FACULDADE DE ENGENHARIA DA UNIVERSIDADE DO PORTO

Managing Flexibility Resources in Energy Communities

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September 30, 2025

Resumo

À medida que a transição energética na Europa ganha velocidade, as comunidades de energia renovável tornam-se um pilar dos sistemas energéticos descentralizados, impulsionados pelos cidadãos. Para além de promoverem a produção local e o autoconsumo coletivo, as comunidades de energia estão a afirmar-se como facilitadoras centrais de flexibilidade: uma característica do sistema de crescente importância face ao aumento da quota de energia renovável variável na produção. Contudo, embora a capacidade técnica de flexibilidade de ativos descentralizados como as baterias seja amplamente reconhecida, a sua aplicação real continua a ser dificultada por barreiras regulamentares, económicas e operacionais.

Esta dissertação explora a capacidade das comunidades de energia para oferecer serviços de flexibilidade, com foco no potencial dos sistemas de armazenamento de energia em baterias à escala comunitária e no contexto atual do mercado português de flexibilidade. A metodologia proposta, composta por duas etapas, é a seguinte: numa primeira fase, a bateria é programada de forma otimizada para minimizar o custo da eletricidade da comunidade; na segunda, o seu potencial para responder a solicitações de flexibilidade por parte do operador da rede de distribuição é analisado, simulando a participação no mecanismo de mercado FIRMe da E-REDES.

Esta estratégia é validada através de um caso de estudo de uma comunidade rural, utilizando dados reais de produção e consumo com resolução de 15 minutos ao longo de um ano. Os resultados demonstram que, se a bateria for reconfigurada para maximizar receitas de flexibilidade em vez de operar com base na minimização de custos para a comunidade, os encargos energéticos podem aumentar até 49%, enquanto a remuneração média obtida se mantém insignificante: inferior a 100€ por ano, mesmo nos cenários mais favoráveis. Verifica-se, assim, um claro compromisso entre a auto-otimização económica e a participação em mercados externos, sendo que os atuais esquemas de incentivos não compensam adequadamente a comunidade pelas poupanças perdidas nem pelo aumento da complexidade operacional.

Para além da análise quantitativa, a dissertação disponibiliza uma ferramenta de simulação que permite a gestores de comunidades e agregadores testar diferentes estratégias operacionais e ofertas de flexibilidade sob as atuais limitações regulamentares. As conclusões sublinham a necessidade de um enquadramento legal mais ajustado e de mecanismos de mercado mais atrativos, de forma a potenciar uma contribuição significativa das comunidades para a flexibilidade do sistema elétrico. O estudo propõe ainda novas direções para investigação futura, nomeadamente o impacto da degradação das baterias associada a padrões de operação orientados para redução de custos, e as dimensões comportamentais da participação comunitária nos mercados de flexibilidade.

Ao colmatar a lacuna entre a modelação técnica e a aplicação prática, esta dissertação fornece uma base robusta para avaliar e expandir estratégias de flexibilidade baseadas em comunidades de energia, promovendo um sistema energético mais resiliente, descentralizado e participativo.

Palavras-Chave: flexibilidade, comunidade de energia, sistemas de armazenamento, autoconsumo, autoconsumo coletivo.

Abstract

As the energy transition in Europe is gaining speed, renewable energy communities are becoming a pillar of decentralized, citizen-driven energy systems. Beyond supporting local production and self-consumption, energy communities are becoming central facilitators of flexibility: a system characteristic of paramount importance in the context of increasing shares of variable renewable energy. But while the technological capability of flexibility of decentralized assets such as batteries is assumed, its real application remains hindered by regulatory, economic, and operational barriers.

This dissertation explores the ability of energy communities to offer flexibility services, with focus on the potential of community-scale battery energy storage systems in the Portuguese flexibility market. The proposed two-stage approach is as follows: first, the battery is optimally scheduled to minimize the community's electricity cost following adaptive price-based rules; second, its potential to respond to distribution system operator flexibility requests is investigated, modeling contribution to the E-REDES FIRMe market mechanism.

This strategy is supported through a case study of a rural community, using actual production and consumption data at 15-minute resolution for one year. Results show that if the battery deviates from cost-optimized operation and is reconfigured to optimize flexibility revenue, energy costs rise by as much as 49% whilst remuneration is still negligible, less than €100 per year, despite even the most favorable assumptions. There is a clear trade-off between economic self-optimization and taking part in external markets, and current schemes of incentives are lacking to remunerate the community for lost savings or increased operational complexity.

Alongside the quantitative modeling, the dissertation offers a simulation tool which enables community managers and aggregators to assess different operating strategies and flexibility offers under real regulatory burdens. The findings highlight the need for more differentiated policy support and more stimulating market mechanisms if energy communities are to contribute significantly to system-wide flexibility. The study also sets new directions for future research, including the impact of degradation of batteries under cost-based operation, and the behavioral dimensions of community participation in flexibility markets.

By bridging the gap between technical modeling and practical application, this book provides a robust foundation on which to evaluate and upscale community-based flexibility strategies, allowing for a more resilient, decentralized, and participatory energy system.

Keywords: flexibility, energy community, battery energy storage system, self-consumption, collective self-consumption.

Acknowledgements

This section is written in Portuguese at the author's personal discretion.

São assim materializados anos de aprendizagem, partilha, luta, e comunidade, num percurso que só pode ser caminhado passo a passo, do qual foi palco a mui nobre Faculdade de Engenharia da Universidade do Porto, à qual estendo a mais profunda gratidão.

Ao Professor Doutor Cláudio Monteiro, agradeço as discussões de ideias, a orientação, a compreensão e o apoio, sempre com uma palavra amiga.

Ao meu Pai, por desde cedo saber que eu podia ser tudo aquilo que quisesse, sempre elevando todos os meus feitos, não olhando à sua dimensão: o meu obrigado.

Ao João Pinho, enalteço a paciência, o companheirismo e o amor que sempre pautaram a nossa vida em comum, com a certeza de que colecionaremos ainda maiores vitórias.

Ao Pedro Mota, amigo e confidente, reconheço as horas de dedicação conjunta a um propósito que se sobrepõe à Academia; por vezes por gosto, outras por teimosia, mas sempre por partilharmos o mesmo conjunto de valores, que de certo perdurarão pelos nossos largos anos de amizade.

Ao Gonçalo, ao Nuno e à Beatriz, agradeço a insistência, a palavra conselheira e o amparo. Ao André e ao Gustavo, pela sua presença em todas as etapas da minha trajetória, e por nela se terem mantido, um abraço de grande apreço.

À M. Idalina, M. de Lurdes e M. da Graça, dedico o meu título de Mestre em Engenharia Electrotécnica e de Computadores. Mais do que berço e colo, são prova de que a educação e o amor podem mudar o mundo. Mulheres de força e coragem, tenho em vós muito orgulho. Levarei comigo, no coração e ao longo da carreira, o exemplo que partilham com todos ao vosso redor.

A quem, de alguma forma, acompanhou o meu percurso académico e pessoal, deixo uma palavra final de reconhecimento.

Beatriz

‘Não te esqueças da mochila do almoço. Beijinho, amo-te.’

Idalina

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List of Acronyms

ANS	Ancillary Services
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
CEC	Citizen Energy Community
CHP	Combined Heat and Power
CIEG	*Custos de Interesse Económico Geral*
CM	Capacity Market
CPP	Critical Peak Pricing
CSC	Collective Self-Consumption
DB	Demand Bidding
DER	Distributed Energy Resources
DSF	Demand-side Flexibility
DSM	Demand-side Management
DSO	Distribution System Operator
DLC	Direct Load Control
DR	Demand Response
EC	Energy Community
EDR	Emergency Demand Response
EGAC	*Entidade Gestora do Autoconsumo Coletivo*
EMD	Electricity Market Design
ENA	Energy Networks Association
ERSE	*Entidade Reguladora dos Serviços Energéticos*
EV	Electric Vehicle
HEMS	Home Energy Management System
INL	Interruptible Load
IU	*Instalação de Utilização*
LEM	Local Energy Market
LFM	Local Flexibility Market
P2P	Peer-to-peer
PHES	Pumped Hydro Energy Storage
PNEC	*Plano Nacional Energia e Clima*
PV	Photovoltaic
REC	Renewable Energy Community
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RESP	*Rede Elétrica de Serviço Público*
RTP	Real-Time Pricing
SDG	Sustainable Development Goals
SME	Small-Medium Enterprise
SOC	State of Charge
TAR	*Tarifa de Acesso às Redes*
TCL	Thermostatically Controlled Load
TE	Transactive Energy
ToU	Time-of-Use
TSO	Transmission System Operator
UPAC	*Unidade de Produção para Autoconsumo*

Chapter 1

Introduction

1.1 Context and Motivation

The entry into force of the Paris Agreement in 2016 served as an impetus for the European Union to set the ambitious goal of striving to be the first climate-neutral continent by 2050. This objective is materialized in the European Green Deal, with the key promise of reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels [1]. A decarbonized EU energy system is thus fundamental to achieving the 2030 climate goals and the long-term strategy of becoming carbon neutral by 2050.

To reach these goals, the integration of Renewable Energy Sources (RES) is crucial. It can be expected that by 2025, 2030, and 2040, the share of end electricity demand met by RES will have grown very substantially, as Figure 1.1 illustrates. In the EU-28, 64% of power can be supplied in 2030 and 78% in 2040 from renewables. With their contribution to the electricity mix rising to as much as 44% by 2030 and 61% by 2040, variable renewables — wind and solar — are leading this transformation [1].

However, the production uncertainty of these resources is a primary cause of grid instability, resulting in issues such as congestion, frequency, and voltage imbalances [2]. Consequently, the rapid deployment of RES poses significant challenges, mainly due to the need for sufficient flexibility to manage the fluctuations in renewable supply, resulting in double the flexibility needs by 2030 [3], as seen in Figure 1.2.

Flexibility refers to the "ability of the energy system to adjust demand and supply in reaction to external conditions" [3]. Traditionally, flexibility is largely provided by fossil-based, dispatchable generation. While this ensures system stability, it comes at the cost of significant greenhouse gas and air pollutant emissions [4], making it increasingly incompatible with the EU's 2030 greenhouse gas reduction target and 2050 climate neutrality objectives. Therefore, the electricity system needs to have a well-designed and suitably incentivized mix of flexibility solutions in order to meet the challenges of today and scale up appropriately in the upcoming decades.

[1] https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en

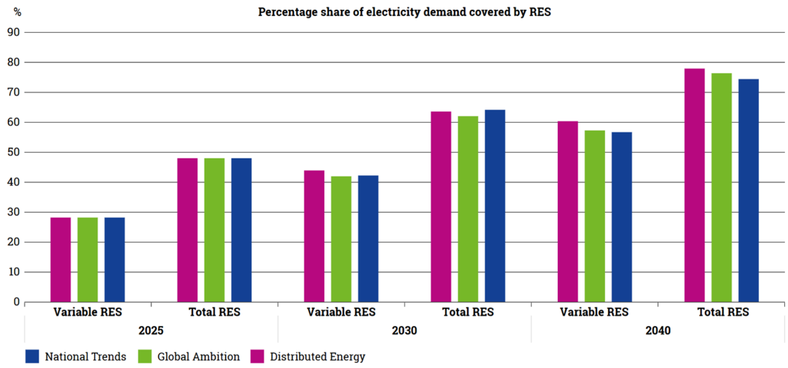

Figure 1.1: Renewable resources share of the total electricity demand in 2025, 2030, and 2040 [1].

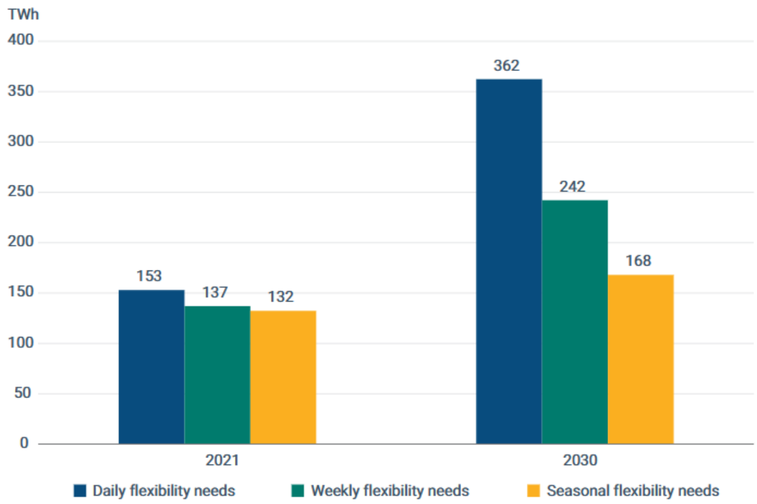

Figure 1.2: European demands for daily, weekly, and seasonal flexibility in 2021 and 2030 [3].

More recently, demand-side flexibility has proved to be a viable approach. Demand-side flexibility (DSF) is defined as "the ability of a consumer to deviate from its normal electricity consumption profile, in response to price signals or market incentives" [5]. Programs such as demand response schemes, where consumers reduce or shift electricity usage during peak periods, have shown promise for decentralized flexibility [6]. However, because individual actions have little effect and necessitate extensive coordination, depending solely on isolated consumer participation poses scalability issues.

To address these challenges, Energy Communities (ECs) emerge as a promising solution, enabling more efficient and collaborative local energy management. Energy communities can take many different legal forms and are frequently municipal corporations or cooperatives. The main goals of community energy initiatives are to provide their members or shareholders with inexpensive energy and to encourage the adoption of new technologies. Through these energy initiatives, citizens are increasingly becoming prosumers who eventually pool their resources, enabling the community to take part in the electricity markets [7].

ECs introduce a more structured approach to flexibility management. Unlike isolated consumers, ECs aggregate flexibility resources across multiple participants, thereby enhancing their collective value. By coordinating flexibility across various consumers, ECs create richer opportunities to optimize energy use, reduce grid congestion, and participate in flexibility markets more effectively than individual consumers alone. This collective strategy not only benefits local participants by lowering energy costs and enhancing self-sufficiency but also supports the broader energy system by reducing reliance on fossil-based flexibility resources. EU-funded projects such as COMPILE [8] have demonstrated the viability of ECs in providing decentralized flexibility while promoting renewable integration.

In Portugal, the regulatory framework has been evolving to support the decentralization of the energy sector. A key milestone in this transition was the Regulation No. 5/2023 issued by Energy Services Regulatory Authority (ERSE) [9], which establishes rules for the flexible operation of the electrical grid. This aligns with broader European directives, such as the Renewable Energy Directive (RED II), which promotes citizen participation in energy markets through Renewable Energy Communities (RECs) [10]. With a growing decentralized network (i.e. an independently operated decoupled energy system [11]) that includes active installations such as renewable generation, storage, and consumption, optimizing grid management now depends on leveraging flexibility from these new technologies. This regulatory framework recognizes the role of active consumers who, individually or collectively within energy communities, generate electricity for self-consumption, inject energy into the grid, store electricity, and provide flexibility services.

Given this context, it is essential to study and understand how energy communities can provide flexibility services, considering the perspectives of different stakeholders and the diverse energy assets managed within the community. Additionally, it is necessary to explore which control and operational mechanisms can be utilized by ECs to efficiently implement these flexibility strategies. This research will contribute to identifying best practices and developing frameworks that enhance the role of ECs in the evolving energy landscape.

1.2 Objectives

The general objective of this dissertation is to investigate the function of flexibility services in energy communities and how flexibility services could be employed to obtain a more efficient and more resilient energy system.

As decentralized energy resources become increasingly interconnected, ECs can help enable the greater deployment of renewable energy, provide demand-side flexibility, and participate in flexibility markets to the advantage of both community members and the wider power system. To this end, it is necessary that there is a strong appreciation of the regulatory framework, economic feasibility, technological choices, and market pressures that are available to ECs.

The aim of this dissertation is to attain a well-structured discussion of the mentioned factors and propose actions on how to maximize flexibility management in ECs.

To attain this general objective, the following are the precise objectives:

- To define the role of energy communities in providing flexibility, and outline their future contribution from that of individual consumers.
- Analyze the regulatory framework that governs flexibility services at the European and Portuguese levels, assessing how policies currently in place enable or restrict EC participation in flexibility markets.
- Identify the most influential stakeholders in EC flexibility management, such as consumers, prosumers, aggregators, and system operators, and describe their roles, responsibilities, and relationships.
- Investigate different types of flexibility resources present that ECs can utilize, such as demand response, distributed storage, and renewable generation curtailment.
- Develop simulation-based techniques to analyze EC participation in flexibility markets based on production and consumption patterns, price risk, and market incentives.
- Assess the economic viability of flexibility services in ECs, such as the economic impact on members of the community, grid operators, and other market participants.
- Explore control frameworks and operating policies that ECs may employ to successfully regulate flexibility and enhance their participation in energy markets.
- Provide recommendations to market and policy stakeholders for best practice and regulatory adjustments which would position ECs in greater prominence within flexibility markets.

With the accomplishment of these objectives, this dissertation shall be an effective contribution toward the whole understanding of how energy communities can optimally utilize flexibility services in a manner that supports their economic and technical sustainability alongside energizing the wider energy transition agendas.

1.3 Methodological Approach

This dissertation takes a systematic approach in exploring how energy communities can contribute most effectively to flexibility services and optimize their management practices. The first step is a thorough analysis of the flexibility mechanisms and services provided in Portugal and an outline of the regulatory and market environment supporting them. This will give a clear picture of the flexibility services provided, their type, and how they are integrated into the national electricity grid.

Subsequently, the dissertation will consider EC organizational arrangements in terms of different governance configurations, stakeholder roles, and operating contexts. This will assess how different community configurations influence the ability of ECs to provide and demand flexibility services.

From this, the research will go on to describe and define flexibility management and control mechanisms that can be utilized by EC operators. These mechanisms will consider the interests of different stakeholders — prosumers, consumers, aggregators, and system operators — as well as different energy assets in ECs. The analysis will cover different kinds of energy resources, such as individual and community-level consumption devices, solar photovoltaic self-generation systems, and energy storage systems, to provide a holistic approach to flexibility.

Once these mechanisms are established, they will be tested by means of a simulation-based analysis of flexibility service implementation. The simulation will focus on the operation of an actual EC with an autonomous BESS for a full year, recording energy flows and flexibility actions at 15-minute resolution. This will allow a thorough investigation of how various flexibility strategies affect the energy balance, market participation, and economic returns to community members.

Finally, the dissertation will undertake an examination of the technical and economic benefits of flexibility services. This includes assessment of the impact of different flexibility strategies on the main stakeholders, optimization of financial revenues, optimization of self-consumption, and ensuring grid stability. Different flexibility strategies will be analyzed to determine their appropriateness in maximizing EC profitability and efficiency of the energy system.

By using this strategy, the dissertation aims to develop an organizational model for integrating flexibility services into ECs with the assurance that their implementation will yield tangible economic and operational advantages.

1.4 Structure

This dissertation is structured to provide a logical progression from the theoretical foundation of energy communities and flexibility services to the practical evaluation of their implementation.

Chapter 1 introduces the research topic by presenting the context and motivation behind the study, defining the objectives, outlining the methodological approach, and detailing the structure of the dissertation.

Chapter 2 provides a comprehensive review of the literature, focusing on the definition and evolution of energy communities, the role of flexibility in the electricity sector, and existing models for demand response. It also examines Portuguese and European regulations regarding energy communities and flexibility markets, identifying gaps that this research aims to address.

Chapter 3 presents the methodology for optimizing community battery operation to minimize electricity costs and details the integration of the battery into the Portuguese flexibility market. It introduces key parameters, valuation formulas, and the contractual framework governing flexibility participation. The chapter also discusses the trade-off between cost savings and market revenues, setting the stage for scenario analyses in later chapters.

Chapter 4 presents the case study application. It will quantify the economic and operational impacts of flexibility strategies, assessing their effects on different stakeholders and the energy system.

Chapter 5 provides a conclusive analysis by summarizing the main findings, verifying whether the initial objectives have been met. It also offers final considerations on the applicability of the results and suggests directions for future research to further explore flexibility in decentralized energy systems.

Chapter 2

Energy Communities as Flexibility Enablers

This chapter provides a comprehensive overview of energy communities as emerging actors in the energy transition, with particular focus on how they can promote flexibility in decentralized power systems. It begins by describing the conceptual and legal foundations of ECs, their purposes, organizational models, and regulatory frameworks at both EU and country levels. Subsequently, the chapter centers on the key dimension of flexibility, exploring how it is modeled, what technological facilitators enable its use, and design of the market structures enabling accommodation of community-based flexibility resources. In integrating technical modeling, legal setting, and market participation, this chapter lays the foundations for exploring how renewable energy communities can, in a positive way, enhance the efficiency, resilience, and sustainability of the system through local flexibility services.

2.1 Objectives and Scope of Energy Communities

Conventionally, energy has been transported across large distances from generation sites to final consumers, following a systematic value chain — generation, transmission, distribution, and supply. Therefore, the centralized management of the power sector allowed a limited number of parties.

The paradigm shifted with the upsurge of alternative energy sources, making it possible for users to generate and consume energy locally. Furthermore, it is technically viable to generate electricity beyond the user's requirements in order to supply an additional user in the area, thereby extending the benefits to the community. However, since various consumers are generally physically connected via the large-scale distribution grid, the standard is determined by the centralized scheme. Thus, the concept of sharing surplus electricity is not easily achievable in the majority of scenarios [12].

Energy communities, aiming at social good, green causes, and community ownership over profit, are a new business model born out of these developments. It enables users to pool their resources and compete on equal terms with the incumbent players in the energy market, both technologically and economically [12].

Despite their promise, effective implementation of ECs requires well-understood structure, governance models, and regulatory regimes. Energy communities are established in European and national law, which sets out their operational boundaries and legal entitlements. Nevertheless, beyond technical definitions, of concern is examining how ECs function in practice, namely their economic and technical advantages, the most pertinent stakeholders, and how they are permitted to be integrated into energy markets. This section aims to provide an integrated presentation of ECs' fundamentals, organizational structures, and how they create opportunities.

2.1.1 Definition and Key Principles of Energy Communities

First defined by European Directive RED II [10], a renewable energy community is a legally recognized organization founded on voluntary and open participation, independent, and efficiently governed by shareholders or members situated close to renewable energy projects, functioning in accordance with the relevant national legislation.

Subsequently, the Electricity Market Directive [13] promoted the idea of a Citizen Energy Community (CEC), which has slightly more limited characteristics than ECs but a wider spatial extent. In this regard, community-based energy systems are becoming more popular among practitioners and policymakers as viable models for bringing about a low-carbon society.

The greatest distinctions between the RECs and CECs definitions are highlighted in Table 2.1. Where RECs only work with renewable energy, CECs can play a role in any sector of the electricity business and are technology-unrestricted. Furthermore, RECs operate on a local foundation, yet CECs are restricted by no such thing. Since RECs tend to have more stringent eligibility criteria, requirements of effective local control, and democratic decision-making, they also form a subgroup of CEC from a governance perspective [1]. According to [14], the core objective of operations by energy communities is to undertake activities that are in favor of regional and local economic and environmental interests in an attempt to attain self-sufficiency.

Regardless of their legal definitions, according to [15], energy communities have to follow these operational principles:

- All users can directly participate in the production, consumption, or sharing of energy.
- Instead of putting profit first, community energy projects prioritize providing members or shareholders with affordable electricity.
- Community energy programs show their ability to support the integrated adoption of new technologies and consumption patterns, such as demand response and smart distribution grids, by interacting directly with customers.
- Through decreased usage and lower supply rates, community energy can also promote family energy efficiency and combat energy poverty.

[1] https://www.rescoop.eu/toolbox/how-can-eu-member-states-support-energy-communities

Table 2.1: Comparison of renewable energy communities and citizen energy communities. Adapted from [8].

	REC	CEC
Distinct Characteristics		
Legal Basis	Renewable Energy Directive	Electricity Market Directive
Control	Effectively controlled by shareholders or members located near renewable projects.	Effectively controlled by members or shareholders, including natural persons, local authorities, or small enterprises.
Scope of Activities	Focused on renewable energy projects.	May engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders.
Shared Characteristics		
Participation	Open and voluntary participation.	
Eligible Participants	Natural persons, Small-Medium Enterprises (SME), local authorities, including municipalities.	
Primary Purpose	Provide environmental, economic, or social benefits to shareholders, members, or local areas rather than financial profit.	

- The market engagement of certain residential customer groups is made possible by community energy.

The successful practical implementation of energy communities not only depends on favorable regulatory frameworks but also on the ability to deal with divergent stakeholders, utilize enabler technologies, and develop business models that are conducive to long-term financial sustainability.

The ensuing sections will highlight the various forms of organization for energy communities and the economic potential they offer, followed by an analysis of the legal framework that governs their existence. While energy communities may be presented in different configurations, the focus of the subsequent sections will be on renewable energy communities since they constitute the most universally applied and clearly defined model in European and national law, though in particular within the Portuguese legal framework.

2.1.2 Organizational Models of Energy Communities

In practice, energy communities display diverging characteristics, mainly in terms of purposes, membership, and governance structures. Through rules on different legal persons, and other forms of collaboration, ECs have considerable space to devise their own internal organization [16]. The organizational models dictate how decisions are made, how benefits are distributed among members, and how the community interacts with the broader energy system. While regulatory frameworks provide a legal foundation for ECs, their implementation depends on the selection of an appropriate structure that captures local needs and stakeholder interests.

2.1.2.1 Governance Structures

Governance is shaped by membership rules, decision-making processes, and control mechanisms. Table 2.2 presents a synthesis of the most prevalent governance models for renewable energy communities identified in the literature and reflected in implementation. These classifications show how communities have the potential to adapt their operation based on the local objectives, profile, and resources [17].

2.1.2.2 Key Stakeholders

Before any technical consideration, the examination of the interactions among the different participants, particularly regarding the long-term stability of the community, is of extreme importance when it comes to energy communities [35].

Stakeholders can be defined as "the range of actors who are likely to use a system or be influenced either directly or indirectly by its use" [36]. To design a EC, a stakeholder analysis must be conducted in order to determine the relevant parties affected by the reconfiguration of the energy system, evaluating its consequences [36]. Stakeholder interactions evolve throughout time to accommodate the uncertainty imposed by several actors. Conversely, multi-stakeholder coordination aids in the effective distribution of resources within the community [7].

To effectively guide the design and management of RECs, it is necessary to understand the specific roles and, in the context of this dissertation, the flexibility contributions of all the stakeholders. These actors range from internal players to external agents dealing with regulation, market interfacing, and infrastructure management. Table 2.3 categorizes the relevant stakeholders, summarizing their functional roles within the REC and explaining how each contributes to system flexibility.

Within the community, it is necessary to aggregate lower capacity assets, in order to diversify the range of flexibility services and further lower service providers' risk [7]. The aggregator is largely responsible for obtaining the flexibility from the community and trading it to the Transmission System Operator (TSO), Distribution System Operator (DSO), or Balance Responsible Party (BRP). In order to implement a Portuguese REC, it is necessary to set up a *Entidade Gestora de Autoconsumo Coletivo* (EGAC), so as to minimize the impact of self-consumption on the commercial relationship between suppliers and the user facilities that supply them. EGAC is "the entity

Table 2.2: Typology of renewable energy communities based on governance and operational focus.

Governance Structure	**Summary**	**Reference**
Energy Cooperatives	Communities collectively invest in renewable energy projects and share the benefits. They prioritize service to members over profit distribution and have driven renewable energy adoption in many countries.	[18], [19]
Neighborhood Communities	Operate within a defined district or neighborhood, aiming to generate and consume energy locally. They foster resident engagement and contribute to zero-energy goals.	[20], [21], [22], [23]
Municipal Communities	Led by local governments to implement renewable energy and energy efficiency initiatives under their jurisdiction. These communities often integrate energy actions with broader urban planning and sustainable development policies.	[24], [25]
Rural and Agricultural Communities	Promote renewable energy use in rural areas and farmland through technologies like solar, wind, or biomass. They support energy self-sufficiency, sustainable agriculture, and income diversification.	[26], [27], [28]
Island Communities	Focus on transitioning from imported fossil fuels to local renewable sources. They often combine generation with storage and smart grid solutions to enhance energy resilience and sustainability.	[29], [30], [31], [32], [33]
Industrial Communities	Formed by networks of industrial firms to co-invest in and manage renewable energy systems. They aim to reduce energy costs, increase self-consumption, and align with decarbonization goals through collaborative energy planning.	[34]

that represents collective self-consumption with respect to operators and competent administrative bodies, ensuring the relationship with the network operator for the purposes of paying network access tariffs for self-consumption via the public network, as well as the relationship with the aggregator of surplus production for sale on the market" [2].

Numerous actors and stakeholders in the energy landscape interact with one another in this flexibility chain, and their involvement is contingent upon a number of factors, including financial gains [7].

[2] https://www.erse.pt/atividade/regulamentos-eletricidade/autoconsumo/

Table 2.3: Roles and flexibility contributions of key stakeholders in renewable energy communities [7], [37].

	Functional Description	**Flexibility Contribution**
Internal Agents		
Producers	Generate renewable energy within the REC, supplying electricity to the grid and members.	Adjust generation, store surplus, and participate in demand-response programs.
Consumers	Use community energy for their own needs without marketing it.	Shift demand based on signals or incentives; engage in demand-side management.
Prosumers	Combine energy consumption with local production and may inject excess power into the grid.	Enable local balancing, energy sharing, and economic optimization.
Central Storage Operators	Manage collective storage systems to align generation with consumption.	Increase self-consumption, support local arbitrage, and buffer variability.
External Agents		
EGAC	Coordinates relationships within the REC and with external entities (e.g., grid, market).	Ensures accurate sharing, pricing, and regulatory compliance to support flexible operations.
BRP	Manages a demand–supply portfolio and commits to balancing it within a control zone, according to energy programs.	Maintains portfolio balance; ensures compliance with system operator schedules and absorbs financial penalties for imbalances.
Aggregator	Intermediaries between RECs and market/grid operators; may be energy suppliers, BRPs, or independent actors.	Aggregate flexibility for resale; optimize schedules; balance system demand [38].
Supplier	Provides energy to end customers through contracts, sourcing it either from own generation or from markets.	Supports REC flexibility by integrating demand, supply, and surplus trading; may act as aggregator.
DSO	Responsible for the safe, secure, and efficient operation, development, and planning of the low-voltage distribution system.	Uses flexibility for grid congestion control and voltage management; promotes efficient use of local generation.
TSO	Manages, operates, and develops the high-voltage transmission network to ensure long-term grid stability and interconnection.	Utilizes flexibility for system-wide frequency regulation, balancing, and large-scale integration of renewables.
Regulators	Set the legal and market framework for REC operation.	Enable flexible participation through tariffs, incentives, and access rules.
Technology Providers	Deliver infrastructure, platforms, and services (e.g., monitoring, installation).	Enable flexibility through real-time data, forecasting, automation, and Distributed Energy Resources (DER) integration.

Balancing the interests of all stakeholders while optimizing the use of local renewable energy resources is key to an effective EC organizational model that ensures economic sustainability and fairness. In order to achieve this, the manner in which economic benefits accrued within the group are allocated among its members must be clearly defined. The energy trading and benefits allocation systems directly influence stakeholder engagement, long-run viability, and are therefore a central building block in constructing energy communities. Extending this reasoning, the next section reviews the mechanisms for energy exchange and benefit allocation in renewable energy communities.

2.1.2.3 Energy Trading and Benefit Distribution

Local energy communities may adopt either a market-based model or a benefit-sharing model. In [39], a centralized market design for pricing and demand scheduling is proposed, where transactions occur without direct user influence. This approach blends elements of both market-based and benefit-sharing models.

Users of market-based models act egoistically to maximize their personal profit, making them non-cooperative [40]. Users exchange energy on a Local Energy Market (LEM) in market-based models [40]. The main common LEM types,Transactive Energy (TE), Collective Self-Consumption (CSC), and Peer-to-peer (P2P), are used interchangeably in the literature today. Even while the three market types have some things in common, they differ in terms of size, operating scope, and primary trading objective [40].

Benefit-sharing models, as opposed to market-based models, make the assumption that users will work together to maximize the benefit of the entire community and that the benefit will be shared with users to determine their energy bill [40]. In comparison to market-based models, benefit-sharing models have the advantage of being simpler and requiring fewer actions from consumers [41].

The implementation of benefit-sharing mechanisms needs a clear methodology for allocating the created benefits to members of a community. Yet, the distribution of these benefits in a fair way in the context of RECs remains an area of ongoing academic investigation and practical experimentation. The literature proposes a variety of distribution methods, ranging from basic schemes to more sophisticated allocation frameworks.

A synthesis of the most commonly referenced market-based and benefit-sharing mechanisms for energy communities is presented in Table 2.4.

Table 2.4: Overview of local energy market and benefit-sharing models. Adapted from [42].

	Description	Reference
Market-Based Models		
P2P	Allows direct trading of energy without an intermediary. Designed to incentivize users to actively engage in energy markets.	[43]
CSC	Involves co-located prosumers trading surplus energy in a market arrangement. The concept emerges from regulation aimed at empowering energy users and is defined by participants' activities rather than market structure.	[8], [10], [44]
TE	Balances supply and demand through decentralized coordination. Utilizes price signals to autonomously manage distributed resources and ensure system stability.	[45]
Benefit-Sharing Models		
Mid-Market Rate	Prices internal energy exchange at the average of wholesale and retail rates. Balances fairness and market alignment.	[46]
Equal Split Benefit	Divides the total community benefit equally among all participants, regardless of individual input.	[47]
Virtual Net-Billing	Tracks virtual consumption and generation for each member and settles benefits using predefined rates.	[41]
Shapley Value	Allocates benefits based on each member's marginal contribution to all possible coalitions. Fair but computationally intensive.	[48]
Nucleolus	Distributes benefits by minimizing the maximum dissatisfaction across all possible coalitions.	[49]
MinVar	Seeks to minimize the variance in net benefits across participants to promote fairness and stability.	[50]
Shapley–Core	Hybrid approach balancing the fairness of the Shapley value with the stability of core allocations.	[51]

The implementation of the above trading and benefit-distribution models relies heavily on an enabling regulatory framework. In recent years, European and national legislation has evolved to support the technical integration of renewable energy communities into the power system and to create the necessary economic conditions for their long-term sustainability.

The subsequent section analyzes the ways in which these legal advancements have increasingly given RECs greater market access, capacity for flexibility, and infrastructure rights essential for their operation and growth.

2.1.3 Regulatory Framework for Energy Communities

The regulatory landscape has played a central role in shaping the development and implementation of energy communities across Europe. Successive legislative frameworks at both the EU and national levels have provided legal clarity and operational rights for ECs, enabling not only their formal recognition but also their participation in electricity markets, demand-side flexibility, and local grid services.

These legislative advances have opened substantial economic and technical opportunities, supporting the transition toward decentralized, citizen-led energy systems. This section reviews the main legal instruments that have contributed to unlocking the potential of renewable energy communities as active participants in the energy transition.

2.1.3.1 European Law

The Clean Energy for All Europeans Package (CEP) [3] in 2019 was a step forward in EU energy policy. It enabled citizens to become active stakeholders in the energy transition by formally recognizing energy communities as real market actors. This legislative package laid the ground for renewable energy communities to be involved in energy production, use, storage, and sharing.

At the center of the CEP is the Renewable Energy Directive (RED II – 2018/2001), which provides RECs with "the right to generate, store, and sell renewable energy, and to access electricity markets on fair and non-discriminatory terms" [10]. RED II also lays down the legal basis for community-scale demand-response and distributed energy storage, making it possible to have more decentralized and flexible energy systems.

In 2023, RED III (2023/2413) continued these provisions. It mandates the inclusion of RECs in building flexibility frameworks, with special assistance for smart and bidirectional EV charging, local energy storage, and demand-response services. Distribution system operators shall provide RECs aggregated and anonymized data on their contribution to system flexibility [52]. These provisions enhance RECs' ability to contribute to grid stability, maximize energy consumption patterns, and reduce peak demand.

In support of RED, the Electricity Market Directive (EMD – 2019/944) levels the playing field for RECs in the electricity market. It allows them to offer flexibility services, demand-response, and storage aggregation directly or indirectly through aggregators [13].

The 2024 EMD amendment (Directive 2024/1711) enhances these rights even more by rendering energy sharing an option through dynamic contractual arrangements, enabling REC engagement with dynamic price-setting instruments, and encouraging local energy balancing and P2P trading. These changes attempt to remove the flexibility potential for small consumers and introduce new business models for community-based energy projects [53].

[3] https://www.entsoe.eu/cep/

Overall, EU legislation increasingly puts RECs centre stage in enabling distributed flexibility, local energy sovereignty, and innovation led by citizens in power grids. To contextualize the pace of rights made possible by law in Europe, Figure 2.1 illustrates the development of the legal achievements that have enabled the technical and market potentialities for renewable energy communities since 2018.

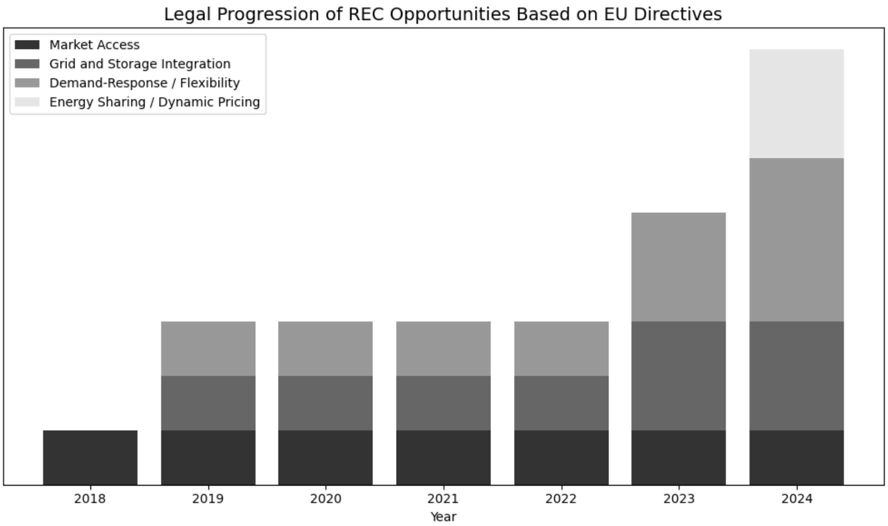

Figure 2.1: Advances in rights and opportunities for renewable energy communities implemented or solidified via EU legislation. The table presents the aggregated legal facilitators across the four functional areas: market entry, grid/storage integration, demand-side flexibility, and energy sharing.

2.1.3.2 Portuguese Law

The EU's ambitious climate and energy goals are translated by Member States into commitments at the national level through their national energy and climate plans. Portugal, through the *Plano Nacional de Energia e Clima* (PNEC) 2030, defines as a line of action the dissemination of distributed production and self-consumption of energy and energy communities, through the promotion, creation, and development of renewable energy communities [54].

To this end, a new legal framework was created, Decree-Law no. 15/2022, of January 14, Organization and Operation of the National Electricity System [55]. This law formally recognizes RECs and enables:

- Individual and collective self-consumption, allowing citizens, businesses, and municipalities to produce and use renewable energy locally.
- The use of *Unidades de Produção para Autoconsumo* (UPACs) and *Instalações de Utilização* (IUs) to structure REC systems.

- A proximity-based connection model for linking generation and consumption via internal networks or the *Rede Elétrica de Serviço Público* (RESP), with defined distance criteria (Table 2.5) depending on the voltage level.

The operation of Portuguese RECs is based on the broader collective self-consumption model, which utilizes UPACs — defined as installations for renewable energy production — and IUs, electrical installations in buildings to provide the owner's energy needs, with or without a supply contract. A Portuguese REC must, therefore, always have an UPAC.

Table 2.5: Proximity criteria for connection between UPACs and IUs in Portuguese RECs. Based on [55].

Connection Type	**Standard Maximum Distance**	**Low-Density Area Maximum Distance**
Low Voltage (LV)	2 km (or same transformer station)	4 km
Medium Voltage (MV)	4 km	8 km
High Voltage (HV)	10 km	20 km
Extra-High Voltage (EHV)	20 km	40 km

In addition, ERSE Regulation No. 5/2023 [9] introduces the concept of RECs as flexibility service providers. RECs can participate in flexibility markets by aggregating distributed resources that are directly or indirectly connected to the public grid. This opens economic opportunities for RECs to offer services such as:

- Peak shaving and load shifting. The first is characterized by a rapid response in consumption reduction, avoiding peak demand charges during a specific time-frame. Load shifting, on the other hand, is an energy management strategy that avoids additional fees by shifting equipment usage to times of lower prices and demand.[4]
- Storage arbitrage.
- Support to DSOs for local congestion management.

Together, these legal instruments empower Portuguese RECs not only to produce and consume renewable energy, but also to provide valuable services to the grid, reduce operational costs, and create new business models around flexibility and energy sharing.

To consolidate the main technical and economic benefits introduced by each legislative milestone, Table 2.6 synthesizes the rights granted across domains such as market access, energy sharing, flexibility provision, and infrastructure integration, illustrating how legislation has progressively empowered RECs to move from passive consumption to active grid participation.

[4] https://www.accuenergy.com/articles/what-is-peak-shaving-and-load-shaving/

Table 2.6: Technical and economical opportunities enabled by legislation for renewable energy communities [9], [10], [13], [52], [53], [55].

Regulation	Opportunities for RECs
European Law	
RED II (2018/2001)	• Produce, consume, store, and sell renewable energy. • Access all suitable electricity markets. • Benefit from fair and non-discriminatory network charges. • Engage in demand-response and energy storage.
RED III (2023/2413)	• Mandatory inclusion of RECs in building flexibility. • Priority for smart and bi-directional charging. • Enhanced support for local energy storage. • DSOs must provide data on REC flexibility contributions.
EMD (2019/944)	• Formal recognition of RECs as market participants. • Access to demand-side flexibility services. • Participation in decentralized storage markets.
EMD (2024/1711)	• Enables energy sharing through dynamic contracts. • Promotes REC participation in dynamic pricing. • Strengthens role in local flexibility services.
Portuguese Law	
Decree-Law 15/2022	• Establishes legal support for collective self-consumption. • Defines technical setup via UPACs and IUs. • Proximity-based grid access rules support localized RECs.
ERSE Regulation No. 5/2023	• Authorizes RECs as flexibility service providers. • Allows aggregation of flexible resources. • Covers consumption, production, and storage linked to the public grid.

The legal development thus described reveals an unmistakable path toward making RECs an integral part of the energy system. As the legislative environment continues to evolve, especially through harmonization of EU directives and domestic implementation, the test will be how to make such rights actionable, scalable, and accessible to citizens and local stakeholders in different settings.

2.2 Flexibility in Energy Communities

As evidenced in the literature, the continuous energy transition brings significant advantages at the local level, from greater energy resilience and flexibility to participation in decision-making. These can only be harvested through planning at a local level and consideration of the provision of local flexibility [56].

The increasingly erratic energy supply necessitates not only a high temporal and spatial resolution to identify the challenges resulting from this shift, but also an appropriate representation of technical flexibility to find out how to effectively overcome these challenges, given that energy communities are inherently decentralized and frequently comprise a mix of residential, commercial, and prosumer actors [56].

Accordingly, 2.2.1 presents the state-of-the-art modeling of the current options for technical flexibility in local energy communities. Next, 2.2.2 gives an overview of the most relevant technological enablers that facilitate flexibility at the local level, with a specific emphasis on DER. These technologies play a fundamental role in putting flexibility into practice, both from a system optimization standpoint and from the user's perspective. In 2.2.3, the emphasis lies in how flexibility is valued and traded within market structures, and examining how energy communities can participate in local and regional flexibility markets. This section thus presents a good foundation for understanding how to model, manage, and monetize flexibility in the context of decentralized community-based energy systems.

2.2.1 Modeling Flexibility in Energy Communities

Flexibility is defined as "the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system" [57].

Flexibility products can be categorized based on their purpose and the system actor they serve, each representing a key driver for the development of flexibility trading mechanisms and market structures. [58] identifies three different types of flexibility in the literature. Balancing flexibility for the TSO can be done at either the transmission system — typically traded in well-established platforms such as intraday energy markets and spinning reserve markets — or at the distribution system, where flexibility is sourced from DERs within the distribution network. These are termed Type I and Type II flexibility, respectively. Type III flexibility is targeted toward the DSO and is used for local system operation, e.g., voltage control, congestion management, and loss reduction. Local Flexibility Markets (LFMs) are increasingly becoming a strategic tool for DSOs in this regard, facilitating decentralized and cost-effective flexibility procurement. Renewable energy communities, that are present in the distribution grid and comprise prosumers with controllable loads and storage, are best suited to provide this form of localized flexibility. Through coordinated management and participation in LFMs, RECs can play a crucial role in facilitating DSO objectives along with enhancing their own economic and energy independence. Therefore, the increasing importance of RECs further supports the applicability and relevance of Type III flexibility in future grid situations.

From the standpoint of electrical systems, flexibility is the ability to balance supply and demand at a specific instant in time by adjusting power for a predetermined amount of time. As a result, a flexibility service is a multifaceted good that has the following qualities (Figure 2.2) [58]:

(a) Direction, i.e., up or down.

(b) Rate of change, i.e., power capacity.

(c) Starting time and its trigger.

(d) Duration.

(e) Location, i.e., node of distribution systems.

Additional metrics such as predictably, time availability, and delivering time are introduced in [59].

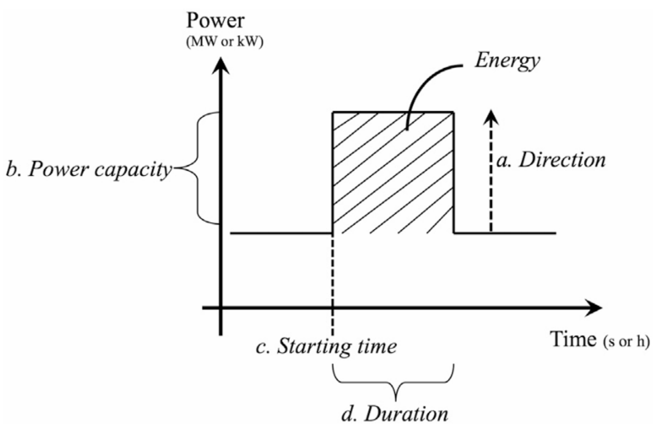

Figure 2.2: Attributes of an electric flexibility service [59].

There are five primary technical flexibility dimensions widely captured in energy system models [56]: supply-side options, Demand-side Management (DSM), energy storage, networks, and sector coupling. The two most prevalent types of flexibility captured are DSM and energy storage, particularly in models of local or community-scale systems. Supply-side flexibility, while important at the larger system level applications, is comparatively less emphasized in the local models as there is limited control over generation assets in the community context. DSM is instead given central attention to being of particular relevance to ECs where domestic and prosumer loads might be price signal or automatically controlled, and load shifting and peak shaving can therefore be enabled. Storage technologies like batteries and thermal storage are subject to detailed modeling, typically using simple storage models that balance energy inputs and outputs while respecting constraints like capacity and efficiency. Sector coupling — the integration of electricity with heating, cooling, or transport — is a growing concept of importance, particularly with the integration of electric vehicles and heat pumps, which introduce new opportunities for flexibility between sectors. The modeling of flexibility in local communities, according to [56], is often of low temporal resolution and low behavioral and spatial diversity representation, hence potentially leading to underestimation of the potential for flexibility. To address this, the authors suggest greater temporal granularity, inclusion of actor heterogeneity, and utilization of multi-dimensional metrics beyond cost and emissions to account for the real value and robustness of flexibility in energy communities.

2.2.1.1 Demand-side Management

Demand-side management is "a set of plans, programs, and technologies implemented on the customer side of the meter to shape the pattern of energy use for the purpose of enhancing electricity system operations" [60]. Demand response is considered one of the key operational pillars within DSM. These schemes can be broadly categorized based on how user flexibility is accessed and controlled — implicitly through economic signals or explicitly via contractual or automated interventions.

Users can choose whether or not to respond to the applied tariff signals, and the employment of tariff modalities that aim to promote or restrict consumption based on the electrical grid's operational conditions is a straightforward and easy model to access flexibility [61]. However, because user participation is not guaranteed and might vary greatly, it is not dependable for operation planning [61]. The fact that flexible resources with more advanced features, such as batteries, are not strategically exploited with the full degree of control they permit under these circumstances should also be taken into account [61].

Conversely, explicit flexibility access strategies allow for the sophisticated exploration of flexible assets, which support both real-time operations and operation planning. This ensures that resources will be available in the future as energy reserves that can be utilized for the efficient operation of the electrical grid [61]. Access to flexibility explicitly can occur in two ways: (i) through an integrated approach with direct controls carried out by the DSO over the equipment, or (ii) in market approaches where a flexibility action can be hired [61].

The demand response mechanisms' classification, as illustrated in Figure 2.3, identifies two broad categories under which end-user flexibility is stimulated: incentive-based programs and price-based programs. The latter use economic signals to affect the level of consumption, according to the voluntary reaction of users to tariff schemes. On the contrary, incentive-based mechanisms function based on either pre-arranged agreements or direct system operator interventions and therefore provide a more controllable and predictable form of flexibility [7]. The figure further groups these mechanisms based on their functional objectives, thus offering a systematic view of how different approaches are framed to manage tariff response, maintain system stability, or allow market-based engagement.

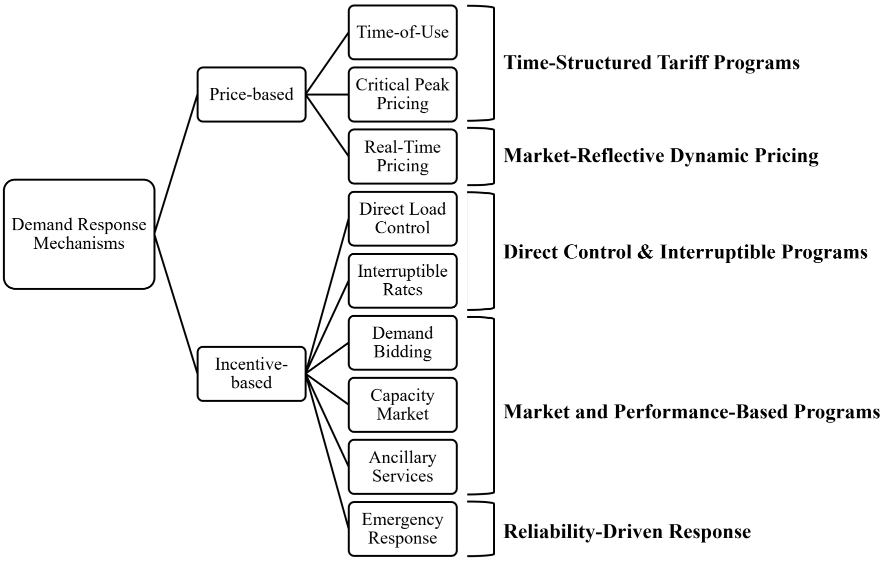

Figure 2.3: Classification of demand response mechanisms as part of demand side management. Adapted from [7].

In addition to this classification, Figure 2.4 shows the widely applied price-based demand response (DR) schemes: Time-of-Use (ToU), Real-Time Pricing (RTP), and Critical Peak Pricing (CPP). The different pricing structures are distinguished based on the level of temporal granularity and the expected responsiveness of customers. Users have a defined framework for modifying their consumption because the tariff in ToU fluctuates for distinct time blocks throughout the day that are known in advance and the duration of one price is constant for numerous hours [7]. Customers who utilize RTP will adjust their electricity use in accordance with the changing price they receive each time step [62]. Regarding CPP, the consumer is only shown a higher pricing during certain hours of the day [62].

In [63], a systematic review on the comparative performance of the above dynamic pricing mechanisms is performed, although its discussion on ECs is indirect. It highlights that consumer response levels are generally greater for ToU than RTP due to lower adjustment costs and simpler tariff designs, thereby making ToU more manageable and simple for typical consumers. Although RTP theoretically provides the best price signal by tracking market changes closely, its practical implementation is typically plagued by low participation because of its intensive cognitive and technological requirement from users, especially in a setting where automation or aggregator assistance is not available. CPP, with its high prices during low-density critical peak hours, has been identified as a more realistic alternative to RTP when full real-time adjustment is not feasible, even though concerns about equity and user acceptance linger due to the high price during peak events.

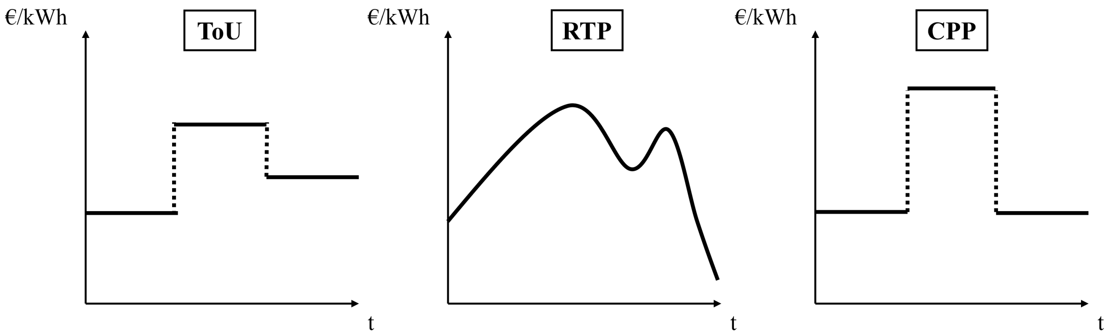

Figure 2.4: Basic dynamic pricing options used in price-based demand response. Adapted from [62].

Subsequently, incentive-based demand response programs embody a more overt and contractually binding framework for harnessing flexibility in renewable energy communities. Unlike price-based methods with voluntary behavioral reactions to tariff signals, these programs guarantee the provision of flexibility when required or based on consensus terms, subject to penalty for default and financial reward as primary incentive. These mechanisms — Direct Load Control (DLC), Interruptible Load (INL), Demand Bidding (DB), Emergency Demand Response (EDR), Capacity Market (CM), and Ancillary Services (ANS) — are most well-suited where DERs, behind-the-meter storage, and heterogeneous load profiles necessitate coordinated, reliable, and frequently fast responses [7], [61].

In RECs, DLC and INL programs allow for near real-time control of appliances such as electric heaters, typically through two-way communication infrastructures or automated schedules. These frameworks are highly suitable for small-scale, residential-oriented RECs in which controllable loads are widespread and user participation is facilitated through pre-existing agreements. In the meantime, DB and CM programs add a market-based level of engagement, enabling REC aggregators to bid demand reductions or capacity commitments into wholesale or local flexibility markets. EDR and ANS, although more niche and fitting for aiding the TSO, provide RECs avenues to assist with grid stability, with ANS demanding sub-minute response times appropriate only for automated or industrial-scale community systems. Each of these programs varies in terms of notification lead time, frequency of events, and response period, all of which influence participant response and system reliability [7]. However, in a market approach where flexibility is traded, the contractual agreements must include the following: (i) notification of the need to participate in DR — can be made day-ahead or hour-ahead; (ii) frequency of DR — refers to the number of times a DR activity is requested [7], since some consumers prefer frequent, low-value events over rare, high-value ones; and (iii) duration of DR — the duration is determined by the operating cycle of flexible assets, while the amount of flexibility must be estimated based on the RECs energy priorities [7]. When determining the sort of DR that can be applicable, the aggregators primarily consider the duration and degree of flexibility [7].

2.2.2 Technological Enablers of Flexibility in Energy Communities

Information regarding aggregated energy flexibility is required to determine the amount of flexibility that can be sold, which is necessary for aggregators to actively participate in the current flexibility markets and enable prompt DR actions [7]. Understanding the various flexible assets is necessary to quantify demand-side flexibility.

Distributed energy resources refer to an expansive range of technologies that could facilitate flexibility for renewable energy communities, categorized loosely into consumption-oriented, generation-oriented, and bi-directional assets. Resources fall into three types, which all have their distinct connections with the grid — altering or reducing demand, flexing generation, or running bidirectionally on a dynamic basis, such as in storage facilities. Understanding the flexibility value of such assets is important for planning, modeling, and aggregating RECs in emerging flexibility markets.

2.2.2.1 Consumption-based

Atomic Loads

Atomic loads are characterized by fixed power profiles that cannot be interrupted, paused, or altered once initiated, making them appear inflexible at the individual level [64]. However, when aggregated, they offer flexibility by allowing their activation to be shifted in time. In particular, atomic loads can only offer flexibility by postponing or accelerating the load or process's start time and substituting a different load profile for the scheduled one before to its commencement [65]. The aggregator cannot alter the load profile of a device that has already been started because atomic loads, unlike general shiftable loads, are constrained by their predetermined operational cycles [65]. For appliances with consistent energy consumption and stringent performance specifications, such as industrial ovens or dishwashers, where choosing an operating mode must be done before activation, this modeling technique is especially pertinent. Thus, flexibility is described as a finite set of discrete time shifts, and aggregators can improve activation timing within system restrictions and cost considerations by shifting the load activation by an integer number of time periods [65].

Thermostatically Controlled Loads

Loads connected to the thermal requirements of the user are Thermostatically Controlled Loads (TLCs). These can be air conditioners, heat pumps, water heaters, and electric heaters. Depending on the grid's flexibility requirements, these devices' operations may vary [64]. The clients' thermal comfort should still be met, nevertheless. Three key ideas, according to [65], define flexibility in these loads:

- The total power profile when no control signals are transmitted to the TCLs is known as the baseline power profile.
- Flexibility power profile is the power profile that changes when control signals are sent to the TCLs as opposed to the baseline power profile. The aggregator provides the market more freedom.

- The difference between the baseline power profile and the power profile following the release of the control signals is known as the rebound power profile. The flexibility activation has the side consequence of producing the rebound power.

Therefore, altering the temperature set points of TCLs allows for greater flexibility [65].

Curtailable Loads

Curtailable loads are those that can be reduced in accordance with the grid's requirements for flexibility. However, there shouldn't be any significant rebound effects from their curtailment [64]. A rebound effect happens when a flexible resource's power consumption changes as a result of activating flexibility at a specific moment, limiting its capacity to do so in later time steps [66].

Additionally, curtailable loads have important limits [67]. One of them can be the fact that some loads may have limited opportunities to decrease their consumption, or the consumer simply deems this action not favorable. Furthermore, sending activation and response verification signals can be expensive in comparison to the benefits because the loads are often small and do not incorporate adequate automation control systems. In conclusion, a major obstacle is the reluctance of the owners and consumers of these resources regarding the potential for shedding.

2.2.2.2 Generation-based

Generation-based resources like wind, photovoltaic, and small-hydro are not only renewable electricity sources but also system flexibility sources through controlled curtailment. Flexibility in such resources is, in effect, in the delivery of down-regulation, in that the supplied grid power is maintained at less than the available generation capability. For PV and wind power systems, the curtailment can be voluntary — e.g., because of price signals, when the payment exceeds the generation cost — and involuntary due to network limitations, security constraints, or due to overproduction.

Small run-of-river hydropower can also provide limited curtailable flexibility even though no reservoirs exist. These kinds of systems operate at full capacity to avoid waste of unused water flow, but are still technically capable of full or partial output reduction if necessary. As a collection, these renewable generation technologies, though less flexible than dispatchable ones, are amenable to REC flexibility when they are controlled with precise forecasting, advanced inverter controls, and appropriate market integration strategies.

Micro-CHP units, which produce electricity and heat at small scale co-generation, are ever more relevant in renewable energy communities due to their high predictability, availability around the clock, and two-service provisions [62]. As specialized electrical and thermal generation systems, they are typically scheduled to meet heating demands and thereby offer around-the-clock availability for electricity production as a by-product [62]. This capability renders them well-suited for engaging in local flexibility markets, especially when combined with smart home Energy Management Systems (HEMS) that are able to coordinate dispatch on the basis of both thermal and market-based signals. Unlike curtailable loads, the flexibility of micro-CHP units is not curtailed by a temporal power ratio; instead, their dispatchability is economically conditional on fuel input continuity [62]. Micro-CHP units can offer upward flexibility in REC dispatchs by providing power during peak tariff times or by fulfilling DSO requests for flexibility.

Their incorporation into RECs has also been investigated via model studies. For example, to compensate for uncertainties in renewable energy availability and increase system flexibility, [68] offers a two-stage robust generation dispatch with strategic renewable power curtailment. Their strategy minimizes the utilization of real-time emergency controls and the operational risks through optimal planning of curtailments beforehand. Apart from that, [69] proposes a data-driven distributionally robust optimization framework for community integrated energy systems taking into account integrated demand response and uncertain renewable generation. The framework encourages the use of renewable resources and minimizes the rate of curtailments through an optimal balance between economic operation and resilience.

2.2.2.3 Bi-directional

Energy storage systems, both mobile and stationary, are primary enablers of flexibility in renewable energy communities. These systems include stationary battery storage and electric vehicles (EVs), as well as niche technologies like small-scale pumped hydro storage (PHES).

Stationary storage can function either as a consumer or generator, depending on whether it is charging or discharging electricity, thereby offering dynamic support to balance local demand and variable renewable generation. PHES, though not as common in urban RECs, functions by accumulating electricity as gravitational potential during low-price hours of the day and discharging during peak-price hours, in accordance with time-shifted demand response strategies. Electric vehicles, both plug-in hybrids and battery electric vehicles, offer significant potential for flexibility. However, these resources face challenges to direct participation in market operations due to their relatively small individual capacities and the complexities brought on by a large number of market players [65]. To overcome this, aggregators act as intermediaries and group multiple scattered storage assets to provide market-compliant flexibility services. In this context, the aggregator's incentive is energy price arbitraging. This is characterized by charging at low prices and discharging at high prices, while having respect for user mobility needs. Moreover, the interaction mechanism with the grid — unidirectional versus bidirectional — affects flexibility supply and battery degradation. While bidirectional usage (e.g., vehicle-to-grid) provides more flexibility and opportunity for profit, it also accelerates battery degradation, and therefore proper compensation mechanisms are necessary for storage owners to offset the utility loss from degradation [65].

Figure 2.5 provides a conceptual overview of the dynamic behavior of different DER classes when delivering grid services, illustrating the nature of their baseline operation, the mechanisms of upward or downward flexibility, and the occurrence of rebound effects, where applicable.

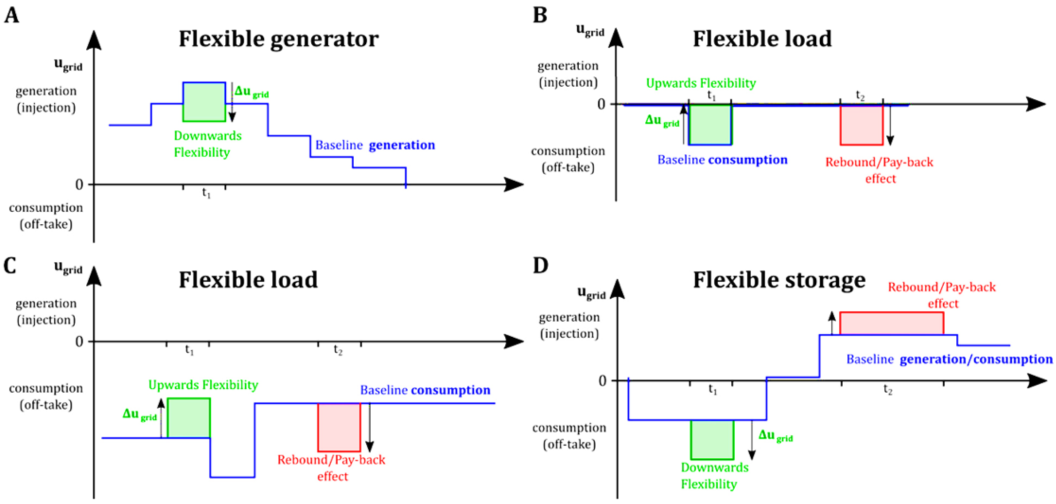

Figure 2.5: Illustrative behavior of different types of distributed energy resources when providing flexibility services to the grid. (A) Flexible generators deliver downwards flexibility by reducing output from their baseline generation. (B) and (C) Flexible loads shift or curtail consumption to provide upwards flexibility followed by a rebound effect. (D) Flexible storage assets adjust both charging (consumption) and discharging (generation), showing symmetrical flexibility with corresponding pay-back effects [67].

2.2.2.4 Control Methodologies

It was explained how several DER types provide flexibility. The various methods for controlling the pertinent DER electric power variables are the main topic of this section.

The categories for controlling the DER are described in Figure 2.6. One criterion in current literature is the *location* of the decision-making to control the resource. It poses the question: *Who has the final say in controlling the flexibility asset?* This can be achieved centrally by a higher-level entity external to the community, such as an aggregator or DSO, in accordance with the DER owner. Another form of control is the *locally*-based control by the owner of the asset. The user typically sets a local objective or establishes an utilization pattern [67].

It should be noted that while price signals from outside sources are taken into consideration when making decisions locally, the local energy management system makes the final choice [67].

A second criterion is the *communication* between the local controller and the higher-level entity. There can be no communication, one-way communication — from high-level to DER signals — or two-way communication — high-level to DER and DER to high-level signals.

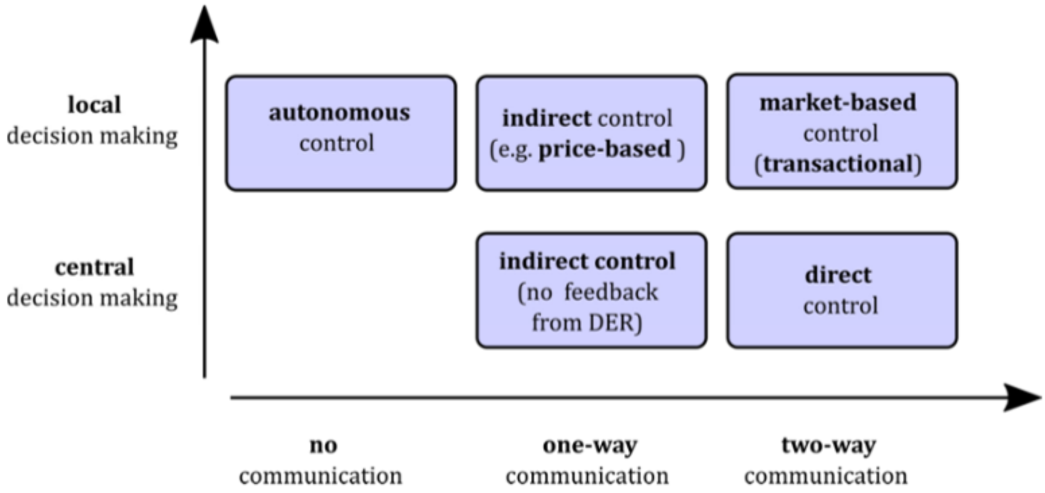

Figure 2.6: Distributed energy resources control categories [67].

These two criteria are combined to establish different control families, namely [67]:

- All DER controllers that make choices without considering any external signals are grouped together under the **autonomous control** category. As a broad illustration, consider a local thermostat in a home where the user sets the reference temperature. There is no signal to control or to influence the user.

- With the **price-based** control, an external agent sends price-based signals to the DER controller. The local controller may then consider these together with its own local goals to modify the resources' power generation and consumption. In this case, the external agent does not receive any feedback from the state of power generation or consumption. As such, it must estimate the reaction of the user. This may be done by using a measurement of the active power fluctuation in response to price over time.

- As for an **indirect** control strategy, an external agent sends requirements to the local DER controller based on a desired action. This can be whether to increase, decrease, or modify operating setpoint constraints, within which in turn affect the power consumption. Therefore, there is no direct control of the active and reactive power. In contrast to price-based indirect control, the local DER must adhere to the external agent's limitations. Thus, decisions are not decided locally, but rather centrally.

- DERs that participate in contracts to allow an outside agent to directly control the DER through two-way communication are grouped together under the **direct control** category. The DER sends control signals to the external entity, which in turn sends control signals to the DER. This means it directly controls the active and reactive power. The DER also reports its current state: storage, charge, and reactive and active power.

- In contrast to direct control, the **market-based** control is characterized by the autonomy of the local agent in making decisions. Multiple DERs and an aggregator submit offers in an automated bid-based market, which serves as the basis for the control. Although these communication needs are reciprocal, unlike the direct control technique, the aggregator just exchanges bid information.

Further, Table 2.7 presents a list of typical DER technologies in the context of renewable energy communities. All equipment is classified depending upon their direction of flexibility (upward, downward, or bidirectional), temporal flexibility attributes (power or energy, response time), and their role in various domains of flexibility (demand-side, supply-side, and grid-side services). Other axes include the level of the grid on which the DER is operating (transmission or distribution), predictability, and the services for which it is most appropriate. This classification serves as a point of departure for linking DER potential to flexibility product design, activation strategies, and REC-specific market designs.

Table 2.7: Classification of DER types with technical flexibility characteristics and domains. Adapted from [58], [62]

DER Type	Flexibility Direction	Power vs. Energy	Response Time	Flexibility Domain	Flexibility Services	Grid Level	Predictability
Atomic Loads	Unidirectional (↓)	Power-type (short duty cycles)	Seconds	Demand-side	Peak shaving, demand reduction	DS	Medium–High
TCLs	Unidirectional (↓)	Energy-type	Seconds–Minutes	Demand-side	Load shifting, demand response, frequency reserve	DS	High
Curtailable Loads	Unidirectional (↓)	Power-type (shed or curtail)	Seconds–Minutes	Demand-side	Curtailment, congestion management, balancing reserve	DS	High
PV, Wind, Hydro Generation	Unidirectional (↑)	Curtailable / Energy-type	Minutes–Hours	Supply-side	Generation limiting, hosting capacity, VRE balancing	DS	Medium–Low
Micro-CHP	Unidirectional (↑)	Energy-type	Slow	Supply-side	Local cogeneration, dispatchable generation	DS	High
BESS	Bidirectional	Power-, Energy-type	Seconds–Minutes	Supply-, Demand-, Grid-side	Balancing, arbitrage, voltage support	DS, TS	High
EVs	Unidirectional (↓), Bidirectional	Power-, Energy-type	Seconds	Demand-, Grid-side	V2G, congestion relief, load shifting, smart charging	DS	Medium–High
Pumped Hydro Storage (small-scale)	Bidirectional	Energy-type	Minutes–Hours	Supply-, Grid-side	Peak shifting, balancing, long-duration energy shifting	TS or large DS	High

↓ = consumption reduction; ↑ = power injection.
V2G: Vehicle-to-grid; DS: Distribution System; TS: Transmission System.

2.2.3 Flexibility Market Design for Energy Communities

Local Flexibility Markets (LFM) are geographically delineated markets wherein explicit flexibility — conceived as flexibility activated by a direct control or market signal — is exchanged among participating actors [70]. Following [58], the fundamental components of an LFM are the traded service or commodity (i.e., flexibility), a market operator, participating parties, and a defined market clearing procedure. [7] additionally portrays that main stakeholders of the market are system-oriented players (e.g., TSO), grid-oriented operators (DSO), and market-oriented stakeholders such as BRP and retailers. In this methodology, the aggregator is fundamental to designing economically meaningful business models in facilitating local energy communities' involvement in LFMs. The aggregator or the DSO may be the LFM operator, effectively playing the role of middleman between RECs and the broader electricity market by purchasing flexibility and reselling it to higher-level grid services. The inherent flexibility of RECs can benefit DSOs by decoupling their dependency on the upstream grid infrastructure, thus promoting a competitive framework where energy communities are encouraged to sell their flexibility services at the distribution level.

The following section expands on the theoretical foundations established by [58] to examine how LFMs can be formulated and adapted to fit the operational, spatial, and governance features of renewable energy communities. This discussion draws on the established taxonomy of LFM structures, market-clearing approaches, and flexibility dimensions. Particular focus is given to the roles of DSOs and aggregators in enabling community participation, measuring flexibility issues, and designing multi-objective market-clearing mechanisms to match grid needs with local social and economic goals.

2.2.3.1 Design and Structure of Local Flexibility Markets

Figure 2.7 illustrates a local flexibility market where various stakeholders participate in the trading of explicit flexibility at a local level, facilitated by an especially designated LFM operator. The flexibility comes from DERs and prosumers in the REC, with the potential to adjust their energy consumption or production. The concerned entities are grouped and portrayed in the market by aggregators, which play a vital role in their participation. The LFM operates as a platform for the trade of flexibility among buyers, hereby flexibility requesting party, such as the DSO for purposes like voltage regulation, congestion relief, and loss reduction, and BRPs to resolve imbalance charges, and sellers portrayed by the aggregators. This framework, as outlined in [58], is a competitive trading sphere that accommodates both market involvement and system stability. The specific functions of each player are outlined in Table 2.8.

The operational process of local flexibility trading in the LFM is illustrated schematically in Figure 2.8, describing a three-stage process of contracting and bidding, activation, and settlement phases [58].

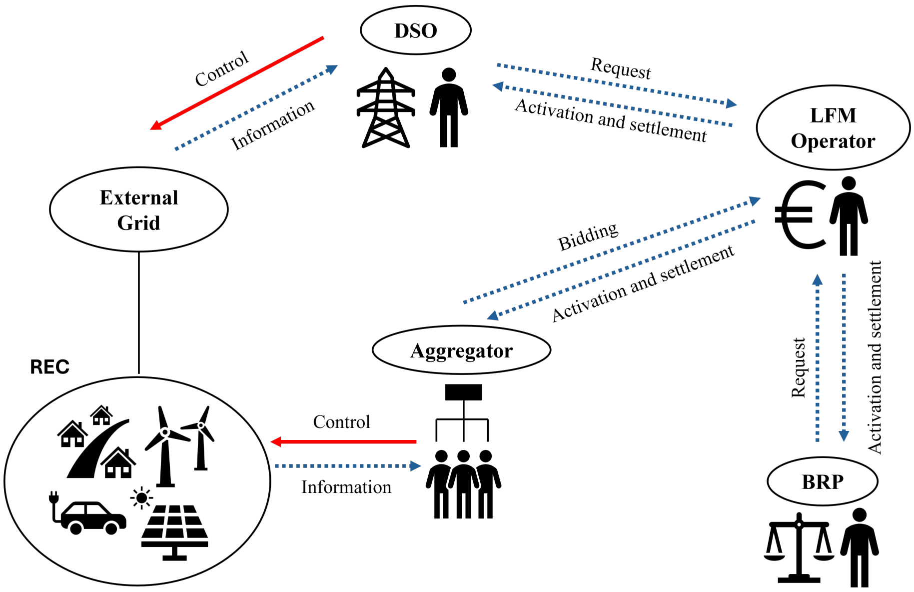

Figure 2.7: Schematic overview of a local flexibility market. Adapted from [58].

During the contracting and bidding stage, the DSO conducts network analysis to identify possible future voltage or congestion risks, and if necessary, sends a request for flexibility as well as system state and locational information to the LFM operator. Similarly, the BRP, based on its imbalance forecasts, can submit a request for flexibility.

The LFM operator sums up these requests and openly calls for flexibility bids from aggregators, who consequently collect flexibility bids from the REC's DERs and prosumers. Upon market clearing, the outcomes are communicated to all the parties involved. In the following activation phase, flexibility provided to the BRP and DSO is enabled by the aggregators through control of their managed assets, and confirmation of delivery is sent to the LFM operator, who finalizes acknowledgment with the buyers.

Lastly, the settlement phase ensures that financial settlements and performance confirmations are exchanged between all the involved stakeholders, e.g., the BRP, DSO, aggregators, the REC, and the LFM operator, finalizing the market cycle [58].

The success of an LFM rests on successful coordination among all stakeholders. For instance, if a DSO publishes flexibility needs — defining properties such as direction, power capacity, timing, and location — such joint knowledge has the potential to facilitate balance in the flexibility market. The coupling between spatially sensitive DSO procurement and volume-oriented BRP optimization necessitates an explicit market design together with well-defined bidding, clearing, and settlement rules.

Having established the roles of stakeholders and coordination strategies, the next part explores the structural design of the LFM itself, i.e., the market mechanisms and flexibility products utilized. Drawing on [58], it is outlined how platforms are structured to enable community-scale par-

Table 2.8: Key participants in local flexibility markets. Adapted from [7], [58], [70].

Participant	Role	Responsibilities	Challenges / Remarks
DSO	System-oriented	Ensures secure and efficient operation of the distribution grid; procures flexibility for congestion management, voltage control, loss minimization, and network planning	Needs access to reliable, local flexibility sources; coordinates activation with aggregators and LFM operator
BRP	Market-oriented	Balances supply and demand within its portfolio; procures flexibility to minimize imbalance charges and optimize trading strategies	Subject to imbalance penalties; depends on forecast accuracy and timely activation
Aggregator	Flexibility enabler	Manages and aggregates DERs/prosumers to participate in LFMs; represents prosumers in bids and settlements; provides flexibility on request	Prevents overload of market by direct DER participation; coordinates activation and baseline estimation
LFM Operator	Market operator	Runs the local market; performs market-clearing; coordinates bids and requests among stakeholders; ensures transparency	Can be DSO or Aggregator; must be neutral and capable of handling communication and computation complexity

ticipation, clear efficiently, and balance the grid's operational limitations with the socio-economic priorities of local actors.

2.2.3.2 Market Clearing Mechanisms

Market clearing in LFMs is the key process for flexibility supply and demand balancing subject to operational and economic constraints. For renewable energy communities, such mechanisms must manage heterogeneity in actor preferences, technical resource capabilities, and geographically distributed network conditions. In the context of clearing models theory, [58] provide a taxonomy of local flexibility market designs based on four predominant modeling paradigms found in the literature: (i) centralized optimization, (ii) game theory-based modeling, (iii) auction theory-based modeling, and (iv) simulation-based frameworks. The models differ significantly in how they conceptualize actor behavior, information sharing, and computational complexity. Their deployment in renewable energy communities needs to balance the trade-offs between scalability, representational realism, and deployability under community-specific digital and regulatory

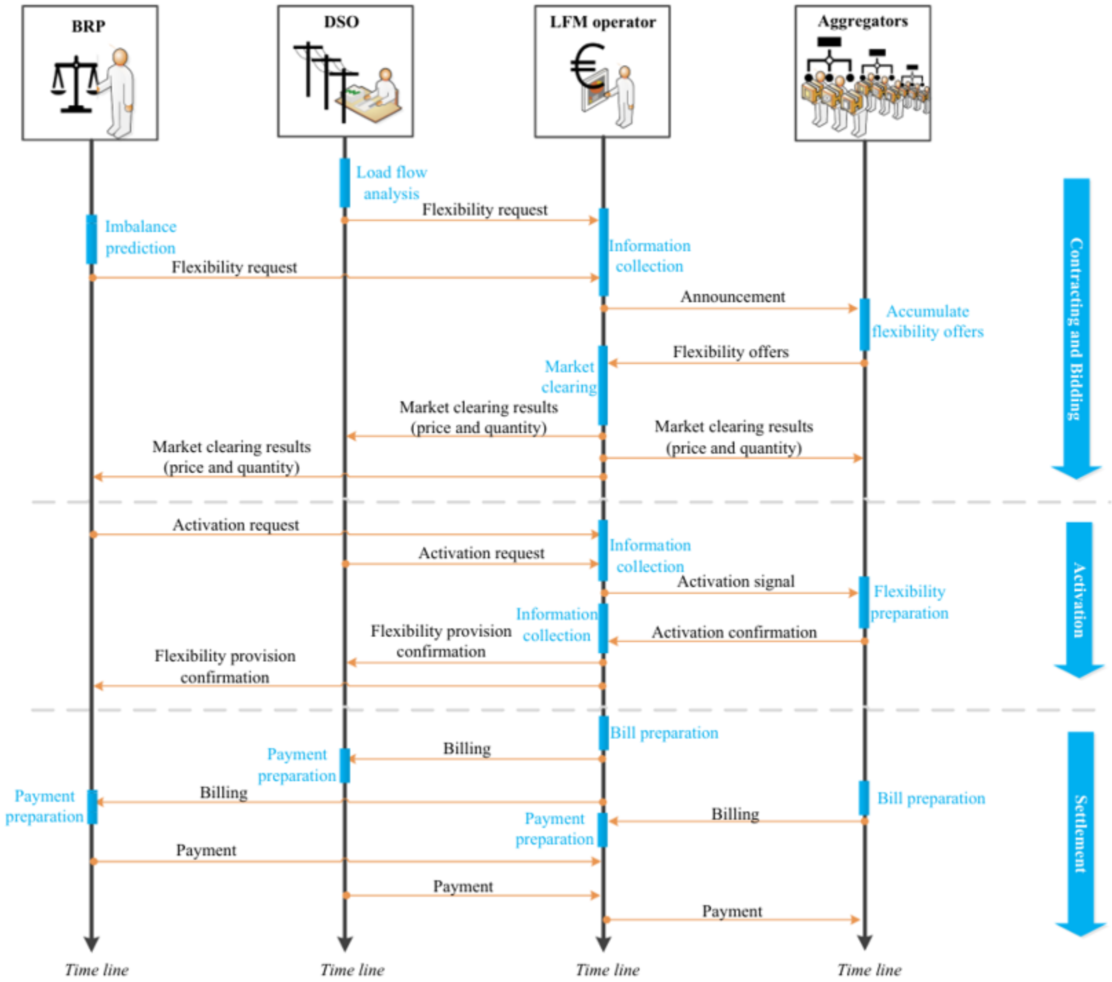

Figure 2.8: Example of the timeline of a local flexibility market [58].

circumstances.

A common strategy in the literature is centralized optimization, where the market is viewed as a single optimization problem that typically aims to minimize operational costs or maximize social welfare. This is a straightforward framework to implement and solve, especially in small to medium-sized systems, as suggested by [58]. However, scalability issues remain, stemming from both communication and computational constraints, and the model often favors the objectives of one stakeholder.

On the other hand, game-theoretic models treat the LFM as a strategic game among rational players where each player's choice influences the others. The models are better suited to large markets and more accurately capture agent goal heterogeneity. All of the players in the LFM can be modeled by them, and they are theoretically scalable, but rely strongly on rationality assumptions and may suffer from multiple equilibria, which makes them difficult to apply to real-world systems.

Auction theory-based models conceptualize the LFM as competitive bidding processes akin to those of stock markets. In this setting, an auctioneer, commonly the market operator, determines prices and assigns flexibility based on bids submitted by participants. Furthermore, the models are scalable and efficient in achieving market equilibrium. Nevertheless, they can be prone to price volatility or abrupt spikes, causing outcomes to be economically infeasible under some circumstances.

Lastly, simulation models specify the LFM as a dynamic interactive system of agents with possibly heterogeneous private or public information and decision rules. These models are very flexible and can reproduce realistic complex behavior for a variety of DERs and actors. Their sole major drawback is computational expense because simulating several interacting agents can be computationally demanding, especially with increasing market size and heterogeneity.

According to [58], iterative and relaxation techniques can be used to transform original models into centralized optimization models, which can then be used to solve market models based on game theory, auction theory, and simulation. Figure 2.9 contrasts centralized and decentralized clearing models. The top part illustrates centralized optimization, in which data from all the participants are aggregated into a single objective, limiting personal representation. The bottom part illustrates game theory, auction, and simulation-based models, in which each participant optimizes individually, facilitating better modeling of heterogeneous goals and interactions. This shows the trade-off between centralized simplicity and decentralized realism, as noted by [58].

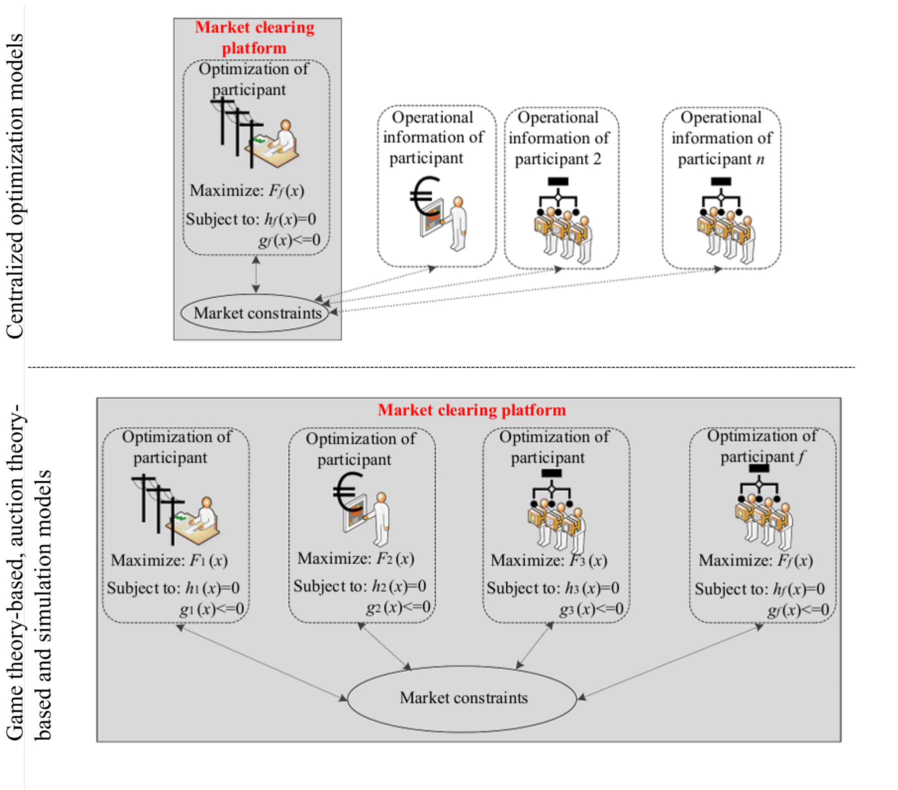

Figure 2.9: Illustrative comparison between market clearing mechanisms. Adapted from [58].

[71] extend this framework to the REC environment through the introduction of a centralized community manager clearing flexibility bids from local members. Their framework endo-

genizes local objectives, i.e., self-consumption maximization and reduction of reliance on upstream grids, within the clearing algorithm itself. By endogenizing localized flexibility value, the framework enables REC-centric clearing logic in line with aggregate LFM coordination. Unlike conventional market-clearing approaches that are premised only on price optimization, this multi-objective framework captures the distinct principles of energy-sharing and fairness that are intrinsic to community-scale energy systems.

Upon discussing the different theoretical market designs, we must now comprehend *how* these are implemented in practice.

2.2.3.3 Flexibility Products and Market Platforms

Real-world clearing processes are increasingly supported by online trading platforms. [72] offer a comprehensive overview of such European-based platforms, such as their user segment, flexibility trading procedures, settlement processes, and flexibility products provided. Some systems facilitate centralized market-clearing with auction houses operated by DSOs, while others facilitate P2P flexibility trading through distributed architectures. In spite of this variety, a lack of standardization is still a major obstacle, especially for aggregators that work across different regulatory zones or try to scale community-based flexibility.

One of the key critical dimensions shaping real-world LFM implementation is the product definition and form of flexibility, which determines involvement of demand-side resources in flexibility markets. Such products have been broadly categorized into standardized or non-standardized:

- **Standardized products** are pre-specified regarding activation time, duration, availability requirements, and payment structure. They are intended to synchronize participation across markets and regions [72].

- **Non-standardized products** are tailored to specific grid needs or pilot conditions, with more flexible or adaptive parameters [72].

Various European projects have suggested different kinds of flexibility products aimed at dealing with the changing requirements of low-voltage grid operation, a significant number of which are relevant to renewable energy communities.

The BeFlexible project [5], for instance, introduces two non-standardized short-term products, Scheduled and Dispatched, which allow distribution system operators to procure flexibility either in advance (with high certainty of requirement) or conditionally (subject to real-time grid signals) [72]. These are especially apt for RECs, where generation uncertainty and asset heterogeneity require responsiveness and locality.

The OneNet project [6] also envisages a set of predictive products that aim to forecast flexibility requirements across multiple time scales, from hours to years, allowing DSOs to postpone infrastructure reinforcements via strategic REC involvement.

[5] https://beflexible.eu/

[6] https://www.onenet-project.eu/

On the other hand, the Energy Networks Association (ENA) developed a set of standardized products — Sustain, Secure, Dynamic, and Restore — which are now being used in commercial platforms [72]. They offer harmonized availability, activation, and payment rules definitions, allowing inter-market interoperability across jurisdictions. Although more organized, they allow integration into regional balancing and constraint management systems, thus being suitable for RECs selling via aggregators or bidding in national tenders. Table 2.9 summarizes the flexibility product types of these programs, dividing them into standardized and non-standardized products, and mentioning their usability for REC use cases such as congestion management, grid restoration, and investment deferral.

Table 2.9: Flexibility products and their applicability to renewable energy communities contexts. Adapted from [72].

Product Type	**Description**	**Use Case for RECs**	**Standardized**
Short-term Scheduled	Activated in advance to prevent overload or voltage violations	DER-driven congestion or voltage management	×
Short-term Dispatched	Option-based product activated in real time based on updated grid conditions	Real-time control of variable generation/load	×
Sustain	Flexibility pre-booked to avoid network issues	Predictable load and generation shifts	✓
Secure	Real-time need-based dispatch with capacity fees	Congestion response from flexible EV and storage	✓
Dynamic	Rapid activation in abnormal grid states	Emergency response via behind-the-meter assets	✓
Restore	Used for grid restoration after faults	Post-fault participation from storage or controllable loads	✓
Predictive Products	Monthly, seasonal contracts for anticipated grid support	Grid investment deferral with REC participation	×

✓: Standardized product with formal definitions; ×: Non-standardized, use-case specific design.

To realize these products, various flexibility market platforms have been created across Europe with differing technical and regulatory frameworks. Table 2.10 overviews principal platforms based on their suitability for REC involvement. These platforms differ in structure, procurement mechanisms, degree of automation, and support for aggregation. Some are explicitly tailored to industrial-scale flexibility, whereas others increasingly address local market actors such as prosumers, microgrids, or municipal energy cooperatives.

Table 2.10: European flexibility market platforms and relevance for renewable energy communities. Adapted from [72].

Platform	**REC Aggregation Support**	**Standard Products**	**Market Type**	**Pilot Regions**	**REC-Relevant Features**
PicloFlex	✓	✓	Long-term tenders	UK, Portugal	• Structured qualification • Local flexibility zones
Flexible Power	✓	✓	Tendered dispatch	UK	• Automated dispatch • Metering via interface
Enedis	△	×	Annual tenders	France	• Low participation • Congestion-focused
NODES	✓	×	Continuous and long-term	Norway, UK, Germany	• No capacity threshold • Centralized matching
OMIE	✓	×	Intra-day to long-term	Spain, Portugal	• Supports EVs, storage
GOPACS	△	×	Continuous congestion bids	Netherlands	• TSO–DSO coordination • Location-based offers
eSIOS–CECRE	×	×	Monitoring and balancing	Spain	• TSO-operated • No REC access

✓ Direct REC support; [△] Aggregator-only or limited; [×] No REC support.

For example, PicloFlex and Flexible Power, which are both being used in the United Kingdom, enable REC involvement through aggregators and employ standardized ENA products with structured qualification and seasonal tenders [72]. PicloFlex has also arrived in continental Europe, e.g., Portugal, where it was used in the E-REDES FIRMe project [7] to procure flexibility services from decentralized low-voltage assets via managed tenders run by the national DSO. This demonstrates the platform's potential to accommodate REC-scale assets in regions with active DSO involvement and developing digital infrastructure In contrast, NODES supports a more decentralized arrangement with non-standardized products, allowing microgrids and small assets to trade flexibility in continuous and short-term markets without a minimum capacity threshold [72].

The OMIE platform, under development in the Iberian Peninsula, integrates long-, mid-, and real-time market layers and is intended to support REC-relevant assets such as community-scale storage initiatives and electric vehicles [72].

Other platforms, like GOPACS (Netherlands) and Enedis (France), focus more on congestion management; they also possess greater entry barriers because of technical complexity or limited

[7] https://www.e-redes.pt/pt-pt/transicao-energetica/inovacao-e-desenvolvimento/firme

participation models [72]. Finally, TSO-level systems like eSIOS–CECRE are primarily employed for system monitoring and balancing functions, with limited or no direct market access for RECs [72].

As evident from Table 2.10, one can see that the platforms such as PicloFlex and NODES have quite developed frameworks for REC participation. Piclo has pre-qualified participation through aggregators, and NODES features flexible asset participation without capacity ceilings and is therefore more aligned to the decentralized nature of RECs. Enedis and GOPACS are, however, more capital-intensive with reduced low-voltage grid issues.

Ultimately, the suitability of an LFM model for RECs will not only rely on theoretical formulation but also on the extent to which it can engage with the disunited technical landscape, policy constraints, and actor configurations in community-scale systems. Platforms that embrace product adaptivity, API-based dispatch, and modular aggregation will likely offer the most suitable fit for facilitating the decarbonization goals of RECs.

2.2.3.4 Flexibility Quantification and Baseline Estimation

One of the biggest challenges of local flexibility markets is measuring flexibility — determining *how much* flexibility a portfolio or asset can provide at a given moment in time.

Traditionally, flexibility is the deviation from a pre-defined baseline, and this is the forecasted energy use or output over a given period should there be no external control or market participation [70]. The majority of market-clearing mechanisms in LFMs have this assumption, employing baseline estimations to determine the actual contribution of a flexibility provider and to support settlement, compliance, and verification procedures [70].

Baselines are benchmark trajectories, and their accuracy is needed to avoid false positives (rewarding normal behavior as flexibility) and false negatives (missing actual flexibility). Methods of baseline estimation range from historical averaging and statistical forecasting to more advanced machine learning methods. However, these methods are likely to require extensive data and may not be capable of capturing the dynamic nature of small prosumers, especially in renewable energy communities with diverse technologies and temporal patterns.

In this case, [70] argue that baseline dependence is not always desirable. They propose a transactional mechanism that adjusts allocation coefficients dynamically after delivery, hence pre-agreed baselines are not needed in energy sharing transactions. However, when the flexibility activation affects actors outside the original transaction (e.g., passive energy transfers), some baseline is still required to quantify the deviation and compute compensation. Thus, even in baseline-free market clearing for local energy sharing, flexibility has to be contrasted with counterfactual behavior.

Recent research goes beyond quantifying flexibility directly, as opposed to using a deterministic point of reference. [66] suggest a portfolio-based approach that accounts for the capability of a pool of flexible resources to fulfill a stated request using three metrics of operation:

- **Expected Unserved Flexible Energy:** Measures the deficit in energy between requested and delivered flexibility over time, with regard to such restrictions as ramp rates and availability of resources.
- **Expected Duration of Insufficient Flexibility:** The total time intervals during which flexibility requests cannot be fully met.
- **Expected Flexibility Index:** A unitless value between 0 and 1 that quantifies the reliability of a portfolio to meet flexibility requirements.

These metrics offer portfolio-level baseline-independent flexibility measurement. They shift the focus away from measuring deviation from nominal behavior and towards measuring the capability of the system for meeting dynamic exogenous demands within operational constraints. This reflects a developing trend within the literature: an ability-to-respond, rather than deviation-from-default, definition of flexibility. Nevertheless, an insightful metric needs to meet the following criteria [66]:

1. Based on the operational behavior of the various resources in the portfolio, provide an assessment of the overall flexibility of the portfolio.
2. Consider network and resource constraints.
3. Consider electricity generation unpredictability, flexible load demand, and flexibility requests.
4. Consider the management and synchronization of the implemented resource strategy.
5. Be intuitive.

In RECs, with energy generation and consumption patterns changing, and participants ranging from households to small-scale prosumers, baseline dependency can impose unrealistic or biased assumptions. Quantification approaches of flexibility based on availability, responsiveness, and reliability, instead of deviation from prediction, are increasingly relevant. [73] introduce a two-stage approach to flexibility modeling and trading in RECs. At the first stage, flexibility is measured by modeling DER behavior during extreme pricing situations (zero and infinite prices) to establish technical upper and lower limits against a self-optimized baseline. During the second stage, a local market clearing mechanism selects flexibility bids at cost minimum considering DSO and peer request, in a manner that activation constraints at device level are respected. The model unites baseline-driven quantification with market-compatible bidding and demonstrates relevance to residential DERs such as BESS and EVs and enables scalable, constraint-aware flexibility trading among RECs.

2.3 Final Remarks

Throughout this chapter, the role of energy communities as new providers of flexibility in the energy system was explained. The chapter began with the legal definition of ECs in European and Portuguese legislation, explaining how ECs evolved from passive consumers to active subjects with the ability to produce, store, and manage energy. ECs have been legally framed as market players through legal tools. In Portugal, regulations establish a national framework for collective self-consumption and participation in flexibility services. However, despite this progress, the path from legal recognition to practice implementation is uncertain, with regulatory ambiguity and absence of operational detail being significant barriers.

The chapter then explained how ECs can provide flexibility above that which can be supplied by individual consumers. By aggregating distributed resources, communities can make grid operation easier while supporting local energy independence. These roles are made possible through the involvement of key stakeholders: consumers, prosumers, aggregators, and system operators, which have respective roles in coordinating, activating, and valuing flexibility.

Technologically, ECs rely on a broad variety of assets. Battery storage and demand response offer downward and upward flexibility. The value of these assets is greatest when supported by effective control approaches, which may either be centralized, market-based, or autonomous. Control approaches determine the way flexibility is summoned and how the duties are shared between local and external parties.

Finally, the chapter explained how ECs can participate in flexibility markets. Local flexibility markets offer a promising framework but with highly variable structure across Europe. While platforms like PicloFlex are open to community participation, others are closed or overly complex. Baseline estimation, product standardization, and settlement mechanisms are among open research and policy questions. Novel metrics that measure the ability of a portfolio to respond, rather than leave from expected behavior, may lead to more accurate and fair means of community flexibility measurement.

Overall, this chapter illustrates that energy communities have the technical potential, legal basis, and stakeholder structures to become reliable sources of system flexibility. Yet, tapping this potential into frequent market participation depends on regulatory clarity, inclusive market design, and the development of scalable implementation models attuned to the community context. In this regard, the next chapter introduces the methodological framework developed to make this vision operational, focusing specifically on the optimization of community-scale battery storage in a Portuguese energy community. By translating internal storage management onto regulatory frameworks and electricity market signals, in particular those defined under the pilot Portuguese flexibility market, this model aims to bridge the gap between theoretical flexibility potential and real-world, revenue-stream-generating participation in actual grid services.

Chapter 3

Managing the Flexibility of Battery Energy Storage Systems in Energy Communities

This chapter presents the methodological framework created to model and optimize the functioning of community-scale battery storage in a REC, focusing specifically on its integration in the Portuguese flexibility market. The internal community battery storage management is presented, where the control approach is mainly motivated by electricity market prices and local generation-consumption patterns. Afterwards, the operation paradigm is extended through the inclusion of engagement in flexibility services tendered by the DSO. This phase considers market regulations and contractual agreements specific to Portugal, namely those presented by the E-REDES FIRMe project. A multi-objective optimization outlook is then presented to reconcile the dual objective of electricity bill minimization and revenue maximization from flexibility service delivery. Thus, the chapter forms a solid basis for the numerical implementation and further result analysis.

3.1 Management of Community Storage

This section outlines the methodology formulated for the autonomous operation of the battery storage system based on market price signals and local energy conditions. The aim is to model an operation cycle for the battery by determining the most appropriate instants to carry out charge and discharge operations, from the point of view of maximizing the benefit for the community.

At the core of this strategy is the use of adaptive threshold parameters, which are calculated based on the day's minimum and maximum electricity market prices. The parameters regulate the battery's charging and discharging set-points, allowing the system to dynamically react to price changes and achieve economic optimality. The battery has discrete modes of operation, such as (i) charging from photovoltaic excess, (ii) charging from the grid, (iii) discharging for serving local load, and (iv) stand-by, each controlled by clearly defined control logic.

The model strictly imposes battery operation constraints, such as state-of-charge (SOC) limits and discrete charging and discharging step sizes, for realistic battery behavior simulation. With this methodology, by optimally scheduling battery actions based on market conditions, we are able to extract maximum value from available local resources. From a control point of view, this approach is an indirect price-based method.

Table 3.1 provides a description of the variables and parameters used in the battery operation Algorithm 1.

Table 3.1: Notation, variable and parameter definitions for battery operation optimization Algorithm 1.

Variable	**Description**	**Unit**
P_t	Electricity price at timestep t	€/MWh
$load_t$	Aggregated local net consumption at timestep t	kWh
$PV_t^{surplus}$	Aggregated PV surplus energy at timestep t	kWh
SOC_t	State of charge of the battery at timestep t	kWh
$charge_t$	Battery charging energy at timestep t	kWh
$discharge_t$	Battery discharging energy at timestep t	kWh
Parameter		
cap_{max}	Maximum battery capacity	kWh
cap_{min}	Minimum battery capacity	kWh
a	Threshold coefficient for charge triggers	–
b	Threshold coefficient for discharge trigger	–
TRF_c	Charge trigger threshold	€/MWh
TRF_d	Discharge trigger threshold	€/MWh
$step_{charge}$	Battery charging step size	kWh
$step_{discharge}$	Battery discharging step size	kWh

Initially, the battery's SOC is set to a known initial value, establishing the baseline energy level at the start of the simulation horizon. For simplification, we will assume that the initial SOC is zero. In line 2, two adaptive threshold coefficients, denoted a and b, are introduced to scale the daily minimum and maximum electricity prices, respectively. These coefficients determine the price levels at which the battery should initiate charging or discharging, allowing for a flexible and responsive control strategy.

Through lines 3 to 6, at each timestep, the algorithm computes the day's minimum and maximum electricity prices, P_t^{min} and P_t^{max}, which serve as dynamic reference points for decision mak-

Algorithm 1 Price-driven battery operation cycle.

Require:
Time series of P_t, $load_t$, $PV_t^{surplus}$
Battery parameters: cap_{max}, cap_{min}, $step_{charge}$, $step_{discharge}$

1: Initialize SOC at $t = 0$ to $SOC_0 \leftarrow 0$
2: Set coefficients a, b
3: **for** each timestep t in simulation horizon **do**
4: Compute daily minimum price P_t^{min} and maximum price P_t^{max} for the day of t
5: Set $TRF_c \leftarrow a \cdot P_t^{min}$
6: Set $TRF_d \leftarrow b \cdot P_t^{max}$
7: **if** $PV_t^{surplus} > 0 \wedge SOC_t < Cap_{max}$ **then** ▷ Charge from PV condition
8: $trigger \leftarrow 1$
9: $charge_t \leftarrow \min(PV_t^{surplus}, step_{charge}, cap_{max} - SOC_t)$
10: $discharge_t \leftarrow 0$
11: **else if** $P_t \leq TRF_c \wedge SOC_t < Cap_{max}$ **then** ▷ Charge from grid condition
12: $trigger \leftarrow 2$
13: $charge_t \leftarrow \min(step_{charge}, cap_{max} - SOC_t)$
14: $discharge_t \leftarrow 0$
15: **else if** $P_t \geq TRF_d \wedge SOC_t > Cap_{min}$ **then** ▷ Discharge condition
16: $trigger \leftarrow 3$
17: $discharge_t \leftarrow \max(load_t, step_{discharge}, SOC_t - cap_{min})$
18: $charge_t \leftarrow 0$
19: **else** ▷ Stand-by condition
20: $trigger \leftarrow 4$
21: $charge_t \leftarrow 0$, $discharge_t \leftarrow 0$
22: **end if**
23: Update battery SOC per Equation 3.3.
24: **end for**

ing. Using these, the charging and discharging trigger thresholds are established as in Equation 3.1.

$$\begin{cases} TRF_c = a \cdot P_t^{min} \\ TRF_d = b \cdot P_t^{max} \end{cases} \tag{3.1}$$

The battery then evaluates whether to charge or discharge based on the current market price and its SOC constraints. As an example, if $a = 1.2$ and $b = 0.6$, we mean to say the following: "In the absence of energy surplus and within its capacity constraints, the battery will charge from the grid at time t if the price at t is up to 20% higher than the day's minimum price. Similarly, the battery will discharge to meet internal load at time t if the price at t is at least 60% of the day's maximum price."

Per lines 7-10, if there is available photovoltaic surplus energy at the timestep and the battery is not fully charged, the battery prioritizes charging from this renewable source. The charge energy in this case is limited by the available energy surplus, the maximum charging step size, and the remaining capacity of the battery to avoid overcharging. This scenario is flagged by a trigger 1, indicating charging from PV.

When PV surplus is absent or insufficient, but the market price falls below the charging threshold and the battery still has capacity, the battery charges from the grid, following the algorithm from lines 11-14. This action is similarly constrained by the maximum charge step and the battery's capacity limits, ensuring safe and efficient operation. The corresponding trigger 2 marks the charging from grid condition.

Conversely, from 15 to 18, if the market price exceeds the discharging threshold and the battery's SOC is above its minimum limit, the battery discharges energy to meet local load demands. The discharge energy is bounded by the local load, the battery's maximum discharge step, and the SOC margin above the minimum capacity to prevent over-discharging. This is indicated by a discharge trigger 3.

If none of the conditions in lines 7, 11, and 16 are met, the battery remains in a stand-by mode, neither charging nor discharging, with zero energy flows and an appropriate trigger 4 (line 19). Equation 3.2 presents the charge and discharge energy calculation according to the different triggers.

$$\begin{cases} charge_t = \min\left(PV_t^{surplus}, step_{charge}, cap_{max} - SOC_t\right) & \text{if } trigger = 1 \\ charge_t = \min\left(step_{charge}, cap_{max} - SOC_t\right) & \text{if } trigger = 2 \\ charge_t = 0 & \text{if } trigger = 3,4 \\ discharge_t = \max\left(load_t, step_{discharge}, SOC_t - cap_{min}\right) & \text{if } trigger = 3 \\ discharge_t = 0 & \text{if } trigger = 1,2,4 \end{cases} \tag{3.2}$$

Following the action determination, the battery's SOC is updated by adding the net energy charged minus the energy discharged. The updated SOC is then bounded within the physical limits of the battery's capacity to ensure operational safety, as in Equation 3.3.

$$SOC_t = SOC_{t-1} + charge_t - discharge_t \quad \text{s.t.} \quad cap_{min} \leq SOC_t \leq cap_{max} \tag{3.3}$$

The coefficients a and b governing the price thresholds should be subject to optimization with the objective of minimizing the total electricity bill. This reflects the economic trade-offs in battery operation and enables adaptive strategies responsive to varying market conditions.

3.1.1 Optimization of Price Coefficients

Grid search was utilized as the optimization technique to find the best pair (a^*, b^*) that minimizes the overall electricity bill throughout the simulation horizon. The technique is an exhaustive search technique that evaluates all possible combinations of the parameters to determine the optimal.

The choice of grid search was motivated mainly by its simplicity and viability. Since the number of parameters is small, the list of combinations is not large, and thus it does not demand a lot of computational power. Additionally, its exhaustiveness ensures that the best-performing pair in the search space is found without the need for probabilistic models.

Equation 3.4 presents the adaptation of the formal mathematical definition in [74] to this work.

$$(a^*, b^*) = \arg \min_{(a,b) \in D} \mathscr{L}\big(\text{electricity bill}\,(a,b),\, D_{\text{sim}}\big) \tag{3.4}$$

where

- D is the search domain for the coefficients a and b,
- $\mathscr{L}$ is the cost (or loss) function measuring the total electricity bill resulting from simulating the battery operation algorithm with parameters a and b,
- electricity bill (a, b) denotes the output electricity bill from the simulation using parameters a and b,
- D_{sim} represents the input data and conditions used for the simulation.

The grid search systematically explores a predefined discrete set of values D for both coefficients:

$$a \in \{1.0, 1.1, 1.2, \ldots, 1.5\}, \quad b \in \{0.4, 0.5, 0.6, \ldots, 1.0\}$$

The decision to confine the coefficients a and b to the specified ranges is a heuristic strategy for parameter optimization. Instead of trying an unconstrained search across all potential values — which would be computationally unfeasible and possibly encompass economically meaningless territory — the heuristic circumscribes the search space to ranges based on domain expertise.

This pragmatic limit concentrates computational effort on parameter values that are most likely to produce significant gains in battery performance and cost reductions. These heuristic approaches are typical in energy systems optimization when trading off solution quality against tractability, particularly in working in software frameworks that have computational constraints.

Capping a at values no greater than 1.5 prevents the charging threshold of the battery from exceeding the daily minimum price by 50%. Above this, the charging price threshold would be too high and might lead the battery to charge even during moderately expensive periods. This would defeat the economic basis of charging at low-price periods and might result in higher costs rather than savings. Similarly, placing the lower limit for b at 0.4 prevents the discharge trigger threshold from going below 40% of the daily maximum price. Permitting b values beneath this point would mean discharging at very low prices, contrary to the aim of achieving maximum savings by discharging at high prices. On the other hand, not permitting b values greater than 1.0 prevents discharge triggers above the maximum observed price that would never be reached.

For each pair (a, b) in the grid, the grid search algorithm proceeds as follows in Algorithm 2.

Algorithm 2 Grid search for optimization of battery operation parameters.

1: **Initialization:** Define the parameter grids for a and b.
2: **for** each (a, b) pair in the grid **do**
3: Execute Algorithm 1 over the full simulation period.
4: Compute the resultant electricity bill using the updated charging and discharging schedules.
5: Store the electricity bill outcome for the parameter pair (a, b).
6: **end for**
7: **Selection:** Identify the pair (a^*, b^*) that yields the minimum electricity bill, representing the optimal coefficient thresholds.

In line 1, the parameter grids for both coefficients are initialized, defining the discrete sets of values to be evaluated. The algorithm then enters a loop (lines 2–6) where, for each (a, b) pair, Algorithm 1 is executed over the full simulation horizon to simulate the battery's behavior under these control parameters.

As described in line 3, the electricity bill resulting from the simulated charging and discharging schedules is computed. This metric quantifies the economic performance for the given parameter pair. Subsequently, line 4 stores the computed electricity bill associated with each combination, enabling comparative analysis across the entire search space.

Finally, line 7 performs the selection step by identifying the pair that yields the minimum electricity bill, representing the optimal charging and discharging thresholds for the battery operation.

After establishing the optimal battery operation for self-consumption and bill minimization, the community evaluates the feasibility and profitability of participating in the Portuguese flexibility market under the current legislative and contractual framework. This decision depends on the battery's flexibility capacity and on the potential revenue from flexibility services versus the impact on the electricity bill.

3.2 Portuguese Flexibility Market Operation

The flexibility market is designed to facilitate transactions between the DSO and flexibility service providers. As described in 2.2.3, Piclo serves as the digital marketplace where flexibility providers submit bids to offer their services, allowing the DSO to procure flexibility capacity as needed. The flexibility providers enter into formal contracts with the DSO, committing to make available flexible capacity that can be dispatched upon request. Figure 3.1 illustrates the general timeline of the flexibility service process, starting with bidding on PicloFlex, followed by qualification tests for prospective providers, and culminating in contract signing and subsequent service delivery. The flexibility products traded on the platform correspond to the standardized offerings summarized in Table 2.9. It is noteworthy that the detailed bidding process and the operational mechanics of the Piclo platform fall outside the scope of this work and are thus not analyzed herein.

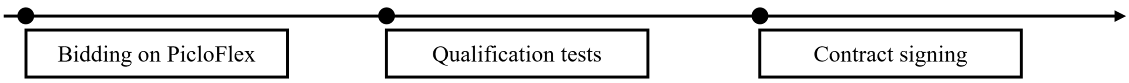

Figure 3.1: Sequential steps in E-REDES flexibility service procurement via the PicloFlex platform.

The Portuguese DSO, E-REDES, establishes a standardized contract defining the rights and obligations of both the DSO and flexibility providers. Below are listed the most relevant terms of the contract to be incorporated in our problem:

- Availability requirements: Flexibility providers must guarantee that their flexible resources are available for activation within specified time-frames and power limits. This is quantified in terms of contracted flexible power and activation windows.
- Activation and utilization: Flexibility activations occur via formal utilization instructions from the DSO, specifying the magnitude, duration, and timing of the requested flexibility. Flexibility providers are required to respond promptly and deliver the requested adjustments.
- Compensation and penalties: The contract defines remuneration mechanisms that distinguish between availability payments (compensating for being ready to provide flexibility) and utilization payments (rewarding actual delivery of requested flexibility). Penalties may apply for non-compliance or failure to meet performance standards.

Before presenting the detailed parameters for flexibility service provision, it is important to contextualize the variability of these parameters. The flexibility parameters differ across geographical areas, reflecting the specific grid constraints and operational needs identified by the DSO in each location.

The bids are organized by combinations of type of day, season, and daily time intervals, reflecting the temporal and seasonal variations in grid conditions and flexibility needs. Each entry includes the maximum active power that the battery can offer, the direction of the flexibility response (whether it involves charging or discharging), and the technical limits on activation, such as the maximum activation time and duration.

Contractual parameters specify the duration of the contract and the expected utilization patterns, including the number of days per week the service can be activated and the estimated maximum annual utilization hours. The expected activation hour denotes the total time within the time slot when flexibility is likely requested, while the maximum activation volume estimates the energy the battery may deliver.

Probabilistic parameters include the expected frequency of activations per year and the energy not fulfilled, quantifying the expected energy shortfall during service provision.

Table 3.2: Parameters for flexibility market participation adapted from E-REDES 2023 documentation.

Parameter	**Unit**
Classification of day (Weekday, Saturday, Sunday)	–
Seasonal classification (Winter, Spring, Summer, Autumn)	–
Time interval within the day (0–8h, 8–18h, 18–0h)	–
Maximum active power expected per time interval	kW
Direction of response	+ / -
Maximum allowed time to fully activate flexibility	min
Maximum permitted activation duration	h
Contractual period of flexibility service	months
Number of utilization days per week	days
Maximum estimated utilization hours per year	h/year
Number of expected activation hours in the time interval	h
Maximum estimated energy activation volume	kWh
Expected annual activation frequency	# / year
Energy not fulfilled (expected unserved energy)	kWh

Details available at: https://www.e-redes.pt/sites/eredes/files/2023-07/Detalhes_oportunidades.pdf

3.2.1 Integration of Community Storage

The approach taken is to leverage the community's battery operation profile, in particular the flexibility capacity present.

We therefore define flexibility capacity as the quantity of energy the battery can charge or discharge solely during stand-by times. Such times are intervals where the battery is fully available to react to flexibility requests from the DSO, without encroaching on its main role of self-consumption optimization. This state of operational readiness guarantees that the battery can deliver the requested flexibility services in a timely manner once activated. In addition, the specifications laid down by market rules and standard agreements call for guaranteed availability and quick response. These provisions are met naturally during stand-by times, which therefore constitute the most suitable windows for providing flexibility. Restricting the provision of flexibility services to these intervals also prevents conflict with the battery's economically optimized charging and discharging cycles. This delineation maintains intact the battery's cost-minimizing operation while ensuring assured flexibility service provision.

The total flexibility capacity for each time interval t is computed as the sum of available charge and discharge energy, limited by the battery's SOC and step sizes:

$$\begin{cases} E_t^{charge} = \text{available charge energy during stand-by at } t \\ E_t^{discharge} = \text{available discharge energy during stand-by at } t \end{cases} \tag{3.5}$$

The quantification of the valued energy, which represents the effective flexibility service delivered to the DSO, follows a methodology adapted from the E-REDES standard [1].

For each 15-minute time interval t, the valued energy E_t^{valued} is computed based on the relationship between the energy actually delivered $E_t^{available}$ and the estimated energy requested $E_t^{estimated}$.

$$E_t^{valued} = \begin{cases} 0, & \text{if } E_t^{available} < \alpha \cdot E_t^{estimated} \\ E_t^{available} \cdot \left(1 - \frac{ENF}{\sum_t E_t^{estimated}}\right) & otherwise \end{cases} \tag{3.6}$$

where

- $E_t^{available}$ is the absolute value of energy available for flexibility in the community at time t,
- $E_t^{estimated}$ is the maximum estimated energy activation volume energy to be requested by the DSO for time t,
- α is a user-defined threshold parameter reflecting the minimum fraction of estimated energy to consider in the valuation,
- ENF quantifies the total shortfall of energy delivery across all intervals.

Equation 3.6 introduces a correction term involving the non-delivered energy factor. Specifically, if the available energy $E_t^{available}$ meets or exceeds a fraction α of the estimated energy $E_t^{estimated}$, the valued energy is adjusted proportionally by $\left(1 - \frac{ENF}{\sum_t E_t^{estimated}}\right)$. This adjustment accounts for typical discrepancies or shortfalls in service delivery across the settlement period, ensuring that expected remuneration aligns with actual performance rather than theoretical maximums.

Moreover, the inclusion of parameter α also constitutes an addition to the E-REDES contractual framework. The parameter $\alpha \in]0,1]$ serves as a pragmatic control lever, allowing the community to define the minimum proportion of the estimated energy $E_t^{estimated}$ that must be available for the energy to be considered valid for remuneration. For example, if $\alpha = 1$, then the maximum estimated energy is requested, and the community may not have the resources to respond.

[1] https://www.e-redes.pt/sites/eredes/files/2023-08/Regulamento_concursos_prestacao_servicos.pdf

By simulating the flexibility revenue for several values of α, the community gains flexibility to align the valuation mechanism with their operational capabilities and market risk appetite. Lower α values result in more inclusive valuation, whereas higher values enforce stricter adherence to expected performance.

Furthermore, Equation 3.7 quantifies the valued flexibility energy within the contractual limits specified by E-REDES. This approach ensures that only energy contributions falling within a $\pm$ 15% margin of the estimated flexibility request $E_t^{estimated}$ are considered for remuneration. Energy values below the 85% threshold are considered insufficient to qualify as effective service delivery and thus receive no valuation. Conversely, any energy exceeding the 115% upper bound is capped to prevent overcompensation and to maintain fairness in the market settlement process.

$$E_t^{valued} = \begin{cases} 0, & \text{if } E_t^{available} < Ref_{inf\%} \cdot \alpha \cdot E_t^{estimated} \\ E_t^{available}, & \text{if } Ref_{inf\%} \cdot \alpha \cdot E_t^{estimated} \leq E_t^{available} \leq Ref_{sup\%} \cdot \alpha \cdot E_t^{estimated} \\ \alpha \cdot E_t^{estimated}, & \text{if } E_t^{available} > Ref_{sup\%} \cdot \alpha \cdot E_t^{estimated} \end{cases} \tag{3.7}$$

where $Ref_{inf\%} = 0.85$ and $Ref_{sup\%} = 1.15$ represent the contractual lower and upper bounds, respectively, defining the acceptable range for flexibility service delivery.

By the time this phase of the simulation is achieved, the community has enough information to determine the time intervals (day, time interval, season) where it is physically able to offer flexibility services to the grid. The subsequent remuneration mechanism completes this by providing more information, allowing the community to determine whether the activation of flexibility during those time intervals can be beneficial in economic terms.

The remuneration of flexibility services provided by the REC battery is structured around two principal components, reflecting both availability and actual utilization.

The availability payment P_D compensates the REC for maintaining the battery's readiness to provide flexibility services during the contracted periods, regardless of actual activation. It is calculated as:

$$P_D = P_F \cdot T_D \cdot H_D \tag{3.8}$$

where:

- P_F is the contracted flexible power capacity (MW),
- T_D is the availability tariff rate (€/MW/hour),
- H_D is the total number of hours the battery is available during the contract period.

The utilization payment P_U rewards the REC based on the volume of flexibility energy actually delivered in response to DSO activation orders. It is expressed as:

$$P_U = T_U \cdot SET \tag{3.9}$$

where:

- T_U is the utilization tariff rate (€/MWh),
- $SET = \sum_t E_t^{valued}$ is the total valued energy delivered over all activation intervals.

The total payment to the REC for flexibility services during the contract period is therefore:

$$Revenue = P_D + P_U \tag{3.10}$$

This payment framework incentivizes both the availability of flexible capacity and its actual deployment, ensuring the REC is compensated for its contribution to grid stability and flexibility.

The above-mentioned tariff rates are stipulated in the contracts between the flexibility provider and the DSO, and vary depending on the product type and location. Not all geographical zones accommodate all standard product types, as reflected in the tariff availability in Table 3.3.

Table 3.3: Fixed and variable tariff rates for different flexibility products across selected geographical zones.

Flexibility Product	**Zone**	€/MW/h	€/MW/year	€/MWh
Dynamic	São Martinho do Campo	500	-	500
Restore	Bragança	-	500	1000
Restore	Beja	-	800	1000
Restore	Marinha Grande	-	400	1000
Restore	Bombardeira	-	400	1000
Restore	Milfontes	-	600	1000
Secure	Paredes de Coura	8	-	56
Secure	Tondela	4	-	15

Source: https://www.e-redes.pt/sites/eredes/files/2023-07/Pre%C3%A7os_Indicativos.pdf

Figure 3.2 illustrates the temporal progression of battery operations within the two-stage control framework developed in this work. Three distinct scenarios are identified:

- **Scenario (A):** Battery is on stand-by but does not participate in the flexibility market. This scenario corresponds to periods where the community opts out of market participation despite operational readiness, due to economic considerations.
- **Scenario (B):** Battery is on stand-by and available for market participation. However, no flexibility activation request is received from the DSO during this interval.

- **Scenario (C):** Battery is on stand-by and actively responds to a DSO flexibility activation request, delivering valued energy E_{valued} within the designated activation window, starting at time t_1 and ending at t_2 following the DSO's request at t_0.

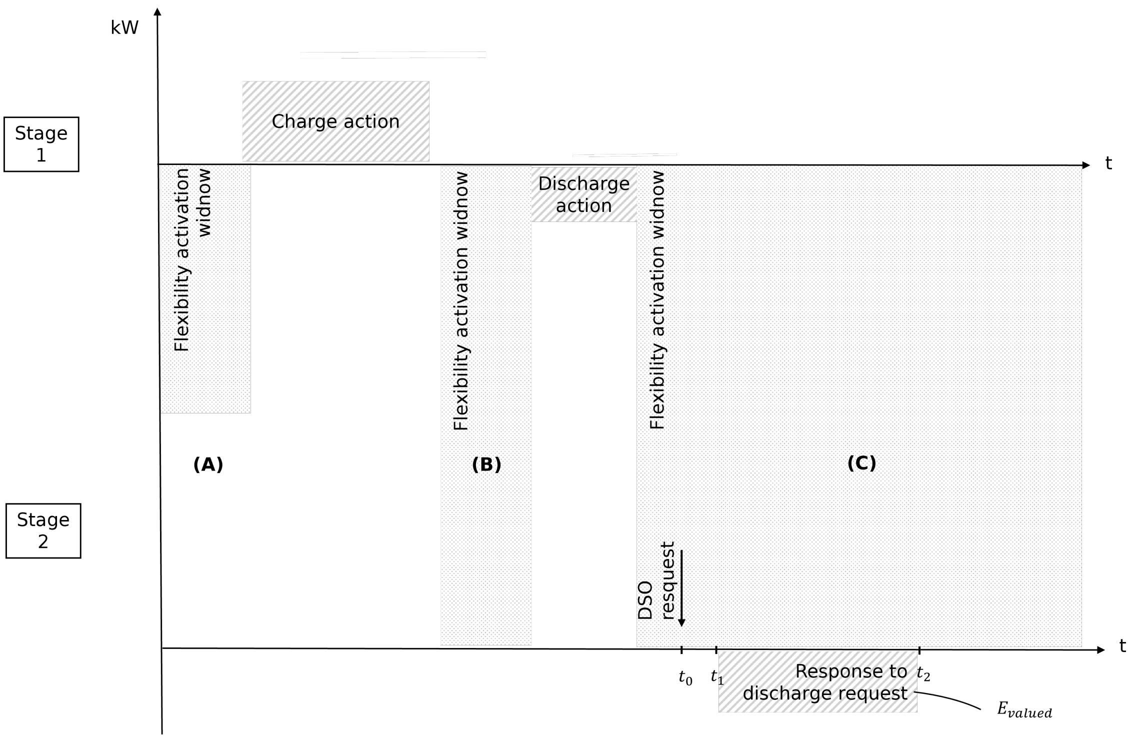

Figure 3.2: Illustration of battery operational states and flexibility market participation within the two-stage control framework. The upper portion (stage 1) shows battery charging and discharging actions with shaded stand-by periods defined by optimized coefficients a and b. The lower portion (stage 2) depicts market participation scenarios: (A) on stand-by without participation, (B) on stand-by without DSO activation request, and (C) active response to DSO flexibility request delivering valued energy E_{valued}.

3.3 Technical Assumptions for Implementation

This section identifies the major technical assumptions taken for the application of the suggested approach. These assumptions specify the data attributes, computational tools, and current regulatory environment on which the simulation and further economic assessment are based.

Historical Data Source and Temporal Resolution

The method presented in this chapter will be implemented in Chapter 4 based on a real REC, with data including production and consumption energy measured at 15-minute intervals over a consecutive one-year term. The dataset spans the 2020–2021 time-frame, while the electricity market prices used in the simulation are the MIBEL market prices observed within the same time-frame. The historical data acts as a proxy to model the community operating profile and battery operation in the years that follow. Although this comprises a time-frame of considerable volatility and extreme price fluctuations, which portray extraordinary conditions, it has some advantages.

First, testing of the battery operating algorithm in stress conditions that stress-test flexibility responses to extreme price signals becomes possible. This has the potential to determine the robustness and flexibility of the control policy in adverse market conditions. Second, despite the volatility, the underlying temporal patterns (daily and seasonal price patterns) continue to hold and provide a realistic foundation for the optimization process.

The battery energy storage system and the prosumers are embedded in a low-voltage distribution grid, which guarantees coherence in the electrical environment and data granularity. Furthermore, it is presumed that the REC already has a functional battery system. Therefore, capital and implementation expenses associated with battery installation are not included in the economic evaluation.

Surplus Energy Repartition Algorithm

The methodology relies on a consumption-based repartition algorithm for distributing surplus energy among community members, formalized by an explicit formula presented in Equation 3.11.

$$E_{\text{repartition},i} = \frac{C_i^{net}}{\sum_{i=1}^{N} C_i^{net}} \cdot \sum_{i=1}^{N} E_i^{surplus} \tag{3.11}$$

where

- $E_{\text{repartition},i}$ is the share of surplus energy allocated to prosumer i (kWh),
- C_i^{net} is the net consumption of prosumer i during the period (kWh),
- N is the total number of prosumers in the community,
- $\sum_{i=1}^{N} C_i^{net}$ is the total net consumption of all prosumers,
- $E_i^{surplus}$ is the surplus energy of prosumer i during the period (kWh),
- $\sum_{i=1}^{N} E_i^{surplus}$ is the total surplus energy available for repartition (kWh).

Of the energy generated by each prosumer, some is locally self-consumed, and the rest is treated as the surplus energy of the community. The process of surplus energy repartition allows a portion of this surplus to be shared and traded among the consumer installations for consumption within the concerned time period. More specifically, during each quarter-hour interval, buildings with a production deficit are assigned a share of the surplus energy from the buildings in surplus production. As per Equation 3.11, the energy assigned to each building is determined by taking the product of the overall surplus energy during the specified quarter-hour with the ratio of the building's net consumption to the sum of the net consumption of all buildings within the community. The subtraction of allocated energy from the overall surplus gives the final surplus energy. This energy, if not stored in the battery, is later sold to the grid.

Simulation Platform

The tool chosen for carrying out the study was Microsoft Excel. While limited in its ability to deal with large datasets, it provides accessibility and flexibility for iterative modeling and scenario analysis.

For the evaluation of economic results, the calculation of the electricity bill follows the tariff frameworks established in current Portuguese law. The methodology of the calculation is explained in the next section, forming the basis for assessing costs in the community.

3.4 Electricity Bill Calculation

The billing of the REC with an autonomous BESS is framed by consolidating all the energy exchanges among the REC members and the BESS and the RESP. The approach guarantees that all the transactions are covered by the relevant tariffs in effect, honoring the principles established by ERSE in [75].

Calculation Principles

The network tariffs and energy prices differ based on the time in which consumption or injection takes place. The tariff structure specifically differentiates between *horas de ponta* (peak hours), *horas de cheia* (flood hours), *horas de vazio* (off-peak hours), and *horas de super vazio* (super off-peak hours). The periods are specified in the regulatory framework and match pre-established daily schedules. Furthermore, the tariff schedules vary between summer time and winter time, as well as among the quarterly periods (I, II, III, and IV). Periods I and IV refer to days between October 1^{st} to March 31^{st}. Periods II and III refer to days between April 1^{st} and September 30^{th}.

The community functions in BTE (*Baixa Tensão Especial*, Special Low Voltage). In this situation, the consumers can opt for the daily cycle regime or the monthly cycle. All the metered amounts of energy are summed up by hourly period prior to the application of the respective unit prices. However, Appendix A presents the structure of both cycles.

Foremost, it is important to distinct between points of delivery of energy, CPE (*Código de Ponto de Entrega*), as the same installation may record flows in both directions, incurring different tariff components. It can be a consumption CPE (CPEc), when the energy flow is counted from the RESP to the installation; or a production CPE (CPEp), when the energy flow is counted from the installation to the RESP. Given the possibility of bi-directionality, the metering system can simultaneously have both a consumption CPE and a production CPE.

Figure 3.3 illustrates the energy flows between the different entities composing the REC and the RESP.

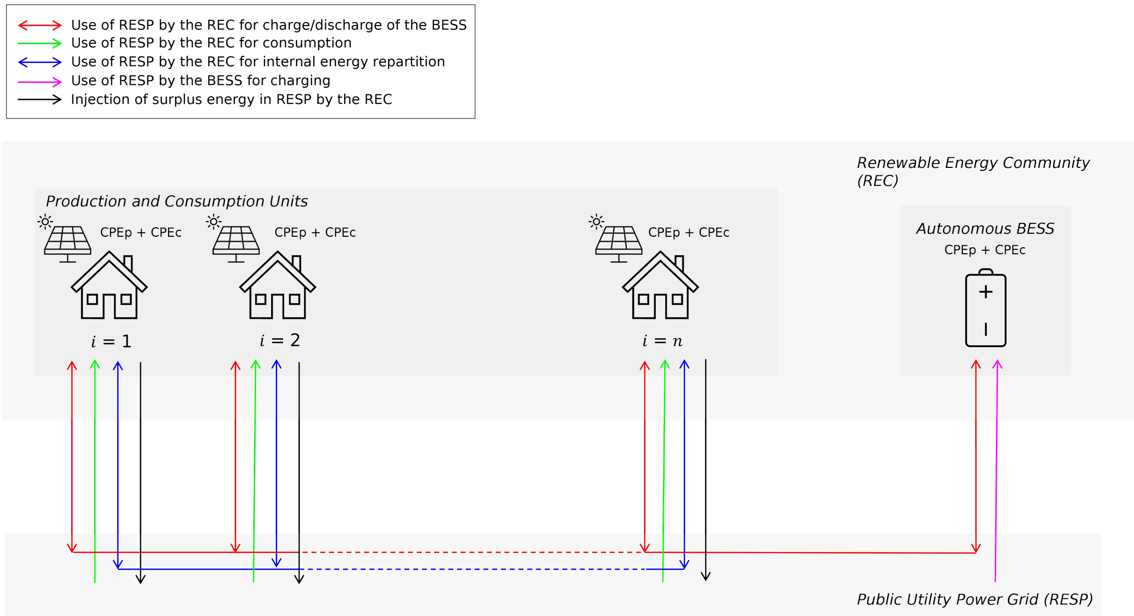

Figure 3.3: Schematic representation of the energy flows between the REC, its autonomous battery, and the RESP. The diagram highlights the distinct transaction types: REC consumption, BESS charging and discharging, internal energy repartition, and surplus injection, each measured via specific consumption (CPEc) and production (CPEp) points of delivery.

Each production and consumption unit (indexed by $i = 1, 2, \ldots, n$) is characterized by a UPAC configuration and therefore integrates both a production point of delivery and a consumption point of delivery. Similarly, the BESS operates as an autonomous unit, with the capacity to both inject and withdraw energy, also maintaining its own CPEp and CPEc.

The energy flows depicted in the diagram are distinguished by color-coded arrows, each representing a distinct operational context:

- **Use of RESP by the REC for energy repartition between installations:** This flow corresponds to the redistribution of self-produced energy among REC members via the RESP. In this case, the locally generated energy is routed through the grid to reach other installations participating in the community. The metering of these transactions is performed at both the injection and withdrawal points of delivery, and the applicable tariffs for access to self-consumption through the RESP, presented in Table B.1, are applied.

- **Use of RESP by the REC for charging and discharging the BESS as part of transacted flows:** This flow represents the transactions in which the REC employs the RESP to channel energy into the BESS or to supply energy stored in the BESS back to REC members. When charging, the energy withdrawal is measured by the metering equipment associated with the BESS consumption point of delivery. Conversely, when discharging, the injection is recorded by the meter corresponding to the production point of delivery. As with other transacted flows, the cost of using the network is borne by the installation that receives the discharged energy and is calculated according to the self-consumption tariffs in Table B.1.

- **Use of RESP by the REC for consumption:** This represents the energy directly imported for consumption from the RESP. The corresponding quantities are measured by the meters installed at each consumption point of delivery (identified by their respective CPEc) and billed according to the applicable tariffs: energy tariff, contracted power tariff, and *horas de ponta* tariff. These are explicit in Table B.2.

- **Use of RESP by the BESS for charging:** This specific case refers exclusively to the energy imported by the BESS from the RESP to store in its batteries. The energy withdrawn is measured by the meter corresponding to the BESS consumption point of delivery (identified by its CPEc), and distinct tariffs, namely specific autonomous storage TAR in Table B.3, are applied.

- **Injection of surplus energy in RESP by the REC:** When the REC's aggregate production exceeds its internal consumption and storage capacity, the surplus energy is injected into the RESP. These quantities are measured by the metering equipment associated with the production points of delivery. The injected energy is remunerated at a fixed unit price, which is subsequently deducted from the total community bill.

In regards to the TAR, the entity responsible for paying these tariffs to the DSO is the EGAC. To that effect, when facilities covered by a REC are set up in a way that self-consumption via the public grid is possible (which is the case) EGAC will have to sign a network usage agreement with the DSO. Additionally, communities utilizing public networks can benefit from an exemption from the General Economic Interest Cost (CIEG), which is a charge within the TAR. Under current law [2], the exemption can reach 100% of the CIEG.

Calculation of the Final Cost

The total cost incurred by the community in each billing period results from the aggregation of all applicable tariff components associated with the energy flows described previously. It is worth noting that the VAT rate and the initial investment made in production facilities are not taken into account in any financial calculations.

The calculation is performed by summing the costs of power and active energy consumption, while deducting the remuneration corresponding to surplus energy injected into the RESP and the revenue from participating in the flexibility market. Formally, the total cost C_{total} is given by:

$$C_{\text{total}} = C_{\text{energetic}} + C_{\text{transacted}} + C_{\text{BESS}} - R_{\text{surplus}} - R_{\text{flexibility}} \tag{3.12}$$

where:

[2] https://diariodarepublica.pt/dr/detalhe/despacho/1393-2025-905459896

- **Energetic Component** ($C_{\text{energetic}}$) represents the cost of the energy imported directly from the RESP for consumption by the REC. It includes:

$$C_{\text{energetic}} = \sum_d \Bigg[\sum_p \left(E^{(p,d)}_{\text{consumption}} \cdot T^{(p)}_{\text{energy}} \right) + \left(P_{\text{contracted}} \cdot T_{\text{power-contracted}} \right) + \left(P^{(d)}_{\text{peak}} \cdot T_{\text{power-peak}} \right) \Bigg], \tag{3.13}$$

  with:

  - $E^{(p,d)}_{\text{consumption}}$: energy imported for consumption during period p on day d (kWh),
  - $T^{(p)}_{\text{energy}}$: energy tariff per kWh applicable to period p,
  - $P_{\text{contracted}}$: contracted power in kW (constant),
  - $T_{\text{power-contracted}}$: contracted power tariff in €/(kW.day),
  - $P^{(d)}_{\text{peak}}$: average power during *horas de ponta* on day d (kW),
  - $T_{\text{power-peak}}$: power tariff for *horas de ponta* in €/(kW.day).

- **Transacted Energy Component** ($C_{\text{transacted}}$) represents the cost of using the RESP to transfer self-produced energy between installations of the REC. It includes:

$$C_{\text{transacted}} = \sum_d \Bigg[\sum_p \left(E^{(p,d)}_{\text{transacted}} \cdot T^{(p)}_{\text{self}} \right) + \left(P^{(d)}_{\text{peak-transacted}} \cdot T_{\text{power-peak}} \right) \Bigg], \tag{3.14}$$

  with:

  - $E^{(p,d)}_{\text{transacted}}$: energy transacted through the RESP during period p on day d (kWh),
  - $T^{(p)}_{\text{self}}$: applicable tariff per kWh for self-consumption flows in period p,
  - $P^{(d)}_{\text{peak-transacted}}$: average power during *horas de ponta* related to transacted energy on day d (kW).

- **BESS Component** (C_{BESS}) represents the cost associated with charging the BESS from the RESP. It includes:

$$C_{\text{BESS}} = \sum_d \Bigg[\sum_p \left(E^{(p,d)}_{\text{BESS}} \cdot T^{(p)}_{\text{energy}} \right) + \left(P_{\text{contracted-BESS}} \cdot T_{\text{power-contracted}} \right) + \left(P^{(d)}_{\text{peak-BESS}} \cdot T_{\text{power-peak}} \right) \Bigg], \tag{3.15}$$

with:

- $E_{\text{BESS}}^{(p,d)}$: energy consumed by the BESS from the RESP during period p on day d (kWh),
- $P_{\text{contracted-BESS}}$: contracted power for the BESS in kW (constant),
- $P_{\text{peak-BESS}}^{(d)}$: average power during *horas de ponta* for BESS charging on day d (kW).

- R_{surplus} is the remuneration for surplus energy exported to the RESP during the billing period, computed as:

$$R_{\text{surplus}} = \sum_i \left(E_{i,\text{export}} \cdot P_{\text{export}}\right),$$

with:

- $E_{i,\text{export}}$: energy injected into the RESP by installation i (kWh),
- P_{export}: agreed remuneration price per kWh of exported energy. This will be 0.05 €/kWh.

- $R_{\text{flexibility}}$ represents the revenue from the flexibility market, calculated according to Equation 3.10.

All quantities $E^{(p)}$ are aggregated per period according to the official period definitions (*horas de ponta*, *horas cheias*, *horas de vazio normal*, *horas de super vazio*), and the tariffs applied depend on the specific CIEG exemption level. The resulting sum constitutes the total amount to be invoiced to the REC for the considered billing cycle.

3.5 Final Remarks

This chapter described the methodology for optimizing the battery operation within the community to minimize electricity costs and has also described the integration of the community's battery storage into the Portuguese flexibility market, including the contractual framework, valuation, and remuneration mechanisms. Figure 3.4 illustrates the two-step methodology adopted.

The parameters a and b of battery operation are optimized to set an operation baseline aimed at reducing the electricity bill of the community by taking strategic charging and discharging measures based on market price signals. This phase guarantees that the battery utilizes hours of low electricity prices to charge and releases power to meet internal consumption during high-price periods, thus optimizing the cost of energy.

But this cost-reduction approach directly influences the battery's SOC profile and the lengths of stand-by intervals. These stand-by intervals are important, since they are the time windows when the battery is ready to engage in the flexibility market.

Market participation follows on from the results of optimal battery operation by sizing the latter's flexibility capacity over these stand-by moments. The community may then judge the financial value of market participation based on the contractual remuneration scheme, such as

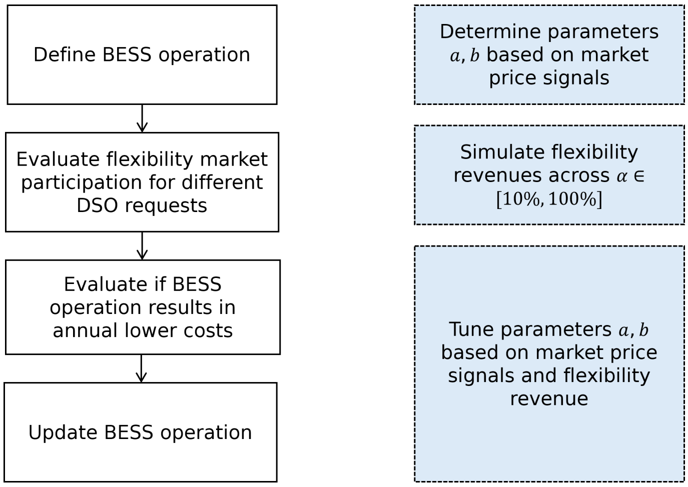

Figure 3.4: Overview of the methodology. Step 1: Parameters a and b are set to minimize the electricity bill. Step 2: Flexibility revenues are simulated for various magnitudes of DSO requests (α). Step 3: Parameters are re-tuned to balance cost savings and flexibility income.

availability and utilization payments. This two-step process allows for an integrated calculation of both the battery's operating performance and its potential in creating additional revenue streams from flexibility services.

One of the main challenges in combining these stages exists in the trade-off between flexibility revenue maximization and bill minimization. Spending more time in stand-by in order to increase flexibility availability can curtail cost-saving opportunities for charging and discharging during battery's price-based approach. On the other hand, bill minimization may aggressively curb the flexibility capacity of the battery, hence market participation.

The conclusions drawn from the examination of the effects of changing α together with the battery operation parameters a and b provide an introduction for the next chapters, which build on this basic understanding to assess the economic and technical performance of a given community with alternative operational scenarios and market participation strategies.

Chapter 4

Application and Validation of Tools: Behavior of a Rural Energy Community

This chapter applies the developed tools to a rural energy community located in northern region Portugal. The community consists of four buildings equipped with photovoltaic systems and a shared battery energy storage system. The analysis begins by characterizing the community's production profile, considering temporal variations and tariff structures.

The second part evaluates different battery operation strategies. A cost-optimal approach is established by adjusting the system's response to electricity market prices. The battery's behavior is then analyzed over time to validate the effectiveness of this strategy.

Finally, the chapter explores the community's potential to participate in the Portuguese flexibility market under the FIRMe project. By simulating various demand scenarios, it assesses the technical feasibility and economic impact of offering flexibility services. The results highlight a trade-off between minimizing energy costs and maximizing flexibility revenue.

4.1 Characterization of the Energy Community

The analyzed energy community in this work brings together four different photovoltaic installations mounted on four different buildings[1], having a total installed power of 73.3 kWp. The arrangement of the PV arrays is presented in Table 4.1, including the number of modules, installed peak power, and orientation of the panels. The installed power per site ranges from 9.9 kWp (producer 1) to 25 kWp (producer 2). It is worthwhile noting that producers 2 and 4 have the largest installed powers, at 25 kWp and 20.4 kWp, respectively, which together represent around 62.0% of the total installed power.

Table 4.2 presents a consolidated overview of the photovoltaic production and tariff plan characteristics for each building in the REC. Notably, producers 2 and 4, which have more installed

[1] Since each building has its own dedicated UPAC and consumes the energy it generates, the terms "producer" and "building" are used interchangeably throughout the text.

Table 4.1: Installed capacity, number of modules, and orientation of the photovoltaic systems.

Producer	Number of Modules	Installed Capacity (kWp)	Orientation
Producer 1	33	9.9	South
Producer 2	78	25.0	South
Producer 3	60	18.0	Southeast
Producer 4	68	20.4	Southeast

peak power, exhibit higher production levels (39.56 MWh and 27.05 MWh, respectively) compared to buildings 1 and 2.

Table 4.2: Annual production and tariff plan characteristics per building.

Building	**Production energy (MWh)**	**Tariff cycle**	**Contracted power (kW)**
Building 1	13.87	Daily	41.41
Building 2	39.56	Daily	41.41
Building 3	26.16	Weekly	41.41
Building 4	27.05	Weekly	41.41

The battery system analyzed in the simulations was set with an energy storage capacity from 0 kWh to 200 kWh and a nominal power of 100 kW. Both the charging and discharging processes were simulated with an energy step of 10 kWh. The operation of the battery is simulated with discrete energy steps, instead of permitting continuous values (i.e., any value between 0 and 200 kWh), for the sake of simplifying control logic.

Table 4.3: Battery parameters used in the simulations.

Min. Capacity (kWh)	Max. Capacity (kWh)	Charge Step (kWh)	Discharge Step (kWh)	Nominal Power (kW)
0	200	10	10	100

4.1.1 Production Profile

This subsection presents a comprehensive characterization of the community's electricity generation profiles, based on aggregated output from the four individual producers. Hourly, tariff, monthly, and seasonal perspectives are all considered, allowing the complete range of temporal variability to be appreciated.

Figure 4.1 shows the hourly energy production profile of the REC, and the contribution by producer. As anticipated, the generation starts at about 5:00 and ends after 19:00, in accordance with the availability of solar irradiance. The energy production follows a bell-shaped profile, with a peak between 11:00 and 13:00. The peak hourly generation is attained at 12:00, with a total of 14.5 MWh, made up essentially of contributions from producer 2 (5.40 MWh), producer 3 (3.57 MWh) and producer 4 (3.69 MWh). Producer 1 contributes less, with 1.89 MWh for the peak hour. Globally, producer 2 keeps the highest energy level all day long, in coherence with its better installed capacity.

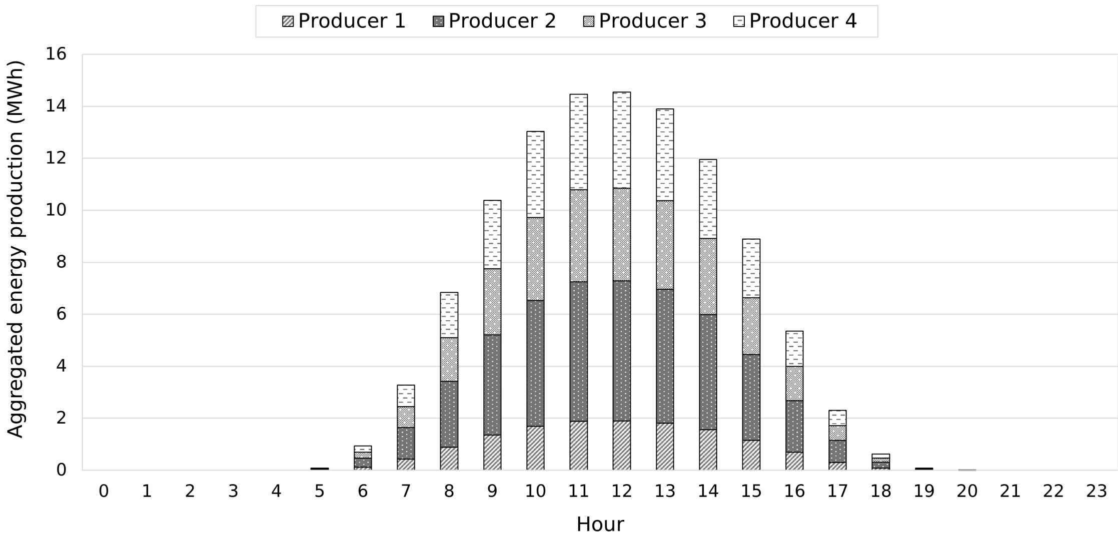

Figure 4.1: Hourly distribution of energy production across REC producers.

To have a closer view of the coincidence between photovoltaic production and the structure of the electricity tariff, the production data per hour were summed up into the four hourly tariff periods (Figure 4.2). Most of the energy was produced during the *horas de cheia* period, reaching a total of about 63.2 MWh, which represented 59.28% of the annual total production. It was followed by the *horas de ponta* period, with 29.7 MWh (27.9%), whereas the *horas de vazio* and *horas de super vazio* periods contributed with 5.7 MWh (5.8%) and 0.2 MWh (0.2%), respectively. Producer 2 continued to be the highest contributor in all periods, and especially in the *horas de cheia* period, with 26.9 MWh, followed by producer 4 (14.0 MWh) and producer 3 (12.8 MWh).

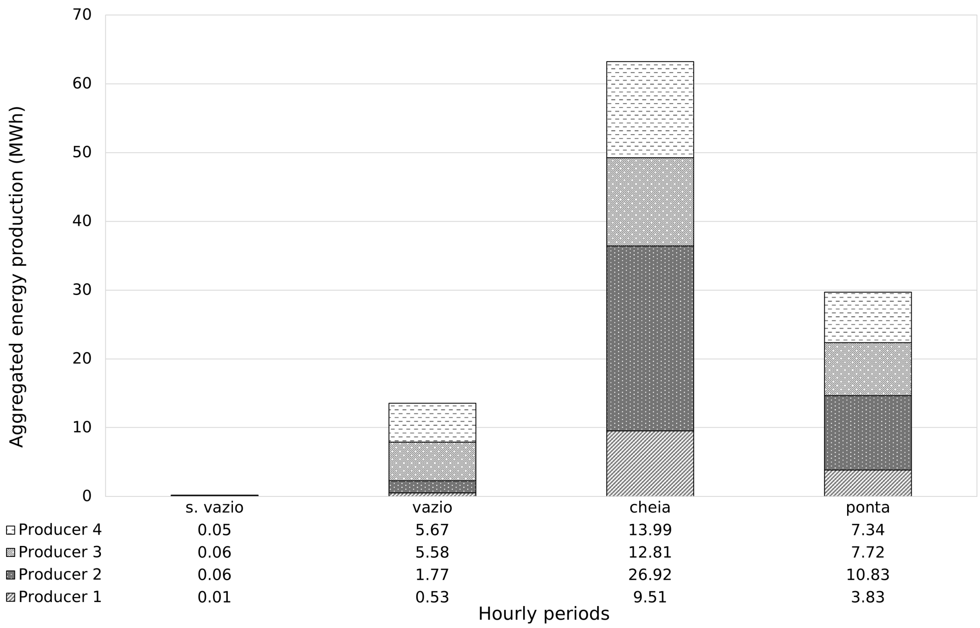

Figure 4.2: Aggregate energy production classified by electricity tariff periods.

The comparatively high production accounted for producers 3 and 4 in the *horas de vazio* period is due to the weekly formulation of the tariff cycles applied. On a weekly cycle, during weekends, the *horas de vazio* period stretches throughout much of the daytime, when solar irradiance is highest. Consequently, energy produced in these hours is accounted for under the *vazio* category, even though it takes place at a time of high photovoltaic output. Conversely, the *horas de ponta* period is only established on weekdays, which causes lower aggregated production values for producers 3 and 4 in this category, as their production on weekends is not accounted for in the total for *horas de ponta*. This difference is observable in Table 4.4, which presents the longer duration of the *vazio* period and shorter duration of the *ponta* and *cheia* periods for the weekly cycle.

Table 4.4: Number of hours per tariff period and tariff cycle.

Building	Cycle	*Horas de super vazio*	*Horas de vazio*	*Horas de cheia*	*Horas de ponta*
Building 1	Daily	5805	8626	14472	5795
Building 2	Daily	5805	8626	14472	5795
Building 3	Weekly	5805	9927	14776	4190
Building 4	Weekly	5805	9927	14776	4190

A broader temporal analysis, illustrated in Figure 4.3, presents the monthly energy production distribution. The REC displays a clear seasonal trend, with increased generation during spring and summer. July is the month with the highest aggregated production, at 14.2 MWh, followed by May and August (each at about 12.6 MWh). In contrast, the lowest production values occur in

December (3.7 MWh) and November (4.4 MWh). Producer 2 provides the highest monthly output consistently, with a maximum of 5.26 MWh in July, while producer 1's contributions are relatively small throughout all months, with a maximum of 1.84 MWh.

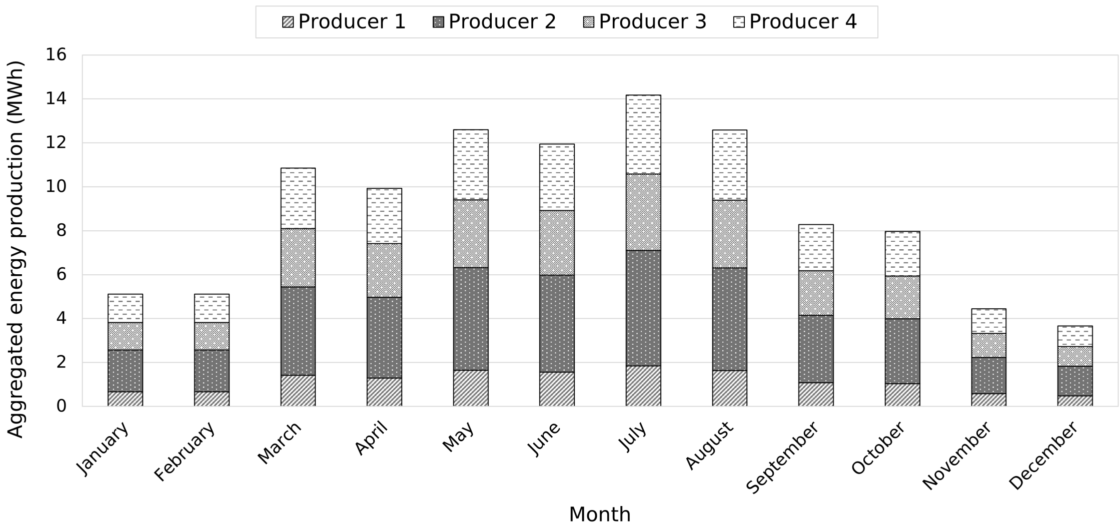

Figure 4.3: Monthly energy production for each REC producer.

The seasonal accumulation shown in Figure 4.4 strengthens this pattern. Summer is the most productive season, with a cumulative generation of 38.7 MWh and a share of 36.8% of the yearly total. It is followed by spring, with 33.4 MWh (31.3%), whilst autumn and winter contribute 20.7 MWh (19.4%) and 13.9 MWh (13.1%), respectively. Such seasonal fluctuations are to be expected, considering the reliance of solar PV generation on irradiance and daylight hours. For the fourth time, producer 2 dominates production in all seasons, contributing 14.35 MWh in summer and 12.38 MWh in spring, while producer 1 keeps a relatively lower profile, with seasonal highs of 5.04 MWh (summer) and 4.34 MWh (spring).

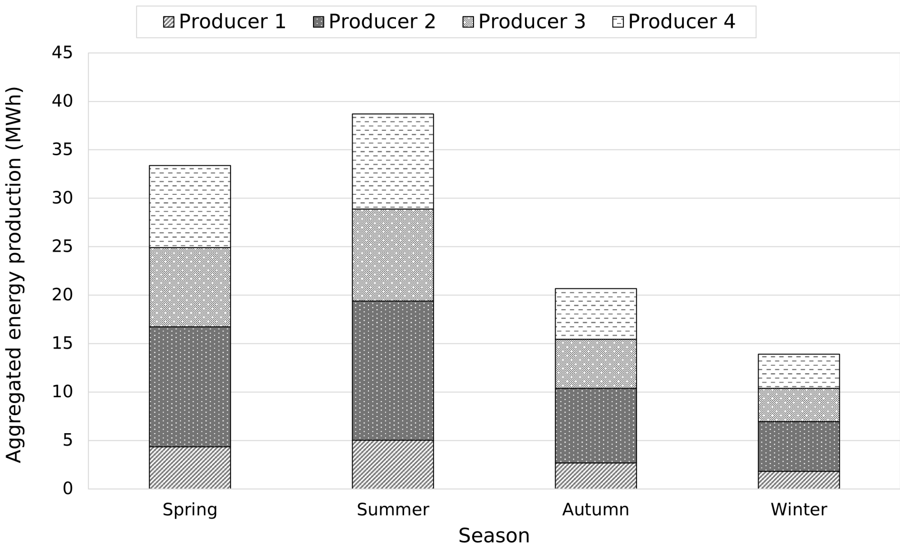

Figure 4.4: Total energy production by season, disaggregated by producer.

In short, the dynamics of production at the REC are a mix of design elements (orientation and installed capacity) and natural variability, i.e., irradiance. With regard to orientation, producers 1 and 2 enjoy south-facing modules, which generally guarantee greater efficiency within Portuguese climatic conditions. Producers 3 and 4 are southeast-facing, which may result in earlier onset of generation but in marginally lower noon-time efficiency. These variations in installed capacity and orientation account for the persistent lead of producer 2 and the relatively lower output of producer 1, as consistent with the patterns of production already outlined.

The coincidence of production during the *horas de cheia* interval increases the economic worth of local generation, especially under self-consumption frameworks. Within the Portuguese tariff system, *horas de cheia* coincide with intermediate electricity prices, above off-peak tariffs. Coinciding PV generation with these hours enables the REC to maximize avoided grid consumption costs and, consequently, the overall economic yield of local production. Furthermore, seasonal variation — with a 64% decrease in winter generation relative to summer — underlines the value of flexibility mechanisms. The REC's BESS, managed under a dynamic price-based control strategy, provides the ability to shift energy consumption temporally, enhancing the overall use of PV output under diverse temporal conditions.

4.2 Battery Management Strategies

The next section uses the optimization approach outlined above to determine the operational performance of the battery energy storage system of the community under different management approaches. The examination starts by determining the values of the parameter set a and b that reduce the electricity bill to a minimum, establishing a cost-optimal operational baseline. Then, the potential for trading in the Portuguese flexibility market is determined for several values of α expressing the amount of energy requested by the distribution system operator.

Two operating strategies are examined in detail: the cost-optimal benchmark, the approach that maximizes flexibility revenue. The discussion goes on to evaluate compromises between the two goals to achieve minimum total annual cost. This comparison aims to investigate when deviating from the cost-optimal operation is beneficial and whether flexibility revenue maximization compromises the efficiency of battery operation.

4.2.1 Cost-Optimal Operation Baseline

The first phase of the methodology involved determining the parameters of battery operation that reduce the annual cost of electricity for the energy community to a minimum. This involved investigating a series of combinations for control parameters which dictate the charging and discharging thresholds as multiples of daily market prices.

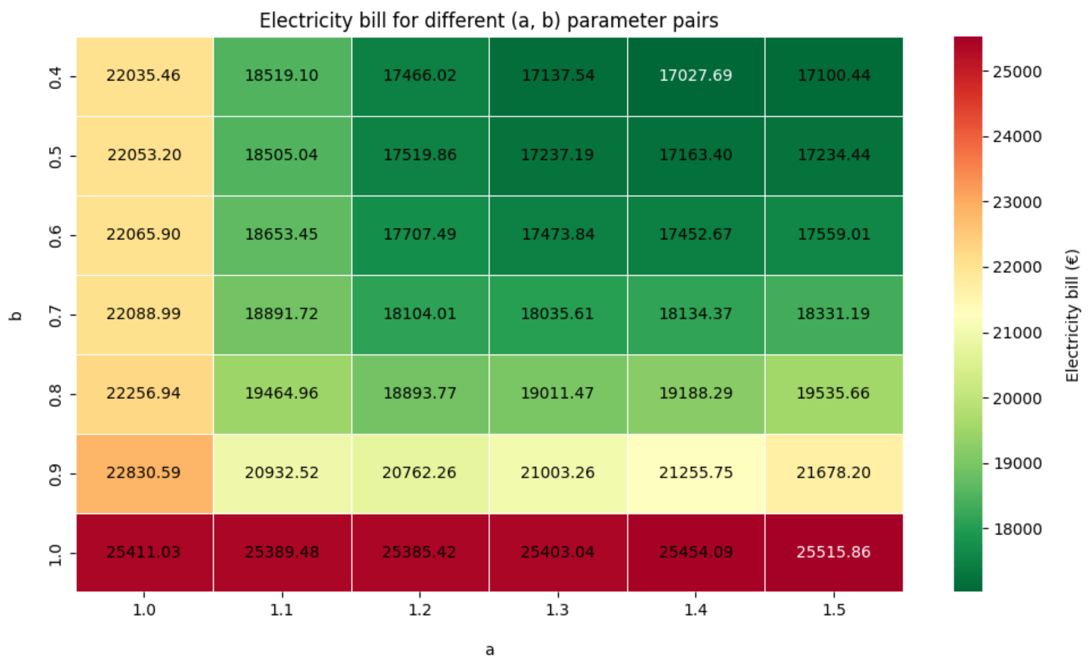

Figure 4.5: Annual electricity bill for different combinations of battery operation parameters a and b.

Figure 4.5 shows the overall electricity cost per year paid by the energy community in different setups of the battery operation.

The heatmap demonstrates an evident minimum and maximum in the parameter space, highlighting the strong effect of the values of (a,b) on the yearly electricity bill. The minimal cost of 17027.69 is obtained for the pair $(a,b) = (1.4, 0.4)$. In this setup, the battery is charged from the grid when the price of electricity at a particular time is up to 40% higher than the daily minimum and discharged to serve internal demand when the price is at least 40% of the daily maximum. This setup is successful in taking advantage of low-price opportunities and saving on costly grid consumption, with a cost decrease of roughly 33% with respect to the most costly setup.

On the other hand, the highest total yearly electricity cost, 25515.86, is associated with the pair $(a, b) = (1.5, 1.0)$. This configuration ties battery activity to only the most pronounced price differentials: charging only when the price is as much as 50% higher than the day's minimum and discharging only when the price hits the daily maximum, thus severely curtailing the battery's involvement and compromising its potential for cost reduction.

The heatmap's spatial evolution also shows a wider green area, denoting lower electricity costs, centered on intermediate to high values of a (ranging from 1.2 to 1.5) and low to moderate values of b (ranging from 0.4 to 0.6). This region illustrates that there is quite a wide combination range of parameters that achieve near-optimal performance, indicating some robustness in the cost-minimization approach. As a rises within this range, the battery becomes more accepting of modestly higher charging prices, widening its charging window without appreciably detracting from economic performance. At the same time, moderate values of b allow the battery to discharge over a greater number of high-price intervals, thus increasing self-consumption and grid independence without over-constraining operation.

This trend demonstrates that optimal battery operation is not dependent on carefully calibrated thresholds but instead arises from being responsive to daily price variability in a balanced manner. This is shown by the presence of an extensive set of (a, b) pairs that result in equally low annual electricity expenditures, with differences below 2% between adjacent parameter pairs within the top-right quadrant green area. Such performance is indicative of the success of a strategy that takes advantage of relative, as opposed to absolute, price signals. This enables the battery to continually take advantage of daily fluctuations without precise calibration. It also demonstrates the robustness of the method under common market volatility, where price distributions vary but continue to display predictable daily structure.

To provide further evidence for the efficacy of the proposed approach, the battery's operation under the threshold pair $(a, b) = (1.4, 0.4)$ that resulted in the lowest overall electricity cost over the analysis period will be reported.

Figure 4.6 illustrates the evolution of the battery's operational trigger throughout a representative day. Table 4.5 highlights the moments in which the battery changes trigger state. These transitions follow precisely the logic defined in Algorithm 1, confirming that the system consistently reacts to real-time pricing signals, PV surplus availability, and internal constraints. On the chosen day, the minimum market price was 21.64 €/MWh, and the maximum market price reached 48.2 €/MWh.

The battery discharges (trigger 3) from 00:00 until 09:00, since prices are high and the battery level is relatively close to maximum at 156.3 kWh capacity. Afterwards, the system remains in stand-by (trigger 4) from 09:15 until 09:45, since there is no PV surplus and grid prices remain above the charging threshold $1.4 \cdot 21.64 = 30.30$ /MWh.

At 10:00, a surplus of 2.5 kWh of PV is available, activating trigger 1. The battery is charged from PV for a short time, increasing SOC to 11.4 kWh by 11:15. As soon as the surplus is zero, the

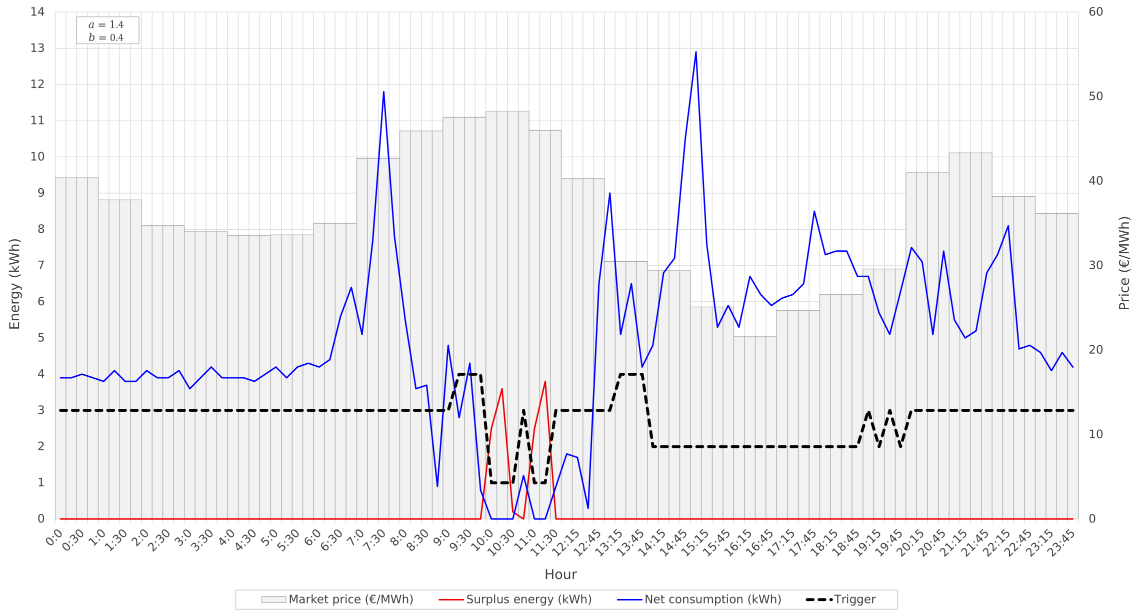

Figure 4.6: Illustration of trigger-based battery operation on 19/10/2020 for $(a,b) = (1.4, 0.4)$.

system restarts discharging briefly (trigger 3), before entering another stand-by period (trigger 4) from 13:15 to 13:45. No action is taken once again because prices remain above the charging threshold and no PV is available.

At 14:00, the market price drops to 29.4 €/MWh, slightly below the charging threshold, enabling grid charging (trigger 2). The battery is charged in increments of 10 kWh until 18:45, when it reaches a complete charge to its maximum capacity of 200 kWh. This charging session confirms the algorithm's ability to exploit low-price periods.

Discharging resumes at 19:00 and continues overnight as demand picks up and the price is driven to 40.99 €/MWh. SOC declines from 200 kWh to 108 kWh at 23:45. These are in line with expectations of a cost-minimizing controller, to the extent that energy is stored during low-price hours and drawn down in high-price hours to reduce consumption from the grid.

It is also interesting to remark on the sudden switching between discharging and charging witnessed in the early evening period, between 19:00 and 19:45. Although the market price remains constant at 29.6 €/MWh over the interval, the system switches between trigger 2 (charging from grid) and trigger 3 (discharging). This behavior is an expression of the physical constraints of the system: the battery is full (200 kWh) at 19:15 and 19:30, and additional charging is impossible. Subsequently, at 20:00, the sudden increase in net demand (7.5 kWh) and market price precipitates an immediate switch to discharging. These are exceptional events caused by boundary conditions and not necessarily oscillations caused by pricing signals. Moreover, in this particular day, the discharge threshold works out to $0.4 \cdot 48.2 = 19.28$ €/MWh, which is below the day's minimum market price. This outcome at first appears counterintuitive but is in fact consistent with intention. Rather than responding to absolute price levels, the control logic interprets prices relative to each day's volatility range. In this case, the discharge condition is always satisfied from a price point of

Table 4.5: Detailed view of trigger-based battery operation on 19/10/2020 for $(a,b) = (1.4, 0.4)$.

Date	Market Price (/MWh)	Surplus (kWh)	Net Consumption (kWh)	Trigger	SOC (kWh)	Charge (kWh)	Discharge (kWh)
19/10/20 0:00	40.40	0.0	3.9	3	156.3	0.0	3.9
...	...	...	...	...	...	...	...
19/10/20 9:15	47.55	0.0	2.8	4	0.0	0.0	0.0
...	...	...	...	...	...	...	...
19/10/20 10:00	48.20	2.5	0.0	1	2.5	2.5	0.0
...	...	...	...	...	...	...	...
19/10/20 10:45	48.20	0.0	1.2	3	5.1	0.0	1.2
...	...	...	...	...	...	...	...
19/10/20 11:15	46.02	3.8	0.0	1	11.4	3.8	0.0
19/10/20 11:30	46.02	0.0	0.9	3	10.5	0.0	0.9
...	...	...	...	...	...	...	...
19/10/20 13:15	30.49	0.0	5.1	4	0.0	0.0	0.0
...	...	...	...	...	...	...	...
19/10/20 14:00	29.40	0.0	4.8	2	10.0	10.0	0.0
...	...	...	...	...	...	...	...
19/10/20 19:00	29.60	0.0	6.7	3	193.3	0.0	6.7
19/10/20 19:15	29.60	0.0	5.7	2	200.0	6.7	0.0
19/10/20 19:30	29.60	0.0	5.1	3	194.9	0.0	5.1
19/10/20 19:45	29.60	0.0	6.3	2	200.0	5.1	0.0
19/10/20 20:00	40.99	0.0	7.5	3	192.5	0.0	7.5
...	...	...	...	...	...	...	...
19/10/20 23:45	36.19	0.0	4.2	3	108.0	0.0	4.2

view; nevertheless, discharging is only executed when there is internal demand and the battery's SOC is greater than its minimum.

Apart from the day-profile, the battery usage must be validated on a longer timescale. The battery state of charge histogram (Figure 4.7) is averaged over one year, reflecting two regimes of main interest: a high-SOC cluster between $[90, 100]\%$, and a low but persistent activity between $[10, 90]\%$. The battery spent approximately 62% of the time near full capacity.

The average daily SOC profile presented in Figure 4.8 reinforces this observation. The battery typically starts the day at a relatively high SOC, decreases progressively as prices rise, and recharges again during low-price afternoon periods. The charging phase tends to begin slightly after midday and continues until early evening, closely tracking periods of minimum market price.

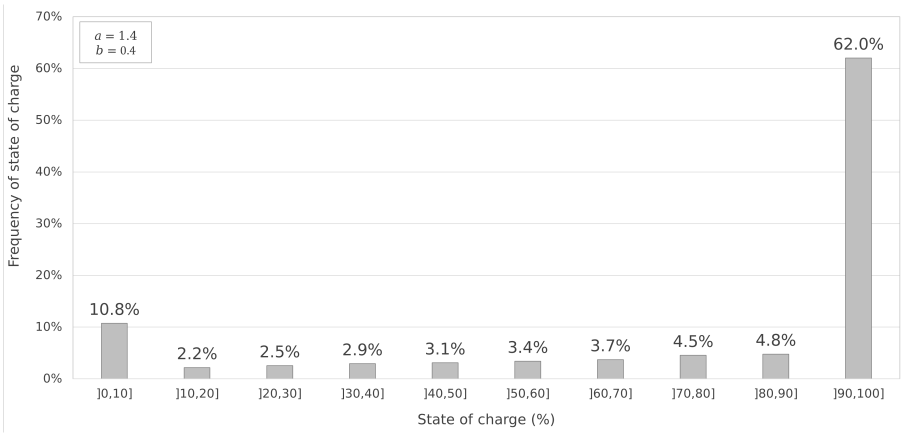

Figure 4.7: Percentage of periods as a function of battery charge status over the course of a year for $(a,b) = (1.4, 0.4)$.

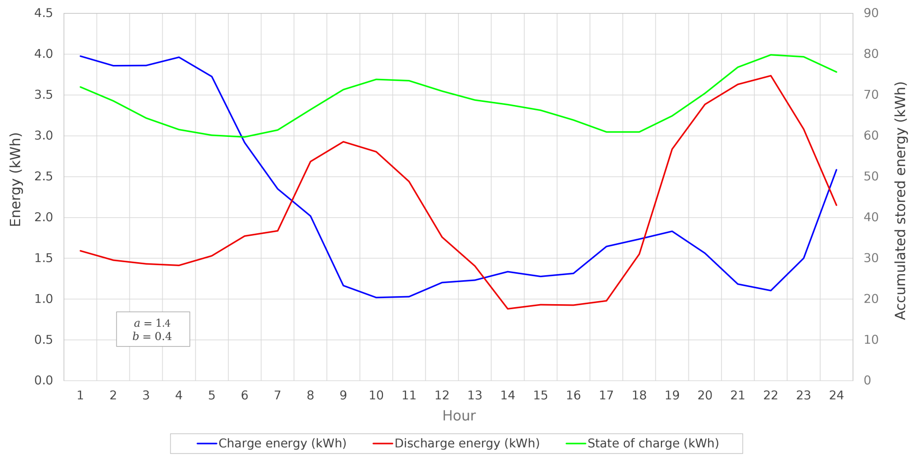

Figure 4.8: Standard hourly pattern of annual battery charge and discharge energy for $(a,b) = (1.4, 0.4)$.

The analysis of energy exchanges within the REC over the simulation year offers insights into the battery's operational role, consumption dynamics, and internal self-consumption efficiency.

Figure 4.9 displays the monthly aggregated net consumption of each building alongside the BESS and the overall REC. Seasonal fluctuations are clearly visible: total energy consumption is significantly higher during winter months, particularly in January and December (22.0 and 20.8 MWh, respectively), while reaching a minimum in June and July (6.6 and 6.4 MWh). The BESS maintains a consistently high contribution throughout the year, accounting for 45.3% of total annual consumption, with monthly peaks aligned with the highest overall demand periods.

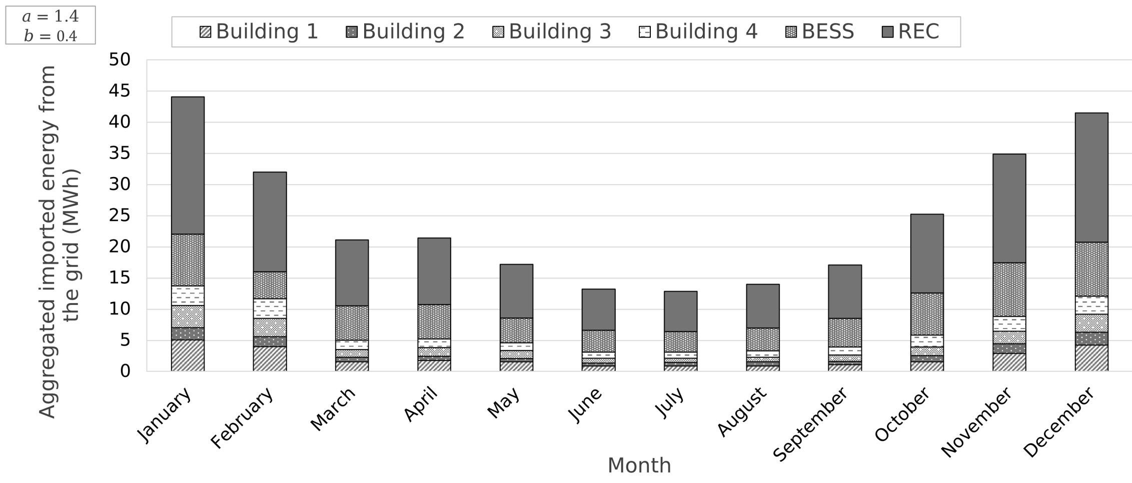

Figure 4.9: Monthly aggregated net consumption for each building, the BESS, and the REC total over the simulation year for $(a,b) = (1.4, 0.4)$.

From a building-level perspective, building 1 represents the largest individual load (18.0% of yearly consumption), followed by buildings 4 (14.9%), 3 (13.5%), and 2 (8.3%).

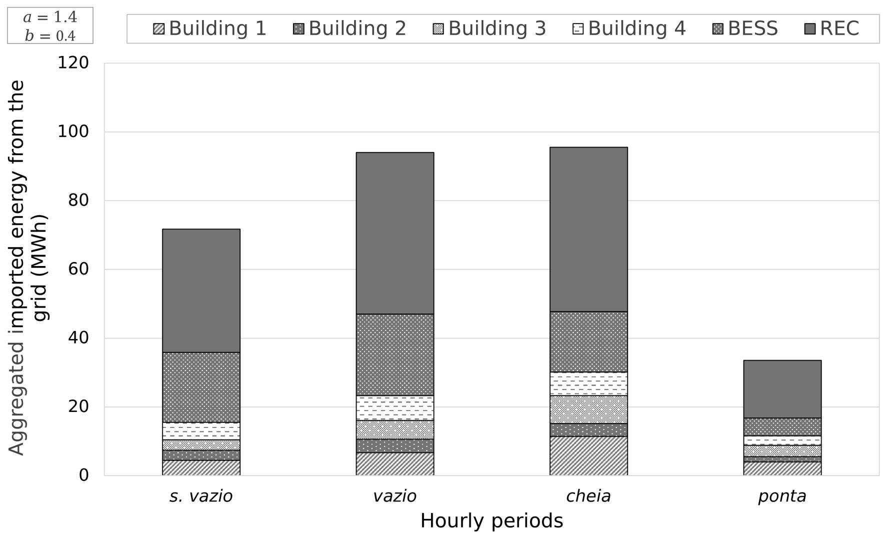

Figure 4.10: Annual net energy consumption by hourly tariff period for $(a,b) = (1.4, 0.4)$.

Figure 4.10 breaks down net consumption by hourly tariff period. The REC exhibits a consumption profile that favors low-cost periods: 47.0 MWh were consumed during *horas de vazio*, 35.9 MWh during *horas de super vazio*, and 47.8 MWh during *horas de cheia*. Only 16.8 MWh occurred during *horas de ponta*, showing that the controller effectively shifts demand away from expensive hours.

The BESS plays a key role in this shift. Of the 66.8 MWh exchanged through the BESS over the year, nearly 71% occurred during *horas de vazio* and *horas de cheia* periods.

As for self-sufficiency, over the course of the year, a total of 71.1 MWh was exported from the battery to the community, demonstrating the system's ability to redistribute stored energy when beneficial. The distribution of these exports in Figure 4.11 reveals a seasonal trend, with the highest values recorded in November (8.75 MWh) and December (8.78 MWh). These two months alone account for a quarter of the yearly exported energy from the BESS to cover internal demand.

The allocation among buildings also follows expected patterns based on their consumption profiles. Building 1 received the largest share, with 23.38 MWh (32.9% of the total), followed by building 4 (19.471 MWh), building 3 (18.02 MWh), and building 2 (10.23 MWh). This proportionality reflects the community's prioritization strategy, which favors buildings with higher baseline needs during periods when surplus is internally available.

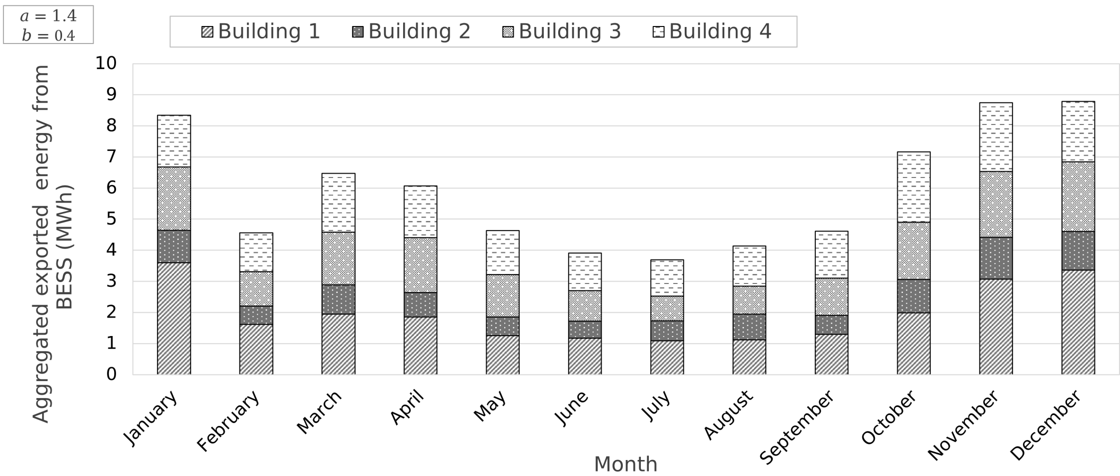

Figure 4.11: Monthly energy exported from the BESS to supply REC consumption for $(a,b) = (1.4, 0.4)$.

The volume of surplus energy exported from buildings to the external grid is presented in 4.12. These exports are concentrated in the summer months (May to August), particularly from building 2, which alone contributed over 10 MWh of exported surplus during the year, accounting for 51.7% of the total. July stands out as the peak month, with building 2 exporting 2.34 MWh, followed by significant exports from buildings 4 (1.43 MWh) and 3 (1.02 MWh).

Buildings 1 and 3 export minimal amounts throughout the year. The low overall export volumes across the REC confirm that the battery strategy was effective in capturing and utilizing most of the local generation internally.

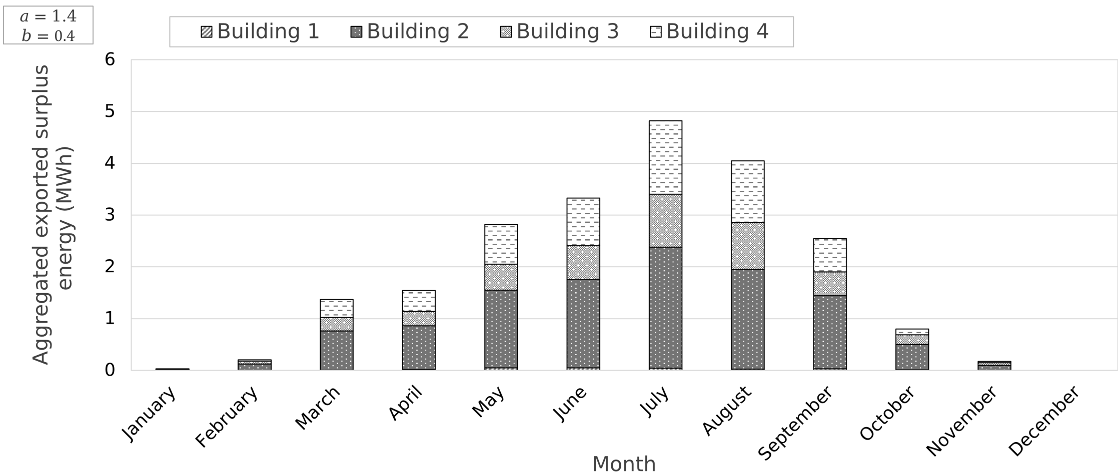

Figure 4.12: Monthly export of surplus energy from each building to the grid for $(a,b) = (1.4, 0.4)$.

Following the characterization of the production and consumption profile of the community and the verification of the put-forward price-based battery operation strategy, the assessment now shifts to evaluating the engagement of the community within the flexibility market. The previously defined baseline scenario — prioritizing cost-optimal battery management — serves as a benchmark for the new phase. However, the potential for additional economic value with the offer of flexibility services necessitates the re-estimation of the BESS operation strategy.

4.2.2 Market Participation and Flexibility Revenue Evaluation

This analysis seeks to quantify the technical performance and economic result of REC in delivering flexibility. Specifically, the study makes use of the key performance indicators such as the volume of available flexible power, percentage effectively traded, incidence of unserved flexibility due to systemic constraints, and the corresponding monetary incentive. These indicators give data about the physical reactivity of the battery system as well as about the economic feasibility of engaging in flexibility markets under real operating conditions.

Regarding the community's location, although confidential, the geographical flexibility requests applicable to the area can be those of Bragança (see Table 3.3), falling under the *Restore* product category. This service requires the community to respond following a fault event, either by reducing its consumption (downward flexibility) or by increasing its generation (upward flexibility). In the context of a battery energy storage system, these requirements translate into charging and discharging actions, respectively. The specific characteristics of the flexibility requests from E-REDES for the Bragança region, including time intervals, durations, and activation probabilities, are summarized in Table 4.6 for a Winter weekday, while the full dataset is provided in Appendix C. Notably, the direction of response in all time intervals is set to increase generation, meaning the community's flexibility potential will be assessed solely based on its ability to discharge during stand-by periods.

Table 4.6: Flexibility service parameters for the Bragança site on weekdays during winter, per time interval.

	0–8	**8–18**	**18–0**
EXPECTED RESPONSE			
Maximum active power expected per time interval (kW)	5177	5567	8244
Direction of response (+/-)	+	+	+
TECHNICAL REQUIREMENTS			
Maximum allowed time to fully activate flexibility (min)	15	15	15
Maximum permitted activation duration (h)	8	10	6
FLEXIBILITY ACTIVATION			
Contractual period of flexibility service (months)	3	3	3
Number of utilization days per week (days)	5	5	5
Maximum estimated utilization hours per year (h/year)	8	10	6
Number of expected activation hours in the time interval (h)	8	10	6
Maximum estimated energy activation volume (kWh)	23865	47575	42624
Expected annual activation frequency (#/year)	0.0009	0.001	0.0007

The evaluation now considers a second operating mode, in which the BESS responds to flexibility service requests issued by the DSO, participating in the market. These requests are defined as a percentage, denoted by α, of the maximum estimated energy activation volume on a given market period.

The average flexibility revenue was computed for each α value across all operation scenarios. Figure 4.13 illustrates the evolution of the mean revenue as the percentage of requested energy increases. Notably, the highest revenues are achieved for α values in the range of 20% to 50%, with peak remuneration occurring at $\alpha = 30\%$ and $\alpha = 50\%$. Beyond this threshold, a clear decline is observed. This trend reflects a trade-off: as requests become more demanding, they increasingly conflict with the internal BESS operation constraints and previously scheduled charging cycles, leading to lower availability and higher rates of unserved flexibility.

It is also important to note that the community under study is characterized by a relatively small installed power and limited energy storage capacity. As such, its ability to respond effectively to large flexibility requests from the DSO is inherently constrained. When α values exceed 50%, the magnitude and frequency of requests surpass the technical capacity of the BESS to respond without compromising its primary function of local optimization. This results in reduced traded flexible energy and diminished financial returns from flexibility participation.

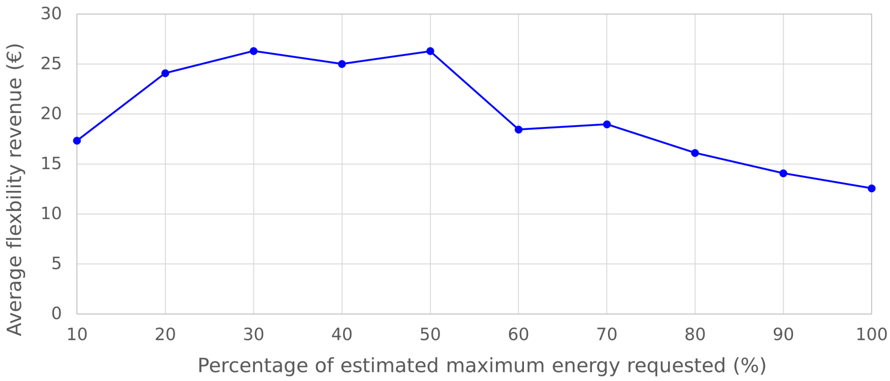

Figure 4.13: Average flexibility revenue as a function of the percentage of estimated maximum flexible energy requested by the DSO.

To understand how flexibility performance varies across the operational parameter space, ten heatmaps were generated — one for each level of estimated energy requested by the DSO. Figure 4.14 presents the flexibility revenue distribution for the best-performing case ($\alpha = 30\%$) and the worst-performing case ($\alpha = 100\%$). A full set of results for intermediate values of α is available in Appendix D.

A clear pattern emerges across all α values: the highest revenues are associated with conservative discharge strategies (i.e., higher values of b), particularly in the range 0.9 to 1.0, combined with moderate charging thresholds (e.g., $a = 1$ to $a = 1.3$). These configurations keep the battery available during periods when flexibility is likely to be requested, avoiding early depletion due to internal demand. On the other hand, aggressive strategies characterized by low b values (e.g., 0.4 or 0.5) result in early discharging to meet internal load and offer minimal availability to the DSO, consistently leading to low or zero flexibility revenue.

As the magnitude of the requests increases, the revenue gradient across the heatmaps becomes flatter and lower. This supports the saturation effect evident in Figure 4.13: higher requests cannot be met, and even well-configured BESS strategies become less effective at capturing revenue. By $\alpha = 100\%$, nearly all operation combinations converge toward similarly low revenues, underscoring the physical limitation of the REC's flexibility capacity.

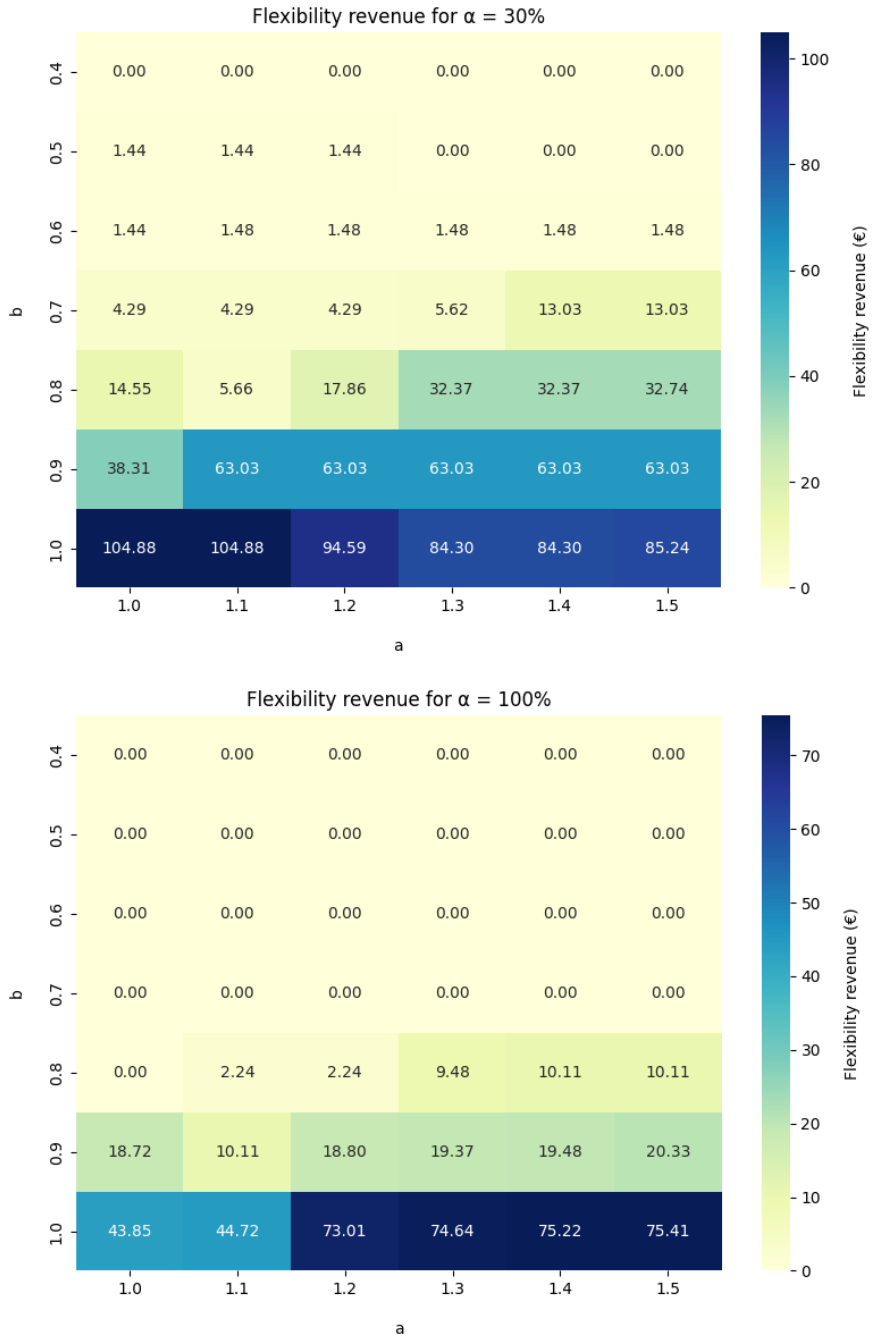

Figure 4.14: Comparison of flexibility revenue across (a,b) pairs for the best-performing case ($\alpha = 30\%$) and the worst-performing case ($\alpha = 100\%$) on average.

On average, configurations where both a and b are relatively high yield the best results. These scenarios maintain the battery in a stand-by mode for longer durations, making energy available to respond to DSO requests. In contrast, low b values lead to immediate discharging under lower price thresholds, which compromises the availability of stored energy during flexibility events, especially when considering that the direction of the flexibility response is always towards injecting energy into the grid.

The results reveal a notable concentration of configurations yielding no financial returns. This observation prompted the introduction of a metric to quantify the battery's operational readiness for flexibility participation across the explored parameter space: the Flexibility Market Eligibility Rate.

This rate reflects the proportion of BESS configurations that resulted in non-zero flexibility revenue for at least one value of α. It captures the fundamental capacity of the community battery scheduling logic to align with external flexibility market signals. In this context, a low eligibility rate suggests that most operating modes are inherently unsuited to respond to the temporal or volumetric structure of DSO flexibility requests.

$$\text{Flexibility Market Eligibility Rate} = \frac{\text{Scenarios with non-zero average revenue}}{\text{Total scenarios}} \tag{4.1}$$

$$= \frac{259}{420} \tag{4.2}$$

$$= 61.7\% \tag{4.3}$$

In the present case study, 259 combinations led to any positive flexibility revenue out of the 420 tested, yielding a flexibility market eligibility rate of approximately 62%. However, despite this seemingly encouraging figure, nearly 95% of these positive outcomes resulted in revenues below €100, indicating limited economic viability in most scenarios. This suggests that, under the tested conditions and considering the likely range of flexibility activation volumes from the DSO, the community appears economically capable of participating in the flexibility market in only a small fraction, approximately 4.8% of the scenarios.

Following this, to further capture participation potential, a complementary metric was introduced: the Revenue-Weighted Eligibility Index. This index quantifies the average revenue of all tested scenarios relative to the best-performing configuration and is defined as:

$$\text{Revenue-Weighted Eligibility Index} = \frac{1}{N}\sum_{i=1}^{N}\frac{R_i}{R_{\max}} \tag{4.4}$$

where N is the total number of scenarios, R_i represents the revenue of scenario i, and $R_{\max}$ denotes the maximum revenue observed across all scenarios. In this case, with $N = 420$, a total revenue sum of €8 364.71, and a maximum scenario revenue of €139.54, the resulting index is:

$$\text{Revenue-Weighted Eligibility Index} = \frac{8364.71}{420 \cdot 139.54} \approx 0.143 \quad \text{or} \quad 14.3\% \tag{4.5}$$

This result reveals that, on average, each scenario achieved only 14.3% of the maximum revenue observed. While the community exhibits theoretical potential for flexibility market participation, the actual economic viability is concentrated in a very limited subset of operational configurations, constrained by the current structure of the community and the rules of the FIRMe project.

To further substantiate these trends, Table 4.7 summarizes key performance indicators for three representative scenarios: the average top performer $(a,b) = (1.2,1.0)$, the average bottom performer $(a,b) = (1.2,0.4)$, and the baseline scenario $(a,b) = (1.4,0.4)$, which was previously defined as cost-optimal. Zero-revenue scenarios were excluded from these metrics.

Table 4.7: Comparative flexibility performance between the most and least effective BESS operation strategies on average.

Average metrics for flexibility evaluation	Top performer $(a,b) = (1.2,1)$	Bottom performer $(a,b) = (1.2,0.4)$	Baseline scenario $(a,b) = (1.4,0.4)$
Available flexible energy (kWh)	318600	9441.90	10427
Traded flexible energy (kWh)	110970.61	268.99	750.26
Traded flexible energy (%)	35	3	7
Expected unserved flexible energy (kWh)	281896.06	68659	68240.50
Expected duration of insufficient flexibility (h)	137.20	280	270
Total utilization compensation (€)	87.38	0.08	0.18
Total availability compensation (€)	1.44	0.96	0.91
Total flexibility revenue (€)	88.82	1.04	1.09

The top-performing configuration offers a substantially higher available flexible energy, reaching 318 600 kWh, over 30 times greater than the bottom performer (9442 kWh) and the baseline (10 427 kWh). This increase translates into a significantly higher traded flexible energy of 110 970.61 kWh, which corresponds to 35% of all requests, compared to just 3% and 7% for the bottom and baseline configurations.

The expected unserved flexible energy remains high across all cases, but the top performer achieves a proportionally better response. Additionally, the duration of insufficient flexibility is cut nearly in half, decreasing from over 270 hours in the lower-performing configurations to 137.2 hours. It is worth noting that the market conveys 288 hours, so neither result is satisfying.

From an economic perspective, the total flexibility revenue achieved by the top performer is nearly €89, with the utilization compensation accounting for €87.38. In contrast, both the bottom and baseline scenarios received less than €0.2 in utilization payments.

Interestingly, the bottom performer and the baseline exhibit nearly identical values across all metrics. This highlights that the cost-optimal operation previously defined is poorly suited for flexibility services, as expected. Early discharging, associated with low b values, results in reduced availability of flexible energy. These results reinforce the underlying trade-off between cost minimization and flexibility maximization.

To contextualise the behaviour of the different battery operation configurations, the temporal distribution of available flexible energy was analysed across seasons, days of the week, and time intervals. These coincide with the market temporal slots described in Table 3.2.

Figure 4.15 shows the breakdown for the top performer. It is evident that weekdays offer significantly more flexibility potential, especially in the morning and afternoon periods (0 to 8:00 and 8:00 to 18:00), when the battery is least likely to be operating under internal cost-based logic. Seasonal variation is present but not dominant, with flexibility potential consistently high during weekdays across all seasons.

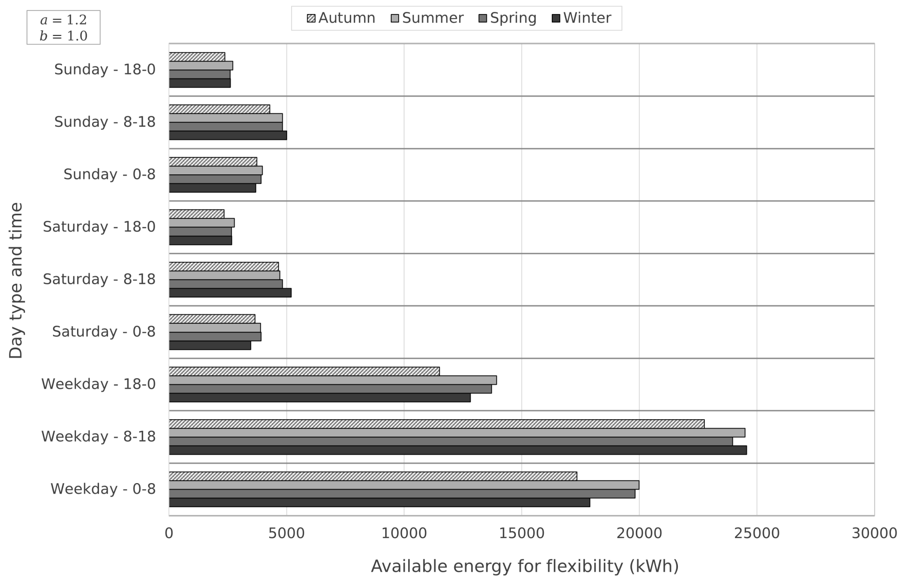

Figure 4.15: Seasonal and temporal distribution of available flexible energy for the top-performing flexibility scenario $(a,b) = (1.2, 1.0)$.

In contrast, the baseline scenario (Figure 4.16) exhibits a markedly lower level of flexibility potential. While the temporal patterns remain similar, the overall availability is considerably reduced. This is consistent with its cost-driven operation, which prioritizes internal optimization and leaves little margin for responding to DSO flexibility signals.

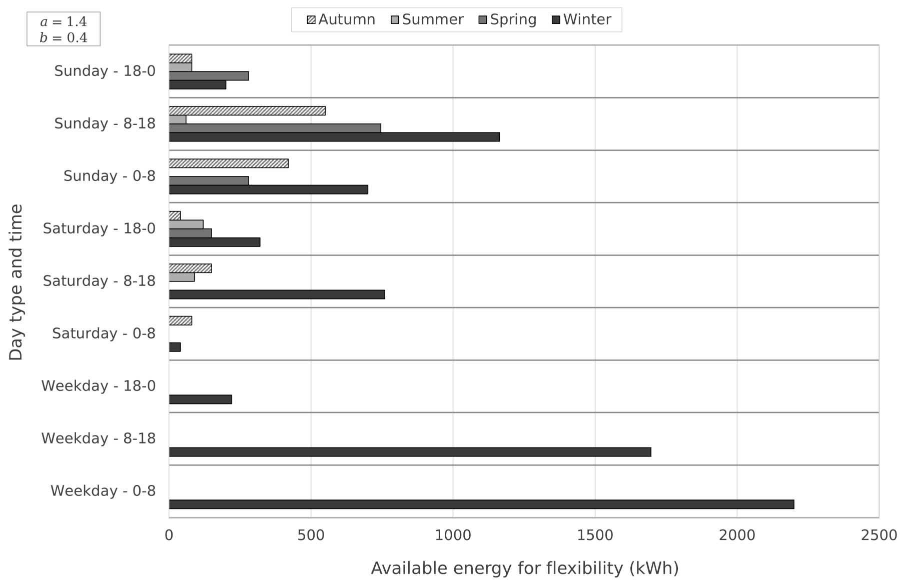

Figure 4.16: Seasonal and temporal distribution of available flexible energy for the baseline cost-effective scenario $(a,b) = (1.4, 0.4)$.

4.2.3 Evaluation of Battery Operation Strategies

Table 4.8 presents a comparative overview of annual energy flows under two distinct battery management strategies: the baseline cost-optimal configuration and the flexibility revenue-maximizing configuration.

In the baseline strategy, the battery is set to charge only at minimum market prices and discharge whenever prices exceed 40% of the daily maximum. Conversely, the flexibility-optimized strategy employs a more relaxed threshold for charging and discharges at peak prices only, shifting the battery's primary role toward external service provision rather than local cost reduction.

This transition in strategy leads to a striking increase in market-oriented operation. Specifically, the energy traded in the flexibility market increases from 0.75 MWh to 110.97 MWh, marking a 14 862% increase. This clearly illustrates the battery's effective repositioning as a market-participating asset.

However, this comes at the expense of local self-sufficiency. The energy imported to the consumption units rises from 13.71 MWh to 136.28 MWh, an 894% increase, reflecting the reduced support of local loads by the battery. Simultaneously, imported energy to the BESS falls sharply by 89.2%, from 66.83 MWh to 7.23 MWh, and discharged energy to the REC is reduced by 88.6%, from 71.12 MWh to 8.14 MWh. These changes underscore the battery's shift from internal optimization to external responsiveness.

From an operational standpoint, this reconfiguration causes a 91.9% decrease in discharge periods and an 88.9% decrease in charge periods, while the system remains in stand-by for 7965 hours, more than 90% of the year. This idle period reflects the battery's reservation for potential flexibility requests, even when not actively dispatched.

Table 4.8: Annual energy flows under the cost-optimal and flexibility-maximizing battery operation strategies.

	Baseline scenario $(a,b) = (1.4, 0.4)$	Optimal flexibility $(a,b) = (1.2, 1.0)$
Consumption (MWh)	232.13	232.13
Production (MWh)	106.67	106.67
Imported energy to the BESS (MWh)	66.83	7.23
Imported energy to the consumption units (MWh)	13.71	136.28
Imported energy to the REC (MWh)	80.53	143.52
Exported surplus energy (MWh)	21.70	25.11
Stored energy from surplus (MWh)	4.50	1.09
Discharged energy to the REC (MWh)	71.12	8.14
Flexibility service provision (MWh)	0.75	110.97
Charge periods (h)	3023.50	333.50
Discharge periods (h)	4646.75	376.00
Stand-by periods (h)	1004.25	7965.00

Following the examination of energy flows, the discussion now shifts to the resulting financial implications for the REC. The tariff structure applied to each energy flow is described in Chapter 3 and accounts for the costs associated with direct consumption, energy redistribution via the RESP, BESS operation, and remuneration for surplus and flexibility participation.

The energetic component, representing the cost of energy imported from the RESP for direct consumption, increases sharply under the flexibility-oriented strategy from €15 210 to €25 245. This 66% rise is a consequence of reduced internal energy support from the BESS, as storage operation shifts from bill reduction to serving market requests. As the battery discharges externally more frequently, the REC becomes more reliant on importing energy from the grid to meet its own demand.

Conversely, the BESS component, reflecting the cost of charging the battery from the RESP, decreases significantly from €886 to €402. This 55% reduction follows the reduced number of charge events in the flexibility-oriented scenario, where charging only occurs when market conditions strictly allow it, delaying action until the daily minimum price falls below a set threshold.

The surplus component increases from €868 to €1 004, consistent with higher amounts of excess energy being exported rather than stored. This shift is again due to fewer charge cycles: more production is left unused by the BESS and exported at the fixed remuneration rate.

As for the transacted energy component related to the BESS, it decreases from €3039 in the baseline to €408 in the flexibility-maximizing case. This 87% drop is directly linked to the shift in discharge strategy. In the baseline, the BESS discharges frequently into the REC, using the RESP and incurring network costs. In contrast, under the flexibility-maximizing operation, the

BESS discharges primarily to serve flexibility requests outside the community, bypassing internal redistribution and thus avoiding this cost.

These component-level changes result in a total bill increase from €19 800 to €26 584 without CIEG exemption, and from €17 028 to €25 385 under full exemption. This corresponds to a 34% to 49% increase in annual billing. Even with a full exemption, the flexibility-maximizing strategy leads to a higher cost burden for the REC. The flexibility revenue does increase under the new strategy, but this remains negligible when compared to the rise in energy costs.

Table 4.9: Comparison of annual billing outcomes under cost-optimal and flexibility-driven battery operation modes. All values are in euro.

	Baseline scenario $(a,b) = (1.4, 0.4)$		Optimal flexibility $(a,b) = (1.2, 1.0)$	
CIEG exemption	No exemption	100% exemption	No exemption	100% exemption
Energetic component	15,210.46	15,210.46	25,244.83	25,244.83
BESS Component	885.78	885.78	401.66	401.66
Surplus Component	867.86	867.86	1,004.26	1,004.26
Transacted Energy Component - Repartition	1,533.32	553.26	1,533.32	553.26
Transacted Energy Component - BESS	3,038.72	1,246.05	408.12	189.93
Total bill	19,800.43	17,027.69	26,583.67	25,385.42
Flexibility revenue	1.09	1.09	88.82	88.82
Total cost	19,799.34	17,026.60	26,494.85	25,296.60

These results clearly demonstrate that operating the battery solely to maximize flexibility provision is not economically viable under the current remuneration schemes. Furthermore, the marginal flexibility revenues are consistently insufficient to offset the significantly higher energy costs incurred by the community. This confirms that, under present regulatory and market conditions, participation in the flexibility market by small-scale RECs leads to net economic losses, undermining the financial attractiveness of such services for community operators.

This conclusion is further corroborated by the scatter plot presented in Figure 4.17, which contrasts the total annual cost against the flexibility revenue for all operational scenarios. The visualization clearly illustrates that higher flexibility revenues are invariably associated with increased community costs, highlighting the absence of a favorable cost-revenue trade-off across the entire decision space.

4.2.4 Assesment of Investment Viability

Although operational optimization already showed that flexibility revenues are maximized at the expense of increased overall community costs, the following questions still remain: *For various battery capacities, is there a case in which it is economically feasible for the community to engage in the flexibility market? Might there be a certain battery sizing and operational strategy combination that would lead to enough flexibility remuneration to counterbalance higher energy*

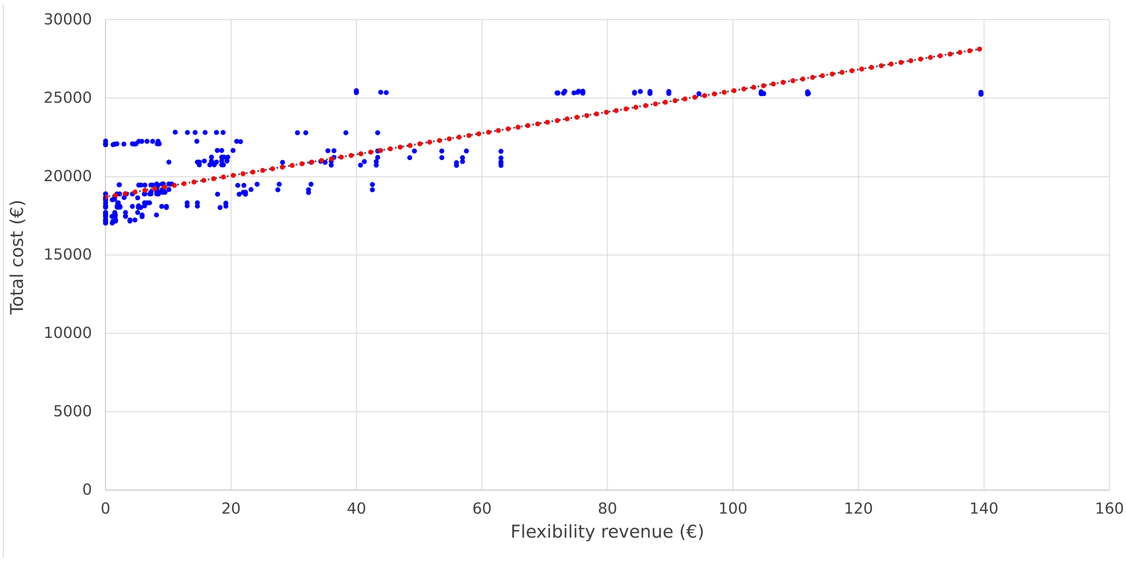

Figure 4.17: Relationship between total annual cost and flexibility revenue for all battery operation scenarios.

expenses? It is necessary to investigate these opportunities to know if, under present or future regulatory and market circumstances, such investments may become financially appealing.

As per the outcome of the 2024 flexibility service procurement under the PicloFlex platform, batteries in Bragança with rated power starting from 1 MW were chosen by E-REDES for flexibility service provision [2]. These prove that battery solutions can be economically feasible under some circumstances. The nature of the assets participating is, however, not revealed, and it is not clear if these batteries are part of energy communities, large production sites, or portfolios aggregated. The much larger capacities, nonetheless, indicate a scale of operation that is quite different from the REC examined in this research.

In order to consider the implications of battery capacity in the concrete case of a small-scale REC, publicly available market prices for batteries were gathered to estimate prices for standard lithium-ion solutions. These are plotted in Figure 4.18. The curve demonstrates the linear relationship between battery capacity and capital cost, with a 1 MWh battery costing around €630 000. Even for lower capacities, investment costs are still over €125 000.

Based on these figures, straight amortization over a 15–20 year life period gives an annualized capital cost of €6250 to €8300, excluding maintenance, degradation, or inverter replacements. Hence, under even the most favorable circumstances, investment in new battery storage for the purpose of flexibility service provision is not economically feasible for this REC.

Additionally, the existing legal restriction of the CIEG exemption to the initial seven years of community existence [3] further undermines the economic argument. Once this exemption ends, tariff-based expenses would be higher, lowering the potential for savings from storage.

[2]Results under "Piclo Portugal Bids" https://data.piclo.energy/.
[3]https://diariodarepublica.pt/dr/detalhe/despacho/1177-2024-839796348

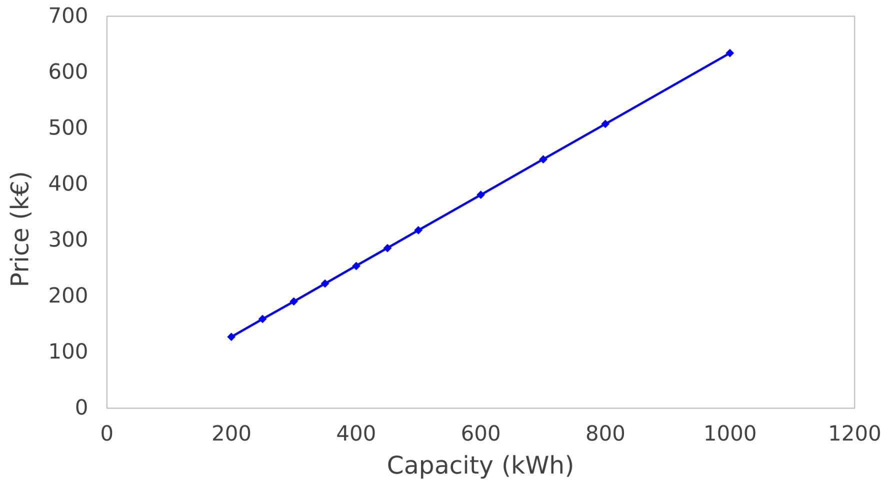

Figure 4.18: Estimated capital cost of battery storage systems as a function of installed capacity.

Finally, the possibility of expanding local production capacity to enhance the prospect for utilization of storage also does not look promising, as consumption by the community is low and seasonal relative.

4.3 Final Remarks

The outcomes in this chapter show that, although technically possible, the economic value of REC participation in flexibility markets is still marginal under existing regulatory and remuneration paradigms. The flexibility-maximizing approach created total yearly revenue of merely €89, which is inconsequential compared to the rise in total yearly energy expenditure, even under complete CIEG exemption. This cost increase is a 49% rise for REC members, driven primarily by increased use of imported grid energy and less internal discharge of the BESS. Grid operators can potentially gain from additional dispatchable capacity, but from the viewpoint of the community, the bargain is economically unfavorable. Aggregators or market intermediaries experience an equivalent lack of balance: operational complexity increases, yet marginal revenue is low unless numerous RECs with larger consumption and generation are aggregated.

In terms of control strategy, setups with conservative discharge and moderate charge strategies were seen to have the best compliance with DSO flexibility requests. The highest-performing strategy traded 110.97 MWh of flexible energy and served 35% of the requested volume, bringing the expected duration of insufficient flexibility down to 137.2 hours (compared to 270 hours for the baseline). However, it also caused a 90% decrease in the energy discharged to the community and increased grid dependency. These findings imply that flexibility-focused operation demands a drastic redistribution of the function of the battery, which might not be worthwhile unless definite compensation or risk-sharing schemes are established.

For energy communities' agility to make a substantial contribution towards the support of the grid, then the schemes of compensation must be tailored to catch the opportunity cost incurred by the communities in shifting battery use away from bill saving and self-consumption. The current incentives do not adequately compensate for this trade-off nor encourage long-term investment in storage technologies by RECs, particularly on the side of small-scale communities with small load and generation capacity.

For policy makers, this implies that subsequent policies must escape from one-size-fits-all flexibility policies. There must be a differentiated approach taking into account the particular nature and constraints of RECs. This may include:

- Higher remuneration rates for flexibility provided by smaller prosumer-based players;
- Long-term financial guarantees or co-financing agreements to reduce investment risks in BESS deployments;
- Expansion of tariff free status such as CIEG outside the initial window of introduction for stable return periods.

From the perspectives of aggregators and DSOs, the study concludes that although battery flexibility from RECs is theoretically desirable due to its responsiveness and dispatchability, it would remain economically viable only when aggregated across multiple communities or consolidated into larger energy networks. Another approach to consider is common BESS schemes across multiple small-scale RECs for better aggregation of flexibility resources and diversification of operating expenses.

For REC developers and community operators, the analysis has a straightforward message: battery operation should aim for internal optimization and bill reduction except when particular incentives are being offered. Any divergence should be put to detailed economic effect assessment. Strategic participation in flexibility markets should only be contemplated if supported by clear cost-benefit analysis and sound remuneration schemes.

Chapter 5

Contributions of the Dissertation

This chapter presents the concluding comments of the dissertation, recapitulating the main results and how they match original intentions. It considers the wider connotations of the findings, especially in terms of the technical and economic feasibility of flexibility services within energy communities. In addition, it provides an indication of possible future work, describing limitations of the present study and suggesting areas in which additional studies could reinforce and extend the results obtained.

5.1 Main Outcomes

The work proposed in this dissertation was motivated by the emergence of new flexibility opportunities in power systems, raising the question of how these could be effectively harnessed within the context of energy communities. In particular, the study aimed to explore how the management of flexible resources, especially storage systems, could enable communities to actively contribute to system-wide flexibility while generating local benefits.

After, this dissertation sought to examine the technical and economic role of flexibility services in energy communities with a particular focus on community-scale battery storage system operation and their integration into new upcoming flexibility markets in Portugal. The study combined a systematic review of literature, regulation framing, and a simulation-based case study for a real-life community context.

The first outcome of the study is the achievement of developing and implementing a two-phase control method to the control of battery energy storage systems in energy communities. The first phase, to reduce electricity cost, introduced a dynamic price-relative policy for guiding daily discharge and charge behavior. This policy exploited market price volatility by defining threshold levels for discharge and charge as functions of the daily minimum and maximum market prices. The second period tested the flexibility capacity of the BESS and its ability to engage in the Portuguese flexibility market, namely under the contractual conditions of the E-REDES FIRMe project.

During cost-optimal operation, battery response showed a uniform charging and discharging pattern: charging during off-peak periods (early afternoon) and discharging during peak times (morning and evening peaks). This policy ensured maximum utilization of internal energy and prevention of high-cost grid imports, as well as minimizing surplus injection to minimum.

When the same system was simulated under participation constraints for flexibility markets, results reflected a sharp trade-off. The configurations optimizing the generation of revenue from flexibility revealed essentially different battery behavior: long periods in stand-by, low local discharges, and high availability for DSO requests. This configuration achieved the highest flexibility revenue but initiated an enormous increase in total energy cost up to 49% higher than the baseline due to the reduced utilization of stored energy for internal consumption.

Consequently, one of the crucial findings of this study is the immanent tension between economic efficiency in battery operation and participation in flexibility markets. In each of the scenarios studied, flexibility remuneration did not succeed in compensating for the corresponding increase in electricity costs even when CIEG tariffs are entirely exempted. This finding reflects some degree of absence of sufficient economic incentives for REC-based flexibility services on the part of existing Portuguese regulatory and market frameworks.

Furthermore, this dissertation employed two complementary metrics to determine the viability of the community's involvement in flexibility markets. First, the Flexibility Market Eligibility Rate measures the percentage of operating conditions for which flexibility involvement is economically feasible (i.e. resulting in revenue). Although a result of 61.7% was discovered, under 5% of all test cases returned financial gains over €100, demonstrating that realistic opportunities for profitable involvement remain low. Thus, a second indicator was created: the Revenue-Weighted Eligibility Index. The secondary index takes the average revenue in all scenarios in relation to the highest achieved outcome. In this case study it only came to 14.3%. These combined measures take up the way in which the examined community would have to pay in order to meaningfully engage in existing flexibility programs using solely a BESS.

Apart from the quantitative results, one major advantage of this study is the availability of a simulation program that REC managers, aggregators, or system planners can use to test the real-world feasibility of participation in the flexibility market. Using the model, different operating strategies, request rates for flexibility, and tariff structures can be experimented with, thus enabling well-informed decisions on *when* and *how* market participation is most likely to be beneficial — or not. Such simulation-based support is important for actors with limited technical or regulatory information but are nevertheless expected to take economically sensible decisions on behalf of the society.

All the objectives defined in Chapter 1 were fulfilled. The overall objective of investigating how energy communities can provide flexibility services was tackled through the design of a holistic simulation-based approach, validated in a real REC in Portugal, under current regulatory and market frameworks. Specifically:

- An extensive literature review and regulation review in Chapter 2 established the **role of energy communities in offering flexibility**, differentiating community-size flexibility from consumer-level ones and discussing its aggregation, control, and market-access benefits.
- **Mapping the regulatory environment** on the European and national levels was conducted through the superimposition of relevant directives (RED II, RED III, EMD) and Portuguese legislation (Decree-Law 15/2022, ERSE Regulation 5/2023), showing how legal instruments enable or restrict REC participation in flexibility services.
- **Identification of stakeholders** and their roles were derived from systematic stakeholder mapping in 2.1.2.2 that identified the roles of prosumers, aggregators, DSOs, BRPs, and REC managers in facilitating flexibility transactions and market integration.
- **Examining flexibility resources types** that RECs have access to was addressed in 2.2.2, and distributed storage and demand-side management, along with in-depth technological characterizations of DERs and their operation constraints.
- **Simulation of simulation-based approaches** was conducted in Chapter 3, where a two-stage battery operation scheme was developed, simulated, and experimented with past data. Local generation, usage, and price signals were used in the simulation to optimize community scheduling of batteries.
- **Assessing economic viability** of REC participation in flexibility services was done by comparing total cost and flexibility revenues under different battery control approaches and levels of DSO requests, along with a full financial assessment.
- **Control frameworks and operating policies exploration** was tackled by applying and comparing price-based control schemes to stand-by-based flexibility activation logic, and analyzing the performance of both with respect to notable operational metrics and revenue results.
- **Providing recommendations to policy and market stakeholders** was done in Chapter 4 and in this final section, including insights on incentive design, risk of battery investment, and differentiated regulatory approaches to small-scale communities.

5.2 Future Work

While the results of this dissertation contribute to the knowledge of flexibility in RECs, they also indicate some of its shortcomings and possible directions for future research.

Most importantly, the small size of the community under investigation: four buildings and a single shared BESS, places limits on the generalization of the findings. Subsequent research needs to test greater communities with more diverse consumption patterns, more generation resources, and multiple storage units. This would allow a more robust evaluation of aggregation effects and their impact upon flexibility capacity and market viability.

Significantly, while cost-optimal charging and discharging policy was effective in reducing electricity bills, battery lifetime was neglected. Cyclic charging and discharging could accelerate the degradation of batteries, reducing the asset life and introducing unknown costs beyond the simulations. The future research needs to include battery health modeling to assess the long-term validity of the control logic and enable stakeholders to make better investment choices from the overall cost of ownership standpoint rather than short-term profit.

Another area for future research is exploring the social and behavioral dynamics of REC participation in flexibility markets. Although technical-economic modeling was the central issue of this dissertation, perceived fairness, complexity, and trustworthiness of the operating regime can affect real community participation. Future studies could investigate the impact of exposing community members to dynamic pricing, flexibility requests, or variable availability of energy. Understanding how these factors affect participation, satisfaction, and cooperation can guide more effective incentive schemes.

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Appendix A

Daily and Weekly Cycles

Table A.1: Daily cycle periods for BTE and BTN in mainland Portugal (2025).

Period	Winter Legal Time	Summer Legal Time
Ponta	09:00–10:30	10:30–13:00
	18:00–20:30	19:30–21:00
Cheias	08:00–09:00	08:00–10:30
	10:30–18:00	13:00–19:30
	20:30–22:00	21:00–22:00
Vazio normal	06:00–08:00	06:00–08:00
	22:00–02:00	22:00–02:00
Super vazio	02:00–06:00	02:00–06:00

Source: https://www.erse.pt/media/oiwgcxk5/diretiva-2_2025-tarifas-2025.pdf

Table A.2: Weekly cycle periods for all electricity supplies in mainland Portugal (2025).

Day	**Period**	**Winter Legal Time**	**Summer Legal Time**
Monday to Friday	*Ponta*	09:30–12:00 18:30–21:00	09:15–12:15
	Cheias	07:00–09:30 12:00–18:30 21:00–24:00	07:00–09:15 12:15–24:00
	Vazio normal	00:00–02:00 06:00–07:00	00:00–02:00 06:00–07:00
	Super vazio	02:00–06:00	02:00–06:00
Saturday	*Cheias*	09:30–13:00 18:30–22:00	09:00–14:00 20:00–22:00
	Vazio normal	00:00–02:00 06:00–09:30 13:00–18:30 22:00–24:00	00:00–02:00 06:00–09:00 14:00–20:00 22:00–24:00
	Super vazio	02:00–06:00	02:00–06:00
Sunday	*Vazio normal*	00:00–02:00 06:00–24:00	00:00–02:00 06:00–24:00
	Super vazio	02:00–06:00	02:00–06:00

Source: https://www.erse.pt/media/oiwgcxk5/diretiva-2_2025-tarifas-2025.pdf

Appendix B

Tariffs: Network Access, Sales to End Costumers and Network Access via Storage

Table B.1: Network access tariffs for self-consumption via RESP in BTE under different CIEG exemption levels.

CIEG exemption level	**Power** *horas de ponta*	**Active energy** (EUR/kWh)			
	EUR/(kW.day)	*Horas de ponta*	*Horas cheias*	*Horas de vazio normal*	*Horas de super vazio*
0%	0.2200	0.0362	0.0326	0.0264	0.0212
50%	0.2200	0.0211	0.0190	0.0155	0.0124
100%	0.2200	0.0061	0.0055	0.0043	0.0036

Source: `https://www.erse.pt/media/oiwgcxk5/diretiva-2_2025-tarifas-2025.pdf`

Table B.2: Sales Tariff to End Costumers in BTE.

Tariff component		**Price**
Fixed term		**EUR/day**
		1.0925
Power		**EUR/(kW.day)**
	Horas de ponta	0.4964
	Contratada	0.0553
Active energy		**EUR/kWh**
Períodos I, IV	*Horas de ponta*	0.1544
	Horas cheias	0.1432
	Horas de vazio normal	0.1203
	Horas de super vazio	0.1038
Períodos II, III	*Horas de ponta*	0.1456
	Horas cheias	0.1382
	Horas de vazio normal	0.1180
	Horas de super vazio	0.1082
Reactive energy		**EUR/kvarh**
	Indutiva	0.0318
	Capacitiva	0.0243

Source: https://www.erse.pt/media/oiwgcxk5/diretiva-2_2025-tarifas-2025.pdf

Table B.3: Network access tariff applicable to storage facilities at BTE.

Tariff component		**Price**
Power		**EUR/(kW.day)**
	Horas de ponta	0.4964
	Contratada	0.0233
Active energy		**EUR/kWh**
	Horas de ponta	0.0108
	Horas cheias	0.0098
	Horas de vazio normal	0.0077
	Horas de super vazio	0.0062
Reactive energy		**EUR/kvarh**
	Indutiva	0.0318
	Capacitiva	0.0243

Source: https://www.erse.pt/media/oiwgcxk5/diretiva-2_2025-tarifas-2025.pdf

Appendix C

Flexibility Opportunity Details

Bragança 1			Inverno								
			Dia Útil			Sábado			Domingo		
			[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[
Resposta Esperada											
Potência ativa máxima	**[kW]**	**8398**	5177	5567	8244	4484	2618	6270	3665	2630	5853
Sentido da Resposta	+/-'	+	+	+	+						
Requisitos Técnicos											
Tempo para ativação total	**[min]**	**15**	15	15	15	15	15	15	15	15	15
Duração máxima da ativação	**[h]**	**36**	8	10	6	8	10	6	8	10	6
Ativação de Flexibilidade											
Período de Contratação											
Período de Utilização	**meses**		3	3	3	3	3	3	3	3	3
Dias da semana de utilização	**#**		5	5	5	1	1	1	1	1	1
Estimativa máximo horas de utilização	**[h/ano]**	**24**	8	10	6	8	10	6	8	10	6
Horário Previsto de utilização	**[h]**		8	10	6	8	10	6	8	10	6
Estimativa de volume de ativação máximo	**[kWh]**	**47850**	23865	47575	42624	18703	20098	31058	13851	16053	28781
Probabilidade de utilização	**[#/ano]**	**0,016**	0.0009	0.001	0.0007	0.0002	0.0002	0.0001	0.0002	0.0002	0.0001
ENF	**[kWh]**	**1111**									

Bragança 1	Primavera								
	Dia Útil			Sábado			Domingo		
	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[
Resposta Esperada									
Potência ativa máxima	2664	3183	4883	1980	1088	3109	1505	1071	2792
Sentido da Resposta	+	+	+						
Requisitos Técnicos									
Tempo para ativação total	15	15	15	15	15	15	15	15	15
Duração máxima da ativação	8	10	6	5,75	9	6	15	8,75	6
Ativação de Flexibilidade									
Período de Contratação									
Período de Utilização	3	3	3	3	3	3	3	3	3
Dias da semana de utilização	5	5	5	1	1	1	1	1	1
Estimativa máximo horas de utilização	8	10	6	5,75	9	6	3,75	8,75	6
Horário Previsto de utilização	8	10	6	8	10	6	8	10	6
Estimativa de volume de ativação máximo	7595	23600	23912	4677	4817	12947	2339	4185	11452
Probabilidade de utilização	0.0009	0.001	0.0007	0.0005	0.0008	0.00014	0.0003	0.0002	0.0001
ENF									

Bragança 1	Verão								
	Dia Útil			Sábado			Domingo		
	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[
Resposta Esperada									
Potência ativa máxima	2391	3051	4024	1875	1134	3309	1611	1076	2845
Sentido da Resposta	+	+	+						
Requisitos Técnicos									
Tempo para ativação total	15	15	15	15	15	15	15	15	15
Duração máxima da ativação	8	10	6	6,25	9,25	6	5,5	9	6
Ativação de Flexibilidade									
Período de Contratação									
Período de Utilização	3	3	3	3	3	3	3	3	3
Dias da semana de utilização	5	5	5	1	1	1	1	1	1
Estimativa máximo horas de utilização	8	10	6	6,25	9,25	6	5,5	9	6
Horário Previsto de utilização	8	10	6	8	10	6	8	10	6
Estimativa de volume de ativação máximo	9053	23034	19702	4528	5314	14299	2851	4941	11995
Probabilidade de utilização	0.0009	0.001	0.0007	0.0001	0.0002	0.0001	0.0001	0.0002	0.0001
ENF									

Bragança 1	Outono								
	Dia Útil			Sábado			Domingo		
	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[	[0;8[	[8;18[	[18;0[
Resposta Esperada									
Potência ativa máxima	5336	5675	8398	3906	3317	6504	3353	2797	5585
Sentido da Resposta	+	+	+						
Requisitos Técnicos									
Tempo para ativação total	15	15	15	15	15	15	15	15	15
Duração máxima da ativação	8	10	6	8	10	6	8	10	6
Ativação de Flexibilidade									
Período de Contratação									
Período de Utilização	3	3	3	3	3	3	3	3	3
Dias da semana de utilização	5	5	5	1	1	1	1	1	1
Estimativa máximo horas de utilização	8	10	6	8	10	6	8	10	6
Horário Previsto de utilização	8	10	6	8	10	6	8	10	6
Estimativa de volume de ativação máximo	22889	47850	42589	15308	27294	32600	13591	20921	29038
Probabilidade de utilização	0.0009	0.001	0.0007	0.0002	0.0002	0.0001	0.0002	0.0002	0.0001
ENF									

Figure C.1: Parameters for flexibility market participation in Bragança. Source: https://www.e-redes.pt/sites/eredes/files/2023-07/Detalhes_oportunidades.pdf

Appendix D

Detailed Heatmaps for Requested Flexibility Response

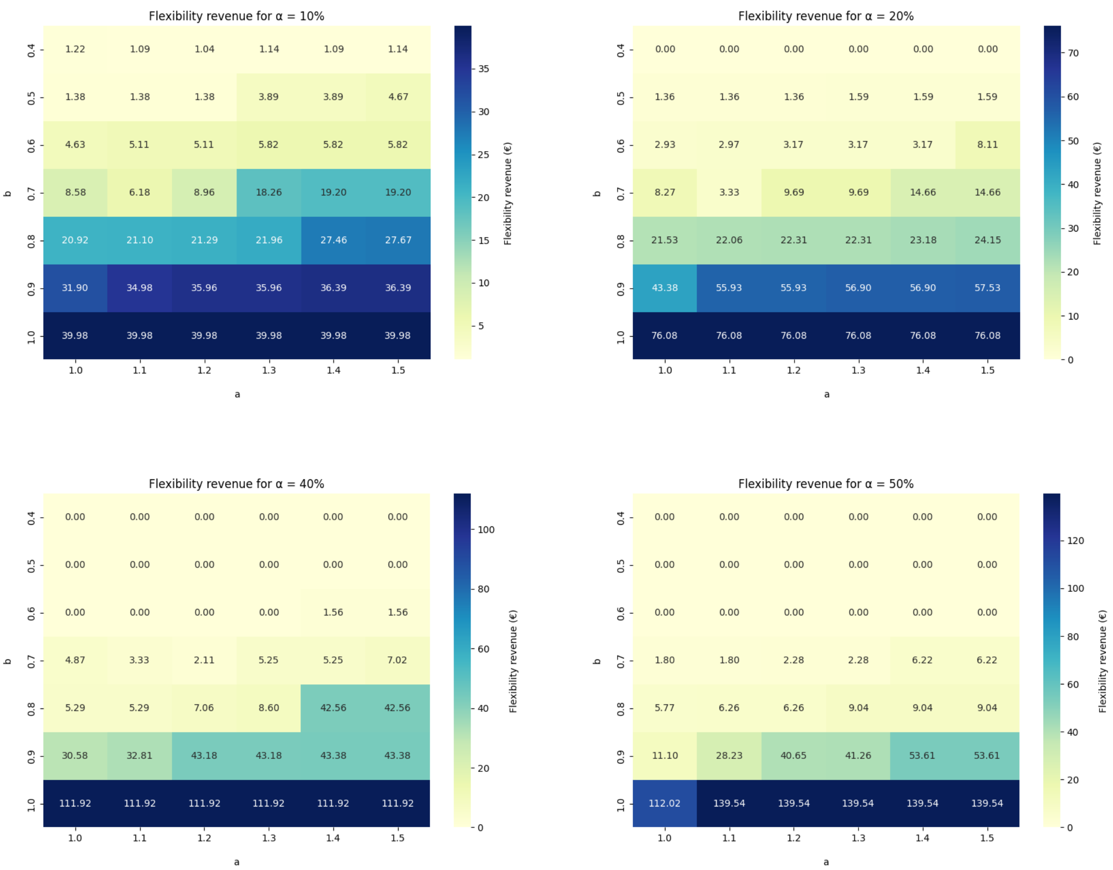

Figure D.1: Flexibility revenue for $\alpha = 10\%, 20\%, 40\%$, and 50%.

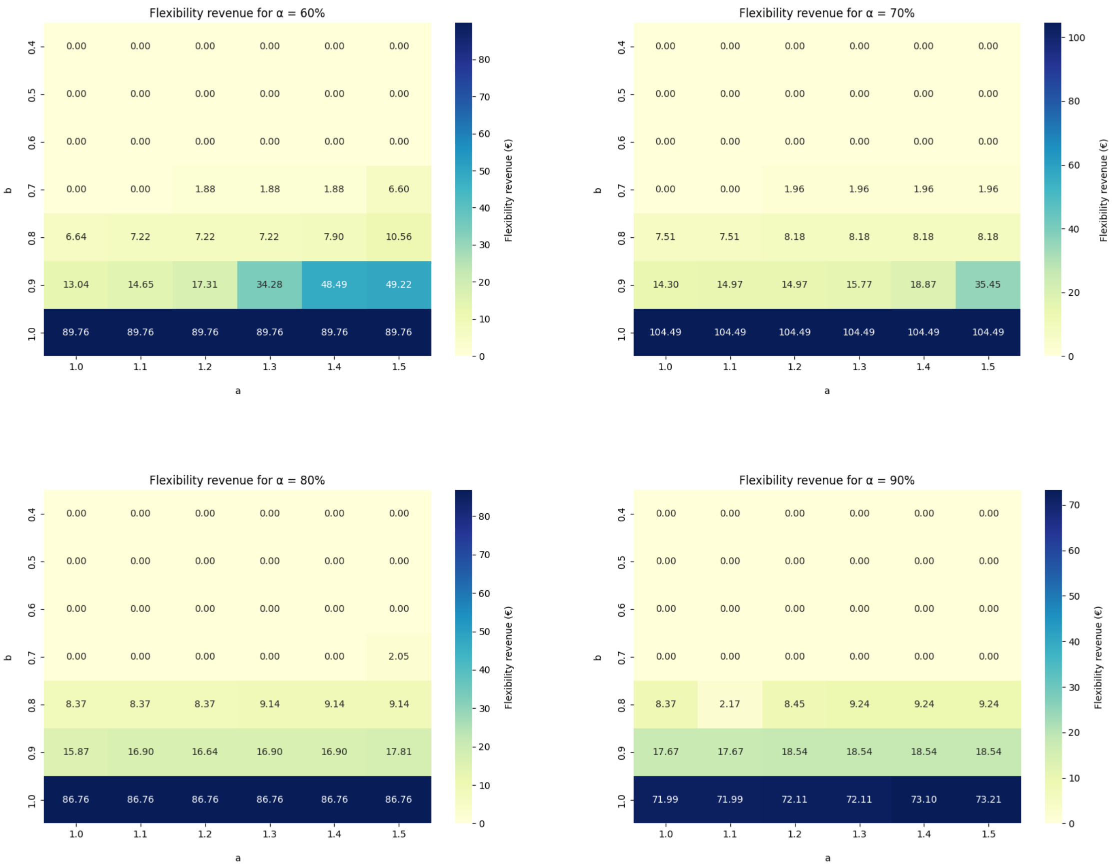

Figure D.2: Flexibility revenue for $\alpha = 60\%, 70\%, 80\%$, and 90%.

Appendix E

Economic Evaluation of Net Cost

Table E.1: Flexibility revenue, electricity bill, and net cost for various scenarios.

a	b	α	Flexibility revenue	Electricity bill	Net cost
1	0.4	10	1.22 €	22,035.46 €	22,034.25 €
1	0.4	20	0 €	22,035.46 €	22,035.46 €
1	0.4	30	0 €	22,035.46 €	22,035.46 €
1	0.4	40	0 €	22,035.46 €	22,035.46 €
1	0.4	50	0 €	22,035.46 €	22,035.46 €
1	0.4	60	0 €	22,035.46 €	22,035.46 €
1	0.4	70	0 €	22,035.46 €	22,035.46 €
1	0.4	80	0 €	22,035.46 €	22,035.46 €
1	0.4	90	0 €	22,035.46 €	22,035.46 €
1	0.4	100	0 €	22,035.46 €	22,035.46 €
1	0.5	10	1.38 €	22,053.20 €	22,051.82 €
1	0.5	20	1.36 €	22,053.20 €	22,051.84 €
1	0.5	30	1.44 €	22,053.20 €	22,051.76 €
1	0.5	40	0 €	22,053.20 €	22,053.20 €
1	0.5	50	0 €	22,053.20 €	22,053.20 €
1	0.5	60	0 €	22,053.20 €	22,053.20 €
1	0.5	70	0 €	22,053.20 €	22,053.20 €
1	0.5	80	0 €	22,053.20 €	22,053.20 €
1	0.5	90	0 €	22,053.20 €	22,053.20 €
1	0.5	100	0 €	22,053.20 €	22,053.20 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1	0.6	10	4.63 €	22,065.90 €	22,061.27 €
1	0.6	20	2.93 €	22,065.90 €	22,062.97 €
1	0.6	30	1.44 €	22,065.90 €	22,064.46 €
1	0.6	40	0 €	22,065.90 €	22,065.90 €
1	0.6	50	0 €	22,065.90 €	22,065.90 €
1	0.6	60	0 €	22,065.90 €	22,065.90 €
1	0.6	70	0 €	22,065.90 €	22,065.90 €
1	0.6	80	0 €	22,065.90 €	22,065.90 €
1	0.6	90	0 €	22,065.90 €	22,065.90 €
1	0.6	100	0 €	22,065.90 €	22,065.90 €
1	0.7	10	8.58 €	22,088.99 €	22,080.41 €
1	0.7	20	8.27 €	22,088.99 €	22,080.73 €
1	0.7	30	4.29 €	22,088.99 €	22,084.70 €
1	0.7	40	4.87 €	22,088.99 €	22,084.12 €
1	0.7	50	1.80 €	22,088.99 €	22,087.19 €
1	0.7	60	0 €	22,088.99 €	22,088.99 €
1	0.7	70	0 €	22,088.99 €	22,088.99 €
1	0.7	80	0 €	22,088.99 €	22,088.99 €
1	0.7	90	0 €	22,088.99 €	22,088.99 €
1	0.7	100	0 €	22,088.99 €	22,088.99 €
1	0.8	10	20.92 €	22,256.94 €	22,236.02 €
1	0.8	20	21.53 €	22,256.94 €	22,235.41 €
1	0.8	30	14.55 €	22,256.94 €	22,242.39 €
1	0.8	40	5.29 €	22,256.94 €	22,251.65 €
1	0.8	50	5.77 €	22,256.94 €	22,251.16 €
1	0.8	60	6.64 €	22,256.94 €	22,250.30 €
1	0.8	70	7.51 €	22,256.94 €	22,249.43 €
1	0.8	80	8.37 €	22,256.94 €	22,248.56 €
1	0.8	90	8.37 €	22,256.94 €	22,248.57 €
1	0.8	100	0 €	22,256.94 €	22,256.94 €
1	0.9	10	31.90 €	22,830.59 €	22,798.69 €
1	0.9	20	43.38 €	22,830.59 €	22,787.22 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1	0.9	30	38.31 €	22,830.59 €	22,792.29 €
1	0.9	40	30.58 €	22,830.59 €	22,800.01 €
1	0.9	50	11.10 €	22,830.59 €	22,819.49 €
1	0.9	60	13.04 €	22,830.59 €	22,817.56 €
1	0.9	70	14.30 €	22,830.59 €	22,816.30 €
1	0.9	80	15.87 €	22,830.59 €	22,814.72 €
1	0.9	90	17.67 €	22,830.59 €	22,812.92 €
1	0.9	100	18.72 €	22,830.59 €	22,811.87 €
1	1	10	39.98 €	25,411.03 €	25,371.04 €
1	1	20	76.08 €	25,411.03 €	25,334.94 €
1	1	30	104.88 €	25,411.03 €	25,306.15 €
1	1	40	111.92 €	25,411.03 €	25,299.11 €
1	1	50	112.02 €	25,411.03 €	25,299.00 €
1	1	60	89.76 €	25,411.03 €	25,321.26 €
1	1	70	104.49 €	25,411.03 €	25,306.54 €
1	1	80	86.76 €	25,411.03 €	25,324.27 €
1	1	90	71.99 €	25,411.03 €	25,339.04 €
1	1	100	43.85 €	25,411.03 €	25,367.17 €
1.1	0.4	10	1.09 €	18,519.10 €	18,518.01 €
1.1	0.4	20	0 €	18,519.10 €	18,519.10 €
1.1	0.4	30	0 €	18,519.10 €	18,519.10 €
1.1	0.4	40	0 €	18,519.10 €	18,519.10 €
1.1	0.4	50	0 €	18,519.10 €	18,519.10 €
1.1	0.4	60	0 €	18,519.10 €	18,519.10 €
1.1	0.4	70	0 €	18,519.10 €	18,519.10 €
1.1	0.4	80	0 €	18,519.10 €	18,519.10 €
1.1	0.4	90	0 €	18,519.10 €	18,519.10 €
1.1	0.4	100	0 €	18,519.10 €	18,519.10 €
1.1	0.5	10	1.38 €	18,550.04 €	18,548.66 €
1.1	0.5	20	1.36 €	18,550.04 €	18,548.68 €
1.1	0.5	30	1.44 €	18,550.04 €	18,548.60 €
1.1	0.5	40	0 €	18,550.04 €	18,550.04 €

a	*b*	α	Flexibility revenue	Electricity bill	Net cost
1.1	0.5	50	0 €	18,550.04 €	18,550.04 €
1.1	0.5	60	0 €	18,550.04 €	18,550.04 €
1.1	0.5	70	0 €	18,550.04 €	18,550.04 €
1.1	0.5	80	0 €	18,550.04 €	18,550.04 €
1.1	0.5	90	0 €	18,550.04 €	18,550.04 €
1.1	0.5	100	0 €	18,550.04 €	18,550.04 €
1.1	0.6	10	5.11 €	18,653.45 €	18,648.34 €
1.1	0.6	20	2.97 €	18,653.45 €	18,650.48 €
1.1	0.6	30	1.48 €	18,653.45 €	18,651.97 €
1.1	0.6	40	0 €	18,653.45 €	18,653.45 €
1.1	0.6	50	0 €	18,653.45 €	18,653.45 €
1.1	0.6	60	0 €	18,653.45 €	18,653.45 €
1.1	0.6	70	0 €	18,653.45 €	18,653.45 €
1.1	0.6	80	0 €	18,653.45 €	18,653.45 €
1.1	0.6	90	0 €	18,653.45 €	18,653.45 €
1.1	0.6	100	0 €	18,653.45 €	18,653.45 €
1.1	0.7	10	6.18 €	18,891.72 €	18,885.55 €
1.1	0.7	20	3.33 €	18,891.72 €	18,888.40 €
1.1	0.7	30	4.29 €	18,891.72 €	18,887.43 €
1.1	0.7	40	3.33 €	18,891.72 €	18,888.40 €
1.1	0.7	50	1.80 €	18,891.72 €	18,889.92 €
1.1	0.7	60	0 €	18,891.72 €	18,891.72 €
1.1	0.7	70	0 €	18,891.72 €	18,891.72 €
1.1	0.7	80	0 €	18,891.72 €	18,891.72 €
1.1	0.7	90	0 €	18,891.72 €	18,891.72 €
1.1	0.7	100	0 €	18,891.72 €	18,891.72 €
1.1	0.8	10	21.10 €	19,464.96 €	19,443.86 €
1.1	0.8	20	22.06 €	19,464.96 €	19,442.90 €
1.1	0.8	30	5.66 €	19,464.96 €	19,459.30 €
1.1	0.8	40	5.29 €	19,464.96 €	19,459.67 €
1.1	0.8	50	6.26 €	19,464.96 €	19,458.70 €
1.1	0.8	60	7.22 €	19,464.96 €	19,457.74 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.1	0.8	70	7.51 €	19,464.96 €	19,457.45 €
1.1	0.8	80	8.37 €	19,464.96 €	19,456.59 €
1.1	0.8	90	2.17 €	19,464.96 €	19,462.79 €
1.1	0.8	100	2.24 €	19,464.96 €	19,462.72 €
1.1	0.9	10	34.98 €	20,932.52 €	20,897.53 €
1.1	0.9	20	55.93 €	20,932.52 €	20,876.58 €
1.1	0.9	30	63.03 €	20,932.52 €	20,869.48 €
1.1	0.9	40	32.81 €	20,932.52 €	20,899.71 €
1.1	0.9	50	28.23 €	20,932.52 €	20,904.28 €
1.1	0.9	60	14.65 €	20,932.52 €	20,917.87 €
1.1	0.9	70	14.97 €	20,932.52 €	20,917.55 €
1.1	0.9	80	16.90 €	20,932.52 €	20,915.61 €
1.1	0.9	90	17.67 €	20,932.52 €	20,914.84 €
1.1	0.9	100	10.11 €	20,932.52 €	20,922.41 €
1.1	1	10	39.98 €	25,389.48 €	25,349.49 €
1.1	1	20	76.08 €	25,389.48 €	25,313.39 €
1.1	1	30	104.88 €	25,389.48 €	25,284.60 €
1.1	1	40	111.92 €	25,389.48 €	25,277.56 €
1.1	1	50	139.54 €	25,389.48 €	25,249.94 €
1.1	1	60	89.76 €	25,389.48 €	25,299.71 €
1.1	1	70	104.49 €	25,389.48 €	25,284.99 €
1.1	1	80	86.76 €	25,389.48 €	25,302.72 €
1.1	1	90	71.99 €	25,389.48 €	25,317.49 €
1.1	1	100	44.72 €	25,389.48 €	25,344.76 €
1.2	0.4	10	1.04 €	17,466.02 €	17,464.98 €
1.2	0.4	20	0 €	17,466.02 €	17,466.02 €
1.2	0.4	30	0 €	17,466.02 €	17,466.02 €
1.2	0.4	40	0 €	17,466.02 €	17,466.02 €
1.2	0.4	50	0 €	17,466.02 €	17,466.02 €
1.2	0.4	60	0 €	17,466.02 €	17,466.02 €
1.2	0.4	70	0 €	17,466.02 €	17,466.02 €
1.2	0.4	80	0 €	17,466.02 €	17,466.02 €

a	*b*	α	Flexibility revenue	Electricity bill	Net cost
1.2	0.4	90	0 €	17,466.02 €	17,466.02 €
1.2	0.4	100	0 €	17,466.02 €	17,466.02 €
1.2	0.5	10	1.38 €	17,519.86 €	17,518.49 €
1.2	0.5	20	1.36 €	17,519.86 €	17,518.50 €
1.2	0.5	30	1.44 €	17,519.86 €	17,518.42 €
1.2	0.5	40	0 €	17,519.86 €	17,519.86 €
1.2	0.5	50	0 €	17,519.86 €	17,519.86 €
1.2	0.5	60	0 €	17,519.86 €	17,519.86 €
1.2	0.5	70	0 €	17,519.86 €	17,519.86 €
1.2	0.5	80	0 €	17,519.86 €	17,519.86 €
1.2	0.5	90	0 €	17,519.86 €	17,519.86 €
1.2	0.5	100	0 €	17,519.86 €	17,519.86 €
1.2	0.6	10	5.11 €	17,707.49 €	17,702.38 €
1.2	0.6	20	3.17 €	17,707.49 €	17,704.32 €
1.2	0.6	30	1.48 €	17,707.49 €	17,706.01 €
1.2	0.6	40	0 €	17,707.49 €	17,707.49 €
1.2	0.6	50	0 €	17,707.49 €	17,707.49 €
1.2	0.6	60	0 €	17,707.49 €	17,707.49 €
1.2	0.6	70	0 €	17,707.49 €	17,707.49 €
1.2	0.6	80	0 €	17,707.49 €	17,707.49 €
1.2	0.6	90	0 €	17,707.49 €	17,707.49 €
1.2	0.6	100	0 €	17,707.49 €	17,707.49 €
1.2	0.7	10	8.96 €	18,104.01 €	18,095.05 €
1.2	0.7	20	9.69 €	18,104.01 €	18,094.32 €
1.2	0.7	30	4.29 €	18,104.01 €	18,099.73 €
1.2	0.7	40	2.11 €	18,104.01 €	18,101.91 €
1.2	0.7	50	2.28 €	18,104.01 €	18,101.73 €
1.2	0.7	60	1.88 €	18,104.01 €	18,102.13 €
1.2	0.7	70	1.96 €	18,104.01 €	18,102.05 €
1.2	0.7	80	0 €	18,104.01 €	18,104.01 €
1.2	0.7	90	0 €	18,104.01 €	18,104.01 €
1.2	0.7	100	0 €	18,104.01 €	18,104.01 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.2	0.8	10	21.29 €	18,893.77 €	18,872.48 €
1.2	0.8	20	22.31 €	18,893.77 €	18,871.46 €
1.2	0.8	30	17.86 €	18,893.77 €	18,875.91 €
1.2	0.8	40	7.06 €	18,893.77 €	18,886.70 €
1.2	0.8	50	6.26 €	18,893.77 €	18,887.51 €
1.2	0.8	60	7.22 €	18,893.77 €	18,886.55 €
1.2	0.8	70	8.18 €	18,893.77 €	18,885.58 €
1.2	0.8	80	8.37 €	18,893.77 €	18,885.39 €
1.2	0.8	90	8.45 €	18,893.77 €	18,885.32 €
1.2	0.8	100	2.24 €	18,893.77 €	18,891.52 €
1.2	0.9	10	35.96 €	20,762.26 €	20,726.30 €
1.2	0.9	20	55.93 €	20,762.26 €	20,706.33 €
1.2	0.9	30	63.03 €	20,762.26 €	20,699.23 €
1.2	0.9	40	43.18 €	20,762.26 €	20,719.09 €
1.2	0.9	50	40.65 €	20,762.26 €	20,721.62 €
1.2	0.9	60	17.31 €	20,762.26 €	20,744.96 €
1.2	0.9	70	14.97 €	20,762.26 €	20,747.30 €
1.2	0.9	80	16.64 €	20,762.26 €	20,745.62 €
1.2	0.9	90	18.54 €	20,762.26 €	20,743.72 €
1.2	0.9	100	18.80 €	20,762.26 €	20,743.47 €
1.2	1	10	39.98 €	25,385.42 €	25,345.44 €
1.2	1	20	76.08 €	25,385.42 €	25,309.34 €
1.2	1	30	94.59 €	25,385.42 €	25,290.83 €
1.2	1	40	111.92 €	25,385.42 €	25,273.51 €
1.2	1	50	139.54 €	25,385.42 €	25,245.89 €
1.2	1	60	89.76 €	25,385.42 €	25,295.66 €
1.2	1	70	104.49 €	25,385.42 €	25,280.94 €
1.2	1	80	86.76 €	25,385.42 €	25,298.67 €
1.2	1	90	72.11 €	25,385.42 €	25,313.31 €
1.2	1	100	73.01 €	25,385.42 €	25,312.42 €
1.3	0.4	10	1.14 €	17,137.54 €	17,136.40 €
1.3	0.4	20	0 €	17,137.54 €	17,137.54 €

a	*b*	α	Flexibility revenue	Electricity bill	Net cost
1.3	0.4	30	0 €	17,137.54 €	17,137.54 €
1.3	0.4	40	0 €	17,137.54 €	17,137.54 €
1.3	0.4	50	0 €	17,137.54 €	17,137.54 €
1.3	0.4	60	0 €	17,137.54 €	17,137.54 €
1.3	0.4	70	0 €	17,137.54 €	17,137.54 €
1.3	0.4	80	0 €	17,137.54 €	17,137.54 €
1.3	0.4	90	0 €	17,137.54 €	17,137.54 €
1.3	0.4	100	0 €	17,137.54 €	17,137.54 €
1.3	0.5	10	3.89 €	17,237.19 €	17,233.30 €
1.3	0.5	20	1.59 €	17,237.19 €	17,235.60 €
1.3	0.5	30	0 €	17,237.19 €	17,237.19 €
1.3	0.5	40	0 €	17,237.19 €	17,237.19 €
1.3	0.5	50	0 €	17,237.19 €	17,237.19 €
1.3	0.5	60	0 €	17,237.19 €	17,237.19 €
1.3	0.5	70	0 €	17,237.19 €	17,237.19 €
1.3	0.5	80	0 €	17,237.19 €	17,237.19 €
1.3	0.5	90	0 €	17,237.19 €	17,237.19 €
1.3	0.5	100	0 €	17,237.19 €	17,237.19 €
1.3	0.6	10	5.82 €	17,473.84 €	17,468.01 €
1.3	0.6	20	3.17 €	17,473.84 €	17,470.67 €
1.3	0.6	30	1.48 €	17,473.84 €	17,472.35 €
1.3	0.6	40	0 €	17,473.84 €	17,473.84 €
1.3	0.6	50	0 €	17,473.84 €	17,473.84 €
1.3	0.6	60	0 €	17,473.84 €	17,473.84 €
1.3	0.6	70	0 €	17,473.84 €	17,473.84 €
1.3	0.6	80	0 €	17,473.84 €	17,473.84 €
1.3	0.6	90	0 €	17,473.84 €	17,473.84 €
1.3	0.6	100	0 €	17,473.84 €	17,473.84 €
1.3	0.7	10	18.26 €	18,035.61 €	18,017.35 €
1.3	0.7	20	9.69 €	18,035.61 €	18,025.92 €
1.3	0.7	30	5.62 €	18,035.61 €	18,029.99 €
1.3	0.7	40	5.25 €	18,035.61 €	18,030.36 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.3	0.7	50	2.28 €	18,035.61 €	18,033.33 €
1.3	0.7	60	1.88 €	18,035.61 €	18,033.73 €
1.3	0.7	70	1.96 €	18,035.61 €	18,033.65 €
1.3	0.7	80	0 €	18,035.61 €	18,035.61 €
1.3	0.7	90	0 €	18,035.61 €	18,035.61 €
1.3	0.7	100	0 €	18,035.61 €	18,035.61 €
1.3	0.8	10	21.96 €	19,011.47 €	18,989.51 €
1.3	0.8	20	22.31 €	19,011.47 €	18,989.16 €
1.3	0.8	30	32.37 €	19,011.47 €	18,979.09 €
1.3	0.8	40	8.60 €	19,011.47 €	19,002.87 €
1.3	0.8	50	9.04 €	19,011.47 €	19,002.43 €
1.3	0.8	60	7.22 €	19,011.47 €	19,004.25 €
1.3	0.8	70	8.18 €	19,011.47 €	19,003.28 €
1.3	0.8	80	9.14 €	19,011.47 €	19,002.32 €
1.3	0.8	90	9.24 €	19,011.47 €	19,002.22 €
1.3	0.8	100	9.48 €	19,011.47 €	19,001.99 €
1.3	0.9	10	35.96 €	21,003.26 €	20,967.30 €
1.3	0.9	20	56.90 €	21,003.26 €	20,946.37 €
1.3	0.9	30	63.03 €	21,003.26 €	20,940.23 €
1.3	0.9	40	43.18 €	21,003.26 €	20,960.09 €
1.3	0.9	50	41.26 €	21,003.26 €	20,962.00 €
1.3	0.9	60	34.28 €	21,003.26 €	20,968.99 €
1.3	0.9	70	15.77 €	21,003.26 €	20,987.50 €
1.3	0.9	80	16.90 €	21,003.26 €	20,986.36 €
1.3	0.9	90	18.54 €	21,003.26 €	20,984.72 €
1.3	0.9	100	19.37 €	21,003.26 €	20,983.89 €
1.3	1	10	39.98 €	25,403.04 €	25,363.05 €
1.3	1	20	76.08 €	25,403.04 €	25,326.95 €
1.3	1	30	84.30 €	25,403.04 €	25,318.74 €
1.3	1	40	111.92 €	25,403.04 €	25,291.12 €
1.3	1	50	139.54 €	25,403.04 €	25,263.50 €
1.3	1	60	89.76 €	25,403.04 €	25,313.27 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.3	1	70	104.49 €	25,403.04 €	25,298.55 €
1.3	1	80	86.76 €	25,403.04 €	25,316.28 €
1.3	1	90	72.11 €	25,403.04 €	25,330.92 €
1.3	1	100	74.64 €	25,403.04 €	25,328.39 €
1.4	0.4	10	1.09 €	17,027.69 €	17,026.61 €
1.4	0.4	20	0 €	17,027.69 €	17,027.69 €
1.4	0.4	30	0 €	17,027.69 €	17,027.69 €
1.4	0.4	40	0 €	17,027.69 €	17,027.69 €
1.4	0.4	50	0 €	17,027.69 €	17,027.69 €
1.4	0.4	60	0 €	17,027.69 €	17,027.69 €
1.4	0.4	70	0 €	17,027.69 €	17,027.69 €
1.4	0.4	80	0 €	17,027.69 €	17,027.69 €
1.4	0.4	90	0 €	17,027.69 €	17,027.69 €
1.4	0.4	100	0 €	17,027.69 €	17,027.69 €
1.4	0.5	10	3.89 €	17,163.40 €	17,159.52 €
1.4	0.5	20	1.59 €	17,163.40 €	17,161.81 €
1.4	0.5	30	0 €	17,163.40 €	17,163.40 €
1.4	0.5	40	0 €	17,163.40 €	17,163.40 €
1.4	0.5	50	0 €	17,163.40 €	17,163.40 €
1.4	0.5	60	0 €	17,163.40 €	17,163.40 €
1.4	0.5	70	0 €	17,163.40 €	17,163.40 €
1.4	0.5	80	0 €	17,163.40 €	17,163.40 €
1.4	0.5	90	0 €	17,163.40 €	17,163.40 €
1.4	0.5	100	0 €	17,163.40 €	17,163.40 €
1.4	0.6	10	5.82 €	17,452.63 €	17,446.81 €
1.4	0.6	20	3.17 €	17,452.63 €	17,449.47 €
1.4	0.6	30	1.48 €	17,452.63 €	17,451.15 €
1.4	0.6	40	1.56 €	17,452.63 €	17,451.07 €
1.4	0.6	50	0 €	17,452.63 €	17,452.63 €
1.4	0.6	60	0 €	17,452.63 €	17,452.63 €
1.4	0.6	70	0 €	17,452.63 €	17,452.63 €
1.4	0.6	80	0 €	17,452.63 €	17,452.63 €

a	*b*	α	Flexibility revenue	Electricity bill	Net cost
1.4	0.6	90	0 €	17,452.63 €	17,452.63 €
1.4	0.6	100	0 €	17,452.63 €	17,452.63 €
1.4	0.7	10	19.20 €	18,134.37 €	18,115.18 €
1.4	0.7	20	14.66 €	18,134.37 €	18,119.72 €
1.4	0.7	30	13.03 €	18,134.37 €	18,121.34 €
1.4	0.7	40	5.25 €	18,134.37 €	18,129.12 €
1.4	0.7	50	6.22 €	18,134.37 €	18,128.16 €
1.4	0.7	60	1.88 €	18,134.37 €	18,132.49 €
1.4	0.7	70	1.96 €	18,134.37 €	18,132.41 €
1.4	0.7	80	0 €	18,134.37 €	18,134.37 €
1.4	0.7	90	0 €	18,134.37 €	18,134.37 €
1.4	0.7	100	0 €	18,134.37 €	18,134.37 €
1.4	0.8	10	27.46 €	19,188.29 €	19,160.83 €
1.4	0.8	20	23.18 €	19,188.29 €	19,165.11 €
1.4	0.8	30	32.37 €	19,188.29 €	19,155.92 €
1.4	0.8	40	42.56 €	19,188.29 €	19,145.74 €
1.4	0.8	50	9.04 €	19,188.29 €	19,179.25 €
1.4	0.8	60	7.90 €	19,188.29 €	19,180.39 €
1.4	0.8	70	8.18 €	19,188.29 €	19,180.11 €
1.4	0.8	80	9.14 €	19,188.29 €	19,179.15 €
1.4	0.8	90	9.24 €	19,188.29 €	19,179.05 €
1.4	0.8	100	10.11 €	19,188.29 €	19,178.18 €
1.4	0.9	10	36.39 €	21,255.75 €	21,219.35 €
1.4	0.9	20	56.90 €	21,255.75 €	21,198.85 €
1.4	0.9	30	63.03 €	21,255.75 €	21,192.71 €
1.4	0.9	40	43.38 €	21,255.75 €	21,212.36 €
1.4	0.9	50	53.61 €	21,255.75 €	21,202.14 €
1.4	0.9	60	48.49 €	21,255.75 €	21,207.26 €
1.4	0.9	70	18.87 €	21,255.75 €	21,236.88 €
1.4	0.9	80	16.90 €	21,255.75 €	21,238.84 €
1.4	0.9	90	18.54 €	21,255.75 €	21,237.21 €
1.4	0.9	100	19.48 €	21,255.75 €	21,236.27 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.4	1	10	39.98 €	25,454.09 €	25,414.10 €
1.4	1	20	76.08 €	25,454.09 €	25,378.00 €
1.4	1	30	84.30 €	25,454.09 €	25,369.79 €
1.4	1	40	111.92 €	25,454.09 €	25,342.17 €
1.4	1	50	139.54 €	25,454.09 €	25,314.55 €
1.4	1	60	89.76 €	25,454.09 €	25,364.32 €
1.4	1	70	104.49 €	25,454.09 €	25,349.60 €
1.4	1	80	86.76 €	25,454.09 €	25,367.33 €
1.4	1	90	73.10 €	25,454.09 €	25,380.99 €
1.4	1	100	75.22 €	25,454.09 €	25,378.87 €
1.5	0.4	10	1.14 €	17,100.44 €	17,099.30 €
1.5	0.4	20	0 €	17,100.44 €	17,100.44 €
1.5	0.4	30	0 €	17,100.44 €	17,100.44 €
1.5	0.4	40	0 €	17,100.44 €	17,100.44 €
1.5	0.4	50	0 €	17,100.44 €	17,100.44 €
1.5	0.4	60	0 €	17,100.44 €	17,100.44 €
1.5	0.4	70	0 €	17,100.44 €	17,100.44 €
1.5	0.4	80	0 €	17,100.44 €	17,100.44 €
1.5	0.4	90	0 €	17,100.44 €	17,100.44 €
1.5	0.4	100	0 €	17,100.44 €	17,100.44 €
1.5	0.5	10	4.67 €	17,234.44 €	17,229.76 €
1.5	0.5	20	1.59 €	17,234.44 €	17,232.84 €
1.5	0.5	30	0 €	17,234.44 €	17,234.44 €
1.5	0.5	40	0 €	17,234.44 €	17,234.44 €
1.5	0.5	50	0 €	17,234.44 €	17,234.44 €
1.5	0.5	60	0 €	17,234.44 €	17,234.44 €
1.5	0.5	70	0 €	17,234.44 €	17,234.44 €
1.5	0.5	80	0 €	17,234.44 €	17,234.44 €
1.5	0.5	90	0 €	17,234.44 €	17,234.44 €
1.5	0.5	100	0 €	17,234.44 €	17,234.44 €
1.5	0.6	10	5.82 €	17,559.01 €	17,553.19 €
1.5	0.6	20	8.11 €	17,559.01 €	17,550.91 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.5	0.6	30	1.48 €	17,559.01 €	17,557.53 €
1.5	0.6	40	1.56 €	17,559.01 €	17,557.45 €
1.5	0.6	50	0 €	17,559.01 €	17,559.01 €
1.5	0.6	60	0 €	17,559.01 €	17,559.01 €
1.5	0.6	70	0 €	17,559.01 €	17,559.01 €
1.5	0.6	80	0 €	17,559.01 €	17,559.01 €
1.5	0.6	90	0 €	17,559.01 €	17,559.01 €
1.5	0.6	100	0 €	17,559.01 €	17,559.01 €
1.5	0.7	10	19.20 €	18,331.19 €	18,311.99 €
1.5	0.7	20	14.66 €	18,331.19 €	18,316.53 €
1.5	0.7	30	13.03 €	18,331.19 €	18,318.16 €
1.5	0.7	40	7.02 €	18,331.19 €	18,324.16 €
1.5	0.7	50	6.22 €	18,331.19 €	18,324.97 €
1.5	0.7	60	6.60 €	18,331.19 €	18,324.58 €
1.5	0.7	70	1.96 €	18,331.19 €	18,329.22 €
1.5	0.7	80	2.05 €	18,331.19 €	18,329.14 €
1.5	0.7	90	0 €	18,331.19 €	18,331.19 €
1.5	0.7	100	0 €	18,331.19 €	18,331.19 €
1.5	0.8	10	27.67 €	19,535.66 €	19,508.00 €
1.5	0.8	20	24.15 €	19,535.66 €	19,511.52 €
1.5	0.8	30	32.74 €	19,535.66 €	19,502.92 €
1.5	0.8	40	42.56 €	19,535.66 €	19,493.11 €
1.5	0.8	50	9.04 €	19,535.66 €	19,526.62 €
1.5	0.8	60	10.56 €	19,535.66 €	19,525.10 €
1.5	0.8	70	8.18 €	19,535.66 €	19,527.48 €
1.5	0.8	80	9.14 €	19,535.66 €	19,526.52 €
1.5	0.8	90	9.24 €	19,535.66 €	19,526.42 €
1.5	0.8	100	10.11 €	19,535.66 €	19,525.56 €
1.5	0.9	10	36.39 €	21,678.20 €	21,641.81 €
1.5	0.9	20	57.53 €	21,678.20 €	21,620.67 €
1.5	0.9	30	63.03 €	21,678.20 €	21,615.17 €
1.5	0.9	40	43.38 €	21,678.20 €	21,634.82 €

a	b	α	Flexibility revenue	Electricity bill	Net cost
1.5	0.9	50	53.61 €	21,678.20 €	21,624.59 €
1.5	0.9	60	49.22 €	21,678.20 €	21,628.98 €
1.5	0.9	70	35.45 €	21,678.20 €	21,642.75 €
1.5	0.9	80	17.81 €	21,678.20 €	21,660.39 €
1.5	0.9	90	18.54 €	21,678.20 €	21,659.66 €
1.5	0.9	100	20.33 €	21,678.20 €	21,657.88 €
1.5	1	10	39.98 €	25,515.86 €	25,475.88 €
1.5	1	20	76.08 €	25,515.86 €	25,439.78 €
1.5	1	30	85.24 €	25,515.86 €	25,430.63 €
1.5	1	40	111.92 €	25,515.86 €	25,403.94 €
1.5	1	50	139.54 €	25,515.86 €	25,376.32 €
1.5	1	60	89.76 €	25,515.86 €	25,426.10 €
1.5	1	70	104.49 €	25,515.86 €	25,411.38 €
1.5	1	80	86.76 €	25,515.86 €	25,429.10 €
1.5	1	90	73.21 €	25,515.86 €	25,442.65 €
1.5	1	100	75.41 €	25,515.86 €	25,440.46 €

UN Sustainable Development Goals

The United Nations Sustainable Development Goals (SDGs) provide a global framework to achieve a better and more sustainable future for all. This agenda encompasses 17 goals designed to address pressing global challenges, including poverty, inequality, climate change, environmental degradation, and access to affordable and clean energy. This dissertation contributes directly to several of these goals, as detailed in Table E.2. In particular, the following SDGs are highlighted:

SDG 7 Ensure access to affordable, reliable, sustainable and modern energy for all

SDG 8 Promote sustained, inclusive and sustainable economic growth, full and productive employment and decent work for all

SDG 13 Take urgent action to combat climate change and its impacts

Table E.2: Contribution of the dissertation to selected SDGs.

SDG	Target	Contribution	Performance Indicators and Metrics
7	7.1	Supporting the integration and optimization of battery storage in RECs facilitates access to more reliable and affordable renewable energy.	Reduction in electricity costs for REC members; improved system self-sufficiency
	7.2	Promotes an increased share of renewable energy in the energy mix by enhancing the operational efficiency of community-based storage systems.	Percentage of local consumption met by renewable generation
8	8.2	Encourages innovation and energy sector digitalization through the development of decision-support tools for REC managers and aggregators.	Deployment of REC-level energy management systems; engagement in flexibility markets
	8.4	Improves resource-use efficiency by minimizing waste of surplus renewable energy via optimized battery operation.	Energy not curtailed due to storage; increase in local energy use
13	13.1	Enhances community resilience to energy system stress by enabling flexible response to grid needs.	Traded flexible energy (kWh); hours of availability for activation
	13.3	Supports climate action through research and modelling that accelerates the adoption of low-carbon community energy solutions.	Dissemination of technical tools; number of informed community strategies