Decision-Making in Renewable Energy Communities

from Joint Investment to Settlement Optimization Models

by

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The miracle is this -
the more we share, the more we have.

From Leonard Nimoy
(American actor, photographer, and author, 1931-2015)

Share your knowledge.
It is a way to achieve immortality.

From Dalaï Lama XIV
(Tibet spiritual leader, 1935-)

Summary

Since the early stages of the deployment of electric networks in the 1880s, electricity has become an essential resource, for all those who have access to it. Today, its usage goes from lighting spaces to driving cars whilst heating up our meals. The liberalised market paradigm, adopted in the 1990s, has clearly been successful in improving the system-level economic efficiency and security of supply by introduction of new generation capacity and the deployment of cross-border exchanges. Nevertheless, the efficiency of liberalised markets remains to be proven for residential consumers as the barriers to enter the market and the market power imbalance among stakeholders may not benefit them. In the current power systems framework, Renewable Energy Communities emerge as a way to foster awareness and give more control to end-users on their electricity bill. By gathering and mutualizing resources at the local level, consumers may reduce their dependence on their traditional electricity supplier. By participating to these communities, citizens have the opportunity to be actively involved in the energy transition by investing in renewable generation while retrieving economic, social and environmental advantages.

While renewable energy communities empower users, efficiently managing them and taking relevant decisions on both the short and long-terms remain challenges for non-specialists individuals who engage in the project. In this context, the main objective of this thesis is to provide optimisation tools that guide stakeholders (e.g., community members, community managers, system operators) involved in sharing activities in their decision-making. These tools cover the whole horizon of community operation, from long-term investment planning, for optimal sizing of Distributed Energy Resources and exchange pricing definition, to short-term coordinated demand-side scheduling, to mobilize flexibility and improve the efficiency of local exchanges. The performances of the models developed are always analysed from two perspectives: the collective benefits and the individual rewards that ensure member engagement. Furthermore, particular attention was paid, all along the thesis, to the understanding and faithful integration of the Walloon (Belgium) regulatory framework in the models. Finally, the last part of the thesis initiates reflections on the appropriate representation of human behaviors in decision-making tools that involve interactions between multiple actors.

Résumé

Depuis l'avènement de l'électricité dans les années 1880, celle-ci est devenue une ressource essentielle au quotidien. Aujourd'hui, on l'utilise pour s'éclairer, faire rouler les voitures, ou encore pour cuisiner. La libéralisation des marchés de l'électricité, à partir des années 1990, a permis d'améliorer l'efficacité économique et la sécurité d'approvisionnement de nos systèmes grâce à de nouvelles capacités de production et au déploiement d'échanges transfrontaliers. Néanmoins, les bienfaits de ces marchés pour les consommateurs résidentiels restent à prouver. Les conditions de participation à ces marchés et le déséquilibre de pouvoir entre les acteurs ne leur sont pas favorables. C'est dans ce système que les Communautés d'Energie Renouvelable apparaissent comme un moyen de sensibiliser les consommateurs et de leur donner plus de contrôle sur leur facture d'électricité. En se rassemblant et en mutualisant leurs ressources localement, ces consommateurs peuvent réduire leur dépendance vis-à-vis du fournisseur d'électricité. En participant à une communauté, les citoyens ont la possibilité de devenir des acteurs majeurs de la transition énergétique en investissant dans les énergies renouvelables tout en bénéficiant d'avantages économiques, sociaux et environnementaux.

Si les Communautés d'Energie Renouvelable visent à rendre les consommateurs plus autonomes, gérer efficacement ces entités et prendre les meilleurs décisions à court et à long terme restent des défis pour les personnes non spécialistes. Dans ce contexte, l'objectif principal de cette thèse est de fournir des outils d'optimisation qui guident les parties prenantes des communautés (ex., membres, gestionnaires) dans leur prise de décision. Ces outils les accompagnent tout au long de la vie des communautés, depuis la planification des investissements, c'est-à-dire, le dimensionnement optimal des ressources énergétiques et la définition des prix d'échange, jusqu'à la coordination des appareils flexibles, afin d'améliorer l'efficacité des échanges locaux. Les performances des modèles sont toujours analysées sous deux angles: les avantages collectifs et les récompenses individuelles qui garantissent l'engagement des membres. En outre, tout au long de la thèse, une attention particulière a été accordée à l'intégration fidèle du cadre réglementaire Wallon (Belgique) dans les modèles. Enfin, la dernière partie de la thèse engage une réflexion sur la représentation appropriée des comportements humains dans les outils d'aide à la décision qui impliquent des interactions entre plusieurs acteurs.

Contents

Acronyms

BSS	Battery Storage System.
CEC	Citizen Energy Community.
CM	Community Manager.
CDF	Cumulative Distribution Function.
DA	Day-Ahead.
DER	Distributed Energy Resource.
DSM	Demand-Side Management.
DSO	Distribution System Operator.
EC	Energy Community.
ESS	Energy Storage System.
EU	European Union.
EV	Electric Vehicle.
HP	Heat Pump.
HV	High Voltage.
KKT	Karush–Kuhn–Tucker.
KoR	Keys of Repartition.
KPI	Key Performance Indicator.
LP	Linear Programming.
LT	Long-Term.

LV Low Voltage.

MILP Mixed-Integer Linear Programming.

MV Medium Voltage.

NPV Net Present Value.

PDF Probability Distribution Function.

PV Photovoltaic.

REC Renewable Energy Community.

ROI Return On Investment.

SG Stackelberg Game.

SOC State-Of-Charge.

SOCP Second-Order Cone Programming.

TLCC Total Life-Cycle Cost.

TSO Transmission System Operator.

WB Water Boiler.

CHAPTER 1.

A Gentle Introduction to Electricity Economics: The end-users perspective

Electricity is an integral part of our daily lives. It has now been over a century since advances in electromagnetic theory brought electricity into our homes, and in all sectors of our society in general. Thanks to the ingenious work and discoveries of brilliant scientists such as Alessandro Volta, Nikola Tesla, James Maxwell, and others, many industrial processes have been automated and household chores were made easier. Building on the innovations of Michael Faraday (electromagnetic rotation) and Zénobe Gramme (first dynamo), electrical machines have notably enabled mass production while reducing human manual labour. Another breaktrough is the replacement of gas lighting by electrical ones which improved the work conditions of companies. The deployment of such electrical technologies has driven the Second Industrial Revolution (1870-1914) that provided important economic growth to industrial countries such as the United State, Germany or the Great Britain.

Electricity also entered our homes at the beginning of the 20th century. At that time incandescent light bulbs started to replace candles and gas lighting to light up the evening. This is the first step towards improving user comfort through electricity usage. Quickly, other household tasks benefited from advances in electrical technologies. The kitchen is the first room in the house to undergo major electrification. From the fridge to the oven, and including the dishwasher, electricity became soon an essential to feed oneself. Little by little, electrical appliances appeared everywhere in the house. Washing clothes, drying hair, entertaining oneself, a large part of daily activities were supported by inventions that are still used today.

At the European level, the share of electricity consumption in the total final energy consumption is about 22 % in 2023 as shown in Figure 1.1 [1]. Final energy represents the energy which reaches the final consumer's door [2]. Hence, electricity consumption exceeds the natural gas consumption (20 %) while oil

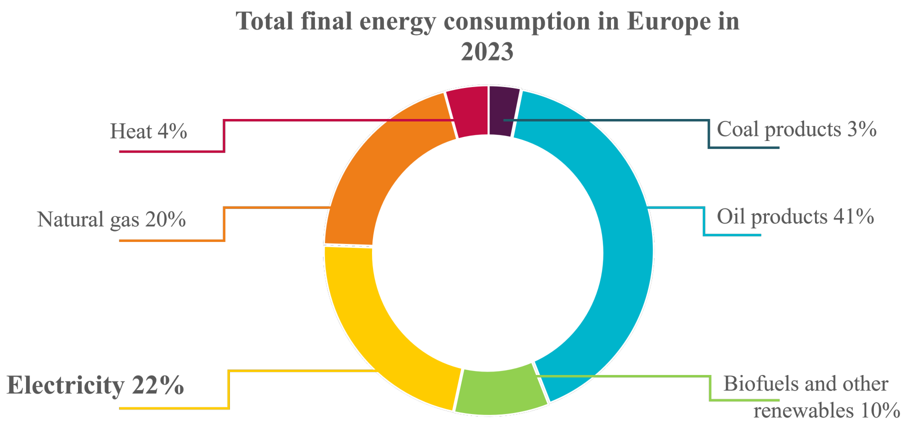


Figure 1.1.: Repartition of final energy consumption in Europe in 2023 by energy vector [3].

products represents the major portion of the overall consumption (41 %). Oil products are mainly used in the transportation sector and in some industries such as the petrochemical industry. In Belgium, electricity consumption was less than 60 TWh per year in 1990, but has increased to a stable level of around 80 TWh each year since the beginning of the 21st century. This evolution of the Belgian electricity consumption is depicted in Figure 1.2. This figure also presents the repartition of this electricity across the different sectors of activity. As stated at the beginning, industries were the first customers to benefit from the electrification of their processes. Today they represent almost half of the total volume consumed. On the other hand, households accounted for 21 % of this volume in 2024.

In recent years, guided by the challenges of the energy transition, additional end-uses has started to shift from their traditional fossil-fuel supply towards electricity. For instance, residential consumers started to rely on electricity to satisfy their heating and mobility demand. This leads to the current rapid deployment of electrical water heaters, heat pumps or electric vehicles in the households. The evolution of the future electricity demand is at the heart of the considerations of power systems operators. Indeed, this significant electrification of uses comes along with the increased penetration of electricity production units relying on renewable sources. These sources are known to be intermittent and not necessarily controllable [5]. In its last adequacy study, ELIA, the Belgian transmission system operator, presented their expectations for the next 10 years [6]. Their scenarios are reproduced in Figure 1.3 and indicates a potential increase of the global electricity consumption of around 50 % (+ 40 TWh).

Electricity is part of our daily lives and will certainly take on an increasingly

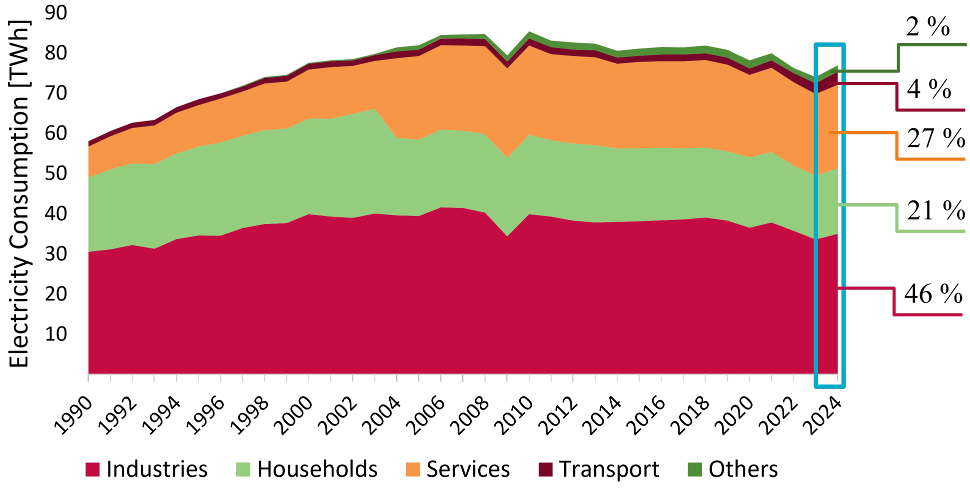


Figure 1.2.: Evolution of the electricity consumption in Belgium from 1990 to 2024, by sector [4].

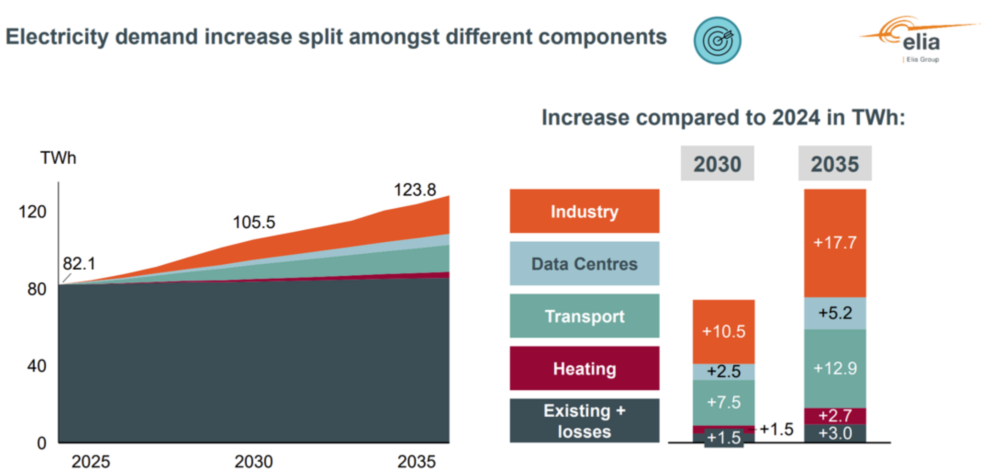


Figure 1.3.: Scenarios of future electricity demand in Belgium [6].

important role in the near future. Nevertheless, this service comes at a cost. In order to benefit from this electricity and thus power all the appliances essential for carrying out our daily tasks, each end-user must contract with an electricity supplier. This stakeholder is in charge of guaranteeing the supply of its customers' needs. In return, end-users pay their monthly electricity bills to this supplier.

In the following section, we will describe the main components of this electricity bill to better understand what does it involve to fed our homes with electricity.

1.1. What does an electricity bill consist of ?

The electricity supply chain has not always been what we know today. In the early 20th century, when electricity started to be produced and distributed in industrial, urban and finally rural areas, the organization was rather centralized. In most of the European countries, the whole supply chain was managed by a vertically (public) integrated utility. As represented in Figure 1.4, its activities encompassed the electricity generation, the operation of the transmission and distribution networks and the sale of electricity to the consumers. As such, the European electricity sector was a natural monopoly which ensured the reliability of the whole system but at high cost for the customers. Regarding the flows of electricity within the infrastructures, they were unidirectional. Large fossil-fuelled or nuclear units were injecting their production in the high voltage layers. This production then filtered through the various voltage levels until it reached consumers.

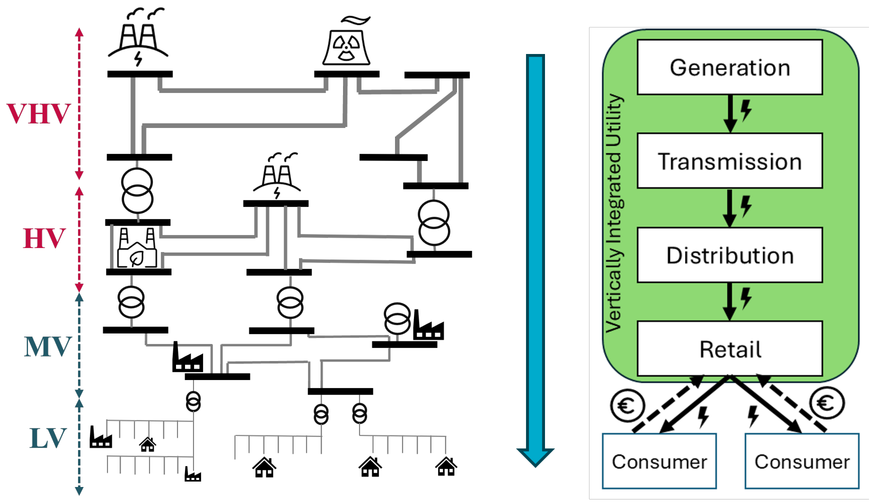


Figure 1.4.: Electricity supply chain (Right) and power systems infrastructures (Left) organisation.

In the 90's the European Union (EU), driven by its objectives of efficiency and security of supply for all its citizens, began a complete paradigm transition of the electricity and gas supply chains. To this end, they decided with the First Energy Package (1996) to open their monopolistic national electricity and gas markets to competition, introducing the liberalisation of energy markets. Since then other directives were issued for the in-depth overhaul of the system. Second Energy Package (2003) resulted in the diversification of energy suppliers whose are intermediate parties between the wholesale market and end-users for the provision of energy. In 2009, the adoption of the Third Energy Package imposed the unbundling of energy generation and distribution (i.e., separating physical from economic flows exchanges) and introduced the need for a coordinated European-scale of transmission operators, responsible of the infrastructures carrying energy over the countries from the generation sites to the distribution ones. This package also came with the establishment of independent market regulators also coordinated at the European level. Figure 1.5 depicts how the electricity supply chain evolved with the liberalisation of the market in Europe, highlighting the clear partition of physical and economic interactions between the various actors of the system. In addition, regarding the power flows circulation, this transition initiated the progressive decentralisation of production units which are now present at every level of the physical system (i.e., from High-Voltage (HV) to Low-Voltage (LV) networks). Even at the local level, with the major deployment of rooftop photovoltaic panels some end-users have become, both, consumers and producers depending on day time. For these customers, the word "prosumer" is often used.

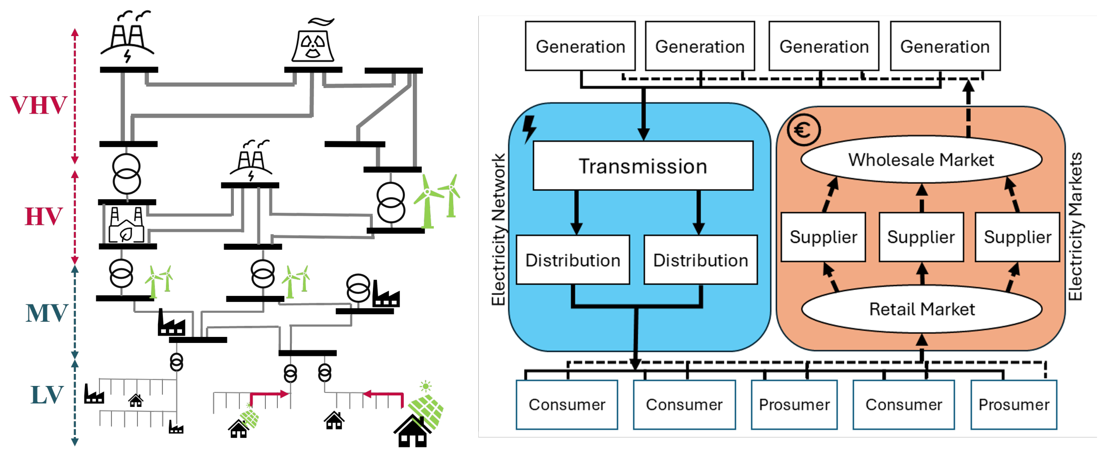


Figure 1.5.: Evolution of the electricity supply chain with the liberalisation.

With the energy market liberalisation responsibilities have been shared among different actors (e.g., retailers, system operators, etc.). When an electron is supplied to an end-user all the parties involved in the supply chain must be remunerated for their services. In today's electricity bills the different components of the electricity supply chain are all represented distinctly. For typical customers involved in no other activities than producing, consuming, and selling excess electricity on their own, their electricity bill is composed of three main components : the cost of electricity commodity, the cost for the usage of network infrastructures to convey electricity and taxes costs. These various costs components are due to different stakeholders of the power systems, even though the invoice is integrally paid to the supplier.

First, commodity costs are paid to the electricity supplier. To meet the needs of its customers, this actor is responsible for trading with electricity producers on the wholesale market. Some volumes may be contracted in advance (from day-ahead up to years ahead) for future delivery in the long-term markets. However, what truly define the commodity price are the day-ahead markets clearing prices. These are defined based on the available generation at the time of requested consumption and the costs associated with the different production sources. For example, when the renewable potential is significant, the day-ahead prices are lower. On the contrary, in case of renewables scarcity, fossil-fuelled plants are turned on and the day-ahead prices are higher as they request to cover the fuel costs to operate. In addition, electricity suppliers are also responsible to ensure at any instant, the balance between contracted production and consumption in their portfolio. For this reason, they are often called Balancing Responsible Parties (BRPs). If they fail in their task, they receive a penalty from the Transmission System Operator (TSO). At the end, all costs related to the supply of electricity, including market trades, imbalance penalties, and human resource costs, are passed to the customers. Electricity suppliers being profit maximiser, the commodity price necessarily includes a profit margin for the company.

With the introduction of smart metering devices that enable to monitor the power flows exchange in both directions, i.e., imports and exports, electricity supplier must also offer a price to buy electricity from their customers. With the growing penetration of distributed production units such as rooftop solar panels, many consumers became *prosumers*. Those actors do not always consume the whole electricity produced, and inject it in the network. The physical laws governing the flow of electricity imply that this electricity is consumed by another consumers in the network (assuming a perfect balance of the production and consumption in the system). The price offered by suppliers hence remunerate them for this injection. Nevertheless, these prices are generally insignificant with respect to the price paid when customers consume electricity [7].

The second cost component, relative to the network usage, is due to both transmission and distribution system operators (T/DSOs). Their activities consist in maintaining the network infrastructures to guarantee the reliability of the electricity provision. In addition, the flows of electricity within the grid naturally generate electricity transmission losses. These losses are not taken into account in the equilibrium of electricity suppliers, therefore it is the responsibility of operators to compensate for the losses by purchasing the equivalent volume in the day-ahead market. These costs are generally passed in the electricity bill using three tariffs: a volumetric tariff, a capacity tariff and a fixed tariff. The first one is charged on the volume of electricity consumed on the billing period. The second tariff does not apply to residential customers in Wallonia but it is the case in Flanders [8]. The capacity cost is based on the maximum power consumption on a given period (usually 12 months). Lastly, the fixed tariff accounts for the connection capacity cost, the associated metering and other operational costs.

On the contrary to electricity suppliers those stakeholders are regulated entities. It means that the prices charged to end-users are reasonably controlled and yearly profits made must be justified by future plans that would serve the quality and security of electricity supply. For example, to support the energy transition, the Walloon DSOs are allowed to get revenues to be invested in new network infrastructures [9].

The last component of the electricity constitutes in all taxes charged by public authorities to serve different purposes. They contribute to the budget for the public lighting, the subsidies for renewable energies and other energy related public plans.

In Wallonia, the repartition of these costs in the electricity bill is shown in Figure 1.6. The commodity costs represents the largest part of the bill (39 %), but it is still less than half of the overall costs. Ultimately, this commodity price is the one that exposes customers the most to volatile market conditions. Every good and bad periods regarding the electricity supply and the associated costs are reflected in this price. In the worst situations, it could drastically increase the cost of electricity for end-users, despite the competition offered by the liberalisation.

Since its introduction in the 90's, the market paradigm has clearly been successful in improving the system-level economic efficiency and security of supply thanks to the rise of new generation capacity and the deployment of cross-border exchanges. Nevertheless, the distribution of market power among the different actors in the energy system is still highly non-uniform. As electricity has become a primary and essential resource for European citizens their reduced elasticity (i.e., demand adaptation when price varies) makes us highly sensitive to price volatility and energy crisis as experienced the last couple of years [11]. During these crises, if market seemed to be the most efficient paradigm from a system (i.e., social welfare) standpoint, big disparities in individual perception of prices rise were observed as some

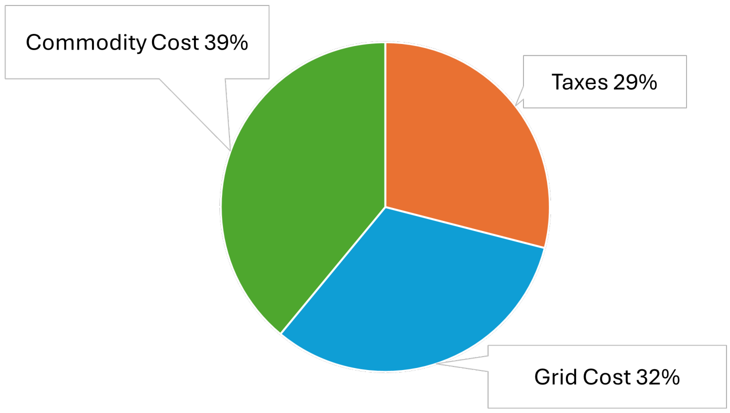


Figure 1.6.: Repartition of the electricity bill components in Wallonia [10].

producers were making extra profit while customers saw their bill steeply increasing.

If the publication of the Fourth Energy Package (2019), also called the Clean Energy Package, was mainly driven by the objective of reducing greenhouse gas emissions (i.e. one of the nine planetary boundaries) in order to be carbon neutral in 2050, it also promotes a new paradigm of energy exchanges that is energy sharing. Energy sharing is an opportunity for citizens to be actively involved in the energy transition at the local level as it fosters individual awareness on energy topics and investment in renewable energy production resources. Another underlying objective is to unlock demand-side flexibility in Low Voltage and Medium Voltage (MV) networks to improve local and systemic performances.

In the following section, the concept of energy sharing is further defined. In addition, the Energy Communities paradigm, that is a form of energy sharing activities and is the central piece of this thesis, is presented.

1.2. What is an Energy Community ?

In its Directive 2019/943 [12], the European Union defined the concept of energy sharing as the possibility to exchange electricity directly between end-users, i.e., consumers and prosumers. The Energy sharing paradigm can take various forms, the most common being the following, also depicted in Figure 1.7 :

- **Peer-to-peer trading** involves two specific end-users contracting with each other to directly exchange energy together. Usually, a prosumer having energy surplus (i.e., producing more than he consumes) sells it to a consumer who can benefit of it upon its needs. In more advanced exchange structures, a single individual may contract with several peers;

- **Collective self-consumption** is building-specific. In this framework end-users living/working in the same building share the production of the generation assets installed at this particular location. For example, photovoltaic panels may be installed on the roof of an apartment building and each resident could receive a portion of it;

- **Energy Communities (ECs)** consist in organized legal entities gathering consumers and prosumers connected to the public distribution network allowed to share energy together. The energy sharing in these communities is organized by a central actor, called community manager. Two types of communities can be distinguished : Citizen Energy Communities (CECs) and Renewable Energy Communities (RECs). Although the two concepts are similar, they differ in terms of rules of membership, admissible generation technologies, the geographic scope, and the allowed activities as summarized in Figure 1.8.

By participating to an Energy Sharing activity, end-users do no longer rely exclusively on the traditional wholesale/retail market structure. Doing so, they reduce their exposure to market prices volatility and can assert their generation and flexibility resources at a more convenient price.

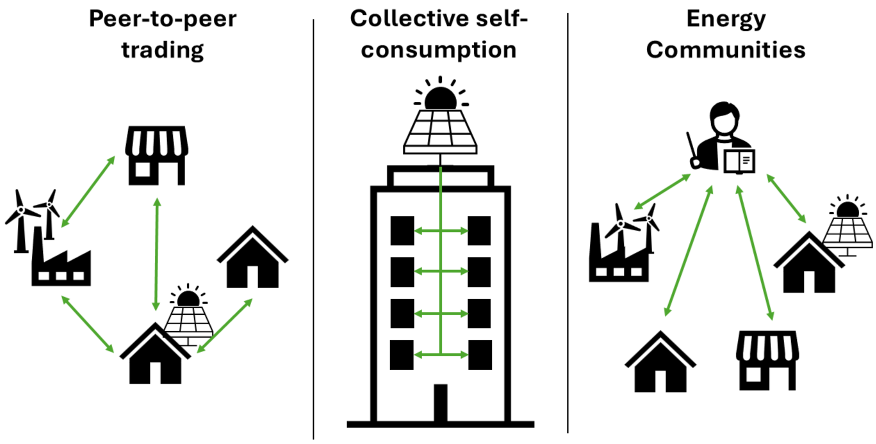


Figure 1.7.: Illustration of the three energy sharing frameworks.

As central pillar of this research project stands the Renewable Energy Community (REC) which can be more particularly defined as :

"A legal and autonomous entity which allows end-users to exchange any type of energy (e.g., electricity, heat, etc.) as long as it comes from renewable energy technologies. The energy exchanges take place within the public distribution network, all members and shareholders locations being constrained by a geographic

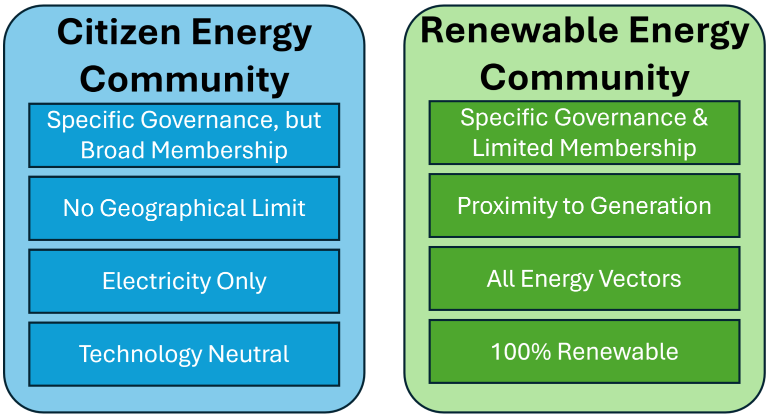


Figure 1.8.: Comparison between CECs and RECs.

limitation, defined by EU states independently. Participants can be natural persons, local authorities, municipalities and enterprises except those considered as "large enterprises". The participation to the REC entity is voluntary and open to all based on non-discriminatory criteria. Finally, the primary purpose of an REC is to provide environmental, economic or social community benefits rather than financial profits."

This legal entity is often represented by a community manager (i.e., a member or a shareholder of the REC) which is responsible for supervising the energy exchanges among members, applying the rules defined for their organisation and centralising the exchange of information between participants and with external actor interacting with the community such as the Distribution System Operator (DSO) or traditional retailers.

The major characteristic of Energy Communities, as encountered in France [13] or Wallonia (Belgium) [14], is the Energy Sharing principle. Among the community members, at each instant, we can distinguish the end-users with extra production that is injected in the local distribution network, and the ones who withdraw electricity from this same grid to supply their loads. As shown in Figure 1.9, the first group aggregates their injected electricity volume in a joint local electricity pool. Then, the community operator is responsible to distribute this electricity pool, following predefined rules, among the other members in need.

As stated in the previous paragraph, adopting the energy sharing principle requires to define allocation rules. Those rules are generally translated in a Key of Repartition (KoR) mechanism. These keys established the portion of the local electricity pool allocated to each participant. Various KoR mechanism can be imagined to meet the objectives of the community members (e.g., fairness, efficiency). Generally the rules are defined at the creation of the REC and applied on a long-run.

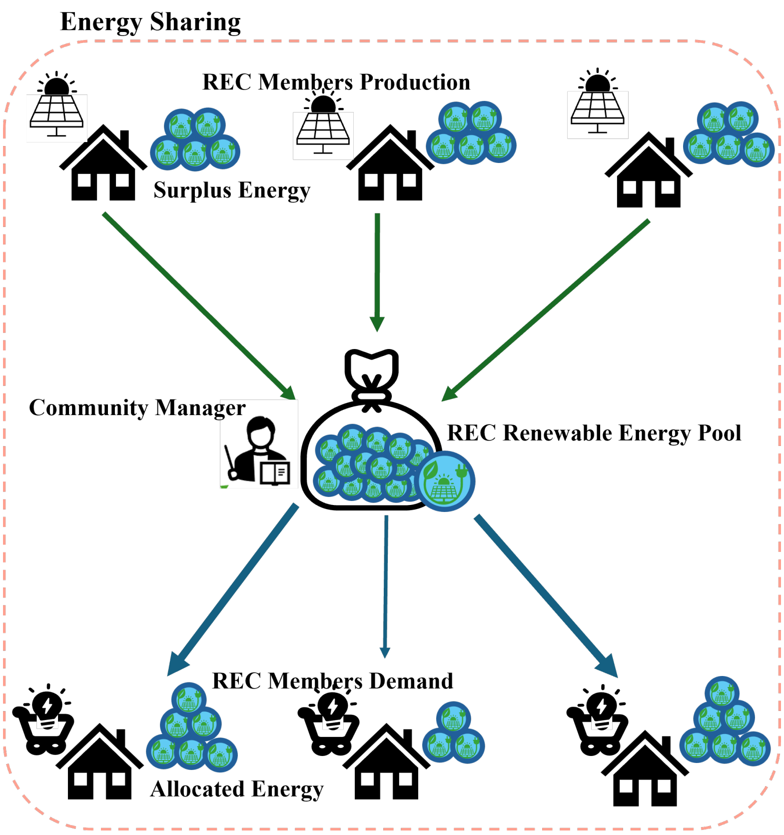


Figure 1.9.: Illustrative example of the Energy Sharing principle.

Based on this allocated volume members split their energy flows in two components : one exchanged within the REC, and traded at a price decided all together, and the other exchanged outside the REC, with their traditional retailer. Consequently, when participating to an energy community applying the energy surplus sharing principle, the bill structure slightly changes as the commodity cost (and revenues) components is divided in two parts. It is on the REC commodity part that participants may expect to make savings when taking part to local exchanges. The grid usage component may also be affected by the organisation of mutual exchanges between end-users if system operators, in accordance with local and national regulators, differentiate their tariffs for both types of energy flows, local and external as it is done in Bruxelles (Belgium) [15]. The traditional and REC members bill templates are provided in Figure 1.10.

If the computation of the annual electricity bill is performed using the true real-

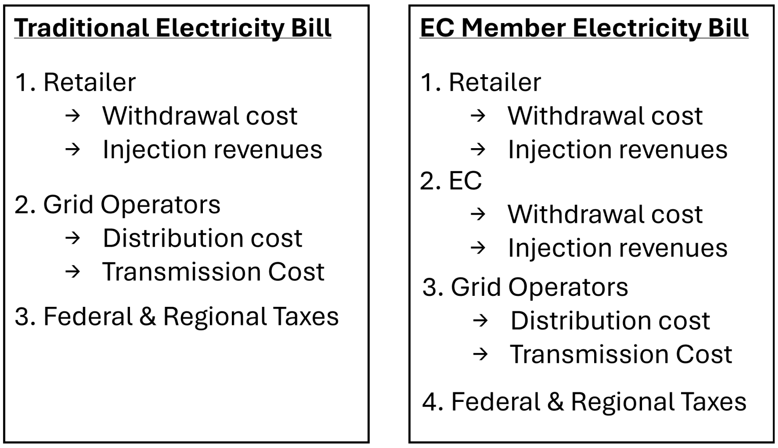


Figure 1.10.: Traditional and EC members electricity bill templates.

ization of energy flows metered in real-time, the latter can be guided by decisions taken ahead by REC members. Indeed, in terms of community organization, two time horizons can be distinguished as depicted in Figure 1.11 : the operational horizon and the investment horizon. The operational horizon encloses the day-to-day activities of the REC with the management of real-time energy flows (i.e., settlement phase) but also the potential scheduling of flexible resources. This scheduling is often carried out a day-ahead from the day of interest (i.e., day-ahead energy scheduling phase) and aims at optimally operate the existing community energy assets (storage, demand-side management, etc.) while mutualizing resources at the community level, in order to minimise the community objective. Readers should note that even if the local electricity exchanges directly affect the electricity bill of REC members, the objective is not necessarily so. It can also be environmental (e.g., minimising the environmental footprint), social (e.g., minimising welfare differences), or energy efficiency (e.g., maximising self-sufficiency). Operational management of resources is not the only concern of REC members as they can also be involved in coordinated investment in renewable Distributed Energy Resources (DERs). Usually investment decisions are taken at the creation of the entity, before the first energy exchanges take place.

In the end, citizens are interested in RECs since they can reap benefits of different natures through the local mutualisation of resources and the coordination in decision-making (e.g., investment in renewable energy technologies, flexible resources scheduling, bundled energy contract). Advantages brought by the local entity can be economic (energy bill reduction, partial immunity to wholesale market current price spikes, lower investment costs, etc.), ecological (renewable energy promotion, greenhouse gas emissions abatement, etc.) and social (enhanced social inclusion, energy poverty decrease, etc.). In addition, participants are involved in

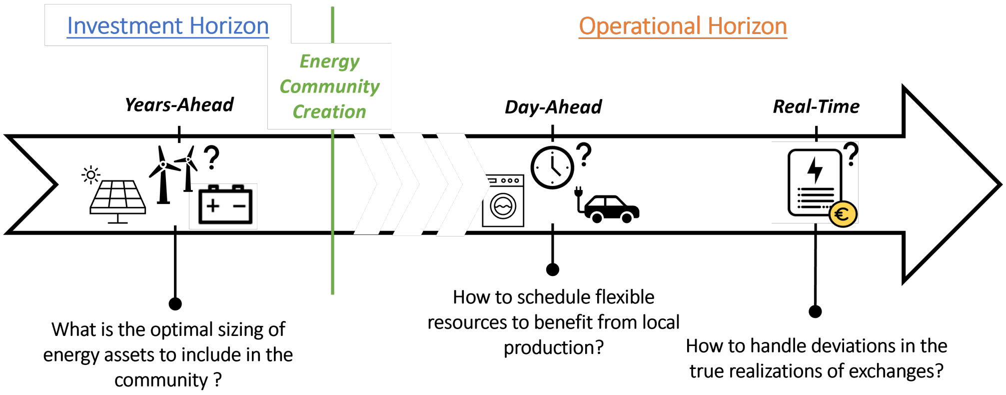


Figure 1.11.: Timeline of Energy Communities decision-making phases.

the decision-making of the community, giving them more responsibility and control over their energy purchased and/or sold.

1.3. Research Objectives

The concept of Renewable Energy Communities enables consumers to regain control over part of their electricity bill. However, not everyone is experienced enough to understand the complex organisation of power systems that is behind and to identify their lever of actions to efficiently organise energy exchanges with their neighbours. The main objective of this thesis is to provide optimisation tools to the stakeholders involved in RECs to support them in their decision-making. The idea is to accompany them all over the REC lifetime, from the investment to the settlement horizon. More specifically, this works has been divided in three parts, each addressing a general research question.

Q1: How can we explicitly induce REC members to provide flexibility ?

To efficiently coordinate the flexible resources of community participants and efficiently benefit of the local production, we first develop an innovative coordinated demand-side management optimisation problem for residential Renewable Energy Communities. The model integrates the various flexible electrical appliances that can be found in households such as dishwasher, clothes dryer, heat pumps or electric vehicles. PV production and battery storage systems are also considered in the model. We also integrate regulatory-compliant energy sharing rules in the model by adopting an innovative mathematical formulation of these rules. Several mechanisms are compared and their impact on the flexibility scheduling performances is quantified. Then, we propose new benefits sharing mechanisms which explicitly rewards flexible members. Hence, we distinguish the benefits arising from the natural complementarity of REC members' behaviors from the additional benefits created by the activation of flexibility. Two sharing frameworks are implemented to distribute the latter beenfits: a rule-based distribution of flexibility benefits and an optimisation-based remuneration of flexible behavior. Community members' discomfort relative to consumption shifts are also integrated in the decision-making process. Finally, we design an intuitive algorithm for the decentralized resolution of the coordinated demand-side management problem. This method allows to comply with data-privacy concerns without significantly affecting the collective performances.

Q2: What is the optimal investment strategy in energy resources to meet both REC and individual objectives ?

As long-term decisions must be taken cautiously, considering all options available, we develop a specific optimal long-term planning problem for Renewable Energy Communities. This problem aims to decide on the optimal investment strategy (i.e., ownership and location) and capacity of the most common DERs, usually found at the distribution level, that are rooftop PV panels, small-scale wind turbines and battery storage systems. At the same time, it aims to optimally reflect the investment costs in the definition of exchange prices inside the community. The definition of local electricity prices is guided by the objective to guarantee fair collective savings distribution among members. Starting from a two-steps sequential procedure, we propose a single-step formulation of the long-term problem to solve fairness issues that can be raised with the former approach. We also study the impact of different sharing rules on collective and individual economic performances by explicitly embedding their mathematical formulation in the long-term decision problem. Finally, we extend the long-term planning problem to EV fleet sizing. We aim to optimally quantify the number, types and locations of EVs and charging stations to be installed for satisfying the mobility demand of the targeted area (i.e., not restricted to the community perimeter) at minimum costs. The model integrates the EV fleet as a member of the community that takes part to the local energy sharing paradigm. The flexibility potential of EV charging patterns to support the network is also investigated by integrating peak power tariffs charged by the distribution system operator (DSO).

Q3: How to faithfully integrate human behaviors in REC decision-making models ?

When multiple actors interact in their decision-making procedure, they may need to anticipate the behaviors of other members to take their own decisions.

Modelling human-decisions strategies is not trivial. Hence, it induces human-related uncertainty when solving the optimisation problems designed for RECs. In this context, in this thesis we first analyse the impact of new EC members on long-term founding members benefits by designing an open-loop stochastic methodology. Founding members are the end-users present since the creation of the REC who were involved in the investment of DERs. In addition, the influence of sub-optimal DER sizes as well as EC founding and new members characteristics (i.e., consumers or prosumers) on the analysis outcomes are observed. Secondly, we propose a bilevel formulation of the coordinated flexibility problem including end-users behaviors facing limited observability. Limited observability refers to the fact that end-users lack perfect information on other actors scheduled actions. We particularly study the influences of members' consumption behaviors on internal price variations. Finally, we observe how limited observability of community members impacts their usage and electricity trading behavior.

1.4. Thesis Outline

This manuscript compiles and presents the various models developed along this thesis and the contributions that resulted from them. It is structured according to three main objectives.

The first part focusing on the operational horizon of RECs, entitled "*Fair and Optimal Coordination of Flexible Resources within Energy Communities*", is organised around three chapters:

- **Chapter 2** defines the concepts of Demand-Side Management and Flexibility Incentives which can be encountered in modern power systems. The transposition of these paradigms to the Energy Community framework is introduced. Existing works on the coordinated scheduling of flexible resources is then reviewed and the main contributions of this thesis relative to this topic are highlighted. Finally, a first baseline coordinated flexibility scheduling model is exposed.

- **Chapter 3** describes the key principles of the two main settlement methods adopted in Energy Communities, that are the distribution of the collective economic surplus or the distribution of the local energy surplus. Different mechanisms adopted in European member states regulation or by the scientific community are presented and compared. Then, to refine the accuracy of flexibility actions schedules and outcomes, the energy surplus settlement rules are embedded in the model. A reformulation of several energy sharing mechanisms applied in Wallonia (Belgium) under the form of mathematical constraints is developed. The performances of the augmented scheduling model are compared to those of the baseline model for a residential Renewable Energy Community.

- **Chapter 4** puts the focus on the repartition of the flexibility effort among the participants. It first defines new reward mechanisms for community members that explicitly account for their willingness to offer flexible resources and help reduce the collective electricity bill. Then, an algorithm enabling to secure the data-privacy of individuals when planning the flexible actions while limiting the impact on REC-scale performances is elaborated. In addition, in this chapter, a finer modelling of flexible appliances is adopted.

The second part addressing question relative to the investment strategies of RECs, entitled "*Optimal Sizing and Pricing of Distributed Energy Resources in Energy Communities*", consists of the following three chapters:

- **Chapter 5** explains the key principles relative to the long-term planning of energy resources. Investment strategies and internal tariffs structures specific to the Energy Communities framework are also introduced. A brief presentation of the state-of-the-art on the long-term planning of Distributed Energy Resources in Communities is exposed. Finally, the main contributions of this thesis regarding decision-making support on the investment horizon are highlighted.

- **Chapter 6** presents an REC-specific optimisation framework to define the best investment strategies in local renewable production and storage assets as well as the best internal tariff structure. First, the chapter exposes a two-steps procedure that guarantees the best collective performances. Then, the innovative reformulation of energy surplus mechanism from Chapter 3 is embedded in the sizing problem to improve the accuracy of individual energy repartition. Finally, a single-step approach is defined to further integrate the trade-off between individual incentives and collective performances.

- **Chapter 7** deviates from the purely electrical application of communities. Mobility is hence considered as another demand in the long-term optimisation problem and the set of long-term decision variables is extended to the sizing of a fleet of shared electric vehicles. Hence, a model is developed to assign mobility demands, represented by trips requests, to the different vehicles of the fleet. The long-term optimisation problem then aims to find the best fleet while accounting for the organisation of local community exchanges.

The third part on the integration of uncertain human behaviors, entitled "*Integration of Human Decisions Uncertainty in optimisation Models for Energy Communities*", presents the associated contributions as follows;

- **Chapter 8** starts by categorizing the different sources of uncertainty that can be encountered in the Energy Communities framework. Focusing on human decisions uncertainty, an overview of existing works addressing this concern is provided and the contributions brought by this thesis are presented. In this thesis, the question of human decision uncertainty is investigated from both a long-term and a short-term perspective. In the remainder of this chapter, a stochastic procedure to quantify the impact of the arrival of new members in the community is designed. The impact is observed on the performances of the long-term decisions (i.e., DERs sizing), focusing on the founding members perspective.

- **Chapter 9** introduces a new structure for local exchanges of electricity within Energy Communities. It adopts a hierarchical vision of the interactions between the community manager and the end-users. The community manager acts as a leader, responsible to supply the whole electrical load of participants. Further in the chapter, the relative confidence of participants regarding the price of electricity offered by the community manager is modelled. A robust end-users decision-making problem is formulated to protect community members against such uncertainty. This problem is embedded in the hierarchical structure and the approach is finally validated on a set of residential community members.

Finally, Chapter 10 summarizes the main contributions of this thesis and proposes guidance for future works on similar topics.

1.5. List of Publications

All the research contributions presented in this thesis resulted into scientific publications.

Part I is based on the following four papers:

- [16] J. Allard et al., "Technical impacts of the deployment of renewable energy communities on electricity distribution grids," in *Proceedings of the 27th International Conference & Exhibition on Electricity Distribution*, Rome: CIRED, 2023.

- [17] J. Allard, L. Sadoine, L. Liégeois, T. Brihaye, F. Vallée, and Z. De Grève, "Integration of energy sharing mechanisms in energy communities demand-side scheduling," *submitted to Energy Economics*, 2025.

- [18] J. Allard, F. Vallée, Z. De Grève, T. Stegen, M. Glavic, and B. Cornélusse, "Quantifying, activating and rewarding flexibility in renewable energy communities," in *2024 IEEE PES Innovative Smart Grid Technologies Europe*, 2024, pp. 1–5.

- [19] T. Stegen, J. Allard, N. Diffels, F. Vallée, M. Glavic, Z. De Grève, B. Cornélusse, "Explicit reward mechanisms for local flexibility in renewable energy communities," *accepted in Electric Power Systems Research*, 2026.

Part II is based on the following two papers; the first one being under preparation and the second is about to be submitted:

- [20] J. Allard, F. Vallée, Z. De Grève, "Fair and Optimal Investment Strategies for Renewable Energy Communities,", *working paper.*

- [21] J. Allard, N. Diffels, F. Vallée, B. Cornélusse, and Z. De Grève, "On the complementarity of shared electric mobility and renewable energy communities,", *preprint*, 2026.

Part III is based on the following two papers:

- [22] J. Allard, M. V. Gasca, R. Rigo-Mariani, F. Vallée, Z. De Grève, and V. Debusschere, "Impact of energy communities membership evolution on founding members' expected benefits," *IEEE Kiel PowerTech*, pp. 1–6, 2025.

- [23] J. Faraji, J. Allard, F. Vallée, and Z. De Grève, "On the limited observability of energy community members: An uncertainty-aware near-optimal bilevel programming approach," *Applied Energy*, vol. 381, pp. 125-177, 2025.

The following publication has been produced during the PhD period. However, as its content does not align with the main thematic of this thesis, it is not presented in this manuscript:

- [24] J. Allard, A. Arrigo, J. Bottieau, G. Bertrand, Z. De Grève, and F. Vallée, "A forecast-driven stochastic optimization method for proactive activation of manual reserves," *Electric Power Systems Research*, vol. 235, p. 110 804, 2024.

Part I.

Fair and Optimal Coordination of Flexible Resources within Energy Communities

The first part of this thesis focuses on the operational horizon of Energy Communities. In the timeline organization of ECs presented in Chapter 1, this horizon embeds the day-ahead scheduling period and the real-time settlement period, as depicted in Figure 1.12. On a daily basis, the scheduling period is used to define the plan of flexible resources usage, for the next day, in order to minimize the electricity bill of the community members. In real-time, the actual electricity flows are metered and the local renewable production is dispatched among participants. Based on this distribution of community volumes, individual electricity bills are computed and sent to end-users. In this Part I, innovative methods for the coordination of flexible resources in the EC are proposed and evaluated on residential case studies. These methods seek to find the best compromise between collective performances and fair repartition of the benefits between members.

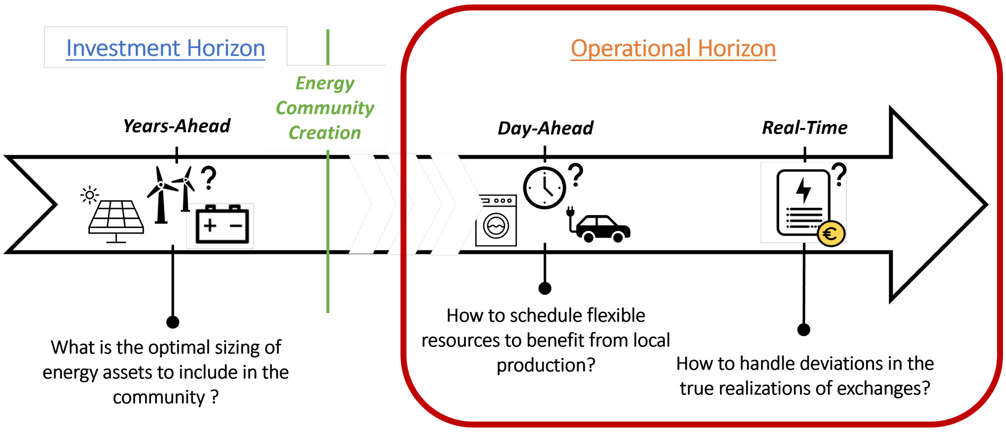


Figure 1.12.: Operational horizon of Energy Communities

This part of the thesis is organized as follows:

- **Chapter 2** defines the concepts of Demand-Side Management and Flexibility Incentives which can be encountered in modern power systems. The transposition of these paradigms to the Energy Community framework is introduced. Existing works on the coordinated scheduling of flexible resources are then reviewed and the main contributions of this thesis relative to this topic are highlighted. Finally, a first baseline coordinated flexibility scheduling model is exposed.

- **Chapter 3** describes the key principles of the two main settlement methods adopted in Energy Communities, that are the distribution of the collective economic surplus or the distribution of the local energy surplus. Different mechanisms adopted in European member states regulation or by the scientific community are presented and compared. Then, to refine the accuracy of flexibility actions schedules and outcomes, the energy surplus settlement rules are embedded in the model. A reformulation of several energy sharing mechanisms applied in Wallonia (Belgium) under the form of mathematical constraints is developed. The performances of the augmented scheduling model are compared to those of the baseline model for a residential Energy Community.

- **Chapter 4** puts the focus on the repartition of the flexibility effort among the participants. It first defines new reward mechanisms for community members that explicitly account for their willingness to offer flexible resources and help reduce the collective electricity bill. Then, an algorithm enabling to secure the data-privacy of individuals when planning the flexible actions while limiting the impact on REC-scale performances is elaborated. In addition, in this chapter, a finer modelling of flexible appliances is adopted.

CHAPTER 2.

Introduction to Coordinated Demand-Side Management in Energy Communities

Once multiple end-users, i.e., consumers and prosumers, have gathered and created the Renewable Energy Community (REC) entity, they may begin sharing energy from mutualized local renewable production resources. Community exchanges are often called "virtual exchanges" and are mainly of economic nature [25]. Indeed, electricity can be traded locally and reduce the volumes exchanged with the traditional electricity supplier even though physical power exchanges at the point of common coupling (PCC) are unchanged with respect to the situation prior the creation of the REC. As defined in the European regulation, the necessary condition to share energy within the REC is that some community members have excess of production, injected in the local distribution network, simultaneously to the electricity deficit, withdrawn from the grid, from other participants. In other words, volumes of energy exchanged within Energy Communities in the two directions, i.e., supplied and requested, must be continuously[1], and locally, balanced.

Naturally, due to the various consumption habits of end-users, energy sharing arises from the complementarity of their electrical net consumption profiles, which balances the net injection and net consumption periods of REC members. This complementarity provides effortless benefits to the community members [26]. However, as mentioned in Section 1.2, well-designed local exchange prices, are a major incentive to encourage consumers to unlock flexibility in their consumption habits. If those prices are competitive with retailer ones, it becomes economically attractive to adjust one's consumption, i.e., adopting flexibility measures, and balance the intermittent renewable production. Doing so, the volumes of electricity exchanged in the community are increased. At the domestic level, the interest for

[1] To align with the granularity of electricity markets, the continuous local balancing constraint is relaxed to match the granularity of smart metering data. Hence, in most of the European countries, the time resolution is 15 minutes [12].

such incentive mechanisms is growing alongside the massive penetration of new flexible electric devices such as electric vehicles, heat pumps or batteries [27], [28], [29].

From a more general perspective, traditionally, the sources of electricity such as coal, gas and nuclear power plants could be controlled to meet the power systems requirements. These dispatchable generation units adjusted their power output to match the demand and ensure the reliability of the system. With the definition of the climate objectives, the generation side started to move away from those fossil fuels-powered plants to integrate more and more renewable production sources in the system such as solar-, wind- or water-powered assets. Hence, the growing penetration of such weather-dependent inverter-based technologies has reduced the generation-side flexibility [30], [31], [32]. In response to this new challenge, the scientific community and system operators have identified the demand-side as another source of flexibility whose potential is steadily increasing with the electrification of the goods. The strategic adjustment of consumption patterns to align them with production is often referred to as "Demand-Side Management" (DSM). Generally speaking, DSM techniques continuously monitor the energy use and the flexible loads of consumers and control directly, i.e., automated control signals sent to devices, or indirectly, i.e., schedule of human-controlled actions, their demand profiles [33], [34]. Doing so, one can optimize the objective targeted by the DSM manager. In the literature, there exists a wide variety of Demand-Side Management methods, but most of them fall into one of the six main categories [35], [36] depicted in Figure 2.1:

a) Peak clipping, or shaving: Reduction of the maximum electricity demand, i.e., peak of the demand curve, by shutting down or diminishing the power usage of some loads during the critical period. It avoids the need for costly generation, that would increase the electricity prices, or the upgrade of infrastructures that can not withstand the peak demand;

b) Valley Filling: Increase of the electricity consumption during low demand, i.e., off-peak, periods by switching on additional loads or augmenting the usage of running loads. It helps to balance renewable energy resources, reducing the wasted volumes;

c) Load Shifting: Rescheduling of the electricity consumption from peak hours to off-peak hours while conserving the total consumption, i.e., integral of the demand curve. It combines the advantages of peak shaving and valley filling to improve the economic efficiency of consumption and the grid stability;

d) Flexible Load Shape: Reshaping of the electricity consumption pattern through peak shaving and valley filling while relaxing the total energy volume conservation constraint. It adds an additional degree of flexibility to the load shifting technique by allowing increase or reduction in the total demand to further improve the grid support;

e) Strategic Growth: Significant increase in the electricity consumption levels beyond the valley filling strategy. This DSM technique can be employed to boost investments in new electrified infrastructures to decarbonise the global energy system and take advantage of the available renewable sources.

f) Strategic Conservation, or energy-efficiency: Significant decrease in the electricity consumption levels beyond the peak clipping strategy. This DSM technique is opposite but complementary to the Strategic Growth principle as it promotes energy-efficient technologies to reduce the overall electricity demand without loss in utility[2].

For now, the most widely used load management technique is the load shifting method because it adapts the consumption profiles of flexible devices through temporal displacements of their usage while preserving the energy demand volume and the associated comfort level.

To engage end-users to adopt Demand-Side Management practices and unlock flexibility, they must receive appropriate incentive signals guaranteeing a fair remuneration commensurate with their efforts. In the current context, the provision of flexibility manifests in two forms: explicit and implicit flexibility. Explicit flexibility is the spontaneous provision of flexibility services by end-users to stakeholders in need, i.e., Flex Requesting Parties (FRPs), such as Transmission and Distribution System Operators (TSOs/DSOs) for adequacy and congestion management, or Balancing Responsible Parties (BRPs) for price arbitrage on the wholesale market. Often gathered and activated by third-party service providers, called "aggregators", this flexibility potential is used for different purposes, presented in Figure 2.2. The flexibility actions are categorized in 4 main services: network constraints management, power system adequacy, wholesale trading, and grid balancing. Depending on its levels of participation, the aggregator can wear the cap of Constraint Management Service Provider (CMSP), Capacity Service Provider (CSP), Balancing Responsible Party and/or Balancing Service Provider (BSP).

In contrast, implicit flexibility is the spontaneous response of consumers to financial incentives, e.g. price signals, as represented in Figure 2.3. These price signals may come from different Energy Service Companies (ESCo), such as the distribution system operators through Time-of-Use or maximum load grid tariffs, or the electrical suppliers via Time-of-Use or dynamic contracts. Time-of-Use contracts offer different prices for electricity usage depending on the period of

[2] Utility is used in economics as a measure of people's satisfaction from certain decisions or system states that they wish to maximise.

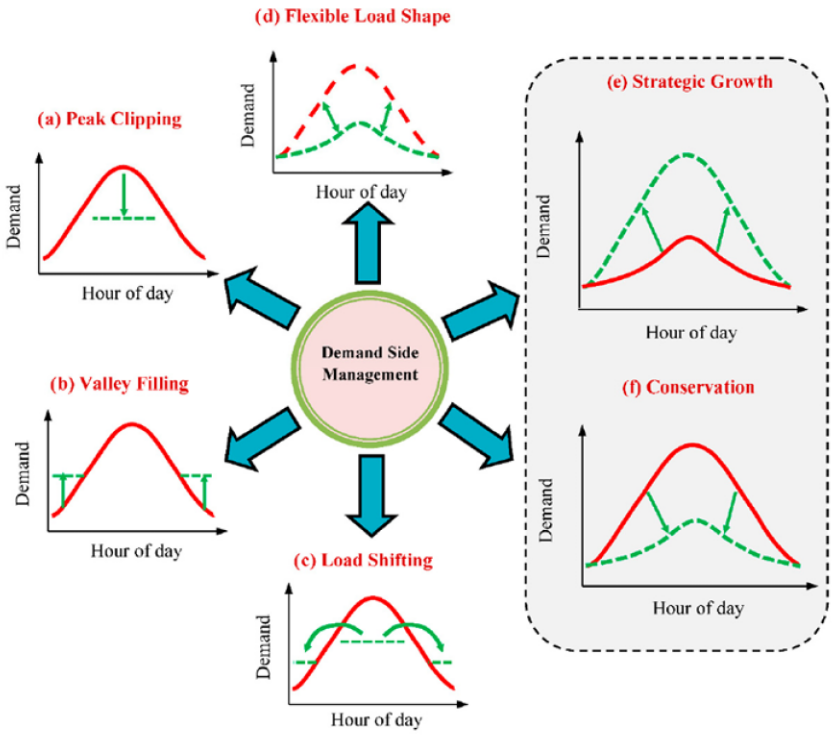


Figure 2.1.: Illustrative examples of the six main DSM techniques [36].

consumption. For example, in Wallonia a new Time-of-Use tariff structure has been introduced the 1st of January 2026 which defines peak periods from 7AM to 11AM and from 5PM to 10PM during which grid usage tariffs are more expensive than the rest of the day [37]. Meanwhile dynamic contracts directly confront consumers with the wholesale market prices volatility by offering prices which varies every quarter of an hour based on the day-ahead spot prices [38].

In this context, attractive local electricity prices set in Energy Communities can be seen as an implicit flexibility signal. Indeed, EC participants are encouraged to shift part of their consumption (e.g., delaying the start of the dishwasher, adapt EVs charging cycles, etc.) to reduce their electricity bills through advantageous electricity price offers. By proposing this flexibility incentive, the Energy Community does not only provide cost reduction benefits to the members but also environmental gains for the power system. Indeed, increasing the share of local electricity exchanged in the community improves the income perceived by the renewable production units owners and encourages investment in distributed renewable resources [40], [41]. Besides, from a consumption point of view, by responding to this signal and mobilising flexibility end-users, increase their green

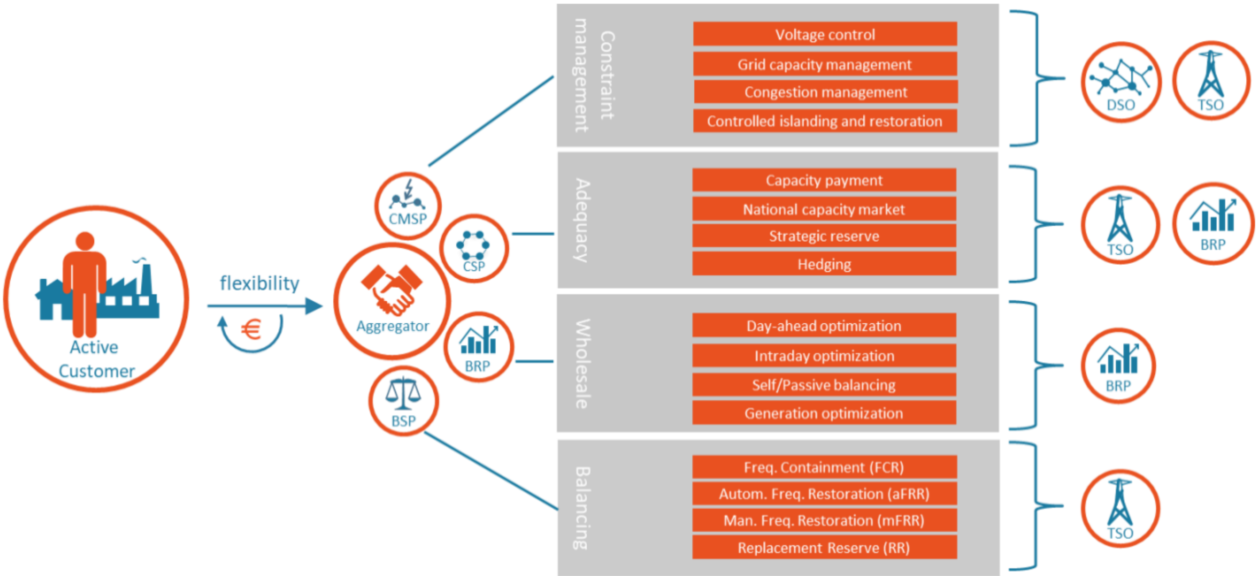


Figure 2.2.: Explicit demand-side flexibility services [39].

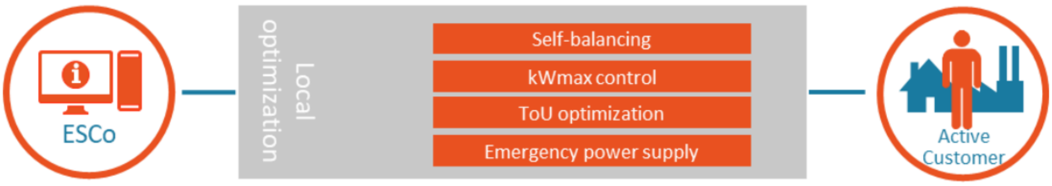


Figure 2.3.: Implicit demand-side flexibility services [39].

share of power supply, contributing to the decarbonization of power systems. In the meantime, they also reduce their exposure to price volatility from standard electricity suppliers and the associated risks in case of extreme events [42], [43].

Nevertheless, access to discounted local electricity within communities is limited. Produced by renewable distributed installations, the energy available in the EC pool is highly dependent on the weather conditions. Hence, to effectively balance the local production, flexible actions from members must be cautiously and harmoniously scheduled in order to ensure that nobody's efforts are wasted. Indeed, when individual consumers or prosumers react simultaneously to a common flexibility signal without considering actions from neighbouring actors there exist a risk that part of the flexibility levers activated would not be remunerated. In this situation, they would produce efforts to shift their consumption and align it with the local production, but if the combined efforts exceed the flexibility needs they may not be fully remunerated for their mobilisation. To cope with this challenge, joint scheduling of flexible resources belonging to different and independent end-users, often defined as Coordinated Demand-Side Management, is required.

More specifically, Coordinated DSM consists of sharing part or all information on the flexibility potential between end-users who gathered in a cooperative entity in order to provide a joint response to a common flexibility incentive signal [44]. To this extend, the organisation of electricity exchanges within Energy Communities offers an appropriate support for explicit flexibility aggregation and coordination. Indeed, the internal structure relying on a central coordination by a community manager can serve other objectives than the economic settlement of local energy exchanges. Indeed, it may also coordinate the potential flexible actions provided by community members [45]. This collective organization of flexible assets (e.g., heat pumps, battery storage, electric vehicles charging) may efficiently increase the usage of local electricity, but Energy Communities, as local aggregators, could extend their activities and provide flexibility services to external stakeholders (as presented in Figure 2.2).

2.1. State-of-the-Art on Coordinated Demand-Side Management

The coordination of demand-response (DR) programs for explicit flexibility services provision have raised interest in the Power Systems and Smart Grids communities over the last decade [46], [47], [48]. By gathering active consumers under the control of an aggregator, they can provide the benefits of Demand-Side Management, i.e., shifting consumption to reduce the need for expensive and polluting peaking power plants (e.g., gas units) and improve the reliability and efficiency of the power system, while optimising the trade-off between economic revenues and discomfort arising from the modification of individuals' consumption patterns [46], [49]. By pooling their flexible resources, consumers and prosumers increase their market power and enables their joint participation to day-ahead or balancing markets [50], [51]. In some cases, the aggregation of resources also involves Distributed Energy Resources (DERs). The whole set of demand and generation-side devices, forming the so called Virtual Power Plants (VPPs), further improves the range of flexibility services provision. Consequently, it generates additional benefits for the involved stakeholders and the system operators [52], [53], [54].

Understandably, with the emergence of the Energy Community paradigm, the scientific community has rapidly identified its potential to become a new local aggregation structure with objectives that combine economic benefits to participants with environmental, energy-efficiency and societal goals [55], [56], [57], [58]. If we pay particular attention to the coordination of energy communities constituted of residential households, [59] proposes a coordinated demand-side management algorithm which schedule shiftable loads (e.g., washing machines and dryers) in accordance to PV availability in REC-based microgrids. They evaluate the performances in terms of participants welfare and community resilience to main grid instabilities. Similarly [60] offers an heuristic approach for the optimisation of flexible energy resources following a price and source-based REC management program. The adopted strategy balances the local electricity generation by shifting flexible loads following personal preferences. Authors also distinguish the residential flexibility offers between time-flexible devices (e.g., dishwasher, washing machine) and fully-elastic devices (e.g., heat pumps). From another perspective, [61] presents a cooperative DSM scenario in a low-voltage network in which each end-users defines its own flexible appliances schedule. A decentralised optimisation problem is implemented in individual smart meters to keep privacy while the communication between EC participants ensure the collective optimality of the global convex problem. In addition, to cope with the European Regulation [12], authors integrates in the model that several retailers can supply electricity to different consumers of the same community.

Authors in [62] extended the focus from residential only communities by studying the complementarity of such actors with larger consumers such as industries, agricultural activities and tertiary services. If the complementarity of net consumption profiles naturally guarantees around 15-20% cost savings compared to the stand-alone position on their case study, they also showed that optimal coordinated demand-response to price incentives could further the collective bill by 50%. Additionally, a section of literature is increasingly interested in the provision of flexibility services by participation of ECs to different electricity markets (e.g., day-ahead, local flexibility markets, etc.) as reviewed in [63]. For example, regarding the impact of REC coordination on distribution network usage, in [64] authors perform an ex-post analysis to quantify the grid performances (e.g., over- and undervoltage, line loading, etc.) when the network hosts a REC jointly investing and operation photovoltaic and battery storage systems. They showed that to reduce the substation transformer loading, it requires a minimum penetration of community members in the overall grid. Nevertheless, when the share of such actors in the grid is not large enough to have significant impact at the substation, one can already observe reduction of the line loading between community participants and the rest of the grid. This result is supported by [65] which highlights the increased self-consumption and associated reverse power flows reduction at the substation thanks to the operation of community-owned battery storage systems. The identified outcomes from the provision include peak shaving and shifting, energy cost minimization, being a part of demand-side management, and self-sufficiency in islanded mode of operation. Load flexibilization within RECs was also considered in [58], [66]. The later revealed the potential for RECs to provide demand-side solutions by creating new business models.

To extract as much value as possible from the local community members flexibility potential, one must provide adequate implicit or explicit incentive/reward mechanisms. Indeed, the remuneration of flexible actions must be sufficient to cover users' (dis)comfort related to electrical consumption shifts. End-users' discomfort modelling issues were addressed in [66], [67]. The thermal end-user comfort was modeled in [66] by the deviation of the indoor temperature from the setpoints. In [67] this was considered through a discomfort index of the consumer. This index was defined by a linear penalization for shifted time slots compared to ideal end-user preference. The flexibility benefits sharing and incentive mechanisms were studied in [68]. Two sharing mechanisms were elaborated and both are based on the distribution of Token currency among REC members: according to member's ownership share of the generation power plant, regardless of their actual contribution to the shared energy of the REC and proportionally to their actual contribution to self-consumption of the energy generated within the EC. An incentive-based and a price-based mechanisms (based on the financial compensation of the participants) for optimisation-based demand response were considered in [69]. They calculated the load change for the incentive and the best times to realize the demand response while accounting for the comfort level.

Authors in [70] propose a sharing mechanism based on keys of repartition (KoRs), which define the shares of available local energy distributed to the different members, for the benefits linked to the frequency reserve provision by REC storage systems. The benefits for the local arbitrage are shared using another standard KoR. In [71] an innovative mathematical model is presented to price the local electricity and share the cost benefits in order to ensure the attractiveness of the community with respect to retailer dynamic tariffs. The model is based on the assumption that the energy community is managed by a community manager (CM) which is also the electricity supplier and organizes the internal market. Note that the latter assumption directly violates the REC members' right to freely choose their energy supplier. The paper propose a centralized post-process sharing method by introducing a two steps mechanism (local electricity pricing before cost benefits sharing) which guarantees benefits for flexible prosumers joining the REC. Reference [72] introduces an approach based on the concept of repartition keys, to determine the electricity exchanges between members of a centrally managed REC, that complies with current regulations on RECs. The economic benefits that the community members derive from their participation are distributed using allocation keys, which determine each member's share of the total local electricity ex-post. These allocation keys are optimally determined by the CM, who aims to minimize the total electricity bills of the REC members via an ex-post optimisation problem. In [73] ten different repartition keys for ex-post electricity allocation are investigated. The decoupled mechanism in the two-stage methodology, operational planning and bill settlement, allows to compare different energy management strategies and different Keys of Repartition used by the community. Hence after collective bill minimization, savings distribution among individuals are computed using the various KoRs. Paper [74] presents a model and methodology for optimizing local energy communities in the Spanish framework. Authors evaluate the integration of battery energy storage systems with different capacities and ownership options and two sharing strategies: static and variable ex-post coefficients. The method follows a meta-heuristic approach, and consists of trial and error until finding the best single solution.

If the use of repartition keys for sharing local energy was adopted by the Walloon regulator in Belgium [14], as well as in some European countries such as France [13] or Spain [75], the lack of clear and precise regulation from EU led to the emergence of various rules and processes for flexibility incentivization in the literature that diverge from the KoR scheme. For example, a large amount of work has been carried on the direct distribution of cost savings, i.e. economic surplus, among the community members to settle the individual electricity bills. Regarding the economic surplus approach, three main frameworks can be distinguished: an endogenous (or ex-ante) approach via non-cooperative games (Nash games [76] or Stackelberg games), coalition games [77] and ex-post allocation. Reference [76] formulates for instance day-ahead energy consumption scheduling games where each member of a residential community optimizes its own costs, and where the shared energy quantities are decision variables. The authors in [78] study energy sharing management in a microgrid, considering the profit of the microgrid DER operator and the prosumers' individual utility via a Stackelberg game. The operator maximizes its revenues and leads the game setting the internal prices, while the users optimize their energy profile. Nevertheless, methods based on game theory can quickly become complex and unsolvable if the problem does not satisfy strong convexity properties, differentiability conditions, etc., which are barely verified in practice. The introduction of binary variables to model time-shiftable appliances prevent authors to adopt such methods. In addition, the complexity of the solution algorithms can increase exponentially with the number of members [79]. On another hand, ex-post allocation permits to overcome this scalability issue, but it disregards the individual allocated volumes/costs in the optimal scheduling process of the first step. This may lead to solutions which are not equilibria of the underlying game and, as exemplified in [71], the economic benefits of each individual member are not necessarily guaranteed with the ex-post approach.

Finally, another area of research related to the coordination of flexible resources within energy communities focuses on preserving data-privacy of participants to ensure the willingness of consumers to be flexible within the REC framework [80], [81]. In this field, game-theoretical approaches which aim to find the equilibrium between participants optimizing their own objective were widely adopted [76], [77], [78], [82] meanwhile other techniques were developed to the decentralized resolution of collective optimisation problem. For instance, the work presented in [83] formulated the coordination of REC members for collective energy consumption and production as a mixed-integer linear problem with coupling constraints. The optimisation problem is decentralized and solved using a decomposition method. Alternating direction method of multipliers (ADMM), for distributed optimisation, has been considered in [84], [85]. In [84], the authors focus on a day-ahead operational planning, and privacy-preserving computation is achieved through ADMM, while [85] dealt with the improvement of REC self-consumption. In the latter work, the equilibrium between the community operator and community members was achieved when the grid imported power was below a predefined threshold, instead of focusing on users preferences satisfaction. A bilevel model is built in [86] to solve the scheduling problem considering renewable uncertainties and demand response with an emphasis on the flexibility potential of electric vehicles.

2.2. Research Objectives and Scientific Contributions

As stated in Chapter 1, the first research objective of this PhD thesis consists in proposing innovative models for the coordinated scheduling of flexible resources in residential Renewable Energy Communities. A key feature of these models is the integration of regulatory-compliant sharing mechanisms aiming for the fair remuneration of every participant. More specifically, the first part of this thesis addresses this research objective by proposing the following 4 contributions:

- **Developing an innovative coordinated demand-side management optimisation problem for Renewable Energy Communities.**
  The cooperative demand-side management model presented in [87] is improved by integrating time-shiftable appliances (e.g., dishwasher, clothes dryer, etc.) as flexible resources and by refining the modelling of power-shiftable loads (e.g., heat pumps, electric vehicles charging, etc.). PV production and battery storage systems are also considered in the model. Exact optimisation methods are used to solve the scheduling problem formulated as a Mixed-Integer Linear Programming (MILP) problem [88]. Binary decision variables are introduced in the problem to represent the starting of time-shiftable devices. If most of the literature focuses on economic, environmental and energy performances of community exchanges, the developed model has been used to quantify the impact of the integration of Renewable Energy Communities in the local

distribution network on its usage (e.g., line loading and losses, voltage plan, reverse power flows, etc.), in the following contribution:

[16] J. Allard et al., “Technical impacts of the deployment of renewable energy communities on electricity distribution grids,” in *Proceedings of the 27th International Conference & Exhibition on Electricity Distribution*, Rome: CIRED, 2023.

- **Integrating regulatory-compliant energy sharing rules in the model and assessing the impact on the flexibility scheduling performances.** Collective benefits arising from local exchanges must be adequately distributed to members to ensure their long-run participation. In the literature, a wide variety of collective value distribution methods have been proposed and compared. These sharing techniques rely either on the collective cost savings or energy surplus distribution among the community members to settle the individual electricity bills. In several EU member states, the national (or regional) regulation have adopted the latter energy surplus sharing principle. All the aforementioned works, whether they adopt game theoretical or a centralized two-stage approach, share a common limitation regarding the consideration of typical energy surplus sharing rules. Indeed, they do not embed an explicit formulation of these rules in the demand-side scheduling problem, which may lead to discrepancies between the expected bill (i.e., typically in day-ahead) and the actual bill computed after the realization of the power exchanges in real-time, even with DSM recommendations perfectly followed, and with a perfect knowledge of the model parameters (forecasts of local generation, baseload, etc.). To close the gap with existing works, we investigated in-depth the implication of selecting a specific sharing rules framework within energy communities. Through this study, we aimed at giving clear insights on the differences between the economic and energy surplus sharing approaches within communities, by computing and analyzing Key Performance Indicators (KPIs) such as the collective community objective, the self-consumption and self-sufficiency of the community, and the distribution of flexibility efforts and related individual cost savings. In addition, while considering demand-side scheduling, we investigate and quantify deviations that may occur between the expected performances in day-ahead and the observed ones in real-time within the energy surplus sharing framework. Indeed, if distribution keys mechanisms are not adequately embedded in the scheduling problem, individual and collective economic performances can vary between the two steps, even if there is no forecast error, and members perfectly follow consumption recommendations. Those deviations might raise skepticism from the participants regarding the efficient operation of the community. Finally, we propose, for the first time to the best of the authors' knowledge, to integrate the energy surplus sharing rules directly within the day-ahead optimal scheduling phase, anticipating that it may reduce deviations in the individual members objectives during the settlement phase in real-time.

[17] J. Allard, L. Sadoine, L. Liégeois, T. Brihaye, F. Vallée, and Z. De Grève, "Integration of energy sharing mechanisms in energy communities demand-side scheduling," *submitted to Energy Economics*, 2025.

- **Proposing new benefits sharing mechanisms explicitly rewarding flexible members.**
  Among the wide variety of energy or economic surplus sharing mechanisms defined in the literature or by energy regulators, some, by design, tend to indirectly encourage greater flexibility in the consumption habits [87]. Nevertheless, none of them explicitly integrates the flexibility potential of end-users nor the activated flexible volumes in the surplus distribution procedure. To cope with this limitation, in this thesis, innovative explicit reward mechanisms were proposed and compared in terms of individual reward of end-users flexibility mobilisation for local arbitrage. In this thesis what is meant by *local arbitrage* is the maximization of the consumption of cheap community electricity rather than buying from the retailer. To this end, we distinguish the benefits arising from the natural complementarity of REC members' behaviors from the additional benefits created by the activation of flexibility. In this work, two benefits sharing framework were implemented and compared: a rule-based distribution of flexibility benefits and an optimisation-based remuneration of flexible behavior. In the meantime, as recent works [66], [67] highlighted the importance to consider the end-users consumption preferences in coordinated demand-side management, community members' discomfort relative to consumption shifts were integrated in the decision-making process.

  [18] J. Allard, F. Vallée, Z. De Grève, T. Stegen, M. Glavic, and B. Cornélusse, "Quantifying, activating and rewarding flexibility in renewable energy communities," in *2024 IEEE PES Innovative Smart Grid Technologies Europe*, 2024, pp. 1–5.

- **Design an intuitive algorithm for the decentralized resolution of the coordinated demand-side management problem.**
  When it comes to the engagement of human-being in coordinated activities, data-privacy is a central question [89], [90]. Not all participants are necessarily willing to share personal information about their consumption habits, their devices ownership with the community operator. To address this concern, game-theoretical [76], [82] and ADMMs [84], [85] approaches emerged in the literature. Nevertheless, their computational complexity explodes when they

are applied to large problems. This notably reduces the attractiveness of the Shapley value as a cost-sharing mechanism proposed in several articles [91], [92]. The definition of the Shapley value, which arise from Cooperative Game Theory, necessitates to compute the different potential coalitions feasible with all the end-users of the community to compute the individual pay-off of members, i.e., their share of the collective sabings. Hence, building on the previous work [18], we propose an intuitive privacy-preserving approach to solve the decentralized problem that allows for embedding more precise (and potentially non-convex) models of flexible appliances. The objective was to quantify the gap in collective cost savings between centralized and decentralized coordination of end-user flexible resources for maximization of collective self-sufficiency and self-consumption in energy communities. To distribute the flexibility effort among members, we implemented and compared explicit rule-based flexibility activation mechanisms which take the form of regulatory-compliant Keys of Repartition in the decentralized coordination scheme. Finally, we extended the flexible resources models, embedding an equivalent storage formulation of four relevant flexible domestic appliances (batteries, electric vehicles, heat pumps, water boilers) in the operational load scheduling problem.

[19] T. Stegen, J. Allard, N. Diffels, F. Vallée, M. Glavic, Z. De Grève, B. Cornélusse, "Explicit reward mechanisms for local flexibility in renewable energy communities," *accepted in Electric Power Systems Research*, 2026.

The remainder of this chapter and the next two chapters are organized around these 4 research objectives and the associated contributions as follows: Section 2.3 presents the baseline coordinated demand-side management problem presented in [16][3] The full mathematical formulation of the MILP problem is derived and described. Then, in Chapter 3 the regulatory-compliant energy sharing mechanisms are introduced. The innovative formulation of these rules proposed in [17] to be integrated in the baseline flexibility scheduling problem is provided. The motivation for the integration of those rules in day-ahead scheduling are extensively discussed as well as the comparison with economic surplus sharing approaches. Finally, Chapter 4 continues on the discussion of flexibility incentivize sharing mechanisms by presenting the works done in [18] and [19]. These works adopt a consumer-centric vision on the activation of flexibility services and aim to provide explicit flexibility remuneration schemes to community members while preserving their data-privacy.

[3]For the sake of conciseness the results presented in this article are not presented in the following.

2.3. Coordinated Flexibility Scheduling Model

An important aspect of energy communities lays in the consumption decisions of the members. To maximize the added value of energy communities, one wants to extract the most value from local production through the mutualization of resources. To this end, the community members should align their consumption with the production periods which are weather-dependent when considering the most common renewable energy sources, wind and solar. In a domestic framework, community members may unlock some flexibility in their consumption profile [93], [94] especially through the optimal use of loads such as the electric vehicle charger, the electrical heating devices or the white goods (e.g., washing machine, dishwasher). In the Energy Community framework, available resources are limited. Therefore, to effectively balance the local production and ensure that nobody's efforts are wasted, adopting a coordinated demand-side management strategy to carefully schedule consumption behaviors shifts is key for energy communities.

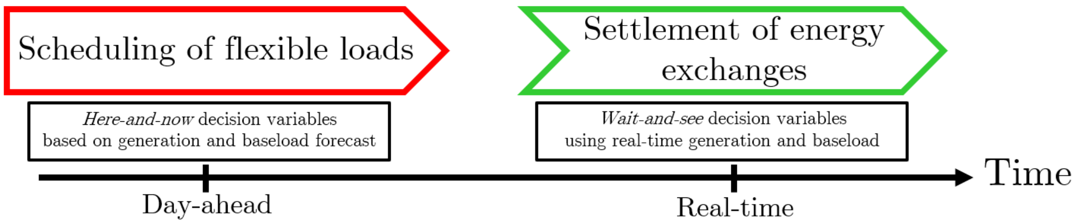


Figure 2.4.: Operational horizon of energy community demand-side management.

The general framework for these coordinated flexible responses often rely on a two-step procedure as represented in Figure 2.4. Indeed, as all flexible appliances are not necessarily automatically controlled, the first step usually consist in a preliminary scheduling of the community members flexible actions in order to meet the community objectives (e.g., maximizing self-consumption within the REC, minimizing the energy bill). This planning phase often occurs with a reasonable time-margin (e.g one day-ahead) with respect to the period of action to give users time to organize themselves without putting too much pressure on their other activities. Consequently, this ahead planning of flexible resources problem is subject to uncertainty regarding the real-time production of renewable assets and the baseline consumption of community members that must be forecasted. However, note that in the first part of this thesis we assume a perfect forecast of those baseload and production profiles and invite readers to refer to the following works [95], [96], [97].

The second step takes place in real-time (at the instant of consumption or time of delivery), and settles the energy exchanges within the energy community and outside of the community (e.g. with the retailer(s)). During this step the sharing rules are applied, based on the true realizations of the local generation and members consumption, enabling the computation of true economic exchanges and consequent electricity bills.

The implementation of this two-step process is described in Figure 2.5. The first step, i.e., a day-ahead optimal flexible resources scheduling problem from [16], forms the core of this section while the real-time settlement procedure is extensively discussed in Chapter 3.

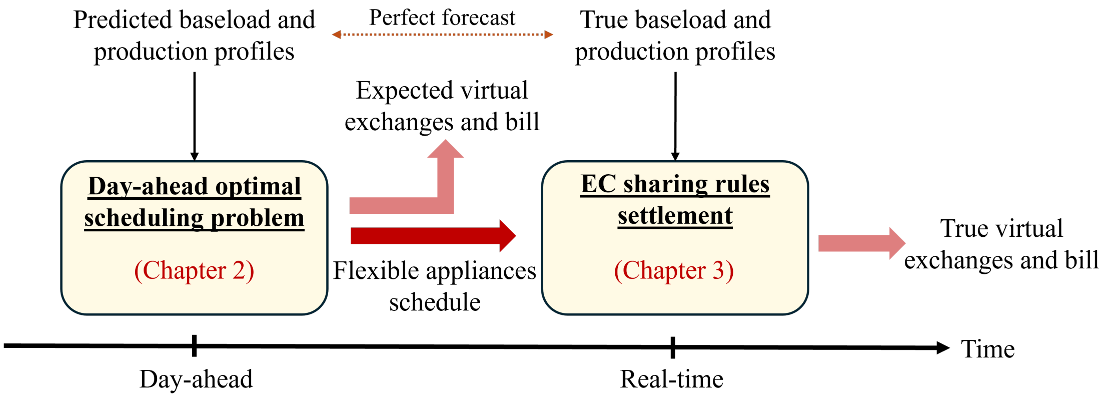


Figure 2.5.: Two-step REC operation process implemented in this thesis.

The proposed day-ahead coordinated optimal scheduling problem aims at minimizing the community objective function by acting on the REC members flexible appliances consumption and their storage systems (i.e., battery) usage. Let $\mathcal{N} = \{1, ..., N\}$ be the set of community members, and $\mathcal{T} = \{1, ..., T\}$ the set of optimisation intervals of duration Δt considered for a day. This day-ahead scheduling problem can then be written in general terms as follows:

$$\begin{aligned} \min_{\Omega} \quad & \text{Objective function (2.2)} \\ \text{s.t.} \quad & \text{Energy exchanges constraints (2.4)} - \text{(2.8)} \\ & \text{Economic exchanges constraints (2.9)} - \text{(2.12)} \\ & \text{Battery storage constraints (2.13)} - \text{(2.20)} \\ & \text{Flexible devices constraints (2.21)} - \text{(2.27)} \end{aligned} \tag{2.1}$$

in which $\Omega := \{l_{n,t}, l^+_{n,t}, l^-_{n,t}, i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t}, s_{n,t}, s^{ch}_{n,t}, s^{dch}_{n,t}, soc_{n,t}, x_{n,t}\}$ are the decision variables representing, respectively for each member $n \in \mathcal{N}$ at each time $t \in \mathcal{T}$, the net power flow metered at the point of common coupling (PCC), the power consumption at the PCC, the power injection at the PCC, the power imported/bought from the community, the power exported/sold to the community, the power imported/bought from a retailer, the power exported/sold to a retailer, the battery net power flow, the battery charging power, the battery discharging power, the battery state of charge, the flexible devices power consumption.

2.3.1. Objective Function

End-users may decide to constitute a REC to meet different objectives based on their preferences [98]. Some communities may aim to reduce the global electricity bill of the REC as much as possible (economic point of view), others would prefer to reduce its carbon footprint (ecological point of view) or reduce their dependency to the external system (resilient point of view) by efficiently use their production and consumption means to reach optimal collective self-consumption and/or self-sufficiency. RECs may also combine multiple goals [99].

In this thesis, the common economic objective function is considered. In this context, the community wants to minimize the global electricity bill denoted by $F(\Omega)$, i.e., aggregation of every member individual bills. As presented in the introductory chapter 1, the individual bills are composed of three mainparts: the commodity costs, the costs for the grid usage and the taxes. The objective function and the three bill components are expressed explicitly as follows:

$$F(\Omega) := B^{REC} = \sum_{n \in \mathcal{N}} B_n \tag{2.2}$$

$$\begin{aligned} B_n = & \underbrace{\sum_{t \in \mathcal{T}} \left[\lambda_{n,t}^{ret,imp} \, i_{n,t}^{ret} + \lambda_{t}^{com,imp} \, i_{n,t}^{com} - \lambda_{n,t}^{ret,exp} e_{n,t}^{ret} - \lambda_{t}^{com,exp} e_{n,t}^{com} \right] \Delta t}_{\text{Commodity Costs}} \\ & + \underbrace{\sum_{t \in \mathcal{T}} \left[\lambda_{n,t}^{ret,grid} \, i_{n,t}^{ret} + \lambda_{n,t}^{com,grid} \, i_{n,t}^{com} \right] \Delta t}_{\text{Grid Costs}} + \underbrace{\sum_{t \in \mathcal{T}} \lambda^{taxes} \, \left(i_{n,t}^{ret} + i_{n,t}^{com} \right) \Delta t}_{\text{Taxes}}, \forall n \in \mathcal{N}. \end{aligned} \tag{2.3}$$

where, B^{REC} is the daily global electricity bill of the REC, i.e., the sum of individual bills, B_n of REC. Commodity costs are composed of the economic exchanges between end-users and their retailer and between end-users and the community. Hence, $\lambda_{n,t}^{ret,imp}$ and $\lambda_{n,t}^{ret,exp}$ are the retailer import and export prices, respectively, charged or received for extra electricity volumes exchanged with the traditional supplier, outside of the REC. Similarly, $\lambda_{t}^{com,imp}$ and $\lambda_{t}^{com,exp}$ are the local import and export prices for electricity exchanged within the REC. Note that retailer prices have a n subscript as each member is free to contract with any supplier as imposed by the European liberalized market rules. However, for the local energy imports/exports it is assumed that there is a consensus on their unique values agreed by all members. These community prices are generally more advantageous than retailer prices to incentivize participation and flexible behaviours. Furthermore, local import and export prices difference allows to account for the remuneration of the community manager and for covering the costs associated with the operation

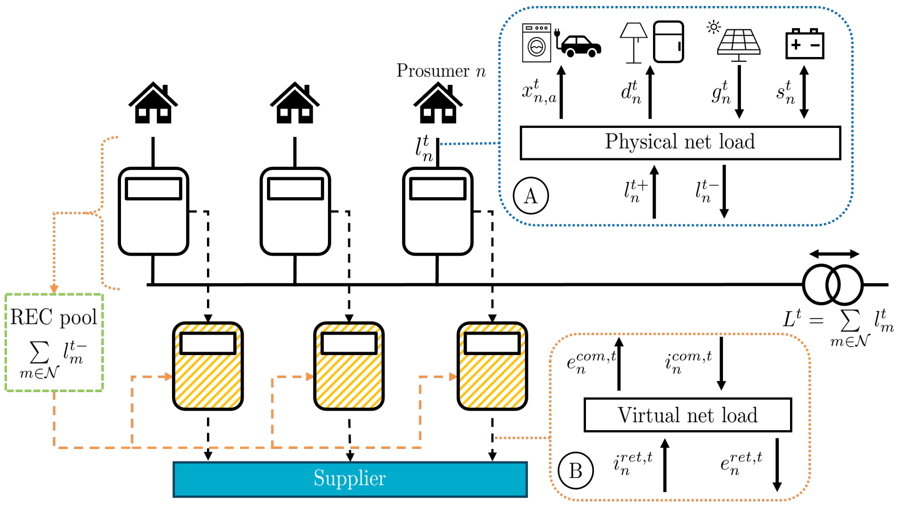


Figure 2.6.: Domestic Renewable Energy Community model [16]

of the communities. Regarding grid costs charged by system operators for the usage of network infrastructures, only volumetric costs are considered in the current model. In this perspective, $\lambda^{ret,grid}_{n,t}$ and $\lambda^{com,grid}_{n,t}$ are the grid usage tariffs for the complementary electricity volume bought to the retailer and the local electricity volume consumed from the REC, respectively. Depending on the regional/national regulation, those two tariffs may not be the same. For example, in Brussels a 50% discount is applied on the local electricity volumes grid tariff [15]. In addition, end-users may adopt different tariff structures depending on their electricity usage, e.g., flat or Time-of-Use tariffs. Finally, all the national and regional taxes relative to the consumption of electricity are represented by an equivalent price λ_{taxes}. All those volumetric prices are expressed in €/kWh. This requires to multiply the power quantities, $i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t}$ assumed constant over an optimisation interval, by the period duration Δt.

2.3.2. Constraints

In a domestic framework, different devices may compose the electrical facilities of a community member, as represented in Figure 2.6. Each household can be equipped with distributed generation units (e.g., PV panels), a storage system (e.g., batteries), non-flexible loads (e.g., lamp, TV) and flexible loads (e.g., electric vehicles, white goods). The aggregation of electricity flows from all the member's devices constitute their physical net load, $l_{n,t}$. This net power flow metered at the PCC based on the flow direction is considered as electricity net consumption (or offtake), $l^+_{n,t}$, or injection, $l^-_{n,t}$.

$$l_{n,t} = b_{n,t} + x_{n,t} + s_{n,t} - g_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{2.4}$$

$$
\begin{aligned}
& l_{n,t} = l^{+}_{n,t} - l^{-}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.5)\\
& 0 \leq l^{+}_{n,t} \leq M \cdot l^{sign}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.6)\\
& 0 \leq l^{-}_{n,t} \leq M \cdot (1 - l^{sign}_{n,t}), && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.7)\\
& l^{sign}_{n,t} \in \{0, 1\}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. && (2.8)
\end{aligned}
$$

Equation (2.4) represents the REC members balancing constraint which expresses the net power flow of each individual as the sum of its fixed baseload/non-flexible power consumption, $b \in \mathbb{R}_{+}^{N \times T}$, its flexible devices power consumption, $x_{n,t}$, its battery power exchanges, $s_{n,t}$, minus its PV power generation, $g \in \mathbb{R}_{+}^{N \times T}$ which is defined by the installed PV capacity and the solar irradiance profile. The physical net load is decomposed into a net consumption (i.e., $l_{n,t} \geq 0$) and an injection (i.e., $l_{n,t} \leq 0$) profiles through (2.5). During each period an individual can only import/consume or export/inject power in the distribution network. This mutually exclusive constraint can be expressed, for each time period and each REC member, as $l^{+}_{n,t} \cdot l^{-}_{n,t} = 0$. However this constraint is non-linear and is therefore reformulated using the state-of-the-art big-M method [100] for linearization by introducing a binary variable representing the direction of the metered net power flow, $l^{sign}_{n,t}$, and an arbitrary big constant value, M, (e.g., point of common coupling's connection capacity) as in (2.6)-(2.8).

$$
\begin{aligned}
& l^{+}_{n,t} = i^{com}_{n,t} + i^{ret}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.9)\\
& l^{-}_{n,t} = e^{com}_{n,t} + e^{ret}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.10)\\
& \sum_{n \in \mathcal{N}} i^{com}_{n,t} = \sum_{n \in \mathcal{N}} e^{com}_{n,t}, && \forall t \in \mathcal{T}, && (2.11)\\
& i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t} \in \mathbb{R}_{+}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. && (2.12)
\end{aligned}
$$

This net physical power flow metered at the point of common coupling is then decomposed in two virtual power flows representing the volumes traded within the community and with the traditional retailer. During periods of net consumption, the REC members power supply can be bought within the REC, $i^{com}_{n,t}$, or to the retailer, $i^{ret}_{n,t}$. Similarly, during periods of injection, the power can be sold to the REC, $e^{com}_{n,t}$, or to the retailer, $e^{ret}_{n,t}$. This disaggregation of physical power flow into virtual (i.e., economic) ones is represented by (2.9) and (2.10). Additionally, as stated in the introduction of this chapter, to be locally traded power within the REC must be continuously balanced, i.e., in each time period. This regulatory constraint is imposed in the problem via (2.11).

$$
\begin{aligned}
& s_{n,t} = s^{ch}_{n,t} - s^{dis}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.13)\\
& -P^{st,max}_{n} \leq s_{n,t} \leq P^{st,max}_{n}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (2.14)\\
& soc_{n,1} = R^{st}_{n} SOC^{st,max}_{n} + \left(\eta^{st} s^{ch}_{n,1} - s^{dis}_{n,1}/\eta_{st}\right) \Delta t, && \forall n \in \mathcal{N}, && (2.15)
\end{aligned}
$$

$$soc_{n,t} = soc_{n,t-1} + \left(\eta^{st} s^{ch}_{n,t} - s^{dis}_{n,t}/\eta_{st}\right) \Delta t, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \setminus \{1\}, \quad (2.16)$$
$$soc_{n,T} = R^{st}_n SOC^{st,max}_n, \qquad \forall n \in \mathcal{N}, \quad (2.17)$$
$$0 \leq soc_{n,t} \leq SOC^{st,max}_n, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \quad (2.18)$$

In a distributed energy generation framework, battery storage systems can be used to store the renewable production surplus and use it to supply loads later in the day. Equation (2.13) differentiates the charging and discharging power flows of the battery which are limited by (2.14) to the maximum battery power exchange, $P^{Max}_{st,n}$. The battery state-of-charge evolution follows equation (2.16) considering the battery efficiency, η_{st}, and is limited to the battery capacity, $SOC^{Max}_{st,n}$ via (2.18). The initial and final state of charge are fixed in (2.15)-(2.17) to a fixed share, $R_{st,n}$ of the battery capacity.

$$s_{n,t} \leq g_{n,t} + i^{com}_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (2.19)$$
$$- s_{n,t} \leq b_{n,t} + x_{n,t} + e^{com}_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \quad (2.20)$$

More specific to the community framework, two additional constraints for the battery storage operation are considered to ensure that electricity flowing through it is green and local. First, (2.19) ensures that power fed into the battery comes either from the local electricity pool, $i^{com}_{n,t}$ and/or from behind-the-meter production means, $g_{n,t}$. In the other direction, (2.20) makes sure the electricity discharged is used for self-consumption, $b_{n,t} + x_{n,t}$ or to supply local REC loads, $e^{com}_{n,t}$.

Among the different devices constituting the net load of a REC member $n \in \mathcal{N}$, flexible devices ($a \in \mathcal{A}_n$) are loads whose power consumption, $x_{n,t}$, can be shifted either in time (e.g., delaying the starting of a dishwasher cycle) and/or in power (e.g., adjusting the power level of the electric vehicle charging station). In this work, we distinguish two categories of flexible devices : time-shiftable devices such as white goods (e.g., dishwasher, washing machine), and power-shiftable devices such as electric vehicles charging stations and thermal loads (e.g., water heater, heat pump). Every flexible device is associated to a temporal flexibility window $\delta_a \in \{0, 1\}^T$, specified by the owner, during which it can be operated, a value of 1 means that member $n \in \mathcal{N}$ agrees to run the appliance a at time t.

Power-shiftable devices ($ps \in \mathcal{PS}_n \subset \mathcal{A}_n$) are considered as loads with a fixed energy consumption during the temporal flexibility window but whose power consumption can be adjusted throughout its operation as represented in Figure 2.7.

$$\sum_{t \in \mathcal{T}} \delta_{ps,t} x_{ps,t} \Delta t = D_{ps}, \qquad \forall n \in \mathcal{N}, \forall ps \in \mathcal{PS}_n, \quad (2.21)$$
$$\sum_{t \in \mathcal{T}} (1 - \delta_{ps,t}) x_{ps,t} \Delta t = 0, \qquad \forall n \in \mathcal{N}, \forall ps \in \mathcal{PS}_n, \quad (2.22)$$
$$0 \leq x_{ps,t} \leq P^{max}_{ps}, \qquad \forall n \in \mathcal{N}, \forall ps \in \mathcal{PS}_n, \forall t \in \mathcal{T}. \quad (2.23)$$

Equation (2.21) fixes the daily energy consumption of the device to D_{ps}. The device's operation is constrained to take place during the temporal flexibility window thanks to (2.22) and the power consumption can be controlled from 0 up to their nominal power, P_{ps}^{max}, via (2.23).

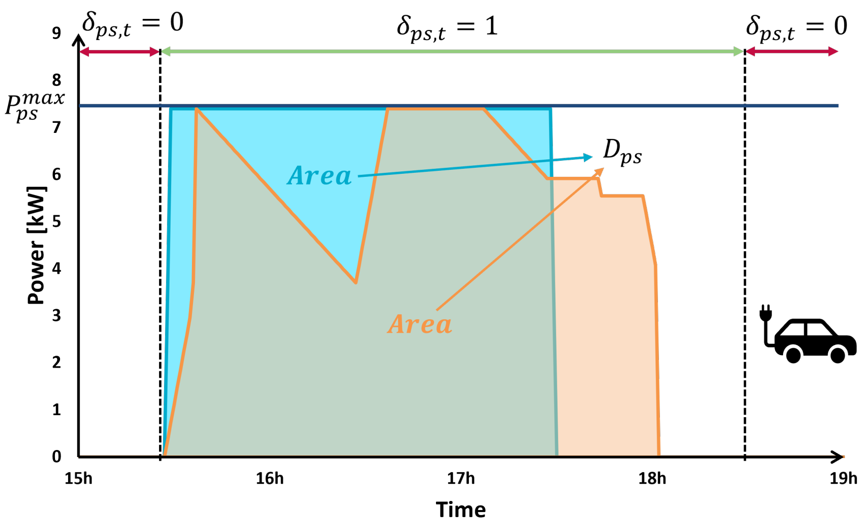


Figure 2.7.: Representative example of power-shiftable devices flexibility potential.

Time-shiftable devices ($ts \in \mathcal{TS}_n \subset \mathcal{A}_n$) are loads with a fixed power consumption profile but whose starting period can be shifted along the day as illustrated in Figure 2.8. Their modelling implies the introduction of a binary decision variable, $z_{ts,t}$, which represents the starting time of the device.

$$\sum_{t \in \mathcal{T}} \delta_{ts,t} z_{ts,t} = 1, \qquad \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \tag{2.24}$$

$$\sum_{t \in \mathcal{T}} (1 - \delta_{ts,t}) z_{ts,t} = 0, \qquad \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \tag{2.25}$$

$$x_{ts,t} = \sum_{\tau = t - \Delta_{ts} + 1}^{t} z_{ts,\tau} P_{ts,t-\tau+1}, \qquad \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \forall t \in \mathcal{T}. \tag{2.26}$$

Equation (2.24) imposes that the device is started only once during the day while (2.25) avoids to launch the operation outside the temporal flexibility window. The power consumption profile of the device over the day is a fixed power pattern, $P_{ts,t}$, of duration Δ_{ts} which starts at t such that $z_{ts,t} = 1$ as expressed in (2.26).

Finally, the total flexible loads' power consumption, $x_{n,t}$, of each REC member

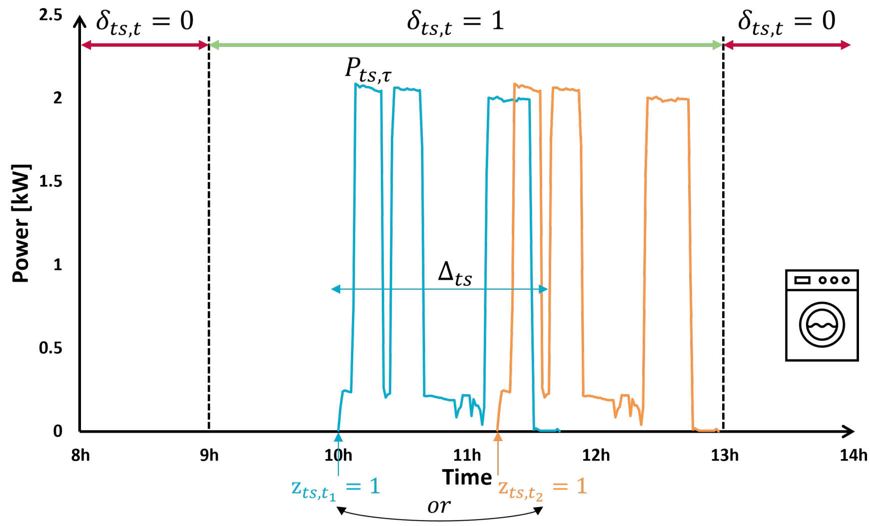


Figure 2.8.: Representative example of time-shiftable devices flexibility potential.

is the sum of all their devices power consumption.

$$x_{n,t} = \sum_{ps \in \mathcal{PS}_n} x_{ps,t} + \sum_{ts \in \mathcal{TS}_n} x_{ts,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{2.27}$$

The coordinated flexibility scheduling model presented in this chapter will serve as a baseline for the integration of the contributions presented in Chapters 3 and 4.

CHAPTER 3.

Integration of Energy Sharing Rules in EC Flexibility Scheduling Models

The coordinated flexibility scheduling problem presented in Chapter 2 enables the Energy Community to achieve the lowest collective electricity bill by optimally planning the usage of flexible devices of community members. This scheduling usually happens one day-ahead of the period of interest to let enough time for community members to anticipate the required actions, especially when flexible devices must be manually programmed. The second-stage in the operational horizon of the community is the settlement period during which benefits are shared and individual electricity bills are computed. In this chapter, the settlement methods commonly applied in real Energy Communities or proposed in the existing literature are described in Section 3.1. Then, among the existing settlement techniques, regulatory-compliant energy sharing rules are formulated in such a way that allows them to be included in the day-ahead scheduling. The formulation is presented in 6.3. An Energy Community composed of 8 residential members with caricatural features is built in Section 3.3, and used to demonstrate the performance of the sharing-rules aware scheduling problem in Section 3.4. Finally, an intermediate conclusion is drawn in Section 3.5.

The contributions presented in this chapter have been submitted for publication in Energy Economics:

[17] J. Allard, L. Sadoine, L. Liégeois, T. Brihaye, F. Vallée, and Z. De Grève, "Integration of energy sharing mechanisms in energy communities demand-side scheduling," *submitted to Energy Economics*, 2025.

3.1. Real-Time Settlement Methods

In real-time, once the actual physical power flows have been metered at the points of common coupling, they go through a settlement mechanism which differentiates the realization of economic exchanges within the energy community, $i^{com}_{n,t}/e^{com}_{n,t}$, from the exchanges with the retailers, $i^{ret}_{n,t}/e^{ret}_{n,t}$. This way, the actual individual bills to be paid by each user can be computed from equation (2.3). This is the second-stage represented in Figure 2.4.

Some energy communities, based on their own preferences or EU member states legislation [14], break away from the standard market mechanism principle that relies on price-volume bids and settles the trades between seller and purchaser using the merit order or auction-based principles [101], [102], [103]. They instead imply the definition of internal sharing rules to redistribute communities surplus linked to their operation. The surplus of a community can be of two natures: economic or energetic. EC's economic surplus refers to the economical profits/savings made in the cooperative framework when comparing the overall community electricity bill with the aggregation of individual ones in the former conditions of members operation alone, without considering local energy exchanges. On the other hand, the energy surplus of an EC constitutes the total local energy production made available by some participants to cover others consumptions. For any of these two surplus types, sharing rules are often defined under the form of distribution keys. The two sharing paradigms are illustrated in 3.1.

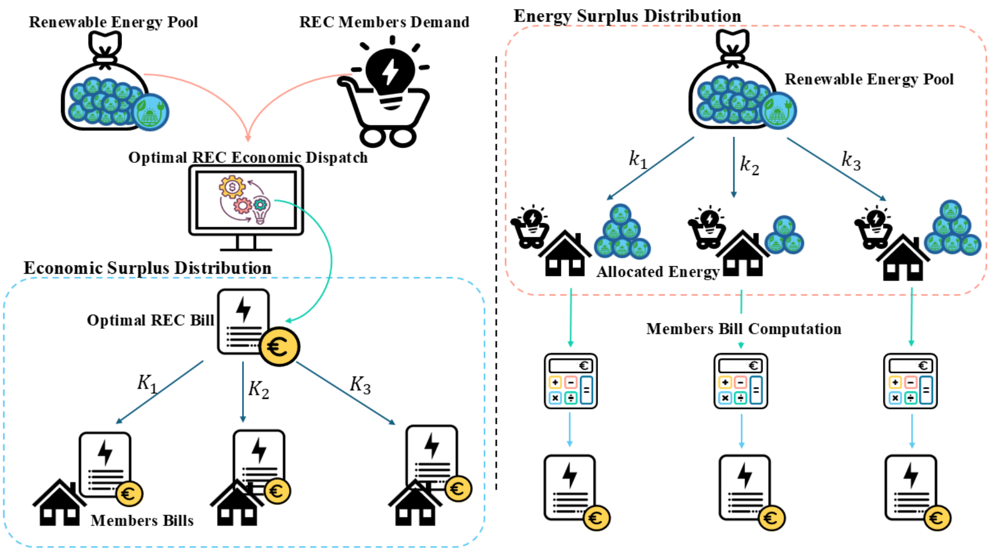


Figure 3.1.: Energy Community sharing paradigms: (Left) Economic surplus distribution - (Right) Energy surplus distribution.

In the remainder of this section, among all the existing keys of repartition from the literature or the regulatory definitions, 14 different distribution keys: 6 for energy surplus and 8 for economic surplus sharing; are described.

3.1.1. Energy Surplus Distribution Keys

In Belgium, and other countries such as France, RECs apply the energetic surplus sharing rules principle. In these communities, the local energy volumes from EC members are gathered and made available to other REC members with a net demand. This aggregated energy volume is often called *local electricity pool*. Local production of electricity may arise from the jointly installed production assets which are owned by the energy community entity (regardless of the investors). All the energy that is produced by these assets is accounted in the local electricity pool. On top of that, the pool may also be filled by production coming from individually owned assets (e.g., domestic member with PV, industrial member with wind turbine). From those particular assets, only the excess production (the energy production that is not directly self-consumed by the owner of the production mean), injected in the distribution network, is accounted for in the local pool. For each period of the day, $t \in \mathcal{T} := \{0, 1, ..., T\}$, the local energy pool P_t^{pool} can be expressed as follows:

$$P_t^{pool} = g_t^{joint} + \sum_{n \in \mathcal{N}} l_{n,t}^{-}, \qquad \forall t \in \mathcal{T}. \tag{3.1}$$

with g_t^{joint} the production of the jointly owned assets and $l_{n,t}^{-}$ the individual net injection/production surplus of REC members $n \in \mathcal{N} := \{1, ..., N\}$. In an energetic surplus sharing framework, this local energy pool is dispatched among REC members using the distribution keys mechanism. There exist numerous options of distribution keys according to the REC objectives (e.g., social inclusion, self-consumption) [14], [73] but for any of them this mechanism can be similarly expressed by:

$$p_{n,t}^{alloc} = k_{n,t} P_t^{pool}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.2}$$

$$i_{n,t}^{com} = \min(p_{n,t}^{alloc}, l_{n,t}^{+}), \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.3}$$

$$\sum_{n \in \mathcal{N}} k_{n,t} = 1, \qquad \forall t \in \mathcal{T}. \tag{3.4}$$

with $p_{n,t}^{alloc}$ the electricity volume from the local pool allocated to each member. This represent the maximum amount of REC energy they can consume, i.e.,$i_{n,t}^{com}$, and for which they benefit of an advantageous tariff. $k_{n,t}$ are the associated distribution keys. Some distribution keys are defined based on non time-varying quantities. Those are called static keys while the others evolving at each period are called dynamic keys. Not more than the available electricity in the local pool must be allocated, meaning that the sum of $k_{n,t}$ must not exceed 100%.

In the following 6 typical energy sharing distribution keys proposed by local regulators (e.g., CWAPE in Wallonia (BE)) [14] and in the literature [73] are introduced.

Members Equal (Key 1)

This first key shares the local electricity pool equally among the REC members in each time period regardless of their physical electricity flow, i.e., net injection or consumption at the PCC (see Figure 3.2). This key simply accounts for the number of REC members.

$$k_{n,t} = \frac{1}{|\mathcal{N}|}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.5}$$

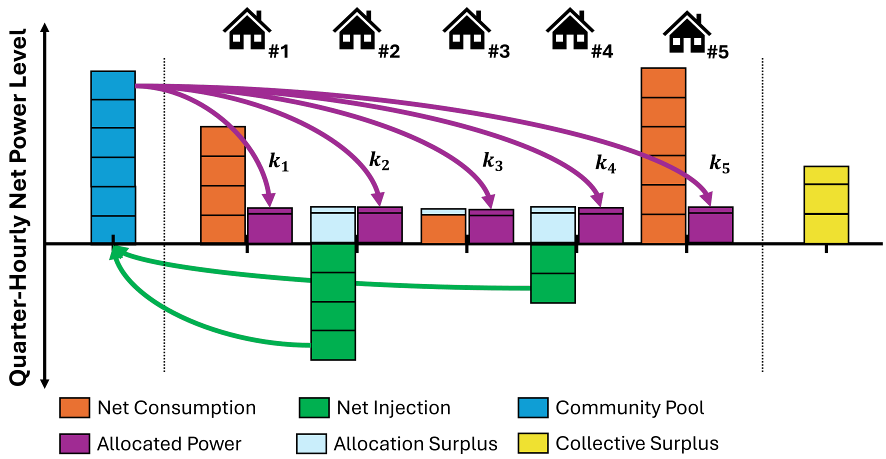


Figure 3.2.: EC Electricity Pool Sharing Example - Members Equal KoR

Consumers Equal (Key 2)

This second key derives from the previous one but reduces the set of REC members considered in the local electricity pool. Hence, only those who have a net consumption are accounted in the repartition (see Figure 3.3). Unlike the previous KoR principle, this KoR is dynamic and the keys values are time-dependent.

$$k_{n,t} = \begin{cases} \frac{1}{|\mathcal{N}_t^{cons}|}, & \forall n \in \mathcal{N}_t^{cons}, \forall t \in \mathcal{T}, \\ 0, & \text{otherwise.} \end{cases} \tag{3.6}$$

with $\mathcal{N}_t^{cons} = \{n \in \mathcal{N} | l_{n,t}^{+} > 0\}$ the set of REC members with a net consumption. $l_{n,t}^{+}$ is the individual net consumption of participants $n \in \mathcal{N}$ during period t.

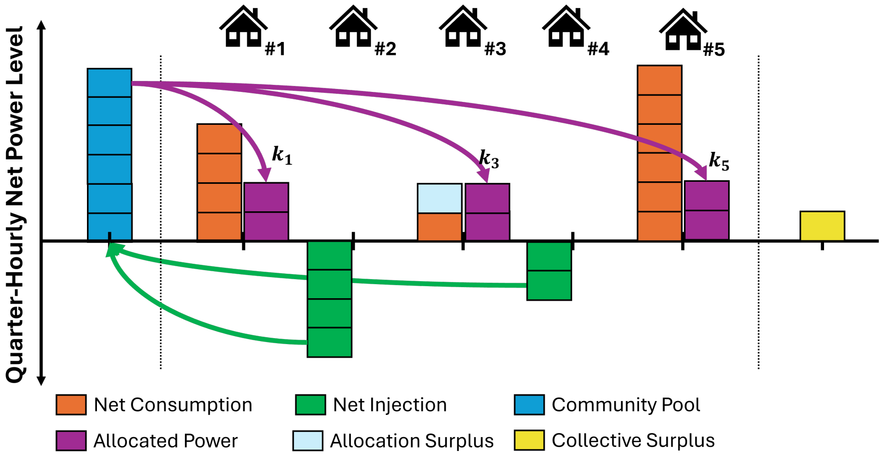


Figure 3.3.: EC Electricity Pool Sharing Example - Consumers Equal KoR

Prorate Consumption (Key 3)

Contrary to the previous keys, this KoR takes into account the electricity volume request of each member. More specifically, it aims to offer a share of the local electricity pool to each member based on its net consumption level, $l^+_{n,t}$, with respect to the overall net consumption inside the REC, $L^+_t = \sum_{n\in\mathcal{N}} l^+_{n,t}$ (see Figure 3.4). By considering the consumption level of the REC members, this key enables an increased collective self-consumption as shown in the following results Section 3.4.

$$k_{n,t} = \frac{l^+_{n,t}}{L^+_t}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.7}$$

Hybrid (Keys 4 & 5)

The *Hybrid Key* is a two steps procedure, i.e., two keys are successively applied. Note that in Wallonia (Belgium), energy communities can define up to three rounds of repartition. In each round, a KoR is applied based on the remaining electricity in the pool and the remaining needs of participants. The *Hybrid Key* has two variants. Indeed, in the first round, either the *Members Equal Key* (Key 4) or the *Consumers Equal Key* (Key 5) is applied to distribute the overall volume available in the local electricity pool. Then, in the second round, the remaining volume in the pool is re-dispatched between the other members in need, proportionally to their remaining consumption (i.e., application of the *Prorate Consumption Key*). This method tries to maximize the self-consumption while ensuring a first fair allocation. Algorithm 1 presents the procedure followed to apply the *Hybrid Key* principle to REC electricity exchanges. Figures 3.5 and 3.6 presents the two keys

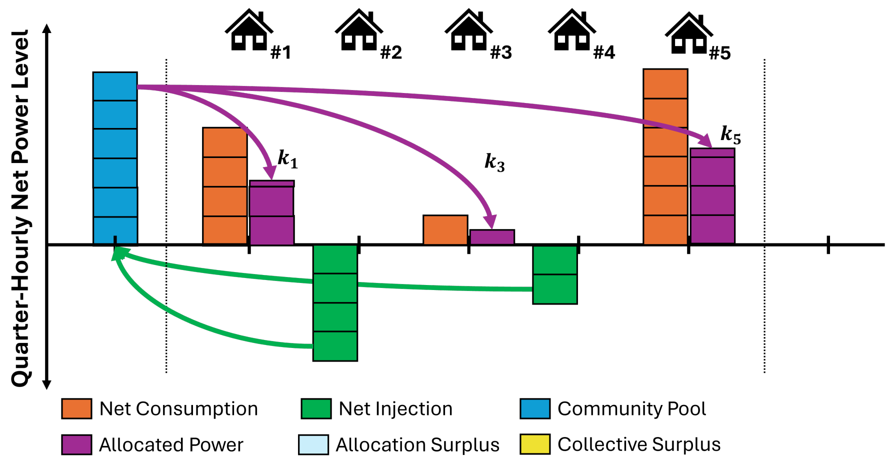


Figure 3.4.: EC Electricity Pool Sharing Example - Prorate Consumption KoR

principle.

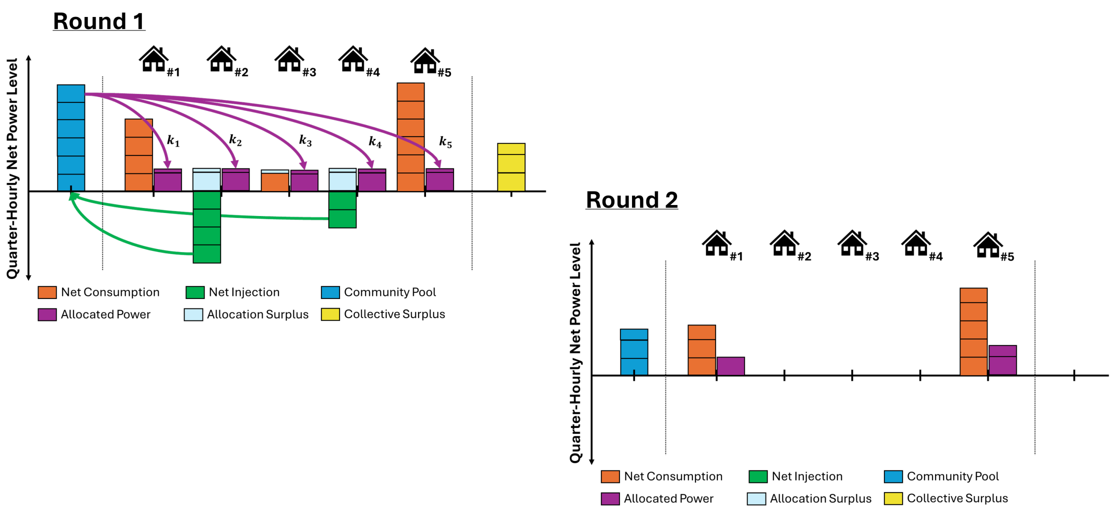


Figure 3.5.: EC Electricity Pool Sharing Example - Hybrid KoR (Key 4)

Cascade (Key 6)

This last key is an iterative application of the *Consumers Equal Key* in order to maximize the collective self-consumption of the local electricity pool (see Figure 3.7). At each iteration, the set of consumer $\mathcal{N}_t^{cons}$ is recomputed based on the remaining demand of each member after the previous allocation rounds. The process stops when the pool is empty or if all the REC members consumption

Algorithm 1: Hybrid Key principle

Input : $l^{+}_{n,t}$, P^{pool}_{t}

foreach $t \in \mathcal{T}$ **do**

  First allocation round:

  A) *Members Equal Key* case

  $p^{alloc}_{n,t} = P^{pool}_{t} / |\mathcal{N}| \quad \forall n \in \mathcal{N}$;

  B) *Consumers Equal Key* case

  $\mathcal{N}^{cons}_{t} = \{n \in \mathcal{N} | l^{+}_{n,t} > 0\}$;

  $p^{alloc}_{n,t} = P^{pool}_{t} / |\mathcal{N}^{cons}_{t}| \quad \forall n \in \mathcal{N}$;

  Remaining net consumption and local electricity pool:

  $l^{+,rem}_{n,t} = l^{+}_{n,t} - \min(l^{+}_{n,t}, p^{alloc}_{n,t}) \quad \forall n \in \mathcal{N}$;

  $L^{+,rem}_{t} = \sum_{n \in \mathcal{N}} l^{+,rem}_{n,t}$;

  $P^{pool,rem}_{t} = P^{pool}_{t} - \sum_{n \in \mathcal{N}} \min(l^{+}_{n,t}, p^{alloc}_{n,t})$;

  Second allocation step:

  $k_{n,t} = l^{+,rem}_{n,t} / L^{+,rem}_{t} \quad \forall n \in \mathcal{N}$;

  $p^{alloc}_{n,t} = \min(l^{+}_{n,t}, p^{alloc}_{n,t}) + k_{n,t} P^{pool,rem}_{t} \quad \forall n \in \mathcal{N}$;

end

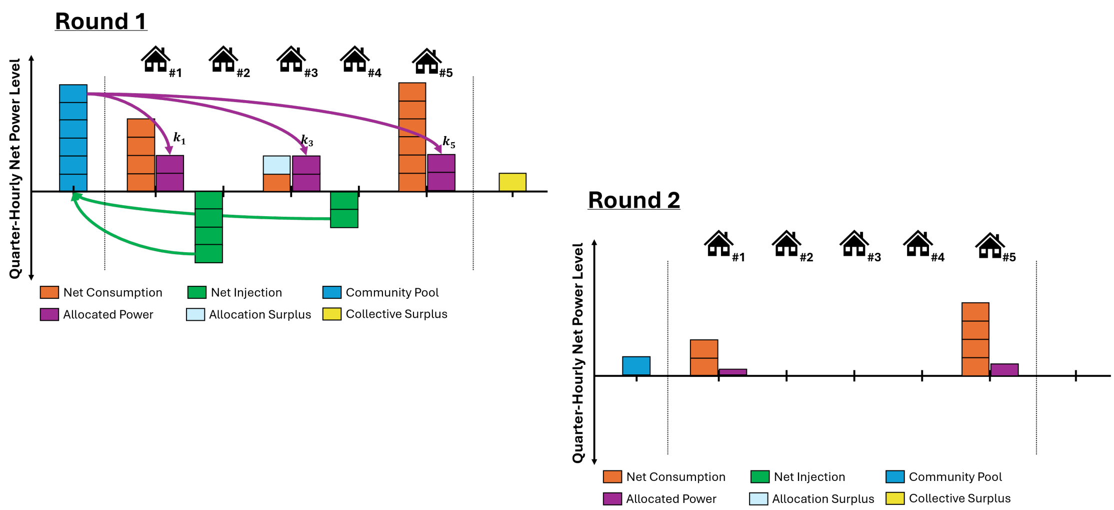


Figure 3.6.: EC Electricity Pool Sharing Example - Hybrid KoR (Key 5)

levels are filled. By using this key, the consumer with the lowest consumption has the higher self-sufficiency. The practical application of the *Cascade Key* to REC members electricity flows follows Algorithm 2.

Algorithm 2: Cascade Key principle

Input: $l^{+}_{n,t}$, P^{pool}_{t}

foreach $t \in \mathcal{T}$ **do**

  Initialize remaining consumption and local electricity pool:

  $l^{+,rem}_{n,t} = l^{+}_{n,t} \quad \forall n \in \mathcal{N}$;

  $L^{+,rem}_{t} = \sum_{n \in \mathcal{N}} l^{+}_{n,t}$;

  $P^{pool,rem}_{t} = P^{pool}_{t}$;

  Initialize allocated power:

  $p^{alloc}_{n,t} = 0 \quad \forall n \in \mathcal{N}$;

  while $L^{+,rem}_{t} > 0$ ***and*** $P^{pool,rem}_{t} > 0$ **do**

    Compute the number of remaining consumers and the allocated power:

    $\mathcal{N}^{cons}_{t} = \{n \in \mathcal{N} | l^{+,rem}_{n,t} > 0\}$;

    $p^{alloc}_{n,t} = p^{alloc}_{n,t} + P^{pool,rem}_{t} / |\mathcal{N}^{cons}_{t}| \quad \forall n \in \mathcal{N}$;

    Update remaining consumption and local electricity pool:

    $l^{+,rem}_{n,t} = l^{+}_{n,t} - \min(l^{+}_{n,t}, p^{alloc}_{n,t}) \quad \forall n \in \mathcal{N}$;

    $L^{+,rem}_{t} = \sum_{n \in \mathcal{N}} l^{+}_{n,t}$;

    $P^{pool,rem}_{t} = P^{pool}_{t} - \sum_{n \in \mathcal{N}} \min(l^{+}_{n,t}, p^{alloc}_{n,t})$;

  end

end

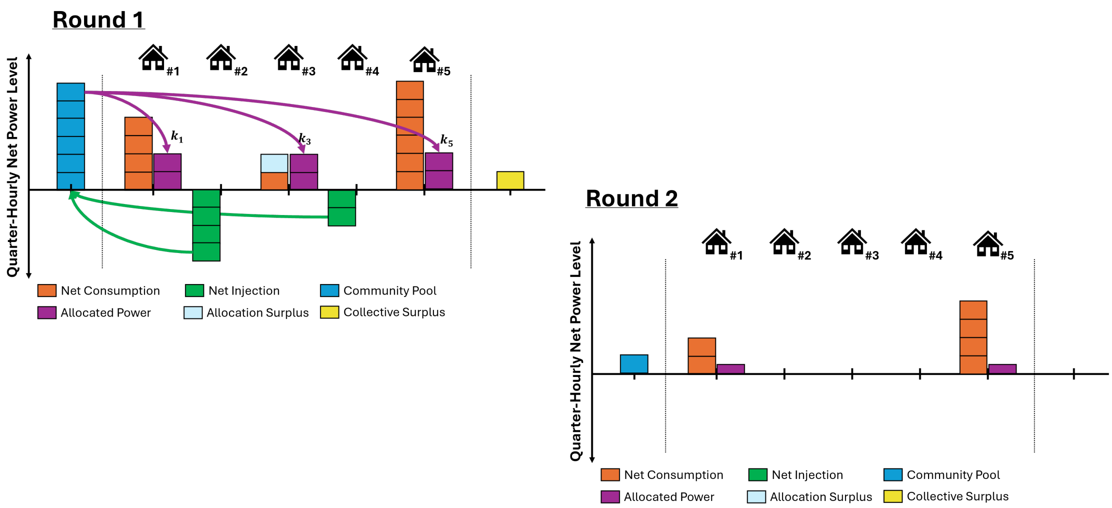


Figure 3.7.: EC Electricity Pool Sharing Example - Cascade KoR

Extra Local Energy - Prorate Injection Key

On the contrary of all the energy distribution key presented so far, this key does not share the local electricity pool between the REC members but rather the extra local energy among prosumers (i.e., REC members with a net power injection). Indeed, in the energy surplus framework it might happen that, during certain time periods, the local electricity pool is not fully consumed by the community members. In this case, the extra local energy is sold on the retail market. As several members may contribute to this pool, the extra local energy must also be dispatched among prosumers. This is often done using a *Prorate Injection Key* which dispatches it proportionally to their contribution to the local electricity pool. This principle is illustrated in Figure 3.8) considering that the local electricity pool is preliminary shared using the *Members Equal Key*.

$$P_t^{pool,rem} = P_t^{pool} - \sum_{n \in \mathcal{N}} i_{n,t}^{com}, \quad \forall t \in \mathcal{T}, \tag{3.8}$$

$$e_{n,t}^{ret} = k_{n,t}^{e} P_t^{pool,rem}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.9}$$

$$k_{n,t}^{e} = \frac{l_{n,t}^{-}}{\sum_{n \in \mathcal{N}} l_{n,t}^{-}}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.10}$$

The extra local energy, $P_t^{pool,rem}$, is defined as the difference between the local electricity pool and the overall purchase within the REC via (3.8). This extra local energy is shared among REC members and exported to their retailers as presented in (3.9). The distribution of this energy is based on a prorate injection key, $k_{n,t}^{e}$.

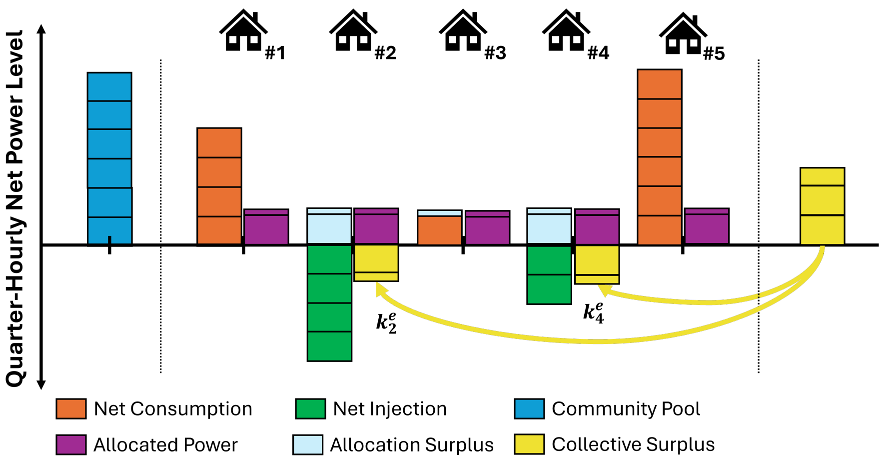


Figure 3.8.: EC Electricity Pool Surplus Sharing - Prorate Injection KoR

3.1.2. Economic Surplus Distribution Keys

Another paradigm often met in the literature is the economic surplus sharing rules principle. In this framework, an optimal economic dispatch is first solved in order to maximize the collective profits/savings of the community with respect to a benchmark case (e.g., individual end-users with no local exchanges). The community economic surplus can be expressed for each period of the day, $t \in \mathcal{T} := \{0, 1, ..., T\}$, or daily as follows:

$$B^{REC,*} = min_{i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t}} \sum_{t \in \mathcal{T}} B^{REC}_t \text{ s.t. (2.9)-(2.12)}, \tag{3.11}$$

$$B^{REC,0} = \sum_{t \in \mathcal{T}} \sum_{n \in \mathcal{N}} B^0_{n,t}, \tag{3.12}$$

$$\Pi^{REC} = B^{REC,0} - B^{REC,*}. \tag{3.13}$$

where $B^{REC,*}$ is the cost-optimal community bill obtained by dispatching the local electricity pool based on individuals retail tariffs. $B^{REC,0}$ is the aggregated sum of community members individual bills $B^0_{n,t}$ in the benchmark case and Π^{REC} is the resulting profit generated by the energy community.

As for the sharing of local energy, these economic profits are dispatched among the community members using a set of rules which most of the time are formulated as distribution keys K_n. The daily individual bills can finally be computed by adding the individual profits to the individual bills of the benchmark case $B^0_n = \sum_{t \in \mathcal{T}} B^0_{n,t}$.

$$\Pi_n = K_n \Pi^{REC} \qquad \forall n \in \mathcal{N}, \tag{3.14}$$

$$\sum_{n \in \mathcal{N}} K_n = 1, \tag{3.15}$$

$$B_n = B^0_n + \Pi_n, \qquad \forall n \in \mathcal{N}. \tag{3.16}$$

Eight economic surplus distribution keys, five static daily keys and three continuous keys, are presented and compared to the previous energy surplus keys. All these keys can be found in the literature (see e.g., [71], [76], [82], [104]).

Members Equal (Key 7)

The first key is similar to the one presented in the *Energy Surplus Distribution Keys* section. In the economic surplus framework it distributes the community's profit evenly among members. Members therefore observe the same bill reduction daily.

$$K_n = \frac{1}{|\mathcal{N}|}, \quad \forall n \in \mathcal{N}. \tag{3.17}$$

Net Flow Proportional Keys

Other well-spread sharing options are based on the individual net electricity flows (i.e., net consumption or injection) either computed over the full day or for each time period. In this work, we consider four variants of the *Net Flow Proportional Keys*.

A) Daily Consumption Prorate (Key 8): This key aims to share the community benefits based on the daily net consumption level of each member with respect to the overall net consumption inside the REC.

$$K_n = \frac{\sum_{t\in\mathcal{T}} l^+_{n,t}}{\sum_{t\in\mathcal{T}} L^+_t}, \quad \forall n \in \mathcal{N}. \tag{3.18}$$

B) Continuous Consumption Prorate (Key 9): This key is similar to the previous one, except that the profits are shared at each time period based on the net consumption level during this particular time period.

$$K_{n,t} = \frac{l^+_{n,t}}{L^+_t}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.19}$$

C) Daily Absolute Net Flow Prorate (Key 10): This third key varies from the *Daily Consumption Prorate Key* by not only considering the net consumption but both net consumption and injection. The surplus is therefore dispatched based on the daily absolute electricity flows of each member $|l_{n,t}|$ with respect to the overall daily REC absolute electricity flows $L^{abs}_t = \sum_{n\in\mathcal{N}} |l_{n,t}|$.

$$K_n = \frac{\sum_{t\in\mathcal{T}} |l_{n,t}|}{\sum_{t\in\mathcal{T}} L^{abs}_t}, \quad \forall n \in \mathcal{N}. \tag{3.20}$$

D) Continuous Absolute Net Flow Prorate (Key 11): This last variant is the continuous version of the previous keys as the key is computed for each time period to share the profits continuously over the day.

$$K_{n,t} = \frac{|l_{n,t}|}{L^{abs}_t}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.21}$$

For the *Continuous* keys, the collective profits must be calculated for each time period as follows:

$$\Pi^{REC}_t = B^{REC,0}_t - B^{REC,*}_t, \quad \forall t \in \mathcal{T}. \tag{3.22}$$

Marginal Profit (Key 12)

This distribution key is calculated based on the normalized Vickrey-Clarke-Groves mechanism. From the point of view of fairness, the profit allocated to each member n should reflect the externality of n. The externality of member n is the difference between the optimal REC profit Π^{REC} and the optimal REC profit that can be achieved without the user n in the community. It is denoted by $V_n := \Pi^{REC} - \Pi^{REC}_{\mathcal{N}\setminus\{n\}}$. A positive impact of user n on the economic surplus reflects in a positive value of its externality. The economic surplus is shared on the prorata of the individual externalities with respect to the aggregated externality $V^{tot} = \sum_{n\in\mathcal{N}} V_n$.

$$K_n = \frac{V_n}{V^{tot}}, \quad \forall n \in \mathcal{N}. \tag{3.23}$$

This requires the solution of $|\mathcal{N}| + 1$ optimisation problems (3.11).

Equal Saving Ratio (Key 13)

If the *Members Equal Key* dispatches evenly the community profits among the members without any further consideration than the REC size, this key takes into account the individual members bill in the benchmark case (i.e., without community exchanges). Doing, so the goal is that the relative savings made by each member with respect to their benchmark bills are equal.

$$\frac{\Pi_n}{B_n^0} = \frac{\Pi^{REC}}{B^{REC,0}}, \quad \forall n \in \mathcal{N}. \tag{3.24}$$

This rule can be equivalently formulated via the following distribution key which represents the relative members bills in the benchmark case without community with respect to the aggregated bill in this benchmark case:

$$K_n = \frac{B_n^0}{B^{REC,0}}, \quad \forall n \in \mathcal{N}. \tag{3.25}$$

Optimal Virtual Flows (Key 14)

Finally, this last key principle simply retrieves the individual bills outcomes from the resolution of the optimal economic dispatch problem (3.11). It can also be seen as an implicit energy sharing mechanism where the distribution keys are decision variables which dispatch the local electricity pool among members based on their individual physical net power flow and retailer tariffs to minimize the collective bill.

3.2. Innovative Constraints Formulation of Energy Surplus Keys

As discussed previously (see Figure 2.5), sharing rules are necessarily applied during the settlement phase in order to split the energy community surplus among its members and/or define the economic exchanges between the different agents (i.e., REC members, retailers). In the case of an energy surplus sharing framework, it might also be relevant to consider the selected rule within the day-ahead optimal scheduling problem. Indeed, in the literature, when the scheduling problem is solved the economic exchanges are only driven by the objective function towards their optimum. Meanwhile, in real-time even with a perfect forecast and perfectly followed recommendations (i.e., flexible devices use, storage systems exchanges) REC members may observe differences between their expected objective value (in day-ahead) and the observed objective value (in real-time) once the sharing rules are applied. This is because optimal energy sharing decisions obtained from the day-ahead planning do not match the sharing rule applied in the settlement phase.

For instance, imagine an energy community which applies the Members Equal KoR (Key 1) and that all EC members have the same external (i.e., retailer and grid) tariffs except one who has higher tariffs. From an optimisation point of view, by solving the optimisation problem (2.1) this particular member receives a greater share of the local and cheaper energy pool as this dispatch strategy has a bigger impact on the global community bill reduction objective. However, in real-time the specific energy sharing mechanism chosen by the EC is used to settle the exchanges. In the current example, every participant receive the same volume of local electricity. Consequently, it leads to a reduced share of the energy pool allocated to the high-tariffs member, hence affecting individual bills (i.e., expected vs real one).

Those deviations might be a source of skepticism for the end-users regarding the efficient operation of the community. To cope with this problem and maintain members' willingness to participate in the community, in this work we propose an original formulation of the 6 energy surplus distribution keys principles presented in the previous section. These formulations take the form of additional constraints on the local electricity exchanges to be embedded in the day-ahead optimal scheduling problem as shown in 3.9, or in any other EC problem requiring to account for the dispatch of the local electricity pool.

Members Equal (Key 1)

The formulation of this key in the scheduling problem is straightforward. The local electricity pool, P_t^{pool} is shared evenly between REC members and set as the upper

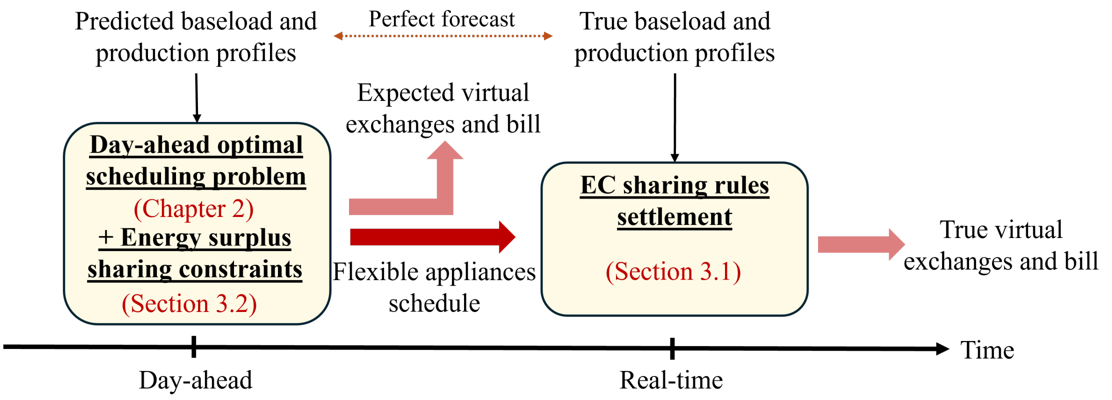


Figure 3.9.: Proposed two-stage REC operation process with embedded energy surplus distribution keys.

bound for the power bought within the REC as follows:

$$i^{com}_{n,t} \leq P^{pool}_t / |\mathcal{N}|, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.26}$$

Driven by the energy community economic objective which incentives participants to consume local energy rather than trading with their retailer, the $i^{com}_{n,t}$ variable naturally tends to get as close as possible from its upper bound.

Consumers Equal (Key 2)

To share the local pool only between REC members with a net power consumption, $\mathcal{N}^{cons}_t = \{n \in \mathcal{N} | l^{+}_{n,t} > 0\}$, the proposed formulation takes advantage of the binary variable introduced in (2.6) and (2.7) to distinguish net power consumption and net power injection flows. The key principle can be exactly formulated through the following constraints:

$$p^{alloc}_{n,t} \cdot l^{sign}_{m,t} = p^{alloc}_{m,t} \cdot l^{sign}_{n,t}, \qquad \forall\ (n,m) \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.27}$$

$$\sum_{n \in \mathcal{N}} p^{alloc}_{n,t} = P^{pool}_t, \qquad \forall t \in \mathcal{T}, \tag{3.28}$$

$$i^{com}_{n,t} \leq p^{alloc}_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.29}$$

$$0 \leq p^{alloc}_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.30}$$

Equation (3.27) imposes that every member with a net power consumption ($l^{sign}_{n,t} = 1$) receives the same allocated volume while those with a net power injection receives zero power. The bilinear expressions present in the constraint are linearized using techniques proposed in [105]. In addition, the total allocated power matches the local electricity pool via (3.28) and the allocated power is set as the threshold for the electricity import from the REC in (3.29).

Prorate Consumption (Key 3)

The direct implementation of the *Prorate Consumption Key* presented in Section 3.1.1 would lead to the following constraint which is strictly non-linear:

$$p_{n,t}^{alloc} = \frac{l_{n,t}^{+}}{\sum_{n \in \mathcal{N}} l_{n,t}^{+}} P_t^{pool}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.31}$$

$$\frac{p_{n,t}^{alloc}}{l_{n,t}^{+}} = \frac{P_t^{pool}}{\sum_{n \in \mathcal{N}} l_{n,t}^{+}} = C_t, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.32}$$

However, when reorganizing (3.31) as presented in (3.32), it allows to interpret this key principle as imposing that the ratio between the allocated power and the net power consumption is the same for every REC member. This distribution key behavior is therefore approximated by introducing an integer variable (i.e., binary expansion of variable y_j) to represent the ratio between the local electricity pool and the overall net power consumption inside the REC. In the following formulation, a granularity of 1% is considered:

$$p_{n,t}^{alloc} = l_{n,t}^{+} \cdot 0.01 \sum_{j=1}^{7} y_{j,t} 2^{(j-1)}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.33}$$

$$\sum_{n \in \mathcal{N}} p_{n,t}^{alloc} \leq P_t^{pool}, \qquad \forall t \in \mathcal{T}, \tag{3.34}$$

$$i_{n,t}^{com} \leq p_{n,t}^{alloc}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.35}$$

$$0 \leq p_{n,t}^{alloc}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.36}$$

$$y_{j,t} \in \{0, 1\}, \qquad \forall j \in \{1, ..., 7\}, \forall t \in \mathcal{T}. \tag{3.37}$$

Equation (3.33) imposes a similar ratio between the individual net power consumption and the allocated power for every REC member. This constraint converts the bilinear relation between two continuous variables to a product of integer and continuous variables which can be linearized using techniques from [105]. The integer percentage value represented by the binary expansion is limited to 100% meaning that the allocated power can not exceed the net power consumption of REC members. For this reason, (3.34) relaxes the quantity dispatched between members to not strictly be equal to the local electricity pool. Indeed, if this local electricity pool is greater than the overall net power consumption within the REC it would make the previous constraint infeasible.

Hybrid (Keys 4 & 5)

To formulate the two rounds procedure of the *Hybrid Key*, the variables related to the allocated power and the imported power from the REC are decomposed in two sets of variables (i.e., A and B). The first set of components, $p_{n,t}^{alloc,A}$ and $i_{n,t}^{com,A}$, are constrained either by (3.26) or (3.27)-(3.30) depending on the variant: *Members Equal KoR (Key 4)* or *Consumers Equal KoR (Key 5)*.

For all the other sharing mechanisms relying on a single allocation rule, the *min* operator of equation (3.3) could be mimicked by setting the allocated power as the upper limit of community imports. Indeed, (2.9) already imposes that $i_{n,t}^{com}$ is lower than the net consumption, $l_{n,t}^{+}$. This second upper limit combined with the objective function that indirectly maximizes the local electricity consumption leads to the expression in (3.3). However, for the Hybrid Keys the sequential application of the two allocation rounds must be conserved when reformulating these sharing rules. Therefore additional constraints must be applied on $i_{n,t}^{com,A}$ to satisfy (3.3) in the first round and avoid arbitrage between the two allocated volumes. These constraints can be formulated as follows:

$$i_{n,t}^{com,A} + M * z_{n,t} \geq l_{n,t}^{+} \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.38}$$

$$i_{n,t}^{com,A} + M * (1 - z_{n,t}) \geq p_{n,t}^{alloc,A} \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.39}$$

$$\tag{3.40}$$

with $z_{n,t}$, an additional binary variable indicating if the allocated power is greater or not than the net consumption volume.

Finally, to set the second round allocation constraints, auxiliary variables representing the remaining individual consumption and the remaining local electricity pool after the first step are introduced and similar constraints than (3.33)-(3.37) are added to the second set of components, $p_{n,t}^{alloc,B}$ and $i_{n,t}^{com,B}$., slack variables representing the remaining individual consumption and the remaining local electricity pool after the first step are introduced and similar constraints to (3.33)-(3.37) are added to the second set of components, $p_{n,t}^{alloc,B}$ and $i_{n,t}^{com,B}$.

$$l_{n,t}^{+,rem} = l_{n,t}^{+} - i_{n,t}^{com,A}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.41}$$

$$P_{t}^{pool,rem} = \sum_{n \in \mathcal{N}} (p_{n,t}^{alloc,A} - i_{n,t}^{com,A}), \qquad \forall t \in \mathcal{T}, \tag{3.42}$$

$$p_{n,t}^{alloc,B} = l_{n,t}^{+,rem} \cdot 0.01 \sum_{j=1}^{7} y_{j,t} 2^{(j-1)}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.43}$$

$$\sum_{n \in \mathcal{N}} p_{n,t}^{alloc,B} \leq P_{t}^{pool,rem}, \qquad \forall t \in \mathcal{T}, \tag{3.44}$$

$$i_{n,t}^{com,B} \leq p_{n,t}^{alloc,B}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.45}$$

$$0 \le p_{n,t}^{alloc,B}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.46}$$
$$y_{j,t} \in \{0,1\}, \qquad \forall j \in \{1,...,7\}, \forall t \in \mathcal{T} \tag{3.47}$$
$$i_{n,t}^{com} = i_{n,t}^{com,A} + i_{n,t}^{com,B}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.48}$$

Equation (3.41) defines the remaining individual power consumption, $l_{n,t}^{+,rem}$ as the difference between the net power consumption and the imported power from the REC after the first allocation step. The remaining local electricity pool is defined as the aggregated allocation surplus after the first step through (3.42). (3.43)-(3.47) apply the same constraints than the one proposed for the formulation of the *Prorate Consumption Key* but on the remaining individual power consumption for the second allocation step. Finally (3.48) aggregates the power bought in the REC in the two allocation rounds in a single variable used to settle the bill.

Cascade (Key 6)

As presented in Section 15, this key principle is an iterative process which might seem difficult to express as a set of constraints. However, the analysis of the resulting allocation shows that, as the *Cascade* name suggests, the REC members net consumptions request are successively fully filled by the local electricity pool from the lowest to the highest volume request. Meanwhile, members that are not fully supplied by the local electricity pool receive equal amount of allocated power. The formulation of this key in the scheduling problem introduces an auxiliary binary variable, $z_{n,t}$, as the state indicator of whether the allocated power reaches the net power consumption of member (i.e., value of 1) or not. It also relies on the fact that community prices are more advantageous than retailer prices which guides the optimal solution towards a maximal internal consumption of the local electricity pool in the REC.

$$p_{n,t}^{alloc} \ge l_{n,t}^{+} z_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.49}$$
$$p_{n,t}^{alloc} \le p_{m,t}^{alloc} + M \cdot z_{m,t}, \qquad \forall n,m \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.50}$$
$$\sum_{n \in \mathcal{N}} p_{n,t}^{alloc} \le P_t^{pool}, \qquad \forall t \in \mathcal{T} \tag{3.51}$$
$$i_{n,t}^{com} \le p_{n,t}^{alloc}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.52}$$
$$0 \le p_{n,t}^{alloc}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.53}$$
$$z_{n,t} \in \{0,1\}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{3.54}$$

Equation (3.49) guarantees that $z_{n,t}$ is set to 1 only if $p_{n,t}^{alloc}$ is at least equal to $l_{n,t}^{+}$. If this is the case for a given member, (3.50) allows other members to receive more power from the electricity pool . Otherwise, all REC members receive equal power.

Extra Local Energy - Prorate Injection Key

Simultaneously to the introduction of any additional set of constraints in the day-ahead optimal scheduling problem to model te chosen local electricity pool distribution key principle, the extra local energy dispatch mechanism is considered.Following the same idea than for the *Prorate Consumption Key*, the *Prorate Injection Key* can be formulated as a set of linear constraints.

$$e^{ret}_{n,t} = \frac{l^-_{n,t}}{\sum_{n\in\mathcal{N}} l^-_{n,t}} P^{pool,rem}_t \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{3.55}$$

$$\frac{e^{ret}_{n,t}}{l^-_{n,t}} = \frac{P^{pool,rem}_t}{\sum_{n\in\mathcal{N}} l^-_{n,t}} = C^e_t \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{3.56}$$

Indeed, (3.56) shows that for each time period, the *Prorate Injection Key* implies that the ratio of the exported power to the retailer and the net power injection is constant for each individual REC member. Therefore, similar constraints than (3.27)-(3.30) can be used to model this key principle.

$$e^{ret}_{n,t} = l^-_{n,t} \cdot 0.01 \sum_{j=1}^{7} y^e_{j,t} 2^{(j-1)} \quad \forall\, t \in \mathcal{T}, \quad \forall\, n \in \mathcal{N} \tag{3.57}$$

$$y^e_{j,t} \in \{0,1\} \quad \forall j \in \{1,...,7\}, \forall t \in \mathcal{T}. \tag{3.58}$$

Equation (3.57) imposes a similar ratio between the individual net power injection and the electricity sold to the retailer for every REC member. This ratio is approximated through the use of binary variables, $y^e_{j,t}$ (3.58).

3.3. Case Study and Key Performance Indicators

This thesis addresses two different objectives surrounding the sharing rules applied in energy communities: 1. comparing the economic and energetic surplus sharing frameworks, and more specifically the most common sharing rules principles presented in Section 3.1.1 and 3.1.2, and 2. evaluating the benefits of including the energy sharing rules in the day-ahead scheduling problem, by including the additional constraints proposed in Section 6.3 on the individual bills realization after the settlement phase.

To meet these objectives, the two steps operation of energy communities depicted in Figure 2.4 is applied on a particular energy community use case composed of 8 low voltage (LV) end-users. The daily operation of this community is simulated for two complete months of the year, one winter month (January) and one summer month (July) with a quarter-hourly timestep. Annual results are extrapolated by considering that those two months are replicated six times each within a year. In

Table 3.1.: Case Study - REC members features.

Members	1	2	3	4	5	6	7	8
PV power [kW_{peak}]	10	10	10	10	0	0	0	0
Storage unit	No	Yes	No	Yes	No	No	Yes	No
Total annual load [kWh]	4169	5046	7438	5602	6283	4855	3836	5666
Power-shiftable load [%]	44	43	0	0	52	56	0	0
Time-shiftable load [%]	15	0	8	0	14	0	15	0
Prices Scheme	ToU	Flat	ToU	Flat	ToU	Flat	ToU	Flat

this REC, members can be equipped with PV panels and a storage system. In this work, only individually owned assets are considered meaning that the definition of the local electricity pool reduces to $P_t^{pool} = \sum_{n \in \mathcal{N}} l_{n,t}^-$. Every storage system unit is considered to have a nominal power of 5 kW, a nominal capacity of 14 kWh, a charging and discharging efficiency of 90 % and an initial and final state of charge of 20 % of the nominal capacity[1]. Additionally, some of the end-users may be prone to adapt the consumption of their time-shiftable and/or power-shiftable loads thereby offering flexibility potential to help reaching the best objective for the community. Hence, the characteristic features of the 8 caricatural members of the REC are presented in Table 3.1. In this table, the flexibility potential for both types of flexible devices are expressed in percentage. It only represents the share of these loads consumption in the annual electricity consumption. These values does not take into account the flexibility windows agreed by members.

Solar load factor profiles and reference consumption profiles are based on historical data of an existing LV grid in the Walloon part of Belgium. Examples of daily solar load factor profiles for the months of January and July are depicted in Figure 3.10 which intuitively gives an insight on the potential benefits for the REC. Regarding the REC members' consumption profiles, two alternatives are considered in this work:

1. **Reference consumption:** This load profile corresponds to the usual consumption behavior of all the appliances (i.e., both non-flexible and flexible loads) that would be realized in real-time without considering any flexibility potential for day-ahead optimal scheduling. An example of reference consumption profile is shown in Figure 3.11.

2. **Baseload consumption:** This second profile is extracted from the first one as it represents solely the power consumption of non-flexible loads. This profile is passed to the day-ahead scheduling problem as baseload power

[1] For a more efficient use of storage systems integrated with PV production units, each simulated day spans from 8 am to 8 am the next day.

consumption and is assumed to stay unchanged in real-time. This profile is also highlighted in Figure 3.11.

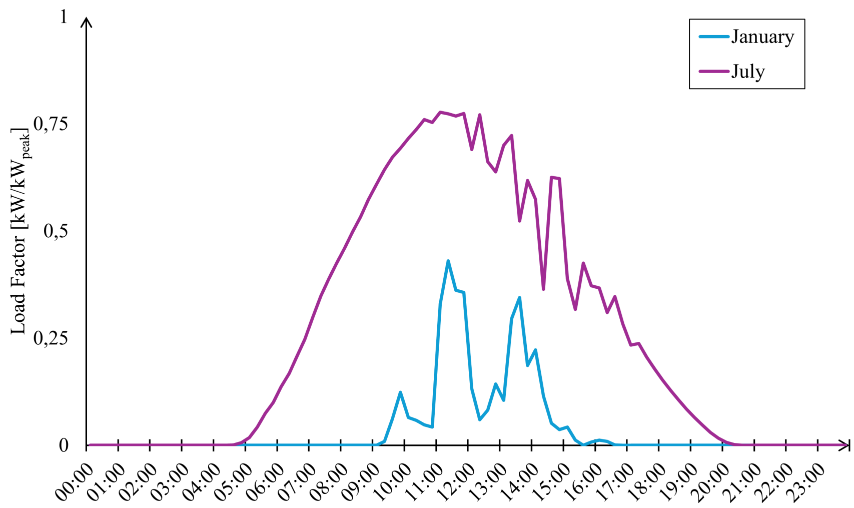


Figure 3.10.: Solar load factor profiles samples (02/01 and 01/07).

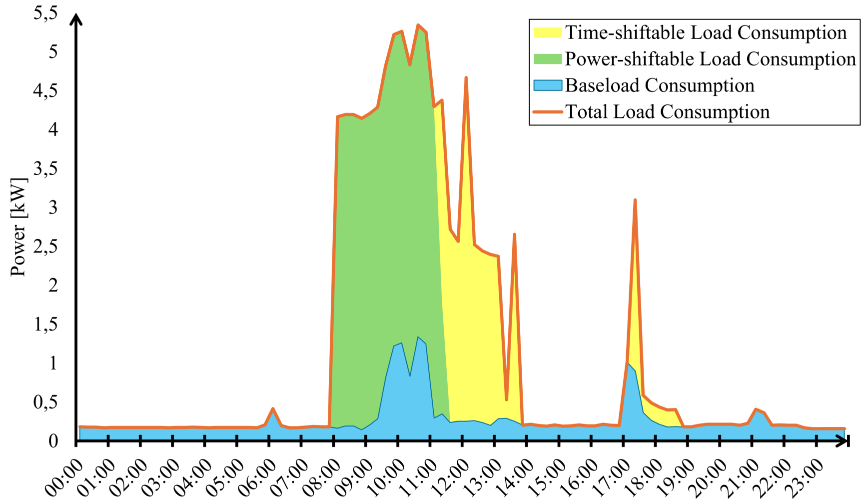


Figure 3.11.: Daily reference load consumption profile sample (26/07 - Member 5) and its disaggregation in baseload and flexible consumption.

As imposed by the liberalized energy framework in Europe, each member can contract with a different supplier and select different price schemes. In this work we consider that they all contract with the same supplier but that there is two options for retailer and grid usage tariffs: either flat prices or time-of-use (ToU) prices. Both options are shown in Figures 3.12 and 3.13 for retailer and grid usage charges respectively. Regarding community exchanges, local prices are set to 0.17 €/kWh for import and 0.13 €/kWh for export. They are flat and common to all REC members. Equivalent taxes price applied to the total imported energy is fixed at 0.046€/kWh.

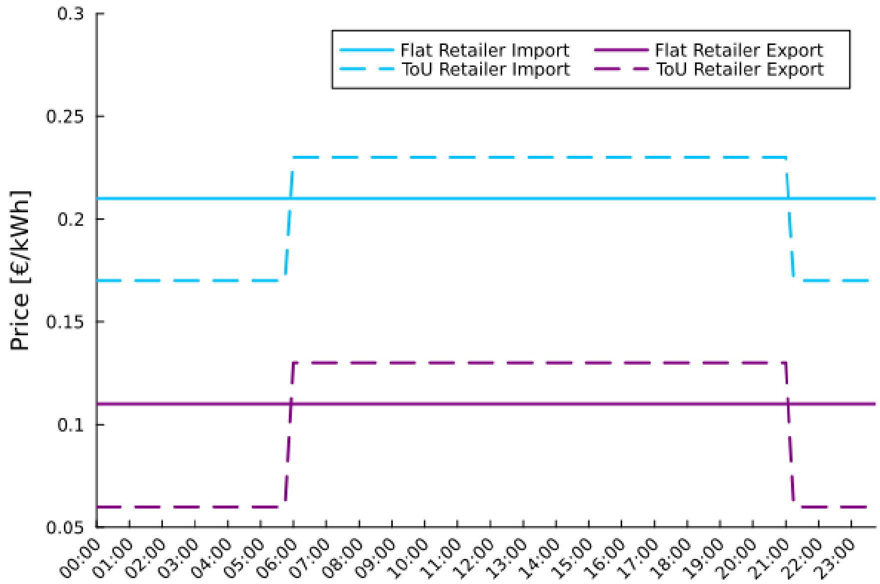


Figure 3.12.: Flat and ToU retailer tariffs for imported and exported energy.

In the following results section, the following key performance indicators (KPIs) are observed and discussed. First regarding economic performances, collective and individual electricity bills are computed. Then, from an energy-efficiency point of view, physical and virtual power flows are retrieved from the community operation to compute self-consumption and self-sufficiency rates. In the REC framework two distinct definitions of each of these two KPIs can be provided regarding the nature of the power flows considered (physical or virtual/economic). Physical self-consumption rate represents the share of power generation produced by one member directly consumed at its location while virtual self-consumption also accounts for the electricity surplus exchanged within the REC. These can be expressed as:

$$SCR_n^{phys} = 1 - \frac{\sum_{t\in\mathcal{T}} l^-_{n,t}}{\sum_{t\in\mathcal{T}} g_{n,t}}, \qquad \forall n \in \mathcal{N}, \tag{3.59}$$

$$SCR_n^{virt} = 1 - \frac{\sum_{t\in\mathcal{T}} e^{ret}_{n,t}}{\sum_{t\in\mathcal{T}} g_{n,t}}, \qquad \forall n \in \mathcal{N}. \tag{3.60}$$

Similarly, the physical self-sufficiency rate is the portion of the total load supplied

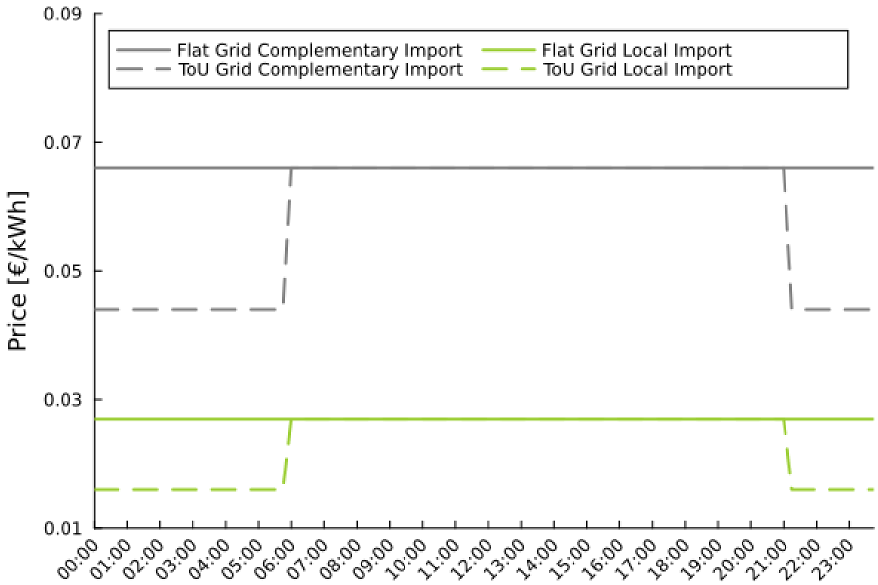


Figure 3.13.: Flat and ToU grid usage tariffs for complementary and local energy.

by individual generation assets meanwhile virtual self-sufficiency rate includes the imported power from the REC:

$$SSR_n^{phys} = 1 - \frac{\sum_{t\in\mathcal{T}} l_{n,t}^{+}}{\sum_{t\in\mathcal{T}}(b_{n,t} + x_{n,t})}, \qquad \forall n \in \mathcal{N}, \tag{3.61}$$

$$SSR_n^{virt} = 1 - \frac{\sum_{t\in\mathcal{T}} e_{n,t}^{ret}}{\sum_{t\in\mathcal{T}}(b_{n,t} + x_{n,t})}, \qquad \forall n \in \mathcal{N}. \tag{3.62}$$

3.4. Results

This section presents the key results which emerge from the work carried out in this thesis on the comparison of the two main sharing paradigms for energy communities and the integration of energy surplus KoR mechanisms in the day-ahead coordinated scheduling of REC members flexible resources. More particularly, three key results that can be summarized as follows stand out and are discussed in this thesis:

1. **Economic Surplus outperforms Energy surplus sharing at the REC scale**;
2. **Distribution key-agnostic coordinated DSM scheme in REC misleads participants on their real-time benefits**;
3. **Embedding Energy Surplus Distribution Keys Enhances and Preserves Day-Ahead Scheduling Performances**.

"Economic Surplus outperforms Energy surplus sharing at the REC scale"

This first analysis enables a comprehensive comparison of the most common sharing rules mechanisms presented in the two previous sections. We assume that the REC does not mobilize members' flexibility (flexible devices or storage systems at disposal), i.e. no DSM scheme is implemented and the consumption profiles are fixed. The virtual energy exchanges are settled and the collective and individual bills are computed ex-post based on the physical net power metered at the individual PCCs in this situation.

We analyze first the global, community-level electricity bills resulting from the application of the 14 different distribution keys, depicted in Tab. 3.2. We observe that, by participating to the REC, 486 to 731 € can be saved each year, compared to the initial situation without local exchanges (i.e., B^0). These savings are driven by the more advantageous prices offered within the community, compared to retailer ones, and the natural complementarity of members net power profiles enabling local exchanges. The savings amount varies depending on the sharing rules applied within the REC. Indeed, in the energy surplus sharing framework, the *Prorate Consumption* (Key 3), *Cascade* (Key 4) and the two *Hybrid Keys* (Keys 5 &6) all achieve a better REC bill than the *Members Equal* (Key 1) and *Consumers Equal Keys* (Key 2). This is due to the fact that the *Equal* keys do not consider the net consumption levels of members to split the electricity pool. This can lead to periods during which local electricity available is sold to retailers while some EC members are still in need. On the other hand, for the other energy surplus sharing keys, the distribution of local energy is based on the electricity needs and available production at any time, which tends to maximize the collective self-consumption. In this situation, the savings are necessarily larger than with the *Members Equal* and *Consumers Equal* keys, as the amount of local electricity shared at a competitive tariff increases.

Then, we focus our analysis on the comparison between the energy and economic surplus sharing frameworks. Results show that the economic surplus distribution leads to higher savings than any energy surplus distribution rule. Indeed, even if the ex-post settlement is made using either the *Prorate Consumption*, the *Cascade* or one of the two *Hybrid* (Keys 3 to 6) distribution keys mechanisms which allow to achieve the highest possible collective self-consumption (i.e., the highest amount of shared electricity), they may not achieve the best collective bill. This is due to heterogeneous retailer tariffs among REC members as the individual economic flows, output of the energy surplus sharing mechanism, therefore have a direct impact on the bill. The different energy surplus sharing keys all miss the retailer price information, hence leading to sub-optimal collective bill. On the other hand, the economic surplus distribution framework sets the optimal savings a REC could make as the economic flows are optimized to get the minimum collective bill while being aware of the different prices schemes contracted by the members. Therefore, when optimizing the economic flows, the prosumers with flat tariffs sell in priority electricity within the REC (i.e., earning an extra 0.02€/kWh), while the consumers with ToU tariffs buy local electricity before the ones with flat tariffs. However, readers should note than in this second framework, if the individual economic flows are dispatched optimally to meet the best collective objective, individual bills are not directly computed based on those flows but rather result from a direct split of the community bill (Keys 7 to 13).

These observations are supported by the self-consumption and self-sufficiency performances represented by the local energy exchanged at both community and individual levels. Indeed, if physical power flows are similar in all cases as the power production and power consumption profiles are fixed (i.e., no DSM case nor uncertainty), the collective self-consumption and self-sufficiency results are affected by the surplus sharing mechanism. Figure 3.14 shows the yearly total community exchanges for the different energy surplus sharing schemes and the optimal amount of shared energy obtained when solving the economic dispatch problem (3.11) in the REC economic surplus sharing framework. It can be effectively observed that the *Members Equal* and *Consumers Equal Keys* are inefficient in allocating local production surplus to members in need. Besides, the four others energy surplus distribution keys lead to the highest self-consumption as they account for the consumption levels to share the local electricity available at maximum. However, last bar of the graph shows that to achieve the best economic objective the collective (i.e., virtual) self-consumption would reach 42.28% instead of 42.44%, the maximum achievable ratio without flexibility.

A closer look at Figures 3.15 and 3.16 gives more insights on the distribution of local exchanges among members in both frameworks. The first figure shows the annual electricity imported and exported locally by each of the 8 members when subject to the energy surplus sharing key, and more specifically the *Prorate Consumption Key*. The second one displays the same results but obtained from the minimization of the collective bill by resolution of problem (3.11)). Although the actual granularity of local exchanges definition is one quarter of an hour, annual volumes still reflects the characteristic behavior of the different members. Regarding the prosumers (i.e. Members 1 to 4), in the energy surplus sharing framework, the electricity sold within the community is dispatched relatively to their injection level through the *Prorate Injection Key*. Having the same production profiles (i.e., same PV capacity and load factor profiles), the surplus to be shared and therefore the local contribution is influenced by the level of raw consumption, with the Member 1 having the most to sold with its lower consumption. If Member 3, with its high consumption level, is exchanging the less with the EC the other two prosumers have a local injection mitigated by the usage of their batteries which allows them to self-consume more PV production. In the second framework, by optimizing the economic flows prosumers with a flat export rates that is lower than the time-of-use tariff during the day, and hence the solar production hours, are prioritized for selling their surplus production locally (i.e. Members 2 and 4) compared to the other ones who can retrieve less marginal benefits from the community. Similarly for the imported power of consumers, with the *Prorate Consumption Key* the dispatch is mainly driven by the raw consumption as Members 5 and 8 consume the most and receive local electricity accordingly. With the economic surplus sharing mechanisms, consumers with ToU contracts (i.e. Members 5 and 7) tend to get a higher share of the local electricity pool than in the previous case at the expense of other members with flat tariffs.

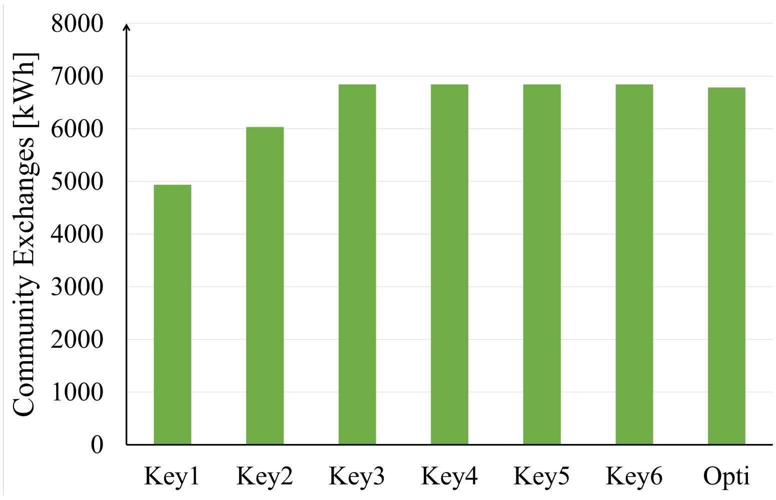


Figure 3.14.: Total REC internal energy exchanges for each energy surplus KoR (Keys 1 to 6) and from the economical optimisation (Opti/Key 14).

We finally analyze the individual bills of community members when adopting the two different frameworks and their respective keys of repartition. Unfortunately, there is no clear consensus on the best surplus sharing mechanism. As indicated in Table 3.2 by the green and red colors, each REC member has a preferred and worst resulting individual bill. Regarding the repartition of energy surplus, yearly individual bills remain intrinsically linked to the level of annual consumption of each member. However, the inefficiency of *Members and Consumers Equal Keys* (i.e., 1 and 2) to allocate the EC electricity pool among members at each period limits the benefits of each participant as the bill reduction requires quarter-hourly balance between consumption and production. For the other Keys (i.e., 4 to 6) differences in savings only results from times of consumption with non-zero surplus production that is lower than the remaining demand. This mainly occurs during the limited sunrise and sunset periods. The rest of the day, all or none of the demand is met.

As stated previously, the distribution of economic surplus gives the best collective bill (i.e., higher savings) that is to be shared among members. From the

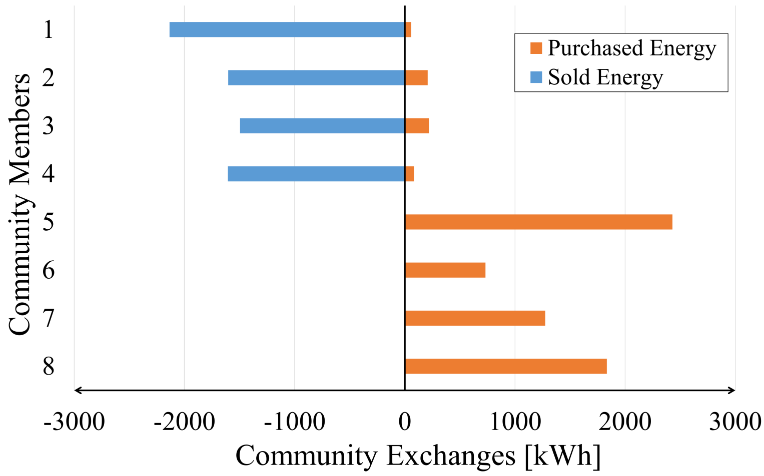


Figure 3.15.: Yearly individual imported and exported local energy with the Prorate Consumption (Key 3).

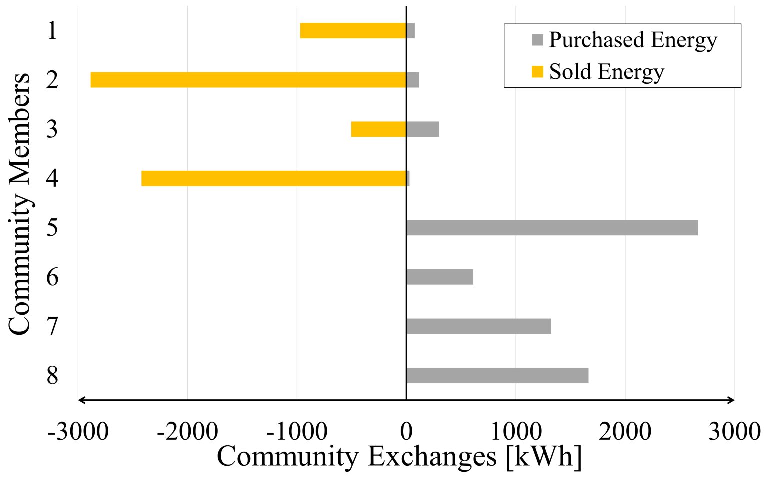


Figure 3.16.: Yearly optimized (Key 14) individual imported and exported local energy.

prosumers perspective the best distribution keys are the *Daily Absolute Net Flow* and *Continuous Absolute Net Flow Keys* (i.e., 10 and 11) as the benefits are shared with respect to the total imported and exported power at REC member's node. Prosumers' relatively high surplus account for a lot in the economic surplus sharing balance. On the other hand, most of the consumers would prefer to go for a *Continuous Prorate Consumption Key* in the economic surplus sharing framework as they get an higher share of the benefits compared to the prosumers who already save money through physical self-consumption. Over the whole community, the *Members Equal Key* applied to the EC economic surplus (i.e., Key 7) leads to the more equitable dispatch of collective savings in absolute value and the *Equal Savings Ratio Key* (i.e., Key 13) achieves the fairest dispatch in relative value. Regarding consumers, Members 5 and 7 almost always face higher individual bills under economic surplus sharing rules than energy surplus sharing ones. The only notable exceptions are Keys 9 and 14. Indeed, these two members consume mainly during the days and are under ToU contracts. For this reason, they benefit of an higher share of the local electricity pool (see Figure 3.16) that is directly reflected with Key 14, but also impacts greatly their savings share with Key 9. Note that Member 5 stands out due to very high overall consumption. Member 8 has a similar position with respect to the different surplus distribution options and also takes advantage of Key 8 thanks to its higher consumption during summer months. Even if his consumption mostly occurs later in the day and benefits less from periods of high local energy availability, the savings dispatch disregards intraday balances and only considers daily consumption. Finally, Member 6, in contrast to other consumers, prefers the *Daily Consumption Prorate Key* (i.e., 8). Despite a flat retailer tariff, its consumption mostly takes place in the evening, which prevents him from participating to dynamic exchanges affecting its bill with continuous mechanisms (Key 10) and optimal economic dispatch strategies (Key 14). Given his consumption pattern, this member might benefit from switching to a ToU contract. Lastly, Key 14 resulting bills are driven by the different retailer contracts among users and follows the above discussion on local energy exchanges with prosumers with flat tariffs and the consumers with ToU tariffs receiving most of the value generated by community exchanges.

"Distribution key-agnostic coordinated DSM scheme in REC misleads participants on their real-time benefits"

This section aims to highlight the deviations that may occur between the demand-side management expected performances, both individual and collective, computed using the baseline day-ahead scheduling problem 2.1, and the observed performances after virtual flows settlement in real time for each of the energy surplus distribution keys presented in Section 3.1.1. To this end, The day-ahead problem is solved distinguishing the baseload consumption profiles of EC members and the flexibility potential offered by their battery storage systems and power and time-shiftable loads. The model schedules the flexible appliances in order to reach the optimal collective bill objective without embedding local energy distribution mechanisms explicitly. The sharing rules are indeed applied *ex-post*, as currently done in Wallonia and France e.g., to settle the true local exchanges and compute the real individual bills. In order to focus on a single source of deviation, namely the ex-post application of sharing rules, we assume a perfect day-ahead forecast of the baseload

Table 3.2.: REC members yearly bill [€] without DSM for each distribution key.

	Members	1	2	3	4	5	6	7	8	Global
	B^0	-161	157	725	393	2101	1564	1257	1825	7860
Energy Surplus	Key 1	-164	126	712	364	1968	1507	1158	1703	7374
	Key 2	-166	118	708	358	1917	1502	1140	1685	7263
	Key 3	-168	109	702	354	1862	1506	1131	1680	7179
	Key 4	-167	111	703	354	1869	1502	1130	1677	7179
	Key 5	-167	111	704	354	1872	1501	1129	1676	7179
	Key 6	-167	111	704	354	1874	1500	1130	1675	7179
Economic Surplus	Key 7	-253	66	633	302	2010	1472	1165	1733	7129
	Key 8	-228	114	650	334	1952	1458	1172	1677	7129
	Key 9	-168	137	701	384	1836	1487	1119	1633	7129
	Key 10	-296	45	596	269	2030	1510	1216	1761	7129
	Key 11	-302	32	603	270	2006	1539	1211	1771	7129
	Key 12	-229	94	684	338	1890	1515	1148	1689	7129
	Key 13	-222	95	643	334	1953	1460	1175	1692	7129
	$B_n^{REC,*}$/Key 14$^+$	-170	90	694	342	1838	1516	1126	1693	7129

$^+$Individual bills directly outputted from the optimal economic dispatch (3.11).

and local production, as well as a perfect compliance of users with the flexible loads and storage system schedules.

Table 3.3 shows that considering demand-side management in the operation of a community can further decrease the optimal collective bill by 21.6 % with respect to the case without DSM in the REC framework (Key 14 in Table 3.2). This improved economic performance is once again directly linked with the energy performances as the collective self-consumption rate raises up to 67.2 % (vs 42.3 % without DSM) and the collective self-sufficiency rate reaches 53.6 % thanks to the flexible loads and storage devices.

From an individual point of view, members' expected bills reductions mainly arise from the optimal scheduling of personal power and time-shiftable loads to better match the production periods but also from the use of storage devices for individual but also collective purpose. The latter explains that although member 8 does not have any flexibility resource, it still benefits from a lower expected electricity bill. Table 3.4 depicts, for each member, the average daily stored energy (i.e., the effective discharged volume used to supply demand) and the percentage of shifted consumption (with respect to the total consumption) computed by the optimal dispatch model. Regarding prosumers (Members 1 to 4), additional savings come from the improved individual self-consumption but also thanks to the increased volume sold in the community as consumers' demand (Members 5 to 8) is shifted to match the production. Following the same price-based prioritization explained in the previous section, Members 2 and 4 have the best gain as output of the DSM problem in day-ahead. Regarding consumers, Members 5 and 6 high demand flexibility potential reduce their bill while Member 7 has a bill increase compared to the optimal economic dispatch without DSM, despite its battery storage system. This can be explained by making its battery available to the community. Indeed, to improve the collective objective Member 7 stores more local energy than for its own use to supply other members in need later on, such as Member 8 who takes advantage of others' storage devices. As community export price is lower than the import price, Member 7 looses money by following this strategy. Additionally, flexibility is deployed by Members with Time of Use contracts to take advantage of their night tariffs when possible.

Nevertheless, if the REC opts for (or is imposed to apply) the energy surplus sharing mechanisms, the expected bill resulting from the resolution of the day-ahead scheduling problem is not necessarily the one actually charged to members, even though they follow the day-ahead optimal recommendations and no forecast errors are observed. This is shown in Table 3.3 for the 6 typical energy surplus distribution keys. As discussed in the previous section without demand-side management, deviations in the economic performances (i.e., bill savings) can be observed at the community and individual level for identical physical flows. This is because the optimal economic dispatch of virtual flows does not correspond to any regulatory-compliant distribution mechanism. *Members and Consumers Equal Keys* (1 and 2) lead to the largest deviation in collective and individual savings between the day-ahead expectations and the real time realization. However, if in the previous section the negative performances of those keys was just a matter of inefficient economic dispatch, in the present case it also leads to uncompensated discomforts for the members. Indeed, with Key 1, Member 5 loses the most potential savings with an increase of 208 € per year while despite having the highest percentage of shifted consumption (i.e., 49 %). Regarding the other distribution keys (3 to 6), they reach the expected levels of collective self-consumption and self-sufficiency rate but the dispatch of economical flows leads to savings degradation.

"Embedding Energy Surplus Distribution Keys Enhances and Preserves Day-Ahead Scheduling Performances"

To cope with the above limitation arising in the energy surplus sharing framework and to avoid the activation of flexibility resources whose related discomfort is not adequately remunerated, we propose to directly integrate the distribution key selected by the energy community in the day-ahead scheduling problem formulation, as presented in Section 6.3. The problem is solved for each of the 6 energy surplus keys that were reformulated to be embedded in the day-ahead model and economical results are presented in Table 3.5.

Table 3.3.: REC members expected ($B_n^{REC,*}$) yearly bill [€] with DSM and real bills after energy surplus distribution with the 6 keys rules.

	Members	1	2	3	4	5	6	7	8	Global
	$B_n^{REC,*}$	-354	-338	548	-126	1676	1446	1130	1609	5591
Ex-post alloc.	Key 1	-318	-201	613	-3	1884	1485	1270	1687	6416 (+14.76%)$^+$
	Key 2	-352	-233	577	-31	1806	1469	1208	1647	6092 (+8.96%)
	Key 3	-393	-281	522	-70	1699	1445	1138	1601	5660 (+1.23%)
	Key 4	-395	-280	525	-70	1701	1443	1137	1602	5663 (+1.29%)
	Key 5	-395	-280	527	-70	1703	1441	1137	1602	5664 (+1.31%)
	Key 6	-395	-280	527	-70	1704	1442	1137	1600	5666 (+1.34%)

$^+$ Relative global bill deviation with respect to the expected collective bill $B^{REC,*}$.

Table 3.4.: Flexibility activated for each member according to the day-ahead scheduling problem.

Members	1	2	3	4	5	6	7	8
Stored energy [kWh/day]	0	6.53	0	7.82	0	0	2.56	0
Shifted consumption [%]	36	30	6	0	49	41	12	0

From a collective point of view, integrating the distribution keys outperforms the typical day-ahead scheduling/ex-post allocation two steps framework. The added value of the proposed method is particularly significant for the *Members Equal* and *Consumers Equal* distribution keys (1 and 2) as it narrows, for instance, the optimality gap with respect to the optimal economic objective ($B^{REC,*}$) by 3.55 % (i.e., from 14.75 % with the two steps method to 11.2% with the proposed method) for Key 1 and by 3.36% for Key 2 (i.e., from 8.96 % to 5.60 %). For the other repartition keys, the resulting collective bill with the sharing rules-aware framework are less than 1% higher than the global optimum one without energy sharing-rules. Indeed, with the collective economic objective function, the two steps approach without explicit consideration of distribution keys in the scheduling phase could lead to consumption shift by REC members driven by the attractive prices of REC internal exchanges during solar production hours. However, in the second phase, applying those two key mechanisms that do not consider the consumption level was leading to uncompensated (and sometimes counterproductive, see Member 7 in the previous section) flexibility activation. Meanwhile, by embedding these keys in the DSM optimisation problem, the REC members consumption is scheduled according to both the differentiated tariffs and the sharing rule directly.

The improved savings with the sharing rules-aware DSM compared to the ex-post

Table 3.5.: REC members expected ($B_n^{REC,*}$) yearly bill [€] with DSM without and with embedded energy surplus distribution keys.

	Members	1	2	3	4	5	6	7	8	Global
	$B_n^{REC,*}$	-354	-338	548	-126	1676	1446	1130	1609	5591
Integrated	Key 1	-328	-220	613	-26	1835	1506	1134	1703	6217 (+11.20%)
	Key 2	-365	-263	578	-58	1773	1477	1106	1658	5904 (+5.6%)$^+$
	Key 3	-389	-287	517	-78	1706	1440	1146	1594	5649 (+1.04%)
	Key 4	-394	-280	518	-78	1708	1437	1142	1601	5654 (+1.12%)
	Key 5	-396	-289	517	-79	1709	1437	1153	1600	5653 (+1.11%)
	Key 6	-393	-284	520	-79	1707	1437	1147	1592	5646 (+0.98%)

$^+$ Relative optimality gap with respect to the best collective bill $B^{REC,*}$.

allocation only are directly connected with the increase in local exchanges made possible by the sharing rules-aware scheduling of power and time-shiftable loads and battery storage devices. Figures 3.17 and 3.18 both present the yearly global flexible volume deployed (i.e., shifted consumption volume and stored energy) along with the yearly collective locally exchanged electricity volume for the ex-post allocation only and direct integration frameworks respectively. One can see that the proposed approach ensures that consumption is not shifted when there is no cheaper local electricity available. If the increased consumption during night hours remains constant for every situation (i.e., DSM without or with any of the 6 distribution keys), the volume that must be shifted to solar production hours to increase local and advantageous electricity exchanges is adjusted according to the sharing rule applied as shown in 3.18. Meanwhile, with the recommended schedules for the power and time-shiftable devices as well as battery storage units by the DSM scheduling problem without explicit distribution keys formulation there is a significant amount of uncompensated flexibility efforts as highlighted in Figure 3.17.

Regarding the computational complexity, the simulation time is highly related to the selected energy surplus distribution key. Indeed as some formulation implies the use of additional binary variables and constraints. For our REC with 8 members, simulation times have been observed on the month of July, during which lots of local exchanges occur due to the high PV potential. They reach on average 0.13s/day without KoR and 94.55s/day at most with embedded keys, the *Members Equal Key* being the most time consuming one as this sharing principle tends to move the solution away from the optimum one.

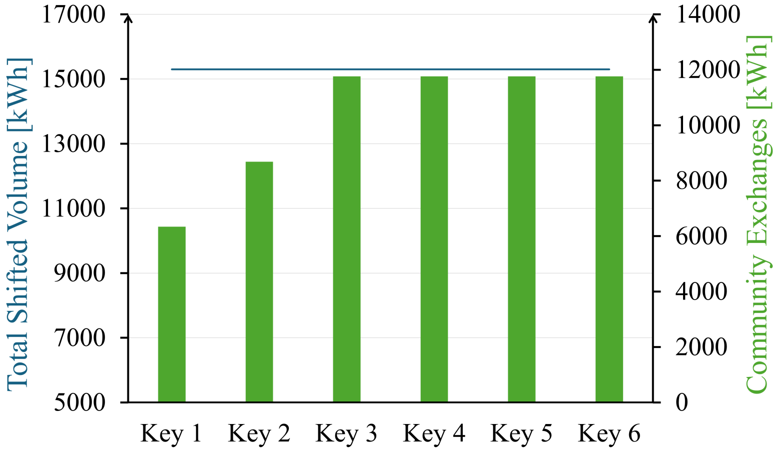


Figure 3.17.: Yearly community exchanges vs total flexibility volume deployed without integrated KoRs

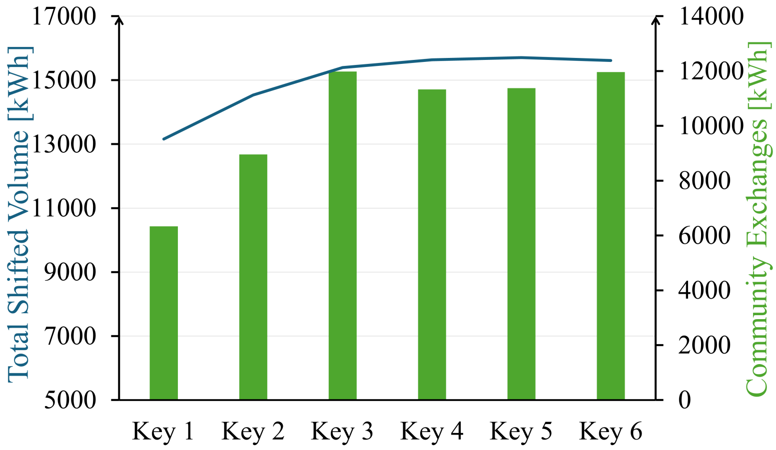


Figure 3.18.: Yearly community exchanges vs total flexibility volume deployed with integrated KoRs.

3.5. Intermediate Conclusion

In this work, authors aimed to provide clear insights on the different local energy sharing mechanisms existing in the literature and in EU member states, and proposed for the first time a Mixed Integer Linear formulation of the day-ahead community optimal dispatch problem which integrates a chosen energy surplus sharing rule among 6 regulatory-compliant [13], [14] ones. To that end, the sharing rules are formulated as explicit constraints of the optimal dispatch problem, so that REC members maximize the economic value of local exchanges (or any other objective function) by operating optimally their flexible devices while anticipating on the sharing rules outcomes.

First, a comparison of the two sharing rules paradigm, namely the Economic Surplus and the Energy Surplus distributions, was performed on a domestic REC made by 8 heterogeneous members without demand-side management. Results show that, from a collective point of view, the economic surplus distribution scheme outperforms the energy surplus one. We show that the *Prorate Consumption* (Key 3), *Cascade* (Key 4) and the two *Hybrid* (Keys 5 & 6) energy distribution keys are intrinsically energy efficient and therefore able to capture the dynamic behaviour and natural balance of local consumption and production. However, they still fail to capture the individual tariffs contracts with retailers to extract the most economic benefits possible, leading up to 3.12 % of savings reduction compared to Economic Surplus sharing schemes. Nevertheless, shifting the regulation towards Economic Surplus distribution might be difficult to justify and implement as the savings could be completely uncorrelated from the energy exchanges.

Then, authors pointed out the misleading effects of disregarding the distribution keys in the day-ahead demand-side management problem as one could observe deviations between the expected electricity bill arising from the flexible resources scheduling and the real-time benefits contracted after the application of settlement rules, raising up to 14.76 % with the *Members Equal Key*, even in case of perfect forecasts of the base load and local generation. This arises when the optimal dispatch of energy flows obtained in day-ahead does not match any energy dispatch using regulatory-compliant sharing rules. Another drawback is that participants may be asked to shift a significant part of their consumption for much lower benefits than expected. For instance, the member 5 was 208 € short from the expected savings after leveraging 49 % of flexible consumption. These deviations and unreliable scheduling may alter the engagement of participants in the local sharing activities.

To cope with this issue, authors exposed the benefits of the proposed integration of the energy sharing mechanisms within the community demand-side scheduling problem. The two main advantages of this method are, first, that by anticipating the settlement mechanism no deviations between the expected (day-ahead) and truly settled (real-time) bills are experienced by REC members, provided that they follow well the DSM recommendations and there is no data uncertainty, ensuring their willingness to participate and unlock flexibility. Secondly, the distribution key-aware scheduling of flexible resources may be improved to get closer to the collective optimum without any sharing rules restriction, by taking into account the individual retailer prices at the same time. This helps to reduce the gap with the best, energy sharing rules free, collective bill to 11.20 % for the *Members Equal Key*. It should be noted that although numerical results are greatly affected by the REC members characteristics, the proposed formulation can only match or improve the results of the traditional ex-post application of energy sharing mechanisms.

Furthermore, it can be extended along with the comparison methodology to any REC, keeping in mind the added computational complexity brought by the added constraints and binary variables.

Future works would further investigate the dependency between REC members characteristics and individual preferences for specific energy or economic surplus distribution schemes. Extending this analysis through case studies or social and behavioral experiments, would also provide valuable insights into the social acceptance and perceived fairness of these sharing mechanisms. Particular attention could be given to households facing energy poverty, in order to assess whether certain sharing rules can promote greater inclusion within RECs. One could also want to assess the performances of the proposed method in case of day-ahead uncertainty regarding the power production and baseload consumption.

Another interesting direction that is investigated in Chapter 4 is the adoption of a decentralized approach (see Section 4.2). Comparing this approach to the centralized approach could help assess the trade-offs between global performance and individual participation, while taking into account data confidentiality issues, which is a key concern in the context of energy communities.

CHAPTER 4.

Community Members-Centred Flexibility Activation

From a collective perspective, the augmented coordinated flexibility scheduling model that integrates the energy sharing rules constraints proposed in Chapter 3 improves the flexibility scheduling by avoiding to send flexible actions request that would not be rewarded. Nevertheless, if we refocus attention on the community members, this model exhibits two main limitations: 1) Energy sharing rules do not explicitly reward flexible members; 2) The centralized approach requires that the community operator gathers information on all flexible devices of individuals. This chapter, presents the mechanisms and techniques developed in this thesis to overcome these limitations. First, in Section 4.1, innovative reward mechanisms explicitly accounting for the flexibility potential and the flexible actions of end-users are designed. Then, a decentralized resolution algorithm for the scheduling of flexible resources without data-privacy violation is proposed.

The contributions of this chapter have been published in the following articles:

[18] J. Allard, F. Vallée, Z. De Grève, T. Stegen, M. Glavic, and B. Cornélusse, "Quantifying, activating and rewarding flexibility in renewable energy communities," in *2024 IEEE PES Innovative Smart Grid Technologies Europe*, 2024, pp. 1–5.

[19] T. Stegen, J. Allard, N. Diffels, F. Vallée, M. Glavic, Z. De Grève, B. Cornélusse, "Explicit reward mechanisms for local flexibility in renewable energy communities," *accepted in Electric Power Systems Research*, 2026.

4.1. New Reward Mechanisms for Flexible Actions

As discussed in the previous section, if flexible actions, i.e., consumption shifts or energy storage usage, are not remunerated accordingly, this could jeopardise the commitment of REC participants in the joint Demand-Side Management of flexible resources, or even in the community exchanges. Indeed, when they mobilize flexibility, end-users accept to leave a more comfortable position (i.e., typical consumption habits based on heterogeneous preferences) with the expectation to perceive economic benefits that would compensate the loss of comfort and provide additional value. This highlights the need to consider the impact of the flexibility activation on end-users' discomfort in the scheduling phase to ensure the responsiveness of members.

Furthermore, we showed in Figure 3.18 that by integrating energy surplus KoRs in the coordinated DSM problem one could reduce the non-remunerated flexibility efforts at the REC scale. However, from an individual perspective no sharing mechanism (economic or energy surplus repartition) explicitly rewards end-users flexibility offers and activations. Some sharing rules, by design, tend to indirectly encourage greater flexibility in the consumption habits, as discussed in [87], but there is no guarantee on the individual profitability of flexible actions. Indeed, one may observe that from a community level, the collective savings compensate all the comfort losses and even provide additional benefits but it is the way these collective savings are distributed that incentivizes flexible behaviours.

The work conducted in this thesis, in collaboration with Thomas Stegen from Université de Liège (Belgium), particularly lies in proposing and comparing innovative explicit flexibility reward mechanisms for unlocking/mobilizing end-users flexibility in a renewable energy community framework for local arbitrage purposes only. The later information indicates that the only flexibility incentive signal considered is the advantageous price of local electricity with respect to retailer one. Two paradigms of reward mechanisms are adopted: the first one, is a rule-based approach under the form of typical Keys of Repartition (see Section 6.3 for more details); the second one, is an optimisation-based pricing approach. These mechanisms are applied after the settlement of exchanges and the activation of flexibility but are not embedded in the scheduling approach. Nevertheless, end-users' discomfort cost associated with flexible loads usage are integrated in the objective function of the central coordinator.

In the following, we first present the augmented coordinated flexibility scheduling problem, which extends the problem presented in Section 2.3 by integrating discomfort costs in the objective function, including local distribution network usage constraints and refining the modelling of Electric Vehicles (EVs) charging (e.g., power-shiftable devices). Then, the two distinct flexibility reward approaches are defined before presenting results for a domestic REC.

4.1.1. Discomfort-Aware Coordinated Flexibility Scheduling Model

Looking at the operational horizon of energy communities in Figure 2.5, the problem described in the following is an extended formulation of the day-ahead coordinated optimal scheduling problem which aims at minimizing the community objective function by optimally schedule the use of flexible devices, battery storage systems and economic exchanges in domestic RECs while integrating discomfort indicators. Namely, energy exchange, battery storage and time-shiftable constraints are kept the same. Meanwhile, a refined formulation of power-shiftable devices is considered. Another main feature added to the model is the integration of local distribution network constraints. Hence, the goal is to ensure that if EC members follow the scheduled flexible actions, and consequently improve the objective of the community, no power flows are induced in the distribution network that would lead to violations of the electrical quantities safe range of operation., such as node voltages or line currents. To ensure convexity of the power flow equations, a state-of-the-art second-order cone relaxed formulation [106] is adopted. The discomfort-aware coordinated flexibility scheduling problem is therefore a Mixed-Integer Second-Order Cone Programming (MISOCP) problem that can be written in general terms as:

$$
\begin{aligned}
\min_{\Omega} \quad & \text{Objective function (4.2)} \qquad (4.1)\\
\text{subject to} \quad & \text{Energy exchange constraints } (4.4) - (4.7),\\
& \text{Battery storage constraints } (4.8) - (4.13),\\
& \text{Time-shiftable devices constraints } (4.14) - (4.16),\\
& \text{Power-shiftable devices constraints } (4.17) - (4.24),\\
& \text{Power flow equations } (4.25) - (4.35),\\
& \text{Discomfort constraints } (4.36).
\end{aligned}
$$

in which $\Omega := \{l_{n,t}, i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t}, s_{n,t}, s^{ch}_{n,t}, s^{dch}_{n,t}, soc_{n,t}, x_{n,t}\}$ are the decision variables representing, respectively for each member $n \in \mathcal{N}$ at each time $t \in \mathcal{T}$, the net power flow metered at the point of common coupling (PCC), the power imported/bought from the community, the power exported/sold to the community, the power imported/bought from a retailer, the power exported/sold to a retailer, the battery net power flow, the battery charging power, the battery discharging power, the battery state of charge, the flexible devices power consumption.

Objective function

The energy community objective may be of different nature (economic, ecological, societal,...). In this work, we consider that the energy community aims to minimize its aggregated costs (i.e., maximize its benefits compared to the individual/stand-alone situation) while considering the REC members' discomfort functions related to the flexible loads usage. In addition, one consider that the community is charged for the power losses induced by participants power exchanges with the network. The global objective therefore writes as:

$$F(\Omega) = B^{REC} + \sum_{n\in\mathcal{N}} J_n^{tot} + \pi^{loss} \sum_{t\in\mathcal{T}} P_t^{loss} \tag{4.2}$$

$$B^{REC} = \sum_{t\in\mathcal{T}} \sum_{n\in\mathcal{N}} [\lambda_{n,t}^{ret,imp} i_{n,t}^{ret} - \lambda_{n,t}^{ret,exp} e_{n,t}^{ret} + \gamma^{com}(i_{n,t}^{\text{com}} + e_{n,t}^{\text{com}})]\Delta t \tag{4.3}$$

with $\mathcal{N} = \{1, ..., N\}$ the set of REC users, and $\mathcal{T} = \{1, ..., T\}$ the set of optimisation periods of length Δt. The collective electricity bill, B^{REC}, accounts for the commodity and upstream grid usage charges (4.3). $\lambda^{i,ret}$ and $\lambda^{e,ret}$ are equivalent retailer import and export prices accounting for those charges. Regarding community exchanges,the local commodity price is considered unique, i.e., there are no difference between import and export prices. Hence, combining this hypothesis with the local balance constraint (4.6) allows to discard the local commodity costs from the collective objective. However, a fee is charged for the intra-community exchanges, γ^{com}, accounting for the internal grid usage costs and the community operator remuneration. In addition, J_n^{tot} is the total discomfort function of member n (4.36) over the day and P_t^{loss} the total power losses in the REC distribution network (4.35) compensated at price π^{loss}.

Constraints

As a reminder, each household can be equipped with distributed generation units (e.g., PV panels), a storage system (e.g., batteries), non-flexible loads (e.g., lamp, TV) and flexible loads (e.g., electric vehicles, white goods). The aggregation of electricity flows from all the member's devices constitute their physical net load, $l_{n,t}$ exchanged with the local distribution network at the point of connection:

$$l_{n,t} = b_{n,t} + x_{n,t} + s_{n,t} - g_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.4}$$

$$l_{n,t} = i_{n,t}^{com} + i_{n,t}^{ret} - e_{n,t}^{com} - e_{n,t}^{ret}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.5}$$

$$\sum_{n\in\mathcal{N}} i_{n,t}^{com} = \sum_{n\in\mathcal{N}} e_{n,t}^{com}, \qquad \forall t \in \mathcal{T}, \tag{4.6}$$

$$i_{n,t}^{com}, e_{n,t}^{com}, i_{n,t}^{ret}, e_{n,t}^{ret} \in \mathbb{R}_+, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.7}$$

with equation (4.4) the physical power balance of REC members considering their fixed consumption, $b_{n,t}$, their flexible devices power consumption, $x_{n,t}$, their battery power exchanges, $s_{n,t}$, and their PV power generation, $g_{n,t}$. The virtual power balance decomposing the physical net power in virtual economic exchanges with the REC and with the retailer is expressed in (4.5) and the continuous local balance is ensured via (4.6).

All community members may use an individual battery storage system modeled with state-of-the-art constraints.

$$
\begin{aligned}
& s_{n,t} = s^{ch}_{n,t} - s^{dis}_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (4.8)\\
& -P^{st,max}_{n} \leq s_{n,t} \leq P^{st,max}_{n}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (4.9)\\
& soc_{n,1} = R^{st}_{n} SOC^{st,max}_{n} + \left(\eta^{st} s^{ch}_{n,1} - s^{dis}_{n,1}/\eta_{st}\right) \Delta t, && \forall n \in \mathcal{N}, \quad (4.10)\\
& soc_{n,t} = soc_{n,t-1} + \left(\eta^{st} s^{ch}_{n,t} - s^{dis}_{n,t}/\eta_{st}\right) \Delta t, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \setminus \{1\}, \quad (4.11)\\
& soc_{n,T} = R^{st}_{n} SOC^{st,max}_{n}, && \forall n \in \mathcal{N}, \quad (4.12)\\
& 0 \leq soc_{n,t} \leq SOC^{st,max}_{n}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \quad (4.13)
\end{aligned}
$$

with equation (4.9) limiting the maximum battery power exchange in both direction. The battery state-of-charge evolution follows equation (4.10)-(4.12) considering the battery efficiency, η_{st}. The state-of-charge is limited to the battery capacity, $SOC^{Max}_{st,n}$ via (4.13)[1].

In this work three types of flexible devices ($a \in \mathcal{A}_n$) are considered: white goods (e.g., dishwasher, washing machine), electric vehicles charger and thermal loads (e.g., water boiler, heat pump). The first type falls in the time-shiftable category ($ts \in \mathcal{TS}_n \subset \mathcal{A}_n$) as the sole control variable is the timing to turn the device ON while the two other devices are power-shiftable devices ($ps \in \mathcal{PS}_n \subset \mathcal{A}_n$). Every flexible device is associated to a temporal flexibility window $\delta_a \in \{0,1\}^T$, specified by the owner, during which it can be operated, a value of 1 means that member $n \in \mathcal{N}$ agrees to run the appliance a at time t.

Time-shiftable devices/White goods (WGs) constraints are unchanged. A binary decision variable, $z_{ts,t}$, is used to represent the starting time of the device.

$$
\begin{aligned}
& \sum_{t \in \mathcal{T}} \delta_{ts,t} z_{ts,t} = 1, && \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \quad (4.14)\\
& \sum_{t \in \mathcal{T}} (1 - \delta_{ts,t}) z_{ts,t} = 0, && \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \quad (4.15)\\
& x_{ts,t} = \sum_{\tau = t - \Delta_{ts} + 1}^{t} z_{ts,\tau} P_{ts,t-\tau+1}, && \forall n \in \mathcal{N}, \forall ts \in \mathcal{TS}_n, \forall t \in \mathcal{T}. \quad (4.16)
\end{aligned}
$$

Equations (4.14) and (4.15) impose that the device is started only once during the day in the temporal flexibility window. Its resulting power consumption profile is defined in (4.16).

On the other hand, the set of power-shiftable devices is divided into two subsets ($\mathcal{PS}_n := \mathcal{E}_n \cup \mathcal{H}_n$): EVs charging ($e \in \mathcal{E}_n$) and thermal loads ($h \in \mathcal{H}_n$), whose

[1] Note that this formulation does not restrict the usage of battery storage system to local and green electricity exchanges. Hence, constraints (2.19) and (2.20) are discarded.

flexible behaviours are modelled in different ways. First, EVs are implement as unidirectional batteries for which we can adjust the charging power. The charging operation is characterized by the arrival time to the charging station and the departure time, t_e^{arr} and t_e^{dep}, as well as the arrival and departure state of charge, $soc_e^{EV,arr}$ and $soc_e^{EV,dep}$.

$$
\begin{aligned}
& soc^{EV}_{e,t_e^{arr}} = soc_e^{EV,arr} + x_{e_u,t_e^{arr}}\Delta t, && \forall e \in \mathcal{E}_n, && (4.17)\\
& soc^{EV}_{e,t} = soc^{EV}_{e,t-1} + x_{e,t}\Delta t, && \forall e \in \mathcal{E}_n, \forall t \in [t_e^{arr}, t_e^{dep}], && (4.18)\\
& soc^{EV}_{e,t_e^{dep}-1} = soc_e^{EV,dep}, && \forall e \in \mathcal{E}_n, && (4.19)\\
& 0 \leq x_{e,t} \leq \delta_{e,t} P_e^{max}, && \forall e \in \mathcal{E}_n, \forall t \in \mathcal{T}, && (4.20)\\
& SOC_e^{EV,min} \leq soc^{EV}_{e,t} \leq SOC_e^{EV,max}, && \forall e \in \mathcal{E}_n, \forall t \in \mathcal{T}. && (4.21)
\end{aligned}
$$

with $soc^{EV}_{e,t}$ the electric vehicle state-of-charge and $x_{e,t}$ the charging power of the electric vehicle e. Constraints (4.17) and (4.18) account for the dynamic evolution of the battery state-of-charge when plugged at the charging station. In addition, (4.19) ensures that the EV reaches the desired state-of-charge of the end-user at the end of the charging station. Finally, the power rating of the charging station and the battery capacity and minimum state-of-charge levels are considered via (4.20) and (4.21), with $\delta_{e,t}$ the EV flexibility window, i.e., a binary vector whose elements have a value of 1 when the car is available at the charging station.

Secondly, thermal loads such as electrical water heater are considered to be fully power-flexible loads. Their operation is formulated using the power-shiftable load constraints from Section 2.3, considering that the flexibility window $\delta_{h,t}$ is equal to 1 all day long:

$$
\begin{aligned}
& \sum_{t \in \mathcal{T}} x_{h,t}\Delta t = D_h, && \forall n \in \mathcal{N}, \forall h \in \mathcal{H}_n, && (4.22)\\
& 0 \leq x_{h,t} \leq P_h^{max}, && \forall n \in \mathcal{N}, \forall h \in \mathcal{H}_n, \forall t \in \mathcal{T}. && (4.23)
\end{aligned}
$$

with $x_{h,t}$ the power consumption of thermal load h and D_h the daily consumption volume of the load.

Finally, the total flexible loads' power consumption, $x_{n,t}$, of each REC member is the sum of all their devices power consumption:

$$
x_{n,t} = \sum_{ts \in \mathcal{TS}_n} x_{ts,t} + \sum_{e \in \mathcal{E}_n} x_{e,t} + \sum_{h \in \mathcal{H}_n} x_{h,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \qquad (4.24)
$$

On the other side of the metering device installed at the point of common coupling, the electricity flows in the distribution network infrastructure between the different nodes, affecting the voltage and current electrical quantities. Therefore, power flow constraints are added to the problem to ensure a reliable operation of the distribution network. The radial configuration of the distribution grid allows usage of a relaxed DistFlow model [106]. Let's consider, $\mathcal{ND} = \{1, ..., ND\}$ the set of nodes in the local radial distribution network and nd_{tf} is the substation node. Line nd represents the electrical line reaching node $nd \in \mathcal{ND}$ from the node upstream up_{nd} with impedance $Z_{nd} = R_{nd} + jX_{nd}$. $\mathcal{C}_{nd}$ is the set of downstream nodes of node nd in the oriented graph of the electrical network. Finally, $\Gamma \in \{0,1\}^{N \times ND}$ is a binary matrix whose elements are equal to 1 if end-user n is connected to node nd. The set of power flows constraints can then be expressed as follows:

$$P^{\text{inj}}_{nd,t} = \sum_{n \in \mathcal{N}} -\Gamma_{n,nd} l_{n,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.25}$$

$$P^{\text{inj}}_{nd,t} + P^{\text{line}}_{nd,t} - R_{nd} I^{\text{sqr}}_{nd,t} = \sum_{c \in \mathcal{C}_{nd}} P^{\text{line}}_{c,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.26}$$

$$P^{\text{inj}}_{nd_{tf},t} = \sum_{c \in \mathcal{C}_{nd_{tf}}} P^{\text{line}}_{c,t}, \qquad \forall t \in \mathcal{T}, \tag{4.27}$$

$$Q^{\text{inj}}_{nd,t} + Q^{\text{line}}_{nd,t} - X_{nd} I^{\text{sqr}}_{nd,t} = \sum_{c \in \mathcal{C}_{nd}} Q^{\text{line}}_{c,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.28}$$

$$Q^{\text{inj}}_{nd_{tf},t} = \sum_{c \in \mathcal{C}_{nd_{tf}}} Q^{\text{line}}_{c,t}, \qquad \forall t \in \mathcal{T}, \tag{4.29}$$

$$\begin{aligned} V^{\text{sqr}}_{nd,t} = {} & V^{\text{sqr}}_{up_{nd},t} - 2(R_{nd} P^{\text{line}}_{nd,t} + X_{nd} Q^{\text{line}}_{nd,t}) \\ & + (R^2_{nd} + X^2_{nd}) I^{\text{sqr}}_{nd,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \end{aligned} \tag{4.30}$$

$$V^{\text{sqr}}_{nd_{tf},t} = V^{\text{sqr},ref}, \qquad \forall t \in \mathcal{T}, \tag{4.31}$$

$$I^{\text{sqr}}_{nd,t} V^{\text{sqr}}_{up_{nd},t} \geq P^{\text{line}^2}_{nd,t} + Q^{\text{line}^2}_{nd,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.32}$$

$$V^{\text{sqr},min} \leq V^{\text{sqr}}_{nd,t} \leq V^{\text{sqr},max}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.33}$$

$$I^{\text{sqr}}_{nd,t} \leq I^{\text{sqr},max}_{nd}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{4.34}$$

$$P^{\text{loss}}_{t} = \sum_{nd \in \mathcal{ND}} R_{nd} I^{\text{sqr}}_{nd,t} \qquad \forall t \in \mathcal{T}. \tag{4.35}$$

First,the constraint (4.25) sets the injected power in node nd to the opposite of the total net consumption of members connected to that specific node. This imply that $P^{\text{inj}}_{nd,t}$ is positive when the electricity flows from the household to the network. Then, equations (4.26) and (4.28) represent active and reactive power balances at each node nd, with $P^{\text{line}}_{nd,t}$, $Q^{\text{line}}_{nd,t}$ and $I^{\text{sqr}}_{nd,t}$, respectively, the active power, the reactive power and the squared magnitude of the current flowing in line nd. At the substation transformer downstream node, these constraints are reduced to (4.27) and (4.29). The core of the second-order cone relaxation of power flow equations lays in (4.30) and (4.32). The first one defines the voltage drop and the second the apparent power flow through the line but it can also be seen as the definition of the (squared) current flow. The substation node is considered as the slack node of the local distribution network. Hence, its voltage level is assumed steady over time as imposed by (4.31). Finally, the physical network limits consist in the (squared) line current threshold (4.34) and the safe (squared) node voltages range (4.33). The latter is usually set to $\pm 10\%$ of the nominal voltage according to the EN 50160 standard [107]. The total active power losses in the system, P_t^{loss}, that is part of the objective function is computed via (4.35).

Finally, as presented in the introduction of this section, a major improvement in the formulation of the coordinated flexibility scheduling problem is the consideration of participants comfort/discomfort level. Indeed, the equivalent cost of a loss of comfort, J_n^{tot}, associated to flexible devices' usage are accounted for in the objective function. This cost is defined as a quadratic function of the deviations in the flexible devices power consumption with respect to a reference consumption pattern. This reference profile is assumed to be the preferred behaviour of the end-user when no incentive is offered. For white goods ($\mathcal{TS}_n$), it represents the favourite time to switch on the cycles. For EVs charging ($\mathcal{E}_n$), it corresponds to the power profile in a full-rate/max-power charging mode upon arrival until the departure or the battery capacity is filled. For thermal loads, it is a typical electricity consumption profile to meet a desired temperature. The discomfort function is formulated as:

$$J_n^{tot} = \sum_{a \in \mathcal{A}_n} \pi_a^{comf} \sum_{t \in \mathcal{T}} (x_{a,t}^{ref} - x_{a,t})^2, \qquad \forall n \in \mathcal{N}, \tag{4.36}$$

with $\mathcal{A}_n := \mathcal{TS}_n \cup \mathcal{E}_n \cup \mathcal{H}_n$ the full set of flexible devices of member n, and π_a^{comf} the discomfort equivalent price for each asset. $x_{a,t}^{ref}$, are the reference consumption profile of flexible loads.

4.1.2. Flexibility Reward Methods

Once the coordinated flexibility scheduling problem (4.1) is solved and assuming that there are no day-ahead forecast errors and that in real-time (second step in Figure 2.5) every flexible devices has been operated as schedule, the community has made some profits by benefiting as much as possible from the cheaper local renewable electricity. Now, the remaining concern of interest is the way these collective benefits are split among community members. The core contribution of this work lies in the definition of reward mechanisms explicitly encouraging flexible behaviours. Before presenting the formal definition of those innovative sharing schemes, the definition of collective savings must be clarified. Indeed, to meet our objective, the benefits arising from the natural complementarity of REC members net consumption patterns are distinguished from the additional benefits created by the activation of flexibility. To do so, one must define different benchmark cases.

Different variants (i.e., benchmark cases) can be derived from the scheduling problem presented in Section . In this work, three particular cases can be created by over-constraining two major features: the flexibility potential and the community exchanges. The first alternative implies to impose that despite the incentive offered by the REC framework, the flexible devices are used as usual. This is represented by constraint (4.37) which imposes the power consumption profile of flexible loads to be equal to their reference one:

$$x_{a,t} = x_{a,t}^{ref} \qquad \forall a \in \mathcal{A}_n, \forall t \in \mathcal{T}, \tag{4.37}$$

The second alternative consists in representing the individual framework in which the end-users are not allowed to exchange energy together by applying the following constraint:

$$i_{n,t}^{\mathrm{com}} = e_{n,t}^{\mathrm{com}} = 0 \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.38}$$

Considering this two additional constraints, one can design the four following variants of the flexible resources scheduling problem depicted in Figure 4.1:

(1) Community, flexible
(2) Community, fixed
(3) Individual, flexible
(4) Individual, fixed

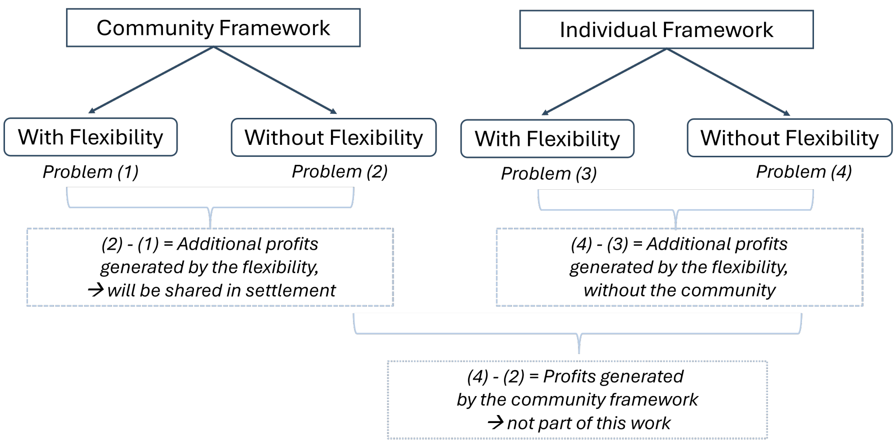


Figure 4.1.: Diagram of flexible resources scheduling problem variants.

Looking at these four problems one can define the benefits from the consumption and production profiles complementarity of REC members, which can be shared with standard techniques [108] as the difference between the costs of Problem 4 and Problem 2. In addition, the benefits related to flexibility activation within the community framework, are expressed as follows:

$$\Pi_d^{flex} = B_d^{\mathrm{REC,fixed}} - B_d^{\mathrm{REC,flexible}} \qquad \forall d \in \mathcal{D}, \tag{4.39}$$

with $\mathcal{D}$ the set of operational days as the rewards are computed on a daily basis, $B_d^{\text{REC,flexible}}$ and $B_d^{\text{REC,fixed}}$ respectively the daily community bills with (Problem 1) and without flexibility (Problem 2) potential.

AS these benefits arise from the engagement of some end-users in flexible actions to benefit the community. This work aims to explicitly reward the actors involved in the coordinated flexibility scheduling scheme and fairly considering the activated and offered flexibility volumes. To this end, the daily activated and offered flexibility volumes are computed for each member. The activated volume is directly related to the optimal usage of the flexible devices obtained by the resolution of the local coordinated flexibility dispatch problem (4.1) while the offered volume is computed by solving another problem which finds the maximum activated volume under the flexible device constraints as presented hereafter:

$$E_{n,d}^{\text{act,flex}} = \sum_{t\in\mathcal{T}} |x_{n,t} - x_{n,t}^{ref}|\Delta t/2, \qquad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}, \tag{4.40}$$

$$E_{n,d}^{\text{cap,flex}} \in \text{argmax } E_{n,d}^{\text{act,flex}} \text{ s.t. (4.14)-(4.24)}, \qquad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}. \tag{4.41}$$

Rule-based Distribution of Flexibility Benefits

The first method proposed to distribute the benefits fairly among the flexibility providers is the application of the following KoR, $k_{n,d}$, which is defined as the ratio of individual weighted sum of activated and offered flexibility with the global one.

$$k_{n,d} = \frac{E_{n,d}^{\text{act,flex}} + \omega E_{n,d}^{\text{cap,flex}}}{\sum_{n\in\mathcal{N}} E_{n,d}^{\text{act,flex}} + \omega E_{n,d}^{\text{cap,flex}}} \qquad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}, \tag{4.42}$$

$$\Pi_{n,d}^{flex} = k_{n,d}\Pi_d^{flex} \qquad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}. \tag{4.43}$$

with $\Pi flex_{n,d}$ the daily individual share of benefits arising from flexible actions and ω the parameter to tune by community members to fine the most suitable trade-off between remuneration of potential and realized flexibility services, knowing that in the later case end-users experience some comfort loss. Several values of this parameter are compared in the results section.

Optimisation-based Remuneration of Flexible Behaviour

The second method is based on the definition of an optimal flexibility price by solving an optimisation problem which aims at minimizing the variance of net individual profits among members, i.e., the profits perceived after compensation of the discomfort cost.

$$\min \sum_{d\in\mathcal{D}} \sum_{n\in\mathcal{N}} [(\Pi_{n,d}^{flex} - J_{n,d}^{tot}) - (\Pi_d^{flex} - \sum_{n\in\mathcal{N}} J_{n,d}^{tot})/|\mathcal{N}|]^2, \tag{4.44}$$

$$\text{s.t.}\Pi_{n,d}^{flex} = \pi_d^{\text{act}} E_{n,d}^{\text{act,flex}} + \pi_d^{\text{cap}} E_{n,d}^{\text{cap,flex}}, \quad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}, \quad (4.45)$$

$$\pi_d^{\text{act}} E_{n,d}^{\text{act,flex}} \geq J_{n,d}^{\text{tot}}, \quad \forall n \in \mathcal{N}, \forall d \in \mathcal{D}, \quad (4.46)$$

$$\textstyle\sum_{n\in\mathcal{N}} \Pi_{n,d}^{flex} = \Pi_d^{flex}, \quad \forall d \in \mathcal{D}, \quad (4.47)$$

with π_d^{act} and π_d^{cap} the decision variables, respectively, defined as the reward prices for the activated and offered flexibility volumes. Equation (4.46) ensures that the total discomfort cost of each member is at least compensated by the benefits of their flexibility activation.

4.1.3. Case Study and Results

This section aims to highlight the most significant results identified in this collaborative work on the integration of discomfort metrics into the coordinated flexibility scheduling problem and the definition of fair explicit reward mechanisms for flexible actions of REC members. In the following, the performances of the proposed scheduling model are compared to the benchmark cases presented in the previous section, specifically looking at the following key performance indicators (KPIs):

1. **Collective Economic Surplus**: The profits generated by the REC Π^{REC};
2. **Flexible Load Usage**: The levels of offered $E_{n,d}^{\text{cap,flex}}$ and activated flexibility $E_{n,d}^{\text{act,flex}}$;
3. **Discomfort Level**: The total discomfort cost of end-users $J_{n,d}^{tot}$;
4. **Grid Usage**: The electrical quantities in the local distribution grid.

Furthermore, the impact of the two proposed value-sharing paradigms for the distribution of benefits arising from flexibility are evaluated in terms of fairness of the net individual surplus repartition among flexible participants. Putting their bill savings in perspective with their discomfort cost.

In this work, this analysis is carried out on a REC composed of 20 domestic end-users connected to a radial distribution grid [109] as depicted in Fig.4.2. Their non-flexible consumption as well as their flexible loads usage parameters are based on the Pecan Street project open data [110]. The first model is solved daily with a one-hour resolution for a complete year. The flexibility rewards settlement problems are run monthly. We assume perfect forecasts of the non-flexible and production profiles in day-ahead (i.e., no deviations between the first and second steps). A constant $\pi_a^{comf} = 0.05$ €/kWh^2 was chosen to represent a community where each participant's aversion to demand flexibilization is equivalent. In this case study, users are considered to have equal and fixed tariffs for retailer imports, i.e., $\lambda^{ret,imp} = 0.4$ €/kWh, and exports, i.e., $\lambda^{ret,exp} = 0.1$ €/kWh. The internal community fees are set to $\gamma^{com} = 0.01$ €/kWh. All input data is available in [111].

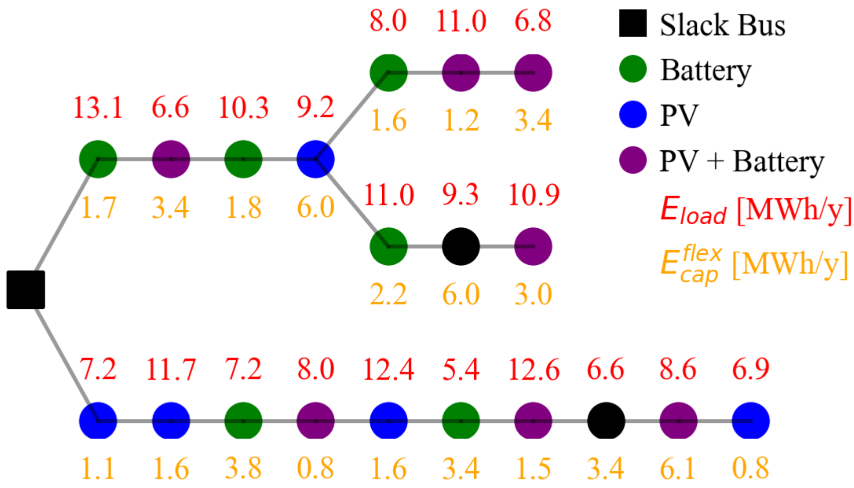


Figure 4.2.: Case study community participants and network configuration.

Collective Economic Surplus Analysis

Figure 4.3 shows the monthly total cost of energy for the four variants of the problem where *Individual* relates to the case without local exchanges (4.38) and *Fixed* relates to the case without flexibility potential (4.37). Table 4.1 displays yearly financial and flexibility usage results. As expected from previous works [17], [112], the community creation significantly reduces the total energy bill. First, in this particular case study, the natural complementarity of members leads to 23.2 k€ (40 %) of yearly savings with respect to the bill in the individual non-flexible framework (i.e., Problem 4 in Figure 4.1). In addition, unlocking end-users' flexibility further improves the benefits of the community, especially during spring and summer periods when the solar potential is the highest (i.e., more local production). These additional savings of 2.7 k€ imply the activation of 9.2 MWh of flexible devices consumption shift. However, if we compare the individual and collective flexible frameworks, we observe that the net cost savings, i.e., difference between total bill savings and discomfort costs, per activated flexibility volume are lower in the collective framework, 252 €/MWh vs 275 €/MWh. This means that as the natural complementarity of consumption patterns already enables members to take advantage of a large portion of the local production, the efforts that must be made to seek additional benefits are more significant.

Flexible Loads Usage and Discomfort level Analysis

Table 4.2 displays flexible load capacity, usage and discomfort for each type of load. It shows that EVs charging represent the biggest share of available flexibility as they are more energy-intensive assets. In contrast, thermal loads demand varies

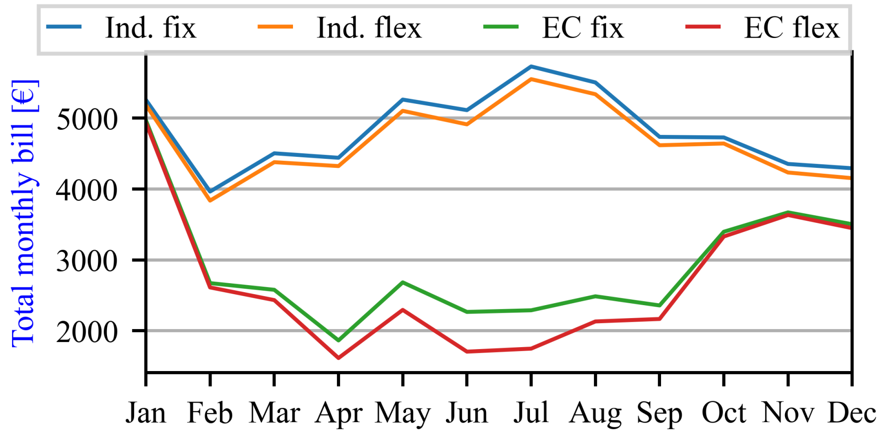


Figure 4.3.: Monthly bills of the whole community for the four problem variants.

Table 4.1.: Yearly financial and flexibility results for the four problems

Framework	Individual		REC	
Demand	Fixed	Flexible	Fixed	Flexible
Total bill [€]	57,900	56,300	34,700	32,000
Total discomfort [€]	0	142	0	382
Activated flexibility [MWh]	0	5.3	0	9.2

over the year with the weather conditions which limits their flexibility potential. Shifted EVs charging pattern are also the most activated flexible actions as the power level can be adjusted during each period of the availability window. On the contrary, white goods usage is less modulated as it implies the shift of the full consumption window. From its definition in 4.36, we naturally observe that the associated loss of comfort cost are directly dependent with the level of activated flexibility.

Table 4.2.: Flexibility usage and associated discomfort

	Individual				REC			
	WG	EV	H	Tot.	WG	EV	H	Tot.
E^{cap}[MWh]	9.1	40.4	4.8	54.3	9.1	40.4	4.8	54.3
E^{act}[MWh]	0.7	2.5	2.0	5.3	1.0	5.1	3.1	9.2
J[€]	37	79	26	142	51	269	61	382

Grid Usage Analysis

Regarding the stress on the distribution network, Table 4.3 shows that if several benefits arise by aggregating end-users in a community, as already demonstrated in [16], the activation of flexibility has a relatively low impact in this case study. This is linked to the limited additional gains that can be retrieved from the community exchanges after the first round of effortless energy sharing. The flexible behaviours of REC participants mainly reduce the losses and improve the self-consumption and self-sufficiency rates in both individual and EC frameworks. Regarding the consumption peak at the REC level, results show that no positive impact is necessarily observed if the cost function only takes into accounts volumetric tariffs.

Table 4.3.: Summary of network usage for the four problems

Framework	Individual		REC	
Demand	Fixed	Flexible	Fixed	Flexible
Total losses [MWh]	143.8	134.6	94.7	86.9
Max voltage [pu]	1.03	1.03	1.02	1.03
Max line loading [%]	74	74	69	70
Self-consumption [%]	51	52	84	87
Self-sufficiency [%]	40	42	67	69
REC peak [kW]	7.56	7.33	7.40	7.56

Individual Economic Surplus

Finally, regarding the distribution of collective economic surplus among end-users, the upper part of Figure 4.4 shows the activated and offered flexibility volumes per member. In the graph, members are ordered by ascending activated flexibility on the x axis. On the other hand, the lower part compares the individual benefits obtained from the different settlement methods. It clearly shows that for all proposed methods, the individual discomforts are compensated. Compared to an equal distribution of the benefits (solid blue line), the different methods proposed (green, red and purple bars) follow the individual flexibility level. Green bars (i.e., activated flexibility only KoR) do not exactly follow the activated flexibility volume as the benefits are aggregated over one year with a daily settlement frequency.

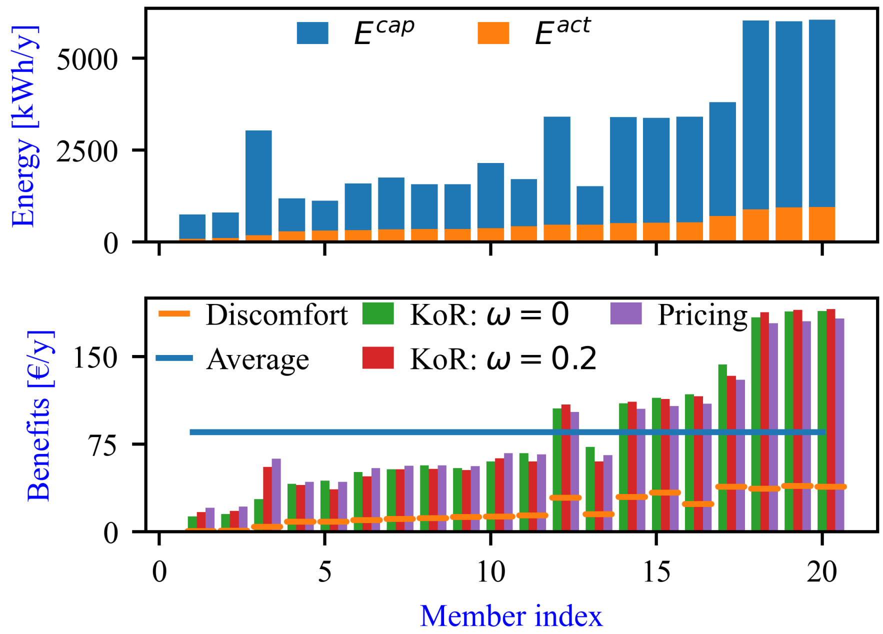


Figure 4.4.: Individual benefits of REC users with different settlement methods.

4.1.4. Intermediate Conclusion

By proposing realistic discomfort modelling and fair flexibility reward methods, this work shows the added value of incentivizing end-users to mobilize flexibility in a REC framework in terms of economic savings and network usage. Readers should also notice that despite the easiest implementation of the rule-based approach, it requires finding an adequate value for ω.

For a REC composed of 20 domestic end-users, we observed that the additional savings arising from the coordinated activation of flexible resources in a collective framework highly depends on the remaining local production after the naturally complementary non-flexible demand is covered by community exchanges. In some situation, significant flexible efforts, in terms of loss of comfort, could be needed to save some extra money. For the same reasons, only minor, but which deserve to exist, impact on the grid performances were observed regarding the reduction of line losses in the local distribution network and increase levels of self-consumption and self-sufficiency.

Regarding the repartition of collective benefits among participants with the proposed explicit flexibility reward mechanisms, we showed that they achieved equivalent performances. Indeed, as they explicitly integrate in their definition/resolution the levels of offered and activated flexibility volumes, a larger share of the savings linked to flexible actions goes to the most flexible end-users.

To improve the work presented in this section, a natural extension is to consider the flexibility capacity as a decision variable of the REC members in a decentralized approach considering the community manager as leader which send explicit flexibility incentives. This second approach is presented in the next section and performances of both the centralized and decentralized approaches are compared.

4.2. Preserving Data Privacy and Collective Performances

Until now, all the coordinated flexibility scheduling problems presented in this thesis are solved using a centralized approach. It means that to optimize the community objective through the use of members flexible devices, the community operator has to gather each day information from participants regarding their flexible load characteristics and expected usage. This principle, often adopted when focusing on the collective performances rather than the individual engagement in unlocking flexible behaviours [59], [60], may raise questions regarding data-privacy concerns [80], [81]. Indeed, end-users would often prepare to limit the exchange of personal information with external parties.

In the continuity of the collaborative work with Thomas Stegen [18] presented in the former Section 4.1, the work presented in this section aims to propose a decentralized resolution approach of the coordinated flexibility scheduling problem. The objective is to maximize the valorization of local arbitrage in energy communities. To this end, we design an intuitive privacy-preserving sequential approach to identify the equilibrium between the community operator flexibility activation decisions and the independent flexible capacity offered by members. In the proposed decentralized methodology, the mobilization of EC members' flexibility is incentivized by the community operator via a requested volume and reward price pair. In response to these explicit signals, consumers rationally offer flexible volumes for activation by the community operator according to their individual capabilities. Finally, besides sending the incentives to the community participants, the community operator also guarantees a fair distribution of the activated volume through a rule-based approach based on regulatory-compliant Keys of Repartition (KoRs) inspired by the Belgian framework [14], [108].

The flexibility potential of domestic end-users is represented in this work by the following flexible loads: water boilers, heat pumps, and electric vehicles charging. Those power-shiftable appliances are intrinsically controllable without user interactions and represent an important part of household consumption when they are present. To model these flexible resources, we embed an equivalent storage formulation of four relevant flexible domestic appliances (batteries, electric vehicles, heat pumps, water boilers) in the operational load scheduling problem. Compared to state-of-the-art bilevel [86] and ADMMs [84] methods, the proposed algorithm allows to embed more precise (and potentially non-convex) models of flexible appliances, without noticeably increasing the computational complexity.

In the remainder of this paper, 4.2.1 describes the flexibility coordination framework for energy communities that is implemented in the optimisation problem. Then 4.2.2 presents the centralized flexibility model, that builds on the model of Section 4.1 with an upgraded formulation of thermal flexible devices. The proposed intuitive privacy-preserving sequential approach to decentralize the model resolution is described in Section 4.2.3. One major objective of this work is to quantify the gap in collective cost savings between centralized and decentralized coordination of end-user flexible resources. Hence, 4.2.4 presents the case study used to assess the performances of both paradigms and showcases the comparison results. Finally, 4.2.5 presents the main conclusions.

4.2.1. Flexibility Coordination Framework

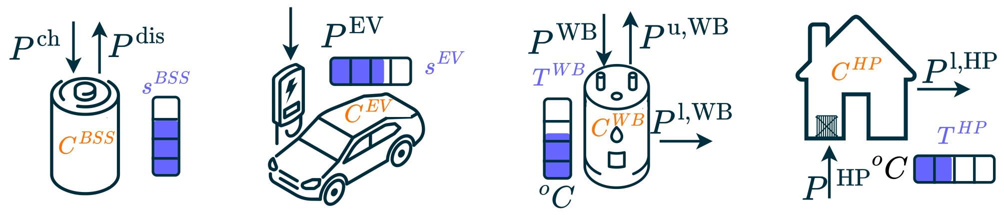
This work considers a REC entity that is constituted by a group of domestic consumers and prosumers, i.e., PV-equipped consumers, that can either exchange electricity with each other or with their traditional retailers. The organization of the local electricity sharing between participants is put in hands of a Community Operator (CO). Besides ensuring local balance and billing of members baseline exchanges within the community, the CO is also responsible for coordinating the flexibility scheduling which is the main focus of this work.

To run this task, assuming a perfect forecast of generation and baseline consumption, the CO identifies the flexibility needs of the community for each time period of the day (in both upward and downward directions) to maximize the value of local arbitrage. Then, it passes this information to members along with a reward price. Based on this volume-price pair, the EC members offer flexibility capacity, i.e., based on flexible loads consumption shifting, to the operator. Finally, the operator activates the offered capacity by applying predefined rules that takes the form of Keys of Repartition.

Hereafter, the different flexible loads considered in this study are presented in detail, as well as the Keys of Repartition compared for the fair activation of flexibility within the REC.

Flexible Load Models

With the growing electrification of energy demand, new opportunities to unlock flexibility in the consumption profiles of end-users emerge. At the residential level, three main devices have been identified and considered in this work, namely, electric vehicles (EVs) charging, water boilers (WBs) and heat pumps (HPs). The first one, once plugged, allows adaptation of the charging strategy to the needs of the owner, while for the other two, the flexibility comes from the elasticity of the thermal demand as some end-users may have a comfort temperature range and not a specific desired value. In this work, all three flexible load types (or the related demand) are modeled similarly to a battery storage system (BSS) as depicted in Figure 4.5. It means that each one has a state variable (i.e., EV's battery state-of-charge, water temperature of the boiler and indoor air temperature), incoming/outgoing electrical power flows, and a capacity that converts the power exchanges to a change of state (in kWh or in C).



(a) BSS model (b) EV model (c) WB model (d) HP model

Figure 4.5.: Equivalent battery representation of the flexible equipments.

Keys of Repartition

Regarding the activation of flexibility, a rule-based approach is adopted by the community operator. These rules are represented by Keys of Repartition that are usually applied to share the local energy available among members in some countries (*e.g.*, Wallonia (BE) or France) as extensively discussed in Section 6.3. The general KoR mechanism is adapted for flexibility activation as follows:

$$P_{n,t}^{act} = \min(k_{n,t} P_{0,t}^{cap}, P_{n,t}^{cap}), \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.48}$$

where $P_{n,t}^{cap}$ is the flexible power capacity offered by each member, $P_{0,t}^{cap}$ is the flexible capacity requested by the CO to minimize the collective bill by favouring local energy exchanges, $P_{n,t}^{act}$ is the activated flexible power of each member and $k_{n,t}$ is the share of the global requested volume asked by the operator to member n. Among the existing KoRs, three specific ones presented in Section 3.1.1, i.e., active users equal (c.f., Key 2), prorate capacity (c.f. Key 3), and cascade (c.f. Key 6) KoRs, are considered and compared in terms of benefits distribution between flexible members. The KoR principles are tuned for their application to the flexibility activation problem as follows:

Active Users Equal Key: This key is the simplest one as it splits the requested flexible volume, for activation, equally between the participants who offer individual flexible capacity.

$$k_{n,t} = \begin{cases} \frac{1}{|\mathcal{N}_t^{flex}|} & \forall n \in \mathcal{N}_t^{flex}, \forall t \in \mathcal{T}, \\ 0, & \text{otherwise.} \end{cases} \tag{4.49}$$

with $\mathcal{N}_t^{flex} = \{n \in \mathcal{N} | P_{n,t}^{cap} > 0\}$ the set of REC participants who offered flexible capacity during period t.

Prorate Capacity Key: This key shares the requested flexibility volumes among participants based on their offered capacity, $P_{n,t}^{cap}$, with respect to the overall capacity available within the REC.

$$k_{n,t} = \frac{P_{n,t}^{cap}}{\sum\limits_{m \in \mathcal{N}} P_{m,t}^{cap}}, \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.50}$$

Cascade Key: This key principle relies on the iterative application of the *Active Users Equal Key* in order to maximize the activated volume and match the requested one. At each iteration, the set of flexibility providers $\mathcal{N}_t^{flex}$ is recomputed based on the remaining non-activated capacity of each member after the previous activation rounds. The process stops when there remains no offered capacity or the community operator's request is met. The practical application at each time period, $t \in \mathcal{T}$, of the *Cascade Key* follows Algorithm 3.

Algorithm 3: Flexibility Activation - Cascade Key Principle

Input: $P_{n,t}^{cap}, P_{0,t}^{cap}$

Initialize remaining individual and requested flexible capacities:

$P_{n,t}^{cap,rem} = P_{n,t}^{cap} \quad \forall n \in \mathcal{N}$;

$P_{0,t}^{cap,rem} = P_{0,t}^{cap}$;

Initialize individual activated volumes:

$P_{n,t}^{act} = 0 \quad \forall n \in \mathcal{N}$;

while $\sum\limits_{n \in \mathcal{N}} P_{n,t}^{cap,rem} > 0$ ***and*** $P_{0,t}^{cap,rem} > 0$ **do**

  Compute the number of remaining flexibility providers:

  $\mathcal{N}_t^{flex} = \{n \in \mathcal{N} | P_{n,t}^{cap,rem} > 0\}$;

  Apply the Equal Key to activate flexibility:

  $P_{n,t}^{act} = \max(P_{n,t}^{cap}, P_{n,t}^{act} + P_{0,t}^{cap,rem} / |\mathcal{U}_t^{flex}|) \quad \forall n \in \mathcal{N}$;

  Update remaining individual and requested flexible capacities:

  $P_{n,t}^{cap,rem} = P_{n,t}^{cap} - P_{n,t}^{act} \quad \forall n \in \mathcal{N}$;

  $P_{0,t}^{cap,rem} = P_{0,t}^{cap} - \sum\limits_{n \in \mathcal{N}} P_{n,t}^{act}$;

end

4.2.2. Centralized Flexibility Activation Problem

The coordinated flexibility scheduling problem that we propose to solve in a decentralized way using the innovative privacy-preserving iterative approach is based on problem (4.1). Only a few adaptations are made in this work. First, white goods are withdrawn from flexible assets as we observed in Section 4.1.3 that their consumption shift potential are not often activated as it implies to move the whole consumption pattern in time, leading to big comfort loss. Then, we decided to remove the direct consideration o of possible impacts of the REC flexible actions on the low voltage distribution network. Hence, power flow constraints

(4.25)-(4.35) are not included in the problem but an *ex-post* power flow analysis is run to observe the effect on electrical quantities. Finally, the thermal load devices options are refined to heat pumps for space heating and water boiler for sanitary water heating. For these devices, similarly to the model adopted for EVs charging in the previous Section, a state-space model of these two flexible devices are considered. The common objective function and constraints from problem (4.1) are recalled hereafter:

$$
\begin{aligned}
\min_{\Omega} \;& F(\Omega) = B^{REC} + \sum_{n\in\mathcal{N}} J_n^{tot} && (4.51)\\
\text{s.t. }\; & B^{REC} = \sum_{t\in\mathcal{T}}\sum_{n\in\mathcal{N}} [\lambda_{n,t}^{ret,imp} i_{n,t}^{ret} - \lambda_{n,t}^{ret,exp} e_{n,t}^{ret} + \gamma^{com}(i_{n,t}^{\text{com}} + e_{n,t}^{\text{com}})]\Delta t, && (4.52)\\
& l_{n,t} = b_{n,t} + x_{n,t} + s_{n,t} - g_{n,t}, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.53)\\
& l_{n,t} = i_{n,t}^{com} + i_{n,t}^{ret} - e_{n,t}^{com} - e_{n,t}^{ret}, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.54)\\
& \sum_{n\in\mathcal{N}} i_{n,t}^{com} = \sum_{n\in\mathcal{N}} e_{n,t}^{com}, \quad \forall t\in\mathcal{T}, && (4.55)\\
& i_{n,t}^{com}, e_{n,t}^{com}, i_{n,t}^{ret}, e_{n,t}^{ret} \in \mathbb{R}_+, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.56)\\
& s_{n,t} = s_{n,t}^{ch} - s_{n,t}^{dis}, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.57)\\
& -P_n^{st,max} \le s_{n,t} \le P_n^{st,max}, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.58)\\
& soc_{n,1} = R_n^{st} SOC_n^{st,max} + \left(\eta^{st} s_{n,1}^{ch} - s_{n,1}^{dis}/\eta_{st}\right)\Delta t, \quad \forall n\in\mathcal{N}, && (4.59)\\
& soc_{n,t} = soc_{n,t-1} + \left(\eta^{st} s_{n,t}^{ch} - s_{n,t}^{dis}/\eta_{st}\right)\Delta t, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}\setminus\{1\}, && (4.60)\\
& soc_{n,T} = R_n^{st} SOC_n^{st,max}, \quad \forall n\in\mathcal{N}, && (4.61)\\
& 0 \le soc_{n,t} \le SOC_n^{st,max}, \quad \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, && (4.62)\\
& soc_{e,t_e^{arr}}^{EV} = soc_e^{EV,arr} + x_{e_u,t_e^{arr}}\Delta t, \quad \forall e\in\mathcal{E}_n, && (4.63)\\
& soc_{e,t}^{EV} = soc_{e,t-1}^{EV} + x_{e,t}\Delta t, \quad \forall e\in\mathcal{E}_n, \forall t\in[t_e^{arr}, t_e^{dep}], && (4.64)\\
& soc_{e,t_e^{dep}-1}^{EV} = soc_e^{EV,dep}, \quad \forall e\in\mathcal{E}_n, && (4.65)\\
& 0 \le x_{e,t} \le P_e^{max}, \quad \forall e\in\mathcal{E}_n, \forall t\in\mathcal{T}, && (4.66)\\
& SOC_e^{EV,min} \le soc_{e,t}^{EV} \le SOC_e^{EV,max}, \quad \forall e\in\mathcal{E}_n, \forall t\in\mathcal{T}, && (4.67)\\
& \text{Water boiler constraints } (4.68)-(4.71),\\
& \text{Heat pump constraints } (4.72)-(4.75),\\
& \text{Discomfort constraints } (4.76)-(4.80).
\end{aligned}
$$

in which $\Omega := \{l_{n,t}, i_{n,t}^{com}, e_{n,t}^{com}, i_{n,t}^{ret}, e_{n,t}^{ret}, s_{n,t}, s_{n,t}^{ch}, s_{n,t}^{dch}, soc_{n,t}, x_{n,t}\}$ are the decision variables representing, respectively for each member $n \in \mathcal{N}$ at each time $t \in \mathcal{T}$, the net power flow metered at the point of common coupling (PCC), the power imported/bought from the community, the power exported/sold to the community, the power imported/bought from a retailer, the power exported/sold to a retailer, the battery net power flow, the battery charging power, the battery discharging power, the battery state of charge, the flexible devices power consumption. The objective function, $F(\Omega)$, accounts for the global electricity bill, B^{REC}, and the aggregated discomfort cost of REC participants, J_n^{tot}. Constraints (4.53)-(4.55), define the individual and REC-scale physical and virtual power balances. Meanwhile (4.57) to (4.62) is the state-of-the-art battery storage system set of constraints. From the three types of flexible devices considered, EVs charging state-space model constraints (4.63)-(4.67) were already implemented in Problem (4.1).

Regarding thermal loads, the heat pump and water boiler battery equivalent models, presented in Figure 4.5, are translated in mathematical constraints, similarly to EVs charging. For these loads, the state-of-charge represents the temperature of the heated medium that is ambient air for space heating heat pumps and water of the tank for the water boilers. The conversion of electricity to heat is assimilated to a coefficient of performance (COP) for heat pump and to an efficiency (η) for electrical water heater. In addition, the impact of heat flows on the temperature is associated to the heat capacity of the middle. Finally, one consider that these systems are subject to thermal dissipation losses. The two types of load flexible models summarized as:

$$x_{w,t} \leq P_w^{max}, \qquad \forall w \in \mathcal{WB}_n, \forall t \in \mathcal{T}, \tag{4.68}$$

$$\Theta_{w,t} = \Theta_{w,t}^{prev} + (\eta_w x_{w,t} - q_{w,t}^{ut} - q_{w,t}^{loss})/c_w^{th}, \qquad \forall w \in \mathcal{WB}_n, \forall t \in \mathcal{T}, \tag{4.69}$$

$$\alpha_{w,t}\Theta_{w,t}^{comf} \leq \Theta_{w,t} \leq \Theta_{w,t}^{max}, \qquad \forall w \in \mathcal{WB}_n, \forall t \in \mathcal{T}, \tag{4.70}$$

$$\sum_{t\in\mathcal{T}} x_{w,t} = \sum_{t\in\mathcal{T}} x_{w,t}^{ref}, \qquad \forall w \in \mathcal{WB}_n, \tag{4.71}$$

$$x_{h,t} \leq P_h^{max}, \qquad \forall h \in \mathcal{HP}_n, \forall t \in \mathcal{T}, \tag{4.72}$$

$$\Theta_{h,t} = \Theta_{h,t}^{prev} + \Delta_T(COP_h x_{h,t} - q_{h,t}^{loss})/c_h^{th}, \qquad \forall h \in \mathcal{HP}_n, \forall t \in \mathcal{T}, \tag{4.73}$$

$$\sum_{t\in\mathcal{T}} x_{h,t} = \sum_{t\in\mathcal{T}} x_{h,t}^{ref}, \qquad \forall h \in \mathcal{HP}_n, \tag{4.74}$$

$$x_{n,t} = \sum_{e\in\mathcal{E}_n} x_{e,t} + \sum_{w\in\mathcal{WB}_n} x_{w,t} + \sum_{h\in\mathcal{H}_n} x_{h,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.75}$$

Let's consider $w \in \mathcal{WB}_n$ and $h \in \mathcal{HP}_n$, respectively, the water boiler and heat pump of member n. First, (4.68) and (4.72) set the upper power bounds based on thermal devices ratings. (4.69) and (4.73) model the evolution of the temperature state variables, i.e., water temperature, $\Theta_{w,t}$, for WBs and ambient air temperature, $\Theta_{h,t}$, for HPs. Each of those variables evolution is affected by the consumed electrical power $x_{w/h,t}$, related to the production of heat, the final energy use, $q_{w,t}^{ut}$, and dissipative losses depending on the external temperature, $q_{w/h,t}^{loss}$. Similarly to BSS, the prev superscript corresponds to the state at $t-1$ except for $t=1$ for which an initial reference state, i.e., $\Theta_{w,1}$ for WBs and $\Theta_{h,1}$ for HPs, is imposed. Constraint (4.70) specifically ensures that hot water temperature is at the requested temperature when used. The time window during which hot water is used by end-users is represented by a binary vector $\alpha_{w,t}$. Finally, (4.71) and (4.74) guarantee a constant daily load with respect to reference as only load shifting is allowed. The different devices power consumption are aggregated as total flexible loads power consumption, $x_{n,t}$, in (4.75).

Finally, the equivalent cost of a loss of comfort, J_n^{tot}, formulation associated to flexible devices' usage is adapted and expressed as linear function of state variables deviations rather than electrical power consumption deviation. The reference state variables values represent for EVs charging the vehicle battery state-of-charge evolution when it is in a full-rate/max-power charging mode upon arrival until the departure or the battery capacity is filled. For the water and ambient air temperature reference points are decided by members based on their comfort perception. The discomfort function are formulated as:

$$J_{n,t}^{\mathrm{EV}} \geq \sum_{e\in\mathcal{E}_n} \pi_e^{comf} \left(soc_{e,t}^{ref,EV} - soc_{e,t}^{EV} \right), \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.76}$$

$$J_{n,t}^{\mathrm{WB}} \geq \sum_{w\in\mathcal{WB}_n} \pi_w^{comf} (\Theta_{w,t}^{comf} - \Theta_{w,t}), \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.77}$$

$$J_{n,t}^{\mathrm{HP}} \geq \sum_{h\in\mathcal{HP}_n} \pi_h^{comf} (\Theta_{h,t}^{comf} - \Theta_{h,t}), \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.78}$$

$$J_n^{tot} = \sum_{t\in\mathcal{T}} J_{n,t}^{\mathrm{EV}} + J_{n,t}^{\mathrm{WB}} + J_{n,t}^{\mathrm{HP}}, \qquad \forall n \in \mathcal{N}, \tag{4.79}$$

$$J_{n,t}^{\mathrm{EV}}, J_{n,t}^{\mathrm{WB}}, J_{n,t}^{\mathrm{HP}} \in \mathbb{R}_+, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.80}$$

with $\Theta_{w/h,t}^{comf}$ the comfort temperature profiles of participants. (4.76), (4.77) and (4.78) are expressed as inequalities because only deviation that leads to lowest state-space variables levels are penalized, i.e., colder temperatures or unfilled batteries.

Before diving into the description of the decentralized resolution approach, let us recall the four variants of the coordinated flexible resources scheduling problem presented in Figure 4.6:

1. Community with Flexibility (ECFlex): It corresponds to the centralized scheduling problem 4.51;

2. Community without Flexibility (ECFix): This case is a variant of the collective problem that disregards the flexibility potential of household devices and assumes that their consumption follows the preferred patterns of end-users. This is imposed by adding the non-flexibility constraint:

$$x_{a,t} = x_{a,t}^{ref} \qquad \forall a \in \mathcal{A}_n, \forall t \in \mathcal{T}. \tag{4.81}$$

3. Individuals with Flexibility (SoloFlex): Another alternative is to consider stand-alone end-users who activate flexibility to take advantage of their own production only. This situation is obtained by excluding local exchanges via:

$$i_{n,t}^{\text{com}} = e_{n,t}^{\text{com}} = 0 \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{4.82}$$

4. Individuals without Flexibility (SoloFix): Finally, if we combine both restrictions, (4.81) and (4.82), we obtain the baseline case in which end-users behave individually and maximise their comfort.

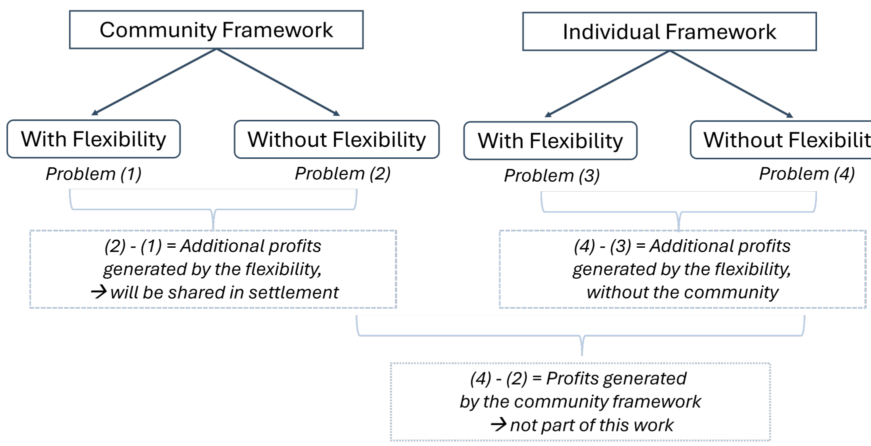


Figure 4.6.: Diagram of flexible resources scheduling problem variants.

Finally, we identified a fifth benchmark case, that can be called *Prioritization of individual self-consumption (ECFix')*. It is a variant of the ECFix case but instead of considering that flexible devices consumption patterns follow the reference ones, we set the flexible power consumption to the optimal individual set-points. Hence, this benchmark represent the case in which EC members first prioritize the use of flexible devices to enhance their own self-consumption before participating to collective actions. This case is implemented in this work by changing the reference power consumption profile of controllable appliances by the output values $x_{n,t}$ from the individual self-consumption (SoloFlex) problem. However, note that state variables reference values are not adapted in the discomfort functions of problem (4.51), meaning that the discomfort created by individual flexibility actions is passed to the coordinated problem. The use of these new reference powers in further models will be indicated by a quotation mark, $x_{n,t}^{ref'}$.

4.2.3. Proposed decentralized resolution approach

If the centralized approach offers collective optimality guarantees, as presented in [18], it raises privacy concern and limits the active implication of end-users in the flexibility provision. The latter may also negatively affect the fairness of benefits distribution, as it may prioritize some individuals based on the resources they have and not on their willingness to participate. To alleviate this issue, the authors describe in the following the decentralized resolution approach of the flexibility activation problem presented in Section 4.2.2.

First, let us split the set of decision variables in two subsets $\Omega := \Omega_n \cup \Omega_{CO}$ and introduce additional decision variables. The set of individual decision variables of REC members is $\mathbf{\Omega}_n := \{l_{n,t}, s_{n,t}, s^{ch}_{n,t}, s^{dch}_{n,t}, soc_{n,t}, x_{n,t}, P^{cap,+}_{n,t}, P^{cap,-}_{n,t}\}$, with $P^{cap,+}_{n,t}$ and $P^{cap,-}_{n,t}$ the global upward and downward flexible loads and battery storage power shift offered to the community operator. On the other hand, $\mathbf{\Omega}_{CO} := \{i^{com}_{n,t}, e^{com}_{n,t}, i^{ret}_{n,t}, e^{ret}_{n,t}, \overline{P}^{act,+}_{n,t}, \overline{P}^{act,-}_{n,t}\}$ are the decision variables of the community operator with $\overline{P}^{act,+}_{n,t}$ and $\overline{P}^{act,-}_{n,t}$ the upward and downward individual limits for flexible devices power shift activation computed by the community operator based on the Keys of Repartition applied for flexibility activation.

Then, let us define $i^{ret,REC}_t = \sum_{n\in\mathcal{N}} i^{ret}_{n,t}$ and $e^{ret,REC}_t = \sum_{n\in\mathcal{N}} e^{ret}_{n,t}$, as the net import and net export power, respectively, with the upstream distribution network obtained after resolution of the Community without Flexibility (ECFix) problem. They are the initial downward and upward flexibility requests from the community operator at each time step that are set as limits for the flexible capacity offers, as presented in Algorithm 4. The third input is the total flexible devices, including storage systems, reference power $P^{ref}_{n,t} = x_{n,t} + s^{ch}_{n,t} - s^{dch}_{n,t}$ defined based on the output of the ECFix problem.

Once the CO has identified the initial flexibility needs of the REC, flexible capacity is offered by end-users and validated (or not) by the operator iteratively until there is no more flexibility request at the collective scale, i.e., no more local generation to take advantage of ($\sum_{t\in\mathcal{T}} e^{ret,REC}_t = 0$) or no member is offering additional flexible capacity ($\sum_{n\in\mathcal{N}} P^{cap,+}_{n,t} + P^{cap,-}_{n,t} = 0$).

At each iteration, there is a two-way communication between REC members and the CO for the activation of flexibility that follows these three steps:

1. Based on the community level flexibility request, each member tries to maximize its revenues from the provision of flexibility by submitting capacity offers to the CO, knowing they can earn $\lambda^{act} = \lambda^{imp,ret} - \lambda^{exp,ret} - 2\gamma^{\text{com}}$ for each displaced kWh. These individual problems are constrained by the set of operating constraints of flexible resources presented earlier in Section 4.2.2 and the following additional ones that represents the interaction between the community operator and REC members variables:

$$P^{cap,+/-}_{n,t} \leq \overline{P}^{cap,+/-}_{0,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4.83a}$$

$$\begin{aligned}
&\textstyle\sum_{t\in\mathcal{T}} P_{n,t}^{cap,+} = \sum_{t\in\mathcal{T}} P_{n,t}^{cap,-}, && \forall n \in \mathcal{N}, && (4.83b)\\
&P_{n,t}^{flex} = P_{n,t}^{ref} + P_{n,t}^{cap,+} - P_{n,t}^{cap,-}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (4.83c)\\
&l_{n,t} = b_{n,t} + P_{n,t}^{flex} - g_{n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. && (4.83d)
\end{aligned}$$

with $\overline{P}_{0,t}^{cap,+/-}$ the global community operator upward and downward flexibility requests that is set as the upper bound for flexibility capacity offers by (4.83a). These capacity offers must be balanced over the day as only consumption shift are allowed (no energy demand reduction or growth) as imposed by (4.83b). Finally, $P_{n,t}^{flex}$, is an aggregated representation of the four different flexible devices, i.e., EVs charger, heat pumps, water boilers and battery storage systems, power consumption and is expressed in (4.83c) as the reference flexible consumption from ECFix on which flexibility has been mobilized. The physical power balance of each household can then be rewritten as (4.83d)

2. The resulting capacity offers obtained by the CO are not aware of other members' decisions. They are provided as if each end-user were the sole member of the REC. Therefore, to ensure a fair contribution to the flexibility activation for everyone, the operator refines individual activation bounds, $\overline{P}_{n,t}^{act,+/-}$, by distributing the flexibility request among the members through the use of a Keys of Repartition mechanism as defined in Section 4.2.1.

3. Finally, as the newly computed individual bounds for each time step may not necessarily ensure constraint (4.83b), consumers solve again the maximization of flexibility revenues problem, considering the output of the Keys of Repartition-based activation as the updated bounds for the activated flexibility as follows:

$$\begin{aligned}
&P_{n,t}^{act,+/-} \leq \overline{P}_{n,t}^{act,+/-}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T} && (4.84)\\
&\textstyle\sum_{t\in\mathcal{T}} P_{n,t}^{act,+} = \sum_{t\in\mathcal{T}} P_{n,t}^{act,-}, && \forall n \in \mathcal{N}, && (4.85)\\
&P_{n,t}^{flex} = P_{n,t}^{ref} + P_{n,t}^{act,+} - P_{n,t}^{act,-}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T},. && (4.86)
\end{aligned}$$

. The resulting flexible resource usage decisions are effectively activated and set the new reference consumption for the next iteration. From the CO perspective, the EC level request is updated to account for the already activated flexibility.

4.2.4. Case Study and Results

This section provides detailed results for a full year of simulation and compares the economic and energy usage performances of the proposed decentralized resolution approach (Section 4.2.3) to the benchmark models and the centralized approach

Algorithm 4: Proposed decentralized resolution algorithm

Input: $i_t^{ret,REC}$, $e_t^{ret,REC}$, $P_{n,t}^{ref}$

Initializing CO flexibility requests as upper bounds for EC members offers:

$\overline{P}_{0,t}^{cap,+}, \Delta\overline{P}^{cap,+} \leftarrow e_t^{ret,REC} \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T};$

$\overline{P}_{0,t}^{cap,-}, \Delta\overline{P}^{cap,-} \leftarrow i_t^{ret,REC} \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T};$

while $\overline{P}_{0,t}^{cap,+/-} > 0$ ***and*** $\Delta\overline{P}^{cap,+/-} > 0$ **do**

  foreach $n \in \mathcal{N}$ **do**

    Optimal individual flexible capacity offers:

$$P_{n,t}^{cap,+/-} \in \Big\{ \text{argmax}_{\ \Omega_n} \sum_{t \in \mathcal{T}} \lambda^{act} P_{n,t}^{cap,+} \Delta t - J_n^{\text{flex}}, \quad \text{s.t. } (4.59) - (4.80), (4.83\text{a}) - (4.83\text{c}) \Big\};$$

  end

  KoR-based definition of individual flexibility activation bounds:

  $\overline{P}_{n,t}^{act,+/-} \leftarrow KoR(\mathbf{P}^{cap,+/-}) \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T};$

  foreach $n \in \mathcal{N}$ **do**

    Optimal individual flexibility activation:

$$P_{n,t}^{act,+/-} \in \Big\{ \text{argmax}_{\ \Omega_u} \sum_{t \in \mathcal{T}} \lambda^{act} P_{n,t}^{act,+} \Delta t - J_u^{\text{flex}}, \quad \text{s.t. } (4.59) - (4.80), (4.84) - (4.86) \Big\};$$

    Updating the reference load profiles based on activated flexibility:

    $P_{n,t}^{ref} = P_{n,t}^{ref} + P_{n,t}^{act,+} - P_{n,t}^{act,-};$

  end

  Updating EC level flexibility requests from CO and keeping track of the activated volume:

  $\overline{P}_{0,t}^{cap,+/-} = \overline{P}_{0,t}^{cap,+/-} - \sum_{n \in \mathcal{N}} P_{n,t}^{act,+/-} \quad \forall t \in \mathcal{T};$

  $\Delta\overline{P}^{cap,+/-} = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} P_{n,t}^{act,+/-};$

end

(Section 4.2.2). More particulary, three key results that can be summarized as follows stand out and are discussed in this thesis:

1. **Preserving privacy does not imply high benefits loss**;
2. **KoRs have a limited influence on fair benefits repartition**;
3. **Flexibility impacts on the grid require explicit incentives**.

The case study on which the different frameworks are evaluated is an energy community composed of 20 domestic end-users whose non-flexible and flexible components are generated using a stochastic residential load profile generator *Resflex* [113]. The penetration levels of the four flexible assets considered in the 20 households are 70% for WBs, 60% for EVs, 50% for HPs, and 25% for BSS. Among the members, 15 also have PV installations ranging from 2 to 20 kW$^{\text{peak}}$, for a total of 147 kW$^{\text{peak}}$ at the community level. Regarding the electricity tariffs, only flat prices are considered with an import price (including retail and grid fees) of $\lambda^{ret,imp} = 0.4$ €/kWh, and an export price of, $\lambda^{ret,exp} = 0.1$ €/kWh. The internal community fees are set to $\gamma^{com} = 0.01$ €/kWh.. Hence, the reward value for each kWh of flexibility activated rises to $\lambda^{act} = 0.28$ €/kWh.

As stated in the introduction of this work, although distributio network constraints are not explicitly considered in the scheduling problem, *ex-post* power flow analyses are run for the different scenarios studied, assuming that REC participants are connected to a benchmark low voltage distribution grid [114].

Table 4.4.: Summary of results for selected scenarios.

	SoloFlex	**ECFix**	**ECFlex**	**ECFlexIt**	**ECFlexIt'**
[€]					
B^{REC}	6,549	6,831	5,243	5,576	5,412
J^{EV}	79	0	188	36	802
J^{WB}	0	0	0	0	0
J^{HP}	0	0	0	0	0
[MWh]					
E^{act}	40.6	0	44.9	23.7	12.7
$E^{\text{act,EV}}$	2.3	0	4.1	0.8	0.6
$E^{\text{act,WB}}$	27.4	0	30.7	17.1	8.5
$E^{\text{act,HP}}$	10.9	0	10.2	5.9	3.6
$E^{\text{dis,BSS}}$	7.3	10.2	7.4	10.1	8.6

"Preserving privacy does not imply high benefits loss"

One of the key findings of this study is that the coordinated decentralized iterative approach converges towards the centralized methodology presented in previous work [18]. As illustrated in Figure 4.7, the proposed *ECFlexIt* and *ECFlexIt'* (*i.e.*, with and without individual prioritization and with an Equal Key) models provides a close, though suboptimal approximation of the case in which the decision-making process is fully coordinated by the CO (ECFlex). Indeed, a residual billing inefficiency remains, as reported in Table 4.4, with a respective 6.35% and 3.22% deviation observed in the overall community cost compared to the centralized benchmark. Nonetheless, this deviation represents the trade-off required to enhance user privacy and decentralize the decision-making process to community members, thereby ensuring individual preferences are more explicitly considered compared to the fully centralized case where the operator optimizes the overall REC outcome.

In addition, one should take a look at the other component of the objective function, that is, the discomfort generated by the activation of flexibility resources. In this perspective, the first interesting outcome observed in Table 4.4 is that

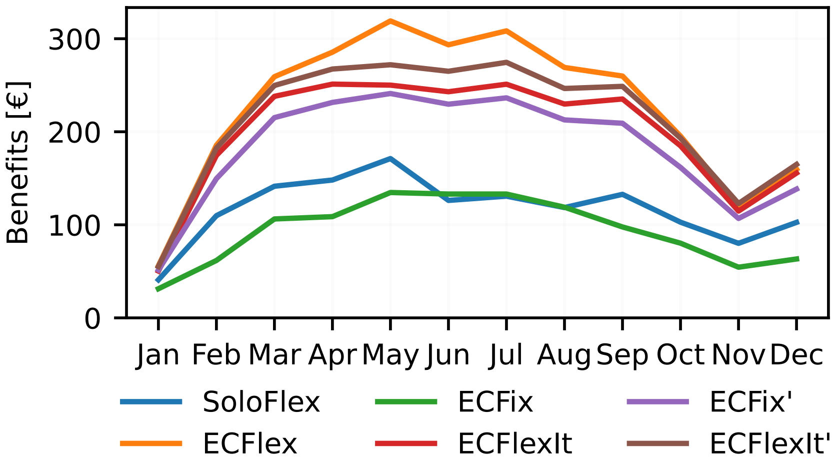


Figure 4.7.: Collective benefits with respect to the SoloFix benchmark.

water boilers and heat pumps have the potential to activate a significant amount of flexibility (up to 30.7% for WBs and 10.2% for HPs) without causing any discomfort, despite α^{HP} and α^{WB} equal to 1. This is made possible as only lower temperatures than the reference ones are penalized. This allows the thermal assets to shift the evening consumption to solar hours to "overheat" the water and air and let it cool down slowly over the end of the day without going below the limit. This emphasizes the flexibility potential at low or negligible costs from other assets than typical BSS, often unique flexible resources considered in this type of study.

On the other hand, shifting EV power only comes with discomfort costs as it delays full charge and limits anticipated departure potential. They are therefore used in cases where other assets do not have enough potential to take advantage of the overall local production available.

Comparing the different scenarios together, one can also notice that in the decentralized framework, without prior self-consumption, the initial use of storage systems before the activation of other flexibility means limits the action of the latter. The centralized approach, on the contrary, can make the direct arbitrage between the free WBs and HPs flexibility and the imperfect battery systems (i.e., 95 % efficiency). The prioritization of individual self-consumption allows for applying similar arbitrage at the individual level before coordinating the responses to remaining flexibility requests of the CO.

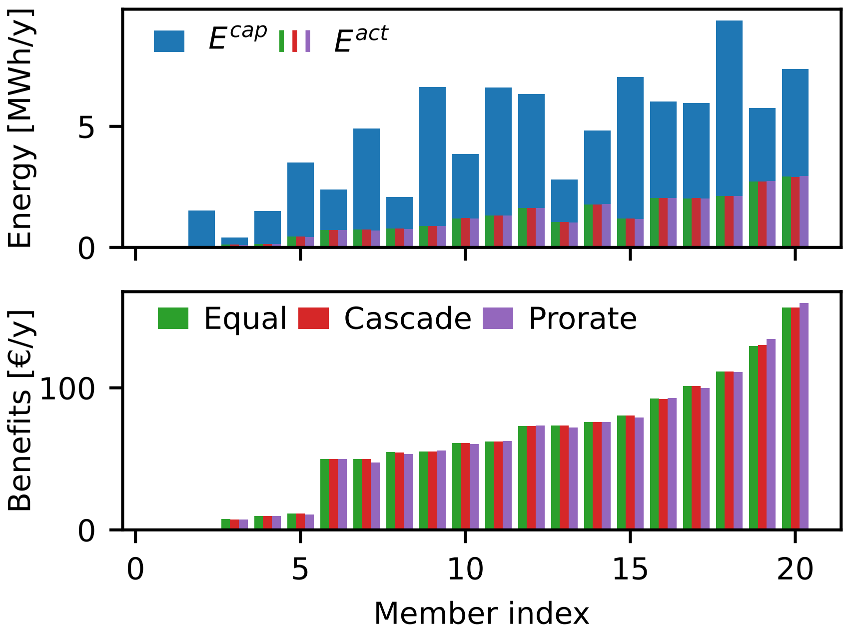


Figure 4.8.: Individualization of the benefits compared to the community with fixed consumption

"KoRs have a limited influence on fair benefits repartition in an iterative framework"

The proposed decentralized resolution approach has been applied without prioritization for the different Keys of Repartition, i.e., Active Users Equal to assess their impact on the individual benefits distribution.

Nevertheless, results displayed in Figure 4.8 show that there are very small differences in terms of flexible energy activation and consequent benefits for the three different key mechanisms. This is mainly due to the iterative nature of the procedure. Indeed, regardless of the KoR applied the flexibility offers-repartition-activation procedure is repeated as long as there exist a need at the REC level and there is flexibility potential at the individual level. The choice of Keys of Repartition, mainly influences the repartition of efforts in case there are more flexibility potential than requested volumes. The chosen KoR have also an impact on the convergence of the iterative procedure, as the cascading and proportional activation tends to reduce the number of required iterations by dispatching all the flexibility offered at each step.

In addition, as discussed in the previous results section, the main driving factor for the participation of individuals to the flexibility coordination procedure is the flexible assets ownership. Hence, users with EVs only (User 2 in Fig. 4.8) may have an interesting flexible capacity (*i.e.*, the overall consumption of owned flexible assets), E^{cap}, but they tend to offer limited capacity to the operator due to the discomfort that it creates. Meanwhile, REC members combining the two thermal assets (WBs and HPs) (*e.g.*, User 20 in Fig. 4.8) can offer a large part of their flexible capacity without a negative counterpart, raising their economic benefits. Regarding heat pumps, it must be pointed out that when they are only considered for heating households, their action is limited during summer periods, while those with water boilers exhibit the highest potential for local exchanges.

Table 4.5.: Priorization impact

	With self-priorization				Without priorization			
	B [k€]	Δ B	J [€]	E^{act}	B [k€]	Δ B	J [€]	E^{act}
SoloFix	7.9				7.9		0	0
SoloFlex	6.5	-1.4	79	40				
ECFix	5.7	-0.8	79	40	6.8	-1.1	0	0
ECFlexIt	5.4	-0.3	803	53	5.6	-1.2	37	24

"Flexibility impacts on the grid require explicit incentives"

Regarding grid performances, it is observed that the yearly average indicators improve in scenarios where flexibility activation is enabled. Specifically, the total power losses are reduced from 840 kWh (*ECFix*) to 690 kWh (*ECFlex'*) in the considered distribution network, improving the local grid efficiency. On top, the activation of flexibility mechanisms results in approximately 12 MWh less energy exchanged with the upstream grid in both directions (both imported and exported energy). This enhanced self-consumption and self-sufficiency of the community also benefits to the global grid by reducing the power flows through the upstream lines.

4.2.5. Intermediate Conclusion

This work aimed to propose an intuitive resolution approach for the decentralized coordination of flexible resources within a Renewable Energy Community to address the privacy concern of typical centralized methods without increasing the computational burden induces by state-of-the-art bilevel or ADMMs techniques. On a 20-household case study, results show that one can reach collective benefits close to the one obtained with centralized coordination with only 3.22% deviation in the best case. Authors also identified thermal loads such as water boilers and heat pumps as promising flexible resources as their smart management can improve the usage without generating any discomfort for the members. On top of that, the investigation of several Keys of Repartition mechanism for the activation of offered flexible capacity did not lead to key differences on the REC level as the iterative nature of the proposed approach makes sure that all the requested flexibility volume is matched when there is enough flexibility potential. Finally, one showed that the flexibility participation and hence the individual benefits distribution is mainly driven by the flexible assets ownership.

Part II.

Optimal Sizing and Pricing of Distributed Energy Resources in Energy Communities

After thoroughly investigating research questions related to the operation of Energy Communities and the mobilisation of flexibility, the second part of this thesis focuses on the investment horizon of Energy Communities. Looking again at the timeline organization of ECs presented in Figure 4.9, this horizon covers the decisions often taken at the creation of the ECs. Indeed, to set up local energy exchanges, renewable production sources must be embedded in the EC structure. The decisions taken at this stage influence the community on a long-run. Hence, when investigating the investment horizon, the operational horizon is also necessarily accounted for in the models. Doing so, the future performances of long-term decisions can be anticipated. In this Part II, optimisation models supporting community members in their long-term planning of Energy Resources and community exchanges rules are developed.

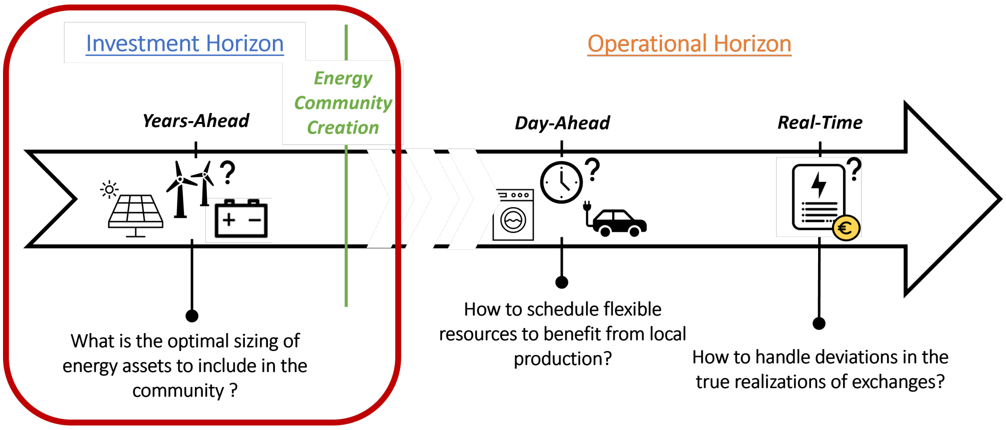


Figure 4.9.: Investment horizon of Energy Communities

This part is organised around the following chapters:

- **Chapter 5** explains the key principles relative to the long-term planning of energy resources. Investment strategies and internal tariffs structures specific to the Energy Communities framework are also introduced. A brief presentation of the state-of-the-art on the long-term planning of Distributed Energy Resources in Communities is exposed. Finally, the main contributions of this thesis regarding decision-making support on the investment horizon are highlighted.

- **Chapter 6** presents a REC-specific optimisation framework to define the best investment strategies in local renewable production and storage assets as well as the best internal tariff structure. First, the chapter exposes a two-steps procedure that guarantees the best collective performances. Then, the innovative reformulation of energy surplus mechanism from Chapter 3 is embedded in the sizing problem to improve the accuracy of individual energy repartition. Finally, a single-step approach is defined to further integrate the trade-off between individual incentives and collective performances.

- **Chapter 7** deviates from the purely electrical application of communities. Mobility is hence considered as another demand in the long-term optimisation problem and the set of long-term decision variables is extended to the sizing of a fleet of shared electric vehicles. Hence, a model is developed to assign mobility demands, represented by trips requests, to the different vehicles of the fleet. The long-term optimisation problem then aims to find the best fleet while accounting for the organisation of local community exchanges.

CHAPTER 5.

Introduction to Investment Strategies Specific to Energy Communities

For a Renewable Energy Community to exist, it must have renewable means of electricity production at disposal within its local trading perimeter. Indeed, the Energy Community principle, as defined by the European Union [12], is based on the mutualization of local energy resources whose generation output is then shared among the community fellows to cover their electrical demand. As presented in Section 1.2, one can distinguish two types of Energy Communities, i.e., Citizen Energy Communities (CECs) and Renewable Energy Communities (RECs), which differ in particular in terms of primary energy sources for the production of electricity and the geographical boundaries of the community entity [115]. RECs restrict that electricity, i.e., the energy in its general form, shared between participants comes from renewable sources only, among which photovoltaic (PV), wind, hydro, biomass or marine energy. In this specific framework, the generation assets must also be "closely" located to the end-users points of common coupling (PCC), the definition of proximity varying from one regulation to another (e.g., electrical proximity in Brussels (Belgium) [15], geographical proximity at the municipality level in Wallonia (Belgium) [14] or fixed geographical radius around the means of production in France [13]). Renewable Energy Communities mainly take advantage of Distributed Energy Resources (DERs) that are small-scale energy resources usually directly connected to the distribution network (at low or medium voltage levels) [116], [117], [118], on the contrary of traditional gas and nuclear power plants which can produce hundreds of megawatts or even gigawatts and are therefore connected to the transportation system. The DERs are often located near consumption points, hence reducing the energy flowing path and the grid usage. Typical DERs are rooftop PV panels [119], battery storage systems [120] and small-scale wind turbines [121].

In the last decades, many EU member states have incentivized the massive deployment of those distributed production means at the low voltage level, especially rooftop PV panels, through subsidies and other economic advantages [122], [123], [124]. Often, the electricity generated is not fully consumed on site, i.e., self-consumed, either because the end-user does not have sufficient flexibility potential to continuously balance the demand and production or because the assets have been oversized. The latter case is common in countries such as Belgium or Spain that used to operate (or still operate) under a compensation system [125]. The compensation principle allowed end-users, with installations whose rated power is lower than 10 kVA, to make the balance of their net consumption from the local grid and their net injection on the grid over a period that spans one year in general. Hence, this balance is computed on a yearly basis without requesting continuous local power balance. The compensation system enables individuals to use the electrical network as an infinite lossless battery storage system that they can charge during production hours, i.e., by injecting power at their PCC, and discharge at other times, i.e., by withdrawing power at their PCC. For long, this scheme has led to investment practices that were sizing the PV assets to match the yearly expected production with the yearly demand, disregarding the production and consumption patterns over the year. In 2019, the European Commission published a directive imposing member states to move out of this compensation systems by the end of 2023 [126]. In the new framework, prosumers, i.e., consumers owning production assets, are encouraged to balance their self production with their needs. This is because, the quarter-hourly net consumption volumes and net injection volumes must be traded with an electricity supplier who always offer a lowest price for the energy received from customers than for the energy sold to them. By joining Energy Communities, these prosumers have the possibility to trade their excess production with other end-users directly at a price which makes the trade-off between consumers cost reduction and prosumers savings.

Nevertheless, the surplus production from prosumer members may not be enough to cover all the needs of the community participants. In some cases, there might be no existing production sources in the neighbouring areas of future Energy Communities. In these cases, members would need to invest in new DER assets. In this perspective, they should carefully decide on the power capacity of production resources, i.e., PV panels or small-scale wind turbines rated power, and on the power and energy capacity of storage systems. The sizing of DERs is a long-term decision process that fall into the category of *Capacity Expansion* problems. These problems require a rigorous techno-economic analysis of the investment project to assess its viability. An investment is viable if investors can recover the money initially invested through the cash flow exchanges all along the project lifetime. To do so, one must represent each year of the life of the newly installed assets, taking into account all operation and maintenance (O&M) costs, taxes, bank interest payments but also the revenues generated by the assets.

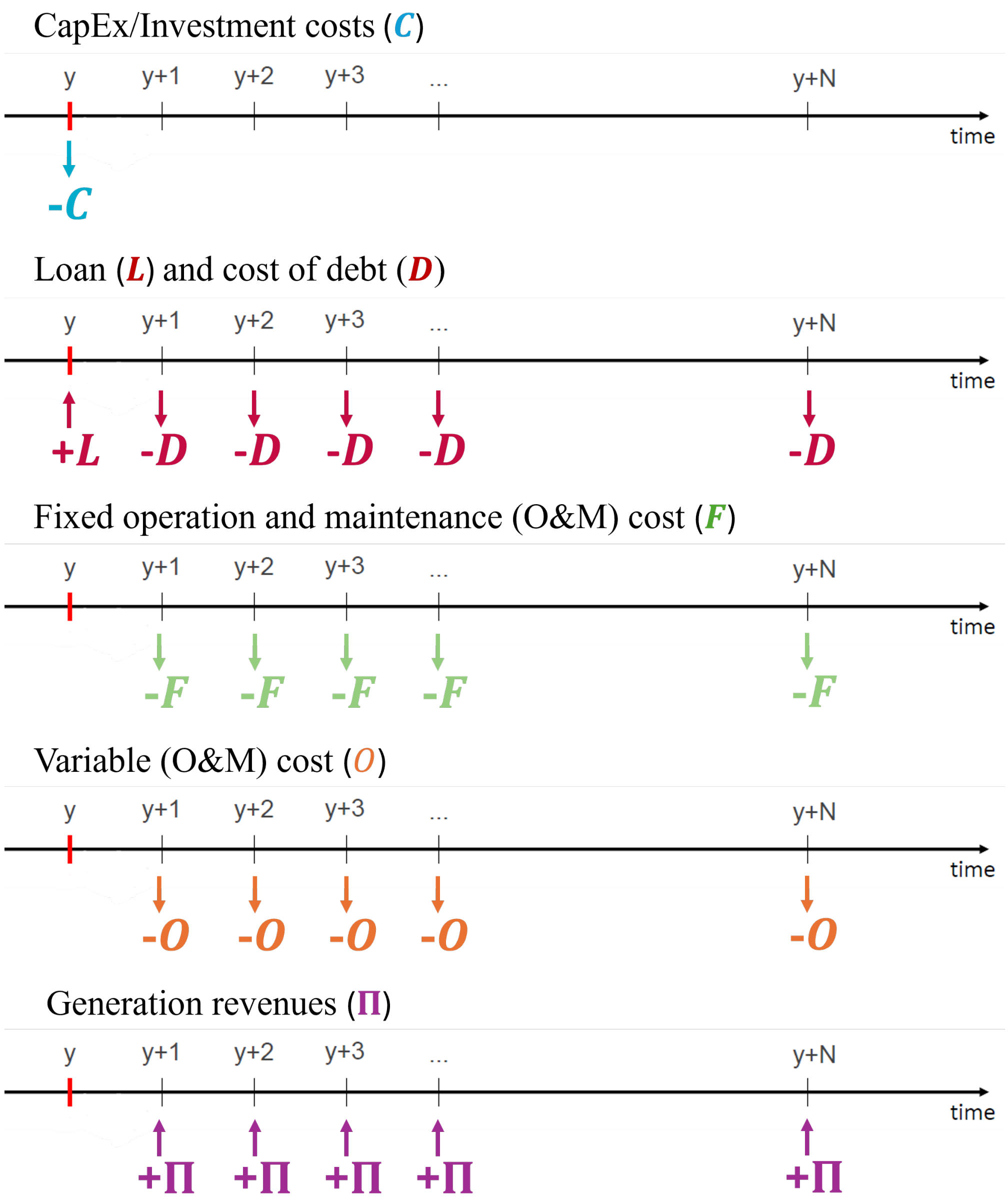


Figure 5.1.: Cash flows for capacity expansion problems in the energy sector.

The money transactions occurring all over the lifetime of general production assets are represented on a timeline in Figure 5.1. In this Figure, C represents the capital expenditures (CapEx) for the purchase and installation of production assets. Those are due at the beginning of the investment period[1]. The money put at risk to cover the initial cost may not exclusively come from investor own funds. Part of the investment may be financed through a loan contracted at the bank with some interest rate. In this case, the investor receives the borrowed money, L, at the time of payment of the capital expenditures. This amount is then reimbursed via annual (or monthly) payments, D, which also cover the interest cost. The portion of CapEx funded by investors capital is called *Equity*, E, in this thesis. From an operational point of view, the production infrastructures can incur additional O&M costs during the whole investment period. These costs can be divided in fixed costs, F, for the periodic control and maintenance of equipments and variable costs, O, which depends on the volumes of electricity produced by these assets. Variable costs often relate to fuel costs for traditional fossil-fuelled power plants that are also affected by their efficiency of conversion. For renewable production units, those are usually neglected. Finally[2], yearly generation revenues, Π, perceived are essential for the investment project to be viable and profitable.

The definition of revenues for a standard professional electricity producer is based on the electricity volume generated by the assets and the price received for each unit sold. However, when consumers decide to invest in DERs, the objective is not to make external profits from their production but rather to help them reduce their electricity bill. Hence, for end-users investing in production means the definition of revenues rather correspond to the savings they can make on their bill with respect to their prior situation. In the current retail market paradigm, i.e., without compensation scheme, these savings are mainly influenced by the capacity of consumers to self-consume the local production. In the REC framework, savings may also arise from the internal valorization of the local production. By selling electricity to other members, prosumers receive a higher price than the one offered by traditional retailers. The participation to energy community creates this way additional value to recover the investment made.

Although the long-term decisions of standalone prosumers are limited to power and energy capacity of DER installations, the Energy Community paradigm adds dimensions to the decision-making process. Indeed, when gathering with other end-users and participating to a Renewable Energy Community, people are involved in additional interactions which also create new opportunities for investment. As a reminder, compared to Citizen Energy Communities, RECs constraint the geographical proximity of participants with respect to the production units engaged

[1] For large investment involving a long-term construction project, the initial payment might be spread over several years ahead of the commissioning.

[2] Readers should note that for the sake of simplicity and clarity taxes, depreciation and amortization are not considered in this thesis although it is important during a detailed assessment of a practical project.

in local exchanges. In addition, the energy traded locally must originate from renewable energy resources only. Nevertheless, the REC framework still enables innovative investment strategies. These strategies are generally categorized based on the assets ownership (individual, joint or third-party) and their location in the network (centralized or decentralized). The ownership and location options are precisely defined as follows and are illustrated in Figure 5.2 :

- **Ownership options** :
  - **Individual investment** implies that a member of the REC invests in distributed renewable energy production sources and storage devices as a typical prosumer. These assets add up to any existing assets installed before integration of the REC and for which he has the full ownership. Being the sole investor, he has the priority on the usage of the electricity produced by these installations. The energy put at disposal in the local pool for other members of the community is the surplus electricity, i.e., the production not self-consumed. Regarding battery storage systems, some actors may decide to share the remaining battery capacity for internal use by other members [127].
  - **Joint investment** involves pooling budget resources, i.e., capital reserves, of participants and of EC's legal entity itself and/or contracting a bank loan to invest in fully-shared DERs. In this case, the property is shared among investing members, usually attributing shares proportionally to the invested equity of each one. However, from an energy point of view, all the energy produced by the joint generation assets is included in the community electricity pool that is shared irrespective of the members participation in the investment. As presented in Chapter 3, the community manager distributes the local electricity available in the pool using predefined allocation rules such as Keys of Repartitions mechanisms (see Section 3.1.1). Through this procedure, end-users investing in joint assets are of course eligible to receive part of the production to cover their needs. On top of that, investors receive part of the revenues generated from the sale of the production of those installations within the Energy Community or to an external supplier. These revenues are generally distributed based on their share in the investment.
  - **Third-party investment** is another existing investment paradigm. It is based on a similar principle than joint investment except that the investment costs are covered by another party external to the REC who rents its installations for local use. The REC is then responsible for the management of the production (or storage) of the devices to generate enough revenues to pay the lease. Although the proposed long-term planning model is general enough to consider this investment option, it is not discussed in this thesis and readers are invited to browse the

following work for more insight [128].

- **Installations Location** :
  - **Centralized assets** refer to medium-scale renewable energy installations (e.g., wind turbines, PV farms) and storage systems with a unique and independent connection point to the network. Usually suitable for joint investment as it ensures the stability of the assets participation in local exchanges when investors decide to pull out, it can also be owned by individuals. In this case, a specific metering device must be installed.
  - **Decentralized assets** are smaller-scale DERs located at each member's premises behind their point of common coupling. In general, these assets belongs to the end-user, i.e., individual investment, that first serve its own consumption. Nevertheless, in some cases, additional jointly invested assets can be installed on remaining available surface with significant production potential that could benefit other participants. In this case, the participant who hosts joint assets on its site receives a rental fee for the provision of space for the joint assets.

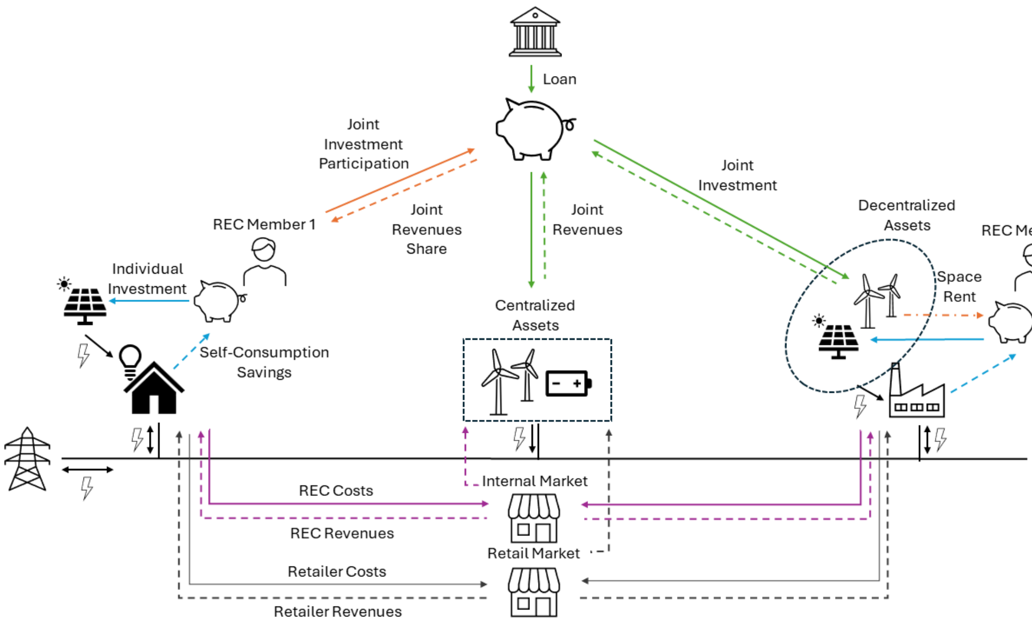


Figure 5.2.: Schematic of REC investment strategies and economic flows.

Some members can combine participations to multiple investment strategies. Hence, the profitability of their investments must be evaluated based on various revenues streams that can be perceived in the global picture represented by dotted arrows in Figure 5.2, namely, the money saved through direct self-consumption and local electricity purchase, the revenues generated by the individual surplus sold either in the REC or to the supplier, the share of revenues from joint assets, and the space renting fee.

Among these revenue streams, the economic valorisation of local exchanges through adequate internal prices definition is also important to guarantee the profitability to every members of participating to the REC. In Chapter 3, we focused on the definition and comparison of energy and cost sharing mechanisms to ensure a fair repartition of the collective benefits retrieved from local energy arbitrage. This notion of arbitrage was driven by the artificial attractiveness of local prices with respect to retailer ones that would incentivize actors to unlock flexibility. Hence, besides decisions related to the DERs installations, i.e., capacity, ownership and location, the local exchange prices are part of the long-term decisions set of the community that must be decided at its creation. They then serve as major incentive signals to encourage end-users participation in local sharing activities. As introduced in Chapter 1, when participating to an Energy Community, end-users see their commodity component being split in two: one accounting for intra-community exchanges and one accounting for complementary exchanges with the retailer. Similarly to the retailer, the REC charges members for their local consumption and remunerates them for their provision of electricity to the pool. As the community paradigm unlocks innovative investment strategies, its internal pricing structure also has multiple degrees of freedom. In this thesis, four different local tariffs have been identified and considered in the long-term planning problem of Energy Communities:

- **Purchase price**: A volumetric price paid by community members for each volume unit of electricity consumed from the local electricity pool;
- **Individual selling price**: A volumetric price perceived by community members when selling their production surplus to the other members;
- **Joint selling price**: A volumetric price earned by joint assets for each unit of electricity sold within the community. The differentiation of individual surplus and joint production tariffs may be motivated by the fact that for individual assets owner, self-consumption revenues already contribute to the investment cost recovery;
- **Space renting price**: A capacity tariff based on the power capacity of joint assets installed on the site.

On top of that, a fixed operation fee is charged by the community manager for the management of the community (e.g., administrative charges, community manager salary). As long as the yearly economic balance is guaranteed, any local pricing structure can be adopted. These structures may differ in terms of price uniformity, i.e., all members are charged/receive the same price for their imports/exports, price unicity, i.e., individual and joint assets exports prices are equivalent, and price periodicity, i.e., prices can be flat or dynamic with different time resolutions.

Finally, a long-term decision variable of Energy Communities rather related to the organisation of local exchanges and the distribution of benefits among participants, is the choice of an adequate sharing mechanism. As extensively discussed in Chapter 3, in some EU member states/regions such as Wallonia [129] or France [13] the sharing principle relies on the allocation of a share of the local electricity pool, i.e., aggregation of individual production surplus and joint assets generation, using Keys of Repartition (KoRs). Choosing the right repartition key to fill the objective of the community is a major decision as the way energy is shared affects its members from an energy efficiency (e.g., self-sufficiency), economic (e.g., cost savings) and social (e.g., distribution of benefits) point of view.

5.1. State-of-the-Art on Long-Term REC Planning

Several research works have dealt with the sizing of DERs, [128], [130], [131], [132] for Energy Communities in general and [64], [133], [134] for Renewable Energy Communities in particular. Practical applications and simulation studies provide valuable insights into the benefits and challenges of ECs and RECs. In [130], authors propose a two-stage Mixed Integer Linear Programming (MILP) model. The first stage addresses the investment decisions by solving an operation optimisation problem to determine the optimal size of energy assets while in the second stage, a Shapley value approach is employed to distribute the community's income among its members, ensuring adequate cash flow for the entire community. The project developed by [131] presents a bi-level optimisation model to identify the generation mix of residential microgrids and model the optimal sizing and energy management of the microgrids by minimising the total customer electricity costs. In [132], a business model for EC aggregators is developed, addressing fair revenue sharing, risk management, and user exit clauses by proposing a penalty fee to be paid by members who would leave the community. This clause is introduced to ensure social welfare, showing that the issue of managing the departure of members is a central question in the REC framework. The study uses MILP and game-theoretic reward distribution schemes to ensure fair and stable profit allocation among EC members. Another study, [128], analyzes the economic feasibility of ECs by examining self-investment and third-party investment options, assessing the impact of various cost allocation methods on household energy costs, exploring the possibility of multiple cost allocation methods within the same community, and formulating an optimisation model applied to three case studies based on real-life consumption data. The sizing of generation assets is based on the annual estimation of production and solar potential.

In [133], a joint investment model for sizing and managing RECs with PV generation and storage assets has been proposed to provide insight on the energetic, economic and social impact of RECs comparing virtual and physical sharing schemes for centralised (i.e. large scale renewable energy installations and storage systems that serves the entire community) and decentralised (i.e. individual renewable energy installations and storage systems located at each member's premises) distribution configurations. In [64], a linear programming (LP) optimisation model is developed to size the PV and battery storage system. Then, the LP model is softly coupled with power flow analysis to study the impact of different ECs configuration on the grids. For DER sizing in REC, the LP optimisation is based on four strategies : economic optimisation, peak shaving, and self-sufficiency with different location of the BSS. Additionally, [134] proposes a MILP model showing that a RECs can reduce the CO2 emissions, with greater reductions when participants invest in a central DER rather than multiple personal DERs.

Moreover, some research, such as [128] also analyses the pricing of electricity exchanged in the community by proposing different pricing schemes based on members' total annual consumption. Local electricity prices are passed as parameters to the operational optimisation problem. Another study such as [135] has explored the allocation and pricing of DERs in apartment buildings. By proposing two energy-sharing models, the study highlights the importance of pricing mechanisms in sharing solar PV and storage resources. Authors propose four pricing schemes (e.g. free electricity scheme with a fixed annuity to recover the investment costs, marginal PV production price, etc.). Nevertheless, the paper does not address the optimal sizing of the PV installation. While considering a joint investment planning problem, [136] addresses the benefits redistribution by proposing a marginal cost redistribution method.

Overall in the literature, most of the authors address the optimal sizing of joint assets assuming that electricity is exchanged for free within the community, with investors recouping their costs through personal savings and by selling excess electricity to retailers and do not investigate if this internal pricing scheme is the optimal one. However, recent research [112] has focused on optimising investment strategies within RECs in terms of both sizing and pricing decisions. Authors present a two-steps approach with the first stage aiming to maximise the total profit of the community through the optimal sizing of DERs and ensure fair profit distribution among members through optimal pricing in the second stage. An intermediate step dispatches the joint investment ownership between members. This cooperative approach provides economic benefits compared to individual investments and demonstrates that joint investment allow for larger investments due to economies of scale. Table 5.1 summarizes the types of investment considered in the above-mentioned papers.

Table 5.1.: Review of investment types addressed in the literature

Type of investment	Joint ownership	Individual ownership
Centralized	[133], [130], [128], [134], [136]	[130], [135], [128], [136]
Decentralized	[133], [130], [134], [136], [112]	[130], [136], [112]

5.2. Research Objectives and Scientific Contributions

The second key objective of this thesis is to propose a REC-specific optimisation framework for the planning of Renewable Energy Communities long-term decisions. The proposed framework jointly considers DERs sizing, local electricity pricing and local pool sharing. Secondly, particular attention is paid to the trade-off between the maximisation of the REC welfare and the minimisation of individual savings disparities. To go into more detail, this work focuses on the following three research objectives:

1. **Developing a REC-specific optimal long-term planning problem for Renewable Energy Communities.**
   Renewable production units are essential resources to enable the creation of Renewable Energy Communities and the sharing of local electricity among participants. Compared to the stand-alone end-users situation, RECs offer a larger variety of investment strategies for the installation of Distributed Energy Resources when the current capacity is not sufficient or is null. In this thesis, an optimal long-term investment and pricing problem adopting a two-steps approach is first proposed. The first-step of the problem aims to decide on the optimal investment strategy and capacity of the most common DERs, usually found at the distribution level, that are rooftop PV panels, small-scale wind turbines and battery storage systems. The objective function of the first problem is to minimize the collective costs of electricity provision. Then, the second-step aims to optimally reflect the investment costs in the definition of exchange prices inside the community and guarantee fair investment-related collective savings distribution among members. Compared to state-of-the-art works [112], [136], this model encompasses all the various innovative strategies of the REC framework, i.e., individual and joint assets ownership, and centralized and decentralized assets location, and the associated cash flows presented in Figure 5.2. In addition, the degrees of freedom of the second optimisation problem are increased with respect to prior works [112],

[135], by implementing advanced local tariff structures adapted to the specific investment strategies of Renewable Energy Communities.

The two-steps REC-specific long-term planning model developed in this thesis is about to be implemented by an IT tool development company. In this way, the optimisation model can be used by all regional development agencies in Wallonia. It will support them to provide quantitative arguments to motivate end-users joining the REC and to define the optimal basis of local exchanges.

2. **Proposing a single-step formulation of the long-term problem to solve fairness issues.**
Adopting a state-of-the-art two-steps approach guarantees to reach the optimal welfare at the REC level by adopting a centralized coordinated planning of DERs resources in the first step. However, one can demonstrate that with this sequential resolution strategy the second optimisation problem is highly constrained by the outputs of the first problem. Indeed, it aims to distribute the total economic surplus to the REC participants as fair as possible by adequately charging the local energy exchanges. Yet, the optimal dispatch of energy arise in the first step which does not account for all individual economic flows and associated welfare. Therefore, as the community seeks to optimize the collective costs, when sizing DERs end-users are discriminated based on the production potential of their sites, their ability to self-consume the local production behind the meter and their retailer tariffs. For instance, if no specific sharing rule is considered participants with high retailer rates tend to receive a bigger share of local energy as they have a greater marginal influence on the collective objective. To cope with this limitation, a first adaptation of state-of-the-art formulations, consists in including Keys of Repartition mechanisms in the first step relying on the innovative formulations proposed in Section 6.3. By embedding explicit sharing rules, it could avoid to discriminate participants in the local operational dispatch model based on their retailer tariffs. The impact of the different key principles on the individual savings distribution are compared. Ultimately, we design a Multi-Objective Mixed-Integer Second-Order Cone Programming (MISOCP) single step optimisation problem that aims to optimally and simultaneously define the whole set of long-term REC decisions, i.e., DERs sizing/ownership/location, and local prices. The multi-objective approach enables to drive the decisions while taking into account both the collective economic surplus and fairness in value distribution concerns. This single-step formulation hence aims to achieve the best trade-off between collective and individual surplus maximization.

This single-step approach and its comparison with the two-steps procedure are the subject of the following article:

[20] J. Allard, F. Vallée, Z. De Grève, "Fair and Optimal Investment Strategies for Renewable Energy Communities,", *working paper*.

3. **Extending the long-term planning problem to EV fleet sizing.**
The general definition of Renewable Energy Communities, introduced by the European Commission [12], does not constraint energy exchanges to the electricity carrier but rather allows to mutualize any form of energy as long as it originates from renewable sources. Combining multiple energy carriers and energy services within a single REC may leverage a larger potential of cost reduction through the complementarity of the energy usage. Among the end-use demand categories, this thesis particularly investigates the complementarity that may exist between community members net consumption patterns, i.e., power withdraw and injection from/in the local distribution network, with the electrical demand of shared e-Mobility. Hence, we propose an original long-term EV fleet sizing and planning optimisation problem within a Renewable Energy Community framework. The problem aims to optimally quantify the number, types and locations of EVs and charging stations to be installed for satisfying the mobility demand of the targeted area (i.e., not restricted to the community perimeter) at minimum costs. The model integrates the EV fleet as a member of the community that takes part to the local energy sharing paradigm. Besides sizing the EV fleet, this work aims to find the optimal location of the charging stations in the local distribution system by considering the network topology and physical constraints. The flexibility potential of EV charging patterns to support the network is also investigated by integrating peak power tariffs charged by the distribution system operator (DSO). The work contributions are presented in the following paper:

   [21] J. Allard, N. Diffels, F. Vallée, B. Cornélusse, and Z. De Grève, "On the complementarity of shared electric mobility and renewable energy communities,", *preprint*, 2026.

The presentation of these contributions is organised in two chapters. Chapter 6 presents the REC-specific long-term planning model in both its two-steps and single-step forms. First, the full mathematical formulation of the optimal DERs investment and the optimal internal pricing problems that are sequentially solved in the two-steps approach are defined. Then, the adaptations proposed to better consider the fair repartition of REC benefits are described. Finally, both approaches are evaluated and compared on a similar residential case study. On another hand, Chapter 7 investigates the potential to include the operation of a shared EV fleet within the local exchange structure of the Energy Communities. More specifically, the adaptation of the long-term planning problem to the sizing of a shared EV fleet is introduced. The short-term ride-vehicle assignment model defining how the mobility demand is covered by the fleet is aslo defined and integrated in the community model.

CHAPTER 6.

REC-Specific Long-Term Planning Model

As described in Chapter 5, several long-term decisions must be taken by Energy Community actors prior to commissioning local exchanges. They can categorized as DERs investment decisions, sharing mechanism selection, and prices definition. The first set of decisions is directly related to the availability of local energy and determines the existence of RECs. Indeed, if among the interested end-users none have any production sources with surplus volumes to be injected in the local electricity pool, no community exchanges can occur. In this case, participants must wisely size the Distributed Energy Resources, including renewable production and battery storage units, to cover their needs. Considering the participation to an Energy Community in the long-term planning may bring several benefits to end-users [130], [131], [132]. From an economic point of view, community exchanges represent and additional source of operational savings to recover the investment cost. Meanwhile, from a technical perspective, coordinating at a local level the installation of DERs may reduce their negative impacts on the distribution network [123] by avoiding assets over-sizing. The most often observed problematic is the voltage rise induced by large injection of power from rooftop solar productions in the distribution network branches. These over-voltages may lead to automatic equipments safety shut-down [137].

To valorise the energy exchanged with other members in the community, the definition of local prices is also of tremendous importance [128], [135]. To encourage participation to Renewable Energy Communities and investment in renewable resources, these prices design must respect two constraints. First, they must be attractive with respect to the traditional retailer tariffs, both for consumers and prosumers, in order to disincentivize members to remain in their standalone situation. To be more precise, the purchase price within the REC must be lower than the one paid for the retail electricity and the selling price in the REC must be higher than the one received from the retailer. Then, in an investment context, the prices must ensure that the overall savings made by each participant fairly compensate their initial investment cost. Besides, prices stability is a key feature that could secure members adhesion to the community. Reducing end-users dependency to retail market prices that are indirectly linked to the potentially volatile wholesale prices [138] is a major argument often used to incentivize participation to local sharing structures.

In this chapter, two methods are adopted to identify the optimal long-term decisions variables. The first one relies on the sequential resolution of two distinct optimisation problems that are presented in Section 6.1. The first problem address the question of DERs sizing and investment strategies definition while the second problem defines the optimal internal tariffs. As this sequential approach can show weaknesses when it comes to the distribution of collective benefits among the EC members, in Section 6.2 a single-step method that combines the two previous optimisation problems is developed. Both methods are validated on several residential EC case studies. Their performances in terms of collective surplus and individual surplus distribution are compared in Section 6.3. Finally, key messages regarding both approaches are provided in Section 6.4.

The contributions of this chapter are the core subject of the following working paper:

[20] J. Allard, F. Vallée, Z. De Grève, "Fair and Optimal Investment Strategies for Renewable Energy Comunities,", *working paper*.

In addition, the two-steps model will be implemented and interfaced in order to be extensively used by key players in the field. It will be made available to all regional development agencies in Wallonia to offer them a support for the creation of future Energy Communities.

6.1. Sequential Sizing and Pricing Procedure

To define the optimal set of long-term decision variables a two-steps approach [112] can be adopted. This procedure aims to sequentially size the Distributed Energy Resources and price their production for exchange within the community. More precisely, the first step is a REC specific generation expansion planning problem whose objective is to find the best DERs capacity, location and ownership to minimise the total life-cycle cost of the REC entity (i.e., coordinated optimisation) while modelling local energy exchanges. The second one then distributes the benefits among members by computing the optimal price of local exchanges to maximise a fairness objective. Different fairness formulations can be adopted such as the maximisation of the minimum individual savings [112], the minimisation of individual savings variance or other indices reviewed in [139]. In addition, an intermediate step is necessary to distribute the joint investment efforts among the participants and define their share in the investment based on their available equity.

The whole long-term planning procedure developed in this thesis is depicted in Figure 6.1.

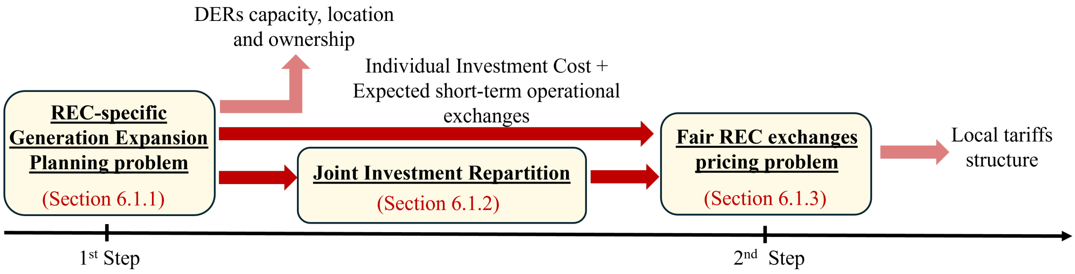


Figure 6.1.: Schematic representation of the two-steps long-term planning method.

In this section, each step of the long-term planning procedure and the associated optimisation problems are presented in detail. Then, the optimal collective performances of the proposed method are validated on a set of domestic energy communities. Finally, the limited space of action of the second problem to ensure fairness and attractiveness of community activities is highlighted.

6.1.1. Cost-Optimal Distributed Energy Resources Sizing (1st Step)

The first optimisation problem solved in the two-steps approach aims at finding the optimal mix of DERs, i.e., rooftop photovoltaic panels, small-scale wind turbines and battery storage systems in this thesis, that minimizes the total life-cycle cost of EC members, i.e., combining assets-related costs and typical electricity bill. Compared to standard generation expansion planning, the following model considers the potential of local energy exchange specific to ECs.

Let's first consider $\mathcal{N}$ as the set of community members, $\mathcal{ND}$ the set of local distribution network nodes that encompass the point of common coupling of the REC members $\mathcal{N}$ and other available connection points for centralized DERs units. In this thesis we assume that all end-users connected in the studied portion of distribution grid are part of the REC. Let then $\mathcal{G}$ be the set of generation technologies that may be invested in.

Then, to solve a long-term planning problem and evaluate the profitability of the investment made initially, the whole investment period, i.e., several years of operation, must be represented to evaluate the yearly costs and savings generated by the newly installed assets. However, the lifetime of rooftop solar units or small-scale wind turbines being around 15 to 20 years, modelling the community operation over this period would lead to an important computational burden that may prevent the resolution of the problem. Hence, a typical method to cope with this challenge consists in the selection of representative days [140], [141], [142], [143].

The goal is to identify a reduced set of days within the complete time series whose characteristics represent the global dynamic of the whole dataset while minimizing the size of this reduced set.

In this thesis, we consider that a single year is replicated over the investment horizon, neglecting evolution of the demand and climate change aspects. In the developed model, $\mathcal{D}$ is the set of representative days selected which have a yearly occurrence factor, π_d. The sum of occurrence factors is equal to 365 to represent the yearly operational horizon of the ECs. Finally, $\mathcal{T}$ is the set of time periods within a day with a time step Δt. The Mixed-Integer Second-Order Cone Programming (MILP) problem reads:

$$
\begin{aligned}
\min_{\Omega^1} \quad & \text{Total REC life-cycle cost (6.2)} \\
\text{s.t.} \quad & \underline{\text{Long-term constraints:}} \\
& \text{Economic constraints (6.8)-(6.11)} \\
& \text{Capacity constraints (6.12)-(6.18)} \\
& \underline{\text{Short-term constraints:}} \\
& \text{Assets production constraints (6.19)-(6.21)} \\
& \text{Battery storage constraints (6.22)-(6.30)} \\
& \text{Flexible consumption constraints (6.31)-(6.35)} \\
& \text{Energy and economic exchanges constraints (6.36)-(6.47)} \\
& \text{Minimum self-consumption constraint (6.48)}
\end{aligned}
\tag{6.1}
$$

with $\Omega^1 = \{\Omega^1_{LT}, \Omega^1_{ST}\}$ the whole set of long-term and short-term decisions. The long-term decision variables of the problem are $\Omega^1_{LT} := \{E^{indiv}_n, E^{joint}, L^{joint}, P^{indiv}_{g,n}, P^{joint}_{g,n}, P^{st,indiv}_n, P^{st,joint}_n, SOC^{st,indiv}_n, SOC^{st,joint}_n\}$, which respectively represent, the end-users equity invested in individually owned assets, the overall equity from community members invested in joint assets, the loan amount requested to cover the joint assets costs, the individual and joint installed generation capacity and the individual and joint storage system ratings, i.e., power and energy capacity. Readers should notice that we only consider the possibility to borrow money for joint investment, as the ability of end-users to bring money to contribute to investment is their own responsibility. Nevertheless, if an individual had to contract a loan to participate to the coordinated planning it could reflect the interest cost in its expected internal rate of return. In addition, individual investment are assumed to be made at end-users location, i.e., behind its own meter only, while joint investment are either centralized or decentralized. To evaluate the operational costs and revenues along the project lifetime, the operational community problem is embedded in the long-term planning one and the related short-term decision variables are, $\Omega^1_{ST} := \{l_{d,nd,t}, v_{d,n,t}, v^{joint}_{d,t}, i^{com}_{d,n,t}, e^{com}_{d,n,t}, e^{com,joint}_{d,t}, i^{ret}_{d,n,t}, e^{ret}_{d,n,t}, e^{ret,joint}_{d,t}, s^{indiv}_{d,n,t}, s^{joint}_{d,nd,t}, soc^{indiv}_{d,n,t}, soc^{joint}_{d,nd,t}, b_{d,n,t}\}$. They respectively correspond to: the physical net power metered at each node, the virtual individual power to be traded, the joint assets power to be traded, the individual community import and export quantities, the electricity sold in the community from joint installations, the individual exchanges with the retailer in both directions, the extra electricity from joint assets sold to a retailer, the individual and joint storage devices power exchanges and state-of charge, and the end-users flexible consumption. Regarding the energy storage systems, it is assumed that individual units are only operated for personal use, i.e., discharging limited to individual consumption, and that joint units are only used to store joint production excess to guarantee that the energy exchanged locally originates from renewable sources only.

Total REC Life-Cycle Cost

The total life-cycle cost (TLCC) can be computed by accounting for the initial investment cost and all the operational cash flows presented in Figure 5.1. In the REC framework, mainly gathering consumers and prosumers rather than exclusive producers, the yearly costs do not only refer to those of production assets but also account for the furniture of their electrical demand. The general definition of TLCC is as follows:

$$TLCC(\Omega^1) = E + \sum_{y \in \mathcal{Y}} \frac{C_y + D}{(1+r)^y}, \tag{6.2}$$

$$C_y = F_y + O_y - \Pi_y, \qquad \forall y \in \mathcal{Y}. \tag{6.3}$$

with E, the invested equity, D the annual debt payment and C_y the overall yearly operational cost. It includes, the fixed F_y and variable O_y cost of electrical production assets, and the generated revenues Π_y as presented in Figure 5.1. r is the internal rate of return expected for the investment. The REC paradigm offers innovative investment opportunities and local exchanges are another source of revenue/savings for participants. In addition, in this thesis, operational costs (fixed and variable) of the considered DERs, i.e., rooftop solar panels, small-scale wind turbines and battery storage systems, are neglected. Hence, the particular definition of the cash flows in a REC framework reads:

$$E = E^{joint} + \sum_{n \in \mathcal{N}} E_n^{indiv} \tag{6.4}$$

$$D = \upsilon(r_L)L = \left[\frac{r_L(1+r_L)^Y}{(1+r_L)^Y - 1}\right] L \tag{6.5}$$

$$\Pi = B^{REC,0} - B^{REC} \tag{6.6}$$

$$B^{REC} = \sum_{d \in \mathcal{D}} \pi_d \sum_{t \in \mathcal{T}} \underbrace{\left[\sum_{n \in \mathcal{N}} \left(\lambda^{ret,imp}_{d,n,t} \; i^{ret}_{d,n,t} - \lambda^{ret,exp}_{d,n,t} e^{ret}_{d,n,t} \right) - \lambda^{ret,joint}_{d,t} e^{ret,joint}_{d,t} \right] \Delta t}_{\text{Retailer Commodity Costs}}$$
$$+ \underbrace{\sum_{n \in \mathcal{N}} (\lambda^{grid}_{d,n,t} + \lambda^{tax}) \; l^{+}_{d,n,t} \Delta t}_{\text{Grid and Taxes Costs}} + \underbrace{\left[\gamma^{com} \sum_{n \in \mathcal{N}} \left(i^{com}_{d,n,t} + e^{com}_{d,n,t} \right) + e^{com,joint}_{d,t} \right] \Delta t}_{\text{REC Costs}} \quad (6.7)$$

where the total equity, E, combines the equity invested in individual, E^{indiv}_n and joint E^{joint} assets in (6.4). The annual debt payment, D, is computed based on the loan amount L, the loan interest rate r_L and the investment period length, Y, using the Uniform Capital Recovery Factor (UCRF), $\upsilon(r_L)$ [144]. This factor aims to distribute the repayment evenly over the term of the loan. The generation revenues Π amounts to the difference between the aggregated initial electricity bills of participants, $B^{REC,0} = \sum_{n \in \mathcal{N}} B^0_n$, and the optimal REC bill[1]. This electricity bill combines the retailer commodity costs with $\lambda^{ret,imp}_{d,n,t}$ and $\lambda^{ret,exp}_{d,n,t}$ the retailer import and export prices, respectively, charged or received for extra electricity volumes exchanged outside of the REC. Regarding grid costs, the system operators only charge members for their net consumption volume $l^{+}_{d,n,t}$ at prices $\lambda^{grid}_{d,n,t}$. λ^{tax} is the equivalent price of all the national and regional taxes relative to the consumption of electricity and γ^{com} is a fee charged for the intra-community exchanges to cover the community operator remuneration.

Long-Term Constraints

REC members can invest in a set of energy resources for local production $g \in \mathcal{G}$ (e.g., rooftop solar panels, small-scale wind turbines) and energy storage systems (e.g., battery system). These assets can be installed over the different REC members network connection point, $\mathcal{N}$, or at a centralized location, $\mathcal{ND} \setminus \mathcal{N}$. Those investments can be individual and/or joint based on the available equity and potential loan as described by the following constraints :

$$E^{indiv}_n \leq \overline{E}_n, \qquad \forall n \in \mathcal{N}, \quad (6.8)$$
$$E^{joint} + \sum_{n \in \mathcal{N}} E^{indiv}_n \leq \sum_{n \in \mathcal{N}} \overline{E}_n, \quad (6.9)$$
$$E^{indiv}_n = C^{st} \left(SOC^{st,indiv}_n + P^{st,indiv}_n \right) + \sum_{g \in \mathcal{G}} C_g P^{indiv}_{g,n}, \qquad \forall n \in \mathcal{N}, \quad (6.10)$$

[1]Note that from an optimisation point of view, the initial REC bill, $B^{REC,0}$, is seen in this problem as a constant additive term. Hence, it does not affect the solution.

$$E^{joint} + L = \sum_{n \in \mathcal{ND}} \left[C^{st}\big(SOC_n^{st,joint} + P_n^{st,joint}\big) + \sum_{g \in \mathcal{G}} C_g P_{g,n}^{joint} \right] \tag{6.11}$$

The amount of equity invested by an EC member in individual assets, E_n^{indiv}, is limited by its budget, $\overline{E}_n$, via (6.8). Besides, the total equity invested in individual and joint assets, E^{joint}, can not exceed the aggregated capital of participants as reflected in (6.9). Individual investment costs, cover by equity, are expressed as a function of the installed generation capacity $P_{g,n}^{indiv}$ and the rated power, $P_n^{st,indiv}$ and energy capacity $SOC_n^{st,indiv}$ in constraint (6.10). Finally, joint investment costs have a similar expression but can also be initially funded by a bank loan L in (6.11).

At each location, renewable production and storage devices capacity are limited by the available space, the connection capacity, or other physical/electrical reasons.

$$\begin{aligned}
&P_{g,n}^{indiv} + P_{g,n}^{joint} \leq \overline{P}_{g,n}, && \forall n \in \mathcal{ND}, \forall g \in \mathcal{G}, && (6.12)\\
&P_n^{st,indiv} + P_n^{st,joint} \leq \overline{P}_n^{st}, && \forall n \in \mathcal{ND}, && (6.13)\\
&SOC_n^{st,indiv/joint} \geq \underline{EP}_n P_n^{st,indiv/joint}, && \forall n \in \mathcal{ND}, && (6.14)\\
&SOC_n^{st,indiv/joint} \leq \overline{EP}_n P_n^{st,indiv/joint}, && \forall n \in \mathcal{ND}, && (6.15)\\
&P_{g,n}^{joint}, P_n^{st,joint}, SOC_n^{st,joint} \geq 0, && \forall n \in \mathcal{ND} && (6.16)\\
&P_{g,n}^{indiv}, P_n^{st,indiv}, SOC_n^{st,indiv} \geq 0, && \forall n \in \mathcal{N}, && (6.17)\\
&P_{g,n}^{indiv}, P_n^{st,indiv}, SOC_n^{st,indiv} = 0, && \forall n \in \mathcal{ND} \setminus \mathcal{N}. && (6.18)
\end{aligned}$$

Constraints (6.12) and (6.13) limit the power capacity of generation and storage resources, respectively. When investing in storage system units both power and energy capacities are considered as decision variables. The ratio between the rated power and rated energy capacity is often called *energy-to-power* ratio, EP. It represents the maximum number of consecutive hours a battery can be charged (or discharged) at its rated power. Based on the technologies, the ratio is restricted as imposed by (6.14) and (6.15). Finally, as stated earlier, individually owned assets can only be installed at end-users PCC while joint assets can be either centralized or decentralized through (6.16)-(6.18).

Short-term Constraints ($\forall d \in \mathcal{D}$) - Coordinated Scheduling Constraints

To evaluate the long-run profitability of investment the generated revenues/bill savings must be estimated by integrating the short-term REC operation in the long-term planning problem. Each REC member is characterized by its distributed generation units (e.g., PV panels), and storage system (e.g., batteries), and by its electrical demand that can be flexible. The operational organisation of the REC is depicted in Figure 6.2.

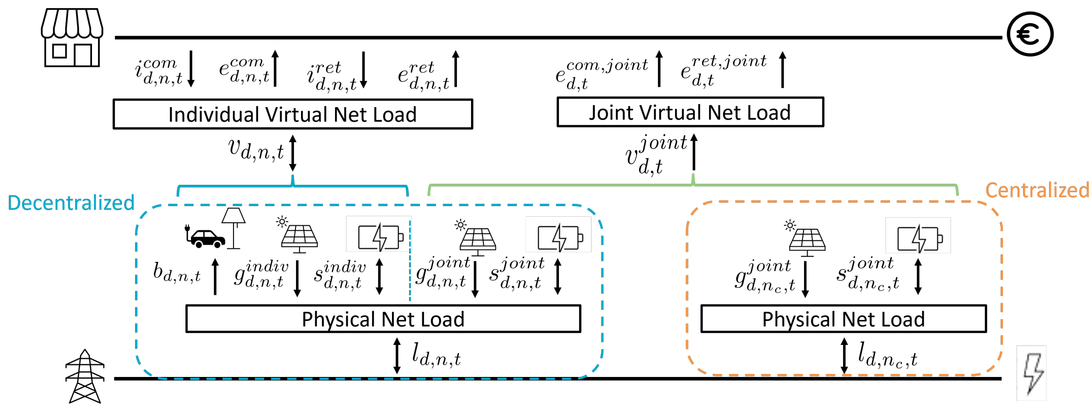


Figure 6.2.: Schematic representation of physical and virtual operational flows.

Power generation from DERs, such as photovoltaic or wind turbines, depends on fluctuating weather conditions. To quantify this variability, the generation potential is generally represented by a capacity/load factor which represents the fraction of the rated capacity that can be produced at a given time.

$$g_{d,n,t}^{indiv} = \sum_{g\in\mathcal{G}} lf_{g,d,n,t} P_{g,n}^{indiv}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.19}$$

$$g_{d,n,t}^{joint} = \sum_{g\in\mathcal{G}} lf_{g,d,n,t} P_{g,n}^{joint}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{6.20}$$

$$g_{d,n,t} = g_{d,n,t}^{indiv} + g_{d,n,t}^{joint}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}. \tag{6.21}$$

The power produced by individual, $g_{d,n,t}^{indiv}$, and joint generation assets, $g_{d,n,t}^{joint}$, is limited in (6.19)-(6.20) by the available potential, lf, at the given spot based on the installation orientation. The total power generated at a given network node, $g_{d,n,t}$, accounts for all the newly installed assets, both individually and jointly, as expressed in (6.21).

The other DERs that can be operated by end-users are battery storage systems. The individual and joint assets operation follow state-of-the-art constraints already presented in Section 2.3.

$$s_{n,t} = s_{n,t}^{ch} - s_{n,t}^{dis}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{6.22}$$

$$soc_{n,1} = R_n^{st} SOC_n^{st} + \left(\eta^{st} s_{n,1}^{ch} - s_{n,1}^{dis}/\eta_{st}\right) \Delta t, \qquad \forall n \in \mathcal{ND}, \tag{6.23}$$

$$soc_{n,t} = soc_{n,t-1} + \left(\eta^{st} s_{n,t}^{ch} - s_{n,t}^{dis}/\eta_{st}\right) \Delta t, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}\backslash\{1\}, \tag{6.24}$$

$$soc_{n,T} = R_n^{st} SOC_n^{st}, \qquad \forall n \in \mathcal{ND}, \tag{6.25}$$

$$0 \le soc_{n,t} \le SOC_n^{st}, \qquad \forall n \in \mathcal{ND}, \tag{6.26}$$

$$-P_n^{st} \le s_{n,t} \le P_n^{st}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T},. \tag{6.27}$$

where equations (6.23)-(6.25) define the evolution of the energy storage system state-of-charge accounting for the charging and discharging efficiencies as well as the initial and final states of the day which are expressed as a share of the installed capacity, R_n^{st}. The installed storage energy and power capacities set upper bounds respectively for the state-of-charge and the power exchanges via (6.26)-(6.27). In storage systems, the electricity flow is bidirectional as they can be charged or discharged as represented in (6.22).

The above state-of-the-art constraints (6.22)-(6.27)) apply to both individual and joint storage assets independently. Additionally, specific constraints are considered to account for the particular the usage of individual and joint storage systems.

$$s_{d,n,t}^{dis,indiv} \leq b_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.28}$$

$$\sum_{n \in \mathcal{ND}} s_{d,n,t}^{ch,joint} \leq \sum_{n \in \mathcal{ND}} g_{d,n,t}^{joint}, \qquad \forall t \in \mathcal{T}, \tag{6.29}$$

$$\sum_{n \in \mathcal{ND}} s_{d,n,t}^{dis,joint} \leq e_{d,t}^{com,joint}, \qquad \forall t \in \mathcal{T}. \tag{6.30}$$

Constraint (6.28) limits the individual storage discharge to own demand supply while constraints (6.29)-(6.30) impose that the joint storage can only be used to supply REC loads with joint production. These constraints guarantee that the electricity exchanged locally is 100 % renewable.

Finally, REC members may agree to unlock some flexibility in their consumption behaviour to better use the available generation and storage means. All along Chapter 4 the different flexible devices operation models were refined to improve the accuracy in representing the impact of the coordinated flexibility scheduling on the performance indicators such as the expected daily benefits or the loss of comfort. Nevertheless, the long-term planning problem considers a much simpler flexibility model to reduce the computational complexity. Furthermore, the estimation of yearly profits is subject to many sources of uncertainty, e.g., production potential, baseline demand, so that the most accurate model would only give an approximated value. Hence, in this work, the flexibility potential is represented by an envelope around the reference consumption profile with a daily maximum load shift volume.

$$\underline{b}_{d,n,t} \leq b_{d,n,t} \leq \overline{b}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.31}$$

$$\Delta b_{d,n,t}^{+} - \Delta b_{d,n,t}^{-} = b_{d,n,t} - b_{d,n,t}^{ref}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.32}$$

$$\sum_{t \in \mathcal{T}} \Delta b_{d,n,t}^{+} \leq F \sum_{t \in \mathcal{T}} b_{d,n,t}^{ref}, \qquad \forall n \in \mathcal{N}, \tag{6.33}$$

$$\sum_{t \in \mathcal{T}} b_{d,n,t} = \sum_{t \in \mathcal{T}} b_{d,n,t}^{ref}, \qquad \forall n \in \mathcal{N}, \tag{6.34}$$

$$\Delta b_{d,n,t}^{+}, \Delta b_{d,n,t}^{-} \geq 0, \qquad \forall n \in \mathcal{N}. \tag{6.35}$$

The flexibility envelope is defined by the upper and lower consumption bounds in (6.31). Then, (6.32) introduces slack variables, $\Delta b^{+/-}_{d,n,t}$, representing the power consumption deviations from the typical demand pattern. Each day, the total volume of deviations is limited to a fraction, F, of the daily reference demand via (6.33). Constraint (6.34) also ensures that only load-shifting actions are scheduled to guarantee the supply of the overall daily needs.

As a reminder, in the community framework a distinction is made between the physical power flows metered at the point of common coupling of the participants with the distribution network and the economic flows, or virtual flows, that are traded between members and with their retailers.

$$l_{d,n,t} = b_{d,n,t} + s^{indiv}_{d,n,t} + s^{joint}_{d,n,t} - g_{d,n,t}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{6.36}$$
$$l_{d,n,t} = l^{+}_{d,n,t} - l^{-}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.37}$$
$$l^{+}_{d,n,t} \cdot l^{-}_{d,n,t} = 0, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.38}$$
$$v_{d,n,t} = l_{d,n,t} - s^{joint}_{d,n,t} + g^{joint}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.39}$$
$$v_{d,n,t} = v^{+}_{d,n,t} - v^{-}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.40}$$
$$v^{+}_{d,n,t} \cdot v^{-}_{d,n,t} = 0, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.41}$$
$$v^{joint}_{d,t} = \sum_{n \in \mathcal{ND}} g^{joint}_{d,n,t} + s^{joint}_{d,n,t}, \qquad \forall t \in \mathcal{T}, \tag{6.42}$$
$$v^{+}_{d,n,t} = i^{ret}_{d,n,t} + i^{com}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.43}$$
$$v^{-}_{d,n,t} = e^{ret}_{d,n,t} + e^{com}_{d,n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.44}$$
$$v^{joint}_{d,t} = e^{ret,joint}_{d,t} + e^{com,joint}_{d,t}, \qquad \forall t \in \mathcal{T}, \tag{6.45}$$
$$\sum_{n \in \mathcal{N}} i^{com}_{d,n,t} = \sum_{n \in \mathcal{N}} \left(e^{com}_{d,n,t}\right) + e^{com,joint}_{d,t}, \qquad \forall t \in \mathcal{T}, \tag{6.46}$$
$$i^{ret}_{d,n,t}, i^{com}_{d,n,t}, e^{ret}_{d,n,t}, e^{ret,joint}_{d,t}, e^{com}_{d,n,t}, e^{com,joint}_{d,t} \geq 0, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{6.47}$$

The physical power balance at each end-user point of connection in the network is expressed in (6.36). It accounts for all assets connected behind the meter of node $n \in \mathcal{ND}$ and the consumption of any end-user connected to that same node. This physical power flow, $l_{d,n,t}$ is decomposed in net consumption, $l^{+}_{d,n,t}$ and net injection, $l^{-}_{d,n,t}$, flows via (6.37) as grid cost are only charged on net consumption volumes. However, these quantities may differ from those effectively traded. Indeed, if one participant host joint assets at its location, the virtual power to be traded by REC members, $v_{d,n,t}$, is defined as the physical metered power from which joint assets power flows contributions are removed (6.39). This is because the end-user does not have the ownership of the assets, hence the energy coming from these resources is made available to everyone. Similarly to the physical power flow, constraints (6.40) distinguish economic import, $v^{+}_{d,n,t}$, and export, $v^{-}_{d,n,t}$, power flows. The energy flowing from collective assets is aggregated in (6.42). Equations (6.43)-(6.45) dispatch the traded power between exchanges within the community and with the retailers. Note that (6.45) implicitly implies that the joint installation can only export power meaning that the joint energy storage system is only used to store production from joint generation assets. Finally, (6.46) ensures the power balance of virtual exchanges within the REC. The non simultaneously non-zero constraints (6.38) and (6.41) are implemented using the big-M method [100] as in constraints (2.6)-(2.7).

As stated by the European Union [12], the objective of Energy Communities is not to make profits but rather to save costs for the supply of the electrical demand of community members. When solving the first step of the long-term planning problem, depending on the retailer prices and assets installation cost parameters considered in the case study, the optimal DERs capacity could be oversized regarding the community needs. This happens if the retailer export price is greater than the marginal cost of production of the DER assets. In this case, end-users are incentivize to sell electricity to the retailer. Hence, to prevent this situation, an annual minimum self-consumption rate (SCR) is imposed to the REC. This ensures that each year, a minimum portion of the generated energy is directly consumed or stored within the community.

$$\sum_{d\in\mathcal{D}}\pi_d\sum_{t\in\mathcal{T}}\left[\sum_{n\in\mathcal{N}}\left(e^{ret}_{d,n,t}\right)+e^{ret,joint}_{d,t}\right]\leq(1-\underline{SCR})\sum_{d\in\mathcal{D}}\pi_d\sum_{t\in\mathcal{T}}\sum_{n\in\mathcal{ND}}g_{d,n,t}\quad(6.48)$$

By imposing a minimum SCR value, $\underline{SCR}$, we set an upper bound to the export power flows to the retailer relative to the available generation by (6.48).

6.1.2. Joint Investment Repartition (Intermediary Step)

Once the first step is solved, the optimal DERs capacity, location and ownership are identified as well as the related investment costs. Although it has no impact on the coordinated optimal solution of the first problem, the repartition of jointly invested capital among potential investor-members is necessary to solve the second optimisation problem. Indeed, this second problem aims to account for the individual perception of the performances of long-term community decisions. Hence, to compute the total life-cycle cost of each participant, the joint investment cost must be distributed *a priori*. In the reference work [112], a cascade repartition method, alike to the Cascade principle for energy sharing surplus presented in Section 3.1.1, is adopted. In this context, the idea behind this sharing method is that the contribution is equally shared until one member reaches its budget limit. Once this situation is encountered, the remaining costs are shared equally among the members with remaining budget until the next limit is reached. The process is repeated until the whole joint investment cost is distributed. The budget limit considered for each end-user is the individual equity capacity, $\overline{E}_n$ from which individual investment cost, E_n^{indiv} are already deducted. The procedure followed in this intermediary step is summarized in Algorithm 5. The resulting individual participation to joint investment, k_n^{joint} and the resulting cost E_n^{joint}, are passed to the second problem.

Algorithm 5: Joint Investment Cascade Repartition

Input : E^{joint}, E_n^{indiv}, $\overline{E}_n$

Initialize remaining joint investment cost and individual budget:
$E^{joint,rem} = E^{joint}$;
$\overline{E}_n^{rem} = \overline{E}_n - E_n^{indiv} \quad \forall n \in \mathcal{N}$;
Initialize individual contribution to joint investment:
$E_n^{joint} = 0 \quad \forall n \in \mathcal{N}$;
while $E^{joint,rem} > 0$ ***and*** $\sum_{n \in \mathcal{N}} \overline{E}_n^{rem} > 0$ **do**
    Compute the number of participants with a positive remaining budget:
    $\mathcal{N}^{inv} = \{n \in \mathcal{N} | \overline{E}_n^{rem} > 0\}$;
    $E_n^{joint} = E_n^{joint} + E^{joint,rem}/|\mathcal{N}^{inv}| \quad \forall n \in \mathcal{N}$;
    Update joint investment cost and individual budget:
    $E_{n,t}^{joint,rem} = E^{joint} - \sum_{n \in \mathcal{N}} E_n^{joint}$;
    $\overline{E}_n^{rem} = \overline{E}_n - E_n^{indiv} - E_n^{joint}$;
end
$k_n^{joint} = E_n^{joint}/E^{joint} \quad \forall n \in \mathcal{N}$.

6.1.3. Fair REC Exchanges Pricing (2nd step)

After the first optimal investment in DERs step and the joint investment distribution, the second step aims to define the optimal local cost structure which ensures the investment profitability for every individual participants while aiming for a fair distribution of savings among all members, investors or not. Compared to the reference work [112], which considers a single uniform and dynamic price, i.e., similar for every member, for both imports and exports and varying every time-step, the proposed second step formulation allows the REC to adopt a more complex tariff structure in line with the innovative investment strategies considered in the first step. The problem is formulated as a Linear Programming (LP) problem and is written in general terms as:

$$\begin{aligned} \min_{\Omega^2} \quad & \text{Objective Function (6.50)/(6.52)/(6.54)} \qquad (6.49) \\ \text{s.t.} \quad & \text{Tariffs structure constraints (6.63)-(6.67) + (6.68)/(6.69)/(6.70)} \end{aligned}$$

with $\Omega^2 = \{\lambda_{d,t}^{com,imp}, \lambda_{d,n,t}^{com,exp}, \lambda_{d,t}^{com,joint}, \lambda^{SR}\}$, the set of decision variables representing, respectively, the local import price , the local export price for the resale of individual production surplus, the local export price for the resale of joint assets production and the annual space renting fee for participants hosting joint installations on their site. The local import price has one dimension less as it is assumed unique for all members because they receive the same product that is electricity from the local pool. However, from the prosumers perspective, the individual export price may differ from one to another as the refund of their investment is also influenced by their capacity to self-consume their own production. A distinction is also made between individual and joint assets prices for similar reasons.

Objective Function(s)

In the reference paper [112], the fairness indicator considered as the objective of the problem is the maximisation of the minimum individual saving with respect to the initial situation before joining the REC. This objective function is as follows:

$$f_1(\Omega^2) = -\underline{CS}, \tag{6.50}$$
$$\underline{CS} \leq CS_n, \qquad \forall n \in \mathcal{N}. \tag{6.51}$$

with $\underline{CS}$ a slack variable representing the minimum cost savings among the community members as defined by (6.51). If the definition of fairness in the energy community context is the aim for equal savings, this objective function may not lead to the expected result. Indeed, in an unconstrained environment, promoting the lowest saving brings every member at equilibrium. However as discussed in Chapter 5, the individual savings may be capped by the energy flows and investment decisions taken in the first step. Therefore, once the member with the lowest benefits upper limit reaches it, there can exist multiple possibilities to distribute the remaining savings among other members without affecting the objective function. In this case, some optimisation results could move away from the targeted fairness definition.

Nevertheless, other objective functions can be used to minimize the disparities in individual savings. For example, a first natural objective function would be to minimize the variance of individual savings. Indeed, variance is a measure of dispersion of sample values with respect to their average value. This second objective function would write as:

$$f_2(\Omega^2) = \sum_{n \in \mathcal{N}} (CS_n - \hat{CS})^2 / |\mathcal{N}|, \tag{6.52}$$

$$\hat{CS} = \sum_{n \in \mathcal{N}} CS / |\mathcal{N}|. \tag{6.53}$$

with $\hat{CS}$ the average individual cost savings among all REC participants. Compared to the previous objective function that is linear, with this objective function the pricing problem becomes a Quadratic Programming (QP) problem.

Finally, a last representation of the fairness target is considered in this work. Inspired by the work of [145], this third objective function is an extension of f_1 as it maximises the minimum individual savings meanwhile the largest one are minimised:

$$f_3(\Omega^2) = \overline{CS} - \underline{CS}, \tag{6.54}$$

$$\underline{CS} \leq CS_n \leq \overline{CS}, \qquad \forall n \in \mathcal{N}. \tag{6.55}$$

with $\underline{CS}$ and $\overline{CS}$ additional slack variables representing respectively the lower and upper cost savings boundaries among end-user.

If different formulations of the objective function can be used to ensure fairness in individual performances, they all rely on the definition of individual savings. In this second step, the annual cash flows considered are extended to account for the local exchanges of energy and additional internal cash flows. In the first step, by focusing on the aggregated electricity cost, the internal REC economic trade, continuously balanced by the community manager, cancel each other in the objective function.

$$CS_n = \sum_{y \in \mathcal{Y}} \frac{\Pi_{n,y}}{(1+r)^y} - (E_n^{indiv} + E_n^{joint}), \qquad \forall n \in \mathcal{N}, \tag{6.56}$$

$$\Pi_n = B_n^0 - B_n, \qquad \forall n \in \mathcal{N}, \tag{6.57}$$

$$\begin{aligned} B_n = {} & \sum_{d \in \mathcal{D}} \pi_d \sum_{t \in \mathcal{T}} \underbrace{\left[\sum_{n \in \mathcal{N}} \left(\lambda_{d,n,t}^{ret,imp} \, i_{d,n,t}^{ret} - \lambda_{d,n,t}^{ret,exp} e_{d,n,t}^{ret} \right) \right] \Delta t}_{\text{Retailer Commodity Costs}} \\ & + \underbrace{\sum_{n \in \mathcal{N}} \left[(\gamma^{com} + \lambda_{d,t}^{com,imp}) i_{d,n,t}^{com} + (\gamma^{com} - \lambda_{d,n,t}^{com,exp}) e_{d,n,t}^{com}) \right] \Delta t}_{\text{REC Operational Costs}} \\ & + \underbrace{\sum_{n \in \mathcal{N}} (\lambda_{d,n,t}^{grid} + \lambda^{tax}) l_{d,n,t}^{+} \Delta t}_{\text{Grid and Taxes Costs}} - \underbrace{\left(k_n^{joint} R^{joint} + R_n^{SR} \right)}_{\text{Joint Investment Revenues}} \qquad \forall n \in \mathcal{N}, \end{aligned} \tag{6.58}$$

$$\begin{aligned} R^{joint} = {} & \sum_{d \in \mathcal{D}} \pi_d \sum_{t \in \mathcal{T}} \left[\lambda_{d,t}^{ret,joint} e_{d,t}^{ret,joint} + (\lambda_{d,t}^{com,joint} - \gamma^{com}) e_{d,t}^{com,joint} \right] \Delta t \\ & - D - \sum_{n \in \mathcal{N}} R_n^{SR}, \end{aligned} \tag{6.59}$$

$$R_n^{SR} = \lambda^{SR}\Big(E_{ess,n}^{joint} + P_{ess,n}^{joint} + \sum_{g\in\mathcal{G}} P_{g,n}^{joint}\Big), \qquad \forall n \in \mathcal{N}. \quad (6.60)$$

Individual cost savings made over the investment period are expressed in (6.56) as the present value of operational savings from which we retain the invested equity refund. As for the first problem, operational savings are computed as the difference between the initial electricity bill before joining the REC and the expected one in the REC framework. The electricity bill of REC participants, expressed in (6.58), accounts for the traditional retailer commodity costs, including both purchases and sales, the grid and taxes costs as well as the operational REC costs arising from the energy traded within the community. In addition, complementary revenues can be generated thanks to the jointly installed assets. A first revenue stream is received by investor-members based on their contribution to the joint investment, k_n^{joint}. The revenues of joint installations are generated by the resale of electricity production within the REC and/or to a retailer. These revenues are first used to cover the potential debt payment and remunerate individuals hosting part of the infrastructures on their site via (6.59). The annual space rent perceived by hosting participants is expressed as a function of the joint capacity installed behind their meter that is charged at price λ^{SR}.

Defining savings as the absolute electricity supply cost reduction is not the only option that can be considered. Indeed, when an REC brings together end-users with different consumption levels and consequently different initial electricity bill ranges, equal savings in terms of economic currencies (e.g., €) may not represent the same incentive for everyone. Hence, relative savings, RCS_n, are sometimes rather used in the literature [108], [139] as a fair incentive in the objective function. Two common examples place the absolute cost savings in perspective with the initial bills, B_n^0, or with the annual load demand supplied, $b_n = \sum_{d\in\mathcal{D}} \pi_d \sum_{t\in\mathcal{T}} b_{d,n,t}\Delta t$. These two variants are therefore expressed in [%] and [€/kWh] respectively and defined in the following :

$$RCS_n^1 = CS_n/B_n^0, \qquad \forall n \in \mathcal{N}, \quad (6.61)$$

$$RCS_n^2 = CS_n/b_n, \qquad \forall n \in \mathcal{N}. \quad (6.62)$$

Tariffs Structure Constraints

Two main constraints on the internal tariffs structure are considered in the problem to encourage end-users in participating to Energy Communities local exchanges and to the coordinated long-term investment strategy. The first one imposes that the internal price is more advantageous than the ones proposed by retailers. The second one aims to guarantee that every participant has a positive cost saving, in other words, that they do not loose money by joining the REC and investing in DERs. In the REC the internal exchange price must not necessarily be unique. As long as the yearly economic balance is respected, a more complex pricing structure that takes advantage of the investment strategies specific to energy communities can be adopted. In the proposed model, three different prices relative to local energy trades are identified: local import price, local individual surplus export price and local joint production export price. Differentiating export price is relevant as the value of the individual remaining electricity depends on the savings already made through individual self-consumption. Therefore, individual surplus may be valued less than joint (raw) production.

This segregation of import and export price is a first option (or degree of freedom) called *price unicity* in the following. Moreover, participants may be charged differently, especially regarding the individual surplus export with regard to their evaluation of the remaining value of individual assets production. This second option is named *price uniformity*. Finally, another degree of freedom that can be exploited is the temporality of prices. Either a flat price can be defined for the whole period if participants aim for reduced price volatility, or it can be adapted dynamically (i.e., each time period) if prices must reflect the availability of local electricity production. Whatever the selected pricing mechanism, pricing decisions must respect the following local economic constraints:

$$\sum_{d\in\mathcal{D}}\sum_{t\in\mathcal{T}}\left[\sum_{n\in\mathcal{N}}(\lambda^{com,imp}_{d,n,t}i^{com}_{d,n,t}-\lambda^{com,exp}_{d,n,t}e^{com}_{d,n,t})-\lambda^{com,joint}_{d,t}e^{com,joint}_{d,t}\right]\Delta t=0, \tag{6.63}$$

$$\lambda^{com,imp}_{d,t}\leq\lambda^{ret,imp}_{d,n,t}, \qquad \forall d\in\mathcal{D},\forall n\in\mathcal{N},\forall t\in\mathcal{T}, \tag{6.64}$$

$$\lambda^{ret,exp}_{d,n,t}\leq\lambda^{com,exp}_{d,n,t}, \qquad \forall d\in\mathcal{D},\forall n\in\mathcal{N},\forall t\in\mathcal{T}, \tag{6.65}$$

$$\lambda^{ret,joint}_{d,t}\leq\lambda^{com,joint}_{d,t}, \qquad \forall d\in\mathcal{D},\forall t\in\mathcal{T}, \tag{6.66}$$

$$CS_n\geq 0, \qquad \forall n\in\mathcal{N}. \tag{6.67}$$

The yearly economic balance of exchanges within the EC is imposed by (6.63). The attractiveness with respect to retailers tariffs is guaranteed by (6.64), (6.65) and (6.66). Finally, the profitability of the current situation is enforced through (6.67) by imposing a positive total cost savings for each REC member.

Besides, different pricing options can be selected for the definition of the local tariff structure by including one or combine the following constraints:

$$\lambda^{com,exp}_{d,n,t}=\lambda^{com,exp}_{d,m,t}, \qquad \forall d\in\mathcal{D},\forall(n,m)\in\mathcal{N},\forall t\in\mathcal{T}, \tag{6.68}$$

$$\lambda^{com,imp}_{d,t}=\lambda^{com,exp}_{d,n,t}=\lambda^{com,joint}_{d,t}, \qquad \forall d\in\mathcal{D},\forall n\in\mathcal{N},\forall t\in\mathcal{T}, \tag{6.69}$$

$$\lambda_{d_i,n,t_k}=\lambda_{d_j,n,t_l}, \qquad \forall(d_i,d_j)\in\mathcal{D},\forall n\in\mathcal{N},\forall(t_k,t_l)\in\mathcal{T}. \tag{6.70}$$

Constraint (6.68) imposes individual surplus export prices uniformity, meaning that all members receive the same price for selling part of their production to other participants. Import prices are assumed to be uniform by default in this thesis.

The price unicity constraint (6.69) even further restrict the number of independent variables by setting all prices to the same value at each time step. If the flat option is selected, the last constraint, (6.70), is applied to every local price category, i.e., import, individual surplus export and joint production export. The different prices structure enabled by those options and the associated constraints are summarized in Table 6.1.

Parentheses are used to indicate that the constraints are redundant with the other

Table 6.1.: Possible internal tariffs structures and associated constraints.

	Constraints		
Tariff Structure	(6.68)	(6.69)	(6.70)
Non uniform, non unique and dynamic	No	No	No
Uniform, non unique and dynamic	Yes	No	No
Uniform, unique and dynamic	(Yes)	Yes	No
Non uniform, non unique and flat	No	No	Yes
Uniform, non unique and flat	Yes	No	Yes
Uniform, Unique and flat	(Yes)	Yes	Yes

one. It especially occurs when considering a unique price which necessarily makes the export prices uniform.

6.2. Balancing Individual and Collective Welfare

Adopting the two-steps procedure to solve the long-term REC planning problem, which aims to both define the best investment strategies for DERs installations, i.e., capacity, location and ownership, and the fairest local tariff structure, presents some advantages and drawbacks. By solving the two questions, i.e., optimal investment and pricing, sequentially, this method prioritizes the REC-level welfare optimisation guaranteeing the best collective performances. Indeed, by coordinating the decisions while being aware of the various end-users characteristics influencing the supply of electricity such as retailer tariffs of members, their installation capacity potential, or their consumption patterns, we can obtain the optimal average electricity supply cost reduction by optimally scheduling the flexible resources usage and the local electricity pool distribution. Nevertheless, as all the power installations (long-term) and exchanges (short-term) decisions are taken in the first step, the second optimisation problem is highly constrained by the outputs of the first problem. The only remaining degree of freedom that can be adjusted for fairness concerns is the internal exchanges price. But the influence of this decision variable on the individual savings is highly dependent on the realization of local energy flows computed in the first problem. These energy flows have a direct impact on REC's operational costs and are therefore driven by the objective to reduce them. Theoretically, to obtain the best objective function value the optimal strategy for local energy flows dispatch is to allocate as much local energy to consumers with the highest retailer import tariff and the most energy surplus to prosumers with the highest retailer export tariff. Doing so the best REC-scale objective can be achieved meanwhile it limits the individual savings other members can reap. Furthermore, from a mathematical point of view, even if all EC participants have the same retailer contract, it might exist multiple optimal solutions for the local energy dispatch. Hence, the individual savings repartition depends on the solution outputed by the solver. With this concern in mind, in this thesis we addressed the following primary research question:

"Can we plan investment decisions that offer the best trade-off between collective and individual welfare maximization ?"

To answer this question, the two following adaptations of the two-steps procedure are identified. These adaptations can be included either independently or at the same time to further constraint the decision set to offer adequate economic incentives to every participants of the community:

1. The first idea is to explicitly embed the formulation of energy sharing mechanisms in the first optimisation problem. These sharing mechanisms usually adopt the form of Keys of Repartition (KoR) that regulate the dispatch of the local electricity pool among members. By specifying rules for the local dispatch of energy, we prevent the adoption of repartition strategies of the local energy only based on retailer prices arbitrage for collective performances

optimisation. The different energy sharing KoRs defined in Chapter 3, namely, the *Equal Keys*, *Prorate Consumption Key*, *Hybrid Keys* and *Cascade Key*, are compared by assessing their impact on the second step objective function.

2. The second adaptation consists in solving the whole long-term planning problem for Renewable Energy Communities in one stroke. Doing so, it enables to make the DERs sizing and local exchange variables aware of the fairness objective. To this end, a single-step general centralised sizing and pricing optimisation problem is conceptualised and formulated. This problem integrates the whole procedure presented in Figure 6.1 in a unique mathematical formulation. The objective function of this problem is a weighted sum of both problems (6.1) and (6.49) objective functions. Hence, the proposed problem aims to find the optimal trade-off between collective and individual surplus maximization.

The two proposed approaches are further presented in the remaining of this section. Section 6.2.1, first recalls the mathematical formulation of one particular Key of Repartition (KoR) presented in Section 6.3. Then, the single-step formulation of the long-term planning problem is presented along with the additional constraints that are required for the simultaneous resolution of the whole set of decision variables in Section 6.2.2. Finally, the performances of the proposed method are evaluated and compared to the two-steps method particularly in terms of trade-off between collective savings and individual savings repartition as well as in terms of computational scalability of the models.

6.2.1. Integrating Energy Sharing Mechanisms

In several EU member states [13], [129], regulators adopted the energy sharing surplus principle to settle the local exchanges within Energy Communities. In these communities, the individual production surplus $v^{-}_{d,n,t}$ and the overall production of joint assets, $v^{joint}_{d,t}$, is aggregated in the community pool, $P^{pool}_{d,t}$. The overall electricity volume of the local pool is then allocated to the community members to (partially) cover their electrical demand. The settlement of allocated volume rely on the application of distribution keys, $k_{d,n,t}$ as follows:

$$P^{pool}_{d,t} = v^{joint}_{d,t} + \sum_{n\in\mathcal{N}} v^{-}_{d,n,t}, \qquad \forall d\in\mathcal{D}, \forall t\in\mathcal{T}, \tag{6.71}$$

$$p^{alloc}_{d,n,t} = k_{d,n,t} P^{pool}_{t}, \qquad \forall d\in\mathcal{D}, \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, \tag{6.72}$$

$$i^{com}_{d,n,t} \leq p^{alloc}_{d,n,t} \qquad \forall d\in\mathcal{D}, \forall n\in\mathcal{N}, \forall t\in\mathcal{T}, \tag{6.73}$$

$$\sum_{n\in\mathcal{N}} k_{d,n,t} \leq 1, \qquad \forall d\in\mathcal{D}, \forall t\in\mathcal{T}. \tag{6.74}$$

with $p^{alloc}_{d,n,t}$ the electricity volume from the local pool allocated to each member. This represent the maximum amount of REC energy they can consume, i.e.,$i^{com}_{n,t}$, and for which they benefit of an advantageous tariff. Not more than the available electricity in the local pool must be allocated, meaning that the sum of $k_{n,t}$ must not exceed 100%.

This mechanism can be explicitly taken into account in the first step of the two-steps procedure for solving the long-term planning problem. There exist numerous options of distribution keys according to the REC objectives (e.g., social inclusion, self-consumption) [14], [73], by adequately selecting one of these it may improve the fairness in savings distribution. In this section, as an example, the implementation of one of the 6 KoR principle presented in Section 6.3, that is the *Prorate Consumption Key*, is recalled.

Energy Sharing Example - Prorate Consumption Key

This KoR takes into account the electricity volume request of each member. More specifically, it distributes the local electricity pool based on the net individual consumption level, $v^{+}_{d,n,t}$, with respect to the overall net consumption inside the REC, $V^{+}_{d,t} = \sum_{n \in \mathcal{N}} v^{+}_{d,n,t}$ (see Figure 6.3).

$$k_{d,n,t} = \frac{v^{+}_{d,n,t}}{V^{+}_{d,t}}, \quad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{6.75}$$

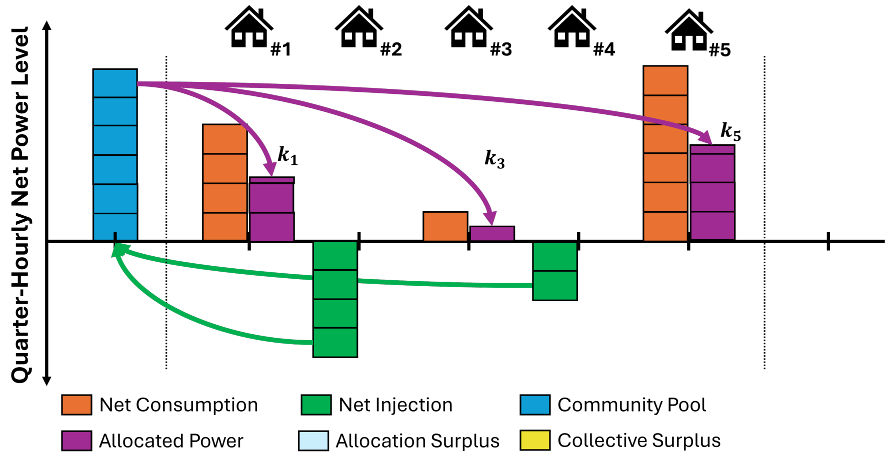


Figure 6.3.: EC Electricity Pool Sharing Example - Prorate Consumption KoR

As it involves a ratio of decision variables, implementing this key as such is not suitable as it would require to embed non-linear constraints in the long-term planning problem, hence, the global optimality of the solution could not necessarily be guaranteed. However, in [17], we proposed a linear constraints reformulation of the key principle by introducing an integer variable (i.e., binary expansion of variable $\nu_{j,d,t}$) to represent the ratio between the local electricity pool and the overall net power consumption inside the REC. In the following formulation, a granularity of 1% is considered:

$$p^{alloc}_{d,n,t} = v^{+}_{d,n,t}\left(\sum_{j=1}^{7} \nu_{j,d,t} 2^{(j-1)}\right)/100, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (6.76)$$

$$\sum_{n \in \mathcal{N}} p^{alloc}_{d,n,t} \leq P^{pool}_{d,t}, \qquad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \quad (6.77)$$

$$i^{com}_{d,n,t} \leq p^{alloc}_{d,n,t}, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (6.78)$$

$$0 \leq p^{alloc}_{d,n,t} \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (6.79)$$

$$\nu_{j,d,t} \in \{0, 1\}, \qquad \forall j \in \{1, ..., 7\}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T}. \quad (6.80)$$

This set of constraints imposes that everyone receives a share of the community pool relative to its net consumption level via (6.76), this allocated quantity limiting the local community import in (6.78). Finally, constraint (6.77) makes sure that no more than the local energy volume is allocated overall in the community.

Extra Local Energy - Prorate Injection Key

If we want to include energy sharing mechanisms for the distribution of the local electricity pool in the long-term optimisation problem, it is necessary to integrate another KoR that distribute the extra local energy among prosumers (i.e., REC members with a net power injection) and the community operator responsible for the joint assets. Indeed, in the energy surplus framework it might happen that, during certain time periods, the local electricity pool is not fully consumed by the community members. In this case, the extra local energy is sold on the retail market dispatching this economic flow among prosumers. This is often done using a *Prorate Injection Key* which dispatches it proportionally to their contribution to the local electricity pool. An illustrative example of the application of this KoR mechanism is presented in Figure 3.8. This example considers that the local electricity pool is preliminary shared equally among all members, whether they produce or consume.

$$P^{pool,rem}_{d,t} = P^{pool}_{d,t} - \sum_{n \in \mathcal{N}} i^{com}_{d,n,t}, \quad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \quad (6.81)$$

$$e^{ret}_{d,n,t} = k^{e}_{d,n,t} P^{pool,rem}_{d,t}, \quad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (6.82)$$

$$e^{ret,joint}_{d,t} = k^{e,joint}_{d,t} P^{pool,rem}_{d,t}, \quad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \quad (6.83)$$

$$k^{e}_{d,n,t} = \frac{v^{-}_{d,n,t}}{P^{pool}_{d,t}}, \quad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{6.84}$$

$$k^{e,joint}_{d,t} = \frac{v^{joint}_{d,t}}{P^{pool}_{d,t}}, \quad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}. \tag{6.85}$$

with, $P^{pool,rem}_{d,t}$, the extra local energy. The virtual power flows sold to the retailer are defined by (6.82) and (6.83) for individual and joint assets, respectively. The repartition keys, $k^{e}_{d,n,t}$, are computed as the individual contribution share to the local electricity pool trough (6.84) and (6.85). To include this community surplus

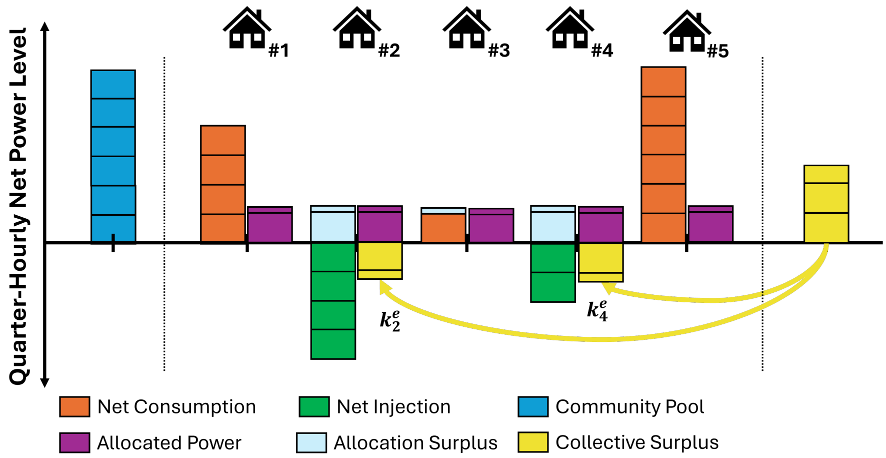


Figure 6.4.: EC Electricity Pool Surplus Sharing - Prorate Injection KoR

sharing rule, similar constraints as (6.76)-(6.80) are implemented:

$$e^{ret}_{d,n,t} = v^{-}_{d,n,t}\left(\sum_{j=1}^{7} \nu^{e}_{j,d,t} 2^{(j-1)}\right)/100, \quad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{6.86}$$

$$e^{ret,joint}_{d,t} = v^{joint}_{d,t}\left(\sum_{j=1}^{7} \nu^{e}_{j,d,t} 2^{(j-1)}\right)/100, \quad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \tag{6.87}$$

$$\nu^{e}_{j,d,t} \in \{0, 1\}, \quad \forall j \in \{1, ..., 7\}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T}. \tag{6.88}$$

6.2.2. Single-Step Long-Term Planning Model

To give more weight to the objective of energy communities to share the added value of local exchanges such that every participant find its way around alongside the efficiency objective, a single-stage optimisation problem is proposed. It provides optimal DERs (production and storage) investment and internal pricing structure decisions simultaneously with a multi-objective approach. The objective function puts in competition the community level economic efficiency and the distribution of savings among members. The two components weights can be adjusted according to the willingness of EC members to push one or another in priority. This objective function is inline with the community concept as it encourages members to maximise the valorisation of local exchanges while taking care to minimise disparities in the benefits to secure participation of all parties. By formulating the whole problem in a single stage, more degrees of freedom are unlocked for a fairer distribution of savings as DERs capacity and the dispatch of local energy flows is also conscious of this social objective. Concomitantly, internal prices have a limited effects on the REC savings, as long as the economic balance of local exchanges is secured, but this additional degree of freedom relaxes the potential opposition of the two objective function components. The problem is a Mixed-Integer Linear Programming (MILP) problem and can be written in general terms as :

$$\begin{aligned} \max_{\Omega} \quad & \omega^{REC} \hat{CS}^{REC} + \omega^{indiv} \left(\underline{CS} - \overline{CS} \right) \qquad (6.89) \\ \text{s.t.} \quad & \text{1st step long-term constraints (6.8)-(6.18)} \\ & \text{1st step short-term constraints (6.19)-(6.48)} \\ & \text{2nd step tariffs structure constraints (6.63)-(6.67) + (6.68)/(6.69)/(6.70)} \\ & \text{Joint investment repartition constraints (6.90)-(6.96)} \\ & \textbf{Internal cost linearization constraints} \end{aligned}$$

with ω^{REC} and ω^{indiv} the weights given to the two objective components that are the community relative cost savings, $\hat{CS}^{REC}$, the mean individual savings among the members, and the indicator of fair distribution of savings $f_3(\Omega)$ from (6.54) which aims to converge every members cost savings to the average one across all the participants. Collective relative cost savings are defined as the total community savings (i.e., opposite of $TLCC$ in the first step) divided by the overall electricity consumption of the members. The new set of decision variables $\Omega = \{\Omega_{LT}, \Omega_{ST}\}$ mainly complements the two-steps method variables by adding, from a long-term perspective, the individual shares in joint investment, $\Omega_{LT} := \{\Omega^1_{LT}, \Omega^2, E^{joint}_n\}$, and short-term decision variables related to energy sharing mechanism, $\Omega_{ST} := \{\Omega^1_{ST}, p^{alloc}_{d,n,t}\}$.

Additionally, to reduce the long-term REC planning problem in a single step the intermediary step presented in Section 6.1.2 that distributes the effort in the joint investment among investor-members must be also integrated to the model. On another hand, the definition of individual cost savings (6.56) implies various cost components presenting a bilinear product of energy exchanges and local prices decisions variables. To keep the model linear those product must be reformulated using appropriate linearization techniques. This additional constraints are presented in the following.

Joint Investment Repartition Constraints

In Section 6.1.2, the total equity invested in joint DERs are shared by applying the cascade distribution principle. This mechanism, following Algorithm 5, is transposed to a set of linear constraints in the same way the cascade KoR sharing energy within REC was reformulated in Section 6.3. The proposed implementation requires to introduce another binary variable, z_n, which indicates if end-users have reach their capital limit. The full set of constraints is as follows:

$$\left(\overline{E}_n - E_n^{indiv}\right) \cdot z_n^{joint} \leq E_n^{\text{joint}}, \qquad \forall n \in \mathcal{N}, \tag{6.90}$$

$$E_n^{joint} \leq E_m^{joint} + M \cdot z_m^{joint}, \qquad \forall (n,m) \in \mathcal{N}, \tag{6.91}$$

$$\sum_{n \in \mathcal{N}} E_n^{joint} = E^{joint}, \tag{6.92}$$

$$E_n^{joint} \geq 0, z_n^{joint} \in \{0,1\}, \qquad \forall n \in \mathcal{N}. \tag{6.93}$$

Invested equity in joint installations is dispatched among REC members based on their remaining budget after individual investment via (6.90). This constraint makes sure that z_n^{joint} is equal to 1 if member n reaches its capacity limit. If it is the case, constraint (6.91) allows other end-users to invest more. Otherwise they share the joint investment cost equally.

Besides, the consideration if individual equity investment in joint assets, the members cost savings includes the remuneration relative to joint production valorization within the REC or on the retail market. The following constraints ensure that each investor-member receives a share of the joint revenues (6.58) proportionally to its contribution to the investment cost:

$$R_n^{joint} = E_n^{joint} \left(\sum_{j=1}^{7} \nu_j^{joint} 2^{(j-1)} \right) / 100, \qquad \forall n \in \mathcal{N}, \tag{6.94}$$

$$\sum_{n \in \mathcal{N}} R_n^{joint} = R^{joint}, \tag{6.95}$$

$$\nu_j^{joint} \in \{0,1\}, \qquad \forall j \in \{1, ..., 7\}. \tag{6.96}$$

Internal Cash Flows Linearization Constraints:

The major challenge regarding the single-step resolution of optimal DERs capacity, energy flows and internal prices identification is the management of the bilinear products in several internal annual cash flows equations: (6.58), (6.59), (6.60) and (6.63). To cope with this challenge, in this thesis we propose to discretize the local prices variables $\lambda_{d,t}^{com,imp}$, $\lambda_{d,n,t}^{com,exp}$, $\lambda_{d,t}^{com,joint}$ and λ^{SR}. To this end, these variables are expressed under the form of a binary expansion:

$$x = a \cdot \sum_{m=1}^{N^{bits}} \nu_m \cdot 2^{(m-1)} \tag{6.97}$$

where x is the discrete variable of interest, ν_m is a set of binary variables used to expand it and N^{bits} the number of bits considered. This number of bits combined with coefficient a sets an upper bound for the variable.

Applying this discretization of local price variables, leaves us with several bilinear products of binary and binary or binary and continuous variables that can be exactly reformulated as a set of linear constraints using standard techniques **Linear**.

6.3. Case Study and Preliminary Results

In this section, we aim to compare the different approaches proposed in this chapter to identify the optimal set of long-term decisions while aiming for both collective performances and fairness in the repartition of benefits. To this end, we consider ten residential end-users that are gathered in a REC. These end-users naturally differ in terms of reference consumption profiles and PV production potential (different rooftop orientations). Their yearly consumption and average PV potential are presented in Table 6.2 The consumption profiles are based on historical data from houses in France. The investment model is simulated over a representative year, constructed from 12 representative days each with a 1 hour time step. This representative year is replicated over a 15-years investment horizon.

Table 6.2.: Community members consumption and production characteristics.

Members	1	2	3	4	5	6	7	8	9	10
Yearly consumption [kWh]	4851	5229	2581	3746	3471	1990	1668	2629	3264	3306
Average PV load factor [%]	11.6	15.2	14.8	14.6	11.5	20.8	14.8	15.1	6.8	6.8

The preliminary results, here after, only consider investment in PV infrastructures. Consumption flexibility and storage devices have been neglected. In addition, members can invest in PV assets individually or jointly with each a budget of 12000 € ($\overline{E}_n$), but only decentralized locations are available. The capacity that can be hosted on each rooftop is limited to 10 kW ($\overline{P}_{PV,n}$). The unit price of PV is equal to 1200 €/kW (C_{PV}), the internal rate of return is of 4 % (r) and the loan interest rate is of 6 % (r_L).

To generalize the results and highlight the limits of the two-steps method, ten different (random) configurations of retailer contracts among the ten members are considered. Two choices are offered to them, a flat tariff and a Time of Use (ToU) tariff. In both cases the retailer export price is 0.02 €/kWh ($\lambda^{ret,exp}$). However, regarding the import price ($\lambda^{ret,imp}$), in the flat contract it is 0.189 €/kWh while in the ToU contract it is 0.167 €/kWh during the night hours (i.e., from 10 PM to 7 AM during the week days and the whole week-end) and 0.199 during day hours. Similarly for the grid tariffs the flat price is 0.155 €/kWh and the ToU prices are 0.114 €/kWh and 0.162 €/kWh, respectively for night and day times. Finally, taxes prices is 0.017 €/kWh and the REC fee paid to the community manager for each volume unit of local exchange amounts to 0.019 €/kWhh (γ^{com}).

The 10 configurations of electricity contracts for the community members are depicted in Table 6.3.

Table 6.3.: Individual electricity contracts of the community members.

Cases	1	2	3	4	5	6	7	8	9	10
Member 1	Flat	ToU	Flat	ToU	ToU	Flat	Flat	Flat	Flat	ToU
Member 2	ToU	ToU	Flat	Flat	Flat	ToU	ToU	ToU	ToU	Flat
Member 3	Flat	Flat	ToU	Flat	ToU	ToU	Flat	ToU	ToU	Flat
Member 4	ToU	Flat	Flat	ToU	Flat	ToU	Flat	Flat	ToU	ToU
Member 5	Flat	Flat	ToU	ToU	ToU	ToU	ToU	Flat	Flat	Flat
Member 6	Flat	ToU	Flat	ToU	Flat	Flat	Flat	ToU	Flat	Flat
Member 7	ToU	ToU	Flat	ToU	Flat	ToU	ToU	ToU	ToU	ToU
Member 8	ToU	ToU	ToU	Flat	ToU	ToU	Flat	Flat	ToU	Flat
Member 9	Flat	ToU	ToU	ToU	ToU	ToU	Flat	ToU	ToU	Flat
Member 10	ToU	ToU	ToU	Flat	ToU	Flat	ToU	Flat	Flat	ToU

The proposed models are implemented using the Julia JuMP package and solved with the Gurobi solver. First, the results of the two-steps approach are presented in terms of PV installations. Then, the optimal local electricity prices obtained by considering the different combinations of uniformity, unicity and flat/dynamic options presented in Table 6.1. The performances are compared in terms of individual savings distribution fairness. In this section, the cost savings definition is considered is the relative one with respect to the overall electricity consumption of the member as presented in equation (6.62). The objective function of the second step is the same as the one integrated in the single-step multi-objective problem introduced in equations (6.54)-(6.55).

Then, the two-steps problem is solved considering the more restrictive internal prices structure, i.e., unique (uniform) and flat price, but including the formulation of Energy Surplus sharing mechanisms. More specifically, the Cascade and Hybrid KoRs formulations from Section are implemented and compared to the previous results.

Finally, the single-step problem is solved on the same 10 EC configurations. The weight of the collective objective (ω^{REC}) is fixed to 1 while a sensitivity analysis is performed on the weight of the fairness objective (ω^{indiv}). The internal tariffs are also considered unique and flat and no KoR is implemented. This allows to clearly observe the impact of each alternative proposed to improve the consideration of fairness in the long-term planning problem of RECs.

6.3.1. Impact of Internal Tariff Structures

Solving the first optimisation problem (6.1) of the two-steps procedure for each EC configuration gives similar results in terms of optimal PV capacity. The results are presented in Table 6.4. Indeed, the PV capacity is optimised to cover the needs of the community by making an arbitrage between the retailer tariffs and the cost of production of PV panels. Regarding the investment strategy, end-users only invest individually and the PV assets are located on the rooftops of all members. Member 6 who has the highest PV potential as naturally the biggest installed capacity. For the others, the investment depends on the PV potential but also on the consumption patterns of end-users. Indeed, when electricity is consumed directly behind the meter, not only the retailer costs are saved but also the grid costs. This incentivize end-users to invest in PV assets to cover part of their daily demand on site. Hence, except for Member 6 all members exhibit a relatively high self-consumption rate (SCR) compared to the 37.76 % estimated in Wallonia [146].

Table 6.4.: Optimal PV capacity and SCR with the two-steps procedure.

End-user	1	2	3	4	5	6	7	8	9	10
PV capacity [kW_{peak}]	1.904	2.099	0.838	1.310	1.071	5.931	0.375	0.737	0.702	0.848
SCR [%]	65	73	56	53	73	10	53	55	92	88

However, the collective performances vary among the different cases due to the different tariffs combinations. It amounts to approximately 1960 € saved each year for the electricity provision. Based on the individual tariffs contracts, the local electricity pool is allocated to members to primarily reduce the retailer import for members with ToU contracts during the week days and to the other members during the week-ends.

Table 6.5.: Optimal yearly costs savings with the two-steps procedure.

Case	1	2	3	4	5	6	7	8	9	10
CS^{REC} [€]	1967	1963	1960	1950	1955	1956	1971	1962	1960	1958

Now, looking at the second optimization problem, Figure 6.5 shows the individual relative savings distribution (in €/kWh) for each internal tariff structure recalled in Table 6.6 and for each EC configuration. First, we can notice from the results that the temporal variability of prices is the only degree of freedom affecting the distributions of relative savings in all cases. The first reason is that as long as there is no joint investment, as it is the case in this section, only relaxing the unicity constraint (e.g., from C to B or from F to E) does not offer any additional possibility for the prices. Indeed, individual export prices and local import prices must guarantee the local economic balance and if the export prices are uniform the prices will necessarily also be unique. In addition, tariff structures A and D offer the possibility to discriminate investor members on the price received when electricity is sold to the community. However, as there is a single retailer export price, the marginal gains will be the same for every prosumers when selling their surplus. Therefore, these prices must be uniform to provide fair benefits distribution.

Over the 10 EC configurations, we can observe that with flat local prices, the individual relative savings range between 0.04 and 0.08 €kWh (i.e., which represents 140 to 280 € saved per year of typical household consumption of 3500 kWh). The spread of savings depends on the retailer tariff conditions. The wider spread is observed in Case 4 that also presents the lowest collective performances and the highest median is obtained in Case 7 which has the highest collective savings. Local flat prices vary between 0.069 and 0.074 €kWh. Finally, we notice that introducing dynamic prices enables to equilibrate the distribution of savings around 0.06 €kWh. In that case, the price continuously oscillates between its boundaries (i.e., that are the flat prices retailer export and import prices). Although this volatility may be interesting to distribute benefits ex-post, planning the future price dynamic on the long-run may be challenging. Also from an external point of view, it may discourage people from participating to the community. Therefore, in the following other alternatives are tested to improve fairness in the savings distribution.

Table 6.6.: Possible internal tariffs structures.

	Tariff Structure
Tariff A	Non uniform, non unique and dynamic
Tariff B	Uniform, non unique and dynamic
Tariff C	Uniform, unique and dynamic
Tariff D	Non uniform, non unique and flat
Tariff E	Uniform, non unique and flat
Tariff F	Uniform, Unique and flat

6.3.2. Impact of Energy Sharing Rules

By embedding explicit Energy Sharing Rules within the first step of the long-term planning problem, the organization of local exchanges and the consequent operational savings are naturally affected. However, looking at Tables 6.7 and 6.8

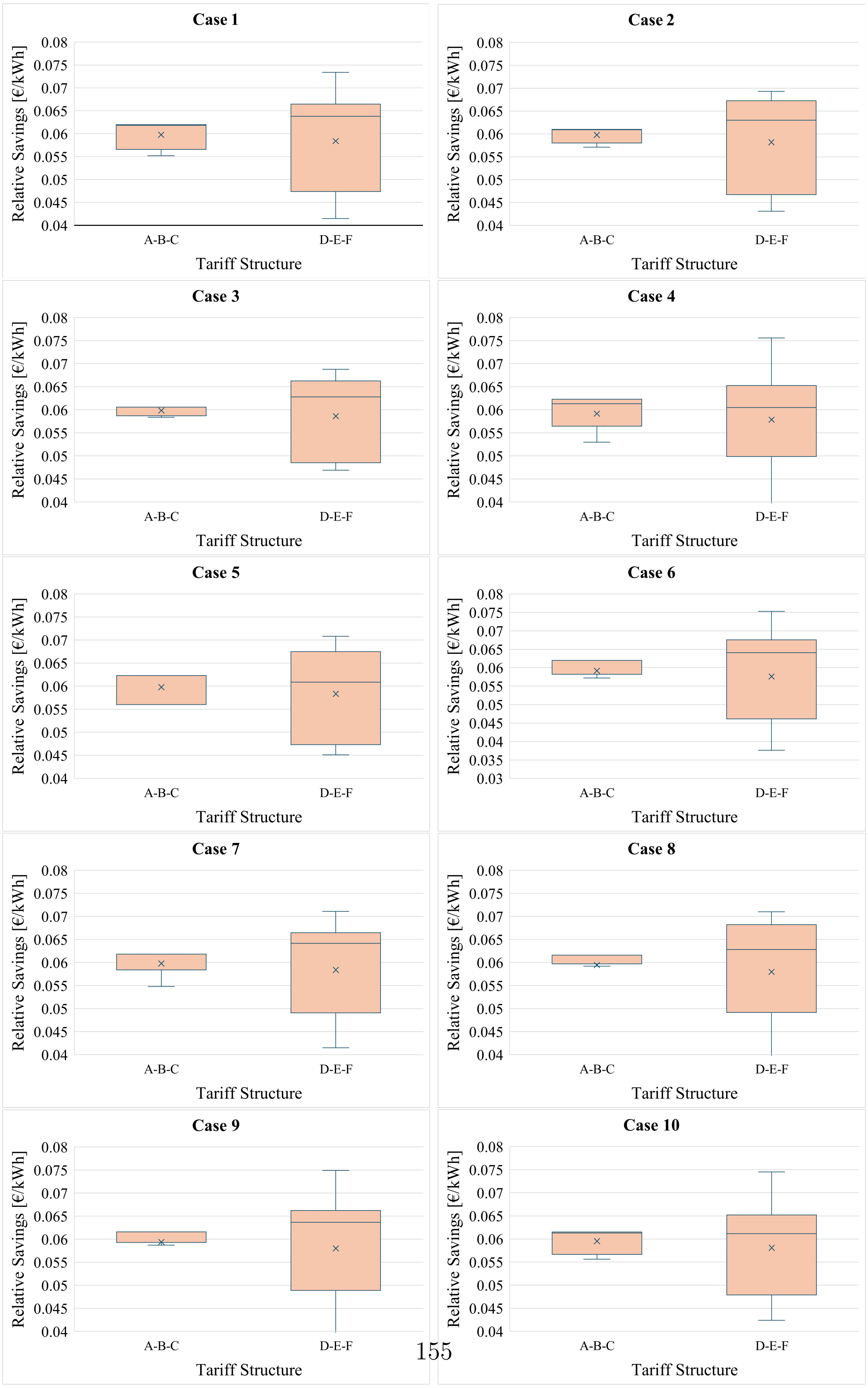


Figure 6.5.: Relative savings comparison for each tariff structure and each EC case. The cross represents the mean value and the line within the box represents the median value.

one can see that the investment strategy is also affected by the choice of the Key of Repartition considered. For instance, investing in joint assets seem to be the optimal strategy instead of relying only on individual investment. The main reason behind this shift of idea is that introducing KoRs limits the potential arbitrage that can be made between retailer costs and PV generation costs. Indeed, for the Prorate KoR the energy is shared based on the instantaneous consumption levels, and with the Hybrid KoR, a first round of equal allocation is applied before applying the Prorate KoR. Doing so, the end-users with ToU contracts are not necessarily the first to be served by local electricity. This reduces the potential operational savings.

To overcome this barrier to the maximization of collective savings, joint PV assets are installed. The advantage of joint production is that it is made fully available to the whole REC without prior individual self-consumption. For example with the Prorate KoR, in Case 1 all members invest less individually except Member 6 with the goal to produce the most electricity possible. As he does not have a large consumption, only 8 % will be directly self-consume and the rest will be made available to all members. On top of that Member 5 (Flat contract) rather install joint assets than individual assets to make the full production available to the REC participants. Doing so, the Prorate KoR will necessarily cover a significant parts of all members, especially those with ToU contracts. In Case 2, which exhibits a higher penetration of ToU contracts (i.e., everyone except Members 3, 4 and 5), the strategy is that Member 6 directly install the extra PV as joint assets whose production is totally injected in the local pool to be shared. With the Hybrid KoR, the philosophy is similar. To be sure to cover the electricity consumption of ToU members, additional assets are either installed individually or jointly.

Table 6.7.: Optimal PV capacity [kW$_{peak}$] for Case 1 with different KoRs.

Members	1	2	3	4	5	6	7	8	9	10
	No KoR									
Individual	1.904	2.099	0.838	1.310	1.071	5.931	0.375	0.737	0.702	0.848
	Prorate KoR									
Individual	1.814	1.494	0.702	1.124	0.107	7.41	0.348	0.488	0.877	0.907
Joint	0.641	0	0	0	1.002	0	0	0	0	0
	Hybrid KoR									
Individual	1.837	2.101	0.728	1.183	1.083	5.377	0.42	0.737	0.701	0.845
Joint	0	0.081	0.152	0.04	0	0.325	0	0.008	0	0.145

The negative consequence of the integration of Energy Sharing rules is that in order to compensate the loss of potential operational savings, additional investment costs are incurred. As sown in Table 6.9, degradation in both operational and

Table 6.8.: Optimal PV capacity [kW_{peak}] for Case 2 with different KoRs.

Members	1	2	3	4	5	6	7	8	9	10
	No KoR									
Individual	1.904	2.099	0.838	1.310	1.071	5.931	0.375	0.737	0.702	0.848
	Prorate KoR									
Individual	2.254	2.101	2.008	0	0.61	5.381	0.281	0.809	0.743	0.849
Joint	0	0	0	0	0	2.322	0	0	0	0
	Hybrid KoR									
Individual	1.936	1.814	0.728	1.198	0.855	7.215	0.351	0.737	0.819	0.907
Joint	2.13	0.222	0	0	0.114	0	0	0	0.398	0.342

total cost savings are observed when those KoRs are introduced. In addition, as their definition does not directly reflect the fairness in relative cost savings distribution they fail to offer an interesting solution to solve the latter concern. Nevertheless, integrating KoRs in the long-term planning problem gives a more accurate estimation of the expected costs when the REC is submitted to regulations that require to adopt these sharing principle.

Table 6.9.: Collective and individual cost savings performances with KoRs.

	No KoR	Prorate KoR	Hybrid KoR
	Operational Savings Π_y [€]		
Case 1	3662	3536	3473
Case 2	3656	3552	3827
	Yearly Cost Savings [€]		
Case 1	1967	1717	1778
Case 2	1963	1685	1701
	Average Relative Cost Savings [€/kWh]		
Case 1	0.058	0.050	0.053
Case 2	0.058	0.049	0.049
	Relative Cost Savings Range [€/kWh]		
Case 1	0.032	0.036	0.036
Case 2	0.026	0.027	0.036

6.3.3. Impact of the Single-Step formulation

Finally, the results are obtained for the different cases using the single-step approach with two values of ω^{indiv}, respectively 0 and 0.05. With the first coefficient value, the problem completely neglects the fair distribution of savings. Doing so, the fairness performances of the two step approach can already be evaluated. Results are further detailed for the two first cases in the following.

Regarding the collective performances and investment strategies, in both Cases we observed that similar yearly cost savings can be obtained at the REC-scale, i.e., 1967 € and 1963 € respectively, while dispatching the PV assets in another way as presented in Tables 6.10 and 6.11. This happens when the fairness objective is neglected (1-Step A). This is a major limit of the two-steps procedure that is that several optimal solutions may exist for the first step meaning that the fairness performances are affected by the (random) selection of the output solution by the mathematical solver.

With a coefficient value of 0.05 for the individual objective in the multi-objective function, the collective savings are only reduced by 4 € per year in both Cases. The installation capacities are also slightly adapted with collective assets being installed at the location of Members 6 and 7. This represents an additional equitable revenue sources as the investment costs are equally shared among participants.

Table 6.10.: Optimal PV capacity [kW$_{peak}$] for Case 1 with different ω^{indiv}.

Members	1	2	3	4	5	6	7	8	9	10
	2-Step									
Individual	1.904	2.099	0.838	1.310	1.071	5.931	0.375	0.737	0.702	0.848
	1-Step A ($\omega^{indiv} = 0$)									
Individual	1.919	2.101	0.838	1.317	1.077	5.814	0.395	0.737	0.724	0.845
	1-Step B ($\omega^{indiv} = 0.05$)									
Individual	1.936	2.101	0.839	1.317	1.147	2.855	0.322	0.737	0.741	0.786
Joint	0	0	0	0	0	2.913	0.073	0	0	0

Table 6.11.: Optimal PV capacity [kW$_{peak}$] for Case 2 with different ω^{indiv}.

Members	1	2	3	4	5	6	7	8	9	10
	2-Step									
Individual	1.904	2.099	0.838	1.310	1.071	5.931	0.375	0.737	0.702	0.848
	1-Step A ($\omega^{indiv} = 0$)									
Individual	1.919	2.101	0.838	1.317	1.077	5.831	0.395	0.737	0.691	0.845
	1-Step B ($\omega^{indiv} = 0.05$)									
Individual	1.919	2.101	0.838	1.326	1.192	2.814	0.332	0.737	0.691	0.845
Joint	0	0	0	0	0	2.942	0.063	0	0	0

From an individual point-of-view, Figures 6.6 highlighted the added value of the proposed single-step by showing that by only loosing 4 € collectively, we can achieve a fair saving distribution among members around 0.06 €/kWh with a fixed price of 0.02 €/kWh for local energy trades. In addition, the end-users hosting joint assets receives 15.6 in Case 1 and 18.2 €/kW$_{peak}$ in Case 2.

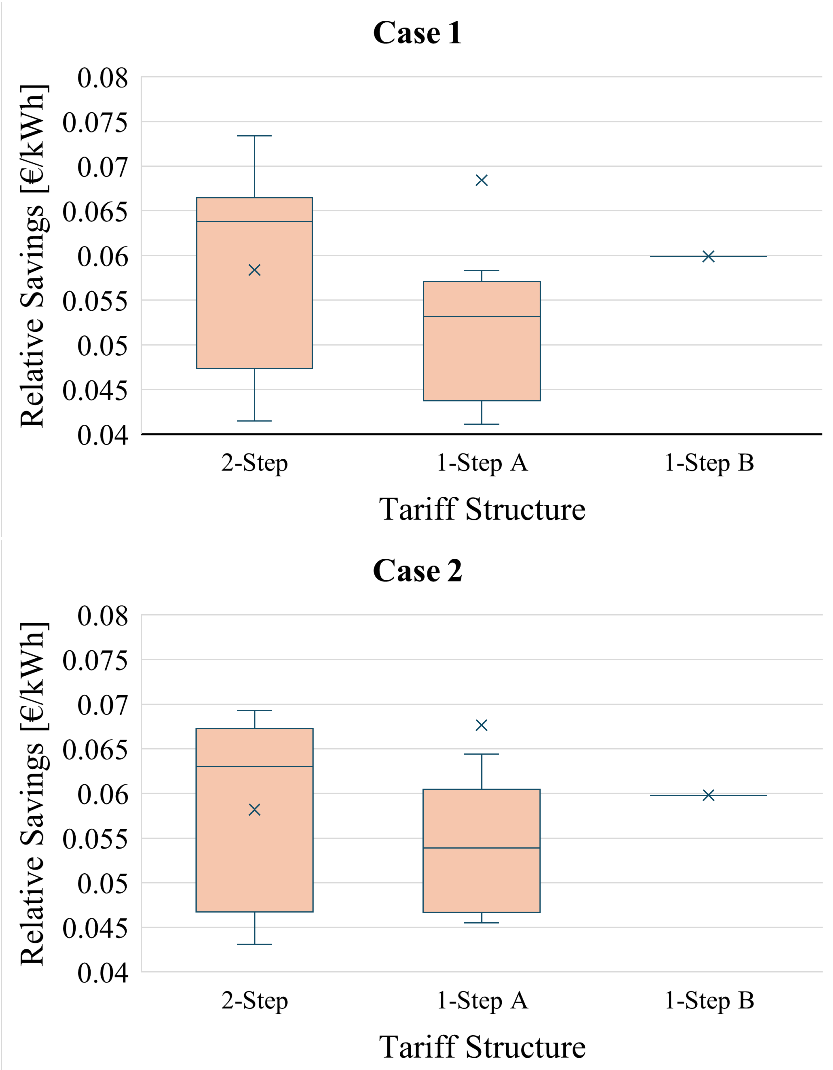


Figure 6.6.: Relative savings comparison for the two-steps method and the single-step formulation with ω^{indiv} =0 (A) and 0.05 (B).

6.4. Intermediate Conclusion

In this chapter, we proposed a REC-specific long-term planning problem to optimize the set of long-term decisions within a REC. These decisions include the sizing of DERs as well as the associated investment strategy (i.e., location and ownership of assets) and the local internal pricing. To solve this problem a two-step was developed that sequentially address the DERs sizing and internal pricing problems. The fair repartition of collective savings being only addressed in the second step, we investigated approaches to further improve the trade-off between collective performances and individual ones.

The first method was to enlarge the options of internal prices structures. Relying on the specific investment strategies of REC, we introduced three options for the prices that are uniformity, unicity and periodicity. On the 10 EC configurations tested, we observed that introducing dynamic prices within Energy Communities can equilibrate the individual savings without degrading the collective objective. Nevertheless, proposing dynamic tariffs to end-users may go against one argument often used by community manager to engage new participants, that is the potential of REC to prevent them from volatile electricity tariffs.

Another option studied was to integrate the Key of Repartition mechanisms introduced in Chapter 3 to already distribute cautiously the energy in the first step of the problem. However, we showed that if these Energy Sharing rules are not directly reflecting the fairness indicator targeted, integrating them within the optimisation problem may negatively impact both collective and individual performances.

Finally, we introduced a single-step formulation of the whole long-term planning problem. This problem considers a multi-objective function optimizing the trade-off between the collective savings and the repartition of individual benefits. The problem is kept linear by discretizing the internal prices variables. On the different EC configurations, it led to only small losses (4 € out of 1967 € in the optimal case) on the collective performances while achieving equal savings.

The long-term planning problem formulations developed in this chapter may be further extend to other energy vectors and end-use demand than electricity. Indeed, the definition of Renewable Energy Communities [12] allows to exchange energy in any form as long as it is generated by renewable resources. In addition, when we think about community sharing, other services could be traded among participants. In the following chapter, the long term planning of shared mobility services provision is addressed building on the models presented here above.

CHAPTER 7.

Planning Local Exchanges of Mobility Services

When conceptualizing the concept of Renewable Energy Communities (REC) through its directive in the Clean Energy Package [12], the EU offered the possibility to locally exchange energy in any form between end-users. The only constraint being that this energy originates from renewable sources. In this thesis, we go deeper into the definition by addressing the possibility to integrate mobility services sharing within the community framework in addition to electricity sharing as considered in the previous sections. The long-term planning problem of Chapter 6 is adapted to include the sizing of a shared EV fleet in its set of long-term decision variables.

Driven by the European Union climate policies and technological advances decreasing batteries costs [147], the Electric Vehicles (EV) market is experiencing a sustained growth in recent years. This rapid mobility paradigm shift raises challenges for the current power systems [148]. Indeed, to ensure an efficient deployment of electric mobility, it must be supported by the massive installation of charging facilities all over the electrical network which requires sufficient grid connection capacity. Besides private EVs, shared mobility (car-sharing, bike-sharing, etc.) has emerged as a key strategy to disconnect vehicle ownership (and associated investment cost) and usage while optimizing vehicle operation [149]. From a grid usage point of view, if charging private EVs during the day at the office has already been proposed as a smart solution to balance solar production during working hours [150], the erection of shared EV stations in high-density residential area where intermittent renewable generation is present is also a promising match. Despite the increased uncertainty in shared mobility demand compared to private cars, charging intervals are usually uniformly spread over the day and may be used to efficiently balance local photovoltaic (PV) production.

One objective of Mobility Service Providers (MSPs) is to offer to end-users the possibility of travelling at low cost. Hence, they are interested to access cheap electricity production from neighbouring producers to charge the vehicles. Therefore, integrating their activity in a REC framework could benefit all parties.

Indeed, by participating to local exchanges the MSP could reduce the cost for charging its EVs and in exchange could offer access to the shared EV fleet for community members mobility needs. Additionally, by coordinating itself with the local end-users connected to the same distribution network, the MSP may size its fleet and associated charging stations more efficiently despite the limited remaining grid connection capacity and even provide flexibility services to system operators [18], [151].

In this chapter, the potential benefits of the participation of a shared MSP to an Energy Community constituted of end-users connected to the neighbouring nodes of the local distribution network is quantified in terms of cost savings for the supply of the electrical demand and grid support potential. More specifically, the long-term optimal investment strategy for the deployment of a fleet of shared EVs by the MSP is identified, accounting for its implication in local electricity exchanges. The model further includes the flexibility potential of the EVs charging patterns to support the distribution system operator (DSO).

The contributions brought by our work on the integration of mobility services in Energy Communities are presented in the follwoing article:

[21] J. Allard, N. Diffels, F. Vallée, B. Cornélusse, and Z. De Grève, "On the complementarity of shared electric mobility and renewable energy communities,", *preprint*, 2026.

7.1. Brief Review of the Related Work

Research investigating the role of mobility (in particular shared mobility) inside the REC framework is still relatively sparse but becomes increasingly relevant. In [152], a rental fleet of EVs management model is integrated into an existing energy community architecture. The proposed day-ahead planning problem, which embeds the EV-ride assignment phase is formulated as a bilevel optimisation problem solved using a heuristic approach. It is also shown that REC participation can reduce charging costs for fleet operators. However, that work considers communities of small sizes (3 to 5 members) with a single EV technology option, and focuses on the day-ahead horizon only. In this paper, we propose a long-term EV fleet planning model solved on a community of 20 members interacting with an MSP that may choose between multiple EVs and charging stations configurations while embedding distribution network constraints. In [153], authors develop a framework for community-owned shared power stations where external users are allowed to charge their own EV in order to increase the local consumption of the community. This paper demonstrates economic benefits when external users are allowed. This result once again stresses the relevance of considering sharing mobility structures in the future, optimizing the vehicles usage when it is more interesting i.e., during the day in case of high PV generation. Several recent contributions explicitly quantify and exploit the flexibility provided by EVs within community frameworks [18], [151]. They show how EV charging can be controlled in community contexts to increase the community social and economic benefits. In the same manner, in [154], the authors propose a prosumer-to-vehicle (P2V) market model in which prosumers sell excess of PV generation to EVs within a local market. Non-negligible community energy cost reductions are observed, demonstrating that explicit local market designs can operationalize EV flexibility for community benefit.

One important aspect to consider when modelling EV integration in a community, despite often being overlooked, is that massive integration of EVs may result in adverse effects on low-voltage distribution grids. The authors in [155] clearly demonstrate that the mean voltage levels and voltage deviations are dependending on EV penetration levels. This indicates the importance of voltage control and appropriate incentives to deploy smart charging mechanisms and flexibility provisions so EV fleets contribute to voltage support rather than network degradation. Furthermore, [156] argues that the size and spatial configuration of charging infrastructures is a crucial decision when integrating mobility into power systems in order to reduce voltage instability, address the decrement of power quality, and keep the power grid as reliable as possible. Moreover, optimal placement and sizing of EV power stations in active distribution networks have been shown to reduce installation costs, and distribution system losses in [157].

7.2. Research Contributions

The work presented in this chapter about the integration of a Mobility Service Provider in a Renewable Energy Community is the result of a collaboration with Noé Diffels from Université de Liège (Belgium). This work proposes an original Mixed-Integer Second Order Cone Programming (MISOCP) long-term EV fleet sizing and planning optimisation problem within a Renewable Energy Community framework. The problem aims to optimally quantify the number, types and locations of EVs and charging stations to be installed for satisfying the mobility demand of the targeted area (i.e., not restricted to the community perimeter) at minimum costs. The model integrates the participation of the MSP to the local energy sharing paradigm along with the relaxed second-order cone formulation of power flow equations to gurantee that network constraints are respected [106]. We further implement distribution system operator peak tariffs to quantify how adapted EV charging strategies may support the distribution network. The main contributions can be summarized as:

1. Proposing an original long-term shared EV fleet planning problem within an Energy Community framework considering optimal charging stations location while respecting LV distribution network constraints.

2. Quantifying the economic and technical benefits brought by the complemen-

tarity of two emergent actors (MSP and REC) in power systems based on real historical data.

3. Studying the flexibility potential of the EV fleet in case of peak power penalties charged by the DSO.

The proposed problem is applied to a case study which considers a benchmark network [109] of 20 nodes with residential consumers and prosumers, i.e., consumers equipped with renewable production assets. The mobility demand profiles are directly extracted from a real historical database of a shared electric vehicle operator operating in Belgium [158].

The remainder of the chapter is organized in four sections. First, in Section 7.3 the MSP and REC business models are presented along with the main assumptions. Then Section 7.4 describes the proposed mathematical formulation of the long-term EV planning problem. Subsequently, the case study illustrating the relevance of the coordination of the two actors is analysed in Section 7.5 before concluding with Section 7.6.

7.3. Framework and Main Assumptions

As many mobility service provider and energy community models can be found in the literature or observed on field, this section aims to introduce the two frameworks specifically considered in this chapter, describing their business models alongside the main assumptions.

7.3.1. Mobility Service Provider

Mobility service providers are emerging actors in the electrical power systems sector driven by the rapid deployment of electric vehicles. Riding the wave of energy transition, they aim to transpose the principle of shared mobility from internal combustion engine vehicles to electrical ones.

The MSP aims to satisfy a mobility demand defined within a delimited area in which it could potentially operate. In this study, the mobility demand is considered fully deterministic. However, the MSP retains the ability to decline ride requests to represent missed opportunities when ride overlaps occur or when the expected revenue from a request is deemed not profitable. Based on this mobility demand, the MSP invests in a car (or a car fleet) made available to any end-user. This way, the EV usage is split over a set of customers who do not have to support the whole investment cost of the car, but who rather pay the MSP a fee proportional to the rental period and/or the driven distance. In addition to EVs, the MSP may also be responsible for installing charging stations at the vehicle deposit, as considered in this work.

Furthermore, it is assumed that the MSP must bear, in addition to the investment costs for charging stations and EVs, annual fixed operation and maintenance (O&M) costs, as well as electricity purchase costs for charging the EV fleet. Therefore, if subject to dynamic tariffs at the deposit charging station, it may want to schedule carefully the charging power based on the planned trips to minimize its costs. These strategic charging actions can also be driven by flexibility incentives sent by the distribution system operator. In addition, if a trip is too long or if the previous charging period is too short to charge the EV up to the requested state-of-charge, users may fill the car during the trip at a price that is assumed more expensive than the one contracted at the deposit charging point. This cost is at the charge of the MSP.

In this work, we assume that the new installations are implemented on a low-voltage feeder of the distribution network already occupied by end-users forming an energy community.

7.3.2. Energy Community

A domestic, PV-driven local energy community is considered so as to assess the complementarity of this type of entity with the activities of MSPs. End-users forming the EC are all connected behind the same medium-voltage/low-voltage substation and can be divided into two classes: PV-equipped prosumers and consumers. The former, after having self-consumed part of the PV production for their own load, pool the excess generation and share it with the participants in need. These local exchanges are dynamically balanced every quarter-hour over the EC and the complementary volumes (injection or consumption) are typically traded with a single retailer, whose tariffs are assumed to be dynamic and differentiated for imports and exports. For local exchanges, a uniform (i.e., similar for each member) more advantageous (i.e., between retailer import and export prices) price is considered.

We assume, without loss of generality, that the MSP is a community member and that the domestic members do not provide flexibility, so as to focus on the benefits arising from EV flexibility scheduling and local electricity exchanges. From the MSP point of view, this represents an access to cheaper electricity to charge its vehicles.

7.4. Mathematical Models

This section presents the mathematical formulation of the MSP-EC coordinated business model. The proposed long-term shared EV planning problem incorporating local electricity exchanges within an energy community framework is expressed as a MISOCP problem. It aims at sizing the shared EV fleet and the deposit point charging stations to cover a mobility demand while minimizing the annual costs of both the MSP, C^{MSP}, and the EC, C^{EC}. The optimisation is also subject to economical and physical long-term and operational constraints, the overall problem is formulated as follows:

$$\begin{aligned}
\min_{\Omega} \quad & C^{MSP} + C^{EC} && (7.1)\\
\text{s.t.} \quad & \text{Investment and operational cost definitions (7.2)-(7.4)}\\
& \text{Binary investment constraints (7.5)-(7.6)}\\
& \text{Ride-EV assignment constraints (7.7)-(7.12)}\\
& \text{EV and CS operational constraints (7.13)-(7.19)}\\
& \text{Power balance constraints (7.20)-(7.21)}\\
& \text{Distribution network constraints (7.22)-(7.28)}
\end{aligned}$$

with $\Omega := \{\boldsymbol{\delta}^{EV}, \boldsymbol{\delta}^{CS}, \boldsymbol{\delta}^{use}, \boldsymbol{\delta}^{state}, \mathbf{p}^{EV}, \mathbf{s}^{EV}, \mathbf{p}^{CS}, \mathbf{e}^{away}, \mathbf{g}, \mathbf{i}^{ret}, \mathbf{e}^{ret}\}$, the set of decision variables that respectively represent the discrete EV models investment choices (i.e., $\boldsymbol{\delta}$ are binary variables), the deposit charging station choice, the customers rides assignment to a particular EV, the EV state (i.e., on charge or in use), the EV charging power, the EV battery state-of-charge, the charging station supplied power, the charged energy volume during a trip, the PV production and lastly, the EC's complementary volumes purchased and sold to the electricity supplier. The two first variables are long-term decisions while the remaining ones are short-term.

7.4.1. Investment and operational cost

Regarding the mobility service provider, its annual equivalent cost, C^{MSP}, is composed of the annualized capital expenditures (CapEx) and the operational expenditures (OpEx) defined as:

$$CapEx = \underbrace{\sum_{k\in\mathcal{K}^{EV}} \Pi_k^{EV} \sum_{n\in\mathcal{N}^{EV}} \delta_{n,k}^{EV}}_{C^{EV}} + \underbrace{\sum_{k\in\mathcal{K}^{CS}} \Pi_k^{CS} \sum_{\substack{n\in\mathcal{N}^{CS}\\ b\in\mathcal{B}}} \delta_{n,b,k}^{CS}}_{C^{CS}}, \tag{7.2}$$

$$\begin{aligned}
C^{MSP} &= \underbrace{CapEx \cdot U(\rho)}_{A} + \underbrace{\sum_{\substack{n\in\mathcal{N}^{EV}\\ r\in\mathcal{R}}} \lambda^{away} e_{n,r}^{away}}_{C^{away}}\\
&+ \underbrace{\pi^{uns} \sum_{r\in\mathcal{R}} e_r^{uns}}_{C_{uns}} + \underbrace{\sum_{k\in\mathcal{K}^{EV}} f_k^{EV} \sum_{n\in\mathcal{N}^{EV}} \delta_{n,k}^{EV}}_{f}, && (7.3)
\end{aligned}$$

$$C^{EC} = \underbrace{\sum_{t \in \mathcal{T}} \lambda_t^{ret,imp} i_t^{ret} \Delta t}_{C^{ret}} - \underbrace{\sum_{t \in \mathcal{T}} \lambda_t^{ret,exp} e_t^{ret} \Delta t}_{R^{ret}} . \tag{7.4}$$

where C^{EV} are the investment cost associated to the purchase of an EV fleet, $\mathcal{N}^{EV}$, chosen among a set of candidate models, $\mathcal{K}^{EV}$, each one with a specific price, Π_k^{EV}. In addition, C^{CS} similarly accounts for the installation cost of charging station units, $\mathcal{N}^{CS}$, at deposit location from a set of devices, $\mathcal{K}^{CS}$. In addition, the location of the shared EV charging points between booked rides over the set of network buses, $\mathcal{B}$, is another optimized dimension. Annual MSP cost (7.3) include the equivalent investment annuity cost, A[1]; the cost, C^{away}, for charging EVs during the trip at price, λ^{away}; the opportunity cost, C^{uns}, modelled as the revenues missed for not serving certain ride demand d_r, $r \in \mathcal{R}$, with $e_r^{uns} = d_r(1 - \sum_{n \in \mathcal{N}^{EV}} \delta_{n,r}^{use})$, valued at price π^{uns}; and the fixed operational and maintenance cost specific to each EV model, f^{EV}. Regarding EC operation, the net cost (7.4) is the difference between the purchase cost, C^{ret}, and the revenues, R^{ret}, for trading with an energy retailer at prices $\lambda_t^{ret,imp}$ and $\lambda_t^{ret,exp}$, respectively for time periods of length Δt [2].

7.4.2. Binary investment constraints

EVs and charging station assets being discrete choices among sets of potential devices, one must ensure that an invested asset is associated to a single model and that for CS, each of them has a unique location:

$$\sum_{k \in \mathcal{K}^{EV}} \delta_{n,k}^{EV} \leq 1, \qquad \forall n \in \mathcal{N}^{EV}, \tag{7.5}$$

$$\sum_{\substack{k \in \mathcal{K}^{CS} \\ b \in \mathcal{B}}} \delta_{n,b,k}^{CS} \leq 1, \qquad \forall n \in \mathcal{N}^{CS}. \tag{7.6}$$

7.4.3. Ride-EV assignment constraints

The proposed long-term shared EV fleet planning problem embeds the following sets of time-overlapping rides-EV assignment and multi-deposit charging stations vehicles' states constraints:

$$\sum_{n \in \mathcal{N}^{EV}} \delta_{n,r}^{use} \leq 1, \qquad \forall r \in \mathcal{R}, \tag{7.7}$$

[1] $U(\rho)$ denotes the uniform capital recovery factor computed as a function of the discount rate ρ, [144].

[2] The cost associated to local exchanges is not explicitly appearing in the model since the local exchanges cancel each other at the EC scale.

$$\delta^{use}_{n,r} \leq \sum_{k \in \mathcal{K}_{EV}} \delta^{EV}_{n,k}, \qquad \forall n \in \mathcal{N}^{EV}, r \in \mathcal{R}, \tag{7.8}$$

$$\delta^{use}_{n,r_1} + \delta^{use}_{n,r_2} \leq 1 \qquad \forall n \in \mathcal{N}^{EV}, (r_1, r_2) \in \mathcal{R}^{2'}, \tag{7.9}$$

$$\sum_{s \in \mathcal{S}} \delta^{state}_{n,s,t} \leq \sum_{k \in \mathcal{K}_{EV}} \delta^{EV}_{n,k}, \qquad \forall n \in \mathcal{N}^{EV}, t \in \mathcal{T}, \tag{7.10}$$

$$\delta^{state}_{n,s,t} \leq \sum_{\substack{k \in \mathcal{K}^{CS} \\ b \in \mathcal{B}}} \delta^{CS}_{s,b,k}, \qquad \forall n \in \mathcal{N}^{EV}, s \in \mathcal{N}^{CS}, t \in \mathcal{T}, \tag{7.11}$$

$$\delta^{state}_{n,u,t} = \sum_{r \in \mathcal{R}_t} \delta^{use}_{n,r}, \qquad \forall n \in \mathcal{N}^{EV}, t \in \mathcal{T}. \tag{7.12}$$

First, (7.7) and (7.8) ensure that only one car can be assigned (i.e., $\delta^{use} = 1$) to each ride and that this car has been actually deployed. In addition, (7.9) checks that the same car is not assigned overlapping rides defined by the set $\mathcal{R}^{2'} := \{(r_1, r_2) \in \mathcal{R} \times \mathcal{R} | t^{dep}_{r_1} \leq t^{ret}_{r_2},\ t^{dep}_{r_2} \leq t^{ret}_{r_1}\}$. Then, let us define $\mathcal{S} := \mathcal{N}^{CS} \bigcup \{u\}$ as the set of potential states of deployed EVs. Those can either be in charge at one of the CS in $\mathcal{N}^{CS}$ or in use, u. As said, EV states are only possible for invested cars as imposed by (7.10). Furthermore, they can only be plugged to existing charging stations via (7.11). Finally, (7.12) sets the state of EVs to u at time step $t \in \mathcal{T}$ when they have been assigned a ride whose booked period spans over this particular time interval, represented by the set $\mathcal{R}_t := \{r \in \mathcal{R} | t^{dep}_r \leq t \leq t^{ret}_r\}$.

7.4.4. EV and CS operational constraints

Electric vehicles are modelled as batteries with intermittent availability whose charging power can be adjusted when standing at the deposit stations before the next ride:

$$-\overline{P}^{EV}_n (1 - \delta^{state}_{n,s,t}) \leq p^{EV}_{n,s,t} \leq \overline{P}^{EV}_n (1 - \delta^{state}_{n,s,t}),$$
$$\forall n \in \mathcal{N}, s \in \mathcal{N}^{CS}, t \in \mathcal{T}, \tag{7.13}$$

$$\sum_{b \in \mathcal{B}} p^{CS}_{s,b,t} = \sum_{n \in \mathcal{N}^{EV}} p^{EV}_{n,s,t}, \qquad \forall s \in \mathcal{N}^{CS}, t \in \mathcal{T}, \tag{7.14}$$

$$-\overline{P}^{CS}_{n,b} \leq p^{CS}_{s,b,t} \leq \overline{P}^{CS}_{n,b}, \qquad \forall s \in \mathcal{N}^{CS}, b \in \mathcal{B}, t \in \mathcal{T}, \tag{7.15}$$

$$s^{EV}_{n,t} = s^{EV}_{n,t-1} + \sum_{n \in \mathcal{N}^{CS}} p^{\mathrm{EV}}_{n,s,t} \Delta t - \sum_{r \in \mathcal{R}^{ret}_t} d_r\, \delta^{use}_{n,r} + \sum_{r \in \mathcal{R}^{ret}_t} e^{away}_{n,r},$$
$$\forall n \in \mathcal{N}^{EV}, t \in \mathcal{T}, \tag{7.16}$$

$$\alpha^{min} \overline{E}^{EV} \leq s^{EV}_{n,t} \leq \overline{E}^{EV}_n, \qquad \forall n \in \mathcal{N}^{EV}, t \in \mathcal{T}, \tag{7.17}$$

$$s^{EV}_{n,t^{dep}_r} \geq \alpha^{dep} \overline{E}_n, \qquad \forall n \in \mathcal{N}^{EV}, r \in \mathcal{R}, \tag{7.18}$$

$$e^{away}_{n,r} \leq \overline{E}^{away}_{r} \delta^{use}_{n,r}, \qquad \forall n \in \mathcal{N}^{EV}, r \in \mathcal{R}. \tag{7.19}$$

In this work, both Grid-to-Vehicle and Vehicle-to-Grid (V2G) capabilities are considered and the power fed to or extracted from EVs at deposit charging stations, $s \in \mathcal{N}^{CS}$, are limited to the car power ratings, $\overline{P}^{EV}_{n} = \sum_{k\in\mathcal{K}^{EV}} \overline{P}^{EV}_{k} \delta^{EV}_{n,k}$, and their presence at that specific location as written in (7.13). The bilinear product of binary variables, δ^{EV} and δ^{state} on the right-hand side of the constraint can be linearized using state-of-the-art techniques [105]. From (7.14)-(7.15) multiple EVs from the fleet can be connected to the same charging facility, but their joint consumption/injection is therefore limited to the maximum power of the station, $\overline{P}^{CS}_{n,b} = \sum_{k\in\mathcal{K}^{CS}} \overline{P}^{CS}_{k} \delta^{CS}_{s,b,k}$. The EV power consumption directly affects the evolution of the vehicle state-of-charge, $s^{EV}_{n,t}$ via (7.16)[3]. The two others terms refer to the consumed energy during its usage by customers and the energy filled during the trip, both terms being included in the evolution equation at the return time (i.e., $\mathcal{R}^{ret}_{t} := \{r \in \mathcal{R} | t = t^{ret}_{r}\}$) as the rides temporal dynamics are not modelled. The EV's battery state-of-charge is bounded above by the battery capacity, $\overline{E}_{n}$, defined similarly to the power rating, and below by a minimum fraction of it, α^{min}, using (7.17). (7.18) imposes that, at departure time of assigned rides, t^{dep}_{r}, a minimum fraction of the battery, α^{dep}, must be available. Finally, the energy volume charged away is limited in (7.19) based on the typical public charging station rating, $\overline{P}^{away}$ and the trip duration as $\overline{E}^{away}_{r} = \overline{P}^{away} \cdot (t^{\text{ret}}_{r} - t^{\text{dep}}_{r})\Delta t$.

7.4.5. Power balance constraints

The net power injected at each bus of the network is a function of the consumption of the EC member connected at the node and the available PV production at the same point of common coupling (PCC). In addition, buses selected to deploy the shared EV fleet deposit charging stations are affected by the consumed power during charging sessions. Finally, economic exchanges with the retailer can be computed at the EC level based on the power flowing through the slack bus, $b = 0$, as follows:

$$p^{inj}_{b,t} = p^{PV}_{b,t} - P^{load}_{b,t} - \sum_{n\in\mathcal{N}^{CS}} p^{CS}_{n,b,t}, \qquad \forall b \in \mathcal{B}, t \in \mathcal{T}, \tag{7.20}$$

$$p^{inj}_{0,t} = e^{ret}_{t} - i^{ret}_{t}, \qquad \forall t \in \mathcal{T}. \tag{7.21}$$

where $p^{inj}_{b,t}$ is the net active power injected at time step t, in bus b, $P^{load}_{b,t}$, is the end-users electrical load consumption and, $p^{PV}_{b,t}$ is the PV production considered as a positive continuous variable capped by the solar potential $\bar{P}^{PV}_{b,t}$.

[3]The initial state-of-charge of the year is fixed at EVs capacity.

7.4.6. Power Flow Equations

State-of-the-art power flow constraints [106] are added to the problem to ensure a reliable operation of the distribution network:

$$p_{b,t}^{inj} + p_{b,t}^{line} - R_b i_{b,t}^{sqr} = \sum_{c \in \mathcal{C}_b} p_{c,t}^{line} \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}, \tag{7.22}$$

$$q_{b,t}^{inj} + q_{b,t}^{line} - X_b i_{b,t}^{sqr} = \sum_{c \in \mathcal{C}_b} q_{c,t}^{line} \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}, \tag{7.23}$$

$$v_{b,t}^{sqr} = v_{a_b,t}^{sqr} - 2(R_b p_{b,t}^{line} + X_b q_{b,t}^{line}) + (R_b^2 + X_b^2) i_{b,t}^{sqr}, \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}, \tag{7.24}$$

$$i_{b,t}^{sqr} v_{a_b,t}^{sqr} \geq p_{b,t}^{line^2} + q_{b,t}^{line^2} \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}, \tag{7.25}$$

$$\underline{v}^{sqr} \leq v_{b,t}^{sqr} \leq \overline{v}^{sqr} \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}, \tag{7.26}$$

$$i_{b,t}^{sqr} \leq \bar{i}_b^{sqr} \qquad \forall b \in \mathcal{B}, \forall t \in \mathcal{T}. \tag{7.27}$$

where $p_{b,t}^{line}/q_{b,t}^{line}$, represents the active/reactive power flowing in the line reaching node b from the node upstream, a_b, with impedance $Z_b = R_b + jX_b$, and $\mathcal{C}_b$ is the set of children nodes of bus b in the oriented graph of the electrical network. Equations (7.22) and (7.23) defines the power balance at each bus b with $q_{b,t}^{inj} = -\tan(\varphi) P_{b,t}^{load}$ while (7.24) and (7.25) link the power flows with the squared voltage drop, $v_{b,t}^{sqr}$, and the squared current, $i_{b,t}^{sqr}$, in each line. The latter quantities physical are respectively bounded by (7.26) and (7.27) based on the electrical norm EN50160 and the line ratings.

In addition, the transformer capacity limits is taken into account as it is a major limiting factor to welcome new customers in existing networks. The transformer power rating, $\bar{P}_0$, sets upper bounds to the power exchanged with the upstream grid at the slack node as follows:

$$-\bar{P}_0 \leq p_{0,t}^{inj} \leq \bar{P}_0, \qquad \forall t \in \mathcal{T}. \tag{7.28}$$

7.5. Case Study and Results

This paper studies the complementarity of a Mobility Service Provider and an Energy Community from three angles: economic benefits, network usage, and flexibility mobilization. The results obtained first with the mutualisation of resources and then with the addition of flexibility services provision are compared to the benchmark case representing the situation in which the REC and EV fleet operator behave individually. In the benchmark analysis, economic benefits (including electricity bills and energy efficiency metrics), and the power exchanges at the community level (i.e. the usage of the transformer capacity at the slack node) are analysed. Based on the given residual capacity, the MSP has the opportunity to integrate the network at the PCC, constrained by the community exchanges with the grid. Subsequently, the MSP and the REC are aggregated and operate in a coordinated process, aiming to enhance the grid performances. Finally, the impact of peak prices signals from the DSO is analysed and the flexibility provided by the MSP is assessed.

The REC considered in this work is composed of 20 households connected to a state-of-the-art radial LV distribution grid [114] as depicted in Figure 7.1, with a slack node transformer rating of 60 kVA. This value corresponds to 120% of the cumulative (if coordinated) individual peak consumptions of households, 2.5 kW/member as estimated by the regulator in Flanders (Belgium) [8]. Among them, 10 end-users are equipped with PV panels whose surplus is exchanged with other members of the EC. The household consumption profiles (with an inductive power factor of 0.8) are non-flexible-and taken from the Pecan Street project [110]. Historical dynamic electricity import and export retail prices are derived from the Belpex historical prices **BelPex** with an additional 0.099 €/kWh for distribution and transportation grid usage [8]. The electricity used to charge the EV when riding is priced at 0.45 €/kWh, which is the highest retailer import price with a 25% margin. To reduce computational complexity, each year of the 7-years investment period is assumed to be the same and each operational year is simulated using four representative weeks of member consumption profiles and solar exposition. During these weeks, the external mobility demand is generated using historical data from a Belgian MSP [158] and is composed of 88 requests. If these requests are not satisfied, a virtual cost of $\pi_{uns} = 2$ €/kWh. Regarding technical investment of the MSP, the considered options regarding the CS are derived from a comprehensive European study from 2022 [159] and listed in Table 7.1. Meanwhile, the set of potential EV and associated costs is based on data provided by an operating Belgian MSP, and is listed in Table 7.2.

Table 7.1.: Charging Station Candidates and Their Properties.

	$\overline{P}^{CS}$ (kW)	Π^{CS} (€)
Low AC	3.7	760
Medium AC	11.0	1800
High AC	22.0	2300

7.5.1. Collaborating to reduce energy supply cost

To quantify the benefits arising from the collaboration of the MSP with the energy community, one must first assess their respective performances when operating

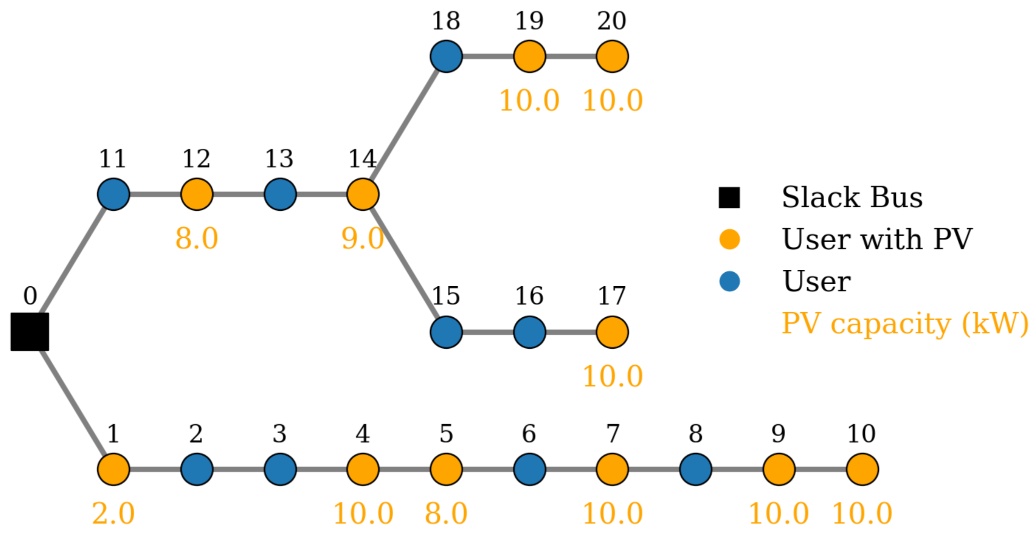


Figure 7.1.: Low Voltage distribution network considered as a case study.

Table 7.2.: EV Candidates and Their Properties.

	$\overline{E}$ (kWh)	$\overline{P}^{EV}$ (kW)	Π^{EV} (€)	f^{EV} (€/*year*)
Nissan Leaf	40	11	9,784	1,814
Renault Megan	60	22	32,149	2,237

individually. To do so, we first solve the EC optimal operational dispatch problem to get benchmark results for its economic and operational performance, but also to get insights on the current network usage and the residual power capacity available at the slack node for potential new connections. The EC problem summarizes as:

$$\begin{aligned} \min_{\Omega^{EC}} \quad & C^{EC} \\ \text{s.t.} \quad & \text{Power balance constraints (7.20)-(7.21)} \\ & \text{Distribution network constraints (7.22)-(7.28)} \end{aligned} \tag{7.29}$$

where $\Omega^{EC} := \{\mathbf{p}^{PV}, \mathbf{i}^{ret}, \mathbf{e}^{ret}\}$ are EC decision variables.

Then the optimal long-term planning problem of a stand-alone MSP being authorized to deploy its fleet with deposit charging stations located at the slack node is solved. Being a new actor in the distribution network, he must adapt to the dynamic residual transformer power capacity computed from the EC stand-alone problem. Its problem summarizes as:

$$\min_{\Omega^{MSP}} \quad C^{MSP} + C^{ret,MSP} \tag{7.30}$$

$$\text{s.t.} \quad \text{MSP constraints (7.2)-(7.21)}$$

$$0 \leq p_{0,t}^{inj} \leq \bar{P}_0 - p_{0,t}^{inj,EC}, \qquad \forall t \in \mathcal{T}. \tag{7.31}$$

where $\Omega^{MSP} := \Omega \setminus \{\mathbf{p}^{PV}\}$ are MSP decision variables, $C^{ret,MSP}$ the retailer cost for charging EVs at its stations and, $p_{0,t}^{inj,EC}$ the slack node power exchange with the EC.

Finally the economic, energy and grid usage benefits of the coordinated EC-MSP scheme are summarized in Table 7.3 for the three considered scenarios, namely: stand-alone EC and MSP models (Scenario 1), coordinated EC–MSP operation without V2G (Scenario 2), and with V2G[4] (Scenario 3). Table 7.4 also shows the impact of joint decisions on MSP's long-term investment strategy and short-term operational planning.

First, it can be seen that although the sparse nature of shared EV mobility demand lets the opportunity to the MSP to schedule its charging period to take advantage of local and cheap PV production, if only grid-to-vehicle capability is considered (Scenario 2) the benefits are bounded by the mobility demand served, e^{use}. Adding the 11 MWh yearly demand from EVs to the existing 101.7 MWh of domestic consumption within the EC decreases the overall cost by 3.1% compared to the combined stand-alone cases. Net supplier cost are reduced by increasing the local consumption, p^{loc} (i.e., self-consumption and EC exchanges), to cover around 60% of the mobility demand. Adding the Vehicle-to-Grid option (Scenario 3) then enables the actors to fully take advantage of the EV fleet batteries when available at the deposit charging station to efficiently use the local PV generation. Doing so, the coordination strategy strengthens their ability to be less grid-dependent; the share of PV generation locally used (i.e. to cover household consumptions and/or EV charging) increasing from 49.75%, to 57.85%, and finally to 66.86% for the three scenarios sequentially. This improves the yearly economic benefits up to 11.3%.

From a mobility-investment point of view, the MSP invests in the same fleet configuration across all scenarios. This consistency is expected, as the covered mobility demand remains constant and the average ride consumption is low enough (9.7 kWh) to be satisfied with the lowest (and cheapest) EV battery capacity. Regarding the charging station, the V2G-enabled scenario upgrades the charging infrastructure from a *Medium AC* to *High AC* charger, enabling larger power exchanges when EVs are used as local storage options. From a short-term planning perspective, the V2G capability also slightly increases the unserved mobility demand

[4]The discharged energy is limited to the supply of EC's electrical demand. Hence, dynamic import-export trading for prices arbitrage is not permitted.

as it is sometimes more beneficial for the global entity to use EVs as storage.

Lastly, total line losses over the distribution network decrease in the EC-MSP coordinated scenarios with the more efficient dispatch of local energy. However, in Scenario 3, an increased solicitation of the transformer is observed for importing power when the MSP decides to rapidly charge EVs using upgraded 22 kW CS during short profitable tariff periods.

Table 7.3.: Comparison of Economic, Energy, and Grid Performances.

Scenario	**1**	**2**	**3**
Economic Indicators			
$C^{EC} + C^{MSP}$ (€/year)	20,362	19,722	18,058
A (€/year)	3,301	3,301	3,379
C^{ret} (€/year)	17,114	16,004	13,413
R^{ret} (€/year)	3,763	3,267	2,559
Energy Performances			
p^{pv} (MWh/year)	72.8	73.6	73.6
i^{ret} (MWh/year)	77.6	70.9	64.4
e^{ret} (MWh/year)	36.6	30.9	24.4
p^{loc} (MWh/year)	36.2	42.7	49.2
Grid Performances			
$\max(i^{ret})$ (kW)	42.33	42.33	60.00
$\max(e^{ret})$ (kW)	60.00	60.00	60.00
p^{loss} (kWh/year)	2099.3	2065.6	1899.5

Table 7.4.: Long-Term and Short-Term Mobility Results.

Scenario	**1**	**2**	**3**
Long-term decisions			
δ^{CS}	*1 x Medium AC installed*		*1 x High AC*
δ^{EV}	*2 x Nissan Leaf are installed*		
Short-term decisions			
e^{use} (MWh)	11,1	11,1	11,0
e^{uns} (kWh)	10.4	10.4	68.4
e^{away} (kWh)	133.5	133.5	133.5

7.5.2. Carefully planning the charging station location to improve grid performances

In the previous section, the MSP was explicitly constrained to install its CS exclusively at the slack node. However, as offered by the proposed formulation of the problem 7.1, a more integrated scenario can be considered in which the fleet operator carefully plan its implementation sites over the network to further enhance the benefits of the coordination. Therefore, an augmented version of Scenario 3 (with V2G) allowing the operator to deploy its charging infrastructure at any bus within the distribution network is solved.

In the particular configuration of the case study, results indicate that the slack node position considered initially leads to the best outcomes for the EC-MSP coordination. Indeed, in any scenario from 1 to 3, no particular voltage or current stress (i.e., values close to boundaries) was observed in the network, meaning that network constraints were not bounding the optimal solution. On the other hand, when CS are located at the slack node, it allows the MSP to purchase large power quantity from the upper grid at advantageous timing without making it flow in the lines where losses are function of the current squared. Finally, the slack node has a central position in the network as it minimizes the sum of distances to the other buses. This also ensures minimal power losses when dispatching the power discharged from EV fleet batteries.

7.5.3. Mobilizing flexibility to decrease DSO's peak charges

If from the EC and MSP perspective the collaboration seems profitable in terms of economic benefits and energy usage performances, Table 7.3 points out that the stress on the transformer capacity can be increased. The transformer loading has a direct impact on its degradation, and the distribution system operator starts to take it into account in their tariff structure, as in Flanders (BE) [8], where they decided to include individual yearly peak consumption cost.

In the previous scenarios (i.e, 1 to 3), traditional analog meter tariffs were applied on the volume and a fixed yearly peak penalty would be added 3,108 €to the total cost (i.e., 21,166 €overall cost). With the introduction of smart meters, another option is made available to consumers that charges 59 €/kW/*year* on the peak consumption power and reduced the volumetric cost to 0.064 €/kWh. This variable peak penalty is implemented within the EC-MSP coordinated with V2G problem to be charged either on individual (at each bus, Scenario 4) or collective (at the transformer, Scenario 5) peak import power.

Table 7.5 clearly shows that the EC-MSP coordinated could provide larger transformer' peak import reduction to the DSO (46 % in Scenario 5 vs 11.5 % in Scenario 4) if the peak penalty cost is charged on the aggregated consumption profile. In addition, this tariff structure would also benefit the EC-MSP entity,

Table 7.5.: Peak tariffs analysis.

Scenario	**3**	**4**	**5**
Economic Indicators			
$C^{EC} + C^{MSP}$ (€/year)	18,058	16,045	15,854
C^{peak} (€/year)	3,108	4,835	1,914
Energy Performances			
p^{loc} (MWh/year)	49.2	47.9	48.9
Grid Performances			
$\max(i^{ret})$ (kW)	60.0	53.1	32.5
p^{loss} (kWh/year)	1899.5	1957.5	1841.1

improving the whole system. This peak reduction is made possible by the inherent flexibility potential of the shared EV fleet that can adapts its charging strategy without degrading significantly the local exchanges performances. Nevertheless, without explicit penalty on exports, the reverse peak power remains at the 60 kVA limit.

7.6. Intermediate Conclusion

In summary, the comparative analysis between stand-alone and coordinated approaches demonstrates that collaboration between EC and MSP yields to mutual benefits, especially when Vehicle-to-Grid capability is considered. In this case, they can save up to 11.3 % on the cost mainly through reduced retail costs with an increased self-sufficiency from 32 % (Scenario 1) to 43 % (Scenario 3). Results also pointed out that the best location for charging stations installation is highly dependent on the network topology and finally, the introduction of V2G functionality unlocks a large flexibility potential to help the system operator reducing the stress at the transformer with a peak reduced by 46 %.

However, one limitation to the approach is the resolution method. Solving large MISOCP problems with standard exact optimisation techniques is computationally intensive (23 minutes and 1 hour for Scenario 3 with 4 and 8 representative weeks, respectively, and 10 hours for Scenario 3 with free location) and it might be worth to investigate heuristic approaches instead. Doing so, one could extend the temporal (more representative weeks) and spatial (larger networks) scope of the analysis.

Part III.

Integration of Human Decisions Uncertainty in Optimisation Models for Energy Communities

Energy Communities bring together multiple end-users who have to coordinate their decisions in order to extract as much value as possible from local exchanges, as highlighted in previous chapters. From a short-term perspective, to assess the benefits of the coordinated demand-side management, we assumed in Part I that community members would strictly follow the day-ahead schedule of flexibility actions in real-time. Also, when planning long-term decisions of ECs in Part II, we considered that the community would not evolve over the lifetime of the assets. In practice, these assumptions are not always verified.

Representing faithfully the behaviour of other agents in such a collective framework is a major challenge. Hence, participants of Energy Communities may experience unexpected decisions of other members or from external stakeholders who revolve around them. In this Part III of the thesis, such sources of uncertainty linked to human decisions are modelled. The objective is to quantify the impact of these factors on the performances of Energy Communities decisions or to integrate them in the decision-making processes.

This part is organised around the following chapters:

- **Chapter 8** starts by categorizing the different sources of uncertainty that can be encountered in the Energy Communities framework. Focusing on human decisions uncertainty, an overview of existing works addressing this concern is provided and the contributions brought by this thesis are presented. In this thesis, the question of human decision uncertainty is investigated from both a long-term and a short-term perspective. In the remainder of this chapter, a stochastic procedure to quantify the impact of the arrival of new members in the community is designed. The impact is observed on the performances of the long-term decisions (i.e., DERs sizing), focusing on the founding members perspective.
- **Chapter 9** introduces a new structure for local exchanges of electricity within Energy Communities. It adopts a hierarchical vision of the interactions between the community manager and the end-users. The community manager acts as a leader, responsible to supply the whole electrical load of participants. Further in the chapter, the relative confidence of participants regarding the price of electricity offered by the community manager is modelled. A robust end-users decision-making problem is formulated to protect community members against such uncertainty. This problem is embedded in the hierarchical structure and the approach is finally validated on a set of residential community members.

CHAPTER 8.

Introduction to uncertainty sources in Energy Communities

From a general point of view, planning actions or decisions is naturally subject to several uncertainty sources. For example, the scheduled harvest period may be delayed depending on weather conditions or the profits generated by a supply chain may be lower than estimated if the price of raw materials increases. Without a crystal ball, it is impossible to guarantee with certainty that plans will unfold as expected and that the desired results will be achieved. Energy systems planning and operation are not exempted from these uncertainties. In every layer of the energy supply chain, several disturbances may affect the economic and technical performances of energy distribution [160], [161]. For example, in recent years, the European electricity and gas markets faced a major disruption related to the natural gas price increase resulting from the conflict between Russia and Ukraine [11]. This event showed how the efficiency of current market design and strategic reserve planning would be deteriorated when such extreme event happens. On another hand, the growing penetration of renewable generation sources fed by natural sources such as solar irradiation and wind speed increased the complexity to balance production and demand in the electrical system [162], [163]. The significant intermittency in the power output of photovoltaic and wind turbines installations requires to activate an increased amount of balancing resources which noticeably increase the balancing settlement cost that are passed to end-users [5]. Other uncertainties affecting the energy systems may also arise from the electrical demand, equipment failures or extreme meteorological events. These various sources of uncertainty that can be faced by stakeholders involved in the energy supply chain can be classified among two categories: exogenous and endogenous uncertainties.

Exogenous uncertainty refers to external factors whose values are resolved independently of the decision-maker's choices. This category is often called *decision-independent* uncertainty (DIU). The probability distribution of the realisation of such uncertain parameters is not affected by the actions taken by the actors. Weather conditions affecting the renewable energy production potential, electrical demand growth, or future market prices are often considered as such exogenous uncertainty factors. Their careful consideration in long-term planning and operational problems is key to secure performances and mitigate the risks when exposed to such disturbances [164], [165], [166].

Endogenous uncertainty, on the contrary, denotes uncertain parameters whose realization is affected or is only resolved after decisions are taken by the operator or planner. This category is therefore called *decision-dependent* uncertainty (DDU). These type of uncertainty is observed when decisions influence the parameter realizations by altering its underlying probability distribution or when decisions influence the parameters realizations by affecting the time at which we observe these realizations [167], [168], [169]. This type of uncertainty is often met in multi-stage programming problem for which a decision taken in one stage affects the uncertainty realizations observed in the following stage. For example, when a generation company participates to both the day-ahead and reserve markets, the uncertain imbalance volume to be activated in real-time is affected by the volume contracted in day-ahead.

In the Renewable Energy Community framework, both categories of uncertainty are encountered. As the local electricity pool can only be fed by production arising from renewable sources, the energy exchange potential in the community is greatly affected by the weather conditions. This induces uncertainty from both a long-term and short-term perspective. In the long-term planning of Distributed Energy Resources (DERs), it influences the revenues/cost savings generated by the production of renewable electricity which condition the profitability of investments. From a short-term perspective, the local potential uncertainty increases the risks to make flexibility efforts that would not be rewarded when scheduling the coordinated mobilisation of flexible resources in day-ahead. The evolution in time of the end-users electrical consumption is also a factor of uncertainty when planning DERs on a long-run. With the accelerated electrification of end-use demand such as heating, cooling and mobility, pushed by European climate policies, the electrical demand will necessarily increase but the dynamics are not easy to predict. Finally, regarding typical exogenous factors, the volatility of wholesale market prices may also be passed on end-users through the supplier's variable prices, affecting the competitiveness guarantee of local exchange prices.

Besides these standard uncertainty factors, the inherent interactive and collaborative nature of Energy Communities give rise to additional forms of uncertainty that would arise from human decisions. The efficiency of local energy sharing activities indeed relies on the commitment of each member to align their behaviour on the collective plans, whether short-term or long-term. For example, regarding the short-term operation of the community as discussed in Chapter 2, when the Community Manager solves the coordinated flexibility scheduling problem to reduce the electricity bills of the members, the expected savings computed in day-ahead assume that in real-time every participant will respect the schedule of flexible devices usage. In other words, the end-users are expected to behave rationally with respect to their objective that is decreasing the cost to cover their electrical demand. This assumption is based on the foundational paradigm in user behavioral modeling, that is Rational Choice Theory. This theory posits that people consciously evaluate search costs and gains in their decision-making process [170]. This might not be the most realistic modeling presumption. Indeed, people face cognitive limitations and barriers in information processing, preventing them from precisely understanding their own preferences and leading to suboptimal outcomes in the final decision-making process [170], [171], [172]. This phenomenon aligns with another concept that is Bounded Rationality Theory. On the contrary of the Rational Choice Theory, it argues that because of constraints on human cognition and knowledge, actors may not behave in a perfectly rational way. Adopting this theory might offer another perspective to the decision-making behavior of community members. As their decisions shape the realistic realization of ECs in current electricity markets [173], [174], [175], considering the Bounded Rationality of end-users decisions in the scheduling problem may thereby improve the precision and applicability of decisions taken by the community manager [171].

From a long-term perspective also, Human decisions may greatly affect the viability and profitability of investments. Indeed, if most of the works in the EC framework were achieved by considering a given community composition over its lifetime, in practice it may not necessarily be the case. From a broader perspective, community members are part of a wider energy system in which other end-users (with or without DERs) connected to the same distribution network may want to join the EC later on, during its lifetime. The possibility to join freely a community is part of the European definition of the concept [12]. However, any evolution of the EC composition will affect the internal energy exchanges and the founding members may see their operational cost savings being affected by the newcomers. Similarly, end-users (with or without DERs) may decide to leave the EC (e.g., to follow another more attractive incentive). By doing so, they would also affect the local energy exchanges and the resulting individual cost savings. Quantifying the impact of EC dynamic composition is therefore of tremendous importance as cost savings reduction may affect the willingness of initial members to participate as well as potential investment recovery.

8.1. State-of-the-Art on Human Decisions Uncertainty

As already discussed in Chapter 5, different authors have already emphasized the potential of coordinated investment in joint and/or individual DERs for EC members, see e.g. [16], [112], [130]. Most related works focus on the community's global cost savings and fair redistribution. In [130] for instance, authors propose a two-stage Mixed Integer Linear Programming (MILP) model. The first one addresses the optimal investment size of energy assets while the second stage distributes the community's income using a Shapley value approach. Another study, [128], analyzes the economic feasibility of ECs by examining self-investment and third-party investment options, assessing the impact of various cost allocation methods on household energy costs and exploring the possibility of applying multiple ones within the same community. In [133], a joint investment model for sizing and managing RECs with PV generation and storage assets highlights the energetic, economic and social impact of RECs comparing virtual and physical sharing schemes for centralised (i.e. shared) and decentralised (i.e. individual) distribution configurations. In [16], an optimal MILP investment sizing model is softly coupled with power flow analysis to study the impact of ECs deployment on the grid. Recent research has focused on optimising investment strategies within RECs in terms of both sizing and pricing decisions through a two-step approach [112]. The cooperative approach provides economic benefits compared to individual investments and it is demonstrated that joint investment allows for larger investments due to economies of scale.

However, all the above-mentioned works assume that all investment decisions are taken at year 1 and do not consider or assess the impact of the potential EC's dynamic composition on the investment decisions nor their final outcomes (i.e., return on investment, global cost savings). In [132], a business model for EC aggregators is developed, addressing fair revenue sharing and introducing users' exit clauses under the form of a penalty fee to be paid when leaving the community, to ensure social welfare. This work initiates discussion on this central question in ECs framework of the departure of members but does not address the case of incoming member which might also have negative impacts. More recently, authors in [176] have investigated the problem of dynamic composition in a peer-to-peer framework. They propose a bi-level approach to select new members for joining the local exchange platform such that already present members minimize their objective deviations while ensuring the global welfare of the EC. Although this work takes a step forward in the problem of EC's dynamic composition, the applied methodology only shows which newcomer profile might be suitable for an existing EC while the participation to EC is free in the EU definition [12]. Furthermore, this work does not quantify the uncertainty of the deviations in founding members' objectives. From a long-term perspective, this uncertainty might impact the investment profitability and the benefits generated by local exchanges for founding members.

The former literature reviewed focuses on the consideration of uncertain future participation of end-users to the community when planning the long-term decisions such as the sizing of energy resources. From an operational perspective, there is a plethora of research works in the literature on ECs' energy and cost optimisation that rely on the assumption of rational behavior among community members, where they consciously seek optimal solutions in the decision-making process. In [177], [178], authors are focused on developing multi-stage and risk-based frameworks for a centralized EC aiming to minimize the electricity billing in day-ahead and real-time balancing markets where the community manager (CM) is the coordinator of the centralized EC. Game-based approaches have been frequently used for modeling interactions between community actors in recent years. References [87], [179], [180], [181], [182] introduced coalitional game-based models for community members to exchange their energy resources, leading to more substantial cost reductions compared to individual operation modes. In [87], scholars proposed a cooperative game approach based on the Shapley value for equitable benefit sharing among energy community (EC) members. The Shapley value comes from Cooperative Game Theory. It aims to assign a portion of the collective gains of the EC to each member based on their marginal contribution to those global savings. Their findings, which compared this approach with centralized methods, indicated that coalition formation enhances fairness in benefit distribution. Similarly, in [179], the authors evaluated two cooperative game schemes using the Shapley value to assess cost reduction within ECs. They found that when both prosumers and consumers participate in energy sharing, the overall cost reduction for all participants is more substantial compared to individual operations. In [180], a Nash-Harsanyi bargaining game was introduced to ensure fair revenue allocation in multi-vector ECs, incorporating uncertainties from variable energy sources. Further, [181] employed Nash Bargaining for cost sharing in decentralized multi-vector transactive energy systems. Also, in [182], the authors examined how both decentralized and centralized EC structures could enhance benefits through coalition formation.

In [183], [184], [185], [186], [187], authors put forward Stackelberg Games (SGs) between the CM and members to determine competitive internal electricity prices and energy exchange schedules within ECs. In [183], the authors developed a hierarchical energy trading framework based on an SG in a two-stage decision-making structure, combining look-ahead energy storage scheduling with real-time, customized price design. Similarly, [184] introduced an SG-based framework for energy sharing within an EC, accounting for the diverse preferences of community members. In [185], a stochastic approach was proposed using a Wasserstein generative adversarial network with a gradient penalty to support a multi-vector EC, facilitating non-cooperative interactions between the aggregator and users. The studies in [183], [184], [185] demonstrate that internal pricing schemes enhance the EC's economic performance, especially compared to individual operations. The authors of [186] proposed an optimal real-time pricing strategy for a centralized EC, utilizing a linear quasi-relaxation approach alongside a dynamic partitioning technique to improve computational efficiency. In [187], a decentralized energy management approach is proposed for a community of residential and commercial buildings, allowing peer-to-peer energy trading among distributed energy owners and consumers. This interaction is structured as a multi-leader-multi-follower SG within a bi-level framework. To protect each entity's privacy and autonomy, a distributed algorithm featuring an efficient (Peer-to-Peer) P2P pricing mechanism is implemented.

In [188], [189], authors also proposed hybrid game-based approaches i.e., non-cooperative and cooperative games for determining competitive internal prices and sharing economic revenues among the participants of ECs. Authors in [188] introduced a hybrid game-based peer-to-peer framework combining a non-cooperative game to set internal electricity exchanges and prices across building communities and a cooperative game to manage transactions and revenue sharing within the same community. When compared with time-of-use pricing, the proposed approach demonstrated enhanced performance. Also in [181], three game-theoretic approaches based on evolutionary and non-cooperative games were suggested for a P2P energy trading strategy. The results demonstrated that incorporating power system impacts into P2P energy trading enhances energy use efficiency.

In recent years, scholars have been intrigued by the modeling of bounded rational behavior among energy users, including those within ECs. Prospect Theory (PT) was the anchor modeling approach for considering the bounded rational behavior of energy users in previous studies. According to PT, energy users value gains and losses differently, tending to overemphasize low-probability negative outcomes and underestimate favorable outcomes with high probabilities. Authors in [190] suggested a decentralized trading strategy based on continuous double auction theory to optimize the trading decisions of prosumers with different subjective preferences. PT is used to model the trading behavior of prosumers in the market. Similarly in [191], PT is used to capture the prosumer-related subjective perceptions on the multi-segment bidding rules. In SGs formulated as bilevel programming, PT is primarily employed to model the bounded rationality of community members.

In [192], an SG was introduced between members and the CM under price uncertainty. The proposal accounted for the subjective decision-making behavior of the prosumers by incorporating the framing effect in PT. Furthermore, the authors in [193] put forth an SG wherein the subjective behavior of members responds to fluctuations in electricity prices. They also examined the impact of members' actions on the distribution grid voltage. In another SG proposed in [194], the prosumer's perception of the probability of potential profits derived from trading energy (arising from wind energy uncertainty) were taken into account. Few other efforts for modeling bounded rational behavior of energy users are, for instance, considering altruistic preferences i.e., respecting others' interests in decision-making behavior [195], and incorporating Mental Accounting Theory, which develops a trading decision-making model based on three user risk attitudes: conservative, speculative, and neutral [196]. In [197], the authors proposed a price-responsive model that incorporates key aspects of end-user bounded rationality, specifically Time-Varying Discounts. They developed a framework using multiple seasonal trend decomposition using Loess and non-stationary Gaussian processes to model the randomness in electricity consumption by end-users and applied a chance-constrained optimisation model to address the irrationality in end-user behavior.

8.2. Research Objectives and Scientific Contributions

In this thesis, authors propose innovative methods to integrate endogenous and exogenous uncertain factors that arise from end-users decisions, whether participating or not to the local energy sharing activity, in optimisation models designed to support decision-making in Energy Communities. In particular, the two following research questions considering human-decisions uncertainty are investigated:

- **Analysing the impact of new EC members on long-term founding members benefits.**
  As defined by the EU, additional end-users can join an Energy Community after creation by other end-users, called founding members in the following. This integration of new members in the local exchanges does not necessarily delight the participants already present, especially when the later have design the production and storage assets capacity based on their own demand. Indeed, if investment were needed at the creation of the community they would have adopted an optimal long-term planning strategy as presented in Chapter 6. Generally, although these optimisation problems can account for exogenous uncertainty factors such as the renewable production potential or the electrical demand evolution, they do not anticipate the evolution of the community composition. Hence, the DERs are optimally designed for the initial situation only. Following regional regulations, transposed from the EU one, that implement energy sharing paradigm, new members are considered as any other participants when it comes to sharing the local electricity pool. If no recourse actions are taken such as new investments or sharing mechanisms adaptation, this affects the volumes of electricity exchanged by founding members within the REC and consequently affects their individual cost savings. As this question have never been addressed in the literature, in this thesis authors fill the gap by proposing a preliminary open-loop stochastic analysis to quantify the impact of the community composition evolution on founding members' benefits. In addition, the influence of sub-optimal DER sizes as well as EC founding and new members characteristics (i.e., consumers

or prosumers) on the analysis outcomes are observed.

[22] J. Allard, M. V. Gasca, R. Rigo-Mariani, F. Vallée, Z. De Grève, and V. Debusschere, "Impact of energy communities membership evolution on founding members' expected benefits," *IEEE Kiel PowerTech*, pp. 1–6, 2025.

- **Proposing a bilevel formulation of the coordinated flexibility problem including end-users behaviors facing limited observability.** In Energy Communities which aim to mobilize flexibility through an implicit flexibility signal rather than an explicit one, the community manager must continuously decide the appropriate local exchange price. This price must incentivize participants to shift their consumption in order to meet the collective objective of electricity bill reduction. When scheduling this tariff ahead (i.e., usually a day ahead) of the settlement period, the CM usually assumes that end-users will schedule rationally their response to this incentive, i.e., taking actions that would reduce their own bill. However, some participants might be sceptical regarding this price. Indeed, they may have experienced that if the local production volume deviates in real-time from its day-ahead forecast or if other end-users do not behave rationally, the actual reward tariff for their flexibility efforts may deviate from the announced incentive. In this context, this thesis investigates two primary research questions. First, what are the influences of members' consumption behaviors on internal price variations ? Second, how limited observability of community members resulting from these factors impacts their usage and trading behavior ? To the best of the authors' knowledge, this is the first attempt in the literature on local energy markets to integrate this important aspect of bounded rationality into the EC dispatch problem. To this end, this works first conceptualizes and formulates limited observability of community users regarding the strategies of the community manager in the form of near-optimality robustness bilevel energy sharing problem. The limited observability from end-users perspective is assumed to come from internal electricity prices [198], [199], it then requires to model the effect of those on the endogenous uncertainty set boundaries. Therefore, an iterative approach for delimiting these boundaries that accounts for deviations in real-time of the load consumption behavior of community users is devised. The proposed formulation is examined regarding the impacts of users' bounded rational behavior i.e., near-optimal responses to optimal pricing strategies of the CM, on EC exchanges and upstream distribution network constraints.

[23] J. Faraji, J. Allard, F. Vallée, and Z. De Grève, "On the limited observability of energy community members: An uncertainty-aware near-optimal bilevel programming approach," *Applied Energy*, vol. 381, pp. 125-177, 2025.

The works conducted around these 2 research objectives focusing on the integration of human decisions uncertainty in REC decision-making problems and the associated contributions are presented in the remainder of this thesis. First, Section 8.3 presents the innovative stochastic approach adopted to quantify the newcomers' impacts on funding members perspective. The developed Monte-Carlo algorithm is applied on several domestic ECs under different configurations of founding members. The second contribution, adopting a bilevel energy community framework, different than the one presented in the other chapters is introduced in Chapter 9. The full mathematical formulation of the bounded rational aware implicit flexibility scheduling is defined and the proposed approach to model the endogenous uncertainty in the local electricity prices captured by end-users is described.

8.3. Open-Loop Analysis of New Members Arrival

If Human-Decisions can be a source of uncertainty in the daily operation of flexible resources for local arbitrage purpose in Energy Communities, long-term planning of DERs resources can also be affected by Human Actions. Let's consider back the REC framework considered in Chapter 6, in which a coalition of consumers and prosumers is formed and decides to invest in Distributed Energy Resources (DERs) that produces electricity locally from renewable sources (e.g., rooftop PV panels, small-scale wind turbines) or store it for optimal local use (e.g., battery storage systems). As depicted in Figure 8.1, the REC paradigm unlocks innovative investment strategies such as the possibility for participants to invest jointly in DERs rather than individually. Joint assets are production or storage devices whose totally shared among community members in contrast to individual assets which usage is primarily dedicated to the owner. Their management is assigned to a Community Manager (CM). Besides, the main actors of an energy community that are the EC members, can make (or already has) an investment in DERs based on their maximum capacity (e.g., rooftop availability) and equity or participate in joint investment. In Europe, EC members may also contract (individually or jointly) with an external electricity supplier to cover their remaining demand, which cannot be covered by the local purchase of electricity, or to sell their excess production not traded within the EC [12].

From an operational point of view, in this work, the energy pool sharing mechanism is applied as considered in Belgium [14] and France [13]. In this framework, the production surplus (i.e., excess electricity after individual self-consumption) from individual installations and the energy generated by jointly owned assets are pooled. This local energy reserve is shared among the EC members by the CM according to predefined allocation rules (i.e., the 'Key of Repartition' principle, see Chapter 3) while ensuring the continuous power balance of local exchanges within the EC. These rules are generally defined, along with the internal exchange prices, when founding members gather and create the EC. By doing so at the investment time, they can foresee their expected cost savings and the profitability of their investment if they operate as an EC and share their DERs.

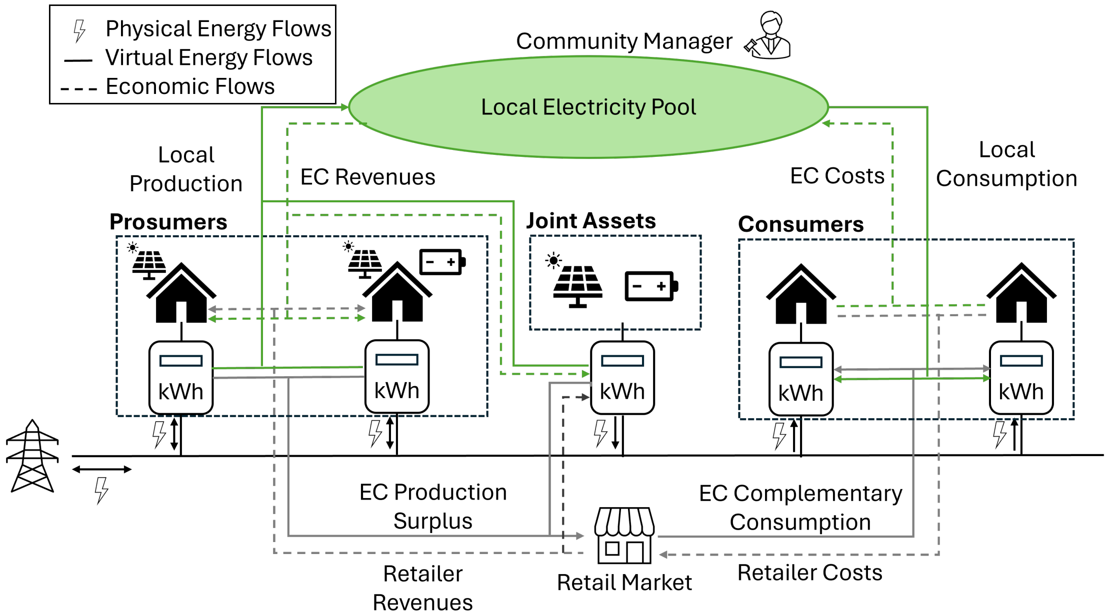


Figure 8.1.: Energy Community framework diagram.

From a broader perspective, those members, by being connected to the public distribution grid, are part of a wider energy system in which other end-users (with or without DERs) connected to the same distribution network may want to join the EC later on during its lifetime, as represented in Figure 8.2. However, any evolution of the EC composition will affect the internal energy exchanges and the founding members may see their operational cost savings being affected by the newcomers. Similarly, end-users (with or without DERs) may decide to leave the EC (e.g., to follow another more attractive incentive). By doing so, they would also affect the local energy exchanges and the resulting individual cost savings. Quantifying the impact of EC dynamic composition is therefore of tremendous importance as cost savings reduction may affect the willingness of initial members to participate as well as potential investment recovery.

However, this uncertainty regarding intra- and extra-community actors decisions on the long-run has never been considered in long-term planning problems for Energy Communities. Most of the literature relies on the hypothesis that the composition of the Energy Community will remain stable over time. Some work [132], [176] started to address the question of dynamic evolution of the EC but either adopt a recourse actions plan [132] to only mitigate the impact of exiting members or adopt a selection methodology for newcomers [176] which is not aligned

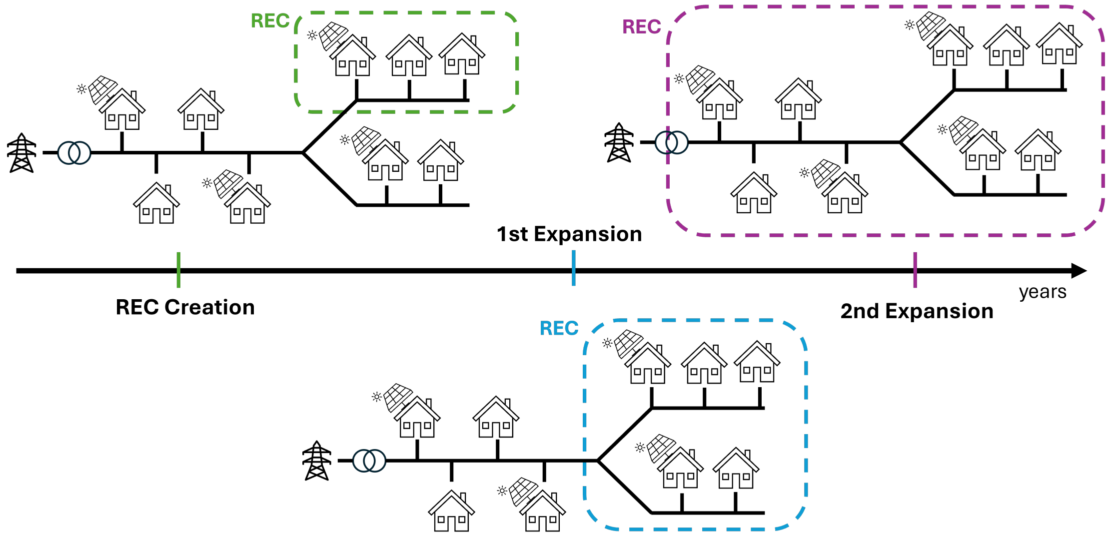


Figure 8.2.: Illustration of a REC expansion after its creation.

with the free and non-discriminatory participation principle [12].

Therefore in this thesis, we started to fill the gap in the literature concerning the impact of the dynamic evolution of membership within ECs by investigating how the individual cost savings of the EC founding members, who jointly or individually invest in energy assets at the EC creation, are affected by newcomers throughout the EC lifetime. In this perspective, a new methodology to quantify the impact of the dynamic evolution of membership on economic indices (e.g., individual cost savings) within an EC is proposed. The bases of comparison considered is the starting point of the community when the founding members invest optimally in energy assets and estimate their future savings. Besides, we further investigate the influence of sub-optimal DER sizes as well as EC founding members profiles (prosumers or consumers) on the dynamic membership method outcomes, for multiple initial EC configurations.

To successfully complete this work, an optimal investment model, presented in Section 8.3.1, accounting for different EC investment strategies (i.e., joint and individual) is first solved to initially size the DER assets in the EC. Then, in Section 8.3.2, a Monte-Carlo approach helps quantify the impact of several newcomers scenarios on the cost savings of founding members by running the optimal operational problem iteratively. In Section 8.3.3, the methodology and analysis are validated on a large set of residential ECs use cases with different initial configurations including the penetration of prosumers and the flexibility potential (i.e., storage system).

The contributions of this work are presented in the following article:

[22] J. Allard, M. V. Gasca, R. Rigo-Mariani, F. Vallée, Z. De Grève, and V. Debusschere, "Impact of energy communities membership evolution on founding members' expected benefits," in IEEE Kiel PowerTech, pp. 1–6, 2025.

8.3.1. Optimal Sizing Problem

When initially creating the energy community, the following optimal DER sizing problem is solved. This problem is similar to the first problem solved in the two-steps approaches of the long-term planning of EC resources presented in Section 6.1. It aims at minimizing the aggregated total life-cycle cost of EC members while considering the energy exchange mechanism specific to EC. Let's consider $\mathcal{N}$ as the set of community members and $\mathcal{ND}$ the enlarged set of distribution networks access points including the end-users point of common coupling and an additional node that could welcome joint assets. A single year is replicated over the investment horizon, nand is represented by a set of representative days, $\mathcal{D}$, which have a yearly occurrence factor, π_d, whose sum is equal to 365. Finally, $\mathcal{T}$ is the set of time periods within a day with a time step Δt. The Mixed-Integer Linear Programming (MILP) DERs sizing problem reads:

$$
\begin{aligned}
\min_{\Omega} \quad & \text{Total REC life-cycle cost (8.2)} && (8.1)\\
\text{s.t.} \quad & \underline{\text{Long-term constraints:}} \\
& \text{Economic constraints (8.6)-(8.9)} \\
& \text{Capacity constraints (8.10)-(8.17)} \\
& \underline{\text{Short-term constraints:}} \\
& \text{Assets production constraints (8.18)} \\
& \text{Battery storage constraints (8.19)-(8.27)} \\
& \text{Energy and economic exchanges constraints (8.28)-(8.39)} \\
& \text{Energy sharing rules constraints (8.40)-(8.47)}
\end{aligned}
$$

with $\Omega = \{\Omega_{LT}, \Omega_{ST}\}$ the set of long-term $\Omega_{LT} := \{E_n^{indiv}, E^{joint}, L^{joint}, P_{g,n}^{indiv}, P_{g,n}^{joint}, P_n^{st,indiv}, P_n^{st,joint}, SOC_n^{st,indiv}, SOC_n^{st,joint}\}$, and short-term decisions $\Omega_{ST} := \{l_{d,nd,t}, v_{d,n,t}, v_{d,t}^{joint}, p_{d,n,t}^{alloc}, i_{d,n,t}^{com}, e_{d,n,t}^{com}, e_{d,t}^{com,joint}, i_{d,n,t}^{ret}, e_{d,n,t}^{ret}, e_{d,t}^{ret,joint}, s_{d,n,t}^{indiv}, s_{d,nd,t}^{joint}, soc_{d,n,t}^{indiv}, soc_{d,nd,t}^{joint}\}$ of the sizing problem. Long-term decisions related to investment in DERs are, respectively, the end-users equity invested in individually owned assets, the overall equity from community members invested in joint assets, the loan amount requested to cover the joint assets costs, the individual and joint installed generation capacity and the individual and joint storage system ratings, i.e., power and energy capacity. To evaluate the operational costs and revenues along the project lifetime, the operational community problem is embedded in the long-term planning one and the related short-term decision variables correspond, respectively, to the physical net power metered at each node, the virtual individual power to be traded by each member, the joint assets power to be traded, the individual shares of the local electricity pool allocated to each participant, the individual community import and export quantities, the electricity sold in the community from joint installations, the individual exchanges with the retailer in both directions, the extra electricity from joint assets sold to a retailer, and the individual and joint storage devices power exchanges and state-of charge. Regarding the energy storage systems, it is assumed that individual units are only operated for personal use, i.e., discharging limited to individual consumption, and that joint units are only used to store joint production excess to guarantee that the energy exchanged locally originates from renewable sources only.

Total REC Life-Cycle Cost

The total life-cycle cost (TLCC) is computed as in (6.2) by accounting for the initial investment cost and all the operational cash flows arising in the community lifetime. In the REC framework, mainly gathering consumers and prosumers rather than exclusive producers, the yearly costs do not only refer to those of production assets but also account for the furniture of their electrical demand. The definition of TLCC adopted in this work is as follows:

$$TLCC(\Omega) = E^{joint} + \sum_{n \in \mathcal{N}} E_n^{indiv} + \sum_{y \in \mathcal{Y}} \frac{-\Pi + D}{(1+r)^y}, \tag{8.2}$$

$$D = \left[\frac{r_L (1+r_L)^Y}{(1+r_L)^Y - 1} \right] L \tag{8.3}$$

$$\Pi = B^{REC,0} - B^{REC} \tag{8.4}$$

$$B^{REC} = \sum_{d \in \mathcal{D}} \pi_d \sum_{t \in \mathcal{T}} \underbrace{\left[\sum_{n \in \mathcal{N}} \left(\lambda_{d,n,t}^{ret,imp} \; i_{d,n,t}^{ret} - \lambda_{d,n,t}^{ret,exp} e_{d,n,t}^{ret} \right) + \lambda_{d,t}^{ret,joint} e_{d,t}^{ret,joint} \right] \Delta t}_{\text{Retailer Commodity Costs}}$$
$$+ \underbrace{\sum_{n \in \mathcal{N}} \lambda_{d,n,t}^{grid} \; l_{d,n,t}^{+} \Delta t}_{\text{Grid and Taxes Costs}} \tag{8.5}$$

with the first two terms of (8.2) representing the overall equity invested in DERs by founding members, while the last term represent the present value of operational cash flows that are the annual debt payment, D, and the cost savings, Π, for the supply of the electrical demand. The annual debt payment is computed in (8.3) based on the loan amount L, the loan interest rate r_L and the investment period length, Y, using the Uniform Capital Recovery Factor (UCRF) **nrel**. The cost savings Π amounts to the difference between the aggregated initial electricity bills of participants, $B^{REC,0} = \sum_{n\in\mathcal{N}} B_n^0$, and the optimal REC bill. End-users bill combines the commodity costs for the retailer complementary exchanges with $\lambda_{d,n,t}^{ret,imp}$ and $\lambda_{d,n,t}^{ret,exp}$ the retailer import and export prices. If retailer costs are based on virtual exchanges, the grid costs and taxes are computed based on the physical power flows. Hence for the usage of the grid a price $\lambda_{d,n,t}^{grid}$ is charged on the net consumption volume. Taxes costs are embedded in the grid tariff.

Long-Term Constraints

In this work, domestic end-users are considered and the set of DERs to be installed is limited to solar panels (on rooftops or a large-scale plant for joint investment) and energy storage systems (i.e., batteries). These assets can be installed over the different REC members network connection point or at a centralized location, $\mathcal{ND} \setminus \mathcal{N}$. Nevertheless, in the following decentralized assets are for individual ownership only while joint assetes are only located at the centralized location. The investment strategy is hence formulated as follows:

$$E_n^{indiv} \leq \overline{E}_n, \qquad \forall n \in \mathcal{N}, \quad (8.6)$$

$$E^{joint} + \sum_{n\in\mathcal{N}} E_n^{indiv} \leq \sum_{n\in\mathcal{N}} \overline{E}_n, \quad (8.7)$$

$$E_n^{indiv} = C^{st}\big(SOC_n^{st,indiv} + P_n^{st,indiv}\big) + C^{PV} P_{PV,n}^{indiv}, \qquad \forall n \in \mathcal{N}, \quad (8.8)$$

$$E^{joint} + L = \sum_{n\in\mathcal{ND}\setminus\mathcal{N}} \Big[C^{st}\big(SOC_n^{st,joint} + P_n^{st,joint}\big) + C^{PV} P_{PV,n}^{joint}\Big] \quad (8.9)$$

The amount of equity invested by EC members in individual or joint assets is globally limited by their budget, $\overline{E}_n$, as reproduced in (8.6)-(8.7). This initial payment is relative to the installed capacity of production and storage assets and the associated costs via (8.8)-(8.9). Joint installations have the particularity to potentially be partially funded by a bank loan.

At each location, renewable production and storage devices capacity are limited by the available space, the connection capacity, or other physical/electrical reasons. In Chapter 6 a minimum self-consumption rate constraint (6.48) is imposed to avoid DERs oversizing. In this work, this oversizing concern is solved by deifning PV capacity upper bounds based on the load level within the community. More specifically, these limits are defined such that the expected production (i.e., computed with an average load factor) does not exceed the yearly demand of end-users.

$$P_{PV,n}^{indiv} + P_{PV,n}^{joint} \leq \overline{P}_n^{PV}, \qquad \forall n \in \mathcal{ND}, \quad (8.10)$$

$$P_n^{st,indiv} + P_n^{st,joint} \leq \overline{P}_n^{st}, \qquad \forall n \in \mathcal{ND}, \quad (8.11)$$

$$SOC_n^{st,indiv/joint} \geq \underline{EP}_n P_n^{st,indiv/joint}, \qquad \forall n \in \mathcal{ND}, \quad (8.12)$$

$$SOC_n^{st,indiv/joint} \leq \overline{EP}_n P_n^{st,indiv/joint}, \qquad \forall n \in \mathcal{ND}, \tag{8.13}$$
$$P_{PV,n}^{joint}, P_n^{st,joint}, SOC_n^{st,joint} \geq 0, \qquad \forall n \in \mathcal{ND} \setminus \mathcal{N} \tag{8.14}$$
$$P_{PV,n}^{indiv}, P_n^{st,indiv}, SOC_n^{st,indiv} \geq 0, \qquad \forall n \in \mathcal{N}, \tag{8.15}$$
$$P_{PV,n}^{indiv}, P_n^{st,indiv}, SOC_n^{st,indiv} = 0, \qquad \forall n \in \mathcal{ND}, \setminus \mathcal{N}. \tag{8.16}$$
$$P_{PV,n}^{joint}, P_n^{st,joint}, SOC_n^{st,joint} = 0, \qquad \forall n \in \mathcal{N}. \tag{8.17}$$

Constraints (8.10) and (8.11) limit the power capacity of PV installations and storage devices. When investing in storage system units both power and energy capacities are considered as decision variables. The energy capacity is limited via (8.12)-(8.13) in a range of energy-to-power ratio $[\underline{EP}_n, \overline{EP}_n]$, representing the maximum number of hours the battery can be used continuously at nominal power in a given direction, i.e., charging or discharging. Finally (8.14)-(8.17) limits the location of individual and joint assets as discussed previously.

Short-term Constraints ($\forall d \in \mathcal{D}$)

To assess the long-run profitability of their investment founding members must quantify their expected bill savings over the community lifetime. To do so, the daily operational model of the local electricity exchanges is integrated in the long-term planning problem. This model consists in the representation of physical power flows exchanged and virtual economic flows traded by each member of the community. Battery storage devices are also accounted as flexible units enabling to better benefit from the local production.

This power generation outputs from the photovoltaic units depending on fluctuating weather conditions. To quantify this variability, the generation potential is generally represented by a capacity/load factor, lf, which represents the fraction of the rated capacity that can be produced at a given time.

$$g_{d,n,t} = lf_{d,n,t}^{PV} \big(P_{PV,n}^{indiv} + P_{PV,n}^{joint}\big), \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}. \tag{8.18}$$

The power produced by individual or joint generation assets is limited in (8.18) by the available potential, lf, at the given spot.

To help community members in balancing the local production and the local consumption, other DERs such as battery storage systems can be installed. Their controllable operation is represented by the following state-of-the-art constraints, whether they are individually or jointly managed.

$$s_{n,t} = s_{n,t}^{ch} - s_{n,t}^{dis}, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{8.19}$$
$$soc_{n,1} = R_n^{st} SOC_n^{st} + \big(\eta^{st} s_{n,1}^{ch} - s_{n,1}^{dis}/\eta_{st}\big)\,\Delta t, \qquad \forall n \in \mathcal{ND}, \tag{8.20}$$
$$soc_{n,t} = soc_{n,t-1} + \big(\eta^{st} s_{n,t}^{ch} - s_{n,t}^{dis}/\eta_{st}\big)\,\Delta t, \qquad \forall n \in \mathcal{ND}, \forall t \in \mathcal{T} \backslash \{1\}, \tag{8.21}$$
$$soc_{n,T} = R_n^{st} SOC_n^{st}, \qquad \forall n \in \mathcal{ND}, \tag{8.22}$$

$$
\begin{aligned}
&0 \leq soc_{n,t} \leq SOC_n^{st}, && \forall n \in \mathcal{ND}, && (8.23)\\
&- P_n^{st} \leq s_{n,t} \leq P_n^{st}, && \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, && (8.24)\\
&s_{d,n,t}^{dis,indiv} \leq b_{d,n,t}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.25)\\
&\sum_{n \in \mathcal{ND}} s_{d,n,t}^{ch,joint} \leq \sum_{n \in \mathcal{ND}} g_{d,n,t}^{joint}, && \forall t \in \mathcal{T}, && (8.26)\\
&\sum_{n \in \mathcal{ND}} s_{d,n,t}^{dis,joint} \leq e_{d,t}^{com,joint}, && \forall t \in \mathcal{T}. && (8.27)
\end{aligned}
$$

where the evolution of the state-of-charge is subject to constraints (8.20)-(8.22) that account for the charging and discharging efficiencies as well as the initial and final states of the day which are expressed as a share of the installed capacity, R_n^{st}. The power charged or discharged is capped by the rated power of the battery via (8.23) and the state-of-charge by the maximum storage volume via (8.24). Additionally, specific constraints for the usage of individual and joint storage systems are integrated to keep the local exchanges fully renewable. First, constraint (8.25) limits the individual storage discharge to the owner's demand supply while constraints (8.26)-(8.27) impose that the joint storage can only be used to supply REC loads with joint production.

As recalled in the definition of the electricity bill, in the EC framework a distinction is made between the physical power flows exchanged with the physical grid at the point of connection and the economic exchanges traded with other stakeholders. The former flows being decomposed into later ones as follows:

$$
\begin{aligned}
&l_{d,n,t} = b_{d,n,t} + s_{d,n,t}^{indiv} + s_{d,n,t}^{joint} - g_{d,n,t}, && \forall n \in \mathcal{ND}, \forall t \in \mathcal{T}, && (8.28)\\
&l_{d,n,t} = l_{d,n,t}^{+} - l_{d,n,t}^{-}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.29)\\
&l_{d,n,t}^{+} \cdot l_{d,n,t}^{-} = 0, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.30)\\
&v_{d,n,t} = l_{d,n,t} - s_{d,n,t}^{joint} + g_{d,n,t}^{joint}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.31)\\
&v_{d,n,t} = v_{d,n,t}^{+} - v_{d,n,t}^{-}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.32)\\
&v_{d,n,t}^{+} \cdot v_{d,n,t}^{-} = 0, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.33)\\
&v_{d,t}^{joint} = \sum_{n \in \mathcal{ND}} g_{d,n,t}^{joint} + s_{d,n,t}^{joint}, && \forall t \in \mathcal{T}, && (8.34)\\
&v_{d,n,t}^{+} = i_{d,n,t}^{ret} + i_{d,n,t}^{com}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.35)\\
&v_{d,n,t}^{-} = e_{d,n,t}^{ret} + e_{d,n,t}^{com}, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, && (8.36)\\
&v_{d,t}^{joint} = e_{d,t}^{ret,joint} + e_{d,t}^{com,joint}, && \forall t \in \mathcal{T}, && (8.37)\\
&\sum_{n \in \mathcal{N}} i_{d,n,t}^{com} = \sum_{n \in \mathcal{N}} \left(e_{d,n,t}^{com}\right) + e_{d,t}^{com,joint}, && \forall t \in \mathcal{T}, && (8.38)\\
&i_{d,n,t}^{ret}, i_{d,n,t}^{com}, e_{d,n,t}^{ret}, e_{d,t}^{ret,joint}, e_{d,n,t}^{com}, e_{d,t}^{com,joint} \geq 0, && \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. && (8.39)
\end{aligned}
$$

At each end-user location, the metered physical power is the aggregation of the electrical demand, assumed non-flexible in this work, and the storage power flow and the PV production is devices are installed at this spot as expressed in (8.28). This physical power flow, $l_{d,n,t}$ can be positive and represent a net consumption, $l^{+}_{d,n,t}$ and or negative and be considered as a net injection, $l^{-}_{d,n,t}$, via (8.29). This distinction is made as grid and taxes cost are only charged on net consumption volumes. These physical quantities may differ from the economic ones that are effectively traded. Indeed, if one participant host joint assets at its location, the virtual power to be traded by REC members, $v_{d,n,t}$, is defined as the physical metered power minus the joint assets power production (8.31). This is because the end-user does not have the ownership of the assets, hence the energy coming from these resources is made available to everyone. Similarly to the physical power flow, constraints (8.32) distinguish economic import, $v^{+}_{d,n,t}$, and export, $v^{-}_{d,n,t}$, power flows. The energy produced by collective assets, instantaneously traded or stored and discharged, is aggregated in (8.34). Equations (8.35)-(8.37) decompose the traded power between exchanges within the community and with the retailers. Finally, (8.38) ensures the power balance of virtual exchanges within the REC. The non simultaneously non-zero constraints (8.30) and (8.33) are implemented using the big-M method [100].

Finally, to comply with the standard regulation applied in Wallonia (Belgium) and France, an explicit energy sharing rule is implemented to limit the local energy that any member can consume. In this work, the *Prorate Consumption* dynamic key, introduced in Section 3.1.1 and adapted to the joint investment framework in 6.2.1, is selected. It dispatches, at each time step, the energy pool among the members based on their net power consumption. In case the local production exceeds the local consumption during a given time period, a *Prorate Injection* dynamic key is also considered for the repartition of the surplus electricity among prosumers to valorize it by trading with their retailer. The repartition is based on the contribution of each prosumer to the local electricity pool. As demonstrated in [17] and previous chapters, these rules can be expressed as sets of linear constraints as follows:

Prorate Consumption Key

$$p^{alloc}_{d,n,t} = v^{+}_{d,n,t}\Bigg(\sum_{j=1:7} \nu_{j,d,t} 2^{(j-1)}\Bigg)/100, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (8.40)$$

$$\sum_{n\in\mathcal{N}} p^{alloc}_{d,n,t} \leq P^{pool}_{d,t}, \qquad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \quad (8.41)$$

$$i^{com}_{d,n,t} \leq p^{alloc}_{d,n,t}, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (8.42)$$

$$0 \leq p^{alloc}_{d,n,t}, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (8.43)$$

$$\nu_{j,d,t} \in \{0,1\}, \qquad \forall j \in \{1,...,7\}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T}. \quad (8.44)$$

This set of constraints imposes that everyone receives a share of the community pool relative to its net consumption level via (8.40). The ratio between the allocated power and the net consumption level is the same for every member and expressed using a binary expansion with the use of auxiliary binary variables, $\nu_{j,d,t}$. The overall allocated volume must not exceed the local pool reserve as imposed by constraint (8.41). In the end, tis allocated quantity limits the local community import in (8.42).

Prorate Injection Key

$$e^{ret}_{d,n,t} = v^{-}_{d,n,t}\Bigg(\sum_{j=1:7} \nu^{e}_{j,d,t} 2^{(j-1)}\Bigg)/100, \qquad \forall d \in \mathcal{D}, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \quad (8.45)$$

$$e^{ret,joint}_{d,t} = v^{joint}_{d,t}\Bigg(\sum_{j=1:7} \nu^{e}_{j,d,t} 2^{(j-1)}\Bigg)/100, \qquad \forall d \in \mathcal{D}, \forall t \in \mathcal{T}, \quad (8.46)$$

$$\nu^{e}_{j,d,t} \in \{0,1\}, \qquad \forall j \in \{1,...,7\}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T}. \quad (8.47)$$

Similarly, the *Prorate Injection* repartition principle can be linearized by introducing a binary expansion of variable $\nu^{e}_{j,d,t}$ to make sure that each point of connection that locally injects electricity receives a share of the local surplus proportional to its contribution to the global injection volume.

8.3.2. Dynamic Composition Analysis

Welcoming new members in an EC affects the local energy exchanges via the KoR mechanism if no compensation actions are taken. Indeed, end-users are considered in the local energy sharing repartition only according to their level of net consumption. Consequently, founding members will observe deviations in their yearly bill (compared to the projected values obtained using model (8.1) although they did not change their behaviour. This section details the generic methodology proposed to quantify the impact of newcomers (consumers and/or prosumers) in the EC on the economic performances of initial EC members that is also depicted in Figure 8.3.

Let us consider a system with a set of $\mathcal{X}$ end-users. The first step consists of sampling a subset $\mathcal{N}$ of end-users who gather to form an EC. At the EC's creation the optimisation problem (8.1) is solved to define the DERs capacity accounting for the predefined energy exchange mechanism (i.e., prorate keys in this case). From this optimal investment, founding members expect to retrieve benefits compared to their initial situation in which they were solely trading with the retailer. Hence individual cost savings CS_n^{opt} can be defined as follows:

$$CS_n^{opt} = \sum_{y\in\mathcal{Y}} \frac{\Pi_{n,y}^{opt}}{(1+r)^y} - (E_n^{indiv,opt} + E_n^{joint,opt}), \qquad \forall n \in \mathcal{N}, \quad (8.48)$$

$$\Pi_n^{opt} = B_n^0 - B_n^{opt}, \qquad \forall n \in \mathcal{N}, \quad (8.49)$$

$$\pi_n^{ut,b} = \sum_{d\in\mathcal{D}} \pi_d \sum_{t\in\mathcal{T}} \sum_{n\in\mathcal{N}} \left[\lambda_{d,n,t}^{ret,imp} i_{d,n,t}^{ret} - \lambda_{d,n,t}^{ret,exp} e_{d,n,t}^{ret})\right] \Delta t + \sum_{n\in\mathcal{N}} \lambda_{d,n,t}^{grid}\, l_{d,n,t}^{+} \Delta t$$
$$+ \sum_{n\in\mathcal{N}} \left[\lambda_{d,t}^{com} \left(i_{d,n,t}^{com} - e_{d,n,t}^{com}\right)\right] \Delta t - k_n^{joint} R^{joint}, \qquad \forall n \in \mathcal{N}, \quad (8.50)$$

$$R^{joint} = -D + \sum_{d\in\mathcal{D}} \pi_d \sum_{t\in\mathcal{T}} \left[\lambda_{d,t}^{ret,joint} e_{d,t}^{ret,joint} + \lambda_{d,t}^{com} e_{d,t}^{com,joint}\right] \Delta t. \quad (8.51)$$

Individual end-users cost savings over the period of interest, as written in (8.48), account for the operational savings relative to the reduction in their electricity bill as well as the equity invested in new DERs. Operational savings are computed as the difference between the initial electricity bill before joining the REC and the one that is estimated when planning the DERs. The electricity bill of REC participants, expressed in (8.50), accounts for the traditional retailer, including both purchases and sales, grid and taxes costs. In addition, complementary revenues can be generated thanks to the jointly installed assets. This revenue stream is received by investor-members based on their contribution to the joint investment, k_n^{joint}. The revenues of joint installations are generated by the resale of electricity production within the REC and/or to a retailer, part of it being first use to cover the potential debt payment. In this work, the budget limit is neglected and therefore, the equity invested in joint assets is equally split among members, i.e., $k_n^{joint} = 1/|\mathcal{N}|$.

Then, to observe the impact of EC dynamic composition on those cost savings a Monte-Carlo approach with two embedded loops is adopted. Strictly speaking, the inner loop consists in a Monte-Carlo algorithm. For each inner loop iteration, j, a different subset of end-users $\mathcal{N}^{new}$ is randomly sampled from the system set $\mathcal{X}$ and added to the initial EC, hence representing a different EC membership evolution. Once newcomers have been included in the EC, an optimal operational problem is solved. This problem is a reduction of the optimal sizing problem (8.1) to the short-term decision variables (i.e. operation only) and constraints, fixing the long-term variables of the founding members to the optimal values retrieved in step 1, as follows:

$$\min_{\Omega^{ST}} \quad \sum_{n\in\{\mathcal{N},\mathcal{N}^{new}\}} -\Pi_n \quad (8.52)$$
$$\text{s.t.} \quad \text{Short-term constraints (8.18)-(8.47)}$$

From the optimal operational model realization, new founding members' cost savings can be obtained and the cost savings deviation can be computed using the following formula:

$$\Delta CS_n^j = CS_n^j - CS_n^{opt}, \qquad \forall n \in \mathcal{N}. \tag{8.53}$$

The Monte-Carlo iterative process is repeated until the following rolling horizon convergence criterion is met:

$$\max_{n \in \mathcal{N}} \sqrt{\frac{\sum_{l=j-L}^{j} (x_{l,n} - \overline{x}_j)^2}{L-1}} \leq tol \tag{8.54}$$

$$\text{with} \quad x_{l,n} = \frac{\sum_{j=1}^{l} \Delta CS_n^j}{l} \qquad \forall l \in \{1, ..., L\} \tag{8.55}$$

$$\text{and} \quad \overline{x}_j = \frac{\sum_{l=j-L}^{j} x_{l,n}}{L} \tag{8.56}$$

In this criterion, $x_{l,n}$ represents the average of cost savings deviations observed after l iterations for end-user n while $\overline{x}_j$ represents the average of this value over the rolling horizon of length L, i.e., the average over the last L iterations. The criterion can the be interpreted as the monitoring of the variability of the average cost savings deviations when the number of iterations increases for each individual. When this variability respects the tolerance level for every founding member, the algorithm is stopped.

Finally, the outer loop represents that this Monte-Carlo analysis is repeated for different initial EC configurations (i.e., k^{max} outer loop iterations) to get a broader view of the potential of cost savings deviations.

8.3.3. Case Study and Results

Results presented in this section are obtained using a set of $|\mathcal{X}| = 92$ domestic end-users. Initial ECs are constituted of $|\mathcal{N}| = 6$ founding members and $|\mathcal{N}^{new}| \in \{1, 2, 3, 4\}$ newcomers are randomly added at each iteration j. Regarding the Monte-Carlo approach of the methodology in Figure 8.3, the inner loop convergence tolerance level is set to 10^{-4} and the rolling horizon length to 100 iterations. The outer loop is run 10 times (i.e., $k^{max} = 10$). All results shown are obtained for the same 10 initial EC configurations. An investment period of $Y = 20$ years is considered and each year is represented by six equiprobable typical days with a 48-period resolution. The power capacity of batteries is capped with the same bound while their energy capacity is limited by the following energy-to-power ratio: $\overline{EP} = 4$, $\underline{EP} = 0.25$. The battery charging and discharging efficiency are set to 0.95 and the daily initial state-of-charge share is equal to 0.2. Finally, economic parameters are presented in Tab.8.1.

The full methodology is implemented in Julia and Gurobi is used as the optimi-

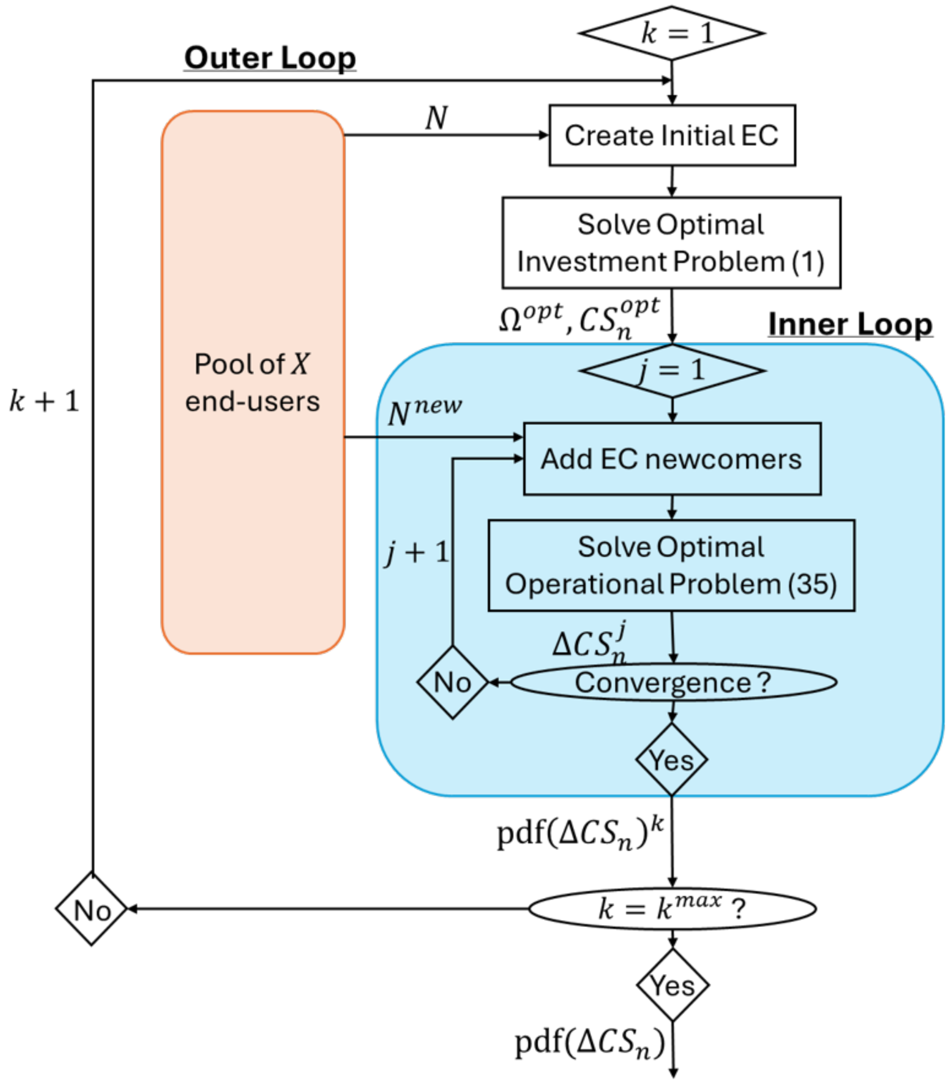


Figure 8.3.: EC's dynamic composition stochastic analysis algorithm.

sation problem solver. The outer loop solving time ranges from 398 to 1153 seconds and the average inner loop iteration is 140 seconds.

Table 8.1.: Economic Parameters

Parameters	**Description**	**Values**
C^{PV}	PV capacity price	1400 €/kW
C^{st}	Battery (power and energy) capacity price	400 €/kW(h)
$\lambda^{ret,imp}$	Retailer import tariff	0.14 €/kWh
$\lambda^{ret,imp}$	Retailer export tariff	0.05 €/kWh
λ^{grid}	Grid import tariff	0.11 €/kWh
λ^{com}	Local electricity price	0.095 €/kWh
r	Minimum internal rate of return	3 %

Impact of (Sub-)Optimal Investment Decisions

Let us first consider investment in joint PV resources only, with all founding EC members being considered as consumers. Figure 8.4 shows the resulting distribution of relative cost savings deviations induced by the arrival of new consumers in the EC after joint investment has been made at its creation. It can be observed that, in any situation, founding members always see a negative impact on their costs if no recourse actions are taken as they share the same cake (i.e., electricity pool) among more end-users. With the initial optimal PV sizing, the deviations span from 2 to 25% with a median loss of 11%.

In the second step, we force the initial investment decisions to be suboptimal, i.e. over or under-investment, by manually increasing or decreasing the installed PV capacity. In the underinvestment case, the impact are worse (14% median loss with 20% PV less) as there is already not enough generation to efficiently cover the needs of founding members, while in the overinvestment case, extra electricity surplus is available, which acts as a buffer to mitigate the losses of founding members (22% maximum loss with 20% additional PV).

Impact of Storage System in the Initial Optimal DERs Mix

Although batteries help to better benefit from solar production over the day, including them in the initial optimal sizing problem does not mitigate the deviation range in case of newcomers as we might expect; on the contrary, the magnitudes of the deviations is increased, as shown in Figure 8.5. Indeed, it is observed in the DERs optimal sizing, considering the same 10 initial EC configurations, that when batteries are added to the local energy mix and the PV capacity is not (or

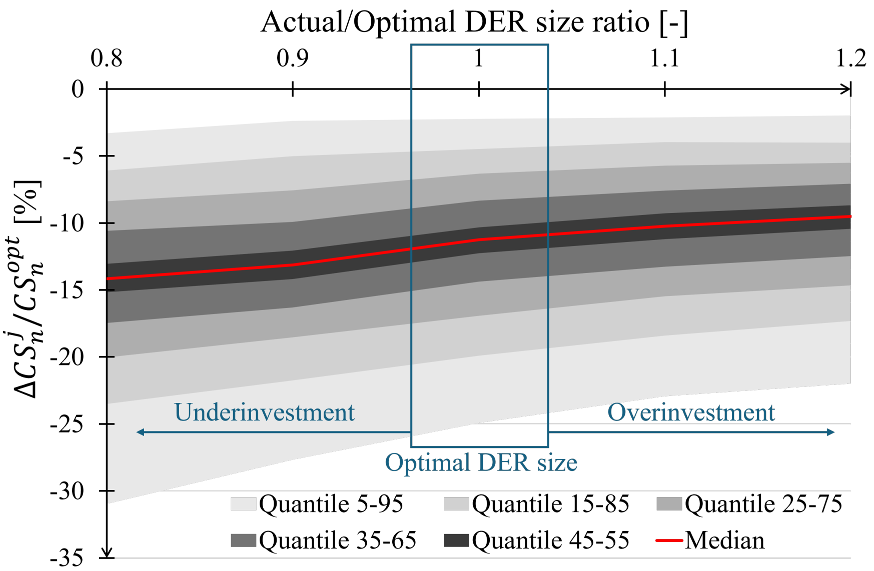


Figure 8.4.: Relative cost savings deviations distribution for different DER sizes.

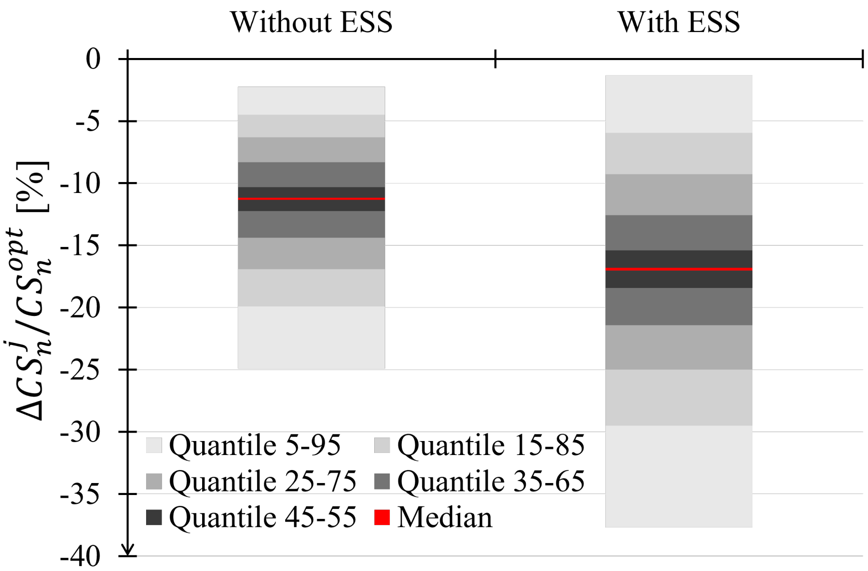


Figure 8.5.: Relative cost savings deviations distribution without and with optimal ESS.

slightly) increased, i.e., the storage is installed for more efficient/local use of the PV production (e.g., self-consumption increased by 21.1% on average). Therefore, founding members can expect initially higher cost savings when batteries are installed, but these benefits are dimmed when the EC composition evolves.

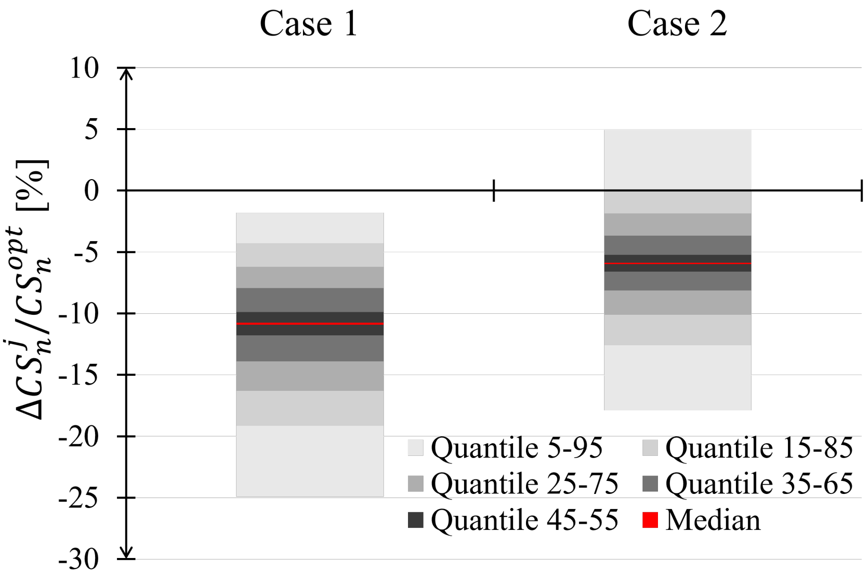


Figure 8.6.: Relative cost savings deviations distribution - Consumers perspective.

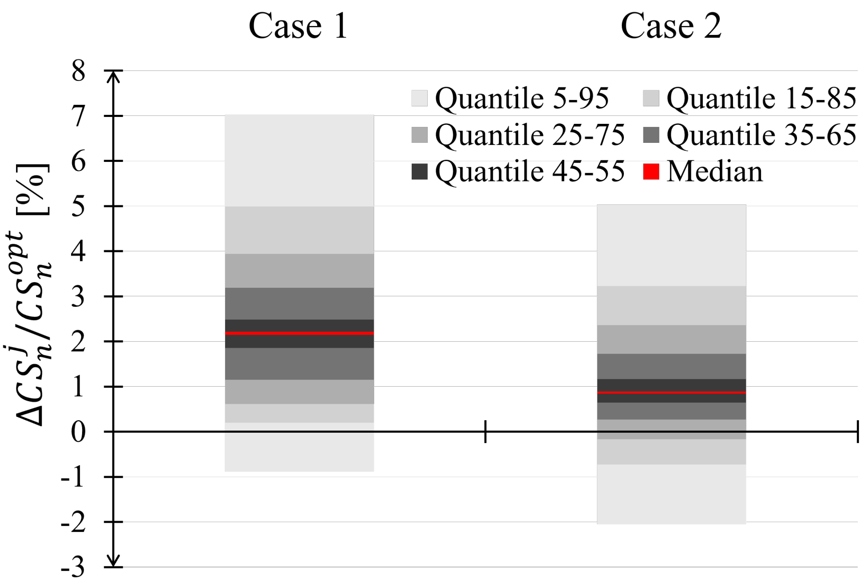


Figure 8.7.: Relative cost savings deviations distribution - Prosumers perspective.

Impact of End-users Profile

Finally, we investigate the situation in which end-users are not solely consumers but some of them may also be prosumers (i.e., they may own or invest in individual assets generating benefits from the sale of electricity surplus within and outside the

EC). Results presented in Figure 8.6 and 8.7 are obtained when allowing 50% of the founding members to also invest individually (on top of the joint investment) in the optimal sizing problem (PV only). Then for the EC's dynamic composition analysis, two cases are run: Case 1) Only consumers are added to the EC; Case 2) Consumers and prosumers may join the EC. In Case 2, there is a 50% chance that newcomers are prosumers and if they are, their PV capacity is randomly sampled between 10% and 100% of their upper bounds as defined previously.

From the founding consumers perspective, as already pointed out in Figure 8.4, adding other consumers (Case 1) to the EC tends to reduce their share of the local electricity pool and therefore degrading their savings as depicted in Figure 8.6 with a median savings loss of $\sim 10\%$. Conversely, prosumers of the initial EC see their arrival as a potential way to sell the extra surplus of electricity sold to the retailer in the initial situation. However, as the DER sizing is optimal for the initial EC configuration, the remaining electricity is limited, their median additional savings being much lower ($\sim 2\%$), as seen in Figure 8.7. Finally, in the most general framework (Case 2) in which the initial members and potential newcomers can either be consumers or prosumers, the relative cost savings deviations are mitigated compared to Case 1 as founding consumers will benefit from new prosumers surplus while being in competition with new consumers. From the initial prosumers perspective, new prosumers will reduce their contribution to the local electricity exchanges although new consumers increase the demand for local surplus.

8.4. Intermediate Conclusion

Through this work, we show that the expected cost savings of the founding members of an EC investing optimally in DER assets is significantly affected by newcomers, in the absence of any recourse action. Indeed, results collected on a test case composed of a set of 92 end-users show that initial members can lose up to 25% savings compared to the initial optimal sizing case while oversizing the assets dampens negative effects. The presence of storage in the initial DER mix increases the expected benefits of founding members, consequently increasing the negative cost deviations when newcomers join the community (up to 35% loss). Furthermore, we show that the impact of newcomers on the economics of the EC depends on their characteristics and on the founding members profiles. An important notice to bear in mind is that the individual perception of newcomers arrival also depends on the sharing rules considered in the EC. In future work, authors will address the management of EC's dynamic composition by taking actions (e.g., new investments, prices update, energy sharing rules adjustment) which would reduce its impact on founding members.

From an operational point of view, interaction between multiple agents can also give rise to uncertainty from human decisions. It is barely possible to accurately represent the behaviour of other actors. Hence, their true actions may deviate from the expected ones. In Chapter 9, the integration of such uncertainty is considered in a bilevel energy framework which adopts a hierarchical decision making structure.

CHAPTER 9.

On the Limited Observability of Energy Community Members

In Chapter 2, the operational organization of local exchanges relies on the gathering and the coordination of the different renewable production and flexible consumption resources of Energy Community (EC) members. The coordinated scheduling of these resources can be interpreted as an explicit flexibility provision mechanism for local arbitrage, i.e., taking advantage of the community attractive price with respect to those of retailers. Nevertheless, other relevant local electricity exchange structures have been proposed in the literature. In this section, a hierarchical community framework is rather considered. In this framework, two sets of actors are identified: the community manager (CM) and the EC participants, that are assumed to be profit-maximizing/cost-minimizing entities. The Community Manager is responsible for all the trades with external stakeholders and the local energy exchanges. The CM can be seen as an aggregator who gathers local consumers and prosumers and guarantees them a cost-attractive electricity supply service. To do so, it defines the local market price for the participants according to the dynamic retailer prices[1] and the local electricity to be shared. If a collective storage system is present in the EC, it also has the responsibility to manage its usage in order to balance the local production and demand. If needed, the CM purchase or sell extra volumes to a retailer. On the other hand, participants only trade electricity with the CM. Hence to optimize their electricity bills, they unlock flexibility in the consumption patterns, i.e., consumption increase or decrease, in response to the internal price that works as an implicit flexibility signal and considering their utility/comfort. This response as well as the price signal are scheduled one day-ahead of the settlement period as all flexible devices are not automated and require human actions. PV-equipped members also sell electricity to the CM to be used by other local consumers. A differentiation may be applied by the CM between

[1] The electricity supplier is not an actor of the EC but rather an external unit responding to power purchase/sell requests by the CM.

the local import and export prices.

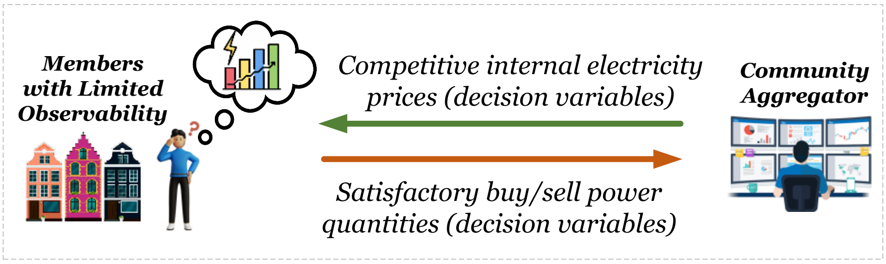


Figure 9.1.: Community manager and members interactions.

This hierarchical organization is formulated as a Stackelberg Game (SG) [200], [201] that is a form of strategic game which considers a leading actor and following actors. In the EC context considered in this section, the community manager is the leader who takes its actions first and the community members are the follower who decide sequentially [183], [184], [186], [192]. As the community manager is aware of its preferential position in the local decision-making sequence, if it wants to optimize its objective, then it needs to anticipate the optimal response of the followers. To estimate the end-users behaviour, the leader's optimisation problem contains a nested optimisation task that corresponds to the follower's optimisation problem. This formulation is called *bilevel optimisation* [202]. The interactions between the two set of actors are depicted in Figure 9.1.

When multiple agents interact with each other and have mutually an influence on one other decision-making, every actor tries to anticipate the behaviour of other to optimize its own actions. Accurately modelling others strategies is challenging, but on top of that, individuals may be influenced by external factors, i.e., not anticipated in the model, which would conduct to unexpected final decisions. Such phenomenon is at the core of the Bounded Rational Theory. This general concept representing the human tendency to deviate from its target has several variants. Among them, Prospect Theory is a key bounded rational modeling approach [190], [191], [192], [193], which focuses mainly on emotional factors that impact decision-making behavior by exploring how individuals value and react to gains and losses in decision scenarios based on a reference point.

In the context of information asymmetries, particularly in SGs modeled as bilevel problems where one party lacks perfect information about the strategies of the other party, an additional manifestation of bounded rationality emerges. This is commonly referred as Limited Observability. This theory considered the limited ability of one player to observe the actions of another. when a player of the Stackelberg game faces this uncertainty regarding other actors decisions, it can influence its own decision-making, potentially leading to a solution that is not necessarily optimal. Unlike data uncertainty, which arises from inaccuracies or inconsistencies in the data itself, decision uncertainty is rooted in the challenges of the decision-making process, such as incomplete information. Therefore, when limited observability emerges, decision-making under decision uncertainty is encountered [203].

This concept has been studied in recent works in operational research, where a player may face limited observability regarding the strategies made by another player in a bilevel framework. Wiesemann *et al* [204] introduced the ϵ-approximation approach to solve the bilevel problem under the limited observability of followers' decisions. The proposal concentrated on the independent case, wherein the lower-level feasible set remained unaffected by upper-level decisions. In [198], the authors generalized the ϵ-approximation approach by introducing the dependent near-optimal robust bilevel problem. Similar to [198], the authors in [199] presented a robust approach to address the limited observability of the lower-level follower's decision concerning the leader's decision. Besançon *et al.* [205] utilized anchoring biases to investigate the impact of limited observability of the follower on the leader's decision.

In the context of ECs the limited observability as a bounded rational behavior becomes even more evident. Despite their follower position, EC members might face limited observability regarding the final community manager strategies. Indeed, the internal electricity prices scheduled anticipate a rational consumption response of all members. Furthermore, they are subject to future retail price movements. However, the CM cannot fully anticipate unforeseen variations in the usage behavior of other members in real-time, which would result in a deviation in the actual internal electricity price. Consequently, after facing these prices deviations between the scheduled and the real-time periods, the members' decision-making process might be affected by this limited observability on the internal prices. Therefore, the members may adopt a more conservative behavior to mitigate the risk of unexpectedly high electricity bills.

In this context, this thesis investigates the influences of members' consumption behaviors on internal price variations and how the associated limited observability impacts their usage and trading behavior. To this end, this works adapts the rational bilevel problem to integrate the limited observability of community users regarding the strategies of the community manager in the form of a near-optimality robustness bilevel energy sharing problem. The limited observability is conceptualized by considering the internal price as an endogenous uncertainty factor in the lower-level problem. The scheduling of individual consumption patterns and the consequent energy exchanges with the CM assumes that the real-time price may deviate by a pre-defined amount around the value sent by the CM. In addition to these major contributions, PV generation uncertainty is considered to assess how users mitigate decision and data uncertainties during the real-time operation of the EC according to the proposed method. This extends the literature by combining the two categories of uncertainty, i.e., exogenous and endogenous, in EC problems. In addition, as depicted in Figure 9.2, this study assumes the EC is a node of the backbone distribution network. Therefore, the EC trades with the upstream grid should adhere to network constraints.

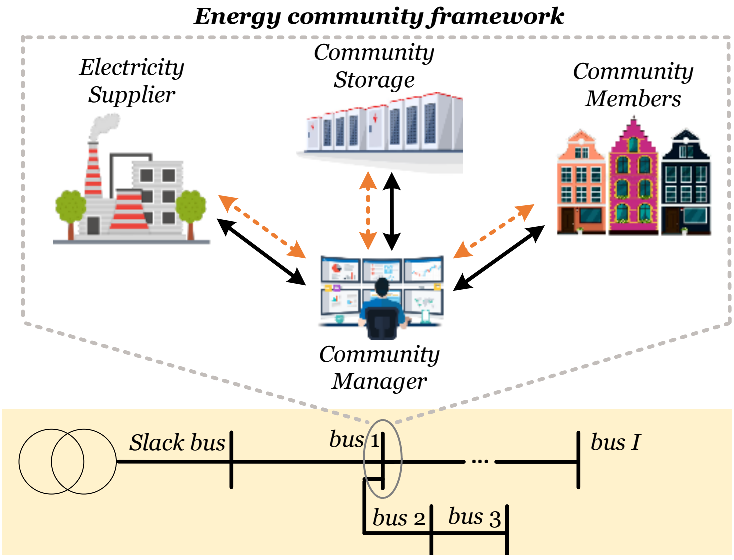


Figure 9.2.: Bilevel Energy Community framework.

The rest of the section is organized as follows. In Sections 9.1 and 9.2, the methodology is presented in detail, integrating the original formulation of the energy sharing problem and the proposed robust formulation with considerations of the limited observability of EC members. Next, Section 9.3 provides case studies and analyzes simulation results, demonstrating the implications of the proposed approach. Finally, Section 9.4 offers key take-away messages as outcomes of the study.

The main contributions presented here after have been published in the following article:

[23] J. Faraji, J. Allard, F. Vallée, and Z. De Grève, "On the limited observability of energy community members: An uncertainty-aware near-optimal bilevel programming approach," Applied Energy, vol. 381, pp. 125-177, 2025.

9.1. Bilevel Energy Sharing Problem

The problem is initially formulated under the assumption of perfect rational behavior by end-users. In the proposed EC, the interactions between actors is akin to a Stackelberg Game structure, with the CM acting as the leader and community members as followers. The uncertainty of end-users' PV power generation (data uncertainty) is considered using scenario-based stochastic programming. Therefore, the SG is formulated as a stochastic bilevel programming problem. Within this framework, competition arises regarding internal electricity prices and internal exchange responses of the users, with each player seeking to maximize their own benefits/minimize their electricity cost. Let $\mathcal{N}$ be the set of community members, $\mathcal{W}$ the set of PV generation scenarios, and $\mathcal{T}$ the set of time steps within a day, the original stochastic bilevel problem is written as:

$$\max_{\Omega^U,\Omega^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}} \Big(\underbrace{\lambda_t^{ret,s} E_{w,t}^s - \lambda_t^{ret,b} E_{w,t}^b}_{O_1} + \sum_{n\in\mathcal{N}} \underbrace{\lambda_t^{com,s} e_{n,w,t}^b - \lambda_t^{com,b} e_{n,w,t}^s}_{O_2} \\ \underbrace{-\big(\lambda_t^{grid,cmp} E_{w,t}^b + \sum_{n\in\mathcal{N}} \lambda_t^{grid,loc} e_{n,w,t}^b \big)}_{O_3} \Big) \Bigg] \tag{9.1}$$

s.t. Upper-level constraints (9.1a)-(9.1z)

$$e_{n,w,t}^b, e_{n,w,t}^s \in \Bigg\{ \arg\max_{\Omega_n^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}} \Big(\underbrace{U_{n,t}}_{O_4} + \underbrace{\lambda_t^{com,b} e_{n,w,t}^s - \lambda_t^{com,s} e_{n,w,t}^b}_{O_5} \Big) \Bigg] \tag{9.2}$$

$$\text{s.t. Lower-level constraints (9.2a)-(9.2d)} \Bigg\}, \forall n \in \mathcal{N}.$$

with $\Omega^U := \{E_{w,t}^s, E_{w,t}^b, \lambda_t^{com,s}, \lambda_t^{com,b}, s_{w,t}^{ch}, s_{w,t}^{dis}, soc_{w,t}\}$ and $\Omega^L := \{b_{n,t}, e_{n,w,t}^b, e_{n,w,t}^s\}$ are the set of CM's (upper-level) and members' (lower-level) decision variables, respectively. When dealing with optimisation problems under uncertainty, decision variables can be classified as: first-stage and second-stage variables [166]. First-stage variables, also called *here-and-now* variables, must be decide before the realization of the uncertain parameters is known, i.e., PV generation in this work. In this day-ahead scheduling problem, the here-and-now decisions are the internal exchange prices at which the community manager sells and buys electricity to the members, $\lambda_t^{com,s}$ and $\lambda_t^{com,b}$. For the end-users the only variable schedule ahead is the power load consumption, $b_{n,t}$. On the other hand, second-stage variables, or *wait-and-see* variables, are taken in response to the realization of the uncertain parameters. In the problem addressed in this section, these variables refer to those whose final decisions will be taken in real-time. These variables have an additional dimension w. For the CM they represent the energy purchased, $E_{w,t}^b$, and sold, $E_{w,t}^{st}$, from/to the retailer and the variables related to the use of the collective storage system that are the power charged, $s_{w,t}^{ch}$, and discharged, $s_{w,t}^{dis}$, and the battery state-of-charge, $soc_{w,t}$. The second-stage variables of the CM enables him to balance the local production and demand. Finally, from the end-users perspective, the realization of the PV generation will affect their internal volume exchanges, $e^b_{n,w,t}$ and, $e^s_{n,w,t}$.

(9.1) formulates the expected profit maximization problem of the leader (CM) within a 24-hour dispatching horizon. The objective function is composed of three terms. Term O_1 represents exchange revenues with the retailer when their is either a collective surplus of deficit of electricity, term O_2 shows exchange revenues with community members, and term O_3 denotes grid costs with different grid fees for the locally exchanged and complementary volumes. In this work, the regulation adopted in Brussels is considered. In Brussels, energy community members are benefiting from discounts on grid tariffs for electricity which is exchanged locally at the community level [15]. Therefore, under this tariff structure, local grid fees ($\pi^{grid,loc}_t$) are paid for any electricity consumed from the distribution grid by EC members and an additional fee is charged ($\pi^{grid,cmp}_t$) when the electricity must be supplied from outside the community. This tariffs aims to encourage energy communities to consume PV generation locally. In the lower-level problem, the followers' objective function comprised of two terms according to (9.2). Term O_4 represents consumption utility of individuals, and term O_5 denotes energy exchange revenues with the CM at internal electricity prices. Including a utility function is a way to represent the loss of comfort associated with a shift in the typical consumption pattern. The following quadratic formulation of this utility function frequently used in previous studies [206], [207] is considered in this work:

$$U_{n,t} = -\pi^{ut,a}_n (b_{n,t} - b^{ref}_{n,t})^2 + \pi^{ut,b}_n (b_{n,t} - b^{ref}_{n,t}) \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}. \tag{9.3}$$

As such the utility function quantifies the deviation between the actual consumption profiles, $b_{n,t}$ and the target consumption profiles $b^{ref}_{n,t}$, where parameter $\pi^{ut,a}_n$ indicates the level of risk aversion preference and $\pi^{ut,b}_n$ represents the marginal utility of consumption based on a price reference, i.e, the threshold price which determines if a consumer agrees to increase or decrease its consumption level. According to the proposed discomfort function, users might increase or decrease their load consumption rather than indiscriminately reducing consumption based on the marginal utility of the load consumption and marginal exchange cost in O_5.

9.1.1. Upper-level constraints

The upper-level objective in (9.1) is subject to several constraints when solving its day-ahead dispatch problem. More specifically, the CM has four main responsibilities when coordinating the local exchanges of electricity. The first one is to guarantee the equilibrium of physical and economic flows within the community. To achieve so, it can trade electricity with a retailer or use the collective storage system. Its second responsibility is therefore related to the conscious management of the storage unit to respect the physical limits of the device. Then, regarding the other balancing lever, as we consider that all the users connected to the same low-voltage distribution feeder are part of the community, the complementary electricity economically traded (i.e., purchased or sold) with the retailer necessarily comes from the upstream distribution network layers. In this work, the responsibility to respect the network limits when withdrawing or injecting electricity at the point of common coupling of the EC is given to the CM. Finally, the CM must ensure that local prices are more competitive with the retailer prices to secure the participation of end-users in the local structure.

Economic and physical balancing constraints of the community manager are expressed in (9.1a)-(9.1c). The first one ensures that the power traded with the retailer and the usage of the local storage system covers the needs of the end-users. Meanwhile, the second constraint denotes nodal level power exchanges of the EC with the distribution system. The studies portion of the distribution grid includes a set of nodes $\mathcal{ND}$ and the node to which the REC is connected is denoted nd'.

$$E^{b}_{w,t} - E^{s}_{w,t} = \left(s^{ch}_{w,t} - s^{dis}_{w,t}\right)\Delta t + \sum_{n\in\mathcal{N}} \left(e^{b}_{n,w,t} - e^{s}_{n,w,t}\right), \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1a)$$

$$P^{inj}_{nd=\{nd'\},w,t}\Delta t = E^{s}_{w,t} - E^{b}_{w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1b)$$

$$E^{b}_{w,t} \geq 0, \quad E^{s}_{w,t} \geq 0, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \quad (9.1c)$$

The operational constraints of the collective storage units introduce an additional binary variable, $z^{st}_{w,t}$, to avoid simultaneous charge and discharge. The set of state-of-the-art [208] constraints are presented in (9.1d)-(9.1i).

$$soc_{w,t} = soc_{w,t-1} + (\eta^{ch} s^{ch}_{w,t} - s^{dis}_{w,t} \big/ \eta^{dis})\Delta t, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1d)$$

$$soc_{w,0} = soc_{w,T}, \qquad \forall w \in \mathcal{W}, \quad (9.1e)$$

$$\underline{SOC} \leq soc_{w,t} \leq \overline{SOC}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1f)$$

$$0 \leq s^{ch}_{w,t} \leq P^{st} z^{st}_{w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1g)$$

$$0 \leq s^{dis}_{w,t} \leq P^{st}(1 - z^{st}_{w,t}), \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1h)$$

$$z^{st}_{w,t} \in \{0, 1\}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \quad (9.1i)$$

In this work, we want to avoid that CM uses the storage system to perform some arbitrage based on the dynamic retailer tariffs, i.e., charging at low price to sell at high price, and rather use it to cover the community needs only. To do so, the charging and discharging power of the storage unit are respectively limited to the surplus power sold by the prosumers and power demand of the members in (9.1j)-(9.1k).

$$\sum_{n\in\mathcal{N}} e^{s}_{n,w,t} \geq s^{ch}_{w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \quad (9.1j)$$

$$\sum_{n \in \mathcal{N}} e^{b}_{n,w,t} \geq s^{dis}_{w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \tag{9.1k}$$

To model the interactions of the community with the upstream distribution network, the second-order cone relaxation of power flow equations for radial configurations is used [106] as in previous chapters. This formulation offers a balanced approach by relaxing the initial non-convex power flow equations, yet effectively considering power losses and maintaining computational tractability. It reduces to the following constraints:

$$P^{\text{inj}}_{nd,w,t} + P^{\text{line}}_{nd,w,t} - R_{nd} I^{\text{sqr}}_{nd,w,t} = \sum_{c \in \mathcal{C}_{nd}} P^{\text{line}}_{c,w,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{9.1l}$$

$$P^{\text{inj}}_{nd_{tf},w,t} = \sum_{c \in \mathcal{C}_{nd_{tf}}} P^{\text{line}}_{c,w,t}, \qquad \forall t \in \mathcal{T}, \tag{9.1m}$$

$$Q^{\text{inj}}_{nd,w,t} + Q^{\text{line}}_{nd,w,t} - X_{nd} I^{\text{sqr}}_{nd,w,t} = \sum_{c \in \mathcal{C}_{nd}} Q^{\text{line}}_{c,w,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{9.1n}$$

$$Q^{\text{inj}}_{nd_{tf},t} = \sum_{c \in \mathcal{C}_{nd_{tf}}} Q^{\text{line}}_{c,w,t}, \qquad \forall t \in \mathcal{T}, \tag{9.1o}$$

$$\begin{aligned} V^{\text{sqr}}_{nd,w,t} = V^{\text{sqr}}_{up_{nd},w,t} &- 2(R_{nd} P^{\text{line}}_{nd,w,t} + X_{nd} Q^{\text{line}}_{nd,w,t}) \\ &+ (R^2_{nd} + X^2_{nd}) I^{\text{sqr}}_{nd,w,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \end{aligned} \tag{9.1p}$$

$$V^{\text{sqr}}_{nd_{tf},w,t} = V^{\text{sqr},ref}, \qquad \forall t \in \mathcal{T}, \tag{9.1q}$$

$$I^{\text{sqr}}_{nd,w,t} V^{\text{sqr}}_{up_{nd},w,t} \geq P^{\text{line}^2}_{nd,w,t} + Q^{\text{line}^2}_{nd,w,t}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{9.1r}$$

$$V^{\text{sqr},min} \leq V^{\text{sqr}}_{nd,w,t} \leq V^{\text{sqr},max}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}, \tag{9.1s}$$

$$I^{\text{sqr}}_{nd,w,t} \leq I^{\text{sqr},max}_{nd}, \qquad \forall nd \in \mathcal{ND}, \forall t \in \mathcal{T}. \tag{9.1t}$$

where nd_{tf} is the substation node, and the nd index also denotes the electrical line reaching node $nd \in \mathcal{ND}$ from the node upstream, up_{nd}, with impedance $Z_{nd} = R_{nd} + jX_{nd}$. Finally, $\mathcal{C}_{nd}$ is the set of downstream nodes of node nd in the oriented graph of the electrical network. Constraints (9.1l)-(9.1o) represents the nodal active power, P, and reactive power balance, Q. The voltage drop across a line (i.e., its squared magnitude) is expressed in (9.1p) with the reference voltage being maintained at the substation node through (9.1q). The relaxed quadratic constraint defining the apparent power exchanged through a line is expressed in (9.1r). Lastly, the physical network limits consist in the (squared) line current threshold (9.1t) and the safe (squared) node voltages range (9.1s). The latter is set to $\pm 10\%$ of the nominal voltage according to the EN 50160 standard [107].

The last set of constraints relate to the attractiveness of internal exchange prices, both for import and export, with respect to standard retailer tariffs to convince end-users participating in the community. The limits are described in constraints

(9.1w)-(9.1z). The limits also embed the grid tariffs indirectly charged to end-users by the CM. ϵ is set to 0.5 in this study to ensure internal price equity. This strategy aims to encourage users to engage in internal electricity transactions with the CM. According to the proposed pricing mechanism, users pay a uniform internal price to the CM. This price is more competitive than the sum of commodity and grid fees associated with exchanges with the upstream supplier.

$$\underline{\lambda_t^{com,b}} \leq \lambda_t^{com,b} \leq \overline{\lambda_t^{com,b}}, \qquad \forall t \in \mathcal{T}, \tag{9.1u}$$
$$\underline{\lambda_t^{com,s}} \leq \lambda_t^{com,s} \leq \overline{\lambda_t^{com,s}}, \qquad \forall t \in \mathcal{T}, \tag{9.1v}$$
$$\underline{\lambda_t^{com,b}} = \left(\lambda_t^{ret,b} + \lambda_t^{grid,loc} + \lambda_t^{grid,cmp}\right)(1-\epsilon) - \lambda_t^{ret,s}\epsilon, \qquad \forall t \in \mathcal{T}, \tag{9.1w}$$
$$\overline{\lambda_t^{com,b}} = \lambda_t^{ret,b} + \lambda_t^{grid,loc} + \lambda_t^{grid,cmp}, \qquad \forall t \in \mathcal{T}, \tag{9.1x}$$
$$\underline{\lambda_t^{com,s}} = \lambda_t^{ret,s}, \qquad \forall t \in \mathcal{T}, \tag{9.1y}$$
$$\overline{\lambda_t^{com,s}} = \lambda_t^{ret,b} - \left(\lambda_t^{ret,b} - \lambda_t^{ret,s}\right)\epsilon, \qquad \forall t \in \mathcal{T}. \tag{9.1z}$$

9.1.2. Lower-level constraints

Thanks to its preferential position in the hierarchical structure of the EC, the CM takes its decisions before the community members. Hence, the expected lower-level response can be anticipated when scheduling its internal prices to optimize its objective. This integration of the lower-level optimal load scheduling problem is represented by equation (9.2). Based on the internal prices offered by the CM, the end-users will unlock some flexibility in there consumption to minimize their bill while accounting for the loss of comfort generated by the consumption shifts. This sub-problem is also subject to some constraints relative to the flexibility potential in the consumption behaviour and the electricity volumes that are allowed to be traded.

$$e_{n,w,t}^b - e_{n,w,t}^s = \big(b_{n,t} - g_{n,w,t}\big)\Delta t : \delta_{n,w,t}, \qquad \forall n \in \mathcal{N}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \tag{9.2a}$$
$$\underline{b_{n,t}} \leq b_{n,t} \leq \overline{b_{n,t}} : \underline{\gamma}_{n,t}, \overline{\gamma}_{n,t}, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{9.2b}$$
$$0 \leq e_{n,w,t}^b \leq \overline{e_{n,t}^b} : \underline{\nu}_{n,w,t}, \overline{\nu}_{n,w,t}, \qquad \forall n \in \mathcal{N}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \tag{9.2c}$$
$$0 \leq e_{n,w,t}^s \leq \overline{e_{n,t}^s} : \underline{\vartheta}_{n,w,t}, \overline{\vartheta}_{n,w,t}, \qquad \forall n \in \mathcal{N}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \tag{9.2d}$$

The individual balances of lower-level actors is presented in (9.2a). The scheduled power consumption may deviate from the reference profile as long as they respect the flexibility limits of end-users via (9.2b). The resulting net electricity volume after self-consumption of the potential PV generation, $g_{n,w,t}$, either results in a net import/purchase or a net export/sale. These net import and export quantities are capped by constraints (9.2c) and (9.2d). The dual variables, i.e., greek symbols after the ":" sign, associated with each of the lower-level constraints are indicated as they are useful for the resolution of the full bilevel problem (9.1).

9.2. Integration of Bounded Rationality in the Problem

In the original stochastic bilevel problem presented in Section 9.1, it has been assumed that the users are perfectly rational. As discussed in the introduction of this work, this assumption may not hold in the proposed framework. Therefore, the uncertainty in users' responses due to their limited observability of the CM's decisions is accounted for in the following reformulation. This translates into an uncertainty for the followers regarding the actual internal prices traded with the leader in real-time, $\lambda_t^{com,b}$ and $\lambda_t^{com,s}$, i.e., representing decision uncertainties. Hence, EC members prefer to schedule their consumption based on uncertain prices, $\widetilde{\lambda}_t^{com,b}$ and $\widetilde{\lambda}_t^{com,s}$, belonging to the given uncertainty set $\mathcal{U}(\widetilde{\boldsymbol{\lambda}})$. The set of potential realizations is centred around the offered prices with a range of disturbances predefined based on past observations of the actual prices deviations between day-ahead scheduling and real-time settlement periods. The robustified lower-level problem is thereby written as follows which enables users to avoid potential welfare losses yet leading to near-optimal responses:

$$\max_{\Omega^U,\Omega^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}} \Big(\lambda_t^{ret,s} E_{w,t}^s - \lambda_t^{ret,b} E_{w,t}^b + \sum_{n\in\mathcal{N}} \lambda_t^{com,s} e_{n,w,t}^b - \lambda_t^{com,b} e_{n,w,t}^s$$

$$-\big(\lambda_t^{grid,cmp} E_{w,t}^b + \sum_{n\in\mathcal{N}} \lambda_t^{grid,loc} e_{n,w,t}^b\big)\Big)\Bigg] \tag{9.4}$$

s.t. Upper-Level constraints (9.1a)-(9.1z)

$$e_{n,w,t}^b, e_{n,w,t}^s \in \Bigg\{ \arg\max_{\Omega_n^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}} U_{n,t} + \Big\{ \min_{\widetilde{\boldsymbol{\lambda}}\in\mathcal{U}(\widetilde{\boldsymbol{\lambda}})} \widetilde{\lambda}_t^{com,b} e_{n,w,t}^s - \widetilde{\lambda}_t^{com,s} e_{n,w,t}^b \Big\}\Bigg]$$

$$\text{s.t. Lower-Level constraints (9.2a)-(9.2d)} \Bigg\}, \forall n \in \mathcal{N}. \tag{9.5}$$

The endogenous uncertainty set is represented in matrix notation $\mathcal{U}(\widetilde{\boldsymbol{\lambda}})$, which is a feasible robustified set with $\widetilde{\boldsymbol{\lambda}} \in \mathbb{R}^r$ as the uncertain observations vector of CM's decisions. The uncertainty set can be parameterized in an affine way as (9.6) [199].

$$\mathcal{U}(\widetilde{\boldsymbol{\lambda}}) = \{\widetilde{\boldsymbol{\lambda}} = \boldsymbol{\lambda} + \boldsymbol{\zeta} : \boldsymbol{\zeta} \in \mathcal{Z} \subseteq \mathbb{R}^r\} \tag{9.6}$$

where $\boldsymbol{\lambda} \in \mathbb{R}^r$ is the vector of CM's scheduled strategy, $\boldsymbol{\zeta}$ is the vector of internal prices deviation which belongs to the perturbation uncertainty set $\mathcal{Z}$. The following represents the general form of this perturbation set.

$$\mathcal{Z} = \{\boldsymbol{H}\boldsymbol{\zeta} \geq \boldsymbol{h} : \boldsymbol{h} \in \mathbb{R}^r, \boldsymbol{H} \in \mathbb{R}^{r \times s}\} \tag{9.6a}$$

The internal price deviation vector, $\boldsymbol{\zeta}$, is bounded by certain constraints according to $\boldsymbol{H}$ and $\boldsymbol{h}$ values. A polyhedral perturbation set was employed in this study, as illustrated in Figure 9.3. Therefore, the perturbation set can be displayed in the form of boundary constraints. Let $j \in \mathcal{J}$ denote the index of each perturbation set boundaries [2], the boundary constraints are then defined as follows.

$$\hat{\alpha}_t^j \zeta_{n,w,t}^b + \hat{\beta}_t^j \zeta_{n,w,t}^s \geq \hat{\Theta}_t^j \quad \forall j \in \mathcal{J}, \forall t \in \mathcal{T} \tag{9.6b}$$

In above, $\hat{\alpha}_t^j$, $\hat{\beta}_t^j$, and $\hat{\Theta}_t^j$ represent the parameters associated with each boundary $j \in \mathcal{J}$, which need to be precisely defined for each perturbation set understudy. For the polyhedral perturbation set in Figure 9.3, the parameters can be represented in the following manner.

$$\begin{aligned}
&\begin{pmatrix} \hat{\alpha}_t^1 & \hat{\alpha}_t^2 \\ \hat{\alpha}_t^3 & \hat{\alpha}_t^4 \end{pmatrix} = \begin{pmatrix} -1 & -1 \\ 1 & 1 \end{pmatrix}, \\
&\begin{pmatrix} \hat{\beta}_t^1 & \hat{\beta}_t^2 \\ \hat{\beta}_t^3 & \hat{\beta}_t^4 \end{pmatrix} = \begin{pmatrix} m_t^1 & m_t^2 \\ -m_t^3 & -m_t^4 \end{pmatrix}, \\
&\begin{pmatrix} \hat{\Theta}_t^1 & \hat{\Theta}_t^2 \\ \hat{\Theta}_t^3 & \hat{\Theta}_t^4 \end{pmatrix} = \begin{pmatrix} m_t^1 \overline{\zeta}_t^s - \mu_t^b & m_t^2 \underline{\zeta}_t^s - \mu_t^b \\ -m_t^3 \overline{\zeta}_t^s + \mu_t^b & -m_t^4 \underline{\zeta}_t^s + \mu_t^b \end{pmatrix} \quad \forall t \in \mathcal{T}
\end{aligned} \tag{9.6c}$$

where μ_t^b and μ_t^s represent the mean values of deviation variables boundaries acknowledging that the coordinate center might not be zero for these variables. Also, m_t^1, m_t^2, m_t^3 and m_t^4 denote the slopes of the equivalent boundaries, defined as follows.

$$\begin{pmatrix} m_t^1 & m_t^2 \\ m_t^3 & m_t^4 \end{pmatrix} = \begin{pmatrix} \frac{\overline{\zeta}_t^b - \mu_t^b}{\mu_t^s - \overline{\zeta}_t^s} & \frac{\overline{\zeta}_t^b - \mu_t^b}{\mu_t^s - \underline{\zeta}_t^s} \\ \frac{\underline{\zeta}_t^b - \mu_t^b}{\mu_t^s - \overline{\zeta}_t^s} & \frac{\underline{\zeta}_t^b - \mu_t^b}{\mu_t^s - \underline{\zeta}_t^s} \end{pmatrix} \quad \forall t \in \mathcal{T} \tag{9.6d}$$

The polyhedral perturbation set requires an appropriate determination of perturbation set boundaries for the internal price deviation variables, $\zeta_{n,w,t}^b, \zeta_{n,w,t}^s$. In the following section, a strategy for deriving perturbation set boundaries, which takes into account the real-time consumption behavior of members as the main

[2] Polyhedral perturbation sets with two uncertain variables are typically characterized by four boundaries; thus, $|\mathcal{J}| = 4$ was set in this study.

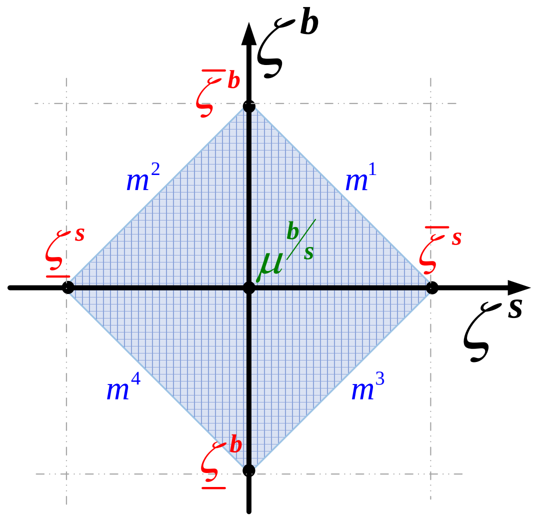


Figure 9.3.: Polyhedral endogenous uncertainty set boundaries for each time t.

factor of limited observability among community members, is outlined.

9.2.1. Uncertainty Perturbation Set Delimitation

By defining near-optimality robustness in the lower-level problem, community members hedge against unforeseen deviations associated with real-time internal prices (upper-level decision variables) that may affect the equilibrium point and consequently their decisions. The impact of members' consumption behavior on the deviations between scheduled and real-time internal prices is analyzed in this section. This analysis provides an appropriate characterization of the internal price perturbation sets and more specifically their boundaries. Algorithm 6 depicts the procedure used for delimiting the uncertainty set boundaries. Initially, the rational profit-maximizing problem in (9.1)-(9.2) is solved for a whole year in a deterministic way by taking the median of the PV scenarios into account, and then optimal values including the objective functions of the different actors and their decision variables are extracted. Afterwards, based on the actual (optimal) consumption profiles, cumulative distribution functions (CDFs) of the deviations from the target consumption profiles are computed for each hour of the day. The computed CDFs are used to represent the potential variations between the scheduled and real-time consumption behaviors. Under the assumption of perfectly forecasted retailer prices, the real-time internal prices are computed by solving the modified upper-level problem in (9.7). Specifically, this problem aims to minimize the deviation of the upper-level objective function value, F, from the scheduled optimal value, denoted as F^*, while adhering to the upper-level constraints and accounting for the perturbed members' power exchanges.

$$\begin{aligned} &\min_{\tilde{\Omega}^U}(|\tilde{F}(\tilde{\Omega}^L) - F^*|) \\ &\text{s.t.} \quad (9.1a) - (9.1y) \end{aligned} \tag{9.7}$$

Hourly probability distribution functions (PDFs) for deviations in internal electricity prices are obtained by iteratively simulating the operational days of the year. Finally, perturbation range boundaries are defined using the 99^{th} and 1^{st} percentiles of the PDFs. The procedure is iterated until either the confidence interval boundaries converge or the iteration limit, $iter_{max}$, is reached. The convergence criterion ensures that the maximum deviation in any boundary value between two consecutive iterations does not exceed the tolerance level, tol.

Algorithm 6: Delimitation of the internal prices perturbation ranges

Solve problem (9.1)-(9.2) for a full year $\rightarrow F^*, \Omega^{U*}, \Omega^{L*}$;
Compute, $\forall n \in \mathcal{N}$, the hourly cumulative distribution function (CDF) of consumption deviations from the target consumption, $b_{n,t} - b_{n,t}^{ref}$;
Initialize iteration index $i = 1$;
Initialize convergence criterion value $c = \infty$;
while $c > tol$ & $i \leq iter_{max}$ **do**
  for *each day of the year,* $d \in \mathcal{D}$ **do**
    for *each time period of the day,* $t \in \mathcal{T}$ **do**
      for *each member of the EC,* $n \in \mathcal{N}$ **do**
        Draw a random deviation sample from the CDF $\rightarrow \Delta b_{n,t}$;
        $\tilde{b}_{n,t} = b_{n,t}^* - \Delta b_{n,t}$;
        $\tilde{e}_{n,t}^b, \tilde{e}_{n,t}^s \leftarrow$ (9.2a);
      end
    end
    Compute the optimal real-time internal prices:
    $\tilde{\lambda}_t^{com,s}, \tilde{\lambda}_t^{com,b} \in \underset{\tilde{\Omega}^U}{\operatorname{argmin}}(|\tilde{F}(\tilde{\Omega}^L) - F^*|)$ s.t. (9.1a)-(9.1y);
  end
  Compute the hourly PDF of deviations in internal electricity prices and define the perturbation range boundaries as 99^{th} and 1^{st} percentiles:
  $\zeta^{b/s} = \tilde{\lambda}^{com,b/s} - \lambda^{com,b/s^*}$;
  $\overline{\zeta}^{b/s}, \underline{\zeta}^{b/s} \leftarrow P_{99}(\zeta^{b/s}), P_1(\zeta^{b/s})$;
  if $i > 1$ **then**
    Update the convergence criterion value:
    $c = \max(|\overline{\zeta}^i - \overline{\zeta}^{(i-1)}|, |\underline{\zeta}^i - \underline{\zeta}^{(i-1)}|)$;
  end
end

9.2.2. Solution Method

The bilevel problem presented above is an NP-hard problem which can not be directly solved using off-the-shelve solvers. The problem is analytically reformulated into a single-level problem that can be directly solved. In the first step, decision uncertainties arising from the limited observability of internal prices in the followers' problem's objective function are handled. Using epigraphical reformulation, the uncertainty set is transformed into a convex constraint with a linear auxiliary variable in the objective function. The epigraphical reformulation of each member lower-level problem (9.4) is represented in (9.8)[199].

$$\min_{\tau_n, \Omega_n^L} \quad \tau_n \tag{9.8}$$

$$\text{s.t.} \quad \sum_{t \in \mathcal{T}} \left[- U_{n,t} + \max_{\widetilde{\boldsymbol{\lambda}} \in \mathcal{U}(\widetilde{\boldsymbol{\lambda}})} \sum_{w \in \mathcal{W}} p_w \left[\widetilde{\lambda}_t^{com,s} e_{n,w,t}^b - \widetilde{\lambda}_t^{com,b} e_{n,w,t}^s \right] \right] \leq \tau_n, \tag{9.8a}$$

Lower-level constraints (9.2a)-(9.2d)

with p_w, the probability of occurence of each PV generation scenario considered. By using the epigraphical reformulation (9.8), the uncertainty is only present in constraint (9.8a). In addition, when expressing the uncertainty set, $\mathcal{U}(\widetilde{\boldsymbol{\lambda}})$, in terms of affine parameters, constraint (9.8a) can be formulated as below.

$$\sum_{t \in \mathcal{T}} \Bigg[- U_{n,t} + \sum_{w \in \mathcal{W}} p_w \left[\lambda_t^{com,s} e_{n,w,t}^b - \lambda_t^{com,b} e_{n,w,t}^s \right] + \max_{\boldsymbol{\zeta} \in \mathcal{Z}} \sum_{w \in \mathcal{W}} p_w \left[\zeta_{n,w,t}^s e_{n,w,t}^b - \zeta_{n,w,t}^b e_{n,w,t}^s \right] \Bigg] \leq \tau_n. \tag{9.8c}$$

For given values of local electricity exchanges $e_{n,w,t}^b$ and $e_{n,w,t}^s$. Solving the inner optimisation problem in (9.8c) is tantamount to the solution of the following linear problem that aims to maximize the deviation in the lower-level objective while respecting the boundaries $j \in \mathcal{J}$ of the polyhedral uncertainty set.

$$\max_{\boldsymbol{\zeta} \in \mathcal{Z}} \quad \sum_{w \in \mathcal{W}} p_w \left[\zeta_{n,w,t}^s e_{n,w,t}^b - \zeta_{n,w,t}^b e_{n,w,t}^s \right] \tag{9.9}$$

$$\text{s.t.} \quad \hat{\alpha}_t^j \zeta_{n,w,t}^b + \hat{\beta}_t^j \zeta_{n,w,t}^s \geq \hat{\Theta}_t^j : \varrho_{n,w,t}^j, \quad \forall j \in \mathcal{J}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T} \tag{9.9a}$$

To remove the max operator of constraint (9.8a), one can rely on the Strong-Duality Theory. Following this theory, the dual objective value of a given optimisation problem is strictly equal to its primal objective value when it reaches the global optimum solution [209]. Let's define $\varrho_{n,w,t}^j$ as the dual variables associated with the boundary constraints in (9.9a). The dual problem of (9.9) is derived as follows:

$$\min_{\varrho^j_{n,w,t}} \quad \sum_{w\in\mathcal{W}}\sum_{j\in\mathcal{J}} \varrho^j_{n,w,t}\hat{\Theta}^j_t \tag{9.10}$$

$$\text{s.t.} \quad p_w e^b_{n,w,t} + \sum_{j\in\mathcal{J}} \varrho^j_{n,w,t}\hat{\beta}^j_t = 0 : \chi_{n,w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \tag{9.10a}$$

$$- p_w e^s_{n,w,t} + \sum_{j\in\mathcal{J}} \varrho^j_{n,w,t}\hat{\alpha}^j_t = 0 : \kappa_{n,w,t}, \qquad \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \tag{9.10b}$$

$$\varrho^j_{n,w,t} \geq 0 : \rho^j_{n,w,t}, \qquad \forall j \in \mathcal{J}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \tag{9.10c}$$

By replacing the maximisation problem by its associated dual formulation in (9.8), the robust counterpart of the lower-level problem under limited observability of CM internal prices can be derived as follows:

$$\min_{\tau_n,\Omega^L_n} \quad \tau_n \tag{9.11}$$

s.t. Lower-level primal constraints (9.2a)-(9.2d)

$$\sum_{t\in\mathcal{T}}\Bigg[- U_{n,t} + \sum_{w\in\mathcal{W}} p_w\Big[\lambda^s_t e^b_{n,w,t} - \lambda^b_t e^s_{n,w,t}\Big] - \sum_{w\in\mathcal{W}}\sum_{j\in\mathcal{J}} \varrho^j_{n,w,t}\hat{\Theta}^j_t\Bigg] \leq \tau_n : \varsigma_n \tag{9.11a}$$

Inner optimisation dual constraints (9.10a)-(9.10c)

As the resulting robust formulation of the lower-level problem is convex for each fixed upper-level decisions, it can be replaced by its Karush-Kuhn-Tucker (KKT) conditions [88] such that the bilevel problem becomes a single-level optimisation problem that can be solved by off-the-shelve solvers. The single-level reformulation of the stochastic near-optimality robust bilevel problem (9.4)-(9.5) is as follows:

$$\begin{aligned}\max_{\Omega^U,\Omega^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}}\Big(&\lambda^{ret,s}_t E^s_{w,t} - \lambda^{ret,b}_t E^b_{w,t} + \sum_{n\in\mathcal{N}} \lambda^{com,s}_t e^b_{n,w,t} - \lambda^{com,b}_t e^s_{n,w,t} \\ &-\big(\lambda^{grid,cmp}_t E^b_{w,t} + \sum_{n\in\mathcal{N}} \lambda^{grid,loc}_t e^b_{n,w,t}\big)\Big)\Bigg]\end{aligned} \tag{9.12}$$

s.t. Upper-Level constraints (9.1a)-(9.1z)

Lower-Level constraints (9.2a)-(9.2d)

Inner optimisation dual constraints (9.10a)-(9.10c)

$$\sum_{w\in\mathcal{W}} \delta_{n,w,t} + \overline{\gamma}_{n,t} - \underline{\gamma}_{n,t} + 2\pi^{ut,a}_n(b_{n,t} - b^{ref}_{n,t})\varsigma_n - \pi^{ut,b}_n\varsigma_n = 0, \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{9.12a}$$

$$-\delta_{n,w,t}+\overline{\nu}_{n,w,t}-\underline{\nu}_{n,w,t}+p_w\lambda_t^{com,s}\varsigma_n+p_w\chi_{n,w,t}=0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12b}$$

$$\delta_{n,w,t}+\overline{\vartheta}_{n,w,t}-\underline{\vartheta}_{n,w,t}-p_w\lambda_t^{com,b}\varsigma_n-p_w\kappa_{n,w,t}=0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12c}$$

$$-\hat{\Theta}_t^j\varsigma_n+\hat{\beta}_t^j\chi_{n,w,t}+\hat{\alpha}_t^j\kappa_{n,w,t}-\rho_{n,w,t}^j=0, \quad \forall n\in\mathcal{N},\forall j\in\mathcal{J},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12d}$$

$$1-\varsigma_n=0, \quad \forall n\in\mathcal{N}, \tag{9.12e}$$

$$0\leq\overline{e_{n,t}^b}-e_{n,w,t}^b\perp\overline{\nu}_{n,w,t}\geq 0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12f}$$

$$0\leq e_{n,w,t}^b\perp\underline{\nu}_{n,w,t}\geq 0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12g}$$

$$0\leq\overline{e_{n,t}^s}-e_{n,w,t}^s\perp\overline{\vartheta}_{n,w,t}\geq 0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12h}$$

$$0\leq e_{n,w,t}^s\perp\underline{\vartheta}_{n,w,t}\geq 0, \quad \forall n\in\mathcal{N},\forall w\in\mathcal{W},\forall t\in\mathcal{T}, \tag{9.12i}$$

$$0\leq\overline{b_{n,t}}-b_{n,t}\perp\overline{\gamma}_{n,t}\geq 0, \quad \forall n\in\mathcal{N},\forall t\in\mathcal{T}, \tag{9.12j}$$

$$0\leq b_{n,t}-\underline{b_{n,t}}\perp\underline{\gamma}_{n,t}\geq 0, \quad \forall n\in\mathcal{N},\forall t\in\mathcal{T}, \tag{9.12k}$$

$$0\leq\varrho_{n,w,t}^j\perp\rho_{n,w,t}^j\geq 0, \quad \forall n\in\mathcal{N},\forall j\in\mathcal{J},\forall w\in\mathcal{W},\forall t\in\mathcal{T}. \tag{9.12l}$$

It is worth mentioning that in (9.11), τ_n serves as an auxiliary variable representing the robustified function value of the users problem, allowing us to eliminate constraint (9.11a) from the single-level problem [199]. In the above formulation, (9.12a)-(9.12e) are the Lagrangian stationary conditions, while (9.12f)-(9.12l) denote the complementary slackness conditions.

However, there are still other sources of nonlinearity in the problem that make the problem hard to solve. The first source are the bi-linear terms in the objective function relative to internal electricity exchanges that combines the upper-level prices decisions and the lower-level volumes decisions, i.e, $\lambda_t^{com,s}e_{n,w,t}^b, \lambda_t^{com,b}e_{n,w,t}^s$). The second source of nonlinearity arise from the complementary slackness conditions in constraints (9.12f)-(9.12l).

To resolve the first concern, the Strong-Duality theory is again used. The dual objective function of the lower-level problem (9.5) is derived and replaces the bilinear terms of the upper-level objective function. The, the big-M method is used to linearize complementary conditions [184]. The final single-level problem is a mixed-integer quadratic problem with second-ordered cone constraints. The extended version of the final problem is presented in (9.13), where (9.13a) and (9.13b) represent the linearized terms associated with complementary slackness conditions in (9.12f)-(9.12l).

$$\max_{\Omega^U,\Omega^L} \mathbb{E}_w \Bigg[\sum_{t\in\mathcal{T}} \Big(\lambda_t^{ret,s} E_{w,t}^s - \lambda_t^{ret,b} E_{w,t}^b + \sum_{n\in\mathcal{N}} \overline{\vartheta}_{n,w,t} \overline{e_{n,t}^s} + \overline{\nu}_{n,w,t} \overline{e_{n,t}^b} \tag{9.13}$$

$$+ \overline{\gamma}_{n,t} \overline{b_{n,t}} - \underline{\gamma}_{n,t} \underline{b_{n,t}} + \delta_{n,w,t} g_{n,w,t} + U_{n,t}$$

$$- \Big(\lambda_t^{grid,cmp} E_{w,t}^b + \sum_{n\in\mathcal{N}} \lambda_t^{grid,loc} e_{n,w,t}^b \Big) \Bigg]$$

s.t. Single-level constraints (9.12a)-(9.12e)

$$Z_{n,(w),t} \leq M I_{n,(w),t}^m, \qquad \forall n \in \mathcal{N}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}, \tag{9.13a}$$

$$Y_{n,(w),t} \leq M(1 - I_{n,(w),t}^m), \qquad \forall n \in \mathcal{N}, \forall w \in \mathcal{W}, \forall t \in \mathcal{T}. \tag{9.13b}$$

with $Z_{n,(w),t}$ the set of primal constraints and $Y_{n,(w),t}$ the associated dual variables. The index w is enclosed in parentheses, as some constraints may not be subject to the PV generaiton uncertainty.

9.3. Case Study and Key Results

The EC under study comprises 15 members, consisting of 8 prosumers and 7 consumers. This distinction aids in analyzing the usage behavior of members more effectively. Thus, odd-labeled users (P) are categorized as prosumers, while even-labeled users (C) are classified as consumers. The EC collectively represents a node within the modified 14-bus distribution network of Flobecq in the Wallonia region of Belgium [210]. The target consumption and PV generation power of users are derived from the Flobecq dataset. External prices are determined based on Belgium retail prices for the year 2022. Figure 9.4 represents external electricity prices including dynamic retail buying/selling prices and grid fees for the understudy day. Dynamic retail prices are higher from 17:00 to 21:00, reaching peak rates at 18:00 and dropping to off-peak rates at 05:00. Grid fees, however, follow a time-of-use scheme, peaking between 07:00 and 22:00 and remaining off-peak for the rest of the day. Additionally, for better visibility, Figure 9.5 combines the time steps across all users to represent the target load demand for all users alongside the PV power generation by the prosumers. According to this figure, prosumer P1 has a PV generation peak that surpasses their target load consumption and has the lowest consumption among all members, giving it the most opportunities to sell electricity to the CM. Additionally, prosumers P7 and P15 show higher generation peaks than other prosumers, while consumer C12 has the highest consumption peak among consumers. Notably, the highest overall consumption peak is observed in prosumer P13. Users display heterogeneity in peak periods, with some, like P13 and C10, peaking at night, while others, such as C2 and C6, peak around noon. The charging and discharging efficiencies of community energy storage are set at 0.90 and 0.95, respectively, with a capacity of 30 kWh and an initial charging rate of 15 kW. The users' usage preferences $\pi_n^{ut,a}$ and $\pi_n^{ut,b}$ are respectively considered as 0.3 and 0.175 for the understudy day. To delimitate the internal prices perturbation ranges, Algorithm 1 is run considering a tolerance value, *tol*, of 0.001 and a maximum iteration number, $iter_{max}$, of 100. Detailed input data regarding consumption loads, PV generation power, network parameters, and electricity prices can be found in the online Appendix [211].

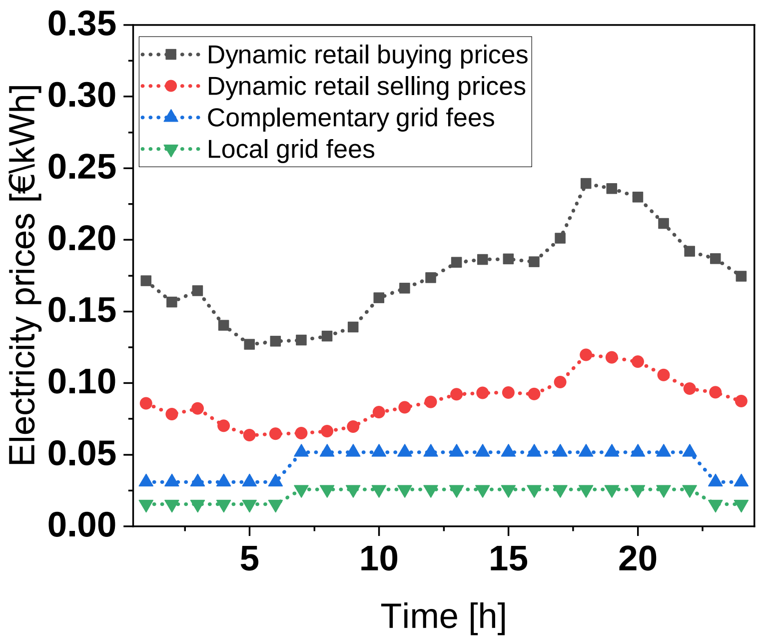


Figure 9.4.: External electricity prices including commodity and grid prices.

To better investigate the proposed method, four case studies are introduced as follows:

- **Case 1:** Bilevel problem resolution with deterministic PV generation neglecting the limited observability regarding internal prices [183], [184].
- **Case 2:** Bilevel problem resolution with stochastic PV generation neglecting

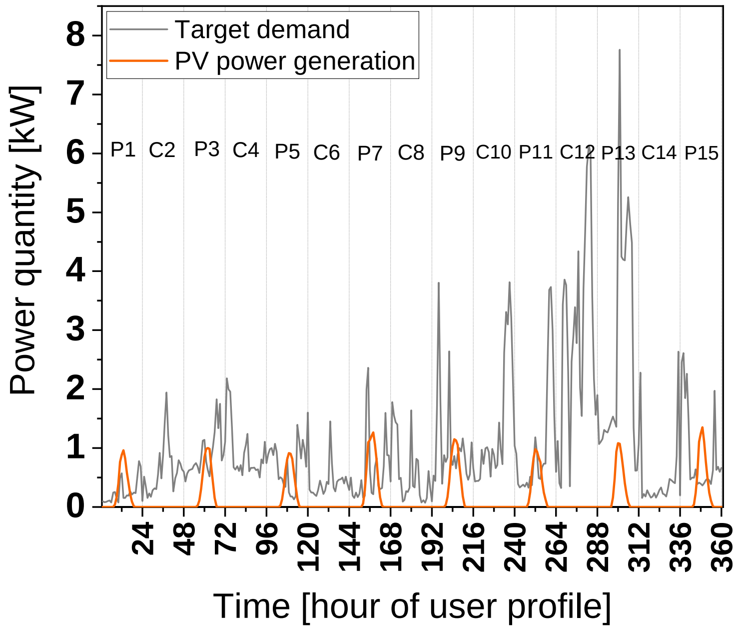


Figure 9.5.: Hourly target load demand of all users and PV power generation of prosumers.

limited observability regarding internal prices [186].

- **Case 3:** Bilevel problem resolution with deterministic PV generation with robust lower-level formulation mitigating the impact of limited observability regarding internal prices.

- **Case 4:** Bilevel problem resolution with stochastic PV generation with robust lower-level formulation mitigating the impact of limited observability regarding internal prices.

Accordingly, **Cases 1** and **2** overlook users' limited observability over internal electricity prices, serving as base cases for comparison with **Cases 3** and **4** where limited observability of users are taken into account. For the deterministic cases, the median of the Flobecq PV dataset (two-year hourly dataset) is used for analysis. For stochastic cases, 20 PV scenarios are generated based on the CDF of the PV dataset for each prosumer, and the results are represented as average values across all scenarios. In the following subsection, various impacts and implications on key outcomes of the community energy sharing problem are investigated in a comparative manner.

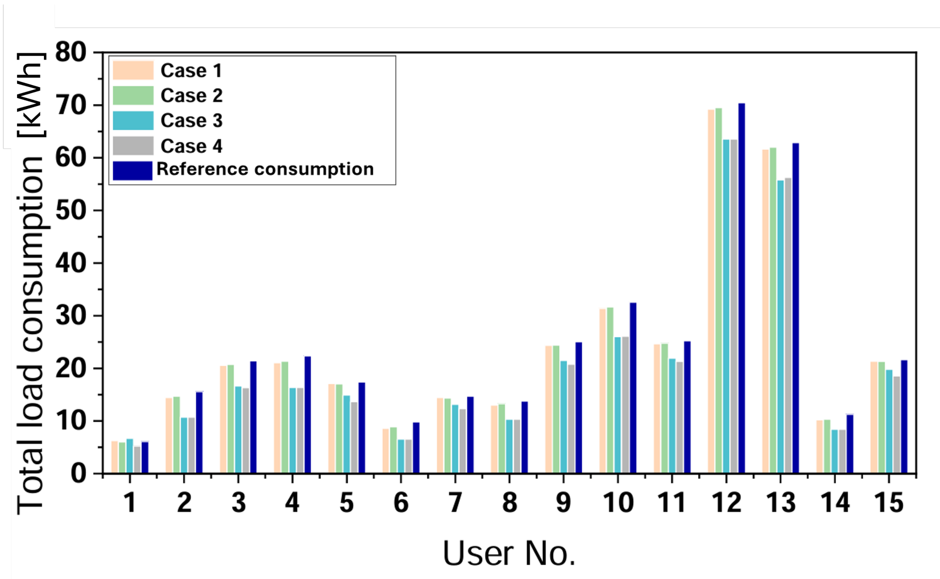


Figure 9.6.: Daily load consumption of community members in the different cases.

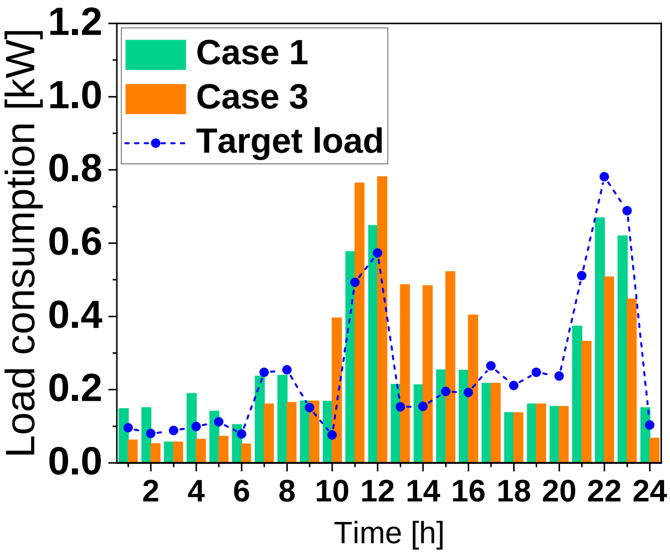


Figure 9.7.: Hourly power load consumption of prosumer P1.

9.3.1. Impacts on Users' Consumption and Internal Electricity Prices

The total load consumption of the members for the whole day is illustrated in Figure 9.6 across different scenarios. Each user's hourly load profile over 24 hours is provided, and to simplify the presentation, the total daily load consumption is

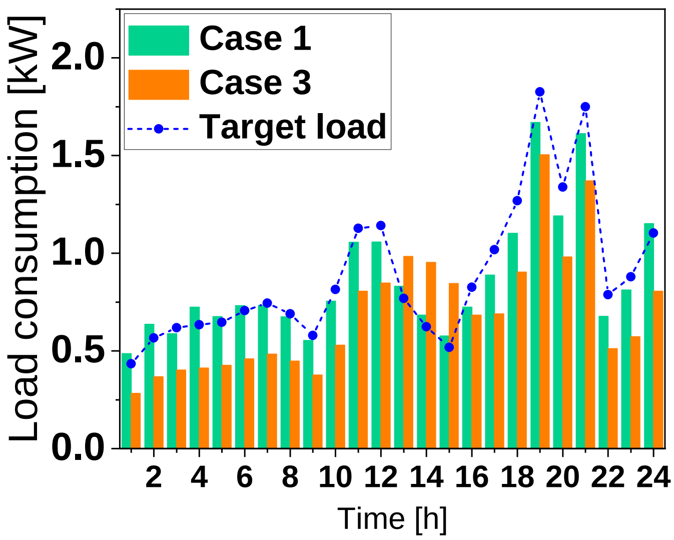


Figure 9.8.: Hourly power load consumption of prosumer P3.

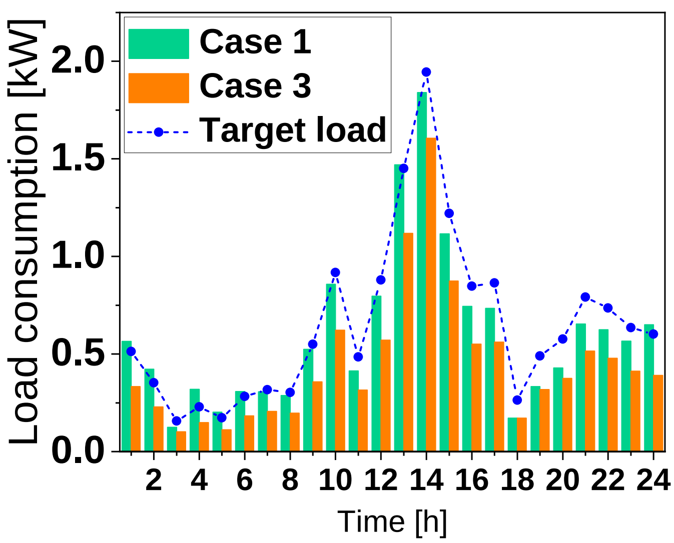


Figure 9.9.: Hourly power load consumption of consumer C2.

shown as a total value in kW instead of displaying each hourly reading. In **Case 1**, characterized by perfectly rational user behavior, while most users consumed less total electricity compared to their target demand, which is influenced by the hourly internal prices and users' marginal consumption utilities[3]. Similar user

[3]According to the quadratic utility function, users can adjust their load consumption based on the marginal utility of consumption relative to the internal electricity prices. This approach

behavior is observed when accounting for uncertainties in PV generation. In **Case 2**, users account for the variability of PV generation and adjust their consumption levels based on the marginal utility of consumption and internal electricity prices. A marginal increase in load consumption is observed compared to **Case 1**, as the stochastic optimisation approach incorporates more realistic PV generation scenarios, resulting in a higher average actual load consumption. In **Case 3**, where users have limited observability regarding internal prices, they exhibit a more conservative approach towards pricing, resulting in greater reductions in daily consumption compared to the perfectly rational behavior case for most members. A notable finding in user behavior is the consumption behavior of prosumer P1, whose total actual load consumption in **Case 3** exceeds that in **Case 1** and total target load demand. As illustrated in Figure 9.5, prosumer P1's PV generation is higher than its targeted load consumption for most hours. The prosumer increases its load since the marginal utility of consumption is greater than the benefit from selling excess power. This response results from limited observability of internal selling prices, leading the prosumer to consume beyond its target load consumption as well. However, when both PV uncertainties and limited observability are factored into the decision-making of the user, a further reduction in actual consumption is evident in **Case 4** compared to target load demand.

To gain deeper insights into users' consumption behavior throughout the day, consumption profiles of sample users i.e., prosumer P1 in Figure 9.7, prosumer P3 in Figure 9.8 and consumer C2 in Figure 9.9, are depicted for **Cases 1** and **3**. In these figures, since the time step for load consumption is 1 hour, energy consumption is directly equivalent to power consumption, which is measured in kW. In **Case 1**, when the marginal utility of consumption surpasses internal electricity buying prices, users demonstrate a willingness to consume beyond the target demand. Therefore, it can be observed that, mostly during off-peak hours, users surpass the target demand while during the day and especially high internal buying prices the consumption does not surpass the target demand. In Case 3, different user behaviors are observed, which require further analysis for each user behavior. According to Figure 9.7, prosumer P1, characterized by lower consumption levels and higher PV generation power, exhibits a greater willingness to increase load consumption during PV generation hours. This behavior is driven by the prosumer's perception that the marginal utility of load consumption outweighs internal electricity prices. Due to this perception, less power is purchased during hours without PV generation. Prosumer P3 exhibits a similar behavior; however, due to its lower PV generation relative to its power consumption, a moderate increase in actual load consumption is observed during hours 13-15. Hence, a transition in the consumption pattern of prosumers P1 and P3 towards hours characterized by increased PV generation is noted. On the other hand, consumer C2 evaluates the marginal utility of load

gives users greater flexibility to determine their consumption levels in response to internal market prices.

consumption only against internal electricity prices, as it lacks a PV system that could provide the flexibility to increase self-consumption during certain hours. Due to its conservative approach in mitigating the effects of limited observability, the marginal utility of load consumption remains lower than the internal prices. Consequently, a reduced consumption profile is observed throughout most hours. However, in **Case 1**, the consumer surpasses the target demand when the marginal utility of consumption exceeds internal buying prices akin to the prosumers. Limited observability influences users' perceptions of internal electricity prices and shapes their consumption behavior based on the quadratic utility function and available PV power generation.

Figure 9.10 illustrates the internal price deviation boundaries, which are computed according to Algorithm 1. It is notable that there is a wider deviation range observed in internal buying prices, which can be attributed to the substantial impact of user load consumption variations on buying prices and the inherent more expensive nature of those prices with respect to selling prices. Figures 9.11 and b respectively depict internal buying and selling prices for different case studies. In Figure 9.11, internal buying prices in **Cases 1** and **2**, where users exhibit optimal power responses, are higher compared to **Cases 3** and **4**, where users respond with near-optimal power quantities. For instance, the peak price at 18:00 in **Cases 1** and **2** is significantly reduced in **Cases 3** and **4**. This trend suggests that as users adopt a more conservative approach to their overall consumption, the CM lowers internal buying prices to encourage increased purchasing. Conversely, as shown in Figure 9.12, the CM raises selling prices when some prosumers begin selling back to the CM. This trend is evident in the internal selling prices in **Case 4** between 9:00 and 17:00.

Therefore, limited observability directly influences internal electricity prices, resulting in a lower buying price range during most hours of the day.

9.3.2. Analyzing Community Energy Trading

Figures 9.13 and 9.14 illustrate the total internal buying and selling power quantities for each user in four case studies. User target demand and PV generation are critical in determining their buying and selling power with the CM. In **Case 1**, users with lower target demand and higher PV generation (e.g. P1) are more likely to sell power to the CM, while those with higher demand and lower/no PV generation (e.g. C12) tend to buy more. Nevertheless, in **Cases 2**, influenced by varying scenarios, an increase in average power selling across all users is observed showing the important influence of the available PV production. A comparison between **Cases 3** and **1** reveals a relative reduction in power purchases from the CM by users in **Case 3**. Particularly for prosumers, a decrease in power selling to the CM is evident as they prioritize self-consumption. In **Case 4**, a decrease in the average power purchase values across all users is observed when compared to

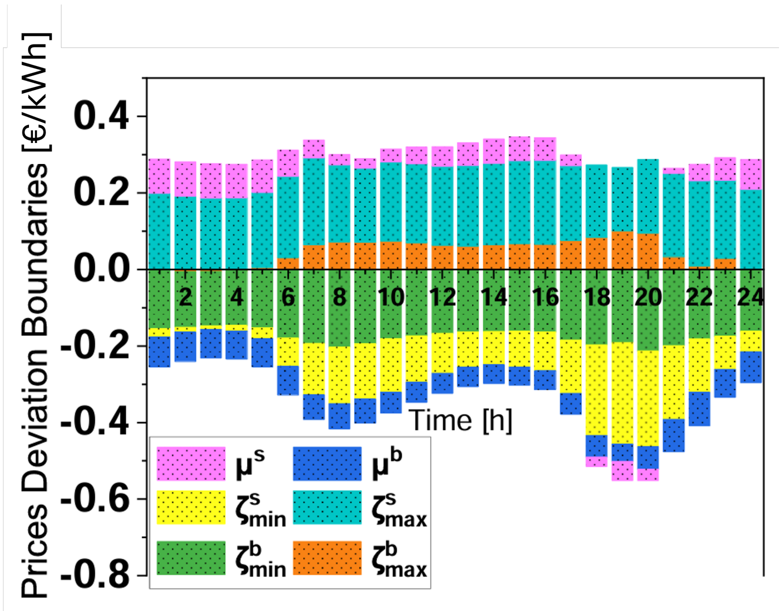


Figure 9.10.: Resulting internal price deviation boundaries.

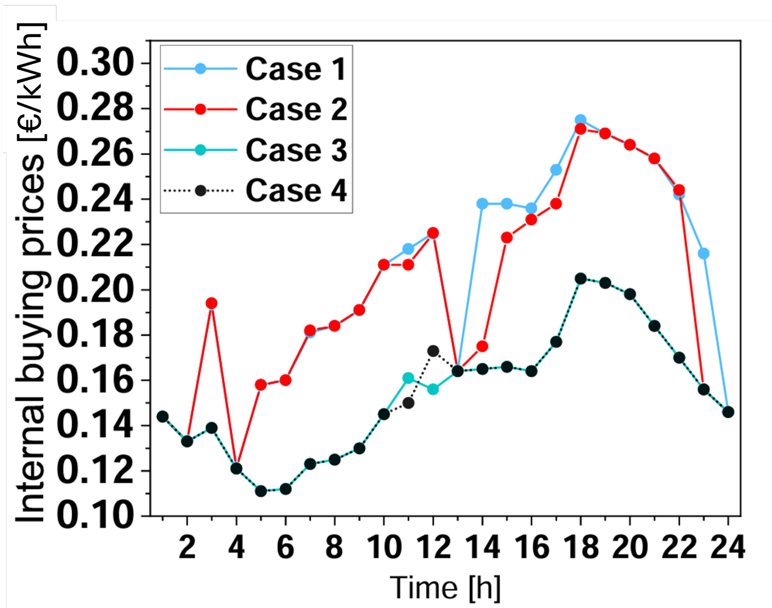


Figure 9.11.: Internal buying prices.

Cases 1 and **2**. This can be attributed to the mitigation of limited observability, which results in reduced load consumption for most users and, consequently, lower power purchases from the CM.

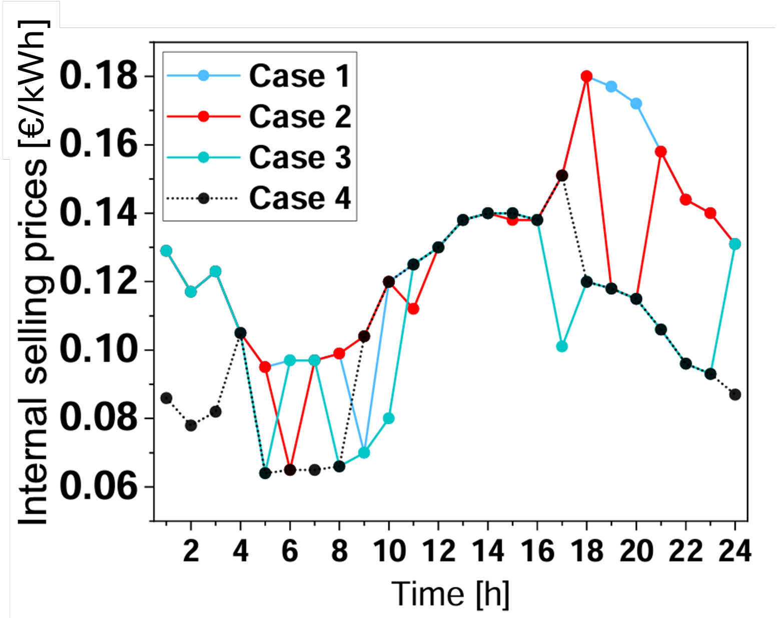


Figure 9.12.: Internal selling prices.

Figures 9.15 and 9.16 depict the external power purchased and sold by the CM in all cases. In Case 1, due to limited PV generation from PV prosumers, no power is sold to the upstream supplier, and all the sold power by the prosumers to the CM is used for internal supply. The peak power purchase occurs at 20:00, reflecting the EC's highest electricity demand, while the lowest purchase is recorded at 8:00, corresponding to a period of relatively low user load consumption. A comparison between **Cases 1** and **3** reveals a decrease in power purchased from the supplier, from a total of 308.80 kW in **Case 1** to 261.82 kW in **Case 3**. Furthermore, in **Cases 2** and **4**, a similar trend is observed in total purchases for the average of scenarios, with a decrease from 309.69 kW in **Case 2** to 256.78 kW in **Case 4**. This reduction reflects the consideration of limited observability and different PV generation scenarios in power exchanges of the EC with the external supplier. Furthermore, it is observed from the Figures 9.15 and c that no power is injected in **Cases 1** and **3**, whereas some injection is evident in **Cases 2** and **4** due to the consideration of different PV scenarios. Moreover, there is an observable increase in power injection in **Case 4**, attributed to prosumers consuming less power. In certain scenarios, PV generation exceeds the demand of prosumers, which results in surplus power available for selling back to the supplier.

The state of charge (SOC) of the CS is illustrated in Figure 9.17. It is noticeable across all cases that the CS charges during hours with PV generation and discharges when external buying prices are higher during 17:00-20:00. An additional observation is the reduction in charging/discharging power levels of CS in **Case**

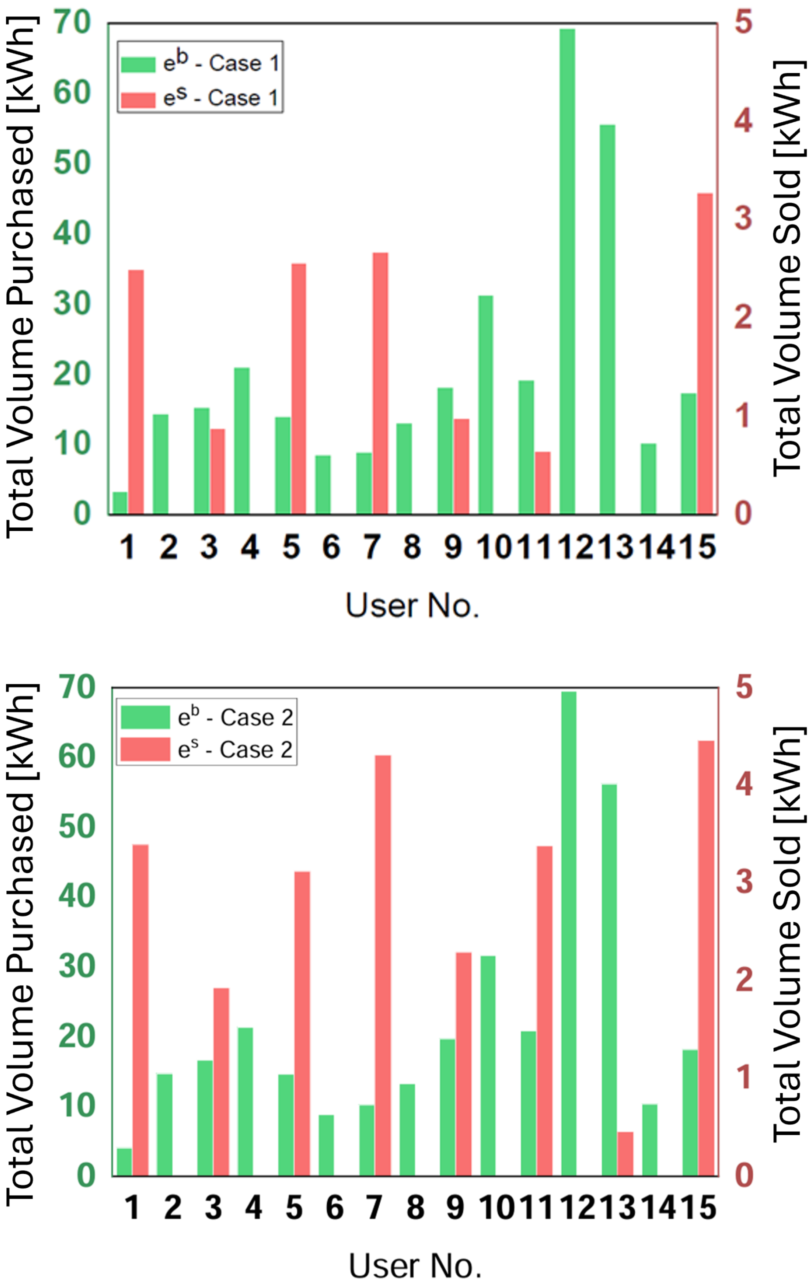


Figure 9.13.: Electricity volume purchased from and sold to the CM by the users in Cases 1 and 2.

3 with peak SOC of 18.03 kW and compared to **Case 1** with peak SOC of 11.30 kW in the day. As users engage more in self-consumption, their sales to the CM

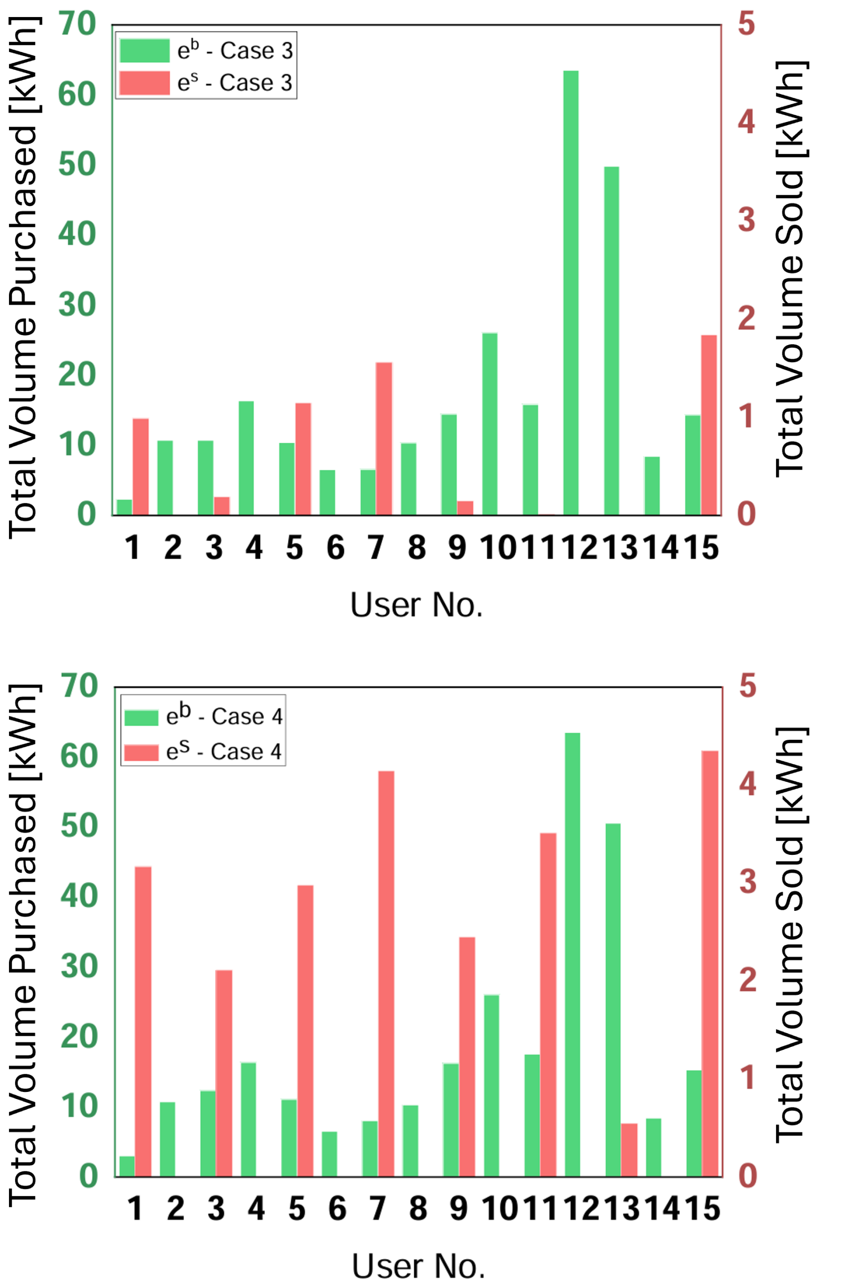


Figure 9.14.: Electricity volume purchased from and sold to the CM by the users in Cases 3 and 4.

decrease, resulting in reduced charging by the CM for the CS. However, it is evident

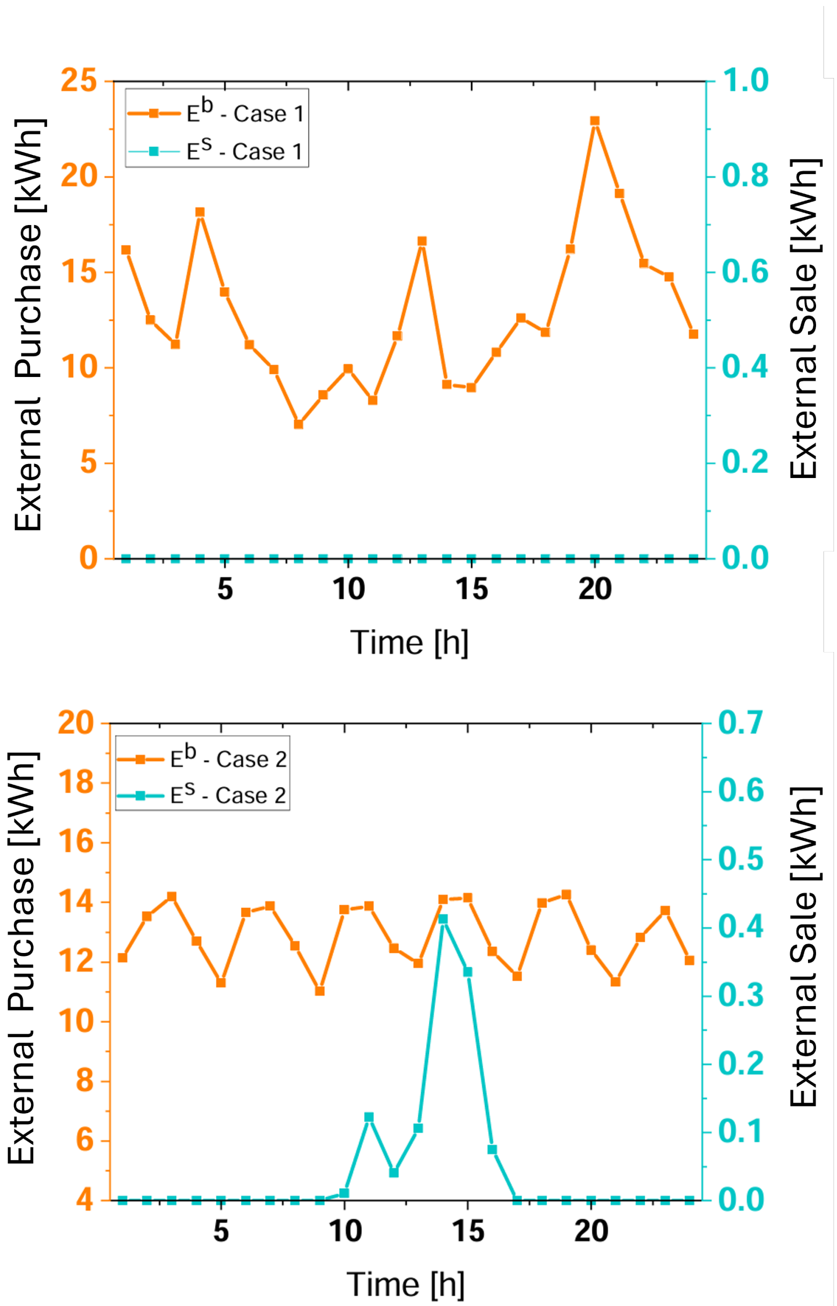


Figure 9.15.: Electricity volume purchased from and sold to the external retailer by the CM in Cases 1 and 2.

that the CS primarily serves the EC demand rather than being utilized for energy arbitrage by the CM.

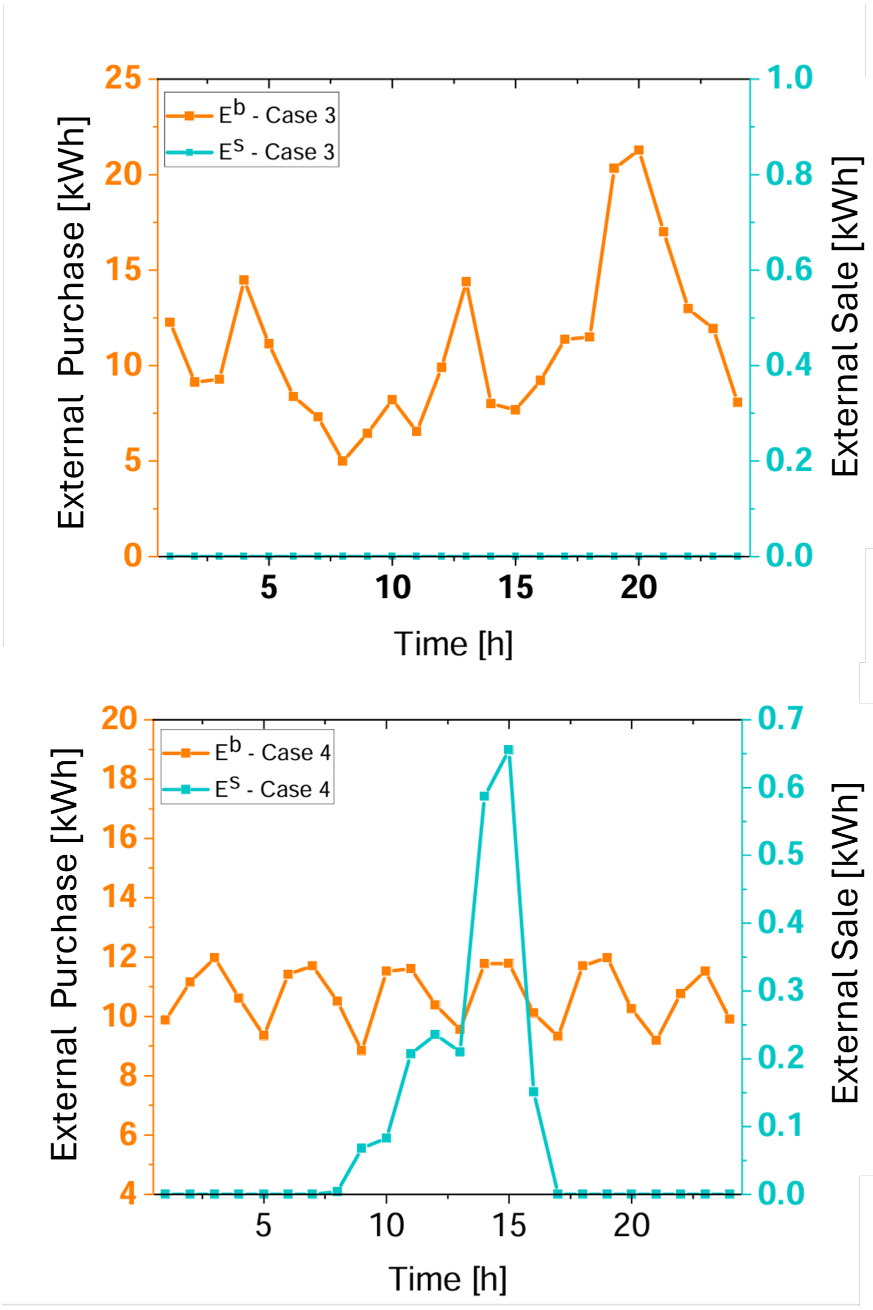


Figure 9.16.: Electricity volume purchased from and sold to the external retailer by the CM in Cases 3 and 4.

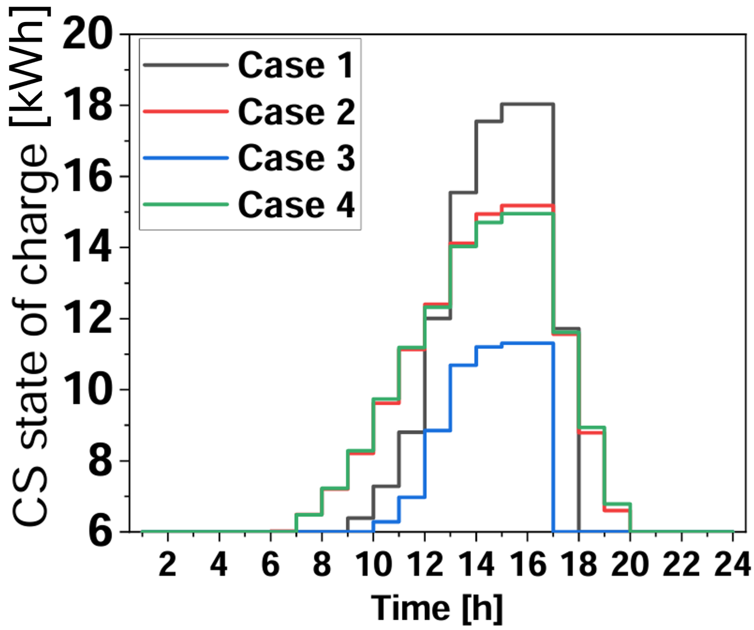


Figure 9.17.: State-of-charge evolution of the community battery storage.

9.3.3. Community Social Welfare

The social welfare results for EC members are presented in Table 9.1. In **Case 1**, consumer C12 experiences the lowest social welfare at -15.27 €, primarily due to high electricity consumption levels. In contrast, prosumer P1 achieves the highest social welfare at -0.37 €, attributed to high PV generation and lower consumption levels. The table shows that most EC members experience an improvement in social welfare, with an average increase of 0.11 €, when prosumers mitigate PV generation uncertainties in **Case 2**. In **Case 3**, EC members hedge against internal price uncertainties due to limited observability. This resulted in lower purchases from the CM and increased self-consumption, thereby reducing associated costs for EC members compared to **Case 1**. Consumer C12 and prosumer P12 experienced the highest improvements in social welfare, with increases of 3.05 € and 2.26 €, respectively. However, mitigating both limited observability and PV generation uncertainties **4**, particularly for PV prosumers, resulted in a more pronounced improvements in the prosumers' objective function values. The last column of Table 9.1 shows the improvements achieved in **Case 4** compared to **Case 1**. This improvement is attributed to mitigating data and decision uncertainties, resulting in an average increase of 12.65% in social welfare compared to Case 1, where both sources of uncertainty are ignored.

Table 9.2 presents the various costs incurred by the CM across four case studies.

Table 9.1.: Social welfare of the EC members in different approaches (negative values represent costs).

User ID	Case 1 (€)	Case 2 (€)	Case 3 (€)	Case 4 (€)	Improvement* (%)
P1	-0.37	-0.40	-0.37	-0.31	16.22
C2	-3.28	-3.09	-2.93	-2.93	10.67
P3	-3.32	-3.31	-3.13	-3.01	9.34
C4	-4.24	-4.11	-3.94	-3.94	7.08
P5	-2.45	-2.46	-2.39	-2.29	6.53
C6	-1.99	-1.92	-1.78	-1.78	10.55
P7	-1.60	-1.61	-1.46	-1.34	16.25
C8	-2.52	-2.46	-2.31	-2.33	7.54
P9	-3.38	-3.41	-3.10	-3.03	10.36
C10	-7.38	-7.17	-6.16	-6.16	16.54
P11	-4.50	-4.37	-3.78	-3.62	19.56
C12	-15.27	-14.91	-12.22	-12.23	19.91
P13	-12.49	-12.08	-10.23	-10.22	18.16
C14	-2.24	-2.07	-1.96	-1.96	12.50
P15	-2.71	-2.72	-2.60	-2.48	8.49

* Improvement in **Case 4** compared to **Case 1** (%).

Table 9.2.: Different costs of the CM associated with coordinating the EC (negative values represent revenues).

Case No.	Total Cost (€)	Ret. Exch. Cost (€)	Int. Exch. Cost (€)	Grid Cost (€)
Case 1	4.49	55.43	-64.92	13.97
Case 2	6.11	55.66	-63.77	14.22
Case 3	17.10	46.59	-41.53	12.01
Case 4	17.70	47.92	-42.12	11.89

In **Case 1**, the CM achieves a profit of 64.92 € from internal exchanges among members, while grid costs and external exchange costs are 13.97 € and 55.43 €, respectively. In **Case 2**, mitigating PV generation uncertainties by PV prosumers results in a slight increase in the CM's total cost to 6.11 €. However, in **Case 3**, a significant rise in the CM's total cost is observed, reaching 17.10 €. This increase in the CM's total costs can be attributed to users' conservative behavior, driven by limited observability. The conservative behavior was reflected in a higher rate of PV self-consumption and reduced power purchases from the community. Specifically, while the CM's external exchange and grid costs decreased in **Case 4** compared to **Case 1**, the CM's revenues from internal exchanges with community users dropped from -64.92 in **Case 1** to -42.12 in **Case 4**. This reduction resulted in an additional cost of 13.21 for the CM compared to **Case 1**.

9.3.4. Study of Nodal Network Quantities

This section investigates the impact of users' limited observability on distribution network constraints. Therefore, **Cases 1** and **3** were compared to better understand these impacts. Figure 9.18 displays the (squared) voltage quantities of different nodes in the network. Accordingly, while all nodes remain within the allowable voltage range in both cases, **Case 3** exhibits lower voltage drops compared to **Case 1**, primarily due to decreased PV power injection into the grid. Figure 9.19 shows active power losses, affirming that in Case 3, there are fewer active power losses, particularly during PV generation hours when prosumers are involved in self-consumption. This suggests that considering limited observability leads to increased self-consumption among EC members, consequently resulting in reduced active power losses.

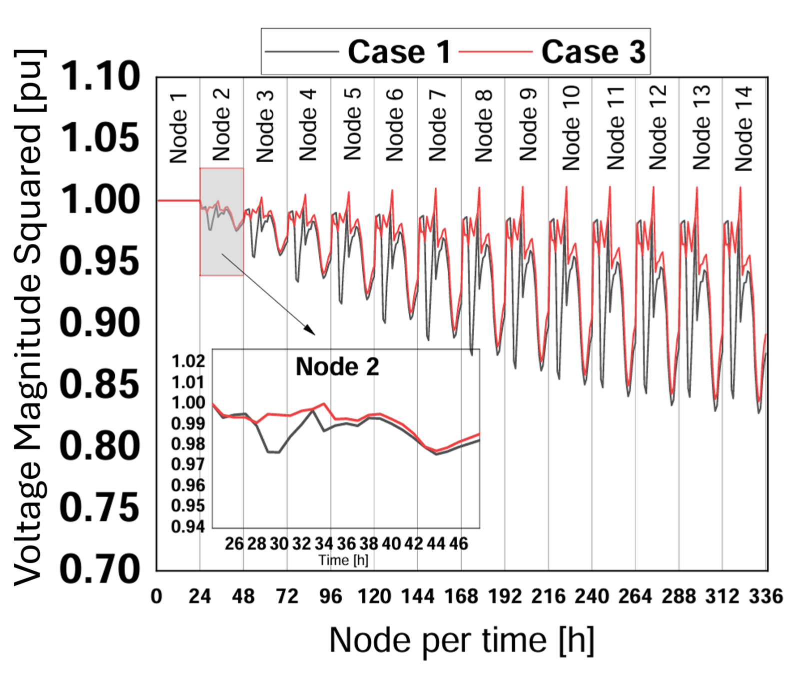


Figure 9.18.: Upstream network voltage plan (squared magnitude).

9.3.5. Out-of-Sample and Worst Case Analyses

In Figure 9.20, the out-of-sample analysis results on PV scenarios are presented. An investigation on the CM's objective function values was conducted using 400 generated (out-of-sample) PV scenarios for the EC users. The results indicate that when employing the stochastic method (**Case 4**), which considers scenarios close to real-world conditions, the objective function values show improvement compared

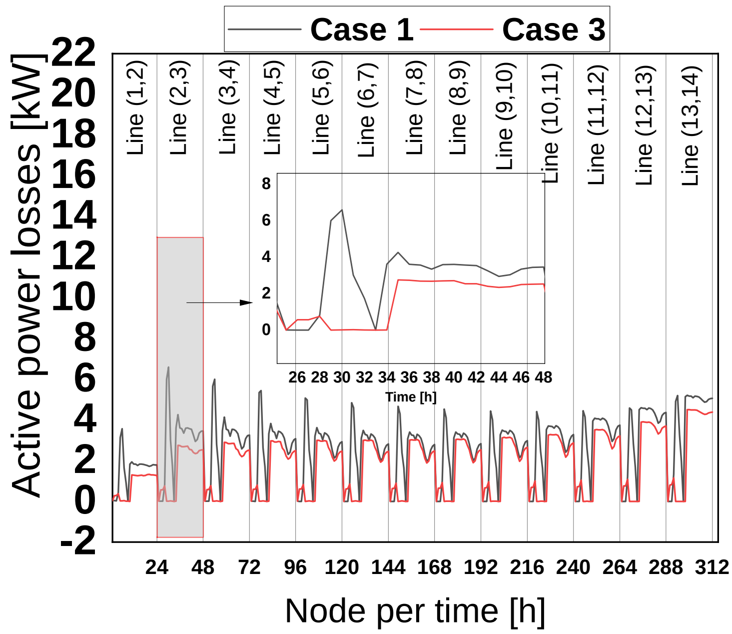


Figure 9.19.: Upstream network active power losses.

to the deterministic approach (**Case 3**). Specifically, the upper-level objective function value for the mean of out-of-sample scenarios in **Case 4** is -21.40 €, which is better than the value of -21.76 € in **Case 3** for the studied day. This difference becomes more significant when considering a longer period (e.g. ≈ 130 €/year).

Figure 9.21 presents the analysis results comparing **Cases 1** and **3** to examine how worst-case deviations in internal prices can affect users' objective function values. The analysis demonstrates that in the scenario of worst-case price deviations, **Case 3** performs better than **Case 1**. Prosumer P1 incurs the lowest cost at -1.45 €, while consumer C13 faces the highest cost at -29.17 € in Case 1. However, in Case 3, users demonstrate greater robustness against internal price deviations, experiencing lower losses when prices deviate from their original values compared to Case 1, where users respond optimally to the declared internal prices. Additionally, users with higher consumption levels benefit more by mitigating internal price uncertainties. For instance, C12 and P13 reduced their costs by 4.22 € and 3.44 € in Case 3 compared to Case 1, respectively.

Tables 3 and 4 demonstrate the computational complexities of the proposed method in four case studies. In Case 1, the complexity for both continuous and binary variables is primarily influenced by the number of community users, network nodes, and time periods, with additional terms accounting for adjacent nodes. The constraints also scale accordingly, with the number of linear and

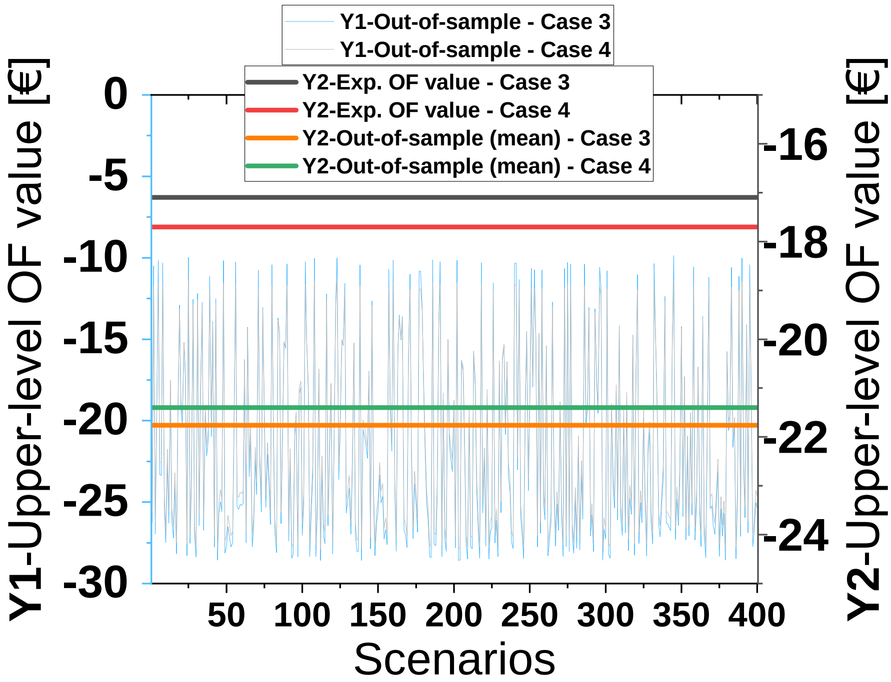


Figure 9.20.: Out of sample analysis for PV scenarios

quadratic constraints growing with users, network nodes, and the number of adjacent nodes. Case 2 introduces further complexity due to including PV power generation scenarios, impacting both the continuous and binary variable complexities. For Cases 3 and 4, the complexity increases with the addition of perturbation set boundaries, further affecting the computational cost. These results highlight that the method's complexity grows with the problem size, especially when considering multiple scenarios and perturbations. However, the model remains manageable for the understudy day-ahead community energy sharing problem with CPU time of less than 2 seconds in all cases.

Table 9.3.: Computational complexity regarding variables.

Case No.	Continuous Variables	Binary Variables
Case 1	$(7 + 10N + 3I + 3\sum_i Y_i) \times T$	$(2 + 6N) \times T$
Case 2	$(2 + 3N + (5 + 7N + 3I + 3\sum_i Y_i) \times W) \times T$	$(2N + (2 + 4N) \times W) \times T$
Case 3	Case 1 $+(2J \times N + 2N) \times T + N$	Case 1 $+J \times N \times T$
Case 4	Case 2 $+(2J \times N + 2N) \times W \times T + N$	Case 2 $+J \times N \times W \times T$

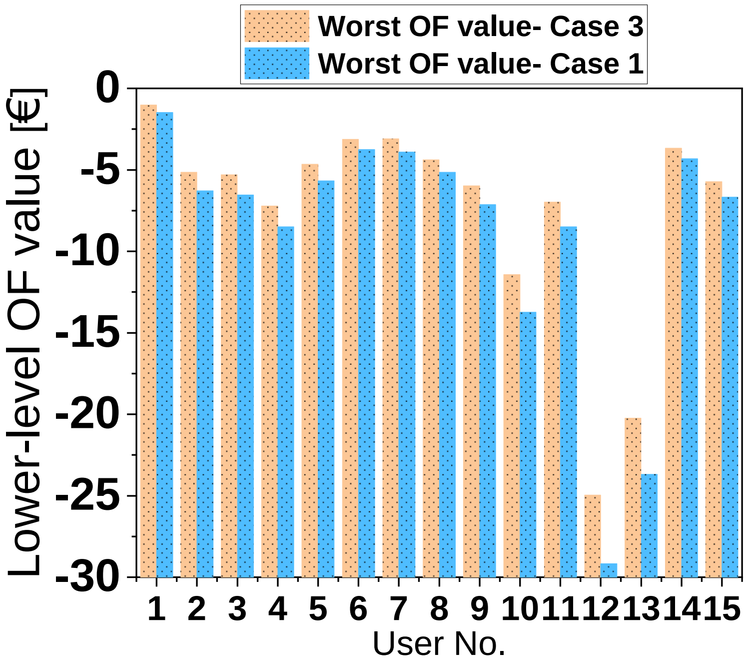


Figure 9.21.: Out of sample analysis for price deviations

Table 9.4.: Computational complexity regarding constraints.

Case No.	Linear Constraints	Quadratic Constraints
Case 1	$(18 + 28N + 4I + 5\sum_i Y_i) \times T + 1$	$(\sum_i Y_i) \times T$
Case 2	$(4 + 9N + (14 + 19N + 4I + 5\sum_i Y_i) \times W) \times T$	$(\sum_i Y_i) \times T \times W$
Case 3	Case 1 $+(5J \times N + 2N) \times T + N$	$(\sum_i Y_i) \times T$
Case 4	Case 2 $+(5J \times N + 2N) \times W \times T + N$	$(\sum_i Y_i) \times T \times W$

9.4. Intermediate Conclusion

In this study, limited observability was introduced as a paradigm of bounded rational behavior among EC users. A stochastic near-optimal robustness bilevel programming approach was proposed for the energy sharing problem of the EC, allowing uncertainties in internal prices caused by limited observability to be mitigated. An approach was also developed to define boundaries for uncertainty sets related to internal price deviation variables. Through the use of epigraphical reformulation and affine parameterization of uncertainty sets, the lower-level problem was reformulated to satisfy KKT conditions and subsequently transformed into a single-level model suitable for analytical solutions.

Simulation results indicate that mitigating data and decision uncertainties leads to tangible alteration in the decision-making behavior of EC users. More specifically, mitigating limited observability of internal electricity prices revealed that prosumers primarily reduced their load consumption during periods of low or no PV generation and increased consumption during PV generation periods to prioritize self-consumption. Similarly, consumers reduced their consumption levels throughout the day, as the marginal utility of load consumption was lower than the internal electricity prices for them. Overall, the results demonstrated that, on average, members reduced their total consumption by 14.64 % when mitigating limited observability. Nevertheless, accounting for PV generation uncertainties had a marginal impact (less than 1 % increase) on the total load consumption for most users, driven by more PV scenario realizations.

The findings confirmed that mitigating both limited observability and PV generation power uncertainties led to an approximate 14 % reduction in the total power purchased by members from the CM, while their total power sales to the CM increased by around 70 %. This improvement is attributed to the realization of various PV generation scenarios. Additionally, the CM experienced an average 17 % reduction in its power purchases from the supplier. Meanwhile, an average of 0.091 kW was sold back to the supplier, whereas in the deterministic case, no power was sold back. The reduced power purchases and self-consumption by PV prosumers led to lower voltage drops and decreased active power losses.

Addressing both uncertainties resulted in an average decrease of 0.5 € and 0.3 € in the internal buying and selling prices, respectively. Additionally, the social welfare of community users improved, rising by an average of 12.56 %. However, the total cost of the CM increased by 13.21 € which is due to a reduction in the revenues of internal exchanges with the community members.

Finally, the out-of-sample analysis on PV power generation demonstrated that employing the stochastic method resulted in more realistic social welfare outcomes compared to the deterministic method with a difference in precision around 2 % between both methods. Worst-case analysis on internal electricity prices revealed that limited observability led to greater robustness against internal price deviations, resulting in fewer degradation in objective function values.

Despite the effectiveness of the proposed method in addressing limited observability, some limitations remain. For the first limitation, the parameters of the quadratic utility functions were assumed in this study. However, deriving these parameters based on actual consumption data could yield more precise insights into user behavior, making this an interesting area for further exploration.

As the second limitation, while the proposed model uses an iterative algorithm to represent deviations in internal electricity prices, these deviations could be further refined using actual data on users' load consumption and internal electricity prices. Incorporating real-time price deviations based on actual data would likely provide a more accurate representation and enhance the model's applicability. Finally, although the method mitigates price uncertainties faced by users, the CM remains unprotected against the near-optimal decisions of the lower-level problem.

To address this, incorporating upper-level robustness against the near-optimal responses of community users would be a valuable avenue for future research.

CHAPTER 10.

Conclusion and Perspectives

Electricity has been widely adopted by our society. From industries to households many human labours have been replaced or are supported by electrical appliances. To access this precious resource, end-users must contract with a supplier who's in charge to trade electricity with the producers to meet its customers needs. Despite the liberalisation of the electricity market which introduces competition in the retail prices offers, the low elasticity of consumers demand exposes them to the market price volatility and they are the most vulnerable actors in case of electricity crisis. In an effort to give consumers back control over their electricity bills and promote investment in renewable production units, the European Union introduced the concepts of energy sharing and Renewable Energy Communities. The second paradigm consist in the aggregation of end-users, geographically close to each other, who mutualize existing or new energy resources such as PV panels, or battery storage systems. By exchanging this electricity at the local level, the participants reduce their dependence regarding their traditional supplier and receive benefits of various natures (e.g., economic, social, environmental).

To efficiently operate these local organisations centred on end-users, several decisions must be taken at the different stages of its life. From a long-term perspective, members must decide on the local electricity prices and the energy sharing rules. If no existing assets can be included in the community at its creation, investment decisions must also be taken regarding the size of production and storage resources, their location and the ownership. From a short-term perspective, to maximise the valorisation of local energy, they should coordinate their flexibility potential by scheduling their usage. For an ordinary person, who is not specialist in the electricity or energy domain, optimizing these decisions is a major challenge.

Therefore, the main objective of this thesis was to provide optimisation tools to the stakeholders involved in RECs to support them in their decision-making. Doing so, we addressed the entire lifetime of the communities from joint investment to settlement models. The thesis addressed three main research questions:

- **Q1: How can we explicitly induce REC members to provide flexibility ?**
- **Q2: What is the optimal investment strategy in energy resources to meet both REC and individual objectives ?**
- **Q3: How to faithfully integrate human behaviors in REC decision-making models ?**

These three questions were investigated sequentially in the three parts of this manuscript.

In Part I, Chapter 2 introduced the concept of coordinated demand-side management and presented a first optimisation model developed in [16] that minimizes the total REC bill by scheduling the usage of members' flexible resources such as white goods, electric vehicles and thermal loads. Building on this first model, in Chapter 3 we provided a thorough explanation of the different local energy sharing mechanisms existing in the literature and in EU member states. Hence, we first compared the two sharing rules paradigm, namely the Economic Surplus and the Energy Surplus distributions, both adopting the Keys of Repartition mechanism. We showed that from a collective point of view, the economic surplus distribution scheme outperforms the energy surplus one. Nevertheless, some energy distribution keys (KoRs 3 to 6) are intrinsically energy efficient and therefore able to capture the dynamic behaviour and natural balance of local consumption and production. However, as they do not integrate the individual tariffs contracts with retailers they lead to 3.12 % of savings reduction compared to Economic Surplus sharing schemes. Secondly, we highlighted the limits of the coordinated DSM problem of Chapter 2 in the Energy Surplus sharing framework. Indeed, on the use case composed of 8 caricatural residential members, we could observe deviations between the expected electricity bill arising from the flexible resources scheduling and the real-time benefits contracted after the application of settlement rules. These deviations raised up to 14.76 % with the *Members Equal Key*, despite a perfect forecast of the base load and local generation. In addition, using the scheduling problem as such led to shifts in the consumption patterns that were not remunerated. For example, the member 5 was 208 e short from the expected savings after leveraging 49 % of flexible consumption. Finally, to avoid these deviations we proposed for the first time a Mixed Integer Linear formulation of the day-ahead community optimal dispatch problem which embeds a chosen energy surplus sharing rule among 6 regulatory-compliant ones. Doing so, the distribution key-aware scheduling of flexible resources was improved and the objective function was closer to the collective optimum without any sharing rules restriction by taking into account the individual retailer prices at the same time. This helped to reduce the gap with the best, energy sharing rules free, collective bill to 11.20 % for the *Members Equal Key*.

Then in Chapter 3, two other research questions related to the coordination of flexible resources within RECs were investigated. First, we proposed two flexibility reward methods explicitly taking into account the offered flexibility volumes and the activated ones. The two methods are respectively, a rule-based approach adopting the Keys of Repartition principle, and a price-based approach. This work showed the added value of incentivizing end-users to mobilize flexibility in a REC framework in terms of economic savings and network usage. The comparison was carried out on a REC composed of 20 domestic end-users. For each of them, a discomfort model is implemented to account for the loss of comfort created by a consumption shift. Globally, on a full year, we observed that the additional savings arising from the coordinated activation of flexible resources in a collective framework highly depends on the remaining local production after the naturally complementary non-flexible demand is covered by community exchanges. Indeed, it may happen that significant flexible efforts, in terms of loss of comfort, could be needed to save some extra money which is not necessarily optimal. For the same reasons, only minor, but which deserve to exist, impact on the grid performances were observed regarding the reduction of line losses in the local distribution network and increase levels of self-consumption and self-sufficiency. Regarding the repartition of collective benefits among participants with the proposed explicit flexibility reward mechanisms, we showed that they achieved equivalent performances. Indeed, as they explicitly integrate in their definition the levels of offered and activated flexibility volumes, a larger share of the savings linked to flexible actions goes to the most flexible end-users.

The second part of Chapter 3 was rather dedicated to the resolution method adopted to solve the coordinated problem. Indeed, with centralized approach it is required from members to communicate all the data relative to their flexible devices with the community manager. To preserve data-privacy, we developed a decentralized and intuitive resolution algorithm to solve the flexibility scheduling problem within the REC. The propose approach enables to offer results close to the centralized method, with only 3.22 % deviation in the best case, without increasing the computational burden like state-of-the-art bilevel or ADMMs techniques. We also pointed out thermal loads such as water boilers and heat pumps to be promising flexible resources as their smart management can improve the usage without generating any discomfort for the members. On top of that, the investigation of several Keys of Repartition mechanism for the activation of offered flexible capacity did not lead to key differences on the REC level as the iterative nature of the proposed approach makes sure that all the requested flexibility volume is matched when there is enough flexibility potential. Finally, one showed that the flexibility participation and hence the individual benefits distribution is mainly driven by the flexible assets ownership.

Then in Part II, we focused on long-term decisions of community members. More specifically, in Chapter 4 we presented the investment strategies specific to Energy Communities which expand the possibilities of assets ownership and location. Then, in Chapter 5, we proposed a two-steps optimisation method. This method sequentially defines the best investment strategy for the installation of Distributed Energy Resources, essential for the organisation of local exchanges, and the local electricity prices, to incentivize members on the long-run. The first objective being the collective performances and the second one being the fairness in the distribution of benefits among members, the hierarchical resolution of those problems limits the feasible set of the second objective. To improve the trade-off between collective and individual performances when solving the long-term planning problem, three ways to adapt the former model, were presented. The first one is to consider a more advanced internal pricing structure than the state-of-the-art unique, but dynamic, price. Relying on the innovative investment strategies allowed by ECs, additional degrees of freedom are considered in the second step of the model to improve fairness. The second alternative is to integrate the Energy Surplus sharing rules mathematical formulation from Chapter 3 in the first step to ensure that individuals are not discriminated when dispatching the local energy based on their retail tariffs. Lastly, we introduced a single-step formulation to define the whole set of long-term decisions while considering a multi-objective function accounting for both individual and collective performances. The different resulting models are validated on multiple combinations of REC with 10 end-users each. Results showed that adopting a dynamic tariff structure can help to equilibrate individual savings without affecting the global performances of the community. On the contrary, including Keys of Repartition in the investment problem degrade both collective and individual performances but the obtained results give a more realistic estimation of future savings when subject to regulatory rules requesting the adoption of such sharing mechanism. Finally, the single-step approach exhibited the potential to offer a flat price to end-users and equal individual cost savings while only loosing a small portion of collective savings.

Although Chapter 6 also addressed questions relative to the long-term planning of energy resources within Energy Communities, it extended the framework to another energy demand that is mobility. The business model (i.e., vehicle-ride assignment, charging costs) of a Mobility Service Provider was coupled with the EC model with the aim to optimally size a fleet of shared electric vehicles. The two business models were evaluated independently from each other and in a coordinated approach. The comparison demonstrated that collaboration between EC and MSP yields to mutual benefits, especially when Vehicle-to-Grid capability is considered. In this case, they can save up to 11.3 % on the cost mainly through reduced retail costs with an increased self-sufficiency from 32 % (Scenario 1) to 43 % (Scenario 3). The proposed model integrated the network configuration and limits to decide on the best location for the charging stations. Results revealed that the optimal location is highly dependent on the network topology and finally, the introduction of V2G functionality unlocks a large flexibility potential to help the system operator reducing the stress at the transformer with a peak reduced by 46 %.

Finally, Part III introduced the concept of human decisions uncertainty. This concept is still barely investigated in the literature but quite sensitive when studying multi-agents problems. Indeed, when end-users are interacting in their decision-making the behaviour of others can affect its own performances. Hence, in this thesis we investigated two situations that may arise within Communities that are linked to uncertainty in the actual decisions of end-users. First, in Chapter 8, we showed the impact of newcomers on founding members savings. These initial members, who invested optimally in DER assets, are significantly affected by new end-users joining the local exchange structure. Indeed, results collected on a test case composed of a set of 92 end-users show that initial members can lose up to 25% savings compared to the initial optimal sizing case. We also demonstrated that oversizing the assets dampens negative effects but reduces the REC performances. The presence of storage in the initial DER mix increases the expected benefits of founding members, consequently increasing the negative cost deviations when newcomers join the community (up to 35% loss). Furthermore, we highlighted that the impact of newcomers on the economics of the EC depends on their characteristics and on the founding members profiles. An important notice to bear in mind is that the individual perception of newcomers arrival also depends on the sharing rules considered in the EC.

In the subsequent Chapter 9, we introduced the concepts of bounded rationality and limited observability in the REC operational framework. To this end, a stochastic near-optimal robustness bilevel programming approach was proposed for the energy sharing problem of the EC, allowing uncertainties in internal prices caused by limited observability to be mitigated. The boundaries for uncertainty sets related to internal price deviation variables were identified using an algorithm reflecting the impact of consumption behaviour deviations on internal prices deviations. Through the use of epigraphical reformulation and affine parameterization of uncertainty sets, the lower-level problem was reformulated to satisfy KKT conditions and subsequently transformed into a single-level model suitable for analytical solutions. The results showed that by mitigating limited observability of internal electricity prices, prosumers primarily reduced their load consumption during periods of low or no PV generation and increased consumption during PV generation periods to prioritize self-consumption. Similarly, consumers reduced their consumption levels throughout the day, as the marginal utility of load consumption was lower than the internal electricity prices for them. Overall, the results demonstrated that, on average, members reduced their total consumption by 14.64 % when mitigating limited observability. Nevertheless, accounting for PV generation uncertainties had a marginal impact (less than 1 % increase) on the total load consumption for most users, driven by more PV scenario realizations. Besides, we quantified that mitigating both limited observability and PV generation power uncertainties led to an approximate 14 % reduction in the total power purchased by members from the CM, while their total power sales to the CM increased by around 70 %. This improvement is attributed to the realization of various PV generation scenarios. Additionally, the CM experienced an average 17 % reduction in its power purchases from the supplier. Meanwhile, an average of 0.091 kW was sold back to the supplier, whereas in the deterministic case, no power was sold back. The reduced power purchases and self-consumption by PV prosumers led to lower voltage drops and decreased active power losses. Regarding community manager prices, an average decrease of 0.5 € and 0.3 € in the internal buying and selling prices, was obtained. Additionally, the social welfare of community users improved, rising by an average of 12.56 %. However, the total cost of the CM increased by 13.21 € which is due to a reduction in the revenues of internal exchanges with the community members. Finally, the out-of-sample analysis on PV power generation demonstrated that employing the stochastic method resulted in more realistic social welfare outcomes compared to the deterministic method with a difference in precision around 2 % between both methods. Worst-case analysis on internal electricity prices revealed that limited observability led to greater robustness against internal price deviations, resulting in fewer degradation in objective function values.

10.1. Perspectives for Future Research

Although this thesis has actively contributed to the research questions identified regarding the decision-making in Renewable Energy Communities, there are still modeling aspects that could be improved or underlying research paths that could be investigated.

10.1.1. On the Fair and Optimal Coordination of Flexible Resources within Energy Communities

Perspective 1: Accounting for data uncertainty in the day-ahead scheduling problem.

As presented in Part II, the scheduling of flexible resources in Energy Communities usually takes place in day-ahead. This gives sufficient time to participants to accommodate with the schedule and plan their actions, especially when flexible devices require a manual action. To optimally schedule these appliances, the local production and baseload consumption must then be estimated as we look ahead of the settlement period. In this thesis, we mainly assumed a perfect forecast of those quantities (except for Chapter 9) which might be optimistic. In practice, there is always a level of uncertainty regarding the realisation of local production and baseload consumption. To adopt a risk-aware scheduling approach, the proposed deterministic optimisation problem may be upgraded into a stochastic problem considering potential scenarios for the next day. Doing, so it would prevent to face major deviations between the scheduled and observed cost reductions due to the imperfect forecast. This perspective began to be addressed in Loïc Liégeois's master's thesis, for which I was co-supervisor [212].

Perspective 2: Extending the provision of flexibility to external stakeholders.

In this thesis, we focused on the provision of flexibility to optimally take advantage of the local production. This objective was mainly driven by the advantageous price traded within the RECs with respect to the retailer ones. Nevertheless, other flexibility incentives, explicit or implicit, may come from other stakeholders outside of the community but who might be affected by their behaviour. For instance, as introduced in Chapter 7, community members may provide a joint response to capacity prices charged by the Distribution System Operator. This could reduce the stress experienced by substation transformers which accelerates their ageing. An other actor who might benefit from the flexibility within Energy Communities is the electricity supplier. To reduce the imbalance settlement cost or to make arbitrage on the wholesale market, it may send incentive signals to members. Their coordinated response would be more reliable than the sum of individual responses (e.g., change in the imbalance direction). Those additional incentives might be taken into account in the objective function of the scheduling problem if they are implicit or modelled as additional constraints for explicit requests.

10.1.2. On the Optimal Sizing and Pricing of Distributed Energy Resources in Energy Communities

Perspective 1: Studying the impact of REC investment strategies on future network infrastructures.

The massive penetration of Distributes Energy Resources within the power systems raises a major challenge for system operators. Considering this major change coupled with the growing electrification of the needs, the old network infrastructures begin to struggle to ensure a reliable supply of electricity. The high injection and consumption levels flowing through substation transformers and cables create significant losses and degrade the installations. In addition, some substation are reaching their maximum capacity which prevents new customers from connecting.

Hence, to support the energy transition, the transmission and distribution system operators are considering modernising their facilities. Nevertheless, this represent a huge investment which might take time to implement. However, by coordinating the long-term and short-term decisions of several end-users located in the same area of the network, Energy Communities may help reduce the stress on the infrastructures and defer the system operators investment. To this end, we started to work on a bilevel model considering the Distribution System Operator as the leader of the Stackelberg game who aims to schedule its future network investment to offer a reliable power supply at minimum cost. In addition, its decision set also include the network tariffs that would be charged to end-users to respect its budget balance. Besides, end-users acting individually or gathered in RECs aim to schedule their investment in local production and storage systems to minimize their electricity bill.

Perspective 2: Speeding up the resolution of the single-step method.

When the single-step approach was introduced in Chapter 6 to solve the long-term planning problem of Distributed Energy Resources in RECs, internal electricity prices were relaxed to discrete variables instead of continuous ones. If this method enabled to keep the problem linear and preserve the global optimality guarantee, it induced the introduction of many binary variables. Besides, Keys of Repartition principle introduced in Chapter 3 and also implemented in the long-term model can also be used in the long-term problem to improve the fairness indicator. For some of them, the mathematical formulation to be embedded also implies additional binary variables, for each time step simulated on the investment horizon. This might significantly increase the computational burden when the model is applied to large communities with large simulation periods. To speed up the resolution of the problem we may think about using evolutionary algorithms. The principle behind these algorithms is to generate and evaluate feasible solutions iteratively to find the best ones, the tested solutions being affected by the results of the previous iterations. In our case, one could assess the objective function value for different combinations of long-term decisions that would serve as input for short-term problems. This would further enable to parallelize the resolution at both time scale by first testing simultaneously different long-term feasible solutions. Then, for each of these solutions, the short-term resolution may be decomposed day by day if we do not consider sequentiality in the short-term decisions (e.g., by imposing a fixed battery state-of-charge at the end of the day).

10.1.3. On the Integration of Human Decisions Uncertainty in optimisation Models for Energy Communities

Perspective 1: Introducing recourse actions when end-users join or exit the REC.

In Chapter 8, we quantified using an open-loop analysis the impact of new members on the individual savings made by founding members who originally created the REC and invested in DERs. To improve this study, we could first extend the scenarios considered to the departure of some founding members. In this case, we should first formalize how the REC would be affected when a member that invested in joint assets leaves it. Indeed, several options may exist. For example, this member could receive the remaining money needed to recover its investment from other members or it may keep part of the assets for its personal usage. Then, the second natural step is to identify what would be the best recourse actions that would reduce the impact of the evolution of REC composition on participating members in order to guarantee their engagement on the long-run. These recourse actions can be of different natures. The internal prices and energy sharing rules may be adapted or additional DERs may be installed to maintain the collective and individual performances stable. Finally, another option to prevent large disturbances for founding members when the community evolves is to anticipate these changes by explicitly consider scenarios of end-users exiting or joining the REC in the long-term planning problem.

Perspective 2: Integrating explicit bounded rational behaviours of REC members in hierarchical flexibility scheduling problems.

We introduced in Chapter 9 the concept of bounded rationality by integrating limited observability in the flexibility scheduling problem. This limited observability paradigm is represented by considering an uncertain deviation range around the price offered by the community manager in day-ahead to the participants. This enables to account for the real price uncertainty that will be affected by the actual behaviour of end-users in real-time. Therefore, the lower-level problems were robustified to limit the effect of such price deviation on their electricity bill. Nevertheless, we may also consider that the community manager directly edge against near-optimal decisions of REC members by taking robust price incentives decisions in day-ahead. We started working on this question by considering the same baseline bilevel problem than in chapter 9. However, in this case, the lower-level actors are assumed to have a tolerance ϵ around their optimal electricity bills. This tolerance is used to reflect the potential bounded rationality of their decisions. On the other hand, the community manager aims to schedule its day-ahead trades in order to limit the real-time imbalance in case of near-optimal decisions of end-users.

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