ACER

European Union Agency for the Cooperation of Energy Regulators



Progress of EU electricity wholesale market integration

2026 Monitoring Report

4 November 2026

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Executive summary

€7 bn	min. 70%	€460 m	70 TWh	95%
Yearly benefits from selected market integration projects	Most EU transmission system operators (TSOs) could not consistently uphold the minimum 70% requirement	Additional surplus generated by intraday auctions under flow-based allocation in the Core region	Remedial actions triggered by EU TSOs in 2025 to address network congestion	Reduction of hours with balancing energy prices for automatic frequency restoration reserve exceeding ±7,500 EUR/MWh

The integration of electricity markets across the EU is central to achieving a secure, affordable, and sustainable energy system. By coupling national markets and improving cross-zonal trade, integration reduces overall generation costs by increasing competition and price convergence, thereby improving affordability for consumers. It supports more renewables, helping the EU meet its long-term decarbonisation and sustainability objectives. A large, interconnected electricity market in the EU enhances security of supply through resource sharing, improves system resilience, and delivers greater flexibility to manage the increasing volatility associated with more renewables.

While progress has been made, significant benefits of market integration remain untapped.

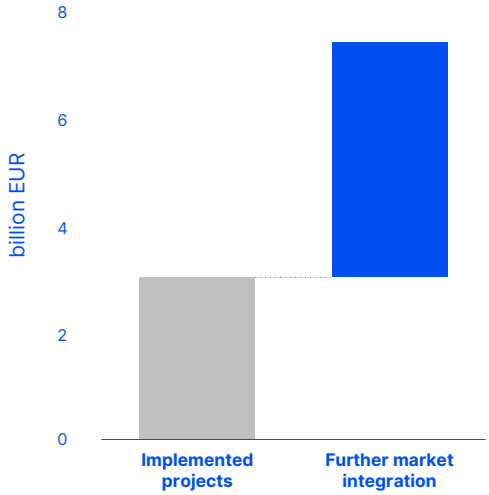
The benefits from EU electricity market integration become increasingly evident as the electricity system grows more complex and weather dependent. Periods of system stress and high prices are no longer only associated with cold winter conditions; they also occur during hot summer periods when electricity demand for cooling is high and generation assets can face operational limitations. A more integrated electricity market helps mitigate the impact of such conditions by sharing available resources and flexibility more efficiently across borders.

Market integration delivers measurable benefits, but the integration process is not yet complete

Over the past decade, market integration has made substantial progress, with multiple projects delivered. In the day-ahead market alone, cross-border trade generates each year about EUR 32 billion in economic surplus. An assessment of a selection of projects over all markets[1] suggests that further integration of electricity markets could deliver at least an additional EUR 4 billion per year. Furthermore, implementation delays[2] led to approximately EUR 700 million of unrealised economic surplus in 2025 alone. This illustrates a consistent theme of this report: while substantial progress has been made, significant benefits of market integration remain untapped.

Selected market integration projects can deliver approximately EUR 7 billion per year

Economic surplus stemming from a selection of market integration projects - 2025 (billion EUR)



1 This assessment should be considered as a lower-bound estimate because it covers only 13 market integration projects.

2 Delays in the implementation of some methodologies may be due to technical complexity, implementation deadlines misaligned with operations or due to being dependent on the full implementation of other related methodologies.

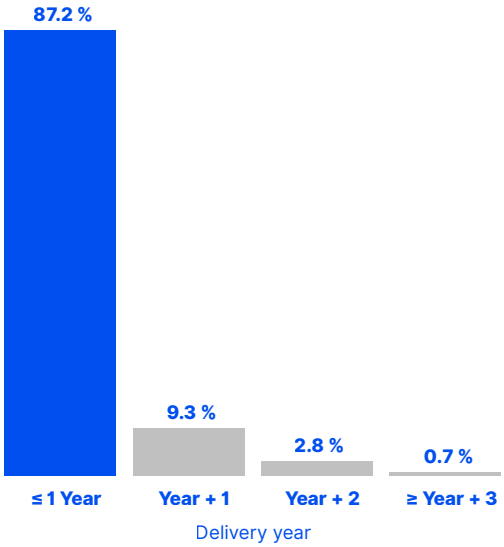
Forward markets face structural liquidity constraints, while the power purchase agreement (PPA) market continues to evolve

Forward market activity in the EU is growing, but liquidity remains concentrated in a small number of bidding zones and declines rapidly for contracts traded further in advance. Long-term transmission rights remain key for accessing liquidity in bidding zones with thinner markets and thus for ensuring equal hedging opportunities across the EU. However, their pricing appears to understate the hedging value they provide, resulting in a net financial transfer from transmission system operators (TSOs) to holders of the product. This points to the need for reform of the current long-term transmission rights framework.

Forward markets thus remain better suited to managing short- and medium-term price exposure. By contrast, longer-term investment risk management increasingly requires complementary arrangements, such as power purchase agreements or public support (such as contracts for difference). Market participants are increasingly interested in power purchase agreements that combine renewable generation with energy storage, supporting investment in renewable energy and increasing flexibility. The design of public support schemes needs to minimise distortive effects on electricity markets, for example by promoting the curtailment of renewable generation during periods of negative prices, so that competitive markets and public support schemes efficiently complement each other.

Forward market liquidity drops beyond one year ahead

Relative shares of traded volume per time to delivery in the EU – 2025 (%)



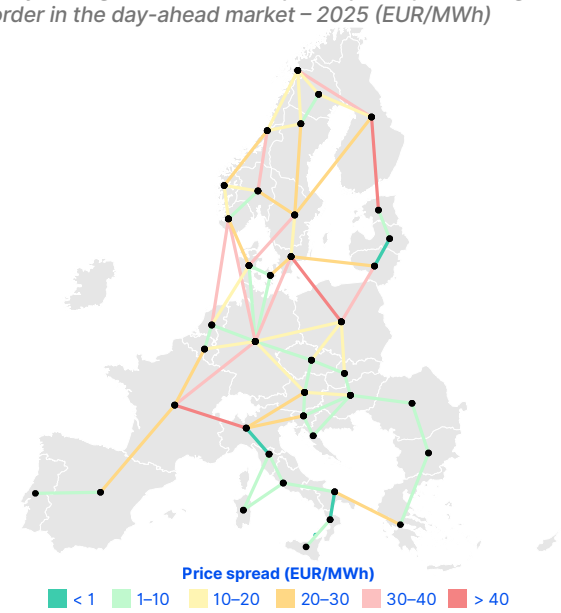
The day-ahead and intraday markets ensure the most efficient use of available resources across the EU, benefitting consumers

The day-ahead and intraday markets play a central role in the efficient operation of the EU electricity system, producing significant savings for EU consumers. Through market coupling, they allow for the efficient dispatch of generation resources across bidding zones, providing transparent and robust price signals for market participants and enabling efficient cross-border electricity trading. Their design has undergone significant improvements in recent years.

Key developments include the introduction of 15-minute market time units in both day-ahead and intraday markets, allowing market results to better reflect short-term variations in supply and demand, such as during ramping up or down of solar power. Less than one year after their introduction on 1 October 2025, 15-minute products already account for around 88 % of total traded volumes in the day-ahead market. Additionally, continuous intraday trading now allows electricity to be traded across bidding zones as close as 30 minutes before delivery. On borders where this is already implemented, around a fifth of cross-zonal intraday trading takes place during the final hour before delivery. These developments are particularly important as the growing share of variable renewable generation increases the need for market participants to reflect rapidly changing system conditions and to adjust their positions closer to real time.

Significant price differences remain across the EU

Yearly average of the absolute price spread per bidding zone border in the day-ahead market – 2025 (EUR/MWh)



The maximisation of cross-zonal capacity, including the implementation of the minimum 70% legal requirement, is still lagging

Well-functioning markets depend on sufficient transmission capacity being available for cross-zonal trade. Ensuring the optimal utilisation of the transmission network can contribute to a more secure system and reduce exposure to price volatility. Nonetheless, the maximisation of cross-zonal capacities in line with the requirements of Regulation (EU) 2019/943 (the Electricity Regulation) remains incomplete across the EU. Such requirements are not only a matter of market efficiency. They also respond to the need to mitigate the discrimination of cross-zonal trade vis-à-vis internal trade, inherent to a zonal market design.

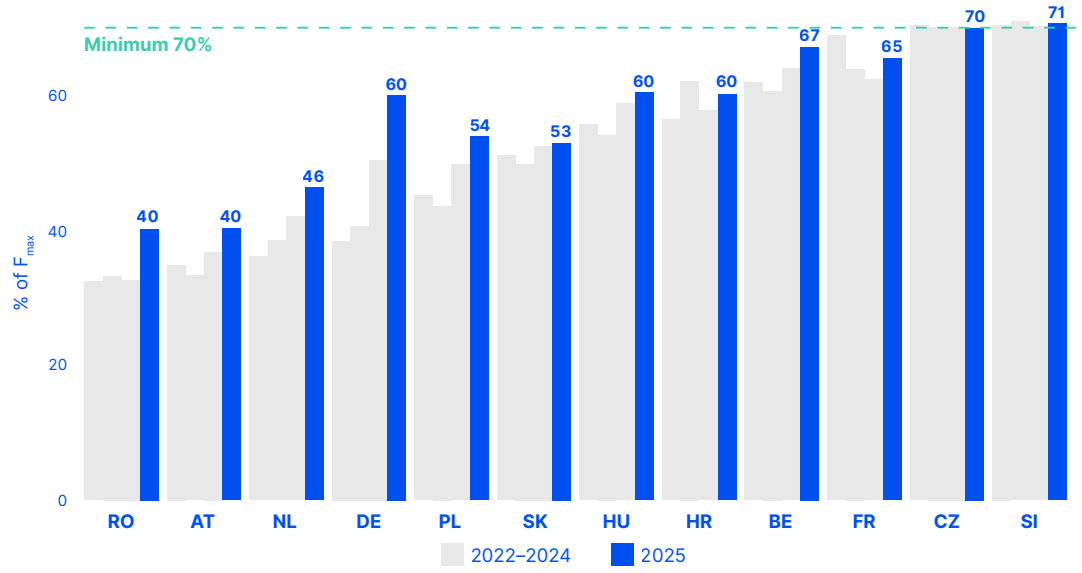
In the Core region, the persistence of excessive loop flows originating in neighbouring bidding zones, together with the absence of coordinated congestion management and cost-sharing processes, results in the recurring approval of yearly derogations from the minimum 70% requirement, which limits the available levels of cross-zonal capacity. In contrast, in the Nordic region the more granular bidding zone configuration limits the intensity of loop flows, although further efforts from TSOs are needed to ensure alignment with the minimum 70% requirement.

The minimum 70% requirement aims to mitigate the discrimination of cross-zonal trade vis-à-vis internal trade

Markets closer to real time, such as intraday and balancing markets, are particularly affected by limited access to cross-zonal trade, with some bidding zones often being isolated from the wider market and a large share of their trading activity taking place only locally. This stems mostly from two factors: first, the allocation of cross-zonal capacities is still based on the available transfer capacity model, therefore foregoing a significant share of the trading possibilities offered by flow-based domains in the Core and Nordic regions; and second, the minimum level of cross-zonal capacity ensured in the day-ahead timeframe is currently not maintained in subsequent market timeframes, which can significantly reduce the possibilities for cross-zonal exchanges. The growing importance of close-to-real-time trading reinforces the need to maximise cross-zonal trading opportunities beyond the day-ahead market.

Derogations due to loop flows limit progress in implementing the 70% requirement in the Core region

Average minimum hourly capacity offered in the Core CCR – 2022-2025 (% of physical capacity)



Congestion management needs continued to grow in 2025, with voltage-related actions playing a larger role following the Iberian blackout

The volume of remedial actions activated to address physical congestion reached 70 TWh in 2025, at a cost of EUR 5.4 billion to the EU power system. This is up from EUR 4.3 billion in 2024 and accounts for a growing share of the electricity bill in some Member States. Beyond the cost to network users, physical congestion can also result in the curtailment of renewable generation, which is then typically replaced by more carbon-intensive generation. For example, 3% and 2.5% of total renewable output were curtailed in Spain and Germany due to grid congestion, respectively. With further renewable capacity being connected to the system and grid reinforcement lagging, congestion management needs are expected to continue growing in the future.

3 % and 2.5 % of total renewable output were curtailed in Spain and Germany due to grid congestion, respectively

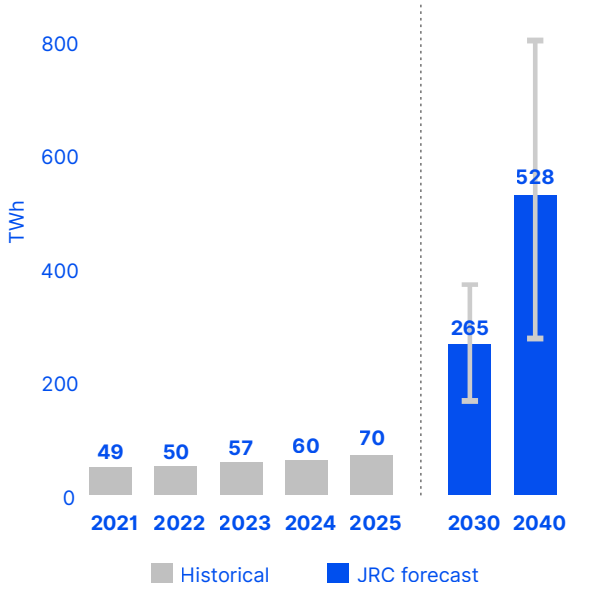
The operational reasons behind redispatching are expanding: the share triggered by voltage limit violations rose from 10 % in 2022 to 33 % in 2025, particularly in Spain and Portugal following the Iberian blackout of 28 April 2025.

As inverter-based resources continue to replace synchronous generation, TSOs will need to secure sufficient voltage control resources through efficient and competitive processes.

Moreover, TSOs rely on remedial actions to comply with minimum cross-zonal capacity requirements. However, the lack of coordination in congestion management processes – together with the absence of an adequate sharing of costs based on the origin of flows causing congestion, along with the limitations reported by TSOs to rely on remedial actions closer to real time – continue to limit cross-zonal capacity offered in the day-ahead and intraday timeframes.

Remedial actions are expected to continue increasing over time

Evolution of remedial action volumes in the EU– 2021-2040 (TWh)

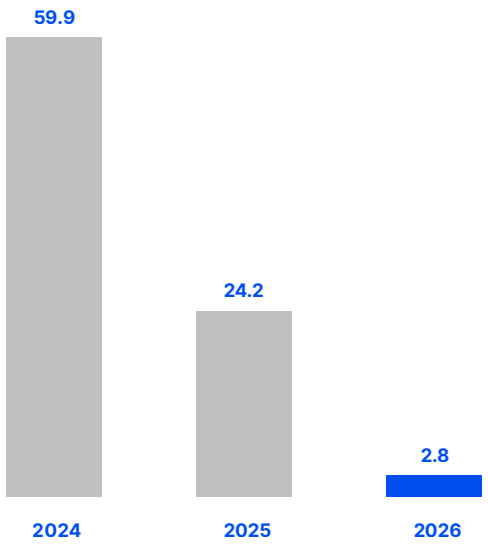


Balancing market integration delivers more stable prices, lower costs and greater system security

European balancing-market integration has improved price stability, lowered costs and strengthened system security. Integration accelerated in 2025: TSOs from nine additional Member States joined PICASSO, the platform for automatic frequency restoration reserves (aFRR), and the Italian TSO reconnected to it. TSOs from two additional Member States joined MARI, the platform for manual frequency restoration reserves (mFRR). By end 2025, TSOs from 17 Member States were connected to PICASSO and TSOs from 11 Member States to MARI. This broader participation increased access to balancing resources across borders and contributed to more stable prices. On PICASSO, the annualised duration of extreme aFRR price events was 95% lower in 2026 than in 2024.

The occurrence of extreme aFRR prices dropped significantly

Annualised hours with aFRR prices outside [−7,500, 7,500] EUR/MWh across TSO areas, 2024–2026; 2026 results are annualised using data available until 15 July 2026.



Integration has also brought measurable benefits in balancing capacity. Regional cooperation allows TSOs to exchange capacity and share reserves, lowering the cost of securing sufficient resources. The frequency-containment reserve (FCR) Cooperation, covering nine countries, generated an estimated benefit of EUR 146.2 million in 2025. Cooperation has also developed for aFRR and mFRR balancing capacity. For the periods analysed, the estimated benefits reached EUR 21.0 million for ALPACA, covering Austria, Czechia and Germany, EUR 847.1 million for the Baltic cooperation and EUR 357.3 million for the Nordic cooperation. These arrangements also strengthen system security by pooling resources across borders, thereby helping TSOs secure sufficient reserves.

The growing participation of batteries and other flexible resources is further increasing competition. In Belgium and the Baltic region, their market entry coincided with substantial reductions in balancing-capacity prices. In the Baltic region, it was also accompanied by a decrease in market concentration. These findings indicate that opening balancing markets to new types of resources can strengthen competition and deliver cost reductions.

Further progress can be achieved by widening geographical participation and access to new resources. Market arrangements should facilitate broader participation by technically capable resources. They should also support robust system operation as resources become faster and more decentralised and network congestion increases.

List of abbreviations

Abbreviation	Term in full
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic frequency restoration reserves
AMR	adjustment for minimum remaining available margin
ALPACA	Allocation of Cross-zonal Capacity and Procurement of aFRR Cooperation Agreement
ATC	available transfer capacity
CACM	capacity allocation and congestion management
CCR	capacity calculation region
CBAM	carbon border adjustment mechanism
CBMP	cross-border marginal price
CEST	central European summer time
CfD	contracts for difference
CGM	common grid model
CNE	critical network element
CNEC	critical network element with contingency
CNTC	coordinated net transfer capacity
CP	(Energy Community) contracting party
D-1	one day before delivery
DA	day-ahead
EMIR	European Market Infrastructure Regulation
ENTSO-E	European Network of Transmission System Operators for Electricity
ER	Electricity Regulation
FCA	forward capacity allocation
FCR	frequency containment reserve
FRR	frequency restoration reserve
FTR	financial transmission right
GL	guideline
GRIT	Greece-Italy
GW	gigawatt
EBGL	electricity balancing guideline
ED	electricity directive
ER NC	emergency and restoration network code
F_{0all}	flow on critical network elements with contingencies not stemming from any cross-zonal exchange
F_{max}	maximum flow on critical network elements, respecting operational security limits
$F_{ref,Core}$	flow originated from the Core net positions already included in the common grid model
F_{uaf}	flow on critical network elements with contingencies resulting from commercial exchanges outside a capacity calculation region
HVDC	high-voltage direct current
IDA	intraday auction
IDCC	Intraday capacity calculation
IDCZGCT	intraday cross-zonal gate closure time
IGCC	international grid control cooperation
ISP	imbalance settlement period
IVA	individual validation adjustment
JAO	Joint Allocation Office
LTA	long-term allocation

Abbreviation	Term in full
LTTRs	long-term transmission rights
MACZT	margin available for cross-zonal trade
MARI	manually activated reserves initiative
MiFIR	Markets in Financial Instruments Regulation
mFRR	manual frequency restoration reserves
MTU	market time unit
MW	megawatt
MWp	megawatt peak
NC	network code
NEMO	nominated electricity market operator
NRA	national regulatory authority
NTC	net transfer capacity
PTDF	power transfer distribution factor
RAM	remaining available margin
RCC	regional coordination centre
RES	renewable energy sources
ROSC	regional operational security coordination
PICASSO	platform for the international coordination of automated frequency restoration and stable system operation
PPA	power purchase agreement
REMIT	Regulation on Energy Market Integrity and Transparency
RR	replacement reserve
SDAC	single day-ahead coupling
SEE	South-East Europe
SIDC	single intraday coupling
SOGL	system operation guideline
SWE	South-West Europe
TERRE	trans European replacement reserves exchange
TSO	transmission system operator
TW	terawatt

Currencies and countries abbreviated in accordance with ISO standards.

Market integration helps tackle new challenges in the electricity system

1 The integration of electricity markets across the EU is central to building a secure, affordable and sustainable energy system. It is about using the physical infrastructure to match supply and demand over Member State borders and over different timeframes. By linking national markets and enabling efficient cross-border trade, integration lowers overall generation costs, strengthens competition and helps prices converge, improving affordability for consumers. It also supports the integration of renewable energy sources, which is essential for long-term decarbonisation. At the same time, a larger and more interconnected market strengthens security of supply by allowing countries to share resources, improving system resilience and providing greater flexibility to manage the variability of wind and solar power.

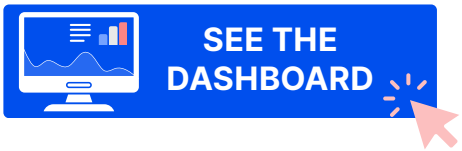
2 Market integration is also becoming more important as the electricity system grows more complex. In the past, high electricity prices were mainly associated with periods of high demand and limited supply, often during winter in large parts of Europe. Today, the picture is more complicated. Hot summers can also push prices up, as higher temperatures increase demand for cooling. At the same time, supply can come under pressure: low river levels may reduce the availability of water needed to cool thermal power plants, while solar generation falls in the evening even though demand often remains high. Climate change and the ongoing transformation of the power system are therefore creating new challenges that require more flexible and better-connected markets.

3 This report helps to explain that growing complexity. It examines the important developments of 2025 and early 2026, showing that market integration is not a one-off achievement but an ongoing process of adaptation and improvement. It also shows the importance of finishing what we started.

4 The main message is clear: Europe needs electricity markets that function well individually and work well together. This means ensuring that each national market has effective price signals, transparent rules and sufficient flexibility, while also strengthening the connections between neighbouring markets so that electricity can be traded to where it is most needed. Efficient trading across borders is essential to improve economic surplus, reduce costs and make better use of available generation and network capacity.

5 At the same time, trust in the market framework is indispensable. Consumers, investors and public authorities need confidence that markets are transparent, fair and properly regulated, and that the principles set out in legislation are effectively implemented in practice. Without such trust, investment may be delayed, cross-border cooperation becomes more difficult, and the benefits of integration are diminished.

6 The report is structured into eight sections, covering the economic benefits of market integration, developments across electricity market timeframes (long-term, day-ahead, intraday and balancing), congestion management, and the integration of Energy Community countries. The final section presents the main conclusions. This report is complemented by a dashboard with additional data on the analyses presented, a data repository with downloadable data for every figure, and two standalone supporting documents providing further details on the economic surplus analysis and the EU PPA market.



The benefits of market integration and the need for further progress

7 Over the past decade, substantial progress has been made in integrating European electricity markets, with recent milestones further strengthening cross-border trading and market efficiency. Key developments include the expansion of flow-based capacity calculation and allocation, the implementation of 15-minute market time units, enhanced intraday trading opportunities, and the continued harmonisation of balancing markets through European platforms for cross-border exchange of balancing energy. Despite these significant advances, further efforts are needed to complete market integration and unlock its full potential.

8 Monitoring the implementation of EU network codes and guidelines and their effectiveness in facilitating the proper functioning and integration of electricity markets is key to tracking the progress. To achieve this goal, ACER publishes annual monitoring reports as well as regularly updated implementation overviews. Moreover, quantifying the benefits stemming from market integration projects is also necessary for monitoring the status of the integration process.

9 This chapter first provides an overview of economic surplus, including a brief explanation of the concept and guidance on how the values should be interpreted. It then presents the findings of the analysis on the economic surplus generated by a selection of market integration projects.

Interpreting economic surplus values

10 In the context of EU electricity markets, economic surplus is a metric to quantify the total net benefit deriving from producing and consuming electricity. Economic surplus is defined as the sum of consumer surplus, producer surplus and congestion rent. Economic surplus is a metric for market efficiency expressed in monetary units and should not be interpreted as actual monetary gains (or losses).

11 Economic surplus can be used for different purposes, ranging from estimating the benefits of market integration to the total value cleared in a given market (e.g. single day-ahead coupling (SDAC)). Despite the fact that the process to compute economic surplus always takes the same components into account (i.e. producer and consumer surplus and congestion rent), it is important to interpret the values on a case-by-case basis.

12 The SDAC algorithm aims to maximise the total economic surplus on a daily basis, which is in the order of magnitude of EUR 4 trillion per year.[3] The total economic surplus resulting from the daily optimisation depends heavily on the maximum and minimum clearing prices.[4] A change in these price limits may increase the total economic surplus without materially affecting price formation or the quantities exchanged.

3 See the 2024 CACM Annual Report (p. 18).

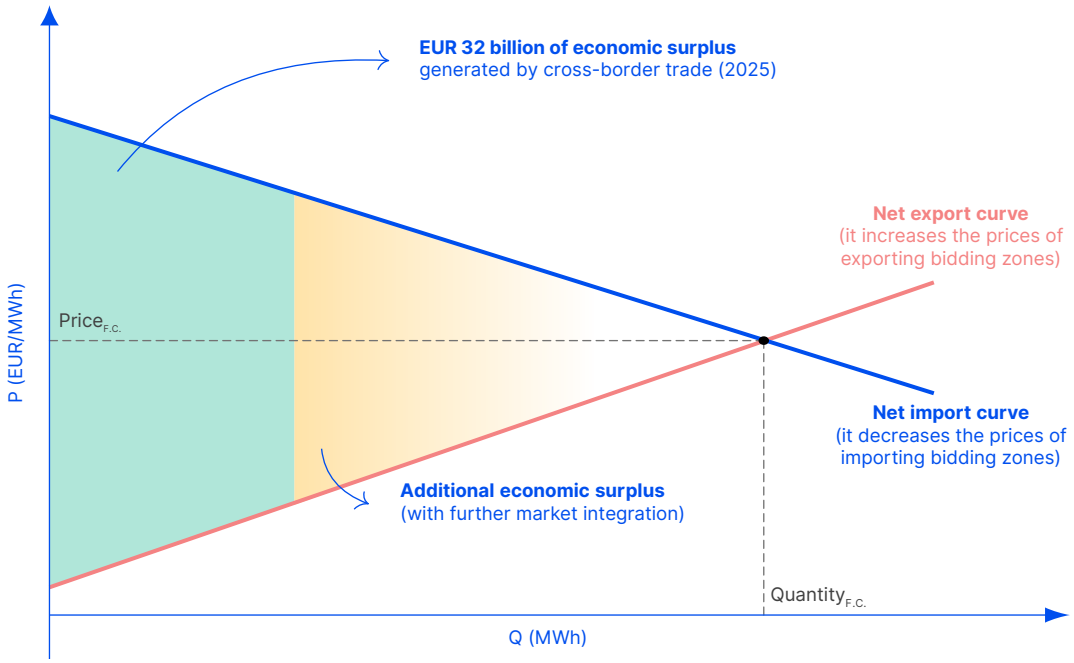
4 For example, an increase in the maximum clearing price may enable market participants to reveal more accurately the actual value of lost load for inflexible consumers. In other words, if the maximum clearing price were already sufficiently high to allow market participants to reveal their true willingness to pay, a further increase in the maximum clearing price would not affect bid prices and, consequently, would not affect economic surplus.

13 By contrast, the total economic surplus generated by cross-border trade has a different order of magnitude, which was estimated to be approximately EUR 32 billion[5] in 2025 (Figure 1). Maximising cross-border trade and unlocking the full potential of market integration have a material impact on the price formation and quantity exchanged, resulting in more affordable, sustainable and resilient market outcomes.

14 Therefore, a meaningful consideration of the figure of economic surplus in the daily SDAC algorithm calculation is not the general sum of economic surplus from a daily SDAC algorithm optimisation process, but the difference of the total economic surplus generated with different functionalities in coupling.

15 For these reasons, although the same metric is used, the two results are fundamentally different and are therefore not directly comparable. Any comparison between them would not be meaningful.

Figure 1: Economic surplus stemming from cross-border trade and market integration (explanatory figure)



Source: ACER

Note: P stands for 'Price', Q for 'Quantity' and F.C. for 'Full Convergence'. The sole purpose of the figure is to provide a visual representation of the economic surplus arising from cross-border exchanges. It should not be interpreted as full price convergence being the ultimate objective of the market integration process.

Estimating the benefits of market integration

16 ACER assessed a selection of market integration projects, estimating the benefits generated by already delivered projects, the impact caused by implementation delays and the additional gains that further market integration is expected to bring.

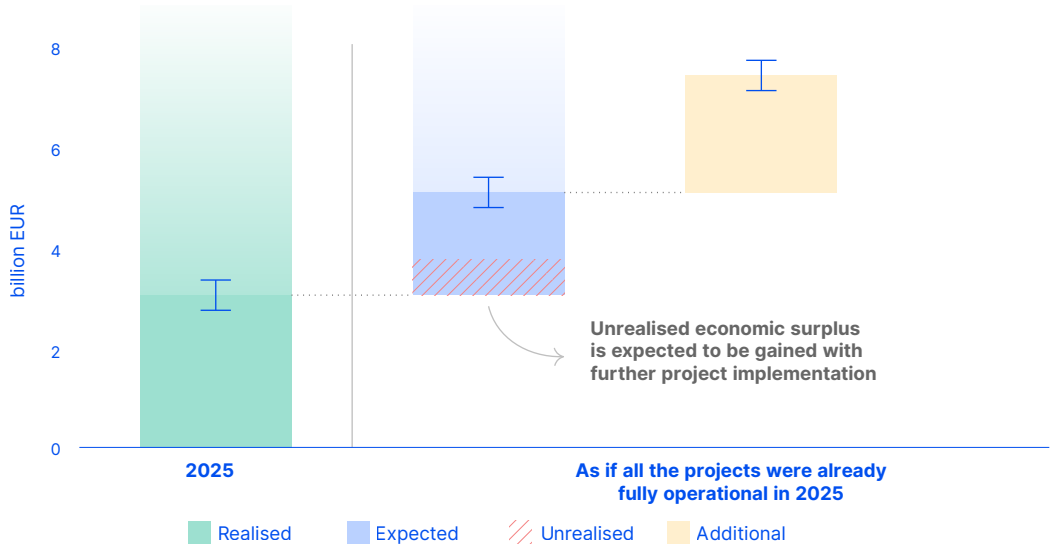
5 TSOs and nominated electricity market operators (NEMOs) estimated that the difference between isolated (zero exchange) and coupled markets in 2025 was approximately EUR 32 billion.

17 The assessment of the 13[6] selected market integration projects points[7] to total economic surplus gains of approximately EUR 7 billion for the year 2025, if all projects were already fully operational (Figure 2).

18 These 13 projects span a wide range of implementation statuses and legal requirements, including projects that have already been implemented (fully or partially), projects whose implementation has been delayed, projects planned for future implementation and projects that would yield benefits if implemented. To accurately visualise the economic surplus stemming from these projects, it is necessary to break the estimates down into categories that capture their specificities:

1. realised economic surplus generated by those projects that have already been implemented (fully or partially);
2. unrealised economic surplus due to implementation delays, including the partial non-implementation of operational projects;
3. expected economic surplus deriving from the implementation of currently delayed projects (full or partial) or projects that are scheduled for implementation in the future;
4. additional economic surplus, if co-optimisation was implemented and a more efficient configuration of bidding zones was in place.

Figure 2: Economic surplus stemming from market integration (13 projects only) - 2025 (billion EUR)



Source: ACER elaboration based on multiple data sources. Additional information is available in the annex.

Note: Faded areas indicate the economic surplus generated by projects for which the surplus was not quantified in this assessment, suggesting that the overall economic surplus from market integration is substantially greater than the estimates presented in this figure. The figure should be interpreted as a lower-bound estimate of the economic surplus stemming from market integration, as the assessment covers only 13 projects.

6 List of market integration projects with quantitative assessment: long-term flow-based (Core CCR), Nordic flow-based in SDAC, Core flow-based in SDAC, TSOs' accession to international grid control cooperation, market-based allocation (Nordic CCR), Minimum 70% requirement (estimate for Core CCR only), TSOs' accession to MARI, TSOs' accession to PICASSO, ROSC-RDCT (Central Europe CCR), Flow-Based allocation in intraday auctions (Core CCR), Energy Community accession to the single day-ahead coupling, bidding zone review, co-optimisation.

7 Calculations are based on assumptions, subject to limitations, and intended to provide only an indicative estimate.

19 Projects that had been fully or partially implemented by the end of 2025 generated benefits amounting to approximately EUR 3 billion of economic surplus in 2025. By contrast, delays[8] in implementation are estimated at approximately EUR 700 million of unrealised economic surplus in 2025 alone, representing a 2% lost opportunity to improve economic surplus generated by cross-border trade, and approximately EUR 8 billion cumulatively between 2020 and 2025. To take measures against such unrealised economic surplus, ACER and national regulatory authorities (NRAs) have been coordinating actions on identified implementation delays since 2024 to ensure efficient and timely implementation. Furthermore, ACER has submitted a recommendation to the European Commission on measures to speed up the effective implementation of EU electricity market rules.

20 The economic surplus stemming from (fully or partially) non-implemented projects (see the categories 'expected economic surplus' and 'additional economic surplus' in Figure 2), is estimated to be approximately EUR 4 billion, representing a 12.5% opportunity to improve economic surplus generated by cross-border trade. In other words, if all 13 market integration projects considered had already been operational in 2025, the EU would have received an extra EUR 4 billion. This suggests that it is of utmost importance to progress in a timely manner with the ongoing market integration process as the internal market is far from being completed yet.

21 The total value of market integration projects exceeds EUR 7 billion. This reflects the fact that this assessment was limited to 13 market integration projects.[9] However, it is important to note that a multitude of other projects[10] also contribute, or will contribute, to economic surplus gains, as illustrated by the shaded areas in Figure 2. For this reason, the total value of market integration projects is significantly higher than the economic surplus estimated in this analysis.

22 ACER would like to thank all the stakeholders who contributed to this analysis. ACER also wishes to acknowledge the considerable efforts required to implement projects of this nature, and to recognise the importance of the progress achieved to date, as reflected in the milestones reached thus far.

A guide to the analysis: exploring and interpreting the economic surplus results

A dedicated annex accompanies this report to ensure transparency and support the interpretation of the findings. It provides (1) a detailed description of the methodological approaches used to estimate economic surplus, and (2) explanatory material with figures and examples.

Together, these two sections make the analysis accessible, allowing interested readers to understand what the results represent, how they should be interpreted and how they were derived.



8 Delays in the implementation of some methodologies may be due to technical complexity, implementation deadlines misaligned with operations or due to being dependent on the full implementation of other related methodologies.

9 ACER selected these 13 projects on the basis of the technical feasibility of producing a meaningful estimate, the availability of existing assessments and their importance for completing the internal electricity market.

10 A non-exhaustive list of additional market integration projects: Italy North flow-based in single day-ahead coupling (Central Europe capacity calculation region (CCR)), advanced hybrid coupling for day-ahead (Core CCR), coordinated validation (Core CCR), 15-minute market time unit, 30-minute intraday cross-zonal gate closure time, pan-EU intraday auctions, flow-based allocation in continuous intraday market, flow-based allocation in balancing energy platforms, regional sizing of reserve capacity, regional procurement of balancing capacity.

1. Long-term markets

23 Long-term electricity markets allow market participants to hedge future generation revenues and electricity costs and, more broadly, manage the price risks associated with investment. Their importance increases in a decarbonising electricity system characterised by volatile short-term prices and substantial investment needs. Liquid and well-functioning long-term markets can reduce participants' exposure to short-term price shocks while enabling sufficient investments in the power system. Within long-term electricity markets, forward markets[11] remain the predominant way in which market participants hedge electricity price risk.

24 Well-functioning forward markets also play a key role in price discovery, providing transparent and independent signals of the expected future value of electricity. These price signals may also serve as a reference for the pricing and design of other long-term arrangements, including power purchase agreements (PPAs), contracts for difference (CfDs) and capacity mechanisms. While PPAs are generally commercially negotiated contracts, CfDs and capacity mechanisms are typically public support instruments used by Member States to support investment or address specific policy objectives where market-based revenues alone may not provide sufficient incentives.

1.1. Challenges in European electricity forward markets

25 Forward electricity markets comprise all transactions in which market participants buy or sell electricity, or the associated price exposure, for delivery or settlement at a future date. They include standardised futures traded on organised exchanges and forward contracts traded over the counter (OTC), either bilaterally or through brokers. These products can be physically or financially settled, and cover different delivery periods, typically months, quarters and years.

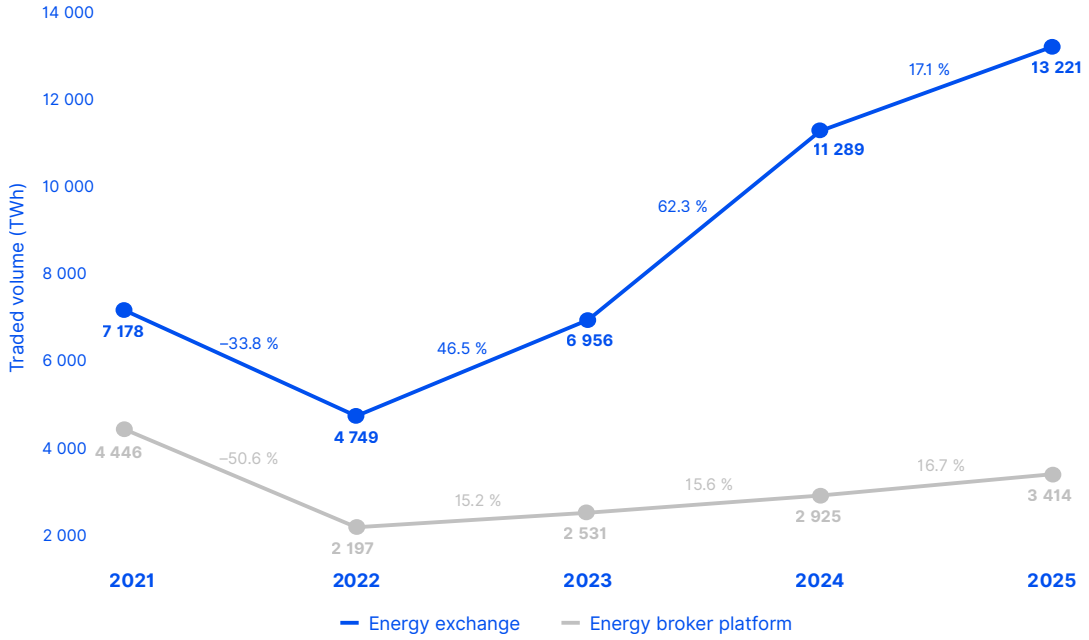
26 The European electricity forward market appears to be suffering from several fundamental issues, which have been described in detail in ACER's policy paper on forward markets. These include insufficient liquidity, market fragmentation, a lack of competition and limited incentives for hedging. While the day-ahead and intraday markets have already undergone a significant revision, harmonisation and integration with the introduction of the single day-ahead and intraday coupling, significant focus from regulators and policymakers has been put in recent years on the development of long-term markets.

27 Forward markets saw a significant drop in trading activity during the 2022 energy crisis, following the supply shock in the gas markets. During this period, extreme price volatility led to sharply higher margin and collateral requirements, increasing liquidity needs and prompting many market participants to reduce their forward positions. Nonetheless, the last two years have seen a significant recovery in activity, reaching values above those observed pre-crisis. Figure 3 shows the yearly evolution of traded volumes in EU forward markets, grouped by the type of trading venue. As observed in the figure, 2025 saw a 17 % year-on-year growth in forward market trading.

28 Traded volumes also show a growing preference for trading on organised exchanges. These marketplaces offer market participants more standardised hedging products with fully covered counterparty risk, which is not typically the case for OTC contracts traded on broker platforms. Although trading at organised exchanges may include explicit trading and clearing fees, centralised liquidity and central clearing generally reduce overall transaction costs relative to bilateral trading.

11 In the context of this monitoring report, the term forward markets refers primarily to conventional wholesale forwards and futures, and does not include longer-term contractual or support arrangements such as power purchase agreements, contracts for difference or capacity mechanisms.

Figure 3: Evolution of total traded volume by type of trading venue – 2021-2025 (TWh)



Source: ACER calculation based on trades reported via REMIT.

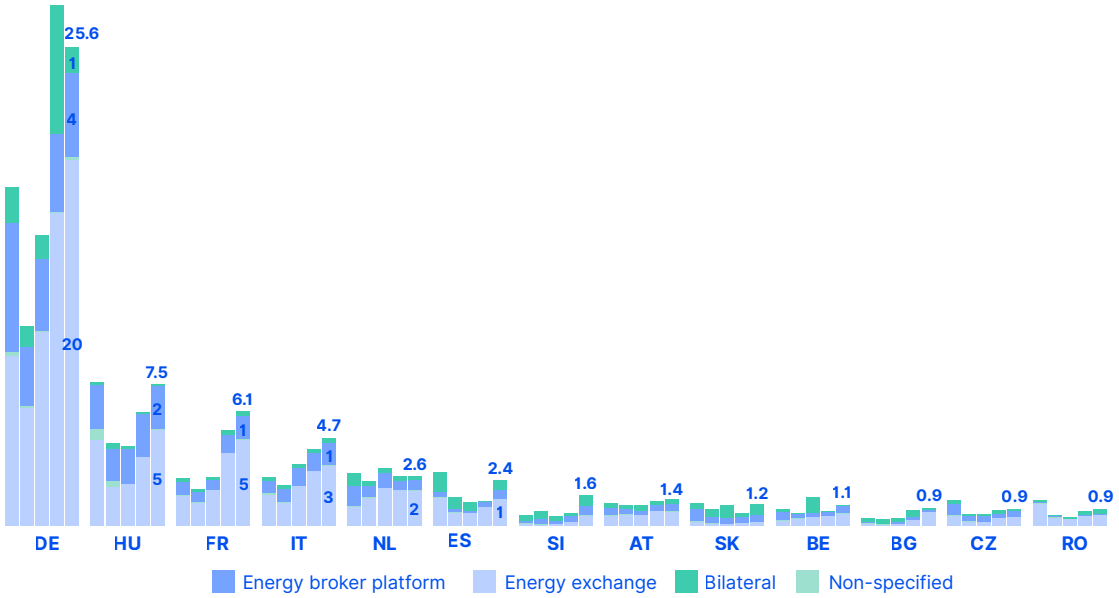
Note: The analysis uses the data reported by reporting parties under REMIT. Such data may not be complete, fully accurate and/or reported in a timely manner. Volume of trades that are not reported via REMIT (e.g. because they are reported under EMIR or MiFIR) is not considered in this figure.

29 Market liquidity, in electricity forward markets as well as in other commodity markets, is typically assessed using churn rates, which measure the ratio of the total volume of a given commodity traded in forward markets in a given area to the consumption of the commodity in that area over the same period. In short, a churn rate indicates how many times the underlying electricity is traded before its delivery. Figure 4 shows the evolution of churn rates in the main European forward markets over recent years.

30 Despite the increase observed in the last two years, liquidity in EU forward electricity markets remains heavily concentrated around the German market, which acts as the main trading hub for market participants across the EU. This implies market participants do not have access to an equally effective forward hedge in every bidding zone. Smaller bidding zones continue to depend much more heavily on the ability to hedge the risk between their local price and the price of a more liquid neighbouring market, as will be discussed in the following subsection.

31 As observed in Figure 4, markets such as France, Hungary, Italy or Spain have also experienced increases of liquidity over the last two years. Liquidity in smaller hubs may be influenced by evolving correlations between their short-term prices and those of larger hubs, namely Germany. When short-term prices are highly correlated, hedging through a larger hub entails a lower basis risk. A declining correlation between prices in smaller markets and those in Germany may therefore contribute to increased trading activity in these markets.

Figure 4: Churn rates in the main European forward markets – 2021-2025



Source: ACER calculation based on trades reported via REMIT.

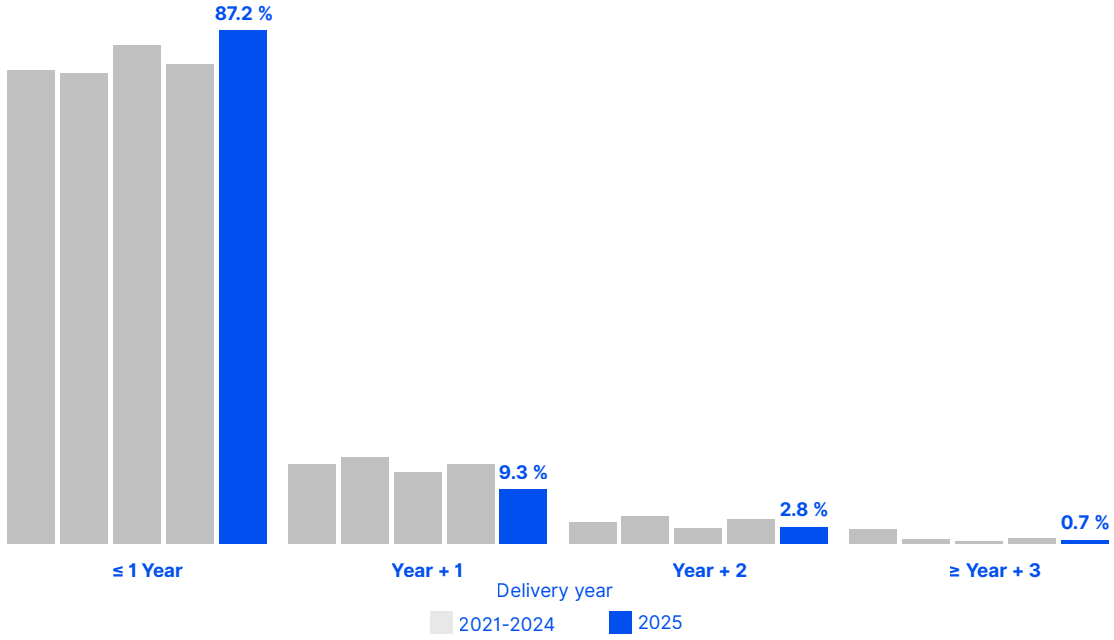
Note: Churn rates are calculated as the volume traded in forward markets, divided by the total electricity demand in the delivery zone. The analysis uses the data reported by reporting parties under REMIT. Such data may not be complete, fully accurate and/or reported in a timely manner. Volume of trades that are not reported via REMIT (e.g. because they are reported under EMIR or MiFIR) is not considered in this figure, which may result in lower volumes for some areas. Bilateral trades are particularly subject to reporting inaccuracies.

32 Moreover, liquidity in forward markets is generally concentrated around shorter maturities and tends to decline the further away from physical delivery or settlement you get. Standardised contracts traded at exchanges generally cover delivery periods of no more than one year, yet market participants can obtain multi-year exposure by combining successive yearly contracts. While yearly futures are available on exchanges several years in advance, liquidity of yearly products tends to be very thin when traded more than one year in advance. This is observed in Figure 5.

33 This drop in liquidity of yearly contracts observed further along the forward curve can partly be explained by declining hedging needs, as well as hedging strategies followed by market participants, such as roll-over hedging, where long-term price risk is hedged by trading front-year contracts every year. Roll-over hedging can be used to some extent to hedge long-term risks, such as those associated with new investments, but its applicability remains limited due to the higher risk it implies.

34 Futures and forwards are primarily used to hedge the price exposure of existing generation assets and electricity consumption. However, the limited liquidity available at longer maturities constrains their ability to hedge the long-term price and revenue risks associated with new investments in generation and demand. They therefore may provide less support for project financing than longer-term contractual arrangements, such as PPAs or state support schemes.

Figure 5: Relative shares of traded volume per time to delivery in the EU – 2021-2025 (%)



Source: ACER calculation based on trades reported via REMIT.

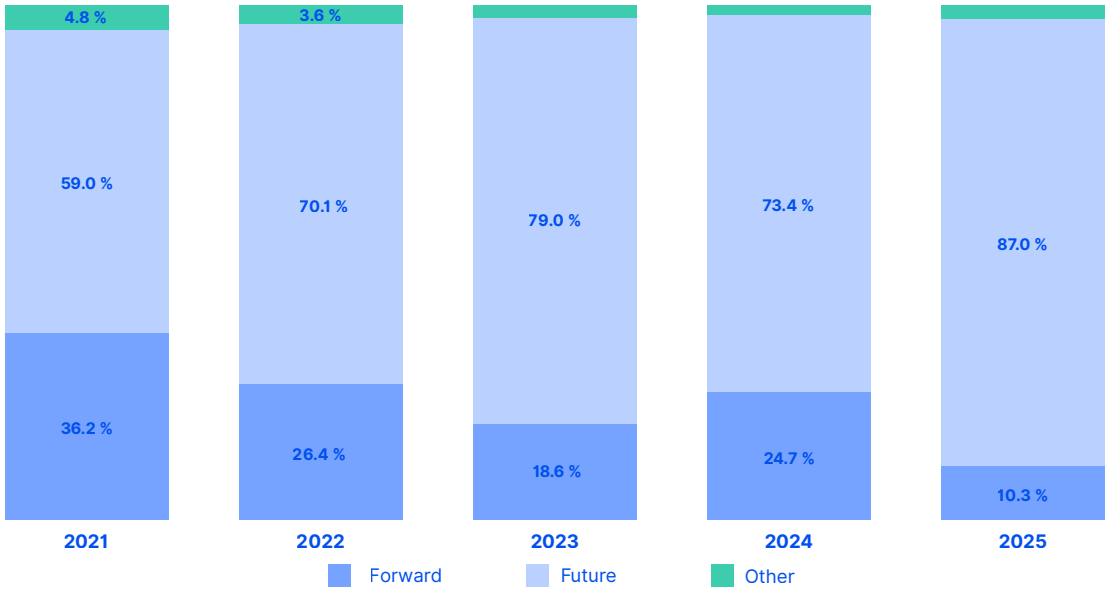
Note: The analysis uses the data reported by reporting parties under REMIT. Such data may not be complete, fully accurate and/or reported in a timely manner. Volume of trades that are not reported via REMIT (e.g. because they are reported under EMIR or MiFIR) are not considered in this figure. Bilateral trades are particularly subject to reporting inaccuracies.

35 EU forward markets in recent years have gradually shifted from contracts involving the physical delivery of electricity towards financial derivatives linked to a reference price, usually that of the day-ahead market. This results from market participants primarily using forward markets to hedge their exposure to price volatility in short-term markets, rather than to procure electricity for physical delivery.

36 When market participants trade only the price exposure in forward markets, the corresponding physical delivery is instead achieved through trading in short-term markets. This allows the price risk to be managed in advance, while physical positions are determined closer to delivery through more liquid short-term markets, when information on system conditions is more complete.

37 Figure 6 shows the share of total traded volume in forward markets by contract type. In 2025, financial contracts without physical delivery, such as futures or financial forwards, accounted for 87 % of total traded volume. This share has increased gradually in recent years, being up from only 54 % in 2020.

Figure 6: Share of total volume traded in EU forward markets categorised by type of contract – 2021-2025 (% of total traded volume)



Source: ACER calculation based on trades reported via REMIT.

Note: The analysis uses the data reported by reporting parties under REMIT. Such data may not be complete, fully accurate and/or reported in a timely manner. Volume of trades that are not reported via REMIT (e.g. because they are reported under EMIR or MiFIR) are not considered in this figure. Bilateral trades can be particularly subject to reporting inaccuracies.

38 Overall, while electricity forward markets have become more active in recent years and liquidity has somewhat improved in several European markets, important limitations remain. Trading activity continues to be concentrated in a relatively small number of markets and generally declines rapidly along the forward curve, limiting the availability of robust hedging opportunities in less liquid markets and at longer maturities. As a result, forward markets remain better suited to managing short- and medium-term price exposure, while longer-term investment risks increasingly require complementary arrangements, such as PPAs or long-term public support.

1.2. Cross-border hedging products are key to integrating forward markets

39 As highlighted in the section above, liquidity in forward markets appears to be concentrated in a limited number of products, most notably those that use the day-ahead price of the German bidding zone as reference. This results in a large share of market participants across the EU using the German market to cover their hedging needs, as it is more difficult for them to find a counterparty in their own market, which in turn adds to the liquidity of the German market. This is referred to as proxy hedging.

40 When using a neighbouring market to hedge its needs, a market participant remains exposed to potential price differences between the neighbouring market and its home market. This is referred to as the basis risk, and it is greater the less correlated the day-ahead prices between two zones are. In the EU, the main mechanism to hedge the basis risk is long-term transmission rights (LTTRs).

41 The Electricity Regulation establishes that it is the responsibility of TSOs to issue LTTRs or have equivalent measures in place to allow for market participants to hedge price risks across bidding zone borders, and that LTTRs shall be allocated in a transparent, market-based and non-discriminatory manner through a single allocation platform (SAP). Currently, they are auctioned primarily in year- and month-ahead through JAO.

42 Some bidding zone borders in the EU do not offer LTTRs, where regulatory authorities have considered that other available products provide sufficient opportunities to hedge the cross-zonal price risk. Most notably, electricity price area differentials (EPAD) are financial derivative contracts available primarily in the Nordic and Baltic regions to hedge against the price difference between the Nordic system price (i.e. hub constructed from the unconstrained price of all Nordic bidding zones) and the price of a given bidding zone.

43 EPADs are primarily market-based financial products traded by market participants, although some TSOs have increasingly become active counterparties in EPAD auctions where insufficient hedging opportunities have been identified.[12] A conceptually similar zone-to-hub instrument is available in Italy in the form of congestion cost coverage (CCC) contracts, which hedge the differential between an Italian zonal price and the national reference price. Unlike ordinary EPAD trading, however, CCCs are directly issued and allocated through auctions by the Italian TSO.

44 Additionally, market-based spread products provide another means of hedging cross-zonal price differences and are available for several bidding-zone pairs across the EU. In practice, such a product replicates a simultaneous long position in a futures contract in one bidding zone and a short position in the corresponding futures contract in the other, thereby providing direct exposure to the price differential between the two zones. Their effectiveness as a hedging instrument, therefore, depends on sufficient liquidity in the underlying futures markets in both concerned bidding zones.

45 In the EU, LTTRs are currently auctioned mostly as financial transmission right (FTR) options. This means that there is no right to physically transfer electricity across the border. Instead, the market participant that holds the FTR is entitled to compensation from the TSO in the case of congestion, equal to the price difference at the border. In case of convergence or price difference in the opposite direction, the market participant is not entitled to any compensation, nor obliged to issue any payment back to the TSO that issued the product.

46 In its 2024 Market Monitoring Report, ACER introduced an analysis on the valuation of LTTRs, comparing the prices resulting from the LTTR auctions with both the realised LTTR payouts from day-ahead market congestion, and with price spreads in the forward markets traded at the same time as the LTTR auctions. In this report, ACER replicated this analysis, including the latest available data, to be able to assess recent developments. This is done through two main indicators:

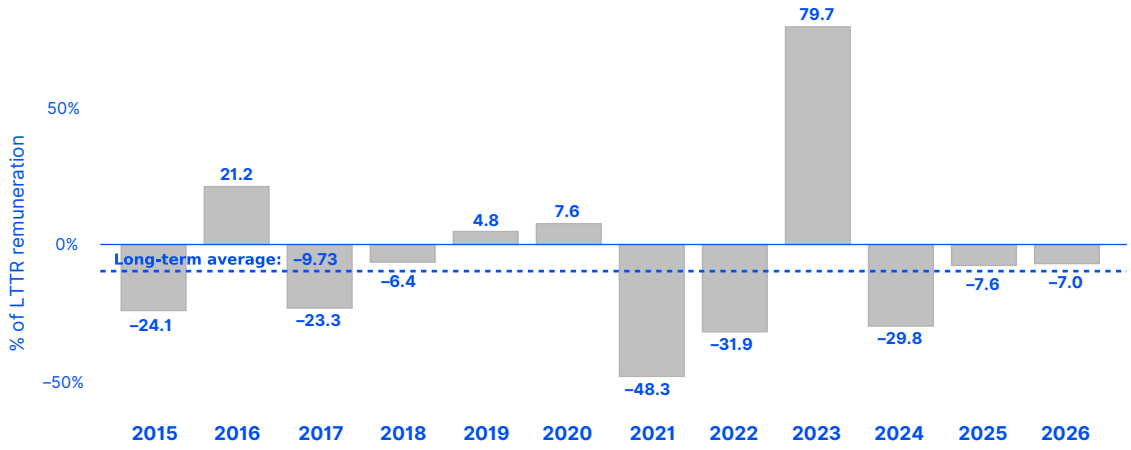
- ***Ex post* risk premium.** Comparison of the congestion income generated by TSOs from issuing LTTRs, with the resulting remuneration to holders of the product. This metric assesses how LTTR buyers value the hedging that LTTRs provide against congestion in the day-ahead market.
- **Forward risk premium.** Comparison of the difference between the auction prices of the LTTRs issued in both directions of a given border,[13] with the price spread in futures contracts traded shortly before the closure of the LTTR auction. This indicator evaluates the extent to which LTTR pricing is aligned with forward market prices.

12 As described, for example, in the Norwegian EPAD auctions 18-month report.

13 The difference between the prices of FTR options auctioned in the two opposite directions of a given border can be compared with the forward-market valuation of the underlying zonal price spread. This follows from the fact that the difference between the payoffs of the two FTR options replicates the signed price spread: $LTTR_{A\ to\ B} - LTTR_{B\ to\ A} = \max(0, P_B - P_A) - \max(0, P_A - P_B) = P_B - P_A$. In other words, the difference between the two option positions replicates an FTR obligation, whose underlying exposure is the signed zonal price spread.

47 LTTR auction prices should represent, at least, the forecasted value of the product; that is, market participants will be willing to bid into the LTTR auction at least the return they expect from holding the product. As the expected return from the product is subject to uncertainty, a large sample is necessary to extract any conclusions from this metric, as this can mitigate the impact of fluctuations in forecast errors. Figure 7 shows an overview of the observed ex post risk premium over the last 12 years, displayed as the yearly difference between LTTR income and associated payout across all LTTRs issued in the EU, as a share of the total payout.

Figure 7: Net financial transfer between TSOs and LTTR holders per year, displayed as the share of the total LTTR remuneration – 2015-2026 (% of LTTR remuneration)



Source: ACER calculations based on JAO auction data and ENTSO-E Transparency Platform data.

Note: A negative value represents a net transfer from TSOs to LTTR holders, while a positive value represents a net transfer from LTTR holders to TSOs. The 2026 value includes the monthly LTTRs allocated until August 2026, as well as the partial valuation of the yearly products.

48 As observed in the figure the collected income from issuing LTTRs has been on average approximately 10% lower than the resulting payout, over the last twelve years. This corresponds to a net transfer from TSOs to LTTR holders of over EUR 2 billion. These results suggest that, on average, market participants have profited from holding LTTRs, rather than having paid a premium for the hedging they provide. Nonetheless, this effect is dependent on the specific border, with some products being valued on average well above the realised payout.[14]

49 The forward risk premium metric aims to complement the above analysis, by minimising the impact of forecast errors in the estimation of LTTR valuation. To do so, it compares LTTR auction prices in both directions of a given border with the price spread of the relevant future contracts (i.e., same maturities) traded at the time of the LTTR auction. As these products are traded exactly at the same time, both indicators are in principle subject to the same uncertainties.

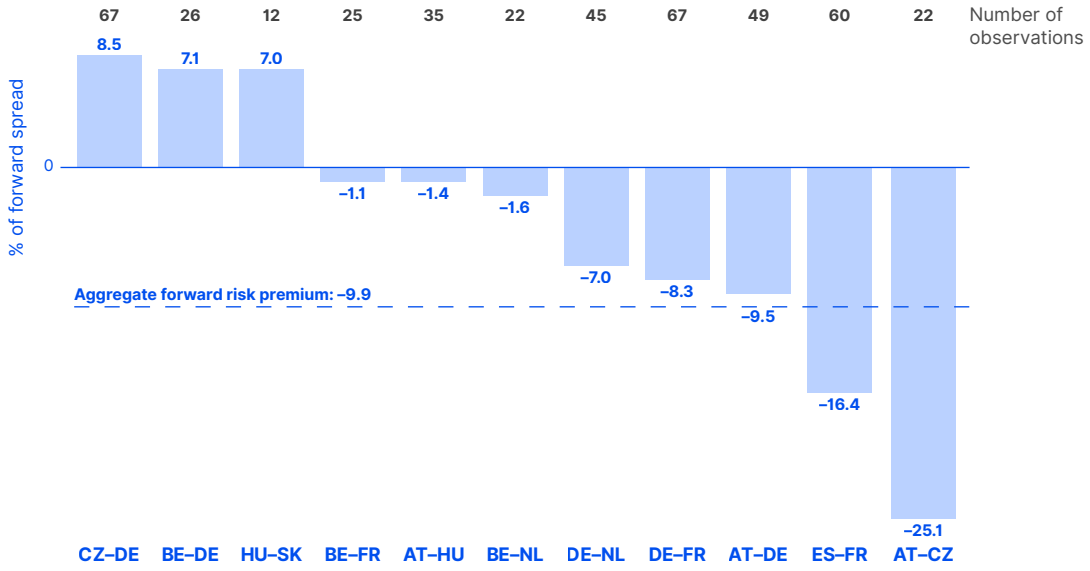
50 Figure 8 assesses to what extent the pricing of long-term transmission rights accurately reflects the price differential forecasted by forward markets, at several EU borders. To do so, the weighted average of the price of all baseload futures traded at European Energy Exchange within the two hours before the gate closure of the relevant LTTR auction is computed and then compared to the difference between LTTR prices on both directions of a given border.

14 The results presented in this report differ from those published in the 2024 Market Monitoring Report for the following two reasons: First, an underestimation of the LTTR payouts during maintenance periods was identified and corrected. Second, the 2024 report included LTTRs on bidding zone borders for periods preceding the implementation of market coupling on those borders, which have been excluded from the present report.

51 The number of observations in this metric varies across borders, as there may not be sufficient trading activity on both bidding zones in the two hours prior to the LTTR auction. Borders with very few observations have thus been removed from the analysis. The analysed data shows that on most of the analysed bidding zones borders the price difference between the LTTRs in both directions is smaller than the price differential forecasted by forward markets. This is particularly true for some of the borders with a bigger number of observations, such as DE–FR or ES–FR.

52 The observed lower LTTR price differential relative to the price spreads in forward markets may indicate an underpricing of LTTRs. This interpretation assumes that the risk premia embedded in LTTR prices are broadly symmetric across the two directions of a given border. As the metric is based on the average of multiple observations, and systematic positive ex post risk premia are not commonly observed across the EU, persistent asymmetries in risk premia are unlikely to be a main driver in these results. They may, however, play a role in specific borders and should therefore not be ruled out when interpreting negative values.

Figure 8: Forward risk premium on selected EU borders, displayed as a percentage of the forward spread – 2021-2026 (% of forward spread and number of observations)



Source: ACER calculation based on JAO Auction Tool data and trades of EEX future contracts recorded through REMIT in the two hours prior to the LTTR gate closure.

Note: A negative value indicates that the pricing of LTTRs for a given border is, on average, below the corresponding price spread observed in forward markets. Borders with less than 10 observations have not been included in this figure, to ensure a minimum level of liquidity on both sides of the border.

53 The mismatch in pricing of LTTRs relative to the equivalent forward spreads may partially be explained by differences in product design. LTTRs are auctioned only at specific times, typically once a year for yearly products and once a month for monthly products; there is no secondary market; they may include reduction periods during which no payout is provided; and their full financial firmness may not always be guaranteed, namely in the event of curtailment.

54 LTTRs remain a key mechanism in the EU to guarantee adequate hedging possibilities in the bidding zones with lower market liquidity, yet their apparent undervaluation could indicate a suboptimal design. ACER's policy paper on the further development of the EU electricity forward market identified several measures to address this undervaluation. These included introducing more competition between borders, such as via the implementation of flow-based allocation;[15] a shift from options to obligations to simplify the valuation of FTRs; potentially reducing the offered capacity in products that are consistently undervalued; or reducing the total number of available products by shifting to zone-to-hub FTRs.

15 The effect of long-term flow based on the undervaluation of LTTRs must be assessed in the context of its implementation.

55 Changes to the LTTR framework are expected through an upcoming amendment of the Forward Capacity Allocation Regulation. Moreover, after two years of delays, the implementation of flow-based allocation in LTTR auctions in the Core region is expected to go live in November of 2026, in time for the yearly 2027 auctions.

1.3. Power purchase agreements drive renewable energy investments and enhance flexibility

1.3.1. Understanding power purchase agreements: contract structures and their main features

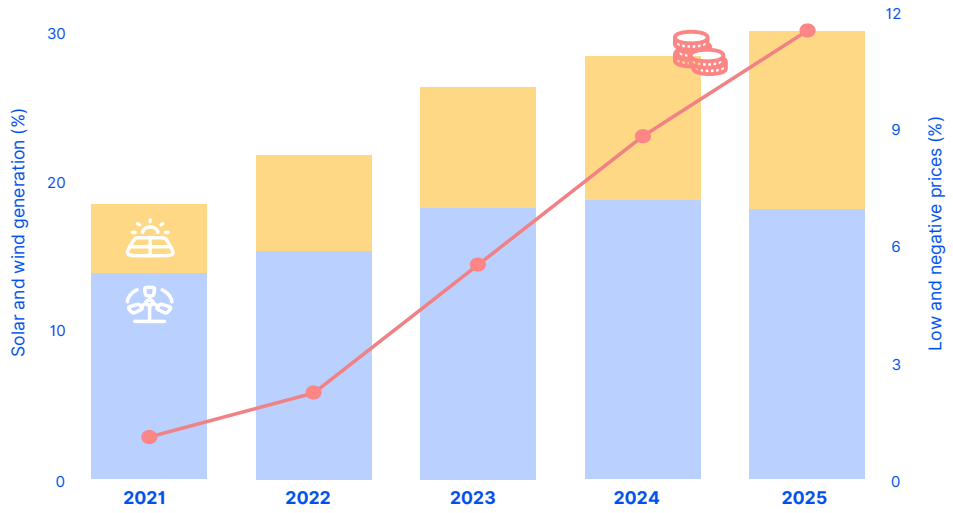
56 A Power Purchase Agreement (PPA) is a long-term contract between a seller (typically a generator or utility) and a buyer (typically a utility or consumer) that defines the commercial terms for the sale of electricity, including volume, pricing, delivery arrangements, contract duration and risk-allocation provisions. PPAs can help large electricity consumers manage energy price exposure in the very long term while supporting investment in new generation capacity, particularly renewable energy projects. The tailored and often confidential nature of PPAs limits market transparency and comparability and can result in lengthy negotiation processes.

57 PPAs can be categorised in several ways. First, they may be classified by contract structure, distinguishing between physical PPAs, which involve the physical delivery of electricity, and financial or virtual PPAs, which are based on a purely financial settlement mechanism. Second, they may be classified according to the location of the project relative to the consumer, distinguishing between on-site PPAs, where generation is located at the site of consumption, and off-site PPAs, where generation is located elsewhere and connected through the grid. Third, PPAs may also be categorised by the type of off-taker involved. In this respect, a distinction is commonly made between corporate PPAs (where the buyer is a final consumer and the seller can be a generator or energy utility) and utility PPAs (where the buyer is a energy utility and the seller is a generator).

1.3.2. Market drivers shaping the EU power purchase agreements landscape

58 Over the past few years, the share of renewable energy generation across the EU has increased significantly. As wind and solar assets have very low marginal costs, their growing presence has contributed to more frequent periods of low electricity prices and increasing instances of negative prices in the day-ahead market (Figure 9).

Figure 9: Share of solar and wind generation and share of low (i.e. below 5 EUR/MWh) and negative prices across EU and Norway bidding zones – 2021-2025 (% of total generation (left) and % total instances of prices (right))



Source: ACER calculation based on ENTSO-E Transparency Platform data.

59 This rise in low and negative price events can reduce the capture prices achieved by renewable assets, thereby negatively affecting their revenues, particularly for solar generation. This may discourage the signing of additional contracts that sell electricity during these low-price periods, such as pay-as-produced PPAs.

A closer look at capture rates and the impact of the cannibalisation effect

The cannibalisation effect in solar energy refers to the reduction in the market value of solar-generated electricity when high levels of solar production depress electricity prices during the same periods. In other words, as more solar power is produced at the same time, the electricity generated tends to be sold when market prices are lower, reducing the value captured by solar assets.

This concept can be illustrated through the capture rate, calculated as the ratio between the capture price and the baseload price, where:

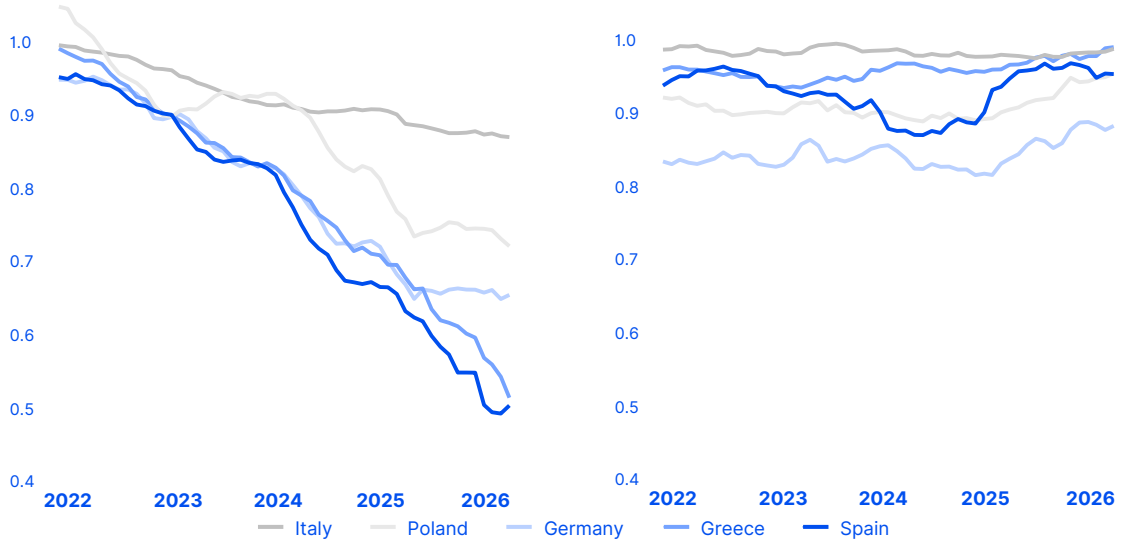
- **capture price** is the average price that a specific power source (e.g. solar) earns for the electricity it generates, weighted by the power it produces, over a given period;
- **baseload price** is the (unweighted) average market price observed over a given period.

The capture rate is a useful indicator for assessing the extent of cannibalisation and the market conditions faced by renewable energy assets.

60 Across the EU, solar capture rates have generally been declining (Figure 10), pointing to increasing cannibalisation effects in several countries. However, these trends are highly country dependent. They display significant differences across national markets, indicating different market maturities and conditions across countries.

61 By contrast, wind capture rates have remained comparatively more stable than those of solar. This is largely because wind generation follows more diverse temporal patterns and is less concentrated within a limited set of daylight hours, thereby reducing the coincidence of generation peaks and the associated downward pressure on market prices. These dynamics may constitute a positive signal for the further deployment of wind capacity, both onshore and offshore, as more stable capture rates support stronger revenue prospects and may improve the investment case for additional wind farms.

Figure 10: Solar (left) and wind (right) capture rates, selection of EU Member States (twelve-month rolling average) – January 2022 - May 2026 (capture rates)



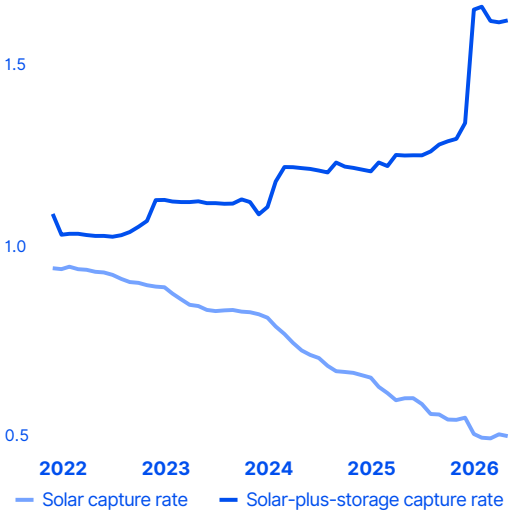
Source: ACER calculation based on Pexapark's data.

62 In this context, arrangements combining renewable energy generation with storage (i.e. hybrid PPAs) can mitigate the cannibalisation effect. These contracts allow renewable generation to be shifted into hours with higher prices and storage to be used to provide more stable generation in hours of low renewable generation, thus increasing the value of generated electricity. Such arrangements can significantly increase capture rates compared to those having less flexibility (Figure 11).

63 By providing off-takers with greater protection against periods of high market prices, hybrid PPAs can offer a more effective hedge, which may in turn strengthen the position of developers in negotiating more favourable contractual terms, likely to result in PPAs settled at higher prices.

64 In other words, higher agreed strike prices between developers and off-takers will improve revenue streams, making the projects more bankable and therefore more viable. Renewable PPAs incorporating storage therefore support renewable energy investment, contribute to greater price stability and strengthen both system and market flexibility.

Figure 11: Solar and solar-plus-storage (two-hour) capture rates (twelve-month rolling average), Spain – January 2022-May 2026 (capture rates)



Source: ACER calculation based on Pexapark's data.

Note: Solar-plus-storage capture rates are estimated by Pexapark's model.

1.3.3. Transformation of the EU power purchase agreements market: adapting to challenges and shaping the way forward

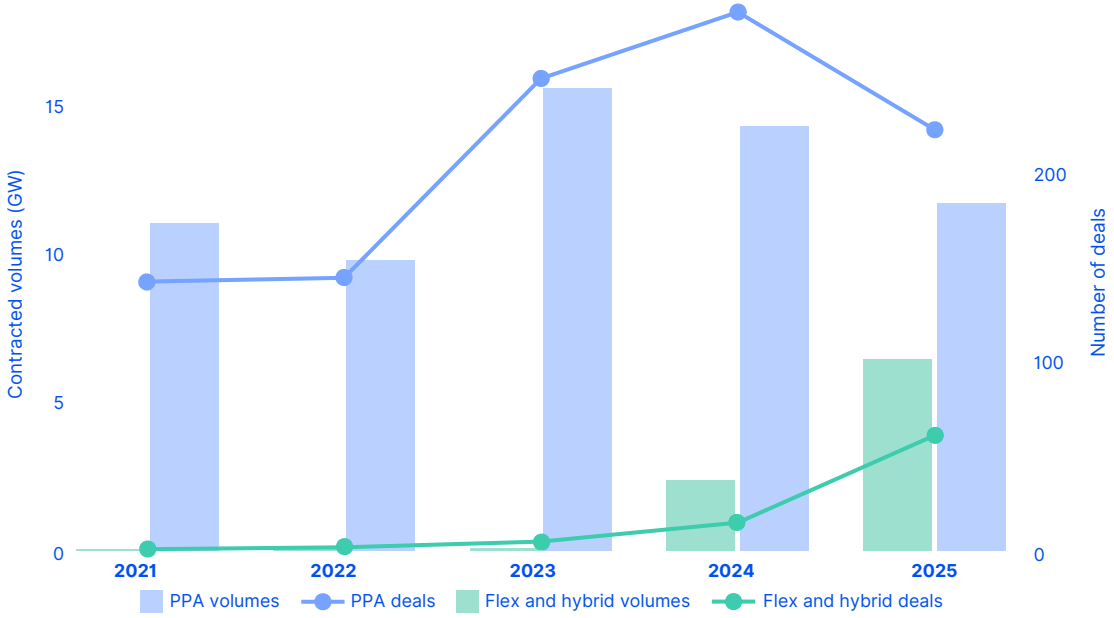
65 Several challenges and barriers constrain the appetite for more PPAs, most notably decreasing capture rates for solar, credit and counterparty risks, and persistent regulatory challenges. Removing these barriers is expected to foster the further development of the PPA market, and it requires a combination of market and policy reactions.

1.3.3.1. Market reactions:

- Declining solar capture rates are reducing the value of solar investments and the prices in 'pay-as-produced' PPAs, under which the off-taker (i.e. buyer) purchases from the developer all electricity generated, whenever it is produced. Nevertheless, current market trends suggest that investors are responding by combining renewable energy source investments with flexible assets and package both into flexible contractual arrangements, including hybrid PPAs, which can achieve higher market value of investments (Figure 12).

  This means that the market is providing the right signals for investments. By incentivising investment in flexible resources and supporting the deployment of affordable, clean, renewable energy generation, the PPA market is playing a key role in achieving this objective.

Figure 12: Contracted volumes and number of deals signed, EU and Norway – 2021-2025 (flexible and hybrid contracts and PPAs)



Source: ACER calculation based on Pexapark's data.

- PPA contracts should include clear provisions for discouraging feeding into the grid during periods of negative market prices. Recent PPAs have adopted such provisions. This will help mitigating the downward trend in (solar) capture rates.

1.3.3.2. Policy reactions:

66 In April 2026, following a call for evidence conducted between late January and late February, the European Commission published a Recommendation on removing barriers to the development of power purchase agreements (PPAs) and other energy purchase agreements. The Recommendation includes initiatives ranging from promoting access to PPAs for small buyers and facilitating multi-buyer PPAs to fostering coordination between national State-backed guarantee schemes and the European Investment Bank's counter-guarantee lending instrument.

67 In March 2026, ACER launched a public consultation process to strengthen its monitoring activity on the EU PPA market. Stakeholders provided insightful information on key regulatory, market and financial factors affecting the development and functioning of PPAs across Member States. ACER developed a dedicated section of the monitoring dashboard and annex, including the inputs received through the public consultation.

68 **Having considered market trends and the responses received during the public consultation, ACER considers the following measures.**

- Contracts for difference (CfDs) provide state support to investments in renewable energy where such investments would likely not occur under normal market conditions. State support must however, be designed carefully to keep incentives for private investments and to preserve efficient market functioning.

  In this context, two-way CfDs should be structured so as not to undermine the development of the PPA market (which is private by default) or reduce liquidity in other electricity market segments. Compatibility between CfDs and PPAs could be strengthened through design features such as carve-out mechanisms, which allow part of the capacity initially contracted under the state support scheme to be resold in the form of a PPA, or by requiring investors seeking state support with CfDs to sell a part of the electricity from the assets under state support via private PPAs. The design of CfDs should also incentivise efficient investment and operation of the supported generation assets such that they maximise the value of generated electricity.

- Grid expansion, electrification, and demand response are essential to support the growth and bankability of PPAs by reducing curtailment risk and limiting the decline in solar capture rates. Network expansion can ease congestion and improve the reliable delivery of renewable generation contracted under PPAs. At the same time, electrification can increase demand for additional renewable capacity, thereby supporting further PPA uptake. Greater demand response, combined with storage, smart charging, and responsive industrial consumption, can help shift demand towards periods of abundant generation, reducing curtailment, improving system efficiency, and strengthening the value of solar generation.

- State-backed guarantees and PPA platforms can play an important role in reducing credit-related barriers and improving market transparency, particularly for smaller buyers and less mature PPA markets. State-backed guarantee schemes can help address counterparty risk by strengthening the creditworthiness of off-takers (i.e. buyers), thereby widening access to PPAs and lowering financing costs for renewable projects. In parallel, PPA platforms can improve price discovery, reduce transaction costs, and facilitate matching between buyers and sellers. Together, these instruments can support a more accessible and transparent PPA market.

1.4. Contracts for difference: a hedge against high electricity prices

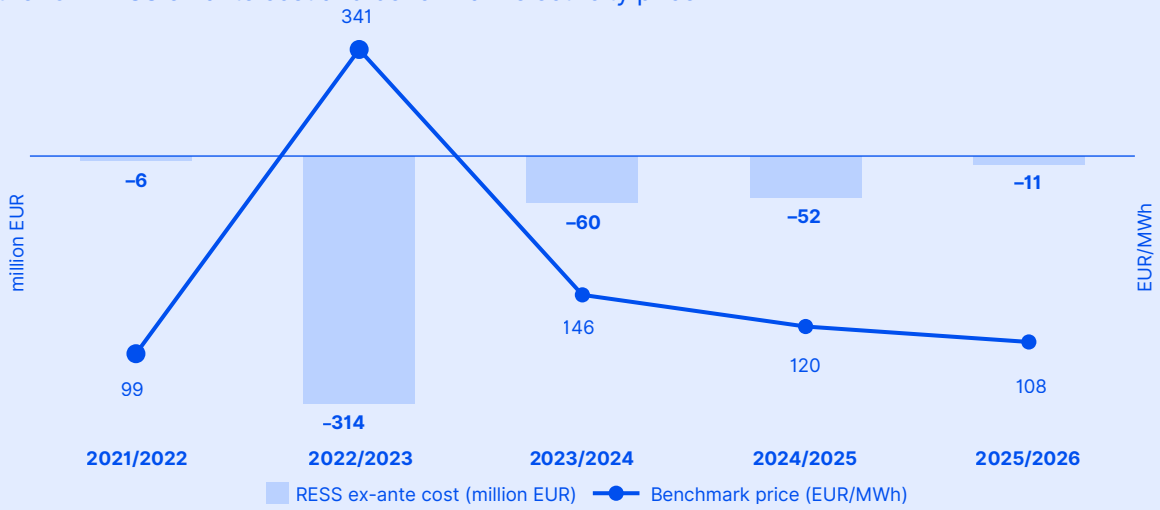
69 During periods of high electricity prices, measures to protect consumers against price peaks are often discussed. In its 2025 assessment of peak-shaving products, ACER considered claw-back mechanisms embedded in support schemes, including two-sided contracts for difference, as a way to reduce consumers' exposure to high electricity prices. This case study examines the Irish RESS as a practical example and assesses the extent to which its claw-back mechanism has hedged consumers during periods of high electricity prices.

Case study: Irish Renewable Electricity Support Scheme (RESS)

70 Ireland's Renewable Electricity Support Scheme (RESS) is a support scheme for renewable electricity projects. Successful projects secure a guaranteed price for the electricity they generate over the support period. Economically, the scheme operates as a two-sided contract for difference: when the market price is below the project's strike price, the scheme provides a top-up payment; when the market price is above the strike price, the project pays back the difference. This claw-back limits the upside retained by subsidised generators and returns revenues above the contracted price to electricity consumers.

71 Figure 13 shows, for each RESS year, the benchmark electricity price used in the ex-ante calculation and the corresponding RESS payment resulting from that price. A negative payment indicates a net transfer from supported generators to electricity consumers. In all years shown, the scheme results in payments to consumers, as market prices were above the strike prices of supported projects. The effect was particularly pronounced during the energy crisis: in 2022/23, when the benchmark electricity price reached EUR 341/MWh, the payment to consumers increased to EUR 314 million, compared with EUR 6 million in 2021/22. As electricity prices subsequently declined, payments to consumers also fell. The experience of RESS therefore illustrates how including a claw-back mechanism in a support scheme can hedge consumers against high electricity prices.

Figure 13: RESS ex-ante cost and benchmark electricity price



Source: ACER computation based on PSO levy's data.

72 The Irish RESS experience confirms the potential of two-sided contracts for difference to hedge consumers against periods of high electricity prices by returning part of generators' upside revenues to consumers. However, the design of such schemes needs to preserve efficient dispatch incentives and avoid distorting generators' short-term operating decisions. These design considerations are discussed further in Section 2.1.

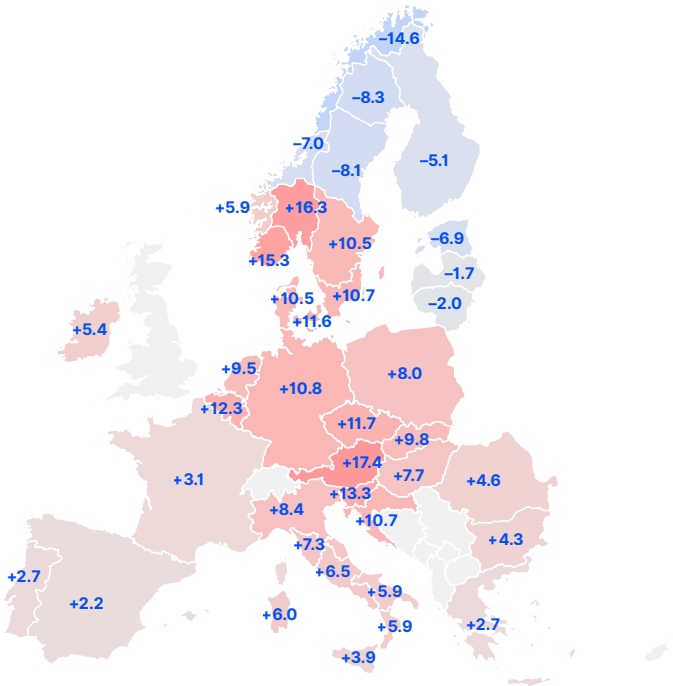
2. Day-ahead markets

73 The day-ahead market plays a central role in the efficient operation of the EU's internal electricity market. Through market coupling, it allows the coordinated allocation of cross-zonal capacity and the efficient dispatch of generation resources across interconnected bidding zones, providing efficient price signals for market participants and supporting efficient cross-border electricity trading. This section analyses the main developments in the EU's day-ahead market in 2025.

2.1. Growing price volatility in day-ahead markets highlights the need for flexibility

74 In 2025, average day-ahead electricity prices increased in most European bidding zones compared with 2024, as shown in Figure 14. The magnitude of the increase differed across bidding zones, reflecting variations in the generation mix, electricity demand, renewable output, cross-zonal exchanges and network constraints. Despite the high level of integration achieved through market coupling, these factors continued to produce significant regional differences in wholesale electricity prices.

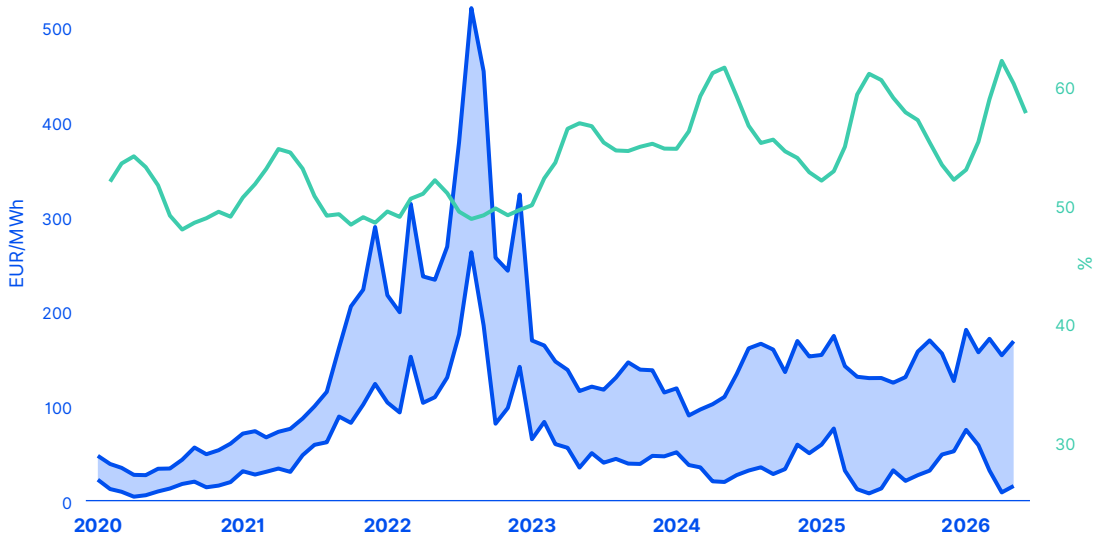
Figure 14: Average price difference in single day-ahead coupling between 2024 and 2025 – 2024-2025 (EUR/MWh)



Source: ACER calculation based on ENTSO-E Transparency Platform data.

75 The increase in average prices was accompanied by a further widening of the difference between low- and high-price hours. As shown in Figure 15, the average daily spread between minimum and maximum day-ahead prices increased from 28.3 EUR/MWh in 2020 to 133 EUR/MWh in 2025. The spread therefore reached almost five times its 2020 level, indicating that market conditions increasingly vary within the same day.

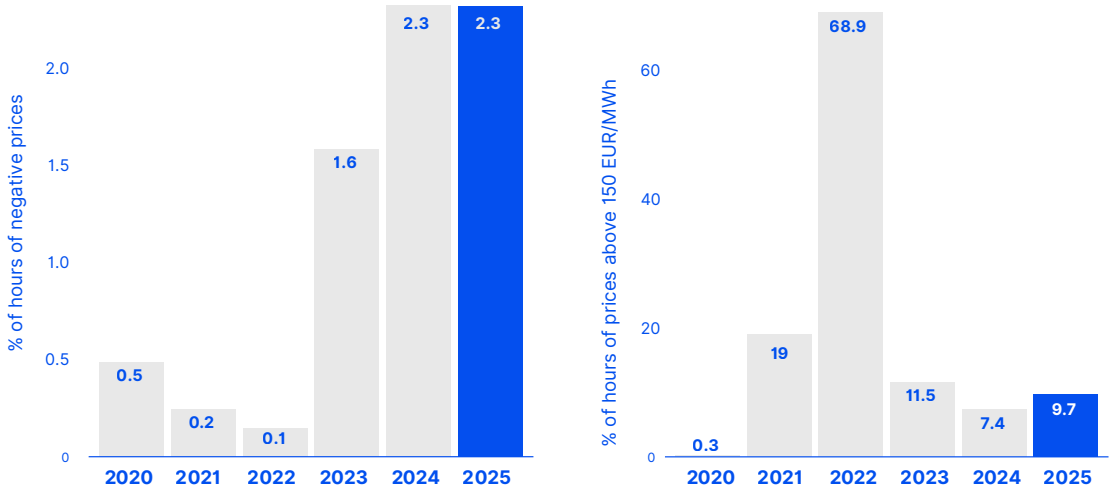
Figure 15: Average of daily minimum and maximum day-ahead prices across bidding zones in SDAC and average share of renewables in electricity generation mix – 2020-2025 (EUR/MWh & % of electricity generation)



Source: ACER calculation based on ENTSO-E Transparency Platform.

76 The broader distribution of prices is also reflected in the increasing occurrence of extreme price outcomes. As shown in Figure 16, negative prices became more frequent between 2020 and 2025, while the occurrence of prices above 150 EUR/MWh remained persistent over the period. Low-price periods generally occurred when available generation exceeded short-term demand, while high-price periods reflected tighter system conditions and a greater reliance on more expensive generation or flexibility resources.

Figure 16: Average share of hours where wholesale prices are below zero (left) and above 150 EUR/MWh (right) across EU and Norway bidding zones – 2020-2025 (% of hours)



Source: ACER calculation based on ENTSO-E Transparency Platform.

2.1.1. Case Study: Electricity demand sensitivity to temperature

77 Weather conditions influence electricity markets through both electricity supply and demand. Temperature is particularly relevant for electricity consumption, as heating and cooling needs can substantially affect demand during periods of cold and hot weather. Table 1 shows ACER's estimates of how electricity demand changes when temperatures fall below 10°C or rise above 20°C across the countries analysed.

Table 1: Estimated change in electricity demand associated with temperature changes

Member State	Demand increase per -1°C below 10°C (% of average demand)	Demand increase per +1°C above 20°C (% of average demand)
FR	4.26	1.19
DE	0.97	0.01
ES	0.93	2.22
GR	2.26	6.34
RO	1.04	1.54
HU	1.40	1.20

Source: ACER calculation based on ENTSO-E Transparency Platform and Copernicus ERA5 data.

Note: Estimates are based on separate country-level regressions for temperatures below 10°C and above 20°C, controlling for hour-of-day and day-of-week effects. Values show the estimated change in electricity demand associated with a 1°C decrease below 10°C or a 1°C increase above 20°C.

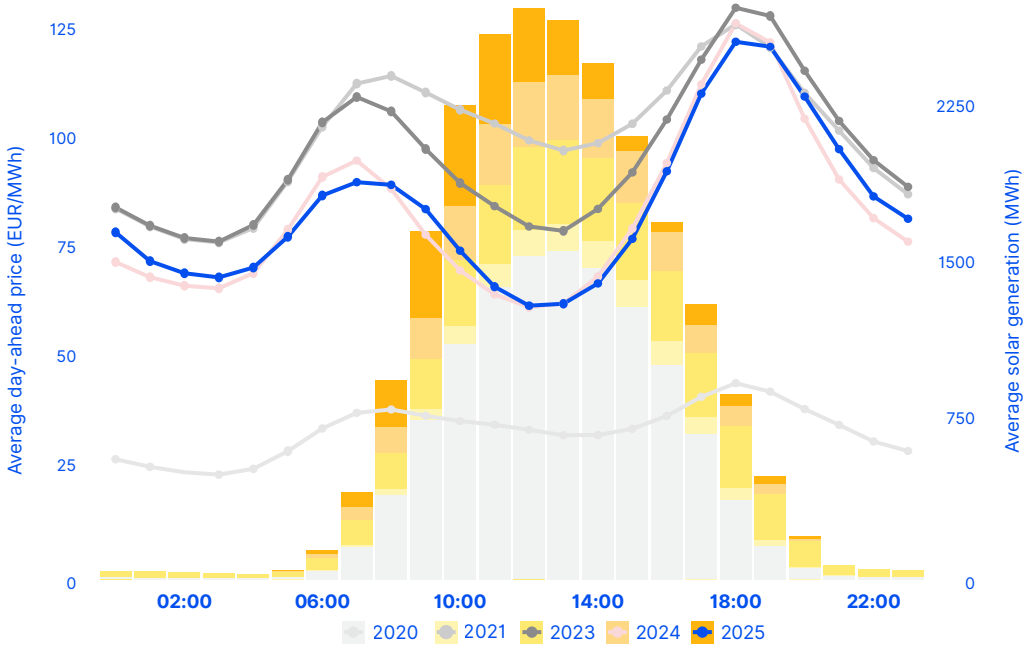
78 At temperatures below 10°C, demand increases as temperatures fall in all countries analysed. The strongest response is observed in France, where electricity demand increases by around 2.4 GW for each 1°C decrease below 10°C, followed by Germany at around 0.8 GW. In the remaining countries analysed, the estimated increase ranges from around 140 MW to 310 MW per degree.

79 At temperatures above 20°C, the response is more heterogeneous. The strongest increases are observed in Spain and France, where demand rises by around 630 MW and 590 MW, respectively, for each additional degree, followed by Greece at around 370 MW. In several other countries, the estimated response is considerably smaller.

80 Periods of particularly high or low temperatures can consequently add to electricity demand and contribute to tighter market conditions, particularly in countries where temperature sensitivity is strongest.

81 The evolution of average hourly electricity prices over recent years highlights the increasing influence of solar generation on day-ahead price formation. As shown in Figure 17, average solar generation has increased steadily since 2020, while the daily profile of wholesale electricity prices has become progressively more pronounced.

Figure 17: Average hourly day-ahead price and solar generation in SDAC – 2020-2025 (EUR/MWh & MWh)



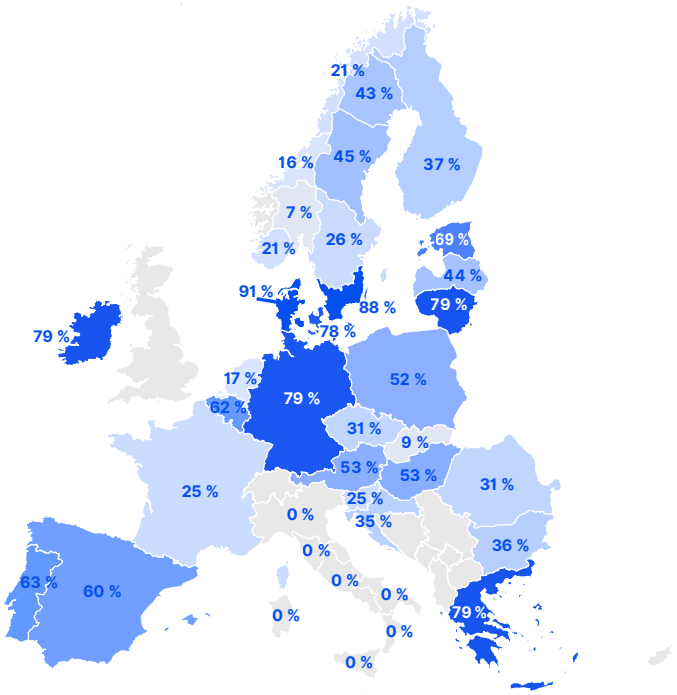
Source: ACER calculation based on ENTSO-E Transparency Platform.

82 During the central hours of the day, when solar generation reaches its highest levels, average day-ahead prices have declined substantially compared to previous years. Conversely, prices remain highest during the morning and, particularly, the evening hours, when solar generation is limited or unavailable and additional generation is required to meet electricity demand. The growing separation between midday and evening price levels illustrates how solar generation increasingly shapes price formation across European electricity markets.

83 The growing influence of solar generation on day-ahead prices is also visible in the generation mix during negative-price periods. Figure 18 shows, for each bidding zone, the share of total electricity generation supplied by solar and wind during market time units in which day-ahead prices were negative. In many bidding zones, these technologies accounted for a substantial share of generation during such periods.

84 Significant volumes of solar and wind generation continued to be produced while day-ahead prices were negative. These volumes were therefore not curtailed, or not fully curtailed, in response to the negative price signal. Solar and wind installations can generally reduce output without significant technical or operational costs. In an efficiently functioning system, they would normally reduce output before technologies for which modulation entails higher costs.

Figure 18: Share of total electricity generation by solar and wind during periods of negative prices – 2025 (% of total generation)



Source: ACER calculation based on ENTSO-E Transparency Platform.

Note: For further information on the share of hours of day-ahead negative prices in each bidding zone, see the Key Developments report, slide 44.

85 One reason for this limited response is the design of some renewable support schemes. Where support payments are linked to production and continue during negative-price periods, producers may still benefit from generating despite the negative market price. Electricity markets rely on prices to signal when producers should generate and when they should reduce output. This mechanism can work efficiently only if most generation responds to those signals. If a large share of generation instead faces incentives to keep producing, other assets must adjust, even where curtailing supported renewable generation would be less costly. This can aggravate negative-price episodes and increase both system and support costs.

86 This concern is increasingly reflected in the EU framework for renewable support. In particular, Article 19d(2)(a)–(b) of the Electricity Regulation (EU) 2019/943 requires two-way contracts for difference to preserve incentives for efficient market participation and prevent distortions to dispatch decisions and bidding behaviour.[16] These provisions improve the design of new support schemes but do not remove incentives embedded in existing contracts. France provides an example of how such legacy arrangements can be adapted.

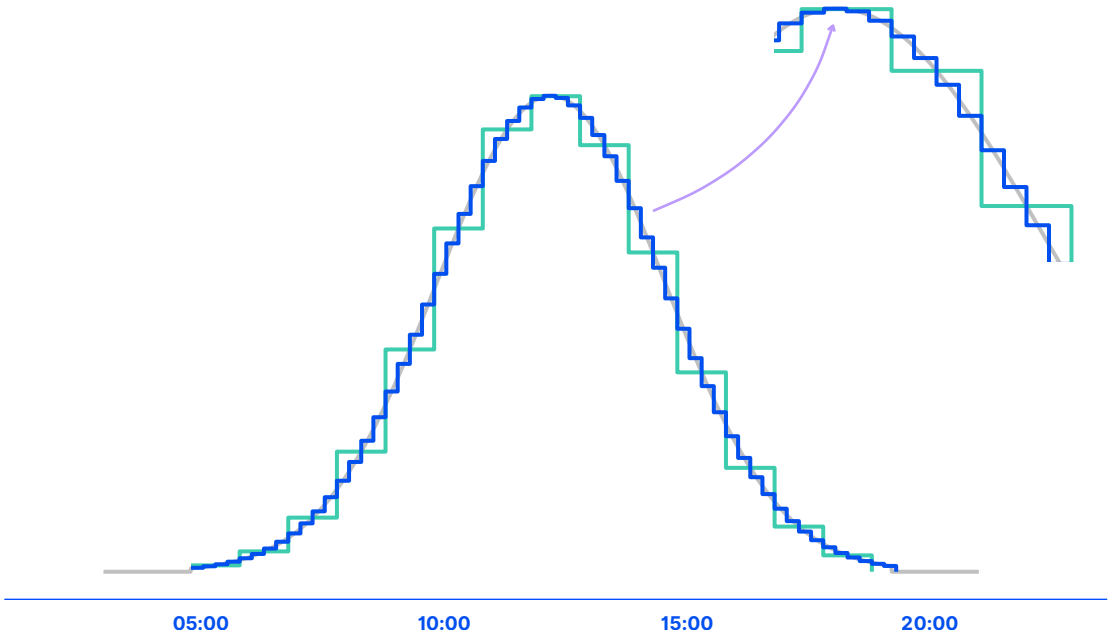
16 One way to preserve efficient dispatch incentives is to decouple support payments from actual electricity production, for example by basing them on an estimate of what the asset could produce under prevailing conditions. This allows producers to adjust output in response to market prices without changing their support payments.

87 In November 2024, the French Energy Regulatory Commission recommended amending historical support contracts so that supported producers would curtail during negative-price periods without losing remuneration for the production foregone.[17] Article 175 of the French Finance Act for 2025 subsequently established a mechanism allowing designated buyers to request eligible installations covered by purchase-obligation contracts to stop or limit generation where this reduces support costs. Producers that comply are compensated for the production foregone; those that do not comply receive neither the purchase tariff nor compensation for the relevant period. This applies to all installations above the relevant threshold. When the mechanism entered into force on 25 December 2025, the thresholds were 12 MWp for solar installations and 10 MW for wind installations. They will be progressively reduced to 1 MWp or 1 MW by 1 March 2027, thereby extending the mechanism to a larger share of the supported fleet. By compensating production foregone, the mechanism removes the incentive for affected producers to continue generating when instructed to curtail, thereby helping to reduce costs while preserving the revenue predictability on which existing investments were based.

2.2. Enabling flexibility: Introduction of 15-minute market time units

88 The introduction of 15-minute market time units represents a major change in the temporal granularity of European short-term electricity markets. Since delivery day 1 October 2025, the Single Day-Ahead Coupling has operated with 15-minute market time units (MTUs), allowing prices and traded volumes to be determined separately for each quarter-hour. Compared with hourly scheduling, the shorter MTUs enable market participants to represent more accurately expected variations in generation and consumption and bring commercial schedules closer to the physical evolution of the electricity system.

Figure 19: Illustrative representation of actual solar generation compared with hourly and 15-minute MTUs



Source: ACER elaboration.

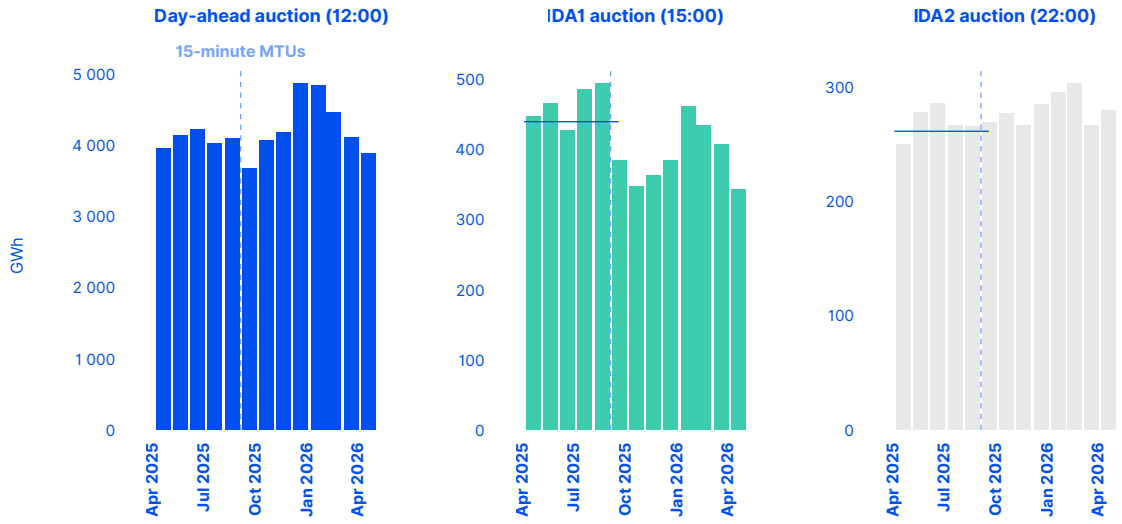
17 Reference: La CRE publie son analyse sur le phénomène de prix de l'électricité négatifs et ses recommandations relatives aux dispositifs de soutien aux énergies renouvelables | CRE.

89 The benefits of greater temporal granularity are particularly relevant for assets whose output changes rapidly within the hour. As illustrated in Figure 19 using a mock solar generation profile, hourly trading results in commercial schedules that represent changes in expected generation through relatively large and constant hourly steps. By contrast, 15-minute MTUs allow traded volumes, and the resulting commercial schedules, to follow the expected generation profile more closely, reducing the difference between scheduled and actual generation. This is particularly relevant during periods of rapid changes in solar output, including the steep increases and decreases before and after peak generation around midday.

90 These benefits are not entirely new to short-term electricity markets, as 15-minute MTUs were already available in intraday trading before their introduction in the day-ahead market. Intraday trading, together with its shorter gate closure times, already allowed market participants to adjust their positions closer to delivery as updated generation and demand forecasts became available. The introduction of 15-minute MTUs in the day-ahead market extends this temporal granularity to an earlier stage of the trading process, allowing day-ahead to provide a more accurate starting position and potentially reducing the extent of subsequent adjustments required in intraday trading.

91 The introduction of 15-minute products affected the distribution of traded volumes across short-term market timeframes. As shown in Figure 20, average day-ahead volumes increased following the transition, indicating that part of the quarter-hourly trading previously conducted in the intraday timeframe was brought forward once the same granularity became available in the day-ahead market.

Figure 20: Evolution of average traded volumes after the implementation of the 15-minute MTUs in different auction scenarios – April 2025 to April 2026



Source: ACER calculation based on Simulation Facility data.

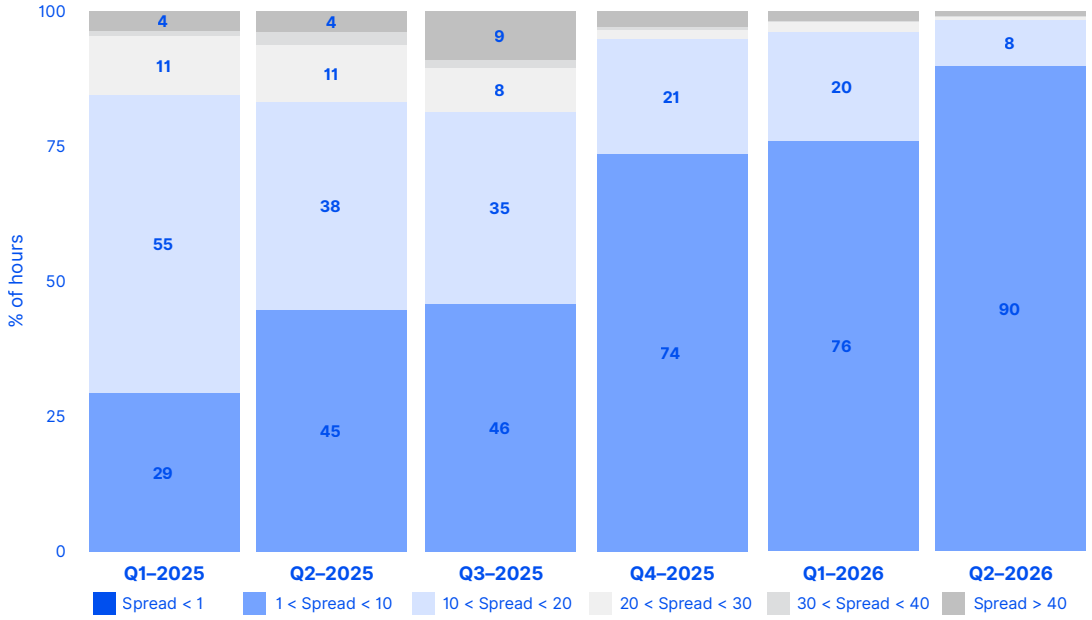
Note: The horizontal lines indicate the average traded volumes before (blue) and after (red) the introduction of 15-minute MTUs in the day-ahead market. The figure is based on average volumes, calculated as the mean of supply and demand volumes.

92 The day-ahead auction can now therefore incorporate, to a larger extent, market participants' expected quarter-hourly positions. In doing so, the quarter-hour information available to market participants can already be incorporated into their bidding for the day-ahead market. Given the increased availability of cross-zonal capacity and flow-based allocation in day-ahead, compared to IDA1, the go-live of 15-min MTUs allows quarter-hourly information to be cleared in a more efficient setting.

93 More granular day-ahead positions may reduce the need for immediate adjustments in IDA1, while IDA2 remains relevant because it takes place closer to delivery and allows participants to update positions using more recent information. Intraday auctions also continue to perform an important role in allocating and pricing the cross-zonal capacity available in the intraday timeframe.

94 Price convergence between the day-ahead market and IDA1 increased following the introduction of the 15-minute MTU, as shown in Figure 21. The growing share of delivery periods with equal or closely aligned prices indicates that price formation in the two auctions became progressively more consistent. This suggests that, as participants adapted their bidding strategies, a larger proportion of the information available before delivery was already incorporated into day-ahead prices rather than being reflected only in subsequent intraday adjustments.

Figure 21: Occurrence of price spread ranges between the day-ahead and IDA1 auctions over time – January 2025 to June 2026 (% of MTUs)

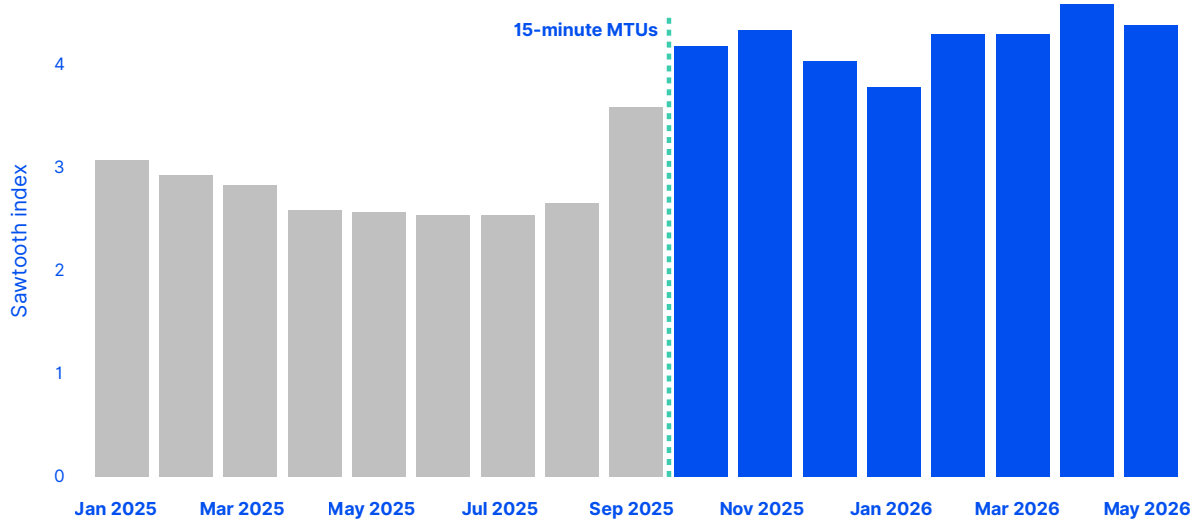


Source: ACER calculation based on ENTSO-E Transparency Platform and Simulation Facility data.

95 The transition to the quarter-hour products in day-ahead was accompanied by significant intra-hourly price volatility, often referred to as a 'sawtooth pattern'. To assess the prevalence of this behaviour, ACER calculated a short-term price volatility index,[18] shown in Figure 22, which captures the extent to which prices exhibit pronounced and recurring changes in direction over consecutive market time units. The index increased markedly following the introduction of the 15-minute MTU, indicating stronger short-term price oscillations. Part of this increase reflects the additional information revealed by quarter-hourly clearing: price differences that were previously aggregated into a single hourly price can now emerge explicitly across the four quarter-hours.

18 The short-term price volatility index is calculated daily for each bidding zone as the product of two components: the average absolute price change between consecutive market time units and the share of consecutive price changes that reverse direction. The first captures the magnitude of short-term price movements, while the second captures how frequently prices alternate between increases and decreases. Higher values indicate more pronounced sawtooth behaviour.

Figure 22: Evolution of short-term price volatility in the day-ahead market before and after the introduction of the 15-min MTU – January 2025 to May 2026

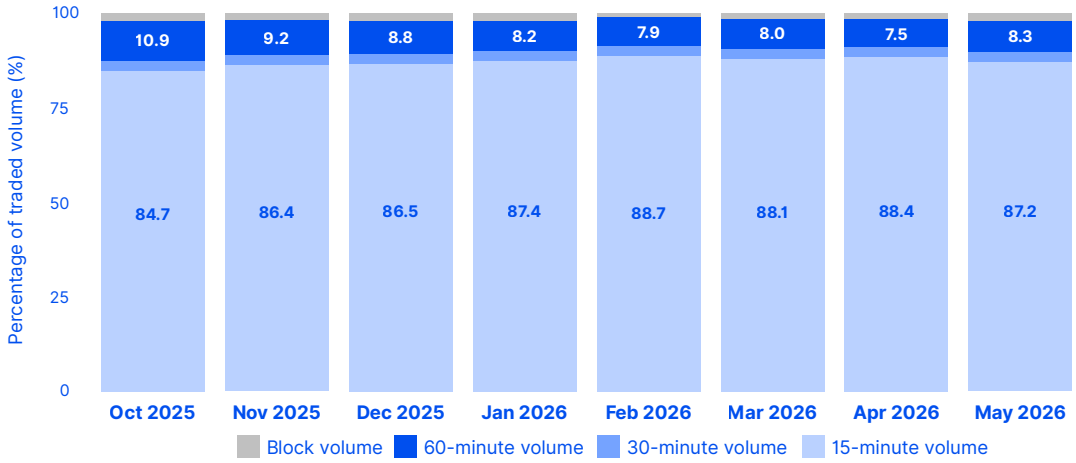


Source: ACER calculation based on ENTSO-E Transparency Platform data.

96 The co-existence of products with different durations may be one of the root causes of this pattern. While 15-minute products allow prices and traded volumes to reflect changes in supply and demand within the hour, some market positions remain defined on an hourly basis. This includes hourly products as well as cross-zonal capacity, which is still calculated for each hour rather than for each 15-minute MTU. The interaction between these hourly constraints and quarter-hourly changes in market conditions may contribute to alternating price movements across consecutive 15-minute intervals.

97 As shown in Figure 23, 15-minute products accounted for a substantial share of traded volumes after the transition, while hourly products continued to represent a smaller but persistent share. Thirty-minute products and block orders also remained in use, resulting in the coexistence of products with different durations. Hourly products may remain appropriate for assets with relatively stable output or consumption profiles and are therefore not inherently inconsistent with a 15-minute MTU.

Figure 23: Share of traded volumes following the implementation of the 15-minute MTU by product type – October 2025 to May 2026 (%)



Source: ACER calculation based on Simulation Facility data.

Note: Due to their small shares, labels for block and 30-minute volumes are not displayed in the figure. On average, block volumes account for 1.7% and 30-minute volume for 2.5% of total traded volumes. The figure is based on the average of supply and demand volumes.

98 Alongside the introduction of the 15-minute MTU, the SDAC product framework was adapted to accommodate products with different time resolutions. Products covering a single MTU correspond to MTU products, while 30- and 60-minute products span respectively two and four 15-minute MTUs and correspond to period products. Simple block products remain a separate product category. Cross-product matching allows products submitted with different durations to interact in the same market-clearing process.[19]

99 Overall, the introduction of the 15-minute MTU improved the precision of market schedules, shifted part of the adjustment activity towards the day-ahead market and strengthened price convergence with IDA1. At the same time, the coexistence of products with different durations and the resulting increase in within-hour price variability show that the full benefits of the shorter MTU depend on the extent to which market participants adapt their bidding strategies and product choices.

2.3. Cross-zonal trade increases the efficiency of day-ahead markets, but congestion is growing

100 Over the past decade, the integration of European electricity markets has advanced significantly, driven by key projects such as the completion of market coupling and the progressive implementation of flow-based capacity calculation and allocation. These developments have strengthened cross-border electricity trading over time, playing a central role in optimising the use of generation resources across the EU.

101 Cross-zonal electricity trading allows for the dispatch of the most cost-efficient generation assets available across the EU. It supports the integration of renewable energy sources into the system and dampens price volatility, which is particularly relevant during periods of sustained high prices, such as the 2022 energy crisis. A highly integrated EU electricity market is thus instrumental in ensuring a cost-efficient energy transition and enhancing the resilience of the power system.

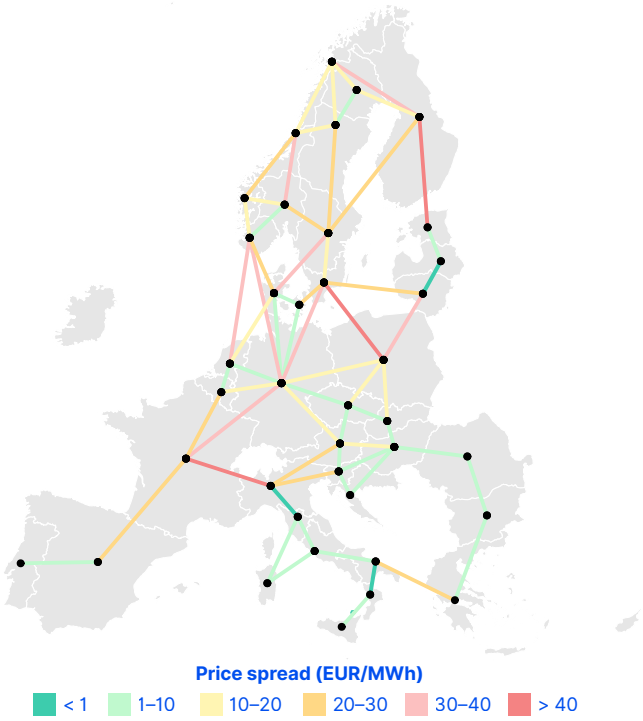
102 The exchanges of electricity across bidding zones are enabled by the levels of cross-zonal capacity made available by TSOs. When available capacity is sufficient to meet all the market's needs, prices across bidding zones will converge. By contrast, insufficient capacity prevents additional cross-zonal exchanges, leading to price differences between bidding zones. Such price differences are the indication of market congestion, signalling that the need for cross-zonal trade was greater than the available capacity.

103 In recent years, capacity calculation and allocation processes have been gradually improved across the EU's different capacity calculation regions (CCRs), increasing the coordination in the calculation of cross-zonal capacity, and ensuring its efficient allocation. In particular, the Core and Nordic CCRs have introduced flow-based market coupling, which better captures the interdependencies between power flows across bidding zone borders.

19 The 60-minute product can be matched against combinations of shorter-duration products covering the same delivery period.

104 Despite this progress, the physical limits of the power grid, together with the existing bidding zone configuration, continue to limit cross-zonal trade in the EU. In 2025, available cross-zonal capacities and differences in market fundamentals led to significant price differences across the EU, with average spreads exceeding 40 EUR/MWh on several bidding zone borders. In recent years, shifts in the electricity generation mix across EU Member States have contributed to the widening of these price spreads, by changing the relative supply conditions and marginal generation costs across markets. Figure 24 presents an overview of the average price spreads at each bidding zone border in 2025.

Figure 24: Yearly average of the absolute price spread per bidding zone border in the day-ahead market – 2025 (EUR/MWh)



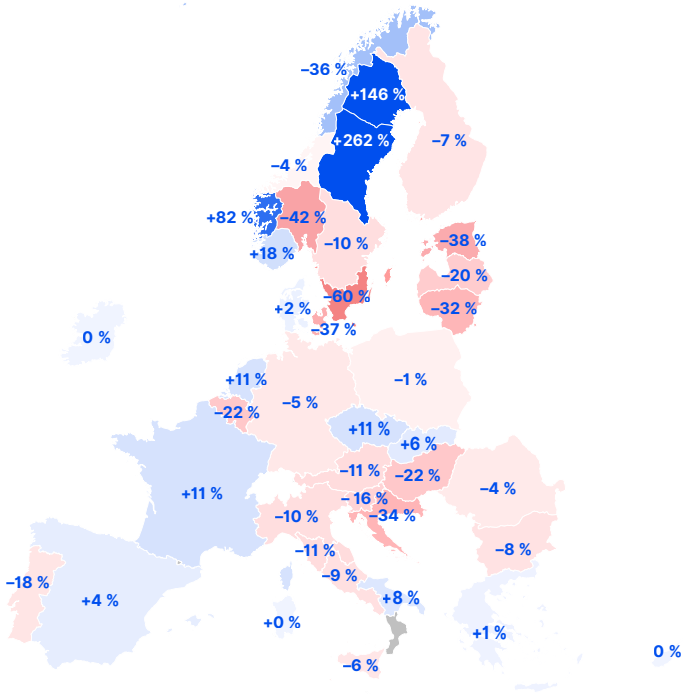
Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: The absolute price spread is used for the purpose of this figure, to avoid misrepresenting the levels of congestion on bidding zone borders where the spread reverses frequently.

105 Cross-zonal trade plays a significant role in the EU internal electricity market to ensure the most efficient dispatch of electricity. Figure 25 shows net day-ahead electricity exchanges as a share of electricity demand in each bidding zone. As observed in the figure, some bidding zones meet a significant proportion of their electricity demand through imports from other zones, as opposed to from local assets. Conversely, some zones with a surplus of electricity can export a large share to neighbouring markets.

106 This ability to draw on assets located in neighbouring bidding zones becomes particularly valuable during periods of scarcity or system tightness. By broadening the pool of resources available to meet demand, cross-zonal trade can reduce reliance on high-cost domestic generation and thus mitigate price spikes. The extent of this effect depends, however, on sufficient cross-zonal capacity being available when the system is under stress.

Figure 25: Net cross-zonal exchanges in the single day-ahead coupling as a percentage of electricity demand per bidding zone in the EU and Norway – 2025 (% of yearly demand)



Source: ACER calculation based on ENTSO-E Transparency Platform data.

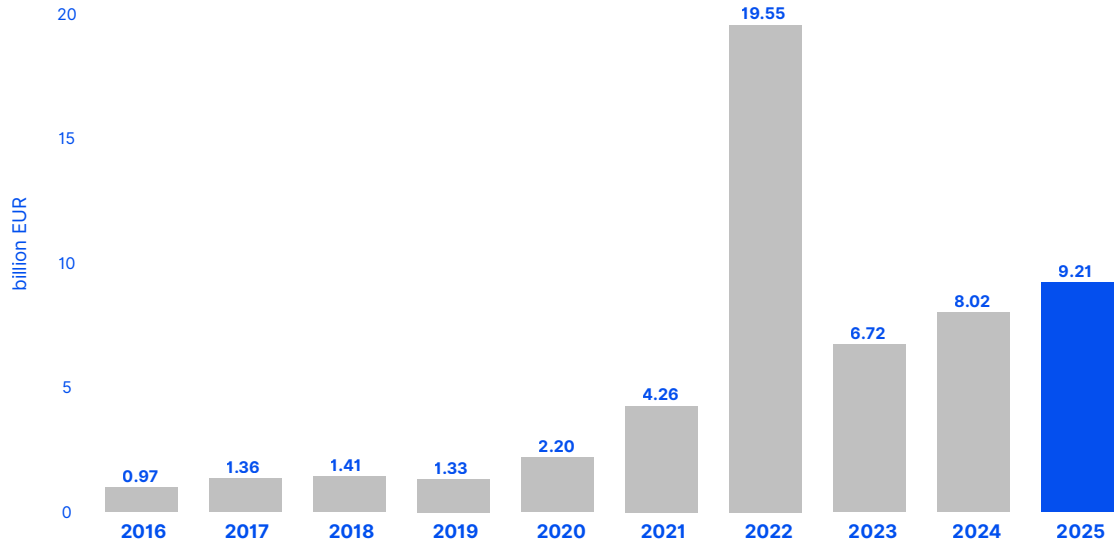
Notes: Positive values indicate net exports, while negative values indicate net imports. Information on the net position of bidding zone Italy Calabria was not available. Ireland and Cyprus show a 0% value, as they are currently not interconnected with any other EU Member State.

107 Price differences between bidding zones generate congestion income for TSOs, which reflects the value of scarce cross-zonal capacity on a given bidding zone border. Consistently high price differentials may signal the need for additional cross-zonal capacity, but need to be weighed against the costs associated with increasing it. The use of congestion income is regulated at EU level: TSOs receiving the congestion income must primarily reinvest it to strengthen the power grid and thus alleviate congestion in the long term.

108 In 2025, the total congestion income generated by SDAC exceeded EUR 9.2 billion, which constitutes a seven-fold increase with regard to the values prior to 2020.[20] As observed in Figure 26, the volume of congestion income generated in 2025 follows a multi-year upwards trend that started in 2020, which signals the increasing value of cross-zonal trade in the EU's electricity system.

20 This does not account for any compensation to which LTTR holders are entitled and is thus a gross figure of congestion income generated in the day-ahead market.

Figure 26: Yearly evolution of congestion income generated by SDAC – 2016-2025 (billion EUR)



Source: ACER calculation based on Simulation Facility data.

Note: Congestion income is calculated as the scheduled commercial exchange multiplied by the price spread on each bidding zone border.

2.3.1. Flow-based market coupling can result in non-intuitive market outcomes, where this contributes to maximising overall economic surplus

109 Cross-zonal trade typically supports the transfer of electricity from lower-priced bidding zones towards higher-priced ones. This contributes to the efficient dispatch of generation resources and promotes price convergence across power markets. However, the net exchanges of individual bidding zones do not always follow this intuitive relationship in flow-based market coupling.

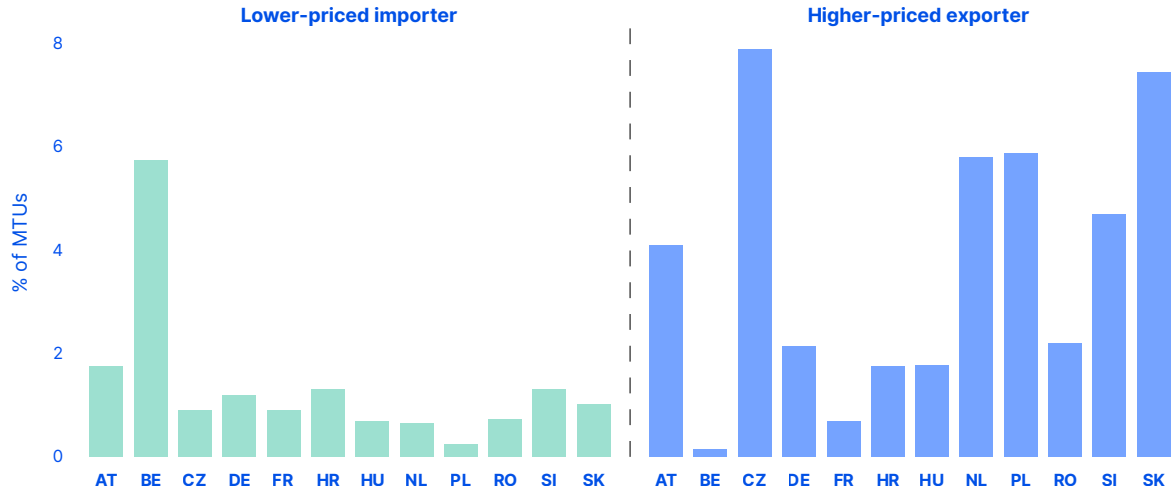
110 This is because market coupling optimises exchanges at the regional level rather than on a purely bilateral basis, taking into account the interaction between multiple trades and network constraints across the region. In some market time units, a relatively high-priced bidding zone may remain a net exporter, while a relatively low-priced bidding zone may record a net importing position. These market outcomes are usually referred to as 'non-intuitive'.

111 A bidding zone may export despite having a higher price than its neighbours because its exports contribute to relieving a constraint or enable a wider pattern of exchanges that increases total economic surplus across the region. Similarly, a lower-priced bidding zone may import where the feasible set of network constraints prevents additional exports from that zone or where its net position forms part of a broader combination of exchanges that enable an optimal market-coupling solution. Such complementary exchanges can facilitate additional trade elsewhere in the region.

112 A result that may therefore appear non-intuitive from the perspective of an individual bidding zone or bidding zone border can be economically efficient when considered as part of regional optimisation. In short, locally non-intuitive market results serve to enable a global market optimum in a flow-based market coupling setting.

113 As shown in Figure 27, the frequency of lower-priced importing and higher-priced exporting positions differs across bidding zones. The figure presents, for each zone, the share of market time units in which either of the two conditions was observed. A higher share indicates that the bidding zone's net trading position more frequently diverged from the direction that would be expected from a simple comparison between its price and the regional weighted average. As observed, non-intuitive market outcomes occur the most in smaller centrally located bidding zones.

Figure 27: Percentage of market time units with non-intuitive day-ahead market results in the Core CCR – 2025 (% of MTUs)

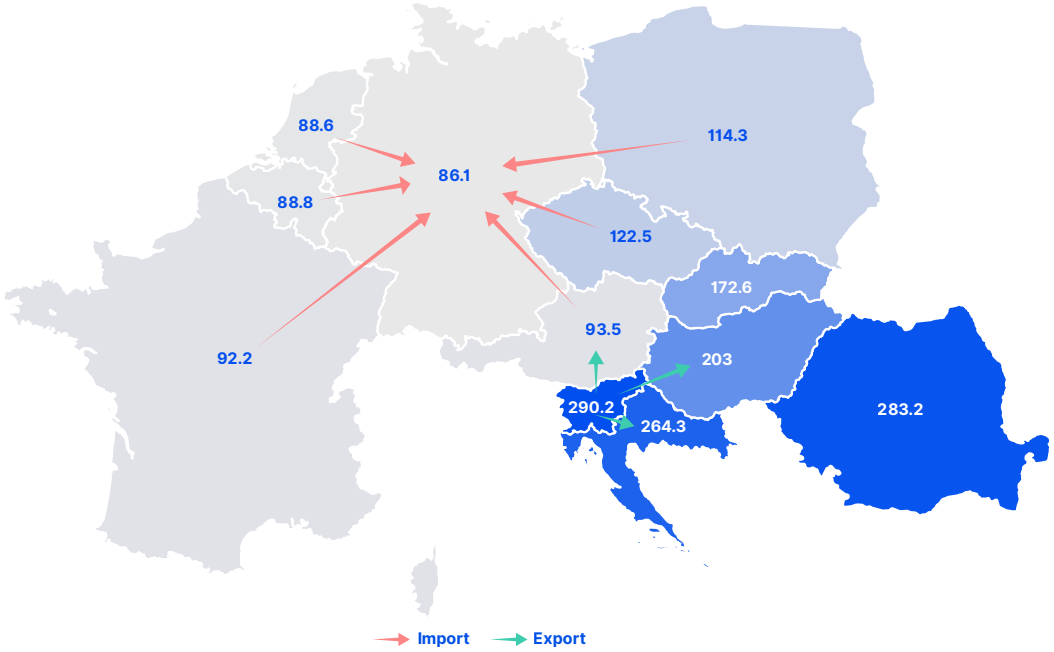


Source: ACER calculation based on ENTSO-E Transparency Platform and JAO Publication Tool data.

Note: For the purpose of this figure, a bidding zone is identified as a higher-priced exporter when its price is above the demand-weighted average price of the Core region, and its Core internal net position is positive. Conversely, it is identified as a lower-priced importer when its price is below the demand-weighted average price of the Core region, and its Core internal net position is negative. Import and export positions are determined using the Core internal net positions published in the JAO Publication Tool.

114 The above aggregate indicator describes how frequently non-intuitive positions occur. Figure 28 presents a particular example by showing the prices and Core internal net positions observed on 23 July 2025 at 18:00. In this market time unit, the Germany–Luxembourg bidding zone is a net importer despite having the lowest price in the region, while Slovenia is a net exporter despite having the highest price in the region.

Figure 28: Illustrative case of non-intuitive market outcomes with simultaneous higher-priced exporters and lower-priced importers – 23 July 2025 at 18:00 CEST (EUR/MWh)



Source: ACER calculation based on ENTSO-E Transparency Platform and JAO Publication Tool data.

Note: The arrows indicate whether a given bidding zone has a positive or negative net position with regards to the remaining Core bidding zones, and they do not indicate direction of border-level schedules.

115 A closer look at the network conditions helps explain Slovenia's apparently non-intuitive position. Although Slovenia had the highest price in the Core region, its exports helped reduce the pressure on one of the network constraints most limiting trade in that hour. The constraint was particularly tight, as indicated by its very high shadow price.[21]

116 In practice, the power flows induced by Slovenian exports moved partly in the opposite direction to the congested network element, thereby easing the constraint and creating more room for other exchanges within the Core region. An export from a high-priced bidding zone can therefore still be beneficial from a regional perspective, even if it appears non-intuitive when looking only at prices.

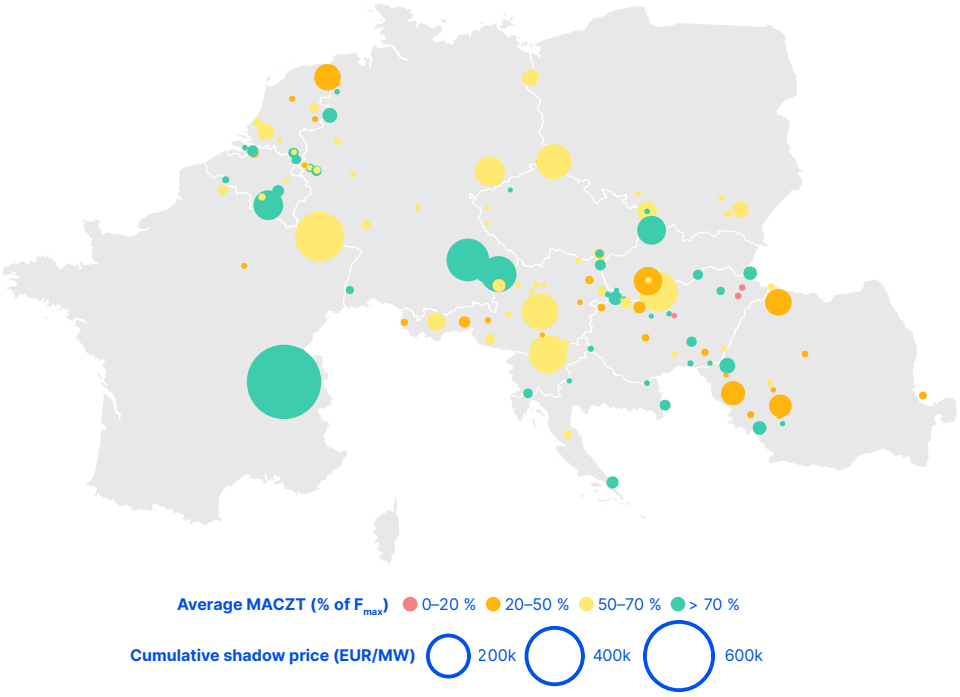
2.3.2. Shadow prices represent the impact of scarce cross-zonal capacity on market efficiency

117 The European market clearing algorithm quantifies the value of relieving every cross-zonal capacity constraint, by computing the potential increase in economic surplus incurred by relaxing the relevant constraint by a single megawatt. This metric is referred to as the shadow price. A non-zero shadow price on a given capacity constraint indicates that there is value in allowing for more capacity, as that would in turn allow for further cross-zonal trade. On the other hand, increasing capacity in network elements with a shadow price of zero would not alter the market dispatch.

118 In flow-based market coupling, capacity constraints are defined by critical network elements and contingencies (CNECs), which represent the conditions of a given network element under the outage of another one. These CNECs also have a shadow price associated with them. Figure 29 represents the most relevant market congestions in Core flow-based market coupling during 2025, weighted by how constraining they were (i.e. weighted by their shadow price), and categorised by the average margin available for cross-zonal trade (MACZT) offered in each congested CNEC over the year. The figure thus shows where relieving capacity constraints in the Core CCR would bring most value to the European internal market.

21 On 23 July 2025 at 18:00, the relevant binding CNEC was *Pleinting* – St. Peter 258, in the DIRECT direction, under the contingency *Pirach – Pleinting* 296/257. The CNEC had a non-zero shadow price of 13.789 EUR/MW and a Slovenian PTDF of -0.00679. The negative PTDF indicates that an increase in Slovenia's net position reduces the flow on this CNEC in the constrained direction.

Figure 29: Market congestion in the Core CCR weighted by the accumulated shadow price and categorised by margin available for cross-zonal trade – 2025 (EUR/MW and % of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

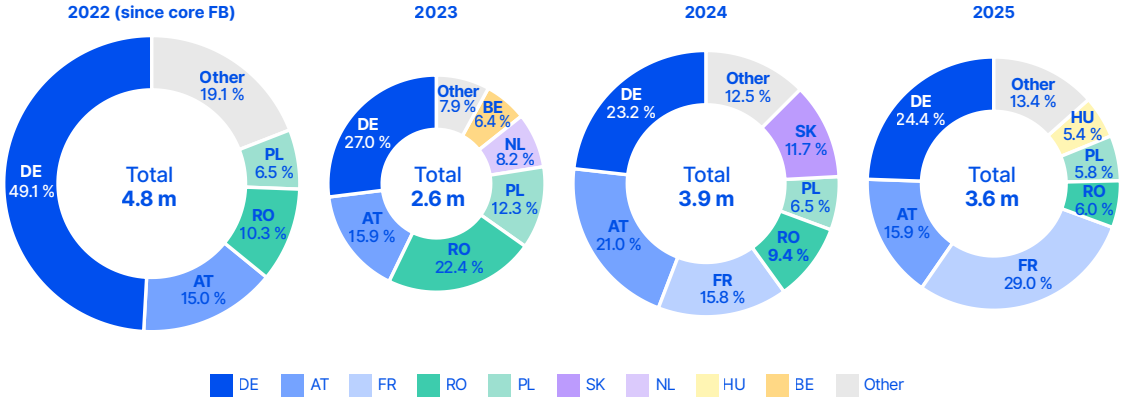
Note: Shadow prices are provided in EUR/MWh, and are thus divided by four as of 1 October 2025, to present a metric in EUR/MW. F_{max} corresponds to the maximum flow on a critical network element that would respect the operational security limits.

119 Comparing patterns of market congestion over time provides insights into the underlying market dynamics and availability of grid capacity. Figure 30 shows the yearly volume of market congestion in the Core CCR since the implementation of flow-based market coupling in June 2022, together with the share of market congestion attributable to CNECs introduced in capacity calculation by each Core TSO.

120 Market congestion in the Core CCR remained broadly stable compared to 2024. Nonetheless, the shares attributable to CNECs of each TSO have been evolving over time. These changes can be explained both by the varying progress in maximising available cross-zonal capacities across Member States, as discussed in the following subsection, and by rapidly evolving market conditions on both the demand and supply sides.

121 France provides a relevant example. Over the past two years, the French electricity system has recorded a significant generation surplus, resulting in increased congestion on network elements that accommodate exports towards its eastern neighbours. In June 2024, RTE introduced several of such network elements into the capacity calculation process, after significant capacity reductions had previously been applied to address constraints arising under high export conditions. Their increasing contribution to market congestion therefore reflects not only changing generation patterns in France and its neighbours, but also the extent to which the network is able to accommodate the resulting export flows.

Figure 30: Evolution of the distribution of market congestion in the Core CCR per Member State – June 2022 to December 2025 (EUR/MW)



Source: ACER calculation based on JAO Publication Tool data.

122 In summary, shadow prices in flow-based market coupling provide a useful indication of the value of additional cross-zonal capacity on individual network elements. Persistently high shadow prices suggest that a given constraint repeatedly limits economically efficient exchanges and may therefore signal a structural need for more capacity for cross-zonal trade at that location. The evolution of shadow prices therefore complements values of generated congestion income, by indicating where specifically capacity constraints are significant and where measures to facilitate additional cross-zonal trade may deliver the greatest benefits.

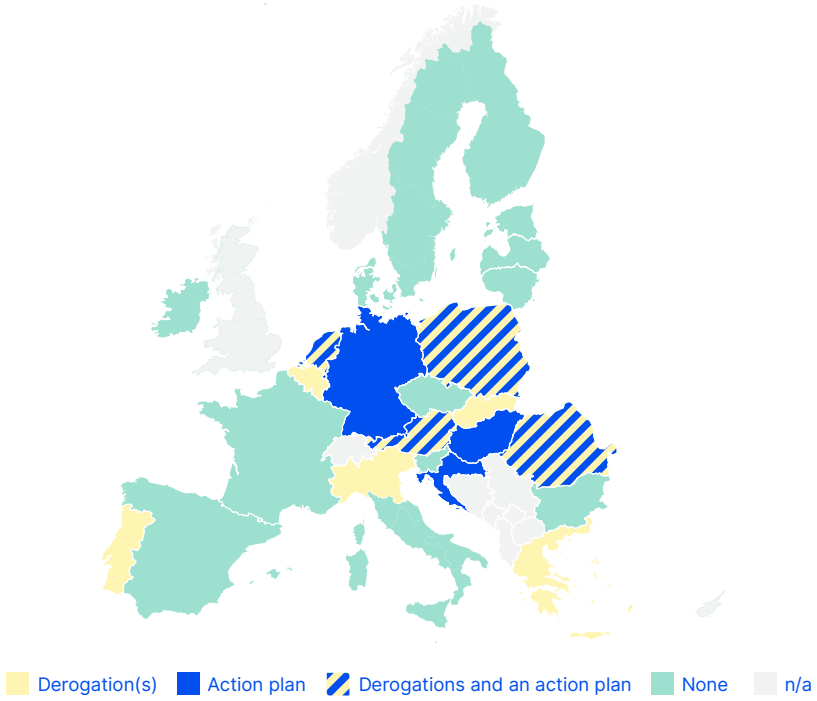
2.4. Cross-zonal capacities and the minimum 70% requirement

123 The development and implementation of processes for the efficient calculation and allocation of cross-zonal capacities for cross zonal trade are an integral part of the efficient functioning of the EU's internal electricity market. Over the last decade, progress in capacity calculation and allocation has been considerable, with all EU bidding zone borders being included in SDAC and single intraday coupling (SIDC), and the introduction of flow-based capacity calculation and allocation. However, progress in maximising the availability of capacities offered for cross-zonal trade across the EU has been slower.

124 The electricity market in the EU is structured into bidding zones. Within each bidding zone, the impact of electricity trade between market participants on physical grid congestion is ignored, even though it may be significant, and thus is not limited by capacity allocation. In contrast, trade between bidding zones is limited by a predefined set of values of cross-zonal transmission capacity, which reflect physical grid congestion in the network. Under this model, internal exchanges effectively receive priority access to scarce network capacity, while cross-zonal exchanges can only make use of the capacity remaining after internal exchanges have been accommodated.

125 To address the need for maximising cross-zonal capacities and mitigate the inherent discrimination of cross-zonal trade in favour of internal trade, the recast Electricity Regulation introduced a minimum level of cross-zonal capacity to be offered to the market by TSOs, while respecting operational security limits. This minimum 70% requirement entered into force in 2020. To implement the requirement, without endangering system security, Member States could opt for an action plan, which enabled TSOs to address structural congestion within bidding zones progressively, until the end of 2025.

Figure 31: Overview of the status of implementation of the minimum 70% requirement in the EU for each Member State – 2025



Source: ACER elaboration based on NRA data.

126 In parallel, as part of a pan-European bidding zone review, EU TSOs were to cooperate to identify structural congestions within and between bidding zones and assess potential bidding zone reconfigurations. On 28 April 2025, EU TSOs delivered the first assessment of bidding zone configuration as per the requirements of the Electricity Regulation and recommended the split of the German and Dutch bidding zones into five and two zones, respectively. This recommendation was later decided against by the relevant Member States, who opted for maintaining the current configuration. ACER issued an Opinion to the Council of the EU, evaluating the TSOs' study against the EU regulatory framework, concluding that the benefits of the studied bidding zone reconfiguration had likely been underestimated due to methodological choices.

127 As of 2026, national action plans are no longer in place, following the expiry of the transitional period for progressively reaching the 70% requirement at the end of 2025. Consequently, the 70% minimum becomes the generally applicable requirement, and TSOs are expected to make at least 70% of the transmission capacity available for cross-zonal trade on relevant network elements.

128 This section primarily focuses on the implementation of the minimum 70% requirement in the Core and Nordic capacity calculation regions, which currently apply the flow-based methodology, and in Italy North, which will transition to this methodology. It also addresses other relevant aspects of capacity calculation. The results of ACER's monitoring of the MACZT for the remaining CNTC regions are available in Annex I to this report.

2.4.1. Derogations due to excessive loop flows continue to limit capacities in the Core region

129 Cross-border electricity infrastructure is used not only by physical flows stemming from commercial exchanges between bidding zones, but also by physical flows resulting from transactions within individual bidding zones. An exchange between generation and consumption located within the same bidding zone may partly flow through the networks of neighbouring bidding zones before returning to its zone of origin. These flows, commonly referred to as loop flows,[22] arise because electricity flows follow the physical characteristics of the interconnected network, rather than the commercial paths assumed by the zonal market model.

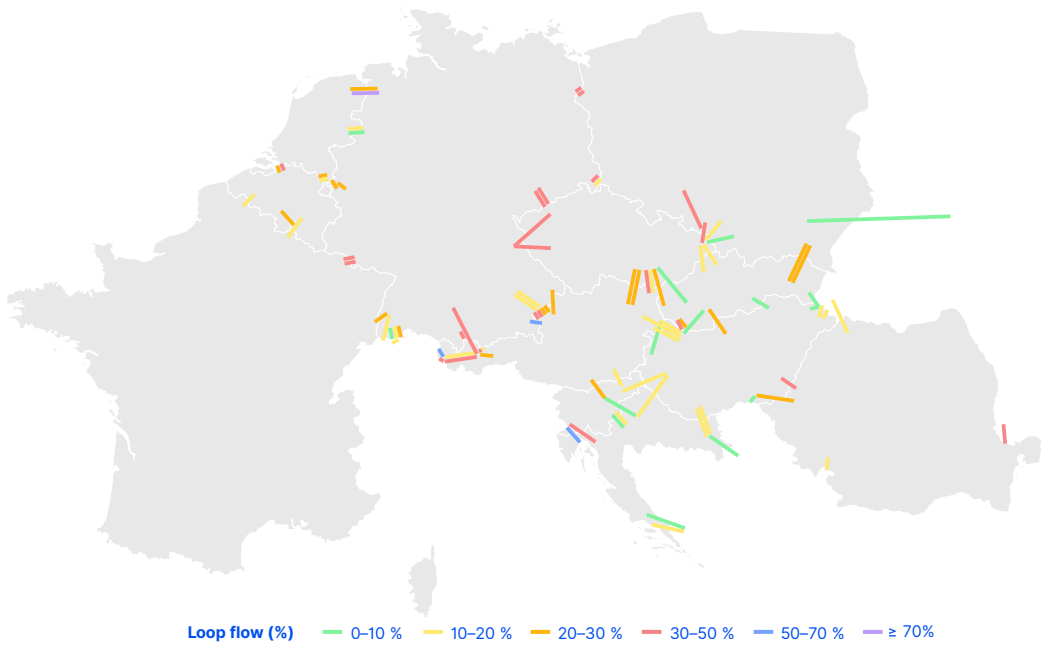
130 Loop flows are a consequence of operating a highly meshed electricity network under a zonal market design, in which trade within bidding zones is not limited by capacity allocation. These flows may use a significant proportion of the physical capacity of critical network elements, without being associated with allocated cross-zonal exchanges, reducing the remaining capacity that can be made available to the market for cross-zonal trade. Moreover, since the underlying transactions originate outside the control area of the TSO operating the affected network element, loop flows may not necessarily be addressed through measures taken by that TSO alone.

131 The Core day-ahead capacity calculation process enables TSOs to forecast the flow component of critical network elements that doesn't stem from capacity allocation (i.e. internal and loop flows). For this purpose, the common grid model (CGM) is brought to a zero-balance position, in which there are no cross-zonal exchanges. The remaining physical flows on the relevant network elements are therefore originated by internal transactions within bidding zones. On cross-zonal network elements, these flows correspond entirely to loop flows.

132 As shown in Figure 32, average forecast loop flows accounted for a significant share of F_{max} on some cross-zonal critical network elements. In some critical network elements, loop flows amount to over 70% of the physical capacity of the line on average. Their incidence was, however, unevenly distributed across the network, with some network elements, particularly those on some of the borders of the German bidding zone, being substantially more affected than others.

22 Internal flows are, on the other hand, those induced by the internal exchange on the internal elements of the bidding zone.

Figure 32: Average forecasted loop flows on pre-solved cross-zonal critical network elements in the Core CCR – 2025 (% of F_{max})



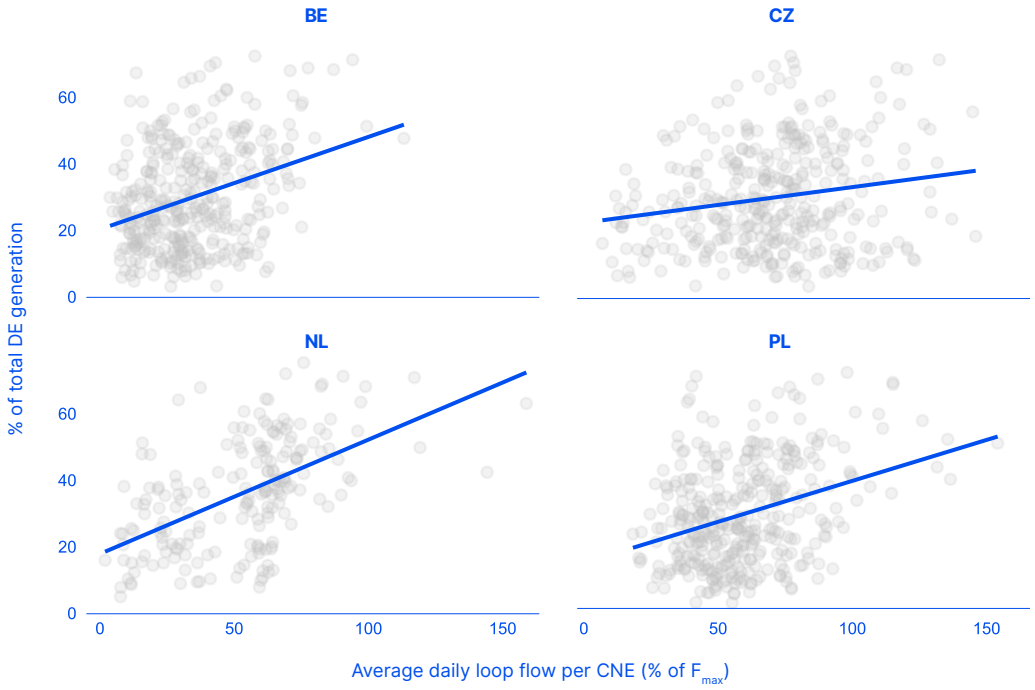
Source: ACER calculation based on JAO Publication Tool data.

Note: Forecast loop flows are calculated using the F0all and F_{max} parameters of CNEs classified as tie-lines with a voltage level of 400 kV, as defined in the final flow-based computation of the Core capacity calculation process. Only pre-solved CNECs are considered. Where multiple contingencies are associated with a given CNE and TSO, the contingency resulting in the highest loop flow is selected. For each CNE, the figure displays the average loop flow for the TSO with the highest average value.

133 The magnitude of loop flows depends, among other factors, on the geographical distribution of generation and demand within bidding zones. Larger bidding zones with a pronounced geographical mismatch between generation and demand are generally more likely to originate loop flows in neighbouring systems, as a greater share of internal transactions may physically transit through external networks. To illustrate this relationship, Figure 33 compares the share of wind generation in total electricity production in Germany with forecasted loop flows measured on cross-zonal CNEs located across several neighbouring Member States.

134 The figure shows that higher shares of wind generation in Germany tend to coincide with higher loop flows across central Europe. This is likely related to the concentration of German wind generation in areas relatively far from major consumption centres, which can increase the share of internal German power flows physically routed through neighbouring networks. The results therefore also illustrate how generation patterns within individual bidding zones can contribute to loop flows experienced elsewhere in the interconnected system.

Figure 33: Correlation between the share of wind generation in Germany and average forecast loop flows on presolved cross-zonal critical network elements in selected bidding zones in the Core CCR – 2025 (% of F_{max} and % of total generation)



Source: ACER calculation based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: Forecast loop flows are calculated based on the parameters F_{0all} and F_{max} of the CNEs defined as tie-lines and with a voltage level of 400kV in the final flow-based computation of the Core capacity calculation process. This figure is calculated using pre-solved CNECs only, using the contingency leading to the highest loop flow in case of multiple contingencies for a given CNE.

Existing derogations discount loop flows above a certain threshold from the applicable requirements

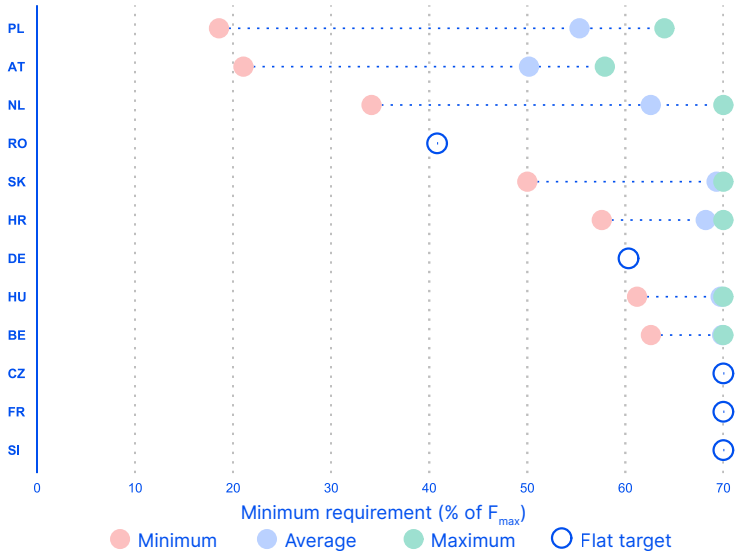
135 In 2025, most TSOs in the Core CCR were not yet fully bound by the minimum 70% requirement, following the approval of an action plan and/or a derogation. These TSOs are instead subject to interim minimum capacity requirements, which are defined in line with the applicable derogations and/or action plans. The interim requirements may be static, constant for all CNECs and hours of the year, or they may be dynamic, setting different values per CNEC and/or hour. Figure 34 presents an overview of the cross-zonal capacity requirements that were applicable in the Core CCR in 2025.

136 Notably, the TSOs of Austria, Belgium, the Netherlands and Poland have requested derogations on the grounds of excessive loop flows from neighbouring Member States. These derogations deduct, for every CNEC, the forecasted loop flows above a certain acceptable threshold from 70% or the action plan linear trajectory value. NRAs have granted such derogations under the assumption that, as the origin of the loop flows is outside the control area of a given TSO, the local remedial action potential is insufficient to alleviate the impact of such flows.

137 As observed in the figure, network situations in which high loop flows are expected can lead to a substantial reduction in the cross-zonal capacity commitments of TSOs that have been granted derogations. This effect is particularly pronounced in Austria, Poland and the Netherlands, while it appears more limited in Belgium. One possible explanation is the optimisation of phase-shifting transformers (PSTs) by the Belgian TSO to mitigate the impact of loop flows during capacity calculation, a practice that may not be applied to the same extent by all TSOs that have these assets.

138 It is important to note that, over the course of 2025, Core TSOs such as those from the Netherlands or Austria introduced a minimum cross-zonal capacity requirement of 20% of F_{max}, to be respected even in the case of excessive loop flows.

Figure 34: Overview of the applicable capacity requirements in the Core CCR for each Member State, considering existing action plans and/or derogations – 2025 (% of F_{max})

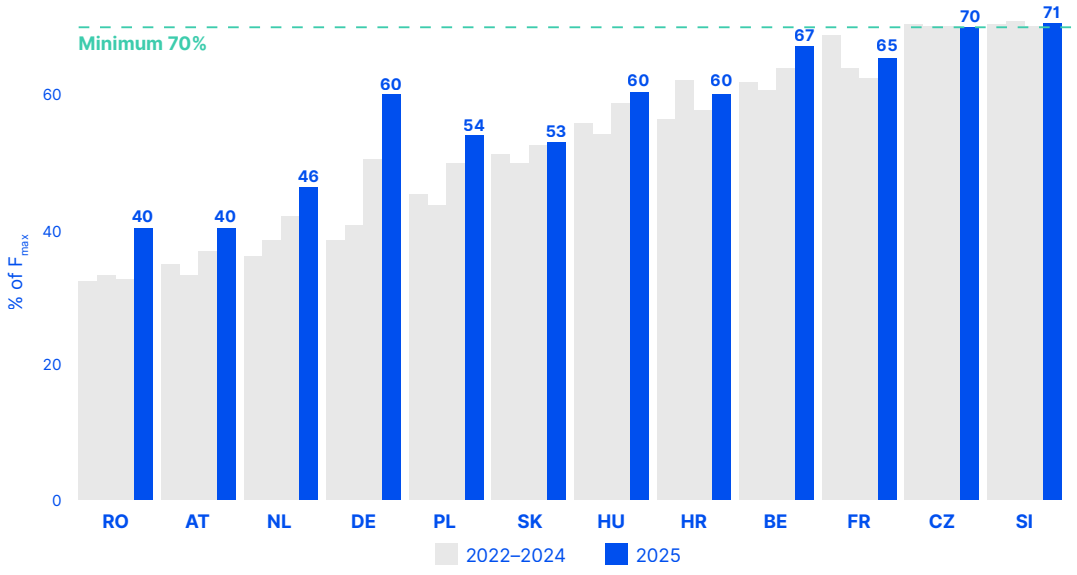


Source: ACER calculation based on Core TSOs data.

Note: In the case of TSOs with varying capacity requirements per CNEC, the figure presents the yearly averages of the CNEC with the lowest, average and highest requirements.

139 Figure 35 presents an overview of the progress made by Core TSOs in implementing the minimum 70% requirement, since the implementation of the flow-based market coupling until 2025. To do so, it highlights the yearly average of the lowest MACZT for every market time unit. Some progress can be observed in several Member States in 2025, compared to previous years, such as in those cases where a linear trajectory defined by an action plan is being followed. As anticipated above, the presence of derogations due to excessive loop flow explains some of the lower values observed in Member States such as the Netherlands or Austria.

Figure 35: Average minimum hourly MACZT in the Core CCR per Member State, considering flows induced by third-country exchanges – 2022-2025 (% of F_{max})



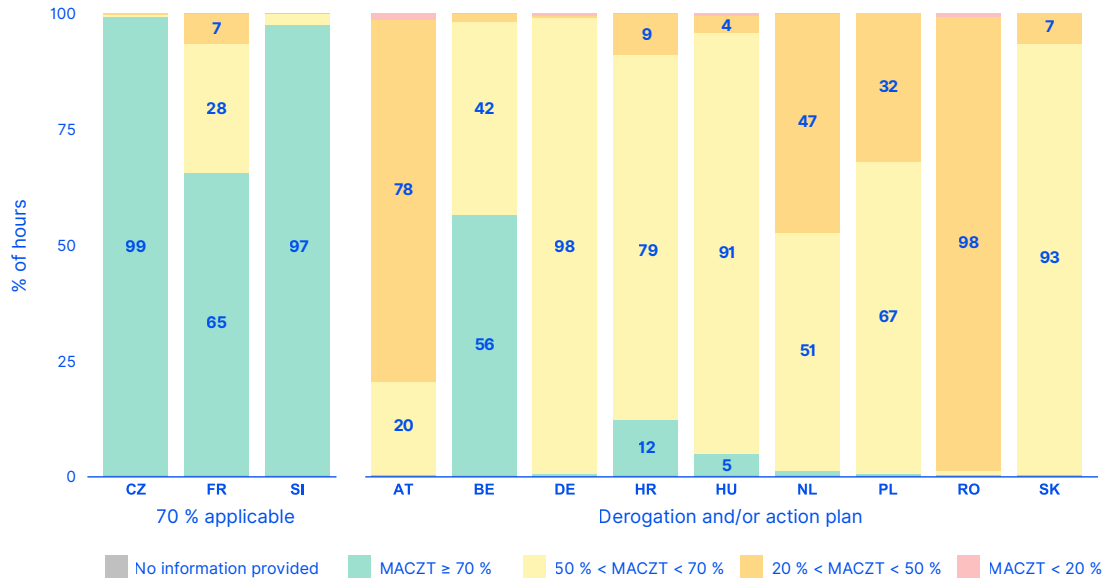
Source: ACER calculation based on Core TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments.

140 Beyond the average levels of MACZT, Figure 36 illustrates how often all relevant grid elements in a bidding zone offered at least 70% of their capacity for cross-zonal trading in 2025, providing insight into the distribution of the MACZT levels over the year. More specifically, the figure shows the percentage of hours when the CNECs with the lowest hourly MACZT of a given Member State offered were above 70% or within different ranges of MACZT.

141 It is important to underscore once again that, in 2025, only three TSOs in the Core CCR were legally bound by the minimum 70% requirement, as all others had approved derogations or action plans. These are the TSOs from Czechia, France and Slovenia. As can be seen in Figure 36, these TSOs do offer, relatively, the highest levels of MACZT in the region, although they do not always uphold the minimum 70% requirement.

Figure 36: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Core CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)



Source: ACER calculation based on Core TSOs data.

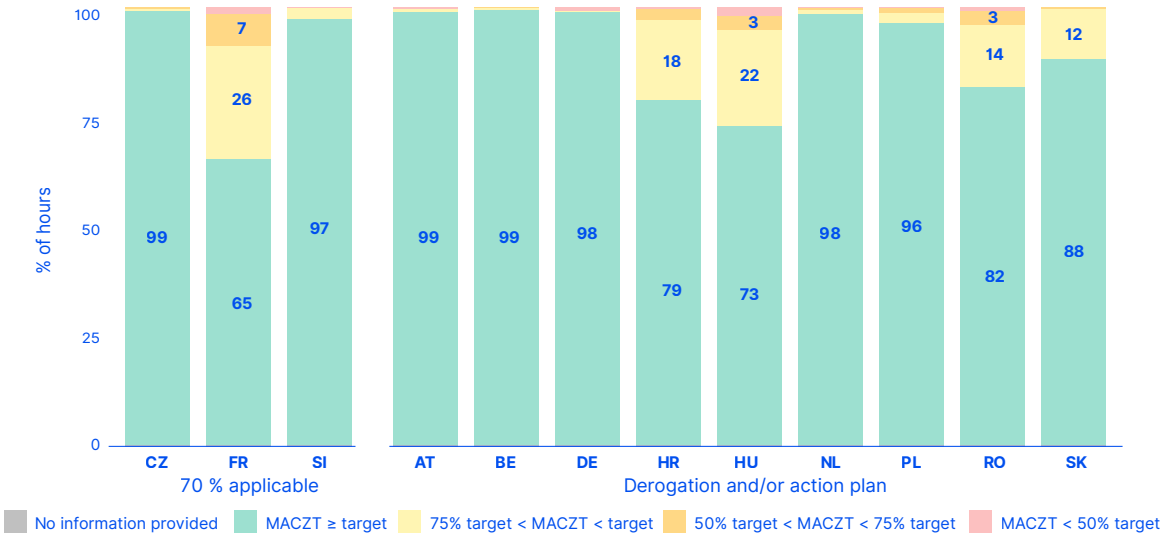
Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of F_{max}, are rounded to one decimal place.

142 Interim targets, defined in line with the approved derogations and/or action plans, have generally been upheld by Core TSOs in recent years. The capacity calculation methodology implemented in the Core CCR ensures that this is so, with an adjustment mechanism that increases the calculated margin of capacity to comply with the applicable requirement (either 70% or the interim target).

143 These adjustments are often referred to as 'virtual capacities', as they result in more than the physical capacity of a given CNEC to be accounted for, relying on remedial actions to secure the capacity offered should the market allocate all of it. Only when an operational security violation is identified and insufficient remedial actions are forecasted to be available to address such violations do TSOs reduce capacities below the applicable interim capacity requirement.

144 While most TSOs can meet the applicable requirements during most hours of the year, as observed in Figure 37, this is not always the case. In the cases of France, Croatia, Hungary, Romania, and Slovakia, the applicable minimum requirements could not be fulfilled on specific CNECs in over 10% of hours of the year.

Figure 37: Percentage of hours when the minimum hourly MACZT was above the applicable requirements in the Core CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)



Source: ACER calculation based on Core TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of F_{max}, are rounded to one decimal place.

Beyond derogations, operational security violations that cannot be addressed with remedial actions also result in reductions of capacity

145 TSOs may, in accordance with Article 16(3) of the Electricity Regulation, deviate from the legally binding minimum cross-zonal capacity requirements, as a measure of last resort when such capacity levels would result in a violation of the operational security limits defined by each TSO. These deviations are accounted for by allowing a reduction in the cross-zonal capacities calculated by the regional coordination centre either unilaterally or in a coordinated manner, whenever a risk to operational security that cannot be resolved through remedial actions is detected.

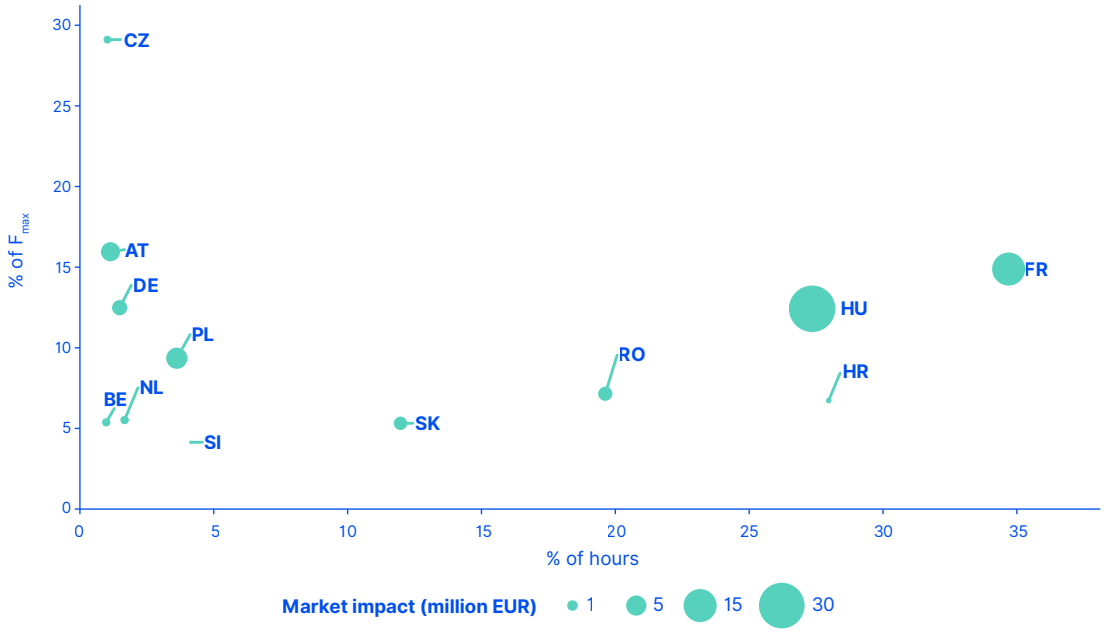
146 Currently, operational security in the validation of capacities is not assessed at the regional level, as a coordinated validation process has not yet been implemented, but is instead assessed within processes individual to each TSO or subset of TSOs. These are known as individual validation adjustments (IVAs). Figure 38 shows how often IVAs were applied (as a percentage of all hours, on the x-axis) and how much they effectively reduced the remaining available margin (RAM) on average (as a percentage of F_{max}, on the y-axis).

147 As observed in the figure, France stood out in 2025 as the Member State with the greatest use of validation reductions in the Core capacity calculation region, both in terms of their frequency and size of their application. Nonetheless, the estimated market impact associated with validation reductions, approximated as the product of the validation reduction and the corresponding shadow price,[23] was highest in Hungary.

23 This metric represents an approximation of the economic impact of the validation reductions, as the shadow price corresponds to the marginal increase in economic surplus from relaxing a capacity constraint by a single megawatt. It therefore does not imply that the same marginal benefit would apply to larger changes in available capacity, as the market outcome and the set of binding constraints may change as the constraint is progressively relaxed. Nevertheless, this metric remains useful as an indicative measure of economic impact.

148 Considering the significant impact of the application of validation reductions, both in terms of fulfilment of the legal requirements on cross-zonal capacity, and the loss of market efficiency due to reduced cross-zonal trade, it is important to ensure sufficient oversight from NRAs on the network conditions resulting in an operational security violation that could not be addressed through remedial actions, as well as on the measures taken to avoid their reoccurrence.

Figure 38: Application of IVA of each Core TSO weighted by the estimated market impact – 2025 (% of F_{max} and % of hours)



Source: ACER calculation based on Core TSOs and JAO Publication Tool data.

Note: The market impact is estimated as the validation reduction (in MW) multiplied by the shadow price of each CNEC (in EUR/MW).

2.4.2. Challenges in fulfilling the minimum 70% requirement in the Nordic capacity calculation region

149 The implementation of Nordic flow-based capacity calculation allows for the MACZT to be computed and monitored on all CNECs defined by Nordic TSOs. The go-live of the Nordic flow-based market coupling increased the degree of coordination among Nordic TSOs when calculating capacities, compared with the previous NTC national calculations.

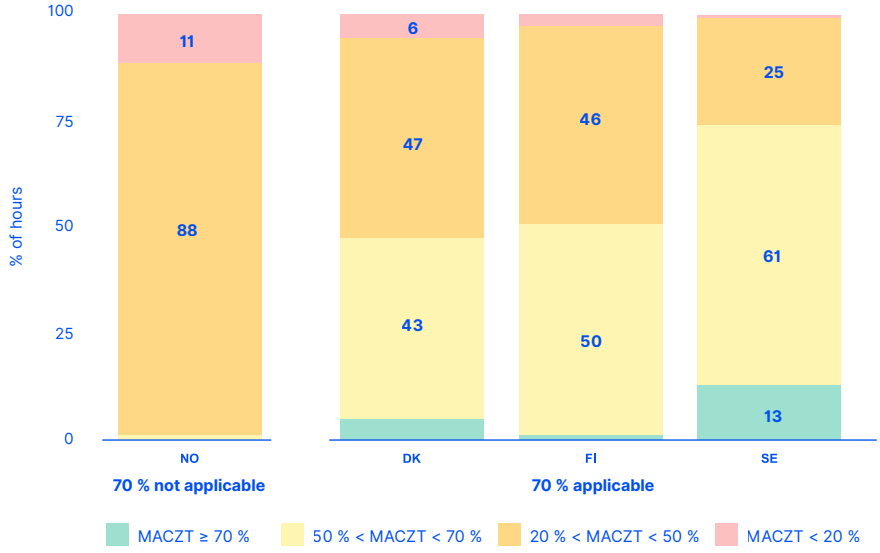
150 In the Nordic CCR, two major considerations are to be considered in terms of the status of the minimum 70% requirement. First, no derogation or action plan is in place in the Nordic CCR, so the minimum 70% requirement is fully applicable. Secondly, the Norwegian TSO is not formally bound by the 70% requirement, as Norway has not yet adopted the Clean Energy Package. Nonetheless, a general requirement to maximise cross-border capacity stems from the Third Energy Package, which Norway has adopted.

151 The more granular bidding zone configuration in the Nordic CCR, compared to other regions, was expected to result in lower loop flows and thus enable higher margins of capacity, without widespread reliance on remedial actions. For this reason, the Nordic capacity calculation methodology does not currently consider the use of virtual capacities to fulfil the minimum 70% requirement.

152 Moreover, since its go-live, Nordic flow-based applies advanced hybrid coupling on the bidding zone borders connecting the Nordic and the Continental Europe synchronous areas.[24] By doing so, such borders are modelled as virtual bidding zones within SDAC, and the capacity released in Nordic CNECs can then be allocated to the border that results in higher economic surplus. This allows both Nordic and Hansa borders to compete for the same scarce capacity on Nordic network elements. For the purpose of MACZT monitoring, advanced hybrid coupling entails that there is no impact from external bidding zone borders on the RAM offered on each CNEC.

153 Figure 39 presents the level of fulfilment of the minimum 70% requirement in 2025. As this requirement is to be respected on all CNECs introduced in capacity calculation, ACER's monitoring focuses, for each hour, on the CNECs with the lowest MACZT values. The results show that Nordic TSOs do not yet consistently make at least 70% of capacity available on every CNEC.

Figure 39: Percentage of hours when the minimum hourly MACZT was above 70%, or within predefined ranges, in the Nordic CCR for each Member State – 2025 (% of hours)



Source: ACER calculation based on Nordic TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. The impact of exchanges with the United Kingdom, as assumed in Nordic capacity calculation, could not be verified for all market time units, as only partial information was made available. MACZT values, expressed as a percentage of F_{max}, are rounded to one decimal place.

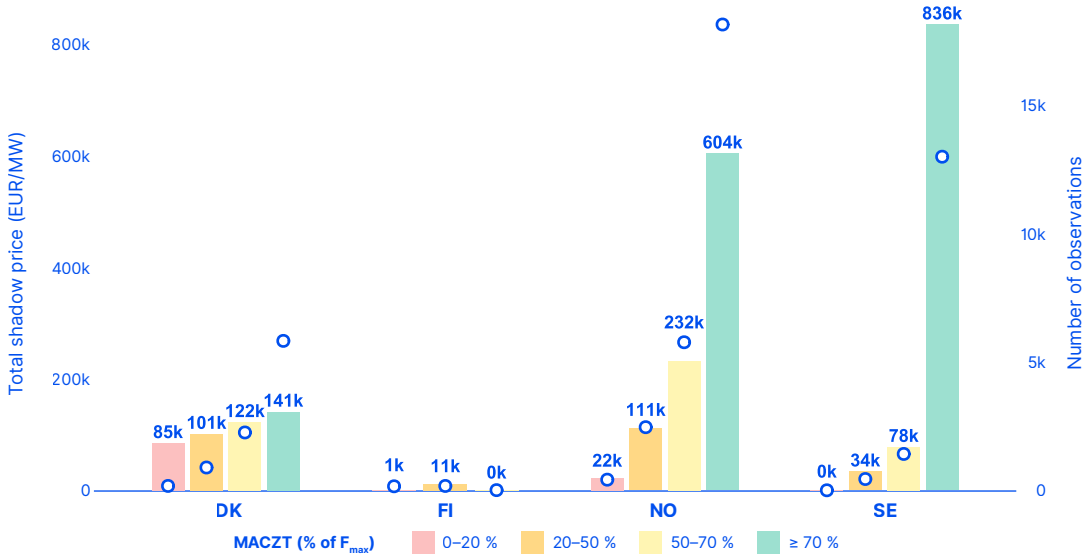
154 However, the observed limitations in the Nordic CCR are concentrated in a relatively small subset of CNECs, which show capacity margins well below 70% during a large share of hours of the year. Depending on the Nordic TSO, this subset represents, on average, between 3% and 10% of all CNECs in each hour. The share of CNECs under 70% is therefore more limited than for most TSOs in the Core CCR.

155 It is important to note that these CNECs are not necessarily the ones preventing additional cross-zonal trade in the Nordic CCR. Internal CNECs that are less affected by cross-zonal trade may offer lower margins of capacity but, given their lower relative sensitivity factors (i.e. lower power transfer distribution factors), may not have a significant impact on cross-zonal trade, as other CNECs with higher margins will remain more constraining.

24 Since 10 June 2026 (for delivery day 11 June 2026), advanced hybrid coupling on these borders has also been implemented from the side of the Core CCR.

156 Nonetheless, a comparison of the margin of capacity offered on the CNECs that did limit cross-zonal trade in the Nordic CCR during 2025 (i.e. the CNECs that had a non-zero shadow price) shows that some of the CNECs that do not respect the 70% requirement do have a significant impact on cross-zonal trade, and thus on market efficiency. This is particularly the case for Denmark and Norway, and less so for Sweden and, especially, Finland. This can be observed in Figure 40. While CNECs providing low margins for cross-zonal trade appear less frequently among the constraints limiting market exchanges, their impact when they do become limiting can be comparatively large.

Figure 40: Accumulated market congestion in CNECs of the Nordic CCR, categorised by the margin available for cross-zonal trade, per Nordic Member State – 2025 (EUR/MW and number of CNECs)



Source: ACER calculation based on JAO Publication Tool data.

Note: Shadow prices are provided by Nordic TSOs in EUR/MWh and are thus divided by four as of the go-live of the 15-minute MTUs on 1 October 2025, to present a metric in EUR/MW. Allocation constraints and PTCs are excluded from this figure.

157 Overall, flow-based market coupling has increased the efficiency of the day-ahead market in the Nordic region, and the bidding zone configuration mitigates the potential impacts of non-allocated flows. Nonetheless, ACER's monitoring shows that several CNECs across the Nordic CCR can't consistently respect the 70% requirement, which in turn does meaningfully affect the market clearing results.

158 Further efforts are therefore needed from Nordic TSOs to ensure that the flow-based capacity calculation process is sufficiently aligned with the applicable minimum capacity requirements. While a more granular bidding zone configuration helps limit the negative impact of loop flows, appropriate consideration of remedial actions is also required to reduce internal flows on congested CNECs and thereby enable the fulfilment of the 70% requirement.

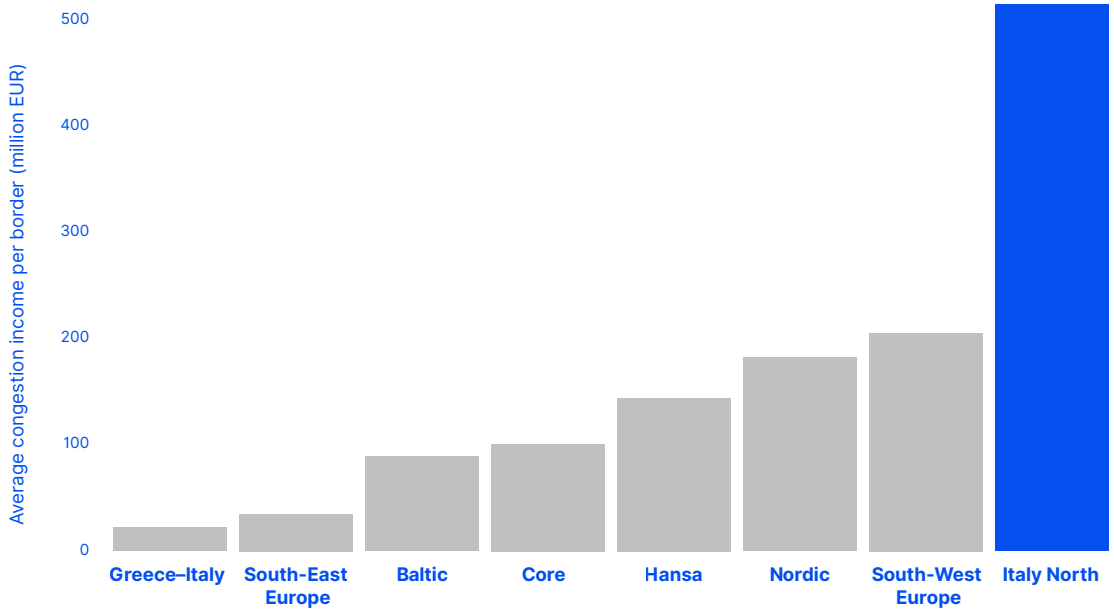
159 Moreover, further monitoring of the impact of exchanges between Nordic bidding zones and the UK is warranted, to ensure that these exchanges are not unduly prioritised over exchanges within the internal electricity market. At present, forecasted exchanges on these borders are treated as fixed inputs to the capacity calculation process, potentially resulting in part of the capacity of Nordic CNECs being effectively reserved to accommodate them, and thus reducing the capacity available for exchanges between Nordic bidding zones.

2.4.3. Flow-based market coupling will ensure the most efficient use of the network in Italy North

160 The Italy North capacity calculation region comprises the EU northern borders of the Italy North bidding zone. As observed in Figure 24, these borders exhibit some of the highest average price spreads among EU bidding zone borders, which has been the case for recent years. These spreads reflect, among other factors, Italy's structural reliance on electricity imports and its relatively high marginal generation costs, driven in part by the significant role of gas-fired generation, together with the availability of cross-zonal capacity relative to demand for exchanges.

161 Consistent with these large price spreads, congestion income generated in Italy North is the highest in the EU, when accounting for the number of bidding zone borders in each region. This indicates that there is significant value in cross-zonal trade in the region, and that additional cross-zonal capacity would enable further economically beneficial exchanges and contribute to reducing price differences. Figure 41 compares the average congestion income generated across EU capacity calculation regions, normalised by the number of bidding-zone borders.

Figure 41: Total congestion income generated by SDAC per capacity calculation region, normalised by the number of bidding zone borders in each region – 2025 (million EUR)



Source: ACER calculation based on Simulation Facility data.

162 Against this backdrop, the efficient use of the available network is particularly important in Italy North. The current capacity calculation process relies on a CNTC approach. In the main scenario, which aims to maximise imports into Italy, the calculation determines the maximum import capability of the Italy North bidding zone by iteratively increasing exchanges on all borders until the first network constraint in the region is reached.[25] In addition, based on a forecast by TSOs, an additional calculation may be performed to account for situations in which Italy North may export electricity across one or more of its northern borders. The resulting aggregate capacity needs to be subsequently translated into bilateral capacities across the northern Italian borders according to a splitting factor that is determined *ex ante*.

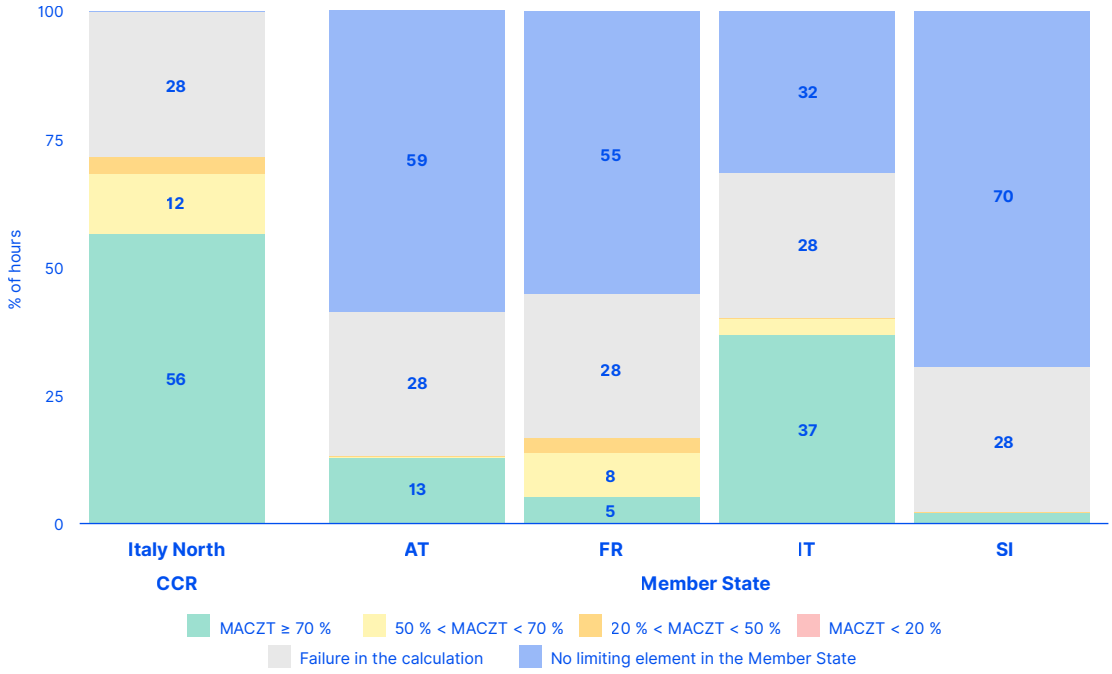
25 Remedial actions are also used in the capacity calculation process to establish whether the identified constraints can be secured.

163 Compared with flow-based capacity calculation and allocation, this approach can lead to a less efficient use of the available network capacity. First, the aggregate transfer capability has to be split into bilateral capacities before market allocation takes place. The splitting factors thus cannot take into account the relative market value of different cross-zonal exchanges at the allocation stage and may therefore allocate capacity differently from the combination of exchanges that would maximise market welfare. Second, CNTC represents the feasible network domain through a limited set of predefined transfer scenarios, rather than allowing the market coupling algorithm to optimise exchanges directly against the relevant network constraints and their sensitivities to cross-zonal exchanges. Consequently, where realised market conditions differ from the assumptions underlying the capacity calculation and splitting process, the available network capacity may not be distributed across borders in the most economically efficient manner.

164 The reliance on a forecast of the market direction also has implications for the monitoring of the minimum 70% requirement. Where no coordinated capacity calculation is performed in a given direction, no limiting CNEC is identified against which compliance with the minimum capacity requirement can be assessed. The monitoring of the margin available for cross-zonal trade therefore focuses on the hours and market directions for which the capacity calculation process identifies a limiting network element. Figure 42 shows the percentage of hours when the limiting element was above the minimum 70% requirement, or within a set of predefined ranges, in each Member State in the region and in the CCR as a whole.

165 A further limitation concerns the robustness of the capacity calculation process. During 28% of the hours of the year, Italy North TSOs reported a failure of the capacity calculation process, meaning that information on the limiting CNEC could not be provided. In such cases, the latest coordinated long-term capacities are used as a fallback and offered to the day-ahead market.

Figure 42: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Italy North CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)



Source: ACER calculation based on Italy North TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments.

166 By early 2028, the common day-ahead flow-based capacity calculation methodology for the Central Europe CCR is expected to be implemented. The Central Europe CCR brings together the bidding-zone borders currently covered by the Core and Italy North CCRs for day-ahead capacity calculation. The introduction of flow-based capacity calculation will, to a large extent, address the inefficiencies highlighted above, by allowing the market coupling algorithm to optimise exchanges across the region based on their impact on the relevant network constraints, rather than relying on an ex ante split of aggregate capacity and a limited set of predefined exchange scenarios. It is therefore expected to improve the efficiency of cross-zonal capacity calculation and allocation across the region, and thus bring significant value to the EU internal market.

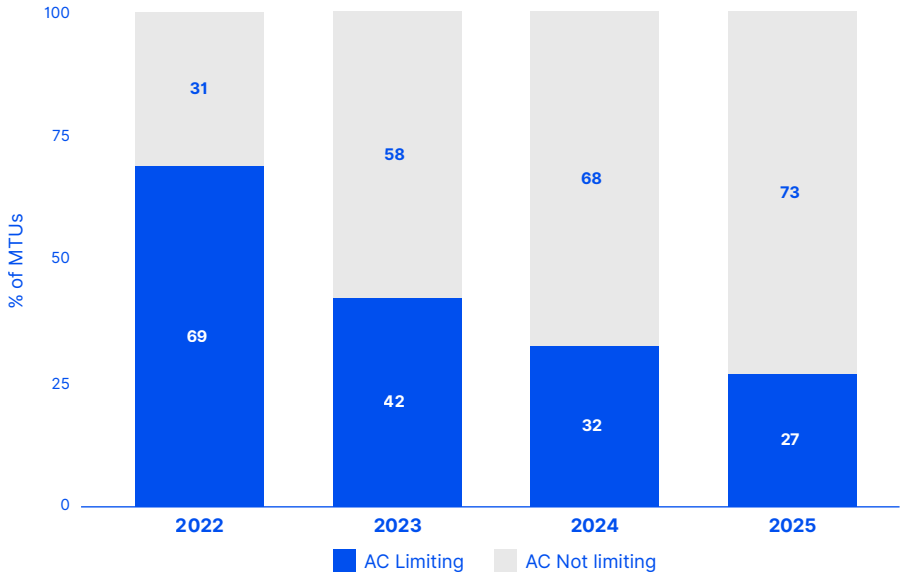
2.4.4. Operational security constraints beyond thermal limits also restrict cross-zonal electricity trade in the EU

167 Beyond the thermal limits of specific pairs of network elements, other network constraints may also result in TSOs imposing limitations to cross-zonal trade, which can also significantly affect market results. These network constraints may be related to respecting the voltage or stability limits of the network or ensuring the availability of balancing services. Such limitations to cross-zonal trade are represented as allocation constraints, which typically reflect operational security limits or other system constraints that cannot be transformed into flow-based parameters on a CNEC or an NTC value on a border.

168 In the Core region, the Polish TSO introduces a limitation to the total import or export position of the Polish bidding zone within SDAC, to ensure that sufficient units remain available to provide balancing services after the day-ahead and intraday markets. As the entire net position is potentially limited, not only the Core bidding zone borders of Poland are affected, but also its borders in the Hansa and Baltic CCRs. This limitation is required, according to the Polish TSO, as there is no dedicated procurement of balancing capacity prior to the day-ahead market.

169 The Polish allocation constraint limited cross-zonal exchanges to or from Poland in 27% of the market time units of 2025. This constituted a significant impact on cross-zonal trade in the region, often decorrelating the price of the Polish bidding zone from that of its neighbours. Nonetheless, this impact has seen a decreasing trend over recent years, and it is down from 68% of hours in the second half of 2022. This trend can be observed in Figure 43.

Figure 43: Percentage of market time units where the allocation constraint AC introduced by the Polish TSO limited the net position of the Polish bidding zone in either direction per year – 2022-2025 (% of MTUs)



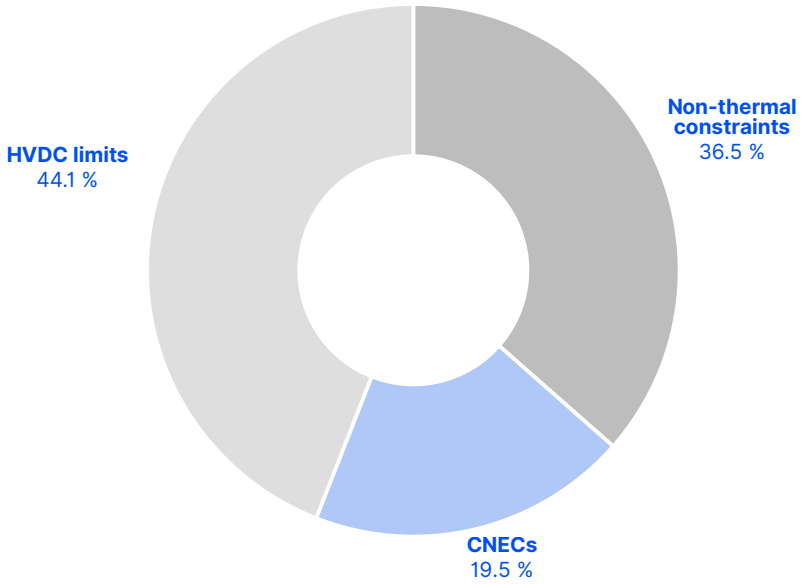
Source: ACER calculation based on ENTSO-E Transparency Platform and JAO Publication Tool data.

Note: The value presented for 2022 only corresponds to the period after the go-live of Core flow-based market coupling on 9 June 2022.

170 In Nordic flow-based market coupling, on the other hand, TSOs also introduce cross-zonal trade limitations on certain network profiles that do not correspond directly to thermal limits on individual CNECs. These are referred to as power transfer corridors (PTCs). Nordic TSOs reportedly use these constraints to capture voltage, rotor-angle and frequency stability limits, where system security depends on transfers across a wider transmission corridor rather than the loading of an individual element. Nordic TSOs introduce these constraints within the flow-based domains, using PTDFs and RAMs in a similar way to conventional CNECs.

171 Figure 44 presents to what extent PTCs have limited cross-zonal trade in the Nordic CCR in 2025. As can be observed, these additional constraints are very relevant in determining the cross-zonal exchanges in the Nordic CCR. However, the determination of the maximum admissible flow (F_{max}) of the PTCs is performed locally by the individual TSOs and provided to the Nordic regional coordination centre directly, which allows for limited scrutiny of these constraints. From a 70% monitoring perspective, these constraints appear to be consistently fully compliant, as TSOs directly determine the F_{max} that can be offered in full.

Figure 44: Relative share of market congestion in the Nordic CCR per type of capacity constraint – 2025 (% of cumulative shadow price)



Source: ACER calculation based on JAO Publication Tool data.

Note: HVDC limits correspond to the allocation constraints introduced by Nordic TSOs on the virtual bidding zones corresponding to the HVDC cables.

172 Operational security limits beyond thermal loading on network elements also play an important role in determining cross-zonal capacity on the Italian bidding zone borders. In the Italy North CCR, Terna applies an allocation constraint to the northern borders of the Italy North bidding zone, to limit total imports into the Italian system, to the extent necessary to maintain adequate voltage profiles and dynamic stability. Similarly, in the Greece–Italy (GRIT) CCR, NTC values are frequently determined by voltage and stability limits rather than by the thermal capacity of network elements. The regional capacity calculation methodology explicitly considers voltage limits under both normal and contingency conditions alongside thermal loading limits.

173 Lastly, the results of the monitoring of the minimum 70% requirement for the Baltic CCR, available in Annex I, show that non-thermal constraints are predominantly defining the NTC values that are made available to the market for cross-zonal exchanges in the Baltic CCR. This is in part a consequence of the operation of the Baltic network under a relatively weak connection to the rest of the synchronous area, following the synchronisation of the Baltic Member States with the Continental Europe synchronous area, which took place in February 2025.

174 It is important that operational security limits beyond thermal limits and other system constraints are addressed through constraints to cross-zonal trade, only when no other alternative remains. When a given operational security constraint is addressed through an allocation constraint, it may disproportionally affect the clearing of the internal electricity market. While the 70% requirement helps ensure that thermal limits on individual network elements do not constrain cross-zonal trade in a way that unduly favours internal flows, other non-thermal constraints introduced by TSOs may be more restrictive and subject to less regulatory scrutiny. These constraints therefore warrant careful assessment from regulatory authorities.

2.4.5. ACER report to the Energy Union Task Force on measures to increase cross-zonal trade in Southeast Europe

175 Following the significant increase in electricity prices observed in Southeast Europe during the summer of 2024, the European Commission tasked ACER with assessing the feasibility of introducing measures to increase cross-zonal capacities and system flexibility in the region, as part of the efforts of the Energy Union Task Force to ensure the affordability of electricity supply. The objective was to identify actions that could help prevent or mitigate similar price developments in the future.

176 ACER's assessment, published in May 2026, found that the 2024 price spikes were driven by a combination of tight regional supply-demand conditions, and limited ability to import electricity from the rest of the EU. Periods of high demand, often linked to heatwaves, coincided with limited flexible supply capable of responding rapidly to changing system needs. The increased reliance on a relatively small pool of flexible generation assets to meet evening demand peaks placed strong upward pressure on prices during evening hours. At the same time, limited cross-border transmission capacity, exacerbated by planned line outages, reduced the possibilities for importing lower-priced electricity from neighbouring markets.

177 In the assessment ACER proposed a set of concrete measures to increase opportunities for cross-zonal trade between Central and Southeast Europe in the short and medium term. Lessons can be drawn from this analysis, and its proposals may, to some extent, also be applicable to other EU regions. The main proposals were:

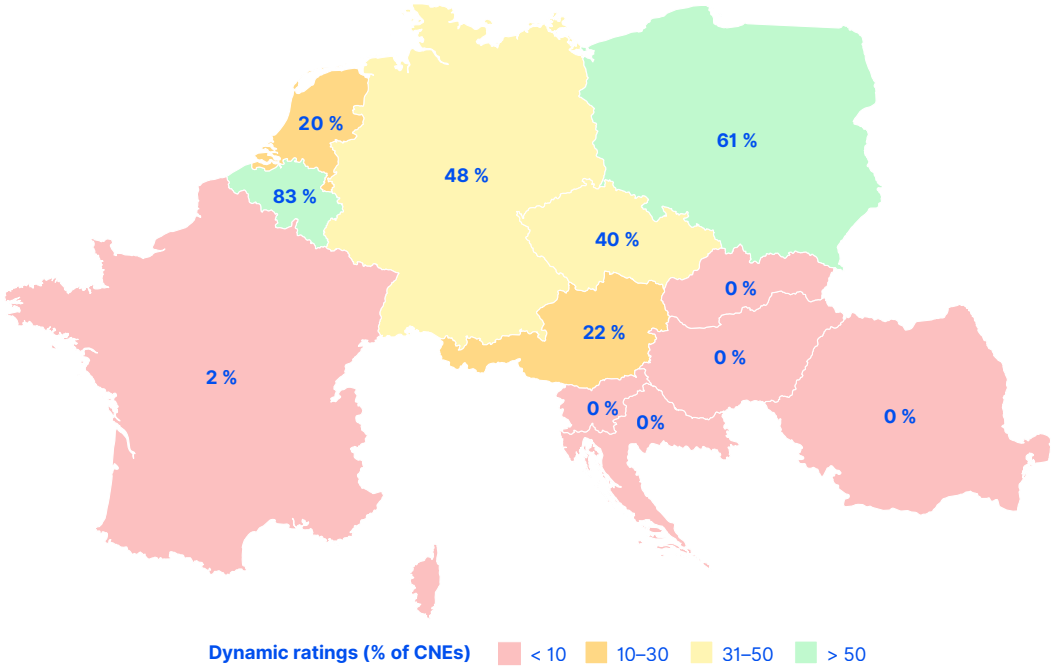
1. wider rollout of dynamic line rating, and its introduction in capacity calculation inputs;
2. upgrading of standard power lines with high-temperature low-sag conductors;
3. finalising the implementation of the minimum 70% requirement;
4. adequate consideration of curative remedial actions in capacity calculation;
5. increasing coordination in network modelling between Central and Southeast Europe;
6. improvements to the regional outage planning coordination processes.

178 As an example, ACER assessed the level of use of dynamic ratings in capacity calculation in the Core CCR for the most congested network elements during 2024, by tracking the reported F_{max} throughout the year. The analysis showed a limited level of consideration for dynamic ratings in capacity calculation, across most TSOs in the region, leading to limitations in cross-zonal trade. In some cases, such as Slovenia, ACER noted a mismatch between the ratings used in real-time operations, which are more often dynamic, and those used in capacity calculation, which tend to be more conservative.

179 When comparing the ratings on congested CNECs for 2025, some progress can be observed in France, where two of the most congested CNEs shifted to seven different ratings over the year, as opposed to seasonal ones.[26] Nonetheless, a large share of the network elements used in capacity calculation in the Core region during 2025, remained under fully fixed or seasonal ratings. This can be observed in Figure 45, where Member States highlighted in red presented fully static or seasonal ratings in over 90% of all network elements used in capacity calculation. At the Core level, around 50% of CNEs introduced in capacity calculation had a fixed rating for the entire year, 18% had seasonal ratings, and approximately 32% had more than four ratings for the year. Progress in this regard in CNTC regions is much more difficult to scrutinise, as no data is made public on all network elements used in capacity calculation.

26 A complete list on the ratings applied on the CNECs that were most congested during 2025 is provided in Annex II of this report.

Figure 45: Usage of dynamic ratings in CNEs introduced in the Core capacity calculation process – 2025 (% of CNEs)



Source: ACER calculation based on JAO Publication Tool data.

Note: For the purpose of this figure, CNEs with over four different F_{max} values over the year have been categorised as dynamic. Nonetheless, TSOs may apply a fixed set of different ratings over the year, which is not traditionally considered as dynamic rating.

180 Longer-term initiatives linked with the availability and efficient use of cross-zonal capacities were also proposed by ACER in the assessment. These included:

1. increasing the network interconnectivity of Southeast Europe, by reinforcing congested areas of the network;
2. improving the design of electricity bidding zones in the EU;
3. expanding market coupling to non-EU neighbours, and the rollout of flow-based calculation and allocation in Southeast and Eastern Europe.

181 A regional tight market situation in Southeast Europe, comparable to that of summer 2024, was experienced again during the summer of 2026. In this case, a prolonged heatwave and drought significantly reduced the margins of the power system across several Member States in Southeast Europe, resulting in prices reaching extreme levels. This recurring pattern in Southeast Europe highlights the vulnerabilities of the region to extreme weather events, and the need to strengthen its interconnectivity levels with the rest of the EU.

3. Intraday markets

182 A well-developed intraday market is a key enabler for a more sustainable, affordable, and secure power system in the EU. The intraday timeframe offers the possibility for market participants to adjust their positions close to real time, which is essential for optimal management of renewable, and intermittent, energy assets. This enables the rapid penetration of renewable energy generation into the system, while reducing the associated balancing needs and costs, which in turn results in a power system that is less reliant on fossil fuels, and therefore more independent and secure.

183 This section reviews continuous intraday trading, the evolution of intraday auctions since their introduction in June 2024 and availability of cross-zonal capacities in intraday markets. It also examines the potential of flow-based allocation in the intraday timeframe. More efficient allocation and clearer price signals close to delivery could support the integration of renewables and help unlock further flexibility.

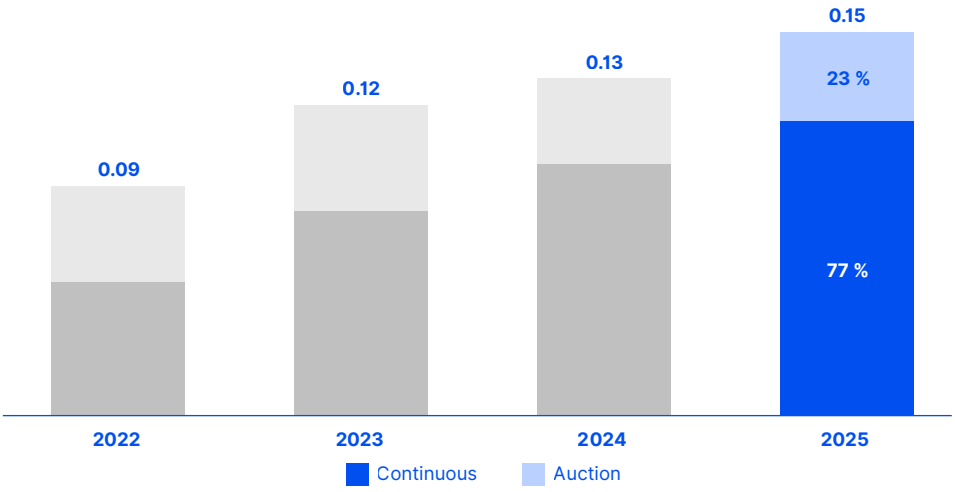
3.1. Main developments in intraday continuous trading

184 The variability and unpredictability of renewable generation drive the need for intraday trading, enabling market participants to correct forecast errors made in SDAC and to follow more closely the variations in supply and demand as delivery approaches. Continuous intraday trading provides a mechanism for market participants to balance supply and demand, supporting the integration of renewable generation. The following analysis considers recent developments in liquidity, timing of trades and market efficiency, highlighting how these factors shape the performance of the intraday market.

3.1.1. Increased liquidity closer to real-time

185 Increasing liquidity in intraday markets helps manage imbalances closer to real time. As in the section on long-term markets, churn factors give an indication of liquidity. Between 2022 and 2025, churn factors rose steadily in line with growing wind and solar shares. Figure 46 shows that the churn factor reached 0.15 in 2025, the highest level recorded so far. The continued growth in total churn factors points to a deepening of intraday market liquidity.

Figure 46: Yearly churn factors in European (EU-27) intraday markets by type of trade – 2022-2025



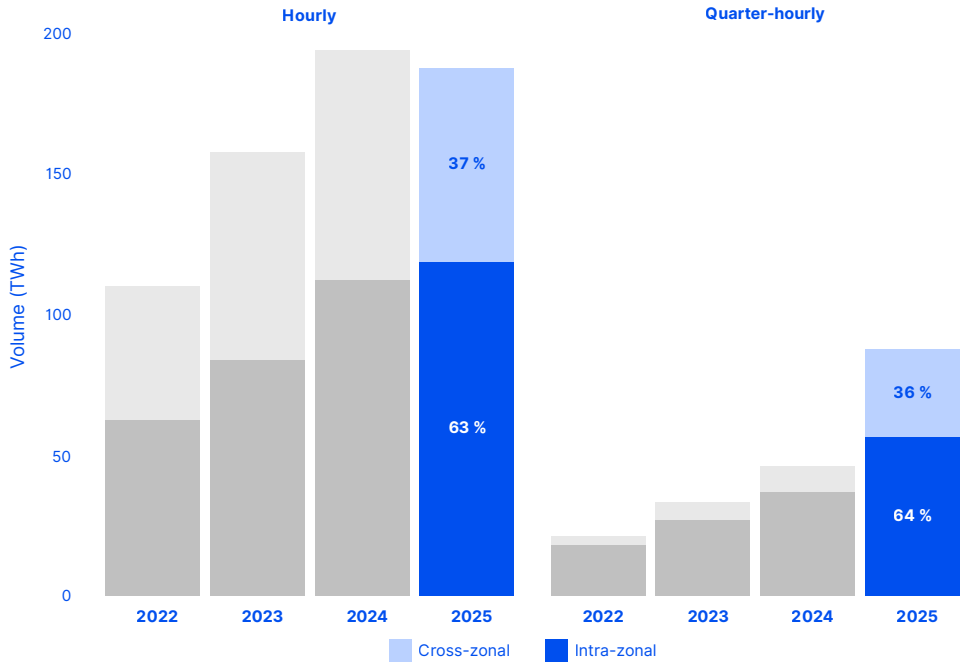
Source: ACER calculation based on REMIT and ENTSO-E Transparency Platform data.

186 In 2025, the highest churn factors were recorded in Denmark (0.53), Germany (0.31), the Netherlands (0.28) and Austria (0.26). Spain (0.19), Hungary (0.18) and Belgium (0.15) followed, while the churn factor remained at or below 0.12 in all other Member States. For more information on the national churn factor per Member State, see Annex III.

187 Hourly intraday trading volumes reached approximately 185 TWh in 2025, reflecting a modest decline from the peak observed in 2024 but remaining well above earlier years. Quarter-hourly volumes,[27] by contrast, continued to rise, as depicted in Figure 47, reinforcing the trend towards shorter trading intervals closer to real-time delivery. Half-hourly traded volumes remain negligible in comparison to hourly and quarter-hourly products, at well below 1 TWh across all years.

188 A particularly notable development in 2025 is the change in the composition of traded volumes. Cross-zonal trading now accounts for 36% of quarter-hourly volumes, compared to a predominantly intra-zonal share in previous years.

Figure 47: Evolution of traded volumes in the intraday continuous market categorised by intra-zonal vs cross-zonal trade in the EU and Norway – 2022-2025 (TWh)



Source: ACER calculation based on data from NEMOs.

Note: Half-hourly products are not shown in the figure. These values can be found on CHEST.

189 Cross-zonal trading gives market participants access to liquidity beyond their own bidding zone and allows them to correct imbalance positions across borders closer to real time. This appears increasingly relevant as variable renewable generation continues to increase its share in the EU generation mix.

27 Member States introduced quarter-hourly intraday products gradually, over the past years.

190 Most bidding zones showed cross-zonal shares of continuous intraday trade above 50% in 2025, with Latvia, Slovenia, Portugal and Estonia at 90% or above. Bidding zones in Denmark, Spain, the Netherlands, Austria, Poland and Finland relied more evenly on cross-zonal and intra-zonal liquidity, with cross-zonal shares between 38% and 50%. Table 2 shows cross-zonal and intra-zonal shares of continuous intraday trade per bidding zone. Furthermore, Annex IV provides charts on the evolution of intraday traded volumes in the continuous market, cross-zonal and intra-zonal shares per bidding zone, which illustrate well the dependency of the intraday liquidity on cross-zonal trade.

191 France and Germany, the two largest bidding zones, are the main exceptions. Both display markedly lower reliance on cross-zonal trade (around 25% and 20%, respectively, in 2025) and correspondingly higher reliance on intra-zonal liquidity.

Table 2: Cross-zonal and intra-zonal share of continuous intraday traded volume by bidding zone – 2025 (% of total volume)

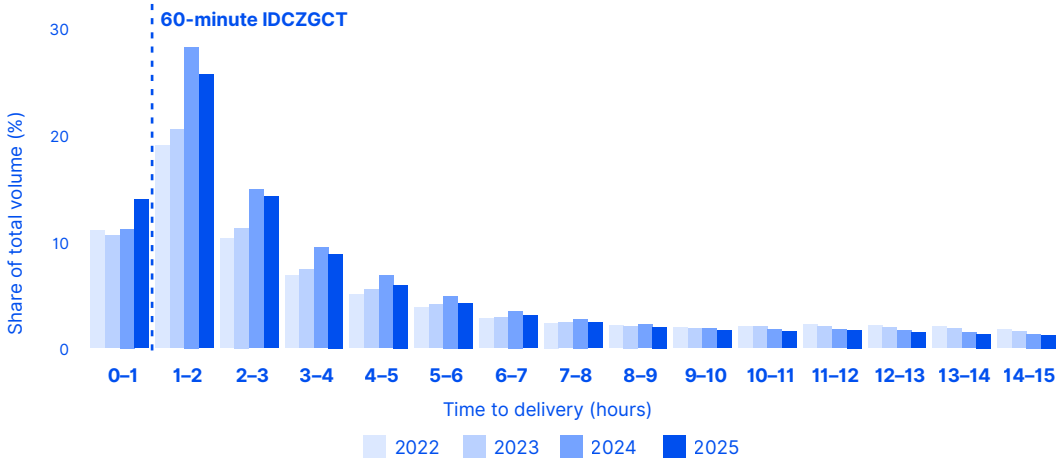
Member States	Cross-zonal - %	Intra-zonal - %
Latvia (LV)	96.5	3.5
Slovenia (SI)	93.9	6.1
Portugal (PT)	91.5	8.5
Estonia (EE)	89.5	10.5
Lithuania (LT)	87.2	12.8
Croatia (HR)	86.4	13.6
Italy (IT)[28]	85.3	14.7
Romania (RO)	85.1	14.9
Slovakia (SK)	83.1	16.9
Norway (NO)[29]	80.6	19.4
Bulgaria (BG)	75.0	25.0
Sweden (SE)[30]	70.3	29.7
Czechia (CZ)	68.4	31.6
Hungary (HU)	66.4	33.6
Belgium (BE)	63.4	36.6
Greece (GR)	56.8	43.2
Denmark (DK)[31]	48.5	51.5
Austria (AT)	45.3	54.7
Netherlands (NL)	43.1	56.9
Spain (ES)	42.1	57.9
Poland (PL)	40.2	59.8
Finland (FI)	38.7	61.3

Source: ACER calculation based on data from NEMOs.

28, 29, 30, 31 The percentage shares of cross-zonal and intra-zonal continuous intraday traded volume, calculated as a weighted average (by traded volumes) across the Italian, Norwegian, Swedish or Danish bidding zones, respectively.

192 Looking more closely at when exactly intraday trading takes place shows that close to 40% of continuous intraday volumes were traded within two hours before delivery in 2025, compared to around 30% in 2022, depicted in Figure 48. This suggests that market participants increasingly use the last hours before delivery to fine-tune their positions.

Figure 48: Share of total volumes traded in continuous intraday market by time to delivery in the EU and Norway – 2022-2025 (% of total volume)



Source: ACER calculations based on data from NEMOs.

Note: The left-most bar (hour = 0-1) includes traded volumes for a limited number of Member States where the intraday gate closure time (ID GCT) is 30 minutes. In most Member States, the ID GCT is 60 minutes (hour = 1-2).

3.1.2. Shift of trades closer to real-time with implementation of the 30-minute intraday cross-zonal gate closure time

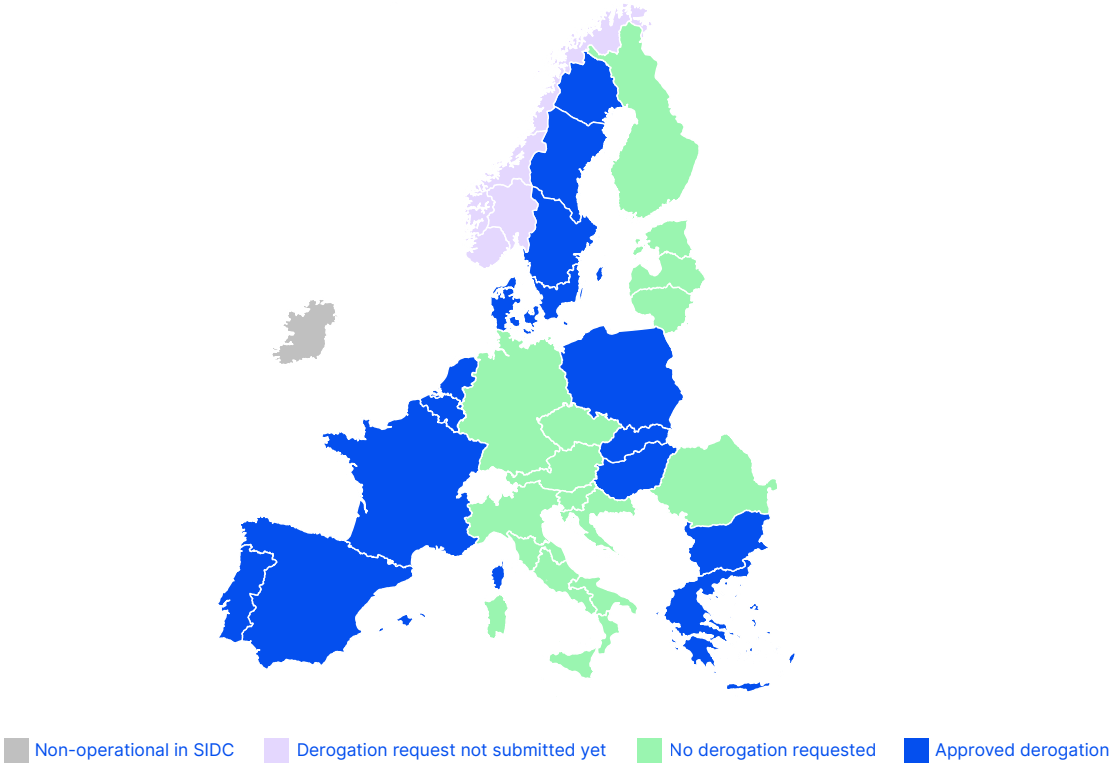
193 The above-mentioned pattern of migrating trading even closer to delivery is further demonstrated with the 30-minute intraday cross-zonal gate closure time (IDCZGCT) being implemented across more Member States.

194 On 1 January 2026, a 30-minute IDCZGCT entered into force on European bidding zone borders, as required under the Electricity Regulation.[32] However, many TSOs requested derogations and maintained a 60-minute cross-zonal gate closure time on their shared borders for various periods. The Bulgarian NRA granted the shortest period (until 1 January 2027), followed by the Netherlands (until 14 January 2027), Belgium and Sweden (until 31 March 2027), Hungary (until 30 June 2027); and Denmark (until 1 September 2027). The NRAs of France, Poland, Portugal, Slovakia and Spain granted the longest derogation period, until 1 January 2029. A decision on Greece's derogation is pending, and Norway had not yet submitted one.

195 The borders where the 30-minute IDCZGCT applies without derogation offer the clearest cases for observing changes in market behaviour. These are the borders between Austria and Czechia, Austria and Germany-Luxembourg, Austria and Italy North, Austria and Slovenia, Croatia and Slovenia, Czechia and Germany-Luxembourg, Estonia and Finland, Estonia and Latvia, and Latvia and Lithuania, as well as the Italian bidding zone borders. These are shown in Figure 49.

32 It is one of the amendments to the Electricity Regulation introduced by the electricity market design reform (EMDR), which entered into force in July 2024.

Figure 49: Status of 30-minute IDCZGCT application across the EU



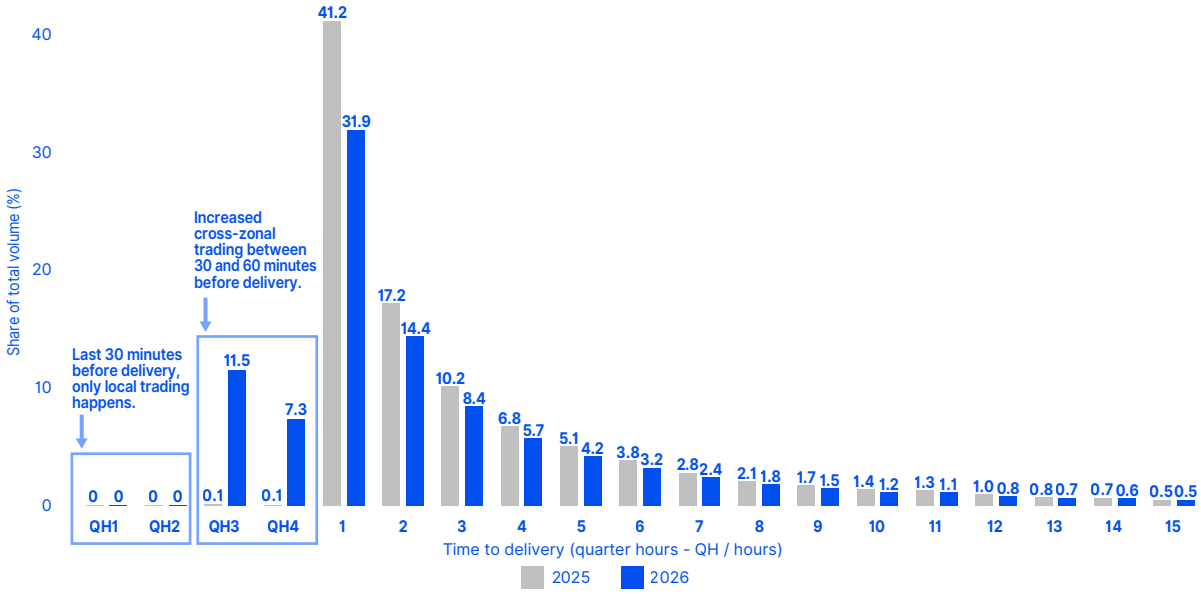
Source: as reported by the transmission system operators.

196 To assess whether the introduction of the 30-minute IDCZGCT was associated with a progressive shift in trading behaviour, intraday cross-zonal traded volumes were analysed for two comparable periods. The reference period runs from 14 January to 30 April 2025, before implementation. The post-implementation period runs from 14 January to 30 April 2026.

197 Volume and trade count data were drawn from ACER's intraday REMIT database. The data are disaggregated by time-to-delivery slot, with quarter-hourly intervals in the first hour and hourly intervals up to 15 hours before delivery.

198 A more granular analysis of cross-zonal trading patterns in the continuous intraday market reveals an important shift in the timing of trades. Figure 50 presents the distribution of cross-zonal volumes by time to delivery for the period from 14 January to 30 April, comparing 2025 and 2026. The analysis covers a selected set of bidding zones without gate closure time derogations, in Austria, Croatia, Czechia, Estonia, Finland, Italy (North), Latvia, Lithuania, Romania and Slovenia.

Figure 50: Share of cross-zonal volumes traded in the continuous intraday market by time to delivery on borders without derogations, before and after the introduction of the 30-minute gate closure time – 14 January to 30 April (% of traded volume)



Source: ACER calculation based on REMIT data.

199 Up to two hours before delivery, share of cross-zonal volume accounts for 41% of total cross-zonal traded volumes in 2025 and 51% in 2026. This shift appears to reflect increased trading in the 30–60 minute slot, which alone accounts for 19% of total cross-zonal volumes and suggests that market participants increasingly seek to correct imbalance positions in the final window before real-time delivery. In 2025, trading in the third and fourth quarter-hours was virtually absent (there was 30-minute IDCZGCT only on Estonia–Finland border before), with shares of around 0.1% each.

200 This trend is consistent with the broader move towards shorter trading intervals. The analysis shows that for those TSOs that did not apply a derogation, market participants benefit from the possibility to trade cross-zonal closer to real time.

201 In 2026, quarter-hourly products gained share closer to delivery in both intra-zonal and cross-zonal trading compared to hourly products. Quarter-hourly products now account for the majority of cross-zonal volumes in the final half hour before delivery.

3.1.3. The rise of algorithmic trading puts pressure on intraday market infrastructure

202 Algorithmic trading is the automated submission, updating and cancellation of orders based on predefined rules, with little or no human intervention. In the continuous intraday market, automated systems allow participants to react within seconds to price signals, updated renewable forecasts and changes in their portfolio positions. As trading shifts closer to real time and the number of tradable products grows, automation appears increasingly attractive, and in some cases necessary, for active participation. The following paragraphs examine how this development has reshaped order activity in SIDC.

203 ENTSO-E and NEMOs under the umbrella of the market coupling steering committee publish monthly SIDC stakeholder reports on their websites.[33] The December 2025 edition[34] points to a marked increase in trades and orders reported by NEMOs between 2018 and 2025. This growth suggests a structural change in intraday market participation. The order-to-trade ratio, a commonly used proxy for the intensity of algorithmic trading, reached a value of 25 by December 2025, and a similar trend continued into 2026.

204 This increasing trend of order-to-trade ratio is consistent with the growing prevalence of algorithmic trading in the continuous intraday market. Automated systems continuously submit, update and cancel bids and offers in response to price signals and changes in underlying market fundamentals, so only a small share of submitted orders ultimately results in an executed trade. The sustained rise in the order-to-trade ratio reflects this change in how participants interact with the order book and growth in order activity does not reflect in equivalent growth in liquidity or settled volumes.

205 While this trend of increased market activity through algorithmic trading is generally welcomed as it increases competition and accuracy of price signals, a downside to this trend is the increasing pressure it exerts on the technical infrastructure of the SIDC continuous central system (XBID). In 2025 and until the latest performance enhancing update in June 2026, the XBID system reached its performance limits, which was noticeable through frequent latency issues in the system (orders are processed and matched with a significant time delay). Unless mitigating measures are taken by NEMOs, this growing trend is expected to continue and the system could soon approach its technical limits again. Efforts to strengthen the resilience of the market infrastructure and to allow for sustainable growth of system usage are necessary.

206 However, such efforts should not delay the introduction of essential market integration functionalities which are expected to create significant economic surplus benefits for the internal energy market, such as the introduction of flow-based capacity allocation in the intraday timeframe. ACER therefore urges NEMOs to address system usage in a way that does not divert resources from the implementation of essential market integration functionalities. Experience from other industries, notably financial markets, where comparable challenges arising from the growth of algorithmic trading are being continuously addressed, offers a range of solutions, including charging fees for excessive system usage.

3.2. Pan-European intraday auctions

207 Intraday auctions (IDAs) complement the day-ahead market by allowing participants to adjust their positions in a centralised manner, as updated information on generation, consumption, and network conditions becomes available. Three auctions were introduced within the Single Intraday Coupling in June 2024.

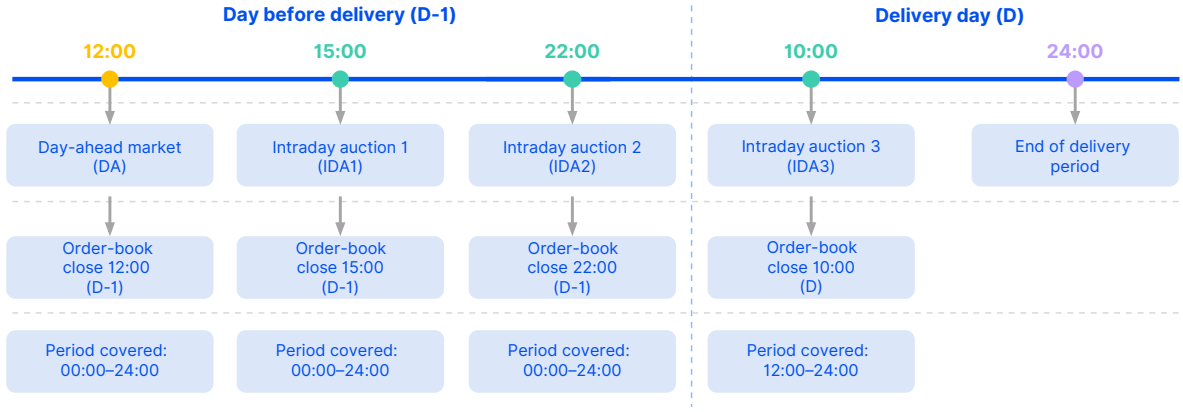
208 As illustrated in Figure 51,[35] intraday auctions take place at successive stages between day-ahead clearing and physical delivery. IDA1 is scheduled at 15:00 on the day before delivery, IDA2 at 22:00, and both cover all delivery periods of the following day. IDA3 is scheduled at 10:00 on the delivery day and clears the period from 12:00 to 24:00, allowing positions to be updated using information available closer to delivery.

33 https://www.entsoe.eu/network_codes/cacm/implementation/sidc/

34 ENTSO-E, SIDC stakeholder report, December 2025, pp. 45 and 46, https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Network%20codes%20documents/NC%20CACM/2025/SIDC_stakeholder_report_1225.pdf

35 All times are presented in CET/CEST.

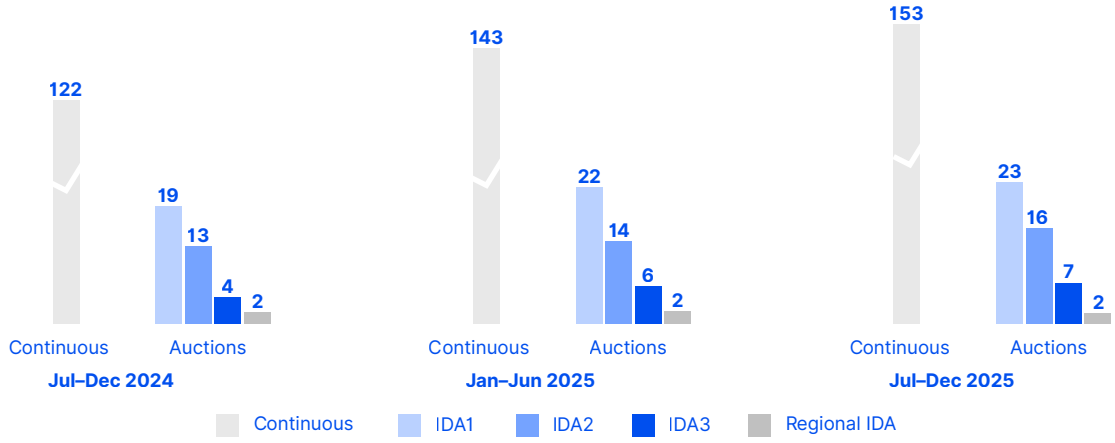
Figure 51: Explanatory diagram on pan-European electricity auctions in the day-ahead and intraday market timeframes



Source: ACER elaboration.

209 Total intraday auction volumes (IDA1, IDA2 and IDA3 combined) grew by approximately 28% between the second half of 2024 and the second half of 2025, as depicted in Figure 52. Continuous trading grew by a broadly similar 25% over the same period. Continuous trading therefore remains the predominant trading mechanism in the intraday timeframe, accounting for around three-quarters of total volume throughout the assessed period.

Figure 52: Evolution of traded volumes in the intraday timeframe by trading type since the introduction of intraday auctions in the EU and Norway – July 2024 to December 2025 (TWh)

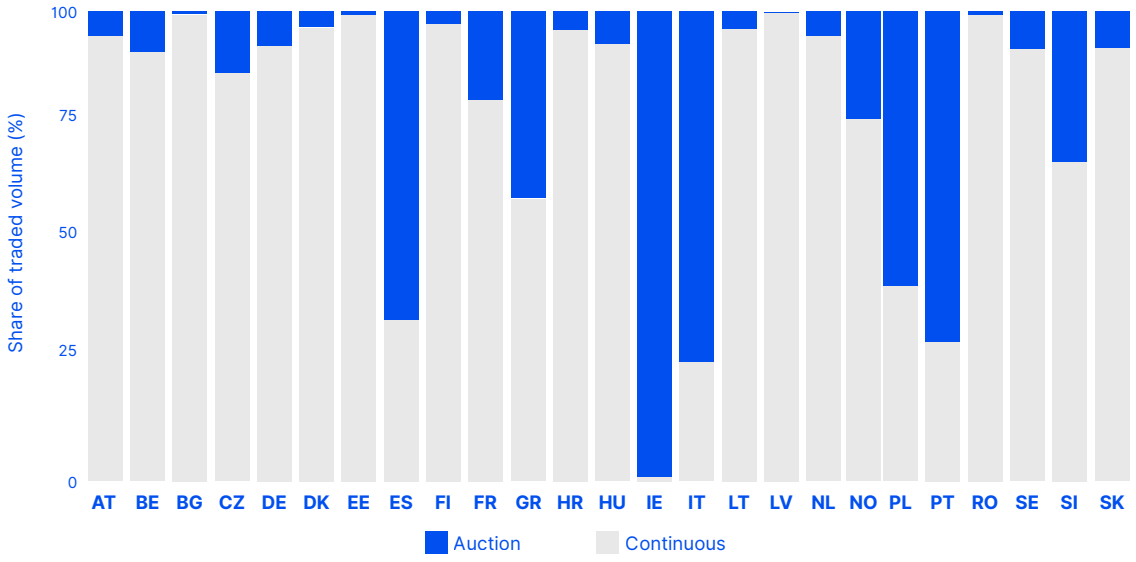


Source: ACER calculations based on REMIT data.

Note: Intraday auctions outside SIDC are still held in Ireland (regional intraday auction).

210 Intraday auctions are available in nearly all Member States, but not all use them extensively. Auction trading remains concentrated in a small group of Member States as shown in Figure 53, several of them in southern Europe with a history of regional auction arrangements. In 2025, Greece, Ireland, Italy, Poland, Portugal, Slovenia and Spain stand out as the main auction-active markets, while most other Member States trade almost entirely through continuous mechanisms (typically 90% or more).

Figure 53: Share of volume traded in auctions and in continuous trading in the EU-27 and Norway – 2025 (% of traded volume)



Source: ACER calculations based on REMIT data.

Note: The intraday auctions in Ireland are regional and not part of SIDC.

211 Poland is the standout development between the two years. Its auction share rose sharply, from approximately 12% in 2024 to around 59% in 2025, pointing to a structural shift in Polish intraday trading behaviour.[36]

Limited liquidity and lack of cross-zonal capacity reduce the efficiency of intraday auctions

212 Since their start in June 2024, the pan-European intraday auctions have faced some notable limitations affecting their relevance in the EU's intraday markets. These are mainly linked to the thin liquidity observed in some EU bidding zones, and the limited levels of cross-zonal trade resulting in significant congestion. This subsection introduces these limitations.

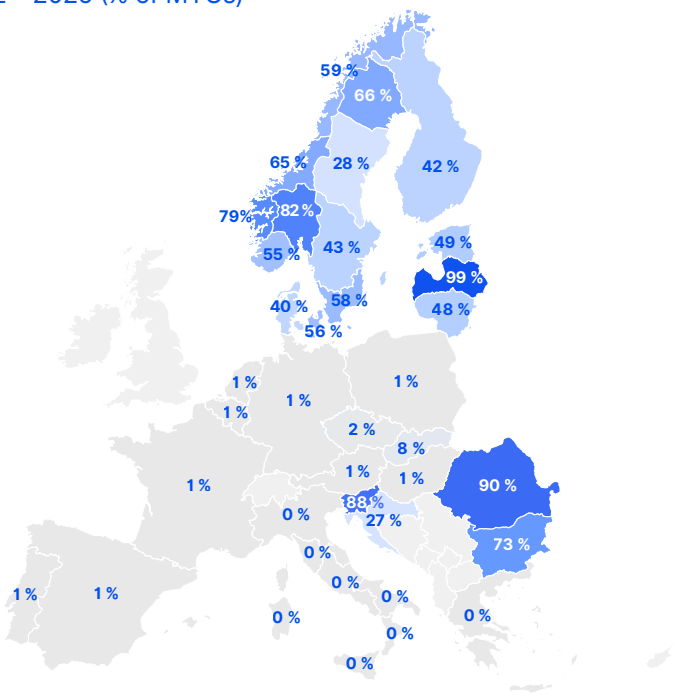
213 The conditions of local participation are the basis for efficient price formation in the auctions. The presence of sufficient buying and selling interest supports more robust price formation, increases the likelihood that orders can be matched, and limits the influence of individual participants on the auction outcome. By contrast, thin order books weaken competitive pressure and make local outcomes more dependent on liquidity in neighbouring bidding zones and available capacity.

214 Figure 54 depicts the instances when the clearing of IDA2 for a given bidding zone resulted in no matched volume on either the supply or the demand side. A high share therefore indicates that, despite the auction being available, no local orders were matched within the bidding zone during a substantial proportion of market time units. As observed in the figure, this is particularly frequent in several bidding zones in the Nordic, Baltic and Southeast Europe regions. These results point to limited local liquidity in the auction and suggest that participation in IDA2 remains relatively thin in parts of the European market. On the other hand, most markets across Continental Europe do see at least some trading activity during all auction sessions.

36 Poland's shift towards a greater use of intraday auctions coincides with the balancing market reform introduced in June 2024, which shortened imbalance settlement to 15-minute intervals and moved to single-price settlement. As both this reform and Poland's participation in the harmonised IDAs took effect at the same time, the continued rise in auction use through 2025 may reflect a gradual market adaptation to the new settlement regime, rather than an immediate response to the reform itself.

215 While the figure focuses specifically on IDA2, broadly comparable results can be observed in the other pan-European intraday auctions. The persistence of a high incidence of zero matched volumes across auction sessions reflects structural differences in the use and liquidity of intraday auctions across bidding zones. This in turn reduces the ability of the auctions to facilitate portfolio adjustments and contribute to robust intraday price formation, particularly where trading activity is concentrated instead in the continuous intraday market.

Figure 54: Percentage of MTUs where no local demand nor supply orders are matched in each bidding zone in IDA2 – 2025 (% of MTUs)



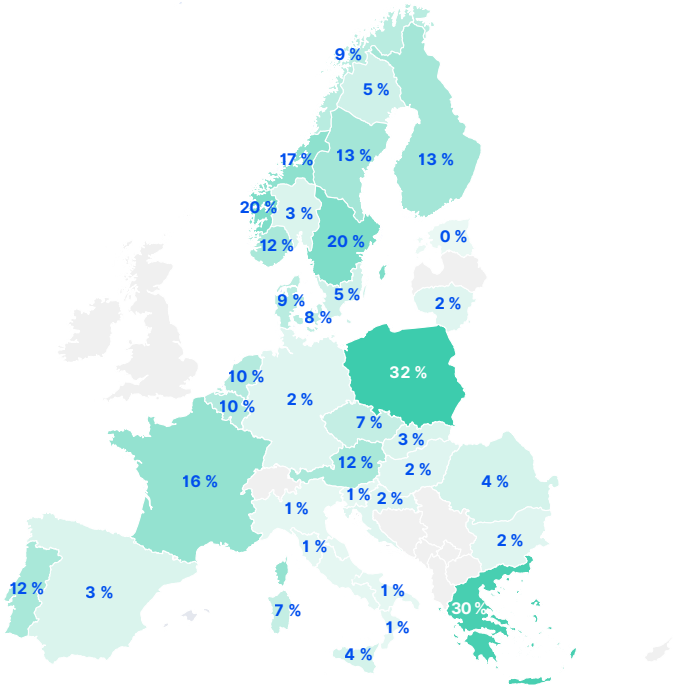
Source: ACER calculation based on Simulation Facility data.

216 Moreover, as will be further elaborated on, the limited availability of cross-zonal capacity in the intraday timeframe results in very modest cross-zonal trading levels. This in turn prevents bidding zones with thin markets from accessing the liquidity of neighbouring markets. This is particularly relevant for the smaller bidding zones in the EU, such as those of the Nordic CCR.

217 These low levels of cross-zonal trading can be quantified by examining the share of market time units where no additional cross-zonal trading takes place in each bidding zone (i.e. its intraday net position is equal to zero). In such cases, the auction clearing does not modify the bidding zone's import or export position established in previous market stages, even where local orders are matched. Figure 55 presents this percentage per bidding zone, focusing again on IDA2 and considering only those market time units in which there is any trading activity. This allows instances with no cross-zonal trading due to no available capacity to be distinguished from instances in which the auction attracts no trading activity.

218 The results show that, even in bidding zones where participation in the auction is significant, such as France, Greece or Poland, a relevant share of market time units only register local trades. This suggests that matched intraday orders are frequently cleared without generating additional exchanges across bidding-zone borders. Consequently, these auctions may not fully benefit from market integration, including the possibility to import lower-priced electricity from neighbouring bidding zones or to export surplus generation where it has a higher value.

Figure 55: Share of MTUs where each bidding zone in SIDC has a net position of zero in IDA2 – 2025 (% of MTUs)



Source: ACER calculation based on Simulation Facility data.

Note: MTUs where no order has been matched are removed from this calculation. Such MTUs will have by default a net position of zero.

219 Limited local participation and insufficient possibilities for cross-zonal trading contribute to weaker price formation and create persistent price differences between bidding zones. Where a bidding zone is relatively isolated, its price is determined by a narrower pool of supply and demand and cannot fully benefit from the resources available in neighbouring markets. Moreover, in the cases of bidding zones that consist predominantly of generation or demand assets, such as those of some Nordic bidding zones, insufficient cross-zonal capacities will prevent such liquidity from being matched with orders in other bidding zones.

3.3. Availability of cross-zonal capacities in intraday markets

220 As explained above, the intraday market is primarily used to adjust positions in response to forecast errors arising after the day-ahead market. In smaller bidding zones with limited intraday liquidity, access to neighbouring markets is essential for market participants to trade out their imbalances. Where insufficient cross-zonal capacity is available in the intraday timeframe, market participants may be unable to trade across borders, leading to greater balancing needs and higher balancing costs.

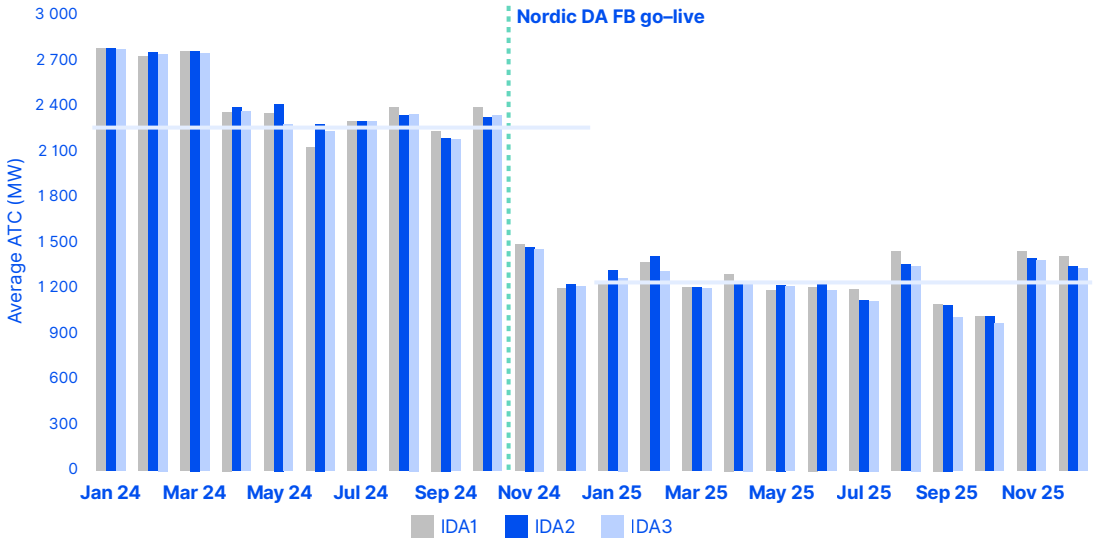
221 More efficient cross-zonal trade in the intraday timeframe, through the improvement of capacity calculation and allocation processes, can meaningfully contribute to the success of intraday markets in enabling renewable penetration. To unlock the full potential of intraday markets in the EU, increasing the availability of cross-zonal capacities also after the day-ahead market will prove increasingly important.

222 The previous subsection clearly illustrates the importance of available cross-zonal capacities on the clearing of intraday auctions. Many bidding zones remain isolated primarily due to a lack of cross-zonal capacity in those MTUs. A similar challenge holds true for continuous intraday trading, which also relies on cross-zonal capacities in order to trade across bidding zones.

223 The single intraday coupling, both for the intraday auctions and continuous trading, still allocates cross-zonal capacities in the form of available transfer capacity (ATC) values. This is due to delays in adjusting existing allocation processes to be able to accommodate flow-based parameters. TSOs in the Core and Nordic CCRs, which calculate capacities using the flow-based approach, thus currently need to perform an ATC extraction to convert the flow-based parameters into border-wise ATCs compatible with SIDC.

224 When extracting ATCs based on a set of market exchanges defined by previous market timeframes, only a conservative area of the flow-based domain can be retained, making a large share of the capacity physically available inaccessible to the market. This is best exemplified by the drop in available capacities for all intraday auctions observed in the Nordic capacity calculation region, since the go-live of flow-based market coupling in the day-ahead market, which is shown in Figure 56.

Figure 56: Average intraday cross-zonal capacities made available for the three pan-European intraday auctions in the Nordic CCR – 2024-2025 (MW)



Source: ACER elaboration based on ENTSO-E Transparency Platform data.

Note: The metric shows the sum of capacity released in both directions of a given bidding zone border, averaged for the whole region. The capacity levels displayed for the period before the implementation of pan-European intraday auctions correspond to the cross-zonal capacity available for continuous trading at 15:00 in day-ahead (D-1), 22:00 D-1 and 10:00 on the day of delivery.

225 The current mismatch between the allocation methods used in the day-ahead and intraday timeframes, with flow-based market coupling implemented in day-ahead across Core and Nordic, and ATC-based allocation in intraday for all regions, results in a significant loss of cross-zonal trading opportunities in the intraday and balancing timeframes. This stresses the need for the prompt roll-out of flow-based allocation also in the timeframes after the day-ahead market, firstly in intraday auctions and, subsequently, in balancing energy platforms and continuous trading.

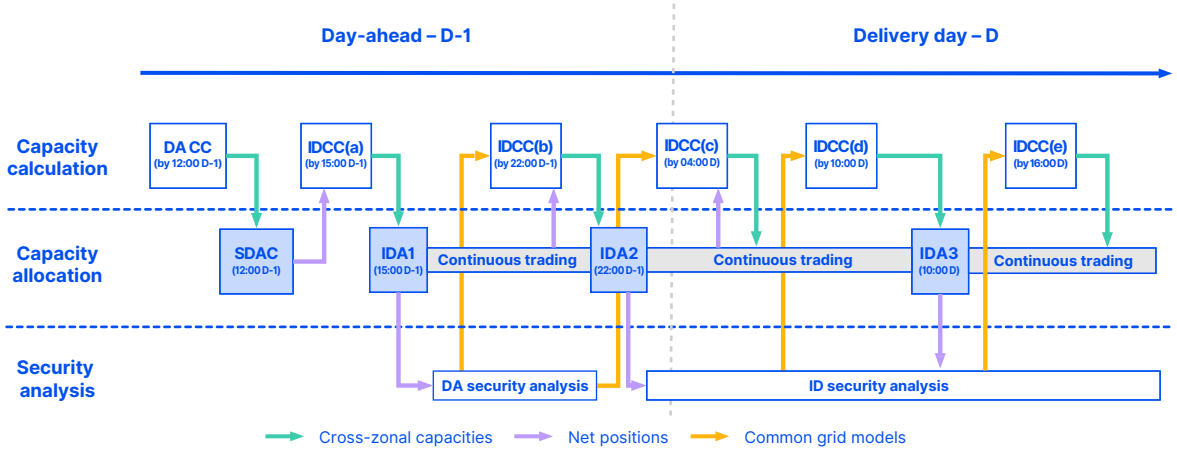
3.3.1. Intraday capacity calculation processes in the Core CCR

226 Historically, intraday markets received the cross-zonal capacities that had not been used in the day-ahead market. Over the last years, Core TSOs[37] have implemented dedicated flow-based intraday capacity calculation (IDCC) processes. These are performed under the latest forecasts of the state of the power system, and feed cross-zonal capacities to the different stages of the single intraday coupling.

37 This is also true of some other CCRs, where intraday capacity calculation processes are live.

227 Generally, capacity calculation processes are preceded by a security analysis, which produces the CGMs representing the status of the network that serve as the basis for capacity calculation. These CGMs consider the exchanges stemming from previous market allocations. A simplified diagram of the capacity calculation and allocation processes in the Core region is presented in Figure 57.

Figure 57: Explanatory diagram on processes for capacity calculation, capacity allocation and security analysis in the Core CCR for the day-ahead and intraday market timeframes



Source: ACER elaboration.

Note: IDCC(e) was not implemented at the time of drafting. It has since been introduced on 14 October 2026.

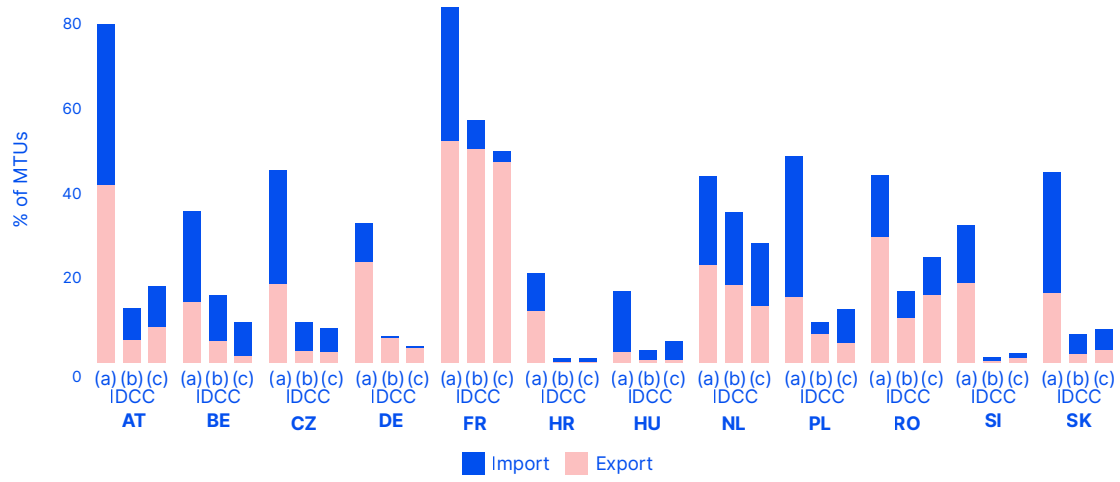
228 While IDCC(a), IDCC(b) and IDCC(d) release capacity directly to the different intraday auctions, IDCC(c) and, once implemented, IDCC(e) release capacity directly to continuous intraday trading. This means that any additional capacity made available through the latter processes is allocated on a first-come, first-served basis, whereas capacity made available through the former is allocated through the auction clearing process based on the transactions that generate the most value.

229 As observed in the diagram, the capacity calculation process preceding IDA1 (i.e. IDCC(a)) does not rely on an updated CGM. This is because IDCC(a) does not effectively recalculate capacities, but instead only extracts leftover capacity from the day-ahead flow-based domains, which may be reduced to remove some of the virtual capacities used in the day-ahead capacity calculation process to comply with the minimum capacity requirements.

230 As mentioned above, the process of extracting ATCs from flow-based domains based on a previous market position results in a significant loss of available capacity, especially when the previous market clearing used all the available capacity in a certain direction. This results in some bidding zones being completely isolated because cross-zonal capacities on all their borders are zero.

231 As highlighted in Figure 58, this is the case primarily in IDA1 because the ATCs are extracted from flow-based domains based on the day-ahead capacity calculation results. In some bidding zones, such as in the case of France, over 50% of MTUs show no possibility to export through any of its borders. On the other hand, the subsequent calculations performed by Core TSOs do mitigate this issue, although only to some extent.

Figure 58: Percentage of MTUs in which no capacity was available on any Core bidding zone border in either the import or export direction, for each bidding zone in the Core region – 2025 (% of MTUs)



Source: ACER calculation based on JAO Publication Tool data.

Note: The numbers for IDCC(c) process cover the period since its go-live in June 2025.

232 The relatively low levels of cross-zonal capacities available in the intraday timeframes, leading to a large share of isolated bidding zones, is a direct result of the conversion of flow-based capacities into border-wise ATC values, but also of the fact that the intraday flow-based domains calculated by Core TSOs are typically smaller than those calculated for the day-ahead market. The reason for this is twofold.

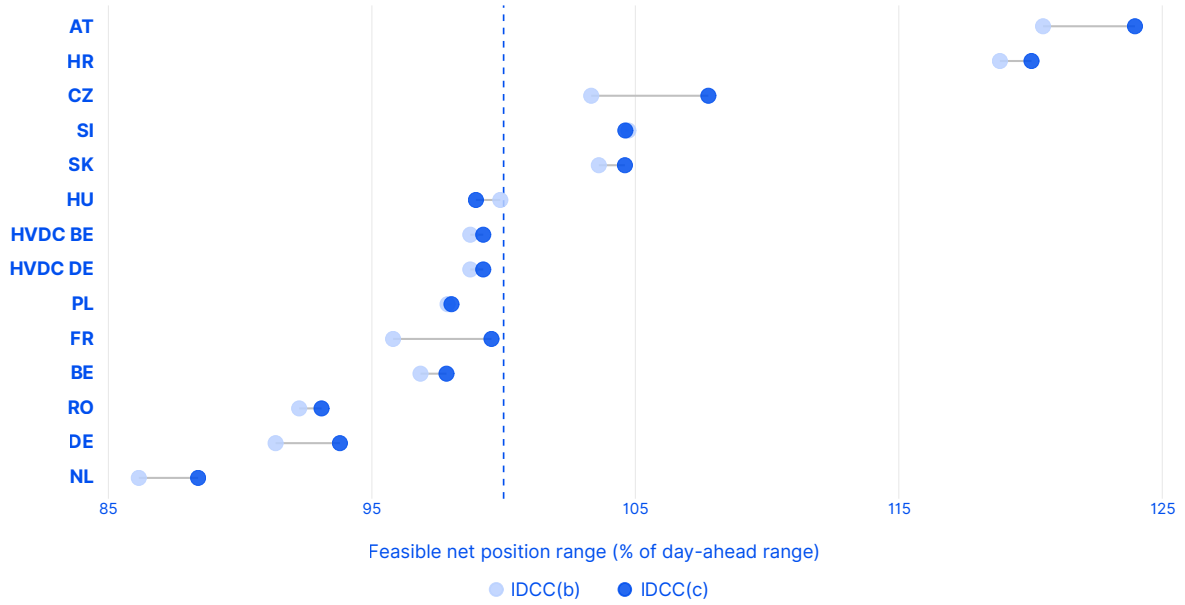
- Firstly, virtual capacity plays a role in enlarging day-ahead domains to ensure the minimum capacity requirements are respected. In the current intraday capacity calculation processes, minimum capacity requirements are not introduced in any way.
- Secondly, in order to guarantee a minimum level of cross-border trade to compensate LTTR holders, Core TSOs also make available the capacities allocated in the long-term timeframe (monthly and yearly LTTR auctions) to the day-ahead market, which may be larger than the calculated flow-based domains.[38]

233 Both these mechanisms may result in the release of cross-zonal capacities in the day-ahead timeframe beyond the physical limits of the network calculated by TSOs, relying on remedial actions to address potential operational security violations resulting from their allocation. Since these capacity increases are not fully reflected in the intraday capacity calculation processes, intraday flow-based domains may be significantly smaller than those calculated for the day-ahead timeframe. This is discussed further in 4.3.

234 Comparing the flow-based domains calculated in the day-ahead and intraday capacity calculation processes points to systematically smaller intraday trading possibilities, particularly in bidding zones whose TSOs rely more heavily on virtual capacities in the day-ahead timeframe. Figure 59 compares, for each Core bidding zone, the average range between the minimum and maximum feasible net positions in IDCC(b) and IDCC(c) with the corresponding range in the day-ahead domain. A value of 100 therefore indicates a feasible range of net position equal to that available in the day-ahead domain, while values below 100 indicate a flow-based domain that allows smaller net positions to be reached in intraday.

38 Following an amendment to the Core day-ahead capacity calculation methodology issued in July 2026, the inclusion of the long-term allocation domain in the day-ahead market clearing process will be discontinued. This is expected as of 2027.

Figure 59: Average range between the minimum and maximum net position achievable within the IDCC(b) and IDCC(c) flow-based domains, as a comparison of the day-ahead domain – 26 June 2025 to 31 December 2025 (% of day-ahead net position)



Source: ACER calculation based on JAO Publication Tool data.

Note: The min-max net position indicator used in the figure represents the most extreme net positions each individual bidding zone could reach under a flow-based domain, but these can't be achieved simultaneously. Since IDCC(c) domains are only available since 26 June 2025 and cover only hours 6-24, and to ensure comparability, only these observations have been included for day-ahead and IDCC(b).

235 As observed in Figure 59, some bidding zones can potentially reach higher net positions under the intraday flow-based domains, on average terms, compared to those calculated in the day-ahead domains. This is mostly the case for TSOs that do not significantly rely on virtual capacities in the day-ahead timeframe. Closer to real time, TSOs have more accurate information on the state of the network, allowing them to apply smaller uncertainty margins.

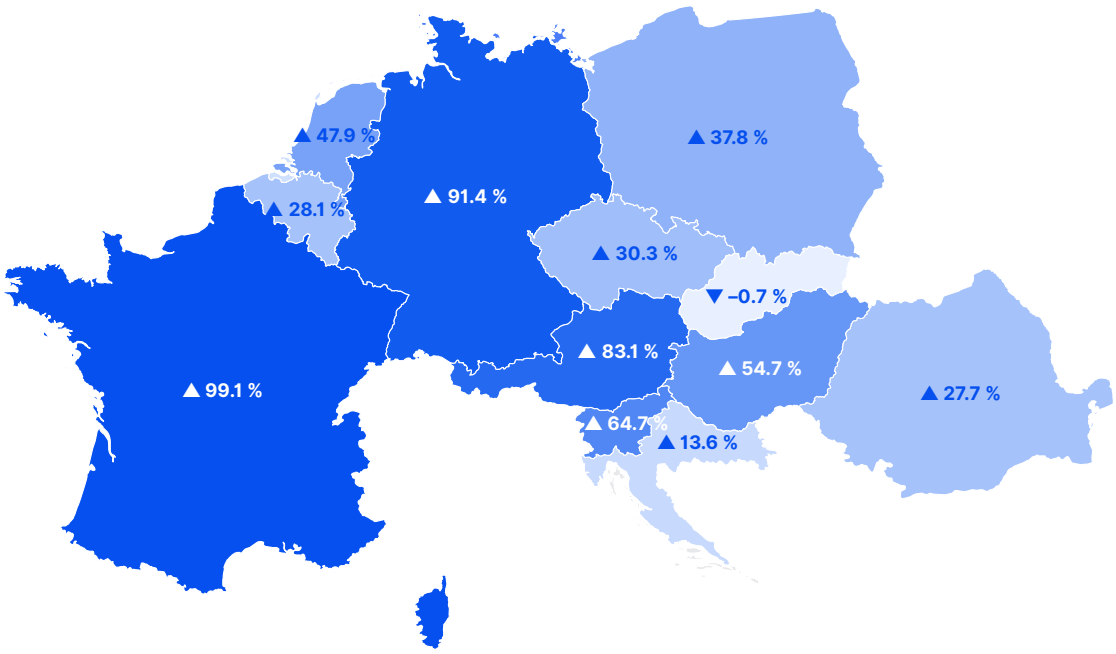
3.3.2. Simulating flow-based allocation in the Core CCR on intraday auctions

236 In order to quantify the benefit of allowing for flow-based allocation in the different intraday auctions, ACER simulated the clearing of the different intraday auctions during a full year, comparing a flow-based market topology and the existing ATC-based topology in the Core capacity calculation region. For this purpose, ACER made use of the Simulation Facility tool, developed jointly by EU NEMOs and TSOs, which replicates the algorithm and input data used in market operations.

237 As detailed above, several capacity calculation processes specifically for the intraday timeframe are now live in the Core CCR, releasing capacities at different stages of the single intraday coupling. The simulations performed by ACER use the most representative flow-based domains for each of the different intraday auctions, that were available during 2025. A detailed description of the methodology followed for this analysis is presented in section 1.4.6. of the methodological document, published in parallel to this report.

238 By accounting for the interdependencies between bidding zone borders, flow-based allocation generally allows bidding zones to reach larger import or export positions. This can be observed in Figure 60, which compares the average of the absolute net positions (import or export) of each Core bidding zone in both the ATC and flow-based allocation scenarios in IDA2. Average (absolute) net positions are higher for almost all bidding zones in the Core CCR under flow-based allocation, with the exception of Slovakia. In some cases, such as that of France or Germany, the average net position almost doubles when allowing for flow-based allocation.

Figure 60: Difference in average absolute net position by Core bidding zone in IDA2 between the simulated flow-based and ATC-based allocation scenarios – 2025 (% of ATC net position)

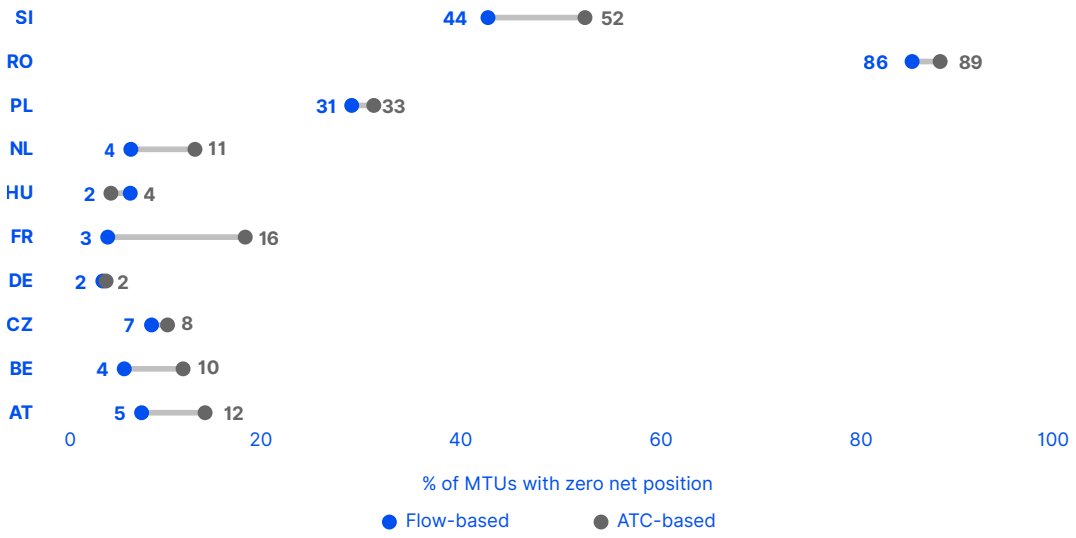


Source: ACER simulation based on Simulation Facility data and flow-based domains from JAO Publication Tool.

239 In 2025, the increase in trading possibilities in the different IDAs allowed by flow-based allocation would have resulted in a significantly higher exporting position for France, while all other Core bidding zones would have been able to import more on average, especially Germany.

240 Moreover, flow-based allocation would meaningfully reduce the number of instances where bidding zones do not import or export at all in the auction, as the direct allocation of flow-based domains, without conversion into border-wise ATC values for Core bidding zone borders, maintains the possibility for the market position to move anywhere within the solution space of the flow-based domain. This is presented in Figure 61.

Figure 61: Percentage of MTUs with no net exchanges per bidding zone in the Core CCR in the simulated flow-based and ATC-based scenarios for IDA2 – 2025 (% of MTUs)



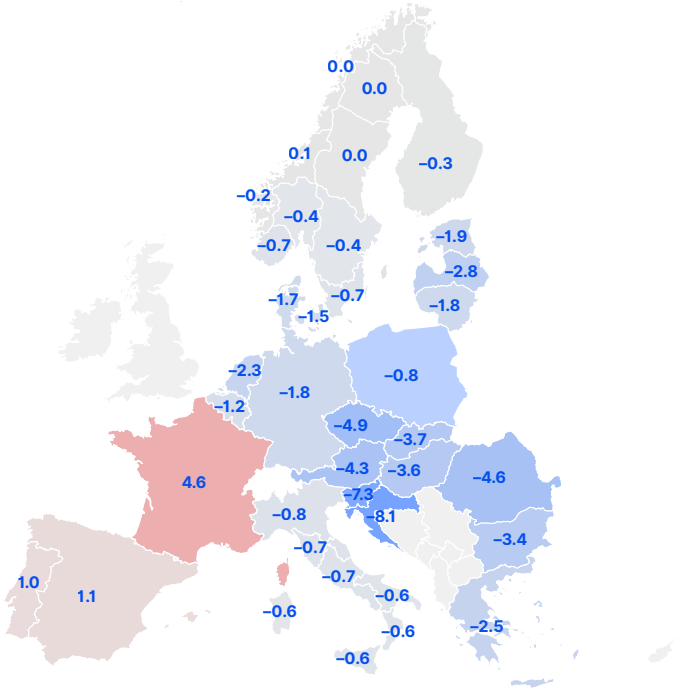
Source: ACER simulation based on Simulation Facility data and flow-based domains from JAO Publication Tool.

Note: The values presented in this figure for both scenarios include instances where no trading activity was recorded in each bidding zone.

241 The introduction of flow-based allocation also materially increases the levels of traded volume across bidding zones. By providing greater access to liquidity in neighbouring markets, it allows additional buy and sell orders located in illiquid markets to be matched in trades that would otherwise have remained unexecuted under ATC-based allocation. The observed higher volumes reflect additional trades executed between different bidding zones as a result of greater access to cross-zonal capacity.

242 The observed changes in net positions and traded volumes also have an impact on the auction clearing prices, with the exporting bidding zones generally seeing an increase in prices, and the importing ones a noticeable decrease. This is highlighted in Figure 62, which shows the difference in average prices per bidding zone between ATC and flow-based allocation in IDA2. In the case of France, flow-based allocation would have led to a 4.6 EUR/MWh increase in average prices in IDA2, while bidding zones such as Croatia or Slovenia would see a drop in average prices of 8.1 and 7.3 EUR/MWh, respectively.

Figure 62: Difference in average IDA2 prices between the simulated flow-based and ATC-based allocation scenarios – 2025 (EUR/MWh)



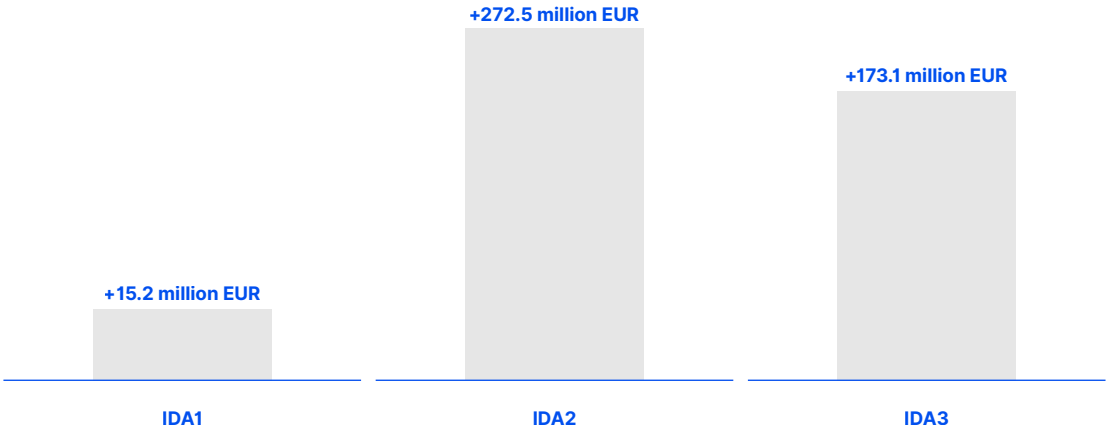
Source: ACER simulation based on Simulation Facility data and flow-based domains from JAO Publication Tool.

243 As a result of the greater levels of cross-zonal exchanges enabled by flow-based allocation, the outcomes of the different intraday auctions are more efficient than they would otherwise be under the current ATC-based allocation. This results in greater levels of economic surplus produced by the auctions. As an example, Figure 63 shows that IDA2 and IDA3 would have produced an additional economic surplus during 2025 of approximately EUR 270 million and EUR 170 million, respectively, under flow-based allocation.

244 In the case of IDA1, the smaller impact on economic surplus indicates that the flow-based domains calculated for the day-ahead market, adjusted to remove virtual capacities, do not enable significantly more cross-zonal trade than the corresponding ATC-based capacities. This is likely explained by the fact that no additional capacity is released specifically for IDA1, as the flow-based domains can only be adjusted downwards through the partial or full removal of virtual capacities, and that the information available to market participants has not changed significantly since the day-ahead market. In practice, however, some Core TSOs do maintain a certain share of virtual capacities in the domains offered to IDA1.

245 To assess the impact of excluding virtual capacities offered in the day-ahead market for the IDA1 allocation, ACER also simulated IDA1 using the day-ahead flow-based domains without this adjustment. The simulation resulted in an increase in economic surplus of EUR 36 million compared with ATC-based allocation. This is higher than in the simulation that excludes virtual capacities but remains well below the impact observed for IDA2 and IDA3 when using recalculated flow-based domains.

Figure 63: Additional economic surplus in the different intraday auctions when simulating flow-based allocation – 2025 (million EUR)



Source: ACER simulation based on Simulation Facility data and flow-based domains from JAO Publication Tool.

Note: The following considerations apply for the simulation results:

- *The simulations for IDA1 are performed with day-ahead flow-based domains that have been adjusted to remove all virtual capacities.*
- *The results presented for IDA2 and IDA3 are based on public IDCC(b) and IDCC(d) flow-based domains that have been adjusted for the changes in net positions that occur through continuous trading during the capacity calculation processes, based on data delivered by Core TSOs.*
- *IDCC(b) domains and the related ATC values were used for IDA3 until the go-live of IDCC(c), after which IDCC(c) domains and the corresponding ATC values have been used.*
- *The values for IDA3 should be interpreted in light of the lower number of MTUs being cleared by this auction (i.e. from 12:00 to 00:00).*

246 In summary, the reliance on border-wise ATC values for allocating cross-zonal capacity creates significant inefficiencies in intraday auctions. This is so because it generally underestimates the transfer possibilities offered by the electricity network. A timely transition towards flow-based allocation would enable higher levels of cross-zonal trade and support more robust price formation across most of the EU. In turn, this would enhance the contribution of intraday auctions to the efficient functioning of the EU electricity market.

4. Congestion management

247 Physical congestion is defined in Regulation (EU) 2015/1222 (Capacity Allocation and Congestion Management Regulation) as a network situation in which forecasted or realised power flows violate the thermal limits of grid elements, and the voltage or angle stability limits of the power system. As these technical limits are only partially represented in the market coupling algorithm, in the form of constraints on cross-zonal exchanges, the resulting market outcome may not always be physically feasible. In such cases, TSOs must rely on remedial actions to address the physical congestion identified.

248 Remedial actions are measures taken by TSOs to address violations of security limits, typically after the gate closure time of day-ahead and/or intraday markets. Specifically, they are triggered to ensure that technical parameters of the system, such as voltage or electrical current, remain within predefined operating ranges. Some actions used by TSOs, such as changes in grid topology or the use of phase-shifting transformers, incur no direct operating costs and thus are generally given priority over other measures, such as redispatching or countertrading, both of which can come at a significant cost to the system.

249 Costly remedial actions to alleviate physical grid congestions typically entail that system operators adjust the market outcome to ensure the system operates securely. Non-costly actions, on the other hand, do not modify the market result at all, but rather are used to distribute power flows differently across the network.

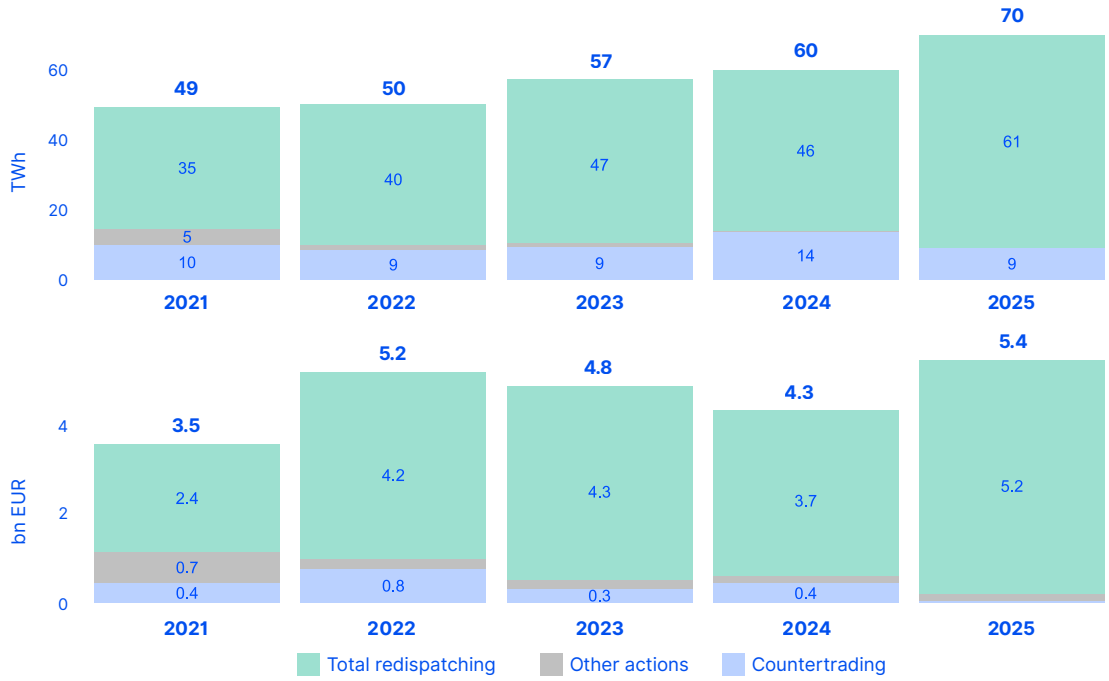
250 Remedial actions, including costly ones, have been used extensively across the EU in recent years, and their use is expected to increase further in the future. This has been forecasted by the European Commission's Joint Research Centre in their 2024 study on redispatch and congestion management.[39] There are several reasons for this growing trend.

- Firstly, given the rapidly growing share of variable renewable electricity generation in the system, and the relatively slower pace in grid infrastructure development, both the severity and frequency of network congestion are likely to increase as power flows continue to diverge from historical patterns. This requires TSOs to activate more remedial actions and to intervene in timeframes closer to real time.
- Secondly, bidding zones in the EU are still mainly defined according to political borders, with some notable exceptions in Italy and the Nordics, and changes to the existing configuration have proven difficult to implement. Thus, they may not efficiently address structural congestion in the network. As a result, locational price signals are partly distorted via wholesale prices that do not always reflect the cost of congestions.
- Lastly, the implementation of the minimum 70% requirement, set out in Article 16(8) of the Electricity Regulation, may result in an increased application of both costly and non-costly remedial actions, in the absence of other structural measures. With a larger share of physical capacity being available for cross-zonal trade, and without significant reinforcements of the power grid or a change in bidding zone configuration, more remedial actions will be needed to deal with congestion stemming from the combination of internal and cross-zonal transactions.

39 Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, JRC137685, https://publications.jrc.ec.europa.eu/repository/handle/JRC137685.

251 EU NRAs report to ACER the costs and volumes of all costly remedial actions activated in each Member State on a yearly basis. In 2025, the data reported confirmed the rising trend detected in previous years. The volume of all costly remedial actions activated in the EU in 2025 amounted to 70 TWh, with the costs totalling EUR 5.4 billion. As highlighted in Figure 64, both the costs and volumes of remedial actions recorded in 2025 reached their highest levels in the historical series.

Figure 64: Evolution of the volume (top) and costs (bottom) of remedial actions activated in the EU and Norway – 2021-2025 (TWh and billion EUR)



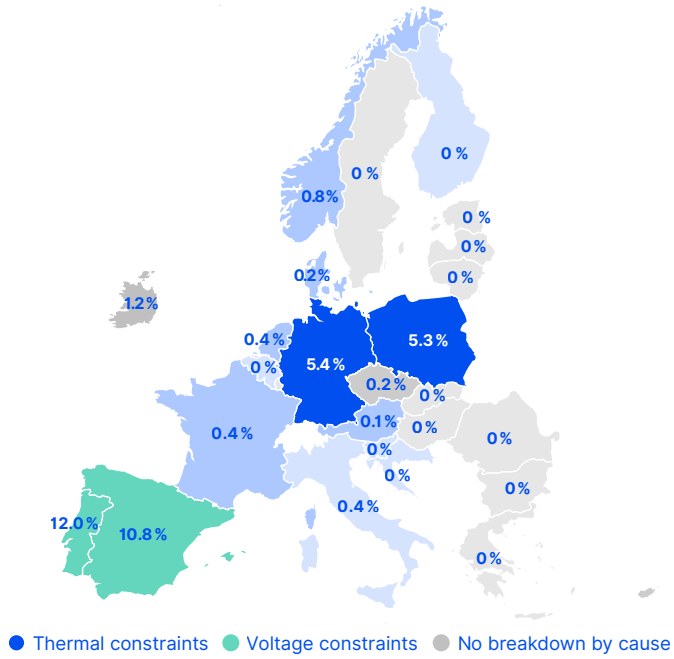
Source: ACER calculation based on NRA data.

Note: The redispatching values presented include counter-activations undertaken to balance every redispatching action. The redispatching volume was not available for Ireland, while the volumes and costs of remedial actions reported for Sweden include only period 1 January 2025 to 3 March 2025.

252 While respecting the thermal limits of transmission assets has typically been the primary reason to activate remedial actions, it is important to underscore that not all remedial actions serve this purpose. Remedial actions may also need to be triggered by TSOs to safeguard other technical limits of the system, such as voltage or frequency stability limits. In 2025, the share of redispatching triggered to respect the thermal limits of the transmission network amounted to 61% in the EU, the lowest value recorded over recent years. Notable examples are the cases of Spain and Portugal, where a large majority of the volume of remedial actions triggered by the TSOs in 2025, aim to prevent or address violations of voltage limits.

253 Figure 65 shows a comparative overview of EU Member States' use of costly remedial actions in 2025, measured as the total volume of remedial actions activated in each Member State as a percentage of the national electricity demand. Moreover, Member States are categorised by the most common operational security violation experienced by the TSO. As highlighted in the figure, the need for congestion management appears to be relatively highest in Portugal, Spain, Germany and Poland.

Figure 65: Volume of remedial actions activated in each Member State as a percentage of electricity demand, and categorised by the most common operational security violation – 2025 (% of electricity demand)



Source: ACER calculation based on NRA data.

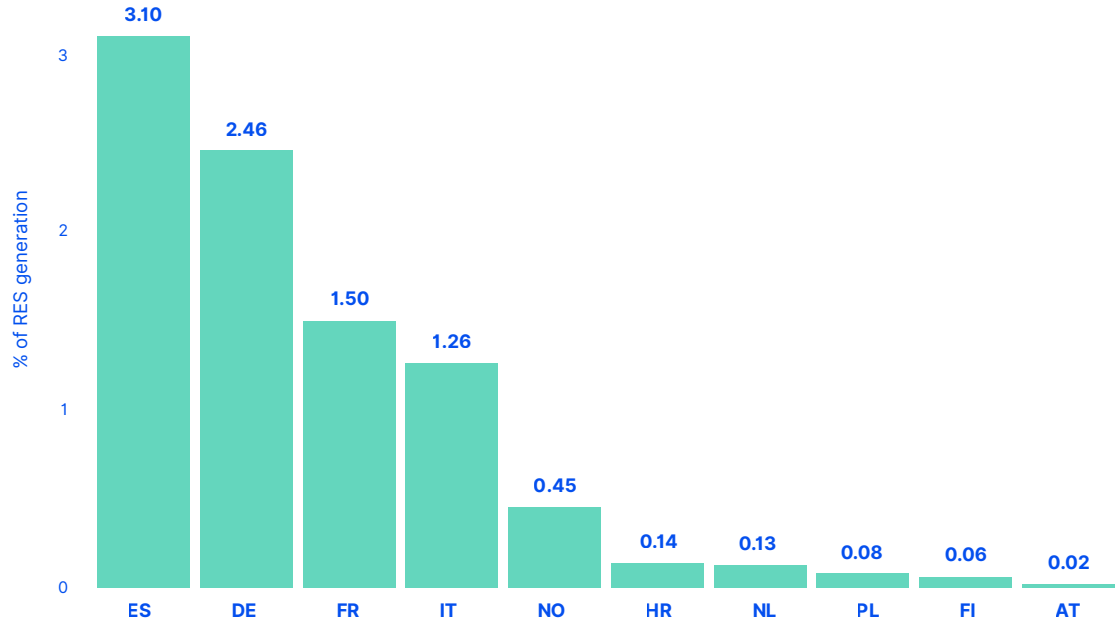
Note: The redispatching values presented include counter-activations undertaken to balance every redispatching action. The redispatching volume was not available for Ireland; the figure therefore includes only countertrading. Remedial action volume reported for Sweden includes only period 1 January 2025 to 3 March 2025.

254 Physical congestion in the transmission network can prevent generation units cleared in the market from being dispatched in real time, requiring TSOs to curtail (or redispatch downwards) part or all of their output in order to maintain secure system operation. Consequently, available renewable generation may need to be curtailed, with the foregone output potentially replaced by generation from conventional units located elsewhere in the network.

255 Figure 66 shows, for each EU Member State, the share of renewable generation curtailed due to grid congestion in 2025. Spain recorded the highest renewable curtailment rate in 2025, at 3.1 % of total renewable generation, followed by Germany, France and Italy. Compared with 2024, curtailment increased in most countries and roughly doubled in Spain, while it declined in Germany.

256 The Electricity Regulation requires network operators to plan their grids so that electricity from renewable sources can be accommodated with the minimum possible redispatching. Nevertheless, network planning may take into account a limited amount of renewable curtailment where the system operator demonstrates transparently that this is more economically efficient and where it does not exceed 5 % of the annual electricity generated by renewable installations directly connected to its grid. The 5 % value should therefore be understood as a threshold for network planning, rather than as a general permissible limit for actual curtailment.

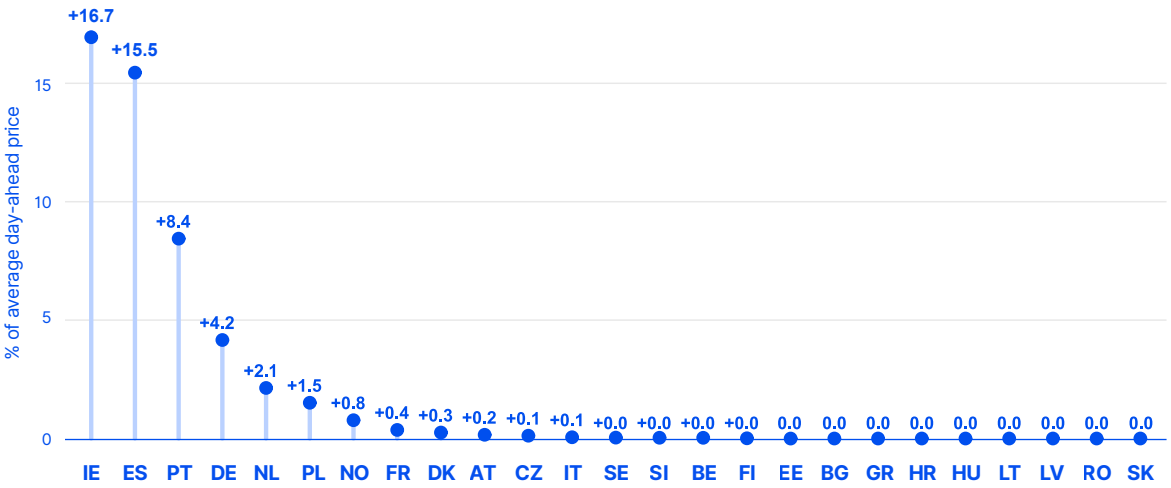
Figure 66: Share of renewable energy curtailed due to physical congestion in each EU Member State and in Norway – 2025 (% of RES generation)



Source: ACER elaboration based on NRA data.

257 The costs of managing grid congestion represent an increasingly significant component of overall electricity system costs. Figure 67 shows, for each EU Member State, the magnitude of congestion management costs relative to average day-ahead electricity prices. In some countries, notably Spain and Ireland, these costs are equivalent to as much as 17 % of the average day-ahead price. Although not directly reflected in day-ahead prices, congestion management costs ultimately form part of the cost of operating the electricity system and should therefore be taken into account when assessing the efficiency of market outcomes.

Figure 67: Cost of remedial actions for each MWh of electricity demand, compared to the average day-ahead price in each EU Member State and in Norway – 2025 (% of average day-ahead price)



Source: ACER elaboration based on NRA data.

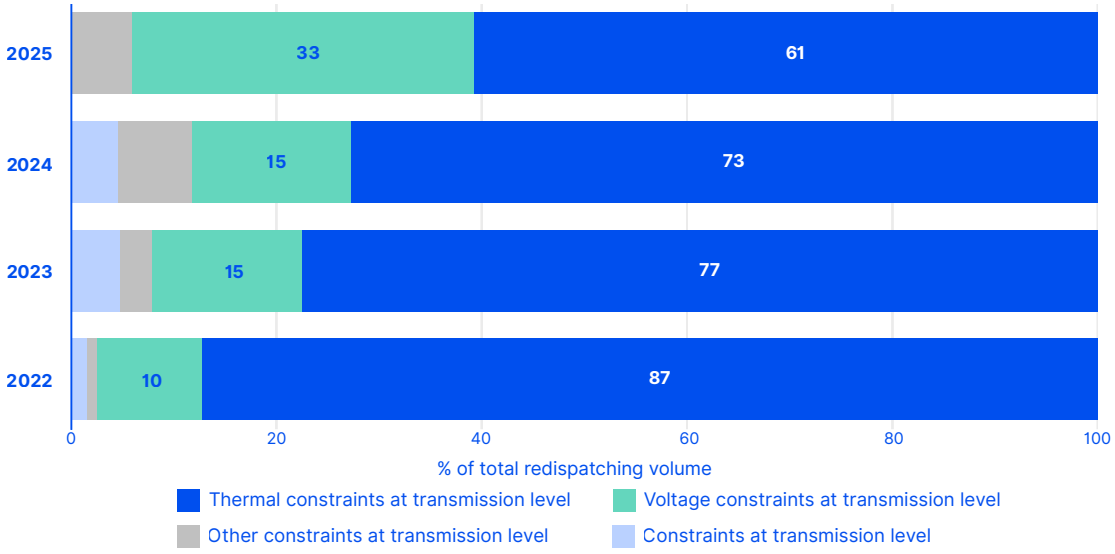
Note: Remedial action costs reported for Sweden only cover 1 January 2025 to 3 March 2025.

4.1. Increase of congestion management needs to safeguard voltage limits

258 As anticipated in the introduction, violations of voltage operational ranges in the network have increasingly been observed in parts of the European power system, leading to a growing volume of costly remedial actions being triggered to address them. Figure 68 shows the total redispatching volume in the EU over recent years, categorised by the type of underlying operational constraint that it is triggered to address. The share attributed to voltage limits has increased from 10 % in 2022 to 33 % in 2025.

259 Unlike thermal constraints, which arise when power flows exceed the current limit of network elements, voltage-related constraints reflect difficulties in maintaining the local balance of reactive power in specific areas of the network. A reactive power imbalance can lead to excessively high or low voltages in the affected area of the network, both of which can eventually lead to grid elements and users disconnecting.

Figure 68: Total redispatching volume categorised by type of underlying operational security violation in the EU and Norway – 2022-2025 (% of total redispatching volume)



Source: ACER elaboration based on NRA data.

260 The increasing occurrence of voltage limit violations is associated with broader changes in the operation of the European power system. These include changes in the resource mix, notably the progressive displacement of conventional synchronous generation by variable and inverter-based resources, along with frequently changing patterns of electricity production and consumption, including the more regular occurrence of operating conditions characterised by high renewable output, low demand and low network loading. Together, these developments are altering the system's ability to maintain adequate voltage control.

261 Voltage limit violations are particularly dependent on local network conditions and cannot always be resolved through conventional active power redispatching alone. TSOs may therefore need to activate a wider range of remedial actions, including the adjustment of reactive power output from generators, the switching of shunt reactors or capacitors, or changes in network topology. In the longer term, TSOs need to design the system to ensure that it provides sufficient voltage control, such as by installing integrated network components, or to re-assess the approach to reactive power control by system users.[40] Where adequate reactive-power resources are not available close to the affected network location, the required interventions may be particularly costly or operationally restrictive.

40 Some longer-term solutions regarding voltage control are elaborated in the Recommendations section of the final report of the expert panel investigating the 28 April 2025 blackout in Iberia (pp. 455–457), as well as in the final report of the expert panel investigating the 18 May 2025 blackout in North Macedonia (pp. 122–123).

262 The growing relevance of voltage constraints highlights the need to ensure that congestion management frameworks adequately reflect both active and reactive power requirements. Improved monitoring, more systematic procurement and efficient remuneration of voltage control services, and investment in assets capable of providing appropriate reactive power support may help reduce reliance on costly corrective actions.

263 Greater consideration of voltage constraints in operational planning, capacity calculation and network development will also be necessary as the European power system becomes increasingly decentralised, inverter-based and dependent on variable renewable generation.

Impact of the Iberian incident on congestion management practices in Spain

264 On 28 April 2025, violations of voltage security limits in parts of the Spanish transmission network triggered a cascading sequence of generation disconnections, ultimately resulting in the blackout of the entire Iberian power system.[41] The event highlighted the growing importance of maintaining adequate voltage control capabilities and sufficient reactive power resources, to manage increasingly complex system conditions.

265 Following the incident, the Spanish TSO introduced a number of changes in their system operation practices intended to help manage voltage security risks. These resulted in a substantial increase in redispatching activations intended to maintain secure voltage profiles and to ensure that sufficient voltage control resources are available in the relevant areas of the network.

266 Specifically, the Spanish TSO began committing more synchronous generation outside the day-ahead market, through their 'technical constraints' process. After the day-ahead market is cleared, the TSO performs an assessment of the network security and modifies the dispatch accordingly to ensure a safe system operation. This increased scheduling of synchronous generation, mostly combined-cycle gas-fired power plants, ensures that such units remain connected to the grid, providing voltage control and/or other services.

267 This operational response comes at a significant cost for the Spanish system, with the total cost of congestion management in Spain reaching EUR 2.3 billion in 2025, up from EUR 1.2 billion in 2024. This increase in Spanish congestion management needs accounts for most of the year-on-year increase in redispatching volumes and costs at the EU level in 2025 that can be observed in Figure 64.

268 Moreover, the dispatch process in Spain had operational consequences beyond the Spanish system in 2025. On several occasions, delays in the Spanish TSO's redispatch process prevented the Spanish NEMO from making its order books available within the required timeline for the first pan-European intraday auction (IDA1). This resulted in an automatic partial decoupling being triggered, which ultimately affected the participation of most EU bidding zones in the auction.

269 As part of the Spanish redispatching process, the day-ahead market results are assessed against operational security limits and adjusted, where necessary, to establish a technically feasible programme for each generation unit. The resulting programme is used by the Spanish NEMO to validate the order books submitted to IDA1. On some occasions, these security analyses took longer than anticipated, meaning that the validated Spanish order books were not available by the relevant IDA1 deadline, and thus the automatic partial decoupling was triggered.[42]

41 As described in the final report of the expert panel investigating the 28 April 2025 blackout in Iberia.

42 See, for example, the SIDC Operations Committee report on the IDA1 automatic partial decoupling of 16 July 2025.

270 The impact of these incidents extended well beyond the Iberian market because the delays were only confirmed after the point at which a targeted decoupling could be performed in advance. Once the market coupling session had started, the automatic partial decoupling procedure relied on a predefined fallback configuration rather than determining which individual market needed to be excluded. Under this configuration, only a limited set of NEMOs could remain coupled, notably those of Greece and Italy, while most other bidding zones were decoupled.

271 To limit the scope of similar incidents, the existing SIDC procedure for advance partial decoupling of the IDAs has subsequently been adapted to address delays in the Spanish redispatch process. Under the amended procedure, where the Spanish TSO anticipates that the security analysis and resulting programme will not be available in time for IDA1, it must notify all relevant parties before a given deadline. This allows the IDA1 coordinator to decouple the Iberian market in advance, while preserving the participation of the remaining bidding zones. The procedure is thus expected to reduce the geographical impact of delays originating in the Spanish redispatch process, provided that these can be identified sufficiently early.

272 It is important to note that, while other EU TSOs perform similar operational security analysis after the day-ahead market, these processes remained compatible with the timings of the different intraday EU allocation stages. At the same time, differences across national systems should be acknowledged, including the degree of distributed renewable integration and the extent to which market schedules are defined and validated at the individual unit level.

273 Other operational changes introduced in the Spanish system include requiring renewable units to follow controlled ramps when their schedules change, rather than changing output instantaneously between programming periods. The stated objective of this measure is to limit rapid changes in active power that could produce abrupt voltage variations, which increased in frequency following the introduction of quarter-hourly market schedules.

4.2. Design of redispatching systems across the EU

274 The design of redispatching arrangements in the EU is mostly a national competence, subject to certain minimum requirements established at the EU level. This section introduces the main redispatching approaches applied at the TSO level across the EU, with a particular focus on the distinction between market-based and non-market-based arrangements, along with a comparison of unitary redispatching costs across the EU.

275 Article 13 of Regulation (EU) 2019/943 establishes market-based redispatching as the general rule. Redispatched resources should be selected through market-based mechanisms and financially compensated. Non-market-based redispatching may be used only in the cases listed below:

- where no market-based alternative is available;
- where all available market-based resources have already been exhausted;
- where too few suitable and independently competing resources are available in the relevant location to ensure effective competition; or
- where congestion occurs so regularly and predictably that market-based procurement would encourage strategic bidding and aggravate internal congestion, in which case the Member State must also have adopted an action plan to address the congestion or ensure compliance with the minimum cross-zonal capacity requirement under Article 16(8).

276 In practice, redispatching arrangements implemented by national TSOs across the EU may rely on market-based, non-market-based or mixed approaches. These approaches may apply, separately or in combination, at different stages of the redispatching process, notably during the selection of service providers and the subsequent activation of the redispatching resources. The first determines which resources are selected or contracted to provide redispatching services; the second determines which of the available resources are actually instructed to modify their scheduled injection or withdrawal when redispatching is required.

277 A redispatching arrangement can therefore involve market-based elements at either stage. Service providers may, for example, be selected through a competitive tender or other bidding process and subsequently activated according to predefined rules. Alternatively, eligible resources may submit activation bids indicating the volume and price at which they are willing to modify their scheduled injection or withdrawal, with the transmission system operator selecting technically effective bids, generally taking account of their location and economic merit. Conversely, where the relevant decision is taken without a competitive bidding process, that element of the procurement can be considered non-market-based.

278 The remuneration of redispatched resources may also differ across national arrangements. The activated resources may be remunerated at their submitted price (i.e. pay-as-bid), through a marginal pricing mechanism, or according to prices established through the competitive procurement of the service. Under non-market-based arrangements, remuneration is normally determined through regulated rules, which may compensate the affected party for additional operating costs, foregone market revenues and lost support payments. Some jurisdictions instead apply administratively defined reference prices or provide no separate compensation for particular curtailment measures.

279 The type of national redispatching design plays a role in the resulting costs of activating resources for congestion management purposes. However, differences in redispatching costs cannot be explained by market design alone. These are primarily affected by the type, location and availability of the assets capable of providing the required congestion management service.

280 Figure 69 presents an overview of the average activation cost of redispatching energy in each EU Member State. The values presented in this figure correspond to the average cost of all redispatched volume, including both upwards and downwards directions. Congestion management costs in 2025 appear greater at the unitary level in Italy and Sweden, while they are cheapest in Croatia.

Strategic behaviour in redispatching processes: what is INC–DEC gaming?

As the volume of redispatching grows, driven by increasing renewable penetration and persistent congestion, the financial stakes of both deliberate gaming and structural arbitrage rise in proportion. An often-raised concern with the market-based activation of redispatch, is the **'increase-decrease (INC-DEC) game'**: generators anticipate that they can profit from the price spread between the day-ahead market and the subsequent redispatch stage, and therefore alter their initial market position accordingly. The concern emerges from the structural inconsistency between a uniform zonal price, with no consideration for network congestions, and a location-specific redispatch market. Redispatching then needs to alleviate any anticipated congestions.

Although this behaviour is typically discussed in the context of redispatching by TSOs, it can also occur at the DSO level. Similar forms of strategic behaviour may also arise through arbitrage between other electricity markets. Such arbitrage does not necessarily constitute gaming. One example is "flip-flopping", where market participants exploit price differences between the day-ahead and balancing markets.

This explanatory box explores different variants of INC–DEC gaming. While this report focuses on monitoring congestion management trends in the EU, it is also important to note that ACER surveils wholesale energy markets for potential market abuse. Any strategic behaviour that constitutes market manipulation falls within the scope of that surveillance.

Two routes to the same game

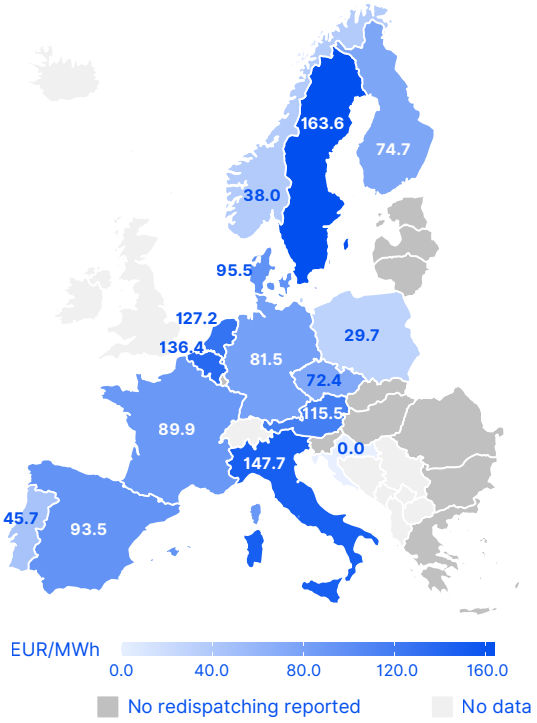
INC–DEC gaming is best understood as a position strategy. The economic object being used is the generator's initial market position: its scheduled output in the day-ahead market (stage 1). This position is inflated to profit from the subsequent decrease in redispatching (stage 2). This position can be inflated through the following two variants:

1. **Price-based INC–DEC:** the generator bids below marginal cost in the day-ahead market, causing the market to schedule more output than is economically efficient. This variant requires a market-based redispatch stage or a cost-based approach with information asymmetry to generate the arbitrage profit. This is the most commonly described variant of INC–DEC gaming.
2. **Volume-based INC–DEC:** the generator declares an inflated schedule, overstating its available or intended production, without necessarily deviating its bid price from the expected marginal cost. The inflation increases the revenue in the day ahead market. In the case of downwards redispatching, the inflation may go unnoticed. This behaviour would appear in both cost-based and market-based redispatching. This variant is less commonly described in literature.

Implications for congestion management

The growing need for remedial actions should not only be viewed in terms of increasing redispatch volumes and associated costs. It also creates more opportunities for strategic behaviour, including different variants of gaming. Strategies such as INC–DEC gaming can occur under both cost-based and market-based redispatch designs. Therefore, the redispatch design alone may not completely eliminate this behaviour.

Figure 69: Average cost per MWh of activating redispatching energy in the EU and Norway – 2025 (EUR/MWh)



Source: ACER calculation based on NRA data.

Note: Remedial action costs reported for Sweden only cover 1 January 2025 to 3 March 2025.

281 ACER plans to issue a dedicated monitoring report on congestion management processes in 2027, providing a more granular assessment of the national frameworks and practices applied across the EU.

4.3. Challenges of relying on congestion management processes to secure cross-zonal capacities

282 In the case of high non-allocated flows at critical network elements, the most immediate way for TSOs to guarantee that the applicable minimum level of cross-zonal capacity can be respected, is to account for more than the thermal limits of the CNECs when calculating the capacity to be offered to the market for cross-zonal exchanges, and then rely on the use of remedial actions after the market clears to address physical congestion on such CNECs, should the market allocate all of the offered capacity.

283 Gradually increasing the minimum cross-zonal capacity requirements towards 70% in line with the linear trajectories defined in action plans applicable across the EU, and without parallel structural mitigation measures such as targeted grid reinforcements or a bidding zone reconfiguration, may thus result in an increase in congestion management needs requiring remedial actions.

284 The degree to which each Member State relies on remedial actions to fulfil the applicable requirements varies across the EU. In the Nordic CCR, TSOs rely mostly on the more granular bidding zone configuration, with limited consideration for remedial actions to increase the calculated capacities. In the Core, South-East Europe (SEE), South-West Europe (SWE) or Italy North CCRs, on the other hand, the applicable capacity requirements are guaranteed to a larger extent by relying on remedial actions, via virtual capacities.

285 However, the reliance on remedial actions to guarantee the fulfilment of the legally binding minimum capacity levels entails several challenges, notably due to the lack of coordination processes at the regional level for the identification, activation and cost-sharing of remedial actions, and the significant lead times currently required by TSOs to implement them. These are discussed in this subsection.

Lack of regional coordination in congestion management processes leads to derogations from the minimum capacity requirements

286 Although the expiry of the national action plans at the end of 2025[43] was expected to reduce the level of loop flows across the Core CCR, by accelerating network development internal to bidding zones, that alone is no guarantee that the negative effect of loop flows in neighbouring control areas is sufficiently tackled. The implementation of processes to forecast, activate and share the cost of remedial actions across the TSOs of the region is necessary to mitigate the detrimental effect of remaining loop flows on the capacity levels made available to the market.

287 The most relevant processes in that regard are the regional operational security coordination (ROSC) and redispatching and countertrading (RDCT) cost-sharing methodologies, along with the coordinated validation step in capacity calculation processes. The coordinated validation step will enable Core TSOs to assess the operational security of the calculated capacities with the consideration of all remedial actions expected to be available in the region. The ROSC and RDCT cost-sharing methodologies will then ensure that regionally optimal remedial actions are triggered, and that their costs are borne by the TSOs at the source of the excessive loop flows.

288 As detailed in Section 2.4.1, several Core TSOs rely on derogations from the minimum 70% requirement, arguing that the absence of coordinated congestion management processes prevents an adequate and fair treatment of excessive loop flows. However, following significant project delays in recent years, the Core ROSC and RDCT cost sharing processes are not expected to become operational before 2030.[44] In parallel, progress in grid development remains limited, while the relevant Member States have decided to maintain the existing bidding zone configuration. As a result, the issue of excessive loop flows is unlikely to be fully addressed in the coming years.

289 These delays have contributed to a number of Core NRAs approving derogations intended to mitigate the impact of loop flows originating in neighbouring bidding zones beyond the expiry of the national action plans, as is already the case for 2026. The continued reliance on such derogations risks prolonging the implementation of the minimum 70% requirement and slowing progress towards full compliance, particularly in those Member States most exposed to excessive loop flows.

Significantly relying on remedial actions to secure cross-zonal capacities in the day-ahead timeframe has knock-on effects on later markets

290 Moreover, as introduced in Section 3.3, significant reliance on remedial actions to secure the minimum cross-zonal capacity requirements in the day-ahead timeframe can have knock-on effects on the capacity that can be made available closer to real time, notably for the intraday and balancing markets.

43 As per Article 15 of the Electricity Regulation.

44 This is the case even after shifting the implementation of ROSC and RDCT cost sharing processes to the Central Europe CCR level (i.e. combining Core and Italy North).

291 In the intraday timeframe, TSOs have less time to identify and activate remedial actions in a coordinated manner where the capacities made available would otherwise result in physical congestion. Against this background, TSOs argue that the technical feasibility of relying on virtual capacity in the intraday timeframe cannot always be ensured. As a result, minimum capacity requirements are generally not enforced in intraday capacity calculation processes in the same way as in the day-ahead timeframe.

292 Continued reliance on virtual capacity in the day-ahead timeframe, without sufficient progress on structural measures to increase the capacity available for cross-zonal trade, such as network development or bidding zone reconfiguration, may therefore constrain the capacity that is made available in subsequent timeframes. This is particularly the case where the remedial actions underpinning the day-ahead capacity cannot be maintained or replaced closer to real time by the relevant TSOs.

293 Nonetheless, this reasoning is difficult to reconcile with the fact that internal intraday trading within bidding zones remains unconstrained by explicit transmission capacity limits until very close to real time, even though changes in internal generation and consumption patterns can contribute to the same physical congestion that constrains cross-zonal exchanges. Restricting cross-zonal capacity on operational security grounds while allowing internal exchanges to continue without equivalent constraints therefore results in an asymmetric treatment of the two types of trade. In practice, this may give internal exchanges priority access to scarce network capacity, which is precisely the discrimination that the 70% requirement aimed to address.

294 In the context of a power system ever more reliant on variable renewable generation, ensuring sufficient cross-zonal trading possibilities in the intraday and balancing timeframes becomes increasingly important. This points to two complementary needs: reducing reliance on remedial actions to support cross-zonal capacities, through structural measures such as network reinforcement or bidding zone reconfiguration; and developing the coordinated processes and operational resources necessary to support the use of virtual capacity closer to real time where such reliance remains necessary.

5. Balancing markets

295 European balancing markets continued to integrate in 2025 and 2026. This chapter assesses four main developments: the evolution of balancing-energy prices; the impact of cross-border balancing-capacity cooperation; the growing participation of flexible resources, particularly large-scale batteries and demand response; and differences in TSO balancing approaches and imbalance-settlement arrangements.

5.1. Balancing energy prices

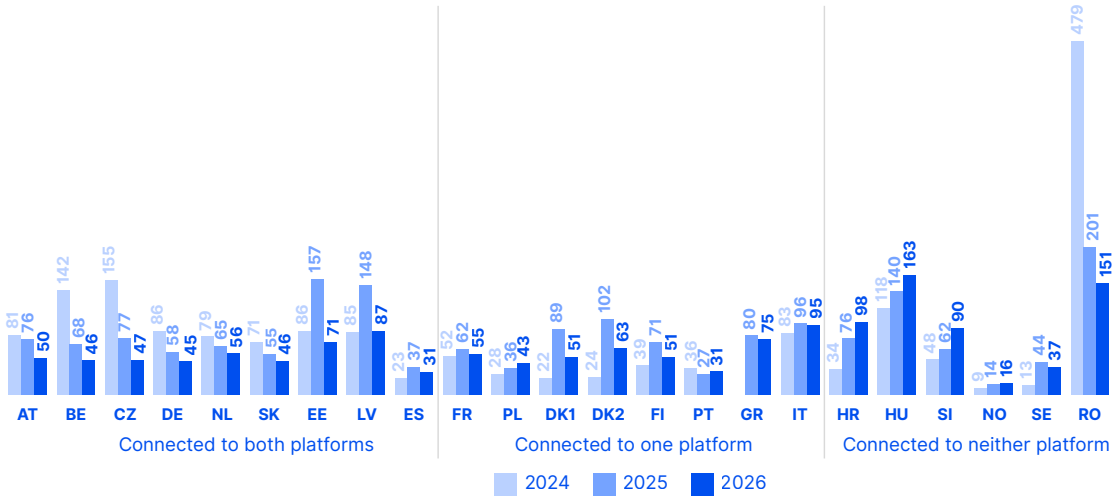
296 The costs of balancing energy activated by TSOs are recovered primarily from balance responsible parties (BRPs) through imbalance settlement. BRPs are financially responsible for deviations between their contracted positions and actual injections or withdrawals, which are settled at the imbalance price. Balancing energy prices are the main building blocks of imbalance prices. Less extreme balancing energy prices therefore generally reduce BRPs' exposure to extreme imbalance settlement prices, although the precise relationship depends on national settlement rules, as discussed in Section 5.3.2. The difference between the imbalance and day-ahead prices therefore provides a comparable indicator of BRPs' additional price exposure from imbalances relative to the day-ahead market outcome.[45]

297 Figure 70 measures this balancing premium as the average absolute difference between the two prices. Between 2024 and 2026, the indicator declined in most countries connected to both PICASSO and MARI, particularly Austria, Belgium, Czechia, Germany, the Netherlands and Slovakia. Estonia and Latvia followed a different pattern: the indicator increased in 2025 before falling in 2026. This coincided with a fundamental transition in Baltic balancing arrangements. Following synchronisation of the Baltic region with Continental Europe in February 2025, the Baltic TSOs assumed full responsibility for frequency control through a newly established regional balancing market. As discussed in Section 5.1.2, limited liquidity initially contributed to higher price volatility, while competition and bid volumes increased as the market matured. By contrast with the overall decline in imbalance premiums observed among countries connected to both platforms, no consistent downward trend is visible among countries connected to only one platform or neither platform.

298 Balancing energy is provided through the activation of aFRR and mFRR, whose prices are the main building blocks of imbalance-price formation, although national settlement rules determine how these prices are combined (see Section 5.3.2). The following sections therefore examine the evolution of aFRR and mFRR prices.

45 Comparing imbalance prices with intraday prices could provide a complementary perspective closer to BRPs' final opportunity to adjust their positions. However, such an indicator would be less suitable for cross-country comparison because intraday liquidity remains limited in several bidding zones.

Figure 70: Average absolute difference between day-ahead and imbalance prices by PICASSO and MARI connection status – 1 January to 15 July in 2024-2026 (EUR/MWh)



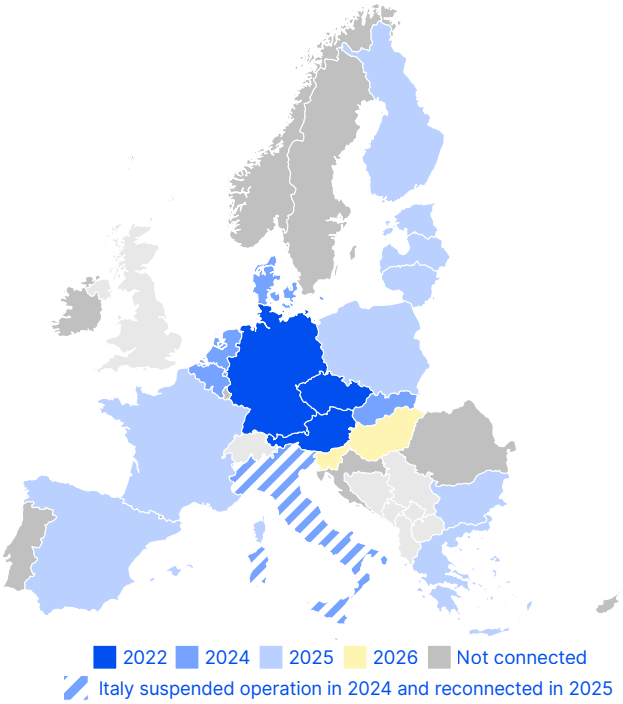
Source: ACER calculations based on ENTSO-E Transparency Platform data.

Note: The indicator is the simple average of the absolute difference between the day-ahead and imbalance prices for January-15 July of each year. Countries are grouped by the platform connection status (connected to 0, 1 or 2 platforms) by end 2025 shown in the figure. For Italy, Norway and Sweden, the value is the simple average of the different bidding zones.

5.1.1. Expanded participation and the introduction of elastic demand improved aFRR price stability

299 The European aFRR platform, PICASSO, jointly selects balancing-energy bids to meet the activation needs submitted by connected TSOs. By the end of 2024, TSOs from seven Member States were connected to PICASSO. In 2025, nine additional TSOs connected and the Italian TSO reconnected. Figure 71 shows this geographical expansion and the year in which each TSO connected. Further TSOs are expected to connect in 2026 and 2027, extending participation beyond that shown in the figure. This wider participation has enlarged the pool of balancing resources available for activation through the platform and created additional opportunities to exchange balancing energy where cross-zonal capacity is available.

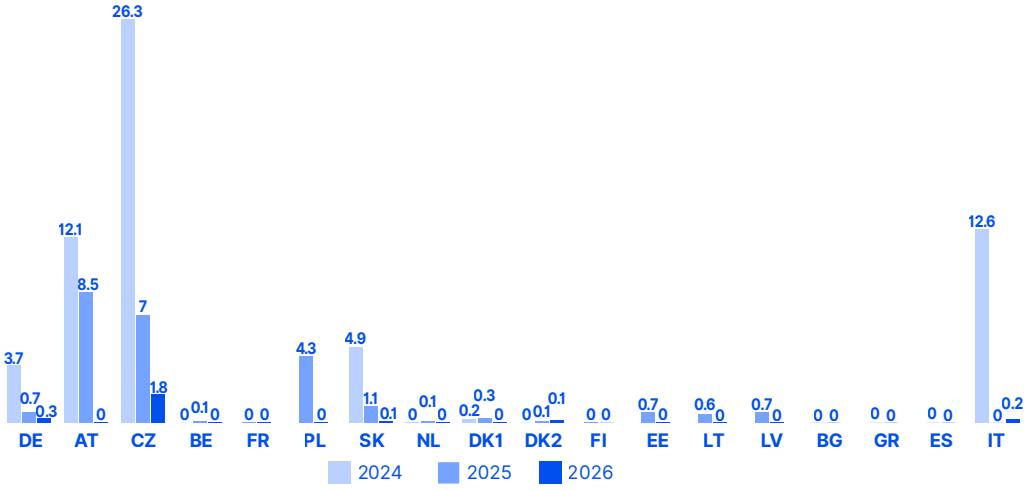
Figure 71: Evolution of TSO participation in PICASSO by year



Source: ACER based on ENTSO-E information.

300 Figure 72 shows that aFRR price incidents[46] became substantially less frequent in 2025 and 2026. The strongest reduction occurred in Czechia, where their annualised[47] duration fell from 26.3 hours in 2024 to 7.0 hours in 2025 and 1.8 hours in 2026. Austria and Italy recorded similarly pronounced improvements. By 2026, the annualised duration of price incidents was below 30 minutes in every bidding zone except Czechia.

Figure 72: Annualised duration of aFRR prices outside ± 7,500 EUR/MWh by TSO area – 1 January 2024 to 15 July 2026 (h/year)



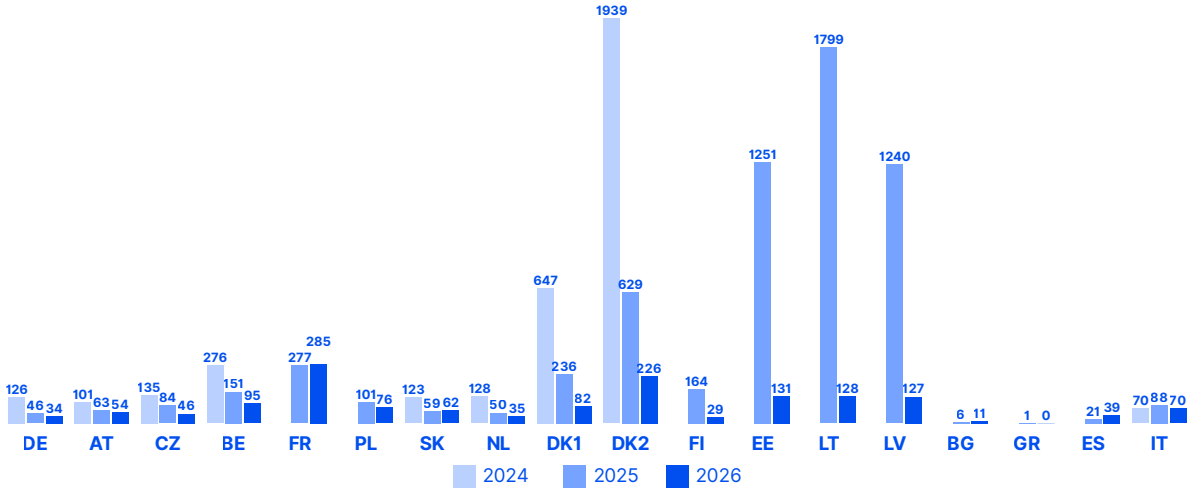
Source: ACER calculations based on TransnetBW transparency data.

Note: Results are expressed as hours per year. Data for 2026 cover the period up to 15 July. Results for incomplete years are annualised to a 365-day year.

Price stability improved more broadly

301 Figure 73 shows that the improvement extended beyond price incidents. The annualised number of hours with aFRR prices outside the range [-200, +400][48] EUR/MWh fell across most TSO areas, with particularly pronounced reductions in the Nordic and Baltic areas. This broad decline indicates a general improvement in price stability and not only a reduction of price incidents.

Figure 73: Annualised duration of aFRR prices outside the range [-200, +400] EUR/MWh by TSO area – 1 January 2024 to 15 July 2026 (h/year)



Source: ACER calculations based on TransnetBW transparency data.

Note: Results are expressed as hours per year. Data for 2026 cover the period up to 15 July. Results for incomplete years are annualised to a 365-day year.

46 In the balancing platforms, price incidents are defined as prices outside ±7 500 EUR/MWh.

47 Results are annualised by dividing the value observed over the available data period by the number of days covered and multiplying it by 365.

48 The illustrative range represents aFRR prices that are considered relatively moderate. Its lower and upper bounds correspond to a deviation of EUR 300/MWh in either direction from a benchmark day-ahead price of EUR 100/MWh.

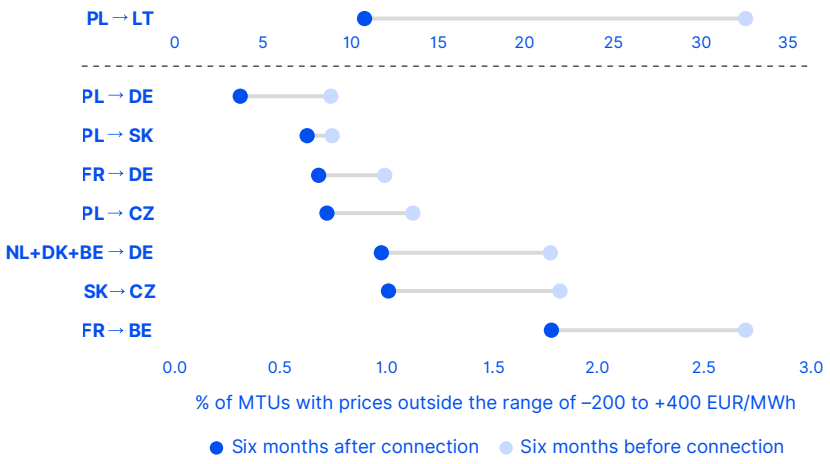
302 Two complementary developments help explain these observations. First, additional TSO connections expanded the pool of available bids and created further opportunities to exchange balancing energy. Second, elastic demand made part of TSOs' activation needs price-sensitive, allowing that demand to remain unsatisfied when the cost of further activation became very high. The following subsections examine how these developments contributed to the increased price stability in the platform.

Price stability improved following additional TSO connections

303 The connection of additional TSOs is expected to improve price stability for TSOs already participating in PICASSO by enlarging the pool of balancing energy bids available for activation, where cross-zonal capacity is available. To examine this effect empirically, ACER analysed connection events for which at least one neighbouring TSO had participated in the platform for a sufficiently long period to allow a comparison. The analysis covers four connection episodes: the connection of Slovakia and its effect on Czechia; the connection of Poland and its effects on Czechia, Germany, Lithuania and Slovakia; the connection of France and its effects on Belgium and Germany; and the combined effect on Germany of the connections of Belgium, Denmark and the Netherlands.

304 The analysis compares the six months preceding the connection with the six months following it. Figure 74 shows the share of MTUs in which aFRR prices were outside the range of [−200, 400] EUR/MWh. This share declined in every case examined, consistent with the expectation that additional TSO connections improve price stability for TSOs already participating in PICASSO. A particularly pronounced decline was observed in Lithuania, where the share fell from approximately 32.5% before Poland's connection to 10.8% afterwards. This decrease may partly reflect the access that Poland's connection provided to the wider pool of balancing resources available in the Core region.[49]

Figure 74: Share of MTUs with aFRR prices outside [−200, 400] EUR/MWh before and after neighbouring TSO connection (% of MTUs)



Source: ACER calculations based on TransnetBW transparency data.

Note: Each comparison covers the six months immediately preceding and following the connection, except PL → LT. For this comparison, the period preceding Poland's connection begins when the Lithuanian TSO connected to PICASSO and is therefore shorter than six months. The labels identify the newly connected TSO or TSOs, followed by the existing participant whose prices are assessed. PL → LT is presented on a separate horizontal scale.

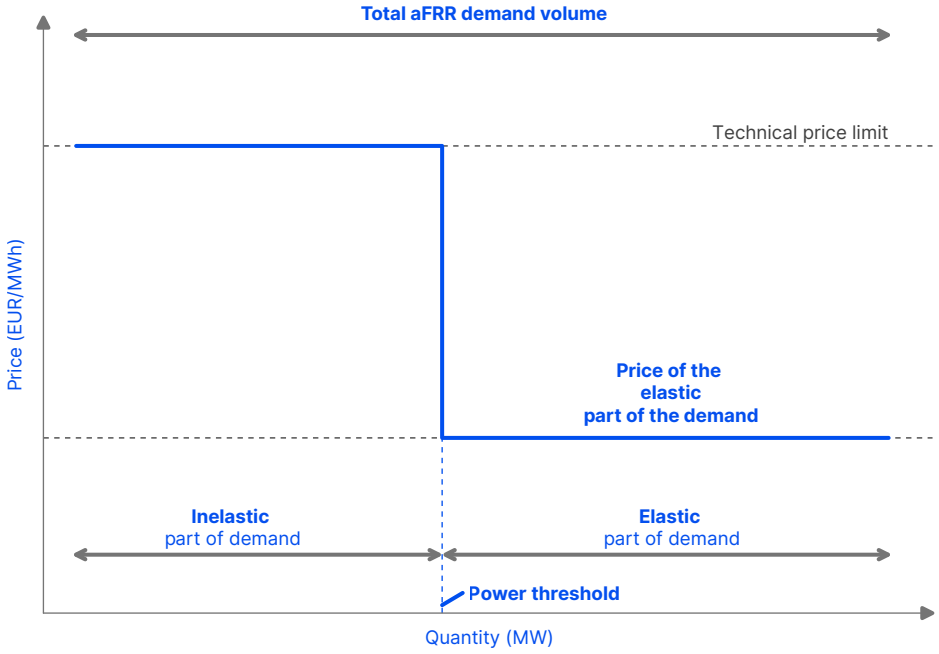
49 Other developments may also have contributed to improved aFRR price stability, particularly in Lithuania. These include the entry of new balancing resources in the Baltic region and the associated increase in competition, as documented in Section 5.2.3.

Elastic demand contributed to a sharp reduction in the occurrence of extreme aFRR prices

305 Following ACER Decision No 08/2024, the part of a TSO's aFRR demand that exceeds its aFRR capacity requirement may be submitted as elastic demand. This allows additional demand to remain unsatisfied when further activation becomes too costly and is not required for operational security, which can consequently reduce the occurrence of extreme aFRR prices.

306 Elastic demand is defined by three parameters: the total aFRR demand; a power threshold[50] separating the inelastic and elastic parts of the demand; and the price assigned by the TSO to the elastic part of the demand (Figure 75). The part of the demand up to the volume threshold remains inelastic and is submitted at the technical price limit. The elastic part of the demand is satisfied only when the clearing price remains below the upward price or above the downward price assigned by the TSO. The mechanism therefore balances the cost of additional activation against the benefit of further improving frequency quality.

Figure 75: Principle of elastic aFRR demand.



Source: ACER.

307 As of November 2026, seven TSOs have implemented elastic demand. They use different approaches to determine the price of the elastic part of their demand (Table 3). Austria, Belgium, Poland and Slovenia apply fixed prices of +1,000 EUR/MWh for upward demand and -1,000 EUR/MWh for downward demand. Denmark, France and Italy use formulas reflecting national prices, balancing bids or operational conditions. Formula-based prices can vary over time, whereas fixed prices remain unchanged.

50 This power threshold has to be at least equal to the aFRR capacity requirement dimensioned by the TSO.

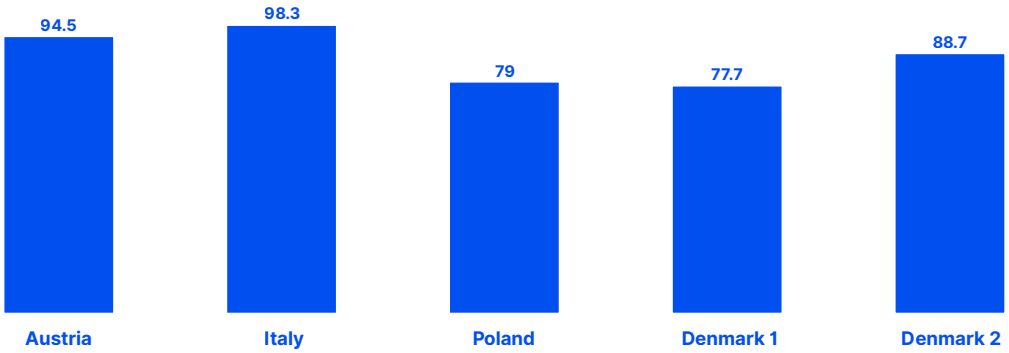
Table 3: Approaches used to determine the price of the elastic part of aFRR demand

Country / TSO	Approach	Price or calculation basis
Austria, Belgium, Poland and Slovenia	Fixed	+1,000 EUR/MWh upward and -1,000 EUR/MWh downward
France	Formula-based	Spot price and weighted average of national aFRR and mFRR bids
Italy	Formula-based	Historical national aFRR bids
Denmark	Formula-based	Historical data, calibrated to avoid excessive area control error

Source: ACER based on information published by TSOs.

308 Austria, Denmark, Italy and Poland introduced elastic demand after initially connecting to PICASSO without it. This allows price outcomes to be compared before and after implementation. Figure 76 shows the relative reduction in the occurrence of prices outside the range of [−1,000, 1,000] EUR/MWh.[51] Following the introduction of elastic demand, the occurrence of prices outside this range fell by between 78% and 98% across the five bidding zones examined.[52] These consistently large reductions indicate that elastic demand contributed to substantially reducing the occurrence of extreme aFRR prices.

Figure 76: Relative reduction in the frequency of aFRR prices outside [−1,000, 1,000] EUR/MWh following the introduction of elastic demand in bidding zones (%)



Source: ACER calculations based on TransnetBW transparency data.

Note: The relative reduction is calculated from the share of MTUs with aFRR prices outside [−1,000, 1,000] EUR/MWh before and after the introduction of elastic demand. The periods considered are as follows: ***Austria*** *before: 1 January to 3 August 2025; after: 4 August 2025 to 15 July 2026.* ***Denmark 1 and Denmark 2*** *before: 1 January to 3 November 2025; after: 4 November 2025 to 15 July 2026. For Denmark, the change date is the date on which the formula for elastic demand was amended rather than the date of the first implementation of elastic demand, as the initial price threshold of the elastic demand was higher than the threshold considered in this analysis.* ***Italy****: before: 1 January to 15 March 2024; after: 25 November 2025 to 15 July 2026.* ***Poland****: before: 15 July 2025 to 3 March 2026 09:00 UTC; after: 3 March 2026 09:00 UTC to 15 July 2026.*

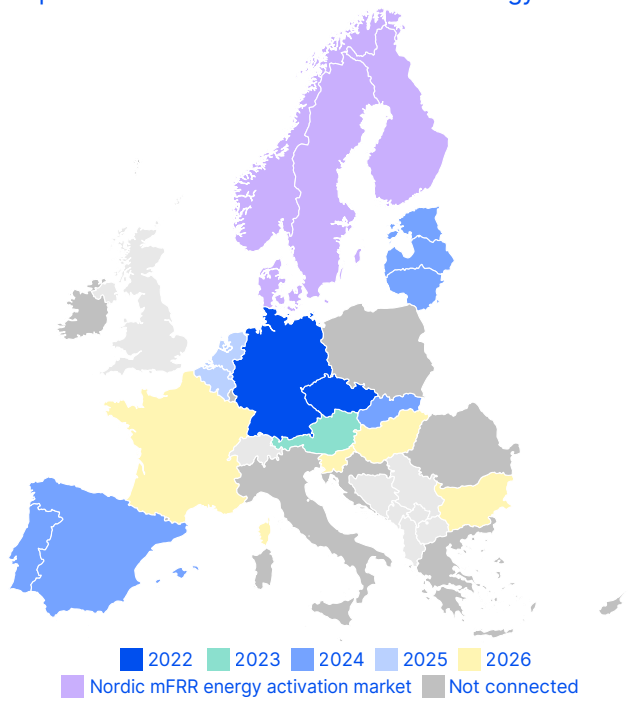
51 The threshold was selected because it corresponds to the elastic-demand prices applied in Austria and Poland and captures more observations than the threshold of ±7,500 EUR/MWh, allowing the impact to be assessed using a larger sample.

52 Other operational and market-design changes may also have affected the frequency of extreme aFRR prices over the period. These include the connection of additional TSOs to PICASSO, such as Italy's reconnection, which may have influenced outcomes in Austria, as well as country-specific developments, such as the implementation of area control error based aFRR in DK2 on 27 August 2025.

5.1.2. Additional TSO connections to MARI advanced mFRR market integration

309 The European mFRR platform, MARI, jointly selects standard mFRR balancing-energy bids to meet the activation needs submitted by connected TSOs. Figure 77 shows successive connections to MARI, distinguishing the year in which each TSO joined the platform. Before joining MARI, the Nordic TSOs also introduced a separate Nordic mFRR market.

Figure 77: Evolution of participation in MARI and the Nordic mFRR energy activation market by TSO and year



Source: ACER based on ENTSO-E information.

310 Successive connections expanded not only MARI's geographical coverage but also the scale and benefits of activity on the platform. The economic surplus generated through MARI increased from EUR 11.7 million in 2024 to more than EUR 104 million in 2025 (see ENTSO-E Balancing report 2026). This increase primarily reflects additional platform accessions, including by TSOs following more proactive balancing strategies and therefore activating mFRR more frequently. Section 5.3.1 examines the differences in national activation strategies underlying this development.

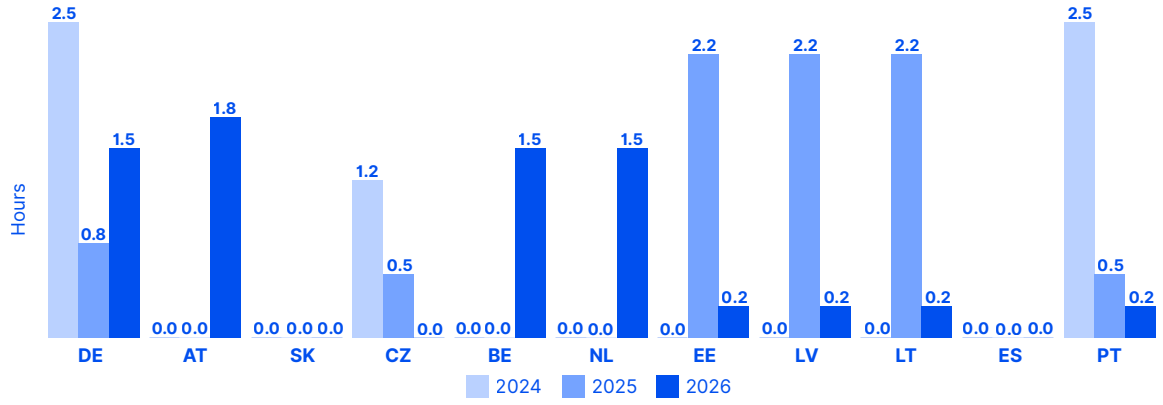
mFRR price developments

311 Figure 78 shows that mFRR price incidents were observed for only a limited number of hours over the year: no Member State recorded more than three hours outside ±7,500 EUR/MWh in any of the three years. The observations for Estonia, Latvia and Lithuania largely reflect the same incidents being recorded across several areas, rather than separate national events. Similarly, the 2026 observations in the western part of the Core region stem from a single incident affecting several areas. These clusters should therefore not be interpreted as a general increase in the frequency of extreme prices. Instead, they reflect event-specific situations that can affect several areas simultaneously. The underlying incidents are examined in more detail in Section 5.1.3.

312 Figure 79 provides a broader indication of mFRR price stability. In 2026, the annualised number of hours with prices below -200 or above +400 EUR/MWh decreased in most areas. The Baltic countries followed a distinct pattern: the indicator increased substantially in 2025 before falling by more than 80% in 2026. The Baltic imbalance-price premium shown in Figure 70 followed a similar evolution.

313 This temporary increase in price volatility coincided with the transition to common Baltic balancing arrangements and synchronisation with Continental Europe in February 2025. AST attributed the sharp price fluctuations observed during summer 2025 to the market's early stage of development and the limited number of participating balancing service providers. As the market developed, competition and offered volumes increased, as illustrated for the balancing-capacity market in Section 5.2.3. This evidence suggests that the 2025 increase partly reflected conditions during the market's initial development and that greater competition and bid availability contributed to the subsequent decline in both mFRR price volatility and the imbalance-price premium.

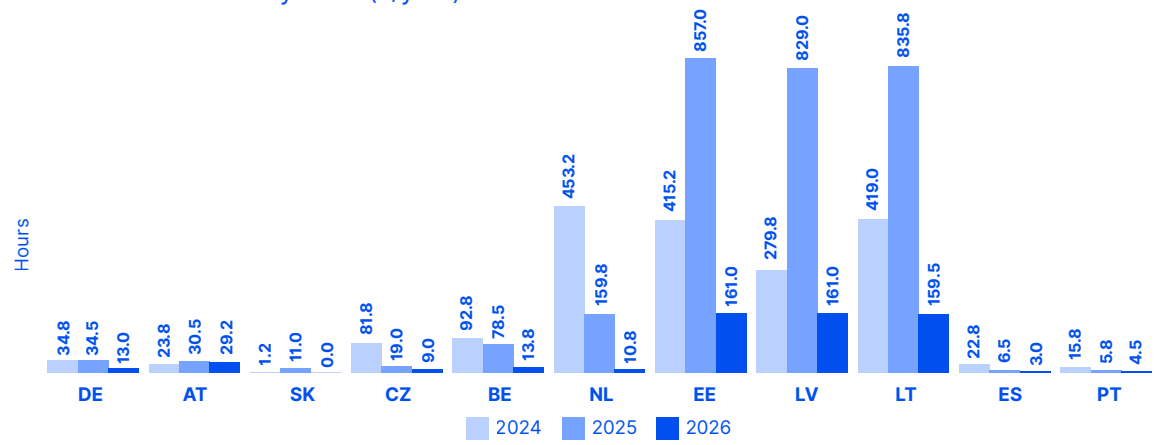
Figure 78: Duration of mFRR prices outside ±7,500 EUR/MWh by TSO area, 1 January 2024–15 July 2026 (h)



Source: ACER calculations based on ENTSO-E data.

Note: Results are expressed as hours and are not annualised. Country coverage reflects data availability. Data for 2026 cover the period up to 15 July.

Figure 79: Annualised duration of mFRR prices outside [–200, +400] EUR/MWh by TSO area – 1 January 2024 to 15 July 2026 (h/year)



Source: ACER calculations based on ENTSO-E data.

Note: Results are expressed as hours per year. Country coverage reflects data availability. Data for 2026 cover the period up to 15 July. Results for incomplete years are annualised to a 365-day year.

5.1.3. Extreme balancing-energy prices arise for different reasons

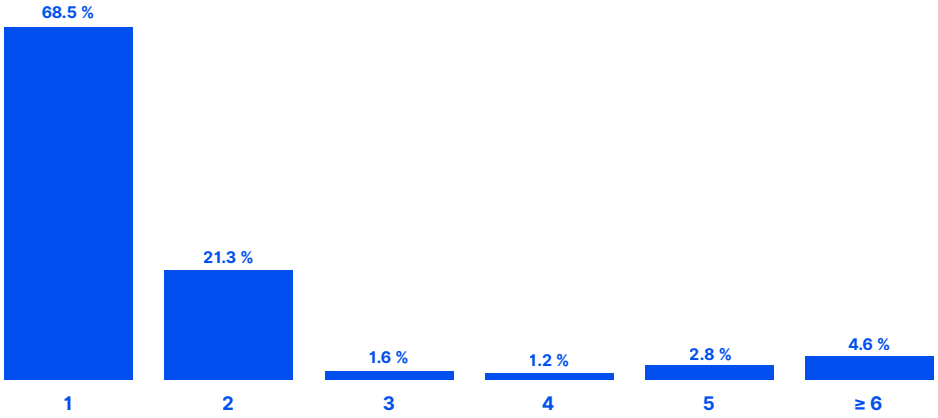
314 The preceding analyses show that increased market integration, new entry and the introduction of elastic balancing demand have reduced the occurrence of extreme balancing prices. This section examines selected remaining price incidents and the conditions under which they occurred. These include insufficient cross-zonal capacity limiting access to less expensive bids; technically flexible resources not appearing to respond to balancing-market price signals; and a thin merit order during the development of a new market.

Limited cross-zonal capacity can isolate bidding zones from less expensive bids

315 Balancing platforms optimise activations across bidding zones only to the extent allowed by the cross-zonal capacity made available to balancing. Where this capacity is insufficient, a TSO cannot access lower-priced bids available elsewhere on the common merit order. A shortage of local bids and the presence of a very expensive bid can consequently translate into an extreme local price event where less expensive balancing resources remain available in neighbouring areas.

316 Among the MTUs in which the most extreme price was outside ±1,000 EUR/MWh, that price was confined to one TSO area in 68.5% of Core PICASSO observations (Figure 80) and to one bidding zone in 81.7% of Nordic mFRR observations (Figure 81). Extreme prices were therefore predominantly local rather than common to the wider balancing region, indicating that the available cross-zonal capacity was insufficient to connect the affected area to the wider pool of balancing bids.

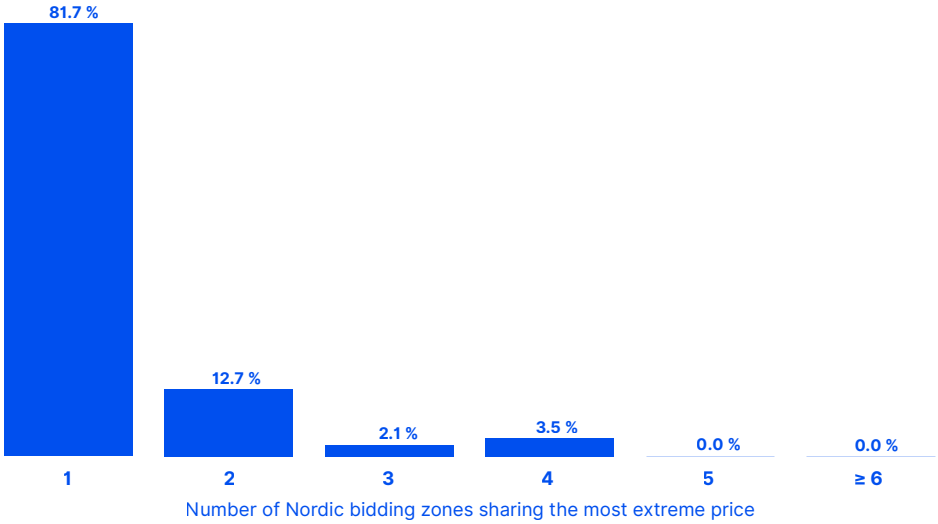
Figure 80: Distribution of the number of TSOs sharing the most extreme Core aFRR price when it is outside ±1,000 EUR/MWh – 2025 (%)



Source: ACER calculations based on data published by TransnetBW on PICASSO.

Note: An MTU is only counted if the most extreme price among Core region TSOs is outside ±1,000 EUR/MWh. TSOs outside the Core region can count towards the number of TSOs sharing that price but cannot, on their own, trigger an MTU's inclusion. In an MTU where several zones are simultaneously extreme, only the single most extreme zone's uncongested-area size is counted.

Figure 81: Distribution of the number of Nordic bidding zones sharing the most extreme mFRR price when it is outside ±1,000 EUR/MWh – 4 March 2025 to 3 March 2026 (%)

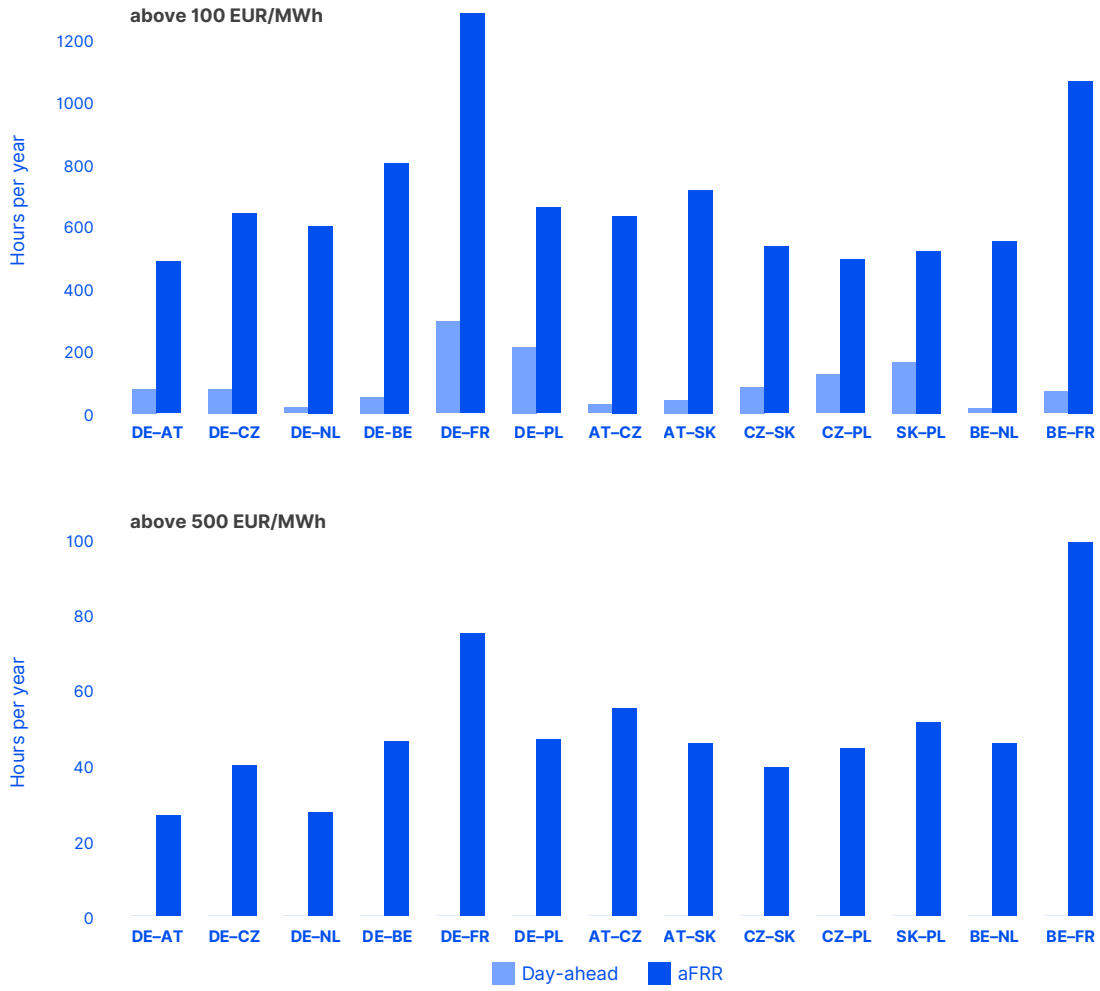


Source: ACER calculations based on ENTSO-E Transparency Platform data.

Note: An MTU is only counted if the most extreme price among Nordic-region TSOs is outside ±1,000 EUR/MWh. In an MTU where several zones are simultaneously extreme, only the single most extreme zone's uncongested-area size is counted.

317 Cross-border price differentials provide a further indication of the potential value of cross-zonal capacity in balancing. Across the Core borders, aFRR price differentials above €100/MWh occurred for more than 400 hours per year on every border, while differentials above €500/MWh occurred for more than 40 hours per year on most borders (Figure 82). Comparable price differentials occurred much less frequently in the day-ahead market. In the Nordic region, mFRR price differentials exceeding 100 EUR/MWh and 500 EUR/MWh also occurred repeatedly across most borders (Figure 83). These differentials reveal substantial opportunities to use cross-zonal capacity to replace expensive local activations with lower-priced bids from neighbouring areas. As discussed in Section 3.3, ATC extraction can significantly limit the cross-zonal capacity available after the day-ahead market in regions applying flow-based day-ahead allocation. Such limitations can restrict access to less expensive balancing resources and materially reduce balancing efficiency.

Figure 82: Annualised duration of cross-border price spreads above 100 EUR/MWh and 500 EUR/MWh in day-ahead and aFRR markets, Core borders – 2025 (h/year)

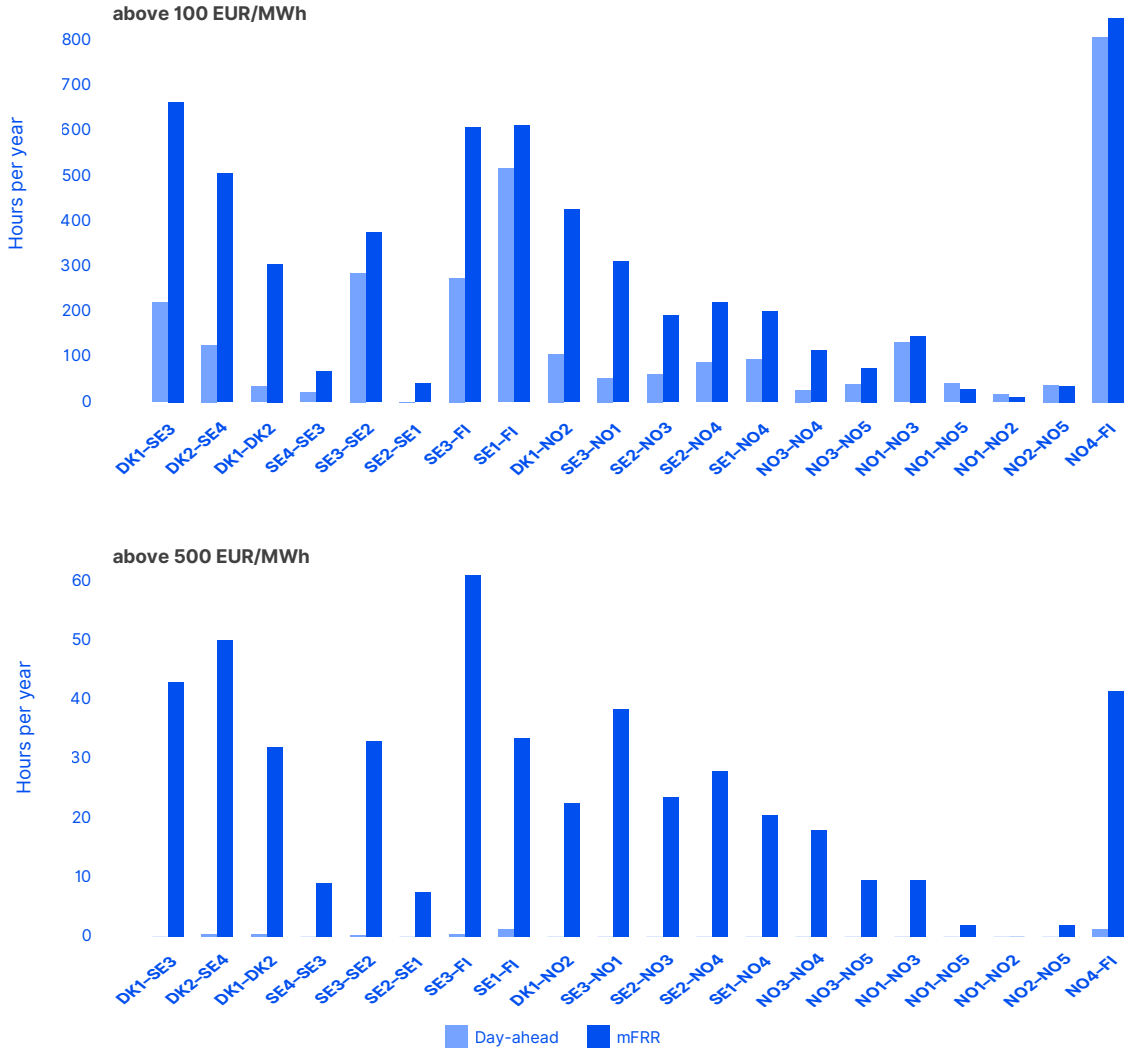


Source: ACER calculations based on ENTSO-E Transparency Platform and data published by TransnetBW on PICASSO.

Note: For borders where one of the two TSOs joined PICASSO after 1 January 2025, hours per year are annualised from the period available since that TSO's accession.

318 These findings also illustrate the benefit of applying a flow-based approach when allocating capacity to balancing energy exchanges. The magnitude of cross-border balancing-price differentials, and the borders on which they arise, can vary substantially between MTUs. Under an ATC approach, transfer capacity is divided ex ante into bilateral capacities for individual borders, before it is known where the largest balancing-price differentials will arise. Capacity assigned to one border cannot be redirected when a more valuable balancing exchange emerges elsewhere. A flow-based allocation instead assesses competing exchanges jointly against the underlying network constraints. It can therefore use the available capacity for the combination of balancing exchanges generating the greatest economic surplus in each MTU, improving access to less expensive bids and reducing the occurrence of extreme balancing prices.

Figure 83: Annualised duration of cross-border price spreads above 100 EUR/MWh and 500 EUR/MWh in day-ahead and mFRR markets, Nordic borders – 4 March 2025 to 3 March 2026 (h/year)

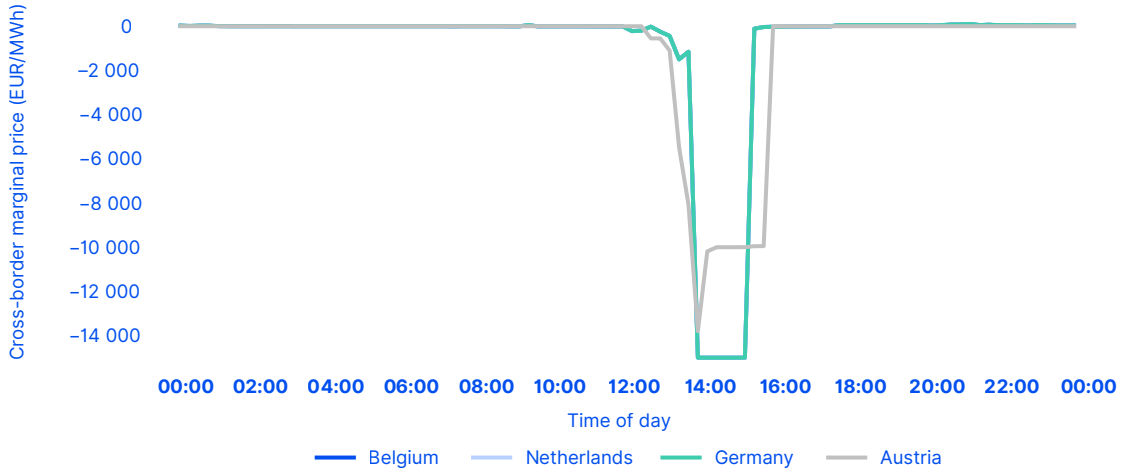


Source: ACER calculations based on ENTSO-E Transparency Platform data.

Extreme negative mFRR prices in the Core region on 6 April 2026

319 Figure 84 shows that the downward mFRR cross-border marginal price reached the technical floor of −15,000 EUR/MWh for several consecutive 15-minute periods on 6 April 2026 in Belgium and Germany. The same price was also calculated for the Netherlands, although Dutch BRPs were not exposed to it through imbalance settlement.[53] Austria also experienced extremely negative prices, but at a different level, indicating a cross-zonal capacity constraint between Austria and Germany. According to Elia's analysis of the incident, Belgium, Germany and Austria were simultaneously submitting downward mFRR demand, while much of the available downward mFRR was concentrated in the Iberian Peninsula and could not be accessed from the Belgium-Germany price area because of cross-zonal capacity constraints. Consequently, all downward mFRR bids accessible to that uncongested area were activated, causing the price to reach the technical floor.

Figure 84: Downward mFRR prices in selected Core bidding zones – 6 April 2026 (EUR/MWh)

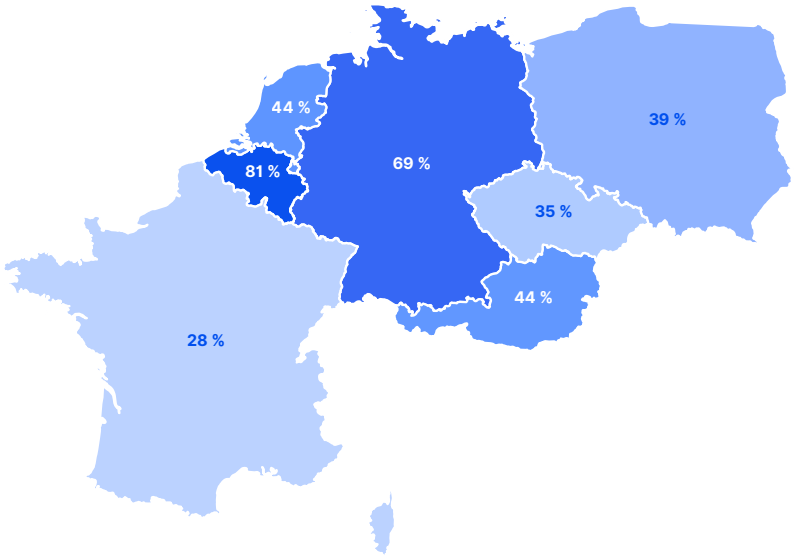


Source: ACER calculations based on ENTSO-E Transparency Platform data.

320 As shown in Figure 85, the event occurred around midday during a period of very high solar generation and low demand, the day being a bank holiday. Between 12:00 and 16:00, the share of load met by solar generation ranged from 28% in France to 81% in Belgium across the bidding zones shown (Figure 85). Realised solar output also exceeded the volumes anticipated in preceding market timeframes, contributing to larger-than-expected system surpluses and an increased need for downward regulation.

53 Although MARI calculated a cross-border marginal price of −15,000 EUR/MWh for the Netherlands, this price was not applied to the imbalance settlement of Dutch BRPs. In the Netherlands, TenneT was operationally connected but does not use MARI to meet Dutch balancing needs, and the MARI price therefore did not determine the imbalance price applied to Dutch BRPs. ENTSO-E also reports a cross-border marginal price of −15,000 EUR/MWh for France during these MTUs. France is excluded from Figure 84 and the analysis because RTE was not yet operationally connected to MARI for balancing-energy activation; it connected on 16 April 2026. A price was nevertheless calculated for the French bidding zone because RTE provided cross-zonal capacity to the platform, enabling exchanges between connected TSOs through France.

Figure 85: Solar generation as a share of load in selected Core bidding zones – 6 April 2026, 12:00 to 16:00 (%)



Source: ACER calculations based on ENTSO-E Transparency Platform data. For the Netherlands, forecast solar generation is shown because data on realised generation were unavailable.

321 Although solar generation has marginal operating costs close to zero, and its output can technically be reduced rapidly and with few operating constraints, the price of downward balancing energy became extremely negative. The key distinction is between flexibility that exists physically and flexibility that participates in the balancing timeframe. For example, rooftop solar behind the meter may be neither remotely controllable nor exposed to the balancing price signal. Even controllable installations may have weak incentives to curtail due to subsidy schemes as explained in Section 2.1. The event therefore suggests that potentially curtailable solar generation was not fully accessible or appropriately incentivised, rather than that the system lacked technically flexible resources.

Price incidents in the Baltic region

322 The Baltic incidents recorded in 2025 occurred while the common balancing arrangements were still developing and the merit order remained relatively thin. On 4 and 5 August 2025, activated mFRR bids reached 9,999 EUR/MWh during six quarter-hours. Following these events, the three Baltic regulatory authorities announced that they will conduct an in-depth analysis to assess whether market participants' bidding behaviour complied with REMIT.

Conclusion

323 Overall, market integration has substantially expanded the pool of balancing energy bids available for activation, contributing to greater price stability and lower balancing costs for BRPs. Further integration should build on these benefits by completing the connection of all TSOs to the European balancing platforms, implementing flow-based capacity allocation for balancing and enabling the widest possible range of technically capable resources to participate. Together, these measures would broaden the pool of competing bids accessible to TSOs and further strengthen effective cross-border competition.

5.2. Balancing capacity

324 Through balancing-capacity markets, TSOs procure capacity in advance to ensure that sufficient balancing-energy bids are available for activation close to real time. The resulting procurement costs are generally recovered through network tariffs and are therefore ultimately borne by electricity consumers. More efficient procurement can therefore reduce TSO costs and the costs passed on to consumers. Balancing-capacity markets remain less integrated than balancing energy markets. This section first examines existing regional balancing-capacity cooperations and how they can reduce procurement costs. It then assesses whether cross-border price spreads indicate that further integration of balancing capacity markets would be beneficial. The analysis subsequently examines how the entry of new assets and providers can strengthen competition and lower balancing-capacity procurement prices.

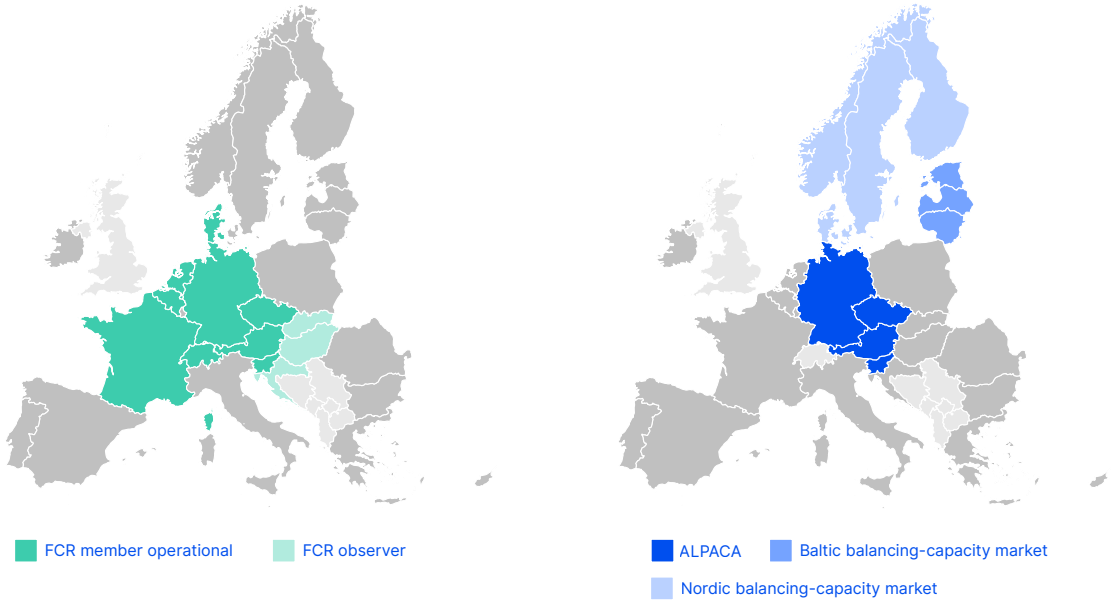
5.2.1. Existing balancing-capacity cooperations reduce procurement costs

325 Balancing capacity is procured for three main reserve products: FCR, aFRR and mFRR. Cross-border cooperation can reduce the cost of procuring these reserves in two ways. The exchange of balancing capacity allows a TSO to procure capacity from providers located in another bidding zone, thereby widening the pool of competing bids without reducing the total volume required. Reserve sharing allows the same capacity to contribute to the requirements of more than one TSO, thereby reducing the aggregate volume that must be procured. For example, if two TSOs require 300 MW and 200 MW respectively, exchanging 100 MW changes where part of the total 500 MW is procured. Sharing 100 MW allows that volume to count towards both requirements, reducing aggregate procurement to 400 MW.

326 The FCR Cooperation is the most geographically extensive regional balancing-capacity cooperation as illustrated in the left panel of Figure 86. In 2025, the TSOs of nine countries participated in the cooperation. Bids are jointly selected through a common optimisation that minimises procurement costs while ensuring that a minimum share of FCR is procured domestically and respecting limits on cross-border exchange. ENTSO-E estimates that the FCR Cooperation generated EUR 146.2 million in economic surplus in 2025 compared with separate national procurement. This illustrates the substantial benefits already delivered by the cooperation and indicates the potential for further gains from extending its geographical scope to additional TSOs.

327 Cross-border integration of aFRR and mFRR capacity markets remains less advanced than for FCR. The right panel of Figure 86 shows the geographical scope of the three aFRR and mFRR regional cooperations: ALPACA, the Baltic cooperation and the Nordic cooperation. They apply different models. The Baltic cooperation combines balancing-capacity exchange with reserve sharing, while the Nordic cooperation implements balancing-capacity exchange without reserve sharing. ALPACA also enables balancing-capacity exchange, using a forecast of the cross-zonal capacity expected to remain available after intraday trading based on a probabilistic method rather than reserving capacity from the day-ahead market. Table 4 summarises the product scope and the treatment of cross-zonal capacity in each cooperation.

Figure 86: Geographical coverage of regional balancing-capacity cooperation.



Source: ENTSO-E website.

Table 4: Product scope and treatment of cross-zonal capacity in regional cooperation.

Arrangement	Product scope	Cross-zonal capacity treatment
FCR Cooperation	FCR	Joint procurement while ensuring that a minimum share of FCR is procured domestically and respecting limits on cross-border exchange
ALPACA	aFRR	Forecast of capacity expected to remain available after intraday trading; no pre-allocation from the day-ahead market.
Nordic capacity markets	aFRR and mFRR	Market-based allocation between day-ahead energy exchange and balancing-capacity exchange. The mFRR market only involves Denmark, Finland and Sweden.
Baltic capacity market	aFRR and mFRR	Market-based allocation between day-ahead energy exchange and balancing-capacity exchange and reserve sharing.

Source: ACER.

Four indicators to quantify the benefits of aFRR and mFRR balancing-capacity cooperations

328 To assess the ALPACA, Baltic and Nordic cooperations, four scenarios ranging from separate national procurement to unconstrained cross-border procurement are defined (Table 5). Indicator 1 represents procurement without cooperation and serves as the baseline. Indicator 2 captures the observed outcome under the existing cooperation. Indicator 3 estimates what could have been achieved within existing network limits if cross-zonal capacity had been allocated with perfect foresight of the realised day-ahead price spreads. Indicator 4 removes cross-zonal-capacity constraints and therefore provides a theoretical lower bound on the modelled cost of balancing-capacity procurement and exchange.[54] Cooperation can also increase the volume of balancing-capacity demand satisfied. This additional satisfied demand is not monetised in the estimated benefits but is reported separately.[55]

54 Indicators 3 and 4 do not account for limits on the maximum volume of balancing capacity that may be exchanged across borders to ensure a minimum level of reserve availability nationally. These indicators could not be calculated for the Nordic cooperation based on the available data; the Nordic assessment therefore covers only Indicators 1 and 2.

55 The analysis does not capture changes in bidding behaviour resulting from the establishment of balancing-capacity cooperation. Increased competition could lead to lower bid prices, generating monetary benefits beyond those estimated. Conversely, the additional satisfied demand could be overestimated if higher-cost providers that participate in isolated markets cease submitting bids after coupling because they expect their bids will not be accepted.

329 Each comparison answers a different question. The cost difference between Indicators 1 and 2 measures the system cost savings delivered by the existing cooperation. The difference between Indicators 2 and 3 estimates the theoretical additional savings achievable by allocating the available cross-zonal capacity with perfect foresight of day-ahead price spreads. The difference between Indicators 3 and 4 indicates the remaining potential that cannot be realised because of network constraints.

330 For each indicator, total cost comprises balancing-capacity system cost and, where relevant, the foregone value of day-ahead trade resulting from the allocation of cross-zonal capacity to balancing capacity exchange. System cost is calculated by multiplying the bid price of each accepted bid by its accepted volume and summing across all accepted bids. When cross-zonal capacity is allocated to balancing capacity before the day-ahead market, the associated foregone value of day-ahead trade is calculated by multiplying the volume reserved for balancing by the maximum of 0 and the realised day-ahead price spread in the direction of the allocation. This represents the value that the capacity could otherwise have generated through day-ahead trade.

Table 5: Indicators used to quantify the benefits of balancing-capacity cooperations

Indicator	Scenario	Scenario definition	What the comparison shows
1	**Procurement without cooperation**	Each bidding zone meets its own requirement from local bids, without exchange or sharing.	Baseline against which cooperation is assessed.
2	**Observed cooperation**	Realised procurement outcome with the applicable cooperation	Compared with Indicator 1: savings delivered by the existing cooperation.
3	**Ex-post optimal cross-zonal capacity allocation**	Existing network limits remain, but available cross-zonal capacity is allocated using realised day-ahead price spreads and therefore with perfect foresight.	Compared with Indicator 2: theoretical additional savings achievable by allocating the available cross-zonal capacity with perfect foresight of day-ahead price spreads.
4	**Infinite cross-zonal capacity**	Cross-zonal capacity does not constrain either day-ahead trade or balancing-capacity exchange.	Compared with Indicator 3: additional potential currently constrained by the network. This is a theoretical lower bound on system costs.

Source: ACER.

331 Figure 87 compares the four cost indicators for the ALPACA and Baltic cooperations and the first two indicators for the Nordic cooperation. For ALPACA, compared with separate national procurement, the observed cooperation reduces estimated total system costs by EUR 21.0 million. Unlike in the Baltic and Nordic cooperations, however, cross-zonal capacity is not systematically reserved to support the balancing-capacity exchanges foreseen under ALPACA. Instead, the cooperation relies on a probabilistic assessment of the cross-zonal capacity expected to remain available close to real time. Consequently, there remains a risk that insufficient cross-zonal capacity is available to support the procured cross-border balancing capacity when it is needed. As an indication of the order of magnitude of the cost of eliminating this risk, reserving sufficient cross-zonal capacity in the day-ahead market to ensure the feasibility of these exchanges would entail an estimated foregone day-ahead market value of EUR 7 million. This illustrative estimate of the foregone day-ahead market value is equivalent to approximately 33% of the estimated cooperation benefit.

332 In the Baltics, cooperation reduces balancing-capacity system costs by EUR 891.1 million compared with separate national procurement. This mainly reflects reserve sharing, which reduces the volume of balancing capacity to be procured by 47% compared with the aggregate volume required if each Baltic TSO procured reserves nationally. The scope for reserve sharing is particularly significant because national dimensioning incidents, notably HVDC interconnector outages, are relatively large compared with the load in each Baltic bidding zone and are unlikely to occur simultaneously in several bidding zones. The same reserve capacity can therefore contribute to covering the needs of multiple TSOs. The allocation of cross-zonal capacity to balancing entails an estimated foregone day-ahead market value of EUR 44 million. After accounting for this foregone value, the overall system cost benefit amounts to EUR 847.1 million, illustrating the substantial cost savings enabled by the Baltic cooperation.

333 Beyond these cost savings, the Baltic cooperation also provides an important system security benefit by enabling a larger share of balancing-capacity demand to be met with the available supply. Under the separate national procurement counterfactual, 18.5% of reserve demand would remain unmet. By pooling resources through reserve sharing and balancing-capacity exchanges, the cooperation enables this otherwise unmet demand to be satisfied. This additional satisfied demand is reported separately and is not assigned a monetary value in the estimated benefit above. This highlights the key role of the Baltic cooperation in ensuring system security in the region.

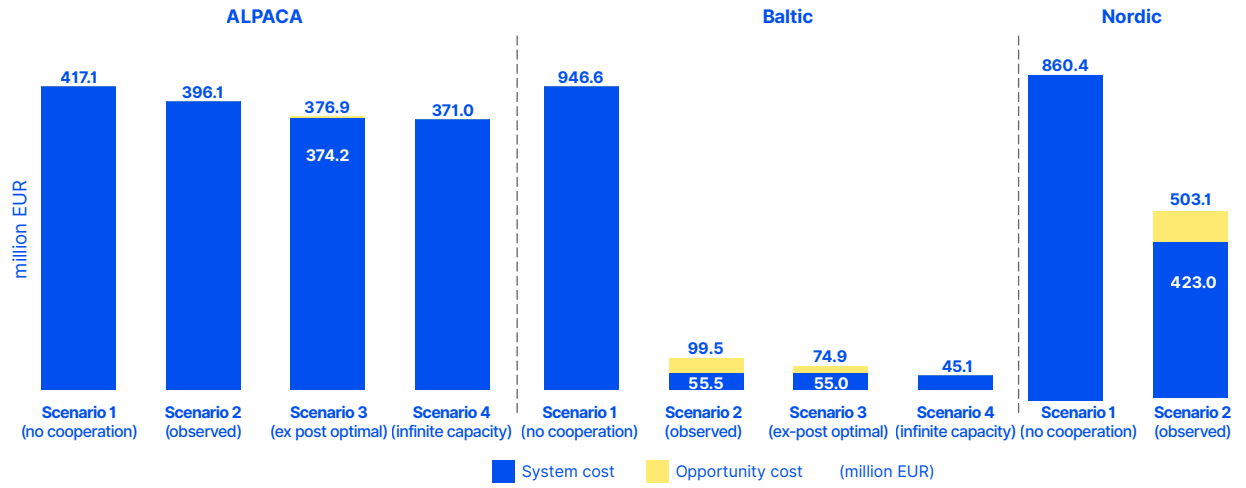
334 In the Nordic region, cooperation reduces balancing-capacity system costs by EUR 437.5 million compared with separate national procurement. The allocation of cross-zonal capacity to balancing entails an estimated foregone day-ahead market value of EUR 80.1 million. After accounting for this foregone value, the overall benefit amounts to EUR 357.3 million, illustrating the substantial cost savings enabled by the Nordic cooperation. As in the Baltic region, cooperation also enables a larger share of balancing-capacity demand to be met. Specifically, it satisfies additional demand equivalent to 8.52% of the total Nordic reserve requirement that would otherwise remain unmet under the separate national procurement counterfactual.

335 The difference between Indicators 2 and 3 represents the additional savings that could be obtained by allocating the available cross-zonal capacity with perfect foresight of day-ahead price spreads. It therefore provides a theoretical benchmark for the gains from better capacity allocation. For ALPACA, this difference amounts to EUR 19.2 million, which is in the same range as the estimated benefit of the cooperation under Indicator 2. Additionally, under Indicator 3, the estimated foregone day-ahead market value amounts to only EUR 2.7 million, compared with a EUR 21.9 million reduction in balancing-capacity system costs. This indicates that, in some MTUs, allocating cross-zonal capacity to balancing-capacity exchange can generate substantially greater benefits than making the same capacity available to the day-ahead market.

336 For the Baltic region, the corresponding additional savings amount to EUR 24.6 million, equivalent to approximately 2.9% of the EUR 847.1 million benefit estimated under the observed cooperation. Accordingly, the observed cooperation already captures around 97% of the total benefit estimated under the perfect-foresight benchmark in Indicator 3, indicating that it realises a very large share of the benefits obtainable with the available cross-zonal capacity.

337 The difference between Indicators 3 and 4 captures the remaining savings that would arise if cross-zonal capacity were no longer a constraint. These savings amount to EUR 5.9 million for ALPACA and EUR 29.8 million for the Baltic region. They represent approximately 24% and 55%, respectively, of the total savings remaining beyond the observed outcome. For ALPACA, this indicates that most of the remaining potential is associated with the allocation of existing cross-zonal capacity rather than with insufficient network capacity. In the Baltic region, the savings associated with removing network constraints are in the same range as those associated with better allocation of the existing cross-zonal capacity.

Figure 87: Balancing-capacity system costs and foregone day-ahead trade value under four cooperation scenarios, ALPACA, Baltic and Nordic regions (million EUR)



Source: ACER calculations based on ALPACA balancing-capacity data, Baltic and Nordic TSO computations and day-ahead prices.

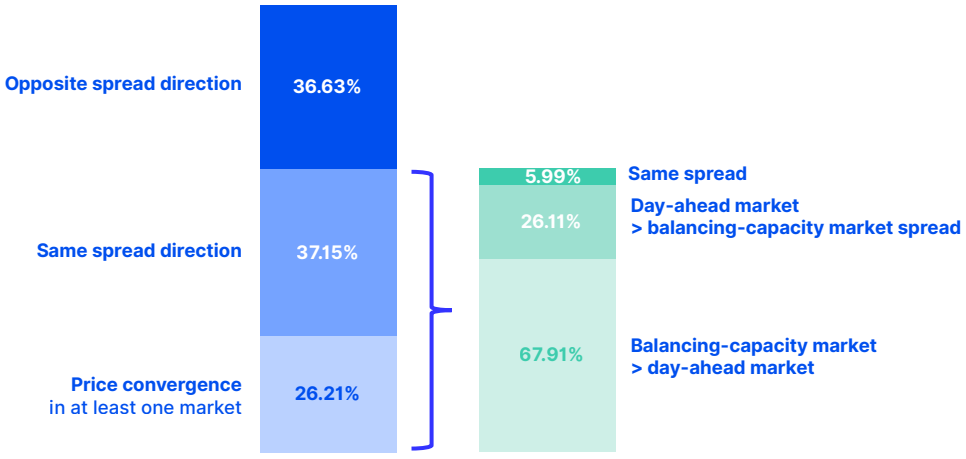
Note: The analysis covers 1 January–31 December 2025 for the Nordic cooperation, 1 October 2025–31 August 2026 for the Baltic cooperation, and 4 September 2025–31 May 2026 for ALPACA. Cost estimates refer to these respective periods and are not annualised.

338 Existing balancing-capacity cooperation nevertheless covers only parts of Europe. The following section assesses whether price patterns indicate scope for extending exchange to other areas.

5.2.2. Price spreads indicate further scope for balancing-capacity exchange

339 Cross-border price spreads provide an indication of where cross-border exchange of aFRR and mFRR balancing capacity may be valuable outside existing cooperation areas. The day-ahead price spread indicates the potential value of cross-zonal capacity for energy trade, while the balancing-capacity price spread indicates its potential value for balancing-capacity exchange. Comparing the direction and magnitude of the two spreads therefore helps identify where making cross-zonal capacity available for balancing-capacity exchange may be beneficial. Figure 88 maps the possible relationships between day-ahead and balancing-capacity spreads.

Figure 88: Direction and relative magnitude of balancing-capacity and day-ahead price spreads – 2025

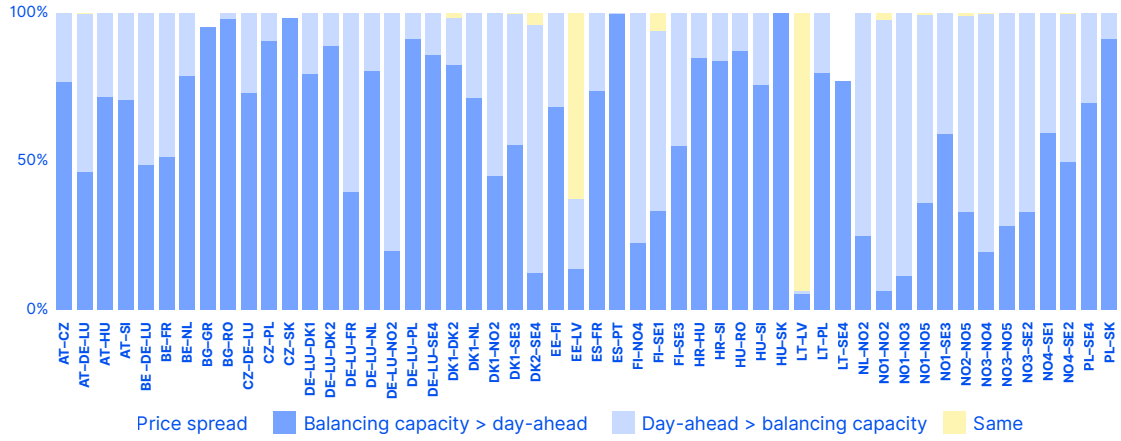


Source: ACER calculations based on ENTSO-E Transparency Platform data. The methodology is described in Annex V.

Note: Comparison of direction of price spreads between balancing capacity markets and day-ahead markets, 2025, left (%); and comparison of the absolute price spreads between markets, for cases where the direction of price spreads is not opposite, 2025, right (%).

340 In 2025, the balancing-capacity and day-ahead spreads pointed in opposite directions in 37% of observations, while the spread was zero in at least one of the two markets in 26% of observations (Figure 88). Opposite directions mean that the bidding zone with lower balancing-capacity prices is not the one with lower day-ahead prices. Cross-zonal capacity may therefore be valuable for balancing-capacity exchange in a direction different from that indicated by the day-ahead market. Excluding observations in which the balancing-capacity and day-ahead spreads pointed in opposite directions, the balancing-capacity spread exceeded the day-ahead spread in 68% of cases. In these cases, cross-zonal capacity may have a higher marginal value for balancing-capacity exchange than for additional day-ahead trade.

Figure 89: Comparison of the magnitude of balancing-capacity and day-ahead price spreads by border – 2025 (%)



Source: ACER calculations based on ENTSO-E Transparency Platform data.

Note: For each border, the figure covers observations in which the balancing-capacity and day-ahead spreads point in the same direction and compares the absolute price difference between the two bidding zones in the two markets.

341 Figure 89 provides the border-level breakdown for observations in which the two spreads point in the same direction. On many borders, the balancing-capacity spread exceeds the day-ahead spread in a large share of observations. This provides further evidence of potential benefits from making cross-zonal capacity available for balancing-capacity exchange, as it may have a higher value in reducing balancing-capacity procurement costs than in supporting additional day-ahead exchanges. On borders covered by the Baltic and Nordic cooperations, observations are more evenly split between cases where the day-ahead spread is larger and cases where the balancing-capacity spread is larger. This suggests that these arrangements have already captured a significant share of the potential benefit. By optimising the allocation of cross-zonal capacity between day-ahead energy exchange and balancing-capacity exchange, they have helped bring the two price spreads closer together.

5.2.3. New assets can strengthen competition and lower balancing-capacity costs

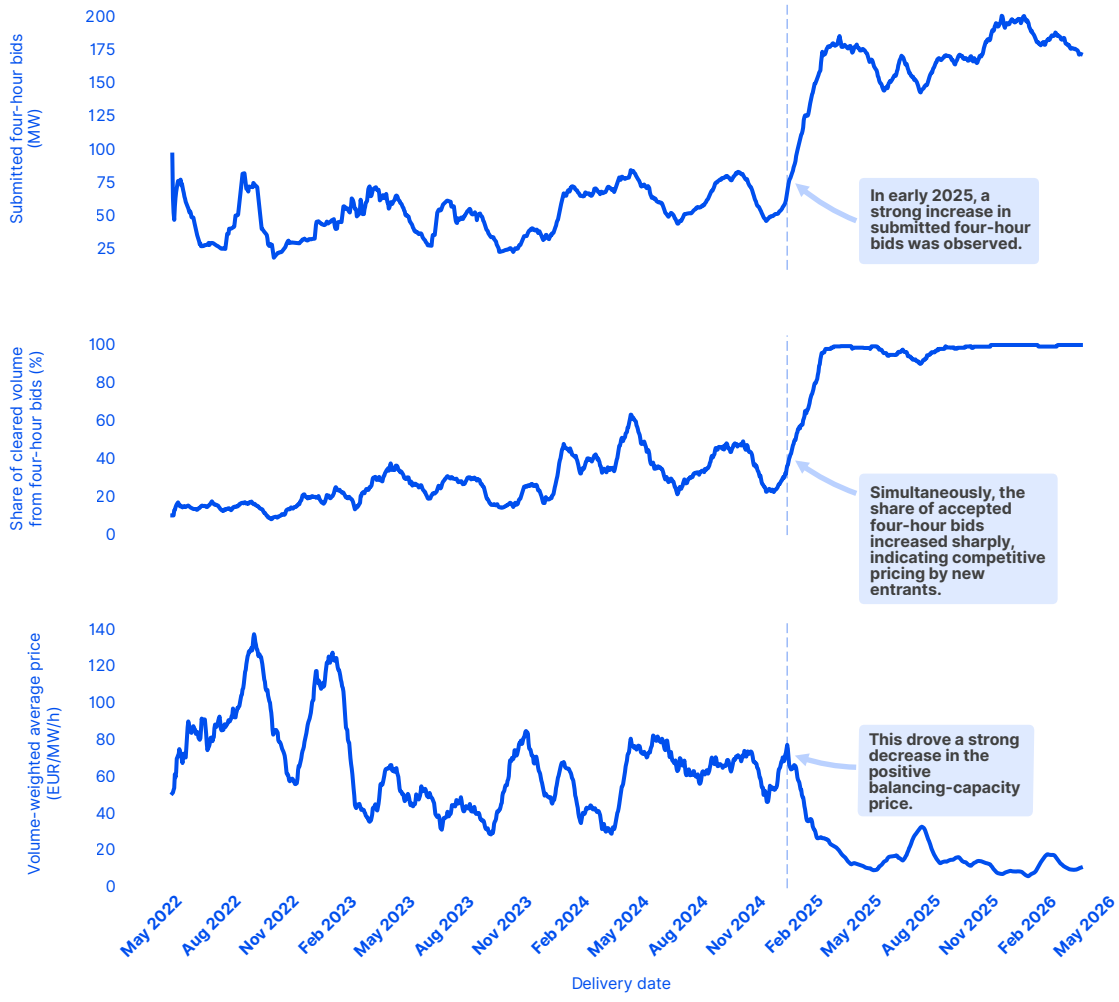
342 A notable development in balancing-capacity markets is the growing participation of new types of assets, including large-scale batteries and decentralised flexibility. Battery projects can be developed at a wide range of scales and often more quickly than conventional power plants, with lower upfront investment per project and simpler operating requirements. Aggregation can similarly allow smaller decentralised resources to participate collectively. These features can lower barriers to entry for new providers. This section examines developments in Belgium and the Baltic region and how new entries may affect competition and procurement prices.

Belgium: shorter aFRR capacity products and battery participation

343 In Belgium, all aFRR capacity is procured through a daily D-1 auction. Balancing service providers may submit 24-hour bids covering the full delivery day or four-hour bids for one of the six blocks. Whole-day bids are suited to the relatively large combined cycle gas turbines, which may need to recover start-up costs. Four-hour bids allow energy-limited resources, including batteries, to align their commitments with state-of-charge constraints and avoid remaining available for the entire day.

344 Figure 90 shows the development of the positive aFRR capacity market. Until the end of 2024, four-hour bids accounted for a limited share of accepted capacity. In early 2025, the volume submitted through four-hour bids increased sharply, and four-hour bids subsequently covered 100% of the procured aFRR capacity. The volume-weighted average procurement price fell sharply at the same time and remained lower through 2026. This illustrates that the entry of batteries and decentralised flexibility can reduce balancing-capacity procurement costs. These resources may be able to provide the service at a lower cost than conventional plants because they do not need to recover start-up costs or the costs associated with remaining online. Their entry can also strengthen competition.

Figure 90: Submitted four-hour upward bids, their share of accepted aFRR capacity and procurement prices in Belgium – May 2022-May 2026



Source: ACER calculations based on Elia individual aFRR balancing-capacity bid data.

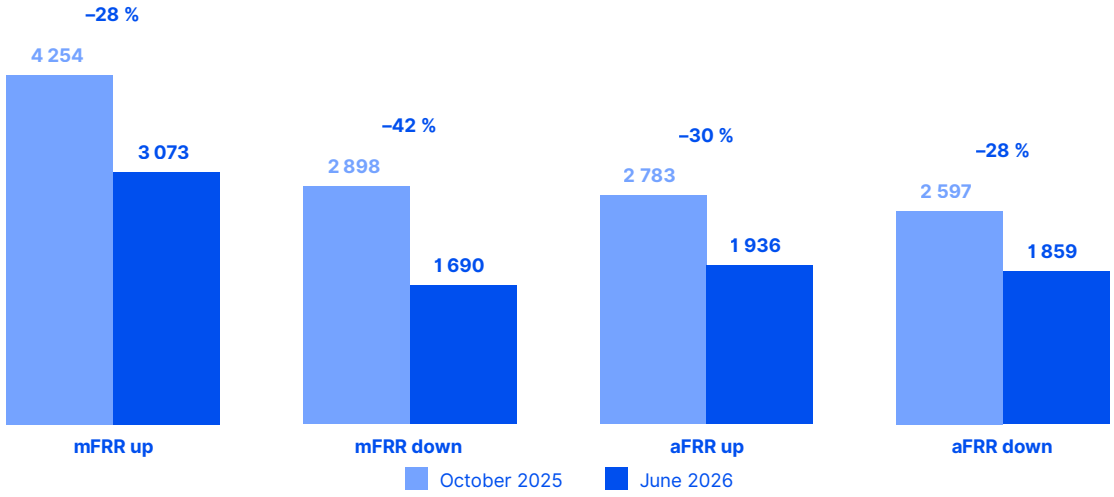
Note: The figure shows 30-day rolling averages to smooth daily fluctuations. The upper panel shows the volume of submitted 4-hour bids. The middle panel shows the share of accepted capacity awarded through four-hour bids. The lower panel shows the evolution of the volume-weighted average aFRR balancing-capacity price.

345 This analysis also illustrates the importance of product design. Product durations and requirements should accommodate the technical characteristics and cost structures of participating assets, allowing them to reflect their costs in their bids. The Belgian experience shows that four-hour products can facilitate the participation of batteries and other energy-limited resources. Germany has taken a further step to facilitate the participation of new types of assets. In October 2025, the introduction of additional 15-minute aFRR and mFRR capacity products alongside the existing four-hour products was approved.[56] The shorter products are intended to facilitate the participation of renewable resources, batteries and other flexible assets.

Baltic markets: lower concentration coincided with lower prices

346 In the Baltic region, several batteries entered the balancing-capacity market in 2025 and 2026. This additional participation increased competition in the market, as indicated by the decline in market concentration. Figure 91 reproduces the development of the Herfindahl-Hirschman Index (HHI) reported by Baltic TSOs, which decreased across all four balancing-capacity products between October 2025 and June 2026.

Figure 91: Balancing-capacity market concentration by reserve product in the Baltic region – October 2025-June 2026 (HHI)



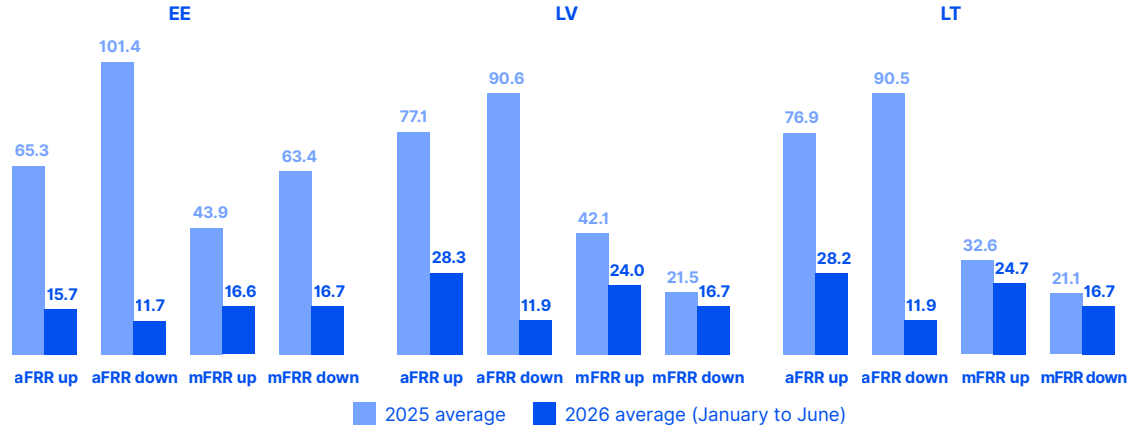
Source: Baltic TSOs, Evaluation Report 2026.

Note: HHI denotes the Herfindahl-Hirschman Index. Lower values indicate a less concentrated market.

347 The entry of new batteries and the accompanying increase in competition also coincided with a sharp decline in Baltic balancing-capacity prices, as shown in Figure 92. Prices in the first half of 2026 were below their 2025 averages for every product in Estonia, Latvia and Lithuania. The decline was particularly pronounced for downward aFRR, for which average prices fell from 91–101 EUR/MW/h to 12 EUR/MW/h. Taken together, the Baltic results provide further evidence that the participation of new types of assets can strengthen competition and reduce balancing-capacity procurement costs.

56 Bundesnetzagentur, Decision BK6-25-212, 28 October 2025.

Figure 92: Average balancing-capacity procurement prices by country and reserve product in the Baltic region – 2025 and January to June 2026 (EUR/MW/h)



Source: Baltic TSOs Evaluation Report 2026.

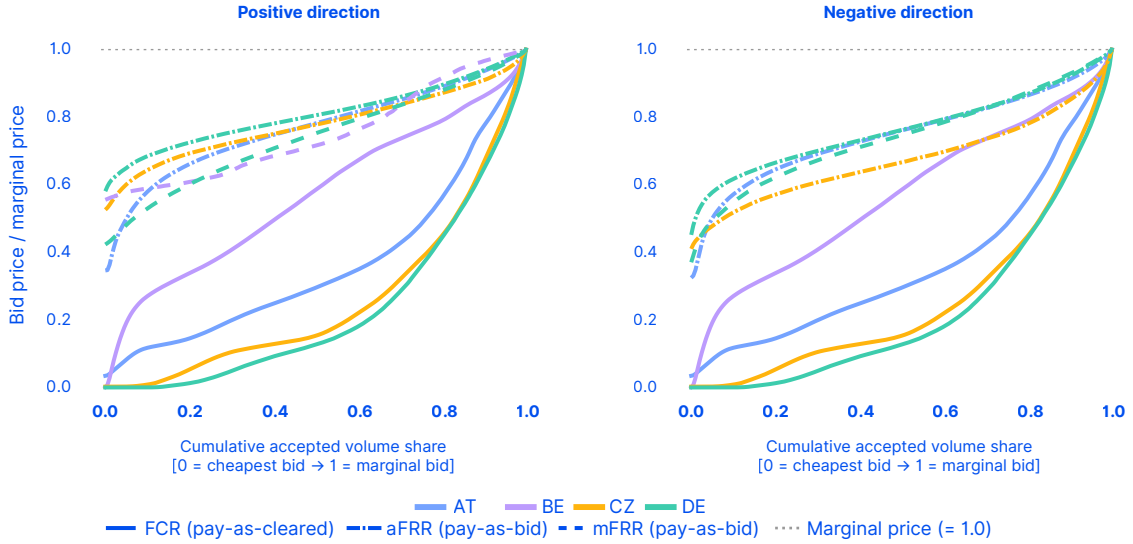
Note: Bars show average procurement prices in 2025 and from January to June 2026.

5.2.4. Pay-as-bid pricing would change bidding strategies, not reveal marginal costs

348 The choice between pay-as-bid and pay-as-cleared pricing is regularly discussed in both day-ahead and balancing-capacity markets. In the day-ahead context, several drawbacks of moving from pay-as-cleared to pay-as-bid pricing, including potential losses of market efficiency, were discussed in ACER's 2022 Final Assessment of the EU Wholesale Electricity Market Design. In the balancing-capacity context, ACER Decision No 11/2023 on the harmonised cross-zonal capacity allocation methodology also considered pay-as-bid and pay-as-cleared pricing and concluded that marginal pricing should apply to balancing-capacity procurement under the market-based allocation process to ensure equal treatment and consistent valuation of cross-zonal capacity across the day-ahead and balancing-capacity markets. Nevertheless, one argument sometimes advanced in favour of pay-as-bid pricing is that it could avoid the inframarginal payments associated with remunerating all accepted bids at the marginal accepted price. A theoretical counterargument is that participants would not continue bidding close to their marginal costs under pay-as-bid pricing. Because they would receive only their bid price, they would have an incentive to anticipate the marginal accepted bid and incorporate that expectation into their own bids. The analysis below tests this expectation against observed bidding patterns in balancing-capacity markets.

349 Balancing-capacity markets offer a useful basis for comparison because some balancing-capacity products apply pay-as-cleared pricing, while others apply pay-as-bid pricing. Figure 93 provides empirical evidence by comparing bids in these balancing-capacity markets that apply different pricing mechanisms. In pay-as-cleared markets, the first accepted bids are substantially below the marginal bid. In pay-as-bid markets, bids are much closer to it. This systematic difference supports the conclusion that market participants adapt their bidding strategies to the applicable pricing mechanism.

Figure 93: Accepted balancing capacity bid curves differ systematically between pay-as-cleared and pay-as-bid markets – July 2025-June 2026 (bid price relative to marginal accepted price)



Source: ACER calculations based on data from the German TSOs' Regelleistung.net platform and Elia.

Note: Bid prices are divided by the marginal accepted price in each market and direction. A value of 1 corresponds to the marginal accepted bid.

5.3. TSO balancing approaches and emerging challenges

350 Common European balancing platforms enable the joint optimisation of balancing energy bids across participating countries. However, they cover only part of the balancing process. National arrangements still differ both in how responsibilities are shared between TSOs and market participants close to real time and in the incentives created by imbalance settlement. Imbalance settlement defines how the imbalance price is calculated. The imbalance price is paid or received by market participants for deviations between their contracted positions and their actual injections or withdrawals. The way the imbalance price is determined, and in particular how it relates to balancing energy prices, therefore provides an important incentive for market participants in deciding how to use their flexible assets close to real time.

351 National arrangements for allocating balancing responsibilities can be categorised along a spectrum from more reactive to more proactive approaches. Under a reactive approach, BRPs are encouraged to respond to imbalance-price signals close to real time. Under a proactive approach, the TSO anticipates system imbalances and market participants are encouraged to offer their flexible resources explicitly in the balancing market. This section illustrates key features of these two stylised approaches without seeking to provide an exhaustive description of existing national practices. Table 6 summarises the main characteristics considered.

Table 6: Stylised comparison of reactive and proactive balancing approaches.

Dimension	Reactive approach	Proactive approach
Role of BRPs	Respond to the system imbalance close to real time.	Balance their portfolios in the intraday market and offer remaining flexible assets to the balancing market.
TSO use of mFRR	Uses mFRR mainly when available aFRR bids are exhausted.	Anticipates balancing needs and may request mFRR in advance.
Information signals	Near-real-time system imbalance information supports BRP reactions.	BRPs are generally not expected to react after the intraday cross-zonal gate closure time.[57]
Main incentive	Encourages BRPs to react to the imbalance price, typically through single pricing that can reward system-supporting deviations.	Encourages BRPs to remain balanced and offer flexibility explicitly, through measures such as setting different effective settlement prices for aggravating and non-aggravating imbalances and legal requirements.

352 The approach applied by each TSO reflects several system-specific factors. The availability and cost of resources with different activation times influence the reserve products procured and how early they may need to be activated. The approach also reflects how the TSO assesses the trade-off between decentralised and centralised coordination. A more decentralised approach enables BRPs to mobilise a broader range of flexibility, including resources that are not prequalified to participate directly in balancing markets, while competition between BRPs can strengthen incentives to improve forecasts of the system imbalance close to real time. On the other hand, a more centralised approach gives the TSO greater control over the timing and volume of adjustments, reducing the risk that uncoordinated BRP reactions overshoot the system's balancing needs.

353 The interaction with intra-zonal congestion management is another relevant factor influencing TSOs' choices between more proactive and more reactive approaches. Where the system frequently operates close to its network limits, balancing activations or BRP reactions may create or aggravate congestion close to real time. A more proactive approach may make it easier for the TSO to use its system-wide information to coordinate these adjustments and restrict actions that could threaten network security. The box below describes three stylised approaches to managing intra-zonal congestion close to real time.

354 The following sections examine the main implications of these approaches. Section 5.3.1 compares TSO activation strategies and their implications for the efficient use of flexible assets, while Section 5.3.2 compares national imbalance settlement approaches. Section 5.3.3 then considers how ongoing developments in the EU electricity system affect the two approaches.

57 Although BRPs are not expected to react to the imbalance price after the intraday cross-zonal gate closure time, their exposure to imbalance prices still incentivises them to balance their portfolios before that time.

How do TSOs manage intra-zonal congestion close to real time?

TSOs must ensure that balancing activations and BRP reactions do not create or aggravate intra-zonal congestion. Three stylised approaches can be distinguished, although they may be combined in practice.

First, redispatching ahead of real time. The TSO can resolve anticipated congestion and create sufficient operating margins through redispatch before the balancing timeframe. This preserves greater freedom for BRPs to adjust their positions close to real time. However, the TSO must anticipate the possible range of BRP reactions and maintain sufficient margins to accommodate them securely. Where congestion is frequent or BRP reactions are difficult to predict, this may require additional redispatch and leave network capacity unused. The suitability of this approach therefore depends on the frequency and complexity of congestion, the predictability of market-participant behaviour and the availability and cost of redispatch resources.

Second, preventing balancing actions from creating congestion. Rather than creating sufficient network margins in advance to accommodate all possible balancing actions, the TSO can control which actions take place close to real time. Both the activation of balancing bids submitted by BSPs and unscheduled reactions by BRPs can alter network flows and create or aggravate congestion. The TSO may therefore filter individual balancing bids or combinations of bids, or restrict BRP reactions in specific areas and directions.

In Belgium, the TSO currently identifies 10 electrical zones within the Belgian bidding zone and publishes a Congestion Risk Indicator for each zone in both directions. The indicator assesses whether an increase or decrease in net injection could create or aggravate congestion. This information can be used by the TSO to filter aFRR and mFRR bids and, where assets deviate from their schedules in a direction that aggravates congestion, request them to return to schedule. This approach leaves scope for BRP reactions where network conditions allow, while enabling the TSO to intervene where necessary.

In Norway, following the intraday cross-zonal gate closure time, BRPs are not expected to react to the imbalance price but to offer their flexible resources explicitly in the balancing market. This gives the TSO greater visibility over the location and volume of potential changes in injection and consumption. The TSO can then mark bids that could create or aggravate local congestion as unavailable before submitting the remaining bids to the common activation optimisation.

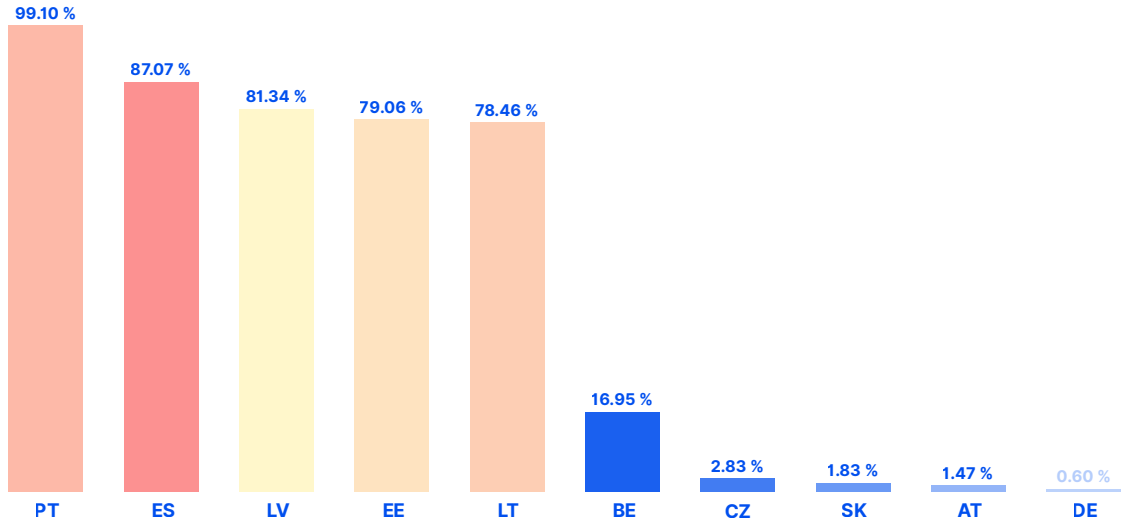
Third, jointly optimising balancing and congestion management. Under this approach, balancing needs and intra-zonal network constraints are included in the same optimisation, allowing the TSO to select the least-cost combination of actions that balances the system while respecting network constraints. This approach is used in US nodal markets and has also been applied within some national central-dispatch arrangements in the EU. A key difference concerns price formation: US nodal prices reflect the marginal cost of network constraints at each location, whereas EU zonal prices do not directly reflect the cost of resolving intra-zonal congestion.

5.3.1. Activation strategies range from proactive to reactive

355 A key difference between balancing approaches is how TSOs determine their balancing energy demand. More reactive TSOs rely mainly on aFRR and request mFRR only when additional balancing energy is needed. More proactive TSOs anticipate how balancing needs will develop and may request mFRR in advance.

356 This difference is clearly reflected in the frequency of non-zero mFRR demand, shown in Figure 94. In 2025, more proactive TSOs, such as the Portuguese, Spanish and Baltic TSOs, recorded non-zero mFRR demand in more than 75% of MTUs. By contrast, more reactive TSOs, such as the German, Austrian, Slovak and Czech TSOs, recorded non-zero mFRR demand in fewer than 3% of MTUs.

Figure 94: Share of MTUs with non-zero mFRR demand by country – 2025 (%)



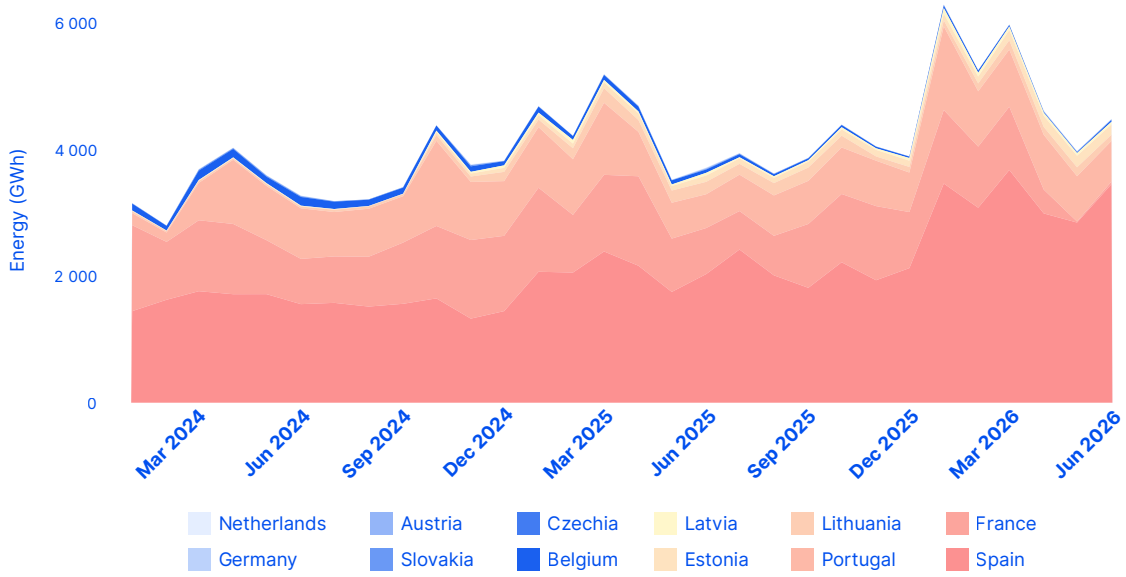
Source: ACER calculations based on ENTSO-E transparency data and national TSO data.

Note: Warm colours represent more proactive TSOs; cool colours represent more reactive TSOs.

357 Activated volumes show the same pattern in Figure 95. More proactive TSOs accounted for most activated mFRR volumes. Activated mFRR volumes from more reactive TSOs also decreased during 2025. One possible reason is greater access to aFRR following additional connections to PICASSO. As these TSOs use mFRR mainly when available aFRR is insufficient, access to a larger pool of aFRR bids reduces their need for mFRR. By contrast, mFRR activation volumes increased for some proactive TSOs. One possible explanation for this increase is the phase-out of TERRE[58] and the transfer to mFRR of balancing needs previously met by replacement reserves (RR).

58 TERRE was the European platform for the exchange of balancing energy from replacement reserves (RR). RR is a slower type of balancing reserve than mFRR.

Figure 95: Activated mFRR bid volumes by proactive and reactive TSO group – 2024-2026 (GWh)

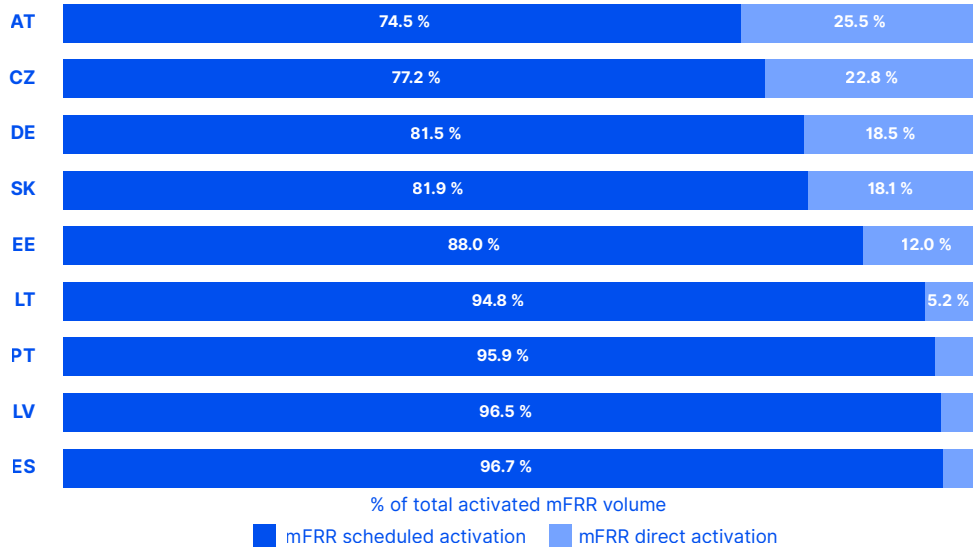


Source: ACER calculations based on ENTSO-E transparency data.

Note: Warm colours represent more proactive TSOs; cool colours represent more reactive TSOs. Partial-year 2026 observations cover 1 January to 30 June.

358 mFRR can be activated either through scheduled or direct activation. Scheduled activation occurs ahead of the delivery period, whereas direct activation allows TSOs to activate mFRR during the delivery period when additional balancing energy is needed. The relative use of direct and scheduled mFRR activation also reflects the distinction between balancing approaches. Reactive TSOs use direct activation for a much larger share of activated mFRR volumes (Figure 96), consistent with using mFRR mainly when additional balancing energy is needed close to real time. Proactive TSOs rely almost exclusively on scheduled activation because they anticipate how system imbalances will evolve.

Figure 96: Share of direct and scheduled mFRR activation volumes by country – 2025 (%)



Source: ACER calculations based on ENTSO-E transparency data.

Note: Values cover observations after each country's connection to MARI. DA denotes direct activation and SA denotes scheduled activation.

Different activation strategies can fragment short-term flexibility

359 The coexistence of different activation strategies across Europe can fragment the market for real-time energy. In broad terms, reactive TSOs leave BRPs to address as much of the system imbalance as possible, whereas proactive TSOs anticipate the imbalances they expect to face and activate balancing energy accordingly. Before the cross-zonal intraday gate closure, BRPs under both approaches can trade flexible assets across borders in the intraday market. Afterwards, however, flexible assets and system imbalances are increasingly handled through different mechanisms. Reactive TSOs rely more on aFRR and BRP reactions, while proactive TSOs rely more on mFRR activation. Table 7 illustrates this stylised split.

Table 7: Different activation strategies can split short-term flexibility across market segments

<table>
<tr><th>Approach</th><th>Cross-zonal intraday open</th><th>After cross-zonal intraday gate closure</th><th colspan="2">Close to real time</th></tr>
<tr><td>Reactive approach</td><td rowspan="2">Common cross-zonal intraday market:
BRPs trade flexible assets across borders</td><td>National intraday trading and self-balancing:
BRP-managed flexibility</td><td>BRP response</td><td>aFRR activation</td></tr>
<tr><td>Proactive approach</td><td>TSO manages flexible assets.
Explicit balancing bids; mFRR may be activated in anticipation</td><td colspan="2">aFRR activation</td></tr>
<tr><td colspan="5">Efficiency implication: flexible assets and balancing demand may be split across different market segments, limiting the scope for cross-zonal optimisation.</td></tr>
</table>

Source: ACER.

Note: Stylised illustration. Blue denotes BRP-managed flexibility; yellow denotes explicit balancing, where BSPs offer flexibility for activation by the TSO. In the reactive approach close to real time, both mechanisms coexist. Exact timing and national arrangements differ across TSOs.

360 This fragmentation can reduce efficiency in two ways. First, neighbouring TSOs may have balancing demand in opposite directions but express it through different balancing products. For example, one TSO may have positive mFRR demand while another has negative aFRR demand. As aFRR and mFRR are optimised separately, this opposing demand cannot be netted within the same optimisation. Second, flexible assets may be mobilised through different market segments. In a reactive system, BRPs are incentivised to respond to the system imbalance, so part of the adjustment is provided through BRP reactions or the local intraday market rather than explicit TSO balancing demand. If a neighbouring proactive TSO has mFRR demand in the opposite direction, the BRP adjustment cannot be matched against this demand in MARI, limiting the cross-border optimisation of flexible assets and demands. It could therefore be beneficial to explore different approaches that allow balancing needs and flexible assets currently expressed in different market segments to be coordinated more effectively across borders. Such an assessment should consider not only the potential gains in efficiency, competition and market integration, but also possible implications for system security, including those related to congestion management, and the transition costs associated with changing existing arrangements.

5.3.2. Imbalance settlement approaches reflect different operational objectives

361 Imbalance settlement determines the financial consequences of BRP imbalances. Imbalance prices are generally based on balancing energy prices, but the formulas used to calculate them remain national. These approaches differ partly according to whether TSOs follow a more reactive or proactive balancing strategy. Table 8 defines seven features used for comparison, and Table 9 summarises the results for the selected countries.

Table 8: Main features of imbalance settlement methodologies.

Feature	What it determines
Pricing method	Whether the main price component of imbalance settlement is the same for positive and negative BRP imbalances (single pricing) or differs between them (dual pricing).
Price direction	Whether the calculation uses balancing energy prices only in the dominant direction (direction of the system imbalance or satisfied demand) or also in the opposite direction.
Price formation	How the relevant balancing energy prices are combined, for example using the maximum price or a volume-weighted average.
System imbalance component	Whether an additional component adjusts the imbalance price when the system imbalance is large, strengthening the incentive for BRPs to reduce it.
Imbalance fee	Whether BRPs pay an additional charge for being imbalanced, strengthening the incentive to remain balanced.
Reference-market price floor	Whether an earlier market price, such as an intraday or day-ahead price, is used to set a floor for the imbalance price when the system is short and a ceiling when the system is long.
Real-time transparency	What information on the system imbalance and imbalance settlement is published close to real time, and when.

Source: ACER.

362 Austria, Germany and Czechia follow a reactive approach and use imbalance settlement to encourage BRPs to help balance the system close to real time. They link imbalance prices to intraday prices so that correcting an imbalance in the intraday market remains preferable to settling it at the imbalance price. They also use a system imbalance component that strengthens the price signal when the national system imbalance is large. The TSOs publish information close to real time, including the system imbalance, to support BRP reactions.

363 Belgium and the Netherlands follow a similar reactive approach but include features to limit instability within the imbalance settlement period. To incentivise BRP reactions, the Netherlands uses the highest relevant aFRR or mFRR price for upward balancing and the lowest for downward balancing, while Belgium applies a system imbalance component that can make the imbalance price more extreme when the national system imbalance is large. Both also include features that moderate the imbalance price when the direction of balancing conditions changes within the ISP. The Netherlands applies dual pricing under specified conditions when balancing activations occur in both directions, while Belgium considers a broader set of aFRR prices, irrespective of the direction of the system imbalance. These features can reduce the risk of an excessively strong price signal when the direction of balancing conditions changes within the ISP.

Table 9: Comparison of imbalance settlement features in selected countries.

Settlement approach	Reactive			Reactive with stability safeguards		Proactive through imbalance fee			Proactive through imbalance price formula			
Feature	**AT**	**DE**	**CZ**	**BE**	**NL**	**NO/SE**	**DK**	**FI**	**FR**	**PL**	**ES**	**PT**
Pricing method	Single	Single	Single	Single	Mixed (single/ dual)[59]	Single	Single	Single	Single[60]	Single	Mixed (single/ dual)	Mixed (single / dual)
Price direction	Dom. dir.	Dom. dir.	Dom. dir.	Both dirs.	Dom. dir.	Dom. dir.	Dom. dir.	Dom. dir.	Dom. dir.	Both dirs.	Dom. dir.	Dom. dir.
Price formation	VWA	VWA	Max. CBMP	max(mFRR, VWA aFRR)	Max. CBMP	Marg. mFRR	max(mFRR, VWA aFRR)	VWA	VWA	VWA	VWA	VWA
System imbalance component	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No	No
Imbalance fee	No	No	No	No	No	Yes	Yes	Yes	No	No	No	No
Reference-market price floor	Intraday	Intraday	Intraday	No	No	No	No	No	No	Day-ahead	No	No
Real-time transparency	SI	SI	SI + a/ mFRR act. vol.	SI + act. vol. & price	SI + act. vol. & price	After ISP	aFRR	mFRR act. + price	After ISP	After ISP	After ISP	After ISP

Source: ACER based on national imbalance settlement methodologies.

Note: SI denotes system imbalance; ISP denotes imbalance settlement period; CBMP denotes cross-border marginal price; VWA denotes volume-weighted average. References to "Max. CBMP" or max(mFRR, VWA aFRR) describe the short-system case; in the long-system case, the corresponding minimum applies. Mixed (single/dual) means that single pricing applies in some ISPs and dual pricing in others, depending on predefined conditions. The table provides a stylised overview; detailed formulas and parameters differ by country. Colour coding is indicative: yellow highlights features that tend to support a more proactive approach, for example by discouraging implicit BRP response, while light blue highlights features that tend to support a more reactive approach by strengthening or enabling real-time BRP response; grey denotes features without a clear directional implication. Some country-specific elements are simplified: the Nordic settlement includes a day-ahead fallback where no balancing activation occurs; and Czechia can switch from the highest bid to a weighted average above a defined price level.

59 The Netherlands, Spain and Portugal apply mixed pricing arrangements under which single or dual pricing may apply depending on balancing activation within the ISP. Spain applies dual pricing when FRR energy is activated in both directions and the volume activated in the smaller direction exceeds 2% of that activated in the other direction. Portugal applies the same principle with a threshold of 10%. In the Netherlands, dual pricing applies under regulation state 2, when balancing energy is activated in both the positive and negative directions within the same ISP and the requested activation volume does not move consistently in one direction. Single pricing applies when these respective conditions are not met.

60 France applies the same volume-weighted average price of balancing activations in the system direction irrespective of the direction of the BRP imbalance. Nevertheless, the neutrality component intended to ensure the TSO's financial neutrality results in different effective settlement prices for positive and negative imbalances.

364 Among proactive TSOs, two main approaches encourage explicit participation in balancing. Nordic TSOs use an imbalance fee. BRPs that remain imbalanced pay an additional charge, which encourages them to keep their portfolios balanced rather than deliberately deviate from their contracted positions to help balance the system. This encourages flexible assets to be offered through balancing bids.

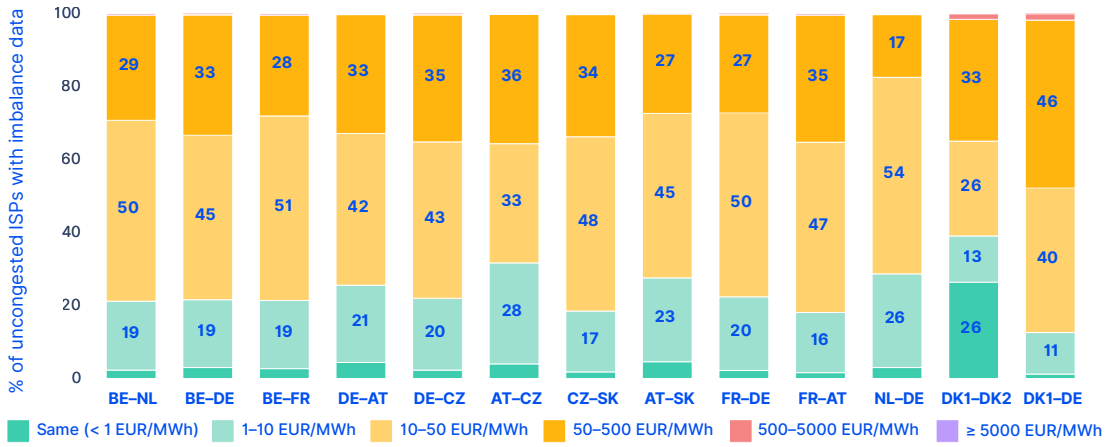
365 France, Poland, Spain and Portugal support a proactive approach mainly through the imbalance price formula and the timing of information publication. However, the precise mechanisms differ for the different countries. France applies single pricing based on a common volume-weighted average price of balancing activations in the system direction, although a neutrality component creates a spread between the effective settlement prices for positive and negative imbalances. By contrast, Spain and Portugal apply mixed arrangements under which single pricing applies in some ISPs and dual pricing in others. In 2025, dual pricing applied in 65% of ISPs in Spain and 71% of ISPs in Portugal, making it the predominant pricing outcome in both countries. When dual pricing applies, aggravating and non-aggravating BRP imbalances are settled at different prices. Aggravating imbalances are settled at a price reflecting the balancing energy activated to address the system imbalance, while non-aggravating imbalances are settled at a less advantageous price and therefore do not fully benefit from the value of their contribution to system balancing. Poland instead considers a broader set of aFRR prices, irrespective of the direction of the system imbalance, which moderates the price signal. These countries also do not apply an intraday price floor or a system imbalance component designed to strengthen BRP reactions close to real time.

366 Although the specific mechanisms differ, the French, Nordic, Portuguese and Spanish arrangements have the same broad incentive effect: they make deliberate deviations from contracted positions less attractive by creating a spread between the effective settlement prices for positive and negative imbalances. The Nordic countries achieve this through an explicit imbalance fee, France through its neutrality component, and Spain and Portugal through dual pricing in the relevant ISPs. In each case, the resulting settlement discourages BRPs from deliberately remaining out of balance.

367 This analysis shows that TSOs design their imbalance settlement arrangements to support their broader approach to balancing the system. Imbalance settlement should therefore not be considered in isolation, but as part of the wider balancing design. Nevertheless, differences between internally consistent national designs can still have cross-border implications.

368 Figure 97 illustrates one such implication by considering only ISPs in which aFRR and mFRR prices were identical on both sides of the border. Across most borders shown, imbalance prices differed by more than 50 EUR/MWh in around 30% of these ISPs. In systems where BRPs are expected to respond to the imbalance price, different price signals within the same uncongested area may cause comparable flexible resources to respond differently, limiting their efficient use across borders. These differences also expose BRPs engaged in cross-border trading to different imbalance costs and risks under otherwise comparable balancing conditions, which may affect the level playing field and limit their ability to hedge imbalance risk across borders.

Figure 97: Distribution of cross-border imbalance price spreads when aFRR and mFRR prices are identical on both sides of the border – 28 November 2024 to 31 December 2025 (%)



Source: ACER calculations based on ENTSO-E transparency data.

Note: The sample includes only imbalance settlement periods in which aFRR and mFRR prices were identical on both sides of the border. Categories show the absolute difference between imbalance prices.

5.3.3. Structural developments in electricity markets affect balancing approaches differently

369 Several developments are changing conditions in the balancing timeframe: deeper cross-border balancing integration, more decentralised and faster flexibility, increasing network congestion and greater uncertainty. Their effects differ between reactive and proactive approaches. This section considers these differences.

Cross-border balancing integration increases the need for consistent BRP and BSP incentives

370 Before the introduction of the European balancing platforms, BSP activations and BRP imbalance incentives mainly reflected national system conditions and were therefore more naturally aligned. The platforms now optimise BSP activations across borders within the wider uncongested area. In reactive systems, BRPs may still respond to an imbalance price based on the national system imbalance. The two signals can therefore differ in direction or strength. For example, the platform may activate BSPs to increase production in a bidding zone to meet balancing demand in another while the national imbalance price encourages BRPs in the same bidding zone to reduce production. Such differences can increase balancing costs by encouraging the use of higher-cost resources while cheaper alternatives remain available. Where the signals induce opposing responses, these can also partly offset each other and increase the balancing volumes required. Annex V provides examples of differences in both the direction and strength of these incentives. To achieve efficient coordination of flexible assets across Europe, market incentives should support their efficient dispatch across borders while accounting for network congestion.

Growing decentralised flexibility changes access to balancing

371 The growth of decentralised flexibility, including batteries, demand response and distributed generation, increases the flexibility available close to real time. Reactive approaches can access some of it indirectly through BRPs because resources that do not individually meet all prequalification[61] or product requirements can still contribute through a BRP's portfolio.

61 Prequalification is the process through which a TSO verifies that a resource or portfolio meets the technical requirements necessary to provide a specific balancing service, such as aFRR or mFRR. These requirements and the barriers they can create for smaller and distributed resources are analysed in ACER's 2025 report on barriers to demand response.

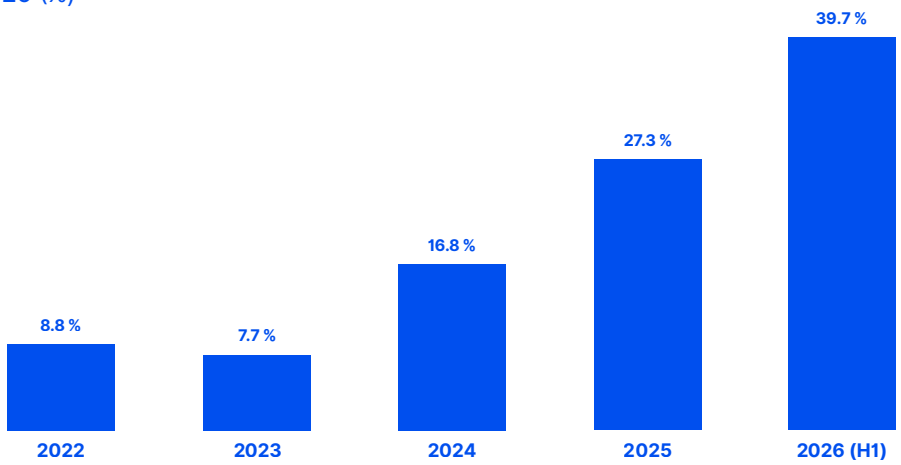
372 Proactive approaches rely more on explicit participation in balancing. Decentralised resources must therefore be prequalified, and BSPs must submit balancing energy bids for those resources to remain available in the balancing timeframe. As their share grows, prequalification and product requirements need to facilitate participation. Otherwise, physically available flexibility may not be accessible to the TSO.

Faster flexibility can amplify intra-ISP instability

373 Faster-responding assets allow market participants to adjust positions more quickly. This supports system balancing but can create coordination challenges in reactive systems. BRPs are settled on their average imbalance over the ISP and may react strongly in the final minutes of a 15-minute period to correct their average position in the ISP. If many BRPs react at the same time, they can create a large instantaneous system imbalance even while improving their individual imbalance settlement period positions.

374 This can lead to overshoot and repeated changes in the direction of the system imbalance. The risk may increase as batteries and other fast-responding resources account for a larger share of flexibility, because larger volumes can react almost instantly to the same signal. Figure 98 illustrates an increase in intra-ISP variability in the Dutch system. Specifically, it shows the percentage of ISPs for which dual pricing is applied in the Netherlands. This can occur when balancing resources are activated in both directions during the ISP. The Dutch TSO has also reported[62] imbalance oscillations in the Netherlands where the system balance changed by more than 1,000 MW within a few minutes, switching from long to short or vice versa. The report from the Dutch TSO also states that similar oscillations have been observed by other TSOs, although of lower magnitude. From a system-operation perspective, such rapid changes can occur faster than load-frequency control can compensate for them, thereby degrading frequency quality and potentially increasing the amount of aFRR and FCR capacity that needs to be procured.

Figure 98: Share of imbalance settlement periods with dual pricing in the Netherlands – 2022 to June 2026 (%)



Source: ACER calculations based on TenneT data.

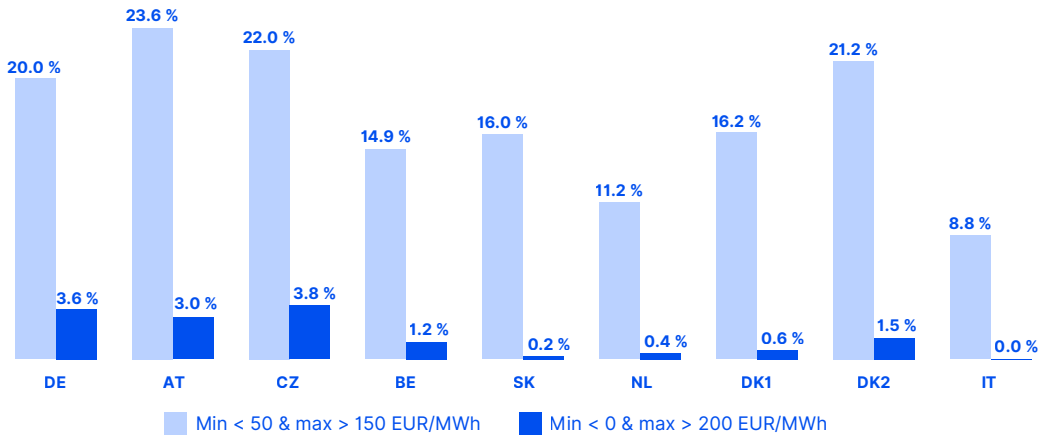
Note: The 2026 value covers the first half of the year.

375 A related challenge is that balancing conditions can vary substantially within a 15-minute ISP. Figure 99 shows that, in many countries, a material share of ISPs in 2025 contained aFRR prices typically associated with both positive and negative activations. A single imbalance price cannot fully reflect all conditions within such an interval. This is particularly relevant in reactive systems, where the imbalance price also guides BRP behaviour close to real time.

62 TenneT, Summary balance delta publication (November 2024).

376 These coordination challenges are expected to be less pronounced in proactive systems because BRPs are not expected to respond to the real-time imbalance signal and fast flexible assets can be coordinated through explicit TSO activation, provided the resources can participate in balancing markets. At the same time, intra-ISP price variation still matters for financial settlement because one imbalance price must represent the whole imbalance settlement period.

Figure 99: Share of imbalance settlement periods with aFRR prices below and above specified thresholds by TSO area – 2025 (%)



Source: ACER calculation based on TransnetBW data.

Note: Dark blue: aFRR price minimum < 0 EUR/MWh and maximum > 200 EUR/MWh; light blue: minimum < 50 EUR/MWh and maximum > 150 EUR/MWh within the same imbalance settlement period.

Increasing congestion challenges the separation between balancing and congestion management

377 As congestion increasingly affects real-time operations, the location of balancing activations becomes more important. More granular locational pricing is the only market-based solution that can systematically reflect network constraints in decentralised dispatch incentives. Without it, TSOs must intervene in the market to prevent balancing activations or BRP reactions from creating or worsening congestion.

378 These TSO interventions are easier under a proactive approach, where flexible assets are offered through explicit balancing bids. This gives the TSO visibility of possible activations and allows it to filter or restrict bids whose activation would worsen network constraints. Under a reactive approach, BRP responses occur outside the balancing platform and are less visible and controllable. TSOs may therefore need to restrict BRP behaviour, for example by requiring schedule-following when network constraints arise. Such interventions can mitigate the operational consequences of congestion, but they may create inefficiencies because they seek to prevent market participants from following their financial incentives, which do not reflect the underlying network constraints.

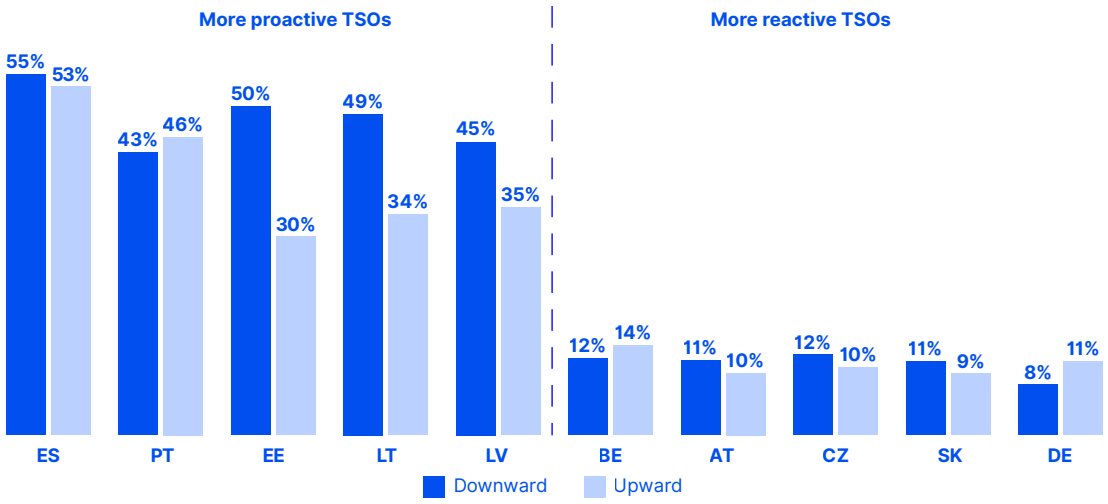
379 With congestion playing an increasingly important role, keeping balancing and congestion management largely separate may become less efficient. This raises the question of whether the two processes can continue to operate as distinct layers or need to be integrated more closely so that flexible assets are used efficiently for both system balance and network security.

Greater uncertainty increases the need to secure sufficient flexibility close to real time

380 Higher shares of variable renewable generation increase uncertainty between day-ahead and real time. Sufficient flexible assets must therefore remain available to accommodate forecast errors and unexpected changes closer to delivery. In reactive systems, this does not necessarily increase explicit TSO balancing demand to the same extent because BRPs are expected to mobilise part of the flexible assets outside the balancing platforms. Proactive TSOs take more responsibility for covering imbalances and therefore need enough balancing energy bids to restore system balance.

381 Figure 100 illustrates one operational consequence. In more proactive systems, scheduled mFRR activations in the same direction often persist for several MTUs, while prolonged activations are much less common in more reactive systems. This is consistent with BRPs correcting persistent imbalances to a greater extent in reactive systems, while proactive TSOs manage them explicitly for longer. Proactive TSOs therefore need sufficient resources to sustain balancing activation and typically perform forward-looking security analyses. Where resources may be insufficient, they can request market participants to start units or keep them available.

Figure 100: Share of same-direction scheduled mFRR activation sequences lasting at least one hour – 2025 (%)



Source: ACER calculations based on ENTSO-E Transparency Platform data.

Note: The figure shows the share of same-direction scheduled mFRR activation sequences lasting at least four consecutive 15-minute MTUs. TSO areas are grouped according to the stylised proactive/reactive classification used in this section.

382 These different approaches can also fragment short-term liquidity. In more reactive systems, decisions to bring additional resources online are largely left to market participants, and these decisions can be reflected in cross-zonal intraday trading. In more proactive systems, forward-looking security analyses may lead TSOs to request specific units to start or remain available, usually through national processes. A need that could otherwise be met through the cross-zonal intraday market may therefore be addressed nationally, limiting competition between resources across Member States.

Summary of upcoming balancing challenges

383 Table 10 summarises how the five developments affect the two high-level balancing approaches.

Table 10: Implications of structural developments for reactive and proactive balancing approaches.

Structural development	Reactive approach	Proactive approach
Cross-border balancing integration	National BRP signals can diverge from platform-wide BSP activations.	Flexible assets are mainly optimised through the common balancing platforms.
Decentralised flexibility	Resources can contribute through BRP portfolios without prequalification.	Requires accessible prequalification processes.
Faster flexibility	Simultaneous reactions can cause intra-ISP overshoot.	Fast flexibility can be coordinated through explicit TSO activation.
Increasing congestion	Where imbalance prices do not reflect intra-zonal network constraints, BRP reactions may create or aggravate congestion and are more difficult for the TSO to control; schedule restrictions may be needed.	Where market prices do not reflect intra-zonal network constraints, TSOs may use locational information on explicit bids to filter or restrict those that could create or aggravate congestion.
Greater uncertainty	BRPs use flexible assets for intraday trading.	TSOs need sufficient balancing energy bids and may need to secure resources in advance, which can withdraw flexible assets from the intraday market and split liquidity across market segments.

Source: ACER.

384 These developments create different challenges for reactive and proactive TSOs. For reactive systems, a key challenge is to maintain consistent incentives for BSPs and BRPs, while ensuring that BRP reactions do not aggravate network congestion or create instability when the imbalance price does not sufficiently reflect locational or intra-ISP conditions. For proactive systems, a key challenge is to ensure that decentralised flexibility can be prequalified and participate effectively in balancing markets. Proactive TSOs also need to ensure that sufficient balancing resources remain available, while limiting fragmentation between national processes used to secure these resources and the cross-zonal intraday market. For both approaches, the growing prevalence of congestion strengthens the case for market signals that better reflect the location of flexible assets and network constraints, rather than relying on TSO interventions that prevent market participants from responding to existing price signals.

6. Market integration of the Energy Community

385 The Energy Community[63] is an international organisation bringing together the EU and its neighbours in South-East Europe and eastern Europe to create an integrated pan-European energy market since 2006. Its key objectives are to extend the EU internal energy market rules and principles to these countries based on a legally binding framework, and to create a regulatory and market framework capable of attracting investment for a stable and continuous energy supply.

386 This section examines the integration of the Energy Community contracting parties into SDAC. Firstly, it reviews the status of the transposition of the electricity integration package (EIP) into the national legislation of the Energy Community contracting parties. Secondly, it describes the evolution of wholesale electricity prices and price convergence in South-East Europe. Finally, it estimates the economic surplus gains that could result from coupling the borders between the Energy Community contracting parties and with the neighbouring EU Member States.

6.1. Status of market regulation transposition into national legislation

387 As part of the Energy Community's coordinated market reforms, the EIP, which includes nine legal acts incorporating the EU electricity market legislation in the Energy Community, sets the framework for integrating national markets into the EU's single market for electricity.

388 Table 11 shows the status of EIP transposition into national legislation and its verification process, for each Energy Community contracting party, as of 1 October 2026.[64]

Table 11: EIP – status of transposition into national legislation and of the verification process, as of 1 October 2026

EnC Contracting Party	Four legal acts from CEP (ED, ER; ACER and Risk-Preparedness) – adapted versions	Five NC&GL (FCA, CACM, EBGL, SOGL and ER NC) – adapted versions	Status of verification of the compliant transposition
Albania	Law aimed to transpose adopted	NRA acts aimed to transpose adopted	Not yet started
Bosnia and Herzegovina	Laws in the parliamentary procedure	Pending	Not yet started
Georgia	n/a	n/a	n/a
Kosovo*	Laws in the parliamentary procedure	Pending	Not yet started
Moldova**	Full transposition notified to EnCS	Full transposition notified to EnCS	In progress
Montenegro***	Full transposition notified to EnCS	Full transposition notified to EnCS	In progress
North Macedonia****	Full transposition notified to EnCS	Full transposition notified to EnCS	On hold

63 The Energy Community comprises the EU Member States and Albania, Bosnia and Herzegovina, North Macedonia, Georgia, Kosovo*, Moldova, Montenegro, Serbia and Ukraine. Armenia, Türkiye and Norway are observer countries. Throughout this section the symbol * refers to the following statement: This designation is without prejudice to positions on status, and is in line with UNSCR 1244/1999 and the ICJ Advisory Opinion on the Kosovo* declaration of independence.

64 The Energy Community Secretariat collected and provided this information to ACER and remains solely responsible for its accuracy and completeness.

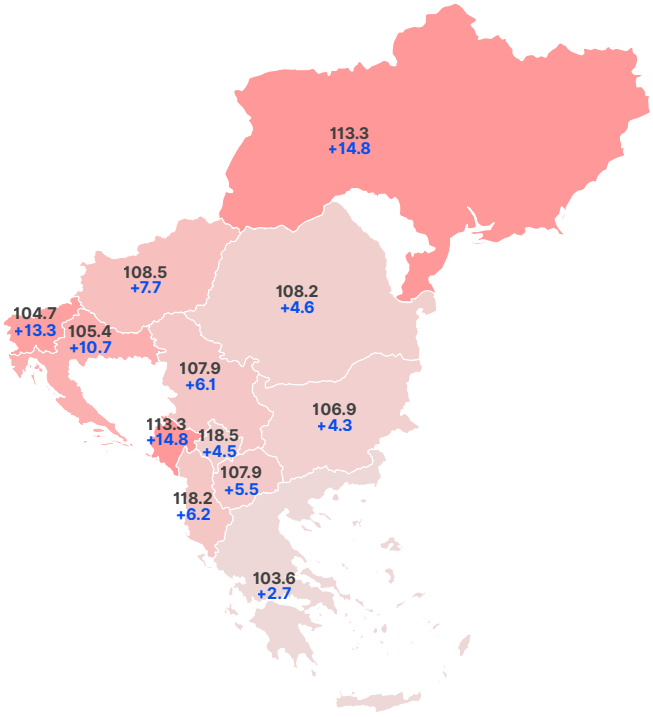
EnC Contracting Party	Four legal acts from CEP (ED, ER; ACER and Risk-Preparedness) – adapted versions	Five NC&GL (FCA, CACM, EBGL, SOGL and ER NC) – adapted versions	Status of verification of the compliant transposition
Serbia***	Full transposition notified to EnCS	Full transposition notified to EnCS	European Commission issued the opinion with recommendations
Ukraine	Law aimed to transpose adopted	Pending	Not yet started

Source: Energy Community Secretariat.
*Note: ** **Moldova** – The verification process was officially initiated on 5 March 2026. EnCS assessment was communicated to the European Commission on 4 June. The European Commission is expected to issue an opinion by the beginning of November 2026.*
*** **Montenegro** – The verification process was officially initiated on 3 March 2026. EnCS communicated its assessment to the European Commission on 15 May 2026. The European Commission is expected to issue an opinion by mid-October.*
**** **North Macedonia** - The verification process was formally initiated on 25 June 2026.*
***** **Serbia** – The verification process was officially initiated on 22 October 2025. EnCS communicated its assessment to the European Commission on 16 December 2025. The European Commission's opinion with recommendations communicated to Serbia on 14 May 2026.*

6.2. Absence of market coupling keeps price spreads wider in South-East Europe

389 Wholesale average electricity day-ahead prices rose across the region in 2025, both in EU Member States and in the Energy Community contracting parties, depicted in Figure 101. Average prices increased in all markets, with the largest increase (14.8 EUR/MWh) recorded in Montenegro. The Western Balkan contracting parties remained the most expensive, with Kosovo*, Albania (both around 118 EUR/MWh) and Montenegro (113.3 EUR/MWh), around 10-15 EUR/MWh above neighbouring EU Member States.

Figure 101: Average day-ahead electricity prices in 2025 and price difference compared to 2024 in contracting parties and neighbouring EU Member States – 2024 and 2025 (EUR/MWh)



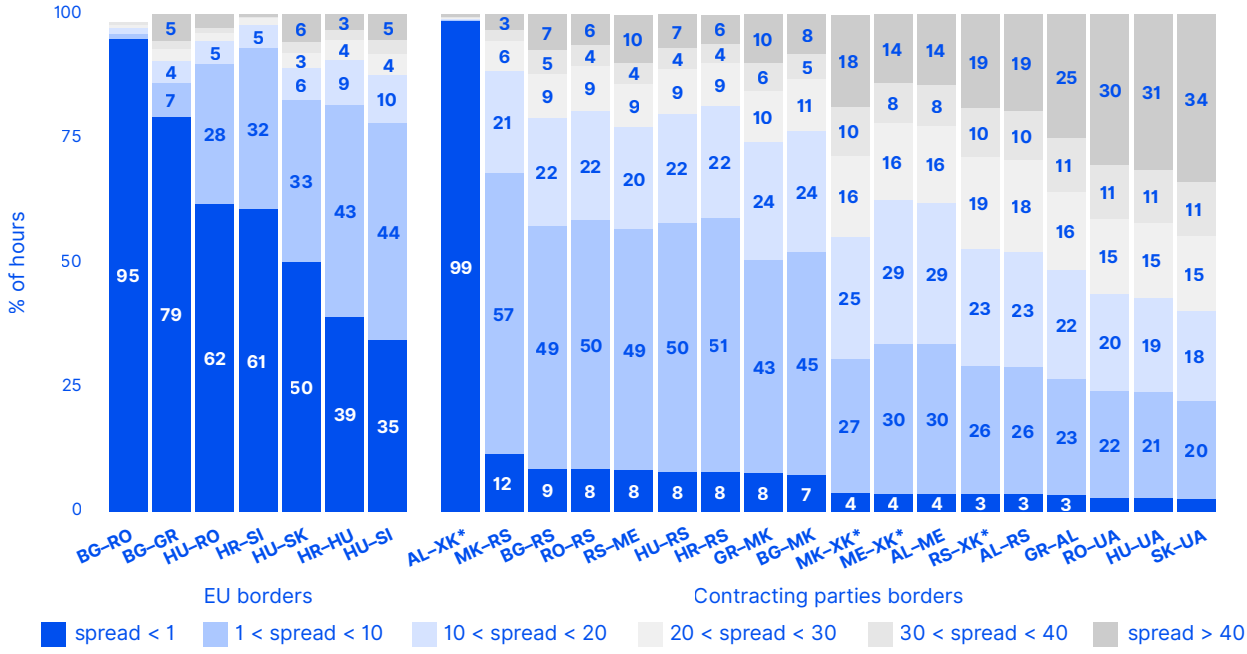
Source: ACER calculations based on ENTSO-E Transparency Platform data.
Note: Bosnia and Herzegovina and Moldova are not displayed as no organized day-ahead market was in operation in 2025.

390 Figure 102 shows that price convergence between the Energy Community contracting parties and their neighbours remained low. On the Serbian borders, prices converged fully in less than 12% of hours on most borders, although spreads stayed within 10 EUR/MWh in around 60% of hours on most borders. This limited convergence is unsurprising, as the net transfer capacities offered by the TSOs of Energy Community contracting parties have remained broadly unchanged over recent years, in both the export and import directions. Moreover, in the absence of market coupling, market participants have to nominate cross-zonal schedules before day-ahead prices are known. Trading therefore relies on expected rather than actual price differences, which can result in flows in the non-economic direction and in wider price spreads.

391 Full price convergence, with spreads below 1 EUR/MWh, remained largely confined to already coupled EU markets. For instance, between EU Member States in the region, the prices converged from 60% to 95% of hours. By contrast, between the non-coupled markets full convergence remained below 12% of hours. Convergence was lowest on the Ukrainian borders with Hungary and Romania, where large spreads occurred most of the time.

392 Most Energy Community contracting parties introduced day-ahead trading only recently. Serbia was the first in the region to launch its day-ahead market, in 2016, followed by Ukraine in 2019. Albania, Montenegro and North Macedonia only began day-ahead trading in 2023, Kosovo* and Georgia followed in 2024, and Moldova launched its market as recently as 2025. These recent launches mean liquidity is still building, which may partly explain the limited price convergence observed in the markets of the EU Member States.

Figure 102: Day-ahead price convergence on Energy Community contracting parties' and neighbouring EU Member States' borders – 2025 (% of hours)



Source: ACER calculations based on ENTSO-E Transparency Platform data.

393 Greater convergence could follow from the further coupling of day-ahead markets in the region and an increase in cross-border capacity, such as through coordinated regional capacity calculation or an implementation of the 70% cross-border capacity availability requirement.

6.3. Potential economic surplus gains from further day-ahead market coupling

394 This subsection, prepared in cooperation with the Energy Community,[65] analyses the economic surplus gains from a potential extension of SDAC to the Energy Community contracting parties, using ACER's methodology and is based on 2025 market data.

395 For each non-coupled border, the potential economic surplus was calculated by combining hourly day-ahead price spreads[66] with the amount of inefficiently used cross-zonal capacity. This inefficiency comprises two components: the arbitrage gains from cross-zonal capacity left unused in the economic direction, and the losses caused by exchanges that flowed against the economic direction.

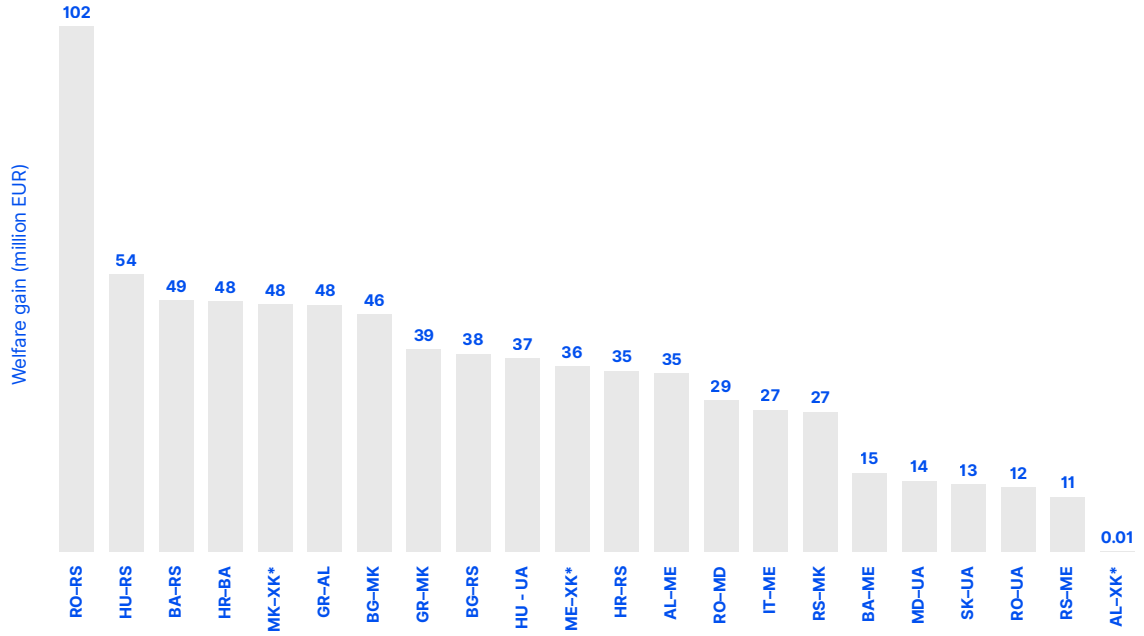
396 The results, presented as an aggregate figure and economic surplus gains per border, indicate that integrating the Energy Community contracting parties into SDAC would have yielded an economic surplus gain of around EUR 763 million in 2025. These estimates should be interpreted as an order of magnitude. The calculation holds price spreads at their observed level, so the estimated gain increases linearly with the volume traded, whereas coupling would in practice narrow the spreads. A comparable ACER exercise, which sets this approach against simulations run in the Simulation Facility, suggests that the overestimation could reach a factor of two. On that basis, the realistically achievable gains could be around half of the values presented in this section.

397 Figure 103 presents the results of the economic surplus gains per Energy Community contracting party borders, based on 2025 market data. The calculation used the day-ahead commercial schedules and the net transfer capacities in both directions, together with the day-ahead prices of the bidding zones on each side of the respective border.

65 The data, methodologies and results were reviewed and endorsed by the Energy Community.

66 Where day-ahead prices were unavailable for an Energy Community contracting party (Bosnia and Herzegovina and Moldova), ACER approximated them using the day-ahead prices of neighbouring markets, adjusted by the clearing prices of day-ahead transmission right auctions. Finally, time periods with incomplete data were linearly extrapolated to cover a full year. Further details are provided in the methodology description accompanying this analysis.

Figure 103: Potential economic surplus gains from day-ahead market coupling per contracting party border – 2025 (million EUR)



Source: ACER calculation based on ENTSO-E Transparency Platform data, SEE CAO and Energy Community regulatory authorities.

398 The distribution of gains across borders largely reflects the size and persistence of day-ahead price spreads, as well as the extent to which cross-zonal capacity remained unused or was nominated against the economic direction.

399 It should be noted that the economic surplus gains calculation for Ukraine is of an indicative nature and should be considered as a lower-bound estimate. Due to Russia's ongoing unprovoked and unjustified military aggression against Ukraine, the Ukrainian system operator (NPC Ukrenergo) was required to impose restrictions on cross-zonal capacity between Ukraine and neighbouring countries throughout 2025. These restrictions were necessary to ensure system balance and the overall security of electricity supply.

7. Conclusions

400 This report confirms that electricity market integration in the EU is delivering clear benefits. It improves welfare, strengthens the security of supply, supports competition, and helps integrate growing volumes of renewable generation more efficiently. The developments observed in 2025 and early 2026 show that integration is an ongoing process that continues to reshape how electricity is traded across timeframes and across borders.

401 The report also shows that the job is not finished. Important elements of the target model remain incomplete. Some of the pending projects are expected to have a significant impact. ACER estimates that 13 market integration projects, if fully implemented, could have generated up to EUR 7 billion in economic surplus gains in 2025. The direction of travel is therefore clear: market integration is working, but its full value will only be realised if implementation gaps are closed.

Forward markets in the EU continue to show structural challenges, while PPAs help drive investments in flexibility and renewable energy

402 Forward electricity markets are becoming more active, yet important gaps remain. Liquidity is still concentrated in a limited number of bidding zones and tends to decline rapidly along the forward curve, constraining hedging opportunities in less liquid markets and at longer maturities. Long-term transmission rights remain essential to access liquidity in neighbouring markets, but persistent signs of undervaluation point to the need for reforms in the current LTTR framework.

403 Considering these limitations, forward markets remain particularly well suited to managing short- and medium-term price exposure, while longer-term risks associated with investments in generation and demand assets increasingly require complementary long-term arrangements, such as PPAs or public support. PPAs and other long-term contracts are becoming more important for supporting investment, particularly in renewables and flexibility. The market is evolving beyond traditional pay-as-produced structures towards contracts that increasingly value flexibility alongside energy output.

Short-term markets are the centrepiece of the European power system, and their design is undergoing continuous improvements

404 The day-ahead and intraday markets play a central role in the efficient operation of the EU electricity system. Through market coupling, they allow the efficient dispatch of generation resources across interconnected bidding zones, providing transparent price signals for market participants and supporting efficient cross-border electricity trading.

405 In 2025, the finalisation of the rollout of 15-minute MTUs in both day-ahead and intraday timeframes increased the granularity of market signals, shifting part of the later trading activity towards the day-ahead market and strengthening price convergence across timeframes. At the same time, the observed within-hour price volatility shows that the full benefits of the 15-minute MTUs also depend on the extent to which market participants adapt their bidding strategies and product choices.

406 Intraday markets are becoming increasingly important in the EU power system. This reflects a system with more weather-dependent generation, better short-term forecasting, and a growing need for flexibility close to delivery. The introduction of a 30-minute cross-zonal gate closure time on the first borders in January 2026 provides strong evidence of this trend: where closer-to-real-time cross-border trading was made possible, market participants used it immediately and in significant volumes. This is a clear sign that market developments should continue to move in the direction of cross-zonal trading close to real time.

The efficiency of short-term markets in the EU is underpinned by the availability of cross-zonal capacity, but progress in its maximisation has been lagging

407 The process of maximising cross-zonal capacities in line with the requirements of the Electricity Regulation remains incomplete across the EU. This is not just a matter of market efficiency; it is, first and foremost, about ensuring that cross-zonal exchanges of electricity are not discriminated against, in favour of internal exchanges. In the Core region, flow-based market coupling continues to deliver tangible benefits, yet the persistence of excessive loop flows, and the lack of coordinated congestion management processes results in the yearly approval of derogations from the minimum 70% requirement. In the Nordic region, on the other hand, TSOs need to make further efforts to ensure alignment with this requirement.

408 Four means are broadly available to maximise cross-zonal capacities. First, the calculation and allocation of cross-zonal capacity can be optimised, for example through the application of flow-based market coupling in meshed areas of the grid. Second, remedial actions can be planned and activated to mitigate congestion stemming from the combination of cross-zonal and internal exchanges. Third, TSOs can increase available capacity through targeted grid investments that reduce the effect of internal trade on critical network elements. And fourth, bidding zones can be reviewed to better reflect structural congestion in the grid.

409 Intraday markets are particularly affected by limited access to neighbouring markets, with bidding zones often being isolated from the wider market and most trading activity taking place within a bidding zone. This stems mostly from two factors: the allocation of cross-zonal capacities being based on the ATC model, therefore foregoing a significant share of the trading possibilities offered by flow-based domains; and the fact that TSOs do not currently rely on remedial actions to secure a minimum level of cross-zonal capacity during intraday capacity calculation, as they do in the day-ahead timeframe.

410 Limiting intraday cross-zonal capacities on operational security grounds while allowing intra-zonal exchanges to continue until very close to real time without equivalent constraints results in an asymmetric treatment of the two types of trade. In practice, this may give internal exchanges de facto priority access to scarce network capacity, which is precisely the type of discrimination that the 70% requirement is intended to address. The growing importance of intraday markets calls for further efforts to maximise available cross-zonal capacity and the prompt implementation of flow-based allocation in the intraday timeframe, where applicable.

The need for congestion management continued to grow across the EU in 2025, as TSOs activated more remedial actions to maintain voltage limits.

411 After market clearing has ensured the most efficient dispatch possible, remedial actions may be needed to relieve observed congestions. Congestion management needs have been steadily increasing over the years, which make them an important aspect to monitor.

412 The volume of costly remedial actions activated in the EU to address physical congestion reached 70 TWh in 2025. This came at a cost of EUR 5.4 billion to the EU power system, up from EUR 4.3 billion in 2024, representing a growing share of the electricity bill across the EU. With further renewable capacity being rapidly connected into the system, and with grid reinforcement still lagging, congestion management needs are expected to continue to increase in the future.

413 The underlying operational reasons are broadening, with the share of redispatching triggered to address voltage limit violations rising from 10% in 2022 to 33% in 2025, especially in Spain and Portugal following the Iberian blackout of 28 April 2025. As inverter-based resources continue replacing synchronous generation, TSOs will need to ensure that enough voltage control resources are secured through efficient and competitive processes.

414 Moreover, most TSOs rely upon remedial actions across the EU to comply with the minimum cross-zonal capacity requirements. Nonetheless, the absence of coordination in congestion management processes and of an adequate cost-sharing mechanism that allocates costs to the TSOs responsible for originating congestion is preventing several TSOs from making greater cross-zonal capacity available.

Balancing integration delivers measurable benefits but requires broader participation

415 The expansion of PICASSO and MARI has improved the performance of European balancing-energy markets. As additional TSOs joined PICASSO and elastic demand was introduced, extreme aFRR price incidents fell sharply. At the same time, the economic surplus generated by MARI increased from EUR 12 million in 2024 to EUR 104 million in 2025 as participation in the platform expanded. Cross-zonal capacity constraints nevertheless remain an important trigger for isolated extreme price incidents. Further progress requires the remaining TSOs to join the European balancing platforms and more efficient use of the available cross-zonal capacity, including through flow-based capacity allocation for balancing.

416 Regional balancing-capacity cooperation lowers system costs and strengthens TSOs' ability to secure the required reserves. The ALPACA, Baltic and Nordic arrangements already deliver measurable benefits, while cross-border price spreads point to further potential beyond the areas currently covered. The entry of batteries and other decentralised flexibility resources has also helped lower costs and reduce market concentration in several markets. TSOs should expand market-based balancing-capacity cooperation and facilitate the participation of new and decentralised flexibility resources.

417 Both reactive and proactive balancing approaches will be tested by the growing role of fast and decentralised resources, increasing congestion close to real time, and deeper integration through cross-border platforms. TSOs should ensure that balancing and imbalance-settlement arrangements are resilient to these developments.

Extending day-ahead coupling to the Energy Community could deliver significant economic surplus gains, contingent on the transposition of the EIP.

418 Finally, the report points to a significant opportunity beyond the EU's current market perimeter. Extending day-ahead coupling to the Energy Community would evidently deliver economic surplus gains. However, these benefits depend on compliant transposition of the EIP and on eventual accession to SDAC. Integration beyond the EU border is therefore both promising and conditional on sustained regulatory progress.

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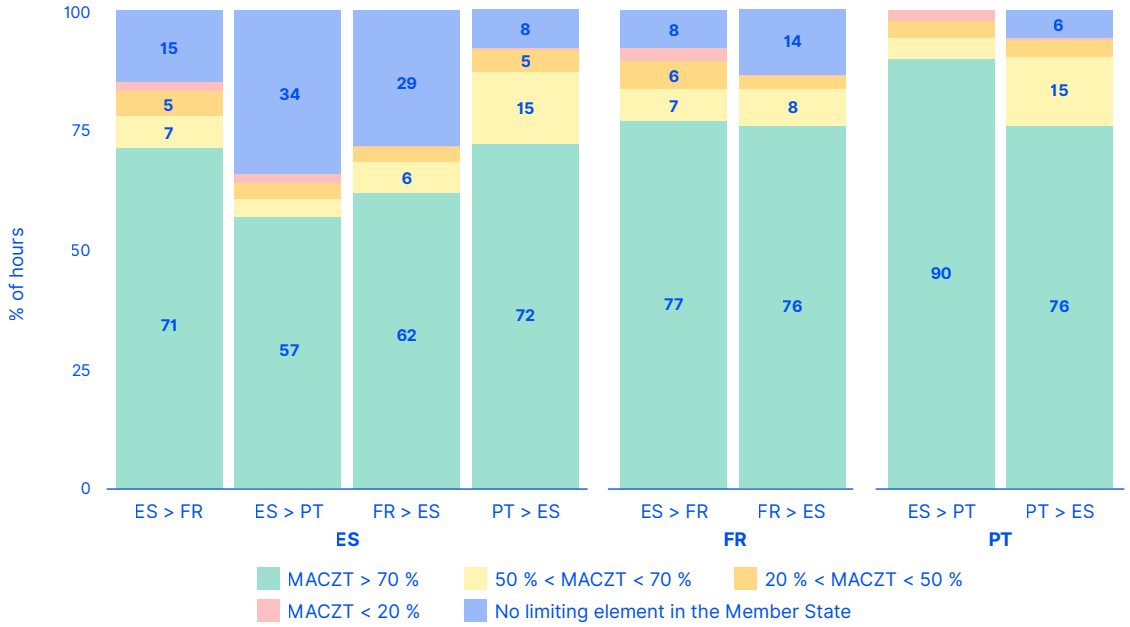
Annex I: Figures on 70% monitoring for remaining CNTC CCRs

419 Beyond the analyses presented in the main body of this report for the Core, Nordic and Italy North CCRs, this annex presents the main results of ACER's monitoring of the margin available for cross-zonal trade for the year 2025 in the CCRs not previously analysed, namely South-West Europe, South-East Europe, Greece-Italy and Baltic.

420 Since the implementation of advanced hybrid coupling on both sides of the Hansa CCR borders, which took place on the Nordic side in October 2024 and on the Core side in June 2026, monitoring of the 70% requirement is performed as part of that of the Core and Nordic CCRs.

South-West Europe

Figure 104: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the SWE CCR for each Member State – 2025 (% of hours)

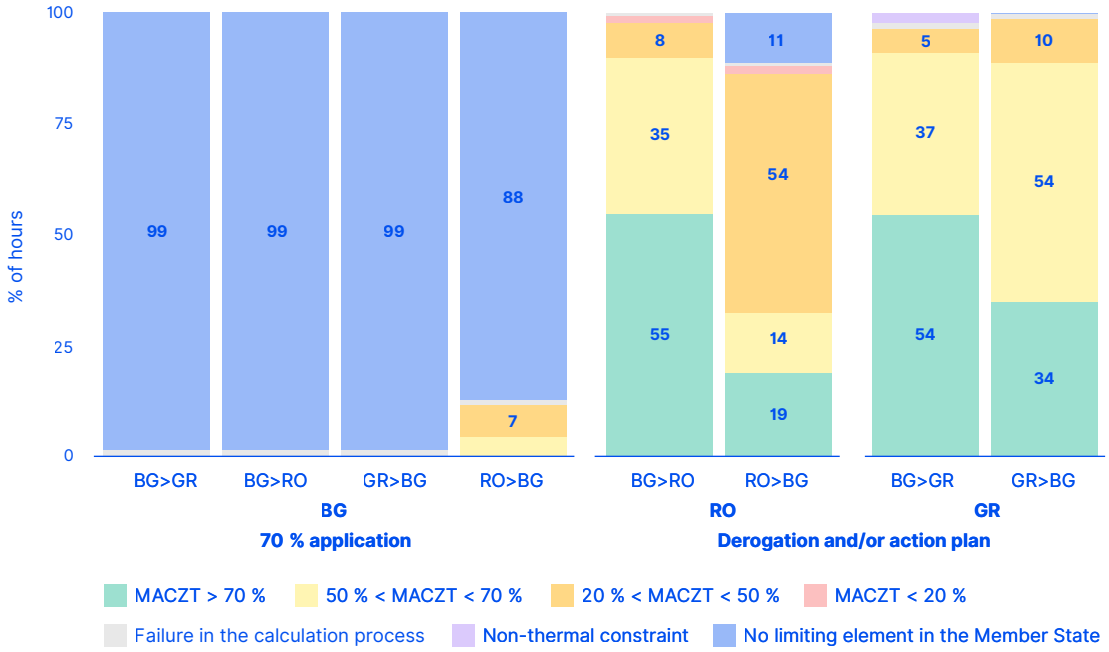


Source: ACER calculation based on SWE TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of Fmax, are rounded to one decimal place. Cross-border lines are accounted for in the results of both TSOs operating the line.

South-East Europe

Figure 105: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the SEE CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)



Source: ACER calculation based on SEE TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of F_{max}, are rounded to one decimal place. Cross-border lines are attributed to the TSO that included them in the capacity calculation.

Figure 106: Percentage of hours when the minimum hourly MACZT was above the applicable requirements in the SEE CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)

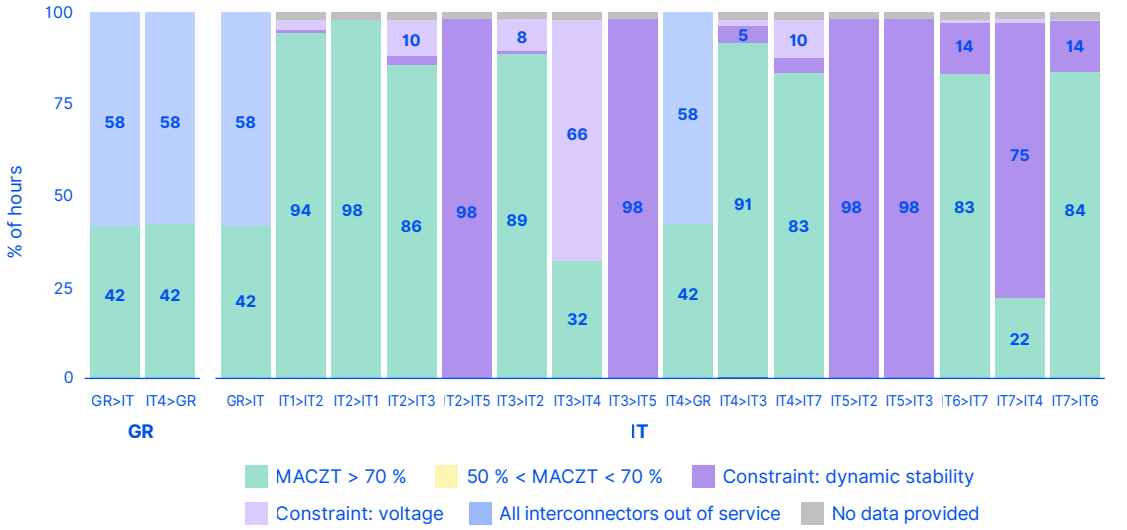


Source: ACER calculation based on SEE TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of F_{max}, are rounded to one decimal place. Cross-border lines are attributed to the TSO that included them in the capacity calculation.

Greece-Italy

Figure 107: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Greece-Italy CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)

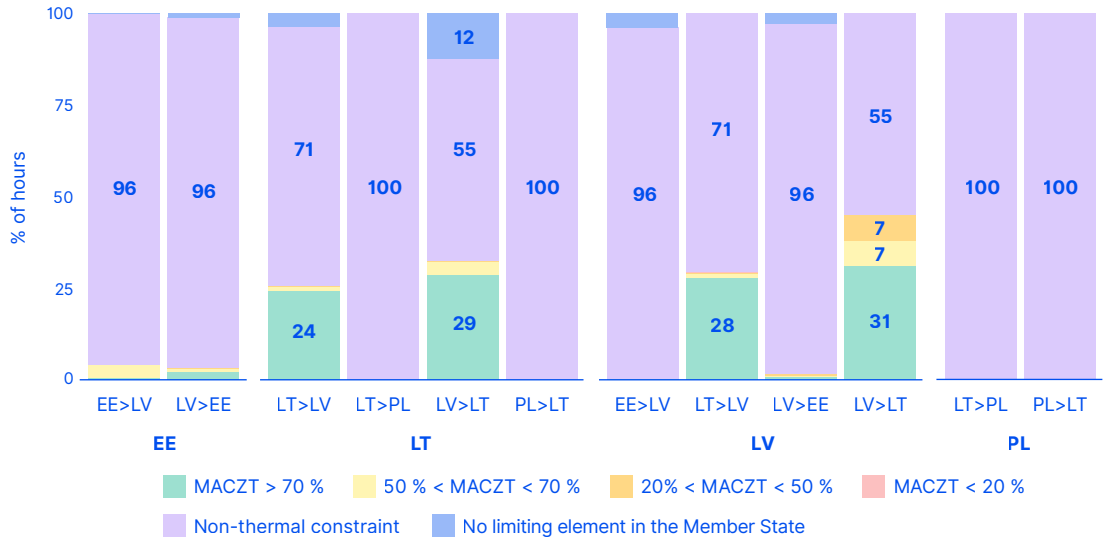


Source: ACER calculation based on GRIT TSOs data.

Note: The internal Italian bidding zones are labelled as follows: IT1 – Italy North, IT2 – Italy Centre-North, IT3 – Italy Centre-South, IT4 – Italy-South, IT5 – Italy Sardinia, IT6 – Italy Sicily, IT7 – Italy Calabria. MACZT values, expressed as a percentage of Fmax, are rounded to one decimal place.

Baltic

Figure 108: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Baltic CCR for each Member State, considering flows induced by third-country exchanges – 2025 (% of hours)



Source: ACER calculation based on Baltic TSOs data.

Note: MACZT values are calculated in line with the principles of ACER Recommendation 01/2019, which may differ from those applied by individual NRAs in national compliance assessments. MACZT values, expressed as a percentage of Fmax, are rounded to one decimal place. Cross-border lines are accounted for in the results of both TSOs operating the line.

Annex II: Application of dynamic line rating on most congested CNEs of the Core CCR

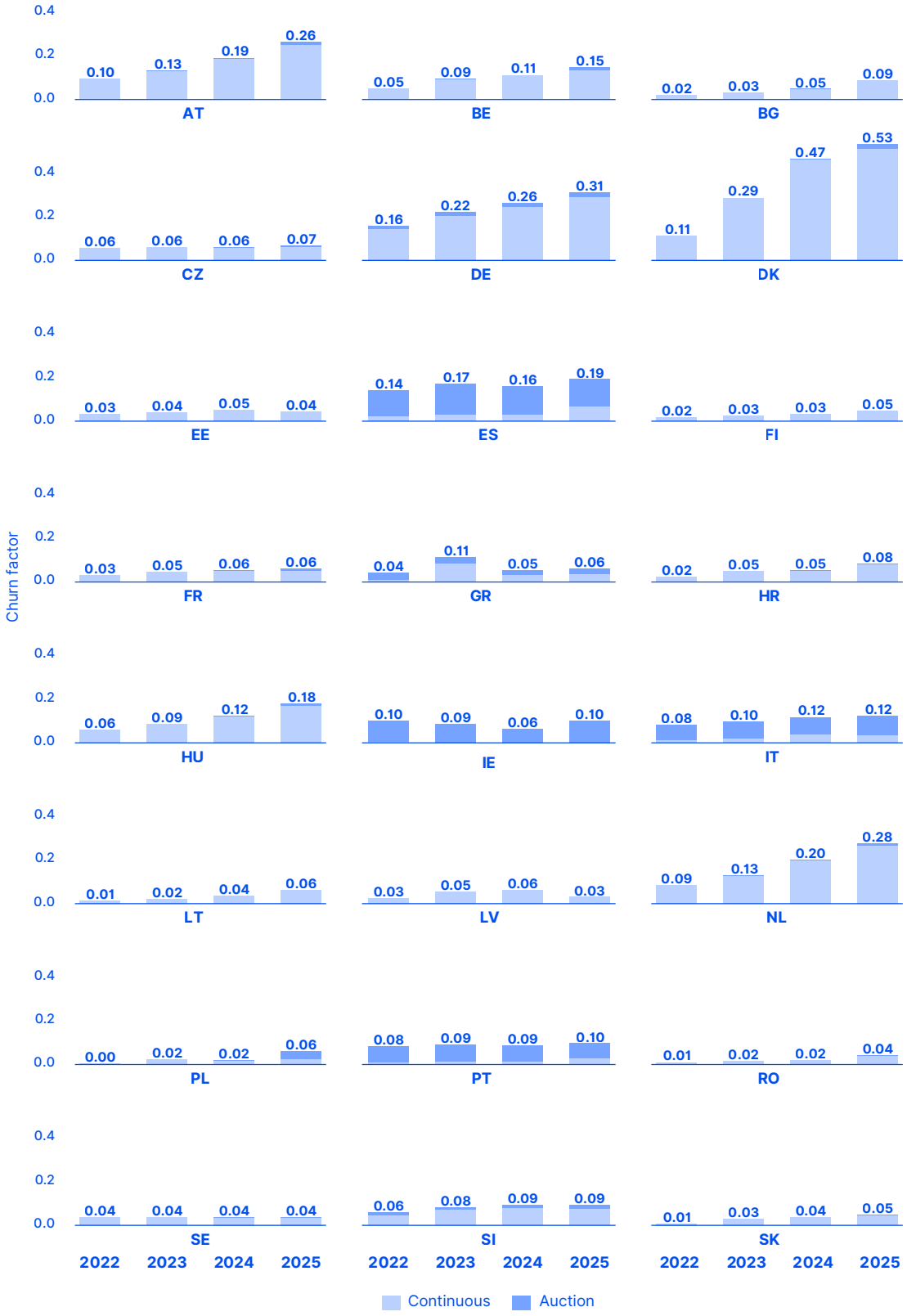
421 This annex presents an overview of the application of dynamic line rating in capacity calculation on the most congested CNEs of the Core CCR during 2025. The higher the number displayed on column 'Distinct Fmax values', the more dynamic the estimation of the rating is by the relevant TSO. Cumulative shadow price represents the incremental increase of economic surplus per year for an additional MW of capacity on a given CNE.

Table 12: Number of different ratings used in capacity calculation on the top 25 most congested network elements in the Core CCR during 2025

CNE name	Responsible TSO	Cumulative shadow price (EUR/MW)	Distinct Fmax values
Creys – St. Vulbas ouest 2	RTE	698,507.6	7
Ensdorf - Vigy 2S	Amprion	286,266.4	1
Creys - St. Vulbas ouest 1	RTE	259,084.2	7
Altheim - Sittling 219	TenneT DE	205,490.2	42
Levice - God	MAVIR	168,857.8	2
Obersielach - Podlog 247	APG	163,214.1	53
Hessenberg - Weissenbach 223	APG	146,282.3	45
Pleinting - St. Peter 258	APG	138,847.7	71
Mikulowa PST1	PSE	130,738.1	1
Altheim - Sittling 220	TenneT DE	119,746.9	42
PST Roehrsdorf 442	50Hertz	89,852.87	1
Achene - Lonny 380.19	Elia	88,290.65	455
Nosovice - Varin	CEPS	82,191	2
V. Dur - Levice 1	SEPS	78,982.6	2
Ensdorf - Vigy 2S	RTE	68,842.04	3
TR Rosiori 400/220 1	Transelectrica	67,388.84	2
PST Meeden 2	TenneT NL	66,869.02	1
Resita - Timisoara c1	Transelectrica	52,711.28	3
Paroseni - Targu Jiu Nord	Transelectrica	45,100.91	4
Altheim - Simbach - St. Peter 233	TenneT DE	31,119.27	42
Wielopole - Nosovice	PSE	30,480.71	17
Ensdorf - Vigy 1N	Amprion	27,523.24	1
Westtirol 1 - Westtirol 2	APG	26,644.18	1
Strass - Thaur 273B	APG	25,807.79	62
Altheim - Simbach - St. Peter 234	TenneT DE	22,857.74	42

Annex III: Intraday churn factors per country

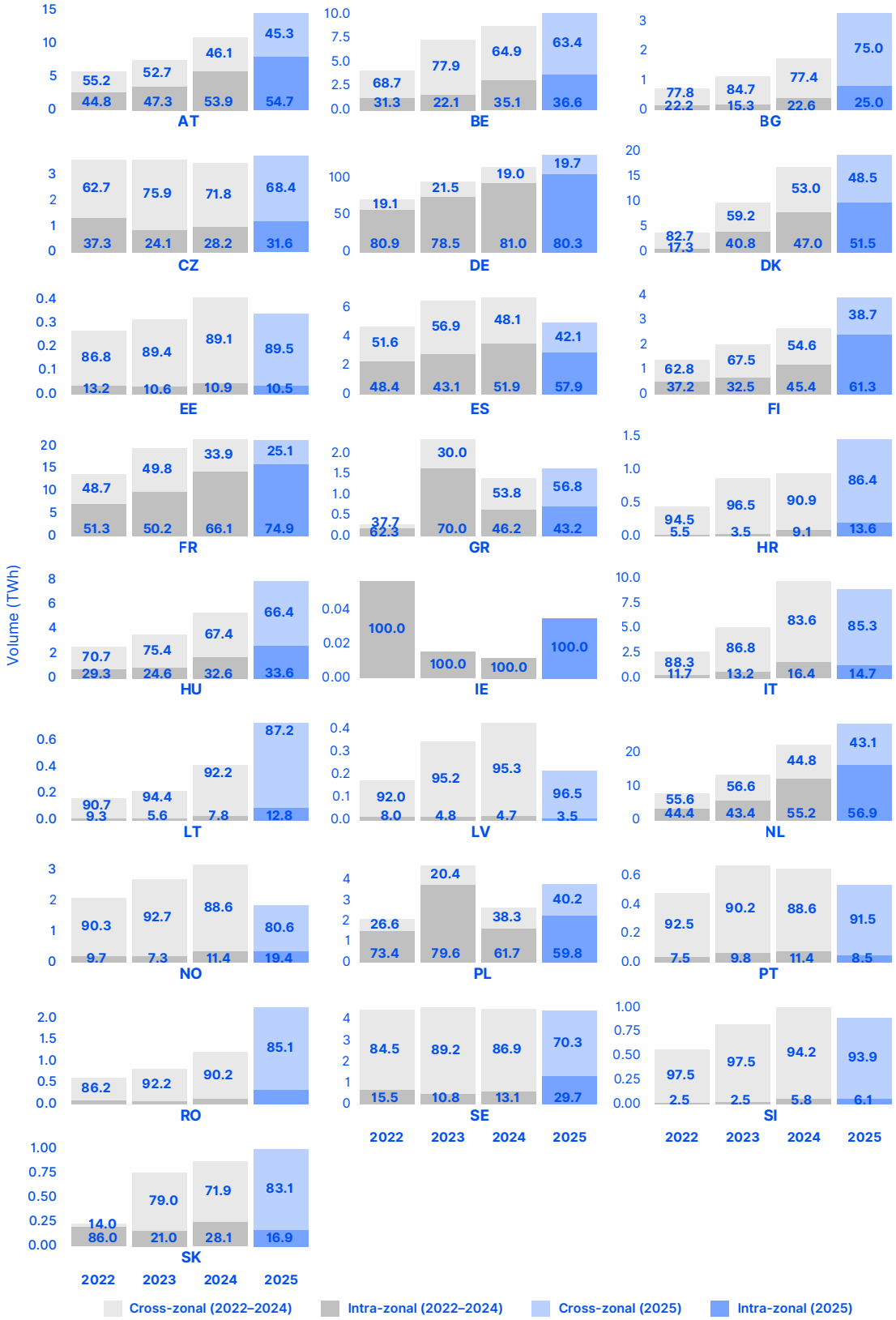
Figure 109: Evolution of yearly churn factors in European intraday markets by type of trade, EU-27, 2022-2025



Source: ACER calculation based on REMIT and ENTSO-E transparency platform.

Annex IV: Shares of domestic and cross-zonal traded volumes in intraday markets

Figure 110: Evolution of intraday traded volumes in the continuous market by intra-zonal versus cross-zonal trade per country, EU-27 and Norway, 2022-2025 (TWh)



Source: ACER calculation based on data from NEMOs.

Note: In countries with multiple bidding zones, the percentage shares of cross-zonal and intra-zonal continuous intraday traded volume were calculated as a weighted average (by traded volumes) across all the bidding zones within the country (Italy, Norway, Sweden and Denmark).

Annex V: Balancing markets

Integration of balancing capacity markets

422 When analysing price spreads, several conditions can be distinguished depending on whether there are several balancing capacity products to be considered, which bidding zone across a border has the higher price in which market, and whether it concerns positive or negative balancing capacity.

423 In a first step, an hourly volume-weighted average price was calculated for the balancing-capacity products to allow comparison with hourly day-ahead prices.

424 In a second step, the direction of the price spreads in both markets was compared. Considering an example with two zones A and B and positive balancing capacity, if the prices are higher in zone A in both markets (for day-ahead energy and balancing capacity), imports from zone B to zone A yield a benefit in both markets, creating a trade-off between allocating cross-zonal capacity to either market. However, when price differences in the two markets point in opposite directions, cross-zonal capacity is valuable in opposite directions. Reserving capacity for balancing-capacity exchange therefore does not directly compete with day-ahead trade for capacity in the economically relevant direction.

425 Positive and negative balancing-energy activations result in power flows in different directions. Balancing-capacity procurement therefore requires cross-border transmission capacity to be available in the corresponding direction.

Examples of divergent BSP and BRP incentives

426 The examples below illustrate situations in which the balancing-energy signal faced by BSPs and the imbalance-settlement signal faced by BRPs pointed in different directions or differed substantially in strength. They are intended as illustrations of the coordination challenge discussed in Section 5.3.3 rather than as a comprehensive assessment of the national settlement methodologies.

Table 13: Belgian area, 5 August 2025 at 11:15 – 11:30

Indicator	Value
System imbalance	-446.80 MW
Alpha component	170.97 EUR/MWh
Marginal incremental price	60 EUR/MWh
Imbalance price	230.97 EUR/MWh
Weighted average aFRR price	32.24 EUR/MWh
MARI mFRR CBMP	-3 EUR/MWh

Source: Elia imbalance-price data and European balancing-platform data.

427 In this ISP, the Belgian area was short by 446.80 MW, while average balancing-energy prices were relatively low. Four-second PICASSO data indicate periods of downward and upward aFRR activation, as well as periods with no aFRR activation, in the uncongested area containing Belgium. The aFRR CBMP, weighted by satisfied demand over the ISP, was 32.24 EUR/MWh. By contrast, the national floor of 60 EUR/MWh and the alpha component of 170.97 EUR/MWh resulted in an imbalance price of 230.97 EUR/MWh, providing BRPs with a financial incentive to increase production or reduce consumption. For example, a BRP expecting this imbalance price would have an incentive to increase production from an available generating unit with a marginal cost of 200 EUR/MWh. That cost exceeds both the average PICASSO CBMP of 32.24 EUR/MWh and the MARI price of −3 EUR/MWh.

Table 14: German area, 1 January 2025 at 11:45 – 12:00

Indicator	Value
AEP Module 1	2,291.02 EUR/MWh
AEP Module 2	-13.27 EUR/MWh
Price-setting module	AEP Module 2
Imbalance price (reBAP)	-13.27 EUR/MWh

Source: German AEP module (reBAP) data.

428 In this ISP, the component of Germany's imbalance-price calculation based on European balancing-energy prices (AEP Module 1) was 2,291.02 EUR/MWh. As the German system was long, the methodology selected the lowest of the applicable components. The component linked to intraday prices (AEP Module 2) therefore determined the final German imbalance-settlement price (reBAP) at −13.27 EUR/MWh. The example illustrates how national settlement rules can produce an imbalance price that differs markedly from the balancing-energy component, including in sign.

Table 15: Austrian area, 8 May 2025 at 12:45 – 13:00

Indicator	Value
Upward aFRR CBMP range during the ISP	69.52–804.23 EUR/MWh
National system imbalance over the ISP	Surplus of 15.80 MWh
National balancing-energy component	42.00 EUR/MWh
Intraday-linked component	17.64 EUR/MWh
Imbalance price	17.64 EUR/MWh

Source: TransnetBW (CBMP range), APCS (price components and imbalance price), and APG data (national system imbalance).

429 During this ISP, the Austrian system was long by 15.80 MWh, while Austrian BSPs supplied upward aFRR to meet upward balancing demand in the wider uncongested area. The upward aFRR CBMP ranged from 69.52 to 804.23 EUR/MWh, with the same maximum observed in ten other TSO areas. For Austria's own balancing needs, however, the national settlement calculation recorded zero aFRR and mFRR energy volumes. The balancing-energy component was therefore based on the value of avoided activation, at 42.00 EUR/MWh. The intraday-linked component determined the imbalance price at 17.64 EUR/MWh. The example illustrates how BSPs can be activated in the upward direction, while BRPs expecting the national imbalance price can have a financial incentive to reduce production from units whose marginal costs exceed that price.