How Many Zones Should an Electricity Market Have? A Cross-Country Perspective on Bidding Zone Design

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Abstract The configuration of bidding zones has become a central issue in the ongoing debate on electricity market design. This paper critically analyzes the effectiveness and limitations of zonal pricing through a comparative analysis of Italy, Norway, and Sweden—three countries with mature zonal systems—and markets such as Texas and California, which initially adopted zonal pricing but later transitioned to nodal regimes. We investigate the institutional, technical and socio-economic factors shaping these divergent trajectories, highlighting how national governance structures and energy system characteristics influence market performance. In zonal market architectures, locational pricing is systematically applied on the supply side, while on the demand side, zonal pricing is optional and depends on the specific market design. By examining zone definition processes, price convergence, redispatch volumes and market liquidity, we identify both the commonalities and context-specific dynamics that underpin zonal market outcomes. While zonal pricing can enhance locational transparency and sup- port efficient investment, its long-term effectiveness relies on regular, data-driven revisions of zone boundaries that reflect evolving grid conditions. Although often conceptualized as an intermediate step toward nodal pricing, zonal pricing in practice tends to exhibit considerable inertia. The evolution of zones is typically gradual, with reconfigurations occurring infrequently and sometimes even resulting in a reduction in the number of zones. The findings support a flexible and adaptive approach to bidding zone design, guided by empirical evidence and aligned with the broader objectives of decarbonization, market integration, and system reliability.

Keywords Zonal pricing, electricity markets, congestion management, bidding zones

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How Many Zones Should an Electricity Market Have? A Cross-Country Perspective on Bidding Zone Design

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1. Introduction

Electricity markets worldwide are increasingly challenged by network congestion, driven by growing electricity demand, expanding renewable generation and transmission infrastructure constraints. Ensuring grid reliability while facilitating efficient market functioning—especially under conditions of climate variability—has placed congestion management at the center of power system design, as the recent blackout in Spain and Portugal has highlighted (ENTSO-E, 2025).

Against this background, zonal pricing has emerged as the dominant approach across European Union, where the internal electricity market has adopted a zonal architecture to balance market efficiency with system feasibility. Zonal pricing operates by partitioning the transmission network into predefined geographic areas or "bidding zones" (BZs)[1], within which electricity prices are assumed to be uniform. This simplification implies that internal transmission constraints are ignored in the day-ahead market clearing process. In principle, each zone aggregates multiple nodes with similar marginal costs and grid conditions. However, in practice, this assumption often proves unrealistic. As generation and consumption patterns evolve, particularly with the rapid deployment of renewable energy sources, internal grid bottlenecks have become increasingly frequent, undermining the foundational assumption of homogeneity within zones[2]. Nowadays, the zonal pricing model is increasingly under scrutiny. Despite its simplicity and political acceptability, its effectiveness in managing congestion is contested. Internal transmission constraints within zones often necessitate costly redispatching actions by Transmission System Operators (TSOs) after the market has cleared, leading to inefficiencies, distorted price signals, and rising system costs. For instance, recent figures report €4.2 billion in congestion management costs in Europe in 2023 alone, reflecting a 14.5% year-on-year increase (ACER, 2024a). These trends raise questions about the adequacy of the current zonal configuration and its ability to cope with growing intra-zonal bottlenecks and ensure economically efficient power flows.

This paper examines whether the zonal pricing framework currently adopted in Europe effectively manages congestion and ensures efficient market outcomes. We begin with the EU

[1]There is no standard size for market zones, but they vary enormously in terms of territory, encompassing extremes such as an entire zone reflecting national borders, such as Germany, and smaller countries divided into several zones, such as Italy.

[2]A useful contrast is provided by nodal pricing systems, as adopted in electricity markets such as the United States (e.g., PJM, ERCOT), Chile, and New Zealand. In these systems, all transmission constraints are explicitly incorporated into market clearing, and locational marginal prices reflect the true cost of delivering electricity at each node.

bidding zone review process to address a core design question: how many zones should a market have? We then assess the experiences of selected electricity markets that have adopted or experimented with zonal pricing, followed by a closer examination of Italy's evolving zone structure. The Italian multi-zone case, in particular, offers relevant insights into whether reviewing bidding zones is necessary to align price signals with the physical realities of the transmission network. Despite the centrality of this issue to electricity market design, the academic literature still lacks a comprehensive analysis of how the number of bidding zones influences market performance. In particular, limited attention has been paid to the dynamic aspects of zone configuration—specifically, the economic and operational implications of adding or reducing the number of zones over time. This paper seeks to address this gap by providing a comparative assessment of different zonal market structures, illustrating how adjustments in zonal granularity affect price formation, congestion management, and market efficiency. These findings contribute to the broader debate on electricity market reform, offering valuable implications for the ongoing discussion surrounding potential redesigns of the Great Britain electricity market (REMA, 2024).

The remainder of the paper is organized as follows. Section 2 reviews the academic literature on methodologies for defining bidding zones, highlighting both theoretical foundations and empirical approaches. Section 3 outlines the legal and institutional framework governing the bidding zone reconfiguration process within the European context. Section 4 presents a comparative analysis of zonal pricing systems across a selection of markets that have adopted or experienced a zonal structure—Sweden, Norway, Texas, California, and Italy—illustrating both convergences and divergences in zonal design and evolution. Section 5 draws lessons from these case studies to identify best practices and policy-relevant insights for the reconfiguration of zonal electricity markets. Finally, the paper concludes by discussing broader implications for ongoing electricity market reforms in Europe and beyond.

2. Zonal pricing in the European electricity market

In Europe, the zonal market design was implemented during the 1990s and early 2000s as part of the transition from vertically integrated monopolies to competitive wholesale electricity markets. Although the concept of nodal pricing was already known at the time—with some markets, such as New Zealand (1997) and the Pennsylvania-New Jersey-Maryland (PJM) interconnection (1998), having adopted nodal pricing—European countries and neighboring nations, including Italy, Norway, and Sweden, opted for zonal pricing instead (Eicke and Schittekatte, 2022). Under this framework, wholesale markets are cleared by power exchanges as if the transmission network within each bidding zone were free of internal constraints. Regardless of the specific implementation of zonal pricing, the fundamental principle remains that day-ahead electricity prices are uniform across all locations within each bidding zone.

The decision to implement zonal pricing in the European electricity market—rather than adopting a nodal pricing system—was primarily the result of a historical and political compromise between efficiency and perceived fairness to consumers and investors. The integration of the European electricity market required a substantial regulatory and institutional coordination effort that could accommodate national sovereignty and regulatory diversity among Member States. A nodal approach would have necessitated the creation of a centralized authority capable of coordinating market design reforms across national jurisdictions, thereby superseding the control of national regulatory agencies. At the time, such centralization was not politically feasible. Given these constraints, the European market design favored a simplified pricing model that respected national borders (Sarfati et al., 2019), thereby minimizing political and economic frictions and enabling a decentralized integration of electricity markets through market coupling.

Zonal pricing was not only a pragmatic solution[3], but also a natural starting point, mirroring the initial approach in the US markets. However, while several US systems (such as PJM) quickly shifted to nodal pricing in response to manipulation and inefficiencies, Europe's zonal systems did not collapse, suggesting more robust infrastructure, stricter regulation, or the absence of highly aggressive actors like Enron Corporation, which notoriously exploited vulnerabilities in US zonal markets. Such strategies would have been far more difficult to implement in jurisdictions like Germany. Nevertheless, although zonal pricing has emerged as a functional solution in Europe, most of the theoretical advantages are often attributed to nodal pricing models. In particular, the recent literature strongly supports nodal pricing systems—also known as locational marginal pricing (LMP)—on the grounds that they explicitly account for transmission constraints in the day-ahead market, as discussed by Hogan (1992) and Bushnell (1999). Under this framework, nodal prices vary in response to network congestion, and each electricity producer is remunerated based on the local price at the node where it operates, which represents the connection between two or more circuits[4]. This allows price signals to accurately reflect real-time grid conditions, thereby enabling more efficient operational decisions and influencing the siting of new generation, consumption, and storage facilities. While nodal pricing offers greater granularity by capturing the true cost of delivering electricity to specific locations, including congestion and loss-related costs, it remains technically and institutionally challenging to implement in the European context, given automatic reconfiguration issues. The lack of a centralized market operator and the absence of standardized dispatch optimization mechanisms across EU Member States constitute significant barriers to the adoption of such a system.

The European approach entails the application of a uniform price within each BZ, thereby promoting greater transparency through a single price signal across a broad geographic area and limiting the market power that individual actors can exert, as explained by the study of Dobos et al. (2025). In a multinational context, this framework also enhances market liquidity and facilitates cross-border electricity trade—an essential element for preventing bottlenecks and minimizing congestion costs at interconnection points. However, the use of a uniform electricity price also presents significant drawbacks (NEMO Committee, 2024). It fails to provide local incentives to adapt to the volatility introduced by increasing shares of renewable energy sources. Furthermore, it can result in notable welfare losses stemming from the constraint of uniform pricing, and it incurs high redispatching costs to address internal congestion within each zone.

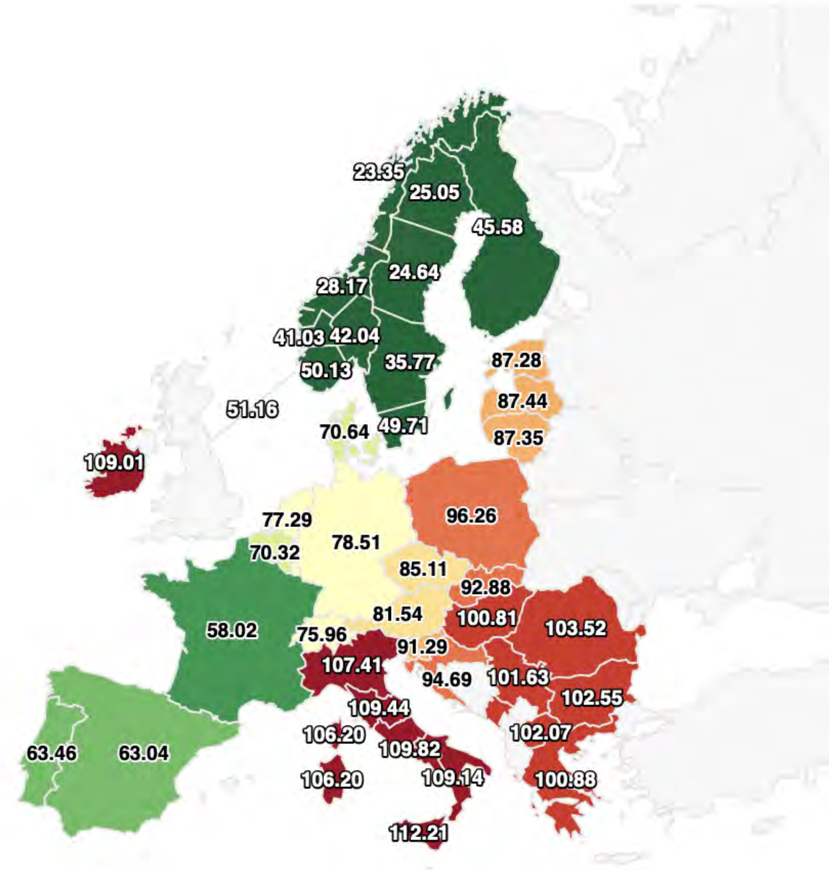
By comparison, PJM, one of the largest wholesale electricity markets in the United States, is a well-established example of the implementation of the nodal model. However, both geographic and electrical scales of the European electricity market, which currently coordinates 61 BZs spread across several Member States (as shown in Figure 1), are significantly larger than those of PJM, which spans 13 federal states and the District of Columbia[5]. Moreover, these 61 zones vary in their configuration: some align with national borders, such

[3]In its simpler application, the zonal system provides for an implementation time of about 18 months, compared to a minimum of 5 years for nodal, which makes it preferable in case of necessary reforms (Ove Arup and Partners Limited, 2024).

[4]Pollitt, M. G. (2023, p. 1)

[5]In terms of size, the ENTSO-E area spans over 4 million km^2 and coordinates more than 1,200 GW of installed capacity with peak loads exceeding 400 GW, across 35 countries and 61 bidding zones. In contrast, PJM covers approximately 820,000 km^2, with a peak load of around 150 GW and an installed capacity of about 180 GW.

Figure 1
Bidding zones in the European electricity market
Average electricity spot market prices in 2024 (EUR/MWh)



Source: ENTSO-E (2024)

as those of France or Germany—whose market is integrated with Luxembourg—simplifying governance and regulatory oversight; others are sub-national, as in the cases of Italy, Sweden, and Norway, which internally divide their territory into multiple bidding zones to better reflect structural transmission constraints and regional differences in supply and demand. This difference in spatial extent, coupled with greater regulatory and infrastructural heterogeneity, poses structural limits to the uniform application of a continent-wide nodal regime. However, over the years, some EU Member States have proposed the implementation of a nodal system. Poland, for example, had planned to implement a nodal pricing system in its internal market in 2015, but the project was abandoned. Although several studies, such as the one by Bjørndal et al. (2018), found that Poland could significantly reduce redispatch costs, the proposal was hindered by neighbouring countries, like Germany, which feared that this reconfiguration would disrupt the integrated zonal market structure, complicating the management of cross-border flows and undermining harmonization at the European level (Frontier Economics and Consentec, 2024). Consequently, although the US experience represents a useful technical benchmark, its full replicability in the European context appears limited, suggesting instead a differentiated and gradual approach.

A final instructive example is offered by the history of the market in Great Britain, which illustrates how multiple countries can instead be aggregated into a single price zone.

In the 1990s, the electricity market in GB was undergoing a significant transformation as a result of the wider privatization wave initiated by the government of Mrs Thatcher. At that time, England and Wales operated as a single integrated market zone under the Central Electricity Generating Board (CEGB) model, which had been dismantled in the early 1990s. Scotland, on the other hand, maintained a separate structure comprising two vertically integrated regional utilities, suggesting a distinct, though not fully deregulated, market structure during this period (Grubb and Newbery, 2018; Davidson and Odubiyi, 2005). It was only in 2005, with the introduction of the British Electricity Trading and Transmission Arrangements (BETTA), that Scotland was formally integrated into a single British market, despite the persistent congestion on the Anglo-Scottish border. In the meantime, Northern Ireland remained institutionally separate from the British market and subsequently developed a unified wholesale market with the Republic of Ireland - the Single Electricity Market (SEM) - which became operational in 2007, creating a single unified electricity trading system across the island of Ireland (CER, 2005).

3. Literature review on defining bidding zones

The European Target model for the internal electricity market (IEM) provides for energy markets - both day-ahead and intraday - structured around a zonal representation of the European electricity system. This zonal logic also extends to the balancing market, where Frequency Recovery Reserves (FRR), in particular within the Europe-wide Manually Activated Reserves Initiative (MARI) platform, are generally purchased and settled at the supply zone level. In these frameworks, BZs play a crucial role in market design and must be established in a way that optimizes congestion management and enhances overall market efficiency, as outlined by the guideline Regulation (EU) 2015/1222, on Capacity Allocation and Congestion Management (CACM). As a result, defining bidding zone boundaries is a key aspect of the IEM and necessitates detailed analysis.

Several studies have analyzed evaluation criteria for defining BZs. The CACM framework sets fundamental guidelines for the definition of BZs, considering factors such as economic welfare, market liquidity, competition, network structure and topology, planned network reinforcement, and re-dispatch costs. However, the European Network of Transmission System Operators for Electricity (ENTSO-E) places greater emphasis on market concentration, liquidity, and price signals, despite the CACM regulatory framework (ENTSO-E, 2024). Building upon this foundation, some studies have proposed additional criteria for bidding zone evaluation. For instance, Supponen (2011) suggests including the direction of wind power flows, while Breuer and Moser (2014) highlights the importance of generation costs, network security constraints, and market power potential. Additionally, Sarfati et al. (2015) introduces five key indicators for assessing the impact of different bidding zone configurations in zonally priced electricity markets, namely Commercial Exchanges Evolution, Price Convergence, Price Divergence, Social Welfare Evolution, and Loop Flows. Similarly, Bemš et al. (2016) identifies criteria that prioritize social welfare, including Congestion Rent, Remedial Actions, Marginal Price Differences, Price Volatility, Transition Costs, and Social Welfare, which can be used to assess the effectiveness of bidding zone configurations. Furthermore, Brouhard et al. (2020) proposes a method that combines sophisticated static grid models with dynamic market simulations, enabling a comprehensive analysis of market efficiency, investment signals, and key performance indicators. Lastly, Griffone et al. (2019) defines ten essential requirements for an effective zonal configuration based on quantitative and objective parameters. However, few existing research provides a direct comparison between zonal and nodal markets[6], and much of it refers to the case of the market in Texas rather than the European context. To bridge this gap, Wu et al. (2024) have developed a set of indicators to effectively evaluate the performance of the Italian bidding zones for the years 2020 and 2021. These indicators allow for a comparison of the main market clearing mechanisms, including:

- Pure economic dispatch, based solely on the intersection of supply and demand curves, without considering network constraints.
- Network-constrained dispatch with nodal representation, which accounts for real transmission capacity limitations.
- Network-constrained dispatch with zonal representation, where the market is divided into bidding zones, considering transmission constraints between them.

Although nodal pricing shows clear advantages in terms of short-term dispatch efficiency, its long-term implications—particularly with regard to investment signals and the development of financial markets—remain relatively underexplored in the academic literature.

4. Legal framework of the bidding zones reconfiguration process

In the Bidding Zone Review Report produced by ENTSO-E (2024a), each national TSO in Europe provides an in-depth analysis of the most efficient configuration of its electricity market. For this reason, the Clean Energy Package[7] affirms that the requirement to undertake a bidding zone review should consider the following rationale behind bidding zones (defined by Article 14.1): *Member States shall take all appropriate measures to address congestions. Bidding zone borders shall be based on long-term, structural congestions in the transmission network. Bidding zones shall not contain such structural congestions unless they have no impact on neighbouring bidding zones, or, as a temporary exemption, their impact on neighbouring bidding zones is mitigated through the use of remedial actions and those structural congestions do not lead to reductions of cross-zonal trading capacity* (Regulation (EU) 2019/943, p. 54–124, Article 14).

According to the report published by ENTSO-E (2024b) on the impact of bidding zone configuration on market liquidity and transaction costs, a reconfiguration of BZs can significantly influence their size, which has a direct impact on market liquidity. The literature generally argues that larger zones improve liquidity due to a larger number of market participants. Studies, such as Hary (2018), ACER (2014) and Laur and Küpper (2020), show that smaller zones tend, on the other hand, to have lower liquidity, making it more difficult to hedge risks, and increase market power issues, which would result in a welfare loss.

[6] See, among the contributions on the topic, the following studies: Zarnikau et al. (2014), Triolo and Wolak (2022) and Wolak (2011).

[7] In May 2019, the EU adopted the Clean Energy for All Europeans package—eight new laws advancing its 2015 Energy Union strategy and based on 2016 Commission proposals—to accelerate the shift from fossil fuels and meet its Paris Agreement targets. While Member States originally had one to two years to transpose these directives, deadlines have since been extended—most notably, the Electricity Market Design reforms (Directive EU/2024/1711 and Regulation EU/2024/1747) required transposition by 17 January 2025. Similarly, the revised Renewable Energy Directive RED III and Directive EU/2023/2413 set a transposition deadline of 21 May 2025. These reforms promise significant benefits for consumers, the environment, and the economy, reinforcing the EU's leadership in the clean energy transition and underpinning its goal of carbon neutrality by 2050.

However, some analyses, as ČEPS, MAVIR, PSE Operator and SEPS (2012), suggest that smaller zones do not necessarily compromise liquidity, turning unplanned transit flows into market-controlled flows. Moreover, in terms of transaction costs, reconfiguring BZs entails substantial transition costs due to the broad range of market and system operations that would be impacted. The creation of smaller, more granular bidding zones would generally involve higher implementation costs than the consolidation or merging of existing zones, as discussed by Consentec for EEX and EPEX SPOT (2015). Empirical research shows that market partitioning can lead to a wider bid/offer spread, reducing liquidity, but this effect is more pronounced in long-term products. In short-term markets, on the other hand, market structure and design play a greater role than the size of bid/offer zones[8]. Liquidity is also critical in intraday markets, which have historically been more difficult to implement under nodal pricing regimes. For example, US nodal markets lacked intraday trading for many years, as discussed by Herrero et al. (2016). Recent efforts, such as the introduction of intraday auctions in PJM, aim to improve short-term flexibility, but can also introduce inefficiencies if producers remain uncertain about dispatch outcomes. However, liquidity concerns are not the only consequence of fragmented market zones. An additional and often overlooked issue is the potential fair value loss in Financial Transmission Rights (FTRs), which arises when market inefficiencies prevent FTRs from accurately reflecting congestion rents. In low-liquidity environments, FTR markets may fail to converge to efficient prices, undermining their role as hedging instruments and further distorting market signals. Some studies, such as Newbery (2002) and Hirth (2006), point out that larger zones shift congestion management to the boundaries, while smaller zones internalize physical network constraints without necessarily reducing liquidity. In addition, market mechanisms such as SDAC (Single Day-Ahead Coupling) and SIDC (Single Intraday Coupling) help to consolidate liquidity, mitigating the effects of a reconfiguration of supply zones. Finally, the restructuring of supply zones affects intra-firm transactions. For vertically integrated firms, the division of zones may entail the need to go through exchanges to trade between different zones, increasing transaction costs but also the volumes traded. Overall, while liquidity in long-term markets appears to be positively correlated with the size of BZs, in short-term markets it is less dependent on it and more influenced by market structure and design.

The actual completion of the single European electricity market came with the start of market coupling in North-West Europe (NWE) on 4 February 2014, thanks to the Price Coupling of Regions (PCR) project. This was joined by South-West Europe (SWE) in May 2014 and Italy in February 2015, leading to an almost complete integration of European day-ahead markets. Subsequently, the first review of the market configuration was launched in 2018. The process ended with maintaining the status quo, i.e. the structure of the BZs as they were previously, given the lack of evidence that the change in configuration would be beneficial. Subsequently, a second review of the ongoing pan-European bidding zones was launched on 5 October 2019, asking all European TSOs to submit a BZs proposal to the regulators for approval. This proposal lacked alternative bidding zone configurations for much of Europe. By 7 April 2020, the TSOs submitted an updated version of the proposal to their respective

[8] Wider bid-ask spreads observed in long-term energy markets are not solely attributable to the exercise of market power. On the contrary, these wider spreads result mainly from structural and liquidity factors inherent in long-term contracts. In particular, the lower frequency of trading in long-term markets leads to lower liquidity, which in turn forces market participants to incorporate higher risk premiums to compensate for the increased uncertainty. In addition, slower price discovery processes and fewer opportunities for arbitrage prevent rapid adjustment of price imbalances. Although market power may contribute to the observed spread, its influence is secondary to the combined effects of liquidity constraints, risk uncertainty and less efficient price discovery mechanisms in long-term energy markets.

regulators, who then forwarded it to the Agency for the Cooperation of Energy Regulators (ACER) for decision. This process highlights a fundamental tension between what can be optimal for the efficiency of an integrated European electricity market and the principle of subsidiarity, which gives priority to national autonomy in regulatory decisions.

Moreover, from an investor perspective, locational pricing can introduce significant risks: long-term local prices are difficult to predict and depend to a large extent on the local investment decisions of network operators, producers and consumers. This unpredictability has contributed to resistance against further zonal fragmentation, particularly in the Nordic region. In these contexts, a market-based capacity mechanism, such as those adopted in some US locational pricing systems, may be needed to ensure the adequacy of investments. A key question remains whether such decisions should indeed be centralized and, if so, what concrete benefits centralization would bring, especially considering that most of the inefficiencies and congestion costs tend to be concentrated within the unreformed national areas. One possible advantage of zonal pricing, however, is political: local politicians in municipalities and counties may be more likely to accept new production if they (and voters) are otherwise penalized by high local zonal prices. This dynamic can help align investment incentives with public acceptance at the local level. However, as the case of the Italian electricity market shows below, inefficiencies and structural bottlenecks can extend beyond zonal boundaries, suggesting that BZs structures may also generate wider market distortions.

The bidding zone review process was initiated in 2018 and is currently ongoing. Initially, on 5 October 2019, all European TSOs submitted a zoning proposal to the relevant regulatory authorities for approval. However, this proposal did not include alternative bidding zone configurations for a large part of the European territory. Subsequently, by 7 April 2020, the TSOs submitted an updated version of the proposal, which was then sent by the regulators to ACER for a final decision.

On 24 November 2020, ACER issued its first decision in terms of revising the zonal configuration, adopting the methodology and assumptions to be used in the process. At the same time, ACER requested that TSOs also submit the results of LMP simulations at this stage in order to decide on alternative bidding zone configurations (ACER Bidding Zone Review). In August 2022, a second decision on alternative bidding zone configurations was published by ACER. These were possible solutions to be considered in continental Europe (Germany, France, Italy and the Netherlands) and the Nordic area (Sweden) to improve market efficiency, as can be seen in Table 1. On 22 December 2023, a third decision was made, following the communication of LMP results concerning the Baltic region, which had been absent from the second publication. According to ACER Decision No. 17/2023, an in-depth and iterative analysis was conducted to evaluate alternative bidding zone configurations for the united synchronous area planned for 2025. For the Baltic region, multiple alternatives were thoroughly examined. The first proposal involved the merger of the Latvian and Lithuanian bidding zones, or alternatively, the merger of the Estonian, Latvian, and Lithuanian zones, with the aim of reducing price fluctuations and increasing market liquidity. The second alternative proposed splitting the existing bidding zones within individual countries to better reflect internal congestion and improve locational price signals. In order to verify the potential economic efficiency and the maximization of cross-zonal capacity of the proposals, ACER adopted the Technique for Order Preference by Similarity to Ideal Solution (TOPSIS)[9] to rank alternative BZ configurations based on price dispersion and internal and

[9]TOPSIS is a multi-criteria decision-making method that identifies the solutions closest to the ideal and farthest from the negative ideal, considering all criteria simultaneously. In this assessment, both indicators were given equal weights to ensure a balanced assessment.

Table 1

ACER Recommendations on Bidding Zones: Country-wise Overview for 2025 target year

Country	Status Quo	Configurations considered by ACER[b]	N. of Zones	Monetised benefits calculated by ENTSO-E (€ million)[a]
Nordic Europe				
Sweden	4	Config 8	3	-7
		Config 9	3	-34.8
		Config 10	4	-2.2
		Config 11	4	-15.9
Central Europe				
France	1	FR3	3	-9
Germany-Luxembourg	1	DE2	2	264
		DE3	3	251
		DE4	4	312
		DE5	5	339
Italy	7	IT2	8	-60
Netherlands	1	NL2	2	9

Source: Authors' elaboration on ACER decision 11/2022 and ENTSO-E Main Report (2025).

[a] The data provided in this table were sourced from Table 53 (p. 105) and Table 62 (p. 127) of the ENTSO-E Main Report on the Bidding Zone Review for the 2025 Target Year.
[b] The names of the proposals are decided by ACER.

loop flows. In addition, as can be seen from the Table 1, for some countries multiple configurations are evaluated to balance the different objectives present in market design, such as improving market efficiency, reducing price volatility, Ensure network stability and optimize the use of transmission capacity. The need for alternative configurations makes it possible to explore different ways of achieving these objectives, taking into account the various factors influencing market dynamics.

From the economic benefits estimated with ENTSO-E projections for the 2025 target year, we can observe that the status quo remains the most efficient solution for most of the countries examined. Only for Germany-Luxembourg do alternative zonal configurations correspond to significant economic benefits, with the division into five zones showing the highest benefits. The detailed results show that an increase in the number of zones does not necessarily correspond to an improvement of the economic outcomes (with 3 zones having lower benefits than 2).

At this stage of the process, Member States have six months to consider the recommendations put forward by the TSOs on ACER's proposed configurations. When the Member States are not unanimous, the European Commission, after consultation with ACER, then also has an additional six months to arrive at a final decision. This process reveals the complexity involved in adjusting bidding zones, both geographically and with reference to the number of zones. Interestingly, while ENTSO-E, ACER, and national TSOs can put forward proposals with respect to configurations of zones, this multiplicity of sources makes the process potentially lengthy and complicated. For example, in the Italian case of introducing Calabria as an independent zone in 2021, the process was relatively swift because it was initiated internally by the national TSO. This demonstrates that, if the national authority opts to reform the market structure, then the process becomes streamlined. By contrast, the lengthy ACER led process will have taken 8 years to recommend a reconfiguration of the German system, which will, quite possibly, be rejected by the German government. This shows the limits of re-zoning led by the EU. The CACM Regulation (Article 34) states that ACER should assess the efficiency of current bidding zone configuration every three years, however the 2018 review will likely complete only in 2026. This slowness reflects the broader challenge of consensus building and harmonization of national and European interests within the redesign of the electricity markets.

5. Examples of zonal pricing systems

A question frequently raised in both political and academic discussions is deceptively simple: what is the appropriate number of zones for an electricity market? In practice, there is no universal answer. The optimal number of bidding zones is inherently context-dependent, shaped by a combination of technical, economic and geographical factors. These include the structure of the transmission grid, the direction and intensity of power flows, the spatial distribution of generation and demand and overarching system objectives such as operational efficiency, market liquidity, and security of supply.

The countries analyzed in the following section show the heterogeneity of approaches adopted in Europe to tackle network congestion and facilitate energy transition. In this context, Italy is a role model for other markets with similar challenges. Many countries, such as Korea, Japan, Chile, Argentina, Great Britain, Norway, Sweden, Finland and Australia, are characterized by 'filiform' transmission networks, with demand concentrated at the end and generation distributed along wide corridors. This geographical configuration accentuates the mismatch between generation and consumption, exacerbating congestion. In such contexts, as the Italian experience shows, solutions such as zonal pricing and innovative market designs are particularly effective in managing structural imbalances in the networks. Moreover, the zonal structure, as well as the nodal structure, allows for hybrid forms of implementation that may facilitate the efficiency of the system. As we will see in the next section, the zonal system is always implemented on the supply side, but not necessarily on the demand side. The Italian market, for example, applied a national average price for consumers until 1 January 2025, to prevent excessive price differences between zones from harming consumers in southern Italy and the islands, where prices were often significantly higher. Subsequently, price differences were progressively reduced thanks to targeted investments in the area, especially in renewable energy production, making the hybrid pricing system unnecessary. In contrast, countries such as Norway and Sweden, which still have substantial price differences between zones, have preferred to apply zonal pricing on the demand side as well. On the other hand, some nodal pricing systems are only applied on the supply side, such as California, where retail consumers are subject to a price calculated on the basis of the weighted average of minimum market prices within three load zones, which correspond to the territories of the distribution network operators (DNOs). These examples illustrate how both zonal and nodal pricing systems can be flexibly adapted through hybrid configurations, allowing policymakers and regulators to balance market efficiency, equity, and political acceptability in response to system-specific conditions and social objectives.

This comparative perspective is particularly relevant for markets—like Great Britain—

Table 2

Number of market zones by zonal pricing market

Country	Date	Peak demand	Number of zones[a]
Norway	2008 – ongoing	25.2 GW	5
Sweden	2011 – ongoing	25.2 GW	4
Italy	2004 – ongoing	49.6 GW	7[b]
Denmark	2000 – ongoing	6.4 GW	2
Australia	1998 – ongoing	32.8 GW	5
California	1998 – 2009	43.9 GW	2[c]
Texas	2002 – 2010	85.5 GW	5[d]
Great Britain	*From 202X?*	*48 GW*	*7–12?*

Source: Authors' elaboration.

[a] The number of zones refers to zonal pricing configurations in place during the indicated periods.
[b] Unlike the other systems which used or currently have zonal prices on both supply and demand sides, the Italian market until January applied zonal prices only to producers, while consumers paid a national average price.
[c] Under nodal pricing, retail consumers are typically settled based on the weighted average of LMPs within three designated load zones, which align with the territories of distribution system operators.
[d] Under nodal pricing, both generators and consumers are exposed to nodal prices.

that are currently considering a major reconfiguration of their zonal design. In recent years, the UK Government has been taking into consideration reforming the energy market, through a wholesale locational (zonal) pricing design through the consultation REMA (2022). The design has been analyzed and refined several times taking into account advice on possible pathways for GB to achieve clean energy by 2030 (CP2030), published by the National Energy System Operator (NESO). Moreover, respectively in 2023 and in 2025, two FTI Consulting reports[10] have presented different assessments regarding the optimal number of bidding zones. The first report proposes a 7-zone structure, while the second presents a 12-zone model, one of the most granular projects among mature electricity markets. The paper offers considerations on the zonal system not only with regard to the imminent decision by the UK to adopt a zonal system or not, but also for other markets which still have a national process structure, such as Germany. Despite clear evidence of structural congestion between the northern and southern regions, Germany continues to operate in one area. Following the Energiewende and the phasing out of nuclear power after Fukushima, redispatch volumes and costs have increased significantly as north-south energy flows intensify without corresponding signals from domestic prices. It is important to note how, in this and many other cases, political and institutional factors have played a decisive role in preserving this market concept. Concerns about economic cohesion, the interests of the industrialized southern Länder and the federal government structure have helped to resist zonal segmentation. Instead, Germany preferred technocratic solutions such as network expansion and redirection reform to structural changes in its supply zone architecture. This underlines that effective market design is not only a technical issue, but is also shaped by political economy considerations.

Table 2 offers a brief overview which highlights a key lesson: there is not a one-size-fits-all number of market zones, but there is the need of an evidence-based assessment of system needs and market conditions. In this light, the experience of other countries that have implemented—or opted against—zonal reforms offers valuable insights.

[10] FTI Consulting (2023) and FTI Consulting (2025)

5.1 The case of Norway

In this comparative analysis of zonal electricity market systems, we begin with the case of Norway—a country dominated by hydropower as the primary source of electricity generation and whose electricity market is organized into five distinct BZs: Eastern Norway (NO1), Southern Norway (NO2), Central Norway (NO3), Northern Norway (NO4), and Western Norway (NO5) (Statnett, 2025) (as shown by Figure 2).

Figure 2
Bidding zones in Norway

Source: Statnett (2025)

The Norwegian electricity market reform was launched with the 1990 Energy Act[11], making Norway one of the first countries to liberalize its electricity sector. Norway started to operate with flexible and temporary zones in 1991, but only in 2008, its market structure began to transition toward a more formal zonal pricing system, progressively increasing the number of bidding zones to better reflect transmission constraints and regional grid conditions[12]. According to Nord Pool Group (2023), between November 2008 and April 2009, the system was initially divided into only two zones: NO1, which encompassed Oslo, Bergen, and Kristiansand, and NO2, which included Molde, Trondheim, and Tromsø. In a first adjustment, Tromsø was separated from NO2 and designated as a standalone zone (NO3) until January 2010, marking the first instance of zone splitting to isolate regional bottlenecks. By March 2010, the zone configuration was further refined: NO1 was split, detaching the regions of Bergen and Kristiansand, which became the new NO2, while Molde and Trondheim were incorporated into a redefined NO3, and Tromsø was reassigned to the newly created

[11]The Act covers the generation, conversion, transmission, trading, distribution and use of energy in Norway.

[12]Norway's mountainous terrain and deep coastal waters make infrastructure costly, with major transport flows often routed through Sweden.

NO4. This restructuring represented a shift toward greater locational granularity in pricing signals. Finally, in September 2015, a fifth zone (NO5) was introduced to isolate the Bergen area, which was previously part of NO2. This consolidation established the current five-zone structure, which remains in use today and reflects an effort to align zonal boundaries with persistent structural bottlenecks in the transmission network. Norway is a clear example of the reconfiguration of BZs over time: the configuration of bidding zones has been changed eight times since 2000, and has varied between two and five bidding zones. This dynamic approach has been important to ensure an efficient utilization of the hydro system and transmission network over this period. Based on the report provided by Energy Norway (2023), not only the split but also merger of zones even across national borders should be addressed. If there is no frequent structural congestion between them and price differences are small, countertrading cost would probably be smaller than the benefits a bigger zone would entail for market development, as the Norwegian case shows.

Since the early 1990s, the Norwegian electricity market has applied market-based principles for congestion management (NVE, 2010). Congestion management systems were introduced when the market was deregulated on the wholesale side and divided into zones, later referred to as Elspot[13] areas. In this model, the day-ahead spot market represents the most important system, where wholesale electricity prices are calculated hourly for the following day through Nord Pool Spot (NPS), the common electricity exchange for the Nordic countries. Electricity supply and demand fluctuate significantly throughout the day. For this reason, hourly price formation is essential to accurately reflect the real value of electricity at any given moment. Electricity prices are free to vary geographically between Elspot areas to ensure economically efficient price signals that reflect both hourly variations and geographical and territorial differences in energy availability and demand. However, unlike a nodal pricing system, where supply and demand bids are placed at a high number of individual nodes, the Nordic market does not provide fully efficient price signals because the division into bidding zones is less detailed compared to a nodal system.

Despite its overall efficiency, the Norwegian zonal market model presents structural limitations. The relatively small number of Elspot bidding zones leads to a market design that does not fully reflect underlying grid constraints or deliver accurate locational price signals (NVE, 2016). Transmission capacity is allocated based on forecasts preceding the submission of binding bids, constraining the efficient use of available infrastructure. Furthermore, the ex-ante publication of trading capacities allows producers to anticipate congestion and strategically adapt their bidding behavior. In particular, vertically integrated producers active in multiple zones may deliberately concentrate generation in low-priced areas, increasing exports to benefit from higher prices elsewhere. This behavior can result in artificial congestion and unbalanced resource allocation, undermining market efficiency. In parallel, some participants may exploit redispatch mechanisms, anticipating compensation through system balancing measures (NVE, 2010). While the zonal structure provides a partial reflection of locational conditions, internal congestion within Elspot areas remains frequent. These inefficiencies necessitate Statnett's interventions through redispatch and countertrading, signaling a persistent misalignment between market prices and real-time grid constraints. Ideally, price signals should internalize both marginal production costs and physical transmission limitations. In practice, however, the current model offers distorted incentives for short-term dispatch and long-term investment, hindering optimal infrastructure development and weak-

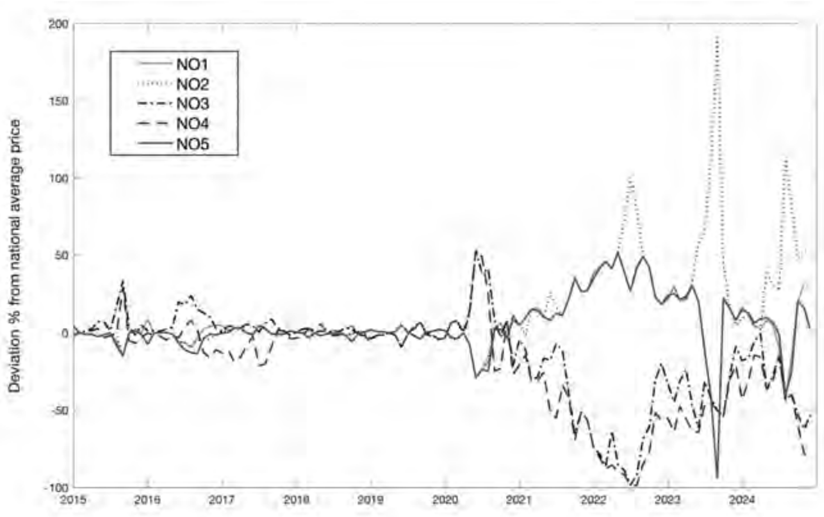
[13] Elspot is the day-ahead electricity market used in the Nordic region. Operated by Nord Pool, it serves as an organized trading platform where market participants submit bids to buy or sell electricity for delivery on the following day.

ening the market's capacity to signal localized scarcity. Nevertheless, the zonal model has been instrumental in managing Norway's hydropower-based system, characterized by high variability due to meteorological and hydrological conditions. Price differentials across zones play a key role in balancing local supply-demand mismatches and promoting efficient resource allocation. Still, persistent inter-zonal price divergences reflect transmission bottlenecks that remain unaddressed, pointing to the need for continued investment in grid infrastructure.

The Norwegian experience illustrates the trade-offs inherent in zonal pricing—balancing operational flexibility and market-based coordination, while exposing the limitations of coarse spatial granularity in high-renewable systems integrated within broader European frameworks. Supply zones have played a crucial role in mitigating the risk of energy shortages within the Norwegian electricity system. As power generation in the country is predominantly hydro-based, the amount of electricity that can be generated annually is conditioned by how full the reservoirs are at the beginning of the year and how much water flows into them over the course of the months. The introduction of the BZs allowed clear price signals to be sent out, incentivizing both the import of energy and the conservation of hydropower resources at times when the risk of future scarcity would be high. Moreover, price zoning has been instrumental in avoiding local energy crises. For instance, during the winter of 2010–2011, Central Norway experienced tight supply conditions due to low reservoir levels and limited import capacity. The zonal pricing system signaled higher prices in this area, encouraging local generation and demand response, which helped in managing the situation without resorting to load shedding. Similarly, in early spring 2013, Western Norway faced challenges due to maintenance work and low inflow to reservoirs. The price signals in the zonal system prompted adjustments in consumption and generation patterns, mitigating the risk of shortages (Statnett, 2023b).

Figure 3

Percentage deviation of monthly average electricity prices from national average price by bidding zone (2015 – 2024)



Source: Authors' elaboration based on ENTSO-E data.

Over the past ten years, the Nordic electricity market has experienced a steady increase in traded volumes. Price differences between areas in Norway have generally increased, especially between southern zones and northern zones (see Figure 3), and deviated from the average during periods of particularly divergent hydrological conditions. Whereas, based on Statnett (2023b), the configuration of the supply zones contributed to increased welfare by providing appropriate incentives to producers and maximizing flows between surplus and shortage areas.

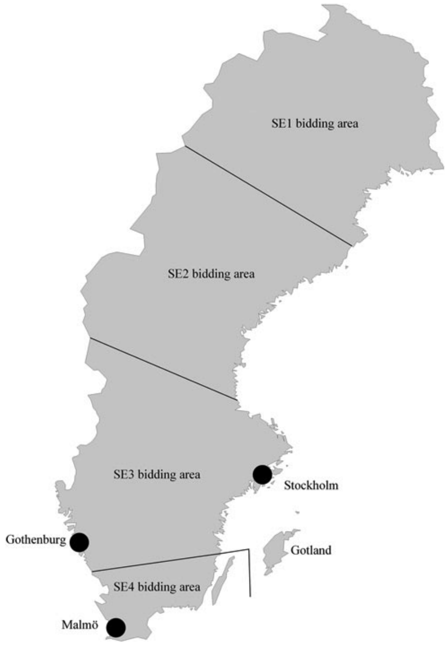
Based on the principle of periodic reconfiguration, the Norwegian TSO, Statnett, has published in 2018 an analysis which indicates that congestion from the northern supply zone, NO4, is expected to increase (Statnett, 2023a). A split of NO4 has therefore been proposed to manage bottlenecks more efficiently. From NO4 there are connections to central Norway (NO3), northern Sweden (SE1 and SE2), and a weak non-market connection to Finland. However, the skewed loading of the corridors prevents full utilisation. Statnett expects this situation to become more frequent due to increased wind power capacity in NO4 and the transmission network's ability to deliver power. The key issue concerns the interaction between the lines to Norway (NO3) and Sweden (SE1). Statnett's simulations show that in many cases the line to SE1 fills up first, leaving capacity to NO3 underused. To resolve this, it is necessary to distribute generation between northern and southern NO4, which is too large geographically to manage flows safely under the current configuration. A more granular zoning may therefore be required to maintain safe operational limits.

5.2 The case of Sweden

Before 1 November 2011, the Swedish electricity market consisted of a single bidding zone, in which energy was traded according to a single price set in the Nord Pool electricity market. Electricity was sold from the North (where cheap and abundant electricity is produced) to the South (where most consumption is concentrated and supply is insufficient to meet demand). However, the transmission line had a bottleneck such that the grid could not always actually deliver the quantity sold. In particular, there was a bottleneck between the northern and southern regions, which meant that electricity bought at the offer price from the North could not flow directly to the South. In congestion situations, the TSO Svenska kraftnät generally reduced exports, particularly to continental Europe, when bottlenecks in north-south transmission emerged. This intervention made it possible to maintain a single, often relatively low price throughout Sweden, even in the presence of internal congestion. This approach is one of the exceptions granted by ACER, which allowed member countries to limit commercial flows on certain lines in the event of internal congestion (Holmberg, 2024). The 70% rule still allows these flows to be reduced by up to 30% for network needs (ACER, 2023). Furthermore, the Nordic network structure, which is predominantly radial with limited loop flows, has favoured a market integration that started already in the 1990s. In contrast, continental Europe is characterized by a more meshed network and more complex flows, which hinder cross-border trade. In 2022, the Nordic and Baltic countries did not make use of exceptions to the 70% rule, unlike most continental countries. Although Sweden sometimes requested exceptions, ACER determined that, as of 2022, internal congestion no longer justified their use (ACER, 2024b). Therefore, cross-border electricity trade appears more reliable in Northern Europe than in other areas of the EU, where expectations of efficiency and transparency are often higher.

In the early 2000s, by reducing the interconnection capacity due to internal congestion, Svenska kraftnät started to treat differently domestic transmission services and transmission services to an interconnector intended for foreign export of electricity. This behavior indirectly led to different treatment of customers depending on their place of residence, contributing to market segmentation between the Member States and the Contracting Parties

Figure 4
Bidding zones in Sweden



Source: Svenska kraftnät (2010)

to the EEA Agreement and preventing customers and producers from taking advantage of the internal market, contrary to the fundamental objectives of the Union. The European Commission started to ask Sweden to stop the practice of curtailing exports on the spot market, reporting it as a distortion of competition. The European Commission (2010) pointed out that the Swedish TSO imposed restrictions on electricity exports to some neighbouring countries (notably Denmark and Finland). These actions were implemented to avoid the need for costly countertrading required to manage internal congestion, in order to maintain grid stability without incurring significant redispatch costs.

In 2007, the Swedish Energy Markets Inspectorate, the TSO, Swedenergy (an umbrella group for producers), and the Confederation of Swedish Enterprise jointly published a report (POMPE, 2007) examining how to split the market. Known by the Swedish acronym POMPE, the report recommended dividing Sweden into two separate price zones. An industry representative from the wind power sector later confirmed that POMPE was widely viewed as the first real move toward a market split (OX2, 2021). Following several years of inquiry, in 2010 Sweden issued a decision mandating that Sweden be split into distinct price areas by 2012. This episode highlights how external institutional pressure—in this case, from the European Commission—can act as a catalyst for market reconfiguration[14] (European Council, 2010). To comply with EU regulations, Sweden adopted a market-splitting

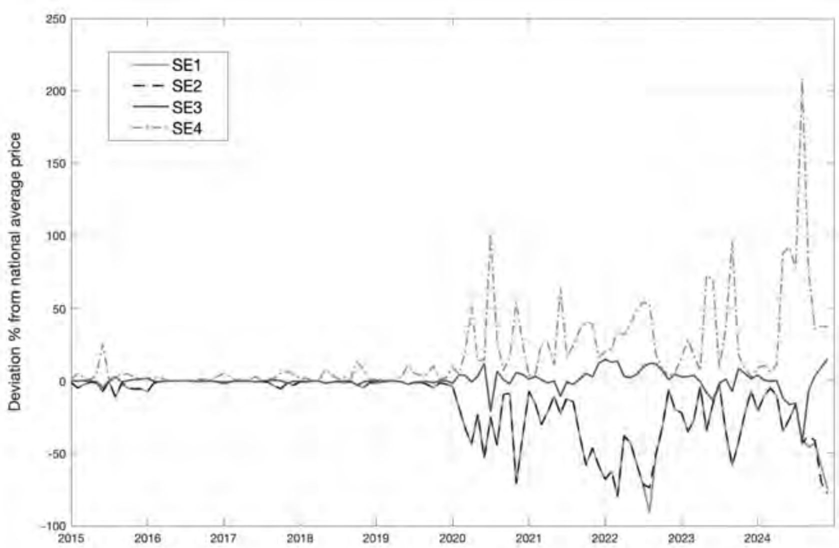
[14]This practice was encouraged by the European Commission with the Electricity Regulation (EU) 2019/943, which requires TSOs to allocate transmission capacity on a non-discriminatory basis. In the case of Germany, however, the situation is more complex. Although Germany has not introduced multiple bidding zones, it has reached an agreement with Denmark to comply with the 70 per cent rule in the day-ahead market, while addressing internal congestion through extensive redispatching and counter-trading costs for which Germany bears full responsibility, spending several billion euros annually on counter trading. In contrast, countries like Norway, outside the EU framework and not bound by the 70% rule, typically manage congestion by reducing exports. This reflects the approach taken by other EU countries prior to the implementation of stricter rules on cross-border trade.

approach, introducing four bidding zones: SE1 (Luleå), SE2 (Sundsvall), SE3 (Stockholm), and SE4 (Malmö) (see Figure 4). The goal of this restructuring was to better reflect physical transmission constraints and provide more efficient price signals, encouraging targeted investments to alleviate congestion (Lundin, 2021).

Holmberg and Tangerås (2023) show that one of the most relevant impact of zonal pricing is a significant price divergence between the southern SE4 zone (Malmö) and the rest of Sweden (Figure 5). SE4 experiences higher prices due to limited transmission capacity from the northern regions and Denmark. In the first months following implementation, price differences were particularly pronounced due to cold winter temperatures that increased demand, reduced transmission capacity between Sweden and Finland that limited energy imports, and temporary outages at Ringhals nuclear reactors that constrained supply. As expected, over time SE4 prices became more aligned with those in DK2 (Western Denmark) due to geographic proximity and strong electricity trade between the two areas, showing consistent price differences across various zones compared to the average national price.

Figure 5

Percentage deviation of monthly average electricity prices from national average price by bidding zone (2015 – 2024)



Source: Authors' elaboration based on ENTSO-E data.

At the same time, in the long term, the new zonal configuration led to several structural benefits, including increased competition and transparency, as market prices began to more accurately reflect local supply and demand conditions. Additionally, it provided clearer investment signals for reinforcing the transmission network and developing new generation capacity in critical areas. The restructuring also highlighted the need for further infrastructure improvements to address congestion issues between zones. The introduction of the zonal system marked a key step toward a more efficiency-driven market approach, allowing Sweden to align with European policies aimed at enhancing electricity market integration and fostering competitiveness in cross-border electricity trade.

To observe the effects of Sweden's zonal market division, we refer also to the findings from Loiacono et al. (2025). The authors use a comprehensive dataset of hourly observations from 2005 to 2019. SE1 and SE2, located in the North, exhibit a positive demand-supply imbalance, whereas SE3 and SE4, in the South, have higher prices and a negative demand-supply imbalance (see Table 3). This outcome aligns with the observation that the northern zones have abundant renewable (mainly hydropower) generation, while most loads are concentrated in the southern part of the country. If we assumed there were no constraints in the market, equilibrium would be reached by presuming that sufficient energy could be transferred freely throughout the country. However, due to transmission limits, it is not possible to achieve such an equilibrium, and the division into four zones highlights this characteristic by resulting in higher prices in the southern zones, where low-cost hydropower is relatively scarce.

Table 3

Electricity consumption, production and hydro share by Swedish zone (TWh)

Zone	Consumption	Production	Prod. hydroelectric
SE1	8.2	19.9	19.2 (96%)
SE2	15.2	39.5	37.4 (95%)
SE3	84.8	78.8	11.4 (14%)
SE4	23.7	6.3	1.7 (27%)
North	23.4	59.4	56.6 (95%)
South	108.5	85.1	13.1 (15%)

Source: Loiacono et al. (2025)

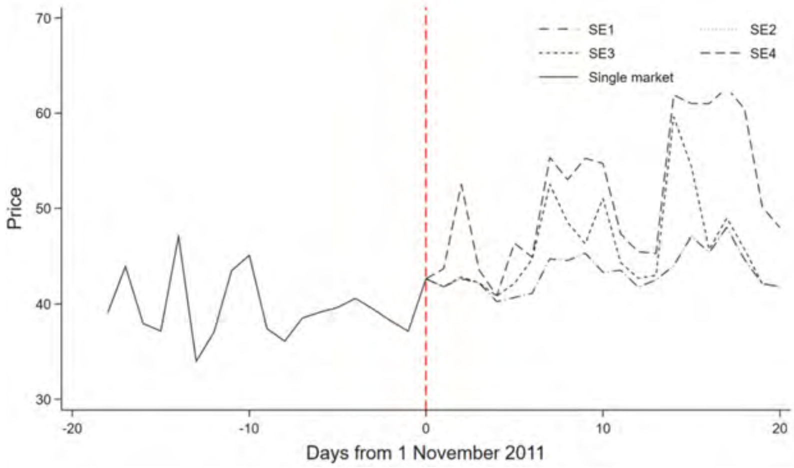
Note: SE1 and SE2 are located in the North of Sweden, while SE3 and SE4 are in the South.

The aim of the work of Loiacono et al. (2025) is to analyze the impact of the shift to the zonal system in Sweden on electricity prices by comparing price developments in the four zones before and after the policy intervention of shifting the market from national to zonal. For this analysis, they use a Regression Discontinuity in Time (RDiT) approach, assuming that, in the absence of the reorganization of the market, prices would have changed continuously at the cutoff date (1 November 2011). Based on a preliminary inspection, prices are found to be higher in the southern area (SE3 and SE4) than in the northern area (SE1 and SE2). The authors estimate the effect both in linear form (prices in absolute values) and in logarithmic form, with clustered errors at the weekly or monthly level. They enter dummies for each zone and interact them with the treatment variable to capture the price variation in each zone after the intervention. The results show that in the northern zones (SE1 and SE2) the price increase is similar, while in SE3 and SE4 the effects are more pronounced. This indicates that zoning has indeed differentiated territorial prices, especially in the South, where demand and population concentration are higher and there are transmission constraints from the North. Moreover, the overall price of energy increased across Sweden after the implementation of zonal pricing in the next 20 days after the reconfiguration. This result can be explained by the fact that, after November 2011, exports increase of more than 150% (see Figure 6).

The initial increase in zonal prices following the splitting of the zones in 2011 was particularly evident in the first 20 days. However, when examining the price trend over the following two years, a reduction can be observed compared to the uniform price calculated in the two years prior to the reconfiguration (see Figure 7). This phenomenon can be interpreted as a typical learning period in electricity markets, during which the market adjusts to the new zone configuration (Doraszelski et al., 2018). In fact, within the framework of its Bidding Zone Review Process, ACER generally includes a transition period during which stakeholders assess the impacts on liquidity, congestion, price convergence, and overall market efficiency. This monitoring period, which may last several months, is crucial for gathering data and providing assessments after the initial adjustment phase.

Figure 6

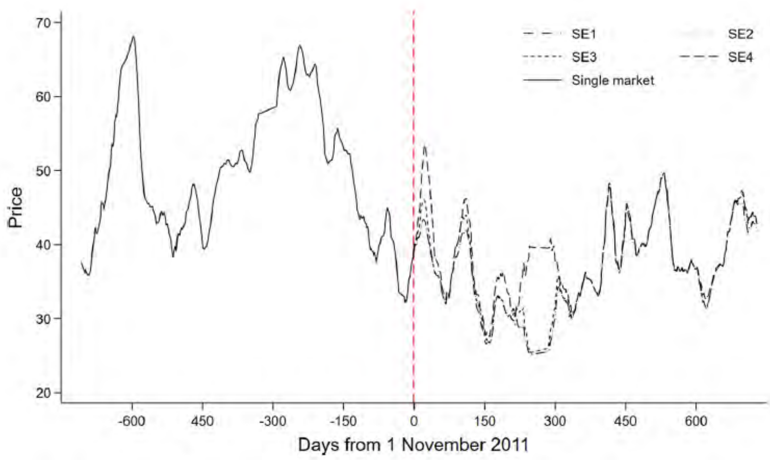
Price discontinuity at the cutoff: prices in the single market and the four zones of Sweden, ***20 days*** *before and after the policy intervention on November 1, 2011.*



Source: Loiacono et al. (2025)

Figure 7

Price discontinuity at the cutoff: prices in the single market and the four zones of Sweden, ***2 years*** *before and after the policy intervention on November 1, 2011.*



Source: Loiacono et al. (2025)

These events sparked political debate until 2024, when the Swedish government rejected a proposal to build a new submarine cable, the Hansa PowerBridge project, for the export of energy to Germany. The Swedish government has stated that connecting southern Sweden, already in an energy deficit, to an inefficient foreign market such as Germany could further destabilize domestic prices. It was added that Sweden would only be willing to reconsider the project if Germany reformed its electricity market, Splitting it into bidding zones to better reflect grid conditions and prevent the over-attraction of low cost Swedish electricity (Milne, 2024).

An interesting point not directly studied by these authors would be to observe, through a counterfactual analysis, how the energy price in Sweden would have been in the absence of the market reconfiguration. If, however, we look at the descriptive statistics on import, export, net export and internal demand in those years, it can be seen that domestic demand and imports remained mostly unchanged in the two years before and after the implementation in November 2011 (respectively a change of 1.16% and 1.18%), while exports increased considerably, with a change of 155.41% before and after treatment, considering a time interval of four years (two years before reconfiguration and two years thereafter). This corresponds to what we hypothesize as a possible explanatory scenario: exports rose after Sweden was no longer permitted to limit them, which contributed to higher prices in SE4. These exports were sensitive to the emerging price differentials revealed by the zonal structure, and the new incentives led to increased flows toward Continental Europe. As export volumes increased, transmission constraints on the southern interconnectors became increasingly tight, operating at or near capacity. According to our interpretation, this export constraint contributed to the rise in electricity prices in SE4, as surplus local supply could no longer flow outward to meet external demand, thereby pushing prices upward to clear the local market. From this perspective, the price increase observed in southern Sweden after the reconfiguration would not primarily reflect changes in national-level supply and demand, but rather the effect of structural bottlenecks and enhanced export incentives brought about by the new zonal market design.

5.3 The case of Texas

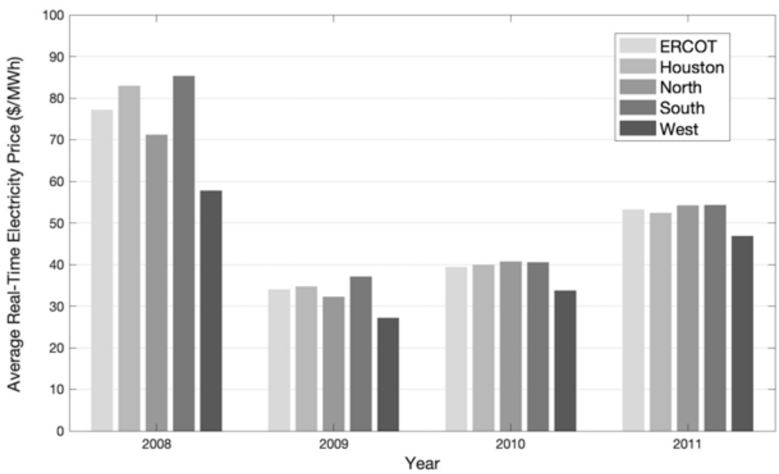
From 2002 to 2010, Texas adopted a zonal market structure, designed to address congestion management in the electricity grid and optimize the distribution of power between different geographic zones. The market was divided into five price zones, each of which had its own electricity price determined by the balance between supply and demand. These separate zones allowed ERCOT (Electric Reliability Council of Texas) to monitor and manage congestion, improving reliability and reducing the risk of blackouts. To monitor inter-zonal congestion, Commercially Significant Constraints (CSCs) were adopted, which represented the operational limits between zones and helped to optimally manage power flow (Mickey, 2018). Within zones, average displacement factors were applied that determined how generation resources in one zone could be used to meet demand in another. This system helped to allocate energy more efficiently, taking transmission capacity and congestion into account. In the event of imbalances between supply and demand, ERCOT used zonal balancing energy to ensure that all zones received sufficient energy, shifting electricity from the less congested zones. Zonal congestion costs were allocated directly to those causing the congestion, applying the principle of 'cost causation'. This system incentivized the efficient management of resources and the reduction of congestion. When situations of high demand occurred within a zone, local congestion management came into play, allowing the activation of 'out of merit' resources to ensure system stability, even if this meant an increase in operating costs. In addition, to avoid price manipulation, there were mitigated offers, which limited price growth in congestion situations, especially during hours of high demand. This congestion and resource management system allowed the zonal market to maintain efficiency and reliability, while facing the challenges of grid congestion and sub-optimal power distribution.

The Texas electricity market is another example of how zones within the market can change. ERCOT's State of the Market Reports show that in 2003, the market was divided into four main zones: Houston, North, South and West. In 2004, a new zone, NorthEast, appears, bringing the total to five zones (Houston, North, NorthEast, South and West). This five-zone configuration remains unchanged in 2005 and 2006. Then, in 2007, the NorthEast zone is removed and the market returned to the original four-zone division (Houston, North, South, West) until the reconfiguration into a nodal structure.

As Figure 8 shows, within the State of the Market Report Real-Time Market (ERCOT, 2011), there were four geographic market zones in the last four years of the zonal system: Houston, North, South and West. The table shows the annual average price for each zone, calculated by multiplying the energy price in each range and zone by the total load in that range, then aggregating the results. As of December 2010, the market switched to a nodal system, so it is possible to see the difference between prices based on the nodal real-time energy market and those derived from the zonal balancing energy market. Load-weighted averages better reflect what consumers actually pay, as real-time energy prices are generally aligned with bilateral contract prices. In 2011, the average price across ERCOT was 35% higher than in 2010, with the system-wide load-weighted average rising from \$39.40 per MWh in 2010 to \$53.23 per MWh in 2011. This increase in prices observed in 2011, particularly in February and August as reported by ERCOT (2011), was driven by extreme weather conditions that led to operational shortages resulting in real-time energy prices of \$3,000 per MWh for extended periods of time.

Figure 8

Average Energy Market Prices in Texas zones (2008-2011)



Source: Author's elaboration based on ERCOT data.

The transition from zonal to nodal has led to multiple changes in terms of efficiency and energy price levels. As the Table 4 shows, the implementation of the nodal market resulted in lower price volatility than the zonal market. In terms of price volatility, it can be seen that the West zone has continued to have higher levels than the other zones, which is to be expected given the very high penetration of of variable wind generation in that area, as explained by ERCOT (2011). According to the ERCOT guide, the zonal model was primarily based on the transfer capacity of the 345 KV transmission system. In practice, transmission flow studies were conducted, the results of which made it possible to group load- and generation-related transmission points into sets that have a similar effect on flows along the main corridors, which reach their limits in contingent situations (such as load variations, dispatching or faults). These corridors formed the basis for identifying 'Commercially Significant Constraints' (CSC), which formed the basis for defining the zones. Finally, the transition to the nodal system was fully implemented, both on the demand and supply side. Within ERCOT, all loads in areas where electricity is open to retail competition are served at nodal prices, which accounts for about 75% of customers, exposing them almost entirely to the nodal system (Ove Arup and Partners Limited, 2024).

Table 4

Price Change as a Percent of Average Price in Texas

Zone	2010 – Zonal	2011 – Nodal
Houston	17.8%	14.0%
South	17.1%	14.5%
North	17.7%	13.1%
West	18.5%	17.1%

Source: ERCOT (2011)

5.4 The case of California

The Californian electricity market is a second example of how a market has evolved from a zonal to a nodal system, due to the constraints imposed by the initial market structure and the need to improve efficiency, transparency and reliability.
The state's transmission network, prior to the establishment of the California Independent System Operator (CAISO) in 1998, was controlled by a set of vertically integrated utilities, whose individual sectors were managed separately. Following the deregulation of the electricity market, CAISO was established to provide services to manage the high-voltage transmission grid and supervise wholesale market operations throughout California (CAISO, 1998a). Since 1998, the CAISO has adopted a zonal market structure, defined by four congestion zones: North of Path 15 (NP15), South of Path 15 (SP15), Humboldt, and San Francisco. However, due to lack of adequate competition in the Humboldt and San Francisco zones, they had been designated 'inactive zones' and were treated collectively as a single congestion zone included in NP15 (CAISO, 1998b). Thus in practice there were actually only two active congestion zones in the ISO system. These zones, which were later called pricing nodes, were intended to reflect regional transmission limits and take into account the different supply and demand conditions throughout the state, with the intention of simplifying congestion management and providing differentiated price signals for different areas.

It was soon apparent that the zonal system had structural vulnerabilities (CAISO, 2001). Treating intra-zonal congestion as negligible often resulted in unfeasible dispatch schedules, causing considerable stress on real-time operations. This inefficiency manifested itself with particular force during the California energy crisis of 2000-2001, when market instability was caused by the absence of accurate congestion costs and inadequate coordination mechanisms. As a result of these problems, the Federal Energy Regulatory Commission (FERC) issued a series of orders requiring the CAISO to redesign its market and correct its operational deficiencies. The result of these negotiations and deliberations was the Market Redesign and Technology Upgrade (MRTU), which went into effect on 1 April 2009 (California Public Utilities Commission, 2011). The MRTU ended the zonal market and ushered in a comprehensive nodal market with fundamental reforms to electricity pricing and dispatch in California. Perhaps the most significant of these changes was the replacement of three active congestion zones with approximately 3,000 nodal price points (nodes), facilitating local marginal pricing for each individual node. In this way, the spatial resolution of price information increased exponentially, allowing the market to capture network constraints much more effectively. The MRTU brought back a centralization of the day-ahead energy market that had not existed since the failure of the California Power Exchange in 2001, creating a new system that provided for the simultaneous co-optimization of three vital elements: energy, ancillary services and transmission congestion.

Despite the implementation of a nodal pricing system in California, consumer exposure remained zonal. To address this, the CAISO adopts a hybrid model, where consumers are charged the weighted average of nodal prices within three designated load zones, which correspond to the territories of distribution system operators (DSOs). As discussed by Neuhoff (2011), aggregating pricing regions, which involves averaging nodal prices across a region, is a commonly used strategy to mitigate consumer price risk exposure. While nodal prices are typically calculated and applied for generation and large loads, retail customers are generally charged an average price based on the nodal prices within the respective region. This approach combines a physically accurate representation of the network with a simplified pricing mechanism for user segments that exhibit limited price responsiveness.

Although technically valid, the shift to a zonal system in 1998 received mixed comments, as discussed by Alaywan (2012) in his study about the process of migrating from a decentralized and zonal based market system to centralized and nodal one.
Proponents of the zonal, especially some Load-Serving Entities (LSEs) and municipal utilities, system argued that zonal pricing represents a simpler and more transparent market that achieves a better balance between efficiency and fairness and allows greater levels of flexibility and innovation in market engagement. Those who criticized nodal pricing noted that its complexity could minimize transparency and stifle the evolution of personalized market products (Eicke and Schittekatte, 2022). However, supporters of the nodal model, such as CAISO[15] and independent power producers, emphasized its greater economic efficiency. Congestion pricing per node allowed for more efficient dispatching, promoted competitive outcomes and facilitated the optimal location of investments in generation and transmission. The nodal model also served to minimize dependence on costly off-market redispatching, a major operational inefficiency of the zonal regime.

5.5 The case of Italy

Before 1999, electricity trade in Italy consisted of a patchwork of bilateral agreements concluded within the framework of regional monopolies. Then, on March 16 1999, the market reform created a legal framework for a centralized wholesale market, opening the door to transparent and coordinated trading and the first taste of congestion management. In 2004,

[15] Supported by recent evidences provided by CAISO (2023)

the Italian Power Exchange (IPEX) was launched and, for the first time, spot prices were set by the meeting of supply and demand within each geographical zone, subject to physical transmission limits, with additional 'virtual' zones for international interconnectors (with neighbouring markets, Corsica, France, Austria, Switzerland, Slovenia and Greece) and small 'limited production' poles, which only inject electricity into the system, including Brindisi and Rossano hubs. While consumers take as their reference price the Single National Price (PUN), which is the weighted average of zonal price quotations for end customers. This led to 1 January 2025, when Italy withdrew the Single National Price, and switched all end customers to their local zonal price. Today, the PUN only survives as a consumption-weighted benchmark, with each market player negotiating at a price that truly reflects the physical reality of their zone. Since 2021, the Italian electricity market is constituted by seven national zones, North, Centre North, Sardinia, Centre South, South, Calabria and Sicily.

The key characteristic of the Italian electricity market is the pronounced energy divide between the North and the South, which significantly influences market prices, transmission flows, and investment strategies. The North experiences high electricity demand and benefits from strong interconnections with neighboring countries such as France, Switzerland, and Austria, enabling substantial electricity imports. While, the South, along with the islands (Sicily and Sardinia), hosts a high concentration of renewable energy production, particularly from solar and wind sources. However, the transmission infrastructure linking the South to the North remains limited, leading to frequent congestion and zonal price differentials. This imbalance between generation and demand, combined with transmission bottlenecks, creates an ideal setting for assessing the impact of zonal pricing on congestion management and market design in renewable energy integration.

Figure 9

Italian market zones before and after 2021

Source: Terna

The increase in Renewable Energy Systems (RESs) capacity and the resulting changes in generation profiles have significantly altered power flow patterns and shifted the location of structural congestion. These changes lead to higher re-dispatching costs for TSOs and a reduction in social welfare. One of the key solutions to address these issues is the redefinition of electricity market bidding zones (Terna, 2024). Before December 31, 2020, the Italian electricity market was divided into six bidding zones: North, Centre-North, Centre-South, South, Sicily, and Sardinia. However, since January 1th 2021, the configuration of the Italian market bidding zones has been modified. Firstly, the Umbria region was reassigned from the Centre North to the Centre South zone. This adjustment aimed to better account for regional negotiations and congestion impacts, ensuring that the zonal structure aligned with the geographical distribution of generation and demand and the operational dynamics of the electricity market[16]. A significant update was the creation of the Calabria bidding zone, introduced to better manage renewable generation growth in the region. By treating Calabria as a separate zone, the market could capture price signals more accurately and improve power flow management, as it is shown in Figure 9.

This reconfiguration was based on expert evaluations of ENTSO-E (2023b), raising questions about whether such modifications contribute to improving market liquidity and efficiency and what criteria should be used for an optimal assessment. The primary motivation behind this change was to adapt the market structure to the evolving energy landscape, improve market efficiency, and enhance grid management in response to shifts in generation patterns and regional dynamics. Moreover, the decision to reconfigure the market, as can be seen from the Italian case, is accepted and politically facilitated when changes to the zone are not expected to significantly alter average electricity prices. As zonal prices were very similar in the Italian electricity market in 2020, this reflected a broader dynamic in which alignment with EU recommendations was more likely as national economic impacts were perceived to be limited, thus reducing resistance to structural reforms even when technically justified.

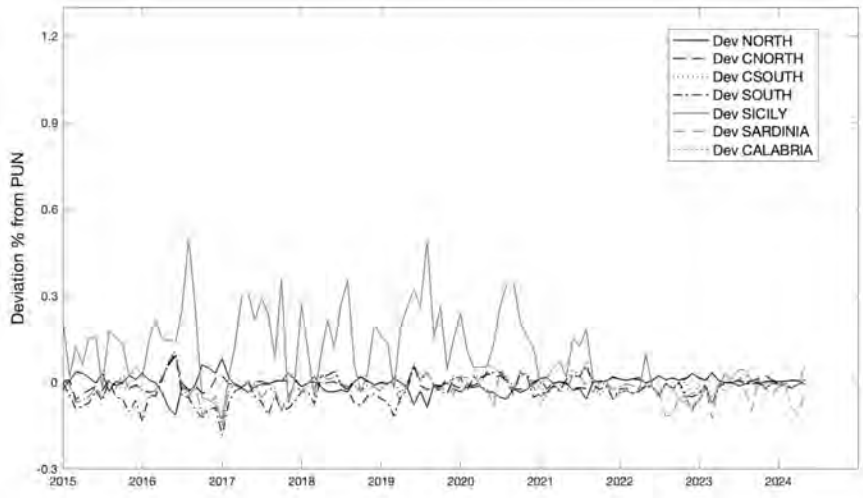
One key aspect of the reconfiguration was the removal of four production hubs (Priolo, Foggia, Brindisi, and Rossano)[17]. This decision was driven by changes in transmission capacity, as grid expansion projects allowed for a more streamlined and efficient market structure. Additionally, some generation capacity was phased out to reflect the changing energy mix, particularly the increasing role of renewable energy sources. This adjustment considered the impact of renewables on power flows and ensured that the market framework aligned with these transformations.

Electricity zone prices in Italy show a trend of gradual convergence, distinguishing themselves from countries such as Sweden and Norway, where price differences between zones remain more marked and persistent. In Italy, the differentials between supply zones have narrowed over time, a sign that investments in network capacity, together with more efficient market dynamics, are helping to equalize price signals. This harmonization process reflects a greater integration of the internal market and a reduction in structural congestion, resulting in a flattening of zonal spreads. Figure 10 shows the percentage deviation of the monthly zonal prices of each zone of the Italian electricity market from 2015 to 2024 (considering Calabria from 2021 onwards) compared to the national average price (PUN), from which it can be seen that the islands in particular have had greater divergence from the total average of prices. Note that the scale in Figure 10 is much smaller than both Figure 3 and Figure 5.

[16] It should be noted that, in the case of Umbria, this change was primarily a boundary movement, meaning that the adjustment mainly involved redefining the regional boundaries to better align with actual grid dynamics rather than representing a wholesale change in market conditions.

[17] Production hubs are specific geographical areas within the Italian electricity market that were designated as separate virtual bidding zones due to network constraints and operational limitations. These hubs typically included large power generation facilities that were subject to particular grid congestion management needs.

Figure 10
Percentage deviation of monthly average electricity prices from PUN by bidding zone (2015 – 2024)



Source: Authors' elaboration based on GME data

The process of reconfiguration for the Italian market started in 2019 by the Italian TSO, Terna, which has developed a number of alternative configurations based on a specific, so-called 'Expert-based' approach, whereby TSOs determine the zonal structure by leveraging statistical analyses, their in-depth knowledge of the electricity system, and insights from various relevant studies in the A*nnex 4: Justification of configurations of the Bidding zone review region Central Southern Italy* (ENTSO-E, 2019). This study includes the Ten-Year Network Development Plan[18], the Medium-Term Adequacy Forecast[19], the National Development Plan, and other technical assessments conducted by Terna. This methodology has been widely adopted and has proven its effectiveness in the Italian electricity market. Alternatively, Bidding Zone configurations can be defined using dedicated clustering algorithms and techniques, called the "model-based" approach. This method has the potential to generate more efficient supply zone delineations, as it is based on quantitative optimization models rather than expert judgement. However, it is still in the research and development phase and further refinements are needed before it can be fully implemented on a large scale.

Terna adopted an expert-based approach for the Bidding Zone review, while simultaneously developing a step-by-step process to refine and integrate model-based techniques for future applications in the Italian electricity market (ENTSO-E, 2023a). As part of this review, six different Bidding Zone configurations were evaluated (shown in Figure 11):

1. Current Configuration: The existing zonal structure in place before the review.
2. Baseline Alternative: Introduced several modifications:
    - The Umbria region was reassigned from the Centre-South to the Centre-North Bidding.
    - All virtual Bidding Zones were merged into their corresponding geographical zones.

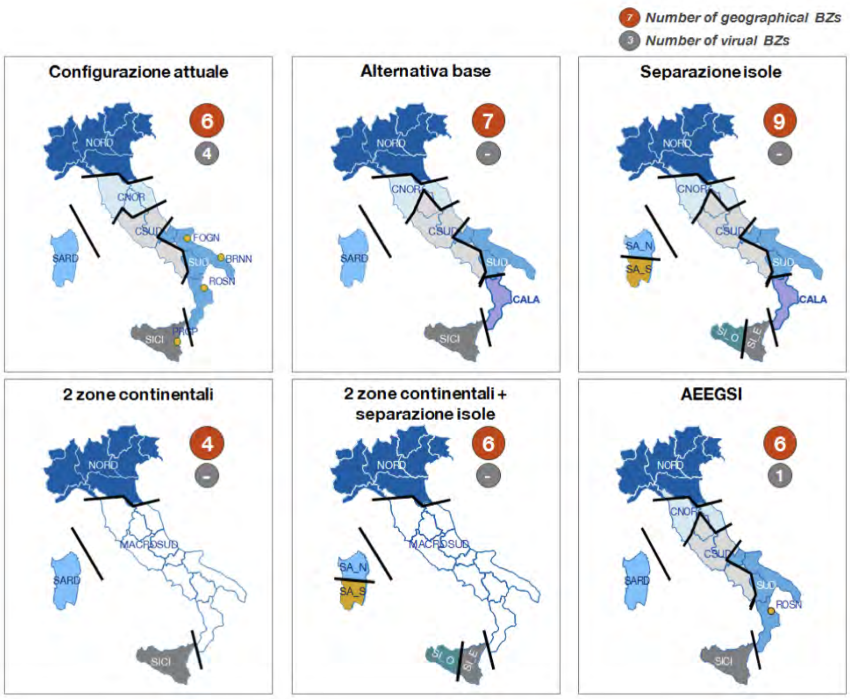
[18]The TYNDP offers a European-level perspective that complements national grid expansion strategies. It outlines a coordinated vision for the future electricity system, assessing how cross-border interconnections and energy storage solutions can facilitate the energy transition efficiently and securely.

[19]The MAF assesses the adequacy of supply to meet demand in the mid-term time horizon while considering the connections between different power systems across the European perimeter.

- A new Calabria Bidding Zone was created.

3. Island Separation ("Separazione Isole"): Built upon the Baseline Alternative, but with the further separation of Sardinia and Sicily into distinct Bidding Zones.
4. Two Continental Zones ("2 zone continentali"): Merged all continental bidding zones under consideration into just two broader zones.
5. Two Continental Zones with Island Separation ("2 zone continentali con separazione delle isole"): Expanded upon the "Two Continental Zones" configuration by keeping Sardinia and Sicily as independent zones.
6. AEEGSI Proposal: Similar to the Baseline Alternative, with the following key adjustments:
    - Umbria was moved from Centre-South to Centre-North.
    - The Foggia, Brindisi, and Priolo virtual Bidding Zones were incorporated into their corresponding geographical zones.

Figure 11
Bidding zone configuration alternatives



Source: ENTSO-E (2023)

These assessments aimed to determine the most efficient market structure, balancing grid management, market liquidity, and the evolving energy landscape. According to Article 33.1 of the CACM Regulation (European Commission, 2015), the assessment of bidding zone configurations must consider network security, overall market efficiency, and stability and robustness. These broad criteria are further specified through detailed aspects that must be evaluated. To meet these requirements, Terna has developed a system of quantitative indicators that allow for a direct comparison of different configurations. Moreover, some CACM criteria are inherently satisfied by the examined configurations, such as the consistency of bidding zones across all capacity calculation time-frames and the requirement that each generation and load unit belongs to a single bidding zone for each market time unit. Additionally, the study scenarios ensure that bidding zones remain sufficiently stable and robust over time, taking into account the costs associated with new infrastructure development to alleviate existing congestion. The criterion related to transition and transaction costs has been evaluated through a dedicated survey submitted to relevant stakeholders during the public consultation process.

Another proposal for the reconfiguration of the Italian electricity market was presented by the study conducted by ENTSO-E (2024b) on the impact of the configuration of supply zones on market liquidity and transaction costs. ENTSO-E put forward a proposal for the reorganization of the supply zones in Italy, envisaging the subdivision of the Northern zone into two new areas: a large Eastern zone (ITI1) and a smaller Western zone (ITI2). The division leads to a marked decline in generation and demand volumes in ITI2—approximately 80% compared to the status quo—while ITI1 experiences only marginal reductions. Despite these changes, market concentration remains stable: the Residual Supply Index (RSI)[20] increases in ITI2 and decreases in ITI1, yet remains above the critical threshold in all cases, and the Pivotal Supplier Index (PSI)[21] is consistently zero. This suggests that the expected decline in liquidity, more pronounced in ITI2, is not driven by concentration effects. Price correlation dynamics also shift, with ITI1 showing improved price alignment and ITI2 exhibiting a modest decline. Overall, the analysis underscores that while the reorganization does not raise competition concerns, it may reduce market liquidity and size, particularly in smaller zones, illustrating the complex trade-offs inherent in zonal market restructuring.

6. Lessons learned from the zonal reconfiguration of electricity markets

Based on a comparative examination of Italy, Norway and Sweden - three countries with a long-standing zonal structure - and California and Texas, which have since opted for a nodal pricing system, we show that zonal configurations can offer significant advantages in aligning price signals with the physical constraints of transmission networks, while introducing design challenges and trade-offs.

Italy, in particular, presents a compelling case of how zonal markets evolve. Since the launch of the power exchange in 2004 and the transition to a fully zonal consumption regime in 2025, Italy has maintained a stable but adaptable zonal structure to manage persistent North-South imbalances. Over time, the zonal price spread has narrowed, thanks to transmission upgrades and the internalization of new renewable generation dynamics. The creation of the Calabria zone in 2021 and the reallocation of Umbria demonstrate how expert-based revisions grounded on operational knowledge and grid planning can improve the spatial granularity of price signals without compromising liquidity or competition. The recent proposal to split the Northern zone further illustrates how changes in the configuration of zones can affect market size, liquidity and efficiency, with simulations showing only marginal effects on competition indexes, but a significant impact on the distribution of trading volumes. Finally, the particularity of the hybrid system in Italy opens up a political issue: the single national price on the demand side has been replaced by the zonal price, which has created

[20]'The RSI for a company i measures the percent of supply capacity remaining in the market after subtracting company i's capacity of supply' (Newbery et al., 2004).

[21]'The PSI examines whether a given generator is necessary (or 'pivotal') in serving demand. In particular, it asks whether the capacity of a generator is larger than the surplus supply (the difference between total supply and demand) in the wholesale market' (Newbery et al., 2004).

a further socio-economic debate. In the logic of pricing generation, the cross-over of supply and demand will reward consumers in the more virtuous electricity zones with higher production and more inclined to flexibility. The political rationale behind this market reform is to reward those areas with more renewable production that will see a lower price, while incentivizing those still tied to fossil fuels to invest in new green technologies. On the other hand, there remains the question of the development of renewables, which at the moment still seems unbalanced in favour of the South while the industry's greatest demand is in the North, which could lead to criticism in northern areas.

Norway, on the other hand, has adopted a more dynamic approach, gradually increasing the number of bidding zones between 2008 and 2015 to reflect changing hydrological balances and grid bottlenecks. The zonal structure helps to integrate the vast hydropower resources into the Nordic market and to send location signals during periods of scarcity, particularly in drought years. However, the presence of internal congestion and strategic supply behaviour in some Elspot areas highlights the limitations of the current zonal resolution. Moreover, the price differences between the various market zones emphasizes Statnett's proposal to split NO4, motivated by increasing wind capacity and flow constraints, highlights the need for continuous boundary refinement even in mature zonal systems. Similar dynamics were observed when Sweden switched from a single-zone market to four-zone markets in 2011. The reform was dictated both by internal congestion management needs and by external pressure from the European Commission, which regarded practices to avoid internal congestion as distortions of competition. Empirical analyses show that the reform was successful in differentiating prices geographically and improving investment signals, particularly for the southern SE4 area. However, the emergence of persistent price differentials and increased volatility in some areas suggests that complementary policies, in particular network strengthening, are needed to stabilise performance.

Despite the diversity of experiences examined, several general conclusions can be drawn. First, zonal pricing can improve transparency and operational efficiency by signaling congestion and guiding investment. However, the benefits depend on the appropriate definition and periodic re-evaluation of zone boundaries. Second, while smaller or more granular zones can internalize constraints more effectively, they may also raise concerns over liquidity, particularly in long-term markets. Yet, as shown in Italy and the Nordic region, institutional mechanisms such as market coupling and coordinated planning can mitigate these effects. Third, price volatility and welfare impacts vary by context: while zonal markets may introduce short-term price differentiation, they can also reduce redispatch costs and deliver longer-term efficiency gains. Finally, a persistent gap in literature and policy practice is the lack of empirical evidence on the true welfare effects of bidding zone reconfigurations. Most existing studies are based on simulation models or partial indicators. There remains a need for more systematic and evidence-based assessment of past reforms, including their impact on consumer surpluses, producer behaviour and system-wide efficiency.

In light of the results presented, we support a dynamic and evidence-based approach to zonal area design. Rather than considering the number of zones as fixed, regulators should consider zonal boundaries as a policy tool that evolves with network constraints, market developments and decarbonization targets. Responsive zone design, supported by expert and model-based assessments, can balance efficiency, liquidity and equity in increasingly complex and integrated energy systems. However, it is equally important to acknowledge that once a zonal structure is implemented, it tends to exhibit institutional and political persistence. This reflects a fundamental trade-off: while more granular reconfigurations may enhance short-run allocative efficiency by better aligning market outcomes with physical grid constraints, frequent structural adjustments can introduce regulatory uncertainty, undermine investment signals, and disrupt long-term market stability. As such, zonal design should be approached with a clear understanding that reconfiguration entails both technical and institutional costs, and that the benefits of greater operational precision must be weighed against the systemic value of predictability and continuity.

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