Table 14 are used for the investment decisions. At first, the possibility of a storage investment is not considered. For the whole community, cost savings of 1.5% for the **No Community** Scenario and 1.7% for the **Community** Scenario are possible. In both cases, PV investment is mainly done by the food production company, as well as partly by the real estate business.

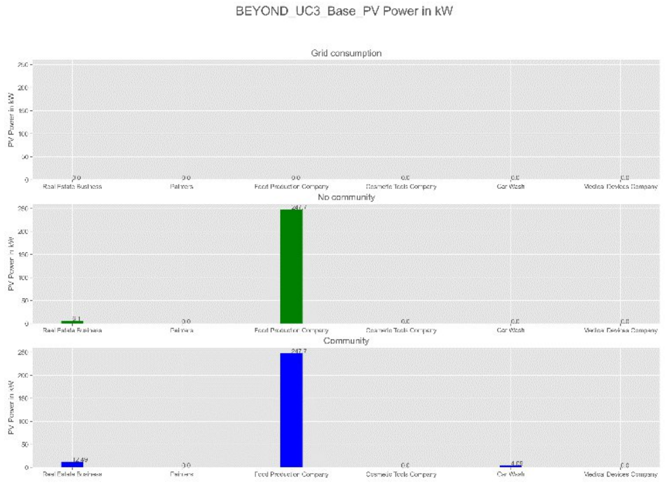

Figure 40: PV Investment Base

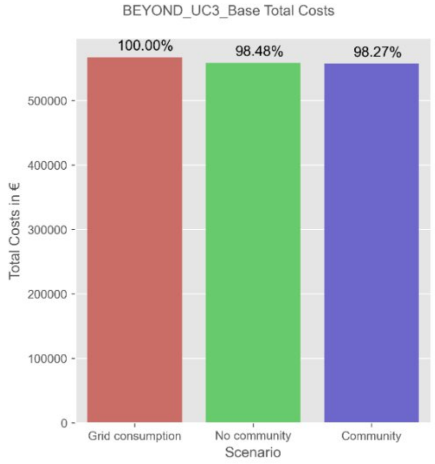

Figure 41: Total Costs Base

The cost breakdown can be seen in Figure 40. Grid costs are replaced by PV costs in the **No Community** and **Community** scenarios.

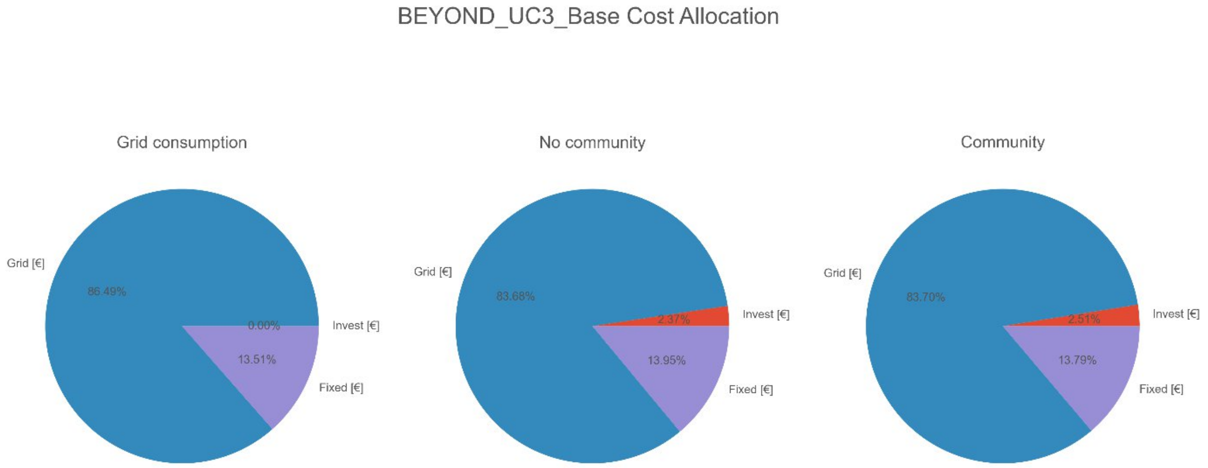

Figure 42 Cost allocation Base

To give a better insight on the energy flows in the different scenarios, heat maps with the energy flows, related to the total yearly energy consumption of the corresponding company are presented.

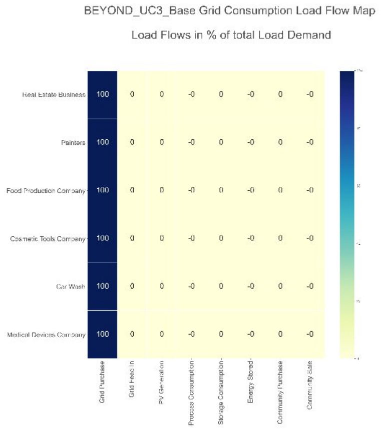

Figure 43: Load Base Grid Consumption

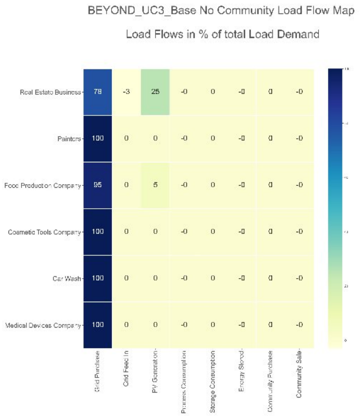

Figure 44: Load Base No Community

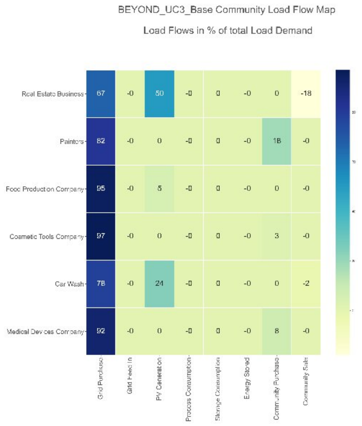

Figure 45: Load Base Community

In the **Grid Consumption** Scenario presented in Figure 43, the loads are only covered by purchase from the public electricity grid. The loads in the **No Community** scenario (Figure 44) of the companies with PV investment are additionally covered by PV generation. In the **Community** scenario in Figure 45 the loads of certain companies are additionally covered by community purchase, whereas the energy is offered to the community by other members.

If subsidized feed-in tariffs are considered instead of day ahead prices, PV investment and cost savings are slightly higher. Community trading is not done, as feeding energy back into the grid emerges as cost-efficient flexibility. Despite this, the PV investments in the **Community** case are higher than in the **No Community** case, as the power-based prices in the **Community** case are considered for the maximum power of the whole community, and the PV systems are installed to lower the peak power. In the heat map, the provision of an additional flexibility option can be seen by a relocation of the load flows towards grid feed-in.

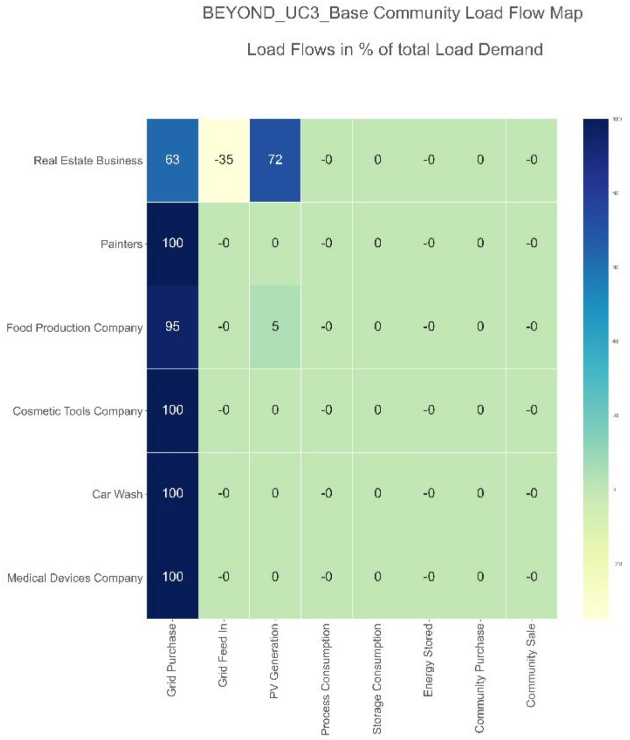

Figure 46 Feed-In Subsidies Heatmap

This leads to the conclusion that future energy system developments like private use of batteries and concepts like energy communities become less attractive with high PV feed-in subsidies. It could be seen that the consideration of day ahead prices would be enough to make PV investments economically feasible.

If only the food production company is considered as a single consumer, community trading cannot be applied. As the rooftop area is limited, PV extension is restricted. In case of the food production company, the PV extension of 247kWp is at its limit. The previous heat map showed, that the entire generated energy is consumed by the food production company itself. Thereby, 5% of the energy demand can be covered by the PV system. Additional PV investment would be feasible, but not possible due to construction limits. Consideration of different feed-in tariffs has no influence on the use-cases with the food production company only, as there is no excess PV production, where the energy could be fed back into the electricity grid.

For the energy community of all other small-sized companies, the total cost reductions of 0.2-0.5% are significantly lower than for the whole community, as the food production company is the major influencing partner in the energy community. Like for the whole community, the PV investment is increasing in the **Community** approach. Thereby, the investments are done by the real estate business, as it has the highest rooftop area and lower investment costs due to the middle-scale PV system. In case of subsidized feed-in tariffs, community trading is not done by the smaller companies. Due to the financial attractive option of feeding electricity into the grid, more PV investment is done, than in the day ahead price cases.

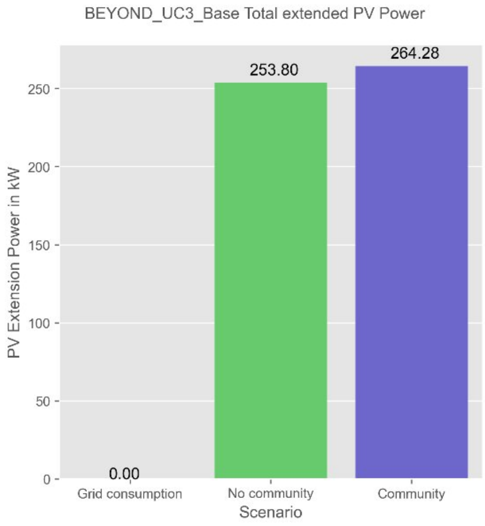

Figure 47. Extended PV Base Day Ahead

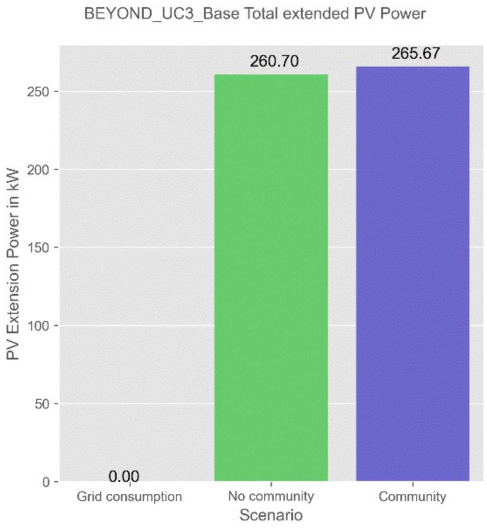

Figure 48. Extended PV Base Subsidies

The possibility of battery investments leads to the same results, which means that battery investments with the assumptions in Table 14 are not economically feasible for the given companies. This is due to the high self-consumption of the food production company, which is the dominating participant in the energy community. Other smaller companies have too low excess energy generation for an investment into batteries.

PV Investment Subsidies

In the next scenario, the impact of PV investment subsidies of 250€/kWp is investigated. This leads to the following PV investment costs.

Table 15 PV Investment Costs Subsidies

Parameter	Value	Unit
PV costs large-scale	750	€/kWp
PV costs medium-sized	1000	€/kWp
PV costs small-scale	1250	€/kWp

In case of the whole community, cost savings of about 35% compared to the cost savings in the base scenario can be achieved. PV investment is increased due to the lower investment costs.

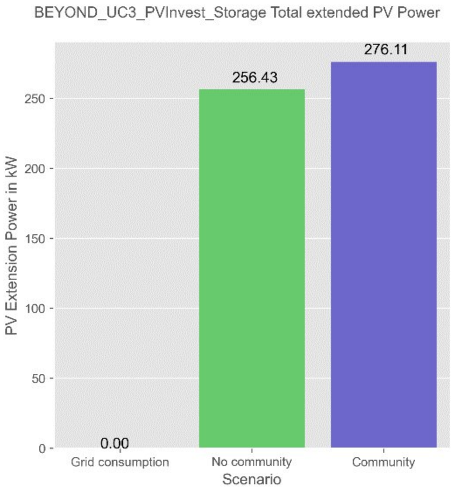

Figure 49:PV Investment with Subsidies

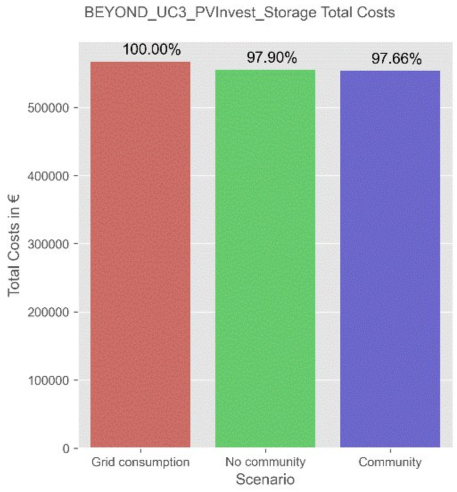

Figure 50: Total Costs PV Subsidies

This leads to increasing community trading between the companies, as it can be seen in Figure 51.

Marginal battery investment with capacities of about 1kWh is also feasible in this scenario. These are positioned at the real estate business and at the painters.

In case of subsidized feed-in tariffs, the PV investments are significantly increased with 183kWp for the **Community** scenario. Additionally, a 6.69kWh battery is installed at the real estate business. The purpose of the battery is to decrease the peak power, rather than increasing the self-consumption, as feeding excess energy into the grid is still a cost-effective flexibility due to the high feed-in tariffs. Like for the previous scenarios with high feed-in tariffs, community trading is not carried out.

In the consideration of the food production company alone, PV investment subsidies only lead to higher total cost savings due to the lower investment costs. Additional investment is not possible due to the limited rooftop area.

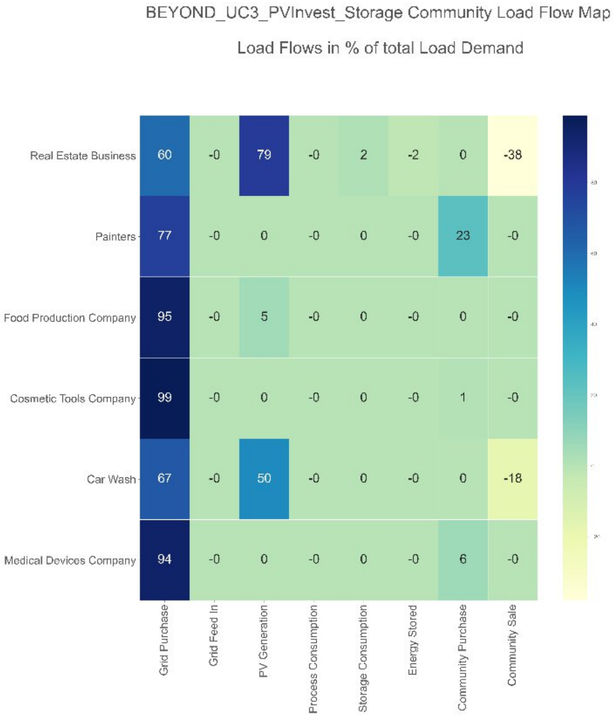

Figure 51 Community Trading with PV Investment Subsidies

The approach for only small companies leads to an increase of the PV investments of 2.5kWp for **No Community** and 8.5kWp for **Community**. For the subsidized feed-in tariffs, a further increase of 16kWp, respectively 20kWp is economically feasible, even though community trading is not done and all the excess energy is fed into the grid. As for the whole community, battery investments for peak power reduction become economically feasible.

Reduced Grid Fees

In this scenario, local grid tariffs for community trading are considered. Thereby, only the grid fees for the low voltage grid are accounted, as for trading between consumers located nearby to each other, often referred to as local trading, only the low voltage grid is directly used. According to an approach of the Austrian regulator E-control, the grid fees should be decreased by 57% for local electricity trading[13].

In case of the entire community, this leads to additional cost savings of 1410€. Community trading is increased and therefore, the PV investments in the **Community** scenario are increased by 184kWp. It is economical for all companies to invest in a PV expansion. In the heatmap in Figure 54 it can be seen that 4% of the electricity demand of the food production company can be covered by community trading with other companies. Unlike the previous scenario, storage investments are not economically feasible. Community trading emerges as an additional flexibility with lower costs than a battery, and is therefore the preferred flexibility option.

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[13] Verordnung der Regulierungskommission der E-Control online https://www.e-control.at/documents/1785851/1811582/SNE-V_2_Novelle_2021_V04_pub.pdf/9193af95-32c4-5c2d-560d-0ee810ef7b78?t=1630566924326 (accessed on 21.09.2021)

In case of subsidized feed-in tariffs, the reduced grid tariffs lead to community trading, which has not been done in previous scenarios with such feed-in tariffs.

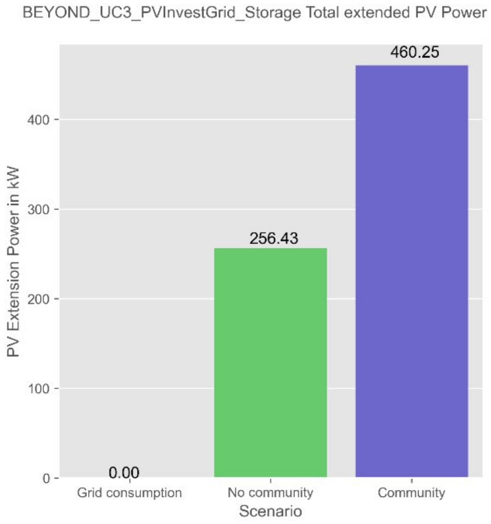


Figure 52: Reduced Grid Fees PV Investment

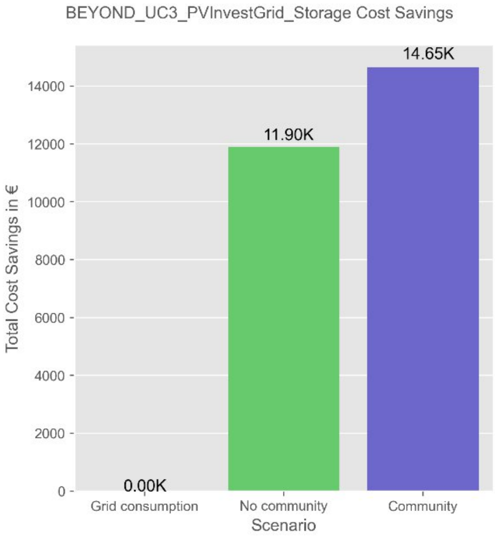
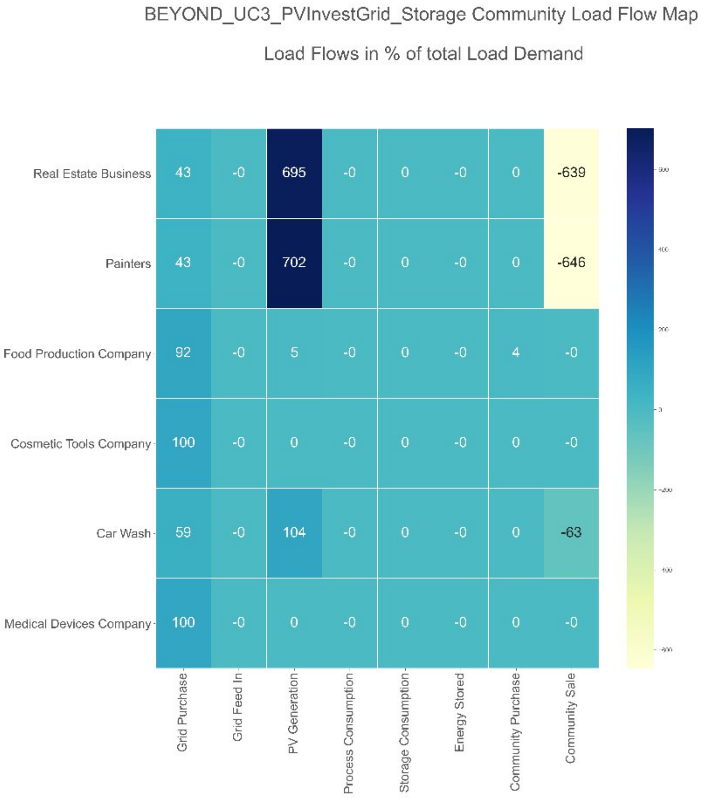


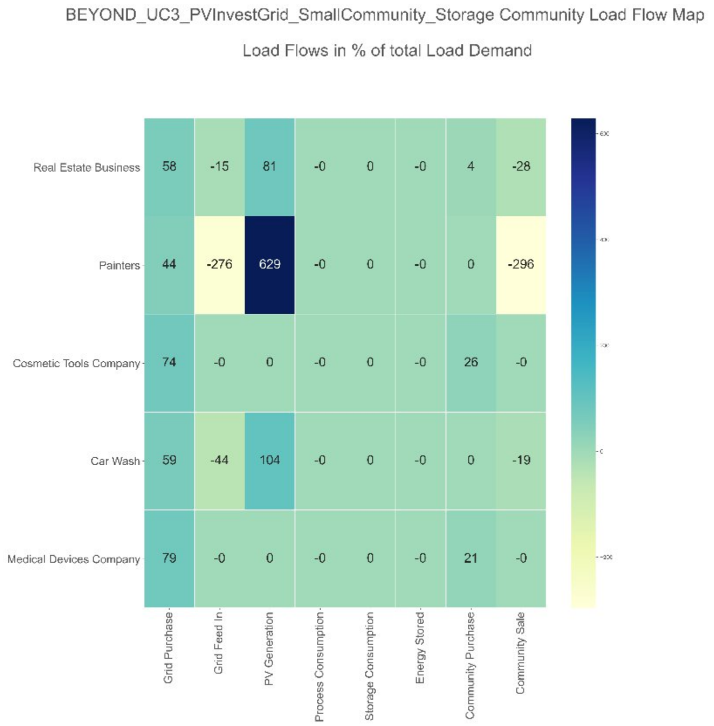
Figure 53: Reduced Grid Fees Cost Savings



	Grid Purchase	Grid Feed In	PV Generation	Process Consumption	Storage Consumption	Energy Stored	Community Purchase	Community Sale
Real Estate Business	43	-0	695	-0	0	-0	0	-639
Painters	43	-0	702	-0	0	-0	0	-646
Food Production Company	92	-0	5	-0	0	-0	4	-0
Cosmetic Tools Company	100	-0	0	-0	0	-0	0	-0
Car Wash	59	-0	104	-0	0	-0	0	-63
Medical Devices Company	100	-0	0	-0	0	-0	0	-0

Figure 54 Heat Map Reduced Grid Fees

For the food production company alone, reduced grid fees have no impact, as the impact is only on the **Community** scenarios. In the case of a community with smaller companies, the costs for the **Community** scenario decrease by 1.2% (330€), PV is increased by 3kWp and the battery investment is slightly increased by 0.22kWh. Generally, the real estate business is increasing its battery capacity to trade electricity within the community.



	Grid Purchase	Grid Feed In	PV Generation	Process Consumption	Storage Consumption	Energy Stored	Community Purchase	Community Sale
Real Estate Business	58	-15	81	-0	0	-0	4	-28
Painters	44	-276	629	-0	0	-0	0	-296
Cosmetic Tools Company	74	-0	0	-0	0	-0	26	-0
Car Wash	59	-44	104	-0	0	-0	0	-19
Medical Devices Company	79	-0	0	-0	0	-0	21	-0

Figure 55 Reduced Grid Fees Small Community Trading

If subsidized flat rates are considered instead of day ahead prices, the PV investments are almost tripled. Community trading is also done to a greater extend by companies with small-scale PV systems. Battery investment is thereby not done, as feeding electricity into the grid is still the more economically feasible flexibility.

As an additional idea for energy community benefits, the exemption of the green electricity flat rate is discussed[14]. This leads to a reduction of the annual fixed costs for each community member and thereby to a decrease of the total costs. As these fixed costs are not related to other parameters, a change in the fixed costs has no impact on the investment decisions, but only on the total costs.

Battery Investment Subsidies

In addition to the PV subsidies, reduced grid fees and exemption of the green electricity flat rate, battery investment subsidies to reduce the battery investment costs to 500€/kWh are introduced in this examination. This leads to an increased battery investment. The battery extensions for the entire community are presented in the following figures.

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[14] Green Energy Lab Online den Gemeinschaftsstrom managen online https://greenenergylab.at/online-den-gemeinschaftsstrom-managen/ (accessed on 21.09.2021)

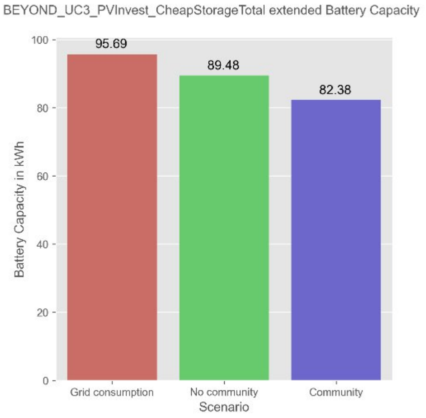


Figure 56: Battery Extension Subsidies

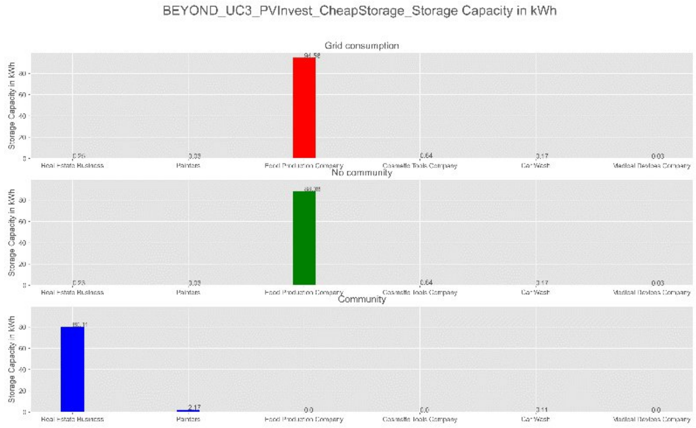


Figure 57: Battery Extension Companies

In the figures it can be seen, that with battery investment subsidies, investments are also done for the **Grid Consumption** scenario to reduce the maximum power. As this is the only possibility to achieve such a reduction, the battery investments are the highest for this scenario. Thus, it can be concluded that batteries with low investment costs can be economically feasible without PV capacities, if the power-based price component is high. For **Community**, the investments are comparably the lowest, as PV investment and community trading are additional flexibilities for peak power reduction. In the heat maps, the use of the batteries can be seen. For the food production company, the contribution of the battery is low compared to the total energy consumption. In the **Community** scenario, the energy flows within the community are more balanced than in the previous scenarios and the batteries are installed at the companies with the highest PV excess generation.

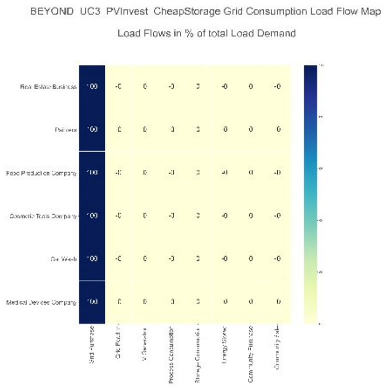


Figure 58: Grid Storage

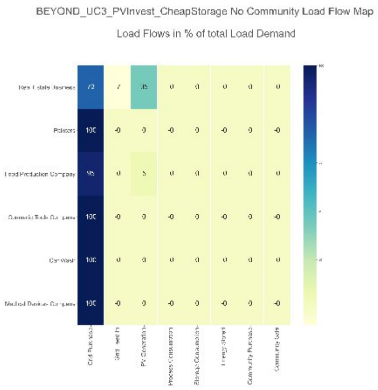


Figure 59: No Community Storage

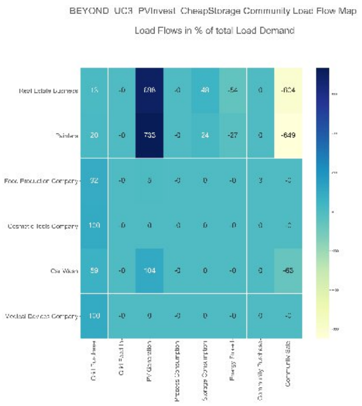


Figure 60: Community Storage

In case of subsidized feed in tariffs, battery investment subsidies have no significant impact on the battery investments. For the **No Community** scenario, PV is extended by 15kWp, as grid feed-in is still a considerable flexibility.

If only the food production company is considered, storage investments lead to peak power reductions for the **Grid Consumption** scenario of 94kW and to 88kW reduction for the **No Community** scenario. As community trading cannot be done and PV extension is on its limit, batteries are the only possibility to reduce the peak power. Compared to other energy flows within the companies, the stored energy is comparably low.

For the community with small companies, no significant battery investments, PV investments or cost savings appear. In the allocation of the battery capacities in the **Community** case, presented in Figure 61 it can be seen that economies of scale emerge, as it is invested into a larger storage at one location, instead of many small storages at several locations.

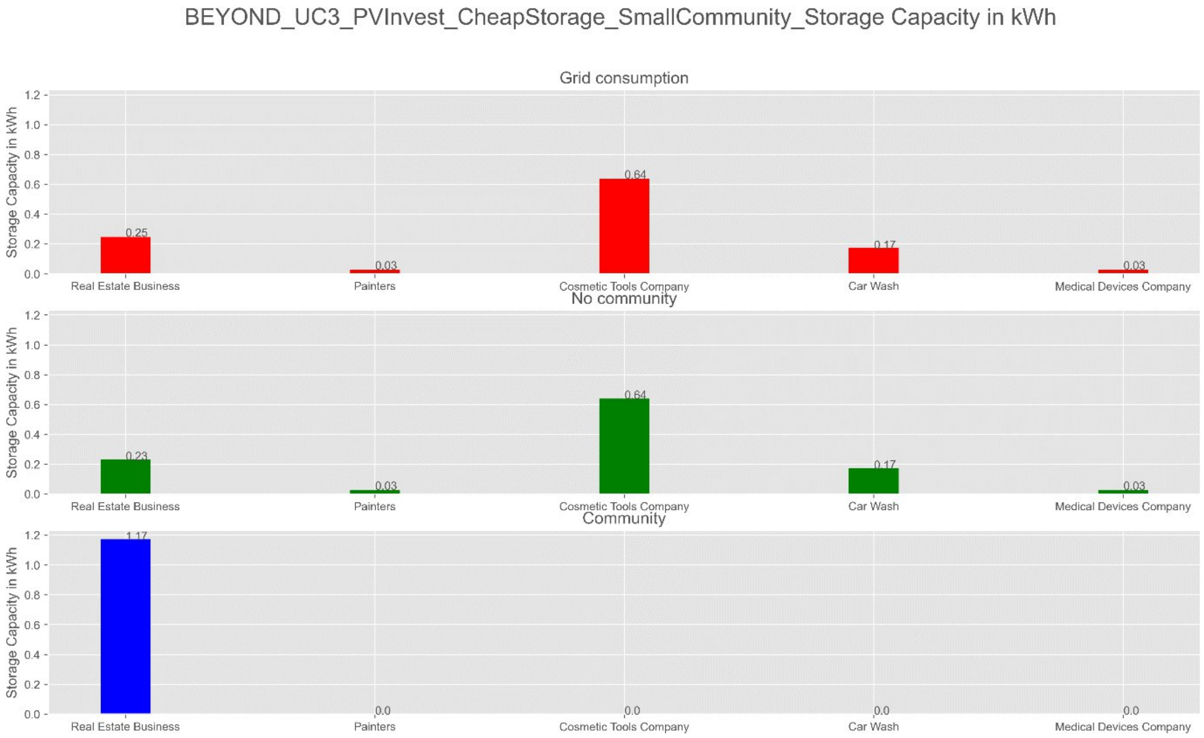


Figure 61 Battery Allocation Storage Subsidies

For higher grid feed-in tariffs, the PV investments for a community with small companies are tripled. At the same time, battery investments are decreasing, as grid feed-in is a feasible flexibility option.

Battery Potential Future Prices

In the final Use Case 3 investigations, potential future investment costs for batteries of 100€/kWh12 are investigated. For the entire community, this leads to further cost savings and PV investments (8-9kWp). In addition to the peak power reduction purpose of the batteries, they are used to increase the self-consumption. For the **Grid Consumption** scenario, the investments are the lowest, as the battery is only used for peak power reduction, while the investment for **No Community** is higher than for **Community** due to the less flexibility options. This can be seen in the heat map, as the stored energy is increasing significantly.

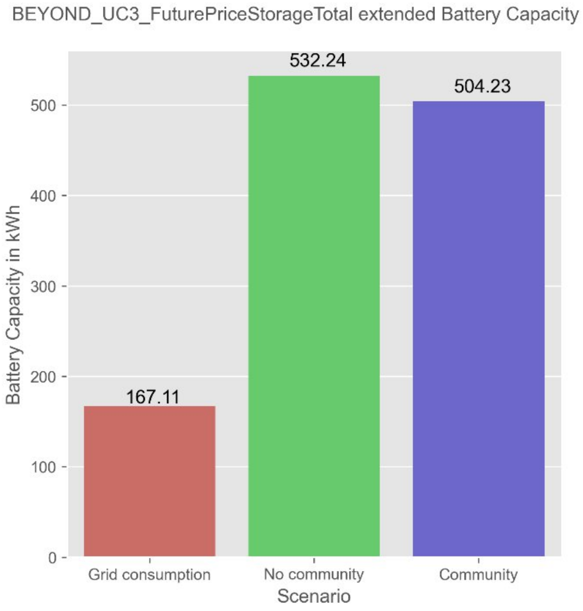
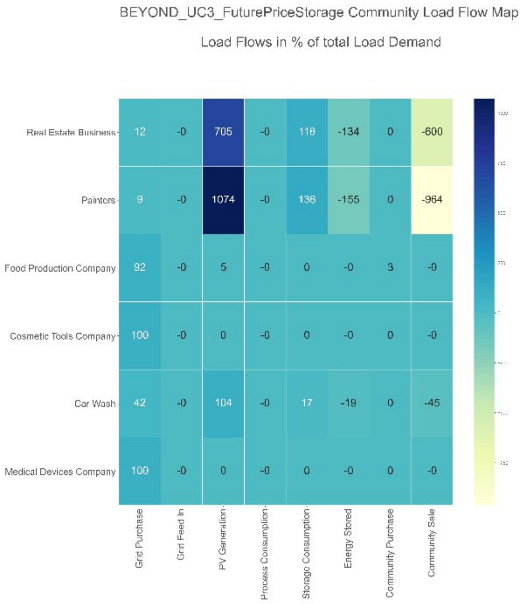


Figure 62: Future Battery Investments



	Grid Purchase	Grid Feed In	PV Generation	Process Consumption	Storage Consumption	Energy Stored	Community Purchase	Community Sale
Real Estate Business	12	-0	705	-0	118	-134	0	-600
Painters	9	-0	1074	-0	136	-155	0	-964
Food Production Company	92	-0	5	-0	0	-0	3	-0
Cosmetic Tools Company	100	-0	0	-0	0	-0	0	-0
Car Wash	42	-0	104	-0	17	-19	0	-45
Medical Devices Company	100	-0	0	-0	0	-0	0	-0

Figure 63: Future Battery Load Flows

For the food production company alone, storage investments lead to peak power reduction of 15.5kW for **Grid Consumption** compared to the previous scenario. Between the **No Community** and the **Grid Consumption** scenario within this consideration, peak power reductions of 100kW can be achieved. No excess energy is thereby fed back into the grid.

In case of the community with smaller companies, the battery investments are significantly increasing, as the battery is used for peak power reduction and the increase of self-consumption. The battery investments are the comparably lowest for the **Community** scenario due to the energy trading flexibility. Like in the previous scenario, economies of scale occur. Additionally, it could be seen that battery investments in this case for the community with small-size and medium-size companies are only feasible in combination with existing PV systems. The consideration of higher feed-in tariffs leads to the same result differences to the day ahead feed-in tariffs like in the previous scenarios.

3. Business Models

This chapter investigates Business models for Energy Communities and local trading on top of the simulation-based operational Use Case investigations in Chapter 2. Further discussions on the commercialization perspectives of these Business Models are provided in the BEYOND project deliverable D5.3.

3.1. Use Case 1: Business Model related cost / benefit analysis

This chapter presents economic cost / benefit calculation results for Use Case 1 to rate the business model related value proposition. These results also are key element of the KPI analyses in Task 5.1.

Accordingly, the following table summarizes implemented economic cost parameters. Total expenditures (TOTEX) per year represent the sum of yearly operational expenditures (OPEX – e.g. proportional cost for internet connection) as well as capital expenditures (CAPEX – i.e. annuity of e.g. Beyond equipment cost).

Table 16: Overview of implemented economic parameters in the Austrian Use Case 1

	Austrian Use Case 1		
22	Consumers analysed		
5	Prosumers analysed		
40 €/unit	Scenario 1: Beyond equipment cost – Smart Meter adapter at each Consumer/Prosumer site (CAPEX) with synergetic use of internet connection (1 €/month as OPEX)		
320 €/unit	Scenario 2: Beyond equipment cost – Additional high-resolution meter (1 second) with high bandwidth internet connection (direct line) at each Consumer/Prosumer site		
2%	Interest rate (Consumer/Prosumer view)		
10	Equipment lifetime in years		
	Scenario1	16,5	€/yr/Consumer
	Scenario 2	35,6	€/yr/Consumer
	Cost for all customers TOTEX		
	Scenario 1	345,5	€/yr
	Scenario 2	748,1	€/yr

Calculated yearly cost are then compared to the Use Case specific revenues from consumers perspective (see chapter 2.3.1 as well as Figure 68). If yearly costs exceed revenues the consumer faces additional cost resulting in a benefit/cost ratio < 1. Otherwise, if revenues exceed costs the consumer can realise savings resulting in a benefit/cost ratio >1.

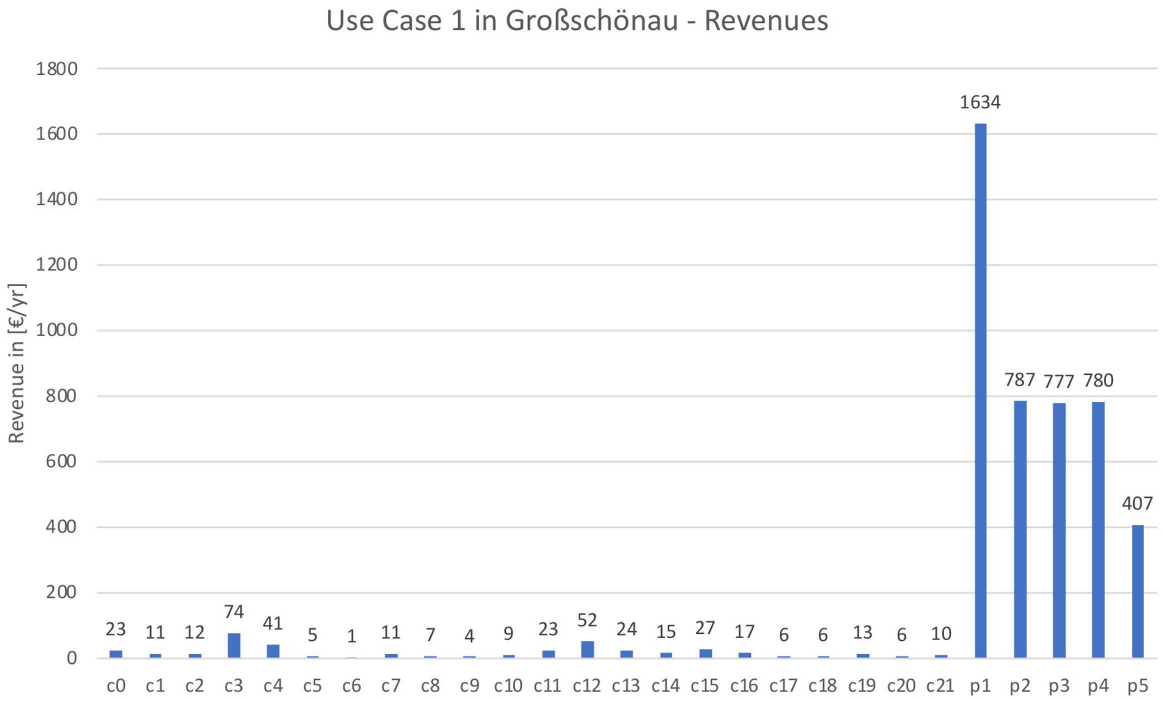


Figure 64: Yearly revenues for consumers/prosumers in Use Case 1 (Großschönau)

3.1.1.Use Case 1 – Cost / Benefit results for Scenario 1

The following figure illustrates economic calculation results for cost scenario 1 of Use Case 1. Only a few consumers can realise savings (compared to electricity cost without an energy community), whereas most of the consumers face additional cost in this Use Case setting. For prosumers however, high savings can be realised as a lot of electricity can be sold within the Energy Community.

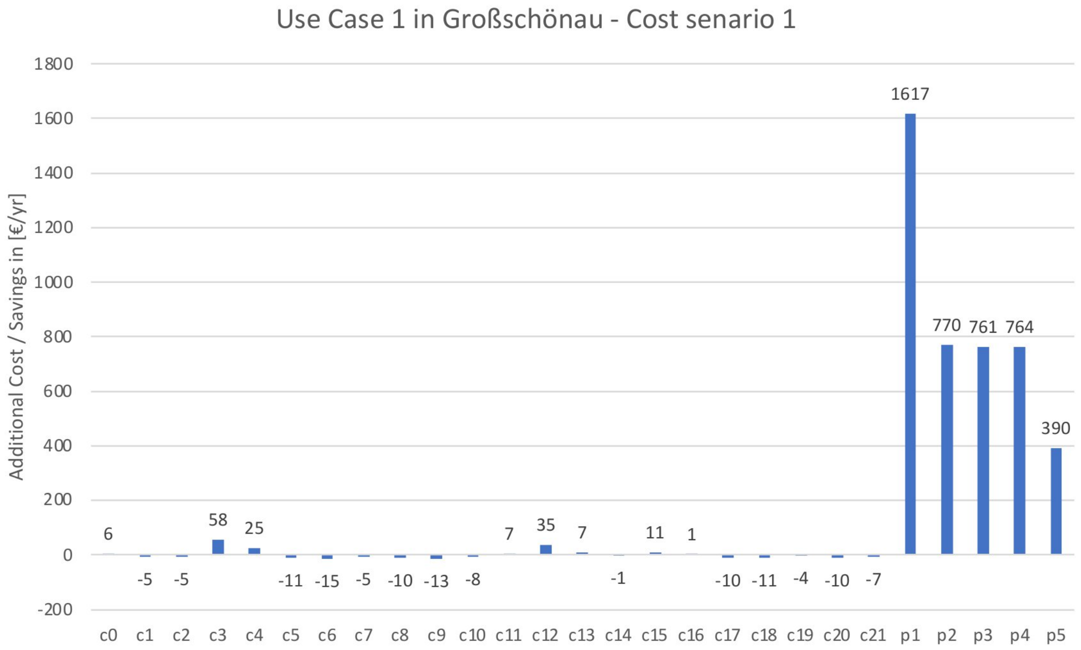


Figure 65: Additional Cost/Savings for consumers/prosumers in cost Scenario 1 of Use Case 1 (Großschönau)

3.1.2. Use Case 1 – Cost / Benefit results for Scenario 2

Cost scenario 2 increases additional cost for consumers and reduces savings for prosumers (due to higher component cost) as can be seen in Figure 66.

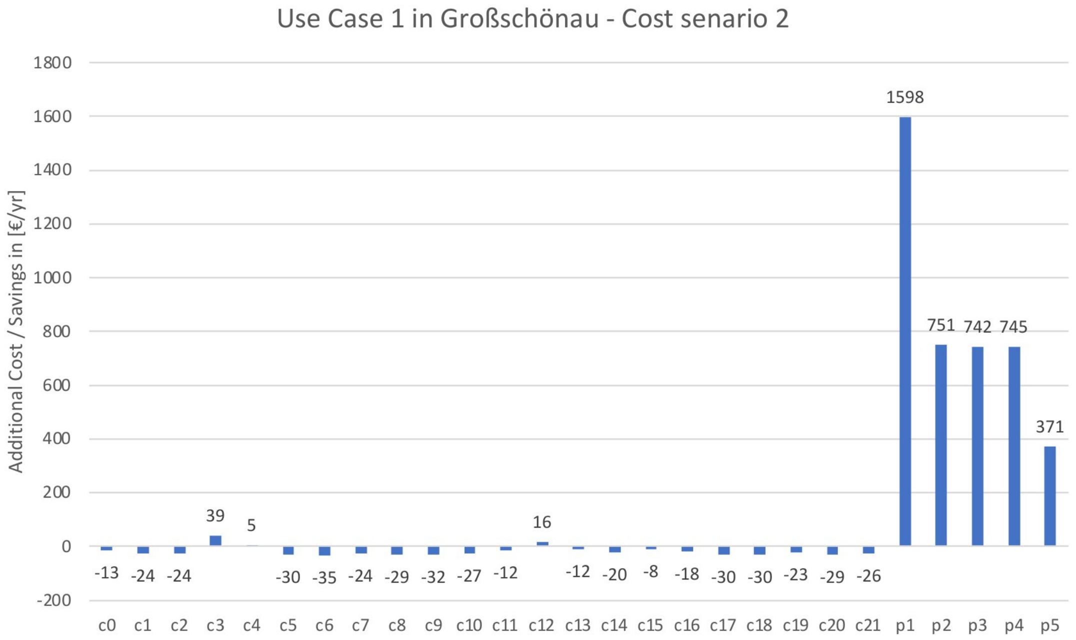


Figure 66: Additional Cost/Savings for consumers/prosumers in cost Scenario 2 of Use Case 1 (Großschönau)

3.1.3. Use Case 1 – Benefit / Cost ratios from community perspective

From the energy community perspective, the following table summarises the calculated cost benefit ratios for each cost scenario. Furthermore, the additional cost (reflecting customers' the Willingness to Pay) as well as achievable savings per customer/prosumer are summarised for different revenue allocation strategies.

In this context "equal shares" allocate revenues equally to each community member. A further option would be to allocate 50% of community revenues equally to all consumers and the rest equally to all prosumers. Another option could be to allocate 50% of community revenue equally to all consumers whereas the rest is shared between prosumers in relation to their nominal PV-capacity (compare also Figure 67)

Table 17: Summary of benefit/cost ratios and savings/additional cost results in the Austrian Use Case 1

Use Case setting			**Cost scenario 1**		**Cost scenario 2**	
		Community revenue in [€/yr]	Benefit/ Cost ratio	Additional cost / savings per customer in [€/yr]	Benefit/ Cost ratio	Additional cost / savings per customer in [€/yr]
Allocation option	Consumers (equal shares)	4782	13,9	-167	6,4	-147
	Prosumers (equal shares)	4782	13,9	-167	6,4	-147
	Consumers 50% equally shared	4782	13,9	-103,0	6,4	-91
	Prosumers 50% equally shared	4782	13,9	-434,0	6,4	-382
	Consumers 50% (equally shared)	4782	13,9	-103,0	6,4	-91
	Prosumers 50% (related to PV -size)	4782	13,9	-199 to -808	6,4	-178 to -712

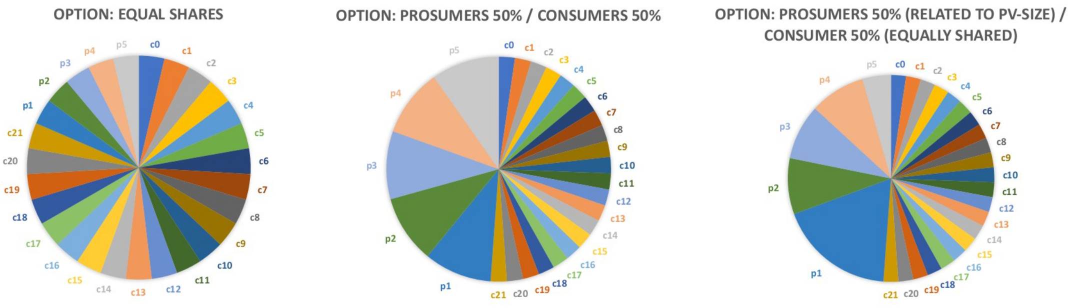


Figure 67: Allocation options of community savings in cost Scenario 1 of Use Case 1 (Großschönau)

3.2. Use Case 2: Business Model related cost / benefit analysis

This chapter presents economic cost / benefit calculation results for Use Case 2 in order to rate the business model related value proposition. These results also are key element of the KPI analyses in Task 5.1.

Accordingly, the following table summarizes implemented economic cost parameters. Total expenditures (TOTEX) per year represent the sum of yearly operational expenditures (OPEX – e.g. proportional cost for internet connection) as well as capital expenditures (CAPEX – i.e. annuity of e.g. Beyond equipment cost).

Table 18: Overview of implemented economic parameters in the Austrian Use Case 2

	Austrian Use Case 2		
30	Customers analysed		
508 €	Beyond equipment cost - Installed by E-Friends (CAPEX)		
450 €	Beyond equipment cost - Installed by customer contractor (CAPEX)		
1	Internet connection (proportional) in €/month (OPEX)		
2%	Interest rate		
10	Equipment lifetime in years		
	Scenario1	68,6	€/yr/customer
	Scenario 2	62,1	€/yr/customer
	Cost for all customers TOTEX		
	Scenario 1	2056,6	€/yr
	Scenario 2	1862,9	€/yr

Calculated yearly cost are then compared to the Use Case specific revenues from customers perspective (e.g. cost changes in Figure 20). If yearly costs exceed revenues the customer faces additional cost resulting in a benefit/cost ratio < 1. Otherwise, if revenues exceed costs the customer can realise savings resulting in a benefit/cost ratio >1.

3.2.1.Use Case 2 – Cost / Benefit results for local grid tariffs

The following two figures illustrate economic calculation results for cost scenario 1 and 2 (compare Table 18) and inflexible customers with non-metered grid tariffs (related to the results in Figure 20). Only a few customers can realise savings (compared to electricity cost without an energy community), whereas most of the customers face additional cost in this Use Case setting.

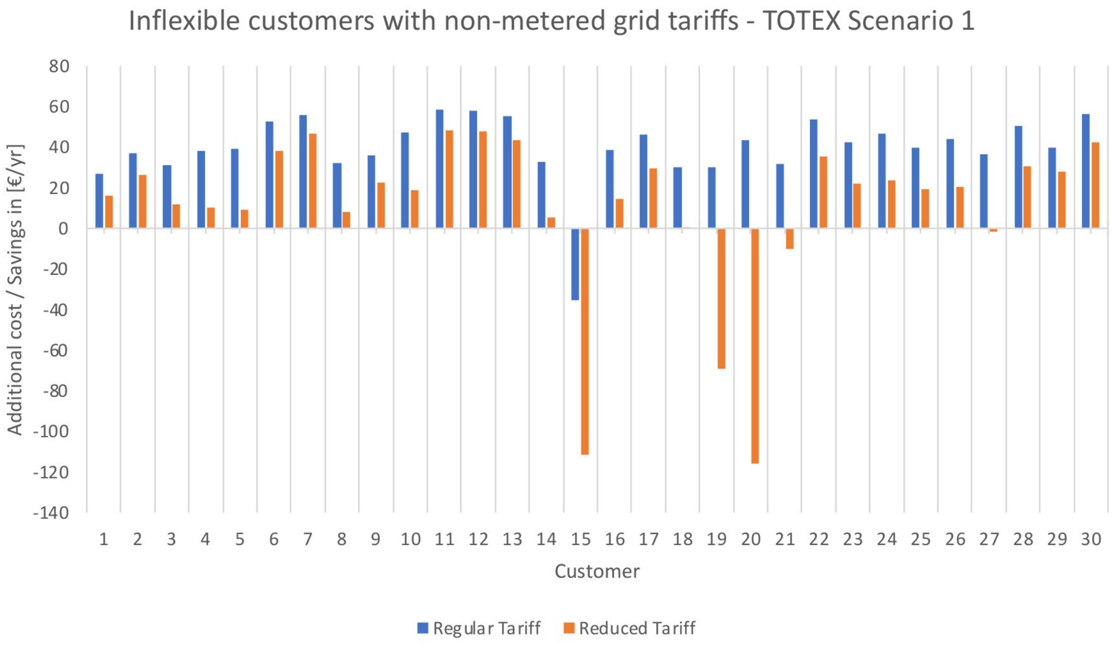


Figure 68: Additional Cost / Savings for inflexible customers with non-metered grid tariffs in cost Scenario 1

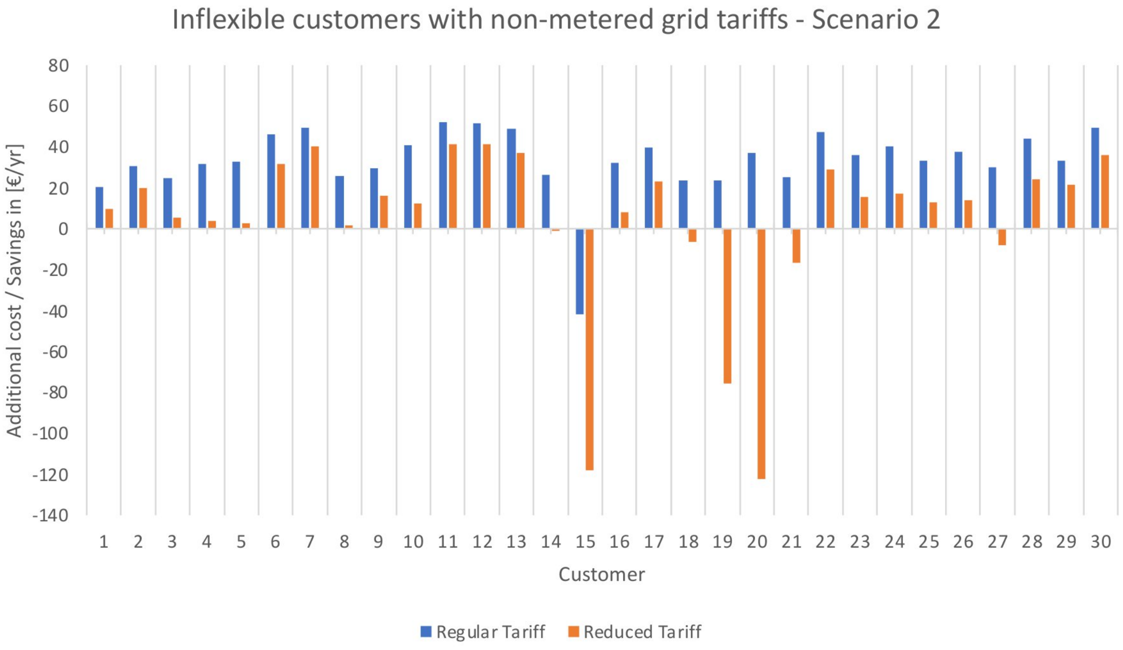


Figure 69 Additional Cost / Savings for inflexible customers with non-metered grid tariffs in cost Scenario 2

If the Use Case setting is changed to metered grid tariffs for inflexible customers, Figure 70 and Figure 71 show that that realise savings increase slightly in both cost scenarios. However, still most of the energy community customers face additional cost.

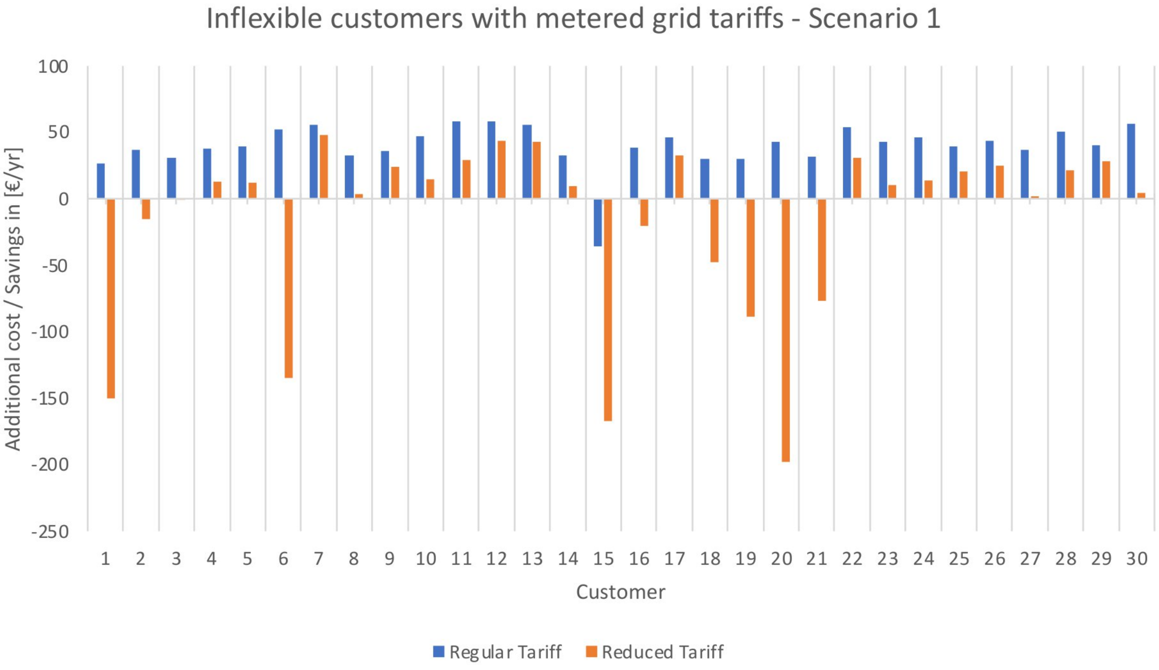


Figure 70: Additional Cost / Savings for inflexible customers with metered grid tariffs in cost Scenario 1

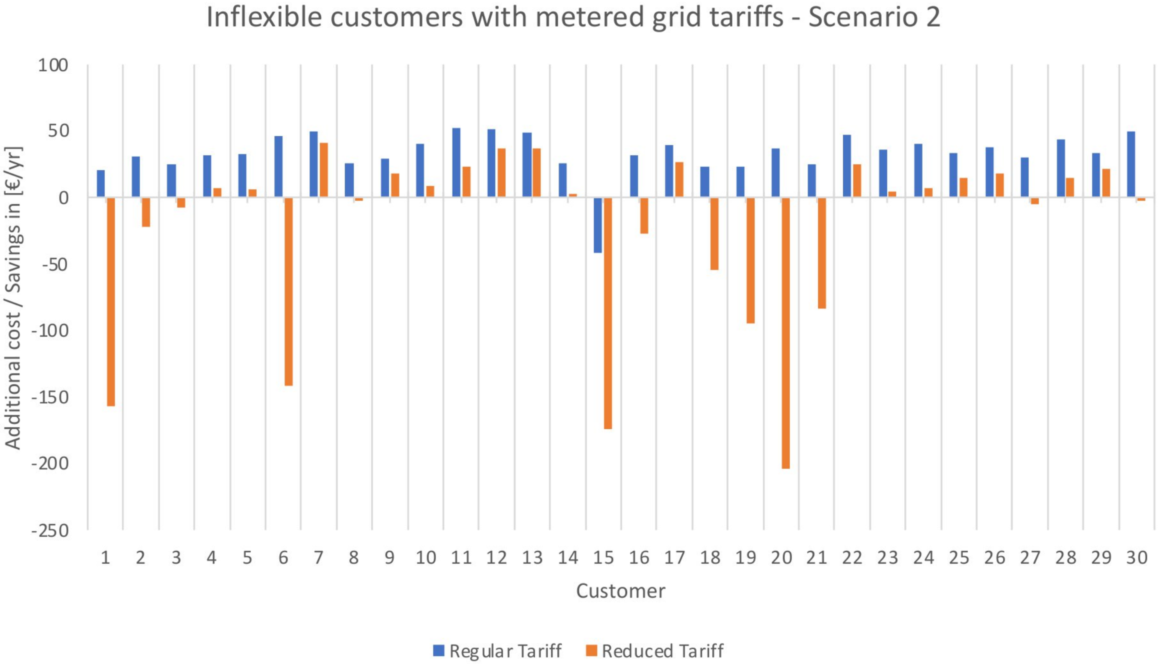


Figure 71: Additional Cost / Savings for inflexible customers with metered grid tariffs in cost Scenario 2

For flexible customers (due to installed batteries) and non-metered grid tariffs again only a few customers can realise savings in both cost scenarios (see Figure 72 and Figure 73). Thus, it seems important to identify mechanisms to allocated realised savings to all community members.

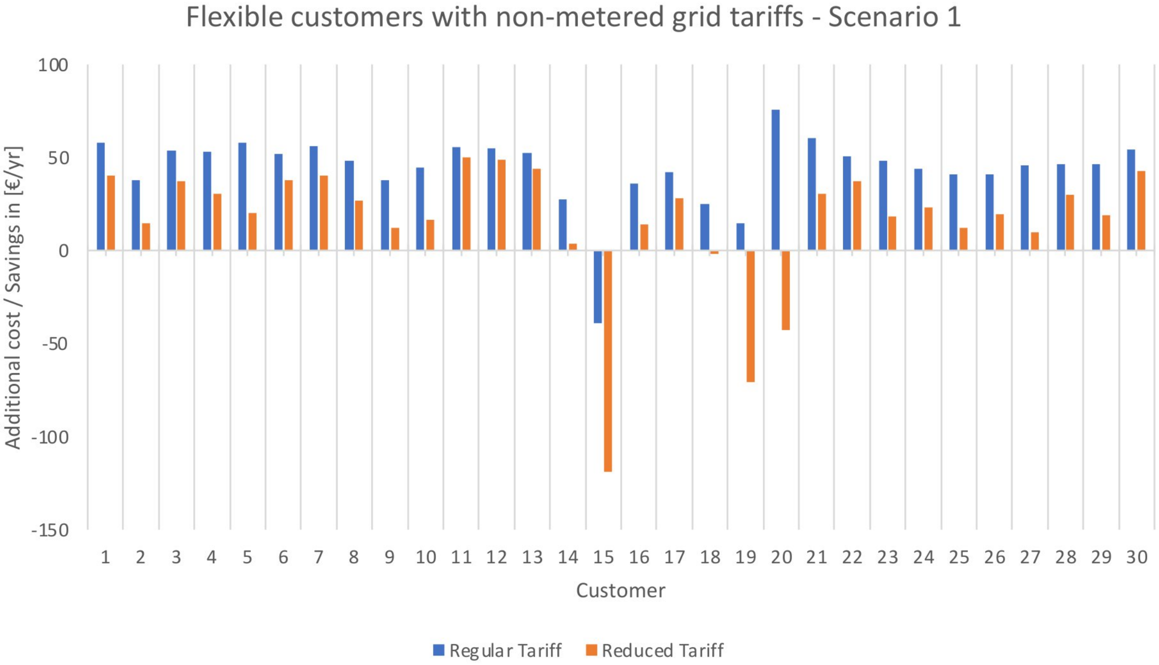


Figure 72: Additional Cost / Savings for flexible customers with non-metered grid tariffs in cost Scenario 1

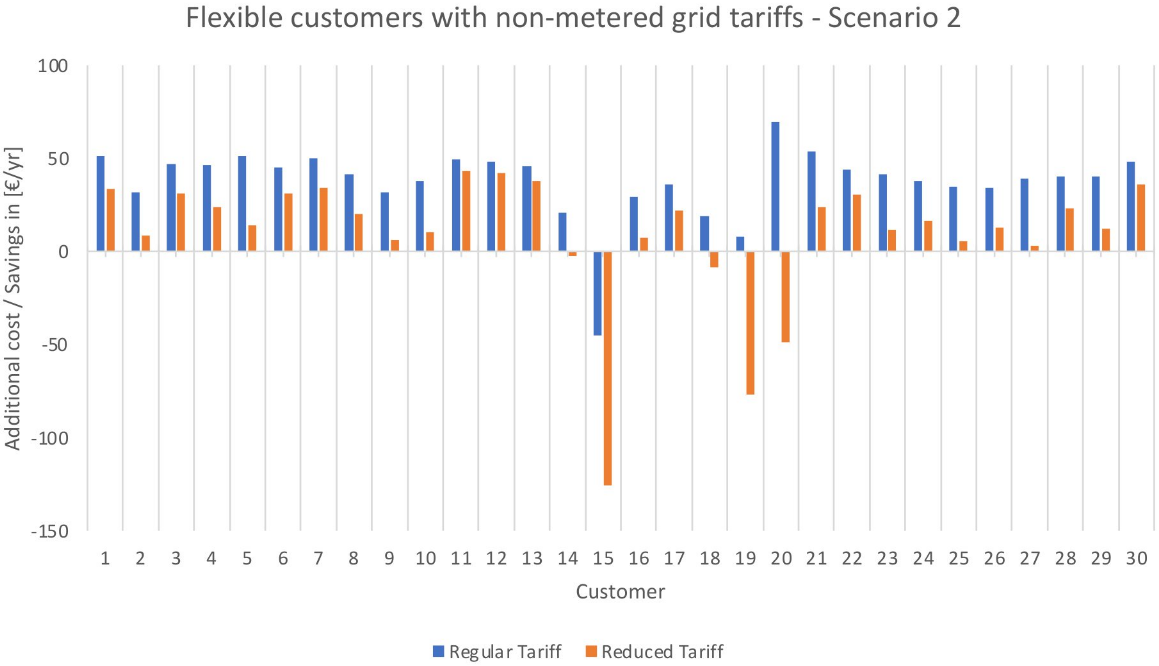


Figure 73: Additional Cost / Savings for flexible customers with non-metered grid tariffs in cost Scenario 2

Only for flexible customers (with metered and reduced grid tariffs) savings for almost all customers can be realized as shown in the following figures.

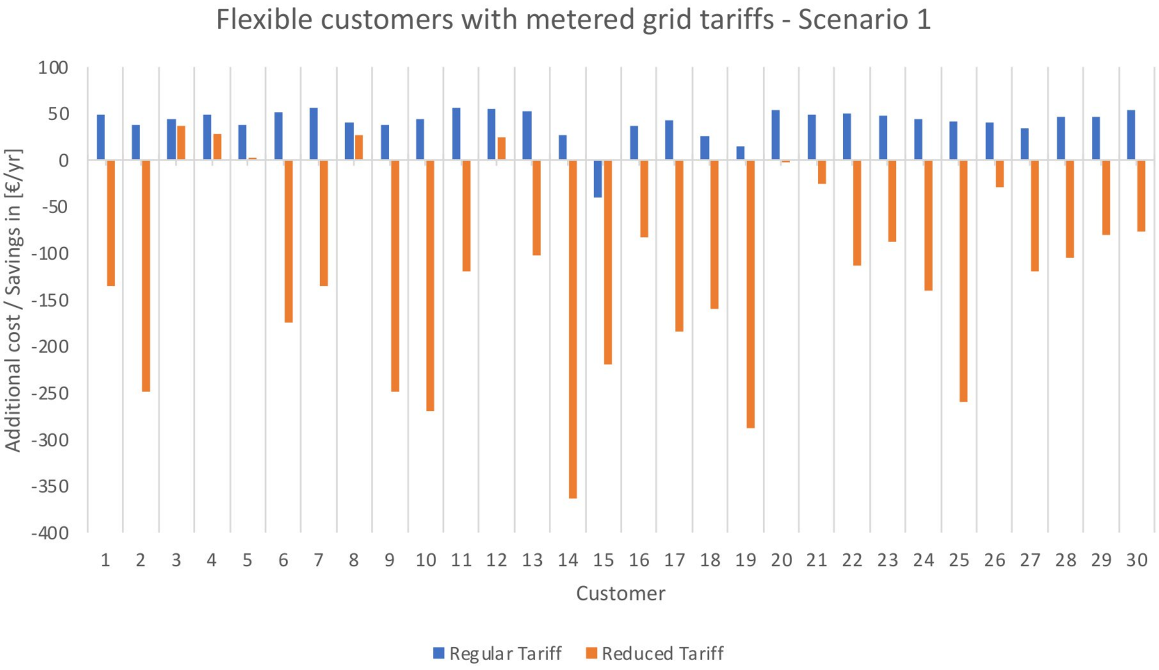


Figure 74: Additional Cost / Savings for flexible customers with metered grid tariffs in cost Scenario 1

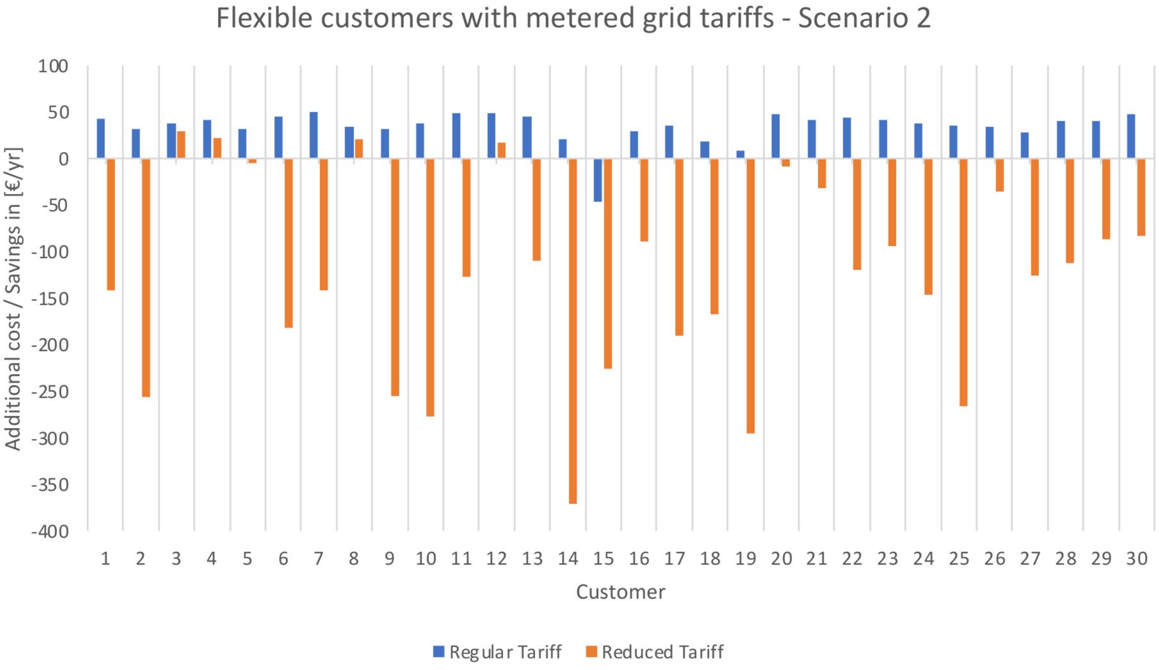


Figure 75: Additional Cost / Savings for flexible customers with metered grid tariffs in cost Scenario 2

3.2.2. Use Case 2 – Benefit /Cost ratios from community perspective

From the energy community perspective, the following table summarises the calculated cost benefit ratios for each Use Case setting as well as cost scenario. Furthermore, the additional cost (reflecting customers' the Willingness to Pay) as well as achievable savings per customer are summarised (assuming that revenues and equipment cost are equally shared between all community members).

Table 19: Summary of benefit/cost ratios and savings/additional cost results in the Austrian Use Case 2

Use Case setting			**Cost scenario 1**		**Cost scenario 2**	
		Community revenue in [€/yr]	Benefit/ Cost ratio	Additional cost / savings per customer in [€/yr]	Benefit/ Cost ratio	Additional cost / savings per customer in [€/yr]
Community (regular tariff)	flexible	730,67	0,36	44,20	0,39	37,74
	flexible metered	824,7	0,40	41,06	0,44	34,61
	inflexible	857,75	0,42	39,96	0,46	33,51
	inflexible metered	857,75	0,42	39,96	0,46	33,51
Community (reduced tariff)	flexible	1579,65	0,77	15,90	0,85	9,44
	flexible metered	5701,21	2,77	-121,49	3,06	-127,94
	inflexible	1740,76	0,85	10,53	0,93	4,07
	inflexible metered	2520,43	1,23	-15,46	1,35	-21,92

3.3. Irish demo site: Business Model related cost / benefit analysis

Irish pilot site has implemented FlexiDAO's community energy management software in the demo site. FlexiDAO solution does not need any additional equipment to be installed in the energy community or customer's premise. It receives the measurements of consumption and generation of the participants (customers engaged in local market) from their smart meters. This involves the national data hub storing smart meter readings to be connected to the FlexiDAO solution. This involves a once-off cost incurs for each country and does not change with the number energy communities or customers in the energy communities. It is taken into account in the CAPEX from the FlexiDAO side. In addition, the CAPEX includes the cost of DER assets which is solar PV facilities for Irish case.

For OPEX calculation, FlexiDAO needs the subscription fee, which covers the cost of service level agreement, maintenance, and infrastructure of community energy management software. Table 20 enumerates the cost of OPEX and CAPEX in terms of number of customers participating in local market facilitated by FlexiDAO solution.

Table 20: OPEX and CAPEX of FlexiDAO solution in each country

No of customers per country	OPEX					CAPEX (for project duration)
	Service Level Agreement Cost	Maintenance Costs	Infrastructure Cost	Total OPEX Cost (per month)	Total OPEX Costs (per year)	
100 (Sc. 1)	246 €	92 €	500 €	838 €	10,059 €	4500 €
1000 (Sc. 2)	271 €	184 €	500 €	955 €	11,457 €	4500 €
10000	283 €	252 €	500 €	1,035 €	12,431 €	4500 €
100000	296 €	321 €	500 €	1,317 €	15,805 €	4500 €

Table 20 indicates that the OPEX and CAPEX solution of FlexiDAO does not increases in proportion with the number of customers. It needs to be clearly mentioned that the number of customers shown in Table 20 refers to the total number of customers operating with FlexiDAO in a country, which can be segregated into a number of energy communities, e.g. Irish pilot being one of the EC. This suggests that for an individual EC to implement the FlexiDAO solution, becomes viable as the total number of customers implementing the solution increases in a country.

In this section, we will conduct the cost-benefit analysis of the Irish pilot for first two scenarios where the number of customers in Ireland has been assumed as 100 (scenario 1) and 1000 (scenario 2) respectively. For both of the scenarios, the number of customers and the DER asset capacity of the Irish pilot is same.

Table 21 Overview of implemented economic parameters in the Irish pilot

	Irish pilot		
20	Customers analysed		
20	DER asset capacity (kWp)- Solar PV		
20	DER asset lifetime in years		
30000€	BEYOND DER asset cost(CAPEX)		
75€	BEYOND DER asset cost /per customer/per year (CAPEX)		
10	FlexiDAO project duration in years		
45€	Scenario 1: CAPEX cost incurred by FlexiDAO (per customer)		
5€	Scenario 2: CAPEX cost incurred by FlexiDAO (per customer)		
101€	Scenario 1: OPEX cost of FlexiDAO (per customer)		
12€	Scenario 2: OPEX cost of FlexiDAO (per customer)		
	Cost for individual customers TOTEX		
	Scenario 1	221€	yr/customer
	Scenario 2	91€	yr/customer
	Cost for the community TOTEX		
	Scenario 1	4420€	yr
	Scenario 2	1820€	yr

Table 21 enumerates the parameters required for the calculation of OPEX and CAPEX for the EC in Irish pilot. The CAPEX includes costs for setting up the software (CAPEX cost passed on by FlexiDAO as part of roll-out of solution in Ireland) and DER assets (by EC itself) in the EC. OPEX cost is primarily from the side of FlexiDAO. The duration of the local market project has been considered 10 years. In Irish pilot, only solar PV has been considered as DER asset as a community owned solar PV facility of 20 kWp capacity with lifetime being 20 years. With deployment of different types or combination of DER assets along with range of capacity, the CAPEX cost and OPEX cost will change in both community-level and on customer level. The TOTEX (=CAPEX+OPEX) cost has been calculated for the whole community and for individual customers. As mentioned above, the two scenarios are based on the assumption that the number of customers in Ireland being 100 (scenario 1) and 1000 (scenario 2) respectively.

Table 22 Summary of benefit/cost ratios and additional cost/savings results for the energy community in Irish pilot

Use Case setting	**Community Perspective**			
	Community revenue in [€/yr]	Benefit/ Cost ratio	Additional cost/savings in [€/yr]	Additional cost/savings for each unit of DER capacity in [€/yr/kW]
Scenario 1	2432	0.55	-1988	-99.4
Scenario 2	2432	1.34	612	30.6

Table 22 presents the additional cost/savings analysis for the energy community for both of the scenarios. As the number of community members and the capacity of DER asset in the Irish pilot remains same for both scenarios, the community revenue remains same in both cases. The additional cost/ savings has changed drastically between scenarios due to the reduction of CAPEX and OPEX cost coming from FlexiDAO solution. This indicates the business case of Irish pilot will be viable from the community perspective as the FlexiDAO energy community management solution is rolled out massively in the country.

In addition to the community perspective, the additional cost/savings is also calculated for individual customer in the energy community. As the distribution of economic savings of the community among its members is done based on their local RES consumption rate and the TOTEX cost is equally distributed among EC members, this results in the additional cost/savings of the EC members to vary. Figure 76 shows the additional cost/savings for the energy community members. Scenario 2 shows better savings compared with scenario 1 which conforms with the energy community perspective. Even in scenario 2, more than half of the EC members does not achieve savings participating in the local market. This is related with local consumption rate. The matching algorithm working behind the FlexiDAO solution encourages

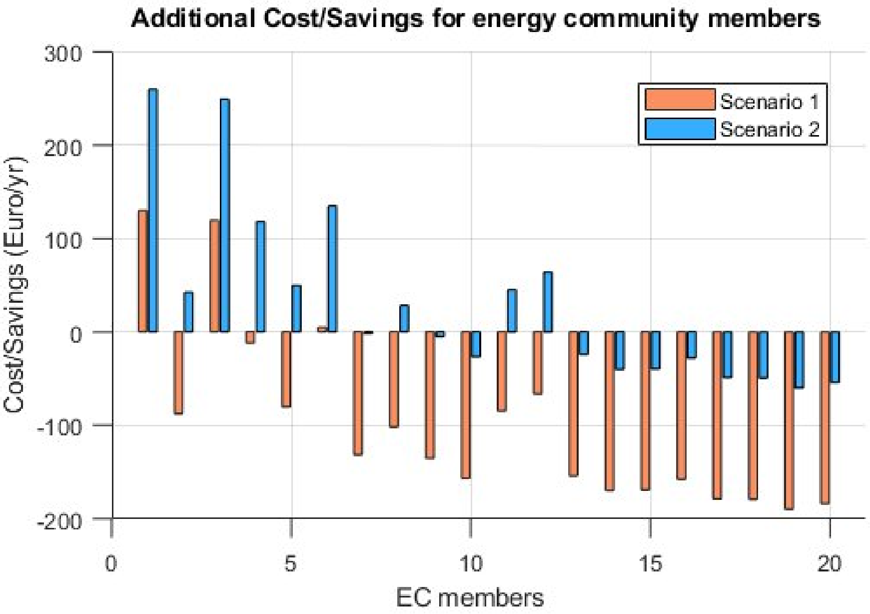


Figure 76 Additional cost/savings for energy community members in Irish pilot

real-time matching of generation and consumption and the EC members with demand coinciding more with generation in temporal dimension are benefitted higher than other peers. The role of demand response is crucial for enhancing local consumption rate, hence savings under studied economic savings model.

4. Conclusions and general recommendations

The simulation-based analyses in for the different Use Cases in Ireland, Norway and Austria show that Energy Communities and local peer-to-peer trading can provide cost reductions in the electricity bill for participants. The savings stem from the difference in the electricity consumption tariff of the buyer and the electricity feed-in tariff of the seller for locally consumed electricity. Hence, the savings correlate with the self-consumption of the locally produced electricity at the community level.

The trading within the energy community can be organized centrally with a top-down matching algorithm or in a decentralized way through auctions or peer-to-peer trading. The centralized option can find the minimum total cost for the community. However, it requires central management and might not always result in benefits for each individual community member. Hence, in this case it is important to investigate different options to distribute community benefits among the participants. Decentralized options do not ensure minimal total community cost. However, experiments in the Norwegian use case show that they can get relatively close to the centralized optimum. In this case, no central planning but a market organizer or platform is required.

Despite the operational benefits achieved by community trading, this concept also requires metering and ICT infrastructure. The business case analysis shows that considering the investment cost for these technologies can result in higher costs with Energy Communities than without. Hence, these investments constitute a major barrier for economic efficiency of business models for Energy Communities.

The investigation of Energy Communities with flexible technologies such as battery energy storages shows that the benefits achieved by local trading are higher for community members without flexible technologies and for Energy Communities with fewer flexibility options. This is because participants with flexible technologies already achieve a higher local consumption and, hence the demand for the additional flexibility option of local trading introduced with Energy communities is lower.

Since locally produced electricity is typically produced from RES, like PV, and Energy Communities increase the self-consumption of local production, the introduction of Energy Communities usually results in lower CO2 emissions. Furthermore, local usage of local production reliefs the electricity distribution grid which may benefit the grid operator. A reduced grid tariff for local trading can increase the economic efficiency of Energy Communities. Hence, it can be used to subsidize Energy Communities, and consequently, incentivize investments in distributed RES.

However, local electricity does not necessarily reduce peak loads on the local or regional distribution grid branch. A peak load pricing component in the grid tariff can provide incentives to achieve this. In combination with a grid tariff reduction for local trades this typically results in the lowest peak loads and highest benefits for the Energy community, if there are flexible technologies available that can be operated in a grid-friendly way.