D5.5 – Comparative Analysis of Market Designs

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Author(s) information (alphabetical)

Name	Organisation	Email
António Couto	LNEG	antonio.couto@lneg.pt
Dawei Qiu	Imperial College	d.qiu15@imperial.ac.uk
Evelyn Sperber	DLR	evelyn.Sperber@dlr.de
Fernando Lezama	ISEP	flz@isep.ipp.pt
Goran Strbac	Imperial College	g.strbac@imperial.ac.uk
Helleik Syse	bitUnitor	helleik@bitunitor.com
Hugo Algarvio	LNEG	hugo.algarvio@lneg.pt
Johannes Kochems	DLR	johannes.kochems@dlr.de
Ni Wang	TNO	ni.wang@tno.nl
Nikolaos Chrysanthopoulos	Imperial College	n.chrysanthopoulos@imperial.ac.uk
Noelia Martin Gregorio	TNO	noelia.martingregorio@tno.nl
Ricardo Faia	ISEP	rff@isep.ipp.pt
Silke Johanndeiter	EnBW	s.johanndeiter@enbw.com

Acknowledgements/Contributions

Name	Organisation	Email
Amelie Schmidt	EnBW	amelie.schmidt@enbw.com
Gabriel Santos	ISEP	gjs@isep.ipp.pt
Niina Helistö	VTT	niina.Helisto@vtt.fi
Zita Vale	ISEP	zav@isep.ipp.pt

Document information

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1.0	30/11/2024	Public	This report details the analysis of market performance as a whole, including the assessment of interaction / cooperation between multiple markets of different scales running simultaneously.

Review and approval

Prepared by	Reviewed and approved by
Fernando Lezama Pedro Faria	Ana Estanqueiro

Disclaimer

Executive Summary

This deliverable presents the overall results obtained by TradeRES project from the perspective of the application of the market models developed to the different case studies designed for different scales of electricity trading. It assesses the connection, interaction and cooperation between the different market scales using (key) market performance indicators.

Building upon previous deliverables of the project, namely, D5.1, D5.2, D5.3, and D5.4, that examined specific market spatial scales, from local energy communities to nation-al/regional and Pan-European wholesale markets, this report brings these findings together to assess how different market designs address different market properties and performance in terms of sustainability, economic efficiency, and variable renewable energy sources integration. Recognizing that each market scale operates under unique policy settings, assumptions, and modeling frameworks, this analysis acknowledges the challenges and limitations of direct comparisons while drawing broad in-sights into market trends and contrasts

The analysis relies on the TradeRES scenarios—Conservative (S1), Flexible (S2), Variable (S3), and Radical (S4)—which depict varying levels of flexibility, generation capacity assumptions, and vRES integration. These scenarios provided the foundation for simulations across case studies:

- **Case Study A** focuses on local energy communities and their decentralized mechanisms for peer-to-peer trading and local energy self-sufficiency.
- **Case Study B** analyzes the Dutch market with emphasis on system adequacy and capacity mechanisms.
- **Case Study C** investigates the German market, exploring renewable energy remuneration schemes.
- **Case Study D** examines the Iberian market (Portugal and Spain), known as MIBEL (Mercado Ibérico de Electricidade), with attention to short-term efficiency and new designs like the Period-Ahead Market (PAM).
- **Case Study E** assesses Pan-European wholesale electricity markets under different interconnectivity levels.

These case studies employed different optimization and agent-based models tailored to their specific market contexts, allowing for the evaluation of market dynamics under near 100% renewable power systems. While direct one-to-one comparisons are limited by the diverse modeling assumptions and regulatory frameworks, this deliverable highlights key trends and challenges critical for designing resilient and adaptive electricity markets. Key findings from the holistic analysis with regard to the different case studies include:

Local and wholesale market dynamics:

- Focused on local interactions, local energy markets promote self-sufficiency and sustainability through mechanisms like peer-to-peer trading and dynamic pricing. For instance, in Case Study A, consumers **saved up to 24%** on electricity costs compared to baseline scenarios by participating in cooperative self-consumption schemes.

- Operating at a broader scale, wholesale markets optimize system reliability and cost efficiency. However, their centralized auctions and standardized pricing structures lack the local adaptability offered by local energy markets.
- Combining local energy markets with wholesale markets can harness local adaptability while maintaining broader system stability. Case studies demonstrated that such integration could enhance energy resilience and reduce overall costs. For example, local energy communities participating in wholesale markets as aggregators achieved **11–13%** reductions in electricity bills.

Environmental and economic impacts based on market performance indicators:

- Regarding curtailment trends, market-based curtailment emerged as a key challenge for vRES integration. For instance, in Germany (Case Study C), offshore wind curtailment reached **up to 18%,** reflecting the absence of balancing market participation and specific support mechanisms. Conversely, MIBEL's variable renewable energy *strategic business* approach reduced curtailment **to nearly 0%** in flexible scenarios by **allocating 20%** of variable renewable energy forecasts to balancing services.
- Economic indicators such as market-based cost recovery reveal that demand-side flexibility and hydrogen prices assumptions were critical determinants of market performance. In MIBEL (Case Study D), flexible scenarios (S2, S4) achieved the lowest day-ahead market prices (as low as **€23/MWh** in Spain) and highest cost recovery rates, demonstrating the value of system adaptability.
- Regarding cross-case observations, hydrogen prices significantly influenced system costs and electricity prices across cases. For example, the Dutch market (Case Study B) showed that the volume-weighted average day-ahead electricity prices increases from **€39/MWh to €60/MWh** due to higher hydrogen costs. Similarly, higher flexibility in German scenarios reduced reliance on costly generation, improving market stability.

New and Alternative Market Design Options:

- The novel Period-Ahead Market (PAM) in the MIBEL case study (an alternative to the well-stablished single day-ahead coupling) demonstrated significant improvements in system efficiency, price stability, and reduced curtailment compared to traditional day-ahead markets. For instance, PAM reduced total system costs by up to **50% in Spain** compared to the day-ahead market, primarily by leveraging improved forecast accuracy and shorter lead times (6 hours vs. 12–36 hours). In addition to PAM, the MIBEL case study also explored the integration of intraday and balancing markets. These markets allowed renewable energy producers to actively adjust their participation, reducing imbalances and associated penalties while improving renewable energy integration. For example, allocating 20% of variable renewable energy forecasts (in the *strategic business simulations*) to balancing services in the MIBEL case showed a marked improvement in system flexibility and reduced overall curtailment. Besides, cross-border price differentials decreased by up to **200 hours per year**, enhancing market uniformity. Thus, the holistic analysis show that PAM's design supported renewable energy players in recovering costs through diversified revenue streams, reducing dependency on conventional support mechanisms like Contract for Differences (CfD).

- Support mechanisms like CfD remain essential to de-risk investments and stabilize market-based cost recovery for variable renewable energy. However, different CfD designs, such as one-way and two-way CfD, introduce trade-offs between cost recovery, system efficiency, and curtailment levels. For instance, in the German case, two-way CfD increased curtailment but improved cost recovery for wind and solar PV. Conversely, production-independent financial CfD showed promise for reducing system distortions and promoting system-friendly dispatch patterns. Regarding investment risks, both the German and Pan-European cases highlighted the importance of aligning CfD strike prices with market realities to avoid under- or over-recovery of costs. For instance, discrepancies between ex-ante strike prices and ex-post revenues led to excess recovery in one-way CfD.

Effects of Interconnectivity:

- Interconnectivity between market scales impacts domestic investments, electricity prices, and market-based cost recovery. For instance, regarding domestic investments, scenarios with reduced interconnectivity led to higher domestic photovoltaic systems and battery installations in Germany, but increased cannibalization effects on market prices. On the other hand, in terms of pricing dynamics, in the MIBEL case higher interconnectivity reduced price differences between Portugal and Spain, contributing to a more cohesive regional market. However, lower interconnectivity in Germany drove up hydrogen turbine usage, increasing prices in high-demand scenarios.

It is important to recall that the findings reported in this document, either in each case study or the holistic analysis, also show the critical role of market assumptions in shaping outcomes and influencing market performance indicators. These assumptions highlight the inherent challenges in direct cross-case comparisons and emphasize the need for adaptive market designs that can accommodate diverse regional and temporal conditions.

Building on these insights, the final remarks of the document reaffirm the importance of designing nuanced electricity markets capable of balancing local adaptability with system-wide efficiency. Future work must address several critical areas to refine electricity market designs and ensure their effectiveness in a near 100% renewable energy landscape. A key area of focus will be integrating local with wholesale markets to combine the adaptability of localized systems with the reliability of regional networks. This integration will require further exploration into operational coordination mechanisms, dynamic tariff structures, and regulatory frameworks that incentivize local investments in generation and storage. Examining the long-term impacts of real-time pricing and cooperative self-consumption on costs and renewable energy sources integration will also provide valuable insights.

Demand-side flexibility and the evolving hydrogen economy are critical factors shaping market outcomes, as highlighted by the strong influence of flexibility levels and hydrogen prices in this deliverable. Future studies should explore mechanisms to enhance demand-side participation, such as load-shifting technologies and dynamic pricing, while investigating the interplay between hydrogen production, storage, and utilization in electricity markets. Understanding the economic viability of hydrogen turbines under different interconnectivity and renewable penetration scenarios will be essential for designing adaptive energy systems.

The novel PAM design demonstrated potential for improving system efficiency, price stability, and renewable integration. However, additional research is needed to optimize its design and scalability. Shorter lead times between market closure and delivery, as well as the application of PAM in interconnected regional markets, could further enhance its effectiveness. Furthermore, integrating PAM with intraday and balancing markets has shown promising results in reducing imbalances and enhancing renewable energy participation, as observed in the MIBEL case study. Allocating renewable energy forecasts to balancing services significantly improved system flexibility, reduced curtailment, and diversified revenue streams for renewable energy producers. Similarly, support mechanisms like CfD must be refined to balance investment de-risking with cost-effectiveness. This includes evaluating variations in CfD structures and reducing ex-ante forecasting risks to ensure robust performance under diverse market conditions.

Interconnectivity emerged as a key factor influencing domestic investments, electricity prices, and market-based cost recovery. Further research should quantify the trade-offs between higher domestic investments and cross-border electricity flows under varying levels of interconnectivity. Advanced transmission technologies, such as dynamic line ratings, could play a significant role in achieving this balance. Additionally, exploring regional cooperation mechanisms will help enhance renewable integration and mitigate curtailment, particularly in areas with uneven resource distribution.

The modeling approaches used in TradeRES highlighted the importance of robust and harmonized methodologies for electricity market analysis. Integrating comprehensive balancing market simulations into existing models and harmonizing scenario definitions and market performance indicators calculations will improve the comparability and reliability of results. Developing standardized approaches to account for key assumptions, such as hydrogen price trajectories and demand flexibility levels, will also enhance the robustness of future studies.

The insights gained from D5.5 emphasize the need for adaptive market designs that can accommodate diverse regional and temporal conditions while supporting long-term sustainability goals. Tools like the *Market Design Web-Decision Tool* (Subtask 7.3.1 of the project), together with the different models within *WP 4 - Development of Open-access Market Simulation Models and Tools,* will play a critical role in empowering stakeholders to evaluate and compare market design options. These tools can bridge the gap between research findings and practical applications, enabling informed decision-making by policymakers, regulators, and market participants.

Finally, future developments should address emerging challenges such as the increasing energy demand, the integration of new technologies, and geopolitical shifts that may affect energy trade and cooperation. By addressing these areas, future work can build on the foundations laid by D5.5, advancing resilient and efficient market designs capable of meeting the challenges of high renewable sources integration across Europe and beyond.

Together, these efforts will support Europe's transition to resilient, efficient electricity markets capable of achieving near 100% renewable integration while balancing economic efficiency, sustainability, and system-wide stability.

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Acronyms

AMIRIS	Agent-based Market model for the Investigation of Renewable and Integrated energy Systems
BPRs	Balance Responsible Parties
CfD	Contracts For Differences
CP	Capacity Premium
DAHP	Day-Ahead Hourly Pricing
DAM	Day-Ahead Market
DAMP	Average Day-Ahead Monthly Pricing
EENS	Expected Energy Not Served
EOM	Energy Only Market
EU	European Union
EVs	Electric Vehicles
FLH	Full Load Hours
GCS	German Case Study
HP	Heat pump
IDM	Intra-Day Market
LEC	Local Energy Communities
LEM	Local Energy Market
LMPI	Local Market Performance Indicators
LOLE	Loss of Load Expectation
MASCEM	Multi-Agent System for Competitive Electricity Markets
MIBEL	Iberian Electricity Market
MMR	Mid-Market-Rate
MPFIX	Fixed Market Premium
MPI	Market Performance Indicators
MV	Market Value
OCGT	Open-cycle gas turbines
OPF	Optimal Power Flow
P2P	Peer-To-Peer
PAM	Period-Ahead Market
PEC	Pan-European Case Study
PV	Photovoltaic
RE-STrade	Multi-Agent Trading of Renewable Energy Sources
RTP	Real-Time Pricing
SDAC	Single Day-Ahead Coupling
SecR	Secondary Reserves
TOU	Time-Of-Use
TR	Tertiary Reserves
vRES	Variable Renewable Energy Sources
WAMP	Volume-Weighted Average Day-Ahead Electricity Prices

1. Introduction

The transformation of electricity markets to support high shares of variable renewable energy sources (vRES) requires a new market design, its economic modelling, including the additional power system flexibility needed to embed large shares of vRES generation. Within the TradeRES project, various market designs were evaluated across different spatial scales—from local energy communities to national/regional, and Pan-European wholesale markets—to study and understand how these configurations and scales can balance economic efficiency, environmental performance, and renewable integration. These analyses are grounded in four ~ 100% renewable energy power system scenarios designed within TradeRES project that represent different energy transition paths (see Annex A) - *Conservative (S1), Flexible (S2), Variable (S3), and Radical (S4)* - each depicting distinct levels of flexibility, generation capacity assumptions, and vRES integration. In addition, a fifth scenario, S0 with a 60% vRES penetration, is considered in some case studies as a *departing* scenario for reference.

The present deliverable, D5.5 - *Comparative analysis of Market Designs*, explores the implications of these market designs and synthesizes a comparative analysis conducted across case studies and market designs, building upon the implementation and findings outlined in previous project deliverables: D5.1 (Couto et al., 2021), D5.2 (Helleik Syse et al., 2024), D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024), and D5.4 (Johanndeiter, Schmidt, et al., 2024). Each of these deliverables focused on specific market level and structure documented within designated case studies: *Case Study A* examines local energy communities (LECs); *Case Study B* focuses on the Netherlands market; *Case Study C* explores the German market; *Case Study D* addresses the Iberian Electricity Market (MIBEL), which comprises Portugal and Spain; and Case Study E analyses the Pan-European wholesale market. Each case study is supported by specific methodologies, modelling tools, and assumptions. Annex B provides the scope of each case study, along with model limitations and simulation constraints.

The core objective of D5.5 is to provide a structured and systematic analysis of these case studies, beginning with an overview of each case in Section 2 and a summary of key results in Section 3. These initial sections serve as a bridge to the detailed comparative analysis presented in Section 4, where it is assessed market design performance across metrics including price sensitivity, economic and environmental impacts, and the influence of interconnectedness on system stability and renewable integration.

Directly comparing these market scales presents certain challenges. Each case study is based on unique modelling assumptions, tailored market instruments, and specific regulatory or policy contexts, complicating direct, one-to-one comparisons. Accordingly, the comparative analysis in Section 4 adopts a “high-level” perspective, aiming to contextualize rather than directly equate outcomes across cases. Therefore, this document offers insights into overarching trends and contrasts that emerge from varied market designs and approaches.

In connection with the broader TradeRES project work plan, the work reported here complements other key deliverables written by the end of the project, including *D3.5 - Market design for a reliable ~100% renewable electricity system* (Ed. 3), *D6.5 - Recommendations* *for market design in a ~100% renewable power system*, and the Market Design Web-Decision Tool (WP7) (H2020 TradeRES project, 2024), each of which addresses different aspects of designing markets with high vRES. For instance, D3.5 provides foundational regulatory frameworks and strategies for achieving a reliable and cost-effective 100% vRES system, while D6.5 extends WP5 findings to formulate targeted recommendations for policymakers, regulators, and stakeholders. Together, these resources establish a cohesive foundation for developing resilient, effective market designs that support vRES integration across both local and regional scales.

The following sections thus lay the groundwork for a nuanced understanding of how different market mechanisms may support—or limit—the goals of sustainability, economic efficiency, and energy resilience across Europe's diverse electricity landscapes.

2. Case Study Description

This section provides a brief overview of the five case studies at the core of the TradeRES project's comparative analysis (see Table 1). These case studies span different market structures and spatial scales, from local, national/regional and the Pan-European electricity markets, each addressing various aspects of vRES integration and market designs. A complete review of each case study, including methodologies, market parameters, and findings are documented in Deliverables D5.2 Ed. 2 (Helleik Syse et al., 2024), D5.3 Ed. 2 (Estanqueiro, Couto, Algarvio, et al., 2024), and D5.4 (Johanndeiter, Schmidt, et al., 2024).

Table 1: The TradeRES case studies.

Case Study	Geographical Scope	Market Focus	Objectives
A	Local Energy Communities (LECs)	Decentralized markets with peer-to-peer trading and self-sufficiency	Assess LEMs' role in promoting local optimization, flexibility, and economic savings
B	The Netherlands	National market	Evaluate system adequacy and test capacity mechanisms for high vRES integration
C	Germany	National market	Examine renewable energy remuneration schemes and market-based cost recovery
D	MIBEL (Portugal and Spain)	Regional market	Analyze short-term market efficiency, vRES participation, and new market designs
E	Pan-European Market	Wholesale market across multiple countries	Study interconnectivity's role in renewable integration and cross-border cooperation

Building upon these case studies, the TradeRES project developed five scenarios to capture key aspects of future energy systems, differing in their levels of demand flexibility, vRES penetration, and assumptions about power generation technologies (e.g., thermal capacity, hydrogen power plants, curtailment). These scenarios, illustrated in Figure A1, include the Starting Point Scenario (SPS) for 2019 and five future-oriented scenarios: S_0 (moderate vRES penetration for 2030), and S_1 through S_4, representing progressively higher shares of vRES under varying flexibility assumptions by 2050. These scenarios formed the basis for simulations across national/regional and Pan-European case studies, serving as critical inputs to model assessments and comparisons.

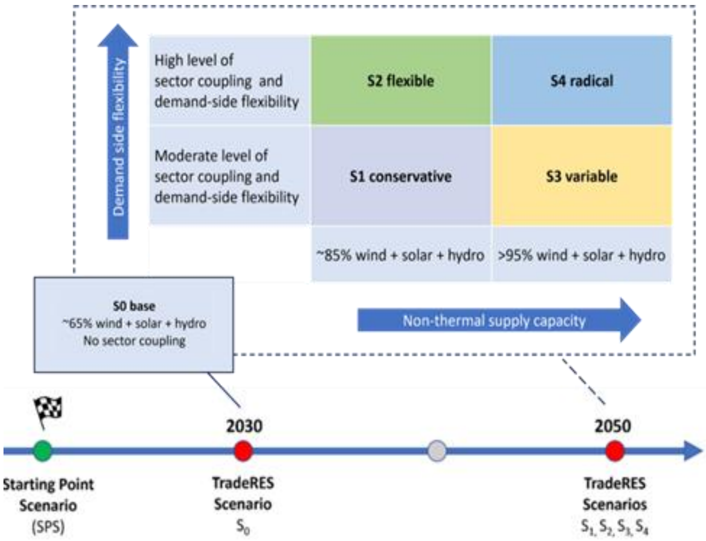

Figure A1. Allocation of TradeRES scenarios on the timeline.

2.1 Local Energy Communities: Case Study A

Within the energy systems research, the concepts of Local Energy Communities (LECs) and Local Energy Markets (LEMs) have emerged as elements in the transition towards more sustainable, decentralised, and participatory models of energy production, distribution, and consumption (Tiago Pinto et al., 2021).

The D5.2 – Performance assessment of current and new market designs and trading mechanisms for Local Energy Communities (Case Study A) (Helleik Syse et al., 2024) explores the decentralisation process by focusing on LECs and LEMs. These concepts can enable consumers to produce, consume, store, and trade energy locally, thereby enhancing energy efficiency and resilience.

The primary objective of this case study is to assess the performance of various market designs and trading mechanisms within LECs, particularly concentrating on peer-to-peer (P2P) markets and microgrid trading. This assessment evaluates how local energy production and consumption affect local electricity prices by exploring optimal market designs through simulations and real-world data. The assessment employs a two-stage approach; the first stage, Centralized Optimization, examines the role of a Market Operator in achieving optimal LEC operation. The second stage, Decentralized Operation, focuses on Peer-to-Peer (P2P) trading, comparing Mid-Market-Rate (MMR) and Double Auction mechanisms, and incorporates machine learning to address information asymmetry.

The market designs and trading mechanisms explored within this case study encompass local-wide, aggregation-wide, and wholesale-wide models to simulate interactions at different market levels and assess their impacts on prosumer behaviour, electricity costs, and market efficiency.

2.2 National and Regional Markets

This section briefly presents the national and regional electricity markets case studies, fully described and analysed within the scope of Task 5.3 of the TradeRES project (and included in first and second editions of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024; Estanqueiro et al., 2022)). The case studies focus on different geographic regions and market designs, each offering unique insights into the role of national and regional markets in the transition toward nearly 100% renewable energy systems.

The Case Study B explores the Dutch electricity market, focusing on system adequacy in an energy-only market framework with varying degrees of renewable energy integration. The Case Study C examines the German electricity market, focusing on the impact of different support schemes on vRES. Finally, the Case study D covers the MIBEL, investigating market efficiency and integration of vRES in short-term markets.

2.2.1. The Netherlands: Case Study B

The **Netherlands case study** of the TradeRES project ***addresses the research question: "To what extent can an energy-only market with/without vRES targets provide system adequacy for a 100% RES system by 2030 and 2050?"***. In fact, the Netherlands (Case study B), as part of the EPEX SPOT market, holds a strategic position in Europe due to its potential for large-scale offshore wind generation in the North Sea. This positions the country to accommodate substantial shares of vRES for both domestic and international electricity demand.

The performance assessment of market designs for the Netherlands was carried out using two distinct models: COMPETES-TNO and AMIRIS-EMLabpy. COMPETES-TNO is a power system optimization model that identifies the least-cost energy mix across European countries, generating a reference scenario that represents the optimal benchmark for the Dutch power system. On the other hand, AMIRIS-EMLabpy, an agent-based model, simulates new market designs by considering interactions between various market players under different regulatory frameworks.

In this case study, the results from the COMPETES-TNO model provide an idealized system configuration in terms of technical and economic performance, which is then compared with the outcomes of the AMIRIS-EMLabpy simulations. This dual-model approach allows for a comprehensive assessment of how different market design bundles perform in practice when compared to an optimal power system scenario. By comparing the outputs of the two models, this case study offers valuable insights into the strengths and limitations of new market designs aimed at facilitating the integration of vRES in the Netherlands' electricity system.

2.2.2. Germany: Case Study C

The ***German case study*** of the TradeRES project ***addresses the research question: "Are renewable energy sources (RES) remuneration support schemes needed and if so, how should they be designed?".***

To answer this question, dispatch simulations are conducted for the German market using the agent-based market model AMIRIS (Schimeczek et al., 2023). Different support instruments are considered for and compared to a situation with no support for vRES, namely: i) fixed market premium (MPFIX) with fixed payments on top of market revenues ii) one-way Contracts for Differences (CfD) with price-variable payments on top of market revenues; iii) two-way CfD with price-variable payments on top of market revenues and an obligation to pay back in case of high prices (clawback); iv) capacity premium (CP) with payments per installed capacity; and v) financial CfD with payments per installed capacity and a pay-back obligation for revenues generated by a reference plant.

As CfD also play an important role in the Pan-European case study,

Table 2 shows the specifics of CfD considered in the German case study. The table highlights different definitions of the reference price and permitted directions of payments for the CfD considered. This will allow for a more accurate differentiation between the CfD considered in the Pan-European and German case studies.

All considered support schemes are parametrized nearly "optimal" in AMIRIS, ensuring that vRES operators recover their costs and that excessive rents do not occur. This is done to guarantee an efficient and effective system for refinancing the necessary investments.

The effects of these support instruments are compared using market performance indicators (MPIs) for different TradeRES' scenarios with different percentages of vRES and degrees of demand flexibility, for 2030 and 2050. These scenarios were obtained using the Backbone optimization model.

Table 2: Types of CfD considered in case study C.

CfD	Unit of payment	Reference price	Direction of payments
one-way	Volume (actual infeed)	Monthly country average vRES-specific market value (before curtailment)	one-way (from state)
two-way	Volume (actual infeed)	Monthly country average vRES-specific market value (before curtailment)	two-way (to or from state)
financial	Capacity (payment from state) Volume (production potential; payment to state)	Monthly country average vRES-specific revenues per capacity (before curtail-ment)	two-way (to and from state)

2.2.3. MIBEL (Portugal/Spain): Case Study D

The MIBEL **case study fo*cuses on addressing the key question: "How can short-term markets be made more efficient to better integrate short-term vRES fluctuations?".*** This case study examines the Iberian Electricity Market (MIBEL), which includes Portugal and Spain, two countries with high penetration of vRES in their power systems.

This case study utilized the Multi-agent System for Competitive Electricity Markets (MASCEM) and Multi-agent Trading of Renewable Energy Sources (RESTrade) simulation tools to replicate real market conditions and test new market designs. MASCEM models the main market entities and their interactions in various markets (day-ahead, intraday, etc.), while RESTrade focuses on integrating vRES into traditional power and reserve markets. Both tools enabled the study of market bundles, the strategic participation of RES producers, and the potential for vRES to contribute to ancillary services trading.

To answer the research question, five scenarios were tested, focusing on different percentages of vRES and degrees of demand flexibility, for 2030 and 2050. These scenarios were also obtained using the Backbone optimization model. The scenarios explored two business strategies designated in the project by "*simple*" and "*strategic"* to assess their efficiency in vRES integration. The definition of these strategies is as follows:

i) *simple strategy business simulations* consider the social value of water and apply a random value to the marginal prices of each technology, according with the values used in Backbone. This approach consists in ***a passive participation of vRES players***.

ii) *strategic business simulations*, in addition to previous considerations, 20% of the vRES forecasts for the Day-Ahead Market (DAM) or Period-Ahead Market (PAM) (Estanqueiro, Couto, Schimeczek, et al., 2024) is allocated to enable participation in reserve markets. The remaining 80% of the vRES expected by the forecasts is bid directly in the DAM/PAM. This approach consists of an ***active participation of vRES players*** across the electricity markets.

In the MIBEL case study, several market instruments were analyzed to assess the different market designs, strategic participation of vRES in different electricity markets and their potential role in ancillary services, and TradeRES scenarios for 2030 and 2050. These instruments include:

- **Day-ahead Market (DAM)**: The current market design in Europe, used for single day-ahead coupling (SDAC).
- **Period-ahead Market (PAM)**: A proposed new design that allows for improved vRES power forecasting, enhancing flexibility and reducing balancing needs. PAM involves bidding six-hour blocks, with four updates throughout the day.
- **Intraday Continuous Market (IDM)**: The Iberian single intraday coupling (SIDC) model, which provides liquidity challenges for vRES due to the timing of bids. To increase vRES liquidity, it was assumed to have the bidding and the pay-as-bid mechanisms of the SIDC with a single clearing time per trading session.
- **Cross-border power flow validation**: Assessed the capacity of overhead power lines and the market splitting occurrences due to network congestion. For 2030, the actual conservative seasonal line ratings used by the Portuguese and Spanish system operators were considered, while for 2050, a dynamic line rating approach is assumed.
- **Secondary reserves (SecR) and Tertiary Reserves (TR)**: vRES participation in these markets was tested, with separate procurement of upward/downward reserves. In Spain, wind players already participate actively in these markets, while the participation of solar photovoltaic (PV) is in pilot phases. In Portugal none of the vRES technologies is allowed to contribute for balancing.
- **Imbalance Settlement**: The Portuguese mechanism was applied in both countries, passing balancing costs equally to balance responsible parties (BRPs).

Figure 1 illustrates the workflow of the simulations performed in MIBEL case study with indications of the markets used, the simulators, inputs and outcomes.

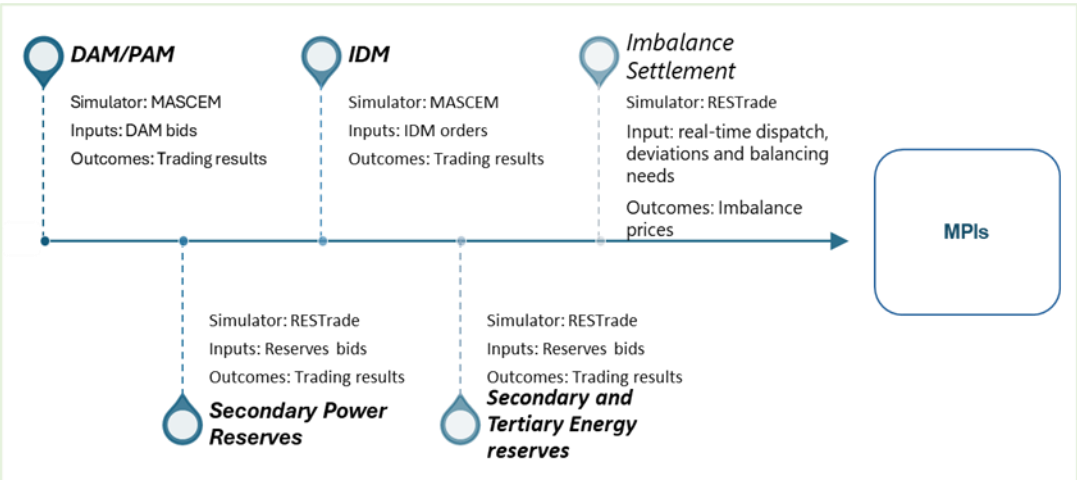

Figure 1: Workflow of the simulations performed in MIBEL case study.

Table 3 summarizes the market bundles studied in each simulation scenario, emphasizing the distinctions between simple and strategic bidding approaches.

Table 3: Market bundles studied per simulation scenario in the Iberian case study.

Scenario	Market Design	Simulation designation	Price Strategy	Energy Strategy
S0	DAM + SecR + IDM + TR	S0_DAM_Simple	Simple	Not Applicable
	PAM + SecR + IDM + TR	S0_PAM_Simple		
	DAM + SecR + IDM + TR	S0_DAM_Strategic	Strategic	✓
	PAM + SecR + IDM + TR	S0_PAM_Strategic		
S1	DAM + SecR + IDM + TR	S1_DAM_Strategic		
S2		S2_DAM_Strategic		
S3		S3_DAM_Strategic		
S4		S4_DAM_Strategic		

2.3 Pan-European Wholesale Electricity: Case Study E

The Pan-European case study focuses on identifying drivers of **market prices and profitability** of vREs in different scenarios of the future Pan-European short-term electricity wholesale market. Applying the energy system optimization framework Backbone, four main scenarios that vary in terms of three scenario dimensions are optimized: (i) the degree of coupling of the hydrogen and power sector as defined by the import price of hydrogen, (ii) the level of demand-side flexibility of the personal traffic and building heat sector, and (iii) the market penetration of vRES. They range from a **conservative** scenario, with moderate levels of vRES market penetration, demand-side flexibility and hydrogen sector-coupling, to a **radical** vision with high levels of these three characteristics (see details in Annex A). Further scenarios that alter each scenario dimension in an isolated manner were optimized to identify it impact on market dynamics and price formation as well as profits and costs of different market actors. As a sensitivity, cross-border transmission capacities are varied. Table 4 and Table 5 depict the main varying scenario assumptions.

Table 4: Overview of varying assumptions of TradeRES main scenarios including sensitivities.

	Conservative (S1)	Flexible (S2)	Variable (S3)	Radical (S4)	S1 trans-fer-	S1 trans-fer+	S4 trans-fer-	S4 trans-fer+
vRES Share	85%	85%	≥95%	≥95%	85%	85%	≥95%	≥95%
EVs	50% flexible	100% flexible	50% flexible	100% flexible	50% flexible	50% flexible	100% flexible	100% flexible
HPs	100% flexible	100% flexible + fuel boilers	100% flexible	100% flexible + fuel boilers	100% flexible	100% flexible	100% flexible + fuel boilers	100% flexible + fuel boilers
H_2 Price	45 €/MWh	117 €/MWh	45 €/MWh	117 €/MWh	45 €/MWh	45 €/MWh	117 €/MWh	117 €/MWh
Transmission capacities	2050 assumptions	2050 assumptions	2050 assumptions	2050 assumptions	-50% per line	+50% per line	-50% per line	+50% per line

Table 5: Overview of assumptions to study isolated scenario changes and CfD.

	Base	vRE↓	H_2Price↑	Flex	Target
vRE share	≥95%	85%	≥95%	≥95%	≥95%
EVs	static	static	static	100% flexible	100% flexible
HPs	static	static	static	100% flexible + fuel boilers	static
H_2 Price	45 €/MWh	45 €/MWh	117 €/MWh	45 €/MWh	45 €/MWh
Wind onshore type	1 per bidding zone (BZ)	1 per BZ	1 per BZ	1 per BZ	2 per BZ

Based on the conclusions on profitability of vRES, the case study also examines a mechanism to mitigate their profit risks, i.e., governmental CfD**.** Governmental CfD stipulate payments between the contract parties defined by the difference in an ex-ante determined strike and an ex post realized reference market price. Within the study, different design options of CfD were evaluated that consider different definitions of the reference price and allowed directions of payments. Assuming them to be issued to two types of wind onshore power plants by bidding zone in a competitive auction, the optimal strike prices were derived based on specific market expectations and were implemented in the optimization model. The CfD types considered are summarized in Table 6. Like the Germany case study (cf. Section 2.2.2), this case study examines a One-way, Two-way and Financial CfD. However, the reference period for the reference prices of these CfD types is one year in contrast to one month. Additionally, a Basic CfD was also considered, with reference price defined as the hourly spot market price.

Table 6: Types of CfD considered in case study E.

CfD	Unit of payment	Reference price	Direction of payments
Basic	Volume	Hourly spot market price	Two-sided
One-way	Volume	Yearly average wind market value by country	One-sided
Two-way	Volume	Yearly average wind market value by country	Two-sided
Financial	Capacity	Yearly average revenues per capacity by country	Two-sided

The case study applies an optimization model of a fully decarbonized European power system that covers the entire European Union except for Malta, but including Norway, Switzerland and Great Britain. On the power supply side, the model allows the implementation of a policy target for a certain share of annual electricity demand to be covered by variable, non-thermal renewables, i.e., solar, wind and hydro power. Besides conventional, static electricity demand, the demand side includes the industrial H_2 sector, the personal road traffic sector and heating and cooling demands for buildings. While personal road traffic only covers demand by electric vehicles, H_2 and heating demand can be covered either by electricity conversion via electrolysers or heat pumps, or alternative renewable fuels. Furthermore, the model includes battery, hydro and H_2 storages.

3. Market Design Results

This section presents a selection of key results from each case study, highlighting the main findings on market design performance and outcomes across market contexts. The focus is on summarizing critical insights into the operation of local energy communities, national and regional markets, and the Pan-European wholesale electricity market.

The results highlighted here offer a high-level view and are intended to support the comparative analysis that follows. For readers interested in a more comprehensive exploration of these results, along with detailed analyses, please refer to TradeRES D5.2 (Helleik Syse et al., 2024), D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024), and D5.4 (Johanndeiter, Schmidt, et al., 2024), which document the complete findings for each case study and its impact on several dimensions, technical, economic, social and environmental.

3.1 Local Energy Communities (LEC): Case Study A

This section presents an overview of the different models used in assessing the Local Energy Communities and Local Energy Markets, which have been the subject matter of this case. Local Market Performance Indicators have been explicitly defined, and in specific instances, they facilitated comparisons. For the simulation needs, this case study defined the Local-wide, Aggregation-wide, and Wholesale-wide environments whilst utilising models for quantitatively assessing the impact of the local coalition formations and/or the local trading. These modelling approaches are not unified but aimed to explore a wide variety of aspects of the problem by setting different analysis barriers and different research questions. Among the outcomes of this case study are the insights into how these local structures support economic performance, system flexibility, sustainability, and social welfare across different scales of energy interaction. Figure 2 presents the different market levels and shows the position of local energy markets within the wider environment.

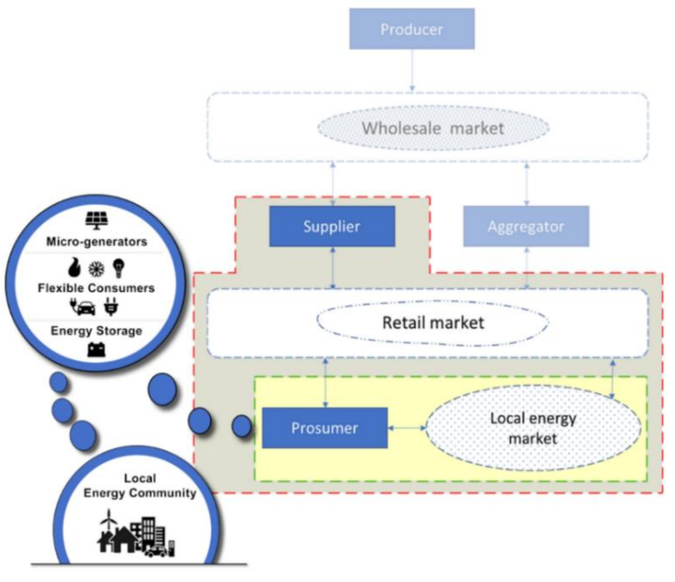

Figure 2: depicts the interactions within the LEC, showing micro-generators, flexible consumers, and energy storage linked to LECs. It illustrates the connections between prosumers, suppliers, retail markets, and their integration with the wholesale market through aggregators.

The ***Local-wide models***, focus more on the narrow environment that is defined within local markets and communities and involves prosumers interactions. These models manage to capture some of the direct benefits for communities, indicating the electricity cost reductions that can be achieved under communal planning, optimized tariffs, strategic local generation use, and active local market participation. Mechanisms like P2P trading and further flexibility utilisation (e.g. demand-response) improve local system flexibility, enabling LECs to adapt to demand-supply fluctuations and achieve better economic performance whilst supporting the grid. This adaptability strengthens the reliability and sustainability of local energy systems.

The ***Aggregation-wide models*** focus on the collective benefits that arise from coordinated interactions among LECs and their integration with retail market structures. Strategic resource aggregation allows for favourable tariff negotiations, efficient shared investments, and significant cost savings. This approach promotes social welfare by distributing economic benefits equitably, advancing renewable energy adoption, and encouraging fair pricing. Aggregation also enhances local sustainability by reducing external energy dependence and supporting carbon-neutral goals. Competitive market dynamics emerge as suppliers respond to aggregated LEC market power with better pricing and services. Effective market competition is also a notable outcome at this level, as the aggregated market power of LECs encourages suppliers to offer competitive pricing and enhanced services to attract participants.

At the ***wholesale-wide level***, models reveal how LECs, mediated by aggregators, achieve cost reductions through strategic participation in day-ahead and intraday markets. Access to wholesale prices, typically lower than retail tariffs, improves financial outcomes for LECs. Aggregated bidding enables smaller communities to harness economies of scale and reduces imbalance costs through accurate forecasting and energy management. These benefits enhance financial performance, distribute economic gains more broadly, and increase equitable access to wholesale markets.

The findings from the models highlight the substantial benefits of effective, context-specific market designs for LECs. Local-wide models evaluate clearing mechanisms and find the double auction to be of better performance when participants behave strategically. Aggregation-wide models indicate the significance that the retail markets and tariffs play in the performance of local structures. At the same time, the local structures enhance competitiveness and shift welfare towards asset owners, supporting the concepts of energy democratization. Wholesale-wide models reveal financial gains and improved market integration when LECs participate strategically in larger-scale energy markets.

To evaluate the performance of local structures, Local Market Performance Indicators (LMPIs) were defined, in some cases by tailoring MPIs defined for the other case studies and in others by introducing new metrics. Key LMPIs include Local Energy Neutrality (LMPI #1), measuring the ratio of local production to consumption; Nodal Consumption (LMPI #2), reflecting demand met by local renewable generation; Import-Export Ratio (LMPI #3), balancing external energy reliance; Total Local Costs (LMPI #4) and Levelized Local Costs (LMPI #5), assessing cost efficiency; and Local Autarky (LMPI #6), indicating energy self-sufficiency. These metrics have been utilized in certain cases for comparison while constitute a preliminary framework for assessing the economic and operational resilience of local structures like LEC and LEM.

Simulation results indicate that LECs can significantly reduce electricity costs through P2P trading, flexible consumption, and cooperative self-consumption. Aggregation-wide strategies, such as shared investments, further enhance cost efficiency and local generation utilization. Active participation in wholesale markets via competitive bidding also yields substantial savings, reducing dependency on retailers and enhancing resilience.

The second edition of D5.2 (Helleik Syse et al., 2024) concludes that decentralizing energy markets through LECs and LEMs can lead to significant improvements in energy efficiency, cost reduction, and sustainability. The comparative performance assessment of different market designs highlights the potential of P2P trading and cooperative self-consumption models in achieving optimal energy management. These findings support the broader goal of creating sustainable and autonomous energy systems, aligning with EU climate and energy objectives. Recommendations include strengthening regulatory frameworks to facilitate the growth of LECs, investing in technologies like blockchain and machine learning to enhance market efficiency, and promoting active participation of consumers in energy markets to leverage local energy resources effectively.

Figure 3 summarizes the outcomes and results of case study A. The squares on the right side of the text with the letters “L”, “A”, and “W” indicate on which environment these findings have incurred.

Figure 3: Summary of outcomes and results from the LEC modelling for Case Study A. The squares labeled “L,” “A,” and “W” indicate which level of modelling—Local-wide, Aggregation-wide, or Wholesale-wide—produces the respective outcomes. The figure highlights the varying contributions of each modelling level to the overall analysis.

3.2 National and Regional Markets

This section presents a comparative analysis of selected results from the national and regional case studies outlined in Task 5.3 of the TradeRES project (reported in D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024)). The case studies analysed different market designs across the Dutch (Case study B), German (Case study C), and Iberian electricity markets (Case study D), each offering valuable insights into the transition to nearly 100% renewable energy systems.

Rather than repeating the detailed descriptions and analyses provided in D5.3, this section focuses on key results that are most relevant for the holistic analysis performed in this deliverable. The goal is to highlight the impact of different market designs on various indicators, such as system adequacy, market efficiency, renewable energy integration, and social welfare across the three case studies.

3.2.1. The Netherlands: Case Study B

In the Dutch case study presented in D5.3, a detailed analysis examined the impact of varying levels of system flexibility and market integration on the performance of the Dutch electricity system under high vRES penetration scenarios. The reader can look into the second edition of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024), where several MPIs were computed capturing critical metrics such as renewable energy integration, system adequacy, cost efficiency, and price stability across different scenarios.

Based on the COMPETES-TNO model results, the Dutch case study in D5.3 showed that higher system flexibility (S2 and S4) significantly improved vRES penetration (see MPI #1), reduced curtailment (see MPI #17), and led to lower system costs (see MPI #26) and price volatility (MPI #41). Scenarios with limited flexibility (S1 and S3), especially in the 'isolated-NL' case, faced increased curtailment due to export constraints and experienced more frequent load curtailment events (see MPI #4 and MPI #5), as measured by Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS). Additionally, flexible scenarios showed better alignment between market revenues and system costs (MPI #32), while less flexible scenarios exhibited the highest costs and price volatility. Higher flexibility also encouraged a cleaner technology mix, reducing dependency on dispatchable resources like hydrogen turbines and nuclear power in favour of vRES. These findings underscore the critical role of flexibility in enhancing system adequacy, cost efficiency, and vRES integration.

Since the goal is to facilitate a comparative analysis, a summary and a comparison between the benchmark results obtained from COMPETES-TNO and the results from AMIRIS-EMLabpy for their Energy Only market (EOM) simulations are provided. COMPETES-TNO can only model an energy-only market and that the EOM is the status-quo which may be considered the basis for the comparative analysis.

The objective of this comparison is to shed some light on how it compares a cost-optimal system against the simulation of an agent-based model such as AMIRIS. For this purpose, two sets of results are selected: the ‘S4-Isolated NL’ from COMPETES-TNO scenarios, and the EOM_LH scenario from AMIRIS-EMLabpy. EOM_LH refers to an EOM scenario modelled with a low hydrogen price assumption of €1.5/kg, based on TradeRES-aligned data and reflecting renewable hydrogen import prices from the TYNDP 2022 Scenario Report (ENTSO-E, 2022). The reason behind contrasting these two cases is to reduce the comparison burdens given by the different capabilities of both models. The 'isolated NL' cases from COMPETES-TNO allow to align better to AMIRIS-EMLabpy results, as no electricity trade is considered. Moreover, some data from EOM_LH was based on the S4 scenario from COMPETES-TNO, such as the electrolyzers capacity and the industrial heat demand. The rest of the data from both simulations was taken from the TradeRES, which makes them comparable. To realize this comparison, some MPIs were selected to contrast both scenario results, which are reported in Table 7. It is important to notice that the MPIs from the EOM_LH reported for comparison correspond to the average of the different weather years, and therefore differ from COMPETES-TNO results, where only one weather year is optimized.

Table 7: Comparison of selected MPIs in Case Study B.

		COMPETES-TNO	AMIRIS-EMLabpy
MPI name	**Unit**	**S4- Isolated NL**	**EOM_LH**
MPI #1: Share of RES-E	%	93%	96%
MPI #4: Loss of load expectation	h	0	4.23
MPI #5: Expected energy not served	GWh	0	6.4
MPI #26: Total costs of the system	Bn €	15.9	10.5
MPI #29: Annual volume weighted average of hourly market-price	€/MWh	52.5	38.5
MPI #32: Market-based cost recovery	-	1.14	1.21
MPI #41: Volatility of electricity prices	-	43.1	4.47

Overall, both scenarios present similar penetration of vRES in the power system, following the storyline of scenario S4, representing more than 90% of the final share of vRES supplying the final electricity demand.

The LOLE parameter from the EOM_LH scenario, obtained using AMIRIS-EMLabpy, presents that (on average), 4.23 of the year involuntarily-curtailment of demand must be performed, which conveys around 6.4 GWh of ENS. In the case of COMPETES-TNO, the domestic supply under the 'S4-Isolated NL' is enough to cover all demand at all hours of the year. In an agent-based model, investments are made until the level that the expected profitability of an additional capacity stops being profitable. For this reason, higher shortages were expected in comparison to an optimization model and confirms that it is a suitable methodology to investigate market designs that aim to reduce the power curtailments.

The resulting total system costs from COMPETES-TNO present a higher value than AMIRIS-EMLabpy. This can be due to several factors. The capital costs are an important part of the total system costs. In the case of 'S4-Isolated NL', there is a total of 218 GW of generation capacity installed, whereas the EOM_LH scenario presents roughly 150 GW. Additionally, the capacity mix from COMPETES-TNO presents 28 GW more of solar energy, 22 GW more of offshore energy, 21 GW more of solar energy, and 6 GW more of bioenergy. AMIRIS-EMLabpy resulted in a higher capacity of open-cycle gas turbines (OCGT), which were not considered as an option in the optimization model. a higher variety of technologies compared to AMIRIS-EMLabpy. A potential explanation of this different need for installed capacities could be differed by the different flexible capabilities between the models. COMPETES-TNO can model a higher degree of flexibility of the system, with its associated electricity demand, which can lead to a higher introduction of capacities.

The market-based cost recovery from the two models does not differ much and indicates a relatively good cost recovery for the investments (as the values are greater than 1). It is, however, calculated on the system level. A detailed calculation of the individual technologies is possible but falls out of the scope of this comparison. The incentives for investments are best shown by the results of AMIRIS-EMLabpy as described in previous sections. The volatility of electricity prices shows a significant deviation between the two. Again, they are not completely comparable as they are aimed at showing different things. COMPETES-TNO shows the volatility of prices in one year, while AMIRIS-EMLabpy shows the volatility of average prices across all the analyzed years.

It is important to note that comparison corresponds to the outcomes of two different models, with different scopes, objectives and capabilities. Therefore, it is always a complex task to draw conclusions from results with different models. In this case, the comparison should also be understood as an acknowledgment of the different models' capabilities.

3.2.2. Germany: Case Study C

The German case study in D5.3 evaluated market-based cost recovery for vRES using the AMIRIS model, exploring remuneration schemes, including fixed market premiums (MPFIX), contracts for difference (CfD), and capacity premiums (CP). Simulations across TradeRES scenarios (S0-S4) highlighted the role of system flexibility and remuneration schemes in ensuring cost recovery for technologies like PV, onshore, and offshore wind. Full details are available into the second edition of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024).

The results of the German case study demonstrate a significant range of market-based cost recovery rates for vRES. The cost recovery rates vary considerably depending on the scenario and policy instrument, with figures ranging from 37% to 98% for PV and from 72% to 151% for onshore wind (see Figure 4).

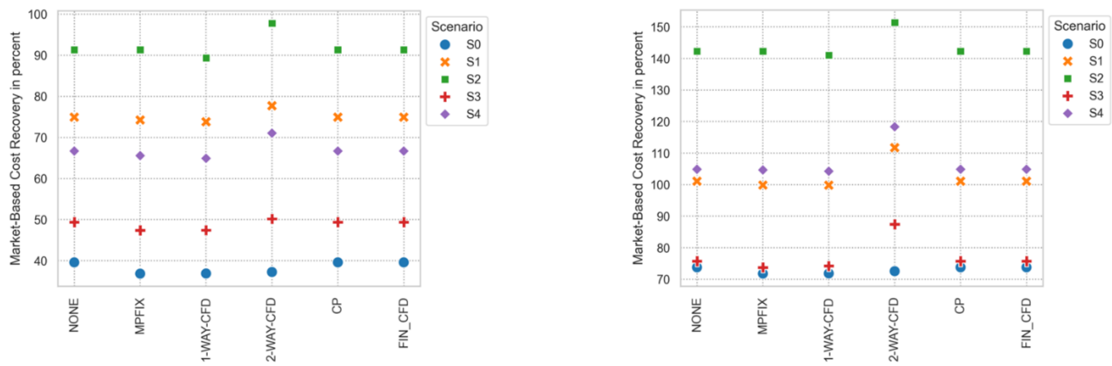

Figure 4: Market-based cost recovery for PV (left) and onshore wind (right) for different support schemes across TradeRES scenarios S0 to S4.

The results are highly dependent on the underlying assumptions of the scenarios. In particular, the flexibility of demand and the price of imported hydrogen have a significant impact on market outcomes. This has a considerably more pronounced effect on cost recovery rates than the support instruments themselves, given the nearly "optimal" parameterisation that underlies the analysis.

The German case study also shows that the examined support schemes result in full cost recovery in all cases investigated, which reduces the risk associated with investments. Furthermore, the results indicate that instruments that do not distort dispatch (capacity premium, financial CfD) lead to a consistently higher level of offshore wind curtailment (MPI #17). It is worth noting that two-way CfD results in a greater level of market-based curtailment of renewables compared to other support schemes. This leads to higher volume-weighted average electricity prices (MPI #29), which in turn tends to stabilize the market value of renewables. Finally, higher system costs for dispatch (MPI #27) must be balanced against lower RES support costs (MPI #31) in the case of two-way CfD.

3.2.3. MIBEL Portugal/Spain: Case Study D

This subsection presents the key results of the Case study D. In D5.3, a comprehensive analysis was conducted to the Iberian case study, focusing on various market design variations to address specific research questions. The scenarios explored included a combination of DAM or PAM with intraday and balancing markets, each assessed under different business and trading strategies in terms of allocation of forecasted energy. In D5.5 the aim is to highlight the key results from these simulations, focusing on MPIs calculated for each scenario. Results showed that an active and strategic participation in different markets, as already implemented in Spain, allowed for better vRES integration MPIs, but that came with trade-offs, including higher overall market prices and dispatch costs. In contrast, the simple business strategy was more cost-effective in the short term. The strategic business simulations indicate that vRES earn higher revenues from the market due to two key factors: i) an increase in DAM/PAM prices, ii) reduction of imbalances (and penalties) and iii) participation in IDM and balancing markets. Providing ancillary services (AS) can significantly enhance the value of vRES plants by diversifying their revenue streams across multiple markets. In contrast, the simple *business strategy* not only does not show the same benefits, but includes severe penalties due to the imbalances generated, as depicted in Figure 5.

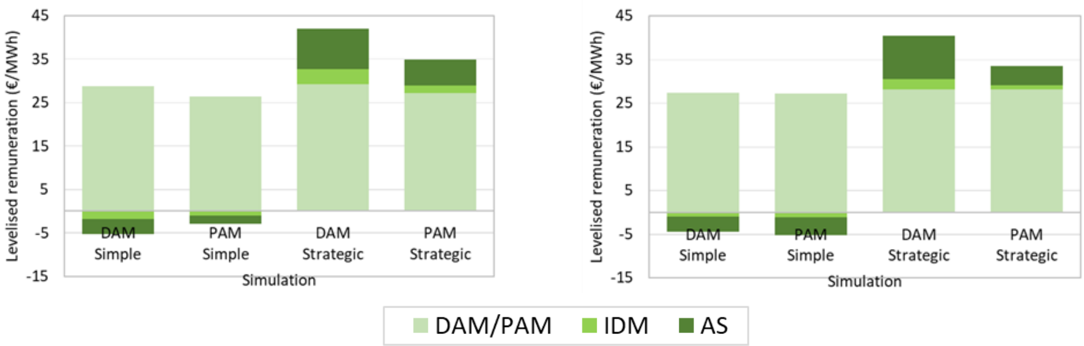

Figure 5: Levelized remuneration in different markets for wind in Portugal (left) and Spain (right).

For the reader looking for more details, Table 22 and Table 23 in 2nd edition of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024) present the market indicators calculated for the Iberian market (MIBEL) using the *strategic business* simulations in scenarios S0-S4. The observed yearly vRES share is high in all scenarios being above 80% in all cases for Portugal. For Spain, the values are slightly lower ranging from 60% to 97%.

In the 2050 scenarios, all production in Portugal and Spain is renewable or carbon-neutral, which means the CO_2 emissions are 0 (MPI #45). For the conditions imposed to obtain the optimized scenarios, both Iberian countries that constitute MIBEL market do not present risks of having LOLE events with EENS (MPIs #4 and #5), as expected. Concerning dispatch costs (MPI #27) obtained within MIBEL, they are significantly decreased from 2030 to 2050 with a strong influence from the retirement of gas power plants.

Regarding day-ahead prices (MPI #29) and investment recovery (MPI #32), inflexible-demand scenarios (S1 and S3) tend to have higher market prices, which allows wind onshore and solar PV technologies to better recover their investment.

Demand flexibility makes demand-side players adjust to vRES production, decreasing market prices and vRES investment return. Under these conditions (as analysed in the TradeRES project's S2 and S4 scenarios) with high demand-flexibility, vRES might need support remuneration schemes to fully recover their investment.

3.3 Pan-European Wholesale Electricity: Case Study E

The case study's results highlight the great uncertainty surrounding future price levels. Figure 6 illustrates the annual volume-weighted averages of hourly day-ahead market prices by bidding zone. Ranging from 28 €/MWh (in Spain and Portugal in the **variable** scenario S3) to 182 €/MWh (in the Balkans in the **conservative** scenario S1), these average market prices appear to vary significantly across both scenarios and bidding zones. In each bidding zone, the minimum difference in average prices between scenarios amounts to 25 €/MWh. At the European level, a comparison of volume-weighted European average prices between scenarios indicates that both increased demand-side flexibility and sector-coupling, as well as a higher share of vRES, generally cause prices to decrease.

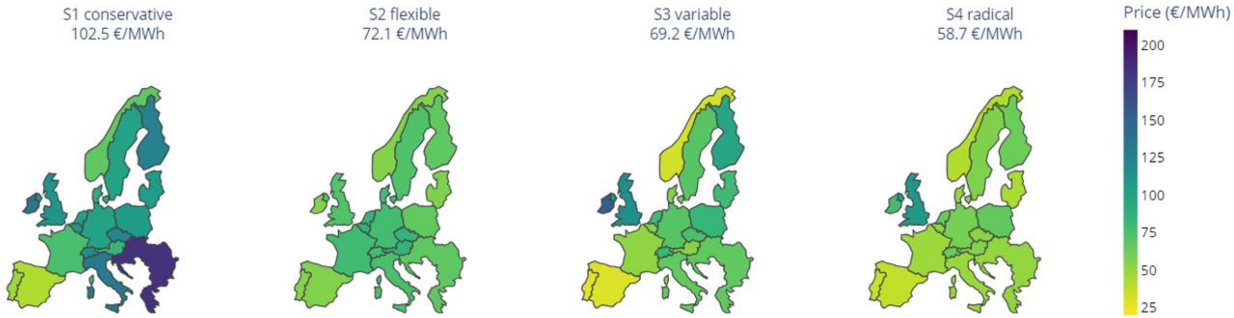

Figure 6. Annual volume-weighted average of hourly day-ahead market price by scenario by bidding zone with the European average depicted above each map.

The results also reveal that even in scenarios where more than 95% of electricity generation is sourced from vRES, average price levels still significantly exceed their variable costs. To explain this result, the case study also identifies the main price-setting technologies in future electricity markets. Figure 7 presents a histogram displaying the price distribution from 0 to 130 €/MWh along with the unweighted mean electricity prices across scenarios designed to study the isolated effect of each varied scenario dimension (cf. Section 2.3). Additionally, on the right-hand-side, it presents the number and unweighted average of observations above 130€/MWh. The analysis indicates that vRES are superseded by electrolyzers as the main price-setting technology in all scenarios featuring a significant share of vRES.

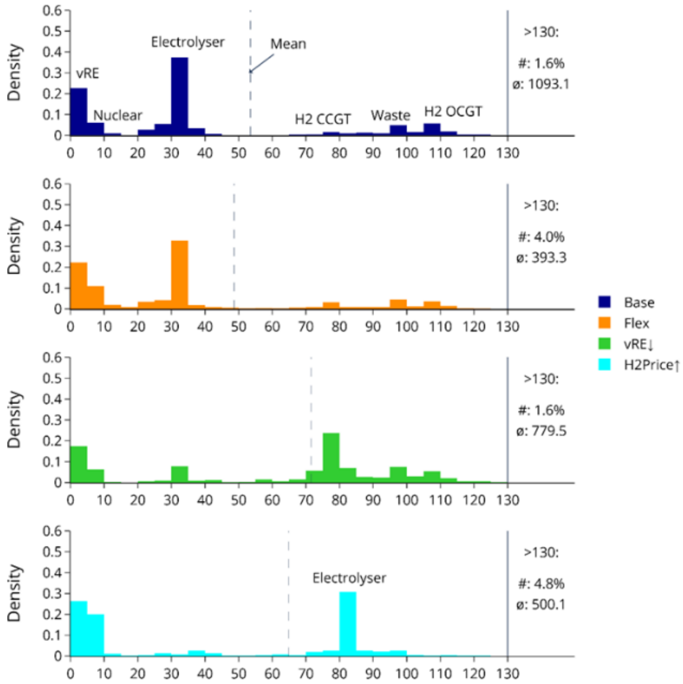

Figure 7. Histogram of electricity prices by scenario, truncated at 130 €/MWh. The overall mean is depicted by the dashed vertical line, while the average (Ø) and number (#) of prices above 130 €/MWh are presented on the right side of the plot.

Therefore, vRES also result to be largely profitable in our main scenarios. Figure 8 presents the rate of cost recovery of vRES in the main scenarios. It shows that especially wind onshore is profitable across all scenarios and bidding zones except for France and Norway in the **variable** scenario S3. Solar PV appears to be exposed to cannibalization to a larger degree, particularly in S3 and the **radical** scenario S4. Despite the risks associated with strongly fluctuating revenue streams and cannibalization, which is particularly relevant for solar PV, the results show that flexibility on the supply side as well as price responsiveness of the demand side tend to increase the profitability of vRES. In fact, investors in vRES benefit considerably from power systems with an already moderate degree of flexibility on either side, as it is the case in the main scenarios of TradeRES.

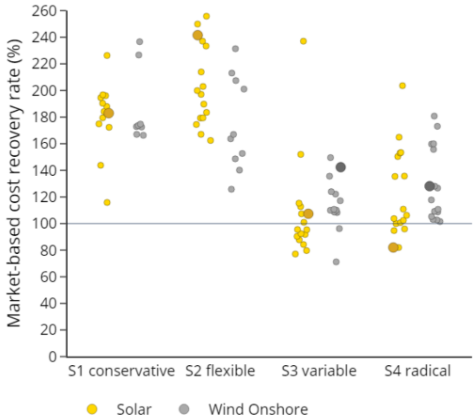

Figure 8: Market-based cost recovery rate (MPI #32) by technology and scenario. Each dot represents a bidding zone with Italy highlighted as an example.

Contracts for Difference (CfD) are an instrument designed to mitigate revenue risks. The case study's results indicate that variations in CfD design impact both investment and dispatch, particularly curtailment. Two types of wind onshore power plants are analyzed for their performance under different CfD designs, namely "High FLH" (Full Load Hours) and "High MV" (Market Value). Figure 9 shows increased investments in the "High FLH" wind onshore type under basic CfD, characterized by high full load hours, but a lower market value than the type "High MV". Conversely, CfD types with a reference price that decouples own market revenues from CfD payments lead to increased investments in the more system-friendly "High MV" type (here, "system-friendly" refers to energy generation technologies or configurations that align well with the broader energy system's needs and priorities). Thereby, curtailment is reduced in these scenarios (cf. Figure 10). Under the basic, one-way, and two-way CfD, curtailment is additionally reduced because their volume-based payments cause wind to be dispatched at prices lower than their variable costs. Therefore, prices and profits also change in the CfD scenarios. Figure 11 shows that the market-based cost recovery, i.e. the cost recovery rate without CfD payments, generally increases in the CfD scenarios compared to the target scenario. A major reason for this result is the rise in electrolyzer activity, which elevates prices. Since CfD payments are based on strike prices defined ex ante based on other market expectations, it is observed an excess recovery of costs in numerous bidding zones in our CfD scenarios. Conversely, under the financial CfD, several wind power plants fall short of recovering their costs. Yet, system costs are lowest under this type of CfD (cf. Figure 12), which was designed to eliminate investment and dispatch distortions of other types of CfD. Overall, these results reveal a trade-off between ensuring revenue certainty for investors but maintaining low system costs for consumers. Remaining revenue uncertainty under different types of CfD, however, could be addressed by adequate risk premia. Their determination requires a deeper investigation of revenue risks under the consideration of more scenarios and should be subject to future research.

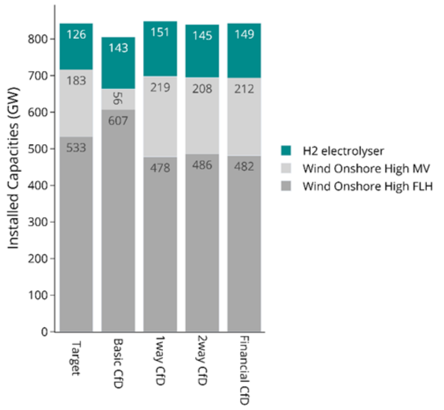

Figure 9: Installed electricity and hydrogen generation capacities in the target and CfD scenarios aggregated over all bidding zones.

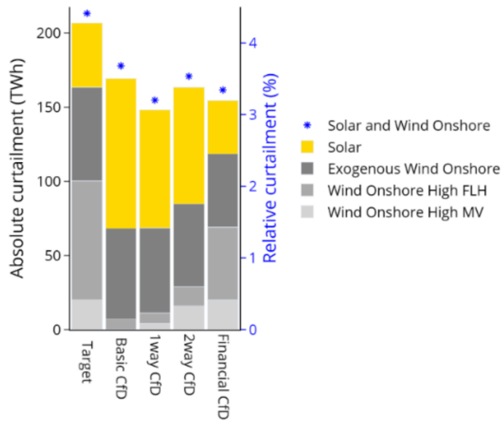

Figure 10: MPI #17: Total absolute and relative curtailment of potential electricity generation by technology and scenario aggregated over all bidding zones.

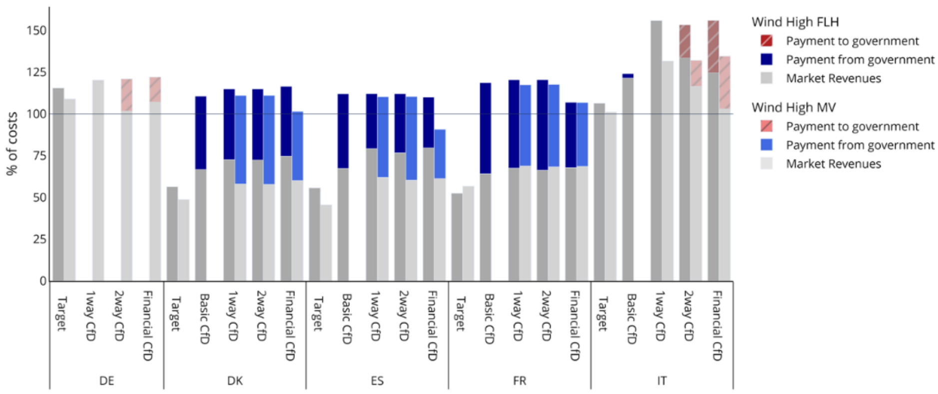

Figure 11: Rate of ex post cost-recovery from market revenues (MPI #32) and CfD payments of wind onshore by wind technology and CfD type in 5 bidding zones in alphabetical order.

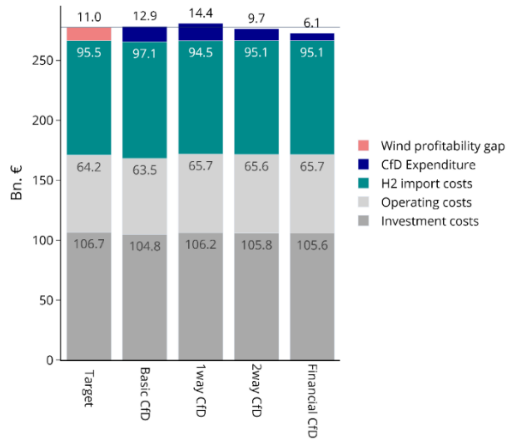

Figure 12: MPI #26: Total system costs distinguished by investment costs, operating costs (MPI #27), H_2 import costs and CfD expenditure (wind profitability gap) by scenario aggregated over bidding zones.

4. Holistic Analysis of Market Design Outcomes and Interactions Across Different Spatial Scales

This chapter presents a holistic analysis across multiple dimensions of market design and model implementation as well as the outcomes, examining key similarities, differences, and interactions within the case studies covered in previous sections. The document provides an analysis of local and wholesale market dynamics, cross-country day-ahead market (DAM) prices, environmental and economic impacts, innovative market designs such as the period-ahead market (PAM), support instruments like CfD, and the implications of interconnectivity across scales.

Section 4.1 begins with a LEC/Wholesale markets analysis, using Case Study A (LECs) and Case Study D (MIBEL), comparing market design aspects, price levels, and sensitivity to fluctuations between local and wholesale structures. This section identifies potential challenges and benefits inherent to each market type, analysing how retail tariff design, price formation mechanisms, and design frameworks differ in terms of resilience, flexibility, and impact on participant behaviour.

Section 4.2 expands the analysis to cross-country comparison of market prices and examines key environmental and economic MPIs across the national case studies: the Dutch market (Case Study B), the German market (Case Study C), and the MIBEL market (Portugal and Spain, Case Study D). This comparison provides insights into how local regulatory frameworks, economic contexts, resource availability, and specific model setups shape price levels and stability across borders. Alongside the DAM price comparisons, and PAM in MIBEL market, environmental and economic impacts are evaluated, including market-based curtailment, emissions, and overall system cost and market-based cost recovery.

Section 4.3 then analysis a new market design option in the MIBEL market (the so-called period ahead market – PAM – proposed in D5.3) and evaluates alternative support mechanisms for vRES at the Pan-European (Case Study E) and German Market (Case Study C) levels. The section explores the role of remuneration schemes, including various CfD designs, in supporting vRES integration and achieving price stabilization, emphasizing the need for robust financial instruments to support resilience amid fluctuating supply and demand conditions across Europe.

Finally, in Section 4.4, it is assessed the effects of interconnectivity between market scales, evaluating how connections between national and regional markets influence overall system performance. This section investigates the advantages and limitations of interconnected structures, particularly regarding cross-border cooperation, and stability in fluctuating market conditions.

Together, these analyses offer a "high-level" perspective rather than strict, one-to-one comparisons. By synthesizing insights across diverse cases, this chapter highlights overarching trends and unique challenges, providing a foundation for future discussions on the development and harmonization of electricity markets across Europe.

4.1 Comparative Analysis of Local and Wholesale Market Dynamics

This section presents a comparative analysis of Local Energy Markets (LEMs) and wholesale (WS) markets, exploring the dynamics of each within the broader context of Local Energy Communities (LECs). The section examines how different market designs, pricing structures, and local market performance indicators (LMPI) shape outcomes in terms of self-sufficiency, cost efficiency, and local versus regional context. Section 4.1.1 examines the structural and operational differences between LEMs and WS markets, focusing on scope, participant roles, trading mechanisms, and performance indicators. Section 4.1.2 explores how real-time pricing (RTP), cooperative self-consumption, and flexible demand impact cost savings and sustainability in LEMs and WS contexts. Together, these subsections provide insights into the challenges and advantages of integrating LEMs with broader market frameworks.

4.1.1. Comparing Market Design Approaches: Local vs. Wholesale

In this section, the differences between LEMs and WS market designs within the context of LECs are examined. It focuses on the role of MPIs and LMPIs, as well as the implications of auction types, pricing structures, and cost recovery mechanisms.

Differences in Market Scope and Objectives: LEMs concentrate on local interactions among prosumers within a LEC, aiming to optimize local energy systems by enhancing self-sufficiency and reducing electricity costs. Participants include prosumers, flexible consumers, micro-generators, energy storage owners, and local operators who engage in energy trading within a localized framework. In contrast, WS markets operate on a broader scale, involving large-scale generators, retailers, and consumers across regions. The primary objective of WS markets is overall system optimization, reliability, and cost-efficiency, with participants such as electricity suppliers, utilities, and industrial consumers.

Trading Mechanisms and Pricing Structures: Trading mechanisms differ significantly between LEMs and WS markets. LEMs utilize decentralized mechanisms such as peer-to-peer (P2P) trading, bilateral negotiations, and local auctions, allowing for flexible and direct energy exchanges between participants. For example, fully decentralized P2P markets operate without a central authority, enhancing autonomy for prosumers. Pricing structures in LEMs are also more flexible, featuring personalized retail prices, dynamic pricing, and mid-market rate pricing. These structures encourage investment in local generation and storage, promoting self-sufficiency and demand-response participation.

WS markets rely on centralized auctions managed by market operators, like day-ahead wholesale markets where prices are determined by the intersection of aggregate supply and demand curves. Prices in WS markets are often standardized and reflect generation costs and the overall balance of supply and demand, offering less flexibility for consumers to influence prices directly.

Role of Performance Indicators: MPIs and LMPIs play a significant role in evaluating the performance of these market designs. MPIs assess the performance of the broader energy market, focusing on system-wide indicators such as total system costs, market-based cost recovery, volatility of electricity prices, and power system emissions. LMPIs are tailored to evaluate performance within LEMs, focusing on metrics like Local Energy Neutrality, Nodal Consumption, Import-Export Ratio, Total Local Costs, Levelized Local Costs, and Local Autarky. Evaluating both MPIs and LMPIs provides insights into the efficiency and sustainability of different market designs under both local and wholesale conditions.

Auction Types and Cost Recovery in Local and Wholesale Markets: Auction types have implications for market outcomes in both LEMs and WS markets. LEMs employ various auction mechanisms that influence price formation, participant strategies, and cost savings. These auctions include bilateral trading, centralized P2P trading with mid-market rate pricing, double-sided auctions with strategic bidding, and discriminatory price auctions. Such mechanisms enable prosumers to actively participate in the market, often resulting in significant reductions in electricity costs due to strategic bidding and local optimization.

Cost recovery mechanisms in LEMs focus on recouping total local costs, including investment, operation, and trading expenses. Levelized local costs provide a measure of economic efficiency, helping assess the viability of local energy systems. Prosumers aim to maximize their economic surplus by participating in the market and optimizing their energy usage and generation. In WS markets, suppliers recover costs by purchasing energy from the wholesale market and selling it to consumers, with costs spread over a larger consumer base. The pricing structures may not reflect local generation and consumption patterns as closely as in LEMs.

Modeling Methodologies and Key Findings: Various modeling methodologies have been employed to analyze the interactions and performance of LEMs and WS markets. Bi-level modeling captures the dynamic relationships among electricity suppliers, flexible consumers, and the wholesale market. For instance, the upper-level problem involves suppliers setting personalized retail prices for consumer clusters, while lower-level problems represent flexible consumers adjusting their consumption to minimize costs and the wholesale market operator clearing the market based on aggregated demand. These interactions illustrate how consumer demand response influences wholesale market clearing processes and, subsequently, wholesale and retail prices.

Fully decentralized P2P market models, such as those employing mid-market rate pricing within a double auction framework, enhance flexibility and autonomy for prosumers. Traders submit bids and offers, and a matching algorithm pairs orders to maximize social welfare. This model allows prosumers to directly participate in energy trading without central authority intervention.

Case studies indicate that strategic pricing and demand response in LEMs lead to reduced electricity bills for consumers and prosumers. For example, centralized P2P trading reduced bills by 11.28%, while competitive bidding in LEMs led to a 12.95% reduction. LEMs can also improve local energy neutrality and autarky, enhancing self-sufficiency. Aggregating local resources and strategic tariff selection can reduce electricity prices, with retail competition at the local level benefiting consumers through better tariffs and services. LEC participation in WS markets via aggregators can significantly reduce electricity costs, although consumers have limited direct influence over wholesale prices compared to LEMs.

In summary, comparing LEM and WS market designs highlights the respective benefits and challenges of each system. LEMs offer enhanced local control, sustainability, and economic advantages by empowering prosumers and encouraging investment in local resources. WS markets provide broader system optimization and reliability but may lack the localized incentives present in LEMs. Integrating LEMs into WS markets could maximize overall energy system performance by combining the strengths of both designs. Advanced modeling techniques, such as bi-level optimization and agent-based simulations, provide valuable insights into effective market designs and can inform policy decisions. Policymakers might consider the benefits of LEMs in energy planning to enhance market efficiency and promote sustainable energy practices.

4.1.2. Pricing Sensitivity and Cost Dynamics in Local and Wholesale Contexts

Considering the study presented in section 4.3.3 of the second edition of D5.2 (Helleik Syse et al., 2024), it has been added a new scenario considering real-time pricing (RTP) where inflexible consumers have an RTP tariff without being part of a LEC. Table 8 summarizes the main LMPIs of the study.

Table 8: LMPIs comparisons

LMPI	RTP	Baseline	Inflexible	Best forecasts	Flexible
#1 Local energy neutrality (%)	0	0	87	87	87
#3 Import-export ratio (%)	100	100	13	13	13
#5 Levelized local costs (€/MWh)	96.47	73.31	65.15	59.90	53.38
#6 Local Autarky/self-sufficiency (%)	0	0	36	36	65

Consumers reduce their costs by 24% from the RTP to the Baseline scenario by being part of a LEC. The difference between these scenarios is an increase in the grid access costs of 23.26 €/MWh in the RTP scenario (see Figure 43 in section 5.2.2 of the second edition of D5.2 (Helleik Syse et al., 2024). Inflexible consumers' choices with cooperative self-consumption resulted in savings of 32% compared to the best RTP retail tariff. If they consistently select the best monthly tariff and have best forecasts, their savings could increase to 38% (Algarvio et al., 2024). For flexible consumers with 10% load-shifting capability, their savings can increase to 45%. Strategic bidding and behaviour by the LEC in wholesale and retail markets enable a 3% profit based on the difference between member payments and total costs.

The majority of LEC costs are allocated to investments in local generation (36%) and its operation and maintenance (29%). There are also notable costs associated with trading (13%), balancing (11%), and other grid-related fees (11%, see Figure 43 in section in section 5.2.2 of the second edition of D5.2 (Helleik Syse et al., 2024) for a detailed distribution of costs). Investing in cooperative self-consumption is a more competitive risk mitigation measure than investing in single self-consumption (Algarvio et al., 2024). Indeed, by investing in local self-consumption, consumers are aware of the majority of their costs, reducing their exposure to wholesale price volatility. By increasing local sustainability, trading costs and other fees could be reduced. The local sustainability index of inflexible LECs is only

36%, meaning most energy is traded in wholesale markets, even though the LEC produces nearly all the energy needed (with a carbon neutrality index of 87%). vRES generation complementarity and demand response have been used, increasing the local sustainability to 65%. Additionally, enhancing forecast accuracy would help lower balancing costs.

4.2 Assessing Environmental and Economic Indicators Across National Case Studies

Within TradeRES, three national case studies have been conducted: a Dutch case study (Case study B), a German case study (Case study B) as well as a MIBEL case study which analyses the countries Spain and Portugal (Case study C). For all case studies, environmental as well as economic MPIs have been assessed. In this Section, the commonly evaluated MPIs and the respective national and/or model effects that influence the results are compared. This way, similarities as well as discrepancies of the results are pointed out and traced back to the driving factors to come to robust cross-country conclusions.

4.2.1. Technical and Environmental Impact on Market-Based Curtailment and Emissions

Market-based curtailment implications for vRES integration and the power system $C0_2$ emissions were examined in Germany and the MIBEL markets, highlighting how support schemes and demand flexibility impact in these MPIs.

Technical MPI #17 - Market-Based Curtailment: In the German case study the curtailment of vRES is significant, especially for offshore wind, which can reach 18% in scenario S1 in case supply bids are not distorted from production-dependent support. This is a consequence of the higher marginal costs of offshore wind compared to the other vRES technologies (Helistö et al., 2024). Different support schemes (see also Section 4.3.2) affect curtailment levels, with the two-way CfD scheme leading to the highest overall curtailment volume due to bids above marginal costs in clawback periods. The overall vRES share (considering S1 to S4) is around 73%, reflecting a strong integration of renewables despite some curtailment.

In the MIBEL case study, for Portugal, the curtailment levels are much lower, with a maximum of 1.2% observed in Scenario S0 under vRES *strategic active business* simulations. Considering scenarios S1, S2 and S4, the curtailment is near to 0% mainly due to the participation of vRES in balancing services and a more balanced supply/demand (including flexibility) mix. Only S3 scenario shows a high level of the curtailment of vRES, which increases by 8% compared to S1, S2, and S4, caused by the high level of vRES share and low demand flexibility available.

It should be highlighted that the differences in curtailment between the MIBEL and Germany cases are influenced by the distinct market scopes and design frameworks applied. For instance, in the MIBEL case study, the inclusion of vRES *strategic active business simulations* into DAM (See Section 2.2.3) by reserving 20% of vRES forecast to participate in balancing services, which helps to significantly reduce curtailment, as seen in scenarios S1, S2, and S4. By contrast, the German case does not address a balancing market's component, which limits the ability of vRES to adjust their market participation dynamically. This difference in design results in Germany experiencing higher curtailment levels, as vRES cannot provide balancing power or adjust in response to market conditions.

Environmental MPI #45 - Power System Emissions: Concerning the power system emissions for the German case study, zero emissions are registered in the scenarios S1 to S4. This is because these four scenarios consider a power system that relies on vRES and green hydrogen only, as German policy goals demand for full greenhouse gas neutrality by 2045 (*German Federal Climate Action Act, Section 3*, 2019) which is reflected in the scenarios. On the other hand, MIBEL-Portugal case achieves high renewable shares in all scenarios, consistently above 80%. By 2050 (scenarios S1 to S4), the Portuguese power system is fully renewable or carbon-neutral, resulting in zero CO2 emissions. For Spain, renewable energy share ranges from 60% to 97%, with emissions decreasing in the PAM simple strategy scenario due to reduced gas power plant production in balancing markets. Similar to Portugal, by 2050, Spain's power system is also expected to be fully renewable or carbon-neutral, achieving zero emissions.

In summary, market-based curtailment is an important MPI for characterizing a nearly 100% RES power system. The German case study reveals high curtailment rates for offshore wind, particularly when support payments do not distort bids. In contrast, Portugal and Spain curtailment rates are nearly 0%, except for Portugal in scenario S3, the scenario with low demand-side flexibility. This is a clear indicative of the impact of effective demand flexibility and vRES integration. The analysis of power system emissions MPI shows that both Germany and the MIBEL region are on track to achieve zero emissions by 2050. Furthermore, support payments per produced kWh in Germany significantly affect curtailments, with two-way CfD potentially increasing absolute curtailment volumes. In the MIBEL case, the interdependencies between vRES participation in balancing markets and the vRES active *strategic* business have shown to reduce the overall curtailment volumes and suggest such an approach to be tested in other markets.

4.2.2. Economic Impact on System and Market-Based Cost Recovery

Economic implications of system operation under different vRES integration levels have been studied in the German and the MIBEL case studies. Central economic MPIs have also been evaluated for the Dutch case. Although results are very dependent on the specific country case and also the applied model setup, the main tendencies are briefly described for common MPIs. For each MPI, it is described the countries compared, what are the main results drivers are and how simultaneities as well as diverging trends for the results can be explained from this.

Economic MPI #27 - System Costs for Dispatch: System costs for dispatch are available for the German and the MIBEL case study. Concerning this indicator, some limitations must be kept in mind: For both, the German as well as the MIBEL case study, system designs and sizing differ quite substantially among the scenarios and so do system costs. Furthermore, bidding behaviour of some market actors is differently represented, which is reflected by deviating system costs for dispatch.

For the German case, system costs for dispatch range from the German case, system costs for dispatch range from 3 €/MWh for S4 to 24 €/MWh for S1. It can be clearly observed that the quantity of electricity provided by hydrogen plants varies greatly across scenarios and thus largely influences system costs. Another influence can be traced back to differences in the hydrogen price, affecting both, costs for backup generation as well as the opportunity cost of electrolysers.

For Portugal, in the MIBEL case study, the dispatch costs are also impacted by higher marginal cost power plants due to dependence on gas and hydro for balancing. However, the period-ahead market design (see also Section 4.3.1) results in lower operational costs compared to the DAM model, showcasing the benefits of demand-side flexibility and efficient management of vRES, especially when low imbalances from these players are expected due to the improved power forecast accuracy.

Economic MPI #29 - Volume-weighted average day-ahead electricity price: The volume-weighted average day-ahead electricity prices (WAMP) can be evaluated for all national and regional case studies. The main observable effects are described and compared below.

The case studies explored the effects of various market designs to answer different research questions under different scenario assumptions in demand flexibility. As defined in the TradeRES project, S1 and S3 present the lower demand flexibility compared to S4 and S2. The results of the case studies, as presented in the deliverable D5.3, showed that flexible scenarios would tend to present a higher share of vRES, as demand-side flexibility allows us to integrate this variable generation through pro-active consumption in periods with production surplus. This also has an effect on multiple aspects, such as electricity prices, market-based cost recovery of vRES, among others.

i) **Dutch case:** for the DAM simulations, two variants were considered, one with low and one with high hydrogen price. The WAMP (MPI #29) increased considerably from around 39 €/MWh in the low hydrogen to 60 €/MWh in the high hydrogen results. This is a result of the hydrogen price impact on the electricity market which comes with the operation of hydrogen turbines. However, the higher hydrogen prices also led to higher ENS and LOLE episodes in the market simulations.

ii) **German case:** presents a considerable range in volume-weighted average day-ahead electricity prices between different scenarios, with values varying from 45 €/MWh in scenario S3 to almost 80 €/MWh in scenario S2. The divergence in scenario assumptions, particularly regarding the hydrogen price and the level of flexibility in the system, are the primary factors contributing to this bandwidth. The former has a significant impact on prices determined by backup units as well as electrolyzers, while the latter affects the market values of vRES. Scenario S4, with the highest vRES share across all scenarios, shows rather low day-ahead electricity prices. Price differences within a scenario could be traced back to the effects of different support instruments. Here, two-way CfD was found to increase prices because of increased curtailment (also see MPI #17 comparison above).

iii) **MIBEL case:** under an active strategic participation in different markets for vRES, the DAM results showed similar trends to those in previous case studies, where flexibility differences between scenarios have a great impact on the electricity prices and on vRES cost recovery. For the year 2050, volume-weighted average prices range from 23 €/MWh for Spain and 24 €/MWh for Portugal in S4 up to around 85 €/MWh for both countries in S1. The reasons for these differences in this MPI among the scenarios can be mainly traced back to the highest demand flexibility to follow vRES production in scenarios S2 and S4, what demonstrates the relevant role flexibility has in the performance of electricity markets. There is a large degree of price convergence between the countries in MIBEL. This price convergence among Portugal and Spain was also found to be largely impacted by the applied active vRES business strategy, as well as the introduction of dynamic line rating to compute the cross-border capacity of the overhead power lines.

Table 9 shows a selection of the most extreme scenarios results regarding WAMP (MPI #29) across the case studies for the DAM, and the final share of vRES production (MPI #1). These extreme scenarios are S1 and S4, which lie opposite of each other in the scenario definition within the TradeRES regarding demand flexibility, hydrogen prices and integration of vRES. The WAMP variation due to integration of vRES is interrelated with the flexibility of the system in some case studies. In the Dutch case, the WAMP is higher under the high hydrogen assumption as explained before. In the German case study, the WAMP is lower for scenarios with high vRES shares, and particularly influenced by the hydrogen price assumption, as for the Dutch case. For MIBEL, the flexibility of the system plays a key role in the difference across the scenarios, where higher flexibility decreases the prices considerably.

Table 9: Selection of extreme scenarios results regarding the volume-weighted average day-ahead electricity price and identification of the vRES and RES shares.

Name	**Case study B Dutch market S4**		**Case Study C German market S1**	**Case Study C German market S4**	**Case study D MIBEL Spain S1**	**Case study D MIBEL Spain S4**	**Case study D MIBEL Portugal S1**	**Case study D MIBEL Portugal S4**
Case study scenario	EOM_LH	EOM_HH	N.A.*	N.A.*	DAM	DAM	DAM	DAM
MPI #1 (%)	96	87	73.2 (vRES); 100 (RES)	99 (vRES); 100 (RES)	92.8	96.8	100	100
MPI #29 (€/MWh)	38.5	60	65.8	47.1	85.5	23.4	84.8	24.2

N.A.* - Not applicable, as no additional scenarios were included in this case study.

Economic MPI #32 - Market-Based Cost Recovery: Market-based cost recovery of vRES is evaluated in the German (Case study C) and the MIBEL (Case study D) cases. The results are described and compared in the following.

In the German case study C, market-based cost recovery was found to be largely influenced by the scenario. The simulations showed that under the DAM with no support instruments, some vRES were not able to fully recover their costs on a pure market basis. This finding was especially true for small-scale solar PV. For wind, however, market-based refinancing was possible in some scenarios. The strong scenario dependency is observable in Figure 4 (Section 3.2.2). For solar PV, market-based cost recovery rates range from 49% in S3 up to on average 91% in S2. For wind onshore, they range from 76% up to 142% and for wind offshore from 67% up to 123% (assuming no support for any vRES). Thus, similarly as for the volume-weighted average wholesale prices, the higher hydrogen price level as well as a higher degree of demand-side flexibility are found to drive refinancing levels. A high hydrogen price together with a high demand-flexibility scenario showed the best performing results for both solar PV and wind. In contrast to wind, refinancing levels for PV in S4 were found to be below those of S1 for PV. This is due to the high installed capacity of PV for S4 and the high simultaneity in its dispatch, which leads to depressing price levels that are not adequately compensated by flexible demand-side resources.

For the MIBEL case, the scenarios with high flexibility and therefore higher vRES integration resulted in low values of this MPI, compared to the scenarios with lower flexibility. This is due to the effect of lower electricity prices resulting from the better integration of vRES through demand following their production pattern. Cost recovery rates for solar range from 45% in S2 up to 426% for S3. The extremely high value for S3 can be traced back to the high balancing prices during daily periods, strongly increasing the remuneration of PV power plants that participate in balancing markets. In comparison, for solar technology, the cost recovery are 79% and 49% for S1 and S4, respectively. For wind onshore, cost recovery rates range from 58% in S4 up to 124% for S1. The general trends for cost recovery for wind and solar PV differ among the scenarios. This can be explained by the low prices in the scenarios with more flexible demand (S2 and S4) reducing the market-based cost recovery of wind and solar PV.

One robust finding for the German and MIBEL case studies is that there may be scenarios in which market-based cost recovery for a system dominated by vRES cannot be assured, what introduces the possible need of measures to de-risking vRES investments, e.g. by applying some sort of support mechanism (see also Section 4.3.2).

In conclusion, the economic MPIs above are significantly influenced by the specific characteristics of the scenarios studied, as particularly pointed out by the German and the Dutch case studies. Price effects of marginal generators, especially based on hydrogen, can be observed on all three case studies. Also, the effects of demand-side flexibility can be identified as a price driver in all cases. These substantial variations indicate the large degree of uncertainty towards future developments introducing the need for suitable and adaptive market and policy designs and de-risking of investments (see chapters 4.4 and 4.5 of this analysis and D3.5 for a comprehensive summary on market design recommendations).

The German case showed the implications of different support instruments for vRES (see also Section 4.3.2) and concerning the MPIs presented here, particularly found an influence on market-based curtailment and resulting price levels. Quantitative effects are by far outweighed by the previously described scenario factors, especially hydrogen prices and the degree of demand-side flexibility. Furthermore, as particularly showcased for the MIBEL case, vRES *business strategy* of participation in balancing markets as well as bidding behaviour and the surrounding market and auction design with its lead times (see also chapter 4.3.1) have a strong effect towards the MPI values observed.

4.3 New and Alternative Market Design Options: PAM and Support Mechanisms

This section explores innovative and alternative market design options aimed at improving the integration of vRES and enhancing market efficiency. It focuses on a novel period-ahead market (PAM) structure and alternative supportive mechanisms like Contracts for Differences (CfD) to better manage vRES participation and stabilize prices. Through MIBEL, Germany, and Pan-European case studies and scenarios, this section assesses how these market adaptations impact costs, pricing, cross-border trading, and sustainability. The analyses provide insights into the potential of PAM and CfD to address emerging challenges in near 100% renewable power system.

4.3.1. Period-Ahead Market Mechanism in MIBEL

The analysis of day-ahead market (DAM) and period-ahead market (PAM) outcomes in the MIBEL case study highlights key differences in their operation and impacts on renewable energy integration, market efficiency, and pricing. The PAM, with its shorter lead times (6 hours compared to DAM's 12-36 hours), allows a better integration of vRES by benefiting from more accurate forecasts. Improved forecast accuracy reduces the need for balancing needs, which is crucial in power systems with a high share of wind and solar PV generation. This improvement has significant impacts across various dimensions addressed in the project.

vRES integration: In both the Day-Ahead Market (DAM) and the Period-Ahead Market (PAM), perform similarly in overall renewable integration. However, PAM enables to obtain equal or superior RES share in the final consumption (MPI #1). While capacity procurement levels in ancillary services are similar in both (MPI #13), PAM slightly lowers actual capacity usage (MPI #14). As a result, when vRES can participate in ancillary services through the active market participation *strategy*, their share increases due to the highest balancing needs. Curtailment of vRES is also higher in the DAM design. Therefore, it is possible to conclude PAM improves renewable efficiency by reducing balancing needs, curtailments, and balancing capacity requirements when compared to DAM.

Cost efficiency and economic performance: From an economic perspective, PAM is more cost-effective than DAM. Simulations show that the total system costs (MPI #26) - including fuel, emissions, and operation and maintenance -, total costs for dispatch (MPI #27) and costs for society (MPI #28) are lower under PAM. For example, Spain had reduced operational costs in PAM due to less reliance on expensive dispatchable generation, like gas plants that are used to provide balancing services. The reduction with PAM in Spain achieved nearly 50%. In Portugal, however, the impact is less significant, with a reduction of less than 1% in total system costs. When vRES players actively participate in different markets, the cost differences between the two market designs decrease, resulting in total system cost reductions of 2.06% for Spain and 1.16% for Portugal. The distortions observed in DAM, which raise overall system costs, allow vRES players to recover or come closer to recovering their investments.

Impact of cross-border trading and pricing: The price differential between control zones in each hour for Portugal and Spain (MPI #33) is lower in PAM due to the reduction of market distortions associated with the forecast errors. PAM also reduces the occurrence of market slitting occurrences (in almost 200 hours depending on the bidding strategy) that lead to price divergence between interconnected zones. As a result, PAM's design helps promote more uniform pricing across borders, which is a significant step towards more integrated and efficient regional electricity markets.

Social and Environmental Impacts: PAM design positively impacts social welfare (MPI #47) by reducing curtailment while it slightly lowers CO2 emissions (MPI #45) since this new design enables players to rely less on fossil fuel power plants. Social welfare, especially for consumers, benefits from more stable energy prices and less dependence on costly balancing needs.

4.3.2. Support Mechanisms for vRES Integration: Contrasting the Pan-European and German Market Scales

Both the Pan-European and German case studies analyse different types of CfD in fully decarbonized electricity market scenarios. The applied models have different strengths that were exploited to draw congruent conclusions on i) the necessity of remuneration schemes for vRES and ii) the design of CfD.

The agent-based model AMIRIS applied in the German case study reflects more accurately the dispatch behaviour as it considers updates of market expectations throughout the simulation year. In contrast, the optimization model Backbone used in the Pan-European case study can capture investment effects induced by the CfD. Furthermore, it captures changes in cross-border trade. For the sake of the prevalent comparative analysis, the strengths of the models are combined. This is achieved by analysing dispatch effects under different types of CfD with the agent-based model for Germany under different capacity assumptions drawn from the optimization model of the Pan-European case study and enriching those with the observed investment effects from the Pan-European case.

Are remuneration schemes for vRES needed? Both case studies, Case study B (German case) and Case study E (Pan-European), investigate the necessity for remuneration schemes for vRES in future power systems with ~100% share of renewables. The results of both case studies indicate that remuneration schemes are likely needed, mainly to de-risk investments in vRES, as (i) market incomes are insufficient to recover costs at the energy-only market in some scenarios for some technologies; and (ii) market performance is highly insecure, subject to scenario assumptions and – what is beyond scope for the prevalent analysis, but addressed for the Dutch case (see D3.5 (Estanqueiro, Couto, Algarvio, et al., 2024)) - also weather variability. Hence, both case studies conclude that remuneration schemes are necessary as some sort of insurance contract ensuring that the desired vRES expansion goals are met by risk averse investors.

Concerning the kind of instrument chosen, CfD are a form of support that addresses the challenge of adequately de-risking investors while simultaneously keeping support payments that are ultimately to be borne by consumers within acceptable thresholds. The latter is done by including some sort of clawback mechanism for high price periods. However, there are a lot of design questions to address for CfD (Kitzing et al., 2024), which can have significant impact on system effects and their market performance. Thus, the associated effects of specific CfD designs are subject to the following comparative analysis which highlights the main conclusions and system effects gained in both, the German and the pan-European case study.

Comparative evaluation of different CfD designs: Both case studies analyse the effects of different support instruments on investment (Pan-European case study only) and the dispatch of vRES plants (both case studies). The focus is on different types of CfD.

The results of both case studies demonstrate that production-dependent support instruments, such as one-way and two-way CfD, influence the dispatch of supported vRES plants due to the opportunity cost of the premia that – depending on the anticipated direction of the payment – raise or decrease price limits of bids above or below variable costs. Market prices are affected accordingly in hours when vRES are price-setting. Thus, from a system point of view, they incentivize an unfavourable dispatch pattern.

In the German case study, there is a clear trend towards higher curtailment volumes and price levels under two-way CfD in periods with a net clawback. The same result is found in the Pan-European case study for bidding zones and scenarios with profitable wind onshore power plants. Conversely, curtailment decreases, when anticipated payments are negative. Additionally, curtailment is affected by the composition of the type of wind onshore power plants that is impacted by the type of CfD. Particularly, curtailment is lower in scenarios with CfD designs that incentivise investments in power plants that better fit load patterns (cf. Section 3.3).

Both case studies also highlight that the ex-post cost recovery under CfD is not necessarily 100% due to differences in ex-ante assumptions used to define the strike price and ex-post outcomes that determine realised CfD payments.

In the German case study, these differences occur for two reasons: One is that a monthly reference period was chosen to spotlight the effect of inter-annual revenue respectively market value variations for the German case study. The other is differences in dispatch, i.e., changes from realized curtailments, that affect the LCOE of power plants, compared to an ex-ante prognosis value which was used to determine the strike price (as it is defined in the current German Renewable Energy Sources Act known as EEG support regime). These effects cause an excess cost-recovery, particularly under one-way CfD.

In the Pan-European case, differences between ex-ante assumptions and ex-post outcomes occur. This is due to (i) the yearly reference period and (ii) since the Pan-European case also considers investment. Generally, it also finds an excess recovery of costs in the scenarios studied since prices tend to increase due to an increased electrolyser activity.

Overall, this highlights different sources of uncertainties that occur for investors even under the risk-mitigating instrument of CfD. A monthly reference period might facilitate the market value respectively premium prognoses – yet, it cancels out the incentive to build power plants with seasonal patterns that are desirable from a system perspective. It also can lead to strong anticipations of clawback for strong monthly variations of market values as observed in the German case study.

Regarding production-independent instruments, such as financial CfD, both case studies find that this can help in removing distortive effects at the dispatch level and incentivize more system-friendly dispatch patterns. The Pan-European case also showed that it may steer investments towards system-friendly plant configurations. In the context of the Pan-

European case, "system-friendly" refers to investments and dispatch strategies that align closely with the grid's residual load, thereby reducing curtailment and enhancing grid stability (Ueckerdt et al., 2013). For example, wind power plants with high market value (High MV), which generate electricity during periods of higher demand or lower overall renewable production, are considered more system-friendly as they complement the system's needs better than plants with high full-load hours but lower market value.

Both case studies show that the cost to society (MPI #28) vary moderately depending on the support instrument. They are highest for one-way CfD due to high support payments and a lack of payback obligations. Conversely, they tend to be lowest for financial CfD depending on the scenario and bidding zone. Hence, there is a trade-off between investment de-risking (one-way CfD are generally a low-risk instrument, while financial CfD entails the new risk of the deviation from the profile of the reference plant) and the costs to society.

Finally, both case studies demonstrate that the market revenues from renewable energies are highly contingent upon the future system configuration. This is particularly true for the level of hydrogen prices as well as the level of flexibility in the system. The impact of scenario assumptions outweighs the impact of policy assumptions in both case studies.

4.4 Effects of Interconnectivity in Markets of Different Scales

In order to assess the connection, interaction and cooperation between the different market scales, a sensitivity analysis has been carried out for the Pan-European and German case study. This sensitivity analysis studies the impact of different levels of interconnectivity between Germany and its neighbouring countries.

To this end, new scenario variants are introduced for S1 and S4 that only vary in the transmission capacity between Germany and its neighbouring countries:

i) The "T+" scenario variants with higher interconnectivity assume a 50% increase in transfer capacities relative to the base scenarios.
ii) The "T-" scenario variants with lower interconnectivity assume a 50% decrease in transfer capacities relative to the base scenarios.

Capacity mixes: Resulting capacities for the German market were optimized within the Pan-European case study using Backbone (cf. Figure 13). Subsequently, the agent-based model of the German case study was applied to simulate the effect of different CfD design in each baseline scenario.

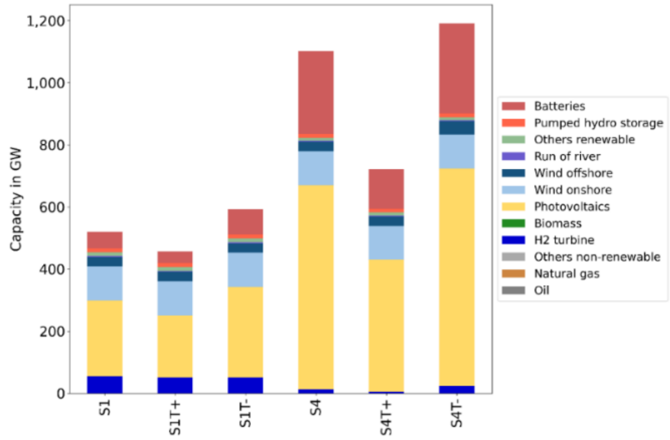

Figure 13: Power generation capacities for different scenario variants of S1 and S4 in Germany.

The results show that an elevated level of interconnectivity is associated with a reduction in domestic power generation capacity. Conversely, when the level of interconnectivity is low, a greater number of PV plants are installed in Germany, along with more batteries, and also more hydrogen plants in S4T-.

Wholesale electricity prices: In the following, the impact of transmission capacity changes on wholesale electricity prices and market-based cost recovery for vRES plants are described. This is done in two ways: first, from a pure dispatch-oriented perspective, but considering different support instruments, as demonstrated in the German case study ("GCS"); and second, additionally taking into account investment effects, as illustrated in the Pan-European case study ("PEC"), not considering any support.

Figure 14 shows the average unweighted electricity prices across the scenario variants. The data points on the left show the results of the PEC, while the data points on the right show the results of the GCS for different support cases.

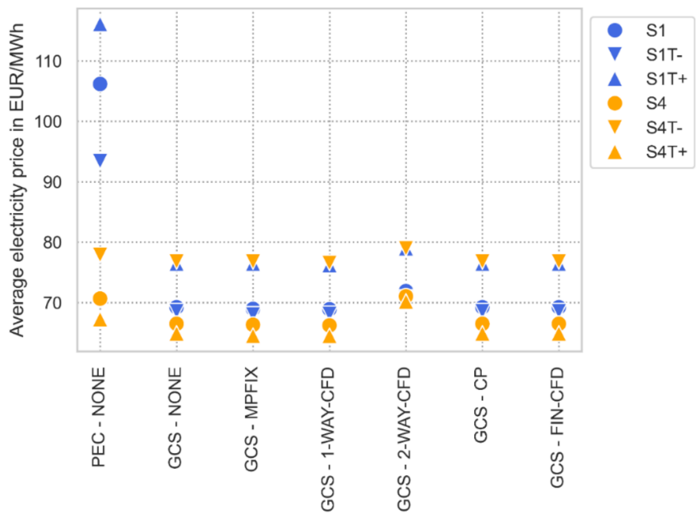

Figure 14: Average electricity prices across scenario variants.

The impact of altered transmission capacities varies according to the underlying scenario (S1 vs. S4), but the effects are consistent across the case studies (PCS and CGS). In the S1 variants, wholesale market prices decrease with lower levels of interconnection. This is due to the high share of domestic PV in S1T-, which leads to high levels of cannibalisation. Conversely, wholesale market prices are higher in S1T+ with lower domestic production capacity.

In the S4 variants, effects are reversed. Here, prices are higher with a lower level of interconnectivity (S4T-). Since hydrogen is more expensive in the S4 scenario, they are hardly built in the S4T+ scenario, where Germany can rely on electricity imports. In S4T-, however, more hydrogen turbines are required to provide electricity when domestic vRES supply is scarce. Therefore, they also become price-setting in a higher number of hours. In terms of the impact of different support instruments, it is evident that two-way CfD results in the highest market prices. This is because vRES operators in this case are more inclined to avoid clawback by reducing their infeed in certain periods, which in turn drives up prices.

Please note that the level of prices differs between the GCS and the PCS particularly for S1. This discrepancy can be attributed to a disparity in the way flexibilities are depicted in the models employed by the two case studies. The GCS utilises the agent-based model AMIRIS, while the PEC employs the optimisation model Backbone, where market prices reflect hourly temporal and sectoral opportunity costs of flexibilities. AMIRIS has some limitations when depicting multiple competing flexibility options, which is why it does not account for explicit bidding behaviour for storage units in the GCS. This may result in an underestimation of the price impact of storages on wholesale prices, leading to lower market prices in AMIRIS compared to Backbone.

Market-based cost recovery: here, the impact of interconnectivity on market-based cost recovery of vRES technologies is outlined.

Figure 15 provides a summary of market-based cost recovery rates for onshore wind. They range between 93% and 140%, depending on the scenario variant. As with average electricity prices, cost recovery rates demonstrate similar trends. The highest cost recovery rates are observed for the S4T- scenario, driven by elevated electricity prices due to higher hydrogen turbine capacities with high fuel prices. Vice versa, higher interconnectivity in the S4 scenario (S4T+) deteriorates cost recovery rates for onshore wind. Effects are reversed in the S1 variants. Here, market-based cost recovery rates are stabilized by higher interconnectivity (S1T+), as cannibalisation decreases because of lower solar and wind capacities required locally. Irrespective of the level of interconnectivity, higher cost recovery rates are possible when two-way CfD are used, due to the price-increasing effect of higher market-based curtailment in clawback periods.

Figure 16 shows the market-based cost recovery of newly installed large PV plants across scenario variants. They range between 90% and 190%. Note that this type of technology is not used in scenario S1T+. As a result of the cannibalisation effects previously outlined for scenario S1T-, which has higher levels of generation from domestic PV, market-based cost recovery is lower in S1T- compared to S1. In contrast, market-based cost recovery rates are higher for any change in the transmission capacity compared to S4. This is due to the implications on hydrogen prices, which are higher in S4T- and S4T+ compared to S4.

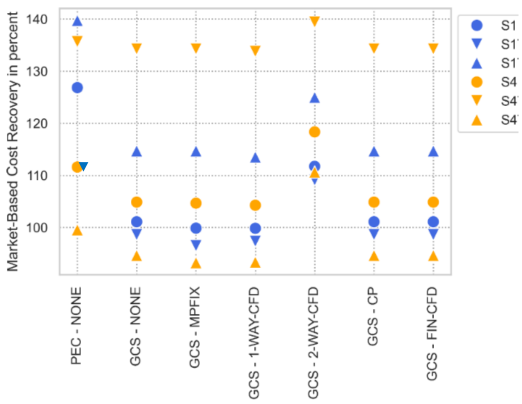

Figure 15: Market-based cost recovery of onshore wind across scenario variants.

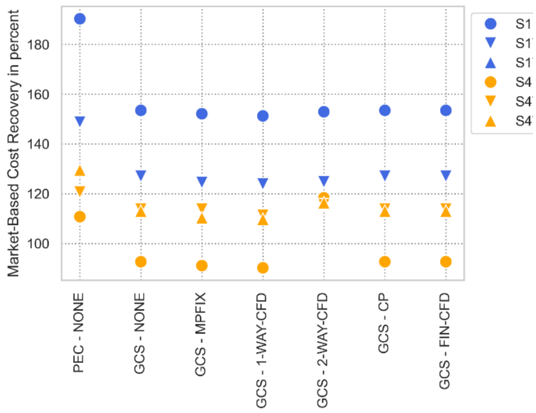

Figure 16: Market-based cost recovery of newly installed large PV plants across scenarios[1].

Again, please note the differences in price levels between the Backbone optimization and AMIRIS simulation run which compared to the above differences in the average price are not as pronounced because of the merit order effect of renewable generators.

Summary and conclusion: The sensitivity analysis yielded the following conclusions:

i) Lower interconnectivity leads to higher domestic investments in PV and batteries in S1 and additionally hydrogen turbines in S4.

ii) The impact of interconnectivity levels on market prices and market-based cost recovery varies significantly depending on two key factors: the base scenario and the vRES technology in question. If only vRES capacities, but not hydrogen turbine capacities are affected by the change in transmission capacity, which is the case for S1, a lower level of interconnectivity has a deteriorating effect on the market-based cost recovery of both onshore wind and PV due to higher cannibalisation.

iii) For any level of interconnectivity, market-based cost recovery rates are highest for two-way CfD, due to the clawback and the highest level of market prices in this case (see also the discussion Section 4.3.2). This effect has been demonstrated to be robust in this sensitivity analysis and throughout all scenarios considered in the German case study.

[1] Note that PV technology is not used in S1T+ due to higher interconnectivity reducing the need for local PV investments, as increased reliance on imports mitigates domestic capacity requirements.

5. Final Remarks

This document, D5.5, provided an overview of the electricity market case studies designed and addressed within TradeRES project and their impacts across multiple scales, from local energy communities (LECs) to national, regional, and Pan-European wholesale electricity markets. It explored how these different aspects influence economic efficiency, environmental outcomes, and the integration of variable renewable energy sources (vRES), grounding the case studies and the analysis conducted on real-world applications.

A summary and the discussion resulting from the different dimensions addressed in the holistic analysis are presented below, together with the additional research identified in the final stages of TradeRES project.

Local and wholesale energy markets: The analysis of the links of local energy markets (LEMs) with respect to wholesale (WS) markets highlights strengths and challenges for each of the electricity trading scale. LEMs, which use decentralized systems like P2P trading and dynamic pricing is set in place, give more control to prosumers and promote self-sufficiency, normally leading to economic savings and better local energy use. This flexibility allows LEMs to quickly adapt to local needs, creating outcomes that encourage investments in local generation and storage. WS markets, in contrast, operate at a much larger scale with centralized auctions focused on efficiency, reliability, and cost-effectiveness across regions. While WS markets support broader system objectives, they may not offer the same local incentives and signals found in LEMs.

Market indicators show that LEMs and LECs are effective in improving sustainability through metrics like Local Energy Neutrality and Local Autarky, which encourage local resource use and demand response. Meanwhile, WS markets have been assumed in most cases as not affected by the introduction of local structures, although, if scaled up some volume will be removed. The broader systems objectives that are enraptured by the WM market, aim to support the holistic management of the overall system costs, without seeing the locational needs and values. Integrating LEMs with WS markets could bring together the adaptability of local markets and the stability of regional networks to improve overall performance. Both LEMs and WS markets offer paths for integrating vRES, but this analysis emphasizes the importance of carefully designing these markets to balance local benefits with broader system goals.

> ***Research Needs:*** *Further research is needed to understand how best to integrate LEMs within WS markets, including operational coordination and policy support for local investments. Examining the long-term impact of real-time pricing and cooperative self-consumption on costs and vRES integration would be beneficial. Additionally, exploring new market structures to support local flexibility while maintaining regional stability could help future energy market development.*

Environmental & Economic MPIs and vRES Support: The comparison of economic MPIs, especially for the case of the Netherlands and Germany, revealed the strong influence of scenario parameters, such as the price for hydrogen or other commodities of marginal generators and the degree of demand-side flexibility. These factors in turn influence price levels and through this, also the market-based cost recovery situation of vRES players. One robust finding was that, for the German case study and, in a much lower extent, for the MIBEL case, situations with insufficient market-based cost recovery of some vRES technologies were observed, which highlights the need for support instruments, essentially for derisking vRES investments. Nevertheless, alternatives for the direct market-support instruments were investigated, e.g. in the MIBEL case study, it was observed that an active and strategic participation of vRES players across different electricity markets, including balancing markets, would strongly contribute to reducing, or even totally eliminate this need.

Looking at the environmental MPIs, Germany exhibited high levels of curtailment rates, particularly for offshore wind, which could be partly attributed to the fact that for this market only DAM trading was addressed. In contrast, the MIBEL case, which benefited from the participation of vRES in balancing services, experienced much lower curtailment levels. Regarding economic MPIs, variations in system costs and average DAM prices were observed across scenarios with different levels of flexibility. For example, higher hydrogen prices were linked to increased electricity prices. The high challenges in market cost recovery for vRES in both the Dutch and German cases, emphasized the importance of demand-side flexibility to accommodate the non-controllable generation. On the other hand, for the MIBEL case, characterized by high flexibility, showed the lowest electricity prices under high vRES integration scenarios, demonstrating the value of system adaptability and flexibility for near 100% RES markets. However, it is important to note that the differences in MPI values were heavily influenced by the distinct modelling setups and scenario assumptions used across the different case studies and specificities of the different models applied.

> ***Research Needs:*** *Future research should focus on refining the modeling of electricity markets, especially in terms of integrating balancing mechanisms and demand-side flexibility across different market scales. Following the positive results obtained with the active strategy of vRES participation in different markets, further work is necessary to explore how optimal division of energy "volumes" among different markets, as well as diverse policy frameworks can contribute to vRES integration and derisk the investment in these technologies, while reducing overall systems costs and energy curtailment. Additionally, deeper understanding the interplay between hydrogen prices, vRES market cost recovery, and the level of flexibility would provide valuable insights for designing more adaptive, future-proof market systems.*

New and Alternative Market Design Options: The introduction of a Period-ahead Market (PAM) with a rolling 6-hour window clearing has been proposed as a new market design and analysed for the case of MIBEL. In the study conducted, PAM demonstrated several advantages over traditional Day-Ahead Markets (DAM), allowing for better vRES integration, an increase in system efficiency (e.g., reducing the need for balancing and curtailment) for MIBEL as well as improving vRES revenues. Thus, in the short term, PAM may be a significant step forward in maintaining the scheduling of large thermal power plants and positively impact the social welfare indicators due to enhanced price stability and lower CO2 emissions. However, in future systems with ~ 100% renewable power systems, as analysed in some TradeRES scenarios, where conventional power plants are phased out, shorter lead times between market closure and delivery should be considered. For vRES players, the (active) *strategy of business* design also revealed a potential benefit by enhancing market-based remuneration through diversified revenue streams, revealing that small changes to existing markets can have important benefits for vRES players, at the same time as they contribute to derisk the investment in those technologies.

In what concerns addressing support and derisking mechanisms for vRES, the German and Pan-European case studies evaluate various CfD types and their influence in market's performance. For the dispatch time scale, curtailment effects of different CfD schemes have been evaluated, and two-way CfD scheme has been found to increase curtailment and market prices. Discrepancies between ex-ante expectations and ex-post realizations of support parameters have been found to lead to deviations from a perfect cost recovery. This result was also obtained for the investment time scale in the Pan-European case study. A general trade-off between a maximum de-risking of investments (which can be achieved in a one-way CfD scheme) and the provision of system-friendly investment and dispatch incentives (which can be achieved by production-independent support instruments such as the financial CfD) has been found. It is important to note that this analysis assumes an almost "ideal" parameterization of the support instruments. However, such support instruments differ, regarding associated ex-ante prognoses risks, which should be addressed in future research.

> ***Research Needs:*** *Despite the insights gained from the MIBEL case study, new market designs such as PAM, along with the development of more active and dynamic strategy of participation in different markets- for vRES players, still require further investigation and a cost-benefit analysis, especially in future vRES-dominated power systems. Additionally, further research is needed to the design of CfD, particularly by examining the impact of various reference periods, seasonal factors, and ex-ante forecasting risks. The analysis in this study assumes an "ideal" parameterization of support instruments, but real-world applications often face significant forecasting and market volatility challenges, that were not taken into account. Addressing these factors in future research will help balance investment de-risking with cost-effectiveness, ensuring that CfD and/or similar mechanisms remain robust and adaptable in evolving market conditions.*

Transmission capacity: In a dedicated analysis, the effect of altered transmission capacity between Germany and its neighboring countries was studied within both the Pan-European and German case studies. Trends for prices and market-based cost recovery were found to align across these cases, although differences in price levels could be attributed to specific model characteristics and limitations. Lower transmission capacities were associated with increased domestic installations of solar PV and batteries in Scenario S1, along with additional hydrogen turbine installations in Scenario S4. The impact of the interconnectivity levels on market prices and market-based cost recovery was shown to vary significantly based on two key factors: the base scenario and the specific vRES technology in question. For instance, when only vRES capacities were affected by the change in transmission capacity—as in Scenario S1—lower interconnectivity had a negative effect on the cost recovery for onshore wind and PV due to higher cannibalization effects. Across all levels of interconnectivity, market-based cost recovery rates were highest under the two-way CfD mechanism, due to clawback effects and the elevated market prices observed in this setup.

> ***Research Needs:*** *Further research is required to explore optimal interconnectivity levels for balancing renewable integration and cost recovery across various market scales. Additionally, examining the effects of CfD designs on different vRES technologies and how they interact with varying transmission capacities could yield insights for more tailored and resilient market structures.*

To finalize, it should be highlighted that, while D5.5 provides a comprehensive (and, where possible) comparative analysis of case studies and their outcomes, it is essential to recognize the inherent challenges posed by the differences in model setups, case study's contexts, and scenario assumptions across regions and market scales. These factors inevitably influence the robustness of cross-comparisons, yet the insights gained here identify consistent trends and important factors that can guide the development of effective market designs for high vRES integration.

In addition, it is important to consider this work, in connection with other key documents of TradeRES project, namely D3.5, D6.4, and the Market Design Web-Decision Tool (Subtask 7.3.1), which collectively address complementary aspects of the market design for power systems with high share of vRES. For instance, D3.5 third edition, outlines necessary regulatory frameworks and strategies to secure a reliable and cost-effective 100% vRES system, D6.4 builds on WP5's findings to offer targeted recommendations for policy makers, regulators, and stakeholders, and the Market Design Web-Decision Tool (H2020 TradeRES project, 2024) enable stakeholders to explore and assess the effects of various market designs on MPIs. Together, these resources offer a cohesive foundation for advancing resilient and effective market designs that support the large-scale integration of vRES, at both local and regional levels.

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Annex A: TradeRES S0-S4 Scenarios

According to the developments in the WP 2 of this project, the TradeRES scenarios that have been defined differ based on demand and supply side parameters. The $S_1 - S_4$ anticipate very high to almost 100% shares of vRES and at the same time differ with respect to the level of demand flexibility and assumptions related to power generation (e.g., thermal capacity, hydrogen power plants, curtailment, etc.). The so-called *TradeRES scenarios*, used in the national/regional and pan-European case studies, are: the "Conservative" (S_1), the "Flexible" (S_2), the "Variable" (S_3) and the "Radical" (S_4). In addition, a S_0 scenario was also established assuming 60% vRES penetration. The timeline shown in Figure A1 positions the scenarios to the key milestone years and also indicates the *Starting Point Scenario (SPS)* that refers to a year prior to the beginning of TradeRES project (i.e., the year 2019).

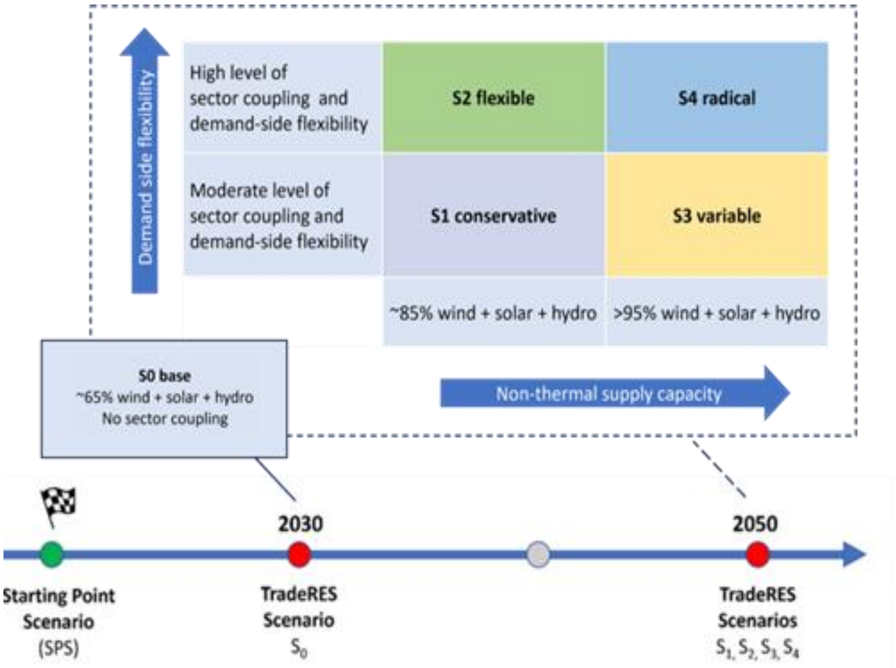

Figure A1. Allocation of TradeRES scenarios on the timeline.

The scenarios developed within TradeRES serve as critical inputs to the models, with their outputs closely tied to the underlying assumptions. Detailed information on the Starting Point Scenario (SPS), Reference Systems, and Market Design Bundles, which form the basis for benchmarking and scenario development, is available in D5.3 (Estanqueiro et al., 2022). These elements are foundational to the analysis presented in this deliverable, and the terminology outlined in **Box 1** is adopted throughout.

Box 1: TradeRES Scenarios definitions

Scenario *within TradeRES refers to a structured input data collection that encapsulates certain properties of the underlying future energy system.*

<u>**TradeRES scenarios**</u>:

- *SPS* - Starting Point Scenario (2019).

- S_0 – 60% vRES penetration (2030);
- S_1 – the "Conservative" scenario; very high vRES shares (2050);
- S_2 – the "Flexible" scenario; very high vRES shares (2050) and a highly flexible demand;
- S_3 – the "Variable" scenario; almost 100% vRES shares (2050);
- S_4 – the "Radical" scenario; almost 100% vRES shares (2050) and a highly flexible demand.

- **Reference System** within TradeRES refers to the structured collection of data that are complementary required by the agent-based models either for being explicitly used in the simulations or to be utilised as basis of comparison.

- **TRS - TradeRES Reference System** is the Reference System created by the optimization models for $S_0 - S_4$.

- **SPRS - Starting Point Reference System** is the Reference System that uses data and conditions of 2019.

- "**Market Design Bundle**" within TradeRES refers to a combination of Market Design Options that are to be studied and jointly evaluated in a case study.

Annex B: Scope of Case Studies, Model Limitations, and Simulation Constraints

This annex provides an overview of the scope, model limitations, and simulation constraints associated with the case studies conducted within the TradeRES project. This contextual information is essential for accurately interpreting the results, understanding the context in which they were derived, and recognizing the assumptions and constraints that may influence their applicability. This approach enables stakeholders to assess the robustness and applicability of the results, facilitating a robust assessment of the outcomes across various scenarios and market designs.

B.1 Backbone Input Data (Based on WP2)

Four carbon-free scenarios (S1, S2, S3 and S4) and one intermediate energy system setup (S0) on the path to decarbonization were created, as described in Deliverable 2.1 (Helistö et al., 2020). The scenarios include exogenous assumptions on inelastic electricity demand and industrial hydrogen demand, as well as assumptions on the consumption and flexibility of electric vehicle charging and heating and cooling of buildings.

Generation and storage technologies cover onshore and offshore wind, utility-scale and rooftop solar photovoltaics, concentrating solar power, run-of-river hydro, reservoir and pumped hydro, battery energy storage systems, hydrogen storage, and thermal power plants, comprising biofuel, waste and nuclear power plants as well as hydrogen-fired combined cycle and open cycle gas turbines. Scenario S0 also includes some fossil power plants. Investments in new electricity generation capacities were limited according to natural potentials. In addition, investments in storage options and electrolysers were allowed.

The input data, which is available in Zenodo (Helistö et al., 2024), covers all EU27-countries with the exception of Malta, but including Great Britain, Switzerland and Norway. Some countries are aggregated together, and the resulting model consists of 19 “bidding zones”, which are connected by exogenous electricity and hydrogen transmission capacities. All load and capacity factor time series reflect the weather year 2019.

The four scenarios S1, S2, S3 and S4 vary three key factors:

- *The level of flexibility of the supply-side*: A certain share of non-thermal renewables (wind, solar, hydro) is enforced at a Pan-European level. In S1 and S2, this share is kept at 85% of annual electricity demand, while it is increased to more than 95% of annual electricity demand for S3 and S4.
- *The level of flexibility of the demand-side*: Demand-side flexibility is increased in scenarios S2 and S4 compared to S1 and S3 by increasing the share of electric vehicles that participate in demand response and by including auxiliary fuel boilers in buildings.
- *The degree of coupling between the hydrogen and power sectors*: The import price of hydrogen from outside Europe is increased in S2 and S4 (€117/ MWh) compared

to S1 and S3 (€45/MWh). A higher import price makes domestic hydrogen production more attractive and hence, increases investments in electrolysers in Europe.

Backbone is an adaptable energy system modelling framework, which can be used for creating and analysing optimised systems based on given assumptions. In TradeRES, the five scenarios were first run with Backbone in the capacity expansion mode, with representative weeks, to optimise investments in electricity and hydrogen production capacities and storage options. After the capacity expansion planning stage, the operation of the resulting capacity mix in each of the scenarios was subsequently optimised in the production cost modelling stage.

B.2 Local Energy Communities: Case Study A

For Case Study A, detailed information on the scope, model limitations, and simulation constraints is not included in Annex B of this deliverable due to the complexity and breadth of the analyses conducted. This case study involved over 15 subcases and submodels, each with unique characteristics, assumptions, and constraints. Compiling this information comprehensively for the annex would not only exceed the scope of this deliverable but also risk oversimplifying key details. However, a thorough account of these aspects is provided in Deliverable D5.2 (Helleik Syse et al., 2024), where the scope of Case Study A, along with its subcases and submodels, is extensively documented. Readers seeking more granular insights into this case study are encouraged to refer to D5.2 for a complete understanding of the methodologies, limitations, and results specific to Case Study A.

Therefore, for more information about the scope and details of the models used for case study A, see Tables 2-4 (page 26-29) in D5.2 – Performance assessment of current and new market designs and trading mechanisms for Local Energy Communities (Case Study A), ver. 2 (Helleik Syse et al., 2024).

B.3 National and Regional Markets

This section outlines the scope, model limitations, and simulation constraints for the national and regional market case studies conducted within TradeRES. Each case study reflects national/regional characteristics and modeling approaches, providing insights into the performance and adaptability of different market designs.

B.3.1 The Netherlands: Case Study B

The Netherlands case study examined the impact of the different TradeRES scenarios on the Dutch Day-Ahead market (DAM) and compared alternative market designs against the current energy-only market.

Modelling approach and limitations: The approach followed in this study comprises the utilization of two models with distinct scopes to address different objectives:

1) COMPETES-TNO model: generated benchmark results for the Dutch Day-Ahead Market and provided data inputs to,

2) AMIRIS-EMLabpy model, an agent-based model employed to explore market dynamics of alternative market designs. A detailed comparison of these models is available in Chapter 3.1 of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024).

The combined used of AMIRIS and EMLabpy aimed to mitigate the myopic investment decision-making in EMLabpy's simulations, by integrating the high-resolution operational time scale of AMIRIS to model demand flexibility. AMIRIS-EMLabpy evaluated the impact of different capacity remuneration mechanisms and compared them with the current market design. However, the AMIRIS-EMLabpy model comprises only the Dutch market and does not include cross-border electricity trade due to computational constraints. Additionally, risk aversion and market power were not considered, which could potentially affect market performance.

COMPETES-TNO optimizes the European power system and includes cross-border trade in its simulation of the Dutch electricity market in its investment decisions. This model produced two sets of results for the Dutch market: one considering cross-border connections with other regions, and another assuming market isolation for comparative analysis with the AMIRIS-EMLabpy outcomes, and to provide input data to it. COMPETES-TNO's results show that considering cross-border energy flows reduces the need of approximately 25% of the generation capacity estimated in AMIRIS-EMLabpy. One limitation of the COMPETES-TNO model is that investment decisions do not account for uncertainty and risks inherited to weather variability of different years, causing myopic investment decisions.

Scenario and input data assumptions: The scenario simulations carried out both in COMPETES-TNO and AMIRIS-EMLabpy were based on the Backbone data, such as technology and fuel costs, and VRE potentials. For Dutch generation capacities, a detailed thermal power plant database from the *Climate and Energy Outlook* (KEV) of the Netherlands was used for the simulations carried in COMPETES-TNO. Additionally, an assumption was made regarding nuclear capacity, extending the lifetime of the Borssele nuclear plant up to 2050, instead of its currently planned decommissioning in 2033, given ongoing political decisions regarding nuclear in the Netherlands.

B.3.2 Germany: Case study C

An in-depth description for the German case study can be found in chapter 3.2 of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024). For the German case study, the model AMIRIS has been applied. Further information on AMIRIS can be found in D4.5, Schimeczek et al. (2023) as well as on the landing page https://dlr-ve.gitlab.io/esy/amiris/home/.

Countries and Markets: For the German case study, the Federal Republic of Germany has been assessed. The resolution has been country- resp. market-zone wide, as of today, Germany has a single market zone. Import and export flows for cross-border electricity trade have been passed as exogenous inputs to the model. The bidding behaviour and resulting market outcomes at the day-ahead market has been studied, whereby an hourly clearing was assumed, and forecast errors were not explicitly considered.

Modelling Approach: AMIRIS is an agent-based simulation model. It focuses on strategic bidding and dispatch decision-making. All information is only accessible for the respective agent and all information exchanges and actions are controlled by contracts between different agents in the system. Financial flows from markets or support payments are explicitly modelled.

Scenario characteristics: Scenario data for the German case study was obtained from the model Backbone for the scenarios described in Section B.1 above. The capacity mix for the scenarios is depicted in Figure B1. The capacity mix is dominated by PV and batteries, particularly in the case of the flexible scenarios S2 and S4. In contrast, the less flexible scenarios (S1 and S3) require more backup capacity in the form of hydrogen turbines. Other scenario data, such as cost information or vRES feed-in potentials has also been aligned with the Backbone model.

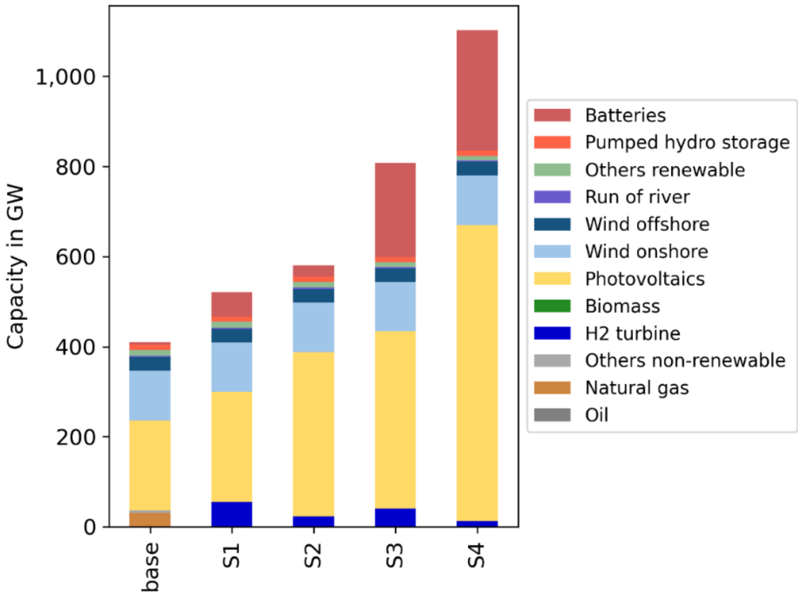

Figure B1. Installed power generation capacities in Germany per TradeRES scenario

Market design elements studied: The focus of the German case study has been on vRES support. Different kinds of vRES support schemes have been studied. These comprise: a fixed market premium, a one-way Contracts for Difference (CfD) and a two-way CfD with a monthly reference period, a capacity premium as well as a financial CfD. A more detailed description of the support schemes can be found in chapter 3.2 of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024).

Assumptions and limitations: Currently, AMIRIS faces some limitations in the representation of multiple competing flexibility options. The dispatch of hydrogen electrolysers as well as industrial demand-side response, i.e. load shedding, is explicitly modelled in AMIRIS. However, the hourly dispatch of other flexibilities, such as storages, flexible heat pumps and electric vehicles, is extracted from Backbone and it is ensured that the same dispatch pattern is applied within AMIRIS.

Concerning the heterogeneity of vRES projects, this is not explicitly depicted as the focus is on average configurations within the system instead of detailed actor-specific cost-benefit analyses. Furthermore, perfect foresight is assumed throughout the simulations, i.e. forecast errors are not accounted for. Also, opportunities at subsequent market stages, such as the intraday market or balancing markets, are not yet depicted.

B.3.3 MIBEL (Portugal/Spain): Case study D

An in-depth description of the MIBEL case study can be found in chapter 3.3 of D5.3 (Estanqueiro, Couto, Algarvio, et al., 2024). For the MIBEL case study, a soft-linking of the Multi-Agent System for Competitive Electricity Markets (MASCEM) and the Multi-agent Trading of Renewable Energy Sources (RESTrade) model was applied. Further information on both models can be found in D4.5, Schimeczek et al. (2023)

Countries and Markets: For the MIBEL case study, the control zones of mainland Portugal and Spain were analyzed, resulting in the consideration of two market zones. The day-ahead and intraday markets account for both countries, while the balancing markets are executed separately for each country, reflecting the current practice.

Import and export flows for cross-border electricity trade were treated as exogenous inputs to the model, based on the existing cross-border capacities in the S0 scenario. For the S1-S4 scenarios, the same approach was used, however, cross-border capacity was assessed hourly using a dynamic line rating approach. This method increases cross-border capacity during most of the analysed hours.

The bidding behaviour and resulting market outcomes in the day-ahead, intraday, and balancing markets were studied, assuming hourly market clearing. The bidding process try to mimic the real behaviour of the electricity markets. Therefore, bid prices are determined by multiplying the respective technology's marginal cost or water value by a random factor within a specified range (+/-10%, batteries (charge and discharge), biofuel, electrolyser, gas, hydro discharge, load, nuclear, other non-renewable and renewable sources, as well as pumped hydro storage (PHS) for both charging and discharging). On the other hand, there are technologies with fixed factor, including demand side response (DSR), electric vehicles (EV), run-of-river hydro (ROR), solar CSP, solar PV (both residential and large-scale), wind (onshore and offshore), hydrogen turbines, and residential heating and cooling system. The corresponding range varies according to the unit's technology type. Thus, bid prices fluctuate within the same technology, aiming to introduce price volatility and competitiveness among players of the same technology, trying to represent real-world scenarios. vRES technologies bids in the different electricity markets are based on power forecasts, according with the methodologies developed in TradeRES

Modelling Approach: The modelling approach implemented in Iberian case study can be seen in Figure B3. The approach uses the MASCEM and the RESTrade models and simulation tools.

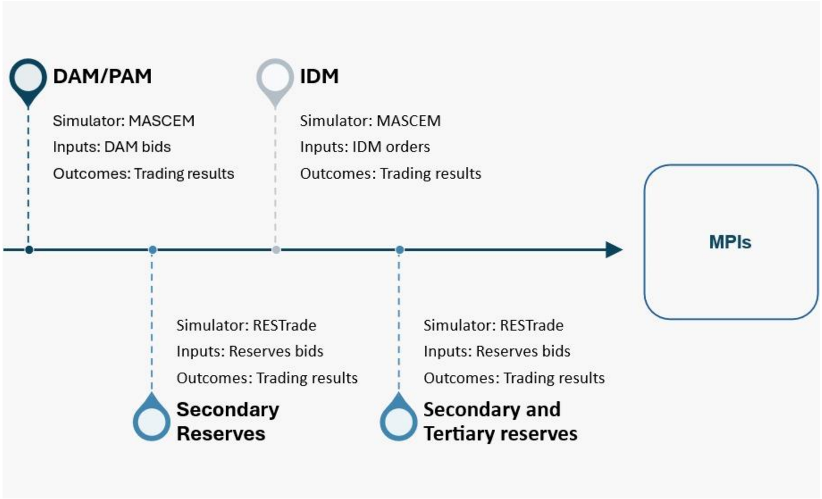

Figure B3. MASCEM-RESTrade coupling workflow.

The implementation of the intra-day market in the MASCEM simulator follows the model used in the MIBEL market. The results of the case study assume that only one period is negotiated in each intra-day session. However, in reality, it is possible to negotiate for different hours within the same session.

Scenario characteristics: Scenario data for the MIBEL case study was also obtained from the model Backbone for the scenarios described above. The capacity mix for the scenarios is depicted in Figure B4. The capacity mix is dominated by solar PV and onshore wind, (onshore) power generation, particularly in the case of scenarios S3 and S4 for Portugal, and S2 and S4 for Spain. Scenarios S2 and S4 require a higher installed capacity for Spain, while S3 and S4 present higher vRES capacities.

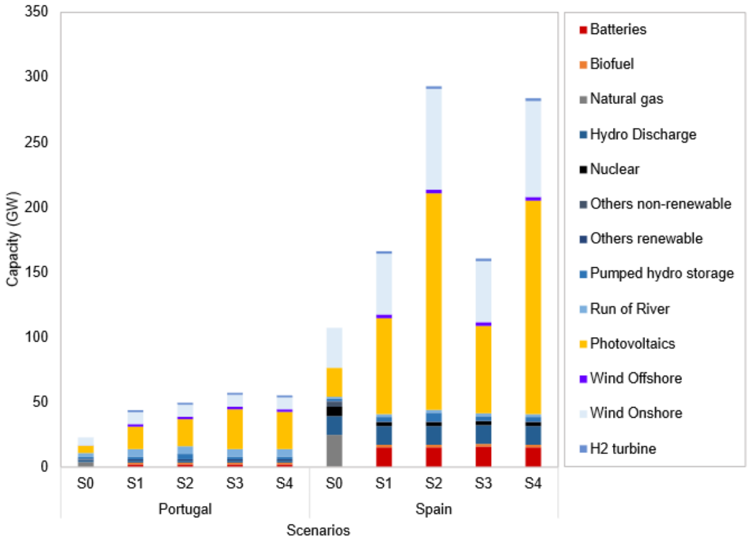

Figure B4. Installed power generation capacity by technology in Portugal (on the left) and Spain (on the right) per scenario.

Assumptions and limitations: The main limitations of the MIBEL case study concern the: 1) input data, 2) energy and price bidding, 3) demand flexibility, 4) representation of the transmission and distribution grids and 5) stationary hourly dispatch and control.

1) **Input data:** This study relies on the data provided by Backbone. It considered the technical and economical characteristics of the technologies presented in Backbone for Portugal and Spain. The study used the MIBEL market participants of 2022 adapted to the capacities of scenarios S0-S4. The number of used agents represents market participants but not their unique characteristics, *i.e.*, their technical, economical and operational features, such as their grid location. The players are aggregated by type, *i.e.*, technology, EV, etc., being the characteristics equal to all. It was only considered two market zones, Portugal and Spain, with one node each connected by a tie-line. However, it was not considered the technical characteristics of the tie lines nor computed the power flow between countries. It was not considered the cross-border exchange with France and Morocco.
2) **Energy and price Bidding:** Bids are submitted based on the marginal prices of the technologies, water values, battery storage and H2 prices. Despite significant efforts to produce realistic input data, the full competitiveness of market players was not applied. Bid prices were determined by multiplying each technology's marginal cost or water value by a random factor within a specified range and did not take into account specific market conditions. Additionally, the strategic bidding approach for vRES players remains static throughout the year. The strategy for these players only considers the volume of energy offered in (i) day-ahead or period-ahead markets and (ii) balancing markets. No complex offers were used. Forecasts are computed based on the representation of some onshore wind parks and solar PV in Portugal being the others aggregated in a single agent. In Spain, Onshore wind and solar PV are represented by players in different spatial areas. The remaining capacity in both countries is represented by aggregated players per country and technology. Inflexible demand is aggregated per country. Forecasts are computed for these players but not for CSP, decentralized solar PV and offshore wind. So, was not considered the deviations of these technologies.
3) **Demand flexibility:** It was considered the prices and quantities of the flexible demand from Backbone except for aggregated pumping prices, and, battery, PHS pumping, electrolyzers and DSR activation quantities. So, the behaviour of some of the demand flexibility, such as EV and heat, was not modelled in the MIBEL study, using the Backbone's outputs.
4) **Transmission and distribution grids:** It was not considered the impact of internally congested distribution and transmission grids in markets. It was computed the aggregated hourly seasonal and dynamic line ratings of all tie-lines connecting Portugal and Spain. Therefore, it was not considered the congestion of specific tie-lines nor the computation of the power flow in Portugal and Spain.
5) **Dispatch and control:** It was not used a dispatch model nor considered the operational characteristics of the players, e.g., ramp rates. The dispatch was

validated based on an hourly energy balance between demand and supply. In balancing markets, it was not considered the frequency control, new stationary hourly deviations were assigned to secondary control and the others (long deviations) to tertiary control.

B.4 Pan-European wholesale electricity: Case study E

Case study E conducts analyses based on the output of the Backbone model for the Pan-European market. First, it should be highlighted that the scenarios are created to identify price dynamics in future markets rather than providing recommendations for an ideal system design or to estimate total system costs. That is because of several simplifications that were made to allow for covering a large technological and geographical scope, while keeping optimizations computationally tractable. They are laid out in detail in Section 3.4.1. of D5.4. (Johanndeiter, Schmidt, et al., 2024) and mainly concern that some capacities in our model are endogenous, while others are exogenously given.

Furthermore, our optimization workflow consisting of an investment expansion based on samples and with a constraint on non-thermal renewable shares, followed by rolling-horizon optimization also leads to the result that – as opposed to standard linear programming optimization problems – investments in new capacities do not necessarily result in zero profits. We argue that this method better reflects a short-term equilibrium in a competitive electricity market with imperfect foresight and policy targets, while the rolling-horizon represents operational conditions, particularly for long-term storage, more realistically. Therefore, the ex-post analysis of resulting profits provides interesting insights on revenue risks of investors in future markets. Similarly, the investment optimization for the analysis of CfD design does not perfectly reflect investor behaviour, as strike prices are calculated based on one particular market scenario, while the modelled investment decisions implicitly contain updated market information. Furthermore, we require additional assumptions to model investments under the basic CfD, which are laid out in more detail in (Johanndeiter, Helisto, et al., 2024).