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Local Market Mechanisms: how Local Markets can shape the Energy Transition

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Abstract

Europe has embarked on a journey towards a zero-emission system, with the power system at its core. From electricity generation to electric vehicles, the European power system must transform into an interconnected, intelligent network. To achieve this vision, active user participation is crucial, ensuring transparency, efficiency, and inclusivity. Thus, Europe has increasingly focused on the concept of markets in all their facets.

This thesis seeks to answer the following questions: How can markets, often considered abstract and accessible only to high-level users, be integrated for end-users? How can market mechanisms be leveraged across various phases of the electrical system? Why is a market-driven approach essential for solving network congestions and even influencing planning? These questions shape the core of this research.

The analysis unfolds in three layers, each aligned with milestones leading to 2050. The first explores how market mechanisms can be integrated into system operator development plans, enhancing system resilience in the face of changes. In this regard, this step addresses the question of how a market can be integrated into the development plans of a network and how network planning can account for uncertainties. Finally, the analysis highlights the importance of sector coupling in network planning, proposing a study in which various energy vectors lead to a multi-energy system. According to the roadmap to 2030, this layer demonstrates how markets can manage several components of the gas and electrical network. Finally, even though the robust optimisation increases the final cost in the market, it allows to cover the system operator from uncertainties.

The second step delves into the concept of network congestion. While congestion management is primarily the domain of operators, it explores how technical and economic collaboration between operators and system users, via flexibility markets, can enhance resilience amid demand uncertainties and aggressive market behaviours. In addition to flexibility markets, other congestion markets are proposed, some radically different, like locational marginal pricing, and others more innovative, such as redispatching markets for distribution. Building upon the first analysis, this section addresses questions of how various energy vectors can be used not only to meet demand but also to manage the uncertainties associated with each resource. Consequently, this second part revisits the concept of sector coupling, demonstrating how various energy vectors can be managed through flexibility markets to resolve network congestion while simultaneously handling uncertainties related to different vectors. The results demonstrate the usefulness of the flexibility market in managing the sector coupling and the uncertainties related to several energy vectors.

The third and most innovative step proposes energy and service markets for low-voltage users, employing distributed ledger technology. Since this step highlights topics that are

currently too innovative to be realized, this third section offers a comparative study between centralised and decentralised markets using blockchain technology, highlighting which aspects of distributed ledger technology deserve attention and which aspects of low-voltage markets need revision. The results show that the blockchain technology is still in the early stage of its evolution, and several improvements are needed to fully apply this technology into real-world applications.

To sum up, this thesis explores the evolving role of markets in the energy transition. Its insights are aimed at assisting system operators and network planners in effectively integrating market mechanisms at all levels of the electrical system. The research objectives, spanning from robust optimization planning to redispatching and blockchain-based transactions, align with a comprehensive vision leading to 2050.

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This dissertation describes the main outcomes of the research activity carried out during the doctoral degree period, part of the contents of this document are based on the following accepted for publication or published papers done in collaboration with other researchers.

1. Conference papers

1.1. **M. Galici**, M. Mureddu, E. Ghiani, and F. Pilo
Agent-based approach for Decentralized Genetic Algorithm
CIRED 2021 - The 26th International Conference and Exhibition on Electricity Distribution, 2021, p. 2919 – 2924.
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Authorship Contribution: M. Galici substantially contributed to the conference paper, from conceptualisation to implementation. He organised data analysis, developed blockchain-based technique, and performed genetic algorithm simulations. Additionally, M. Galici significantly helped writing the manuscript.

1.2. R. Tonelli, M. Marchesi, A. Pinna, M. Mureddu, E. Ghiani, F. Pilo, and **M. Galici**
Blockchain Oriented Software Engineering for DApp smart contracts in smart energy markets
CIRED 2022 Shanghai Workshop, 2022, p. 319 – 323.
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1.3. **M. Galici**, E. Ghiani, M. Mureddu, F. Pilo, A. Pinna, R. Tonelli, and M. Marchesi
Data security and protection in blockchain-based local energy markets for smart cities
CIRED 2022 Shanghai Workshop, 2022, p. 324 – 329.
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1.4. G. Celli, **M. Galici**, G. Murtas, F. Pilo, and S. Ruggeri
A risk-based planning tool for integrated urban energy systems
CIRED 2022 Shanghai Workshop, 2022 p. 330 – 335.
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Authorship Contribution: M. Galici significantly contributed to the conference paper, he conceptualised and implemented the analysis. He organised data analysis, developed robust optimisation models, and performed the model simulations. Additionally, M. Galici significantly helped writing the manuscript.

1.5. S. Carrus, **M. Galici**, E. Ghiani, L. Mundula, and F. Pilo
Multi-Energy Planning of Urban District Retrofitting
2021 International Conference on Smart Energy Systems and Technologies (SEST), Vaasa, Finland, 2021, pp. 1-6.
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Authorship Contribution: M. Galici contributed to the conference paper, from the conceptualisation and implementation of the optimisation analysis. He organised data analysis, developed optimisation models, and performed the model simulations. Additionally, M. Galici significantly helped writing the manuscript.

1.6. **M. Galici**, E. Ghiani, F. Pilo, and G. Pisano
Dynamic Programming for Optimal Energy Management in Nanogrids
2021 IEEE 6th International Forum on Research and Technology for Society and Industry (RTSI), Naples, Italy, 2021, pp. 103-108.
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1.7. G. Celli, **M. Galici**, M. Mousavi, F. Pilo, and G. G. Soma
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2022 IEEE 21st Mediterranean Electrotechnical Conference (MELECON), Palermo, Italy, 2022, pp. 69-73.
DOI: https://doi.org/10.1109/MELECON53508.2022.9843058
Authorship Contribution: M. Galici contributed to the conference paper, he conceptualised and implemented the analysis. He organised data analysis, improved the grey wolf model, and performed the model simulations. Additionally, M. Galici significantly helped writing the manuscript.

1.8. G. Celli, **M. Galici**, and F. Pilo
A robust exploitation of flexibility from aggregation of EVs
CIRED Porto Workshop 2022: E-mobility and power distribution systems, Hybrid Conference, Porto, Portugal, 2022, pp. 1134-113.

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1.9. **M. Galici**, E. Ghiani, M. Mureddu, and F. Pilo
Distributed Ledger Based Management of Local Energy Markets with a Federated Learning Approach
2022 Workshop on Blockchain for Renewables Integration (BLORIN), Palermo, Italy, 2022, pp. 57-61.
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1.10. **M. Galici**, G. Celli, E. Ghiani, S. Ruggeri, G. Pisano, and F. Pilo
Multi-Energy Smart City Urban District Planning with Robust Optimisation
2022 57th International Universities Power Engineering Conference (UPEC), Istanbul, Turkey, 2022, pp. 1-6.
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1.11. G. Celli, **M. Galici**, and F. Pilo
Definition of a Stochastic Charging model of EV Aggregation and Estimation of its Flexibility Amount
2022 2nd International Conference on Energy Transition in the Mediterranean Area (SyNERGY MED), Thessaloniki, Greece, 2022, pp. 1-5.
DOI: https://doi.org/10.1109/SyNERGYMED55767.2022.9941468
Authorship Contribution: M. Galici contributed to the conference paper by implementing the analysis. He developed the stochastic model by means of the Monte Carlo model, and the EV model. Additionally, he performed the simulations and the result analysis. Finally, M. Galici significantly helped writing the manuscript.

1.12. G. Celli, **M. Galici** and F. Pilo
Distribution system planning with models of flexibility markets
27th International Conference on Electricity Distribution (CIRED 2023), Rome, Italy, 2023, pp. 3996-4003
DOI: 10.1049/icp.2023.0495.
Authorship Contribution: M. Galici contributed to the conference paper by implementing the analysis. He developed the planning model, the flexibility market and the agent-based learning model through the Roth-Erev algorithm. Additionally, he performed the simulations and the result analysis. Finally, M. Galici significantly helped writing the manuscript.

1.13. R. Trevisan, M. Mureddu, E. Ghiani, **M. Galici**, and F. Pilo
Transactive Energy Systems in Decentralized Autonomous Renewable Energy Communities
2023 IEEE Power & Energy Society General Meeting (PESGM), Orlando, FL, USA, 2023, pp. 1-5.
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2. Journal papers

2.1. **M. Galici**, M. Mureddu, E. Ghiani, G. Celli, F. Pilo, P. Porcu, and B. Canetto
Energy Blockchain for Public Energy Communities
Applied Sciences. 2021; 11(8):3457.
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2.2. G. Celli, **M. Galici**, F. Pilo, S. Ruggeri, and G.G. Soma
Uncertainty Reduction on Flexibility Services Provision from DER by Resorting to DSO Storage Devices
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2.3. **M. Galici**, M. Mureddu, E. Ghiani, and F. Pilo
Blockchain-Based Hardware-in-the-Loop Simulation of a Decentralized Controller for Local Energy Communities
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3. Chapters

3.1. E. Ghiani, M. Mureddu, **M. Galici**, M. Troncia, and F. Pilo
13 - The digitalization of peer-to-peer electricity trading in energy communities
Energy Communities, Academic Press, 2022; Pages 211-227, ISBN: 9780323911351.
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Nomenclature

ACER	Agency for the Cooperation of Energy Regulators
ADMM	Alternating Direction Method of Multipliers
ASIC	Application Specific Integrated Circuit
BRP	Balance Responsible Parties
CCHP	Combined Cooling Heat and Power
CDA	Continuous Double Auction
CHP	Combined Heat Pump
CQR	Clear Quantity Ratio
CS	Charging Station
CSC	Collective Self Consumption
DA	Double Auction
DAG	Direct Acyclic Graph
DAO	Decentralised Autonomous Organisation
DApp	Decentralised Application
DER	Distributed Energy Source
DLMP	Distribution Locational Marginal Price
DLT	Distributed Ledger Technology
DMS	Distribution Management System
DR	Demand Response
DSO	Distribution System Operator
EH	Energy Hub
EHP	Electric Heat Pump
ESS	Energy Storage System
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicle
EVM	Ethereum Virtual Machine
FSP	Flexibility Service Provider
GF	Gas Flow
GHG	Greenhouse Gas

GPU	Graphic Processing Unit
ICT	Information Communication Technology
IGDT	Information Gap Decision Theory
IoT	Internet of Things
JRC	Joint Research Center
KKT	Karush-Kuhn-Tucker
LEM	Local Electricity Market
LMP	Locational Marginal Price
LoLE	Loss of Load Expectation
LP	Linear Programming
LSC	Local Sustainable Communities
MAR	Minimum Acceptance Ratio
MC	Monte Carlo
MES	Multi Energy System
MO	Market Operator
P2G	Power to Gas
P2H	Power to Heat
$P2H_2$	Power to Hydrogen
P2L	Power to Liquid
P2P	Peer to Peer
PCDA	Pseudo Continuous Double Auction
PDF	Probabilistic Distribution Function
PLF	Probabilistic Load Flow
PoW	Proof of Work
PoS	Proof of Stake
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
REMIT	Regulation on Wholesale Market Transparency and Integrity in Energy
RES	Renewable Energy Source
RO	Robust Optimisation
SC	Smart Contract
SCADA	Supervisory Control and Data Acquisition
SME	Small/Medium Size Enterprise

SO	System Operator
SoC	State of Charge
STC	Solar Thermal Collector
TE	Transactive Energy
TES	Thermal Energy Storage
TS	Tabu Search
TSO	Transmission System Operator
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
V2G	Vehicle to Grid
V2V	Vehicle to Vehicle
VPP	Virtual Power Plant

1 Introduction

This introductory chapter sets the stage for an in-depth exploration of the European Union's (EU) ambitious roadmap for the year 2050, a comprehensive strategy aimed at achieving sustainable and resilient energy systems. The chapter delves into the multifaceted aspects of the EU's vision for a low-carbon future, highlighting how these topics have driven the thesis work in mitigating climate change, promoting energy security, and modernising the energy system, the latter a cornerstone of the EU’s roadmap 2050.

The chapter begins by contextualising the urgency of addressing climate change and the imperative for transitioning towards cleaner and more efficient energy sources. It outlines the key drivers behind the EU's commitment to decarbonise its energy sector, emphasizing the interconnectedness of environmental, economic, and social factors. The discussion then pivots to the evolution of the power system, tracing its historical development and the challenges it faces in the present day.

1.1 Background and Motivation

1.1.1 Roadmap to 2050

Over the course of European history, the reduction of greenhouse gas (GHG) emissions has emerged as a pivotal and evolving concern in the region's ongoing commitment to environmental sustainability. Rooted in the recognition of the interconnectedness between human activities and the Earth's climate, Europe's journey towards emissions reduction has undergone a series of transformative phases. From early recognition of the environmental impacts of industrialisation to the contemporary pursuit of ambitious climate targets, the EU and its member states have displayed a dynamic approach to addressing the global challenge of climate change.

The emergence of the industrial revolution in the 18th century marked a pivotal turning point in European history, catalysing rapid economic growth but also triggering increased emissions of GHGs [1]. As the detrimental consequences of unchecked emissions became apparent, a nascent awareness of the need for environmental stewardship began to take shape.

Throughout the 20th century, escalating concerns about air quality, pollution, and their associated health impacts prompted the introduction of environmental regulations and the establishment of international agreements. In the early 1970s, environmental protection emerged as a prominent topic on the agenda of the European community, with the first directive based on the *polluter-pays principle*. The principle entails that a company responsible for environmental harm is accountable, requiring them to undertake preventive or remedial measures and cover associated expenses.

The signing of the United Nations Framework Convention on Climate Change (UNFCCC) in 1992 represented a significant milestone, where European nations collectively acknowledged the imperative of stabilizing GHG concentrations in the atmosphere.

The liberalisation of the energy sector in 1996 with the decision of the European Parliament set the basis for the renovation of the internal electricity market [2]. This revolution was brought by the need to achieve the objectives of the Union policy on energy that include secure and competitively priced supplies, renewables and climate change targets of 2020 and beyond, and a significant increase in energy efficiency across the whole economy [3]. That market should be based on fair and open competition. To achieve those public policy objectives, it is widely accepted that there is a need for some public intervention in electricity markets.

The subsequent decades witnessed the EU's proactive role in spearheading initiatives aimed at emissions reduction. The establishment of the Emissions Trading System (ETS) in 2005 marked the creation of the world's first major carbon market, demonstrating again the EU's commitment to market-based mechanisms. This approach strengthens the subsequent policy frameworks, such as the Climate and Energy Package in 2008, which set binding targets for emission reductions, renewable energy integration, and energy efficiency improvements.

In recent years, the urgency of addressing climate change has been underscored by the European Green Deal, launched in 2019. This ambitious policy framework reaffirms the EU's commitment to achieving climate neutrality by 2050. The European Climate Law, adopted in 2021, solidified the 2019’s goals into binding legislation, committing the EU to a trajectory of substantial emissions reductions and sustainable development. The European Climate Law set the legal objective of achieving climate neutrality by 2050, with an intermediate goal of reducing net GHG emissions by at least 55% by 2030 compared to 1990 levels. Climate neutrality entails net zero GHG emissions for the EU by 2050 through emission cuts, green technology investment, and environmental protection. It sets a legally binding target for net zero emissions by 2050, establishes a process for regular reviews, introduces a 2030 target of 55% emission reduction, emphasizes sector-specific roadmaps for climate neutrality, and institutes measures for stronger adaptation to climate change, among other provisions [1].

Commencing with the implementation of the inaugural environmental EU directive, European countries embarked on a progressive trajectory of GHG emission reduction. Nonetheless, as shown in Figure 1, the current pace of reduction remains insufficient to align with the stringent 2030 and 2050 EU requirements mandated for achieving climate objectives [4]. Due to the increased frequency and intensity of expected extreme weather events, the severe consequences call for improving the environmental sustainability of our society. In the path toward a climate-neutral society, the energy sector has been recognised pivotal by the EU [5].

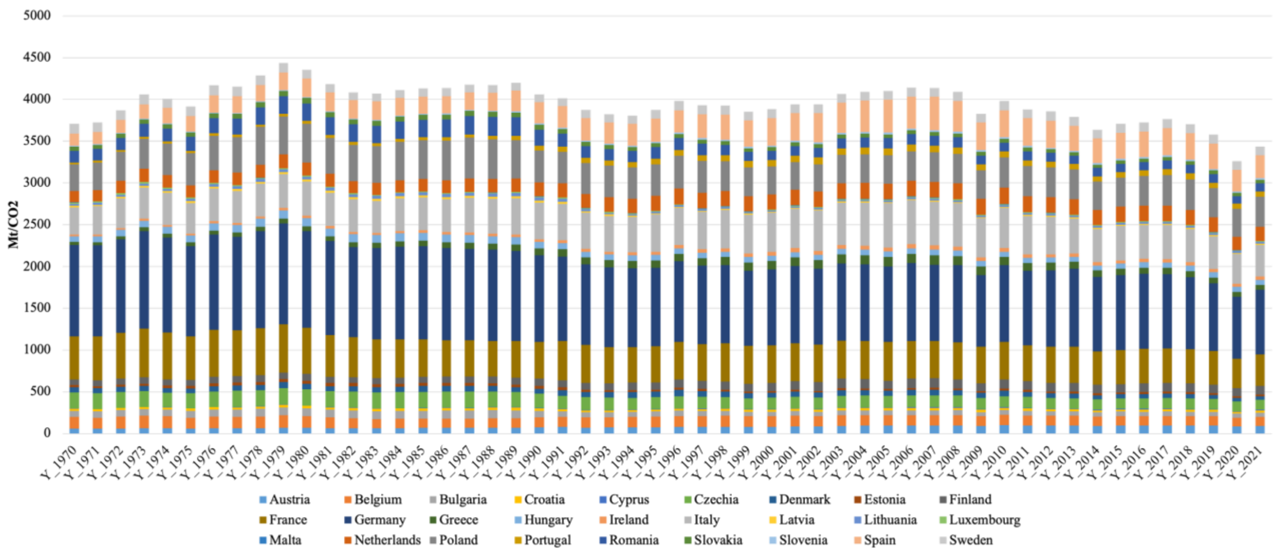


Figure 1. Greenhouse gas emission (CO_2) of EU member states from 1970 to 2021 [6].

Energy serves as a fundamental cornerstone for the well-being of people, industry, and the economy, underpinning safety, security, sustainability, and affordability. In the context of a modern society, energy's crucial role is often overlooked in Europe, despite its historical evolution spanning centuries and diverse fuels and distribution systems. Initially catering to elemental needs, the energy system has progressively expanded to encompass heating, warm water, industrial and transport fuels, and electricity, contributing to comfort and freedom while concurrently harming the environment and depleting resources. The present energy framework remains unsustainable due to:

- environmental pollution;
- resource depletion;
- high GHG emissions of which the great majority is directly or indirectly linked to energy which are not compatible with the EU objectives;
- security of supply risk which is high dependable on foreign sources of energy imported from a limited number of suppliers; and finally
- competitiveness risks related to high energy costs and underinvestment.

In the EU's vision, market mechanisms play a pivotal role in steering the continent towards enhanced energy security, sustainability, and competitiveness. This vision acknowledges the complex and multifaceted challenges facing the EU's energy landscape, where no single energy source can provide a flawless, all-encompassing solution. To address these challenges effectively, the EU recognises the need for well-designed market mechanisms. The current regulatory environment, while crucial, may not be sufficient to facilitate the necessary transformation. Urgent decisions are paramount because a well-functioning European energy market is not just a matter of convenience, it is a linchpin for controlling consumer costs, preserving Europe's competitive advantage, and safeguarding the environment. One key reason for embracing market mechanisms lies in their ability to encourage substantial investments. These investments are indispensable to replace aging energy infrastructure and transition towards a more sustainable, secure, and diverse energy mix. Markets create incentives for both private and public stakeholders to channel resources into renewable energy, energy efficiency, and innovative technologies. Thus, driving economic growth, fostering job creation, and promoting regional development and fuels innovation. Moreover, the concept of adopting market mechanisms aligns with the EU's broader goals of environmental preservation and energy security. By facilitating the adoption of low-carbon energy sources and efficient energy use, markets help reduce GHG emissions, mitigate climate change, and enhance energy independence. They provide the framework for diversifying energy sources, reducing reliance on external suppliers, and strengthening Europe's resilience to external energy shocks.

In this scenario, EU highlights three key principles of the energy transition: *i*) secure and affordable energy supply, *ii*) fully integrated, interconnected and digitalised energy market, and *iii*) energy performance of buildings as well as the development of a power sector based largely on renewable energy sources (RES).

The research and development conducted by the EU on optimisation models and algorithms for power distribution planning, flexibility and local redispatch market mechanisms, and local electricity and service markets effectively encapsulate these principles. These themes harmonise seamlessly with the overarching framework of the EU 2050 roadmap, aligning perfectly with its progressive vision for the establishment of sustainable energy systems.

These topics directly contribute to the implementation of several key priorities outlined by the EU Commission:

1. *Building Interconnected Energy Systems and Integrated Grids*. Optimisation models and algorithms play a pivotal role in designing interconnected energy systems and integrated grids that efficiently accommodate RES and multi vector energy sources. These technologies enable the efficient management of energy flows, facilitating the integration of decentralized renewable sources while maintaining grid stability.
2. *Promoting Innovative Technologies and Modern Infrastructure*. The application of optimization models and algorithms facilitates the deployment of innovative technologies and the creation of modern energy infrastructure. These tools enable the optimisation of energy distribution, enabling the incorporation of smart grid technologies, energy storage, and demand-response (DR) mechanisms.
3. *Decarbonising the Energy Sector and Smart Integration*. Flexibility and local redispatch market mechanisms facilitate the efficient employment of renewable and low-carbon gas sources. By enabling smart integration across sectors, these mechanisms promote the transition to a cleaner and sustainable energy mix.
4. *Empowering Consumers and Tackling Energy Poverty*. Local electricity and service markets empower consumers by providing them with choices and control over their

energy consumption and production. This contributes to tackling energy poverty by enabling access to affordable and clean energy solutions.

The integration of these principles advances the European Commission's multi-faceted strategy for clean energy transition, ensuring sustainable, efficient, and accessible energy systems that align with Europe's commitment to combat climate change and promote a greener future.

1.1.2 3D paradigm: Decarbonisation, Decentralisation and Digitalisation

To fight the climate crisis, ensure accessible and affordable energy, reduce reliance on Russian fossil fuels, and achieve sustainable goals, a comprehensive digital and sustainable transformation of the energy system is imperative. This entails installing solar panels on commercial and public building's roofs by 2027 and on new residential buildings by 2029, deploying 10 million heat pumps in five years, and replacing 30 million fossil fuel-powered cars with zero-emission vehicles by 2030. Achieving a 55% GHG emissions reduction and 45% renewables share in 2030 necessitates an advanced energy system [7].

The decarbonisation of the energy system dictated by the EU 2050 roadmap leads to an increasing use of renewable resources. This high penetration of distributed energy sources (DER) throughout the power system inevitably leads to a decentralisation of energy sources, no longer centralised in large non-renewable power plants. Energy and resource efficiency, decarbonisation, electrification, sectoral integration and decentralisation of the energy system require massive digitalisation efforts.

The principles of decarbonisation, decentralisation, and digitalisation of the energy system are integral components of both the European Green Deal, of the Digital Decade Policy Programme 2030 and of the Internal Energy Market directive, reflecting their alignment with the EU's overarching goals for sustainability and technological advancement [8]. These three principles are organised into the so-called *3D paradigm*.

- **Decarbonisation**: The European Green Deal places a primary emphasis on decarbonising the economy to combat climate change. It sets ambitious targets for reducing GHG emissions, including the goal of achieving climate neutrality by 2050. In addition, the internal energy market facilitates the transition to cleaner, low-carbon energy sources by promoting competition and encouraging the integration of renewable energy. Through increased cross-border trade and market integration, driven by competition enforcement, the market helps ensure that RESs can flow freely across borders. This, in turn, aids in achieving the decarbonisation goals by harnessing the potential of renewable energy.
- **Decentralisation**: Decentralisation aligns with the principles of empowering local communities, fostering innovation, and promoting energy security. The Digital Decade Policy Programme complements this by enabling the integration of DERs, local

electricity markets (LEM), and community-driven energy initiatives. Moreover, the market opening, and increased competition create an environment where a variety of energy suppliers, including small-scale and local ones, can thrive. Consumers, including households and small businesses, have the flexibility to choose from several suppliers. This decentralised approach empowers consumers and fosters the development of distributed energy resources, contributing to the decentralisation of energy generation and distribution.

- **Digitalisation**: All the EU directives recognise the transformative role of digitalisation in advancing sustainability goals. Digitalisation enhances the monitoring, management, and optimisation of energy systems, enabling efficient resource allocation, DR mechanisms, and predictive maintenance. The Digital Decade Policy Programme underscores the role of digitalisation in creating a pan-European energy data space, deploying Internet of Things (IoT) devices, enhancing connectivity, and enabling innovative energy solutions. Also, the internal energy market embraces digitalisation through its focus on transparency and efficiency. Market coupling and the use of price comparison tools enable consumers to make informed decisions and optimise their energy consumption. Regulations such as the Regulation on wholesale market transparency and integrity in energy (REMIT) enhance transparency in energy markets, creating a more data-driven and digitally connected energy ecosystem.

Therefore, the European Green Deal and the Digital Decade Policy Programme form a cohesive approach that synergistically accelerates the transition towards a sustainable, decentralised, and digitally empowered energy system, aligned with the EU's broader objectives for a greener and technologically advanced future [9].

Needless to say, in the energy sector, digitalisation is already in progress. New devices like electric vehicles (EV), photovoltaic (PV) panels installations, and electric heat pumps (EHP) are incorporated with smart technologies enabling data generation and remote control. The world is poised for a rapid increase in active IoT devices, projected to exceed 25.4 billion by 2030. Within the EU, 51% of households and small/medium size enterprises (SME) are equipped with smart electricity meters. The digital and energy policies of the EU currently steer the digitalisation of energy, addressing issues such as data interoperability, cybersecurity, privacy, and consumer protection.

In this context, research and development conducted by the EU on the integration of market mechanisms at all levels (i.e., from planning the energy sector to operate the electricity network) is a crucial component that align with the 3D paradigm outlined in the EU roadmap for the energy sector towards 2050.

Strategically incorporating RES into the energy mix is the objective of the decarbonised distribution planning which involves optimising the placement of PV panels, wind turbines, and other RESs within the distribution grid, effectively reducing reliance on fossil fuels. Encouraging the integration of DERs such as energy storage systems (ESS) at various points within the grid, further promotes decentralisation. Moreover, digitalisation plays a pivotal role in enhancing distribution planning by enabling the utilization of advanced modelling and simulation tools. These tools, powered by digitalisation, facilitate the optimization of renewable resource integration, accurate prediction of grid behavior, and support for efficient decision-making processes.

Local markets encourage the adoption of renewable energy solutions at a community level. By enabling local producers, such as households with rooftop solar panels, to sell excess energy to their neighbours or the grid, these markets create incentives for decentralised renewable energy generation. This reduces the reliance on centralised fossil fuel-based power plants and fosters the use of cleaner energy sources, contributing to decarbonisation. These local markets leverage digital platforms to enable transparent and efficient energy transactions among local producers, consumers, and the grid. Through digitalisation, participants can monitor real-time energy prices, consumption patterns, and production levels. This data-driven approach empowers consumers to make informed decisions about when and how they consume or sell energy. Digital tools facilitate seamless communication, automated billing, and data sharing, fostering a digitally connected ecosystem that promotes local renewable energy generation and consumption.

Redispatch refers to the reallocation of electricity generation resources to ensure grid stability and minimise congestion. This type of markets includes flexibility markets, local service markets and locational marginal price mechanisms. In the context of decarbonisation, redispatch markets can effectively optimise the use of RESs. When there is an excess of renewable generation, it can be prioritised over conventional fossil fuel generation, reducing emissions and dependence on carbon-intensive power sources. This way, they helps balance the grid while promoting the use of cleaner energy. Digitalisation enhances redispatch markets by enabling real-time monitoring of grid conditions, energy flows, and supply-demand imbalances. Advanced sensors, smart meters, and communication technologies provide grid operators with accurate data to identify areas of congestion or instability. Digital tools aid in swiftly reallocating energy generation resources to address these challenges. Automation and data-driven decision-making streamline redispatch processes, ensuring grid stability while optimizing renewable energy integration.

1.1.3 Transition to a Decarbonised Power System

As emphasized by the EU strategy, the energy sector, especially the electricity sector, plays a crucial role in the journey towards a climate-neutral society. The decarbonisation of the economy necessitates an energy transition, which mandates a transformation of power system planning and operational practices.

1.1.3.1 Traditional Power System

Traditionally, power systems were planned and designed by assuming unidirectional power flows from power stations to customers. However, nowadays, various factors such as the liberalisation of the electricity market, the need for reliability, and environmental concerns have led to a situation where electricity generation occurs downstream at the distribution level.

Historically, the electricity grid, an intricate network comprising high, medium, and low voltage lines, acted and serves as the vital link connecting power generators to end-users. Recognised as a cornerstone of Europe's critical infrastructures, the power network bestows security, stability, comfort, and progress upon customers, promoting industrial competitiveness while being widely regarded as an essential public good. At its core, the grid serves as the backbone of the electrical value chain, efficiently channelling electricity from centralized power plant through substations, transformers, transmission, and distribution lines.

Within this network, electricity flows through a matrix of transmission lines, encompassing high voltage lines managed by transmission system operators (TSOs), as well as low voltage lines overseen by distribution system operators (DSOs). Medium voltage lines can be managed by either TSOs or DSOs, and the voltage is modulated by substations. Traditionally, transmission lines connect large power plants to transformers, where voltage is adjusted before distribution. TSOs are tasked with the optimal operation and maintenance of these transmission lines, ensuring the proper assessment of electricity demand, coordinating with generators regarding short and long-term power needs, and efficiently managing interconnector flows.

The interconnectors, border-crossing lines linking national power grids, enable the seamless flow of electricity across Europe, fostering trade and exchanges between EU Member States. This interconnection is pivotal for ensuring supply security, enabling regions with excess generation to support those facing shortages. Meanwhile, distribution networks, often comprising medium and low-voltage lines, deliver electricity to consumers. These networks fall under the purview of DSOs, who oversee grid congestion, customer connections, reconnection after outages, and collaborate with TSOs to facilitate grid-connected participation in retail, wholesale, and balancing markets.

1.1.3.2 Current Power System

Distribution and Transmission grids are a linchpin of the energy transition, pivotal in advancing the EU’s climate and energy policies and facilitating a cost-efficient transition to a carbon-neutral economy. Over the past several decades, the EU and its Member States have implemented a comprehensive array of policies and strategies aimed at driving the energy transition, reducing GHG emissions, and promoting the adoption of RESs. Central to the EU’s energy transition initiatives is the ambitious goal of achieving a high penetration of RESs within the electricity network, which fits with the overarching objective of the Paris

Agreement [10], At both the EU and national levels, policies have been crafted to facilitate the integration of renewables into the electricity mix. These policies encompass a broad spectrum of measures, including [11]:

- *Incentives for renewable energy generation*. To boost the advancement of renewable energy projects and foster wider adoption of RESs throughout the EU, in September 2020, the European Commission introduced a financing mechanism, which has been prompted by the provisions outlined in Article 33 of the Governance Regulation (EU) 2018/1999 [12].
- *Promotion of equitable market participation among all stakeholders*. To bolster the transformative change both within private enterprises and public entities, policymakers are encouraged to explore the promotion of decentralized, community-driven renewable energy systems.
- *Investment in research and development*. Awareness raising about and sensitising stakeholders to the characteristics of renewable-based DER solutions can address some of the barriers faced by the new technologies.
- *Establishment of supportive regulatory frameworks*. The EU has strategically shaped its internal energy market to support the goals of the Paris Agreement. It highlights a key element on the cost-effective investments. In particular, the EU wants to ensure that energy investments are cost-effective, curbing pre-tax expenses for households and industries. In addition, through smart technologies, the EU wants to empower consumers to manage energy consumption effectively, promoting reduced usage and even small-scale electricity generation. Finally, the promotion to open and fair access to transmission grids, wants to foster competition and support for the integration of renewables. Regulatory measures, including unbundling and competition rules, ensure efficient transmission infrastructure use, facilitating the transition to clean energy, a central Paris Agreement objective.

Several EU Member States have implemented significant mechanisms to bolster the integration of RESs within the power sector [13]. For instance, key frameworks are the feed-in tariffs and feed-in-premiums. These mechanisms set prices and premiums for purchasing electricity generated by RES producers. Within these frameworks, producers have the option to receive either fixed feed-in tariffs or premium feed-in tariffs through network operators.

Consequently, the traditional representation of the electrical power system no longer accurately reflects the situation due to the aforementioned factors. These elements have contributed to a scenario where increasingly growing quantities of small-to-medium scale renewable generation capacity have been integrated into the networks, resulting in bi-directional power flows. This transformation is a direct outcome of EU policies promoting renewable energy, which have driven the substantial integration of RESs.

Since 2004, the renewable capacity in Europe has undergone a remarkable and exponential increase, reflecting a substantial surge in the adoption and integration of RESs across the continent. As depicted in Figure 2, Between 2004 and 2021, the number of renewable producers in Europe more than doubled. While the capacity of hydroelectric generators remained relatively stable, the photovoltaic and wind generators experienced a consistent and continuous growth trajectory [14].

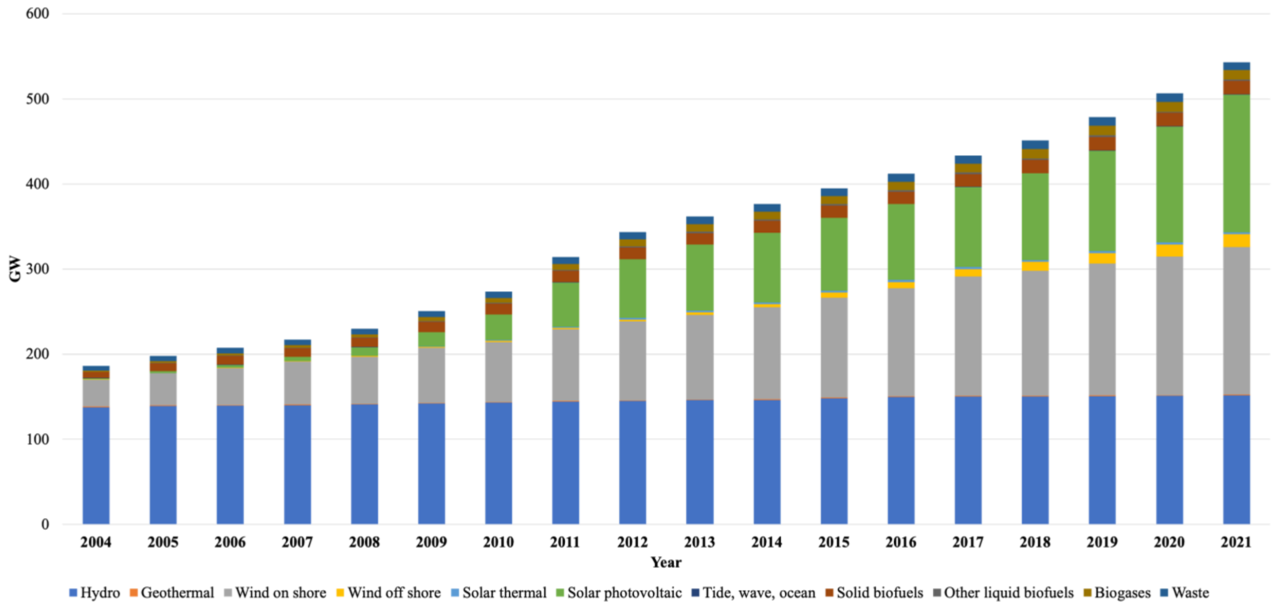


Figure 2. Renewable capacity in Europe from 2004 to 2021.

In the case of photovoltaics, the combined capacity across EU member states was around 1 GW in 2004, compared to a substantial increase to 162 GW by 2021. Similarly, the trend is mirrored in wind generation. In 2004, the total registered capacity for on-shore and off-shore wind generators in EU member states was 32 GW, a figure that significantly contrasts with the registered capacity of 188 GW as of 2021. However, this massive growth is not spread evenly across all member states. As depicted in Figure 3, it becomes apparent that while a considerable number of EU member states have made substantial strides in augmenting their renewable generator capacities, the extent of this growth varies considerably among different regions. This observable incongruity becomes particularly evident when undertaking a comparative analysis of the renewable resource capacity possessed by each member state in the year 2004, compared against the capacities they have achieved by the year 2021.

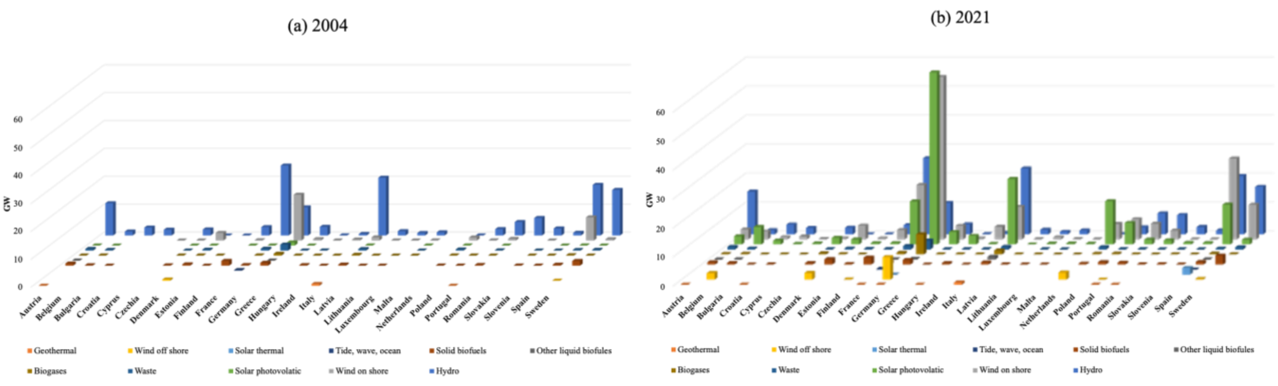
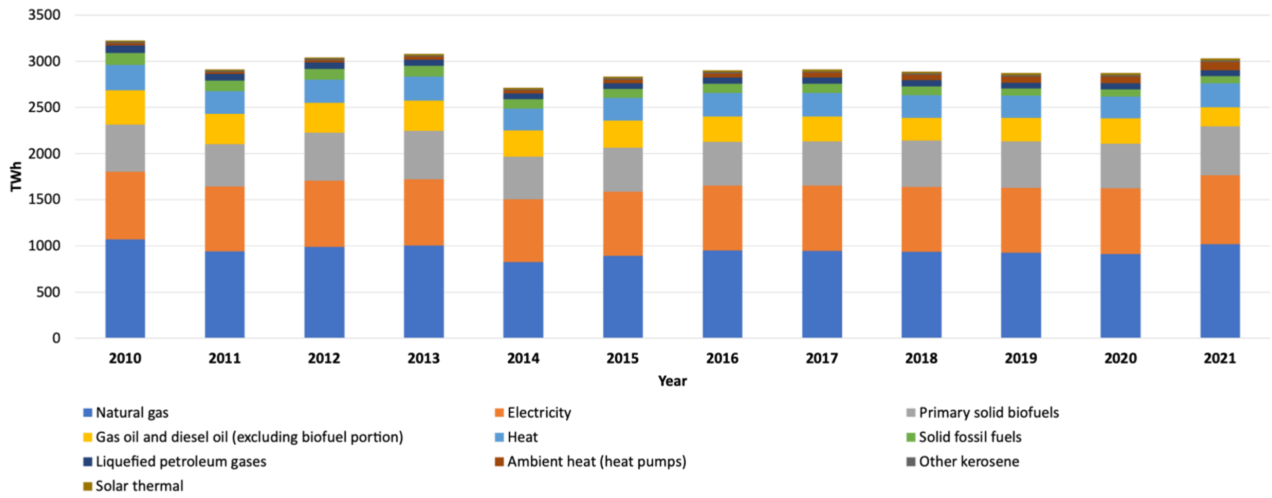


Figure 3. Renewable capacity from EU member states. (a) 2004; (b) 2021.

Nevertheless, it's important to note that the expansion of renewable generation is closely accompanied by the electrification of final consumption. This correlation is evident from the information depicted in Figure 4, which illustrates a notable uptick in final consumption attributed to the energy carrier electricity, marking a substantial increase of 20 TWh over the past decade [15].



[16]

Figure 4. Households' final consumption by type of fuel from 2010 to 2021.

The transportation sector is also experiencing significant transformations due to European climate policies, paralleling the trend of heightened electricity consumption. This transformation is primarily driven by the surge in EVs on the streets and amplified efforts towards environmentally friendly mobility. Nevertheless, as depicted in Figure 5, this sector remains in contention with combustion-powered vehicles, indicating that the transition to fully sustainable transportation still faces considerable challenges [16]. While there has been a noteworthy rise of 5 TWh in electric consumption for transportation within the last decade, the complete phase-out of conventional heat-powered vehicles still appears to be a distant objective from the perspective of European targets.

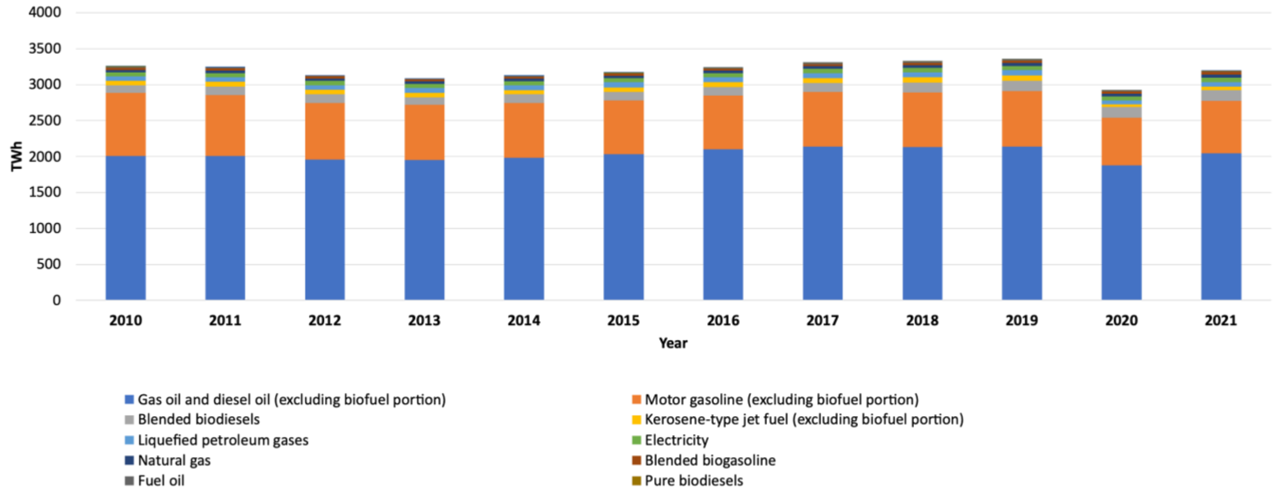


Figure 5. Transportation's final consumption by type of fuel from 2010 to 2021.

Another sector that has been subject to an increasing trend in final consumption is the industrial sector. Many European countries and industries have been working towards reducing their carbon footprint and transitioning to more sustainable energy sources, including electricity. This involves replacing traditional fossil fuel-based processes with electrified alternatives, which can include using electric furnaces, machinery, and equipment powered by RESs. Indeed, the increase of 50 TWh in industrial final consumption powered by renewable sources over the span of ten years, as depicted in Figure 6, is a promising and positive development. This trend reflects a significant shift towards a more sustainable and environmentally friendly industrial sector [17]. The adoption of RESs for industrial processes not only contributes to reducing carbon emissions and environmental impact but also signifies a commitment towards achieving the sustainability goals set by the EU and global climate initiatives. It's a clear indication of progress in the transition towards cleaner energy solutions and a more sustainable future for industries across Europe.

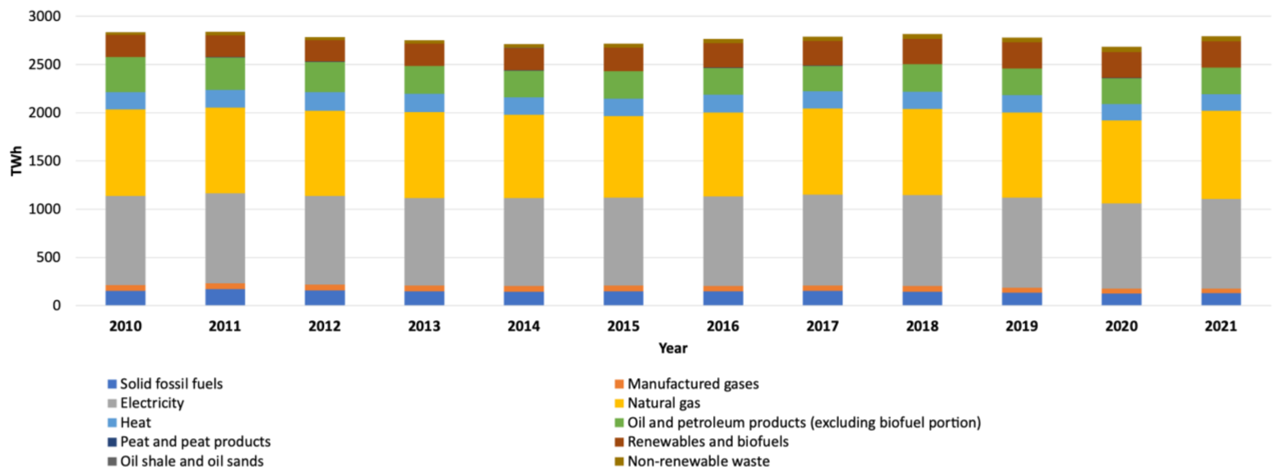


Figure 6. Industry's final consumption by type fuel of fuel from 2010 to 2021.

In light of this reality, ensuring the seamless integration of this substantial renewable generation into power system networks while upholding existing service quality and managing costs has become paramount. The adoption of an active and intelligent approach across multiple domains, including planning, operation, and energy transactions, is imperative. As the prevalence of renewables continues to surge, the electricity market finds itself in a state of transformation, necessitating adaptation to these dynamic shifts while preserving efficacy, accessibility, and environmental viability. This evolution, catalysed by the proliferation of renewable generators, has prompted the liberalisation of the electricity market, reshaped conventional norms and established a groundwork for a more competitive and ecologically conscious energy sector.

1.1.4 Implications for the Electric Power System

The energy transition has significant affected various aspects of the energy sector, including the transmission system and the distribution system. In addition, this transition has direct implications for the utilisation of electricity as an energy carrier, leading to significant effects on the decarbonisation efforts across various energy-intensive sectors. These sectors encompass heating and cooling, mobility and transportation, industrial activities, as well as residential and tertiary applications.

One of the repercussions has been on the adequacy of the system. Adequacy refers to the power system’s capacity to consistently meet electricity demand while maintaining safe operating conditions. The adequacy of the system is influenced by various uncertainties, including fluctuations in demand, unavailability of thermal power plants, uncertainties in non-programmable plants (like renewables), and network constraints. In the EU, adequacy is measured using the Loss of Load Expectation (LoLE), which indicates the number of hours in a year when load reduction might be necessary to ensure system security [18]. It is important to highlight that the adequacy is an assessment of what could happen; it is not a prediction of what will happen. In the last ten years, due to reduced thermal capacity, adverse climate conditions, and unavailability of foreign production capacity, the adequacy margin has declined. According to the ERAA assessment, adequacy risks are a widespread concern across Europe, impacting various countries and regions differently [19]. In 2025, Ireland is expected to face significant scarcity issues with a LoLE exceeding 24 hours per year, followed by Malta with 22 hours per year. Countries such as Germany, Italy, Spain, France, Belgium, Denmark, and Hungary experience LoLE values ranging from 6 to 11 hours per year. Finland and Southern Sweden also exceed national reliability standards, with LoLE values of 3.5 and 2 hours per year respectively. Moving into 2027, the adequacy situation remains stressed, particularly in Belgium, Germany, Denmark, and other countries. However, adequacy risks decrease in the remaining countries. Notably, Ireland sees an improvement in LoLE values, dropping below the national standard. By 2030, Germany and Luxembourg emerge with the highest LoLE values at 21.5 hours per year.

One of the most harmful impacts of this transition is the reduction of security. Security in the context of the power system refers to its capacity to withstand changes in working conditions, especially unexpected disturbances, without breaching safety limits. Fundamental parameters characterising a power system are frequency and voltage. While nominal voltage levels are classified as high, medium, and low, the EU maintains a fixed nominal frequency of 50 Hz. The role of the TSO, and of the DSO, is to ensure system stability and restore nominal condition post-fault or disturbance, thus preventing system blackouts. This is achieved through the regulation of active and reactive power as expressed by power system's equations. The security of the power system is not a novel topic, but several studies already investigated on the matter [20],[21].

Another effect of the transition, and in particular of the high penetration of RESs, is the introduction of challenges to the quality of services of the networks. Ensuring the quality of the electricity service is paramount as it guarantees a seamless supply of electricity within strict parameter limits [22]. This is of increasing importance in the context of evolving energy systems, particularly with the electrification of final energy needs. Industries, in particular, rely heavily on high-quality energy provision. Originally devised under a centralised network framework, fault clearing systems face vulnerabilities stemming from the presence of RESs. This susceptibility is particularly evident in scenarios of inverse power flow. In these situations, the energy flows from lower to higher voltages and subsequently back to lower voltages. The involvement of static generators inherent to PV, and wind turbine further complicates matters as they lack the capacity for short circuit power. As a result, faults induce voltage reductions that impact broader sections of the grid, ultimately contributing to a degradation in power quality.

The energy transition has also had profound implications for energy markets across Europe. It has ushered in a new era characterised by more choice and flexibility for consumers. With multiple electricity and gas companies now active in several Member States and numerous electricity suppliers in twenty Member States, even households and small businesses have an array of options to choose from [23]. The introduction of price comparison tools has empowered consumers to seek out better energy deals, leading to high switching rates in several Member States. Countries like Sweden, the UK, Ireland, Belgium, and the Czech Republic have experienced significant shifts in supplier choices, driven by insights into potential gains from such changes. Furthermore, the energy transition has fostered more competitive pricing. Market opening increased cross-border trade, and market integration, driven by EU legislation and rigorous enforcement of competition and State aid rules, have contributed to keeping energy prices in check. In parallel, the energy transition has facilitated more liquid and transparent wholesale markets [23]. The gradual improvement in liquidity and transparency in electricity markets has been driven by market coupling between Member States. Currently, 17 Member States are *coupled*, leading to increased cross-border trade and greater price convergence. Additionally, regulations such as the REMIT adopted in 2011 have further contributed to enhanced transparency. In the context of gas trading, there has been remarkable growth in gas trading platforms between 2003-2011. This growth has resulted in more active trading between gas companies. EU markets with liquid gas hubs have reaped the benefits of gas-to-gas competition, including exposure to global markets influenced by events outside the EU, such as the "*shale gas revolution*" in the United States (US) [24]. The contrast between the positive effects on wholesale gas prices in liquid and competitive markets within the EU, compared to less liquid and competitive markets, is particularly striking.

1.1.5 Future Trajectories of the Electric Power System

Addressing the complexity of secure network operations in a decarbonised environment requires a comprehensive strategy, guided by the objectives of EU directives. A first tool that from the foundation of the power system is of primary effectiveness is to invest on the renewal and efficiency of grid infrastructure. Additional tools, which Europe has highlighted as of primary importance for the development of a high renewable penetration environment, are markets. European policies are often driven by a market-based approach, due to its efficient ways to allocate resources, promote competition, drive innovation as well as align with the principles of consumer choice and empowerment. As a matter of fact, they provide consumers with the freedom to choose their energy sources, reduce energy consumption during peak hours, and even participate as active players in energy markets.

Infrastructural investments represent a pivotal tool at the disposal of grid operators to foster unhindered electricity trading across Europe while upholding power system security. In accordance with EU Regulation 2018/1999 [25], Member States are mandated to achieve a 2030 electricity interconnection target of at least 15%, signifying the correlation between transmission capacity and installed generation capacity within an area. While infrastructural expansion yields tangible benefits such as congestion alleviation, enhanced market zone coupling, and bolstered system resilience, it entails substantial costs and long-term recovery periods. Therefore, the assessment of alternatives must meticulously factor in cost-effectiveness of free-market operations, alongside the short and long-term territorial externalities stemming from infrastructural expansion.

In a RES-focused context with substantial initial investments and negligible marginal costs, the prevalence of electricity markets relying solely on energy-based remuneration can pose challenges. To address this, establishing consistent and foreseeable long-term price signals for both electricity producers and consumers becomes essential. Potential solutions could involve adopting capacity-based remuneration methods. These strategies aim at creating a more conducive environment for RES integration and sustainable energy development. Capacity markets play a crucial role in incentivizing the establishment of generation capacity through extended contractual agreements. These mechanisms prioritize the readiness to generate electricity, irrespective of actual production levels, offering an early incentive for the construction of power plants. By assuring system adequacy, capacity markets contribute to a dependable energy supply. Another beneficial tool is balancing capacity remuneration, which offers compensation for furnishing energy-intensive and power-intensive services within shorter to medium-term timeframes. By incorporating these instruments, the energy market becomes better equipped to align with the distinct attributes of RESs. This approach fosters stability, bolsters investor confidence, and fosters sustainable expansion within the evolving energy terrain [26].

In the European market-based scenario, one concept that has taken hold over the years is the concept of flexibility. Flexibility in a power system refers to its capacity to promptly adjust electricity generation, consumption, and distribution to accommodate fluctuations in supply and demand. It allows the grid to smoothly manage variations from renewable sources, demand changes, and unexpected events, ensuring stability and reliability. The EU has recognized the importance of flexibility and has outlined its significance [27]. As a matter of fact, EU wants to establish and foster flexibility markets, which enable the efficient trading of flexibility services to optimize grid operations, enhance integration of renewable sources, and enhance overall system resilience [28]. Flexibility emerges as a cost-efficient strategy to mitigate the variability and uncertainty arising from renewable energy sources and new loads. It may serve as an alternative to network reinforcement, potentially curbing or indefinitely delaying network investments [29]. Flexibility holds a crucial position in synchronizing the balance between electric energy supply and demand across various temporal scales. In everyday operations, it acts as a robust mechanism to counterbalance the inherent oscillations in both energy consumption and generation [28]. Conversely, traditional strategies solely focused on expanding the grid infrastructure would demand exorbitant investments to manage routine as well as emergency situations [30].

1.2 Research objectives

In this thesis, the research objectives are intricately woven into the fabric of advancing market mechanisms at various stages of the energy transition. The overarching goal is to steer energy systems towards sustainability, efficiency, and resilience, thereby paving the way for a decentralised, renewable-integrated, and digitally enabled future. The comprehensive framework proposed by this thesis introduces and studies the concept of market mechanisms across several critical facets of the energy transition, encompassing planning, operation, and local electricity markets.

The primary research framework revolves around three interconnected objectives, each aligned with specific milestones leading up to 2050:

1. *Roadmap to 2030 - Robust Optimisation Planning of a Multi Energy System*. The initial objective focuses on developing robust optimisation models and algorithms tailored for planning Multi Energy Systems (MES). These MES encompass various components, including electricity, natural gas, and district heating networks, all harmonised to optimise resource allocation, DR strategies, and resource flexibility operation. This stage highlights accommodating non-linearity and operational uncertainties, resulting in a resilient and cost-effective MES capable of seamlessly integrating a high share of renewables. The research delves into designing market mechanisms within the planning phase to ensure efficient resource allocation and flexibility.
2. *Roadmap to 2040 - Redispatching Markets for Renewable Integration*. Building upon the robust planning framework established earlier, the subsequent objective is to design and implement redispatching markets. These markets are pivotal in facilitating the integration of RESs while maintaining system stability. Market mechanisms come into play by enabling the flexible reallocation of energy resources in response to the inherent fluctuations of renewables, shifts in demand, and evolving network constraints. This phase highlights the importance of market design in enabling the smooth integration of renewables into the energy landscape.
3. *Roadmap to 2050 - Integration of Local Utility and Energy Markets through Blockchain Transactions*. The final research objective explores the concept of blockchain technology and its transformative potential in local utility and energy markets. By 2050, these markets are envisioned to be fully digitalised, driven by secure and transparent transactions among consumers, prosumers, and grid operators. Market mechanisms, in the form of blockchain-based smart contracts, facilitate peer-to-peer (P2P) energy trading and service exchanges. These mechanisms ensure that participants can seamlessly interact within the energy market while upholding system stability and reliability. This phase underscores the critical role of blockchain-based market mechanisms in shaping the future of local electricity markets.

By addressing these research objectives, this thesis endeavours to make significant contributions to the advancement of sustainable energy systems. It underlines the pivotal role of market mechanisms in diverse aspects of the energy transition, spanning from planning the distribution system within the framework of MESs to the operation of redispatch markets, flexibility markets, and blockchain-based energy trading within LEMs. Through this multifaceted approach, the research aims at providing valuable insights into designing robust optimisation models, enhancing renewable integration, and fostering secure, decentralised transactions in the dynamically evolving energy landscape.

2 Market Models for the Power System Planning in an Energy Transition Context

The global energy panorama is undergoing a profound transformation driven by the imperative of sustainability and the need to transition towards cleaner and more efficient energy systems. In this context, the planning and management of distribution networks (MV and LV networks) have emerged as critical elements in accommodating RESs, enhancing grid resilience, and optimising the integration of MES. This chapter delves into the pivotal role of market models in shaping the planning process of different elements of these networks during the energy transition. The chapter aims at: *i*) introducing the fundamental concepts of optimisation in the context of a planning process, *ii*) examining various optimisation approaches used in power system design, *iii*) highlighting the significance of optimisation in addressing challenges associated with renewable energy integration, load growth, and operational efficiency and finally *iv*) showcasing a real-world case study and application where optimisation models have been successfully deployed to enhance a planning processes of a LV network in a urban context.

2.1 Research questions

This paragraph frames the main research questions for this section of the thesis.

The research question "*How can non-linearity and operational uncertainty in modern system planning be effectively addressed?*" seeks to investigate innovative approaches to tackle the complexities arising from non-linear behaviours and uncertainties in the context of power system planning. This question delves into the challenges posed by the integration of RESs, demand variability, and dynamic operational conditions. The focus is to explore methodologies, techniques, and tools that can efficiently model and manage non-linear interactions and uncertainties to ensure reliable, resilient, and optimised system planning outcomes.

The research question "*How can robust optimisation techniques be applied to address the uncertainties and operational constraints in the integrated planning and scheduling of a smart city district?*" focuses on the application of robust optimisation methods to enhance the efficiency and resilience of integrated planning and scheduling in the context of a smart city district. In the case study section of this chapter, the analysis aims at exploring innovative strategies that can effectively handle uncertainties. By employing robust optimisation, the study seeks to develop approaches that ensure reliable and feasible plans and schedules for diverse urban services and systems, promoting the sustainable development and functioning of smart city districts.

The research question "*How can a holistic, multi-generation approach be implemented to integrate electricity and natural gas networks in urban districts considering the uncertainties of renewable resources?*" investigates the development of a comprehensive framework for seamlessly integrating and optimising electricity and natural gas networks within urban areas. The case study designs a strategy that synergistically exploit these interconnected energy systems, enhancing overall efficiency, resilience, and sustainability while accounting for the inherent challenges posed by renewable resource fluctuations. By adopting a holistic, multi-generation approach, the research endeavours to provide practical solutions for urban energy planning and management, fostering a more integrated and sustainable energy landscape.

The research question "*How does the integration of resource flexibility impact the overall system performance and resilience in the urban district?*" investigates the effects of integrating resource flexibility on the overall performance and resilience of an urban district energy system. It seeks to understand how the incorporation of flexibility mechanisms, such as DR actions, energy storage, and smart control strategies, influences the system ability to efficiently manage energy supply and demand, respond to uncertainties, and maintain stable operations. By examining various scenarios and strategies, this research question aims at providing insights into how resource flexibility enhances the energy system reliability, stability, and adaptability in the context of urban districts, contributing to improved sustainability and resilience.

2.2 Distribution Network and Smart City Planning in the Energy Transition

The energy transition demands a re-evaluation of distribution planning and related urban areas. They are traditionally designed around centralised generation and one-way power flow. The integration of RESs, such as solar and wind, introduces variability and uncertainty. Furthermore, the emergence of MES, combining electricity, natural gas, and other carriers, adds complexity to grid operation. This section underscores the significance of distribution network planning in adapting to these changes and introduces the research questions and objectives guiding our exploration.

2.2.1 Traditional Planning

The problem of planning networks and urban areas has always consisted of finding the optimal topology from both a technical and economic perspective, determining the most cost-effective cross-sections for network branches, and establishing the optimal configuration. Traditionally, planning and managing such networks involved complex and diverse issues. For instance, the connection of future nodes to an existing network, or even the optimal configuration for the tree-structured network, identifying where the existing meshed network must be segmented. However, for the planner, the dynamic evolution of the system must be taken into account since this evolution can manifest as the connection of new user nodes or changes in the load demanded by those already powered. All of this can necessitate the commissioning of a new primary substation to serve a certain area alongside the existing ones. Therefore, it becomes crucial to determine the optimal location for constructing this substation, choosing from a given number of possible sites.

To handle this complexity, the experience of the planner is not sufficient to simultaneously identify a configuration that is techno-economically optimal. Therefore, the use of optimisation methods oriented towards the technical-economic optimal allocation of resources is of utmost importance [31].

Distribution networks are usually managed with a tree-like configuration, consisting essentially of one or more primary substations from which the feeders and their respective branches depart. This structure is chosen primarily because it offers significant cost savings, ease of installation, and extreme operational simplicity. However, such a structure has evident disadvantages, for instance it does not meet the requirement for flexibility, meaning it is not easily adaptable to expansions and load increases. Moreover, it is characterised by poor service quality because in the event of a fault at one point in the network, a significant number of loads are affected. To overcome these drawbacks, the objective of planning optimisation is precisely to search for a radial structure that is valid both technically and economically and to identify the most cost-effective way to introduce counter-feed sides into it to achieve a predetermined level of service quality.

One key element of planning is the economic model. In the past, this consisted of a network cost model. This could include aspects such as the allocation of primary and secondary substations, study period duration, line construction and maintenance costs, inflation rates, interest rates, etc. In general, the objective function should encompass capital costs for facility construction and network management, and maintenance costs [30].

If we were to define a scenario in which we want to minimise the cost of constructing new facilities in a distribution network, the objective cost function could be generally defined as in Equation (1).

$$C = \sum_{i=1}^{N_{element}} C_i \tag{1}$$

Where the generic cost will be given by the sum of the various elements to be considered in the optimisation. An example is the construction of new branches, in which the cost can consist of construction costs, residual costs, operating costs, loss costs, and service quality costs. In any case, whatever the subdivision of the final cost, all these costs must be discounted. The need to discount in planning approaches is rooted in the time value of money and the principle that a sum of money today can worth more than the same sum of money in the future. To do this, the discount factor is adopted. This factor depends on two main coefficients, the interest rate and the inflation rate. Considering these two coefficients, we can define the cost discount factor as in Equation (2).

$$a = \frac{1+v}{1+i} \tag{2}$$

Where v represents the inflation rate and i the interest rate. To make accurate assessment about the asset value, the residual value must be introduced. It takes into account the fact that the period of study may not align with the entire operational lifetime of components. Therefore, we need to represent the estimated worth of an asset at the end of its useful life or study period. To represent this value, we can adopt the formula in Equation (3).

$$R_0 = C \cdot \left(1 - \frac{N-n}{N_{life}}\right) \cdot a^N \tag{3}$$

Where R_0 represents the residual value, C the cost for component, a is the discount factor, N is the period of study, N_{life} is the lifetime of the component and finally n is the period in which the component has been installed.

In a planning process, constraints play a fundamental role, especially in the context of the energy sector. Planners must consider and address various constraints that can impact the design and operation of distribution networks. The first important group of constraints are the reliability constraints. The reliability constraint is taken as the expectation of loss of power after failure occurs. This concept also aligns with the term *quality of service*. Indeed, this corresponds to the compliance of voltage and frequency with nominal values and the continuity of energy supply. The economic damage caused by the service disruption is assessed through the *cost of energy not provided*. This economic parameter is calculated based on the expenses that individual users have to bear due to imperfect service. These expenses are divided into short-term and long-term expenses. Therefore, the constraints aim at minimising the costs resulting from service disruptions. Another type of constraint is related to radial conditions. This constraint specifies that during the development and planning of the network, it must adhere to a tree-like structure in which energy flows from a point of supply to various endpoints of use, which can be substations or even homes and industrial facilities. The last type of constraints that need to be included in a planning study are technical constraints related to power balance at each node, the cross-sectional area of conductors, which must be chosen so that the current does not exceed the thermal capacity of the material, and finally, constraints related to voltage drops at nodes, which must be within upper and lower boundaries.

The problem of optimal planning for a distribution network can be approached in different ways. One example is to analyse all possible network configurations and then choose the one that guarantees the optimum of the objective function. However, this combinatorial analysis would involve computational burdens in terms of processing time and memory usage that are not acceptable. The more reasonable approach is that of heuristic methods. These methods limit the search to configurations that, based on certain criteria, are judged in advance as the most promising, leading to a solution that, while not representing the global optimum, provides sufficient assurance of not being very far from the best solution. This solution, called suboptimal, offers a middle ground between the global optimum and solution computation.

These steps used in the past, but still today, represent the fundamental points for defining a planning study. Traditionally, these steps employed deterministic analyses that predicted certain, fixed data over certain time intervals. The traditional approach has long been a deterministic planning strategy, where networks are meticulously designed based on worst-case scenarios involving loading conditions, voltage drops, and security constraints. In this approach, all uncertainties are brushed aside, and lines, switches, and substations are sized without consideration for potential variations. It hinges on the belief that comprehensive network oversizing at the planning stage can pre-emptively address all operational challenges, reducing operational actions to a minimum, reserved only for unforeseen events. However, in modern era, characterised by the proliferation of distributed generation, the old-fashioned worst-case scenario methodology no longer holds up. This traditional approach risks leading planners down a path of unreasonable and exorbitant network upgrades. The massive investments required to accommodate this oversizing approach can stifle the proliferation of distributed generation assets and unconventional loads. Modern planning embraces uncertainty as an inherent part of the equation and seeks to optimise network design for real-world scenarios, not just the worst-case possibilities [32].

2.2.2 3D-based Paradigm Planning

The planning process has traditionally revolved around optimising various aspects of the network, including the location of substations, feeders, and the configuration of transformers. The conventional approach aimed at designing systems capable of addressing all operational challenges during the planning phase, following a *fit and forget* policy. This strategy sought to minimise the reliance on operational systems. However, since 1998, the electric power distribution landscape has undergone significant transformations, driven by factors such as liberalisation, unbundling, and the integration of diverse generation resources [33]. These changes have introduced complexity and uncertainty into planning and operations. Consequently, there has been a departure from the fit and forget approach. The increasing adoption of RESs presents distribution system operators (DSOs) with the challenge of integrating these new generation sources efficiently while maintaining service quality. The traditional fit and forget policy, often requiring substantial capital expenditures, is no longer deemed suitable for modern distribution networks. Emerging approaches are reshaping this landscape. The new paradigm emphasizes maximising the exploitation of existing assets and infrastructure, allowing them to operate closer to their physical limits. By adopting these solutions to address operational challenges, it becomes possible to increase the hosting capacity for RESs with fewer network investments. Effective distribution planning now necessitates the integration of enabling technologies to support RES exploitation. The Distribution Management System (DMS) plays a pivotal role in active network operation. Additionally, incorporating meteorological models to account for fluctuating renewable generation and local weather conditions, which impact Information and Communication Technology (ICT) wireless communication networks, has become essential. Therefore, modern distribution planning must cope with a range of factors, including Supervisory Control and Data Acquisition (SCADA) systems, databases, communication technology, and automation facilities. This evolving paradigm demands a transition toward more decentralised and digitally driven planning approaches.

2.2.2.1 The Importance of Renewable Sources in the Planning Process

Renewable sources play a pivotal role in modern network planning. These resources encompass various technologies like PV, wind, energy storage systems (ESS), and more. When strategically integrated into the network, RESs can offer a spectrum of challenges and solutions that are vital for the sustainable and efficient operation of the system. Distribution planners tackle RESs from two primary perspectives, each offering unique insights into their role in network planning [34]:

1. *Challenges for the System*. On the one hand, RESs pose challenges to the system. This perspective acknowledges that these resources, especially intermittent ones, can introduce variability and unpredictability into the network. RESs depend on non-dispatchable energy sources, leading to variable and sometimes unreliable outputs. For instance, the power generated by solar panels fluctuates with sunlight availability, and wind turbines depend on wind speeds. These variations can disrupt the stability and reliability of the system, raising concerns for the system operators.
2. *Alleviation of Grid Constraints*. On the other hand, RESs are seen as valuable resources that can help alleviate grid constraints. This perspective envisions RESs as dynamic assets that, if strategically integrated and managed, can actively contribute to grid stability and efficiency. Instead of merely accommodating RESs, planners consider ways to harness their potential to reduce congestion in the network and minimise the need for extensive infrastructure interventions.

To effectively accommodate RESs in distribution planning, several critical factors must be considered. The first one is the *voltage control*. Voltage levels often serve as limiting factors when integrating RESs. Flexibility in voltage control through devices like regulators or capacitors is essential to expand the capacity of RESs. Another factor is the *feeder configurations*. The configuration of distribution feeders plays a pivotal role in determining how effectively RESs can be accommodated. Utilities that employ reconfiguration schemes must assess alternative configurations to ensure that RESs can be seamlessly integrated. This evaluation is similar to how load considerations are traditionally addressed in planning. The last factor to be account is the *characteristics of renewable technologies*. The specific characteristics of renewable technologies should be thoroughly understood. Intermittent RESs such as solar and wind interact with the grid differently than dispatchable resources like ESSs. The inherent variability and unpredictability of intermittent RESs necessitate specialised planning approaches to ensure grid stability [35].

While integrating RESs presents unique economic and environmental opportunities, it also introduces complexity into the distribution planning process. RESs exhibit inherent variability, which can be challenging to predict accurately. Their availability may not always align with grid needs, leading to a need for alternative solutions. Dispatchable resources, like ESSs, offer the advantage of enhancing system reliability by providing a more consistent output. However, it is crucial to consider the limitations associated with energy storage capacity. The integration of RESs requires distribution planners to strike a delicate balance between harnessing the benefits of renewable energy and mitigating the challenges they introduce. This balance involves optimising the use of RESs to minimise grid constraints while ensuring the overall reliability and stability of the distribution system.

RESs can offer both challenges and solutions, and planners must adopt a dual perspective to make informed decisions. By carefully accommodating and strategically integrating RESs, distribution networks can harness the economic and environmental advantages of renewable energy while ensuring the reliability and resilience of the grid in an evolving energy landscape.

2.2.2.2 Challenges of the Energy Transition

The energy scene is undergoing an intense revolution, characterised by a shift towards sustainability, decarbonisation, and greater reliance on RESs, which indeed leads to decentralisation of sources and digitalisation of the energy system. This monumental transition is reshaping the way we generate, distribute, and consume energy. Among this transformation, distribution and urban network planning emerges as a fundamental piece of the puzzle, tasked with ensuring that the electricity grid remains resilient, efficient, and capable of accommodating the evolving energy ecosystem. The energy transition brings forth multitude complexities and considerations that planners must face.

As the energy landscape undergoes a monumental shift towards sustainability, one of the foremost challenges that utilities and operators face is balancing the intermittent nature of RESs with the consistent demand for electricity. While RESs, like solar and wind, hold great promise for a cleaner, greener future, their inherent variability presents a unique set of planning challenges. In this context, the concept of flexibility markets, an innovative and crucial mechanism for optimising the supply and demand of energy, has been introduced.

This transformative shift in the energy distribution sector is driven by the surge in decentralised energy resources and by the Electricity Directive 2019/944 of the EU Clean Energy Package [27]. This transition firmly places distribution grid users and DSOs at the epicentre of the evolving European energy system. The significance of this transformation is underscored by several compelling reasons: *i*) connecting new grid users, *ii*) integration of new grid users, *iii*) grid congestion challenges and *iv*) EV revolution. The first one sees DSOs grappling with a formidable challenge, which means connecting the ever-expanding population of new grid users to their networks. This surge in demand has triggered an urgent need for substantial grid investments and effective congestion management strategies to ensure the smooth flow of energy. The second reason involves the integration of new grid users which encompasses a diverse range of technologies, including EV charging infrastructure, heat pumps, PV units, and wind turbines. For DSOs, engaging these new users offers a significant opportunity to enhance network management, effectively mitigate congestion, and optimise their operations. The third reason can be seen as a consequence of the others. As the transition unfolds across Europe, DSOs are increasingly encountering grid congestion, a multifaceted issue that requires strategic management. Grid congestion challenges first emerged in countries like Germany, where injection peaks from wind and solar farms led to situations with excess generation, causing congestion in local lines and transformers [36]. This challenge subsequently spread to countries like Netherlands, where congestion resulted from generation peaks driven by renewables and load surges from new data centres. Finally, the latter reason is poised to be the next significant wave of grid congestion. Leading countries in EV adoption, such as Norway, have already grappled with distribution grid congestion due to EV charging [37]. The United Kingdom is also witnessing congestion in distribution grids, attributed to the surge in EVs or the intermittent nature of renewable generation, depending on the specific region. To effectively address and communicate congestion challenges, DSOs often rely on tools like heatmaps or hosting capacity maps [38]. These visual aids provide critical insights into the network capacity status across different areas. While congestion challenges have acquired significant attention in some regions, many parts of Europe have yet to fully address this issue. However, the experiences of countries dealing with congestion underscore the potential for these challenges to emerge rapidly, often catching DSOs unprepared. The rapid pace of decision-making by grid users, as they invest in renewable generation, establish new data centres, or embrace EVs, frequently outpaces the traditional grid expansion planning and execution processes. Although congestion is a well-recognised issue in transmission grids, its emergence at the distribution level presents unique complexities. One of the most prominent challenges is incorporating network constraints into market pricing algorithms, a task that is inherently more intricate at the distribution level [39]. In light of these multifaceted challenges, the concept of flexibility markets emerges as a pivotal solution for future distribution planning approaches. Flexibility markets provide mechanisms for grid users to trade and balance their energy needs efficiently, offering a path to alleviate congestion and optimise grid operations.

Embracing flexibility markets in the face of evolving congestion challenges can pave the way for a more adaptable and responsive energy ecosystem.

One of the significant aspects of the energy transition is the concept of sector coupling, which aims at seamlessly integrating various energy sectors such as electricity, heat, and transportation. This paradigm shift presents DSOs with complex challenges. These challenges emerge from the integration of innovative loads, including EV charging infrastructure and heat pumps, alongside the incorporation of distributed resources such as PV units and wind turbines. To address these complexities, DSOs are required to engage in extensive planning and the reinforcement of energy systems. However, traditional methodologies, like the substitution of power cables, are no longer sufficient to meet these evolving demands. In response to this challenge, the energy sector is actively exploring innovative technologies as potential solutions. These technologies encompass a range of options, including coupling elements. Among these coupling elements, power-to-gas units (P2G) and combined heat and power units (CHP) have garnered significant attention [40]. These elements are being examined as alternatives to conventional network expansion and are recognised as indispensable components in the transition toward more sustainable energy systems that align with climate targets [41]. The central objective in the planning of energy networks is to furnish end consumers with energy solutions that are not only cost-effective but also technically reliable and environmentally friendly. A pivotal economic consideration throughout this process is the minimisation of both investment and operating costs. To achieve this, the integration of power and gas network planning with coupling element technologies has been proposed as a prominent solution. This integrated approach broadens the spectrum of optimisation solutions, potentially leading to more cost-effective outcomes. Furthermore, it offers the advantage of avoiding the creation of redundant parallel infrastructures and takes into account the intricate interactions between different energy networks. Various approaches have been developed for the integrated planning of power and gas networks, with a predominant focus on the employment of CHP units [42].

Finally, one of the most known and recognised challenge of the energy transition is the uncertainty associated with RESs. Several uncertainties and rapid variations mark the electrical distribution system due to the increasing penetration of RESs. In this scenario, two actions are explored in the literature as a solution: *i*) a probabilistic network calculation (i.e., probabilistic load flow calculation) to represent the typical planning data and the existing correlations (among loads, among generators, and between loads and generators), and *ii*) the use of the risk concept in choosing the best planning alternatives [43]. The several uncertainties that mark the power system suggest using probabilistic models to represent the typical planning data and the concept of risk in the choice of the planning alternatives. In the sources of uncertainty, renewable generations and loads are the main components that exhibit random variations in their behaviours. Suitable probability distribution functions can modulate these uncertainties if probabilistic data as input variables are available. Depending on the stochastic distributions assumed (i.e., Gaussian, Beta, Rayleigh, etc.), network calculation can be performed by specific probabilistic load flow (PLF) algorithms or the more general Monte Carlo (MC) simulation approach. On the other hand, the planner can resort to robust optimisation techniques when the probabilistic data are unknown [30].

2.3 Uncertainties in the Network Planning Process

Distribution systems are witnessing a huge penetration of distributed generations. These resources encompass renewable and non-renewable energy sources, for instance ESSs, plugged-in EVs, and micro-CHP plants. They are strategically located within or in close proximity to the electricity consumers, driven by government incentives and the goal of reducing GHG emissions [44]. This penetration introduces bidirectional power flows, voltage fluctuations, fault level complexities, lower power losses, and operational uncertainties due to intermittent RESs, load variability, demand growth, and fluctuating electricity market prices. These factors demand new planning approaches beyond traditional unidirectional power flow paradigms. Conventional planning methods aimed at minimising investment and operational costs, however, the shift to bidirectional power flows, coupled with operational uncertainties, requires introducing new objectives and variables, like load growth, uncertainties in generation and forecast, or even in the price of the wholesale markets [45]. Effective uncertainty management is crucial to optimally integrate distributed generations. The planning models must consider the whole picture, so conservative assumptions that lead to unnecessary expenditure are no longer possible. A key factor in this framework is uncertainty and its representation. Uncertainty modelling techniques play a pivotal role in network planning. Several methodologies exist, including probabilistic, stochastic optimisation, robust optimisation (RO), possibilistic, hybrid probabilistic–possibilistic, and information gap decision theory [46]. However, selecting the appropriate technique depends on the specific planning problem and the nature of uncertain input variables. In the following, the chapter is going to delve into the multifaced scenario of uncertainties associated with distribution and urban network planning.

2.3.1 Uncertainties associated with the Energy Transition

The energy transition, marked by the penetration of RESs and the adoption of advanced technologies, presents a panorama filled with both promise and perplexity. As distribution utilities step into this new era, they encounter a host of uncertainties stemming from the deployment of novel technologies and resources [35]. One of the fundamental aspects of the energy transition is the explicit consideration of various uncertain input parameters. These uncertainties are multifaceted, with many stemming from the temporal variability and randomness associated with emerging technologies and resources. Broadly, these uncertainties can be classified into two main groups: *i*) technical and *ii*) economic uncertainties [47].

The technical uncertainties encompass several factors. The first one is the *intermittent generation from renewables*. RESs like wind and PV panels are central to the transition. However, their intermittency poses a substantial technical challenge. The variability in wind speeds and sunlight availability makes predicting renewable generation outputs inherently uncertain. Another factor is the *load demand*. As consumption patterns evolve and energy efficiency measures advance, predicting future load demand becomes a complex task. Shifting trends in consumer behavior, electrification of sectors like transportation, and the adoption of distributed resources introduce uncertainties into load forecasting [48]. One modern uncertainty is the rapid growth of *electric vehicle* and their integration. The proliferation of EVs is a key component of the energy transition. Yet, uncertainties surround the adoption rate and charging patterns of EVs, making it challenging to predict their impact on the grid accurately [49]. The last factor is the *generator or line outages*. The reliability of the grid is contingent on the health of its components. The potential for generator and distribution line outages due to unforeseen events, such as extreme weather events or equipment failures, introduces unpredictability into grid operations [50].

On the other hand, the economic uncertainties embrace aspect more abstract. The first factor to be cited is the *fuel supply*. For traditional power generation, the availability and cost of fuel sources like coal, natural gas, or uranium are pivotal economic factors. However, the energy transition seeks to reduce reliance on fossil fuels, which introduces uncertainty about future fuel supply dynamics. Moreover, the EU goal of reducing the dependency on fuel from Russia, increase the fuel supply uncertainty. This inevitably led to market volatility. As a matter of fact, energy markets are subject to price fluctuations and volatility due to various factors, including geopolitical events, supply and demand dynamics, and market speculation. High dependence on a single supplier can expose the EU to price shocks and uncertainty regarding the cost of energy imports [51]. Another economical uncertain factor is the *cost of production*. The economics of energy production are evolving. The cost of renewable energy technologies has been decreasing, but the future trajectory is uncertain. Furthermore, the costs associated with integrating these technologies into the grid introduce additional economic uncertainties [52]. As known the *electricity market prices* are one of the most important uncertain factors. Several examples are reported in the literature, not only during the Ukrainian war, but also because of Covid pandemic [53]. The transition to a cleaner energy mix can affect electricity market dynamics. Fluctuations in market prices due to supply and demand shifts, regulatory changes, and the entry of new market players introduce uncertainty into revenue streams for energy producers. Lastly, the *economic growth* can add uncertainty in the energy transition. Broader economic conditions, including economic growth and employment rates, can influence energy consumption patterns and investment decisions. These macroeconomic factors introduce a layer of unpredictability into energy demand projections. Moreover, the economic growth leads to variation of the inflation rate. The purchasing power of currencies can erode over time due to inflation. This can affect the cost of energy infrastructure projects and long-term financing, adding another layer of economic uncertainty.

The energy transition is a journey toward a sustainable and resilient energy future. However, this path is full of uncertainties, especially concerning the adoption and integration of new technologies and resources. To navigate this evolving landscape successfully, stakeholders and system operators must embrace uncertainties.

2.3.2 Strategies for Uncertainty Mitigation in the Planning Process

One of the central challenges in network planning is addressing uncertainties associated with factors such as renewable energy generation, load demand, and equipment reliability. Traditionally, network planning has adopted deterministic analyses with good results, but as mentioned before, nowadays this approach fails to deal with the many uncertainties that plague an electricity system planning. In order to handle the uncertainties, it is necessary to change the deterministic analyses into more robust ones. The term robust is intended precisely to indicate the fact that the analysis is robust to variations in parameters, which means that the result will still be valid even if the parameters deviate, within a certain limit, from those expected. These analyses must therefore consider probability distributions, and probabilities of occurrence of events that might not happen except in very rare events or consider events that were not considered in previous deterministic analyses.

The deterministic approach, historically prevalent in network planning, relies on a fixed set of input parameters and assumptions. This method assumes that the future will unfold exactly as anticipated based on these fixed parameters. For instance, planners might consider a specific level of renewable energy generation, load demand, and equipment reliability throughout the planning horizon. The deterministic approach provides simplicity and ease of computation, making it a commonly used method. However, it carries inherent risks. If the assumptions are overly optimistic, it may lead to underinvestment in the network, resulting in reliability issues. Conversely, overly pessimistic assumptions can lead to overinvestment and increased costs for utilities and consumers [30]. To overcome this issue, sensitivity analysis has been introduced. This analysis is a tool used within the planning process to evaluate how variations in input parameters affect planning outcomes. The deterministic sensitivity analysis is commonly used to evaluate the sensitivity of cost-effectiveness models to individual parameters or sets of parameters. However, traditional sensitivity analysis methods have several limitations, including arbitrary parameter ranges, the inability to account for non-linearities, neglecting parameter correlations, and reporting results in the incremental cost-effectiveness ratio, which can lead to biased estimates [54].

In contrast, robust approaches consider a range of possible scenarios or probabilistic distributions for input parameters. Rather than relying on a single fixed value, robust planning considers a spectrum of possibilities, explicitly addressing uncertainties.

Robust planning may employ probability distributions and assigns probabilities to different scenarios, allowing planners to quantify the likelihood of various outcomes. The primary goal of robust planning is to minimise risk and ensure the performance of the distribution network under various conditions. It seeks solutions that are not overly sensitive to uncertain factors, thereby reducing the likelihood of underinvestment or overinvestment. These approaches that consider the risk associated with a given outcome are called risk-oriented planning procedures. The risk-oriented procedure makes it possible to assess the risk violation of technical constraints associated with a specific network planning configuration. In order to perform a risk assessment procedure, it is required to implement a probabilistic simulation study. Therefore, each node behaviour of the network has to be represented according to time-series profiles. Hence, the risk-oriented methodology is performed exploiting a probabilistic load flow for each timestep of the days to accomplish the risk assessment procedure. In addition, in order to account for all the network conditions, an N-1 analysis must be performed, to understand all the network operating conditions (i.e., normal operating conditions and the emergency configurations obtained by removing one network element at a time according to the N-1 analysis) [55]. The combination of probabilistic modelling and risk assessment to evaluate the likelihood of technical constraint violations in different network configurations and hours is one robust planning solution.

Other robust approaches want to include in the probabilistic modelling the active management of distributed resources as strategies to mitigate these risks and improve overall network performance.

However, probabilistic modelling is not the only one that exists. There are other solutions such as the stochastic optimisation. This optimisation involves using representative scenarios that have specific probabilities to account for uncertainties. This approach is particularly useful when it is challenging to model uncertain parameters using probability distribution functions. On the other hand, the robust optimisation represents uncertain input parameters using parametric bounds. Instead of relying on historical data, it focuses on establishing parameter ranges within which the optimisation solution should perform well. This method aims at creating solutions that are robust across a range of uncertain conditions. Finally, the information gap decision theory techniques handle uncertainties by evaluating the disparities between uncertain input parameters and their approximations. It quantifies the difference between the operating point considered most feasible by the decision maker and the actual, but unknown, operating point [56].

In summary, deterministic planning relies on fixed assumptions and may lead to suboptimal or risky outcomes, in contrast, robust planning explicitly considers uncertainties, offering a more flexible and resilient set of solutions that can perform well under a variety of conditions.

As the energy landscape continues to evolve, understanding and implementing robust planning methods will be essential for ensuring the reliability and efficiency of distribution networks in the face of uncertainty.

2.3.3 Robust Planning Approaches

In this section, an explanation of the robust approaches is proposed. The description is going to consider four methodologies: *i*) probabilistic approach which consider the MC numerical technique, *ii*) stochastic approach, *iii*) robust approach and *iv*) information gap theory approach. However, an extensive explanation of the probabilistic, stochastic and information gap decision theory is outside the scope of this document, but a detailed description is available in the references of the specific section.

2.3.3.1 Probabilistic Techniques

A probabilistic approach is a common way to deal with uncertainty, which aims at estimating the statistical parameters of the relevant variables. To perform the probabilistic optimisation, probability distribution functions (PDFs) of the input parameters need to be estimated from the respective historical data of uncertain parameters. A PDF is a mathematical concept used to characterise the likelihood of continuous random variables taking on specific values or falling within certain ranges. It provides a quantitative framework for dealing with uncertainty, making it invaluable in power system analysis. PDFs essentially map out the probability distribution of a random variable. They describe the probability of this variable assuming particular values or lying within particular intervals. Different types of PDFs, such as normal, uniform, exponential, and log-normal distributions, are employed based on the nature and characteristics of the variable under consideration [57]. The adoption of PDFs in power system analysis is multifaceted and extends across various domains, like renewable generation [58], or load demand forecast [59], but also uncertainty analysis and risk assessment [30]. To estimate the PDFs, MC simulation is widely adopted, generating samples in either a sequential or non-sequential way according to the problem formulation, allowing to estimate the PDFs of uncertain parameters. For doing so various sampling techniques, including Latin hypercube sampling [60] and Markov chains [61], can be employed. There exist different MC techniques, like sequential MC, also known as the particle method. This method determines the posterior distribution and is used to evaluate distribution system reliability and assess intermittent renewable generators and variable demand [62], [63]. Another technique is the pseudo-sequential MC. This method involves non-sequential sampling of system states followed by sequential simulation of sub-sequences related to failure states. It has been adopted to assesses the reliability of smart distribution networks and the impact of high PV unit penetration on nodal reliability, system energy, and reserve deployment [64], [65]. Finally, it is worth mentioning the non-sequential MC. This methos has been used to determine the well-being of composite systems and optimise the dispatch of conventional power plants and wind turbines to minimise GHG emissions [66], [67].

2.3.3.2 Stochastic Optimisation Approaches

Stochastic optimisation exploits representative scenarios with specific probabilities to account for uncertainties. These techniques are particularly valuable when modelling uncertain parameters is challenging using PDFs [68]. The quality of solutions obtained through stochastic optimisation depends on the number and suitability of scenarios. While a higher number of scenarios can yield better planning solutions, it can also lead to computational inefficiency. Therefore, it is crucial to effectively select and reduce the number of representative scenarios using techniques like backward and forward scenario reduction [69], interval linear programming [70], Taguchi orthogonal testing array [71], and clustering methods based on normalisation [72]. In certain cases, when sufficient historical data is available, clustering techniques can be employed to group closely matched scenarios into clusters representing typical operational states. The k-means clustering technique is a common choice for this purpose [73]. These scenarios are then used as input data for investment planning problems [74]. A characteristic scenario is chosen from each cluster, with its weight proportional to the number of operational states in that cluster.

2.3.3.3 Robust Optimisation Approaches

RO is a valuable methodology for addressing optimisation problems when there is uncertainty in the data. It operates within a predefined set of uncertain parameters and aims at finding the best solution that remains feasible under any possible realisation of this uncertainty. The problem addressed by robust optimisation is often referred to as the *robust counterpart optimisation problem*. One of the key advantages of robust optimisation is that it enables the analysis of problems under uncertainty without requiring specific information about probability distributions. In contrast to the min-max optimisation approach, which seeks solutions that perform well in the worst-case scenarios, robust optimisation offers greater flexibility in controlling solution quality. Additionally, when compared to other techniques like multiple stage stochastic programming and parametric optimisation, robust optimisation has a notable advantage. It does not suffer from exponential increases in computational complexity as the number of uncertain parameters grows. This makes RO a practical and efficient choice for addressing optimisation problems in the presence of data uncertainty [75]. In the end, the robust optimisation has been developed to overcome the drawbacks of identifying the PDF of an uncertain variable. Hence, it seeks to find the optimal solution with acceptable performance under most realisations of the uncertain inputs and does not need distribution assumptions on uncertain parameters. The robust optimisation assumes that the uncertainties lie in an uncertainty set. A RO solution is defined as the solution that satisfies all possible values of the constraints of the uncertainty set. A general robust formulation is reported in Equation (4), considering a linear programming problem.

$$
\begin{aligned}
& min\{C' \cdot x\} \\
& \text{Subject to: } \max_{\eta \in \mathbb{U}} \{A(\eta) \cdot x - b(\eta_0)\} \\
& l \leq x \leq u \\
& x \in \mathbb{R}^n; \quad \forall \eta \in \mathbb{U} \subseteq \mathbb{V}
\end{aligned}
\tag{4}
$$

Where x is the vector of decision variables, A is the constraint matrix and b is the right-hand side vector. η is a random variable, $\mathbb{V}$ is the whole uncertainty set and finally $\mathbb{U}$ is the subset of $\mathbb{V}$ used for the optimisation. The quality level of the result in the presence of uncertainty depends on the dimension of $\mathbb{U}$, which means that the desired protection level against uncertainty depends on the extent of $\mathbb{U}$ covered by $\mathbb{V}$. For instance, the worst-case scenario would require the robust optimisation to consider simultaneously all possible variations of the input data and, accordingly, $\mathbb{V} \equiv \mathbb{U}$. However, this option is generally over-conservative, because it also considers combinations of parameter values that are extremely rare to happen. Therefore, if a minimum risk is acceptable, a subset of $\mathbb{U}$ can be used.

The generic uncertain coefficient $\tilde{a}_{ij}$ of matrix A is modelled as a symmetric and bounded random variable that varies in the interval $[a_{ij} - \hat{a}_{ij}; \quad a_{ij} + \hat{a}_{ij}]$, where a_{ij} is the nominal value of $\tilde{a}_{ij}$ and $\hat{a}_{ij}$ is the extreme deviation from the nominal value. The hypothesis of modelling uncertainty with symmetric and bounded random variables is necessary to preserve the convexity of $\mathbb{V}$ [76]. Associated to the uncertain coefficient $\tilde{a}_{ij}$, it is defined the random variable $\eta_{ij} = \left(\tilde{a}_{ij} - a_{ij}\right)/\hat{a}_{ij}$, which follows an unknown, but symmetric, distribution and takes values in $[-1; \quad 1]$. With the above definition, the original ith constraint can be rewritten as in Equation (5).

$$
\sum_{j \notin J_i} a_{ij} \cdot x_i + \left[-\eta_{i0} \cdot \hat{b}_i + \sum_{j \in J_i} \eta_{ij} \cdot \hat{a}_{ij} \cdot x_i\right] \leq b_i \tag{5}
$$

Where J_i represents the index subset that contains the variable indices whose corresponding coefficients are subject to uncertainty. In this robust optimisation definition, with a predefined uncertainty set $\mathbb{V}$, the aim is to find solutions that remain feasible for any η_{ij} in the given uncertainty set $\mathbb{V}$ so as to immunise against infeasibility. Therefore, the formulation is strongly dependants from the definition of the uncertainty set. Several choices are available in literature: *i*) box, *ii*) ellipsoidal *iii*) polyhedral sets and finally *iv*) combination of the previous, like depicted in Figure 7.

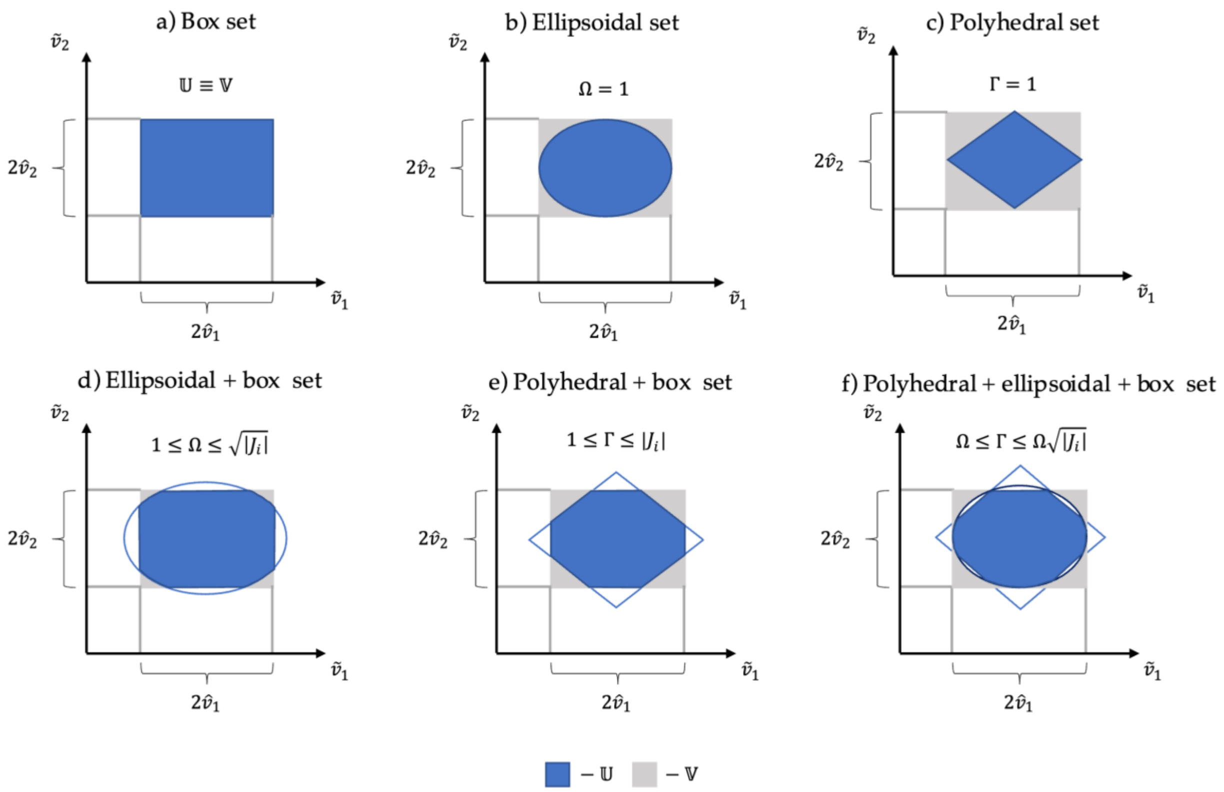


Figure 7. Uncertainty set for a constraint with two uncertain parameters.

The box set corresponds to the worst-case scenario which assumes that all parameters will take the worst possible value. It is the most straightforward approach but also the most conservative, with the highest deterioration of the objective function [77]. To address the excessive conservatism of the box set, an ellipsoidal uncertainty set has been proposed on the observation that corners tend to be unlikely to happen. However, it introduces non-linearity in the model. The polyhedral representation constitutes a compromise between the two previous models because it still allows controlling conservatism while preserving computational tractability. The idea behind this model is that, even if every uncertain parameter can always assume the worst-case value, only a few of them does it simultaneously, and their number is controlled by the so-called *uncertainty budget*, Γ. The selection of a given uncertainty set will introduce changes to the final formulation of the problem, called the robust counterpart of the problem. If, for example, one was to consider an intermediate but still linear set of uncertainty, such as *box* + *polyhedral*, then one would obtain a representation as follows in Equation (6).

$$\begin{cases} \sum_{j \notin J_i} a_{ij} \cdot x_i + \left[\Gamma \cdot z_i + \sum_{j \in J_i} p_{ij} + p_{i0} \right] \leq b_i \\ z_i + p_{ij} \geq \hat{a}_{ij} \cdot |x_i| \quad \forall j \in J_i \quad z_i + p_{i0} \geq \hat{b}_i \\ z_i \geq 0 \quad p_{ij} \geq 0 \quad p_{i0} \geq 0 \end{cases} \tag{6}$$

Where the auxiliary variables z_i and p_{ij} are used to eliminate the inner maximisation by using its dual formulation. This process requires resorting to the absolute value $|x_i|$. If the variable is positive, the absolute value operator can be directly removed. Otherwise, it can be eliminated by introducing an additional auxiliary variable y_i and the constraint $-y_i \leq x_i \leq y_i$.

All the discussion so far has been about symmetrical uncertainty intervals. This very strong assumption, however, limits its application. This is precisely why robust optimisation studies with asymmetric intervals were introduced [78]. To deal with the asymmetric uncertainty sets, the generic coefficients a_{ij} and b_i of matrix A and vector b, respectively, are affected by uncertain parameters that follow an asymmetric distribution. Assuming that the generic variable $a_{ij} \in \left[a_{ij}^L, a_{ij}^U\right]$, where $a_{ij}^L \leq a_{ij}^U$, and that $\bar{a}_{ij}$ is the expected value, it is possible to define the forward deviation as $d_{ij}^F = a_{ij}^U - \bar{a}_{ij}$ and the backward deviation as $d_{ij}^B = \bar{a}_{ij} - a_{ij}^L$. Using these deviations, we can rewrite as $a_{ij} \in \left[\bar{a}_{ij} - d_{ij}^B, \bar{a}_{ij} + d_{ij}^F\right]$. For each row i of A, we can define $J_i = \left\{j \mid a_{ij}^L \leq a_{ij}^U\right\}$, i.e., $J_i = \left\{j \mid a_{ij} \text{ is random}\right\}$,, and we assume that a_{ij}j for all i and $j \in J_i$, are independent random variables [79]. Consequently, it is possible to define the new asymmetric uncertainty set, $\mathbb{I}$, as in Equation (7).

$$\mathbb{I} = \begin{Bmatrix} a_{ij} \in \left[\bar{a}_{ij} - \lambda_{ij} \cdot d_{ij}^B, \bar{a}_{ij} + \lambda_{ij} \cdot d_{ij}^F\right], \ \ \forall i,j \\ \left\|\lambda_{ij}\right\|^D \leq \Delta \end{Bmatrix} \tag{7}$$

Where $\|\cdot\|^D$ represents the generic D-norm and Δ is the uncertainty set size parameter.

To clarify the difference between symmetric and asymmetric uncertainty set, Figure 8 graphically exemplifies the difference.

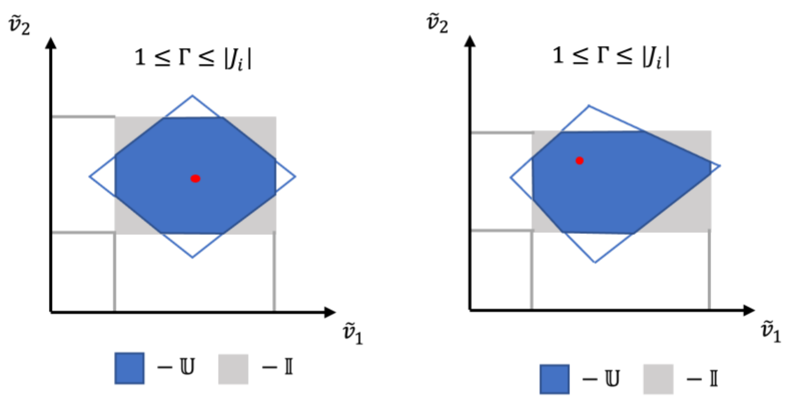


Figure 8. Difference between *box* + *polyhedral* uncertainty sets.

Combining the asymmetric uncertainty set $\mathbb{I}$ with the robust counterpart of the optimisation problem, we obtain the counterpart expressed in Equation (8).

$$\begin{cases} \sum_{j} \bar{a}_{ij} \cdot x_j - \bar{b}_i + \left[\sum_{j \in J_i} p_{ij} + p_{i0} + \Gamma_i \cdot z_i \right] \leq 0 \quad \forall i \\ \nu_{ij} - \mu_{ij} = x_j \quad \forall i, j \\ \nu_{i0} - \mu_{i0} = -1 \quad \forall i \\ z_i + p_{ij} \geq d_{ij}^F \cdot \nu_{ij} + d_{ij}^B \cdot \mu_{ij} \quad \forall i, j \\ z_i + p_{i0} \geq d_{i0}^F \cdot \nu_{i0} + d_{i0}^B \cdot \mu_{i0} \quad \forall i \\ \nu_{ij}, \mu_{ij}, p_{ij} \geq 0 \quad \forall i, j \\ z_i, \nu_{i0}, \mu_{i0}, p_{i0} \geq 0 \quad \forall i \\ l \leq \boldsymbol{x} \leq u \end{cases} \tag{8}$$

It is worth mentioning that for the sake of simplicity each equality constraint was converted into two inequality constraints, adding for each constraint a new auxiliary variable which is introduced to account for equality constraints violations.

Finally, once the robust problem has been defined, it is paramount to provide an indicator that defines the risk associated with a less conservative optimisation. If the random variables η_{ij} are assumed independent distributed, an upper bound of the probability of constraint violation can be given by Equation (9).

$$\varepsilon_i = e^{\frac{\Delta_i{}^2}{2}} \tag{9}$$

Where Δ_i is the adjustable parameter for different uncertainty sets: $\Delta_i = 1$ for the box set, $\Delta_i = \Omega_i$ for the ellipsoidal set, and $\Delta_i = \Gamma_i$ for the polyhedral set [80].

2.3.3.4 Information Gap Decision Theory Techniques

The Information Gap Decision Theory (IGDT) techniques address uncertainties by assessing the disparities between uncertain input parameters and their estimations. IGDT employs nested sets to describe different levels of information gaps, with each element representing a feasible operating point [81]. To use IGDT, an initial evaluation of uncertain parameter values is required. Decision-makers then assess either a robustness function or an opportuneness function. The robustness function indicates the maximum allowable deviation from the predicted value in an unfavourable direction while still maintaining an acceptable reduction in the objective value. Conversely, the opportuneness function represents the minimum necessary deviation from the predicted value in a desired direction, resulting in an expected improvement in the objective value. IGDT has been applied in various contexts, including distribution system planning with intermittent renewable generation and variable load demand [82]. It has also been used to address uncertainty related to wind generation in voltage stability-constrained optimal power flow problems and to manage voltage congestion in distribution networks with a high penetration of wind turbines [83], [84].

2.4 Multi Energy System Integration

The increasing integration of new technologies and energy sources, such as EV charging infrastructure, heat pumps, PV units, and wind turbines, is driving DSOs to rethink and reinforce their energy systems. Traditional methods of network expansion, like adding more power cables, have been the norm, but innovative technologies and strategies are emerging. One of these innovations is sector coupling, which involves integrating different energy sectors, like electricity and gas networks [85]. In modern distribution network planning, not only is the primary goal to provide end consumers with cost-effective energy, but also reliable and environmentally friendly. Achieving this involves minimising both investment and operating costs during the planning period, and combining power and gas network expands the range of optimisation solutions. This approach allows for more cost-effective solutions, minimises the need for redundant infrastructure, and takes into account the interactions between different energy networks [86]. The integration of different carriers, energy infrastructure and markets, including the generation side can be called MES. In this chapter we delve into this topic analysing its technologies, benefits and challenges as well as how to integrate this paradigm into distribution network planning.

2.4.1 Definition of Multi Energy System

The concept of MES has gained significant attention in recent years as a result of global efforts to transition towards sustainable and carbon-neutral societies. European and global institutions have introduced initiatives such as the European Green Deal and the Sustainable Development Goals to guide stakeholders, researchers, policymakers, and citizens in achieving these sustainability goals [87]. These initiatives encompass various sectors and stress the adoption of approaches like the smart electrification and sector coupling to create decarbonised energy systems. In this evolving scenario, MES represents a paradigm shift in energy system analysis. As a matter of fact, it considers the optimisation of all energy sectors and vectors as a whole, rather than as isolated entities. This holistic approach breaks down traditional barriers that have separated different energy sectors, allowing for the simultaneous optimisation of various energy vectors, from generation to consumption [88], [89].

A MES is an advanced energy system that transcends the optimisation of individual energy sectors or vectors. It integrates all energy sources and sectors into a unified analysis and optimisation framework. This approach facilitates the efficient deployment of both centralised and decentralised resources, making it a crucial concept in modern energy planning. Its relevance is particularly pronounced in densely populated urban or industrial contexts with developed networks for various energy vectors such as electricity, gas, and district heating. In order to deploy a MES in an energy system three main technologies can be adopted: *i*) Communication and Control Technologies, *ii*) Cross-vector technologies and *iii*) Power2X technologies [90], [91].

Thanks to the improvement in the field of communication and control technologies, devices able to modify their behavior according to feedback signals obtained through sensors, data, and built-in algorithms can be deployed across the energy system. These technologies increase the degree of automation and interactions within the energy network, facilitating the integration of intermittent renewables and enabling the combined operation of multiple energy systems. Through smart devices, information can be exchanged and stored in large data sets and actively analysed to identify trends and make predictions. Forecasted data, like weather conditions and customer behavior, can be used by the control and management algorithms for optimising operational procedures, mitigating their effects, and identifying the optimal solution for achieving specific goals, such as lower costs, mitigating demand peaks, reduced emissions, and improved efficiency [92]. Moreover, disruptive events can be predicted, allowing increased reliability of the system by responding, adapting, and optimising the system through proper configuration automation. Example of smart devices are meters, monitoring systems, and distributed system resources such as power generators, EVs, and ESSs. At the consumer level, such devices can increase the involvement of end-users in the energy system, allowing altering their consumption patterns and generating profits from the participation in the market. At the electricity and gas grid level, automation is enabled by a network of smart meters, controls, and flexibility options, such as thermal storage, curtailment, and demand-side management technologies. All these devices linking different energy sources, technologies, and services allow the development of multi energy systems at various scales, from individual customers through to different levels of community [93].

Another important step for the development of MESs is taken by the cross-vector technologies. These scientific know-hows lead to the cross-vector integration paradigm. This paradigm is a crucial concept in modern energy systems, bringing together various energy vectors and technologies to enhance efficiency, sustainability, and resilience [93]. This integration can occur through the use of multiple types of fuel or by generating multiple products from a single energy source, known as polygeneration. Within polygeneration, two key technologies are cogeneration and trigeneration. Cogeneration, also called combined heat and power, is a well-established method that simultaneously produces electricity and useful heat, significantly improving overall efficiency compared to traditional power plants. These combined heat and power systems are versatile, running on fuels like natural gas, oil, biomass, and coal [94]. Cogeneration plants can be integrated with district heating networks, optimising the consumption of thermal and electrical energy while benefiting from aggregated and diversified loads. This integration ensures maximum fuel use, although CHP plants are typically set up to provide 50-60% of heat demand due to variations in electricity and heat demands [95]. To further boost efficiency, combined heat and power can be combined with thermally activated cooling, creating a trigeneration system known as combined cooling heat and power (CCHP). This system enhances overall efficiency by efficiently providing cooling, heating, and electricity [91]. In regions with minimal heating demands during the summer, the efficiency of combined heat and power can decline. Seasonal trigeneration addresses this by coupling an absorption chiller with a CHP plant, providing cooling when heating demand is low. This approach is frequently used by offices, supermarkets, and hotels. Cross-vector technologies facilitate this integration, enabling the control and management of different energy vectors within an energy system. They encompass distributed multi-generation systems, such as micro-CHP and reversible electric heat pumps, allowing the generation of electricity, hot water, space heating, and cooling from multiple energy sources. These integrated urban energy systems, resulting from cross-vector integration, are complex and require sophisticated modelling and assessment approaches. Effective storage integration, both electrical and thermal, enables energy production to be decoupled from local demand, enhancing flexibility and efficiency. Even though, the MES can be fully autonomous, centralised management systems, established by energy service companies or energy retailers, play a pivotal role in ensuring the reliable supply of multi-energy services to local communities [93].

The final paradigm is the Power2X technologies. Power2X technologies are a vital component of modern energy systems, allowing surplus electricity, often from RESs, to be converted into alternative products denoted as *X* [91]. These products encompass a wide range, including hydrogen, methane, methanol, ammonia, chemicals, heat, mobility fuels, and syngas, among others. These technologies offer a flexible approach to link power and fuel networks, effectively integrating intermittent renewable resources into energy systems and services. By enabling surplus power from the electricity sector to be applied in various sectors such as transport, heat, gas network, and industrial processes, Power2X technologies play a crucial role in managing energy use and reducing carbon emissions. One significant advantage of Power2X systems is their capacity for long-term storage of intermediate products, allowing for daily and inter-seasonal energy coverage. Additionally, these technologies leverage existing fuel infrastructures, enhancing their practicality and accessibility. The core principle underlying Power2X technologies involves electrolysis, which uses electricity to break chemical bonds, especially the bond between hydrogen and oxygen in water [96]. This process leads to the production of versatile energy carriers like hydrogen, which can be stored as a liquid or gas and used in various applications. Hydrogen can serve as a fuel for power generation or as a feedstock in industrial processes. In the Power2X paradigm, the P2G is a key process within Power2X, where electricity is converted into gaseous carriers, such as hydrogen or methane [97]. Electrolysis is used to generate hydrogen, which can then be combined with carbon dioxide, often with the assistance of biocatalysts, to produce methane. Synthetic methane serves as a low-cost replacement for fossil natural gas and can be employed in various applications, including marine transport and power generation. It also offers an efficient means of seasonal energy storage and energy transport through existing infrastructure. Furthermore, the Power-to-liquid (P2L) processes take electrolytically generated hydrogen and transform it into liquid fuels, including synthetic crude, gasoline, diesel, and jet fuel [98]. This versatility in fuel production can further reduce the dependence on fossil fuels in various sectors, including transportation. While Power2X technologies offer significant benefits, it's worth noting that the round-trip efficiency of power-to-gas pathways is relatively lower compared to battery storage systems. However, improvements can be achieved, with round-trip efficiency potentially reaching 70% through the use of reversible solid oxide electrochemical cells, waste heat recycling, and the provision of both heating and electricity services. In addition to fuel production, Power2X also encompasses power-to-heat (P2H) solutions, where surplus electricity is used to generate heat through heat pumps or large electric boilers [99]. These solutions can be deployed in both centralised district heating systems and decentralised setups for individual buildings, contributing to load shifting, peak shaving, and the efficient use of renewable energy.

2.4.2 Challenges and Opportunities of Sector Coupling

Sector coupling integration holds immense potential as a means to enhance resource efficiency, bolster power grid flexibility and security, and accelerate the transition to a low-carbon energy sector. While the specific value of MES technologies can vary depending on geographic location and energy needs, it offers numerous advantages across diverse contexts, from urban areas in developed countries to rural regions in developing nations.

The first one to be noted is the efficient use of available resources. The historical drive for efficiency improvement gained prominence in the 1940s with industrial streamlining, emphasising coordination of overlapping systems and waste product reuse. Combining three or more energy vectors appears to offer greater synergistic economies than exploiting single or dual vectors [100]. A more extensive degree of integration allows for higher resource adoption rates, especially when considering the incorporation of additional energy networks like gas and heating. Capturing and reusing wasted heat, responsible for substantial energy losses, is critical in reducing fuel consumption and carbon emissions. Approximately 51% of energy is lost through conversion in the worldwide production and use of electricity and heat [101]. Another advantage is the decarbonisation. Efficiency improvements in the energy sector directly translate into cost and emissions reductions. Wider integration among energy systems and sectors provides additional opportunities to reduce the carbon footprint [102]. Electrification of traditionally carbon-intensive sectors, such as heat and transport, is a key decarbonisation pathway. Electric machines are typically more efficient, reliable, and consume less fuel than their combustion engine counterparts. This transition can be facilitated by integrating RESs, potentially compensating for increased electricity demand [103]. MES integration can also contribute to the decarbonisation of the gas network through the integration of renewable gases like biogas, synthetic methane, and hydrogen [104]. Another factor that improves the adoption of MESs is the employment of MES as a source of system services. One way could be the utilisation of MESs as a source of flexibility. The increasing penetration of intermittent renewables in the power grid necessitates greater flexibility to balance supply and demand. Flexibility services, including interconnectors, flexible generation, storage technologies, and DR schemes, can be integrated into the energy system. Higher integration across energy systems enhances overall system flexibility by diversifying input and output streams, enabling demand to shift between systems [93]. Moreover, MES integration enhances both reliability and resilience in energy systems. Smart technologies embedded into interconnected systems enable accurate prediction and faster response to weather-related events and power outages. Additionally, diversifying the energy supply through connected systems, such as CCHP and microgrids, increases system resilience [105]. Finally, the cost reduction is considered to be an opportunity. MES offers cost reduction through optimal asset utilisation, avoiding redundant investments, and sharing assets between systems. Integrated energy storage and automation enabled by smart technologies and big data further contribute to cost savings [106].

Although, the integration of MESs brings advantages, there are still several points that block their integration. These barriers are multifaceted, presenting obstacles to the seamless integration of energy systems. A comprehensive classification classifies these barriers into two primary areas: *i*) techno-economic barriers, and *ii*) policy and regulatory barriers. In the techno-economic barriers, we can encounter:

- *Innovation and Collaboration*. A significant hurdle in the adoption of MESs is the imperative need for innovation across various facets, spanning supply, demand, transmission, distribution, and storage. While some technologies, like CHP, demand substantial capital investments, others are costly due to their early-stage lifecycle, hampering their competitiveness, and raising concerns for end-users. Additionally, the need for collaborative efforts among operators adds another layer of complexity. This collaboration, currently lacking a structured framework under regulations/policies and complicated by a fragmented market regime, represents a technical barrier that further complicates the adoption of MESs [107].
- *Performance Enhancement*. The efficacy of these technologies, encompassing efficiency, durability, and degradation rates, presents formidable barriers to their implementation. For instance, there is a pressing need to enhance the durability and degradation aspects of fuel cell mechanisms. Biomass-based carbon-capture and storage technologies call for heightened efficiency. A lack of efficiency labels complicates consumers selection of the most efficient technologies [108].
- *Infrastructure Readiness*. Existing infrastructures are ill-prepared for the transition from natural gas to diverse gas types, necessitating interlinkage between the electricity and gas sectors. This infrastructure adaptation entails adjustments to technical regulations and standards to accommodate hydrogen and biomethane injections into the gas grid [109].
- *Market Conditions*. Market dynamics introduce a substantial barrier to sector coupling technologies, with competitiveness varying based on applications and geographic regions. Factors like disparities in electricity and gas prices significantly influence the

feasibility of technologies like Power-to-Hydrogen ($P2H_2$) and P2G. The low market value of gas and competition for biomass feedstock further add complexity to the landscape [109].

In addition, in the policy and regulatory barriers we can encounter:

- *Integrated Planning*. A fundamental challenge within the policy and regulatory realm is the absence of integrated planning and operation across diverse energy vectors and levels. Current energy market designs frequently fall short of encompassing all externalities linked to different technologies, resulting in an inadequate carbon pricing mechanism [108].
- *Market Design*. Existing market designs in the gas and electricity sectors pose obstacles to sector coupling. This encompasses issues such as must-run requirements for power plants, distinct procurement processes for upward and downward markets, and the formulation of tariff structures for grid connection and access. These barriers manifest differently across technologies and regions [110].
- *Consumer Acceptance*. Resistance from consumers due to concerns about intrusive technologies, elevated tariffs, or data privacy issues can impede the adoption of sector coupling technologies [110].
- *Inherent Risk*. Inherent risks linked to innovative projects, encompassing economic viability and consumer acceptance, underscore the need for judicious investment assessment. Blindly funding innovation may prove costly, necessitating a thorough evaluation of investments in innovative technologies within the context of potential consumer benefits [110].

In conclusion, realizing the potential of sector coupling technologies stands as a critical milestone in the journey toward establishing a sustainable and fully integrated energy system. The path ahead, however, is fraught with multifaceted barriers that span the realms of techno-economics and policy and regulation.

2.5 Market-based Network Planning

In an era marked by an unprecedented transformation of the energy landscape, network planning has emerged as a pivotal component in the journey towards a sustainable and resilient energy system. The traditional role of distribution and urban networks, primarily tasked with the reliable delivery of electricity to end-users, has evolved dramatically. Today, they must accommodate a plethora of distributed resources, support electrification of various sectors, and integrate advanced grid technologies. As these networks adapt to the evolving energy paradigm, traditional electric system planning mostly based on network investments are changing towards the integration of service exploitation from new resources. Thus, planning tools have started to be modified for including these solutions, that nowadays, are required to be procured by means of market-based mechanisms.

In light of this transformation, this chapter embarks on a comprehensive exploration of market models designed to facilitate and enhance network planning. This chapter serves as a crucial bridge between the intricate world of energy markets and the planning and operation of networks.

2.5.1 The concept of Market-based Mechanism

In the realm of network planning, market-based mechanisms have emerged as a transformative approach to addressing the challenges of several network topics, such as grid expansion, DR actions, and network investments. These mechanisms harness the principles of supply and demand, offering a dynamic framework that departs from traditional top-down planning approaches. In the field of grid expansion, market-based mechanisms are able to introduce a level of competition and responsiveness into grid expansion strategies. Instead of relying solely on predetermined, often static plans, these mechanisms enable network operators to signal their medium and long-term flexibility needs to a broader array of stakeholders. By doing so, they lay the foundation for a more adaptable and scalable grid infrastructure. This approach allows for the optimisation of existing resources and the efficient allocation of investments where they are most needed [27]. In addition, market-based mechanisms play a pivotal role in facilitating DR programs. Through transparent network development plans and consultations, DSOs can identify areas where flexible capacity is required to avoid costly grid expansions [38]. Market mechanisms then invite service providers to participate in fulfilling these needs. This synergy between DSOs and service providers not only enhances the reliability and resilience of the grid but also opens new business opportunities for service providers. It encourages innovation in demand-side management and empowers consumers to actively participate in grid operations. Finally, market-based approaches extend their influence on network investments. DSOs, in their network development plans, can signal their intentions to rely on alternatives to system expansion, such as energy storage facilities, DR programs, or energy efficiency measures. In the Article 32 of the EU directive 2019/944, it is reported as market mechanisms facilitate the collaboration between network operators and potential network investors or operators. This collaborative approach promotes efficient capital allocation, reducing the need for costly grid upgrades and ensuring that investments are aligned with actual demand and usage patterns [27].

The idea of integrating marker-based mechanism in the DSO network development plans wants to bring several advantages such as cost efficiency, flexibility, innovation and transparency. As a matter of fact, market-based mechanisms promote cost-efficient solutions by encouraging competition among service providers. This competition drives innovation and cost optimisation, ultimately leading to more economical outcomes compared to traditional, static expansion plans. Needlessly to say, market-based approaches offer a high degree of flexibility. They enable rapid adjustments in response to the changing grid conditions, emerging technologies, or shifts in consumer behavior. This adaptability is crucial in the current dynamic energy landscape. Moreover, by fostering collaboration between DSOs and a diverse set of stakeholders, market-based mechanisms stimulate innovation. They create fertile ground for the development of new technologies, services, and business models, promoting the integration of RESs and the electrification of various sectors. Finally, market mechanisms prioritise transparency in network development plans, consultations, and decision-making processes. Stakeholders, including consumers, have access to vital information about grid development, fostering trust and participation [27].

2.5.2 Market Models for a Network Planning Process

Nowadays, DSOs are undergoing a paradigm shift in their investment planning approaches. For more than a decade, investment plans have paved the way for a harmonised, coordinated strategy through the 10-year network development plan, a remarkable achievement of harmonisation and collaboration across many countries. However, recently, the spotlight has turned to distribution and urban networks as a potential bottleneck for the European electricity market functioning and the broader transition toward a sustainable energy system. The Article 32 of the Electricity Directive 2019/944 introduced new regulations for emphasizing the need for network investment plans for distribution systems. DSOs are responding to this transformation by embracing market-based integration into their network plans. The evolving landscape has given rise to diverse approaches in designing these network investment plans [38]. The first one is the *European plan*. This approach states that evening peaks in household electricity demand will be a pivotal driver of congestion and subsequent investments in distribution grids. It underscores the influence of solar production concentrated around noon, creating unique challenges and opportunities. Key assumptions include renewable energy objectives, electrification of transport and heating, and the availability of flexibility. The European plan treats flexibility as an assumption, whereas European legislation necessitates DSOs to navigate the trade-off between flexibility and network expansion [111]. The second approach is focused on *local DSO plans*. Some DSOs have proactively published their first versions of multiannual network investment plans, providing insights into the congestion levels anticipated in different regions by 2030 if network expansion does not occur. Furthermore, they explore alternative solutions such as dynamic network operation (i.e., flexible connections), distribution network tariffs, mandatory flexibility services, and market-based flexibility procurement. While the comprehensive trade-off mechanism between flexibility and network investment is still evolving, these local DSOs offer a glimpse into how it may take shape [112].

As DSOs embark on this journey towards market-based integration in their network plans, questions arise regarding the potential of flexibility as a viable alternative to traditional distribution grid investments. Some advocate for cost-reflective distribution network tariffs as sufficient incentives for users to manage their consumption peaks. The following sections delve into the most pivotal and recognised service market mechanisms proposed in the literature for the integration of market-based principles into network development plans. The first market mechanism provide flexibility for the DSO, the second mechanism focuses on locational marginal price mechanism. The latter aligns with the network tariffs idea.

2.5.2.1 Flexibility Markets

The term *flexibility* can be defined as the ability to adjust patterns of electricity generation and consumption in response to signals, typically in the form of price or activation signals [113]. Flexibility is envisioned as a multifaceted commodity encompassing various services that can be traded within flexibility markets. This good is a dynamic and responsive adjustment of electrical power at a specified time, for a defined duration, at a specific location or node within the distribution system. This concept is characterised by five fundamental attributes [114]:

1. *Direction*. It specifies whether the adjustment is upward (increasing power) or downward (decreasing power).
2. *Rate of Change*. This attribute concerns the power capacity associated with the adjustment, representing the extent of power increase or decrease.
3. *Starting Time and Trigger*. It signifies when the adjustment commences and what starts it.
4. *Duration*. It denotes the duration for which the adjustment persists.
5. *Location*. This attribute specifies the precise node or location within the distribution system where the adjustment is required.

Flexibility markets, within the broader context of the electric distribution system, are platforms that facilitate the trading of these flexible services or commodities. They provide a space where various participants, including DSOs, Balance Responsible Parties (BRPs), aggregators, and market operators (MO), converge to enable the exchange of flexibility resources. In this context, flexibility resources can be classified into three main sources: *i*) supply-side flexibility, *ii*) demand-side flexibility and *iii*) grid-side flexibility [115].

The supply-side flexibility is achieved through the coordinated operation of multiple generators and energy storage units. These sources can include CHP systems, diesel generators, fuel cells, and various types of energy storage technologies. On the other hand, demand-side flexibility is realised by actively managing and adjusting the energy consumption patterns of energy consumers, which can be individual prosumers, smart homes, smart buildings, or microgrids equipped with flexible resources. These resources can include ESSs, and controllable loads such as EVs, heat pumps, and heating, ventilation, and air conditioning systems. Noteworthy, buildings can be modelled as virtual energy storage systems, leveraging the thermal mass of buildings to provide demand-side flexibility. Additionally, EVs, with the ability to shift their charging loads away from peak hours, also contribute to demand-side flexibility. Finally, grid-side flexibility can be achieved through the control of grid equipment and the physical characteristics of the electric distribution network. Grid equipment can be adjusted to optimise the operation of the distribution system and improve grid-side flexibility. Grid-side flexibility enhancements can lead to improved power supply capabilities, enhanced voltage quality, and optimised power flow. This flexibility can also extend to providing voltage support for transmission networks through coordination between TSOs and DSOs.

In a flexibility market, there are several key participants, each with distinct roles and objectives.

- *DSO*. The objective of the DSO is to efficiently deliver electricity to consumers while ensuring the secure operation of the distribution system and the quality of electricity delivery services. In a flexibility market, the DSO can procure flexibility for various operational purposes, such as managing congestion, controlling voltage, minimising losses, and planning purposes like deferring network reinforcements.
- *BRP*. BRPs are traders in energy markets who work on behalf of their clients' portfolios, so their objective is to optimise portfolio transactions. Their role is to balance energy supply and demand during specific time periods. If they fail to maintain this balance, they may incur in imbalance penalties. BRPs can be entities like retailers, generators, or aggregators.
- *Aggregator*. The objective of an aggregator is to gather and manage groups of prosumers to participate in energy and flexibility markets. Their role is crucial since it represents individual energy resources and prosumers. It collects and bundle the flexibility from these individual sources to create various flexibility services that can be traded in the market.

These participants collaborate within flexibility markets to exchange flexibility services. The DSO, BRP, and aggregators are the primary actors in these markets.

A flexibility market therefore allows different actors to aggregate in order to be able to buy and sell flexibility. This aggregation of participants, however, can take different forms. In this respect, there are several models explored in the literature. The most important are centralised optimisation models from the point of view of one participant, game theory-based models, auction theory-based models and simulation models [113].

The centralised optimisation model is the simplest model. It is formulated as a centralised optimisation problem subject to techno-economical constraints which objective functions must be optimised. Here, two main optimisation model can be found, the social welfare maximisation and the operational cost minimisation [116]. In the first approach, the objective is to maximise the total social welfare of the market participants. Social welfare is calculated as the sum of the benefits of all participants in the market, which is essentially the revenue minus the cost for each participant. In the latter approach, taking into account the perspective of one participant, like the DSO, the goal is to minimise the operational cost for procuring flexibility in the market. The objective is to minimise the cost incurred by the participant to obtain the needed flexibility.

The game theory-based models are based on mathematical tools that analyse strategies in competitive situations where the outcome of a participant choice of action depends on the actions of other participants [117]. They can be classified into noncooperative and cooperative games. The first model considers participants with partially or totally conflicting interests making independent decisions. Nash equilibrium is often used to find solutions where no participant can benefit by changing their strategy unilaterally [118]. The cooperative games involve rational players with cooperative behaviours. Participants work together to maximise their collective profits or benefits [119].

The auction-based models employ auction mechanisms, like those in economic auctions, to balance supply and demand through competitive bidding [120]. They aim at finding a clearing price that balances supply and demand while maximising economic efficiency. The most famous and efficient model is the double-sided auctions, where both buyers and sellers participate. They enable multiple buyers and multiple sellers to trade flexibility.

Finally, the simulation models, often based on multiagent systems, allow for a more realistic representation of market behaviours [121]. Each participant is represented as an agent, and these agents can simulate human-like behaviours, making the modelling more accurate. These models can capture the dynamics of market interactions and various bidding procedures, providing a comprehensive view of market behavior.

When designing models for flexibility markets, several approaches are available, each with its strengths and limitations. Centralised optimisation models offer simplicity and ease of implementation, but they may struggle to scale for larger, more complex systems. In contrast, game theory-based and auction theory-based models excel in representing all market participants, making them well-suited for markets with numerous players. Simulation models, particularly those based on multiagent systems, provide the most realistic portrayal of market behaviours. However, this increased realism comes at the cost of computational intensity. One challenge with game theory-based models is their assumption of participant rationality, which does not always align with real-world behaviours. These models can also be complex and have multiple equilibria. On the other hand, auction theory-based models face issues like unviable auction price spikes in highly competitive markets. The choice of modelling approach for a flexibility market hinges on the specific market needs and the desired level of detail and realism in simulating participant behaviours. Each approach has its advantages and disadvantages, and the selection should align with the objectives of market analysis or design.

Around the globe, and particularly in Europe, several market platforms and initiatives are aiming at enhancing flexibility within energy grids. These initiatives focus on addressing challenges related to grid congestion, peak electricity demand, and the integration of RESs and DR programs into energy markets. The most noteworthy are Enera, demonstrated in Germany [122], GoPACS, demonstrated in Netherlands [123], IREMEL, developed in Spain [124], Piclo Flex, adopted in the UK [125] and NODES, demonstrate in Norway [126], even though other platforms allow to trade service under the form of redispatch markets instead of flexibility services. These platforms facilitate coordination between DSOs and TSOs to manage grid congestion and include flexibility bids in balancing services. Piclo Flex, on the other hand, focuses on providing flexibility services to DSOs through advance booking contracts. These contracts help optimise grid operation during peak load periods and address location-specific grid requirements. Concurrently, the project CoordiNet [127] and INTERRFACE [128] are involved in large-scale demonstration projects across multiple European countries. CoordiNet is active in Greece, Spain, and Sweden, while INTERRFACE is conducting demonstrations in nine different locations. These initiatives explore innovative approaches to procure flexibility, particularly from small residential consumers. In this context, several initiatives, including InteGrid, InterFlex, GOFLEX, and IREMEL, prioritise delivering flexibility services to DSOs. They also aim at enabling the active participation of distributed resources in existing energy markets. InteGrid showcases new tools for DSOs to manage low and medium voltage networks efficiently by leveraging flexibility from small consumers and aggregators. InterFlex conducts six different demonstrations in five countries, involving a range of resources such as EVs, ESSs, and DR actions. Moreover, GOFLEX conducts demonstrations in three countries with the goal of reducing grid reinforcements by addressing electricity demand peaks, preventing congestion, and ensuring a reliable energy supply. Finally, IREMEL, an initiative supported by the Iberian MO, shares the objective of enabling the participation of distributed generators and DR resources in energy and flexibility markets.

The characteristics of each initiative can vary based on project demonstrations and the countries of implementation. Most initiatives follow a one-sided market approach where service providers compete to meet service requirements defined by DSOs and/or TSOs. However, exceptions exist with Enera, GoPACS, NODES, and IREMEL, which adopt a two-sided market structure. In two-sided markets, participants, including buyers and sellers, directly or through intermediaries, determine both demand and supply dynamics. Through market-clearing processes, they ascertain cleared prices and quantities. For instance, GoPACS matches flexibility bids based on their network location to address specific congestion issues, with the DSO or TSO covering the price difference between matched buyer and seller offers. Talking about project, it is noteworthy to report that in the CoordiNet project, the flexibility market for congestion operates on a day-ahead basis preceding the day-ahead energy market. This enables BRPs participating in the CoordiNet congestion market to adjust their consumption and/or production.

For what concerns the timing of the existing real-world flexibility markets, there are notable variations in their operational mechanisms. Specifically, NODES, GoPACS, and Enera markets, are tightly synchronised with existing intraday continuous markets. Enera, for instance, operates with 15-minute trading intervals. In contrast, Piclo Flex, adopt an auction-based approach, but their timing differs significantly. Piclo Flex plans auctions well in advance, with a lead time of at least six months for long-term flexibility contracts.

Regarding pricing methods, the norm across platforms is a pay-as-bid system, aligning with continuous trading principles. Bids that address local congestions and appear in respective order books are selected.

These projects have different characteristics, some of which are specific to the electrical system to which they have been applied, others have more general features applicable to different environments. Table I gives more details about such projects [129].

Table I. Comparison of the main features for five existing real-world flexibility markets.

	Piclo Flex	**Enera**	**GoPACS**	**NODES**	**IREMEL**
Timeframe	Months ahead	Intraday	Before intraday gate closure time	Configurable per region and markets, and compatible with imbalance settlement in existing markets	Months ahead and near real-time
Voltage Level	Distribution	Transmission & Distribution	Transmission & Distribution	Transmission & Distribution	Transmission & Distribution
Participants	Aggregators, asset owners, consumers, community and municipality, electric vehicles, generators, and DSO	Aggregators, asset owners, TSO and DSO	Residential, commercial, industry, energy companies, TSO and DSO	Balancing Responsible Parties, microgrids, aggregators, TSO and DSO	Aggregators, consumers, generation asset owners, TSO and DSO
Offering mechanism	Pay-as-bid. Flexibility is offered as availability (capacity) and activation (energy) products	Pay-as-bid. Flexibility can be offered only as activation (energy) product. No remuneration for availability (energy) product	Pay-as-bid. Flexibility can be offered only as activation (energy) product. No remuneration for availability (energy) product	Pay-as-bid. Flexibility can be offered and contracted through a combination of availability (capacity) products and activation (energy) products	Pay-as-clear or pay-as-bid.
Market clearing	Auction	Continuous trading	Continuous trading	Continuous trading	Continuous auction
Platform operator	Independent market operator	TSO and DSO	TSO and DSO	Independent market operator	Independent market operator

Creating a flexibility market, particularly at the distribution level, is not easy to implement. This requires pilot projects, regulatory sandboxes and different actors' perspectives. For instance, such a market model would include the European Commission, system regulators, academics, stakeholders, industries, system operators, aggregators, and consumers organisations. However, in such a complex environment, several questions arise. In the power system, selling services to the system operators has already been implemented. An example can be found at the transmission level, where the TSO asks grid users to modify their plans to provide frequency and voltage regulation services. On the other hand, such kind of market is not implemented nor yet conceptualised at the distribution level. Therefore, many actors wonder how it is possible to integrate such a market at the distribution level and whether current market systems could be used to integrate flexibility services. An answer to this question is given in [111] [87], where it is described that flexibility services can be traded in different marketplaces. For instance, the wholesale market, from day-ahead to intraday, the balancing market or even the congestion management market. Hence, these markets can operate through coinciding timeframes and may concern similar or distinct products.

As a consequence of this solution, many people wonder whether the coordination between TSO and DSO is indeed achievable to operate such a solution. Definitely, a single-entry point to different market processes could be a concept to seek. Intermediaries such as aggregators are part of the solution to enhance all customer participation and generate additional value. Indeed, the feasibility of each option should be assessed at a national level, taking into account local specificities and their interaction with the global electricity system and market. Yet, TSOs and DSOs that adopt this principle must implement TSO-DSO coordination and exchange all the necessary information to ensure the feasibility of such a market. Although the promising solution, many prefer to theorise an utterly different market platform. In this way, the process is simplified, not only for market users but also for SOs sometimes forced to exchange information that they do not always want to give up [130].

Another question concerns the role of the MO. The MO should ensure market access and secure operations, clearly define their needs, facilitate the participation of all market parties, while complying with EU and national privacy regulations, to ensure a fair marketplace by delivering transparency on grid and system needs, and on rules for requesting, selecting, validating and settling flexibility services. The MO must be neutral towards all flexibility service providers in this context.

A further critical aspect in creating a flexibility market includes transparency of data and market processes. Users of the flexibility market know what they have to provide and why. Transparency of market processes and rules should be evaluated. The MO must ensure a fair market environment for trading, and the system operator (SO) role as a (single) buyer should be regulated, as stated by Council of European Energy Regulators [131].

2.5.2.2 Locational Marginal Pricing Mechanisms

Locational marginal prices conventionally are the cost to deliver one additional megawatt hour to a given bus within a network. It is a fundamental component of the standard market design in the US and has been implemented in every market across the US [132]. The concept of using location-based spot pricing for managing congestion in electricity markets was initially proposed in earlier research such as [133], but since then it has since evolved into the current framework of locational marginal prices (LMP) [134]. LMP-based markets are operating in various countries, including New Zealand, Australia, and obviously the US. Even though, LMP has been widely used for pricing energy, it was also adopted for co-optimising ancillary services such as reserves and regulation [135]. In general, LMP are a pricing method used to establish the price for energy purchases and sales at specific location and under a specific operating regime. To evaluate these prices, LMPs calculate the security constrained economic dispatch. The LMP process yields three portions corresponding to the energy component, the loss component and congestion component [132]. The energy component does not depend on the physical location in the system, while the loss and congestion components are uniquely calculated at each specific system bus. One of the main challenges of the LMP approach is the presence of non-convexities, which disrupt the traditional application of Karush-Kuhn-Tucker (KKT) conditions. This necessitates the use of non-linear pricing methods. Unlike convex cases where pricing is straightforward, mixed-integer problem solutions may not yield a clear set of prices that support equilibrium conditions. This is because the shadow prices are not easily evaluated.

Commonly, LMP-based markets are applied to transmission levels, however, nowadays distribution networks are emerging as an important component of power system operations due to the deployment of RESs and the need to activate the flexibility of consumers that are connected to the low-voltage networks. In this scenario, correct price signals at the distribution level are essential to provide correct incentives for improving fuel cost efficiency, limiting real power losses over distribution lines, promoting the employment of RESs, preventing the overloading of circuits [136], and enabling the provision of ancillary services by distributed resources [137]. The concept of distribution locational marginal price (DLMP) is pivotal in the described context, since it refers to the price signals set at the distribution level of an electricity grid. Residential and commercial consumers, who constitute a significant portion of the electricity market, offer substantial flexibility in their energy usage patterns [138]. Since many of these consumers are connected to distribution grids, pricing energy and services at the distribution level becomes increasingly significant in the overall electricity market design. DLMPs enable these consumers to make informed decisions about their electricity consumption, considering not only cost factors but also the condition and capacity of the local distribution infrastructure. Moreover, with the growing prevalence of EVs and PV installations, DLMPs become even more critical [139]. For instance, EV charging requires coordinated scheduling to prevent grid congestion, and DLMPs can guide consumers in making optimal charging decisions. Similarly, PV installations may generate excess electricity, and DLMPs can incentivise consumers to use this energy locally, reducing the strain on distribution networks and enhancing overall grid stability.

The LMP mechanism must solve a security constrained economic dispatch. Traditionally, the objective of the economic dispatch is to maximise social surplus and satisfying operational constraints. It is important to point out that in the constraints must be included the power balance at each node. The prices are derived from the dual solution of the economic dispatch with commitment statuses of the units fixed. The general economic dispatch is an optimal power flow program with security constraints and can be formulated as in Equation (10).

$$\begin{aligned} &\min_{p} C^T \cdot p \\ &\text{Subject to: } p - d - L = 0 \quad (\lambda > 0) \\ &G_i \cdot (p_i - d_i) \leq F_i^{max} \quad \forall i \quad (\mu \leq 0) \\ &P^{min} \leq p \leq P^{max} \quad \left(\eta^{min}, \eta^{max} \leq 0\right) \end{aligned} \tag{10}$$

Where p represents the power production, d is the power demand, L are the losses, G is the generation shift factor from generator to line, and finally C are the costs of production. The shadow prices are shown in parenthesis next to each corresponding constraint. The LMP is defined as a change in production cost to optimally deliver an increment of load at the location, while satisfying all the constraints. From this definition, at the optimal point, taking into account complementarity conditions, the LMPs for each bus can be obtained as the partial derivative of the Lagrangean.

$$L = C^T \cdot p - \lambda \cdot (p - d - L) - \mu \cdot (G \cdot (p - d) - F^{max}) + \eta^{max} \cdot (p - P^{max}) + \eta^{min} \cdot \left(P^{min} - p\right) \tag{11}$$

$$\lambda_i = \frac{\partial L}{\partial d} \tag{12}$$

The LMP mechanism is easy to apply in a nodal pricing network. As a matter of fact, power systems in which the price signals are fixed for each node of the network are called nodal pricing network. These types of networks are quite different from the European networks. European electricity markets adopt the concept of bidding zones, which define the geographical areas where energy can be exchanged without capacity allocation. Thus, European networks adopt the zonal pricing mechanism. Even though switching from zonal pricing to nodal pricing is difficult, the EU Agency for the Cooperation of Energy Regulators (ACER) in 2020 issued a decision specifying the methodology, assumptions, and alternative to bidding zone configurations. The decision requested TSOs to provide the results of a European LMP simulation, which is crucial for defining an alternative to bidding zone configurations[140]. The TSOs and Joint Research Center (JRC) analysis compares nodal pricing to the existing zonal model and addresses various factors, especially those related to the challenges posed by RESs [141]. The key conclusions from the analysis brought by ENTSO-E are:

- Nodal pricing aligns with standard economic principles and reduces transaction costs when the independent system operator centrally coordinates energy and services. This makes it theoretically favourable.
- Both theory and empirical evidence from the US suggest that transitioning to a nodal pricing system can have an overall positive impact. However, a Europe cost benefit analysis is yet to be conducted.
- Experience from the US and Europe indicates that defining new zones can be a complex and time-consuming process.
- While the current European market design theoretically permits nodal pricing, transitioning from a zonal to a nodal system is challenging and necessitates overcoming several obstacles.
- Nodal pricing would necessitate a shift in focus toward the balancing market, which would become the reference market. Day-Ahead and Intraday markets would serve as forward markets for the reference.
- Implementing nodal pricing would require significant institutional changes, particularly in defining new roles and responsibilities, especially within the context of the balancing market.
- With the increasing decentralisation of power generation, and the introduction of nodal pricing, the interaction between TSOs and DSOs becomes a critical question.

While transitioning to a nodal pricing mechanism for the entire European electricity market may be challenging, several companies are introducing innovative home energy management systems that adopt a DLMP approach. These systems enable homeowners to have greater control over their energy consumption and are offered by companies like General Electric, Schneider Electric, and Hitachi [142]. These home energy management systems apply DLMP principles to provide users with tools for remote monitoring and management of various appliances and power circuits within their homes. Specifically, users can control devices such as heating, ventilation and air conditioning compressors, water heaters, pool pumps, and more. DLMP-based systems offer advantages in terms of optimising energy usage and cost savings.

2.5.2.3 Integration of Markets-based approach in the Network Planning Process

The increase in renewable generation and electrification of energy sectors such as heating and cooling, transport, and industrial processes could require massive investment in electricity networks unless certain mechanisms are efficiently developed to handle local variability of loads and generation. One of such mechanisms was proposed by the European Commission, the so-called market-based mechanism. The need to perform an economic assessment of these mechanisms urges a paradigm change in current network planning practices. The best mechanism proposed so far has been the flexibility market mechanism, however, DLMP are other mechanism that are proposed in the literature. In the following, some examples are brought to gather attention on the subject of integrating such market mechanisms into distribution network planning.

One interesting study about the adoption of flexibility contract mechanism in a network planning approach is proposed by [143]. The study highlights the natural synergies between flexibility mechanisms and current options in distribution network planning. In particular, the study highlights that traditional planning often makes investment decisions based on the worst-case scenario, assuming the fastest demand growth. This approach limits the potential value of flexibility mechanisms, as it does not consider the possibility of greater investment deferral when demand grows slower than anticipated. To illustrate the benefits of the new current options, the study presents a scenario analysis example involving two possible distribution upgrades: *i*) investing in a feeder with a 2-year lead time and 12 MW additional capacity for the grid; and *ii*) investing in a DR contract with a 1-year lead time, offering 4 MW additional capacity, and renewable yearly contract renewal. Three scenarios for future peak demand are considered, with a grid initial capacity of 16 MW. Interestingly, the study demonstrates how traditional planning and *the new current options* planning yield different investment decisions contingent on evolving information over time. In traditional planning, the focus is on avoiding projected overloads. To prevent the projected overload in year 3, a DR contract is invested at the end of year 1. The second overload is projected for year 7, leading to an investment in a feeder at the end of year 4. On the other hand, current options planning adapts to information over time, avoiding unnecessary investments. Investment decisions are based on two rules. The first one defines to invest in flexibility when demand reaches or surpasses 15 MW, then the second defines to invest in the feeder when demand reaches or surpasses 17 MW. In the end, current options planning leads to different investment decisions for each scenario, with investment deferral periods based on actual demand growth. As highlighted from the study, the traditional planning can lead to poor valuation and underutilisation of flexibility mechanisms. In particular, in the proposed example, maintaining traditional planning techniques may discourage the use of flexibility mechanisms due to a lack of proper valuation. Even though, the case study is limited, the investigation underscores the potential of current options to significantly improve decision-making in distribution planning, particularly during the energy transition. The final results call attention to an interesting point for DSOs, since embracing the new current options, system operators can adapt to evolving conditions and make more informed, cost-effective investment decisions. The study also highlights the importance of aligning regulatory incentives with the adoption of flexibility mechanisms and emphasizes the suitability of projected scenarios for real options planning.

Another interesting study is provided by [144]. The investigation wants to determine the optimal investment decision-making process for both conventional and non-conventional, i.e., contracted flexibility, expansion technologies within a distribution network. The goal is to minimise the total annual cost, which includes investment and operational expenses associated with network expansion over the planning horizon. Investment costs for power lines and transformers are computed as annuities, discounted over the expected lifetime of the asset. The total annual cost encompasses investment annuities, annual maintenance costs for transformers and power lines, and annual contracting costs for flexibility. The use of annuities allows for the comparability of costs across assets with varying lifetimes, facilitating a meaningful comparison between conventional network expansion and non-conventional alternatives like flexibility products, which typically have shorter lifecycles and different cost structures. The planning process also includes the technical constraints of the network, which encompass voltage limits, and thermal limits for transformers, power lines, or cables. Finally, the radiality condition is included in the problem. During the planning process, constraint violations in the network at the planning horizon year are addressed by determining the optimal set of binary expansion decision variables for all branches, transformers and lines, and binary contracting decision variables for flexibility contracts at network nodes. The former decision variables represent the installation of additional capacity or the expansion of existing transformers and lines, while the latter represent load reduction through contracted flexibility at the time of network peak load. The goal of the planning process proposed is to identify the optimal set of decision variables that result in a network configuration with the lowest total annual cost at the planning horizon, while simultaneously meeting all operational constraints and ensuring the supply of all loads. Although the optimisation objective does not explicitly account for power distribution losses, the losses are considered in voltage drop calculations to guarantee compliance with operational constraints and avoid violations. Solving the planning process is a challenging task due to the multitude of decision variables and the complex, non-convex search space characterised by numerous local optima. To address these challenges, the study adopts a Tabu Search (TS) meta-heuristic algorithm. TS combines the knowledge of system behavior with technically and economically appropriate heuristics guided by the intelligence of the TS algorithm. Like all the heuristic approaches, TS algorithm employs an iterative process that update the list of feasible solution iteration per iteration. Adopting this strategy, the paper performs a sensitivity analysis with respect to the cost of flexibility contracting. This analysis shown that different thresholds exist, depending on the particular feeder conditions and the available load flexibility, below which load flexibility provision is preferably used over conventional expansion. Additionally, the results of the study show that the use of load flexibility, as an alternative to conventional expansion can reduce the total cost with respect to the conventional expansion solution by 7.5%, at a load flexibility cost of 5000 €/MW per year. Taking into account the high costs of distribution system expansion for the underlying load growth scenario, this would translate into major savings if applied for the whole distribution systems of a country or region.

Another study is the one proposed in [145]. In this study, the authors propose a transactive distribution network planning approach that focuses on transactive operation of local distribution area to supply the load growth locally and move toward nearly zero energy local distribution areas. They adopt the term transactive since the proposed planning process is included in a transactive energy market, where the transactive energy provides the market-based platform for the participants that aim at maximising their profit due to their optimum scheduling for generation or demand management. The study proposes an iterative transmission and distribution system planning algorithm designed for the expansion planning of distribution networks. The proposed algorithm aims at identifying optimal locations, sizes, and installation years for new energy resources and feeders across the entire planning horizon. It also takes into account the reliable, secure, and efficient operation of the local distribution area. The algorithm employs a modified Benders decomposition approach, dividing the complex planning problem into a mixed-integer investment problem as the master problem and corresponding reliability and optimality sub-problems. To ensure the reliability and technical viability of investment decisions, the planning process includes a reliability check sub-problem. This sub-problem investigates the reliability of the investment problem solution under various outage scenarios involving distributed resources, feeders, or a combination of both. It calculates the loss of expected energy as the local area reliability index, aiming at minimising power mismatches in each scenario. If the investment problem solution provides acceptable reliability, the planning algorithm proceeds to the optimality sub-problem. The sub-problem conducts an AC optimal power flow within the local area to determine new values of DLMPs and power flow prices for the next iteration of the algorithm. This sub-problem simulates the clearing process for a distribution transactive market to calculate modified DLMPs as new price signals. The core of the planning algorithm is obviously the investment problem, which formulates the expansion planning as a maximisation problem. The objective is to maximise the total net present value of yearly planning profits over the entire horizon. The net present value accounts for revenue from power generation by new resources, power flow revenue from feeder upgrades, annual investment costs, operational costs of planned resources, and costs related to power exchange with the transmission network. Like all the investment optimisation problem, this problem considers various constraints, including investment limitations, maximum power flow capacities for candidate feeders, power generation limits for candidate generators, power exchange limits between the local areas and the transmission network, and constraints related to load management through DR programs. Finally, the authors introduce some source of uncertainty. In particular, the uncertainties are related to renewable power forecasts, LMPs of the transmission bus, and local area load forecasts. To handle these uncertainties, robust optimisation is employed. The study was tested on the 33-IEEE bus network in a 10-year planning horizon. The study examined three scenarios with different robust budgets. As the robust budget increases, planning costs also rise, representing the degradation of the objective function. As a matter of fact, the highest robust budget scenario required upgrading a feeder in the first year to ensure reliability and security. The introduction of DR actions has a significant effect on planning study. Higher DR levels correspond to lower planning costs and more attractive decisions for investors. In a scenario with 20% DR, feeder upgrading is no longer necessary, demonstrating how the transactive market and DR can lead to more efficient infrastructure investments. In addition, a sensitivity analysis on DR percentages reveals that an increase in DR percentage leads to increased planning profitability. The most significant impact on planning profit occurs with the first 10% DR adoption. After approximately 33.8% DR adoption, further increases do not significantly affect profitability. This is because, at higher DR levels, load profiles are smoothed, reducing the need for costly infrastructure investments. Finally, the calculated DLMPs, which serve as price signals in the transactive planning algorithm, vary based on load blocks. Investment in new distributed resources within the local area helps manage electricity prices for consumers, preventing excessively high prices linked to wholesale electricity rates. Increasing DR participation levels influence DLMPs to decrease the supplying cost for local area customers.

The final study tries to integrate the flexibility market mechanism into the optimal planning process of a distribution network [146]. Instead of relying on flexibility contracts, the paper aims at incorporating flexibility market mechanisms into the planning process to estimate the flexibility required for the distribution network and its associated costs, a critical aspect for an effective electric distribution system development plan. Additionally, the study introduces agent-based modelling to simulate the behavior of various entities participating in the flexibility market. These entities encompass consumers, producers, prosumers, storage devices, and aggregators of small resources. In this simplified model, the focus narrows down to two types of flexibility resources: *i*) distributed generators capable of curtailing production and consumers offering DR services. This agent-based approach enables predictions of how market participants react to different conditions, enhancing trading efficiency. To simulate the agent behavior and the flexibility market, the paper adopts a three-step iterative procedure. The study simulates the flexibility market structure both in capacity (€/kW/h) and energy (€/kWh). The linearised OPF is employed to minimise flexibility exploitation costs, considering technical constraints, nodal voltages, branch currents, and resource limits. To manage the risk of technical constraint violations, a probabilistic analysis is performed, focusing on configurations with non-negligible probabilities of constraint violations. To simulate the agent behaviours, a learning-based model based on the Roth-Erev algorithm simulate agents' adaptability over time to market feedback. The paper proposed the methodology applied on a real MV distribution network. The MV network exhibits no abnormal voltage variations under normal operating conditions. However, during emergencies, the network is reconfigured to maintain electricity supply. Three critical post-fault reconfigurations are shown: *i*) case A, the big generator causes voltage overages in secondary substations; *ii*) case B, voltage drops from 12:00 to 17:00 and finally *iii*) case C, similar to case B but with voltage drops occurring only at 13:00. The study introduces a flexibility market and observes its evolution throughout iterations. All agents offer their maximum bid, and resources are selected based on their effectiveness in addressing technical issues, leading to the highest initial cost. As agents identify the need to compete and lower their bids, competition among flexibility resources intensifies. The cost of flexibility services reduces both due to the decreased bids from initially selected agents and the entry of additional, more economical resources. A comparison is made between the flexibility exploitation with fixed prices and the flexibility market. The results show that the flexibility market causes more resources to participate by lowering their bids.

In conclusion, the rise of renewable energy and increased electrification in various sectors necessitate substantial investments in electricity networks. Market-based mechanisms, such as flexibility markets and DLMPs, offer promising solutions. Real options theory can enhance traditional planning practices by adapting to evolving conditions and avoiding unnecessary investments. A study showcased how traditional planning, often based on worst-case scenarios, may discourage flexibility mechanisms use due to undervaluation. Another study demonstrated that load flexibility can reduce total costs compared to conventional expansion. Additionally, a transactive approach to distribution network planning integrates reliability and optimality sub-problems, considering uncertainties through robust optimisation. These findings underline the potential of market-based mechanisms and real options theory in distribution network planning. Embracing flexibility mechanisms and aligning regulatory incentives can lead to more informed, cost-effective, and adaptive decisions during the ongoing energy transition, ensuring a sustainable energy infrastructure.

2.6 Multi-Energy-based Urban Network Planning Case Study

In the modern network planning scenario, other than the distribution network it is equally crucial to plan modern urban cities. The connection lies in the fact that effective distribution network planning is linked with the appropriate planning of urban areas. In this context, smart cities envision a future where cutting-edge technology synchronises with urban living to enhance efficiency, resilience, and overall quality of life. In this scenario, the following case study embarks on an exploration of this vital intersection, where an innovative approach takes center stage. It focuses on the adoption of the robust optimisation techniques to engineer a robust planning solution that deal with the complexities of an urban district. The motivation behind choosing smart cities as an energy hub optimization case study is rooted in the understanding that a well-planned urban environment sets the stage for optimised distribution systems. When secondary substations are capable of accommodating various energy vectors while effectively managing uncertainties, it becomes simpler to plan distribution networks according to the MES paradigm. The involved resources encompass a multifaceted array, including RESs, ESSs, DR programs, and other flexible assets that collectively underpin the district energy ecosystem. The significance of this case study is twofold. Firstly, it serves to exemplify the importance of meticulous urban planning as a precursor to effective distribution network planning. By showcasing how smart cities can be optimised as EHs, it underscores the need for a holistic approach that considers the urban context. Secondly, the case study acts as a demonstration of the adaptability of distribution systems in urban districts. When these districts are equipped to handle different energy vectors and uncertainties, it becomes a pivotal step towards embracing the MES paradigm.

It is important to acknowledge that this is just one step in the journey towards smarter, more resilient cities. Future works in this field are actively focusing on incorporating the flexibility market of the resources involved in the smart city district. This development will enable a comprehensive analysis of various market models, allowing for a thorough exploration of their technical, economic, regulatory, and social aspects. By integrating the flexibility market into the existing framework, we can further optimise the utilization of resources, enhance market dynamics, and offer a more efficient and sustainable energy ecosystem for smart cities. The findings of these works will not only contribute to academic knowledge but also have profound implications for real-world smart city development. They are poised to contribute to the creation of practical guidelines and decision-making tools that empower urban planners, policymakers, and stakeholders. These tools will pave the way for even more efficient and resilient integrated planning and scheduling of energy usage in the dynamic landscapes of smart city environments.

2.6.1 Overview of the Case Study

The drive for energy sustainability has led to a focus on integrating RESs into our energy mix. To achieve this, Smart Grid paradigm, initially designed for electrical power distribution networks, are extending into city district networks, integral components of smart cities. These districts boast a diverse array of energy carriers tailored to different needs. Essential to creating an efficient energy system within such districts is the development and optimisation of MESs, capable of simultaneously managing various energy carriers, including natural gas and fossil fuels. Central to this endeavour is the concept of the Energy Hub (EH). EH offers a holistic approach, leveraging the synergies among diverse energy carriers within a district. This shift towards MES and EH principles is crucial in planning smart city districts, facilitating the efficient orchestration of renewable and conventional energy resources, enhancing resilience, and fostering sustainability. EH performs the functions of generators, conversion and storage systems combined in an integrated unit. It connects consumers, producers, storage devices and transmission devices directly or via conversion equipment, managing one or more carriers. The EH in Figure 9 has its input ports supplied with electricity, natural gas and irradiation. In the Italian context, the decision has been made not to consider the district heating network as it is not yet present in the Italian territory. Similarly, the water network is excluded as it does not affect any of the equations under examination. In this case study, the inner elements of the EH consist of the following forms of generation and storage devices: CHP, EHP, PV panels, solar thermal collectors (STC), ESSs and thermal energy storages (TES). At the EH output ports, the EH supplies electricity, heating, natural gas and cooling. The optimisation framework proposed defines mathematical models of energy hub components, energy balances, and includes cost and efficiency constraints.

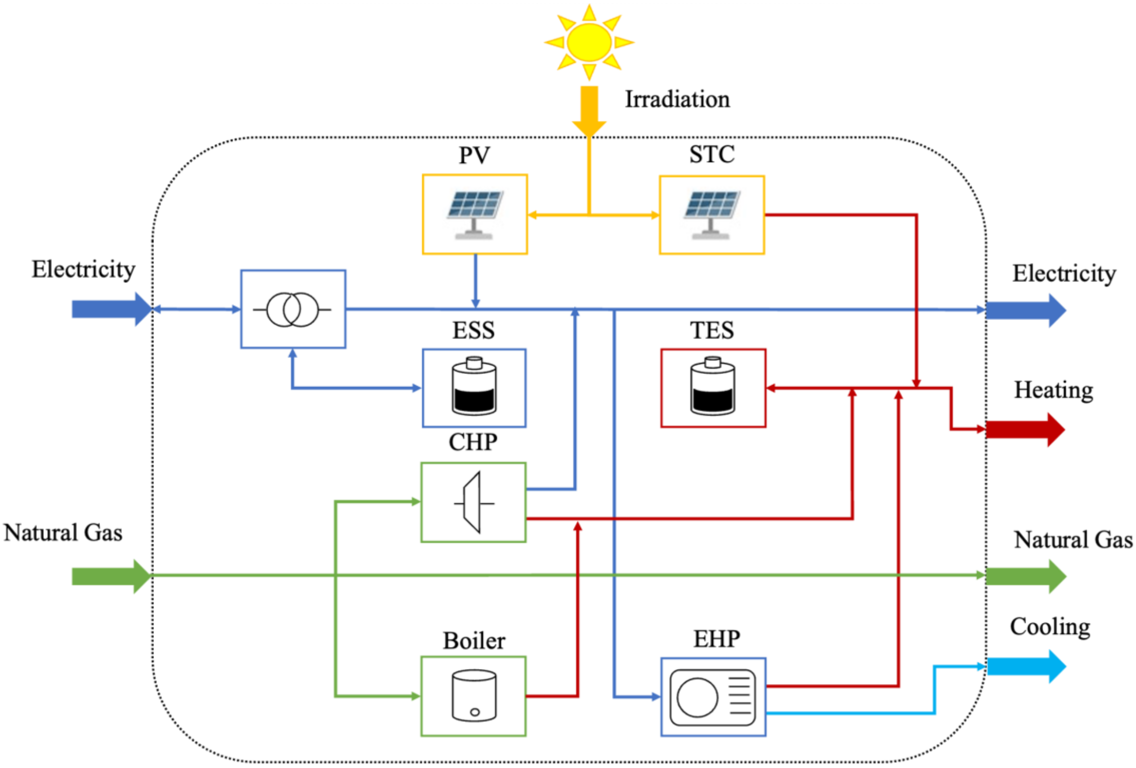


Figure 9. EH model for the smart city district.

CHP technology generates electricity and captures waste heat to provide thermal energy. In the model, the CHP is used to produce electric power and heat as a product of the hot exhaust gases. The fuel used in CHP systems can be supplied from the city district gas network. The relation between the thermal output H_t^{chp}, expressed in kWh_{th}, and the electrical output P_t^{chp}, expressed in kWh, at time t, is modelled as in Equation (13).

$$H_t^{chp} = \frac{\eta_{chp}^{th}}{\eta_{chp}^{e}} \cdot P_t^{chp} \tag{13}$$

Where η_{chp}^{th} is the thermal efficiency and η_{chp}^{e} is the electrical one. The gas consumption of the CHP unit is given by Equation (14).

$$G_t^{chp} = -\frac{\eta_{chp}^{th} \cdot P_t^{chp}}{LHV_g \cdot \eta_{chp}^{e}} \tag{14}$$

G_t^{chp} represents the gas consumption of the CHP units at time t in m^3, and LHV_g represents the lower heating value expressed in kWh_{th}/m^3 to meet the dimensional constraint.

The solar panels are subdivided into two categories: PV for electricity production and STC for heat production. Since the panel output at time t, P_t^{pv} and P_t^{stc}, is non-programmable, they are both functions of the number of panels installed and finally of the area covered (m^2). Since the PV power output depends on the available solar irradiance, in this paper, the PVGIS database has been used to extract the average radiation data to build the PV production curves. The panel power outputs at time t are defined with the Equation (15) and (16).

$$P_t^{pv} = S_{pv} \cdot \eta_{pv} \cdot \eta_{BoS} \cdot Irr_t \tag{15}$$

$$P_t^{stc} = S_{stc} \cdot \eta_{stc} \cdot Irr_t \tag{16}$$

Where S_{pv} and S_{stc} are the space occupied by the PV and the STC panels, respectively. η_{pv}, η_{BoS} and η_{stc} are the PV panel, balance of system and STC panel efficiencies, respectively.

ESS and TES are essential for compensating fluctuations in renewable resources and multiple load variations in EHs. Although the high capital and operational expenses have always characterised ESSs, they have become more affordable in recent years. The following Equation (17) and (18) have been implemented to model the ESSs.

$$SoC_t^{ess} = SoC_{t-1}^{ess} + \left(\eta_{trip}^{ess} \cdot P_t^{ess}\right) \cdot \Delta t \tag{17}$$

$$SoC_t^{tes} = SoC_{t-1}^{tes} + \left(\eta_{trip}^{tes} \cdot P_t^{tes}\right) \cdot \Delta t \tag{18}$$

Where P_t^{ess} and P_t^{tes} represent the power output from the storage system for ESS and TES, respectively. η_{trip}^{ess} and η_{trip}^{tes} are the ESS and TES round-trip efficiency, respectively. SoC_t^{ess} and SoC_t^{tes} are the state of charge at time t for the ESS and TES system, respectively. Finally, Δt is the time during the power output considered. In Equation (17) and (18), P_t^{ess} and P_t^{tes} are intended to vary from negative to positive numbers according to the storage system constraints.

As the heat pump performance continues to increase, they become one of the most efficient and environmental-saving methods to save energy and supply thermal and cooling demands in building and houses. In this case study, only electrical heat pumps are considered for meeting the heating and cooling constraints demand. Due to these relationships, they can be found in almost all energy balance equations. In particular, in the electrical balance equation, they are expected to consume electrical energy at time *t*. In contrast, in the thermal and cooling balance equations, they are supposed to produce thermal and cooling energy. The following Equation (19) and (20) express respectively the thermal energy production H_t^{ehp} and the cooling energy production C_t^{ehp} of electric heat pumps.

$$H_t^{ehp} = COP_{ehp} \cdot P_t^{ehp} \tag{19}$$

$$C_t^{ehp} = EER_{ehp} \cdot P_t^{ehp} \tag{20}$$

Where COP_{ehp} is the coefficient of performance and EER_{ehp} is the energy efficiency ratio.

In the proposed energy district, there are existing heat production systems capable of meeting the heat demand. These are conventional boilers that transfer most of the sensible heat from air combustion to hot water. In the study, the replacement of existing boilers with modern condensing boilers that can reduce emissions and increase thermal efficiency is assumed. The heat balance Equation (21) is given below.

$$H_t^{boiler} = \eta_{boiler} \cdot P_t^{boiler} \tag{21}$$

Where P_t^{boiler} represents the thermal power required to produce H_t^{boiler} at time t expressed as kWh_{th}, η_{boiler} is the boiler system efficiency, and H_t^{boiler} is the thermal power effectively exploited by the user expressed as kWh_{th}.

For each time step t, the EH balance equations require that the sum of the user's consumptions (i.e., L_t^e, L_t^{th}, L_t^g, and L_t^c expressed as electrical, heating, natural gas and cooling) and energy demand from unit m equal the sum of production from unit m, the net energy exchange with storage systems (P_t^{ess} and P_t^{tes}) and the net energy imported from the external grid (P_t^{purch} and G_t). The energy balance Equations (22)-(25) are expressed in the following.

$$P_t^{purch} - P_t^{sold} + P_t^{chp} + P_t^{pv} - P_t^{ehp} - P_t^{ess} = L_t^e \tag{22}$$

$$\frac{\eta_{chp}^{th}}{\eta_{chp}^{e}} \cdot P_t^{chp} + P_t^{stc} + \eta_{boiler} \cdot P_t^{boiler} + COP_{ehp} \cdot P_t^{ehp} - P_t^{tess} = L_t^{th} \tag{23}$$

$$G_t - \frac{\eta_{chp}^{th}}{LHV_g \cdot \eta_{chp}^{e}} \cdot P_t^{chp} - \frac{1}{LHV_g} P_t^{boiler} = L_t^g \tag{24}$$

$$EER_{ehp} \cdot P_t^{ehp} = L_t^c \tag{25}$$

This case study aims at developing an EH risk-based network optimisation model that can be adopted by DSOs. This model minimises the capital and operational expenses in the EH urban district. The operational cost is approximated by the weighted sum of several scenarios based on their occurrence probabilities. The objective function in Equation (26) accounts for investment costs, costs related to emissions and resource management and represents the total annual cost for energy services in the EH.

$$\min\left\{\begin{array}{c}\sum_{j=1}^{N_c} c_j^{inv}\cdot(1-R)\cdot\frac{(1+r)^{N_j}-1}{r\cdot(1+r)^{N_j}}\cdot P_j^{nominal}+\\ +N_{day}\cdot\sum_{s=1}^{N_s} w_s\cdot\left[\sum_{t=1}^{T} c_p\cdot P_t^{purch}-c_s\cdot P_t^{sold}+c_g\cdot G_t\right]+\\ +\sum_{t=1}^{T} c_{€/tCO_2}\cdot\left(e_{pw}\cdot P_t^{purch}+e_{gas}\cdot G_t\right)\end{array}\right\} \tag{26}$$

Where c_j^{inv} is the investment cost for the j^th unit expressed in $€/(\mathrm{kW}\cdot\mathrm{year})$ and the term $(1+r)^{N_j}-1/r\cdot(1+r)^{N_j}$ is the annuity factor coefficient, used to convert a single investment into an annual expenditure and allow the comparison between the resource investments and the yearly cost for purchasing and selling energy. Finally, R is the residual rate, r is the discount rate, and N_j is the lifetime of the j^{th} system component. With these parameters, the first line of Equation (26) represents the equivalent annualised value of the investment cost. The second line denotes the annual operation cost for purchasing energy from the main system, where the terms c_p, c_s and c_g are the price for buying and selling electrical energy, and purchasing gas from the main grid, expressed in €/kWh and €/m^3, respectively. In addition, w_s is the probability of scenario s and is used as the contribution rate of scenario s to the total annual operational cost of the EH. It is worth mentioning that if the representative scenario s represents d_s days, then w_s equals the proportion of these days in one year, d_s/365.

Finally, the last line of Equation (26) represents the emission costs, where e_{pw} and e_{gas} are the conversion factor and $c_{€/tCO_2}$ is the cost of emissions, expressed as €/tCO_2. The optimisation problem is solved by a linear programming approach. The problem constraints are the four balance Equations (22)-(25), the rated power capacity and rated energy capacity (for storage devices) of the relevant EH components.

The described methodology has been tested considering a hub model, as shown in Figure 9, and considering the optimisation problem formulated as in previous sections. In the RO problem, uncertainty affects the following parameters: investment costs, management costs, electricity demand, thermal energy demand, gas demand, cooling demand, and solar radiation data. The cost terms are represented by a symmetrical interval, while asymmetrical intervals constrain the demand profiles. Demand profiles are strongly influenced by uncertainty, such as measurement inaccuracy or time variability. Having as much information as possible about the input data within a planning problem is crucial. Indeed, the straightforward characterisation of demand profiles with symmetrical ranges could lead the optimisation problem to a low probability of occurrence solutions. Therefore, to evaluate the best possible solution, the case study requires studying the optimisation problem under the assumptions of deterministic input data and uncertain input data on symmetrical and asymmetrical intervals.

The case study considers a planning horizon of 20 years. The yearly energy demand profiles are extracted from [147]. However, for a more simplified representation of the model, while avoiding the inclusion of too many time variables, only one typical day has been used to simulate the customers' demands throughout the whole year. The skew normal distribution modelled the hourly variability. As an example, in Figure 10 the solar radiation profile obtained from [148] is shown and the maximum and minimum deviation from the mean value are shown. Instead, in Figure 11 the weekly load profiles for electricity, heat, gas and cooling. It is important to report that the profiles used in the study are daily profiles. However, these are taken from annual profiles, which were processed using clasterisation techniques, in particular k-means, in order to find the daily profile.

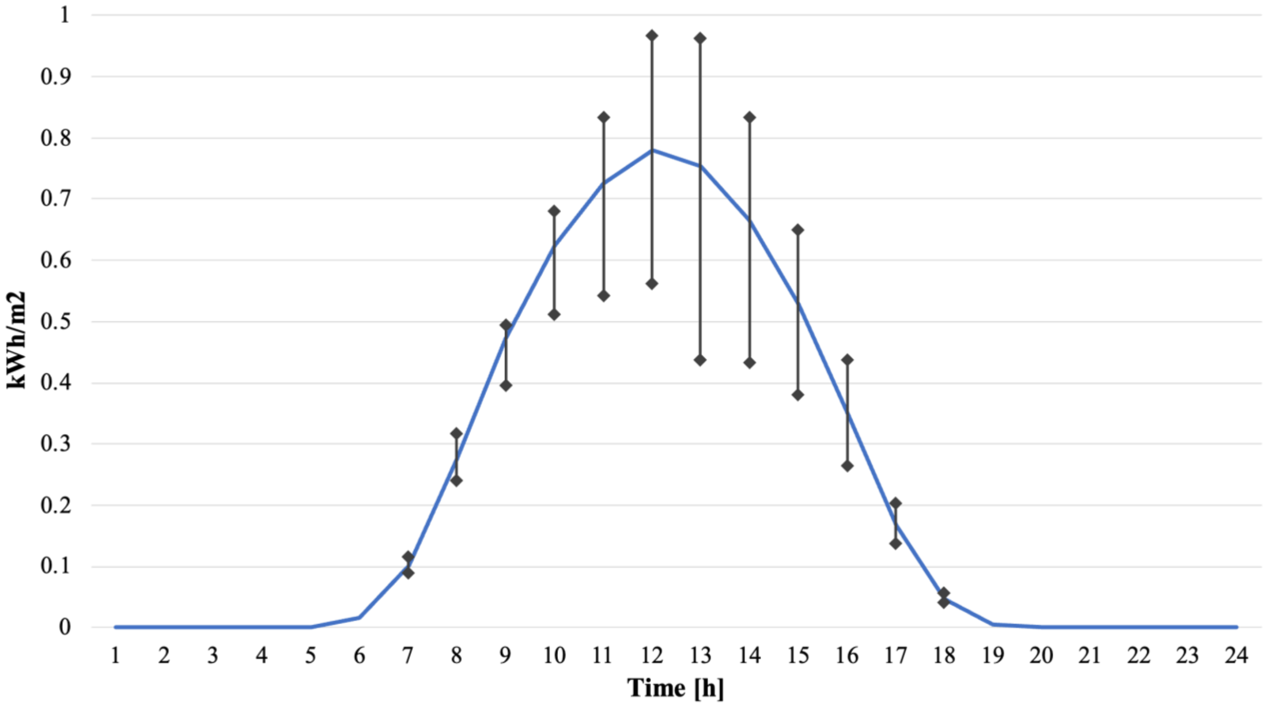


Figure 10. Solar radiation profile and maximum-minimum deviation.

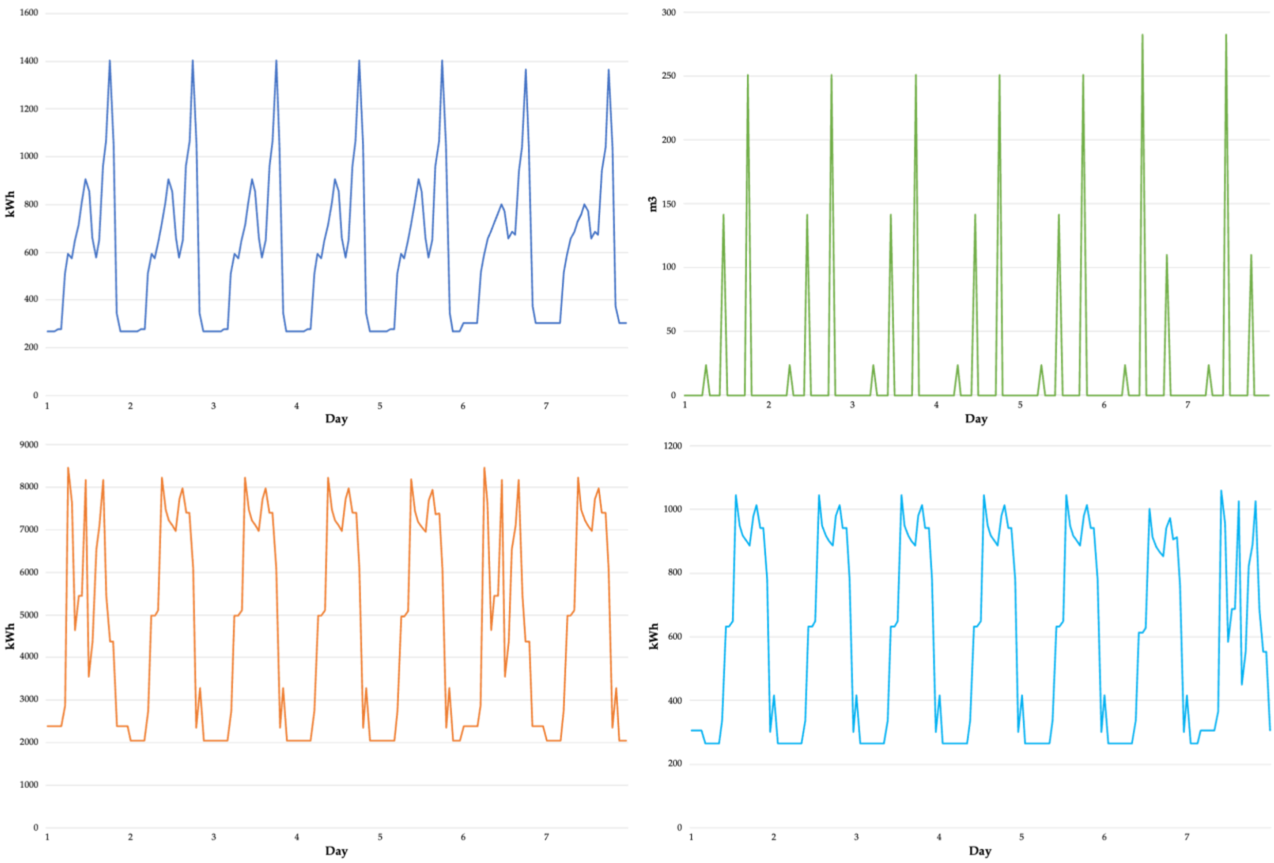


Figure 11. Load profiles (blue - Electricity, green - Gas, orange - Heat, - light blue - Cooling).

In Table II the investment costs and the component lifetimes are summarised, while Table III reports the purchasing/selling prices adopted in the case study.

Table II. Investment costs and component lifetimes.

	EHP	**Boiler**	**ESS**	**TES**	**CHP**	**PV**	**STC**
c_i	900 €/kW	200 €/kW	160 €/kW - 240 €/kWh	75 €/kW - 125 €/kWh	800 €/kW	226 €/m2	400 €/m2
N_j	20 y	15 y	12 y	20 y	30 y	30 y	20 y

Table III. Purchasing and selling energy and gas prices.

$\mathbf{c_p}$ [€/kWh$_e$]	$\mathbf{c_s}$ [€/kWh$_e$]	$\mathbf{c_g}$ [€/m^3]
0.2	0.05	0.8

Concerning the other parameters, the discount rate, r, is equal to 8%, and the energy efficiencies consider the maximum and minimum SoC either for the ESS and for the TES unit, which are equal to 90% and 10% for the ESS, and 90% and 0% for the TES system. The term $\eta_{chp}^{th}/\eta_{chp}^{e}$ is equal to 1.25 while η_{boiler} to 0.9% since high-efficiency boilers are considered in the study. Finally, COP_{ehp}, EER_{ehp} and LHV_g are respectively equal to 4, 4, and 9.806.

2.6.2 Results Evaluation

The results are subdivided into deterministic, symmetric robust and asymmetric robust. They are going to be presented in separately and then compared.

The problem is solved considering the deterministic and the robust approaches, both symmetric and asymmetric, and the optimisation results are reported in Table IV. In the robust solutions the a priori risk ε_i is equal to 10%.

Table IV. Results for the three cases.

	Deterministic	Symmetric robust	Asymmetric robust
$P_{ehp}^{nominal}$ [kW]	100	90	90
$P_{ess}^{nominal}$ [kW]	0	27	90
$P_{tes}^{nominal}$ [kW_{th}]	960	465	445
$P_{boiler}^{nominal}$ [kW]	155	1120	480
$P_{chp}^{nominal}$ [kW]	960	945	960
S_{pv} [m^2]	2590	0	0
S_{stc} [m^2]	4670	0	3040
E_{ess} [kWh]	0	125	220
E_{tes} [kWh_{th}]	3405	465	570
Gas_{purch} [m^3]	2310	3740	2740
$Energy_{purch}$ [kWh]	786	382	259
$Energy_{sold}$ [kWh]	1634	1661	1736
Cost [k€]	1080	1369	1291
Emissions [tCO_2]	4.95	7.57	5.54

The deterministic solution has the lowest cost and emission values because the robust solutions are affected by the degree of protection we are looking for. If $\Gamma_i = |J_i|$, the constraint ith will be completely protected from violations. On the other hand, choosing $\Gamma_i = 0$, the ith constraint will not be protected. In this sense, Γ_i can be seen as the level of protection of the ith constraint. The difference between the deterministic and the robust solution is the degradation of the objective value that results from improving the level of protection by selecting Γ. Therefore, the deterministic solution that is not protected from possible constraint violations considers the massive utilisation of PV panels for both electric and thermal demand. In this way, there is no need to install storage systems, which have high investment costs and a shorter lifetime than other components.

The robust symmetrical solution has the highest costs and emissions. The symmetric solution considers the probability distribution of uncertain variables according to a symmetric range. This initial assumption not only penalises the degradation of the objective function but also considers possible values of the uncertain variables that are unlikely to be realised. Therefore, the robust symmetric approach is the one that most considers the worst-case scenario. Indeed, the robust symmetric solution does not consider the installation of either PV or solar collectors, preferring a massive utilisation of boilers to cover the thermal demand. The robust symmetric solution adopts electrical storage system to eliminate any possible uncertainty from irradiance profiles (i.e., the profiles most affected by uncertainty). However, such a solution requires relatively high investment costs. Although the robust symmetric solution tries to protect from uncertainties through electric storage systems, it is forced to use boilers heavily. This solution reduces both the number of thermal batteries and the number of STCs. Therefore, the massive adoption of boilers leads to higher costs of purchasing gas from the grid.

The robust asymmetric solution has the best trade-off between uncertainty protection and degradation of the objective function. The asymmetric solution differs more from the symmetric solution in the sizes of electrical storage systems, solar thermal panels, and finally, the amount of electricity bought and sold. The representation of the uncertain variables according to a probability distribution of greater detail (i.e., adopting an asymmetric distribution) means that the installation of solar panels is not discarded outright. The installation of solar thermal panels makes it possible to reduce the investment in boilers compared with the symmetrical solution. Moreover, installing a substantial number of electrical storage systems ensures high self-sufficiency of the energy hub, reducing the electricity purchased and increasing the electricity sold.

To show the impact of the different approaches, Figure 12 shows the amount of gas purchased from the grid for the three solutions. The three solutions differ the most in the middle hours of the day.

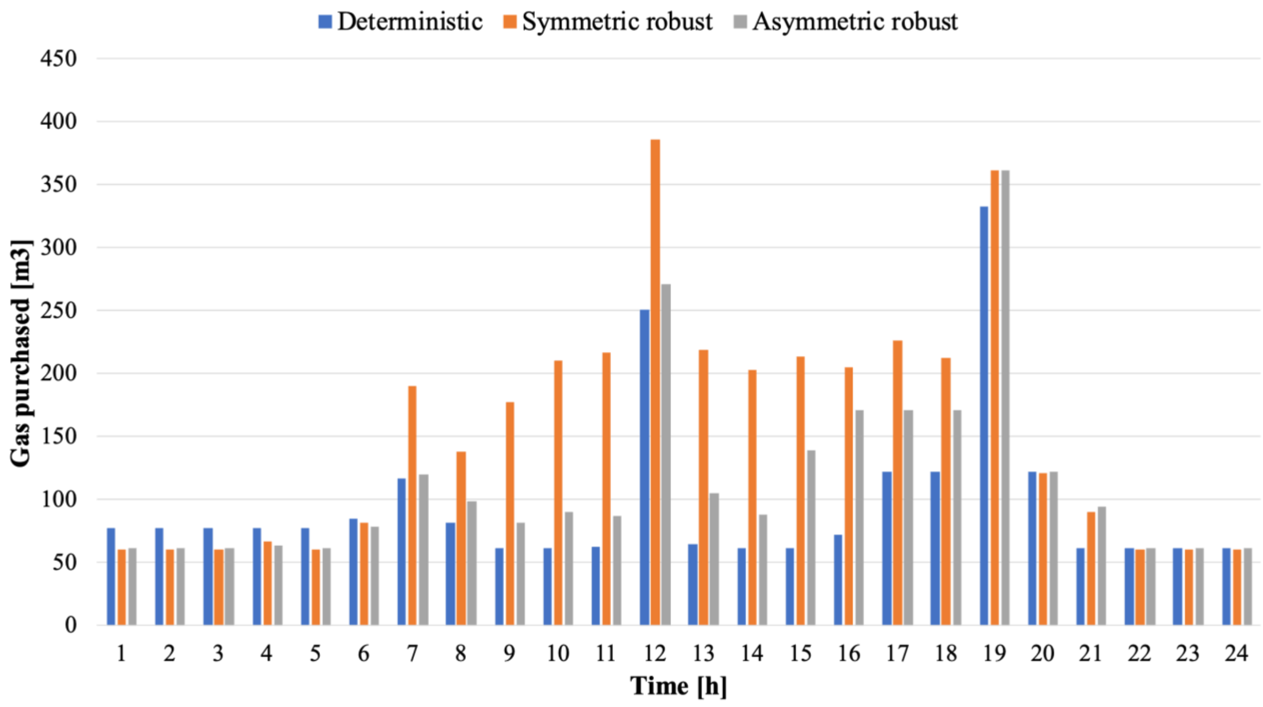


Figure 12. Gas profiles purchased from the grid: deterministic, symmetric and asymmetric robust approach.

The solar irradiance has the most significant variation from the expected profile during those hours. Consequently, the robust symmetrical solution shows how the uncertainty of irradiance requires a more considerable gas purchase to cover the demand of the boilers, compensating for the lack of solar thermal collectors. Contrarily, the robust asymmetric approach reduces gas demand compared to the robust classical approach. Indeed, the asymmetric solution selects a total heat output of the boilers that is not as high as for the symmetric method and simultaneously requires the installation of 3040 m^2 solar thermal panels. The asymmetric approach identifies a solution that avoids buying a large amount of gas from the grid to keep the level of risk smaller than 10%.

2.6.3 Conclusion and Future Works

This chapter has navigated the intricate landscape of distribution planning within the context of modern smart cities, underlining the significance of urban energy systems in shaping the future of urban living. The case study proposed an innovative approach to multi-energy system planning, employing deterministic and robust optimisation techniques. Notably, the research encompassed both symmetric and asymmetric uncertainty representations, with robust optimisation emerging as a powerful tool for managing risk and ensuring reliable energy planning.

As we look forward to future research directions, the horizon is promising. Our focus will be on the refinement of models for asymmetric uncertainty representation, including factors such as energy prices, demand, and solar radiation. Yet, the most transformative journey lies ahead. In particular, in the integration of flexibility markets into the planning of smart city distribution networks. This visionary step promises to redefine the urban energy landscape, promoting greater efficiency, sustainability, and resilience.

In conclusion, our work is a foundational step toward the creation of smarter, more adaptive cities. By embracing the ever-evolving energy transition paradigm and incorporating flexibility markets, we aim to empower urban planners, policymakers, and stakeholders with the tools needed to navigate the dynamic landscapes of smart city environments efficiently and effectively.

3 Markets for Distribution-level System Services

In the dynamic landscape of modern energy systems, the role of distribution networks has evolved significantly. No longer confined to merely delivering electricity, distribution networks have become critical components in ensuring the stability, resilience, and sustainability of the entire power grid. The integration of RESs into power generation, while crucial for sustainability, poses challenges due to their intermittency and decentralised nature. This shift has given rise to congestion issues in distribution networks, where imbalances in electricity supply and demand lead to bottlenecks. Congestion can be managed technically by grid operators or through procuring flexibility services from markets. Flexibility, defined as the ability to modify generation and consumption patterns in response to external signals, plays a vital role in addressing congestion.

This chapter explores congestion management in distribution networks, focusing on the comparison of market mechanisms for distribution-level system services. The uniqueness of this chapter lies in its thorough analysis of different market mechanisms for distribution-level system services. It aims at uncovering the strengths, weaknesses, and potential impacts of these mechanisms on distribution network resilience and reliability. This chapter wants to provide to the reader a deeper understanding of how diverse market mechanisms can shape the future of congestion management in distribution networks.

3.1 Research questions

This paragraph frames the main research questions for this section of the thesis.

The research question “*What are the challenges and opportunities associated with integrating renewable resources into distribution system services?*” seeks to uncover the multifaceted landscape of integrating renewable resources into distribution system operation. It aims at identifying and analysing the array of challenges that arise alongside the opportunities presented by the incorporation of RESs at the distribution level. The investigation delves into the technical, operational, and economic complexities that emerge as distribution networks accommodate intermittent and decentralised energy generation. By addressing these challenges and identifying the potential benefits, the question aims at providing a comprehensive understanding of the dynamics that shape the integration of renewables into distribution system operation.

The research question “*How can flexibility sources, such as demand response, energy storage, and electric vehicles, be leveraged to enhance the operation and reliability of a distribution network?*” focuses on exploring the utilization of flexibility sources, including demand response, energy storage, and electric vehicles, to optimise the operation and bolster the reliability of a distribution system. The question seeks to understand how these diverse flexibility options can be strategically harnessed to address the challenges posed by the integration of RESs and the increasing decentralisation of power generation. By investigating the synergies between flexibility sources and their potential to mitigate operational uncertainties and enhance system resilience, the research aims at providing insights into creating more adaptive, efficient, and secure distribution networks.

The research question "*How do different market mechanisms handle the variability and uncertainty associated with flexibility resources and local redispatch actions?*" focuses on the exploration of diverse market mechanisms and their strategies in effectively addressing the challenges posed by the variability and uncertainty inherent in flexibility resources and local redispatch actions. Throughout the chapter, the question aims at analysing how different market approaches tackle the integration of these dynamic resources into the operation of the distribution system. By examining these aspects, the research wants to provide insights into the strengths, weaknesses, and potential enhancements of various market models in achieving seamless integration and optimal utilization of flexibility resources and local redispatch actions.

3.2 Distribution System Services in the Energy Transition

The contemporary landscape of energy generation and consumption is witnessing significant transformations, imposing growing stress on distribution networks, which can lead to congestion. In the consumption sector, urbanisation is driving a substantial migration to cities. Simultaneously, the electrification of transportation, particularly the surge in EVs, is anticipated to grow exponentially, reaching 145 million by 2030 [149]. This substantial electrification will result in a six-fold increase in electricity demand, with EVs contributing significantly, accounting for 4% of Europe electricity consumption.

Simultaneously, in the production sector, the drive towards sustainable electricity generation has brought solar power prominently into urban environments. These shifts in consumption and production are not the sole factors contributing to distribution network challenges. New and innovative business models are emerging, empowering consumers to become prosumers and participate actively in various markets. While this paradigm offers benefits to service providers, it introduces complexities into distribution grid operations. The unpredictability of load and generation, driven by rapid responses to market signals, amplifies uncertainty and volatility in network state forecasts, further complicating congestion management. In this evolving scenario, two approaches can be distinguished. The first involves the use of congestion management techniques through non-market mechanisms. The second approach instead adopts market-based management techniques. Market-based techniques include methodologies that exploit resource flexibility as well as approaches using price signals, based on DLMP. Flexibility facilitates optimal resource management and helps prevent congestion by enabling strategic activities such as shifting EV charging to coincide with peak PV generation.

In light of this context, this chapter introduces the evolution of congestion management markets for distribution systems. The chapter begins with a description of the concept of congestion, explaining what congestion means, when it can occur and what kind of service the system operator needs to solve congestions. Finally, the chapter introduces traditional methodologies based on non-market congestion management techniques and continues with modern market-based approaches, introducing the concept of RES in congestion management markets.

3.2.1 Congestion in Distribution Systems

The EU commission regulation provides a clear definition of physical congestion in transmission-level networks, describing it as any network situation where forecasted or actual power flows exceed the thermal limits of grid elements and affect voltage stability or angle stability within the power system [150]. However, shifting to distribution networks, the considerations differ due to the absence of angle stability. As a matter of fact, at the distribution level, the focus is on voltage-related issues encompassing over-voltage, under-voltage, and harmonic content, alongside current and thermal limit violations.

Voltage violations are particularly pertinent in distribution networks, and they align with the European standard EN 50160 [151]. This standard sets forth minimum power quality requirements for MV and LV customers, encompassing parameters like frequency, voltage magnitude, rapid voltage fluctuations, and harmonic content. Notably, the standard requires that steady-state voltage magnitude in LV and MV networks should remain within a range of ±10% of the nominal voltage for at least 95% of the week. Among these voltage quality concerns, over-voltage presents a growing challenge in distribution networks. Over-voltage can be attributed to active power injection, and its adverse effects can lead to congestion. Thus, grid operators must ensure that power generation from distributed resources does not push voltage levels beyond permitted limits.

With the exception of scenarios where power production and consumption coincide at the same location, electricity must cross the physical distance between production and consumption points. Congestion arises when the flow of current between these points exceeds the ampacity of essential infrastructure such as underground cables, overhead lines, transformers, and circuit breakers. Addressing congestion induced by overloading necessitates strategies like conductor resizing, constructing new lines, and redistributing loads among adjacent feeders according to their current-carrying capacities.

Furthermore, thermal equilibrium ensures that conductors maintain a steady temperature. Any deviation from this equilibrium results in temperature fluctuations. Conductor resistance contributes to ohmic losses, stemming from the flow of electrical current. Additionally, forced-convection cooling power facilitates heat dissipation, with a portion of generated heat dissipating through thermal radiation [152]. The thermal limit serves as a critical constraint in power system operation. If an excessive amount of energy is generated in a specific area, surpassing what local loads consume, the surplus energy flows to neighbouring loads. This excess energy transfer can lead to breaches of the thermal limits of grid components, potentially causing congestion.

It is noteworthy that the underlying causes of congestion can vary over time, even within a single network. For instance, congestion on a distribution feeder during winter may result from overloading the secondary substation transformer, whereas congestion on the same feeder in summer could stem from excessive power injection from rooftop solar panels, leading to over-voltage issues. Consequently, DSOs must continually monitor network constraints and anticipate potential congestion based on their grid's strengths and weaknesses.

To dealt with these technical problems, DSOs can rely on congestion management techniques. Traditionally, these have always been based on non-market techniques, but currently, thanks to European pushes, there is a shift towards a system increasingly focused on the use of the market, also for congestion management. Congestion management techniques, both non-market and market techniques, can offer three kinds of services: *i*) short-term, *ii*) operational, and *iii*) long-term services.

The concept of a short-term service in the context of congestion management is centered on addressing congestion issues when the system operator has a strong likelihood of upcoming congestion in the immediate future. System operators employ various grid tools, such as congestion forecasts, to predict potential congestion within their networks for the next day. These forecasts become more accurate as they approach the actual operation time. Congestions that are highly likely to occur are identified, and they become candidates for resolution through short-term congestion management techniques [153].

The concept of operational service in the context of congestion management addresses situations where grid operators have uncertainty about the occurrence of congestion in the upcoming days. In such scenario, a conditional re-profiling product is employed to manage potential congestion. Conditional re-profiling is a pivotal concept in the realm of congestion management services, enabling grid operators to efficiently handle uncertainties related to congestion. In essence, conditional re-profiling entails a commitment from the service provider to have the necessary capacity available for modifying demand or generation profiles as per real-time requests from buyers. Unlike scheduled re-profiling, which necessitates the activation of the service, conditional re-profiling encompasses a two-stage payment process, comprising capacity reservation and subsequent activation, through the energy that is effectively provided to the operator [153]. System operators frequently opt for conditional re-profiling when faced with uncertainty regarding congestion. This uncertainty often stems from various factors such as inaccuracies in weather forecasts, load predictions, and production forecasts. To navigate this uncertainty, grid operators adopt a more cautious approach to congestion management, reserving the necessary capacity in advance. The choice between scheduled re-profiling and conditional re-profiling is a multifaceted decision for system operators, influenced by various factors. These factors include the operators prior experience in managing congestion and their level of confidence in congestion forecasts. Conditional re-profiling reservations generally tend to be the more cost-effective option for the operators. However, it is essential to note that if conditional re-profiling is eventually activated, it can often become more expensive than the scheduled re-profiling. Consequently, system operators engage in a decision-making process that revolves around selecting the most suitable service based on their specific needs and their level of confidence in their congestion forecasts [154].

Finally, the concept of long-term service within the domain of congestion management plays a crucial role in addressing flexibility needs that can be anticipated well in advance. This anticipation often depends on the regularity of market operations, which can span varying timeframes, such as annually, seasonally, monthly, or weekly. Long-term congestion management services provide grid operators with a means to assess their future flexibility requirements based on several factors, including scheduled maintenance plans, seasonal variations in hosting capacity, and expected changes in load or production. Referred to as hosting capacity and maintenance, the long-term service essentially revolves around grid operators hosting capacity needs and maintenance requirements. Much like conditional re-profiling, the capacity reservation for hosting capacity and maintenance takes place when the market operates, typically in advance, such as a week ahead [155]. However, the decision for activation must be made a day ahead of real-time operations. The lead time for long-term congestion management services can vary significantly, ranging from annual markets to weekly markets, depending on national regulations, specific needs, and stakeholder considerations. The choice of lead time in long-term congestion management services significantly impacts stakeholder behavior. Longer lead times, as seen in annual markets, come with higher risks for traders due to increased uncertainty, primarily arising from prediction errors. This can result in more conservative behavior among market players [156]. From a DSO perspective, when exploiting network reconfiguration as a long-term congestion management solution, the timing of long-term congestion management technique should ideally align with network switching state changes. For manually operated switches, which are usually reconfigured seasonally or monthly, shorter lead times in long-term products prove beneficial. However, this discussion may not apply if congestion management relies on fully automated switches that operate in real-time, as the timing of long-term congestion management would not align with real-time congestion management. Furthermore, shorter lead times in congestion management, such as weekly markets, may be more influenced by well-established markets like day-ahead or intraday markets. This influence can lead to fluctuating prices in long-term congestion management [154].

3.2.2 Non-Market-based Congestion Management Approaches

Approaches for addressing congestion can be broadly classified into market-based and non-market-based solutions. In the realm of non-market-based solutions, both TSOs and DSOs share similar alternatives, albeit with implementation-level variations, to manage congestion effectively. Non-market-based solutions encompass a range of strategies and techniques. These include network reinforcement, active power curtailment [157], network reconfiguration [158], grid code compliance, grid tariff adjustments [159], reactive power compensation [160], contracted DR actions, and coordinated voltage control [161]. These solutions represent established approaches to congestion management, often preferred by system operators due to their extensive technical expertise. Additionally, some non-market-based solutions, like network reconfiguration, offer the advantage of self-governance, reducing the need for extensive coordination with external stakeholders. It is essential to note that the inclination of grid operators towards traditional solutions over newer, market-based alternatives is influenced by factors such as technical familiarity and operational experience.

The process of reducing the electrical impedance within the network, which facilitates the flow of electricity from production to consumption points, is commonly known as network reinforcement. This technique involves actions like resizing conductors or constructing new power lines with lower impedance. While network reinforcement is a highly effective solution for addressing congestion, it comes with substantial costs. In many cases, it represents the initial choice for numerous DSOs when confronted with congestion challenges. DSOs frequently resort to network reinforcement because of their extensive experience in this area and their technical capabilities [162]. However, there are circumstances where network reinforcement may not be the ideal choice. First and foremost, it can be expensive and time-consuming, making it less feasible for immediate deployment. Secondly, considering the extended planning horizon often spanning two decades, uncertainties related to key parameters like electricity generation, consumption patterns, and urban planning can significantly escalate. Factors such as the growing trend of prosumers injecting intermittent renewable energy into the grid due to favourable feed-in tariffs and the increasing prevalence of EVs add complexity to load forecasting. Given these challenges, it becomes prudent to minimise the frequency and scale of network reinforcement projects. To achieve this, a more strategic and forward-looking approach is necessary. This approach involves complementing network reinforcement with alternative solutions, particularly those with long-term benefits. These complementary strategies may include coordinated voltage control, as well as market-based solutions and others. Such an integrated approach enhances the efficiency of the network planning process and mitigates the inherent risks associated with making long-term decisions in an evolving energy landscape [163].

Managing congestion in a distribution system often involves curtailing the active power output of generators, a common congestion management strategy [164]. While this approach effectively alleviates congestion in the short term, it is typically not a financially sustainable long-term solution. This viability depends on several factors, including the required duration of curtailment in a fixed period, the associated congestion costs for a DSO, the age and financial capacity of the existing network, and more. These factors collectively determine whether active power curtailment is considered a long-term, medium-term, or short-term solution. DSOs usually do not have the authority to curtail the active power of production units arbitrarily. Instead, they offer various connection capacity schemes, including firm and non-firm options [165]. Non-firm connections allow DSOs to curtail power generation within agreed-upon limits, often reducing the connection costs for electricity producers compared to those with firm connection capacity. While non-firm connections offer cost savings, they may entail active power curtailment when needed. From a financial perspective, the lower connection cost of RESs contrasts with their expensive investment costs. Consequently, RES owners and environmentally conscious stakeholders typically oppose active power curtailment as a congestion solution. This resistance is due to the desire to extract the maximum energy from RESs, aligning with climate and sustainability goals. Active power curtailment may find acceptance when feed-in peaks are infrequent and of short duration, often making it a viable and pragmatic solution under these specific circumstances [166].

In the context of distribution networks, where numerous switches are available, in order to manage congestion, DSOs may decide to alter the status of switches [167]. To understand the network reconfiguration approach, we can consider the following scenario, where a primary substation supplies two feeders. In this scenario, a particular switch known as the normally open switch is set to ensure the radial operation of the two feeders. This setup highlights that meshed networks poses greater complexities compared to radial networks, necessitating the normally open switch to remain in its normally open mode. If a distributed generator provokes an overvoltage at a specific bus and neighbouring buses, the DSO could decide to increase the load on the same feeder by introducing a MV load. To do this, the DSO decide to open the normal open switch and close another switch that connect the MV load to the other feeder. In this way, the MV load is now connected to the feeder subject to overvoltages. This strategic adjustment ensures that the power generated by the generator is consumed locally, preventing reverse power flow and overvoltage. However, to avoid overloading on the feeder when the generator is shut down, the network must return to its initial configuration. Achieving this requires a robust automation system responsible for coordinating the actions of all relevant switches. However, this solution is feasible only when both the normal open switches are fully automated and capable of seamless coordination with the distributed generation automation systems. Altering the status of switches serves as a mid-term alternative for relieving congestion effectively in such scenarios.

A grid code is a set of conditions that generation units must adhere to, in order to obtain grid connection approval. The stringency of the grid code increases with the rating of the production unit because larger generators can significantly impact the grid [168]. Grid codes are crafted to regulate the behavior of power plants under both steady-state and transient conditions. These codes can vary from one country to another and are tailored to the specific characteristics of the power system they are designed for. For example, the grid code established by ENTSO-E outlines requirements for grid connection that are applicable to all generators [169]. It is relatively more flexible compared to the IEEE-1547 standard [170]. This flexibility is essential because ENTSO-E must accommodate the diverse features of national power systems across European countries within a single standard. Grid codes typically encompass requirements related to the quality of frequency and voltage for generators under both steady-state and transient conditions. Voltage-related requirements can be structured to support congestion management. For instance, a grid code may mandate the implementation of Volt/Var control systems for all generators seeking grid interconnection. By bolstering the grids voltage, these measures can reduce the likelihood of congestion caused by overvoltage or undervoltage. Consequently, a well-established grid code can serve as a tool for congestion management.

Another congestion management approach is the grid tariff technique. Grid tariff has the capacity to gradually influence customers consumption patterns, making it a potent tool to achieve various objectives, including enhancing energy efficiency, reducing bills, minimising losses, or making long-term cuts in grid infrastructure investments [171]. The grid tariff is pertinent to congestion management due to its potential to modify customer behavior in favour of congestion alleviation. Typically, the conventional grid tariff structure employed by some DSOs consists of two main components: *i*) energy tariff and *ii*) capacity tariff [172]. The former component entails periodic fees that grid users are obligated to pay based on the total energy they consume. Often, the price for each megawatt-hour (MWh) of consumed energy remains fixed, meaning that users pay a consistent rate regardless of the load on the distribution grid at the time of consumption. While this design encourages overall energy conservation, it lacks granularity in providing information about congested points of total utilisation. DSOs can enhance this by introducing variations in the energy price over time. For instance, they might charge lower rates for energy consumed in points of total utilisation with low grid loads and higher rates for energy consumed in congested points of total utilisations. An example of this approach is a day-night tariff, where energy costs more during the day and less during the night. In the capacity tariff component, users pay the DSO based on the maximum power they draw, incentivising end-users to limit their peak consumption. A peak tariff is one form of capacity tariff where the payment to the DSO is determined by the peak load resulting from the end user's consumption, multiplied by a predefined tariff rate. This tariff can be a fixed amount or vary based on the magnitude of the peak load. A tier tariff, a discretised version of the peak tariff, is described by a pricing structure associated with specific capacity steps. Users’ payments are determined by the capacity class to which their peak load belongs. These tariff structures aim to promote more efficient energy consumption and to provide economic incentives for consumers to manage their peak demands, which, in turn, can contribute to congestion management within the distribution grid.

Reactive power compensation is a highly valuable tool in the realm of congestion management [173]. It provides several critical benefits for power distribution systems. Reactive power compensation allows distributed generators, especially synchronous generators, to actively adjust their reactive power output. This capability enables them to either absorb or generate reactive power at their terminals. The significance of this lies in its impact on voltage regulation within the network. Reactive power compensation not only influences active power generation but also gives control over the networks voltage profile. By adjusting the amplitude and sign of the reactive power output, these generators can effectively aid in preventing congestion. Additionally, reactive power compensation plays a crucial role in addressing voltage-related issues. When there is a risk of voltage surges, these generators can consume a limited amount of reactive power to dampen voltage increases. Conversely, in situations where voltage might drop too low, they can inject reactive power to stabilise the network. To ensure seamless operation, generators equipped with reactive power compensation capabilities, like synchronous generators, are often fitted with control systems such as volt/var controllers. These systems manage reactive power and ensure it complements other voltage regulation devices, such as on-load tap changers, for optimal network performance. Reactive power compensation proves invaluable not only in voltage regulation but also in congestion scenarios caused by overloaded network components. In such cases, the generator's reactive power compensation becomes a function of the apparent power flowing through the network at specific points. Overall, reactive power compensation is a versatile and indispensable tool in congestion management, offering a wide range of benefits for grid stability, voltage control, and network reliability.

When a distribution network enters the amber phase [174], market-based solutions for congestion management are typically the primary consideration. However, if the situation escalates to the red phase, more drastic emergency measures, like load shedding, become necessary [175]. Load shedding involves disconnecting certain customers from the grid temporarily, based on prior agreements between the DSO and the customers. These agreements allow the DSO to shed loads for a specified duration, which can vary from yearly to monthly intervals. Load shedding serves as one of the short-term solutions employed by DSOs when congestion arises due to the overloading of grid components. Load shedding is a viable option when there is a risk of a blackout or potential damage to critical network assets. In some cases, load shedding is strongly recommended because it selectively disconnects specific devices of a few chosen customers based on a predetermined plan. In contrast, failing to implement load shedding under severe congestion conditions could result in a substantial blackout affecting a significant portion of the distribution system. Such an outage would impact customers with varying supply priorities, including households, hospitals, data centres, and more. It is important to note that load shedding remains a valuable alternative for congestion management, particularly when dealing with loads of lower priority, such as those related to cooling and heating systems. This approach allows for a more controlled and strategic response to congestion issues, minimising the risk of broader service disruptions.

Finally, coordinated voltage control plays a pivotal role in advancing the concept of the smart distribution system. In the context of distributed hierarchical control architecture within distribution systems, decision-making occurs through a series of tiers, including stand-alone controllers, secondary controllers (comprising secondary substation automation systems), and tertiary control at the distributed management level [176]. It is essential to note that this distributed hierarchical control system represents one viable approach to implementing controllability across the distribution system, recognising that various other control structures exist. Coordinated voltage control is specifically deployed at the secondary control level for managing the LV network [163]. Additionally, it finds application in the decentralised management system for controlling the MV network, offering a multitude of available options for customisation. The fundamental concept behind coordinated voltage control involves identifying the optimal solution for operating the distribution system, taking into account both the multi-objective function of optimal power flow and various constraints. This multi-objective function may involve objectives like minimising power losses, curtailing active power, and executing tap changing operations on on-load tap changers, among others. A candidate solution that achieves the best value for the objective function while simultaneously satisfying all network constraints, such as voltage and current, is deemed the final answer in the context of optimal power flow.

3.2.3 Market-based Congestion Management Approaches

Across Europe, network congestion has been increasing at both transmission and distribution levels, driven in particular by the uptake of variable renewable energy and decentralised resources, as well as delays in network expansion. The further uptake of EVs, heat pumps and other electric appliances adds a new dimension to the challenge, especially at distribution level [177]. These appliances add substantial new load, but at the same time have the potential to be significant flexibility resources.

Relying only on grid investments to cope with this challenge could take too long to realise and would be very expensive. On the other hand, making use of distributed flexibility resources not only for transmission but also for distribution network management can lead to very significant cost savings and much more efficient integration of RESs [178]. This is recognised by the electricity market directive where it is established that DSOs should procure flexibility services where these are cheaper than grid expansion [27]. It also indicates that incentive structures for DSOs should be adapted, and DSOs *shall procure such services in accordance with transparent, non-discriminatory and market-based procedures*. It is important to note that when the directive refers to *flexibility*, it is not limited to a rigid, predefined definition. Instead, flexibility encompasses a broader spectrum of services and capabilities aimed at enhancing the overall performance and reliability of the energy system. This more comprehensive understanding of flexibility aligns with the dynamic and evolving nature of the energy landscape, where diverse resources and innovative approaches contribute to the effective integration of RESs and the efficient management of both transmission and distribution networks. In this scenario, to solve congestion, the system operator can resort to congestion management markets. In these markets, system operator can order market participants to change their positions, either by increasing or reducing production and consumption depending on the side of the congestion the market participant finds itself. In short, the system operator can ask the market participants, which can be generators, consumers and even storage systems, to adjust their consumption or injection according to a price signal that is provided by a market. Market-based approach bases the decision on price signals linked to the need for flexibility action. This kind of markets act after the wholesale market, operating in a similar manner to the already existing balancing markets and other ancillary services. These mechanisms engage generation, demand and storage to solve congestions in the cheapest way. They serve as a cost-effective alternative to expensive grid reinforcement while increasing the overall system efficiency.

According to the literature, these congestion management mechanisms bring several benefits, which can be classified as follow.

- *Increased competition due to a wider spectrum of technologies participating*. A market-based mechanism is better suited for incorporating flexibility of resources into the energy system compared to a regulated approach. Flexibility differs from traditional generation in that it does not have fixed costs but instead incurs opportunity costs that fluctuate based on factors such as time, location, and the entity providing it. Regulated approaches tend to limit flexibility provision to generators, while market-based approaches encourage participation from various technologies, making them more inclusive and adaptable [179].
- *Increased transparency*. In many European countries, the network components of consumer bills have been rising significantly, but information on the actual causes of this is often unknown. If congestion management actions are based on bilateral agreements or obligations, this naturally centralises knowledge and power with system operators. Regulatory oversight is often challenging, especially because transparent information on market alternatives is not usually available in such cases. Instead, a market-based approach can bring transparency to system management challenges and congestion problems, it reveals the variety of flexibility services available in the market, allowing the most cost-effective solutions to be identified. Allowing a wide variety of resources to compete in order to provide congestion management services will increase liquidity and reduce the likelihood of any market party being able to exercise market power. The potential of this approach is already well understood from

the procurement of ancillary services for transmission system management, which has produced cost-effective outcomes, even though the flexibility potentials are still far from being fully developed [156].

- *Reduced grid reinforcement investment costs*. Market-based procurement of congestion management is more cost-effective for the system operator compared to cost-based or regulated approaches. It allows for the inclusion of various technologies, including DR actions, making it cheaper and more efficient. In order to highlight the potential for significant cost savings, EU estimates that we could save up to 5 billion euros per year in avoided investments by 2030 [111]. In addition, Germany could reduce by 55% by 2035, resulting in total savings of €20 billion in that period [144].
- *Cost-effective integration of variable RES and environmental benefits*. A genuine market for congestion management, which is technology-neutral and inclusive, has multiple advantages. It not only provides financial benefits and enhances social welfare but also contributes to the better integration of RESs. Specifically, a market-based approach to flexibility could reduce the need for RES curtailment by up to 65%, resulting in a substantial environmental benefit of avoiding the emission of 1.5 million tonnes of CO_2 per year [180].

Concerns regarding congestion management markets primarily revolve around the potential for market abuse. These concerns stem from the structural design of European electricity markets, particularly the subsequent markets that follow the initial wholesale markets, which consist of day-ahead and intraday markets. The literature has identified two significant concerns that could limit its societal benefits [181], [182].

- *Locational Market Power*. One concern is the emergence of locational market power, which can lead to limited market liquidity. This situation may result in higher electricity prices compared to a regulated approach.
- *Strategic Bidding*. Another concern involves strategic bidding practices, often referred to as *increase-decrease gaming*. This strategy involves manipulating electricity markets to create and profit from congestion. These concerns are not limited to traditional generators and large consumers, but it can be applied also to local congestion management. However, several factors can mitigate the risk of strategic bidding in congestion management markets. These factors include:
    - *Demand Participation:* The involvement of demand in these markets can reduce the potential benefits of strategic bidding for generators. Demand characteristics, such as volatility, price sensitivity, and external factors like human behavior, make short-term congestion forecasting challenging. This, in turn, narrows the gap between flexibility prices and day-ahead prices, reducing the attractiveness of strategic bidding.
    - *Differing Incentives:* Generators and demand-side participants have fundamentally different economic incentives. Generators profit from the

price difference between their production costs and market prices, whereas the demand side benefits from the marginal cost of using additional energy units.

- *Main Activities:* Demand-side participants often have primary activities unrelated to energy production, such as industrial processes or commercial services. Their focus remains on these core activities, making the potential penalties and risks associated with strategic bidding less appealing.

In the literature on market-based congestion management, three notable examples are frequently discussed to address congestion efficiently and foster a more responsive and adaptable electricity grid: *i*) flexibility markets, *ii*) distribution locational marginal price and *iii*) redispatch markets.

Flexibility markets are designed to harness the potential of distributed flexibility resources, such as DR programs, ESSs, and distributed generation, to alleviate congestion. Flexibility markets enable market participants to offer their resources in response to price signals, allowing the grid to balance supply and demand more effectively.

Distribution locational marginal price methods assign prices to different locations within the distribution grid based on real-time conditions. This helps incentivise consumers and distributed energy resources to adjust their behavior or output to alleviate congestion where it is most needed.

Redispatch markets are similar to flexibility markets. They allow for the reallocation of resources within the distribution network to relieve congestion and ensure reliable electricity supply.

These market-based solutions empower market participants, including consumers and smaller-scale RESs, to actively contribute to congestion management, promoting grid stability, reducing the reliance on expensive grid upgrades, and facilitating the integration of renewable energy into the electricity system. Each approach offers unique advantages and can be tailored to specific grid conditions and regulatory environments.

3.2.3.1 Definition of Congestion Management Markets

In the context of electricity networks, congestion is the term used to describe a critical scenario when the flow of energy through a network approaches the maximum capacity that an electricity line can effectively support. The primary objective of congestion management is to prevent energy flows from exceeding the limits of line capacities. To achieve this, a network model is developed with constraints, imposing maximum power flow limits for each line. However, it is important to note that these measures may not completely eliminate the occurrence of lines operating at full capacity, which means congestion costs may still persist [152]. An optimisation model that incorporates congestion management strives to leverage the inherent flexibility found in market bids for energy injection, consumption, import, and export contracts. Within the domain of energy markets, the concept of *market product* represents the specific type of commodity traded. In general, talking about energy markets, the focus is on three key products: *i*) reserve (capacity), *ii*) energy, and *iii*) reactive power [153]. Bids are made in units of megawatts for reserve markets and megawatt-hours for energy markets. Reactive power considerations often come into play when voltage control is necessary, making the market products dimension intricately connected to the broader spectrum of market services.

As we delve deeper into the realm of congestion management markets, it is crucial to understand the fundamental market dimensions that play a pivotal role in their design. These dimensions encompass critical choices that impact the market structure and function. In this chapter, we will explore these dimensions, including: *i*) trading type, *ii*) auction type, *iii*) level of centralisation, *iv*) market pricing scheme, *v*) bid types, and *vi*) objective type [183], [184]. This foundational understanding will pave the way for a more comprehensive exploration of how these concepts align with each market models presented in the subsequent chapters.

In the domain of congestion management markets, four primary trading types emerge and are presented in the following [185].

1. *Unit-based trading*. This approach revolves around individual market bids corresponding to specific generation or consumption units. It caters to large physical entities like gas turbines, nuclear power plants, or virtual power plants. Unit bids are designed to recover running costs and generate profits. This method offers a direct modelling of physical asset constraints, such as ramping or start-up costs.
2. *Portfolio-based trading*. Contrasting with unit-based trading, portfolio-based trading is prevalent in the European Union, notably in the day-ahead EU spot market. Here, bids are structured as collections or aggregations of units. The portfolio owner may not necessarily own the individual units but compiles bids to optimise profits and manage risks effectively. While profit is a goal, risk reduction through hedging is also a key consideration. Portfolio bidding offers more diverse bid types with indirect ties to asset constraints.
3. *Bilateral trading*. In bilateral trading, market interactions involve only two participants. While it simplifies the trading process, it raises questions about the market competitiveness, transparency, and efficiency, especially when compared to multilateral markets.
4. *Multilateral Trading*. Multilateral trading thrives on the participation of numerous actors on both the supply and demand sides. This approach fosters the attributes typically associated with robust markets, such as low entry barriers, high transparency, liquidity, and healthy competition. These characteristics contribute to market efficiency and overall effectiveness.

Auction types are fundamental components in shaping congestion management markets, influencing the timing and processes of bid acceptance [186]. Two primary auction types are mostly adopted.

1. *Simple auction market*: In a simple auction market, all bids, whether from supply or demand, must be submitted and received before a predetermined deadline known as the gate closure time. Bids arriving after this deadline are typically rejected. Shortly after the closure time, the market clearing process commences, considering only timely submitted bids. Importantly, the processing of bids is typically independent of their submission time.
2. *Continuous market*: In continuous markets, there is no distinct separation between bid collection and processing phases. Bids are processed by the market as soon as they are received, with the treatment of bids contingent on their precise submission time.

In such context, it is important to mention the horizon of the market. In general, the market can be represented by an independent horizon, or by a rolling horizon. In markets with independent horizons, subsequent market clearings have disjunct time horizons. This means that each time step falls within the horizon of only one market. Decisions made by a market for a particular time step are considered final, as they will not be revaluated by subsequent markets. Independent horizons simplify decision-making, as each market outcomes do not influence future market iterations. On the other hand, rolling horizon markets feature overlapping time horizons between consecutive market clearings. Decisions made by the first market for a time step within this overlapping period are advisory and subject to reconsideration by the subsequent market. This introduces complexity in bid acceptance and processing, as outcomes from one market may impact future decisions.

Centralisation level within congestion management markets pertains to the degree of organisational centralisation or decentralisation. While the term *market* traditionally implies the gathering of bidding parties in one place, modern energy markets exhibit varying levels of centralisation or decentralisation to accommodate evolving needs and circumstances. Centralised markets operate with a focal authority or central actor overseeing market operations. This central entity plays a pivotal role in market governance, coordination, and decision-making. Traditional electricity markets often exhibit high centralisation, as seen in day-ahead markets managed by grid operators or market administrators. In contrast, decentralised markets depart from the centralised model by replacing a single global market with numerous, locally bound, and independently functioning sub-markets. These sub-markets can operate autonomously, serving distinct geographical regions or specific market niches. The shift towards decentralisation can be driven by factors like deregulation, disintermediation, or the availability of localised and often RESs. Peer-to-peer energy markets are a notable example of decentralised market structures. The motivation for decentralization may extend beyond strict market economics, as it can result in lower market efficiency due to increased fragmentation and decoupling. However, the benefits include enhanced resilience, adaptability, and the ability to integrate diverse energy resources efficiently.

In congestion management markets, different pricing methods play a crucial role in determining how participants are compensated for their contributions and how market efficiency is maintained [187]. Two key distinctions in market pricing methods are:

1. *Uniform Pricing*. This scheme involves selling a commodity at the same price for all sellers and buyers within a specific market. In the context of electricity markets, this means that a megawatt of energy for a certain time and location is paid at the same price regardless of the producer. Uniform pricing simplifies transactions by providing all participants with the same price per unit of the commodity.
2. *Non-Uniform Pricing*. Conversely, non-uniform pricing entails different sellers and buyers receiving or paying varying prices for the same commodity. In such systems, participants do not all receive the same compensation for their transactions. A common example is pay-as-bid, where participants are compensated based on their individual bid prices.
3. *Complex Non-Uniform Pricing*. In some situations, non-uniform pricing schemes can become more complex. For example, when equilibrium prices cannot be easily determined, side payments may be introduced to ensure that all participants have the right incentives. This adds another layer of differentiation to pricing, as some participants receive these additional payments.

Another distinction in market pricing is between nodal and zonal pricing. Nodal pricing is used when a market covers multiple locations or nodes, and it allows for different cleared prices at each node. Variations in cleared prices between nodes can arise due to factors like line losses, congestion, or a lack of physical connections between nodes. Typically, electricity flows toward locations with higher prices, but there can be exceptions, known as non-intuitive flows. On the other hand, zonal pricing ensures that all nodes within a defined zone share the same cleared price. This means that participants within a zone receive or pay the same price for their transactions. Zonal pricing simplifies market operations but often requires additional constraints in the market model to ensure that supply and demand cleared prices are uniform within the zone.

In congestion management markets, different types of bids play a crucial role in shaping market dynamics and outcomes [183], [188], [189]. These bids vary in complexity and are designed to represent the interests of market participants. The main bids can be classified as follow.

1. *Single quantity bid*. This is the simplest type of bid, specifying a single quantity in MW(h) and a single price for reserved capacity or for energy for a single time step and bidding area. In a pay-as-bid system, a fraction of the quantity is accepted, and the market operator pays for supply bids or receives the same for demand bids.

2. *Multi-quantity bid*. In cases where a bidder wants variable prices as more of their bid is accepted, a sequence of subsequent single quantity bids with their own prices can be used. These bids can have positive and/or negative quantities. This type of bid is generally shown as a collection of single quantity bids along the quantity axis, with non-decreasing prices.
3. *Multi-quantity, multi-time step or block bids*. This higher-level bid collects a series of multi-quantity bids, compared in subsequent time steps. In electricity markets, it is commonly referred to as a block bid. This type of bid is represented as a series of multi-quantity bids defined for different time steps. In general, block bids come with a boolean acceptance variable, where the bid is either fully accepted or fully rejected.

These bid types provide flexibility and granularity in expressing market participants preferences and strategies in congestion management markets. Depending on the complexity and objectives of the market, participants can choose the most suitable bid type to achieve their goals, whether it is maximising social welfare, minimising activation costs, or meeting other specific market requirements.

Although many congestion markets avoid including complexities in the market, other types of markets, such as redispatch markets, adopt constraints to represent technical constraints or economic constraints of market participants [183], [189], [190]. Constraints are pivotal components, shaping the rules and dynamics of these markets. The most important constraint types can be classified as follow.

1. *Ramping constraint*. Ramping constraints limit the change in acceptance from one time step to the next. They address temporal changes in bids. These constraints help manage sudden shifts in production units energy output to maintain system stability.
2. *Integral constraint*. Integral constraints limit the total accumulated acceptance over a multi-time step, multi-quantity bid. They operate across the entire bidding horizon. Integral constraints are used to ensure that the total accepted quantity does not exceed certain limits over the entire bidding period.
3. *Cumulative constraint*. Cumulative constraints require that the sum of acceptance variables for both bids in a bid couple does not exceed 1 (100%). These constraints model situations where two processes are alternative sources, constrained by a shared input with a fixed upper limit.
4. *Implication constraint*. Implication constraints enforce that when the first bid is accepted (at any non-zero level), the second must also be accepted (at any non-zero level).
5. *Link constraint*. Link constraints mandate that the first bid must be accepted before the second can be accepted. This is sometimes called *parent-child* linkage.
6. *All-or-Nothing constraint*. All-or-nothing constraints dictate that either all bids in a list are accepted, or all are rejected (at any non-zero level). They can also be modelled using minimum up time constraints.

7. *Minimum Income / Maximum Payments constraints*. These constraints relate to the income earned or payments made by production units. Minimum income ensures participation if production exceeds a set level, while maximum payments restrict purchase if the cost exceeds a fixed value.

In the context of congestion management markets, the objectives must guide the decision-making processes and shape market outcomes [189], [191]. Several objective types are prevalent.

1. *Maximizing social welfare*. This is the classical and widely used objective for energy markets. Social welfare is calculated as the sum of producer surplus, consumer surplus, and congestion rent. Maximising social welfare means striving to combine as many supply-side and demand-side bids as possible while ensuring that no participant incurs losses.
2. *Minimising Activation Cost*. Instead of maximising social welfare, the market aims to minimise the supply-side costs. This objective is equivalent to maximising social welfare when dealing with inelastic demand. In cases with elastic demand or other complexities, this objective can substantially deviate from the social welfare maximisation, particularly in how the surplus is distributed among market participants.
3. *Combined Objectives*. Sometimes, it is preferable to pursue the maximisation of social welfare or the minimisation of activation costs while also keeping another secondary measure as low as possible or as high as possible. For instance, in voltage control, where it is crucial to model voltage and energy flows accurately, these variables are co-constrained according to a second-order constraint. In such cases, an additional term is added to the objective function to co-optimise these variables alongside the main objective.

3.3 Distribution Locational Marginal Pricing Mechanism

Traditionally, power systems operated in a unidirectional manner, with electricity generated centrally and then transported through transmission and distribution lines to end-users. However, in recent decades there have been a shift towards a bidirectional energy flow, provided by distributed resources, including PVs, microturbines, wind turbines, and ESSs. Moreover, looking at the demand side, there is a growing emphasis on encouraging industrial, commercial, and even residential customers to participate in DR programs.

As distribution networks become more active due to the integration of these resources, the coordination between the transmission and distribution networks becomes paramount. Additionally, there is a need for an improved pricing mechanism in distribution market operations. This pricing mechanism must meet specific criteria, including coordination with existing wholesale markets, incentivising the proper operation and development of distributed resources, reflecting the distribution system cost and physical operating conditions, and rewarding resources for flexibility and grid services [186]. These requirements can be achieved through mechanisms like DLMP, which is analogous to the LMP used in transmission-level markets. DLMP is designed specifically for the distribution network and can play a helpful role in congestion management. As described in previous chapter, this mechanism adopts a power flow model. However, the application of the traditional DC power flow model, commonly used in transmission-level studies, directly to distribution networks is not straightforward. Distribution networks exhibit distinct characteristics, such as power losses, reactive power demands, and voltage limitations. Consequently, it is imperative to incorporate a more complex AC power flow model to accurately account for these factors in DLMP calculations [192].

DLMP, also distribution-level nodal pricing, was initially proposed with a focus on addressing network losses [193]. It quantified the value of distributed generators by reducing line losses and loading. DLMP models have evolved to include energy, congestion, power loss components, and even voltage components. These pricing mechanisms have been developed to reflect operational conditions accurately and reward resources contributions to distribution system operation, making DLMP a topic of significant interest and relevance for future distribution markets and policymaking.

At the distribution-level, several participants can be identified. The first type of actor are the distribution market operators. These actors serve as profit-neutral entities that provide a trading platform for transparent energy transactions. They facilitate interactions between electricity producers and consumers, clear the market, broadcast price signals, and determine market settlements at the distribution level [194]Another fundamental actor is the DSO, which is responsible for system planning, network operation, outage restoration, and network security management. Also, the electricity retailers can be included in the actors list. They purchase electricity from the wholesale market during deficits and sell surplus electricity to the wholesale market. Needlessly to say, distributed generation is of main importance. This set includes various sources like microturbines, PVs, wind turbines, CHP units, DR users and ESSs. From the demand side point of view, large consumers that have substantial load demands and can participate directly in the market can be considered [195]. Finally, load aggregators can play a crucial role in distribution networks. They act as intermediaries between consumers and the DSO, managing the flexibility offered by multiple consumers. They bid in the distribution market on behalf of consumers and distribute the purchasing power to contracted consumers [196].

In literature, two models are provided for DLMP implementation: *i*) pool-based market and *ii*) peer-to-peer (P2P) market. In a pool-based market, the primary responsibility for efficient market operation and coordination of distributed resources lies with the DSO. Transactions in this market are centralised and top-down. The DSO collects bids and offers from market participants, clears the market centrally, and provides incentives for energy resources. The market operates with the objective of minimising system generation costs or maximising social welfare through optimal power flow problem [197], [198]. On the other hand, the P2P market is less centralised, freer, and built on a bottom-up approach, allowing suppliers and consumers to autonomously transact electricity and services. In this peer-centric architecture, participants negotiate, accept, or reject trades based on their preferences, rationalities, and privacy considerations. The P2P market can be structured in various ways, including fully decentralised, coordinated, community-based, and hybrid (composite) models, each with its own trade negotiation dynamics. Network constraints may be considered in some models, with the DSO involved in trade validation. DLMP plays a crucial role in promoting transactions that facilitate system operations and penalising those unfavourable from the DSO point of view [199].

In the following a general DLMP model is introduced. It is important to note that, even though DLMP primarily focuses on the energy market, a fundamental component of overall electricity market operation, it can also accommodate the integration of the ancillary service market through a co-optimisation formulation. A typical market-clearing model is shown below.

$$min \sum f(P,Q) \tag{27}$$

Subject to: $\sum P_i^G - \sum P_i^D - Loss = 0 \quad (\lambda^p)$ (28)

$$\sum Q_i^G - \sum Q_i^D - Loss = 0 \quad (\lambda^q) \tag{29}$$

$$S_l^{min} \leq S_l \leq S_l^{max} \quad \left(\omega_l^{min}, \omega_l^{max}\right) \tag{30}$$

$$V^{min} \leq V_i \leq V^{max} \quad \left(\alpha_i^{min}, \alpha_i^{max}\right) \tag{31}$$

$$P_i^{G,min} \leq P_i^G \leq P_i^{G,max} \quad \left(\gamma_i^{p,min}, \gamma_i^{p,max}\right) \tag{32}$$

$$Q_i^{G,min} \leq Q_i^G \leq Q_i^{G,max} \quad \left(\gamma_i^{q,min}, \gamma_i^{q,max}\right) \tag{33}$$

This generic model represents the objective function in Equation (27) as much generic as possible. However, several solutions are allowed, for instance minimisation of the total electricity generation cost including the electricity purchasing cost from the wholesale market and the generation cost of generators, but also the maximisation of the social welfare of the community. In addition, constraints (28) and (29) represent the active and reactive power balance constraints from which the energy shadow prices are extracted, Constraint (30) is the congestion constraint and constraint (31) is the voltage constraint. From these two constraints are evaluated the congestion shadow prices. Finally, Constraints (32) and (33) are the generators active and reactive power output limits.

The DLMP model is significantly influenced by the complex nature of solving the AC OPF in distribution systems. In particular, this can be seen from the fact that the voltage and current values in Equation (30) and (31) must be calculated using non-linear equations. To enhance computational efficiency while preserving accuracy, various techniques have been introduced to approximate and relax the AC OPF model. These techniques fall into two main categories: linearisation and convexification, each with distinct mathematical properties and approaches. Linearisation approximates the nonlinear AC OPF model by making specific assumptions, often simplifying complex aspects like power losses and voltage angles. Various methods have been developed, such as the linearised *DistFlow* model [200], piecewise linear formulations [198], and Taylor approximations [201], among others. Contrarily, convexification relaxes the AC OPF problem using two primary methods: semidefinite programming and second-order cone programming. The former relaxation aims at solving the dual of an equivalent AC OPF formulation, while the latter relaxation transforms quadratic equality constraints into inequality constraints.

However, the model presented is too general. In order to represent all actors in more detail, it is better to model the constraints on the PQ plane of generators and loads. In addition, if we were also to consider storage systems, further equations are required to represent the operation of an ESS. To solve these requirements, the constraints presented below can be added.

$$\begin{cases} SoC_{w,t} = SoC_{w,t-1} + \left[\eta_{trip} \cdot P_{w,t} - \left(1 - \eta_{Q_{inv}}\right)\left|Q_{w,t}\right|\right] \cdot \Delta t & if\ t \neq 1 \\ SoC_{w,t} = SoC_{w,0} + \left[\eta_{trip} \cdot P_{w,t} - \left(1 - \eta_{Q_{inv}}\right)\left|Q_{w,t}\right|\right] \cdot \Delta t & if\ t = 1 \end{cases} \tag{34}$$

$$\left(P_{w,t}\right)^2 + \left(Q_{w,t}\right)^2 \leq (S_w)^2 \tag{35}$$

$$-S_w \leq P_{w,t} \leq S_w \tag{36}$$

$$-S_w \leq Q_{w,t} \leq S_w \tag{37}$$

$$SoC_w^{min} \leq SoC_{w,t} \leq SoC_w^{max} \tag{38}$$

$$P_{z,t} \cdot \tan(\cos^{-1}(pf^{max})) \leq Q_{z,t} \leq P_{z,t} \cdot \tan\left(\cos^{-1}\left(pf^{min}\right)\right) \tag{39}$$

$$\left(P_{f,t}\right)^2 + \left(Q_{f,t}\right)^2 \leq \left(S_f\right)^2 \tag{40}$$

$$P_{f,t} \cdot \tan(\cos^{-1}(pf^{max})) \leq Q_{f,t} \leq P_{f,t} \cdot \tan\left(\cos^{-1}\left(pf^{min}\right)\right) \tag{41}$$

Where Equation (34)-(38) represent the ESS constraints, Equation (39) the load constraint, and Equations (40)-(41) the generator constraints.

In the modern distribution system, however, there are also DR users. That is, users capable of changing their consumption plans based on price signals or contractual agreements. It is therefore necessary to introduce equations that represent DR behaviour. However, it is important to recognise that the integration of DR actions can also exhibit a rebound effect. This effect refers to situations where consumers, after responding to price signals by reducing consumption during peak periods, may subsequently increase their consumption when prices are lower, potentially leading to unexpected surges in demand. Managing and mitigating this rebound effect becomes crucial for maintaining grid stability and preventing strain on the distribution system. Properly addressing the rebound effect involves a nuanced approach that balances the benefits of DR actions with the need for consistent load management to ensure the reliable operation of the distribution network. One way to represent the DR model with a rebound effect can be via the following equations.

$$P_{z,t}^{After} = P_{z,t} - P_{z,t}^{cut} + P_{z,t}^{rb} \tag{42}$$

$$P_{z,t}^{rb} = \sum_{\tau=t-1}^{t-\delta} \left(r_{z,\tau} \cdot P_{z,\tau}^{cut}\right) \tag{43}$$

$$0 \leq P_{z,t}^{cut} \leq \left[P_{z,t} + \sum_{\tau=t-1}^{t-\delta} \left(r_{z,\tau} \cdot P_{z,\tau}^{cut}\right)\right] \tag{44}$$

$$0 \leq P_{z,t}^{rb} \leq \sum_{\tau=t-1}^{t-\delta} \left(r_{z,\tau} \cdot P_{z,t}\right) \tag{45}$$

$$0 \leq \sum_{t=1}^{T} P_{z,t}^{rb} \leq \gamma \cdot \left(\sum_{t=1}^{T} P_{z,t}^{cut}\right) \tag{46}$$

$$r_{z,\tau} \begin{cases} \alpha_t & t \in (t^0 - \delta) \\ 0 & otherwise \end{cases} \tag{47}$$

Where $P_{z,t}$ represents the actual load consumption. $P_{z,t}^{cut}$ is the DR action and $P_{z,t}^{rb}$ represents the rebound effect. The rebound effect is composed of the components of the DR action in the previous $t - \delta$ instants, where δ is the memory parameter, and represents the number of intervals after t^0 in which the customer can intervene with a payback effect. $r_{z,\tau}$ controls the energy payback rate from time t to δ. For instance, when cooking with an oven, if an oven is currently warm enough because of a latest operation, less electric energy would be needed to warm it up. However, if the oven responds to DR by delaying its operation to later intervals, more electric energy would be needed to warm it up. Thus, $r_{z,\tau} > 1$ would be adopted to represent this energy payback phenomenon from time t to a later time δ. In addition, by adopting a very large positive value of $r_{z,\tau}$ one can prohibit energy payback to specified time intervals [202].

If we combine all these constraints into one problem, then we can obtain a DLMP model for distribution. Then, based on (27)-(33), the Lagrangian function of the DLMP model can be written as follows.

$$
\begin{aligned}
L &= \sum f(P,Q) \\
&-\lambda^{p} \cdot \left(\sum P_i^G - \sum P_i^D - Loss\right) - \lambda^{q} \cdot \left(\sum Q_i^G - \sum Q_i^D - Loss\right) \\
&-\sum \omega_l^{min} \cdot \left(S_l - S_l^{min}\right) - \sum \omega_l^{max} \cdot \left(S_l^{max} - S_l\right) \\
&-\sum \alpha_i^{min} \cdot \left(V_i - V^{min}\right) - \sum \alpha_i^{max} \cdot \left(V^{max} - V_i\right) \\
&-\sum \beta \cdot g(P,Q)
\end{aligned} \tag{48}
$$

Where $g(P,Q)$ represent the remaining constraints. The active and reactive DLMP are the first-order partial derivatives of the Lagrangian function with respect to the active and reactive load demands, respectively.

$$
\begin{aligned}
\pi_i^p &= \frac{\partial L}{\partial P_i^D} = \lambda^p + \lambda^p \cdot \frac{\partial Loss}{\partial P_i^D} + \lambda^q \cdot \frac{\partial Loss}{\partial P_i^D} \\
&+\sum \left(\omega_l^{max} - \omega_l^{min}\right) \cdot \frac{\partial S_l}{\partial P_i^D} + \sum \left(\alpha_l^{max} - \alpha_l^{min}\right) \cdot \frac{\partial V_i}{\partial P_i^D}
\end{aligned} \tag{49}
$$

$$
\begin{aligned}
\pi_i^p &= \frac{\partial L}{\partial Q_i^D} = \lambda^q + \lambda^q \cdot \frac{\partial Loss}{\partial Q_i^D} + \lambda^p \cdot \frac{\partial Loss}{\partial Q_i^D} \\
&+\sum \left(\omega_l^{max} - \omega_l^{min}\right) \cdot \frac{\partial S_l}{\partial Q_i^D} + \sum \left(\alpha_l^{max} - \alpha_l^{min}\right) \cdot \frac{\partial V_i}{\partial Q_i^D}
\end{aligned} \tag{50}
$$

Where π_i^p and π_i^p refer to the active and reactive DLMP at each node, respectively. In Equation (49), the active DLMP consists of four components: the marginal energy price, the marginal power loss price, the marginal congestion price, and the marginal voltage support price.

The process of determining the DLMP in the context of distribution market operation relies on solving the OPF problem for the distribution system. Various methods have been developed to efficiently tackle this problem, which can be categorised into three main groups: *i*) centralised methods, *ii*) distributed methods, and *iii*) decentralised methods.

Centralised optimisation involves considering the entire system as a whole and making coordinated decisions [203]. Mathematical programming-based algorithms, like the simplex method and interior point method, are capable of finding optimal solutions for typical OPF problems. Commercial solvers such as CPLEX and GUROBI can effectively handle the clearing model. However, the computational time tends to increase significantly with problem scale. Metaheuristic algorithms like genetic algorithms and particle swarm optimization offer the advantage of finding sub-optimal solutions for nonlinear and nonconvex problems that programming-based algorithms struggle with, although they are time-consuming [204], [205]. As the distribution market involves numerous participants, solving large-scale problems becomes computationally challenging for centralised methods. Distributed methods aim at alleviating this burden and address data privacy concerns by decomposing the original model into smaller sub-problems, which are solved independently until convergence [206]. Two commonly used distributed algorithms are the Alternating Direction Method of Multipliers (ADMM) and analytical target cascading. The ADMM is robust, and it does not require strong assumptions, and ensures data privacy protection. It has been applied to various power system problems, including clearing markets with residential loads and EVs [207]. The analytical target cascading method enables win-win cooperation between distribution networks and multi-microgrids and has been used for economic dispatch and optimisation [208]. Decentralised methods, similar to distributed methods, break down large-scale problems into smaller ones. The primary distinction is that they do not involve a central coordinator; instead, sub-problems only exchange information with their neighbours. Two decentralised algorithms are the proximal message passing and the auxiliary problem principle. The proximal message passing algorithm, fully decentralised, enables parallel sub-problem solving and has been tested in distribution market-clearing problems. The auxiliary problem principal algorithm decomposes problems into auxiliary problems with shared variables, allowing information exchange among neighbours without requiring a central coordinator. It has been applied to various power system optimisation problems [209]. These methods play a crucial role in calculating the DLMP, providing options for balancing computational efficiency, optimality, and data privacy in distribution market operations.

3.4 Flexibility Markets

The concept of a flexibility market has previously been introduced and elucidated in an earlier chapter. To prevent redundancy, this chapter leverages the concept of a flexibility market to construct an illustrative model. Flexibility markets serve as platforms facilitating the exchange of flexible services and commodities. These markets bring together diverse participants, encompassing DSOs, BRPs, aggregators, and MOs, enabling the seamless flow of flexibility resources.

Drawing from real-world examples and initiatives in flexibility markets worldwide, we can gather invaluable insights and practical experiences. These instances act as tangible demonstrations of how flexibility can be effectively harnessed to elevate the performance of energy grids. Building upon these real-world cases, we put forth a flexibility market model tailored to address the distinctive challenges and requisites encountered at the distribution level. This model aspires to provide a comprehensive framework for the trading of flexibility services, fostering collaboration among an array of stakeholders, and ultimately bolstering the efficiency and resilience of our electrical distribution systems.

The initial element imperative to delineate within a flexibility market framework is its target audience. In this instance, we adopt the perspective of the DSO. Consequently, the market overarching objective aligns with that of the DSO, and correspondingly, the objective function centres on minimising the costs associated with activating and reserving flexibility resources. Within this context, it becomes evident how the flexibility market accommodates two distinct cost and service dimensions. Firstly, it encompasses a service in capacity, wherein the DSO reserves a service within a defined timeframe. However, since this service may not be immediately required, flexibility is reserved in terms of power slots. Secondly, activation pertains to the actual delivery of the flexibility service, for which compensation is contingent on the actual power supplied to the DSO.

The constraints integral to shaping the market pertain to the flexibility budgets stipulated by the DSO. To establish the market, participants must be capable of proffering their services at specified prices. Nonetheless, it falls upon the DSO to close the market in accordance with a clearing mechanism. In this scenario, market closure transpires when the most efficient flexibility offers by participants are determined, serving to mitigate the DSO flexibility requirements at the minimum cost feasible. The final set of constraints pertains to the lower and upper bounds of flexibility services. Precisely, it becomes imperative to define the limits within which a flexibility offer operates. These bounds may either be indirectly ascertained by the capacity value stipulated in the offer or explicitly specified by the user during the offer submission phase.

Finally, it must be point out the concept of flexibility service location and consequently, the concept of sensitivity factor. This concept is crucial for understanding and optimizing the dynamics of this market. Sensitivity factor represents the responsiveness of a resource or participant to changes in market signals, such as price or activation signals. It quantifies how effectively a resource can adjust its electricity generation or consumption in response to these signals. The sensitivity factor helps market operators and participants assess the effectiveness of different resources in meeting the dynamic needs of the grid. Resources with higher sensitivity factors can respond more precisely to market signals, making them valuable assets for grid management.

A flexibility market clearing process can be approached either with or without the consideration of network data. There exist various methodologies for incorporating network data and flow constraints into market models designed for distribution systems. These methodologies encompass second-order cone programming formulations [210], quadratically constrained programming [211], or proposals that linearise power flow constraints [212]. However, it is worth noting that the practical implementation of these solutions can be particularly challenging, especially when dealing with networks comprising thousands of nodes. Hence, sensitivity factors emerge as a potential solution for streamlining market representations while factoring in grid-related information during the market-clearing process. The DSO calculates sensitivity factors for each flexible service provider (FSP) concerning the flexibility requirement. These sensitivity factors are computed based on various factors, including the geographic locations of the FSP assets, their influence on resolving grid constraints, and any limitations inherent in their bids. To calculate sensitivity factors for congestion management, an analysis of the sensitivity of power flow in critical branches to the power injections from FSPs is essential. This sensitivity analysis relies on the Power Transfer Distribution Factor (PTDF) matrix [211]. The PTDF matrix is used to quantify the change in the flow of power along a particular line in response to a power injection at one node and an equivalent withdrawal at another node. Mathematically, this relationship can be expressed as:

$$\Delta P_{ij} = PTDF_{ij,km} \Delta P_{km} \tag{51}$$

To determine the total flow over a given line a summation is performed, considering the PTDFs for all relevant nodes. This can be represented as:

$$P_{ij} = \sum_{m} PTDF_{ij,km} P_m \tag{52}$$

It is important to note that node k typically represents the slack bus, and all PTDFs are calculated with reference to this specific node.

In the process of flexibility market clearing, the primary objective is to select the most efficient flexibility bids offered by FSPs in order to address the identified needs of the DSO while minimising costs. This process relies on several key inputs:

- *DSO Flexibility Needs for Congestion Management*.
- *Flexibility Bids from FSPs*. FSPs submit their flexibility bids, which include crucial information such as:
  - Quantity. The amount of flexibility they can provide.
  - Location. Where the offered flexibility resources are located within the distribution network.
  - Price. The cost associated with activating their flexibility resources.
  - Direction. Indicating the direction of flexibility, which can involve both the increase and reduction of generation (upward and downward flexibility) connected at a distribution node, as well as the reduction and increase of demand (upward and downward flexibility) at a distribution node. This direction specification is essential for understanding how the flexibility can be utilized.
  - Sensitivity Factors: These factors play a pivotal role in determining the merit order within the market. Sensitivity factors are influenced by factors such as the geographic locations of FSP assets, their impact on resolving grid constraints, and any limitations on their bids. When combined with bid price,

quantity, and location, sensitivity factors help establish the order in which bids will be cleared during the market-clearing process.

The market formulation, which outlines the rules and mechanisms governing the market clearing process, will be introduced in the subsequent subsection. This formulation ensures that the market operates efficiently, taking into account DSO needs, FSP bids, sensitivity factors, and other relevant parameters, ultimately leading to the selection of the most suitable flexibility bids to address congestion and grid-related challenges within the distribution system.

As the local congestion management aims to resolve congestion issues at minimum cost, a linear programming flexibility market clearing formulation is proposed [213]. The details of the formulation are presented below.

$$\min\left\{\sum_{f}\left[c_f \cdot P_f + \sum_{t} e_{f,t} \cdot \Delta P_{f,t}^{Up/Down} \cdot \Delta t + VnSF \cdot \left(s_{i,t}^{Down} + s_{f,t}^{Up}\right)\right]\right\} \tag{53}$$

Subject to: $P_t^{Up_{DSO}} - \sum_f PTDF_f \cdot \Delta P_{f,t}^{Up} - s_{f,t}^{Up} \leq 0 \quad \forall f, \forall t$ (54)

$$P_t^{Down_{DSO}} - \sum_{f} PTDF_f \cdot \Delta P_{f,t}^{Down} - s_{f,t}^{Down} \leq 0 \quad \forall f, \forall t \tag{55}$$

$$P_f^{Up_{min}} \leq \Delta P_{f,t}^{Up} \leq P_f^{Up_{max}} \quad \forall f, \forall t \tag{56}$$

$$P_f^{Down_{min}} \leq \Delta P_{f,t}^{Down} \leq P_f^{Down_{max}} \quad \forall f, \forall t \tag{57}$$

$$s_{i,t}^{Down}, s_{f,t}^{Up} > 0 \tag{58}$$

The flexibility market clearing for congestion management is used to determine the most efficient flexibility bids from FSPs to mitigate the DSO flexibility needs at minimum cost. The objective function of this flexibility market is defined by Equation (53), and it can be divided into three parts: the first term represents the capacity terms and the second the upward/downward flexibility activation cost, while the last term represents the cost of the expected not-supplied flexibility.

The constraints (54) and (55) match flexibility requests from the DSO with flexibility offers from FSPs, respectively for upwards and downwards bids. It is relevant to mention that in these equations, each FSP bid is multiplied by its respective sensitivity factor (PTDF) which will affect the merit order on the market. Constraints (56) and (57) capture the limits of the submitted bids from FSPs, and constraint (58) ensures that the variable corresponding to the not-supplied flexibility is positive.

3.5 Redispatch Markets

Congestion issues, similar to those encountered at the transmission level, are becoming more prevalent in distribution networks. These congestions can be attributed to several factors, including the rapid growth of intermittent renewable energy production and shifts in electricity demand and usage patterns. These changes can lead to localised grid constraint violations and challenges in ensuring a reliable energy supply. In this context, it has been already described how market-based approaches, where market participants adjust their production or consumption to alleviate congestion through price signals, are often favoured for their potential efficiency and flexibility. Here, in the context of market-based congestion management mechanisms, the introduction of redispatch markets at the distribution level are a topic of growing interest and discussion in response to local congestion issues within various distribution networks [214], [215].

Redispatch, especially in central European countries, is a process organised and procured through regulatory obligations, where various generators are mandated to participate in the redispatch process [216]. However, this obligation generally excludes smaller, renewable-based, and CHP generators. This regulatory approach is perceived as somewhat discriminatory, as it limits the freedom of dispatch or the free movement of goods for the market participants involved, as defined in the European Parliament Directive 2009/72/EC [217]. An alternative approach to regulatory redispatch is the concept of redispatch market. In these markets, redispatch activities are driven by economic principles and take place on a voluntary market. This means that market participants have the flexibility to compete in a market that operates separately from the wholesale electricity market. They do so by submitting bids that represent the prices at which they are willing to adjust their generation or demand to alleviate congestion in the grid [216]. Redispatch market aligns with other segments of the energy-only market and offers certain advantages. However, it also introduces operational challenges that need to be addressed. One challenge is the forecast variations. This can lead to changes in the required redispatch power or energy. Market participants must adapt to these changes swiftly. In addition, not only is it crucial to avoid unnecessary redispatch actions to minimise costs and ensure efficient grid management, but also reduce the risk that the available redispatch supply might not be sufficient to address congestion adequately, potentially leading to grid issues. One challenge that is most recognise is the strategic bidding of participants. Market actors can manipulate the market to their advantage, which can impact the fairness and effectiveness of the redispatch market. Participants who foresee grid congestion have motivations to manipulate their bids, even without having significant market power. Certain resources upstream, expecting requests to reduce their output, may boost their profits by submitting bids below their actual costs on the spot market. Similarly, some downstream resources, expecting requests to increase their output, can enhance their profits by submitting bids above their actual costs on the spot market, anticipating higher payments in the redispatch process. This strategic bidding strategy, known as increase-decrease gaming, results in artificially inflated profits for these resources. Even more concerning, it worsens grid congestion. To address these incentive problems, many markets, especially in the US, have switched to nodal markets [218].

The redispatch market must be consistent with the intraday trading model operated in most of Europe. This is to enable more rapid implementation of the market. Indeed, many of the features can be taken from already implemented intraday markets, like EPEX Spot [219], Nord Pool [220] and OMIE [221]. The purpose of a redispatch market is to efficiently centralise local redispatch offers. This allows system operators, both TSOs and DSOs in a coordinated effort, to relieve physical congestion reliably and economically on the grid close to real time. It also provides a means for redispatch providers to offer and price their services. In addition, following the EU directives, the market must have a high level of transparency. Prices and volumes by location are public and determined in a clear process. The market encourages coordination between system operators with clear communication protocols. A neutral power exchange operates the market. The exchange uses a continuous double auction or a simple double auction with a displayed order book. Physical certification and verification are ensured by the system operators. Throughout the intraday timeframe, redispatch providers offer their flexibility. The offers are in separate order books that run in parallel with the zonal intraday market. The key new element of orders for redispatch is the location of the resource or need. The product is deviation from a baseline (redispatch), rather than energy. Providers include power plants, storage, renewables, aggregators, and virtual power plants. Special attention is given to expanding the set of providers both in terms of voltage (low, medium, and high) and technology (power-to-x, CHP, etc.). Redispatch demand comes from the TSO, mid-voltage DSO, and low-voltage DSO. The exchange matches bids and asks continuously or period per period, according to the auction adopted.

The concept of redispatch markets closely resembles that of flexibility markets. However, a subtle yet significant difference lies in the market mechanism. In flexibility markets, the primary emphasis is placed on optimising the system and efficiently employing available resources. To achieve this, a comprehensive optimisation process is conducted by the DSO. On the other hand, in redispatch markets, this optimisation is carried out primarily to resolve the auction, rather than focusing on resource optimisation. Consequently, the solutions permitted in redispatch markets may encompass resources that are neither economically nor technically advantageous. This divergence arises because the central objective of the redispatch market is to maximise social welfare or to minimise cost for resources.

3.5.1 Handling Redispatch Markets

Future energy markets are going to be characterized by a high penetration of RESs and by a highly developed robust coordination among power supply, grid management, load handling, and energy storage. These markets necessitate the design of versatile transaction and bidding forms to cater to the diverse needs of various market participants. Complex bids enable these participants to engage in flexible trading activities that align with their unique physical and economic characteristics. One particularly effective schema for addressing these complexities is block orders. Block orders are applicable across a wide spectrum of markets, spanning medium, long-term, and day-ahead markets, including energy and ancillary service markets. This mature time-sharing bidding and clearing mechanism provides a centralised platform for matchmaking that seamlessly integrates with traditional time-sharing medium and long-term energy markets. In contrast to conventional markets, those incorporating block orders introduce the innovative concept of *blocks*. These blocks can exhibit distinct characteristics tailored to match the specific attributes of various types of products. Participants have the flexibility to represent their products within these blocks and submit bids to the market, allowing them to achieve their desired trading outcomes. The block orders model was initially introduced on the Nord Pool market and rapidly gained popularity across Europe due to its exceptional effectiveness and scalability. Today, the block orders framework is widely adopted in central Europe, northern Europe, the United Kingdom, and various other regions, continually evolving with the introduction of new types and features. It has emerged as a pivotal time-sharing power bidding and clearing mechanism capable of handling complex bids and transactions.

An overview of the different complex bids available in different energy markets is presented in Table V.

Table V. Overview of complex bids and constraints.

	OMIE	EPEX Spot	Nord Pool	HEnEx Spot
Indivisibility Condition	X			
Minimum Income Condition	X			
Scheduled Stop Condition	X			
Gradient Condition	X			
Link Bid Orders		X	X	X
Loop Bid Order		X		
Curtailable Bid Order		X	X	X

Profile Bid Order			X	
Flexi Bid			X	
Maximum Power Condition	X			
Maximum Payment Condition	X			
Immediate or Cancel		X	X	X
Fill or Kill		X	X	X
Linked Fill or Kill		X	X	
All or None		X	X	X
Good for Session		X		X
Good till Date		X		X
Iceberg Order		X	X	X
User-Defined Block Order			X	

As can be seen, complex bids play a crucial role in various energy markets. To understand each complex bid, here is presented an overview of the different bids available in the table above.

- *Condition of Indivisibility*. Specifies that a block of bids must be matched in its entirety, or it must be rejected.
- *Minimum Income Condition*. Requires that a bid is only considered submitted for matching if the seller obtains the minimum income selected.
- *Scheduled Stop Condition*. This is the condition that sellers may include in the sale bids they submit for each production unit so that, in the event that these bids are not matched due to the application of the minimum income condition, they can be treated as simple bids in the first block of the first three hourly scheduling periods of the scheduling horizon. The electricity bid which includes the scheduled stop condition shall be decreasing during the above-cited three hourly scheduling periods.
- *Gradient Condition*. Establishes maximum upward or downward differences in energy variation between consecutive hourly scheduling periods.

- *Linked Bid Orders*. Bid orders can be linked together, i.e., the acceptance of individual bids can be made dependent on the acceptance of other bids. The bid which acceptance depends on the acceptance of another bid is called *child bid*, whereas the bid which conditions the acceptance of other bid is called *parent block*. The block orders (parent *C_01* and child(ren) *C_02*) linked together are called linked family.
- *Loop Bid Orders*: A 2-bid linked orders where the two bid orders are parent of each other, and they can be of different product types.
- *Curtailable Bid Orders*. Bid orders that can be partially accepted based on a user-defined Minimum Acceptance Ratio (MAR).
- *Profile Bid Orders*. Bid orders where volume can differ over the entire market horizon.
- *Flexi Orders*. A flexible order must specify an energy volume that the participant would be willing to purchase or sell in one or a series of consecutive periods, the applicable order price limit and the nominated delivery range in respect of which the flexible order may be matched. The hour is not defined by the participant but will be determined by the algorithm (hence the name “flexible”). The hour in which the flexible hourly order is accepted, is calculated by the algorithm and determined by the optimisation criterion.
- *Maximum Payment Condition*. Similar to the minimum income condition but from the buyer perspective.
- *Immediate-or-Cancel*. An order in which as much of the order volume as possible is matched immediately upon submission, and the remaining volume is withdrawn.
- *Fill-or-Kill*. An order that is either fully matched immediately upon submission or withdrawn from the market.
- *Linked Fill or Kill*. Multiple Fill-or-Kill orders have a linked execution constraint, and they are either all executed, or all cancelled.
- *All or None*. The order is executed completely or not at all.
- *Good for Session*. The order is deleted at the end of the trading session unless it is matched, deleted, or deactivated before.
- *Good till Date*. The order is deleted at a specific date and time set by the exchange member.
- *Iceberg Orders*. These orders are only visible with part of their total quantity in the market, while their full quantity is exposed to the market for matching. Part of the hidden quantity shall be disclosed for trading as soon as the part that had already been disclosed has been executed. Iceberg orders include an executable volume of the product that is only partially visible to the market, leaving a quantity divided into smaller parts hidden. The total volume of the order is divided into smaller parts, with only one part being displayed in the order.
- *User-Defined Bid Orders*. User-Defined Bid Orders are orders consisting of one or several (up to 24) consecutive hourly products. User-defined bid orders are all-or-nothing orders where only the entire volume may be executed.

These complex bids cater to various trading strategies and market conditions, offering flexibility and customisation for market participants in different energy markets.

3.6 Multi Energy-based Flexibility Market Case Study

In the modern evolving landscape of energy systems, the integration of distributed resources has emerged as a pivotal force reshaping the way we generate, consume, and manage our energy. This paradigm shift is particularly evident in the EU, where ambitious energy transition goals are driving the exploration of innovative solutions for optimising the distribution system while accommodating the intermittent nature of RESs. Within this dynamic and transformative context, the case study represents a pioneering step in the pursuit of sustainable energy solutions. It delves into the implementation of a flexibility market designed to harness the available potential of distributed resources. In this context, the case study analyses a scenario in which several energy vectors are included, bringing together the MES paradigm. At its core, this case study showcases a flexibility market that operates within a multi-energy network. The market employs diverse sources of energy, encompassing a wide array of vectors, each with its distinctive characteristics and availability patterns. What truly sets this market apart is its reliance on a robust optimisation approach, a methodology suitable to mitigate the effects of unpredictability and volatility in energy generation and consumption patterns. By deploying robust optimisation techniques, not only ensures the market the reliable operation of the distribution system, but also it optimises the deployment of resources even in the face of fluctuating supply and demand dynamics.

However, this case study is just the starting point. As the EU energy market continues its relentless evolution, future efforts will delve deeper into alternative market mechanisms. The focus will extend to exploring DLMP methods, which promise to bring even greater efficiency to the energy allocation process. Furthermore, redispatch markets will be a key area of exploration, seeking to address the complex challenges posed by increased resource integration and the need for grid stability in an era of renewable energy dominance.

3.6.1 Robust Multi Energy System Flexibility Market

The case study focuses on developing a model that simulates the exploitation of the flexibility provided by the resources distributed in the network to resolve contingencies that arise on the grid. The main purpose of the objective function is to provide services to the DSO. In addition to the common representation of flexibility services provided by the electric grid solitary, the proposed model also includes the representation of the gas grid model and building thermal consumption. Each node can be considered as an EH which integrates different types of resources. The concept of *energy hub* refers to an integrated facility that manages and optimises the production, storage, distribution, and consumption of various forms of energy, including electricity, heat, and sometimes even transportation fuels [222].

To handle contingencies that can arise in a given network during normal operating conditions or during a specific emergency reconfiguration, a classic OPF problem should be solved, which minimise the overall active management cost, subject to technical constraints related to network and resources operation. Thanks to the validity of the distribution network approximation, a Linear Programming (LP) approach can be used. Based on the same considerations, the Gas Flow (GF) problem was linearised by employing specific sensitivity matrices. In the case study, it was assumed that the operators of the electric and gas networks had access to a communication channel for sharing information regarding power and gas flow calculations. Specifically, in the market context, the operators interact with the market through the market operator. Noteworthy, this configuration does not currently exist; rather, it was adopted as an assumption for the purposes of the study.

The cost function minimises the weighted sum of the flexibility services provided by all accessible resources involved. In this case study, the flexibility remuneration is expressed only in terms of energy. The primary focus of this case study is to underscore the effectiveness of the flexibility market in alleviating congestion, prioritising this aspect over its economic efficiency. Consequently, whether the compensation is categorised into capacity and energy or solely energy holds less significance within the scope of this study. However, it is worth noting that future developments and real-world markets may encompass capacity considerations as well.

Therefore, when a resource is qualified to participate in the service, it is rewarded only when it is called to provide the service. Consequently, the optimisation problem can be formulated as in Equation (59).

$$\min\left\{\sum_{t=1}^{T}\sum_{i\in N_{EH}} c_{i,t}^{up,\mathbb{R}^{up}}\cdot\Delta P_{i,t}^{up,\mathbb{R}}+c_{i,t}^{dwn,\mathbb{R}^{dwn}}\cdot\Delta P_{i,t}^{dwn,\mathbb{R}}\right\} \tag{59}$$

Subject to: $V_{min}\leq V_{j,t}+\sum_{i\in N_{EH}}\left\{\left(\frac{\Delta V}{\Delta P}\right)_{j,i}\cdot\left[\Delta P_{i,t}^{up,\mathbb{R}}-\Delta P_{i,t}^{dwn,\mathbb{R}}\right]\right\}\leq V_{max}$ (60)

$$I_{k,t}+\sum_{i\in N_{EH}}\left\{\left(\frac{\Delta I}{\Delta P}\right)_{k,i}\cdot\left[\Delta P_{i,t}^{up,\mathbb{R}}-\Delta P_{i,t}^{dwn,\mathbb{R}}\right]\right\}\leq I_{max} \tag{61}$$

$$\Delta P_{i,t}^{up,\mathbb{R}^{min}}\leq\Delta P_{i,t}^{up,\mathbb{R}}\leq\Delta P_{i,t}^{up,\mathbb{R}^{max}}\qquad\Delta P_{i,t}^{up,\mathbb{R}}\geq 0 \tag{62}$$

$$\Delta P_{i,t}^{dwn,\mathbb{R}^{min}}\leq\Delta P_{i,t}^{dwn,\mathbb{R}}\leq\Delta P_{i,t}^{dwn,\mathbb{R}^{max}}\qquad\Delta P_{i,t}^{dwn,\mathbb{R}}\geq 0 \tag{63}$$

$$\begin{aligned}p_{min}\leq p_{g,t}+\sum_{i\in N_{EH}}&\left\{\left(\frac{\Delta p}{\Delta G}\right)_{g,i}\right.\\&\left.\cdot\left[-\eta_{P2G}\cdot\Delta P_{i,t}^{dwn,P2G}+3.6\,\frac{\left(\Delta P_{i,t}^{dwn,CHP_e}-\Delta P_{i,t}^{up,CHP_e}\right)}{\eta_{CHP_e}\cdot HHV}\right]\right\}\leq p_{min}\end{aligned} \tag{64}$$

$$L_{p,t} = L_{p,t-1} + \sum_{i \in N_{EH}} \left(\frac{\Delta L_p}{\Delta G}\right)_{p,i} \cdot \left(3.6 \frac{\left(\Delta P_{i,t}^{up,CHP_e} - \Delta P_{i,t}^{dwn,CHP_e}\right)}{\eta_{CHP_e} \cdot HHV} - \eta_{P2G} \cdot \Delta P_{i,t}^{dwn,P2G}\right) \cdot \Delta t \tag{65}$$

$$L_p^{min} \leq L_{p,t} \leq L_p^{max} \tag{66}$$

$$SoC_{i,t}^{TES} = SoC_{i,t-1}^{TES} + \left(P_{i,t}^{TES} - \frac{\left(\frac{SoC_{i,t}^{TES}}{C_i^{TES}} - T_{i,t}\right)}{R_i^{TES}} \right) \cdot \Delta t \tag{67}$$

$$\left(T_i^{min,TES} - T_{i,t}\right) \cdot C_i^{TES} \leq SoC_{i,t}^{TES} \leq \left(T_i^{max,TES} - T_{i,t}\right) \cdot C_i^{TES} \tag{68}$$

$$SoC_{i,0}^{TES} = SoC_{init} \tag{69}$$

$$\left[-P_{i,t}^{TES} + \frac{\eta_{CHP}^{th}}{\eta_{CHP}^{el}} \cdot \left(\Delta P_{i,t}^{up,CHP_e} - \Delta P_{i,t}^{dwn,CHP_e}\right) + \eta_{EHP} \cdot \left(\Delta P_{i,t}^{up,EHP} - \Delta P_{i,t}^{dwn,EHP}\right)\right] \cdot \Delta t = H_{i,t} \tag{70}$$

Where T is the total number of intervals considered for the optimisation, N_{EH} is the number of EH in the considered network, $c_{i,t}^{up,\mathbb{R}^{up}}$ and $c_{i,t}^{dwn,\mathbb{R}^{dwn}}$ are the proportional costs of the corresponding flexibility service, and $\Delta P_{i,t}^{up,\mathbb{R}}$ and $\Delta P_{i,t}^{dwn,\mathbb{R}}$ are the flexibility service provided to the DSO. Finally, $\mathbb{R}$ represents the set of components that characterise an EH. In this particular implementation, one EH can be composed by CHP, EHP, TES, PV panels and P2G technologies. All these resources are considered able to provide service to the DSO. In addition, DR programs from costumers are considered as a source of flexibility for the DSO. Each system is characterised by network constraints. For the power system, constraints related to voltage on nodes and the current flowing in branches are considered and linearised through sensitivity coefficients of each nodal voltage and line current ($\frac{\Delta V}{\Delta P}$, $\frac{\Delta I}{\Delta P}$) with respect to any flexibility action, as expressed by Equations (60)-(61). In addition, through power flow calculation, the node voltage and line current ($V_{j,t}$, $I_{k,t}$) are evaluated per each timestep of each typical day.

For the gas network constraints on pressure at the nodes and linepack in the lines are taken into account, through sensitivity coefficients of each gas node pressure and linepack ($\frac{\Delta p}{\Delta G}$, $\frac{\Delta L_p}{\Delta G}$), where the linepack represents the amount of gas contained in the pipeline. The gas flow calculation is implemented by means of an approach widely used in the literature [223], that allows to evaluate the gas node pressure in each gas node per each timestep of each typical day ($p_{g,t}$). This approach involves the use of Kirchhoff's law at the nodes in combination with

Renouard's Simplified Formula or Cox's formula for Mean Pressures [223], [224]. For calculating the linepack and its constraints, the approach used in [224] is adopted. With regard to the CHP, EHP and TES, they are modelled following the approach proposed in [225].

For what concern the TES model, the $SoC_{i,t}^{TES}$ represents the state of charge (SoC) at time t^{th} and EH i^{th}. $T_{i,t}$ represents the ambient temperature, C_i^{TES} and R_i^{TES} the thermal capacity and thermal resistance of the TES. Using Equation (67), the behaviour of the accumulation can be fixed by explicating the losses by means of the last term on the right. While Equation (70) binds the flexibility actions to the satisfaction of the thermal load of the EH. Indeed, Equation (70) ensures that the building's thermal load is fully satisfied even considering the flexibility actions.

It is important to report that, the LP problem can become unfeasible due to the lack of sufficient resources to solve all the contingencies. To overcome this limitation and allow the optimisation to always provide a solution, *slack* variables have been introduced in the objective function and in the nodal voltage, line current, gas node pressure and linepack inequality constraints. Dimensionally, they represent the residual gaps that the available resources are not able to close for satisfying the corresponding technical constraints. In the objective function, they are weighted by a very large cost, to avoid that they could be used needlessly. A final comment that must be included in the study is the fact that nowadays, the system operators that manage the distribution electrical network and the gas network are different. This issue creates several barriers and limitations to the study; however, the case study is a prototype suitable for proof of concept and need further improvement on this regulatory topic.

3.6.2 Overview of the Case Study and Results Analysis

The proposed flexibility market has been applied to a test network derived from a real Italian MV distribution network (Figure 13), which consider two network overlayed: the electrical network and the gas network. In particular, the gas pipes overlap with the electrical lines, creating an identical network but referred to the gas network. However, the distribution network does not consider the thermal network since it is not yet present in the Italian territory.

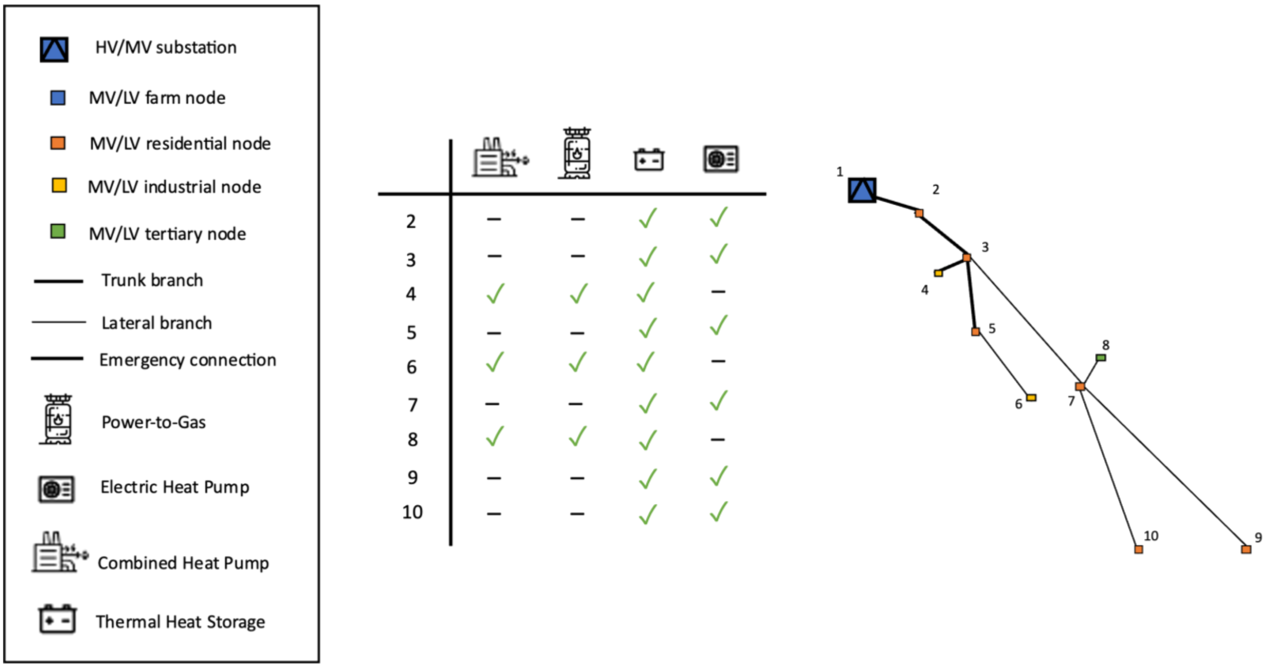


Figure 13. Distribution test network.

Long overhead lines supply small loads. The conductor cross-sections are relatively small due to the low load density, and voltage drop issues can be expected. Table VI, Table VII and Table VIII summarise respectively the data of customers, branches and conductors.

Table VI. Data of Loads, Generators, Energy Storage and Electric Vehicles.

Node	Load		CHP	EHP	P2G	TES	
	P [MW]	Q [MVAr]	P [MW_{th}]	P [MW_{th}]	P [MW_{th}]	Temp. Min [°C]	Temp. Max [°C]
2	0.33	0.11	-	0.20	-	20	90
3	0.13	0.04	-	0.10	-	20	90
4	0.36	0.12	0.40	-	0.12	20	90
5	0.23	0.07	-	0.10	-	20	90
6	0.36	0.12	0.45	-	0.12	20	90
7	0.18	0.06	-	0.15	-	20	90
8	0.21	0.07	0.23	-	0.12	20	90
9	0.15	0.05	-	0.12	-	20	90
10	0.13	0.04	-	0.10	-	20	90

Table VII. Characteristic of the LV Distribution Network Branches.

Branch [From Node – To Node]	**Length** [m]	**Linecode**
1 – 2	864	1
2 – 3	1520	1
3 – 4	1003	1
3 – 5	2105	1
5 – 6	2051	1
3 – 7	5000	1

7 – 8	1024	2
7 – 9	1658	2
7 – 10	2419	2

Table VIII. Electric Parameters for different line codes.

Linecode	**r** [Ohm/km]	**x** [Ohm/km]	**c** [μF/km]	**Ampacity** [A]
1	0.320	0.125	0.350	95
2	1.118	0.419	0.008	16

Four different customers are connected to the system: *i*) residential, *ii*) tertiary, *iii*) agricultural and *iv*) industrial. In each EH have been placed one or more of the following resources able to provide flexibility services: P2G, EHP and CHP. In addition, the possibility of DR action from customers is considered. Data on resources parameters are shown in Table IX. Note that since the operation of EHP and CHP is related to the thermal load of the EH, the possibility of these resources to provide flexibility service is contingent on the presence of thermal storage. Hence, the thermal storage is placed in each EH of the network.

Table IX. Characteristic parameters of resources.

EHP	**CHP**	**P2G**	**TES**
$\eta_{EHP} = 2.6$	$\eta_{CHP}^{th} = 0.35$	$\eta_{p2g} = 0.55$	$R_i^{TES} = 568\ [°C/kW]$
	$\eta_{CHP}^{el} = 0.45$		$C_i^{TES} = 2.33\ [kWh/°C]$
			$T_{i,t} = 25\ [°C]$
			$SoC_{start}^{TES} = 50\ [\%]$

Due to the massive number of equations, to prove the model and reduce calculation times, a single typical day has been used to model the electric and thermal load behaviour along the whole year. The load profiles are extracted from [226], [227] and represented in Figure 14 and Figure 15 for electrical and thermal demand respectively.

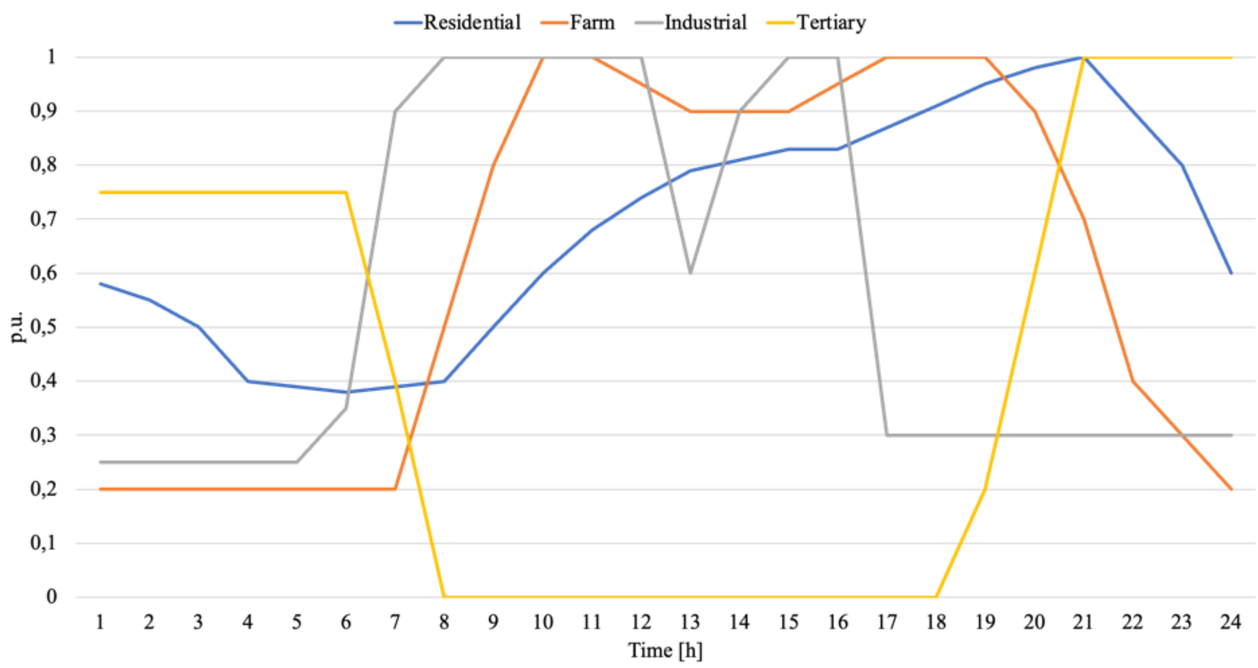


Figure 14. Load profiles of customer categories (hourly values of active power absorbed adopted as base of p.u.).

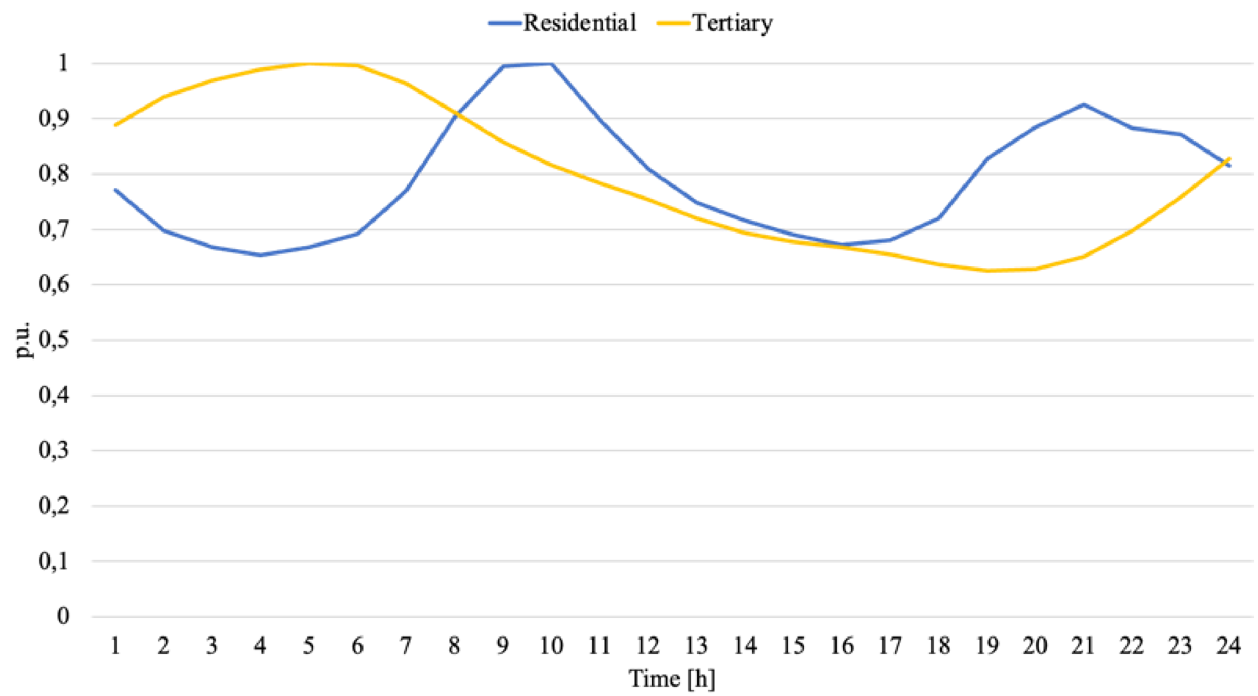


Figure 15. Thermal profiles of customer categories.

The data from [227] extracted the heat load profiles referring only to heating and domestic hot water for residential and tertiary users. Given the lack of information on the industrial sector, the heat demand of the industrial users is likened to a tertiary one. Finally, to analyse the impact of flexibility actions on the gas network, a medium-pressure (5 bar) network was defined. The gas network mirrors the electrical network shown in Figure 13. The gas network pipelines have diameters of 0.8 meters and lengths that follow the electrical conductors.

When the network is in its normal operating conditions, excessive voltage drops may appear in the peripheral nodes, particularly during the evening peak, due to the growth of residential demand and the simultaneous fall of the PV production (Figure 16). The same condition of pressure drop appear in the peripherical nodes of the gas network (Figure 17).

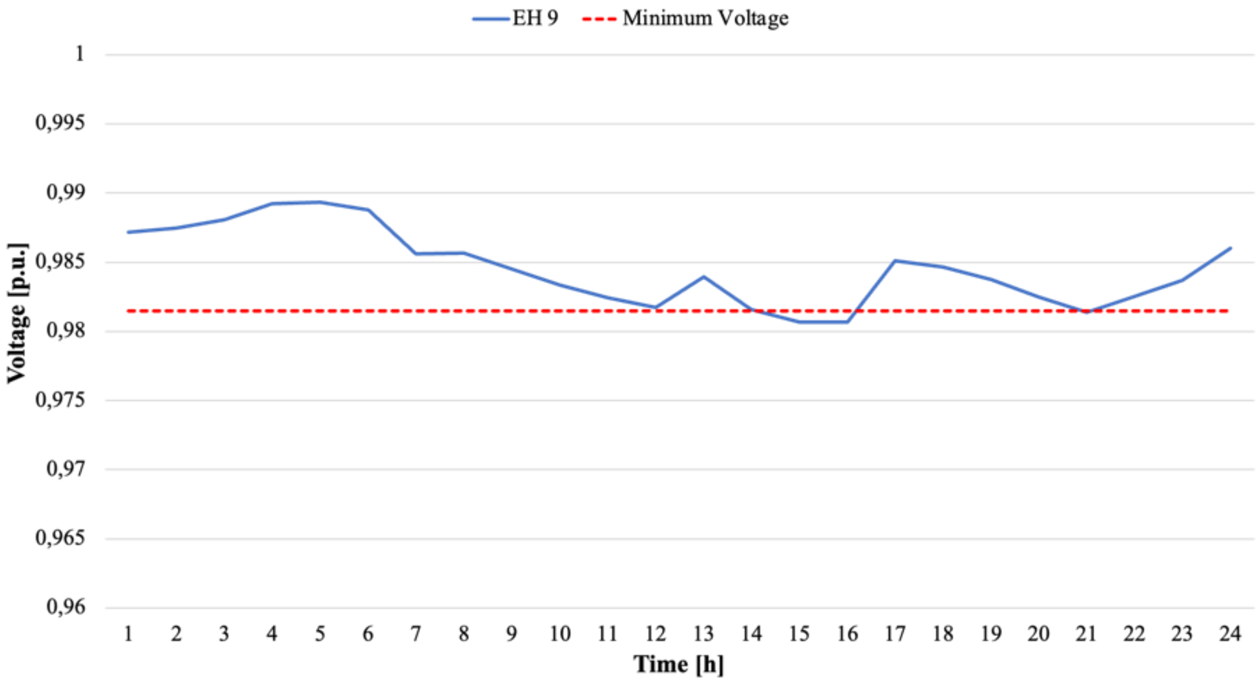


Figure 16. Daily profile of the minimum voltage of EH 9.

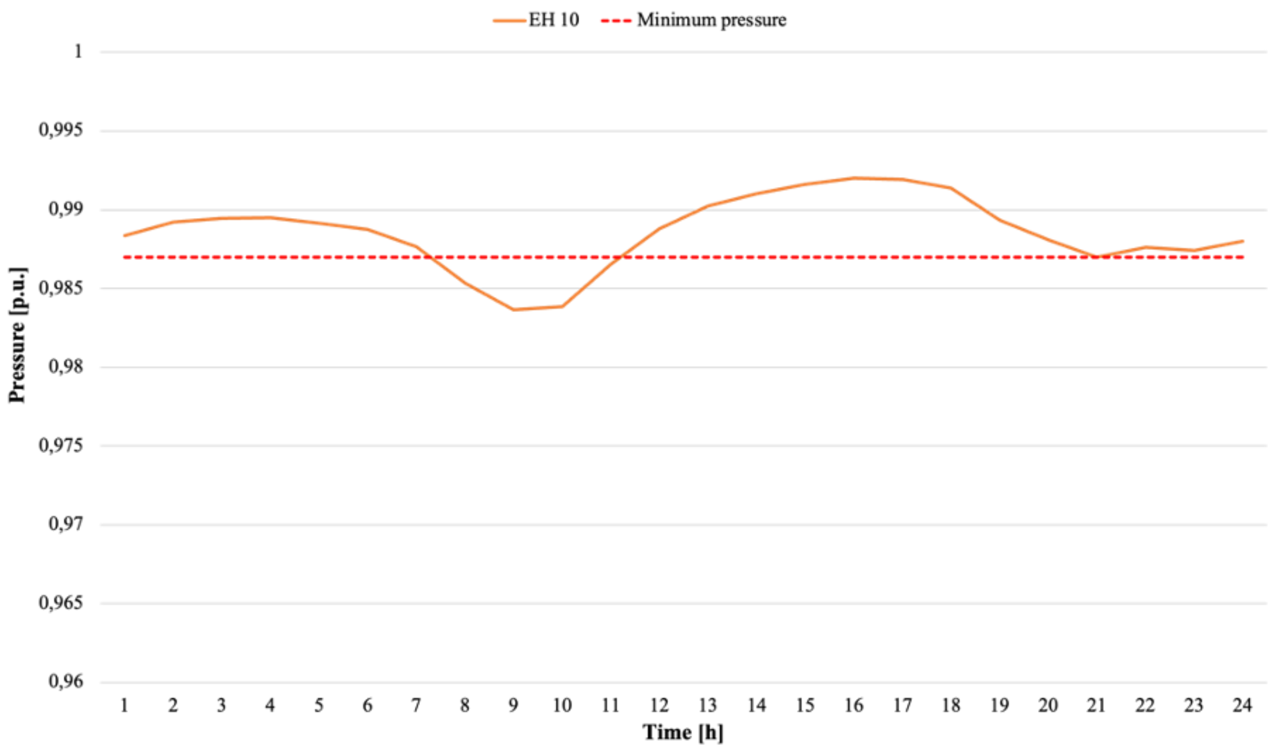


Figure 17. Daily profile of the minimum pressure of EH 10.

The optimization correctly identifies the flexibility needed by each EH to solve the contingencies of electrical and gas network. As an example, in Figure 18 are depicted the flexibility requests in the RO with an a priori risk of 20%.

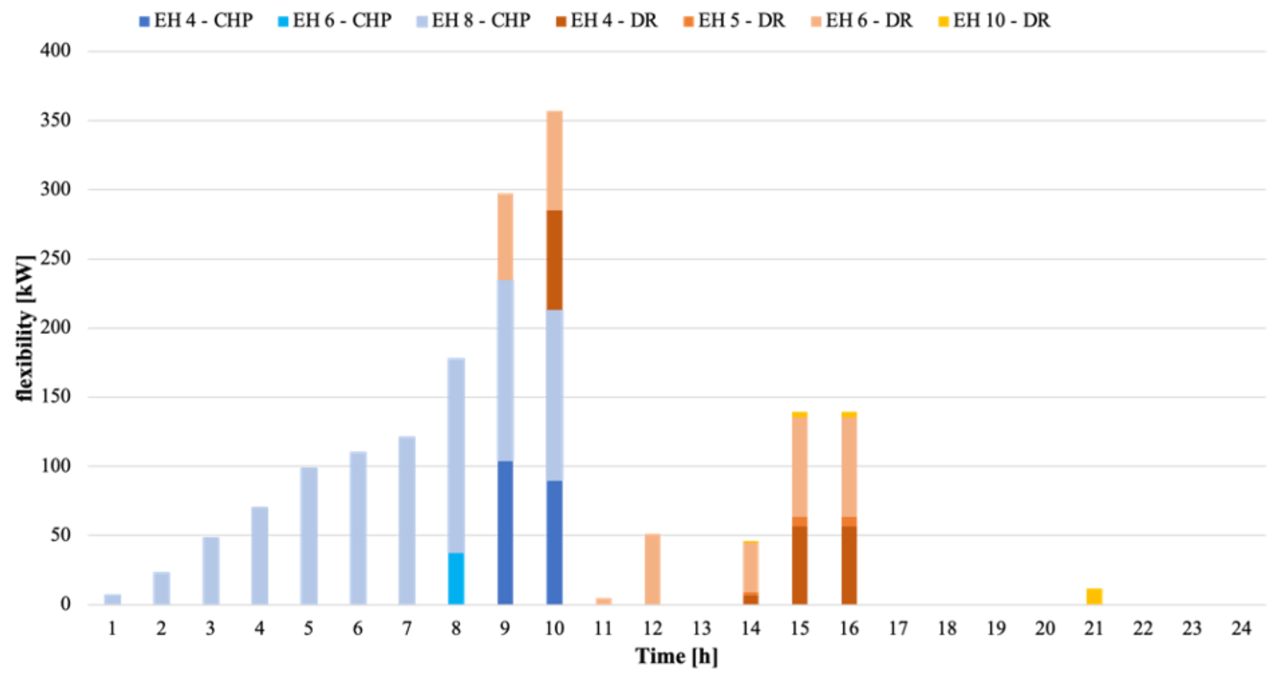


Figure 18. Flexibility exploitation - robust solution.

It is noteworthy that, despite the hourly intervals in which contingencies occur, both in the electrical and gas networks, the flexibility market reacts by demanding more flexibility than necessary, even in intervals without contingencies. This fact is attributed to the intertemporal relationships present in the equations. A clear example is evident in the Linepack equations in equation (65). From Figure 18, it can be observed that, to address undervoltage issues in the electrical network, the market intervenes with EH 4. Specifically, for each EH, the market requests a reduction in electricity consumption from electrical loads. However, it is observed that some EH, particularly EH 4 and EH 6, activate the DR service even in the intervals 9^{th} and 10^{th}. As a matter of fact, a reduction in consumption in those intervals allows the market to activate energy production in the same intervals by the CHP resources. Increased electrical generation by the CHP results in higher gas consumption and a consequent increase in pressure in the gas lines. The CHP resource, therefore, provides an upward service where higher gas consumption allows the resolution of contingencies in the gas network, which is in a low-pressure condition. However, the Linepack equation, which features intertemporal relationships, requires activation of the CHP resource in several consecutive hours to comply with its relationship. Finally, it is interesting to note that by exploiting the CHP resource, the system operator manages to satisfy equation (70) without resorting to the use of thermal storage.

Finally, to demonstrate the difference between the deterministic and the robust solution Figure 19 depicts the difference in terms of required flexibility. The robust solution employs a more significant amount of flexibility to be protected against uncertainty related to resource response. The solutions show that CHP resources, which can provide flexibility service to both the gas and electric grids, are used as little as possible. This exploitation is the consequence of these resources. Indeed, CHPs introduce uncertainty on several equations, so their massive exploitation would not guarantee the respect of both voltage and pressure constraints.

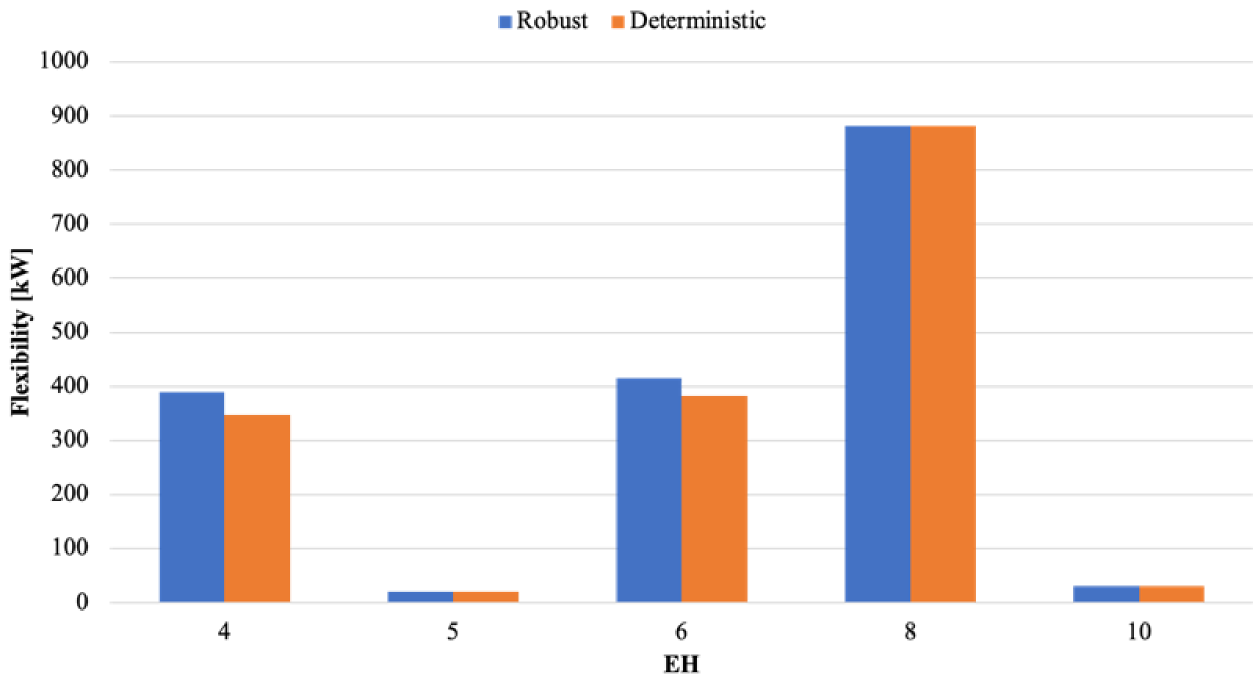


Figure 19. Flexibility request according to EH and model solution.

3.6.3 Conclusion and Future Works

In the broader context of distribution system services, this section dealt with the intricacies of flexibility markets, distribution locational marginal prices, and redispatch markets. These market mechanisms hold great promise in enhancing the efficiency and reliability of energy distribution systems.

In this section, the chapter proposed a case study that highlights the ongoing research landscape surrounding the integration of electricity and gas grids, a crucial aspect of handling uncertainties associated with the rise of RES. The studies have demonstrated their capacity to effectively address the uncertainties related to the exploitation of flexibility services from a diverse array of resources. The robust optimisation methodology showcased here has proven to be a valuable tool for navigating these complexities. It is noteworthy that the current formulation for calculating linepack does not include considerations for linepack swing. This represents an area ripe for further exploration and refinement in future research endeavours. As authoritative approaches for medium-pressure scenarios remain elusive, we have chosen to maintain a broader constraint on linepack and will leave the incorporation of linepack swing effects to upcoming studies.

Looking ahead, future research endeavours will concentrate on the implementation of a robust DLMP mechanism and a redispatch market within a multi-energy system framework. This approach will enable a comprehensive comparison of these market mechanisms, shedding light on their respective strengths and limitations. Such comparative studies will play a pivotal role in shaping the future landscape of distribution system services, ensuring that they remain adaptable and resilient in the face of evolving energy challenges.

4 Empowering the Energy Transition: Local Markets and Distributed Ledgers

In this era of energy transition, the dynamics of electricity and service markets are undergoing a transformative shift. As the world moves towards decarbonisation, decentralised energy systems, and greater consumer empowerment, traditional centralised energy exchange mechanisms are facing new challenges and opportunities. This chapter delves into the realm of local electricity and service markets, where the transformative potential of distributed ledger technologies (DLT), commonly referred to as blockchain, is explored. The chapter aims at unravelling how these technologies can revolutionise energy exchange by enabling secure, transparent, and decentralised transactions at the local level. Through an in-depth analysis, this chapter seeks to illuminate the multifaceted landscape of DLTs in the context of energy markets, shedding light on their role in fostering efficient, flexible, and community-driven energy exchange ecosystems.

4.1 Research questions

This paragraph frames the main research questions for this section of the thesis.

The research question "*What are the potential applications of distributed ledger technology in the energy sector? How distributed ledger technology can be adopted for local markets?*" delves into the extensive possibilities offered by DLT within the energy sector. It aims to uncover and examine how DLT can be effectively applied in the LEMs context.

The research question "*How does distributed ledger technology and blockchain facilitate local energy trading in the context of peer-to-peer transactions?*" delves into the specific area of how DLT and blockchain are exploited to enable local trading within the framework of P2P transactions. The question seeks to investigate the mechanisms through which DLT can empower individuals and small-scale energy producers to directly exchange energy without intermediaries. By examining the technical, economic, and regulatory aspects, the research aims at understanding how blockchains' decentralised and transparent nature can facilitate secure and efficient energy trading at the LV network level.

The research question "*Under what conditions are peer-to-peer transactions suitable for the electricity system?*" focuses on the assessment of the circumstances and criteria that make P2P transactions a viable and effective option within the electricity system. It aims at exploring the various factors, including technical, economic, regulatory, and social aspects, that contribute to the feasibility and success of implementing P2P energy exchanges. This question aims to provide insights into the prerequisites and considerations necessary for integrating P2P into the electricity system in a meaningful and impactful way.

The research question "*How does the implementation of distributed ledger technology in P2P energy markets contribute to the achievement of specific goals, such as cost reduction, energy efficiency, grid resilience, and increased renewable energy utilization?*" explores the ways in which the adoption of DLT in energy markets can drive the realisation of targeted objectives, including cost reduction, enhanced energy efficiency, improved grid resilience, and greater integration of RESs. By analysing real-world case studies and conducting simulations, the research aims at uncovering the direct and indirect impacts of DLT on these specific goals.

Finally, the research question "*How does the use of distributed ledger technology enhance transparency, trust, and security in local energy trading, and what are the implications for market participants and stakeholders?*" delves into the impact of integrating DLT on the transparency, trust, and security aspects of local energy trading. By examining the technical features of DLT, such as its immutability and decentralised nature, the research seeks to uncover how these attributes contribute to creating a more transparent, trustworthy, and secure environment for participants engaged in local energy transactions.

4.2 Introduction to Decentralised Marketplaces

The global energy landscape is undergoing a transformation, with community-driven renewable energy projects, known as *energy communities*, gaining prominence. These projects are reshaping the traditionally centralised and fossil fuel-dependent energy market [228]. To meet international climate goals and transition to a low-carbon future, substantial investments in community energy are paramount. Nonetheless, the benefits extend beyond environmental considerations, encompassing societal advantages like community resilience, economic opportunities, and social development [229]. Engaging communities as active participants is crucial for accelerating the transition to clean energy. This engagement not only garners political support but also fosters local acceptance of new energy developments and infrastructure. Globally, local energy communities and community-based energy projects have emerged as powerful tools for achieving these goals. These initiatives offer a range of benefits, including *i*) the deployment of decentralised energy production, *ii*) the enhancement of energy efficiency by means of upgrades on the buildings, *iii*) cost reduction, *iv*) improved access to reliable power, and *v*) the enhancement of the grid resilience [230]. The EU has recognized and regulated these local communities, defining them as non-profit organisations, or legal entities effectively controlled by local shareholders or members. Most importantly they are typically driven by the values of improving the distributed generation, and accept services for the distribution system operator, supplier, or aggregator at the local level [231]. However, these entities require management [232]. As the general European attitude is *pro market* and European electricity legislation generally supports market-based solutions, this management can shift from instruments such as markets, giving rise to local markets. These markets aim to encourage participation from small-scale energy consumers, producers, and prosumers in a competitive marketplace, facilitating the local exchange of energy. One of their key objectives is to effectively balance the supply and demand of energy at the local level.

4.2.1 Overview of Local Markets

Local energy and service markets are instrumental in the ongoing energy transition. They play a pivotal role in shaping the future of energy systems for several key reasons.

First and foremost, these architectures facilitate the decentralisation of energy production. They empower local communities to harness RESs like solar panels and wind turbines. This shift from centralised power plants to localised energy generation is essential for reducing GHG emissions and fostering a more sustainable energy landscape. Moreover, local markets empower local communities by involving them in energy production and consumption decisions [199]. This active participation enhances community engagement and promotes responsible energy use. It gives communities a stake in their energy future, fostering a sense of ownership and responsibility. Energy efficiency is another critical aspect of local markets. These markets encourage consumers to optimise their energy consumption patterns. Through DR programs and smart grid technologies, local markets promote efficient energy use, ultimately reducing energy waste. One of the most immediate benefits of local market is the potential for lower energy costs. By facilitating local energy trading and competition, these markets can lead to reduced energy expenses for consumers [233]. Local energy production and consumption can mitigate the need for costly long-distance energy transmission. These markets also contribute to the resilience and reliability of the energy grid [234]. In the face of disruptions or outages, local communities can continue to generate and distribute energy, reducing the impact of blackouts. This resilience is particularly important in the context of climate change and extreme weather events [235]. Furthermore, local markets are catalysts for innovation in the energy sector. They encourage the development of new technologies, business models, and market mechanisms that can improve overall energy system efficiency and effectiveness. This innovation is vital for staying ahead in an evolving energy landscape.

It is noteworthy to mention the job creation. This feature is another notable outcome of the growth of these market systems, especially in the renewable energy sector. These markets can generate local employment opportunities and stimulate regional economies, providing a significant economic boost to communities. Finally, grid flexibility is a fundamental attribute. They allow for the integration of diverse energy sources, including intermittent renewables. This flexibility is essential for maintaining grid stability and accommodating the variability of renewable energy generation. Last but not least, local markets promote a more democratic and participatory approach to energy governance. They give local stakeholders a voice in energy decision-making, ensuring that energy systems align with the needs and values of the communities they serve. This approach fosters transparency, accountability, and inclusivity [236].

These markets are not just about changing how we produce and consume energy but also about empowering communities and individuals to shape a more sustainable and equitable energy future.

4.2.2 The role of Distributed Ledger Technologies

In the envisioned energy landscape of 2050, ongoing trends suggest a significant shift towards decentralisation, following the 3D paradigm, and in particular at the distribution level [7]. This transformation revolves around the idea which local communities will take on a more prominent role in energy generation and management through local markets. Several key factors contribute to this evolving scenario. Firstly, RESs, such as solar, wind, and storage systems, are expected to dominate the energy mix [4]. These decentralised energy sources are well-suited for local generation and will reduce dependence on centralised fossil fuel power plants. Secondly, advancements in energy storage technologies will enable communities to store surplus energy efficiently for later use. This will enhance self-sufficiency and grid stability, making local energy management more feasible [237]. Thirdly, the implementation of smart grid technologies will facilitate precise monitoring, control, and optimisation of energy distribution [30]. This will make it easier to integrate decentralised energy sources and enhance the resilience of local energy systems. Moreover, the widespread adoption of EVs will further contribute to decentralisation. EVs will serve as mobile energy storage units, capable of charging during periods of surplus energy and discharging during peak demand or grid disruptions [49].

In this evolving scenario, local communities will play a pivotal role by forming energy cooperatives or collectives. These groups will collectively produce, consume, and trade energy, giving them greater control over their energy sources and consumption patterns. Central to this vision are the emergence of local energy markets, which will serve as vital platforms for P2P energy trading within communities. These markets will allow prosumers to exchange surplus energy directly with one another [238]. Under these circumstances, DLT, often implemented through blockchain, is expected to be central to the operation of LEMs.

DLT offers a transparent and immutable ledger of energy transactions, fostering trust and ensuring the integrity of transactions. Moreover, the technology provides robust security, resisting tampering or unauthorised access and safeguarding sensitive energy data [239]. The decentralised nature of DLT aligns seamlessly with the distributed character of local energy systems, eliminating the need for central authorities and reducing vulnerabilities associated with single points of failure. Smart contracts (SC), a feature of blockchain technology, will automate energy transactions based on predefined rules, enabling trustful trading without the need for intermediaries [240]. DLT can also play a crucial role in efficiently balancing energy supply and demand, supporting dynamic pricing mechanisms, and optimising the local grid. Lastly, DLT platforms can easily integrate with existing energy infrastructure, facilitating the transition to decentralised energy markets while ensuring compatibility with current systems [241].

The energy system following the roadmap to 2050 is expected to undergo substantial decentralisation, with local communities actively participating in energy generation, consumption, and trading. LEMs, underpinned by DLT, will empower individuals and communities to make informed energy choices, promote RESs, and contribute to a sustainable and resilient energy future.

4.3 Local Markets

LEMs are designed to promote a more decentralised and consumer-centric approach to electricity trading, fostering greater integration of RESs and encouraging local communities. LEMs serve as a decentralised tool for coordinating participants within a grid by utilizing market prices as a common benchmark. The prices facilitate local energy trade, emphasizing exchanges within smaller spatial distances. Engagement in these markets can also bolster local energy production, create jobs, and stimulate economic growth. As said, LEMs has been identified as a crucial tool for the large-scale integration of RESs in a 3D paradigm-based power system [242]. To shed light on LEMs, in the following, the concept of LEM will be explored and described in all its facets that have been described and presented in the literature.

4.3.1 Topology of Local Markets

LEMs have emerged as a beacon of inspiration in the pursuit of a decentralised and decarbonised energy system. These markets empower local communities, businesses, and even individual households to participate actively in the energy marketplace, challenging the traditional top-down energy supply model. The structure of LEMs encompasses different configurations, involving either P2P direct trading or pool-trading via market aggregation. LEM structure can be categorised into three topologies [243]:

1. *Centralised LEM*. Centralised LEMs are akin to traditional energy systems. They are typically managed and operated by a central authority or utility company. In this model, electricity generation, distribution, and pricing decisions are centralised, offering limited flexibility to local communities.
2. *Hybrid LEM*. Hybrid markets represent a middle ground between centralised and decentralised models. They combine elements of both to strike a balance between efficiency and local empowerment. In hybrid markets, local community entities and third-party aggregators have a significant role in their energy generation and management, while centralised guarantee ensures stability and grid reliability.
3. *Decentralised LEM*. Decentralised LEMs represent a paradigm shift in energy governance. Here, local communities and prosumers take a pivotal role in the market. Energy generation and distribution are highly localised, with homes, businesses, and

communities producing and trading electricity independently. No third-party entities are entitled of managing the interactions with the grid since all these actions are up to the community actors to resolve.

These topologies offer distinct advantages and challenges. Fully decentralised markets empower consumers, consider prosumer preferences, and promote democratisation, but face obstacles related to scalability, ICT systems, and power system resilience. Centralised markets encourage cooperation, resilience, and energy sharing but confront issues such as fairness, management complexity, and integration difficulties. Hybrid markets offer scalability and compatibility benefits but require coordination, data integration, and multi-market alignment [244].

4.3.2 Categorisation of Local Markets

LEMs have risen as a critical approach for the integration of RESs into the power grid. LEMs target the engagement of small energy consumers, producers, and prosumers in competitive energy exchanges while locally balancing energy supply and demand. According to the literature, we can classify LEMs into three groups [245]:

1. *P2P markets*. These markets facilitate direct energy trading between participants without intermediaries. Participants vary in size from residential consumers and prosumers to larger entities like buildings and microgrids. P2P markets are likely to be more decentralised and enable direct energy exchanges among participants by means of bilateral negotiation and making use of contracts for the settlements [246]. The main objective of this market is the empowerment of the market actors, allowing them to trade directly.
2. *Community or Collective Self-Consumption* (CSC). CSC markets involve closely located energy prosumers who trade surplus energy. These markets often operate collaboratively and may have non-profit central managers. This type of market is akin to the centralised topology or the hybrid one discussed before. Participants are typically small-scale and focus on incentivising local generation and resource utilisation. The primary objective of this market is to optimise the overall well-being of the community, encompassing both economic and social aspects.
3. *Transactive Energy* (TE) *markets*. TE markets prioritise the balance of energy supply and demand while offering grid services. These markets can operate at various scales, from local distribution networks to entire electricity grids [247]. They focus on providing secure and efficient energy services, integrating flexible loads, and accommodating storage devices. TE markets often consider technical complexities, operating conditions, and reliability constraints. Most of the time, TE markets operate by means of negotiations or auction clearing mechanisms.

To sum up, key distinctions among these market types include their operational scale, governance structure, and market objectives. P2P and CSC markets tend to operate at small scales within distribution networks, emphasizing local resource utilisation. In contrast, TE markets encompass a broader range of scales, aiming at providing grid services and balance supply and demand. TE markets also place a higher emphasis on market structure and design, often involving bidding, price negotiations, and auction-based mechanisms.

4.3.3 Pricing Mechanism of Local Markets

Another significant classification pertains to the pricing mechanisms employed in markets. Here there are several methodologies, each with advantages and disadvantages.

Price formation is a crucial mechanism in determining market prices, and it operates within the framework of market institutions. These institutions define how market participants can communicate messages, who is allowed to do so, and the methods by which transactions occur [248]. In the context of LEMs, various mechanisms are employed to determine prices [245].

- *Single Auction*. In a single auction, only one side of the market actively communicates and participates in the transaction process. This approach is commonly employed when one side of the market is represented by a single entity or agent, such as a single buyer looking to acquire energy or services from suppliers. For instance, consider a scenario where a group of consumers within a local community wishes to purchase excess renewable energy available at a specific time. These consumers express their interest by submitting bids, indicating the price they are willing to pay for the renewable energy. To facilitate this process, a market operator is typically involved. This operator can take various forms, including an aggregator or a local energy operator. Their role is to manage the auction, evaluate the submitted bids, and determine which consumers will be able to acquire the excess renewable energy based on their bid prices [249].
- *Double Auction*. Double auctions are widely used in P2P markets, CSC, and TE systems. The double auction mechanism allows both buyers and sellers to actively participate in the trading. In this process, buyers convey their willingness to pay. Conversely, sellers indicate their willingness to accept, indicating their price thresholds. This mechanism is widely employed in various markets, including wholesale energy markets. What distinguishes the double auction is its ability to facilitate bidirectional communication, enabling both sides to engage in price determination. It fosters efficient outcomes by creating an environment rich in information, making it a preferred choice for markets where mutual exchange occurs frequently. This mechanism's effectiveness is demonstrated in its wide usage across various domains, ensuring that transactions align closely with the preferences and costs of buyers and sellers [250]. Another mechanism is the continuous double auction. This mechanism means that the market is cleared continuously, such as in stock markets that use order books to keep track of standing bids and offers [251].

- *System-Determined Mechanisms*. In some cases, prices are determined by system-determined mechanisms rather than by market bids and offers. The operator, which could be a community aggregator, local retailer, or DSO, sets prices based on predefined mechanisms or formulas. Examples include uniform or fixed prices, fixed feed-in tariffs, or time-of-use prices.
- *Negotiation-Based Mechanisms*. Negotiation-based mechanisms are more decentralised and resemble bilateral search. They involve one-to-one or one-to-many negotiations between participants.
- *Equilibrium-Based Mechanisms*. Equilibrium-based mechanisms involve price formation based on bids and offers from agents, such as prosumers or suppliers. The price is derived as an equilibrium of the interaction, often using game-theoretic concepts like Nash equilibrium. Bids and offers iteratively lead to a price equilibrium.

These different price formation mechanisms serve various purposes within LEMs and reflect the diverse approaches taken to establish prices based on the specific market context and goals.

4.3.4 Type of Participants of Local Markets

A key element in LEMs are the actors who participate in the market. Market designs and operating conditions vary depending on the roles of participants. Seven distinct market participant types can be distinguished: *i*) generators, *ii*) consumers, *iii*) prosumers, *iv*) aggregators, *v*) retailers, *vi*) central market operators, and *vii*) grid operators.

Prosumers, consumers, and market operators are the dominant participants in LEM markets. For instance, TE markets place greater emphasis on grid operators, generators, and aggregators, reflecting their focus on providing grid services. This diversity of participants is essential for creating a variety of load and generation profiles, but it can also increase market complexity. Additionally, controllable assets, such as energy generators or loads that can be dispatched on demand, play a significant role in all market types. Storage devices and dispatchable loads, including small-scale residential ESSs, are common. Controllable loads typically involve shiftable appliances, air conditioners, and heat pumps, with TE markets focusing more on dispatchable generation, such as combined heat and power or traditional fuel-based generators. EVs are considered in all market types but less frequently than other controllable assets. Non-controllable assets vary between LEMs. P2P markets predominantly include PV generators, often small-scale rooftop PV systems, with a few instances of PV paired with wind generation. In contrast, TE markets more frequently incorporate other types of distributed generation, particularly wind energy [245].

4.3.5 Network Constraints in Local Markets

In LEMs, an important aspect is how to manage the impact of market and energy transactions on the grid. Failure to consider this impact can lead to infeasible situations and thus force the system operator to resort to recovery actions. Depending on the market topology and the market type, various solutions enable the verification of technical network constraints. Some models involve interactions with a central entity for transaction management and optimisation, while others employ a priori or a posteriori assessment through supplementary markets. Generally, methodologies for incorporating technical network constraints into the market can be classified into two broad groups: *i*) iterative coordination between markets and system operators and *ii*) adopting network operations into the market model to address congestion and voltage problems [252].

In the iterative coordination, the market operator and the system operator solve their problems iteratively, working towards a mutually beneficial solution. In [253], the proposed approach employs network fees updated iteratively by the system operator based on the distance between nodes. To improve the methods, in [254] topological distribution factors are adopted to trace power flow, determining each peer's impact on network usage, congestion, and voltage. In [255], the system operator at the distribution level submits bilateral trading contracts in the DLT platform with network information to guide participants. It is noteworthy to highlight the study in [256] where the authors employed a k-factor continuous double auction algorithm for sequential power and price settlement, with the DSO validating transactions. On the same line, [257] presents a two-stage approach, where a local market operator manages a P2P energy market, and the system operator with the local market operator coordinate the resource’s flexibility to meet network constraints.

On the other hand, joint operation combines market and grid operation problems, often through a central entity that aggregates roles. In this category, it is important to highlight the study in [258] where the authors internalize network constraints into the P2P market model by using DC-OPF to reduce the non-linearity of AC-OPF. In [259], the authors exploited the sensitivity coefficients to evaluate the impact of transactions on the network, introducing network fees to guide P2P market clearing. The research in [260] presents a P2P trading scheme to reduce peak demand by modifying prices based on network operation. In contrast, [261] proposes a two-phase algorithm for P2P trading and network operation, with a semi-decentralised structure. [262] introduces a P2P market design with network constraints, user preferences, and trade-independent network fees. The distance between peers serves as a consumer preference metric.

4.3.6 Real-world Examples of Local Markets

LEM operates on a market-based approach, providing a platform for customers to engage in energy trading within their communities, whether defined socially or geographically. Since the inception of this innovative concept, numerous projects and applications have endeavoured to implement local markets. Here are various applications of LEMs in various contexts.

The first project is the VPP-Wuppertal project, which aims at establishing a Virtual Power Plant (VPP) that considers both cross-sector optimisation and the current grid conditions. In this context, energy generators, loads, and storage systems are used in a way that benefits the distribution grid's operation and allows optimisation of community social welfare and GHG emissions in order to achieve an economically efficient and CO_2-reduced operation. The approach involves both direct control measures and indirect control through incentive signals. Optimisation is based on forecasts, which are adjusted based on the effects of incentive signals. Any remaining open positions will be balanced on trading markets. Sector coupling will be promoted by integrating additional Power-to-X facilities, such as hydrogen production for public transport and industrial processes. Overall, the project contributes to the long-term development of a sustainable energy supply system in Wuppertal [263].

The second project is called Hybrid LSC, where LSC means local sustainable communities. The project focuses on promoting holistic sustainability in settlement areas by optimising the combination of technical, economic, and social measures. The project extends beyond the energy system to include resources like water and waste. The project develops intelligent control strategies to optimize energy and other resource demands, such as heat, cold, mobility, water, and waste, within an LSC. Citizens and stakeholders are actively involved in the project, which is applicable to various settlement types, whether in rural or urban areas. The project has been applied in Vienna, where building components were exploited as storage for the public district heating system [264].

The SoLAR project aims at reducing the CO_2 emissions by 75%, while demonstrating the feasibility and operation of a decentralised real-time pricing system maximising the integration of intermittent RESs. SoLAR demonstrates that sector coupling, combined with intelligent control of CHP, heat pumps, and EV charging, can provide substantial flexibility and grid support. Seasonal energy storage using hydrogen or synthetic methane is also considered. The project involves a housing development in Allensbach, where each house has rooftop PV and possibly a battery, with intelligent control of up to 100 appliances, aiming to increase self-consumption from 50% to over 80%. The control system involves price signals derived from grid conditions, allowing appliances to operate during financially attractive periods. The project highlights how appliances like fridges and freezers can contribute to grid stability within a real-time price system, potentially providing valuable primary control power. It demonstrates that climate-neutral energy supply with 100% renewables is possible by maximizing temporal flexibility in energy consumption [265].

The last LEM project presented is the serve-U project [266]. The project aims at developing a digital optimisation platform for energy communities. This platform will enable these communities to efficiently control the use of RESs, offering flexibility without significant technical complexity or cost. The system integrates whether forecasts, market-based price data, and self-learning consumption forecasts. The project focuses on forecasting and optimising energy flows within communities.

LEMs represent an innovative approach to energy trading within communities. Several noteworthy projects have emerged to implement LEMs in various contexts, showcasing their potential benefits. These projects collectively underscore the versatility and potential of LEMs in shaping more sustainable and efficient energy systems.

4.4 Distributed Ledger Technologies

DLTs, notably blockchain, are transforming the energy sector, particularly in LEMs. LEMs empower consumers and boost renewable energy integration. DLTs create secure, decentralised ledgers that enable energy trading platform, reducing reliance on intermediaries and fostering active community participation. DLTs boost local renewable energy use, aligning with sustainability and reducing reliance on fossil fuels. They facilitate transparent energy trading, driving economic growth, creating new businesses, and generating employment in communities. This shift supports decentralised and democratised energy trends. To understand DLT in the energy sector, its definition and applications are explored, shedding light on its multifaceted role.

4.4.1 Distributed Ledger Definition

One of the latest transformative forces in the field of information technology are DLTs. Marking the initial stride into this realm was the advent of Bitcoin in 2008, proposed by Satoshi Nakamoto [239]. This innovative technology emerged from the collaborative efforts of hackers and cryptography scholars, married by the aspiration to build a digital currency, commonly referred to as cryptocurrency, that could operate independently of centralised authority.

Embedded within the emergence of the DLT is its symbiotic relationship with the burgeoning realm of the IoT. The IoT envisages an intricate web of interconnected machines and devices, endowed with the autonomy to interact and exchange data via the channel of the Internet. This vision of a fully digitised system interconnected by digital machines is easily associated with future predictions of the energy system.

The DLT is a platform for the orchestration, synchronisation, and empowerment of a complex decentralised database. This database, distinguished by its intrinsic ability to perpetuate itself, hinges upon an intricate nexus of information interchange amidst the computational devices of platform participants, colloquially termed *nodes*.

Structurally, the Distributed Ledger represents a decentralised and certified repository of information, universally accessible and unshackled from centralised custodianship. The very essence of this technology resonates with the P2P paradigm [267], endowing each participant with the authority to engage in transactions, thereby contributing to the collective repository known as the shared ledger. The decentralised architecture facilitates seamless onboarding and disengagement of nodes, an inherent attribute that bears no consequence on the ongoing information processing.

The architectural fabric augments the capacity to disseminate information across a globally distributed network of computational entities. The DLT unveils distinctive attributes such as [240]:

- *Decentralisation*: The DLT fosters direct P2P transactions, rendering intermediaries superfluous. Universally uniform in attributes and privileges, network nodes partake in the authentication and input of data into the shared ledger. This egalitarian construct empowers nodes to effectuate information and transaction exchange irrespective of geographical disparities.
- *Immutability*: The architecture fosters an environment wherein alterations to pre-existing ledger information are rendered exceedingly complex, a testament to the robust verification and security mechanisms at play.
- *Traceability*: An intrinsic facet of the technology lies in its ability to retrospectively track the progression of transactions culminating in the present network state. This faculty, rooted in cryptographic authentication, establishes a chronological lineage interlinking database elements, underscored by timestamps, transaction senders and recipients.
- *Transparency*: Inherent in the tenets of technology is the mandate that information finds simultaneous residence across myriad network nodes, granting stakeholders unimpeded accessibility to shared insights.

In the history of DLTs, the blockchain network, with the Bitcoin, pioneered the use of a distributed ledger to store transactions and account data. It employed an embedded programming language called Script for transaction mechanisms. Bitcoin's blockchain maintained data integrity and prevented double-spending. To support more complex transactions, Ethereum introduced Turing-complete languages and SC that operate without downtime or interference. SCs have financial, semi-financial, and non-financial applications. While Bitcoin acts as a decentralised calculator, Ethereum is likened to a decentralised computer, extending features like faster block mining, smart contracts, and simpler transactions.

In the last years, a novel concept emerged from the framework of DLTs. This concept is the direct acyclic graph (DAG). DAG data structures enhance scalability and speed for transaction processing, making DAG platforms suitable for microtransactions.

In the world of DLT there are different types of ledgers. One of the most commonly used classifications is the distinction between public and private ledges. Public DLTs lack data privacy, while private ones implement access control and user management. Public DLTs are less suited for applications like energy markets due to privacy limitations. Private DLTs offer better data privacy, suitable for applications like energy markets. In the end, public and private DLT platforms offer diverse consensus mechanisms, and their applicability can span from digital identity, and data management to governance, tokenisation, and smart contracting.

4.4.2 Blockchain

In a world where Internet is widespread, the cost of global information communication has drastically reduced. Activities like Bitcoin have shown that by leveraging consensus mechanisms, default settings, and voluntary adherence to social contracts, the Internet can facilitate a decentralised value transfer system that is widely accessible and nearly free to employ. This structure, called blockchain, can be viewed as a specialised form of a transaction-based, cryptographically secure state machine. Following this concept, subsequent systems like Ethereum adapted this technology to provide an integrated end-to-end system for building software.

The core idea behind blockchain is to create a decentralised and tamper-resistant digital ledger that records transactions in a secure and transparent manner. Unlike traditional centralised systems that rely on a single authority or intermediary, a blockchain operates on a distributed network of computers, where each computer maintains a copy of the entire ledger.

Given the multitude of existing blockchains, all similar due to the intrinsic characteristics of the technology, in the following chapters, Ethereum's blockchain will be used as a reference, as it remains the most widely adopted today. While Ethereum may exhibit some differences compared to other blockchains, these distinctions will be highlighted to illustrate how blockchain technology can vary based on its ultimate purpose.

The blockchain is precisely a chain of blocks. These blocks contain specific information that occurs within, or even outside under certain conditions, of the blockchain platform. The blockchain is a decentralised system characterized by nodes that can communicate directly using the P2P paradigm. As is well known, the blockchain adopts a chain system that forms a tree structure. This tree is commonly referred to as a Merkle Tree. This Merkle Tree forms a shared and globally accessible ledger for everyone on the blockchain platform. Unlike a regular book, it is not only available in one place, but everyone involved in the blockchain has an identical copy of the ledger. Therefore, it is transparent, and since it is available in many places rather than just one, it is decentralised. The blockchain is a chain to which new data blocks can be added. In the case of the Bitcoin, many transactions are combined into one block and added to the chain. On the other hand, Ethereum operates as a transaction-based state machine, starting from a genesis state and using transactions to evolve into a current state. The current state represents the accepted version of Ethereum's world, encompassing elements like account balances, trust arrangements, and various data. Valid transactions form valid state changes, which are executed through transactions. Unlike Bitcoin, Ethereum operates as a state machine running on a globally accessible virtual machine called the

Ethereum Virtual Machine (EVM). However, this difference in the way it operates does not change its characteristics, in fact, the shared ledger remains accessible and immutable [240].

In all blockchains, transactions are grouped into blocks and linked through cryptographic hashes. Blocks serve as journals, recording transactions and creating incentives for mining. Mining involves dedicating effort to strengthen a block's transactions using cryptographic consensus algorithm. Mining serves as an incentive for nodes to support the network and distribute coins since there's no central authority. The steady addition of new coins is similar to gold mining. The incentive can be funded by transaction fees. As more coins circulate, the incentive can shift to transaction fees, becoming inflation-free. This system encourages nodes to be honest, as it's more profitable to follow rules that benefit them than to undermine the system.

In contrast to other blockchains like Bitcoin, Ethereum adopts an intrinsic currency system primarily to incentivise the use of the platform for computation. On the contrary, blockchains like Bitcoin develop their own virtual currency to facilitate direct currency exchange between entities without the need for third-party entities, like banks [239]. This phenomenon also occurs in Ethereum, but it is a consequence of the actual intention for which the virtual currency was created.

In the decentralised system, new blocks are added to existing blocks, forming a tree structure. To agree on the blockchain path, a consensus scheme is required. If there's a disagreement on the best blockchain path, a fork occurs, leading to multiple coexisting system states. This situation must be avoided as it would cause uncertainty and undermine confidence in the system. This phenomenon, despite efforts to avoid it as much as possible, happens more often than one might imagine. This occurrence can happen for various reasons, such as a cyber-attack or delays in Internet communication. While the former is rare or quite difficult nowadays, the latter reason is still very likely. In fact, if two nodes manage to validate a new block to be added to the chain almost simultaneously, in terms of internet communication, they could receive the same timestamp, resulting in the creation of forks. The blockchain resolves this issue by using the longest chain of blocks in subsequent states, meaning the chain with the least old timestamp. Of course, the forks that have been created are not eliminated but remain attached to the chain. From these never-eliminated chains, cryptocurrencies like Litecoin are created, which is a fork of Bitcoin [268].

To explain how adding new blocks to the blockchain works and how consensus throughout the platform is implemented, the block structure is express in the following [269]. A block consists of a block header and a block body. The block body contains all transactions that are to be added to the blockchain. The block header contains several pieces of information, the most important are:

- *Parent Hash*. It is a hash of the block header of the previous block. Since each block references the hash value of the previous block, and the hash value changes completely with every slightest change to the input, the blockchain is tamper-proof because any subsequent change to content would invalidate the hash value in the subsequent block.

- *Transactions Root*. The Merkle tree root can be thought of as a summary of all the transactions in a block. To create a Merkle tree, a hash value is generated for each transaction. Subsequently, a new hash value is formed from two neighbouring hash values until one arrives at the Merkle tree root, which comprises all hashes of all transactions in the block.
- *Beneficiary*. The address to which all fees collected from the successful mining of this block be transferred.
- *Difficulty*. A scalar value corresponding to the difficulty level of this block. This can be calculated from the previous block's difficulty level and the timestamp.
- *Timestamp*. A scalar value equal to the reasonable output of Unix's time at this block's inception.
- *Nonce*. A 64-bit value which, combined with the mix-hash, proves that a sufficient amount of computation has been carried out on this block.

These six elements represent the fundamental information included in all blockchain's blocks. However, Ethereum differs from other blockchains since the nature of Ethereum is as a distributed computer and not manly as distributed ledger. Therefore, in order to avoid issues of network abuse and to sidestep the inevitable questions stemming from Turing completeness, all programmable computation in Ethereum is subject to fees [240]. The fee unit is called gas, and any given fragment of programmable computation, which means creating contracts, utilising and accessing account storage and executing operations on the virtual machine, has a cost in terms of gas. So, the computations on the EVM are limited by a parameter called gas. Tariffs for gas are applied in three distinct circumstances, all three as a prerequisite for the execution of a transaction. The first situation occurs in the case of operation calculation. Different fees depend on the calculation type and the transaction [269]. The second case happens in case you want to call a function or create a contract. The last scenario occurs if you use either volatile or non-volatile memory. In other words, whenever you want to increase the required memory space.

It is noteworthy to highlight that the EVM is a stack-based machine. A stack machine can be represented as a virtual machine whose main activity is moving temporary values to and from a push-down stack. The concept of the stack represents a data type that serves as a collection of elements with two primary operations:

- *Push*, which adds an element to the collection, and
- *Pop*, which removes the last added element.

The elements of the Ethereum stack are represented by the assembly instructions that the EVM can execute. Each time an action is performed, an instruction can be added and removed from the stack. The number of instructions added and removed are represented by the parameters **δ** and **α**, respectively. Each time an instruction is added the **δ** parameter is incremented, while each time an instruction is removed from the stack the **α** parameter is incremented. Each time an element is added or removed from the stack, a cost function evaluates the entire cost, in gas, required to execute the given instruction. Once the gas cost of a transaction has been evaluated, the user must enter that transaction into the blockchain network. This can be done through the consensus algorithm. However, an additional fee must be paid to network miners to run the algorithm. The higher the fee, the faster the transaction is validated and officially added to the blockchain network.

Except for the previous differences, Ethereum runs like other blockchains, which means that the nodes in the network must reach a consensus on which blocks to add to the chain while preventing abusive use and without the involvement of a trusted third party [270]. There are several consensus protocols, the most notable are the Proof-of-Work (PoW) and the Proof-of-Stake (PoS). Adding blocks to the chain, which also secures the system against fraudulent transactions, is called mining.

Consensus algorithms are designed to address two main issues in blockchain platforms: the Double Spending problem and the Byzantine Generals problem [271]. Double Spending refers to reusing the same currency in two transactions simultaneously. This arises due to slow connections or block validations, allowing a malicious actor to use the currency from a previous transaction for another. Blockchain resolves this by validating transactions simultaneously across many distributed nodes in the network. The other issue is the Byzantine Generals problem. This problem was introduced to model consensus in a network of computers subject to unpredictable failures, a common challenge in fault-prone distributed systems.

PoW is the most known consensus algorithm. Its basic idea is to reward participants who are the first to solve a hashing problem with virtual currency. Each participant attempting to solve the problem is called a Miner. Based on information from the previous block, every Miner calculates the solution to a mathematical problem. The calculation phases are as follows:

1. *Get Difficulty*. The mining algorithm dynamically adjusts based on the network's hash rate. It changes the mining problem's difficulty according to the speed at which miners solve it. In this way the consensus algorithm is always balanced, and no nodes are advantaged.
2. *Collect Transactions*. All pending transactions on the network are gathered after producing the last block. The Merkle Tree of these transactions is then calculated, and the block fields are filled with the hash of the previous block, Nonce, and other information.
3. *Calculating*. Using the Nonce, ranging from 0 to 232, the Hash of the previous block is calculated (to fill the *Hash* field in step 2). If the resulting hash verifies the difficult criteria, the block can be validated and added to the network.

4. *Restarting*. If a node fails to calculate the hash value within a certain time interval, step two is repeated. If no other node completes the calculation, the process starts again from point 1.

PoW considers the workload each participant bears as a safeguard. This means that participants must use computational power and energy to solve the mathematical problem. If someone wanted to manipulate the blockchain, they would need to control over 50% of the hashing power to have a chance to generate the last block and dominate the longest chain. However, nowadays for platform like Bitcoin and Ethereum, this would require a prohibitively high cost.

Due to the competition among participants, miners have increasingly improved the performance of their hardware, using Graphic Processing Units (GPU) or Application Specific Integrated Circuits (ASIC), which in turn consume more electricity. Furthermore, participants with lower computational capacity have low chances of winning the competition and receiving rewards. They often join Mining Pools to increase their earning opportunities [272]. A Mining Pool is a group of participants who collaborate by sharing their resources. This distributes the mining activity across multiple participants, spreading the significant computational demand that a single individual would otherwise need to handle among all participants in the Pool.

The other important consensus algorithm is the PoS. The concept of *Stake*, translated from English, corresponds to *Guarantee* that is assets pledged as collateral. In PoS, the mining process becomes virtual, and miners become validators. Validators pledge some of their cryptocurrency before starting to validate blocks. After the validation phase, if the block is accepted, the validators receive compensation for each transaction belonging to that validated block. However, if the block is rejected, validators lose their Guarantee. In the PoS, the competitive search for a mathematical problem solution with other nodes no longer exists. Instead, a single validator is selected for each new node to validate. This validator is chosen based on the Stake they can offer as collateral, rather than their computational power, as in the case of PoW [273].

Through the selection process based on the Guarantee, a node's likelihood of being selected as a validator no longer depends on its hardware. This approach also reduces energy consumption compared to the PoW mechanism. Finally, block generation and transaction confirmation speeds are maintained at constant and lower values compared to PoW.

In the PoS mechanism, two main problems exist [274]:

- *Transaction speed*. This, much faster than the PoW mechanism, would cause the size of the blockchain to grow too rapidly. Some nodes might find the data volume it contains unmanageable.
- *Nothing at Stake attack*. In this attack, a validator validates a series of blocks without publishing them. After hiding a series of validated blocks longer than the blockchain's

current chain, they could publish it to execute a Fork and have the entire network accept transactions in which the malicious node performs Double Spending or other malicious actions.

4.4.2.1 Types of blockchains

There are two main types of blockchain: *public*, and *private* [275].

Public, or permissionless, blockchains provide access to the network, transactions, and block verification without authorisation. These systems are decentralised, lacking a central authority for access control. Access is shared among all nodes, ensuring no user has special privileges and preventing control or modification of stored information. The concepts of public and permissionless are closely tied, with non-approval-based blockchains being considered public. Data on these blockchains is encrypted for privacy, like Bitcoin's use of pseudonymous wallet addresses. Scalability is a concern, as stability improves with more participants, while transaction speed remains constant. Public blockchains use PoW consensus algorithms, being open-source and allowing anyone to read/write or audit transactions without permission. Transparency enables individuals to participate by downloading, running nodes, and engaging in various activities on the blockchain. Decisions are made through decentralised consensus algorithms like PoW and PoS.

Private, or permissioned, blockchains, mainly developed by private entities, limit access to reading, writing, and auditing transactions. Write/audit permissions are centralised, while read permissions may vary. Decision-making processes, like mining rights, are overseen by trusted central entities. They offer scalability, security, and data privacy advantages over public blockchains. Private blockchains, smaller and membership-controlled, are preferred by consortia for confidential trade. All blockchains use cryptography for secure ledger management, negating the need for central authority. Permissioned blockchains rely on central authority for access control. These blockchains entrust chosen nodes for verification, not allowing everyone. Private blockchains resemble permissioned ones, prioritizing storage, speed, and cost reduction over decentralisation. Trusted organisations control access, data reading, and rule changes. Enhanced privacy stems from authorisation requirements.

4.4.2.2 Blockchain in Economics and Governance

The evolution of cryptocurrency values and the transformative power of blockchain technology have ushered in a new era of financial innovation. Among the prominent examples is the Ethereum blockchain, which has revolutionised the financial landscape through its decentralised finance mechanism, effectively bypassing intermediaries and reshaping traditional currency exchanges. This unique characteristic of blockchains set them apart from conventional financial systems, shielding them from the direct influence of central bank policies. Unlike traditional currencies, cryptocurrencies are not subject to the decisions and interventions of central banks. Instead, their value is dynamically shaped by the actions of traders and the continuous technological advancements unfolding within the blockchain platform.

A visual representation in Figure 20 outlines Ether cryptocoin's price trajectory from 2017 to 2019, revealing an astonishing surge that peaked at 1.1 k€ in January 2018. This meteoric rise was predominantly fuelled by a wave of investors who recognised the potential of the Ethereum network. The momentum carried forward in 2021 with the release of Ethereum 2.0, a substantial upgrade that ignited further interest and investment in Ether. Consequently, Ether experienced remarkable growth during this period, further cementing its significance in the cryptocurrency landscape.

However, an important facet to consider is the inherent volatility of cryptovalues, and in particular of the Ether cryptovalue. This volatility, while characteristic of many cryptocurrencies, holds particular implications for its application across various sectors. Notably, LEM are among those where the impact of crypto fluctuations is amplified. The cost dynamics of implementing blockchain-based solutions within LEMs are intricately tied to the ever-changing value of the crypto. As a result, these fluctuations can lead to variable costs, presenting challenges and opportunities for blockchain integration in energy markets.

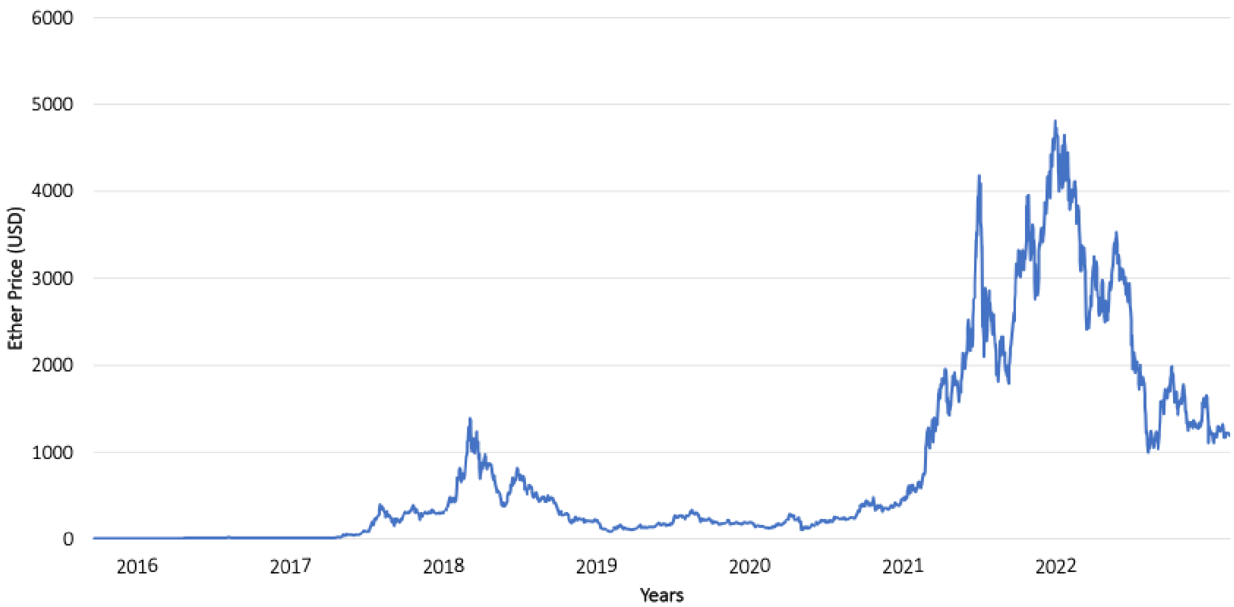


Figure 20. Conversion rate factor from 30th July 2015 to 31st December 2022 [276].

In addition to simple transactions involving cryptocurrencies or other valuable items, blockchain technology developed a new avenue for online markets and programmable transactions known as smart contract. A SC is a digital protocol that automatically executes transactions without the need for third parties. The fundamental concept underlying SCs is to ensure the binding strength of contracts not through legal means, but directly through computer code. SCs are algorithmic entities residing within the blockchain environment, but in particular in Ethereum, the blockchain platform that invented this technology. Moreover, these contracts can be externally invoked, allowing real interaction with them. However, similar to all blockchain elements, the content of these contracts must be immutable and not random but consistently repeatable within the blockchain. These algorithms stand out for their inherently accessible and user-friendly nature, catering to any network participant. In essence, a SC provides a genuine computational equivalent to traditional paper contracts. It executes the contract's code, meticulously records and validates all stages within the adopted blockchain. As a result, this process safeguards the entirety of contract data, preventing subsequent modifications or deletions [277].

SCs are commonly written in Solidity (JavaScript-oriented), Ethereum-based proprietary programming language. The most widely used SC standard is ERC20, employed for creating and managing tokens (digital assets, cryptocurrencies) on the Ethereum network [278]. Among the well-known benefits of SCs are:

- *Flexibility*. This feature can underlie a broader agreement. It allows parties who establish off-chain agreements, outside of a blockchain, to formalize some or all subsequent stages using a smart contract.
- *Unambiguity*. Suitable for constructing the entire structure of agreements between parties.
- *Completeness*. It can impose dual conditions on an agreement between parties. On one hand, it addresses formalizing the agreement, and on the other hand, it facilitates the execution of agreements by compelling the involved parties to adhere to it.

In the context of SCs, a new paradigm has risen, the Decentralised Application (DApp) paradigm [279]. A DApp is a type of application that operates independently of control center or central servers, relying instead on a decentralised network where users have full control. In a DApp the backend logic is connected to a SC executed on a blockchain, such as Ethereum. SCs ensure unequivocal DApp functionality through programmable operations, offering transparency and security as they are visible and public. It is important to remember that data storage is fully decentralised. Each DApp user stores a complete history of actions on the DApp network, with interactions recorded within blockchain blocks using cryptographic security to prevent unauthorised access. DApps function similarly to blockchain networks, with each user being a node within the network, overseeing operations and validating interactions. The SC acts as an intermediary verifying interaction validity. With each new operation, platform information is updated on each node, contributing to maintaining the application using individual computer resources. This structure ensures continuous service and resistance to Denial of Service or Distributed Denial of Service attacks, as it's technologically challenging to simultaneously remove all nodes from the network. These applications fully leverage blockchain systems, enjoying benefits such as security, privacy, and anonymity. These features provide DApp users with absolute control over their data at all times.

Developing this new Blockchain-based technology has given rise to new entities like Decentralized Autonomous Organizations (DAO). DAOs present an innovative approach to governance and organisational structure, leveraging blockchain technology to establish consensus without relying on a central decision-making authority. They offer advantages like safety, accountability, reliability, and robustness to local social networks. The prevalence of DAO-managed initiatives is increasing, as they enable decentralised and distributed management of people and assets, eliminating the need for intermediaries. The blockchain's accessibility and tamper-proof nature enhance mutual trust among participants [280].

DAOs redefine traditional leadership, knowledge access, and decision-making by implementing rules and protocols through SCs, algorithms, and deterministic coded regulations. While DAOs are often associated with cryptocurrency projects, they are also being explored by mainstream brands to connect with digital-native audiences. In scientific literature, DAOs are depicted as virtual entities possessing coordination and self-governing traits empowered by SCs. Their potential to establish distributed governance structures is studied, albeit with hurdles related to technology and legal issues due to lack of regulations in many countries [281]. Moreover, DAOs are being investigated for their potential to enhance efficiency and transparency in e-government systems. To establish a DAO, mission statements, ownership, and governing rules are defined, allowing adaptation for various scenarios and levels of decentralisation. Decision-making authority can be tailored to trusted users or distributed among all members. While blockchain technology's role in the energy sector is explored, the application of the DAO model for managing, governing, and operating renewable energy projects remains an unaddressed topic in current literature [282].

4.4.3 Direct Acyclic Graph

Directed Acyclic Graph is an innovative distributed ledger technology that challenges the traditional blockchain structure for managing and recording digital transactions. Unlike a ordinary blockchain, which arranges transactions in chronological order within blocks, DAG employs a more intricate and flexible network structure to achieve consensus and record transactions. This technology has gained attention as an alternative to traditional blockchains due to its potential to address certain limitations such as scalability, transaction speed, and energy efficiency.

The emergence of DAG technology is a response to the limitations of traditional blockchains, particularly in terms of scalability and speed. With the growth of blockchain use, challenges like slow transaction processing and network congestion arose. To tackle these issues, innovators aimed to redefine transaction validation and recording. DAG technology draws inspiration from graph theory and distributed systems, employing a non-linear structure where transactions form a directed acyclic graph. This differs from the sequential block arrangement of traditional blockchains. DAG enables simultaneous validation of multiple transactions, potentially leading to quicker confirmations and higher throughput. Pioneered by IOTA [283], DAG-based systems introduced the *Tangle*, a distributed ledger alternative to traditional blockchains. The Tangle's distinctive architecture and *tip selection* consensus mechanism enable fast and secure transactions without requiring miners and their energy consumption. Other projects, like Nano, also adopted DAG to enhance scalability and energy efficiency [284].

In the realm of DAG, transactions are depicted as vertices while connections are represented as edges. In IOTA, posting a transaction involves linking it to two prior transactions and verifying their data. The count of incoming edges, referred to as transaction weight, determines validity upon reaching a set threshold. In Nano, graph edges are formed through send and receive points. However, time traceability within a DAG structure is ensured only for directly or transitively linked transactions.

DAGs offer advantages like minimal to no transaction fees and rapid transaction processing. They allow concurrent validation, making them highly scalable and efficient. As DAG networks expand, they gain security, yet they remain susceptible to attacks that could decrease transaction processing volume. To mitigate risks during initial stages, many DAG solutions employ a centralised transaction coordinator or pre-selected validator nodes. These validators serve as centralisation points. Complete decentralisation in DAG networks is achieved when central coordinators are no longer necessary.

4.5 The Distributed Ledger relevance to the Energy Sector

The ongoing pursuit of achieving a society with net-zero carbon emissions has led to profound transformations in the landscape of electricity distribution networks. High RESs penetration, electrification of transportation and heating sectors, and the increasing inadequacy in terms of efficiency and cost-effectiveness of traditional planning approaches for handling increasing demand are requiring a new transition [285]. This transition involves adopting a more proactive approach to manage distribution networks by leveraging *smart* alternative technical solutions and innovative market approaches. The emerging DLT presents a decentralised data management paradigm that can establish a trustworthy platform for system operators to effectively manage multiple parties, assets, and devices within distribution networks. There are multiple applications studied to date of blockchain technology in the energy sector. Applications that have the potential to revolutionise the system if implemented. However, the features of DLT can have potential drawbacks [286], [287]. Verifiability and transparency enhance trust but can raise privacy concerns. Redundancy prevents single points of failure but demands significant storage and computational resources. The open-source nature may lead to security issues, such as vulnerabilities in SCs that malicious nodes could exploit, while measures like *sharding* and *off-chain* solutions aim at addressing speed and scalability issues in blockchains. Different consensus mechanisms offer trade-offs between trustworthiness, security, speediness, and scalability.

Very often DLT applications, just like its features, align with the needs of the system operator, even though some features limit the adoption of such technology.

DLT offers a decentralised, verifiable, and transparent infrastructure that can suit the needs of system operators, enabling multiple untrusted parties in distribution networks to engage in negotiations, trade, agreements, and services, creating something akin to a market-based system. However, the transparency reduces the customer privacy, and the decentralised structure can impact on the quickness condition required by the network operator. Decentralisation prevents manipulation by a single entity and enhances trust among parties, meeting the security requirements of system operators. Verifiability adds traceability and reliability. SCs on DLT enforce agreements automatically, eliminating chances of cheating when properly designed. DLT's tamper-proof nature safeguards data integrity and cybersecurity by detecting any malicious tampering and preventing unauthorised alterations. Decentralisation facilitates easy inclusion of new participants, ensuring scalability for system operators managing increasing RESs, parties, and services. Redundant data storage across the decentralised network enhances infrastructure reliability, resilient against single point of failures, but it reduces scalability and quickness. Open-source DLT variants allow diverse parties to develop products and services freely without vendor lock-in. On the other hand, the open-source feature influences the security of the platform [288].

In this plethora of pros and cons, we can classify the most important application of DLT to energy sector as *i*) P2P trading, *ii*) flexibility market enablement, *iii*) EV charging, *iv*) network pricing, and *v*) distributed resource register.

4.5.1 Distributed Energy Resource Register

The energy market has witnessed a shift towards sustainable electricity production, driven by the integration of RESs. Integrating RESs without costly control devices remains a challenge. Coordination between TSOs and DSOs emerges as a potential solution, avoiding expensive investments [289]. TSOs handle overall system security and transmission, while DSOs manage distribution-level voltage stability and congestion.

Regulatory barriers hinder TSO/DSO coordination, despite promising technical concepts. EU regulations and various network programs lay the groundwork for coordination models. Efforts have been made to evaluate the feasibility of integrating RESs in a coordinated environment. Data exchange between TSOs, DSOs, and aggregators is crucial, with a need for dedicated platforms and standardised approaches. Despite progress, a standardised data exchange mechanism is still lacking, impeding full integration of RESs. As a matter of fact, in the current landscape, comprehensive information about RESs is often inadequately shared among the various stakeholders. For instance, this challenge is evident in cases like Great Britain, where the TSO has no visibility to the generators associated to the DSO. In this scenario, the establishment of a *Distributed Resource Register* can be a helpful solution, serving as a mechanism to share resources related information within DSOs, TSOs, and other key stakeholders like aggregators.

Given its decentralised database features, DLT stands as an optimal solution for creating a distributed register that can be securely shared among multiple entities in the electricity supply chain. In this domain, the best trial comes from the United Kingdom, where the TSOs and DSOs initiated a blockchain-powered pilot project for a RESs asset register, called *RecorDER* in 2019 [290]. This pioneering initiative aims at building a shared asset register encompassing electricity generation and storage assets connected to both transmission and distribution networks. The idea is to enhanced visibility and accessibility of data in order to enable the development of new systems, facilitating RES smart penetration and reducing overall operating costs. The initial phase of the project focused on mapping generation and storage assets with capacities exceeding 1MW. Subsequent stages are exploring advanced platform applications, including refining contractual visibility of assets and integrating assets into diverse market procurement processes.

This asset register is certainly an interesting idea that would ensure secure and fast information exchange without intermediaries. At the same time, using a single platform ensures that users don't have to share the same information repeatedly. However, even though this idea is noteworthy, the fact remains that such information would be public. Therefore, a public platform is not acceptable, but instead, an access-controlled platform is advisable.

4.5.2 Network Pricing

The traditional evolution of electricity tariffs alongside the development of electricity systems has undergone significant changes due to the drivers of digitalisation, decarbonisation, and decentralisation. This transformation challenges conventional tariff designs that were based on energy consumption and the operation of vertically integrated utilities. With the rise of RESs and digital technologies, consumers are becoming active participants in the energy market. However, existing tariff structures are not equipped to accommodate these changes, leading to inefficiencies and inequitable outcomes. For instance, volumetric tariffs intended to recover network costs are incentivising distributed generation installation, causing distortions in cost recovery. Digitalisation and decentralisation enable consumers to respond to electricity prices with greater accuracy, offering opportunities for efficiency improvement. Additionally, climate change policies and renewable subsidies impact electricity tariff design, raising questions about how to allocate associated costs among users [291].

In this context, some projects are dealing with the improvement of network tariffs by means of DLTs [292]. The idea is that DLT enables the creation of customisable and dynamic tariff models. Instead of one-size-fits-all tariffs, DSOs can design tariffs based on individual energy usage profiles, time-of-use, location, and grid conditions. This ensures that consumers are charged fairly and encourages energy consumption during off-peak hours. Moreover, DLT can facilitate real-time settlement of network usage charges. Smart meters, IoT devices, and energy meters can record and transmit usage data to the DLT. The system can then automatically calculate and settle charges based on predefined tariff rules. This approach eliminates delays and errors associated with traditional billing processes. One technology that can help DLT is SC. SCs can automate complex tariff calculations and adjustments. For instance, during periods of high demand or network congestion, tariffs can automatically adjust to encourage load shifting and reduce strain on the grid.

This approach to DLT brings certainly interesting advantages, however, the lack of coordination among system operators hinders its development. Currently, a network tariff system developed through DLT is unlikely. The first factor is the young age of the technology, which makes it seem distant and unattainable. Furthermore, this also prevents its development as it is described as complex to adopt. Another factor is derived from its limited scalability and slow speed when dealing with highly developed networks. All these reasons undoubtedly restrict its development in the coming decades. However, in a roadmap towards 2050, aiming for the complete development of the 3D paradigm, this technology is certainly a leader among the technologies nearing adoption.

4.5.3 Electric Vehicles

In recent years, the electric car market has witnessed remarkable growth, setting the stage for a transformative shift in transportation dynamics. The projected stocks of EVs, ranging between 9 and 20 million by 2020 and anticipated to surge to 40-70 million by 2025, underscore the accelerating pace of EV adoption [293]. This expansion is further reinforced by the ambitious *EV30@30* campaign, which is steadfast in its goal to establish a 30% EV market share by 2030 [294]. As the automotive landscape evolves, innovative approaches are sought to address the associated challenges, particularly the effective management of EV charging services and the extensive charging records they generate. However, EVs could be transformed from a grid burden to an asset if their loads are aggregated and controlled, acting as an energy buffer to store surplus energy from renewables and alleviate peak load periods. In this scenario, DLT offers a decentralised and secure solution for secure data storage, information sharing, and trusted transactions. It could potentially provide an alternative way to reward EV users without relying solely on utility pricing schemes. In the following three use-cases are reported. These use cases demonstrate how, even in the early stages of research, the adoption of DLT brings advantages when coupled with the realm of EVs.

In [295], the authors present a solution to address grid congestions using EVs through the application of DLT and fuzzy logic approaches. Fuzzy logic approaches are methods of processing data and making decisions based on degrees of truth rather than strict binary values, allowing for the representation of uncertainty and imprecision in decision-making processes. In the paper, the authors aim at coordinating EV charging to mitigate its impact on the grid by using a combined approach of blockchain consensus and uncertain fuzzy-logic-based decision-making. Specifically, they adopt the PoS consensus algorithm. In their study, the fuzzy logic consensus mechanism's weights are used as *stakes* of the consensus mechanism. Individuals with more stakes have the ability to validate new nodes and charge their vehicles with higher currents. The weights in the fuzzy logic consensus mechanism are determined based on network load and vehicle parameters. If the combination of these parameters results in a lower impact on the grid, the weights are higher, offering more opportunities for vehicle charging. This algorithm ensures increased vehicle charging during mid-day hours, particularly in networks with high renewable penetration, especially PV systems. Although the developed idea is promising, it still requires improvement. The algorithm might fail under extreme conditions where a vehicle needs to charge in a critical network area while having low state of charge (SoC) and limited charging time. In these cases, the algorithm might not guarantee vehicle charging, potentially dissatisfying the end user. An industrial application of this concept is challenging.

In [296], the authors want to improve the EV energy trading by deploying a new blockchain-based consensus mechanism, while a Stackelberg game is introduced to solve the vehicle-to-vehicle (V2V) trading. The authors establish a private blockchain and SCs as system core components. EVs are grouped into clusters based on their mobility characteristics, with each cluster including buyer, seller, and transaction validator EVs. The private blockchain ensures the security and transparency of transactions, while SCs facilitates the interaction between EVs defining the logic of energy trading. The Stackelberg game is formulated to maximise the benefit of both sellers and buyers. To guarantee secure consensus and efficient energy trading, the authors developed a new consensus algorithm. The algorithm selects validators based on reputation, considering both subjective and objective trust evaluations. EVs' reputation values are calculated based on collected evidence and opinions from within their respective clusters, which are then recorded in the blockchain. The features of the consensus mechanism ensures that blocks are added to the blockchain only when a significant majority of validator nodes verify their legitimacy, mitigating potential attacks. While the proposed methodology is very intriguing and demonstrates proven benefits, it still remains distant from real industrial applications. The developed system appears complex and redundant in certain aspects, such as the dual consensus system between blockchain and external consensus. Moreover, the proposed method does not provide indications regarding its scalability. Lastly, the use of a private blockchain, while useful for access control, diminishes the effectiveness of the system if transitioned to a public blockchain.

In [297], the authors propose a P2P energy trading solution using a private blockchain for demand response management in a vehicle-to-grid (V2G) environment. The proposed idea is to use EVs as resources to manage network congestion. In order to implement this process, the authors adopt a double auction market mechanism to maximise social welfare. In this process, the blockchain acts as the auctioneer. Auction bids are submitted to the blockchain via SC by EVs and the system operator to facilitate the double auction mechanism. Once the bids are submitted, the blockchain, using SCs, solves the optimal allocation problem to determine the energy quantity. To address the problem on the blockchain, the authors employ a linearisation method for its resolution. The proposed application of using EVs to manage network congestion through a blockchain-based double auction mechanism offers benefits like congestion relief and enhanced energy management. However, there are significant challenges to address. Scalability issues may arise with increasing EV participation, potentially leading to slower transactions. Latency could affect real-time operations due to blockchain confirmation times. Energy consumption for blockchain consensus may counteract energy savings from congestion management. Privacy concerns about sensitive data exposure need addressing. Regulatory adaptation is essential, and adoption challenges could hinder widespread use. Complexity, algorithmic fairness, single points of failure, and the need for education also pose obstacles.

In conclusion, the application of DLT in conjunction with EVs presents promising avenues for various sectors, as evidenced by the examination of three distinct case studies. While these studies reveal substantial benefits in areas such as energy trading, grid management, and congestion alleviation, they also highlight several notable drawbacks that must be addressed for successful implementation. Challenges like scalability issues, potential energy consumption trade-offs, privacy concerns, and regulatory adjustments emerged across the case studies, underscoring the complexity and multifaceted nature of integrating DLT and EVs.

4.5.4 Flexibility Markets

As RESs become more integrated into power systems, the demand for flexibility from TSOs and DSOs increases to maintain grid stability. TSOs prioritise frequency preservation, while DSOs focus on voltage preservation [298], The *evolvDSO* project estimates that 90% of RES are connected to DSO networks, alongside EVs and heat pumps [299]. To ensure grid security, TSOs and DSOs need to coordinate closely. The well-known traffic light model categorises grid states into green (optimal), yellow (flexible adjustments), and red (critical). While the traffic light model suggests incentives for the yellow phase, its implementation is complex due to multiple human interactions and data exchange challenges. In this scenario, DLT emerges as a solution to enable secure transactions among parties involved. Unlike centralised databases, this technology offers distributed database and validation of transaction records, enhancing security against failures and attacks. In the context of this intersection, this chapter explores the outcomes of three studies and application that assess the implementation of DLT-based flexibility (service) markets. While these case studies reveal substantial potential for enhancing grid resilience and maximising renewable energy application, they also underscore certain drawbacks that warrant consideration.

The first study is the *Equigy* project [300]. This project is a collaborative initiative among European TSOs focused on crowd-balancing the electricity market. This platform adopts a permissioned blockchain technology, and it aims at connecting various electricity market participants, such as TSOs, DSOs, energy communities, and aggregators, enabling smaller distributed flexibility assets to contribute to the energy system through aggregation. Although it lacks a tokenisation system, it efficiently connects participants, records transactions across different blockchains, and provides a single version of unalterable truth. The platform primarily focuses on energy balancing operations and emphasizes traceability within the renewable energy sector. It suggests that a *Guarantees of Origin* system would be valuable but requires adjustments for blockchain integration. Tracking energy flows using devices is proposed, even though such technologies are not yet widely available. Equigy indirectly contributes to emissions reduction through the shift from thermal power plants to distributed source. The Equigy project allows to connect various energy market actors enhancing the electricity balancing markets through a closed and permissioned blockchain platform. While offering benefits, there are potential drawbacks to consider. The adoption of a permissioned blockchain and the absence of tokenization might limit transparency, participation incentives, and decentralisation. Integrating energy flow tracking devices and technologies could be challenging due to their availability and compatibility. The project's complexity, involving numerous stakeholders and blockchain channels, might impact scalability and efficiency. Ensuring seamless interoperability with existing systems poses a challenge. Data privacy and security are crucial, given the sensitive nature of energy market data. Encouraging user adoption and engagement across all participants requires education efforts. Regulatory compliance and legal considerations are significant, especially in the energy and financial sectors. Lastly, integrating the transition from conventional RESs effectively within the project's framework could require additional strategies.

In [301], the authors introduce the concept of ancillary services within P2P trading communities. Ancillary services, crucial for power system stability, are examined through a framework involving P2P trading, residual balancing, and ancillary service mechanisms. The proposed framework initiates with the P2P trading mechanism, based on a continuous double auction where customers within the community engage in direct energy trading agreements. Residual generation/demand is then balanced by the power utility in the residual balancing mechanism, and finally, the ancillary service provision mechanism enables the power utility to solicit ancillary services from the P2P community. Customers respond to the utility's incentives by bidding to provide ancillary services, considering economic benefits. The paper acknowledges that the proposed sequential mechanism might not achieve the global optimum due to potential sub-optimality. However, running energy and ancillary service markets at the same time could enhance decision-making. Needlessly to say, obstacles tied to intricate market structures and industry regulations could hinder the practicality of this simultaneous approach. The paper provides an example, in particular in Great Britain, where different organizations obtain ancillary services using different methods, making it difficult to unify these diverse approaches into a single market. Although the study is interesting as it provides an example of a P2P market for services, it does have some limitations. Firstly, the sequential approach may not achieve optimal results due to its step-by-step nature. Secondly, simultaneous operation of energy and ancillary service markets, practiced in certain regions, could yield better decision optimization but faces challenges such as market complexity and industry institutions. For instance, regions like Great Britain have separate entities purchasing ancillary services through various methods, complicating market integration. The paper also points out the complexity of adapting the framework to existing market structures, which involves regulatory, technical, and institutional considerations. Moreover, the inclusion of ancillary services in P2P trading introduces complexity and raises open questions requiring further research. Lastly, the study's limited focus on specific types of ancillary services provided through P2P trading could restrict its applicability in wider power system operations. These limitations underscore the potential hurdles and considerations when implementing the framework within the context of current energy market systems.

In [302] the authors introduce a blockchain-based TSO-DSO flexibility platform to facilitate flexibility trading among prosumers, TSOs, and DSOs in a case study in Romania and Bulgaria. This platform aims at enhancing flexibility management and engagement of TSOs and DSOs in energy flow control. It ensures coordination between TSO and DSO needs, preventing redundant asset activation by enabling interaction between merit order lists. Effective signalling mechanisms and coordination are enabled through DLT. The trading process includes efficient asset registration, validation of metering data, and financial settlement via SCs. The project involves several key steps. First, a market-based procurement platform for DSO flexibility is established, allowing DSOs to identify and display the availability of RESs and pool their resources. DLT is used for secure asset registration, enabling flexibility providers to register their resources and create a trusted registry. The process involves call auction phases where flexibility providers offer their resources, and a freeze phase allows for order modifications. Matching rules automatically pair offers with requests. Flexibility activation is a critical step, where the DSO issues real-time activation requests to address congestion. Flexibility providers are instructed to deliver flexibility, and the DSO monitors this delivery. One of the project's central aims is to integrate TSO congestion management, streamlining coordination between TSOs and DSOs. DLT ensures transparent and secure transactions, and the platform categorizes, matches, and activates flexibility resources based on predefined rules. Although all the features of the case study, it presents several potential drawbacks. The project's technical complexity, requiring the creation of a secure blockchain network, could lead to implementation challenges. The gradual adoption of new technologies in the energy sector might slow down the industry-wide acceptance. Additionally, human intervention needs for decision-making and rapid responses during congestion events could introduce inefficiencies. Concerns around data privacy, security, and the integration of different regional regulations might hinder seamless implementation. Operational challenges related to managing flexibility resources and ensuring real-time data accuracy could impact grid stability. The resistance to organizational change, economic viability, and alignment with existing regulatory frameworks are also significant considerations.

4.5.5 P2P Trading

Empowering consumers with the agency to shape their energy choices and engage in preference-driven trading has ignited a paradigm shift in the energy sector, that leads to local P2P trading markets. Several studies investigated the adoption of P2P approach and its usage throughout the energy system, and it can be said that from the investigation, the P2P trading connect the realms of both coordinated and decentralised markets [303], [241]. The P2P efficacy is most pronounced when combined with value-added services such as energy storage, DR actions, energy optimisation, and information provisioning. A cornerstone of its potency lies in the integration of DLTs, which not only ensure the security and transparency of transactions but also nurture a foundation of trust among participants. Despite these merits, the journey of P2P trading is riddled with challenges. The absence of clear regulatory frameworks governing P2P transactions, coupled with low public awareness and the intricate nature of the technology, hinders its seamless adoption. Additionally, the stance of governmental bodies toward embracing and incentivising P2P trading plays a pivotal role in shaping its trajectory.

This paragraph will explore the application of the P2P paradigm and how some international projects have embraced it.

In [304] a multi-bilateral economic dispatch has been introduced where producers, consumers and prosumers participate and interact directly among them. The authors proposed a fully decentralised LEM, through blockchain, in which the network constraints are considered in the transactions. In [305], a real-time and forward P2P market is described where customer’s preferences and uncertainties are considered. The energy transaction is applied by means of bilateral contracts. In [306] a P2P pool market for EV charging is demonstrated, in which two disjoint optimisation problems are solved. The first problem is an individual EV optimal charging algorithm. The second one is a P2P optimisation algorithm that determines the optimal P2P delivery price to be paid at every location and during each time slot. In [307], the authors solve a P2P optimisation problem. To decentralise the problem by means of a blockchain, they adopted the ADMM. The idea is that the dual variables of the method are shared among the peers and updated accordingly. In [308], the authors adopt a decentralised version of the genetic algorithm in order to optimise the P2P energy trading within a local community. In this paper, the idea is to share the best solution of the algorithm iteration per iteration, until the solutions do not change anymore.

With the idea of breaking away from a fully decentralised LEM, [309] introduced a hybrid TE market in which peers are able to interact directly by means of a DLT platform, and the interaction with the grid are managed by a central aggregator. On the other hand, [249] developed a multi-class energy management system in which the P2P market is centralised. The P2P energy market platform coordinates energy trading between distribution network prosumers and the wholesale electricity market, by accounting for individual prosumer energy preferences. Concurrently, [310] implemented an auction scheme for a CSC market. The market adds a storage system that enable energy transaction only within the community. Finally, in [311], the authors introduced a three-tier hybrid design for distribution grids, including cell-level trading, microgrid trading within cells, and community-market designs within individual microgrids. Similarly, [312] proposed a hybrid model for microgrids within a distribution grid, incorporating grid constraints into P2P trading between microgrids, adopting an optimal power flow formulation while simplifying price and negotiation mechanisms between microgrids.

The emergence of P2P energy trading is revolutionising the energy sector, bridging the gap between coordinated and decentralised energy markets. P2P trading is most effective when combined with value-added services like energy storage, DR actions, optimisation, and information provision. Integrating DLTs enhances security, transparency, and trust among participants. The literature has explored diverse P2P applications, from decentralised LEMs addressing network constraints to real-time P2P markets considering customer preferences. Some projects focus on niches like P2P EV charging markets, while others use heuristic methods for P2P optimization. The transition from fully decentralised LEMs to hybrid models managed by central aggregators, multi-class centralised P2P energy management systems, and community-centric auction schemes showcases P2P adaptability. Three-tier hybrid designs for distribution grids and microgrid models illustrate scalability and flexibility, despite challenges like scalability and consensus mechanisms.

4.5.6 DLT-based Local Market Examples

DLT can establishes a platform for customer to partake in energy trading within their communities. Since the birth of DLT and LEM concepts, several initiatives demonstrated how this marriage is feasible with advantages and disadvantages. This chapter examines cases of DLT applied in LEMs, highlighting real-world implementations and their impact. These projects provide valuable insights into how DLT is transforming and heightening local energy trading and services.

The first project is Quartierstrom [313]. The project explores a transactional energy system using blockchain technology to manage the exchange and remuneration of electricity between consumers, prosumers, and the local grid provider. This project operates in Switzerland, involving prosumers with PV plants, consumers, grid-attached battery storage, and an EV fast-charging station. To model the energy exchange, the authors adopted a P2P double auction mechanism. Smart meters, improved by means of IoT devices that enable blockchain-based communications, play a key role in transmitting bids and information. In the platform, the double auction is implemented as a SC on the blockchain. In order to operate successfully, the LEM records the power consumption of each individual household every 15 minutes and places the data on the market as a bid, by means of a blockchain transaction. This process can reveal personal data like usage profiles. While blockchain offers pseudo-anonymity, the European Blockchain Observatory considers public keys as personal data under GDPR due to linkability risks [314]. To address these privacy issue, Quartierstrom explores various approaches, including Zero Knowledge Proofs, and Linkable Ring Signatures. Zero Knowledge Proofs offer private transactions but are computationally heavy. In addition, Linkable Ring Signatures are less computationally demanding, but it may not be suitable for lightweight nodes, implemented on smart devices like Raspberry Pi. To maintain the grid stability, a dynamic tariff structure incentivises local balancing of energy production and consumption. The dynamic tariff is designed to incentivise grid-stabilising behavior and enhance the profitability of well-placed storage systems. The project adopts an approach based on grid levels which introduces voltage-dependent reward and/or penalty terms. When the grid operates within a tolerance band, no reward or penalty applies. However, during conditions like heavy irradiation and low consumption, the tariff may decrease to encourage flexible loads. Conversely, during situations like simultaneous EV charging causing voltage drops, the tariff increases to promote load shifting.

The second project presented is Landau Microgrid project [315]. The project proposes a P2P blockchain-based auction market. Although this idea is already proposed by many other projects, the novelty of the project lies in the possibility for users to indicate their preference on the type of energy they are going to buy. This means that users can decide whether to buy energy on the basis of energy type preference (PV, Wind, Water, Biomass), on the basis of geographic distance (local, regional, and national), or on a mix of the two. To address the challenge of valuing different energy sources within the LEM, the project adopts a two-step market mechanism. In this way, the auction mechanism can incorporate individual preferences. To do this, the auction integrates a preference-based voting system. Noteworthy, each electricity source is treated as a distinct good, traded separately in its own market, thus eliminating the problem of handling heterogeneous goods while maintaining the merits of the merit-order auction. In order to determine the chronological order of these markets a voting system is introduced, which allows voters to rank choices according to their preferences. The most favoured choice gets the highest score. The market mechanism has been put into practice in Landau, Germany, involving 11 household consumers, a 20 kWp PV system, and a 60 kWp Combined Heat and Power system. Trading within LAMP occurs in 15-minute periods. While the proposed two-step market mechanism addresses the challenge of varying valuations among different energy sources, there are several potential drawbacks and considerations to be aware of. The first one is the vulnerability to strategic behaviours. As a matter of fact, participants that play strategically can change the market. For instance, if a participant anticipates that a particular market will no longer be needed due to high supply, they could adjust their bidding behavior to influence the market order. This strategic behavior could potentially lead to inefficient market outcomes. Another important issue is the market power. The same authors acknowledge that market power can be a concern in LEMs, where markets are small and limited to specific geographical areas. Therefore, it is essential to consider how the proposed mechanism addresses potential market power issues and whether it provides adequate safeguards against anti-competitive behavior.

The following project, called Pebbles, shifts the focus from P2P markets to TE markets [316]. As explained before, a TE market-based LEM can have very different scaling ratios, and this is the case for this project. Hence, the participants are different, these can range from simple private users to Virtual Power Plants to energy campuses. Their spatial location is equally distinct. The system architecture of the Pebbles project is designed to develop a blockchain-based platform for energy and grid services. The Pebbles platform consists of three main components. The first one is the market software, then the blockchain-based transaction infrastructure, and finally the cloud-based value-added services for data processing, evaluation, and visualisation. In order to connect to the platform, the customers can use external interfaces connecting the utility and the DSO to the platform. In particular, the utility handles compensation, billing, and LEM-related tasks, while the DSO manages grid services and provides technical support. Another interface is the blockchain. Each user is assigned a blockchain node for communication and storage of bids. Each user is provided with an EMS. This can be either hardware-based or cloud-based. The EMS optimises user schedules and communicates with local controllers to operate connected assets such as PV systems and batteries. It also interacts with the blockchain node for bid submissions and acceptance.

The last project presented is the so-called Energy Collective project [309]. In this project, the energy collective concept is introduced, which is defined as a community of prosumers collaborating to optimise their energy resource usage. In this framework, members can trade excess or deficit energy. A non-profit virtual node called the community manager coordinates the prosumer. As can be seen, the definition resemblance the definition of a TE market, thus the project is included in the TE market group. In this project, a supervisory node, referred to as the community manager, serves as the interface between the collective members and different markets. This allows a community, especially a large one, to interact with various existing markets, such as wholesale, balancing, and ancillary services, as well as future market designs. The market is organised in order to accommodate P2P transactions among communities. Nested optimisation mechanisms are exploited in which sub-communities become assets of higher-level collectives. For smaller communities, the community manager can interface with retailers and their contracts, including dynamic electricity tariffs based on market prices. The core of this project market lies in the negotiation process, incorporating agreements handled by the community manager. However, since a decentralised structure is adopted, each prosumer inevitably is required to optimise its set of assets. For each market time unit, each player has to find the optimal power set-points of each asset in view of the respective cost function and technology constraints. In the project, not only serves the community manager as supervisor of convergence to system optimality but also as interface between collective members and market and system operator. Due to the requirements of decentralisation, the project adopts a decomposition technique called ADMM. This algorithm allows to explicitly define individual problems for each prosumer and supervise the exchange of information between the collective members and the community manager. To test the model, the project was tested in a city in Denmark. The neighbourhood comprises 20 private houses equipped with PV panels and a collectively owned common house with a ground heat pump. The project explored the potential of blockchain technology to create a decentralised P2P market. Despite the great innovations, the project faced significant technological challenges, particularly with the adoption of blockchain technology. The immaturity of blockchain platforms, high transaction costs, and energy inefficiency posed significant barriers to the final objectives. Additionally, the project was conducted within a specific co-housing community with a unique focus on energy matters. This context may not be representative of larger communities or urban environments, where different dynamics and challenges may arise.

In conclusion, DLT has opened the door to exciting possibilities in the realm of LEMs. This chapter has delved into real-world projects that have harnessed the potential of DLT to revolutionise local energy trading and services. These projects exemplify the advantages and drawbacks associated with the application of DLT in LEMs. Privacy concerns, computational demands, strategic behavior, and market power are among the issues that must be carefully addressed in the pursuit of decentralised and efficient energy trading systems. Furthermore, the specific context in which these projects were conducted highlights the need for adaptable solutions that can cater to various community sizes and characteristics.

4.6 Local Market Techno-Economic Analysis

In the plethora of DLT-based LEM scenarios, this chapter embarks on a case study that showcases the transformative potential of DLT, specifically blockchain, within the domain of decentralised LEM energy exchange. This chapter proposes a techno-economic analysis, in which three LEMs are implemented. The LEMs are developed in a DLT platform and a centralized server. The case study wants to offer a comprehensive analysis of various market models, allowing for a thorough exploration of their technical, economic, regulatory, and social aspects. This choice is supported by several reasons. Firstly, it enables a well-rounded evaluation of different approaches to LEMs by comparing multiple models and assessing various aspects. This approach helps measure the effectiveness and efficiency of each model, providing insights into their performance under different circumstances. Furthermore, the study allows for an examination of market dynamics within these models, shedding light on how DLT impacts market participant behavior and overall performance. The case study contributes to the advancement regarding the benefits and challenges of using DLT in LEMs, informing future research and policy decisions. Importantly, this case study aligns well with the overarching thesis goal of exploring market models for the energy transition, specifically examining the application of DLT in local markets. Overall, the proposed case study is a comprehensive and valuable addition to the thesis chapter on local energy and service markets through distributed ledgers.

4.6.1 Proposed Market Models

To perform the analysis on the centralised and distributed markets, three models are adopted, tailored for both centralised and distributed operation. This paragraph delves into these three markets. Specifically, it considered the double auction (DA), the pseudo-continuous double auction (PCDA), and the continuous double auction (CDA). In the centralised market, the operations are placed in the hands of a third-party agent, i.e., a market operator, tasked with ensuring seamless market functioning. This market operator collects bids, orchestrates the market matching system, and oversees the equitable redistribution of established quotas. The centralised market is configured as an auction platform incorporating a pay-as-clear clearing mechanism. In the distributed market, the market operator is absent. Instead, the operations are managed by a distributed platform, here enabled by blockchain technology. In the blockchain, a SC allows bid publication and post-match market clearing. Within this distributed platform, the chosen market model is the CDA, complemented by a modified version called PCDA. The CDA entails an auction system with a predetermined duration where buyers and sellers engage in competitive transactions, matching buy and sell bids whenever conditions align. All these markets are divided into three steps:

- *Energy trading*. This step establishes the guidelines for users to submit their bids and the rules governing bid clearance.
- *Congestion and voltage check*. This step ensures compliance with network constraints by reviewing them after each trading session.
- *Congestion and voltage management*. In this step, if congestions or/and under/over-voltage are present, the network operator secures necessary bids to mitigate network constraint violations.

The combination of these processes defines the general framework for the three market models to be complemented with different timeframes and additional subprocesses that characterize each market model. The proposed market flowcharts are visually depicted in Figure 21.

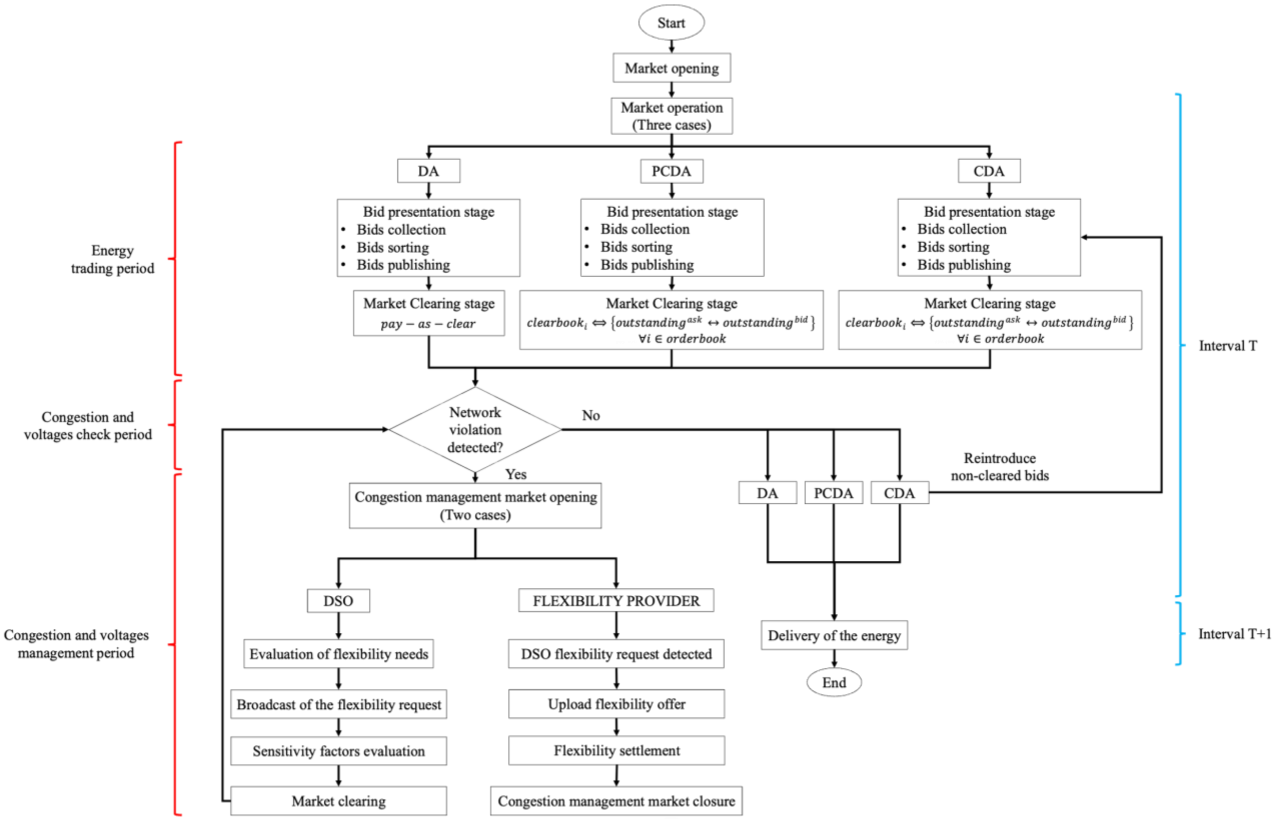


Figure 21. The flowchart of the proposed markets.

The energy trading step comprises two phases:

1. *Bid presentation*. All markets share this stage. It involves the submission of two types of bids, to buy and to sell. These bids include energy quantity, unit price, identification number, and connection node identifier. Both bid types operate as elastic limit orders, expressing the intent to buy or sell energy within specified price bounds. The market state is publicly accessible through orderbooks, sorted by descending purchase price and ascending selling price.
2. *Market clearing*. The mechanism for matching user bids depends on the market model.
    a. Centralised Market. In this setup, the market operator collects the participants' bids and sorts them by price. Demand and supply curves are formed, intersecting to determine the market price, quantity, accepted bids, and injection/withdrawal schedules. The market clearing price identifies the inframarginal and extramarginal bids. Bids beyond the clearing price match with the energy retailer, which disadvantage both individuals and the market's welfare. Algorithm 1 presents the matching process for the centralised market, whilst the matching with the energy retailer are described by the $match^{p,q}_{Energy\ Retailer}$ function presented in Algorithm 3.
    b. Distributed Market. For the CDA and the PCDA, bids' collection is managed by a SC. Bids are ordered into purchase and selling orderbooks, based on price. In CDA, orderbooks clear continuously, while PCDA clears once. To identify the

suitable bids to be coupled, the highest quote of a buyer is called the outstanding bid, and the lowest quote of a seller is called the outstanding ask. A transaction occurs when the outstanding bid equals or exceeds the outstanding ask. During the matching process, the outstanding bid is matched with the outstanding ask, and the transaction price is the average of their quotes. This matching process continues until the outstanding bid is lower than the outstanding ask - or when there are no bids or asks in the market. Algorithm 2 presents the step of the distributed markets. The $match_{Energy\ Retailer}^{p,q}$ function in Algorithm 2 describes how the remaining bids in the orderbooks are matched with the energy retailer prices. The $match_{Energy\ Retailer}^{p,q}$ function is described in Algorithm 3. Noteworthy, the frequency at which this function is called depends on whether the market is categorized as CDA or PCDA. When the market is CDA, this function is only executed when the delivery stage is soon. However, when the market is PCDA, this function is executed every time the clearing process occurs. Additionally, the $match_{Energy\ Retailer}^{p,q}$ function is only called once during the market clearing process.

Algorithm 1 Centralised clearing process

Input $supply^{p,q}$, $demand^{p,q}$
Output p, q
$p, q, i, j = 0$
while $min\left\{\sum_i demand_i^q, \sum_j supply_j^q\right\} > 0$
    if $demand_i^p \geq supply_j^p$ **do**
        $p = min\left\{demand_i^p, supply_j^p\right\}$
        if $demand_i^q > supply_j^q$ **do**
            $q += supply_j^q$
            $demand_i^q -= supply_j^q$
            $supply_j^q = 0$
            $j += 1$
        else if $demand_i^q < supply_j^q$ **do**
            $q += demand_i^q$
            $supply_j^q -= demand_i^q$
            $demand_i^q = 0$
            $i += 1$
        else do
            $q += demand_i^q$
            $demand_i^q = 0$
            $supply_j^q = 0$
            $j += 1$
            $i += 1$
        end if
    else do
        $break$
    end if
end while
call function $match_{Energy\ Retailer}^{p,q}\left(obook_{buy}^{p,q};\ obook_{sell}^{p,q}\right)$

Algorithm 2 Distributed clearing process

Input $obook_{buy}^{p,q}$, $obook_{sell}^{p,q}$
Output $cbook^{p,q}$
for $\_k$: $min\{length(obook_{buy}), length(obook_{sell})\}$
  if $obook_{buy,\ \_k}^{p} \geq obook_{sell,\ \_k}^{p}$ **do**
    $pr\_c = mean(obook_{buy,\ \_k}^{p,q}; obook_{sell,\ \_k}^{p,q})$
    if $obook_{sell,\ \_k}^{q} \geq obook_{buy,\ \_k}^{q}$ **do**
      $cbook_{\_k}^{p,q} \leftarrow match(pr_c;\ obook_{buy,\ \_k}^{p,q})$
    else do
      $cbook_{\_k}^{p,q} \leftarrow match(pr_c;\ obook_{sell,\ \_k}^{p,q})$
    end if
  else do
    $break$
  end if
end for

call function $match_{Energy\ Retailer}^{p,q}(obook_{buy}^{p,q};\ obook_{sell}^{p,q})$

Algorithm 3 Centralised and Distributed market - Energy Retailer Matching process for unmatched bids

Input $obook_{buy}^{p,q}$, $obook_{sell}^{p,q}$
Output $cbook^{p,q}$
for $\_bid$: $obook_{buy}$ **and** $\_ask$: $obook_{sell}$ **do**

$$cbook^{p,q} \leftarrow \begin{cases} match(ER_{sell}^{price}, \_bid^{q}) \\ match(ER_{buy}^{price}, \_ask^{q}) \end{cases}$$

end for

The congestion and voltage check aims at finding possible grid congestion and under/over voltage situations. These situations arise from high power flows in assets like lines or transformers, potentially causing overloads or during high consumption/production intervals which can rise voltage drop or overvoltage issues. Ensuring that each market transaction aligns with network constraints is crucial. To do this, the power flow model is applied on the current network state post transactions. The DSO centrally handles power flow, maintaining grid parameters and user power ratings across all market models.

After checking harmful situations, the role of addressing these challenges falls to the congestion management market. This market ensures the required flexibility, supplied by market participants, meets the DSO's needs. The congestion management process operates both centrally and in a distributed manner. Due to this dual nature, its explanation is divided between DSO actions (centralised execution) and steps taken by flexibility providers (executed through central or distributed platforms depending on the market type). This separation is crucial, given that the DSO functions centrally, while flexibility providers' roles vary depending on market specifics.

- **DSO Operations**
  1. *Congestion detection*. Identify congestions from LEM outcomes.
  2. *Flexibility need evaluation*. Calculating flexibility requirements for congestion management based on power flow results. DSO determines the need for active power adjustments, upwards or downwards, for violating elements.
  3. *Broadcasting flexibility request*. Transmitting flexibility requests via the chosen platform. This is shared with market participants to invite their flexibility offerings.
  4. *Sensitivity factor assessment*. Computing sensitivity factors for each flexibility provider. Sensitivity is based on their location, impact on grid constraints, and potential limitations. Sensitivity factors are determined by considering the change in power flow due to a provider's injection or withdrawal.
  5. *Market clearing*. Selecting optimal flexibility bids to alleviate congestion cost-effectively. DSO collects flexibility bids, solves a linear programming problem, and clears the market using from Equation (71) to (76).

$$\min_{P_i^{up}, P_j^{down}, s_r^{up}, s_r^{down}} \left\{ \sum_{i \in FSP_{up}} c_i^{up} \cdot P_i^{up} + \sum_{j \in FSP_{down}} c_j^{down} \cdot P_j^{down} + \sum_{r \in R} c^{slack} \cdot \left(s_r^{up} + s_r^{down} \right) \right\} \tag{71}$$

Subject to: $$P_r^{DSO_{up}} - \sum_{i \in FSP_{up}} PTDF_{i,r} \cdot P_i^{up} - s_r^{up} \le 0 \qquad \forall r \in R^{up} \tag{72}$$

$$P_r^{SO_{down}} - \sum_{j \in FSP_{down}} PTDF_{j,r} \cdot P_j^{down} - s_r^{down} \le 0 \qquad \forall r \in R^{down} \tag{73}$$

$$P_i^{up_{min}} \le P_i^{up} \le P_i^{up_{max}} \qquad \forall i \in FSP_{up} \tag{74}$$

$$P_j^{down_{min}} \le P_j^{down} \le P_j^{down_{max}} \qquad \forall j \in FSP_{down} \tag{75}$$

$$s_r^{up}, s_r^{down}, P_i^{up}, P_j^{down} \ge 0 \tag{76}$$

Where c_i^{up} and c_j^{down} are the cost for upward and downward respectively, while c^{slack} is the cost of not provided flexibility. The $PTDF$ represents the sensitivity factor between flexibility provider location (node) and the congested network element (line/transformer). Finally, P_i^{up}, P_i^{down}, s_r^{up} and, s_r^{down} represent respectively the cleared upward/downward flexibility from provider i, and the upward/downward slack flexibility to cover the not provided request r.

6. *Post-evaluation*. Performing a new power flow analysis to ensure network constraint adherence based on adjusted load and generation profiles.

- **Flexibility Provider Operations**
  1. *DSO request notification*. Upon DSO uploading flexibility requests, the congestion market opens. Eligible users, those previously able to trade energy, can submit flexibility offers.
  2. *Flexibility bid submission*. Eligible users upload flexibility offers to the distributed platform, specifying price, quantity, and connection node.
  3. *Acceptance notification*. Users with successful post-evaluation results are informed.
  4. *Flexibility settlement*. Payments are redistributed based on energy trading. Users who didn't trade energy have no extra cost for flexibility requests since they are not impacting on the network with their energy usage. Cost distribution is described by Equation (77). Where c_h^{CMM} is the proportional flexibility cost for user h, c_{CMM} is the total flexibility cost, and kWh_h is the energy exchanged by user h in the energy market.

$$c_h^{CMM} = \frac{c_{CMM} \cdot kWh_h}{\sum_{i=1}^{N_{user}} kWh_i} \quad \forall h \in N_{user} \tag{77}$$

4.6.2 Performance Metrics

The idea of this case study is to understand the performance of different P2P market build in different ways, centralised and decentralised through DLT. To do this, performance metrics are adopted. These metrics encompass various aspects:

- *Local Welfare and Cleared Quantity Ratio*. Local welfare, reflecting consumer and producer surplus within the LEM, and the cleared quantity ratio (CQR), denoting cleared energy as a percentage of offered energy, are key indicators. A higher local welfare indicates enhanced social welfare among local users, while a greater CQR signifies improved trading volumes and market liquidity. The CQR is expressed in Equation (78).

$$CQR = \frac{tot\ quantity\ cleared\ [kWh]}{tot\ quantity\ bid\ [kWh]} \tag{78}$$

- *Cost and Complexity of Blockchain*. The complexity and corresponding cost of smart contracts on the blockchain shape this metric. Complexity assesses the intricacy of interactions and processes within the platform, while cost involves transaction fees translated into cryptocurrency and euros. The market's external dynamics influence these costs.

- *Bid Waiting Time*. This metric measures the time difference between bid submission and clearance, utilizing statistical measures such as quartiles, median, minimum, maximum, and error values.
- *Flexibility Costs*. The cost of flexibility provided to the DSO, which is later redistributed among participants, is evaluated based on a defined equation.
- *Flexibility Volume*. This metric quantifies the volume of flexibility provided to the DSO.

These metrics collectively provide a comprehensive evaluation of the effectiveness and efficiency of the market models, considering economic aspects, complexity, time efficiency, and flexibility provisions.

4.6.3 Overview of the selected scenario

The proposed local markets are applied to a realistic distribution grid scenario by exploiting a portion of a network from the ATLANTIDE database [226]. The grid portion is a rural distribution grid, radially operated representative of a three-phase, 4-wire, low-voltage (230/400 V) distribution network. The grid is fed by a secondary substation with a 250 kVA (20/0.4 kV) transformer. The network can be represented by a set of nodes N and connecting lines L. In particular, the node 0 is selected as the point of common coupling (PCC), which performs the slack bus for the power flow analysis. Each peer has a single access to the distribution network to fed and withdraw electricity. In the network, some peers present local generation for self-consumption, energy exchange, charging the local battery (if present) or the available EV (if present). The test case, shown in Figure 22, is a network consisting of 16 nodes, with 5 distributed generators (i.e., PV and CHP), 5 energy storages, and 6 EVs.

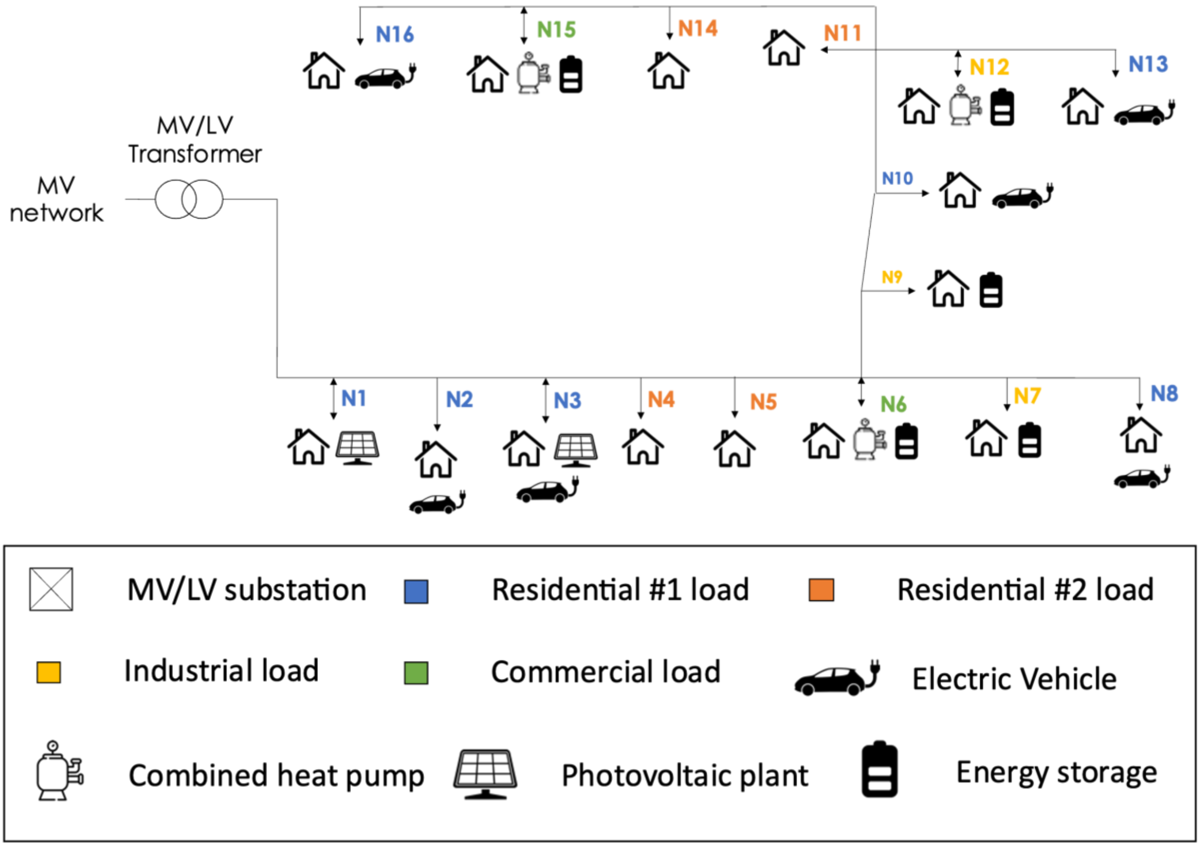


Figure 22. Schematic diagram of the LV distribution network.

Table X presents data of loads (i.e., active and reactive power consumption), generation (i.e., active and reactive power generation), energy storage for consumers and prosumers (i.e., inverter power rating and battery storage capacity in kWh), and EVs (i.e., charger power rating and EV battery capacity in kWh). Table XI and Table XII summarise data of branches (i.e., length of lines and their electrical characteristics).

Table X. Data of Loads, Generators, Energy Storage and Electric Vehicles.

Node	Load		Generator		Energy storage		Charging station
	P [kW]	Q [kVAr]	P [kW]	Q [kVAr]	P [kW]	E [kWh]	P [kW]
1	3	1.45	10	-	-	-	-
2	4.5	2.18	-	-	-	-	3
3	3	1.45	6	-	-	-	3
4	4.5	2.18	-	-	-	-	-
5	3	1.45	-	-	-	-	-
6	4.5	2.18	15	-	5	10	-
7	6	2.91	-	-	5	10	-
8	3	1.45	-	-	-	-	3
9	4.5	2.18	-	-	5	10	-
10	3	1.45	-	-	-	-	3
11	3	1.45	-	-	-	-	-
12	4.5	2.18	30	-	5	10	-
13	3	1.45	-	-	-	-	3
14	3	1.45	-	-	-	-	-

15	4.5	2.18	10	-	10	20	-
16	4.5	2.18	-	-	-	-	3

EVs input data are the charging power of the charging station (CS) and the hourly profile in which these batteries are stationary and charging at the CS. Given the plethora of EVs present in the market, and for a more extensive representation of the different types of EVs, the kWh of each battery is selected by a Gaussian distribution. According to an analysis of EVs in the current market, the mean value of the distribution is set equal to 57 kWh, and the standard deviation equal to 15. This last value is calculated as 33.33% of the difference between the market's maximum EV capacity value and the average capacity value considered. EVs are assumed to have a unidirectional charger and therefore operating in the charging mode only. The EV chargers power rating is 3 kW. It is assumed that the EVs are connected for charging between hour 18 and 7. They are used for mobility between hour 8 and 17. The nodes are fed by short cable lines with lengths not exceeding 30 meters. The low load density ensures little, or no voltage drop. Simultaneously, the high penetration of distributed generation into the grid can create overloading of the lines, particularly during periods of high generation, which produces an inversion of the power flow.

Table XI. Characteristic of the LV Distribution Network Branches.

Branch [From Node – To Node]	**Length** [m]	**Linecode**
1 – 2	30	1
2 – 3	10	1
3 – 4	30	1
4 – 5	10	1
5 – 6	10	1
6 – 7	30	2
7 – 8	10	2
6 – 9	10	1
9 – 10	10	1
10 – 11	10	1
11 – 12	20	3
12 – 13	20	3
11 – 14	20	2
14 – 15	30	2
15 – 16	20	2

Table XII. Electric Parameters for different line codes.

Linecode	**r** [Ohm/km]	**x** [Ohm/km]	**c** [nF/km]	**Ampacity** [A]
1	0.190	0.082	720	185
2	0.250	0.085	640	161

3	0.330	0.085	620	137

Four different types of customers are connected to the system. Their typical profiles were derived from the daily curves of the ATLANTIDE project [98]. All the profiles are depicted in Figure 23. The first and second classes represent residential customers characterised by two different profiles. Residential profiles are distinguished by high consumption during the night. However, the two residential profiles differ in the level of consumption in the middle of the day. Indeed, residential profile #2 consumes more than #1 and it is characterized with a high slope from 7 a.m. to 8 a.m. The other two classes represent the industrial and the commercial users.

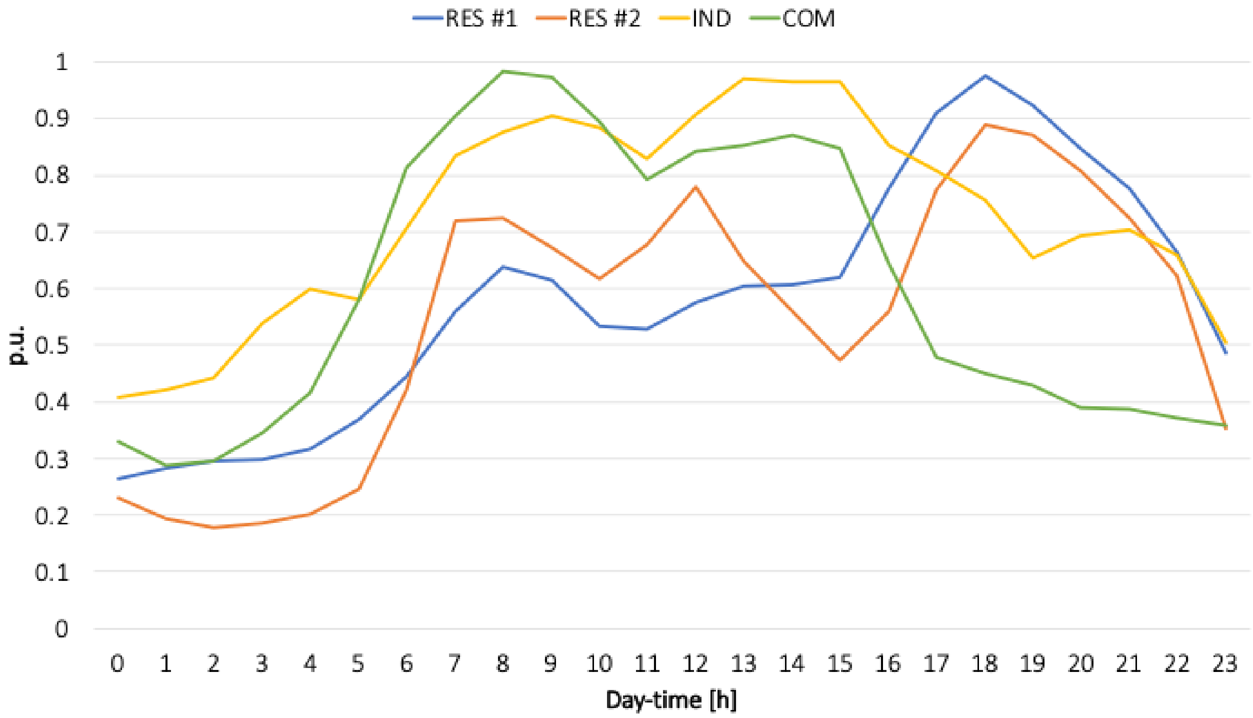


Figure 23. Consumption profiles of different consumers/prosumers with values in p.u.

In the distribution network, 2 PV systems are installed. The remaining generators are CHP generators. In particular, the profile of these generators accounts for the thermal production of the peer to which are connected. Indeed, the CHP generators are destined for heating and not for electricity generation. Node #12 has the biggest CHP generator, whereas the lowest one is the PV system connected to the node #3. Figure 24 depicts the sum of homes' production and consumption of the system. The load profiles showed a peak load of 50.8 kW during the 18th hour of the day with an average load of 37.7 kW. Finally, the generation profile showed a peak production of 49.5 kW during the 7th hour.

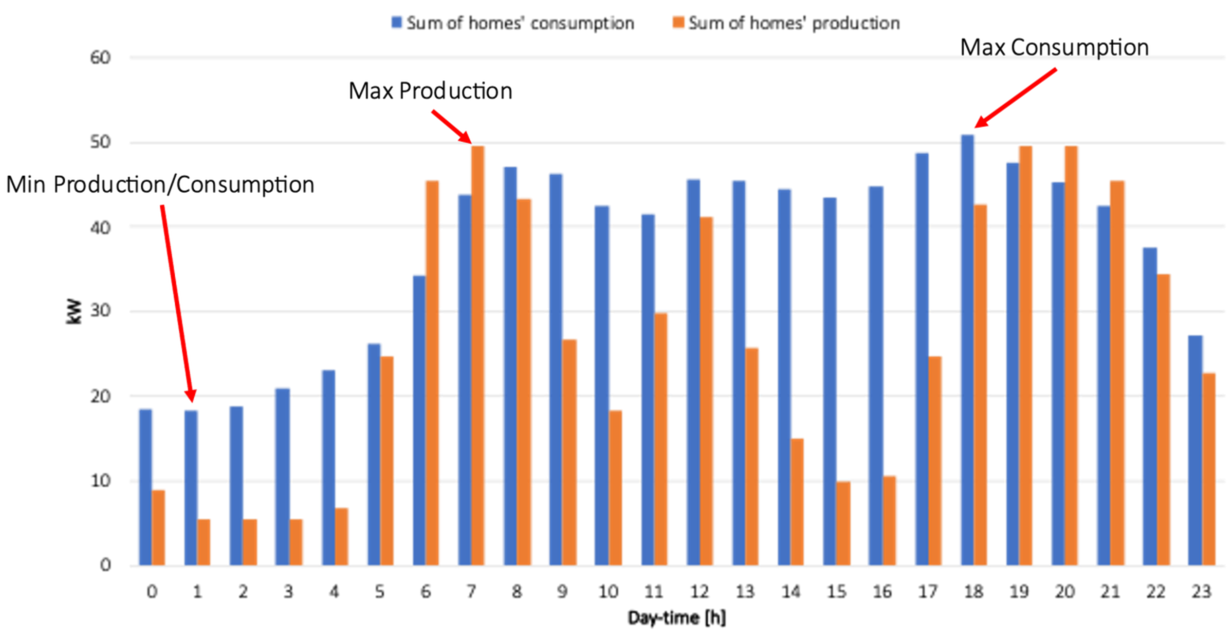


Figure 24. Load and Generator profiles of the whole network for one typical day.

The production profiles, shown in Figure 25, are scaled from original values such as to create three peaks. The first and last related to CHP production, and the second related only to the PV production.

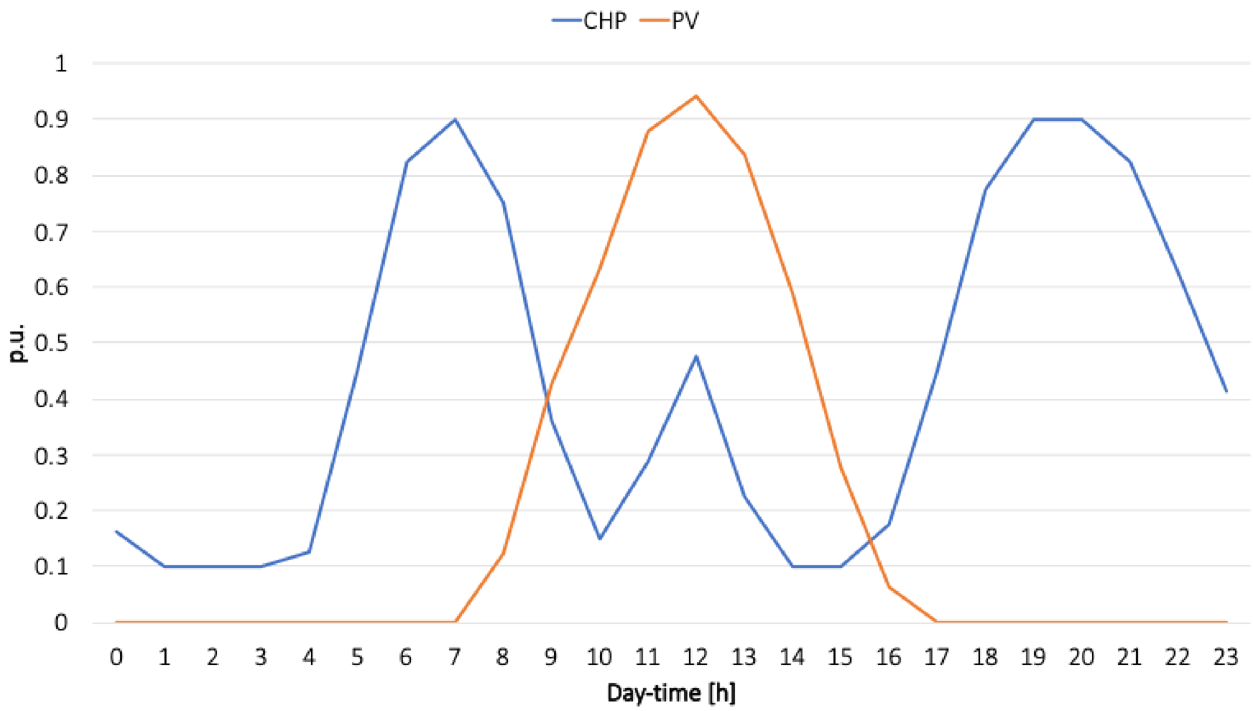


Figure 25. Production profiles of different prosumers with values in p.u.

To regulate the prices of the energy market and the congestion management market, the prices in Table XIII define the maximum and minimum values within which the prices of the two markets can be contained. In particular, for the energy market, the prices define the values of the energy retailer's purchase and selling prices. These values were extracted from an analysis of PicloFlex market prices concerning the congestion management market prices [125]. In particular, these two values are defined as the market's maximum and minimum closing values on a typical day during the winter of the year 2023/2024.

Table XIII. Maximum and Minimum price values of energy and congestion management market.

Energy market prices	
Maximum price [€/kWh]	*Minimum price* [€/kWh]
0.4	0.025
Congestion management market prices	
Maximum price [€/kWh]	*Minimum price* [€/kWh]
0.4995	0.1662

The analysis was conducted by exploiting two scenarios. The scenario A assumes that in the portion of the network adopted as a case study does not have network congestions during the entire study interval. In contrast, the scenario B includes network congestions that may occur in specific time intervals. In scenario B, the ampacity values of these two lines were reduced, as shown in Table XIV.

Table XIV. Electrical parameters of the lines for the two scenarios.

Scenario A				
Linecode	**r** [Ohm/km]	**x** [Ohm/km]	**c** [nF/km]	**Ampacity** [A]
1	0.190	0.082	720	185
2	0.250	0.085	640	161
3	0.330	0.085	620	137
Scenario B				
Linecode	**r** [Ohm/km]	**x** [Ohm/km]	**c** [nF/km]	**Ampacity** [A]
1	0.190	0.082	720	185
2	0.250	0.085	640	161
3	0.330	0.085	620	65

With the electrical parameters in Table XIV for the scenario B congestions in the network occur. The choice of those two specific lines for congestion was driven by the desire to perform a proof-of-concept study.

4.6.4 Analysis and Evaluation of Results

4.6.4.1 Techno-economic assessment

The results represent the various performance indicators on a red-to-green scale, with red representing the worst value, green the best value, and yellow the intermediate value. The comparison is presented in Figure 26 (scenario A) and Figure 27 (scenario B). It is important to remember that in the following, all evaluations will be based on the comparison of the three market models using the DA model as a reference.

	DA	CDA	PCDA
Local Welfare [EUR]	24.204	23.599	24.204
Clear Quantity Ratio [%]	24.933	27.452	24.933
Waiting Clearing Time [min]	30.021	28.061	30.398
Complexity [δ]	4167	4347	2871
Complexity [α]	4304	4531	2992
Gas Cost [Gas/GWei]	995585	1017130	921378
Complexity [$\delta+\alpha$]	8471	8878	5863

Figure 26. Comprehensive results (Scenario A).

As shown in Figure 26, the centralised DA market does not guarantee the best results for all metrics. Indeed, the DA market ensures the highest local welfare, as expected from pay-as-clear pricing mechanism; however, its performance reduces when it comes to Waiting Clearing Times (WCT) and quantity of energy cleared. The detail that needs to be highlighted is that the results of the PCDA market mirror those of the DA. This fact reflects the characteristics of the two markets. The PCDA market has the same solution as the DA market since the time of bid arrival is not considered in the clearing algorithm and thus, they consider the entire set of bids during collection and sorting processes. In contrast, the CDA collects and sorts bids in each market clearing round, disregarding potential future transactions that could lead to a better optimum. Consequently, the DA and PCDA can identify the optimal welfare by evaluating the complete set of bids, despite variations in their pricing mechanisms. Although the LW metric is lower for the CDA market, this is not the case for the CQR and WCT indicators. These results demonstrate how the distributed CDA market could succeed in increasing the quantities cleared given the same amount placed in the market and reducing the WCT. In particular, the latter factor enables fast user turnover and introduces an additional complexity term. On the other hand, the CDA market is the worst in terms of costs related to Distributed Ledger and its complexity. This aspect is dictated by continuous matching, increasing user-ledger interactions considerably. In contrast, the PCDA case is the best option regarding these two metrics. This fact is ensured by one-shot distributed ledger interactions, instantaneous and not iterative bid matching. Regarding scenario B, the comprehensive results include the solution for the congestion market. For scenario B, the comprehensive results are shown in Figure 27.

	DA	CDA	PCDA
Local Welfare [EUR]	23.953	23.395	23.953
Clear Quantity Ratio [%]	25.621	27.906	25.621
Waiting Clearing Time [min]	30.359	27.901	30.740
Complexity [δ]	4503	4750	3274
Complexity [α]	4651	4946	3407
Gas Cost [Gas/GWei]	1271598	1293279	1197527
Complexity [δ+α]	9154	9696	6681
Flexibility Volume [kWh]	42.489	42.114	42.489
Flexibility Cost [EUR]	18.691	18.850	18.691

Figure 27. Comprehensive results (Scenario B).

As depicted in Figure 27, scenario B mirrors the results of scenario A. Therefore, we can assume that the three market models for the analysed case study maintain their performance as the electrical network changes. Having similar behaviour without congestions, DA and PCDA market performances are equivalent. The amount of flexibility accepted and the final cost for flexibility delivered is the same as both markets have the same trading period; the same quantities are traded in the market and the flexibility prices are the same, leading the congestion management market to the same result. The final cost of flexibility for the CDA market is higher than for the other market models, and the quantity delivered is lower. The costs of the CDA market are higher, in addition to the fact that fewer users are available to offer flexibility. This consequence is because the market is continuously cleared, thus increasingly fewer users are available to enter the congestion market. The LW and the CQR of market DA and PCDA are the same and close to the results of the CDA. However, the differences among the performances of the market models are evident hourly-wise. For the easiness of representation, only hour 12th is reported; Figure 28 shows the corresponding orderbook after sorting the bids for the three market models, Figure 29 shows the corresponding market clearing results. Due to the similarity in the results between scenarios A and B, only the scenario without congestion is reported. Figure 29 presents the market results as pairings between participants, divided into three columns. The first represents the contract number signed by each participant. Some market participants sign several contracts at the same hour, and this is represented as b1-2, indicating that this is the second contract signed by participant b1. The other two columns represent the sale and/or purchase price, and the quantity agreed for that contract.

Orderbook – 12th hour					
Buy orders			Sell orders		
#	Price [EUR/kWh]	Quantity [kWh]	#	Price [EUR/kWh]	Quantity [kWh]
b1	0.391	2.337	*s1*	0.101	3.933
b2	0.283	2.337	*s2*	0.123	10.169
b3	0.273	2.337	*s3*	0.197	2.301
b4	0.259	3.506	*s4*	0.265	7.705
b5	0.233	1.725			
b6	0.225	4.082			
b7	0.223	5.442			
b8	0.221	1.725			
b9	0.179	2.588			
b10	0.145	1.725			
b11	0.115	2.588			

Figure 28. Orderbook for the three markets after sorting at 12th hour - Scenario A.

Clear book CDA – 12th hour			**Clear book DA – 12th hour**			**Clear book PCDA – 12th hour**		
# Contract	Price [EUR/kWh]	Quantity [kWh]	# Contract	Price [EUR/kWh]	Quantity [kWh]	# Contract	Price [EUR/kWh]	Quantity [kWh]
b1-1	0.294	2.301	*b1*	0.197	2.337	*b1*	0.246	2.337
b1-2	0.246	0.036	*b2*	0.197	2.337	*b2-1*	0.192	1.596
b2	0.203	2.337	*b3*	0.197	2.337	*b2-2*	0.203	0.741
b3	0.269	2.337	*b4*	0.197	3.506	*b3*	0.198	2.337
b4	0.180	3.506	*b5*	0.197	1.725	*b4*	0.191	3.506
b5-1	0.167	0.392	*b6*	0.197	4.082	*b5*	0.178	1.725
b5-2	0.178	0.665	*b7*	0.197	0.079	*b6-1*	0.174	1.860
b7	0.173	5.442	*s1*	0.197	3.933	*b6-2*	0.211	2.222
b8	0.172	1.725	*s2*	0.197	10.169	*b7*	0.210	0.079
s1-1	0.246	0.036	*s3*	0.197	2.301	*s1-1*	0.246	2.337
s1-2	0.180	3.506				*s1-2*	0.192	1.596
s1-3	0.167	0.392				*s2-1*	0.203	0.741
s2-1	0.203	2.337				*s2-2*	0.198	2.337
s2-2	0.173	5.442				*s2-3*	0.191	3.506
s2-3	0.172	1.725				*s2-4*	0.178	1.725
s2-4	0.178	0.665				*s2-5*	0.174	1.860
s3	0.294	2.301				*s3-1*	0.211	2.222
s4	0.269	2.337				*s3-2*	0.210	0.079

Figure 29. Clearing results for the three market at 12th hour - Scenario A.

An in-depth analysis of the 12th hour shows that the distributed CDA market allows actor s4, linked to node 1 who is equipped with a renewable generator, to sell energy in the market by creating a peer contract. This is not the case in the DA and PCDA markets, as they resolve the market once all bids have been collected. Hence, in the CDA market, the offer from actor s4 arrives after the first market clearing, together with other purchase requests. This event series allows actor s4 to sell energy at the next market clearing. Contrarily, in the DA and PCDA markets, actor s4 is left outside, preventing him from selling the excess energy. The difference in energy that is cleared between the markets is 2.37 kWh. However, in the CDA market solution, the energy that user 1 can trade is sold at such a price that the difference between the selling price and the user's minimum limit price does not guarantee a high profit for the producer. This scenario reduces the benefit to the community as another seller would sell the same quantity at a better price, increasing the seller's profit and thus the community's benefit. This happens in the DA market, where the final solution disadvantages the user but improves the community benefit. The same situations happen in other hours. For instance, during the 20th hour, user 12 sells 3.61 kWh more in the CDA market than in the DA market. A similar example occurs during the 23rd hour, where user 6 manages to sell 1.9 kWh more in the CDA market than in the DA market, and user 15 can sell 1.4 kWh more in the CDA market than in the DA market, as bids arrive early.

4.6.4.2 Market time assessment

Another critical point is the different waiting clearing timing for the three market models. Their characteristics and the way they are realized affect the timing of each bid in the market. Figure 11 shows the three markets' median, maximum and minimum values for the case with and without congestion, respectively. Figure 30 represents the time analyses for the three market models for the two scenarios. However, the final evaluations occur between the market models in the same scenario. Whereas, assessing the same market model in two different scenarios evaluates the impact of congestion on that market model.

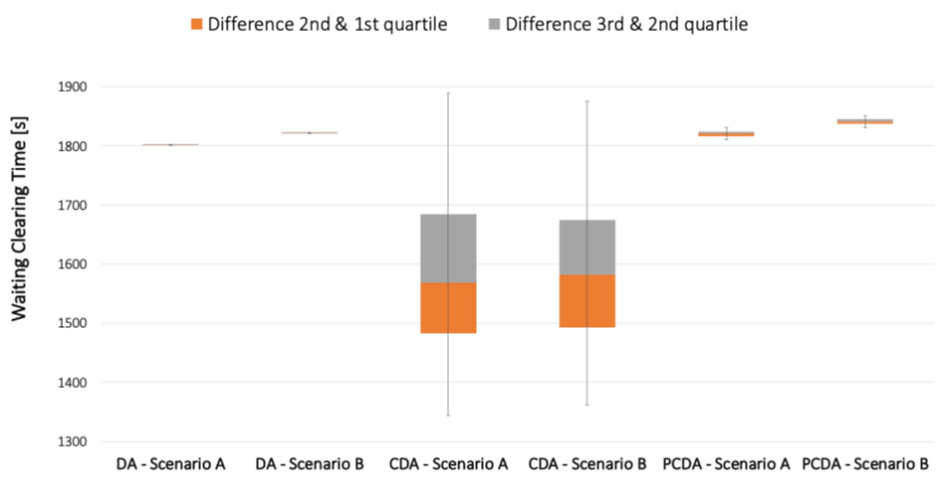


Figure 30. Waiting clearing time average results - Scenario A and Scenario B.

As can be seen, the centralized DA market guarantees users that the waiting time agreed upon contract agreement is met, always keeping the time needed to clear the market as reliable as possible. In contrast, the distributed PCDA market, which represents the intermediate design between DA and CDA, shows more significant variation than the median. The multiple communications shape these deviations a distributed managed market must endure completing the market clearing process.

Finally, the CDA market is the worst case since the time variations in that market are vast and never provide certainty of the time required before a user's bid is accepted. However, the third quartile parameter of the CDA market guarantees lower waiting times than the other two market types.

4.6.4.3 Blockchain-based complexity assessment

The four fundamental elements of an energy market are *i*) Data Acquisition, which involves collecting consumption and production data from market users, primarily using smart meters, *ii*) Data Management, which encompasses software components that process user interactions with the market, *iii*) Data Processing, that covers the execution and validation of market actions based on acquired data, and *iv*) Data Provisioning, which describes how data are made accessible to users, particularly after the clearing process. The study adopts these elements, with a focus on smart meters for data acquisition and management. The agent software module handles user registration, allowing access to the market, and the placement of buy or sell orders based on consumption and production data. The clearing process is executed through a dedicated module, ensuring the exchange of funds within the market. Ultimately, data is made accessible to registered users. In summary, this study's technical architecture for energy markets is designed around four core market functions: participant registration, bid placement, market clearing, and fund transfer. These functions are fundamental to the energy and congestion management markets developed in the study.

In this paragraph the market blockchain-based complexity based on the complexity of the functions describe before. Table XV and Table XVI show the complexity values $\boldsymbol{\alpha}$ and $\boldsymbol{\delta}$ for the different functions required to develop a market. The four fundamental functions constitute the basis on which the market models are implemented on the blockchain network and on which the $\boldsymbol{\alpha}$ and $\boldsymbol{\delta}$ parameters are calculated. Since the three markets are distinguished primarily by how the market is cleared, the “Register participant”, “Place bid” and “Transfer money” functions are identical for the three market models. The $\boldsymbol{\alpha}$ and $\boldsymbol{\delta}$ values for these functions are shown in Table XV along with the cost in euros that would be required to call those functions with only one bid placed in the market.

Since there is no tested methodology developed for assessing the complexity of the Ethereum blockchain, and thus since this analysis would have been excessively time-consuming, the analysis results in Table XV and Table XVI are reported as a single call to the functions in a single hour.

As can be seen in Table XV and Table XVI, the function that requires the most significant expenditure is the one that enables market clearing. This cost corresponds to the loops that perform the matching. In fact, in the blockchain platform, calling a loop has a monetary cost. As Table XV and Table XVI demonstrate, the final cost for a single call to these functions can be high. However, this cost depends on the conversion rates between official currencies and cryptocurrencies. Table XV and Table XVI report the costs using the 2022 conversion factor and the past conversion factor of 2020.

Table XV. Blockchain-based complexity and cost for "Register participant", "Place bid" and "Transfer money" functions.

	Register participant	**Place bid**	**Transfer money**
Complexity - **δ**	99	403	540
Complexity - **α**	100	415	559
Gas Cost – Gas/GWei	52690	276149	190395
EUR Cost (2020)	0.299	1.570	1.082
EUR Cost (2022)	0.742	3.890	2.682

Table XVI. Blockchain-based complexity and cost for "Clearing market" function.

	DA	**CDA**	**PCDA**
Complexity - **δ**	3058	3305	1829
Complexity - **α**	3162	3457	1918
Gas Cost – Gas/GWei	476351	497896	402144
EUR Cost (2020)	2.708	2.832	2.287
EUR Cost (2022)	6.708	7.014	5.665

4.6.4.4 Market behaviour during congestions

The last element analysed is the congestion market. The flexibility results are shown in Figure 31. This figure shows the flexibility values that users make available throughout the day for the three markets DA, CDA, and PCDA.

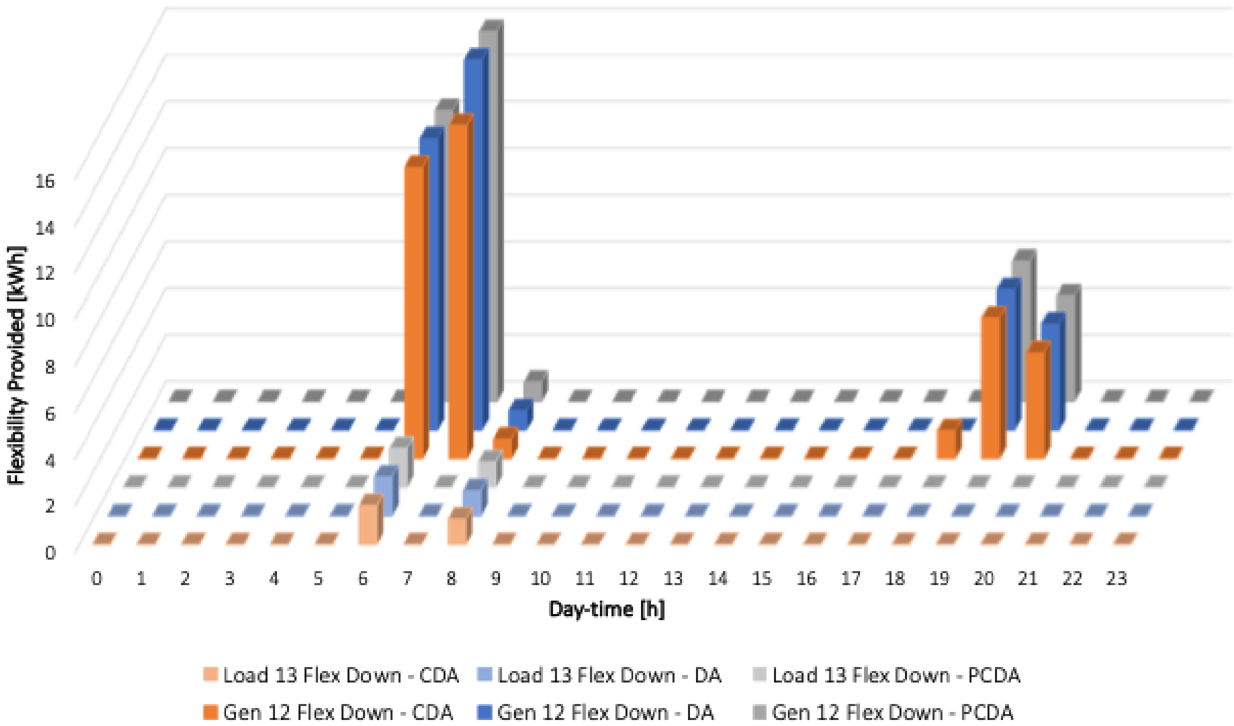


Figure 31. Flexibility results throughout the day.

As illustrated in Figure 31, the only flexibility involved is the downward flexibility of the generator in node #12 and the downward flexibility of the load in node #13. This is due to the congestion in scenario B in lines 11-12 and 12-13. As a result, only users 11, 12, and 13 may provide services to alleviate congestion. However, only users 12 and 13 are selected as providers since provider 11's sensitivity to the congested line 11-12 is lower than providers 12 and 13.

Significant differences are evident among the congestion management market (CMM) solutions of the three market models during the 7th and 18th hours, which CMM orderbooks are presented in Figure 32 and Figure 33. Only the DA and CDA markets are presented to ease the discussion. It is worth noting that Figure 32 and Figure 33 only discuss load and generator downward flexibility. In fact, as scenario B does not consider the load and generator upward flexibility, they are not shown in the figures for clarity. Figure 32 and Figure 33 present the bids submitted to the CMM as the node submitting the bid, the price of the flexibility service and the amount of upward or downward flexibility depending on the net power at the node's delivery point. Figure 33 shows no price for the DA market because, during the 18th hour, the DA market has no congestion and therefore, no CMM is required.

CMM Orderbook DA – 7th hour		
# Node	Price Flex [EUR/kWh]	Downward Flex. [kWh]
1	0.112	0.839
2	0.168	1.258
3	0.112	0.839
4	0.215	1.616
5	0.144	1.077
6	0.629	-9.428
7	0.309	2.320
8	0.112	0.839
9	0.250	1.877
10	0.312	2.339
11	0.144	1.077
12	1.550	-23.247
13	0.112	0.839
14	0.144	1.077
15	0.116	-1.747
16	0.168	1.258

CMM Orderbook CDA – 7th hour		
# Node	Price Flex [EUR/kWh]	Downward Flex. [kWh]
1	0.151	0.839
3	0.151	0.839
9	0.338	1.877
10	0.421	2.339
11	0.194	1.077
12	0.405	-14.707
15	0.157	-1.747
16	0.069	1.258

Figure 32. Congestion management market orderbook during the 7th hour for the DA and CDA market.

CMM Orderbook DA – 18th hour		
# Node	Price Flex [EUR/kWh]	Downward Flex. [kWh]
1	-	1.298
2	-	3.446
3	-	2.798
4	-	1.850
5	-	1.233
6	-	-8.786
7	-	2.148
8	-	2.798
9	-	1.611
10	-	2.798
11	-	1.233
12	-	-20.028
13	-	2.798
14	-	1.233
16	-	3.446

CMM Orderbook CDA – 18th hour		
# Node	Price Flex [EUR/kWh]	Downward Flex. [kWh]
1	0.028	1.298
3	0.060	2.798
6	0.026	-2.466
12	0.074	-15.083
13	0.060	2.798
14	0.026	1.233
16	0.074	3.446

Figure 33. Congestion management marker orderbook during the 18th hour for the DA and CDA market.

During the 7th hour, there are differences in the offers accepted among the market models, the corresponding CMM orderbooks differ in the number of offers from generators. For the DA market, there are 3 generators available, while for the CDA market, there are only 2. This fact significantly reduces the downward flexibility made available by generators. Although the second supplier is not selected as the flexibility provider in the CDA market, as the combination of the sensitivity factors of supplier 15 with the amount of flexibility made available is not sufficient to solve the congestion, it is still clear that the amount of flexibility needed by the system operator is different. This difference in the amount of flexibility needed is because congestion occurs in the CDA market after the energy demand of user 11 is accepted and cleared by the market. When user 11's energy request is cleared from the CDA market, users 14, 7 and 2, who placed the bid at latest clearing instants of the energy trading period, have yet to offer in the energy market. During the 7th hour, for both the DA, PCDA and CDA market, the only seller available is the generator in node #12, which takes over all the energy requests of the users until it covers all its available production. Therefore, in the CDA market, where congestion occurs several clearing instants before the closure of the energy trading period, the amount of flexibility requested by the grid operator from the flexibility provider in node #12 is lower because the provider in node #12 provides less flexibility available, compared to the plans established in the energy market. This process is not observed in the DA market, as there is only one clearing instant.

The opposite happens in the 18th hour (Figure 33). During this hour, the DA market and PCDA do not foresee network congestions. For completeness, the DA market orderbook during hour 18th is reported, but as shown in Figure 33, the prices for flexibility are not present. In the CDA market, congestion occurs after the fourth time the market has been cleared. In this situation, user 13, who can relieve congestion, has yet to enter the market, thus preventing high flow in line 11-12. Therefore, the generator located at node 6 can partially supply the demand of users 1 and 3, while the generator located at node #12 must supply the request from all other users. However, the lack of demand from the other users forms congestion in line 11-12. This congestion does not exist in the DA and PCDA market models results, as service delivery is made once all bids have been collected and cleared.

4.6.5 Conclusion and Future Works

This case study proposes a comparative analysis of three different market models: double auction (DA), continuous double auction (CDA) and pseudo-continuous double auction (PCDA). The DA market model is proposed as a centralised version, while the CDA and PCDA market models are realised via blockchain platform. The three market models include network congestion management, which is solved using a centralised optimisation problem that involves service providers.

Simulations show that different market models can be developed and executed on the blockchain. The study proves that the DLT ensures that market models can be implemented in a fully distributed manner, in which the distributed platform has a central role in the process. In addition, the study implements a techno-economic evaluation of different market models, considering their implications in terms of blockchain-based complexity LEM operational and management costs of the network violations. These results interest policymakers, energy communities, and stakeholders interested in creating a LEM. For the analysed case study, it is self-evident that no market outclasses the others. The centralized DA market reduces LEM operational cost (expressed in terms of Gas and EUR) by 2% compared to a distributed CDA market but fails compared to a distributed PCDA market by 7%. In addition, a centralized DA market reduces blockchain-based complexity, as measured by the number of transactions, by 5% compared to a distributed CDA market but is clearly at a 31% disadvantage compared to a distributed PCDA market.

In conclusion, the results show that a CDA market may require higher costs for flexibility, given its characteristic of market clearing, which occurs continuously several times in a single interval. Therefore, based on the results obtained, blockchain technology, in its current state of development, seems only partially suitable for P2P energy transactions. In particular, the gas cost characteristic and the influence of the cryptocurrency market severely limit blockchain technology deployment. Therefore, DLT can be an added value for LEMs by eliminating transaction costs. A promising development could be DLT without cryptocurrencies like IOTA. Further study developments focus on managing the uncertainties that characterized the proposed case study. Additionally, the vehicle-to-grid mode of operation of the EVs will be included.

Although the study presents exploitable results, it is essential to acknowledge certain limitations. The implemented market platforms are prototypes designed for a proof of concept, suggesting the need for further enhancements for applications in pilot projects or on a larger scale. However, the results obtained may be scalable in terms of number of transactions and network size. The results presented are valid for the network and scenario tested, so replicability analysis should be considered considering different networks and scenarios. The market models are not affected by network characteristics, and their results can be considered generally valid, but this statement needs to be tested through simulations. In addition, due to the inherent gas cost characteristic of the Ethereum blockchain, blockchain technology requires higher maintenance costs that are strongly influenced by the cryptocurrency market. The blockchain itself requires an additional cost given by the fee paid for miners, i.e., evaluators of the blockchain network. In this context, a centralized DA market increases computation time by 7% compared to a distributed CDA market but reduces it by 1% compared to a distributed PCDA market.

5 Conclusion

This thesis represents an advancement in understanding and leveraging market mechanisms amid the dynamic landscape of the energy transition. The exploration covered various facets, starting from intricate planning in the vast MES domain to intricate modelling of redispatch markets, with a specific emphasis on flexibility markets. The research finished in an investigation of blockchain technology, shedding light on its transformative impact on local energy and service markets.

The first section of this research highlighted the pivotal role of market mechanisms in guiding the planning of urban distribution systems within the MES paradigm. Robust optimisation techniques emerged as a powerful tool to navigate the complexities of MES planning, embracing both symmetric and asymmetric uncertainty representations. The first section of the thesis contributes to highlighting how a robust approach can manage uncertainties in an EH model. Additionally, the research proposes a market model that integrates with a planning model for an urban area where different energy vectors interconnect. The final results demonstrate that the choice of multiple energy vectors, although complicating the analyses, allows for a broader range of solutions. However, these solutions must effectively manage various uncertainties.

In the broader context of distribution system services, the thesis unfolded a compelling case study that spotlighted the integration of electricity and gas network as an effective strategy for addressing uncertainties associated with the rise of RESs. Robust optimisation methodologies demonstrated again their efficacy in mitigating the uncertainties of this integration.

Finally, the last chapter unveiled the transformative potential of blockchain technology in forging local utility and energy markets. Through case studies and techno-economic evaluations, this thesis underscored the profound impact of Distributed Ledger Technology on the energy market landscape. It showcased the feasibility of fully distributed market models realised on a blockchain platform, offering valuable insights for policymakers, energy communities, and stakeholders venturing into the realm of LEMs. The results painted a subtlety picture, revealing the cost implications and scalability considerations associated with blockchain technology. While highlighting the potential of DLT without cryptocurrencies, like IOTA, it also underscored the challenges posed by gas costs and cryptocurrency market volatility.

Future research will focus on implementing robust DLMP mechanisms and redispatch markets within the expansive framework of MES paradigm. The focus on DLMP mechanisms and redispatch markets within the context of MES represents a strategic commitment to advancing our understanding of market dynamics in a complex, interconnected energy environment. For instance, through rigorous comparative analyses, these future studies can provide insights that can inform effective decision-making in the planning and operation of MESs. This trajectory aligns with the broader objective of enhancing the efficiency and reliability of distribution systems while accommodating the increasing integration of RESs. Another promising avenue for future exploration is the transformative potential of blockchain technology in the realm of LEMs. The thesis has laid the groundwork by unveiling the impactful possibilities offered by DLT in local utility and energy markets. Future studies in this domain are likely to delve deeper into the implications of fully distributed market models realised on blockchain platforms. This exploration will involve a thorough consideration of scalability, cost implications, and the intricate challenges presented by factors such as gas costs and the volatility of cryptocurrency markets.

To sum up, this thesis forms a comprehensive path that incorporate the multifaceted role of market mechanisms within the energy transition. It embodies a unified vision that spans from the meticulous planning of distribution systems through the modelling of redispatch markets and culminating in the exploration of blockchain technology’s transformative potential for LEMs. As the energy landscape continues to evolve, this thesis stands as a foundational milestone, providing valuable insights, innovative methodologies, and a roadmap for navigating the intricate terrain of energy markets in a world undergoing a profound energy transition.

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