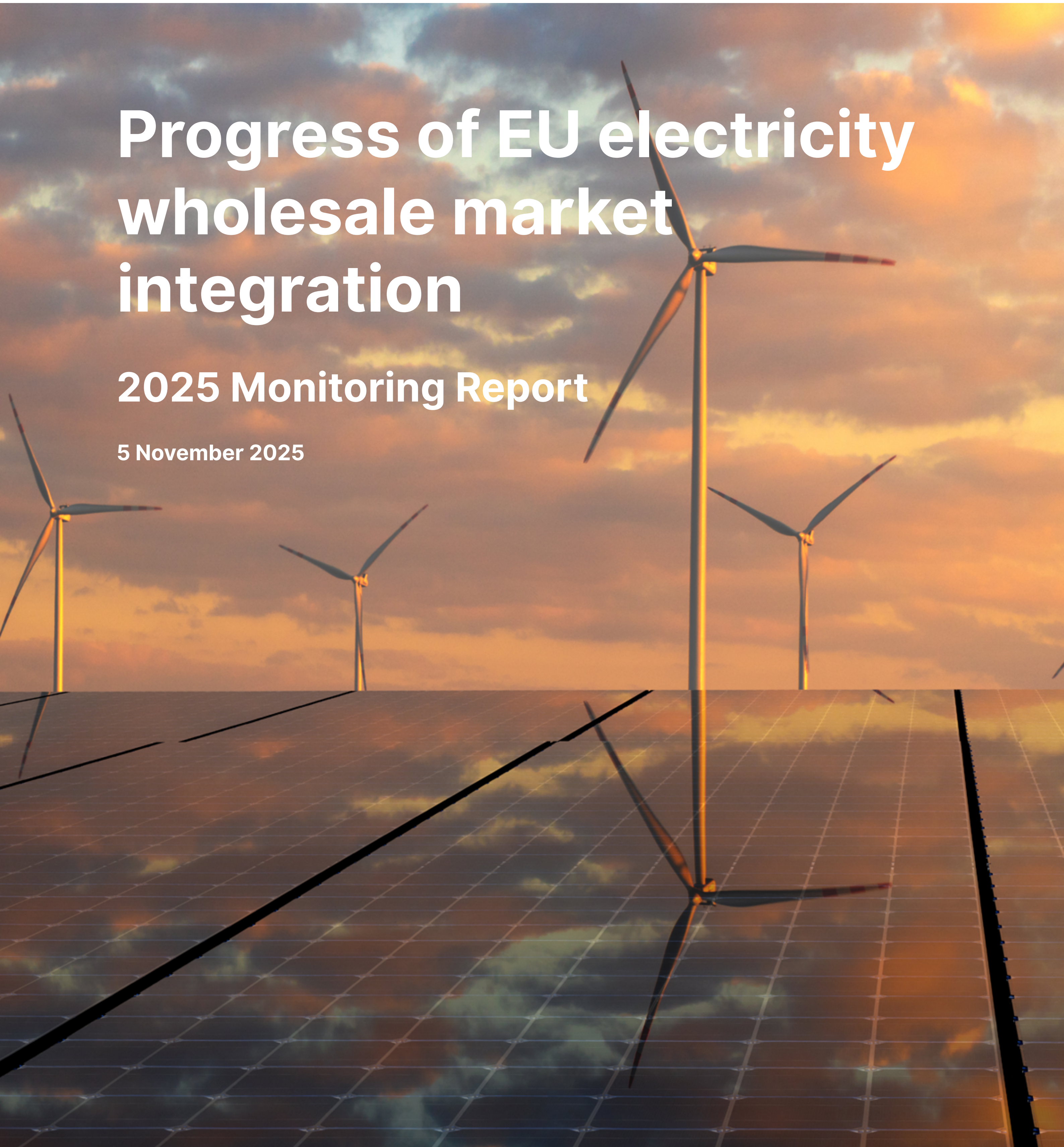
ACER

European Union Agency for the Cooperation of Energy Regulators

Progress of EU electricity wholesale market integration

2025 Monitoring Report

5 November 2025



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Executive summary

EUR 1.6 billion

Welfare gains from balancing market integration

3 times the average price

Spain's price spike during November 2024 heatwave

1000 EUR/MWh

Southeast Europe evening price peaks, summer 2024

Flexibility is now the central challenge for Europe's electricity system[1]

The European electricity market – the largest integrated market in the world – has become a cornerstone of the clean energy transition. Its coordinated day-ahead and intraday coupling now covers almost all Member States, improving price formation and cross-border competition. EU electricity market integration continues to enhance resilience, reduce costs for consumers, and support investment in renewable generation.

The system is undergoing unprecedented change, with price volatility persisting across market timeframes. Episodes of extreme prices (from lows to highs) occur in day-ahead, intraday and balancing markets. Another focus of ACER's analysis in this report is weather-driven price volatility, arising when unusually low renewable generation coincides with higher-than-normal demand due to exceptional weather conditions. Price spikes often coincide with reduced renewable output or demand surges. Changing supply-demand patterns increase the need for short-term flexibility.

Persistent delays reduce efficiency and increase consumer costs

Several structural issues continue to affect market performance:

- **Long-term markets lack liquidity:** Hedging opportunities are limited beyond two years. Forward markets struggle to provide reliable price signals for investment.
- **Further EU market integration supports energy transition and flexibility, and shields consumers from volatility.** Yet key cross-border integration projects are delayed, posing strategic risks to Europe's resilience. Poor or slow implementation of rules reduces efficiency and consumers' benefits. Scrutiny of the root causes of delays, including governance gaps, can accelerate progress.
- **Lack of system flexibility remains a concern and must be tackled.** The lack of storage, demand-side response, and flexible generation increases the system's exposure to weather-driven price volatility.

Key cross-border integration projects are delayed, posing strategic risks to Europe's resilience.

- **Market outcomes depend on operational decisions:** Outages, fallback auctions, and maintenance schedules affect prices significantly. Insufficient coordination among transmission system operators (TSOs) can reduce market efficiency.

1 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (OJ L 158, 14.6.2019, p. 54, ELI: http://data.europa.eu/eli/reg/2019/943/oj) defines flexibility as 'the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes.

Targeted tools and coordinated actions are addressing system risks

Three main types of response are being implemented:

1. Enhancing market integration and cross-border coordination

Market coupling in day-ahead and intraday markets enables efficient electricity flows across borders. This reduces local price volatility and cross-zonal price divergence. The European Union Agency for the Cooperation of Energy Regulators (ACER) monitors progress and tracks delayed projects using detailed data and interactive tools.

The findings of ACER's 2025 capacity report confirm that increasing cross-border capacity remains a key driver of integration and efficiency.[2] Planned new cross-zonal interconnectors, and the related investments to transit this electricity within bidding zones are expected to improve resilience by allowing trades between regions with uncorrelated wind patterns.

Flow-based allocation is already applied in the day-ahead timeframe in the Nordic and Core regions and is expected to bring further welfare gains as it will be extended to the Italy North region by merging with the Core region. Flow-based allocation has also been planned in the long term, for the forward capacities in 2027. This report focuses on intraday and balancing, where flow-based allocation is underway for intraday auctions and could bring further benefits for continuous intraday and balancing markets. It enables more efficient use of cross-zonal transmission capacity than traditional methods (available transfer capacity (ATC)).

The ongoing bidding zone review is important. Bidding zones aligned with grid congestion can improve cross-border trade, guide smarter network investments, and lower the cost of adding new technologies. Finally, ongoing reforms of the Forward Capacity Allocation Regulation[3] and Capacity Allocation and Congestion Management Regulation[4] can also strengthen market functioning and integration.

Integration is progressing within and beyond EU borders: the Baltics' February 2025 synchronisation disconnecting from Russia and connecting to continental Europe marked a major milestone, while Moldova and Ukraine's synchronisation represents a key step with these neighbours, with further alignment expected. For Moldova and Ukraine, synchronisation enhances the security of supply and reduces dependence on Russia, while opening access to the EU electricity market. It strengthens operational stability by allowing emergency support and coordinated system operation.

2. Expanding long-term market tools and transparency

Power purchase agreements (PPAs) are increasingly used to support renewable investment. They complement contracts for difference (CfDs) and future contracts.

PPAs vary widely by design. Some trading platforms, like Italy's, aim to increase standardisation, transparency, and demand pooling. To avoid distortions, PPAs should reflect costs and include clauses for negative prices. Without this, they could lead to inefficient bidding and suboptimal price signals.

Further improvements to forward markets, including more harmonised long-term capacity allocation and enhanced liquidity, remain essential to provide reliable price signals for investment and hedging.

2 ACER, 2025 Monitoring Report – Transmission capacities for cross-zonal trade of electricity and congestion management in the EU, 2025, https://www.acer.europa.eu/monitoring/cross-zonal-electricity-trade-2025.

3 Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (OJ L 259, 27.9.2016, p. 4, ELI: http://data.europa.eu/eli/reg/2016/1719/oj).

4 Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (OJ L 197, 25.7.2015, p. 24, ELI: http://data.europa.eu/eli/reg/2015/1222/oj).

ACER has developed country-level overviews of PPA uptake, guarantees, and risk-sharing mechanisms.[5]

3. Improving operational flexibility, system responsiveness and trust

Electricity network flexibility is of existential importance: it enables the EU to mitigate shocks, reduce dependence on imported fuels, and support the clean energy transition.

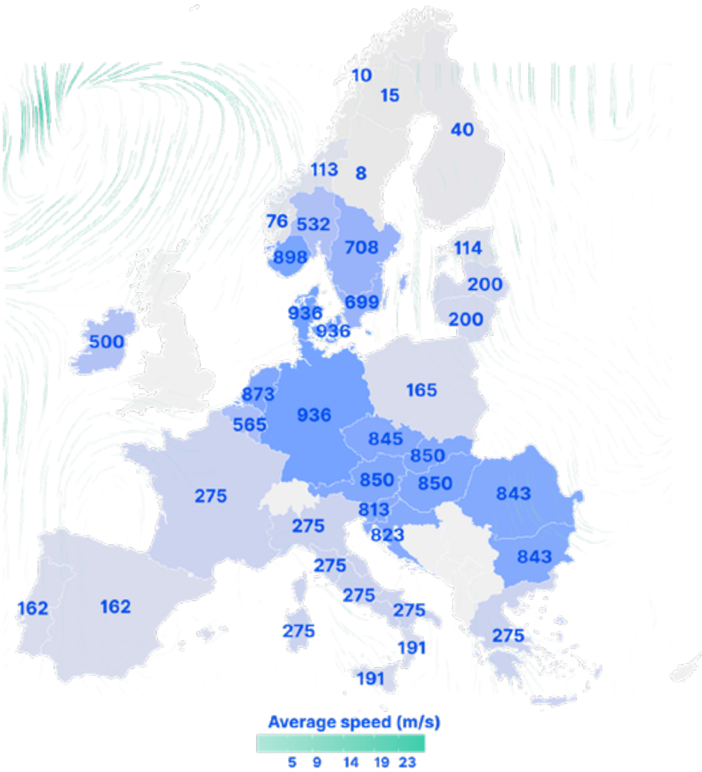
Price volatility in 2024 confirmed the importance of flexibility during system stress. On 12 December 2024, a Dunkelflaute (period of low wind and high demand) drove price surges in the Core region, averaging 227 EUR/MWh across bidding zones - twice the monthly average. In Spain, heat-driven demand spikes in November 2024 combined with reduced solar output pushed prices to 180 EUR/MWh. South East Europe saw peaks nearing 1000 EUR/MWh, during hot evenings in the summer of 2024.

Price volatility in 2024 confirmed flexibility is crucial during system stress.

In each case, insufficient cross-border flows, limited storage, and timing mismatches played a central role. Ex-post monitoring should examine and determine whether bidding behaviour was manipulative.

Figure 1: Low wind drives high prices

Day-ahead prices and wind speed in the EU and Norway, 12 December 2024 at 17:00 CET (EUR/MWh)



Source: ACER elaboration based on ENTSO–E Transparency Platform data and Copernicus data – ERA5.

5 ACER, 2025 Monitoring Report – Power purchase agreements country sheets, 2025, https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/ACER-PPA-Country-sheets-2025.pdf.

Looking ahead: delivering planned improvements is key to market resilience

Several priorities have been identified to improve system performance in 2025–2026.

1. **Reinforce flexibility.** Greater investment is needed in demand response, storage, and dispatchable backup. These resources help absorb weather variability and reduce consumer exposure to price volatility.

2. **Complete key EU electricity market integration projects.** Coordinated use of remedial actions, and flow-based capacity allocation must expand to new areas and time frames without delay. Incomplete or late implementation continues to hamper reforms and the related welfare gains.

3. **Expand balancing market integration.** The platforms for the exchange of balancing energy and imbalance netting and the Nordic balancing capacity market delivered over EUR 1.6 billion in welfare gains in 2024. Wider transmission system operators' participation could further reduce volatility and price incidents and deliver even more value for the EU and its market participants.

Incomplete or late implementation continues to hamper reforms and the related welfare gains.

4. **Improve cross-zonal capacity availability, in particular under stress.** It is crucial that cross-zonal capacity be increased (see ACER's 2025 capacity report, and the ongoing bidding zone review, mentioned above). Further, transmission system operators should maintain available capacity during critical hours. Redispatch and maintenance planning must adapt to system needs.

5. **Strengthen long-term market foundations:** Improvements in long-term cross-zonal capacity allocation are needed to support the market for standard forward electricity products more efficiently. The design of PPAs, contracts for difference, and futures should be aligned so these products strengthen each other. Transparent PPA platforms can support smaller actors and improve price discovery.

6. **Enhance monitoring and oversight:** Real-time indicators and event-based surveillance should track both physical constraints and stakeholder actions. Increasing transparency can help deter potential market manipulation.

7. **Leverage ongoing reforms:** Updates to the Forward Capacity Allocation Regulation and the Capacity Allocation and Congestion Management Regulation will improve the functioning and integration of electricity markets.

Efficient markets depend on system readiness and coordinated action by transmission system operators

The EU electricity market design has proved resilient. It continues to support dispatch efficiency and renewable integration. However, system performance increasingly depends on timely implementation, operational decisions, and physical flexibility. To limit risks for consumers and investors, it is now essential to ensure full delivery of existing plans. Coordination across borders and actors is also essential.

Efficient markets are the keystone of affordable and resilient electricity. Trust in markets relies on the effective enforcement of rules, for both TSOs and Member States.

Efficient markets are the keystone of affordable and resilient electricity.

List of abbreviations

Abbreviation	Term in full
AC	alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic frequency restoration reserves
ALPACA	Allocation of cross-zonal capacity and procurement of aFRR cooperation agreement
AOF	activation optimisation function
ATC	available transfer capacity
CBMP	cross-border marginal price
CCR	capacity calculation region
CfD	contracts for difference
CNEC	critical network element with contingency
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	frequency containment reserve
FRR	frequency restoration reserve
GME	Gestore dei Mercati Energetici
GOs	guarantees of origin
GSE	Gestore dei Servizi Energetici
IDA	intraday auctions
IGCC	international grid control cooperation
JAO	Joint Allocation Office
LTTRs	long-term transmission rights
MARI	manually activated reserves initiative
mFRR	manual frequency restoration reserves
MTE	Mercato a Termine
MTUs	market time units
NEMO	Nominated Electricity Market Operator
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 reserves
SD	standard deviation
SDAC	single day-ahead coupling
SIDC	single intraday coupling
TERRE	Trans European Replacement Reserves Exchange
TSO	transmission system operator
VAR	vector autoregression
VMA	vector moving average

Introduction

The EU acts on affordability and investment certainty

1 During the energy crisis, electricity prices stayed high for long periods as gas-fired power plants often set the marginal price, reflecting the shortage of gas and the resulting higher gas prices. This led to higher consumer bills, even when cheaper renewables supplied most of the electricity.

2 During the crisis, public concerns focused on price volatility, perceived windfall profits for non-gas generators. After the crisis, attention shifted towards weak investment signals for clean flexibility and storage, despite the need for substantial investment to meet future targets. Some proposals called for splitting renewable and non-renewable markets. However, such structural changes risk weakening price signals and creating distortions, without resolving the root causes of high prices.

3 Instead of abandoning marginal pricing, the EU is enhancing market design with tools to support affordability and investment.[6] These include contracts for differences (CfDs), capacity mechanisms, and hedging instruments such as forward contracts (including PPAs) and futures. Such measures preserve the efficiency of marginal pricing while improving predictability and consumer protection.

Market integration helps limit electricity price spikes

4 Electricity price spikes are temporary but can occur across all market timeframes – from forward to balancing – particularly when supply and demand are misaligned in time and space.

5 Examples include France's low nuclear availability in August 2022, when day-ahead prices exceeded 700 EUR/MWh, and Germany's intraday prices nearing 1 000 EUR/MWh in December 2024 during a Dunkelflaute.[7] Despite their rare occurrences, price incidents in the balancing energy markets can have an impact on average balancing energy prices and imbalance prices. They mostly occur when the balancing energy demand reaches or exceeds the locally available balancing capacity and exchange possibilities are limited.

6 Cross-border market integration helps reduce the frequency and scale of such spikes, as shown by the expansion of TSOs participating in balancing platforms, which has decreased the number of price incidents.

Forward markets reduce exposure to volatility

7 Forward markets protect both consumers and producers from extreme price swings. Buyers can hedge against surges, while sellers limit risks of prolonged low revenues.

8 Medium-term products, such as standard forward contracts up to three years ahead, provide cost certainty for buyers and sellers. During the 2022 energy crisis, such contracts helped manage fuel cost uncertainty. PPAs for renewables also provide long-term price stability. Shorter contracts, such as week-ahead deals used in the Nordic region, support operational planning, especially for hydro resources.

6 Since the energy crisis, major EU reforms include: REPowerEU (May 2022), Electricity Market Reform Proposal (Mar 2023), Council - Parliament Deal (Dec 2023–Apr 2024), Affordable Energy Action Plan (Feb 2025)

7 *Dunkelflaute* is a German term describing periods of low wind and solar generation, often occurring in winter, when both wind speeds and sunlight are limited (from *dunkel*, meaning dark, and *flaute*, meaning calm).

Flexibility moderates price shocks

9 Ongoing cross-border and pan-European market integration projects can deliver significant welfare gains. Their timely completion is crucial to bringing benefits for consumers and improve system efficiency.

10 Greater system flexibility also helps moderate price shocks. Flexibility includes demand-side response, storage (such as batteries and electric vehicles), distributed generation, and cross-border infrastructure. Market design improvements - such as shorter trading intervals[8] to allow faster reactions to change, and stronger locational signals to guide resource use - further support efficiency. Digital solutions such as smart grids improve forecasting and system operation, thus supporting renewable integration and helping to limit price spikes.

Market integration remains a major source of welfare gains

11 Market integration strengthens the resilience and efficiency of the European electricity system. By integrating national markets across all time frames – forward, day-ahead, intraday, and balancing – integration reduces costs and accelerates the clean energy transition.

12 However, delays in implementation limit or defer these benefits, particularly for high-impact projects with wide cross-border effects. This reflects concerns already highlighted in the 2024 edition of this report: incomplete or late implementation continues to hamper reforms and the related welfare gains.

13 Some projects are essential for the functioning of the wider market design. Persistent delays often stem from systemic issues, such as unclear responsibilities, distributed tasks with limited accountability, and a governance framework that falls short of ensuring effective implementation. Clearer responsibilities, stronger enforcement, and improved cooperation mechanisms are needed to unlock system-wide efficiency gains.

14 Authorities should continue to prioritise high-impact market integration projects, where delays have the widest consequences for consumers and market efficiency. Strengthened monitoring, incentives for timely delivery, and closer scrutiny of the root causes of delays, including governance gaps, can support collective ownership and accelerate progress.

15 Since 2012, ACER has tracked progress on implementing European market design rules. This report continues that work, reviewing integration efforts across all market segments.

8 Decision No 13/2024 of the European Union Agency for the Cooperation of Energy Regulators of 25 September 2024 on amendments to products that can be taken into account in the single day-ahead coupling, https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER_Decision_13-2024_SDAC_Products.pdf.
This decision approved the introduction of 15-minute market time unit (MTU) products in the single day-ahead coupling (SDAC), to be implemented by January 2025. EPEX SPOT introduced 15-minute MTU across all SDAC day-ahead markets on 30 September 2025 (for delivery on 1 October 2025).

Closing the gap between market rules and practice

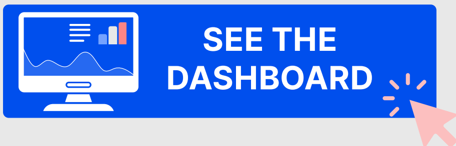
The 2024 edition of the market integration report highlighted delays in implementing EU-wide and regional electricity market rules.[9] It marked the beginning of more detailed monitoring of implementation progress.

Since last year, ACER has:

- collected detailed data on implementation;
- improved its implementation monitoring webpages; and
- developed a continuously updated interactive map.

It will publish recommendations to support implementation later this year.

ACER notes that implementation - especially at the regional level - continues to face significant obstacles.



9 ACER, 2024 Market Monitoring Report – Progress of EU electricity wholesale market integration, 2024, https://www.acer.europa.eu/monitoring/electricity_market_integration_2024.

1. Long-term markets

16 Forward markets support hedging of generation revenues, demand costs, and investment risks. In a context of high short-term volatility, the risk of price shocks, and the growing need for investment in a decarbonised electricity system, properly functioning forward markets are essential.

17 The European electricity forward market faces several persistent challenges: low liquidity, limited accessibility, weak competition, and limited transparency. Long-term cross-zonal capacity allocation supports forward markets by offering hedging through long-term transmission rights (LTTRs). Yet, as highlighted in last year's market integration report, LTTRs have been systematically undervalued over the past decade. While day-ahead and intraday markets already benefited from substantial harmonisation and integration through single day-ahead and intraday coupling, similar progress is still needed for long-term cross-zonal capacity allocation and forward market integration. In response, ACER has proposed measures to address the undervaluation of LTTRs and strengthen support for the European electricity forward market.[10] Regulators and policymakers are now focusing on improving the forward market rules.

18 A properly functioning and efficient market for standard forward electricity products provides a transparent and reliable signal for the future value of electricity. This price signal underpins other long-term markets segments, such as PPAs. As non-standard forward contracts, PPAs allow market participants to directly manage price and production risks linked to renewable volatility. Although PPAs still represent a small share of the forward market, they are attracting growing interest from renewable investors.

19 This section reviews recent developments in forward markets. Given the increasing role of PPAs and ACER's mandate to assess them,[11] it also examines their expansion, and the risks of poorly designed CfDs, highlighting both opportunities and challenges.

20 More data is available on the ACER website in the form of dashboards.

SEE THE DASHBOARD

SEE THE DASHBOARD

1.1. Traditional forward and future markets show limits for long-term investment

21 As Europe advances towards carbon neutrality and faces increasingly frequent extreme weather, liquid and properly functioning long-term markets are essential in order to provide hedging, and reliable long-term price signals, and protect market participants from spot market volatility.

22 While a revision of the Forward Capacity Allocation Regulation to improve the support of forward markets is pending,[12] liquidity remains limited, and trading rarely extends beyond three years. These factors constrain the ability of traditional markets to support long-term investment.

10 Additional details are available in "ACER policy paper on the further development of the EU electricity forward market", ACER, 2023.

11 Article 19b(1) of Regulation (EU) 2019/943, amended by Article 2(9) of Regulation (EU) 2024/1747.

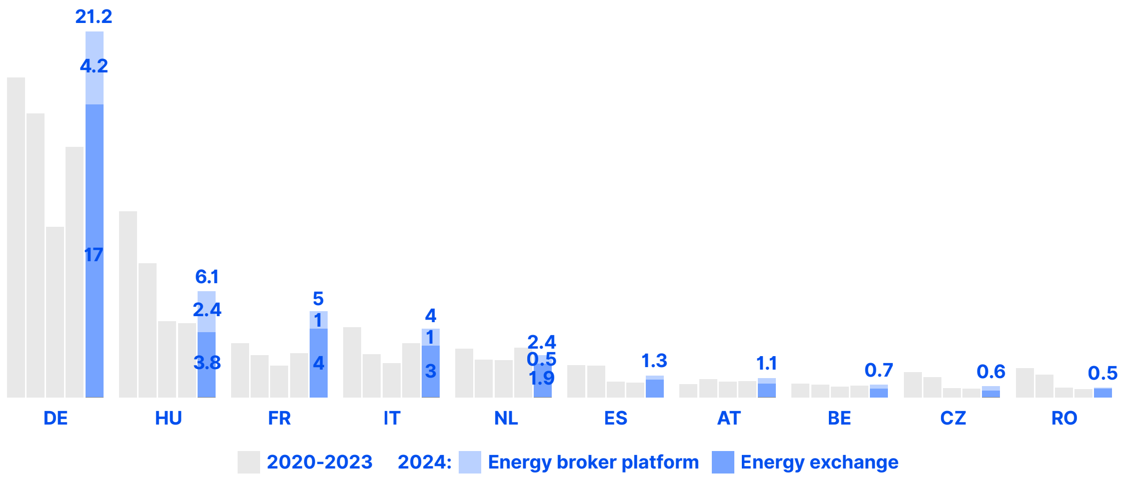
12 Article 9 of Regulation (EU) 2019/943, amended by Article 2(6) of Regulation (EU) 2024/1747.

23 Trends from 2020 to 2024 confirm the challenges identified in previous market integration reports. Churn factors remain low in most European markets (Figure 2), pointing to limited trading frequency and reduced hedging opportunities.

24 Hedging of long-term investment is further constrained by the short maturity of liquid standard forward products (Figure 3).

Figure 2: Low churn factors show limited hedging opportunities in most EU markets

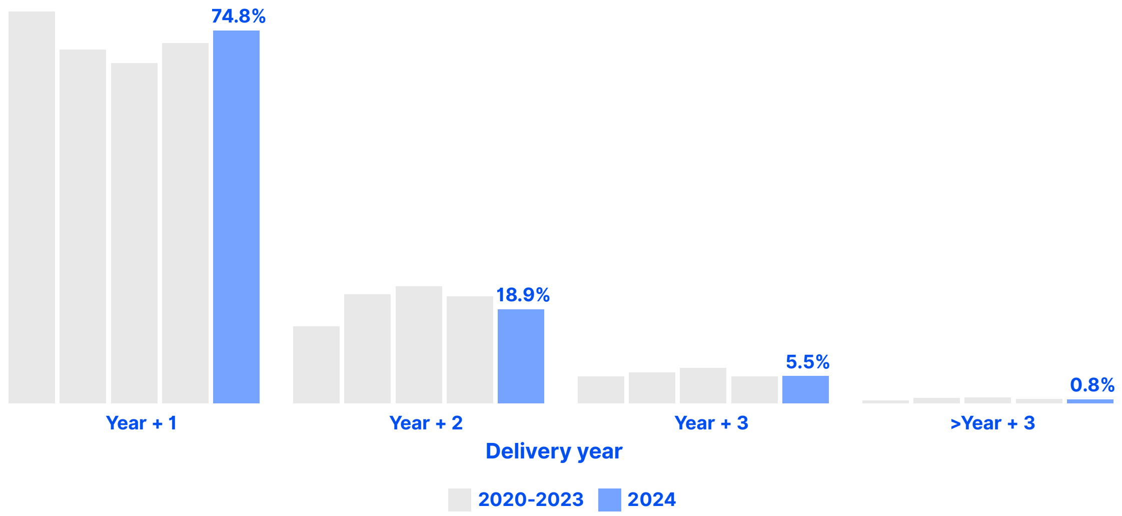
Churn factors in a selection of European forward markets, 2020-2024 (Churn factor is calculated as volume sold in forward markets divided by total demand).



Source: ACER calculations based on REMIT data.

Figure 3: Forward trading concentrates on short maturities, with few contracts beyond three years

Relative shares of traded volume for yearly products by delivery year in Germany, 2020-2024 (%)



Source: ACER calculations based on REMIT data.

1.2. Power purchase agreements are long-term contracts with unique features

Power purchase agreements

A **Power Purchase Agreement** or PPA is a long-term contract between a power producer and a customer (consumer or trader) defining electricity supply terms such as quantity, prices, and penalties. PPAs vary in form, providing physical or virtual electricity, and help large consumers manage market price risks and reduce the cost of investment in renewable energy.

25 Traditional long-term markets also influence the PPA market, providing signals for pricing the future value of electricity. This helps align the price expectations of producers and off-takers. However, as noted above, forward and futures markets in their current form offer limited support for long-term renewable investments. In this context, tailored instruments such as PPAs and CfDs are emerging as key enablers of renewable deployment, ensuring price and revenue stability, and improving the financial viability of new projects.

26 In recent years, PPAs have become a key mechanism for mobilising investment in new renewable capacity, providing cost stability to corporate off-takers and stable revenue streams to developers. These features are necessary to support project viability from development to operation and repayment.

27 Although new platforms for trading standardised PPAs have emerged (see Section 1.3.1, 'Case study: Italian PPA platform'), PPAs remain predominantly long-term contracts tailored to market needs and characterised by specific features.

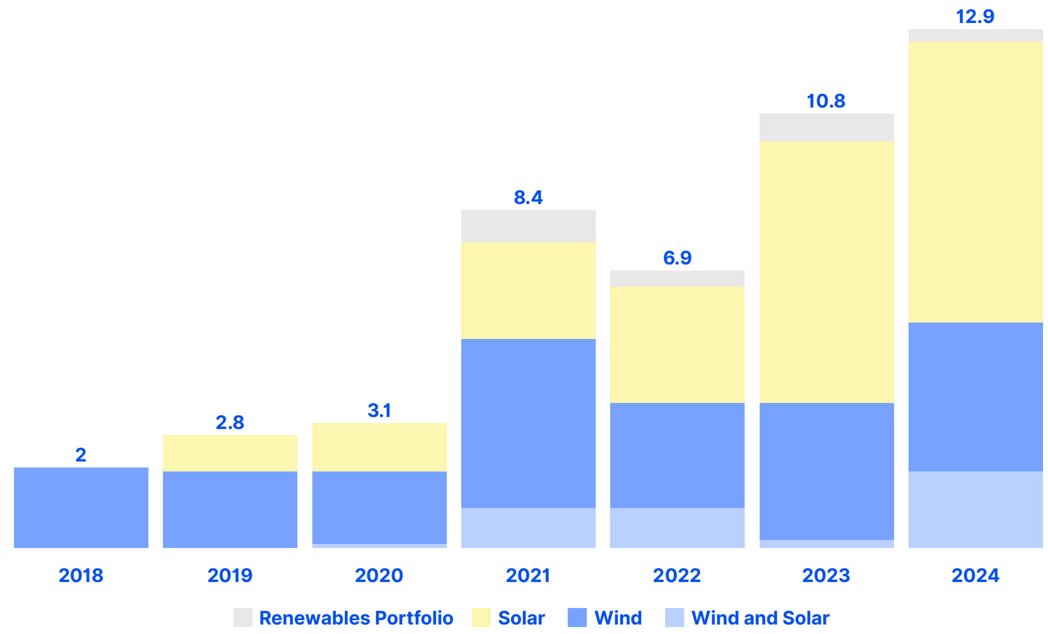
- **Volume.** PPAs can be categorised as pay-as-produced, where buyers take a share of actual output; baseload, where a predetermined volume is guaranteed; or pay-as-consumed, where the producer assumes full volume risk. Currently, the majority of PPAs have a pay-as-produced structure.
- **Sustainability.** PPAs are often coupled with guarantees of origin, verifying that the electricity comes from renewable resources. Bundled guarantees of origin serve as regulatory and commercial traceability tools, enabling companies to meet sustainability goals.
- **Purpose.** Unlike forward markets, where contracts beyond three years are rare (see Figure 3), PPAs in the EU average 12 years and can directly relate to the produced volume of an investment. This facilitates long-term investment hedging, reduces the cost of capital through greater revenue predictability, and enhances bankability. PPAs are closely linked to 'additionality', as most contracts support new renewable assets. According to RE-Source, around 80% of corporate renewable PPAs signed to date are tied to new assets.[13]

13 "RE-Source's corporate PPA guide - How to help more corporates sign renewable power purchase agreements", RE-Source, July 2025.

1.3. The power purchase agreement market is growing, bringing both new opportunities and new challenges

Figure 4: Rapid growth in the EU PPA market between 2020 and 2024

Evolution of the PPA market: annual contracted capacity by renewable technology (GW)



Source: ACER calculations based on data from RE-Source, "RE-Source's PPA deal tracker"

Note: The PPA market has grown significantly in recent years. Between 2020 and 2024, disclosed contracted capacity has quadrupled, supporting investments in new renewable capacity across the EU as shown in Figure 4.

28 Given the growing importance of the market, support for growth requires that existing barriers be removed and a supportive regulatory and financing landscape be ensured (e.g. state-backed guarantees, PPA platforms, demand pooling facilities to be used on a voluntary basis).

29 ACER is monitoring market trends, financing frameworks, regulatory settings, and key challenges and opportunities for each EU Member State and Norway, by means of country sheets.

30 As an illustration, the Italian PPA platform provides the first example of how market-based regulatory instruments can support PPAs.

1.3.1. Case study: Italian power purchase agreement platform[14]

Overview - Gestore dei Mercati Energetici (GME) is developing a PPA Platform as a dedicated trading venue for standardised renewable PPAs within Italy's forward electricity market (*mercato elettrico a termine* – MTE).[15]

To ensure effective risk management, GME acts as central counterparty, while Gestore dei Servizi Energetici, the state-owned company responsible for issuing state back-guarantees, serves as guarantor of last resort for contracts covered by state-backed guarantee.

The goal is to integrate the platform with the existing forward market and to increase transparency in the PPA market.

Tradable products. Trading is limited to standardised physical PPA contracts with baseload and peak-load profiles, in line with MTE. The contract duration ranges from 5 to 10 years.

Functioning. Trading on the PPA platform will be conducted through a one-sided marginal auction mechanism with anonymous orders. PPA trades and the interaction with MTE are considered as follows:

- In the pre-trading phase, bids/offers are only admitted if the relevant auction participant has sufficient collateral at MTE for the first delivery year of a transaction.
- Once a successful trade is concluded, the PPA contract position for the first delivery year is transferred to MTE.
- This process of transferring the upcoming yearly position of the PPA contract to MTE is repeated ahead of each year of the PPA contract's delivery period, unless one of the counterparties has insufficient collaterals at MTE to cover the transferred year. If the transfer cannot be executed, the counterparty with insufficient collaterals at MTE will be penalised.

Eligibility criteria. The scheme applies to renewable energy facilities that are newly built, reconstructed, reactivated, upgraded or under construction. Participants must obtain electricity market qualification before accessing the platform.

Limitations. The platform does not accommodate pay-as-produced PPAs or virtual PPAs, limiting the scope of tradable PPAs. Standardisation facilitates a streamlined negotiation process but narrows contractual options.

Conclusion. The Italian PPA platform, though still under development, is a market-based initiative aiming for the integration of PPAs into the market for standard forward products. On a voluntary basis, such platforms could complement existing arrangement and support the growth of the EU PPA market by offering additional trading alternatives for market participants.

14 Note: This explanatory box outlines the main features of the Italian PPA platform. While similar initiatives are emerging across the EU, it represents the first regulated PPA market, coupled with state-backed guarantees also acting as a demand pooling facility. The case study is provided for illustrative and information purposes only.

15 GME has also been operating a PPA bulletin board since 2022. The bulletin board functions as a structured non-binding registry of anonymous buy and sell interests for renewable electricity, supporting transparency and streamlining negotiations between counterparties. Additional details are available here.

1.3.2. Case study: negative prices[16]

A larger PPA market increases interactions with spot and forward markets, which may reduce liquidity and raise the likelihood of negative prices if producers are incentivised to generate regardless of demand (*produce-and-forget*). Poorly designed CfDs, including support schemes and virtual PPAs, can create such incentives. The following case study illustrates the risks and design considerations.

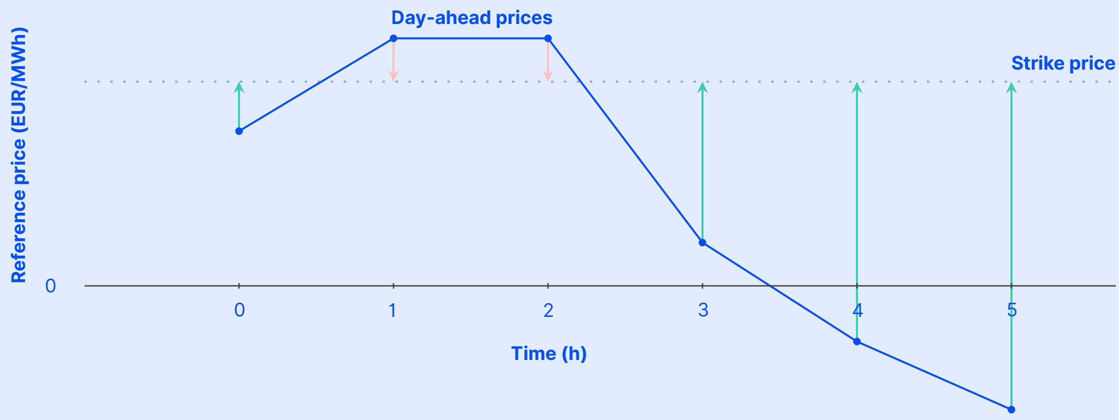
How does a two-sided contract for difference work?

CfDs are widespread financial products with various applications, ranging from cross-zonal risk hedging tools (e.g. LTTRs) to products that drive investments in new renewable assets (e.g. support schemes and virtual PPAs). A CfD is a financial product typically concluded between a generator and an off-taker. In the case of private deals, the market usually refers to them as "virtual PPAs" or "financial PPAs"; however, a CfD can also be a support scheme aiming at driving investments in new renewable energy assets.

It defines a strike price and a reference price, which may be set in various ways, such as the day-ahead market price, an ex-ante or ex-post computation (e.g. the average of day-ahead prices in the previous year). The reference price is settled against the strike price, meaning that if the reference price is lower than the strike price the generator receives a payment while a clawback applies if the reference price is higher than the strike price.

In this qualitative case study, the reference price is the hourly day-ahead market price (Figure 5).

Figure 5: Explanatory figure on the functioning of a two-sided CfD



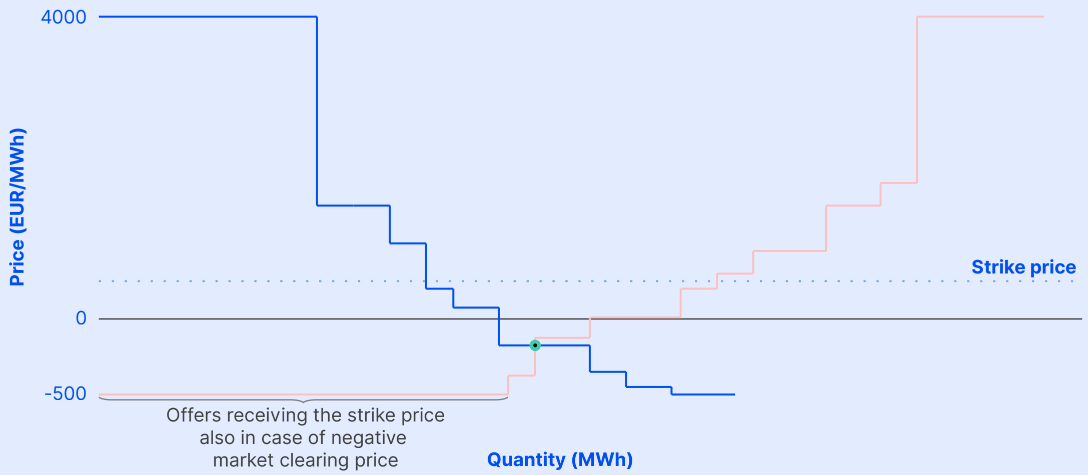
Source: ACER

16 Note: This explanatory box outlines the potential negative effects of poorly designed CfDs, such as virtual PPAs or support schemes, on the day-ahead market. The case study is provided for illustrative and information purposes only. Additional details on the design of CfDs can be found in "Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation", Kitzing L., Held A., Gephart M., Wagner F., Anatolitis V., Klessmann C., RSC/FSR, 2024.

What impact do poorly designed contracts for difference have on the market?

If not properly designed, CfDs may distort bidding behaviour by incentivising generation during periods of negative prices, a *produce-and-forget* effect, whereby producers continue to receive a strike-price payment, meaning a top-up payment from the reference price to the strike price, even if market prices fall below zero. In such cases, the market risk is shifted to the off-taker, and generators may submit bids as low as -500 EUR/MWh, knowing they will be compensated up to the strike price.

Figure 6: CfDs incentivising the produce-and-forget effect increase the occurrence of negative prices



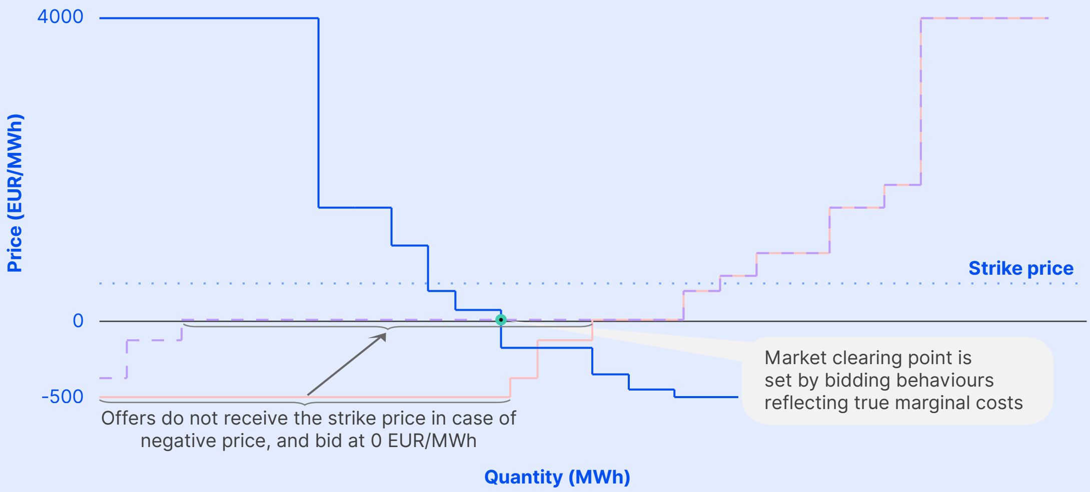
Source: ACER

Qualitative case study

Figure 6 illustrates a market scenario with low demand, high renewable generation, and no scope for cross-border exchanges.

The scenario assumes widespread use of virtual PPAs (i.e. private CfDs) and the absence of provisions to address negative prices. As a result, producers under such contracts may offer their volumes at -500 EUR/MWh. This bidding behaviour increases both the likelihood and the severity of negative prices. In this case, poorly designed CfDs contribute directly to a negative market clearing price.

Figure 7: CfDs not incentivising the produce-and-forget effect reduces the occurrence of negative prices



Source: ACER

Figure 7 shows a similar scenario of low demand and high renewable generation. In this case, CfDs are designed to avoid the produce-and-forget effect. Generators are incentivised to offer volumes at their true marginal cost, which for solar and wind is 0 EUR/MWh. As a result, the market clears at 0 EUR/MWh.

CfDs, whether subsidy schemes or private virtual PPAs, should not incentivise generation when prices are negative. Support schemes should limit payouts in such cases, while PPA contracts should clearly define how to handle the risk of negative prices and disincentivise generation when prices are negative. Based on available information, some recent PPAs have included clauses to mitigate this risk, with contractual flexibility enabling tailored solutions.

2. Day-ahead markets

31 Day-ahead results set the main price reference for electricity markets. They guide forward trading expectations and influence real-time balancing actions. Understanding how weather, network constraints, and bidding behaviour affect day-ahead prices therefore helps explain market dynamics across all timeframes.

32 Day-ahead market outcomes are increasingly shaped by weather conditions and system events. This section reviews the main drivers, illustrates them through case studies, and highlights possible responses to certain market outcomes.

33 More data is available on the ACER website in the form of dashboards. The first dashboard focuses on renewable generation and key system indicators, providing insights into the occurrence of negative prices and their link to generation, load, temperature, and wind conditions.

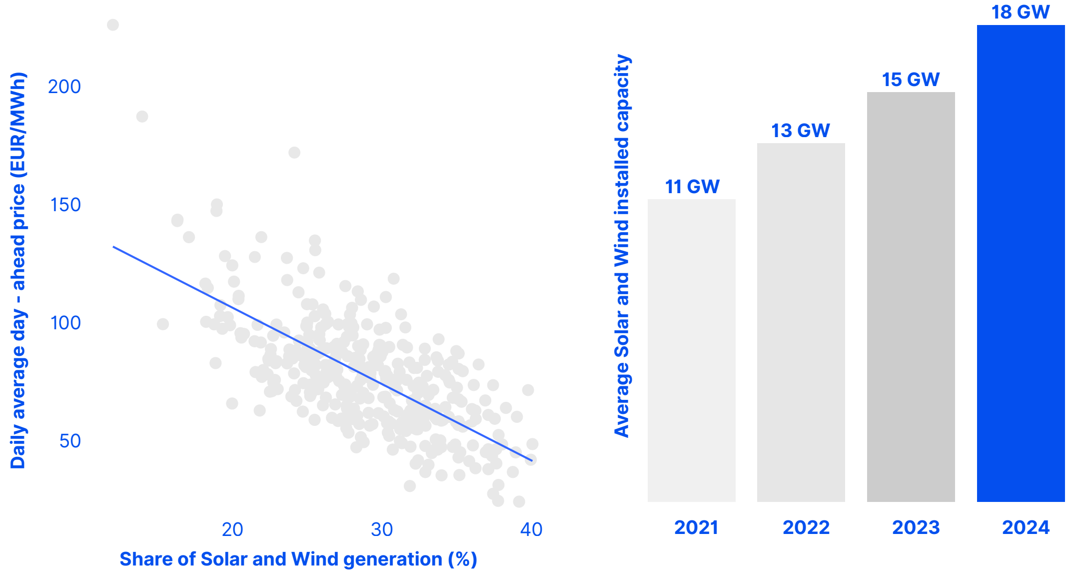
34 The second dashboard offers an overview of market dynamics, using REMIT data to track developments in the day-ahead and intraday markets, as well as churn factors.

2.1. Weather conditions are increasingly shaping electricity price dynamics

35 The growing share of renewable energy sources, particularly wind and solar, is reshaping price formation in European electricity markets. Figure 8 shows that day-ahead prices fall when renewable generation is high, highlighting their price-lowering effect during sunny or windy conditions. The progress of European decarbonisation, supported by increasing installed renewable capacity, which helps to reduce reliance on fossil fuels, especially during daytime and windy periods.

Figure 8: More use of renewables is leading to lower prices as installed solar and wind grow

Average daily price as a function of the share of solar and wind generation in the EU, 2024 (% and EUR/MWh), left, and average solar and wind installed capacity in the EU, 2021-2024 (GW), right



Source: ACER elaboration based on ENTSO-E transparency platform data.

Note: The daily share of solar and wind generation was calculated as a percentage of total electricity production.

2.2. Weather events and interdependence affect market outcomes

36 The weather-dependent nature of solar and wind energy introduces sources of price variation. Periods of low renewable output, particularly during the winter months, can result in pronounced price increases. This phenomenon shows the growing sensitivity of day-ahead prices to short-term weather conditions.

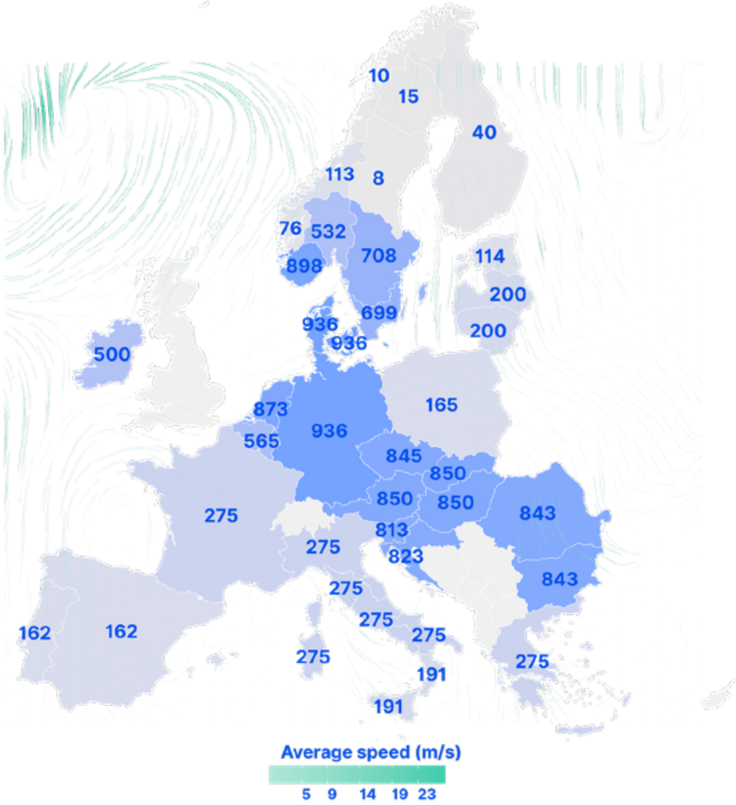
2.2.1. Low renewable output in winter

37 This sensitivity was illustrated in December 2024, when large parts of Europe experienced a significant reduction in renewable generation due to a winter Dunkelflaute.[17] Figure 9 shows that on 12 December 2024 day-ahead prices rose sharply across Central and South-Eastern Europe, particularly during the evening peak hours. The drop in renewable output was mainly compensated for by higher generation from gas-fired power plants, which acted as price setters in most bidding zones.

17 Dunkelflaute is a German term describing periods of low wind and solar generation, often occurring in winter, when both wind speeds and sunlight are limited (from "dunkel", meaning "dark", and "flaute", meaning "calm").

Figure 9: Low wind and sun output drive sharp day-ahead price increases

Day-ahead prices and wind speed in the EU and Norway – 12 December 2024 at 17:00 CET (EUR/MWh)



Source: ACER elaboration based on ENTSO – E transparency platform data and Copernicus data – ERA5.

38 During such periods of system stress, local pressure can spread across borders, highlighting the importance of regional coordination and shared resilience mechanisms. While the *Dunkelflaute* event of 12 December 2024 had a pan-European dimension, its impact was not uniform across countries and bidding zones.

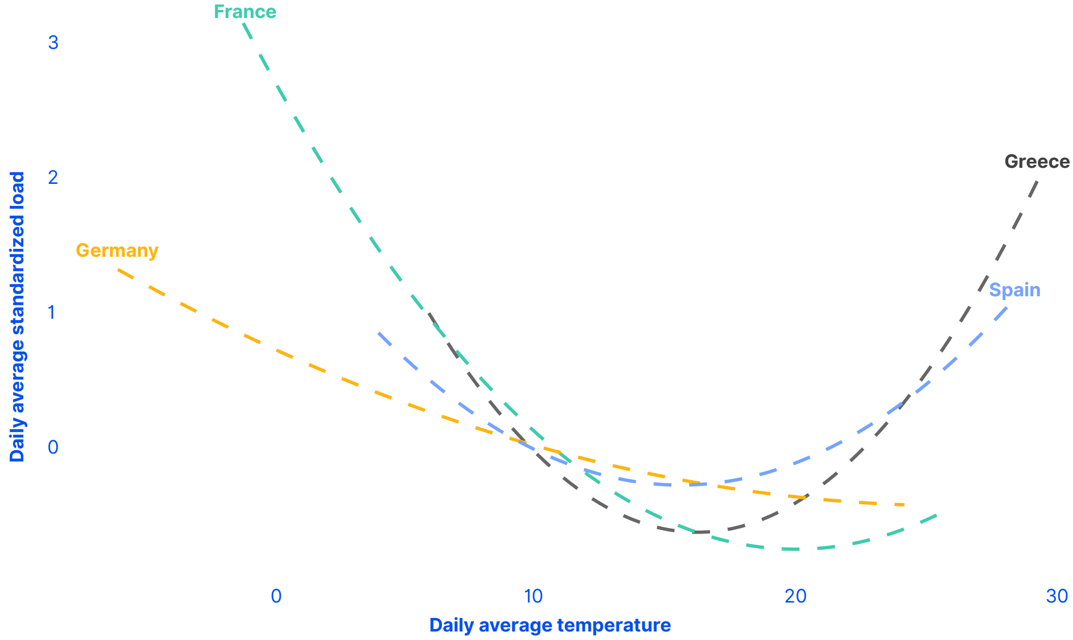
39 In the Central and West Europe regions, the *Dunkelflaute* was paired with a significant shortfall in renewable output and marked price swings. Germany, the largest market and a net importer during the event, played a key role in regional price formation, highlighting the interconnected nature of the shock. A detailed explanation of Germany's impact and the analytical approach is provided in Annex I.

2.2.2. High electricity demand in the summer

40 While winter *Dunkelflaute* events have long been recognised for their impact on renewable generation and market stability, summer heatwaves are increasingly seen as another source of systemic stress. These climatic extremes place upward pressure on electricity demand and market prices, adding to volatility across the system.

Figure 10: In the south, higher temperatures drive electricity demand

Temperature–demand[18] relationship in Europe and selected Member States, 2024 (MW per °C)



Source: ACER elaboration based on ENTSO – E transparency platform data and Copernicus data – ERA5.

41 When temperatures rise above 20 °C, electricity demand tends to increase, primarily driven by cooling needs. On average across Europe, for each country, demand grows by approximately 100 MW per additional degree Celsius. However, this effect is notably stronger in some Member States, with demand rising by 388 MW per degree in Greece and 592 MW per degree in Spain in 2024.

42 This demand rise is not uniform across Europe and is influenced mainly by local climate conditions. Member States experiencing higher temperatures show a more pronounced trend.[19]

18 Demand is normalised to ensure comparability of the temperature-demand relationship across countries. See Annex I for more details.

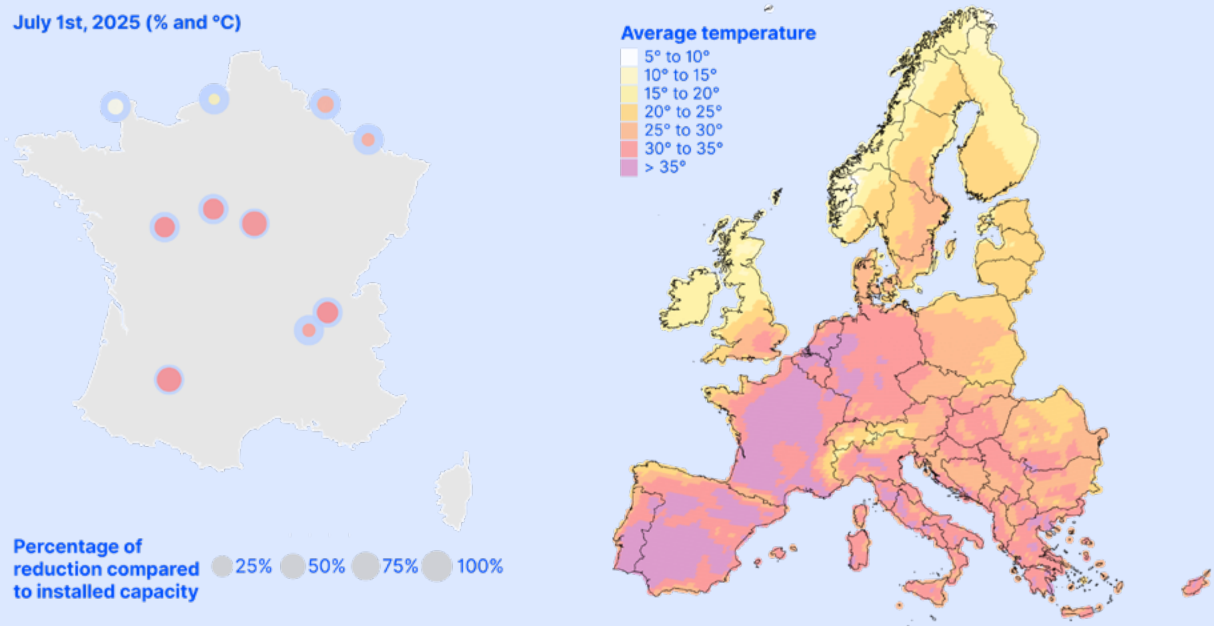
19 The intensity of the trend reflects not only temperature but also national demand structures and the share of electricity in household energy use.

2.2.3. Case study: 1 July 2025 heatwave stress

Summer temperature-induced stress occurred on 1 July 2025, when a persistent heatwave impacted large parts of West and Central Europe. In France, nuclear generation was curtailed by high river temperatures, which limited cooling capacity. At the same time, electricity demand surged, driven by widespread use of air conditioning during a period in which national average temperatures exceeded 35 °C, with local peaks surpassing 40°C.

Figure 11: Heatwave cuts nuclear output while demand increases

Reduction in offered capacity of French nuclear power plants on 1 July 2025 (% and °C), left, and maximum European temperatures in July 2025 (°C), right



This mismatch between evening electricity demand peaks and declining solar output, created market pressure. In the absence of sufficient flexibility resources such as cross-zonal flows, energy storage or responsive demand, electricity prices rose sharply across several Member States. On that day, day-ahead prices exceeded 230 EUR/MWh in France and reached 470 EUR/MWh in Germany and Poland, illustrating how extreme weather conditions can spread across interconnected markets.

This episode illustrates a heat-driven stress sequence:

1. demand increased sharply (+6% in France), reaching +600 MW per degree above 20°C;
2. nuclear output declined due to cooling limitations;
3. evening hours saw reduced solar input but sustained high demand;
4. flexibility was insufficient to stabilise prices.

43 Summer renewables lull periods (known in German as Hitzeflaute or Sommer-Dunkelflaute) combine high temperatures reducing supply with raising demand, exposing the power system to volatility and higher prices. These situations highlight the importance of system flexibility and cross-border coordination in supporting the clean energy transition.

44 Climatic conditions are playing an increasingly visible role in shaping interconnected electricity system dynamics. Weather-related factors, such as prolonged periods of low renewable output or temperature-driven spikes in consumption, have tangible and widespread effects across European markets. Yet, a more renewable and interconnected system also brings greater energy independence and resilience, provided flexibility and integration continue to improve.

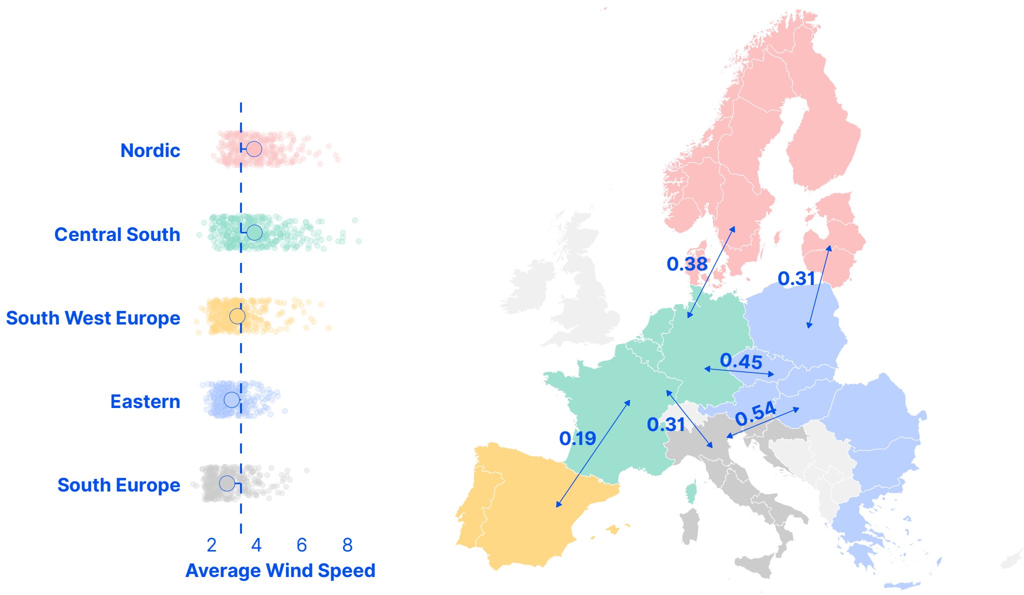
2.3. Infrastructure and coordination support more stable price dynamics

2.3.1. Different wind patterns support resilience through cross-regional integration

45 Weather patterns are not evenly spread across Europe. This variation can become an asset through appropriate infrastructure and coordination. When renewable output is low in one region, other areas may still generate a surplus. Figure 12 illustrates the correlation of hourly wind speeds across selected European regions in 2024.[20] These regions, or clusters, were defined by grouping together bidding zones with the most similar temporal wind patterns. The analysis reveals that several clusters are only weakly correlated with one another. This highlights the potential benefits of geographic diversification. Such statistical independence suggests that wind generation deficits in one cluster may not coincide with surpluses elsewhere. This creates opportunities to exchange electricity between these clusters.

Figure 12: Uncorrelated wind patterns offer opportunities for resilience

Correlation of wind speeds in selected areas of the EU and Norway, and corresponding daily average wind speed, 2024 (m/s)



Source: ACER elaboration based on Copernicus data – ERA5

20 For the detailed definition of correlation and the methodology applied to identify the clusters, see Annex I.

2.3.2. Case study: Spain – France interconnection brings additional capacity for cross border trade

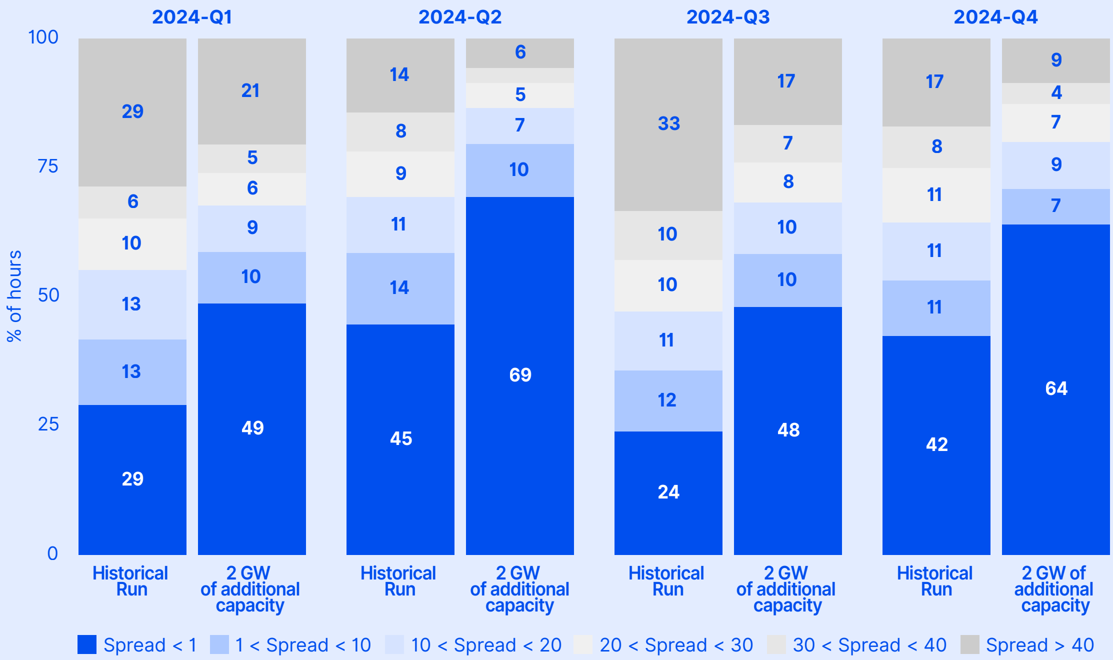
A new interconnection currently under construction between Spain and France illustrates a broader design principle: interconnections between zones with uncorrelated renewable profiles deliver greater system value, especially during periods of high stress.

This new 2 GW interconnection, supported by EUR 2.8 billion of investment, is designed to enhance cross-border capacity between these two markets. A simulation of the whole year of 2024, assuming the interconnection already to be in place, suggests that this additional capacity would significantly improve price convergence, facilitate renewables' integration, and strengthen system-wide resilience.

Price convergence in the Spain and France border benefit by the additional capacity illustrates the simulated[21] improvement in price convergence across the Spain-France border under this scenario.

Figure 13: Price convergence across the Spain-France border benefits from the additional capacity

Level of price convergence bringing additional capacity for cross border trade – 2024 (% of hours)



Source: ACER simulation based on Simulation Facility

These findings underline the wider importance of building interconnections between areas. Such links not only improve cross-border trade but also unlock flexibility gains that help damped weather-driven volatility and support the integration of renewable across Europe.

21 The Simulation Facility tool replicates the European market coupling algorithm. Due to inherent limitations in its reproducibility, simulation outcomes may vary across different runs, potentially leading to divergent results.

2.4. Market functioning under stress

46 The analysis so far has shown that weather conditions can place stress on the day-ahead market. Market functioning can also become a determining factor, either due to technical issues in market coupling or bidding behaviour that amplifies inefficiencies.

47 Two case studies illustrate these aspects. The first examines a partial market decoupling caused by technical problems that limited market integration. The second analyses bidding behaviour, showing how participants' changing bidding influence price formation.

2.4.1. Case study: partial market decoupling on 25 June 2024

Operational resilience is essential. Beyond weather-related stress, market functioning can also be challenged by technical incidents, as illustrated by the decoupling of the European Power Exchange (EPEX SPOT) in the day ahead market in June 2024. While the drivers differ, both cases highlight the need for resilient day-ahead market design and robust contingency planning.

On 25 June 2024, a technical incident prevented EPEX SPOT (hereafter: EPEX) from participating in the single day-ahead Coupling (SDAC) session for the delivery day of 26 June 2024, disrupting the coordinated European day-ahead electricity market. As a result, EPEX order books from the relevant bidding zones were decoupled from the rest of the SDAC and cleared separately via local auctions, without access to cross-zonal trade. Such local auctions could not benefit from the usual level of coordination in price formation, guaranteed by market coupling, leading to sharp price differences across bidding zones in the local auctions of EPEX and within the same bidding zone between the EPEX and the SDAC prices.

To assess the impact of the incident, a counterfactual simulation was conducted using the Simulation Facility tool, which replicates the day-ahead market coupling algorithm under different configurations.[22,23] Since the EPEX order book for the relevant delivery day was not available within the tool, and considering that bidding behaviour of certain market participants may have been affected by the decoupling event itself, the simulation was performed using trading sessions from the same week,[24] characterised by comparable market conditions. By averaging several weekdays, the analysis delivers a more robust estimate of the day-ahead efficiency loss linked to the partial decoupling.

The analysis compared two scenarios, using the average outcome from selected trading sessions within the week of the incident to ensure robustness of results.

1. **Full integration.** The historical day-ahead market outcome simulated under normal market coupling conditions,
2. **EPEX partial decoupling.** This was modelled through two complementary configurations.
   - *EPEX local auctions.* All order books except those corresponding to EPEX for Continental Europe were removed and cross-zonal capacity was set to zero on all SDAC bidding zone borders, simulating the relevant EPEX market clearing locally without cross-border exchanges.

22 The methodology is detailed in Annex I.

23 The Simulation Facility tool replicates the European market coupling algorithm. Due to inherent limitations in its reproducibility, simulation outcomes may vary across different runs, potentially leading to divergent results.

24 The analysis considered trading sessions from 24, 27 and 28 June 2024. Trading session from 25 June 2024 was excluded due to a failure of the Core capacity calculation process, leading to constrained cross-zonal capacities.

- *SDAC without EPEX*. The EPEX order books for continental Europe were removed and cross-zonal capacity between continental Europe and the Nordic region was set to zero, representing the conditions of SDAC on the day of the EPEX partial decoupling.

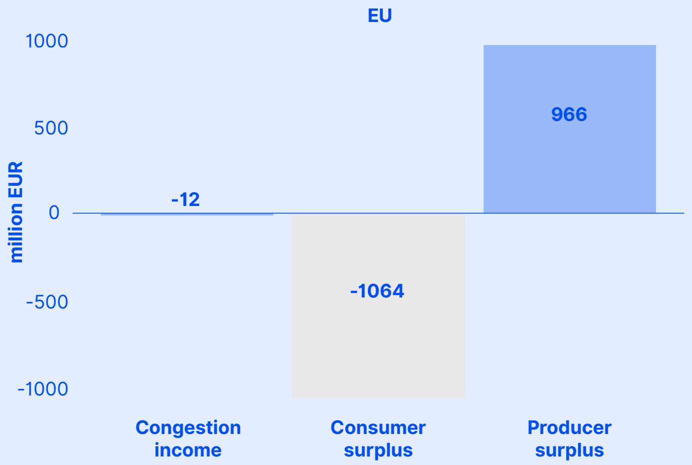
The welfare impact of the partial decoupling was then assessed by calculating the economic surplus, defined as the sum of consumer surplus, producer surplus (directly provided by the Simulation Facility) and congestion income.[25] By comparing the total economic surplus between the full integration and EPEX partial decoupling scenarios, the analysis quantifies the welfare loss attributable to the decoupling event.

The simulation shows a welfare loss of EUR 110 million on average for the simulated days, when comparing the fully coupled and partially decoupled scenarios. This gap highlights how the absence of a single order book and limited cross-zonal trade reduces the efficiency of day-ahead market. Some of these efficiency losses may be offset by higher trading activity in later timeframes, such as pan-European intraday auctions (IDAs) and continuous trading. Volumes traded during the intraday timeframe at EPEX on the day of the partial decoupling were approximately 79% higher than the average of the remaining days of that same week.

The results also show that welfare losses are uneven across Member States and market stakeholders. Changes in producer and consumer surplus show a significant welfare transfer between them, as shown in Figure 14, which highlights the varying impact on consumer and producer surplus.[26]

Figure 14: Distributional effects of partial decoupling

Average changes in producer surplus, consumer surplus and congestion income in Single Day-Ahead Coupling as a consequence of an EPEX partial decoupling – 24, 27, 28 June 2024



Since the decoupling event, ACER has worked closely with EU nominated electricity market operators (NEMOs) and TSOs through a series of workshops to identify measures to strengthen the robustness of market coupling, reducing the likelihood of decoupling and mitigating its impact when it occurs. Discussions focused on improving order-book submission, developing better fallback capacity allocation solutions, ensuring a single reference price, and introducing limited deadline flexibilities.

25 Congestion rents were derived from the commercial exchanges between zones multiplied by the corresponding interzonal price differentials.

26 A detailed breakdown of the impact across all bidding zones in the EPEX core region is provided in Annex I.

48 Day-ahead markets remain central to efficient price formation, but their resilience relies on system readiness. Strengthening flexibility through storage, demand response, and dispatchable capacity helps absorb weather-driven shocks. Strategic interconnections, especially between zones with uncorrelated renewable profiles, reduce volatility and improve collective security of supply. Robust monitoring and coordinated operations support timely and transparent responses, while contingency planning for technical incidents, such as partial decoupling, safeguards market efficiency and trust.

2.4.2. Analysis of bidding curves during high prices in South-East Europe during summer 2024 - A case study considering Greece

Background. During summer 2024, the Southeast Europe region experienced numerous occurrences of severe high day-ahead prices, reaching up to ~1000 EUR/MWh, especially in the evening hours.

Several factors contributed to this scenario, including:

1. high electricity demand, due to exceptionally high temperatures and increased export to Ukraine;
2. scarcity in supply and lack of flexibility, due to outages in gas-fired power plants and low levels in hydro reservoirs; and
3. limited cross-zonal exchanges, due to planned outages in transmission assets.

Content of the analysis. Considering these aspects, ACER assessed the change in bidding curves and its impact on market prices. Focussing the case study on Greece made it possible to benefit from the unique data availability and transparency of the order books in South-East Europe.[27] ACER re-built the hourly day-ahead demand and supply curves for the bidding zone Greece. The analysis focused on two items.

1. **Shapes of demand and supply curves,** to assess how the curves changed when the market was tighter.

2. **Shifts of supply curves,** to assess to what extent changes in supply-side drivers during tight periods affect market prices. Such changing drivers can include outages of generation assets, additional cross-zonal trade or the exercise of market power.

Methodology – The analysis considered the period from 15 June 2024 to 15 September 2024 at 20:00 (local time). The sample included 93 observations, meaning 93 pairs of demand and supply curves.

How were hourly curves re-constructed? To re-build Greek hourly demand and supply curves three datasets were considered: (1) Aggregated (and anonymised) buy and sell order curves. This dataset also included information on explicit import and export (i.e. electricity exchanges with non-EU Member States); (2) block orders; (3) implicit import and export (i.e. electricity exchanges resulting from the EU internal electricity market).

To re-construct supply curves, offers were sorted by increasing price. Accepted block orders were placed at -400 EUR/MWh, while rejected block orders were placed at +3500 EUR/MWh; implicit import was placed at -300 EUR/MWh. Due to limited availability of data, these assumptions were taken. Therefore, the results presented in this assessment need to be considered as estimates. For further information on limitations, please find them at the end of the case study.

27 Data on the order books are publicly available on the website of EnEx S.A. (i.e. Greek NEMO). Moreover, RAAEY (i.e. Greek national regulatory authority) provides visual representation of hourly demand and supply curves through publicly available dashboards.

Average aggregated curves. To assess the changes in the curves, and the profitability of exercising market power, when the market was tight, ACER created four scenarios filtering the sample by different price thresholds.

- **Baseline.** This scenario included all the 93 observations. Note that the market clearing price was always above 100 EUR/MWh.
- **Stressed.** This scenario included 17 observations. The sample was filtered considering only market clearing prices equal to or above 500 EUR/MWh.
- **Critical.** This scenario included 2 observations. The sample was filtered considering only market clearing prices equal or above 900 EUR/MWh.
- **Extreme.** This scenario included only one observation, with the highest market clearing prices equalling 942 EUR/MWh. This scenario referred to 04 September 2024 at 20:00.

Average aggregated curves, representing more than one hour of data, considered the willingness to buy/sell rescaled based on the number of observations in the sample.

The findings suggest that demand and supply curves change when the market becomes tighter.

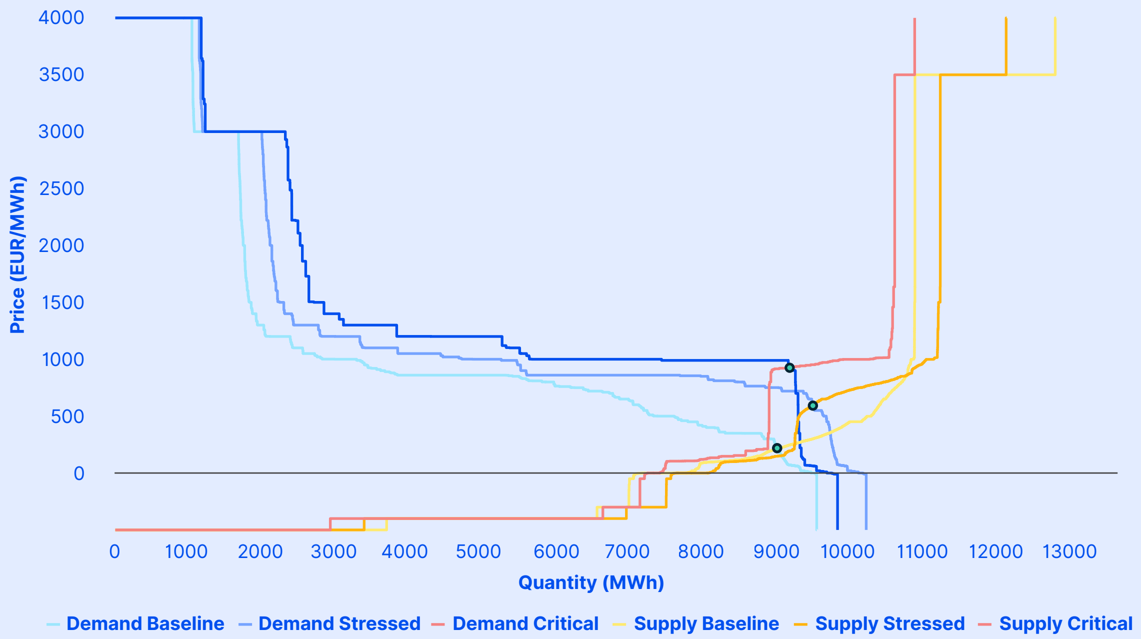
Analysis 1 (Shapes of demand and supply curves). The purpose of this analysis was to assess how bidding curves changed when the market was tighter. The analysis focused on the shape of the supply curves especially in the area surrounding the market clearing point.

Figure 15 provides a visual representation of the average aggregated curves for the scenarios Baseline, Stressed and Critical. The following can be observed.

- **Baseline scenario.** Average aggregated supply (i.e. 'Supply baseline ') increased gradually and smoothly with no particular change in shape before the market clearing point. In the area surrounding the market clearing point the shape of the curve was concave, with no price jumps. Average aggregated demand (i.e. 'Demand Baseline ') also decreased gradually and smoothly.
- **Stressed scenario.** Average aggregate supply (i.e. 'Supply Stressed ') showed a different pattern compared to the previous scenario. In the area surrounding the market clearing point the shape of the curve was no longer concave but convex, with a visible price jump. Average aggregated demand (i.e. 'Demand stressed ') also showed a different pattern, with bids showing a clear willingness to buy electricity at a higher price. In this scenario, the results suggest a change in bidding behaviour, in both demand and supply orders, which might have impacted the price formation and contributed to high prices.
- **Critical scenario.** Average aggregated supply (i.e. 'Supply Critical') showed a pattern similar to the stressed scenario but much more exacerbated. A vertical price jump was visible before the market clearing point, and almost no sell orders[28] were placed in the 200-900 EUR/MWh price range. Average aggregated demand (i.e. 'Demand critical') showed a similar (and more exacerbated) pattern to the stressed scenario. In this scenario, the results suggest a change in bidding behaviour, in both demand and supply orders, which might have impacted the price formation and contributed to high prices.

28 From the dataset 'aggregated (and anonymized) buy and sell orders curves'.

Figure 15: Greek average aggregated demand and supply curves feature different shapes under different market conditions – Baseline, Stressed and Critical scenarios.



Source: ACER

Analysis 2 (shifts of supply curves) – This analysis aimed to investigate the impact of changes in supply-side drivers on market prices when the market is tight. This gives an indication of the profitability of exercising market power. To achieve this goal, counterfactual supply curves were constructed for the scenarios Baseline, Stressed and Extreme. As a counterfactual the addition of generation capacity of a competitively priced power plant was considered, to estimate how much prices would have decreased if additional generation capacity was offered to the market.[29] For the given example a shift of the actual supply to the right of 650 MWh[30] was implemented.

Therefore, counterfactual equilibria would have lower market clearing prices, while the impact on the volumes would remain negligible. The results on the prices were as follows.

- **Baseline scenario.** The price dropped by ~100 EUR/MWh.
- **Stressed scenario.** The price dropped by ~420 EUR/MWh.
- **Extreme scenario.** The price dropped by ~630 EUR/MWh.

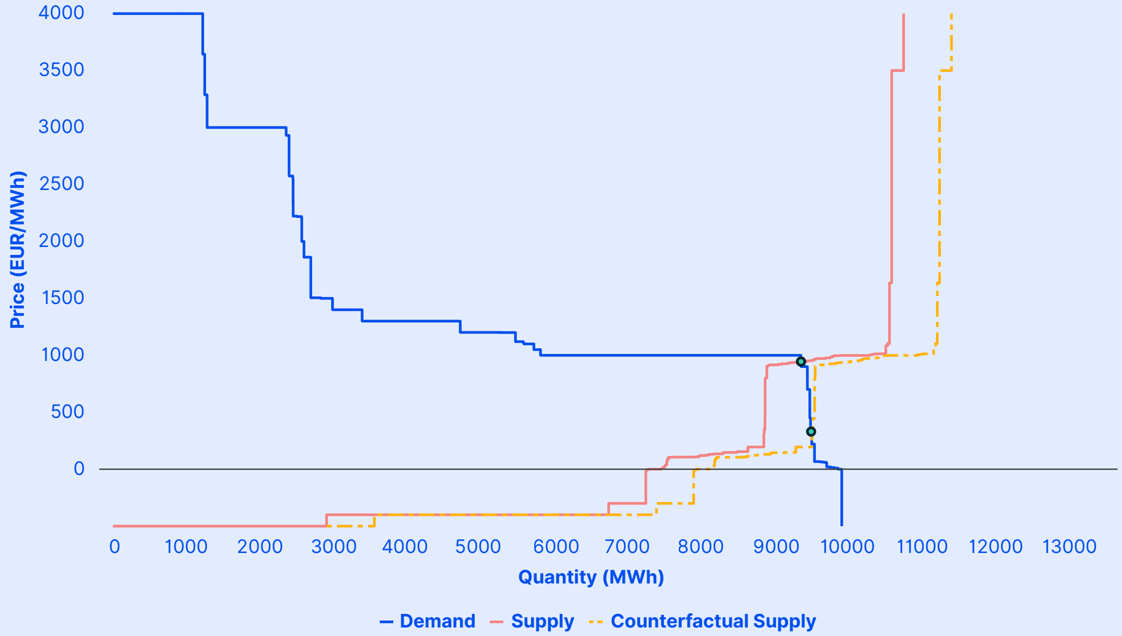
Figure 16 provides a visual representation of the price drop in the "extreme" scenario. The results suggested that, when the market is tight:

- unavailable generation capacity or limitations in cross-zonal trade have a significant impact on market prices;
- the exercise of market power becomes more profitable.

29 In this scenario, a shift to the right means that the additional generation is placed at -500 EUR/MWh. Despite constituting a limitation for the baseline case, it is unlikely to be a limitation for the stressed and extreme case. In other words, even if the additional generation was plugged in the counterfactual supply at a reasonably higher price, for example reflecting the true average marginal cost of a CCGT power plant, simulation results for the stressed and extreme scenarios are unlikely to be affected since the supply curve would in any case intersect the demand at the same counterfactual market clearing point.

30 Please note that 650 MWh is an indicative number, representing ~7% of the total volumes exchanged and ~50% of the rejected offered volumes. Alternative counterfactual supply curves could be considered.

Figure 16: Greek day-ahead actual demand, actual supply, and counterfactual supply curves – 4 September 2024 at 20:00 – Extreme scenario.



Source: ACER

Conclusions and recommendations – The results presented in this assessment suggest the following.

- **Bidding behaviours** change when the market is tight, contributing to high prices.
- **Changes in supply-side drivers** significantly affect market prices, especially when the market is tight. This implies that the exercise of market power becomes more profitable in such cases.

Transparent and competitive EU electricity markets are a cornerstone of the energy transition. The findings of the analysis could trigger the following measures to be considered and discussed:

1. Market integration promotes cross-border competition, mitigating the risk of exercising market power. The internal electricity market allows for the activation of the cheapest units to meet electricity demand across the whole of the EU, combining the bids and offers of all coupled bidding zones, provided that sufficient cross-zonal capacity is made available by EU TSOs. Over the past decade, much progress has been made in terms of integrating electricity markets. However, further integration would have allowed the high-price events seen in the South-East Europe region to be mitigated. As examples, the timely implementation of the 70% requirement, the expansion of flow-based capacity calculation and allocation to South-East Europe, the integration of the Western Balkans into market coupling, and the improvements in the coordination of transmission and generation outages would have all contributed to mitigating these high-price events. In particular, the 2025 market monitoring report on cross-zonal capacities and congestion management demonstrated that increased access to cross-zonal trade would have significantly mitigated the observed high-price events by allowing for additional cross-border competition.
2. Further fostering of accessible, high-quality publicly available data to increase market transparency.
3. Further analysis by national regulatory authorities and competition authorities on whether market power was used to manipulate the market or abuse dominant positions (for example, in the form of capacity withholding).
4. Consider and study other measures, such as, but not limited to, those raised in the `ACER's Final Assessment of the EU Wholesale Electricity Market Design` and the `Report on the impact of developing peak-shaving products on the Union electricity market under normal market circumstances`.

Additional information on methodology and limitations

Additional information on methodology to construct aggregated demand and supply curves. In the explanatory example (in the table below), the sample included only two demand curves (i.e. hourly demands 1 and 2), each composed of only one order. The average aggregated demand rescaled the quantity by the number of observations (i.e. in this case, it divided the quantity of each bid by 2) and kept the same orders' prices. The average aggregated demand included two rescaled orders.

Hourly demand 1	Hourly demand 2	Average aggregated demand
• Order Q=100; P=50	• Order Q=80; P=40	• Order Q=50; P=50 • Order Q=40; P=40

Additional information on limitations. Despite the high-quality standards of the publicly accessible data for the Greek day-ahead market provided by Hellenic Energy Exchange (and the informative dashboard provided by the Regulatory Authority for Energy, Waste and Water, RAAEY), not all of the necessary information was available to re-build the curves with an accuracy of 100%.

Therefore, assumptions needed to be made to rebuild the curves.

1. **Block orders and implicit coupling.** Only information on volumes is available, prices were undisclosed. Therefore, an assumption on the price was needed. Information on block orders and implicit coupling was added to the curves with the following assumptions on price:
   - **Supply curve.** Accepted block orders were placed at -400 EUR/MWh, while rejected block orders were placed at +3500 EUR/MWh; implicit import was placed at –300 EUR/MWh.
   - **Demand curve.** Accepted block orders were placed at +3500 EUR/MWh, while rejected block orders were placed at -400 EUR/MWh; implicit export was placed at +3000 EUR/MWh.

   In other words, this way, block orders and implicit coupling shifted the curves only without affecting their overall shapes. Accepted sold block orders in the three scenarios presented on the first analysis varied as follows:
   - baseline: ~2900 MWh;
   - stressed: ~3500 MWh;
   - critical: ~ 3700 MWh;

   Despite constituting a limitation, the difference among the accepted block orders in the three scenarios was not substantial enough to (fully) explain the shape among the average aggregated curves.
   Moreover, the counterfactual scenarios presented in the second analysis did not consider possible changes in implicit import and export between bidding zones. This affected the results for the baseline and stressed scenarios, but not the results for the extreme scenario.

2. **Hybrid curves.** Greek curves are hybrid (i.e. linear piecewise and stepwise).[31] In this assessment, curves were rebuilt as if they were stepwise only.

3. **Consideration of outages.** Unavailable generation capacity can affect both the shape and the shift of the supply curves.

49 Findings from the day-ahead timeframe provide essential context for intraday and balancing markets. They highlight how day-ahead price signals influence real-time system operation, guiding the use of flexible resources and coordination between neighbouring markets. The following chapters build on this link to assess how intraday and balancing integration can strengthen system efficiency and stability.

31 For additional information on stepwise, linear piecewise and hybrid curves, please check "EUPHEMIA Public Description", All NEMO Committee, 2024.

3. Intraday markets

50 Intraday market outcomes are increasingly important for managing variability from renewable generation and short-term system events. This section reviews continuous trading and the new IDAs launched in June 2024, set against rising renewable generation, and highlights the potential of flow-based allocation for cross-border efficiency.

51 More data is available on the ACER website in the form of dashboards.

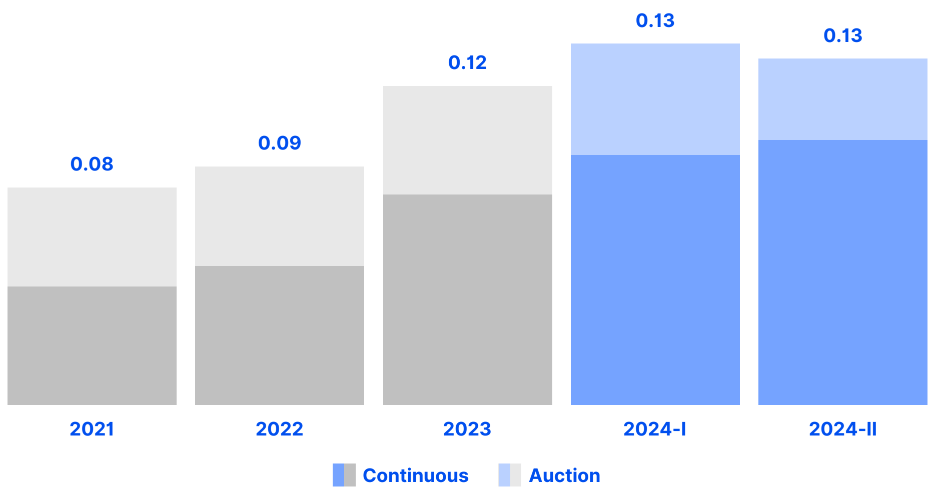
3.1. Intraday markets: liquidity, efficiency, and renewable integration

52 Continuous intraday market trading plays a central role in balancing supply and demand close to delivery. It enables participants to correct renewable or demand forecast errors and supports the integration of variable generation. This section reviews 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 supports renewable integration

53 Increasing liquidity in intraday markets helps manage imbalances closer to real-time. Such imbalances can stem from unplanned outages of generation facilities or from forecast errors for renewable generation. Between 2021 and 2024, churn factors and traded volumes rose in line with growing wind and solar shares. Figure 17 shows this trend for churn factors. For 2024, values are split into two periods, namely before and after the go-live of IDAs, which is further covered in Section 3.2. Figure 18 indicates the increase in traded volumes, both domestically and cross-zonally.

Figure 17: Intraday market activity increased in line with renewable growth
Yearly churn factors in intraday markets by type of trade, EU, 2021-2024

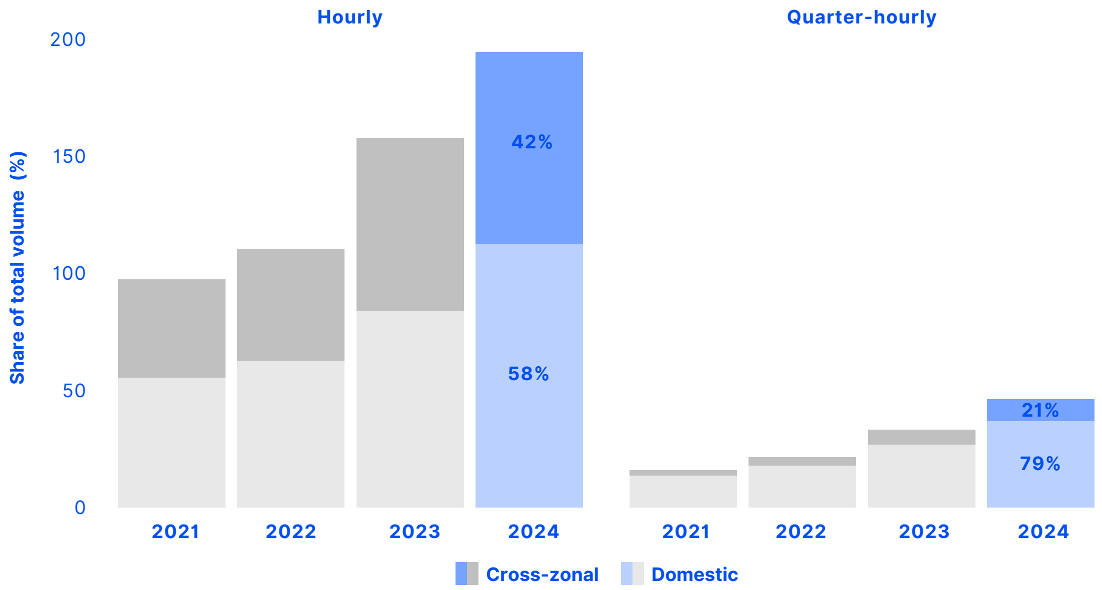


Source: ACER calculations based on REMIT and ENTSO-E Transparency Platform data.

Note: The data for 2024 is split into I) before and II) after go-live of the Single Intraday Coupling (SIDC) intraday auctions on 13 June 2024 to indicate potential changes in liquidity. The intraday auctions before go-live are regional, held in several Member States.

Figure 18: Intraday traded volumes increased steadily, with cross-zonal trading playing a growing role

Evolution of intraday traded volumes in the continuous market by domestic versus cross-zonal trade, EU, 2021-2024 (TWh)



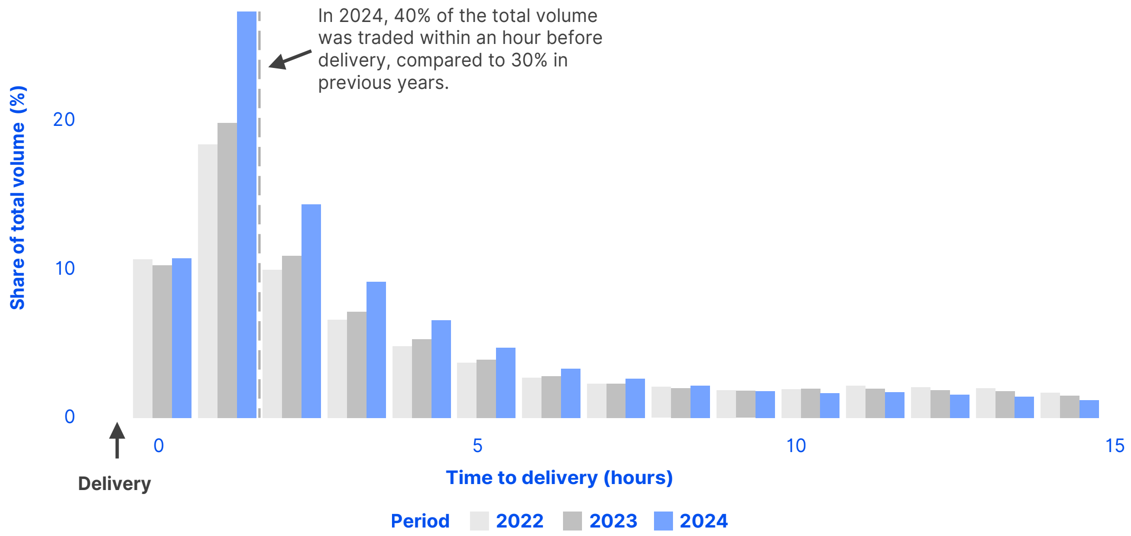
Source: ACER calculations based on data from NEMOs.

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

54 A higher share of intraday volumes is traded in the last hours to delivery. This shows that the intraday market is increasingly used to correct imbalance positions before real-time, which is essential with more variable renewables in the system. Figure 19 illustrates this shift, with liquidity moving closer to delivery in recent years.

Figure 19: Intraday trading is shifting closer to real time

Breakdown of time to delivery for volumes traded in the continuous intraday market, EU-27, 2022-2024 (%)



Source: ACER calculations based on data from NEMOs.

Note: The left-most bar (hour = 0) 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), which explains the higher traded volumes observed in the corresponding bar.

3.1.2. Day-ahead – intraday spread indicates market efficiency

55 Day-ahead and intraday price spreads are a simple test of market efficiency. They show how well electricity prices reflect real-time supply and demand. In efficient markets, the average spread is close to zero, meaning day-ahead prices anticipate real-time conditions. Persistent deviations point to structural inefficiencies.

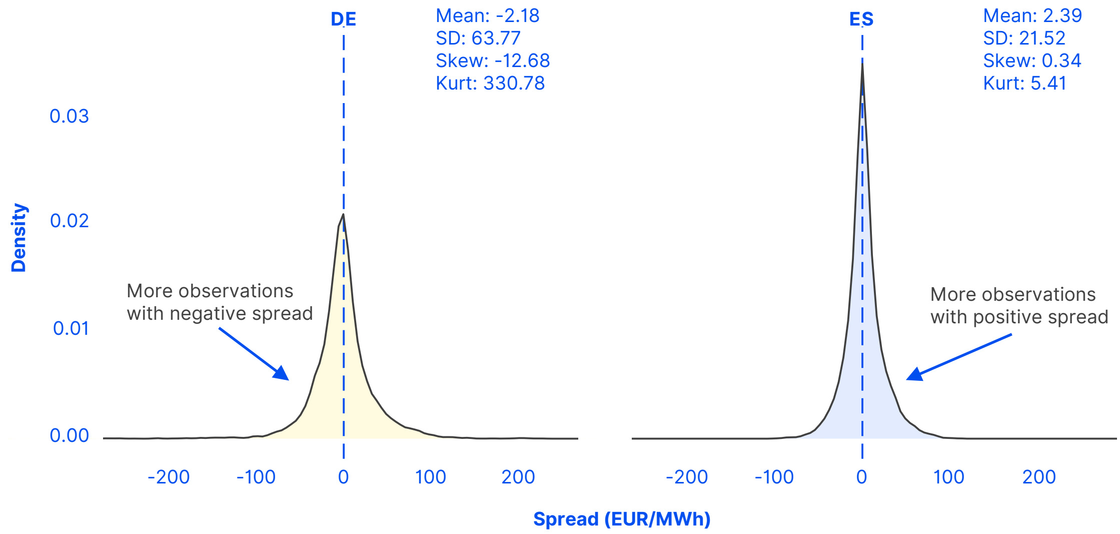
56 Figure 20 shows spreads for Germany and Spain. Both spot markets are broadly efficient. Germany's negative mean points to under-pricing of risk and higher real-time scarcity, signalling lower flexibility. Spain's positive average spread suggests greater risk aversion.[32]

57 Figure 21 shows that errors in wind or solar forecasts drive larger spreads. For example, when the forecast is higher than the actual generation, intraday prices tend to be higher than day-ahead prices (*+error, -spread*). As renewable shares grow, such errors are becoming more frequent and impactful. Better forecasting could narrow spreads and improve efficiency.

58 Efficiency matters more as renewable shares grow. It shows whether market design works well or whether systemic issues need attention. These include limited flexibility, imbalance prices, or cross-zonal constraints.

Figure 20: Day-ahead – intraday spreads confirm efficiency but reveal system differences

Distribution of day-ahead – intraday price spreads for selected bidding zones, Germany and Spain, 2024.



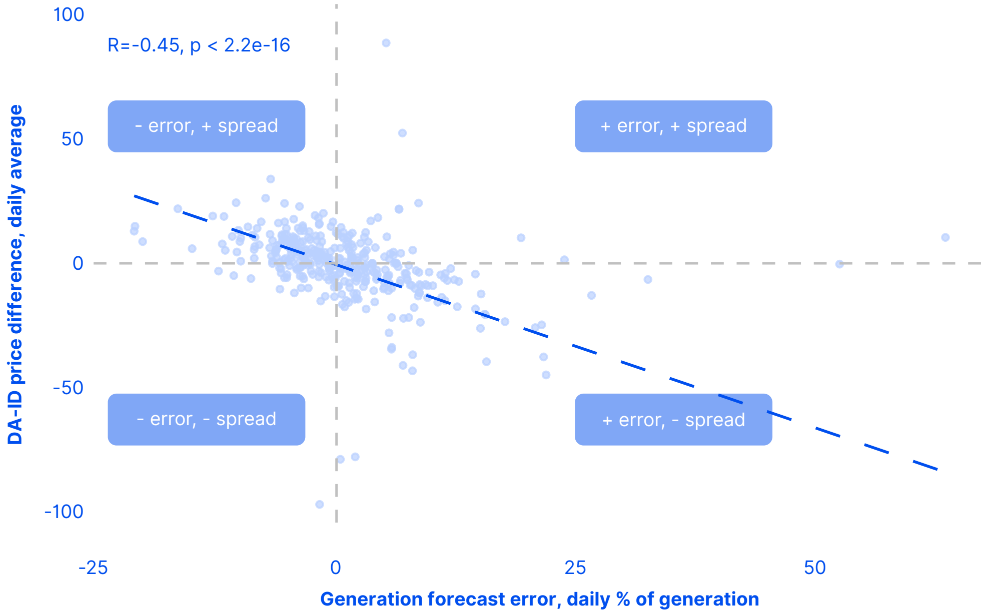
Source: ACER calculations using ENTSO-E Transparency Platform data for day-ahead prices and data from NEMOs for intraday prices.

Note: Indicators on the direction ('skewness') and extremes ('kurtosis') of price spreads reveal potential asymmetric price risk for the countries analysed. The skewness and kurtosis are explained in Annex II.

32 Spread distributions for other countries can be found in Annex II and suggest overall efficiency.

Figure 21: Forecast errors widen intraday spreads, highlighting the need for better tools

Impact of renewable forecast errors on intraday prices, Germany, 2024, price spread (EUR), forecast error (%)



Source: ACER calculations based on ENTSO-E transparency platform data and data from NEMOs.

*Note: The figure shows the correlation between wind and solar generation of the day-ahead forecast error and day-ahead and (continuous) intraday price difference. The forecast error is calculated as follows: error = (day-ahead forecast – actual generation)/ actual generation * 100. The R-value in the figure is the Pearson correlation coefficient, indicating the strength and direction of the relationship between the two variables.*

3.2. Introduction of intraday auctions: benefits for pricing and cross-border integration

59 IDAs were introduced in June 2024. Their intended goal is to increase the efficiency of intraday trade through price-based capacity allocation rather than allocation on a first-come first-served basis, giving market participants clearer price signals. This section analyses their main features and benefits.

60 The auctions indeed offer several benefits: uniform clearing prices improve transparency; and price signals ensure efficient cross zonal capacity allocation. These benefits will be examined further, along with the possible concern that the auctions may reduce liquidity in the intraday continuous trading.

Intraday auctions

Intraday Auctions (IDAs) were introduced in the single intraday coupling (SIDC) to complement continuous trading by offering scheduled auctions for cross-zonal electricity trading for the next and current days. They went live on 13 June 2024, with first delivery on 14 June 2024.

Auction schedule:

- **IDA1.** Gate closure at 15:00 CET (D-1), delivery hours 00:00–24:00.
- **IDA2.** Gate closure at 22:00 CET (D-1), delivery hours 00:00–24:00.
- **IDA3.** Gate closure at 10:00 CET (D), delivery hours 12:00–24:00.

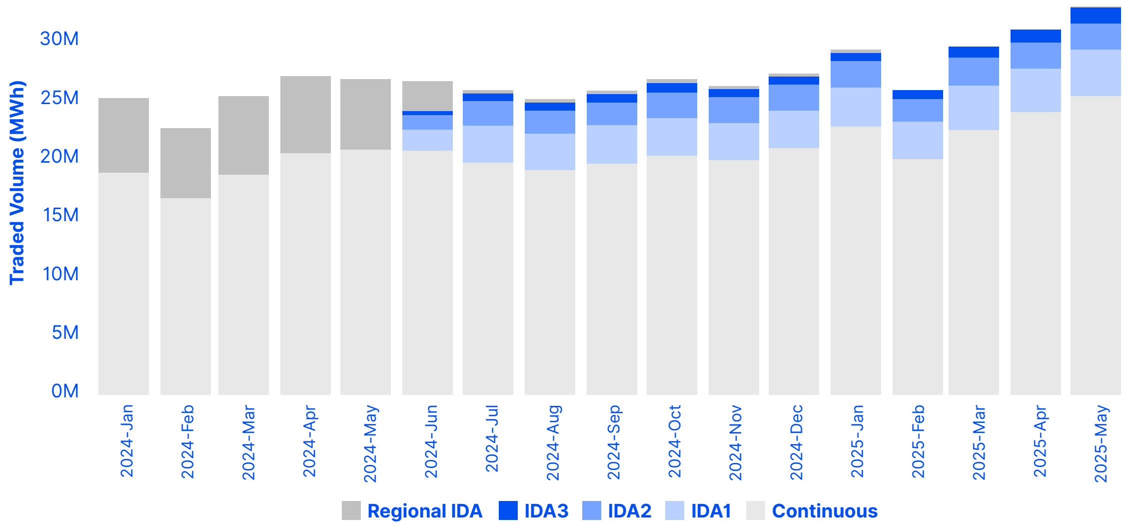
Capacity rules:
Cross-border continuous trading is paused for 20 minutes before and after each auction gate closure.
IDA1 allocates leftover day-ahead capacity.
IDA2/IDA3 use recalculated intraday capacity.

61 One possible concern regarding IDAs is that they compromise liquidity within the intraday continuous market. The analysis of churn factors in Section 3.1.1 and the evolution of traded volumes in Figure 22 show that this is not the case: liquidity increased in 2024, and continuous market volumes grew after the introduction of pan-European IDAs. In contrast, auction volumes have remained at similar levels to those seen previously, with a slow increase mostly occurring towards the end of 2024 and in early 2025. This suggests the IDAs have somewhat replaced the previous regional auctions.[33]

62 Figure 23 shows that most of the auction trading takes place in countries that previously held regional auctions, i.e. Ireland, Greece, Spain, Italy, Portugal, and Slovenia. Figure 22 also indicates that most volumes are traded in the first IDA, while the third auction records have the lowest activity, partly because it covers only half of the day.

Figure 22: Continuous trading volumes grew after IDAs went live

Evolution of traded volumes in intraday timeframe per product per month, EU (MWh).

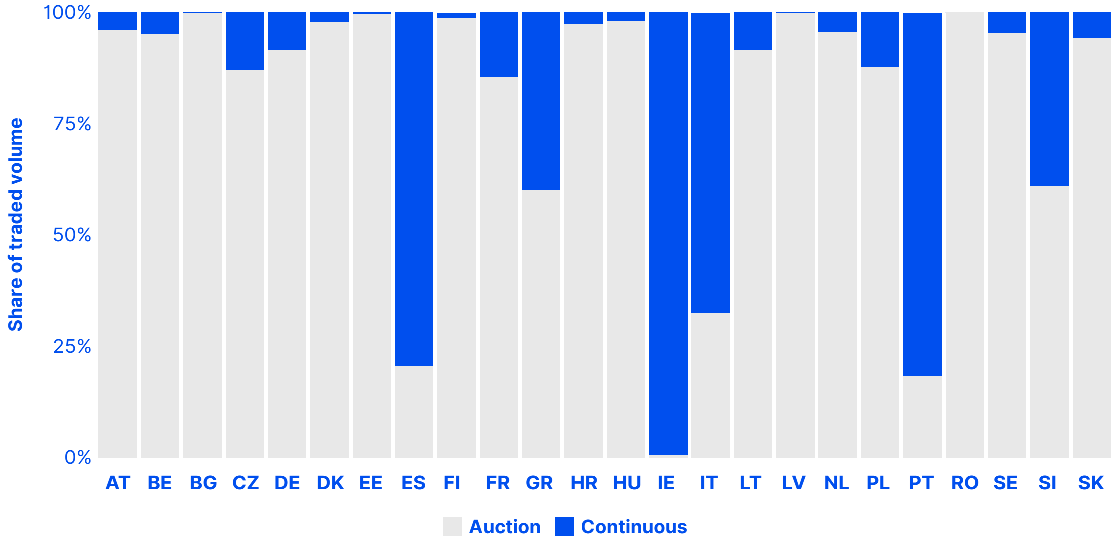


Source: ACER calculations based on REMIT data.

33 These regional auctions include complementary regional intraday auctions (CRIDAs) which were held on the borders of Greece, Italy, and Slovenia. Before IDA go-live, six regional IDAs were held in the Iberian Electricity Market MIBEL zone (Spain and Portugal). In Italy, three auctions were held in the intraday time frame. All regional auctions are now included in the SIDC IDAs, except for Ireland, which still holds regional auctions.

Figure 23: Auction trading concentrated in former regional auction Member States

Share of volume traded in auctions and in continuous trading in the EU by Member State, 2024 since IDA go-live. (%)



Source: ACER calculations based on REMIT data

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

63 One expected benefit of IDAs is that scarce cross-zonal capacity is allocated more efficiently than it would be on a first-come, first-served basis to the continuous market. More efficient allocation helps improve price convergence. Figure 24 shows that for the second IDA, held after intraday capacity recalculation, spreads were lowest for most market time units (MTUs) and borders in the Core capacity calculation region (CCR) in 2024. This indicates that prices between bidding zones often converged. This may be due to recalculation of cross-border capacity, which increases the capacity availability for cross-border trading and allows flows towards areas where electricity is most needed. However, spreads for the third auction are less comparable, as it covers only half of all the delivery hours.

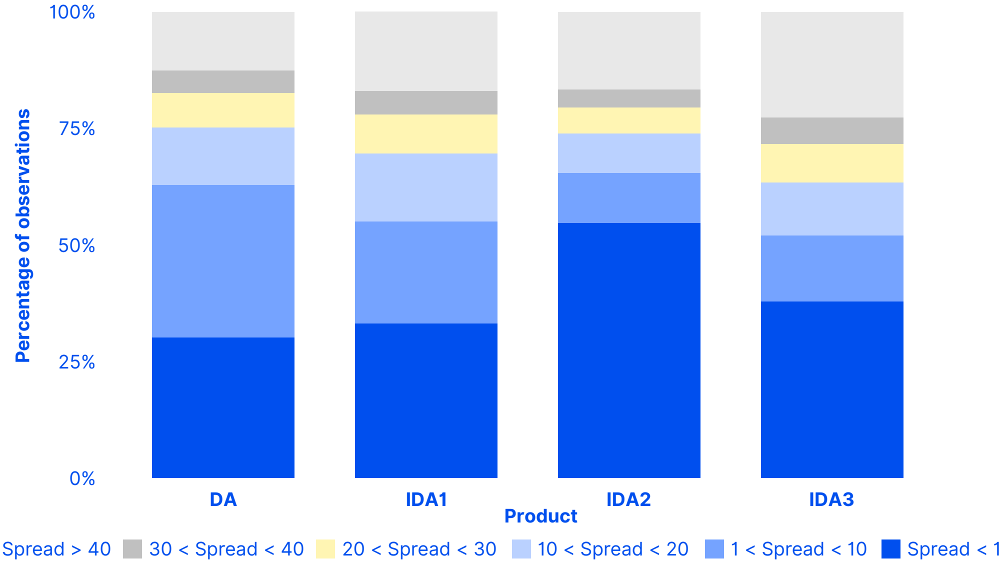
64 For the MTUs shown in Figure 24, the changes in direction of the spread between consecutive auctions were calculated to indicate how often the price spread changed. A change in the direction of the spread indicates a change in the trading direction and hence a shift from importing to exporting bidding zones (and vice versa). From day-ahead to IDA1, the spreads remained in the same direction 86% of the time, indicating that there was a change in direction in 14% of cases. The spreads in IDA1 and IDA2 were in the same direction 90% of the time, whereas for IDA2 and IDA3, this figure increased to 95%. The closer it is to delivery time, the less likely spreads are to change direction. This indicates coherent price convergence, with no instability detected in 2024.

65 The market clearing prices of IDAs give a clearer reflection of actual cross-border capacity scarcity at a given moment. Figure 24 shows that in about half of the MTUs in IDA2 in the Core CCR, capacity was scarce, pointing to the high value of additional cross-zonal capacity. Scarcity is even more prevalent in IDA1 and IDA3. Figure 25 provides an indication of scarcity per border in Core, which also indicates that scarcity is most prevalent in IDA1 and IDA3, with a few exceptions. The high average spreads for IDA3 could be due to this auction only including MTUs between 12:00 and 00:00. To make better use of scarce cross-zonal capacity, flow-based allocation should be implemented in the intraday timeframe, as discussed in the next section and in the 2025 monitoring report on cross-zonal capacities and congestion management.[34] More efficient allocation and pricing are especially important for integrating variable renewable generation and improving system flexibility.

34 See the 2025 monitoring report on transmission capacities for cross-zonal electricity trade and grid congestion management.

Figure 24: The second IDA improved price convergence through recalculated capacity

Breakdown of spread for Core borders in 2024 after the IDA go-live, per product (%)

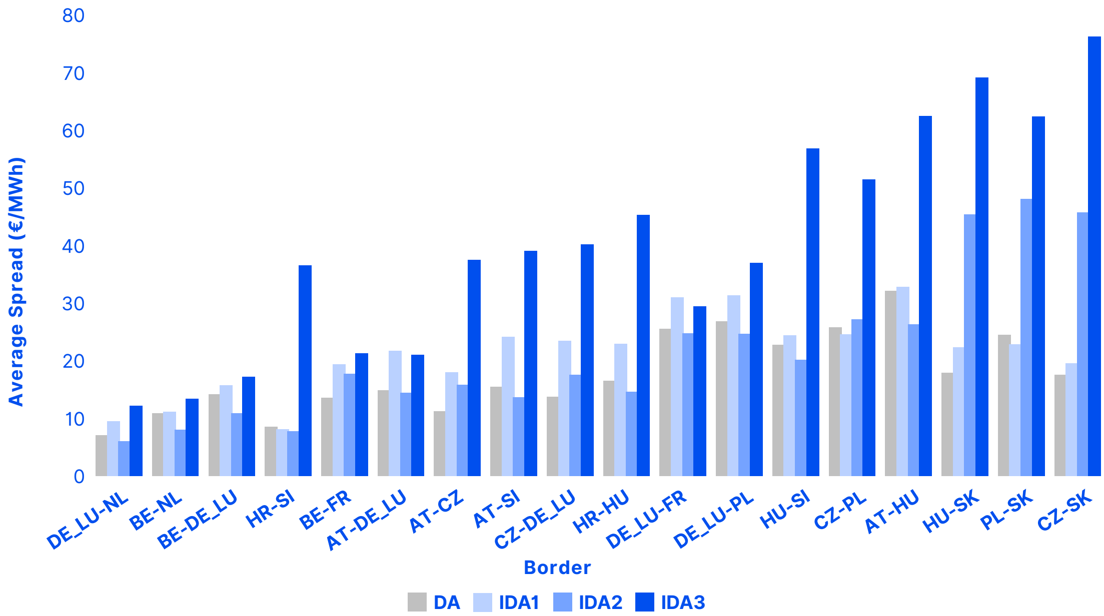


Source: ACER calculations based on JAO data.

Note: the spread is calculated for 2024, for all delivery hours since the go-live of the SIDC IDAs on 13 June 2024. The spread is calculated for the borders in the Core CCR, including borders of the following Member States: Belgium, Czechia, Germany, France, Croatia, Luxembourg, Hungary, Netherlands, Austria, Poland, Romania (not yet coupled in 2024), Slovenia and Slovakia. The breakdown is provided for day-ahead (DA) and for the three intraday auctions (IDA).

Figure 25: Frequent scarcity in Core IDAs highlights need for improved capacity calculation

Average price spread per border, for the day-ahead and IDAs, Core CCR, 2024 since IDA go-live. (EUR/MWh)



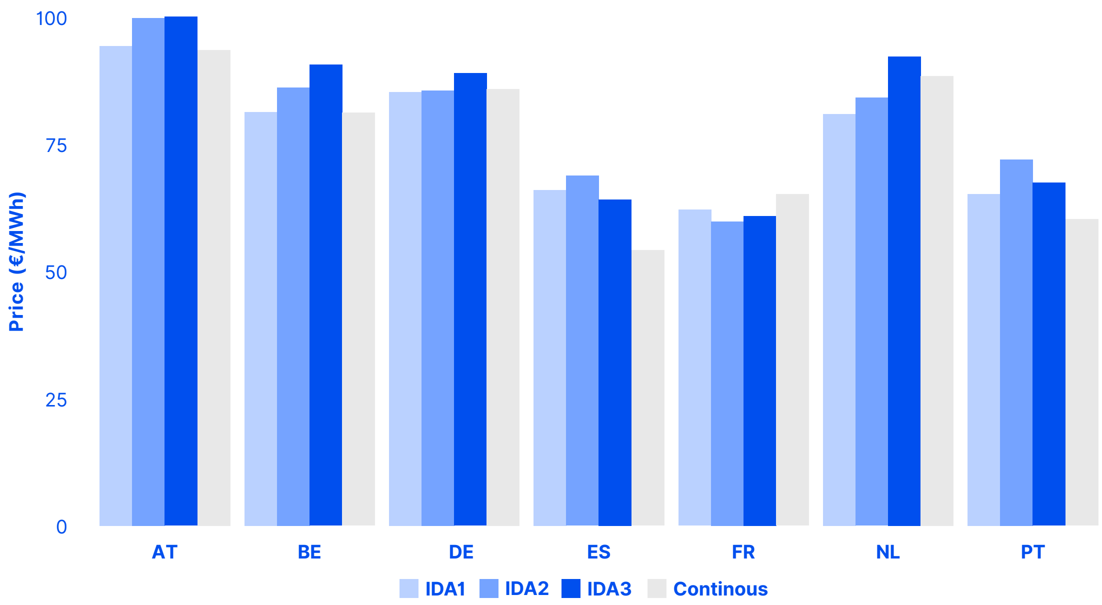
Source: ACER calculations based on data from the JAO Publication Tool.

Note: the spread is calculated for 2024, for all delivery hours since the go-live of the SIDC IDAs on 13 June 2024. The spread per border is calculated as the absolute price difference per border. The spread is calculated for each of the non-directed borders in the Core Capacity Calculation Region (CCR), including borders of countries: Belgium, Czechia, Germany, France, Croatia, Luxembourg, Hungary, the Netherlands, Austria, Poland, Romania (not yet coupled in 2024), Slovenia and Slovakia. Romania is excluded, as the borders were not coupled yet in 2024.

66 Another benefit of IDAs is that they provide a clear price signal. Figure 26 shows that in many countries, average auction prices (volume-weighted) are similar to continuous market averages. This suggests that auctions help anchor prices in the continuous market. A case study for Germany in 2024 explores this in more detail.

Figure 26: IDAs help anchor continuous prices across European markets

Volume-weighted average prices in pan-European IDAs and the continuous market, EU, 2024 (EUR/MWh)



Source: ACER calculations based on REMIT data.

Note: instead of the average market clearing price, the volume-weighted average price was calculated for IDAs due to insufficient information on the delivery hours in the data. The comparison of the volume-weighted averages also provides an estimate of how close the prices traded where.

3.2.1. Case study: intraday auction market clearing prices in Germany

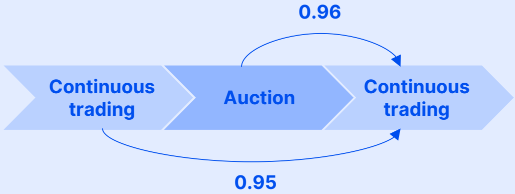
A case study on IDA market clearing prices in Germany examined whether auction prices set continuous market prices. The analysis focused on Germany in 2024 after IDA go-live and relied on REMIT data, which contain all orders and trades of the market. Germany was chosen as it has a large liquid intraday market, so it was especially interesting to study the impact of the auctions on continuous trading. The price setting was analysed for IDA2, as this auction happens after recalculation of cross-zonal capacity for the intraday timeframe through the intraday capacity calculation(b) or IDCC(b) process,[35] whereas IDA1 uses left-over capacities from the day-ahead market. Only MTUs for which congestion was determined in at least one of the borders were considered.

The analysis calculated the correlation between the pre-auction continuous prices and the post-auction continuous prices, and the correlation between the auction price and the post-auction continuous prices, as shown in Figure 27. Both correlations are high, at 0.97 and 0.96 respectively, indicating that both the pre-auction continuous price, and the auction price have a significant influence on the post-auction continuous price. This seems to suggest that the IDA gives an adequate price signal to the markets. This signal is taken up by the continuous trading after the IDA.

35 The Intraday Capacity Calculation process IDCC(b) delivers capacities by 21:45 for all delivery hours (00:00 - 24:00) of the subsequent day.

Figure 27: IDAs seem to influence the continuous market.

Correlation between pre-auction continuous prices and post-auction continuous prices, and auction market clearing prices and post-auction continuous clearing prices, IDA2, Germany, October-December 2024



Source: ACER calculations based on REMIT data.

3.3. Benefits of flow-based allocation in the intraday timeframe

67 Flow-based allocation in the intraday timeframe offers clear advantages over ATC. The switch to flow-based allocation in the day-ahead timeframe in the Core and Nordic regions has already shown these benefits.[36] Similar gains are also expected in intraday and balancing markets.

68 The greater performance of flow-based allocation comes from better capacity use, better congestion management, and wider access to flexibility. It captures interdependencies among all exchanges, while ATC only considers bilateral flows in isolation. In intraday markets this is key: ATC starts from the day-ahead clearing point but cannot reflect the network-wide optimisation behind it. As a result, ATC often remains locked around that point and constrains feasible trades.[37]

69 Case studies, such as the one on Czechia (see below), show how congestion on a single line can block several exchanges under ATC. Flow-based allocation, by contrast, allows more efficient use of the grid. In the Nordic day-ahead market, the switch to flow-based allocation reduced total ATC for intraday trading by more than 40%, confirming this structural shortcoming.[38]

36 See the 2025 monitoring report on transmission capacities for cross-zonal electricity trade and grid congestion management.

37 A simplified example of this mechanism is provided in Annex III.

38 See the 2025 monitoring report on transmission capacities for cross-zonal electricity trade and grid congestion management.

3.3.1. Case study for Czechia, showing benefits of flow-based allocation

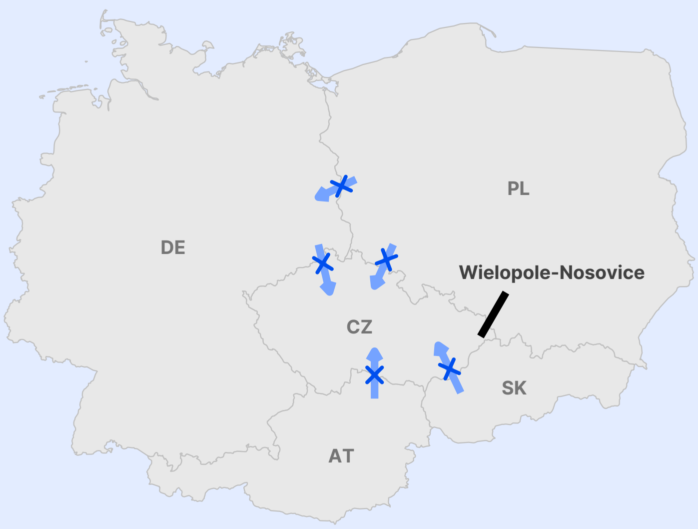
To illustrate this decrease in ATC for intraday, ACER analysed one hour on 23 January 2025 (01:00 to 02:00). In the day-ahead market, three congested critical network elements and contingencies (CNECs) in the eastern Core region were identified. Table 1 shows that 19 borders[39] had zero cross-zonal capacity due to ATC extraction and these congested CNECs. The Nosovice–Varin line blocked exports from Czechia, whereas the Wielopole–Nosovice line blocked imports to Czechia, which is illustrated in Figure 28. Together, these constraints eliminated all exchange possibilities for Czechia, even though other feasible flow patterns could have alleviated the overloads.

Table 1: Congestion on three CNECs blocked 19 cross-zonal borders
List of congested CNECs and associated blocked borders, 23 January 2025.

Congested CNEC	Blocked border
Nosovice (CZ) - Varin (SK)	Nine borders: CZ-AT, CZ-DE, CZ-PL, CZ-SK, AT-HU, HR-HU, AT-SI, DE-AT, PL-SK
Wielopole (PL) - Nosovice (CZ)	Five borders: AT-CZ, DE-CZ, SK-CZ, PL-CZ, PL-DE
Gonyu (HU) – Gyor (HU)	Five borders: HU-AT, HU-HR, HU-RO, SK-PL, HR-SI

Source: ACER elaboration on data from the JAO Publication Tool.

Figure 28: Congestion on a line can result in many exchanges not being possible with ATC extraction
Congested Wielopole – Nosovice CNEC and the borders with zero ATC because of this congestion, 23 January 2025



Source: ACER elaboration based on data from the JAO Publication Tool.

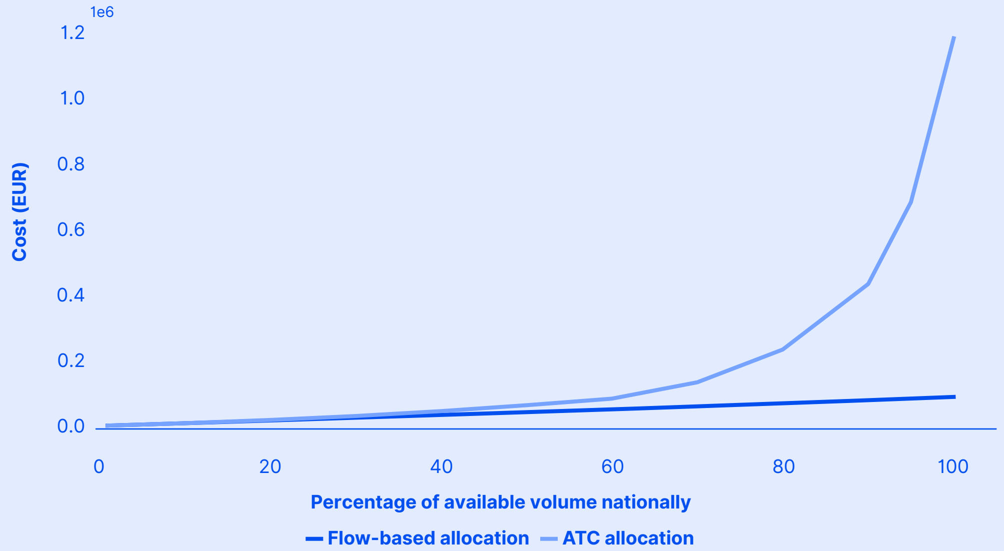
ACER developed a case study to demonstrate the greater efficiency of flow-based allocation. In the simulation, Czechia had varying demand, while demand in other Core bidding zones was set to zero. Figure 29 shows the costs of meeting Czech demand under ATC and flow-based allocation, using the flow-based domain and ATCs of the selected hour. When demand nears the top of the

39 Oriented borders account for both the border and flow direction (import or export).

Czech merit order, flow-based costs are far lower than those for ATC. Under ATC, imports are blocked, so the most expensive Czech bids must be activated to cover the demand. Under flow-based allocation, cheaper imports from other Core bidding zones are possible. Figure 30 illustrates this: when Czech demand equals the available local Czech sell orders, ATC allocation (left) blocks and drives prices up. Flow-based allocation (right) allows imports, keeping prices much lower, as only about 20% of the Czech local sell orders is activated. This shows the system is not in scarcity and confirms that ATC fails to capture feasible exchanges that flow-based allocation can unlock.

Figure 29: Flow-based allocation prevents scarcity and therefore the activation of expensive bids

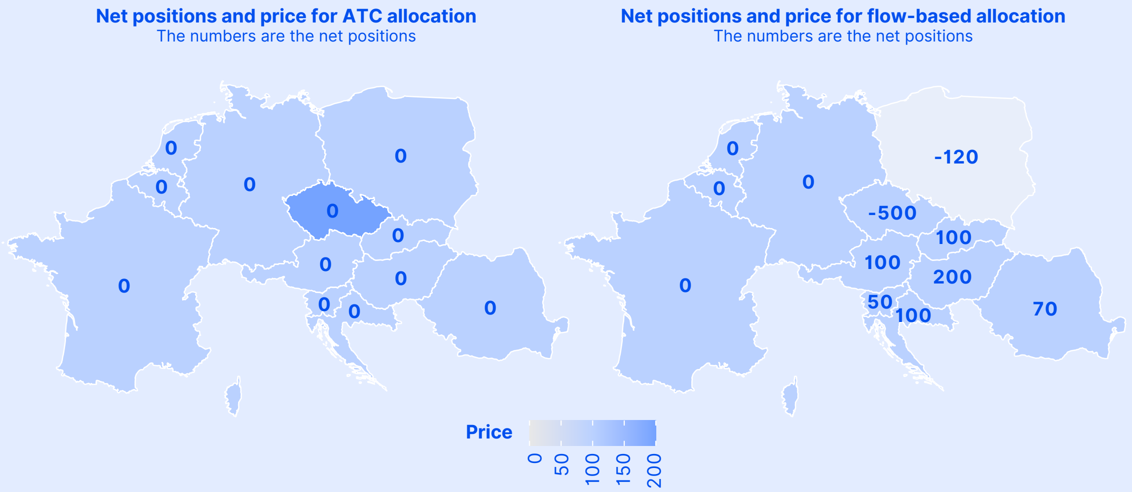
Cost of procuring different volumes with ATC and flow-based allocation, Czechia, 23 January 2025 01:00-02:00 (EUR)



Source: ACER calculations based on data from the JAO Publication Tool.

Figure 30: Flow-based allocation unlocks cheaper cross-border bids and helps in avoiding extreme prices

Net positions and prices for ATC (left) and flow-based (right) allocation, Core CCR, 23 January 2025 01:00-02:00, (MW and EUR)



Source: ACER calculations based on data from the JAO Publication Tool.

Note: the values in the bidding zones are net positions, whereas the shades represent prices. The net positions and prices were calculated for a demand of 600 MW in Czechia and 0 MW in other bidding zones, for the scenarios of ATC allocation, on the left, and flow-based allocation, on the right.

70 Overall, the case study shows the clear advantages of flow-based allocation over ATC. First, it uses the network more efficiently, lowering dispatch costs. Second, by expanding cross-zonal exchanges, it strengthens competition and reduces price volatility. Third, by widening exchange options, it helps Member States share flexibility more effectively, reducing overall system needs. Together, these effects lower costs for consumers.

71 Given these significant benefits, ACER stresses that flow-based allocation in intraday markets must be completed without further delay. This applies to both IDAs and the single continuous market, where it has been legally required since August 2023.[40] The lack of delivery delays efficiency gains and prevents consumers from benefiting from lower costs.

72 Intraday markets are becoming more important as the volume of variable renewable generation grows. Intraday trading provides the ability to trade in close to real time, where IDAs add clear and transparent price signals and more efficient use of cross-border capacity.[41] Flow-based allocation offers further potential to improve efficiency and resilience by unlocking cheaper bids and supporting the integration of renewable energy. Together, these developments strengthen system responsiveness and reduce exposure to weather-driven system imbalances.

40 See Annex III to ACER decision 11/2024.

41 See also 2025 monitoring report on transmission capacities for cross-zonal electricity trade and grid congestion management.

4. Balancing markets

73 Balancing the electricity system ensures frequency stability. TSOs are responsible for balancing generation and demand in real-time. To do so, they use various products: frequency containment reserve, automatic frequency restoration reserves (aFRR), manual frequency restoration reserves (mFRR) and replacement reserves (RR).[42] To secure sufficient resources, balancing capacity is procured in advance for each product, dimensioned according to the provisions of the System Operation Regulation.[43] Balancing energy is activated as required in real-time.

74 While day-ahead and intra-day markets are fully coupled, market integration is more limited for balancing markets. This leads to persistent high price spreads between national balancing markets. Therefore, further market integration and exchange are expected to deliver significant benefits for both balancing capacity and balancing energy. A dashboard published with this report gives an overview of the evolution of volumes, prices and exchanges of balancing services in the EU in recent years.

75 Before the Electricity Balancing Regulation, there was a wide range of national approaches to balancing.[44] These included regulated provision of services, varying product shares, and different approaches to ensuring frequency quality. The regulation paves the way towards more integrated balancing markets by:

- setting the basis for the standardisation of balancing products through a minimum set of standard characteristics,
- harmonising imbalance settlement and the imbalance settlement period to 15 minutes;[45]
- establishing two methodologies – market-based and co-optimisation - for allocating cross-zonal capacity for the exchange of balancing capacity and sharing of reserves; and
- laying the ground for European platforms enabling the exchange of balancing energy between TSOs.

42 RR and the platform for the exchange of balancing energy from RR is phased out until the end of 2025. (Announcement_from_RR_TSOs.pdf)

43 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation: Regulation - 2017/1485 - EN - EUR-Lex.

44 Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing: Regulation - 2017/2195 - EN - EUR-Lex (europa.eu).

45 ACER's monitoring shows broad implementation of the electricity imbalance settlement harmonisation methodology across the EU | www.acer.europa.eu.

76 Based on this foundation, several market integration projects were implemented or expanded. These include the platform for imbalance netting (the international grid control cooperation project), the platforms for the exchange of balancing energy from aFRR (the platform for the international coordination of automated frequency restoration and stable system operation (Picasso)), mFRR (the manually activated reserves initiative) and RR (the trans-European replacement reserves exchange project, which is to be phased out), and the Nordic and Baltic balancing capacity market. Existing market integration generated an economic surplus of more than EUR 1.6 billion in 2024.[46]

77 This section reviews recent developments in balancing markets and progress of market integration, focusing on PICASSO for the exchange of balancing energy from aFRR. It further analyses the potential for further exchanges in balancing capacity markets.

4.1. Progress of market integration on the platform for the exchange of balancing energy from automatic frequency restoration reserves (Picasso)

78 In the context of Picasso, the platform for aFRR, TSOs use an algorithm to optimise balancing energy activation from aFRR across Europe. Figure 31 shows the status of the platform accession.

79 By the legal deadline of July 2024,[47] only four Member States' TSOs were active on the platform: those of Czechia, Germany, Italy and Austria. In August 2024, two amendments were implemented, one regarding the pricing methodology and one regarding the implementation framework (see Section 4.1.1 for more details). A few months later, the TSOs of Belgium, Denmark, the Netherlands and Slovakia joined. Italy is a special situation, as its TSO joined in 2023 but suspended its participation in 2024. It is expected to rejoin by the end of November 2025. For more details on the Italian case, see last year's market integration report.[48] The following sections focus on developments in 2024, while also covering selected events and data from 2025.

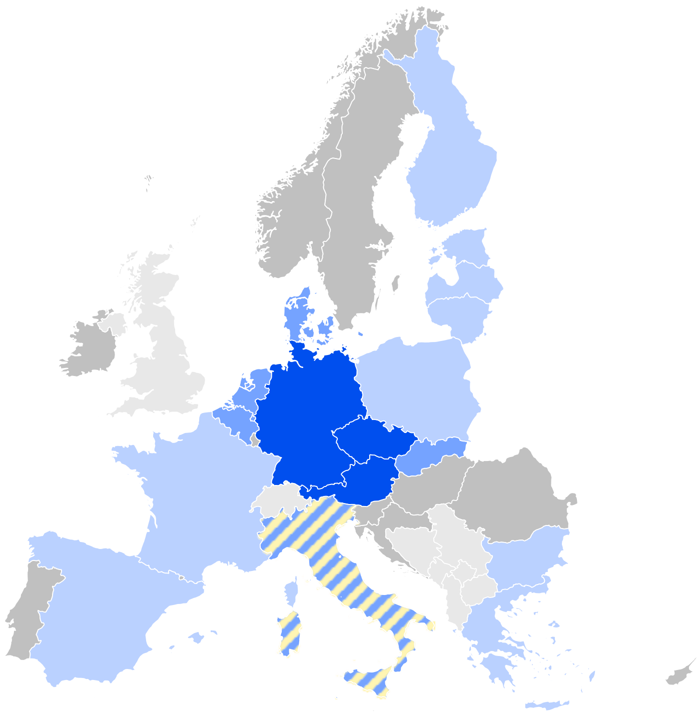
46 Sources: ENTSO-E, Market Report 2025; Nordic TSOs, Evaluation Report – The Nordic aFRR capacity market.

47 The legal deadline to join was in July 2022. However, TSOs could be granted a derogation to join at a later stage with the latest end date in July 2024.

48 See ACER's Market Integration Report: Progress of EU electricity wholesale market integration, 2024.

Figure 31: Limited accession by the end of 2024

Years in which TSOs joined Picasso by Member State, status in July 2025



Source: Picasso. For information on future membership please refer to the latest accession roadmap published on the Picasso website.

Note: The TSO of Luxemburg (Creos) is a non-operational member of Picasso. It is integrated via a common load frequency control area with the German TSO Amprion.

Background information on developments in the Nordic balancing markets

The Nordic synchronous area presents a special case, as historically all TSOs belonged to one load-frequency control area. Therefore, balancing service providers respond to a common frequency deviation, while the balancing energy demand is split pro-rata across TSOs. Such an approach can distort market prices, as balancing needs may be distributed arbitrarily.

To address this distortion, the TSOs that have joined the PICASSO platform, FI and DK2, plan to transition to area-control-error-based balancing with dedicated load-frequency controllers. For the accession of Norway and Sweden, each bidding zone will become a separate load-frequency control area, which will remove the shortcomings of the current pro-rata allocation.[49]

An additional challenge results from the fact that currently only Denmark and Finland have joined. While Sweden is not connected, there are no exchange possibilities between them. This limitation could be mitigated through ATC-sharing (see Section 4.1.3).

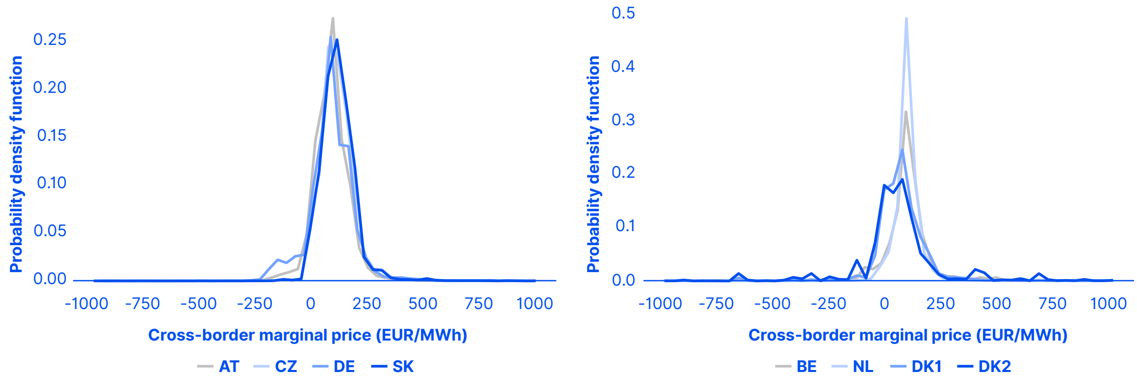
49 In parallel, with the implementation of the new automated Nordic mFRR balancing model in March 2025, the rest of the Nordic transitioned to a procurement of balancing services based on smaller LFC areas per bidding zone.

4.1.1. Amendments and the connection of further transmission system operators reduced the occurrence of price incidents

80 While most prices for activated balancing energy from aFRR remain in the range between - 200 and + 400 EUR/MWh across Member States active on Picasso (see Figure 32), rare high prices significantly influenced average activated balancing energy and imbalance prices. This report therefore follows up on the analysis of price incidents in last year's market integration report.

Figure 32: Prices for activated balancing energy rarely exceed 400 EUR/MWh

Distribution of prices for activated balancing energy on Picasso, including both positive and negative balancing energy, 2024



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

Note: The x-axis has been limited to the range between -1 000 and 1 000 for better readability. The full range including the price incidents is between -15 000 and 15 000.

Amending the pricing methodology reduced price incidents

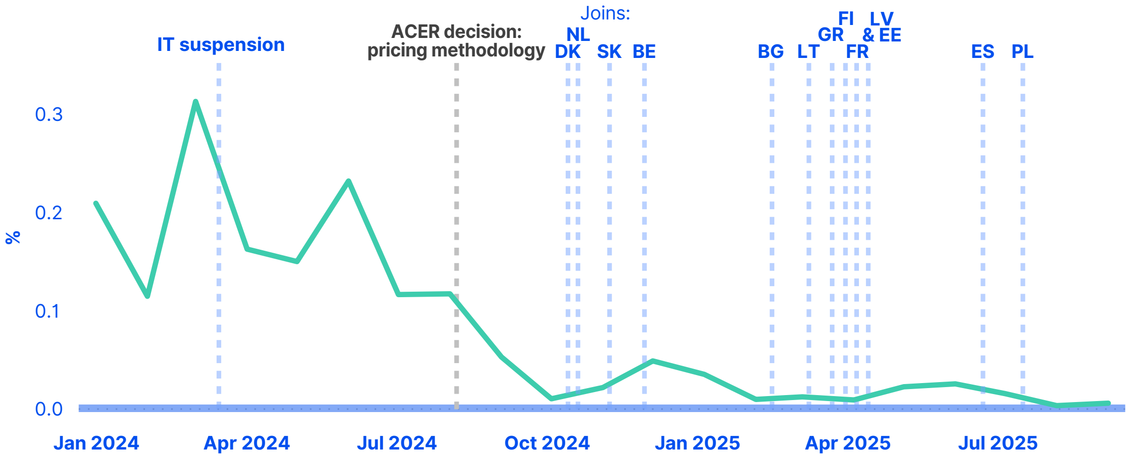
81 The analysis examines the impact of the August 2024 amendment to the balancing pricing methodology.[50] This amendment concerns the determination of the cross-border marginal price on the aFRR platform. Previously, the price was set by the highest bid selected by the Picasso activation optimisation function (AOF). However, due to the behaviour of load-frequency controllers, the bid setting the price was sometimes not actually activated by the TSO controller. To address this, the methodology was amended so that the cross-border marginal price is determined by the highest bid both selected by the AOF and activated by the TSO controller.

82 The benefits of this amendment are shown in Figure 32, which illustrates the reduction in the daily share of price incidents following its implementation. In Picasso, price incidents are defined as prices exceeding ±7 500 EUR/MWh.

50 ACER Decision 09/2024.

Figure 33: Price incidents decreased after the 2024 pricing methodology amendment

Share of optimisation cycles[51] with price incidents before and after the amendment, January 2024-September 2025 (%)

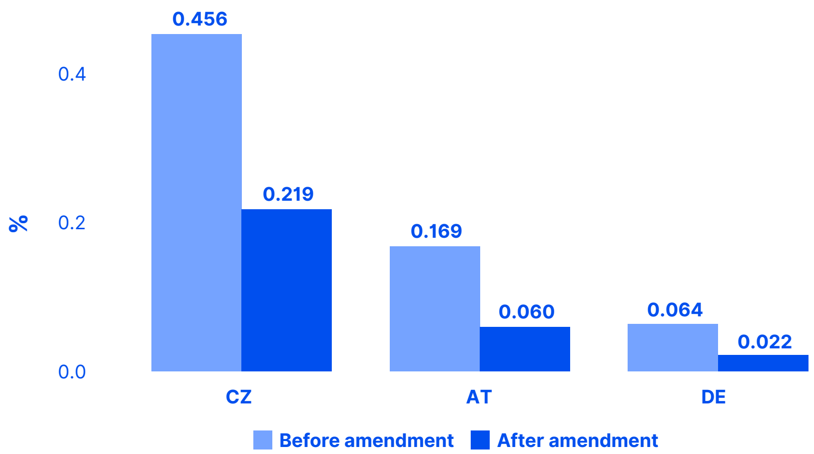


Source: ACER calculations based on ENTSO-E transparency platform data.

83 Between the amendment and the accession of additional TSOs (i.e. the Danish TSO on 10 October 2024), the occurrence of price incidents fell by 65%.[52] Figure 34 shows the isolated effect of the pricing methodology amendment on the reduction of price incidents.

Figure 34: Reduction of price incidents for all TSOs after the amendment

Share of optimisation cycles with price incidents before (1 January 2024 – 4 August 2024) and after the amendment, but before further TSOs joined (6 August – 10 October 2024) (%)



Source: ACER calculations based on TransnetBW data on Picasso

Elastic demand reduces price volatility

84 The aFRR implementation framework was amended through ACER Decision 08/2024, introducing elastic demand for aFRR to mitigate extreme price outcomes. By connecting to Picasso, TSOs can activate additional demand and thereby improve frequency quality. However, TSOs are not required to pursue improvements beyond their aFRR capacity requirements needs at any cost. The introduction of elastic demand allows TSOs to set a maximum price they are willing to pay for such improvements, ensuring a more efficient trade-off between costs and improved frequency performance.

51 Picasso's AOF optimises the social welfare at European level every four seconds. These four-second intervals are called optimisation cycles.

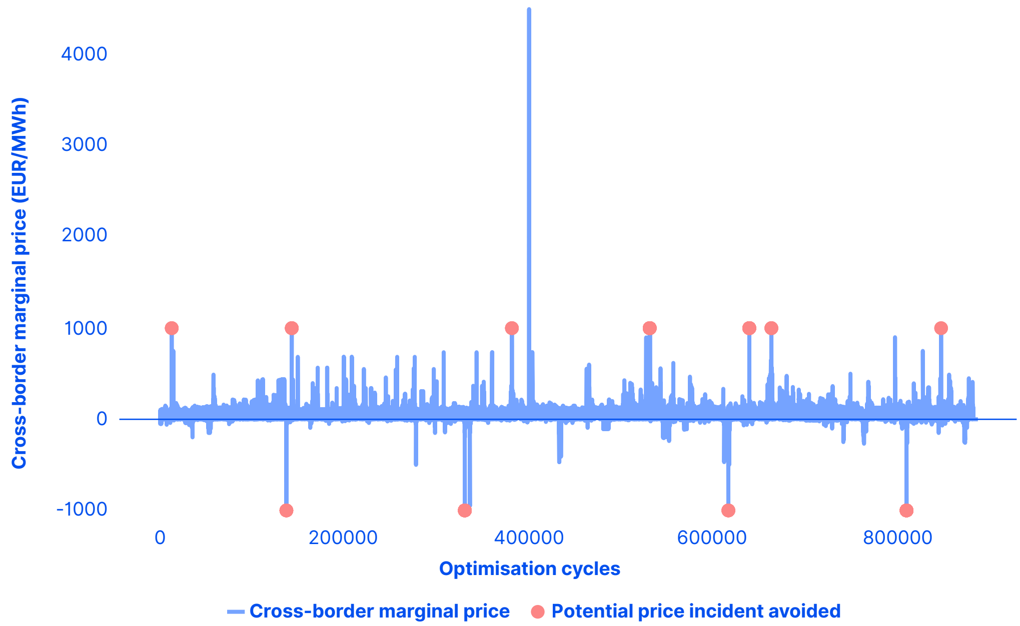
52 60% when considering the same period in the previous year.

85 So far, aFRR elastic demand has been implemented in Belgium and France upon their accession to Picasso, and more recently in Austria (from 8 August 2025) and both Danish bidding zones (from 27 August 2025).

86 This case study examines the impact of introducing elastic demand by the Austrian TSO. Elastic demand was set at 1 000 EUR/MWh for positive balancing energy and –1 000 EUR/MWh for negative balancing energy. Figure 35 shows the Austrian cross-border marginal price after implementation. The red dots mark instances where prices approached the elastic demand threshold, indicating that without this mechanism, prices in these periods could have been significantly higher.

Figure 35: Reduction in prices more extreme than ±1 000 EUR/MWh before and after the introduction of elastic demand in Austria

aFRR cross-border marginal price in Austria after the implementation of an aFRR elastic demand (9 August – 13 September 2025) (EUR/MWh)

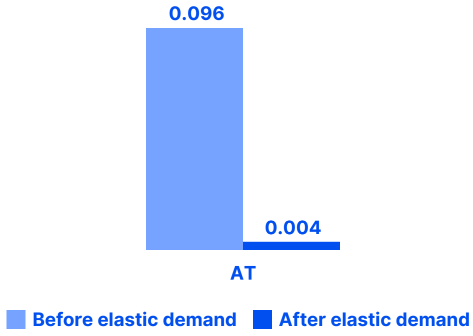


Source: ACER calculations based on TransnetBW data on Picasso

87 Figure 36 compares the share of optimisation cycles with prices beyond ±1 000 EUR/MWh before and after the introduction of elastic demand. Since its introduction, the share of price incidents has decreased by 96%. Although given the short observation period, seasonality may have influenced the results, the evidence points to fewer extreme price events and, consequently, a positive effect on consumer costs in Austria.

Figure 36: The introduction of elastic demand has reduced price incidents in Austria by 96%

Share of optimisation cycles with prices incidents 40 days before and after the introduction of elastic demand (on 9 August 2025) in Austria (%)



Source: ACER calculations based on TransnetBW data on PICASSO

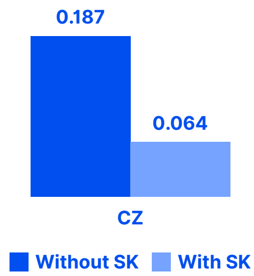
Accession of new transmission system operators further reduced price incidents and volatility

88 In late 2024, the TSOs from Belgium, Denmark, the Netherlands, and Slovakia joined PICASSO. Their accessions increased the number of offered bids and available transmission capacity, leading to further reductions in price incidents and volatility.

89 For example, Slovakia's accession expanded the exchange possibilities for Czechia, cutting price incidents by 66% compared to the post-amendment period (Figure 37).

Figure 37: Accession of the Slovak TSO reduced price incidents in Czechia by 66%

Share of optimisation cycles with price incidents in Czechia before and after Slovakia joined – 2024 (with Slovakia joining on 5 November 2024) (%)



Source: ACER calculations based on TransnetBW data on Picasso

4.1.2. Positive impact of the platform on prices for newly connected transmission system operators

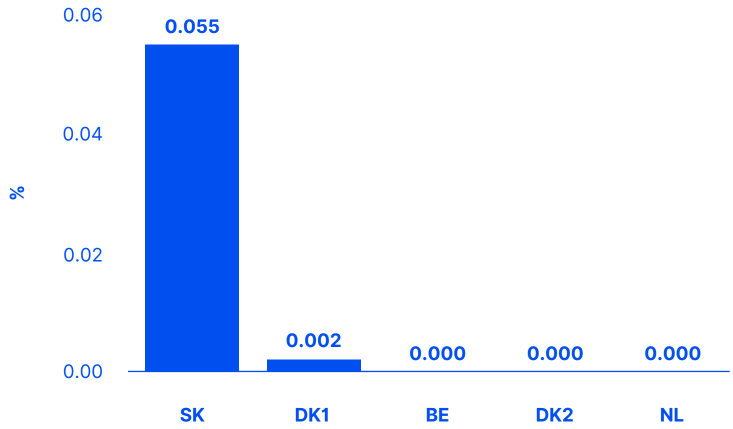
Few price incidents for newly connected transmission system operators

90 Price incidents were almost absent for newly connected TSOs in 2024 (Figure 38). One exception was Slovakia, at the edge of the area, which was sometimes faced with limited available cross-zonal transmission capacity and price incidents. As was the case for Czechia, the number of price incidents in Slovakia is expected to fall once additional TSOs join.[53]

53 The first analyses of the evolution of price incidents after the Polish TSO joined in July 2025 already show a corresponding reduction in price incidents in Slovakia.

Figure 38: Very few price incidents for newly connected TSOs in 2024.

Share of optimisation cycles with prices incidents for newly connected TSOs - 2024 (%)



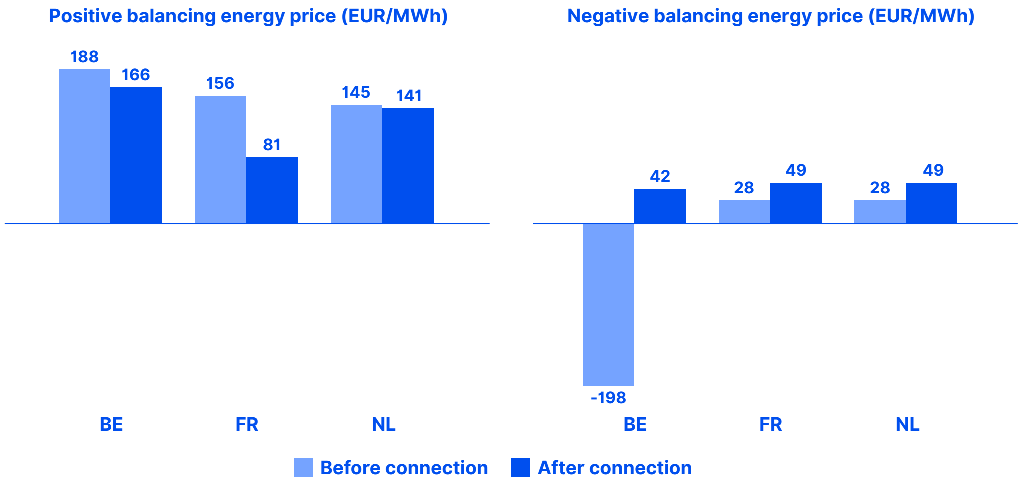
Source: ACER calculations based on TransnetBW data on PICASSO

Cost reduction after Picasso accession

91 This case study compares activation prices for the Belgian, French and Dutch TSOs before and after joining Picasso, using data from their TSOs. After accession, prices for both positive and negative balancing energy became more favourable, reflecting greater competition via access to neighbouring merit-order lists. In France, the average price for positive balancing energy fell by nearly half.[54] In Belgium, the average price for negative balancing energy shifted from negative (indicating a cost for the TSO) to positive. In France, the average price for positive balancing energy fell by nearly half.

Figure 39: Accession to Picasso has improved prices for several TSOs

Comparison of average prices for balancing energy from aFRR before and after connection to Picasso for Belgium, France and the Netherlands – January 2024 – September 2025, (EUR/MWh)



Source: ACER calculation based on data from ELIA, RTE and TenneT Netherlands

Note: Accession dates: Netherlands – 17 October 2024, Belgium – 26 November 2024, France – 4 April 2025

54 Due to the limited period of observation after accession, seasonality may also affect the result. For example, in France, average day-ahead market prices also fell during the same period.

4.1.3. Cross-zonal capacity can enable further improvements

92 As shown in the case study above, access to the merit-order of neighbouring TSOs increases competition and helps reduce balancing costs for TSOs and consumers. Such benefits depend on sufficient cross-zonal capacity being available for exchanges. This subsection therefore explores options to further increase cross-zonal capacity in the balancing timeframe, with a particular focus on Picasso.

Short-term measures: lifting profile limits and sharing available transfer capacities

93 Some TSOs apply profile limits, i.e. fixed limits[55] to their net position when accessing the platform. Such limits should only be applied where strictly necessary. Past experience shows that relaxing them facilitates exchanges and reduces price volatility. Their continued use should therefore be critically assessed.

94 Picasso also allows TSOs to offer ATCs on their borders even if they are not yet directly connected to the platform. This was the case for France, which offered ATCs before it connected, meaning that Spain could trade with central European TSOs. This creates additional trading opportunities; for example, Bulgaria and Greece could exchange with the rest of Europe before Hungary and Romania connect, if their TSOs were to enable ATC sharing.

95 Both the lifting of profile limits (where possible) and the sharing of ATCs are relatively simple, short-term measures that can already deliver tangible market efficiency gains.

Longer-term structural solution: flow-based calculation and allocation

96 While short-term measures can deliver quick wins, more substantial efficiency gains require a structural shift towards flow-based calculation and allocation in the balancing timeframe. At present, ATCs are extracted from the intraday flow-based domains, which limits exchanges in both intraday and balancing markets. Applying flow-based directly in the balancing timeframe could expand exchanges and thereby reduce prices and lower system costs.[56]

97 To provide an indicative estimate of the benefit, ACER has implemented a simplified version of the Picasso clearing algorithm under both ATC and flow-based allocation. Based on sample calculations[57] for the period between 1 January and 10 January 2025 (216 000 optimisation cycles), flow-based allocation could significantly increase exchange possibilities and reduce balancing energy costs on Picasso by around 30%.

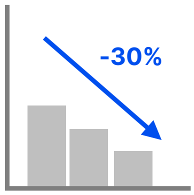
55 Some TSOs limit their exchanges for system security reasons.

56 The general rationale for these expected benefits is outlined in Section 3.3.

57 The assumptions made for this study can be found in Annex III.

Figure 40: Implementing flow-based allocation in the balancing timeframe will reduce costs by approximately 30%

Estimated cost reduction of the implementation of flow-based allocation in the balancing timeframe, as found by a case study on 216 000 optimisation cycles between 1 and 10 January 2025 (%)



Source: ACER calculations based on data from ENTSO-E Transparency Platform, TenneT NL, JAO Publication Tool, and TransnetBW on PICASSO, as described in Annex III.

98 Based on these insights, ACER invites TSOs to reflect on the steps required for implementing flow-based allocation in the balancing timeframe.

4.2. Balancing capacity markets

99 To ensure that enough balancing energy is available for the TSO to balance the system in the case of a system imbalance, TSOs procure balancing capacity. This implies reserving generation or demand capacity to ramp up or down when balancing energy needs to be activated. The methodology for dimensioning required reserves is defined in the System Operation Regulation.

100 The cost of procuring balancing capacity constitutes a major part of the total cost of balancing service across the EU. This section therefore analyses both the current level and the potential for further integration in balancing capacity markets.

4.2.1. First regional initiatives for the exchange of balancing capacity and sharing of reserves exist

101 Frequency containment reserve cooperation is the largest existing balancing capacity market integration project encompassing nine Member States. However, the integration of the balancing capacity markets for other balancing products remains limited. With the Nordic balancing capacity market (go-live in December 2022) and the Baltic balancing market (go-live in February 2025) two regional projects have been established for the exchange of balancing capacity and/or the sharing of reserves considering frequency restoration reserves. In addition, the ALPACA (allocation of cross-zonal capacity and procurement of aFRR cooperation agreement) project went live at the beginning of September 2025.[58] It is an extension of the previous German-Austrian balancing capacity cooperation, now also including Czechia.

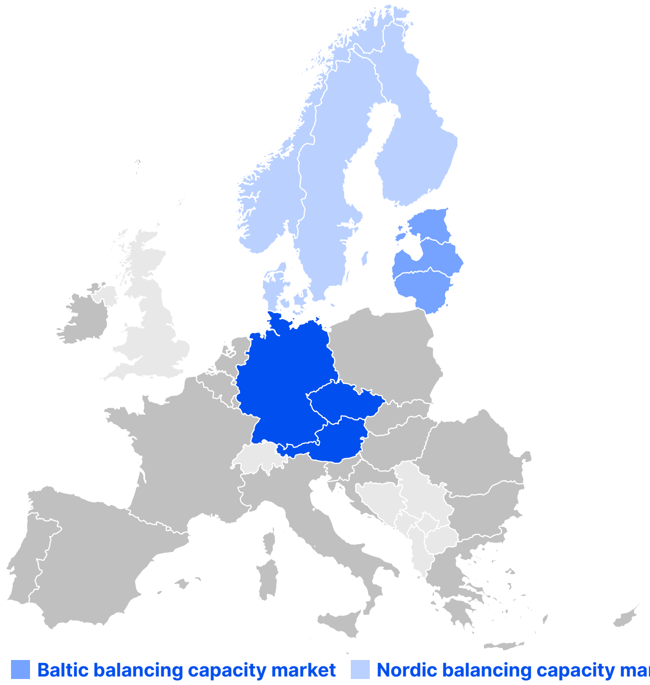
102 Based on an estimation by the Baltic TSOs, the annual welfare gain of capacity market integration in the Baltics is estimated at EUR 470 Mio,[59] with most of the welfare gain stemming from the sharing of reserves.

58 ENTSO-E, Website: ALPACA_Go-live_announcement.pdf.

59 ENTSO-E, Website: Notification on the use of market Baltic CCR.pdf.

Figure 41: Regional initiatives for balancing capacity market integration

Existing regional projects for the exchange of balancing capacity or sharing of reserves considering FRR, status in September 2025



Source: ENTSO-E website

103 The exchange of balancing capacity and sharing of reserves across borders requires the availability of cross-border capacity. However, as balancing capacity is generally procured just ahead of or at the same time as the day-ahead market trading times, cross-zonal capacity needs to be allocated to either the balancing capacity market or the day-ahead market.[60]

104 As stated in the introduction, the Electricity Balancing Regulation lists two methodologies for how TSOs may allocate cross-zonal capacity for the exchange of balancing capacity and the sharing of reserves, namely co-optimisation and market-based allocation. For market-based allocation, a forecast of either day-ahead or balancing capacity prices is used to estimate where cross-zonal capacity can generate more benefits. Co-optimisation integrates both markets into a single optimisation algorithm, removing the need for forecasts but increasing implementation complexity. The existing Baltic and Nordic balancing capacity market initiatives are based on regional methodologies implementing market-based allocation. Through ACER Decision 01/2025, a stepwise approach towards the harmonisation of these methodologies has been set out, with the first milestone expected to be reached by mid-2027. Given the potentially significant implications for the European market design, for co-optimisation, research needs for co-optimisation have been identified and will be further pursued in 2026, as laid down in ACER Decision 11/2024.

60 An exemption to this is the ALPACA project, where a probabilistic method is used to forecast remaining cross-zonal capacities after the intraday market.

4.2.2. Further benefit to the market integration of balancing capacity markets

105 As the integration of balancing capacity markets remains limited, this section analyses additional potential via an ex-post analysis, comparing the price spread between balancing capacity markets to the price spread in the day-ahead market for different borders for balancing capacity from frequency restoration reserves (aFRR and mFRR). If the price spread in the balancing capacity markets is higher than in the day-ahead market, allocating cross-border transmission capacity for exchanging balancing capacity could yield a benefit.

106 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.

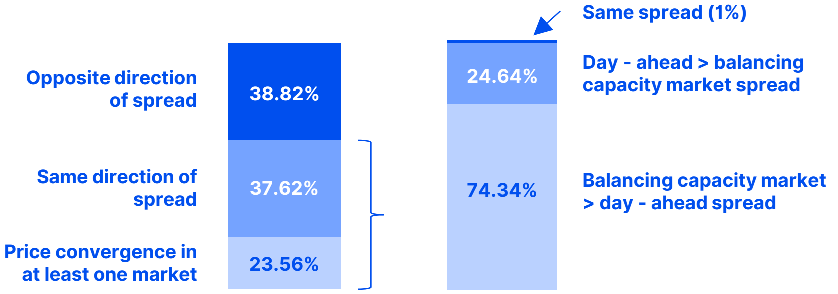
107 In a first step, an hourly volume-weighted average price of the balancing capacity products was calculated to be able to compare them with the hourly day-ahead prices.

108 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 and for 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, direction of the price difference differs per market, the available transmission capacity increases in one market based on the activity in the other market due to the opposite direction of power flow across the border, such that there is no trade-off to be made. For further information on the distinction of the direction of price spreads, also including the distinction between positive and negative balancing capacity, refer to Annex III.[61]

109 Figure 42 (left) shows that, in 2024, there was an approximately equal share of cases where the price spread was the same or opposite (around 40% of cases) and a smaller share where one of the two markets had price convergence. Price spreads in the opposite direction indicate a lack of coordination between the balancing capacity and day-ahead markets. Further market integration could reduce such spreads. In the following analysis, only cases where price spreads were not opposite are considered. Figure 42 (right) shows that the price spread in balancing capacity markets was greater than in day ahead markets in over 75% of these cases.

Figure 42: Transmission capacity could bring more benefits in balancing capacity markets 75% of the time

Comparison of direction of price spreads between balancing capacity markets and day-ahead markets, 2024, left(%); and comparison of the absolute prices spreads between markets, for cases where the direction of price spreads is not opposite, 2024, right (%)



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

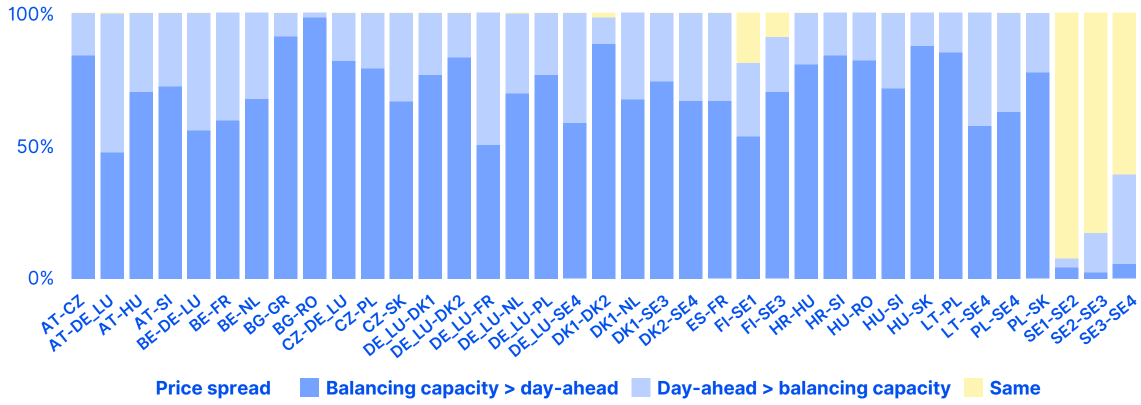
61 Positive and negative balancing energy would result in power flows in different directions and therefore need the availability of cross-border transmission capacity in different directions, when procuring balancing capacity. See Annex III for a detailed analysis of the different cases.

110 When comparing the price spread per border, most borders have a higher price spread in balancing capacity markets than in the day ahead market (see Figure 43). On average, the price spread in the balancing capacity market was 42 EUR/MWh greater than in the day-ahead market. High-voltage direct-current borders and Polish borders in particular exhibit higher price differences. For borders with higher price spreads in balancing capacity markets, an evaluation of where best to allocate available transmission capacity could result in greater welfare overall by allocating cross-zonal capacity to the balancing capacity markets instead of the day-ahead market.

111 In comparison to those borders without existing balancing capacity market integration, the Swedish borders, which are part of the Nordic balancing capacity market stand out. Nordic borders are the only borders that have occurrences with the same price spreads in both markets. The underlying reason is price convergence in both markets for these borders. While for all other borders, price convergence was rather low, with spreads regularly above 10 EUR/MWh, Figure 44 shows higher price convergence on the Swedish bidding zone borders.

Figure 43: Price spread in balancing capacity markets is often higher than in day-ahead markets

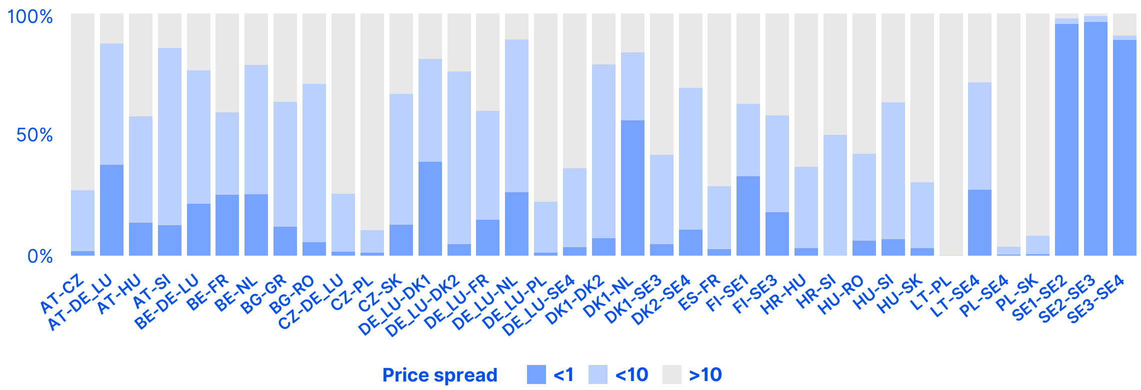
Share of price spreads that are higher in the balancing capacity market than in day-ahead, vice versa or when they are the same per border for all cases where the price spread is not in opposite directions, 2024 (%)



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

Figure 44: Low price convergence in the balancing capacity market for most borders in 2024

Share of price spread per border is <1 EUR/MWh, < 10 EUR/MWh or > 10 EUR/MWh – 2024 (%)



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

Conclusions and recommendations

Flexibility is now the central challenge for Europe's electricity system.
The system is changing fast, with volatility across all market timeframes. Extreme prices (low and high) in day-ahead, intraday, and balancing markets show the need for risk hedging solutions and flexibility during stress events.

Persistent delays in integration and rule implementation reduce efficiency and raise costs
Further EU electricity market integration would support the clean energy transition, enhance flexibility, and shield consumers from volatility. Yet cross-border projects are delayed, reducing markets efficiency and consumer benefits. **Implementation of key market integration projects, including cross-border redispatch coordination and cost-sharing and flow-based allocation in all timeframes, must be accelerated.**

Long-term markets need deeper liquidity and aligned design
Forward markets remain underdeveloped, with liquidity rarely extending beyond three years. PPAs are expanding but vary widely in design, with risks of inefficient bidding if costs and negative prices are not fully reflected. CfDs and futures must be designed to complement rather than fragment the market. **Regulators should strengthen long-term cross-zonal capacity allocation, improve the regulatory framework for forward markets, and promote transparent PPA platforms that also support smaller actors.**

Market oversight and transparency must keep pace with system change
Episodes of extreme prices in 2024 confirmed the need to monitor both market constraints and participants behaviour. In South-East Europe, bidding strategies during tight supply raised concerns. Strong ex-post surveillance and transparency can deter potential manipulation and build trust in markets. **ACER and national regulatory authorities should ensure transparency through access to data and relevant indicators, and strong surveillance.**

Flow-based allocation and bidding zone reform can be critical enablers of efficiency
Flow-based allocation already delivers benefits in the day-ahead market and is being extended to Italy North. Its timely application in intraday and balancing markets is legally required and must not face further delay. The ongoing bidding zone review can ensure that market design reflects grid realities, reduces congestion costs, and guides efficient network investment. **TSOs and member states should finalise flow-based implementation in intraday and consider it for balancing markets and deliver the bidding zone review without delay.**

Balancing integration delivers proven welfare gains but requires broader participation
In 2024, European balancing platforms and the Nordic capacity market generated welfare gains of over EUR 1.6 billion. Wider EU TSO participation in balancing platforms could reduce volatility further, smooth price incidents, and unlock additional flexibility. **TSOs should accelerate their accession to Picasso, the manually activated reserves initiative and other balancing platforms, and ensure sufficient cross-zonal capacity is made available for balancing exchanges.**

The EU electricity market design has proved resilient, but performance depends increasingly on timely delivery, available flexibility resources, and coordinated TSO action.
Efficient and competitive markets remain the keystone of affordable and resilient electricity. Policymakers and regulators must prioritise the delivery of existing reforms, strengthen cross-border coordination, and ensure that the enforcement of rules is consistent and effective for all actors.

Annex I: Day-Ahead markets

This annex includes explanatory material and visuals on the relevant metrics used in this Market Monitoring Report. The figures are intended for educational purposes.

Methodology for deriving wind speed at 10 meters

To derive horizontal wind speed at 10 meters above the surface, we rely on the decomposition of wind into its two horizontal components: the **eastward component (u)** and the northward component (v). These are standard meteorological variables, typically expressed in meters per second (m/s), and represent the wind's direction and intensity along the respective axes:

- u-component: wind speed toward the east (positive values correspond to wind blowing from west to east),
- v-component: wind speed toward the north (positive values correspond to wind blowing from south to north).

In this analysis, the neutral wind v-component is used. This refers to a formulation under the assumption of a neutrally stratified atmosphere, i.e. an atmospheric condition in which thermal effects (stability or instability) are neglected, and vertical gradients of temperature have minimal impact on horizontal wind fields.

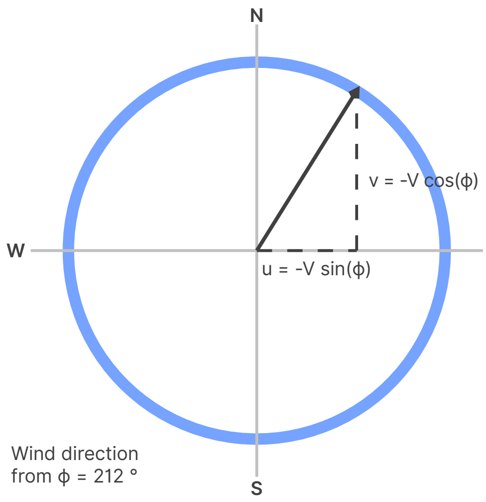
The horizontal wind speed at 10 meters is then calculated as the magnitude of the wind vector formed by these two orthogonal components:

$$\left|\vec{V}\right| = \sqrt{u^2 + v^2}$$

Given a wind direction angle Φ the components of the wind vector can be computed as:

$$u = -\left|\vec{V}\right| \sin\varphi$$

$$v = -\left|\vec{V}\right| \cos\varphi$$



Methodology for estimating temperature sensitivity to electricity demand

To assess how electricity demand responds to high temperatures, a dataset combining hourly temperature and load values was assembled for each bidding zone. Given the differences in absolute demand levels across zones, the raw load values were standardized using z-scores. This normalization process ensures comparability across regions by expressing demand in terms of standard deviations from the local mean, allowing for a clearer interpretation of temperature-induced effects.

The analysis specifically targeted days when the daily average temperature exceeded 20°C, a threshold commonly associated with increased electricity usage due to cooling needs (e.g. air conditioning). For each of these days, the temperature exceedance above 20°C was computed and used as the key explanatory variable in the model.

To estimate the magnitude of the relationship between temperature and demand, daily load values were aggregated at the bidding zone level, and a simple linear regression model was fitted. The regression coefficient provides a direct estimate of how much electricity demand increases for each additional degree Celsius above the 20°C threshold—an intuitive and actionable measure of temperature sensitivity.

The regression model is specified as follows:

$$\text{Load}_{\text{daily}} = \beta_0 + \beta_1 \times (T - 20) + \varepsilon$$

where:

- T is the daily average temperature (only for T > 20°C),
- β_0 represents the expected demand at exactly 20°C,
- β_1 is the sensitivity coefficient, quantifying how much demand increases per additional °C,
- ε is the residual error.

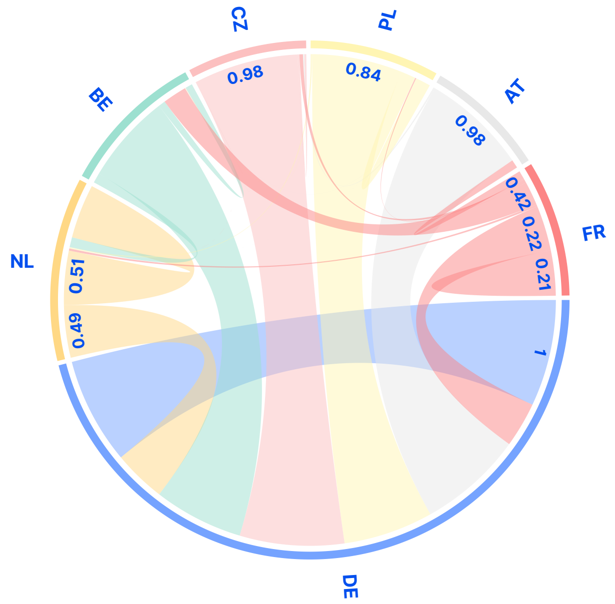
A positive β_1 reflects higher electricity demand with rising temperatures, likely driven by increased use of cooling systems.

Variance decomposition analysis: amplifiers and buffers in regional price dynamics

Some bidding zones can amplify stress, while others buffer it, depending on their size, interconnection levels, and domestic generation mix. Larger and more interconnected countries often have a stronger influence on regional volatility patterns, making their flexibility capabilities especially relevant for broader market stability.

To better understand these dynamics Figure 45 presents a connectedness analysis of day-ahead prices across selected bidding zones for 12/12/2024. The idea is to measure how price fluctuations in one country spill over into others and vice versa.

Figure 45: Variance analysis shows interconnected price dynamics across regions



Source: ACER elaboration based on ENTSO – E transparency platform data and Copernicus data – ERA5.

In simple terms, the analysis looks at how much of the uncertainty in a country's prices is driven by its own shocks versus shocks originating elsewhere. For example, a value of "1" for Germany at the first step means that 100% of its price variance is initially explained by domestic shocks, indicating that, in the very short term, it is not immediately affected by shocks from other countries.

This is implemented using the Diebold–Yilmaz connectedness framework, which estimates a Vector Autoregression (VAR) model to capture the dynamic interactions among the time series. The key output is the forecast-error variance decomposition, which quantifies the proportion of each country's forecast-error variance attributable to shocks in all the other countries in the system.

For this analysis, the following mathematical assumptions underlie the approach: let a VAR model

$$y_t = \nu + \varphi_1 y_{t-1} + \varepsilon_t$$

And his Vector Moving Average or VMA representation:

$$y_t = \mu + \sum_{i=0}^{\infty} \varphi_1^i \varepsilon_{t-1}$$

His orthogonal component can be decomposed to obtain the variance decomposition where the single element of the matrix represents the contribute of one component to explain the total variance:

$$\mathrm{FEDV}_{i,l}\left(h\right) = \frac{\sum_{i=0}^{h-1} \theta_{j|i,l|}^2}{\sum_{i=0}^{h-1} \theta_{j|i,1|}^2 + \sum_{i=0}^{h-1} \theta_{j|i,2|}^2 + \cdots + \sum_{i=0}^{h-1} \theta_{j|i,k|}^2}$$

This connectedness framework used here goes beyond the contemporaneous co-movement given by correlation. This specific metric gives only a static snapshot: it shows how strongly two variables move together at the same point in time and in which direction, and it is always symmetric. Meanwhile, the variance decomposition captures how shocks in one market propagate to others over time, quantifying both the direction and the magnitude of these spillovers. In other words, while correlation describes co-movement, connectedness analysis reveals dynamic influence, identifying which bidding zones tend to transmit volatility and which tend to absorb it.

Correlation and Regional Clustering of Wind Patterns

To better understand regional wind dynamics, bidding zones are grouped into clusters that reflect similarities in their hourly wind speed patterns. The logic behind this approach is straightforward: if zones display highly correlated wind profiles, they tend to experience periods of surplus and deficit at the same time. Conversely, when correlations are low, wind fluctuations in one zone may be offset by opposite fluctuations elsewhere, providing opportunities for exchanges across regions.

The clustering procedure is based on a simple but robust idea. First, hourly wind speed series are compared pairwise, and the correlation between each pair of zones is computed. Correlation is a statistical measure that indicates the strength and direction of a linear relationship between two variables observed at the same time. It is symmetric, meaning that the correlation between zone A and zone B is identical to that between zone B and zone A. Values close to 1 indicate that two series move together, while values close to 0 suggest little or no relationship. Negative values, which are rare in this context, would imply that one zone tends to experience wind surpluses when another faces deficits.

Table 2: Illustration of correlation for selected bidding zones

PL	0.6	0.57	0.6	0.67	0.41	0.51	1
NL	0.94	0.99	0.93	0.96	0.8	1	0.51
FR	0.85	0.8	0.84	0.83	1	0.8	0.41
DE	0.98	0.97	0.98	1	0.83	0.96	0.67
CZ	1	0.95	1	0.98	0.84	0.93	0.6
BE	0.96	1	0.95	0.97	0.8	0.99	0.57
AT	1	0.96	1	0.98	0.85	0.94	0.6
	AT	BE	CZ	DE	FR	NL	PL

Once all correlations are computed, they are converted into distances, so that zones with higher correlation are considered "closer" to one another. A clustering algorithm is then applied to these distances. The method used, Ward's approach, works by successively grouping the most similar zones together and ensuring that each cluster remains as internally consistent as possible. The result is a set of regions that are not defined by geography alone but by the empirical co-movement of wind patterns across time.

Assessing the market impact of Decoupling – social economic loss calculation

To better understand the welfare impact of a partial decoupling, the analysis relies on a counterfactual simulation performed with the Simulation Facility, which replicates the EUPHEMIA algorithm.[62] The welfare impact is measured through the calculation of total economic surplus, defined as the sum of consumer surplus, producer surplus, and congestion income.

62 See footnote 23 above.

Consumer and producer surplus values are directly provided as outputs of the Simulation Facility. By contrast, congestion income is derived from commercial exchanges and price differentials between bidding zones, using the following formula:

$$Congestion\ Income_{(A-B)} = Exchange_{(A\rightarrow B)} \times (price_{(A)} - price_{(b)})$$

Where exchange denotes the net commercial flow from zone A to zone B.

The partial decoupling case is modelled through two simplified configurations (EPEX local auctions and SDAC without EPEX), already discussed in the main text. The simulated outcomes are compared with the historical fully integrated market, and the difference in total economic surplus quantifies the welfare loss due to decoupling.

Table 3 summarises the impact across all bidding zones in the EPEX Core region, as a difference between the historical data compared to the simulated scenario for the produces and consumer surplus.

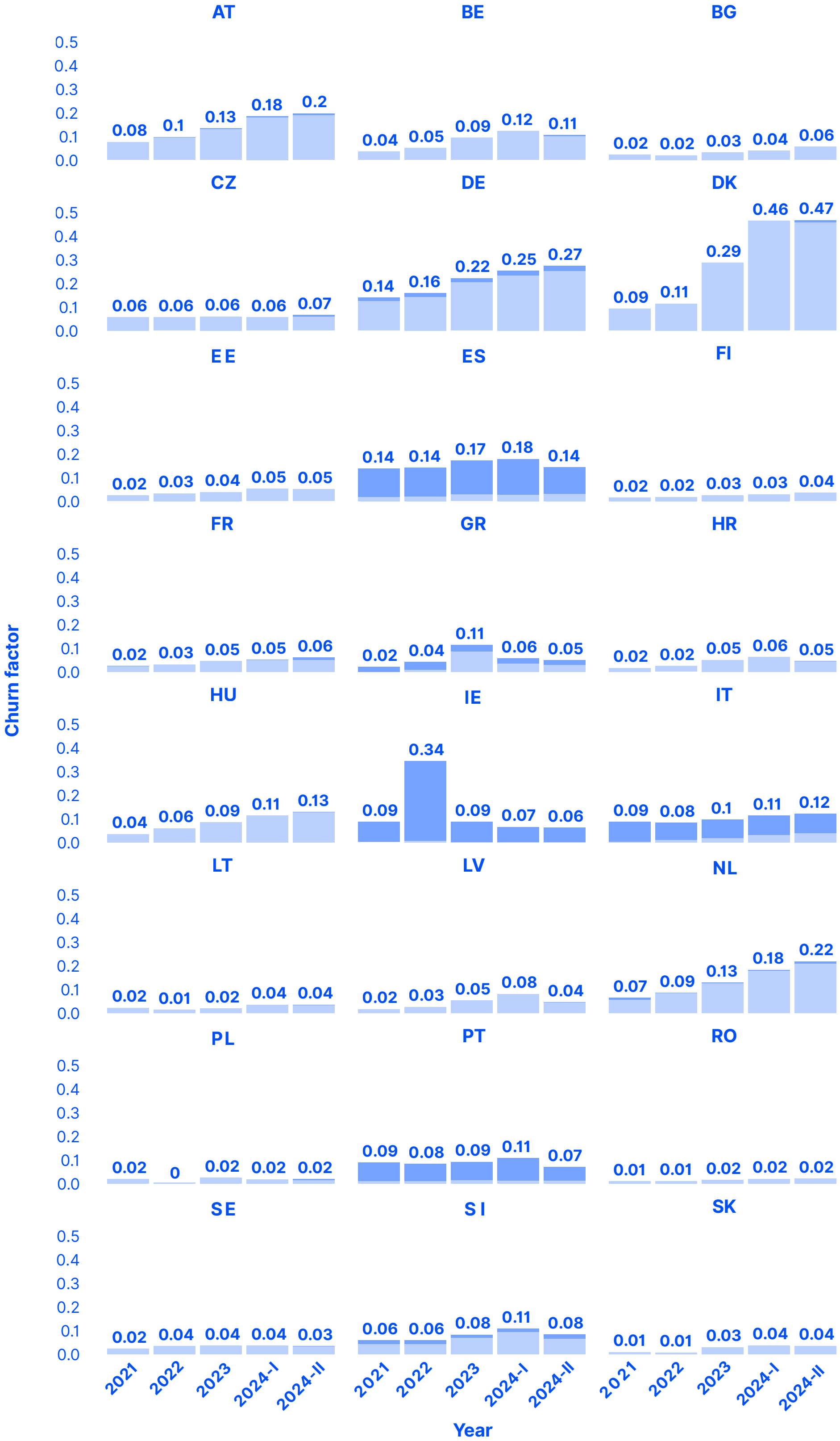
Table 3: Change in producer and consumer surplus across EPEX Core bidding zones

Member state	Producer surplus gain	Producer surplus loss	Consumer surplus gain	Consumer surplus loss
AT	1.869.830	-	-	2.055.148
BE	11.335001	-	-	14.175.037
DE	982.806.479	-	-	1.065.994.546
FR	-	23.880.769	15.603.385	-
NL	-	6.516.261	5.246.905	-
PL	1.148.906	-	-	2.996.353

Annex II: Intraday markets

Intraday churn factors per country

Figure 46: Intraday Churn factors per country



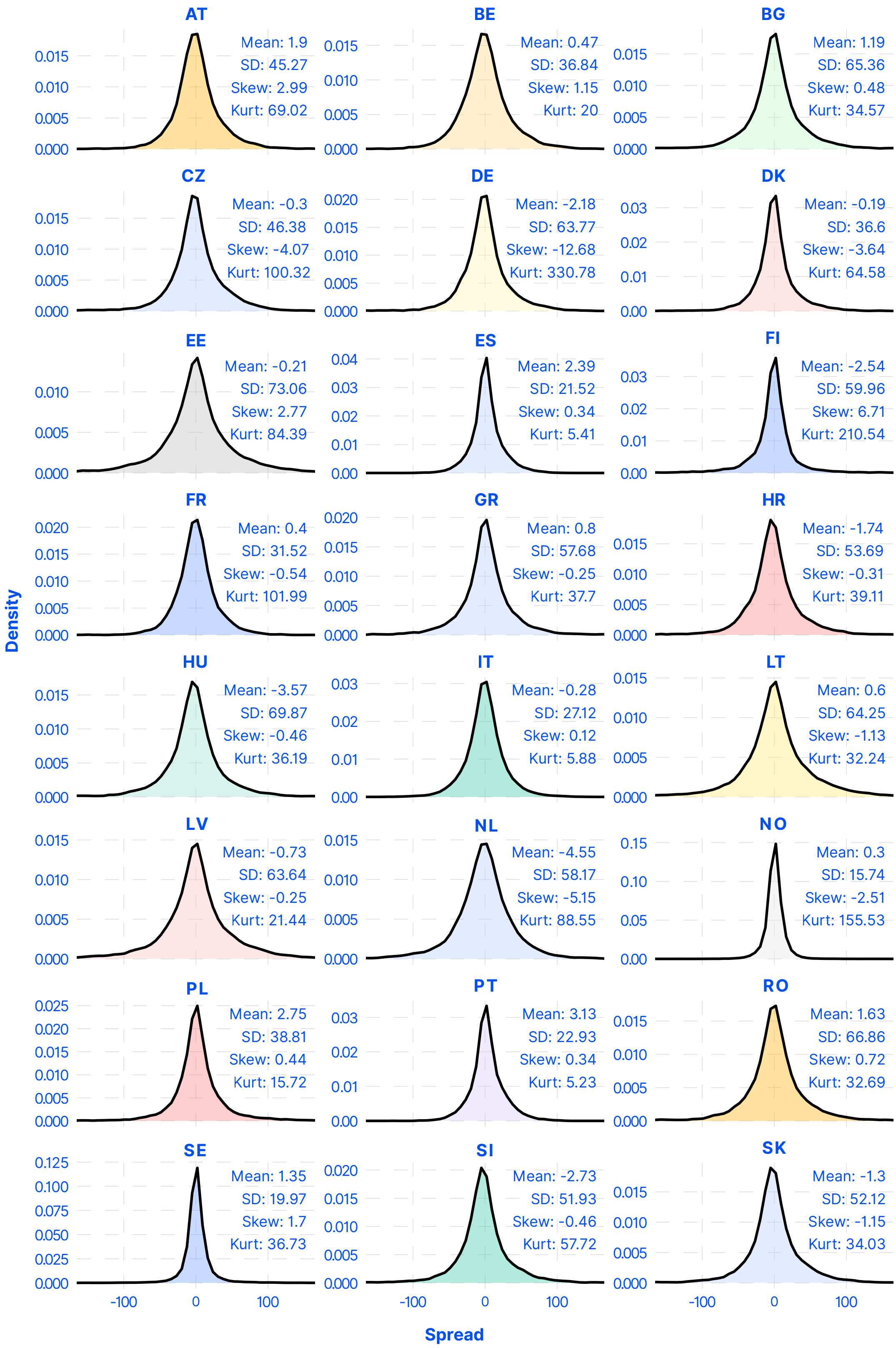
Source: ACER calculations based on REMIT data and ENTSO-E Transparency Platform.

Note: The figures include a breakdown between continuous and auction market. For 2024, two bars are shown, one for the churn factor before the go-live of the intraday auctions (I), and one for the churn factor after the go-live of the intraday auctions (II).

Day-ahead – intraday spreads

This annex shows the day-ahead – intraday spreads for 2024 per country. The calculated mean, standard deviation (SD), skewness (Skew), and kurtosis (Kurt) are also provided.

Figure 47: Day-ahead - intraday spreads indicate market efficiency



Source: ACER calculations based on NEMOs data for intraday prices and ENTSO-E Transparency Platform for day-ahead prices

Statistical characteristics of day-ahead – intraday spreads

Mean:

A positive mean spread (day-ahead > intraday) indicates a risk premium, with buyers paying more in advance to secure supply.

A negative mean spread (intraday > day-ahead) signals scarcity or forecast errors, reflecting producer risk aversion or under-pricing of risk in the day-ahead market.

Standard deviation:

The standard deviation captures volatility in the price difference between markets.

A high value indicates greater uncertainty and a stronger role for risk premia in day-ahead prices.

A low value reflects stable conditions with smaller, more predictable risks.

Skewness:

Skewness shows whether extreme outcomes tend to raise or lower intraday prices relative to day-ahead.

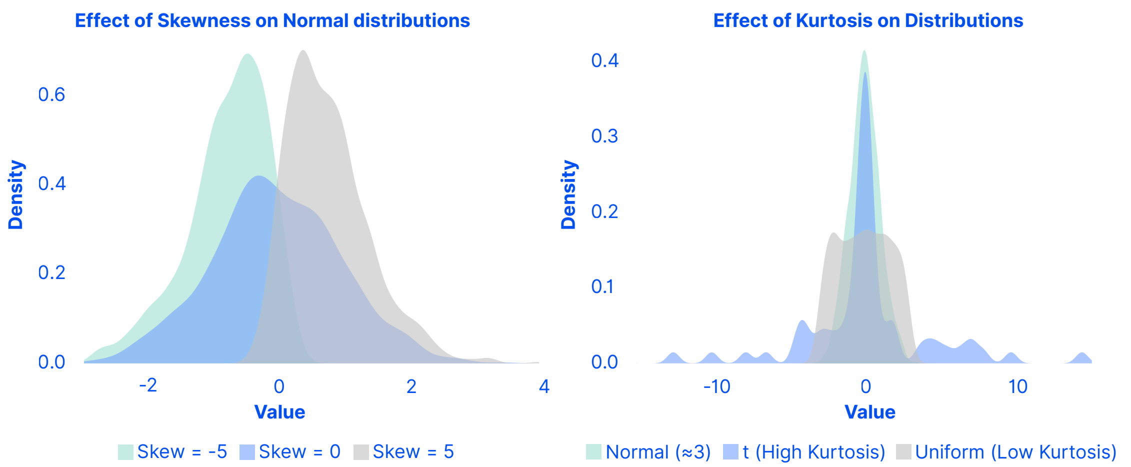
A negative skew (left tail) means intraday prices more often exceed day-ahead prices, pointing to asymmetric risks or structural imbalances. This can be seen in Figure 48 (left).

Kurtosis:

Kurtosis measures the frequency of extreme spread values.

High kurtosis means prices are usually near the mean but occasionally experience large shocks—caused by unexpected renewable fluctuations, demand spikes, or outages—revealing exposure to rare but severe events. This can be seen in Figure 48 (right).

Figure 48: Examples of skewness and kurtosis



Source: ACER example.

Annex III: Balancing markets

Benefits of flow-based allocation in intraday and balancing Comparison of the domains for ATC and flow-based allocation in day-ahead and intraday

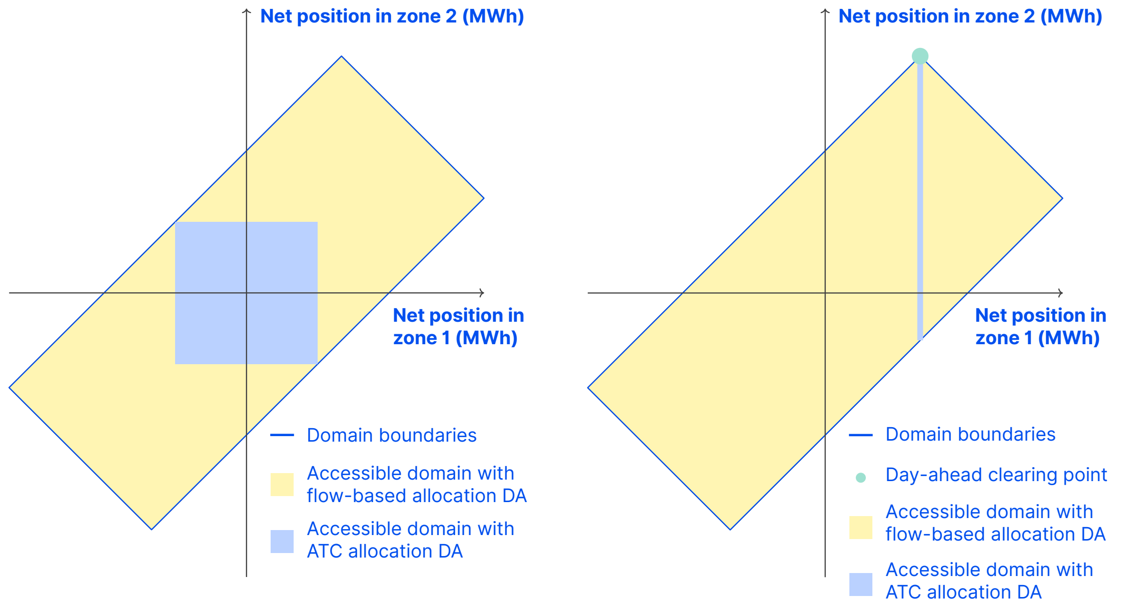
This annex provides a theoretical example that illustrates the differences between the available transfer capacity (ATC) allocation domain and the flow-based domain for both the day-ahead and intraday markets. The flow-based domain is much larger than the ATC domain, which is especially the case in the intraday market. Figure 49 shows two graphs depicting the different domains for ATC and flow-based allocation domains for day-ahead (left) and intraday (right).

ATC extraction works by drawing a box around the starting net position (0 for day-ahead) and the day-ahead clearing point for intraday, shown as the blue box in the left graph and the blue line in the right graph. The flow-based domain is shown in yellow in both figures and is much larger than the ATC domain in both the day-ahead and intraday markets. The ATC method limits trading by cutting out a large part of what would otherwise be possible.

This inefficiency is worse in the intraday market because the ATC is set based on the day-ahead clearing point (shown as the green dot on the right-hand figure) which is often near the edge of the flow-based domain. This leaves even less capacity available for trading. As a result, some bidding zones are unable to import or export, not due to physical constraints, but due to limitations introduced by the ATC method.

Figure 49: Intraday ATC is inefficient due to dependence on day-ahead leftovers, while flow-based allocation improves capacity use

The domain of ATC allocation and of flow-based allocation for day-ahead (left) and for intraday (right).



Source: ACER elaboration on data from the JAO Publication Tool.

Assumptions for the case study on benefits of flow-based allocation in balancing

This annex provides an overview of the assumptions made in the study on the benefits of implementing flow-based allocation within the balancing timeframe as described in Section 4.1.3. The results of the study are also provided.

Network assumptions

We only model the Core CCR.
We use the flow-based domain and the ATC domain from intraday capacity calculation or IDCC(b).[63]

Available bids assumptions

For Austria, Belgium, Czechia, Germany, Hungary, Romania and Slovenia, we use the bids available from ENTSO-E Transparency Platform.
For the Netherlands, we use the data from the TenneT website.
For Slovakia and Poland, we assume the same shape as the Czech merit order, and we rescale the volume to meet the procured volume of balancing capacity.
For Croatia, we apply the same procedure with Slovenia as a reference.
For France, we apply the same procedure with Belgium as a reference.

Demand assumptions

For countries connected to the PICASSO platform (Austria, Belgium, Czechia, Germany, Netherlands and Slovakia), we compute the 4-second activated volume as the volume corresponding to the cross-border marginal price (CBMP) in the national merit order. This might slightly underestimate the demand because, following the amendment, the price can be lower than the price of the bid selected by the platform.

Demand for **Scenario 1:** Demand = activation – net position.

Demand for **Scenario 2:** Demand = activation.

Scenario 1 probably overestimates cases with scarcity because the net position achieved from the balancing starting point might not be achievable from the intraday starting point.

Scenario 2 underestimates cases of scarcity because the demand never exceeds the number of bids nationally available.

Modelling assumptions

We model the problem as a welfare maximisation problem.

This means that counter activations are allowed.

We set the price as the highest selected bid of the model, as we are not modelling the bids that are really activated by the TSO controller.

Results

Cost reductions and reductions in the number of price incidents are provided for both scenarios described in the assumptions.

63 The Intraday Capacity Calculation process IDCC(b) delivers capacities by 21:45 for the all delivery hours (00:00 - 24:00) of the subsequent day.

Table 4: Cost reduction and price incident reduction after implementing flow-based allocation, for two scenarios with different demands

	Demand Scenario 1	Demand Scenario 2
Cost reduction flow-based	-39%	-32%
Price incident reduction flow-based	-95.6%	-98.6%

Source: data in the table are results from calculation based on data as described in the assumptions above.

The results of the two scenarios analysed suggest that the implementation of flow-based allocation would be very beneficial in terms of cost reduction. It also has the potential to strongly reduce the number of price incidents that take place by increasing the competition in the market.

Integration of balancing capacity markets

This annex provides a more detailed analysis for three cases in the study on the benefits to market integration of balancing capacity markets in Section 4.2.2. The study compares the price spread of the balancing capacity markets with the price spread in the day-ahead markets, to indicate where the cross-border transmission capacity could provide more benefits.

The cases for positive and negative balancing capacity are considered separately, as these result in power flows in different directions and therefore need the availability of cross-border transmission capacity in different directions.

First, an hourly volume-weighted average price of the balancing capacity products was calculated to be able to compare them with the hourly day-ahead prices.

The price spread of the directed border from zone A to zone B is calculated as the price in zone A minus the price in zone B. A positive spread indicates a higher price in zone A than in zone B.

Table 5: Cases for study on integration of balancing capacity markets.

Case	Positive or negative balancing capacity	Price spread day-ahead	Price spread balancing capacity	Delta of price spreads	Price spread direction	Is price spread balancing > price spread day-ahead?
1	Positive	5	10	5	Same	Yes
2	Positive	10	5	-5	Same	No
3	Negative	5	10	5	Opposite	Yes

Source: ACER examples.

In case 1 of Table 5 where positive balancing capacity is considered, the day-ahead price in zone A is 5 EUR/MWh higher than in zone B and the balancing capacity market price is 10 EUR/MWh higher in zone A than in zone B. This suggests that zone A would benefit from imports from zone B in both markets, as described in Section 4.2.2. In this case, the price spreads are in the same direction, and the balancing capacity market price spread is higher than the day-ahead market price spread, indicating potential benefits of allocating the available transmission capacity to the balancing capacity markets.

In case 2 of Table 5 for positive balancing capacity, these price spreads are reversed, i.e. the price in zone A compared to B is 10 EUR/MWh higher for the day-ahead market, and 5 EUR/MWh higher for the balancing capacity market. As in case 1, the spreads have the same direction. However, the balancing capacity price spread is lower than the day-ahead spread.

In case 3 of Table 5, we consider negative balancing capacity, thus a potential power flow in the opposite direction. The price spreads are the same as in case 1, so the balancing capacity spread is higher than the day-ahead spread. However, the spreads are in opposite direction, indicating a lack of coordination between the balancing capacity and day-ahead markets.

List of figures