

Sara Haghifam

**Sector-coupling
and P2X2P
Enabling Energy
Market Structures
and Related
Solutions for
Future Flexible
Energy Systems**



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Tiivistelmä

Uusiutuvan energiantuotannon, hajautettujen energia- ja joustoresurssien sekä sektoreita yhdistävien teknologioiden, kuten Power-to-X (P2X), käyttöönotto muuttaa sähköjärjestelmien teknistä ja taloudellista toimintaa sekä kanta- että jakeluverkkotasolla. Tässä väitöskirjassa ehdotetaan uusia viitekehyksiä tulevaisuuden jakeluverkkotason energiamarkkinoille, jotta voitaisiin mahdollistaa resurssien tehokas hyödyntäminen paikallisissa jakeluverkkotason ratkaisuisissa. Toteuttamiskelpoisuus ja taloudellinen tehokkuus huomioiden ehdotetut viitekehykset koostuvat esimerkiksi sektoreita yhdistävistä selvitysmekanismeista sekä koordinoinnista sähkön tukkumarkkinoiden kanssa. Väitöstutkimus kattaa koko ketjun paikallisten sähkö- ja monienergiamarkkinoiden suunnittelusta, paikalliset sähkömarkkinat, sektorikytkentä, monienergiajärjestelmät, integroidut energiamarkkinat, hierarkkinen koordinointi, aggregaattorit, riskitietoinen optimointi, Power-to-X, hajautetut energioresurssit, joustoresurssit. Tutkimuksessa ehdotetut uudet markkinaratkaisut voivat mahdollistaa usean aggregaattorin kilpailun jakeluverkon rajoitteet huomioiden ja yhdistetyssä sähkö-lämpömarkkinassa voidaan hyödyntää Power-to-Heat (P2H) -teknologioita ja hybridienergiavarastoja mahdollistaen täten sektoreiden välisten joustoja hyödyntämisen. Keskitetty malli jakeluverkkotason marginaalihinnoittelulla huomioi verkkojen ja sektoreiden vuorovaikutukset sekä tarjoaa myös läpinäkyviä sijainti- ja aikaspesifisiä hintasignaaleja.

Järjestelmätason tavoitteiden saavuttamiseksi väitöskirjassa ehdotetaan hierarkkista koordinoitikehystä, joka yhdistää paikalliset markkinat tukkusähkömarkkinoihin. Tämä rakenne asettaa paikallisen joustavuuden ja joustotarpeet etusijalle, parantaen kustannustehokkuutta, uusiutuvien energialähteiden integraatiota ja sektoreiden välistä tasapainotusta. Lisäksi väitöskirjassa on kehitetty hinnanmuodotukseen vaikuttavia ja riskitietoisia osallistumisstrategioita, joissa stokastinen optimointi huomioi epävarmuudet hinnoissa, tuotannossa, kysynnässä ja kilpailijoiden käyttäytymisessä. Näin on mahdollista tasapainottaa kannattavuus ja toimintavarmuus vaihtelevissa markkinaolosuhteissa. Yhteenvetona voidaan todeta, että tämä väitöstutkimus esittää uusia markkinapohjaisia ratkaisuja, jotka yhdistävät teknisen toteuttamiskelpoisuuden, taloudellisen tehokkuuden, koordinoinnin ja päätöksenteon epävarmuuden alla, tukien siirtymää kohti joustavia, vähähiilisiä ja resiliентtejä monienergiajärjestelmiä.

Avainsanat: paikalliset sähkömarkkinat, sektorikytkentä, monienergiajärjestelmät, integroidut energiamarkkinat, hierarkkinen koordinointi, aggregaattorit, riskitietoinen optimointi, Power-to-X, hajautetut energioresurssit, joustoresurssit.

Abstract

The accelerating integration of renewable generation, distributed energy resources (DERs), flexibility assets, and cross-sector conversion technologies such as Power-to-X (P2X) is fundamentally reshaping the operational and economic landscape of modern power systems. This doctoral thesis develops coordinated, market-based frameworks at the distribution level to enable the efficient utilization of these resources within local energy markets. The proposed approaches embed network-aware, sector-coupled clearing mechanisms and advanced coordination with wholesale electricity markets to ensure both technical feasibility and economic efficiency.

The research spans the full chain of requirements for next-generation energy systems: from the design of local electricity and multi-energy market architectures, through coordinated operation across local-wholesale layers, to strategic and risk-aware offering models for key participants, including DER aggregators and energy hubs. Local market designs allow multiple independent aggregators to compete under distribution power-flow constraints, while extended electricity-heat platforms integrate Power-to-Heat and hybrid storage technologies to unlock cross-sector flexibility and reduce curtailment. A centralized clearing methodology with distribution locational marginal pricing for both electricity and heat is introduced, internalizing network and sectoral interactions to provide transparent, location- and time-specific price signals.

In order to distributed actions with system-wide objectives, a hierarchical coordination framework links local integrated markets with the wholesale market, prioritizing local flexibility before upstream procurement and enabling bidirectional price and dispatch consistency. Finally, price-making and risk-aware participation strategies are developed for DER aggregators and energy hubs, using stochastic optimization with risk constraints to capture uncertainty in prices, renewable generation, demand, and competitor behavior. This enables participants to balance profitability with operational resilience while contributing to overall system efficiency. Collectively, the thesis delivers a comprehensive set of market-based solutions that bridge technical feasibility, economic efficiency, coordination, and strategic decision-making under uncertainty, supporting the transition toward flexible, decarbonized, and resilient multi-energy systems.

Keywords: local electricity markets, sector coupling, multi-energy systems, integrated energy markets, hierarchical coordination, DER aggregators, energy hubs, Risk-aware optimization, Power-to-X technologies, distributed energy resources, flexibility.

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Abbreviations

AG	Aggregator
BESS	Battery Energy Storage System
CHP	Combined Heat and Power
CVaR	Conditional Value at Risk
DA	Day-Ahead
DER	Distributed Energy Resource
DG	Dispatchable Generator
DLMP	Distribution Locational Marginal Price
DSO	Distribution System Operator
EB	Electric Boiler
ED	Electric Demand
EH	Energy Hub
EHP	Electric Heat Pump
ESS	Energy Storage System
EV	Electric Vehicle
GFG	Gas-Fired Generator
HESS	Hybrid Energy Storage System
HS	Heat Station
HSS	Heat Storage System
ICE	Information and Communication Technology
IEA	International Energy Agency
IES	Integrated Energy Systems
IESO	Integrated Energy System Operator
ILEHM	Integrated Local Electricity-Heat Market
IRENA	International Renewable Energy Agency
KKT	Karush-Kuhn-Tucker
LEIM	Local Electricity Market
LEnM	Local Energy Market
MDES	Multi-Dimensional Energy System
MILP	Mixed-Integer Linear Programming
NGESS	Natural Gas Energy Storage System
NGFG	Non-gas Fired Generator

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P2F	Power-to-Fuel
P2G	Power-to-Gas
P2H	Power-to-Heat
P2M	Power-to-Mobility
P2X	Power-to-X
P2X2P	Power-to-X-to-Power
PV	Photovoltaic System
RES	Renewable Energy Sources
RT	Real-Time
SOSD	Second-Order Stochastic Dominance
ST	Solar Thermal System
TESS	Thermal Energy Storage System
TSO	Transmission System Operator
V2G	Vehicle-to-Grid
WEM	Wholesale Electricity Market
WT	Wind Turbine

Publications

Publication 1:

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1 INTRODUCTION

Traditional energy systems have been designed around centralized power generation and long-distance transmission to meet demand. However, system operators and planners have identified numerous drawbacks to this paradigm (Martín-Martínez et al., 2017). Accordingly, centralized systems face energy security risks due to reliance on finite fossil fuel resources, contribute to environmental pollution through fossil fuel combustion, and drive climate change via rising greenhouse gas emissions. They are also often marked by inefficiencies in generation, transmission, and distribution, and struggle to adapt to increasingly dynamic demand patterns. The severe environmental impacts, particularly CO₂ emissions, have intensified global concerns, prompting a profound transformation in the global energy landscape. This transition is marked by decarbonization, decentralization, and digitalization (Di Silvestre et al., 2018). While the integration of renewable energy sources such as wind and solar is essential for mitigating climate change, their inherent intermittency and non-dispatchable nature pose significant challenges for traditional grid management.

To address the limitations of traditional energy systems, renewable energy generation at the distribution level, and even at the consumer level, has gained significant traction in recent years. However, the non-dispatchable nature of these resources makes flexibility at the distribution level a critical requirement. The growing deployment of distributed energy resources (DER) such as wind, solar, batteries, and responsive loads is empowering consumers to actively participate in grid management by balancing their own supply and demand. This decentralization enhances grid resilience and reduces dependence on centralized generation (International Energy Agency, 2022). Furthermore, sector coupling, facilitated by power-to-X (P2X) technologies, offers a pathway to unlock further flexibility by converting surplus electricity into heat, hydrogen, or other energy carriers for storage and later use (Ramsebner et al., 2021). Despite these advancements, most existing market structures fail to fully integrate DERs into their operational and pricing mechanisms, limiting their ability to contribute effectively to a flexible, resilient, and low-carbon grid.

One of the most promising approaches for future energy systems is the establishment of mechanisms that allow local prosumers to trade energy within distribution-level networks, commonly referred to as local energy markets (LEnMs). LEnMs serve as innovation hubs where producers, aggregators, and energy hubs exchange energy closer to the point of consumption, reducing transmission losses and improving overall efficiency (Dudjak et al., 2021). They form a core component of transactive

energy frameworks, enabling decentralized, economically efficient coordination among small- and medium-scale participants. By supporting peer-to-peer energy trading, LEnMs democratize the energy landscape, transforming consumers into active participants and decision-makers. In doing so, they not only unlock new revenue streams and business models for energy service providers but also enhance grid flexibility, support renewable integration, and promote a more resilient and sustainable energy system.

In future energy systems, LEnMs will need to evolve beyond simple electricity trading platforms. They should enable multi-energy transactions, allowing different energy carriers to exchange various forms of energy within a unified market structure. In this regard, P2X assets will be central to this vision, converting surplus electricity into heat, hydrogen, or synthetic fuels to enhance flexibility and storage options. Hence, well-designed LEnMs should interface with other infrastructures, such as district heating networks, to create a more holistic, sector-coupled, and efficient energy system. Moreover, effective coordination mechanisms should allow LEnMs to interact with wholesale energy markets, enabling them to address local systems' shortages or surpluses through external transactions. This integration will help maintain a stable, reliable energy supply while optimizing resource utilization.

1.1 Background and Motivation

Power systems are undergoing a fundamental transformation driven by three intertwined forces: decarbonization, decentralization, and digitalization. While variable renewable sources such as wind and solar are becoming widespread across many regions, their intermittency and non-dispatchability challenge legacy market structures and operational practices designed for large, centralized, and controllable generation. At the grid edge, rapidly expanding portfolios of rooftop solar panels, behind-the-meter batteries, electric vehicle charging infrastructure, flexible loads, and community-scale resources represent a significant reservoir of flexibility, provided they can be effectively coordinated and fairly compensated (Zaboli et al., 2024). LEnMs have emerged as a promising mechanism to unlock this potential, enabling the valuation and orchestration of distributed flexibility resources close to the point of consumption while ensuring that distribution-network constraints are respected. In response, utilities and regulators are actively exploring LEnM structures that integrate local flexibility into market processes through locationally granular pricing and distribution-aware market-clearing mechanisms.

In parallel with the exploration and development of LEnMs, sector coupling, particularly the integration of electricity and heat networks, has emerged as a key

pathway for enhancing flexibility, improving energy efficiency, and advancing decarbonization targets. In this context, power-to-heat (P2H) technologies, such as heat pumps, electric boilers, and thermal storage, can absorb surplus low-cost renewable electricity and shift it to meet peak thermal demand, reducing curtailment and providing valuable flexibility to the grid (Kauko et al., 2024). Beyond P2H, P2X solutions expand cross-sector flexibility by converting excess electricity into other energy carriers, such as hydrogen (Wulf et al., 2020). Realizing the full potential of sector coupling depends on market-operation integration, ensuring that price signals accurately capture cross-sector opportunity costs so that operators can fully exploit arbitrage potential and deliver system-wide benefits through coordinated multi-energy management.

While sector-coupled energy systems as well as local electricity and integrated market platforms can unlock significant flexibility and efficiency gains, their full value can only be realized through effective coordination with the wholesale electricity market. Without this linkage, local actions risk being misaligned with broader system needs, potentially leading to inefficient dispatch, grid congestion, or missed opportunities for cost savings. Coordinating local and wholesale market operations ensures that price signals reflect both upstream and downstream conditions, enabling distributed resources to respond optimally to system-wide supply-demand dynamics. This bidirectional exchange allows local markets to support bulk system balancing, accommodate higher shares of renewable generation, and reduce reliance on expensive peak-period imports, while wholesale markets can leverage local flexibility to enhance reliability and defer costly infrastructure upgrades. By integrating decision-making across these layers, market frameworks can achieve more efficient resource utilization, align economic incentives, and strengthen overall grid resilience.

Within evolving local integrated energy market frameworks, the effectiveness of system operation depends heavily on the participation strategies of diverse actors, including DER aggregators, energy hubs, and other providers of energy and flexibility services. These entities must navigate complex market environments characterized by fluctuating prices, network constraints, and uncertain renewable generation, while making strategic decisions on offer volumes and prices. Their bidding behavior not only determines their own profitability but also influences local price formation, congestion patterns, and the overall efficiency of market outcomes. In multi-energy settings, operational coupling between electricity and heat, or other energy carriers, adds another layer of complexity, as decisions in one sector directly impact the other. Consequently, well-designed optimal offering strategies that account for competition, uncertainty, and network realities are essential for aligning individual incentives with broader system objectives. Such strategies can transform participating actors

from passive responders into proactive market shapers, capable of delivering both economic benefits and enhanced system flexibility.

Realizing the full potential of local, sector-coupled, and coordinated market frameworks requires addressing persistent technical, operational, and economic gaps. Current pricing mechanisms in many local energy markets fail to fully capture the physical realities of distribution networks, such as line capacities and voltage limitations, and often overlook the interdependencies created by multi-energy interactions. Without such considerations, local markets risk dispatching resources inefficiently, producing price signals misaligned with wholesale market dynamics, and even exacerbating congestion or curtailment. Likewise, without robust coordination between local and wholesale market layers, there is a heightened risk of conflicting incentives, underutilized flexibility, and increased overall system operational costs. The transition from experimental LEnM pilots to scalable and operative platforms demands integrated market designs that jointly incorporate distribution-network physics, cross-sector coupling, and hierarchical coordination into a coherent and implementable framework, an area where the literature remains fragmented and incomplete.

At the same time, the growing presence of DER aggregators, energy hubs, and other multi-energy providers at the distribution level introduces a strategic dimension to local market participation that is not fully addressed. As they grow, these entities can gain significant pricing power, influencing how local market prices are set and how dispatch decisions are made. Many existing market models still treat such participants as passive price-takers or restrict analysis to single-energy sectors, overlooking the operational coupling between electricity and other energy carriers, a gap that leads to suboptimal use of multi-energy resources. Moreover, high uncertainty in market prices, renewable generation, and demand exposes these actors to financial and operational risks that deterministic bidding cannot effectively manage. These gaps highlight the need for market-based frameworks that (1) embed network-aware, multi-carrier pricing into the local market-clearing process; (2) ensure consistent coordination between local market decisions and wholesale market outcomes; and (3) enable strategic, risk-aware offering strategies for active local market participants.

Addressing these challenges forms the central motivation of this doctoral thesis. The work develops market-based solutions that (i) design local electricity market platforms under realistic network constraints, (ii) operationally integrate electricity-heat energy systems and design a pragmatic market platform for these integrated networks, (iii) establish coordinated local-wholesale market architectures to improve overall grid efficiency, and (iv) create advanced offering models for strategic

local market participants under a wide range of uncertainties, thereby providing a comprehensive foundation for the next generation of distributed, multi-energy market systems.

1.2 Objectives of the Thesis

The primary objective of this doctoral thesis is to design and develop coordinated, market-based frameworks that enable the effective integration of diverse DERs into local electricity markets and extend these designs to sector-coupled, multi-energy market platforms, thereby unlocking the full potential of P2X technologies and other flexibility assets. The research spans the complete spectrum of requirements for next-generation market systems: from creating advanced local market architectures that account for distribution network constraints, through integrating electricity-heat coupling within multi-energy trading platforms, to establishing hierarchical coordination between local and wholesale markets for consistent price formation and efficient resource utilization. In its final stage, the thesis focuses on the development of strategic and risk-aware participation strategies for key local market participants, such as DER aggregators and energy hubs, that balance profitability with resilience to uncertainty, while contributing to more flexible, reliable, and decarbonized energy systems.

In this context, the objectives of the doctoral thesis can be listed as follows:

- **Designing Advanced Local Electricity Market Platforms:** Developing comprehensive market architectures that enable the competitive and economically efficient participation of multiple DER aggregators within a common trading environment. These platforms must ensure that market outcomes remain technically feasible by embedding grid-aware clearing mechanisms that incorporate distribution power grid constraints. The objective is to design a market that not only facilitates fair competition and transparent price formation but also aligns operational dispatch with the physical realities of the network, supporting the effective integration of small- and medium-sized DERs.
- **Integrating Sector-coupling into Local Market Operations:** Developing integrated market-based frameworks that explicitly model and optimize electricity-heat interactions, embedding the operational characteristics of P2X technologies, such as heat pumps, electric boilers, thermal storage systems, and combined heat and power (CHP) units, into local market-clearing processes. This integration enables the coordinated scheduling, dispatch, and trading of multiple energy carriers within a unified platform,

ensuring that operational coupling between electricity and heat networks is captured in both price formation and dispatch. By doing so, the framework unlocks cross-sector flexibility to improve renewable integration, reduce surplus power curtailment, and enhance economic efficiency and system resilience at the distribution level.

- **Coordinating Local Integrated Markets with the Wholesale Market:** Developing coordination mechanisms between local and wholesale market layers that enable consistent decision-making, aligned price formation, and efficient exchange of flexibility across system boundaries. This involves creating hierarchical market structures in which the local energy market-clearing process operates with full awareness of upstream wholesale market conditions. Such mechanisms must ensure that local dispatch and pricing reflect both local network constraints and broader system dynamics, preventing conflicting operational signals, avoiding inefficient resource allocation, and maximizing the value of DERs and P2X assets for system-wide balancing. By integrating local and wholesale markets within a coherent framework, the approach enhances the optimal operation of energy systems, facilitates greater renewable integration, and reduces reliance on costly peak-period imports.
- **Modeling Strategic and Risk-aware Participation in Local Electricity and Integrated Markets:** Developing practical offering strategies for key market entities, including DER aggregators and energy hubs, operating as active, price-maker participants in both local electricity and sector-coupled integrated energy markets. The modeling framework captures strategic behaviors that enable these distribution-level actors to influence price formation while fully accounting for technical market constraints and network limitations. To address uncertainties in players' decision-making processes, such as their rival actions, renewable outputs, and demand fluctuations, the framework integrates stochastic optimizations and risk-aware methods to balance profitability with robustness. This dual treatment of uncertainty and risk enables the design of offering strategies that are not only economically optimal but also operationally reliable, ensuring that active participants can navigate volatile conditions while contributing to broader system objectives.

In pursuit of these objectives, this doctoral thesis addresses the following central research questions (**Q1-Q4**), with more detailed sub-questions raised and examined within each chapter:

Q1. How can local electricity markets be designed to integrate multiple independent DER aggregators in a way that ensures economic efficiency while maintaining power distribution network security? (Chapter 3, related to Publication 1)

Q2. How can sector coupling between electricity and heat be effectively incorporated into local market frameworks to unlock cross-sector flexibility trading without compromising technical or economic feasibility? (Chapters 4 & 5, related to Publications 2, 3, 4 & 5)

Q3. Which coordination mechanisms best align local energy market decisions with wholesale electricity market outcomes, ensuring bidirectional consistency in prices and dispatch for overall system efficiency? (Chapter 6, related to Publication 6)

Q4. How can the strategic behavior of distribution-level market participants, such as DER aggregators and energy hubs, be modeled to reflect their price-making capabilities in local electricity and integrated markets, and how can uncertainty and risk preferences be incorporated to develop offering strategies that balance profitability with robustness under volatile market conditions? (Chapter 7, related to Publications 7 & 8)

Guided by the presented objectives and research questions, this doctoral thesis advances a cohesive framework of market-based solutions for the next generation of distributed, multi-energy systems, bridging the gaps between technical feasibility, economic efficiency, market coordination, and strategic decision-making under uncertainty.

1.3 Overview of Methodological Frameworks

This dissertation adopts a multi-method research framework that integrates market design theory, multi-energy system modeling, advanced optimization techniques, and stochastic decision-making. The overall methodology is structured to reflect the progression of the thesis: starting with the conceptual and mathematical design of local electricity markets, extending to sector-coupled multi-energy local market platforms, and then to coordinated local-wholesale architectures. It further incorporates strategic and risk-aware participation models for key local market participants. Across these stages, the chosen methods and models ensure both technical rigor, by capturing network and multi-energy operational constraints, and operational realism, by addressing uncertainty, competition, and practical market dynamics, spanning from conceptual formulation to detailed modeling and numerical validation. Below, the core methodological components of the thesis are summarized as follows:

Market Design and Game-Theoretic Modeling (Publications 1, 6, 7 & 8):

- Bi-Level (Stackelberg) optimization models: Capture hierarchical decision-making process between different energy market operators and between operators and market participants, as leaders and followers of the problem.
- One-leader multi-follower Stackelberg extensions: Extend the Stackelberg formulation to set a competition outline for a leader and multiple followers.
- Application: Apply for designing local electricity markets, coordinating local-wholesale interaction, and developing participation strategies for key local entities.

Sector-Coupled Energy Networks and Integrated Market Operations (Publications 3, 4 & 5):

- Integrated electricity-heat system models: Model electricity networks via AC power flow and represent district heating networks through thermal-hydraulic constraints, ensuring both sectors' operational characteristics are captured.
- Coordinated multi-energy market-clearing: Perform simultaneous optimization of electricity and heat markets within a unified platform, enabling cross-sector flexibility trading and jointly minimizing system cost or maximizing social welfare.
- Multi-energy nodal pricing mechanisms: Derive distribution locational marginal prices for electricity and extend the pricing formulation to heat networks, ensuring that cross-sector operational couplings are reflected in market price signals.

Optimization and Solution Techniques (Publications 1, 3, 4, 5, 6, 7 & 8):

- Mixed-integer linear programming methods: Apply to model the operation of DERs, P2X technologies, multi-energy storage systems, and other discrete decision variables in decision-making processes.
- Piecewise linearization methods: Use to relax the nonlinear AC power flow constraints of distribution networks, enabling their integration into market-clearing and optimization problems in a computationally tractable manner.
- Karush-Kuhn-Tucker reformulation with Big-M and strong duality theorem linearization: Utilize to convert bi-level optimization problems into

equivalent single-level formulations and to handle nonlinearities arising both in the original problem and during the reformulation process.

Uncertainty Modeling and Risk Management (Publications 3, 7 & 8):

- Two-stage stochastic programming approaches: Apply for stochastic problems, with a first stage used for day-ahead scheduling decisions and a second stage used for real-time adjustments.
- Scenario generation and reduction techniques: Generate a large number of scenarios by Monte Carlo simulation and reduce them to an adequate number via a fast backward/forward scenario reduction algorithm to preserve statistical characteristics while improving computational tractability.
- Risk management measures: Use Second-Order Stochastic Dominance (SOSD) to explicitly control the risk associated with market participation and limit exposure to extreme adverse outcomes.

Implementation and Numerical Validation (Publications 1, 3, 4, 5, 6, 7 & 8):

- Software and solvers: Implement the proposed models in MATLAB, GAMS, and Python, utilizing commercial solvers such as CPLEX and Gurobi.
- Test systems and case studies: Evaluate the models using IEEE distribution feeder test systems and representative district heating networks to assess both technical feasibility and economic performance.
- Sensitivity analyses: Conduct systematic sensitivity studies to demonstrate the robustness of the proposed frameworks.

1.4 Main Contributions of the Dissertation

This doctoral thesis advances the state of the art in local and integrated energy market design by bridging theoretical modeling with practical, network-aware, and sector-coupled implementations. The work contributes both methodologically and conceptually by developing novel frameworks that address the technical, economic, and strategic dimensions of future distributed multi-energy systems. The main contributions can be grouped into the following areas:

- **Designing Local Electricity Markets**

A Stackelberg game-based framework is developed for local electricity markets in which the distribution system operator (DSO) acts as the leader and multiple independent DER aggregators participate competitively as followers. The model is formulated as a bi-level optimization problem that is reformulated into a tractable single-level structure while preserving the hierarchical decision-making logic. Importantly, the market-clearing process embeds power flow constraints, ensuring that dispatch outcomes and prices are both economically efficient and technically feasible within the distribution network. By enabling transparent price formation that reflects grid conditions, the framework supports fairer allocation of benefits among participants while maintaining system reliability. Compared to conventional approaches such as fixed-tariff bilateral contracts, the proposed design achieves improved DER utilization, more balanced profit-sharing, and grid-aware dispatch, thereby advancing the operational and economic efficiency of local markets.

- **Designing Local Integrated Electricity-Heat Markets**

Building on the local electricity market framework, the design is extended to integrated electricity-heat markets, introducing a multi-energy market-clearing mechanism that explicitly incorporates sector coupling. The proposed platform coordinates the operation of P2H technologies spanning electrical and thermal domains. By extending the concept of distribution locational marginal pricing (DLMP) to cover both electricity and heat networks, the mechanism internalizes cross-sector interactions, network congestion, voltage limits, and thermal-hydraulic constraints. This allows for transparent, location- and time-specific price signals across both carriers, which in turn facilitates efficient cross-sector trading. The integrated design not only reduces renewable energy curtailment and improves system efficiency but also demonstrates how coordinated sector-coupled market operation can unlock additional flexibility that would remain untapped in siloed markets.

- **Coordinating Local Energy and Wholesale Electricity Markets**

A hierarchical coordination framework is developed that links local multi-energy markets with the wholesale electricity market to ensure consistency in both price signals and dispatch decisions. Within this architecture, the local market operator aggregates the net position of DER and P2H units and then interacts with the wholesale market operator as a single entity. A bi-level optimization structure is employed, enabling local clearing to prioritize distributed flexibility while wholesale prices and allocations feed back into local dispatch. This coordinated approach reduces operational conflicts and avoids price inconsistencies across market layers, ensuring that local actions remain aligned with system-wide marginal costs. This mechanism improves overall cost efficiency, enhances renewable energy integration,

and strengthens cross-sectoral balancing, offering a practical pathway to harmonized operation between distribution and transmission system levels.

- **Presenting Offering Strategies for Local Market Participants**

Strategic and risk-aware offering models are introduced for key distribution-level participants, including DER aggregators in local electricity markets and multi-energy hubs in integrated electricity-heat platforms. These entities are modeled as price-making entities capable of influencing local market-clearing outcomes rather than acting as passive price-takers. To capture the uncertainties inherent in renewable generation, energy demand, market prices, and competitors' behaviors, the models employ scenario-based stochastic programming. Risk preferences are incorporated using Second-Order Stochastic Dominance (SOSD) constraints, allowing participants to shape the distribution of potential outcomes rather than focusing solely on expected values. This approach enables aggregators and energy hubs to safeguard against adverse market conditions while still capturing profitable opportunities, ultimately balancing profitability with operational robustness. This strategic, risk-aware model not only enhances the economic performance of actors but also contributes to the efficiency of local market operations.

1.5 Summary and Contribution of Publications

This doctoral thesis comprises eight publications (Publications 1-8), presented across Chapters 3 to 7, which collectively chart a research pathway from the design of local electricity markets, through the operational integration of sector coupling and multi-energy market platforms, to the coordination of local energy markets with wholesale electricity markets, and ultimately to the development of strategic, risk-aware participation models for key local market entities. In the following, each chapter's scope, related publications, and the main contributions are outlined.

Chapter 3: Design of Local Electricity Markets

Publication 1 (P1): Modeling a Local Electricity Market for Transactive Energy Trading of Multi-Aggregators.

This article proposes a local electricity market framework for transactive energy trading among DSO and multiple DER aggregators.

Contributions of (P1):

- ❖ Novel market-based platform bridging centralized control and decentralized participation: Positions the distribution system operator as an active market

leader and enables DER aggregators to operate as financially autonomous participants, enhancing transparency, operational efficiency, and strategic flexibility in local energy trading.

- ❖ Bi-level Stackelberg formulation with network-aware clearing mechanism: Models the system operator as the leader optimizing net profit, with DER aggregators as followers minimizing operational costs. Embeds AC power flow constraints to ensure technical feasibility and maintain grid reliability.
- ❖ Dynamic, grid-aware price formation: Adapts local market-clearing prices to meet supply-demand conditions and network constraints, providing meaningful locational and temporal signals for DER utilization, storage arbitrage, and load shifting, without requiring centralized dispatch.
- ❖ Balanced outcomes compared to bilateral contracts: Quantitative analysis shows the proposed local market achieves a fairer profit distribution between the system operator and DER aggregators than fixed-tariff bilateral trading, avoiding one-sided gains or losses and maintaining network security.

Chapter 4: Sector Coupling and Multi-Dimensional Energy Systems for Flexibility Provision

Publication 2 (P2): Overview of Modern Multi-Dimension Energy Networks.

This article provides a comprehensive overview of modern multi-dimensional energy networks, emphasizing the role of sector coupling in future energy systems.

Publication 3 (P3): Hybrid Energy Storage Systems for Optimal Operation of the Heat and Electricity Incorporated Networks.

This article investigates the role of hybrid energy storage systems in the coordinated operation of electricity and heat networks.

Contributions of (P2) and (P3):

- ❖ Conceptual framework for sector coupling: Defines the scope of sector coupling and multi-dimensional energy systems, identifies enabling technologies, and highlights key barriers. Establishes a research roadmap addressing the lack of holistic co-optimization methods and limited real-world demonstrations.
- ❖ Co-optimized operation of integrated electricity-heat systems: Proposes an optimization model integrating CHP units, P2H technologies, and hybrid energy storage systems, including battery, thermal, and natural gas storage

units. Utilizes a two-stage stochastic programming approach to address uncertainties in demand, prices, and renewable outputs.

- ❖ Value of storage complementarity: Quantifies the economic and operational benefits of diversified storage portfolios in sector-coupled systems, showing increased profitability, improved renewable utilization, and reduced dependence on external imports. Finds the highest performance when battery, thermal, and natural gas storage systems operate jointly under coordinated scheduling.
- ❖ Operational robustness under uncertainties: Demonstrates that sector-coupled scheduling with hybrid storage adapts effectively to renewable and demand fluctuations, ensuring technical feasibility and sustained economic efficiency.

Chapter 5: Local Market Platforms for Integrated Energy Systems

Publication 4 (P4): A Market-Based Mechanism for Local Energy Trading in Integrated Electricity-Heat Networks.

This Article focuses on the design and implementation of local energy market platforms for integrating electricity and district heating systems.

Publication 5 (P5): A local energy market for integrated electricity-heat networks.

This Article introduces a local market framework for the integrated operation of electricity-heat networks.

Contributions of (P4) and (P5):

- ❖ Centralized cross-sector auction-based platform: Develops a local market framework in which the system operator coordinates DERs, CHP units, P2H technologies, and multi-energy storage within a unified clearing process, enforcing AC power flow constraints for electricity and thermal balance equations for district heating networks..
- ❖ Distribution locational marginal pricing for integrated electricity-heat systems: Extends distribution locational marginal pricing to both energy carriers, internalizing congestion, voltage limits, and sector interactions to produce transparent, location-specific, and time-varying incentives for market participants.
- ❖ System-level efficiency and flexibility improvements: Demonstrates that the coordinated market-clearing outline reduces total operating cost, increases renewable energy utilization without curtailment, and exploits CHP-P2H

complementarity to manage peak electrical and thermal loads more effectively.

- ❖ Operational insights from spatial-temporal pricing patterns: Shows that distribution locational marginal price variations pinpoint congestion pockets and guide targeted flexibility deployment, enabling more equitable and economically efficient dispatch decisions across the integrated energy system.

Chapter 6: Coordinating Local Integrated Energy Markets with the Wholesale Electricity Market

Publication 6 (P6): Design of an auction-based local energy market for integrated electricity and heat networks coordinated with wholesale market.

This article proposes a platform for coordinating the local integrated electricity-heat markets with the wholesale electricity markets.

Contributions of (P6):

- ❖ Hierarchical bi-level coordination: Proposes a two-layer market architecture where the local integrated electricity-heat market operator aggregates bids from DERs, P2H assets, and storage units, interacts with the wholesale electricity market, and feeds back upstream prices and allocations into local dispatch, ensuring bidirectional consistency of prices, quantities, and operational decisions.
- ❖ Economic and operational gains: Demonstrates that prioritizing local flexibility before wholesale procurement reduces total system costs, improves renewable energy utilization through P2H-based load shifting, and aligns distributed resource operation with system-wide marginal costs, enhancing transparency, economic efficiency, and welfare.
- ❖ Complementarity of flexible sector-coupling assets: Highlights how P2H technologies and CHP units can operate in a coordinated manner, absorbing surplus electricity during low-price periods and supplying heat or power during high-price periods, thereby improving peak load management and cross-sector balancing.
- ❖ Scalability and multi-sector extensibility: Provides a modular and transparent architecture adaptable to larger systems and capable of integrating additional energy carriers, e.g., gas and hydrogen, while maintaining coherent price formation and clear separation of responsibilities between local and transmission-level operations.

Chapter 7: Optimal Participation Strategies for Various Entities in Local Energy Markets

Publication 7 (P7): A two-stage stochastic bilevel programming approach for offering strategy of DER aggregators in local and wholesale electricity markets.

This article proposes an offering strategy for the optimal participation of DER aggregators in local and wholesale electricity markets.

Publication 8 (P8): Offering strategy of price-maker energy hubs in integrated local electricity and heat markets.

This article presents an offering strategy for the optimal participation of energy hubs in integrated local electricity and heat markets.

Contributions of (P7) and (P8):

- ❖ Price-making strategies for DER aggregators in local and wholesale markets: Develops a bi-level, two-stage stochastic optimization framework in which DER aggregators act as price-maker players in local electricity markets and price-taker players in wholesale electricity markets. The model co-optimizes day-ahead commitments and real-time adjustments while accounting for renewable variability, market price uncertainty, network constraints, and rival bidding behavior, enabling optimal allocation of flexible resources across market layers.
- ❖ Price-making risk-aware strategies for energy hubs in local integrated energy markets: Proposes a bi-level, stochastic optimization model in which energy hubs act as price-maker players in local integrated markets. The model accounts for uncertainty in market prices, renewable outputs, and demand through scenario-based stochastic programming. Risk management is incorporated via SOSD constraints, enabling operators to shape the full distribution of potential outcomes, safeguard against unfavorable scenarios, and achieve a balanced trade-off between profitability and robustness. This also allows for the full exploitation of cross-sector flexibility for economic gain while maintaining operational resilience and supporting broader system objectives.
- ❖ Empirical insights: Coordinated participation across local and wholesale market layers, as well as across multiple energy carriers, increases traded volumes and overall profitability. Diversification across storage types and technologies enhances operational resilience, while explicitly modeling market power prevents the inaccuracies that arise from assuming participants are passive price-takers.

To provide a transparent overview of the research process and the interactions between the different publications, a block-diagram representation has been outlined in Figure 1. This figure summarizes the workflow and shows how each part of the study contributes to the overall research objectives.

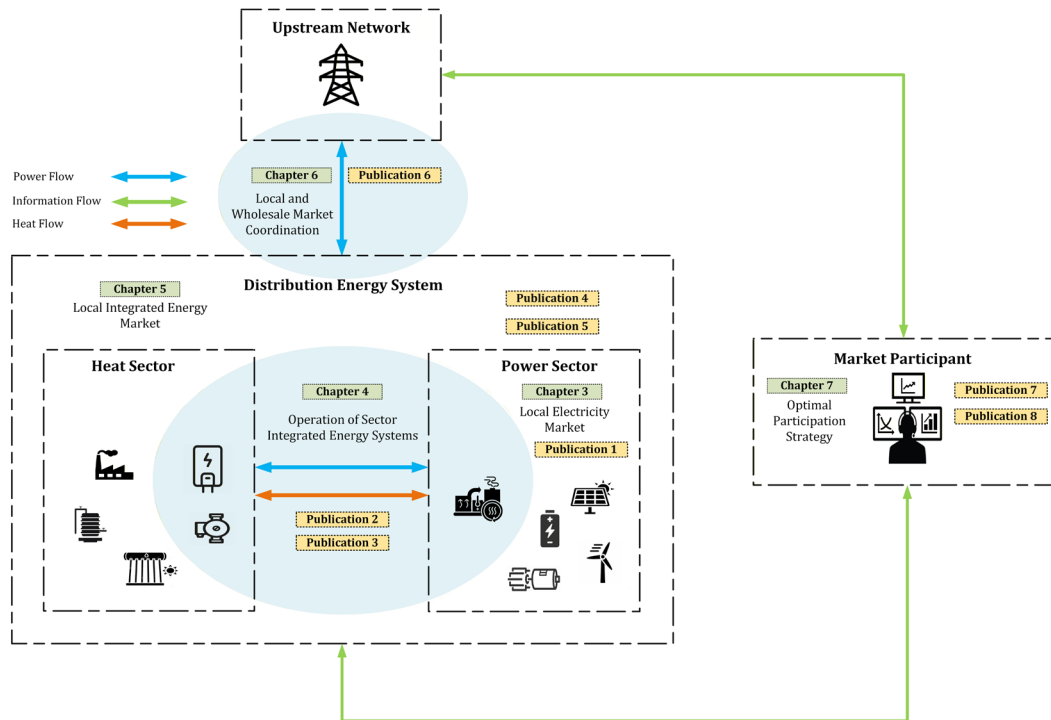


Figure 1. Overview of the Research Workflow and the Interactions Among the Publications Included in the Doctoral Thesis.

1.6 Thesis Outline

The remainder of this doctoral thesis is organized as follows:

Chapter 2: Literature Review on Market Structures and Flexibility in Future Energy Systems

Reviews the evolution of electricity and multi-energy market platforms, with particular emphasis on the growing need for flexibility and the pivotal role of sector-coupling in future energy systems. It brings together insights from EU Horizon projects, pilot initiatives, and working group reports, highlighting ongoing regulatory, technical, and governance investigations as well as persisting gaps.

Chapter 3: Design of Local Electricity Markets

Introduces a market-based framework for local electricity markets with multiple independent DER aggregators, modeled within a bi-level Stackelberg structure. The chapter outlines the proposed local market architecture, embedding AC power flow constraints to ensure network feasibility, and presents key contributions and findings showing how the design improves operational efficiency, enables transparent price formation, and supports fairer profit distribution compared to bilateral contracts (Publication 1).

Chapter 4: Sector Coupling and Multi-Dimensional Energy Systems for Flexibility Provision

Provides a conceptual overview of modern multi-dimensional energy systems and sector coupling, identifying enabling technologies, barriers, and research gaps. It then develops a co-optimization approach for integrated electricity-heat systems operation, leveraging P2H technologies, CHP units, and hybrid energy storage systems to enhance flexibility, reduce curtailment, and improve system economics under uncertainty (Publications 2 & 3).

Chapter 5: Local Market Platforms for Integrated Energy Systems

Extends the local electricity market framework to a centralized platform that jointly clears electricity and heat markets, applying a distribution locational marginal pricing mechanism for both energy carriers. The chapter's contributions demonstrate how location- and time-specific prices can internalize network and cross-sector constraints, guide flexibility where it is most valuable, and improve renewable integration and cost efficiency (Publications 4 & 5).

Chapter 6: Coordinating Local Integrated Energy Markets with the Wholesale Electricity Market

Proposes a hierarchical coordination architecture linking local integrated energy markets with the wholesale electricity market. The contributions confirm how the proposed approach ensures bidirectional price and dispatch consistency, prioritizes local flexibility before upstream procurement, and can be scaled to multi-carrier systems such as gas and hydrogen while supporting cost efficiency and renewable integration (Publication 6).

Chapter 7: Optimal Participation Strategies for Various Entities in Local Energy Markets

Examines strategic and risk-aware participation of various distribution-level entities, including DER aggregators and energy hubs in local electricity and integrated energy markets. It develops price-making participation strategies under a wide range of

uncertainties, applies stochastic optimization and the SOSD method for risk management, and highlights how coordinated, multi-carrier bidding strategies can improve profitability, operational resilience, and alignment with system-wide efficiency objectives (Publications 7 & 8).

Chapter 8: Conclusion and Future Research Direction

Summarizes the key findings and contributions of the thesis, discusses the broader implications for market design and coordination, and identifies promising avenues for advancing the operation and coordination of future integrated multi-energy markets.

2 LITERATURE REVIEW ON MARKET STRUCTURES AND FLEXIBILITY IN FUTURE ENERGY SYSTEMS

2.1 Introduction

The power sector is undergoing a profound structural transformation. The rapid deployment of renewable generation, the decentralization of energy resources, and the digitalization of operations are creating new paradigms for planning and operating both transmission and distribution networks. While renewable electricity from wind and solar is essential for decarbonization, their intermittency and non-dispatchable characteristics introduce operational uncertainty and volatility. At the same time, electrification of transport, heating, and industry, coupled with the increasing deployment of distributed energy resources (DERs), has shifted much of the flexibility challenge to distribution networks, which were not originally designed for such dynamic, bidirectional power flows (MERLON project, 2019).

Flexibility, defined as the ability of the power system to respond to variability and uncertainty in supply and demand, is now seen as a cornerstone of the energy transition. With the rapid increase in variable renewable generation, electrification of heating and transport, and the growing complexity of distribution networks, flexibility is no longer viewed as a supplementary service but as a prerequisite for maintaining system security and economic efficiency. The European Union, through the Clean Energy Package (CEP, 2019) and numerous Horizon projects (FLEXGRID, 2019; ELEXIA, 2022; FEDECOM, 2022), has stressed the importance of developing frameworks that unlock flexibility from distributed and cross-sectoral resources, including demand response, storage, and sector-coupling technologies. A growing set of pilot initiatives, demonstration projects, and expert working group reports provides concrete demonstrations of this emerging paradigm. These efforts highlight not only the technical feasibility of mobilizing flexibility at the distribution level but also the institutional and market innovations required to ensure that flexibility is visible, tradable, and fairly compensated across different system layers.

This chapter provides a state-of-the-art review that situates the thesis within the broader context of ongoing developments in energy systems and markets. It examines how existing and emerging market structures are evolving to integrate DERs and flexibility services, and why the growing need for flexibility is becoming central to future power system operation. Special attention is given to sector coupling and power-to-X (P2X) technologies, which are increasingly recognized as enablers of cross-sectoral flexibility and improvements. In addition, the chapter discusses the role and potential of sector coupling in future flexibility provision, while also

addressing the market and regulatory challenges that currently limit its deployment. Finally, it highlights regulatory developments shaping flexibility utilization in distribution networks, particularly in the European context. Together, these perspectives provide a comprehensive background and motivation for the methodological and conceptual contributions developed in the subsequent chapters of this thesis.

2.2 Existing and Emerging Market Structures

Traditional electricity market structures were designed around centralized, large-scale generation and unidirectional power flows from transmission networks toward passive consumers. Wholesale electricity markets at the transmission level have long been the primary venue for price formation, balancing, and system reliability, while distribution networks remained outside the market sphere, serving mainly as passive delivery infrastructures. This separation is increasingly inadequate in today's environment of distributed generation, prosumer activity, and electrification of new sectors, where flexibility must be harnessed closer to the point of consumption.

In response to these challenges, commercial platforms for local energy and flexibility markets, alongside research-driven pilot projects, are being actively investigated and tested across Europe and beyond. These initiatives explore market-based mechanisms that enable various stakeholders, including distribution system operators (DSOs), aggregators, and prosumers, to trade energy and flexibility services locally, thereby addressing congestion management, voltage control, and system balancing needs.

Some of these pilots, consensus development projects, and studies are as follows:

- **FinFlex (Finland):** A national pilot initiative designed to test the procurement of distribution-level flexibility for alleviating local network constraints and supporting balancing. It serves as a practical demonstration of how DSOs can mobilize local flexibility from DERs, prosumers, and aggregators. In this platform, any electricity-consuming, producing, or storing flexible resource is allowed to participate in the congestion management market. The flexible resource must be located in Finland (Finflex, n.d.).
- **Nodes Marketplace (Nordic Region):** A neutral cross-border commercial marketplace developed to enable both distribution and transmission system operators to procure flexibility from DERs in a transparent, non-discriminatory manner. This platform facilitates a simple process for service providers to offer flexibility to system operators (Home, n.d.).

- **CIREC Working Group on Network Planning with Flexibility:** As an international expert report emphasizes that harnessing flexibility can defer costly network reinforcements, improve system security, and provide more sustainable pathways for network planning (CIREC Working Group, 2023).
- **Transactive Energy Pilots in the United States:** Pacific Northwest Smart Grid Demonstration, as an example, offer alternative models, where distributed price signals guide DER operations directly, illustrating different approaches to embedding flexibility into markets (Pacific Northwest National Laboratory, 2015).

Looking ahead, future market structures are moving toward multi-layered, interoperable coordination frameworks where wholesale, local, and even peer-to-peer trading can coexist. EU Horizon projects such as **CoordiNet** (CoordiNet, 2018), **OneNet** (OneNet, 2020), and **INTERRFACE** (INTERRFACE, 2018) are at the forefront of shaping this vision by developing scalable architectures, standardized market products, and digital platforms that enable seamless interaction across transmission and distribution layers. These initiatives extend to address the trading of energy and flexibility services, ensuring that distributed energy resources are visible, dispatchable, and fairly rewarded. Together, they point toward a future energy landscape that delivers not only technical balancing but also economic efficiency, enhanced system resilience, and accelerated progress toward long-term decarbonization targets.

2.3 The Need for Flexibility in Future Power Systems

The accelerating penetration of variable renewable energy sources, particularly solar and wind power units, has fundamentally changed the operational requirements of power systems. Unlike conventional dispatchable generation, these resources are inherently weather-dependent, leading to increased variability and uncertainty in the supply side. Projections by the **IEA** (International Energy Agency, 2021) and **IRENA** (International Renewable Energy Agency, 2021) suggest that flexibility requirements could increase dramatically by 2050 in systems with very high renewable penetration. Such flexibility is essential to maintain reliability and efficiency across multiple time scales:

- **Seconds to Minutes:** Rapid-response services to ensure frequency control, inertia provision, and local voltage stability.
- **Hours to Days:** Balancing intraday fluctuations in renewable generation, managing load ramps, and maintaining adequate reserves.

- **Seasonal Horizons:** Addressing structural mismatches between renewable supply and demand, particularly in relation to heating, cooling, and long-duration storage needs.

At the distribution level, the proliferation of DERs introduces additional layers of complexity. High concentrations of solar panels can lead to midday reverse power flows and voltage deviations, while the clustering of electric vehicle (EV) charging creates new evening demand peaks and local congestion. The growing electrification of heating and industry, through electric heat pumps, electric boilers, and other power-to-heat applications, further amplifies variability at the distribution level and introduces strong seasonal and sectoral dependencies, underscoring the need for tighter coordination between electricity and thermal networks. Traditional responses to these challenges, like reinforcing network infrastructure with new lines or transformers, are often capital-intensive, slow to implement, and socially disruptive. Instead, flexibility procurement is emerging as a dynamic and cost-effective alternative. Flexibility can be mobilized from both supply-side resources, including flexible generation, storage, as well as sector-coupled assets, and demand-side measures, including demand response, EV charging, and building thermal inertia (Astapov et al., 2025).

The CIRED Working Group on Network Planning with Flexibility emphasizes that without sufficient flexibility, DSOs would face escalating costs to maintain security of supply, manage congestion, and ensure voltage compliance. Instead of relying solely on costly grid reinforcements, well-designed local energy and flexibility market platforms, supported by transparent procurement schemes, enable both distribution and transmission system operators to dynamically manage network constraints, integrate higher shares of renewables, and improve overall system efficiency. Moreover, when extended to include sector-coupling solutions such as power-to-heat and hybrid energy storage systems, these platforms unlock additional cross-sector flexibility that can be mobilized through market signals. Flexibility thus emerges not only as a technical necessity but also as an economic and strategic enabler of the energy transition, underpinning the coordinated planning and operation of future multi-energy systems across local and wholesale layers (Mellot et al., 2025).

2.4 Sector Coupling and Power-to-X Technologies

Sector coupling refers to the systematic integration of electricity, heat, gas, and transport systems to enable cross-sector energy flows and enhance system-wide flexibility. By linking these traditionally separate energy infrastructures, sector coupling supports more renewable integration, improves overall system efficiency,

and reduces reliance on fossil fuels. This integration is made possible by a suite of P2X technologies, which convert electricity, preferably excess renewable outputs, into other energy carriers that can be stored, transported, and utilized flexibly across sectors. Among these technologies, several pathways have emerged as particularly relevant for near to medium-term deployment, each contributing differently to flexibility provision and market integration (Fridgen et al., 2020):

- **Power-to-Heat (P2H):** Large-scale heat pumps and electric boilers convert electricity into thermal energy, feeding district heating networks. When combined with thermal storage systems, they allow renewable power surplus to be absorbed and shifted to periods of peak heat demand. Small-scale heat pumps provide an energy-efficient method for localized heating and cooling by transferring existing heat rather than generating new heat, resulting in lower energy consumption, reduced carbon emissions, and the ability to target specific zones, whether individual rooms or an entire home.
- **Power-to-Gas (P2G):** Electrolysers transform electricity into hydrogen (H₂) through electrolysis. Hydrogen can be used directly, stored seasonally, or further converted into synthetic methane (CH₄) via methanation, providing long-term flexibility and supporting industrial decarbonization.
- **Power-to-Fuels/Products (P2F):** Building on P2G, hydrogen serves as a key feedstock for producing synthetic fuels, including e-methanol, ammonia, synthetic kerosene, and other industrial products. These pathways extend the role of P2X from energy storage into hard-to-abate sectors such as aviation, shipping, and chemicals.
- **Power-to-Mobility (P2M):** EVs, coupled with smart charging and vehicle-to-grid (V2G) technologies, provide flexible demand response and distributed storage at scale. EV fleets represent a rapidly growing and highly flexible asset base that can be activated through local energy markets or aggregator-driven platforms.

Several projects demonstrate the potential of sector coupling for flexibility provision and market participation. For example, the **MAGNITUDE** H2020 project (MAGNITUDE, 2017) has developed and validated optimization tools for cross-sector operation of multi-energy hubs across Europe, demonstrating improved system efficiency and market value of sector-coupled flexibility. The **X-Flex** project (X-FLEX, 2019) explores how P2X assets can participate in local and wholesale energy markets, testing market platforms and information and communication technology (ICT) solutions for real-world integration. These efforts highlight how sector coupling not

only provides additional flexibility options but also creates new opportunities for coordinated multi-energy market designs.

2.5 Role of Sector Coupling and Power-to-X in Flexibility Provision

Sector coupling significantly broadens the range of flexibility options available to the power system, going beyond traditional demand-side response and battery storage. By enabling energy conversion and shifting across various sectors, P2X technologies provide new levers to balance variability from renewable generation and to enhance the resilience of both electricity, thermal, and gas systems. The main flexibility contributions of sector coupling can be categorized along several dimensions, illustrating how P2X assets provide both short-term and long-term balancing capabilities across energy sectors (Chyong et al., 2024):

- **Absorbing Surplus Renewable Generation:** P2H technologies such as heat pumps and electric boilers can utilize excess wind and solar power outputs that would otherwise be curtailed. District heating systems with integrated thermal storage, for example, in Finland and Northern Europe, provide cost-effective means to capture renewable surpluses and defer their use to peak demand periods.
- **Load Shifting and Storage:** Thermal storage tanks and hydrogen storage act as buffers that can decouple generation from consumption across hours, days, and even months. These assets enable renewable generation to be absorbed when available and dispatched later, smoothing intraday variability and reducing stress on the grid.
- **Cross-Sectoral Substitution:** By enabling substitution between electricity, heat, and gas, sector coupling provides system operators and consumers with new choices. For instance, in periods of high electricity prices, heating demand can be supplied by combined heat and power units or gas boilers, whereas during low-price periods, P2H technologies can dominate. This dynamic allocation supports both economic efficiency and network security.
- **Seasonal Balancing:** Among P2X pathways, P2Gas offers the most promising form of seasonal flexibility. Electrolysers convert surplus summer renewables into hydrogen, which can be stored and later used for winter heating, industrial applications, or reconverted into power. This long-duration storage complements batteries and short-term demand response, providing flexibility across different time scales.

Evidence from European Horizon projects reinforces these benefits. As an example, the **MAGNITUDE** project demonstrated that cross-sector optimization in multi-energy hubs can reduce total system costs, increase renewable energy utilization, and defer grid reinforcements. Similarly, the **BestRES** (BestRES, 2016) and **X-Flex** projects highlighted how integrating P2X assets with local market frameworks enhances both the availability and tradability of flexibility services. These findings suggest that sector coupling and P2X are not only technological solutions but also institutional enablers, as they make flexibility visible and tradable in market platforms, while ensuring more effective use of electricity, particularly renewable.

In summary, sector coupling transforms flexibility from a single-sector challenge into a multi-sector opportunity, enabling the efficient orchestration of distributed energy resources across various networks, including electricity, heat, transportation, and gas. This multi-dimensional flexibility is essential to support higher shares of renewables, reduce curtailment, and achieve cost-effective decarbonization at both local and system-wide levels.

2.6 Regulatory and Market-Related Challenges

Despite the strong technological promise of sector coupling and P2X solutions, as well as their potential advantages in flexibility provision, several regulatory and market-related challenges still hinder their large-scale deployment. To translate this potential into practical system value, these solutions must overcome economic, institutional, and governance hurdles that currently limit their scalability and integration into mainstream energy markets (Ilo et al., 2021):

- **Market Design Gaps:** Current electricity market structures are still tailored to single-carrier operation and do not fully reward the arbitrage value of cross-sector resources. For example, while P2H units can absorb excess renewable power, most wholesale and retail markets lack mechanisms to remunerate their contribution to congestion relief or renewable integration properly. EU Horizon projects such as **MAGNITUDE** and **X-FLEX** have emphasized these barriers, proposing innovative multi-energy business models and market mechanisms to enable flexibility procurement not only in electricity but also across heat and gas networks.
- **Tariff Structures:** In many jurisdictions, retail tariffs are static or poorly aligned with system needs, discouraging flexible behaviors such as shifting EV charging or operating heat pumps in response to local or wholesale conditions. For instance, findings from the **BestRES** project showed that inappropriate tariff designs could erode much of the potential savings from

demand response and P2X-based flexibility. Transitioning toward dynamic, cost-reflective tariffs is thus seen as critical to unlock consumer participation in sector-coupled flexibility.

- **DSO Role Ambiguity:** A recurring debate concerns whether DSOs should remain purely neutral market facilitators or take an active role in flexibility procurement and market operation. The **CoordiNet** and **OneNet** projects have experimented with both roles: in some pilots, DSOs directly procured flexibility for congestion management, while in others, they coordinated with independent platforms to ensure neutrality. The outcomes highlight the need for a clear regulatory framework to define responsibilities, ensure non-discrimination, and safeguard transparency.
- **Interoperability and Data Exchange:** Seamless coordination of multi-energy networks depends on standardized communication protocols, secure data sharing, and interoperable platforms. The absence of common standards remains a significant barrier to sector coupling solutions. Projects such as **X-FLEX** and **InterPED** (InterPED, 2024) are tackling this challenge by developing advanced ICT and cloud-based architectures, along with robust data exchange frameworks, to enable secure, transparent, and efficient integration of sector-coupled assets into emerging markets.

The CIRED Working Group on Network Planning with Flexibility stresses that governance and neutrality are central to overcoming these barriers. Clear rules for data ownership, standardization of market interfaces, and consistent pricing mechanisms across electricity and other energy carriers are needed to ensure that a wide range of flexibility is not only technically available but also economically viable and socially equitable. These challenges form the backdrop against which this thesis develops coordinated, market-based frameworks for local and sector-coupled energy systems, aiming to bridge the gap between technical feasibility and economic efficiency.

2.7 Regulatory Developments Related to Flexibility in Distribution Systems

Recent policy and regulatory steps have increasingly emphasized the central role of flexibility in future energy systems, reflecting its importance not only as a technical necessity but also as a regulatory and economic priority. Across Europe, both national initiatives and EU-level programs are introducing concrete mechanisms and platforms to bring distributed and sector-coupled services into formal market operations.

- **EU Clean Energy Package (2019):** A landmark policy requiring DSOs to consider flexibility solutions, such as demand response or distributed storage, before resorting to costly grid reinforcements. This marked a shift from viewing flexibility as optional to treating it as a mandated planning alternative.
- **PicloFlex (UK):** A commercial marketplace where DSOs procure flexibility services from DERs to manage congestion and maintain reliability. It represents one of the first scalable platforms that bridges regulatory approval with market practice (Piclo, n.d.).
- **FinFlex (Finland):** A national marketplace enabling distribution-level flexibility trading, designed to integrate both commercial flexibility providers and research-driven pilot projects. It illustrates how DSOs can rely on markets instead of only traditional reinforcement investments.
- **SINTEG (Germany):** A large-scale demonstration program trialing local and regional platforms, testing business models for integrating renewables, storage, and sector-coupled assets into market-based coordination (SINTEG, n.d.).
- **CoordiNet:** Focusing on distribution and transmission system operators' coordination frameworks, enabling distributed resources to be accessed by both operators in a non-conflicting and transparent manner.
- **INTERFACE:** Developing interoperable ICT platforms and standardized interfaces that allow DERs and sector-coupled technologies to provide flexibility across different energy system layers.
- **OneNet:** Proposing a scalable, pan-European market architecture for energy and flexibility management, with emphasis on harmonized market rules, interoperability, and cross-border consistency.

Together, these initiatives and projects demonstrate a growing recognition of distributed and sector-coupled services as a formal system resource rather than a supplementary option. However, they also reveal persistent gaps, showing that regulation remains fragmented across countries, standardization is incomplete, and mechanisms for cross-sectoral trading are still at an early stage. This highlights the crucial need for harmonized regulatory frameworks as well as market designs that can unlock the full potential of DERs and integrated electricity, heat, gas, and mobility systems.

2.8 Summary and Link to the Thesis

The review of existing literature, pilot projects, and policy developments highlights several consistent themes. Traditional electricity markets, designed primarily for wholesale-level operations, are increasingly inadequate in the context of high renewable and distributed energy resource penetration, particularly at the distribution level. At the same time, the need for flexibility is expanding rapidly, spanning fast-response frequency services to long-term seasonal balancing, with distribution networks becoming focal points for both challenges and opportunities. Sector coupling and P2X technologies emerge as promising enablers, capable of unlocking cross-sectoral flexibility and providing new pathways for renewable integration, demand shifting, and energy storage.

The reviewed real-world pilots and EU Horizon projects demonstrate that establishing market-based platforms for flexibility and sector-coupled services is both technically and institutionally feasible. However, they also reveal unresolved challenges, including fragmented regulation, insufficient incentives for cross-sector arbitrage, governance uncertainties regarding the role of DSOs, and the lack of standardized data exchange protocols. Policy efforts, such as the EU Clean Energy Package, mark an important step forward, but comprehensive and harmonized frameworks remain under development.

These gaps motivate the contributions of this doctoral thesis. The subsequent chapters move beyond existing pilots and conceptual proposals to develop a set of integrated, market-based solutions: network-aware local markets that embed distribution systems constraints, sector-coupled market-clearing mechanisms that value cross-sectoral flexibility, hierarchical coordination frameworks that align local and wholesale decisions, and risk-aware participation strategies for local market players. Collectively, these contributions aim for the next generation of distributed, multi-energy market systems.

This doctoral thesis proposes a local energy market for future distribution networks, in which consumers and producers can trade energy and provide flexibility services close to their point of connection. Under current European legislation and unbundling rules, DSOs are not intended to clear the competitive markets. The term “DSO-operated local energy market” used in this thesis serves solely as a modeling proxy for a neutral platform that is tightly coordinated with the distribution system operators. It does not imply transferring the commercial operation of local energy markets to DSOs.

In the intended end-state, a neutral and independent platform operator or a common TSO-DSO platform can perform the role of market operator by receiving offers and

bids, clearing transactions, and settling payments. In this context, the DSO supports the platform by providing:

- Location-specific requirements and network constraints (e.g., feeder limits and voltage boundaries).
- Prequalification criteria and asset registration to ensure resources are technically capable and traceable.
- Secure data exchange for metering and telemetry, complying with privacy and cybersecurity requirements.
- Activation signals for congestion management and voltage control during system operation.

This setup aligns with current EU practice, in which DSOs procure flexibility through market-based procedures without conducting competitive market operations. It also reflects ongoing European pilot projects, including DSO tenders and TSO-DSO coordination platforms, which implement these interfaces even when an independent entity acts as the market operator.

The models presented in this thesis capture the technical and governance conditions required for the viable operation of local energy markets. Within these frameworks, local market operators require reliable access to operational data, adequate locational data for feeders and nodes, and observability of relevant grid states through appropriate measurements. While DSOs remain independent regulated entities, they are responsible for enabling market operators to access this data via standardized and secure interfaces.

The results and algorithms presented in this work can function when the market is operated by an independent entity, such as a nominated market operator, or through a joint TSO-DSO solution. Reviewing existing projects shows that defining the roles and responsibilities of entities involved in local energy markets is challenging and requires further research and pilot studies. Although this thesis does not aim to define regulations and responsibilities for local distribution system entities, for the sake of simplicity, the term “DSO” is used throughout the work as shorthand for a “DSO-facilitated local market”, in which competitive market operations are conducted by a neutral, independent party, and the DSO acts as a regulated, non-profit facilitator ensuring compliance with distribution network constraints. This assumption preserves unbundling, maintains neutrality, and enables the reliable and scalable integration of distributed energy resources into local market processes.

3 DESIGN OF LOCAL ELECTRICITY MARKETS

3.1 Introduction and Background

The ongoing decentralization of electricity systems, driven by the proliferation of distributed energy resources (DERs) such as rooftop photovoltaics, wind turbines, battery energy storage systems, and demand response technologies, is fundamentally changing how electricity is produced, managed, and consumed. With this shift, the limitations of centralized electricity markets are increasingly evident, particularly at the distribution level, where conventional market frameworks fail to efficiently incorporate small and medium-scale DERs. These trends have spurred growing interest in the local electricity markets (LEIMs) concept, which enables transactive energy trading close to the point of generation and consumption (Moradi et al., 2023).

A common thread across the literature on LEIMs is their potential to enhance grid reliability, increase customer engagement, and promote efficient use of local resources. Yet, despite significant advances, most existing approaches fall short of providing a practical and scalable solution for real-world implementation. A recurring limitation is the absence of a well-defined market-based mechanism that balances the economic interests of various actors, especially DER aggregators (AGs) and distribution system operators (DSOs), while satisfying the technical constraints of the grid. Many prior models assume centralized control, overlook market dynamics, or fail to empower participants as autonomous decision-makers (Tsaousoglou et al., 2022).

Publication 1, entitled ***“Modeling a Local Electricity Market for Transactive Energy Trading of Multi-Aggregators,”*** addresses these gaps by proposing a structured, game-theoretic model that integrates economic and operational layers of an electricity market at the distribution level. It aims to answer the following research questions:

- What kinds of mechanisms can enable greater participation of small and medium-sized DERs in the DSO energy management process?
- How can LEIMs be structured to support decentralized, transactive energy trading among multiple independent AGs and a proactive DSO?
- What modeling framework can simultaneously capture economic incentives and grid constraints in a local market environment?

- How can market efficiency and fairness be ensured while preserving operational feasibility at the distribution level?

The core research motivation is rooted in the following statement:

“The growth of renewable energy resources within distribution electricity networks highlights the importance of existing and designing a market-based platform for the efficient operation of these units under the local energy market concept.”

3.2 Research Method and Framework

To respond to these research questions and facilitate the engagement of several DERs in the energy management program of the DSO, Publication 1 introduces a local market-based model structured as a Stackelberg game, a hierarchical decision-making framework particularly well-suited for problems involving independent players with distinguished and conflicting objective functions as leaders and followers (Lei et al., 2023).

In the proposed local market outline:

- The DSO acts as the leader, seeking to optimize its net profit by procuring electricity from local DERs, its own generators, and the wholesale market, all while respecting system constraints.
- The independent DER AGs, acting as followers, aim to minimize their operating costs and maximize revenues by strategically bidding into the local market.

This paper analyzes a case in which the DSO owns and operates local generation, which conflicts with EU unbundling rules that require DSOs to remain neutral and avoid competitive generation interests. This assumption is made to study incentives, market power, and dispatch interactions when a network operator also has merchant interests. As part of the early stages of this thesis, the analysis focuses on non-EU contexts where distribution utilities may be vertically integrated or own generation assets. For an EU-compliant design, the same framework can be applied with a DSO that does not own generation, while market functions are carried out by an independent market operator.

The proposed approach uses a bi-level optimization structure (Sinha et al., 2018), where the upper level models the DSO's profit maximization, and the lower level encapsulates the AGs' cost minimization strategies (Detailed formulation in

Publication 1). This hierarchical structure is then transformed into a single-level problem through the Karush-Kuhn-Tucker (KKT) conditions and linearized using the Big-M method to ensure solvability (Wulf et al., 2020).

Figure 2 illustrates the proposed framework for designing the considered LEIMs. It shows the DSO at the top of the decision hierarchy, broadcasting price signals to the DER AGs. These AGs, as independent entities, then submit their bids and offers based on their available generation and storage resources. The framework captures the dual-directional relationship: price signals flow from the DSO to DER AGs, and energy offers and bids flow back from DER AGs to the DSO. The central clearing process then considers both technical constraints, such as voltage limitations, as well as power flows, and financial objectives, such as cost minimization and profit maximization, in settling the market.

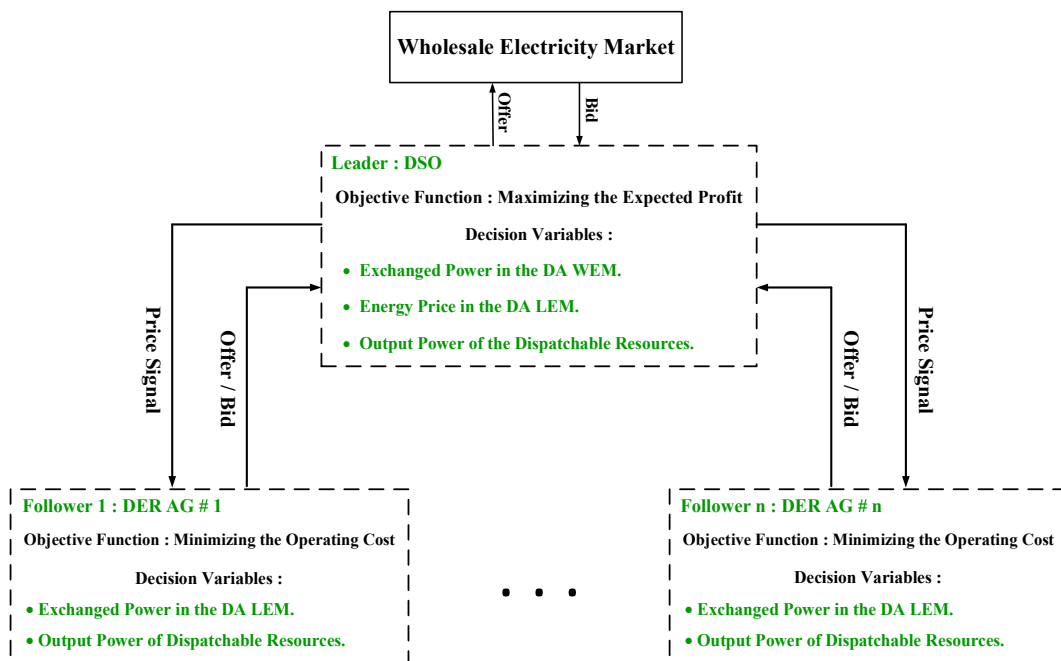


Figure 2. Schematic of the Stackelberg-Based Local Electricity Market Framework (From Publication 1).

The Stackelberg-based structure for LEIMs is particularly suitable because it allows for decentralized control with coordinated operation. It maintains strategic autonomy for each participant while preserving grid integrity and economic efficiency. Moreover, the explicit inclusion of network constraints ensures that solutions are not only economically optimal but also technically viable.

The method provides a clear mathematical representation of power flows, voltage levels, DER dispatch limits, and market price formation, which enables the evaluation

of both economic outcomes, including profit and cost, as well as technical feasibility, including line capacity, voltage deviation, etc.

To evaluate the proposed framework, the model is applied to a representative case study using a modified IEEE-33 bus distribution test system, as shown in Figure 3. Notably, all local distributed energy resources are assumed to already exist in the system, and the study focuses on their optimal operation within a local market platform rather than on investment decisions. The case study incorporates key assumptions and system data, including DERs locations, generation capacities, demand profiles, flexibility resources, and the technical configuration of the distribution test system to ensure a realistic evaluation. Detailed input data for running the algorithm and the resulting outputs are provided in more detail in Publication 1.

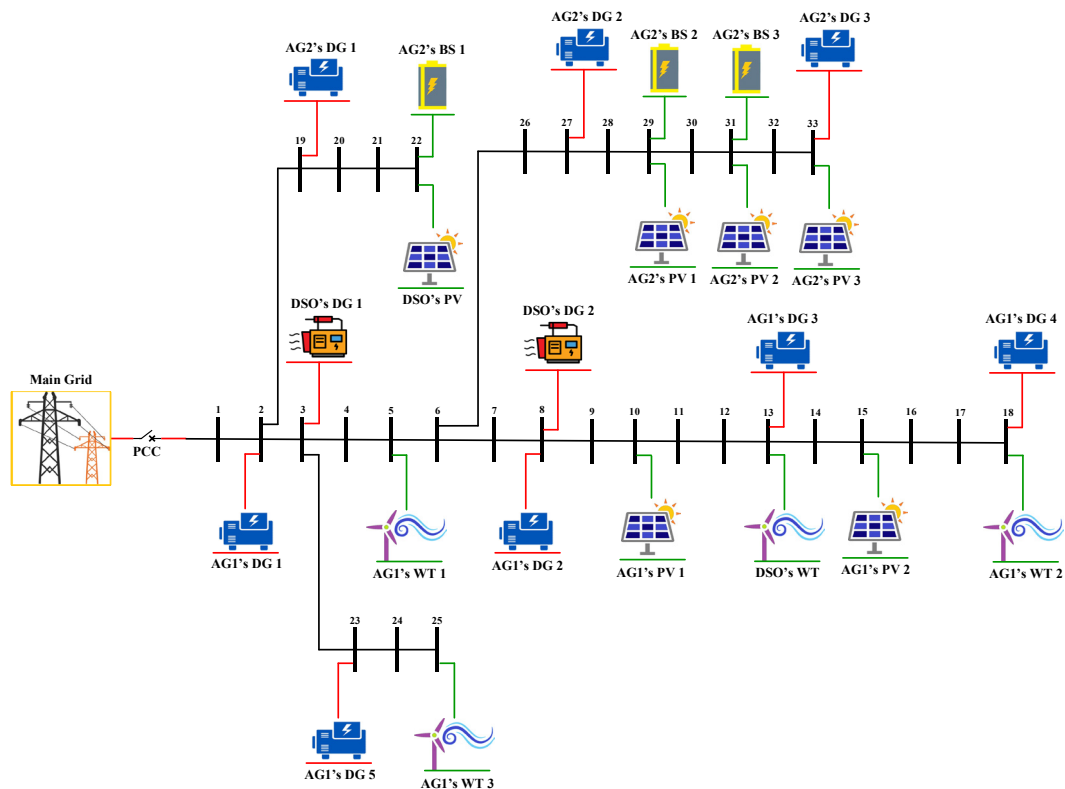


Figure 3. Single-Line Diagram of the Modified IEEE-33 Bus Test System (From Publication 1).

3.3 Main Contributions and Findings

Publication 1 proposes a novel market-based platform at the distribution level that bridges the gap between centralized planning and decentralized market

participation. By positioning the DSO as an active market participant and enabling DER AGs to operate as financially autonomous entities, the model promotes transparency, efficiency, and strategic flexibility in local market operations.

The key findings of the study are as follows:

- First, the research demonstrates that when DER AGs are empowered to participate in a well-regulated and well-structured LEIM using transactive mechanisms, they can effectively coordinate with the DSO to optimize both individual and collective objectives. This interaction results in enhanced operational performance and cost-effectiveness for the power distribution system.
- Second, the market-clearing mechanism naturally adjusts local energy prices in response to supply-demand dynamics, offering price signals that encourage DER utilization during peak hours and storage charging during low-demand periods. This feature enables temporal arbitrage and load shifting without the need for direct central dispatch.
- Third, the findings reveal that the Stackelberg-based coordination in LEIMs leads to a “win-win” outcome: DER AGs gain fair access to revenue streams while the DSO retains control over network safety and reliability. Moreover, the model’s flexibility in handling grid constraints ensures operational feasibility under various load and generation scenarios.
- Fourth, the research underscores the importance of network capacity and topology in shaping local market outcomes. For instance, constraints in the line connecting the distribution network to the wholesale market increase local market prices, as shown in Figure 4, and incentivize greater reliance on internal DERs. This figure highlights how network constraints influence the LEIM clearing prices, so that reducing the transmission line capacity increases the LEIM clearing prices during peak hours, and even slightly during off-peak hours, as the most expensive DERs become marginal producers in the LEIM. Moreover, the impact of line capacity on economic outcomes is summarized in Table 1. The results show that as the line capacity decreases, the DSO’s expected profit declines due to reduced energy exchanges with the wholesale market, while the DER aggregators’ profits increase owing to higher local market-clearing prices. These findings clearly demonstrate the model’s capability to reflect realistic grid limitations and provide economically meaningful signals for DER engagement.

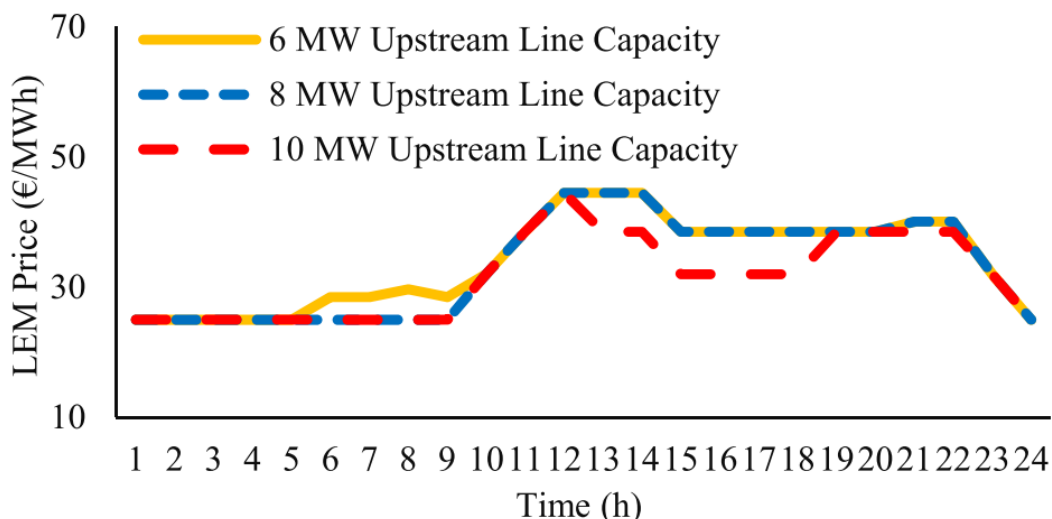


Figure 4. Impact of Grid Constraints on LEIM Clearing Prices (From Publication 1).

Table 1. Impact of Grid Constraints on Economic Outcomes of LEIM's Players (From Publication 1).

Case Study	Daily Profit (€)		
	DSO	DER AG 1	DER AG 2
10 MW Upstream Line Capacity	2932.61	1343.44	881.91
8 MW Upstream Line Capacity	2912.50	1504.30	997.03
6 MW Upstream Line Capacity	2854.57	1548.80	1012.89

- Finally, a comparative analysis between the proposed LEIM framework and a bilateral contracting approach reinforces the value of an organized marketplace. When energy trading occurs through fixed-price bilateral agreements rather than dynamic market clearing, outcomes tend to favor one party at the expense of others, depending on tariff structure and grid conditions. In contrast, the local market-based platform enables a more balanced profit distribution among DSOs and independent DER AGs by reflecting real-time price signals and operational constraints. This supports that structured local markets foster more efficient, transparent, and mutually beneficial energy trading compared to bilateral contracts. Table 2 presents a comparative summary to illustrate this point, based on three different bilateral contract tariffs, set higher than, equal to, and lower than the wholesale market price, between the DSO and two distinct DER AGs.

Table 2. A Comparison between the LEIM Framework and the Bilateral Contracting Approach (From Publication 1).

Case Study		Daily Profit (€)		
		DSO	DER AG 1	DER AG 2
Bilateral Contract	Tariff 1 (< Wholesale Price)	3166.66	166.32	1188.34
	Tariff 2 (=Wholesale Price)	-616.73	3094.22	1881.33
	Tariff 3 (> Wholesale Price)	-919.24	1927.73	240.42
	LEIM Platform	2932.61	1343.44	881.91

As the table's results show, bilateral contracts can create one-sided benefits depending on tariff structures, either overcompensating DER AGs or placing financial burdens on the DSO. In contrast, the presented LEIM framework provides dynamic, transparent pricing that supports more balanced profit outcomes, grid-aware dispatch, and strategic use of resources, enabling a win-win condition for all participants.

3.4 Conclusion

By proposing a decentralized, incentive-compatible market design, Publication 1 lays the groundwork for scalable and practical local electricity markets that can effectively support high penetration of small and medium-sized DERs at the distribution level. The proposed Stackelberg game-based method not only models realistic market behaviors but also embeds technical feasibility within the economic decision-making process. This approach contributes directly to the broader objective of this doctoral thesis: developing market structures and mechanisms that facilitate sector coupling and enable power-to-X-to-power (P2X2P) transactions in flexible future energy systems.

4 SECTOR COUPLING AND MULTI-DIMENSIONAL ENERGY SYSTEMS FOR FLEXIBILITY PROVISION

4.1 Introduction and Background

The rapid penetration of renewable energy sources (RES) in distribution-level energy systems has introduced new operational challenges, primarily due to their intermittent and non-dispatchable nature (Yeboah et al., 2025). These challenges necessitate a paradigm shift in how modern energy systems are structured and operated. One of the most promising approaches for enhancing flexibility and resilience in such systems is sector coupling, which integrates various energy carriers, including electricity, heat, and gas, into a unified, interoperable framework. This approach aims to break the siloed operation of energy sectors and leverage synergies among them to provide enhanced balancing, storage, and demand-side management opportunities (Calvo García et al., 2025).

In parallel, the notion of multi-dimensional energy systems (MDES) has emerged to characterize these integrative infrastructures. MDES not only refers to the physical interconnection of different energy sectors but also encompasses the virtual, operational, and market-level mechanisms that facilitate coordination across sectors. The increasing complexity and interdependence in such systems call for innovative control strategies, digital infrastructures, and market mechanisms that can address the technical and economic intricacies of integrated networks (Berjawi et al., 2021).

To guide the investigation into these concepts, several research questions are posed:

- How can sector coupling and MDES address the flexibility limitations in renewable-dominated energy systems?
- What are the benefits and challenges associated with the integration of various energy sectors?
- What operational and market models best represent the dynamics of multi-dimensional energy systems?
- How can hybrid energy storage systems and cross-sector control improve the efficiency and reliability of integrated energy systems?

This chapter builds upon these foundational questions through two complementary publications. Publication 2, entitled ***“Overview of Modern Multi-Dimension Energy Networks,”*** offers a comprehensive review of recent advances in sector coupling, identifying trends, benefits, challenges, and gaps across various implementations.

Publication 3, entitled ***“Hybrid Energy Storage Systems for Optimal Operation of the Heat and Electricity Incorporated Networks,”*** presents a pragmatic modeling framework for the optimal operation of integrated heat and electricity networks using hybrid energy storage systems (HESS), illustrating the practical application of sector coupling for enhancing operational flexibility and reliability in future distribution networks.

The research is anchored in the following statement:

“The importance of flexibility in renewable-dominated distribution energy systems, given the intermittent nature of these units, highlights the need for integrated, multi-dimensional energy networks, which aim to integrate electricity, heat, and gas energy sectors both physically and virtually.”

4.2 Sector Coupling and Multi-dimensional Energy Systems: A Theoretical Overview

4.2.1 Conceptual Framework and Definitions

Sector coupling refers to the strategic interconnection and coordinated operation of different energy sectors to improve system-wide efficiency and flexibility. In practice, this includes technologies such as power-to-heat (P2H), power-to-gas (P2G), combined heat and power (CHP) systems, as well as HESS that interact across multiple domains (Zhang et al., 2021). Multi-dimensional energy systems expand on this by incorporating virtual coupling through integrated markets, ICT infrastructures, digital twin models, and coordinated operation strategies that span across electricity, heat, and gas networks.

This conceptual framework presents the structural and functional integration points necessary for effective cross-sector energy system operation, illustrating the foundational role of digital and market linkages in enabling flexibility and interactivity.

Figure 5 illustrates an architecture of unified energy systems, capturing the physical, operational, and informational interconnections between several energy carriers. It shows how electricity, heat, and gas systems can interact through shared assets, including CHP, P2H, P2G, and, more generally, power-to-X-to-power (P2X2P), along with hybrid storage units, all coordinated via ICT platforms and market-based mechanisms. The layered structure also emphasizes the importance of control

hierarchies, from local operational control to market integration and planning functions.

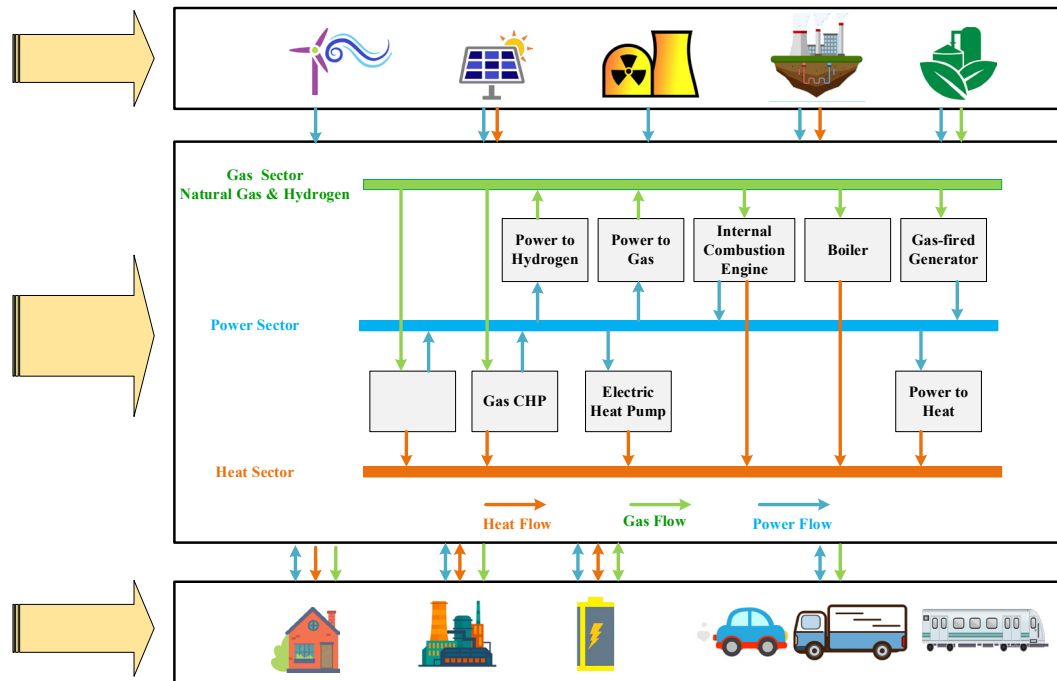


Figure 5. Sector Coupling Architecture and Integration Layers (From Publication 2).

4.2.2 Technological Enablers and Barriers

Publication 2 highlights key technological enablers of sector coupling, including advancements in smart grid infrastructure, sector-integrated operating models, demand-side flexibility mechanisms, and digital communication technologies.

Smart grid advancements allow for real-time monitoring and control of decentralized assets, while demand response and dynamic pricing provide economic incentives for cross-sector coordination. Hybrid and multi-carrier storage technologies serve as physical enablers of temporal flexibility. Additionally, the proliferation of data-driven control and automation via IoT and AI further supports real-time decision-making across multiple energy sectors (Rajaperumal & Columbus, 2025).

Despite progress, challenges remain. These include regulatory fragmentation, a lack of unified optimization frameworks, insufficient cross-sector data sharing, and high capital investment requirements for physical infrastructure, such as CHP and P2X2P plants and various types of storage systems. Integration is further complicated by

differing operational timelines, safety standards, and market mechanisms among sectors, creating barriers to full system-level coordination and efficiency.

4.2.3 Knowledge Gaps and Research Directions

Most existing research works explore either single-domain energy system optimization or partially integrated systems with limited cross-sector interactions. Publication 2 emphasizes the need for holistic co-optimization frameworks that can internalize both technical and economic trade-offs across various sectors. Furthermore, it points to a lack of experimental validation and operational models that consider real-world uncertainties in renewable generation, dynamic pricing, and consumption behaviors.

Another notable gap lies in the insufficient integration of digital technologies with physical infrastructure. While tools such as digital twins, real-time monitoring, and predictive analytics are discussed conceptually, few studies implement these features in actual operational models. Moreover, the interoperability challenges between different communication standards and control protocols across energy sectors continue to hinder seamless integration.

The literature also reveals a limited exploration of market mechanisms that incentivize cross-sector integration for flexibility provision. Most energy markets are still structured around single-carrier systems, leading to inefficiencies in valuing and trading flexibility services across electricity, heat, and gas networks.

Addressing these issues requires policy reform, standardized data exchange, and new market designs that can support P2X2P transactions and dynamic pricing in multi-carrier environments. Hence, it is crucial to develop robust co-optimization models, integrate intelligent digital infrastructures, validate system performance under uncertainties, and design transactive energy markets that align with the operational realities of integrated multi-energy systems.

4.3 Modeling and Operation of Sector-Integrated Energy Systems

As a solution to developing robust co-optimization models that enable the validation of integrated energy systems' performance under a wide range of uncertainties, Publication 3 presents an operational model that integrates distributed energy resources (DERs), combined CHP units, P2H units, and HESS composed of battery energy storage systems (BESS), thermal energy storage systems (TESS), and natural

gas energy storage systems (NGESS), within a unified electricity-heat distribution-level energy network. The model aims to reduce total integrated system costs and maximize efficiency through a mixed-integer linear programming (MILP) approach (Detailed formulation in Publication 3) (Liu et al., 2023).

The proposed operational framework co-optimizes the heat and power sectors under realistic constraints such as power and heat balances, gas flow limits, P2H units, including electric heat pumps and electric boilers, CHP units, and HESS operations. In this platform, CHP and P2H units function as the interface between the electricity and thermal networks, while HESS, comprising BESS, TESS, and NGESS, plays a crucial role in temporally shifting energy across these sectors.

Figure 6 provides the schematic structure of the above-defined integrated power-heat network in the presence of varied elements and possible energy flows among them. A full description of the modelling approach, including component-level formulations, technical assumptions, and the numerical input data for generation units, P2X technologies, and loads used in the case study, is provided in more detail in Publication 3.

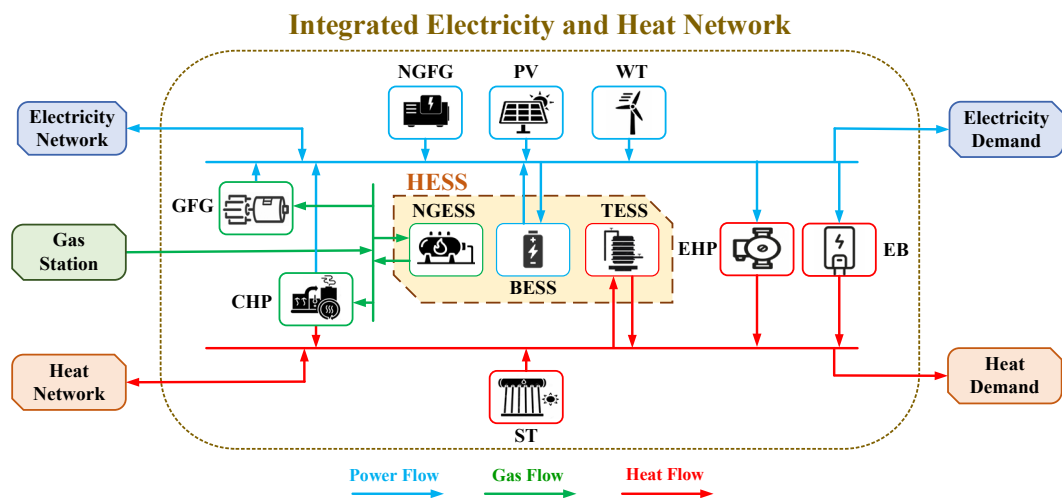


Figure 6. Conceptual Schematic of a Coupled Electricity-Heat Network (From Publication 3).

Overall, sector-integrated energy systems face substantial operational uncertainties due to the variable nature of renewable energy resources, fluctuating electricity and heat demands, and volatile market conditions. Coping with these uncertainties is critical to achieving reliable and efficient system performance. To this end, Publication 3 employs a scenario-based two-stage stochastic programming approach (Dadashi et al., 2022). In this method, key stochastic parameters, i.e., electricity and heat consumption, electricity and heat prices, wind speed, and solar irradiance, are

treated probabilistically. Scenarios representing these uncertainties are generated using Monte Carlo Simulation and reduced to a manageable number through a fast backward/forward scenario reduction algorithm (Haghifam et al., 2020).

In the mentioned two-stage optimization method, two types of decisions are taken: first-stage or here-and-now decisions and second-stage or wait-and-see decisions. Accordingly, in the first stage, the day-ahead exchanges of electricity and heat are determined based on expected values. In the second stage, after the realization of stochastic factors, real-time adjustments are made to minimize imbalance costs using available dispatchable and flexible resources. Accordingly, for the case study in Publication 3, ten reduced scenarios are generated using the above-described stochastic modelling and scenario-reduction technique. These scenarios represent the uncertainty in electricity and heat demands, electricity and heat prices, wind speed, and solar irradiance, and are fully reported in the publication.

This strategy and the proposed platform reduce the curtailment of renewable outputs, enhance grid independence during peak loads, and enable dynamic adjustment of energy flows based on real-time pricing and forecasted demand. Furthermore, this operational synergy ensures system efficiency under real-world variability and significantly boosts overall system flexibility and responsiveness.

4.4 Main Contributions and Findings

Together, Publications 2 and Publication 3 offer both a conceptual and applied foundation for understanding and implementing sector coupling in modern energy systems. The key contribution of Publication 2 lies in framing the broader landscape, clarifying terminology, identifying key technological and regulatory barriers, and setting a research agenda for multi-carrier energy networks.

On the other hand, Publication 3 validates these directions by presenting a quantitative and pragmatic operational model for integrated energy systems. It shows that sector coupling, when supported by HESS and overall P2X2P technologies, significantly enhances energy system flexibility, reduces reliance on external markets, and ensures cost-effective use of renewable, DER, and P2X2P resources.

The key findings of these studies can be summarized as follows:

- First, sector coupling improves system-wide flexibility by enabling various energy flows across electricity and heat networks.

- Second, hybrid energy storage systems, aggregating battery, thermal, and gas storage units, offer an effective means to absorb renewable energy surplus and balance peak demand.
- Third, co-optimization of CHP, P2H, and DER units' operations leads to lower operational costs and reduced reliance on external grid imports.
- Fourth, robust operational models in the integrated systems can handle uncertainties in renewable generation and load profiles by dynamically adjusting storage and generation assets.
- Fifth, the presence of hybrid energy storage systems enables the coupled networks to optimally manage their energy flows, reducing dependence on upstream networks during peak hours and storing low-cost energy for later use. This is illustrated by the exchanged power and heat of the considered system with and without HESS in Figures 7A and 7B, respectively.

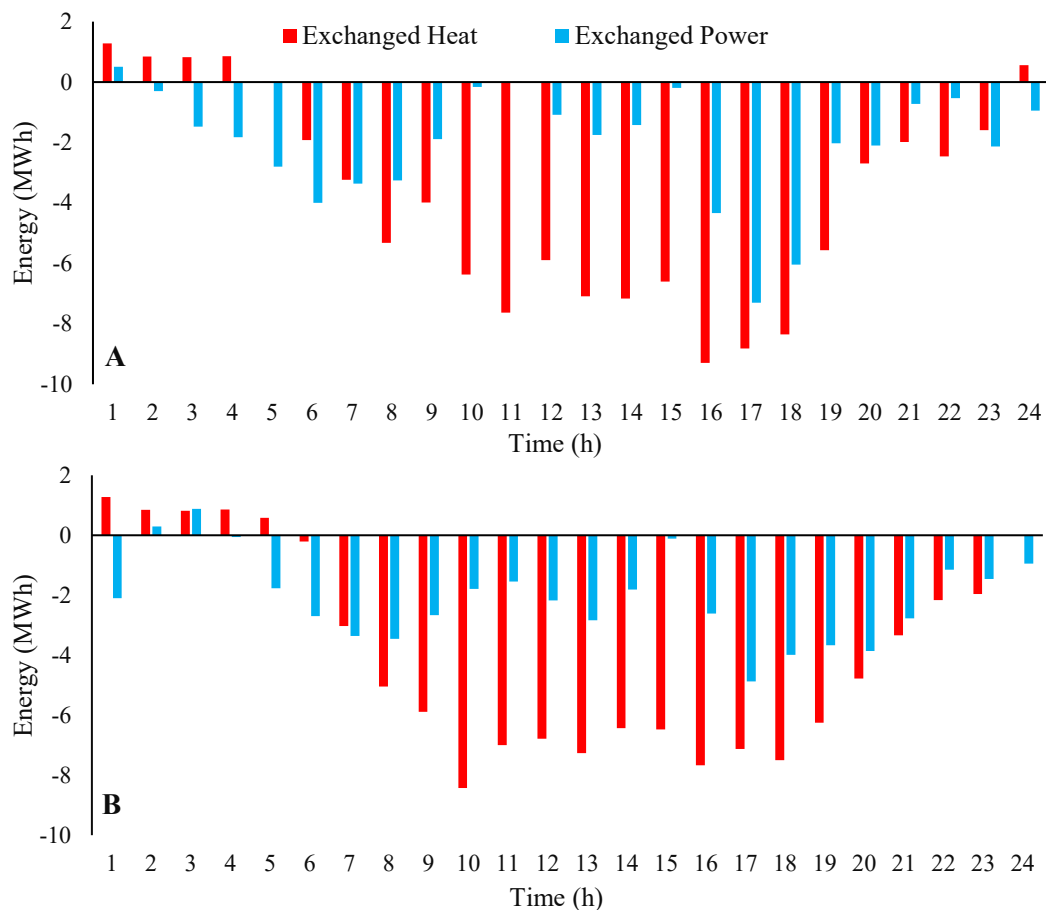


Figure 7. The Impact of HESS on Integrated Energy Systems' Dependence on the Upstream Network (From Publication 3).

- Finally, deployment of HESS, by combining BESS, TESS, and NGESS, improves economic performance and increases expected profit in integrated operational settings. A comparative case study presented in Table 3 demonstrates this matter by evaluating five different configurations, ranging from an integrated energy system without any storage elements to one equipped with all types of storage technologies. The configuration that includes all three types of storage units as a whole HESS achieves the highest profitability, illustrating how storage diversification and sector integration together enhance system value.

Table 3. Expected Profit of Electricity-Heat System in Different Storage Configurations (From Publication 3).

	BESS	TESS	NGESS	Profit (\$/day)	Variation (%)
Case 1 (Base)	✘	✘	✘	5432.76	–
Case 2	✘	✓	✓	6662.69	22.64
Case 3	✓	✘	✓	6773.58	24.68
Case 4	✓	✓	✘	6533.93	20.27
Case 5	✓	✓	✓	7226.5	33.02

In summary, these contributions and findings well emphasize the critical importance of coordinated operation across various energy sectors in achieving a sustainable, resilient, and flexible future energy system.

4.5 Conclusion

This chapter reinforces the thesis's core argument that multi-dimensional energy systems are essential for enhancing system adaptability amid growing RES and DER integration. Rather than viewing sector coupling as merely a structural alignment of energy carriers, it should be seen as a strategic enabler of intelligent coordination across diverse energy resources. The insights gained from both theoretical and applied perspectives show that integrated operation and planning of multi-carrier systems can significantly boost the scalability, efficiency, and resilience of energy infrastructures, laying the groundwork for the advancement of transactive, P2X2P-enabled energy networks.

5 LOCAL MARKET PLATFORMS FOR INTEGRATED ENERGY SYSTEMS

5.1 Introduction and Background

As energy systems continue to evolve toward higher shares of renewable energy sources (RES), achieving flexibility, reliability, and economic viability at the distribution level becomes increasingly critical. These renewable-based systems are inherently variable and uncertain, creating operational challenges for traditional grid infrastructure that was designed for unidirectional power flows and centralized generation (Shahzad & Jasińska, 2024). In this context, integrated energy systems (IES), which couple electricity, heat, and in some instances, gas networks, have emerged as a viable pathway to manage these challenges by enabling energy sector integration and local balancing. By leveraging the synergies between various energy sectors, such as converting electricity surplus to heat through power-to-heat (P2H) units, IES can optimize resource usage and improve the responsiveness of local systems (Faisal & Gao, 2024).

To fully realize the flexibility potential of IES, there is a growing need for robust local market designs that not only facilitate technical coordination but also deliver appropriate economic incentives. These platforms must efficiently manage distributed energy resources (DERs), power-to-X (P2X) technologies, and local energy demand across multiple carriers, including electricity and heat. Beyond technical optimization, local markets play a critical role in translating operational capabilities into value for participants.

The importance of such market platforms is underscored by the increasing complexity of sector-coupled energy systems. Coordinating DERs, combined heat and power (CHP) units, P2H technologies, and storage systems, especially at the distribution level, requires a structured framework that balances network constraints with market participation. A well-functioning local market bridges these domains, enabling active participation of various actors while aligning system operations with decarbonization and energy flexibility objectives.

Despite expanding academic interest and pilot-level implementations of IES, research gaps persist in the design of efficient market mechanisms capable of handling the operational and economic intricacies of multi-carrier energy systems. Existing market designs often operate in silos, focusing on individual energy carriers without accounting for the synergies and interdependencies between electricity and heat networks. Furthermore, most current approaches lack the spatial and temporal resolution needed to capture localized network constraints or to reward flexible

behavior among several units effectively. There is limited work on how local market platforms can simultaneously coordinate electricity and thermal energy flows in a cohesive framework while offering fair, location-specific price signals that incentivize cross-sectoral flexibility and investment.

To address these gaps, the following research questions are posed:

- How can local energy markets facilitate coordinated operation of integrated electricity and heat networks?
- What market mechanisms and pricing strategies best capture the operational complexity of integrated energy systems?
- How can the technical constraints of both electricity and heat distribution systems be managed in an integrated market platform?
- How can market-based mechanisms incentivize the strategic deployment of P2H technologies within integrated electricity and heat networks?
- How does the local market platform facilitate renewable energy integration by addressing variability, uncertainty, and sectoral coordination challenges?

This chapter explores these gaps and questions through insights derived from two complementary publications. Publication 4, entitled ***“A Market-Based Mechanism for Local Energy Trading in Integrated Electricity-Heat Networks,”*** and Publication 5, entitled ***“A local energy market for integrated electricity-heat networks,”*** together provide a comprehensive framework for designing local markets for sector-integrated systems.

These studies advance the concept of local market platforms by moving beyond simplified assumptions, presenting a more practical and scalable framework. They address gaps in coordinating DERs and P2H technologies, while developing pricing mechanisms that internalize the technical and economic constraints of multi-carrier systems.

The development of this chapter is driven by the following foundational statement:

“Integrated energy systems offer a promising solution to enhance flexibility and accommodate more renewable energy resources, supporting decarbonization targets. Designing an appropriate market-based platform that enables efficient cooperation and interaction among various energy carriers at the distribution level is essential to achieving this goal.”

5.2 Conceptual and Structural Framework: Local Market Platform for Sector-Coupled Energy Systems

The implementation of local energy markets (LEnMs) in integrated energy systems requires a well-coordinated interplay between physical infrastructures and market mechanisms. These systems operate at the intersection of power and thermal energy networks, where elements like CHP units, electric boilers (EBs), and electric heat pumps (EHPs) act as mediators between these two sectors. This section introduces both opportunities and challenges, such as optimal energy flow coordination, technical and economic constraint management, and ensuring fair market access for all participants.

A well-designed conceptual framework for LEnMs in IES must not only facilitate energy exchange across different sectors but also support real-time decision-making based on accurate pricing and load conditions. The physical characteristics of the integrated networks, such as thermal inertia in heating systems and voltage constraints in power distribution, must be carefully accounted for in market operations. Moreover, the pricing mechanism must internalize network constraints, generation costs, and cross-sectoral interactions to provide appropriate economic signals.

Figure 8 illustrates the schematic outlook of the proposed local market platform in Publications 4 and 5, depicting the interaction between various DERs, P2Hs, thermal units, and market layers within an integrated electricity and heat distribution system. It highlights how coordination between these resources is managed through centralized market signals and operational constraints. The diagram also showcases the bidirectional flow of both energy and information between different layers. Market players submit bids to the market, while the market sends price and dispatch signals back. The flow of electricity and thermal energy is shown moving toward consumption, while data and control signals circulate between market operators and system assets, enabling dynamic, real-time coordination across the network.

This framework captures the real-time and locational dynamics of energy dispatch, enabling cost minimization and flexibility utilization through market-based coordination. By dynamically matching local supply and demand, the platform not only improves operational efficiency but also enhances system reliability and promotes greater integration of variable renewable energy sources. The design supports transparent and fair access for all market participants, while accommodating the physical constraints of both electricity and heating infrastructures (Pan et al., 2017). Such integration ensures that decisions made at the

market level align with grid operational needs and consumer preferences, fostering a resilient and flexible energy system.

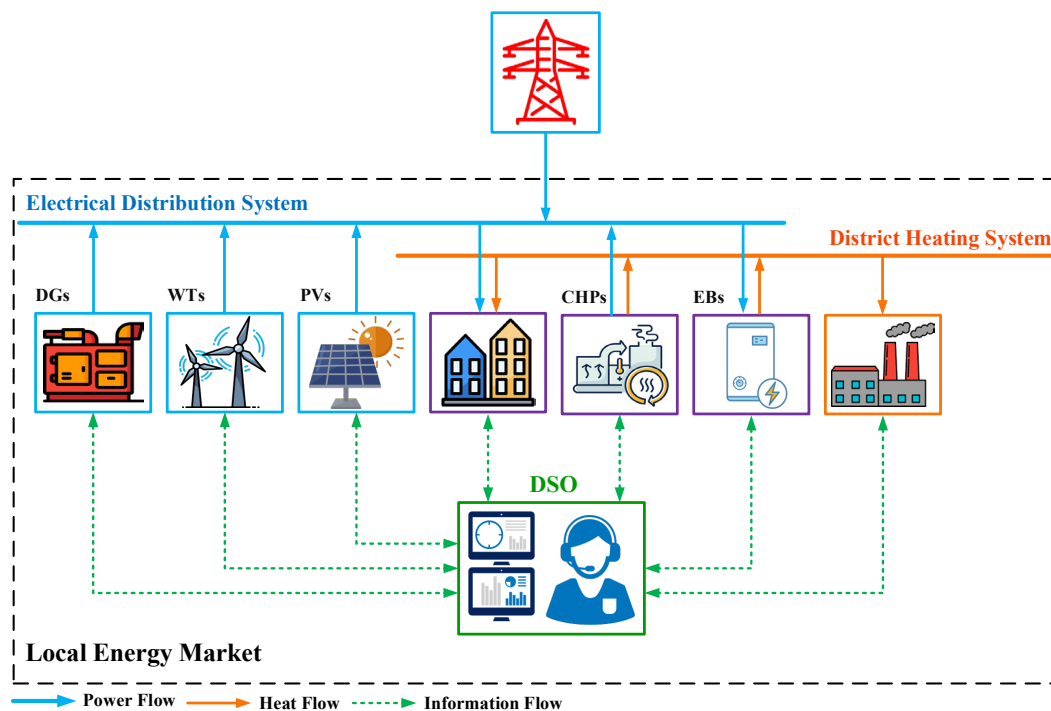


Figure 8. Schematic Structure of a Local Market Platform for the Integrated Energy Systems (From Publication 4).

5.3 Methodological Foundation of the Local Market Platform

The local market platform, developed across Publications 4 and 5, is a centralized, auction-based mechanism in which the distribution system operator (DSO) coordinates DER, CHP, and P2H units, as well as other flexible assets within an integrated electricity and heat distribution system. This centralized clearing mechanism allows the DSO to match local energy supply and demand dynamically, while simultaneously satisfying the physical and operational constraints of both sectors. At its core, the platform is designed as a one-sided auction. Producers submit bids defining the volume and price of electricity or heat they are willing to provide. These bids are processed centrally to determine the most cost-effective dispatch, minimizing system-wide procurement costs while complying with AC power flow constraints for the electricity network (Sepulveda et al., 2024), thermal balance equations for the district heating network (Pařka et al., 2023), and generator-specific operational limitations such as ramp rates and capacities.

A key advancement lies in the application of distribution locational marginal prices (DLMPs), which reflect the marginal cost of delivering an additional unit of electricity or heat to each node in the system. These DLMPs are derived from dual variables in the optimization model and internalize factors such as grid congestion, voltage limits, and sector-coupling interactions, so-called shadow prices. As a result, they offer spatially differentiated pricing signals that better guide market behaviors and operational decisions. This pricing architecture ensures that all power and heat units receive price signals aligned with their true value to the system. It also promotes transparency, fairness, and responsiveness, thus enabling more efficient use of distributed assets while reducing reliance on upstream grids.

The objective of the market-clearing mechanism is to minimize the total cost of energy procurement for the integrated electricity and heating network via selecting the most cost-effective combination of bids (Detailed formulation in Publications 4 and 5). This cost includes contributions from dispatchable assets within the system as well as imports from the upstream grid. The optimization is subject to multiple constraints that reflect the real-world operational conditions:

- AC power flow constraints to ensure the feasible operation of the electrical grid and maintain voltage stability.
- Heat balance constraints within the district heating system, accounting for supply-demand equilibrium across thermal nodes.
- Capacity and ramp rate limits for generators and P2H units, ensuring technical feasibility of dispatch schedules.
- Thermal and voltage limits in the networks, which guarantee that energy delivery does not violate infrastructure capabilities or safety margins.

All in all, the strength of the proposed market platform stems from its ability to integrate the electricity and heat sectors within a unified optimization framework, capturing the interdependencies across energy carriers to support coordinated and flexible operation. By incorporating various energy providers into a centralized market-clearing mechanism, the model optimizes local resource utilization, reduces reliance on upstream grids, and enhances responsiveness to system variability. Additionally, the platform's modular architecture makes it adaptable for future expansions, such as integrating gas or hydrogen networks and applying stochastic optimization methods to handle uncertainties in demands, prices, and renewable outputs. Hence, the proposed platform offers a future-ready solution, adaptable to the evolving needs of decarbonized and flexible energy systems.

To demonstrate the applicability of the proposed sector-coupled local energy market platform, the model is implemented on a representative integrated electricity and heat network, in which a modified 13-node power distribution system is coupled with a test 4-node district heating system through a heat station (HS), as illustrated in Figure 9.

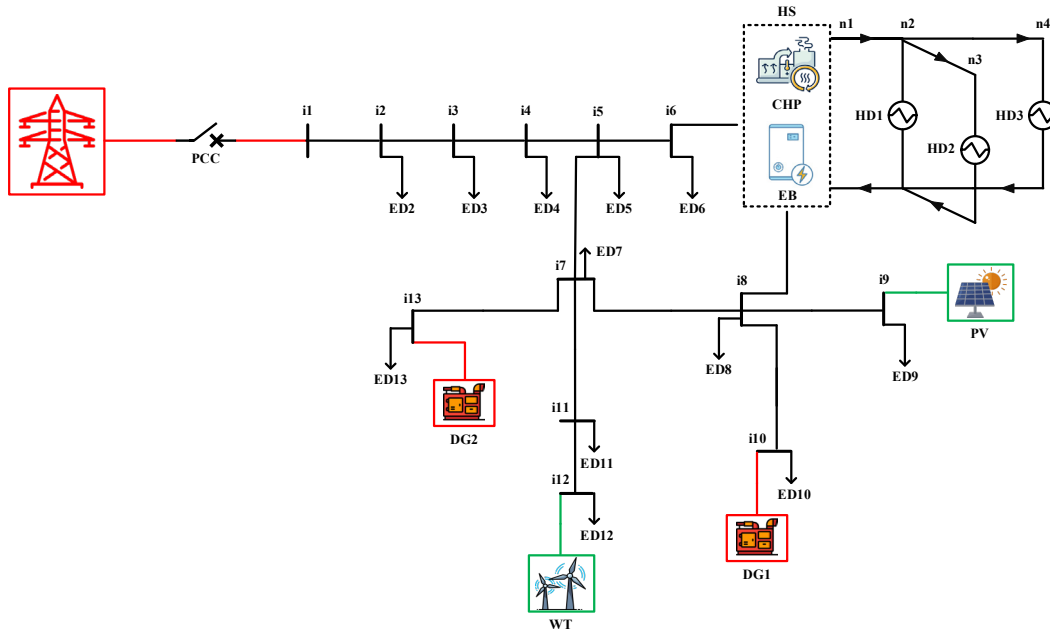


Figure 9. Single-Line Diagram of the Integrated Electricity-Heat System (From Publication 4).

In this case study, all DERs, including renewable generators, dispatchable units, and P2X technologies, are assumed to already exist within the network. Accordingly, the analysis focuses exclusively on the operational performance of these assets within the integrated local market platform, while investment-related aspects remain outside the scope of this work. The test system incorporates key elements, such as the technical specifications of both energy networks, DER locations, maximum quantity offers to the LEnM, P2H units' operating characteristics, and both electrical and thermal demand profiles, ensuring a realistic representation of coordinated sectoral operation. Detailed specifications, modeling assumptions, and the numerical data used to execute the proposed framework are presented in more detail in Publications 4 and 5.

5.4 Main Contributions and Findings

Publications 4 and 5 together provide a coherent and practical framework for designing a local market platform capable of coordinating integrated electricity and

heat systems. A major contribution lies in the development of a centralized market structure that enables the DSO to act as a coordinator, aligning operational decisions with real-time economic incentives across different energy carriers. This structure supports coordinated dispatch of DERs, CHP units, P2H assets, and various storage technologies, enabling cost-effective and efficient energy system management.

On the other hand, the distribution locational marginal pricing mechanism is utilized for the designed local market platform, which provides price signals for both power and heat-based units. This mechanism internalizes network constraints, offering more accurate and equitable incentives for market participants. Furthermore, the platform is designed to be scalable and modular, capable of extending to more complex configurations, involving gas and hydrogen, making it adaptable for future energy transitions.

The primary findings of the research work are listed as follows:

- First, coordinated market clearing between the electricity and heat sectors results in a significant reduction in total system operation costs by optimizing local generation and consumption patterns.
- Second, the market-based local platform achieves higher acceptance of low-cost renewable energy bids, demonstrating its capacity to accommodate more variable renewable sources without curtailment. Based on Figure 10, the maximum quantity offers of wind turbines and photovoltaic units of the system are fully accepted in the LEnM clearing process, reflecting the platform's effectiveness in prioritizing renewable generation. This observation is further supported by the operational data and the corresponding figures and tables provided in Publications 4 and 5.

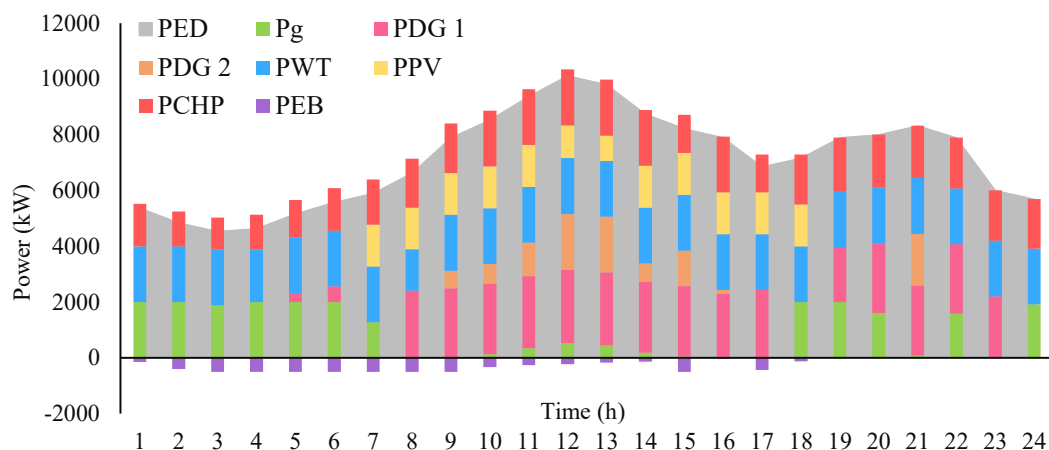


Figure 10. Optimal Operating Points of Power Resources Participating in the Local Integrated Energy Market (From Publication 4).

- Third, the presence of CHP and P2H elements enables the system to respond more effectively to peak loads, particularly when thermal demand is high, thereby showcasing improved load-following capability.
- Fourth, DLMP-based pricing leads to more balanced and economically efficient dispatch outcomes by respecting localized grid constraints. This is exemplified in Figure 11, which illustrates the temporal and spatial variations of electricity DLMPs within the local market-clearing process. The temporal analysis shows that as electricity demand increases, the DLMP rises accordingly, reflecting higher marginal procurement costs. Spatially, the figure reveals that peak-hour consumption leads to congestion in certain parts of the distribution network, resulting in differentiated DLMPs across system nodes. These localized price signals enable more accurate and equitable dispatch decisions, supporting the operational efficiency of incorporated energy systems.

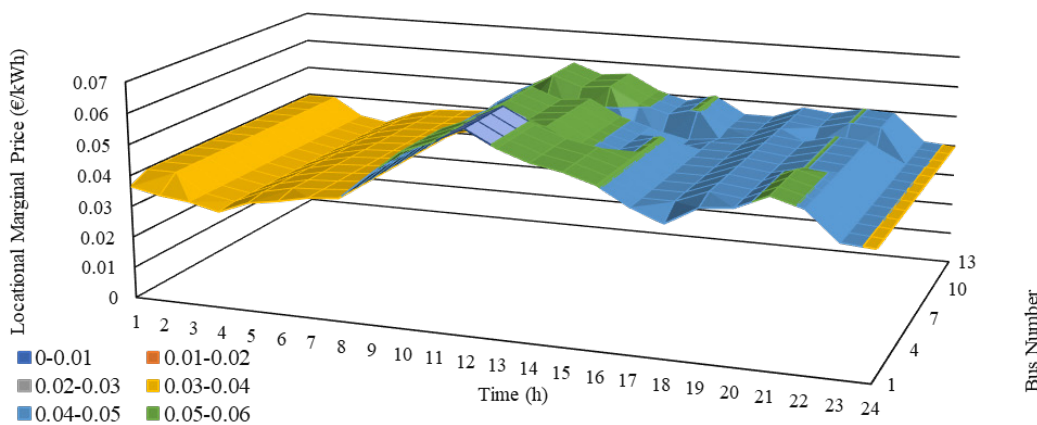


Figure 11. Variation of Distribution Locational Marginal Price of Electricity (From Publication 4).

- Finally, P2H technologies are able to shift thermal loads in response to electricity price signals, effectively managing peak demand and improving reliability.

Collectively, these findings highlight the value of a coordinated market-based platform in operating sector-coupled energy systems, reinforcing their role in advancing decarbonization goals and enhancing system flexibility in future energy networks.

5.5 Conclusion

Building on the local electricity market principles discussed in Chapter 3 and the operational integration of energy carriers explored in Chapter 4, this chapter introduces a pragmatic local market framework tailored for sector-coupled energy systems. It moves beyond single-sector optimization by enabling coordinated, market-based interactions between electricity and heat networks. This directly advances the core thesis objective of developing P2X2P-enabling market structures that promote system flexibility, operational efficiency, and active participation of DERs. Through a centralized market-clearing mechanism and cross-sector coordination, the proposed platform improves local system adaptability while aligning with broader decarbonization and resilience targets.

6 COORDINATING LOCAL INTEGRATED ENERGY MARKETS WITH THE WHOLESALE ELECTRICITY MARKET

6.1 Introduction and Background

The growing integration of renewable energy sources (RES) and the increasing electrification of industrial as well as heating sectors have elevated the importance of flexible, resilient, and efficient energy systems. Local integrated energy markets offer a promising solution to coordinate a wide range of distributed energy resources (DERs), enhance the operational flexibility of energy networks, and improve the utilization of power-to-X (P2X) technologies. These kinds of platforms enable local prosumers and flexible units to exchange electricity and heat within a coordinated, market-based framework, supporting the broader energy transition by facilitating decarbonization and decentralization at the distribution level (Khaskheli & Anvari-Moghaddam, 2024). Beyond providing localized energy balancing, local integrated markets serve as intelligent control layers that dynamically optimize supply and demand across multiple energy sectors, especially in response to variability introduced by intermittent renewable generation. Their ability to unlock and monetize the flexibility of small and medium-scale, distributed assets is essential for maintaining grid stability and achieving system-wide efficiency as the energy landscape becomes more decentralized and complex (Doepfert et al., 2025).

However, most provided local integrated market platforms are scheduled and operated without incorporating strategic signals or pricing mechanisms from upstream networks, particularly wholesale electricity markets. This kind of disconnection in local markets' decision-making processes leads to systemic inefficiencies by overlooking the potential benefits of coordinated market integration, such as optimized resource dispatch, improved price alignment, and more effective flexibility sharing between local and wholesale levels (Menci et al., 2025). In a decarbonized future where distributed and centralized resources must operate in harmony, insufficient coordination between local and wholesale markets risks underutilizing local flexibility, generating conflicting dispatch signals, impairing system balancing, and ultimately increasing overall operational costs. These risks are particularly acute when considering the volatility of RES and the increasing need for fast-reacting, flexible assets across energy sectors.

As a result, despite growing academic and practical interest in local market design, substantial research gaps remain. Much of the existing literature concentrates on intra-sector coordination, primarily within electricity networks, or short-term

operational optimization, often neglecting the structural and economic interactions between local markets and the wholesale electricity market. This has led to a shortage of structured local market designs capable of enabling seamless coordination and bidirectional exchange of energy and price signals with the wholesale levels, particularly in ways that capture the interdependencies between electricity and heat networks at the distribution level. Furthermore, existing frameworks often fail to adequately capture the role of local prosumers' participants in supporting system-wide objectives such as congestion management, grid balancing, and RES integration. Therefore, it is essential to develop a local integrated market architecture that incorporates wholesale market dynamics into its operational decisions.

Moreover, the growing adoption of P2X technologies, particularly power-to-heat (P2H), alongside other flexible assets in local market platforms, underscores the need for integration strategies that recognize their operational value across both local and wholesale levels. In the absence of coordinated market structures, these technologies risk being underutilized or misaligned with broader system objectives. Effective frameworks must support cross-layer optimization and offer economic incentives that reflect upstream grid constraints, ensuring that flexible resources are deployed strategically to enhance overall system efficiency, reliability, and progress toward decarbonization.

To address the mentioned gaps, the following research questions are posed:

- What are the operational and economic benefits of coordinating local integrated energy markets with the wholesale electricity market?
- How can local integrated electricity and heat markets be structured to effectively interact with the wholesale electricity market?
- How can local DER and P2X technologies be effectively aligned and optimized across energy markets to support system-wide goals, including congestion management, balancing, and increased RES integration?
- How can price signals from the wholesale market be transmitted and reflected within local market operations?

This chapter investigates these gaps and questions through insights derived from the study presented in Publication 6, entitled "***Design of an auction-based local energy market for integrated electricity and heat networks coordinated with wholesale market***". The publication provides a multi-layered market outline where a local integrated energy market interfaces with the wholesale electricity market through coordinated pricing and optimized resource allocation. It introduces a hierarchical

bidding and clearing mechanism that not only facilitates joint dispatch of interconnected electricity and heat distribution networks but also ensures consistency in market signals across both local and wholesale levels.

The development of this study and this chapter is guided by the following research statement:

“The integration of electricity and heat networks via local energy markets improves distribution-level resiliency and flexibility, while coordination with wholesale markets not only strengthens overall grid performance and system-wide efficiency but also enables more efficient P2X2P resource utilization.”

6.2 The Proposed Conceptual and Methodological Framework

To effectively bridge the operational gap between local integrated energy markets and the wholesale electricity market, a robust and coordinated framework is required. Such a structure must extend beyond isolated control of local assets and instead enable dynamic interaction across energy carriers and market layers. Particularly in coupled electricity and heat systems, the framework should accommodate the physical interdependencies of the networks, facilitate coherent dispatch strategies, and allow for real-time responsiveness to changing system conditions. In this context, an effective market structure must integrate distributed flexibility resources, reflect wholesale price signals at the local level, and support bidirectional exchanges that align local operations with broader system objectives.

Building on this need, the framework proposed in Publication 6 introduces a structured decision-making process for local market operators to enable seamless coordination between local integrated energy markets and the wholesale electricity market. At the core of this model is the local integrated market operator, which acts as an intermediary entity linking the electricity and heat sectors, specifically DERs, P2H units, and other local flexible assets. The local market-clearing objective is to maximize social welfare, defined as the net economic benefit to market participants. This is calculated as the difference between the total utility or willingness to pay of buyers and the costs of sellers, including the economic effects of energy exchanged with the wholesale electricity market, while respecting local network and technical constraints. In this framework, social welfare is maximized not only to meet the integrated electricity and heat system demands under the technical constraints of both the electric distribution and district heating networks, but also to coordinate with the wholesale electricity market by aligning local dispatch decisions with upstream price signals and system conditions. In practice, the integrated market

operator collects bids from local participants, co-optimizes their dispatch based on local network constraints and cross-sectoral synergies, and then aggregates the net position for interaction with the wholesale electricity market. The formulation and optimization approach are provided in more detail in Publication 6.

Through the considered outline, the integrated market operator ensures that local energy market operations remain closely coupled with the upstream grid dynamics. In this regard, all power and heat market participants submit their bids and offers to the local market operator, who co-optimizes dispatch decisions while considering sectoral interdependencies as well as power and heat networks constraints. Importantly, this operator engages directly with the wholesale electricity market by translating the local integrated market's collective demand and supply into corresponding offers and bids. Once the wholesale market is cleared at the transmission system operator (TSO) level, taking into account overall social welfare and technical constraints, the resulting market outcomes, including updated prices and allocations, are communicated to the local market operator, who adjusts dispatch and pricing decisions accordingly. This bidirectional coordination ensures that local markets function in synchrony with transmission-level operations, enabling them to influence and respond to wholesale signals. As a result, the framework effectively aligns operational and economic objectives across both levels, leverages the physical coupling between electricity and heat systems, and enhances flexibility, cost-efficiency, and overall system resilience.

In summary, the proposed hierarchical architecture operates through two coordinated layers, as follows:

- **Local Integrated Market Layer:** In this layer, DERs, P2H technologies, and other local flexible assets submit their bids and offers to the integrated energy system operator (IESO). Then this market operator performs a co-optimization of electricity and heat dispatch while respecting local network constraints and sectoral interdependencies.
- **Wholesale Market Layer:** The integrated market operator aggregates the local market's net position and submits corresponding bids and offers to the wholesale market. Upon this market clearing, the accepted offers and bids are communicated back to the local layer. These signals are then used to adjust local dispatch schedules, ensuring alignment between the upstream grid and the local system.

To mathematically capture the interaction between local and wholesale market layers, the proposed hierarchical structure adopts a bi-level programming approach, modeling both the local integrated energy market and the wholesale electricity

market as interrelated optimization problems. The upper-level problem represents the local market-clearing process, which co-optimizes electricity and heat dispatch, while the lower-level problem models the wholesale market-clearing process. Both levels aim to maximize social welfare while respecting the technical constraints of the distribution power network, the district heating network, and the transmission system (Detailed formulation in Publication 6). To solve this optimization problem, the bi-level problem is reformulated into a single-level model using Karush-Kuhn-Tucker (KKT) conditions, the Strong Duality theorem, and the Big-M method, enabling tractable co-optimization of multi-layer market operations. Figure 12 illustrates the conceptual structure of this problem.

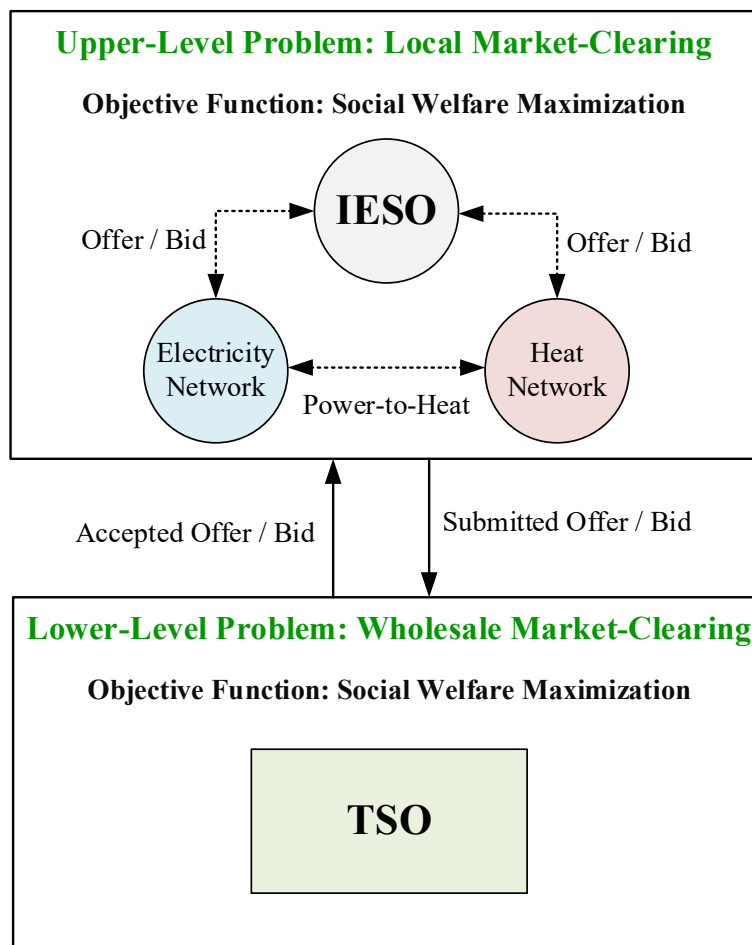


Figure 12. Schematic of the Bi-Level Model for Coordinating Local Integrated Energy and Wholesale Electricity Markets (From Publication 6). This figure has been reproduced with permission from The IET, 2023.

Overall, a key strength of this hierarchical structure lies in its ability to prioritize local flexibility while maintaining active coordination with the upstream grid and wholesale market dynamics. Rather than operating in isolation, the local integrated

market remains responsive to real-time wholesale price signals, allowing dynamic adjustment of bids and dispatch decisions across time and space. This two-way interaction enables local DERs and P2X technologies to respond not only to local grid conditions but also to broader system requirements, facilitating strategies like load shifting and surplus renewable absorption. By aggregating local market behaviors and feeding them into the wholesale market, while simultaneously incorporating upstream outcomes into local dispatch and pricing, the integrated market operator facilitates a continuous, bidirectional cycle of economic and operational optimization. This approach ensures both local and system-wide constraints are respected, enhances transparency through locational pricing, and promotes efficient dispatch decisions across market layers. Ultimately, the structure supports economic viability, improved resource utilization, and alignment with long-term decarbonization and flexibility objectives.

To demonstrate the functionality of the proposed local integrated energy market and its coordination with the wholesale electricity market, the model is implemented on a representative energy system, consisting of a 6-node electric transmission network, a 13-node electric distribution network, and a 4-node district heating system. The topology of the studied system is illustrated in Figure 13.

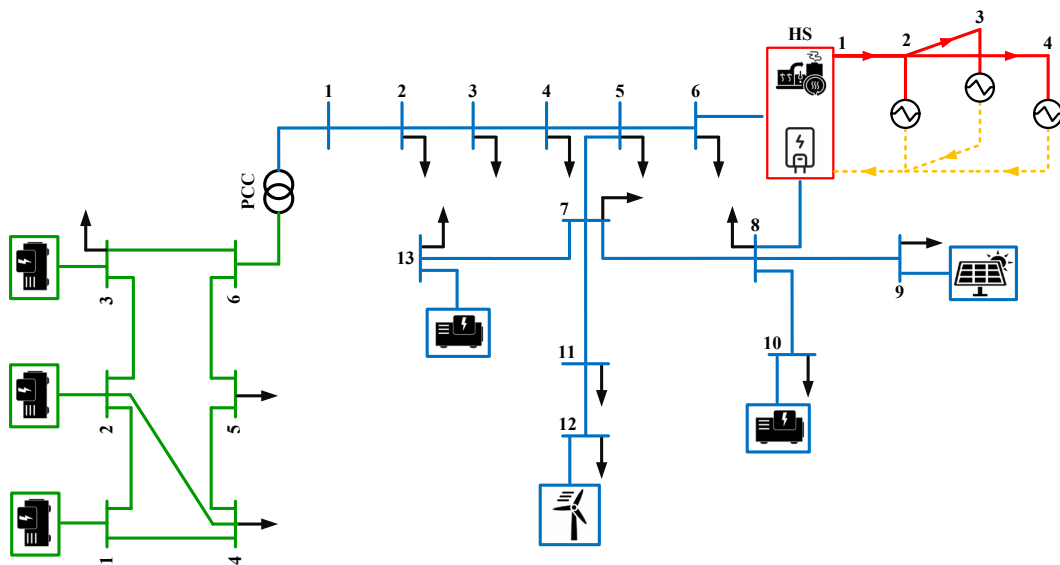


Figure 13. Single-Line Diagram of the Studied Integrated Energy System (From Publication 6). This figure has been reproduced with permission from The IET, 2023.

The transmission network includes several conventional producers, while the distribution system hosts a mix of dispatchable generators and renewable units. The district heating system is coupled to the electricity network via a heat station equipped with both CHP and EB units. Maximum offer and bid quantities, market offer prices, as well as electric and thermal demand profiles used in the simulations are detailed in the corresponding publication (Publication 6), along with all technical assumptions and system data required to execute the model. Consistent with the approach in previous chapters, all DERs and P2X units are assumed to pre-exist in the system; therefore, investment planning is not considered, and the analysis focuses solely on their operational performance and market interactions within the proposed framework.

6.3 Main Contributions and Findings

The study in Publication 6 delivers a major advancement by proposing a hierarchical framework that effectively bridges local integrated electricity-heat markets and the wholesale electricity market. Unlike conventional models that treat local and wholesale markets in isolation, the presented framework adopts a coordinated, bi-level optimization problem that allows seamless interaction between local and system-wide market layers. At the upper level, the integrated market operator manages the local market-clearing process by co-optimizing electricity and heat dispatch from DERs and P2H units under power distribution and district heating network constraints. At the lower level, i.e., the TSO level, the market operator clears the wholesale electricity market by maximizing social welfare while respecting upstream network constraints.

By enabling the integrated market operator to aggregate local bids and offers and engage directly with the wholesale market, this model supports bidirectional price and dispatch coordination, ensuring that local system operations are not only optimized internally but also aligned with upstream grid conditions and economic signals. This architecture promotes multiple benefits: it enhances the utilization of local flexibility, reduces operational costs through optimized dispatch, improves renewable energy integration by accommodating variability, and supports decarbonization goals. Moreover, the transparent and modular structure of the model makes it highly scalable, adaptable to various network sizes, and extensible to include additional sectors such as hydrogen.

The major findings derived from this study include:

- First, the coordinated clearing process between local integrated and wholesale markets leads to a reduction in total energy procurement costs. By

prioritizing local flexibility before resorting to more expensive wholesale transactions, the framework maximizes cost-effectiveness while ensuring secure operation.

- Second, the framework facilitates better integration of variable renewable energy by leveraging P2H units and other flexible resources for temporal and spatial load shifting. This flexibility reduces renewable curtailment and supports the decarbonization targets of future energy systems.
- Third, P2H units, particularly Electric Boilers (EBs), act as controllable and responsive assets that react dynamically to electricity market prices. As shown in Figure 14 and determined in the conducted case study, during periods of low electricity prices, EBs convert surplus electricity into heat, effectively shifting electric load and meeting peak heat demands later in the day. When electricity prices rise, combined heat and power (CHP) units take over the heat supply, illustrating the complementary operation between P2H and CHP assets. This operational flexibility enhances both peak shaving and load balancing across the electricity and heat sectors. These outcomes are further supported by the operational data and corresponding figures and tables presented in Publication 6.

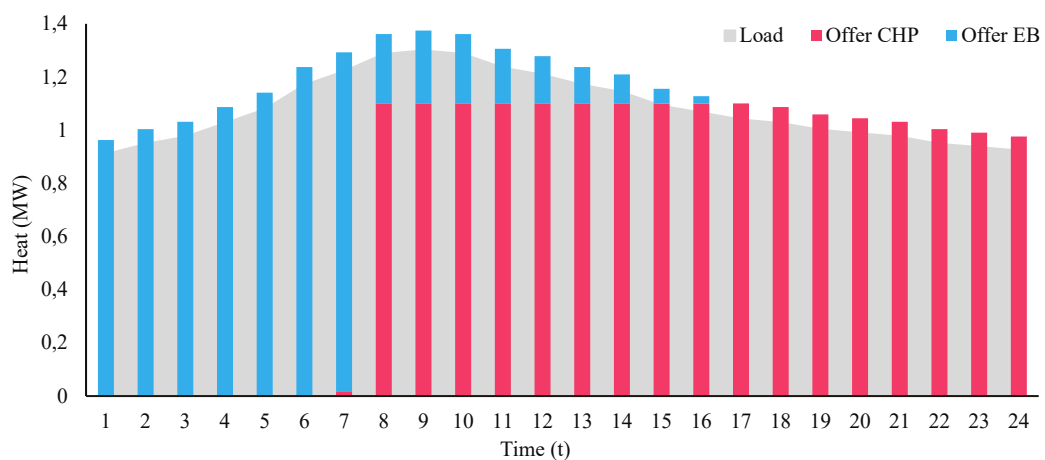


Figure 14. Schematic of the Bi-Level Model for Coordinating Local Integrated Energy and Wholesale Electricity Markets (From Publication 6). This figure has been reproduced with permission from The IET, 2023.

- Fourth, embedding wholesale market signals into local dispatch decisions ensures that distributed resources operate in alignment with system-wide marginal costs. This leads to improved economic efficiency, transparency, and more accurate price formation at the local energy system level.

- Fifth, the hierarchical framework demonstrates scalability across different system sizes and is flexible enough to accommodate additional energy sectors such as gas and hydrogen. This makes it a suitable solution for future integrated energy systems with more complex multi-carrier interactions.
- Finally, the model enables all market participants, including DERs and P2X assets, to access locationally and temporally granular price signals that reflect both upstream wholesale dynamics and local network conditions. This facilitates more informed and equitable participation, increases market liquidity, and improves economic transparency at the distribution level. Figure 15 illustrates the spatiotemporal electricity price variation in the local integrated market across different nodes and hours. The observed pricing patterns are shaped by a combination of local network constraints, nodal demand-supply imbalances, and price feedback from the wholesale market. The figure illustrates how the proposed hierarchical coordination mechanism produces location- and time-sensitive price signals, ensuring that local market actions are efficiently aligned with overall system conditions and upstream grid signals.

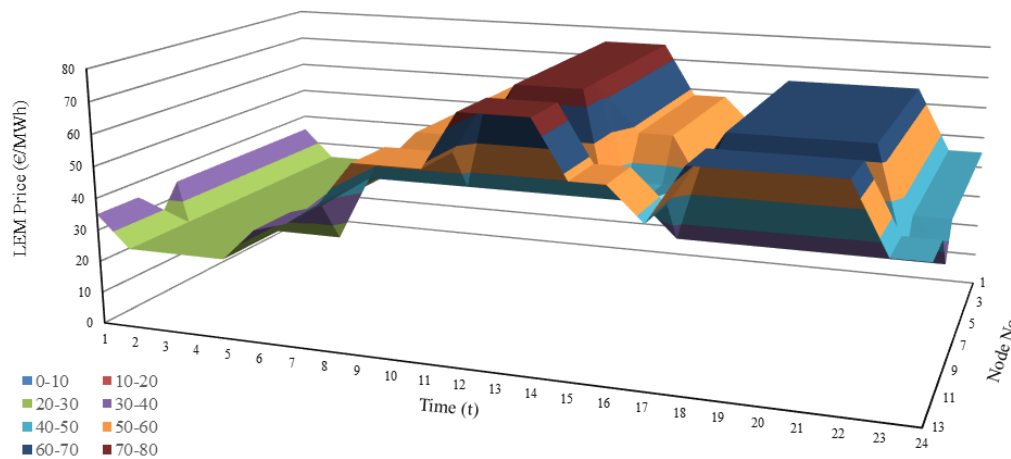


Figure 15. Temporal and Spatial Variation in Electricity Prices of the Integrated Local Market (From Publication 6). This figure has been reproduced with permission from The IET, 2023.

Together, these results highlight the essential role of coordinated, multi-layered market architectures in managing sector-coupled energy systems. By bridging local flexibility with system-wide requirements, the proposed architecture enables a more robust, low-carbon, and cost-effective energy landscape.

6.4 Conclusion

This chapter introduces a hierarchical framework that systematically coordinates local integrated electricity and heat markets with the wholesale electricity market. By involvement of local integrated market operators, the proposed structure enables bi-directional price and dispatch coordination across energy carriers and market layers. This integration ensures that DERs, P2H, and other P2X technologies are co-optimized not only within local incorporated networks but also in alignment with upstream market dynamics and system-wide objectives. By embedding wholesale electricity prices into local market operations and aggregating net positions for participation in the wholesale market, the framework enhances both operational efficiency and economic transparency. It allows for strategic utilization of local flexibility, reduces curtailment of renewable generation, and improves system-wide social welfare outcomes. The bi-level optimization model adopted in the framework mathematically captures the interaction between local and wholesale layers while respecting the technical constraints of electric distribution, district heating, and transmission networks. Building on the foundations laid in previous chapters, this chapter contributes a scalable market design that strengthens P2X2P integration and supports the thesis goal of enabling flexible, decarbonized, and economically robust energy systems through coordinated multi-layer energy market architectures.

7 OPTIMAL PARTICIPATION STRATEGIES FOR VARIOUS ENTITIES IN LOCAL ENERGY MARKETS

7.1 Introduction and Background

The rapid transformation of energy systems, driven by decentralization, digitalization, and decarbonization, has led to the emergence of local energy market (LEnM) frameworks as a vital component of future grid architectures. These markets are designed to facilitate the coordination and transaction of energy among distributed energy resources (DERs), flexible demand, and prosumers at the distribution level. By enabling peer-to-peer trading, local balancing, and sector coupling, LEnMs support the integration of renewable energy, power-to-X (P2X) technologies, enhance grid flexibility, and improve overall system efficiency. However, as these markets become more sophisticated, particularly through the inclusion of multiple energy sectors such as electricity, heat, and gas, they face growing challenges in market design, pricing and clearing mechanisms, and operational coordination among sectors (Farsani et al., 2023). The inherent variability of renewable generation, the interdependency between sectors, and the limited visibility of local network constraints make optimal market operation complex. In such an environment, the economic and technical viability of local markets hinges on the active and strategic participation of local actors. Therefore, beyond designing the market architecture itself, it becomes essential to equip DER owners, aggregators, and multi-energy entities, e.g., energy hubs, with robust offering strategies. These strategies must account for uncertainties, market dynamics, and the competitive behavior of other market participants, ensuring that local assets can be efficiently dispatched and fairly compensated within the local market framework.

In the evolving landscape of local energy markets, key participants such as aggregators and energy hubs play a growing role in enhancing system flexibility and facilitating market-driven coordination. Aggregators primarily focus on the optimal operation and participation of various DERs, aiming to maximize their profit within local electricity markets. Similarly, energy hub operators manage integrated multi-energy systems, spanning electricity, heat, and potentially gas, making them key enablers of sector coupling and cross-sector optimization within local market platforms (Papadimitriou et al., 2023). These actors act as critical interfaces between local assets and market structures, aiming to align operational behavior with economic incentives. However, their effective participation is challenged by factors such as market price volatility, physical and regulatory constraints, sectoral interdependencies, and the strategic actions of competing players. As local markets become increasingly decentralized and integrated across multiple energy sectors, the

need for robust offering strategies becomes critical. These strategies must combine predictive insights into market behavior with the capacity to account for system constraints, manage uncertainties, and adapt to the strategic actions of competing participants.

While previous chapters focused on the structural design of local electricity as well as integrated electricity-heat markets and their coordination with wholesale layers, a crucial gap remains in understanding the strategic behavior of local market participants, especially those that act as price-maker entities in these platforms. Specifically, there are limited research studies on how DER aggregators and energy hubs, as active, strategic participants, can formulate optimal offering strategies in environments characterized by uncertainty, sectoral coupling, and competition. Many existing studies either assume idealized market conditions, such as perfect competition and price-taking behavior, or overlook key complexities, including stochastic bidding of rivals, the potential influence of participants on local price formation, i.e., market power, and the physical constraints imposed by electricity distribution and district heating networks. This simplification fails to reflect real-world conditions, where such actors must account for stochastic renewable generation, demand fluctuations, interdependent electricity and heat systems, and the stochastic actions of competitors. As a result, there is a growing need for methodological frameworks that enable price-maker entities to make informed, robust, and adaptive decisions in local market platforms.

To address these issues, this chapter explores the following research questions:

- How can DER aggregators optimally participate in local electricity markets under uncertainty and in the presence of competitors?
- How can energy hubs co-optimize electricity and heat dispatch while strategically participating in local integrated markets?
- What modeling approaches enable strategic bidding behavior that accounts for price fluctuations and network constraints?
- What are the impacts of market uncertainties on the decision-making process of DER aggregators and energy hubs?
- In what ways can risk-aware and stochastic programming methods support optimal local market engagement by DERs and P2X technologies?

To address these research gaps, this chapter explores how DER aggregators and energy hubs can develop optimal participation strategies in local electricity and integrated electricity-heat markets. The focus is on enhancing both individual

profitability and overall market efficiency in the face of uncertainty, competition, and physical system constraints. This investigation draws on insights from two complementary studies: Publication 7, entitled *“A Strategic Offering Model for DER Aggregators in Local Electricity Markets under Uncertainty”*, and Publication 8, entitled *“Optimal Bidding Strategy for Energy Hubs in Local Integrated Electricity-Heat Markets”*. Together, these research works provide a comprehensive perspective on how different types of local market participants, ranging from aggregators operating in single-energy-sector markets to multi-energy entities operating in sector-coupled markets, can formulate strategic, system-aware bidding strategies suited to increasingly complex local energy market environments.

The investigation in this chapter is driven by the following research statement:

“The optimal participation of DERs and P2X technologies in local energy markets requires the development of robust, uncertainty-aware decision-making frameworks that enhance the profitability of market participants while considering market competition, inter-sectoral interactions, and the operational constraints of energy systems.”

7.2 Offering Strategy of DER Aggregators in Local Electricity Markets: Conceptual and Methodological Insights

7.2.1 Overview and Problem Context

DER aggregators have emerged as key players in the evolving electricity market landscape, serving as intermediaries that consolidate the capacity of decentralized power resources, such as renewables, batteries, electric vehicles, and responsive loads, and strategically offer this aggregated capacity into structured energy markets. By pooling and managing these distributed assets, DER aggregators not only enable broader participation of small- and medium-scale producers in electricity trading, but also contribute to enhanced grid flexibility, operational efficiency, and system resilience (Gao et al., 2021).

While DER aggregators are traditionally able to participate in wholesale electricity markets, their growing involvement in local electricity markets presents new opportunities for addressing distribution-level challenges such as congestion management, local balancing, and more renewable integration. Within these localized platforms, DER aggregators face the need to make more content-aware and proactive decisions, including optimal offer prices and volumes, amid various uncertainties in

their decision-making process. When participating as strategic, price-maker entities rather than passive price-takers, aggregators can influence local market outcomes, particularly in smaller systems where their aggregated bid volumes represent a substantial share of total supply. This strategic role introduces both opportunities for enhanced profitability and challenges related to anticipating competitive behaviors, respecting grid constraints, and adapting to dynamic market conditions.

To address the complexities of aggregator participation in emerging local electricity markets, Publication 7 proposes a novel offering strategy that captures the strategic behavior of DER aggregators operating as active market participants. This contribution is particularly significant as it extends beyond conventional aggregator roles by enabling coordinated participation in both local and wholesale electricity markets. The framework considers aggregators as influential market actors whose bids can impact local price formation, especially in distribution-level markets with limited competition or constrained infrastructure. To capture this reality, a decision-making model is developed in which the aggregator strategically determines its offer volumes and prices in anticipation of competitor actions and prevailing market conditions. Moreover, the proposed framework introduces a dual-market participation structure, allowing the aggregator to intelligently allocate its resources between the local and wholesale markets while accounting for operational limitations, inter-market dynamics, and uncertainties in their decision procedure. This strategy not only supports individual profit maximization but also contributes to broader market efficiency by better aligning DER operations with system-wide objectives.

7.2.2 The Proposed Methodological Framework

As noted earlier, the primary aim of this research is to investigate the optimal offering strategy of DER aggregators, considering their dual roles as price-maker players in local electricity markets and price-taker players in wholesale electricity markets. In this context, an independent financial entity, acting as the aggregator, combines a diverse portfolio of DERs located at the distribution level to enable more effective and coordinated participation across both market layers. Accordingly, several real and virtual DERs collaborate as a coalition, enabling them not only to trade energy internally but also to address excess generation or shortages through simultaneous participation in considered markets. With substantial aggregated generation and storage capacities, the aggregator gains the ability to exercise a degree of market power, positioning itself as a strategic player in the local market.

The offering strategy of the DER aggregator is formulated as a bi-level stochastic optimization model to capture the hierarchical decision-making process between the

aggregator and the local market operator, i.e., the distribution system operator (DSO). At the upper level, the aggregator determines its optimal offers in both the local and wholesale markets, while at the lower level, the DSO clears the local market in the presence of other non-strategic competitors (Detailed formulation in Publication 7). This formulation adopts a Stackelberg game-theoretic structure, in which the DER aggregator acts as the leader, able to exercise local market power, while other participants behave as non-strategic followers. Modeling the aggregator as a price-maker enables it to influence local market-clearing prices to its advantage by strategically adjusting submitted offers and bids. Furthermore, allowing the aggregator to participate simultaneously in both markets enhances its flexibility and expands the scope for profit-maximizing decisions.

On the other hand, to address the stochastic nature of uncertain variables, such as market prices, wind speed, and solar irradiance, a scenario-based two-stage stochastic programming framework is employed. In the first stage, the DER aggregator determines its accepted offers in the day-ahead markets along with the operating points of dispatchable generators within the coalition. In the second stage, once the random parameters are realized, the model specifies the aggregator's traded power in the real-time markets, the upward and downward adjustment of dispatchable units, and the charging or discharging schedules of storage systems. This structure enables the aggregator to make forward-looking day-ahead commitments while retaining the flexibility to adapt to real-time conditions. To this end, a high number of scenarios are generated by the Monte Carlo simulation technique and reduced to an adequate number by utilizing the fast backward/forward scenario reduction algorithm. In Publication 7, a total of ten reduced scenarios are generated to capture the variability in solar irradiance, wind speed, and day-ahead and real-time energy prices. These scenarios are demonstrated in the publication.

The overall structure of the proposed scheme for the DER aggregator's offering strategy in both electricity markets is illustrated in Figure 16. At the upper level, the objective is to maximize the aggregator's expected profit using a two-stage stochastic optimization framework. The lower level represents the local market-clearing process, executed by the DSO, to maximize social welfare, defined as the net economic benefit to local market participants. This is calculated as the difference between the utility of local market buyers and the costs of local sellers, while respecting a set of technical and operational constraints. This hierarchical setup clearly distinguishes the aggregator's strategic decision-making from the market operator's neutral role in coordinating an efficient and fair market outcome. The proposed methodology and its detailed formulations are presented in Publication 7.

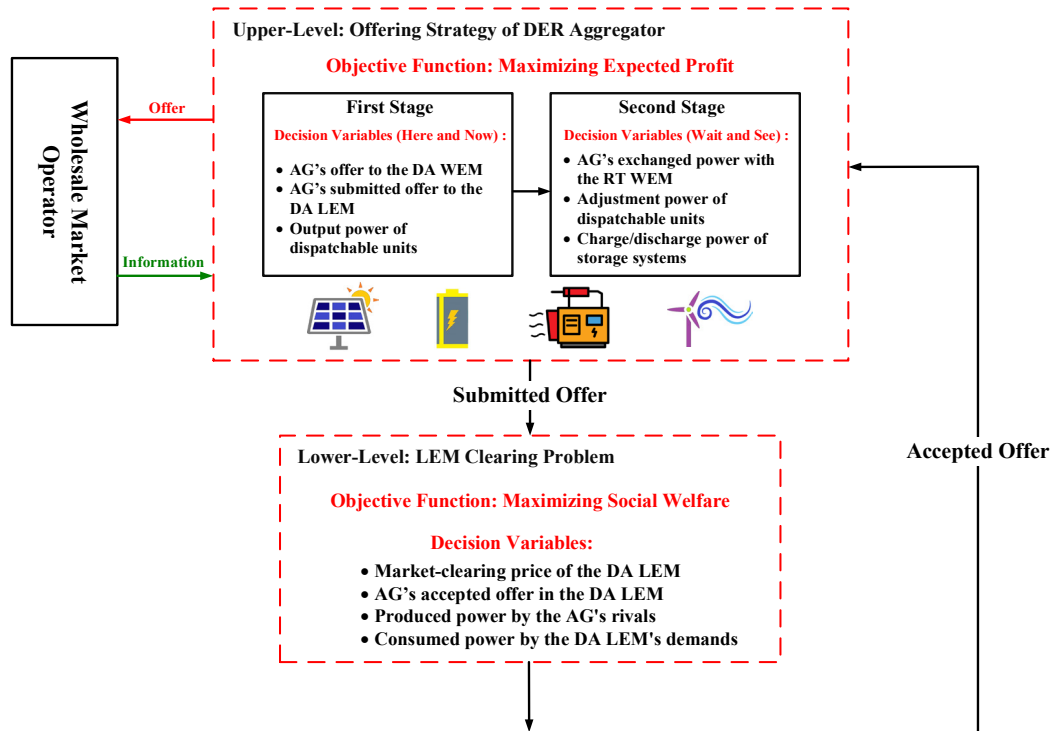


Figure 16. Offering Strategy of DER Aggregators in Local and Wholesale Electricity Markets (From Publication 7).

7.3 Offering Strategy of Energy Hubs in Local Integrated Energy Markets: Conceptual and Methodological Insights

7.3.1 Overview and Problem Context

Energy hubs have emerged as key operational entities within modern integrated energy systems, serving as centralized multi-energy conversion, storage, and distribution nodes capable of dynamically managing multiple energy sectors. In practical terms, energy hubs act as both a physical and economic interface, linking diverse energy supply sources with end-use demands through advanced conversion technologies and intelligent control strategies. By incorporating assets such as combined heat and power (CHP) units, electric boilers, electric heat pumps, renewable generation units, and both thermal and electrical storage facilities, energy hubs can flexibly allocate resources to meet varying demand patterns for electricity, heat, and potentially other carriers such as cooling, hydrogen, or gas. This multi-energy integration enables the energy hubs to exploit sector coupling synergies, allowing for coordinated use of electricity, heat, and other energy carriers in a way

that maximizes overall system efficiency. Such operational versatility positions energy hubs as pivotal actors in balancing supply and demand across various sectors, mitigating the intermittency challenges of renewable generation, and reducing reliance on expensive peak-period imports from upstream networks.

The role of energy hubs becomes especially critical in local integrated electricity-heat markets, where market-based coordination mechanisms value flexibility and efficient resource allocation. Within these integrated markets, energy hubs can strategically offer both electricity and heat, leveraging their aggregated capacity to influence local price formation and contribute to broader objectives such as congestion management, renewable integration, and peak shaving. By engaging in both sectors under a unified framework, they not only minimize their operational costs but also advance decarbonization and enhance system resilience. Operating as active market participants, energy hubs submit their electricity and heat offers, with the integrated nature of their assets creating strong interdependencies between these two sectors. As a result, operational choices in one domain directly affect performance in the other, demanding sophisticated optimization to maximize profitability while satisfying technical and market constraints. Unlike pure electricity market players, energy hubs must carefully manage sector-coupled assets, i.e., power-to-X (P2X) technologies, and navigate the inherent limitations of certain systems, including the slow thermal dynamics of district heating networks (Ebrahimi & Sheikhi, 2023).

However, the participation of energy hubs in local integrated markets is inherently challenged by multiple sources of uncertainty, including fluctuations in market prices, variations in electricity and heat demands, and the intermittency of renewable generation. These uncertainties directly affect both profitability and the feasibility of operational schedules, making accurate forecasting and adaptive decision-making essential. While scenario-based stochastic approaches are a well-established tool for capturing such variability, they are not the only means of risk management. In highly volatile market environments, relying solely on forecast-driven strategies can still expose energy hubs to significant financial risks, particularly when unexpected deviations occur. This calls for complementary decision-making frameworks that explicitly integrate risk considerations into the market participation strategy, ensuring robust performance under a wide range of possible system conditions.

To address the complexities of energy hub participation in local integrated electricity-heat markets, Publication 8 proposes a risk-aware offering strategy that reflects the multi-energy, price-making nature of energy hub operations. Unlike conventional single-energy participants, energy hubs must simultaneously manage coupled electricity and heat outputs under uncertain conditions. These operational interdependencies make bidding decisions more complex, as actions in one energy

carrier directly influence performance in the other. The proposed strategy positions energy hubs as active market participants, capable of shaping both electricity and heat prices in the local integrated market while effectively navigating these uncertainties. It introduces a market participation strategy that balances profitability with resilience, enabling the energy hubs to adapt their offers in response to changing system conditions and risk preferences. By integrating risk management principles into the offering process, the framework empowers these entities' operators to mitigate the impacts of unfavorable market scenarios while seizing opportunities in favorable conditions. This approach not only improves the economic performance of the energy hubs but also strengthens their role as a flexibility provider, supporting system-wide objectives such as congestion management, more renewable integration, and efficient sector coupling.

7.3.2 The Proposed Methodological Framework

As noted earlier, the primary aim of this research is to investigate the optimal participation of strategic energy hubs in local integrated electricity-heat markets, recognizing their role as price-maker entities capable of influencing both electricity and heat outcomes. In this context, an energy hub integrates a diverse portfolio of multi-energy resources at the distribution level, including conventional units like CHP plants and gas-fired generators, renewable energy sources like wind turbines, photovoltaic arrays, and solar thermal systems, as well as flexible conversion and storage technologies such as electric boilers, heat pumps, power and heat storage systems. By operating as a coordinated multi-energy node, the energy hub can manage and convert energy across carriers, trade both electricity and heat within the local integrated market, and address any surplus or deficit through flexible reallocation of resources. The scale and diversity of its assets allow the energy hub to exert a measurable influence on local price formation, positioning it as a strategic participant whose operational decisions can significantly affect both sectoral interactions and system-wide performance.

To this end, a bi-level programming approach is adopted, where the upper level determines the scheduling and operation of the energy hub to maximize its profit, while the lower level models the local integrated electricity-heat market-clearing process to minimize total operating costs (Detailed formulation in Publication 8). The modeled energy hub incorporates a diverse mix of assets, including a CHP unit, a gas-fired generator, renewable resources such as wind, photovoltaic, and solar thermal systems, as well as electricity and heat storage systems. Power-to-heat conversion is enabled through electric boilers and electric heat pumps, providing additional operational flexibility. The conceptual configuration of the considered energy hub,

along with its interaction with the local integrated market operator, is illustrated in Figure 17, providing an overview of the system architecture and energy flows underpinning the proposed scheduling framework.

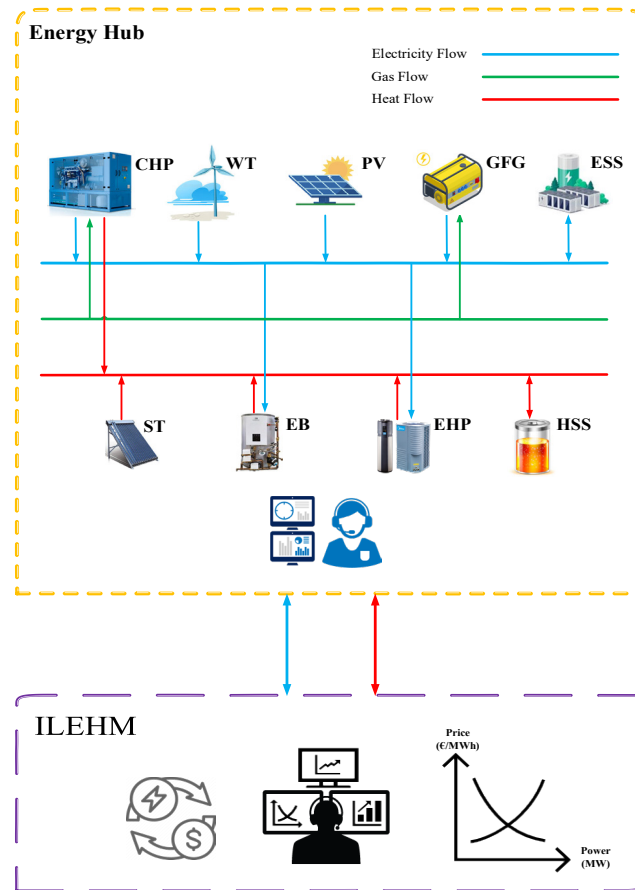


Figure 17. Conceptual Configuration of the Energy Hub and Its Interaction with the Local Integrated Market Operator (From Publication 8).

Given the stochastic nature of decision-making in local integrated markets, the energy hub operates under considerable uncertainty stemming from multiple sources. These include the variable outputs of wind turbines, photovoltaic units, and solar thermal heat production across different scenarios, as well as fluctuations in electricity and heat demands of the integrated local energy market. Market-related uncertainties are also considered, including the unpredictable submitted price and quantity offers of other participants, i.e., various rivals. Each scenario is associated with a probability reflecting its likelihood of occurrence, enabling the evaluation of expected operational performance under uncertainty. These uncertain parameters and their associated probabilities are presented in Publication 7. Such uncertainties can significantly influence both the profitability and the operational feasibility of the energy hub's schedules, making robust and adaptive risk management an essential component of its offering strategy (Yang et al., 2024).

To address this, Second-Order Stochastic Dominance (SOSD) constraints are adopted to explicitly control the risk associated with the energy hub's participation in the local integrated market (Norouzi et al., 2024). Compared to conventional risk approaches such as Conditional Value at Risk (CVaR), SOSD offers greater flexibility to the decision-maker by defining a feasible decision space that balances the pursuit of higher profits with the need to mitigate exposure to worst-case outcomes. Rather than focusing solely on extreme tail events, SOSD considers the entire distribution of potential outcomes, ensuring that the chosen strategy is acceptable across a broad range of scenarios. This enables energy hubs to adopt bidding strategies that are resilient to unfavorable market conditions while retaining the ability to capitalize on favorable opportunities. A high-level overview of the proposed method and its detailed procedural structure are presented in Figures 18 and 19, respectively.

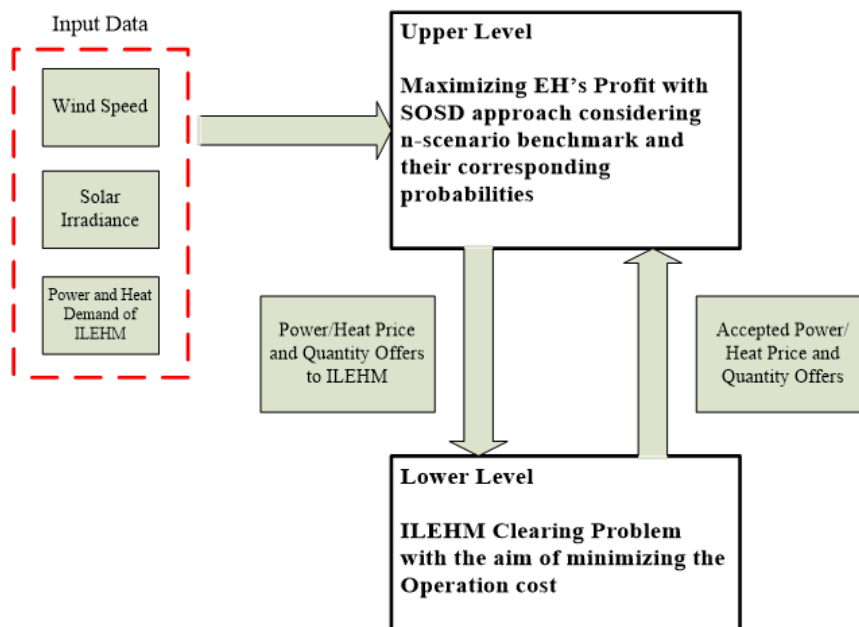


Figure 18. A High-Level Overview of the Methodology (From Publication 8).

7.4 Main Contributions and Findings

The research presented in this chapter advances the strategic participation of various entities, namely DER aggregators and energy hubs, in emerging local electricity and integrated electricity-heat markets. While the focus of each study differs, with Publication 7 centering on DER aggregators in local and wholesale electricity markets and Publication 8 targeting energy hubs in local integrated markets, both share the overarching aim of designing intelligent offering strategies that leverage flexibility, address uncertainty, and enhance profitability while remaining aligned with system-wide operational objectives.

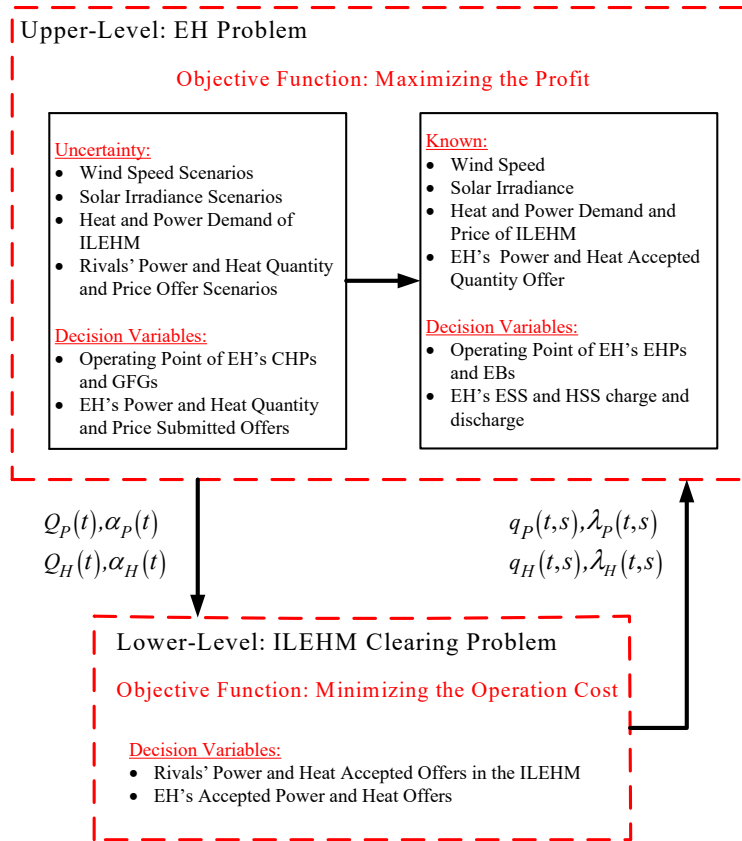


Figure 19. Detailed Procedural Structure for the Offering Strategy of the Energy Hubs (From Publication 8).

Publication 7 introduces a bi-level, two-stage stochastic optimization framework in which DER aggregators act as price-makers in local electricity markets and price-takers in wholesale markets, enabling optimal resource allocation across both layers while accounting for network limitations, renewable variability, and market uncertainty. Publication 8 extends this concept to energy hubs in local integrated electricity-heat markets, modeling them as multi-energy, strategic participants whose coordinated bids can influence prices in both sectors. Risk management is incorporated through SOSD constraints, creating a decision space that balances profitability with protection against unfavorable outcomes, allowing energy hubs to exploit sector-coupling synergies while remaining resilient to market volatility.

Collectively, these two studies contribute advanced modeling frameworks that explicitly represent the hierarchical interaction between strategic market participants and market operators. They demonstrate how multi-market and multi-energy participation strategies can be optimized under technical, market, and behavioral uncertainties, and how risk management can be embedded directly into the offering process. In doing so, they deliver decision-support tools that strengthen both the economic and operational performance of local market participants. Beyond

improving profitability and competitiveness, these strategies contribute to wider system benefits, including more effective use of DERs, alleviation of network bottlenecks, smoother integration of variable renewable resources, and coordinated management of multiple energy carriers to maximize overall system efficiency.

The key findings resulting from these research works can be listed as follows:

- First, both DER aggregators and energy hubs achieve higher expected profits when operating as strategic, price-maker entities, as their ability to influence local market-clearing prices enables more favorable trading outcomes compared to non-strategic participation.
- Second, coordinated participation in both local and wholesale electricity markets enables DER aggregators to unlock the full value of their flexibility portfolio by dynamically allocating resources between market layers according to prevailing price signals and network conditions. This approach improves operational efficiency by allowing optimal use of dispatchable units, storage systems, and variable renewable generation, while reducing exposure to unfavorable transactions in either market. By leveraging the complementary opportunities of local and wholesale trading, aggregators can achieve higher trading volumes, smooth variability through real-time adjustments, and better align generation with demand. The resulting synergy not only yields substantial profit improvements but also underscores the strategic importance of flexible resources within a two-stage stochastic decision-making framework. Table 4 compares the optimal performance of the studied DER aggregator under three participation scenarios: engagement exclusively in the wholesale electricity market, participation solely in the local electricity market, and coordinated participation in both markets.

Table 4. Comparison of DER Aggregator Performance Across Different Market Participation Scenarios (From Publication 7).

	Both LEIM and WEM	Only WEM	Only LEIM
Traded Power (MWh/day)	694.1	439.3	370.5
Daily Income (\$/day)	20129.7	18483.9	13930.5
Daily Cost (\$/day)	6469.6	5962.4	3784.3
Expected Profit (\$/day)	13660.1	12521.5	10146.2

- Third, coordinating diverse generation assets, storage systems, and P2X technologies within energy hubs and participating in integrated electricity-heat markets enables effective load shifting, the absorption of surplus renewable energy, and the mitigation of peak demand impacts.
- Fourth, using SOSD constraints for risk management enables energy hub operators to explicitly set minimum acceptable profit levels in worst-case scenarios, aligning bidding strategies with defined risk preferences. Unlike conventional CVaR methods, SOSD allows the creation of a tailored feasible decision region based on benchmark scenarios, offering greater control and flexibility. Furthermore, increasing the number of benchmark scenarios enhances robustness by improving worst-case outcomes while preserving much of the potential for high profits, resulting in a more balanced trade-off between risk and reward. This behavior is clearly illustrated in Figures 20 and 21, where the two-scenario and four-scenario benchmarks show progressively higher guaranteed worst-case profits while keeping best-case profits much closer to those of the risk-neutral solution, resulting in increasing expected profit.

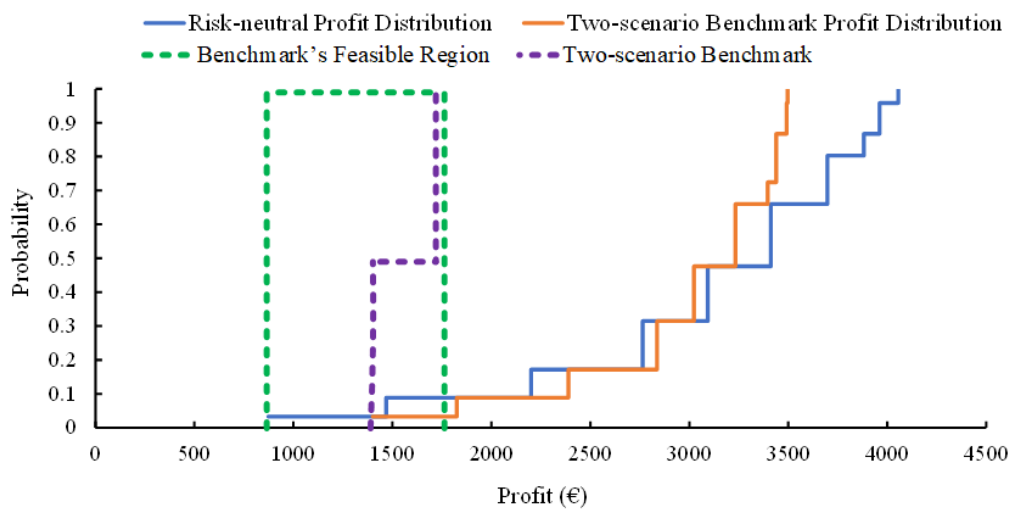


Figure 20. Profit Distribution Under the Two-Scenario SOSD Benchmark (From Publication 8).

- Finally, the modeling frameworks are adaptable to a range of market sizes, configurations, and asset portfolios. While demonstrated on electricity-heat coupled systems, the principles can extend to additional energy carriers such as gas and hydrogen, supporting future multi-vector energy systems.

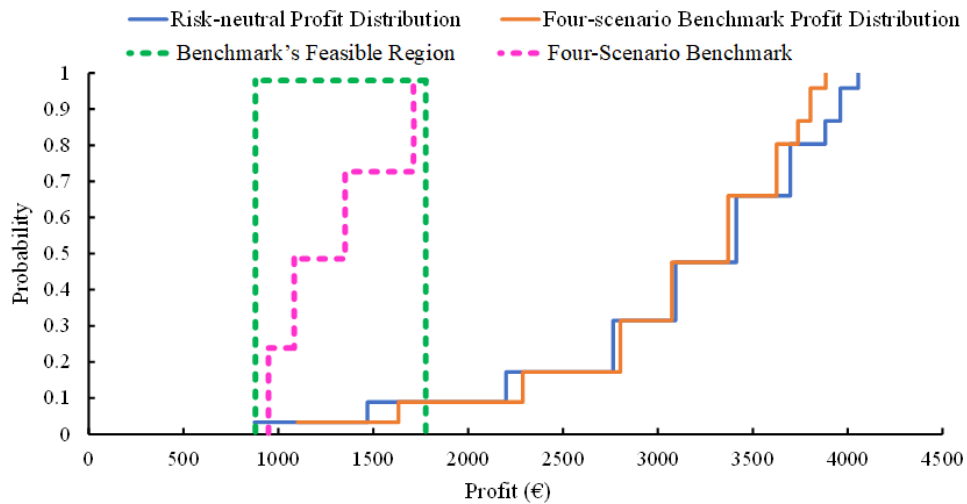


Figure 21. Profit Distribution Under the Four-Scenario SOSD Benchmark (From Publication 8).

7.5 Conclusion

This chapter presents advanced offering strategies for various market participants in local electricity and integrated electricity-heat markets. The proposed frameworks capture the strategic role of participants as active price-maker entities, capable of shaping local market outcomes while navigating diverse sources of uncertainty. Through coordinated participation across market layers and energy carriers, the approaches leverage flexibility resources, sector-coupling technologies, and risk-aware decision-making to create a cohesive and adaptive market engagement strategy. Such integration not only facilitates higher penetration of renewable energy but also improves the operational efficiency and reliability of distributed energy systems. Beyond individual profitability, these strategies contribute to the evolution of local market structures toward more adaptive, transparent, and resilient energy systems, reinforcing the broader thesis objective of enabling P2X2P-driven coordination for a low-carbon, economically sustainable energy future.

8 CONCLUSION AND FUTURE RESEARCH DIRECTION

As the global energy systems undergo a profound transformation toward decentralization, decarbonization, and sectoral integration, this doctoral thesis has demonstrated how local electricity and local multi-energy market frameworks can serve as a cornerstone for unlocking flexibility, improving economic efficiency, and ensuring seamless coordination between distributed energy resources and higher-level system operations. By combining advanced market design principles, sector-coupled operation, hierarchical coordination across market layers, and strategic participation modeling for distribution-level energy providers, the research closes critical technical and economic gaps in existing approaches. This concluding chapter synthesizes the main contributions of the work, provides direct responses to the research questions posed in previous chapters, and discusses the limitations, practical implementation considerations, and policy implications of the proposed frameworks. It also outlines promising directions for future research toward fully integrated, flexible, and resilient multi-energy systems.

8.1 Summary of Contributions

This thesis has developed an united set of market-based frameworks that collectively address three core layers of the emerging distributed, multi-energy paradigm: (i) local electricity markets designed to operate under realistic distribution grid constraints; (ii) sector-coupled local market platforms that jointly clear electricity and heat while internalizing cross-sector interactions; and (iii) a hierarchical coordination architecture that ensures alignment between local market decisions and wholesale electricity market outcomes. This methodological foundation is complemented by the development of strategic, risk-aware offering models for key distribution-level entities, such as DER aggregators and multi-energy hubs, capable of operating as price-maker participants under deep uncertainty in prices, renewable output, demand patterns, and competitor behavior.

Local electricity market design (Chapter 3, related to Publication 1): A bi-level Stackelberg game-based local electricity market platform is developed, in which the distribution system operator acts as the leader and multiple independent DER aggregators act as followers. This hierarchical formulation is subsequently reformulated into an equivalent single-level optimization while preserving the leader-follower decision logic. Market clearing incorporates full distribution power-flow constraints to ensure that nodal prices and dispatch decisions remain technically feasible. Compared with fixed-tariff bilateral contracts, the proposed local market-

based trading delivers more balanced profit sharing, transparent price formation, and grid-aware dispatch, while maintaining participant autonomy.

Sector coupling and integrated energy systems operation (Chapter 4, related to Publications 2 & 3): A co-optimization framework is proposed for integrated electricity-heat energy systems, incorporating combined heat and power units, power-to-heat technologies, such as electric heat pumps and electric boilers, as well as hybrid energy storage systems comprising battery, thermal, and gas storage units. A two-stage stochastic programming approach captures uncertainties in power and thermal demands, prices, as well as renewable outputs. The framework exploits cross-sector temporal shifting to reduce renewable curtailment and operating costs. Diversified storage portfolios yield the highest profitability and operational robustness, underlining the complementarity of sector coupling and multi-carrier flexibility.

Local energy market design for integrated systems (Chapter 5, related to Publications 4 & 5): A centralized, auction-based local trading platform is presented to jointly clear electricity and heat, enabling the simultaneous optimization of both energy carriers within a single market framework. The platform extends the distribution locational marginal pricing mechanism to cover both electricity and heat networks, thereby internalizing sector interactions, network congestion, voltage limits, and thermal-hydraulic constraints, while providing transparent, location- and time-specific price signals for both carriers. By integrating sectors and leveraging energy conversion assets, the system can respond more effectively to peak loads, particularly during periods of high thermal demand, enhancing load-following capability and operational flexibility.

Hierarchical coordination of local-wholesale energy markets (Chapter 6, related to Publication 6): A hierarchical bi-level framework is suggested to link integrated local energy markets with the wholesale electricity market, enabling the participation of distributed energy resources, storage units, and power-to-X technologies in the distribution-level market outline while feeding back wholesale prices and allocations to guide local dispatch. Prioritizing local flexibility before wholesale procurement aligns local actions with system-wide marginal costs, improves cost efficiency, and strengthens cross-sector balancing.

Strategic, risk-aware offering models for local market participants (Chapter 7, related to Publication 7 & 8): Price-making offering strategies are developed for DER aggregators in local electricity markets and for energy hubs in local integrated electricity-heat markets, both formulated as stochastic bi-level optimization problems. Operating as price-makers enables these entities to achieve higher expected profits, as their ability to influence local market-clearing prices leads to

more favorable trading outcomes. Uncertainties in rivals' behavior, prices, renewable outputs, and demands are addressed through scenario-based stochastic programming, while risk preferences are incorporated via Second-Order Stochastic Dominance constraints. This combination allows participants to shape the entire distribution of possible outcomes, safeguard against adverse scenarios, and maintain a balanced trade-off between profitability and operational robustness.

8.2 Answers to Research Questions

Q1: How can local electricity markets be designed to integrate multiple independent DER aggregators in a way that ensures economic efficiency while maintaining power distribution network security? (Chapter 3, related to Publication 1)

A1: Local electricity markets can be effectively designed to integrate multiple independent DER aggregators by adopting a Stackelberg game-based framework in which the distribution system operator is modeled as the leader and the aggregators as followers. The market-clearing process explicitly incorporates full distribution power-flow constraints, so that resulting dispatch schedules and nodal prices are not only economically optimal but also technically feasible for secure grid operation. This approach generates locational and temporal price signals that reflect real-time network conditions, thereby incentivizing aggregators to strategically adjust storage, generation, and demand response actions in ways that relieve local stress points and improve efficiency. In doing so, it enables aggregators to act as autonomous, profit-maximizing entities while ensuring that overall system operations remain secure.

Q2: How can sector coupling between electricity and heat be effectively incorporated into local market frameworks to unlock cross-sector flexibility trading without compromising technical or economic feasibility? (Chapters 4 & 5, related to Publications 3, 4 & 5)

A2: Sector coupling between electricity and heat can be effectively incorporated into local market frameworks by extending the market design into a centralized, cross-sector clearing platform that jointly optimizes both carriers within a unified structure. In this framework, combined heat and power units, power-to-heat technologies, and diversified storage assets are co-optimized so that flexibility can be exchanged seamlessly across sectors. The introduction of a distribution locational marginal pricing mechanism for both electricity and heat ensures that sectoral interactions, grid congestion, voltage limits, and thermal-hydraulic constraints are internalized directly in the market outcomes. This provides participants with transparent, location- and time-specific price signals that reflect the true value of cross-sector flexibility. This market platform not only enhances efficiency and

renewable integration but also unlocks new revenue streams for distributed assets, demonstrating that cross-sector flexibility trading can be realized without compromising economic or technical viability.

Q3: What coordination mechanisms best align local energy market decisions with wholesale electricity market outcomes, ensuring bidirectional consistency in prices and dispatch for overall system efficiency? (Chapter 6, related to Publication 6)

A3: A hierarchical bi-level coordination mechanism best aligns local energy market decisions with wholesale electricity market outcomes by establishing bidirectional consistency in both prices and dispatch. In this framework, the local integrated market operator first aggregates distributed flexibility from various multi-energy assets and submits the net position to the wholesale market. Local flexibility is thus prioritized and utilized before resorting to costly upstream procurement, reducing overall system costs and improving renewable integration. At the same time, wholesale market outcomes, including prices and dispatch allocations, are fed back into the local clearing process, ensuring that local decisions reflect system-wide marginal costs. This two-way interaction not only enhances balancing across sectors and network layers but also provides transparency and coherent price signals, avoiding the inefficiencies and conflicts that arise from uncoordinated operations.

Q4: How can the strategic behavior of distribution-level market participants, such as DER aggregators and energy hubs, be modeled to reflect their price-making capabilities in local electricity and integrated markets, and how can uncertainty and risk preferences be incorporated to develop offering strategies that balance profitability with robustness under volatile market conditions? (Chapter 7, related to Publications 7 & 8)

A4: The strategic behavior of distribution-level participants such as DER aggregators and energy hubs can be effectively modeled using stochastic bi-level optimization frameworks that explicitly account for their price-making influence in local electricity and integrated electricity-heat markets. Within these models, participants are positioned as leaders who anticipate rivals' strategies, price volatility, and uncertainty in renewable generation and demand, while network limits ensure technical feasibility. Risk preferences are incorporated through Second-Order Stochastic Dominance constraints, allowing participants to shape the entire outcome distribution, safeguard against unfavorable scenarios, and achieve a controlled balance between expected profitability and robustness.

8.3 Limitations, Practical Considerations, and Policy Implications

The proposed frameworks, while comprehensive, face a few limitations. First, simplified power-flow and heating-network models are adopted to balance accuracy and tractability, which may require refinement for deployment in complex and real distribution power and district heating systems. Second, the computational scalability of stochastic optimizations, particularly when modeling uncertainty in prices, renewable output, and demand, remains a challenge for large-scale applications. Third, the behavioral models assume rational competition among DER aggregators or energy hubs; expanding this to capture heterogeneous actors, repeated interactions, and potential collusion would strengthen realism.

From a practical perspective, the feasibility of the distribution locational marginal pricing mechanism and integrated market clearing depends on access to detailed electrical and thermal network data, which may be incomplete or unavailable. Translating sophisticated multi-energy locational marginal prices into fair, simple, and politically acceptable retail tariffs, mitigating local market power, and clarifying the evolving roles of the distribution system operator versus an independent market facilitator, in the presence of local market platforms, remain key regulatory and coordination challenges. Sector-coupled operation also demands harmonized data standards and secure, privacy-preserving information exchange between system operators to prevent interoperability failures and cyber risks.

Policy implications are significant. Locational and cross-sector prices can form the basis for transparent procurement of flexibility by the distribution system operator, reducing curtailment and deferring costly reinforcements. Gradually aligning retail tariffs with locational marginal prices would encourage efficient DER siting and sector-coupling investments, provided protections for vulnerable consumers are included. The hierarchical coordination model complements ongoing wholesale market reforms, creating coherent incentives across all market layers. Finally, the rise of strategic, price-making aggregators and energy hubs highlights the need for regulatory oversight of bidding behavior, ensuring that risk-aware strategies contribute to system efficiency and resilience.

8.4 Future Research Directions

Building on the contributions and limitations identified in this doctoral thesis, several promising research avenues can be pursued to further advance the design, coordination, and implementation of local and integrated multi-energy markets. These directions span methodological advances, improved treatment of uncertainty

and resilience, enhanced market design, deeper sectoral coupling, and real-world validation. Key directions include:

❖ **Algorithmic and computational advances:**

1. Develop scalable decomposition and approximation techniques for bi-level and multi-level market-clearing problems, and explore equilibrium formulations for multi-leader multi-follower interactions.
2. Incorporate learning-based surrogates for optimal power flow and distribution locational marginal pricing to accelerate computation and enable real-time decision support in local and integrated markets.

❖ **Uncertainty, risk, and resilience:**

1. Extend the current Second-Order Stochastic Dominance-based risk modeling with distributionally robust optimization and dynamic risk measures to capture evolving uncertainty profiles.
2. Model multi-energy cooperation under extreme events like supply shortages, heatwaves, and cold spells, and design resilience services priced consistently with locational marginal prices to ensure fair cost allocation.

❖ **Market design and coordination:**

1. Prototype joint coordination platforms between transmission system operators, distribution system operators, and local-level energy providers for energy and flexibility trading, ensuring transparency, neutrality, and fairness across layers.
2. Explore advanced market services and products like reserve provision and cross-sector balancing that can be layered onto local multi-energy markets to enhance flexibility, resilience, and operational efficiency.

❖ **Cross-sectoral expansion:**

1. Expand the frameworks to include other energy carriers such as gas, hydrogen, and mobility, namely electric vehicles and charging infrastructure, as part of sector-coupled networks.
2. Quantify the additional flexibility potential from electric vehicles integration and building thermal inertia, and assess how these can be effectively valued within multi-energy systems.

❖ Implementation and validation:

1. Carry out pilot projects, field trials, and digital twin simulations to validate the technical, economic, and social impacts of the proposed market frameworks.
2. Publish open-access datasets, benchmarks, and reproducible case studies to support comparative research and foster community-wide progress.

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RESEARCH ARTICLE

Modeling a Local Electricity Market for Transactive Energy Trading of Multi-Aggregators

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ABSTRACT The present article aims at modeling a day-ahead local electricity market (DA LEM) for transactive energy trading at the distribution level. In this regard, a wide range of distributed energy resources (DERs) in the form of multiple aggregators (AGs) participates in the DA LEM in order to trade energy with the distribution system operator (DSO), the operator of the market. On the other hand, the DSO, as the owner of the system, has the responsibility to procure the required energy of its customers with respect to the technical constraints of the distribution network. To settle the designed local market, a Stackelberg game-based approach is exploited in this research work. In the raised Stackelberg scheme, the leader of the game, the DSO, seeks to maximize its expected profit, while followers of the game, DER AGs, tend to minimize their operating costs. Ultimately, to evaluate the proposed framework, a typical case study is implemented on a modified IEEE-33 bus test system.

INDEX TERMS DER aggregator, distribution system operator, local electricity market, Stackelberg game, transactive energy trading.

NOMENCLATURE

Acronyms:

AG	Aggregator
BS	Battery Storage
DA	Day-Ahead
DER	Distributed Energy Resource
DG	Dispatchable Generator
DSO	Distribution System Operator
LEM	Local Electricity Market
PV	Photovoltaic System
WT	Wind Turbine
WEM	Wholesale Electricity Market

Sets and Indices:

$b \in B$	Set of BSs
$i \in I$	Set of DGs

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m	Index in modeling the DGs' minimum up / down time
$n \in N$	Set of AGs
$l \in L$	Set of Loads
$t \in T$	Set of Hours
$v \in V$	Set of PVs
$w \in W$	Set of WTs
α, β	Set of Buses
Λ	Set of Lines
Ω_{\times}	Set of \times connected to set of buses
$\Xi^{n^{\text{th}} \text{Follower}}$	Set of n^{th} follower's decision variables
Ξ^{Leader}	Set of leader's decision variables

Parameters:

$a_{DSO}^{DG}, b_{DSO}^{DG}$	Linear cost coefficients of DSO's DGs
$b_{\alpha\beta}, g_{\alpha\beta}$	Susceptance / conductance of line $\alpha\beta$
c_{AG}^{DG}	Marginal generation cost of AGs' DGs

$dt_{DSO}^{DG}, ut_{DSO}^{DG}$	Parameters in modeling the DGs' minimum down / up time
$E_{AG}^{BS,ini}$	Initial energy stored in AGs' BSs
$E_{AG}^{BS,max}, E_{AG}^{BS,min}$	Maximum / minimum energy stored in AGs' BSs
$mdt_{DSO}^{DG}, mut_{DSO}^{DG}$	Minimum down / up time of DSO's DGs
$P_{AG}^{BS,ch,max}, P_{AG}^{BS,ch,min}$	Maximum / minimum charge power of AGs' BSs
$P_{AG}^{BS,dch,max}, P_{AG}^{BS,dch,min}$	Maximum / minimum discharge power of AGs' BSs
$P_{AG}^{DG,ini}$	Initial generation power of AGs' DGs
$P_{AG}^{DG,max}, P_{AG}^{DG,min}$	Maximum / minimum generation power of AGs' DGs
$P_{DSO}^{DG,max}, P_{DSO}^{DG,min}$	Maximum / minimum generation power of DSO's DGs
$P_{DSO}^{Load,F}$	Forecasted demand of DSO
$P_{exch}^{LEM,DA,max}$	Maximum exchange power in DA LEM
$P_{AG}^{PV,F}, P_{DSO}^{PV,F}$	Forecasted generation power of AGs / DSO's PVs
$P_{AG}^{WT,F}, P_{DSO}^{WT,F}$	Forecasted generation power of AGs / DSO's WTs
$P_{\alpha\beta}^{max}$	Maximum capacity of line $\alpha\beta$
$RD_{AG}^{DG}, RU_{AG}^{DG}$	Ramp down / up rate of AGs' DGs
$sdc_{DSO}^{DG}, suc_{DSO}^{DG}$	Shut down / start up price of DSO's DGs
V_{nom}	Nominal voltage
λ_{Cus}	Price of DSO's sold energy to customers
$\lambda_{LEM,DA,max}$	Maximum amount of energy price in DA LEM
$\lambda_{WEM,DA}$	Energy price in DA WEM
$\eta_{AG}^{BS,ch}, \eta_{AG}^{BS,dch}$	Charge / discharge efficiency of AGs' BSs
ε	Maximum voltage variation

Variables:

E_{AG}^{BS}	Energy stored in AGs' BSs
$P_{AG}^{BS,ch}$	Charge power of AGs' BSs
$P_{AG}^{BS,dch}$	Discharge power of AGs' BSs
P_{AG}^{DG}	Generation power of AGs' DGs
P_{DSO}^{DG}	Generation power of DSO's DGs
$P_{exch}^{LEM,DA}$	Exchange power in DA LEM
$P_{exch}^{WEM,DA}$	Exchange power in DA WEM
SDC_{DSO}^{DG}	Shut down cost of DSO's DGs
SUC_{DSO}^{DG}	Start up cost of DSO's DGs

V	Voltage magnitude
ΔV	Voltage deviation
$\lambda^{LEM,DA}$	Energy price in DA LEM
λ, μ	Dual variables
θ	Voltage angle

Binary Variable:

U_{DSO}^{DG}	Binary variable for operation of DSO's DGs
Z	Binary variable in Big-M method

I. INTRODUCTION

Over the past few years, the high penetration of real DERs, including generation units, as well as virtual DERs, including storage units and demand response programs, aligned with the growing development of smart technologies, has led to the transformation of centralized electricity systems into decentralized and smart networks [1]. These trends have challenged the conventional methods of supplying and selling electricity. That is because, for the effective integration of DERs and benefit from their provided advantages, the implementation of new control and operational layers at the distribution level is highly required. Recently, various solutions have been raised to implement these layers and exploit these emerging resources. One of the most important and practical ways is to create a new platform called the local electricity market (LEM) [2]. In different references, several definitions have been provided for LEMs. For instance, in [3], the LEM is considered as a marketplace for the energy exchange between producers and consumers at variable prices. In [4], the LEM is based on a local community in which a variety of prosumers, producers, and consumers are engaged to serve more sustainable energy on involved members. In [5], the LEM is taken into account as a market platform for exchanging locally produced electricity between residential agents within a community. Finally, in [6], the LEM is interpreted as transactive energy management based on market rules and regulations. Transactive Energy is a framework that enables the integration of the individual preferences and resource characteristics of prosumers in the energy management program [7]. The entire mentioned definitions for the LEM contain two common features: engagement of customers as well as the localization of the market [8]. Engagement of customers indicates that customers are active players in the LEM decision-making process. Furthermore, localization of the market emphasizes on both the position of customers in the formation of the LEM and the transactive energy exchange at the distribution level.

In general, the development of LEMs presents numerous advantages to different stakeholders [9]. In this regard, the LEM participants are able to consume their generated energy and share their excess with the DSO or with other customers on a local platform. Hence, customers strengthen their position as effective and active players in the LEM. Moreover, local energy trading not only reduces voltage fluctuations

and losses in transmission and distribution lines but also increases the stability and reliability of the whole power system. On the other hand, through the integration and coordination of small-scale DERs in the LEM framework, a variety of services including energy sales to different markets as well as voltage and frequency control of distribution networks can be provided. To achieve these goals, designing a proper model for the LEM is very essential. Nonetheless, since the LEM needs to address conflicting objectives, the procedure of designing an efficient framework for these types of markets is a challenging matter [10]. Accordingly, several studies have been carried out in the most recent years in order to model the LEM. In the following, some of these research works are highlighted:

For coordination of the DSO with multiple microgrids, a local market-based platform has been provided in [11]. In this framework, the DSO attempts to promote its profit, whereas microgrid owners try to diminish their operating costs. This research has proposed a game-based approach to settle the considered LEM. For the optimal operation of distribution networks, a DA LEM has been modeled in [12], in which various prosumers, producers, and consumers are administered at the local level by participating in the market. The designed LEM is cleared by the DSO with the aim of social welfare maximization and satisfying the technical constraints of the system. In [13], a LEM has been provided for allowing small players, including microgrids, to participate in fully transactive energy systems. In this context, a two-stage stochastic programming method has been exploited to solve the market transactions within this framework. To organize a variety of real and virtual DERs at the distribution level, a DA LEM has been provided in [14]. To this end, an energy services company, as the operator of the LEM, manages the entire participants in a coordinated manner to maximize its expected profit. A feeder-based market has been proposed in [15] for energy trading at the local level. In this market, the distribution system is divided into several LEMs with a limited number of players, and in each market, producers and consumers exchange power in a way to maximize their social welfare. In this study, the feeder-based market is settled in two-step and by utilizing the primal-dual decomposition method. In [16], an architecture of the LEM has been suggested for peer-to-peer energy exchange between a group of prosumers equipped with various DERs in a transactive environment. In this study, a heuristic-based algorithm has been utilized to minimize the electricity bill of market participants. A LEM has been modeled in [17], in which the DSO and several microgrids are able to interact with one another in this platform. This study has implemented a game-based method to not only set the power trading in the LEM but also evaluate its impact on the wholesale market.

A two-step LEM has been designed in [18] for peer-to-peer energy and uncertainty trading among PV owners and consumers with flexible demands. The clearing mechanism of the considered market is based on the unilateral auction with the aim of maximizing the production and flexibility

capacities of PVs and consumers, respectively. A LEM has been presented in [19] for transactive energy trading among several microgrids and the DSO at the distribution level. In this market, the DSO tends to reduce its operating costs, while each microgrid owner tries to increase its expected profit. Hence, to clear the LEM, a game-based method has been used in this study. To provide an appropriate marketplace for microgrids' interaction with one another, a DA LEM has been designed in [20]. For clearing the considered market, a bi-level programming approach has been utilized, in which the operating cost of each microgrid is minimized at the upper level, and the social welfare of the entire players is maximized at the lower level. A distributed optimization approach has been exploited in [21] for clearing a grid-connected DA LEM while preserving the privacy of the entire market participants. The purpose of this study is to reduce the cost of energy procurement in the presence of the distribution network's technical constraints. A LEM has been suggested in [22] to support peer-to-peer energy exchange among multiple prosumers in a transactive framework. In this article, the impact of peer-to-peer trading on the technical constraints of the distribution system, including voltage fluctuations, power losses, etc., has been investigated. A DA LEM has been designed in [23] to manage peer-to-peer transactions among different kinds of prosumers integrated within a local community. The modeled market is settled from a central operator's point of view by a centralized method in order to minimize the total operating costs of the community.

To get the maximum benefit from the high penetration of electric vehicles at distribution systems, a DA LEM has been exploited in [24]. In this regard, the market, which is cleared by a centralized method, seeks to determine the optimal power transaction among prosumers equipped with DERs and electric vehicles. The objective function of the LEM operator is to minimize the operating cost of the community. To enable peer-to-peer local energy sharing and trading among multiple consumers in a community, a bi-level programming approach has been suggested in [25]. Accordingly, the community, which is the owner of several flexible units, seeks to maximize its profit at the upper level of the problem, while consumers attempt to minimize their utility bills at the lower level. A market-based framework that handles the energy trading between the DSO and several microgrids at the local distribution level has been proposed in [26]. To this end, a two-level approach has been employed, in which, at the first level, the DSO sets the energy exchange price in a way to increase its earnings from the trading. At the second level, each microgrid operator is responsible for solving the optimal power flow problem to decrease both the generation cost as well as power loss of the system. Different types of auction-based algorithms for clearing LEMs have been compared with one another in [27]. The primary objective of this study is to satisfy the willingness to pay and preference of the market participants. A potential LEM has been modeled in [28] to facilitate the high deployment of DERs owned by residential customers at the distribution level. The LEM

operator, as a central entity, minimizes the cost of importing power and maximizes the income from exporting power to the upstream grid in the presence of distribution network constraints. In the end, a local market-based platform has been provided in [29] for the interaction among the DSO and different types of AGs at the distribution level. In this study, to settle this interaction, a bi-level programming method has been executed.

Analyzing the above articles demonstrates that, normally, the LEM modeling has been implemented from a central operator's perspective, and independent financial identity has not been considered for the market participants. Indeed, the entire stakeholders are required to share all their information with the operator as passive players in the LEM. Thus, these works have not been able to raise practical solutions for establishing a competitive environment among the existing participants. On the other hand, the proposed models in these works have not provided a suitable platform for the coordination and cooperation of decentralized DERs and getting fully advantages from their provided services. Therefore, these works have not been able to properly assess the technical and operational constraints of the distribution system and manage the DSO's challenges in the presence of a wide range of DERs. Since the presented paper is conducted to handle the mentioned gaps, its primary contributions are as follows:

1. Integration of decentralized DERs in the multi-AG platform for the transactive energy trading with the DSO at the local level and dealing with technical challenges of the distribution system in the presence of an extensive amount of DERs.
2. Modeling a DA LEM and utilizing a Stackelberg game-based approach to consider the selfish behavior of independent financial entities with distinguished objective functions in this market.

Table 1 clarifies the novelties and contributions of this article by comparing it with the reviewed research works.

II. METHODOLOGY

As previously mentioned, the key goal of this article is modeling a DA LEM to facilitate the participation of various small and medium-sized DERs in the energy management program of the DSO. To this end, it is assumed that different types of decentralized DERs are integrated into the multi-AG platform to trade energy with the DSO in the local marketplace as autonomous financial entities. On the contrary, the DSO, as the owner of the system, has the responsibility to procure the needed energy of its customers from the LEM and wholesale electricity market (WEM) as well as its local generation resources with respect to the technical constraints of the distribution network. Owing to the existence of independent players with distinguished objective functions in the modeled LEM, a Stackelberg game-theoretic method is utilized in this paper to settle the market [30]. The general scheme of the proposed framework is illustrated in Figure 1. While the DER AGs might be able to participate in other markets as well, their

TABLE 1. Taxonomy of the previous studies.

# Ref.	Competitive environment in the LEM	Technical constraints of the distribution system	Integration of decentralized DERs
[11]	✓	×	×
[12]	×	✓	×
[13]	×	×	×
[14]	×	×	×
[15]	×	×	✓
[16]	×	×	×
[17]	✓	✓	×
[18]	×	×	×
[19]	✓	✓	×
[20]	✓	×	×
[21]	×	✓	×
[22]	×	✓	×
[23]	×	×	×
[24]	×	×	×
[25]	✓	×	×
[26]	✓	✓	×
[27]	×	×	×
[28]	×	✓	×
This Paper	✓	✓	✓

participation in the proposed LEM will be more beneficial for these players and the DSO. The reason is that since integrated DERs within the AGs are located at the distribution networks, these entities are required to utilize the DSO's infrastructure for their energy trading in different markets. However, the extensive presence of these resources and their independent energy exchange with other markets endanger power quality indices of distribution systems and cause voltage fluctuations, high power losses, etc. Accordingly, by exploiting the presented local market-based framework, not only the DER AGs can sell their energy to the DSO by considering their financial interests, but also the technical constraints of the distribution network are well satisfied.

In the raised Stackelberg scheme, the leader of the game, the DSO, seeks to maximize its expected profit, while followers of the game, DER AGs, tend to minimize their daily operating costs. In this procedure, LEM energy price signals, as well as market players' bids/offers, act as linking variables between the leader and followers. Accordingly, the DSO sends the energy price signal to the AGs at the local level. Based on the signal, AGs submit their offers/bids to the LEM operator. Afterward, the DSO optimizes its objective function and evaluates its expected benefit based on AGs' received offers/bids. For the sake of clarification, non-linking and linking decision variables of the leader and followers are stated in Figure 1 as well.

In the following of this section, objective functions and also technical constraints of players are mathematically formulated.

A. PROBLEM FORMULATION OF THE LEADER–DSO

The DSO, as the leader of the game, has the responsibility to provide its demand by taking part in the existing markets, the LEM and WEM, as well as utilizing its local dispatchable and

non-dispatchable units. Hence, the objective function of the DSO is to promote its expected profit, which is defined as the difference between income and expenditure. The considered objective function is formulated mathematically in Eq (1).

$O.F_{Leader}$

$$= \text{Max} \sum_{t \in T} \left\{ \sum_{l \in L} P_{DSO}^{Load,F}(l, t) \lambda^{Cus}(t) - P_{exch}^{WEM,DA}(t) \lambda^{WEM,DA}(t) - \sum_{n \in N} P_{exch}^{LEM,DA}(n, t) \lambda^{LEM,DA}(t) - \left(\sum_{i \in I} a_{DSO}^{DG}(i) P_{DSO}^{DG}(i, t) + b_{DSO}^{DG}(i) U_{DSO}^{DG}(i, t) + \text{SUC}_{DSO}^{DG}(i, t) + \text{SDC}_{DSO}^{DG}(i, t) \right) \right\}, \quad (1)$$

The first term of Eq (1) is related to the DSO's revenue from selling energy to its customers. The second and third terms are related to the DSO's costs from participating in the WEM and interacting with DER AGs in the LEM platform, respectively. Finally, the last term is associated with the operating costs of the DSO's DGs.

This objective function is subject to a set of constraints as follows:

$$P_{exch}^{WEM,DA}(t) = \sum_{\beta: (\alpha, \beta) \in \Lambda} \left[V_{nom} (\Delta V(\alpha, t) - \Delta V(\beta, t)) g_{\alpha\beta} - V_{nom}^2 (\theta(\alpha, t) - \theta(\beta, t)) b_{\alpha\beta} \right], \quad \forall \alpha = 1, t \quad (2)$$

$$\begin{aligned} & \sum_{w: (w, \alpha) \in \Omega_W} P_{DSO}^{WT,F}(w, t) + \sum_{v: (v, \alpha) \in \Omega_V} P_{DSO}^{PV,F}(v, t) \\ & + \sum_{i: (i, \alpha) \in \Omega_I} P_{DSO}^{DG}(i, t) - \sum_{l: (l, \alpha) \in \Omega_L} P_{DSO}^{Load,F}(l, t) \\ & + \sum_{w: (w, \alpha) \in \Omega_W} \sum_{n \in N} P_{AG}^{WT,F}(n, w, t) \\ & + \sum_{v: (v, \alpha) \in \Omega_V} \sum_{n \in N} P_{AG}^{PV,F}(n, v, t) \\ & + \sum_{i: (i, \alpha) \in \Omega_I} \sum_{n \in N} P_{AG}^{DG}(n, i, t) \\ & + \sum_{\beta: (\beta, \alpha) \in \Omega_B} \sum_{n \in N} (P_{AG}^{BS,dch}(n, \beta, t) - P_{AG}^{BS,ch}(n, \beta, t)) \\ & = \sum_{\beta: (\alpha, \beta) \in \Lambda} \left[V_{nom} (\Delta V(\alpha, t) - \Delta V(\beta, t)) g_{\alpha\beta} - V_{nom}^2 (\theta(\alpha, t) - \theta(\beta, t)) b_{\alpha\beta} \right], \quad \forall \alpha \neq 1, t \quad (3) \end{aligned}$$

$$-P_{\alpha\beta}^{max} \leq \left[\begin{array}{c} V_{nom} (\Delta V(\alpha, t) - \Delta V(\beta, t)) g_{\alpha\beta} \\ -V_{nom}^2 (\theta(\alpha, t) - \theta(\beta, t)) b_{\alpha\beta} \end{array} \right] \leq P_{\alpha\beta}^{max}, \quad \forall (\alpha, \beta) \in \Lambda, t \quad (4)$$

$$-\varepsilon V_{nom} \leq \Delta V(\alpha, t) \leq \varepsilon V_{nom}, \quad \forall \alpha, t \quad (5)$$

$$V(\alpha, t) = V_{nom} + \Delta V(\alpha, t), \quad \forall \alpha, t \quad (6)$$

$$-\pi \leq \theta(\alpha, t) \leq \pi, \quad \forall \alpha, t \quad (7)$$

$$0 \leq \lambda^{LEM,DA}(t) \leq \lambda^{LEM,DA,max}, \quad \forall t \quad (8)$$

$$P_{DSO}^{DG,min}(i) U_{DSO}^{DG}(i, t) \leq P_{DSO}^{DG}(i, t) \leq P_{DSO}^{DG,max}(i) U_{DSO}^{DG}(i, t), \quad \forall i, t \quad (9)$$

$$U_{DSO}^{DG}(i, t) - U_{DSO}^{DG}(i, t-1) \leq U_{DSO}^{DG}(i, t + \text{ut}_{DSO}^{DG}(i, m)), \quad \forall i, t \quad (10)$$

$$U_{DSO}^{DG}(i, t-1) - U_{DSO}^{DG}(i, t) \leq 1 - U_{DSO}^{DG}(i, t + \text{dt}_{DSO}^{DG}(i, m)), \quad \forall i, t \quad (11)$$

$$\begin{aligned} & \text{ut}_{DSO}^{DG}(i, m) \\ & = \begin{cases} m, & m \leq \text{mut}_{DSO}^{DG}(i) \\ 0, & m > \text{mut}_{DSO}^{DG}(i) \end{cases}, \quad \forall i \quad (12) \end{aligned}$$

$$\begin{aligned} & \text{dt}_{DSO}^{DG}(i, m) \\ & = \begin{cases} m, & m \leq \text{mdt}_{DSO}^{DG}(i) \\ 0, & m > \text{mdt}_{DSO}^{DG}(i) \end{cases}, \quad \forall i \quad (13) \end{aligned}$$

$$\begin{aligned} & \text{SUC}_{DSO}^{DG}(i, t) \\ & \geq \text{suc}_{DSO}^{DG}(i) [U_{DSO}^{DG}(i, t) - U_{DSO}^{DG}(i, t-1)], \quad \forall i, t \quad (14) \end{aligned}$$

$$\begin{aligned} & \text{SDC}_{DSO}^{DG}(i, t) \\ & \geq \text{sdc}_{DSO}^{DG}(i) [U_{DSO}^{DG}(i, t-1) - U_{DSO}^{DG}(i, t)], \quad \forall i, t \quad (15) \end{aligned}$$

Eqs (2) and (3) are related to the power balance constraints of the DSO in the slack and other buses, respectively. In this study, a linear AC power flow has been exploited, as presented in [31]. In this regard, Eq (4) limits the amount of power flow in distribution lines. Eq (5) restricts the voltage deviation of buses. The voltage magnitude of each bus is represented by Eq (6). Eq (7) illustrates the limitation of voltage angle. Furthermore, energy price in the DA LEM is a non-negative variable that is limited by Eq (8). Operational constraints of the DSO's DGs are specified by Eqs (9) to (15). Accordingly, the generation power of DGs is limited by Eq (9). Eqs (10) to (13) model the minimum up and down time limitations of these units. Finally, Eqs (14) and (15) formulate the start up and shut down costs of these sources. It should be noted that the produced power of non-dispatchable units, namely WTs and PVs, are calculated by expressions that have been presented in [32].

In the end, the leader's set of decision variables are listed as follows:

$$\Xi_{Leader} = \left\{ \begin{array}{l} P_{exch}^{WEM,DA}(t), \lambda^{LEM,DA}(t), P_{DSO}^{DG}(i, t) \\ U_{DSO}^{DG}(i, t), \Delta V(\alpha, t), V(\alpha, t), \theta(\alpha, t) \end{array} \right\}$$

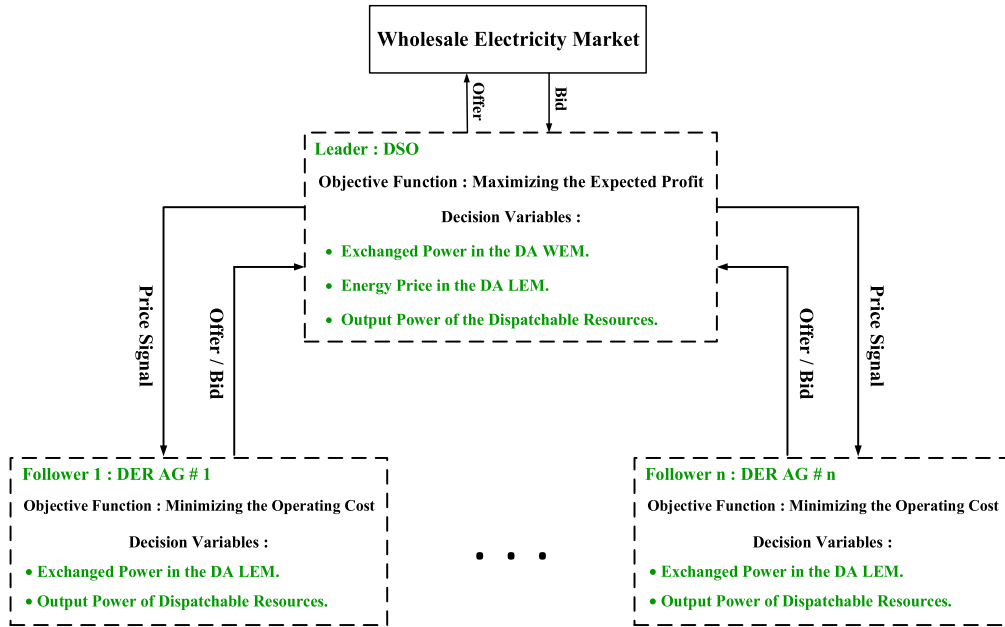


FIGURE 1. Overview of the proposed framework.

B. PROBLEM FORMULATION OF THE FOLLOWERS—DER AGS

On the other hand, each DER AG seeks to diminish its daily operating cost by integrating decentralized DERs at the distribution level and exchanging their generation as well as storage capacities with the DSO in the LEM platform. Each DER AG's objective function is mathematically formulated in Eq (16).

$$O.F^{n^{th} \text{ Follower}} = \text{Min} \sum_{i \in T} \left\{ \begin{array}{l} \sum_{i \in I} P_{AG}^{DG}(n, i, t) c_{AG}^{DG}(n, i) \\ -P_{exch}^{LEM, DA}(n, t) \lambda^{LEM, DA}(t) \end{array} \right\}, \quad (16)$$

The first and second terms of Eq (16) are related to the operating costs of the nth AG's DGs and its income from participating in the LEM, respectively.

This objective function is also subject to a set of constraints as follows:

$$\begin{aligned} & \sum_{w \in W} P_{AG}^{WT, F}(n, w, t) + \sum_{v \in V} P_{AG}^{PV, F}(n, v, t) \\ & + \sum_{i \in I} P_{AG}^{DG}(n, i, t) \\ & + \sum_{b \in B} (P_{AG}^{BS, dch}(n, b, t) - P_{AG}^{BS, ch}(n, b, t)) \\ & = P_{exch}^{LEM, DA}(n, t), \quad \lambda_1(n, t), \quad \forall n, t \end{aligned} \quad (17)$$

$$\begin{aligned} -P_{exch}^{LEM, DA, max}(n) \leq P_{exch}^{LEM, DA}(n, t) \leq P_{exch}^{LEM, DA, max}(n), \\ \mu_1(n, t), \mu_2(n, t), \quad \forall n, t \end{aligned} \quad (18)$$

$$P_{AG}^{DG, min}(n, i) \leq P_{AG}^{DG}(n, i, t) \leq P_{AG}^{DG, max}(n, i), \quad \mu_3(n, i, t), \mu_4(n, i, t) \quad \forall n, i, t \quad (19)$$

$$P_{AG}^{DG}(n, i, t) - P_{AG}^{DG}(n, i, t-1) \leq RU_{AG}^{DG}(n, i), \quad \mu_5(n, i, t), \quad \forall n, i, t > 1 \quad (20)$$

$$P_{AG}^{DG}(n, i, t) - P_{AG}^{DG, ini}(n, i) \leq RU_{AG}^{DG}(n, i), \quad \mu_6(n, i, t), \quad \forall n, i, t = 1 \quad (21)$$

$$P_{AG}^{DG}(n, i, t-1) - P_{AG}^{DG}(n, i, t) \leq RD_{AG}^{DG}(n, i), \quad \mu_7(n, i, t), \quad \forall n, i, t > 1 \quad (22)$$

$$P_{AG}^{DG, ini}(n, i) - P_{AG}^{DG}(n, i, t) \leq RD_{AG}^{DG}(n, i), \quad \mu_8(n, i, t), \quad \forall n, i, t = 1 \quad (23)$$

$$P_{AG}^{BS, dch, min}(n, b) \leq P_{AG}^{BS, dch}(n, b, t) \leq P_{AG}^{BS, dch, max}(n, b), \quad \mu_9(n, b, t), \mu_{10}(n, b, t), \quad \forall n, b, t \quad (24)$$

$$P_{AG}^{BS, ch, min}(n, b) \leq P_{AG}^{BS, ch}(n, b, t) \leq P_{AG}^{BS, ch, max}(n, b), \quad \mu_{11}(n, b, t), \mu_{12}(n, b, t), \quad \forall n, b, t \quad (25)$$

$$\begin{aligned} E_{AG}^{BS}(n, b, t) \\ = E_{AG}^{BS}(n, b, t-1) + P_{AG}^{BS, ch}(n, b, t) \eta_{AG}^{BS, ch}(n, b) \\ - P_{AG}^{BS, dch}(n, b, t, s) / \eta_{AG}^{BS, dch}(n, b), \\ \lambda_2(n, b, t), \quad \forall n, b, t > 1 \end{aligned} \quad (26)$$

$$\begin{aligned} E_{AG}^{BS}(n, b, t) \\ = E_{AG}^{BS, ini}(n, b) + P_{AG}^{BS, ch}(n, b, t) \eta_{AG}^{BS, ch}(n, b) \\ - P_{AG}^{BS, dch}(n, b, t, s) / \eta_{AG}^{BS, dch}(n, b), \\ \lambda_3(n, b, t), \quad \forall n, b, t = 1 \end{aligned} \quad (27)$$

$$\begin{aligned} E_{AG}^{BS, min}(n, b) \leq E_{AG}^{BS}(n, b, t) \leq E_{AG}^{BS, max}(n, b), \\ \mu_{13}(n, b, t), \mu_{14}(n, b, t), \quad \forall n, b, t \end{aligned} \quad (28)$$

Eq (17) is related to the power balance constraint of the n th AG. Eq (18) confines the exchange power of the AG in the DA LEM. Eqs (19) to (23) are associated with DGs' operational constraints and their power limitations. Accordingly, the generation power of the AG's DGs is limited by Eq (19). Moreover, Eqs (20) and (21) limit the maximum increase, and Eqs (22) and (23) limit the maximum decrease in the output power of DGs. Ultimately, mathematical and technical requirements of the AG's BSs are demonstrated in Eqs (24) to (28). In this regard, BSs' discharge and charge power limitations are stated in Eqs (24) and (25), respectively. Also, energy stored in BSs and their related limitations are illustrated in Eqs (26) and (27) as well as Eq (28), respectively.

In the end, the n th follower's set of decision variables are listed as follows:

$$\Xi^{n^{\text{th}} \text{ Follower}} = \left\{ P_{\text{exch}}^{\text{LEM,DA}}(n, t), P_{\text{AG}}^{\text{DG}}(n, i, t), P_{\text{AG}}^{\text{BS,dch}}(n, b, t), P_{\text{AG}}^{\text{BS,ch}}(n, b, t), E_{\text{AG}}^{\text{BS}}(n, b, t), \lambda, \mu \right\}$$

C. SOLVING THE PROPOSED STACKELBERG GAME-BASED FRAMEWORK

Since problems of followers, DER AGs, are linear, continuous, and thus convex, the considered one-leader-multi-follower game-based model could be reformulated to a single-level model by replacing the followers' problem with their Karush-Kuhn-Tucker (KKT) conditions [33]. In this context, KKT conditions, including the stationary, complementary slackness, and dual feasibility, are illustrated in Eqs (29) to (48).

$$\begin{aligned} & \frac{\partial \text{LF}}{\partial P_{\text{exch}}^{\text{LEM,DA}}(n, t)} \\ &= -\lambda^{\text{LEM,DA}}(t) + \lambda_1(n, t) \\ & \quad + \mu_1(n, t) - \mu_2(n, t) = 0, \quad \forall n, t \end{aligned} \quad (29)$$

$$\begin{aligned} & \frac{\partial \text{LF}}{\partial P_{\text{AG}}^{\text{DG}}(n, i, t)} \\ &= c_{\text{AG}}^{\text{DG}}(n, i) - \lambda_1(n, t) + \mu_3(n, t) - \mu_4(n, t) \\ & \quad + \mu_5(n, t)|_{t>1} - \mu_5(n, t+1) + \mu_6(n, t)|_{t=1} \\ & \quad - \mu_7(n, t)|_{t>1} + \mu_7(n, t+1) - \mu_8(n, t)|_{t=1} = 0, \\ & \quad \forall n, i, t \end{aligned} \quad (30)$$

$$\begin{aligned} & \frac{\partial \text{LF}}{\partial P_{\text{AG}}^{\text{BS,dch}}(n, b, t)} \\ &= -\lambda_1(n, t) + \mu_9(n, b, t) - \mu_{10}(n, b, t) \\ & \quad - \lambda_2(n, b, t) / \eta_{\text{AG}}^{\text{BS,dch}}(n, b) \Big|_{t>1} \\ & \quad - \lambda_3(n, b, t) / \eta_{\text{AG}}^{\text{BS,dch}}(n, b) \Big|_{t=1} = 0, \quad \forall n, b, t \end{aligned} \quad (31)$$

$$\begin{aligned} & \frac{\partial \text{LF}}{\partial P_{\text{AG}}^{\text{BS,ch}}(n, b, t)} \\ &= \lambda_1(n, t) + \mu_{11}(n, b, t) - \mu_{12}(n, b, t) \\ & \quad + \lambda_2(n, b, t) \eta_{\text{AG}}^{\text{BS,dch}}(n, b) \Big|_{t>1} \\ & \quad + \lambda_3(n, b, t) \eta_{\text{AG}}^{\text{BS,dch}}(n, b) \Big|_{t=1} = 0, \quad \forall n, b, t \end{aligned} \quad (32)$$

$$\begin{aligned} & \frac{\partial \text{LF}}{\partial E_{\text{AG}}^{\text{BS}}(n, b, t)} \\ &= -\lambda_2(n, b, t)|_{t>1} \\ & \quad + \lambda_2(n, b, t+1) - \lambda_3(n, b, t)|_{t=1} \\ & \quad + \mu_{13}(n, b, t) - \mu_{14}(n, b, t) = 0, \quad \forall n, b, t \end{aligned} \quad (33)$$

$$0 \leq P_{\text{exch}}^{\text{LEM,DA,max}}(n) - P_{\text{exch}}^{\text{LEM,DA}}(n, t) \perp \mu_1(n, t) \geq 0, \quad \forall n, t \quad (34)$$

$$0 \leq P_{\text{exch}}^{\text{LEM,DA}}(n, t) + P_{\text{exch}}^{\text{LEM,DA,max}}(n) \perp \mu_2(n, t) \geq 0, \quad \forall n, t \quad (35)$$

$$0 \leq P_{\text{AG}}^{\text{DG,max}}(n, i) - P_{\text{AG}}^{\text{DG}}(n, i, t) \perp \mu_3(n, i, t) \geq 0, \quad \forall n, i, t \quad (36)$$

$$0 \leq P_{\text{AG}}^{\text{DG}}(n, i, t) - P_{\text{AG}}^{\text{DG,min}}(n, i) \perp \mu_4(n, i, t) \geq 0, \quad \forall n, i, t \quad (37)$$

$$0 \leq \text{RU}_{\text{AG}}^{\text{DG}}(n, i) - P_{\text{AG}}^{\text{DG}}(n, i, t) + P_{\text{AG}}^{\text{DG}}(n, i, t-1) \perp \mu_5(n, i, t) \geq 0, \quad \forall n, i, t > 1 \quad (38)$$

$$0 \leq \text{RU}_{\text{AG}}^{\text{DG}}(n, i) - P_{\text{AG}}^{\text{DG}}(n, i, t) + P_{\text{AG}}^{\text{DG,ini}}(n, i) \perp \mu_6(n, i, t) \geq 0, \quad \forall n, i, t = 1 \quad (39)$$

$$0 \leq \text{RD}_{\text{AG}}^{\text{DG}}(n, i) - P_{\text{AG}}^{\text{DG}}(n, i, t-1) + P_{\text{AG}}^{\text{DG}}(n, i, t) \perp \mu_7(n, i, t) \geq 0, \quad \forall n, i, t > 1 \quad (40)$$

$$0 \leq \text{RD}_{\text{AG}}^{\text{DG}}(n, i) - P_{\text{AG}}^{\text{DG,ini}}(n, i) + P_{\text{AG}}^{\text{DG}}(n, i, t) \perp \mu_8(n, i, t) \geq 0, \quad \forall n, i, t = 1 \quad (41)$$

$$0 \leq P_{\text{AG}}^{\text{BS,dch,max}}(n, b) - P_{\text{AG}}^{\text{BS,dch}}(n, b, t) \perp \mu_9(n, b, t) \geq 0, \quad \forall n, b, t \quad (42)$$

$$0 \leq P_{\text{AG}}^{\text{BS,dch}}(n, b, t) - P_{\text{AG}}^{\text{BS,dch,min}}(n, b) \perp \mu_{10}(n, b, t) \geq 0, \quad \forall n, b, t \quad (43)$$

$$0 \leq P_{\text{AG}}^{\text{BS,ch,max}}(n, b) - P_{\text{AG}}^{\text{BS,ch}}(n, b, t) \perp \mu_{11}(n, b, t) \geq 0, \quad \forall n, b, t \quad (44)$$

$$0 \leq P_{\text{AG}}^{\text{BS,ch}}(n, b, t) - P_{\text{AG}}^{\text{BS,ch,min}}(n, b) \perp \mu_{12}(n, b, t) \geq 0, \quad \forall n, b, t \quad (45)$$

$$0 \leq E_{\text{AG}}^{\text{BS,max}}(n, b) - E_{\text{AG}}^{\text{BS}}(n, b, t) \perp \mu_{13}(n, b, t) \geq 0, \quad \forall n, b, t \quad (46)$$

$$0 \leq E_{\text{AG}}^{\text{BS}}(n, b, t) - E_{\text{AG}}^{\text{BS,min}}(n, b) \perp \mu_{14}(n, b, t) \geq 0, \quad \forall n, b, t \quad (47)$$

$$\lambda, \text{ Unrestricted} \quad (48)$$

Nonetheless, the final single-level model of the problem is non-linear due to the presence of some sources of nonlinearities, i.e., complementary slackness in Eqs (34) to (47) as well as $P_{\text{exch}}^{\text{LEM,DA}}(n, t) \lambda^{\text{LEM,DA}}(t)$ in Eq (1). For linearization of these expressions, the Big-M methodology and strong duality theorem (SDT) are utilized in this article [34]. Eq (49) demonstrates the generic formulation of the Big-M method. The important point in utilizing this method is selecting a

proper value for “M” as a sufficiently large parameter. That is because, too small “M” leaves the optimal solution out of the feasible space, while too large “M” may lead to computational inefficiencies in the solution of the obtained model. Furthermore, the dual problem of Eq (16) that leads to deriving the linear form of $P_{exch}^{LEM,DA}(n, t) \lambda^{LEM,DA}(t)$ is stated in Eq (50).

$$\begin{aligned}
0 \leq \psi \perp v \geq 0 &\rightarrow \begin{cases} \psi \leq MZ \\ v \leq M(1-Z) \end{cases} \quad (49) \\
\sum_{t \in T} \left\{ \begin{array}{l} \sum_{i \in I} P_{AG}^{DG}(n, i, t) c_{AG}^{DG}(n, i) \\ -P_{exch}^{LEM,DA}(n, t) \lambda^{LEM,DA}(t) \end{array} \right\} \\
= \sum_{t \in T} \left\{ -\lambda_1(n, t) \left(\begin{array}{l} \sum_{w \in W} P_{AG}^{WT,F}(n, w, t) \\ + \sum_{v \in V} P_{AG}^{PV,F}(n, v, t) \end{array} \right) \right. \\
- \mu_1(n, t) P_{exch}^{LEM,DA,max}(n) \\
- \mu_2(n, t) P_{exch}^{LEM,DA,max}(n) + \sum_{i \in I} \\
\times \left(\begin{array}{l} -\mu_3(n, i, t) P_{AG}^{DG,max}(n, i) \\ + \mu_4(n, i, t) P_{AG}^{DG,min}(n, i) \\ - \mu_5(n, i, t) RU_{AG}^{DG}(n, i)|_{t>1} \\ - \mu_6(n, i, t) [RU_{AG}^{DG}(n, i) + P_{AG}^{DG,ini}(n, i)]|_{t=1} \\ - \mu_7(n, i, t) RD_{AG}^{DG}(n, i)|_{t>1} \\ - \mu_8(n, i, t) [RD_{AG}^{DG}(n, i) - P_{AG}^{DG,ini}(n, i)]|_{t=1} \end{array} \right) \\
+ \sum_{b \in B} \left(\begin{array}{l} -\mu_9(n, b, t) P_{AG}^{BS,dch,max}(n, b) \\ + \mu_{10}(n, b, t) P_{AG}^{BS,dch,min}(n, b) \\ - \mu_{11}(n, b, t) P_{AG}^{BS,ch,max}(n, b) \\ + \mu_{12}(n, b, t) P_{AG}^{BS,ch,min}(n, b) \\ - \mu_{13}(n, b, t) E_{AG}^{BS,max}(n, b) \\ + \mu_{14}(n, b, t) E_{AG}^{BS,min}(n, b) \\ + \lambda_3(n, b, t) E_{AG}^{BS,ini}(n, b)|_{t=1} \end{array} \right) \Bigg\}, \quad (50) \\
\forall n, t
\end{aligned}$$

As a point of interest, if the feasibility of the resulting single-level model is not obtained momentarily due to the violation of the distribution network’s operational constraints, as well as technical constraints of the existing resources, the DSO as the operator and monitor of the system is potentially able to relax some constraints if the electricity supply reliability and quality can still be maintained at the feasible and allowable level.

III. SIMULATION RESULTS AND DISCUSSION

In this part of the article, the proposed LEM model for enabling the possibility of transactive energy exchange between the DSO and DER AGs is implemented and

evaluated on a modified IEEE-33 bus test system, depicted in Figure 2.

As shown in Figure 2, the DSO has two DGs, one WT and one PV, which have been located at buses 3, 8, 13, and 22, respectively. In addition, it is presumed that two DER AGs trade energy with the DSO at the distribution level. DER AG 1 contains five DGs, three WTs, and two PVs without any BS. These resources have been located at buses 2, 8, 13, 18, 23, 5, 18, 25, 10, and 15, respectively. DER AG 2 contains three DGs, three PVs, and three BSs without any WT. These resources have been located at buses 19, 27, 33, 29, 31, 33, 22, 29, and 31, respectively.

The output power of all these units is depicted in Figure 3. Note that both wind speed and solar irradiation profiles have been assumed to be the same for these DERs in the distribution system. On the other hand, the input data and technical specifications of these resources are summarized in Tables 2, 3, and 4.

It is worth noteworthy that since the primary purpose of this study is not to size and cite the available DERs at the distribution level, it has been assumed that the entire resources already exist in the network, and it is only attempted to evaluate their operating status.

On the other hand, the peak demand of the DSO’s customers in each bus is reported in Table 5.

The per-unit forecasted demand profile of the DSO is shown in Figure 4. Notably, in this research work, a forecasting technique or model has not been utilized, and it has been presumed that the demand profile is a forecasted value obtained from historical data.

Moreover, the DSO’s price of sold energy to its customers is a three-tariff price, which includes 30 €/MWh, 55 €/MWh, and 45 €/MWh in off-peak, peak, and mid-peak hours, respectively. Finally, it is assumed that the DSO’s maximum amount of exchange power with the upstream grid, WEM, is 10 MW.

Before presenting the output results, the list of assumptions that have been made in the simulation process is summarized as follows:

1. The entire DERs are assumed to be already located in the distribution system.
2. The wind speed and solar irradiation profiles are assumed to be the same for all DERs in the distribution system.
3. The forecasted demand profile is assumed to be obtained from historical data.
4. The price of sold energy to customers is assumed to be a three-tariff price.
5. The maximum amount of exchange power with the upstream grid is assumed to be 10 MW.

The optimal participation of the DSO in both WEM and LEM, as well as WEM forecasted price and LEM clearing price, have been displayed in Figure 5. Notably, the DSO’s purchased power is shown by positive bars, and its sold power is shown by negative bars.

Based on Figure 5, in the peak of the DA WEM price, i.e., hours 12 to 13 and 21 to 22, the DSO has supplied its excess

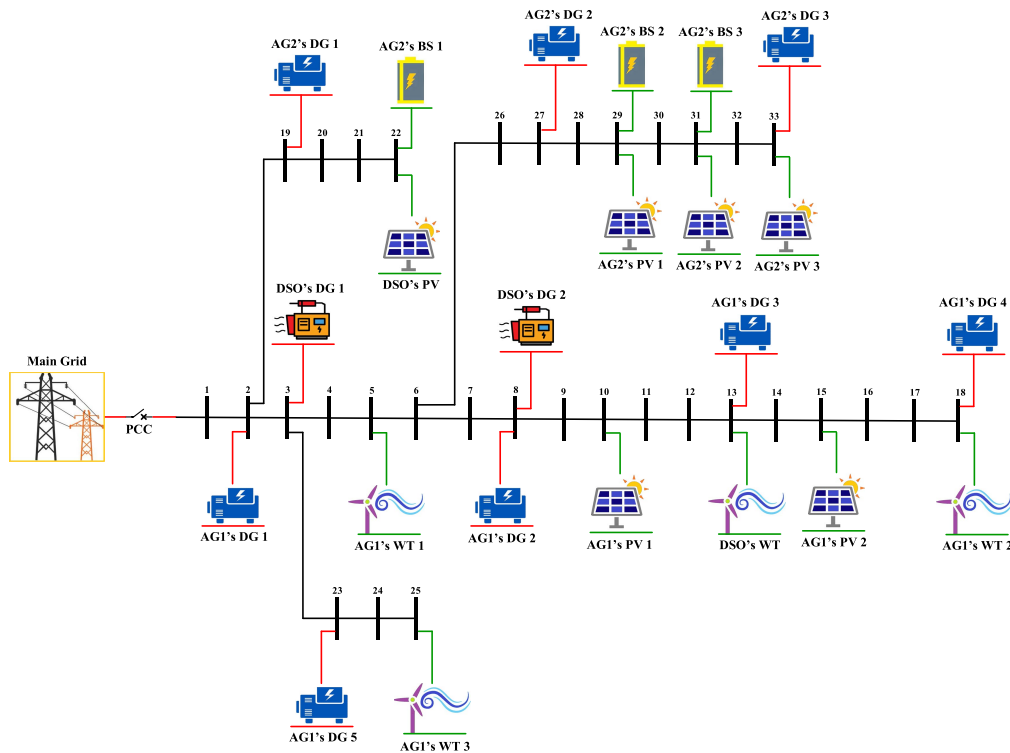


FIGURE 2. Single-line diagram of the modified IEEE-33 bus test system.

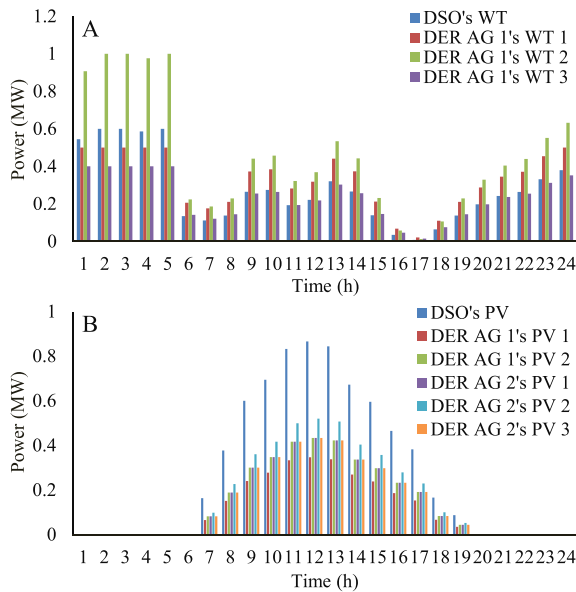


FIGURE 3. Output power of non-dispatchable DERs. (A) WTs. (B) PVs.

power to the market. This power has been procured from the DA LEM as well as the DSO-own local DERs. In other words, at these hours, the WEM price is at the maximum value, and

TABLE 2. Technical specifications of system's dispatchable units.

DSO					
#	$P_{DSO}^{DG,min}$	$P_{DSO}^{DG,max}$	a_{DSO}^{DG}	b_{DSO}^{DG}	$sdc_{DSO}^{DG}, suc_{DSO}^{DG}$
Unit	(MW)	(MW)	(€/MWh)	(€)	(€)
1	0.16	1.6	12.5	25.0	15.0
2	0.12	1.2	25.0	30.0	10.0
DER AG 1					
#	$P_{AG}^{DG,min}$	$P_{AG}^{DG,max}$	c_{AG}^{DG}	$RD_{AG}^{DG}, RU_{AG}^{DG}$	
Unit	(MW)	(MW)	(€/MWh)	(MW/h)	
1	0	1.0	25.0	0.5	
2	0	2.8	44.5	1.4	
3	0	2.4	38.5	1.2	
4	0	1.0	22.5	0.5	
5	0	4.2	51.5	2.1	
DER AG 2					
#	$P_{AG}^{DG,min}$	$P_{AG}^{DG,max}$	c_{AG}^{DG}	$RD_{AG}^{DG}, RU_{AG}^{DG}$	
Unit	(MW)	(MW)	(€/MWh)	(MW/h)	
1	0	0.5	20.0	0.3	
2	0	1.2	32.0	0.6	
3	0	1.0	28.5	0.5	

it is higher than the operating costs of the DSO's DGs as well as the LEM clearing prices. Hence, the DSO has exploited its DGs at full capacity and purchased the maximum amount of energy from the LEM to not only meet the system's demand

TABLE 3. Technical specifications of system's non-dispatchable units [35].

DSO					
# Unit	P_{DSO}^{WTR} (MW)	V_{DSO}^{WTR} (m/s)	$V_{DSO}^{WT,CI}$ (m/s)	$V_{DSO}^{WT,CO}$ (m/s)	$P_{DSO}^{PV,R}$ (MW)
1	0.6	14.0	4.0	20.0	1.0
DER AG 1					
# Unit	P_{AG}^{WTR} (MW)	V_{AG}^{WTR} (m/s)	$V_{AG}^{WT,CI}$ (m/s)	$V_{AG}^{WT,CO}$ (m/s)	$P_{AG}^{PV,R}$ (MW)
1	0.5	12.5	3.0	22.0	0.4
2	1.0	14.0	4.0	25.0	0.5
3	0.4	13.0	3.0	22.0	—
DER AG 2					
# Unit	P_{AG}^{WTR} (MW)	V_{AG}^{WTR} (m/s)	$V_{AG}^{WT,CI}$ (m/s)	$V_{AG}^{WT,CO}$ (m/s)	$P_{AG}^{PV,R}$ (MW)
1	—	—	—	—	0.5
2	—	—	—	—	0.6
3	—	—	—	—	0.5

TABLE 4. Technical specifications of the system's battery storage units.

DER AG 1					
# Unit	$E_{AG}^{BS,max}$ (MWh)	$E_{AG}^{BS,min}$ (MWh)	$P_{AG}^{BS,ch,max}$ (MW)	$P_{AG}^{BS,ch,min}$ (MW)	$\eta_{AG}^{BS,ch}$ (%)
1	—	—	—	—	—
2	—	—	—	—	—
3	—	—	—	—	—
DER AG 2					
# Unit	$E_{AG}^{BS,max}$ (MWh)	$E_{AG}^{BS,min}$ (MWh)	$P_{AG}^{BS,ch,max}$ (MW)	$P_{AG}^{BS,ch,min}$ (MW)	$\eta_{AG}^{BS,ch}$ (%)
1	4.0	0.4	2.0	0	0.98
2	4.0	0.4	2.0	0	0.98
3	4.0	0.4	2.0	0	0.98

TABLE 5. Peak load of the system.

# Bus	Demand (MW)	# Bus	Demand (MW)	# Bus	Demand (MW)	# Bus	Demand (MW)
2	0.21	10	0.71	18	0.36	26	0.95
3	0.93	11	0.20	19	0.52	27	0.83
4	0.81	12	0.89	20	0.32	28	0.56
5	0.88	13	0.86	21	0.90	29	0.57
6	0.97	14	0.49	22	0.38	30	0.74
7	0.55	15	0.59	23	0.75	31	0.13
8	0.83	16	0.31	24	0.89	32	0.70
9	0.22	17	0.82	25	0.67	33	0.53

but also sell its surplus to the WEM. Therefore, it can be inferred that the operating costs of the DSO's DGs and its costs from interacting with AGs in the LEM platform are lower than the profit made by selling energy to the WEM. On the contrary, in the off-peak of the DA WEM price, i.e., hours 3 to 4 and 16 to 17, the DSO has supplied its excess

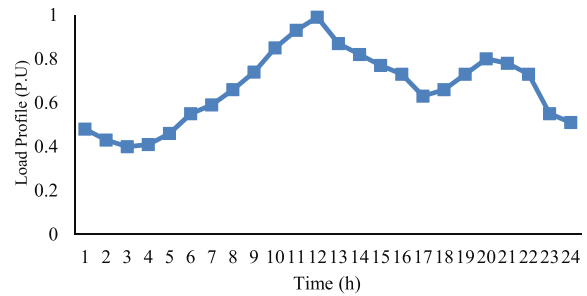


FIGURE 4. Load profile of the system.

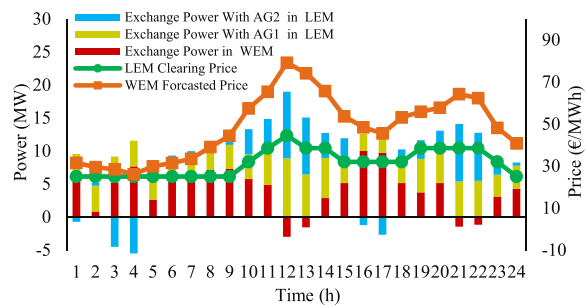


FIGURE 5. DSO's participation in both markets and market prices.

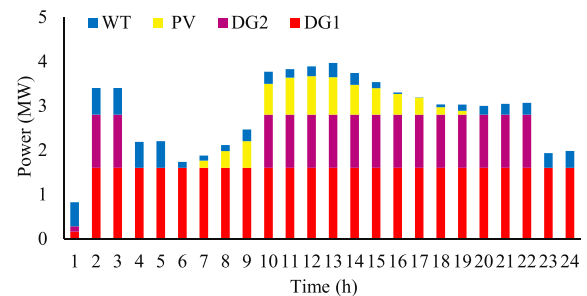


FIGURE 6. Operating points and generation profiles of the DSO's local resources.

power to the DER AG 2 in the LEM platform. This power has been procured from the WEM and DER AG 1. Moreover, during the whole day, the DSO has purchased the power from AG 1 in the LEM platform. On the other hand, as shown in Figure 5, the LEM clearing price has reached its highest value in the middle hours of the day, where the DSO's demand and the WEM price are high as well. Hence, the peak of the LEM clearing price is aligned with the peak of the WEM price. Indeed, owing to the peak demand, the DSO's bids in the LEM have increased.

The optimal operating points of the DSO's DGs and the generation profile of its non-dispatchable renewable resources are illustrated in Figure 6.

According to Figure 6, the DSO's DG 1 has been exploited with the maximum capacity during the whole day. Nonetheless, the DG 2, which has a high production cost, has been

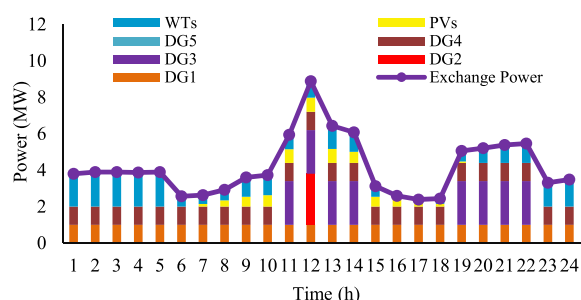


FIGURE 7. Optimal performance of the DER AG 1 in the DA LEM.

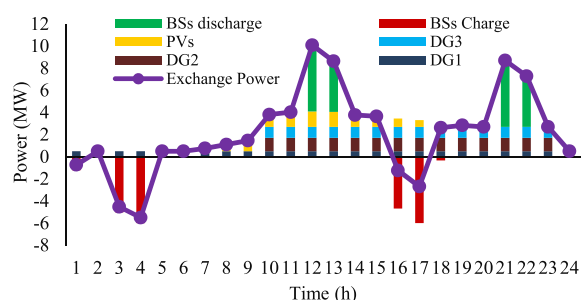


FIGURE 8. Optimal performance of the DER AG 2 in the DA LEM.

exploited only in the middle hours of the studied day. The generated power of these resources in the middle hours has been exploited by the DSO to inject energy into the WEM because their operating costs are lower than the profit made by selling this energy to the market. It can be emphasized that, since DGs' operational constraints, namely minimum up and down time, have been considered in the presented model as well, there are some limitations for turning off/turning on these units from the optimization point of view. By considering some specific constraints and costs, such as the amount of emission and its related cost, it may be better for the DSO to turn off its DGs instead of selling energy at peak hours.

On the other hand, Figures 7 and 8 represent the DER AG 1 and DER AG 2's optimal participation in the DA LEM, respectively, which has resulted from operating points as well as generation profiles of integrated DERs inside each AG.

According to Figure 7, the AG 1's DG 1 and DG 4 have been utilized with the maximum capacity during the whole day. At hours 1 to 9 and 24, the AG 1's DG 1 is the marginal producer in the LEM. The AG 1's DG 3 has been utilized in the peak of the DSO's demand and the WEM price, where the DSO's bids in the LEM have increased. At these hours, DG 3 has become the marginal producer, and the LEM clearing price has reached 38.5 €/MWh. Additionally, at hour 12, in which the DSO's demand and WEM price are at their highest value, the DER AG 1 has brought DG 2 to the service, and hence the LEM price has increased to 44.5 €/MWh. It is noteworthy that the AG 1's DG 5 has not been used over the studied day.

Based on Figure 8, the AG 2's DG 1 has been utilized with the maximum capacity during the whole day. At hours

TABLE 6. DSO's performance to supply the demand.

#	WEM	AG 1	AG 2	Local DERs	Load
T	(MW)	(MW)	(MW)	(MW)	(MW)
1	5.73	3.81	-0.72	0.82	9.64
2	0.83	3.90	0.50	3.40	8.63
3	5.25	3.90	-4.52	3.40	8.03
4	7.67	3.88	-5.50	2.19	8.24
5	2.63	3.90	0.50	2.20	9.23
6	6.23	2.58	0.50	1.73	11.04
7	6.58	2.63	0.76	1.87	11.84
8	7.11	2.93	1.10	2.11	13.25
9	7.32	3.61	1.46	2.46	14.85
10	5.75	3.73	3.81	3.77	17.06
11	4.86	5.96	4.03	3.82	18.67
12	-2.99	8.88	10.09	3.89	19.87
13	-1.57	6.44	8.63	3.96	17.46
14	2.87	6.08	3.78	3.74	16.47
15	5.15	3.12	3.65	3.53	15.45
16	10.00	2.59	-1.24	3.30	14.65
17	9.75	2.39	-2.69	3.19	12.64
18	5.15	2.44	2.63	3.03	13.25
19	3.73	5.06	2.84	3.02	14.65
20	5.15	5.21	2.70	3.00	16.06
21	-1.47	5.38	8.70	3.04	15.65
22	-1.16	5.47	7.28	3.06	14.65
23	3.09	3.32	2.70	1.93	11.04
24	4.27	3.49	0.50	1.98	10.24

10 to 23, the AG 2's DG 2 and DG 3 have been brought to the service and exploited with the maximum capacity. Thus, at hours 10, 15 to 18, and 23, AG 2's DG 2 has become the marginal producer, and the LEM clearing price has reached 32 €/MWh. On the other hand, DER AG 2 has charged its BSs in off-peak hours and discharged it in peak hours to sell power to the DSO via the LEM platform. It must be mentioned that some part of the BSs' charge power has been procured from the LEM, while some parts have been provided from the AG 2's own generation sources. For instance, at hour 17, for charging the AG 2's BSs, 2.7 MW power has been purchased from the LEM, and 3.3 MW power has been provided from DG 1, DG 2, DG 3, and PVs that are located at different buses.

To analyze the output results more accurately, the DSO's performance to supply its demand via the existing sources is reported numerically in Table 6. The second, third, and fourth columns of this table illustrate the DSO's exchanged power with the WEM, AG 1 in the LEM platform, and AG 2 in the LEM platform, respectively. Similar to Figure 5, the purchased power is shown by positive numbers, while the sold power is shown by negative numbers. The fifth column is associated with the generation power of the DSO-own DERs. Finally, the last column shows the distribution system's load in MW.

Based on Table 6, from hour 11 to hour 12, the DSO's situation has changed from purchasing energy to selling energy to the WEM, while the generation profile of its DERs, as well as its demand, are nearly the same at these hours. In this regard, the DSO has increased its purchasing powers from the DER AG 1 and DER AG 2 in the LEM by about 2.9 MW and 6.1 MW, respectively, to fulfill the network's load and

TABLE 7. Players' hourly revenue and costs.

# T	DSO			DER AG 1		DER AG 2		
	Customer Revenue	WEM Revenue	LEM Revenue	Operating Costs	LEM Revenue	Operating Costs	LEM Revenue	Operating Costs
1	289.01	-180.52	-77.06	85.00	95.18	47.50	-18.11	10.00
2	258.90	-24.48	-110.00	105.00	97.50	47.50	12.50	10.00
3	240.84	-149.22	15.51	105.00	97.50	47.50	-113.01	10.00
4	246.86	-200.06	40.60	55.00	96.90	47.50	-137.50	10.00
5	276.97	-78.65	-110.00	45.00	97.50	47.50	12.50	10.00
6	331.16	-195.83	-76.78	45.00	64.28	47.50	12.50	10.00
7	355.24	-219.83	-84.77	45.00	65.75	47.50	19.02	10.00
8	397.39	-277.24	-100.66	45.00	73.08	47.50	27.58	10.00
9	816.85	-324.78	-126.71	45.00	90.21	47.50	36.50	10.00
10	938.27	-330.21	-241.25	115.00	119.31	47.50	121.93	76.90
11	1026.58	-317.61	-384.12	105.00	228.91	139.90	155.20	76.90
12	1092.81	236.52	-844.15	105.00	395.35	264.50	448.81	76.90
13	960.35	116.70	-580.22	105.00	247.8	139.90	332.42	76.90
14	905.16	-188.24	-379.31	105.00	233.96	139.90	145.35	76.90
15	849.96	-276.02	-216.86	105.00	100.00	47.50	116.86	76.90
16	805.81	-484.16	-43.24	105.00	82.88	47.50	-39.64	76.90
17	568.98	-443.60	9.50	105.00	76.54	47.50	-86.04	76.90
18	596.08	-273.53	-162.18	105.00	78.09	47.50	84.09	76.90
19	659.30	-207.89	-304.21	105.00	194.90	139.90	109.31	76.90
20	722.52	-297.06	-304.66	105.00	200.71	139.90	103.95	76.90
21	704.46	94.49	-542.24	105.00	207.29	139.90	334.95	76.90
22	659.30	72.28	-490.81	105.00	210.38	139.90	280.43	76.90
23	496.73	-148.78	-192.54	55.00	106.14	47.50	86.40	76.90
24	460.61	-174.07	-99.58	45.00	87.08	47.50	12.50	10.00

export its excess, nearly about 3 MW, to the WEM. Similarly, from hour 20 to hour 21, the DSO has been able to act as a seller at the WEM by increasing its purchasing power from the DER AG 2.

To better investigate the income and costs of the considered players, the hourly distribution of their revenue and costs are reported in Table 7. The second, third, and fourth columns are related to the DSO's income from selling energy to its customers, participating in the WEM, and exchanging energy with DER AGs in the LEM platform, respectively. The fifth column is related to the operating costs of the DSO's DGs. The sixth and seventh columns are associated with the DER AG 1's income from participating in the LEM and operating costs of its DGs, respectively. Similarly, the eighth and ninth columns are associated with the DER AG 2's income from participating in the LEM and operating costs of its DGs, respectively. Obviously, the negative revenue in this table determines the costs of entities.

As clear in Table 7, the DSO has purchased energy from the WEM at most hours of the day, and only at hours 12 to 13 as well as 21 to 22 has achieved income from selling energy to the WEM. In addition, the DSO's cost of buying energy from the LEM has reached its maximum value at the mentioned hours. Notably, at only hour 17, the DSO has received revenue from selling energy to the LEM, where the DER AG 2 has purchased a considerable amount of energy from the DSO to charge its BSs. On the other hand, both DER AGs have received the highest amount of income at 12, where the LEM clearing price is at its maximum value.

TABLE 8. Players' daily profit and exchanged energy.

Player	Exchanged Energy (MWh)		Profit (€)
	WEM	LEM	
DSO	101.90	152.20	2932.61
DER AG 1	-	100.70	1343.44
DER AG 2	-	51.50	881.91

The daily profit of the LEM's players, as well as their traded energy, are summarized and compared in Table 8. It is notable that, the total exchanged energy of both DER AGs with the LEM is equal to the DSO's exchanged energy with this market.

In the following of this section, the impact of the transmission line capacity between the upstream grid and distribution network on the LEM clearing prices is evaluated. To this end, in addition to the base case with 10 MW line capacity, simulations are executed for 8 MW and 6 MW line capacities as well. It should be pointed out that since increasing the line capacity from 10 MW had no effect on the DSO's profit and its exchanged energy with the WEM, in this study, 10 MW capacity has been selected as the base case for the line between the upstream grid and the distribution network. Figure 9 compares the LEM prices in these three cases.

As depicted in Figure 9, by decreasing the transmission line capacity, the LEM clearing prices have increased in peak hours. These prices have raised in off-peak hours, i.e., 6 to 9, as well, for 6 MW line capacity. That is because, by confining

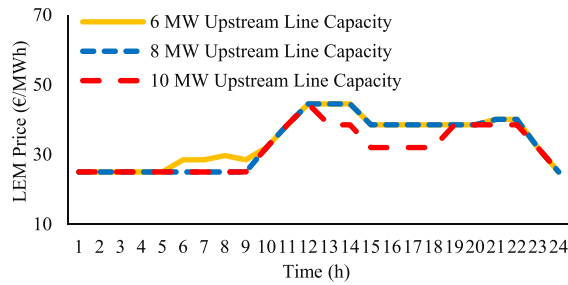


FIGURE 9. LEM clearing prices in three different cases.

TABLE 9. Players' daily profit in three different cases.

Case	Daily Profit (€)		
	DSO	DER AG 1	DER AG 2
10 MW line capacity	2932.61	1343.44	881.91
8 MW line capacity	2912.50	1504.30	997.03
6 MW line capacity	2854.57	1548.80	1012.89

the DSO's exchange power with the WEM, the DER AGs' most expensive DGs have been brought to the service and become marginal producers in the considered LEM.

Additionally, expected profits of the DSO and DER AGs in the aforementioned cases are reported and compared with one another in Table 9.

Based on Table 9, the DSO's profit has decreased by reducing the transmission line capacity between the upstream and distribution networks. On the contrary, both DER AGs' profits have increased owing to the raise in the LEM clearing prices.

Finally, to further highlight the potential advantages of the presented platform for implementing the LEM, another case study is analyzed in the following, in which electricity is traded between the DSO and DER AGs outside an organized marketplace. In this context, a bilateral contract is assumed to be made between the DSO and these entities to exchange energy at fixed prices. In this case study, three different tariffs are considered for the made bilateral contract, including:

Tariff 1 - 10 €/MWh less than the WEM price.

Tariff 2 - The WEM price.

Tariff 3 - 10 €/MWh more than the WEM price.

In Table 10, the obtained results from these three tariffs in the second case study are presented and compared with each other and with the first case study.

As shown in Table 10, when the price of the traded power between the DSO and DER AGs is less than the WEM price, the DSO has gained the highest amount of profit. In contrast, the DER AG 1's profit has been reduced remarkably due to the decrease in the contracted price with the DSO. In the meantime, the DER AG 2 has been able to improve its situation and gain more profit owing to the existence of

TABLE 10. Comparison between case studies.

Case Study	Daily Profit (€)			
	DSO	DER AG 1	DER AG 2	
Bilateral Contract	Tariff 1	3166.66	166.32	1188.34
	Tariff 2	-616.73	3094.22	1881.33
	Tariff 3	-919.24	1927.73	240.42
LEM Platform	2932.61	1343.44	881.91	

multiple BSs in its collation. Accordingly, the available BSs have helped the AG 2 to store its produced energy at off-peak prices and sell it to the DSO at peak prices.

When the price of the traded power between the DSO and DER AGs is equal to the WEM price, due to the high price of the WEM and the bilateral contract, the DSO has not only failed to make a profit but also incurred a cost. On the contrary, both DER AGs have gained more profit compared to the first tariff since they could sell their power at a higher price to the DSO.

When the price of the traded power between the DSO and DER AGs is more than the WEM price, the DSO has tended to procure its required demand from the WEM. Nonetheless, due to the technical constraints of the network, the DSO has had to provide some part of its needed power from the DER AGs at a higher price. Hence, this entity has faced more costs compared to the second tariff. Moreover, as a result of the DSO's unwillingness to purchase power from the DER AGs, their profits have declined as well.

The output results from two implemented case studies illustrate that in the presence of a local market-based platform for energy trading, a win-win situation can establish between the DSO and DER AGs, and these players are able to achieve their highest possible amount of profit.

IV. CONCLUSION

A DA LEM was modeled in this article to manage various types of real and virtual DERs at the distribution level. In this regard, several decentralized DERs were integrated within multi-AGs to trade their generation and storage capacities with the DSO as the operator of the LEM and the owner of the distribution system. In contrast, the DSO attempted to procure its demand through the DA LEM, DA WEM, as well as its local generation units, considering the technical constraints of the system. Since the mentioned players were independent financial entities with distinct objective functions, a Stackelberg game-theoretic method was executed in this study to settle the modeled LEM. To assess the effectiveness of the raised framework, two different case studies were conducted on a modified IEEE-33 bus test system. In the first case, the interaction between the DSO and AGs was implemented under the market-based platform, while in the second case,

this interaction was executed via the bilateral contract. Simulation results demonstrated that the existence of a potential LEM establishes a win-win situation between the market participants, and these entities can gain the highest possible amount of profit. For another point, it was observed that LEM clearing price is associated with different key factors, consisting of the WEM forecasted price, marginal prices of DGs, the forecasted demand of the DSO, and the topology of the distribution system.

For future work, the authors tend to investigate the impact of insufficient energy generation in the LEM on the optimal operation and profit of the market participants, as well as the energy prices customers receive.

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3

Overview of Modern Multi-Dimension Energy Networks

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Nomenclature

Acronyms

CO ₂	carbon dioxide
CHP	combined heat and power
EI	energy internet
EVs	electric vehicles
ESS	energy storage system
GDH	generation district heating
ICT	information and communication technologies
IMO	International Maritime Organization
IoT	internet of things
PEM	proton exchange membrane
PtG	power-to-gas
PtH	power-to-heat
PtX	Power-to-X
P2P	peer-to-peer
RERs	renewable energy resources
PV	solar photovoltaic
MDENs	multi-dimension energy networks
VESS	virtual energy storage system
WT	wind turbine

3.1 Introduction

Under the Paris agreement in 2015, to cope with global warming and climate change effects, a large number of countries were committed to implementing policies to reduce greenhouse gas emissions; and as of April 2021, 44 countries and the European Union have pledged to reach carbon neutrality targets [1]. To this end, a transition in the global energy sector to fulfill the world's climate goals is inevitable. Thereby, the penetration levels of RERs in power systems rise dramatically in recent years. As a considerable proportion of emissions are related to electricity generation from gas and coal-fired power plants, a significant reduction in global emissions is expected by increasing the penetration levels of RERs in the energy systems [1]. Also, deploying the high-efficient multidisciplinary energy technologies and electrification of the end-users play a key role in emission reduction across all sectors to accelerate realizing CO₂ net-zero society [1].

On the other hand, the swift rise of RERs' penetration levels in power systems has highlighted the necessity of more flexibility in the power system to mitigate generation uncertainty and availability [2]. In this context, MDENs are widely concerned as a solution for improving energy system efficiency and flexibility [3]. The MDENs can be realized by physically and virtually connecting various energy sectors, including electricity, heat, gas, etc., across infrastructures and markets to widely exploit synergies among different types of energy carriers [4]. In the MDENs, interconnecting and interactions between different energy networks have brought advantages as well as disadvantages. It is derived substantial benefits from increasing the flexibility, efficiency, resiliency, and emission reduction of the MDENs; however, the emergence of new interactions and interconnecting has resulted in more complexity in the management and operation of the MDENs [5].

There has been a rapid acceleration in moving toward modern MDENs because of advances in sector coupling technologies, ICT, and the advent of new market opportunities. In the modern MDENs, due to the high penetration level of RERs, sector coupling technologies provide a promising way to exploit or store the surplus electricity generated by RERs. Not only do recent advances in sector coupling technologies enable the realization of modern MDENs, but they also provide high levels of flexibility for energy systems by increasing the possibility of energy conversions [6]. Moreover, advancements in ICT and the internet of things (IoT) are expected to provide sufficient interconnection between MDENs and proper management tools. As one of the features of modern MDENs is their ability to make automated and optimized decisions in real-time, the role of ICT is absolutely crucial in modern energy systems [7]. On the other hand, modern MDENs can establish new opportunities for separate energy businesses to enter into partnerships on the market level. Hence, new market environments help to accelerate moving toward modern MDENs [8]. Notably, ICT development in modern MDENs can

result in new market opportunities and consequently change consumer behaviors. Consumers transform from passive users to influential parts can directly interact with the rest of the system by changing their usage patterns or participating in the energy markets as a prosumer [9]. Furthermore, it is worth noting that by advancements in communication technologies, further expectations are aroused by consumers. For example, they expect to have the ability to manage their energy surplus and shortage through peer-to-peer (P2P) online services [10].

Based on these descriptions, there is a great necessity to assess the features of modern MDENs from different aspects. Therefore, in this chapter, after scrutinizing the benefits of MDENs, the coordinated operation and planning of the modern MDENs are evaluated through innovative solutions, including new technologies and energy trading mechanisms. Then, different plans of various countries to increase the penetration of RERs and MDENs are presented. Finally, challenges related to modern MDENs are addressed to facilitate moving toward future energy systems.

3.2 Multi-Dimension Energy Networks

Scarcity of fossil fuels, pollutant emissions associated with them, low efficiency, and high loss in the conventional energy networks have led to the transition toward modern energy systems based on high penetration of RERs [11, 12]. According to [13], decarbonization, decentralization, and digitalization are major drivers of energy system transition. Decarbonization refers to reducing CO₂ emissions from energy production and consumption processes, which can be achieved on the supply-side by switching from fossil fuel-based conventional power plants to renewable-based energy generation. On the demand side, electrification of end-user services is a possible solution to move toward deep decarbonization as end-use electricity technologies are highly efficient with no CO₂ emissions. In this regard, electric vehicles (EVs) and heat pumps are highly efficient end-use electricity technologies [13]. The decentralization of energy systems is the other driver of the energy transition to make energy production closer to energy consumption sites. Increasing the penetration levels of RERs in power systems facilitates the decentralization of energy generation since these technologies can be employed in the consumption points on more minor scales. The decentralized energy systems can be realized by using more distributed energy resources, including renewable-based power generation units as well as energy storage technologies [14]. The other factor facilitating energy system transition is digitalization, known as exploiting advanced ICT in the energy systems' appliances and networks. Digitalization makes possible the adoption of smart controllability strategies on energy systems' management. In modern energy systems, digitalization enables the energy systems' operators to automatically control the fluctuations associated with RERs by adopting flexible options while allowing end-users

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to be involved in the demand side management. [15]. It is expected that digitalization will become more prominent in future energy systems by the advent of new market opportunities for end-users.

The uncertainties associated with integrated energy systems can lead to an imbalance between supply and demand, which can be managed via flexibility provision options. In this regard, MDENs with the ability to provide high levels of flexibility can be considered a practical solution to realize energy transition targets [16]. According to [17], the integration of heating and electricity sectors not only improves the efficiency and flexibility of a holistic energy system but also fulfills decarbonization targets. In this respect, the integration of heating and electricity sectors comes into sharp focus. Incorporating of these two sectors in the form of an integrated energy system can be realized through co-generation plants such as combined heat and power (CHP) plants and sector coupling technologies like Power-to-X options (PtX) [18]. Notably, a CHP simultaneously produces electricity and heat from fuel sources like natural gas, waste, and biomass. However, apart from the high efficiency, the integration of CHP plants in the power systems with high penetration of RERs is likely to limit renewable energy integration in the power systems [19]. Obligations to meet a given heat demand not only can reduce the flexibility of the CHP plant but also may restrict high levels of RERs penetration in the energy system [20]. In this regard, thermal storage can be utilized along with a CHP plant as a practical solution to increase the energy system's flexibility. [21]. Moreover, low-cost thermal energy storage in the integrated heat and electricity sectors can be used to maintain balance against the fluctuating generation of electricity from RERs [17, 22]. The other option that links the electricity and heating sectors is Power-to-Heat (PtH) technologies which are key elements of PtX options. It is worth noting that PtH technologies can categorize into two groups, including centralized and decentralized options [23]. According to the centralized approach, produced heat by electricity is located far from the location of heat demand. Consequently, there is a need for a district heating network to distribute the heat to the site of demand. In contrast, electricity is converted to heat right at/or near the heat demand location under the decentralized approach [23]. The most common PtH technologies are various kinds of heat pumps and electric boilers, mostly falling into two categories of centralized and decentralized options according to their scale [23]. A heat pump utilizes electricity to transport heat from a lower temperature region to a higher temperature region. Due to improving the efficiency of the heating sector as well as providing decarbonization of energy systems, heat pumps have recently attracted more attention in the building sector [17]. In [24], the integrated 2050 Danish energy system is analyzed, and the results reveal the importance of heat pumps and municipality solid waste CHP technologies on district heat networks to meet the emission reduction targets. Electric boilers are the other leading PtH technologies categorized into electrode

boilers and electric resistance boilers [23]. The high efficiency of both kinds of electric boilers has made them attractive options that can contribute to the decarbonization of the energy system. According to [25, 26], the exploitation of electric boilers and CHP plants can relax CHP units' heat-electric constraints provide more integration of wind power into the power grid, and effectively address the accommodation of curtailed wind power issues.

It is worth noting that historically heating was the central focus; however, the new generation of district heating networks has to satisfy both heating and cooling demands. In this regard, 4th- and 5th generation district heating (GDH) systems that integrate into a smart MDEN are introduced to fulfill heating and cooling needs. These systems can operate at low temperatures with high efficiencies, so implementing of 4GDH and 5GDH systems is crucial to fulfilling decarbonization targets [27, 28]. Moreover, both 4GDH and 5GDH systems facilitate the integration of RERs into the power grid and the cooperation of CHP plants and thermal storage systems. Consequently, the development of the new generation of district heating can strengthen the interconnectedness between heat and electricity networks [29].

In addition to the capability of PtH options to integrate between heating and electricity sectors, PtX technologies play a crucial role in realizing the integration of heating, electricity, and gas sectors [6]. By exploiting PtX technologies, further processing of renewable energy generation takes place via electrolysis to produce hydrogen, synthetic liquid and gases fuels, and synthetic chemicals, which their storage and transportation over long distances are much cheaper than electricity. Therefore, PtX productions can be easily used in every place energy is needed, and consequently, exploiting PtX technologies in renewable-based energy systems can provide further levels of flexibility [30]. Among the PtX options, Power-to-Gas (PtG) technology is highly focused owing to its potential to offer long-term seasonal storage of renewable electrical energy [31]. Extra electricity produced by RERs can be converted to hydrogen and synthetic natural gas via PtG technology and stored in the gas networks [32]. In this respect, not only do PtG technologies increase the connectedness between power and gas networks, but they also provide additional flexibility options. On the other hand, in the last decade, the power system has witnessed a rise in the proportion of natural gas in electricity production due to natural gas's continuous price reduction and low-rate greenhouse emissions, leading to increasing the interconnectedness between power and gas sectors [33]. It should note that produced gas by the PtG options can be utilized in the heating sector to fulfill high-temperature demands with reduced carbon emissions [34]. Furthermore, with increasing the penetration levels of RERs and PtX technologies, the deployment of different types of electrolyzers is on the rise. Currently, several electrolysis methods are on the focus; among them, proton exchange membrane (PEM) electrolysis is acknowledged as a promising technology for PtG technology [35]. It is worth noting that PEM electrolysis while

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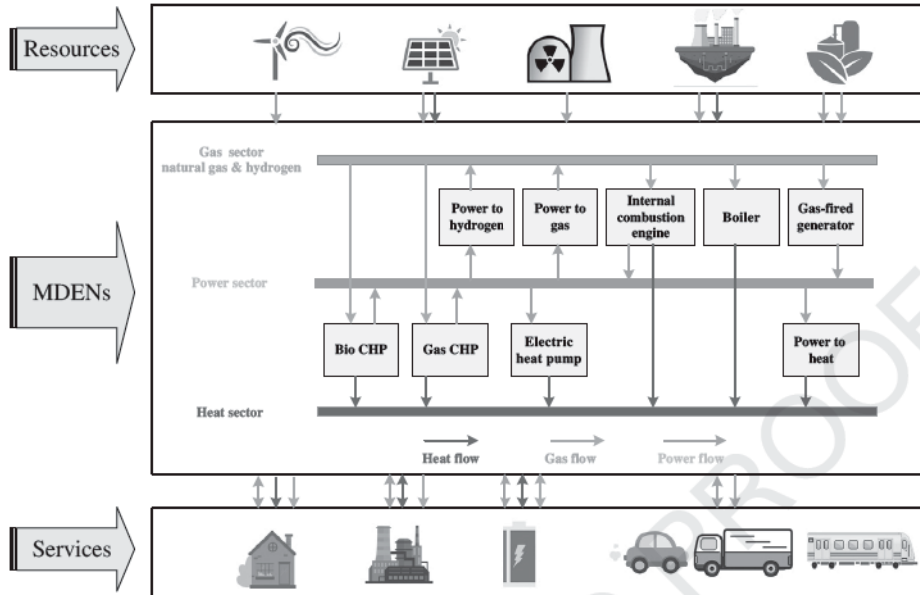


Figure 3.1 Interactions between MDENs technologies and networks.

producing hydrogen produces excess heat. The harnessing and integration of the produced excess heat in the district heating network can provide the other supply to meet heat demands. The method of capturing and exploiting of produced excess heat via a PEM electrolyzer is investigated in [36]. To sum up, it is concluded that MDENs enable the full exploitation of synergies between different energy carriers to accelerate moving toward decarbonized energy systems. Also, the high levels of uncertainty that have been a feature of energy transition can be fully addressed by MDENs, due to their high flexibility provision options. A simple overview of interactions between MDENs technologies and networks is depicted in Figure 3.1.

3.3 Benefits of MDENs

MDENs, as a potential solution for future energy systems, offer considerable advantages, shown in Figure 3.2, stemming from exploiting synergies between multi-energy carriers. In the following subsections, the main benefits of MDENs are provided.

3.3.1 Enhancing System Efficiency

The energy crisis problem has been challenging as energy consumption is rapidly increasing and traditional fossil fuel is quickly exhausted. In this context, the need for efficient usage of energy resources has been an utmost problem [37]. The

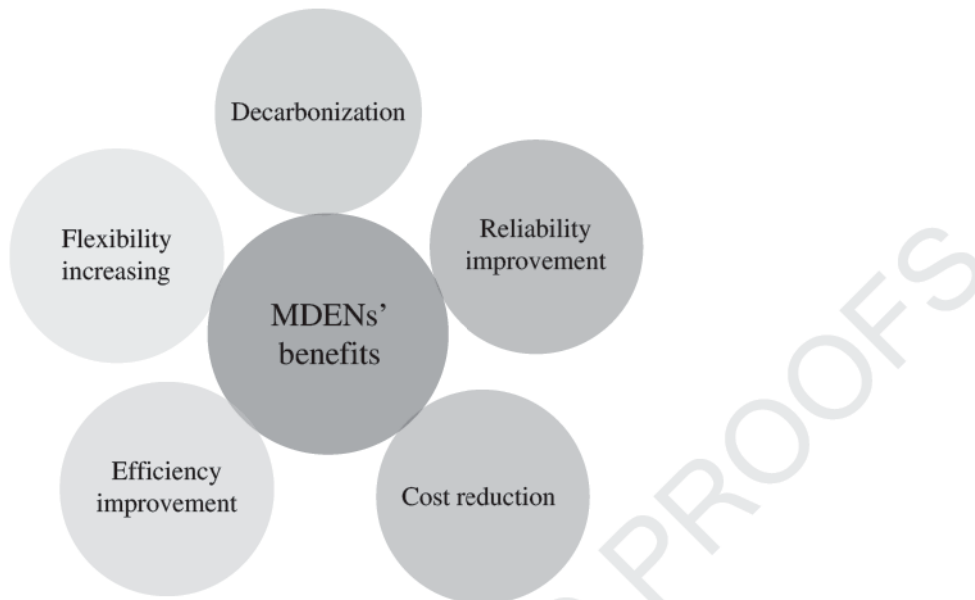


Figure 3.2 Benefits of MDENs.

efficiency of overall energy utilization can be improved via MDENs. In other words, higher integration of MDENs and a holistic approach toward the whole energy system may allow more efficient usage of resources. Furthermore, polygeneration systems with the ability to capture and reuse waste heat in the framework of MDENs are the other options to improve the energy system's efficiency [38].

3.3.2 Decarbonization

One of the most critical drivers of the energy transition is governments' policies to decrease greenhouse gas emissions from the energy sector, known as decarbonization [12]. To this end, the penetration level of RERs into the power system is increased to reduce the energy production from traditional systems with a high share of pollutant emissions. In this context, MDENs enable raising RERs' accommodation to foster fulfilling climate and energy targets. In addition, efficient usage of energy resources directly affects the decreasing pollutant emissions. Furthermore, electrification of the heat sector is vital in decarbonizing energy systems [39], which can be realized through MDENs.

3.3.3 Reducing System Operation Cost

First, MDENs enable efficient usage of energy resources which directly affects the reducing operation cost of the energy system. In addition, a holistic perspective

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toward the energy system and consequently optimizing the entire energy system operation cost rather than separately optimizing each energy sector is an effective way of simultaneously reducing the MDENs operation cost [3].

3.3.4 Improving System Flexibility and Reliability

Increasing the penetration level of intermittent RERs in the power system may result in demand and supply imbalance challenges. In this context, the need for flexible resources to provide the system with greater flexibility and reliability is of utmost importance. Employing diverse inputs and outputs in MDENs lets demand shift from one energy sector to another. As a result, one practical solution that offers more flexibility and reliability to the system is exploiting MDENs [3].

3.4 Moving Toward Modern Multi-Dimension Energy Networks

To successfully fulfill the energy transition, moving toward modern MDENs is inevitable. Nevertheless, future modern MDENs will confront a high level of complexity requiring revolutionary solutions in technological, policies, regulation, and societal aspects of meeting energy transition targets. Mostly, the design of the markets and regulatory structures are hardly keeping up with technological advancements [40]. Therefore, to accelerate moving toward future modern MDENs, both the technical side and regulatory and social side, must be concentrated. The following sections describe the pathways that can make progress toward modern MDENs.

3.4.1 Technology Advancements

Flexibility solutions in power systems are utilized to balance supply and demand, maintain the bus voltages, and increase transfer capacity [41]. Flexibility requirements and solutions can be categorized into three timescales: seconds to minutes, hourly, and seasonal/interannual fractions [42]. In the following, flexible solutions that have the potential to be used in the modern MDENs are described. At seconds to minutes timescales, synchronous condensers [43] and fast frequency response services from energy storage systems (ESS) [44] or other innovative solutions will be utilized to provide stability for the modern electricity sector equipped with 100% RERs. According to [45], coordination between networks or energy carriers in the modern MDENs can provide flexibility at longer timescales. Furthermore, exploiting different types of ESS and trade-based balancing solutions will be the other options to present flexibility in the hourly timescale for the modern MDENs [45].

Additionally, demand-side resources like EVs and various types of responsive loads will provide flexibility at an hourly timescale. It is expected in the modern MDENs, the concept of virtual energy storage system (VESS) will have attracted more attention. VESS aggregates various energy systems' controllable components to provide a considerable amount of ESS capacity with cheaper capital cost than the deployment of such real high capacity ESS [46]. Flexible loads, conventional ESS, multi-vector energy systems, microgrids, distributed generators all are examples of controllable components in power systems that can be incorporated into the framework of a VESS [46]. However, it will be crucial to adopt the advanced smart control and management tools and design novel market frameworks to fully exploit the potential of incorporated devices in the platform of the VESS in the modern MDENs. Finally, advanced long-term storage solutions like P2G and Power-to-Liquid will provide promising flexibility provision options for seasonal/interannual timescale [45]. Notably, financial issues and the economic feasibility of deploying novel long-term storage solutions create critical barriers to exploiting such technologies. According to [5], one of the main motivations for expanding electrolyzer technology is financial tax exemption. For this purpose, the electrolyzer technology does not need to be classified as an end-user, but it should be classified as a producer or energy conversion technology.

The decentralization trend will transform conventional centralized energy systems into distributed ones in future energy systems. In this context, to successfully meet energy transition targets, it is vital to create an environment in which such big data from distributed energy systems can be stored and processed. To this end, digitalization can provide an environment to support fulfilling decentralization targets. IoT is one of the recently emerged communication technologies that enable communication between devices employing different data types [47, 48]. In digitalized future power systems, exploiting advanced ICT as well as the IoT will enable making the optimal decision and fast processing by storage and process of extensive real-time data, improving control and monitoring, and also creating two-way energy and information flow between various parts of energy systems including generation, transmission, distribution, and end-users [49, 50]. In this regard, the concept of energy internet (EI) with the ability to provide digital interconnection between MDENs will be of absolutely central importance for modern MDENs [51]. It is worth noting that the concept of EI is different from the smart grid. The core of EI is smart grids; however, EI provides more interconnection between various energy networks through a cyber-network [52]. According to [53], future energy systems will be realized via EI with prominent features, including achieving flexibility of MDENs physical space and digitalization of cyber-space, which is based on real-time data and increasing the involvement of aware customers of social space. As the most recent emerging technology, IoT will be one of the promising options to create two-way energy and communication signal flow between

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different devices that can be employed in the framework of EI in future interconnected energy systems [47].

3.4.2 Policy-Regulatory-Societal Framework

Along with technological advancement, there is a pressing need to form a new policy- regulatory-societal framework to enable the shift from conventional separate energy networks to modern MDENs while satisfying energy transition targets. In modern MDENs, the implementation of clear policies will be paved the way to overcome the challenges related to the lack of hardware and technology standards, inappropriate energy markets, tariff design, high energy taxation, and data protection insecurity [40, 45, 54]. Furthermore, it will be essential to shape policies to provide a stable environment for increasing the investment in modern MDENs [54].

It is worth noting that the incorporation of an immense amount of renewable energy generation into existing liberalized power markets has resulted in very low or even negative electricity prices. Hence, this situation may hinder investors from increasing investments in renewable energy generation technologies and participating in power markets [55]. Therefore, to move toward renewable-based modern MDENs, a new market-clearing mechanism that stimulates investors to raise their involvement in the power market is of the utmost importance. In addition, new retail tariff designs should be focused on modern MDENs to incentivize consumers and energy-related established businesses providing products and services [56].

The other influential factor contributing to successful energy transition and facilitating progress toward modern MDENs is adopting new regulations. The outdated laws bring considerable benefits to network infrastructure rather than other cost-effective alternatives. They thus can limit the involvements of other market players such as consumers and prosumers in energy markets and demand response programs [40]. Moreover, outdated local regulations can impose restrictions on exploiting advanced ICT [40]. Notably, making the change in the regulatory environment is a highly complex matter, so the regulatory reform process can be particularly carried out locally during a relatively long period of time.

Realizing the digitalized future energy systems will bring out significant advantages as well as cybersecurity challenges. In the modern MDENs, cybersecurity challenges will become more complex as multiple digital systems will be connected in new ways, such as IoT. Furthermore, energy trading capabilities in modern MDENs seem to intensify cybersecurity challenges. In this context, the privacy of various types of stakeholders' data will need to be the main focus of attention in modern MDENs [57]. Private information leakage will have harmful consequences, including a degrading experience for market participants, cyber-attack threats, lack of confidence in services, economic losses, etc. [58]. In this regard, to ensure the privacy of market participants, especially customers, new policies must be shaped in the

modern MDENSs, aiming to trade-off between the benefits and risks received by market participants. To sum up, there is a pressing need for the adoption of an efficient policy-regulatory-societal framework to support profitable investment in RERs while facilitating the safe participation of prosumers and consumers in the energy markets and demand response programs by the advanced ICT.

3.5 Coordinated Operation of Modern MDENSs

Traditionally, all energy distribution networks are operated independently based on the existing regulatory and market frameworks. The move toward MDENSs has led to the widespread use of PtX technologies such as heat pumps, PtG, etc., resulting in increased synergies among different energy sectors [59]. Recently, considerable efforts have been expended to investigate the operation and scheduling of MDENSs as an integrated energy system [60, 61]. From this perspective, the operation cost of MDENSs is minimized in the day-ahead period rather than optimizing each energy distribution network's operation cost. According to [62, 63], coordinated operation of different sector coupling technologies, as well as the associated networks, can be beneficial in terms of facilitating the integration of RERs, improving the reliability and efficiency of the whole energy system, making balance between demand and supply, and providing congestion relief services in the various networks. However, the coordinated operation of different energy networks can be highly challenging due to the high rate of uncertainties and complexities. Increasing the interconnectivity between energy sectors will require advancements to address the issues related to high variability, unpredictability, stability, and complexity in modern MDENSs' coordinated operation problem. In this regard, the following subsections are provided to investigate the requirements to be adopted.

3.5.1 Technologies

In different energy sectors, scheduling tools supplying demand at the lowest cost while considering technical constraints. From the holistic perspective toward modern MDENSs' coordinated operation problem, exploiting advanced scheduling tools will be essential to propose a comprehensive solution while considering more detailed information about all energy sectors. Accordingly, in the following subsections, requirements of technological advancements are provided to effectively address the problem.

3.5.1.1 Enhanced Optimization Tools and Methods

The current status of the electricity, heat, and gas systems' infrastructures is reviewed in [64]. The results reveal that, despite many similarities, different characteristics of

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electricity, gas, and heat networks lead to dissimilar technical challenges as various nonlinearities resulting from various dynamic phenomena are considered in the modeling. In this regard, different technical aspects are involved in the modeling approaches. To effectively address the coordinated operation problem of modern MDENs, multi-energy modeling considering multiple technical aspects should be focused on methodologies. In addition, in modern MDENs, optimization tools need to be developed to assess the stochastic nature of the resources. In this regard, probabilistic, risk-based, and innovative multi-stage approaches will be required to economically and efficiently address the coordinated operation problem of modern MDENs. There is a pressing need for enhanced calculation methods to manage the complexity of the problem. Compared to traditional offline deterministic optimization methods, online and real-time stochastic optimized decisions will be beneficial in maintaining the reliable operation of modern MDENs under increasing uncertainty.

3.5.1.2 Improved Forecasting Tools

Due to the significant advantages of modern MDENs, these networks will play a vital role in future energy systems. In this regard, it is of utmost importance to consider the complex coupling relationships between various energy demands in load forecasting [65]. The load forecasting methods are used to define patterns based on historical data to predict specific future data in different periods [66]. Considering the tight coupling of modern MDENs, accurately forecasting multiple loads will be a crucial prerequisite to providing a more efficient solution for scheduling future energy systems. Adopting appropriate forecasting tools will likely be essential in reducing overall errors and the impact of uncertainties in the operation of modern MDENs. To this end, in the modern MDENs, machine learning methods and high-performance deep learning methods deriving from them will be focused on accurately forecasting multiple loads [67].

3.5.2 Markets

In modern-MDENs, the high rate of uncertainties will highlight the necessity for valuable solutions to increase the reliability of the energy supply while ensuring a dynamic energy balance. In this regard, the multi-energy trading possibility can be one of the most effective solutions which will help ensure the energy supply's reliability while creating a dynamic energy balance [68]. It is crucial to redesign the end-user side to incentive them to participate in a large-scale multi-energy market. Strengthening demand-side integration in scheduling applications requires the introduction of new market mechanisms and effective regulations, which enable the involvement of customers and encourage the emergence of agents aggregating demand-side resources to provide a large number of consumers with participating

in energy markets [45]. In this regard, different market mechanisms in which energy trading becomes possible are proposed in the following subsections.

3.5.2.1 Real-time Market Mechanisms

Advancements in communication technologies have led to a continuous transition from traditional energy grids to smart grids [69]. The use of smart grid-related technologies enables two-way communication of information flow, resulting in realizing real-time energy management [70]. In other words, the ability to exchange information provides distribution network operators with advanced management and monitoring systems to carry out real-time automated operations. In modern MDENs, the high share of RERs can create challenges in establishing real-time dynamic energy balance. Therefore, by exploiting advanced ICT, developing a real-time market mechanism will ensure a hedge against the high rate of uncertainties to achieve reliable energy supply and dynamic balance in modern MDENs.

With the proven necessity of real-time market mechanisms, different approaches can be taken into account for real-time energy management in the framework of a real-time market. Methods like multi-objective optimization and mixed-integer linear programming include a central operator that enables transaction management in real-time. In these methods, all participating units upload their information to the central operator, where then the energy management strategy will be determined and sent to each participant [71]. However, as the number of participants increases, real-time scheduling of resources is getting more difficult in these methods. Meanwhile, adopting these real-time energy management methods with a central operator makes it difficult for participants to adjust their bidding strategy based on received real-time information. Participants have to upload all their information to the central operator in these methods; therefore, energy management mechanisms based on the central part lack secure private communication. Thus, adopting real-time energy management methods with a central operator in the framework of real-time market mechanisms can reduce real-time transaction rates and participating units' overall profit while participants' privacy is invaded. As in the modern MDENs, the real-time energy market will be an effective solution for enhancing the system's reliability and stability; the aforementioned challenges must be addressed effectively. In this regard, the following subsection presents more flexible and efficient energy trading environments.

3.5.2.2 Peer-to-Peer Market Mechanisms

Prosumers who are both energy producers and consumers can play a crucial role in modern MDENs. Prosumers can use their production to satisfy their demands, while the excess energy can be sold to consumers or stored for later use. To encourage the prosumers to increase renewable energy generation, creating local energy markets in which the production of RERs can be traded between prosumers and

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consumers without any intermediary entity is essential. P2P transactions have turned out to stimulate prosumers to actively participate in the energy market [72]. In this market mechanism, a peer can be referred to one or a group of generators, consumers, and prosumers who are enabled to sell or buy energy directly with each other. P2P trading provides prosumers with the opportunity to sell their surplus renewable energy production and leads to energy cost reduction by giving end-users more flexibility in choosing suppliers [73]. Furthermore, a P2P-based market can be beneficial in terms of improving the local balance of energy production and consumption [74]. To sum up, P2P energy trading as a transparent market mechanism that enables real-time energy management will play a key role in mitigating the impacts of uncertainties on the coordinated operation of modern MDENs. In this regard, exploiting advanced digital technologies is essential for developing P2P energy transactions based on online services.

Recently emerging blockchain technology has received significant attention for successfully addressing security and transparency issues in the energy sector [75]. Blockchain technology can be applied to different areas of the energy system. In wholesale [76] or local level energy trading applications such as P2P energy trading [73], blockchain technology prove capable of providing a reliable and transparent energy trading environment without any central operator acting as a trusted intermediary. Blockchain technology can give prosumers more incentives to engage in P2P energy trading applications and provide local dynamic energy balance in the operation of distributed energy systems. A simple overview of the P2P market mechanism in the blockchain-based network is depicted in Figure 3.3. In terms of demand-side energy management, blockchain technology demonstrates the potential for realizing real-time energy management [77]. EVs, as one of the essential demand-side resources, can both play the role of energy suppliers and consumers in the distributed power system. Two-way communication of EVs with modern power systems can help alleviate the problem of imbalances in demand

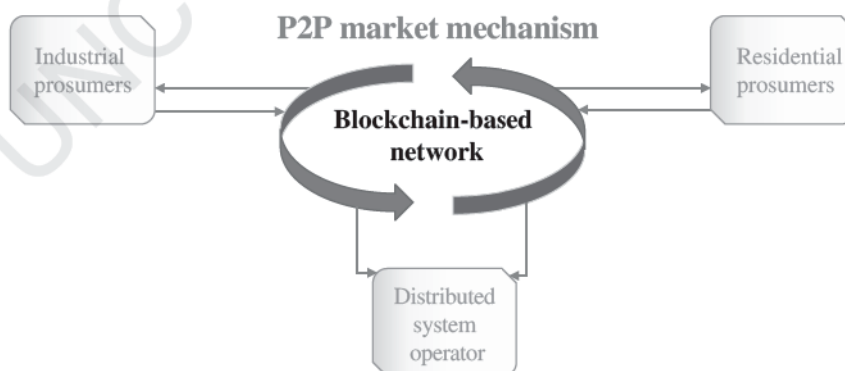


Figure 3.3 P2P market mechanism in blockchain-based network.

and supply. Blockchain technology can provide EVs with secure charging services and an easy payment mechanism to create a demand-supply energy balance in the operation of modern energy systems [78].

3.6 Coordinated Planning of Modern MDENs

Traditionally, the energy infrastructures such as natural gas, electricity, and district heating networks are designed and planned separately. However, to fully benefit from the advantages of MDENs and realize energy transition targets, the coordinated planning of various energy networks is essential [79]. The targets of coordinated planning of MDENs are to find optimal investment plans of all the assets associated with MDENs, including multi-energy generation, transmission, distribution, storage, and coupling components to meet growing demand, replace retiring infrastructures, and strengthen existing networks [80]. In this regard, the objective function of the coordinated planning of MDENs is minimizing the investment, operational, and maintenance costs while considering technical constraints and satisfying current and future demand at different time horizons. Furthermore, environmental performance, energy reliability, energy losses, and system quality can be considered in the objective function along with other terms [80, 81]. In the coordinated planning of modern MDENs, with a high penetration level of RERs, it is crucial to consider more ESS as well as conversion technologies to store and transform renewable energy generation.

Furthermore, as modern MDENs will be more digitalized and decentralized, energy and data security must be focused on the coordinated planning problem of modern MDENs [82]. Future scenarios with advanced integrated modeling of MDENs and associated sector-coupling technologies must be investigated to effectively address the coordinated planning problem. Notably, advanced analytical and optimization methods are required to handle the high complexity and long-term uncertainties related to the problem. In the future, the regulatory strategies, the emergence of energy markets, and fluctuations in energy prices can be influential factors in employing various investment strategies of companies. Therefore, the impacts of regulatory and market factors must be considered in the coordinated planning of modern MDENs to obtain more investment savings and efficient energy utilization [81].

3.7 Future Plans for Increasing RERs and MDENs

Over the last few decades, RERs have become an obvious alternative to realize decarbonization targets. Besides solar photovoltaic (PV) and onshore wind farms, offshore wind farms are attractive options for increasing the RERs penetration in

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the energy system. The significant advantage of offshore wind farms is the consistency in generation power [83]. Currently, offshore wind farms are highly focused in the EU, with 84% of global installations, due to technical and commercial maturity in this industry. The United Kingdom, Germany, Denmark, the Netherlands, and Belgium are large European offshore wind energy producers, respectively. In addition, the offshore wind industry in China has been rapidly expanding; as a result, China is placed third in global offshore wind energy producers after the United Kingdom and Germany [84].

Notably, hydrogen production from offshore wind farms can be exploited in the transport and heat sectors to fulfill decarbonization targets. Hydrogen can be stored and transported long distances with fewer costs than power transmission lines [85]. On the other hand, according to European Commission's hydrogen strategy released in 2020, developing a viable hydrogen market at a significant scale is vital to meet carbon neutrality targets. In this regard, exploiting high-potential offshore wind farms to produce hydrogen is essential to fulfilling decarbonization targets [86].

According to International Maritime Organization (IMO), 3–5% of the total Green House Gases emissions are related to maritime transportation; however, this portion will increase to 18% by 2050 if no actions are taken into account. Thereby, decarbonization of maritime operations is essential to realize the decarbonization targets of the energy transition. In this regard, the concept of seaport microgrid is proposed to increase RER's penetration in energy systems and consequently hit the decarbonization targets [87]. Therefore, renewable energy generation technologies such as PV systems, wind turbines (WTs), ocean energy, geothermal sources, biomass, and hydrogen contribute to power generation in seaports. As the world's largest solar power generation port, the Jurong port, Singapore, with more than 10 MW of PV modules, plans to become the first zero-carbon footprint port worldwide. To this end, it is vital to focus on the seaport microgrid concept to facilitate renewable energy integrations and meet decarbonization targets [87].

Improving efficiency and flexibility is essential to achieve ambitious goals in expanding the use of RESs and reducing greenhouse gas emissions. In this regard, MDENs are suitable solutions for the adaptation of future energy systems with efficiency and flexibility demands. The future MDEN-rich energy systems will face high levels of complexity that require fundamental changes in technological, policy, regulation, and social perspectives [45].

3.8 Challenges

As large-scale RERs will be the heart of future energy systems, a high share of uncertainty will be one of the most critical challenges of modern MDENs. According to [5], one of the most critical requirements moving toward future modern MDENs is

substantial infrastructure investments to increase the electricity distribution grid's capacity and sufficiently provide renewable energy storage and transformation. Exploiting transformation technologies, such as P2G, in the modern MDENs will be essential but struggling due to their high capital cost and limited-hours full-load application in response to excess renewable energy generation [88]. Therefore, technological advancements in transformation technologies, such as P2G, are necessary to increase transformation efficiency and benefits of investors.

From the modeling perspective of modern MDENs, long-term and short-term uncertainties effects must be considered [89]. Notably, modern MDENs modeling is influenced by multi-energy systems' infrastructures and associated sector coupling technologies and is also affected by the regulatory strategies and various market stakeholders' attitudes [90]. Therefore, modern MDENs require increased research on holistic energy systems modeling while considering social and regulatory aspects. However, the effects of regulations, customers, and market stakeholders have rarely been included in the future energy system's modeling scenarios [91]. Accordingly, it is necessary to define new evaluation frameworks of modern MDENs' modeling to investigate their effectiveness from different aspects and various points of view, including end-users, utilities, and market stakeholders [92].

On the other hand, the digitalization trend has led to deploying advanced smart devices and producing a large amount of data from different parts of modern MDENs. Hence, it is notable that the risk of data leakage or destruction during transmission is potential. These produced data are valuable for energy producers and companies, grids' operators, prosumers, and consumers to spur participation in energy markets and also can be used to forecast future energy supply and demand [93]. As a result, modern MDENs will face the challenges of large amounts of data management, including information technology infrastructures, data collection and sharing, data processing, analysis, and data security and privacy issues [89]. Furthermore, the emergence of new market mechanisms in modern MDENs will intensify the importance of real-time data management and data security. For example, while P2P-based market mechanisms, as a new market mechanism, provide both prosumers and grid operators with significant benefits, the privacy of individual participants and the security of the grid are critical challenges that modern MDENs will face in the presence of new market mechanisms [94]. Notably, modern MDENs will face regulatory problems apart from technical and technological challenges. Notably, exploiting technological advancement can be done in the framework of the applicable legislative rules. For instance, the establishment of P2P energy markets and encouraging prosumers and retailers to participate in energy trading are all related to decisions of the regulatory board [95]. As a result, to successfully deal with challenges related to modern MDENs, both technological and regulatory aspects must be considered, as shown in Figure 3.4.

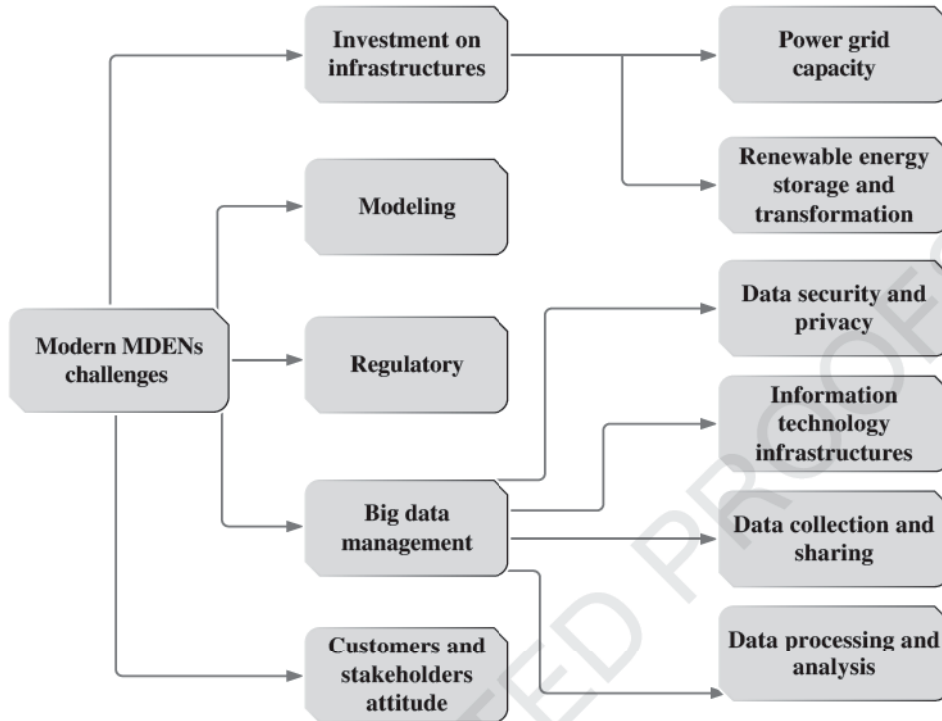


Figure 3.4 Challenges of modern MDEN.

3.9 Summary

The energy system transition has started in response to three drivers: decarbonization, decentralization, and digitalization. In this regard, the proven capabilities of MDENs make them a practical option for fulfilling energy transition targets. On the other hand, advances in ICTs and sector coupling technologies accelerate moving toward modern MDENs. According to these matters, after evaluating MDENs and their associated benefits in this chapter, technological and regulatory drivers accelerating moving toward modern MDENs are discussed. Furthermore, after investigating technological advancements and market-based solutions to address the modern MDENs' coordinated operation, significant issues related to the coordinated planning problem of modern MDENs are presented. Then, different plans of various countries to increase the penetration of RERs, and as a result, to realize energy transition targets are discussed. Finally, the primary challenges that modern MDENs will face are provided.

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12

Hybrid Energy Storage Systems for Optimal Operation of the Heat and Electricity Incorporated Networks

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Nomenclature**Acronyms**

BESS	Battery Energy Storage System
CHP	Combined Heat and Power
DA	Day-Ahead
EB	Electric Boiler
EHP	Electric Heat Pump
GFG	Gas Fired Generator
GST	Gas Station
HESS	Hybrid Energy Storage System
IEHN	Integrated Electricity and Heat Network
NGESS	Natural Gas Energy Storage System
NGFG	Non-gas Fired Generator
P2X2P	Power-to-X-to-Power
PV	Photovoltaic System
RT	Real-Time
ST	Solar Thermal System
TESS	Thermal Energy Storage System
WT	Wind Turbine

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Sets and Indices

$bs \in BS$	Set of BESSs
$c \in C$	Set of CHPs
$eb \in EB$	Set of EBs
$g \in G$	Set of GFGs
$gs \in GS$	Set of NGESSs
$hp \in HP$	Set of EHPs
$ng \in NG$	Set of NGFGs
$p \in P$	Set of PVs
$s \in S$	Set of Scenarios
$st \in ST$	Set of STs
$t \in T$	Set of Hours
$ts \in TS$	Set of TESSs
$w \in W$	Set of WTs

Parameters

α, β	Cost coefficients of NGFGs
CP	EHPs' coefficient of performance
D^E, D^H	Electricity/heat demand of IEHN
$E_{BESS}^{ini}, E_{BESS}^{max}, E_{BESS}^{min}$	Initial/maximum/minimum electrical energy stored in BESSs
$E_{NGESS}^{ini}, E_{NGESS}^{max}, E_{NGESS}^{min}$	Initial/maximum/minimum gas energy stored in NGESSs
$E_{TESS}^{ini}, E_{TESS}^{max}, E_{TESS}^{min}$	Initial/maximum/minimum thermal energy stored in TESSs
$G_{NGESS}^{in,max}, G_{NGESS}^{in,min}$	Maximum/minimum charged gas of NGESSs
$G_{NGESS}^{out,max}, G_{NGESS}^{out,min}$	Maximum/minimum discharged gas of NGESSs
$H_{EHP}^{max}, H_{EHP}^{min}$	Maximum/minimum produced heat of EHPs
H_{HN}^{max}	Maximum heat exchanged with heat network
H_{ST}	Output heat of STs
$H_{TESS}^{ch,max}, H_{TESS}^{ch,min}$	Maximum/minimum charged heat of TESSs
$H_{TESS}^{dch,max}, H_{TESS}^{dch,min}$	Maximum/minimum discharged heat of TESSs
HPR	Heat-to-power ratio of CHPs
HV_{gas}	Heat value of natural gas
$P_{BESS}^{ch,max}, P_{BESS}^{ch,min}$	Maximum/minimum charged power of BESSs

$P_{\text{BESS}}^{\text{dch,max}}, P_{\text{BESS}}^{\text{dch,min}}$	Maximum/minimum discharged power of BESSs
$P_{\text{CHP}}^{\text{max}}, P_{\text{CHP}}^{\text{min}}$	Maximum/minimum generated power of CHPs
$P_{\text{EB}}^{\text{max}}, P_{\text{EB}}^{\text{min}}$	Maximum/minimum generated power of EBs
$P_{\text{EN}}^{\text{max}}$	Maximum power exchanged with electricity network
$P_{\text{GFG}}^{\text{max}}, P_{\text{GFG}}^{\text{min}}$	Maximum/minimum generated power of GFGs
$P_{\text{NGFG}}^{\text{max}}, P_{\text{NGFG}}^{\text{min}}$	Maximum/minimum generated power of NGFGs
P_{PV}	Output power of PVs
P_{WT}	Output power of WTs
$RD_{\text{CHP}}, RU_{\text{CHP}}$	Ramp-down/up ratio of CHPs
$RD_{\text{GFG}}, RU_{\text{GFG}}$	Ramp-down/up ratio of GFGs
$RD_{\text{NGFG}}, RU_{\text{NGFG}}$	Ramp-down/up ratio of NGFGs
$sd_{\text{CHP}}, su_{\text{CHP}}$	Shout-down/start-up price of CHPs
$sd_{\text{GFG}}, su_{\text{GFG}}$	Shout-down/start-up price of GFGs
φ	Scenario probability
λ_D^E, λ_D^H	Sold price to electricity/heat demand
$\lambda_{\text{DA}}^E, \lambda_{\text{DA}}^H$	DA electricity/heat price
λ_{gas}	Natural gas price
$\lambda_{\text{RT}}^E, \lambda_{\text{RT}}^H$	RT electricity/heat price
$\eta_{\text{BESS-ch}}, \eta_{\text{BESS-dch}}$	Charge/discharge efficiency of BESSs
$\eta_{\text{CHP-E}}, \eta_{\text{CHP-H}}$	Electricity/heat efficiency of CHPs
$\eta_{\text{EB-H}}$	Heat efficiency of EBs
$\eta_{\text{GFG-E}}$	Electricity efficiency of GFGs
$\eta_{\text{NGESS-in}}, \eta_{\text{NGESS-out}}$	Charge/discharge efficiency of NGESSs
$\eta_{\text{TESS-sb}}, \eta_{\text{TESS-ch}},$	Standby/charge/discharge efficiency of TESSs
$\eta_{\text{TESS-dch}}$	

Decision Variables

E_{BESS}	Electrical energy stored in BESSs
E_{NGESS}	Gas energy stored in NGESSs
E_{TESS}	Thermal energy stored in TESSs
G_{GST}	Gas flow from GST
$G_{\text{GST-CHP}}$	Gas flow from GST to CHPs
$G_{\text{GST-GFG}}$	Gas flow from GST to GFGs
$G_{\text{GST-NGESS}}^{\text{in}}$	Total charged gas of NGESSs from GST
$G_{\text{NGESS}}^{\text{out}}$	Total discharged gas of NGESSs
$G_{\text{NGESS-CHP}}$	Gas flow from NGESSs to CHPs
$G_{\text{NGESS-GFG}}$	Gas flow from NGESSs to GFGs

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H_{CHP}	Generated heat of CHPs
H_{DA}	DA exchanged heat with heat network
H_{EB}	Generated heat of EBs
H_{EHP}	Generated heat of EHPs
H_{imb}	Imbalance heat
H_{RT}	RT exchanged heat with heat network
$H_{\text{TESS}}^{\text{ch}}, H_{\text{TESS}}^{\text{dch}}$	Charged/discharged heat of TESSs
OC_{CHP}	Operating cost of CHPs
OC_{GFG}	Operating cost of GFGs
OC_{NGESS}	Operating cost of NGESSs
OC_{NGFG}	Operating cost of NGFGs
$P_{\text{BESS}}^{\text{ch}}, P_{\text{BESS}}^{\text{dch}}$	Charged/discharged power of BESSs
P_{CHP}	Generated power of CHPs
P_{DA}	DA exchanged power with electricity network
P_{EB}	Consumed power of EBs
P_{EHP}	Consumed power of EHPs
P_{GFG}	Generated power of GFGs
P_{imb}	Imbalance power
P_{NGFG}	Generated power of NGFGs
P_{RT}	RT exchanged power with electricity network
SDC_{CHP}	Shout-down cost of CHPs
SUC_{CHP}	start-up cost of CHPs
SDC_{GFG}	Shout-down cost of GFGs
SUC_{GFG}	start-up cost of GFGs
Δ_H, Δ_P	Index for calculation of imbalance heat/power

Binary Variables

U . Binary variable for the performance of •

12.1 Introduction

By and large, a considerable amount of energy consumption is provided by fossil fuels. These days, due to the lack of these fuel sources as well as their irreversible environmental impacts, the tendency towards the exploitation of renewable-based resources in energy systems has increased remarkably [1]. Accordingly, the

ultimate goal of the European Union is to reach a 100% renewable-based energy system and carbon neutrality by the end of 2050 [2]. While the emergence of renewable energies is able to overcome the mentioned challenges, the stochastic and intermittent nature of these units is increased the need for flexibility in the electricity sector [3]. In recent years, several solutions have been presented to promote flexibility in power systems. One of the most prevalent solutions for flexibility provision is the utilization of real and virtual energy storage systems like compressed air, battery, and pumped hydropower storage units, as well as demand response programs [4]. Apart from using storage resources as enabling technologies, other solutions have been raised currently to provide more flexibility in electricity networks. Out of the novel and pragmatic solutions, coupling of different energy sectors, including electricity and heat, in the form of an incorporated energy system has attracted more attention [5]. Nonetheless, for connecting these two sectors and establishing an integrated electricity and heat network (IEHN), the existence of power-to-X-to-power (P2X2P) conversion technologies is highly required [6]. P2X2P is a set of technologies that provides synergies among different networks and allows for converting an energy carrier into other energy carriers, some of which are combined heat and power (CHP) plants [7], power-to-heat (P2H) units like electric heat pump (EHP) and electric boiler (EB) [8], heat-to-power (H2P) units, power-to-gas (P2G) units [9], gas-to-power (G2P) units like a gas-fired generator (GFG) [10], etc. In this regard, power-to-X (P2X) interface elements provide the opportunity to transfer and consume surplus electricity production in the form of other energies. On the other hand, it is possible to store the excess power generation in other sectors by using the storage capacities. Then, the stored energy can be returned to the electricity system by X-to-power (X2P) interface elements when the network is faced with a shortage. Based on these explanations, it seems that coupling of heat and electricity networks by P2X2P infrastructures as well as exploiting various kinds of electricity, heat, and gas storage units in the form of a hybrid energy storage system (HESS) [11] not only promote flexibility of these systems but also diminish the operating costs of IEHN owing to the reduction in fuel consumption.

In the past few years, several research works have been conducted to assess the impact of sector coupling as well as P2X2P and storage technologies on the optimal operation of the IEHN, some of which are highlighted in the following:

A mixed-integer linear programming model has been used in [12] to evaluate the coordinated operation of heat and power networks in the presence of demand response programs. The objective function of this problem is to minimize the operating cost of the IEHN considering the technical constraints of the whole system. A robust optimization model has been developed in [13] for the economic

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operation of the IEHN in the presence of an uncertain environment as well as demand response programs. The primary goal of this research work is to examine the impact of CHP units on the total operating cost of the incorporated system. To enhance the use of wind energy, the coupling of power and heat networks, as well as exploiting P2X technologies, including CHP, EB, and EHP, has been provided in [14]. The objective of this study is to minimize the operating cost of dispatchable units and the curtailment cost of wind power. A distributed optimization technique has been suggested in [15] to investigate the optimal operation of the IEHN in a decentralized manner. The objective function of this study is to diminish the total operating cost of the incorporated system taking into account its technical constraints. A two-stage stochastic programming approach has been utilized in [5] for the optimal operation of the IEHN in both day-ahead (DA) and real-time (RT) stages. The raised framework has considered the detailed reserve modeling of P2X2P and storage elements with the aim of expected cost minimization. A distributed optimization approach has been suggested in [16] for the optimal performance of an IEHN, which is operated by separate power and heat system operators. The main goal of this problem is to minimize the operating cost of coupled networks considering privacy-preserving matters of each independent system operator. A distributed optimization model combined with a hybrid stochastic-robust technique has been presented in [17] to cope with various uncertainties in the operation of the IEHN in a decentralized way. The primary objective of this problem is to decrease the operating costs of the IEHN with the minimum information exchange between power and heat system operators. A novel optimization approach has been proposed in [18] to relax non-convexities raised from the coupling of heat and power sectors through CHP units. This study's objective function is the minimization of operating costs and losses of the considered IEHN. A two-stage stochastic programming scheme has been utilized in [19] for the optimal operation of the IEHN with the detailed modeling of reserve provision and heat regulation of the existing P2X infrastructures, i.e., CHP units, EHPs, EBs, etc. This work has attempted to minimize the operating cost of the IEHN in two different stages, namely the DA operational costs as well as RT regulation costs. A two-stage robust optimization model has been executed in [20] for the energy and reserve co-optimization of the IEHN in the DA operation and RT regulation stages, respectively. The considered problem's first stage is associated with the DA energy and reserve costs minimization, while the second stage is related to the minimization of the RT regulation cost caused by the error of wind power forecasting. A two-stage robust model has been provided in [21] to optimize the operation of the IEHN in the presence of integrated demand response programs. The purpose of this problem is to evaluate the effect of integrated demand

response programs on the optimal operation of the studied system with the aim of net profit maximization.

Reviewed articles reveal that while the impact of the electricity-heat sector coupling and related conversion technologies on the optimal performance of IEHNS has been assessed in several studies, the simultaneous role of battery (BESS), thermal (TESS), and natural gas (NGESS) energy storage systems in a platform called HESS has not been analyzed in the previous research works. Accordingly, the present chapter tends to model an IEHN in the existence of numerous interface elements in the first step. Next, by modeling BESS, TESS, and NGESS and building a HESS, it seeks to evaluate the importance of these devices on the optimal operation of the incorporated network. In order to implement the mentioned problem and to deal with raised uncertainties in the IEHN operator's decision-making process, a scenario-based two-stage stochastic programming approach is exploited in this chapter.

The rest of this chapter is arranged as follows: the structure of the considered IEHN, the proposed methodology, and problem formulations are explained in more detail in Section 12.2. The implementation of a case study and its discussions are provided in Section 12.3. Ultimately, the chapter is concluded in Section 12.4.

12.2 Methodology

As mentioned earlier, this chapter aims at modeling an IEHN in the presence of various sector coupling and storage technologies and investigating the effect of a HESS, consisting of BESS, TESS, and NGESS, on the optimal performance of the incorporated network. The schematic structure of the considered IEHN is illustrated in Figure 12.1.

As shown in Figure 12.1, the electricity and heat sectors have been coupled with one another via CHP units, EBs, and EHPs. In this regard, CHP plants cogenerate thermal and power energy, while EBs and EHPs consume power to produce thermal energy. The electricity demand of the system can also be provided by dispatchable and non-dispatchable resources, namely non-gas fired generators (NGFGs), gas-fired generators (GFGs), wind turbines (WTs), and photovoltaic systems (PVs). On the contrary, the heat demand of the system can also be provided by solar thermal systems (STs). Besides the available elements, the IEHN operator has the opportunity to compensate for/supply its shortage demands/excess generation from/to the upstream power and heat networks as well. On the other hand, the IEHN contains the combination of BESS, TESS, and NGESS, as a HESS, to

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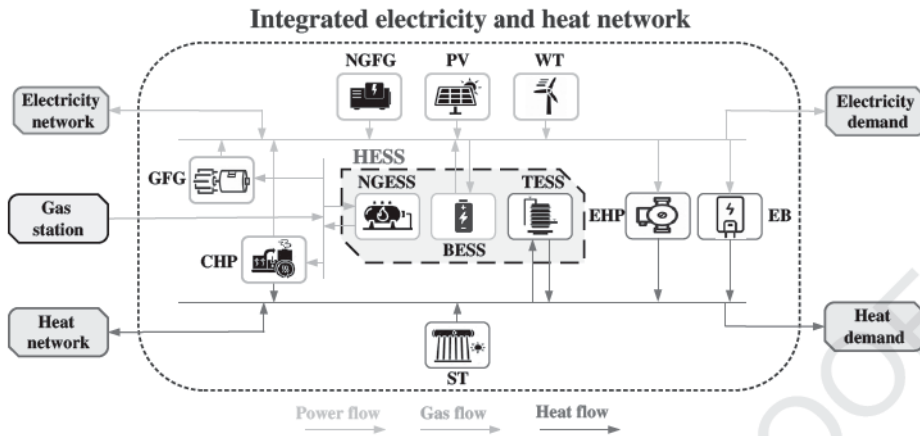


Figure 12.1 Structure of the IEHN.

enhance the flexibility of the whole system and adjust the exchanged energy with the upstream networks through dispatching these resources.

A scenario-based two-stage stochastic programming scheme is executed to achieve the optimal operation of the considered IEHN and handle the existing uncertainties in the decision-making process of the IEHN operator. Electricity and heat demand, electricity and heat price, wind speed, and solar irradiance are the stochastic variables of the problem. It is notable that, for the realization of these uncertain parameters, a high number of scenarios are generated by the Monte Carlo Simulation technique and reduced to an adequate number by utilizing the fast backward/forward scenario reduction algorithm [22]. In two-stage optimization models, two types of decisions are taken, first-stage or here-and-now decisions and second-stage or wait-and-see decisions [23]. In this regard, at the first stage, the IEHN operator determines its optimal DA exchanged power and heat with the upstream networks based on data available at the time of the decisions. At the second stage and after the realization of stochastic factors, the operator tries to decrease its RT imbalance cost and compensate for its forecasted errors by adjusting the available dispatchable as well as flexible units.

The objective function of the considered problem is maximizing the expected profit of the IEHN operator, which is defined as the difference between the operator's income and expenditures. The income includes the revenue from DA exchanging power and heat energy with upstream grids as well as selling power and heat energy to customers. In contrast, expenditures include RT imbalance costs as well as operating costs of available dispatchable and flexible units. In this context, the RT imbalance cost is a penalty cost resulting from the deviation of the IEHN's RT generation/consumption from its DA scheduled energy, see Eq. (12.1).

$$\text{ObjFun}_{\text{IEHN}} = \text{Max} \sum_{t=1}^T \left\{ P_{\text{DA}}(t) \cdot \lambda_{\text{DA}}^E(t) + H_{\text{DA}}(t) \cdot \lambda_{\text{DA}}^H(t) \right. \\ \left. - \sum_{s=1}^S \varphi(s) \cdot \left[\begin{array}{l} P_{\text{imb}}(t,s) \cdot \lambda_{\text{RT}}^E(t,s) + H_{\text{imb}}(t,s) \cdot \lambda_{\text{RT}}^H(t,s) \\ + \sum_{c=1}^C \text{OC}_{\text{CHP}}(c,t,s) + \sum_{\text{gs}=1}^{\text{GS}} \text{OC}_{\text{NGESS}}(\text{gs},t,s) \\ + \sum_{g=1}^G \text{OC}_{\text{GFG}}(g,t,s) + \sum_{\text{ng}=1}^{\text{NG}} \text{OC}_{\text{NGFG}}(\text{ng},t,s) \\ - D^E(t,s) \cdot \lambda_D^E(t) - D^H(t,s) \cdot \lambda_D^H(t) \end{array} \right] \right\}, \quad (12.1)$$

In Eq. (12.1), the first and second terms are the income from DA exchanging power and heat with the upstream electricity and heat networks, respectively. The third and fourth terms are costs of RT imbalance power and heat, respectively. The fifth, sixth, seventh, and eighth terms are related to the operating costs of CHP, NGESS, GFG, and NGFG, respectively. Ultimately, the ninth and tenth terms are the revenue from selling power and heat energy to the customers, respectively. The mentioned objective function is subject to a set of constraints as follows:

12.2.1 Power and Heat Balance Constraints

$$P_{\text{RT}}(t,s) = \left[\begin{array}{l} \sum_{c=1}^C P_{\text{CHP}}(c,t,s) + \sum_{g=1}^G P_{\text{GFG}}(g,t,s) + \sum_{\text{ng}=1}^{\text{NG}} P_{\text{NGFG}}(\text{ng},t,s) \\ + \sum_{w=1}^W P_{\text{WT}}(w,t,s) + \sum_{p=1}^P P_{\text{PV}}(p,t,s) + \sum_{\text{bs}=1}^{\text{BS}} P_{\text{BESS}}^{\text{dch}}(\text{bs},t,s) \\ - \sum_{\text{bs}=1}^{\text{BS}} P_{\text{BESS}}^{\text{ch}}(\text{bs},t,s) - \sum_{\text{hp}=1}^{\text{HP}} P_{\text{EHP}}(\text{hp},t,s) - \sum_{\text{eb}=1}^{\text{EB}} P_{\text{EB}}(\text{eb},t,s) - D^E(t,s) \end{array} \right], \forall t,s \quad (12.2)$$

$$P_{\text{imb}}(t,s) = [P_{\text{DA}}(t) - P_{\text{RT}}(t,s)] \cdot \Delta_P(t,s), \forall t,s \\ \Delta_P(t,s) = \begin{cases} 1 & , P_{\text{DA}}(t) > P_{\text{RT}}(t,s) \\ -1 & , P_{\text{DA}}(t) < P_{\text{RT}}(t,s) \end{cases} \quad (12.3)$$

As shown in Eq. (12.3), P_{imb} is calculated as the difference between the IEHN's DA and RT exchanged power with the upstream electricity network. However, since the RT imbalance cost is considered as a penalty cost for the IEHN operator, Δ_P is utilized as an auxiliary index to enter P_{imb} as a positive term into the objective function, whether the RT exchanged power is higher or lower than the DA exchanged power.

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$$H_{RT}(t, s) = \left[\begin{aligned} & \sum_{c=1}^C H_{CHP}(c, t, s) + \sum_{hp=1}^{HP} H_{EHP}(hp, t, s) + \sum_{eb=1}^{EB} H_{EB}(eb, t, s) \\ & + \sum_{st=1}^{ST} H_{ST}(st, t, s) + \sum_{ts=1}^{TS} H_{TESS}^{dch}(ts, t, s) - \sum_{ts=1}^{TS} H_{TESS}^{ch}(ts, t, s) - D^H(t, s) \end{aligned} \right], \forall_{t,s} \quad (12.4)$$

$$\begin{aligned} H_{imb}(t, s) &= [H_{DA}(t) - H_{RT}(t, s)] \cdot \Delta_H(t, s), \forall_{t,s} \\ \Delta_H(t, s) &= \begin{cases} 1 & , H_{DA}(t) > H_{RT}(t, s) \\ -1 & , H_{DA}(t) < H_{RT}(t, s) \end{cases} \end{aligned} \quad (12.5)$$

Similarly, Δ_H is used as an auxiliary index in Eq. (12.5) to enter H_{imb} as a positive term into the objective function, whether the RT exchanged heat is higher or lower than the DA exchanged heat.

12.2.2 Exchanged Power and Heat with Upstream Networks Constraints

$$-P_{EN}^{\max} \leq P_{RT}(t, s) \leq P_{EN}^{\max} \quad (12.6)$$

$$-H_{HN}^{\max} \leq H_{RT}(t, s) \leq H_{EN}^{\max} \quad (12.7)$$

The IEHN's RT exchanged power and heat with the electricity and heat upstream networks are limited by Eqs. (12.6) and (12.7), respectively.

12.2.3 Gas Flow Constraints

$$G_{GST}(t, s) = \sum_{c=1}^C G_{GST-CHP}(c, t, s) + \sum_{g=1}^G G_{GST-GFG}(g, t, s) + \sum_{gs=1}^{GS} G_{GST-NGESS}^{in}(gs, t, s), \forall_{t,s} \quad (12.8)$$

$$\sum_{gs=1}^{GS} G_{NGESS}^{out}(gs, t, s) = \sum_{c=1}^C G_{NGESS-CHP}(c, t, s) + \sum_{g=1}^G G_{NGESS-GFG}(g, t, s), \forall_{t,s} \quad (12.9)$$

Based on Eq. (12.8) and as shown in Figure 12.1, the total amount of gas flow from the gas station (GST) is equal to the required gas of CHPs, GFGs, and NGENSSs. On the other hand, NGENSSs are able to procure the needed gas of CHPs and GFGs during their discharging mode. In this regard, Eq. (12.9) is utilized to specify the share of NGENSSs in supplying the gas of the aforementioned units.

12.2.4 Combined Heat and Power Plants Constraints

$$G_{\text{GST-CHP}}(c, t, s) + G_{\text{NGESS-CHP}}(c, t, s) = \frac{P_{\text{CHP}}(c, t, s)}{\text{HV}_{\text{gas}} \cdot \eta_{\text{CHP-E}}(c)}, \forall_{c,t,s} \quad (12.10)$$

$$H_{\text{CHP}}(c, t, s) \leq P_{\text{CHP}}(c, t, s) \cdot \text{HPR}(c) \cdot \eta_{\text{CHP-H}}(c), \forall_{c,t,s} \quad (12.11)$$

$$P_{\text{CHP}}^{\min}(c) \cdot U_{\text{CHP}}(c, t, s) \leq P_{\text{CHP}}(c, t, s) \leq P_{\text{CHP}}^{\max}(c) \cdot U_{\text{CHP}}(c, t, s), \forall_{c,t,s} \quad (12.12)$$

$$H_{\text{CHP}}(c, t, s) - H_{\text{CHP}}(c, t-1, s) \leq \text{RU}_{\text{CHP}}(c) \cdot U_{\text{CHP}}(c, t, s), \forall_{c,t,s} \quad (12.13)$$

$$H_{\text{CHP}}(c, t-1, s) - H_{\text{CHP}}(c, t, s) \leq \text{RD}_{\text{CHP}}(c) \cdot U_{\text{CHP}}(c, t, s), \forall_{c,t,s} \quad (12.14)$$

$$0 \leq \text{SUC}_{\text{CHP}}(c, t, s) = \text{su}_{\text{CHP}}(c) \cdot (U_{\text{CHP}}(c, t, s) - U_{\text{CHP}}(c, t-1, s)), \forall_{c,t,s} \quad (12.15)$$

$$0 \leq \text{SDC}_{\text{CHP}}(c, t, s) = \text{sd}_{\text{CHP}}(c) \cdot (U_{\text{CHP}}(c, t-1, s) - U_{\text{CHP}}(c, t, s)), \forall_{c,t,s} \quad (12.16)$$

$$\text{OC}_{\text{CHP}}(c, t, s) = G_{\text{GST-CHP}}(c, t, s) \cdot \lambda_{\text{gas}} + \text{SUC}_{\text{CHP}}(c, t, s) + \text{SDC}_{\text{CHP}}(c, t, s), \forall_{c,t,s} \quad (12.17)$$

Technical and operational constraints of CHP plants are stated in Eqs. (12.10)–(12.16). Moreover, the operating costs of these units are computed by Eq. (12.17) [24].

12.2.5 Electric Heat Pumps Constraints

$$H_{\text{EHP}}(\text{hp}, t, s) = P_{\text{EHP}}(\text{hp}, t, s) \cdot \text{CP}(\text{hp}), \forall_{\text{hp},t,s} \quad (12.18)$$

$$H_{\text{EHP}}^{\min}(\text{hp}) \leq H_{\text{EHP}}(\text{hp}, t, s) \leq H_{\text{EHP}}^{\max}(\text{hp}), \forall_{\text{hp},t,s} \quad (12.19)$$

By consuming the electricity, EHPs generate heat energy, as shown in Eq. (12.18). Furthermore, the generated heat of these resources is limited by Eq. (12.19) [20].

12.2.6 Electric Boilers Constraints

$$P_{\text{EB}}^{\min}(\text{eb}) \leq P_{\text{EB}}(\text{eb}, t, s) \leq P_{\text{EB}}^{\max}(\text{eb}), \forall_{\text{eb},t,s} \quad (12.20)$$

$$H_{\text{EB}}(\text{eb}, t, s) = P_{\text{EB}}(\text{eb}, t, s) \cdot \eta_{\text{EB-H}}(\text{eb}), \forall_{\text{eb},t,s} \quad (12.21)$$

Similar to EHPs, EBs produce thermal energy by consuming electricity as well. Eq. (12.20) limits their power consumption, and Eq. (12.21) shows the amount of their generated heat [20].

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12.2.7 Non-Gas Fired Generators Constraints

$$P_{\text{NGFG}}^{\min}(\text{ng}) \leq P_{\text{NGFG}}(\text{ng}, t, s) \leq P_{\text{NGFG}}^{\max}(\text{ng}), \forall_{\text{ng}, t, s} \quad (12.22)$$

$$P_{\text{NGFG}}(\text{ng}, t, s) - P_{\text{NGFG}}(\text{ng}, t-1, s) \leq \text{RU}_{\text{NGFG}}(\text{ng}), \forall_{\text{ng}, t, s} \quad (12.23)$$

$$P_{\text{NGFG}}(\text{ng}, t-1, s) - P_{\text{NGFG}}(\text{ng}, t, s) \leq \text{RD}_{\text{NGFG}}(\text{ng}), \forall_{\text{ng}, t, s} \quad (12.24)$$

$$\text{OC}_{\text{NGFG}}(\text{ng}, t, s) = \alpha(\text{ng}) \cdot P_{\text{NGFG}}(\text{ng}, t, s) + \beta(\text{ng}), \forall_{\text{ng}, t, s} \quad (12.25)$$

Technical and operational constraints of NGFGs are specified by Eqs. (12.22)–(12.24). Also, these sources' operating costs are calculated by Eq. (12.25).

12.2.8 Gas Fired Generators Constraints

$$G_{\text{GST-GFG}}(g, t, s) + G_{\text{NGESS-GFG}}(g, t, s) = \frac{P_{\text{GFG}}(g, t, s)}{HV_{\text{gas}} \cdot \eta_{\text{GFG-E}}(g)}, \forall_{g, t, s} \quad (12.26)$$

$$P_{\text{GFG}}^{\min}(g) \cdot U_{\text{GFG}}(g, t, s) \leq P_{\text{GFG}}(g, t, s) \leq P_{\text{GFG}}^{\max}(g) \cdot U_{\text{GFG}}(g, t, s), \forall_{g, t, s} \quad (12.27)$$

$$P_{\text{GFG}}(g, t, s) - P_{\text{GFG}}(g, t-1, s) \leq \text{RU}_{\text{GFG}}(g) \cdot U_{\text{GFG}}(g, t, s), \forall_{g, t, s} \quad (12.28)$$

$$P_{\text{GFG}}(g, t-1, s) - P_{\text{GFG}}(g, t, s) \leq \text{RD}_{\text{GFG}}(g) \cdot U_{\text{GFG}}(g, t, s), \forall_{g, t, s} \quad (12.29)$$

$$0 \leq \text{SUC}_{\text{GFG}}(g, t, s) = \text{su}_{\text{GFG}}(g) \cdot (U_{\text{GFG}}(g, t, s) - U_{\text{GFG}}(g, t-1, s)), \forall_{g, t, s} \quad (12.30)$$

$$0 \leq \text{SDC}_{\text{GFG}}(g, t, s) = \text{sd}_{\text{GFG}}(g) \cdot (U_{\text{GFG}}(g, t-1, s) - U_{\text{GFG}}(g, t, s)), \forall_{g, t, s} \quad (12.31)$$

$$\text{OC}_{\text{GFG}}(g, t, s) = G_{\text{GST-GFG}}(g, t, s) \cdot \lambda_{\text{gas}} + \text{SUC}_{\text{GFG}}(g, t, s) + \text{SDC}_{\text{GFG}}(g, t, s), \forall_{g, t, s} \quad (12.32)$$

Technical and operational constraints of GFGs are illustrated by Eqs. (12.26)–(12.31). In addition, these generators' operating costs are calculated based on Eq. (12.32).

12.2.9 Hybrid Energy Storage System Constraints

As previously stated, the studied IEHN is equipped with a HESS, which consists of three main elements, i.e., BESS, TESS, and finally, NGESS. The operational and technical constraints of these devices are mathematically modeled in the following.

12.2.9.1 Battery Energy Storage System

$$P_{\text{BESS}}^{\text{ch},\text{min}}(\text{bs}).U_{\text{BESS}}(\text{bs}, t, s) \leq P_{\text{BESS}}^{\text{ch}}(\text{bs}, t, s) \leq P_{\text{BESS}}^{\text{ch},\text{max}}(\text{bs}).U_{\text{BESS}}(\text{bs}, t, s), \forall_{\text{bs},t,s} \quad (12.33)$$

$$\begin{aligned} P_{\text{BESS}}^{\text{dch},\text{min}}(\text{bs}).(1 - U_{\text{BESS}}(\text{bs}, t, s)) &\leq P_{\text{BESS}}^{\text{dch}}(\text{bs}, t, s) \\ &\leq P_{\text{BESS}}^{\text{dch},\text{max}}(\text{bs}).(1 - U_{\text{BESS}}(\text{bs}, t, s)), \forall_{\text{bs},t,s} \end{aligned} \quad (12.34)$$

$$E_{\text{BESS}}(\text{bs}, t, s) = E_{\text{BESS}}(\text{bs}, t-1, s) + P_{\text{BESS}}^{\text{ch}}(\text{bs}, t, s) \cdot \eta_{\text{BESS-ch}}(\text{bs}) - P_{\text{BESS}}^{\text{dch}}(\text{bs}, t, s) / \eta_{\text{BESS-dch}}(\text{bs}), \forall_{\text{bs},t > 1,s} \quad (12.35)$$

$$E_{\text{BESS}}(\text{bs}, t, s) = E_{\text{BESS}}^{\text{ini}}(\text{bs}), \forall_{\text{bs},t=1,s} \quad (12.36)$$

$$E_{\text{BESS}}^{\text{min}}(\text{bs}) \leq E_{\text{BESS}}(\text{bs}, t, s) \leq E_{\text{BESS}}^{\text{max}}(\text{bs}), \forall_{\text{bs},t,s} \quad (12.37)$$

The charged and discharged power of BESSs is limited by Eqs. (12.33) and (12.34), respectively. Additionally, the amount of electrical energy stored in these systems and its limitations are demonstrated by Eqs. (12.35)–(12.37) [25].

12.2.9.2 Thermal Energy Storage System

$$H_{\text{TESS}}^{\text{ch},\text{min}}(\text{ts}).U_{\text{TESS}}(\text{ts}, t, s) \leq H_{\text{TESS}}^{\text{ch}}(\text{ts}, t, s) \leq H_{\text{TESS}}^{\text{ch},\text{max}}(\text{ts}).U_{\text{TESS}}(\text{ts}, t, s), \forall_{\text{ts},t,s} \quad (12.38)$$

$$\begin{aligned} H_{\text{TESS}}^{\text{dch},\text{min}}(\text{ts}).(1 - U_{\text{TESS}}(\text{ts}, t, s)) &\leq H_{\text{TESS}}^{\text{dch}}(\text{ts}, t, s) \\ &\leq H_{\text{TESS}}^{\text{dch},\text{max}}(\text{ts}).(1 - U_{\text{TESS}}(\text{ts}, t, s)), \forall_{\text{ts},t,s} \end{aligned} \quad (12.39)$$

$$E_{\text{TESS}}(\text{ts}, t, s) = E_{\text{TESS}}(\text{ts}, t-1, s) \cdot \eta_{\text{TESS-sb}}(\text{ts}) + H_{\text{TESS}}^{\text{ch}}(\text{ts}, t, s) \cdot \eta_{\text{TESS-ch}}(\text{ts}) - H_{\text{TESS}}^{\text{dch}}(\text{ts}, t, s) / \eta_{\text{TESS-dch}}(\text{ts}), \forall_{\text{ts},t > 1,s} \quad (12.40)$$

$$E_{\text{TESS}}(\text{ts}, t, s) = E_{\text{TESS}}^{\text{ini}}(\text{ts}), \forall_{\text{ts},t=1,s} \quad (12.41)$$

$$E_{\text{TESS}}^{\text{min}}(\text{ts}) \leq E_{\text{TESS}}(\text{ts}, t, s) \leq E_{\text{TESS}}^{\text{max}}(\text{ts}), \forall_{\text{ts},t,s} \quad (12.42)$$

The charged and discharged heat of TESSs is limited by Eqs. (12.38) and (12.39), respectively. Also, the amount of thermal energy stored in these systems and its limitations are shown by Eqs. (12.40)–(12.42) [26]. It must be noted that $\eta_{\text{TESS-sb}}(\text{ts})$ in Eq. (12.40) models the efficiency of TESSs for storing thermal energy in their standby period.

12.2.9.3 Natural Gas Energy Storage System

$$\begin{aligned} G_{\text{NGESS}}^{\text{in},\text{min}}(\text{gs}).U_{\text{NGESS}}(\text{gs}, t, s) &\leq G_{\text{GST-NGESS}}^{\text{in}}(\text{gs}, t, s) \\ &\leq G_{\text{NGESS}}^{\text{in},\text{min}}(\text{gs}).U_{\text{NGESS}}(\text{gs}, t, s), \forall_{\text{gs},t,s} \end{aligned} \quad (12.43)$$

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$$\begin{aligned} G_{\text{NGESS}}^{\text{out, min}}(\text{gs}) \cdot (1 - U_{\text{NGESS}}(\text{gs}, t, s)) &\leq G_{\text{NGESS}}^{\text{out}}(\text{gs}, t, s) \\ &\leq G_{\text{NGESS}}^{\text{out, max}}(\text{gs}) \cdot (1 - U_{\text{NGESS}}(\text{gs}, t, s)), \forall_{\text{gs}, t, s} \end{aligned} \quad (12.44)$$

$$\begin{aligned} E_{\text{NGESS}}(\text{gs}, t, s) &= E_{\text{NGESS}}(\text{gs}, t-1, s) + G_{\text{GST-NGESS}}^{\text{in}}(\text{gs}, t, s) \cdot \eta_{\text{NGESS-in}}(\text{gs}) \\ &\quad - G_{\text{NGESS}}^{\text{out}}(\text{gs}, t, s) / \eta_{\text{NGESS-out}}(\text{gs}), \forall_{\text{ts}, t > 1, s} \end{aligned} \quad (12.45)$$

$$E_{\text{NGESS}}(\text{gs}, t, s) = E_{\text{NGESS}}^{\text{ini}}(\text{gs}), \forall_{\text{gs}, t = 1, s} \quad (12.46)$$

$$E_{\text{NGESS}}^{\text{min}}(\text{gs}) \leq E_{\text{NGESS}}(\text{gs}, t, s) \leq E_{\text{NGESS}}^{\text{max}}(\text{gs}), \forall_{\text{gs}, t, s} \quad (12.47)$$

$$\text{OC}_{\text{NGESS}}(\text{gs}, t, s) = G_{\text{GST-NGESS}}^{\text{in}}(\text{gs}, t, s) \cdot \lambda_{\text{gas}}, \forall_{\text{gs}, t, s} \quad (12.48)$$

The amount of charged and discharged gas of NGENSSs is restricted by Eqs. (12.43) and (12.44), respectively. Moreover, the amount of gas energy stored in these systems and its limitations are stated by Eqs. (12.45)–(12.47). Finally, their operating costs are calculated by Eq. (12.48) [27].

It is worth noting that, the mathematical model of PVs, WTs as well as STs and their associated expressions are part of data pre-processing, where the values of wind speed and solar irradiation are converted into power and heat values. Then, these values act as input data for the raised optimization problem. In order to calculate the output power and heat of these renewable-based resources, expressions that have been presented in [23] are exploited in this study.

12.3 Numerical Results and Discussions

In this section of the chapter, a typical case study is conducted to investigate the impact of a HESS on the optimal performance of IEHNs. Notably, the optimization problem provided in the previous section has been solved by the CPLEX solver in the GAMS programming software. Before analyzing simulation results, the studied IEHN and its technical specifications are presented in the following.

As stated, to consider the stochastic nature of electricity and heat prices, electricity and heat demands, wind speed, and solar irradiance in the IEHN's optimal operation, a two-stage programming scheme is executed, and at the RT stage, ten reduced scenarios are generated based on the utilized model in [22]. Figure 12.2 shows the electricity and heat demands of the system for these scenarios.

Also, Figure 12.3 depicts the RT electricity and heat prices for the generated scenarios. In this study, the price of natural gas is considered as three tariffs based on Figure 12.4. Moreover, the heat value of natural gas is assumed to be $0.0093 \text{ m}^3/\text{MWh}$.

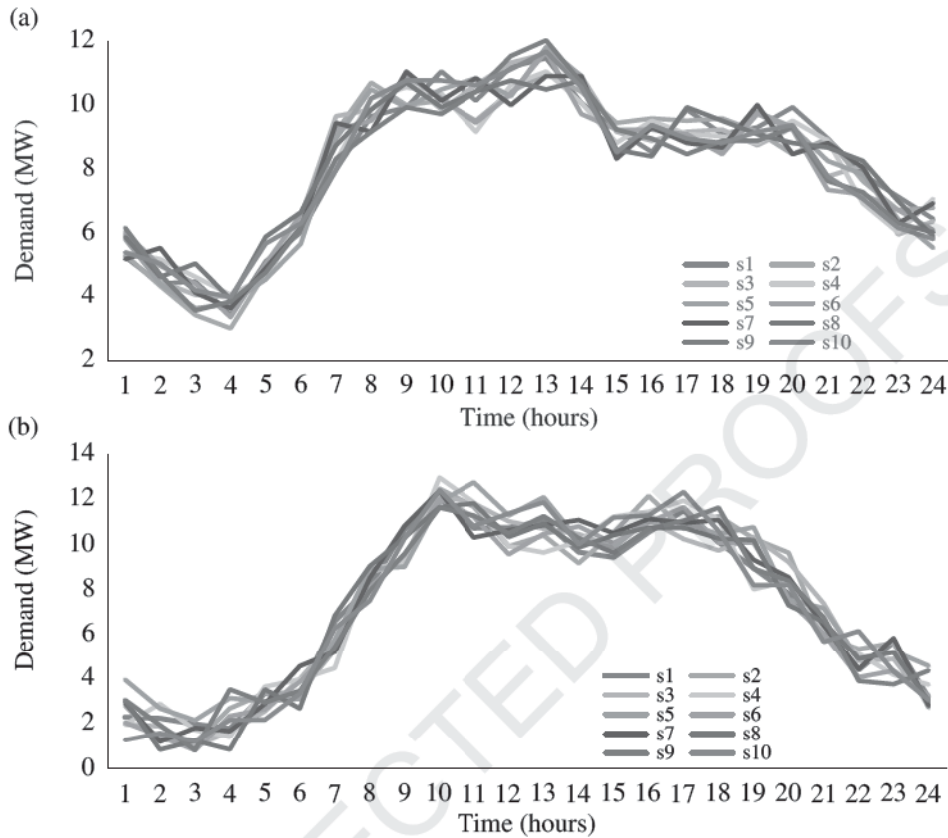


Figure 12.2 (a) Electricity demand and (b) heat demand.

Technical specifications of the IEHN's generation sources, as well as P2X technologies, are summarized in Table 12.1. Characteristics of the available BESS, TESS, and NGESS within the HESS are reported in Table 12.2. In the end, the installed wind power, solar power, and solar heat capacities of the IEHN are 2.0 MW, 3.15 MW, and 3.2 MW, respectively.

As mentioned in Section 12.2, the IEHN's exchanged power and heat energy with the upstream electricity and heat networks is performed in two DA and RT stages. In this context, the DA traded power and heat of the IEHN equipped with the HESS are illustrated in Figure 12.5. Notably, in this figure, positive bars are exported or sold energy and negative bars are imported or purchased energy.

Based on Figure 12.5, the IEHN has imported power from the electricity network in most hours of the day, and merely at hour one, it has exported power to the upstream grid. On the other hand, the IEHN operator has exported heat energy to the upstream network at hours 1–4 and 24. In the rest hours of the day, heat

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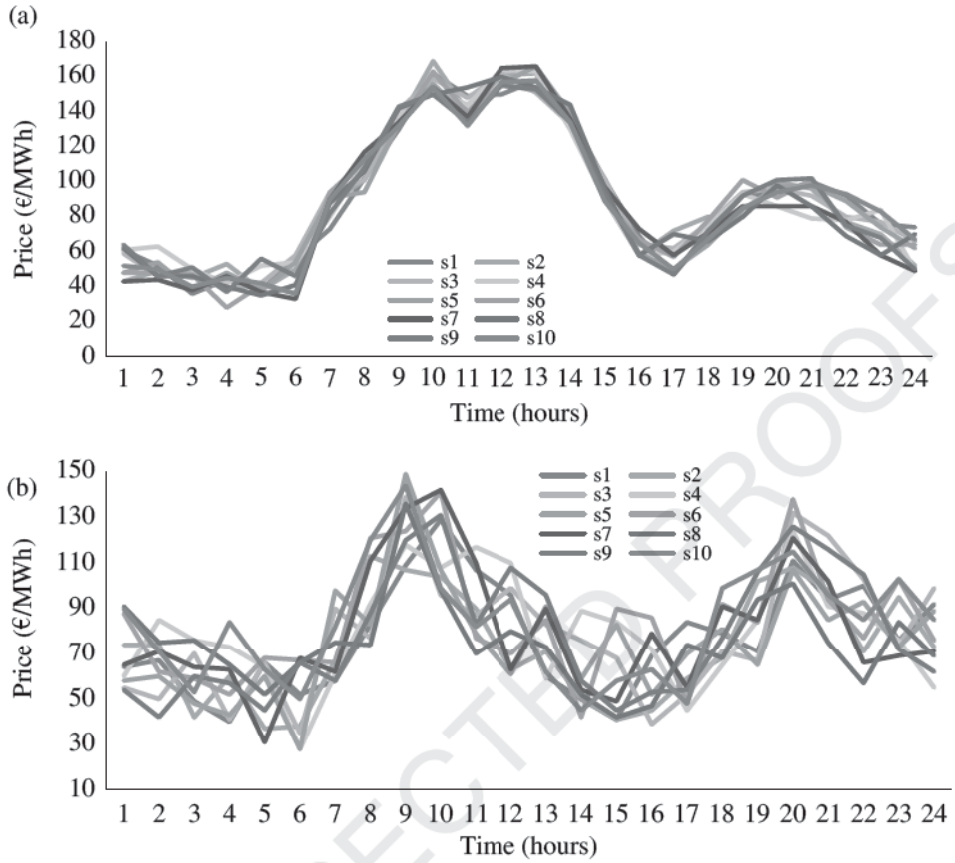


Figure 12.3 (a) Electricity price and (b) heat price.

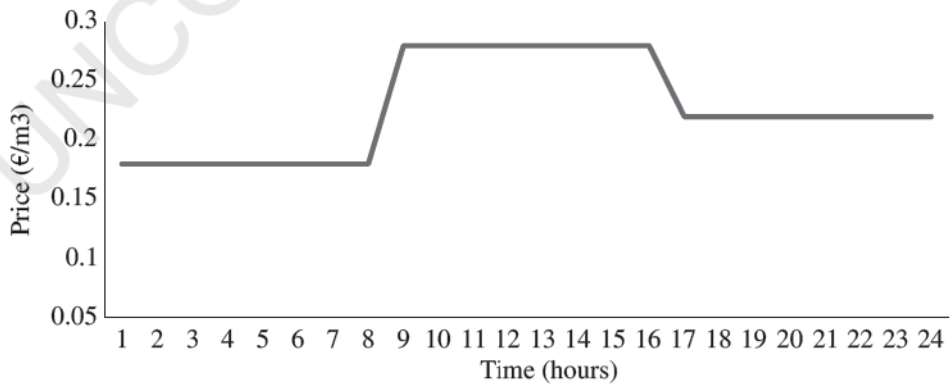


Figure 12.4 Natural gas price.

Table 12.1 Technical specifications of generation units and P2X technologies.

CHPs					
# Unit	$P_{\text{CHP}}^{\text{max}}$	$P_{\text{CHP}}^{\text{min}}$	$\eta_{\text{CHP-E}}$	$\eta_{\text{CHP-H}}$	HPR
1	5	0.5	0.45	0.55	1
GFGs					
# Unit	$P_{\text{GFG}}^{\text{max}}$	$P_{\text{GFG}}^{\text{min}}$	$\eta_{\text{GFG-E}}$	$RD_{\text{GFG}}, RU_{\text{GFG}}$	
1	2	0.2	0.85	1, 1	
NGFGs					
# Unit	$P_{\text{NGFG}}^{\text{max}}$	$P_{\text{NGFG}}^{\text{min}}$	α, β	$RD_{\text{NGFG}}, RU_{\text{NGFG}}$	
1	3	0.3	26, 42	1.5, 1.5	
EHPs					
# Unit	$H_{\text{EHP}}^{\text{max}}$		$H_{\text{EHP}}^{\text{min}}$		CP
1	1.5		0		2.5
EBs					
# Unit	$P_{\text{EB}}^{\text{max}}$	$P_{\text{EB}}^{\text{min}}$		$\eta_{\text{EB-H}}$	
1	2	0		0.8	

Table 12.2 Technical specifications of the HESS.

BESS					
# Unit	$E_{\text{BESS}}^{\text{max}}, E_{\text{BESS}}^{\text{min}}$	$P_{\text{BESS}}^{\text{ch,max}}, P_{\text{BESS}}^{\text{ch,min}}$	$P_{\text{BESS}}^{\text{dch,max}}, P_{\text{BESS}}^{\text{dch,min}}$	$\eta_{\text{BESS-ch}}, \eta_{\text{BESS-dch}}$	
1	5, 0.5	1, 0	1, 0	0.95	
TESS					
# Unit	$E_{\text{TESS}}^{\text{max}}, E_{\text{TESS}}^{\text{min}}$	$H_{\text{TESS}}^{\text{ch,max}}, H_{\text{TESS}}^{\text{ch,min}}$	$H_{\text{TESS}}^{\text{dch,max}}, H_{\text{TESS}}^{\text{dch,min}}$	$\eta_{\text{TESS-ch}}, \eta_{\text{TESS-dch}}, \eta_{\text{TESS-sb}}$	
1	4, 0	2, 0	2, 0	0.98, 0.98, 0.95	
NGESS					
# Unit	$E_{\text{NGESS}}^{\text{max}}, E_{\text{NGESS}}^{\text{min}}$	$G_{\text{NGESS}}^{\text{in,max}}, G_{\text{NGESS}}^{\text{in,min}}$	$G_{\text{NGESS}}^{\text{out,max}}, G_{\text{NGESS}}^{\text{out,min}}$	$\eta_{\text{NGESS-in}}, \eta_{\text{NGESS-out}}$	
1	1000, 50	250, 0	250, 0	0.98	

energy has been imported from the network. For another issue, it is observed that the grid operator has purchased less power from the electricity network during the middle of the day when the electricity price is at its peak value and prefers to utilize its own dispatchable resources. The reason is that at these hours, generation prices

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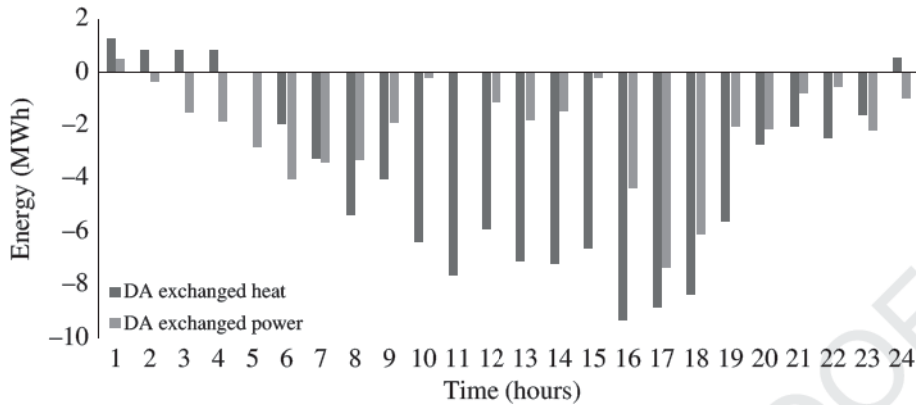


Figure 12.5 IEHN's DA exchanged energy in the presence of the HESS.

of these types of resources are lower than electricity prices. Additionally, the operator expects that available PVs generate more power at the considered time interval.

To better investigate the HESS's impact on the optimal operation of the IEHN, the DA traded power and heat of the system in the absence of all storage elements is demonstrated in Figure 12.6.

By comparing Figures 12.5 and 12.6, it is shown that if the IEHN does not contain the energy storage capacity, it is forced to import more power and heat energy from the upstream networks at peak hours, which leads to high operating costs. For another, it can be concluded that in the presence of the HESS, the IEHN has purchased more energy from the heat and electricity upstream grids during hours 16–18. That is because at these hours, the energy price in both sectors

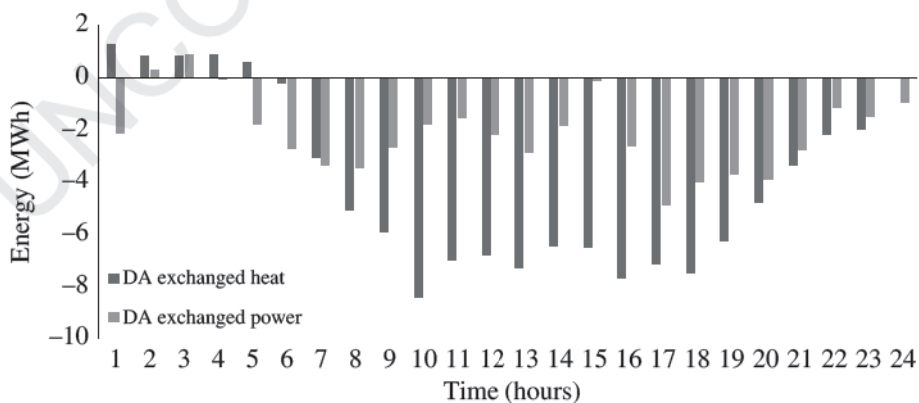


Figure 12.6 IEHN's DA exchanged energy in the absence of the HESS.

has reduced, and the IEHN operator has tended to store more energy in the existing HESS and use it at peak hours.

To assess the performance of the studied IEHN at the RT stage, in the following of this section, the operating points of the system's generation units, P2X elements, and storage systems, as well as its imbalance power and heat energy, are analyzed in more detail for a sample scenario, scenario 4. In this regard, the production and consumption profiles of connected resources to the electricity sector, as well as the amount of charged and discharged power of the BESS are displayed in Figure 12.7.

According to Figure 12.7, the IEHN operator has exploited the BESS's storage capacity to transfer power from off-peak hours to peak hours and hence enhance its expected profit. Moreover, to improve the incorporated network's flexibility and efficiency, the available EB has consumed electricity at off-peak hours to produce thermal energy due to the lower electricity price compared to the heat price. As for the EHP, due to the high CP, this unit has been in service for most hours of the studied day, and it is out of service only at peak hour 12, when both power consumption and electricity prices are at their peak values.

On the other hand, the production profiles of connected resources to the heat sector, as well as the amount of charged and discharged heat of the TESS, are depicted in Figure 12.8.

As clear in Figure 12.8, the IEHN has generated the highest amount of heat energy at hours 9–10 and 20–21, where the price of the heat network is at its peak value. Furthermore, clearly, the TESS has charged at off-peak hours and discharged at peak hours to supply more thermal energy to the IEHN.

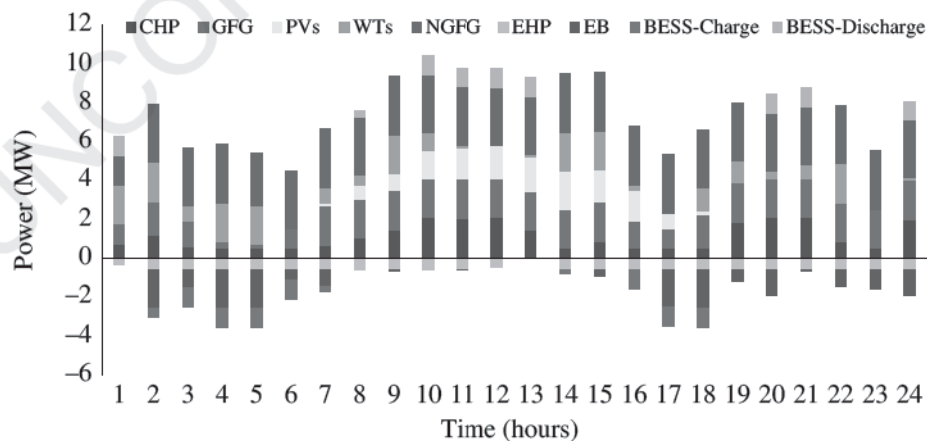


Figure 12.7 Operating points of connected sources to the electricity sector in scenario 4.

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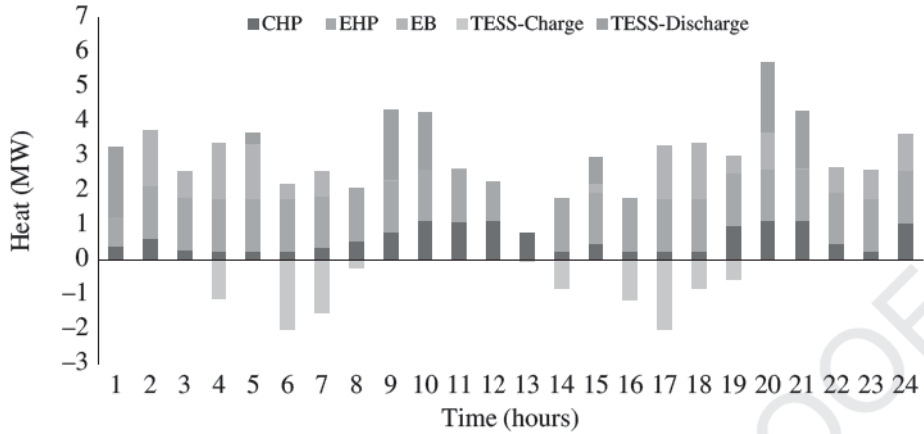


Figure 12.8 Operating points of connected sources to the heat sector in scenario 4.

The amount of gas consumption by the IEHN’s gas-based resources, namely GFG and CHP, as well as the amount of gas exchange with the NGESS, are shown in Figure 12.9.

In Figure 12.9, the total amount of discharged gas from the NGESS is equal to the sum of discharged gas to the CHP and GFG. Similar to the BESS and TESS, in the NGESS, gas has stored during off-peak hours and discharged at peak hours as well. Moreover, during the peak of electricity and heat consumption, the IEHN’s gas-based resources, i.e., CHP and GFG, have consumed the highest amount of gas. In addition to the gas flow from the GST, the discharged gas of the NGESS has also provided some part of the consumed gas of these units.

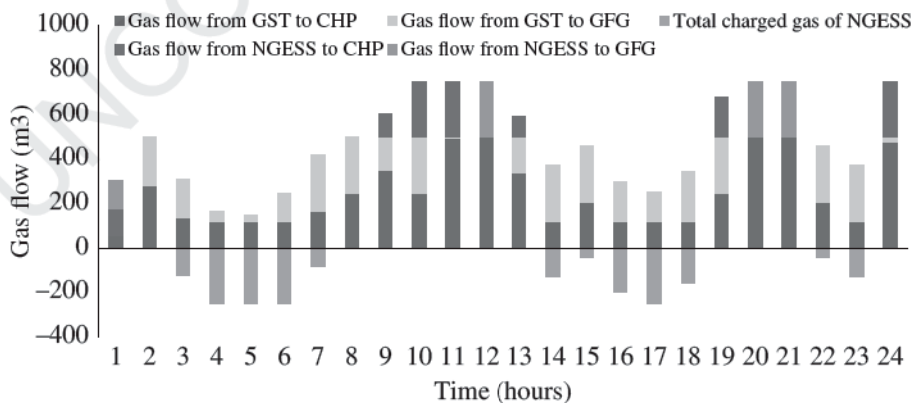


Figure 12.9 Gas flow of resources within the IEHN in scenario 4.

To evaluate the effect of the HESS presence on the IEHN's RT operation, the imbalance power and imbalance heat of the system with and without considering the storage capacity are compared with one another for a sample scenario, scenario 4, in Figures 12.10a, b.

As it is shown in Figures 12.10a, b, in the absence of all storage elements, the imbalance power and heat of the IEHN have increased significantly at the RT stage. The reason is that by adding more flexibility to the IEHN, storage devices allow the system operator to adjust its RT production/consumption more appropriately and minimize its imbalance costs.

To confirm the effective impact of the HESS on the IEHN's low imbalance power and imbalance heat costs, these costs are calculated for all scenarios and compared in two varied cases, with and without considering the HESS. Table 12.3 shows the obtained results.

According to Table 12.3, the system's imbalance costs in both electricity and heat sectors have been reduced remarkably by exploiting the HESS. As stated before, the reason for this reduction is to improve the flexibility of the IEHN at the RT

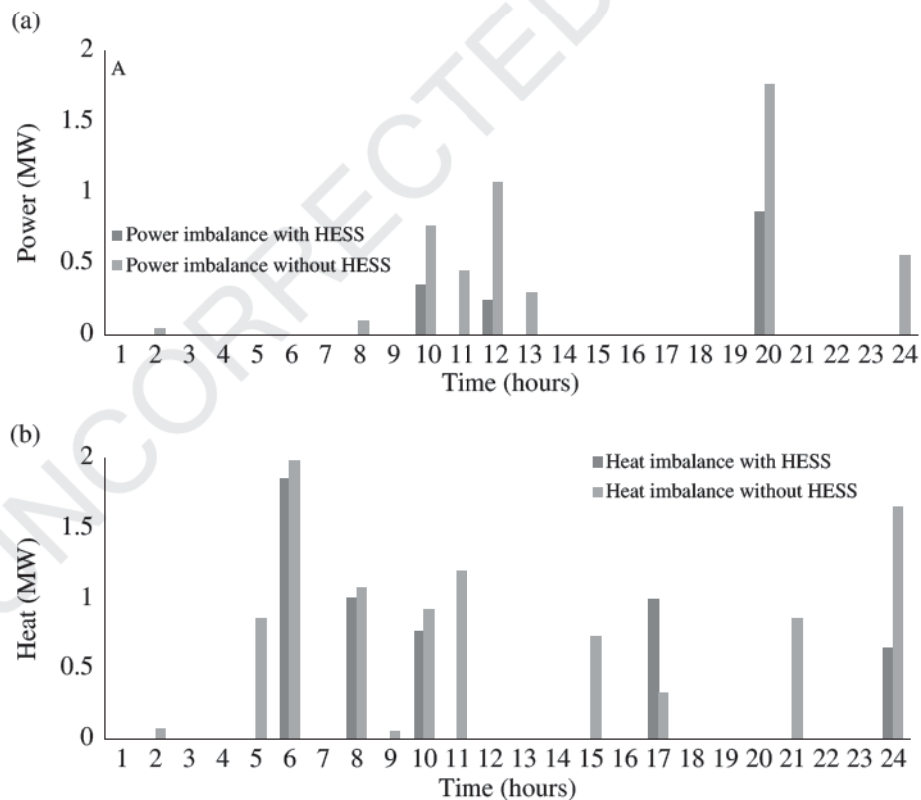


Figure 12.10 (a) Imbalance power in scenario 4 and (b) imbalance heat in scenario 4.

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Table 12.3 Comparison of imbalance costs in all scenarios.

Number scenario	Imbalance cost without the HESS (€/day)		Imbalance cost with the HESS (€/day)		Cost variation (%)	
	Heat	Power	Heat	Power	Heat	Power
s1	549.49	313.94	274.39	28.85	-50.06	-90.81
s2	572.22	436.67	292.12	17.78	-48.95	-95.93
s3	544.98	1161.48	339.07	729.10	-37.78	-37.23
s4	707.76	598.55	308.17	167.58	-56.46	-72.00
s5	1156.78	505.14	737.31	289.00	-36.26	-42.79
s6	374.93	758.25	16.11	409.65	-95.70	-45.98
s7	593.11	324.55	376.08	0	-36.59	-100
s8	683.20	515.92	275.68	227.13	-59.65	-55.98
s9	378.91	522.47	46.63	145.33	-87.69	-72.18
s10	562.42	916.88	237.80	598.19	-57.72	-34.76

stage so that the system operator is able to adjust its generation in a way the lowest possible cost is imposed on the system.

Based on Table 12.3, the highest imbalance cost reduction is related to the power sector in scenario 7, where the IEHN has been able to diminish its imbalance power cost to zero by utilizing the HESS. To further analyze this matter, in Figures 12.11a, b, the considered system's imbalance powers with and without the existence of HESS are compared.

As clear in Figures 12.11a, b, by adding the capacity of flexible resources to the system, the IEHN operator has been able to match the DA and RT powers and hence reduce imbalance power and its associated cost to zero.

In the end, the daily profit of the IEHN operator in the presence and absence of the HESS is compared with each other in Table 12.4. Moreover, to evaluate the role of the BESS, TESS, and NGESS, the profit of the IEHN operator without considering one of the mentioned elements is calculated in this table as well.

As expected, the highest amount of profit is associated with the case in which the HESS is equipped with all three storage systems, case 5. Among cases 2, 3, and 4, the best case is related to case 3, in which the HESS contains BESS and NGESS. This matter specifies that the IEHN's electricity sector, as the backbone of the whole incorporated system, has a better situation. The reason is that, on the one hand, the system has the BESS that has procured some part of its required power. On the other hand, by charging gas in the NGESS and discharging it to the CHP and GFG, it has been able to provide some part of its needed power at the peak of electricity consumption and price.

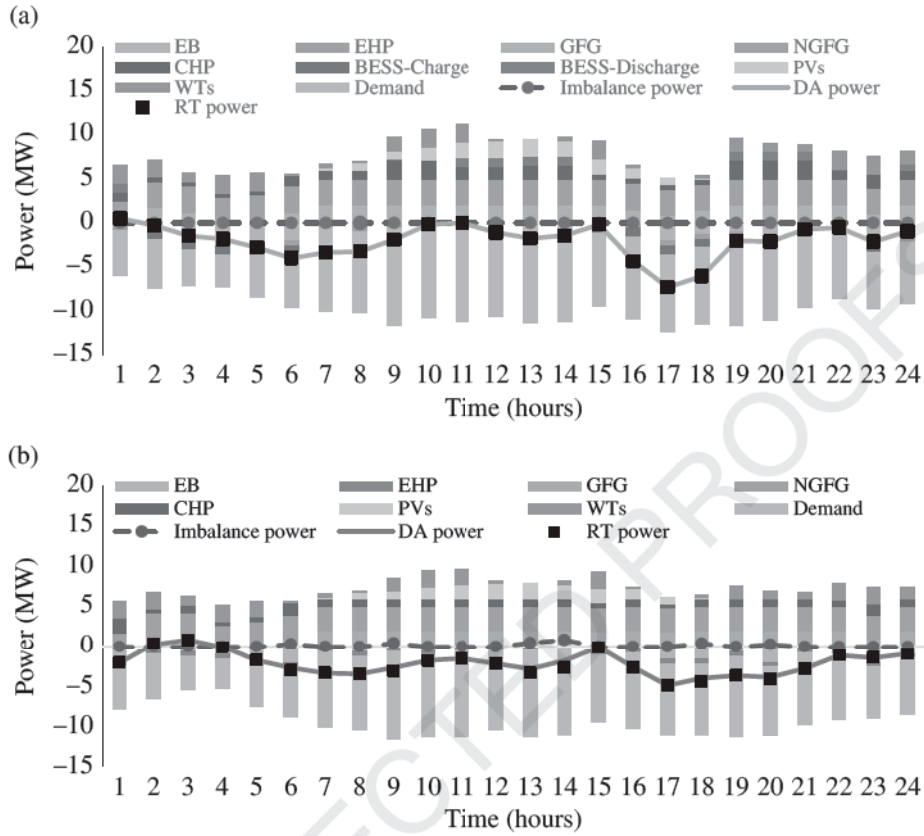


Figure 12.11 (a) Powers with the HESS in scenario 7 and (b) powers without the HESS in scenario 7.

Table 12.4 Expected profit in different cases.

	BESS	TESS	NGESS	Profit (€/day)	Variation (%)
Case 1 (Base)	✗	✗	✗	5432.76	—
Case 2	✗	✓	✓	6662.69	22.64
Case 3	✓	✗	✓	6773.58	24.68
Case 4	✓	✓	✗	6533.93	20.27
Case 5	✓	✓	✓	7226.50	33.02

12.4 Conclusion

This chapter modeled an IEHN in the presence of various generation units, P2X conversion elements, as well as storage devices and evaluated the effect of a HESS, consisting of BESS, TESS, and NGESS, on the optimal operation of the incorporated network. To consider a wide range of uncertainties in the mentioned decision-making problem, a two-stage stochastic programming scheme was suggested in this study. A typical case study was implemented to investigate and compare the performance of the system in the presence and absence of the HESS. Simulation results represented that in the absence of storage devices, the operator is forced to import more power and heat energy from the upstream grids in the DA stage, which leads to high operating costs of the system. On the other hand, by utilizing a HESS with all three elements, the RT imbalance power and RT imbalance heat of the IEHN are decreased remarkably, and hence the benefit of the system operator could be increased up to 33%. For another issue, it was observed that in the studied system, the combination of the BESS and NGESS, as a HESS, is more profitable than other possible cases so that the operator could earn 24% more benefit as opposed to the base case, without the HESS.

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A Market-based Mechanism for Local Energy Trading in Integrated Electricity-Heat Networks

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Abstract

Due to the proliferation of power-to-X-to-power (P2X2P) conversion technologies across various energy systems, the sector-integration concept has gained considerable attention in recent years. In this context, to facilitate the integration of local energy systems at the distribution level and take advantage of their provided privileges, the development of an efficient and pragmatic market-based mechanism is required. Hence, the present chapter focuses on modeling a local energy market (LEM) framework that enables the integration of electrical distribution systems (EDSs) as well as district heating systems (DHSs) via power-to-heat (P2H) conversion technologies. The suggested LEM platform is based on a centralized one-sided auction-based energy trading process which is settled by the distribution system operator (DSO) with the objective of social welfare maximization. In the end, the raised LEM clearing model is applied on an integrated electricity-heat network (IEHN) in the presence of technical constraints of both EDS and DHS.

Keywords: Local Energy Market; Integrated Electricity-Heat Network; Electrical Distribution System; District Heating System; Social Welfare.

Nomenclature

Acronyms	
CHP	Combined Heat and Power
DG	Dispatchable Generator
DHS	District Heating System
DSO	Distribution System Operator
EB	Electric Boiler
ED	Electric Demand
EDS	Electrical Distribution System
HD	Heat Demand
HES	Heat Exchanger Station
HS	Heat Station
IEHN	Integrated Electricity-Heat Network
LEM	Local Energy Market
Power-to-Heat	P2H
Power-to-X-to-Power	P2X2P
PV	Photovoltaic System
WT	Wind Turbine
Sets and Indices	
<i>ch</i>	CHP indices
<i>dg</i>	DG indices
<i>eb</i>	EB indices
<i>ed</i>	ED indices

hd	HD indices
i, j	Set of nodes in EDS
ij	Indices of lines in EDS
n	Set of nodes in DHS
nm	Indices of pipelines in DHS
pv	PV indices
t	Time indices
wt	WT indices
Ω_{CHP}	Set of CHPs connected to set of nodes
Ω_{DG}	Set of DGs connected to set of nodes
Ω_{EB}	Set of EBs connected to set of nodes
Ω_{ED}	Set of EDs connected to set of nodes
Ω_{HD}	Set of HDs connected to set of nodes
Ω_{HES}	Set of HESs connected to set of nodes
Ω_{HS}	Set of HSs connected to set of nodes
Ω_{PV}	Set of PVs connected to set of nodes
Ω_{hr}, Ω_{hs}	Set of return / supply pipelines in DHS
$\Omega_{hr-B}^n, \Omega_{hr-E}^n$	Set of return pipelines beginning / ending at node n
$\Omega_{hs-B}^n, \Omega_{hs-E}^n$	Set of supply pipelines beginning / ending at node n
Ω_{WT}	Set of WTs connected to set of nodes
Ω_e	Set of lines in EDS
Parameters	
b_{ij}, g_{ij}	Susceptance / conductance of line ij in EDS (ohm^{-1})
C_w	Specific heat capacity of water ($\text{J/g } ^\circ\text{C}$)
H_{HD}	Heat demand of DHS (kW)
HPR	Heat-to-power ratio of CHPs
HV_{gas}	Heat value of natural gas (kWh/m^3)
L_{nm}	length of pipelines in DHS (km)
m	Mass flow rate of nodes in DHS (kg/s)
m_R, m_S	Mass flow rate of return / supply pipelines in DHS (kg/s)
$p_{CHP}^{max}, p_{CHP}^{min}$	Maximum / minimum generated power of CHPs (kW)
$p_{EB}^{max}, p_{EB}^{min}$	Maximum / minimum generated power of EBs (kW)
P_{ED}	Electric demand of EDS (kW)
p_{ij}^{max}	Maximum capacity of line ij in EDS (kW)
Q_{DG}, Q_{PV}, Q_{WT}	Maximum quantity offers of DGs / PVs / WTs in LEM (kW)
T_{Amb}	Ambient temperature ($^\circ\text{C}$)
T_R^{max}, T_R^{min}	Maximum / minimum temperature of return pipelines in DHS ($^\circ\text{C}$)
T_S^{max}, T_S^{min}	Maximum / minimum temperature of supply pipelines in DHS ($^\circ\text{C}$)
V_{nom}	Nominal voltage (V)
$\lambda_{DG}, \lambda_{PV}, \lambda_{WT}$	Offer prices of DGs / PVs / WTs in LEM ($\text{€}/\text{kWh}$)
λ_{gas}	Natural gas price ($\text{€}/\text{m}^3$)
λ_g	Locational marginal price of PCC ($\text{€}/\text{kWh}$)
$\eta_{CHP-E}, \eta_{CHP-H}$	Electricity / heat efficiency of CHPs (%)
η_{EB-H}	Heat efficiency of EBs (%)
ϑ	Maximum voltage variation (%)
κ	Heat transfer coefficient of pipelines in DHS ($\text{W}/\text{cm } ^\circ\text{C}$)
Variables	
G_{CHP}	Gas flow to CHPs (m^3)
H_{CHP}	Output heat of CHPs (kW)
H_{EB}	Output heat of EBs (kW)
P_{CHP}	Output power of CHPs (kW)
P_{DG}	Offer of DGs in LEM (kW)
P_{EB}	Output power of EBs (kW)
P_g	Imported electricity from upstream grid (kW)
P_{PV}	Offer of PVs in LEM (kW)
P_{WT}	Offer of WTs in LEM (kW)
T_R, T_S	Return / supply temperature of nodes in DHS ($^\circ\text{C}$)
$T_{R,in}, T_{S,in}$	Return / supply temperature at inlet of pipelines in DHS ($^\circ\text{C}$)

$T_{R,out}, T_{S,out}$	Return / supply temperature at outlet of pipelines in DHS (°C)
V	Voltage magnitude (V)
ΔV	Voltage deviation (V)
α, β	Dual Variables or shadow prices (€/kWh)
θ	Voltage angle (rad)

1. Introduction

In recent years, a lack of fossil fuel sources and their irreversible environmental damages have led to a marked increase in the exploitation of renewable energy resources in power distribution systems [1]. Although the high penetration of renewable energies can overcome the above-mentioned challenges, the stochastic and intermittent nature of these units drives the need for flexibility in the electricity sector [2]. As one of the pragmatic and new solutions for flexibility provision at the distribution level, the coupling of different energy sectors, including the EDSs and DHSs, in the form of IEHNs has attracted more attention in the past few years [3]. To establish an IEHN via the sector-coupling concept, the presence of P2X2P, more specifically P2H, conversion technologies in the energy systems is required [4], [5]. Combined heat and power (CHP) plants [6], electric boilers (EBs) [7], and electric heat pumps (EHPs) [8] are the most prevalent P2H elements in IEHNs.

In general, P2H solutions require techno-economic interactions with two local energy sectors, namely power and heat. Nevertheless, these kinds of interactions add new challenges to the optimal operation of IEHNs due to the lack of a suitable coordination platform [9]. To cope with this issue and implement sector-coupling at the distribution level, proposing an appropriate market-based framework is of great importance. Accordingly, local market-based solutions for sector-coupling have received widespread attention over the last few years. The following literature review highlights some important studies in this area:

A decentralized optimization method has been raised in [10] to model a LEM for the coordinated operation of the EDS and DHS in the form of an IEHN. In the suggested framework, EDS and DHS are able to be operated independently by solving optimal power and thermal flows, respectively. A LEM has been designed in [11] to investigate the energy trading within an IEHN and in the presence of multiple strategic players. In the provided framework, locational marginal prices of electricity and heat achieved from optimal power and thermal flows have been exploited to settle the considered market. A bi-level optimization model has been presented in [12] for clearing a LEM and modeling its interaction with the wholesale electricity market. Accordingly, at the upper level, the DSO settles the LEM and determines locational marginal prices, while at the lower level, the wholesale market clearing, as well as the DSO's interaction with this market, are specified. A linear optimization-based approach has been developed in [13] to model a LEM enabling the integration of the EDS and DHS at the distribution level. The market-clearing process has been conducted from a

central operator's perspective to maximize consumers and producers' surplus. A novel market-based platform has been introduced in [14] to couple the EDS and DHS and facilitate the utilization of P2H and storage technologies at the local level. The primary goal of this research work is to develop innovative market orders that respect energy system integration. A LEM mechanism has been suggested in [15] to provide the possibility of peer-to-peer power and heat energy trading and investigate the cooperative behaviors among peers. In this study, each peer is able to promote its own profit by determining the joined coalition and its role as a seller or buyer of heat and electricity within this coalition. In the end, a fully decentralized market-based framework has been employed in [16] that supports peer-to-peer energy trading among several price-maker agents at the distribution level. To determine the optimal strategy of participated agents in the designed LEM and improve their net profit, a linear optimization model has been utilized in this study.

Due to the importance of establishing an efficient market-based environment for coupling of electricity and heat sectors at the local level, this chapter tends to model a LEM that enables the integration of EDSs and DHSs through CHPs and EBs, as fundamental P2H conversion technologies. The design of the considered LEM is based on a centralized one-sided auction-based energy trading process which is settled by the DSO with the objective of social welfare maximization. To this end, the schematic structure of the designed LEM, as well as the mathematical model for the market clearing process, are expressed in more detail in section 2. The implementation of a case study and its discussions are provided in section 3. Finally, the work is concluded in section 4.

2. Methodology

As briefly mentioned in the previous section, the main purpose of the current chapter is to design a LEM for facilitating energy trading within integrated energy networks. Before delving into the mathematical model of the proposed market-based framework, its overall structure and regulations are described.

In this work, the considered LEM is designed based on a centralized one-sided auction format. In this case, it is assumed that a central operator is responsible for the operation of the IEHN at a specific time through the complete exchange of energy and information among two electricity and heat sectors. Hence, in order to identify the market settlement point, all participants are required to submit their bids/offers to the LEM operator. Furthermore, it is presumed that the clearing mechanism of the LEM is according to the one-sided auction method, in which only production offers are considered in the negotiation procedure [17]. As a result, since multiple energy carriers are traded simultaneously in the presented market-based platform, each offer contains specific information, including the type of energy, quantity as well as valuation of the offer, the delivery time, and location

of the injected energy to the network. On the other hand, the pricing system of the LEM is uniform, in which all players are paid at the same market clearing price regardless of their submitted offers. This clearing price is set at the offer price of the most expensive supplier chosen for providing the service [18].

The schematic structure of the presented LEM platform for the integration of the EDS and DHS is illustrated in Figure 1. According to the figure, the DSO as a central operator is responsible for the LEM clearing and meeting the IEHN's demands in the presence of both networks' technical constraints. To this end, the DSO firstly collects offers from the existing market participants like dispatchable generators (DGs), wind turbines (WTs), and photovoltaic systems (PVs). Then, considering the locational marginal price of the PCC, as well as the operational condition of the available CHPs and EBs, this entity attempts to settle the market and determine accepted offers as well as distribution locational marginal prices for the optimal scheduling of the IEHN. The electric demand (ED) of the system is procured from DGs, WTs, PVs, CHPs, and the upstream grid, while the heat demand (HD) is procured from CHPs and EBs.

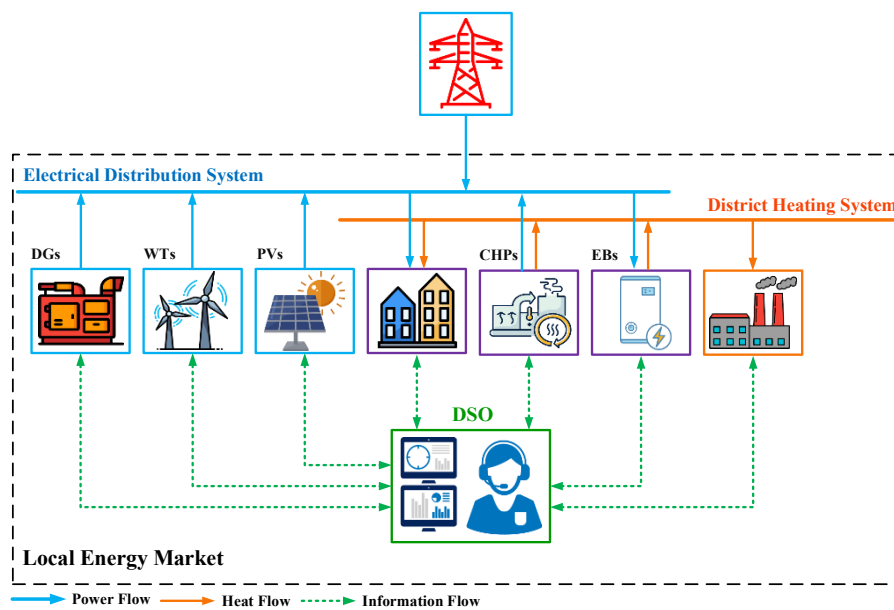


Figure 1: Schematic structure of the proposed LEM framework.

As stated above, the DSO as the market operator clears the suggested LEM platform with the objective of social welfare maximization [19], which is equal to the total energy cost minimization in this study. The mathematical formulation of the mentioned objective function is expressed by Eq (1). In this equation, the first term is related to the cost of imported electricity from the upstream grid. The second, third, and fourth terms are related to the marginal costs of the LEM participants. In the end, the fifth term is related to the operating cost of the CHP units.

$$\begin{aligned}
\text{Min } \sum_t \left\{ & P_g(t)\lambda_g(t) \right. \\
& + \sum_{dg} P_{DG}(dg, t)\lambda_{DG}(dg, t) \\
& + \sum_{wt} P_{WT}(wt, t)\lambda_{WT}(wt, t) \\
& \left. + \sum_{pv} P_{PV}(pv, t)\lambda_{PV}(pv, t) + \sum_{ch} G_{CHP}(ch, t)\lambda_{gas}(t) \right\}
\end{aligned} \tag{1}$$

The considered objective function is subject to a set of linear technical as well as operational constraints, as follows:

$$P_g(t) = \sum_{j:(i,j) \in \Omega_e} \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\}, \alpha(i, t) \tag{2}$$

$$\begin{aligned}
& \forall i = 1, t \\
& \sum_{dg:(dg,i) \in \Omega_{DG}} P_{DG}(dg, t) + \sum_{wt:(wt,i) \in \Omega_{WT}} P_{WT}(wt, t) \\
& + \sum_{pv:(pv,i) \in \Omega_{PV}} P_{PV}(pv, t) + \sum_{ch:(ch,i) \in \Omega_{CHP}} P_{CHP}(ch, t) \\
& - \sum_{eb:(eb,i) \in \Omega_{EB}} P_{EB}(eb, t) - \sum_{ed:(ed,i) \in \Omega_{ED}} P_{ED}(ed, t) \\
& = \sum_{j:(i,j) \in \Omega_e} \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\}, \alpha(i, t)
\end{aligned} \tag{3}$$

$$\begin{aligned}
& \forall i \neq 1, t \\
& -P_{ij}^{max} \leq \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\} \leq P_{ij}^{max}, \\
& \forall (ij) \in \Omega_e, t
\end{aligned} \tag{4}$$

$$-\vartheta V_{nom} \leq \Delta V(i, t) \leq \vartheta V_{nom}, \forall i, t \tag{5}$$

$$V(i, t) = V_{nom} + \Delta V(i, t), \forall i, t \tag{6}$$

$$-\pi \leq \theta(i, t) \leq \pi, \forall i, t \tag{7}$$

Eqs (2) to (7) demonstrate technical constraints of the EDS that model the linear AC power flow in this work [20]. Accordingly, the power balance of the electricity sector is expressed by Eqs (2) and (3), and their dual variables or shadow prices are specified after the colon. The LEM clearing price or distribution locational marginal price of electricity is achieved from the shadow prices of the power balance constraints [21]. Moreover, the power flow in distribution lines, as well as voltage deviation of nodes, are limited by Eqs (4) and (5), respectively. Also, Eq (6) represents the voltage magnitude of nodes. Finally, the voltage angle of each node is restricted by Eq (7).

$$0 \leq P_{DG}(dg, t) \leq Q_{DG}(dg, t), \forall dg, t \quad (8)$$

$$0 \leq P_{WT}(wt, t) \leq Q_{WT}(wt, t), \forall wt, t \quad (9)$$

$$0 \leq P_{PV}(pv, t) \leq Q_{PV}(pv, t), \forall pv, t \quad (10)$$

$$G_{CHP}(ch, t) = P_{CHP}(ch, t) / HV_{gas} \eta_{CHP-E}(ch), \forall ch, t \quad (11)$$

$$H_{CHP}(ch, t) \leq P_{CHP}(ch, t) HPR(ch) \eta_{CHP-H}(ch), \forall ch, t \quad (12)$$

$$P_{CHP}^{min}(ch) \leq P_{CHP}(ch, t) \leq P_{CHP}^{max}(ch), \forall ch, t \quad (13)$$

$$P_{EB}^{min}(eb) \leq P_{EB}(eb, t) \leq P_{EB}^{max}(eb), \forall eb, t \quad (14)$$

$$H_{EB}(eb, t) = P_{EB}(eb, t) \eta_{EB-H}(eb), \forall eb, t \quad (15)$$

On the other hand, Eqs (8) to (15) display operational constraints of the existing energy resources in the IEHN. In this regard, inequalities (8), (9), and (10) restrict DGs, WTs, and PVs' offers in the LEM to their maximum quantity offers, respectively. The relation between the gas flows to the CHP units and their output powers is determined by Eq (11). Furthermore, the relation between the output heat and the output power of CHPs is defined by Eq (12). Ultimately, the CHPs' output powers are confined to their minimum and maximum values by Eq (13) [22]. As stated, EBs are P2H elements that consume electricity to produce thermal energy. In this context, the power consumption of these units is limited by Eq (14), and their generated heat is displayed by Eq (15) [23].

DHSs contain supply pipelines that transfer hot water from heat sources to HDs, and return pipelines that return back cold water from HDs to heat sources [24]. Normally, these networks are controlled in four different modes, including constant-flow-constant-temperature, constant-flow-variable-temperature, variable-flow-constant-temperature, and variable-flow-variable-temperature. Eqs (16) to (25) depict technical constraints of the DHS that model the constant-flow-variable-temperature strategy in this work [25]. Notably, as non-linear hydraulic terms are eliminated in the considered model, the ultimate thermal model is linear.

$$\sum_{\substack{ch:(ch,n) \in \Omega_{CHP} \\ \forall n \in \Omega_{HS}, t}} H_{CHP}(ch, t) + \sum_{\substack{eb:(eb,n) \in \Omega_{EB}}} H_{EB}(eb, t) = C_W m(n, t) \{T_S(n, t) - T_R(n, t)\}, \quad (16)$$

$$\sum_{\substack{hd:(hd,n) \in \Omega_{HD} \\ \forall n \in \Omega_{HES}, t}} H_{HD}(hd, t) = C_W m(n, t) \{T_S(n, t) - T_R(n, t)\}, \beta(n, t) \quad (17)$$

$$T_{S,out}(nm, t) - T_{Amb}(t) = \{T_{S,in}(nm, t) - T_{Amb}(t)\} e^{\frac{-\kappa L_{nm}}{C_W m_S(nm, t)}}, \forall nm \in \Omega_{HS}, t \quad (18)$$

$$T_{R,out}(nm, t) - T_{Amb}(t) = \{T_{R,in}(nm, t) - T_{Amb}(t)\}e^{\frac{-\kappa L_{nm}}{C_{wm}R(nm,t)}}, \forall nm \in \Omega_{hR}, t \quad (19)$$

$$T_S^{min} \leq T_S(n, t) \leq T_S^{max}, \forall n, t \quad (20)$$

$$T_R^{min} \leq T_R(n, t) \leq T_R^{max}, \forall n, t \quad (21)$$

$$T_{S,in}(nm, t) = T_S(n, t), \forall nm \in \Omega_{hS-B}^n, n, t \quad (22)$$

$$T_{R,in}(nm, t) = T_R(n, t), \forall nm \in \Omega_{hR-B}^n, n, t \quad (23)$$

$$\sum_{nm \in \Omega_{hS-E}^n} \{m_S(nm, t)T_{S,out}(nm, t)\} = T_S(n, t) \sum_{nm \in \Omega_{hS-B}^n} m_S(nm, t), \forall n, t \quad (24)$$

$$\sum_{nm \in \Omega_{hR-E}^n} \{m_R(nm, t)T_{R,out}(nm, t)\} = T_R(n, t) \sum_{nm \in \Omega_{hR-B}^n} m_R(nm, t), \forall n, t \quad (25)$$

Accordingly, Eqs (16) and (17) show the heat balance of the system in heat stations (HSs) that are equipped with heat sources and heat exchanger stations (HESs) that are modeled as HDs, respectively [26]. The dual variable or shadow price of Eq (17) is presented after the colon that specifies the LEM clearing price or distribution locational marginal price of heat. The temperature drop caused by heat loss in supply and return pipelines is represented by Eqs (18) and (19), respectively. Inequalities (20) and (21) restrict the temperature of nodes in supply and return pipelines. Eqs (22) and (23) ensure that the inlet temperature of supply and return pipelines is equal to the nodes' temperature. Finally, according to Eqs (24) and (25), the nodes' temperature is computed as the mixture temperature of mass flows entering the nodes.

3. Case Study

In this section, the LEM clearing model is applied to an IEHN, including a 13-node EDS [27] and a 4-node DHS. The single-line diagram of this integrated system is depicted in Figure 2.

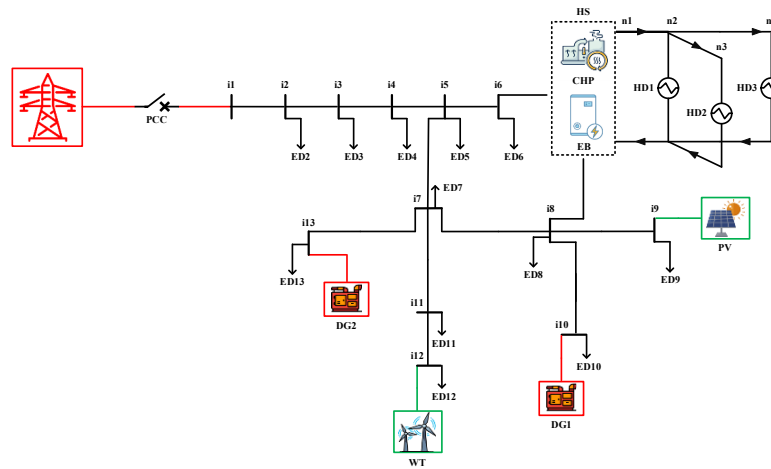


Figure 2: Studied IEHN.

Accordingly, the EDS contains two DGs, one WT, and one PV at nodes 10, 13, 12, and 9, respectively. The EDS nodes 6 and 8 are connected to the HS of the DHS, which is equipped with one CHP and one EB. The maximum quantity offers of the LEM participants as well as technical specifications of the existing P2H elements are provided in Tables 1 and 2, respectively.

Table 1: Maximum offers of LEM participants.

# Unit	Maximum Quantity Offers (kW)
DG 1	3000
DG 2	2000
WT	2000
PV	1500

Table 2: Characteristics of P2H units.

# Unit	Minimum Power (kW)	Maximum Power (kW)	Heat Efficiency (%)	Electricity Efficiency (%)	Heat-to-Power Ratio
CHP	200	2000	55	45	1
EB	0	500	80	–	–

Offer prices of the available market participants, as well as locational marginal prices of PCC, are illustrated in Figure 3. The electric and heat demand profiles of the studied IEHN are displayed in Figure 4. Furthermore, the peak demand of the system in each node is expressed in Table 3.

On the other hand, it is assumed that the temperature of supply pipelines in the DHS varies between 60 °C and 100 °C, while the temperature of its return pipelines varies between 20 °C and 60 °C. In addition, the ambient temperature is 10 °C, specific heat capacity of water is 4.182 J/g °C, and heat transfer coefficient of pipelines is 0.00455 W/cm °C [28].

In the end, the natural gas price is considered a three-tariff price, and the heat value of natural gas is presumed to be 11.7 kWh/m³.

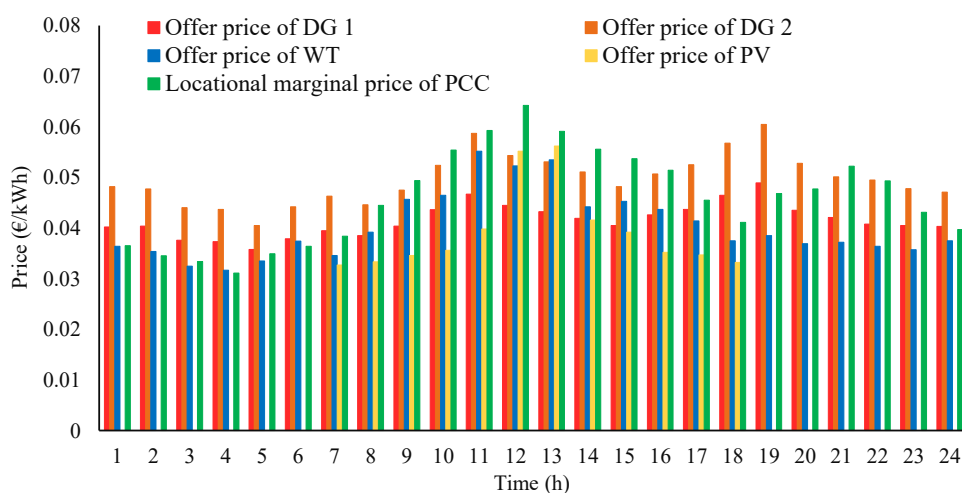


Figure 3: Prices in the LEM clearing process.

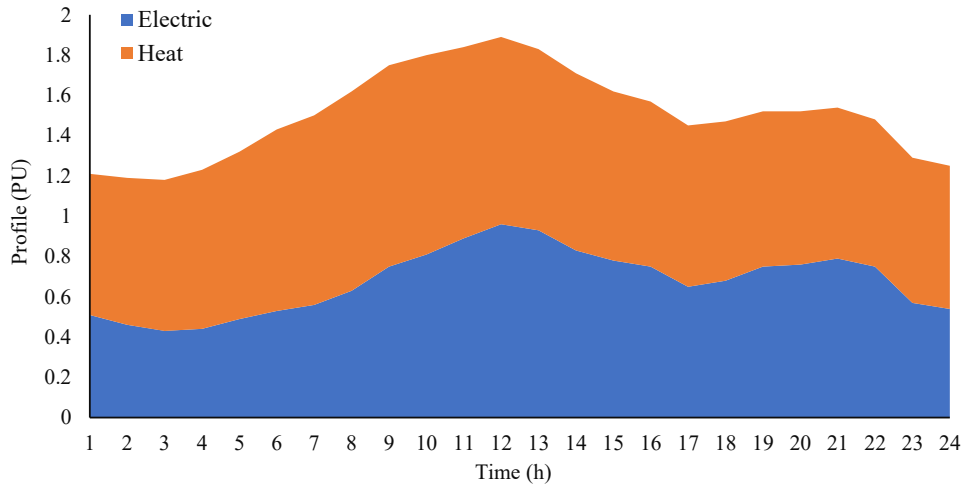


Figure 4: Demand profiles of the IEHN.

Table 3: Peak demand of the IEHN.

# Node	1	2	3	4	5	6	7	8	9	10	11	12	13
Electric Demand (kW)	0	890	628	1112	636	474	1342	920	766	662	690	1292	1124
Heat Demand (kW)	0	450	400	450	-	-	-	-	-	-	-	-	-

Accepted offers of the LEM participants, namely DGs, WT, and PV, as well as the output power of P2H elements, namely CHP and EB, are demonstrated in Figure 5. In this figure, the DSO’s imported electricity from the upstream grid is displayed as well. Notably, the line graph shows the system’s whole ED during the studied day.

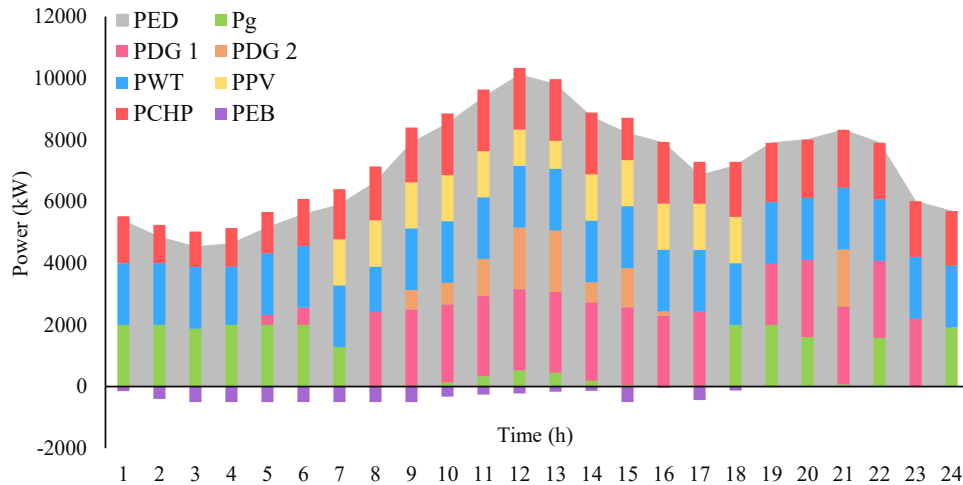


Figure 5: Optimal operating points of power resources in the LEM.

As shown, the entire produced and imported powers have procured the required powers of the EB and ED. On the other hand, based on Figures 3 and 5, since the offer prices of WT and PV are

lower than the offer prices of DGs and locational marginal prices of PCC in most hours of the day, their maximum quantity offers have been accepted in the LEM clearing process.

The output heat of P2H elements, i.e., CHP and EB, are depicted in Figure 6. Similarly, the line graph shows the system's whole HD during the studied day.

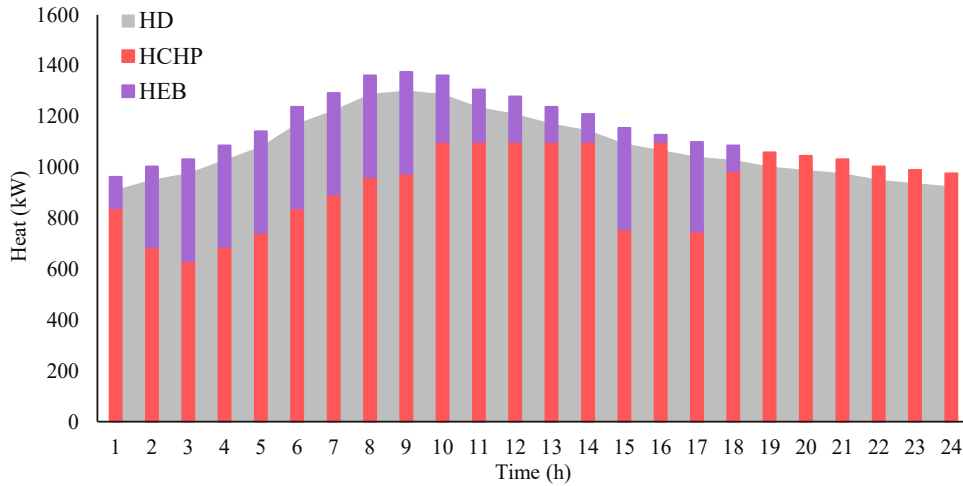


Figure 6: Optimal operating points of heat resources in the LEM.

Based on the DHS modeling in the previous section and Figure 6, it is observed that the generated heat at each hour has procured not only the HD but also heat loss in supply and return pipelines. Also, since the electricity price is low in the early hours of the day, the DSO has preferred to transform the power to heat by the available EB and satisfy the peak HD of the system.

The amount of gas consumption by the available CHP unit in the IEHN, as well as the three-tariff natural gas price, are depicted in Figure 7. Clearly, during the peak of electric and heat demands, the considered CHP has consumed the highest amount of gas.

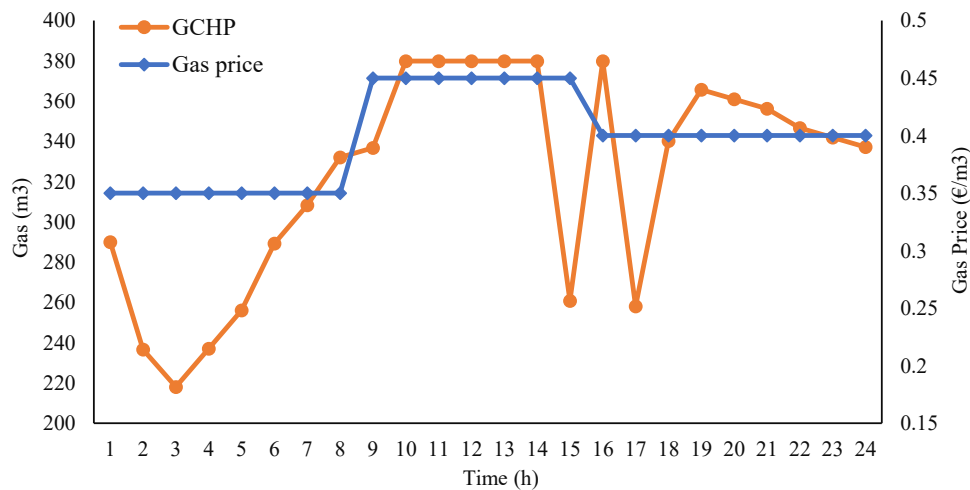


Figure 7: CHP's gas consumption and natural gas price.

Temporal and spatial variation of distribution locational marginal price of electricity in the LEM clearing procedure is presented in Figure 8.

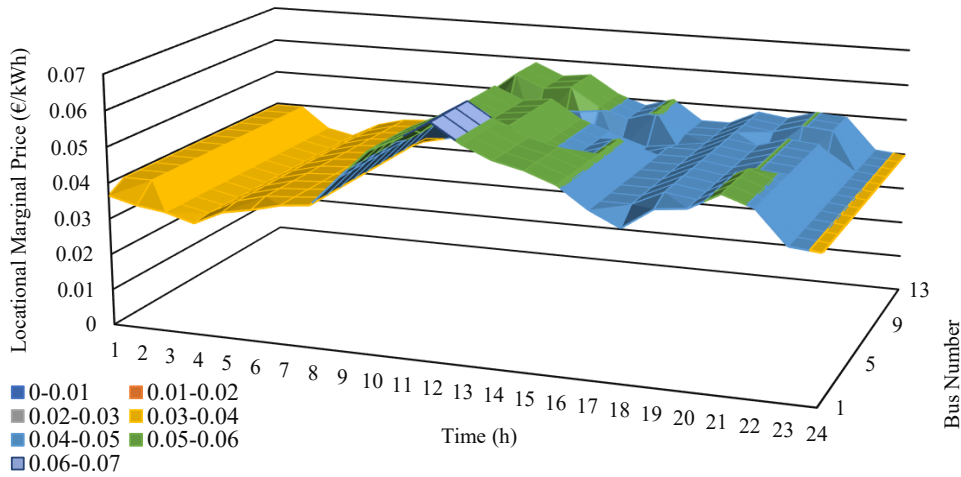


Figure 8: Variation of distribution locational marginal price of electricity.

The generic temporal analysis shows that by increasing the ED, the distribution locational marginal price is increased as well. On the other hand, according to the spatial analysis, the increase in the ED during peak hours leads to congestion in the EDS, which changes the LEM clearing price at different nodes.

To better investigate the spatial level, distribution locational marginal prices of the EDS nodes at hours 12 and 21 are represented in Figure 9.

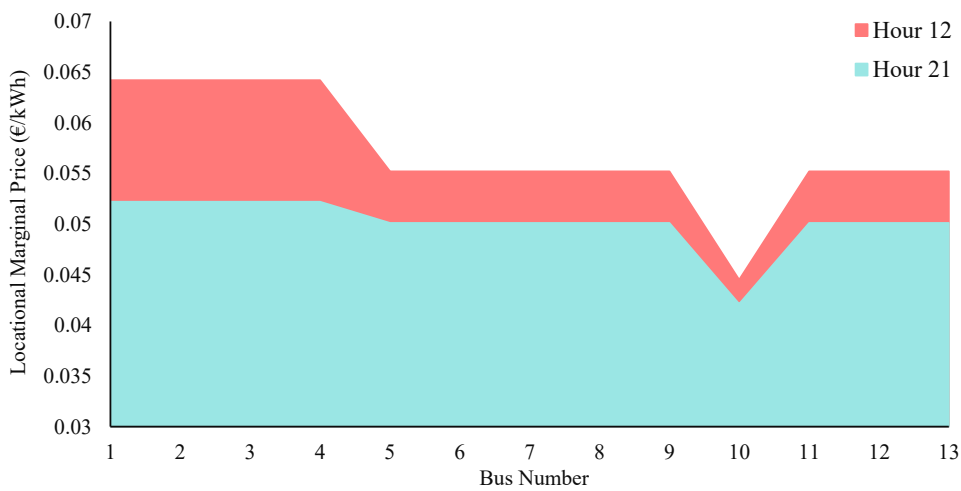


Figure 9: Distribution locational marginal prices at hours 12 and 21.

Based on Figure 9, at hours 12, distribution locational marginal prices at nodes 1 to 4 are equal to locational marginal prices of PCC. Due to the congestion in line 4-5, the rest of the nodes' marginal

prices have been affected by the offer prices of the LEM participants. In this context, PV as a marginal producer has determined distribution locational marginal prices at nodes 5 to 9 and 11 to 13. The marginal price of node 10 has resulted from offer price of DG 1, which is located at this node. The important point here is that while the offer price of DG 1 is lower than the offer price of PV, this unit has not been able to affect other nodes' marginal prices due to the congestion in line 8-10. Similarly, at hour 21, distribution locational marginal prices at nodes 1 to 4 are equal to locational marginal prices of PCC. Because of the congestion in line 4-5, distribution locational marginal prices at nodes 5 to 9 and 11 to 13 have been determined by DG 2 as a marginal producer. Also, because of congestion in line 8-10, DG 1 has only been able to impact the marginal price of node 10.

4. Conclusion

The high penetration of renewable energies has increased the need for flexibility in power distribution systems. Recently, the coupling of EDSs and DHSs in the form of IEHNs has been raised as one of the promising solutions for flexibility provision. Nonetheless, establishing IEHNs and optimally operating them requires the development of an appropriate and practical market-based mechanism. In this context, this chapter modeled a LEM for the integration of the EDS and DHS at the distribution level. The considered LEM was cleared by the DSO using a centralized one-sided auction to maximize social welfare. Then, the suggested LEM clearing model was applied to an IEHN under the technical constraints of both EDS and DHS. Output results specified that distribution locational marginal prices are affected by a set of factors, including the topology as well as demands of the network.

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A local energy market for integrated electricity-heat networks

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Abstract

To implement sector-coupling in local energy systems and benefit from their advantages at the distribution level, the development of an appropriate market-based mechanism is highly important. In this context, the present article aims at modeling a local energy market (LEM) framework to facilitate the integration of electrical distribution systems (EDSs) as well as district heating systems (DHSs) via power-to-heat (P2H) conversion technologies. The presented LEM is based on a centralized one-sided auction-based energy trading process which is settled by the distribution system operator (DSO) with the objective of total energy cost minimization. The raised LEM clearing model is applied on an integrated electricity-heat network (IEHN) in the presence of technical constraints of both EDS and DHS.

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Keywords: Local energy market; integrated electricity-heat network; distribution system operator

Nomenclature

ch, dg, eb	CHP / DG / EB indices
ed, hd	ED / HD indices
i, j, ij	Set of nodes / set of lines in EDS
n, nm	Set of nodes / set of pipelines in DHS
pv, wt	PV / WT indices
t	Time indices
Ω	Set of \blacksquare connected to set of nodes
$\Omega_{hS/hR}$	Set of supply / return pipelines in DHS
$\Omega_{hS/hR-B}^n, \Omega_{hS/hR-E}^n$	Set of supply / return pipelines beginning / ending at node n
Ω_e	Set of lines in EDS
b_{ij}, g_{ij}	Susceptance / conductance of line ij in EDS (ohm^{-1})
C_w	Specific heat capacity of water ($\text{J/g } ^\circ\text{C}$)
H_{HD}	Heat demand of DHS (kW)
L_{nm}	length of pipelines in DHS (km)

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$m, m_{S/R}$	Mass flow rate of nodes / supply / return pipelines in DHS (kg/s)
P_{ED}	Electric demand of EDS (kW)
P_{ij}^{max}	Maximum capacity of line ij in EDS (kW)
Q_{DG}, Q_{PV}, Q_{WT}	Maximum quantity offers of DGs / PVs / WTs in LEM (kW)
T_{Amb}	Ambient temperature (°C)
$T_{S/R}^{max}, T_{S/R}^{min}$	Maximum / minimum temperature of supply / return pipelines in DHS (°C)
V_{nom}	Nominal voltage (V)
$\lambda_{DG}, \lambda_{PV}, \lambda_{WT}$	Offer prices of DGs / PVs / WTs in LEM (€/kWh)
λ_{gas}	Natural gas price (€/m ³)
λ_g	Locational marginal price of PCC (€/kWh)
ϑ	Maximum voltage variation (%)
κ	Heat transfer coefficient of pipelines in DHS (W/cm °C)
G_{CHP}	Gas flow to CHPs (m ³)
H_{CHP}, P_{CHP}	Output heat / power of CHPs (kW)
H_{EB}, P_{EB}	Output heat / power of EBs (kW)
P_{DG}, P_{PV}, P_{WT}	Offer of DGs / PVs / WTs in LEM (kW)
P_g	Imported electricity from upstream grid (kW)
$T_{S/R}$	Supply / return temperature of nodes in DHS (°C)
$T_{S/R,in}, T_{S/R,out}$	Supply / return temperature at inlet / outlet of pipelines in DHS (°C)
$V, \Delta V$	Voltage magnitude / deviation (V)
α, β	Dual Variables or shadow prices (€/kWh)
θ	Voltage angle (rad)

1. Introduction

In recent years, a lack of fossil fuel sources and their irreversible environmental damages have led to a marked increase in the exploitation of renewable energy resources in power distribution systems [1]. Although the high penetration of renewable energies can overcome the above-mentioned challenges, the stochastic and intermittent nature of these units drives the need for flexibility in the electricity sector [2]. The use of real and virtual energy storage units, including battery storage units and demand response programs, is one of the most common ways of providing flexibility in power systems [3]. Besides, as one of the pragmatic and new solutions for flexibility provision at the distribution level, the coupling of different energy sectors, including the EDSs and DHSs, in the form of IEHNS has attracted more attention in the past few years [4]. To establish an IEHN via the sector-coupling concept, the presence of power-to-X-to-power (P2X2P), more specifically P2H, conversion technologies in the energy systems is required [5]. Generally, P2H solutions require techno-economic interactions with two local energy sectors, namely power and heat. Combined heat and power (CHP) plants, electric boilers (EBs), and electric heat pumps (EHPs) are the most prevalent P2H elements in IEHNS [6].

In general, P2H solutions require techno-economic interactions with two local energy sectors, namely power and heat. Nevertheless, these kinds of interactions add new challenges to the optimal operation of IEHNS due to the lack of a suitable coordination platform [7]. To cope with this issue and implement sector-coupling at the distribution level, proposing an appropriate market-based framework is of great importance. Accordingly, local market-based solutions for sector-coupling have received widespread attention over the last few years. The following literature review highlights some important studies in this area:

A decentralized optimization method has been raised in [8] to model an LEM for the coordinated operation of the EDS and DHS in the form of an IEHN. In the suggested framework, EDS and DHS are able to be operated independently by solving optimal power and thermal flows, respectively. An LEM has been designed in [9] to investigate the energy trading within an IEHN and in the presence of multiple strategic players. In the provided framework, locational marginal prices of electricity and heat achieved from optimal power and thermal flows have been exploited to settle the considered market. A bi-level optimization model has been presented in [10] for clearing an LEM and modelling its interaction with the wholesale electricity market. Accordingly, at the upper level, the DSO settles the LEM and determines locational marginal prices, while at the lower level, the wholesale market clearing, as well as the DSO's interaction with this market, are specified. A linear optimization-based approach has been developed in [11] to model an LEM enabling the integration of the EDS and DHS at the distribution level. The market-clearing process has been conducted from a central operator's perspective to maximize consumers and producers' surplus. A novel market-based platform has been introduced in [12] to couple the EDS and DHS and facilitate the utilization of

P2H and storage technologies at the local level. The primary goal of this research work is to develop innovative market orders that respect energy system integration. In the end, a fully decentralized market-based framework has been employed in [13] that supports peer-to-peer energy trading among several price-maker agents at the distribution level. To determine the optimal strategy of participated agents in the designed LEM and improve their net profit, a linear optimization model has been utilized in this study.

Due to the importance of establishing an efficient market-based environment for coupling of electricity and heat sectors at the local level, the primary contribution of this paper is to design an LEM that enables the integration of EDSs and DHSs through CHPs and EBs, as fundamental P2H conversion technologies, to provide flexibility in the presence of a wide range of renewable energy resources. The design of the considered LEM is based on a centralized one-sided auction-based energy trading process which is settled by the DSO with the aim of reducing total energy costs. To this end, the schematic structure of the designed LEM, as well as the mathematical model for the market clearing process, are expressed in more detail in section 2. The implementation of a case study and its discussions are provided in section 3. Finally, the work is concluded in section 4.

2. Methodology

As briefly mentioned in the previous section, the main purpose of the current article is to design an LEM for facilitating energy trading within integrated energy networks. Before delving into the mathematical model of the proposed market-based framework, its overall structure and regulations are described.

In this work, the considered LEM is designed based on a centralized one-sided auction format. In this case, it is assumed that a central operator is responsible for the operation of the IEHN at a specific time through the complete exchange of energy and information among two electricity and heat sectors. Hence, to identify the market settlement point, all participants are required to submit their bids/offers to the LEM operator. Furthermore, it is presumed that the clearing mechanism of the LEM is the one-sided auction method, in which only production offers are considered in the negotiation procedure. As a result, since multiple energy carriers are traded simultaneously in the presented market-based platform, each offer contains specific information, including the type of energy, quantity as well as valuation of the offer, the delivery time, and location of the injected energy to the network. On the other hand, the pricing system of the LEM is uniform, in which all players are paid at the same market clearing price regardless of their submitted offers. This clearing price is set at the offer price of the most expensive supplier chosen for providing the service. The schematic structure of the presented LEM platform for the integration of the EDS and DHS is illustrated in Fig. 1.

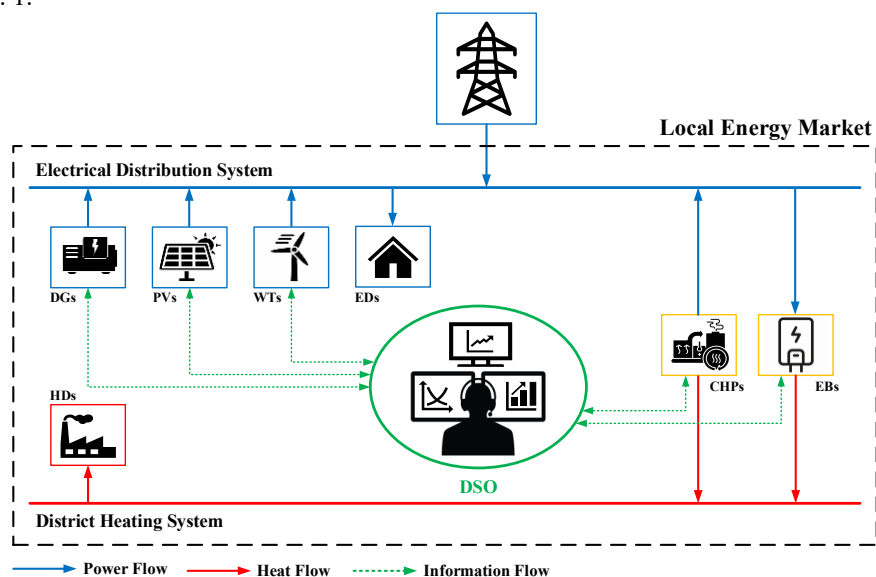


Fig. 1. Schematic structure of the proposed LEM framework.

According to Fig. 1, the DSO as a central operator is responsible for the LEM clearing and meeting the IEHN's demands in the presence of both networks' technical constraints. To this end, the DSO firstly collects offers from the existing market participants like dispatchable generators (DGs), wind turbines (WTs), and photovoltaic systems (PVs). Then, considering the locational marginal price of the PCC, as well as the operational condition of the available CHPs and EBs, this entity attempts to settle the market and determine accepted offers as well as distribution locational marginal prices for the optimal scheduling of the IEHN. The electric demand (ED) of the system is procured from DGs, WTs, PVs, CHPs, and the upstream grid, while the heat demand (HD) is procured from CHPs and EBs. In this study, the objective function of the DSO is to minimize the total cost of energy. The mathematical formulation of the mentioned objective function is expressed by Eq (1).

$$\begin{aligned} \text{Min} \sum_t \left\{ P_g(t) \lambda_g(t) + \sum_{dg} P_{DG}(dg, t) \lambda_{DG}(dg, t) + \sum_{wt} P_{WT}(wt, t) \lambda_{WT}(wt, t) \right. \\ \left. + \sum_{pv} P_{PV}(pv, t) \lambda_{PV}(pv, t) + \sum_{ch} G_{CHP}(ch, t) \lambda_{gas}(t) \right\} \end{aligned} \quad (1)$$

This objective function is subject to a set of linear technical as well as operational constraints, as follows:

$$P_g(t) = \sum_{j:(i,j) \in \Omega_e} \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\}, \alpha(i, t) \quad (2)$$

$$\forall i = 1, t$$

$$\begin{aligned} \sum_{dg:(dg,i) \in \Omega_{DG}} P_{DG}(dg, t) + \sum_{ch:(ch,i) \in \Omega_{CHP}} P_{CHP}(ch, t) \\ + \sum_{wt:(wt,i) \in \Omega_{WT}} P_{WT}(wt, t) + \sum_{pv:(pv,i) \in \Omega_{PV}} P_{PV}(pv, t) \\ - \sum_{eb:(eb,i) \in \Omega_{EB}} P_{EB}(eb, t) - \sum_{ed:(ed,i) \in \Omega_{ED}} P_{ED}(ed, t) \\ = \sum_{j:(i,j) \in \Omega_e} \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\}, \alpha(i, t) \end{aligned} \quad (3)$$

$$\forall i \neq 1, t$$

$$-P_{ij}^{max} \leq \{V_{nom}[\Delta V(i, t) - \Delta V(j, t)]g_{ij} - V_{nom}^2[\theta(i, t) - \theta(j, t)]b_{ij}\} \leq P_{ij}^{max}, \quad (4)$$

$$\forall ij \in \Omega_e, t$$

$$-\vartheta V_{nom} \leq \Delta V(i, t) \leq \vartheta V_{nom}, \quad (5)$$

$$\forall i, t$$

$$V(i, t) = V_{nom} + \Delta V(i, t), \quad (6)$$

$$\forall i, t$$

$$-\pi \leq \theta(i, t) \leq \pi, \quad (7)$$

$$\forall i, t$$

Eqs (2) to (7) demonstrate technical constraints of the EDS that model the linear AC power flow in this work [14]. Accordingly, the power balance of the electricity sector is expressed by Eqs (2) and (3), and their dual variables or shadow prices are specified after the colon. The LEM clearing price or distribution locational marginal price of electricity is achieved from the shadow prices of the power balance constraints.

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$$\begin{aligned} 0 \leq P_{DG}(dg, t) \leq Q_{DG}(dg, t), \\ \forall dg, t \end{aligned} \quad (8)$$

$$\begin{aligned} 0 \leq P_{WT}(wt, t) \leq Q_{WT}(wt, t), \\ \forall wt, t \end{aligned} \quad (9)$$

$$\begin{aligned} 0 \leq P_{PV}(pv, t) \leq Q_{PV}(pv, t), \\ \forall pv, t \end{aligned} \quad (10)$$

Inequalities (8), (9), and (10) restrict DGs, WTs, and PVs' accepted offers in the LEM to their maximum quantity offers. On the other hand, operational constraints of CHP and EB units are modelled, as stated in [15].

DHSs contain supply pipelines that transfer hot water from heat sources to HDs, and return pipelines that return back cold water from HDs to heat sources. Eqs (11) to (16) depict technical constraints of the DHS that model the constant-flow-variable-temperature controlled strategy in this work [16].

$$\begin{aligned} \sum_{ch:(ch,n) \in \Omega_{CHP}} H_{CHP}(ch, t) + \sum_{eb:(eb,n) \in \Omega_{EB}} H_{EB}(eb, t) = C_W m(n, t) \{T_S(n, t) - T_R(n, t)\}, \\ \forall n \in \Omega_{HS}, t \end{aligned} \quad (11)$$

$$\begin{aligned} \sum_{hd:(hd,n) \in \Omega_{HD}} H_{HD}(hd, t) = C_W m(n, t) \{T_S(n, t) - T_R(n, t)\} \beta(n, t), \\ \forall n \in \Omega_{HES}, t \end{aligned} \quad (12)$$

$$\begin{aligned} T_{S/R,out}(nm, t) - T_{Amb}(t) = \{T_{S/R,in}(nm, t) - T_{Amb}(t)\} e^{\frac{-\kappa L_{nm}}{C_W m_{S/R}(nm, t)}}, \\ \forall nm \in \Omega_{hS/hR}, t \end{aligned} \quad (13)$$

$$\begin{aligned} T_{S/R}^{min} \leq T_{S/R}(n, t) \leq T_{S/R}^{max}, \\ \forall n, t \end{aligned} \quad (14)$$

$$\begin{aligned} T_{S/R,in}(nm, t) = T_{S/R}(n, t), \\ \forall nm \in \Omega_{hS/hR-B}^n, n, t \end{aligned} \quad (15)$$

$$\begin{aligned} \sum_{nm \in \Omega_{hS/hR-E}^n} \{m_{S/R}(nm, t) T_{S/R,out}(nm, t)\} = T_{S/R}(n, t) \sum_{nm \in \Omega_{hS/hR-B}^n} m_{S/R}(nm, t), \\ \forall n, t \end{aligned} \quad (16)$$

Eqs (11) and (12) show the heat balance of the system in heat stations (HSs) that are equipped with heat sources and heat exchanger stations (HESs) that are modelled as HDs. The dual variable or shadow price of Eq (12) is presented after the colon that specifies the LEM clearing price or distribution locational marginal price of heat.

3. Case study

The proposed LEM clearing model is applied to an IEHN, including a 13-node EDS and a 4-node DHS. The single-line diagram of this integrated system is depicted in Fig. 2. The EDS contains two DGs, one WT, and one PV at nodes 10, 13, 12, and 9, respectively. The EDS nodes 6 and 8 are connected to the HS of the DHS, which is equipped with one CHP and one EB. The maximum quantity offers of DG 1, DG 2, WT, and PV are 3000, 2000, 2000, and 1500 kW, respectively. In addition, the maximum capacities of the existing CHP and EB are 2000 and 500 kW, respectively.

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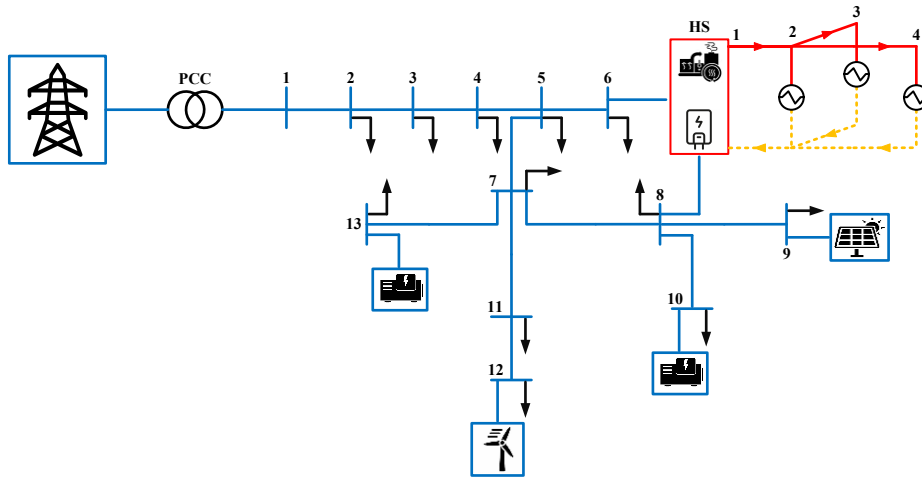


Fig. 2. Studied IEHN.

Offer prices of the available market participants, as well as locational marginal prices of PCC, are illustrated in Fig. 3. The electric and heat demand profiles of the studied IEHN are displayed in Fig. 4.

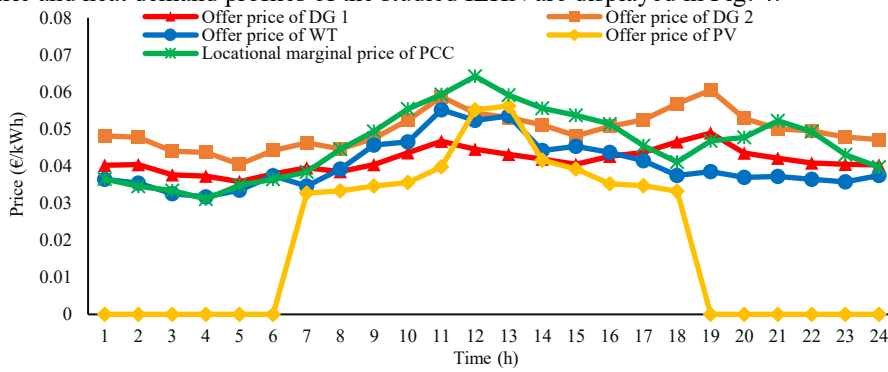


Fig. 3. Prices in the LEM clearing process.

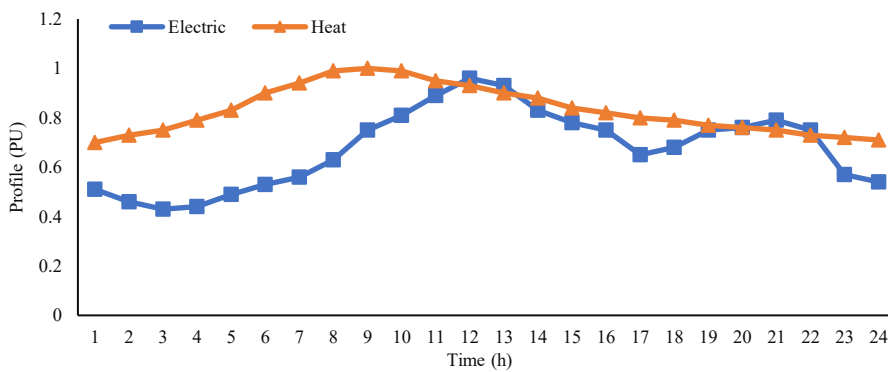


Fig. 4. Demand profiles of the IEHN.

Accepted offers of the LEM participants, namely DGs, WT, and PV, as well as the output power of P2H elements, namely CHP and EB, are demonstrated in Fig. 5. In this Fig., the DSO's imported electricity from the upstream grid is displayed as well. Notably, the line graph shows the system's whole ED during the studied day. As shown, the

entire produced and imported powers have procured the required powers of the EB and ED. Based on Fig. 3 and Fig. 5, since the offer prices of WT and PV are lower than the offer prices of DGs and locational marginal prices of PCC in most hours of the day, their maximum quantity offers have been accepted in the LEM clearing process.

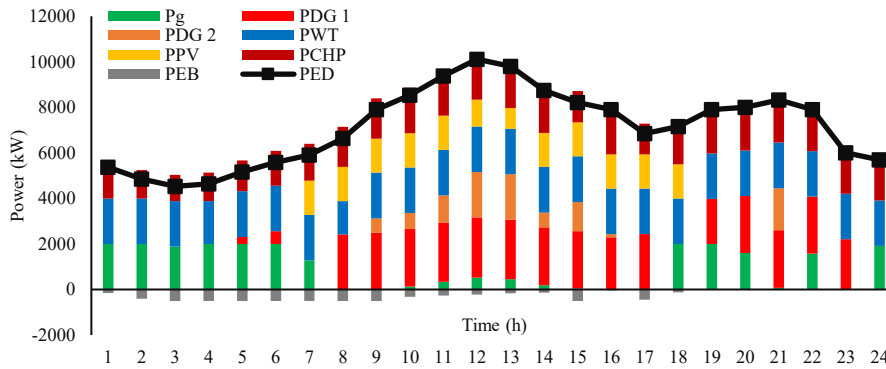


Fig. 5. Optimal operating points of power resources in the LEM.

The output heat of P2H elements, i.e., CHP and EB, are depicted in Fig. 6. The line graph shows the system’s whole HD during the studied day. Based on the DHS modeling in the previous section and Fig. 6, it is observed that the generated heat at each hour has procured not only the HD but also heat loss in supply and return pipelines. Moreover, since the electricity price is low in the early hours of the day, the DSO has preferred to transform the power to heat by the available EB and satisfy the peak HD of the system.

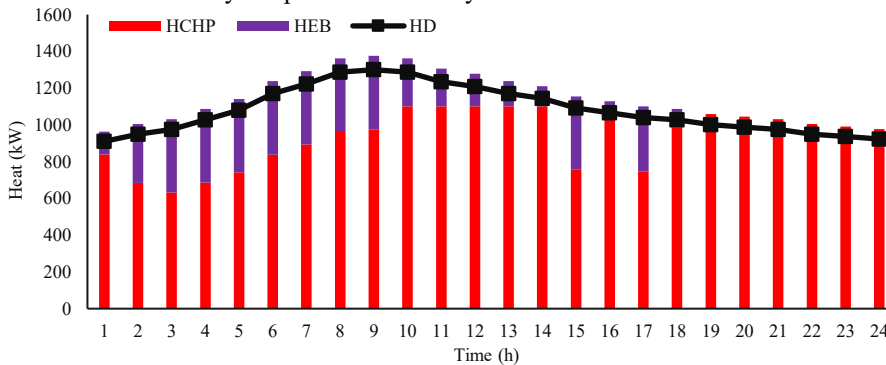


Fig. 6. Optimal operating points of heat resources in the LEM.

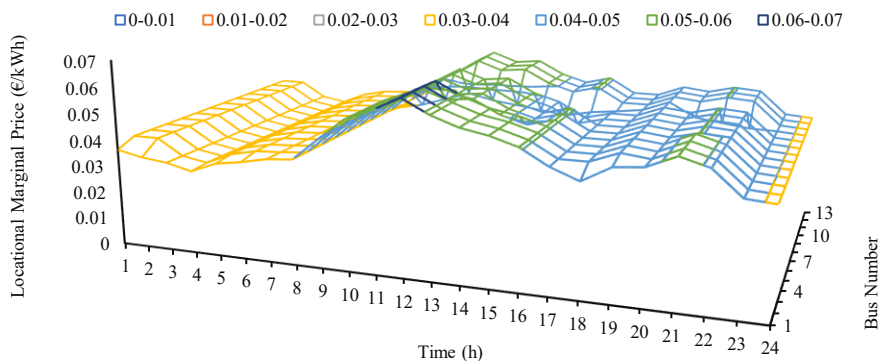


Fig. 7. Variation of distribution locational marginal price of electricity.

Temporal and spatial variation of distribution locational marginal price of electricity in the LEM clearing procedure is presented in Fig. 7. The generic temporal analysis shows that by increasing the ED, the distribution locational marginal price is increased as well. On the other hand, according to the spatial analysis, the increase in the ED during peak hours leads to congestion in the EDS, which changes the LEM clearing price at different nodes.

To better investigate the spatial level, distribution locational marginal prices of the EDS nodes at hour 12 are represented in Fig. 8. Accordingly, distribution locational marginal prices at nodes 1 to 4 are equal to locational marginal prices of PCC. Due to the congestion in line 4-5, the rest of the nodes' marginal prices have been affected by the offer prices of the LEM participants. In this context, PV as a marginal producer has determined distribution locational marginal prices at nodes 5 to 9 and 11 to 13. The marginal price of node 10 has resulted from DG 1 offer price, which is located at this node. The important point is that while the offer price of DG 1 is lower than the offer price of PV, this unit has not been able to affect other nodes' marginal prices due to the congestion in line 8-10.

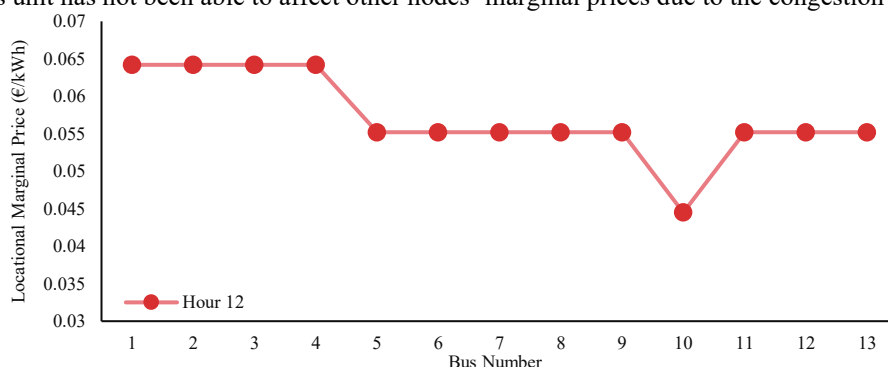


Fig. 8. Distribution locational marginal price at hour 12.

4. Conclusion

Establishing IEHNs requires the development of an appropriate market-based mechanism. In this regard, this article modeled an LEM for the integration of the EDS and DHS at the distribution level. The considered LEM was cleared by the DSO using a centralized one-sided auction. Finally, the suggested LEM clearing model was applied to an IEHN under the constraints of both EDS and DHS. Output results specified that distribution locational marginal prices are affected by a set of factors, including the topology as well as demands of the network.

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DESIGN OF AN AUCTION-BASED LOCAL ENERGY MARKET FOR INTEGRATED ELECTRICITY AND HEAT NETWORKS COORDINATED WITH WHOLESALE MARKET

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ABSTRACT

This article presents a market-based framework for coupling of electricity and heat sectors at the local level via power-to-heat (P2H) units. The considered local energy market (LEM) is designed based on an auction-based energy trading process which is settled by the integrated energy system operator (IESO) with the objective of social welfare maximization. Moreover, as part of the suggested mechanism, the coordination between the IESO and the transmission system operator (TSO) is considered to evaluate the mutual impact of the designed LEM on the wholesale electricity market (WEM) and vice versa. To this end, a bi-level programming model is employed, in which the LEM clearing problem is implemented at its upper level (UL) while the WEM clearing problem is executed at its lower level (LL). To assess the operation of the LEM and its coordination with the WEM, a case study is considered in which an integrated energy system (IES), including a 13-node electric distribution system and a 4-node district heating system, is connected to a 6-node transmission system.

Nomenclature

Sets

a	Set of nodes in district heating system
$e \in E$	Set of power participants in LEM
$g \in G$	Set of conventional producers in WEM
$h \in H$	Set of heat participants in LEM
i, j	Set of nodes in electric transmission system
i	Set of nodes in electric transmission system connected to electric distribution system
$ld \in LD$	Set of loads in electric distribution system
$lh \in LH$	Set of loads in district heating system
$lt \in LT$	Set of loads in electric transmission system
n, m	Set of nodes in electric distribution system
\hat{n}	Set of nodes in electric distribution system connected to electric transmission system
$t \in T$	Time

Parameters

b_{ij}	Susceptance of lines in electric transmission system
b_{nm}, g_{nm}	Susceptance/conductance of lines in electric distribution system
C_w	Specific heat capacity of water
m	Mass flow rate in district heating system
P_{LD}, P_{LH}, P_{LT}	Demand of electric distribution/district heating/ electric transmission system
$q_E^{bid\ max}/q_E^{offer\ max}$	Max bid/offer of power participants in LEM
q_G^{max}	Max offer of conventional producers in WEM
$q_H^{offer\ max}$	Max offer of heat participants in LEM
V_{nom}	Nominal voltage of electric distribution system
$\lambda_E^{bid}, \lambda_E^{offer}$	Bid/offer price of power participants in LEM
λ_G	Offer price of conventional producers in WEM
λ_H^{offer}	Offer price of heat participants in LEM

Variables

$C_{WEM}^{bid}, C_{WEM}^{offer}$	Submitted bid/offer price of IESO in WEM
dV	Voltage deviation

q_E^{bid}, q_E^{offer}	Bid/offer of power participants in LEM
q_G	Offer of conventional producers in WEM
q_H^{offer}	Offer of heat participants in LEM
$q_{WEM}^{bid}, q_{WEM}^{offer}$	Accepted bid/offer of IESO in WEM
$Q_{WEM}^{bid}, Q_{WEM}^{offer}$	Submitted bid/offer of IESO in WEM
T_R, T_S	Return/supply temperature of nodes in district heating system
$\lambda_{LEM-E}, \lambda_{LEM-H}$	Electricity/heat LEM-clearing price
λ_{WEM}	WEM clearing price
θ, δ	Voltage angle in distribution/transmission system

INTRODUCTION

In order to manage a large amount of distributed energy resources (DERs) in restructured power systems and benefit from their flexibility service provision potential, the concept of LEM has been gaining increased interest [1]. In general, LEMs are one of the most promising solutions for ensuring flexibility at the distribution level, dominated by stochastic renewable energy resources. The reason is that these markets provide a transactive platform for local electricity exchange among various kinds of prosumers, such as dispatchable and non-dispatchable units as well as energy storage systems. In the meanwhile, nowadays, the emergence of power-to-X-to-power (P2X2P) technologies and their widespread exploitation at the local level allows other energy carriers, including heat and gas, to be traded in the LEMs as well [2]. Hence, several attempts have been made in recent years to design LEMs with good functionality and scalability. Accordingly, authors in [3]–[5] have proposed the LEM structure that supports peer-to-peer electricity exchange among several prosumers equipped with DERs and energy storage units with the objective of social welfare maximization for all market participants. Authors in [6]–[8] have presented the LEM framework, in which various independent financial entities, including aggregators and microgrids, are able to compete with one another to trade electricity with the distribution system operator (DSO) in the market and simultaneously pursue their conflicting objectives. On the other hand, authors in [9]–[11] have designed the centralized LEM for the optimal operation of integrated energy systems that enable the trade of electricity and heat among the entire participants of these two sectors with the aim of social welfare maximization. Finally, authors in [12]–[14] have suggested decentralized frameworks for the LEM design that provide the possibility of power and heat energy trading among these two systems considering their independent operation. By and large, the organization of a variety of multi-carrier DERs, P2X2P units, and energy storage systems in LEMs helps IESOs to procure a considerable percentage of their required demand at the local level and only compensate for the shortage from the upstream grid or the WEM. Furthermore, it is possible for these operators to supply their surplus to the WEM in the form of offer packages and make a profit. On the other hand, by decreasing bids as well as increasing offers from the distribution side, the



demand in the WEM is reduced, resulting in low energy prices in the TSO-level market. As a result, since the interaction between emerging LEMs and the WEM has potential benefits and importance, multiple recent research works have attempted to propose optimal solutions for the better coordination of distribution and transmission systems [15]–[17].

Considering the significance of LEMs and their two-way impact on the WEM, this article proposes a centralized two-sided auction-based LEM that not only facilitates the coupling of electricity and heat sectors to get benefit from multi-carrier DERs and P2X2P units but also takes into account its coordination with the WEM. To this end, a bi-level programming method is employed, in which the LEM clearing process by the IESO is implemented at its UL, while the WEM clearing process by the TSO is executed at its LL. The primary goal of this study is to assess the mutual influence of the designed LEM on the WEM and vice versa.

METHODOLOGY

As mentioned previously, a LEM is designed in this paper so that it integrates the electric distribution system and the district heating system through P2H units, such as combined heat and power (CHP) plant and electric boiler (EB). In the designed framework, the coordination of the LEM with the WEM is evaluated as well. For this purpose, a bi-level programming approach is utilized to consider both markets' clearing processes. The outline of the suggested model is demonstrated in Figure 1.

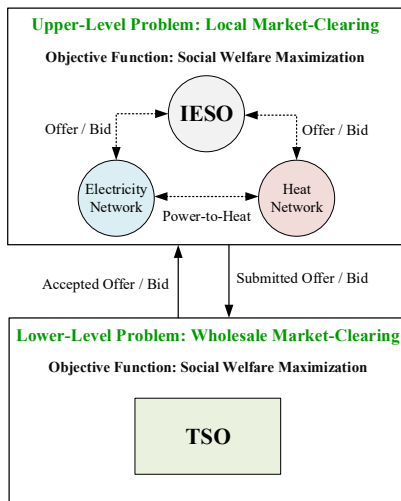


Figure 1. Outline of the proposed bi-level framework.

As shown in Figure 1, at the UL of the problem, the IESO is responsible for clearing the LEM with the objective of social welfare maximization and meeting the IES's power and heat demands in the presence of both the electric distribution system and the district heating system's technical constraints. The energy trading in the considered LEM is based on a two-sided auction-based format, in which the entire power and heat market participants are required to submit their offers and bids to the operator. In this procedure, the IESO's coordination with the TSO is also modeled so that this entity is able to submit its offers and bids to the WEM for energy exchange between

distribution and transmission systems. In addition, at the LL of the problem, the TSO is responsible for clearing the WEM with the objective of social welfare maximization and meeting demands in the presence of the transmission system's technical constraints. The energy trading in the WEM is also based on a two-sided auction-based format, in which the entire market participants, including conventional power producers and IESO, are required to submit their offers and bids to the operator. In the following of this section, objective functions as well as operational and technical constraints of both levels are formulated mathematically.

A. UL Problem Formulation

The UL's objective function in Eq. (1) is the minimization of the minus social welfare.

$$\begin{aligned} \text{Min} \sum_{t \in T} & \{\lambda_{WEM}(i=t, t)q_{WEM}^{Bid}(t) - \lambda_{WEM}(i=t, t)q_{WEM}^{Offer}(t) \\ & + \sum_{e \in E} [\lambda_E^{Offer}(e, t)q_E^{Offer}(e, t) - \lambda_E^{Bid}(e, t)q_E^{Bid}(e, t)] \\ & + \sum_{h \in H} [\lambda_H^{Offer}(h, t)q_H^{Offer}(h, t)]\}, \end{aligned} \quad (1)$$

This objective function is subject to a set of linear technical and operational constraints:

$$\begin{aligned} q_{WEM}^{Bid}(t) - q_{WEM}^{Offer}(t) = & \sum_{m:(n,m) \in \Delta_D} \{V_{nom}[dV(n, t) - dV(m, t)]g_{nm} \\ & - V_{nom}^2[\theta(n, t) - \theta(m, t)]b_{nm}\}, \\ \lambda_{LEM-E}(n, t), \quad \forall n = \hat{n}, t \end{aligned} \quad (2)$$

$$\begin{aligned} \sum_{e:(e,n) \in E} [q_E^{Offer}(e, t) - q_E^{Bid}(e, t)] - \sum_{ld:(ld,n) \in LD} P_{LD}(ld, t) \\ = \sum_{m:(n,m) \in \Delta_D} \{V_{nom}[dV(n, t) - dV(m, t)]g_{nm} \\ - V_{nom}^2[\theta(n, t) - \theta(m, t)]b_{nm}\}, \\ \lambda_{LEM-E}(n, t), \quad \forall n \neq \hat{n}, t \end{aligned} \quad (3)$$

$$\begin{aligned} \sum_{h:(h,a) \in H} q_H^{Offer}(h, t) = C_w m(a, t) \{T_S(a, t) - T_R(a, t)\}, \\ \forall a \in \text{Heat Station}, t \end{aligned} \quad (4)$$

$$\begin{aligned} \sum_{lh:(lh,a) \in LH} P_{LH}(lh, t) = C_w m(a, t) \{T_S(a, t) - T_R(a, t)\}, \\ \lambda_{LEM-H}(a, t), \quad \forall a \in \text{Heat Exchanger Station}, t \end{aligned} \quad (5)$$

$$Q_{WEM}^{Offer}(t) \geq 0, \quad Q_{WEM}^{Bid}(t) \geq 0, \quad \forall t \quad (6)$$

$$C_{WEM}^{Offer}(t) \geq 0, \quad C_{WEM}^{Bid}(t) \geq 0, \quad \forall t \quad (7)$$

$$0 \leq q_E^{Offer/Bid}(e, t) \leq q_E^{Offer max/Bid max}(e), \quad \forall e, t \quad (8)$$

$$0 \leq q_H^{Offer}(h, t) \leq q_H^{Offer max}(h), \quad \forall h, t \quad (9)$$

Eqs. (2)-(3) are the LEM power balance in the connected bus to the transmission system and the rest of the buses, respectively. Eqs. (4)-(5) are the LEM heat balance in heat stations and heat exchanger stations, respectively. Eqs. (6)-(7) are related to the IESO's submitted offer/bid packages to the WEM. Eqs. (8)-(9) restrict LEM power and heat participants' offers to their maximum quantity offers. Notably, technical constraints of electric distribution and district heating systems are adopted from [6],[10].

B. LL Problem Formulation

The LL's objective function in Eq. (10) is the minimization of the minus social welfare, as well.

$$\text{Min} \sum_{t \in T} \left\{ \sum_{g \in G} \lambda_c(g, t) q_c(g, t) + C_{WEM}^{offer}(t) q_{WEM}^{offer}(t) - C_{WEM}^{bid}(t) q_{WEM}^{bid}(t) \right\}, \quad (10)$$

This objective function is also subject to a set of linear technical and operational constraints:

$$q_{WEM}^{offer}(t) - q_{WEM}^{bid}(t) = \sum_{j:(i,j) \in \Delta_T} \{b_{ij}[\delta(i, t) - \delta(j, t)]\}, \quad (11)$$

$$\lambda_{WEM}(i, t), \quad \forall i = i, t$$

$$\sum_{g:(g,t) \in G} q_c(g, t) - \sum_{lt:(lt,t) \in LT} P_{LT}(lt, t)$$

$$= \sum_{j:(i,j) \in \Delta_T} \{b_{ij}[\delta(i, t) - \delta(j, t)]\}, \quad (12)$$

$$\lambda_{WEM}(i, t), \quad \forall i \neq i, t$$

$$0 \leq q_{WEM}^{offer}(t) \leq Q_{WEM}^{offer}(t), \quad 0 \leq q_{WEM}^{bid}(t) \leq Q_{WEM}^{bid}(t), \quad (13)$$

$$\forall t$$

$$0 \leq q_c(g, t) \leq q_c^{max}(g), \quad \forall g, t \quad (14)$$

Eqs. (11)-(12) are the WEM power balance in the connected bus to the distribution system and the rest of the buses, respectively. Eq. (13) limits the accepted offer/bid of the IESO in the WEM to its submitted offer/bid. Eq. (14) restricts conventional power producers' offers in the WEM to their maximum quantity offers. Notably, technical constraints of electric transmission system are adopted from [15].

The suggested bi-level model is re-formulated to a linear single-level model by Karush-Kuhn-Tucker conditions as well as the Strong Duality theory and the Big-M method, as stated in [6].

CASE STUDY

In this part, the provided model for the design of the LEM and its interaction with the WEM is applied to a system consisting of a 6-node electric transmission system, a 13-node electric distribution system, and a 4-node district heating system. Figure 2 illustrates the single-line diagram of the studied system.

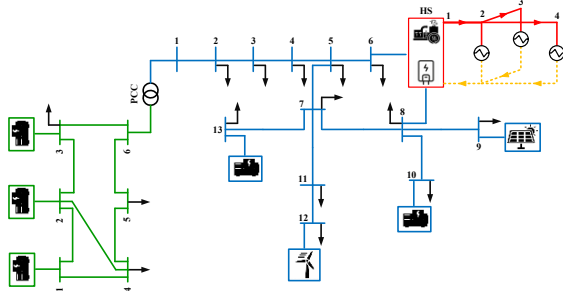


Figure 2. Topology of the IES connected to the transmission system.

As shown, the electric transmission system has three conventional producers (CPs) at nodes 1,2,3, the electric distribution system has two dispatchable generators (DGs), one wind turbine (WT), and one photovoltaic (PV) system at nodes 10,13,12,9, and finally, the district heating system has one CHP and one EB at the heat station, which is coupled to nodes 6 and 8 electric distribution system.

The maximum offer/bid of these participants in their associated markets is shown in Table 1 and Figure 3. Moreover, the offer/bid prices of these units to the LEM and WEM are depicted in Figure 4. On the other hand, demand consumption of the IES, as well as the transmission system, are demonstrated in Figure 5.

Table 1. Maximum offer/bid of the LEM and WEM participants.

# Unit	Maximum Offer/Bid (MW)
DG 1	3.0
DG 2	2.0
CHP	2.0
EB	1.5
CP 1	14.0
CP 2	5.0
CP 3	12.0

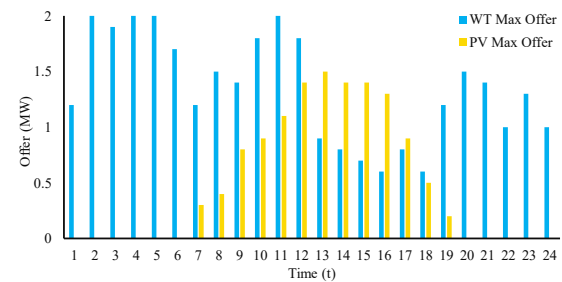


Figure 3. Maximum offer of the renewable resources in the LEM.

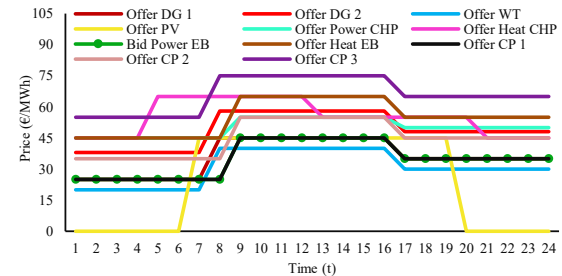


Figure 4. Offer/bid prices of market participants.

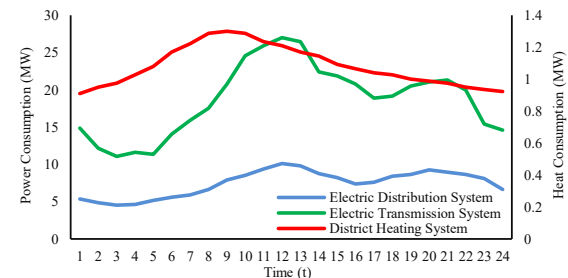


Figure 5. Load profiles of three systems.

In the end, it is assumed that the capacity of the line between the electric distribution system and the electric transmission system is confined to 3 MW.

In the following, the output results from the simulation are presented. In this paper, more attention is paid to the way of optimal interaction between these two markets, the optimal operation of the available resources in systems, as well as the impact of LEM and WEM prices on each other. In this regard, the accepted offer/bid of power participants in the LEM, as well as the accepted offer/bid of the IESO



in the WEM, are represented in Figure 6. The area graph in this figure shows the electric distribution demand.

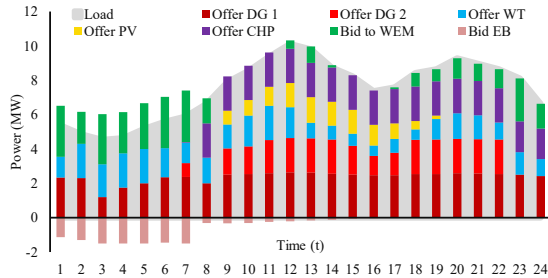


Figure 6. Operating power points in the LEM.

Based on Figure 6, on the studied day, the IESO acts as a power consumer in the WEM. Accordingly, in the early hours of the day, this entity has preferred to import more power from the WEM to consume in the EB and produce heat for the district heating system. This issue has occurred due to low WEM prices at these hours. In addition, since the offer prices of DG 1 and WT are lower than the rest of the LEM participants' offer prices, these two resources have been exploited whole the day, while DG 2 and CHP have been exploited more at peak hours. On the other hand, the accepted offer of heat participants in the LEM and district heating demand have been illustrated in Figure 7.

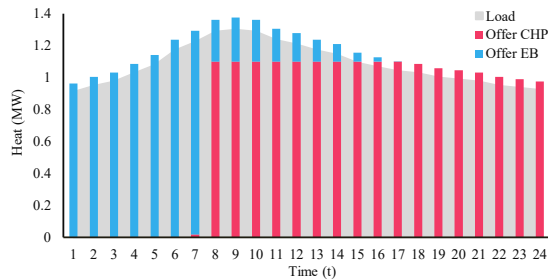


Figure 7. Operating heat points in the LEM.

Based on Figure 7, since the electricity price is low in the early hours of the day, the generated power in the LEM and imported power from the WEM has been transferred to heat by the existing EB to procure the peak heat demand of the system. By increasing the electricity price, the heat demand procurement has been assigned to the CHP. As clear in this figure, the generated heat at each hour has satisfied not only the demand but also heat loss in supply and return pipelines. Additionally, Figure 8 depicts the temporal and spatial variation of the electricity price in the LEM-clearing process.

Based on Figure 8, as expected, LEM-clearing prices have increased at peak hours. Additionally, as a result of congestion in lines of the electric distribution system, the LEM electricity price has changed in some nodes of the system. In order to better analyze the temporal level, prices in nodes 10 and 12 of the electric distribution system over the whole day have been shown in Figure 9. In order to better analyze the spatial level, node prices in the electric distribution system at hours 12 and 21 have been shown in Figure 10.

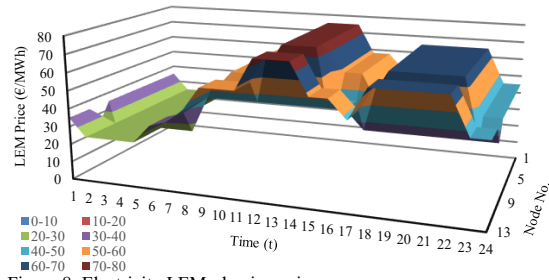


Figure 8. Electricity LEM-clearing price.

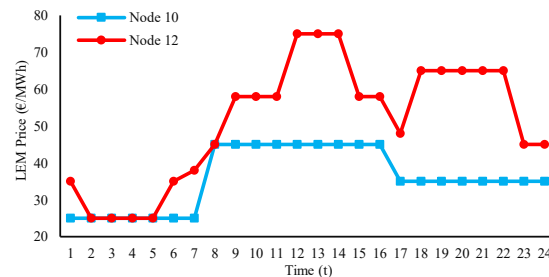


Figure 9. Temporal analysis of electricity LEM-clearing price.

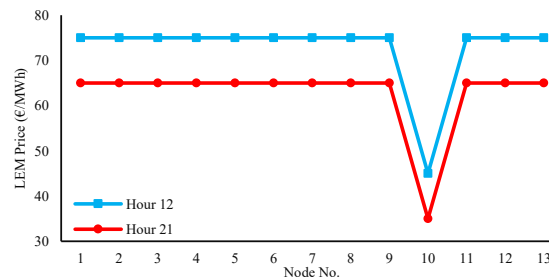


Figure 10. Spatial analysis of electricity LEM-clearing price.

Based on Figure 9, the electricity price in node 10 is equal to the offer price of DG 1, which is located at this bus. On the other hand, in hours that the line 8-10 distribution system is not faced with congestion, i.e., hours 3-4-5-8, the electricity prices in other nodes, including node 12, are also equal to the offer price of DG 1. However, in the rest of the hours that the line 8-10 distribution system is faced with congestion, the electricity prices in other nodes, including node 12, are equal to the offer prices of marginal producers in the LEM or WEM. For instance, at hour 1, the electricity price in node 12 is equal to the offer price of CP 2 in the WEM since other producers with lower prices are at their maximum production capacity. For another example, at hour 7, the electricity price in node 12 is equal to the offer price of DG 2 in the LEM. The important point here is that at this hour, CP 2 in the WEM, which has a lower offer price than DG 2 in the LEM, has not been able to determine the price of node 12. That is because the line between electric transmission and distribution systems is congested, and there is no possibility to import more power from the WEM to the LEM.

Based on Figures 10 and 6, at hours 12 and 21, all power participants in the LEM except for DG 1 are at their maximum production capacity. Hence, it is expected that



DG 1, as a marginal producer, determines the LEM price in different nodes. Nonetheless, due to congestion in the line 8-10, this unit has been able to merely affect node 10's price. Consequently, the IESO is forced to compensate for its shortage from the WEM, and the LEM-clearing prices are affected by WEM-clearing prices. So, at these two hours, CP 3, with offer prices of 65 €/MWh and 75 €/MWh, is the marginal producer in both transmission and distribution systems.

Finally, the accepted offer of participants in the WEM, as well as the temporal and spatial variation of the electricity price in the WEM-clearing process, are displayed in Figures 11 and 12, respectively.

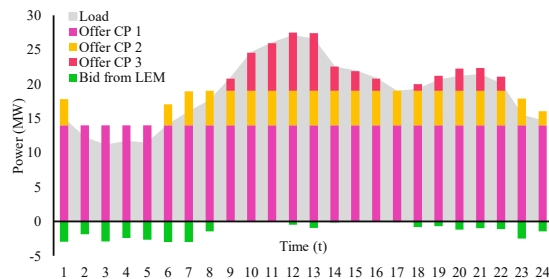


Figure 11. Operating power points in the WEM.

As shown in Figure 11, CP 1, which is the cheapest producer in the WEM, has been exploited with full capacity over the studied day. However, CP 3, which is the most expensive producer in the WEM, has been exploited only at peak hours.

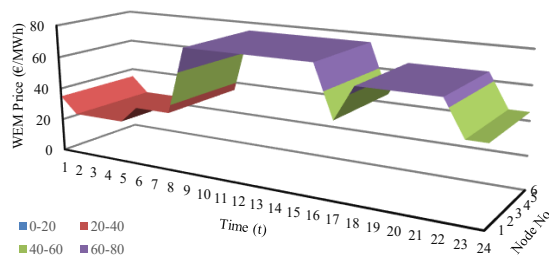


Figure 12. WEM-clearing price.

Based on Figure 12, WEM-clearing prices have increased at peak hours. Also, since none of the transmission system lines are congested, the WEM electricity prices are the same at different nodes.

CONCLUSION

The present paper suggested a LEM platform for the integration of electricity and heat sectors at the distribution level that considered this market's coordination with the WEM as well. For modeling the considered problem, a bi-level programming approach was utilized, in which the LEM and WEM-clearing processes are implemented at the UL and LL, respectively. This model was tested on an IES, including a 13-node electric distribution system and a 4-node district heating system, which is connected to a 6-node transmission system. The simulation results showed

how WEM-clearing prices influence LEM-clearing prices.

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ORIGINAL RESEARCH

A two-stage stochastic bilevel programming approach for offering strategy of DER aggregators in local and wholesale electricity markets

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Abstract

A two-stage stochastic programming scheme is proposed in order to evaluate the offering strategy of a distributed energy resource aggregator in both wholesale and local electricity markets and appropriately cope with uncertainties associated with its decision-making problem. In this regard, the aggregator combines a broad range of virtual and real distributed energy resources to simultaneously participate in the local electricity market as a price-maker or strategic player and the wholesale electricity market as a price-taker or non-strategic player. To model the studied aggregator as a strategic entity in the local market, a bilevel programming approach is exploited in this work. Accordingly, at the upper level of the raised problem, the aggregator tends to promote its expected profit through taking part in the wholesale and local electricity markets, while at the lower level, the considered local market is cleared in a way to maximise the social welfare. In the end, the effectiveness of the proposed framework for the simultaneous participation of the distributed energy resource aggregator in these two markets has been explored utilising a case study.

KEYWORDS

local electricity market, offering strategy, strategic DER aggregator, two-stage stochastic bilevel approach

1 | INTRODUCTION

By and large, distributed energy resources (DERs) are real or virtual generation units that are directly connected to the distribution systems. Depending on their nature and characteristics, these resources are divided into three different categories, including generation units like wind turbines (WTs) and photovoltaics (PVs), energy storage systems like battery storage units (BSUs), and finally, controllable loads such as demand response programmes (DRPs) [1]. Real DERs refer to resources that convert energy from different sources into electricity, such as WT and PVs. On the contrary, virtual DERs refer to various sources that only exchange electricity or flexibility with the grid, like BSUs and DRPs. Recently, to organise a variety of DERs at the distribution level and get benefit from their provided advantages, including improvement of voltage profile, flexibility, and

reliability, peak shaving etc., a concept named the aggregator (AG) platform for integrating the generation as well as the storage capacity of them has been presented [2]. This concept allows DERs' provided energy services to be aggregated to move upward from the local distribution level to the system-wide or transmission system operator (TSO) level. Also, this platform causes easier control and operation of DERs at the distribution level. Accordingly, multiple decentralised sources cooperate with each other in the form of a coalition to not only present valuable services to the distribution system operator (DSO) but also to participate in various electricity markets as an independent financial entity. It is worth noting that the DER AG is a software-based digital platform so it is not necessary for the entire units to be physically integrated within a specific area, and they must be only connected to the AG operator by information and communication technologies (ICTs). In

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general, the operator of the DER AG acts as an intermediary between customers and varied stakeholders such as the DSO, retailer, and microgrid [3]. Accordingly, its energy trading process is summarised in the following two layers. At the first layer, the AG interacts with its customers by designing appropriate contracts or sending incentive signals. Implementation of this layer requires secure ICT infrastructures, including software, hardware, firmware, and networks at the distribution level that could be achieved in developed countries in the coming years. At the second layer, this agent interacts with different markets to exchange energy or flexibility services. At this stage, the AG makes decisions regarding its optimal participation, namely bids/offers, in different markets. According to the capacity and type of aggregated resources within the DER AG, technical specifications of the distribution and transmission systems, as well as the structure and regulations of the existing electricity markets, this emerging entity is able to take part in varied markets, i.e. the wholesale electricity market (WEM) and local electricity market (LEM), as a price-maker or price-taker player [4]. It is noteworthy that nowadays, even in developed countries, including Nordic countries, energy exchanges between various AGs, customers, and system operators are based on long-term price signals and contracts [5]. Unlike a price-taker DER AG that has only an impact on market outcomes, a price-maker AG has an adequate share of the market to exercise market power and alter market prices for its own benefit. Nonetheless, to implement the decision-making process of a strategic AG, the comprehensive view concerning its objective function, operational constraints of aggregated DERs, technical constraints of networks, uncertainty modelling, and the behaviour of the AG's competitors in markets should be obtained. On the other hand, since the DER AG is an autonomous financial player, it has the opportunity to simultaneously take part in distinct electricity markets such as the WEM and LEM. Nevertheless, this matter requires an appropriate model that can assess several key factors, including the impact of two markets on the optimal offering strategy of the DER AG, the way of interaction among markets, the effect of each markets' uncertainties on the decision-making procedure of the AG, the impact of available participants' behaviour in each market etc.

In recent years, numerous research works have been conducted on the optimal participation of DER AGs in different electricity markets, consisting of the WEM and LEM, some of which are highlighted as follows:

For participation of multiple DERs in the virtual power plant (VPP) platform in the WEM, a two-stage programming scheme has been suggested in [6]. At the first stage of this model, the day-ahead (DA) scheduling of the VPP, as a price-taker player, is optimised in a way to maximise its daily profit. At the second stage, the real-time (RT) imbalance cost of this agent is minimised through adjusting operating points of integrated units within the VPP. A stochastic mixed-integer linear programming method has been utilised in [7] to model the offering strategy of a DER AG in the DA WEM. In this regard, the AG is responsible for managing the energy and financial interactions between DERs and the WEM. This scheduling has been executed from a price-taker AG's point of view aimed at maximising its expected

profit. The offering strategy of one DER AG as a price-taker entity in the DA LEM is evaluated in [8]. In this regard, the daily profit of this player has been maximised using a risk-based mathematical optimisation model. For the simultaneous participation of a microgrid in WEM and LEM, a two-stage programming approach has been employed in [9]. Accordingly, at the first stage, offers of this price-taker actor to the DA markets and the optimal operating points of generation units are determined. At the second stage, the optimal operating points of flexible units are achieved. The objective function of this problem is to minimise the total operating costs of the studied microgrid. A robust optimisation model has been utilised in [10], in which a DER AG can simultaneously take part in the DA and RT WEM and LEM as a price-taker agent. Accordingly, the considered AG trades power with the operator of the mentioned markets to minimise its total operating costs. A robust optimisation model has been suggested in [11] to study the bidding strategy of the AG of real and virtual DERs in the DA and RT WEM. The objective function of this price-taker entity is to promote its profits from the involvement in the considered markets. In order to optimise the bidding strategy of several microgrids in the DA LEM, a bilevel competitive model has been suggested in [12]. At the upper level (UL) of this framework, microgrid owners seek to reduce their operating costs by submitting offers to the DSO as the LEM operator. While, at the lower level (LL), the LEM operator clears the market via getting offers from these strategic players. To enhance the participation of DERs in the form of an independent AG in the DA LEM, a bilevel scheme has been provided in [13]. Accordingly, at the UL of the problem, the operating cost of this price-maker entity is minimised, and at the LL, the total welfare of LEM participants is maximised. A linear programming approach has been presented in [14] to optimise the offering strategy of an AG of DERs in the DA reserve market. The main purpose of this price-taker agent is to maximise its expected profit through adjusting the operating points of integrated sources. An optimal bidding strategy according to information gap decision theory has been used in [15] to model the participation of a price-taker DER AG with a wide range of uncertainties in its decision-making process in the WEM. The optimisation problem has been conducted from the AG's viewpoint with the aim of maximising its daily profit. A novel offering strategy has been suggested in [16], in which DER AGs offer price-elastic bids based on the technical constraints of the distribution system to the WEM. This research's objective is to promote the expected profit of the studied AG as well. A stochastic bilevel programming approach has been presented in [17] for investigating the optimal participation of a strategic VPP in the energy and reserve WEM. Accordingly, at the UL of the problem, the VPP, which has aggregated several real and virtual DERs, maximises its expected profit. On the contrary, at the LL of the problem, energy and reserve markets are settled in a way to enhance social welfare. A distributed optimisation method has been suggested in [18] to enable the network-secure bidding strategy of a price-taker DER AG in the RT energy and reserve WEM. In this context, the DER AG interacts and negotiates with the DSO in order to present offers to the WEM that perfectly satisfy the technical as well

as operational constraints of the distribution system. In the end, a risk-based bi-objective optimisation framework has been utilised in [19] to study the bidding strategy of a price-taker VPP in the DA WEM. The primary purpose of this work is to not only maximise the profit of the studied VPP but also to minimise the emission of the aggregated units within the VPP.

Analysing the reviewed papers reveals that, normally, in the offering strategy of the DER AG, this entity has been taken into account as a non-strategic player. Considering this simplification, the AG's submitted bids and offers to different markets cannot perfectly reflect the flexible and optimal behaviour of the integrated DERs within the coalition. As a result, this agent is unable to gain the highest possible amount of profit via taking part in electricity markets. For another, it is seen that in most studies, the DER AG has got the opportunity to simultaneously participate in two separate markets, namely WEM and LEM. Hence, these articles have not been able to properly examine the impact of these two markets on the optimal performance of this independent actor as well as the impact of the WEM conditions on the LEM clearing conditions. Aiming to fill the mentioned research gaps, two primary contributions of this study are:

1. Proposing a novel bilevel optimisation model for the offering strategy of a DER AG as a strategic or price-maker player in the LEM considering the behaviour of competitors.
2. Presenting a novel two-stage programming framework to enable the simultaneous involvement of the DER AG in both LEM and WEM.

The remainder of the article is organised as follows: the general overview of the problem, its mathematical formulations, and the utilised solution approach are described in Section 2. The implementation of a typical case study and its discussions are presented in Section 3. Finally, the conclusion is provided in Section 4.

2 | METHODS AND MATERIALS

As mentioned earlier, the main purpose of this study is to investigate the offering strategy of DER AGs in the LEM and the WEM as price-maker and price-taker actors, respectively. In this regard, it is presumed that an independent financial entity aggregates a wide range of DERs located at the distribution level to have more effective and simultaneous participation in both WEM and LEM. In this context, several real and virtual DERs collaborate as a coalition to not only trade energy with one another but also to supply/compensate for their excess/shortage through simultaneous involvement in the mentioned markets. In this case, since a considerable amount of generation and storage capacities is integrated, AGs have the chance to exercise market power via taking part in the LEM as strategic players. To model the behaviour of a strategic AG in the LEM, a bilevel programming approach is executed in this study. At the UL of it, the DER AG's offering strategy in both

considered markets is determined, and at the LL, the LEM is cleared by the DSO as the market operator and in the presence of the AG's non-strategic competitors. The described bilevel framework is based on the Stackelberg game-theoretic since the AG as the leader of the game, has the opportunity to obtain local market power, and other participants, as followers of the game, have non-strategic behaviour in this market. In other words, according to the strategic decisions of the DER AG, its competitors compete with one another in a non-cooperative manner. Considering the AG as a price-maker agent allows it to alter LEM clearing prices for its own interests through adjusting the submitted offers/bids. Moreover, enabling the AG's simultaneous participation in both markets increases its flexibility in the decision-making process. On the other hand, to overcome the stochastic nature of uncertain variables, including the RT WEM price, wind speed, and solar irradiance, a scenario-based two-stage stochastic programming scheme has been implemented in this problem. Accordingly, the DER AG's accepted offers in the DA LEM and WEM, as well as operating points of the available dispatchable generators (DGs) within the coalition, are determined at the first stage. At the second stage, after the realisation of random parameters, the AG's traded power with the RT WEM, as well as upward/downward adjustment power of DGs and charge/discharge power of BSUs, are specified. It should be mentioned that, for the realisation of the existing stochastic factors in the raised decision-making process, a high number of scenarios are generated by the Monte Carlo simulation technique and reduced to an adequate number by utilising the fast backward/forward scenario reduction algorithm [20].

The general overview of the raised scheme for the DER AG's offering strategy in both electricity markets is illustrated in more detail in Figure 1.

As shown in Figure 1, the UL's objective function is to increase the expected profit of the considered DER AG through a two-stage stochastic optimisation approach. In contrast, the LL is associated with the LEM clearing process with the aim of social welfare maximisation. By maximising the social welfare, each consumer's surplus and each producer's surplus is increased, which leads to the improvement of the LEM's efficiency. The submitted and accepted offers of the AG in the LEM act as linking variables of these two levels.

2.1 | Problem formulation

Referring to the previous explanations, in the following subsections, objective functions and constraints of the bilevel optimisation problem are formulated from a mathematical viewpoint.

2.1.1 | Upper level problem: offering strategy of DER AG

At the UL of the suggested bilevel framework, the offering strategy of the DER AG as a price-maker player in the LEM and as a price-taker player in the WEM is assessed. This level's

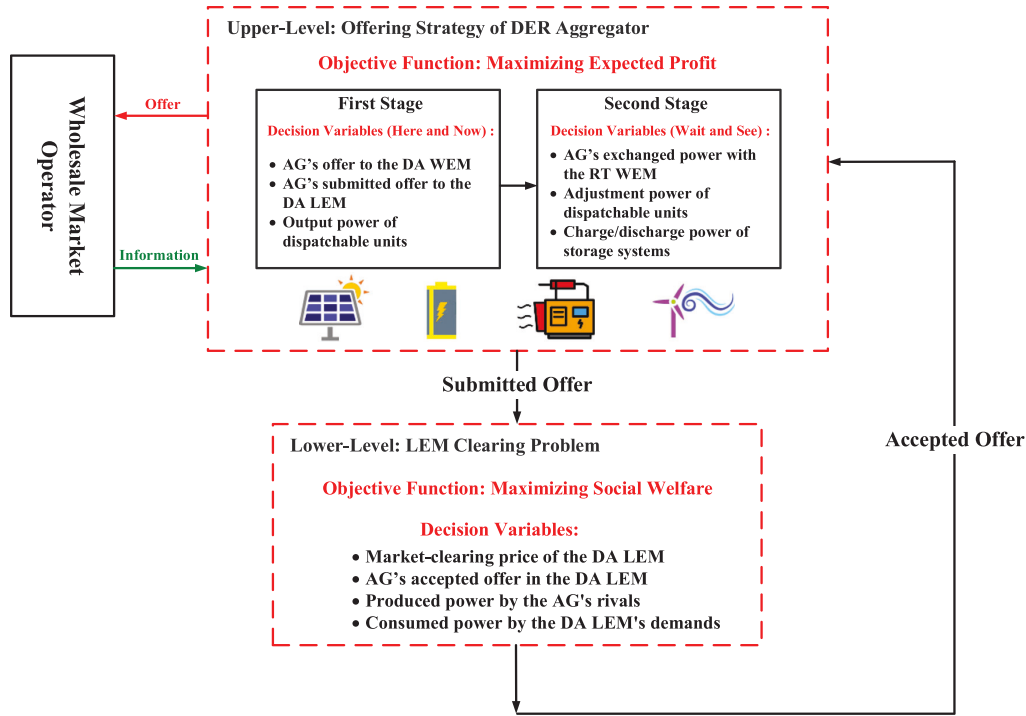


FIGURE 1 Overview of the suggested framework

objective function is to maximise the expected profit of the AG through a two-stage stochastic technique. This objective function is defined as the difference between its income and expenses and includes three main parts, namely income from participation in the DA and RT WEM, income from participation in the DA LEM, and finally, operating costs of DERs integrated within the AG, see Equation (1):

$$\begin{aligned}
 \text{ObjFun}_{\Omega^{\text{UL}}}^{\text{UL}} = \text{Max} \sum_{b=1}^H & \left\{ q_{\text{WEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{WEM,DA}}(b) \right. \\
 & + q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA}}(b) \\
 & - \sum_{j=1}^J P_{\text{DG}}(j, b) \cdot \lambda_{\text{DG}}(j) \\
 & + \sum_{s=1}^S \varphi(s) \cdot \left[q_{\text{WEM,RT}}^{\text{AG}}(b, s) \cdot \lambda_{\text{LEM,RT}}(b, s) \right. \\
 & - \sum_{j=1}^J (R_{\text{DG,up}}(j, b, s) \cdot \lambda_{\text{DG,up}}(j) \\
 & \left. \left. - R_{\text{DG,dn}}(j, b, s) \cdot \lambda_{\text{DG,up}}(j)) \right] \right\} \quad (1)
 \end{aligned}$$

The first and second lines of Equation (1) are related to the first stage of the two-stage stochastic scheme. The first and sec-

ond terms represent the obtained revenue from taking part in the DA WEM and DA LEM, respectively, and the third term indicates the marginal generation cost of DGs. In turn, the third and fourth lines of this equation are associated with the second stage of the two-stage stochastic scheme. The fourth term represents the AG's revenue/expense from involvement in the RT WEM, and the fifth expression shows the power adjustment costs of DGs. The introduced objective function is subject to a set of technical and operational constraints, as follows:

1. Constraints of the DA and RT power balance

Clearly, the amount of power offered by the AG to both DA markets should be equal to the generation capacity of its own units, i.e. DGs, WTs, and PVs, as shown in Equation (2):

$$\begin{aligned}
 & q_{\text{WEM,DA}}^{\text{AG}}(b) + q_{\text{LEM,DA,Of}}^{\text{AG}}(b) \\
 & = \sum_{j=1}^J P_{\text{DG}}(j, b) + \sum_{w=1}^W P_{\text{WT}}^F(w, b) + \sum_{p=1}^P P_{\text{PV}}^F(p, b), \quad \forall b
 \end{aligned} \quad (2)$$

After the realisation of stochastic factors, the DER AG must compensate for its shortage or supply its excess by involvement in the RT WEM. This issue is demonstrated in more detail in Equation (3). As shown in this expression, the studied AG exploits the storage capacity of BSUs and the upward/downward adjustment power of DGs to trade its

surplus or shortage in the RT WEM.

$$\begin{aligned}
 q_{\text{WEM,RT}}^{\text{AG}}(b, s) = & \sum_{w=1}^W (P_{\text{WT}}(w, b, s) - P_{\text{WT}}^F(w, b)) \\
 & + \sum_{p=1}^P (P_{\text{PV}}(p, b, s) - P_{\text{PV}}^F(p, b)) \\
 & + \sum_{j=1}^J (R_{\text{DG,up}}(j, b, s) - R_{\text{DG,dn}}(j, b, s)) \\
 & + \sum_{b=1}^B (P_{\text{BSU,dch}}(b, b, s) \\
 & - P_{\text{BSU,ch}}(b, b, s)), \quad \forall b, s \quad (3)
 \end{aligned}$$

2. Constraints of offers to the DA LEM and WEM

In general, offers of the DER AG to both DA markets are non-negative decision variables that are depicted by Equations (4) and (5).

$$q_{\text{WEM,DA}}^{\text{AG}}(b) \geq 0, \quad \forall b \quad (4)$$

$$q_{\text{LEM,DA,Of}}^{\text{AG}}(b) \geq 0, \quad \forall b \quad (5)$$

Since the pricing mechanism in the DA WEM is uniform, it is presumed that the DER AG submits its offers to the independent system operator at zero price in order to guarantee their acceptance. In the uniform pricing mechanism, the entire suppliers are paid at the same market-clearing price regardless of their presented offers, which is set at the offer price of the most expensive source selected to provide service [21]. On the contrary, offers of the AG to the DSO as the operator of the DA LEM are submitted with $\lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b)$, which is a non-negative variable.

3. Constraints of generation units

The generation and adjustment power of DGs integrated within the DER AG are limited by Equations (6) to (9). Additionally, operational constraints of these units are modelled by Equations (10) and (11) [22]:

$$P_{\text{DG}}(j, b) + R_{\text{DG,up}}(j, b, s) \leq P_{\text{DG}}^{\text{max}}(j), \quad \forall j, b, s \quad (6)$$

$$P_{\text{DG}}(j, b) - R_{\text{DG,dn}}(j, b, s) \geq P_{\text{DG}}^{\text{min}}(j), \quad \forall j, b, s \quad (7)$$

$$R_{\text{DG,up}}^{\text{min}}(j) \leq R_{\text{DG,up}}(j, b, s) \leq R_{\text{DG,up}}^{\text{max}}(j), \quad \forall j, b, s \quad (8)$$

$$R_{\text{DG,dn}}^{\text{min}}(j) \leq R_{\text{DG,dn}}(j, b, s) \leq R_{\text{DG,dn}}^{\text{max}}(j), \quad \forall j, b, s \quad (9)$$

$$P_{\text{DG}}(j, b) - P_{\text{DG}}(j, b-1) \leq RU_{\text{DG}}(j), \quad \forall j, b \quad (10)$$

$$P_{\text{DG}}(j, b-1) - P_{\text{DG}}(j, b) \leq RD_{\text{DG}}(j), \quad \forall j, b \quad (11)$$

According to the forecasted amount of wind speed and solar radiation, the generation power of WTs and PVs in the first DA stage is calculated by expressions that are obtained from [23]. Notably, these equations are valid for the second RT stage as well.

4. Constraints of energy storage units

Mathematical models as well as operational constraints of BSUs are stated by Equations (12) to (18) [20]. In this regard, the charge and discharge power of these systems is limited by Equations (12) and (13), respectively. Equation (14) is also used to prevent simultaneous charge and discharge of BSUs. Furthermore, the amount of energy stored in BSUs and their related limitations are expressed by Equations (15) to (18):

$$\begin{aligned}
 P_{\text{BSU,ch}}^{\text{min}}(b) \cdot U_{\text{BSU,ch}}(b, b, s) & \leq P_{\text{BSU,ch}}(b, b, s) \\
 & \leq P_{\text{BSU,ch}}^{\text{max}}(b) \cdot U_{\text{BSU,ch}}(b, b, s), \quad \forall b, b, s \quad (12)
 \end{aligned}$$

$$\begin{aligned}
 P_{\text{BSU,dch}}^{\text{min}}(b) \cdot U_{\text{BSU,dch}}(b, b, s) & \leq P_{\text{BSU,dch}}(b, b, s) \\
 & \leq P_{\text{BSU,dch}}^{\text{max}}(b) \cdot U_{\text{BSU,dch}}(b, b, s), \quad \forall b, b, s \quad (13)
 \end{aligned}$$

$$U_{\text{BSU,ch}}(b, b, s) + U_{\text{BSU,dch}}(b, b, s) \leq 1, \quad \forall b, b, s \quad (14)$$

$$SOC_{\text{BSU}}(b, b, s) = SOC_{\text{BSU}}^{\text{ini}}(b), \quad \forall b, b = 1, s \quad (15)$$

$$\begin{aligned}
 SOC_{\text{BSU}}(b, b+1, s) = & SOC_{\text{BSU}}(b, b, s) \\
 & + P_{\text{BSU,ch}}(b, b, s) \cdot \eta_{\text{BSU,ch}}(b) \\
 & - P_{\text{BSU,dch}}(b, b, s) / \eta_{\text{BSU,dch}}(b), \\
 & \forall b, b < 24, s \quad (16)
 \end{aligned}$$

$$\begin{aligned}
 SOC_{\text{BSU}}^{\text{fin}}(b) = & SOC_{\text{BSU}}(b, b, s) + P_{\text{BSU,ch}}(b, b, s) \\
 & \cdot \eta_{\text{BSU,ch}}(b) - P_{\text{BSU,dch}}(b, b, s) / \eta_{\text{BSU,dch}}(b), \\
 & \forall b, b = 24, s \quad (17)
 \end{aligned}$$

$$SOC_{\text{BSU}}^{\text{min}}(b) \leq SOC_{\text{BSU}}(b, b, s) \leq SOC_{\text{BSU}}^{\text{max}}(b), \quad \forall b, b, s \quad (18)$$

Accordingly, the initial/final amount of energy stored at the start/end of the first/last time period is modelled by Equations (15) and (17), respectively. Additionally, the energy stored and its limitations at each time interval are expressed by Equations (16) and (18), respectively. In the end, decision variables of the UL problem are listed as the following set:

$$\Omega^{\text{UL}} = \left\{ \begin{array}{l} q_{\text{WEM,DA}}^{\text{AG}}(b), q_{\text{LEM,DA,Of}}^{\text{AG}}(b), \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) \\ P_{\text{DG}}(j, b), R_{\text{DG,up}}(j, b, s), R_{\text{DG,dn}}(j, b, s) \\ P_{\text{BSU,ch}}(b, b, s), P_{\text{BSU,dch}}(b, b, s), SOC_{\text{BSU}}(b, b, s), \\ U_{\text{BSU,ch}}(b, b, s), U_{\text{BSU,dch}}(b, b, s) \end{array} \right\}$$

2.1.2 | Lower level problem - LEM clearing process

At the LL of the suggested bilevel framework, the DSO, as the LEM operator, collects offers and bids of the entire market participants at the distribution level to settle the DA LEM with the aim of social welfare maximisation. As previously stated, in this situation, all market participants' surplus is increased, which leads to the improvement of the LEM efficiency [24]. This objective function is defined as the difference between the utility of buyers and the cost of sellers who take part in the market [25]. Equation (19) mathematically models the desired objective function:

$$\begin{aligned} \text{ObjFun}_{\Omega^{\text{LL}}}^{\text{LL}} = & \text{Max} \sum_{b=1}^H \left\{ \sum_{d=1}^D P_d(d, b) \cdot \lambda_d(d, b) \right. \\ & - \sum_{c=1}^C P_{\text{com}}(c, b) \cdot \lambda_{\text{com}}(c, b) \\ & \left. - q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) \right\} \quad (19) \end{aligned}$$

In the above expression, the first, second, and third terms demonstrate the utility of all consumers, the cost of producers who are the AG's non-strategic competitors, and the cost of the studied DER AG, respectively. The introduced objective function is subject to a set of technical and operational constraints, as follows:

1. Constraint of the LEM power balance

Generally, the accepted offers of all market producers, namely the DER AG and its rival, have to meet bids of all market consumers, as stated in Equation (20):

$$\begin{aligned} q_{\text{LEM,DA}}^{\text{AG}}(b) + \sum_{c=1}^C P_{\text{com}}(c, b) \\ = \sum_{d=1}^D P_d(d, b); \lambda_{\text{LEM,DA}}(b), \quad \forall b \quad (20) \end{aligned}$$

2. Constraints of the LEM offers and bids

In the clearing process of the DA LEM, accepted offers of the DER AG, which is a non-negative variable, should be limited by the submitted offer of this player to the market. This matter is well illustrated in Equation (21):

$$0 \leq q_{\text{LEM,DA}}^{\text{AG}}(b) \leq q_{\text{LEM,DA,Of}}^{\text{AG}}(b); \underline{\mu}(b), \bar{\mu}(b), \quad \forall b \quad (21)$$

In addition, offers of DER AG's competitors and bids of consumers in the LEM are limited by Equations (22) and (23), respectively:

$$P_{\text{com}}^{\text{min}}(c, b) \leq P_{\text{com}}(c, b) \leq P_{\text{com}}^{\text{max}}(c, b); \underline{\alpha}(c, b), \bar{\alpha}(c, b), \quad \forall c, b \quad (22)$$

$$P_d^{\text{min}}(d, b) \leq P_d(d, b) \leq P_d^{\text{max}}(d, b); \underline{\beta}(d, b), \bar{\beta}(d, b), \quad \forall d, b \quad (23)$$

It is worth noting that in Equations (20) to (23), the dual variables of constraints are shown after the semicolon. In the end, decision variables of the LL problem are listed as the following set:

$$\Omega^{\text{LL}} = \left\{ \begin{array}{l} q_{\text{LEM,DA}}^{\text{AG}}(b), P_{\text{com}}(c, b), P_d(d, b) \\ \lambda_{\text{LEM,DA}}(b), \underline{\mu}(b), \bar{\mu}(b), \underline{\alpha}(c, b), \bar{\alpha}(c, b), \underline{\beta}(d, b), \\ \bar{\beta}(d, b) \end{array} \right\}$$

2.1.3 | Outline of the raised bilevel problem

To further clarify the suggested bilevel programming problem in this article, the UL and LL's linking, as well as non-linking decision variables, are displayed in Figure 2.

As it is clear in Figure 2, the DER AG submits $q_{\text{LEM,DA,Of}}^{\text{AG}}$ and $\lambda_{\text{LEM,DA,Of}}^{\text{AG}}$ as the offer and its related price to the LEM operator. Based on this offer as well as received offers and bids from other producers and consumers, the operator settles the DA LEM and makes optimal decisions as for market-clearing points, i.e. $q_{\text{LEM,DA}}^{\text{AG}}$, $\lambda_{\text{LEM,DA}}$, P_{com} , and P_d . Afterwards, the LL's linking variables are returned to the DER AG's offering strategy problem so that this entity can evaluate its daily profit.

2.2 | Solving the proposed bilevel problem

As shown in section 2.1.2, the LL's model is continuous, linear, and thus convex. Consequently, the introduced bilevel scheme could be rewritten as a one-level scheme by replacing the LL with its corresponding Karush–Kuhn–Tucker (KKT) conditions [26,27]. In this regard, by forming the LL's Lagrangian function and utilising the related KKT conditions, the bilevel problem's one-level model is formulated as stated in Equation (24):

$$\text{ObjFun}_{\Omega}^{\text{one-level}} = \text{Max Equation}(1) \quad (24)$$

In the above expression, Ω is a set of decision variables in the ultimate one-level model, which includes:

$$\Omega = \left\{ \begin{array}{l} q_{\text{WEM,DA}}^{\text{AG}}(b), q_{\text{LEM,DA,Of}}^{\text{AG}}(b), \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b), \\ P_{\text{DG}}(j, b), R_{\text{DG,up}}(j, b, s), R_{\text{DG,dn}}(j, b, s) \\ P_{\text{BSU,dch}}(b, b, s), P_{\text{BSU,ch}}(b, b, s), \text{SOC}_{\text{BSU}}(b, b, s), \\ U_{\text{BSU,dch}}(b, b, s), U_{\text{BSU,ch}}(b, b, s) \\ q_{\text{LEM,DA}}^{\text{AG}}(b), P_{\text{com}}(c, b), P_d(d, b) \\ \lambda_{\text{LEM,DA}}(b), \underline{\mu}(b), \bar{\mu}(b), \underline{\alpha}(c, b), \bar{\alpha}(c, b), \\ \underline{\beta}(d, b), \bar{\beta}(d, b) \end{array} \right\}$$

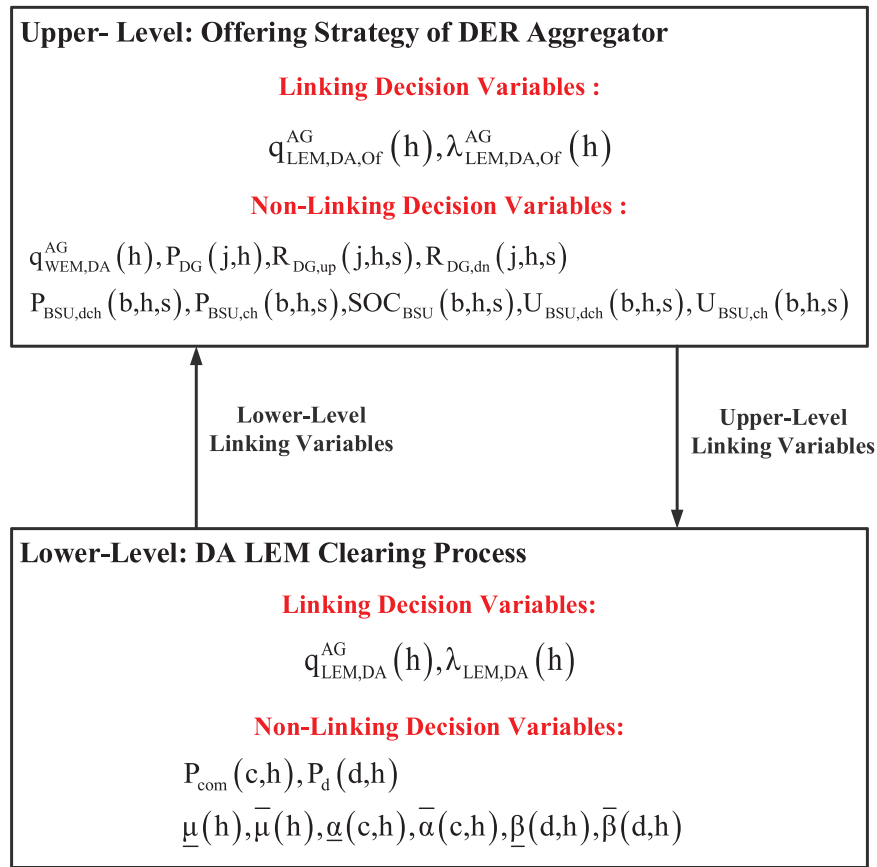


FIGURE 2 Decision variables in the proposed bilevel problem

On the other hand, Equation (24) is subject to a set of constraints, as follows:

$$\text{Equations(2) - (18), Equation(20)} \quad (25)$$

$$-\lambda_{LEM,DA,Of}^{AG}(b) + \lambda_{LEM,DA}(b) - \bar{\mu}(b) + \underline{\mu}(b) = 0, \quad \forall b \quad (26)$$

$$-\lambda_{com}(c,b) + \lambda_{LEM,DA}(b) - \bar{\alpha}(c,b) + \underline{\alpha}(c,b) = 0, \quad \forall c,b \quad (27)$$

$$\lambda_d(d,b) - \lambda_{LEM,DA}(b) - \bar{\beta}(d,b) + \underline{\beta}(d,b) = 0, \quad \forall d,b \quad (28)$$

$$0 \leq (q_{LEM,DA,Of}^{AG}(b) - q_{LEM,DA}^{AG}(b)) \perp \bar{\mu}(b) \geq 0, \quad \forall b \quad (29)$$

$$0 \leq q_{LEM,DA}^{AG}(b) \perp \underline{\mu}(b) \geq 0, \quad \forall b \quad (30)$$

$$0 \leq (P_{com}^{max}(c,b) - P_{com}(c,b)) \perp \bar{\alpha}(c,b) \geq 0, \quad \forall c,b \quad (31)$$

$$0 \leq (P_{com}(c,b) - P_{com}^{min}(c,b)) \perp \underline{\alpha}(c,b) \geq 0, \quad \forall c,b \quad (32)$$

$$0 \leq (P_d^{max}(d,b) - P_d(d,b)) \perp \bar{\beta}(d,b) \geq 0, \quad \forall d,b \quad (33)$$

$$0 \leq (P_d(d,b) - P_d^{min}(d,b)) \perp \underline{\beta}(d,b) \geq 0, \quad \forall d,b \quad (34)$$

$$\lambda_{LEM,DA}(b) \text{ Unrestricted}, \quad (35)$$

Nevertheless, the provided one-level problem in Equations (24) to (35) is nonlinear owing to the presence of two sources of nonlinearities, namely the product of $q_{LEM,DA}^{AG}(b) \cdot \lambda_{LEM,DA}(b)$ in Equation (24) as well as the complementary slackness constraints in Equations (29) and (34).

To linearise complementary slackness, the Big-M method [28] is exploited in this work. Also, to linearise $q_{LEM,DA}^{AG}(b) \cdot \lambda_{LEM,DA}(b)$, the strong duality theorem (SDT) [29] and the LL's KKT conditions are utilised. Based on the SDT concept, the

LL's dual problem is written by Equation (36).

$$\begin{aligned} & \sum_{b=1}^H \left\{ \sum_{d=1}^D P_d(d, b) \cdot \lambda_d(d, b) - \sum_{c=1}^C P_{\text{com}}(c, b) \cdot \lambda_{\text{com}}(c, b) \right. \\ & \quad \left. - q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) \right\} \\ & = \sum_{b=1}^H \left\{ \sum_{d=1}^D \left(P_d^{\text{max}}(d, b) \cdot \bar{\beta}(d, b) - P_d^{\text{min}}(d, b) \cdot \underline{\beta}(d, b) \right) \right. \\ & \quad + \sum_{c=1}^C \left(P_{\text{com}}^{\text{max}}(c, b) \cdot \bar{\alpha}(c, b) - P_{\text{com}}^{\text{min}}(c, b) \cdot \underline{\alpha}(c, b) \right) \\ & \quad \left. + q_{\text{LEM,DA,Of}}^{\text{AG}}(b) \cdot \bar{\mu}(b) \right\} \quad (36) \end{aligned}$$

From Equation (26):

$$\begin{aligned} \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) &= \lambda_{\text{LEM,DA}}(b) - \bar{\mu}(b) + \underline{\mu}(b) \\ q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) &= q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \left(\lambda_{\text{LEM,DA}}(b) - \bar{\mu}(b) + \underline{\mu}(b) \right) \quad (37) \end{aligned}$$

From Equations (29) and (30):

$$q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \bar{\mu}(b) = q_{\text{LEM,DA,Of}}^{\text{AG}}(b) \cdot \bar{\mu}(b) \quad (38)$$

$$q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \underline{\mu}(b) = 0 \quad (39)$$

According to Equations (37) and (39):

$$\begin{aligned} & q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA,Of}}^{\text{AG}}(b) \\ & = q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA}}(b) - q_{\text{LEM,DA,Of}}^{\text{AG}}(b) \cdot \bar{\mu}(b) \quad (40) \end{aligned}$$

Finally, by replacing Equation (40) in (36), the considered non-linear term turns into a linear term, as displayed in Equation (41).

$$\begin{aligned} & \sum_{b=1}^H q_{\text{LEM,DA}}^{\text{AG}}(b) \cdot \lambda_{\text{LEM,DA}}(b) = \\ & \sum_{b=1}^H \left\{ \sum_{d=1}^D P_d(d, b) \cdot \lambda_d(d, b) - \sum_{c=1}^C P_{\text{com}}(c, b) \cdot \lambda_{\text{com}}(c, b) \right. \\ & \quad - \sum_{c=1}^C \left(P_{\text{com}}^{\text{max}}(c, b) \cdot \bar{\alpha}(c, b) - P_{\text{com}}^{\text{min}}(c, b) \cdot \underline{\alpha}(c, b) \right) \\ & \quad \left. - \sum_{d=1}^D \left(P_d^{\text{max}}(d, b) \cdot \bar{\beta}(d, b) - P_d^{\text{min}}(d, b) \cdot \underline{\beta}(d, b) \right) \right\} \quad (41) \end{aligned}$$

3 | CASE STUDY

In this section, the effectiveness of the suggested framework for the simultaneous participation of the DER AG as a price-maker and price-taker player in the LEM and WEM is scrutinised through a typical case study. Accordingly, first, the technical specification of the DER AG and the considered electricity markets are introduced. Next, the results of the simulation and their discussions are presented more accurately.

3.1 | Input data

Characteristics of DERs, including DGs, WTs, PVs, and BSUs, integrated inside the AG are summarised in Table 1 [30,31]. In addition, the solar irradiance and wind speed during the day and in each of the scenarios are displayed in Figures 3 and 4, respectively. Notably, the forecasted values in the DA stage are distinguished with bold lines in these figures. On the other hand, as mentioned earlier, in the two-stage programming scheme, the DER AG is able to participate within the RT WEM to adjust the excess/shortage of its provided offers in the DA first stage. In this regard, energy prices in the RT WEM are demonstrated in Figure 5. In this figure, the energy price in the DA WEM is distinguished with bold lines as well. Concerning the DA LEM, it is presumed that six varied producers participate in this market as the DER AG's non-strategic competitors. Besides, bids from four different consumers are submitted to the LEM operator. It is noteworthy that in this study, offers and bids of these participants are considered on an hourly basis.

3.2 | Simulation results and discussions

In this section, obtained results from the simultaneous participation of the studied DER AG in introduced markets are provided, and the optimal performance of this entity in the presence of both markets is compared with the situation in which this player is only able to take part in one of the existing markets. The considered one-level model in Equations (24) and (41) is a mixed-integer linear programming (MILP) problem that has been solved by the CPLEX solver in GAMS software.

Regarding the outputs, offers of the DER AG to both DA LEM and WEM, as well as the WEM forecasted prices and the LEM clearing prices, are displayed in Figure 6.

Based on Figure 6, the DER AG has provided more power to the DA LEM in the early hours of the day. In contrast, in the middle of the day, when WEM prices are high, the AG has sold more power to this market so that at hours 10 to 12, the AG's total generation capacity is allocated to the WEM. After these hours, since the LEM prices have increased, this player has preferred to allocate most of its production to the local market. Finally, in the last hours of the day, by increasing the energy price in the DA WEM, the entire production capacity of aggregated units has been sold to this market. It is also important to point out that in the studied problem, the offer price of the DER AG

TABLE 1 Technical specifications of the considered DER AG

DGs						
# Unit	P_{DG}^{max}	λ_{DG}	$R_{UDG}/R_{D_{DG}}$	$R_{DG,up}^{max}/R_{DG,dn}^{max}$	$\lambda_{DG,up}$	$\lambda_{DG,dn}$
1	1.3	37.0	0.5	0.2	37.0	17.5
2	1.5	35.5	0.7	0.2	35.5	16.7
3	2.5	32.3	1.1	0.4	32.3	11.6
4	2.7	27.5	1.4	0.6	27.5	7.9
5	3.1	29.4	1.5	0.9	29.4	8.4
WTs						
# Unit	P_{WT}^R	V_{WT}^{ci}	V_{WT}^R	V_{WT}^{co}		
1	2×2	4.0	13.0	25.0		
2	4×1.25	3.0	11.0	25.0		
3	5×1	3.6	12.5	20.0		
PVs						
# Unit	P_{PV}^R	γ^{Ref}	G^{Ref}	Ψ		
1	2×3.0	25.0	1.0	-0.005		
2	4×2.0	25.0	1.0	-0.005		
BSUs						
# Unit	SO_{BSU}^{max}	SO_{BSU}^{min}	$p_{BSU,dch}^{max}/p_{BSU,ch}^{max}$	$\eta_{BSU,dch}/\eta_{BSU,ch}$		
1	10.0	1.0	2.0	0.95		

Abbreviations: AG, aggregator; BSUs, battery storage units; DER, distributed energy resource; DGs, dispatchable generators; PVs, photovoltaics; WTs, wind turbines.

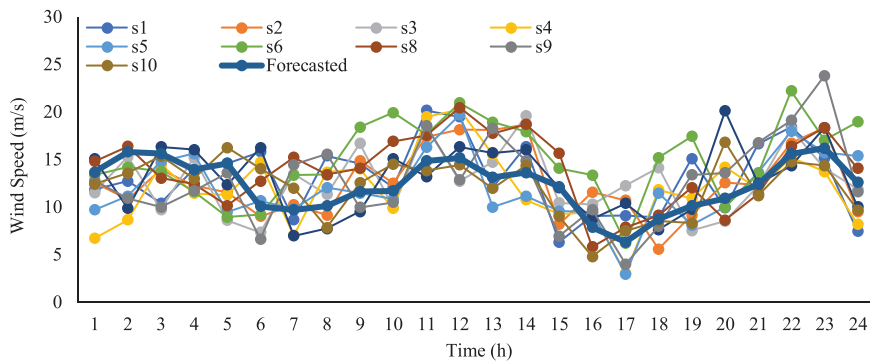


FIGURE 3 Wind speed in DA and RT stages. DA, day-ahead; RT, real-time.

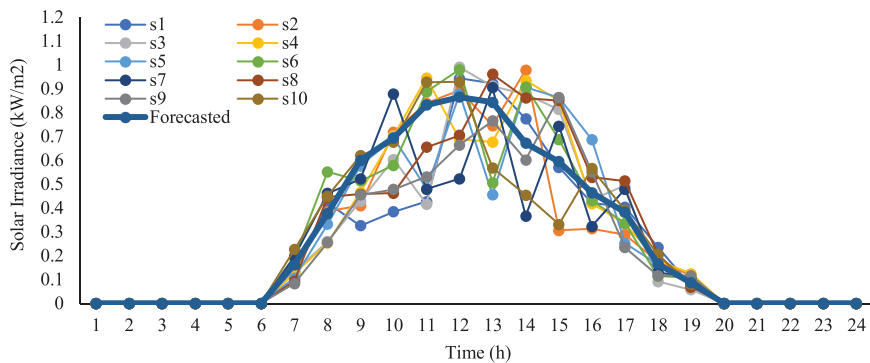


FIGURE 4 Solar radiation in DA and RT stages. DA, day-ahead; RT, real-time.

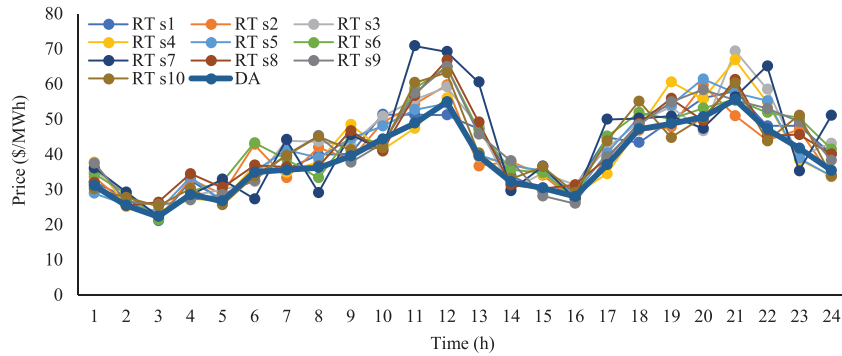


FIGURE 5 DA and RT WEM energy prices. DA, day-ahead; RT, real-time; WEM, wholesale electricity market.



FIGURE 6 Offers of the AG to the DA markets and their energy prices. AG, aggregator; DA, day-ahead.

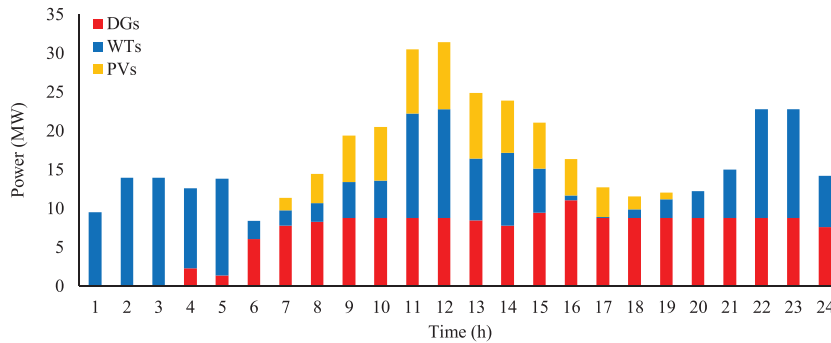


FIGURE 7 Operating points of DERs integrated within the AG. AG, aggregator; DERs, distributed energy resources.

in the LEM is equal to the LEM clearing price, as depicted in Figure 6.

On the other hand, the share of each DER in the AG's offers to the DA markets is determined in Figure 7. It should be noted that in this figure, the total generation of DGs, WTs, and PVs is depicted. Accordingly, the output power of non-dispatchable resources, i.e. WTs and PVs, has been calculated based on the forecasted wind speed and solar radiation. Furthermore, the

output power of DGs has been determined according to their marginal prices as well as energy prices in the DA markets. As depicted in this figure, in the early hours of the day, DGs have not been exploited since their marginal prices are higher than the price of energy in both markets.

The DSO, as the LEM operator, settles the market with the aim of social welfare maximisation after receiving offers and bids from all producers and consumers. Figure 8 depicts

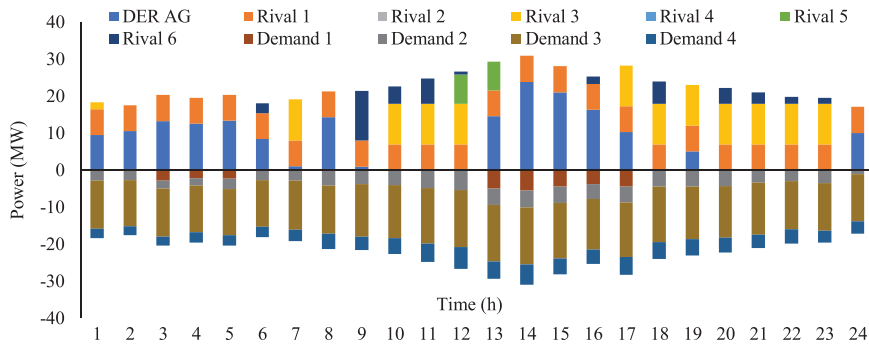


FIGURE 8 LEM clearing points. LEM, local electricity market.

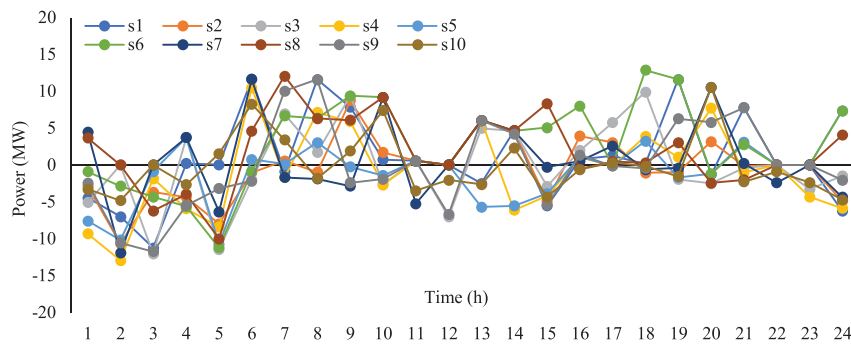


FIGURE 9 Variations of WTs' generation power in the RT stage. RT, real-time; WTs, wind turbines.

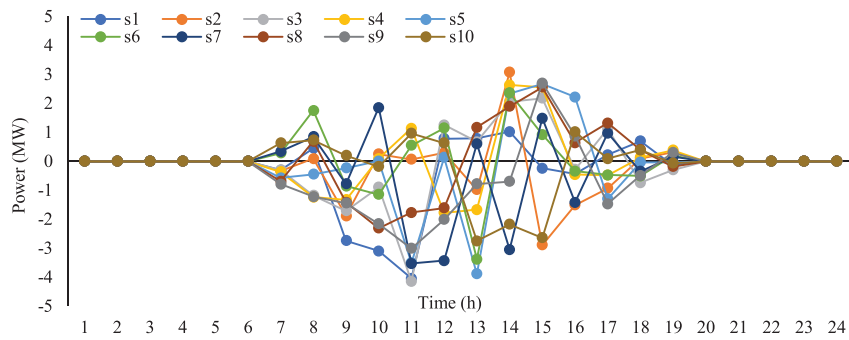


FIGURE 10 Variations of PVs' generation power in the RT stage. PVs, photovoltaics; RT, real-time.

accepted offers and bids of the market players in the DA LEM, in which offers of sellers and bids of buyers have been specified by positive and negative bars, respectively.

It must be noted that the LEM clearing prices in Figure 6 have been determined based on the marginal producers/consumers that are illustrated in Figure 8. Moreover, as evident in Figure 8, the accepted offers of all sellers, including the DER AG and its non-strategic competitors, have supplied the accepted bids of all buyers in the LEM.

As described in the above sections, at the second stage of the two-stage offering strategy and after the realisation of stochastic variables, the DER AG makes optimal decisions regarding its participation in the RT WEM. These decisions directly depend on the generated scenarios that clarify the changes in the real values of random parameters from their forecasted values. For further understanding, the variations of WTs and PVs' generation power over the day and for each of the scenarios are presented in Figures 9 and 10, respectively. It is worth emphasising

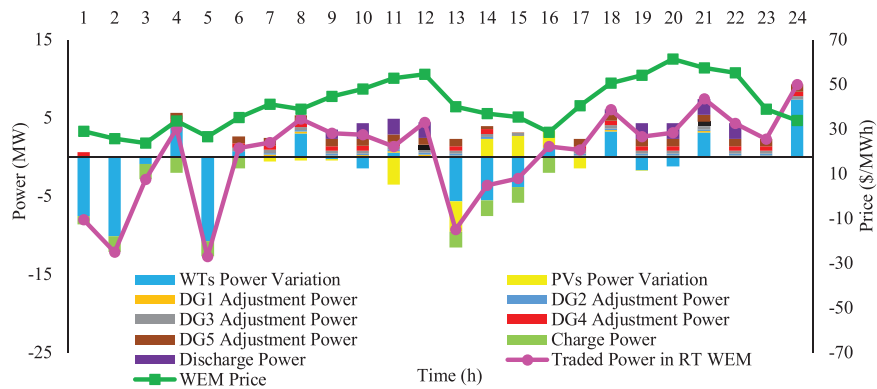


FIGURE 11 Optimal performance of the AG in scenario 5. AG, aggregator.

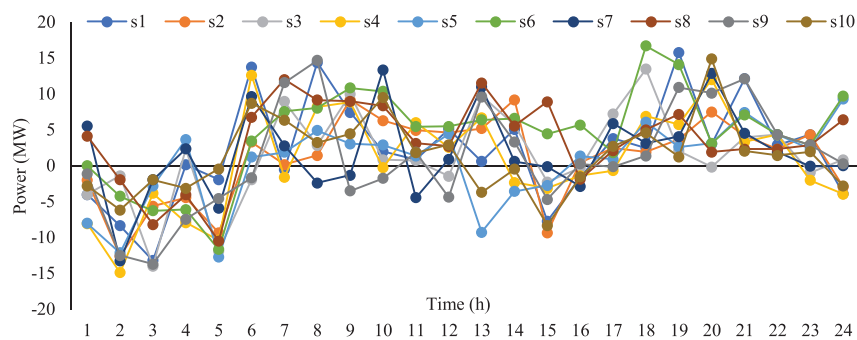


FIGURE 12 Optimal involvement of the AG in RT WEM and all scenarios. AG, aggregator; RT, real-time; WEM, wholesale electricity market.

that, in these two figures, an increase in the generation power of WTs and PVs has been demonstrated by positive values, while a decrease in the generation power of these units has been demonstrated by negative values.

At this stage of programming, the DER AG can compensate for/supply its shortage/excess by involvement in the RT WEM or by adjusting the upward/downward power of DGs and discharge/charge power of BSUs. To investigate the influence of uncertain factors on the optimal performance of the AG, this entity's participation in the RT WEM, upward/downward adjustment power of DGs, discharge/charge power of BSUs, as well as changes of WTs and PVs' generation power are provided for a sample scenario, i.e. scenario 5, in Figure 11. It is noteworthy that in this figure, the RT WEM energy prices for scenario 5 have been depicted as well. In Figure 11, an increase in the generation power of all resources and discharge power of BSUs have been specified by positive bars; hence, a decrease in the generation power of all units and charge power of BSUs have been determined by negative bars. In addition, positive values in the traded power of the AG with the RT WEM indicate the selling energy to the market and negative values indicate the purchasing energy from the market.

In Figure 11, it can be seen that the involvement of the DER AG in the RT WEM is completely consistent with changes in the market's energy prices. In other words, at hours when the price of energy is minimum, the AG has provided its shortage from the RT WEM. In contrast, at hours when the price of energy is maximum, this player has supplied its excess to the market. In the end, Figure 12 shows the studied AG's optimal participation in the RT WEM and the entire scenarios.

Referring to Figure 12, in the early hours of the day, the DER AG is mainly the buyer in the RT WEM, while in the middle and last hours of the day, it is mainly the seller in the target market. This matter has originated from the pattern of energy price. In addition to the traded power of DER AG in the RT WEM, this player's distribution of income at the second stage and for each of the scenarios is reported in more detail in Table 2. Notably, for calculating the presented income, the probability of scenarios is taken into account as well. Clearly, the negative income in the table represents the AG's cost in the RT WEM.

On the other hand, to evaluate the daily profit of the DER AG and shed light on the role of each scenario and each market in the expected profit, the income and cost distribution of this agent in the DA and RT markets are expressed in Table 3.

TABLE 2 AG's distribution of income in the RT WEM

Revenue of the DER AG (\$)										
# Hour	RTS1	RTS2	RTS3	RTS4	RTS5	RTS6	RTS7	RTS8	RTS9	RTS10
1	-9.7	-5.8	-15.9	-31.8	-30	-0.2	22.9	12.5	-3.1	-7.1
2	-17.4	-28.1	-4.5	-39.1	-40.3	-16.1	-44.7	-4.8	-23.8	-14.3
3	-21	-10.6	-33.9	-9.5	-8.8	-17.7	-5.2	-20.6	-25	-4.2
4	0.3	-12.7	7.3	-22.6	15.7	-23.6	7.6	-13.3	-14.3	-7.9
5	-4	-23	-39.8	-29.1	-43.7	-49.4	-22.4	-30.5	-9.3	-1
6	37	12	-6.9	48	5.3	19.5	30.3	23.5	-4	24.4
7	-1.5	0.4	43.4	-5.9	9.8	38.3	14	41.5	32.7	20.8
8	42.8	5.1	13.7	32.2	24.6	34.9	-8.1	31.7	47.1	12
9	22.4	30.4	47	44.7	17.4	64.3	-7	39.7	-9.5	15.1
10	7.5	26.4	4.6	-1.3	17.8	58.2	63.4	32.4	-5.5	33
11	3.1	23.1	4.4	29.6	9.2	41.6	-36.4	16.7	7.6	8.9
12	19.5	23.6	-9.7	14.7	31.1	46.3	6.9	17	-20.4	15.2
13	2.1	16.3	51.8	27.3	-47.8	39.2	76.2	53.8	31.1	-12.5
14	12.8	29.8	18.9	-9.1	-17.2	30.7	1.9	16.3	8.9	-1.4
15	-17.2	-27.4	-8.8	-11.3	-12.6	20.1	-0.7	25.6	-9.4	-25.3
16	-3.8	1	-1	-4.1	4.9	20.4	-9.1	-5.7	0.4	-3.8
17	12.7	7.7	33.3	-2.5	4.5	10.7	33.7	7.7	-0.5	9.8
18	8	7.6	73.4	34	39.7	113.2	18	23.2	4.7	20.8
19	58.6	15	12.1	36.1	18	92.3	23.7	38	42.4	4.5
20	12.6	38.3	-1	69.6	24.5	21.7	70	8.9	41.9	62.1
21	52.5	18.2	30.3	23	55	51.7	29.2	13.4	47.5	10.2
22	10.3	8.7	27.9	24.5	30.6	29.2	14.2	9.9	16.2	5.1
23	15.5	17.4	-4.3	-8.2	11.6	18.8	-0.4	12.4	10	8.2
24	-11.8	-8.6	3.9	-14	40.5	52.5	-0.3	24.2	0.7	-8
Total	231.5	164.6	246.4	195.3	159.9	696.8	277.8	373.4	166.4	164.8

Abbreviations: AG, aggregator; DER, distributed energy resource; RT, real-time; WEM, wholesale electricity market.

Accordingly, the second and third columns of the table show the AG's revenue from taking part in the DA WEM and LEM, respectively. In the last row of these two columns, the daily income has been calculated. Additionally, in the fourth column of the table, the operating cost of DGs at the DA stage has been stated on an hourly basis. Considering the probability of each scenario, the revenue from involvement in the RT WEM and the operating costs of DGs at the RT stage are listed in columns 5 and 6, respectively. Ultimately, the AG's hourly and daily profit, which is obtained from the difference between all incomes, including columns 2, 3, and 5, and all costs, including columns 4 and 6, are computed in the last column of Table 3. As shown, the DER AG has earned nearly about \$13,660 benefit from simultaneous participation in both LEM and WEM.

To conclude, the optimal performance of the DER AG in the presence of both LEM and WEM is compared with the situation in which this player is only able to take part in one of the existing markets. Table 4 summarises the results of the

mentioned cases. To calculate the third column of the table, it is assumed that the DER AG participates in the DA and RT WEM, whereas to calculate the fifth column of the table, it is assumed that this entity only takes part in the DA LEM. In the last case, since it is not possible for the DER AG to participate in the RT market, it cannot utilise the adjustment power of DGs as well as the storage capacity of BSUs. Furthermore, in this case, the scheduling of renewable units is merely based on the forecasted wind speed and solar irradiance.

As obvious in Table 4, by providing the possibility of simultaneous participation in both markets, the AG is capable to sell more energy and consequently make more profit. This profit in the second and third cases has decreased by 8.3% and 25.7% in comparison with the first base case, respectively. The obtained results not only confirm the importance of a two-stage stochastic programming framework but also the impact of flexible energy resources in the two-stage decision-making process of the DER AG.

TABLE 3 DER AG's revenue, cost, and profit

# Hour	DA WEM Income (\$)	DA LEM Income (\$)	DA Operating Cost (\$)	RT WEM Income (\$)	RT Operating Cost (\$)	Expected Profit (\$)
1	0	347.3	0	-68.2	51.7	227.4
2	86.5	375.2	0	-233.1	8.5	220.1
3	15.6	432.3	0	-156.3	0	291.5
4	0	399.4	65.9	-63.5	34.4	235.6
5	12.2	440.9	39.8	-252.1	23.5	137.7
6	0	304.3	182.8	189.3	53.1	257.6
7	365.7	41.5	240.1	193.5	66.4	294.3
8	6.6	519.1	258.6	236.1	61.6	441.5
9	728	40.7	277.1	264.6	70.4	685.8
10	910.8	0	277.1	236.4	70.4	799.8
11	1492.6	0	277.1	107.7	70.4	1252.9
12	1726.2	0	277.1	144.3	70.4	1523
13	407.3	630.7	266	237.5	69.7	939.7
14	0	994.2	237.8	91.8	42.2	806
15	0	827.1	290.5	-67	11.8	457.8
16	0	674	347.5	-1	0	325.5
17	90.7	439.8	277.1	117.3	68.9	301.9
18	546.3	0	277.1	342.5	70.4	541.3
19	340	250.9	277.1	340.7	70.4	584.1
20	620.1	0	277.1	348.6	70.4	621.2
21	834.4	0	277.1	331	70.4	817.8
22	1075.2	0	277.1	176.7	70.4	904.4
23	951.7	0	277.1	80.9	68.7	686.7
24	146.8	378.8	233.8	79.1	64.6	306.3
Total	10356.6	7096.2	5211.1	2676.8	1258.5	13660.1

Abbreviations: AG, aggregator; DER, distributed energy resource; LEM, local electricity market; RT, real-time; WEM, wholesale electricity market.

TABLE 4 Comparison between the mentioned cases

	Both LEM and WEM	Only WEM		Only LEM	
		Value	Variation	Value	Variation
Traded energy (MWh/day)	694.1	439.3	-36.7 (%)	370.5	-46.6 (%)
Daily income (\$/day)	20129.7	18483.9	-8.2 (%)	13930.5	-30.8 (%)
Daily cost (\$/day)	6469.6	5962.4	-7.8 (%)	3784.3	-41.5 (%)
Expected profit (\$/day)	13660.1	12521.5	-8.3 (%)	10146.2	-25.7 (%)

Abbreviations: LEM, local electricity market; WEM, wholesale electricity market.

4 | CONCLUSION

The authors have presented an optimisation model to investigate the offering strategy of a DER AG as a price-maker player in the LEM and as a price-taker player in the WEM. This novel framework not only suggested a new approach for simultaneous participation of DER AGs in both WEM and LEM but

also allowed the AG to involve in the LEM as a price-maker actor which has not been addressed in previous studies. In the proposed framework, a bilevel programming approach was performed to examine the participation of the AG as a strategic entity in the LEM. In this context, at the UL of the problem, the DER AG's offering strategy in both mentioned markets was modelled through a two-stage stochastic scheme, while at

the LL, the DA LEM was cleared with the objective of social welfare maximisation and in the presence of the AG's non-strategic competitors. To scrutinise the suggested framework for the simultaneous participation of the considered AG in different electricity markets, a typical case study was implemented, and the optimal performance of the DER AG in the presence of both markets was compared with the situation in which this actor is merely able to take part in one of the existing markets. The simulation results represented that providing the possibility of offering in both markets can considerably increase the expected profit of the AG. That is because by utilising the proposed framework, the studied AG has the privilege of participating in both electricity markets and can select any market in each time step that is economically more attractive and profitable. It is expected that in the coming years, with the development of ICT infrastructures, high deployment of DERs, as well as the enactment of appropriate regulations and policies, LEMs will play a more dominant role in the distribution systems. In such networks, the aggregation of small- and medium-scale resources in the AG platform will be vital, and these AGs will be able to participate more effectively in both LEM and WEM. For future work, the LEM could be cleared by the market operator in both DA and RT stages and in the presence of the distribution system's technical constraints to assess the electricity trading at the local level based on distribution locational marginal prices.

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CONFLICT OF INTEREST

The authors have no conflict of interest.

NOMENCLATURE


$b \in B$	set of BSUs
$c \in C$	set of competitors in DA LEM
$d \in D$	set of demands in DA LEM
$j \in J$	set of DGs
$s \in S$	set of scenarios
$h \in H$	set of hours
$p \in P$	set of PVs
$w \in W$	set of WTs
Ω	set of decision variables
Ω^{LL}	set of LL decision variables
Ω^{UL}	set of UL decision variables
$SOC_{BSU}^{ini}, SOC_{BSU}^{fin}$	initial/final energy stored in BSUs (MWh)
$SOC_{BSU}^{max}, SOC_{BSU}^{min}$	maximum/minimum energy stored in BSUs (MWh)
$P_{BSU, ch}^{max}, P_{BSU, ch}^{min}$	maximum/minimum charge power of BSUs (MW)

$P_{BSU, dch}^{max}, P_{BSU, dch}^{min}$	maximum/minimum discharge power of BSUs (MW)
p_d^{max}, p_d^{min}	maximum/minimum bid of demands in DA LEM (MW)
$P_{DG}^{max}, P_{DG}^{min}$	maximum/minimum generation power of DGs (MW)
$P_{com}^{max}, P_{com}^{min}$	maximum/minimum offer of competitors in DA LEM (MW)
P_{PV}, P_{PV}^F	generate/forecast power of PVs (MW)
P_{WT}, P_{WT}^F	generate/forecast power of WTs (MW)
$R_{DG, dn}^{max}, R_{DG, dn}^{min}$	maximum/minimum downward adjustment power of DGs (MW)
$R_{DG, up}^{max}, R_{DG, up}^{min}$	maximum/minimum upward adjustment power of DGs (MW)
RD_{DG}, RU_{DG}	ramp down/up rate of DGs (MW/h)
λ_d	scenario probability (constant)
λ_{DG}	bid price of demands in DA LEM (\$/MWh)
$\lambda_{DG, dn}, \lambda_{DG, up}$	marginal price of DGs (\$/MWh)
λ_{com}	downward/upward adjustment power price of DGs (\$/MWh)
λ_{com}	offer price of competitors in DA LEM (\$/MWh)
$\lambda_{WEM, DA}, \lambda_{WEM, RT}$	DA/RT WEM price (\$/MWh)
$\eta_{BSU, ch}, \eta_{BSU, dch}$	charge/discharge efficiency of BSUs (%)
SOC_{BSU}	energy stored in BSUs (MWh)
$P_{BSU, ch}$	charge power of BSUs (MW)
$P_{BSU, dch}$	discharge power of BSUs (MW)
P_d	bid of demands in DA LEM (MW)
P_{DG}	generation power of DGs (MW)
P_{com}	offer of competitors in DA LEM (MW)
$q_{LEM, DA}^{AG}$	accepted offer of AG in DA LEM (MW)
$q_{LEM, DA, OF}^{AG}$	submitted offer of AG in DA LEM (MW)
$q_{WEM, DA}^{AG}$	offer of AG in DA WEM (MW)
$q_{WEM, RT}^{AG}$	offer of AG in RT WEM (MW)
$R_{DG, dn}$	downward adjustment power of DGs (MW)
$R_{DG, up}$	upward adjustment power of DGs (MW)
$\lambda_{LEM, DA}$	DA LEM clearing price (\$/MWh)
$\lambda_{LEM, DA, OF}^{AG}$	submitted offer price of AG in DA LEM (\$/MWh)
α, β, μ	dual variables
$U_{BSU, ch}$	charge situation of BSUs (0 or 1)
$U_{BSU, dch}$	discharge situation of BSUs (0 or 1)
χ	linearization of non-linear terms (0 or 1)
BSU	battery storage unit
DA	day-ahead
DER AG	distributed energy resource aggregator
DG	dispatchable generator
DSO	distribution system operator
LEM	local electricity market
LL	lower level
PV	photovoltaic
RT	real-time
UL	upper level

WEM wholesale electricity market
WT wind turbine

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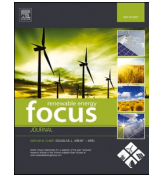
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Research Paper

Offering strategy of price-maker energy hubs in integrated local electricity and heat markets

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ABSTRACT

Integrated energy systems are considered a promising solution for increasing the flexibility of energy systems and accommodating more renewable energy resources to achieve decarbonization targets. In the context of EU countries, power-to-heat technologies are useful for achieving sector-coupling aspirations. However, designing an appropriate market-based platform that facilitates efficient cooperation and interaction among various power and heat units is crucial. Integrated energy systems in the form of energy hubs play an important role in this market-based framework as interface agents among different energy carriers. To this end, the paper proposes a market design based on a simultaneous market clearing in local power and heat markets, in which a price-maker energy hub participates in an attempt to maximize its revenue by offering in the joint markets. Hence, a bi-level programming method is used, in which, at the upper level of the problem, the focus is on maximizing the entity's profit, while the lower level addresses the local integrated market-clearing process. Second-order stochastic dominance constraints are also imposed on the problem to mitigate the studied energy hub's market participation risks. The problem is solved in two different sections, including the risk-neutral and risk-averse perspectives of the energy hub operator. The results of the proposed risk-averse bi-level scheme are demonstrated to be appropriate for each EH to promote its benefit in the joint power and heat markets while controlling the profit distribution and the risk of market participation based on the operator's market preference. The results indicate that implementing the proposed approach allows EH's owner to adjust its day-ahead offers in real time using flexible units in both power and heat forms. Also, imposing second-order stochastic dominance constraints enables the EH's operator to adjust its profit in the worst scenario based on its preference in a wide range, 873 € to 1737 €, which is not possible in other risk-management methods like CVaR.

Introduction

Environmental concerns, limited fossil fuel resources, and increasing energy demand have paved the way for increasing renewable energy penetration in the power sector. One of the main drawbacks of utilizing renewable resources in energy systems is the intermittent and stochastic production profile of these resources. Accordingly, increasing the flexibility of the power system to cope with renewable energy generation volatility is of paramount importance. In the meantime, power-to-X (PtX) technologies that provide the possibility of storing excess power produced by renewable energy resources in other forms of energy carriers, including heat and gas, can play a significant role in the flexibility provision of the power system [1] and [2]. In this vein, power-to-heat

(PtH) units are seen as potential sources for increasing the flexibility of the power system at all voltage levels, especially at the distribution level, as well as fulfilling decarbonization targets in the heat sector [3]. Using the potential synergy between power and heat energy carriers requires integration of the power and heat networks. Connecting the heating and electricity sectors with smart grid technologies not only improves the regulation, monitoring, and optimization of heat and electricity flows but also allows the possibility of recycling heat losses in the integrated energy system and utilizing thermal storage units to add flexibility [4,5]. To this end, simulations are required to evaluate operating conditions and performance in different circumstances [6].

Besides the physical integration of these two energy systems, the design of a local market-based platform to facilitate coordination between diverse players is crucial. Multiple research works have addressed

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Nomenclature	
Acronyms	
CDF	Cumulative Distribution Functions
CHP	Combined Heat and Power
CO ₂	Carbon Dioxide
CVaR	Conditional Value at Risk
DA	Day-Ahead
EB	Electric Boiler
EH	Energy Hub
EHP	Electric Heat Pump
ESS	Electricity Storage System
HSS	Heat Storage System
ILEHM	Integrated Local Electricity-Heat Market
IGDT	Information Gap Decision Theory
KKT	Karush-Kuhn-Tucker
LL	Lower Level
LMPs	Locational Marginal Prices
MPEC	Mathematical Program with Equilibrium Constraints
Obj	Objective Function
Obj ^{UL}	Upper-Level Objective Function
Obj ^{LL}	Lower-Level Objective Function
PM	Price Maker
PtH	Power-to-Heat
PtX	Power-to-X
PT	Price Taker
PV	Photovoltaic System
P2P	Peer-to-Peer
RH	Rival Heat
RP	Rival Power
RT	Real-Time
SDT	Strong Duality Theory
SOSD	Second-Order Stochastic Dominance
ST	Solar Thermal System
SILEHM	Stochastic Integrated Local Electricity-Heat Market
UL	Upper Level
WT	Wind Turbine
Sets and Indices	
$c \in C$	Set of CHPs
$e \in E$	Set of EHPs
$es \in ESS$	Set of ESSs
$b \in EB$	Set of EBs
$g \in G$	Set of GFGs
$p \in P$	Set of PVs
$rp \in RP$	Set of ILEHM's RPs
$rh \in RH$	Set of ILEHM's RHs
$sv \in SV$	Set of STs
$s \in S$	Set of Scenarios
$t \in T$	Set of Times
$hs \in HSS$	Set of HSSs
$w \in W$	Set of WTs
v, v'	Set of benchmark scenarios used in SOSD
Parameters	
CP	EHP's coefficient of performance (constant)
$E_{ESS}^{min}, E_{ESS}^{max}$	Minimum/maximum electricity stored in ESSs (MWh)
$E_{HSS}^{min}, E_{HSS}^{max}$	Minimum/maximum thermal energy stored in HSSs (MWh)
$E_{ESS}^{in}, E_{HSS}^{in}$	Initial electricity/heat stored in ESSs/HSS (MW)
H_{Demand}	ILEHM's heat demand (MW)
H_{SV}	Solar thermal produced heat (MW)
$H_{EHP}^{min}, H_{EHP}^{max}$	Minimum/maximum produced heat of EHPs (MWh)
$H_{HSS}^{ch,min}, H_{HSS}^{ch,max}$	Minimum/maximum charged heat of HSSs (MWh)
HPR	Heat-to-power ratio of CHPs (constant)
HV_{gas}	Natural gas heat value (MWh/m ³)
k	Prefixed value of benchmark scenarios used in SOSD (constant)
P_{Demand}	ILEHM's electricity demand (MW)
$p_{ESS}^{dch,min}, p_{ESS}^{dch,max}$	Minimum/maximum discharged power of ESSs (MW)
$p_{ESS}^{ch,min}, p_{ESS}^{ch,max}$	Minimum/maximum charged power of ESSs (MW)
$p_{GFG}^{min}, p_{GFG}^{max}$	Minimum/maximum produced power of GFGs (MW)
$p_{CHP}^{min}, p_{CHP}^{max}$	Minimum/maximum produced power of CHPs (MW)
$p_{EB}^{min}, p_{EB}^{max}$	Minimum/maximum consumed power of EBs (MW)
P_{PV}, P_{WT}	Output power of PVs, WTs (MW)
$q_{RP}^{min}, q_{RP}^{max}$	Minimum/maximum amount of RPs' offers (MW)
$q_{RH}^{min}, q_{RH}^{max}$	Minimum/maximum amount of RHs' offers (MW)
Q_p, Q_H	EH's power/heat quantity offers to ILEHM (MW)
ρ	Scenario probability (constant)
λ_{gas}	Natural gas price (€/MWh)
α_p, α_H	EH's submitted electricity/heat offer prices (€/MWh)
α	Defined confidence level in CVaR(constant)
β	Risk-aversion parameter used to apply CVaR (constant)
η_{EB}^E	The efficiency of EBs (%)
$\eta_{CHP}^E, \eta_{CHP}^H$	Electricity/heat efficiency of CHPs (%)
η_{GFG}^E	The efficiency of GFGs (%)
$\eta_{ESS}^{ch}, \eta_{ESS}^{dch}$	Charge/discharge efficiency of ESSs (%)
$\eta_{HSS}^{sb}, \eta_{HSS}^{ch}, \eta_{HSS}^{dch}$	Standby/charge/discharge efficiency of HSSs (%)
τ	Probability of each predefined benchmark scenario (constant)
Decision Variables	
CVaR	Conditional Value at Risk (€)
E_{ESS}, E_{HSS}	Electricity/ Heat stored in ESSs/HSS (MWh)
G_{CHP}, G_{GFG}	Gas flow from gas station to CHPs/GFGs (m ³)
$H_{CHP}/H_{EHP}/H_{EB}$	Generated heat of CHPs/EHPs/EBs (MW)
$H_{HSS}^{dch}, H_{HSS}^{ch}$	Discharged/charged heat of HSSs (MWh)
OC_{CHP}, OC_{GFG}	Operating cost of CHPs /GFGs (€)
P_{GFG}	Generated power of GFGs (MW)
$p_{ESS}^{dch}, p_{ESS}^{ch}$	Discharged/charged power of ESSs (MW)
P_{CHP}	Generated power of CHPs (MW)
P_{EHP}, P_{EB}	Consumed power of EHPs/EBs (MW)
q_p, q_H	EH's accepted power/heat offers (MW)
q_{RH}, q_{RP}	RH/RP's quantity offers (MW)
$\lambda_{RP}, \lambda_{RH}$	RH/RP's price offers (MW)
μ	Dual variables of LL's non-equality constraints
λ_p, λ_H	DA electricity/heat market clearing prices (€/MWh)
VaR, ξ	Auxiliary variables used to apply CVaR (constant)
ψ	Auxiliary variable used to apply SOSD constraints (constant)
Binary Variables	
U _•	Binary variable for the performance of

market perspectives in the operation of integrated power and heat systems. Since power and heat systems are usually managed by independent entities, decentralized optimization methods are focused on in many studies. In this context, a decentralized multi-period operation approach for interconnected power and heat networks is proposed in [7], while each optimal power flow and optimal thermal flow problem is solved independently considering the operational status of another network.

The evaluation of the design of the potential local interconnected energy markets that facilitate the integration of power and heat distribution systems and provide an extra level of flexibility is very important. In [8], a model for the future interconnected power and heat markets is proposed, in which both electricity and heat sectors are considered equally important energy carriers. In this study, a linear formulation of power market clearing considering AC power flow and achieving exact locational marginal prices (LMPs) is proposed. Furthermore, the optimal thermal flow problem is solved, and heat LMPs are obtained. A fixed point between optimal power flow and optimal thermal flow represents the integrated market equilibrium and is reformulated in the framework of mixed-integer linear programming. In [9], a local market design based on a centralized auction-based trading mechanism is presented, in which integrating multiple energy carriers can facilitate the efficient use of available resources as well as employing flexible solutions. The objective of the market clearing process is to maximize the sum of producers' and consumers' surplus. A double-sided auction-based local market design for the application of integrated power and heat energy systems is introduced in [10], in which the objective of the market clearing process is to maximize social welfare based on the submitted orders in the market. A two-stage integrated market clearing model is presented in [11] to ensure the benefits of market players and establish a fair framework for the competition of market participants. The real-time (RT) operational costs and day-ahead (DA) dispatch costs are minimized in the market-clearing process to mitigate the operational risk of integrated energy systems with high penetration of renewable energy resources.

In order to provide end-users with active participation in a distribution-level market framework, the concept of peer-to-peer (P2P) energy trading is introduced. In this regard, facilitated energy transactions between agents while addressing the mutual interdependencies between diverse energy carriers can incentivize participants to be actively involved in local market transactions. A novel P2P energy market framework is presented in [12], in which mutual interdependencies between power and heat sectors are considered in the settlement of energy transactions in the integrated power and heat market. A linear optimization problem is proposed in this study to achieve optimal strategies for the existing agents in the designed market and obtain optimal operational scheduling for market participants. Finally, a P2P multi-energy market mechanism is developed in [13], in which peers can trade both electricity and heat by joining one of the predefined coalitions, including an electricity-heat trading coalition and an electricity-only trading coalition. Each energy market is cleared separately per energy carrier and per coalition.

Notably, some entities can trade power and heat in the electricity-heat-integrated local markets. Energy hubs (EHs) as interface agents between diverse energy carriers are one of those actors. In general, the self-scheduling of EHs, including net energy trading between the existing units, the amount of stored energy in storage resources, etc., is manageable within their framework. However, the optimal participation of these entities within local integrated electricity-heat markets and in the presence of multiple uncertain factors, including the behavior of their rivals, market outcomes, and renewable energy resources, is a critical issue and requires precise scheduling. In the following, some studies that have focused on the scheduling of EHs in the presence of power and heat markets have been reviewed. A two-stage risk-constraint optimal operation strategy for an EH is proposed in [14] in the presence of DA and RT electricity and heat markets. The objective function of the

problem is not only to maximize the expected profit of the EH but also to minimize the risk level and carbon dioxide (CO₂) emission. In this work, the stochastic p-robust optimization approach is executed to manage financial risk. A mathematical program with equilibrium constraints (MPEC) formulation is proposed in [15] for an EH that participates in the distribution-level electricity and heat markets. At the upper level (UL) of the problem, the studied EH submits bids, including quantities and prices, to the markets. The market-clearing process, which is implemented based on optimal power and thermal flows, determines the transaction between the EH and the two mentioned energy markets at the lower level (LL) of the problem. A risk-constrained stochastic scheduling method for an EH participating in power, heat, and gas markets is presented in [16]. The objective function of the problem is to minimize operating and emission costs. The conditional value at risk (CVaR) measure is incorporated with the objective function to manage the risk in the worst scenarios with higher operating costs. The concept of a virtual EH is introduced in [17], which is an integrated energy system with self-scheduling methods to maximize its revenue while participating in different energy markets. In this study, the information gap decision theory (IGDT) is applied to propose a scheduling method for a virtual EH participating in the local power and heat energy markets. When the uncertainties of the problem are considered, the proposed method enables the virtual EH to follow two different strategies, including the risk-seeker strategy and the risk-averse strategy. A scenario-based robust self-scheduling method for a virtual EH that is capable of participating in DA and RT power and heat markets is proposed in [18]. The objective function of the problem is to maximize the profit of the virtual EH and to manage financial risk by considering the downside risk method.

On the other hand, in some studies, the scheduling problem of an EH is addressed only in the presence of power markets. The strategic scheduling of a price maker (PM) multi-energy system in the DA wholesale market is proposed using bi-level optimization [19], in which the UL problem minimizes EH's operation cost, and the LL maximizes public satisfaction in the market. The optimal operation problem of an EH in the presence of the wholesale electricity market is proposed [20], in which the objective function is to minimize the operation cost of the studied EH. Both the robust chance-constrained approach and the robust IGDT method are employed to solve the problem by considering risk level in decision-making. In [21], a two-stage risk-aware stochastic method is proposed for the scheduling of an EH that is capable of participating in DA and RT electricity markets. Value-at-risk is used as a risk metric to restrict the emergence of high operation costs in the worst scenarios. The results determine the components' operating points and the EH's transactions of electricity and natural gas. In [22], a two-stage stochastic programming method is proposed for the scheduling of an EH participating in DA and regulating electricity markets. The CVaR term is used to manage the risk of high operation costs in the worst scenarios. The objective function of the problem is to minimize the total expected cost of the considered EH. Ultimately, a bi-level optimization approach is exploited in [23] to propose the optimal bidding and scheduling of an EH equipped with advanced-adiabatic compressed air energy storage. Accordingly, at the UL of the problem, self-scheduling and power purchase of the EH from the distribution-level electricity market to minimize operation costs are addressed. Meanwhile, in the LL, the market-clearing problem is considered to minimize generation costs and upstream grid payments. A brief summary of reviewed papers is provided in Table 1.

Based on the reviewed papers and Table 1, the following research gaps are identified:

Although increased sector coupling in the power and heat networks makes them more dependent on each other, none of the reviewed papers in (3-9) consider the ILEHM, where simultaneous market clearing processes in power and heat markets are done. (RG1)

Table 1
Comparison of reviewed studies with the present paper.

Ref.	Market Participation		EH Modeling		Market Modeling				Risk Management	
	Wholesale	Local	PM	PT	Power	Heat	ILEHM	SILEHM	Methods	SOSD By CVaR
[14]	x	✓	x	✓	✓	✓	x	x	CVaR	x
[15]	✓	x	✓	x	✓	✓	x	x	x	x
[16]	✓	x	x	✓	✓	✓	x	x	CVaR	x
[17]	x	✓	x	✓	✓	✓	x	x	IGDT	x
[18]	✓	x	x	✓	✓	✓	x	x	Downside Risk	x
[19]	✓	x	✓	x	✓	x	x	x	Robust	x
[20]	✓	x	✓	x	✓	x	x	x	Robust Chance-Constrained Robust IGDT	x
[21]	✓	x	x	✓	✓	x	x	x	VaR	x
[22]	✓	x	x	✓	✓	x	x	x	CVaR	x
[23]	x	✓	x	x	✓	x	x	x	x	x
This Paper	x	✓	✓	x	✓	✓	✓	✓	x	✓

Although papers (10-14) consider the participation of the integrated energy systems in the form of EH in power and heat markets, none of them consider their participation in ILEHM. (RG2)

Additionally, papers (15-19) only consider EH's participation in a power market. Also, in most of the studies (10), (12-14), and (17-19), EH is not considered as a PM entity, where they can generate a considerable amount of power and heat, resulting in ignoring their effects in the market clearing process. (RG3)

Although in some of the studies, risk measures are used to control the risk of the EH's participation in power and heat markets, none of them used second-order stochastic constraints as risk measures, which provides the EH's operator with more freedom in implementing their preferences in risk-management, which is not possible through common risk measures like VaR and CVaR. (RG4)

According to defined gaps, this paper proposes a stochastic integrated local electricity and heat market (SILEHM), in which not only the market clearing process is done simultaneously for power and heat markets but also the stochastic behavior of power and heat market participants, as well as the uncertainty of demand, are also considered. As an integrated energy system, EH participates in this market to maximize its profit. Additionally, since the studied EH is assumed to be a PM entity, its effect on the market clearing process is also considered. To this end, a two-stage stochastic method is nested in the UL of a bi-level programming method to maximize the profit of the EH participating in ILEHM. In the LL of the problem, the market clearing process is done for power and heat markets simultaneously. The main contributions of this paper are defined as follows:

SILEHM is introduced in this study to give market operators and participants greater flexibility and freedom in energy management, increasing participants' profit and improving the network's overall performance. (Address RG1)

EH is modeled as a PM player participating in the ILEHM and affects the market clearance process via a bi-level programming approach. (Address RG2 and RG3)

Second-order stochastic dominance (SOSD) [20] constraints are added to the problem to control the risk of EH's participation in the proposed local market platform, giving more freedom to the EH's operator in confronting the worst scenarios. (Address RG4)

In the proposed SOSD risk management method, a feasible region for controlling risk is defined by CVaR, which guarantees the feasibility of the problem.

HYPERLINK "SPS:id::Sec1" Methodology

This study aims to propose a scheduling method for the participation of a PM EH in the ILEHM to not only maximize EH's profit but also take into account the market-clearing problem with the objective of

operation cost minimization. Hence, to model the participation of the EH as a strategic player in the ILEHM, a bi-level programming approach is proposed, in which the scheduling and operation of the EH is implemented in its UL, while the local market-clearing procedure is implemented in its LL. Studied EH consists of a combined heat and power (CHP) and a gas-fired generator (GFG) as conventional units, renewable energy generators such as wind turbine (WT), photovoltaic system (PV), and solar thermal system (ST), energy storage systems including electricity storage system (ESS) and heat storage system (HSS), as well as PtH technologies including electric boilers (EBs) and electric heat pumps (EHPs), as shown in Fig.1.

As stated, EH participates in the ILEHM as a PM player, so its offers will affect the market clearing process and market clearing prices. The stochastic behavior of EH's power and heat rivals and the uncertainty of market demands are considered, so the market is modeled as a stochastic integrated local electricity and heat market (SILEHM) in which both power and heat market clearing processes are done simultaneously. To address EH's scheduling considering market clearing problems, a bi-level method is used in which the UL maximizes EH's expected profit, which is the difference between the amount of revenue obtained by selling energy and the operation cost of CHPs and GFGs. The LL solves the ILEHM market clearing problem, and its objective function is to minimize the operation cost of the market. EH operator faces a wide range of uncertainty factors while making decisions, including the energy profile of wind turbine (WT), photovoltaic (PV), and solar thermal (ST) units, power and heat demand, as well as offers of its rivals in the power and heat markets. Therefore, applying appropriate risk-management methods is highly important to deal with these uncertainties. Hence, SOSD constraints are implemented in this paper to control the EH's risk of participation in the local market, which is superior to other common risk-management methods such as CVaR. A high-level overview of the methodology and detailed proposed methodology are represented in Figs. 2 and 3. The UL of the problem consists of two stages. The first stage determines the EH's submitted power and heat prices and quantity offered to the ILEHM, as well as the operating points of its CHP and GFG units. Hence, decision variables of this stage are not dependent on scenarios. On the other hand, after realizing the stochastic parameters, the operating points of the EH's flexible units, including EHPs, EBs, ESS, and HSS, are specified in the second stage to maximize this entity's profit. Furthermore, in the LL of the problem, the EH's accepted power and heat offers, power and heat-market clearing prices, as well as accepted offers of the EH's power and heat rivals, are determined with the objective of minimizing the operation cost. In this procedure, EHs submitted and accepted power and heat offers in the ILEHM act as linking variables between these two levels.

Problem Formulation

This section presents the mathematical formulation for scheduling

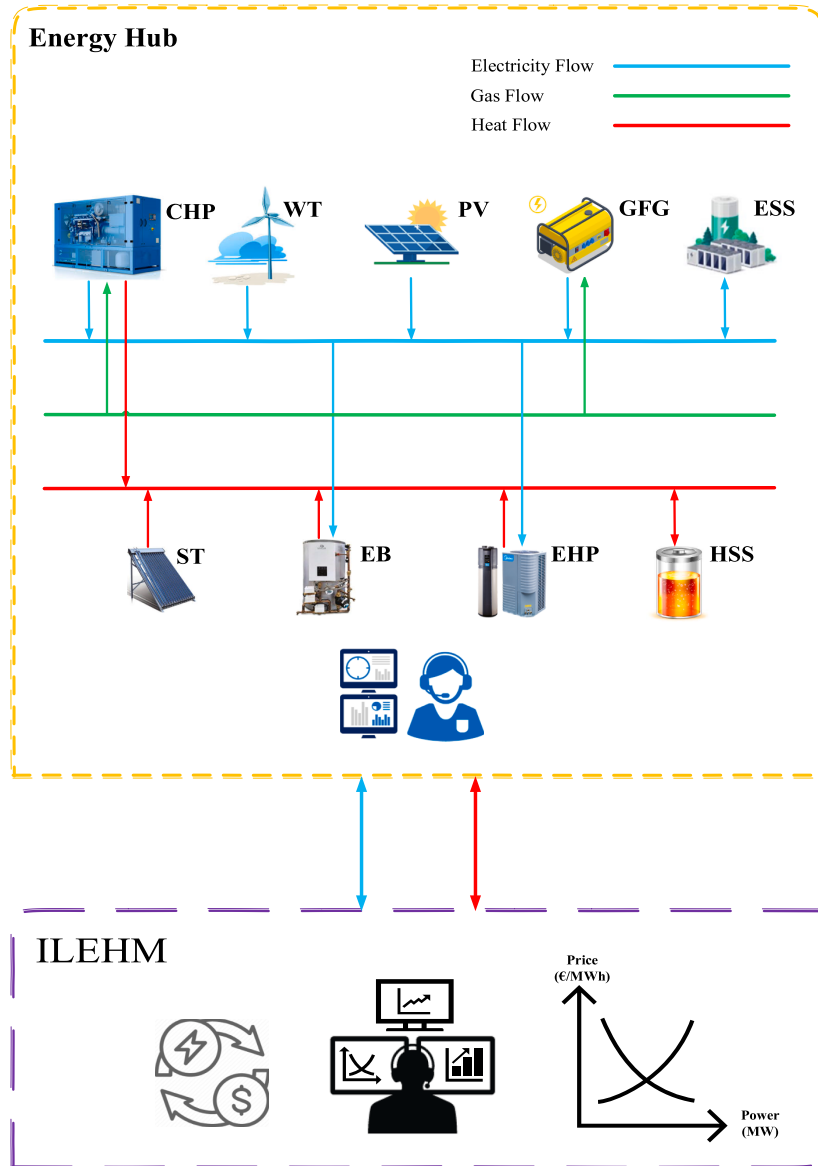


Fig. 1. Detail description of the studied EH considering participating in ILEHM.

EH to participate in ILEHM as a strategic player.

UL Problem: Scheduling of the Strategic EH

The objective function of the UL is to maximize the expected profit of the EH using a two-stage stochastic programming approach, in which q_p and q_H are EH's accepted power/heat offers, ρ is the probability of scenarios, λ_p and λ_H are DA electricity/heat market clearing prices, and OC_{CHP} and OC_{GFG} are operating cost of CHPs /GFGs. The differences between the profit of EH resulting from selling power and heat to the local market, based on the uniform market clearing outcomes, and the operation costs of the available CHPs and GFGs form the objective function at this level.

$$OF^{UP} = \text{Max} \sum_{t \in T} \left[+ \sum_{s \in S} \rho(s) \cdot (q_p(t, s) \cdot \lambda_p(t, s) + q_H(t, s) \cdot \lambda_H(t, s)) - \sum_{c \in CHP} OC_{CHP}(c, t) - \sum_{g \in GFG} OC_{GFG}(g, t) \right] \quad (1)$$

The considered objective function is subject to a set of constraints as follows:

1 Constraints of the EH's power and heat offers in the ILEHM:

The EH's submitted power and heat offers to the ILEHM are non-negative variables that are denoted in inequalities (2), in which Q_p and Q_H are EH's power and heat quantity offers to ILEHM, and α_p and α_H are EH's submitted electricity and heat offer prices.

On the other hand, as it is demonstrated in Eq (3) and Eq (4), the accepted power and heat offers of the EH need to be restricted to the generation capacity of the aggregated dispatchable as well as non-

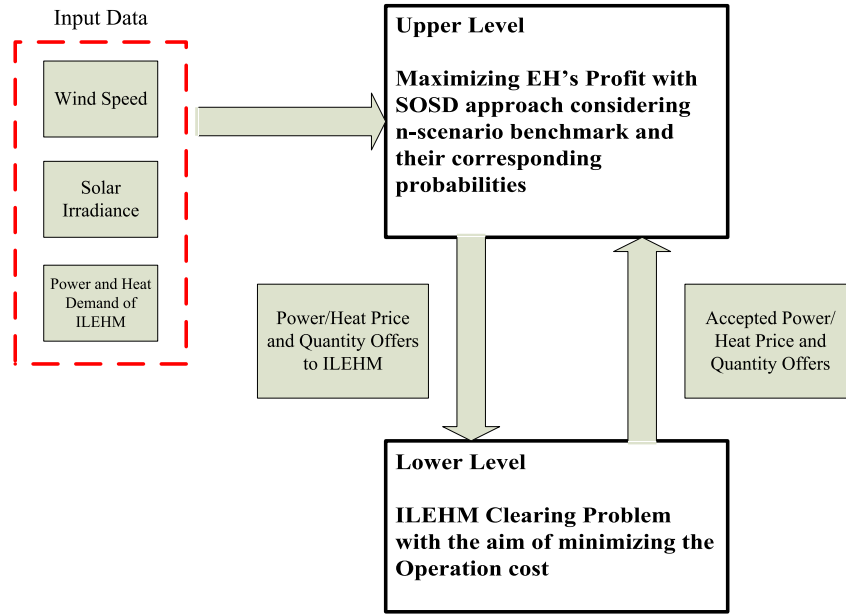


Fig. 2. A high-level overview of the proposed methodology.

dispatchable resources within the studied EH. In these equations, P_{CHP} , P_{GFG} , P_{WT} , P_{PV} , $P_{ESS}^{dch}/P_{ESS}^{ch}$, P_{EHP} , P_{EB} , are generated power of CHPs, GFGs, WTs, PVs, discharged/charged power of ESSs, and consumed power of EHPs and EBs, respectively. Also, H_{CHP} , H_{EHP} , H_{EB} , H_{SV} , $H_{HSS}^{dch}/H_{HSS}^{ch}$ are generated heat of CHPs, EHPs, EBs, STs, and discharged/ charged heat of HSSs, respectively.

$$\begin{aligned} Q_p(t) &\geq 0, \quad \alpha_p(t) \geq 0, \quad \forall t \\ Q_H(t) &\geq 0, \quad \alpha_H(t) \geq 0, \quad \forall t \end{aligned} \quad (2)$$

$$\begin{aligned} q_p(t, s) &\leq \sum_{c \in CHP} P_{CHP}(c, t) + \sum_{g \in GFG} P_{GFG}(g, t) \\ &+ \sum_{w \in WT} P_{WT}(w, t, s) + \sum_{p \in PV} P_{PV}(p, t, s) \\ &+ \sum_{es \in ESS} P_{ESS}^{dch}(es, t, s) - P_{ESS}^{ch}(es, t, s) \\ &- \sum_{e \in EHP} P_{EHP}(e, t, s) - \sum_{b \in EB} P_{EB}(b, t, s) \quad ; \forall t, s \end{aligned} \quad (3)$$

$$\begin{aligned} q_H(t, s) &\leq \sum_{c \in CHP} H_{CHP}(c, t) + \sum_{e \in EHP} H_{EHP}(e, t, s) \\ &+ \sum_{sv \in SV} H_{SV}(sv, t, s) + \sum_{b \in EB} H_{EB}(b, t, s) \\ &+ \sum_{hs \in HSS} H_{HSS}^{dch}(hs, t, s) - H_{HSS}^{ch}(hs, t, s) \quad ; \forall t, s \end{aligned} \quad (4)$$

2 Constraints of the CHP units:

CHP refers to the units that produce power and heat simultaneously. Using these units increases energy efficiency while protecting the environment since they produce less greenhouse gas emissions by 13-18% [24-25]. These units in the structure of the EH are formulated by Eqs (5) to (8), in which the first one demonstrates the relation between output power and units' injected gas, G_{CHP} . In Eq (5), HV_{gas} and η_{CHP}^E are natural gas heat value and electricity efficiency of CHPs. Eq (6) indicates the correlation between the thermal and electrical output of these units, in which HPR and η_{CHP}^H are the heat-to-power ratio of CHPs and heat efficiency of CHPs, the power generation of CHPs is restricted by Eq (7), in which P_{CHP}^{min} and P_{CHP}^{max} are minimum and maximum produced

power of CHPs. Ultimately, the operation costs of CHPs are calculated by Eq (8) [26], in which λ_{gas} is the natural gas price.

$$G_{CHP}(c, t) = \frac{P_{CHP}(c, t)}{HV_{gas} \cdot \eta_{CHP}^E(c)} \quad ; \forall c, t \quad (5)$$

$$H_{CHP}(c, t) \leq P_{CHP}(c, t) \cdot HPR(c) \cdot \eta_{CHP}^H(c) \quad ; \forall c, t \quad (6)$$

$$P_{CHP}^{min}(c) \leq P_{CHP}(c, t) \leq P_{CHP}^{max}(c) \quad ; \forall c, t \quad (7)$$

$$OC_{CHP}(c, t) = G_{CHP}(c, t) \cdot \lambda_{gas}(t) \quad ; \forall c, t \quad (8)$$

3 Constraints of the GFG units:

GFG units are mathematically formulated by Eqs (9) to (11). The relation of consumed fuel, G_{GFG} , of these units and units' output power is depicted by Eq (9), in which η_{GFG}^E is the efficiency of GFGs. Moreover, GFGs' generated power is restricted by Eq (10), which P_{GFG}^{min} and P_{GFG}^{max} are the minimum and maximum produced power of GFGs. The operation cost of these units is calculated through Eq (11) [26].

$$G_{GFG}(g, t) = \frac{P_{GFG}(g, t)}{HV_{gas} \cdot \eta_{GFG}^E(g)} \quad ; \forall g, t \quad (9)$$

$$P_{GFG}^{min}(g) \leq P_{GFG}(g, t) \leq P_{GFG}^{max}(g) \quad ; \forall g, t \quad (10)$$

$$OC_{GFG}(g, t) = G_{GFG}(g, t) \cdot \lambda_{gas}(t) \quad ; \forall g, t \quad (11)$$

4 Constraints of the ESS units:

The mathematical formulation of the ESS is presented in expressions (12) to (16). The charged and discharged powers of the ESS are limited by Eqs (12) and (13), respectively. In these equations, $P_{ESS}^{ch, min}$, $P_{ESS}^{ch, max}$, $P_{ESS}^{dch, min}$, $P_{ESS}^{dch, max}$ are the minimum/maximum charged power of ESSs, and minimum/maximum discharged power of ESSs. Eqs (14), (15), and (16) are used to express the amount of electrical energy stored in the ESS [27]. In these equations, E_{ESS} , $E_{ESS}^{min}/E_{ESS}^{max}$, $\eta_{ESS}^{ch}/\eta_{ESS}^{dch}$ are electricity stored in ESSs, minimum/maximum electricity stored in ESSs, and charge/discharge efficiency of ESSs.

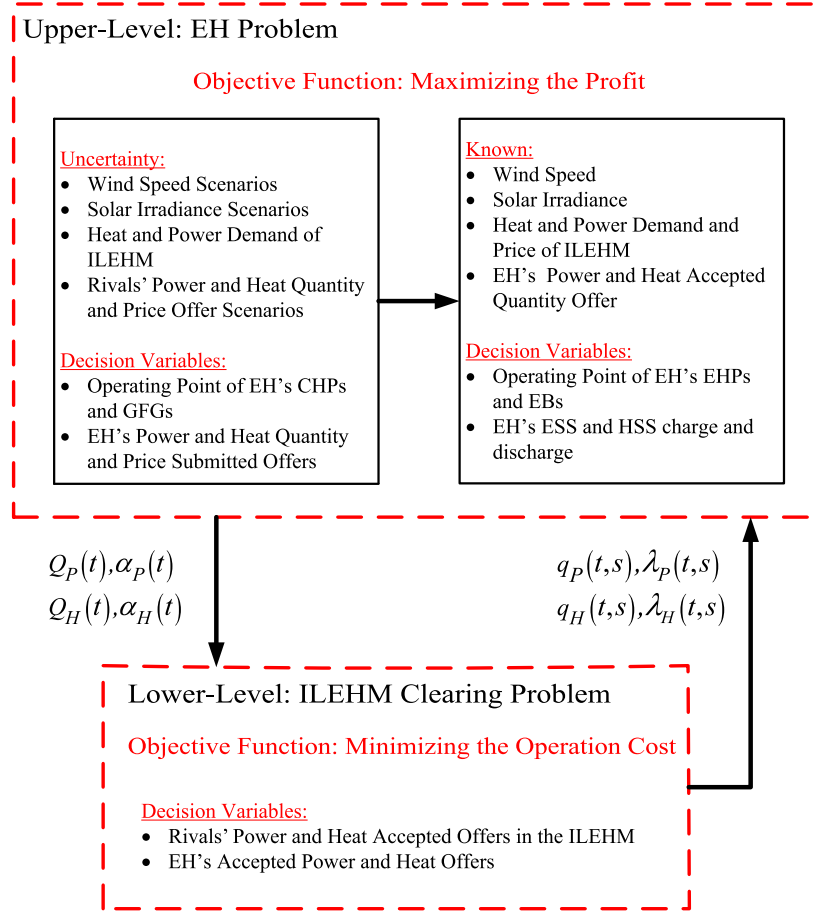


Fig. 3. Detailed proposed methodology for scheduling of the studied EH participating ILEHM.

$$P_{ESS}^{ch,min}(es) \cdot U_{ESS}(es, t, s) \leq P_{ESS}^{ch}(es, t, s) \leq P_{ESS}^{ch,max}(es) \cdot U_{ESS}(es, t, s) \quad ; \forall es, t, s \quad (12)$$

$$P_{ESS}^{dch,min}(es) \cdot (1 - U_{ESS}(es, t, s)) \leq P_{ESS}^{dch}(es, t, s) \leq P_{ESS}^{dch,max}(es) \cdot (1 - U_{ESS}(es, t, s)) \quad ; \forall es, t, s \quad (13)$$

$$E_{ESS}(es, t, s) = E_{ESS}^{in}(es) \quad ; \forall es, t = 1, s \quad (14)$$

$$E_{ESS}(es, t, s) = E_{ESS}(es, t - 1, s) + P_{ESS}^{ch}(es, t, s) \cdot \eta_{ESS}^{ch}(es) - P_{ESS}^{dch}(es, t, s) \cdot \eta_{ESS}^{dch}(es) \quad ; \forall es, t > 1, s \quad (15)$$

$$E_{ESS}^{min}(es) \leq E_{ESS}(es, t, s) \leq E_{ESS}^{max}(es) \quad ; \forall es, t, s \quad (16)$$

5 Constraints of the HSS units:

Expressions from (17) to (21) are used to model HSS Units. The charged and discharged heat of these units are limited by Eqs (17) and (18), respectively, in which $H_{HSS}^{ch,min}$, $H_{HSS}^{ch,max}$, $H_{HSS}^{dch,min}$, $H_{HSS}^{dch,max}$, $P_{ESS}^{ch,max}$ are minimum/maximum charged heat of HSSs, minimum/maximum discharged heat of HSSs.

The amount of thermal energy stored in HSS is expressed through Eqs (19) and (20). Finally, Eq (21) is utilized to limit the amount of heat stored in HSS [28]. In these equations, E_{HSS} , E_{HSS}^{min} , E_{HSS}^{max} , η_{HSS}^{ch} , η_{HSS}^{dch} , η_{HSS}^{sb} are heat stored in HSSs, minimum/maximum heat stored in HSSs, and charge/discharge/ standby efficiency of HSSs.

$$H_{HSS}^{ch,min}(hs) \cdot U_{HSS}(hs, t, s) \leq H_{HSS}^{ch}(hs, t, s) \leq H_{HSS}^{ch,max}(hs) \cdot U_{HSS}(hs, t, s) \quad ; \forall hs, t, s \quad (17)$$

$$H_{HSS}^{dch,min}(hs) \cdot (1 - U_{HSS}(hs, t, s)) \leq H_{HSS}^{dch}(hs, t, s) \leq H_{HSS}^{dch,max}(hs) \cdot (1 - U_{HSS}(hs, t, s)) \quad ; \forall hs, t, s \quad (18)$$

$$E_{HSS}(hs, t, s) = E_{HSS}^{in}(hs) \quad ; \forall hs, t = 1, s \quad (19)$$

$$E_{HSS}(hs, t, s) = E_{HSS}(hs, t - 1, s) \cdot \eta_{HSS}^{sb}(hs) + H_{HSS}^{ch}(hs, t, s) \cdot \eta_{HSS}^{ch}(hs) - H_{HSS}^{dch}(hs, t, s) \cdot \eta_{HSS}^{dch}(hs) \quad ; \forall hs, t > 1, s \quad (20)$$

$$E_{HSS}^{min}(hs) \leq E_{HSS}(hs, t, s) \leq E_{HSS}^{max}(hs) \quad ; \forall hs, t, s \quad (21)$$

6 Constraints of the EHP units:

EHP units consume electricity to produce heat, as shown in Eq (23), which CP is EHP's coefficient of performance. Also, the produced heat of EHPs is limited by Eq (22) [29], in which H_{EHP}^{min} and H_{EHP}^{max} are minimum and maximum produced heat of EHPs.

$$H_{EHP}^{min}(e) \leq H_{EHP}(e, t, s) \leq H_{EHP}^{max}(e) \quad ; \forall e, t, s \quad (22)$$

$$H_{EHP}(e, t, s) = P_{EHP}(e, t, s) \cdot CP(e) \quad ; \forall e, t, s \quad (23)$$

7 Constraints of the EB units:

EBs utilize electricity to produce heat, as shown in Eq (24), in which η_{EB}^H The efficiency of EBs. Generated heat by EBs is limited by Eq (25)

[26], in which P_{EB}^{\min} and P_{EB}^{\max} are minimum and maximum consumed power of EBs.

$$H_{EB}(b, t, s) = P_{EB}(b, t, s) \cdot \eta_{EB}^H(b) \quad ; \forall b, t, s \quad (24)$$

$$P_{EB}^{\min}(b) \leq P_{EB}(b, t, s) \leq P_{EB}^{\max}(b) \quad ; \forall b, t, s \quad (25)$$

Constraints of the risk management:

CVaR:

In this part, the constraints of the CVaR as a common risk measure are provided from Eq (29) to Eq (32). In order to apply this measure to the EH's problem, the objective function of the UL problem should be written according to Eq (29) to set a trade-off between the obtained expected profit and its risk level [30]. In these equations, VaR , ξ are auxiliary variables used to apply CVaR. α and β are defined as confidence level and risk-aversion parameters.

$$\text{Maximize } (1 - \beta) \cdot OF^{UL} + \beta \cdot CVaR \quad (29)$$

$$CVaR = VaR - \frac{1}{1 - \alpha} \sum_s \rho(s) \cdot \xi(s) \quad (30)$$

$$VaR - \sum_{t \in T} \left[\begin{array}{l} q_p(t, s) \cdot \lambda_p(t, s) + q_H(t, s) \cdot \lambda_H(t, s) \\ - \sum_{c \in CHP} OC_{CHP}(c, t) - \sum_{g \in GFG} OC_{GFG}(g, t) \end{array} \right] \leq \xi(s) \quad ; \forall s \quad (31)$$

$$\xi(s) \geq 0 \quad ; \forall s \quad (32)$$

SOSD:

The constraints from Eq (33) to Eq (35) are added to the problem to use SOSD constraints as a risk-management method. The preference of this approach over other risk-management methods is that it directly controls the expected profit of the worst scenario by imposing benchmark distribution through the definition of $k(v)$ or $k(v')$ and their related probability $\tau(v)$ or $\tau(v')$ [31]. In these equations, k and ψ are prefixed values of benchmark scenarios and auxiliary variables to apply SOSD constraints.

$$k(v) - \sum_{t \in T} \left[\begin{array}{l} q_p(t, s) \cdot \lambda_p(t, s) + q_H(t, s) \cdot \lambda_H(t, s) \\ - \sum_{c \in CHP} OC_{CHP}(c, t) - \sum_{g \in GFG} OC_{GFG}(g, t) \end{array} \right] \leq \psi(s, v) \quad ; \forall s, v \quad (33)$$

$$\sum_{s \in S} \rho(s) \cdot \psi(s, v) \leq \sum_{v'} \tau(v') \cdot \max(k(v) - k(v'), 0); \quad \forall v \quad (34)$$

$$\psi(s, v) \geq 0 \quad ; \quad \forall s, v \quad (35)$$

To sum up, the set of decision variables of the UL is shown as follows:

$$\Delta^{UL} = \{ Q_p(t), Q_H(t), \alpha_p(t), \alpha_H(t), P_{CHP}(c, t, s), P_{GFG}(g, t, s), P_{EHP}(e, t, s), P_{EB}(eb, t, s), P_{ESS}^{ch}(es, t, s), P_{ESS}^{dch}(es, t, s), H_{CHP}(c, t, s), H_{EB}(eb, t, s), H_{EHP}(e, t, s), H_{HSS}^{ch}(hs, t, s), H_{HSS}^{dch}(hs, t, s), G_{GFG}(g, t, s), G_{CHP}(c, t, s), E_{HSS}(hs, t, s), E_{ESS}(es, t, s), U_{HSS}(hs, t, s), U_{ESS}(es, t, s), VaR, \xi(s), k(v), \psi(s, v) \}$$

LL Problem: Integrated Local Market-clearing Process

As noted, the ILEHM clearing process is performed in the LL of the proposed bi-level problem from the EH viewpoint, considering the stochastic behavior of EH's power and heat rivals participating in the market. Accordingly, the EH, as well as its rivals, submit their power and heat price and amount of offers to the ILEHM. Then, after performing the market-clearing procedure, clearing prices for both power and heat, as well as accepted offers of the EH and rivals, are determined with the aim

of minimizing the operating cost of the market. q_{RH}/q_{RP} , $\lambda_{RP}/\lambda_{RH}$ are RH/RP's quantity and price offers.

$$\begin{aligned} & \text{Min} \sum_{rp \in RP} q_{RP}(rp, t, s) \cdot \lambda_{RP}(rp, t, s) \\ & + \sum_{rh \in RH} q_{RH}(rh, t, s) \cdot \lambda_{RH}(rh, t, s) \\ & + q_p(t, s) \cdot \alpha_p(t) + q_H(t, s) \cdot \alpha_H(t) \quad ; \forall t, s \end{aligned} \quad (36)$$

The above-mentioned objective function is subject to a set of constraints as follows:

1 Power and heat balances in the ILEHM:

The accepted offers of the EH and its power and heat rivals should satisfy the local market's forecasted power and heat demands. In this regard, the offers are accepted in the market-clearing process from the lowest price until satisfying the market's demand based on Eqs (37) and (38). Notably, dual variables associated with each constraint of the LL are indicated after a semicolon. The dual variables associated with the power and heat balance constraints represent the power and heat local market-clearing prices. P_{Demand} and H_{Demand} are ILEHM's power and heat demand.

$$q_p(t, s) + \sum_{rp \in RP} q_{RP}(rp, t, s) = P_{Demand}(t, s) \quad ; \forall t, s \quad ; \quad \lambda_p(t, s) \quad (37)$$

$$q_H(t, s) + \sum_{rh \in RH} q_{RH}(rh, t, s) = H_{Demand}(t, s) \quad ; \forall t, s \quad ; \quad \lambda_H(t, s) \quad (38)$$

2 Power and heat offer limitations:

Accepted offers of ILEHM participants, including the EH and its power and heat rivals, should be lower than their submitted power and heat offers to the market, as shown in Eqs (39) to (42). μ represents dual variables of LL's non-equality constraints.

$$0 \leq q_p(t, s) \leq Q_p(t) \quad ; \forall t, s \quad ; \quad \mu_1(t, s), \mu_2(t, s) \quad (39)$$

$$0 \leq q_H(t, s) \leq Q_H(t) \quad ; \forall t, s \quad ; \quad \mu_3(t, s), \mu_4(t, s) \quad (40)$$

$$0 \leq q_{RP}^{\min}(rp) \leq q_{RP}(rp, t, s) \leq q_{RP}^{\max}(rp) \quad ; \forall rp, t, s \quad ; \mu_5(rp, t, s), \mu_6(rp, t, s) \quad (41)$$

$$0 \leq q_{RH}^{\min}(rh) \leq q_{RH}(rh, t, s) \leq q_{RH}^{\max}(rh) \quad ; \forall rh, t, s \quad ; \mu_7(rh, t, s), \mu_8(rh, t, s) \quad (42)$$

The set of decision variables related to LL is represented as follows:

$$\begin{aligned} \Delta^{LL} = \{ & q_{RP}(rp, t, s), q_{RH}(rh, t, s), q_p(t, s), q_H(t, s), \\ & \lambda_p(t, s), \lambda_H(t, s), \mu_1(t, s), \mu_2(t, s), \mu_3(t, s), \\ & \mu_4(t, s), \mu_5(rp, t, s), \mu_6(rp, t, s), \mu_7(rh, t, s), \\ & \mu_8(rh, t, s) \} \end{aligned}$$

Reformulation of the Bi-level Problem to a Single-level Problem

Since the LL of the presented framework is linear and continuous, it is a convex problem. As a result, Karush-Kuhn-Tucker (KKT) conditions can be used to reformulate the bi-level model to a single-level mathematical program with equilibrium constraints (MPEC). To this end, the LL problem can be substituted with its KKT conditions. The formulation of the bi-level problem and their transformation to MPEC using KKT conditions are provided in [32] with great detail. After developing the Lagrange function of the LL, the KKT conditions associated with it that have been demonstrated from Eq (43) to Eq (54) are replaced with the LL problem.

1 Stationary constraints:

Table 2
Technical characteristics of EH's power and heat units.

CHP					
# Unit	P_{CHP}^{min}	P_{CHP}^{max}	η_{CHP}^E	η_{CHP}^H	HPR
1	0.5 (MW)	4.2 (MW)	0.45	0.55	1.0
GFG					
# Unit	P_{GFG}^{min}	P_{GFG}^{max}	η_{GFG}^E		
1	0.25 (MW)	2.5 (MW)	0.75		
WT, PV, ST					
# Unit	P_{WT}^{max}	# Unit	$P_{PV}^{max}, H_{SV}^{max}$		
1	2.4 (MW)	1	3.0, 2.0 (MW)		

$$\lambda_{RP}(rp, t, s) - \lambda_P(t, s) - \mu_5(rp, t, s) + \mu_6(rp, t, s) = 0 \quad ; \forall rp, t, s \quad (43)$$

$$\lambda_{RH}(rh, t, s) - \lambda_H(t, s) - \mu_7(rh, t, s) + \mu_8(rh, t, s) = 0 \quad ; \forall rh, t, s \quad (44)$$

$$\alpha_P(t) - \lambda_P(t, s) - \mu_1(t, s) + \mu_2(t, s) = 0 \quad ; \forall t, s \quad (45)$$

$$\alpha_H(t) - \lambda_H(t, s) - \mu_3(t, s) + \mu_4(t, s) = 0 \quad ; \forall t, s \quad (46)$$

2 Complementary constraints:

$$0 \leq q_P(t, s) \perp \mu_1(t, s) \geq 0 \quad ; \forall t, s \quad (47)$$

$$0 \leq [Q_P(t) - q_P(t, s)] \perp \mu_2(t, s) \geq 0 \quad ; \forall t, s \quad (48)$$

$$0 \leq q_H(t, s) \perp \mu_3(t, s) \geq 0 \quad ; \forall t, s \quad (49)$$

$$0 \leq [Q_H(t) - q_H(t, s)] \perp \mu_4(t, s) \geq 0 \quad ; \forall t, s \quad (50)$$

$$0 \leq [q_{RP}(rp, t, s) - q_{RP}^{min}(rp)] \perp \mu_5(rp, t, s) \geq 0 \quad ; \forall rp, t, s \quad (51)$$

$$0 \leq [q_{RP}^{max}(rp) - q_{RP}(rp, t, s)] \perp \mu_6(rp, t, s) \geq 0 \quad ; \forall rp, t, s \quad (52)$$

$$0 \leq [q_{RH}(rh, t, s) - q_{RH}^{min}(rh)] \perp \mu_7(rh, t, s) \geq 0 \quad ; \forall rh, t, s \quad (53)$$

$$0 \leq [q_{RH}^{max}(rh) - q_{RH}(rh, t, s)] \perp \mu_8(rh, t, s) \geq 0 \quad ; \forall rh, t, s \quad (54)$$

Therefore, the presented bi-level problem is transformed into a single-level problem, and its objective function is the objective function of the UL problem, Eq (1), with constraints of Eqs (2) to (35) and (43) to (54).

Linearization of Non-linear Terms

The existence of non-linearity sources in the final MPEC of the proposed bi-level problem, including terms $q_P(t, s) \cdot \lambda_P(t, s)$, $q_H(t, s) \cdot \lambda_H(t, s)$, and complementary constraints in Eqs (47)-(54) makes the MPEC problem nonlinear. To linearization the non-linear terms following procedures are applied.

1 Linearization of complementary constraints:

The Big-M method is utilized in this study for the linearization of complementary constraints [33]. The following set of equations, in which U is an auxiliary binary variable and M is a very large number, are replaced to non-linear complementary constraints.

$$\text{If } 0 \leq \tau \perp v \geq 0 \Rightarrow \begin{cases} \tau \leq M \cdot U \\ v \leq M \cdot (1 - U) \end{cases} \quad (55)$$

2 Linearization of the non-linear terms in the UL's objective function:

The Strong Duality Theorem (SDT) is used for the linearization of the non-linear terms existing in the UL's objective function [34]. According to this theory, in a convex problem, the value of the optimal point in primal and dual problems is the same. As a result, the dual of the LL's objective function is written as Eq (56).

Table 3
Technical characteristics of EH's Pth technologies.

EHP			
# Unit	H_{EHP}^{min}	H_{EHP}^{max}	CP_{EHP}
1	0.0 (MW)	1.0 (MW)	2.5
EB			
# Unit	P_{EB}^{min}	P_{EB}^{max}	η_{EB}^H
1	0.0 (MW)	2.0 (MW)	0.8

Table 4
Technical characteristics of EH's energy storage systems.

ESS						
# Unit	$E_{ESS}^{min}, E_{ESS}^{max}$	$P_{ESS}^{ch, min}, P_{ESS}^{ch, max}$	$P_{ESS}^{dch, min}, P_{ESS}^{dch, max}$	$\eta_{ESS}^{ch}, \eta_{ESS}^{dch}$		
1	0.4, 4 (MWh)	0.0, 1.0 (MW)	0.0, 1.0 (MW)	0.95, 0.95		
HSS						
# Unit	$E_{HSS}^{min}, E_{HSS}^{max}$	$H_{HSS}^{ch, min}, H_{HSS}^{ch, max}$	$H_{HSS}^{dch, min}, H_{HSS}^{dch, max}$	$\eta_{HSS}^{ch}, \eta_{HSS}^{dch}, \eta_{HSS}^{sb}$		
1	0.0, 3.0 (MWh)	0.0, 2.0 (MW)	0.0, 2.0 (MW)	0.98, 0.98, 0.95		

$$\begin{aligned} & \text{Min} \sum_{rp \in RP} q_{RP}(rp, t, s) \cdot \lambda_{RP}(rp, t, s) \\ & + \sum_{rh \in RH} q_{RH}(rh, t, s) \cdot \lambda_{RH}(rh, t, s) \\ & + q_P(t, s) \cdot \alpha_P(t) + q_H(t, s) \cdot \alpha_H(t) \\ & = P_{Demand}(t, s) \cdot \lambda_P(t, s) + H_{Demand}(t, s) \cdot \lambda_H(t, s) \\ & - Q_P(t) \cdot \mu_2(t, s) - Q_H(t) \cdot \mu_4(t, s) \\ & + \sum_{rp \in RP} [q_{RP}^{min}(rp) \cdot \mu_5(rp, t, s) - q_{RP}^{max}(rp) \cdot \mu_6(rp, t, s)] \\ & + \sum_{rh \in RH} [q_{RH}^{min}(rh) \cdot \mu_7(rh, t, s) - q_{RH}^{max}(rh) \cdot \mu_8(rh, t, s)] \quad ; \forall t, s \quad (56) \end{aligned}$$

From Eqs (45) and (47):

$$\alpha_P(t) \cdot q_P(t, s) - \lambda_P(t, s) \cdot q_P(t, s) + \mu_2(t, s) \cdot q_P(t, s) = 0 \quad (57)$$

From Eqs (46) and (49):

$$\alpha_H(t) \cdot q_H(t, s) - \lambda_H(t, s) \cdot q_H(t, s) + \mu_4(t, s) \cdot q_H(t, s) = 0 \quad (58)$$

From Eqs (57) and (48):

$$\alpha_P(t) \cdot q_P(t, s) = \lambda_P(t, s) \cdot q_P(t, s) - Q_P(t) \cdot \mu_2(t, s) \quad (59)$$

From Eqs (58) and (50):

$$\alpha_H(t) \cdot q_H(t, s) = \lambda_H(t, s) \cdot q_H(t, s) - Q_H(t) \cdot \mu_4(t, s) \quad (60)$$

By replacing Eqs (59) and (60) in the LL's dual problem, the linear form of UL problem's non-linear terms can be achieved, shown in Eq (61).

$$\begin{aligned} & \lambda_P(t, s) \cdot q_P(t, s) + \lambda_H(t, s) \cdot q_H(t, s) \\ & = P_{Demand}(t, ds) \cdot \lambda_P(t, s) + H_{Demand}(t, ds) \cdot \lambda_H(t, ds) \\ & - \sum_{rp \in RP} q_{RP}(rp, t, ds) \cdot \lambda_{RP}(rp, t, ds) - \sum_{rh \in RH} q_{RH}(rh, t, ds) \cdot \lambda_{RH}(rh, t, ds) \\ & + \sum_{rp \in RP} [q_{RP}^{min}(rp) \cdot \mu_5(rp, t, s) - q_{RP}^{max}(rp) \cdot \mu_6(rp, t, s)] \\ & + \sum_{rh \in RH} [q_{RH}^{min}(rh) \cdot \mu_7(rh, t, s) - q_{RH}^{max}(rh) \cdot \mu_8(rh, t, s)] \quad (61) \end{aligned}$$

Case Study and Simulation Results

In the following of the article, a typical case study is presented to

Table 5
Probabilities of each reduced scenario

# Scenario	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
Probability	0.042	0.064	0.091	0.143	0.184	0.161	0.143	0.084	0.056	0.033

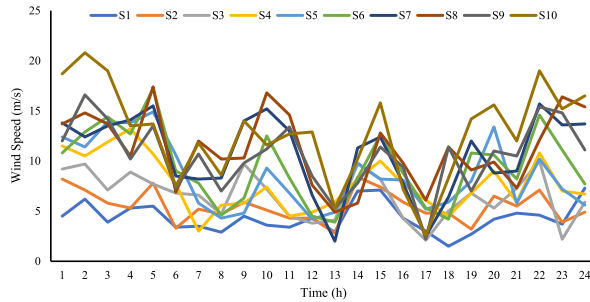


Fig. 4. Wind speed in different scenarios.

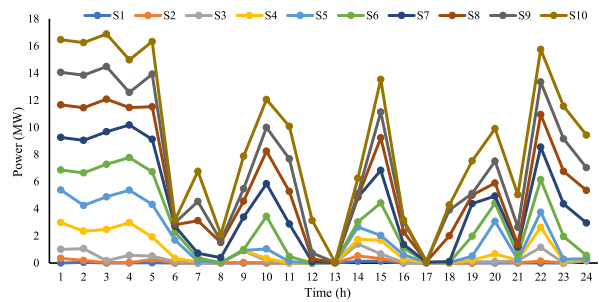


Fig. 6. WT's produced power in different scenarios.

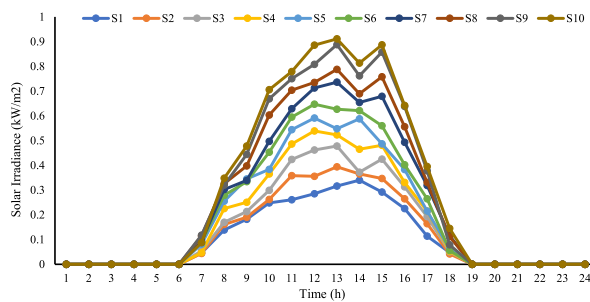


Fig. 5. Solar Irradiance in different scenarios.

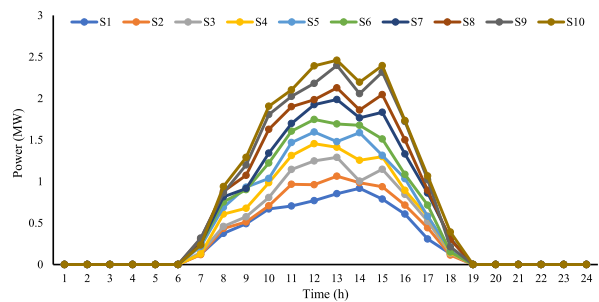


Fig. 7. PV's produced power in different scenarios.

demonstrate the effectiveness of the proposed methodology for the optimal participation of a strategic EH in an ILEHM, considering the stochastic behavior of power and heat rivals in the market, as well as management of this entity's risk via SOSD risk-management method.

Input data

As shown in Fig. 1, the studied PM EH consists of various units namely CHP, GFG, WT, PV, ST, ESS, HSS, EB, and EHP. Technical specifications of these components are provided in Tables 2, 3, and 4.

To model the uncertainty of stochastic parameters, including wind speed, solar irradiance, ILEHM's power and heat demands, as well as offers of the strategic EH's power and heat rivals, in the proposed model, 10 scenarios are considered, and their associated probabilities are represented in Table 5.

Furthermore, wind speed and solar irradiance in these 10 scenarios as well as the available WT, PV, and ST's produced power and heat are represented in Figs. 4, 5, 6, 7, and 8, respectively. The data relating to these figures are provided in Tables 1, 2, 3, 4, and 5, respectively, in the supplement material.

As described in section 2, in the proposed framework, the existing uncertainties in the ILEHM have been modeled as well. In this context, power and heat demand of the designed local market in 10 scenarios are displayed in Fig. 9 and Fig. 10, respectively. The data relating to these figures are provided in Tables 6 and 7, respectively, in the supplement material.

On the other hand, in the ILEHM, it is assumed that the strategic EH has 4 power rivals and 3 heat rivals as price-taker players in the market. For the sake of space, only the submitted offers of RP3 and RH3 in 10 scenarios are depicted in Fig. 11 and Fig. 12, respectively. The data

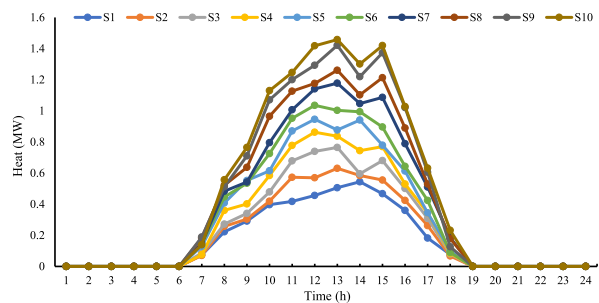


Fig. 8. ST's produced heat in different scenarios.

relating to these figures are provided in Tables 8, 9, 10, and 11, respectively, in the supplement material.

Risk-neutral Scheduling of EH considering SILEHM

In this part of the paper, the results of the obtained risk-neutral scheduling of the studied PM EH in the presence of the SILEHM are represented. In this regard, the obtained quantity and price offers of the EH in the integrated power and heat market are shown in Fig. 13. The EH's offers to the local market depend on various parameters, including power and heat rivals' offers, market's power and heat demands, as well as EH's local productions, which can be analyzed in different scenarios. Moreover, the power and heat offers of the strategic EH in the market are dependent on each other due to coupling elements between the power

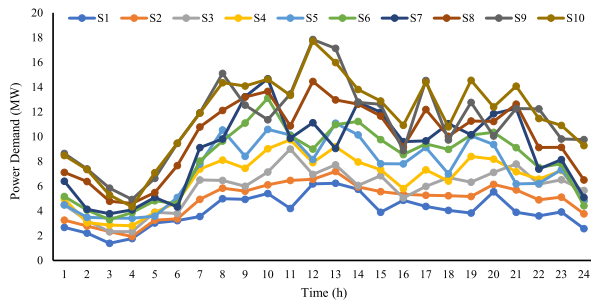


Fig. 9. ILEHM's power demand in different scenarios.

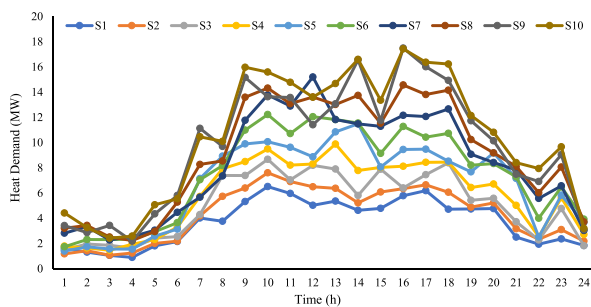


Fig. 10. ILEHM's heat demand in different scenarios.

Table 6
Submitted power quantity and price offers in scenario 1 and at hour 16.

	Submitted Quantity (MW)	Submitted Price (€/MWh)
EH	0	0
RP1	2.2	126.0
RP2	1.3	60.9
RP3	2.0	43.8
RP4	1.3	45.1

Table 7
Submitted heat quantity and price offers in scenario 1 and at hour 13.

	Submitted Quantity (MW)	Submitted Price (€/MWh)
EH	1.2	23.8
RH1	2.3	67.9
RH2	2.1	84.1
RH3	1.8	59.1

and heat sectors via PtH technologies. Therefore, analyzing the EH's offers to the market is a challenging task. In the following, the output results of scenario 5 are explained in more detail to better clarify the relation of different parameters in the scheduling and offering process of the EH.

The power dispatch of the EH's available resources in scenario 5 is depicted in Fig. 14. In this figure, the power produced by resources is represented in the DA and RT stages. Accordingly, the power production of GFG and CHP units is equal in all scenarios, including scenario 5. However, the operator of the EH could utilize its dispatchable resources, including PtH and storage units, to adjust its offers in the RT stage in each scenario. Additionally, this figure shows the dispatchable units' involvement in the power supply. According to the obtained results, when the power production of the EH is higher than its accepted power offers, the EH's operator transfers a part of its surplus power to the heat sector via PtH technologies, i.e., EB and EHP, or stores excess energy in the ESS.

In a similar way, the heat dispatch of the EH's resources in the

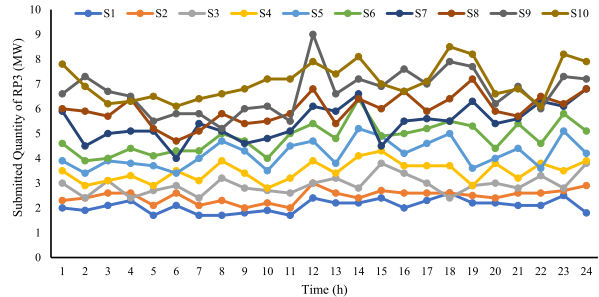
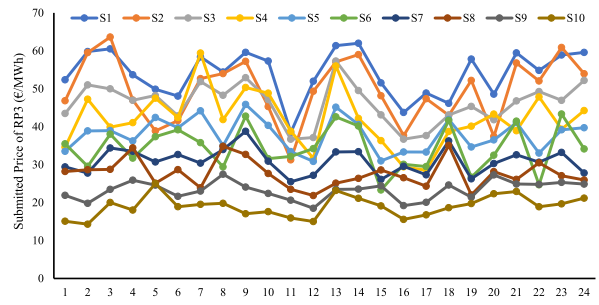


Fig. 11. Submitted price and quantity offer of RP3 in different scenarios.

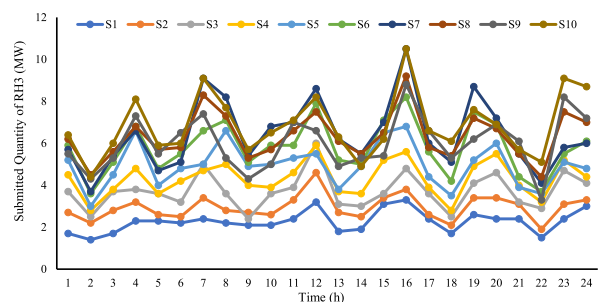
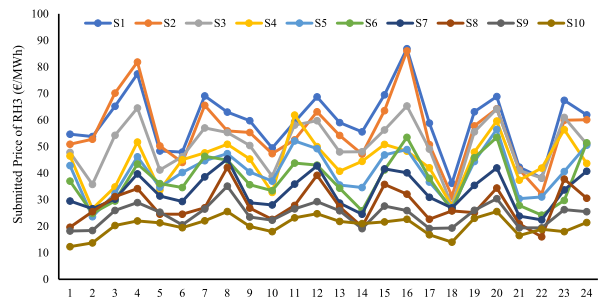


Fig. 12. Submitted price and quantity offers of RH3 in different scenarios.

studied day and in scenario 5 is shown in Fig. 15. In this figure, the CHP's produced heat is equal in all scenarios since it is one of the DA stage variables in the proposed scheduling model. In addition to this, the operator of the EH has the capability to adjust the production of heat resources based on its offers in the ILEHM by utilizing the existing flexible units. For instance, the EH's resources produce more power than its accepted offer by the market in hours 21 and 22, so the operator stores the excess produced power in HSS, which is discharged immediately at hours 23 and 24.

To investigate the integrated local market-clearing process, the EH's accepted power offers in different scenarios are depicted in Fig. 16. On the other hand, the power market-clearing prices in the studied day and

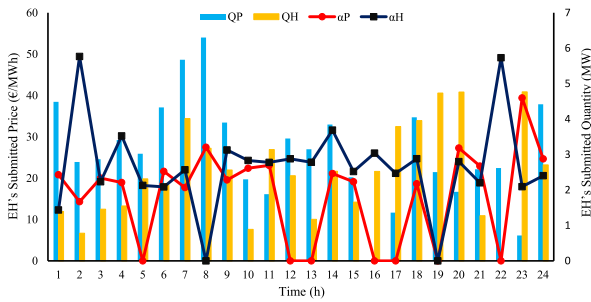


Fig. 13. EH's submitted price and quantity offers in the ILEHM.

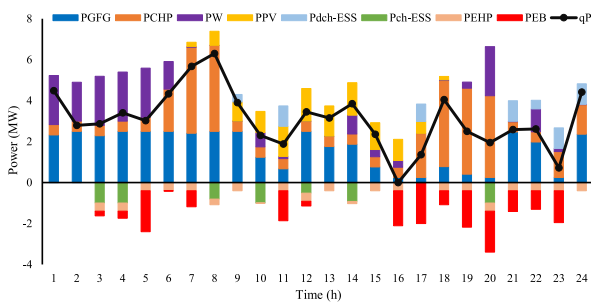


Fig. 14. EH's power balance in scenario 5.

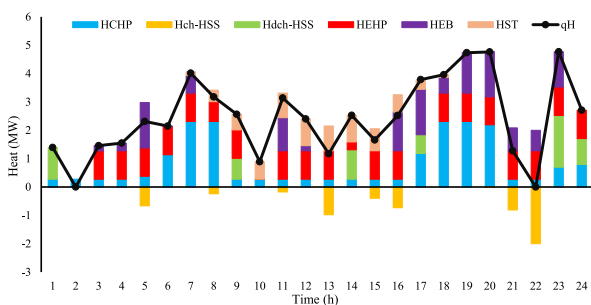


Fig. 15. EH's heat balance in scenario 5.

in the considered scenarios are represented in Fig. 17.

By comparing output results in Fig. 16 and Fig. 13, it is evident that the EH's DA submitted offers are equivalent to its accepted offers in the ILEHM in the middle hours of the studied day. However, in the early and late hours of the day, i.e., off-pick hours, the operator of the ILEHM accepts only some parts of the EH's submitted offers.

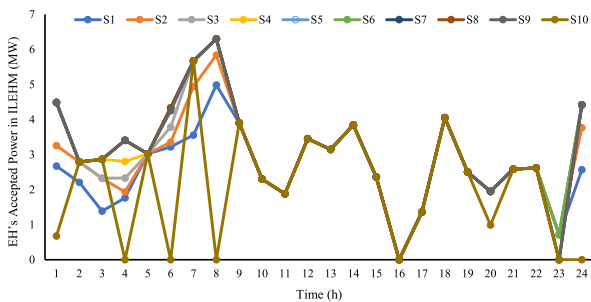


Fig. 16. EH's accepted power offers in the ILEHM and in different scenarios.

As shown in Fig. 17, in some scenarios and hours of the day, the market operator faces peak prices in the ILEHM. For instance, at hour 16 and in scenario 1, the power price of the market is 126 €/MWh. To evaluate this matter, submitted power and price offers of the market players in this scenario and hour are investigated. According to Fig. 9, the total power demand of the ILEHM at this hour is equal to 4.9 MW. Also, the submitted power and price offers of the market players in this scenario and at this hour are represented in Table 6. Based on the information in this Table, whole submitted offers of RP2, RP3, and RP4, which are equal to 4.6 MW, are accepted by the market; as a result, RP1, with a submitted price offer of 126, becomes a marginal producer and determines the market's power price.

Similarly, in the heat sector, accepted heat offers of the EH in 10 different scenarios are shown in Fig. 18. Like the power sector, in the middle hours of the day, the submitted heat offers of the EH is equal to the accepted heat offers by the ILEHM; however, a partial of submitted heat offers of the EH is accepted in the earlier and late hours of the studied day.

Fig. 19 demonstrates the heat market-clearing prices in all scenarios for the studied day. Based on Fig. 19, the maximum heat market price is 84.1 €/MWh at hour 13 and in scenario 1, where the submitted heat offers of market players are represented in Table 7.

Based on Fig. 10, the total heat demand of the ILEHM at this hour is equal to 5.4 MW. Hence, the cheapest submitted heat offers to the market, which are related to offers of EH, RH1, and RH3, are accepted to satisfy 5.3 MW of the heat demand. Consequently, RH2, with a submitted price offer of 84.1 €/MWh, becomes a marginal producer and determines the heat market-clearing price at hour 13.

Finally, Fig. 20 and Fig. 21 illustrate the accepted power and heat offers of the EH's RP3 and RH3 in different scenarios. The accepted power and heat offers of the mentioned rivals are dependent on power and heat market-clearing prices, which are reported in Fig. 17 and Fig. 19, and the amount of submitted offers in the market, Fig. 11 and Fig. 12. To illustrate, if the submitted price offers of the rivals is lower than the market-clearing prices, their total submitted quantities are accepted. In addition, in the case that price offers become marginal, the partial quantity offers are accepted in the market.

Risk Management of EH

The main aim of risk-management methods is to ensure the operator will not encounter lower defined amounts of profit. In other words, the amount of profit in the worst scenario will get better while the obtained profit in the best scenario will be decreased. Based on common risk management methods, like CVaR, it is impossible to determine the amount of the profit in the worst scenario based on the operator's preferences. However, using SOSD constraints as a risk management method enables the operator to directly decide the amount of profit in the worst scenario. Notably, the most critical point in imposing SOSD constraint is selecting the feasible region, in which benchmark scenarios are determined based on the operator's preference. By defining

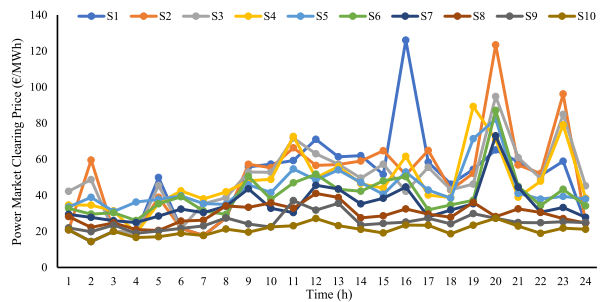


Fig. 17. Power market-clearing prices in different scenarios.

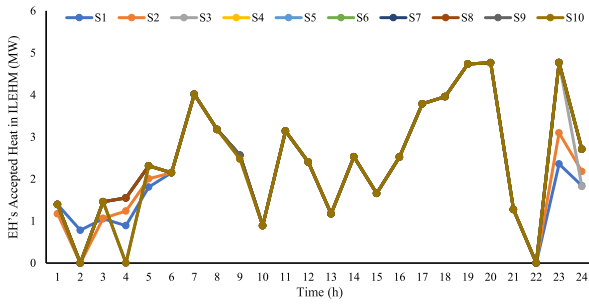


Fig. 18. EH's accepted heat offers in the ILEHM and in different scenarios.

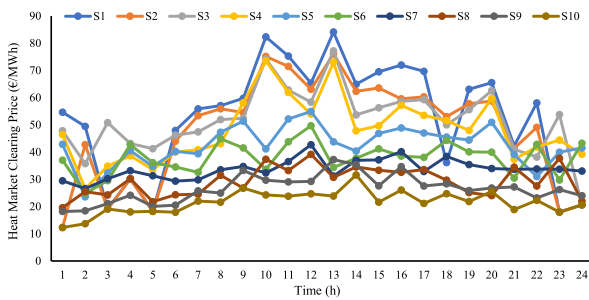


Fig. 19. Heat market-clearing prices in different scenarios.

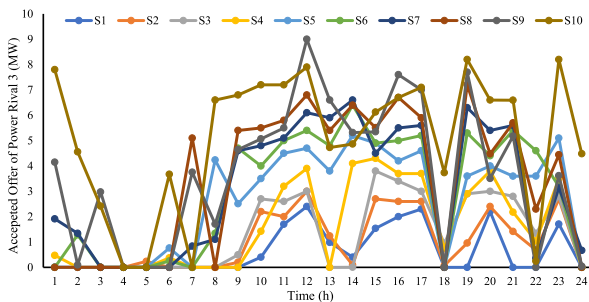


Fig. 20. Accepted power offers of RP3 in different scenarios.

benchmark scenarios out of the feasible region, the optimal problem will be infeasible. Both the risk-neutral problem and the risk-averse problem considering the CVaR risk management method with $\beta = 1$ and $\alpha = 99\%$ are solved to determine the feasible region of imposing benchmark scenarios. Then, optimal profit cumulative distribution functions (CDFs) of each problem are obtained considering the probability of obtained profit in each scenario. Left and right-hand-side borders of a feasible region of imposing benchmark scenarios are determined based on the amount of profit in the worst scenarios, which is illustrated in Fig. 22.

According to the EH operator's risk preference, the number of benchmark scenarios, their prefixed values, and their probabilities are determined. The CDFs of applied benchmarks to the problem, including one-scenario, two-scenario, and four-scenario benchmarks, are represented in Fig. 23. Imposing more benchmark scenarios provides the operator with better risk management; however, it increases the computational burden of the problem.

The one-scenario benchmark and resulting corresponding profit distribution are represented in Fig. 24. As evident in this figure, the amount of profit in the worst scenario is adjusted to proceed with the predefined value of the one-scenario. Nevertheless, the amount of profit

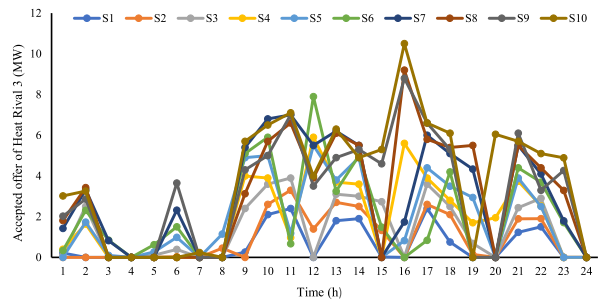


Fig. 21. Accepted heat offers of RH3 in different scenarios.

in the best scenario is decreased considerably.

The two-scenario benchmark and resulting corresponding profit distribution are depicted in Fig. 25. As shown in this figure, not only is the amount of profit in the worst scenario adjusted to exceed the predefined value of two-scenario benchmarks but also the amount of profit in the best scenario is approached to the amount of profit in the risk-neutral problem, resulting in increasing expected profit.

The four-scenario benchmark and obtained profit distribution resulting from imposing it are demonstrated in Fig. 26. The amount of profit in the worst scenario is determined to exceed the least amount of the four-scenario benchmark. Notably, the amount of the profit in the best scenario gets closer to the amount of profit in the risk-neutral problem.

To clarify the difference between CVaR and SOSD risk-management methods based on Fig. 22, imposing CVaR risk-management results in defining the profit in the worst scenario based on the input data of the risk measurement, which is 1737 € and reducing the amount of the profit in the best scenario, which is 2435 €, which is far less than the amount of the profit in the best scenario in the risk-neutral approach, 4172 €. Based on the results in Fig. 24, defining a one-scenario benchmark at 1690 € forces the profit in the worst scenario to go higher than this point while the profit in the best scenario is 2816 €, which is higher than that of in the CVaR method. Additionally, as seen in the results of Figs. 24 and 25, increasing the benchmark scenarios results in efficient risk management of the problem since the profit in the best scenario has not considerably reduced.

Conclusion

The presented article aimed to offer an efficient bi-level risk-averse scheduling method for the optimal participation of a strategic EH in the ILEHM, considering the uncertainties dominated in the local market. The UL of the proposed framework consisted of a two-stage stochastic model, in which the first stage determined the EH's submitted power and heat offers to the ILEHM as well as the operating points of its CHP and GFG units, while the second stage determined the operating points

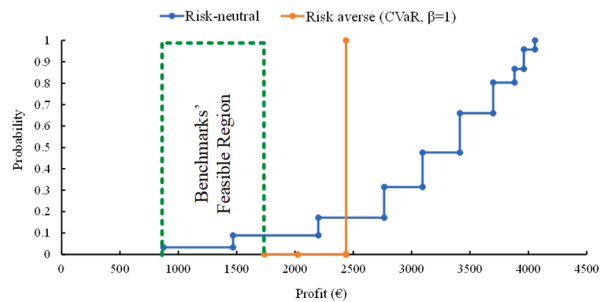


Fig. 22. Definition of benchmark's feasible region.

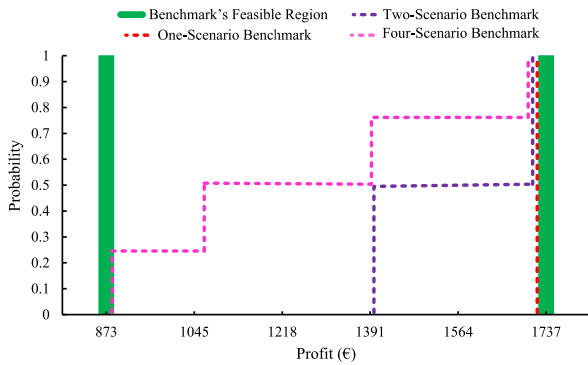


Fig. 23. Imposed benchmark scenarios.

of the EH's flexible PtH and storage units. At the same time, the local market-clearing process was addressed in the LL of the model to minimize the system's operation costs. In the raised framework, the uncertainty in the behavior of EH's power and heat rivals, as well as the market's power and heat demands, were also considered. The results indicate that EH's owner can adjust its DA offers in RT by using flexible units, such as ESS, EHP, HSS, and EB, in both power and heat forms, bringing more flexibility to EH's operator. Additionally, the results showed that market SILEHM clearing price for power and heat is associated with different factors, including SILEHM's forecasted power and heat demand, market participants' submitted price, and quantity offers in both electricity and heat markets. For another point, it was observed that in the cases where the submitted price offers of the participants were lower than the market clearing prices, the total submitted quantity offers associated with them were accepted. In contrast, when the price offers became marginal, a part of their submitted quantity offers was accepted in the market.

On the other hand, SOSD constraints were added as a risk measure to the considered methodology to mitigate the EH's risk through participation in the ILEHM. The most challenging matter in imposing SOSD constraints as a risk measure was determining the feasible region for defining the value and probabilities of benchmark scenarios. To this end, the CVaR risk measure was used to determine the feasible region and guarantee the feasibility of the problem. The risk-averse problem was

solved by considering different benchmark scenarios. According to the obtained results, increasing the number of benchmark scenarios can increase the expected profits while controlling the amount of expected profit in the worst scenario.

For future work, the authors intend to investigate the impact of the PM EH's participation in SILEHM, aiming to maximize its benefit while increasing the resiliency in the distribution network.

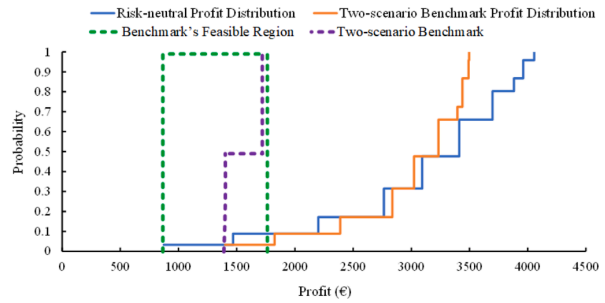


Fig. 25. Two-Scenario benchmark.

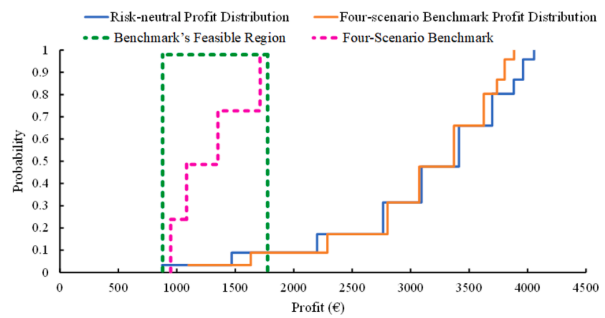


Fig. 26. Four-Scenario benchmark.

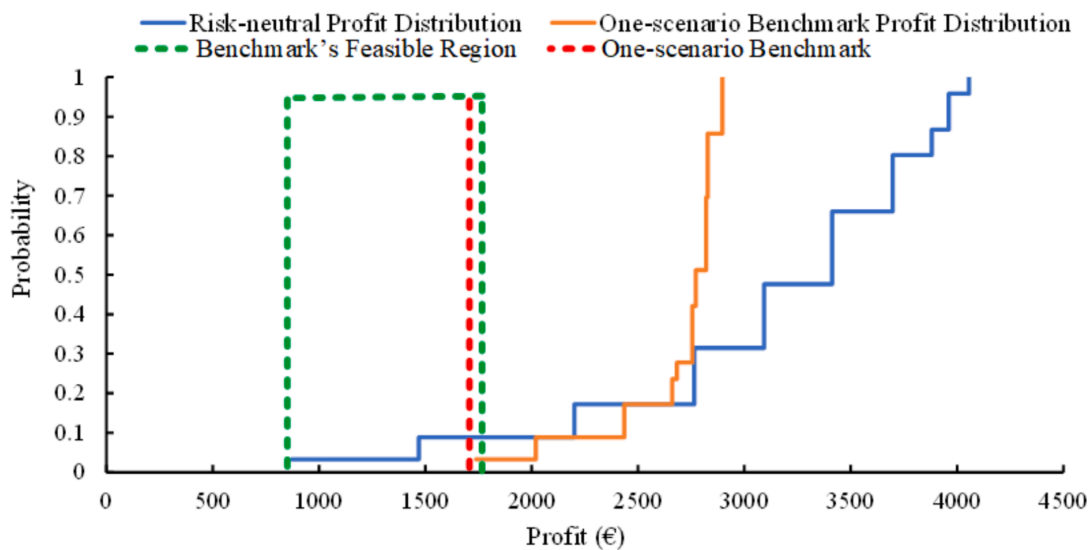


Fig. 24. One-Scenario benchmark.

CRedit authorship contribution statement

Saba Norouzi: Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Mojtaba Dadashi:** Writing – review & editing, Visualization, Validation, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Sara Haghifam:** Writing – review & editing, Visualization, Validation, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Hannu Laaksonen:** Writing – review & editing. **Kazem Zare:** Writing – review & editing, Supervision, Project administration, Investigation, Formal analysis.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.ref.2025.100689>.

Data availability

Data will be made available on request.

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