KAPITEL 3 / *CHAPTER 3* [3]
A REVIEW OF THE EUROPEAN ELECTRICITY MARKET

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Introduction

Over the past three decades, European electricity markets have undergone continuous evolution in response to technological advancements, policy shifts, and socio-economic transformations. Despite this extensive development, the market design remains unsettled, facing new challenges such as the increasing penetration of renewable energy sources, decentralization of production, and the growing importance of demand-side flexibility. These developments challenge the adequacy of the current market model, particularly as smart grids enable the integration of distributed resources and bidirectional power flows supported by real-time data.

Recent literature highlights the absence of a comprehensive solution to current market design challenges. Rather, it suggests the integration of various partial solutions into a coherent and sustainable framework. Numerous modelling approaches have been developed to support electricity market analysis. These include energy system optimization models for normative scenario planning, simulation models for forecasting and operational analysis, equilibrium models capturing competitive interactions, and mixed-method approaches for narrative and qualitative assessments. Each model type offers unique insights, and their combined application may inform the development of a more adaptive and future-proof electricity market architecture. Siala et al. [1] conducted a comparative analysis of five power market modelling frameworks—four optimization models (DIMENSION, EUREGEN, E2M2, and Urbs) and one simulation model (Hector)—evaluating them based on model type, planning horizon, temporal granularity, and spatial resolution. Their findings included recommendations for improved model application. They further categorized electricity market models into three types: partial equilibrium models emphasizing technical constraints, agent-based models, and oligopoly models focusing on strategic behavior.

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Employing a systematic literature review methodology based on PRISMA guidelines, the study examines relevant publications retrieved from Scopus using 11 keyword combinations during October–November 2022. The findings are organized thematically by market mechanism, including: bidding zone configuration, market coupling, nodal pricing, intraday and balancing markets, capacity remuneration mechanisms, market add-ons, market clearing processes, modelling and bidding optimization, risk hedging, and the use of power-based versus energy-based modelling.

3.1. Main criteria of the EU electricity market

Achieving a uniform electricity price across an entire market area would require unlimited transmission capacity and zero losses—conditions that are not technically feasible. Consequently, various pricing mechanisms have been developed. In Europe, uniform pricing is applied within bidding zones, whereas U.S. markets rely on nodal pricing. European electricity is traded either through power exchanges (e.g., Nord Pool, EPEX SPOT) offering standardized products, or via bilateral over-the-counter (OTC) agreements. Exchange-based markets are open, anonymous, and optional for qualified participants. These typically operate through sealed-bid auctions, with market clearing prices determined by the intersection of supply and demand curves. In both zonal and nodal markets, marginal pricing is used to determine the short-term market price [1]. In OTC trading, transactions occur directly between buyer and seller, outside organized exchanges. Since 1999, the EU has progressively established an internal electricity market through directives and regulations aimed at fostering competition, supply security, and sustainability. The current European Electricity Target Model is based on zonal pricing, where bidding zones are defined geographically. Electricity is traded not only as energy but also as transmission capacity and flexibility, due to the spatial and temporal variability of its value [3]. Market structure varies by timeframe. Forward markets facilitate the trading of standardized products from a few years to one month ahead, either through financial exchanges or OTC contracts [2]. The day-ahead market—Europe’s reference market—uses hourly auctions to determine prices for the next day. Intraday markets address real-time fluctuations and generally operate through continuous trading, though some countries (e.g., Italy, Spain, Portugal) use staggered auctions. Balancing markets are critical for maintaining real-time supply-demand equilibrium. Effective spot markets supported by forward contracting and competitive retail frameworks are considered essential for meeting future challenges. A robust climate policy linked to carbon pricing is also necessary to reduce investment uncertainty.

Within bidding zones, limited or no congestion is assumed [2]. When internal or cross-zonal congestion occurs, different pricing zones may emerge. Internal congestion is managed post-market through re-dispatching, wherein Transmission System Operators (TSOs) adjust generator outputs in exchange for remuneration. Cross-zonal capacity is determined using either the Available Transfer Capacity (ATC) or Flow-Based (FB) methodologies. ATC allocates capacity bilaterally at zonal borders, while FB—used within Capacity Calculation Regions (CCRs)—considers grid externalities and involves coordinated TSO calculations. The FB method is preferred due to its potential to enhance socio-economic welfare, security of supply, and price convergence across regions.

3.2. Impact of the criteria on the development of the market

This systematic literature review seeks to elucidate the current discourse surrounding the European electricity market model and its underlying mechanisms, as well as to examine the range of reform proposals aimed at improving its design. The review categorizes findings according to distinct electricity market mechanisms and, additionally, assesses the modelling methodologies employed in the literature. To provide context, the temporal distribution of the selected publications was analyzed, revealing a consistent increase in the volume of research over recent years which presents both absolute and relative annual publication counts. The rise of renewable energy has increased grid congestion and management costs, prompting regulators to consider structural solutions like bidding zone reconfiguration. In Europe, the CACM

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regulation sets criteria for bidding zones focused on network security, market efficiency, and stability.

In the current zonal market, grid constraints distort price signals and investment decisions, leading to increased administrative intervention. They suggest using locational pricing or zone redefinitions to reduce these issues. Felling and reconfiguring price zones in Central Western Europe using clustering algorithms, showing that optimal zones often cross national borders and reduce price disparities. Ambrosius et al. [4] find that anticipated bidding zone changes can encourage earlier investments in generation and transmission infrastructure. With European cross-border capacity targets for 2025, further market splitting reforms are expected. Key indicators for assessing bidding zone impacts include cross-border exchanges, price convergence, social welfare, and loop flows.

Market coupling enables efficient electricity flow across European borders by using price signals to direct power where needed. Through implicit trading—combining energy and transmission capacity trading—it eliminates inefficiencies linked to separate markets for electricity and transmission rights. Also found that market coupling improves generation adequacy and economic welfare in Central Western Europe, recommending its expansion with a stable, harmonized regulatory framework and cross-border congestion managed via implicit auctions. However, expanding interconnections doesn’t always guarantee welfare gains.

In the Core region (13 countries and multiple TSOs and NEMOs), congestion between bidding zones is managed by Flow-Based Market Coupling (FBMC), introduced in 2015 for day-ahead markets and planned for broader use. FBMC’s impact, noting Germany and France’s key roles, with Germany’s high renewable share causing grid congestion affecting cross-border trade. Nodal pricing, also referred to as locational marginal pricing (LMP), reflects the real-time cost of delivering electricity considering transmission constraints and losses between specific nodes in the power grid. This model allows prices to vary spatially, thereby sending more accurate economic signals for electricity consumption and production at different grid locations.

The implementation of a hybrid nodal-zonal pricing system in a joint day-ahead electricity market that included Poland, Germany, the Czech Republic, and Slovakia. In this setup, nodal pricing was applied solely to Poland, while the rest of the market adhered to zonal pricing. Their comparative analysis of this hybrid model with fully nodal and fully zonal systems revealed several key outcomes. Notably, countries subject to significant inflows of wind-generated electricity from neighbouring markets benefited from nodal pricing, particularly in terms of alleviating grid congestion. Additionally, nodal pricing reduced the reliance on costly re-dispatching and load curtailment while enhancing congestion rent collection. Interestingly, the study found that countries with substantial domestic wind power generation might fare better under zonal pricing. Furthermore, the hybrid model led to a reduction in average electricity unit prices compared to a purely zonal system.

In the domain of reactive power markets the application of nodal pricing to incentivize investments in reactive power resources at critical grid locations. They argue that the conventional nodal pricing model for reactive power possesses notable limitations, such as the failure to send accurate economic signals and the omission of opportunity and availability compensation for generators. As a remedy, they propose an enhanced nodal pricing model that incorporates separate payments for the availability of generation capacity, thereby offering a more comprehensive and economically sound approach. Intraday electricity markets are essential for managing short-term fluctuations in demand and supply, particularly in systems with high shares of variable renewable energy sources (RES). Kuppelwieser and Wozabal conducted a comparative analysis of continuous trading systems, such as that used in Germany, and auction-based systems, exemplified by the Italian model, from the perspective of liquidity costs. To capitalize on the respective advantages of these market structures, the authors propose a hybrid intraday trading system, akin to the model implemented in Spain in 2018. In this hybrid framework, auction-based trading conducted several hours before delivery facilitates greater liquidity by aggregating bids and offers. In contrast, continuous trading conducted closer to real-time allows for more accurate adjustments based on updated forecasts, thereby mitigating forecasting errors for RES output. This dual-structure approach is positioned as a means of enhancing market

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efficiency while accommodating the inherent variability of renewable energy generation.

Balancing markets play a critical role in maintaining real-time equilibrium between electricity supply and demand. The potential benefits of regional coordination in balancing capacity procurement using Central Western Europe as a case study. The findings indicate that regional cooperation enables more cost-effective procurement of balancing resources and more efficient electricity scheduling. When balancing capacities are exchanged across borders, and especially when integrated with flexible capacity resources—such as seldom-used high-capacity demand response—there is a reduced dependency on back-up generation.

In the short term, such coordination allows the power system to operate more cost-efficiently without requiring additional capital investments. Over the long term, it may reduce the need for new generation capacity by enabling better utilization of existing infrastructure and market mechanisms. This could also lessen the reliance on financial incentives to attract new investments in generation.

Ehrhart and Ocker [5] studied recent modifications to the design of Germany’s balancing power market. These changes included the implementation of the mixed-price rule (combining capacity and energy bids), the introduction of ‘free energy bids’ to enhance flexibility, the application of uniform pricing to encourage truthful bidding, and adjustments to the prequalification criteria for market participation. The study concludes that the mixed-price rule does not significantly alter market equilibrium but may inadvertently encourage strategic bidding behavior. Moreover, ‘free energy bids’ appear ineffective in promoting competition, while uniform pricing does not reliably lead to truthful bidding. Conversely, the relaxation of prequalification requirements shows promise in reducing system costs and broadening market participation. The transition to low-carbon energy systems—characterized by high shares of variable renewable energy sources (RES)—poses challenges to ensuring long-term generation adequacy. One of the central debates in power market design is whether energy-only markets can sustain adequate investment in generation capacity, or whether supplementary capacity remuneration mechanisms (CRMs) are necessary to guarantee supply security.

Keles et al. [6] explored this issue in the context of the German power market. They examined whether the current energy-only market structure provides sufficient incentives for new power plant investments or if complementary mechanisms such as strategic reserves or centralized capacity markets are required. Their findings suggest that while the energy-only market can maintain market equilibrium in the short and medium term, it fails to ensure generation adequacy over the long term. A strategic reserve can improve investment signals and enhance security of supply in systems with high RES penetration; however, a centralized capacity market demonstrates superior long-term performance. Nevertheless, the authors caution that capacity markets introduce risks of overcapacity, which could lead to inefficient allocation of resources and increased costs. Hach et al. [7] further investigated capacity market designs using a dynamic investment model applied to the British power system. Their analysis considered three scenarios: the absence of a capacity market, a capacity market for new capacity only, and one encompassing both new and existing capacity. Results showed that capacity markets improve generation adequacy and reliability without necessarily increasing total generation costs. Additionally, these mechanisms may stabilize wholesale prices and reduce price volatility—benefits that contribute to overall system robustness.

However, centralized procurement of capacity by non-commercial entities also introduces design inefficiencies, as highlighted by Billimoria and Poudineh [4]. They argue that such mechanisms allocate outage-related risks to consumers, who lack the tools to manage or transfer this risk. Moreover, recovering the costs of procured capacity via volumetric tariffs can result in inequitable outcomes. To address these issues, they propose an “insurer-of-last-resort” model, which embeds a financial risk-reward structure within the central procurement authority, allowing for more efficient and transparent capacity acquisition decisions.

Comparing price-based capacity payment systems and quantity-based capacity markets within an energy-only framework. Their long-term simulation analysis demonstrated that integrating CRMs—especially capacity markets—can dampen construction cycles characterized by alternating periods of over- and under-investment. This stabilization contributes to more predictable and firm system evolution. Furthermore, capacity markets are more effective than capacity payments in promoting long-term investment, increasing supply security, and enhancing system resilience. However, the higher electricity prices associated with such mechanisms may, paradoxically, spur investment in new capacity, even under conditions of uncertainty. The importance of coordination in CRM implementation across Europe showed unilateral national capacity mechanisms to a coordinated, European-wide capacity market. It found that asymmetric adoption of CRMs—where some countries implement capacity markets while others do not—leads to market distortions, investment inefficiencies, and free-riding behavior. In the short term, countries without CRMs benefit from others’ investments; in the long term, these markets experience increasing risks of “missing money,” prompting producers to exit and thereby reducing supply security. Simulation results indicate that coordinated European capacity mechanisms result in lower system costs and capacity requirements due to optimized allocation of resources and relocation of generation investments to lower-cost regions. Nevertheless, reliance on imports may increase for some countries, potentially compromising self-sufficiency during concurrent scarcity events. The United States provides diverse examples of CRM implementation through different approaches adopted by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). As discussed in Ref. [4], ISO New England proposed a two-settlement capacity auction system designed to manage retirement and entry signals effectively. In the first auction, a minimum offer price rule excludes most renewable generation, while retirement bids below the clearing price are assigned a delivery obligation. The second auction allows for the reconfiguration of capacity commitments based on the retirement decisions made in the first round. This two-tiered structure attempts to balance reliability, market efficiency, and technological neutrality, though its exclusionary nature toward renewables raises questions regarding long-term sustainability.

In summary, capacity remuneration mechanisms represent a critical component in ensuring long-term reliability in power systems with increasing shares of intermittent generation. While capacity markets appear to offer more stable investment signals and better manage system adequacy over time, their design and coordination—particularly in integrated regions like Europe—must be carefully considered to avoid inefficiencies, distortions, and dependency risks. Moreover, the emerging capabilities of demand-side participation and storage technologies may provide a cost-effective complement or even substitute to traditional capacity mechanisms.

Effective market clearing is essential for ensuring both economic efficiency and system reliability in electricity markets. It must transparently reflect the interplay between supply-demand balance, network constraints, and system security considerations. Market clearing is typically performed using economic dispatch or unit commitment (UC) models, with the latter accounting for forecasted demand, reserve requirements, and generator schedules.

In Europe, the Euphemia algorithm is used for day-ahead market clearing. It operates at the bidding zone level and aims to maximize social welfare while respecting market and network constraints. Euphemia solves a Mixed-Integer Quadratic Programming (MIQP) problem to determine market clearing prices (MCPs). However, several limitations have been identified in current clearing mechanisms. Challenges such as non-convexities and tight computational timelines have motivated alternative models. Security-constrained models have also gained traction. The Security Constrained Optimal Power Flow (SCOPF) model that ensures system stability by accounting for voltage margins and congestion, while robust clearing models using stochastic and box uncertainty sets.

Pricing rules are another focal point. Linear (uniform) pricing rules, which internalize non-convexities, were found to promote a more efficient generation mix compared to non-linear (discriminatory) pricing schemes. However, their effect on long-term investment signals remains limited.

Clearing models also differ in their treatment of time and uncertainty. Sequential market clearing—used in Europe—clears day-ahead and reserve markets independently, often resulting in inefficiencies. Stochastic and joint market clearing approaches, as used in North America, account for interdependencies and uncertainty in a single optimization framework, showing better social welfare outcomes. Yet, despite the higher efficiency of joint clearing, technical and regulatory barriers may hinder its adoption in Europe.

In sum, while advances in market clearing models aim to better accommodate renewable integration and flexibility, future improvements must balance computational efficiency, reliability, and investment incentives in evolving electricity markets.

Traditional energy-based electricity market models approximate demand as constant within hourly intervals, creating stepwise demand curves that ignore intra-hour dynamics. This simplification can lead to inconsistencies between day-ahead schedules and real-time operations, particularly when ramping constraints are not adequately represented.

Power-based modelling addresses this issue by using continuous load trajectories that account for the ramping capabilities of generation units. This leads to schedules that better align with real-time operational feasibility [8]. Studies show that power-based scheduling improves consistency and efficiency compared to energy-based approaches, especially under high renewable penetration.

Rahmati and Akbari Froud [8] found that while power-based models reduce infeasibilities in scheduling, they can also lead to more volatile price profiles due to greater sensitivity to load fluctuations. Philipsen et al. [9] argue that energy-based markets trade the “wrong product” and demonstrate that power-based models can reduce system costs and improve frequency stability. As renewable energy shares grow, the advantages of power-based market models become more pronounced, potentially yielding significant economic benefits.

Conclusion

The European electricity market model has evolved over decades and now faces new challenges from the energy transition and increased renewables. This article is, to the authors’ knowledge, the first to combine a comprehensive market design review, a

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systematic literature review, and a comparison of modeling methods for specific market mechanisms. The review found that research well identifies challenges in key areas like market clearing, bidding optimization, capacity remuneration, and bidding zone configuration. Optimization dominates as the preferred modeling approach, though varied methods exist within it.

Two main findings emerged: studies largely follow the EU framework and goals without challenging them, leading to a lack of radical reform proposals; and surprisingly few publications address this topic, though research is growing—especially amid the ongoing energy crisis. Looking ahead, as electrification deepens and sectors integrate, more market-focused research is needed. Future studies should assess how the current market model affects investments, particularly in energy storage, and consider regional market differences beyond Europe, such as in the US, Australia, and China.

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