ENTSO-E
Market Report 2025

Foreword

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association of the European transmission system operators (TSOs). The **40 member TSOs, representing 36 countries,** are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world.**

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective through the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"*** shows that this is within our reach, but additional work is necessary to make it a reality.

In its Strategic Roadmap presented in 2024, ENTSO-E has organised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

* https://vision.entsoe.eu/

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Executive Summary

Capacity allocation and congestion management mechanisms are essential for ensuring the effective operation of cross-border electricity markets across all time frames, from long-term planning to real-time operations. This report, which reviews progress in further shaping these mechanisms in the reporting period between June 2024 and May 2025, outlines ongoing efforts to develop a more interconnected and efficient European internal electricity market. Advancements in these areas play a key role in ensuring efficient resource use and security of supply at the lowest possible cost to consumers.

As the market moves closer to full integration, Europeans can expect enhanced cost-effectiveness in electricity supply due to optimised resource allocation. The improvements noted during the reporting period demonstrate a commitment to realising the vision of an internal European electricity market that serves the interests of all citizens across the continent.

During the summer of 2024, electricity prices maintained a low level due to a high output from nuclear, hydro, and renewable generation resources. Towards the end of 2024, wholesale gas and electricity prices were impacted by lower gas storage levels as the winter approached, contributing to increased market pressure and higher prices. Rising geopolitical tensions exacerbated the situation by creating uncertainty regarding energy supply routes and availability. These factors combined to create a scenario where both gas and electricity prices reached annual highs at the end of 2024. In 2025, wholesale electricity prices across Europe have shown notable volatility from January through early May. Prices peaked in January and February – exceeding 140 €/MWh in some markets – driven by high gas prices, low wind power output, and increased demand. However, starting in March, prices began to decline due to warmer weather, reduced demand, falling natural gas prices, and strong solar generation. By April, spot prices had more than halved from early-year highs.

Following the successful implementation of bilaterally coordinated capacity allocation on all Ukrainian borders during the first quarter of 2024, discussions began in June 2024 on introducing monthly long-term and intraday (ID) auctions for these borders. Currently, the rules for these auctions are being developed by the dedicated group of experts.

To foster non-discriminatory and cross-zonal trade in the internal market for electricity, Article 16(8) of the EU Electricity Regulation requires European TSOs to make at least 70% of the transmission capacity (respecting operational security limits) available for cross-zonal electricity trading. Where TSOs have requested a "derogation" from this requirement pursuant to Article 16(9) or member states have invoked an "action plan" pursuant to Article 15, a less ambitious target may apply for a given year or a transitional period defined in the action plan. In the annual ENTSO-E market report, TSOs provide an easily accessible 70% requirement overview of the (individual) national assessments, its differences among them and also with ACER assessment, that uses a uniform methodology for it. Moreover, TSOs recall for prudence when it comes to applying the 70% requirement in the ID timeframe, as security is at stake.

Forward capacity allocation at a glance

In forward capacity allocation (FCA), where cross-zonal transmission rights are allocated in explicit allocations via a single pan-European platform, the high quality of the operation was maintained. The amendment to FCA guidelines expected in June 2026 could have a major impact on the future of forward markets. As a first step, the European Commission (EC) conducted a targeted consultation, to which ENTSO-E submitted a contribution in the second half of 2024. Some insights on ENTSO-E's views on the future of forward markets can be found in this report. At the same time, transmission system operators (TSOs) and the Joint Allocation Office (JAO) have been active in implementing existing legislation, meaning long-term flow-based allocation (LTFBA) for the Core and Nordic capacity calculation regions (CCRs). The LTFBA go-live is planned for the end of 2026, covering the long-term yearly and monthly products for 2027. Furthermore, an update of the Harmonised Allocation Rules (HAR) is being conducted based on a regular process.

Market coupling

The second half of 2024 focused on advancements in market coupling by supporting improvements in operational processes and enhancing reporting following the successful intraday auctions (IDA) go-live in the ID market on 13 June. This milestone was followed by the implementation of Nordic flow-based (FB) coupling in the day-ahead (DA) market on 29 October. Another highlight of 2025 was the synchronisation of the Baltic states' electricity systems with the Continental European Synchronous Area (CESA) on 9 February, a key step in strengthening energy system resilience and regional security.

Additionally, the introduction of the Multi-NEMO (Nominated Electricity Market Operator) Arrangement (MNA) in Romania, with the new NEMO (BRM) entering the market, marked an important development. As part of preparations for the key development of the DA 15-minute market time unit (15-min MTU) go-live in October 2025, gradual transitions to the ID 15-min MTU have been underway across the remaining borders and bidding zones (BZs). Looking ahead, TSOs and NEMOs are focused on achieving the next key milestones, including the Core advanced hybrid coupling (AHC), Baltic MNA and the implementation of FB in ID.

Balancing

The European electricity system is undergoing major changes from both the regulatory and technical perspectives, driven by the implementation of the Electricity Balancing (EB) Regulation.

A key part of this transformation has been the introduction of several balancing energy platforms across Europe:

- The Trans-European Replacement Reserves Exchange (TERRE) was launched in early 2020 to facilitate the activation of replacement reserves (RR).
- The International Grid Control Cooperation (IGCC) followed in mid-2021, enabling the netting of automatic frequency restoration reserve (aFRR) needs.
- The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) became operational in mid-2022, providing a platform for aFRR activation and also netting of aFRR needs.
- The Manually Activated Reserves Initiative (MARI) started in late 2022, supporting the activation of manual frequency restoration reserve (mFRR).

These platforms play a crucial role in the European balancing market. They improve cooperation among TSOs, increase market liquidity and competition, enhance system security, and ultimately contribute to a more efficient and reliable electricity system.

The main achievements in 2024–2025 with respect to the balancing market are:

- Many additional TSOs have been connecting to both the MARI and PICASSO platforms throughout 2024–2025. Thorough planning of testing activities is being performed to ensure smooth integration and prevent bottlenecks.
- The TERRE project will shut down in early 2026, as the RR process is incompatible with the new 30-minute cross-zonal ID gate closure time (GCT). This change comes from the Electricity Market Design Reform (EMDR), adopted on 21 May 2024 and effective from 1 January 2026.
- The launch of a major update to the Capacity Management IT (CM IT) Solution in July 2024 further supports the efficiency of consecutive platforms. It enables the execution of the affected TSO procedure for connected TSOs in the CM IT Solution.
- In July 2024, all TSOs submitted their amendments to the harmonising cross-zonal capacity allocation methodology (HCZCAM). Ongoing market-based initiatives such as the Nordic, Baltic, and Allocation of CZC and Procurement of aFRR Cooperation Agreement (ALPACA), initiatives are underway to further align with the HCZCAM (ALPACA is investigating a transition from a probabilistic approach to a market-based approach).
- A group of 14 TSOs are currently participating in the Common Optimisation of Balancing Reserve & Cross-Zonal Capacity Allocation (COBRA) project, which is leading the development of harmonised market-based allocation optimisation function to efficiently allocate interconnection capacity between reserve and energy markets for future regional initiatives in Europe, using a market-based approach defined by HCZCAM.
- On co-optimisation, the Agency for the Cooperation of Energy Regulators (ACER) issued its decision on amendments to the price coupling algorithm methodology, which serves as the basis for ongoing co-optimisation research and development (R&D). The first draft report on co-optimisation (R0) was drafted by TSOs and NEMOs and submitted to ACER in April 2025 and to public consultation in May 2025.
- Due to frequent price incidents on the PICASSO platform, ACER issued its decision on proposals for price mitigation measures submitted by all TSOs to ACER in July 2024, with associated amendments for the aFRR implementation framework (IF) and pricing methodology.
- Regarding the imbalance settlement harmonisation (ISH) methodology, all TSOs have adjusted their systems to a 15-minute imbalance settlement period (ISP) as of January 2025 to align with the methodology.

Despite challenges, advancements in European electric power systems reflect the industry's commitment to regulatory compliance, system efficiency, and collaboration among stakeholders. The Market Report 2025 provides an in-depth analysis of the dynamics of the balancing markets, complemented with corresponding performance indicators (for the natural year 2024).

1 Introduction

Each year, ENTSO-E monitors the development of European electricity markets. This monitoring covers the various time frames in which electricity is traded, ranging from long-term to DA, ID, and balancing markets. The 2025 edition of ENTSO-E's annual Market Report covers the period from June 2024 to May 2025. The report is formally submitted to ACER and is published on ENTSO-E's website following the reporting period.

Electricity markets from long-term to real-time

Electricity remains a non-storable commodity that must be generated at the moment it is consumed, in real time. However, trading of electricity occurs both before and after this point in time, across multiple market time frames. TSOs continue to play a central role in enabling the efficient functioning of the European electricity markets by providing the optimal level of cross-border transmission capacity across all market stages – from long-term planning to real-time operations.

The further integration of cross-border markets across all time frames, supported by harmonised processes and regulatory frameworks, enhances the efficiency and resilience of the European power system. This market integration ultimately delivers increased security of supply, more competitive prices, and greater value for all European consumers.

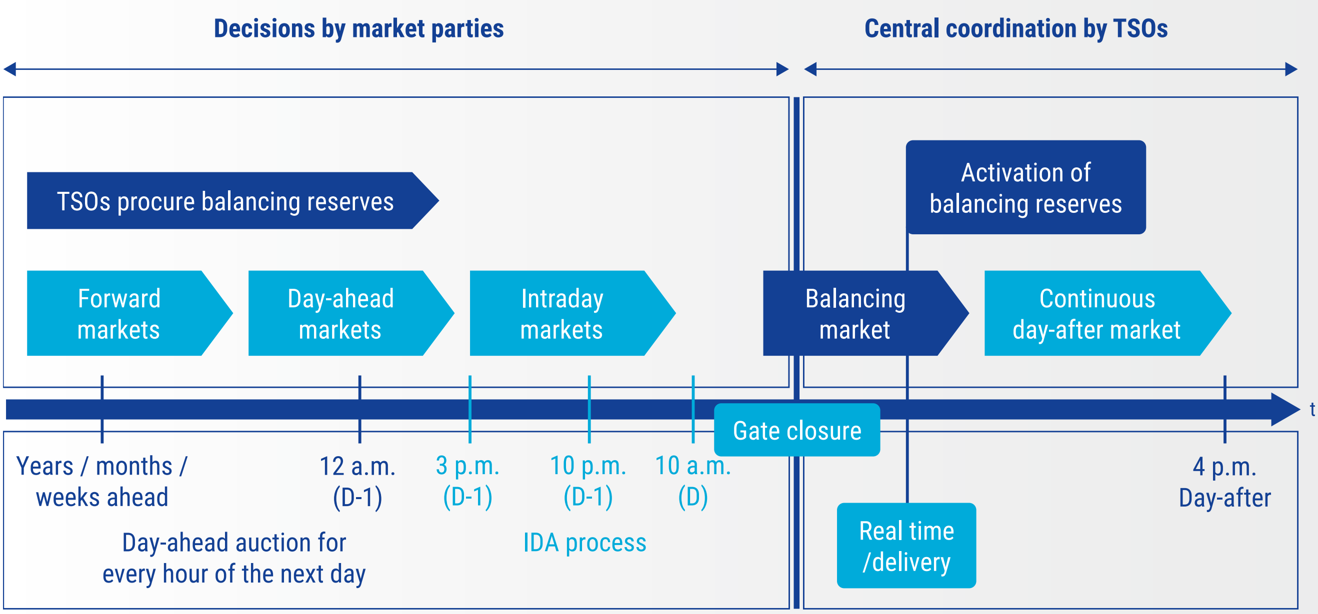


Figure 1.1: Overview of different time frames of the wholesale and balancing markets

Long-term capacity calculation

As of 2025, TSOs continue to determine the appropriate level of long-term cross-border transmission capacity up to 1 year ahead of the actual delivery date. This capacity is calculated for the borders they manage and forms the basis for the allocation of long-term transmission rights (LTTRs), which are offered through explicit auctions on the Single Allocation Platform (SAP), operated by the JAO. Determining long-term capacity remains a complex task due to the high level of uncertainty associated with extended lead times. TSOs must make informed assumptions and ensure that the transmission rights allocated can be honoured throughout the product period. Factors such as unexpected outages, evolving network conditions, and variations in generation and consumption patterns must all be taken into account.

Unlike near-real-time capacity calculations, long-term assessments must be made with significantly less reliable input data, making this process fundamentally different.

The Commission Regulation (EU) 2016/1719 (Guideline on FCA), in force since 17 October 2016, continues to provide the regulatory framework for the calculation and allocation of LTTRs. It also outlines rules for the financial compensation of LTTR holders in the event of curtailment due to capacity recalculations before the DA time frame. The overarching aim is to enable market participants to effectively hedge cross-border trading risks in scenarios where forward electricity markets do not offer sufficient hedging instruments.

Short-term day-ahead and intraday capacity calculation

As TSOs move closer to the actual delivery time, they can make more accurate forecasts regarding system conditions. This allows for a more precise determination of the available cross-zonal transmission capacity between BZs. Physical constraints in the transmission network are translated into commercial constraints, which are then factored into the market-clearing algorithms that determine prices and cross-zonal flows.

In 2025, capacity calculations for short-term time frames – such as DA and ID – are conducted across several stages. These include the DA calculation and the first ID capacity calculation (IDA2) 1 day before delivery, followed by the second ID calculation (IDA3) and continuous capacity assessments on the day of delivery.

Congestion issues that arise after the allocation phase are addressed through remedial actions, such as countertrading or redispatching, coordinated in real time by all affected TSOs to maintain system stability.

The Commission Regulation (EU) 2015/1222 (Guideline on Capacity Allocation and Congestion Management, CACM) continues to serve as the legal basis for the implementation of an integrated European electricity market in the DA and ID time frames. It defines the principles for calculating cross-zonal capacities and the methodologies for capacity allocation in these time frames, supporting efficient price formation and cross-border electricity trade.

Real-time balancing

Power generation and demand are subject to forecasting errors and technical disturbances. To balance deviations and maintain the network frequency within permissible limits, TSOs operate load frequency control processes. The energy activated in this process is called balancing energy. The procurement and settlement of balancing energy is organised in balancing markets. The Commission Regulation (EU) 2017/2195 of 23 November 2017 (EB Regulation) establishes detailed rules for the implementation of these balancing energy markets in Europe, which aim to foster effective competition, non-discrimination, transparency, and balancing market integration. This will ultimately enhance the efficiency of the European balancing system as well as the security of supply. Imbalance settlement aims to ensure the efficient maintenance of the system balance by incentivising market participants to maintain, keep, and restore their individual – and thereby ultimately the overall – system balance. In this sense, an imbalance settlement constitutes a cornerstone of a fully and efficiently functioning internal electricity market.

To ensure fairness, objectivity, and transparency within the mechanism, the EB Regulation sets out rules for financial imbalance settlement that must be implemented through terms and conditions for balance responsible parties (BRPs). The EB Regulation establishes the guidelines for creating an integrated balancing market in different time frames, in which TSOs can share their resources to ensure generation equals demand at all times. The ultimate goal of the EB Regulation is to integrate balancing markets and promote the potential for exchanges of balancing services while contributing to operational security. The regulation lays down principles for the exchange of balancing energy and the associated settlement among TSOs and between TSOs and connected balancing service providers (BSPs) regarding the following set of products: frequency restoration reserves (FRR – both with automatic [aFRR] and manual activation [mFRR]), RR, and a common methodology for the exchange and sharing of reserves, as well as for the procurement of frequency containment reserves (FCR), although to a lesser extent.

Report structure

This report is mainly structured according to the time frames described above:

- **Chapter 2** provides insight and ENTSO-E positions on current and future developments impacting the European electricity market.
- **Chapter 3** introduces the progress of the electricity market across all time frames previously described.
- **Chapter 4** provides a detailed overview of the common European processes of long-term electricity trading and transmission capacity.
- **Chapter 5** outlines the current situation in achieving a single European DA and ID coupling process according to the CACM Regulation.
- **Chapter 6** provides an update on the harmonisation and integration of European balancing markets governed by the implementation of the EB Regulation.
- **The annex** includes additional information, such as a market process overview of the FCA, CACM, and EB Regulations, as well as an explanation of how TSOs comply with the 70 % minimum capacity target requirement per country.

2 Current and future developments impacting the European electricity market

2.1 Development of short-term markets: Reservation of cross-zonal capacity for balancing capacity markets

With the final approval of the CZCA Harmonised Methodology, Article 38(3) of the EB Regulation, the allocation of cross-zonal capacity (CZC) for balancing capacity can be applied by two or more TSOs through two different methods: market-based or co-optimisation.

Ongoing R&D activities related to co-optimisation by NEMOs and TSOs have raised several concerns among TSOs. Co-optimisation represents a substantial and complex shift from current practices – both for TSOs, where many questions remain unanswered, and for market participants. R&D has so far highlighted how the proposed new bid formats and linking options – required to adequately reflect cost structures and technical constraints – may significantly increase complexity for market participants. Therefore, from an all-TSO perspective, the expected net benefit of co-optimisation remains unclear at this time. Instead, many TSOs continue to believe that the market-based approach, with its sequential clearing process, provides several key advantages for both market participants and TSOs. Due to its relative simplicity and alignment from an allocation process perspective, it is considered better suited to market needs.

Market simplicity

Sequential clearing, in which energy and balancing capacity are procured in distinct steps, reflects the traditional bidding structure familiar to market participants. This design supports simpler market operations, enabling clearer understanding and more effective participation. Its intuitive nature reduces complexity, promotes transparency, and is expected to improve liquidity.

Procurement processes

Separate procurement processes allow market participants to manage their positions with greater flexibility and reduced risk. Participants can adapt their bids in response to evolving market signals without the constraints of simultaneous commitments, supporting robust and responsive market behaviour.

Market efficiency

Achieving the highest possible market efficiency when allocating balancing capacity across BZs is also a central concern of TSOs. The theoretical economic optimum is potentially higher when avoiding forecasting of DA prices (co-optimisation). On the other hand, with the market-based harmonised methodology, measures for forecast validation must be developed by Regional Coordination Centres (RCCs), which help manage forecasting errors and ensure efficient markets. Additionally, with the market-based method, cross-zonal capacity allocation (CZCA) is limited to 10% of all available CZC, which is not the case for co-optimisation.

Another central economic efficiency concern is ensuring the most effective market clearing. With the market-based allocation method, the DA and balancing capacity markets are cleared sequentially, avoiding the risk of inefficiencies in DA clearing that may arise with co-optimisation, where the markets are mixed. Such spillover effects should be avoided, as TSOs are concerned they could lead to substantial economic inefficiencies.

TSOs believe that under the current regulatory framework, co-optimisation may not be well-suited for a system increasingly driven by renewables. As renewable penetration grows, final dispatches will be established closer to real time. While the single day-ahead coupling (SDAC) auction currently has the highest clearing volume compared to IDAs, this could shift in the future due to the increasing forecast dependency of generation. This raises the fundamental question of whether it makes sense to invest in a setup that was decided about 10 years ago and may not be the best choice in the future.

Market-based progress

A group of 14 TSOs are actively engaged in the **COBRA project**, which is developing harmonised software aligned with the CZCA methodology.

Additional progress includes:

1. The launch of a market-based CZC market between Estonia, Latvia, and Lithuania (**see Chapter 6.2**).

2. The launch of a market-based mFRR market between Denmark, Finland, and Sweden (**see Chapter 6.2**).

Introducing a market-based or co-optimised allocation process requires adapting regional processes (DACC, IDCC, ROSC, BTCC) to ensure that the CZC allocated for the exchange of balancing capacity is secure in the balancing time frame.

2.2 Development of long-term markets: FCA 2.0

ENTSO-E welcomes the EC's mandate to conduct an impact assessment of various potential forward-market solutions before a final decision is made under Article 9 of the Electricity Regulation pursuant to electricity market design reform. All potential models should be thoroughly assessed in consultation with stakeholders to address unclear points and ensure a comprehensive evaluation of all potential impacts.

The goal of this assessment is to improve the ability of market participants to hedge price risks in the internal electricity market when necessary. Existing shortcomings of the electricity forward markets, such as limited liquidity in some BZs, should not be addressed through disruptive legislative acts such as imposing regional virtual hubs, which are untested and lack market support. Instead, promising alternatives such as an improved auction design based on options or obligations should be explored, as they offer a more practical and timely path to delivering benefits in the coming years.

Therefore, ENTSO-E continues to explore more promising alternatives to the virtual hub model that could serve as target models for all TSOs, pending positive regional assessments. The models under evaluation maintain the current border-wise approach, focusing on providing hedging opportunities to proxy hedging areas. Hedging between non-neighbouring BZs can still be achieved through power exchanges using spread products. Further details on the models can be found in the dedicated **ENTSO-E Advocacy Note on Forward Markets**, which outlines alternatives to the virtual hub model. No-regret measures common to all models have been identified, including removing long-term (LT) allocation inclusion, increasing auction frequency, and extending maturities to at least 2 years. The impact assessment should place special emphasis on collateral requirements, the volume determination of LTTRs, and revenue adequacy.

2.2.1 Collaterals – a major concern for TSOs

The new EU regulation (EU 2024/1747) to improve electricity market design may introduce new products and processes that potentially entail collateral requirements for TSOs. These requirements could significantly impact TSO and tariff-payers costs, while also affecting the ability to undertake other investments and operations.

Collateral requirements, consisting of initial and variation margins, are designed to protect one party in a contract against the risk of default by the other party and are established under financial regulations and/or directives such as EMIR, MifiD II, and MiFIR. The potential cost burden of such requirements on TSOs trading financial derivatives is a major concern and must be carefully considered in any proposals involving TSO participation in forward market design.

Based on TSO internal stress tests using 2022 data, collateral requirements could amount to several billion euros for some TSOs in extreme market conditions. Under normal market conditions, ENTSO-E expects margin calls to be smaller, but still in the range of several hundred million euros. The stress test also revealed potential daily volatility in margin calls, which could require some TSOs to inject up to €1 billion at short notice. The operational feasibility of this cannot be confirmed.

In general, TSOs would need to secure liquidity via credit lines and/or partially via bank or public guarantees, potentially resulting in high costs for tariff payers. Collateral requirements could also negatively impact creditworthiness, making it more costly and difficult to acquire the necessary working capital for grid investments and operations. It must be noted that collateral requirements impose varying costs and impacts on individual TSOs, depending on factors such as ownership structure and liquidity conditions. As a result, collateral creates an unequal financial burden across TSOs.

Given the high costs of collateral and potential liquidity risks, ENTSO-E calls for a comprehensive cost–benefit analysis of market design scenarios. This should also include an examination of changes in collateral requirements for market participants as part of the FCA 2.0 impact assessment.

Collateral is a complex topic with unresolved questions, including who is responsible for financially backing TSOs. Possible solutions include creating a forward market model where TSOs are not required to provide collateral, or that at least ensures access to funds to cover liquidity and operational costs if collateral is required.

2.2.2 Volume determination

The volume of hedging products offered to the market by TSOs is a key component of market design. It must be sufficient to meet market parties' hedging needs without endangering the financial security of TSOs (e.g. revenue adequacy and/or collateral levels).

Accordingly, TSOs have established key principles on this issue:

1. The purpose of LTTRs is to promote effective hedging opportunities to market participants.

2. LTTRs will become purely financial products, with no allocated physical capacity.

3. DA and LT time frames are fundamentally different.

4. The goal of LTTRs is not to "bring the futures/forwards markets together".

5. TSOs should not auction volumes exceeding the natural hedge they hold – the congestion income generated by DA flows through physical interconnectors they own.

6. The volumes offered under option and obligation setups should be different, as these product types are distinct and offer different payouts.

7. Feedback loops derived from revenue adequacy and collateral levels (if collateral is imposed on TSOs) should influence offered volumes. If financial risk is too high, future auction volumes must be adjusted to reduce it.

8. There is a trade-off between the volume offered and full financial firmness. To account for the added risk to TSOs under full financial firmness, the offered volume should be lowered.

9. Coordination between TSOs and National Regulatory Authorities (NRAs) will increasingly focus on managing financial risk exposure. This risk can be reduced through additional safety nets, such as a supply function or a reserve price. A supply function would enable TSOs to adjust the volume offered based on price levels, in contrast to the current situation, where the offered volume is price inelastic.

In short, any market feature that increases risk exposure for TSOs should be followed by a decrease in offered volumes to mitigate the increased risk. Alternatively, any new risk borne by TSOs would ultimately be covered by grid tariff payers as it would reduce congestion income (CI). Policy decisions on the use of CI (support of hedging in LT markets, network development, reduction of tariffs, etc.) involve trade-offs. Therefore, TSOs call for a thorough, collaborative impact analysis – including costs, benefits, and risks – before adopting any new market features.

2.3 Trade developments with Ukraine and Moldova

Trade development with Ukraine

Following the development of the daily harmonised allocation rules during 2023 by a dedicated group of experts from ENTSO-E, TSOs and the Joint Allocation Office (JAO), the common daily auctions on the Slovakia-Ukraine, Hungary-Ukraine and Poland-Ukraine, organised by JAO, went live during the first quarter of 2024. In June 2024, the same expert group initiated the discussion on the introduction of LT and ID auctions for the Ukrainian borders.

The group decided to proceed with:

- Monthly LT auctions for Slovakia–Ukraine, Hungary–Ukraine, and Romania–Ukraine, to be organised by JAO, and
- ID explicit auctions for Slovakia–Ukraine and Hungary–Ukraine organised by JAO, with Romania–Ukraine auctions organised through a bilateral auction platform.

From June through December 2024 (and continuing in 2025), a dedicated group of experts is working on the development of auction rules, including:

- For monthly LT auctions, EU Harmonised Allocation Rules with Border Specific Annex (EU HAR with BSA) will be applied. The annex focuses on Articles from EU HAR that require changes (i. e. curtailment processes);
- For explicit IDAs on the borders run by JAO, an updated set of CH ID rules will apply to reflect the necessary changes for the specific profiles on the borders with Ukraine; and
- For explicit IDAs on the Romania–Ukraine border, bilaterally developed ID rules from Ukrenergo and Transelectrica will apply.

Trade development with Moldova

For background, the power system of the Republic of Moldova is part of the joint Moldova and Ukraine load frequency control (LFC) block, with Ukrenergo acting as leader of the block. The Republic of Moldova's electricity system is divided between the right and left banks of the Dniester River, with the left bank not fully under the control of the government. The right bank region accounts for approximately 70 % of total energy consumption, with approximately 30 % consumed by the Transnistrian (left bank) region.

Several developments took place on the borders with Moldova in 2024. First, the IDA go-live on the Moldova–Romania border took place on 12 July 2024.

Then, Moldova saw a decline in electricity production in the second half of 2024, while its electricity demand typically peaks in the winter months. Moldova announced that starting 1 January 2025, the transit of natural gas through Ukraine would cease. As a result, any electricity needed beyond local production on the right bank must be sourced from providers other than the Russian-owned Kuchurgan power plant (MGRES). To support Moldova, in December 2024, the neighbouring TSOs agreed to reallocate all non-allocated and non-nominated capacities from the Poland–Ukraine, Slovakia–Ukraine, Hungary–Ukraine, and Romania–Ukraine borders to Moldova IDAs.

The graphs below show the power balance of the right bank region of the Moldovan power system for December 2024 and January 2025, highlighting the increased import capacity to support Moldova's security of supply.

Power balance in December 2024:

TOTAL Demand (RB) – 469 GWh

Coverage:
Internal sources (including MGRES) – 323 GWh
Import (daily capacity auctions) – 140 GWh
Import (ID capacity auctions) – 6 GWh

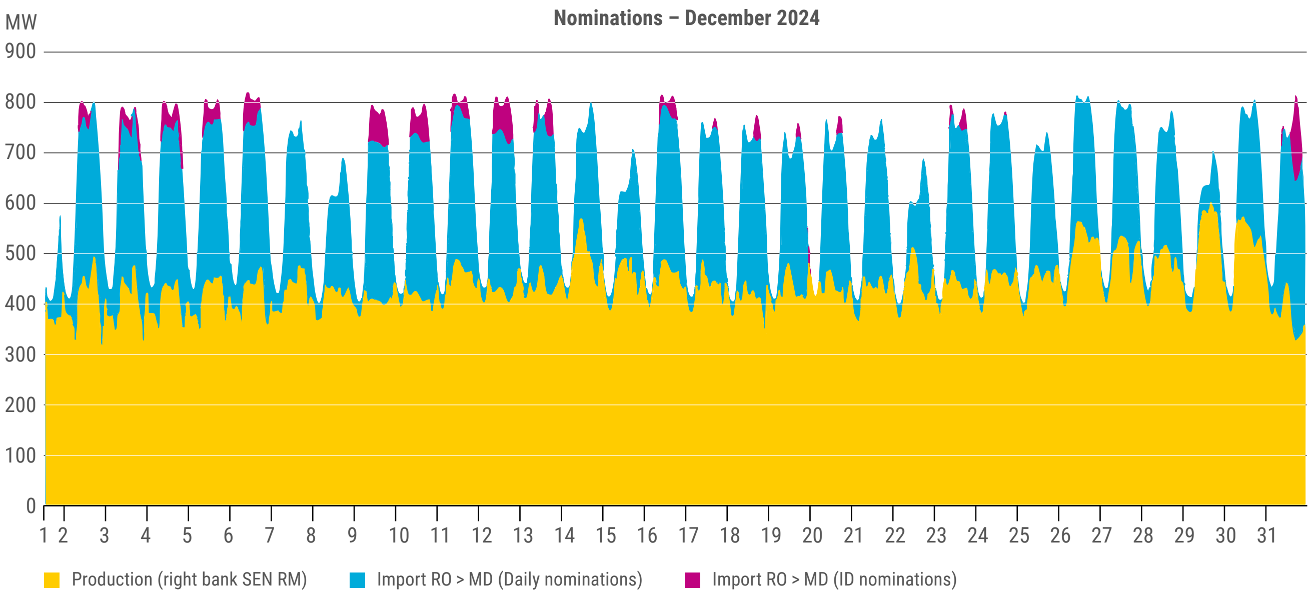


Figure 2.1: Nominations December 2024

Power balance in January 2025:

TOTAL Demand (RB) – 440 GWh

Coverage:
Internal sources – 198 GWh
Import (daily allocations) – 218 GWh
Import (ID allocations) – 23 GWh

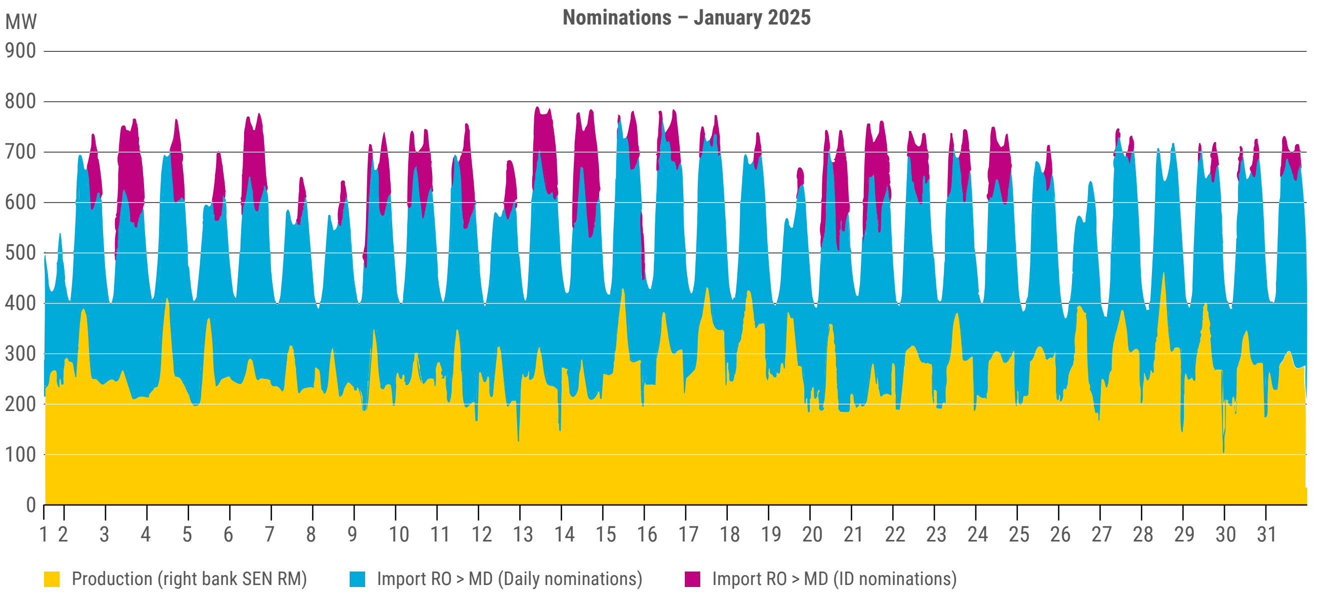


Figure 2.2: Nominations January 2025

ENTSO-E and continental Europe TSOs will continue to support Ukrenergo and Moldelectrica in maintaining the stability of their power system and working towards further development of coordinated capacity allocation in different time frames.

ENTSO-E would like to thank the external stakeholders and all TSOs involved for their support and assistance during and after the synchronisation process.

2.4 Implementation of CEP70 minimum capacity targets

To foster non-discriminatory and cross-zonal trade in the internal electricity market, Article 16(8) of the EU Electricity Regulation requires European TSOs to make at least 70% of transmission capacity (respecting operational security limits) available for cross-zonal electricity trading. Where TSOs have requested a "derogation" from this requirement pursuant to Article 16(9) or Member States have invoked an "action plan" pursuant to Article 15, a less ambitious target may apply for a given year or a transitional period defined in the action plan.

2.4.1 Monitoring the fulfilment of the CEP70 requirement: Why do several reports exist?

Assessments of the fulfilment of the CEP70 requirement under Article 15(4) of Regulation 2019/943 are based on contributions from each TSO, subject to NRA approval. Since the NRA requirements for approval of individual contributions are not homogeneous, several reports for assessing the fulfilment of the applicable target exist. While NRAs are responsible for assessing TSOs' compliance with the CEP70 provisions, below we provide an overview of the existing reports:

National compliance assessments/ENTSO-E Market Report

In ENTSO-E's annual market reports, TSOs provide an easily accessible overview of (individual) national assessments for external stakeholders. However, it should be noted that the values in these market reports are based on national compliance methodologies, which may differ from each other. Therefore, the comparability of individual values is limited. For instance, some countries evaluate all contingencies for each critical network element per MTU, resulting in multiple values per MTU, while others report only a single value per MTU. To ensure transparency, TSOs provide country fact sheets (see Annex IV) with brief descriptions of each national compliance assessment and detailed information on the differences between the national methodologies. These sheets specify whether an NRA's compliance approach aligns with ACER's monitoring methodology and highlight key differences between the assessments.

ACER Market Monitoring Report

In parallel, ACER publishes an independent assessment as part of its annual market monitoring, applying a uniform methodology. ACER's approach differs from that of individual NRAs when approving TSO contributions. Therefore, to draw valid conclusions on whether cross-zonal trade capacity meets the minimum requirement or follows a linear trajectory, the legally required national compliance assessments must be checked. Another difference between the ENTSO-E Market Report and national assessments is that the ACER report provides both a comparison to the target minimum capacity (i.e. 70%) and, where action plans or derogation apply, to the transitional minimum capacity. As a summary of national compliance assessments, the ENTSO-E Market Report always compares the current fulfilment of the CEP70 provisions solely to the (transitional) minimum capacity, which can be lower than 70% if action plans or derogations are in place.

To support transparency, the graphs provided in Section 2.4.2 for 2024 aim to establish a basic level of comparability. Nonetheless, the comparability of these results remains limited due to the variations in the underlying methodologies and data used to produce the visualised values. An overview of CEP70 fulfilment from 2021 to 2023 can be found in the ENTSO-E **Technical Report**.

2.4.2 Overview of national monitoring results by region for 2024

As noted in the introduction, the following graphs aim to enable a certain level of comparability by presenting national results by region and using the same categories as **ACER's monitoring reports.** However, the ENTSO-E Market Report is based on national compliance methods, whereas ACER applies a harmonised monitoring methodology focused on the percentage of MTUs. Therefore, the main differences in the national methodologies are displayed by grouping national methods (e.g. percentage of constraints, percentage of MTUs). A detailed description of national specificities is provided in the country fact sheets in the annex. However, it is important to acknowledge that the comparability of these results is limited due to differences in methodologies and underlying data.

The ENTSO-E Market Report summarises national compliance assessments by comparing the fulfilment of CEP70 provisions against the applicable 2024 target. Here, "target" refers either to the final minimum capacity target of 70 % or a lower intermediate value set by action plans or derogations.

Furthermore, it should be noted that the 70 % minimum capacity is not an absolute (minimum) target, as deviations due to operational security are legally permitted. TSOs have the legal duty to reconcile it with physical reality. Article 16.3 of the EU Electricity Regulation allows deviations from the 70 % rule to ensure grid operational security. If necessary, such deviations – i. e. capacity reductions – arise from the mandatory validation step in capacity calculation and are used only as a last resort when remedial actions are insufficient to secure the grid.

Core CCR

In the following, the (national) monitoring results for 2024 are provided for the Core CCR. Figure 2.3 shows the relative margin available for cross-zonal electricity trade (MACZT) for each country in the Core region and across all relevant MTUs in 2024. It excludes MTUs where coordinated capacity calculation failed and fallbacks (e. g. spanning or default FB parameters) were used – 33 MTUs in 2024 (0.38 % of 2024). Note that MTUs here always refer to hours.

Countries are grouped based on the approach used by NRAs for the national compliance assessment. This differs significantly from ACER market monitoring, which benchmarks countries using a uniform methodology. More methodological differences are explained in the country fact sheets in Annex IV. The main difference concerns the scope of monitored instances. AT, PL, HR, and DE monitor the margin of each constraint per MTU (multiple values per MTU), while HU, NL, RO, BE, SI, CZ, and SK monitor the constraints with the lowest margin of a given MTU (one value per MTU). FR also follows this approach, but also filters MTUs based on set criteria. Only MTUs without price convergence, where limiting critical network elements with a contingency (CNECs) were located in France, are assessed. The cross-zonal high-voltage direct current (HVDC) interconnector ALEGrO between Belgium and Germany is considered in isolation due to its unique integration into the FB capacity calculation (one value per MTU and direction).

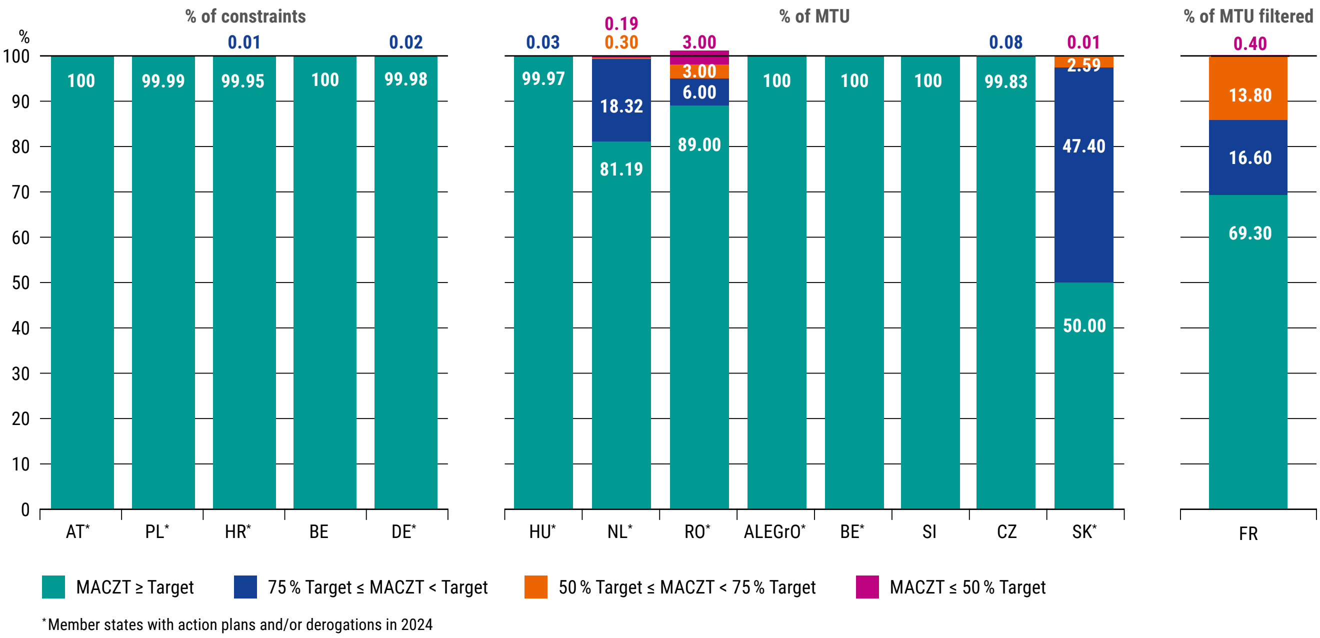


Figure 2.3: National monitoring results for 2024 in the Core CCR compared to the applicable values under derogations and action plans

Notes: Individual applicable targets can be found in the country fact sheets in Annex IV. The relative MACZT margin for BE is shown as % of constraints and % of MTU, aligning with NRA annual reporting.

In line with the German action plan, the applicable intermediate target for German critical network elements (CNEs) in the Core region has been increased from 41.8 % in 2023 to 50.5 % in 2024. In 2024, the required margins have been provided in nearly every instance, specifically, for 99 % of all CNEs for each hour. TSOs consider all instances where the intermediate minimum margin was not met to be admissible under the Electricity Regulation. These results show that German TSOs are on track to fulfilling the linear trajectory set out in the German action plan, consistently increasing market capacity each year while maintaining secure grid operation.

In line with the Austrian action plan and the granted derogation for the Core CCR, the 2024 minimum capacity target of 49.4 % has been met. As in Germany, the few instances where minimum capacities had to be reduced at the CNEC level during the capacity validation step – via individual validation adjustment (IVA) based on available remedial action potential – are also deemed compliant, as these measures were necessary to maintain grid security.

For Romania, Transelectrica has an action plan in place to increase the minimum available capacity yearly by 2026. In 2024, a derogation was in place to ensure operational security for the RO–HU border, requiring a minimum of 33 % of transmission capacity. Instances where this target was not met were due to security considerations and reductions applied during the capacity calculation process, which may have been due to multiple planned disconnections causing CNEC overloads or insufficient costly remedial actions.

Slovakia was granted a derogation for 2024 with the following conditions: it must provide 50 % MACZT for two CNEs in at least 80 % of MTUs and 60 % MACZT for two CNEs in at least 80 % of MTUs, contingent on maintaining the security of the power system. For the remaining CNEs, a target of 70 % MACZT was established. Based on the specific features of the Slovak BZ and transmission system, such as its size and geographic location within the Core region, SEPS considered granting a derogation essential to maintaining the operational security of the interconnected systems. Compared to SEPS's 2023 derogation request, the 2024 request reduced the scope from six to four CNEs and increased the minimum offered MACZT from 50 % to 60 % for CNEs V477 and V478 Lemešany–Krosno–Iskrzynia (PL), applicable for at least 80 % of MTUs in 2024.

France has no action plan nor derogation in place, so the target level remains 70 %. In 2024, this target was reached for 70 % of MTU, down from 80 % in 2023. This decrease is attributed to limitations in cross-border capacity to guarantee operational security on French CNECs between March and June 2024, mainly due to high exports, transit flows, and required grid maintenance. Since then, additional eligible CNECs compliant with capacity calculation methodologies have been added to the Core capacity calculation to deal with such situations.

Overall, the Core TSOs demonstrate a high degree of fulfilment with the applicable targets, including intermediate targets from action plans and derogations. Nearly all Core TSOs achieve results close to 100 % fulfilment of their respective targets considering derogations and/or action plans.

Italy North CCR

In the following figure, the (national) monitoring results for 2024 are provided for the Italy North CCR. The percentages in the figure are based on the national assessments of Italy North TSOs. In the coordinated net transfer capacity (cNTC) calculation, each MTUs is assigned with a potentially limiting CNEC, limiting the possible exchanges/allocations over the entire Italy North border. In 19 % of the MTUs in 2024, no limiting CNEC could be calculated due to process failure; therefore, the compliance assessment is based on the remaining 81 % MTUs. In the graphic below, "No limiting CNEC" refers to cases where the most limiting CNEC was outside the corresponding BZ.

For Italy's northern borders, the 70 % criterion is considered fulfilled once at least one limiting CNEC on the border meets this condition, regardless of the specific national frontier. According to the methodology approved by the NRAs of the CCR, the Italy North border is treated as a single entity.

APG, assessing compliance at the CNEC level, limited exchanges in only ~5.8 % of the MTUs with potential limiting CNECs or MTUs without process failure. In line with the Austrian action plan for the Italy North CCR, the minimum target for 2024 has been met for these CNECs. The few cases where minimum capacities on potentially limiting CNECs were reduced during the capacity validation step are also considered compliant, as these measures were necessary to maintain grid security. Compliance is also confirmed for all hours when the potentially limiting CNEC was outside the APG BZ or during hours with process failure.

RTE applies the 70 % target on the FR–IT border. MTU filtering is also considered, and MTUs with price convergence with Italy North BZs are considered compliant. In 2024, compliance was high because for 70 % of MTUs, the most limiting CNEC was outside France.

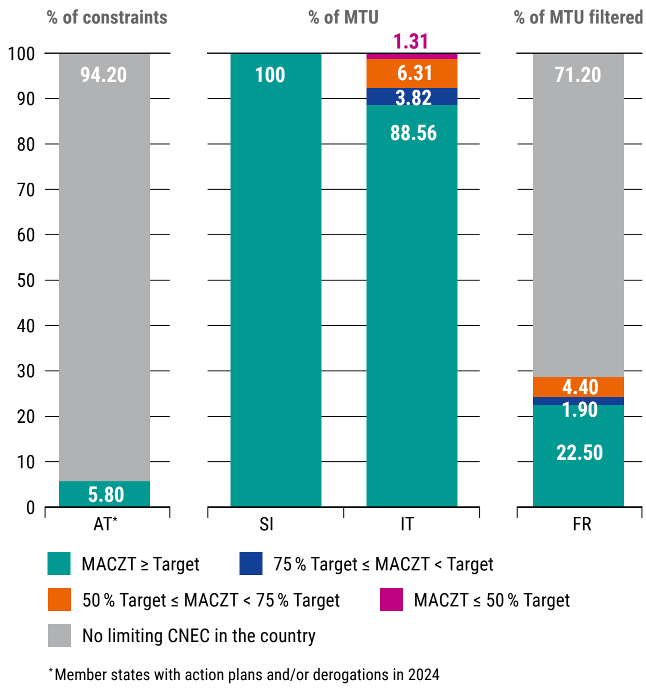


Figure 2.4: National monitoring results for 2024 for the Italy North CCR compared to the applicable values under derogations and action plans

Note: Individual applicable targets can be found in the country fact sheets in Annex IV.

South-West Europe CCR

In the following, the (national) monitoring results for 2024 are provided for the South-West Europe (SWE) CCR.

SWE data is calculated and provided by its RCC, CORESO. Given that the cNTC approach is used, only limiting CNECs are monitored. When the limiting CNEC is not an interconnector but rather an internal element of one country, it is counted as "no limiting CNEC in the country" for the other bordering country. This implies fulfilment of the 70% criterion, since that country is not limiting the net transfer capacity (NTC).

The amended regional capacity calculation methodology guarantees the monitoring of all MTUs by including a fallback mechanism that assigns a limiting CNEC and MACZT values even if the capacity calculation process fails. Another key feature of the SWE implementation is the use of available costly remedial actions to increase NTC values when the 70% criterion is not met following the capacity calculation. This approach results in a high level of fulfilment.

While Portugal has a derogation of Art. 16(8) for 2024, Spain and France do not. None of the three SWE countries has an action plan in place.

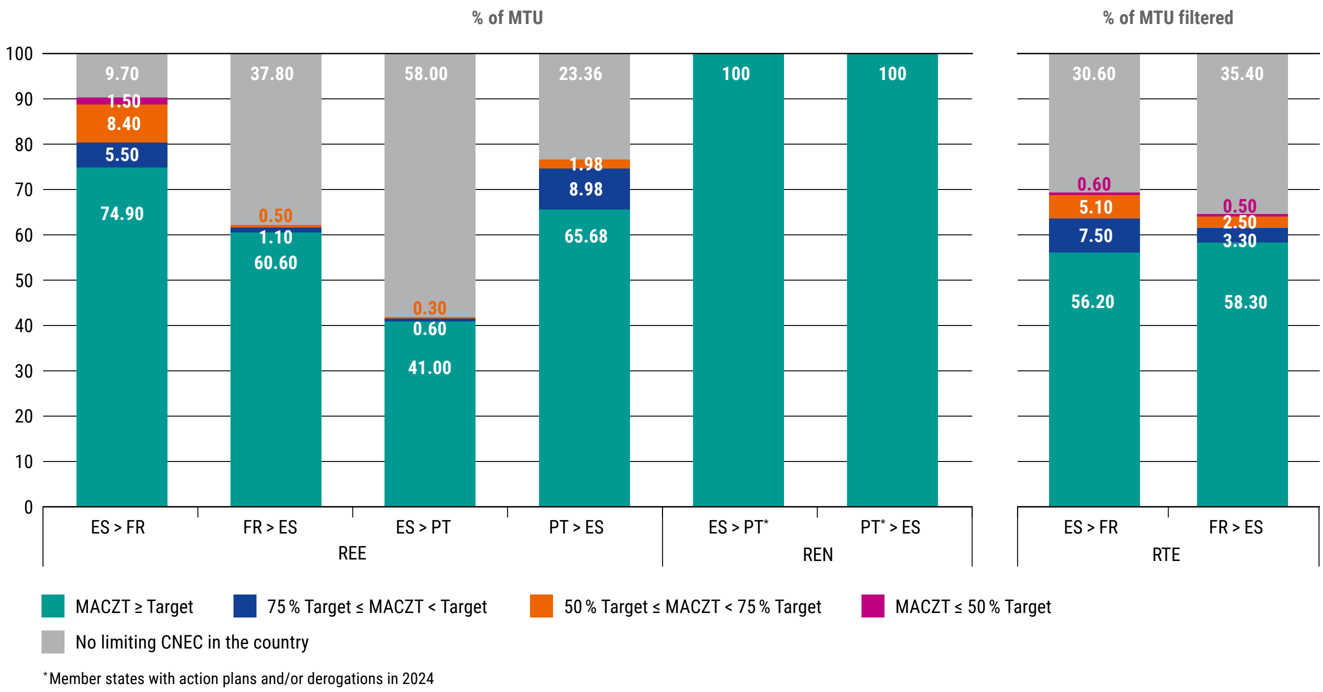


Figure 2.5: National monitoring results for 2024 for the South-West Europe CCR compared to the applicable values under derogations and action plans

Note: Individual applicable targets can be found in the country fact sheets in Annex IV.

South-East Europe CCR

In the following, the (national) monitoring results for 2024 are provided for the South-East Europe (SEE) CCR. The graph below shows the MACZT margin for each SEE TSO, without distinguishing whether a derogation, action plan, or the final 70% target applies. Timestamps where the capacity calculation process failed are excluded and marked as "process failure". Additionally, if the limiting CNEC is neither an internal element nor an interconnector involving the reporting country, the MTU is counted as "no limiting CNEC in the country" for that country. Currently, the SEE CCR amended methodology is being implemented, enabling TSOs to calculate MACZT directly within the capacity calculation platform. Until the platform becomes available, SEE TSOs rely on ACER data to perform the calculations using inputs provided by the TSOs.

For the SEE CCR, the TSOs of Romania and Greece have applicable derogations and action plans for 2024, while the Bulgarian TSO applies the final target of 70 %.

For Romania, Transelectrica has an action plan in place to increase the minimum available capacity annually by 2026. In 2024, a derogation was in place to ensure operational security for the RO–BG border. According to this derogation, a minimum of 43 % of transmission capacity must be ensured for this border.

Transelectrica also applies ACER Recommendation No. 01/2019 for MACZT calculation. As noted, the data on multilateral coordinated capacity calculation (MCCC) and multilateral non-coordinated capacity calculation (MNCC) is not directly available to the TSOs; however, Transelectrica succeeded in calculating the power transfer distribution factors (PTDFs) for this year, enabling a more accurate representation of the MACZT values for the RO–BG border.

Greece had a derogation in place for 2024, setting the target at 60 %, excluding periods of maintenance on Greek tie-lines or times of very low load conditions. For northern Greek imports, the target was met in 74 % of total MTUs, while for exports it was 90 %. This difference can be attributed to the significant influence of MNCC on Greece, particularly for imports, where high negative values from the non-coordinated areas are observed.

These high values may also be caused by ACER's methodology, as PTDF values are calculated based on five reference common grid models (CGMs), so they cannot be considered completely accurate.

However, the primary reason Greece did not consistently hit the target is that three of its four borders are within non-EU TSOs. As a result, only the Greece–Bulgaria border undergoes daily calculations, while the others rely on monthly agreements.

For Bulgaria, MACZT results are based on ACER's calculations, which use limiting CNECs from the DA capacity calculation data provided by the SEE RCC SELENE.

Flows with third countries in the SEE region are currently handled according to the existing SEE coordinated capacity calculation methodology, which does not consider the impact on MACZT values stemming from the fact that three of Bulgaria's five borders are with non-EU countries not bound by EU regulations. Currently, Bulgaria relies on PTDFs calculated by ACER, which are based on a limited number of snapshots, as it is unable to perform internal PTDF calculations. This might lead to some inaccuracy in MACZT estimates. The data shows that for nearly all MTUs, there is no limiting CNEC within its control area, especially for the BG–GR border. In most other MTUs, the limiting elements are the interconnection lines between the respective borders.

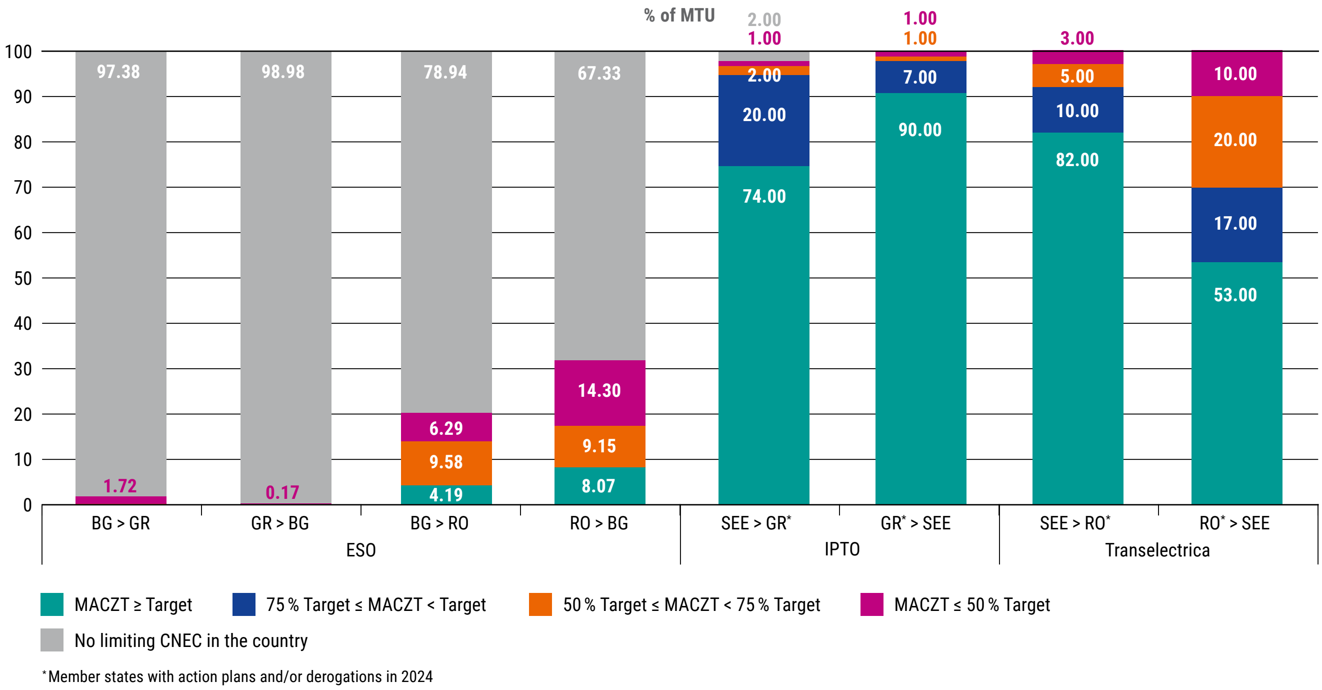


Figure 2.6: National monitoring results for 2024 for the South-East Europe CCR compared to the applicable values under derogations and action plans (Romania and Greece) or the final applicable target (Bulgaria)

Note: Individual applicable targets can be found in the country fact sheets in Annex IV.

Greece–Italy CCR

In the following, the (national) monitoring results for 2024 are provided for the Greece–Italy CCR.

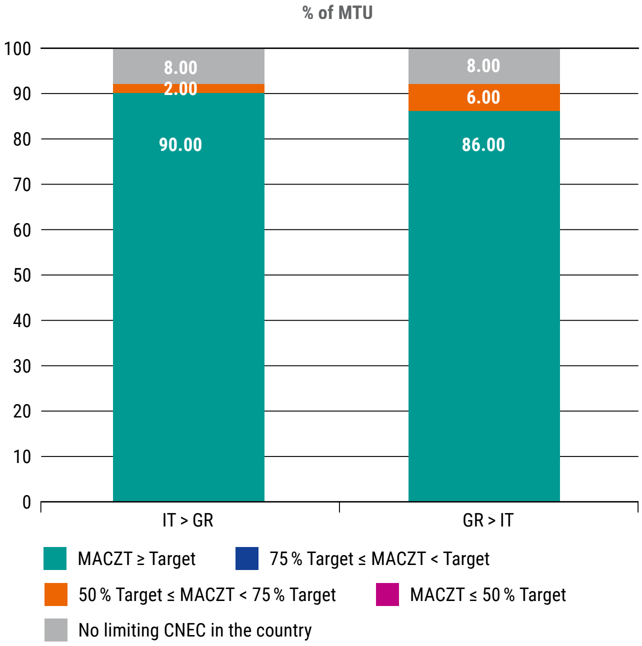


Figure 2.7: National monitoring results for 2024 for Greece–Italy CCR compared to the applicable values under derogations and action plans

Nordic CCR

In the following, the (national) monitoring results for 2024 are provided for the Nordic CCR.

The Nordic CCR transitioned to flow-based market coupling (FBMC) on 29 October 2024. Consequently, the graph below covers two distinct calculation methodologies: NTC for the period before the FB implementation and FB for the period following its introduction.

To ensure transparency and accurate MACZT reporting, the 2024 report will distinguish between these two methodologies for Fingrid and Energinet, while for Svenska Kraftnät report data for 2024 will only be available for the period in which the FB capacity calculation method was applied, thus from October 29 to December 31, as requested by ACER. This means that data from the NTC period will be excluded from the reporting for Sweden.

Please note that NTC data is subject to change pending ACER's calculation of the MAZCT and should therefore be considered preliminary estimates that may differ from the final values from ACER's monitoring.

The main challenge to reach MACZT >70 % for all CNECs and MTUs for Sweden is generation plants directly connected to cross-border elements in the transmission network. This results in a high F0-flow which leads to a lower allocation of capacity for cross-border trade. The predicted production volumes for these plants in the individual grid model have a big impact on the outcome of the calculation.

The results presented for Sweden are based on the grid element with the lowest MACZT for each hour. Looking at the full dataset including all non-redundant CNECs registered for Sweden for the relevant period about 98 % of the CNEC's have an MACZT >70 %.

In 2024, a significant unplanned outage of EstLink-2 had a notable impact on market conditions. Additionally, the Nordic PTDFs and F0 values for the North Sea Link and Viking Link were not estimated for 2024, creating difficulties in accurately reporting MNCC data. However, the Nordic RCC is actively working on implementing these missing values to improve reporting accuracy.

The approach used by Nordic NRAs for individual national compliance assessment is specified in the country fact sheets in Annex IV. For transparency, the results in this section for FI, DK, and SWE are presented based on compliance assessment by monitoring the constraints with the lowest margin of each MTU (one value per MTU).

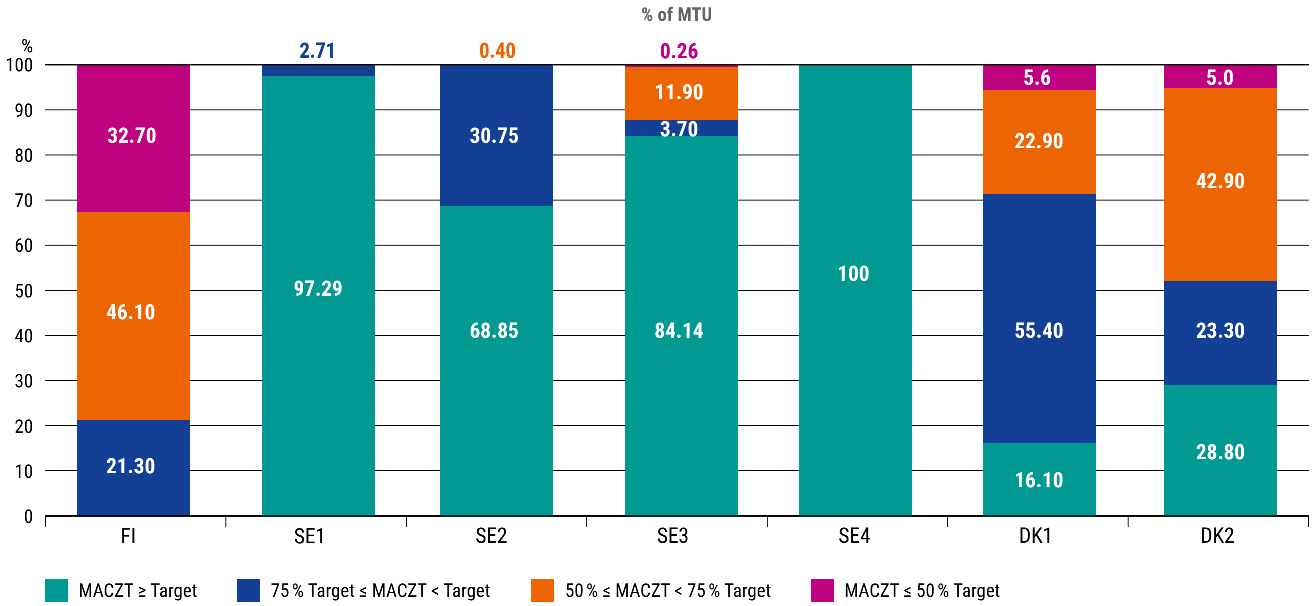


Figure 2.8: National monitoring results from 29 October to 31 December (FB only) for the Nordic CCR compared to the applicable values under derogations and action plans

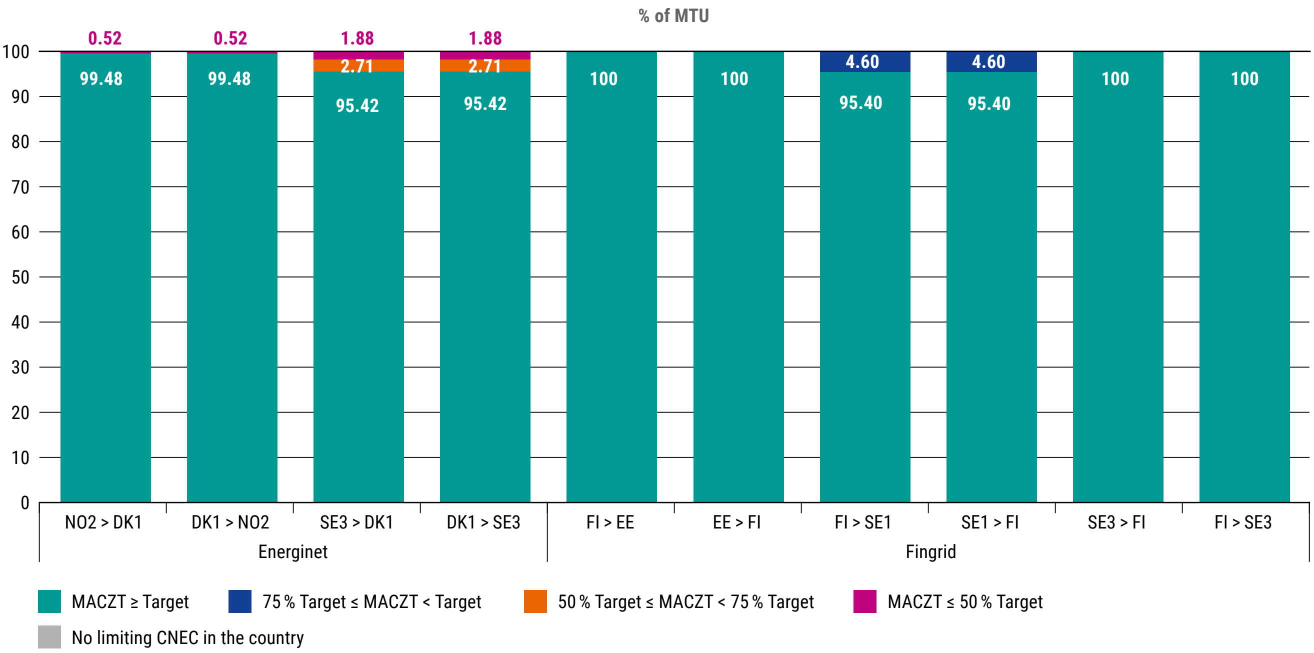


Figure 2.9: National monitoring results for 1 January to 28 October (cNTC only) for the Nordic CCR compared to the applicable values under derogations and action plans

Baltic CCR

In the following, the (national) monitoring results for 2024 are provided for the Baltic CCR.

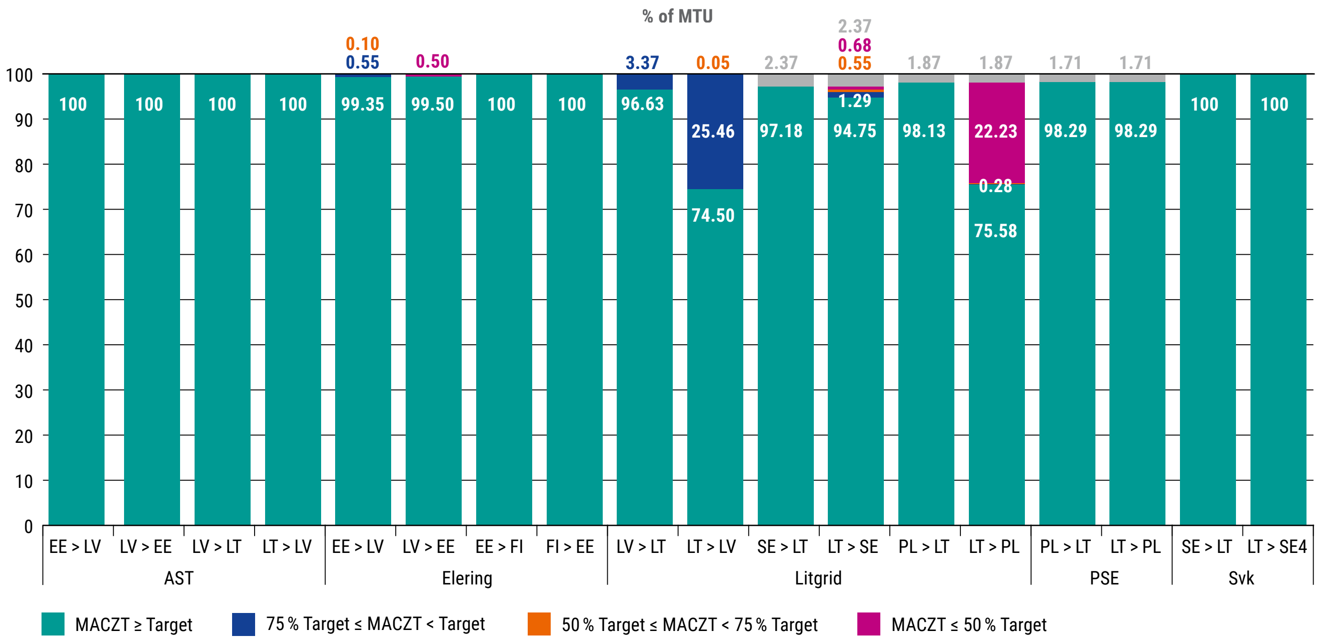


Figure 2.10: National monitoring results for 2024 for the Baltic CCR compared to the applicable values under derogations and action plans

Hansa CCR

In the following, the (national) monitoring results for 2024 are provided for the Hansa CCR.

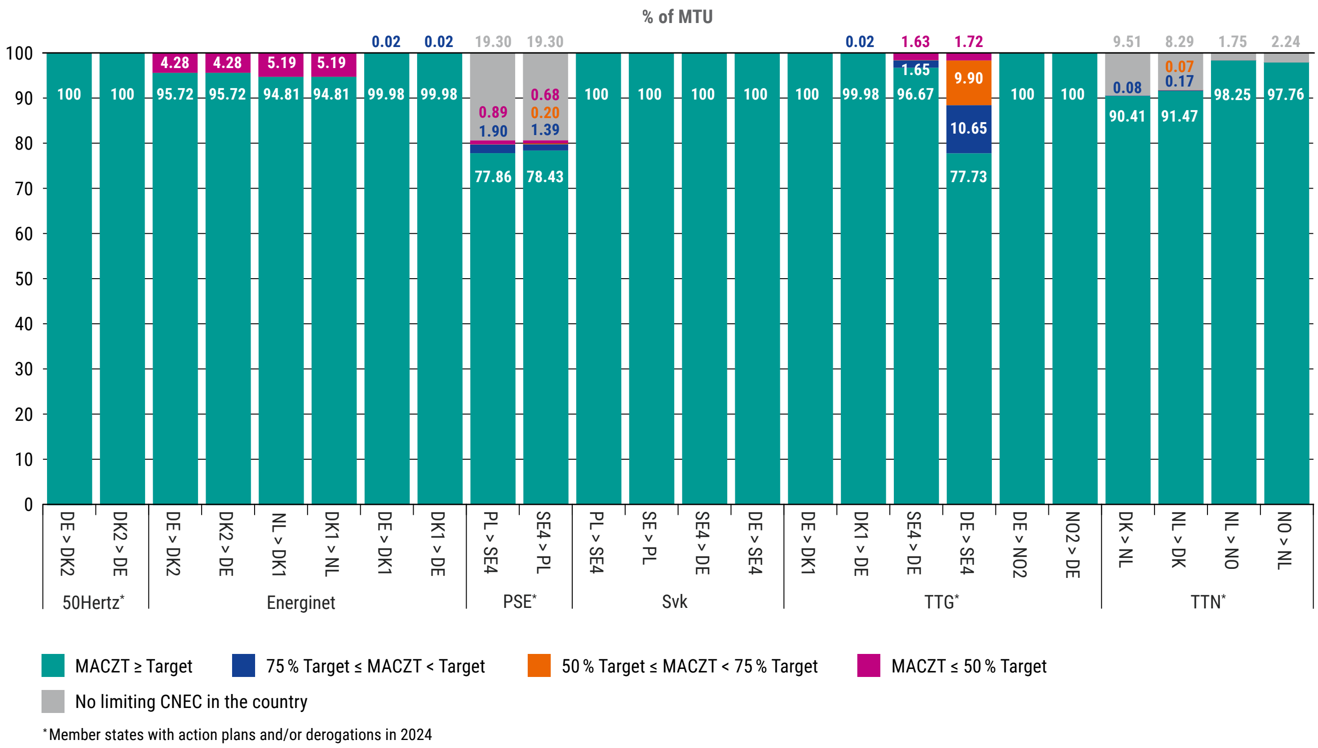


Figure 2.11: National monitoring results for 2024 for the Hansa CCR compared to the applicable values under derogations and action plans

Note: Individual applicable targets can be found in the country fact sheets in Annex IV.

On the DE–SE4 border, several deviations from the linear trajectory occurred in 2024, all of which were duly justified in line with Article 16(3) of the Electricity Regulation. These were mainly driven by planned and unplanned outages of critical grid elements in the TenneT control area, including distribution grid assets. Many outages were necessary to implement grid reinforcements – most notably the construction of the Ostküstenleitung – which aims to resolve the specific connection constraints of the Baltic Cable by improving transmission availability in the region. The Ostküstenleitung, a 380 kV overhead line project between Göhl and Lübeck, is key to strengthening the integration of the Baltic Cable into the German extra-high voltage grid. This strategic grid reinforcement will enable full utilisation of the interconnector and help meet European targets for cross-border electricity trade.

2.4.3 Flow-based go-live in the Nordic CCR

The Nordic CCR transitioned to FBMC on 29 October 2024. Consequently, the 2024 MACZT monitoring report will cover two distinct calculation methodologies: NTC for the period before the FB implementation and FB for the period following its introduction.

FBMC has had a positive impact by increasing cross-zonal flows from north to south and optimising power transmission. The utilisation rates of interconnections have also improved due to more efficient use of the transmission network.

While the 70% rule remains the central focus of this report, it is important to acknowledge the new market dynamics introduced by the FB methodology. The capacity calculation methodology (CCM) project has consistently provided updates on market effects within Nordic CCM stakeholder communications. When analysing the 70% compliance data, these contextual differences should be considered.

By addressing these challenges and recognising the benefits of the FB approach, the Nordic CCR remains committed to enhancing MACZT transparency and reliability in its market reports.

2.4.4 TSOs urge caution in applying the requirement within the ID time frame, as security is at stake

Providing sufficient CZC for the ID time frame is crucial to a well-functioning ID market and the integration of renewable energy resources into Europe's power system. TSOs provide sufficient cross-border capacities following their action plans and derogations (where applicable) for all time frames. TSOs firmly believe that repeating the (minimum) 70 % requirement from DA to ID will not help achieve that goal. An overarching approach across both time frames is essential: offering a 70 % minimum capacity in the DA time frame often means offering virtual capacities to the market.

This involves TSOs offering capacities that may not physically exist to virtually increase cross-zonal trading. In doing so, TSOs assume that potential congestions in the transmission grid can be resolved after DA market clearing through remedial actions, such as redispatching power plants. Therefore, offering CZCs that fulfil the 70 % requirement implicitly depends on anticipating the availability of sufficient measures to alleviate the resulting congestion at a later stage.

However, this does not apply in the ID time frame for the following reasons:

1. Compared to the DA market, there is no equivalent coordination process for remedial actions after the closure of the ID market. Moreover, TSOs lack visibility into potential congestion resulting from ID market trades before real time and hence have no time to react to them.

2. The remedial actions available to TSOs to maintain operational grid security diminish as security processes move closer to real time. For example, the lead times of generation units for redispatch are several hours, making them unavailable for deployment closer to real time. With the ID market closing 1 hour before delivery (or 30 minutes in the near future), current redispatch and coordination processes and generation units cannot accommodate such short lead times, leaving TSOs insufficient time to activate remedial actions before real time. Therefore, TSOs cannot provide virtual CZCs at the minimum 70 % level for allocation so close to real time without jeopardising secure system operation.

3. The liquidity of the ID market is uneven, with significantly more trading activity occurring near real-time operation and limited interest many hours in advance. However, the ability to apply remedial actions close to real time to enable virtual capacities is severely limited, if feasible at all. This becomes even more relevant with the implementation of the new ID market closure time (i. e. 30 minutes before real time). Since many changes in the ID time frame already occur shortly before delivery, allowing trading up to 30 minutes before real time leaves even less time for TSOs to act.

4. Finally, when approaching real-time grid operation, other technical aspects, such as reactive power control and voltage regulation, gain importance and must be considered when taking remedial actions.

To summarise, physical capacity cannot be increased beyond the security limits. TSOs are responsible for maintaining operational security. A strict 70 % minimum capacity requirement in the ID time frame will, in practice, be offset to maintain operational security – meaning it will not lead to additional capacity being made available for trade during this period. Alternative measures, such as grid investments and BZ reconfigurations, will not mitigate this issue, as they operate on longer time frames and are designed to address congestion with a more structural nature. Furthermore, as congestion patterns become more variable and temporary, TSOs will need to complement LT measures with daily capacity calculation and allocation to manage these congestions efficiently.

As previously noted, TSOs provide sufficient cross-border capacities following their action plans and derogations (where applicable) and are making significant investments in grid expansion, including cross-border connections. To meet CEP70 requirements, TSOs are working diligently and demonstrating mutual support. One example of this collaboration is the DAVinCy validation process in the Core CCR, where the German, Austrian, and Dutch TSOs jointly assess validation adjustments in the DA capacity calculation. TSOs see a risk of being forced into an unrealistic obligation to provide virtual capacities in the ID time frame. This requirement disrupts the fragile balance between maximising CZC and ensuring the grid's operational security. Clarifying contradictions in the current regulation and focusing on an efficient transmission system alongside ID markets that accurately reflect physics will benefit all stakeholders during the challenging energy transition.

2.5 Network Code on Demand Response topics

The development of the proposal on Network Code on Demand Response (NC DR) was initiated in response to the EC's request dated 9 March 2023, aligning with the ACER Framework Guideline submitted on 20 December 2022.

The proposal holds significant importance for DSOs and TSOs in three main areas: (I) ensuring the safe, efficient, and reliable transmission and distribution of electricity, (II) facilitating the integration of electricity markets, and (III) expediting the decarbonisation of the power system.

Following the mandate received from the EC, ENTSO-E, and the EU DSO Entity submitted their NC DR proposal to ACER on 8 May 2024. ACER then revisited key topics, reviewed the proposal, and delivered its final recommendation to the EC on 7 March 2025.

We acknowledge the challenging timeline for reviewing our original proposal and appreciate ACER's efforts to foster constructive discussions, provide an opportunity to revisit key topics, and facilitate a better mutual understanding.

While welcoming ACER's amendments, ENTSO-E wishes to highlight several remaining concerns regarding ACER's Recommendation on NC DR to the EC:

- ACER proposes reducing the minimum balancing bid size from 1 MW to 0.1 MW and lowering bid granularity (e.g. 1.1 MW). During discussions with aggregators and stakeholders, ENTSO-E acknowledged that allowing lower bid granularity offers greater value to aggregators, and therefore proposes setting the granularity of standard balancing product bids to 1 decimal.

- Regarding the minimum balancing bid size, ENTSO-E has previously explained that minimum bid size does not pose a barrier when aggregation is allowed. This was also recognised in a **recent study** by DG COMP, which stated that "Barriers for demand response participation in electricity markets and State aid support". On page 42, the study says: "the recommendation is to maintain minimum bid sizes in the order of MW and in the meantime ensuring aggregation". ENTSO-E therefore proposes keeping the minimum bid size unchanged. Allowing only one bid per BSP below 1 MW would limit operational risks for the TSO-run balancing platforms, but filtering bids adds complexity. Additionally, TSOs would need to assess the reliability of locally steering and monitoring aFRR provision for smaller resources. Thus, lowering the minimum bid size of standard balancing products below 1 MW is seen as an unnecessary complication with uncertain benefits.

- NC DR should allow sufficient implementation timelines, taking into account past challenges with the implementation timelines of other EU regulations and the need for TSOs and DSOs to jointly discuss and align proposals for national terms and conditions. The timelines proposed in ACER's recommendation (07/03/2025) are short (e.g. terms, conditions and/or methodologies (TCMs) for TSO–DSO and DSO–DSO coordination must be drafted 6 months after the NC DR goes into effect). Considering the large number of system operators in different Member States, these short timelines may endanger the timely delivery and implementation of NC DR. Moreover, the EU-wide harmonisation process, which ACER has proposed be undertaken concurrently with the national implementation, risks delaying the timely implementation of national terms and conditions. Further EU harmonisation is foreseen based on reporting and monitoring of the NC DR implementation (pursuant to Articles 55 and 56). ENTSO-E supports first identifying best practices and applied solutions as a starting point for further EU harmonisation. ENTSO-E is committed to creating a level playing field, which requires sufficient involvement of market participants, close coordination between system operators and regulatory authorities, and careful consideration of all provisions. This process requires adequate time for coordination and implementation, which ENTSO-E believes is currently insufficient.

ENTSO-E looks forward to continuing constructive cooperation with the EC, ACER, DSO Entity and all the relevant stakeholders to facilitate the timely adoption of NC DR.

3 Implementation progress of the FCA, CACM, and EB Regulations

3.1 FCA Regulation

The FCA Regulation, which entered into force in September 2016, sets out rules on CZC calculation and allocation in the forward time frame, typically year-ahead and month-ahead.

On the calculation side, its core elements are the establishment of a common methodology for the calculation of long-term CZC. As a result of this calculation, TSOs provide the optimal amount of long-term cross-zonal capacities for the allocation of LTTRs. On the allocation side, FCA establishes the method for explicit auctions of LTTRs.

Annex II outlines the implementation progress of this regulation, including links to all relevant documents, such as TSO proposals and ACER decisions.

In accordance with Article 9 of Regulation (EU) 2024/1747, in August 2024, the EC launched a target consultation and call for evidence to revise the electricity guideline on FCA, to which ENTSO-E submitted a response. The EC is currently conducting an impact assessment of measures to improve the ability of market participants to hedge price risks in the internal forward electricity market. This impact assessment will be completed by January 2026 and will result in the amendment of the FCA Regulation. The amended FCA Regulation will enter into force 6 months later, in June 2026, with implementation beginning immediately after. All TSOs and ENTSO-E will work on its implementation.

Long-term flow-based allocation

The TSOs and JAO have been working on the implementation of the LTFBA project to prepare for the go-live in the Core and Nordic CCRs. Several workshops have been organised to share the progress of the project and the expected results of the implementation. The LTFBA go-live is planned for the end of 2026 for the long-term yearly and monthly products for 2027. TSOs are fully committed to implementing LTFBA by November 2026 and are working intensively in cooperation with NRAs and ACER to achieve this goal.

Harmonised Allocation Rules methodology (Articles 51 and 52 of the FCA Regulation)

ENTSO-E has reviewed the HAR methodology according to Article 68(5) of the HAR. The HAR should be periodically reviewed by the SAP and the relevant TSOs (at least every 2 years involving the registered participants). All TSOs submitted HAR proposed amendments to ACER on 27 March 2025 according to the biennial update.

The current amendment proposal contains: (1) MTU-related changes; (2) changes related to registration; (3) refusal of application, suspension, and termination; (4) clarification on prices; (5) price cap publication; (6) financial-related changes; and (7) additional clarifications and corrections. ACER's decision on the proposal is expected by the end of September 2025.

3.2 CACM Regulation

The rules set by the CACM Regulation provide the basis for implementing an internal energy market across Europe in the DA and ID time frames. All the terms, conditions, and methodologies (TCMs) deriving from the CACM Regulation have been submitted and approved, and implementation is ongoing. Annex II provides tables showing the implementation progress of this regulation. TSOs are also engaging in the process of amending the CACM Regulation, providing the EC, NRAs, and Member States with the necessary technical information during the amendment process.

3.2.1 Main developments in all TSOs' deliverables

Determination of the CCRs (Article 15 of the CACM Regulation)

In 2024, the Energy Community Task Force (EnC TF) explored options for either maintaining the default CCR configurations as defined by Annex I to the adapted CACM Guideline or proposing alternative configurations. Regarding Italy–Montenegro (IT–ME) and East Europe (EE), there was no alternative proposal to the default configuration. For South-East Europe (SEE), the West Balkan Energy Community – EMS, CGES, MEPSO, NOSBiH, KOSTT, and OST – have worked with their European Union neighbours, with the help of ENTSO-E, to strengthen regional power system cooperation in SEE. While the journey has not been without challenges, all the concerned TSOs agree that a new framework for cooperation in the region is needed.

Following an intense round of bilateral and multilateral discussions facilitated by ENTSO-E, the West Balkan TSOs have agreed on a comprehensive framework for cooperation in the years to come as the best possible solution to collaborate and move forward, taking into account the needs and realities of all the countries of the region. The agreed solution will establish the geographical organisation for coordinated power system operation and the trading and auctioning of electricity, integrating West Balkan TSOs with the established areas of Central Europe and SEE. This organisation will strengthen the security of electricity supply and market integration for the whole continent, in accordance with European Union and energy community legislation. Following the ENTSO-E's 15th anniversary conference in Brussels on 4 December 2024, the West Balkan TSOs have adhered to a joint declaration describing the proposal and their commitment to make it happen. This declaration has been endorsed by TSOs from all interconnected neighbouring EU Member States. The Joint Declaration of the West Balkan Energy Community TSOs can be found **here.**

Following up on this joint declaration, on 30 January 2025, ACER sent a request to all TSOs for a proposal to amend the determination of CCRs under Commission Regulation (EU) 2015/1222 in order to include the CCRs of the energy community.

All TSOs are tasked with developing the proposal to fulfil the following requirements:

- Assign each BZ border (BZB) to one CCR.
- Ensure efficient coordinated capacity calculation and network security for all time frames and in all implementation phases by including, to the extent possible, all highly interdependent BZB and corresponding TSOs in the same CCR.
- Allow for a realistic timeline to implement coordinated capacity calculation and related capacity allocation, bearing in mind the readiness of the EnC TSOs and NEMOs, the implementation projects already in the pipeline in the various CCRs, and the challenges TSOs and NEMOs face in meeting relevant legal deadlines.

In accordance with this request, all TSOs are performing the required step to deliver by the deadline set by ACER. The draft proposal is consulted from 14 May to 14 June 2025. The final submission is expected by 31 July 2025.

Intraday gate cross-zonal gate opening and intraday cross-zonal gate closure time methodology (Article 59 of the CACM Regulation)

The current intraday cross-zonal gate opening time (IDCZGOCT) methodology proceeds from Article 59 of CACM, and was approved in 2018. Given the latest developments, according to Article 2(5)(a) EMD Regulation 2024/1747, from 1 January 2026, the intraday cross-zonal gate closure time (IDCZGCT) shall not be more than 30 minutes ahead of real time. The EMD Regulation allows for a possibility of derogation until 1 January 2029, and a further derogation of up to 2.5 years.

In accordance with the EMD Regulation, all TSOs are performing the required step to submit the proposal for amending the IDCZGOCT methodology to ACER. The draft proposal mainly focuses on the time change to 30 minutes. In accordance with the process for submitting a proposal for amendment to the methodology, the draft proposal is consulted from 24 April to 24 May 2025. The final submission is expected by 2 July 2025.

Day-ahead scheduled exchanges methodology (Article 43 of the CACM Regulation)

The scheduled exchange calculation (SEC) methodology is a regional methodology according to CACM Article 49(7). The SEC is an optimisation problem built into the DA market coupling algorithm. This process generates the so-called commercial flows on interconnectors as an output of the DA algorithm alongside net positions and prices, which are produced by a separate optimisation problem within the market coupling process.

With the MTU in the DA market coupling process transitioning from 60 to 15 minutes, initially expected in Q1 2025, the algorithm required performance enhancements to handle the larger data volume and deliver timely results. ACER approved the amendment proposal introduced by TSOs in Q2 2024 in its decision of 25 September 2024.

Congestion income distribution for TSOs affected by allocation mechanisms with cross-CCR impact (Article 73 of the CACM Regulation)

On 21 December 2023, ACER published its decision approving the amendment of the congestion income distribution (CID) methodology for European electricity markets in accordance with Article 73 of the CACM Regulation. This methodology addresses how to manage unintuitive flows caused by allocation constraints (AC) and AHC through the virtual hub approach. By implementing this approach, the impact of allocation mechanisms (non-intuitive flows) is overcome, and congestion income is directed to the areas actually experiencing congestion.

In accordance with the CACM CID methodology, TSOs mutually affected by allocation mechanisms with cross-CCR impact in SDAC or IDA (e.g. AHC or AC) are jointly developing, testing, and validating the algorithms, tools, and procedures for calculating congestion income on their BZB by June 2025.

JAO has been designated to develop an integrated tool for calculation, distribution, and invoicing of CID for TSOs affected by allocation mechanisms with cross-CCR impact. The tool is planned to be ready by March 2026. For the period until March 2026, TSOs will perform the congestion income calculation and redistribution manually.

Core flow-based market coupling project

As requested by the Core DA CCM, by the end of March 2025, Core TSOs had completed the technical preparations for implementing AHC in capacity calculation and published the requested analysis to assess its impact. The go-live and full implementation of the Core AHC is subject to SDAC readiness, with an indicative timeline between Q4 2025 and Q3 2026, contingent on the evaluation of the DA algorithm's performance. This evaluation is expected after the switch to the 15-min MTU in the DA market, which is currently planned for October 2025.

In May 2024, Core ID capacity calculation (IDCC) with available transfer capacity (ATC) extraction for IDA 2 (IDCC(b)) was implemented, followed by the capacity calculation with ATC extraction to IDA 1 (IDCC(a)) in June 2024. This represents a major milestone, as capacities are now recalculated using a more recent and thus more accurate grid model. The next phase of Core ID CCM implementation is IDCC(c), to provide updated capacities to the market on the morning of the delivery day. The go-live is planned for June 2025, preceded by an external parallel run. In January 2025, Core TSOs submitted a fourth amendment to the Core ID CCM that includes changes related to the IDCC(c). This fourth amendment has been approved by the Core NRAs. The TSOs are investigating potential improvements in the capacities to the ID market. The report on the analysis is scheduled for delivery to ACER and NRAs beginning of June 2025.

In 2025, Core TSOs plan to submit the fourth DA CCM proposal and fifth ID CCM proposal for amendment. Public consultations on the two amendments are expected in or shortly after summer.

EirGrid and the System Operator for Northern Ireland (SONI) formally adhered to the Core Cooperation Agreement in July 2024 and January 2025, respectively. The commercial operations for the Celtic Interconnector are expected to commence by Q4 2026 – Q1 2027.

The Core TSOs are committed to implementing scenario-based FB long-term capacity calculation (LTCC) by November 2026. This implementation will be carried out in parallel with the implementation of LTFBA within JAO.

Nordic flow-based market coupling project

The go-live of FB capacity calculation for the DA time frame in the Nordics took place on 29 October 2024. All results and public material from the external parallel run are available at the N-RCC website, and the FB domain is published daily at the JAO Publication Tool.

Based on the results from the first months with FB, larger flows have been enabled in the Nordics compared to the corresponding periods from the previous years, demonstrating that FB enables more efficient grid utilisation than capacity calculation based on net transfer capacity (NTC). The north-to-south flows through the Nordics are higher compared to previous winters, and the average and maximum flows are also larger on other borders, such as SE3–NO1, FI–SE3, and from NO5 and NO1 to NO2.

In February 2025, the Nordics switched to a new, improved tool for ATC extraction (ATCE) of capacities to the ID market, which was necessary to accommodate the transition to the 15-min MTU on the ID and DA markets. ATCE results produced with the new tool were provided in parallel with production for the period from 7 October to 7 December 2024, allowing for the comparison of outputs from the two tools.

The Nordic TSOs are working on a follow-up report on the implementation of FB. The Nordic NRAs have requested that the TSOs deliver a report with 6 months of data on the actual effects of the ID ATCE implementation, compared to the expected outcome. The report will be submitted by the end of June 2025.

Nordic TSOs, along with N-RCC, have initiated a project to implement FB on ID. The indicative timeline for implementing FB in IDAs is early 2027, aligned with pan-European development.

The Nordics are currently working on implementing LTCC (FB). The Nordic Y-1 FB capacity calculation is currently undergoing development and testing for Y-1, with finalisation expected by September 2025 and a planned go-live at the end of October 2025 – 12 months after the implementation of FB on the DA market. Similarly, the M-1 FB capacity calculation is expected to go live in Q1 or Q2 2026.

Bidding zones review

On 28 April 2025, the European electricity TSOs released a report on the BZ Study, in which the TSOs within the electricity markets of the Central Europe and Nordic regions evaluated 14 alternative BZ configurations specified by ACER (1,3).

A BZ is a geographical area within the electricity market where electricity can be bought and sold without considering physical grid limitations. The BZ review aims to establish optimal BZ configurations in Europe to maximise economic efficiency and cross-zonal trading opportunities while maintaining security of supply.

The report contains two proposals – one for Central Europe and one for the Nordic region – to help Member States decide whether to amend or maintain current BZ configurations. This study was conducted in accordance with EU regulation (2).

Conclusions in the BZ report

According to the bidding zone review (BZR) methodology defined by ACER, TSOs were requested to assess 14 alternative configurations based on 22 criteria grouped into four categories: network security, market efficiency, BZ stability and robustness, and the energy transition. According to this methodology, the BZ configurations were ranked using the "economic efficiency" criterion.

The results of the economic efficiency criterion of alternative BZs are as follows:

- For the Nordic Region: None of the studied alternative BZ configurations provide greater economic efficiency. The result shows a negative change in economic efficiency for the configurations ranging from €2 million to €35 million compared to the status quo for the target year 2025.
- For the Central Europe Region:
  - The simulation results show higher economic efficiency for all German–Luxembourgish split configurations (ranging from €251 million to €339 million for the 2025 target year), with the split of Germany–Luxembourg into five BZs showing the greatest economic efficiency among the analysed alternative configurations.
  - The Dutch split configuration also shows a slight positive effect on economic efficiency (€9 million for the 2025 target year).
  - The French and Italian alternative configurations show a negative effect in economic efficiency.

The report includes two TSO proposals (one from Central Europe TSOs and one from Nordic TSOs) on the future configuration of BZs in Europe, which are:

- The Nordic TSOs propose maintaining the current BZ configuration in Sweden, as the report shows a negative monetised benefit for all analysed Nordic configurations compared to the status quo.
- For the Central Europe TSOs, the simulation results indicate that the configuration with the highest positive monetised benefit in relation to criterion four (economic efficiency) compared to the status quo would be the split of Germany–Luxembourg into five BZs. The Central Europe TSOs' proposal emphasises that this result stems from the BZR methodology defined by ACER and does not consider additional important aspects. Therefore, it should not be viewed in isolation but rather alongside certain considerations that require thorough assessment before any final decision by any Member State(s) affected by a potential split in the future BZ configuration, as these factors could significantly influence the interpretation and outcomes of the BZ study conducted by the TSOs.

Stakeholder engagement on the BZ review

Stakeholder expertise is essential for any discussion of a fundamental market design element, such as the adaptation of BZ configurations. ENTSO-E and the TSOs engaged with a broad range of stakeholders from the outset of the BZ study, including the Bidding Zone Review Consultative Group (BZR CG), Market European Stakeholder Committee (MESC), as well as through multiple public workshops and a public consultation.

- The BZR CG comprises representatives from 17 stakeholders, including European market parties' associations, national market parties' associations from BZs of active bidding zone review regions (BZRRs), as well as European research institutes and think tanks. In the second part of 2024, meetings were held with the BZR CG on 11 July and 5 November 2024.

- Pursuant to Article 17 (4) of the BZR methodology, the TSOs organised a public consultation between 19 July and 4 September 2024 to gather stakeholder feedback on the following subjects:
  - Market liquidity and transaction costs
  - Transition costs
  - Measures to mitigate negative impacts
  - Practical implementation considerations

On 20 August 2024, a public webinar on the BZR public consultation was organised during the public consultation period.

- To facilitate stakeholder engagement, ENTSO-E and TSOs organised a webinar on 6 May 2025 to present and discuss the outcomes of the BZ study.

3.2.2 Main developments in ENTSO-E deliverables

Technical report on the current bidding zone configuration for the 2021–2023 period

On 24 February 2025, ENTSO-E published the technical report on the current BZ configuration for the 2021–2023 period. The ENTSO-E Bidding Zone Configuration Technical Report provides transparent and factual information on congestion status across the European Union, flows scheduled outside the market, and the costs of these congestions, and includes the Clean Energy Package's 70 % minimum capacity assessment.

The report is a key input to the efficiency assessment of the current BZ configuration performed by ACER. An adequate BZ configuration is a crucial factor for efficient congestion management and well-functioning markets.

3.2.3 Main developments in NEMOs' deliverables

CACM Annual Report

On 19 September 2024, the All NEMO Committee organised its second Annual Conference. Part of this conference was dedicated to the key findings from the **CACM Annual Report 2023**, which was delivered on 13 September 2024. The report focused on demonstrating the safe navigation of an energy crisis, showcasing the effectiveness of market coupling during difficult times.

Algorithm methodology

At ACER's request, NEMOs also amended the algorithm methodology Art 37 to consider the requirements submitted by the TSOs for the co-optimisation of balancing energy. Following NEMOs' submission to ACER on 24 November 2023, ACER made revisions to the NEMOs' initial proposal and published its **decision** on the amended methodology on 23 September 2024. The **updated methodology**, particularly regarding the DA coupling algorithm, enables the investigation of a co-optimised allocation of CZC ("co-optimisation"). This approach would allow efficient sharing of the available CZC between energy trading and exchanges linked to balancing services, facilitating the integration of balancing capacity markets. Discussions between ACER, NEMOs, and TSOs are ongoing, with current efforts focused on R&D to enable a clearer definition of the concept.

Cost report

NEMOs and TSOs developed the **CACM Cost Report 2023**, published on 24 July 2024, which presents a comprehensive overview of expenditures related to the development of market coupling in Europe.

Single day-ahead coupling product methodology

ACER issued its **decision** on SDAC products on 25 September 2024. The amended methodology, following NEMOs' proposal, focuses on (1) enabling the implementation of 15-min MTU products into the SDAC, (2) removing entry barriers for market participants trading 15-min MTU products, and (3) allowing them to buy and sell electricity for each 15-minute period, enhancing market flexibility.

Single intraday coupling product methodology

NEMOs conducted a public consultation on a proposal to amend the single intraday coupling (SIDC) methodology through 23 September 2024. Afterwards, the proposal was formally submitted to ACER for a decision. The amendments are related to 15-min MTU product adoption, IDA activation, and the introduction of scalable complex orders.

Harmonised maximum and minimum clearing price methodology

According to CACM Article 41, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices (HMMCP) to be applied in all BZs that participate in SDAC. CACM Article 54 stipulates that a similar proposal shall be developed for SIDC. The proposals shall take into account an estimation of the value of lost load.

In February 2025, NEMOs shared with all TSOs their proposal for amending the HMMCP methodologies. During Q1–Q2 2025, all NEMOs held a public consultation, with all TSOs providing formal feedback.

HMMCP methodologies showcase the need for strong cooperation between NEMOs and TSOs to ensure the effective functioning and operation of market coupling in Europe.

3.2.4 Single day-ahead and intraday coupling observership and non-disclosure agreement

The CACM GL requires that TSOs, ENTSO-E, power exchanges (PXs), and market operators or PXs acting s NEMOs to cooperate and exchange information to fulfil the obligations set out in the CACM GL for completing the single DA and ID coupling. To protect the exchange of confidential information, the Single Day-Ahead and Intraday Coupling Observership and Non-Disclosure Agreement (CACM Global NDA) went into effect on 23 February 2016, replacing individual NDAs from early implementation projects.

Following up on the information presented in the previous edition of this report (ENTSO-E Market Report 2024), this section provides an update on the new parties that have joined the CACM Global NDA between March 2024 and April 2025. Importantly, in accordance with Article 8 of the CACM Global NDA, all CACM Global NDA parties must give their consent to the adherence of a new party.

On the basis of the above-mentioned Article 8, the following parties adhered to the CACM Global NDA during the period from March 2024 to April 2025:

a. 16 October 2024: Operatul Pietei de Energie M. SRL ("OPEM"), the operator of the electricity market in the Republic of Moldova

b. 14 January 2025: Bursa Shqiptare Energjisë Elektrike sh.a ("ALPEX"), the entity responsible for managing and operating the organised electricity markets within the Albanian BZ

c. 22 January 2025 : Moldelectrica, the TSO for the power system of the Republic of Moldova

d. 7 April 2025: Operator Sistemi Transmisioni dhe Tregu sh.a. ("KOSTT"), an established Electricity Transmission and Market Operator

Table 3.1 lists all parties under the CACM Global NDA (through April 2025) and the date when each party became part of the agreement.

Name of party	Member since
Affärsverket Svenska Kraftnät	23 February 2016
Amprion GmbH	23 February 2016
Austrian Power Grid AG	23 February 2016
Britned Development Limited	23 February 2016
Creos Luxembourg S.A	23 February 2016
Elia System Operator NV/SA	23 February 2016
Energinet Elsystemansvar A/S	23 February 2016
Fingrid Oyj	23 February 2016
National Grid Interconnectors Limited	23 February 2016
Red Eléctrica de España, S.A.U.	23 February 2016
REN – Rede Eléctrica Nacional, S.A.	23 February 2016
RTE Réseau de transport d'électricité	23 February 2016
Statnett SF	23 February 2016
TenneT TSO B.V	23 February 2016
TenneT TSO GmbH	23 February 2016
TransnetBW GmbH	23 February 2016
50Hertz Transmission GmbH	23 February 2016
Vorarlberger Übertragungsnetz GmbH	23 February 2016
Elektroenergien Sistemen Operator EAD	23 February 2016
Swissgrid AG	23 February 2016
Cyprus TSO	23 February 2016
ČEPS a.s	23 February 2016
Elering AS	23 February 2016
National Grid Electricity Transmission plc	23 February 2016
SONI Limited	23 February 2016
Moye Interconnector Limited	23 February 2016
Independent Power Transmission Operator S.A	23 February 2016
Croatian Transmission System Operator PLC.	23 February 2016
MAVIR – Hungarian Independent Transmission Operator Company Ltd	23 February 2016
EirGrid plc	23 February 2016
Landsnet hf	23 February 2016
Terna – Rete Elettrica Nazionale S.p.A	23 February 2016
Litgrid AB	23 February 2016
AS "Augstsprieguma tīkls"	23 February 2016
CGES AD	23 February 2016
MEPSO – Operator na elektroprenosniot sistem na Makedonija AD	23 February 2016
Polskie Sieci Elektroenergetyczne S.A	23 February 2016
Compania Naţională de Transport al Energiei Electrice Transelectrica SA	23 February 2016
EMS – JOINT STOCK COMPANY Elektromreža Srbije BeLGRADE	23 February 2016
Slovenská elektrizačná prenosová sústava, a.s	23 February 2016
ELES, d.o.o, sistemski operater prenosnega elektroenergetskega omrežja	23 February 2016
SP Transmission Limited	23 February 2016
Scottish Hydro Electric Transmission plc	23 February 2016
APX Power B.V. and APX Commodities Ltd.	23 February 2016
Belpex NV	23 February 2016
Croatian Power Exchange Ltd.	23 February 2016
EPEX SPOT SE	23 February 2016
Gestore dei Mercati Energetici S.p.A	23 February 2016
Nord Pool AS	23 February 2016
OMI – Polo Español S.A.	23 February 2016
OTE A.S.	23 February 2016
HEnEX S.A (LAGIE legal successor)	23 February 2016
HUPX Hungarian Power Exchange Company Limited by Shares	23 February 2016
EirGrid plc	23 February 2016
Towarowa Giełda Energii S.A.	23 February 2016
Operatorul Pieţei de Energie Electrică şi de Gaze Naturale SA	23 February 2016
OKTE a.s	23 February 2016
BSP Regional Energy Exchange LLC	23 February 2016
SONI Limited	23 February 2016
Independent Bulgarian Energy Exchange EAD	23 February 2016
EXAA Abwicklungsstelle für Energieprodukte AG	23 February 2016
SEEPEX	13 June 2016
Nemo Link Limited	26 July 2017
Operatori i Sistemit të Transmetimit Albania sh.a	29 January 2018
ElecLink Limited	9 March 2018
Kraftnät Åland	27 March 2019
Nasdaq Oslo ASA	1 April 2019
National Grid NSL Ltd.	28 June 2019
National Grid IFA2 Ltd.	28 June 2019
Berza elektricne energije d.o.o. (BELEN)	21 January 2020
MEMO	17 July 2021
Baltic Cable	13 August 2021
ETPA	02 August 2022
JSC MO	17 November 2022
BRM	11 October 2023
OPEM	16 October 2024
ALPEX	14 January 2025
Moldelectrica	22 January 2025
KOSTT	7 April 2025

Table 3.1: Overview of global non-disclosure agreement signatories (in chronological order, through April 2025)

3.3 EB Regulation

The EB Regulation establishes a set of technical, operational, and market rules to govern the functioning of electricity balancing markets and facilitate the integration of balancing energy markets across the EU. It establishes rules for procuring balancing capacity, allocating cross-zonal transmission capacity for cross-border trades, activating and netting balancing energy, and settling the financial obligations of BRPs and BSPs.

This section of the chapter outlines the key milestones achieved under the EB Regulation roadmap, with a focus on the development of cross-border balancing capacity procurement, progress in the ISH process, regulatory measures to mitigate high balancing energy prices, and an assessment of how the 30-minute ID GCT could impact the balancing energy procurement and activation processes.

3.3.1 Regulatory developments in balancing capacity procurement and the associated allocation of cross-zonal transmission capacity (market-based approach)

In December 2022, all TSOs submitted the proposal to harmonise the methodology for the allocation process of CZC for the exchange of balancing capacity or sharing of reserves per time frame (HCZCAM), in accordance with Article 38 (3) of the EB Regulation. This methodology combines co-optimised and market-based allocation processes and involves balancing capacity procurement between BZs, occurring 1 day before the capacity is provided.

While ACER approved the methodology in July 2023, ACER simultaneously requested specific amendments for the market-based allocation process. These amendments particularly focused on the governance of balancing capacity platforms, maximum volume limits for the exchange of balancing capacity, and CID provisions.

Following a **public consultation**, all TSOs submitted the amended HCZCAM to ACER in July 2024, and ACER issued its decision on 30 January 2025.

Additionally, as required by the HCZCAM, all TSOs finalised and submitted the set of requirements (SoR) in March 2024, defining the market-based cross-zonal capacity allocation optimisation function (CZCAOF) software specifications. These specifications were handed over to the **COBRA** project. COBRA project TSOs are currently laying the groundwork for implementing the CZCAOF across platforms and applications, in line with the HCZCAM and Article 41 of the EB Regulation.

3.3.2 Regulatory developments on the co-optimised approach

The concept of co-optimisation, as outlined in Article 40 of the EB Regulation, aims at an optimal allocation of CZC through a joint procurement of energy and balancing capacity as part of the SDAC market.

In response to ACER's request in November 2022, NEMOs submitted an updated algorithm methodology to ACER on 24 November 2023. ACER's first **public consultation** on amending the electricity price coupling algorithm methodology ran from 18 January to 20 February 2024. From 27 May to 19 June 2024, ACER conducted a second **public consultation** within the ongoing proceedings with a specific focus on its **welfare study findings**. In addition, from 26 June to 15 July 2024, ACER organised a hearing procedure on ACER's preliminary position on the implementation of co-optimisation in the electricity price coupling algorithm methodology.

On 23 September, ACER **issued** **Decision No 11/2024** on amendments to the price coupling algorithm and the continuous trading (CT) matching algorithm, including common SoRs. This decision incorporated the concerns of both TSOs and NEMOs and serves as the basis for ongoing R&D on co-optimisation.

Between 2024 and November 2026, NEMOs, in cooperation with TSOs, are required to deliver three reports that cover different R&D aspects of co-optimisation. The requirements for each R&D report are outlined in Articles 4(15) and 4(16) of **Annex 1** to ACER's decision No 11/2024. In addition to the submission of these reports to ACER and NRAs, engagement with other relevant stakeholders is strongly recommended. The graph in Figure 3.1 shows the timeline for the ongoing R&D phases.

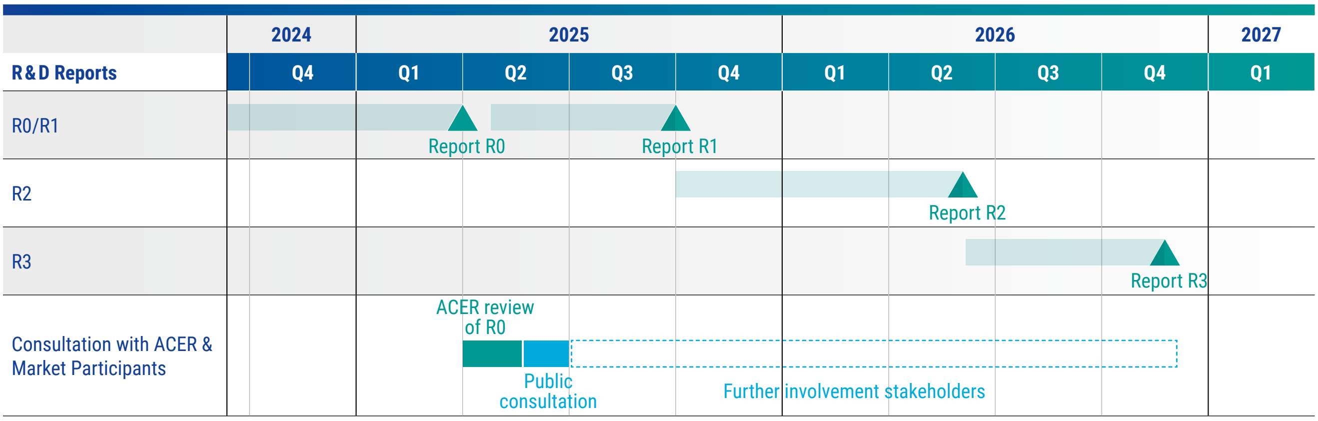


Figure 3.1: R&D timeline on co-optimisation per the plan outline in the ACER decision

Per ACER decision No 11/2024, in April 2025, NEMOs and TSOs submitted the first draft report (R0) to ACER, covering R&D on bidding products, bidding formats, and prices. In May 2025, the **public consultation** with market participants on the report was launched. The documents published for consultation include the draft report (R0) and the assessment of the draft report conducted by NEMOs, in cooperation with TSOs, as well as ACER's assessment of the draft report.

NEMOs and TSOs will carefully review and consider the feedback from the public consultation and issue an updated version of the R1 report, which will provide a selection of options for product and bid design to be evaluated in the next R&D phase. Subsequently, the R2 report will evaluate, among other aspects, the technical feasibility of the options selected in R1.

3.3.3 European implementation of imbalance settlement harmonisation methodology

In July 2020, ACER decided on the ISH methodology under Article 52 (2) of the EB Regulation, aiming to further specify and harmonise imbalance settlement rules. The ISH methodology was scheduled for national implementation by January 2022, with the possibility of further derogations where necessary.

In line with Regulation (EU) 2019/943, the EB Regulation establishes a mandatory 15-minute ISP for calculating BRPs' imbalances, as outlined in Article 53 of the EB Regulation. The ISH methodology standardises the number of additional price components that each TSO may apply in its imbalance price calculation and harmonises the conditions for applying dual imbalance pricing. Additionally, the ISH sets minimum time intervals for NEMOs to provide market participants with trading opportunities in both DA and ID markets.

The 15-minute ISP must either:

- Be implemented within 3 years of the EB Regulation's entry into force (by January 2021);
- Be subject to derogation (with implementation required by 1 January 2025 at the latest); or
- Be subject to an exemption for an entire synchronous area (SA), in which case the ISP shall remain 30 minutes (with implementation by January 2025 at the latest).

The progress of 15-minute ISP implementation and the application of the ISH methodology is detailed in Table 1 – BRP T&Cs. Since the publication of the 2024 Balancing Report, 26 TSOs have successfully implemented the 15-minute ISP following their derogation, doubling the number of implementations in 1 year.

After the implementation of this methodology, each connecting TSO applying a self-dispatching model shall calculate, in each imbalance area for each ISP, a single final position for each BRP equal to the sum of all scheduling units' external and internal commercial trade schedules. Each connecting TSO applying a central dispatching model shall calculate, in each imbalance area for each ISP, a single final position for each scheduling unit of each BRP equal to the sum of this scheduling unit's external and internal commercial trade schedules of each scheduling unit (under Article 54 (3)(c) of the EB Regulation).

Option	Status
Was the 15-minute ISP implemented by 1 January 2025?	Implemented: 26 Exemption: 4
Has your TSO made use of additional components following ISH methodology Art. 9(6) as of 1 January 2025?	Yes: 26 No: 7
Has your TSO made use of dual pricing as of 1 January 2025?	Yes: 5 No: 26

Table 3.2: BRP T&Cs

3.3.4 Regulatory developments on high-price mitigation measures

Due to the developments and observations on balancing energy markets integrated via the European balancing energy platforms outlined in the **Balancing Report 2024**,[1] all TSOs identified that amendments to the regulatory framework are needed to ensure efficient market functioning. Therefore, all TSOs found it necessary to propose amendments to the pricing methodology and IF for the European platform for the exchange of balancing energy from aFRR (aFRR IF).

The proposed measures aimed to address potential inefficiencies across the three fundamental pillars of price formation:

- demand side (voluntary price elastic aFRR demand)
- supply side (maximum and minimum prices for balancing energy)
- price determination (aFRR CBMP better reflecting the activated aFRR)

All TSOs submitted the proposed amendments to ACER on 7 February 2024.

On 5 July 2024, ACER issued:

- **Decision No 08/2024** on the second amendment to the IF for a European platform for the exchange of balancing energy from FRR with automatic activation pursuant to Article 5(2)(b) and Article 5(6) of Regulation (EU) 2019/942, and Article 5(1), Article 5(2)(a), Article 6(3), and Article 21(1) of Commission Regulation (EU) 2017/2195 (EB Regulation); and

- **Decision No 09/2024** on the second amendment to the methodology for pricing balancing energy and CZC used for the exchange of balancing energy or operating the imbalance netting (IN) process (Article 30(1) of EB Regulation).

ACER approved all TSOs' proposals subject to the amendments described in ACER's decisions.

With regard to the voluntary price elastic aFRR demand, ACER mainly followed all TSOs' proposal but introduced limitations on the application of elastic aFRR demand. Specifically, a TSO applying elastic aFRR demand cannot change thresholds during operation, although it might be necessary to ensure balance, if not predefined in the formula through local rules. Any deviation from the formula defined in local rules can occur only in the event of a change of system state. On the PICASSO side, the elastic aFRR demand functionalities of the activation optimisation function (AOF) were implemented within the legal deadline provided by ACER decision No 08/2024. The Belgium TSO (Elia Transmission Belgium) connected to PICASSO on 26 November 2024, becoming the first TSO to apply elastic aFRR demand.

With regard to harmonised maximum/minimum balancing energy prices (HMMBEP), ACER rejected all TSOs' proposal to decrease the transitory limit from ±€15,000/MWh to ±€10,000/MWh. The transitory limit applies until July 2026. For the period thereafter, ACER approved a permanent price limit of ±€15,000/MWh and established a price adjustment mechanism requiring TSOs to implement an automated process to adjust the maximum price incrementally – by +€500/MWh upward and −€100/MWh downward – when the following triggering conditions are met: in at least one BZ, the triggering conditions per direction are met for at least two ISPs (each 15 minutes) in at least 2 different days, with the second day occurring within 30 rolling days of the first):

- The mFRR cross-border marginal price (CBMP) per direction, from the MARI platform, in the MTU corresponding to the considered ISP exceeds a value of 70% of the HMMBEP applicable to the relevant direction;

- The volume weighted average of aFRR CBMPs per direction, from the PICASSO platform, of all the MTUs (4s) that are part of the considered ISP exceeds a value of 70% of the HMMBEP applicable to the relevant direction; and

- The sum of the balancing border capacity limits to or from that BZ in the MARI platform is at least equal to the sum of the volume of bids offered in the MARI and PICASSO platforms in that BZ by its largest BSP in the relevant direction.

1 See section "1.4 Regulatory developments regarding high prices mitigation measures" (pp. 13–15)

During the transitory period through July 2026, all TSOs are required to simulate the theoretical evolution of the price limits that would have occurred if the adjustment mechanism had already been applied (i.e. a dry run), which will be reported to ACER on a quarterly basis ([Quarterly Pricing Reporting]). ACER also requested bi-yearly assessments of the HMMBEP in its decision. All TSOs are currently implementing the price adjustment mechanism to ensure appropriate coordination to meet the tight deadlines (the adjustment must be communicated 7 days after the event triggers a change to the HMMBEP.

Regarding the aFRR CBMP determination, ACER followed all TSOs' proposal. In August 2024, the new algorithm for the CBMP calculation went live in PICASSO. Due to the potential distortive effects of observed aFRR CBMP price peaks on the balancing energy markets, which often correspond to a CBMP that does not reflect the value of activated aFRR balancing energy bids, all TSOs proposed a short-term solution to reduce price peaks, which was approved by ACER. Under the former conditions, the aFRR CBMP could be determined by a bid not even considered for activation by a local load-frequency controller. The amendments aimed to reduce the occurrence of short-duration price incidents by considering, within the determination of the aFRR CBMP, the local setpoints for aFRR activation.

The updated aFRR CBMP determination influences prices not only during high price situations but also generally. Figure 3.2 shows the result of the updated aFRR CBMP determination (bottom subfigure) compared to the old approach (upper subfigure). The updated aFRR CBMP determination more accurately reflects the requested aFRR (blue curve) and prevents significant price spikes (see scale of red y-axis) that do not reflect real aFRR activation requests (black dashed line). This improvement is primarily due to the proportional integral behaviour of the participating TSOs' LFCs.

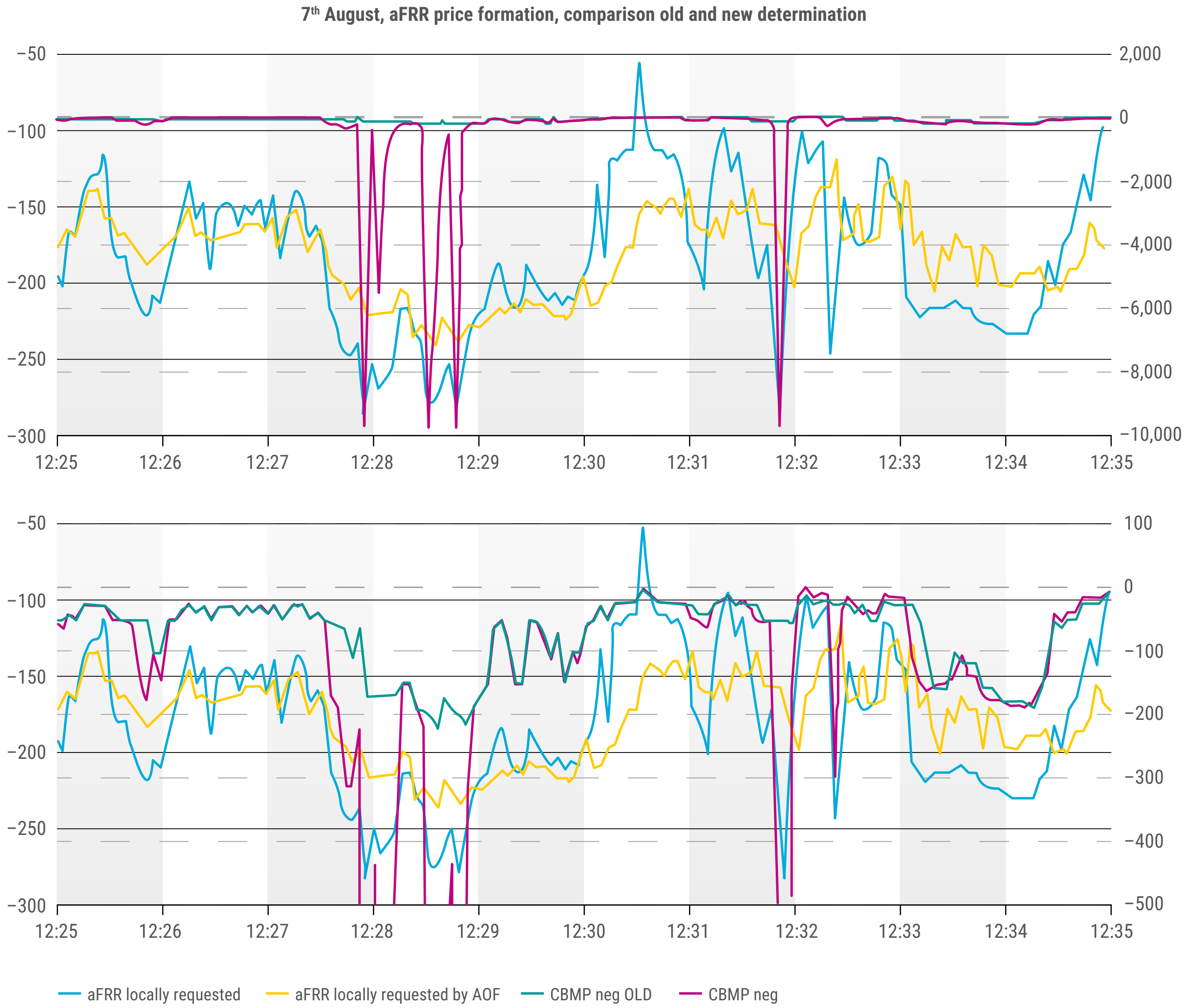
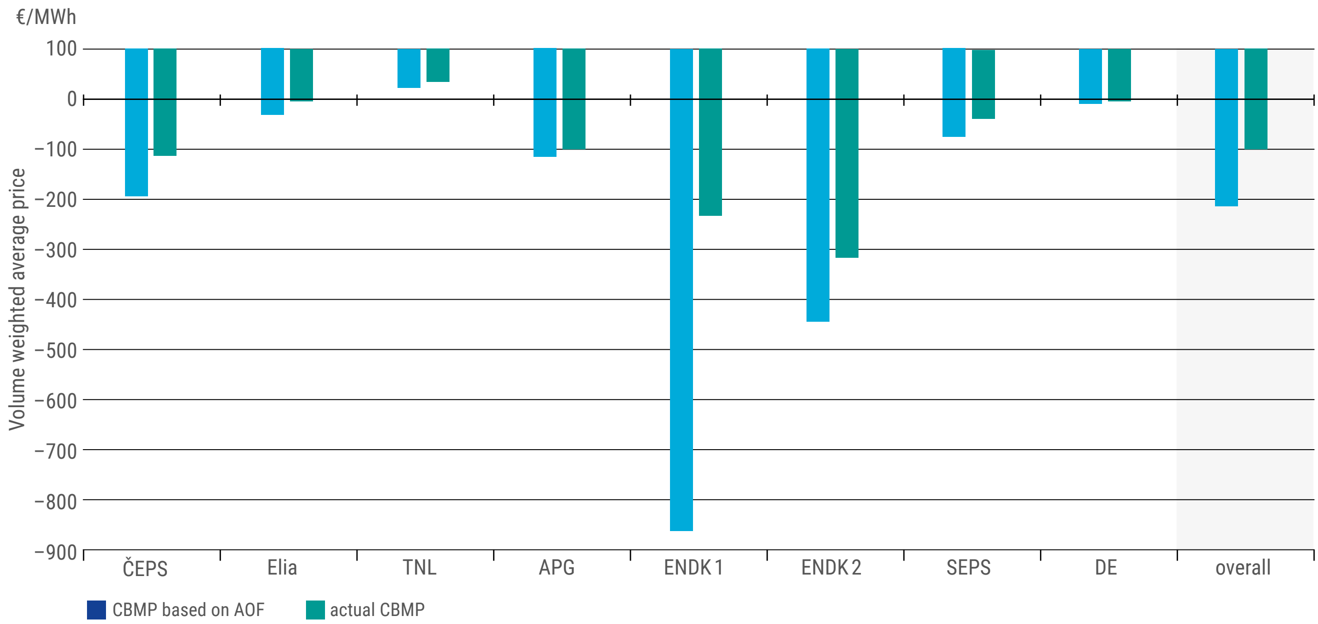


Figure 3.2: aFRR price formation: Updated aFRR CBMP determination compared to the old approach

The overview in Figure 3.3 shows the influence of the aFRR CBMP on the price level per LFC area participating in PICASSO. To show the effect of the new CBMP calculation method on the general price level, the volume weighted average price of each biding zone and per direction (upward in positive direction, downward in negative direction) is compared to the volume weighted average price based on the "old" CBMP method for the period as of 5 August 2024 (or the respective connection date) until the end of the year. Figure 3.3 shows that the general price level of the updated CBMP (green) is below the price level of the past approach (blue), confirming that the change met expectations.



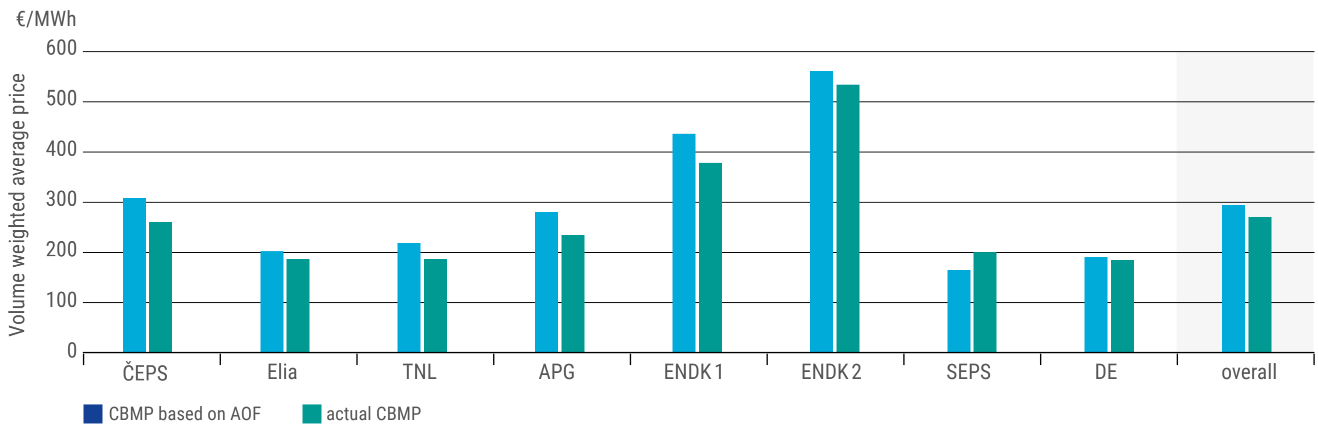


Figure 3.3: Price level of the aFRR CBMP per bidding zone participating in PICASSO

4 Forward capacity allocation

In accordance with Article 49 of the FCA Regulation,[2] as of 1 November 2018, all TSOs have appointed a JAO to act as the SAP for FCA. JAO is a joint service company currently owned by 25 TSOs[3] that hosts SAP services for TSOs.

SAP enables long-term auctions of transmission capacity and currently services 25 TSOs from 22 EU countries. The IT system is scalable on a border-by-border basis, allowing for annual, non-calendar annual, half-yearly, quarterly, monthly, weekly, weekend, daily, and ID auctions.

4.1 Governance

In accordance with Article 1 of the approved SAP methodology, all TSOs and regulatory authorities[4] bound to the FCA Regulation agreed to appoint JAO as the SAP operator. Consequently, the SAP Cooperation Agreement (SAP CA), according to Article 2(2)(t) of the SAP methodology, was developed and signed by all TSOs that issue LTTRs.

The SAP operator is governed by the SAP Council, consisting of TSOs and JAO representatives, which is the sole competent body for deciding on operational topics and budget related to the fulfilment of SAP tasks, in accordance with the FCA Regulation.[5]

Figure 4.1: Countries whose TSOs are obliged to be part of the SAP Council and are part of the SAP CA (as of May 2025)[6]

2 All TSOs' proposal of 7 April 2017 for the establishment of SAP in accordance with Article 49 of the FCA regulation and for the cost-sharing methodology in accordance with Article 59 of the FCA regulation.

3 Also includes TSOs/companies operating undersea cable interconnectors. These are: 50Hertz, Amprion, APG, ČEPS, Creos, EirGrid, ELES, ELIA, EMS, Energinet, ESO, HOPS, IPTO, MAVIR, Moyle, PSE, RTE, SEPS, Statnett, Swissgrid, TenneT DE, TenneT NL, Terna, Transelectrica, and TransnetBW.

4 Some Regulatory Authorities (those of Lithuania and Sweden) have exempted their TSOs pursuant to Article 30(1) of FCA Regulation from issuing LTTRs and therefore, according to Article 30(7) of the FCA Regulation and these TSOs, are not yet part of the SAP CA.

5 Further details on the governance structure of JAO can be found in the ENTSO-E Market Report of 2020

6 Creos does not issue LTTRs, nor commercialise any interconnector. Brexit did not have any impact on EirGrid participation as a full member of SAP CA and the SAP Council.

4.2 Operations

JAO performs all tasks in compliance with the SAP CA, the SAP methodology and the HAR.[7] As of 2025, the SAP operator organises forward capacity rights auctions at 67 BZ directional borders and provides services via a common IT system for more than 440 registered market participants.[8] Only yearly, quarterly, and monthly products are being allocated at EU borders in 2025.

A gradual shift is being observed from physical transmission rights (PTR) to financial transmission rights (FTR) options at EU borders. This tendency is supported by the fact that PTR holders on average nominate only around 5.72% of allocated rights. A broad transition to FTRs occurred in the context of the launch of FB DA market coupling in Core CCR, when a vast majority of remaining BZBs in the region switched to FTRs.

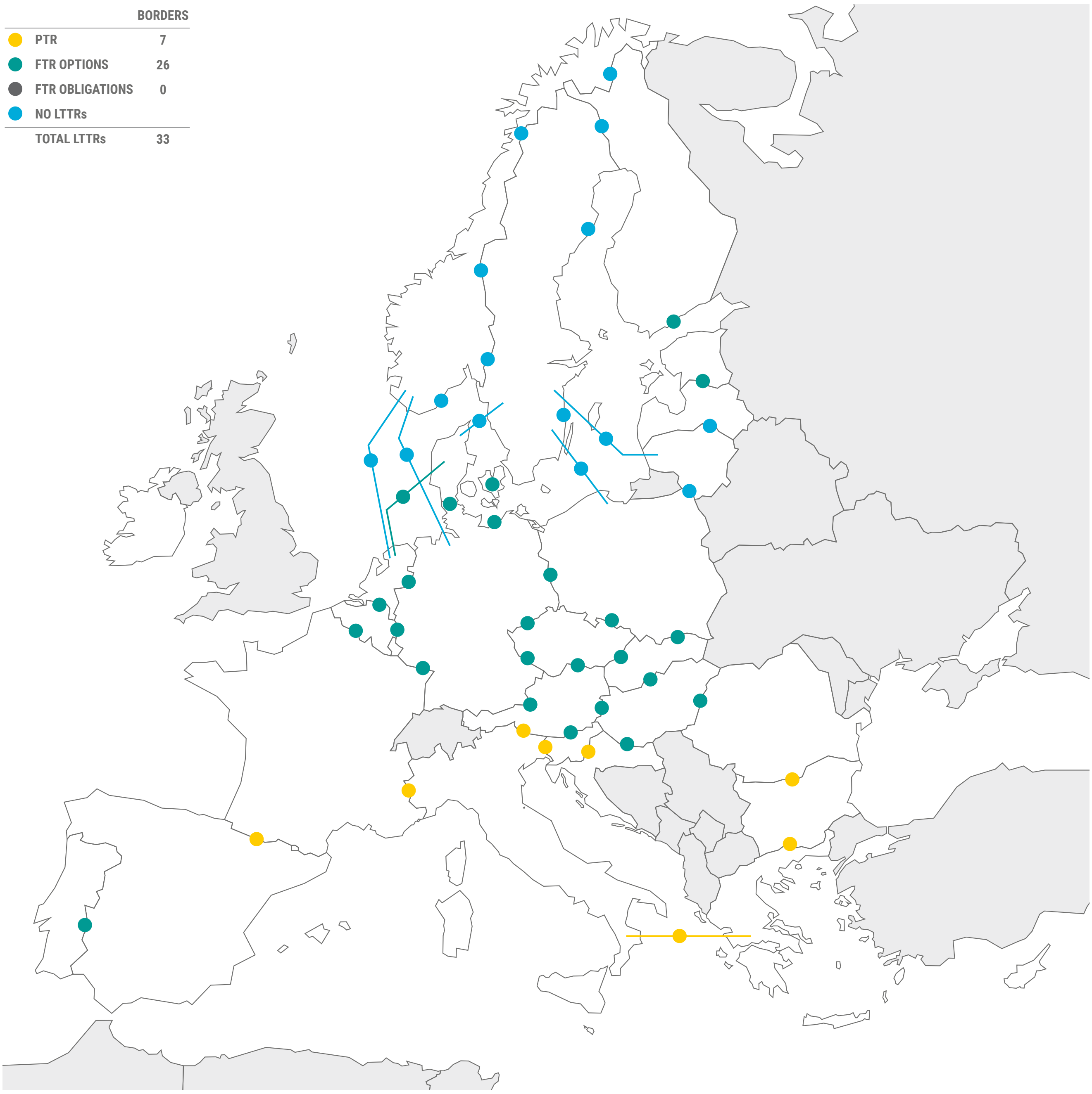


Figure 4.2: Overview of products offered at SAP (as of 2025)[9]

7 More details on SAP tasks are described in the **ENTSO-E Market Report of 2020**.

8 A detailed description of the common IT System eCAT can be found in the ENTSO-E Market Report 2019.

9 At the DE–CZ border, FTR options are offered for CZ–DE (TenneT) and CZ–DE (50Hertz). At the EE–LV and FI–EE borders, FTR options are only offered for the directions EE to LV and FI to EE.

Regarding the above-mentioned borders, in 2024, the SAP operator organised more than 841 auctions with LTTRs. A similar number is expected for 2025.

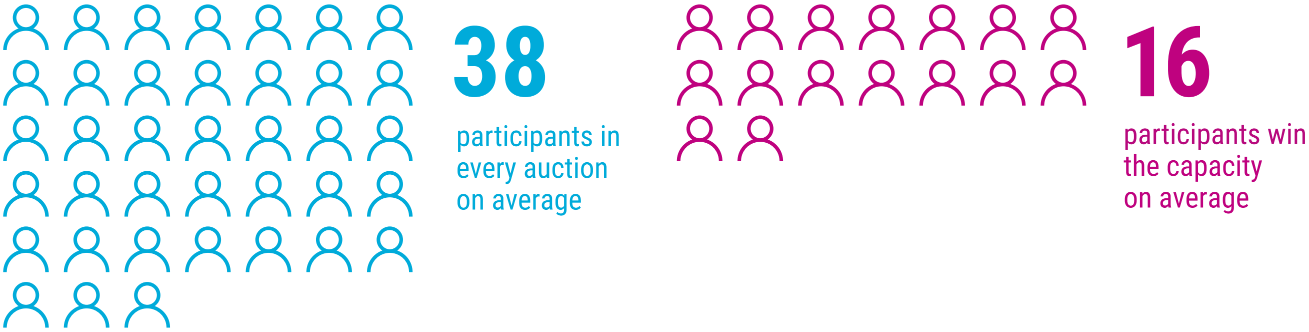


Figure 4.3: Number of participants in every auction versus number of participants that win the capacity during 2024

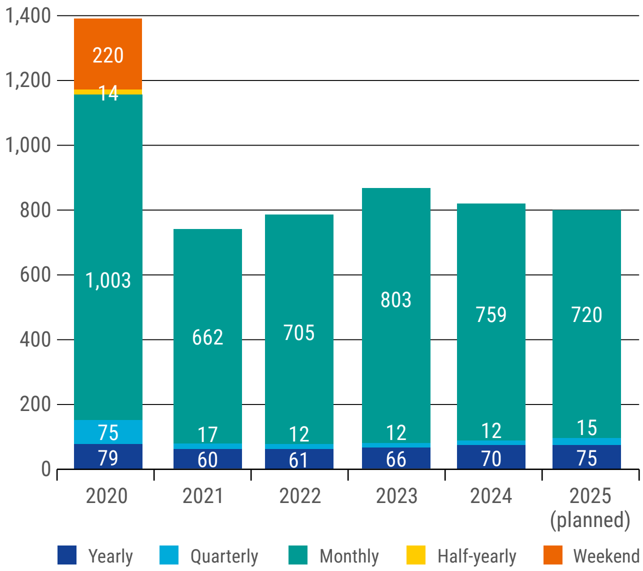


Figure 4.4: Overview of auctions

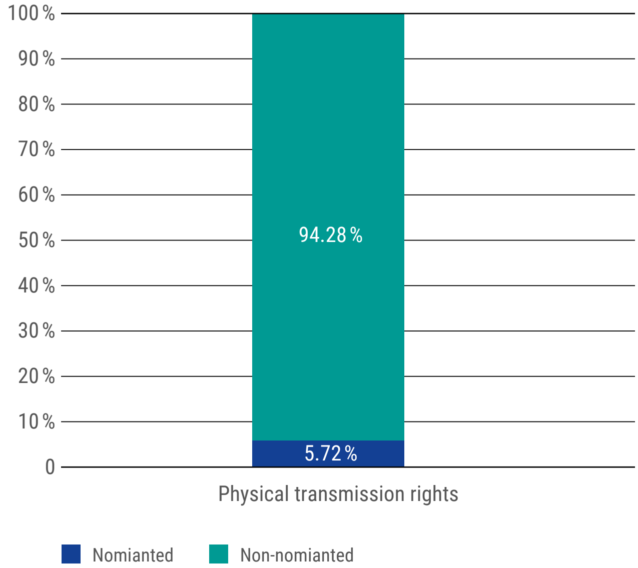


Figure 4.5: Usage (nomination) rate of long-term transmission rights

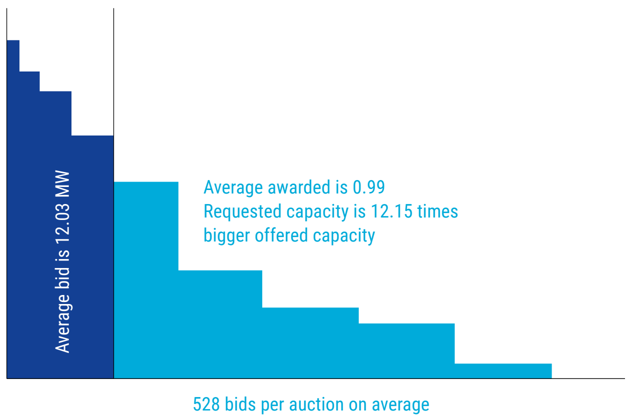


Figure 4.6: Average long-term capacity rights auction structure

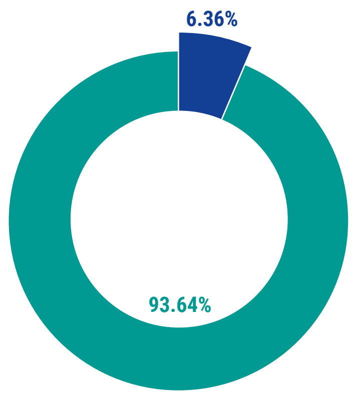


Figure 4.7: Rate of return of long-term capacity rights for reallocation at subsequent long-term auction

4.2.1 Quality of operations

The SAP Council regularly monitors the quality of operations performed by the SAP operator. More than 6,500 auctions have taken place since SAP operations began. In 2024, due to an incorrect ATC calculation for the September auction for CEEXD and upon TSO alignment, JAO conducted a second round of the auction.

To monitor the SAP operator's operation quality, the TSOs of the SAP Council calculated 23 detailed key performance indicators (KPIs) which were merged into three meta-KPIs[10] (see Table 4.1).

CATEGORIES	DETAILS
› Fulfilling reporting Obligations	› Whether data to be reported was provided to EMFIP and ACER platform in line with Transparency and REMIT Regulations and whether the data were correct
› Operational Effectiveness	› SAP system availability – Invoicing correctness – Operational incidents occurrence
› Customer Satisfaction	› User's satisfaction with JAO – SAP's effectivity in solving user's problems and requests – Website usabilty

Figure 4.8: SAP key performance indicators

Month	Fulfilling reporting Obligations	Operational Effectiveness	Customer Satisfaction	TOTAL	Quarterly Score
Jan-24	10	10	7	9	9.11
Feb-24	10	10	9	9.67	
Mar-24	10	10	6	8.67	
Apr-24	10	10	9	9.67	8.87
May-24	9.9	10	6	8.63	
Jun-24	9.9	8	7	8.3	
Jul-24	9.9	8	6	7.97	8.52
Aug-24	9.9	8	7.5	8.47	
Sep-24	9.9	10	7.5	9.13	
Oct-24	10	10	9	9.67	9.31
Nov-24	10	10	9	9.67	
Dec-24	9.8	10	6	8.6	
Jan-25	9.8	9	6	8.27	8.68
Feb-25	9.9	9	7.5	8.8	
Mar-25	9.9	9.5	7.5	8.97	

Table 4.1: Overview operation of SAP meta-KPIs (as of March 2025)

10 A more detailed description is available in the last ENTSO-E Market Report 2020

Customer interaction and satisfaction

JAO has created a platform to gather feedback and requests from users of the JAO eCAT system related to IT interfaces and other services performed. The users' expertise and views are essential for the continuous improvement of the services provided by JAO. Therefore, JAO has established the User's Group, which serves as a platform for relevant stakeholders. The User's Group comprises representatives from key European stakeholder organisations interested in participating therein while ensuring broad geographical coverage by the group.

In an annual survey that was conducted in early 2024 and is being repeated in 2025, market participants rated JAO's performance as very good. General satisfaction improved to 4.3 out of 5, from 4.0 the previous year. Scored increased in all other categories as well, except in invoicing, which remained stable.

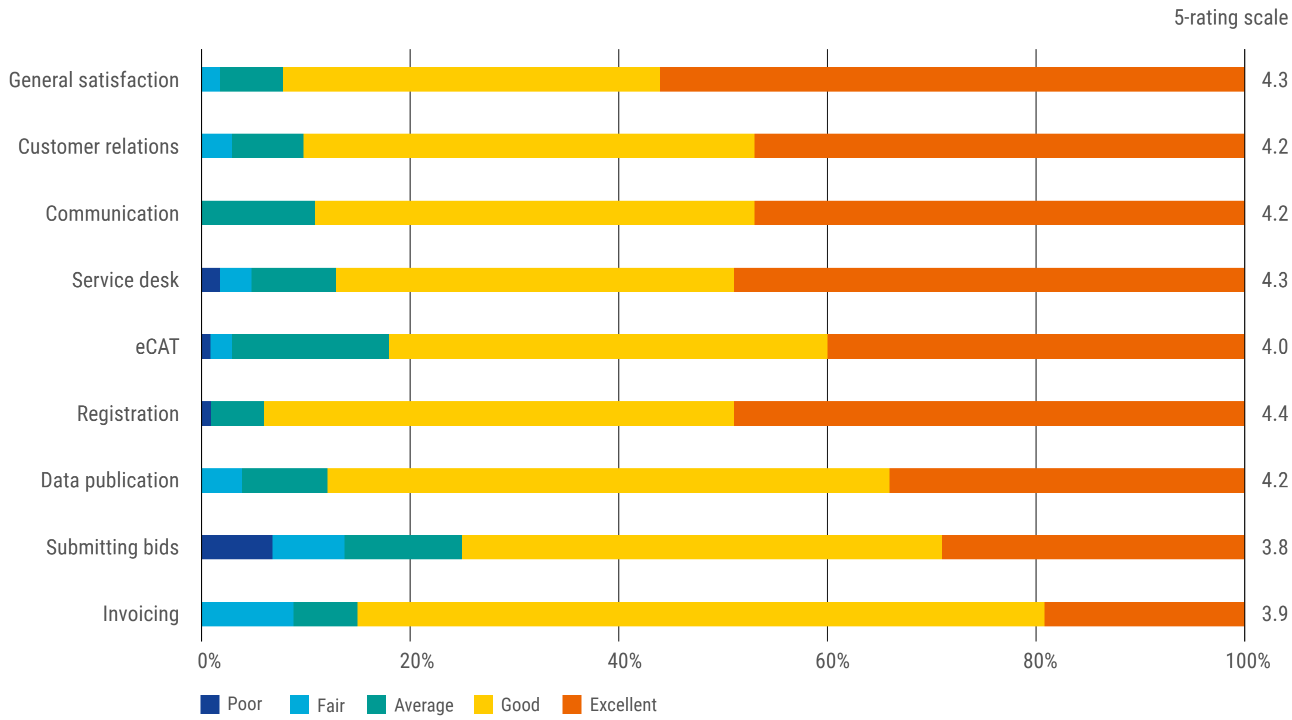


Figure 4.9: SAP customer interaction and satisfaction

4.3 Expenditures

This report provides a summary of TSOs' common costs of establishing, amending, and operating the SAP. Figure 4.10 depicts the planned and actual costs since 2018.[11] Larger investment costs are anticipated due to changes needed for FB DA and long-term allocation.

The reported establishment and development costs consist of annual depreciation and amortisation of investments to establish and develop SAP in addition to the existing tools in JAO. SAP operational costs consist of annual depreciation and amortisation of the tools and other assets used for LT auctions. They also include the financial clearing and settlement of auction revenues (including bank fees) and operational support covering the entire long-term allocation process, contact with market participants, service desk, risk management, and other related services.

Compared to SDAC/SIDC projects, the SAP costs cover the entire business chain for capacity allocation to market participants. The organisation and meeting of the SAP-Council generated no direct costs.

SAP fee principles are defined based on the SAP methodology, which is derived from all TSOs' proposal for the establishment of the SAP in accordance with Article 49 and the cost-sharing methodology in accordance with Article 59 of the FCA Regulation.

The SAP methodology is applicable to the costs of running long-term auctions on the SAP borders only, and to the relevant SAP tasks, as defined in Article 9 of the rules establishing the SAP as of October 2018 (i.e. the date of establishing the SAP).

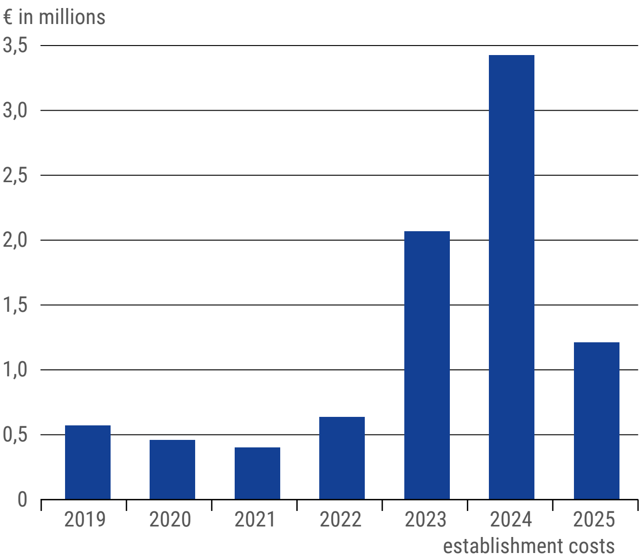


Figure 4.10: Overview of the single allocation platform for establishing and amending costs

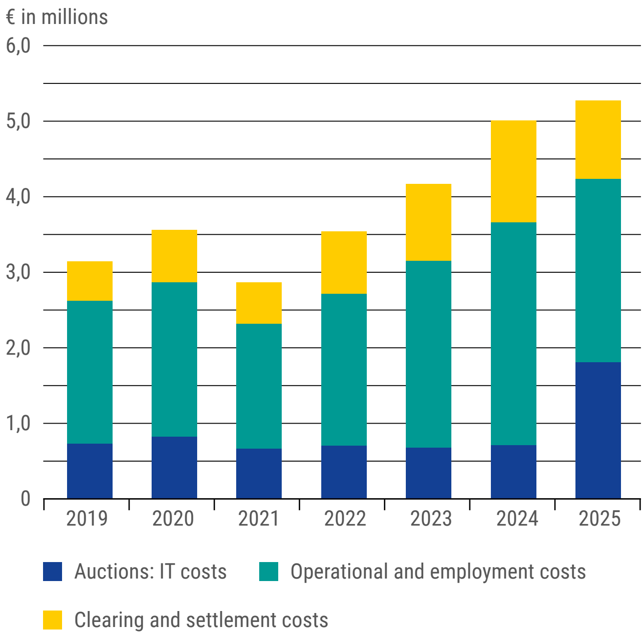


Figure 4.11: Overview of operating costs for the single allocation platform

11 In line with the regulatory guidance costs for the coupling, projects are planned and shared between TSOs and/or NEMOs as of 14 February 2017.

4.4 Evolution of services

The SAP operator has implemented and operates all obligations stemming from the FCA Regulation. All TSOs focus on the continuous improvement of SAP operator services provided to both TSOs and market participants.

4.4.1 Operations

With the go-live of the DA FBMC in the Core CCR, most of the Core CCR BZBs shifted from PTR to FTR options.

With the introduction of 15-minute DA market products, the SAP operator will also need to adapt IT tools and procedures to this new market scheme.

4.4.2 Long-term capacity calculation and allocation

The go-live of the LTFBA is planned for the end of 2026 for the long-term yearly and monthly products for 2027. This implies a delay of 1 year compared to the communication in the previous version of this report. The main reason for this delay is that certain project management decisions had to be made later than planned and no longer aligned with the IT suppliers' available resources to deliver the LTFBA function by the end of 2025. As of the writing of this report, TSOs are fully committed to implementing LTFBA by November 2026 and are working intensively in cooperation with NRAs and ACER to achieve this goal.

5 Market coupling

This chapter has been prepared in cooperation with the All NEMO Committee, which has reviewed the content and accompanying illustrations for compliance, considering confidentiality requirements. The information on costs provided by this report is a summary of the full content from the CACM Cost Report 2024 to be released by all TSOs and NEMOs later in the year.

All NEMOs and TSOs have been working in close cooperation in recent years, striving to create a more integrated European electricity market. SDAC aims to create a single pan-European cross-zonal DA electricity market. SDAC uses the DA market coupling operator (MCO) function to calculate electricity prices and matched volumes across Europe and to implicitly allocate CZC in a single auction. The algorithm used is called the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA).

SIDC aims to create a single EU cross-zonal ID electricity market. Since 13 June 2024, SIDC has enabled both cross-border CT and IDAs across Europe.

SIDC CT is based on a common IT system (XBID) with a shared order book (SOB), a single capacity management module (CMM) and a shipping module (SM). This common IT system facilitates the continuous matching of orders from market participants from several BZs, provided CZC is available.

SIDC IDAs make use of both EUPHEMIA and XBID via the intermediate system, namely IDA Central Interface Point (CIP). IDAs are organised as implicit auctions where collected orders are matched, and CZC is allocated simultaneously for different BZB. IDAs provide the ability to accumulate offers and efficiently allocate limited transmission capacity. In comparison, CT capacity is allocated on a first-come, first-served basis.

Cross-zonal capacities cannot be allocated simultaneously for IDAs and CT along the same borders. Therefore, CZC allocation within CT is suspended for a limited period, during which cross-zonal capacities are allocated via IDAs. However, continuous intrazonal trading may be allowed during IDAs, at least in BZs with more than one active NEMO.

The structure of SDAC and SIDC facilitates competition among multiple NEMOs offering trading solutions within the relevant BZs, in accordance with CACM provisions. This is made possible through the MNAs, which, although not applicable to all BZs, are implemented in certain BZs.

5.1 Governance

The joint Market Coupling Steering Committee (MCSC) was established in January 2022. Its governance structure consists of working groups (WG), mirrored between SDAC and SIDC, to enhance efficiency and ensure synergies between the projects. The sole distinction is the inclusion of an additional group under SDAC: the Simulation Facility (SF).

The dedicated Market Coupling Consultative Group (MCCG) was established in June 2022. During the reporting period, four MCCG meetings took place, ensuring regular exchange and alignment with market participants.

To improve coordination between system providers, the SDAC group "Quality Assurance and Release Management" (QARM) was established in early 2023 to further optimise MCSC's governance and DA operations.

Regarding governance changes during the period covered by this report, MCSC approved the SIDC post-go-live testing governance (consisting of the Central Testing Group and Extended Testing Group), the re-activation of the Governance taskforce (in anticipation of CACM 2.0), and the creation of the EU-GB task force as a sub-group of SDAC QARM (aiming to address on an ad hoc basis technical questions from stakeholders on the GB MC initiative). In terms of members, MCSC approved the observer status of SEEPEX (Serbian NEMO), BELEN (Montenegrin NEMO), and CGES (Montenegrin TSO) to both SIDC and SDAC.

During the reporting period, the TSO MCSC approved and signed the TSO Cooperation Agreement for Market Coupling (TCMC), merging the TSO Intraday (TCID) and Day-Ahead (TCDA) Cooperation Agreements. The TSO MCSC is now governed under a single agreement, replacing the previous dual contractual structure. This significantly streamlines and simplifies the contractual setup while also facilitating further extensions, adherence, and contract change management processes.

5.1.1 Single day-ahead coupling

In total, 32 TSOs[12] and 18 NEMOs[13] from 26[14] countries cooperate under the Day-Ahead Operational Agreement (DAOA), the agreement governing SDAC. Since November 2024, BRM[15] (Bursa Romana de Marfuri, Romanian Commodities Exchange) has become an operational member of SDAC. ETPA (Energy Trading Platform Amsterdam) is an observer of DAOA, a non-operational member until its accession.

5.1.2 Single intraday coupling

In total, 30 TSOs[16] and 17 NEMOs[17] from 26[18] countries cooperate under the Intraday Operational Agreement (IDOA), the agreement governing SIDC. With the sixth go-live wave of SIDC in May 2024, BRM went live as the second NEMO operating in the Romanian market.

The IDOA governs the pan-European SIDC and regulates the cooperation of TSOs and NEMOs regarding the establishment, amendment, and operation of market coupling. In 2024, several IDOA exhibits were amended to further develop the principles of the NEMOs and TSOs' cooperation, given the current and future development, implementation, and operation of IDAs. On 13 June 2024, IDAs were introduced in all countries cooperating in the SIDC. Notably, IDAs were introduced for cross-zonal trading in Romania in March 2025 (previously traded locally).

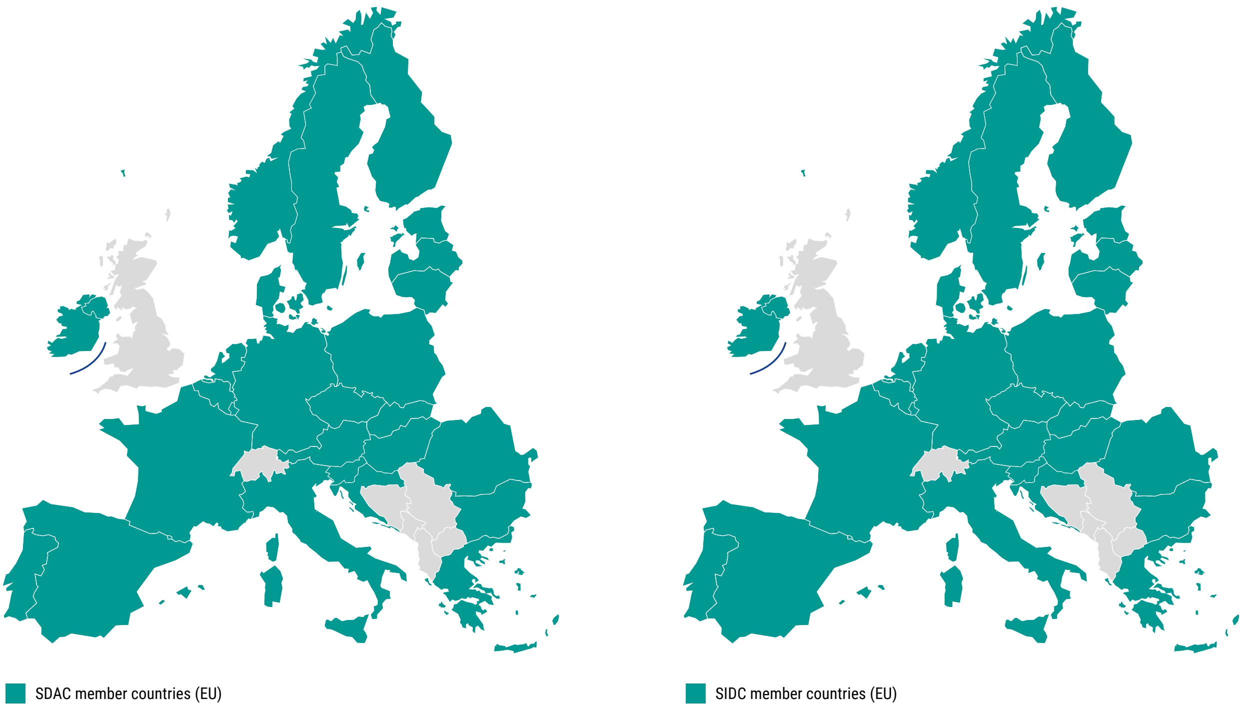


Figure 5.1: Countries of SDAC (left) and SIDC (right) (as of June 2024)

12 50Hertz, Amprion, APG, AST, Baltic Cable, ČEPS, Creos, HOPS, EirGrid, ESO, Elering, ELES, Energinet, Elia, Fingrid, IPTO, Kraftnät Åland, Litgrid, MAVIR, Transelectrica, PSE, Red Eléctrica, REN, RTE, SEPS, SONI, Statnett, Svenska Kraftnät, TenneT NL, TenneT DE, Terna, and TransnetBW.

13 BRM, BSP SouthPool, CROPEX, EirGrid and SONI acting jointly as SEMOpx, EPEX SPOT, ETPA (non-operational until accession), EXAA, GME, HEnEx, HUPX, IBEX, Nasdaq, Nord Pool EMCO, OKTE, OMIE, OPCOM, OTE, and TGE.

14 Austria, Belgium, Bulgaria, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Italy, Ireland, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Poland, Portugal, Romania, Slovenia, Slovakia, Spain, and Sweden.

15 Bursa Romana de Marfuri (Romanian Commodities Exchange).

16 50Hertz, Amprion, APG, AST, ČEPS, Creos, HOPS, EirGrid, ESO, Elering, ELES, Energinet, Elia, Fingrid, IPTO, Kraftnät Åland, Litgrid, MAVIR, Transelectrica, PSE, Red Eléctrica, REN, RTE, SEPS, Statnett, Svenska Kraftnät, TenneT NL, TenneT DE, Terna, and TransnetBW.

17 BRM, BSP SouthPool, CROPEX, EirGrid and SONI acting jointly as SEMOpx, EPEX SPOT, ETPA, GME, HEnEx, HUPX, IBEX, Nord Pool EMCO, OKTE, OMIE, OPCOM, OTE, and TGE.

18 Austria, Belgium, Bulgaria, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Italy, Ireland, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Poland, Portugal, Romania, Slovenia, Slovakia, Spain, and Sweden.

5.2 Operations

The main milestone in 2024 was the IDA launch.

The figure below shows the relationship between the normal operation processes on SDAC and SIDC with the IDAs.

In SDAC, the GCT occurs at noon on D-1 for delivery day D. In SIDC, trading is continuous, with the gate opening time (GOT) starting at D-1 15:00 for delivery day D. During the IDAs, for each auction, cross-border SIDC trading is halted for 40 minutes (20 minutes before GCT and 20 minutes after GCT). For IDA1 (GCT D-1, 15:00) and IDA2 (GCT D-1, 22:00), market participants can submit orders for the next delivery day D; while for IDA3 (GCT D, 10:00), the auction and allocation period take place on the same day, delivery day D. The allocation period for IDA1 and IDA2 is 24 hours long (00:00–24:00), while for IDA3, it is only 12 hours long (12:00–24:00).

Overall, operations remained robust throughout 2024, with the exception of two partial decoupling incidents within SDAC in June and July. These were thoroughly addressed by the projects, with ongoing evaluation of potential process improvements and mitigation measures.

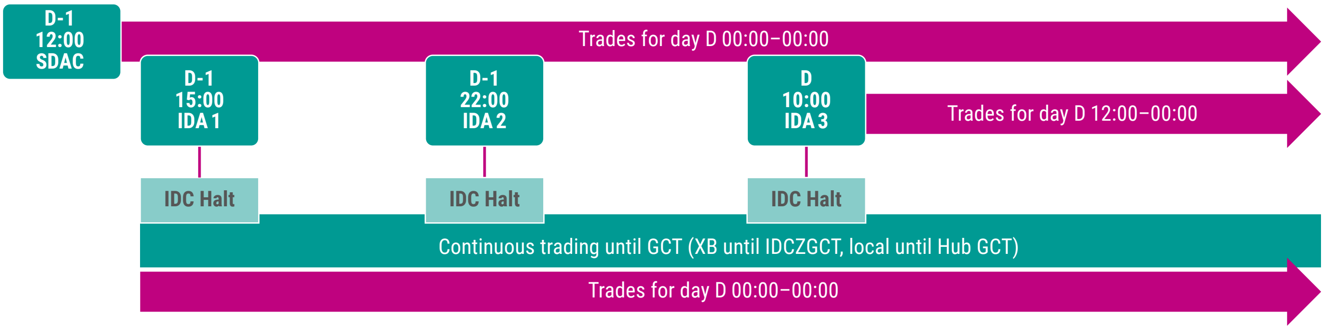


Figure 5.2: Sequence of operation processes in SDAC and SIDC

5.2.1 Single day-ahead coupling

Several key milestones were achieved during the reporting period, reflecting significant progress and contributing to the advancement of the SDAC market.

After BRM was designated as a new NEMO in Romania in July 2023, the process of setting up a new NEMO trading hub (e.g. MNA) within the Romanian BZ began, along with the implementation of essential connections and updates to the supporting tools. As a result, BRM officially went live on 18 November 2024.

A significant milestone for DA coupling was the successful implementation of FBMC in the Nordic region, which went live on 29 October 2024. This achievement not only marked a significant advancement in market integration but also encompassed the deployment of several regional improvements, such as a new design for the Nordic CID.

In 2024, after aligning with market parties, NEMOs concluded that second auctions could not serve as a reliable safety mechanism for market participants, as price thresholds were unlikely to be triggered. The second auction procedure is triggered when specific price thresholds are reached. After that, the order books are reopened, allowing market participants to adjust their positions. The final calculation is then carried out by NEMOs, while the network data remains unchanged by the TSOs. Notably, only certain SDAC countries have the second auction procedure in place. Per alignment with market participants, NEMOs decided to decommission the second auction process. In the first phase, all the BZs, except the Baltic states, proceeded with the decommissioning process on 29 January 2025. As of the time of writing this report, the decommissioning in the Baltic states is planned ialong the go-live of the 15-min MTU in DA.

At the time of reporting, the latest development in SDAC involves the synchronisation of the Baltic states' electricity systems with the continental European electricity system, strengthening energy system resilience and enhancing regional energy security. The change entailed the disconnection of interconnectors with Russia and Belarus, as well as the adaptation of the LitPol interconnector from direct current (DC) to alternating current (AC). This historic milestone occurred on 9 February 2025.

SDAC continues to operate successfully without full decoupling. In fact, no full market decoupling has occurred since operations began in February 2014. However, there have been seven partial decoupling events through the years, with the two most recent occurring in 2024. The first partial decoupling event in 2024 took place on 25 June, followed by the second on 24 July.

The first event was caused by a technical issue on a local NEMO trading platform, while the second resulted primarily from a combination of technical issues and unexpected processes. To prevent recurrences, the project conducted an ongoing investigation and made continuous improvements to identify and apply measures to mitigate (partial) decouplings, implement procedural improvements, enhance communication, and anticipate challenges with future developments. For example, procedural updates have been implemented to clarify messaging and information shared on shadow actions, along with efficiency improvements in incident committee facilitation and reporting on (partial) decoupling cases.

Since the previous report, other minor operational incidents have occurred, all of which have been actively communicated to market participants in accordance with SDAC operational procedures. All incidents are regularly monitored and analysed. Process updates are introduced through the SDAC Operations Committee (OPSCOM) to mitigate relevant risks. The figure below illustrates these incidents by severity type.

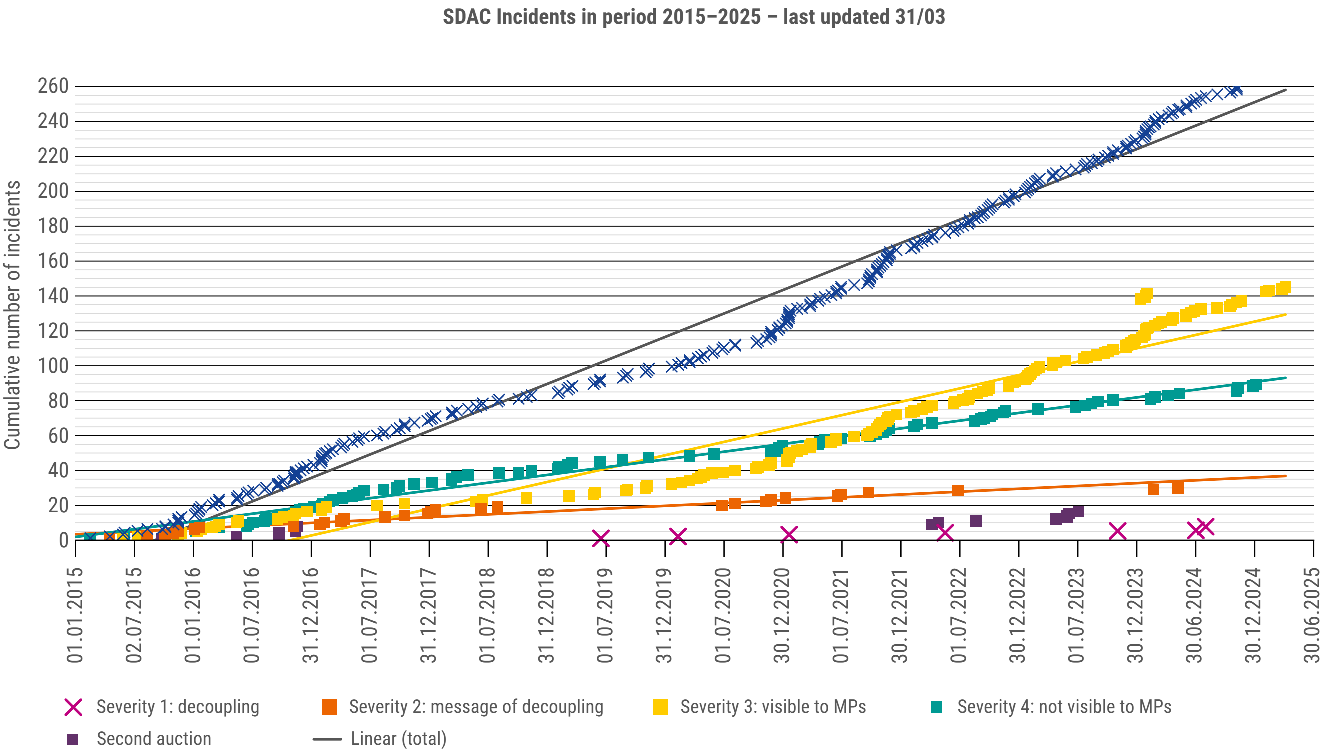


Figure 5.3: SDAC incidents since 2015

Details on the incidents can be found in the annual CACM report.[19]

19 See CACM reports for 2018, 2019, 2020, 2021, 2022, and 2023.

5.2.2 Single intraday coupling

SIDC became operational in 15 countries on 12 June 2018. The platform expanded through multiple go-live waves, beginning with the second wave in 2019, which included seven additional countries (Bulgaria, Croatia, Czechia, Hungary, Poland, Romania, and Slovenia). The third wave in 2021 integrated Northern Italian borders and internal BZ borders into the coupled ID region, followed by the fourth wave in 2022, which added Greece and Slovakia.

Additionally, the number of NEMOs has increased with the entry of ETPA in the Netherlands on 1 August 2023 and in Germany on 16 April 2024. BRM also went live in Romania on 22 May 2024, establishing new MNA areas.

Continuous trading

In SIDC, the joint TSOs and NEMOs' IT systems, with one SOB, a CMM, and an SM, **continue to show robust operational performance**. In total, approximately 580 million trades have been executed within SIDC from its inception through the end of December 2024 (see figures below).

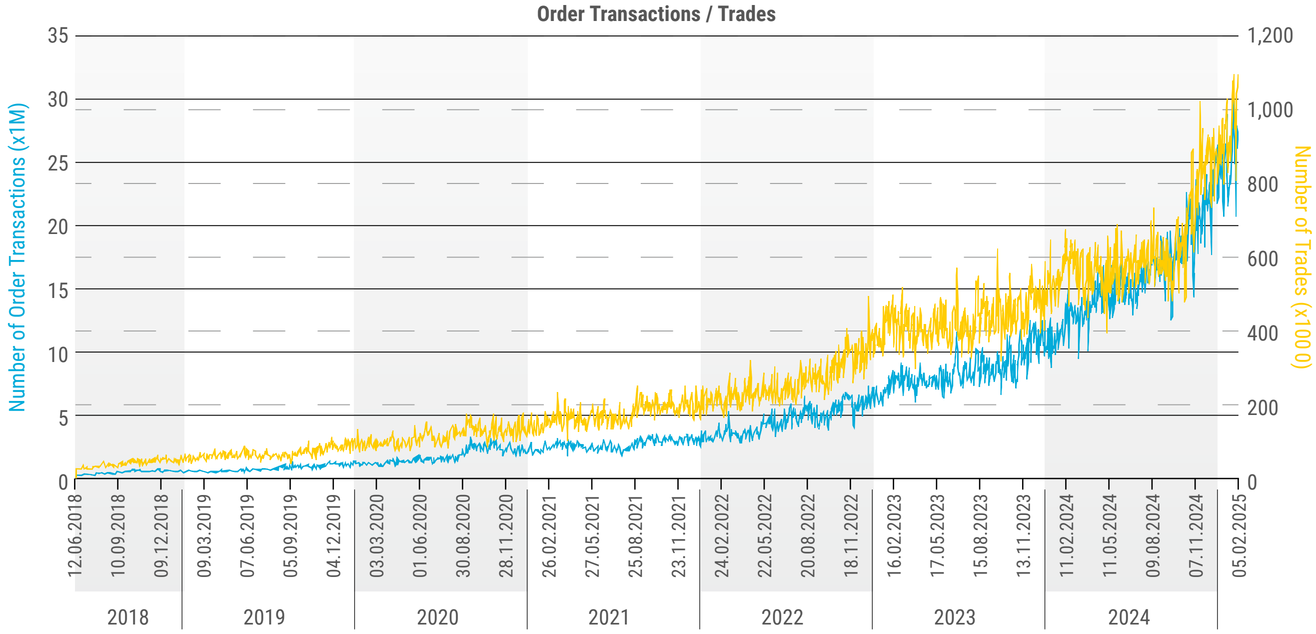


Figure 5.4: SIDC daily order transactions/trades since 2018

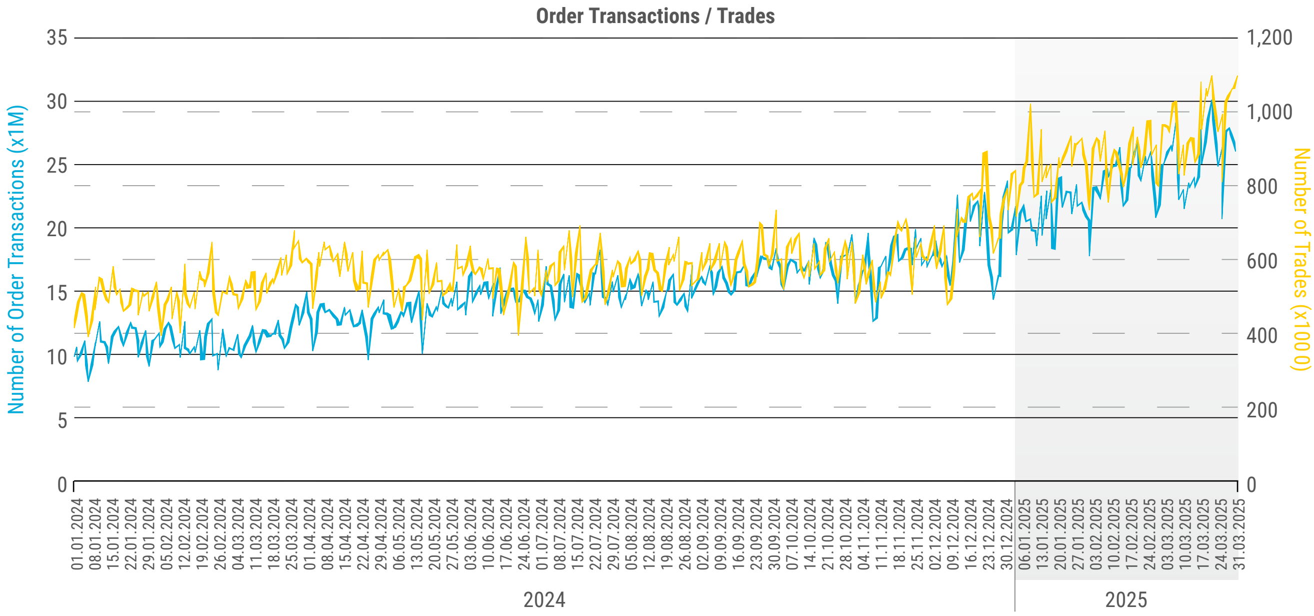


Figure 5.5: SIDC daily order transactions/trades until March 2025

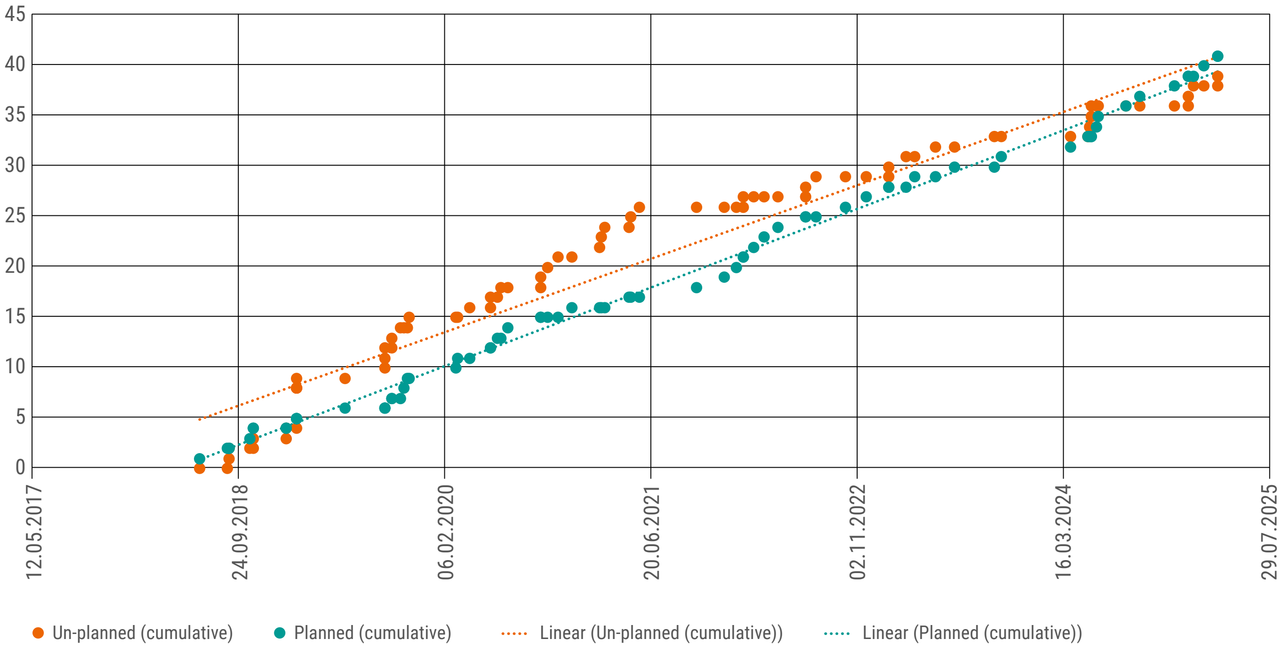


Figure 5.6: Number of unplanned and planned SIDC non-availabilities (as of January 2025)

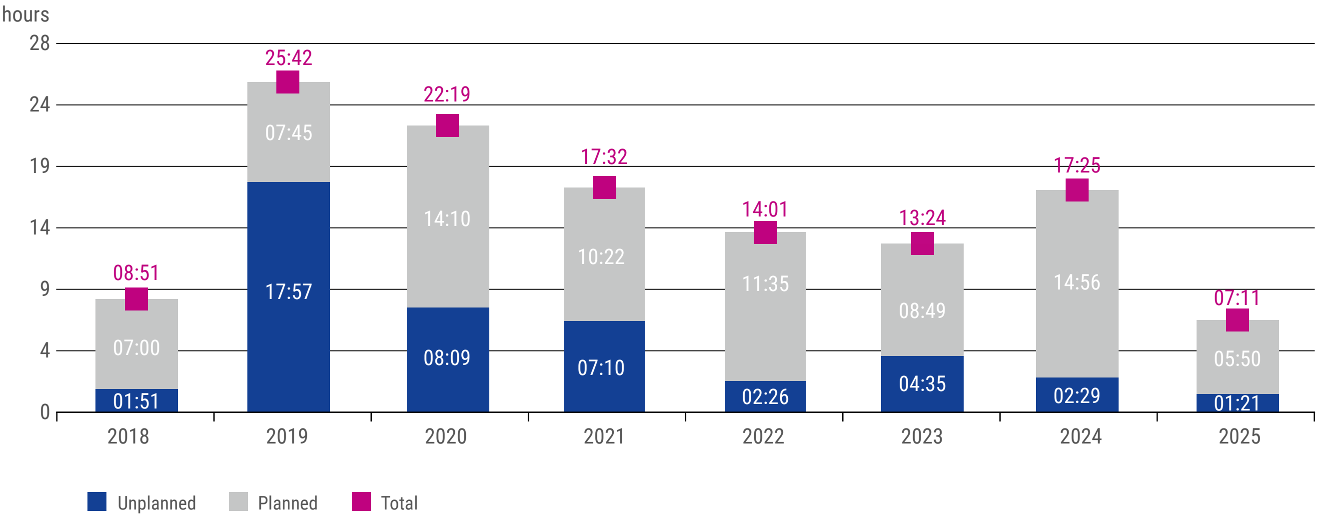


Figure 5.7: Time of unplanned and planned XBID non-availabilities

At the time of writing, two critical CT incidents have occurred during the reporting period. The first, on 21 May 2024, was caused by two CMM node instances running in parallel, competing to send data for capacity publishing. This incident resulted in a total of 64 minutes of unexpected outage in SIDC CT operation. The second incident took place on 28 August 2024 and lasted for 20 minutes. This incident was caused by maintenance performed by the Energy Communication Platform (ECP) hosting party, which led to a disruption in cross-border data processing and delayed TSO responses.

Since the previous report, other minor operational incidents have occurred, some of which have been actively communicated to market participants in accordance with SIDC operational procedures. All operational incidents are regularly monitored and analysed. Process updates are introduced through the SIDC OPSCOM to mitigate relevant risks.

In the period covered by this report, two XBID releases were used for production. This concerned the seventh and eighth releases, respectively known as XBID release R4.0 and R4.1. R4.0, which was developed, tested, and approved in 2024 and deployed on 16 May 2024, contained new functionalities to integrate IDAs. The following R4.1 release, deployed on 14 January 2025, introduced key upgrades to security and operational efficiency, including a simplified password reset process and more flexible market data submission. It also replaced outdated tools with modern, user-friendly systems, enhancing trade management and minimising operational risks.

Intraday auctions

Since the go-live of IDAs, 980 auctions have been performed, of which 965 sessions have been carried out satisfactorily, with results published to market participants on time, resulting in an IDA availability rate of 98.47 % until 05/05/2025. In total, 15 IDA sessions have been cancelled due to local/technical issues at the time of writing the report. In nearly on year of operations, the IDA market cleared approximately 115 TWh, showing a slight increasing trend. The trading volumes are particularly high during IDA 1.

Months	Year	Total Cleared Energy (GWh)
June	2024	6,278
July	2024	11,891
August	2024	11,502
September	2024	11,522
October	2024	12,345
November	2024	12,096
December	2024	12,122
January	2025	12,570
February	2025	11,563
March	2025	13,662
TOTAL		**115,555**

Table 5.1: Cleared volumes in IDAs per months since go-live

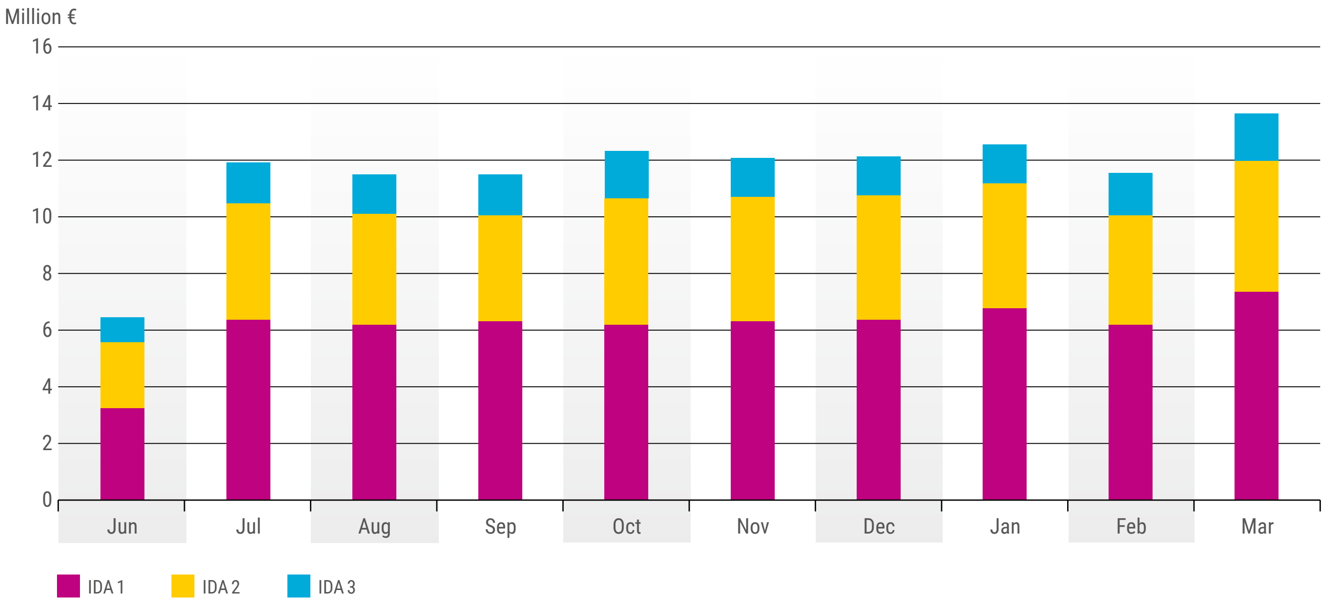


Figure 5.8: Volume of traded IDAs per month since go-live

More information on IDAs can be found on the ENTSO-E[20] and NEMO Committee[21] websites, where IDAs are reported on a weekly basis.

20 ENTSO-E IDA reporting.

21 NEMO Committee IDA reporting.

5.3 Expenditures

TSOs and NEMOs provide an annual detailed cost report to ACER and the NRAs in accordance with Article 80 of the CACM Regulation.[22]

5.3.1 Single day-ahead coupling

This section provides a summary of the costs of establishing, amending, and operating the SDAC, categorised by TSO-only costs, NEMO-only costs and joint costs (from all TSOs and all NEMOs). Figure 5.9 and Figure 5.10 show the budgeted and actual costs since 2017. The second Y-axis displays the total MWh traded for SDAC.

All TSOs' costs (e.g. for external TSO support), all NEMOs' costs (e.g. for third-party services), and joint TSO–NEMO costs are governed by the respective cooperation agreements: the TCMC, the All NEMO Cooperation Agreement (ANCA), and the DAOA.

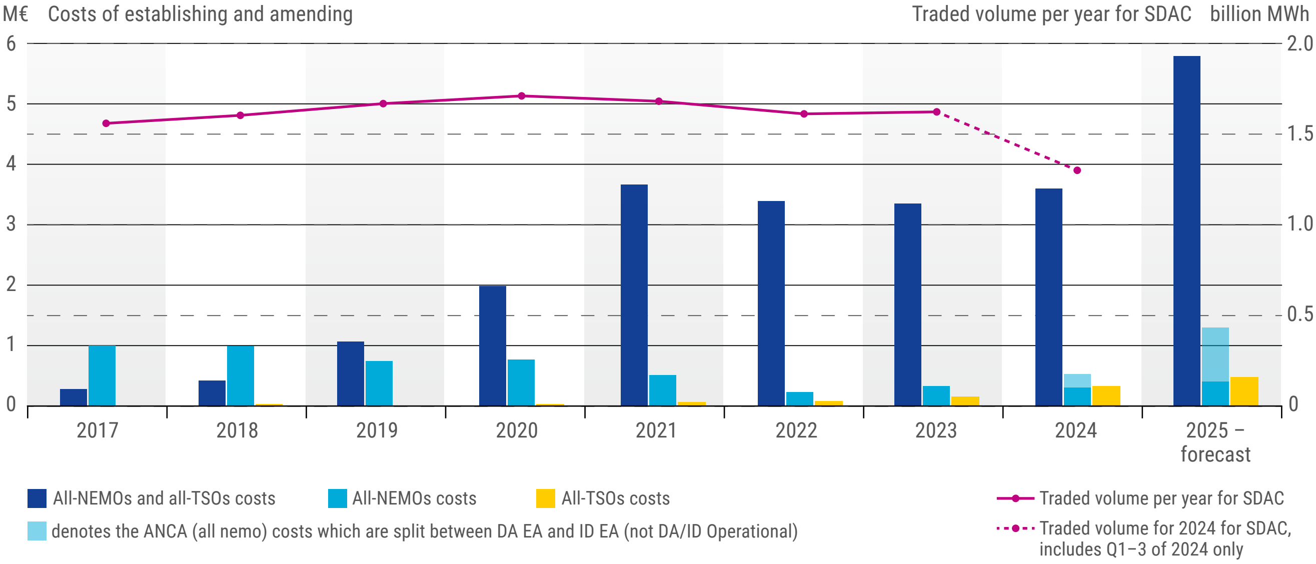


Figure 5.9: Overview of SDAC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of establishing and amending

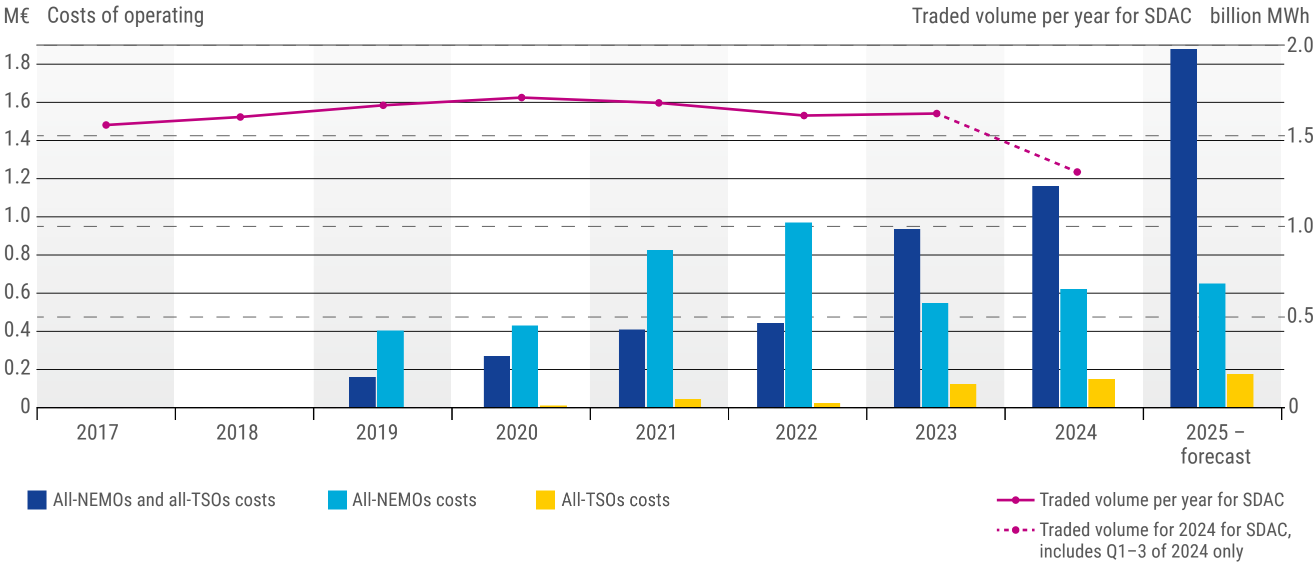


Figure 5.10: Overview of SDAC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of operating

22 See CACM reports for 2018, 2019, 2020, 2021, 2022, and 2023.

5.3.2 Single intraday coupling

This section provides a summary of the common costs of establishing, amending, and operating the SIDC, categorised by TSO-only costs, NEMO-only costs, and joint costs. Figures 5.11 and 5.12 show the budgeted and actual costs since 2017.[23] The second Y-axis shows the total MWh traded for SIDC.

All TSOs' costs (e.g. for external TSO support), all NEMOs' costs (e.g. for third-party services), and all TSO and NEMO costs (e.g., for advanced SIDC solution) are governed by the respective cooperation agreements: the TCMC, the ANCA, and the IDOA.

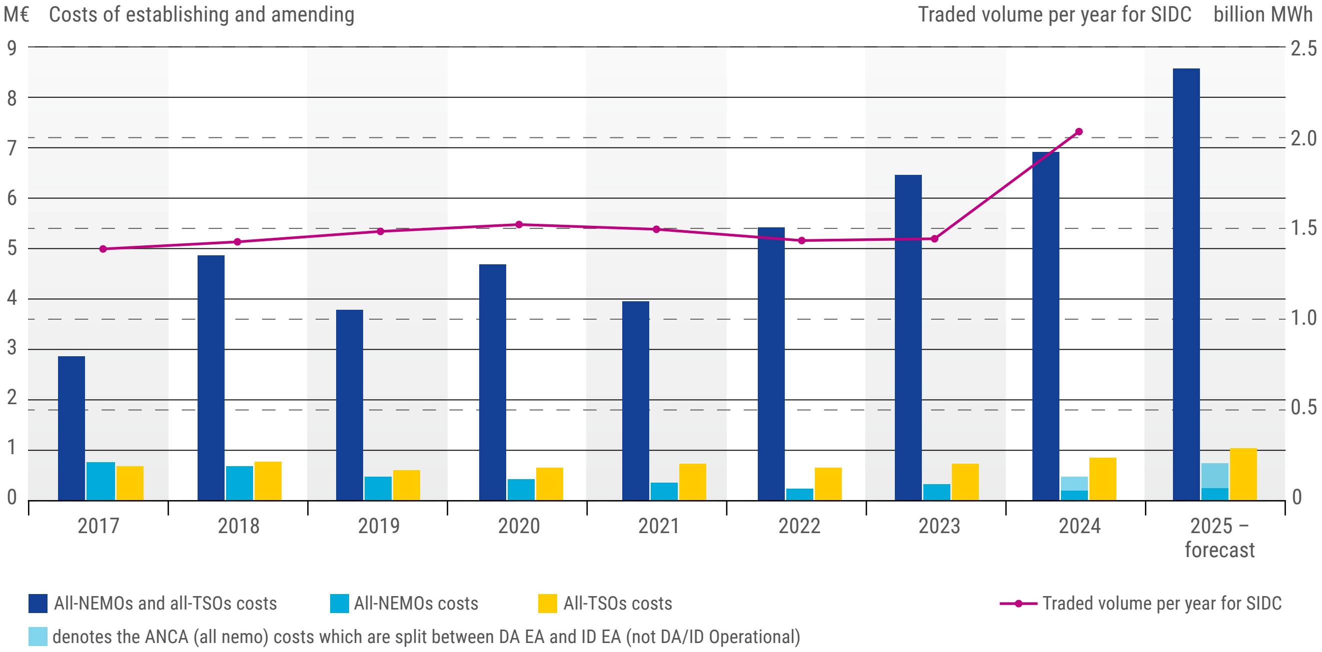


Figure 5.11: Overview of SIDC for "all TSOs' costs", "all NEMOs' costs", and "all NEMOs' and all TSOs' costs" of establishing and amending

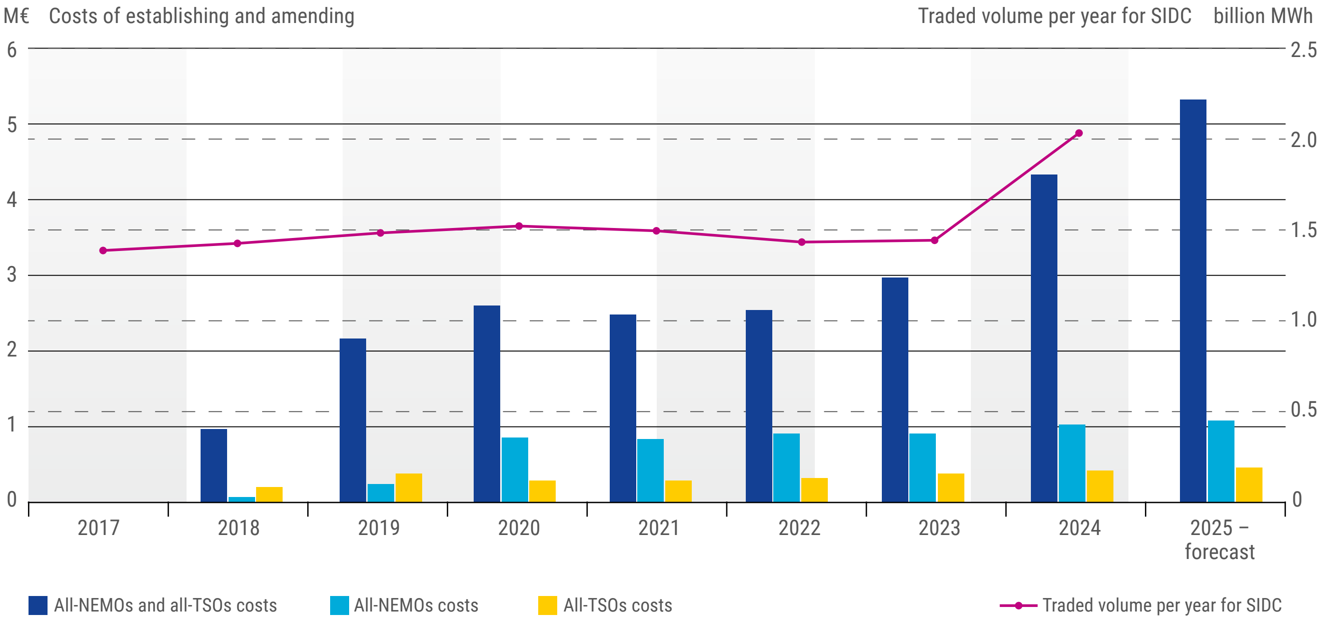


Figure 5.12: Overview of SIDC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of operating

23 In line with the regulatory guidance, costs for the coupling projects are planned and shared between TSOs and/or NEMOs as of 14 February 2017.

5.4 Evolution of services

5.4.1 Single day-ahead coupling

The SDAC is continuously evolving in terms of topology and system functionalities. Over the current reporting period, the following SDAC functional projects went live:

- The latest releases of both the PCR Matcher and Broker IT system (PMB) (13.0) and EUPHEMIA (11.3) algorithm were deployed in September 2024, introducing several product-related changes and IDA functionalities.
- FB capacity calculation was implemented in the Nordics starting in October 2024.
- The MNA with BRM as a second NEMO in Romania was implemented in November 2024.
- The decommissioning of second auctions across all BZs, except the Baltics, began in January 2025.
- The removal of third countries (Russia and Belarus) from the Baltics and changes to the LitPol interconnector due to CESA synchronisation began in February 2025.

Technical advancements were planned and implemented as part of the SDAC R&D program. The improvements were developed under the Euphemia Lab R&D program, where challenges related to optimality, repeatability, and scalability are being addressed (see below). The next versions of EUPHEMIA (11.4) and PMB (13.1) are scheduled to go live in Q2 2025, ahead of the 15-min MTU go-live. Since its launch, EUPHEMIA has been continuously developed, with the latest releases introducing and refining necessary changes for future projects, including the implementation of the 15-min MTU.

Algorithm improvements are made through the change control procedure and the algorithm methodology.[24] Both frameworks aim to address changes efficiently and with minimal disruption and controlled risk: the change control procedure outlines the process for implementing changes in SDAC operations, while the NEMO algorithm methodology establishes transparent rules and principles for the management (submission, evaluation, decision, and implementation) of requests for changes related to the SDAC algorithm (EUPHEMIA). During the current reporting period, the MCSC finalised improvements of the change control procedure to ensure effective handling of change requests.

24 Available here: [LINK]

Implementation of the 15-min MTU

The transition to the 15-min MTU in the SDAC marks a significant milestone in the evolution of Europe's energy markets. This implementation is designed to enhance the precision of market operations, enabling better integration of renewable energy sources and promoting increased market efficiency and flexibility. By improving adaptability to fluctuations in energy generation and consumption, the new system will allow for more accurate pricing and scheduling, ultimately benefiting market participants.

According to Article 53(1) of the Electricity Balancing Guideline (EB GL), by 3 years after the entry into force of this regulation, all TSOs shall apply the ISP of 15 minutes in all scheduling areas, while ensuring that all MTU boundaries shall coincide with ISP boundaries. Article 8 of the EU Electricity Regulation requires NEMOs to give market participants the opportunity to trade energy in time intervals that are at least as short as the ISP for both DA and ID markets. Consequently, a project was established under the MCSC to coordinate the implementation of 15-minute products in the DA and ID time frames across the EU (15-min MTU implementation).

Originally, NRAs decided on the gradual implementation of 15- or 30-minute ISPs. Given the impact on the entire chain of market coupling processes, regional implementation projects were established. However, due to algorithm performance issues, rather than an incremental go-live approach, the Big-Bang implementation approach was agreed upon in June 2022.

The Big-Bang 15-min MTU implementation approach means that there is one single go-live, where all BZs and BZBs in SDAC must switch from 60-min MTU data to 15-min MTU data jointly at the same time. From a product design perspective, within the BZs, regardless of the Big-Bang approach, there can still be products in multiple MTUs (15-min, 30-min, and 60-min). An exemption is granted to Ireland, where the finest granularity will be 30-min MTU.

At the time of writing this report, the target approach is for all BZs and BZBs (and all their TSOs and NEMOs) to jointly switch to the final expected MTU setup on trading day 30 September 2025 (delivery day on 1 October 2025). Functional testing (end-to-end functional process testing) took place from October 2024 to February 2025, with procedural testing (simulation test by operators after functional issues were resolved) concluded in March 2025, followed by acceptance tests. Accordingly, member testing (providing market parties with the opportunity to test before go-live) on the SDAC level was performed in April and May 2025.

Research and development program

A significant part of the SDAC budget is spent investigating ways to improve the performance of the algorithm so that it can accommodate all required changes. Research is conducted under the umbrella of the EUPHEMIA Lab program, which has shown overall positive results and is leading to the industrialisation of promising improvements in the algorithm. The R&D for the algorithm is categorised into the following areas:

- Functional: This focuses on enhancing the core functionalities of the algorithm, improving performance, and ensuring efficient and reliable operations.
- Algorithm: This involves modifications and optimisations to the underlying algorithm, aiming to refine computational processes, improve scalability, and address potential limitations. Examples include new branching strategies, new heuristics, removal of flow variables in FB, etc.
- Features: This introduces new capabilities and enhancements to the algorithm, expanding its scope by integrating additional functionalities that address evolving market or operational requirements. Examples include new mechanisms to limit polarity reversals on HVDC links, new order types, etc.

Co-optimisation

Art. 40 of the EB GL requires all TSOs to develop a proposal for a methodology for a co-optimised allocation process ("co-optimisation") of CZC for exchanging balancing capacity or sharing reserves. Work on this feature has been ongoing for several years, but it has proven more complex than originally anticipated.

ACER Decision 11/2024 on the algorithm methodology now limits references to co-optimisation to the definition of an R&D program with three phases, ending in September 2025, May 2026, and November 2026. A final decision on implementation will be made after the completion of the third phase.

Towards the end of 2024, NEMOs and TSOs started to work on a report for Phase 1, which was submitted on 30 March 2025. This part of the R&D aims to research bidding alternatives and basic design considerations, specifically analysing concepts for bidding formats, bid linking, and pricing. A public consultation will be held on this report.

TSOs and NEMOs recognise the importance of involving stakeholders at an early stage and in a timely manner. Therefore, an informal survey was conducted in Q4 2024 to improve the contents of the report.

Flow-based capacity allocation

On 8 June 2022, the Core CCR, comprising the former Central Western Europe (CWE) and Central Eastern Europe (CEE) CCRs, introduced the FBMC methodology. The go-live of the Nordic Flow-Based Day-Ahead Market Coupling project took place on 29 October 2024 (with a first trading day for delivery on 30 October 2024). The Core CCR is currently working on implementing AHC, which is expected to go live in Q4 2025. Following the ACER decision, work has been further initiated on the **Central Europe CCR** (merger of the Core and Italy North CCRs).

Multi-NEMO arrangement

The ability to manage multiple NEMOs within and between BZs was first implemented in the CWE CCR in July 2019. Since then, this capability has been gradually introduced in other regions: the Nordics in June 2020, the Hansa CCR (starting with NorNed in November 2020, followed by the Cobra Cable and Danish borders in June 2021), Poland (for the SwePol Cable and LitPol Link in February 2021, with the remaining borders in June 2021), and some of the Italian Borders Working Table (IBWT) in June 2022. The MNA on the French–Spanish border was launched in February 2024, followed by its implementation in Romania in November 2024. Although the Baltic CCR is also an MNA, only one NEMO, Nord Pool, has been operational in the region so far. While EPEX SPOT has the licence to operate in Baltics, it is scheduled to become operational in 2025.

Regional projects

Several regional projects require changes in SDAC and vice versa. These projects include Hansa CCR Phase 2, which assigns the capacity submission role to TSCNET and the Nordic RCC (planned go-live end of 2025); AHC in CCR (planned go-live Q4 2025); Celtic Cable (planned go-live in 2026); and MNAs.

5.4.2 Single intraday coupling

In 2024, the main development in SIDC was the introduction of IDAs and subsequent efforts to improve and optimise processes. However, numerous other deployments have taken place, with continued work on 15-min MTU implementation, geographical extensions, new functionalities, and FB design solutions.

New functionalities

The implementation of the 15-min MTU in SIDC (for CT and IDAs) is a prerequisite for the SDAC 15-min MTU go-live. Following the IDA go-live in June 2024, a phased approach in SIDC was adopted to transition from the 60-min to the 15-min MTU, with testing organised around specific go-live windows. Centrally coordinated testing support was arranged to facilitate streamlined transition across the numerous borders and BZs that needed to adopt the 15-min MTU before the SDAC go-live. Notably, the transition to 15-min MTU in SIDC did not require any updates to central assets; nevertheless, a centrally coordinated approach supported by an efficient transition process, including testing for both CT and IDAs, was required.

Several 15-min MTU capacity allocation go-lives occurred in 2024. The first included the Croatian borders that went live in January 2024. The second occurred in June, along with the IDA go-live for Czech BZ and BZBs (except for the Czech–Poland border).

In July, an interim solution of 15-min resolution for intrazonal products in Poland was implemented until Polish borders switched to the 15-min MTU. Additionally, 15-min MTU products were introduced in Baltic BZs and BZBs (EE–LV and LV–LT) in December. The final 15-min MTU go-live in 2024, which took place on 31 December, included Italian BZs and internal borders.

In January 2025, the go-live window was successfully completed, transitioning the French BZ and BZBs (including FR–IT, FR–BE, and FR–DE) and Italian BZ and internal as well as external borders (IT–AT, IT–SI) and Estlink (EE–FI) to a 15-min MTU. On 18 March, the switch to the 15-min MTU took place for Nordic internal and external borders and BZs, Iberian borders and BZs, Polish borders, as well as activation of the Romanian external borders in IDAs. The final phase of the 15-min MTU transition in SIDC, covering the Greek market (including the GR–BG border), is scheduled to go live along the SDAC Big-Bang 15-min MTU implementation.

Extensions

The development of the market through geographical extensions increases system performance needs. Performance is constantly monitored and improved if needed. Analysis of the first set of performance optimisation measures was finalised and implemented as part of the XBID R3.3, developed and validated at the end of 2022 and released to production in January 2023. Furthermore, SIDC developed and prepared the testing of the following XBID release (R4.0), which was deployed in May 2024 to support the subsequent introduction of IDAs.

The latest XBID release (R4.1) was implemented in January 2025, containing change requests (CRs) not included in the R4.0 version to avoid delaying the IDA go-live in June 2024. Moreover, additional service requests (ASRs) were signed in 2024 to investigate the possibility of updating the XBID platform while understanding its current performance limits. The outcomes of this investigation led to several CRs, which will be implemented in 2025 as part of the new XBID releases (XBID R4.1.5 and R5.0), bringing improved performance.

Flow-based allocation in continuous trading

After the implementation of IDAs, a key priority in SIDC has been the integration of FB capacity allocation in CT. FB allocation is regarded as having the potential to enhance social welfare compared to ATC-based models, as it can make more capacity available and enable more complex trades. However, due to the complexity of the FB design and its novel impact on SIDC, additional R&D resources, including third-party expertise, have been devoted to investigating different approaches. Given the significant time and effort required for the assessment, an interim solution was agreed upon – FB implementation in IDAs to be followed by its introduction in CT. While work on both solutions is progressing in parallel, the primary focus remains on the interim solution.

Implicit intraday losses

In line with algorithm methodology requirements, the CT matching algorithm shall consider losses on interconnectors between BZs during capacity allocation. Applying the losses will, in most cases, require regulatory approval. Losses in CT imply that the volumes and prices are different on both sides of the respective interconnector. The continuation of the analysis on the introduction of losses in XBID for CT is subject to the completion of R&D for FB in CT.

6 Balancing markets

The Commission Regulation (EU) 2017/2195 of 23 November 2017 (the EB Regulation) lays down guidelines for creating balancing markets to enable countries to share resources and balance electricity generation and demand in real time.

Balancing markets are designed to facilitate access for new market participants, including demand response, storage technologies, and integrated renewables. Enhanced efficiency and competition are key drivers of market evolution. These markets play a crucial role in ensuring security of supply, promoting fairness and transparency, and generating social welfare benefits. Ultimately, the EB Regulation aims to integrate balancing markets and foster the exchange of balancing services while contributing to operational security.

The EB Regulation defines the principles for the exchange of balancing energy and the associated settlement processes between TSOs and between TSOs and BSPs. These processes cover the following types of reserves: FRR (both aFRR and mFRR), RR, and IN. Additionally, the EB Regulation sets out a common methodology for **the exchange and sharing of reserves.**

In compliance with the EB Regulation, ENTSO-E publishes a biennial joint balancing report. The first edition was released in **2020**, followed by the second edition in **2022**, and the third edition in **2024**. **This chapter** of the ENTSO-E Market Report 2025 provides an update on recent developments in European balancing markets since the publication of the third balancing report in June 2024, covering the period up to May 2025. The performance indicators presented in Section 5 of this chapter are calculated using data from January to December 2024.

This chapter of the ENTSO-E Market Report examines the design and implementation of balancing markets at the pan-European, regional, and national levels. It highlights developments in cross-border balancing capacity procurement, the development and harmonisation of methodologies, advancements in balancing energy platforms (both regulatory and technical aspects) and the progress in the ISH process.

The chapter is divided into the following chapters:

- **Section 1** provides an update on the main achievements and new participants in the balancing energy platforms TERRE, MARI, PICASSO, and IGCC, along with the latest developments in the CM IT solution (CMM project).
- **Section 2** showcases the advancements in balancing capacity cooperation at the European level, including the Nordic aFRR and mFRR capacity markets, the market-based application in the Baltics, and the COBRA project, among others.
- **Section 3** provides an overview of EB performance indicators for the period from January to December 2024.

The key regulatory developments related to the EB Regulation roadmap are included in Chapter 3 of this report.

A glossary is provided at the end of this report for readers' convenience, along with the legal references and requirements that form the basis of this report.

6.1 Procurement and activation of balancing energy

The reporting period from 2024 to 2025 has been marked by significant progress in integrating EU balancing energy markets through the balancing energy platforms and alignment with the evolving regulatory framework. Key developments during this period are as follows:

- Baltic TSOs (Litgrid, AST, and Elering) joined the mFRR platform (MARI) in October 2024. They were followed by Portuguese TSO REN in November, and Slovakian TSO SEPS and Spanish TSO Red Eléctrica (REE) in December.
- Danish TSO Energinet and Dutch TSO TenneT NL joined the aFRR platform (PICASSO) in October 2024. SEPS followed in November, with Belgian TSO Elia joining in December.
- The TERRE project announced its termination in early 2026 in response to the cross-zonal ID GCT reduction to 30 minutes, scheduled for 1 January 2026. Czech TSO ČEPS exited TERRE in July 2024, followed by Italian TSO Terna in January 2025.

While further TSO connections to the MARI and PICASSO platforms are anticipated in the coming years, the precise timelines for these integrations are detailed in the respective accession roadmaps.

Implementation of the electricity market design reform and the TERRE phase out

The EMDR, adopted on 21 May 2024, sets the cross-zonal ID GCT at 30 minutes before real-time, effective from 1 January 2026. Given that the RR process is incompatible with this reduced time frame, the TERRE project will **cease** operations at the start of 2026.

With the GCT moving closer to real time, BSPs will have only 5 minutes to submit their mFRR/aFRR balancing energy bids to TSOs. However, market participants will benefit from increased trading flexibility and liquidity, allowing them to balance their positions closer to real time.

Additionally, the 30-minute cross-zonal ID GCT poses challenges for the cross-border mFRR direct activation process, as this activation affects two consecutive quarter-hours. Therefore, timely delivery of relevant AOF inputs (e.g. available CZC) is crucial.

In summary, TSOs have made considerable progress in integrating EU balancing energy markets through the balancing energy platforms by utilising standard products for balancing energy. Many TSOs have also proactively adapted their local market designs in preparation for future integrations, reaffirming their commitment to enhancing efficiency and market integration across European balancing markets.

6.1.1 Replacement reserves platform (led by the TERRE project)

The TERRE project is the European implementation project for exchanging RR in line with Article 19 of the EB Regulation. This fundamental regulation provides the technical and operational framework and defines the market rules governing the functioning of balancing markets. It also sets out rules for the procurement of balancing capacity and the allocation of cross-zonal transmission capacity for cross-border trades, activation of balancing energy, and the financial settlement of BRPs.

Main events and achievements

At the end of 2024, following extensive discussions with RR NRAs, TERRE TSOs decided to cease operations on the LIBRA platform by the end of 2025 and formally conclude the TERRE project at the beginning of 2026. The TERRE project communicated this decision in the "**Announcement from Replacement Reserve TSOs**" and presented it to stakeholders during ENTSO-E's **Balancing Platforms Stakeholders' Workshop**.

The RR process is incompatible with the new timing requirements introduced by EMDR. Consequently, the TERRE project will cease operations at the start of 2026. To ensure a structured and coordinated phase-out, TERRE TSOs have agreed on the following measures:

- ČEPS and Terna disconnected from the LIBRA platform on 1 July 2024 and 30 December 2024, respectively.
- PSE will not connect to the platform due to the planned phase out of TERRE.
- REE, REN, RTE, and Swissgrid will continue operating on the platform with 24 clearings per day until 31 December 2025 (at the latest).
- Each TSO may disconnect earlier, provided this is coordinated with other TSOs.
- Operations on the LIBRA platform will be fully discontinued by 31 December 2025 (at the latest).

The platform will be decommissioned at the beginning of 2026, marking the official end of the TERRE project.

A large part of the work done by TERRE TSOs during 2024 was dedicated to collaborating and agreeing on these decisions, reporting all progress made to RR NRAs, and framing the end of the project in several streams (budget, supplier contracts, platform decommissioning, and consequences of the project termination).

The end of the TERRE project has direct consequences for the use of RR products by TERRE TSOs. Since TSOs will no longer participate in a Europe-wide RR exchange in accordance with Article 19 of the EB Regulation, it will no longer be feasible for European RR TSOs to exchange RR standard products or use local RR products under these new circumstances. TSO members of the TERRE project will gradually stop performing the RR process in accordance with Part IV of the System Operation Regulation. Instead, they will implement alternative national balancing solutions tailored to their specific system needs, ensuring the continued security of balancing operations.

In 2024, TSOs in Region 1 (REE, REN, RTE, Swissgrid, and Terna) engaged in more intensive coordination efforts compared to previous years. Meanwhile, ČEPS, which remained in isolated mode in Region 2, disconnected from the platform in July 2024.

From an economic perspective, the total surplus increased to €458 million in 2024, compared to €280 million in 2023 (a 64% increase). However, this was not driven by a significant increase in satisfied balancing needs. The volume of balancing energy satisfied in 2024 was 7,806,269 MWh, only slightly higher than the 7,116,530 MWh recorded in 2023. Instead, this increase in economic surplus was primarily attributed to rising electricity prices across all market segments (long-term, DA, ID, and balancing) throughout 2024.

As in 2023, Red Eléctrica remained the most active TSO on the platform, fulfilling an average of more than 190,000 MWh of positive balancing needs and over 320,000 MWh of negative balancing needs.

Throughout 2024, the platform only had two periods of unavailability. The first occurred on 9 May 2024 and comprised 4 hours of unavailability. The second, also with a duration of 4 hours, occurred on 26 September 2024.

Governance of replacement reserves platform

As of January 2025, there are four members in the TERRE project: Red Eléctrica (Spain), REN (Portugal), RTE (France), and Swissgrid (Switzerland). These four TSOs are governing the TERRE project through the TERRE Steering Committee (TSC), the decision-making body of the project. The chairmanship of the project is assumed by each TSO in turn, following a 6-month rotation period. More information about the governance structure is available in the Market Report 2023.[25]

The project also includes three former members: ČEPS (Czech Republic), PSE (Poland), and Terna (Italy). This new type of membership was defined in the last amendment of the TERRE Cooperation Agreement. It was created to allow these TSOs to remain involved in the project for the decommissioning of the platform (as historical actors).

In addition, three TSOs are TERRE project members: Amprion, Statnett, and Svenskä Kraftnät. The term "project member" was intentionally distinguished from TERRE members. Project members joined the TERRE project for the sole purpose of participating in the development operation and management of the IT solution (LIBRA software) and obtaining the intellectual property rights of the IT solution in order to make use of and continue to develop it as part of a regional project in the case of the Nordics TSO, or as part of the MARI project.

Finally, Mavir (Hungary) is a TERRE observer, as is ENTSO-E. Both have access to all project information but are not directly involved in it.

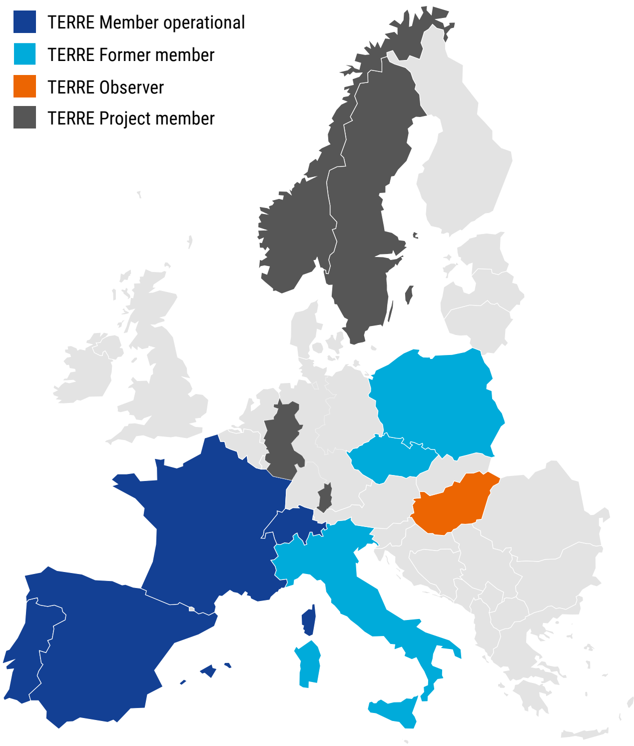


Figure 6.1: RR platform: TSOs part of the TERRE project (as of May 2025)

25 Market Report 2023

Evolution: Implementation timeline and accession TSOs' accession roadmap

Due to the upcoming termination of the TERRE project, no major implementations were carried out on the platform. As a result, TERRE TSOs decided to reduce their investments in new functionalities on the platform. Nevertheless, 2024 operations were completely stable.

Aside from the platform termination, TERRE TSOs worked on the following topics:

a. **KPI reports:** Since Q1 2024, all KPIs reports are published in the TERRE section of the ENTSO-E website.[26]

b. **CMM implementation for TERRE:** The TERRE platform is connected to CMM, and TERRE TSOs conducted tests to ensure operational stability with each CMM version.

c. **TERRE CA amendment:** TERRE TSOs approved and signed an amendment to the TERRE Cooperation Agreement to legally secure the end of the project.

Until the end of the project, no important changes may be implemented in the platform. TERRE TSOs will ensure the stability of the platform and its operations.

TERRE expenditures

Please see the EB Cost Report 2025 for TERRE expenditure information.

26 https://www.entsoe.eu/network_codes/eb/terre/.

6.1.2 mFRR platform (led by the MARI project)

MARI is the European implementation project for the creation of the European mFRR platform. The platform has been operational since October 2022, when the four German TSOs and ČEPS successfully connected to the platform. Today, 12 TSOs are connected to the platform.

Main events and achievements

From May 2024 to May 2025, the following primary goals were achieved in the scope of the MARI project:

- The three Baltic TSOs – Elering, AST, and Litgrid – accessed the mFRR platform, joining the German TSOs, ČEPS, and APG in October 2024.
- REN accessed the mFRR platform in November 2024, and SEPS and Red Eléctrica accessed in December 2024.
- The balancing platforms stakeholder's workshop, held on 11 December 2024, informed stakeholders of the evolution of the platform and gathered feedback for future developments.

Governance of the mFRR platform

MARI consists of 29 member TSOs plus five observers, including ENTSO-E. There are currently 12 TSOs connected to the mFRR platform: 50Hertz, Amprion, ČEPS, TenneT Germany, TransnetBW, APG, Elering, AST, Litgrid, REN, SEPS, and REE.

The structure of governance of the MARI project is specified in the mFRR IF, Article 14[27]. The mFRR platform project has a two-level governance structure: a steering committee (SC) and WGs. The MARI SC has at least one representative from each TSO. For subjects common across MARI and PICASSO, there is a joint SC consisting of the members of the respective MARI and PICASSO SCs.

As of May 2025, there are five active WGs: IT WG, TSO Testing WG, Technical WG, Legal WG,[28] and CMM WG. The WGs report directly to the SC. In addition to the WGs, there is also an operational committee (OC) in place to handle the day-to-day operational decisions related to MARI. In Q3 2025, the MARI OC will be merged with the PICASSO OC to create a joint OC (Joint OPSCOM). In the SC and WGs, all TSOs have the right to vote, while in the OC, the right to vote is reserved for the TSO participating on the platform.[29]

In addition to the WGs and the OC, there are joint task forces with PICASSO and TERRE.

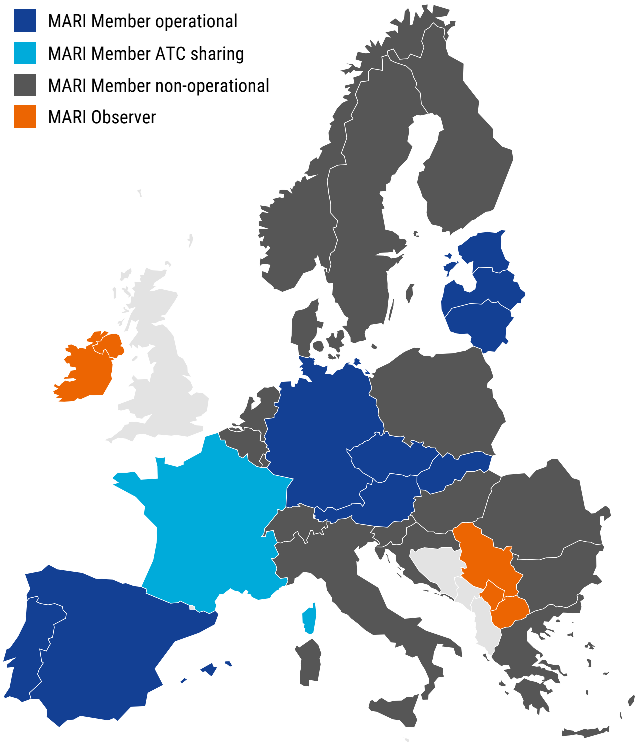


Figure 6.2: Map with MARI members[30]

27 220921_ACER Decision 14-2022 on the Amendment of the mFRRIF – Annex II.pdf (entsoe.eu).

28 Legal WG is shared with PICASSO.

29 Participating TSOs means TSOs that are currently connected to the MARI mFRR platform or will connect within the next 6 months.

30 The technical readiness of Swissgrid has been acknowledged. The participation of Switzerland in the mFRR platform is regulated based on Articles 1.6 and 1.7 of the EB Regulation and is currently the subject of litigation by Swissgrid at the Court of Justice of the European Union.

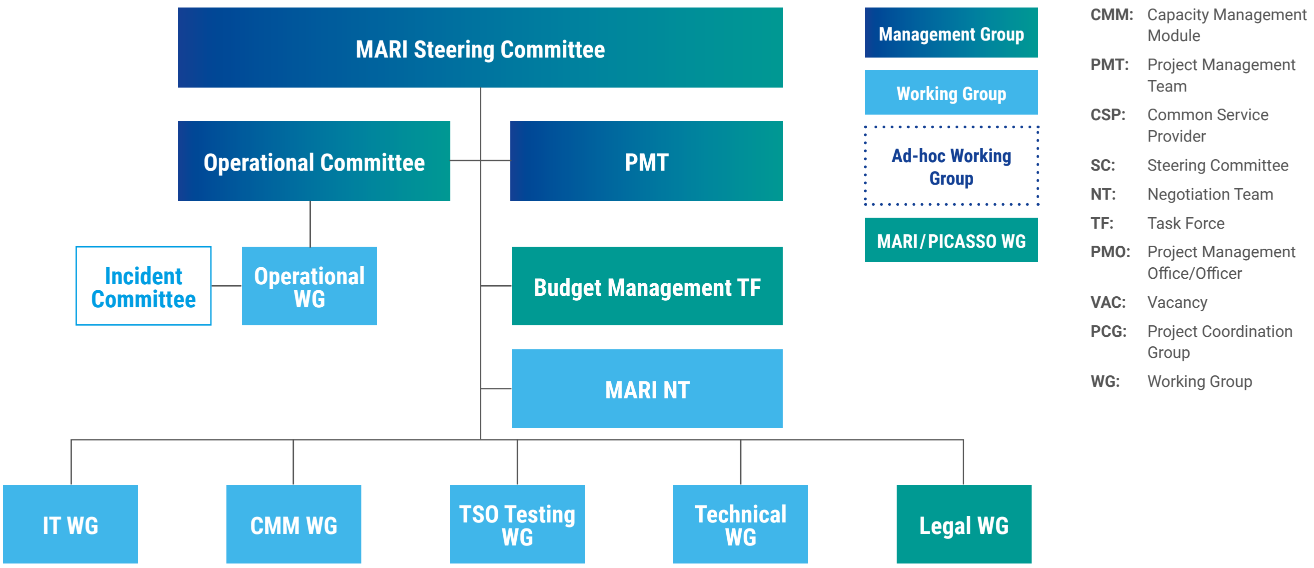


Figure 6.3: MARI governance structure

Evolution: Implementation timeline and TSOs' accession roadmap

An accession roadmap was established as mandated by the IF Article 5. The roadmap is updated at least twice per year, usually in April and October. The latest version of the accession roadmap can be found on the MARI **web page** on the ENTSO-E website, under Publications. The main steps within the MARI project for the years 2024 to 2026 are **described** in Figure 6.5.

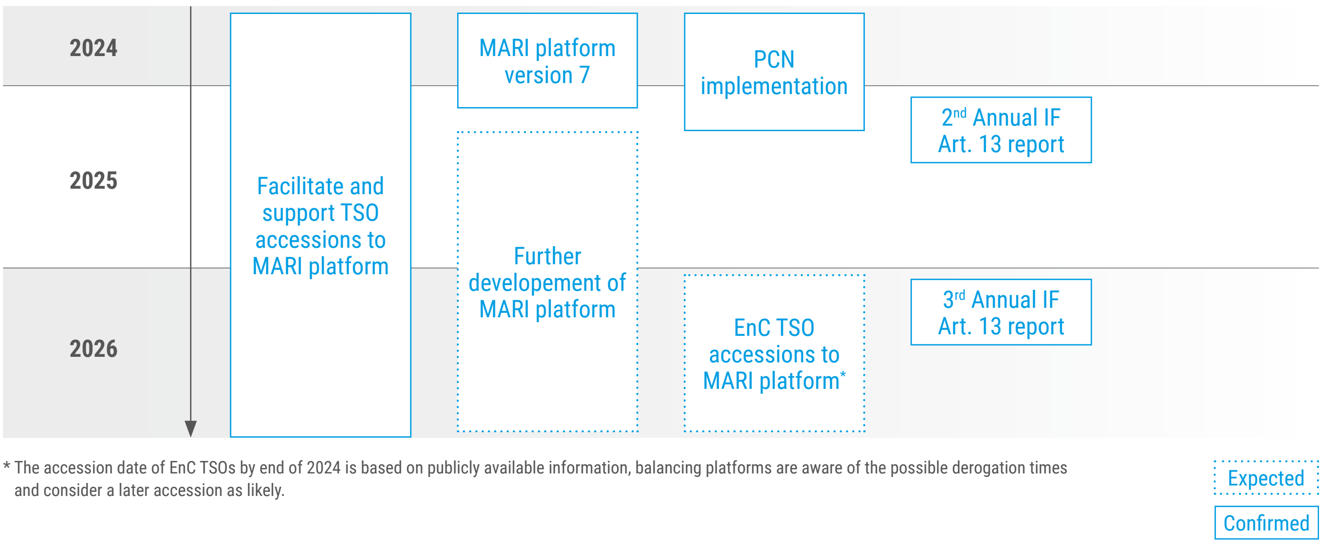


Figure 6.4: Upcoming steps for the MARI platform

Expenditures

Please see the EB Cost Report 2025 for MARI expenditure information.

6.1.3 aFRR platform (led by the PICASSO project)

PICASSO is the implementation project endorsed by all TSOs through the ENTSO-E Market Committee to establish the European platform for the exchange of balancing energy from FRR with automatic activation (aFRR platform), pursuant to Article 21 of the Commission Regulation (EU) 2017/2195 of 23 November 2017, which establishes a guideline on electricity balancing (EB GL).

Main events and achievements

Since 2017, the PICASSO project has been leading the design and implementation of the European domestic energy market for aFRR energy based on a common standard product.

The aFRR platform comprises 29 TSO members and one TSO observer. It fosters operational stability by coordinating aFRR activation using an MTU of 4 seconds. The PICASSO IT solution is also used for IGCC, which closely interacts with PICASSO's optimisation to maximise economic surplus while fully utilising the netting potential of all IGCC TSOs.

On 1 June 2022, the platform became operational (according to the EB Regulation, 24 July 2022 was the legal deadline to implement and make the platform operational). After connecting to the platform, all TSOs will use the aFRR platform to submit all standard aFRR balancing energy bids, exchange all aFRR balancing energy bids, and strive to fulfil all their corresponding balancing energy needs.

The first aFRR exchange between the RGCE (Regional Group Continental Europe) SA and the Nordics took place in October 2024.

Based on **ACER decision 8/2024** and **ACER decision 9/2024**, the PICASSO project developed and implemented elastic demand to address high prices in PICASSO and implemented a new determination of the CBMP. Elastic demand can be implemented by a TSO submitting a price threshold. Elastic demand is covered up to this threshold. This is in contrast to inelastic demand, where the aFRR demand in the range of dimensioned aFRR must be satisfied regardless of the price.

Each TSO that uses elastic demand is required to publish local terms on how elastic demand and the price threshold are calculated.

In February 2025, the PICASSO KPI Report update was updated to include the implemented elastic demand.

On the operational stream, the economic surplus reached € 132.8 million (without surplus from additional demand satisfaction). The additional surplus is up to € 588 million in 2024 for additional demand satisfaction, depending on the assumed price.

From June 2024 to May 2025, the PICASSO project made several operational enhancements, including updates to a) the Operational Handbook, b) the Pricing & Settlement Implementation Document, and c) the Technical Implementation Document.

Governance of aFRR platform

As of January 2025, there are 29 members in the PICASSO project: APG (Austria), Elia (Belgium), ESO (Bulgaria), HOPS (Croatia), ČEPS (Czech Republic), Energinet (Denmark), Elering (Estonia), Fingrid (Finland), RTE (France), 50Hertz, TenneT DE, Amprion, TransnetBW (Germany), IPTO (Greece), MAVIR (Hungary), Terna (Italy), AST (Latvia), Litgrid (Lituania), Creos Luxembourg (Luxembourg), TenneT NL (Netherlands), Statnett (Norway), PSE (Poland), REN (Portugal), Transelectrica (Romania), SvK (Sweden), ELES (Slovenia), SEPS (Slovakia), Red Eléctrica (Spain), and Swissgrid (Switzerland). In addition, MEPSO (North Macedonia) is an observer, as is ENTSO-E. Observers have access to all project information but are not directly involved in it and cannot participate in any decisions.

The 29 members are part of the PICASSO SC, the decision-making body of the project. The chairmanship of the project is elected for a 1-year period. The current chairman is Andras Szili (Mavir).

The PICASSO platform has a strong connection with the IGCC platform, as the IGCC TSOs use the same IT system as PICASSO for their IN process. Therefore, the PICASSO and IGCC parties share a common OC (OPSCOM).

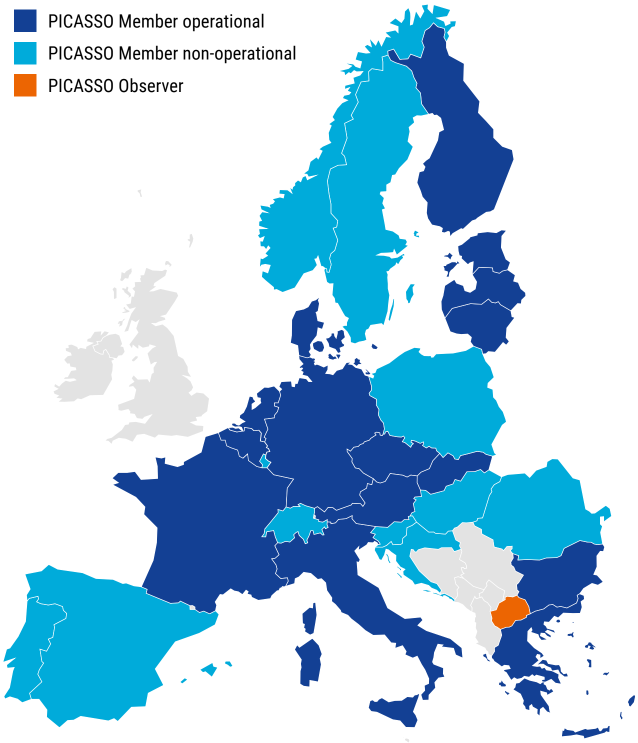


Figure 6.5: Map with PICASSO members

Evolution: Implementation timeline and accession TSOs' accession roadmap

From June 2024 to May 2025, 13 TSOs accessed the PICASSO platform: Energinet and TenneT Netherlands in October 2024; SEPS and Elia in November 2024; ESO in February 2025: Elering, Litgrid, AST, Fingrid, and ADMIE in March 2025; RTE in April 2025; and Red Eléctrica in May 2025.

The evolution of PICASSO is outlined through the implementation timeline and TSOs' **accession roadmap**, available on the ENTSO-E website.

Expenditure

Please see the EB Cost Report 2025 for PICASSO expenditure information.

6.1.4 IN-Platform (led by the IGCC project)

In February 2016, ENTSO-E selected IGCC as the implementation project for the European platform for the IN process (IN-Platform), as defined by EB Regulation Article 22 and established in the IN IF.41

IGCC was launched in October 2010 as a regional project and has grown to cover 28 countries and all TSOs that must implement the IN-Platform according to the EB Regulation.

In 2024, the operation of the IN-Platform experienced no major incidents. With more TSOs joining PICASSO, the overall explicit netting volume has decreased as expected.

IGCC governance

The design and implementation of the IN-Platform is led by the IGCC implementation project, which counts 31 TSO members and observers. The three Baltic TSOs (LitGrid, AST, and Elering) joined the IN-Platform as full members in Q1 2024.

Since Q1 2022, the PICASSO and IGCC projects have a common project management and meeting organisation to capitalise on their numerous similarities. Governance structures and decision processes remain separated. Further information on the high-level design of the IN-Platform can be found in the ENTSO-E Balancing Report 2020.

Figure 6.6: Map with IGCC members

IGCC evolution: Performance indicators on monetary saving due to imbalance netting

TSOs' increasing participation in the IN process resulted in energy savings of more than 1.2 TWh in March 2024, corresponding to nearly €110 million in monthly savings. This not only improves the efficiency of energy use but also increases the security of the European electricity transmission system by making additional aFRR capacity available.

The cumulative savings generated through international co-operation by the IGCC since the start of the project in October 2011 surpassed €3 billion in September 2024, reaching €3.2 billion in December 2024. Data related to the IN-platform have been published on the Transparency Platform since June 2021. The reports on IN volumes are published on a dedicated site on the **ENTSO-E website**.

IGCC evolution: TSOs' accession roadmap

Baltic TSOs (Litgrid, AST, and Elering) became full members in Q1 2024 and will join the IN-Platform as operational members in the first month of 2025. The interaction between aFRR optimisation and IN optimisation will make the IN process unnecessary once all IN optimisation participants also take part in aFRR optimisation. However, it is currently not possible to determine when this transition will occur, as some TSOs within the IGCC project have not yet planned their accession to the PICASSO platform.

IGCC expenditures

Please see the EB Cost Report 2025 for TERRE expenditure information.

6.1.5 Capacity management in real time (CM IT solution)

All European balancing energy platforms must be provided in real time with the available cross-zonal capacity limits (CZCLs) to optimise the cross-border activation of balancing energy. The TSOs of each border are responsible for providing and managing these capacities while ensuring compliance with operational security limits. To streamline this process, TSOs have agreed to implement a centralised approach to capacity management through a dedicated IT tool, enabling them to provide, manage, and amend CZCLs across all balancing energy platforms.

The CMM Project has been established to develop and enhance this centralised solution, ensuring it meets availability and performance requirements.

Currently, four TSOs are connected to the CMM: ČEPS and Swissgrid joined on 10 October 2023, Litgrid on 19 September 2024, and Red Eléctrica on 19 February 2025. Additional TSOs are expected to connect in 2025, including RTE, 50Hertz, Amprion, TenneT Germany, TransnetBW, ELES, and ESO.

Main events and achievements

From May 2024 to May 2025, the following primary goals were achieved in the scope of the CMM Project:

- Go-live of one major CMM platform release with new and improved functionalities (Version 2) on 30 July 2024 (e.g. enabling the execution of the affected TSO procedure for connected TSOs in CMM).
- Design, development, testing, and deployment of two minor CMM platform releases with new and improved functionalities (Version 3.1 on 11 December 2024 and Version 3.2 on 3 April 2025).
- Further improvements to the incident management process and the alignment of CMM and balancing platform configurations, along with an updated operational handbook (OH v3, focused on the affected TSO procedure).
- Specifications for the required changes to implement the 30-minute ID GCT and to meet the specific capacity calculation requirements for HVDC interconnectors.
- EU tender launched to identify suppliers for the future development, maintenance, and support of the CMM platform.

Governance of mFRR platform

- CMM is governed by the MARI project and therefore has the same member TSOs as MARI.

Evolution: Project timeline

The main steps within the CMM project for the years 2025 and 2026 are described in the figure below.

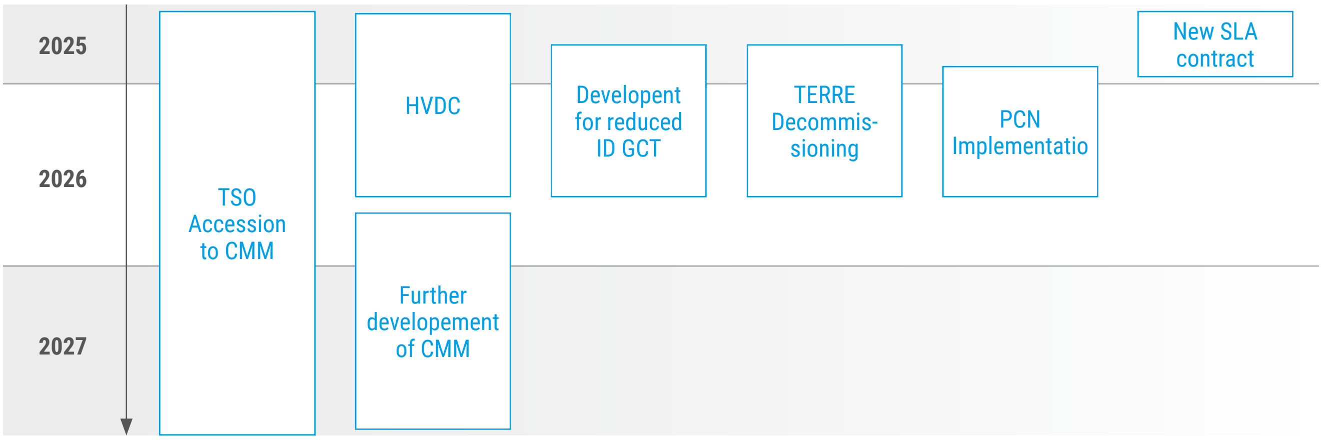


Figure 6.7: Project timeline of the CMM platform

The main tasks are the accession of additional TSOs and the development, testing, and deployment of the capacity calculations for HVDC interconnectors.

Expenditures

Please see the EB Cost Report 2025 for CMM Platform expenditure information**.**

6.2 Integration of balancing capacity markets

This section provides an overview of the existing sharing/exchange reserve platforms in Europe that are operating on a voluntary basis.

6.2.1 Nordic balancing capacity market development

The Nordic aFRR capacity market was launched in December 2022 between the four Nordic TSOs (Energinet, Fingrid, Statnett, and Svenska kraftnät). In 2024, the market continued to support the optimal use of balancing capacity resources across the Nordic area. During 2024, the main changes affecting the aFRR capacity market were the accession of PICASSO for Energinet, the implementation of FB in the DA time frame in the Nordics, and early preparations for the harmonised methodology implementation in Nordic balancing capacity markets.

In November 2024, Energinet joined the PICASSO platform as the first TSO from the Nordic region. Since the accession, we have seen a significant increase in the volume of bids submitted to the aFRR capacity market in DK2, helping to increase competition and decrease total procurement costs for the Nordic region. The sharp increase in bids submitted in DK2 is primarily due to the shift to a different pricing scheme that allows energy and capacity to be priced separately.

The Nordic FB DA market coupling went live in October 2024. The go-live of the FBMC improved the utilisation of the Nordic grid but also introduced larger price volatility between BZs. As the current Nordic forecasting methodology relies on a simplified approach, Nordic TSOs will monitor the efficiency of the current market setup under the new conditions over time.

All four Nordic TSOs participate in the COBRA project, supporting the development of the market-based CZCA optimisation function software. Simultaneously, Nordic TSOs have begun analysing and preparing for the implementation of the CZCA optimisation function within the existing Nordic markets and market management system.

In addition to the common aFRR capacity market, a trilateral mFRR capacity market was launched in November 2024 between the three Nordic TSOs: Energinet, Fingrid, and Svenska kraftnät. The trilateral mFRR capacity market allows the Nordic TSOs to secure sufficient mFRR resources in a more functional and cost-effective way going forward.

Overall, the Nordic aFRR capacity market experienced a positive surplus in 2024. Analysis by the Nordic TSOs found that the negative effect on the SDAC is smaller compared to the positive effect on the aFRR CM. The effect on the SDAC per day has been −€ 62,432 while the positive effect on the aFRR CM has been € 609,647.

	Producer surplus [M€]	Procurement cost benefit [M€]	Congestion rent [M€]	SDAC [M€]	Total benefit [M€]
Nordic aFRR CM	17.91	194.16	11.06	− 22.85	200.28

The total economic surplus from the exchange of balancing capacity in 2024 was € 200.28 million, with an average daily surplus of € 547,215.

6.2.2 Market-based application in the Baltics

The Baltic TSOs did not commonly procure balancing capacity in 2024 due to still being connected to the Russian/Belarussian SA. However, preparations were ongoing throughout 2024 to start the joint Baltic balancing capacity market in February 2025 by Estonian TSO Elering, Latvian TSO Augstsprieguma tīkls, and Lithuanian TSO Litgrid. Work on the Baltic balancing capacity market was part of the preparation for the desynchronisation of the Baltic power systems from the Russian/Belarussian SA and synchronisation with the CESA. Connecting to a European SA gives the Baltic electricity grids electricity independence from third countries while also applying European balancing standards for Baltic TSOs.

Before synchronisation, the Baltic TSOs only used mFRR energy products to balance the system, while after synchronisation, they also use FCR and aFRR. Synchronisation took place on the afternoon of 9 February, when the AC lines between Lithuania and Poland were switched on and Baltic power systems became part of the CESA.

The Baltic balancing capacity market along with the market-based allocation started on 4 February 2025, a few days before the Baltic TSOs synchronised with the CESA. Since that date, the three Baltic TSOs have engaged in joint procurement of FCR capacity, and a joint procurement mFRR balancing capacity along with market-based allocation of CZC for balancing capacity exchange and reserves sharing. Unfortunately, due to the delay in Baltic TSOs joining the PICASSO platform, the common aFRR balancing capacity procurement was delayed, commencing on 15 April 2025.

6.2.3 German–Austrian aFRR balancing capacity cooperation and future ALPACA cooperation

The German–Austrian balancing capacity cooperation (AT–DE–BCC) was established at the end of 2017 to facilitate the exchange of up to 80 MW of CZC for aFRR between Germany and Austria. The allocation optimisation process is conducted on both a monthly and weekly basis:

The monthly optimisation determines the allocation result, which is then considered in the monthly capacity auction conducted by the JAO for the upcoming month.

The weekly optimisation refines the monthly result using more recent data but cannot exceed the previously allocated monthly CZC. If the weekly optimisation results in a lower allocation, the difference is returned to the energy market.

The weekly result serves as a constraint for the common procurement optimisation.

To expand the balancing capacity exchange beyond Germany and Austria, German TSOs and Austrian TSO APG initiated **ALPACA**. Since 2020, Czech TSO ČEPS, the German TSOs, and Austrian TSO APG jointly develop ALPACA by harmonising markets, developing a platform and a procurement algorithm. The TSOs TenneT NL, MAVIR, ELES, Swissgrid, and HOPS are currently observing the process.

Within ALPACA, TSOs plan to implement a probabilistic methodology in accordance with Article 33(6) of the EB Regulation to enhance aFRR balancing capacity (BC) procurement. This initiative will complement the existing AT–DE aFRR BCC, which will continue operating even after ALPACA goes live.

In 2024, the ALPACA NRAs approved methodologies under Articles 33(1), 33(6), and 58(3) of the EB Regulation. Throughout 2024, ALPACA TSOs have been implementing these methodologies, with common procurement scheduled to commence in the second half of 2025.

The application of the probabilistic methodology represents an intermediate step towards adopting the harmonised market-based allocation process proposed in the all TSOs methodology submitted under Article 38(3) of the EB Regulation. ALPACA TSOs intend to align with this approach and are therefore actively supporting:

- The amendment of CORE methodologies, including DA and ID capacity calculation methodology, CID methodology, and regional operational security coordination methodology.
- The development of the allocation algorithm for the harmonised market-based allocation process as part of the COBRA project.

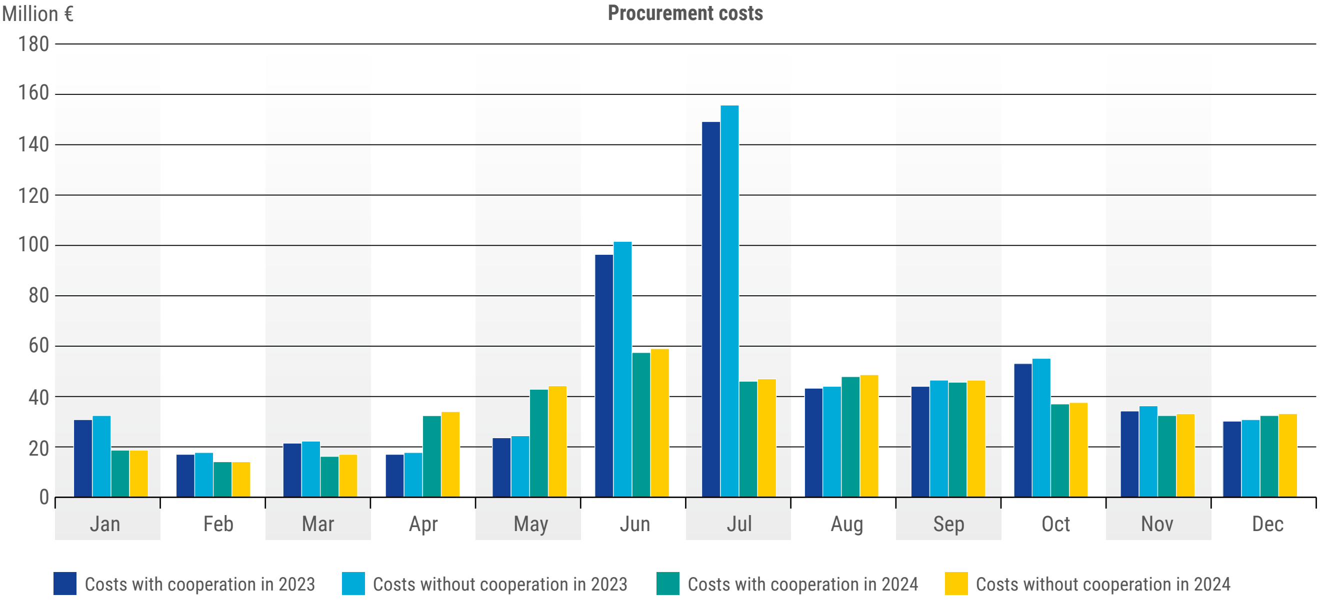


Figure 6.8: Comparison of procurement costs with and without the aFRR cooperation

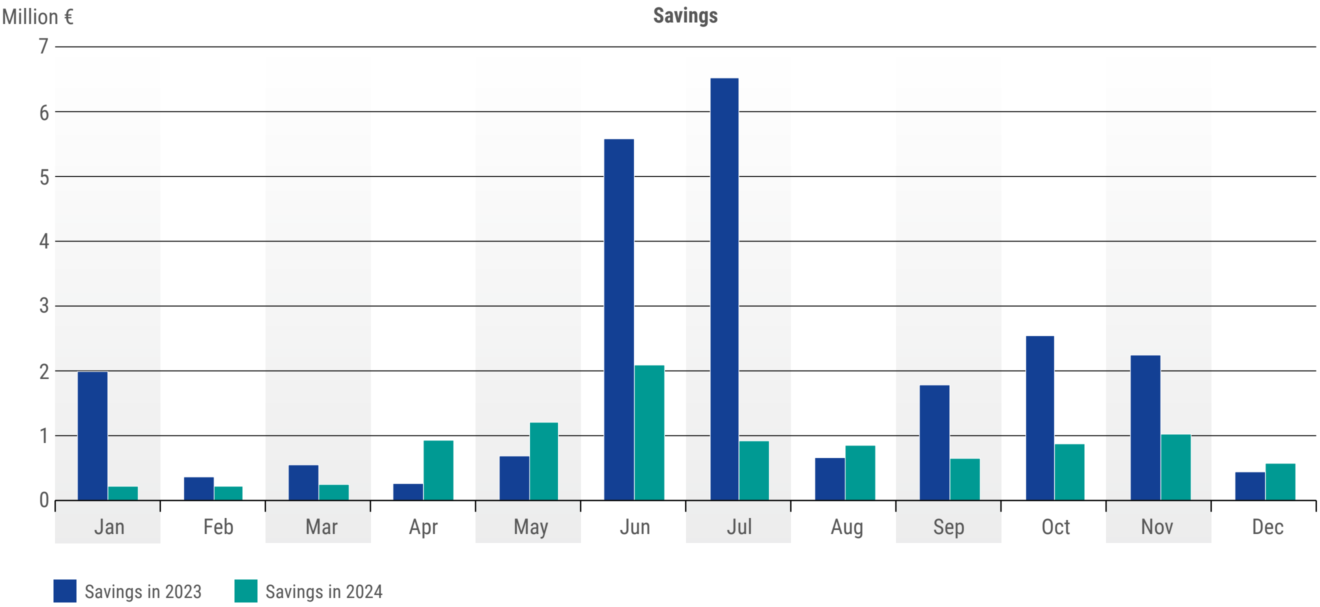


Figure 6.9: Savings from the aFRR cooperation

German and Austrian TSOs have commonly procured aFRR balancing capacity since February 2020. The reduction in procurement costs observed in previous years was also achieved in 2024.

The total balancing capacity costs of the cooperation amounted to €421.3 million (€390.8 million for Germany and €30.5 million for Austria) in 2024, whereas costs without cooperation would have been €431.3 million.

6.2.4 COBRA project

The COBRA project was established as an implementation project to develop a common optimisation function for the market-based allocation of CZC. The project is based on the HCZCAM, which requires TSOs submitting an application pursuant to Article 38(1)(b) of the EB Regulation and TSOs intending to apply the market-based allocation process to jointly develop the market-based CZCAOF software. The project, called Common Optimisation of Balancing Reserves and CZC Allocation, currently includes the TSOs of Austria, Denmark, Estonia, Finland, Germany, Latvia, Lithuania, the Netherlands, Norway, and Sweden, with ČEPS set to join in 2025. The initial steps of the project involved drafting the business requirements for the CZCAOF algorithm, enabling the subsequent phases of software development. The CZCAOF development deadline is 30 June 2026.

6.2.5 FCR Cooperation

In line with the objectives of the EB Regulation, the FCR Cooperation is a voluntary common market for the procurement and exchange of FCR capacities. The FCR Cooperation currently involves 12 TSOs from nine countries, along with three observers. The main principles, governance, and decision-making process did not change in 2024. A detailed overview can be found in the ENTSO-E Balancing Report 2020 (page 31) and Market Report 2021 (pages 101–108).

Market development

In 2024, the Croatian TSO HOPS joined the FCR Cooperation as an observing member. TSOs can become observing members of the FCR Cooperation to learn more about the common procurement of FCR within the cooperation.

Evolution of FCR prices in 2024

In 2024, FCR procurement prices were broadly similar to previous years, with the exception of 2022, when unusually high prices were seen following the rise of energy prices in Europe beginning in 2021 (see Figure 6.11). Belgium, however, saw a slight increase in prices, even compared to 2021.

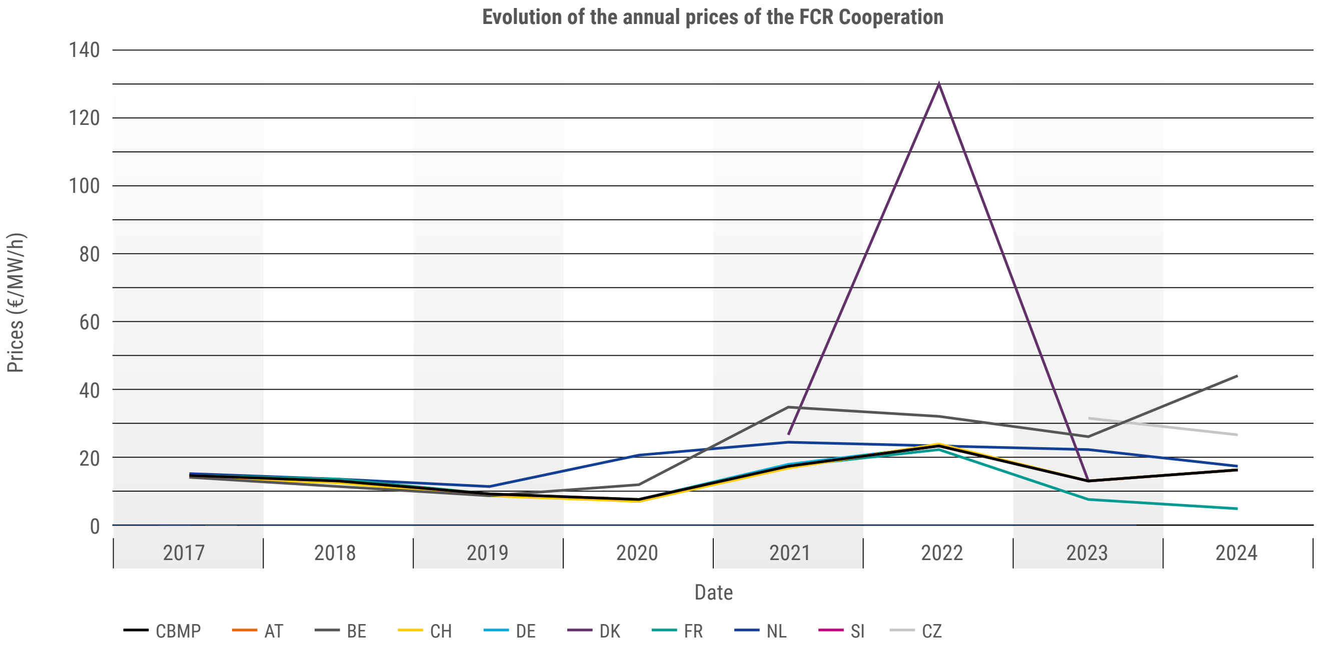


Figure 6.10: Evolution of the annual prices of the FCR Cooperation

Figure 6.12 shows the daily prices for each FCR Cooperation country in 2024, as well as the level of convergence of prices. The price converges when the locational marginal pricing (LMP) is equal to the CBMP. This is usually the case when no constraints are hit (e.g. import or export limit) which could influence the LMP. Austria, Denmark, Germany, the Netherlands, Slovenia, and Switzerland had a very high convergence of prices in 2024, approaching or attaining 100%, with only a few situations with a higher or lower LMP. On the other hand, Belgium often reached its core share, resulting in prices decoupled from the rest of the cooperation and a lower price convergence compared to other countries. The level of price convergence per TSO for 2024 is shown in Figure 6.13. Czechia had relatively high prices in 2023, but in 2024, FCR prices were more in convergency with the CBMP.

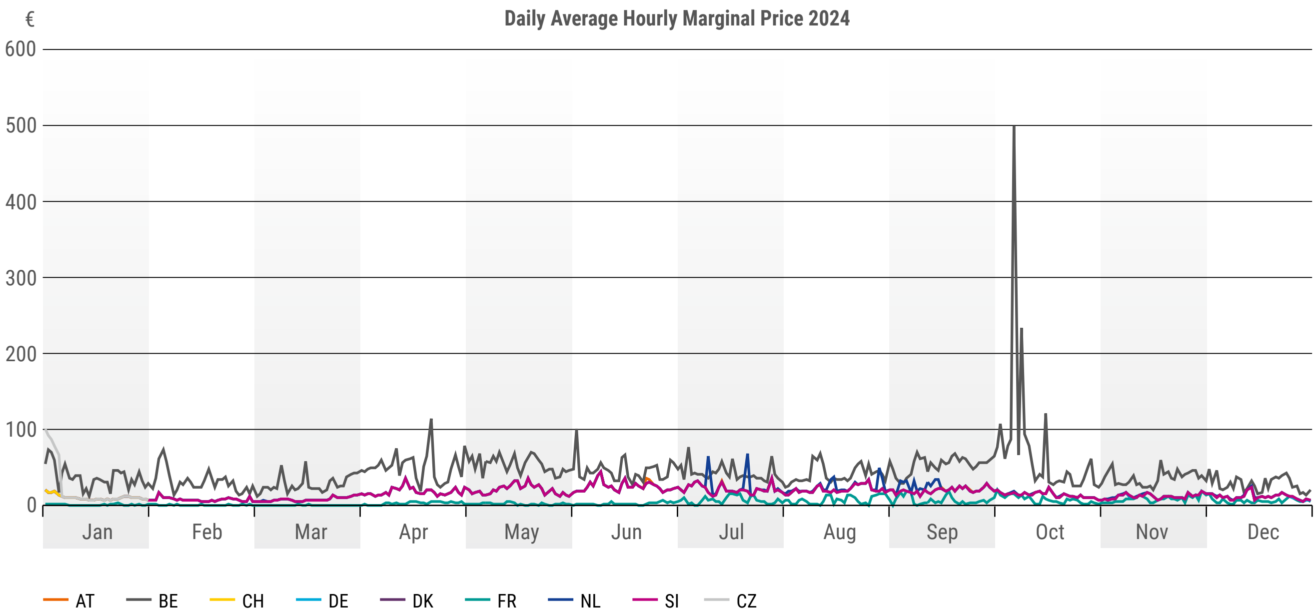


Figure 6.11: Daily average hourly marginal price (€/MW) 2024

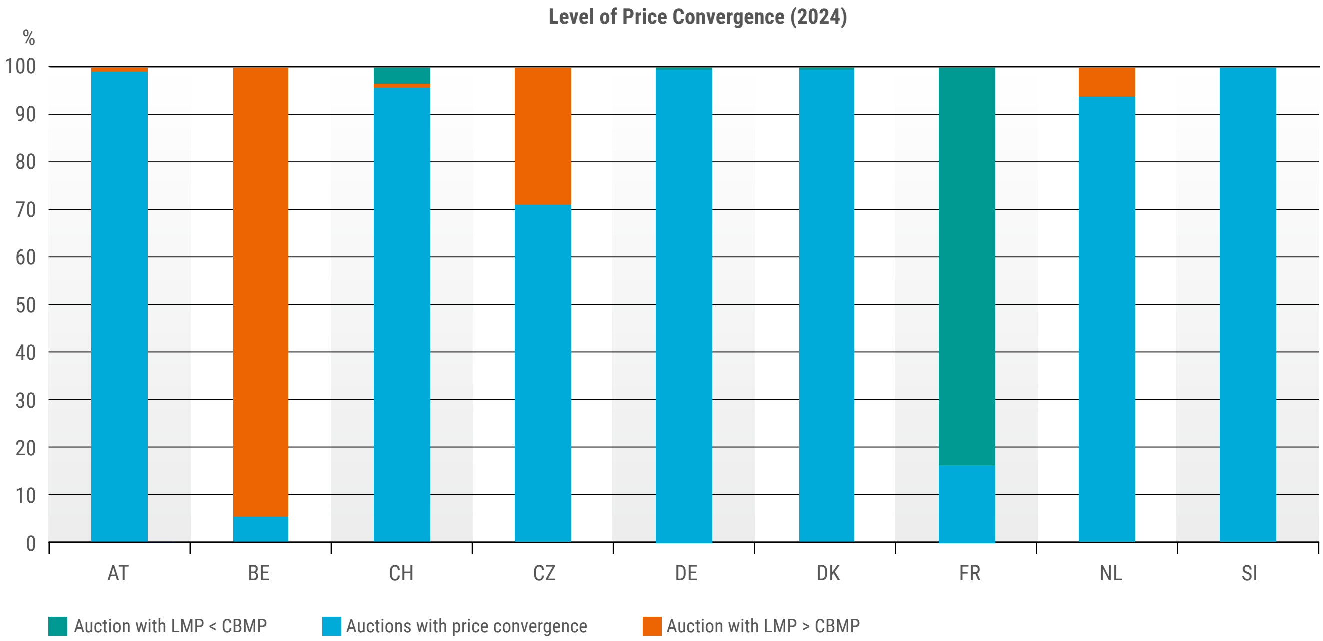


Figure 6.12: Level of Price Convergence (2024)

Figure 6.14 shows the amount of imported (negative value) or exported (positive value) FCR as a mean value across all 2,196[31] auctions in 2024. Figure 6.15 shows the percentage share of export and import (or auctions with no exchange necessary). France was clearly the main exporting country in 2024, both in total amount and percentage share, frequently reaching its export limit. It was followed by Germany, with Austria and Switzerland also maintaining a mean exporting position. France exported in nearly 100 % of FCR auctions, followed by Germany with 76 % and Austria with 67 %. Conversely, Belgium, Czechia, Denmark, the Netherlands, and Slovenia were importing FCR to fulfil their demand.

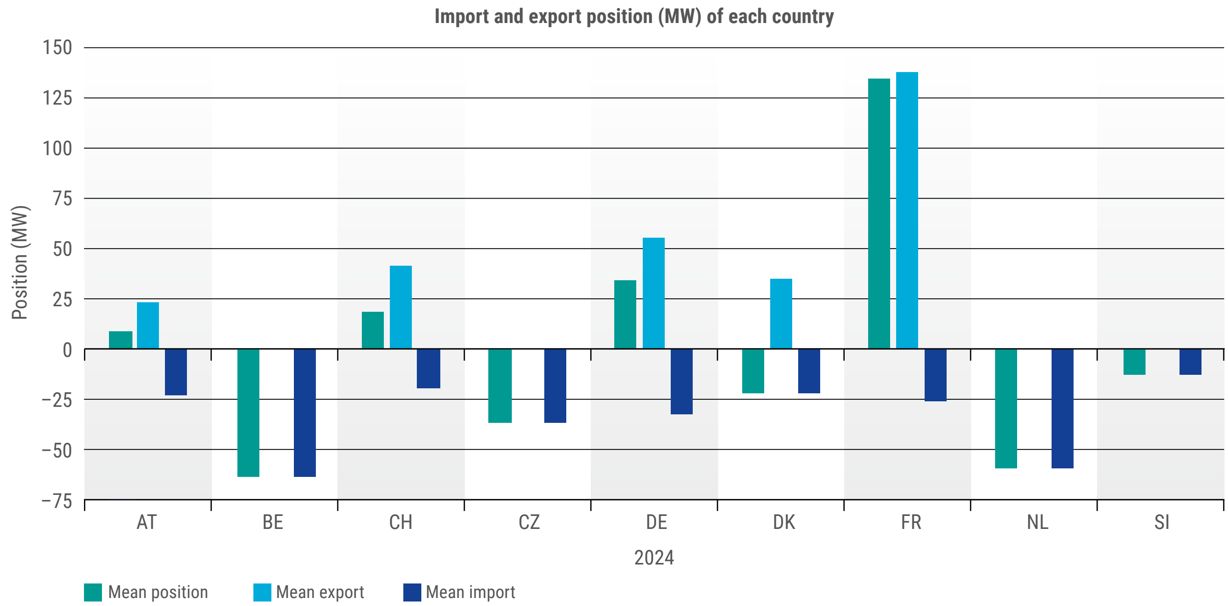
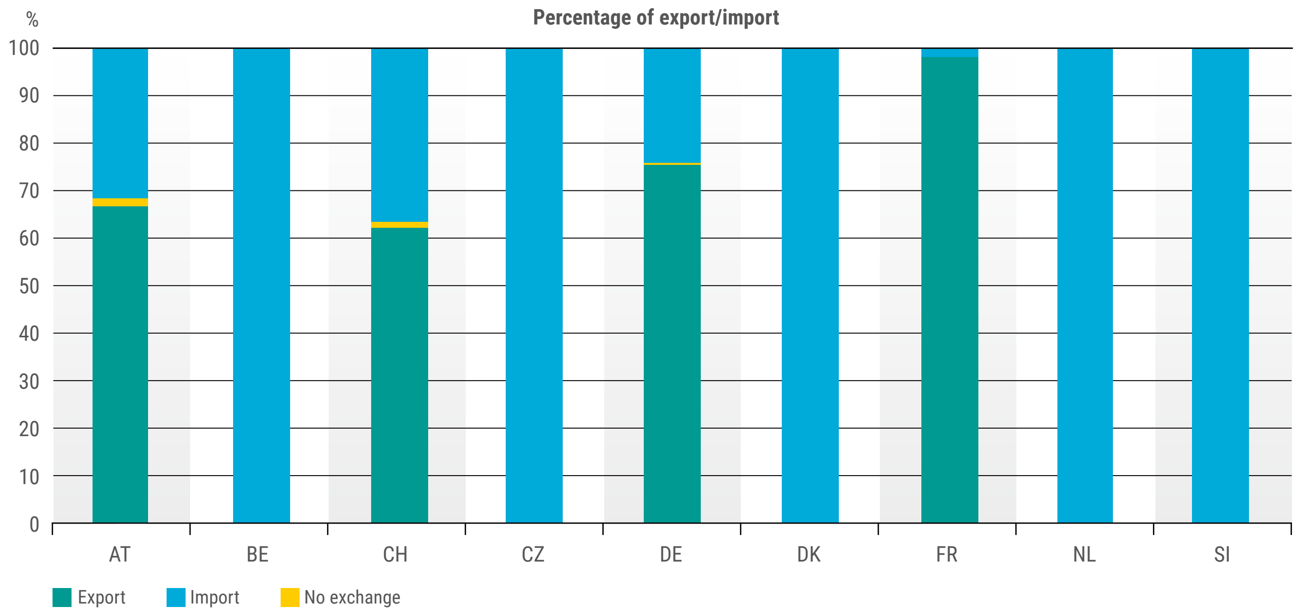


Figure 6.13: Import and export position (MW) of each country



	AT	BE	CH	CZ	DE	DK	FR	NL	SI
Export	67 %	0 %	62 %	0 %	76 %	0 %	98 %	0 %	0 %
No exchange	2 %	0 %	1 %	0 %	0 %	0 %	0 %	0 %	0 %
Import	31 %	100 %	36 %	100 %	24 %	100 %	2 %	100 %	100 %

Figure 6.14: Percentage of export/import

31 Six FCR auctions per day x 366 days.

Evaluation of benefits

The benefits of the FCR Cooperation are evaluated based on a comparison between two situations:

- **Case A:** Each country procures its FCR demand separately
- **Case B:** Joint procurement of FCR (while taking into account the core share and export limits of each country), which reflects the current situation

These scenarios were analysed for a 1-year period, from January 2024 to December 2024, using the *merit order lists* used in auctions in 2023. The starting assumption is that the bids would be the same in both cases. In reality, it is likely that the scenarios' different conditions would affect the bids. The FCR Cooperation attempts to address this in two ways:

- Valuing the under-procured volumes at the LMP
- Removing extreme high-priced bids

For the two scenarios, the procurement costs and the BSP surplus (i.e. the difference between the marginal price and the bid price for the activated bids) are compared. The overall impact on procurement costs and BSP surplus provides an indication of the benefits linked to the joint procurement in terms of social welfare.

Under-procurement of FCR

Under-procurement occurs in a country when there are insufficient local bids to cover the demand for that country. In case B, this occurs very rarely or never: with imports, the entire demand of each country can be covered by bids in the merit order list. Using the same bids, in simulation A, there is a significant volume of under-procurement. The cooperation likely discouraged some BSPs from bidding their entire FCR flexibility, as the most expensive bids were unlikely to be selected. This suggests that without the FCR Cooperation, more assets would have been offered in the market. Therefore, the FCR Cooperation assumes that under-procurement in a country could be resolved with more bids at the respective local marginal price.

Extreme high-priced bids

Sometimes, BSPs submit bids with extreme prices (sometimes over 1,000 times the LMP). If the FCR Cooperation uses the existing merit order list for the simulation of FCR procurement without exchanges, these bids cause extreme procurement costs that are considered unrealistic. (If there is no regular exchange of BSPs, it is expected that BSPs will submit additional bids at a lower price.) Therefore, the simulation has been executed with a price cap, removing all unselected bids with a price at or above €10.000/MW/4h.

Results

For 2023, the calculated benefit was €120 million per year. Using the same methodology to calculate benefits, the estimate for 2024 benefits was significantly higher. This is due to a high number of high-priced bids (between €1,000 and €9,000 per 4-hour block) submitted in the Netherlands. These bids are not selected in the daily auctions (Case B) but are part of the merit order list selected in Case A.

The FCR Cooperation does not believe this simulation provides a realistic view of its benefits. Therefore, an alternative simulation was conducted, in which the Netherlands' FCR demand and export limits were set to zero, removing any benefits due to high-priced bids in NL.

The results of these adjusted simulations are summarised in the Table 6.1 below.

	Procurement costs (Million EUR p.a.)	BSP surplus (Million EUR p.a.)	Under-procurement	Impact on social welfare (Million EUR p.a.)
Simulation A	309	163	187 MW	–
Simulation B	160	115	~0	–
B-A	149	–48	–	101

Table 6.1: Evaluation of the benefits of the FCR Cooperation

6.3 Electricity balancing performance indicators

EB performance indicators are a tool that enables analysis and assessment of the results of balancing market integration, following the EB Regulation. This section is based on Transparency Platform data, provisions from voluntary reserve exchange TSO cooperation, and currently operational balancing energy platforms.

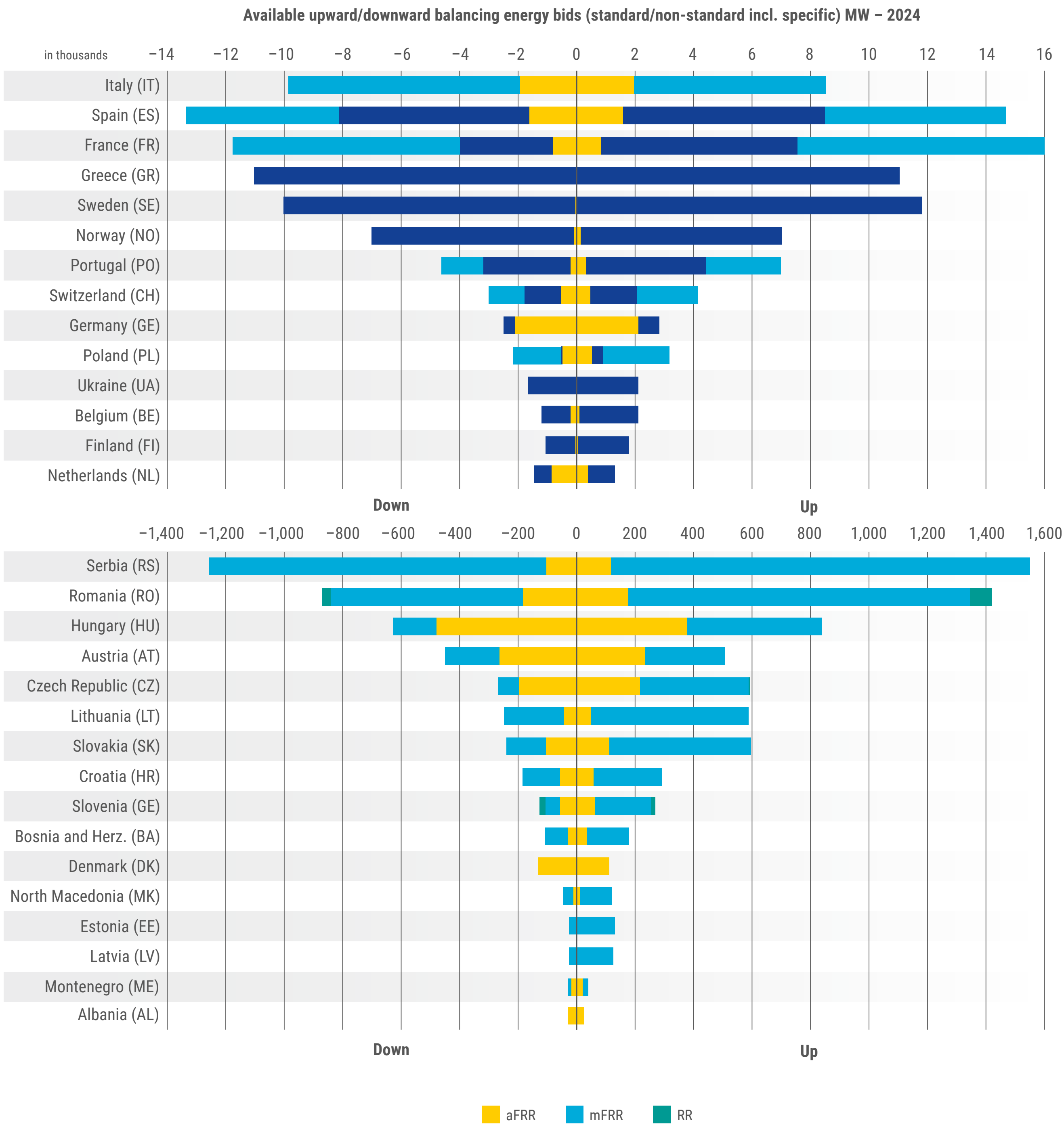
6.3.1 Indicator on the availability of balancing energy bids, including bids from balancing capacity

Definition	Yearly average values of submitted available (MW) and unavailable (MW) bids of balancing energy per process (aFRR, mFRR, and RR), per direction (upward/downward) and per type of product (standard/specific)[32] as collected by TSOs. All balancing energy products (RR, mFRR, aFRR) appear together in the same graph for each TSO. **The indicator includes per TSO/LFC area/BZ/LFC Block:** 1. **Available upward** balancing energy bids for each type of process and product 2. **Available downward** balancing energy bids for each type of process and product 3. **Unavailable upward** balancing energy bids for each type of process 4. **Unavailable downward** balancing energy bids for each type of process
Legal reference	Article 59 (4) (a) of the EB Regulation
Time reference	Yearly
Clarifications on data from Transparency Platform	Transparency Platform data has been merged in terms of standard and local/specific products (aFRR, aFRR LS, and aFRR CS into aFRR and mFRR DA, mFRR SA, and mFRR into mFRR) to display the data below. Furthermore, TransnetBW – TSO_Name data has been merged into different TSOs due to it being the PICASSO Common Service Provider (CSP) and reporting such data for different TSOs. Presented data for Greece combines both aFRR and mFRR energy bids.

Table 6.2: Indicator 3.1 on the availability of balancing energy bids[33]

32 with specific including both specific and local products.

33 aFRR and mFRR local and specific data has been merged.



Available upward/downward balancing energy bids (standard/non-standard incl. specific) MW – 2024
in thousands
−14
−12
−10
−8
−6
−4
−2
0
2
4
6
8
10
12
14
16
Italy (IT)
Spain (ES)
France (FR)
Greece (GR)
Sweden (SE)
Norway (NO)
Portugal (PO)
Switzerland (CH)
Germany (GE)
Poland (PL)
Ukraine (UA)
Belgium (BE)
Finland (FI)
Netherlands (NL)
Down
Up
−1,400
−1,200
−1,000
−800
−600
−400
−200
0
200
400
600
800
1,000
1,200
1,400
1,600
Serbia (RS)
Romania (RO)
Hungary (HU)
Austria (AT)
Czech Republic (CZ)
Lithuania (LT)
Slovakia (SK)
Croatia (HR)
Slovenia (GE)
Bosnia and Herz. (BA)
Denmark (DK)
North Macedonia (MK)
Estonia (EE)
Latvia (LV)
Montenegro (ME)
Albania (AL)
Down
Up
aFRR
mFRR
RR

6.3.2 Social welfare impact due to exchange and sharing of reserves and activation of balancing energy platforms using standard products and savings derived from imbalance netting

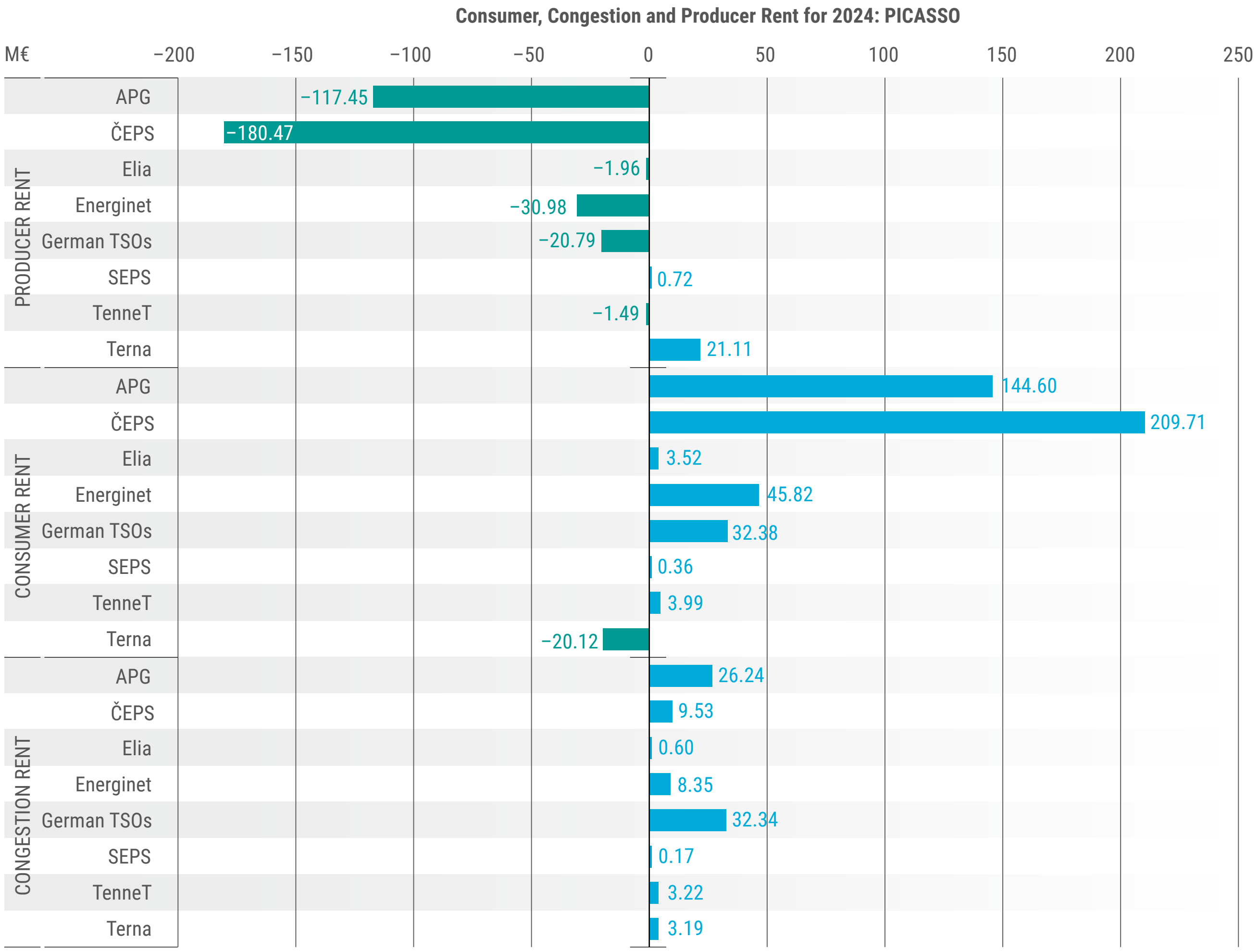
6.3.2.1 Balancing energy activation social welfare impact

Definition	a) **Social welfare impact:** The social welfare increment for each exchange balancing energy market is calculated by comparing coupled/decoupled clearings. The social welfare positive increments for balancing energy activation are calculated by comparing coupled and decoupled market results. The social welfare in each market is understood as: a) BSP's surplus, b) TSO's savings (inelastic needs) / TSO's surplus (elastic needs), and c) TSO's congestion income. TSOs will report the social welfare impact on a monthly basis per cooperation level, not at the TSO level.
Legal reference	Articles 59 (4) (b) and 59 (4) (c) of EB Regulation
Time reference	Yearly

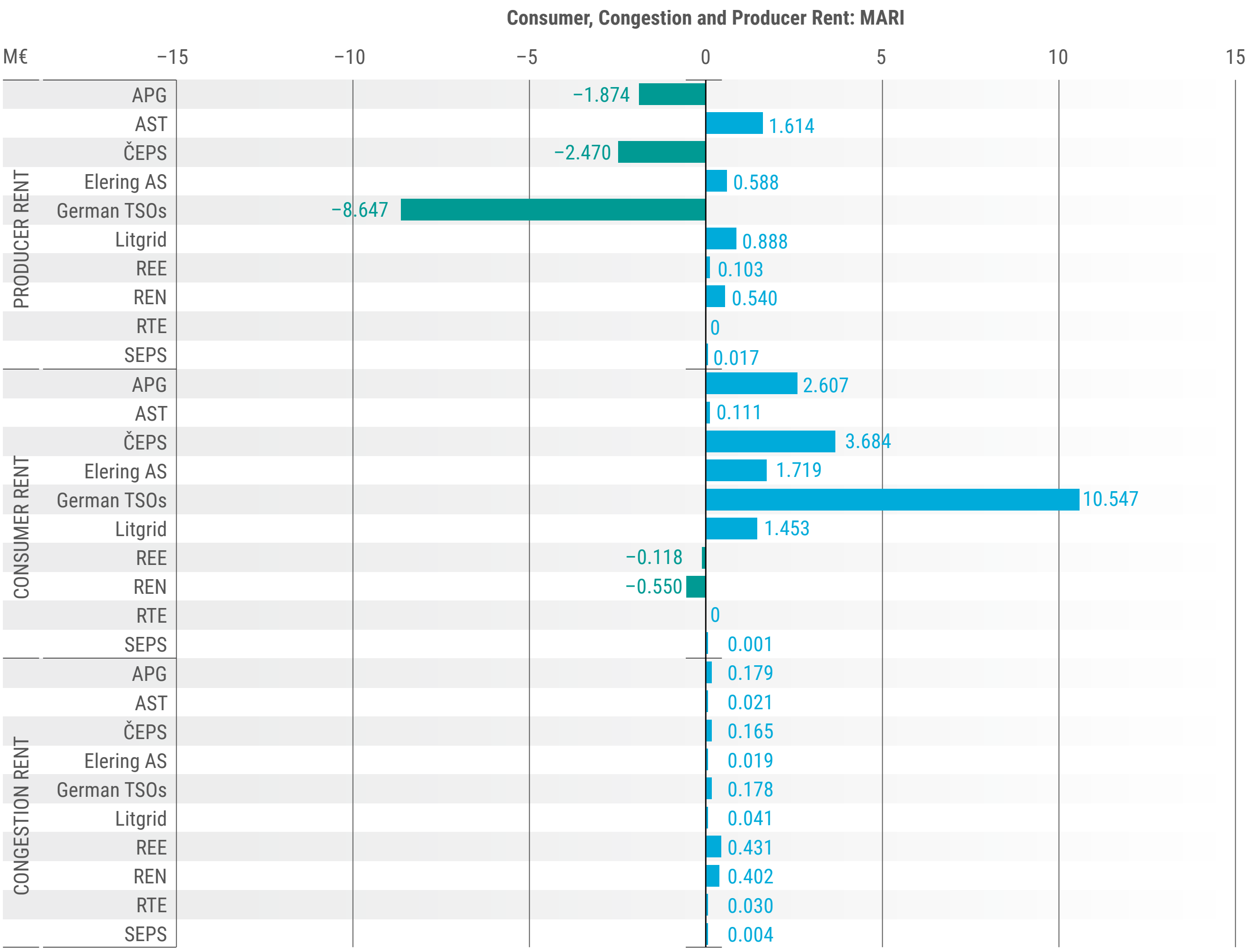
Table 6.3: Indicator 6.3.2.1 on balancing energy activation social welfare impact

KPI 6.3.2.1: aFRR platform: Social welfare impact: Producer rent, consumer rent, and congestion rent (M€)

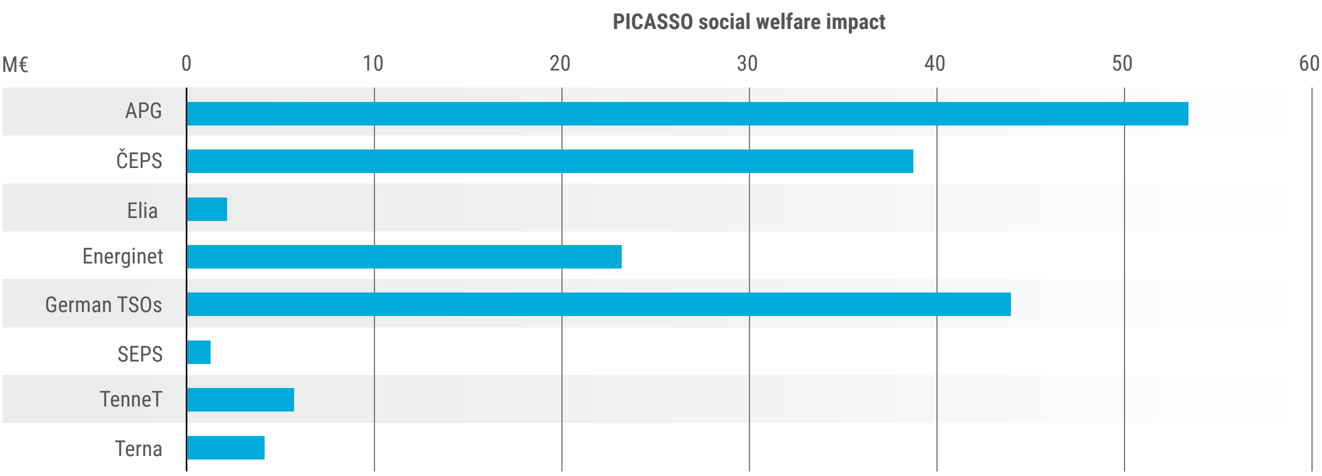
Social welfare impact is incremental, representing the difference between final social welfare and the social welfare of the decoupled run mode, rather than absolute values. Please note that the values for TSOs are impacted by their respective accession timelines.



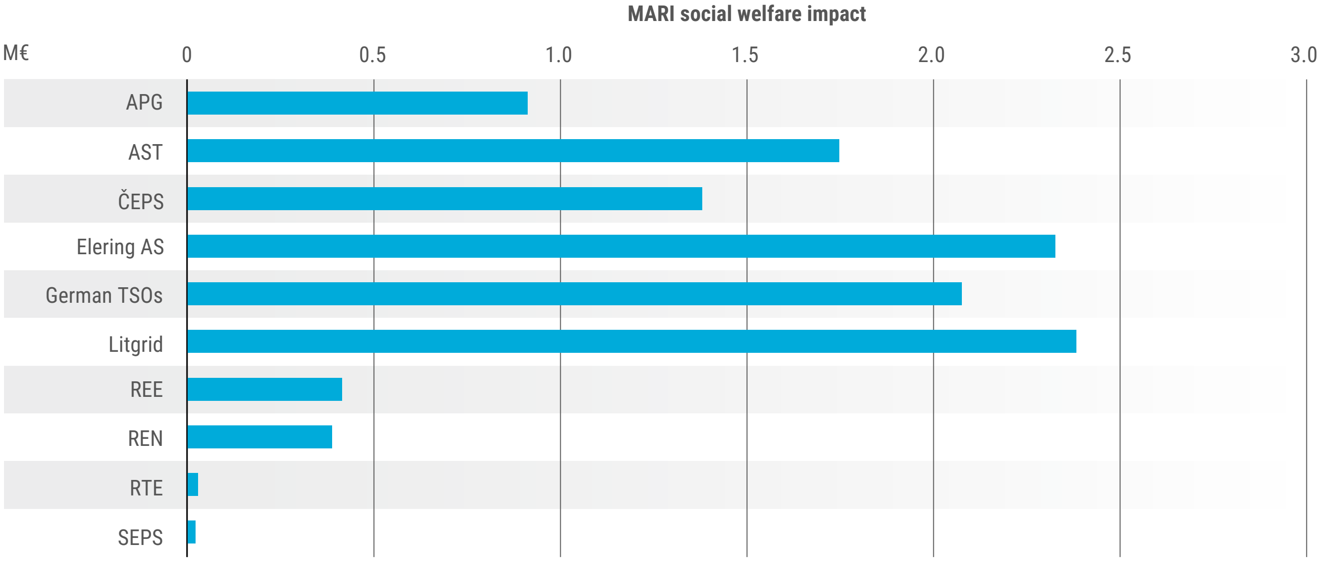
KPI 6.3.2.1: mFRR platform: Social welfare impact: Producer rent, consumer rent, and congestion rent (M€)



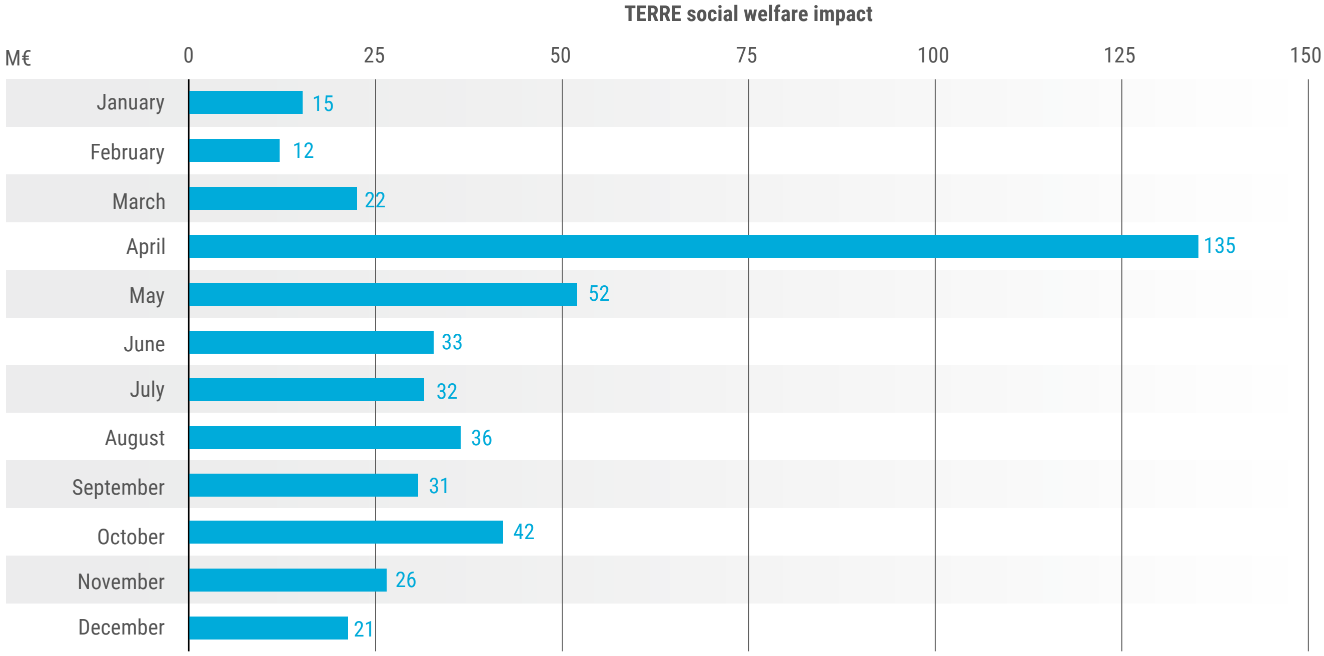
KPI 6.3.2.1: aFRR: Differential final vs dc (social welfare final – social welfare decoupled run) (M€)



KPI 6.3.2.1: mFRR: Differential final vs dc (social welfare final – social welfare decoupled run)(M€)



KPI 6.3.2.1: RR: Differential final vs dc (social welfare final – social welfare decoupled run) (M€)

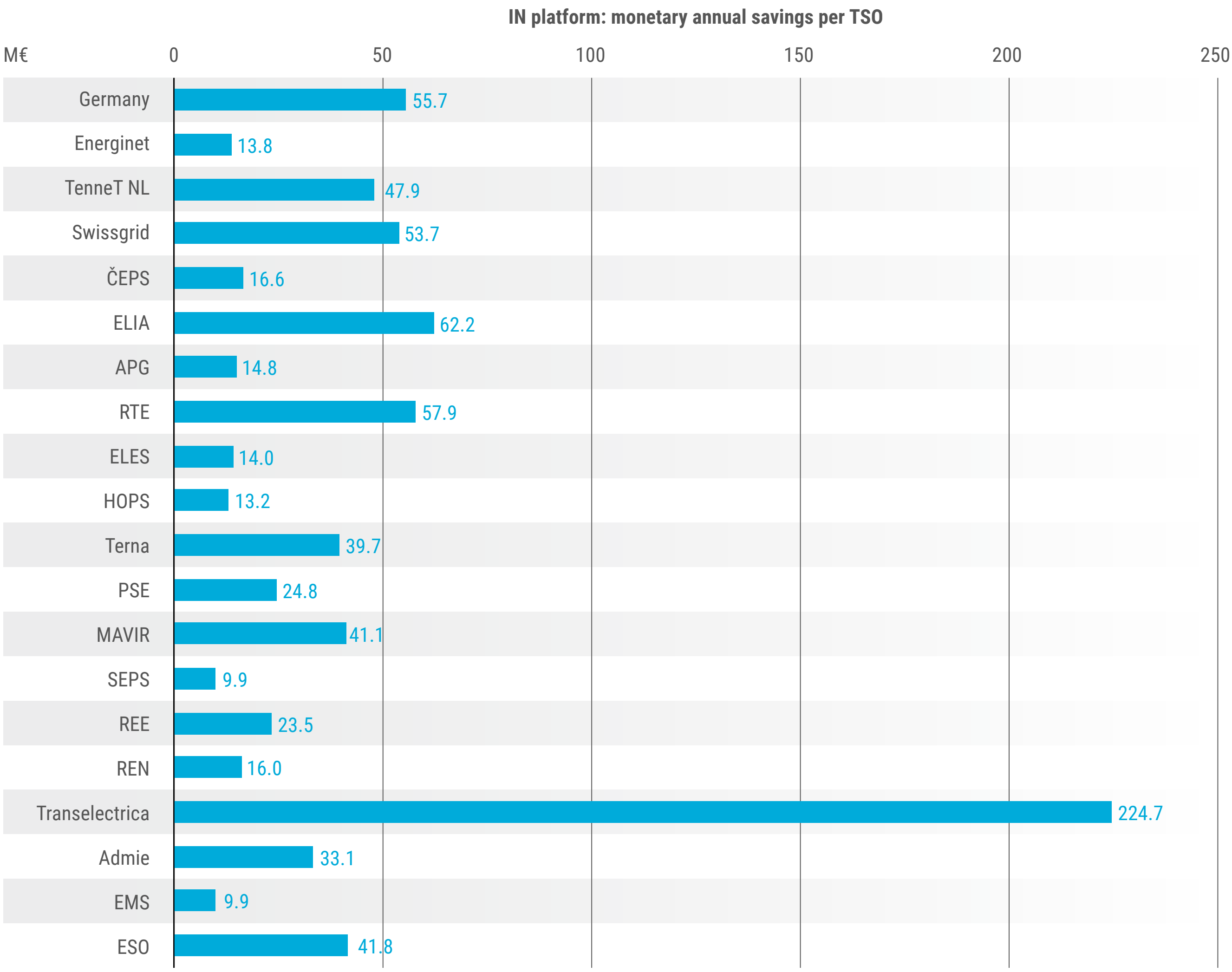


6.3.2.2 Imbalance netting savings

Definition	The monetary saving for IN is calculated based on the difference between the respective TSO's aFRR opportunity prices and its IN settlement prices, for imported or exported energy.
Legal reference	Articles 59 (4) (b) and 59 (4) (c) of EB Regulation
Time reference	Yearly

Table 6.4: Indicator 5.2.2 on imbalance netting savings

KPI 6.3.2.2: Imbalance netting savings – IN-Platform: Monetary annual savings per TSO (M€)



6.3.2.3 Sharing and exchange of reserves

Definition	The social welfare increment is calculated by comparing coupled and decoupled clearings for each market sharing and exchange balancing reserve market. The social welfare in each market is understood as: BSP surplus and TSO savings, and TSO congestion income. In the case of exchange/sharing of balancing capacity with CZC allocation, the potential negative impact on the DA market coupling social welfare will be considered. In the market-based approach, the forecasted data of energy market will be used. In the case of an inverted market-based approach, the forecasted data of the capacity market will be used. The overall social welfare assessment process at market-based/inverted market-based for computing PI 5.2.3 is thus based on forecasted bid curves.
Legal reference	Articles 59 (4) (b) and 59 (4) (c) of EB Regulation
Time reference	Yearly

Table 6.5: Sharing and exchange of reserves

KPIs on the sharing and exchange of reserves are included in Section 4.

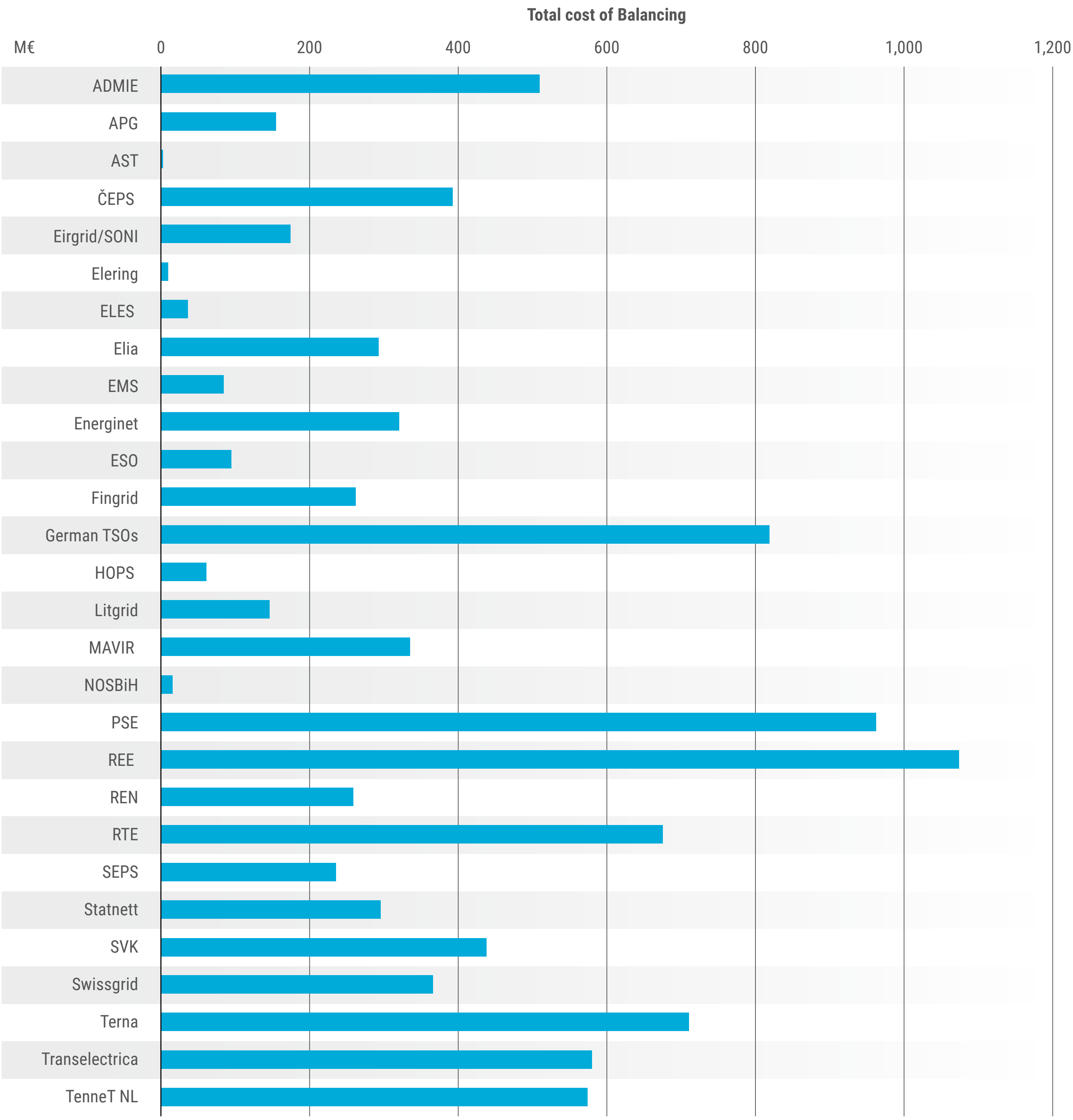
6.3.3 Total cost of balancing

Definition	This indicator calculates the annual costs (€/year) for each TSO for non-standard (local/specific) and standard products (both balancing energy activation and reserve procurement costs). For each TSO or country (e. g. Germany), the total costs of balancing will be segmented by a) FCR, aFRR, mFRR, and RR procurement reserve costs from its connected BSPs, adjusted for the results of TSO–TSO settlements of FCR, aFRR, mFRR, and RR reserves (adjusted only when any sharing/exchange of reserve schemes applies); b) the costs for the activation of balancing energy (FCR, aFRR, mFRR, and RR) from its connected BSPs (payment to BSPs minus incomes from BSPs),[34] adjusted when applicable with the results of TSO–TSO settlements of balancing energy; and c) the net result (cost) of TSO–IGCC settlement of IN. Regarding TSO–TSO settlement in the case of balancing energy platforms, congestion rents of non-participating countries should not be considered. Please note that volume weighted average price (VWAP) of balancing energy activation and reserve prices will be reported under PI 5.9.
Legal reference	Article 59 (4)(d) of the EB Regulation
Time reference	Yearly

Table 6.6: Total cost of balancing

34 Payment to BSPs (comprised of upward activation in case of positive prices plus downward activation in case of negative prices minus income from BSPs (comprised of downward activation in case of positive prices plus upward activation in case of negative prices).

KPI 6.3.3: Total cost of balancing



6.3.4 Economic efficiency and reliability of the balancing markets

Definition	This indicator asses the efficiency and reliability of each balancing platform. This indicator **focuses on the balancing energy markets only**. This PI includes the following for each balancing platform: 1. Monthly volume (MWh) and volume weighted average prices (€/MWh) of submitted bids per direction and per TSO 2. Monthly volume of demand per direction and per TSO (MWh)[35] 3. Monthly volume of selected bids per direction and per TSO (MWh)[36] 4. Repartition of the use of inelastic and elastic need per TSO (% of share of total demand being covered by elastic and inelastic demand) 5. Monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1 %, 5 %, 10 %, 90 %, 95 %, 99 %) 6. Monthly average value of the available and used CZC per BZ border and per direction (MW) 7. Monthly average value of the number of uncongested areas 8. Number of occurrences (% of MTU) of unsatisfied inelastic need/TSO and its volume (MWh) 9. Incident overview[37]
Legal reference	Article 59 (4) (e) of the EB Regulation
Time reference	Monthly

Table 6.7: Indicator 5.4 on the economic efficiency and reliability of the balancing markets

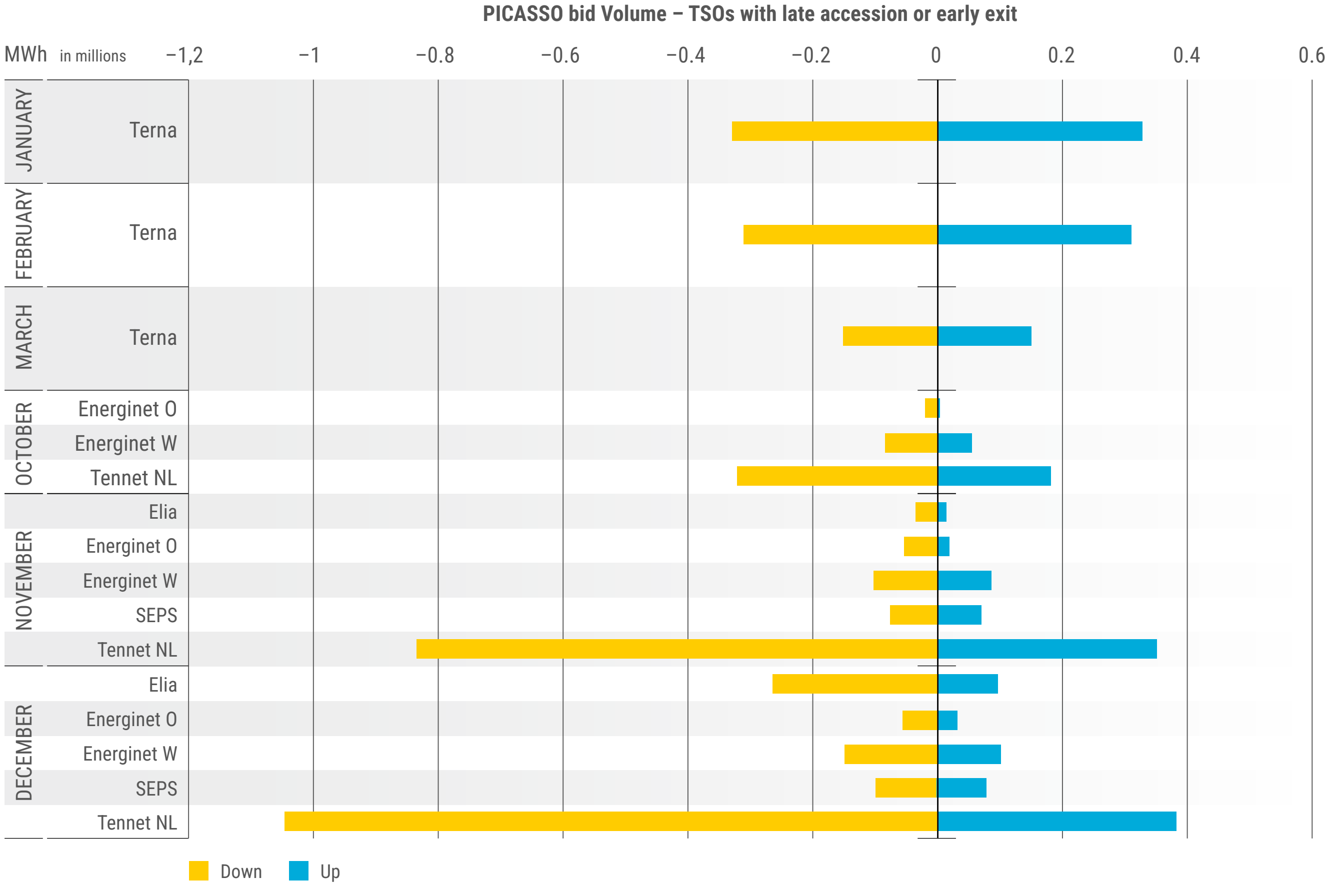
35 For 3.4.2, TSOs will provide one single graph representing total demand upward/downward of all products per TSO.

36 For 3.4.3, TSOs will provide one single graph representing total selected bids for upward/downward of all products per TSO.

37 For 3.4.9, TSOs will include a reference to the platforms operational reports instead of reporting it in Market/Balancing Reports.

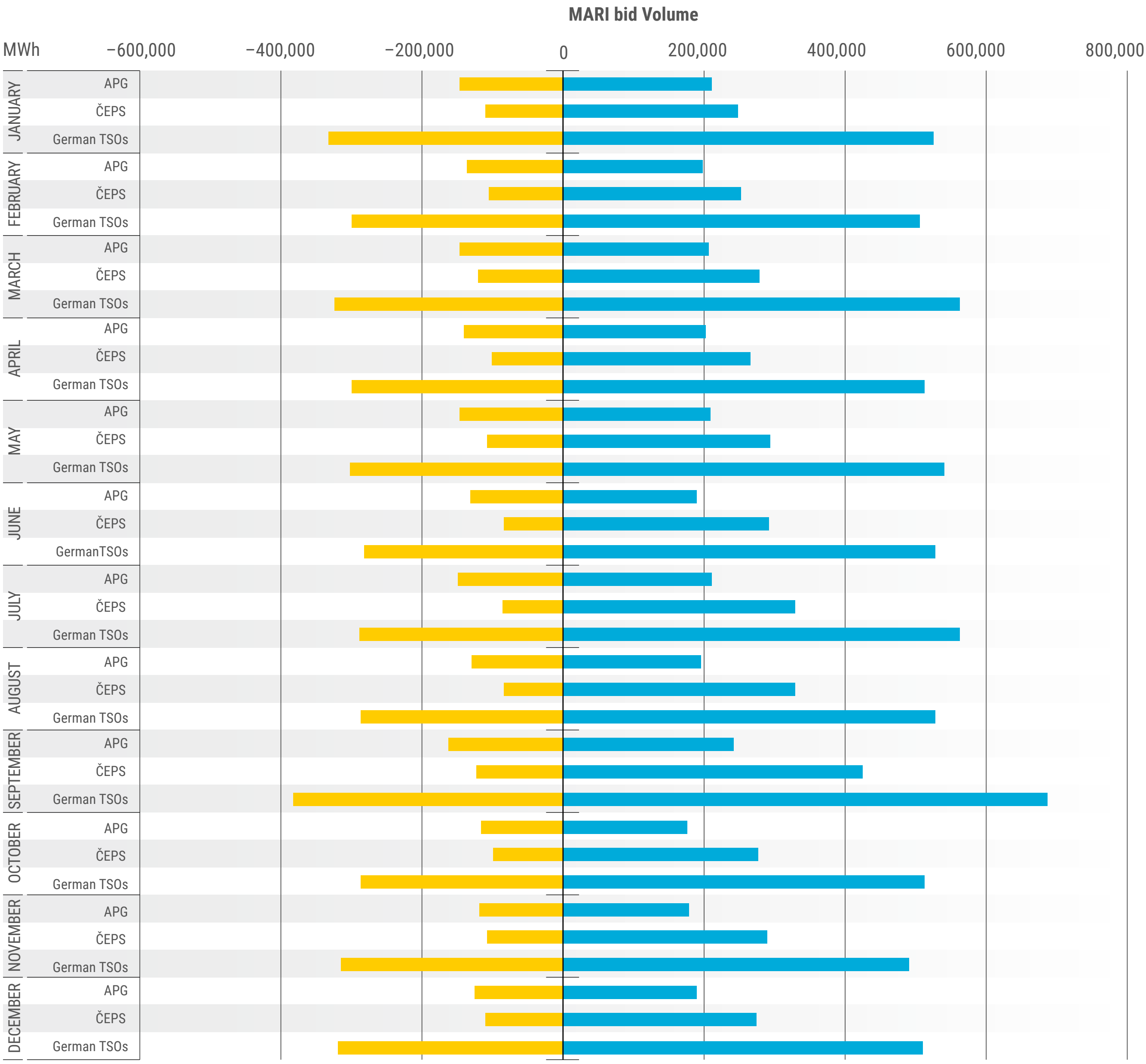
KPI 6.3.4.1: aFRR platform: Monthly volume (MWh) of submitted bids per direction and per TSO

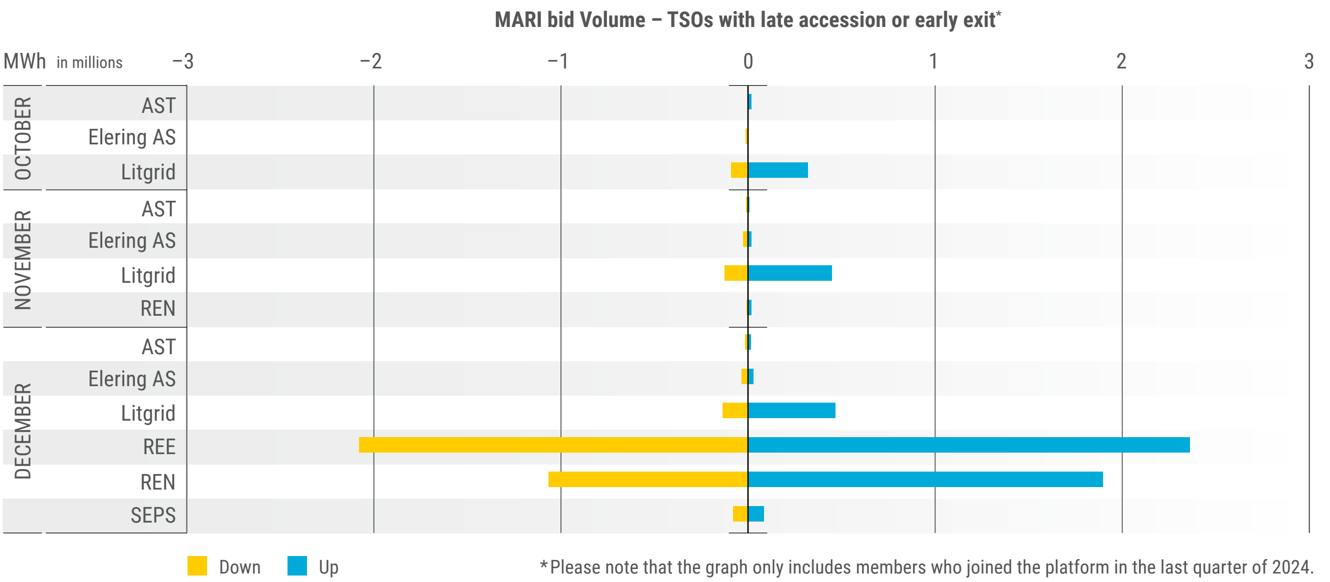
APG


PICASSO bid Volume – TSOs with late accession or early exit
MWh in millions
−1,2
−1
−0.8
−0.6
−0.4
−0.2
0
0.2
0.4
0.6
JANUARY
Terna
FEBRUARY
Terna
MARCH
Terna
OCTOBER
Energinet O
Energinet W
Tennet NL
NOVEMBER
Elia
Energinet O
Energinet W
SEPS
Tennet NL
DECEMBER
Elia
Energinet O
Energinet W
SEPS
Tennet NL
Down
Up

KPI 6.3.4.1: mFRR platform: Monthly volume (MWh) of submitted bids per direction and per TSO

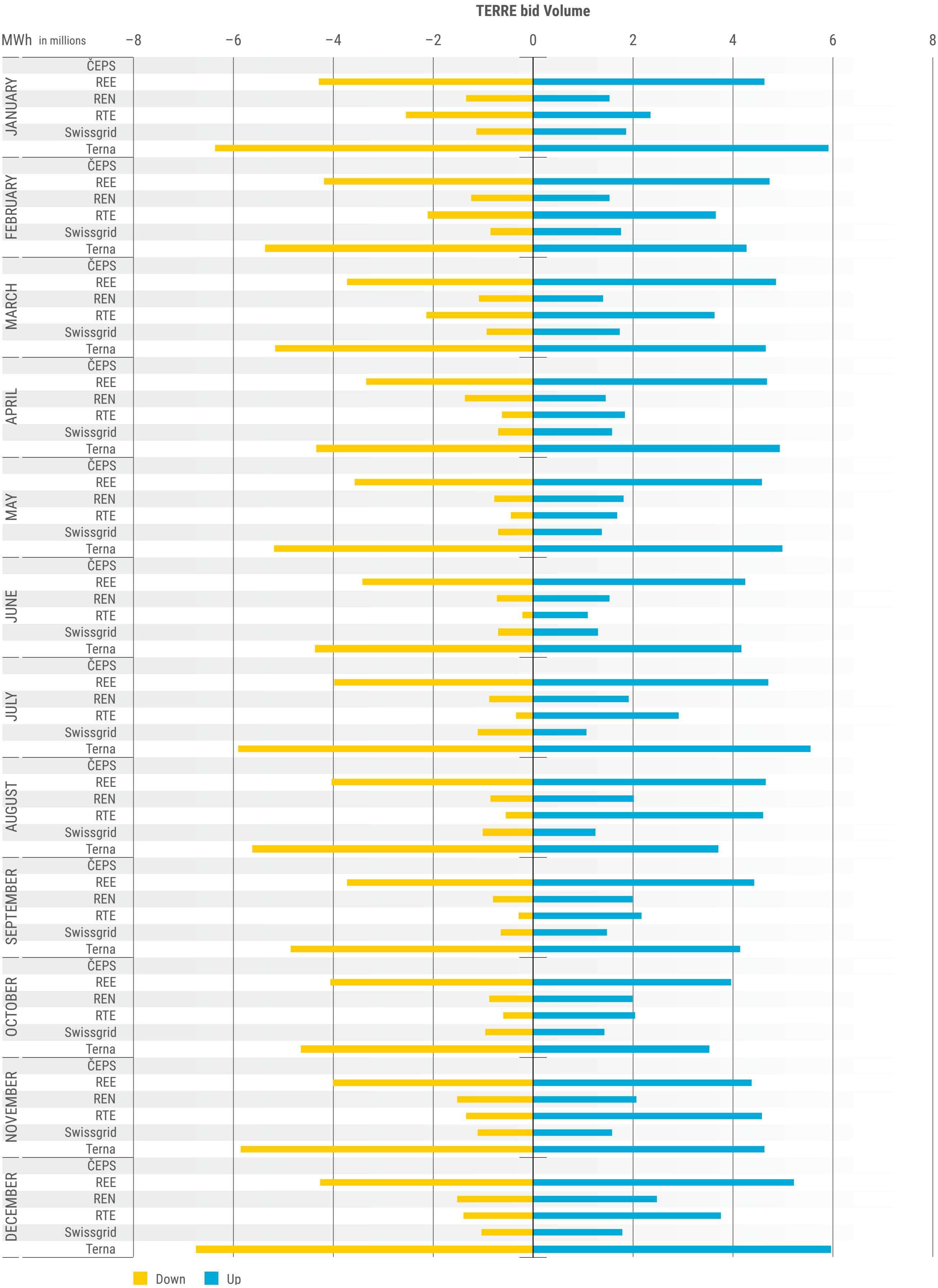
The data for this indicator is represented in two graphs – one including the year-round platform members and one including the members that joined the platform in the last quarter of 2024. Each graph uses a different scale.



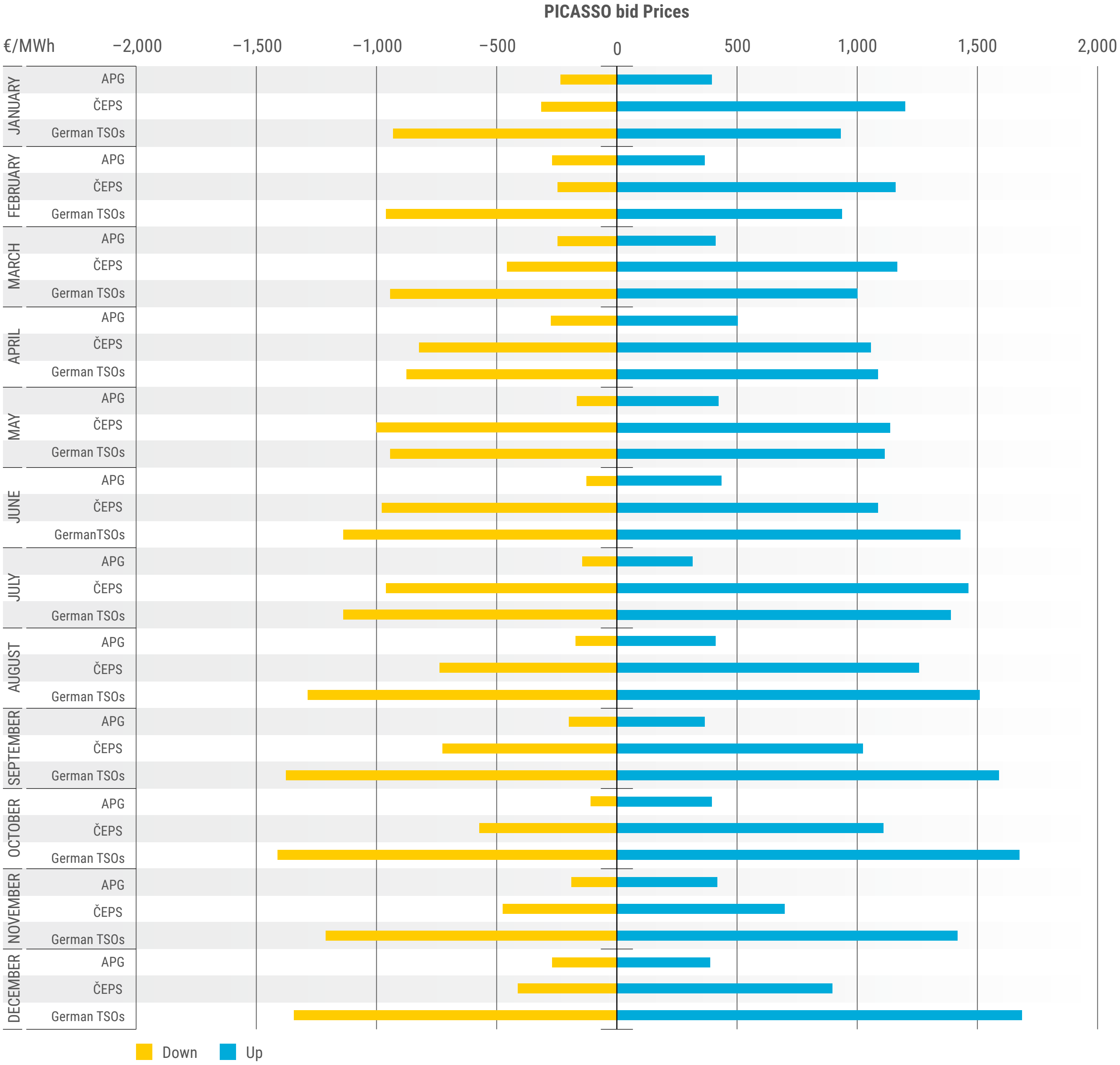


*Please note that the graph only includes members who joined the platform in the last quarter of 2024.

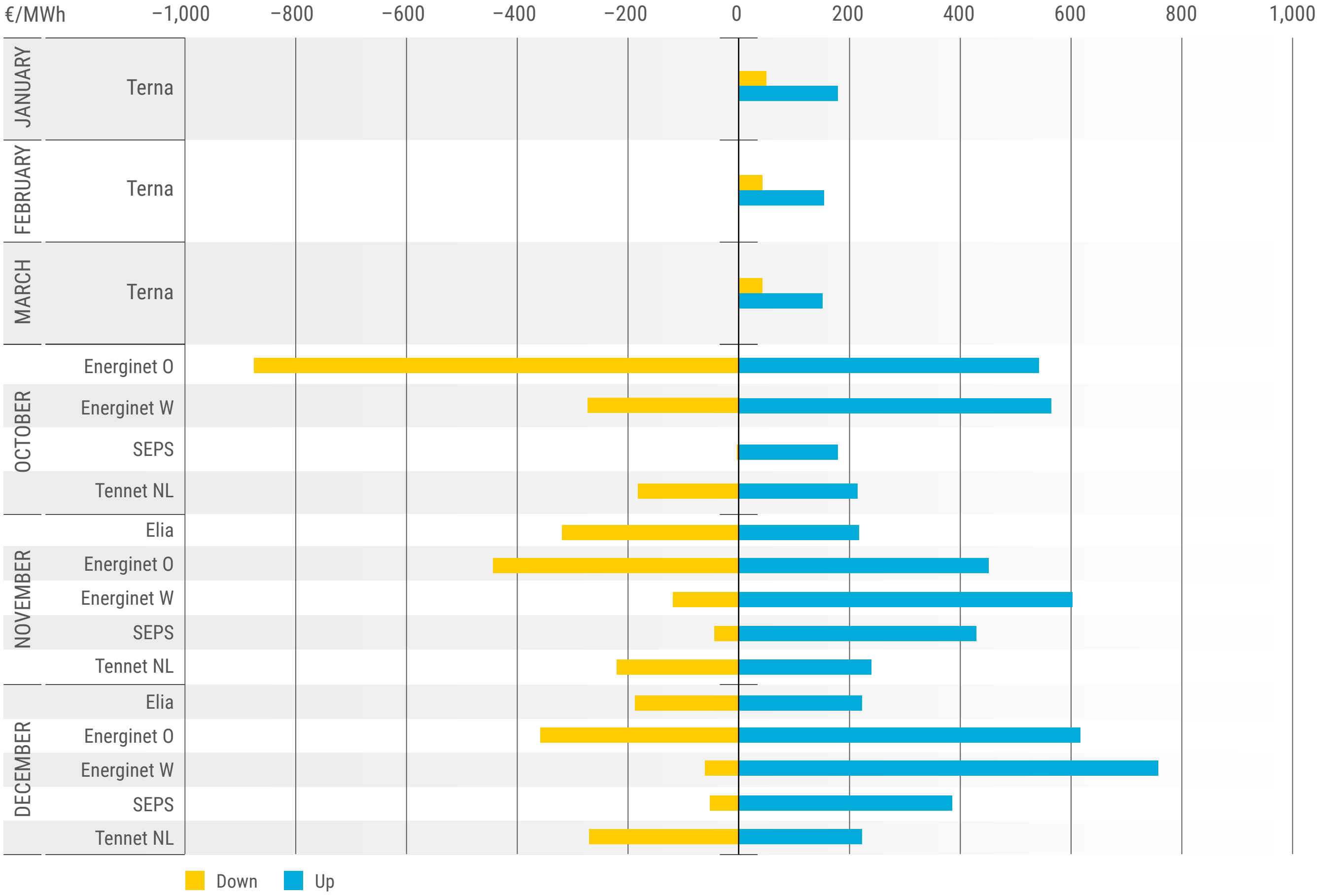
KPI 6.3.4.1: RR platform: Monthly volume (MWh) of submitted bids per direction and per TSO



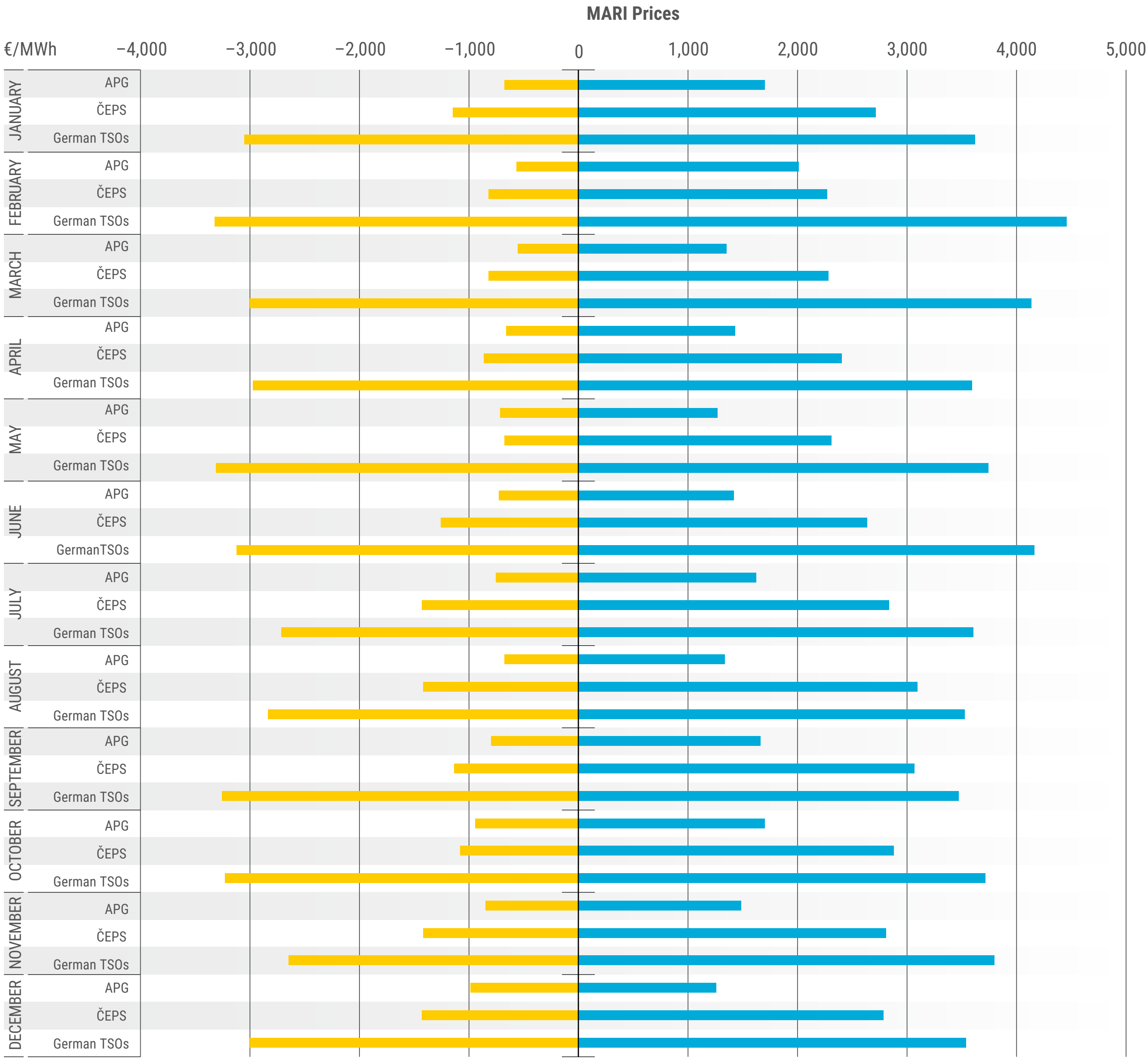
KPI 6.3.4.1: aFRR platform: Volume weighted average prices (€/MWh) of submitted bids per direction and per TSO

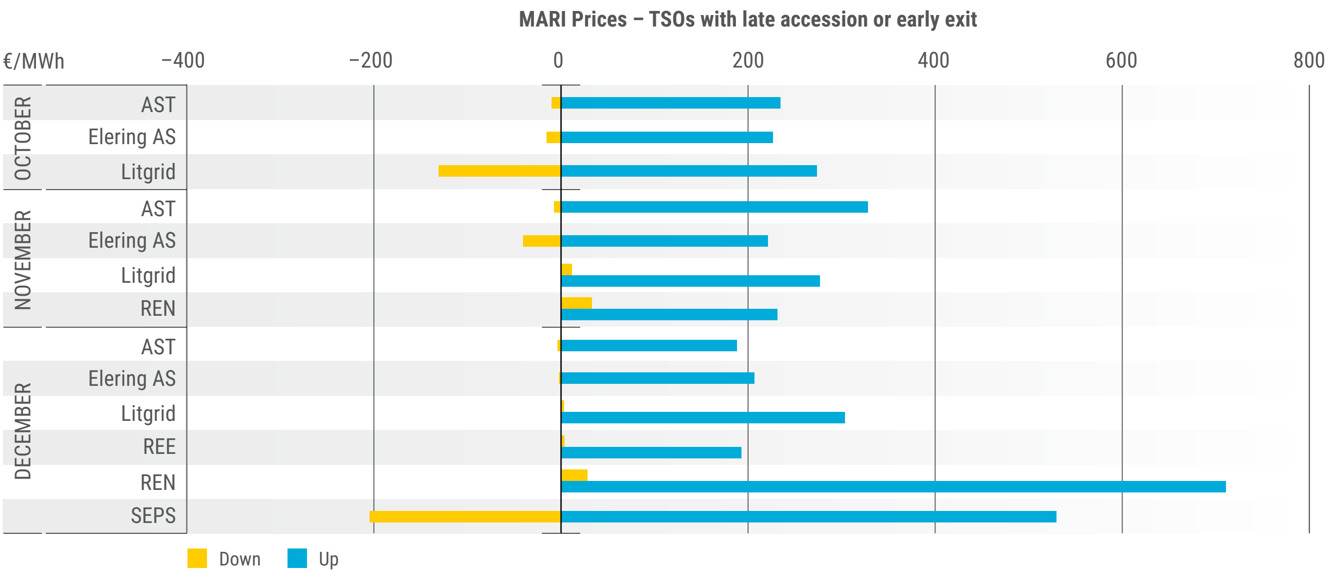


PICASSO Prices – TSOs with late accession or early exit

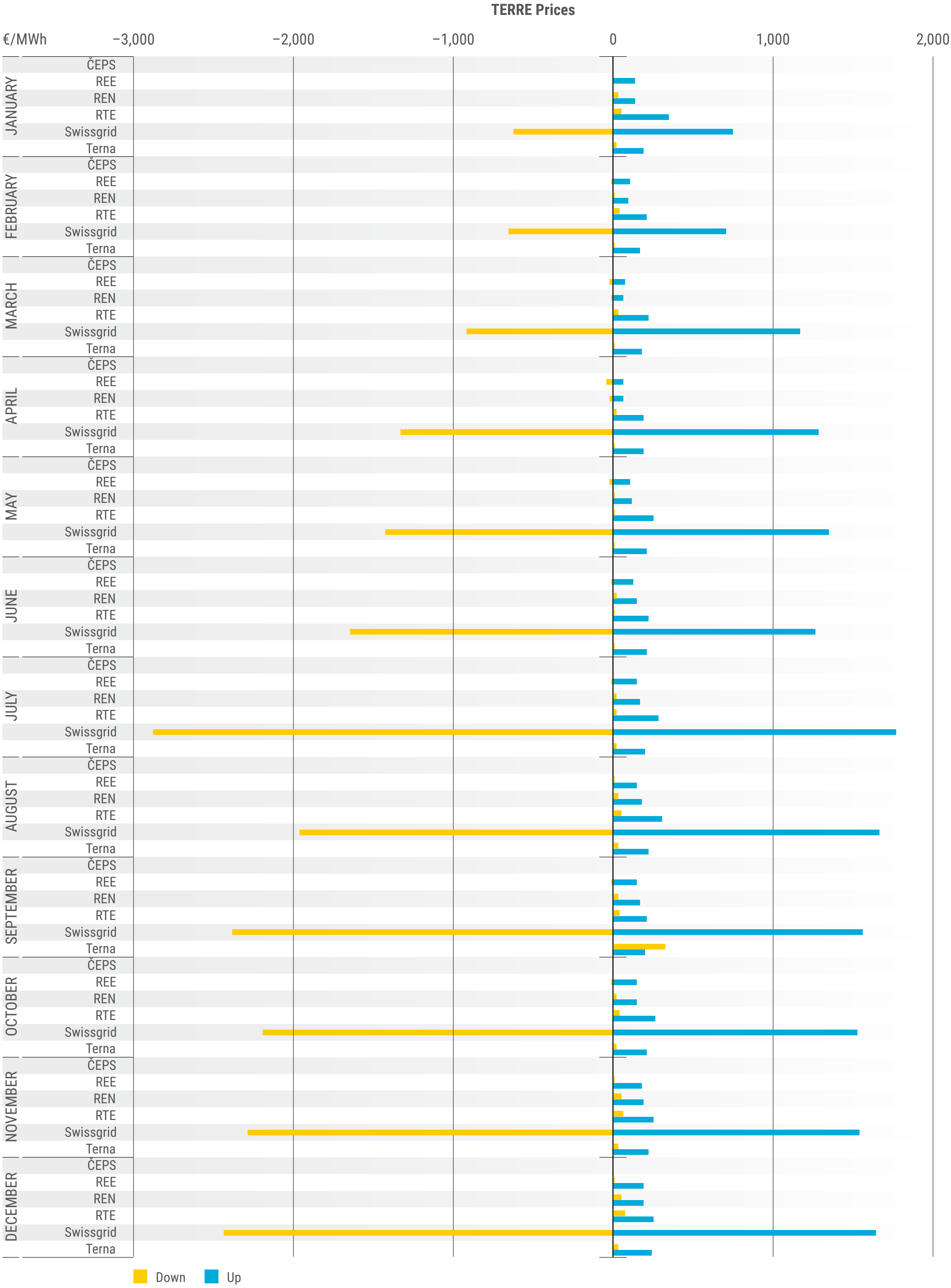


KPI 6.3.4.1: mFRR platform: Volume weighted average prices (€/MWh) of submitted bids per direction and per TSO

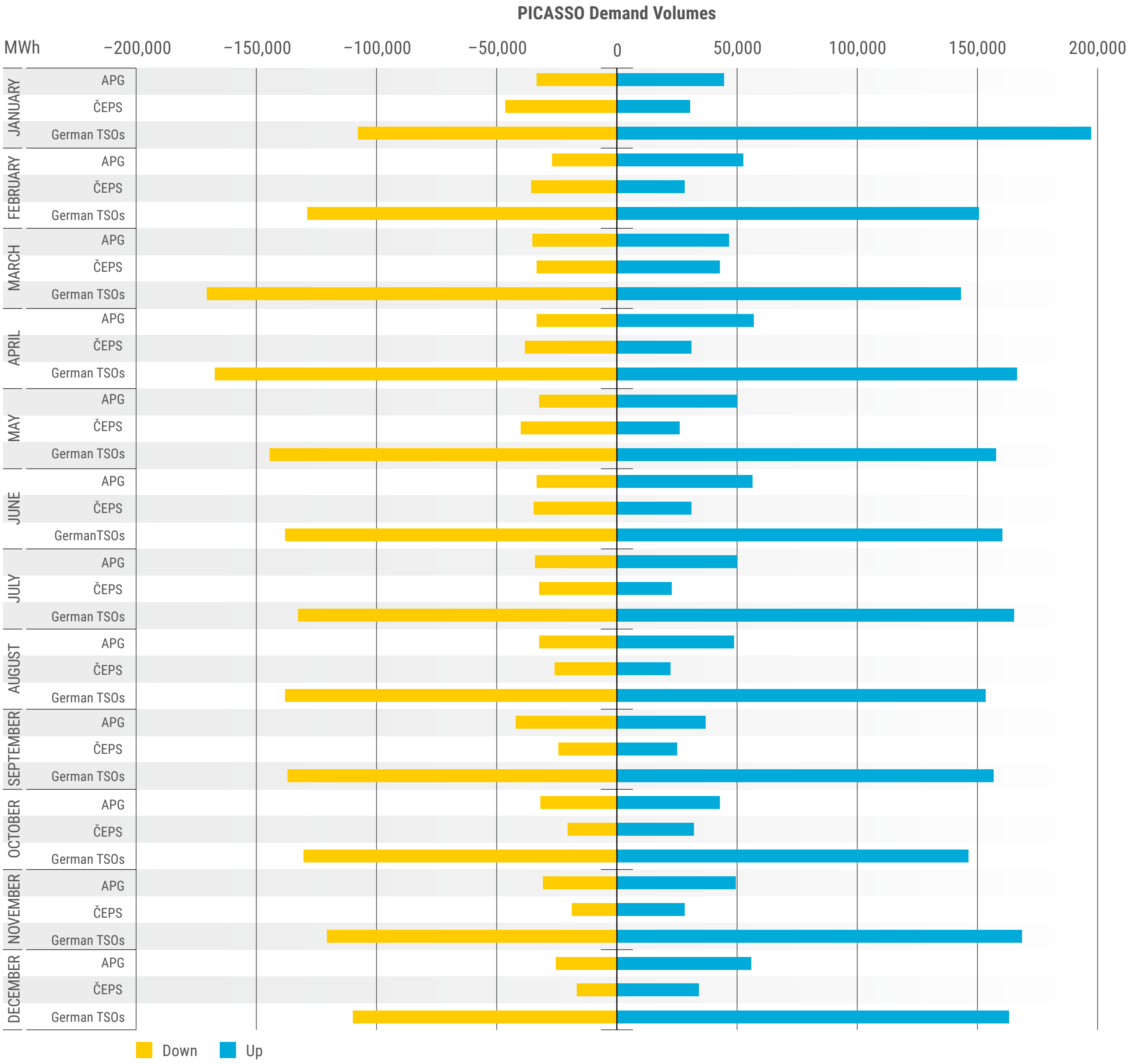




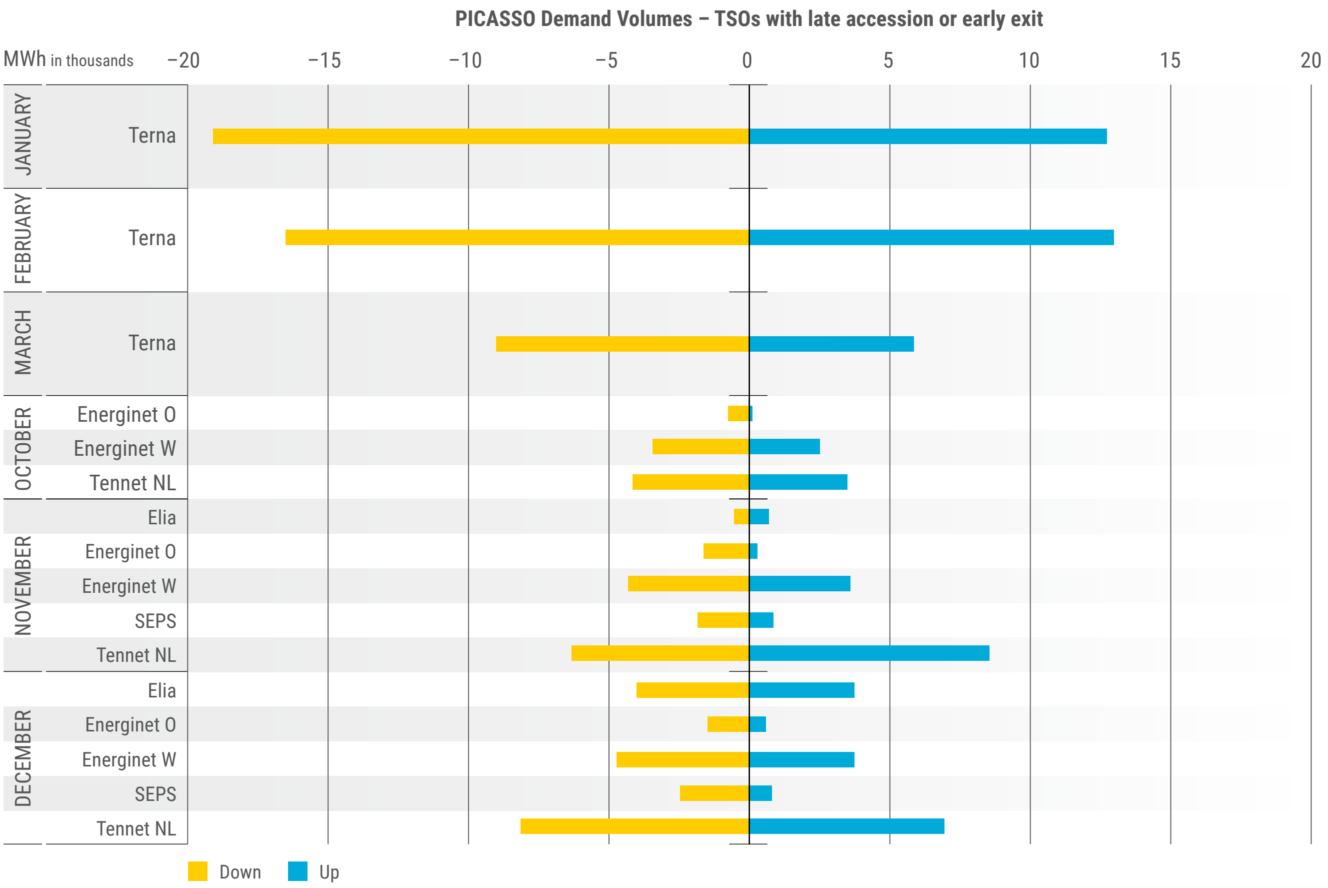
KPI 6.3.4.1: RR platform: Volume weighted average prices (€/MWh) of submitted bids per direction and per TSO



KPI 6.3.4.2: aFRR platform: Monthly volume of demand per direction and per TSO (MWh)



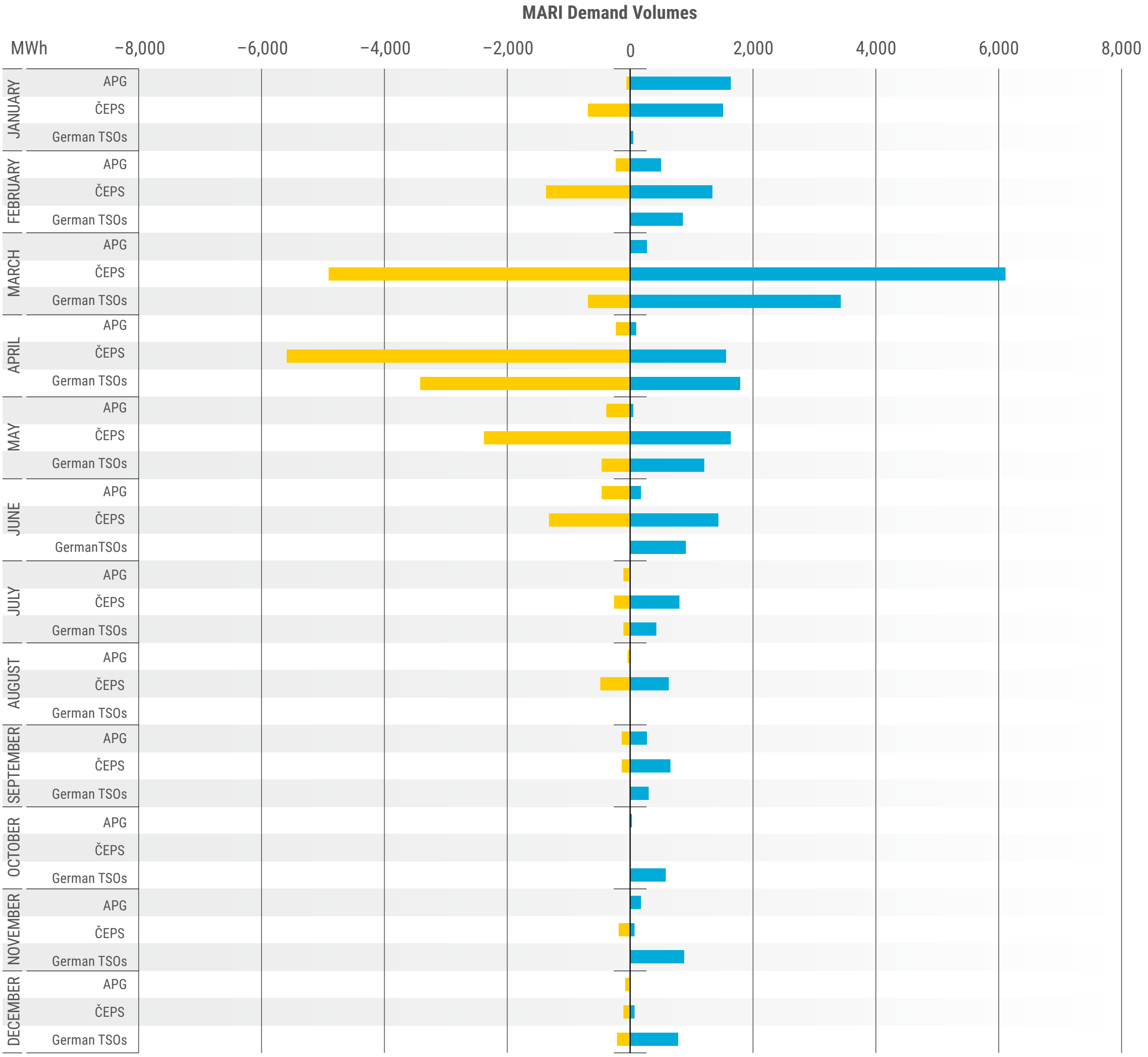
APG

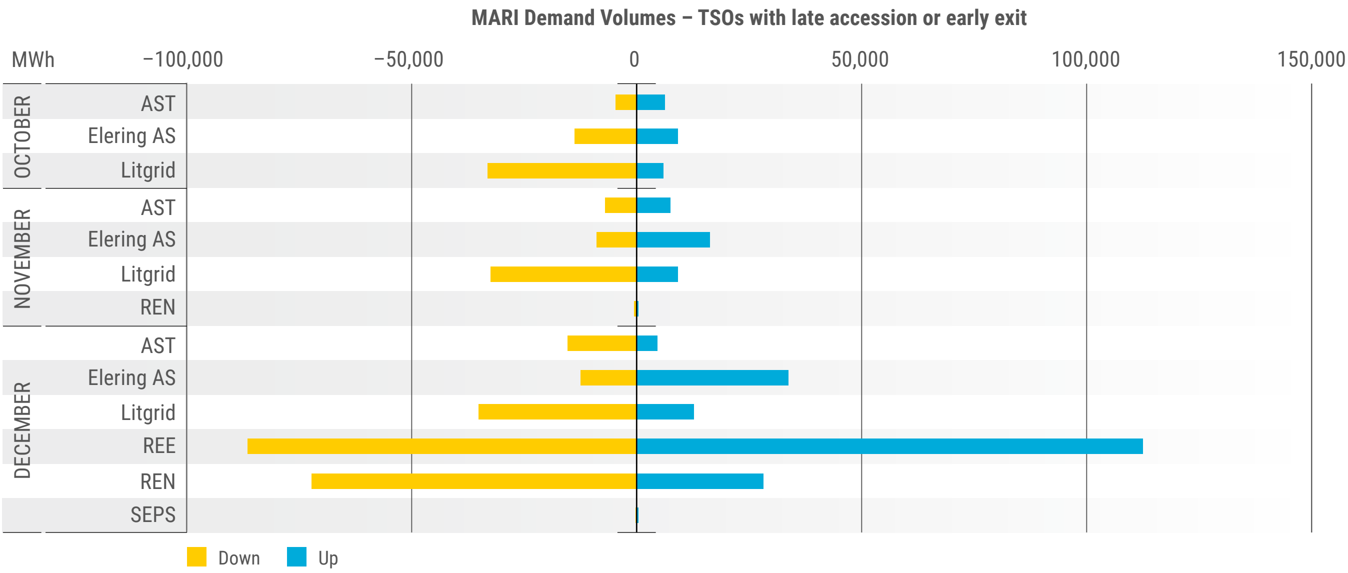


PICASSO Demand Volumes – TSOs with late accession or early exit
MWh in thousands
−20
−15
−10
−5
0
5
10
15
20
JANUARY
Terna
FEBRUARY
Terna
MARCH
Terna
OCTOBER
Energinet O
Energinet W
Tennet NL
NOVEMBER
Elia
Energinet O
Energinet W
SEPS
Tennet NL
DECEMBER
Elia
Energinet O
Energinet W
SEPS
Tennet NL
Down
Up

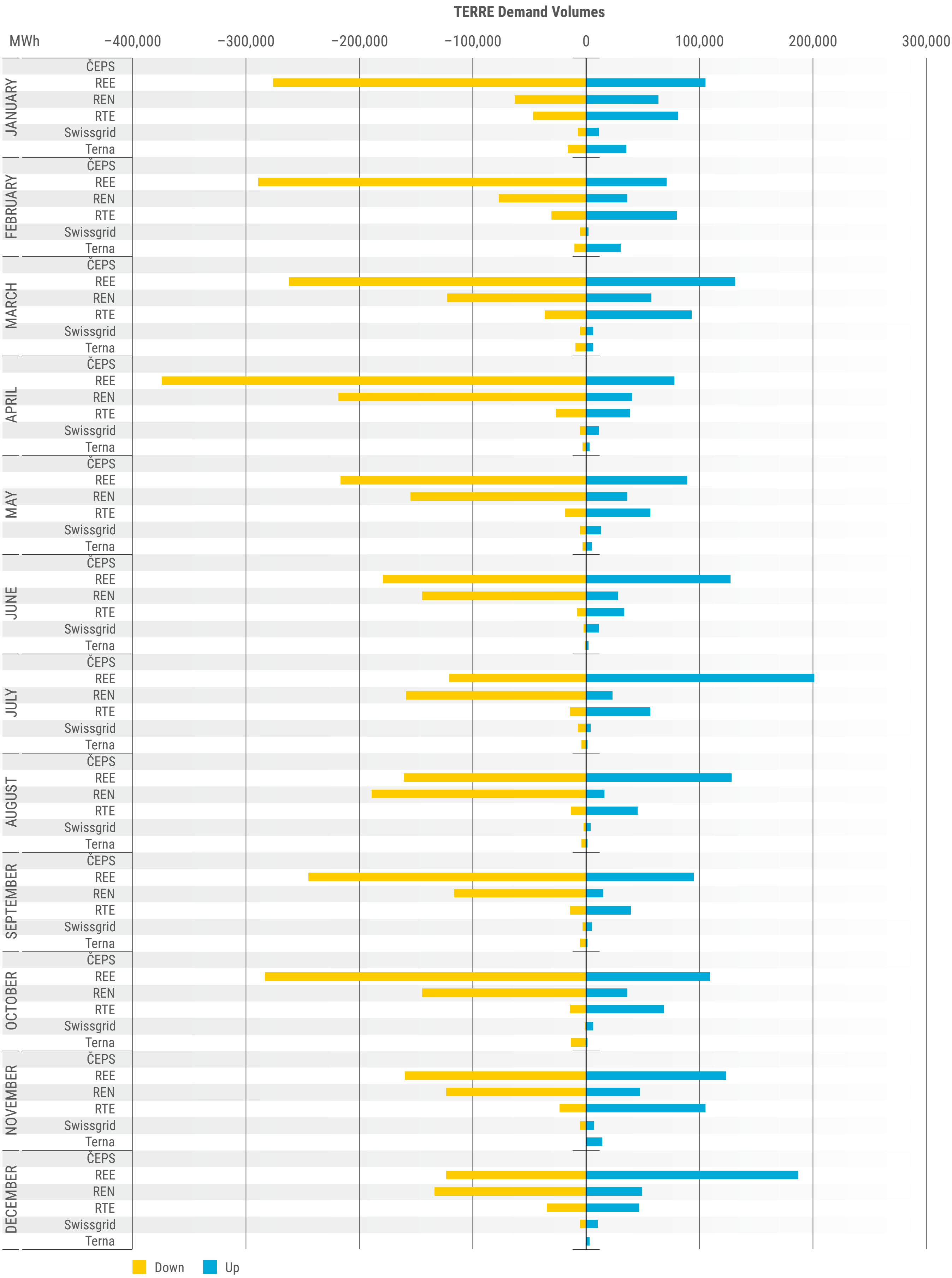
KPI 6.3.4.2: mFRR platform: Monthly volume of demand per direction and per TSO (MWh)

Please note that the graph is split over two pages, and that the axes of the first half are at a different scale.

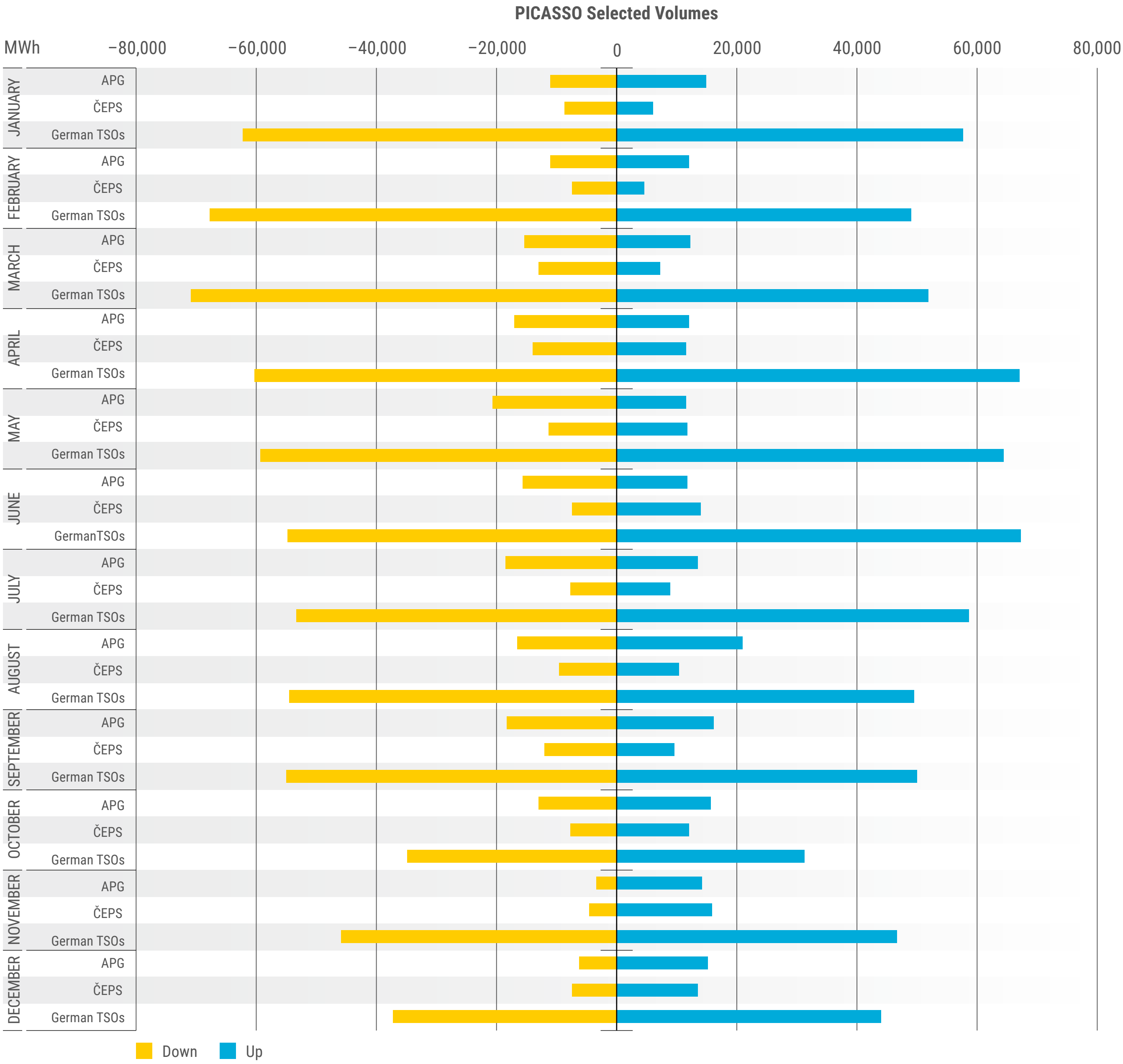




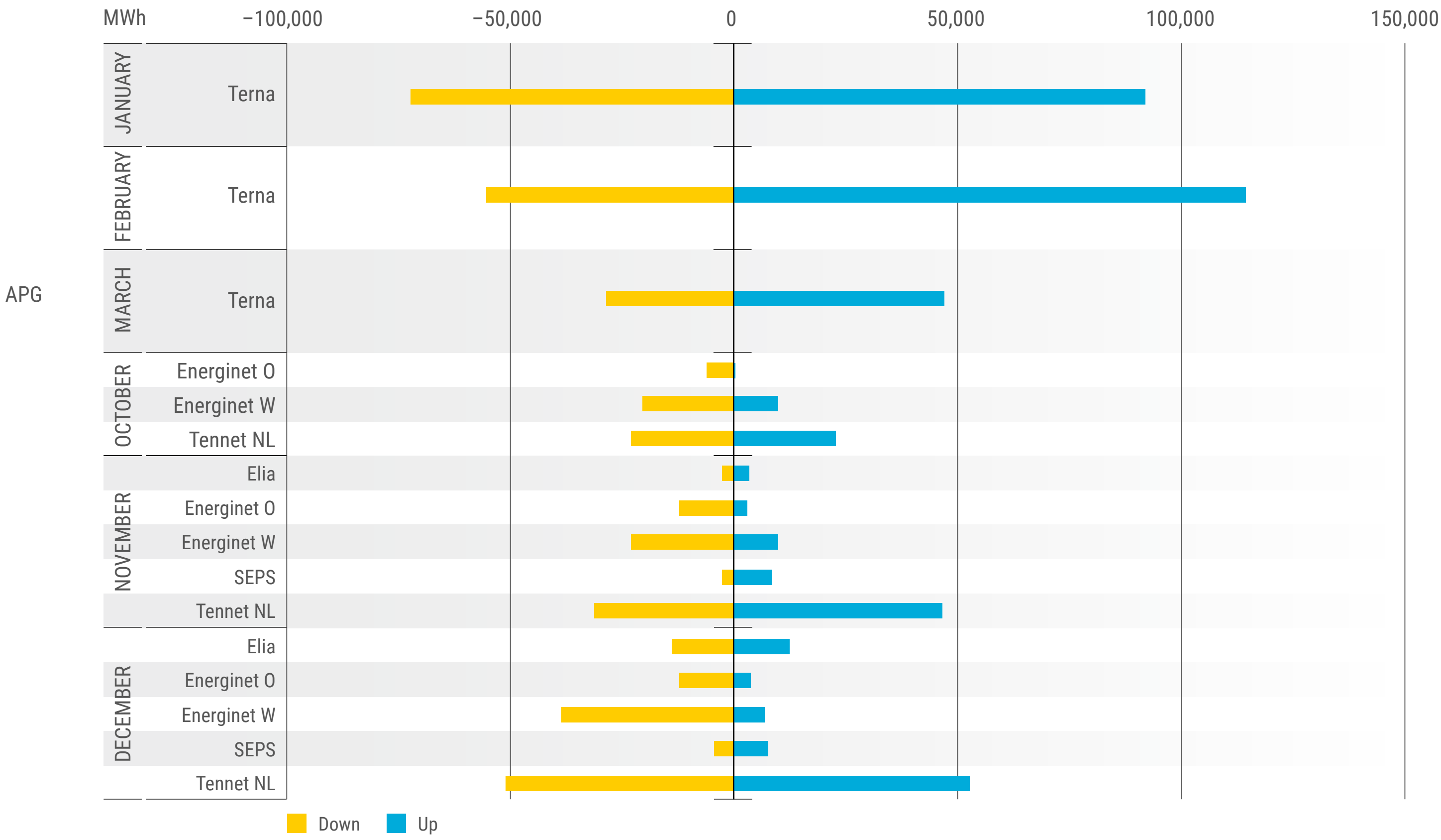
KPI 6.3.4.2: RR platform: Monthly volume of demand per direction and per TSO (MWh)



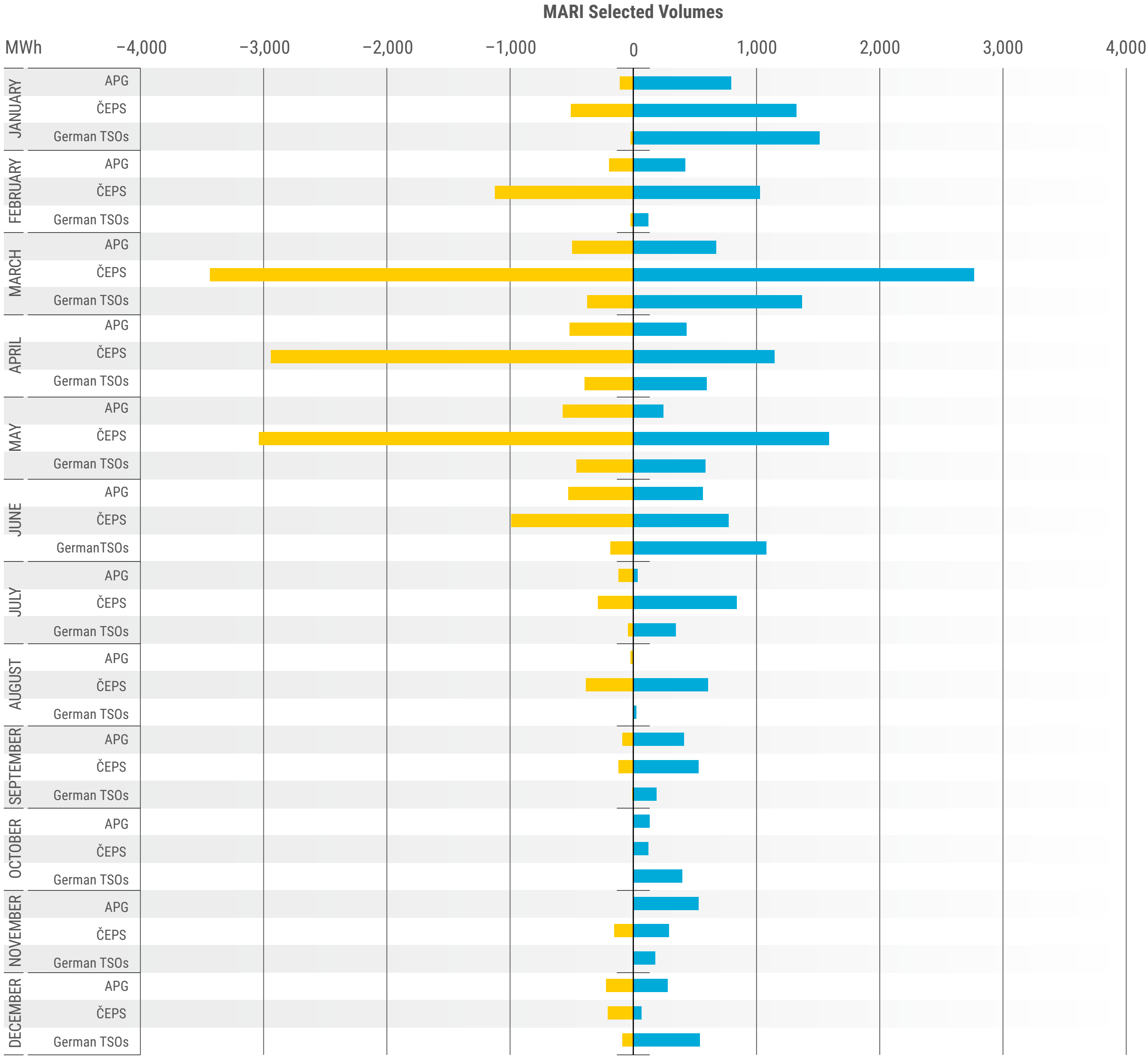
KPI 6.3.4.3: aFRR platform: Monthly volume of selected bids per direction and per TSO (MWh)

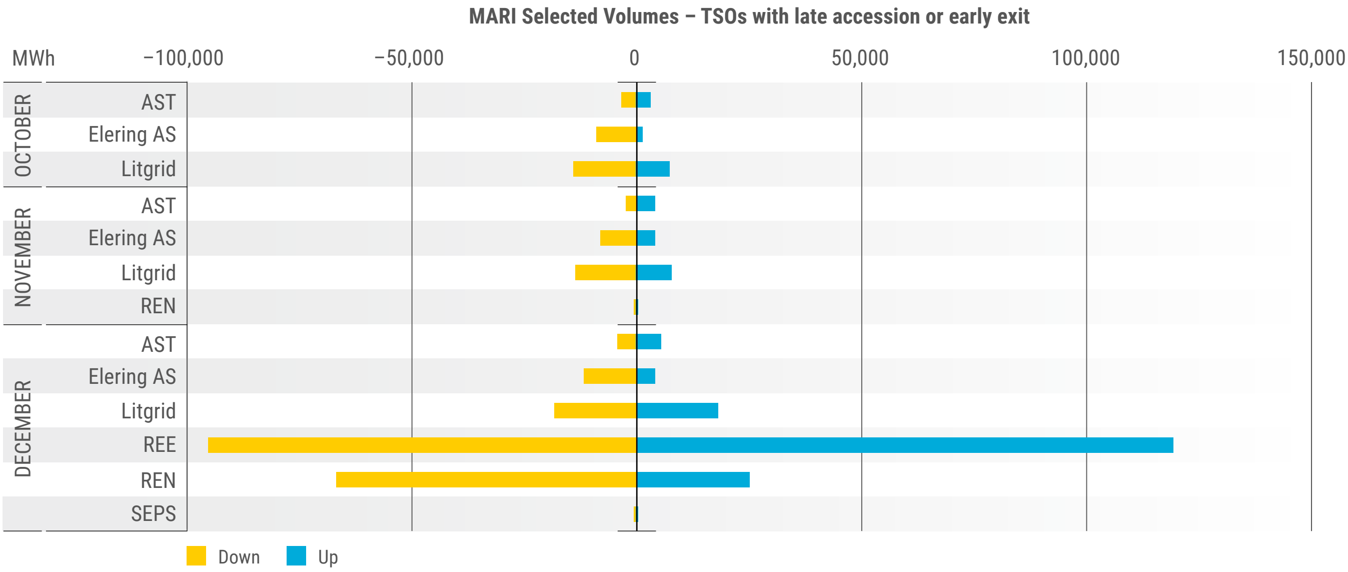


PICASSO Selected Volumes – TSOs with late accession or early exit

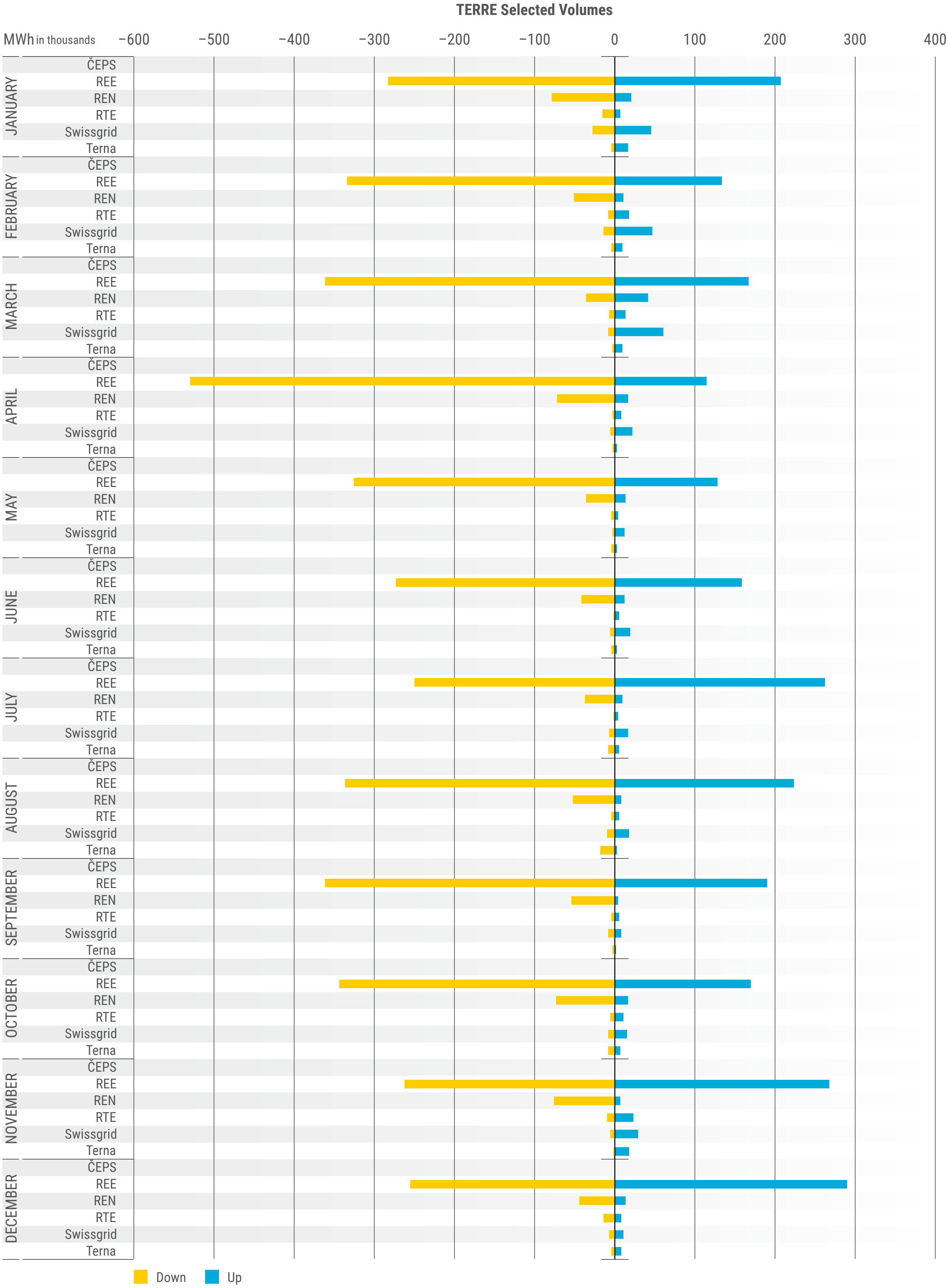


KPI 6.3.4.3: mFRR platform: Monthly volume of selected bids per direction and per TSO (MWh)

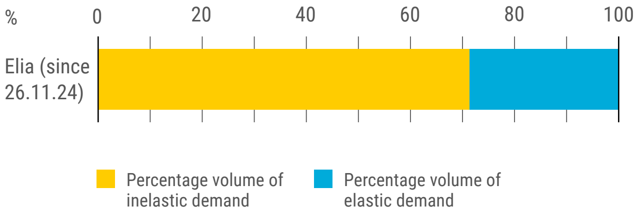




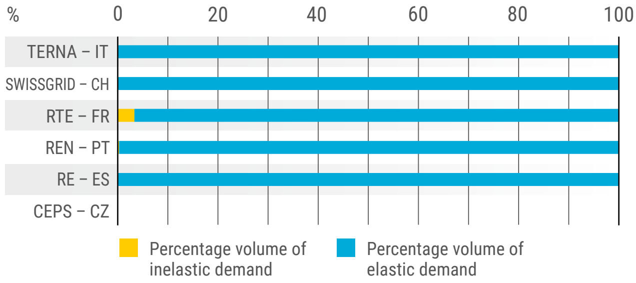
KPI 6.3.4.3: RR platform: Monthly volume of selected bids per direction and per TSO (MWh)



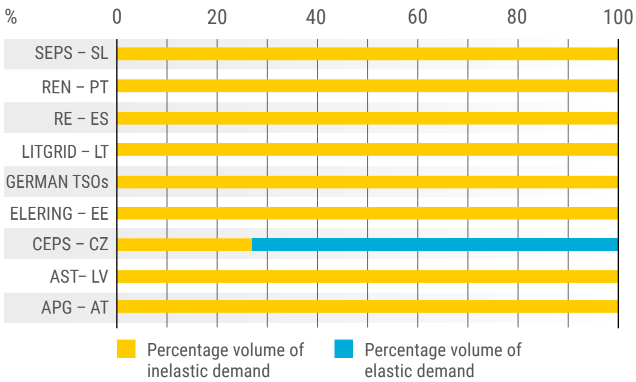
KPI 6.3.4.4: aFRR platform: Repartition of the use of inelastic and elastic need per TSO (% of share of total demand being covered by elastic and inelastic demand)



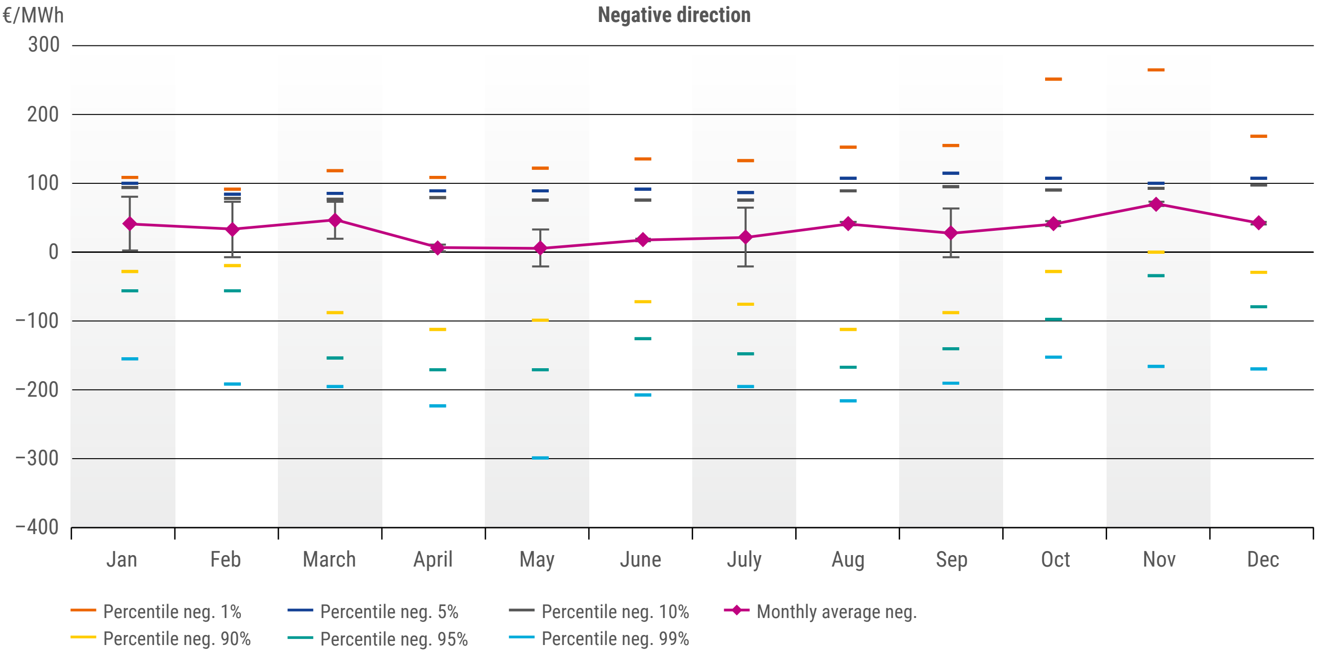
KPI 6.3.4.4: RR platform: Repartition of the use of inelastic and elastic need per TSO (% of share of total demand being covered by elastic and inelastic demand)

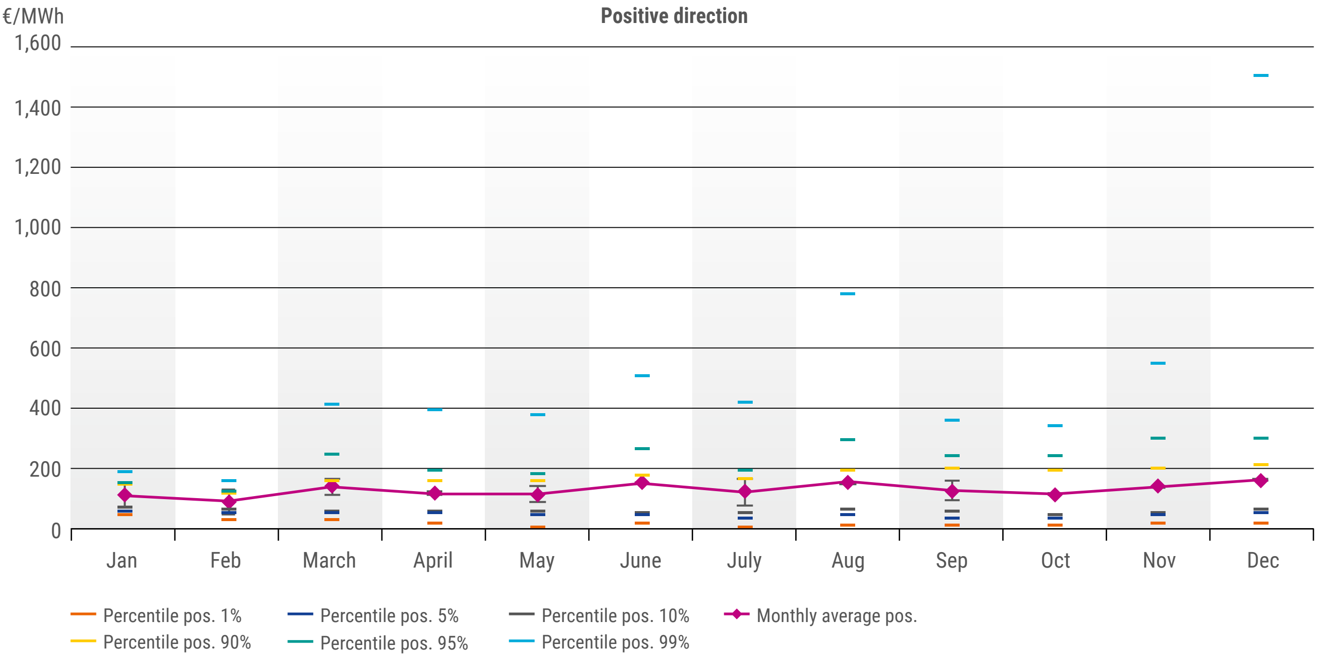


KPI 6.3.4.4: mFRR platform: Repartition of the use of inelastic and elastic need per TSO (% of share of total demand being covered by elastic and inelastic demand)

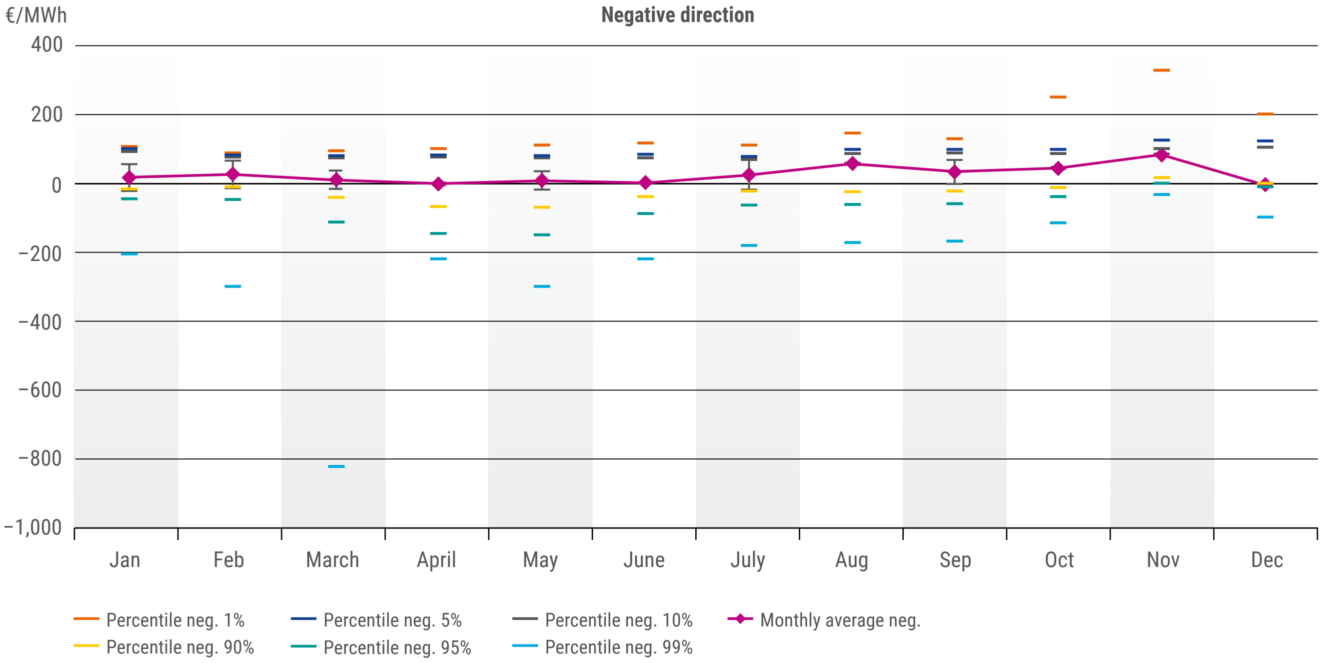


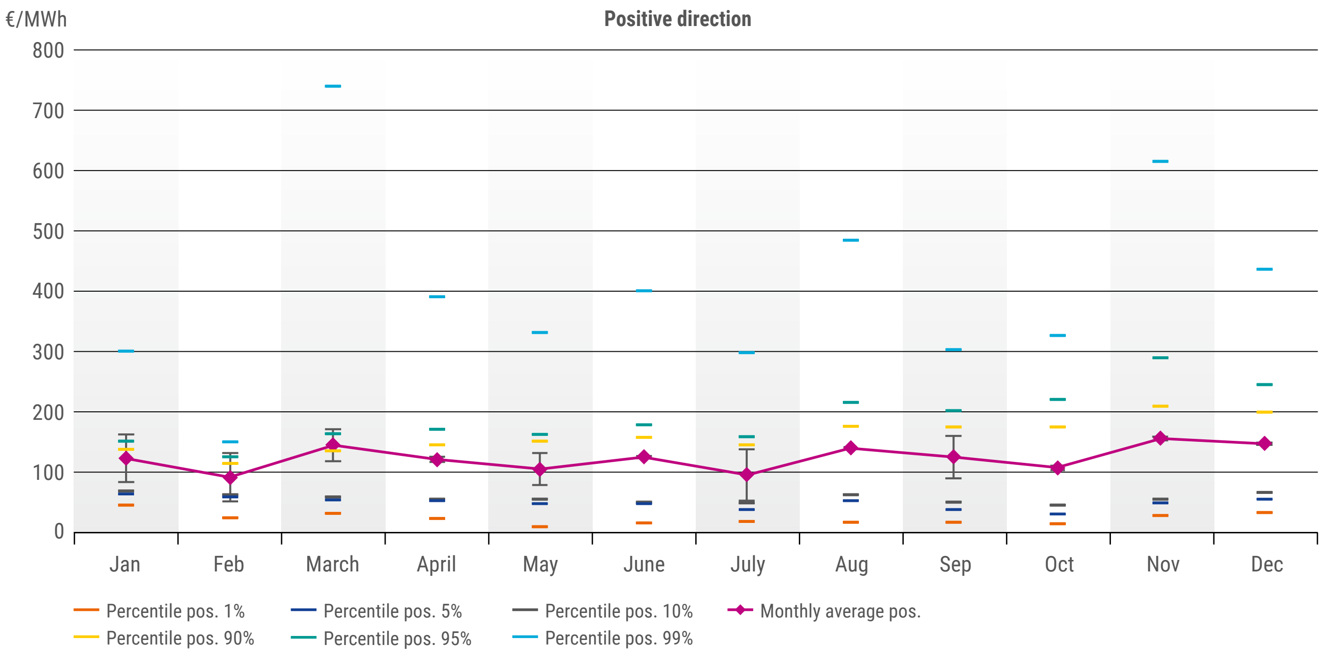
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – German TSOs (€/MWh)



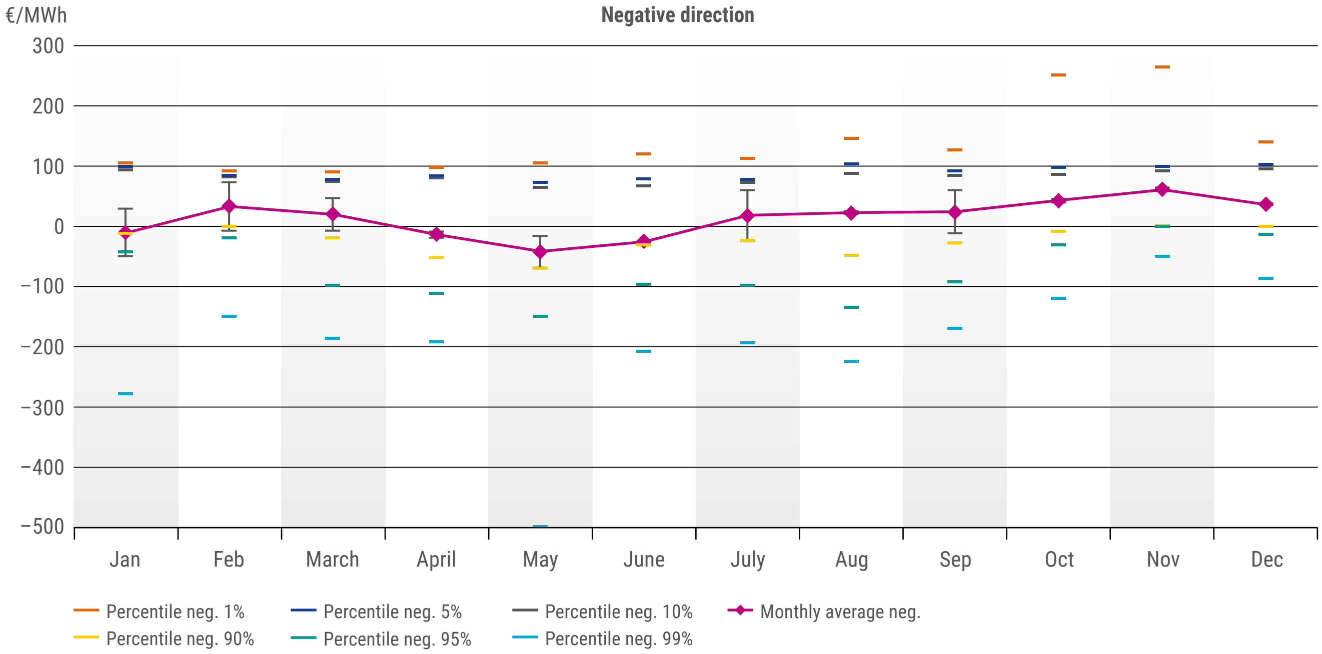


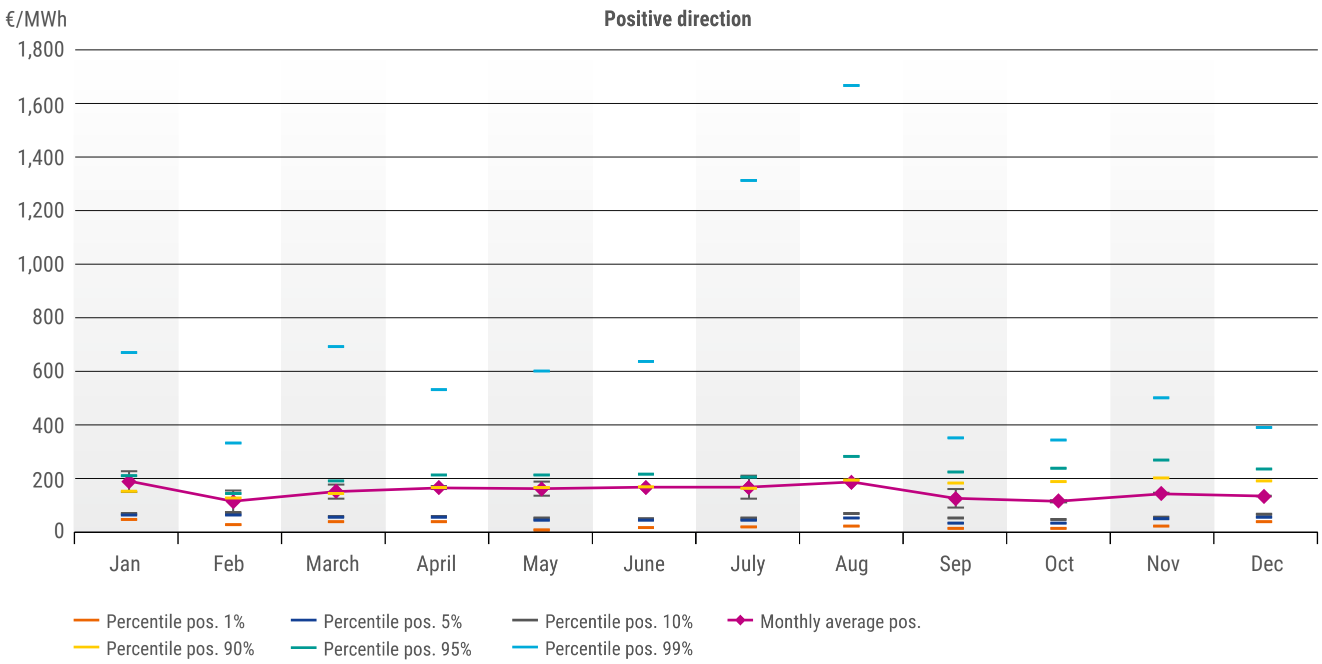
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – APG (€/MWh)



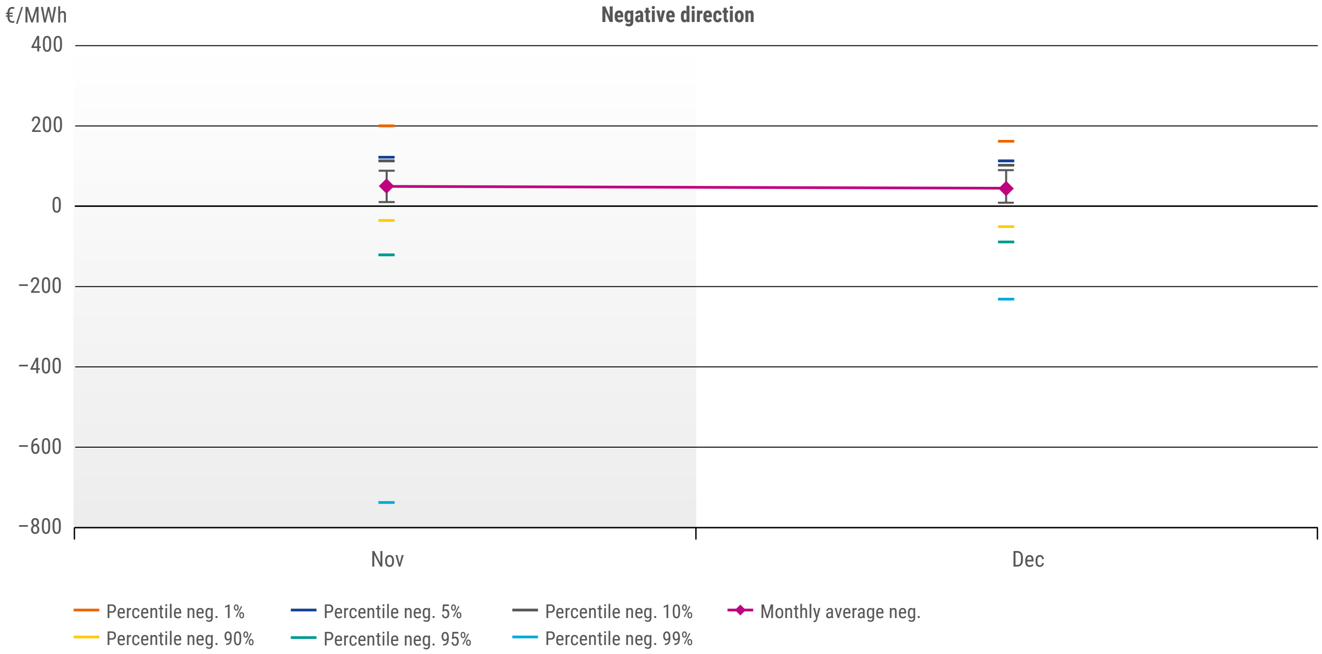


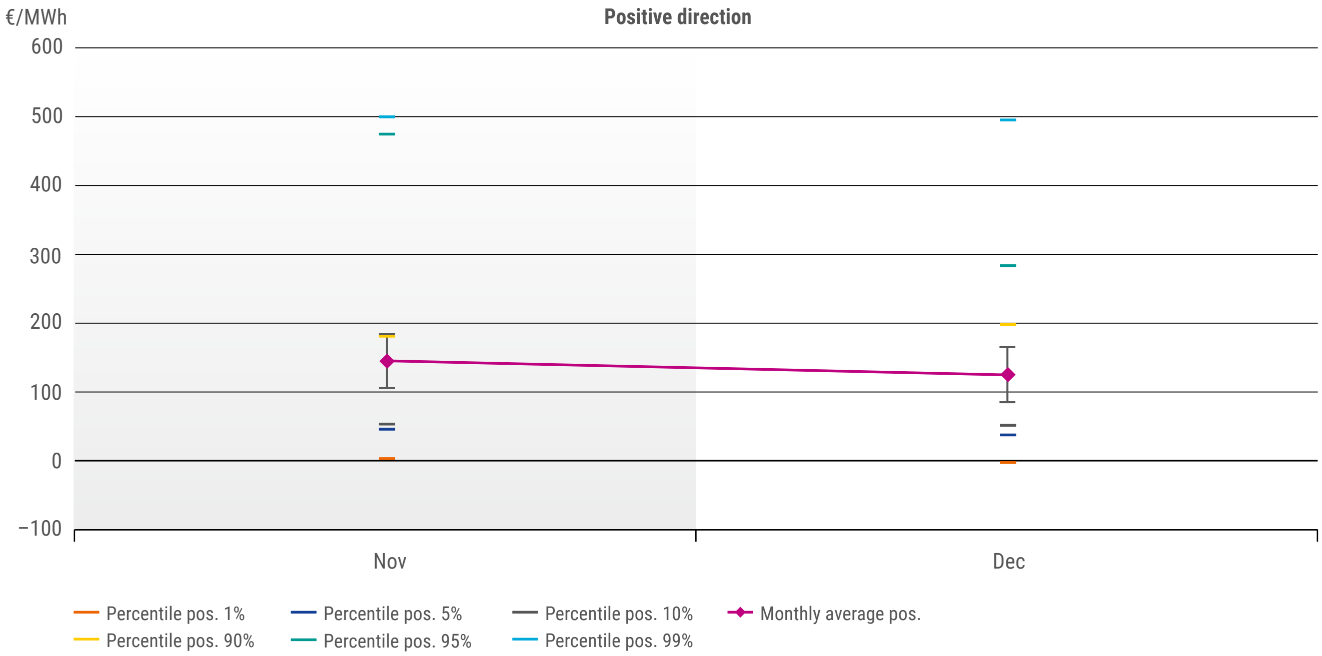
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – ČEPS (€/MWh)



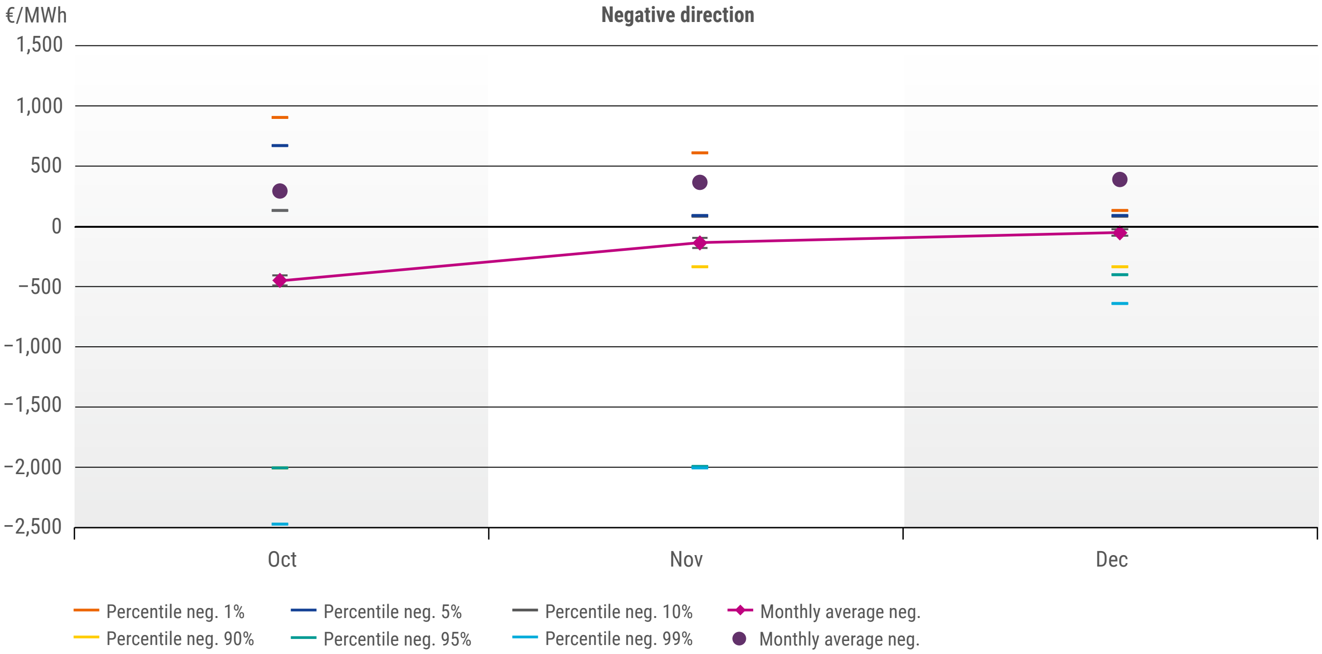


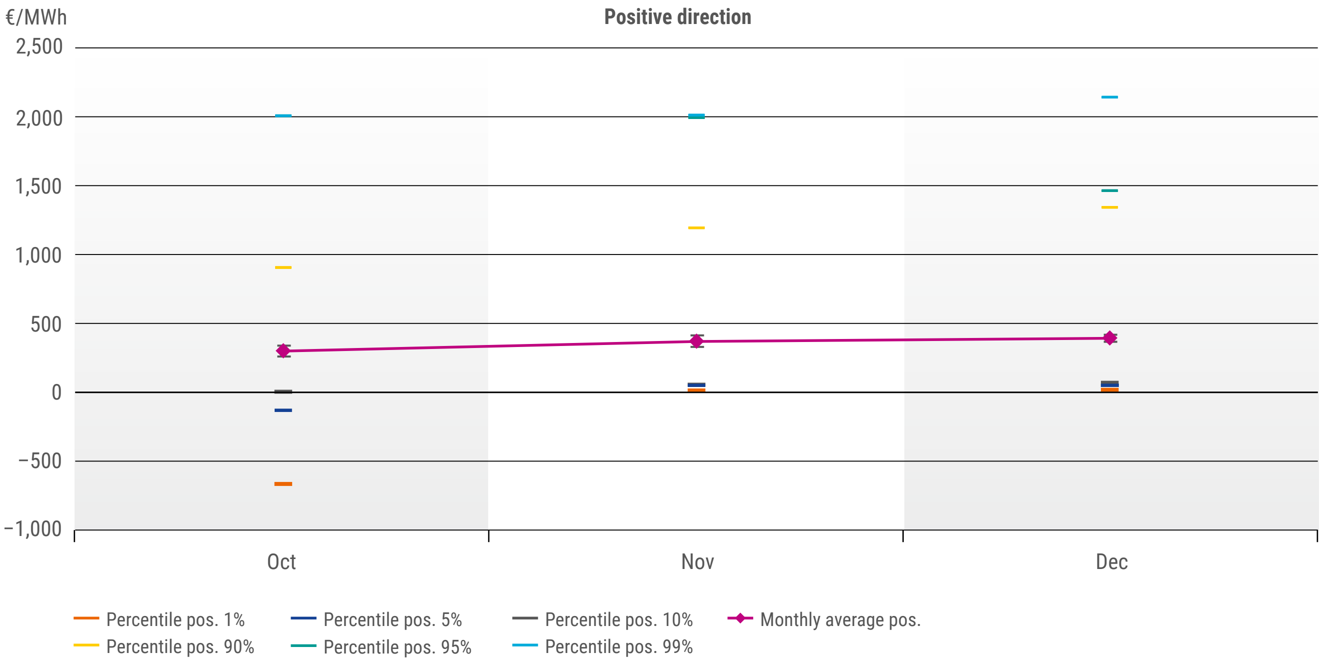
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Elia (€/MWh)



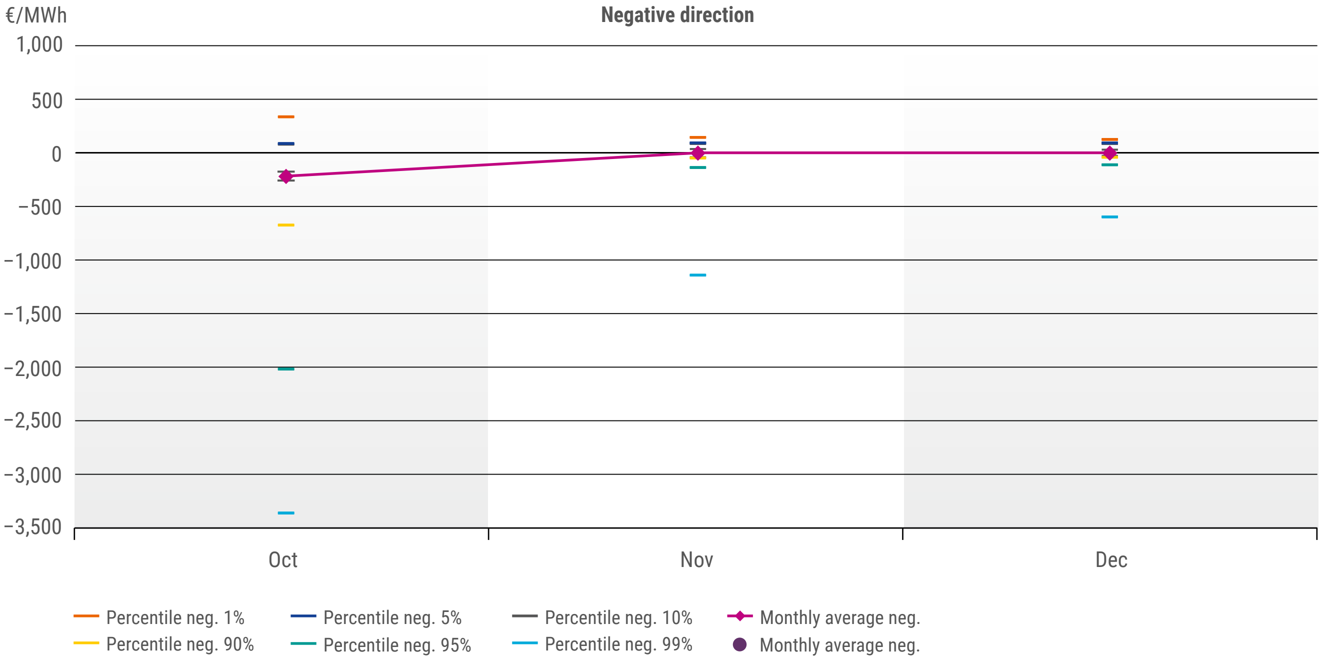


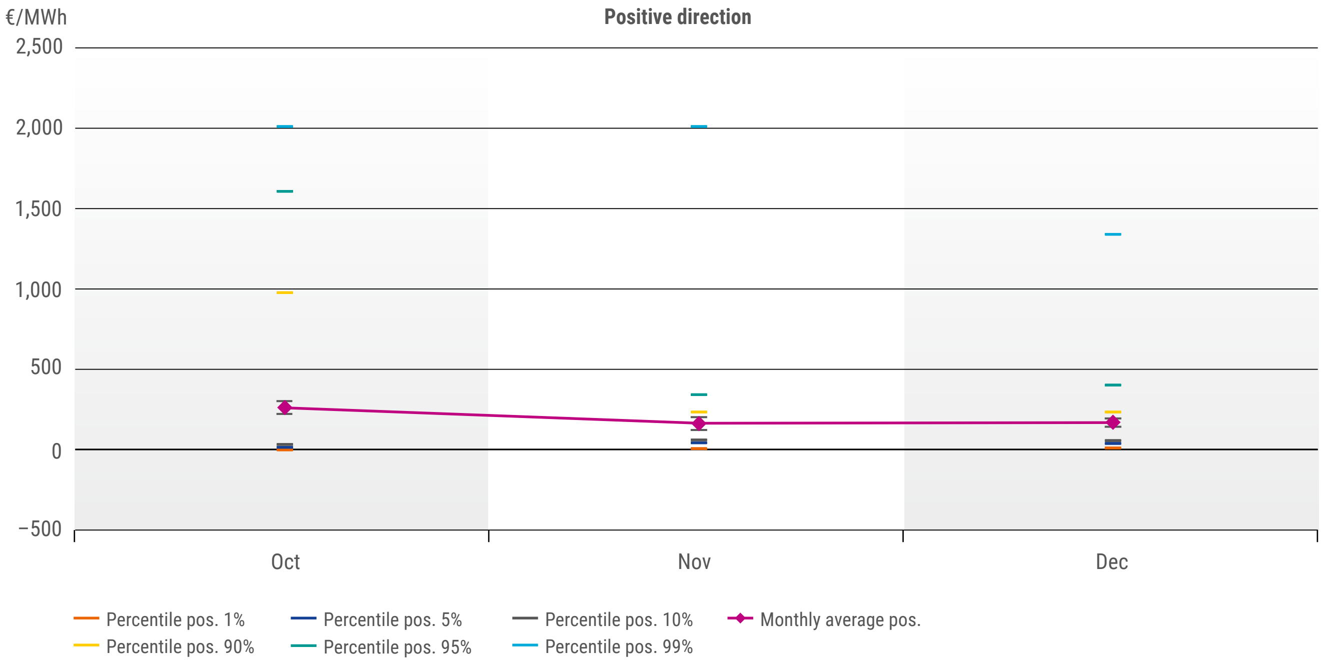
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Energinet O (€/MWh)



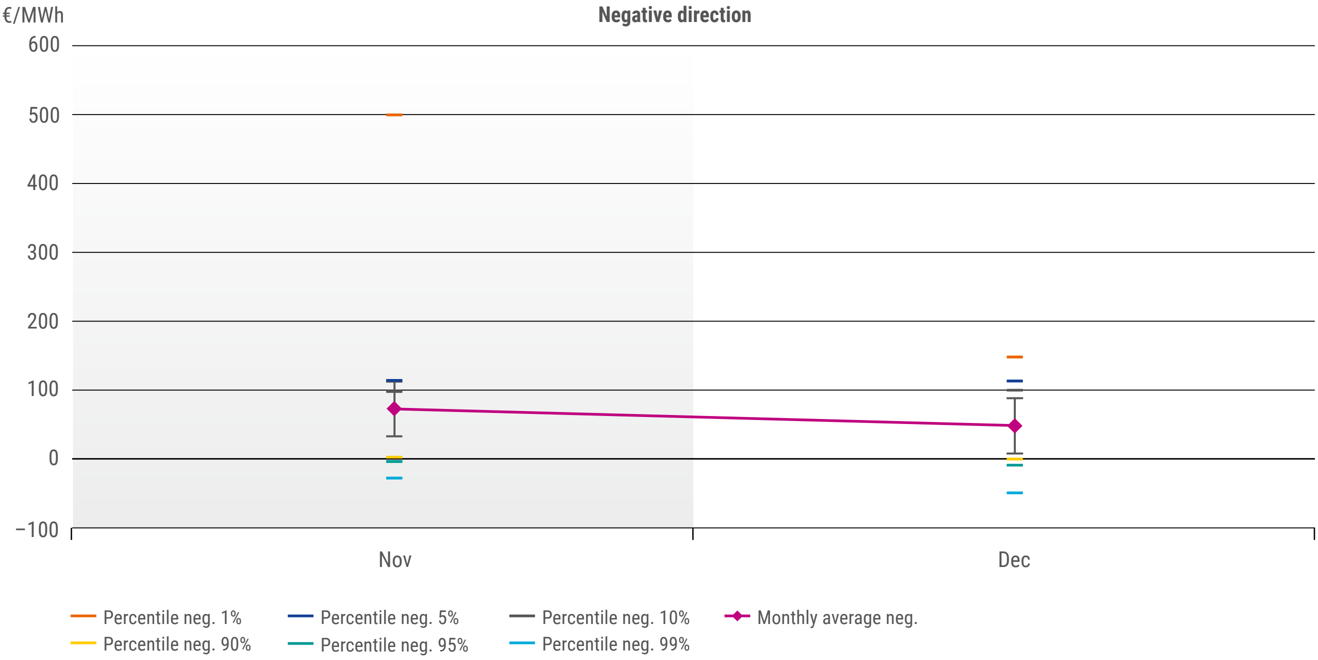


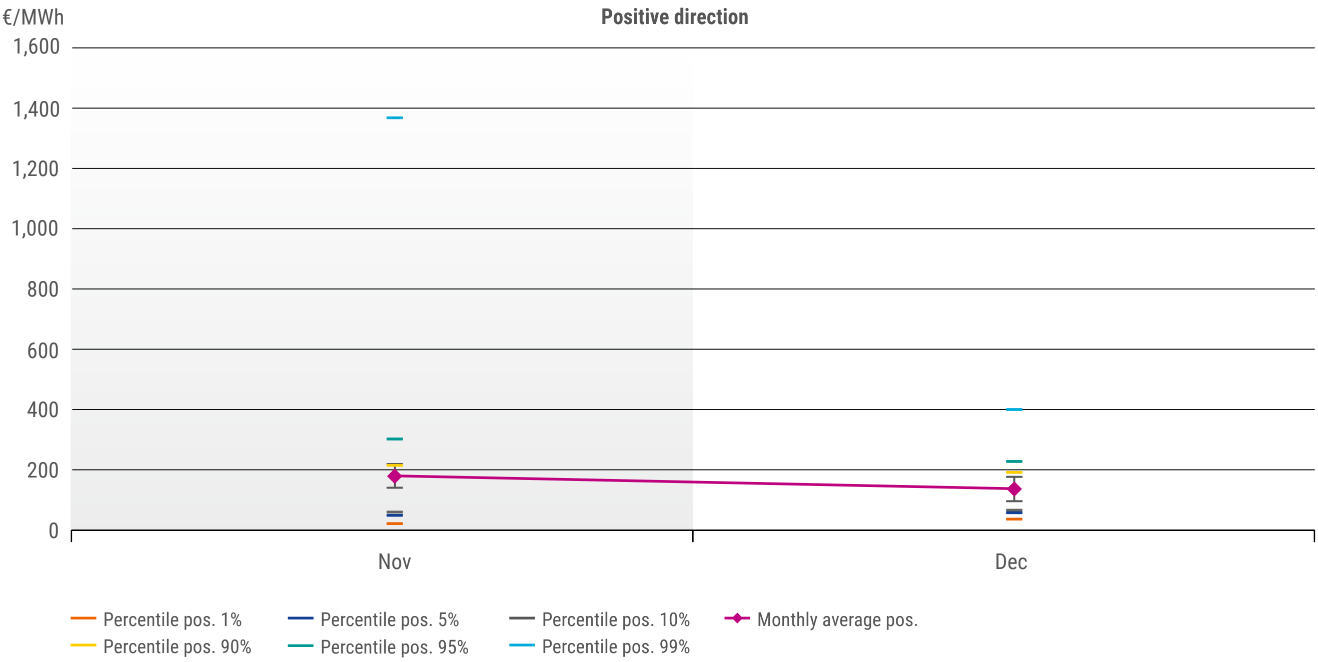
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Energinet W (€/MWh)



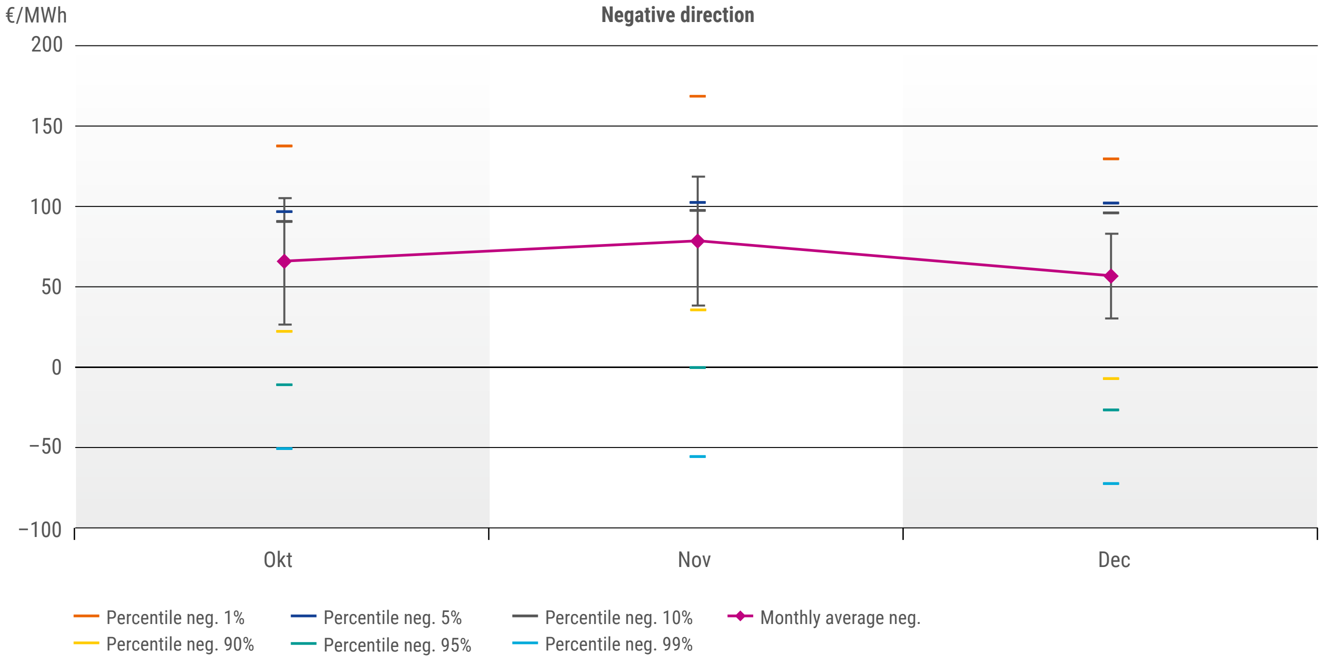


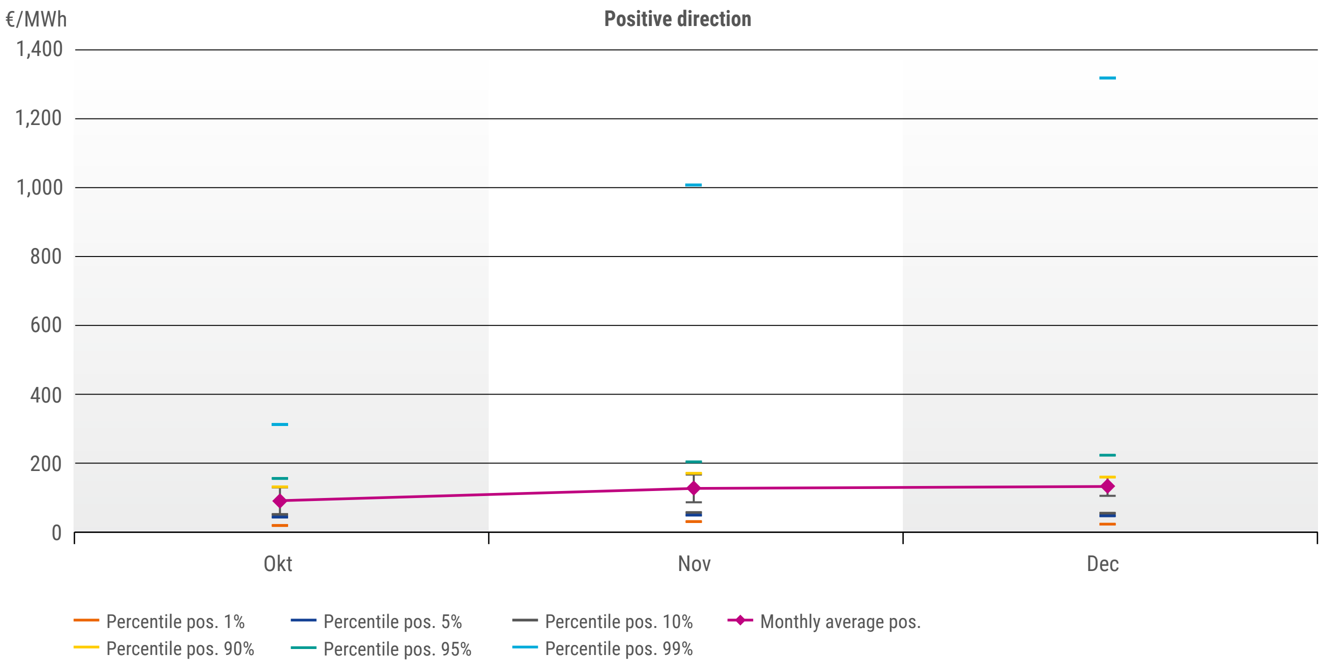
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – SEPS (€/MWh)



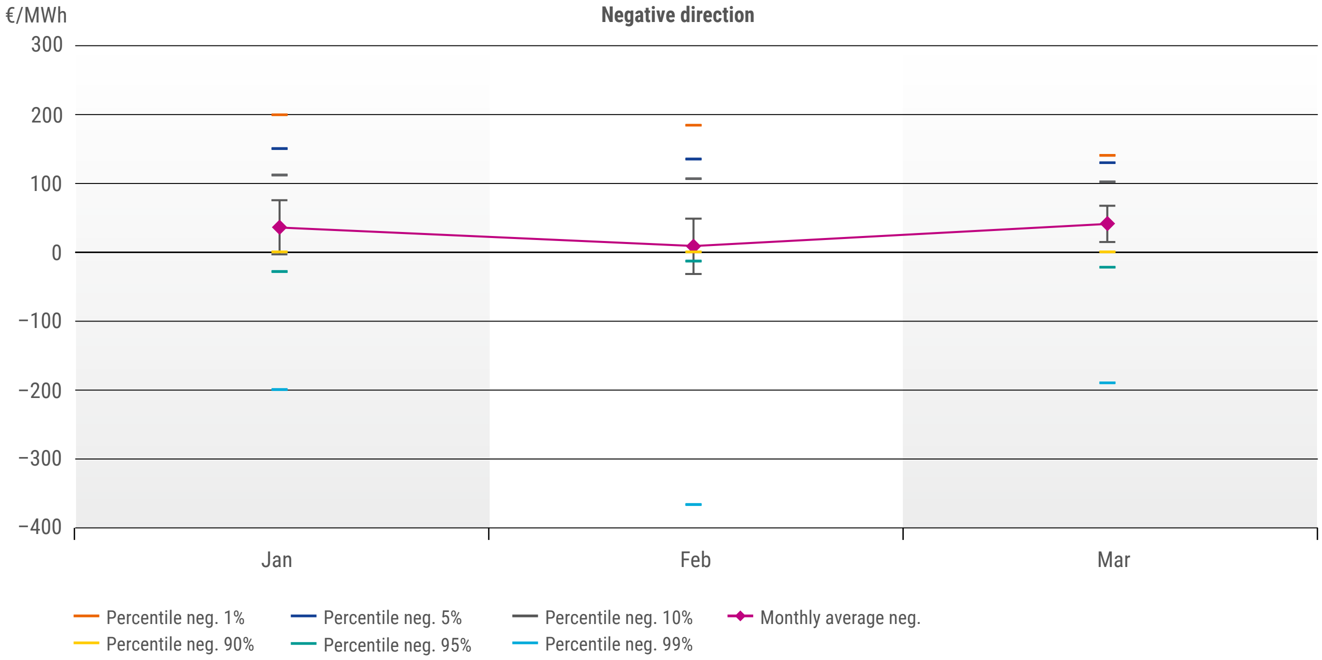


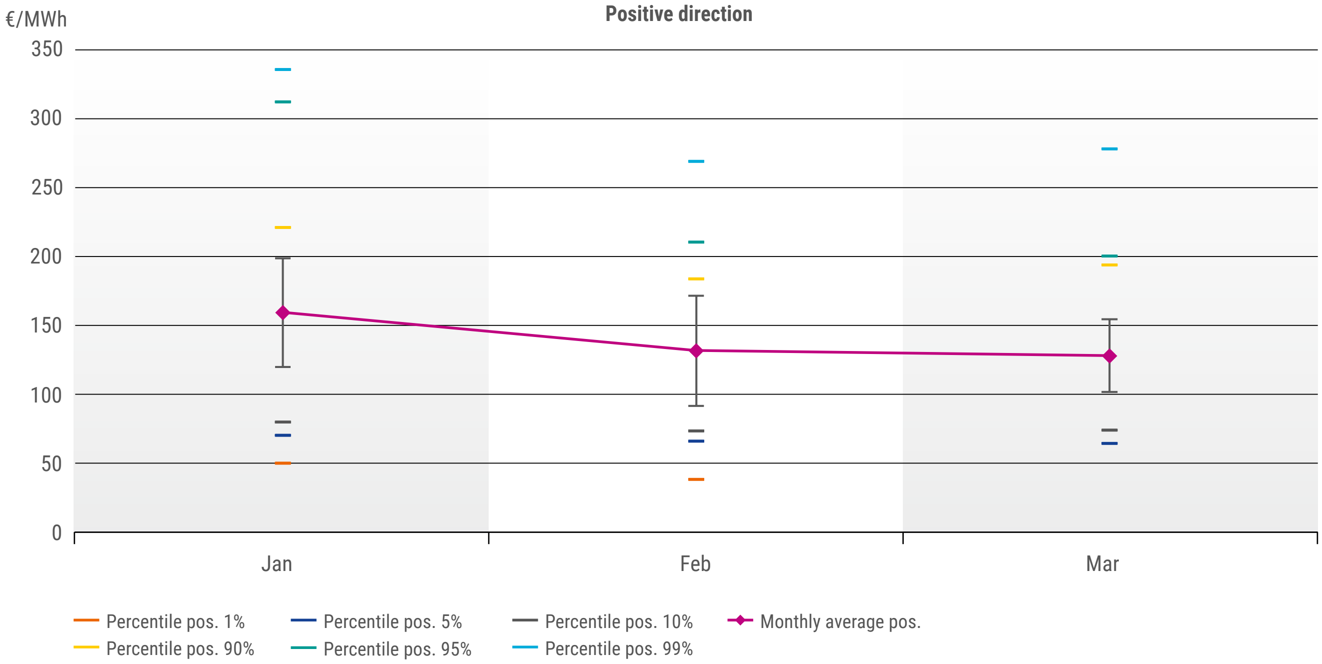
KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Tennet NL (€/MWh)



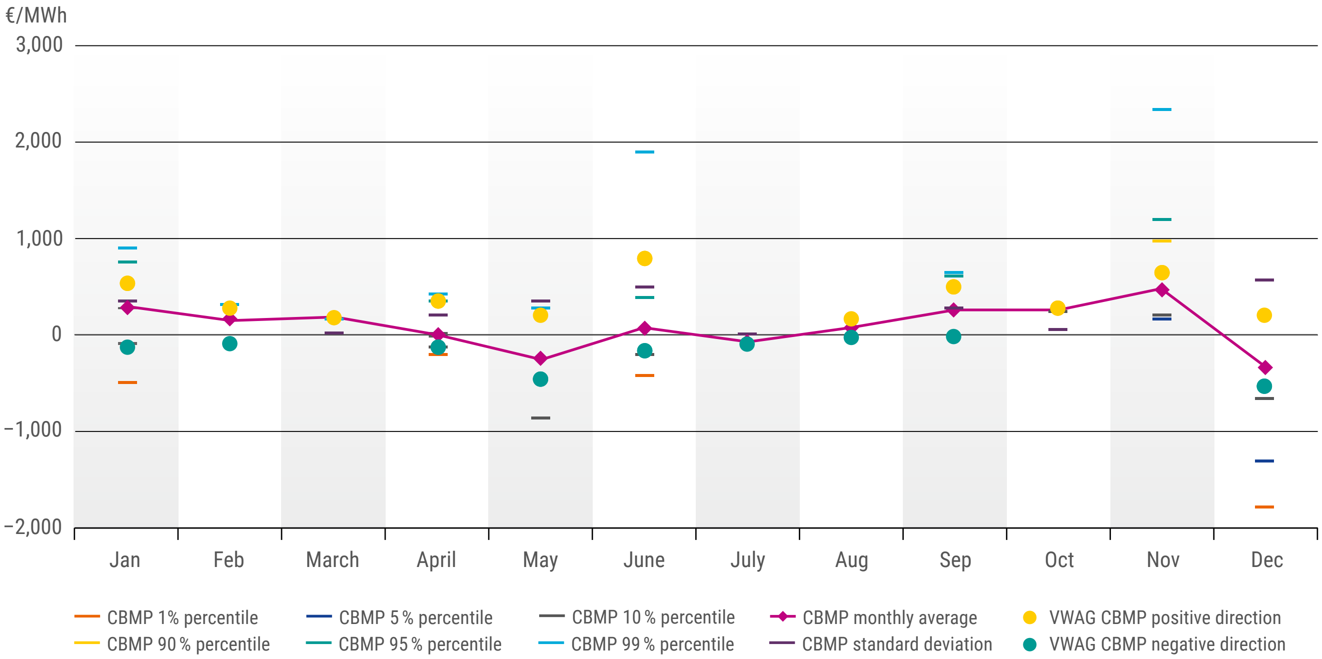


KPI 6.3.4.5: aFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Terna (€/MWh)

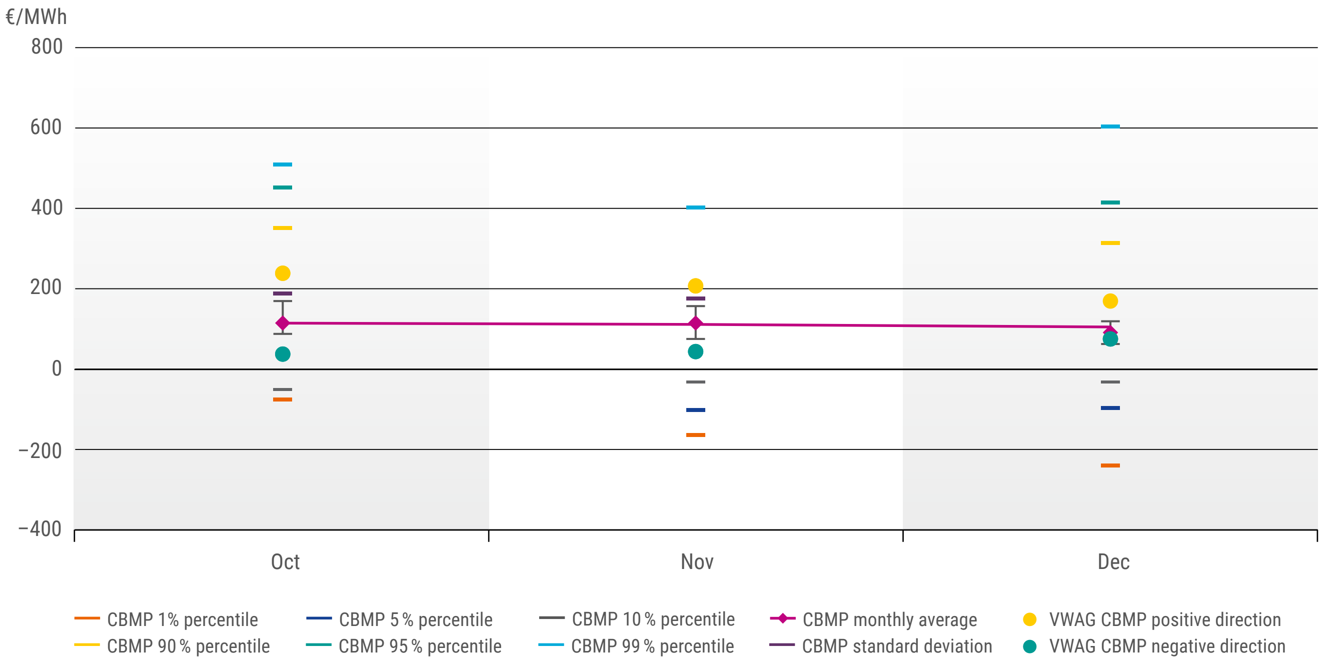




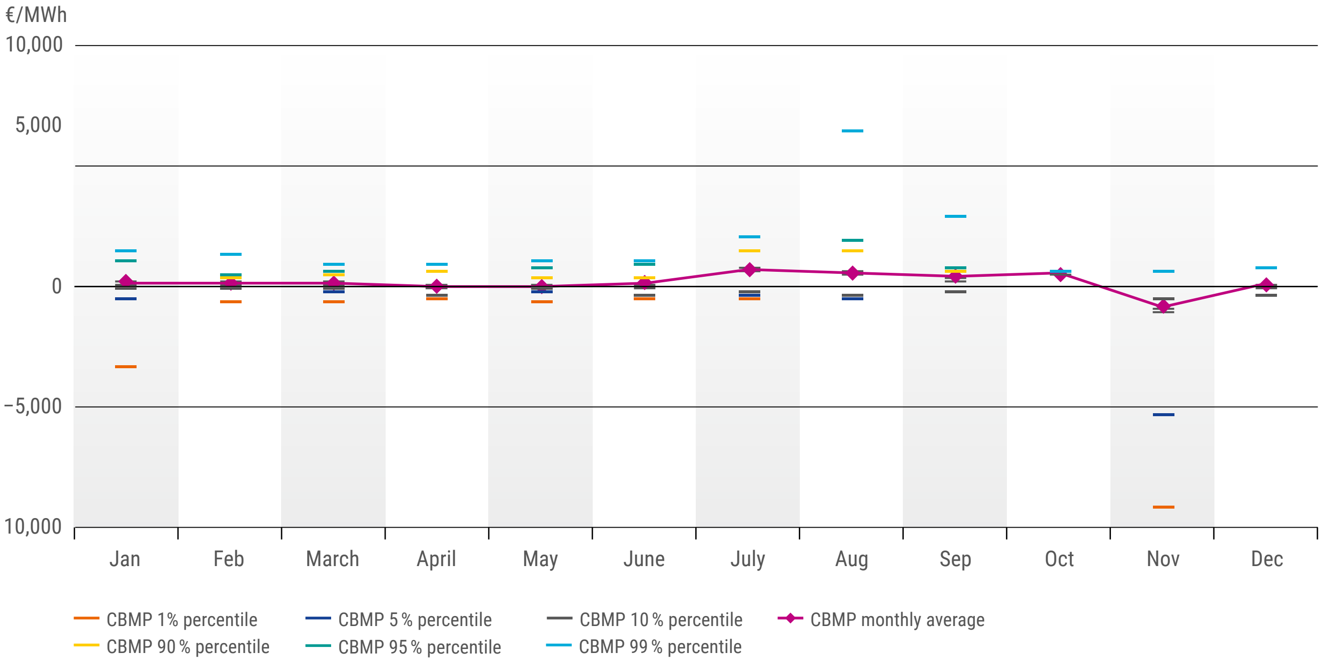
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – APG (€/MWh)



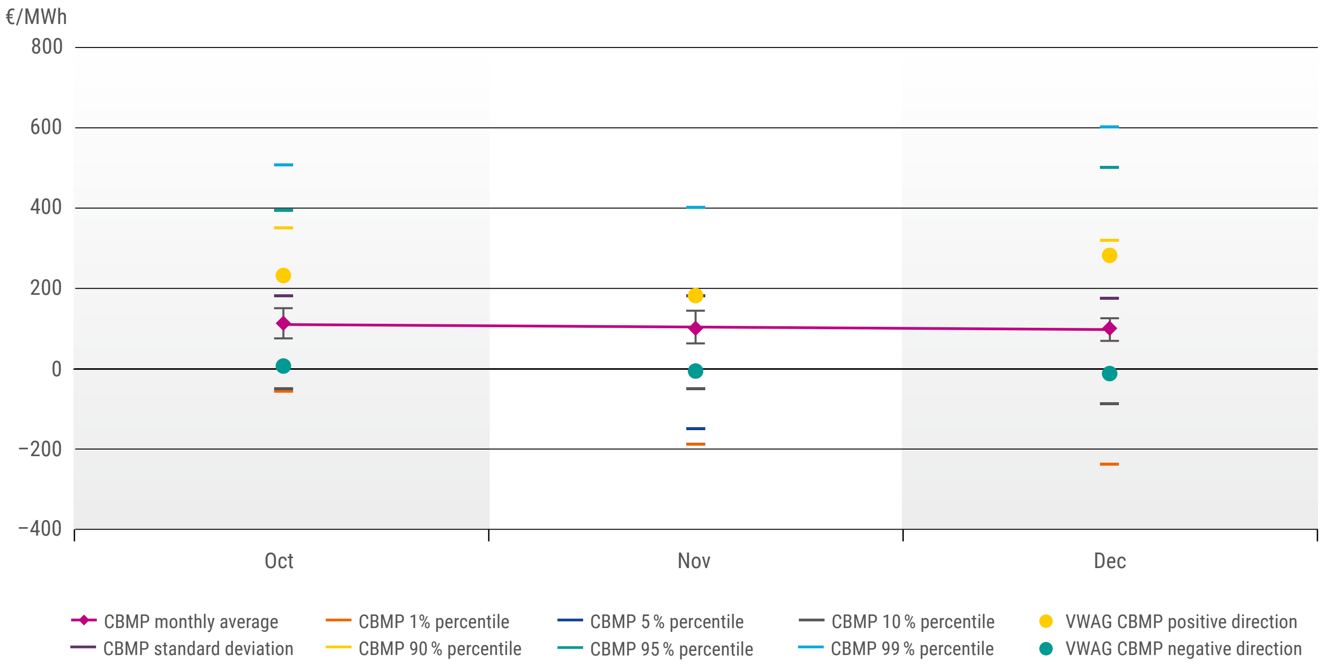
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – AST (€/MWh)



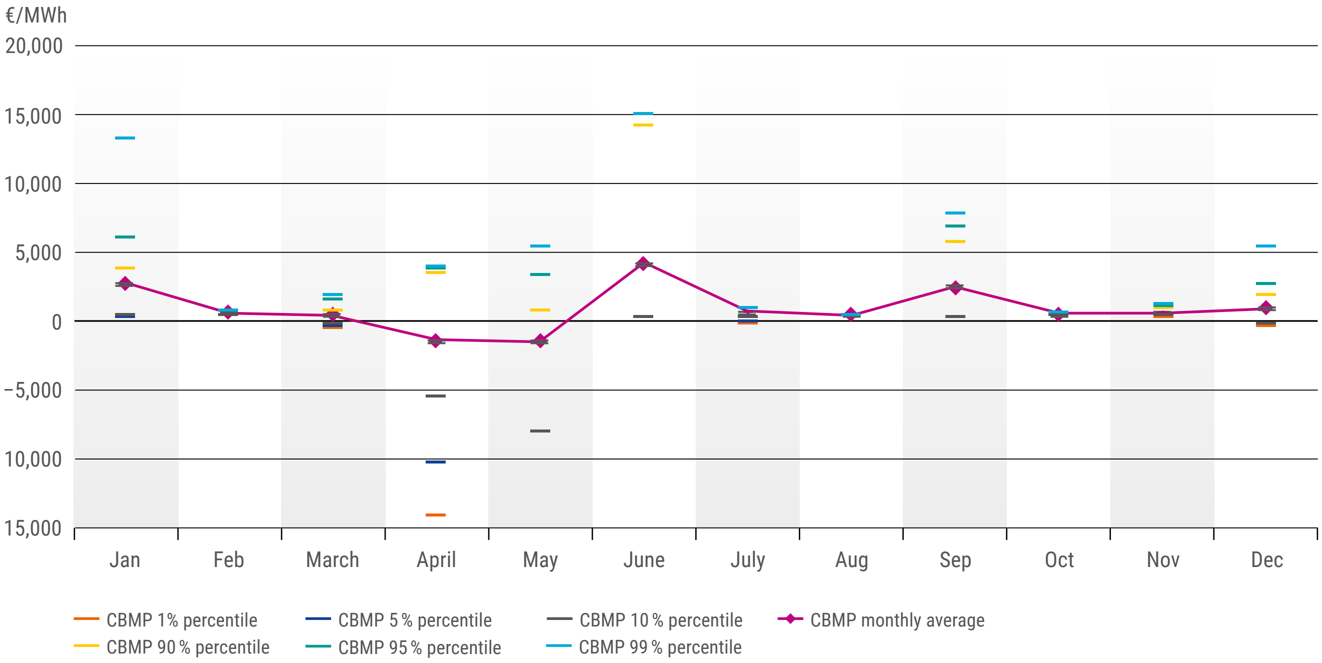
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – ČEPS (€/MWh)



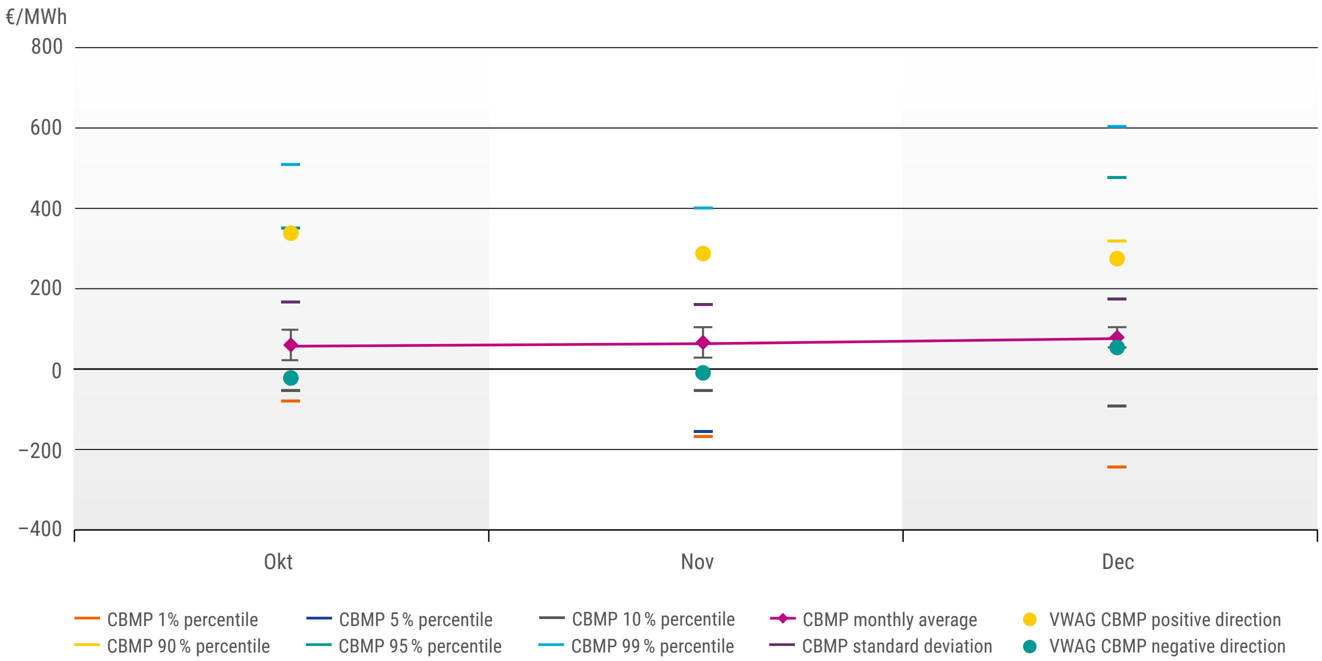
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Elering (€/MWh)



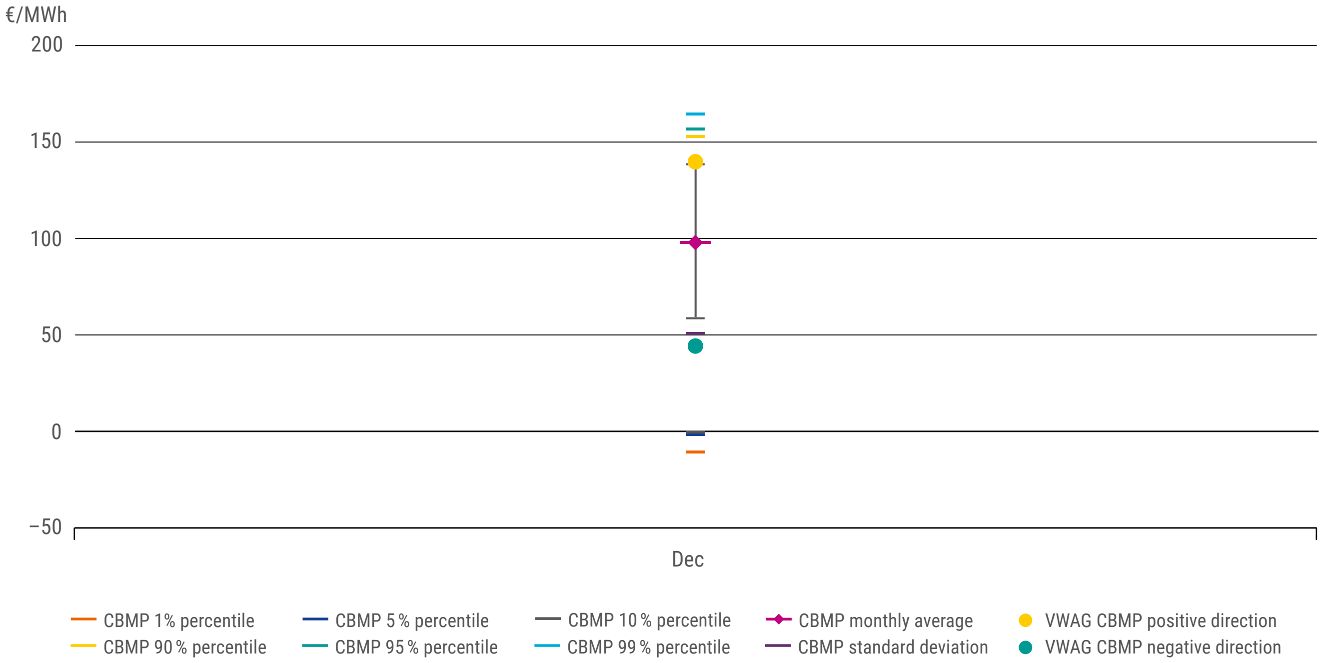
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – German TSOs (€/MWh)



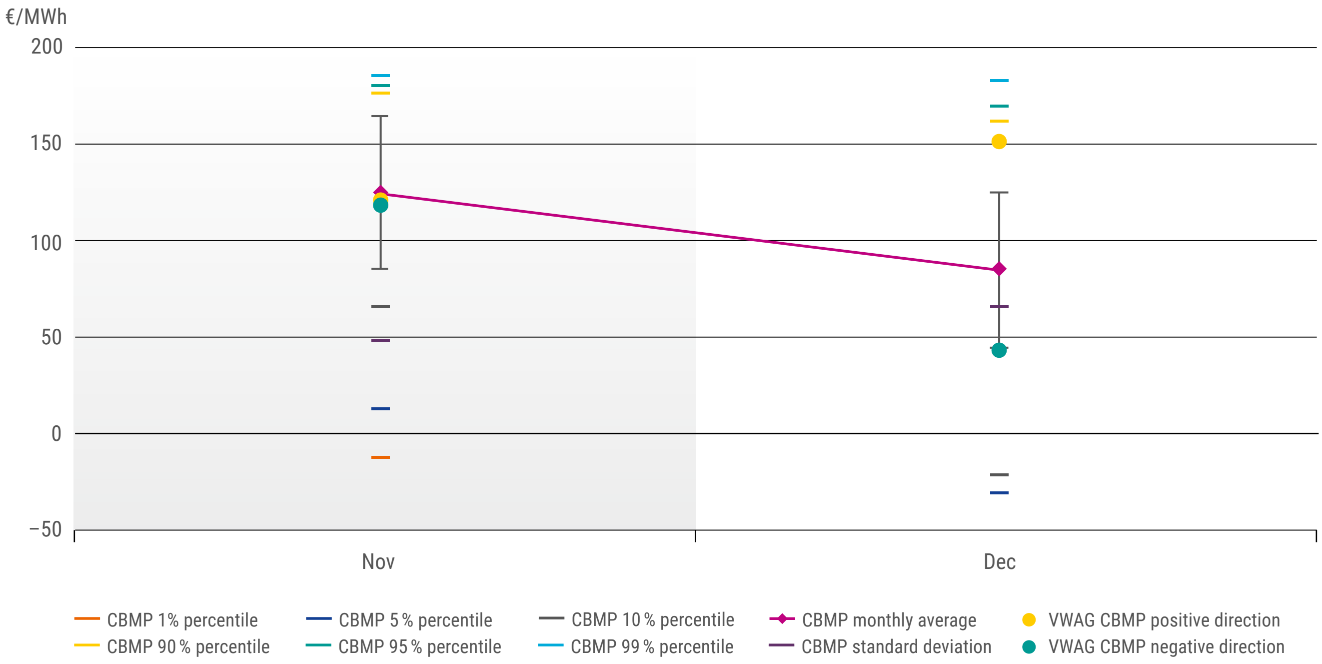
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Litgrid (€/MWh)



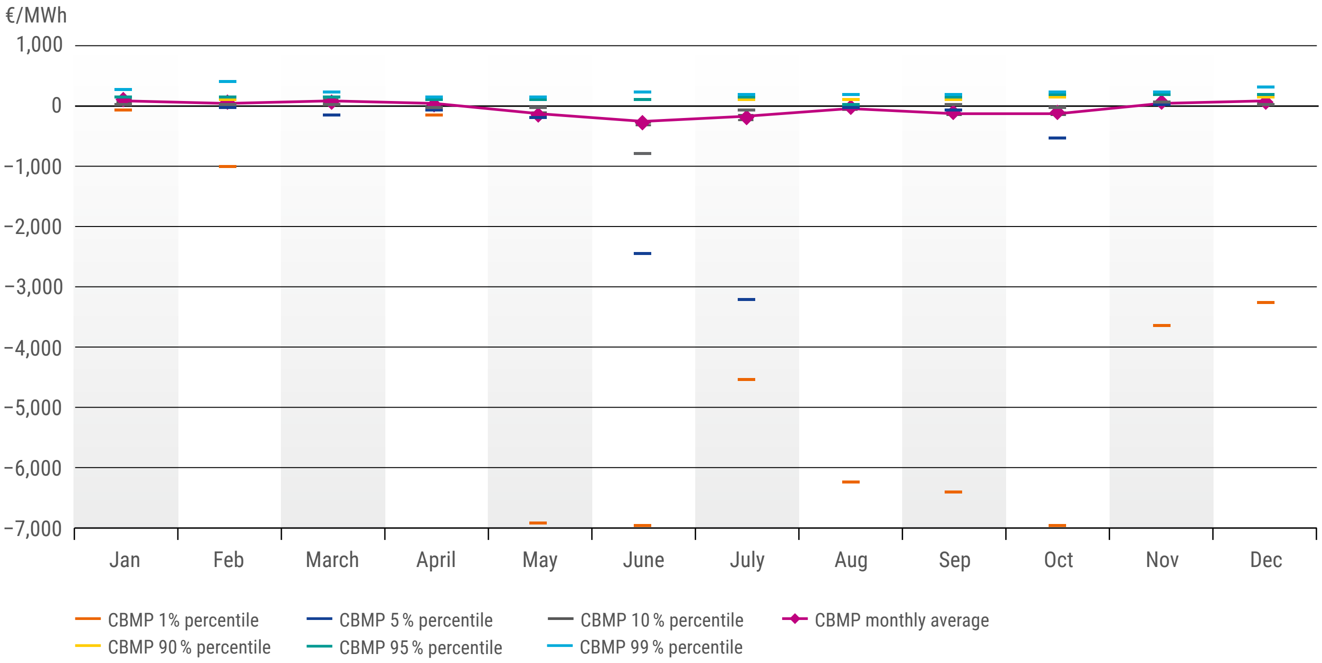
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – Red Eléctrica (€/MWh)



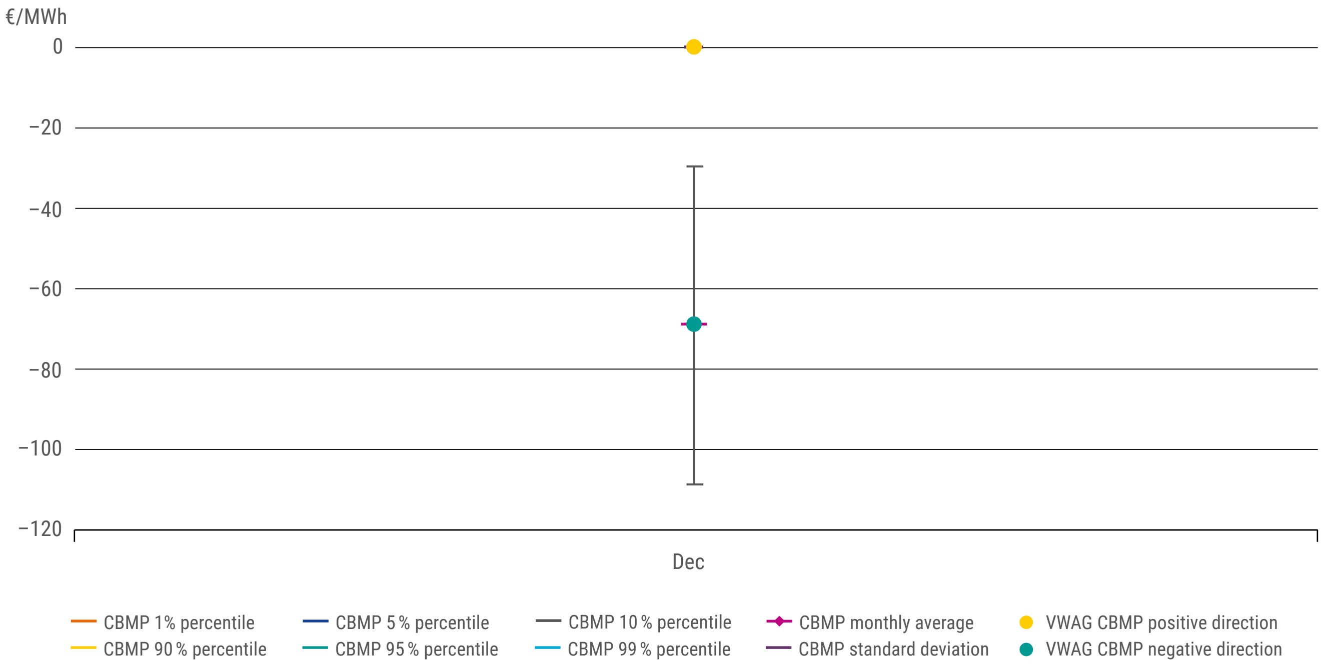
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – REN (€/MWh)



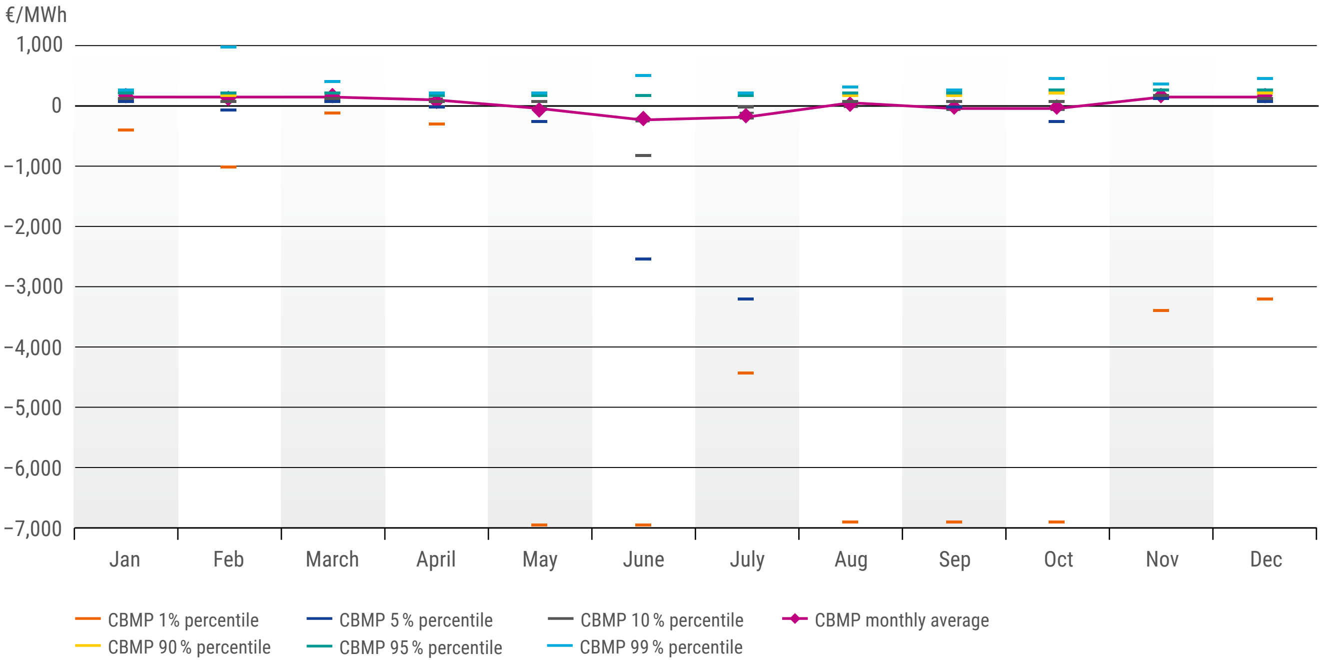
KPI 6.3.4.5: RR platform: Monthly average and standard deviation values and distribution of the CBMP per month – RTE (€/MWh)



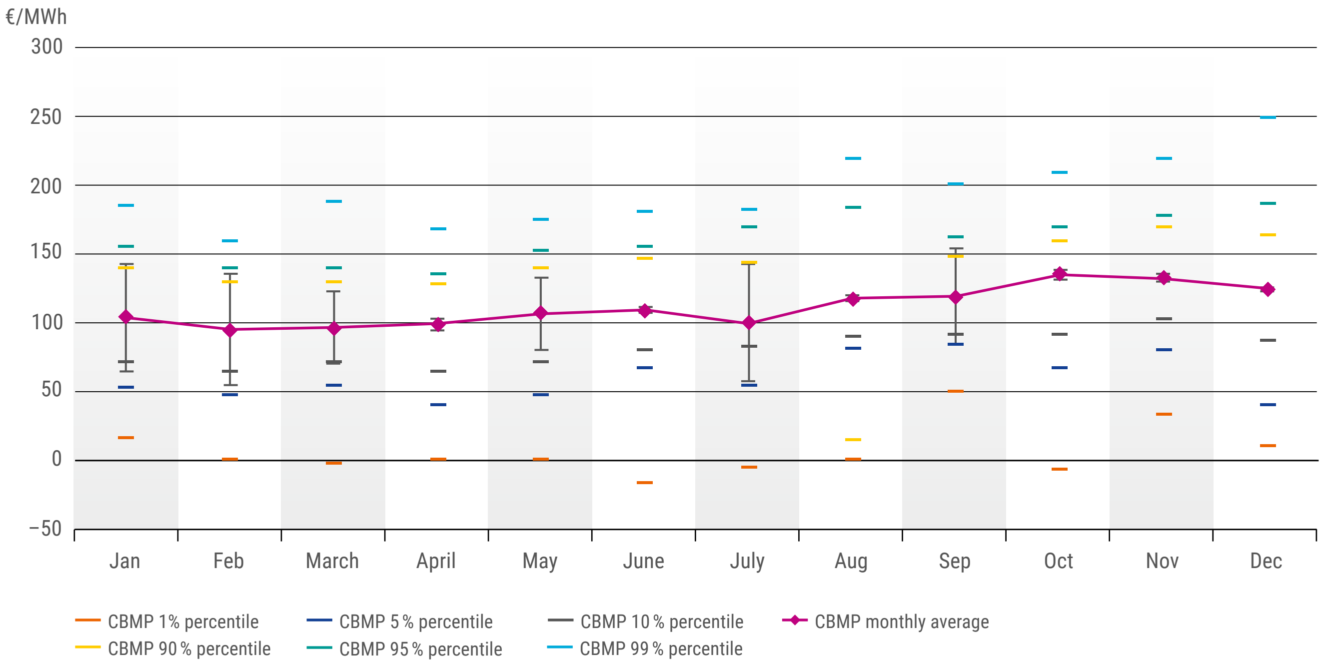
KPI 6.3.4.5: mFRR platform: Monthly average and standard deviation values and distribution of the CBMP per month – SEPS (€/MWh)



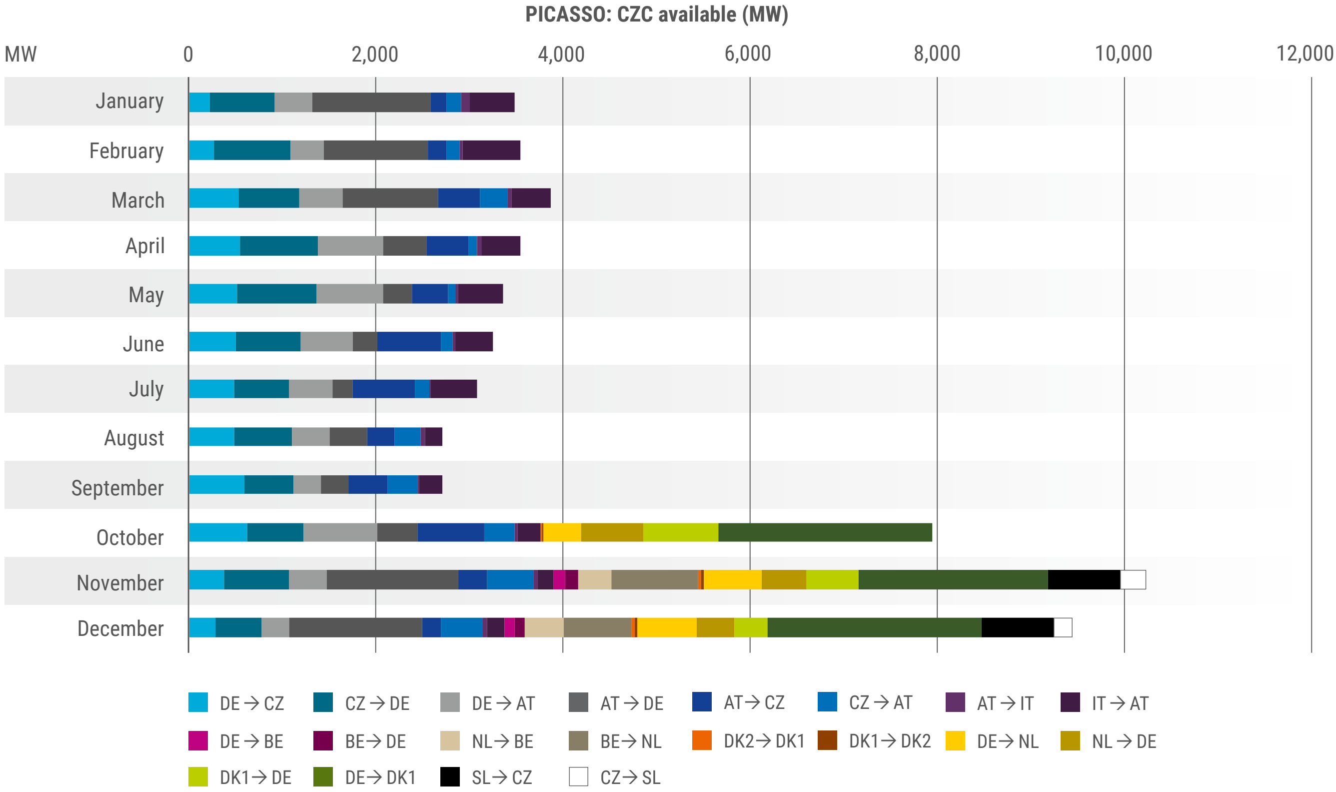
KPI 6.3.4.5: RR platform: Monthly average and standard deviation values and distribution of the CBMP per month – SWISSGRID (€/MWh)



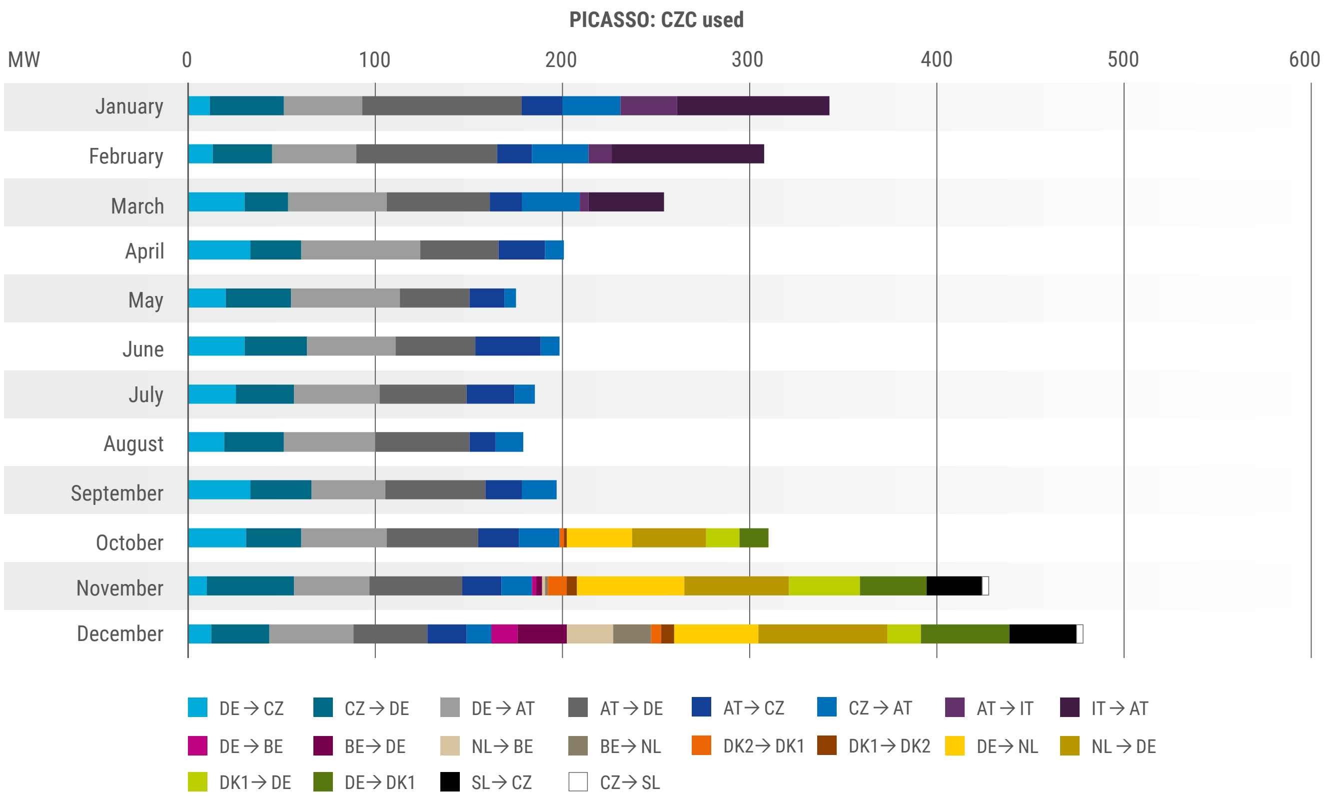
KPI 6.3.4.5: RR platform: Monthly average and standard deviation values and distribution of the CBMP per month – TERNA (€/MWh)



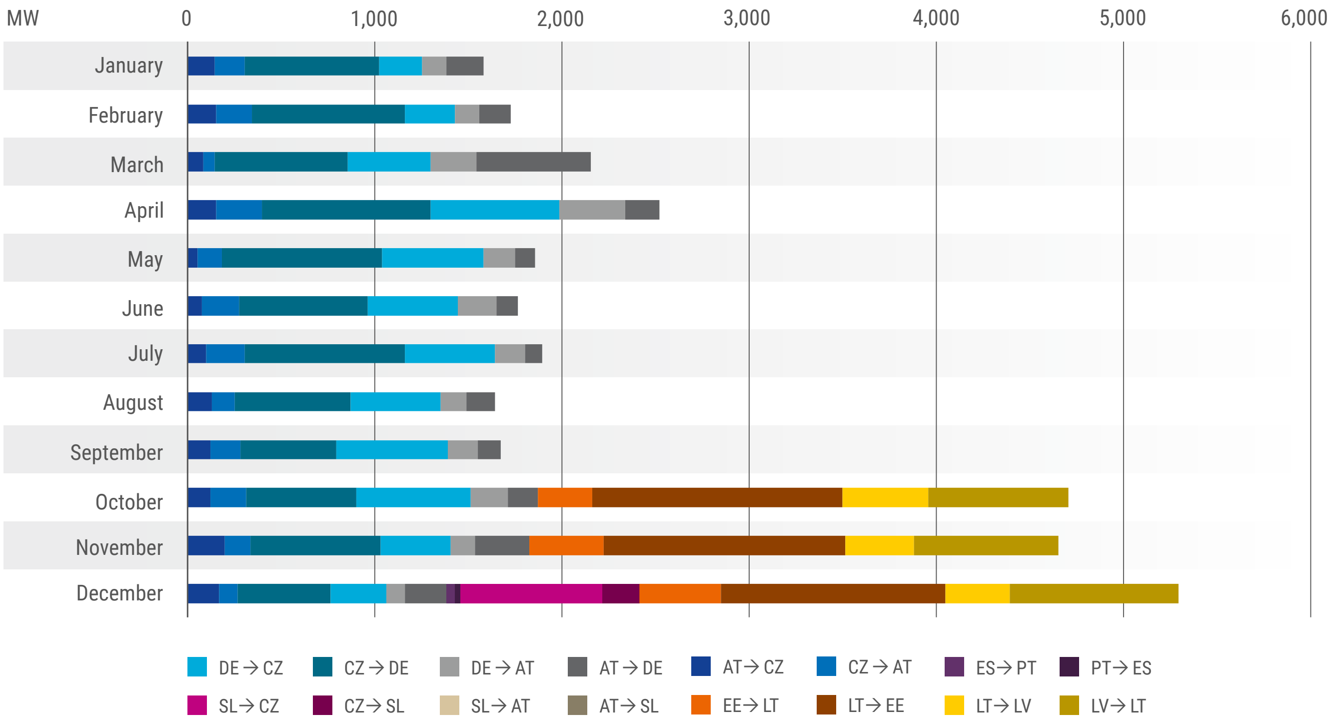
KPI 6.3.4.6: aFRR platform: Monthly average value of the available CZC per BZB and per direction (MW/MTU)



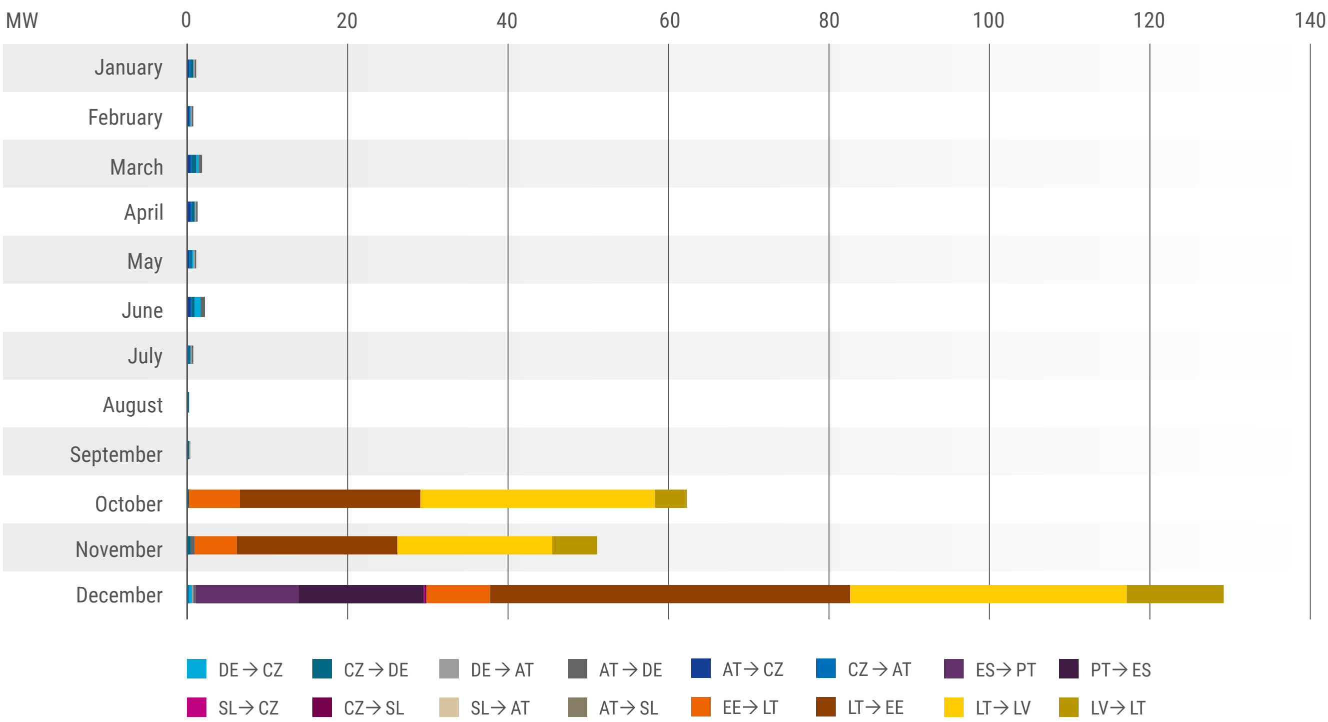
KPI 6.3.4.6: aFRR platform: Monthly average value of the used CZC per BZB and per direction (MW)



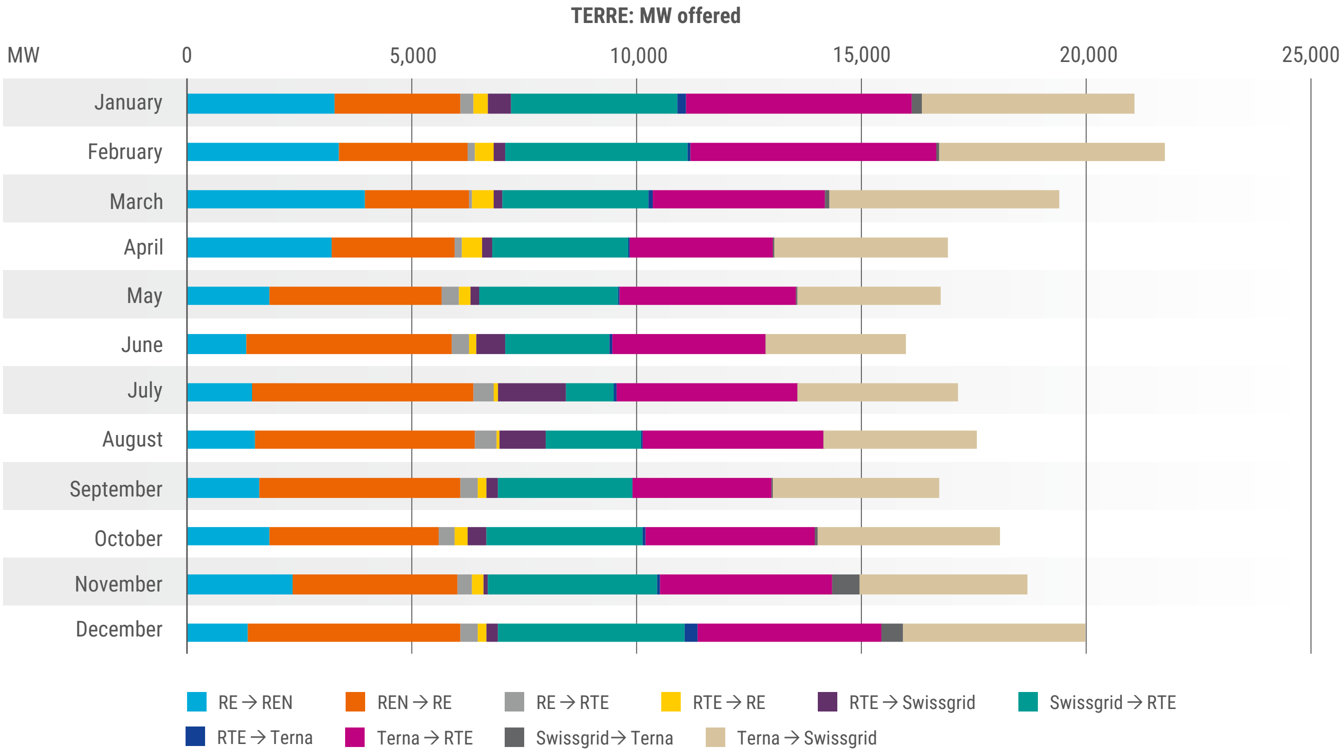
KPI 6.3.4.6: mFRR platform: Monthly average value of the available CZC per BZB and per direction (MW)



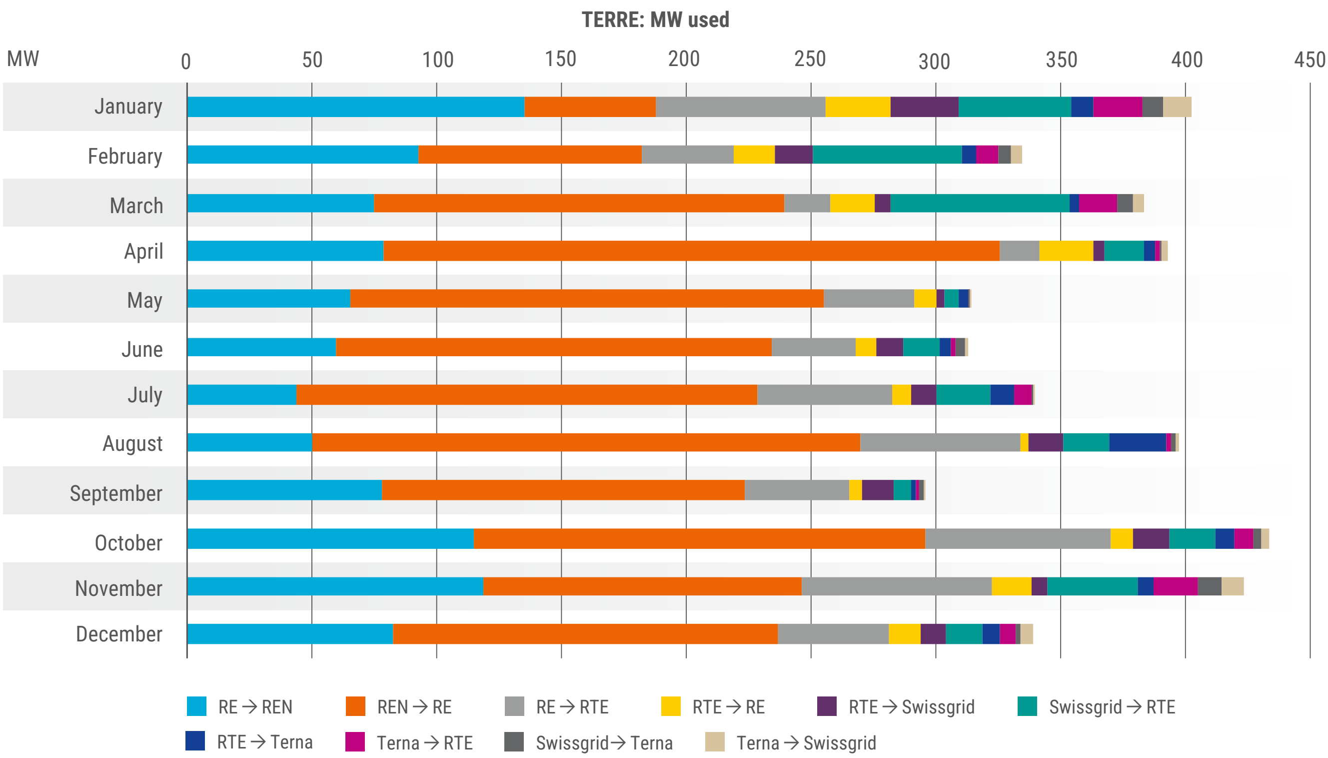
KPI 6.3.4.6: mFRR platform: Monthly average value of the used CZC per BZB and per direction (MW)



KPI 6.3.4.6: RR platform: Monthly average value of the available CZC per BZB and per direction (MW)[38]



KPI 6.3.4.6: RR platform: Monthly average value of the used CZC per BZB and per direction (MW)

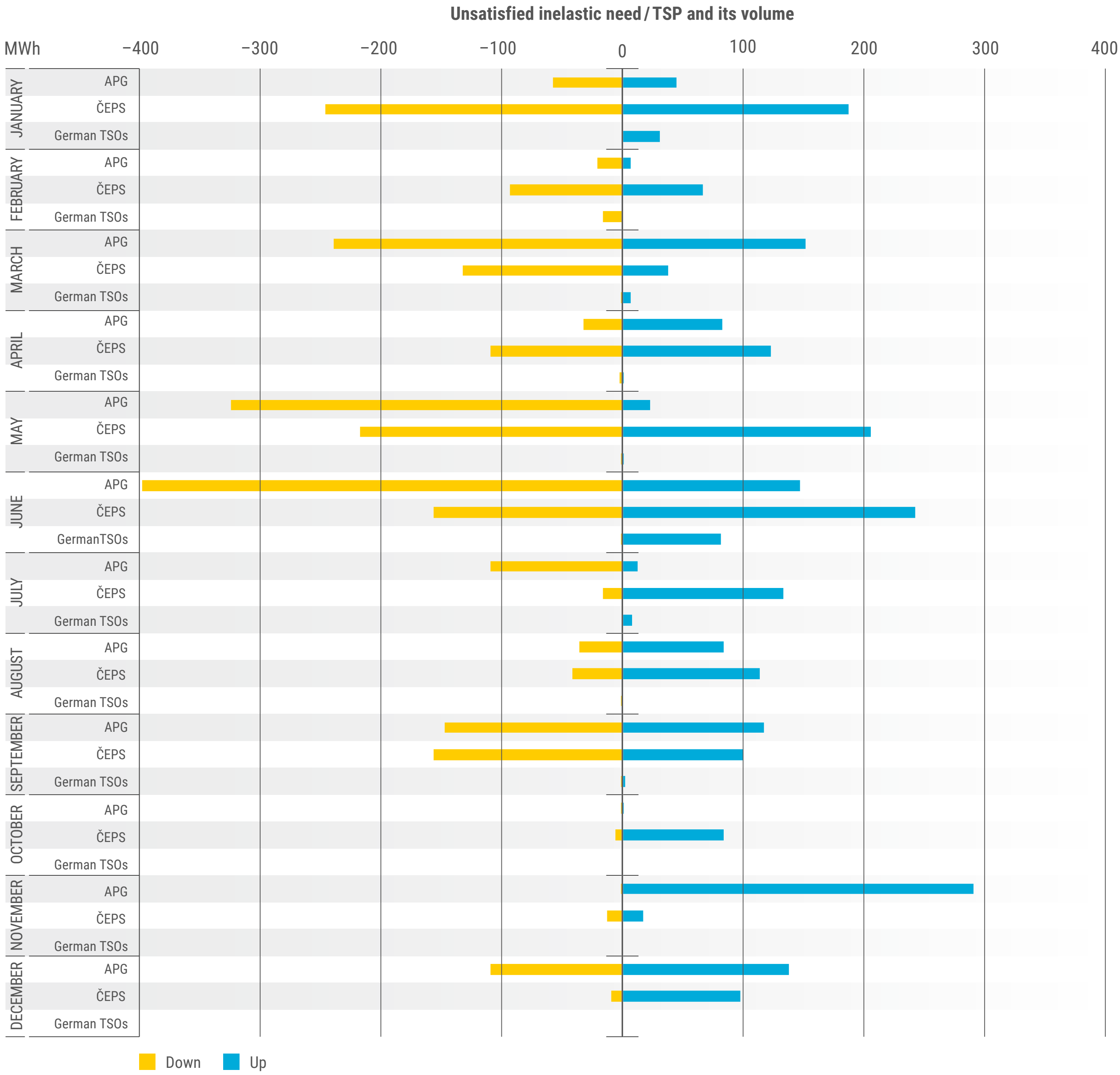


38 The maximum RR flow on the France–Spain border is limited by RTE in order to maintain power system reliability. RR flows are limited to a maximum of 300 MW in the direction of the scheduled flows and to a maximum of 500 MW in the opposite direction of the scheduled flows.

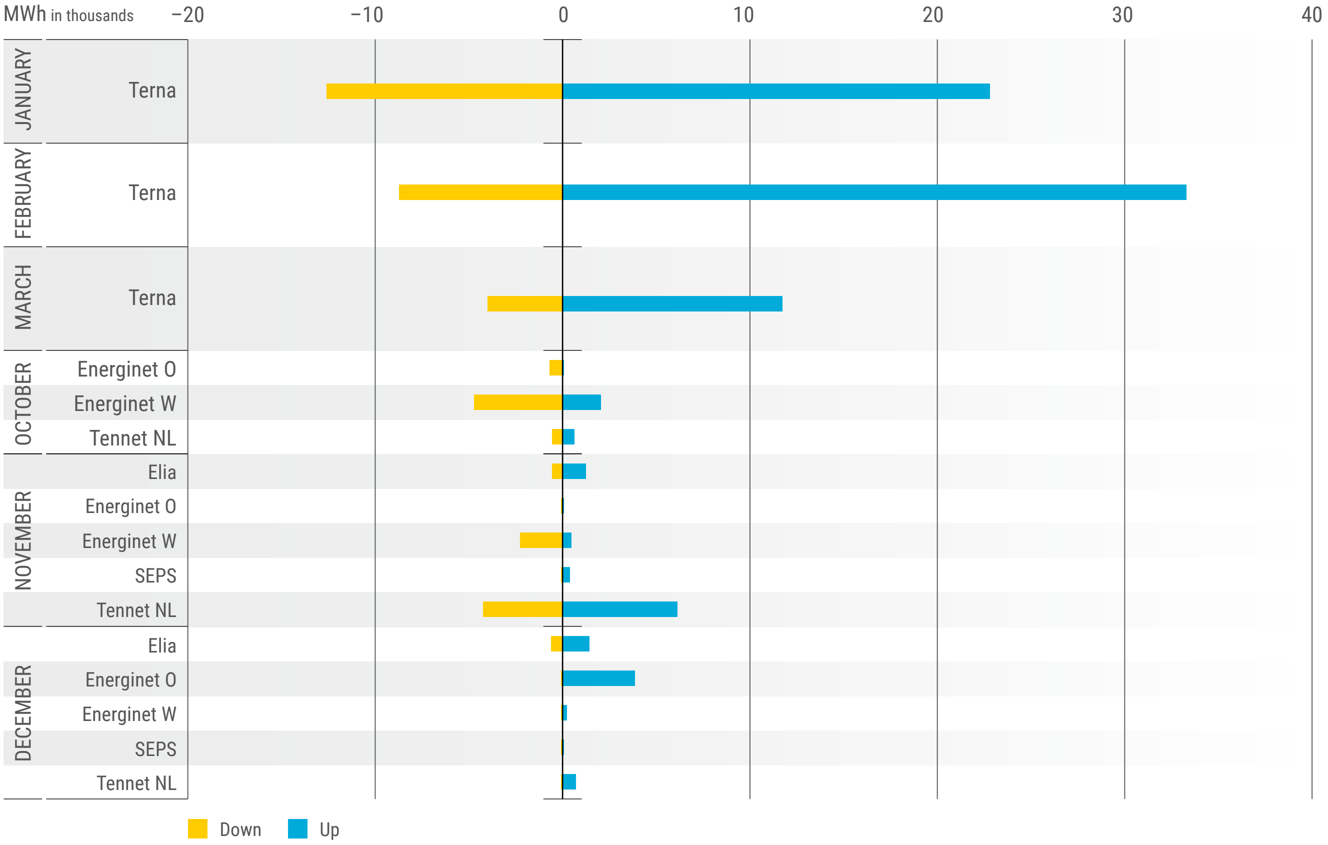
KPI 6.3.4.7: Monthly average value of the number of uncongested areas per platform

	Average value of uncongested LFC areas		
	TERRE	PICASSO	MARI
January	9.31 (of 14)	2.16 (of 4)	2.56 (of 3)
February	9.62 (of 14)	2.19 (of 4)	2.69 (of 3)
March	9.97 (of 14)	1.80 (of 4)	2.38 (of 3)
April	10.00 (of 14)	1.57 (of 3)	2.86 (of 3)
May	10.41 (of 14)	1.61 (of 3)	2.66 (of 3)
June	10.00 (of 14)	1.51 (of 3)	2.74 (of 3)
July	9.98 (of 14)	1.51 (of 3)	2.80 (of 3)
August	10.14 (of 14)	1.50 (of 3)	2.70 (of 3)
September	9.92 (of 14)	1.49 (of 3)	2.53 (of 3)
October	9.90 (of 14)	2.18 (of 6)	5.33 (of 6)
November	9.70 (of 14)	2.91 (of 8)	6.24 (of 7)
December	9.83 (of 14)	3.49 (of 8)	8.36 (of 9)

KPI 6.3.4.8: Number of occurrences (% of MTU) of unsatisfied inelastic need/TSO and its volume (MWh)



Unsatisfied inelastic need / TSP and its volume – TSOs with late accession or early exit



6.3.5 Possible inefficiencies and distortions of balancing markets[39]

Definition	This indicator assesses the following data for each balancing platform and each month: CZC available and used by the balancing energy platform. Each balancing energy platform must report four values per BZ border: the initial CZC (reflecting the remaining capacity after the consecutive previous processes that affect each border: last ID market, TERRE/RR market, MARI market) available per border and per direction and the CZC used per border and per direction. The monthly average values per MTU should be calculated for each balancing energy platform per BZ border in both directions. The average percentage of both submitted and activated standard balancing energy bids per product and per direction with prices higher than 50 %, 75 %, 90 %, 95 %, and 99 % of the upper or lower transitory price limit. The volume-weighted average price (€/MWh) of the 5 % most expensive submitted standard energy bids for each European balancing platform per direction and per participating TSO. As this indicator is already published under the quarterly reports under the pricing methodology, TSOs will reference the quarterly reports of the previous year in the Market and Balancing Reports.
Legal reference	Article 59 (4)(f) of the EB Regulation[40]
Time reference	Yearly with monthly granularity

Please refer to the quarterly pricing reports on the **ENTSO-E website.**

6.3.6 Efficiency losses due to specific products

Definition	TSOs consider that specific products can be used locally only when approved by its NRA according to the conditions specified by Art. 26 (1)(f) of the EB Regulation, hence there is no significant loss to be reported on.
Legal reference	Article 59 (4)(g) of the EB Regulation
Time reference	Not applicable

Table 6.8: Indicator 5.6 on the efficiency losses due to specific products

6.3.7 Volume of balancing energy used for balancing purposes, both available and activated, from standard and specific products

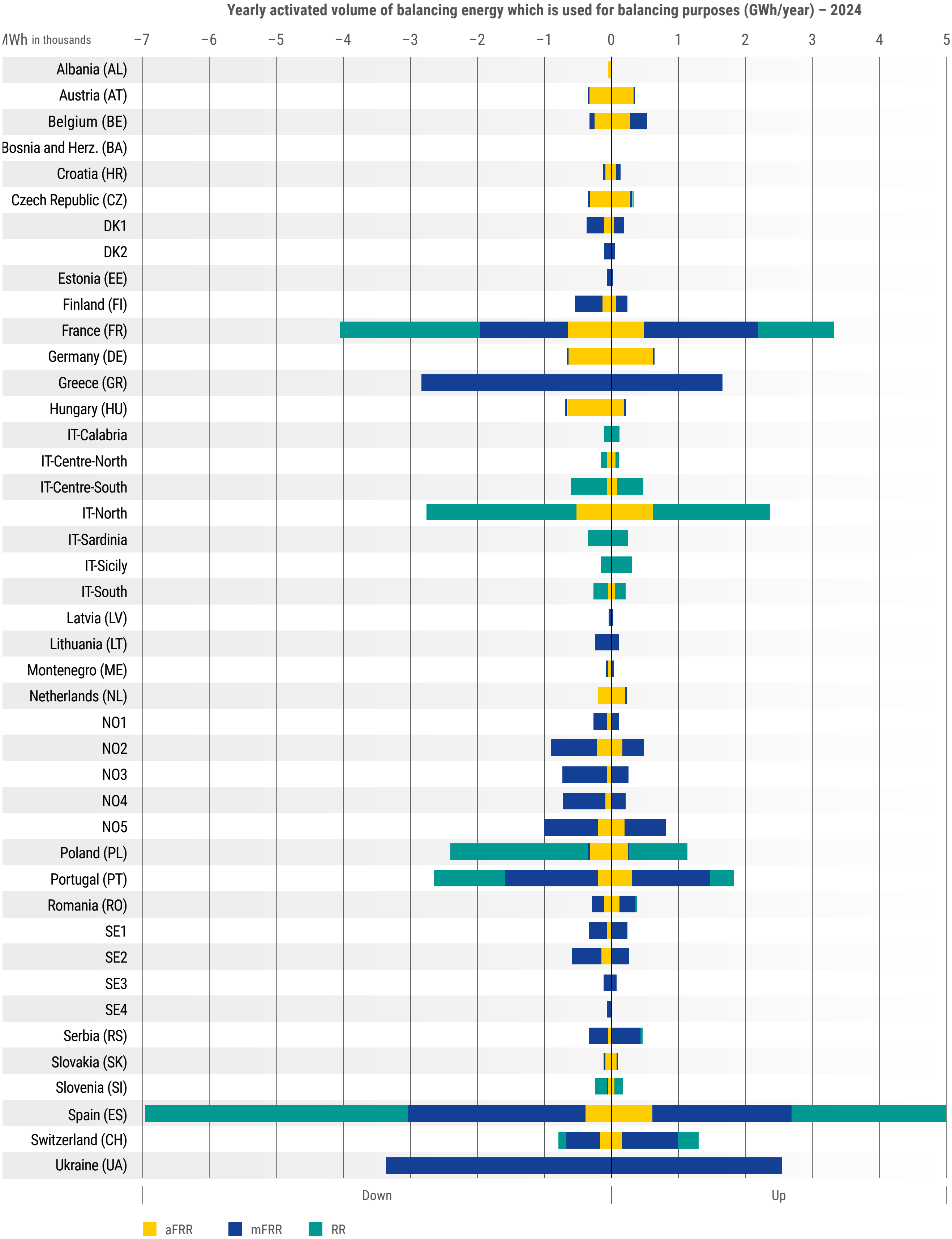
Definition	This indicator[41] displays: • The yearly activated volume of balancing energy used for balancing purposes per BZ, per process (if applicable per product type), and per direction (GWh). This will be displayed in a single graph for all products (aFRR, mFRR, and RR). • Regarding the yearly weighted-average price (VWAP) of the activated balancing energy per BZ, per process (if available, per product type), and per direction (€/MWh), the new PI 3.9 will centralise all VWAP prices for both energy and reserve.
Legal reference	Article 59 (4)(h) of the EB Regulation
Time reference	Yearly
Clarifications on Transparency Platform data	Data for Greece also include redispatch activations

Table 6.9: Indicator 5.7 on the volume and price of balancing energy used for balancing purposes

39 The annual and bi-annual reports will include links to the quarterly reports arising from the pricing methodology, where a higher level of analysis of price incidents are accomplished.

40 After the approved IFs for the European platforms pursuant to Articles 19 (5), 20 (6), 21 (6), and 22 (5) of the EB Regulation become operational. Further changes shall be made in accordance with Article 59 (9) of the EB Regulation.

41 These parameters reflect the perspective of the connected BSPs that supply TSO (in case of TSO–TSO exchanges, it does not reflect fulfilling the TSO demand).

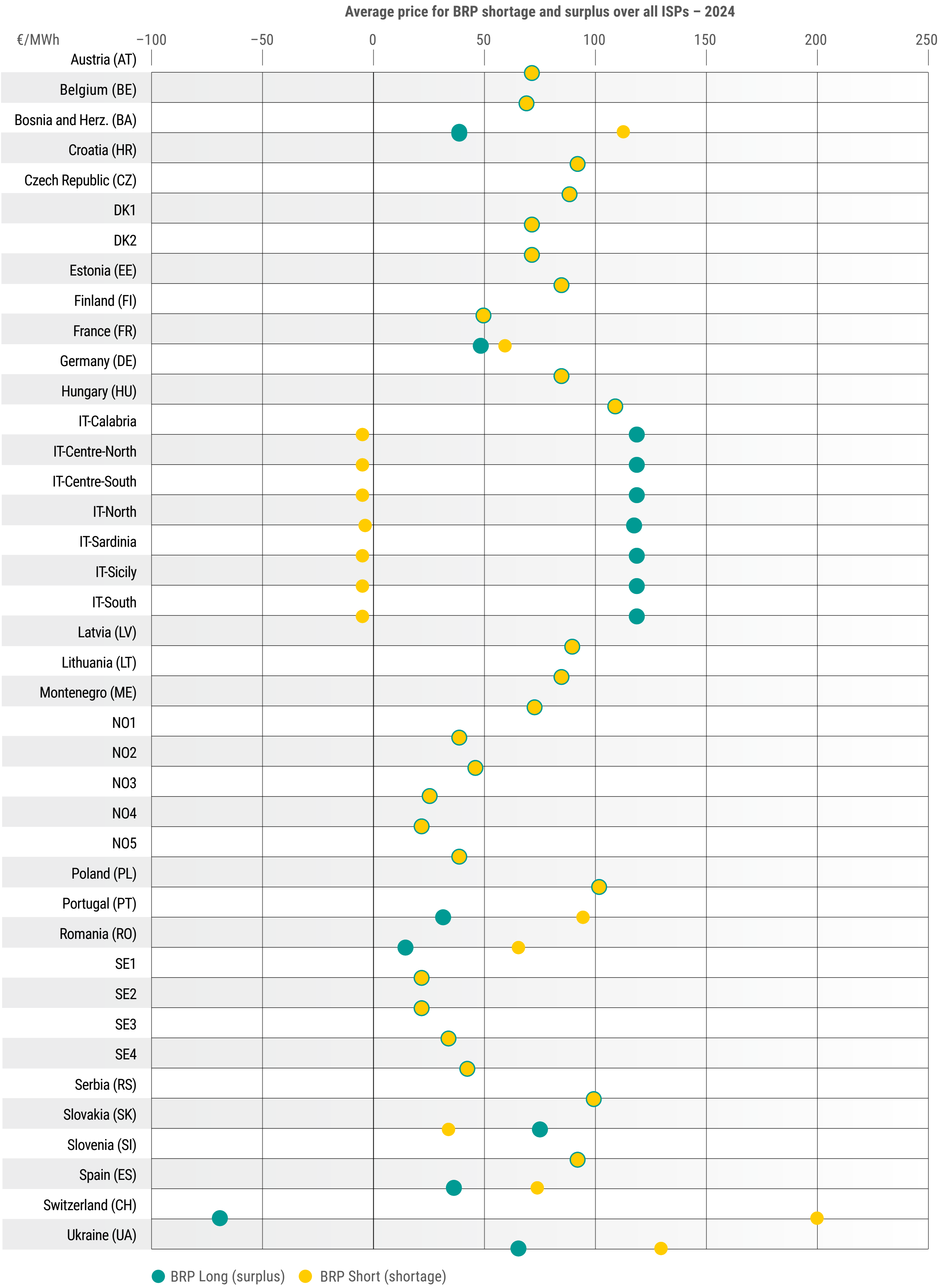

Yearly activated volume of balancing energy which is used for balancing purposes (GWh/year) – 2024
MWh in thousands
−7
−6
−5
−4
−3
−2
−1
0
1
2
3
4
5
Albania (AL)
Austria (AT)
Belgium (BE)
Bosnia and Herz. (BA)
Croatia (HR)
Czech Republic (CZ)
DK1
DK2
Estonia (EE)
Finland (FI)
France (FR)
Germany (DE)
Greece (GR)
Hungary (HU)
IT-Calabria
IT-Centre-North
IT-Centre-South
IT-North
IT-Sardinia
IT-Sicily
IT-South
Latvia (LV)
Lithuania (LT)
Montenegro (ME)
Netherlands (NL)
NO1
NO2
NO3
NO4
NO5
Poland (PL)
Portugal (PT)
Romania (RO)
SE1
SE2
SE3
SE4
Serbia (RS)
Slovakia (SK)
Slovenia (SI)
Spain (ES)
Switzerland (CH)
Ukraine (UA)
Down
Up
aFRR
mFRR
RR

6.3.8 Imbalance prices and system imbalances

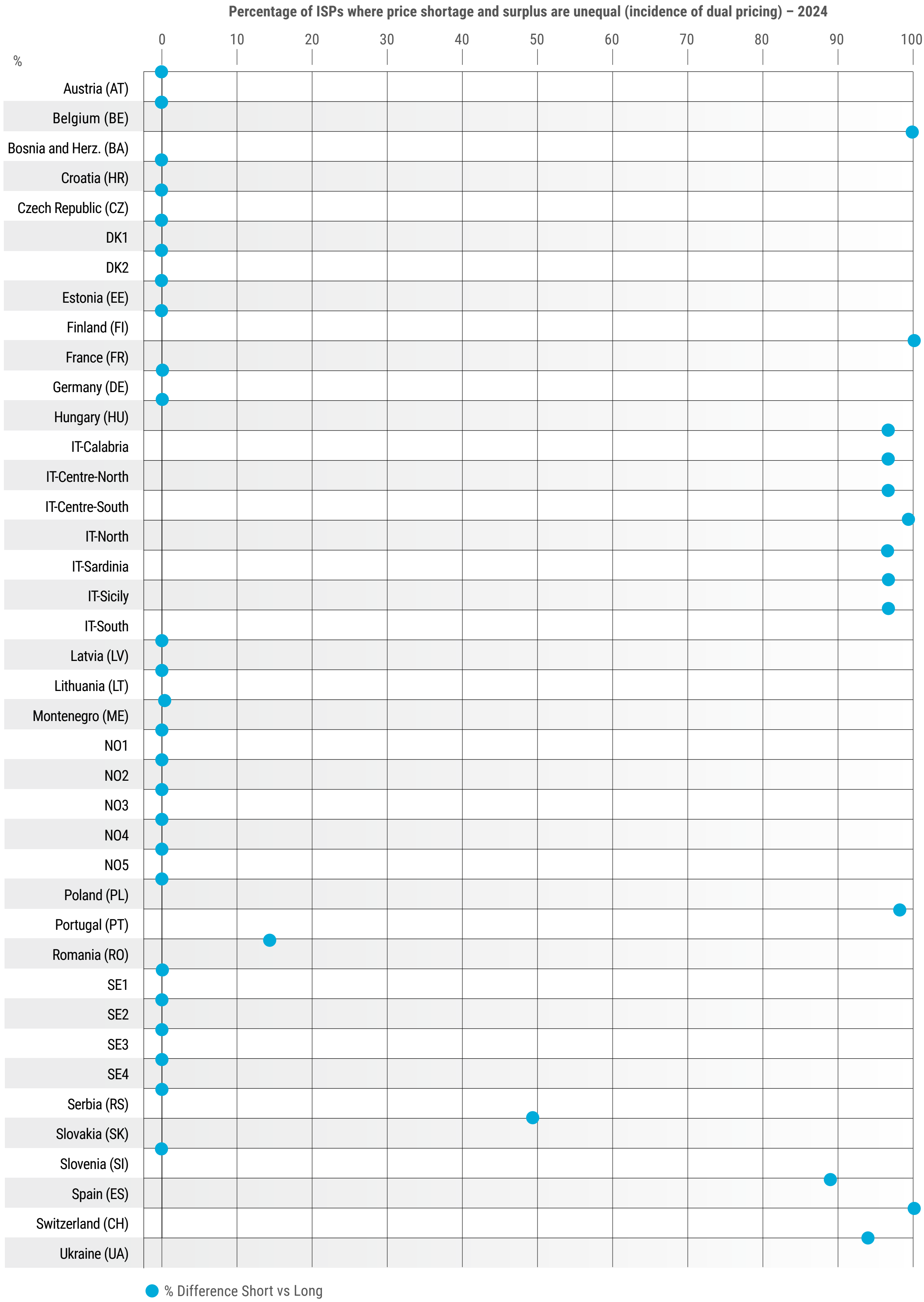
Definition	This indicator is based on the imbalance prices and system imbalances. It indicates whether dual pricing has been applied by reflecting the average imbalance prices per BRP imbalance direction (shortage/surplus). This PI includes the following: 1. Average price for BRP shortage over all ISP 2. Average price for BRP surplus over all ISP 3. Percentage of ISPs where price shortage and surplus are unequal (incidence of dual prices) 4. Percentage of ISPs with positive respectively negative system imbalance[42] Some points to consider for this indicator: • If there are no IPSs with dual pricing, the average imbalance prices over all ISPs for shortage and surplus are equal. • The percentage of ISPs with dual pricing is provided as a separate sub-indicator. • The average price (or prices) over all ISPs is (are) indicative of the value of imbalance for a BRP. • The spread of the average imbalance prices over those ISPs where the system imbalance is short (item 4, respectively long, item 5) indicates: a) the volatility of the imbalance prices b) the incentive for BRPs to avoid imbalances that aggravate system imbalance to support system balance • The percentage of ISPs with negative (respectively positive) system imbalances is given as a separate sub-indicator and reflects whether the system was predominantly short or long. Positive or negative system imbalance parameter should reflect the BZ.
Legal reference	Article 59 (4)(i) of the EB Regulation
Time reference	Yearly

Table 6.10: Indicator 5.8 on the imbalance prices and the system imbalances

42 The percentage of positive and negative system imbalance will be presented jointly in a graph for indicator 3.8.4

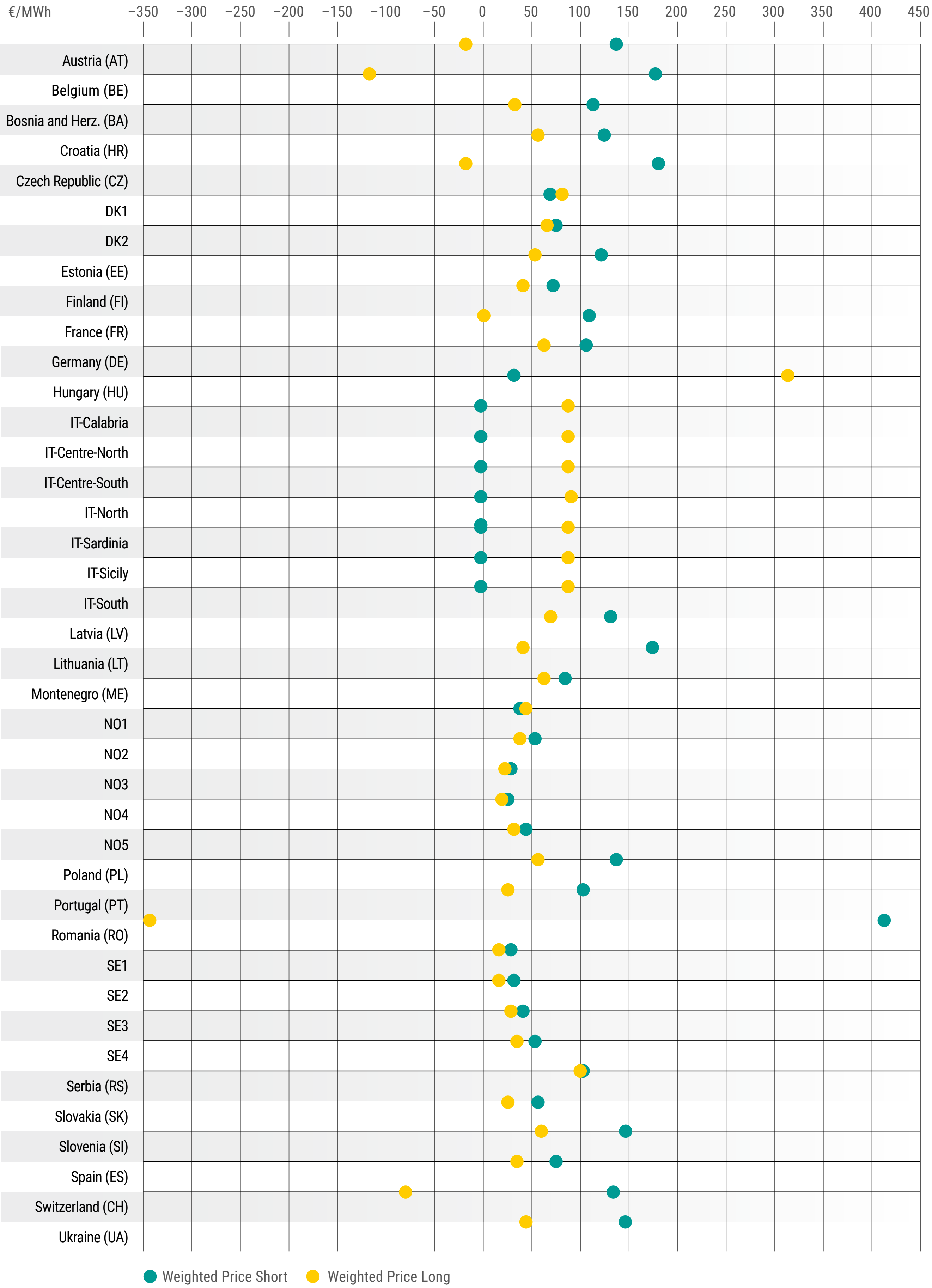


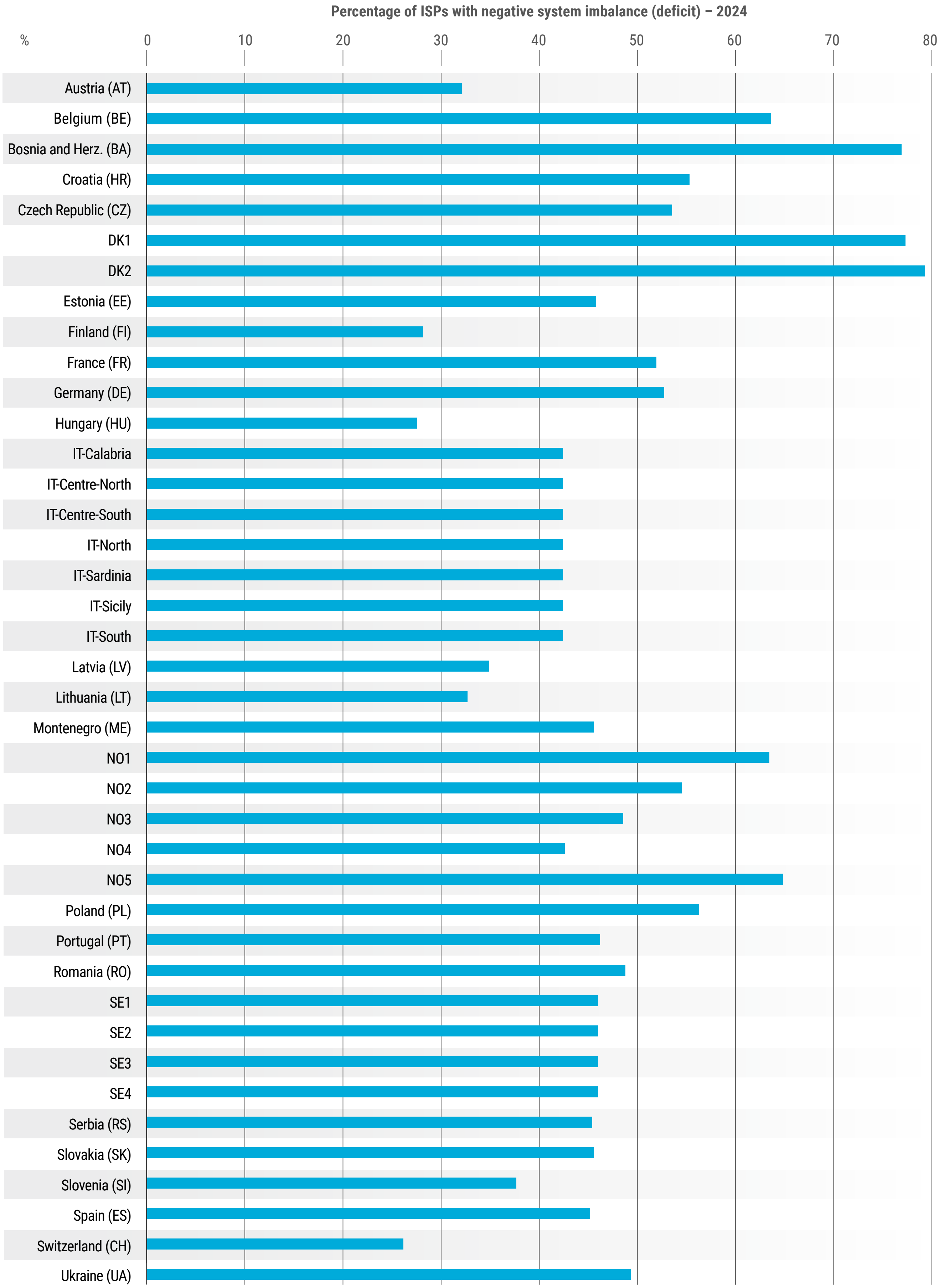
Average price for BRP shortage and surplus over all ISPs – 2024
€/MWh
−100
−50
0
50
100
150
200
250
Austria (AT)
Belgium (BE)
Bosnia and Herz. (BA)
Croatia (HR)
Czech Republic (CZ)
DK1
DK2
Estonia (EE)
Finland (FI)
France (FR)
Germany (DE)
Hungary (HU)
IT-Calabria
IT-Centre-North
IT-Centre-South
IT-North
IT-Sardinia
IT-Sicily
IT-South
Latvia (LV)
Lithuania (LT)
Montenegro (ME)
NO1
NO2
NO3
NO4
NO5
Poland (PL)
Portugal (PT)
Romania (RO)
SE1
SE2
SE3
SE4
Serbia (RS)
Slovakia (SK)
Slovenia (SI)
Spain (ES)
Switzerland (CH)
Ukraine (UA)
BRP Long (surplus)
BRP Short (shortage)

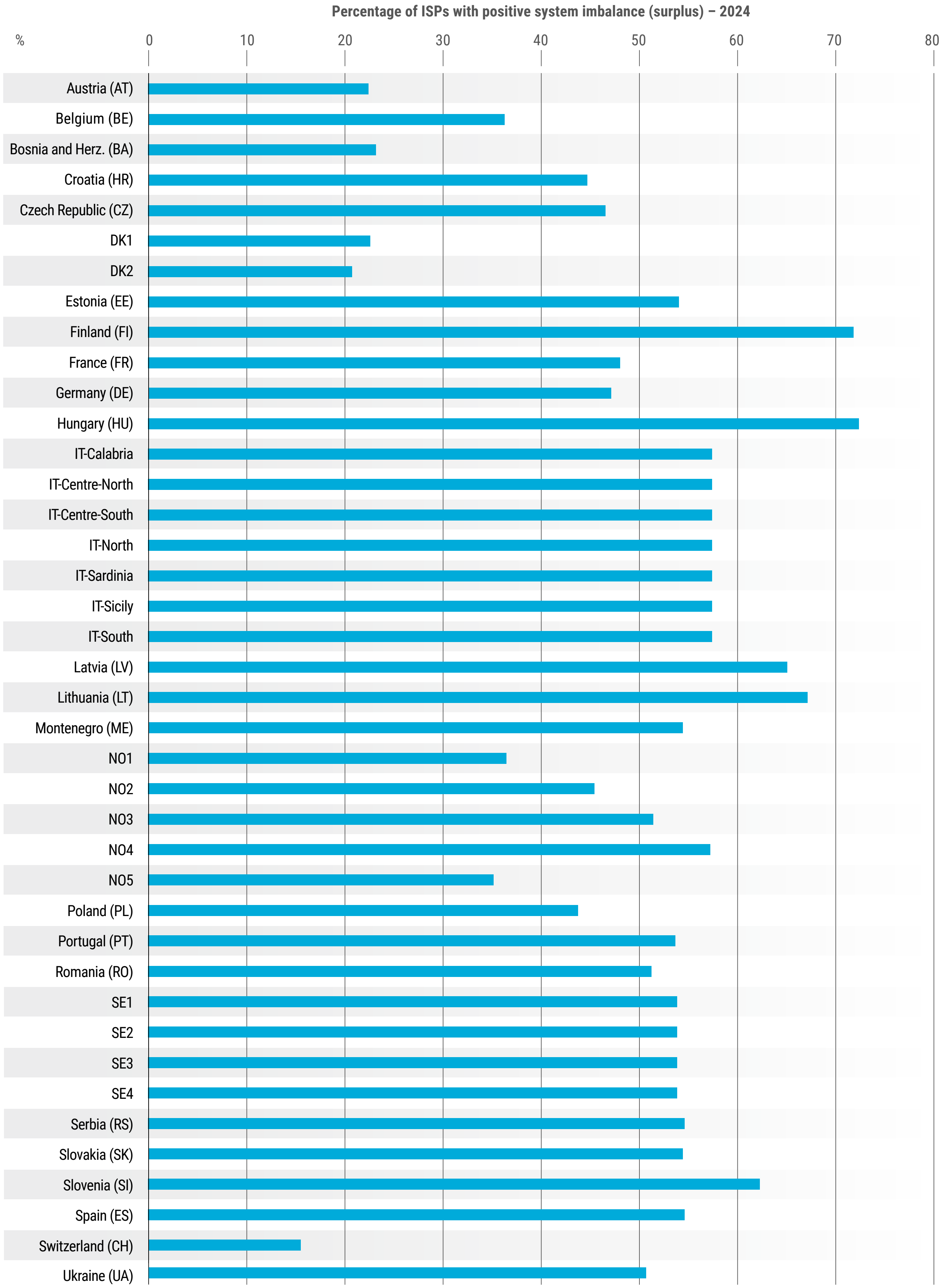


Percentage of ISPs where price shortage and surplus are unequal (incidence of dual pricing) – 2024
%
0
10
20
30
40
50
60
70
80
90
100
Austria (AT)
Belgium (BE)
Bosnia and Herz. (BA)
Croatia (HR)
Czech Republic (CZ)
DK1
DK2
Estonia (EE)
Finland (FI)
France (FR)
Germany (DE)
Hungary (HU)
IT-Calabria
IT-Centre-North
IT-Centre-South
IT-North
IT-Sardinia
IT-Sicily
IT-South
Latvia (LV)
Lithuania (LT)
Montenegro (ME)
NO1
NO2
NO3
NO4
NO5
Poland (PL)
Portugal (PT)
Romania (RO)
SE1
SE2
SE3
SE4
Serbia (RS)
Slovakia (SK)
Slovenia (SI)
Spain (ES)
Switzerland (CH)
Ukraine (UA)
% Difference Short vs Long

Average price for BRP shortage over all ISPs when system imbalance indicates short and long, and average prices for BRP surpluses over all ISPS when system imbalance indicates long (EUR/MWh ISP all) – 2024



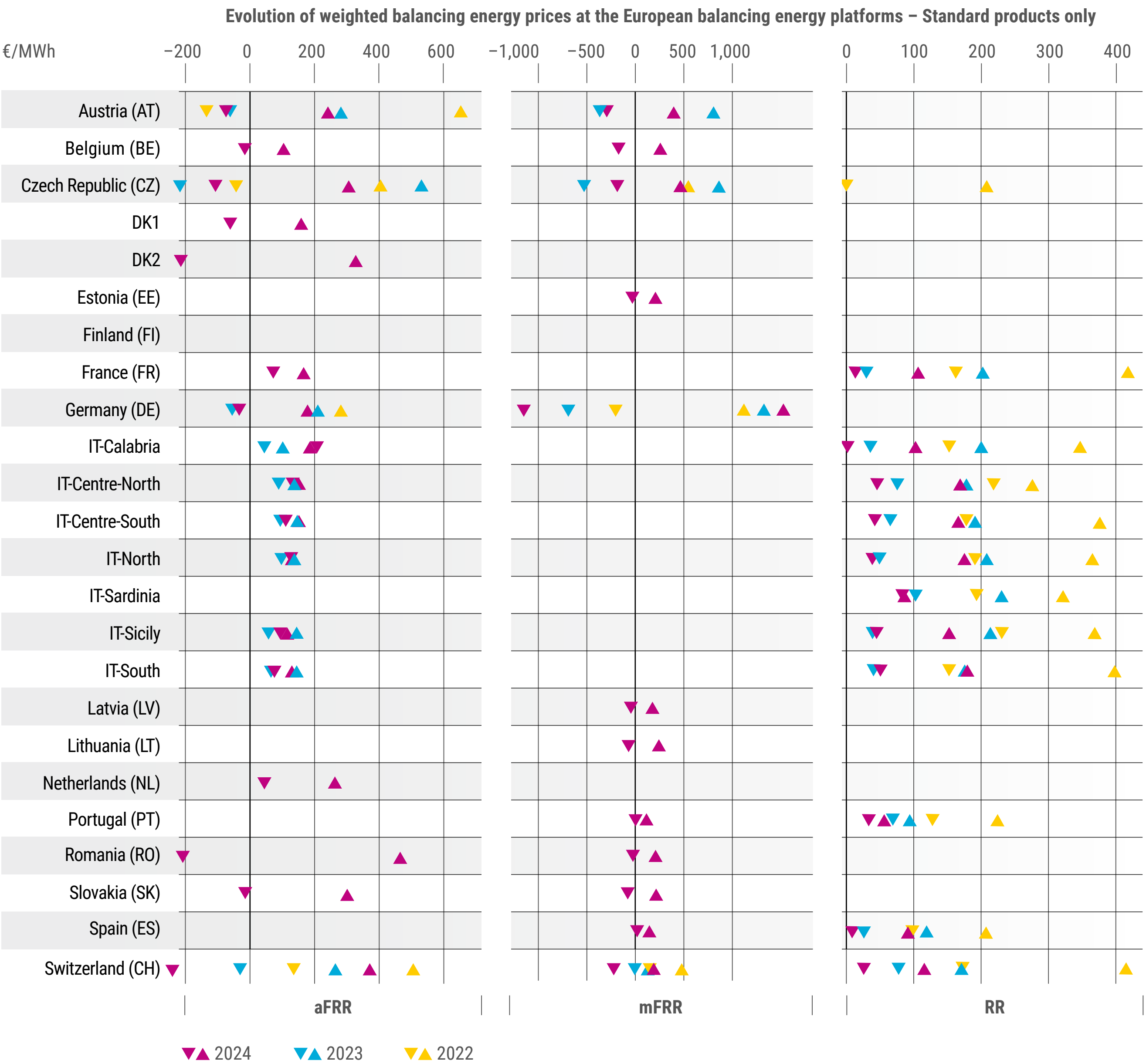

Percentage of ISPs with negative system imbalance (deficit) – 2024
%
0
10
20
30
40
50
60
70
80
Austria (AT)
Belgium (BE)
Bosnia and Herz. (BA)
Croatia (HR)
Czech Republic (CZ)
DK1
DK2
Estonia (EE)
Finland (FI)
France (FR)
Germany (DE)
Hungary (HU)
IT-Calabria
IT-Centre-North
IT-Centre-South
IT-North
IT-Sardinia
IT-Sicily
IT-South
Latvia (LV)
Lithuania (LT)
Montenegro (ME)
NO1
NO2
NO3
NO4
NO5
Poland (PL)
Portugal (PT)
Romania (RO)
SE1
SE2
SE3
SE4
Serbia (RS)
Slovakia (SK)
Slovenia (SI)
Spain (ES)
Switzerland (CH)
Ukraine (UA)


Percentage of ISPs with positive system imbalance (surplus) – 2024
%
0
10
20
30
40
50
60
70
80
Austria (AT)
Belgium (BE)
Bosnia and Herz. (BA)
Croatia (HR)
Czech Republic (CZ)
DK1
DK2
Estonia (EE)
Finland (FI)
France (FR)
Germany (DE)
Hungary (HU)
IT-Calabria
IT-Centre-North
IT-Centre-South
IT-North
IT-Sardinia
IT-Sicily
IT-South
Latvia (LV)
Lithuania (LT)
Montenegro (ME)
NO1
NO2
NO3
NO4
NO5
Poland (PL)
Portugal (PT)
Romania (RO)
SE1
SE2
SE3
SE4
Serbia (RS)
Slovakia (SK)
Slovenia (SI)
Spain (ES)
Switzerland (CH)
Ukraine (UA)

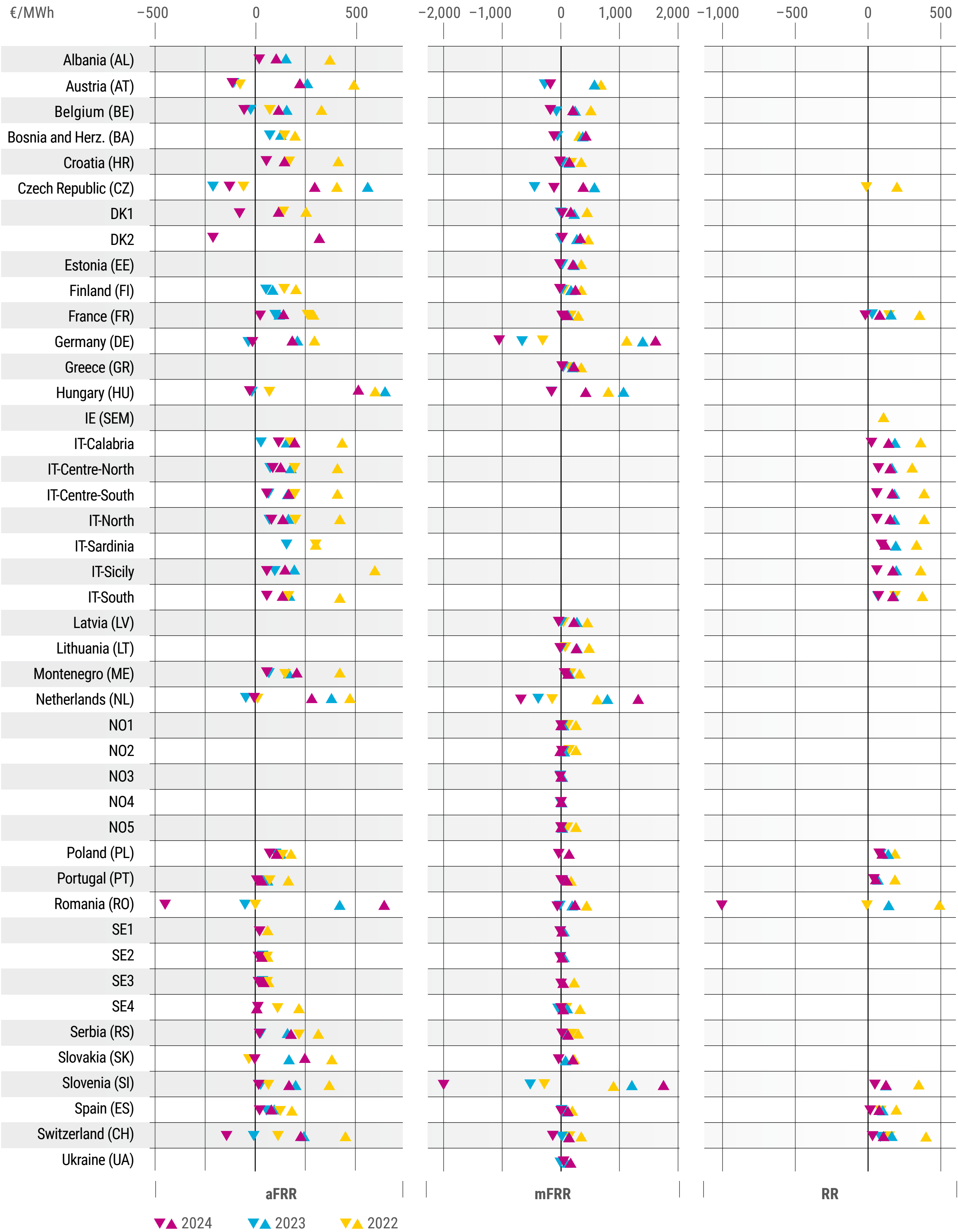
6.3.9 Evolution of balancing service prices from previous years

Definition	This indicator shows the evolution of the annual average prices for the balancing services over the past 3 years (whenever data are available). This PI includes: 1. Evolution of weighted average balancing energy prices at the European balancing energy platforms (standard products only) 2. Evolution of weighted average balancing energy prices at each TSO and where available, per BZ **(including specific products)** 3. Evolution of weighted average balancing capacity procurement prices aligning these prices with a capacity procurement time of 1 hour
Legal reference	Article 59 (4)(j) of the EB Regulation
Time reference	Yearly

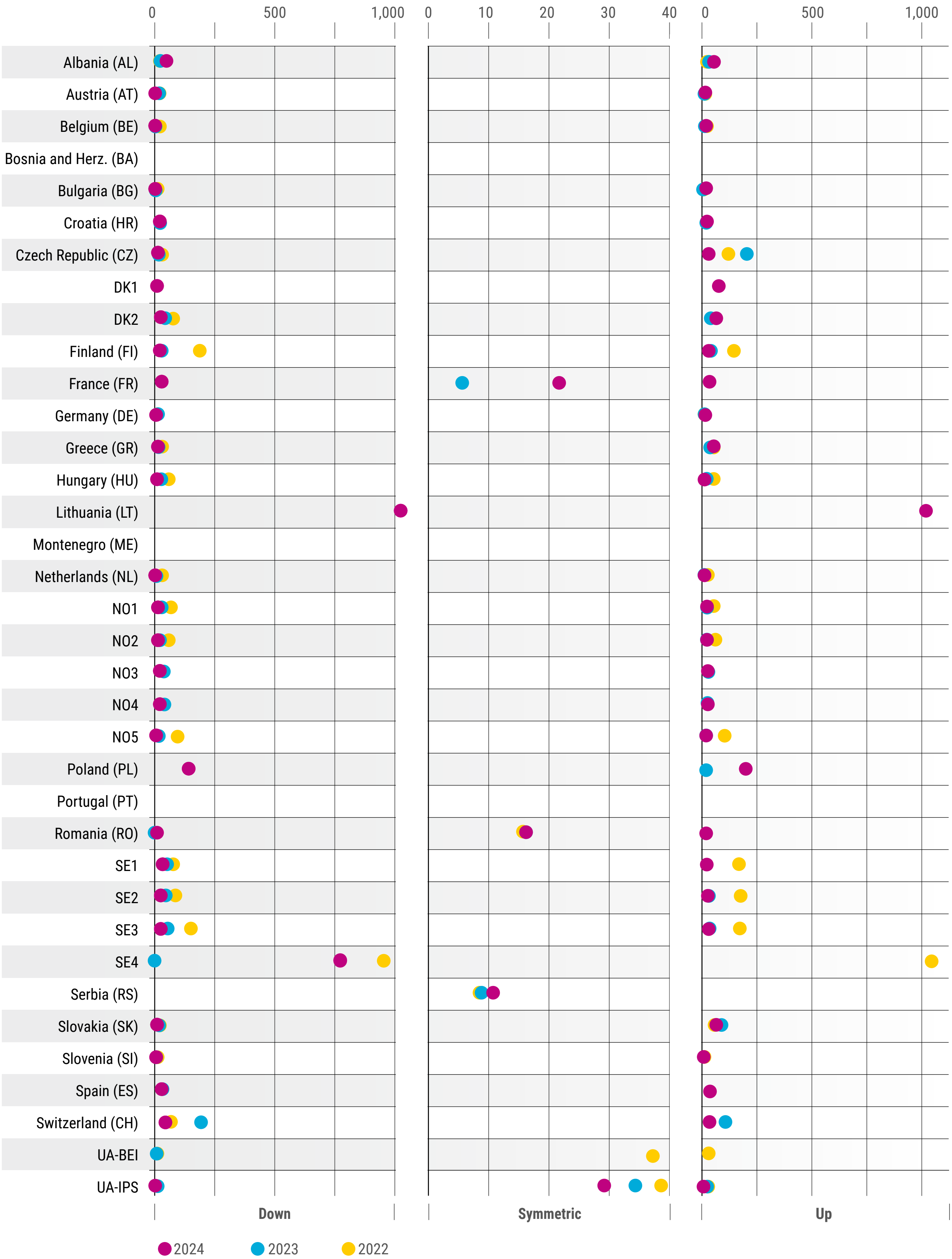
Table 6.11: Indicator 5.9 on the evolution of balancing service prices of the previous years



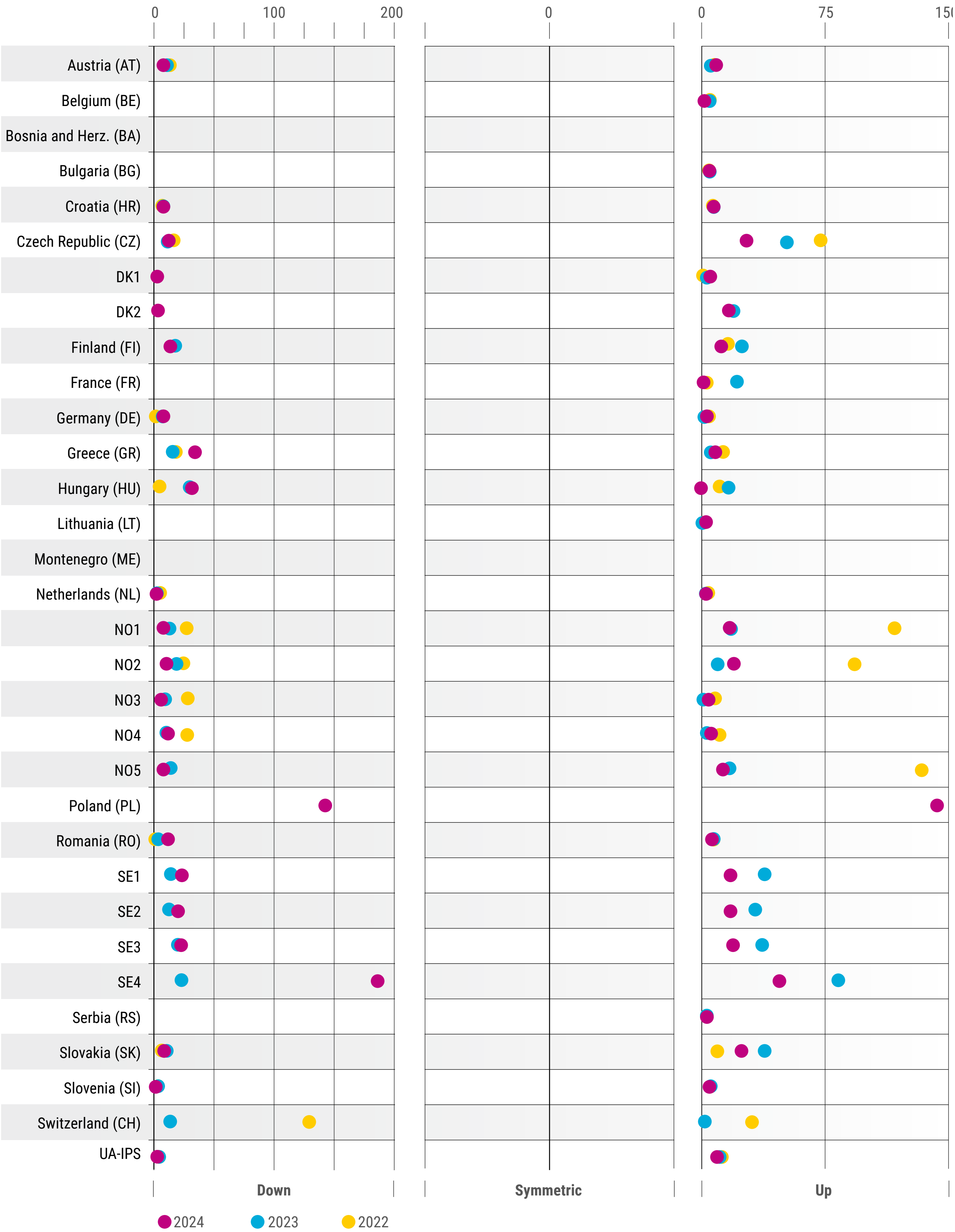
Evolution of weighted balancing energy prices at the European balancing energy platforms – Including specific products



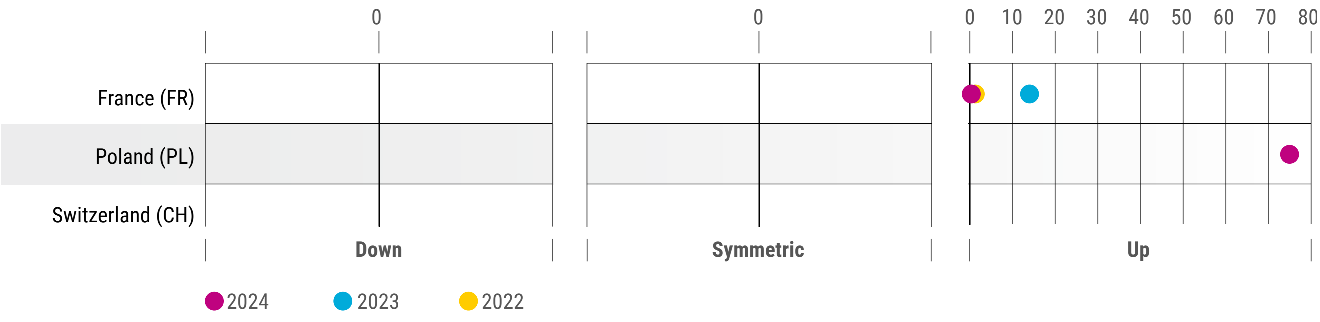
Evolution of weighted balancing capacity procurement prices aligning these prices with capacity procurement time of one hour – aFFR



Evolution of weighted balancing capacity procurement prices aligning these prices with capacity procurement time of one hour – mFFR



Evolution of weighted balancing capacity procurement prices aligning these prices with capacity procurement time of one hour – RR



6.3.10 Comparison of expected and realised costs and benefits from all allocations of cross-zonal capacity for balancing purposes

Definition	This indicator compares the expected benefits with the realised benefits (or losses) for each application of a CZC allocation methodology, based on forecast values (whether for balancing capacity bids or DA energy market bids).[43] This PI includes: • For market-based application (Art. 41 (1) of EB Regulation), compute the social welfare by considering the forecasted DA energy bids and real reserve capacity bids.
Legal reference	Article 59 (4)(k) of the EB Regulation
Time reference	Yearly

Table 6.12: Indicator 5.10 on the comparison of expected and realised costs and benefits from all allocations of cross-zonal capacity for balancing purposes

€	SDAC surplus	aFRR surplus	Total surplus	Avg. daily surplus
Realised Benefits	−22,850,109	223,130,769	200,280,660	547,215
Expected Benefits	−22,693,002	223,130,769	200,437,767	547,644
Delta	−157,107	0	−157,107	−429

43 Once the CZC allocation methodology and RCC procurement methodology enter into force, PI 3.10 will be provided by RCCs.

Annexes

Annex I – Legal references and requirements

The report is based on ENTSO-E monitoring obligations pursuant to Article 8(8) of Regulation (EC) No. 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 . Nevertheless, upon its entry into force, Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (the Electricity Regulation) repealed Regulation (EC) No. 714/2009.

The Electricity Regulation does not include an equivalent of Article 8(8) of Regulation (EC) No. 714/2009 and does not foresee new ENTSO-E monitoring tasks of network codes and guidelines implementation. Therefore, ENTSO-E general monitoring obligations in the network codes and guidelines linked to Regulation (EC) No. 714/2009 cannot be considered binding after the Electricity Regulation entered into force. However, ENTSO-E has decided to continue with the monitoring activities as a good project management practice to ensure high-quality deliverables of network codes and guidelines.

This report focuses on Article 82(2)(a) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation); Articles 63(1)(a) and 63(1)(d) of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA Regulation); and Article 63(1)of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB Regulation).

Annex II – Overview of all TSOs' FCA, CACM, and EB deliverables

The following table provides an overview of All TSOs' deliverable based on FCA

Proposal	FCA regulation article(s)	First submission	NRAs' request for amendments	TSO Submission after Request for Amendment	NRAs approval or ACER decision	TSOs' request for amendment
Common Grid Model (CGM)	17[44] 18[45]	May 2017 June 2017	– February 2018	– May 2018	October 2017 June 2018	
Harmonised Allocation Rules (HAR)[46]	51	April 2017			October 2017[47] October 2017[48] October 2017[49]	July 2019
Single Allocation Platform (SAP)	49 59	April 2017			September 2017	September 2022
Congestion Income Distribution (CID)	57	May 2018	November 2018	March 2019	May 2019	September 2022
Cost of ensuring firmness and remuneration of LTTRs (FRC)	61	April 2020			October 2020 October 2020	

Table A.1: Overview of All TSOs' FCA regulation deliverables (as of May 2025)

The following table provides an overview of All TSOs' deliverable based on CACM

Type	Proposal	CACM regulation Art.	First submission	NRAs' approval(s) or ACER decision	TSOs' request for amendment	NRAs' approval(s) or ACER decision
All-TSO (I)	Capacity calculation Regions	15(1)	October 2015	November 2016[53]	June 2017[54]	September 2017

Table A.2: Regulatory process of the proposal for the determination of capacity calculation regions

44 Generation and load data provision methodology for long-term time frames
45 CGM methodology for long-term time frames
46 As part of the biennial review of the HAR, All TSOs submitted a third TSO proposal on June 2021, and ACER made a decision (No 15/2021) on November 2021, approving a new HAR methodology.
47 On 17 August 2017, all NRAs referred to ACER to adopt a decision.
48 On 2 October 2017, ACER took a decision (No 03/2017)
49 HAR 2017 approved methodology
50 On 29 October 2019, ACER adopted a decision (No 14/2019)
51 HAR 2019 approved methodology
52 "EFTA Surveillance Authority decision" to be considered also for other relevant decisions
53 Referral to ACER from all NRAs
54 All TSOs drafted an amendment to Annex I of the CCRs established by ACER decision 06/2016 ("the draft CCR Amendment Proposal") to include the BZB between Belgium and Great Britain (BE–GB) and to assign this new BZB to the Channel CCR by 17 January 2018. The CCR amendment proposal was adopted upon the decision of the last Regulatory Authority concerned (14 February 2018).
55 All TSOs drafted an amendment to include the new BZB:
– DK1–NL and its corresponding TSOs to the Hansa CCR
– add the TSOs National Grid IFA2 Limited and Eleclink Limited to the FR–GB BZB in the Channel CCR, and
– add the TSO Amprion to the BE–DE/LU BZB in the Core CCR.
56 Referral to ACER from all NRAs
57 As a result of the General Court decisions on T-332/17 and T-333/17 cases towards ACER appeal (A-001-2017), on 22 May 2020 issued a decision inviting the competent party or parties to the concerned proposal. Then, ACER addressed All TSOs to amend or confirm it.

ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment
October 2019[50] October 2019[51]	June 2021	November 2021 November 2021	March 2023 resubmitted in August		August 2023	December 2023 December 2023	March 2025
March 2023 March 2023							
March 2023 March 2023							
October 2021 October 2021	September 2022	March 2023 March 2023					

TSOs' request for amendment	NRAs' approval(s) or ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision[52]	TSOs' request for amendment
March 2018[55]	April 2019[56]	November 2020[57]	May 2021	October 2022	April 2023 April 2023	November 2023

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment	First Submission after the request for amendment
All-TSO (II)	Common grid Model	16 17	May 2016	December 2016	April 2017
	ID cross zonal GOT ID cross zonal GCT	59	December 2016	June 2017	August 2017
	Scheduled exchange	43 56	February 2018 February 2018	September 2018	December 2018[59] December 2018[60]
	ID cross zonal capacity pricing	55 (3)	August 2017	Referred to ACER	
	Congestion income distribution	73	June 2016	January 2017	April 2017

Table A.3: Overview of All TSOs' CACM regulation deliverables (as of May 2025)

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment	First Submission after the request for amendment
All-TSOs & All-NEMOs	Day-ahead and intraday algorithm	37	February 2017[64]	July 2017	November 2017
	Max/min price	41 54	February 2017 February 2017	Referred to ACER	

Table A.4: Overview of All TSO and All NEMO CACM regulation deliverables (as of May 2025)

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment
All-NEMOs	plan of the market coupling operator	7 (3)	April 2016	September 2016
	Back-up methodology	36	February 2017	July 2017
	Products accommodated	40 53 (4)	February 2017 February 2017	July 2017 July 2017

Table A.5: Overview of All NEMOs' CACM regulation deliverables (as of May 2025)

58 Referral to ACER from all NRAs
59 DA proposal
60 ID proposal
61 DA Costs coefficients – 2021 update
62 ID Costs coefficients – 2021 update
63 All-NRAs' referral to ACER
64 DA and ID requirements as annexes
65 Referral to ACER from all NRAs
66 All NEMOs' request for amendment
67 On 22 December 2020, ACER took a decision (No 37/2020)
68 SDAC Products
69 On 30 January 2020, ACER took a decision (No 05/2020)
70 SIDC Products

NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	Request for amendment	ACER decision
May 2017				
April 2018[58] April 2018				
February 2019[61] February 2019[62]	December 2022	May 2023 May 2023	March 2024	September 2024
January 2019				
December 2017[63]	July 2021	December 2021 December 2021	June 2023	December 2023 December 2023

NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	Request for amendment	ACER decision
July 2018[65]	August 2019	January 2020	November 2023	September 2024 September 2024
November 2017 November 2017 November 2017 November 2017	Day Ahead: September 2022 Intraday: September 2022	Day Ahead: January 2023 January 2023 Intraday: January 2023 January 2023		

First Submission after the request for amendment	NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	ACER decision
December 2016	June 2017			
November 2017	January 2018			
November 2017 November 2017	January 2018 January 2018	June 2020[66]	December 2020[67] December 2020[68] January 2020[69] January 2020[70]	September 2024 March 2025

Balancing implementation status

Type	Proposal	EB Art	First TSOs' submission	NRAs' approval/1st request for amendment/Referral to ACER
All-TSOs	Implementation framework for the European RR platform	19	18 June 2018	15 January 2019 (approval)
All-TSOs	1st Amendment of the Implementation framework for the European RR platform	19	16 March 2021	18 October 2021[71]
All-TSOs	2nd Amendment of the Implementation framework for the European RR platform	19	31 March 2022	
All-TSOs	Implementation framework for the European mFRR platform	20	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment of the Implementation framework for the European mFRR platform	20	31 March 2022	
All-TSOs	2nd Amendment of the Implementation framework for the European mFRR platform	20	31 March 2022	
All-TSOs	Implementation framework for the European aFRR platform	21	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment for the Implementation framework for the European aFRR platform	21	31 March 2022	
All-TSOs	2nd Amendment for the Implementation framework for the European aFRR platform	21	31 January 2024	5 July 2024
All-TSOs	Implementation framework for the European IN platform	22	18 June 2018	9 November 2018 (RfAs by individual NRAs)
All-TSOs	1st Amendment for the Implementation framework for the European IN platform	22	31 March 2022	
All-TSOs	Classification of the activation purposes of balancing energy bids	29	11 February 2019	23 July 2019 (RfAs by individual NRAs)
All-TSOs	Pricing method for all products	30	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment – Pricing method for all products	30	28 August 2021	
All-TSOs	2nd Amendment – Pricing method for all products	30	31 January 2024	5 July 2024

Table A.5: Status of the balancing energy procurement and activation deliverables

71 Approval from RR NRAs was received via email. No official letter/document has been issued at the point of publication of this report.

72 2nd RfAs are not available (same as 1st RfAs) as those requests made by each NRA to their respective TSO.

73 2nd RfAs are not available (same as 1st RfAs) as those requests made by each NRA to their respective TSO.

1st TSOs' submission after the request for amendment	NRAs' approval/2nd request for amendment/Referral to ACER	2nd TSOs' submission after the request for amendment	ACER/NRAs decision
			24 January 2020
			30 September 2022
			24 January 2020
			30 September 2022
23 January 2019	19 July 2019 (2nd RfA[72]) 16 January 2020 (referred to ACER)	10 September 2019	24 June 2020 Corrigendum: 8 December 2020
			30 September 2022
11 November 2019	19 July 2019 (2nd RfA[73]) 16 January 2020 (referred to ACER)		15 July 2020
			24 January 2020
			25 February 2022

Type	Proposal	EB Art.	First TSOs' submission	NRAs' approval/1st request for amendment/Referral to ACER
All-TSOs	List of standard balancing capacity products for FRR and RR	25	18 December 2019	
All-TSOs	Methodology for the allocation of cross-zonal capacity based on the co-optimisation allocation process	40	18 December 2019	
All-TSOs	Cross-Zonal Capacity Allocation Harmonised Methodology (HCZCA)	38	17 December 2022	
All-TSOs	1st Amendment – Cross-Zonal Capacity Allocation Harmonised Methodology (HCZCA)	38	31 July 2024	
All-TSOs	ENTSO-E Proposals for the Regional Coordination Centres' (RCCs) Procurement and Sizing		17 March 2023	
Regional	Methodology for the allocation of the cross-zonal capacity market-based allocation process	41	Baltic: 18 December 2019	18 June 2020
Regional			Core: 18 December 2019	12 August 2020
Regional			GR/IT: 18 December 2019	1 July 2020
Regional			Hansa: 18 December 2019	24 July 2020
Regional			IT North: 18 December 2019	29 June 2020
Regional			Nordic: 7 April 2019	17 October 2019
Regional	Methodology for the allocation of cross-zonal capacity based on an economic analysis	42	Core: 18 December 2019	12 August 2020
Regional			GR/IT: 18 December 2019	1 July 2020
Regional			Hansa	Did not submit.
Regional			IT North: 18 December 2019	29 June 2020

Table A.6: Status of the balancing capacity procurement and CZC allocation deliverables

Type	Proposal	EB Art.	First TSOs' submission	NRAs' approval/1st request for amendment/Referral to ACER
All-TSOs	TSO–TSO settlement of intended exchanges of energy as a result of the RRP, FRP and INP	50.1	18 December 2018	23 July 2019
All-TSOs	TSO–TSO settlement of intended exchanges of energy due to ramping restrictions and FCR between synchronous areas	50.4	18 June 2019	4 December 2019
All-TSOs	TSO–TSO settlement of unintended exchanges between synchronous areas	51.2	18 June 2020	
Regional	TSO-TSO settlement of intended exchanges of energy due to ramps and FCR within synchronous area continental Europe and of unintended exchanges of energy within synchronous area continental Europe	50.3	18 June 2019	4 December 2019
Regional		51.1	18 June 2019	4 December 2019
Regional	TSO–TSO settlement of unintended exchanges within synchronous area Nordics TSOs of synchronous area and TSO–TSO settlement of intended exchanges of energy due to ramps and FCR within the Nordic synchronous area	50.3a	18 June 2019	18 December 2019
Regional		51.1b		
All-TSOs	Imbalance settlement harmonisation	52	11 February 2019	11 July 2019

Table A.7: Status of the imbalance settlement and other settlements deliverables (FSkar)

1st TSOs' submission after the request for amendment	NRAs' approval/2nd request for amendment/Referral to ACER	2nd TSOs' submission after the request for amendment	ACER/NRAs decision
			17 June 2020
			17 June 2020
			Decision No 11/2023 of 19 July 2023
			29 January 2025
			Decision No 12/2023 of 19 July 2023
28 August 2020	30 October 2020 (2nd RfA)	30 December 2020 (NRAs forwarded for decision to ACER on 19 February 2021)	ACER approved on 13 August 2021
6 December 2020	NRAs forwarded for decision to ACER on 22 February 2021		ACER approved on 13 August 2021
24 September 2020	1 December 2020 (2nd RfA)	1 April 2021	NRAs approved on 22 June 2021
13 October 2020	Withdrawn by respective TSOs on 12 May 2021		
4 September 2020	15 December 2020 (2nd RfA)	26 March 2021	NRAs approved on 1 June 2021
17 December 2019	28 February 2020 (referred to ACER)		5 August 2020
4 December 2020	Withdrawn by respective TSOs on 24 May 2021		
24 September 2020	1 December 2020 (2nd RfA)	9 April 2021	NRAs approved on 22 June 2021
4 September 2020	15 December 2020 (2nd RfA)	26 March 2021	Withdrawn by corresponding TSOs on 27 May 2021

1st TSOs' submission after the request for amendment	NRAs' approval/2nd request for amendment/Referral to ACER	2nd TSOs' submission after the request for amendment	ACER/NRAs decision
11 November 2019	16 January 2020 (referred to ACER)		16 July 2020
27 March 2020	22 May 2020 (NRAs' approval)		
	4 December 2019 (NRAs' approval)		
15 March 2020	27 May 2020 (NRAs' approval)		
15 March 2020	27 May 2020 (NRAs' approval)		
18 February 2020	31 March 2020 (NRAs' approval)		
	16 January 2020 (referred to ACER)		15 July 2020

Annex III – Market process overview of FCA, CACM, and EB Regulations

Abbreviations and legend used in the following process overview:

AC	Allocation Constraint
AOF	Activation Optimisation Function
aFRP	Automatic Frequency Restoration Process
aFRR	Automatic Frequency Restoration Reserves
BC	Balancing Capacity
BE	Balancing Energy
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CCC	Central Capacity Calculator
CCP	Central Counter Party
CET	Central European Time
CGM	Common Grid Model
CI	Congestion Income
CID	Congestion Income Distributor
CNEC	Critical Network Element and Contingency
CPOF	Capacity Procurement Optimisation Function
CZC	Cross-Zonal Capacity
D2CF	D-2 Congestion Forecast
DA	Day-Ahead
DACF	Day-Ahead Congestion Forecast
DAFD	Day-Ahead Firmness Deadline
EBP	European balancing platforms: European platforms for operating the imbalance netting process and exchanging the balancing energy from aFRR, mFRR, and RR
FRP	Frequency Restoration Process (aFRP + mFRP)
GCT	Gate Closure Time
GOT	Gate Opening Time
GSK	Generation Shift Key
ID	Intraday
IDA	Intraday Auction
IDCF	Intraday Congestion Forecast
IDCZGCT	Intraday Cross-Zonal Gate Closure Time
IDCZGOT	Intraday Cross-Zonal Gate Opening Time
IGM	Individual Grid Model
IN	Imbalance Netting
ISP	Imbalance Settlement Period
LT	Long Term
LT Nom.	Long Term Nomination
MCO	Market Coupling Operator
mFRP	Manual Frequency Restoration Process
mFRR	Manual Frequency Restoration Reserves
mFRR-DA	Direct Activation of mFRR

mFRR-SA	Scheduled Activation of mFRR
MP	Market Participant
MR	Market Result
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PTR	Physical Transmission Rights
RA	Remedial Action
RRP	Reserve Restoration Process
RR	Restoration Reserves

Legend

- Approved target model timing
- Draft target model timing
- Applied best practice
- Task can be done well in advance
- Recurrent task
- Regional task

Forward capacity allocation process

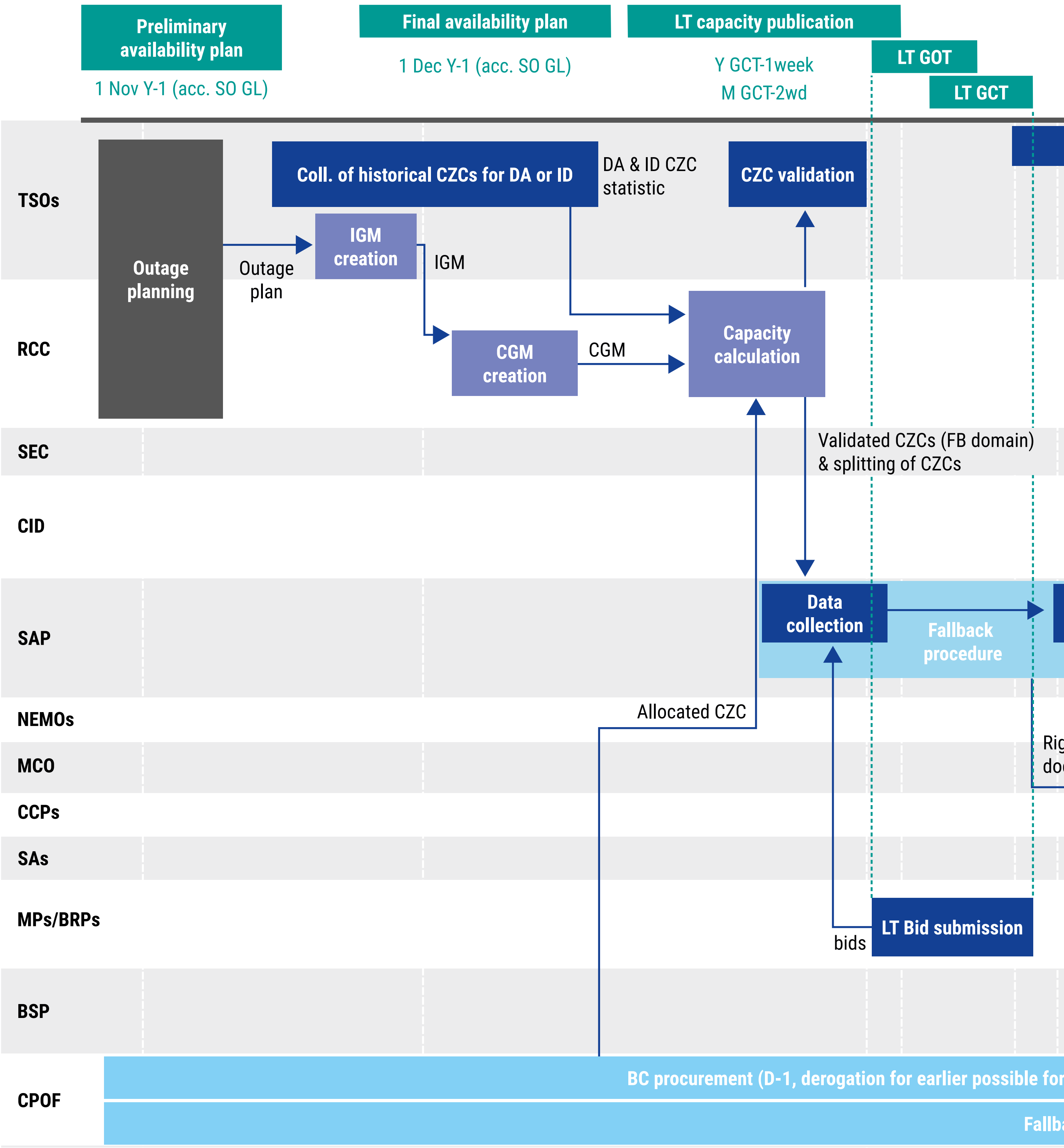
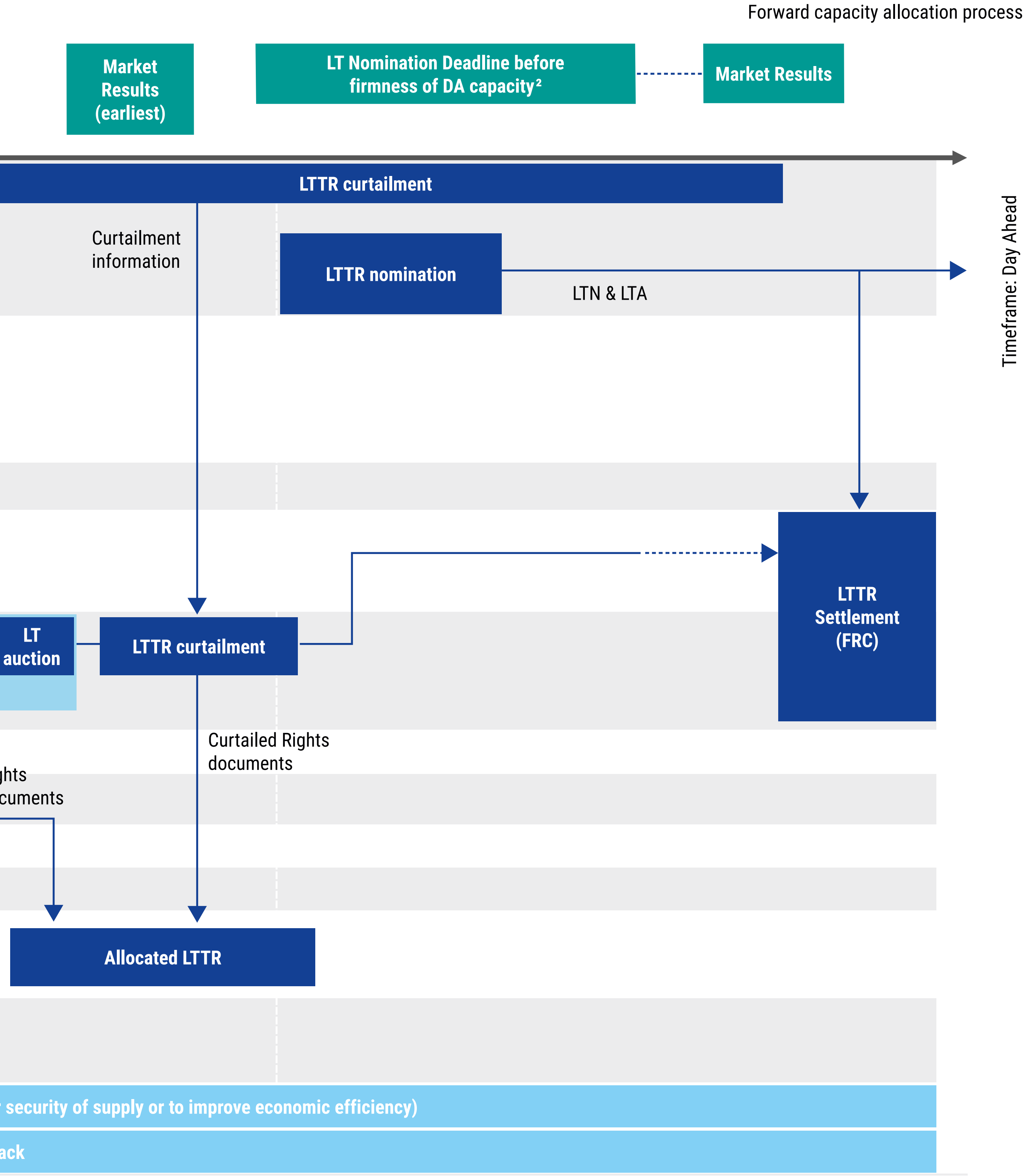
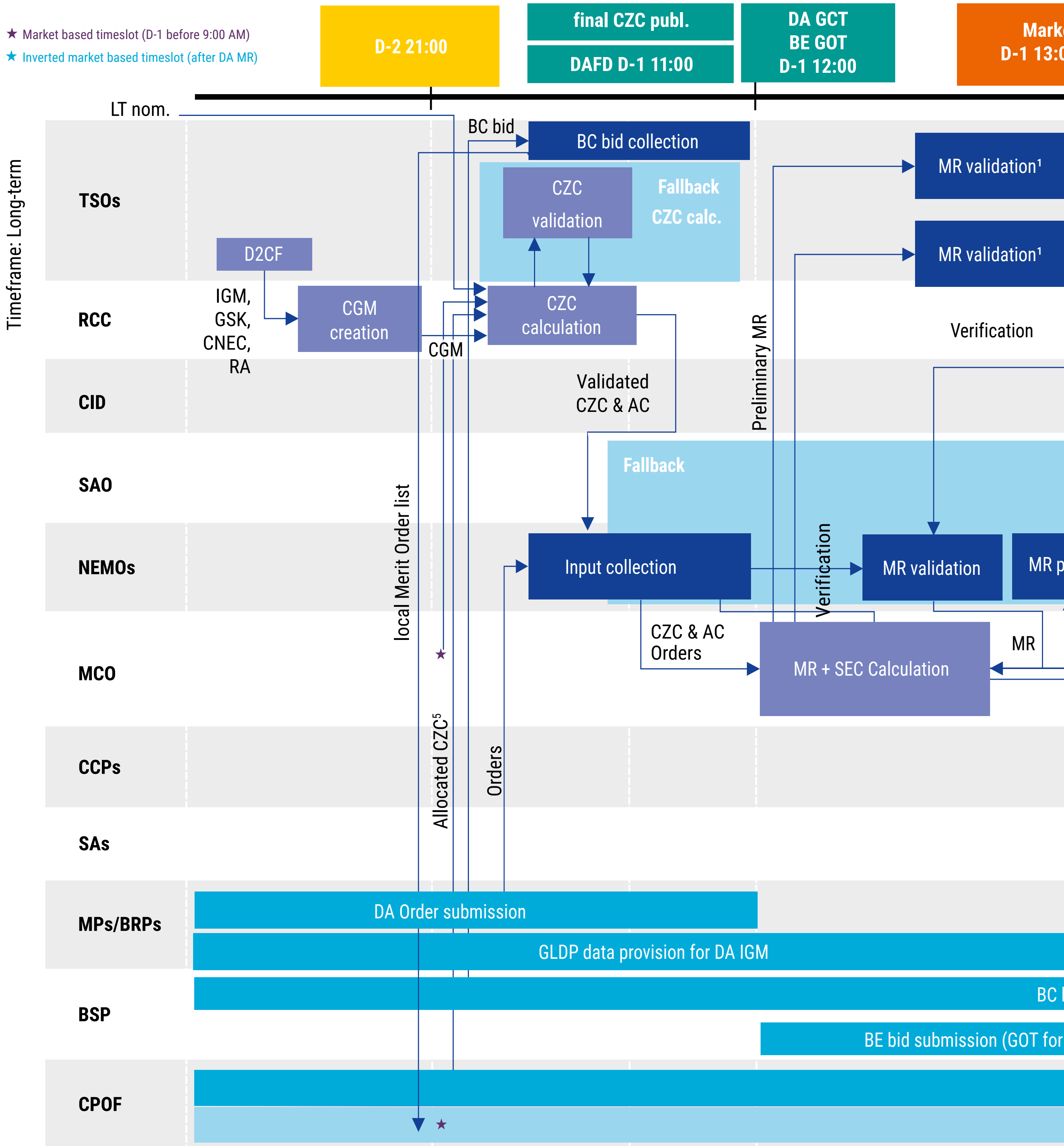


Figure A.1: Forward capacity allocation process



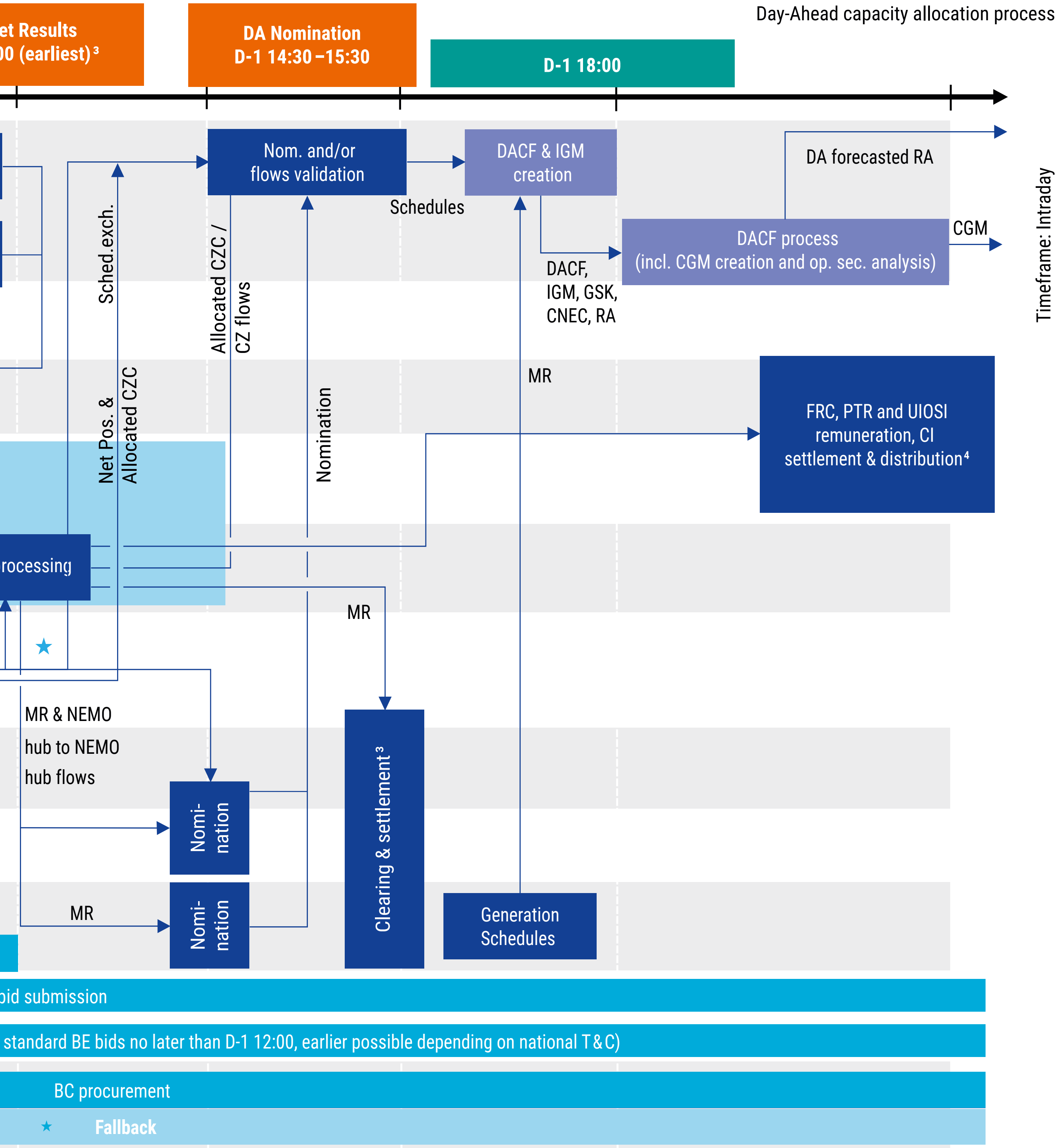
Forward capacity allocation process
Market Results (earliest)
LT Nomination Deadline before firmness of DA capacity²
Market Results
LTTR curtailment
Curtailment information
LTTR nomination
LTN & LTA
Timeframe: Day Ahead
LTTR Settlement (FRC)
LT auction
LTTR curtailment
Curtailed Rights documents
ghts
cuments
Allocated LTTR
security of supply or to improve economic efficiency)
ack

Day-Ahead Capacity Allocation Process



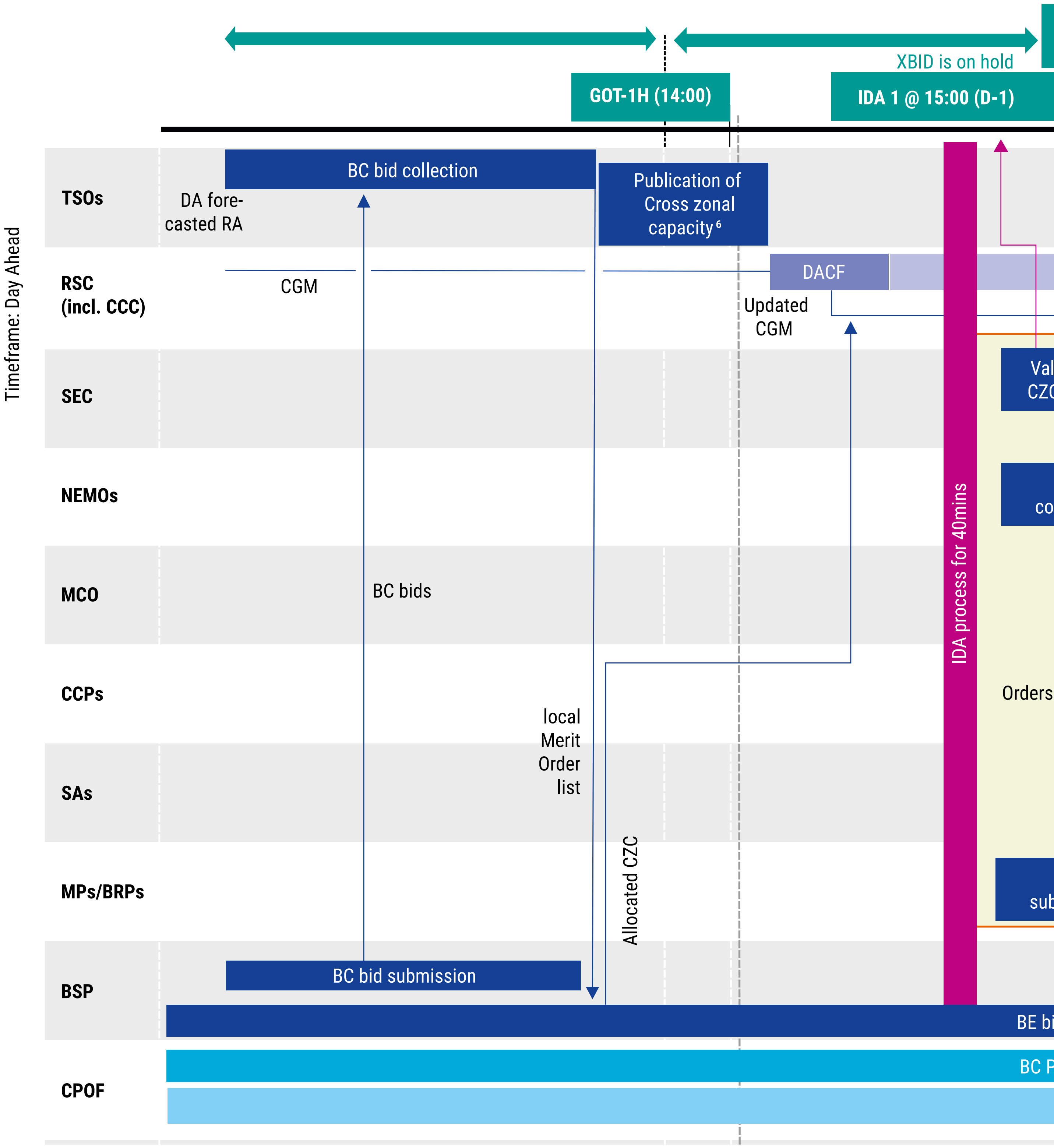
1) No parallel processes, solution depends on the regional design. 2) Only in case of market-based allocation and economic efficiency analysis based allocation.
4) This processes are performed close to the delivery date or even after delivery. 5) The implementation design of the co-optimized CZC allocation according to E

Figure A.2: Day-Ahead Capacity Allocation Process



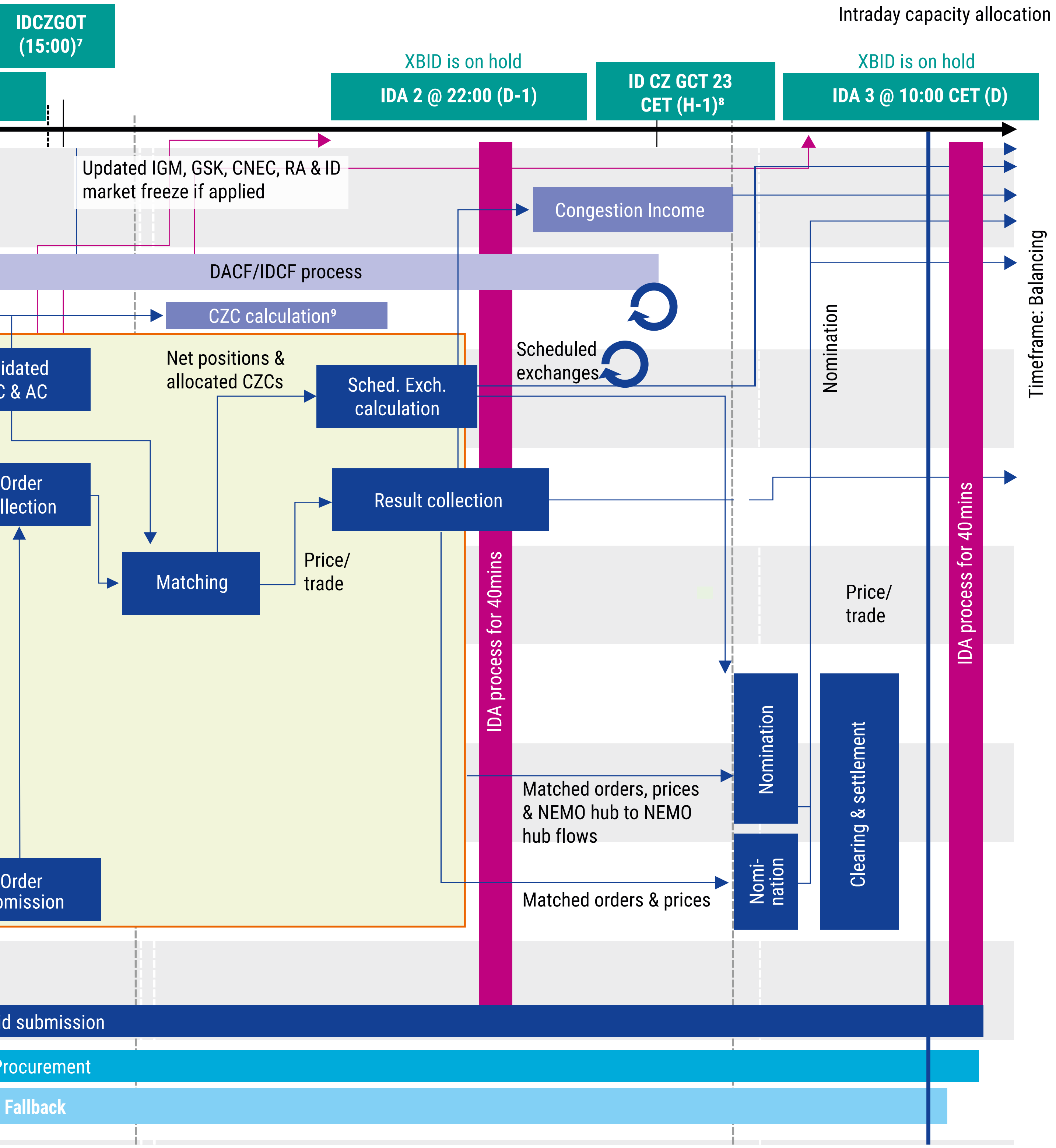
. Please note that co-optimization is not shown on the slide. **3)** The latest possible time of market results publication is D-1 15:30 (in fallback situations).
EB Art. 40 and its respective methodology is under discussion until mid-2022.

Intraday capacity allocation



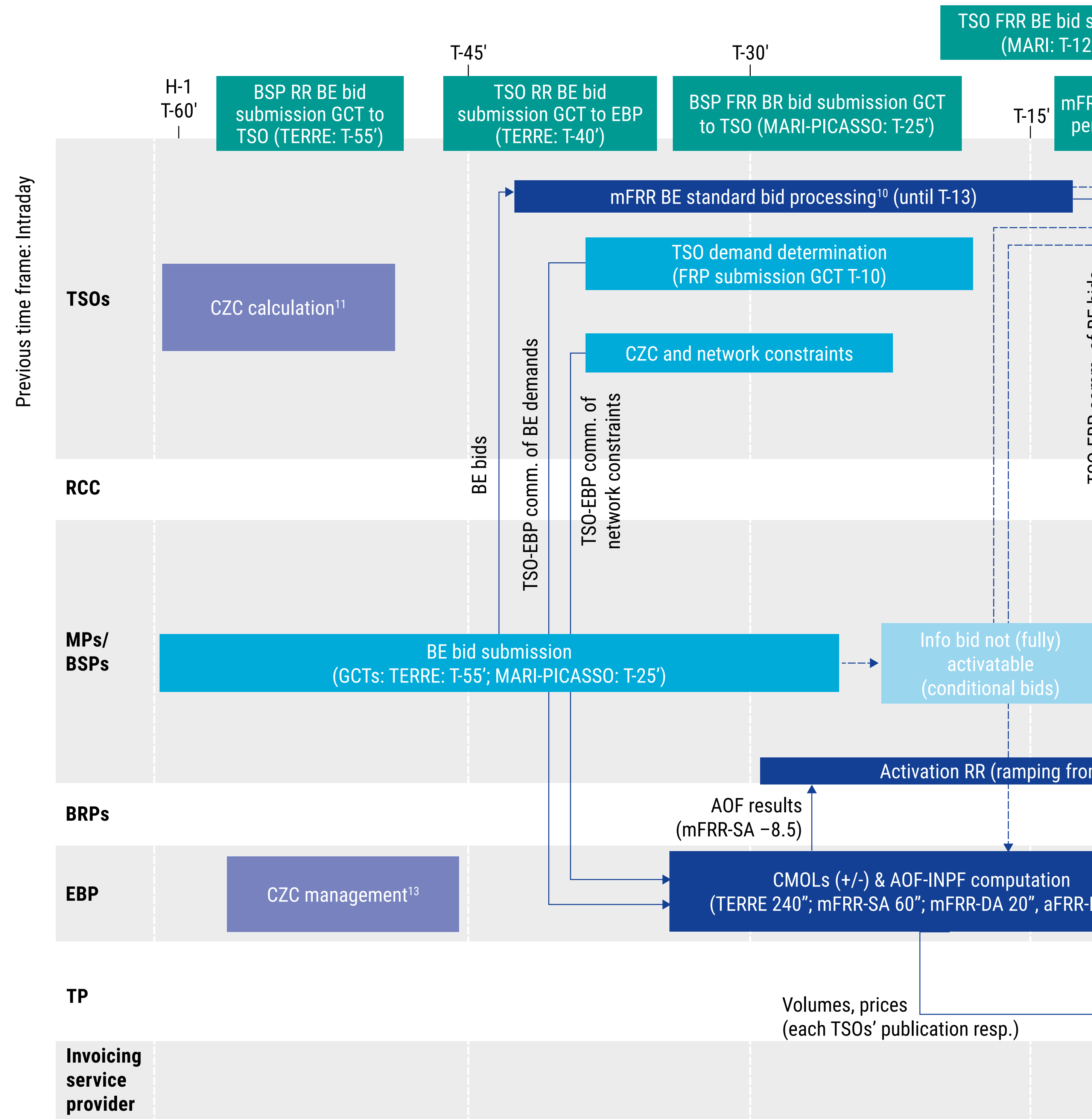
6) Preparation of CGM might be completed close or even after publication deadline. **7)** IDCZGOT-15:00 D-1, IDCZ capacity might not be available at IDCZGOT on
Time suspension of the continuous trading for IDAs is 40 min in the target model and one hour in an interim phase of one year **8)** first GCT for the first MTU of t

Figure A.3: Intraday capacity allocation



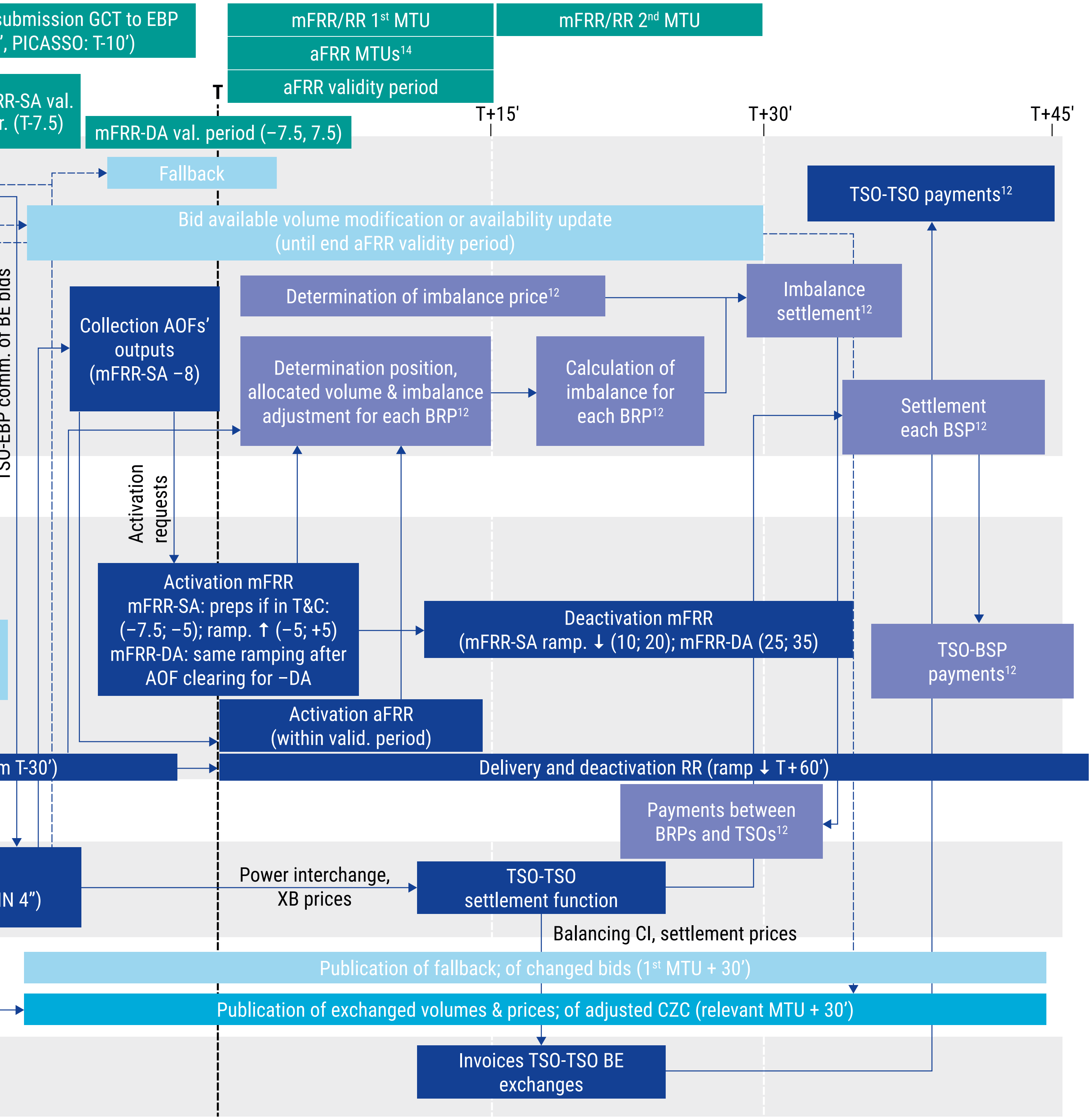
some interconnections and might be provided only at 22:00 D-1 depending on CCR.
he next day is 23 D-1 **9)** first IDCC is carried out ahead of IDA at 10

Cross-Zonal Balancing Energy Processes



10) Including collecting, conversion integrated scheduling process bids and specific BE bids to standard BE bids, modification bids EB 29(9), update availability o
11) CCRs' CZC calculation methodologies are currently under approval process. The entity or entities performing CCRs' EB CC are yet to be decided (e. g. EBPs, RC
12) The imbalance settlement and payments detailed process and timing is defined nationally. For the points under reference 8), the time scale on the top does no
13) A new capacity management function manages the updates of CZC usage of all balancing platforms.
14) Each aFRR MTU corresponds to an optimisation cycle of the AOF of the aFRR-Platform (four seconds).

Figure A.4: Cross-Zonal Balancing Energy Processes



f bids EB 29(14), validation, preparation for submission and submission of standard BE bids to EBP.
CCs, TSOs...)
ot represent actual timings.

Annex IV – CEP70 Country Fact Sheets

In Chapter 2 of this report, TSOs provide an overview of their performance related to the CEP70 provision in 2024. Recognising that NRAs are responsible for assessing TSOs' compliance with the CEP70 provisions, this report aims to provide external stakeholders with an easily accessible overview of the national compliance assessments. In addition to the overview of national monitoring results 2024 (see Section 2), this will be supported by country fact sheets offering a brief description of the national assessment methodology, an indication of whether ACER recommendations have been applied, national monitoring results (if available), and information on whether an action plan and/or derogation was applied in 2024.

Austria

TSO(s)

Austrian Power Grid AG (APG)

Borders/Region

Core region and Italy North

Competent regulatory authority

Energie-Control Austria (E-Control)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ **Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943**

☑ **Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943**

Applicable ta rget in 2024

49.4% (not including Core CCR derogation on CNEC level, respecting MTU situation)

Summary of national compliance assessment for 2024

In the report submitted to the national regulatory authority, APG finds that the minimum capacity requirement (considering the national action plan, the approved derogation and the compliance methodology of E-Control) was fulfilled in all hours, including:

- Compliance for Core CCR
- Compliance for Italy North CCR
- The assessment of APGs report by E-Control is not closed yet (May 2025)

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

Where the Agency only assesses the critical network element with the lowest trade margin per MTU, E-Control assesses each critical network element (including contingencies, “CNEC”) of each relevant MTU in 2024.

Each of those CNEC entries is assessed with a compliance value (regarding the approved derogation and action plan target). The compliance of a CCR is based on the average of all related CNEC entries.

Whereas in the Core CCR, all CNECs from the final domain are considered relevant, in Italy North, only those CNECs that were potentially limiting the coordinated NTC are assessed.

Belgium

TSO(s)

Elia

Borders/Region

Core region

Competent regulatory authority

Commission de Régulation de l'Electricité et du Gaz (CREG)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70 % MACZT in at least 31 % of the hours

70 % > MACZT > 50 % in 57 % of the hours

50 % > MACZT > 20 % in 12 % of the hours

Summary of national compliance assessment for 2024

The minimum target is reached on all CNECs ~100 % of the time. The minMACZT target is defined according to the rules set out in the derogation on excessive loop flows granted to Elia. In this approach, 70 % is used as the baseline and is reduced only by the amount of excessive loop flows observed on the specific CNEC during the capacity calculation for that particular MTU. Elia uses remedial actions to reduce excessive loop flows by optimising the settings of its phase shifting transformers (PSTs), thereby further reducing the extent of the derogation.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

CREG evaluated Elia's compliance with the target from its derogation.

Bulgaria

TSO(s)

ESO EAD

Borders/Region

SEE Region

Competent regulatory authority

Energy and Water Regulatory Commission (EWRC)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Summary of national compliance assessment for 2024

The MACZT results for Bulgaria are based on the results received from the ACER calculations, which rely on limiting CNECs from the DA capacity calculation provisions received from the SEE RCC SELENE.

Several timestamps show MAZCT values below 70%, which we believe is due to the fact that flows with third countries in our region are currently threatened under the existing SEE coordinated capacity calculation methodology. This version of the SEE DA CCM does not account for how having three out of five borders with non-EU members not bound by EU regulations affects the MACZT value. In addition, we currently rely on PTDFs calculated by ACER using a limited number of snapshots, as we lack the resources to perform these calculations internally. This contributes to inaccuracies in the MACZT estimation. The DA and ID CCM for the SEE region was amended over the past year to allow MACZT calculations on limiting CNECs in our region, in line with ACER's recommendations. Borders with non-EU neighbouring countries, which are part of the current North Greek and South Romania cross-section, were included in the MACZT estimation process as technical counterparties.

Together with Transelectrica, IPTO, RCC SELENE, and the vendor, we are currently working to implement these new amendments concerning the 70% requirement in a new tool. The amended methodology is expected to be fully implemented by July 2025. From that point on, RCC SELENE will perform all PTDF calculations and MACZT estimations. We expect this to improve the quality of MACZT estimates and increase the percentage of timestamps compliant with the 70% target.

Considering the explanations above and the fact that Bulgaria is heavily influenced by flows from third countries, the 2024 results are satisfactory.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Croatia

TSO(s)

Croatian Transmission System Operator (HOPS)

Borders/Region

Core region

Competent regulatory authority

Croatian Energy Regulatory Agency (HERA)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

Core region: 45.2% on all CNECs for each MTU

Summary of national compliance assessment for 2024

- In the report submitted to HERA, HOPS finds that the minimum capacity requirement (considering the national action plan) was fulfilled in all hours.
- In the report submitted to HERA on average cross-zonal trading capacities, HOPS meets the 2024 linear trajectory based on the FB approach, maintaining minimum MACZT on all CNECs throughout all time units and averaging over 70% MACZT on most CNECs. Deviations from the linear trajectory occurred on four CNECs during 4.7% of the time in 2024, which is permitted due to operational security considerations.
- Given that HOPS meets the linear trajectory requirements 100% of the time for average MACZT values and 95.3% of the time for observed minimum MACZT values, it can be concluded that HOPS conforms to action plan requirements.
- The report was submitted on 7 March 2025 and has not yet been approved by HERA.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

- Where the Agency only assesses the critical network element with the lowest trade margin per MTU, HERA assesses each critical network element (including contingencies, “CNEC”) of each relevant MTU in 2024.
- Each of those CNEC entries is assessed with a compliance value (regarding the approved action plan target). The compliance of a CCR is based on the average of all related CNEC entries.

Czech Republic

TSO(s)

ČEPS

Borders/Region

Core region

Competent regulatory authority

ERÚ

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Summary of national compliance assessment for 2024

The Czech Republic is in full compliance with Art. 16 of Regulation (EU) 2019/943. There are only minor deviations in the CZ Core direction, where the IVA (Individual Value Adjustment) was applied to to reduce capacities to maintain operational safety.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☐ Partially (see explanation)

☑ No (see explanation)

Denmark

TSO(s)

Energinet

Borders/Region

DK1

DK2

DK1–DE_LU/Hansa CCR

DK1–NL/Hansa CCR

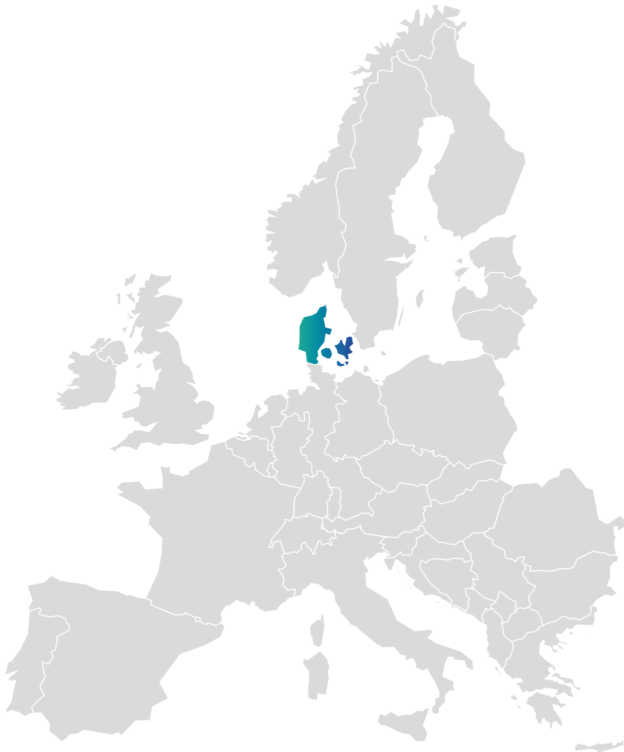
DK2–DE_LU/Hansa CCR

DK1–DK2/Nordic CCR

DK1–NO2/Nordic CCR

DK1–SE3/Nordic CCR

DK2–SE4/Nordic CCR



Competent regulatory authority

Danish Utility Regulator

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

Summary of national compliance assessment for 2024

The Nordic CCR transitioned to FBMC on 29 October 2024. Consequently, the 2024 MACZT report will cover two distinct capacity calculation methodologies: NTC for the period prior to the FB implementation. Energinet has provided both NTC and FB monitoring data to ACER. A decrease in compliance was observed during the transition to FB due to the monitoring of all CNECs.

One challenge that remains is the reporting of MNCC data due to the unavailability of certain PTDF and F0 for North Sea Link and Viking Link.

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One challenge that remains is the reporting of MNCC data due to the unavailability of certain PTDF and F0 for North Sea Link and Viking Link.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

It is assumed that the NRA will maintain alignment with ACER’s recommendation in transitioning to FB capacity calculation.

Estonia

TSO(s)

Elering

Borders/Region

EE > FI

FI > EE

LV > EE

EE > LV

Competent regulatory authority

Estonian Competition Authority

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Summary of national compliance assessment for 20234

Estonia uses the coordinated NTC approach for cross-border capacity calculation for the Estonia–Finland and Estonia–Latvia borders. For both, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Finland

TSO(s)

Fingrid

Borders/Region

FI > SE1

FI > SE3

FI > EE/Nordic CCR

Competent regulatory authority

EV (Energiavirasto)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Summary of national compliance assessment for 2024

In 2024, both NTC and FB data were included. For the NTC data, the minimum target was reached for most MTUs in 2024.

For the FB data, compliance levels are insufficient according to ACER's method, which focuses on the CNECs with the lowest MACZT values for every hour.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

The approach for national compliance assessment has not yet been verified. Therefore, the FB data results in the market report are presented as if the compliance assessment were conducted following ACER's recommendation.

France

TSO(s)

RTE

Borders/Region

Core region, Italy North region, SWE region

Competent regulatory authority

CRE

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Summary of national compliance assessment for 2024

- The 2024 results are satisfactory regarding the criterion of compliance agreed with the French regulator CRE.
- CRE publishes an annual report on the application of the 70% target on French borders to assess national compliance.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

According to the smart compliance agreed with CRE, an MTU is considered compliant with the 70% criterion if at least one of the following conditions is met:

- Price convergence is reached with BZs inside the corresponding CCR
- All limiting CNECs are in a neighbouring country
- The minimum MACZT is over 70%

Germany

TSO(s)

50Hertz Transmission GmbH, Amprion GmbH, Baltic Cable AB, TenneT TSO GmbH, TransnetBW GmbH

Borders/Region

Core CCR, Hansa CCR

Competent regulatory authority

Bundesnetzagentur (BNetzA)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ **Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943**

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

Core CCR borders: 50.5% on all CNEs for each MTU

DE–DK1: 54.6% on all CNEs for each MTU

DE–DK2: 70% for Kontek cable/46.7% for KF CGS

DE–SE4: 60.5% of Baltic Cable NTCs

DE–NO2: 46.7% on all CNEs for each MTU

Summary of national compliance assessment for 2024

- In the report submitted to the regulatory authority, the German TSOs confirm full compliance with Art. 16 of Regulation (EU) 2019/943 at all times. Any capacity adjustments below the minimum threshold were duly justified.
- At the time of ENTSO-E Market Report publication, approval of the compliance report by BNetzA was still pending.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

- Where the Agency only assesses the critical network element with the lowest trade margin per MTU, the BNetzA assesses each critical network element per MTU (taking into account the most limiting contingency; only FB borders).
- Diverging MNCC calculation: Where ACER recommends using forecasted transfer capacities, the BNetzA uses offered transfer capacities (both FB and cNTC borders).
- BNetzA also considers the additional capacity provided through extended long term allocation (LTA) inclusion (only FB borders).

Greece

TSO(s)

IPTO

Borders/Region

SEE

Competent regulatory authority

RAAEY

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

60% MACZT excluding periods of maintenance on Greek tie-lines or very low load conditions

Summary of national compliance assessment for 2024

IPTO has a derogation in place for the northern Greek borders for 2024. The assessment is based on the limiting CNEC per direction and MTU, compared to both the applicable target and the 70% requirement. Given that Greece is significantly affected by flows from third countries, since three of its four borders are with non-EU countries, only results that consider flows from third countries are used.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Hungary

TSO(s)

MAVIR

Borders/Region

Core region

Competent regulatory authority

Magyar Energetikai és Közmű-szabályozási Hivatal (MEKH)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70%

Exceptions: applicable for five CNEs

Different minimum capacity per CNEC in line with action plan

36.25–47.5% for four CNEs

42.25–51.5% for one CNE

Summary of national compliance assessment for 2024

In line with our expectations, most transmission lines fulfil the 70% requirement. For the five network elements pre-recorded in the adopted action plan, the threshold values stated in the linear trajectory were met in all but 2 hours in 2024.

The national compliance report was sent to our national regulator (MEKH) on 28 March in the Hungarian language.

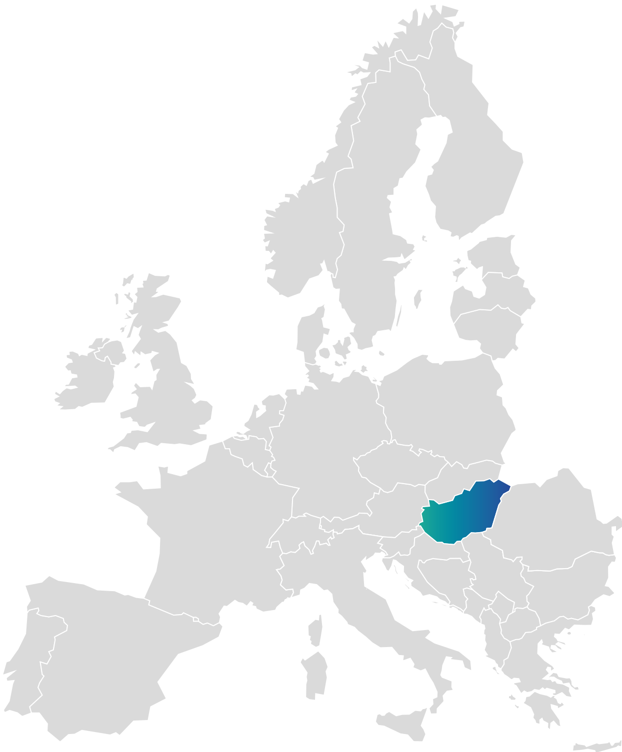
Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)



Explanation

In line with our expectations, most of the transmission lines fulfil the 70% requirement. For the five network elements pre-recorded in the adopted action plan, the threshold values stated in the linear route were met in all but 2 hours in 2024.

In our action plan, the limit value of certain network elements was not reached at least 95% of the time due to significant power flows from the import direction across HU's northern borders, combined with a planned special grid situation that lasted several months. The situation could only be managed through remedial actions to maintain operational security. As a result, we complied with the 70% rule and our individual minimum capacity according to our action plan 94.36% of the time.

Ireland

TSO(s)

EirGrid

Borders/Region

No EU borders in 2024

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2023

Not applicable

The SEM market is currently not physically interconnected to other Member States or third countries that apply EU VO 2019/943. Hence, SEM runs as an isolated market. The assessment of cross-zonal trade capacity will become relevant when the SEM reconnects to the European IEM with the commissioning of the Celtic interconnector.

Italy

TSO(s)

TERNA

Borders/Region

Italy North, GRIT

Competent regulatory authority

ARERA

Is any transitional regulation in place?

☑ No for GRIT, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ **Yes for Italy North, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943**

Applicable target in 2024

70 % for Italy North, except derogation period (allocation constraints, export when export corner is not triggered)

70 % for GRIT

Summary of national compliance assessment for 2024

For Italy North, a derogation was in place for 2024 for all MTUs where allocation constraints are applied. No minimum capacity target was defined.

The 70 % criterion is considered fulfilled if at least one limiting CNEC on Italy's northern border satisfies this condition, regardless of the specific national frontier involved. According to the methodology approved by the NRAs of the CCR, the Italy North border is assessed as a single entity.

The percentages are calculated based on MTUs without process failures, which account for 81 % of the total. In the remaining 19 %, the calculation process failed.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

According to the methodology in force, all the borders of Italy North are considered together.

Latvia

TSO(s)

AST

Borders/Region

EE–LV/LV–LT/Baltics

Competent regulatory authority

The Public Utilities Commission Regulation, English (PUC) and Latvian (SPRK)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

Summary of national compliance assessment for 2024

AST uses the coordinated NTC approach for cross-border capacity calculation on the Latvia–Lithuania and Estonia-Latvia borders. For both, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Lithuania

TSO(s)

LITGRID

Borders/Region

LT–LV/LT–SE/LT–PL/Baltics

Competent regulatory authority

National Energy Regulatory Council (NERC)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

Summary of national compliance assessment for 2024

Lithuania uses the coordinated NTC approach for cross-border capacity calculation for the Lithuania–Sweden, Lithuania–Poland, and Lithuania–Latvia borders. For all borders, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Luxembourg

TSO(s)

Creos Luxembourg

Borders/Region

Core region

Competent regulatory authority

Institut Luxembourgeois de Régulation (ILR)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

§16.8 CEP does not apply to the specific Luxembourg situation, as the Creos transmission system does not limit flows for cross-zonal exchanges. Luxembourg is part of the German/Luxembourg BZ, and cross-border capacities are currently not available due to operational constraints.

Netherlands

TSO(s)

TenneT TSO BV

Borders/Region

Core region, HVDC

Competent regulatory authority

Autoriteit Consument & Markt

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

Changes by CNE, statistics:

Minimum: 53 %

Maximum: 70 %

Average: 54 %

Median: 53 %

Summary of national compliance assessment for 2024

Link to national compliance report:

https://www.acm.nl/system/files/documents/verzoek-ten-net-goedkeuring-beoordelingsverslag-actieplan2024.pdf

Methodology

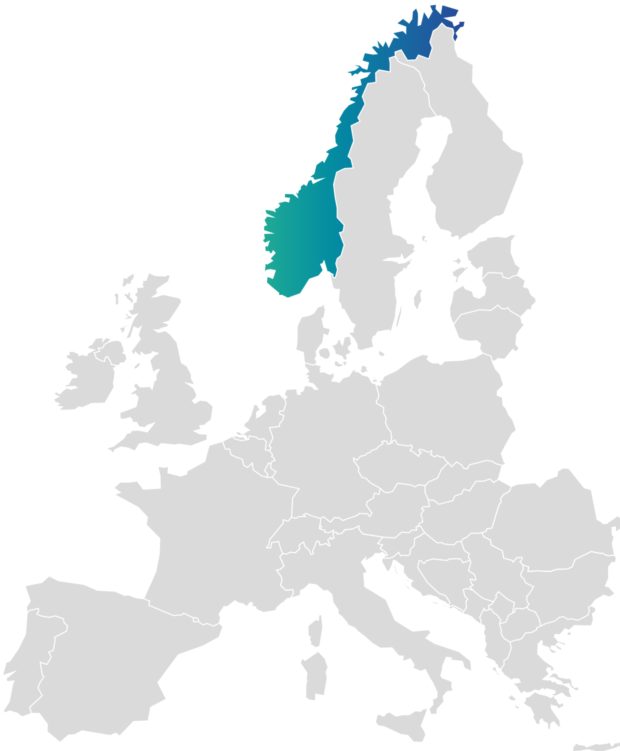
Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Norway



TSO(s)

Statnett SF

Borders/Region

Nordic CCR, DE–NO2, NL–NO2, UK–NO2

Competent regulatory authority

Reguleringsmyndigheten for Energi (RME)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

None

Summary of national compliance assessment for 2024

The Norwegian regulator RME has not completed a national compliance assessment for 2024.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☐ Partially (see explanation)

☑ No (see explanation)

Explanation

The minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is not fully applicable in Norway because Regulation (EU) 2019/943 is not implemented in the EEA agreement.

Poland

TSO(s)

Polskie Sieci Elektroenergetyczne S.A. (PSE)

Borders/Region

Core region, PL–LT, PL–SE4

Competent regulatory authority

Urząd Regulacji Energetyki (URE)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943

Applicable target in 2024

Different minimum capacity per CNEC in line with action plan:

CORE: average 45 %

PL › LT: 70 %

LT › PL: 70 %

PL › SE4: 60 %

SE4 › PL: 70 %

Summary of national compliance assessment for 2024

In the national report submitted to the NRA (URE), PSE considers the minimum capacity requirement fulfilled in all hours. Hours meeting the minimum required MACZT levels are marked as fulfilled. Similarly, hours in which the minimum MACZT was considered conditionally fulfilled due to legitimate reasons (outages, derogations, lack of redispatching potential) are also marked as fulfilled.

A link to the national compliance report is not yet available as the approval is pending (June 2025).

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

› ACER only evaluates the critical network element with the lowest trade margin per MTU, whereas URE evaluates each critical network element (including contingencies, "CNEC") for each relevant MTU.

An important difference from the Agency's approach is the treatment of allocation constraints, defined as "constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into CZC or that are needed to increase the efficiency of capacity allocation". Minimal capacity obligations consider the percentage of capacity that respects operational security limits, so the application of allocation constraints cannot reduce capacities below the trajectory thresholds. However, in its monitoring report, ACER recalculated the CZC figures for Poland by reducing the capacities made available on the Polish DC borders, even though the full capacity of the link was usually offered (or at least the minimal threshold or derogation was respected). The basis for this interpretation is unclear, as the applicable legal framework clearly allows for the application of allocation constraints. Besides aiming to maintain the system within operational security limits, allocation constraints are not listed in Regulation 2019/943 as factors included within the 30 % margin designated for, among others, loop flows. It should be emphasised that for hours marked by ACER as not fulfilled, the respective DC borders were used for transits through Poland (often to the full capacity of the links), thus contributing to European social welfare.

Portugal

TSO(s)

REN – Rede Eléctrica Nacional, S.A.

Borders/Region

SWE Region

Competent regulatory authority

ERSE – Entidade Reguladora dos Serviços Energéticos]

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ **Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943**

Applicable target in 2024

70% MACZT in at least 85% of the hours

Summary of national compliance assessment for 2024

- The SWE RCC has conducted the CZC regional monitoring process since April 2021.
- CZC recalculations using countertrading began in February 2022.
- A fallback CNEC has been used to compute the MACZT when the CNEC is unavailable (since 2022).
- In 2024, there was a derogation for REN. During this period, REN applied the amended capacity calculation methodology proposal in the SWE CCR for the operational DA coordinated capacity calculation process (approved by SWE NRA in January 2022), ensuring continued operational security in the SWE CCR. REN provided at least the minimum required capacity in accordance with Article 16(8)(a) of Regulation 2019/943 during 85% of the hours in which this 1 year derogation was applied, where he minimum levels were offered in line with Article 16(8)(a) of Regulation 2019/943 and paragraphs 4.2 and 5.1 of ACER Recommendation No. 01/2019 regarding limiting CNECs.
- The SWE capacity calculation methodology includes a fallback CNEC mechanism, allowing compliance with the CEP70 requirement to be assessed when the CNEC is not available within the allotted time frame.
- For the 70% compliance assessment in the previous chapter, the following criteria were applied:
  1. MTUs with a limiting CNEC outside Portugal are deemed compliant.
  2. For MTUs where the SWE capacity calculation process did not provide a limiting CNE, the methodology includes a fallback CNEC, allowing for the assessment of compliance with the CEP70 requirement.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

- ERSE's compliance assessment for 2024 is not closed.

Romania

TSO(s)

Transelectrica

Borders/Region

Romania–Hungary/Core
Romania–Bulgaria/SEE

Competent regulatory authority

National Energy Regulatory Authority (ANRE)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943 (**Romanian action plan**)

☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943 (Derogation for **2024**)

Applicable target in 2024

Romania–Hungary: Derogation: 33 % on all CNEs for each MTU

Romania–Bulgaria: action plan: 43 % on all CNEs for each MTU

CNTEE Transelectrica SA applied for a derogation from the obligations set out in Article 16(8) of Regulation (EU) 2019/943 for the Romania–Hungary and Romania–Bulgaria borders, in accordance with Article 16(9) of Regulation (EU) 2019/943. In Decision No. 2947 of 20.12.2023, ANRE granted the derogation, requiring Transelectrica SA to maintain a minimum available capacity for cross-zonal trade of 800 MW (33 % of transmission capacity) for the Romania–Hungary border and 1,560 MW (43 % of transmission capacity) for the Romania–Bulgaria border in 2023.

Summary of national compliance assessment for 2024

- Transelectrica applies ACER Recommendation No. 01/2019 to assess the compliance of its borders with the interim targets set by the action plan and derogation.
- The national compliance report is split between the SEE and Core regions as follows:

a) Core (RO–HU)

The assessment is carried out relative to both the 70 % target and the 33 % interim target according to the derogation granted by ANRE. The CNECs with the lowest RAM per MTU are used for this evaluation.

The results include values both with and without third countries. Given that Romania is heavily influenced by the flows of third countries, it is essential to consider the values that include them.

The report presents average MACZT values overall, as well as MACZT when targets were met and when they were not.

Figures are also provided for all presolved CNECs per MTU and month, along with their average values.

Another major factor is the MNCC values, as Romania has four other borders with third countries that are subject to daily allocation.

b) SEE (RO–BG)

The assessment is carried out relative to both the 70 % target and the 43 % interim target according to the action plan. Limiting CNECs per MTU and direction are used for this evaluation.

The results include values both with and without third countries, as well as a breakdown by direction. Given that Romania is heavily influenced by the flows of third countries, it is essential to consider the values that include them. The report presents average MACZT values overall, as well as MACZT where targets are met and when they are not.

Additionally, as the action plan sets an annual NTC [MW] target, the report includes both the calculated capacity values and the validated NTC values provided by Transelectrica.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes ☐ Partially (see explanation)

☐ No (see explanation)

Explanation

The 2024 assessment has not yet begun.

Slovak Republic

TSO(s)

Slovenská elektrizačná prenosová sústava, a.s. (SEPS)

Borders/Region

Core region

Competent regulatory authority

Úrad pre reguláciu sieťových odvetví (ÚRSO)/Regulatory Office for Network Industries (RONI)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

50% MACZT (applicable for two CNEs, in at least 80% of MTUs if the security of the power system is secured)

60% MACZT (applicable for two CNEs, in at least 80% of MTUs if the security of the power system is secured) 70% MACZT (applicable for the remaining CNEs)

Summary of national compliance assessment for 2024

- In accordance with the granted derogation for 2024 to provide 50% of MACZT (applicable to two CNEs, in at least 80% of MTUs if the security of the power system is secured), the target value was reached in 50% of MTUs during the year.
- In accordance with the granted derogation for 2024 to provide 60% of MACZT (applicable to two CNEs, in at least 80% of MTUs if the security of the power system is secured), the target value was reached in 92.4% of MTUs during the year. During the remaining 7.6% of MTUs where the target was not met, the average MACZT value was 57.9%. Therefore, the derogation was removed for 2025.
- For the remaining CNEs, the 70% MACZT target value was reached in 100% of MTUs during the year prior to the application of the IVA.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

- SEPS is not aware whether RONI fully adopted the non-binding ACER Recommendation No. 01/2019 for its compliance assessment.

Slovenia

TSO(s)

ELES

Borders/Region

CORE and Italy North

Competent regulatory authority

Agencija za energijo

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

Summary of national compliance assessment for 2024

- In the Core region, the 70 % target was reached for 90.21 % of MTUs.
- When the 70 % target was not reached (9.8 % of MTUs), the MACZT fell within the 50 %–70 % range.
- In the Italy North region, the 70 % target was reached in 99.77 % of MTUs when SI CNECs limited the NTC calculation.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

- In the Core region, the CNEC with the lowest MACZT is considered for each MTU.
- In the Italy North region, CNEC(s) limiting the coordinated NTC calculation are considered.

Spain

TSO(s)

Red Eléctrica de España S.A.U. (Red Eléctrica)

Borders/Region

SWE CC region/Spain – France, Spain – Portugal

Competent regulatory authority

Comisión Nacional de los Mercados y la Competencia (CNMC)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

› The CC methodology currently implemented in the SWE CCR has the following relevant features related to 70 %:
  1. The SWE RCC has conducted the regional monitoring process since April 2021.
  2. CZC recalculations using countertrading began in February 2022.
  3. Since 2022, a fallback CNEC has been used to compute the MACZT when the capacity calculation algorithm does not identify a limiting CNEC. This fallback procedure ensures MACZT monitoring for 100 % of the MTUs.

› Since February 2022, the SWE region has applied an amended SWE capacity calculation methodology for the operational DA coordinated capacity calculation process, approved by SWE NRAs in January 2022. This amendment introduced the principles and goals set out in the EU Regulation to meet minimum capacity requirements according to Article 16 of the Electricity Regulation, taking into account the availability of costly remedial actions. When a limiting CNEC does not meet the CEP70 requirement, Red Eléctrica, together with the relevant TSO, implements costly remedial actions (such as countertrading) to increase the MACZT and thus raise capacity to meet the 70 % target.

› In addition, the methodology includes the use of a fall-back CNEC, which enables the assessment of CEP70 compliance when the CNEC is not available within the allotted time due to a failure in the regional capacity calculation tool. This approach ensures that a limiting CNEC and its corresponding MACZT are identified for 100 % of the hours in both directions of each border.

› These improvements in the SWE CC methodology have resulted in a very high level of compliance. As a result, no derogation or action plan has been requested since January 2023.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

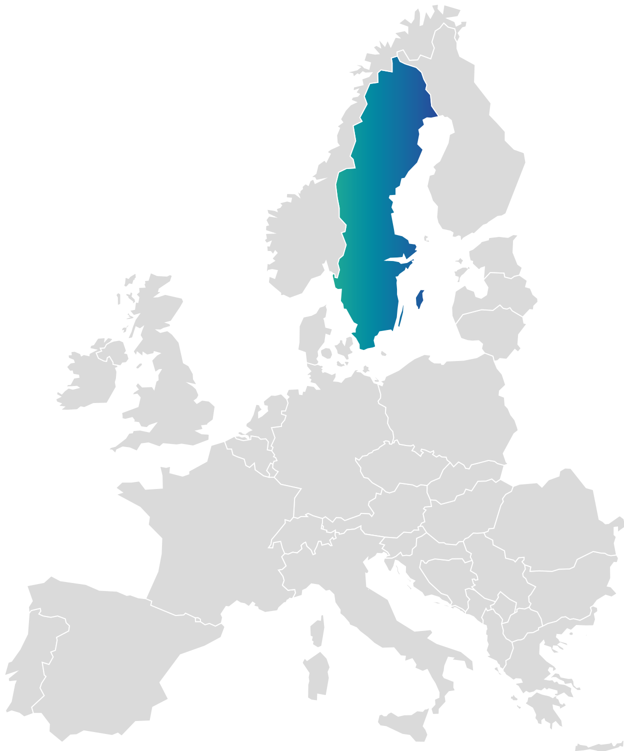
Explanation

The methodology proposed by ACER Recommendation No. 01/2019 is implemented in the SWE CC methodology to calculate the MACZT for each limiting CNEC, per border, direction, and MTU.

Sweden

TSO(s)

Svenska kraftnät



Borders/Region

Nordic CCR, DE – SE4, PL – SE4, LT – SE4

Competent regulatory authority

Energimarknadsinspektionen (Ei)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943

Applicable target in 2024

70 %

Summary of national compliance assessment for 2024

- National regulatory authority Energimarknadsinspektionen (Ei) has not performed a compliance assessment for 2024 and will rely on ACER methodology.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

- Compliance assessment for 2024 is not completed. The Swedish NRA will rely on ACER methodology.

Annex V – Glossary

4M MC	4M Market Coupling between the Czech Republic, Slovakia, Hungary, Romania
50Hertz	50Hertz Transmission GmbH (1 out of 4 German TSOs)
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Frequency Restoration Reserves with Automatic Activation
AHC	Advanced Hybrid Coupling
AL	Albania
Amprion	Amprion GmbH (1 out of 4 German TSOs)
ANDOA	All NEMOs Day-Ahead Operational Agreement
ANIDOA	All NEMOs Intraday Operational Agreement
AOF	Activation Optimisation Function
APG	Austrian Power Grid AG (Austrian TSO)
AST	AS Augstsprieguma tikls (Latvian TSO)
AT	Austria
ATC	Available Transfer Capacity
BA	Bosnia and Herzegovina
BC	Balancing Capacity
BCC	Balancing Capacity Cooperation
BE	Belgium
BEPP	Balancing Energy Pricing Periods
BG	Bulgaria
BRP	Balance Responsible Party
BSP	Balancing Service Provider
BZB	Bidding Zone Border
BZR	Bidding Zone Review
BZRR	Bidding Zone Review Region
CA	Cooperation Agreement
CACM	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CBMP	Cross Border Marginal Price
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CEE	Central Eastern Europe
CGES	Crnogorski Elektroprenosni Sistem AD (Montenegrin TSO)
CGM	Common Grid Model
CGMM	Common Grid Model Methodology
CH	Switzerland
CID	Congestion Income Distribution
CMM	Capacity Management Module
CMOL	Common Merit Order List
CNE	Critical Network Element
CNEC	Critical Network Element and Contingency
cNTC	Coordinated Net Transfer Capacity
CWE	Central Western Europe
CZ	Czech Republic
CZC	Cross-Zonal Capacity
DAOA	Day-Ahead Operational Agreement
DC	Direct Current
DE	Germany

DK	Denmark
EB	Commission Regulation (EU) 2017/2195 of 23 November establishing a guideline on electricity balancing
EE	Estonia
ELIA	Elia System Operator SA (Belgian TSO)
EMIR	Regulation (EU) No 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories (European Market Infrastructure Regulation)
EMD	Electricity Market Design
EMS	Joint Stock Company Elektromreža Srbije (Serbian TSO)
ENTSO-E	European Network of Transmission System Operators for Electricity
ES	Spain
ESO	Electroenergien Sistemen Operator EAD (Bulgarian TSO)
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAT	Full Activation Time
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FCA	Forward Capacity Allocation
FCR	Frequency Containment Reserve
FI	Finland
FR	France
FRR	Frequency Restoration Reserves
FTR	Financial Transmission Right
GB	Great Britain
GCT	Gate Closure Time
GL	Guideline
GOT	Gate Opening Time
GR	Greece
HAR	Harmonised Allocation Rules
HOPS	Croatian Transmission System Operator Plc. (Croation TSO)
HR	Croatia
HU	Hungary
HVDC	High-Voltage Direct Current
IBWT	Italian Working Table
IDA	Intraday Auction
IDCC	Intraday capacity calculation
IDOA	Intraday Operational Agreement
IDSC	Intraday Steering Committee
IE	Ireland
IFA	Interconnexion France-Angleterre
IGCC	International Grid Control Cooperation
IGM	Individual Grid Model
IN	Imbalance Netting
IPTO	Independent Power Transmission Operator S.A. (Hellenic TSO)
ISP	Imbalance Settlement Period
IT	Italy
JAO	Joint Allocation Office
KPI	Key Performance Indicator

LFC area	Load-Frequency Control area
LIP	Local Implementation Project
LMP	Locational Marginal Pricing
LTA	Long Term Allocation
LTTR	Long-Term Transmission Rights
LU	Luxembourg
MACZT	Margin Available for Cross-Zonal Electricity Trade
MARI	Manually Activated Reserves Initiative
MAVIR	Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság (Hungarian TSO)
MC	Market Coupling
MCCC	Multilateral Coordinated Capacity Calculation
MNCC	Multilateral Non-Coordinated Capacity Calculation
MCO	Market Coupling Operator
ME	Montenegro
MEMO	Electricity Market Operator of North Macedonia
MEPSO	Macedonian Transmission System Operator AD (Macedonian TSO)
mFRR	Frequency Restoration Reserves with Manual Activation
MifiD II	Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU (recast) (Markets in Financial Instruments Directive II)
MiFIR	Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012 (Markets in Financial Instruments Regulation)
MNA	Multiple NEMOs Arrangement
MRC	Multi Regional Coupling
MTU	Market Time Unit
NTC	Net Transfer Capacity
NDA	Non-Disclosure Agreement
NEMO	Nominated Electricity Market Operator
NL	Netherlands
NO	Norway
NOS BiH	Nezavisni Operator Sustava u Bosni i Hercegovini (Bosnian and Herzegovinian TSO)
NRA	National Regulatory Authority
OPSCOM	Operations Committee
OST	OST sh.a – Albanian Transmission System Operator (Albanian TSO)
PCR	Price Coupling of Regions
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PL	Poland
PMB	PCR Matcher and Broker IT system
PSE	Polskie Sieci Elektroenergetyczne (Polish TSO)
PST	Phase Shifting Transformer
PT	Portugal
PTDF	Power Transfer Distribution Factor
PTR	Physical Transmission Right
QARM	Quality Assurance and Release Management
R&D	Research and Development
RA	Regulatory Authorities

RCC	Regional Coordination Center
REE	Red Eléctrica de España S.A.U. (Spanish TSO)
REN	Rede Eléctrica Nacional, S.A. (Portuguese TSO)
RGCE	Regional Group Continental Europe
RO	Romania
RR	Replacement Reserves
RS	Serbia
RTE	Réseau de Transport d'Electricité (French TSO)
SA	Synchronous Areas
SAFA	Synchronous Area Framework Agreement
SAP	Single Allocation Platform
SAP CA	Single Allocation Platform Cooperation Agreement
SDAC	Single Day-Ahead Coupling
SE	Sweden
SEE	South-East Europe
SEPS	Slovenská elektrizačná prenosová sústava, a.s. (Slovakian TSO)
SI	Slovenia
SIDC	Single Intraday Coupling
SK	Slovakia
SM	Shipping Module
SOB	Shared Order Book
SONI	System Operator for Northern Ireland Ltd. (Northern Irish TSO)
Statnett	Statnett SF (Norwegian TSO)
Svenska	Svenska kraftnät (Swedish TSO)
SWE	South-Western Europe
Swissgrid	Swissgrid ag (Swiss TSO)
TCDA	TSO Cooperation Agreement for Single Day-Ahead Coupling
TCID	TSO Cooperation Agreement for Single Intraday Coupling
TCM	Terms, Conditions and/or Methodologies
TCMC	TSO Cooperation Agreement for Market Coupling
TenneT DE	TenneT TSO GmbH (1 out of 4 German TSOs)
TenneT NL	TenneT TSO BV (Dutch TSO)
Terna	Rete Elettrica Nazionale SpA (Italian TSO)
TERRE	Trans-European Restoration Reserves Exchange
Transelectrica	National Power Grid Company Transelectrica S.A. (Romanian TSO)
TransnetBW	TransnetBW GmbH (1 out of 4 German TSOs)
TSO	Transmission System Operator
VWAP	Volume Weighted Average Price
XBID	Cross-Border Intraday Project

The terms used in this document carry the meanings defined in Article 2 of the CACM, FCA, and EB Regulations.

Annex VI – List of Figures

Annex VII – List of Tables

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