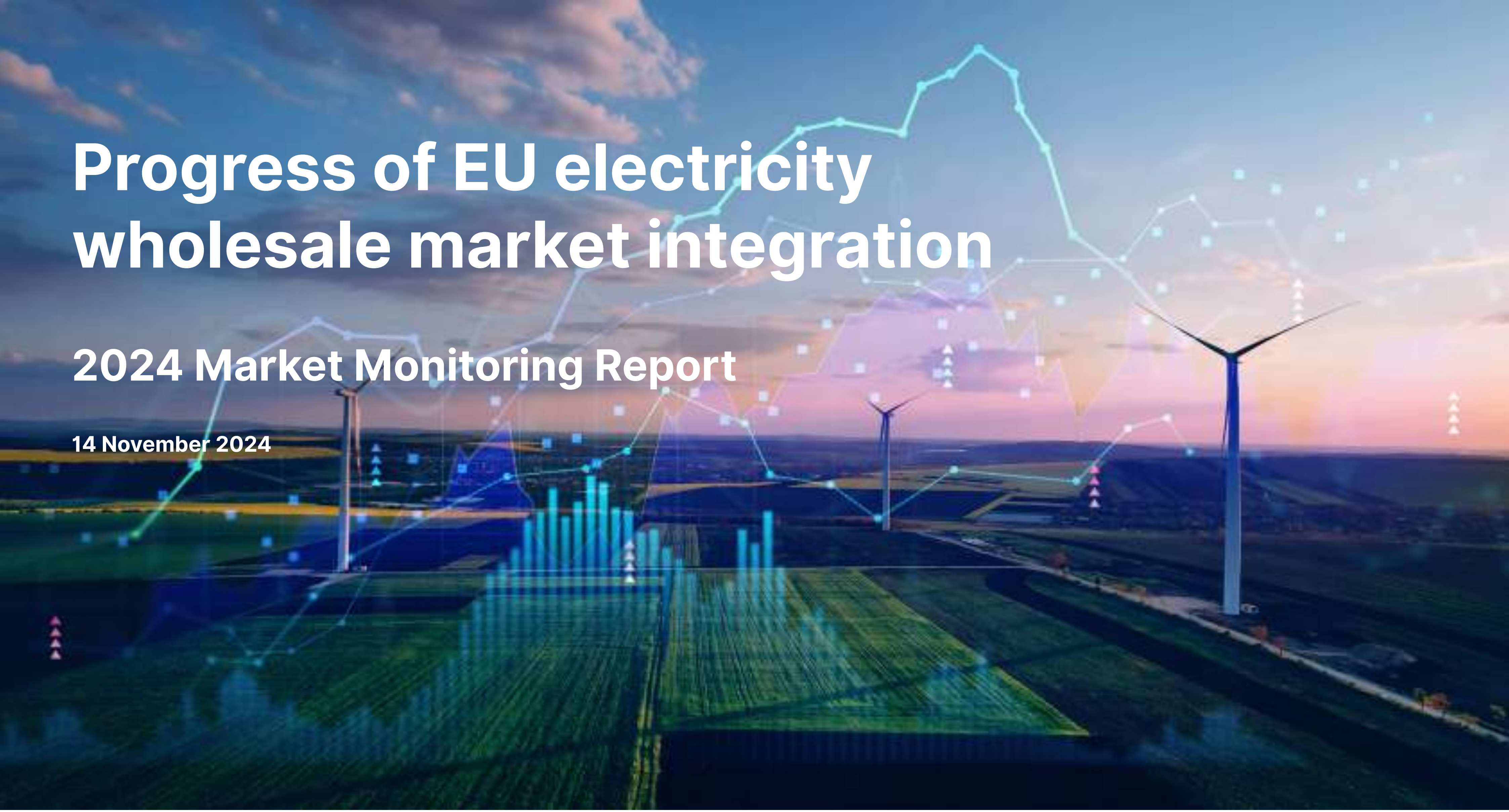

Progress of EU electricity wholesale market integration

2024 Market Monitoring Report

14 November 2024

ACER
European Union Agency for the Cooperation of Energy Regulators

Progress of EU electricity wholesale market integration

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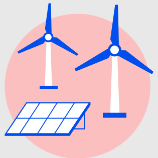
Executive summary

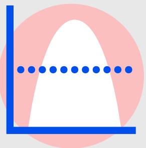
+ 10%

Hours when generation was mostly non-responsive



7,000 h

Prices below 5 EUR/MWh (1,400 hours in 2019)



EUR 4 bn

Cost of managing EU power grid congestion in 2023

27%

Methodologies face implementation delays in 2024

This 2024 market monitoring report assesses progress in EU electricity wholesale market integration. For the first time, this annual monitoring report is accompanied by three dashboards on key market indicators, balancing and long term transmission rights.

Limited system flexibility led to high day-ahead prices and instances of low or negative prices, creating challenges for market operations and investment.

Changes in energy generation affect electricity market dynamics. For years, Fossil fuel generators have helped balance electricity systems by quickly adjusting their output to meet short-term changes in demand. As Europe is transitioning to a clean energy future, with more renewables and becoming less import dependent, fossil fuel generators are phased out. The flexibility they provide is lost. Unfortunately, the pace of the rollout of new clean flexibility alternatives, such as cross-zonal capacity, storage and demand response, is delayed due to persistent barriers and the slow implementation of methodologies that define market operations.

In 2023, limited market flexibility triggered price volatility

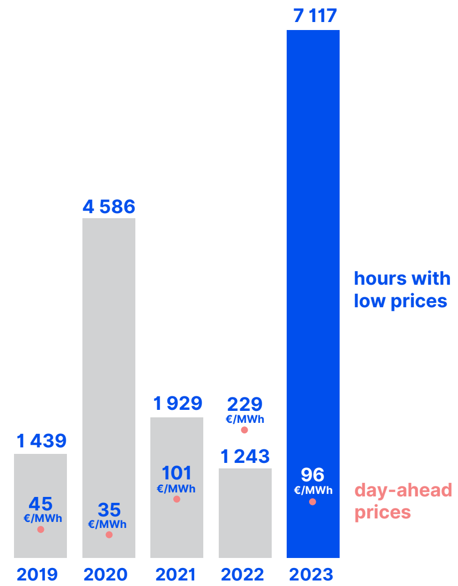
In 2023, renewable energy increased its share of total generation, marking significant progress towards a more sustainable and affordable energy future.

However, the rise in non-responsive[1] generation which does not adjust its output to short-term changes in demand has led to challenges such as low or negative electricity prices and price spikes in Europe. At the same time, average day-ahead prices remained twice as high as before the 2020 crisis, driven by fossil fuels, affecting economic competitiveness. Limited market flexibility results in low prices during periods with surplus renewable energy, hurting renewables' profitability. Demand response, whereby consumers adapt their consumption patterns, can offer much needed flexibility that can mitigate both very high and very low prices. A slow development of demand response therefore deters investment and hinder long-term price reductions.

1 Non-responsive generation does not follow market price signals and can include wind, solar, hydro (non-reservoir), combined heat and power, and nuclear generation. Whether or not these power plants are non- responsive depends on multiple factors. Much of the nuclear generation in France adjusts output to price signals and is therefore considered responsive.

More episodes of very low prices

Number of low-price events and average day-ahead prices across all EU-27 bidding zones, 2019-2023 (number of hours when prices are below EUR 5 /MWh and EUR/MWh, respectively)



Source: European Union Agency for the Cooperation of Energy Regulators (ACER) calculations based on European Network of Transmission System Operators for Electricity (ENTSO-E) and regulation on wholesale energy market integrity and transparency (REMIT) data.

Note: EU-27 = the 27 Member States comprising the European Union; MWh = megawatt-hours.

Unlocking flexibility requires fixing persistent implementation delays of methodologies that define market operations

27% of operational rules affecting day-ahead, intraday and balancing markets face implementation delays in 2024.

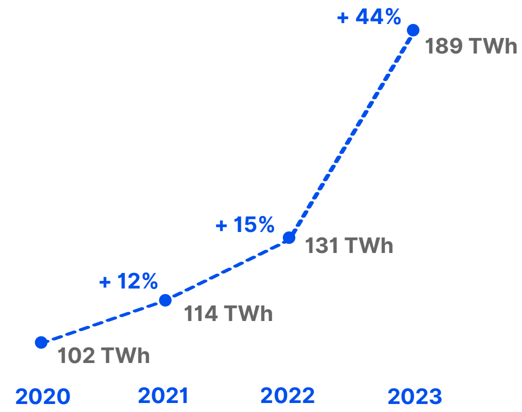
Delays in implementing required market design changes are worsening issues in electricity markets.

Slow progress in day-ahead and intraday markets limits flexibility.

Day-ahead and intraday markets are well-designed to match supply and demand close to real time, with traded volumes increasing over the years.

Intraday volumes rising

Yearly intraday trading in Europe, 2020-2023 (% and TWh)



Source: ACER calculations based on REMIT data.

Note: TWh = terawatt-hours.

Nevertheless, 27% of the related technical methodologies are facing implementation delays in 2024. Since 2016, many methodologies have been adopted, but challenges in implementing them have emerged, sometimes due to complex processes. Moreover, high interdependencies in the implementation of multiple methodologies affect overall effectiveness, with delays in one methodology affecting others.

Balancing market integration shows limited progress in 2023 as electricity transmission system operators delay joining EU balancing platforms

A pan-European electricity balancing market would make the activation of balancing services cheaper for the European consumers. PICASSO, MARI and TERRE are the projects from transmission system operators establishing the three European electricity balancing platforms. Despite supportive regulations and recent amendments to the rules governing the platforms[2], the integration of balancing markets remains limited[3]. Europe's balancing energy platforms can only reach their full potential with the participation of more transmission system operators. The limited number of active transmission system operators in 2023 reduced possibilities to exchange balancing energy.

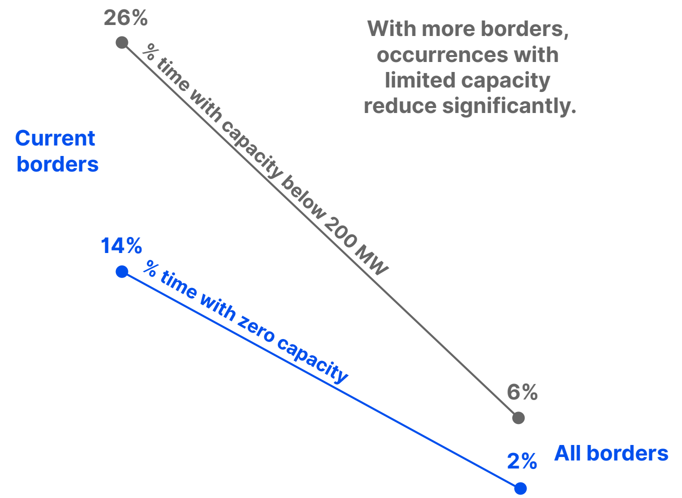
Europe's balancing energy platforms can only reach their full potential with the participation of more transmission system operators.

2 See, ACER Decisions 2024/08 and 2024/09 on the amendment of the the balancing energy from frequency restoration reserves with automatic activation or "aFRR" implementation framework and of the balancing pricing methodology.

3 As of November 2024, the situation remains similar to 2023, with two additional TSOs joining PICASSO and three joining MARI.

Increased participation from transmission system operators in balancing platforms means more options to exchange balancing energy

Percentage of time Czechia had no available transfer capacity (blue) and less than 200 MW transfer capacity (grey), considering current or all borders are active on PICASSO, 2023



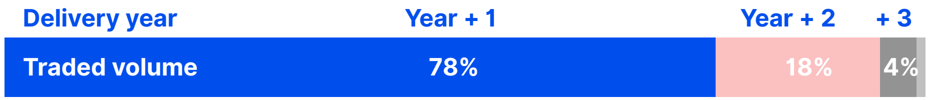
Source: ACER calculations based on the JAO Publication Tool and TransnetBW website on PICASSO.

Challenges in forward markets hamper long-term investment

Transitioning to a decarbonised electricity system will require significant investment. High volatility in short-term markets demands effective hedging options, to guarantee revenue certainty for producers and to hedge risks for consumers. ACER has identified key weaknesses in the functioning of the EU forward market, including a lack of liquidity in contracts longer than 1 year and a high concentration in specific hubs. These weaknesses limit the effectiveness of forward markets in supporting long-term investment. Specifically, shortcomings in the design of long-term transmission rights (LTTRs) hinder the integration of national forward markets into a single market, resulting in their undervaluation. Wholesale price signals, including from forward markets, should remain the main investment driver for renewables.

Forward markets mostly provide visibility up to 1 year ahead

Relative shares of traded volume per year in the future for delivery in Germany, 2023



Source: ACER calculations based on REMIT data.

Improving flexibility will drive the energy transition and strengthen European competitiveness

The flexibility needs of the EU power system must double by 2030 to accommodate the energy transition. In many EU Member States, rising price volatility, such as negative prices and price spikes, shows the unmet need for flexibility. The EU must leverage the current flexibility potential while also developing new flexibility resources. To promote needed investment and keep electricity prices competitive, ACER recommends fully implementing market design changes to unlock flexibility. Improved integration of regional electricity markets can help balance supply and demand. This way, surplus renewable energy in one region can be exported to areas with higher demand just as easily as a shortage in one area can be addressed with solutions from another.

To support investment and maintain competitive electricity prices, ACER calls for the full implementation of market design changes to unlock flexibility.

ACER sets out a set of recommendations to further improve electricity market integration to the benefits of EU consumers and businesses.

Integrating markets, strengthening connections

ACER recommends taking a proactive approach to further integrate power markets and strengthen connections. Specifically, ACER undertakes several initiatives to drive this integration:

- **For effective governance,** in 2025, ACER and national energy regulatory authorities will engage in an in-depth monitoring of the implementation of existing methodologies that define market operation. Meanwhile, the European Commission will assess ACER's policy proposals for improving the EU forward market by January 2026.
- **For market efficiency,** ACER has updated balancing platform rules and calls for transmission system operators to join the platforms to enable more exchanges of balancing energy. Balancing markets still show significant price spreads between Member States, and increasing these exchanges promises significant benefits. Additionally, in 2025, ENTSO-E and transmission system operators must improve data quality for monitoring balancing.
- **Looking ahead,** in October 2024, ACER assessed whether a Power Purchase Agreement template can improve market transparency and efficiency. ACER will start monitoring Power Purchase Agreements from 2025 onwards.

Stronger infrastructure, stronger future

ACER recommends an efficiency-first approach in both infrastructure investments and usage, ensuring that every installed megawatt is fully utilised. ACER is taking the following actions:

- **For future investments,** in its 2021 position paper, ACER called for incentives for smart investments in grid infrastructure to manage renewable energy variability. ACER's December 2024 infrastructure development report will outline steps for efficient investments. Upgrading transmission lines and rolling out innovative grid technologies is essential.

- **To increase connectivity,** ACER will continue to monitor yearly how transmission system operators implement the minimum 70% requirement and maximise cross-zonal capacities offered to the market. Interconnection projects will improve electricity transfers between countries.

- **For transparent and efficient grid pricing,** ACER will review network tariff approaches in its 2025 electricity tariff report. Grid tariffs should reflect the real costs of the network and promote system efficiency by sending price signals to customers and producers. ACER offers best practices to national regulatory authorities on how to achieve this.

Breaking barriers, building opportunities

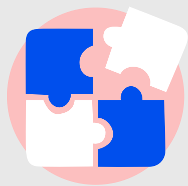
ACER recommends removing barriers to demand response and is committed to improving regulation through the following actions:

- **To enhance flexibility,** in December 2023, ACER published an assessment of demand-side response barriers to be removed. As a follow up, ACER will publish a list of no-regret measures early 2025.

- **To enhance regulation,** ACER supports the ongoing development of the regulatory framework for demand-side flexibility. After a public consultation in 2024, ACER will submit a proposal for a network code on demand-side flexibility to the European Commission by March 2025.

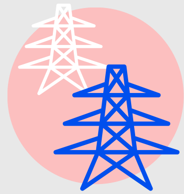
Integrated markets, strengthening connections

Delivering the single electricity market and the related benefits.



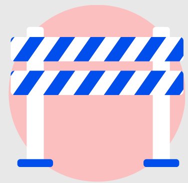
Stronger infrastructure, stronger future

Maximising value-for-money of infrastructure investment.



Breaking barriers, building opportunities

Lifting barriers encourages demand response, storage, and distributed generation flexibility.



Introduction

Integrated markets help provide a resilient energy supply through a robust network, making the transition to a low-carbon economy more efficient. Since 2012, ACER has supported and tracked the progress of integrating European energy markets, facilitating cross-border trade across all time frames.

Day-ahead and intraday markets are now fully coupled in the EU, ensuring market integration across all Member States. These markets' full benefits will be further reaped once all the corresponding market design rules are fully implemented.

The pan-European forward and balancing markets have the most to gain from further integration.

These market developments are happening alongside shifts in energy supply and demand.

This report first examines how changes in energy generation affect market outcomes. It then reviews the implementation of current regulations and analyses the market situation across all timeframes, with a stronger focus on forward and balancing markets. The report ends by evaluating market developments in the Energy Community contracting parties.

This report is complemented with dashboards.

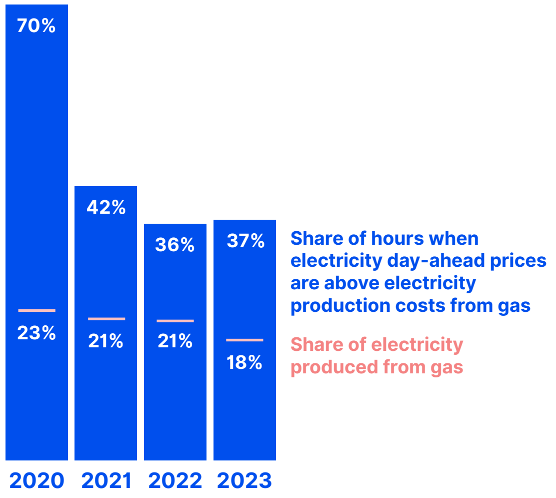
Non-responsive generation[4] calls for system flexibility[5]

A growing share of non-responsive generation does not provide flexibility to the system, raising price spikes, negative prices and volatility

1 In 2023, renewables rose to a record 45% of overall electricity generation. This trend is tied to the 2022 REPowerEU commitment to renewables and an increased target of 42.5% renewable energy sources (RES) in the EU's energy provision by 2030. Wind and solar are powering this growth, with an 18% surge in solar generation in 2023. Wind-powered electricity exceeded both gas and coal generation for the first time. The rise in renewables and lower power demand led to a reduced role for gas as the marginal price setter. Overall, gas-fired generation decreased by -16% (- 70 TWh) from 2022 to 2023.

Reduced role of gas-fired generation as a marginal price setter

Figure 1: Percentage of hours when electricity day-ahead prices were above costs of producing electricity from gas and gas-produced electricity as a share of the total electricity production (%) on average in the EU-27 – 2020-2023



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

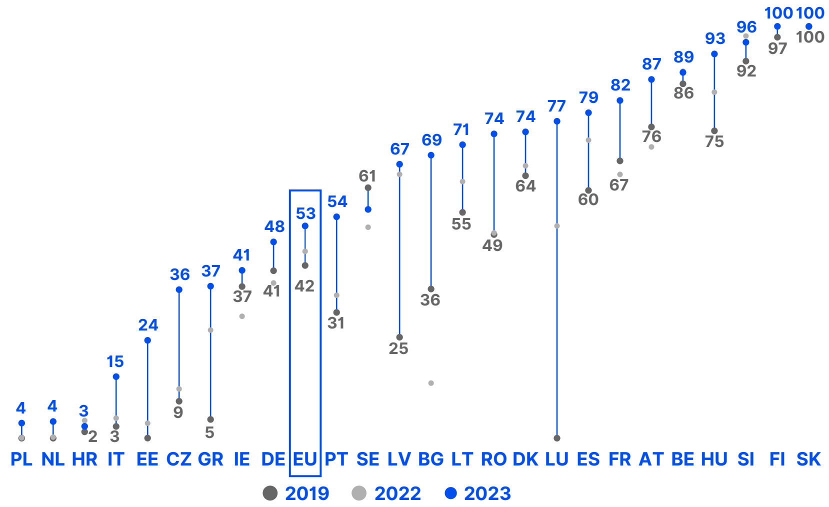
2 The reduced role of gas reflects a larger phase-out of traditional power plants. Along with the rise in renewable generation, this has contributed to a broader shift to non-responsive generation sources. Non-responsive generation sources do not adapt production to short-term demand or price signals. While renewable generation is technically able to adjust its output, its response to market signals might be limited through less-than-ideal subsidy schemes. In 2023, the percentage of the time when most generation was ensured by potentially non-responsive generation grew by 10% to reach 55%.

4 Non-responsive generation does not follow market price signals and can include wind, solar, hydro (non-reservoir), combined heat and power, and nuclear generation. Whether or not these power plants are non- responsive depends on multiple factors. Much of the nuclear generation in France adjusts output to price signals and is therefore considered responsive.

5 Flexibility refers to the ability of energy resources and consumers to change or adjust their consumption or production in response to price signals or to help system operators solve imbalances or network congestions. (see ACER report on barriers to demand response, 2023).

More than half of the time, more than half of the generation is potentially non-responsive

Figure 2: Percentage of the time when potentially non-responsive generation[6] represents at least half of total generation in the EU-27, 2019-2023 (% of hours)

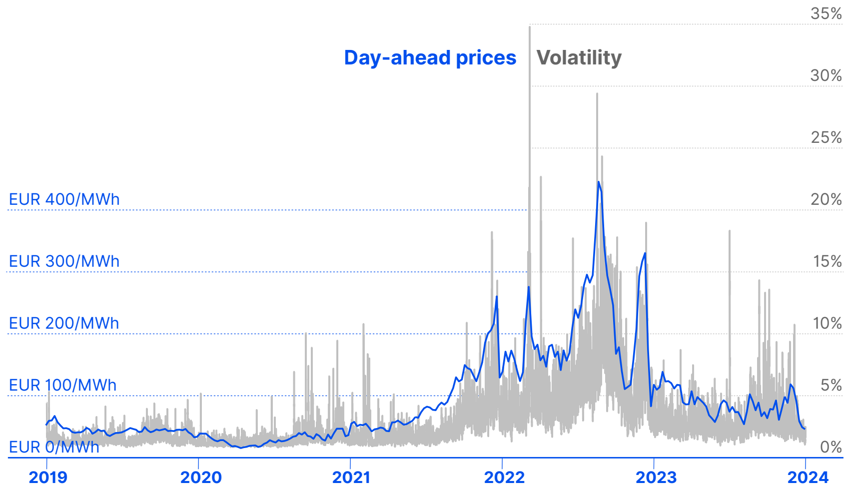


Source: ACER calculations based on ENTSO-E transparency platform (actual generation per type).

3 The lack of flexible generation responding to market conditions has contributed to greater price volatility, worsened by the 2022 energy crisis[7]. The reduced responsiveness in generation and slow progress on the demand response or storage side caused extreme price swings, ranging from negative or very low prices to extremely high ones. This volatility may continue until responsiveness to market conditions improves through more responsive renewable generation, demand response, storage and more time-granular and closer to real-time cross-zonal trade.

Price volatility remains significantly higher than before the energy crisis

Figure 3: Day-ahead prices and volatility in the EU-27, 2019-2023 (EUR/MWh and %, respectively)



Source: ACER calculations based on REMIT data.

Note: the volatility reflects a percentage of variation of the daily prices. Volatility was estimated using a GARCH model (Generalized Autoregressive Conditional Heteroskedasticity), which measures the conditional standard deviation of returns, capturing time-varying fluctuations in price movements. It offers a dynamic estimation of risk, providing deeper insights into market uncertainty.

6 See footnote 1 above.

7 Another factor contributing to electricity price volatility is gas price volatility.

Low system responsiveness can delay investment in renewables

4 In 2023, average day-ahead prices remained higher than before the crisis. At the same time, episodes of low and negative prices multipled, particularly during periods of high renewable generation and low demand, like on a sunny or windy Sunday (see Figure 10, Figure 11, and Figure 12 below).

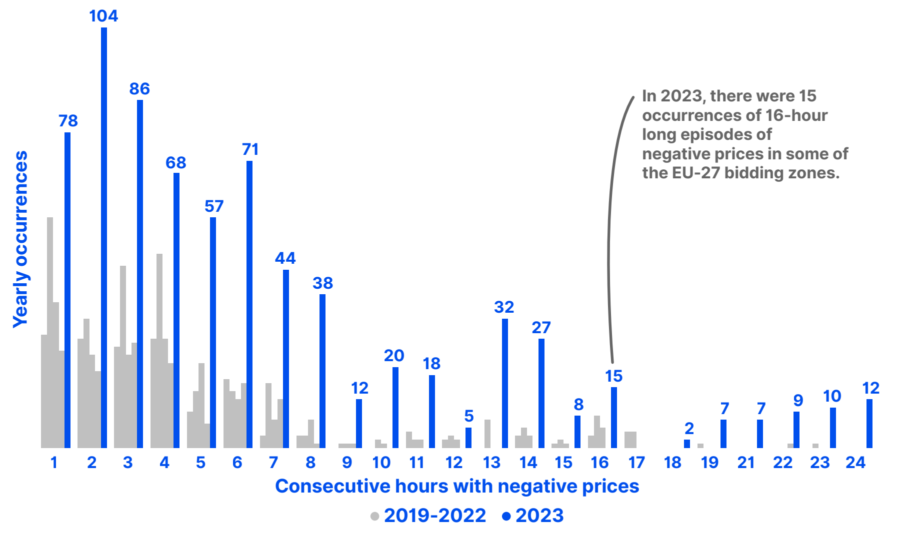
5 Non-responsive generation drives prices down. Simultaneous wind and solar power's generation during favourable weather conditions fosters surplus supply. At the same time, some non-responsive conventional plants continue generating, as they must remain available for hours of higher demand and lower renewable generation. Their operational limitations prevent them from adapting their output to shorter-term demand evolution.

6 Negative prices are an extreme illustration of low-price episodes, in the context of specific subsidy schemes. Non-responsive conventional plants compete with subsidised renewable generation that benefits from guaranteed revenue (e.g. feed-in-tariffs or guarantees of origin) even for negative prices. This competition pushes prices below zero. Subsidies paid by consumers, cover the resulting gap between market prices and guaranteed revenue for renewable generation. Ideally, subsidy schemes should provide renewable producers with incentives to produce when it is valuable for the electricity system[8]. This may reduce the frequency of negative prices episodes.

7 Situations of surplus supply lead to renewable generators selling electricity at prices below the yearly market average[9]. As this occurs more frequently, wind and solar revenues decline. These low-price episodes reduce renewable profitability and deter investment in renewables, requiring EU Member States to rely on subsidy schemes to ensure meeting their renewables targets.

More frequent and longer episodes of negative prices

Figure 4: Yearly occurrences of negative prices as a function of their duration in consecutive hours in the EU-27, 20219-2023 (sum of occurrences per bidding zone)



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

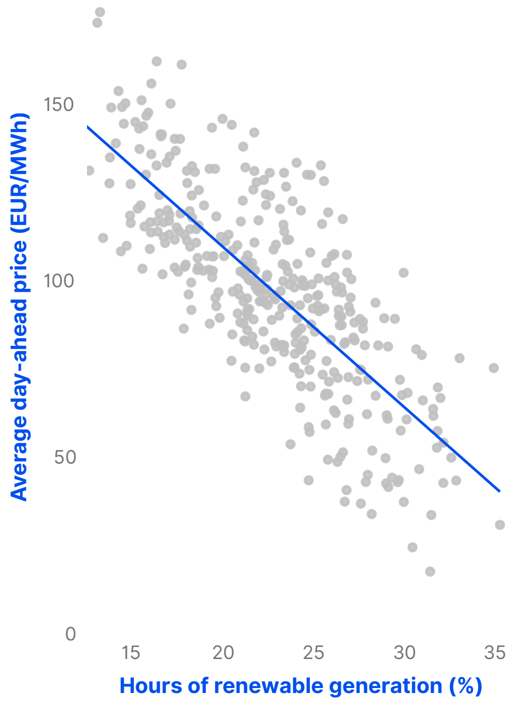
8 The rise in renewables is lowering prices, which is a positive development. However, end-users with regulated prices do not fully benefit from these lower prices, as they are exposed to average day-ahead prices significantly higher than pre-crisis. Additionally, subsidies for low and negative market prices could lead to higher taxes.

8 The Florence School of Regulation research report "Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation" provides additional details on how contracts for difference (CfDs) are designed to stop payouts when negative prices occur (e.g. after a given number of consecutive hours when negative prices occurred).

9 Metrics related to competition between RES can be found in a dedicated ACER dashboard.

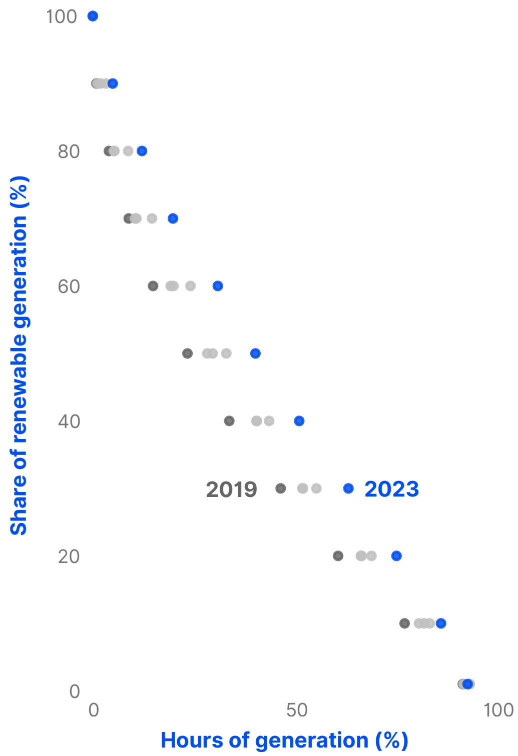
When the wind blows and the sun shines, prices are low.

Figure 5: Average day-ahead price as a function of the share of inflexible generation in the EU-27, 2023 (% and EUR/MWh)



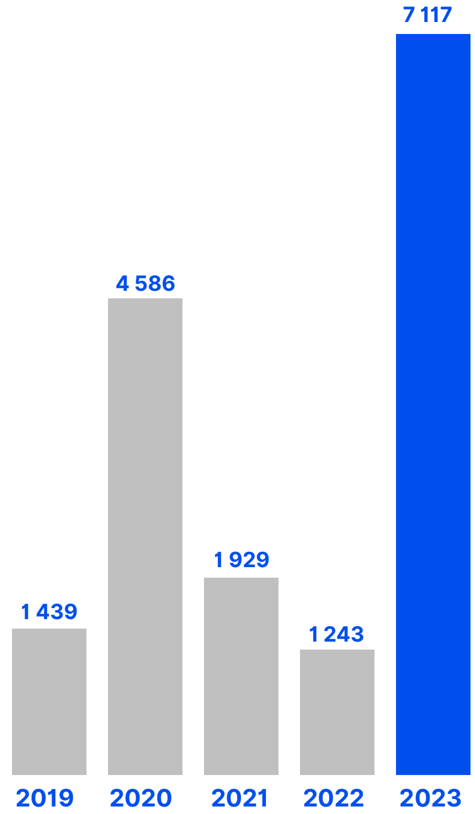
There is more renewable generation, more often...

Figure 6: Percentage of hours when a certain share of renewable generation is met in the EU-27, 2019-2023 (%)



...resulting in more episodes of very low prices

Figure 7: Number of hours when prices are below EUR 5/MWh in the EU-27, 2019-2023 (sum of number of hours per bidding zone)



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

Member States need to unlock local flexibility and share it across borders

9 The growing share of non-responsive generation capacity calls for a European response to the current need for flexibility. Such response implies sharing flexibility resources and increasing responsiveness on both the generation and demand sides. Available flexibility is becoming more crucial for an economic and efficient energy transition. In 2023, grid congestion in the EU curtailed over 12 TWh of renewable electricity, and the cost of managing congestion was EUR 4.2 billion. Sufficient cross-zonal capacity, more time-granular and closer-to-real-time cross-zonal trade, large-scale storage options and the removal of barriers to demand response unlock such flexibility.

EU flexibility increases with cross-zonal trade

10 Cross-zonal trade is a key provider of flexibility across the EU. Member States steadily rely on cross-zonal trade to manage production and demand fluctuations[10]. However, the level of cross-zonal exchanges remained stable in 2023 compared with 2022.

Increasing cross-zonal capacity will improve flexibility sharing, regardless of where the demand for flexibility arises.

11 The lack of system flexibility becomes evident during instances of negative pricing in one bidding zone adjacent to a bidding zone with largely positive prices, typically occurring when demand is low, and non-responsive generation cannot be exported to meet demand in neighbouring markets, as in Figure 8[11]. Similarly, in the summer of 2024, large price gaps emerged between Eastern and Western Europe (Figure 9).

12 Increasing cross-zonal capacity will improve flexibility sharing, regardless of where the demand for flexibility arises.

13 Improving cross-zonal trade, for example, by ensuring more cross-zonal capacities, allowing for more granular cross-zonal trade closer to real-time and employing innovative grid technologies would enhance flexibility, especially in a high-renewable-energy scenario. It would lift the barriers that currently limit effective energy exchange. Greater network interconnectivity will enable better use of regional solar, and especially wind, resources, demonstrating greater complementarity across Europe.

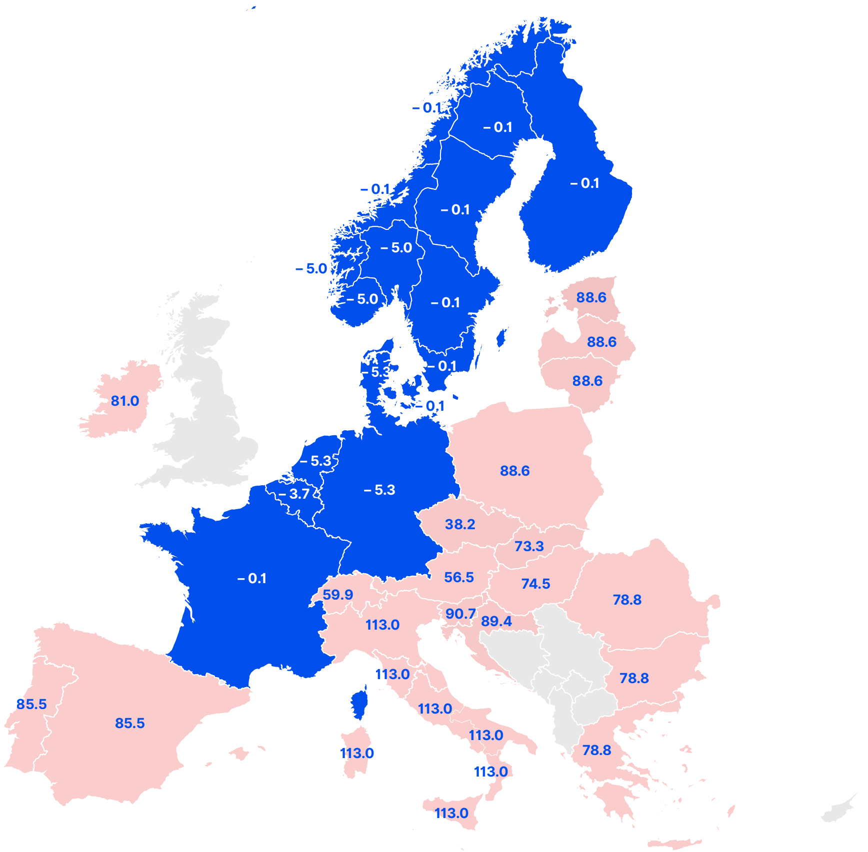
14 While providing flexibility to the market, increased network interconnectivity would contribute to mitigating price volatility, ensuring a secure energy supply, and enhancing renewable integration.

10 In 2023, the average ratio of across EU-27 bidding zones of net electricity import over total electricity demand was 10%.

11 Reaching full price convergence is not an objective, as it would require overinvestment in network infrastructure.

Negative prices in 2023: when export meets bottlenecks

Figure 8: Day-ahead prices in the EU-27/EEA(Norway), and Switzerland, as at 20 September 2023, at 11:00 (EUR/MWh)



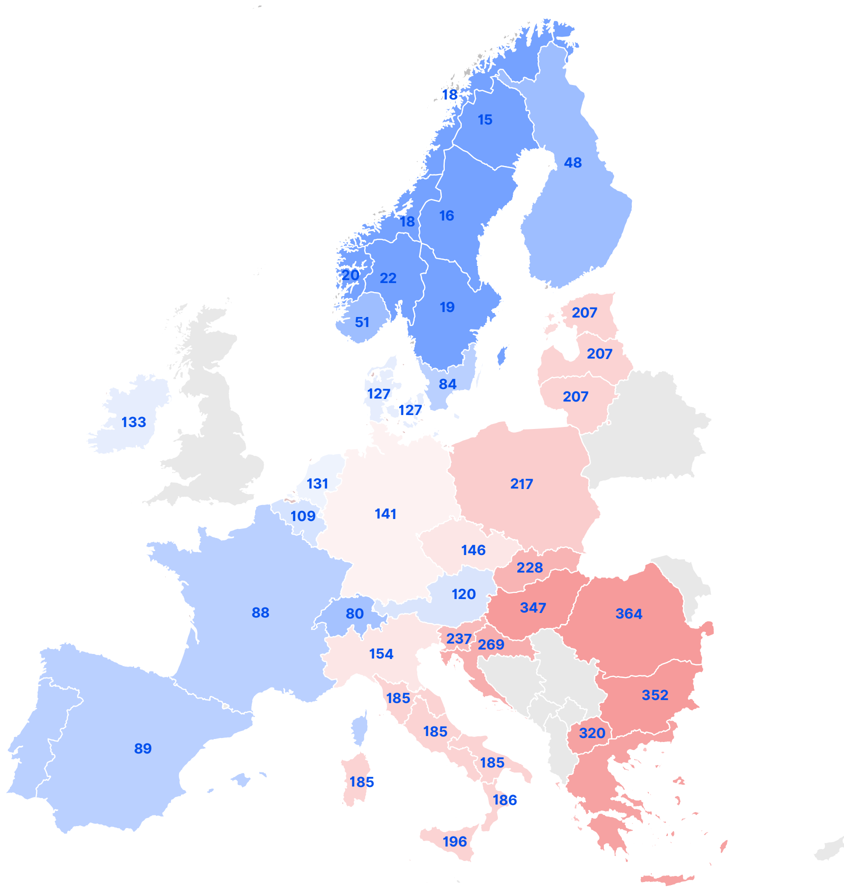
Source: ACER calculations based on ENTSO-E Transparency Platform data.

Note: "bottleneck" should be understood as "market congestion", a "situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints" (see [Capacity Allocation & Congestion Management](#)).

Through the European Economic Area ('EEA') agreement Norway implements most EU energy legislation and is a member of the internal energy market.

Summer 2024: price gaps widen between east and west

Figure 9: Average day-ahead prices in the EU-27/EEA(Norway), Switzerland, between 1 July 2024 and 23 September 2024, at 19:00 (EUR/MWh)



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

Price fluctuations make demand response and storage more profitable

Occurrences of frequent significant daily price fluctuations highlight the profitability of the flexibility to shift consumption or production over time.

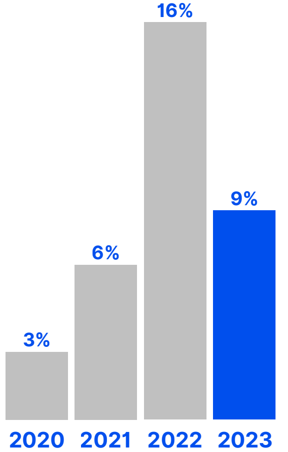
15 Price swings create ideal arbitrage opportunities for demand response and storage. Energy can be stored, or demand increased when prices are low. At high prices, demand can be reduced or stored energy can be supplied, for example with batteries. This contributes to the stability of the grid.

16 Since 2020, with the pandemic and the energy crisis, volatility has started to increase significantly; the trend was confirmed in 2023, with larger and more frequent price fluctuations in comparison to pre-crisis levels.

17 As more renewable energy leads to greater and more frequent volatility, investing in energy storage will become increasingly profitable and essential for a sustainable future.

In 2023, flexibility's potential value is confirmed

Figure 10: Average return on investment of a large-scale battery in the EU-27, (2020-2023)



Source: ACER calculations based on REMIT data and the Joint Research Centre report Batteries for Energy Storage in the European Union – Status report on technology development, trends, value chains and markets – 2022.

Note: Calculations assume an investment of 300 EUR/kWh, for a battery of 40 MWh of capacity, with a 90% efficiency in storing energy.

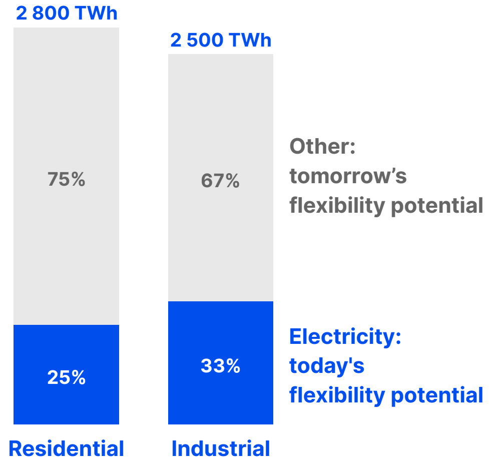
Retail markets: an untapped flexibility source

18 Retail markets could become a readily available source of flexibility. However, current regulations and market structures create barriers to flexible retail contracts and dynamic pricing, limiting consumer engagement and grid stability. Furthermore, distribution system operators must digitalise their networks to ensure smooth coordination with transmission system operators (TSOs).

19 Currently, within retail markets, industrial demand response holds the most potential. The potential of residential flexibility will grow with increased electrification.

Being more electrified than the residential sector, the industrial sector shows more flexibility potential today

Figure 11: Share of electricity in final energy demand in residential and industrial sectors in the EU-27, 2022 (TWh)



Source: EUROSTAT.

20 ACER recommends regulatory changes to improve access to flexibility, and better information to consumers about the benefits of flexible energy consumption. Unlocking flexible retail consumption is essential for the energy transition and offers consumers lower energy prices.

ACER actively supports market design changes

21 ACER actively supports a series of market design changes to address challenges from the shifting energy generation mix. These changes outline ways to unlock more flexibility in the system:

1. **Align market design with system's physical needs:** reduce market time units and imbalance settlement periods, and harmonise trading intervals.

2. **Efficiently allocate cross-zonal transmission capacity to high-need areas:** implement flow-based capacity calculation in the Nordics, extend regions, add advanced hybrid coupling for the day-ahead time frame, and implement flow-based capacity calculation in the intra-day time frame.

3. **Enhance balancing services exchange:** amend the rules governing the balancing platforms, expand the cross-border exchange of balancing energy, and pursue a wider application of processes governing the allocation of cross-zonal capacity for the exchange of balancing capacity and sharing of reserves.

4. **Improve market access for demand response and small players:** establish the EU framework for market access considering, among others, a correct allocation of balancing responsibility, including when implementing aggregation models, prequalification processes, and requirements and principles for the setup of local markets and their interactions with other markets.

5. **Integrate further forward markets in the EU:** implement long-term flow-based allocation and propose solutions to better integrate markets also in the long term.

6. **Review bidding zones:** identify efficient designs for the EU.

Regulation of demand-side response

What the current framework provides:

The electricity regulation and directive already cover key areas like:

- **Role definition:** defines active customers, market participants engaged in aggregation, and citizen energy communities.

- **Market access:** requires the opening of all electricity markets to different resources and participants.

- **System operation:** enables system operators to use demand response, especially at the distribution level, for balancing and congestion management.

Despite this, barriers remain, as noted in the 2023 ACER report on demand response. Member States can act now to implement the existing EU framework without waiting for the new demand response network code.

What the new demand response network code will bring:

The new network code will remove further regulatory barriers and improve market participation for demand response, energy storage, and distributed generation. Key points include:

- **Participation of small users:** clear rules for aggregation models and a European registry for baselining.

- **Access to balancing and local markets:** simplified product verification, faster pre-qualification, and a national flexibility information system.

- **Local market setup:** default use of market-based procurement with clear rules for market interaction.

- **Efficient operation:** coordination between transmission and distribution system operators and among distribution system operators, for better congestion and voltage control.

Following a public consultation, ACER will submit the network code proposal to the Commission by March 2025.

Prompt implementation of market design rules contributes to system flexibility

Major delays have occurred in the implementation of methodologies defining market operations

22 Regulations require (TSOs), national regulatory authorities (NRAs), and ACER to create common rules for EU electricity markets. Since 2016, ACER and NRAs adopted over 190 methodologies defining rules for operating the system and markets.

23 These methodologies are regional or EU-wide. ACER notes delays in implementations in both instances. While some delays are due to the technical complexity of the methodologies, others occur because the methodologies are dependent on the full implementation of related methodologies.

24 ACER and NRAs have identified delays in the implementation of nine EU-wide terms and conditions or methodologies, most of which relate to electricity balancing regulation methodologies. Several regional methodologies are also delayed (38), with delays affecting between two and seven methodologies per region.

Implementation delays of methodologies defining market operations hinder the EU energy market's proper function.

25 Delays can greatly affect consumers' cost, especially for projects with substantial welfare effects. For example, Nordic TSOs reported a social welfare gain of 63.3 million euros during the three-month period of the Nordic flow-based parallel runs (12.12.2022-12.03.2023).

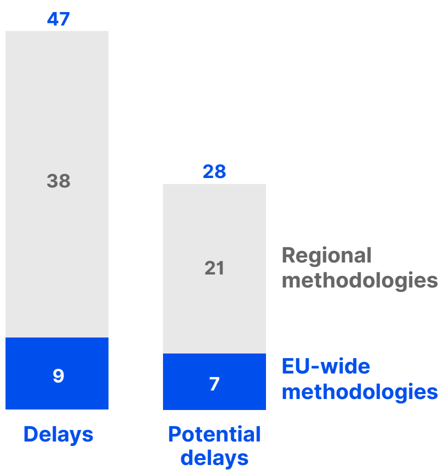
There is high interdependence between the implementations

26 Multiple terms and conditions or methodologies set key rules, platforms or methods needed for implementing other related methodologies. ACER and NRAs agree that it is imperative to prioritise the effective implementation of those methodologies which are the root cause of other delays, such as the common grid model methodology (CGM), the balancing platforms (manual frequency restoration reserve (mFRR) and automatic frequency restoration reserve (aFRR)), and the long-term flow-based project (Core long-term capacity calculation methodology (and single allocation platform (SAP) methodologies), along with the regional operational security coordination (ROSC) methodologies.

27 Delays in implementing these methodologies can postpone related rules, hindering the EU energy market's proper functioning and causing potential welfare losses.

47 to 75 out of 173 methodologies could face delay

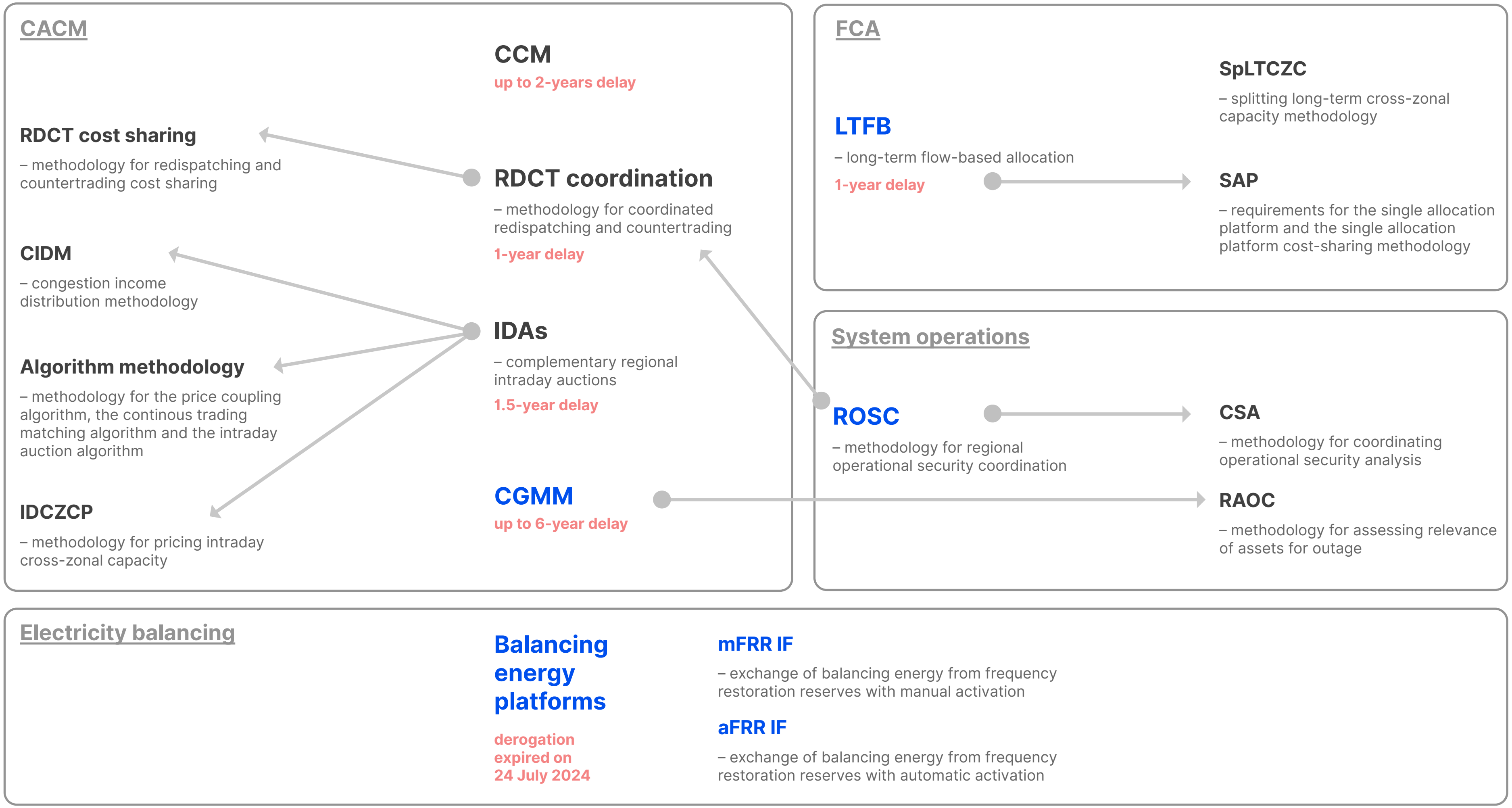
Figure 12: Status of implementation of terms and conditions or methodologies under Capacity Allocation and Congestion Management, Forward Capacity Allocation, Electricity Balancing and System Operation Regulations (count of methodologies)



Source: National Regulatory Authorities.

High interdependence between implementations

Figure 13: Overview of terms and conditions or methodologies ***to be implemented in order of priority*** *as from November 2024 and interdependencies with other methodologies*



Source: ACER.

Note: The implementation of methodologies highlighted in blue is a priority. A detailed implementation status of terms and conditions or methodologies can be found on [the ACER website.]

ACER and NRAs are committed to improving enforcement

28 There are multiple reasons for the delays – such as the technical complexity and interlinkage of the methodologies, changing of requirements in the processes, alleged technical or resource constraints, implementation timelines or the number and diversity of the involved entities, and the (regional) decisions governance framework. An important factor is the need to reinforce the cooperation framework for effective monitoring, implementation and a robust framework for enforcement:

- ACER/ Council of European Energy Regulators Report on Challenges of the Future Electricity System – among other actions, 'energy regulators commit to develop (further) incentive frameworks for TSOs, NEMOs and other entities for earlier implementation of integration projects and to improve the enforcement of compliance in case of delays'.
- 39th European Electricity Regulatory Forum ('Florence Forum') conclusions – 'Commission's request to ACER and NRAs to make a recommendation on how to strengthen the regulatory framework to reduce implementation delays, looking into enforcement, incentives and governance'.

29 **The ACER website contains more detailed information about the status of the implementation of terms and conditions or methodologies.**

30 The information gathered by ACER is based on the input provided by NRAs and presents an estimated status of implementation of the European and regional methodologies. In some cases, additional information or clarifications from regulatory authorities might be needed. ACER has started to conduct detailed implementation monitoring of the obligations contained in each of the methodologies to obtain precise indications on their implementation status. Interactive dashboards will be published on ACER's website on a rolling basis as soon as the information becomes available.

Terms and conditions or methodologies defining rules for operating the system and markets stem from four regulations

1. **Capacity Allocation and Congestion Management Regulation (CACM) methodologies** cover rules on the common grid model, capacity calculation regions, the algorithm for price coupling, continuous trading matching and intraday auction, data provision regarding generation and load, the market coupling operator plan, rules on products and back-up, day ahead and intraday products, maximum and minimum prices and scheduled exchanges, among others.
2. **Electricity Balancing Regulation (EB) methodologies** cover, among other things, the implementation framework for the European platforms for the exchange of balancing capacity, standard products, activation purposes, the allocation process of cross-zonal capacity for balancing, TSO settlement rules and the harmonisation of imbalance settlement.
3. **Forward Capacity Allocation Regulation (FCA) methodologies** cover rules on the common grid model, the single allocation platform, data provision regarding generation and load, rules on congestion income distribution and on long-term transmission rights.
4. **System Operation Regulation (SO) methodologies** cover, among other things, rules on the common grid model, the coordination of operational security analysis, the assessment of assets relevant for outage coordination and the key organisational requirements, roles and responsibilities relating to data exchange.

Liquidity and efficiency in coupled day-ahead and intraday markets support renewable integration

31 **The integration of EU Day-ahead and intraday markets has generated welfare year after year, supported by ongoing market improvements. Such improvement must continue with the implementation of remaining methodologies that define market operations.**

32 Day-ahead and intraday markets are coupled across Europe[12]. In 2023, intraday trading relied on continuous trading. On top of the continuous trading, auctions were introduced in June 2024 to price cross-zonal capacity pursuant to ACER Decision 06/2022. Market liquidity is crucial for efficient electricity trading. It shows how easily participants can trade large volumes without significant price swings. One way to measure liquidity is through the 'churn factor', which compares the total volume traded to a Member State's actual consumption.

33 Day-ahead market liquidity remained stable in 2023, reflecting a mature market.

34 Intraday churn factors rose by 50% in 2023, reflecting growing demand for short-term adjustments due to increased renewable generation. Since 2021, cross-zonal intraday volume nominations have risen, showing an 18% increase in 2023, driven by the growth in intraday trading across Member States.

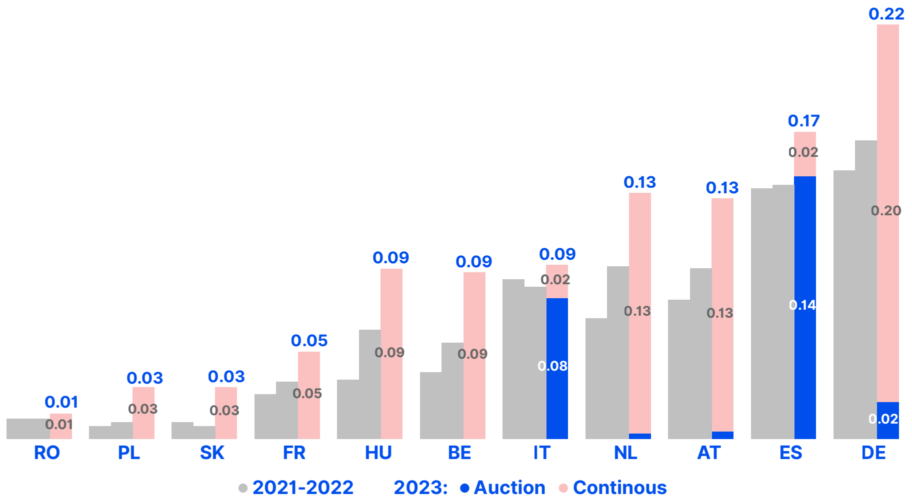
Reflecting the renewed success of day-ahead and intraday market integration, day-ahead markets remained stable in 2023, while intraday trading increased by 50% due to growing renewable generation and improved market efficiency from single intraday coupling.

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

12 For further information, please refer to https://www.nemo-committee.eu/sdac and https://www.nemo-committee.eu/sidc.

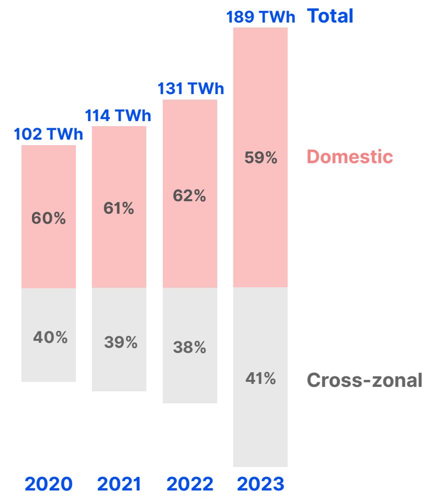
In 2023, intraday market churn rose 50%, with an 18% increase in cross-zonal trade nominations.

Figure 14: Yearly churn factors in major European intraday markets by type of trade – 2021–2023



Source: Nautilus.

Figure 15: Share of continuous intraday-traded volumes according to infra-zonal versus cross-zonal nature of trades in Europe and yearly continuous intraday-traded volumes – 2020-2023 (% and TWh)



Source: ACER calculations based on REMIT data.

Well-functioning long-term markets will be key to supporting much-needed investment

36 The transition to a decarbonised electricity system requires massive investment. Providing investment certainty and revenue predictability is key to delivering this investment at the lowest possible cost.

37 Long-term markets[13] are crucial to support such massive investment. They are a major tool for hedging risks in electricity trading by fixing a price over a longer period in advance. Indeed, buying a long-term product can mitigate the risk of paying a high price for electricity in spot markets. Similarly, selling electricity through a long-term product guarantees a certain revenue for future electricity generation.

38 A well-functioning and efficient forward[14] electricity market provides transparent, robust, independent, and possibly the only signal for the value of electricity in the future. This price information provides a crucial foundation for pricing in other long-term markets, such as power purchase agreements (PPAs), contracts for difference (CfDs), and capacity mechanisms. While PPAs are typically commercial deals, CfDs and capacity mechanisms are subsidy-backed support schemes. Member States use such support schemes when market signals do not trigger sufficient investment.

39 The European electricity forward market appears to be suffering from several issues, such as insufficient liquidity, accessibility, competition and transparency, and concentrated market power. While the day-ahead and intraday markets have already undergone a significant revision, harmonisation and integration with the introduction of single day-ahead and intraday coupling, regulators and policymakers are now focusing on the further development of the long-term markets, with a focus on forward markets.

40 The following section examines the current functioning of electricity forward markets in the EU, highlights the limitations in the design of long-term transmission rights to effectively integrate national hubs into a single EU market, and explores alternative mechanisms to promote investment through long-term contracts.

Forward markets show post-crisis recovery in 2023, yet structural weaknesses endure

41 After a significant drop in forward trading during the 2022 energy crisis, forward markets benefited from the stabilisation of the energy sector in 2023, with an overall increase in market liquidity. Market liquidity can be measured by churn rates, which show the ratio of the total volume of power traded to electricity consumption during a specific period. Overall, as shown in Figure 16, churn rates increased on average by 27% in 2023.

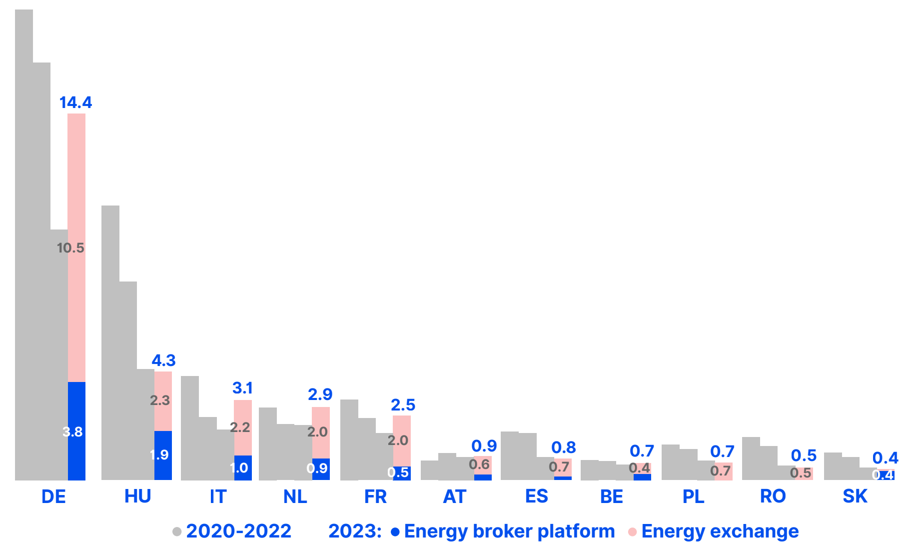
42 Despite this increase, liquidity in most EU forward electricity markets has yet to return to pre-crisis levels. Furthermore, it remains heavily concentrated in the German hub, which acts as the main trading hub for market participants across the EU to hedge their price risks (i.e., proxy hedging).

13 Long-term markets refer to forward and futures markets but also to the contracting of PPAs or CfDs.

14 When this report refers to forward markets, it implies the trading of forward and future contracts.

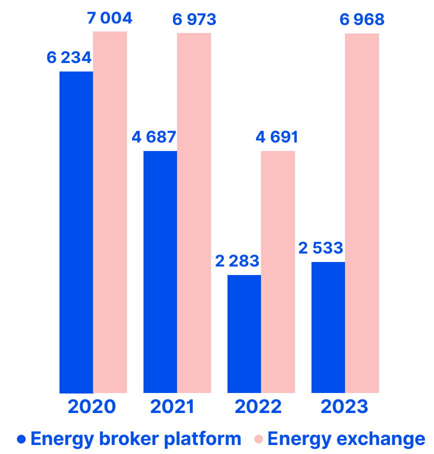
Churn rates are increasing but have not returned to pre-crisis levels yet

Figure 16: Churn factors in a selection of European forward markets – 2020-2023 (%)



Source: ACER calculations based on REMIT data.

Figure 17: Evolution of brokered versus exchange trading in the EU-27 – 2020-2023 (TWh)



Source: ACER calculations based on REMIT data.

43 A churn rate exceeding 10 usually indicates a liquid market, while a rate above 40 corresponds to a highly liquid market. By this standard, only the German forward electricity market qualifies as liquid in the EU. For comparison, the International Energy Agency estimated the churn rate at the main natural gas hub in the United States, the Henry Hub, to be 44 in 2023. In contrast, the combined churn rate for EU and UK gas hubs was calculated at 17 in that same year[15].

44 Over the last years, there has been a shift in European forward markets, from brokered trading to trading via power exchanges, a trend confirmed in 2023. As prices lowered after the peak of the crisis in 2022, the cost of collaterals logically followed. The volumes traded at organised marketplaces rose back to pre-crisis levels. Over The Counter (OTC) trading, including brokered trading, stabilised but remained low compared to pre-crisis levels.

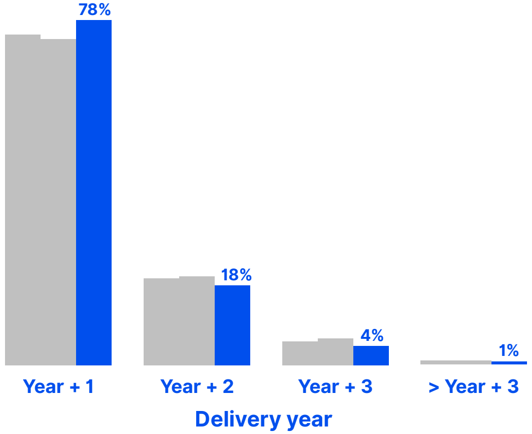
45 Well-functioning forward markets need to provide visibility to investors about the electricity price in the future. However, even in the most liquid forward market in Europe, Germany, most of the volume is traded only up to one year ahead. The liquidity of longer maturity contracts drops significantly after one year ahead and is almost non-existent beyond three years ahead. This indicates that current forward markets may not be well suited for the

15 Gas Market Report Q1-2024, International Energy Agency.

hedging of investments, which require a much longer time horizon. The costs of collaterals, which expand with longer time horizons, are a major obstacle in accessing longer maturity contracts for investment hedging.

Forward markets mostly provide visibility up to one year ahead

Figure 18: Relative shares of traded volume per year in the future for delivery in Germany – 2021-2023 (%)



Source: ACER calculations based on REMIT data.

46 Although most trading in EU forward markets occurs up to one year in advance, an increase of liquidity in longer-term maturities contracts, such as Y+2 products, can be observed in some EU markets. This trend supports the case for introducing Long-Term Transmission Rights (LTTRs) with maturities beyond one year, to better support this segment of forward markets.

47 Further insights into the functioning of EU forward markets are available through the public dashboard, which is published alongside this report.

Undervaluation of long-term transmission rights reveals shortcomings in their design

48 LTTRs are the main regulatory mechanism in the EU to integrate national forward markets and thus address some of the challenges associated with the current forward market design. ACER has identified several shortcomings in the design of LTTRs, that limit their ability to combine the liquidity of small and large zones into one single integrated market.

49 These shortcomings relate in particular to the infrequent auction schedules (typically once a year for yearly products and once a month for monthly products), a lack of a secondary market, maximum product maturities of one year, and the issuing of spread options, as opposed to obligations. These in turn limit the ability of LTTRs to support cross-zonal hedging.

What are long-term transmission rights?

LTTRs constitute the main mechanism in the EU to hedge against the risk associated with congestion between bidding zones.

- **Physical transmission rights (PTRs)** provide the holder the right to the physical transfer of electricity between two bidding zones, or to receive renumeration during periods of congestion.

- **Financial transmission rights (FTRs) - Options** only entitle the holder to renumeration during periods of congestion.

Remuneration and income derived from LTTRs

Monthly and yearly LTTRs are issued by TSOs and allocated through auctions organized by a single allocation platform.

- **LTTR congestion income:** When LTTRs are auctioned, TSOs collect congestion income from the participants who obtained the rights.

- **LTTR remuneration:** At delivery, the LTTR holders are entitled to receive from TSOs the day ahead price difference, if positive, between two bidding zones.

50 In this analysis, ACER assesses the market valuation of LTTRs using two indicators:

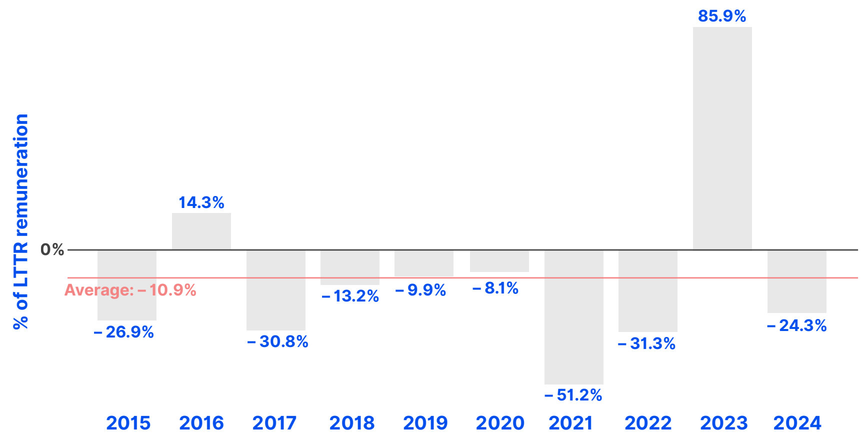
- **Ex-post risk premium:** Comparison of the congestion income derived from issuing LTTRs with the associated remuneration to holders of the product. This metric indicates how LTTR buyers value the hedging that LTTRs provide against congestion in the day-ahead market.
- **Forward risk premium:** Comparison of the price difference between the LTTRs issued on both directions of a given border, with the price spread in future contracts traded shortly before the closure of the LTTR auction. This indicator evaluates the extent to which LTTR prices align with forward market prices.

51 LTTRs auction prices represent, at least, the forecasted value of the product. That is, market participants will be willing to bid into the LTTR auction at least the return they expect from holding the product. As the expected return from the product is subject to uncertainty, a large sample is necessary to calculate the ex-post risk premium, to mitigate the impact of fluctuations in forecast errors.

52 Figure 19 summarises the observed **ex-post risk premium** in the period from 2015 to 2024, presenting the difference between LTTR income and associated remuneration, as a share of the total remuneration.

Historical LTTR valuation results in net transfer of congestion income from TSOs to LTTR holders

Figure 19: Net financial transfer from TSOs to LTTR holders, displayed as the share of the total LTTR renumeration per year – 2015-2024 (%)



Source: ACER calculation based on JAO Auction Tool and ENTSO-E transparency platform data.

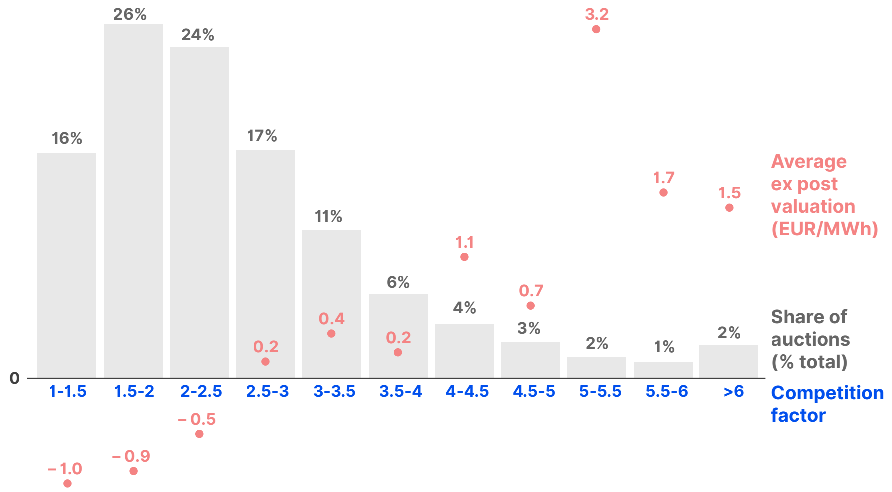
Note: Further information on the calculation and assumptions used for the creation of this figure is available in Annex.

53 The analysed data shows that the collected income from LTTR has been on average lower than the remuneration by TSOs to LTTR holders. The opposite was however observed in 2016 and, to a higher extent, in 2023. Over the analysed period, TSOs have collected a total of **EUR 15 billion**, while they have remunerated LTTR holders with **EUR 16.8 billion**, thus resulting in a net transfer of **EUR 1.83 billion** (or around 11% of the total LTTR remuneration) from TSOs to LTTR holders, which is socialised among network users through network tariffs. The assessed results suggest that market participants have on average profited from holding LTTRs, rather than having paid a premium for the hedging they provide over congestion in the day-ahead market.

54 A negative ex-post risk premium is usually driven by insufficient competition. Figure 21 indeed implies that the offered capacity is exceeding the actual demand for LTTRs from market participants looking to hedge against congestion in the day-ahead market. This may suggest that a share of LTTRs is being allocated with the expectation of a profit, rather than for covering the hedging needs of market participants.

Increased auction competition results in higher ex-post risk premium

Figure 20: Distribution of LTTR auction competition, measured as the ratio between number of auction participants and auction winners, and average ex-post risk premium – 2016-2024 (% and EUR/MWh)



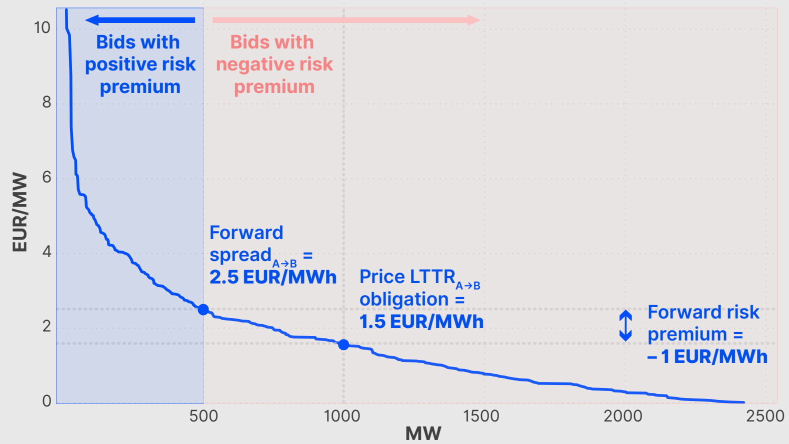
Source: ACER calculation based on JAO Auction Tool and ENTSO-E transparency platform data.

How to interpret a negative risk premium in LTTRs?

To ease the understanding of the possible underlying dynamics leading to negative risk premium in LTTRs, a theoretical example of the calculation and its possible interpretation is presented here. Figure 21 displays:

- A typical demand curve for FTRs. For simplicity, FTR obligations are used to enable better comparison with futures contracts,
- The clearing price of the FTR auction, and
- The forward spread computed as the difference between future contracts traded at the time of an FTR auction.

Figure 21: Theoretical example on the interpretation of risk premium in LTTRs



Source: ACER elaboration.

Note: Since most LTTRs are currently issued as FTR-Options, the forward risk premium in the analysis is calculated based on the price difference between the LTTRs issued on both directions of a given border.

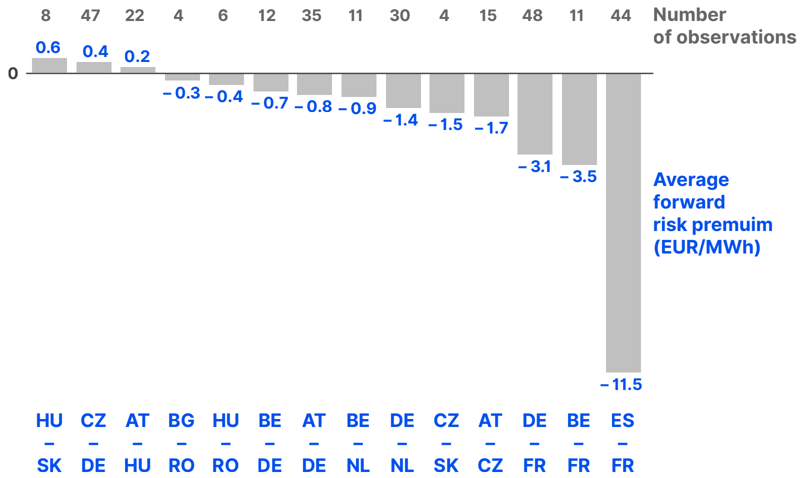
FTR bids to the left of the forward spread are above the intrinsic value of the FTR, and thus likely carry a positive risk premium and/or higher expected day-ahead price spread, while bids to the right of the forward spread, likely carrying a negative risk premium and/or lower expected day-ahead price spread. Thereby it is likely that some FTR bids represent a genuine hedging need from a market participant, yet their volume may be insufficient to set the auction price of the FTR.

55 Other factors may influence the expected value of LTTRs, potentially contributing to the observed undervaluation. These include the lack of full financial firmness of LTTRs, costs associated with participating in LTTR auctions and the risk of imperfect price hedging through forward markets in illiquid hubs.

56 Analysing the **forward risk premium** is another way to filter out the impact of forecast errors in the analysis of LTTR valuation. It compares LTTR prices with the price spread of relevant (i.e., same maturities) future contracts traded at the time of the LTTR auction. As these are traded at the same time, both indicators are subject to the same forecast error.

Comparison with future contracts traded during the LTTR auction also shows undervaluation of LTTRs

Figure 22: Forward risk premium on selected EU borders based on EEX baseload future contracts traded in the two hours before auction gate closure, 2021-2024 (EUR/MWh and number of occurrences



Source: ACER calculation based on JAO Auction Tool data and trades of EEX future contracts recorded through REMIT.

Note: EEX = European Energy Exchange.

57 Figure 22 assesses to what extent the pricing of long-term transmission rights accurately reflects the expected price differential at several EU borders. To do so, the weighted average of the price of all EEX baseload futures traded within the 2 hours before the gate closure of the relevant LTTR auction is computed, and then compared to the difference between LTTR prices on both directions of a given border. The obtained results show that LTTRs were mostly underpriced compared to trading in forward markets in the analysed bidding zone borders, apart from three borders.

58 ACER's policy paper on the further development of the EU electricity forward market identified seven measures to address the undervaluation of LTTRs:

1. introduce more competition between borders, such as via flow-based allocation[16].
2. shift from options to obligations to simplify the valuation of FTRs.
3. guarantee full financial firmness to ensure compatibility with future contracts.
4. adjust the offered capacity of LTTRs based on observed undervaluation.
5. organise more frequent auctions with less capacity.
6. improve the suitability of LTTRs for proxy hedging by allocating all FTRs towards a regional proxy.
7. reduce LTTR market fragmentation by shifting to Zone-To-Hub FTRs, which has only one product per bidding zone.

Shortcomings in design of long-term transmission rights result in their undervaluation. ACER lists proposals, including increased competition, products with longer maturities, ensuring full financial firmness, and holding more frequent auctions to enhance cross-border hedging.

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

Current forward markets may prove insufficient to support long-term investments

59 Well-functioning long-term markets, with transparent and robust prices are required to support investment. As previously noted, EU forward markets reveal weaknesses, particularly low liquidity, in longer-term timeframes. Mobilising the necessary investment to transition the EU power sector to net-zero is thus also likely to require some degree of state support. This may come as state guarantees for reducing collateral costs in long-term contracts (such as futures or Power Purchase Agreements), or direct contracts with the public entity (such as Contracts for Difference)[17].

Contracts for Difference are financial agreements that usually involve a public entity and a market participant. They include a set strike price, a reference price, CfD type (i.e. one-sided or two-sided) and other relevant aspects. Unless other clauses are in place (like for negative prices), the public entity pays the difference when the reference price is lower than the strike price. If the reference price is higher, the market participant pays the difference, but only in a two-sided CfD.

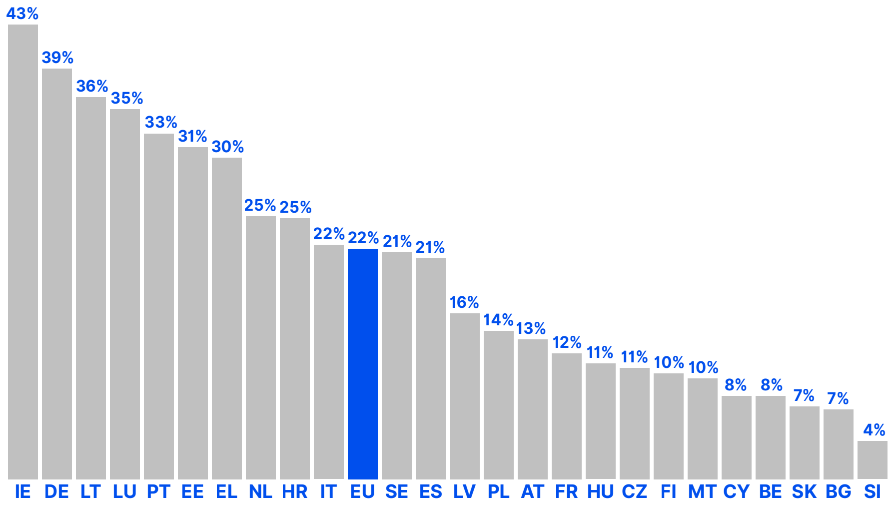
A **Power Purchase Agreement** is a long-term contract between a power producer and a customer (consumer or trader) defining electricity supply terms such as quantity, prices, and penalties. It can vary widely in form, providing physical or virtual electricity, and helps large consumers manage market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

Support schemes

60 Support schemes are significantly employed across EU Member States as effective tools to boost the development of RES projects. On average, approximately 23% of the total electricity produced in the EU received RES support during 2020. There were considerable differences among EU Member States, ranging from Ireland holding the highest share (42.8%) and Slovenia having the lowest (3.6%), as depicted in Figure 23.

Support schemes are widely used for RES development across EU

Figure 23: Share of total electricity produced receiving RES support in 2020 (%)



Source: "Status Review of Renewable Support Schemes in Europe for 2020 and 2021", CEER

61 Poorly designed support schemes can affect the bidding behaviours of market participants (e.g. the 'produce-and-forget' effect), altering the structure of the supply curves and thus generating non-market-based equilibria. Moreover, poorly designed support schemes can also negatively affect investment decisions (e.g. siting).

62 Support schemes thus need to be designed in such a way as not to distort the market, always ensuring fair competition with commercial alternatives. Among the several ongoing activities to improve the design of support schemes, ACER and EU NRAs recommended that European Commission develop best practices on the design of support schemes to minimise market distortions.

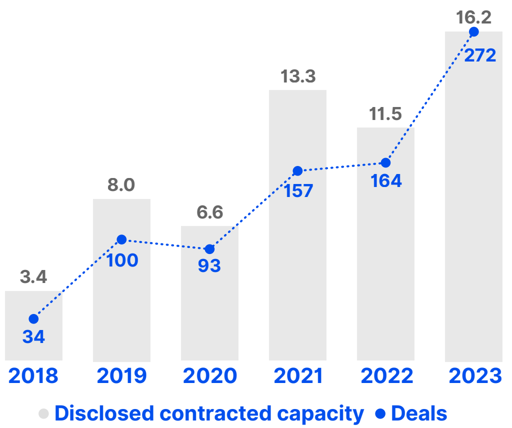
17 While the focus of this section is on CfDs and PPAs, other forms of state support may also exist.

Power purchase agreements

63 The European PPA market experienced significant growth in 2023, with 16.2 gigawatts (GW)[18] of contracted volumes and a total of 272 signed deals (a 41% increase in contracted volumes and a 65% increase in signed deals, with regards to the previous year), as shown in Figure 24. Germany and Spain accounted for more than half of the contracted capacity (51%). Solar PPAs accounted for 65% of the contracted capacity, significantly overrunning wind PPAs (both onshore and offshore) compared to the past few years. The IT sector held the biggest offtaker share of contracted capacity (22%).

Significant growth recorded in the EU PPA market

Figure 24: Disclosed contracted capacity (GW) and deals (#)



Source: European PPA Market Outlook 2024 by Pexapark.

64 Despite such growth, several barriers are still restraining growth in the PPA market, including:

1. difficulty in accessing credit guarantees increases the financial uncertainty, making projects less likely to be bankable.
2. unstable regulatory environment and lengthy administrative procedures.
3. support schemes, such as some CfDs, providing the wrong incentives, make private arrangements less appealing.

65 Despite some mitigation strategies already in place, such as public entities issuing guarantee schemes, it is crucial to further enhance them and have the right guidance in place. Among the valuable recommendations provided in 'The future of European competitiveness' by Mario Draghi, the report suggests developing market platforms, a useful tool for demand pooling, and strengthen the access to guarantees.

66 ACER is monitoring the evolution of the EU PPA market, as mandated by Regulation (EU) 2024/1747. Moreover, ACER facilitated discussions over Power Purchase Agreements, evaluating the need for additional voluntary template PPA contracts within the European energy market by, assessing their feasibility, benefits and drawbacks. ACER delivered the assessment on templates in October 2024. Future monitoring reports will include an assessment on the EU PPA market.

Long-term investment needs state support due to EU market inefficiencies. Power Purchase Agreements (PPAs) grew significantly in 2023 but face barriers like credit access, regulatory uncertainty, and administrative delays.

18 During 2023, the installed RES capacity in EU increased by 38 GW. Source: ACER calculations based on ENTSO-E data.

Balancing markets must be integrated further

67 Balancing the electricity system is crucial for system security. It is done in or close to real time by the TSOs to ensure supply-demand balance and frequency stability. TSOs have different products available to balance the system, such as frequency containment reserve (FCR), automatic frequency restoration reserves (aFRR), manual frequency restoration reserves (mFRR) and replacement reserves (RR). Balancing capacity is procured in advance for each of these products to ensure sufficient resources are available to balance the system. Balancing energy is activated according to the needs occurring in real-time.

68 This section examines the status of the markets for the different balancing services. It highlights how the existing balancing platforms increase welfare, how existing limited participation in balancing markets restricts the exchange possibilities, and how amendments to the existing platforms can reduce costs, using the platform for the exchange of balancing energy activated from aFRR as an example.

The electricity balancing regulation paves the way for integrated markets

69 In comparison to intra-day and day ahead markets, which are fully coupled, market integration is less advanced for balancing markets. The limited market integration also results in **persisting high price spreads** between different national balancing markets in comparison to the day-ahead market. Therefore, increasing the exchange between national balancing markets through market integration is expected to deliver significant benefits for both balancing capacity, and balancing energy. An overview of volumes, price and exchanges of balancing services in the EU can be found in this dashboard published alongside this report.

70 To date, there have been different national approaches to balancing, including regulated provision of services, varying shares of products and different approaches to ensuring frequency quality. The electricity balancing regulation[19] paves the way towards more integrated balancing markets by, e.g.:

- setting the basis for standardisation of balancing products by listing the minimum set of standard characteristics.
- harmonising the imbalance settlement and the imbalance settlement period to 15 minutes[20].
- establishing two methodologies through which TSOs may allocate cross-zonal capacity for the exchange of balancing capacity and sharing of reserves.
- setting the ground for the creation of European platforms, allowing the exchange of balancing energy between TSOs.

71 In the last 2 years, the launch of the platforms for exchange of aFRR in June 2022 and for exchange of mFRR in October 2022 marked the biggest steps forward in balancing market integration. Previously, the platform for the exchange of RR went operational as part of the regional project TERRE in January 2020. The platforms enable the exchange of balancing energy between TSOs, allowing the activation of cheaper balancing energy bids across borders.

72 In the process of the amendment of the aFRR implementation framework and the balancing pricing methodology (ACER Decisions 08/2024 and 09/2024), many questions were raised by stakeholders on the functioning of the platform for the exchange of aFRR, often known under its project name PICASSO. In the following sections, ACER highlights analyses it has carried out related to PICASSO.

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

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

Assessment of the functioning of the PICASSO platform

73 In the context of PICASSO, TSOs use a digital platform to optimise their balancing energy activation from automatic frequency restoration reserve across Europe. Only the TSOs of four Member States were active on the platform in 2023, namely those from Austria, Czechia, Germany and Italy.

74 Generally, and in line with the overall price trends in the energy markets, the average prices on PICASSO decreased after the energy crisis of 2022, with the aFRR platform launched at the height of the crisis.

PICASSO enables greater coordination and access to neighbouring markets

75 During 2023, the platform delivered significant benefits to the participants. It supported price convergence between the participating TSOs, resulting in aFRR price convergences between all areas in over 50% of the time.

76 Additionally, the cross-border exchanges can result in cheaper bids being activated compared to those available nationally. For example, 40% of the time, Austria has an aFRR price that is lower than its cheapest national bid, because it can access cheaper bids from other Member States.

77 Based on data published by APG[21], for slightly over 1.8% of the time Austria activated more than 300 MW from other PICASSO Member States. Such volume is larger than their national aFRR merit order. Without any cross-border contributions, the Austrian aFRR merit order would have been exhausted on those occasions, possibly leading to extreme prices (if no mFRR was activated).

21 APG data publication website for aFRR data: markttransparenz.apg.at/en/markt/Markttransparenz/Netzregelung/Sekundaerregelreserve.

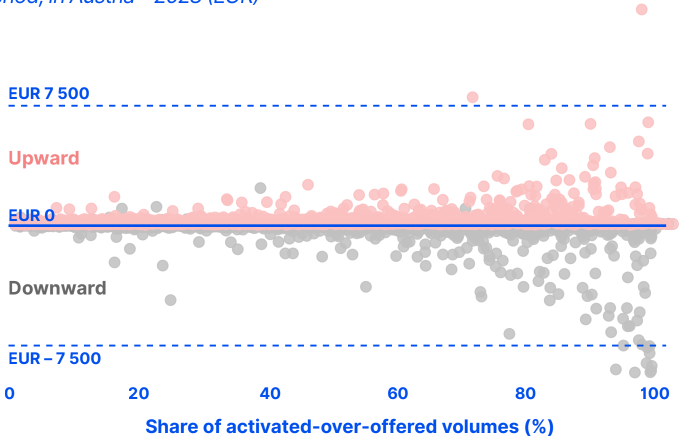
The rare occurrences of high prices still warrant attention and case-by-case assessment

78 Although prices incidents, defined as occurrences of prices exceeding ± EUR 7500, were recorded for less than 0.2% of the time, they still received attention. The following sections therefore take a closer look at the circumstances in which high prices and price incidents occur.

79 Figure 26 shows that the average Austrian aFRR prices increase when the activated volume is getting closer to the offered volume. This is expected, since the cheapest bids are activated first, following the merit-order principle.

High prices mostly occur when most of the offered volumes is used

Figure 25: Average cross border marginal price plotted against the share of activated over offered balancing energy from aFRR on PICASSO considering exchanges for each 15-minute imbalance settlement period, in Austria – 2023 (EUR)



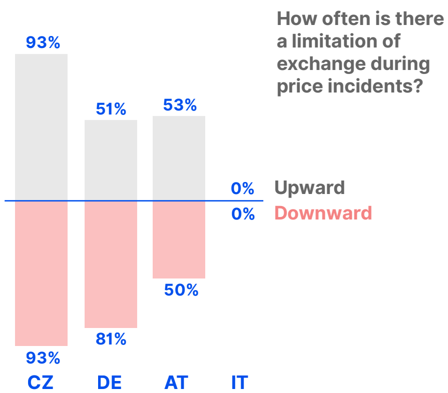
Source: ACER calculations based on ENTSO-E transparency platform.

Note: The average prices shown are the 15-minute averages of the 4-second cross-border marginal prices based on the output of the activation optimisation function of PICASSO, which optimises the social welfare at the European level. The volumes correspond to the offered and aggregated bids of aFRR standard volumes as reported in "Aggregated balancing energy bids", Balancing Guideline 12.3(e), in 15-minute granularity, representing volumes activated and offered on PICASSO in a specific scheduling area. To account for the activation and offer of volumes on PICASSO from other areas, the exchanges resulting from the AOF are considered in the volumes. The considered volumes and prices cannot be directly matched as they are the output of different processes, but the combination allows the assessment of the general trend of prices over offered and activated volumes.

80 Figure 26 illustrates that the available cross-border exchange possibilities impact the occurrence of high prices and price incidents. It highlights two different cases of price incidents. In the Italian case, price incidents occur due to demands exceeding the volume of nationally available bids, rather than low cross-zonal capacities. Such excess demand triggers the activation of expensive bids from other Member States. In contrast, the Czech case sees price incidents coinciding with low availability of cross-zonal capacities. These two cases are further analysed in the following sections.

Price incidents often coincide with low cross-border capacity

Figure 26: Share of price incidents during which the bidding zones having price incidents face cross-border capacity limitations in the direction of all neighbouring bidding zones, 2023 (%)



Source: ACER calculations based on TransnetBW data on PICASSO.

ACER updates rules to better align balancing prices with system conditions – the Italian example

81 The initial Picasso market design resulted in an increase of frequency quality no matter the additional associated cost. The Italian market is used as an example to illustrate this further.

82 Before joining PICASSO, when the aFRR demand in Italy exceeded the volume of nationally available bids (costing up to EUR 400 /MWh), aFRR demand was only partially met. This approach maintained sufficient stability and reliability according to the dimensioning rules set out in the guideline on electricity transmission system operation[22].

83 After joining PICASSO, when the aFRR demand in Italy exceeded the volume of nationally available bids, a higher amount of this Italian aFRR demand could be met by offers available to neighbouring TSOs, with prices up to 15000 EUR/MWh. However, the resulting cost increase did not proportionally improve system security for the Italian transmission system.

84 For TSOs to better reflect the trade-off between better frequency quality and cost, the second amendment to the aFRR implementation framework[23] introduces an elastic demand.

85 This allows TSOs to specify a portion of their aFRR demand as 'elastic', i.e. to be met only if offers are below a certain price threshold. The rest of the ('non-elastic') demand must be met at any cost. This enables TSOs to reflect the trade-off between an increase in frequency quality and associated cost.

Price incidents often coincide with low cross-border capacity. Increased competition, better coordination, and broader access to neighbouring markets through the PICASSO platform could reduce price incidents and volatility.

22 Art. 157.2 of Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation requests that TSOs have enough balancing capacity to cover their imbalances for at least 99% of the time. This article describes how to compute the FRR capacity requirement, which is the amount of FRR necessary for system security.

23 Amendment to the aFRR implementation framework: ACER Decision 2024/08.

More participation in PICASSO increases competition and helps reduce costs – the Czech example

86 Historically, a limited number of Czech market players have been providing aFRR reserves to the Czech TSO.

87 Since the Czech TSO joined the PICASSO platform, the price of these national offers has increased. An analysis of the 10 most extreme price incidents per month shows an increase in the national offers from EUR 2000 /MWh in July 2022 to EUR 14000 /MWh in December 2023 (considering both positive and negative balancing energy).

During 68% of price incidents Czechia had no available transfer capacity with any other PICASSO country

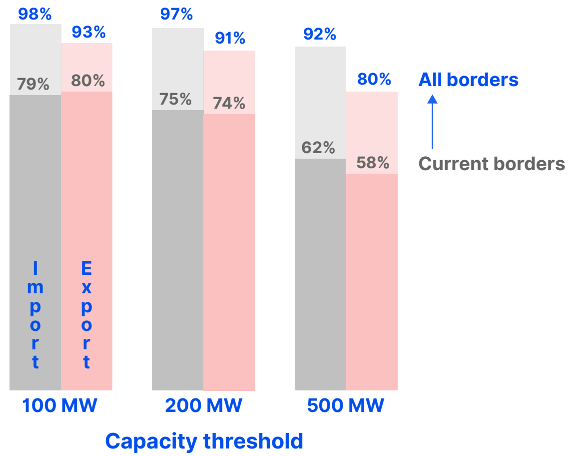
88 Despite having joined the platform, the Czech TSO regularly has access only to national offers due to the unavailability of transfer capacity with neighbouring PICASSO members (Germany, Austria). Consequently, on those occasions the Czech TSO has no access to offers in those markets. Under such circumstances, limited and costly national offers trigger price incidents.

Additional transmission system operators joining PICASSO will reduce times with limited transfer capacity

89 In the short run, the participation of more TSOs in the PICASSO platform would offer more opportunities to the Czech TSO and mitigate the occurrence of price incidents. For example, with access to the Slovakian and Polish markets, the percentage of time during which the Czech TSO is limited to imports of 100 MW or below would be reduced from 21% to 2%, as depicted in Figure 27. A temporary solution to mitigate the negative impact of connection delays by certain TSOs on the availability of cross-zonal capacities could be the implementation of available transmission capacity sharing. In this approach, TSOs not yet connected to the platform would allow those already connected to use their cross-zonal capacities. For example, RTE has already implemented available transfer capacity sharing. This enables non-zero cross-zonal capacity between Spain and Germany for 59% of the time from Germany to Spain and 48% of the time in the opposite direction.

More TSO participating means more capacity and competition

Figure 27: Percentage of time Czechia has available transfer capacity above a given threshold, considering current or all borders active on PICASSO, 2023, (%)



Source: ACER calculations based on the JAO Publication Tool and TransnetBW website on PICASSO.

90 In the long run, if not driven by the competitive interplay between supply and demand, the reasons for an increase in national offer prices should be evaluated to determine if they reflect higher marginal and opportunity costs.

Capacity is missing where it is most needed

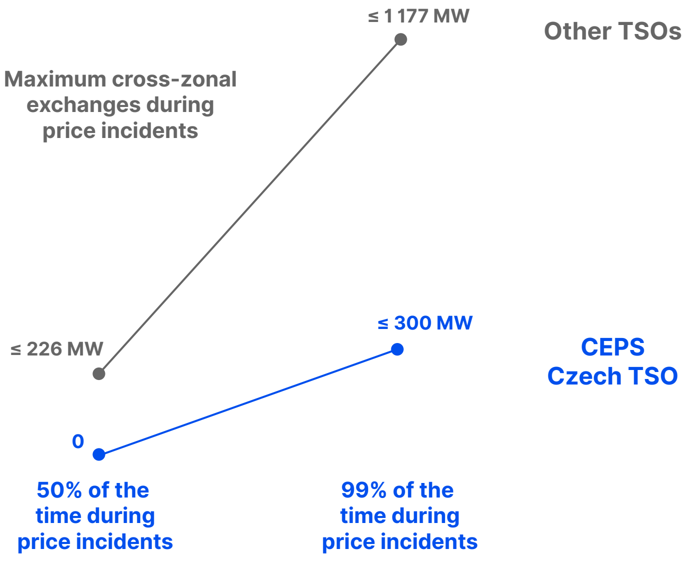
91 The maximal availability of cross-border capacity is a key factor in reducing price volatility and high prices also in the balancing time frame. The first step is therefore the joining of further TSOs to the platform to increase the overall capacity available for exchanges on the platforms. A potential subsequent step to increase efficiency would be to improve the calculation and allocation of available capacity. Allocation in the balancing time frame is based on available transfer capacities (ATCs). The capacity is allocated to the borders before it is known at which border the capacity would be most beneficial. This can result in a loss of welfare especially in balancing, because the price spread between bidding zones can be orders of magnitude higher than in previous markets.

92 Figure 28 shows the limited exchanges during price incidents for the balancing time frame for Czechia. In 50% of these incidents, Czechia did not import or export any balancing energy, while higher exchanges were recorded between the other participants of PICASSO.

93 A more coordinated and optimised calculation and allocation of capacity to the different borders could help to decrease prices and the occurrence of price incidents. TSOs should therefore study ways to improve capacity calculation and allocation, which could include considering the close to real time congestion forecast or using PICASSO's monitoring function on flow-based allocation to assess whether and where additional capacity could be made available[24].

During price incidents, Czechia has limited exchange while capacity is available on other borders

Figure 28: The median and 99th percentiles of the absolute net position for the Czech TSO and the corresponding averages for all other PICASSO TSOs during price incidents in Czechia, 2023, (MW)



Source: ACER calculations based on the TransnetBW website on PICASSO.

24 For further information, please refer to the PICASSO Algorithm Description.

Limited data quality is hindering in-depth analysis

A key requirement for in-depth analysis of the balancing platforms and markets is the availability of data. The transparency regulation and electricity balancing regulation mandate that a large set of data be published on ENTSO-E's transparency platform. At this point in time, the data is not in a format to allow comprehensive and straightforward analysis of the balancing markets. The identified issues include:

- different reporting approaches by TSOs requiring harmonization, including inconsistent labelling
- data quality issues, including missing or wrongly reported values
- non-matching sets of data for volumes and prices, inhibiting among other aspects costs analysis.

ACER has reported such issues to TSOs and ENTSO-E, but significant efforts are still needed to allow straightforward analysis of the balancing markets.

Advancing regional electricity integration: progress and challenges in the Energy Community

94 The Energy Community is an international organisation that brings together the EU and its neighbours to create an integrated pan-European energy market. The Energy Community has nine Contracting Parties: Albania, Bosnia and Herzegovina, Kosovo*[25], North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine. Armenia, Norway and Türkiye take part as Observers.

95 The Energy Community Secretariat monitors compliance, while the Regulatory Board (ECRB) provides coordinated regulatory positions, harmonises regulatory rules across borders and shares regulatory knowledge and experience. The ECRB gained new decision-making powers under the Electricity Integration Package.

96 **As part of the Energy Community's coordinated market reforms, the Electricity Integration Package, which includes key regulations and guidelines, sets the framework for integrating national markets into the EU's single market.**

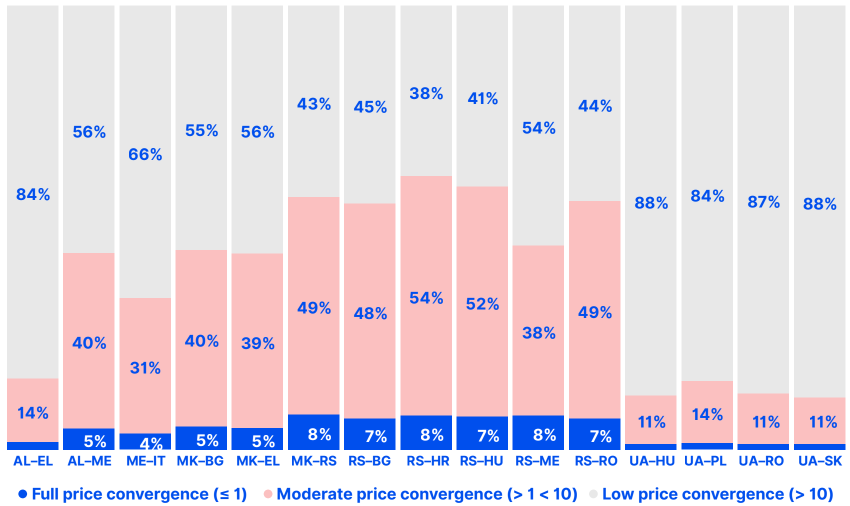
Congestion and low-price convergence reveal the limits to current market integration

97 Electricity price convergence remains low across the Energy Community and with neighbouring EU countries. In 2023, Serbia showed the highest convergence with the EU, while Ukraine lagged due to limited cross-border transmission capacity and price caps. That same year, Albania, Montenegro, and North Macedonia launched their day-ahead electricity markets for the first time. Greater price convergence is expected as market integration improves, regional capacity calculations are coordinated, and the 70% cross-border capacity availability requirement is met.

25 Throughout this text the designation "Kosovo*" is without prejudice to positions on status and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo declaration of independence.

Serbia converges with EU, Ukraine faces constraints

Figure 29: Day-ahead price convergence per border - 2023 (%)



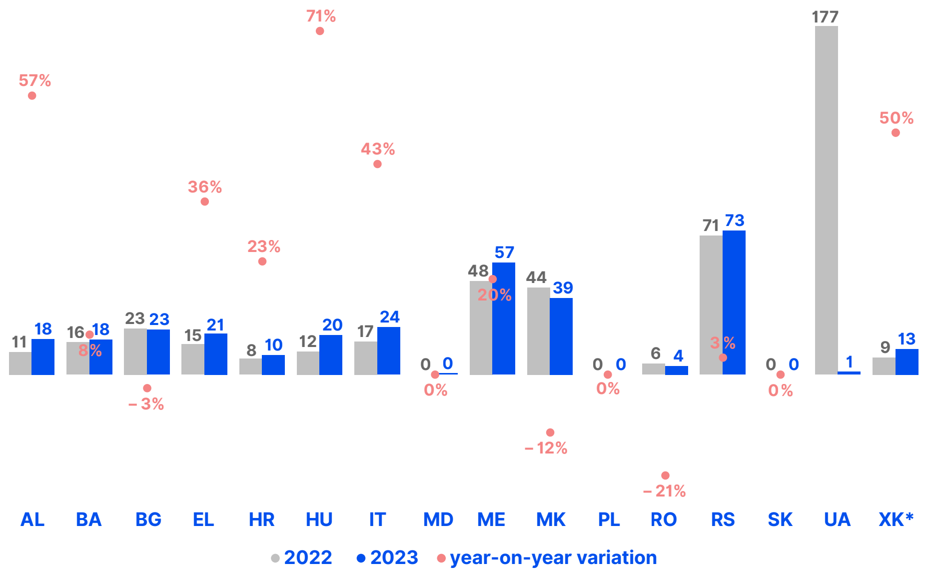
Source: Energy Community Regulatory Authorities

Note: Hourly data for 2023 are used. Day-ahead market data are available for Albania from 12 April 2023, Montenegro from 27 April 2023, and North Macedonia from 11 May 2023.

98 Congestion incomes varied across the region in 2023. Serbia and Bosnia and Herzegovina saw stable increases of less than 10% compared to 2022. Meanwhile, Albania and Kosovo* experienced significant increases, with congestion revenues rising by 57% and 50%, respectively, with Montenegro saw a 20% rise. In contrast, North Macedonia's cross-border revenues fell by 12%. Ukraine's once-high cross-border revenues dropped sharply in 2023 due to a ban on electricity exports, delays in auctions, and market conditions.

Rises in congestion incomes

Figure 30: Annual congestion income per Energy Community Contracting Party and adjacent EU Member State, and year-on-year change, 2022-2023 (Million EUR and %)



Source: Energy Community Regulatory Authorities and ACER

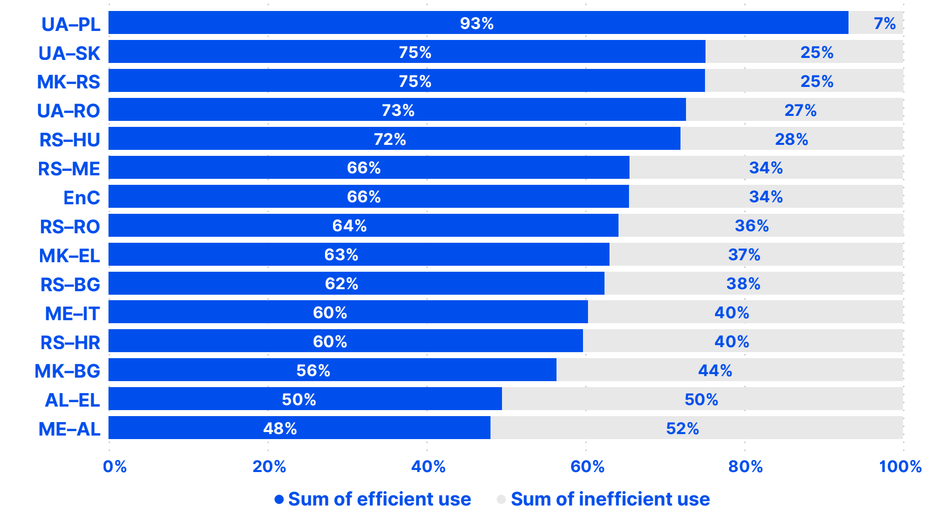
Note: Data for Georgia is unavailable.

Further integration will enhance resilience and improve efficiency

99 Market coupling will significantly improve efficiency. In 2023, the average efficiency rate at Energy Community borders was 66%, with lower rates in Albania, Montenegro, and North Macedonia due to a lack of market coupling and early-stage day-ahead markets. Efficiency peaks when markets are coupled, and further integration within the Energy Community will lead to better use of available cross-border capacity.

Two thirds of the cross-border trades bring welfare

Figure 31: Level of efficient use of cross-zonal capacity in the day-ahead market timeframe - 2023 (%)



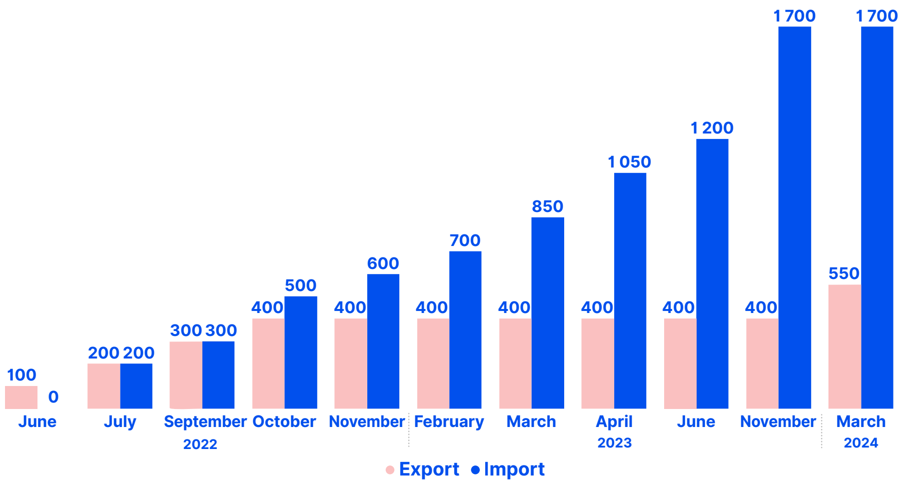
Source: Energy Community Regulatory Authorities

Note: Hourly data for 2023 has been used. Day-ahead market data was available as follows: Albania from 12 April 2023, Montenegro from 27 April 2023, and North Macedonia from 11 May 2023. For the Ukraine-Poland border, only periods with allowed commercial exchanges were assessed.

100 Further integration would strengthen network resilience, as illustrated with Ukraine. Ukraine's cross-border capacity with the EU has gradually increased, allowing imports up to 1700 MW. This capacity increase remains insufficient to meet demand. Since Russia's invasion of Ukraine, electricity generation and consumption in Ukraine have fallen by over 30%. Ongoing attacks on energy infrastructure have caused severe capacity shortages and network bottlenecks, resulting in widespread outages. Ukraine faces significant risks for the 2024/2025 winter season, threatening both consumers and critical infrastructure.

Russia's invasion accelerated integration of Ukrainian and European networks

Figure 32: Network Transfer Capacity development for Ukraine's export and import commercial exchanges with Europe – June 2022 to September 2024 (MW)



Source: ENTSO-e, Energy Community Regulatory Authorities.

Since 2023, the acceleration of market development confirms the Energy Community's commitment to further integration

101 Recent developments in the Energy Community's electricity markets include several key milestones:

- **In 2023, Albania and Montenegro started their day-ahead markets in April, and North Macedonia followed in May.** Before this, only Serbia (since 2016) and Ukraine (since 2019) had day-ahead markets in the Energy Community.
- **In July 2023, Serbia launched its intraday electricity market,** becoming the second in the Energy Community after Ukraine, which has had an intraday market since 2019.
- **In February 2024, Kosovo* introduced its day-ahead market, coupled with Albania.** These are the only coupled markets in the Energy Community so far.
- **In July 2024, Georgia launched its day-ahead and intraday electricity markets.**

102 The Energy Community Contracting Parties are still working on fully transposing and implementing the Energy Community Acquis to integrate regional electricity markets. As of now, nominated electricity market operators (NEMOs) have been designated in five of the nine Contracting Parties: Albania, Kosovo*, North Macedonia, Montenegro, and Serbia[26].

The Energy Community advanced electricity market integration in 2023, launching day-ahead markets in Albania, Montenegro, and North Macedonia. Serbia led price convergence, while Ukraine faced transmission constraints. Further integration promises increased efficiency.

26 This reflects information notified by the Contracting Parties and is not to be understood as a compliance assessment.

Annex: LTTR valuation assessment

Ex-post risk premium

- **Description:** Comparison of LTTR congestion income with the associated remuneration to the LTTR holders.

- **Calculation:**

$$[\text{Price}_{LTTR\ A>B} - \max(0, \text{Price}_{DA\ B} - \text{Price}_{DA\ A})] * \text{Allocated capacity} * \text{No. of hours}$$

  - $\text{Price}_{LTTR\ A>B}$: Price of LTTR issued in oriented border A>B.
  - $\text{Price}_{DA\ A,\ B}$: Hourly day-ahead prices in bidding zones A or B.

- **Why is it relevant:** Ex-post valuation analyses are subject to forecast error, as there is uncertainty in the expected return. However, when a sufficiently large timespan is considered, individual forecast errors are averaged out.

- **Scope:** All EU borders where LTTRs are issued and allocated capacity is not 0 MW, in both directions.

- **Timeframe:** Yearly and Monthly LTTRs with contract start between January 2015 and August 2024.

- **Reduction periods** are considered by weighing the ex-post risk premium calculation for each hour by the ratio of reduced capacity during maintenance over the total allocated capacity

- **Limitations and assumptions:**

  - Reduction periods for year 2015 were not available, and thus are not considered. This may affect in particular the ex-post valuation of borders in the Italy North region.

Forward risk premium

- **Description:** Comparison of the spread between the LTTRs issued on both directions of a given border with the price spread in future contracts traded within the two hours before the closure of the LTTR auction.

- **Calculation:**

$$(\text{Price}_{LTTR\ A\rightarrow B} - \text{Price}_{LTTR\ B\rightarrow A}) - (\text{Price}_{FW\ B} - \text{Price}_{FW\ A})$$

  - $\text{Price}_{LTTR\ A>B,\ B>A}$: Price of LTTR issued in oriented border A>B or B>A.
  - $\text{Price}_{FW\ A,\ B}$: Average price of EEX baseload futures traded within 2 hours before LTTR auction closure in bidding zone A or B.

- **Why is it relevant:** The intrinsic value of LTTRs options corresponds to the average positive expected spot price difference. The difference between the price of two LTTR options on a given border should thus correspond with the average expected spot price difference (or forward price spread) on that border.

- **Scope:** Select EU borders between hubs where EEX baseload futures are traded, in the direction of the positive forward spread.

- **Timeframe:** Yearly and Monthly products between January 2021 and July 2024.

- **Limitations and assumptions:**

  - Reduced number of observations in some borders due to low forward market liquidity in one or both relevant hubs.
  - Calculation of forward price references based on future contracts traded on EEX, representing only a section of all forward trades (i.e., not including trading via OTC, PPAs...).
  - Reduction periods are not considered, yet they may affect the valuation of LTTRs (and not that of future contracts). These are, however, not common on the analysed borders.
  - This indicator is calculated based on the assumption that the expected spot price volatility and risk premia are similar on both sides and directions of a given bidding zone border.
  - The assessment covers the 2021-2024 timeframe, which includes the exceptional crisis period experienced by the EU and emergency regulatory measures that impacted market spreads between countries.

Abbreviations and country codes

Abbreviations	
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic frequency restoration reserve
CACM	capacity allocation and congestion management
CCM	capacity calculation methodology
CfDs	contracts for difference
CGMM	common grid model methodology
EB	electricity balancing
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
EU-27	the 27 Member States comprising the European Union
FCA	forward capacity allocation
FTRs	financial transmission rights
GW	gigawatt
JAO	Joint Allocation Office
LTTRs	long-term transmission rights
mFRR	manual frequency restoration reserve
MW	megawatt
MWh	megawatt-hour
NRAs	national regulatory authorities
Picasso	platform for the international coordination of automated frequency restoration and stable system operation
PPA	power purchase agreement
RDCT	redispatching and countertrading
REMIT	regulation on wholesale energy market integrity and transparency
RES	renewable energy sources
ROSC	regional operational security coordination
SAP	single allocation platform
TSOs	transmission system operators
TWh	terawatt-hour

Country codes	
AL	Albania
AT	Austria
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
CY	Cyprus
CZ	Czechia
DE	Germany
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain
FI	Finland
FR	France
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
MD	Moldova
ME	Montenegro
MK	North Macedonia
MT	Malta
NL	Netherlands
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
SE	Sweden

Country codes	
SI	Slovenia
SK	Slovakia
UA	Ukraine
UK	United Kingdom