ENTSO-E Market Report 2023

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The **39 member TSOs**, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the interconnected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources.

ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with **climate objectives** and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility.**

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with **transparency** and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its **legally mandated tasks**, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (**Ten-Year Network Development Plans, TYNDPs**);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

Contents


2,900.00
2,800.00
2,700.00
2,600.00
100
80
60
40
0
Jan
Feb
March
April
May
June

Executive Summary

Capacity allocation and congestion management are the cornerstones of the European single electricity market as they harmonise the manner in which cross-border electricity markets operate from long-term to real-time. An interconnected, integrated and well-functioning European electricity market ensures the use of the most efficient resources and is key to ensuring security of supply at the lowest cost for consumers. Significant progress has been made again during the reporting period from June 2022 to May 2023 across the market's various time frames, bringing an internal European electricity market for the benefit of all Europeans closer to full realisation.

The period was marked by an extremely complex geopolitical and economic context: Following the Russian invasion of Ukraine, the synchronisation of the grids of Ukraine and Moldova with Continental Europe synchronous area accelerated and was successfully conducted under extremely difficult circumstances. Following this major milestone of 2022, ENTSO-E and Continental Europe TSOs have and will continue to support Ukrenergo and Moldelectrica in maintaining the stability of their power system and working towards achieving another major milestone: the go-live of common daily capacity allocation between Ukrenergo, Moldelectrica and neighbouring Continental Europe TSOs.

Due to the large number of projects with high complexity and high quality requirements, prioritisation of the numerous tasks allocated to TSOs and other stakeholders was necessary. In cooperation with the European Union Agency for Energy Regulators (ACER) and market participants, it has been agreed that NEMOs and TSOs should first work on a well-advanced project. For the time period after 2025, projects shall be prioritised and legal implementation deadlines set accordingly by regulatory bodies.

As for the forward market, a discussion on the potential evolution of a long-term transmission rights (LTTRs) mechanism arose as one alternative to better support suppliers and consumer to manage their risk against extremely volatile prices over longer periods of time, especially on how to improve liquidity levels on these markets. Whereas the majority of evolutions could be addressed by practical evolutions of the current set-up, others require deep analysis as they would represent a disruptive approach with long implementation times (5–10 years), as is the case. As such, the regional virtual hub approach is not supported by the vast majority of market stakeholders. Regional Virtual Hubs currently remain an untested solution with significant uncertainties in terms of costs and risks for end consumers, TSOs and market participants whose interest in such Regional Virtual Hub arrangements is far from evident. ENTSO-E sees the need for a thorough assessment of both practical solutions fit for market parties' hedging needs as well as of regional virtual hubs, before proposing any amendment to the FCA Regulation.

Due to ongoing market reform, the planed amendment of the Commission Regulation (EU) 2015/1222 on the establishing a guideline on capacity allocation and congestion management (CACM) was suspended in 2022. Nevertheless, TSOs and NEMOs continue to improve the intraday (ID) and day-ahead (DA) market in the interest of market participants and aim to achieve major implementation steps in the provision of the 15 minute products on DA and ID by 2025 without endangering the available functionalities and services of the DA and ID algorithms. Any provision on timing shall remain in CACM methodologies to be accompanied by adequate impact assessments.

As regards balancing platforms, TSOs strongly support the European target model but are worried as the current price formation (based on marginal pricing, which in a scenario of low competition may imply rice incidents), may lead to national concerns and reservations regarding the timely connection to different balancing energy activation platforms. Furthermore, a discussion on the definition of a price incident as currently described in the amended pricing methodology might be necessary. Therefore, a discussion with all relevant stakeholders for short and long-term improvement is required.

The Energy Community (EnC) has made significant strides in aligning its regulatory framework with that of the EU. Relatedly, the Ministerial Council of EnC decided on the transposition of EU regulations into national legislation of its Contracting Parties. These actions pave the way for a more integrated and efficient energy market including the Energy Community Contracting Parties.

With its Transparency Platform, ENTSO-E has contributed since its launch in 2015 to the objective of creating a level playing field between market participants by providing electricity market information. The ENTSO-E Transparency Platform has been equipped with a new user friendly and interactive interface. This will help users to get easy to use graphs readily from the platform.

As in the 2022 edition, this report provides an assessment of the minimum cross-zonal trading capacity targets of the Clean Energy for all Europeans Package (CEP), called the 'CEP70 provisions'. With a few exceptions, TSOs reached the required capacity targets in 2022.

Forward capacity allocation at a glance

Forward capacity allocation (FCA) uses a single pan- European platform, established in October 2018, to explicitly allocate auction-based cross-zonal transmission rights.

The project includes 21 countries with 25 TSOs that cover 67 serviced borders and have more than 400 active market participants.

In total, more than 4,200 cross-border auctions have been successfully completed since the go-live in October 2018.

The introduction of long-term flow-based (FB) capacity allocation in the Nordic and Core capacity calculation regions (CCRs) in the coming years will mark a major milestone in the evolution of FCA.

Market coupling at a glance

Following the entry into force of the new joint governance of SDAC and SIDC on 14 January 2022, the joint Market Coupling Steering Committee (MCSC) was established. The way of working has undergone further optimisation throughout the period covered by this report. As such, the joint governance secures synergies between single day-ahead coupling (SDAC) and single intraday coupling (SIDC). TSOs and NEMOs continue to develop ideas to further improve market coupling and streamline its organisation. The Day-ahead Operational Agreement (DAOA) and Intra-day Operational Agreement (IDOA) were amended in September 2022 to implement the joint governance, harmonise the SIDC and SDAC contractual frameworks, and implement Qualified Majority Voting (QMV).

Single day-ahead coupling

SDAC utilises the day-ahead MCO function to calculate electricity prices and matched volumes across Europe, and to implicitly allocate cross-zonal capacity in a single auction. The algorithm used is called the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA).

There have been no changes in the membership of SDAC compared to the time of writing of the 2022 market report. As such, SDAC continues to serve 27 countries with 32 TSOs and 17 NEMOs. Since 2021, there has been one common SDAC in operation across all EU countries. On 8 June 2022, FB implicit allocation was implemented for the Core CCR as the target solution required by regulation.

At the same time as Core FB market coupling was introduced, the Multi-NEMO Arrangement (MNA) on the Italy North CCR bidding zone borders (BZBs) was implemented.

Single intraday coupling

SIDC enables continuous cross-border trading across Europe in the ID timeframe. It is based on a common IT system with a Shared Order Book (SOB), a single Capacity Management Module (CMM) and a Shipping Module (SM). The common XBID IT system facilitates the continuous matching of orders from market participants from several bidding zones (BZs), provided that cross-zonal capacity is available. The IT system also enables multiple NEMOs to participate per country.

With the go-live of the 4th wave of SIDC of Greece and Slovenia in November 2022, 25 counties are operational with at least one border.

In the period covered by this report, two releases were used for production. This concerned the fifth and sixth release, respectively release 3.2 and 3.3. With these releases all performance optimization measures are covered to fully support the geographical extension of SIDC.

Balancing markets at a glance

The period covered in this report, June 2022 to May 2023, has been crucial regarding EB Regulation implementation. In particular, the go-live of the last two European balancing energy platforms have been a major milestone. In June 2022 the PICASSO (International Coordination of Automated Frequency Restoration and Stable System Operation) platform for the exchange of frequency restoration reserves with automatic activation (aFRR) started its operation followed by the MARI (Manually Activated Reserves Initiative) platform for the exchange of frequency restoration reserves with manual activation (mFRR) in October 2022. With these milestones all four European balancing energy platforms mandatory to be implemented pursuant to Electricity Balancing (EB Regulation) are now successfully in operation (the imbalance netting [IN] platform and the TERRE [Trans European Replacement Reserves Exchange] platform for the exchange of replacement reserves [RR] has already gone live in previous years). Over the next few years the objective is to connect all TSOs that are obliged to join the respective balancing energy platforms and have a derogation, allowing them to connect to the platforms after the legal deadline passed in 2022. With these foreseen connections, synergies among TSOs will be maximised, and the liquidity of the balancing energy markets will increase. In addition, the cross-platform Capacity Management Module (CMM) implementation project has accomplished important progress during the past year supporting its go-live scheduled for Q3 2023 that will allow an optimal management of cross border capacity available at balancing timeframe between the different balancing markets.

Regarding regulatory framework changes, ACER decided on the amendments to the IN, aFRR and mFRR Implementation Frameworks (IFs) in September 2022 (previously, TSOs submitted the IFs' amendments in March 2022 to designate the entities which will operate the CMM and the different functions of the respective balancing platforms). The most important changes to IFs, approved by ACER, are that the amended IFs are now fully in line with the current governance of the European balancing energy platforms (collaboration of All TSOs via Steering Committee governing the operation and decision making of the platforms). In this sense, the aFRR Activation Optimisation Function (AOF) and the respective TSO–TSO settlement function by TransnetBW under the governance of PICASSO Steering Committee, mFRR AOF and the respective TSO–TSO settlement function are being provided by Amprion and the CMM cross-platform function will be provided by ČEPS both under the governance of MARI Steering Committee. In addition, the amendments foresee a joint steering committee for the three platforms together with a joint operational committee (JOPSCOM), among other changes.

In December 2022, TSOs submitted the Harmonised Cross-Zonal Capacity Allocation Methodology (HCZCAM) pursuant to Article 38(3) of EB Regulation to ACER defining the key features that should be harmonised for the different allocation processes for cross zonal capacity (CZC), namely co-optimisation, market-based and inverted market-based. The harmonisation of these processes is relevant for future voluntary regional balancing capacity platforms through which any of the six standard reserve balancing products (RR, mFRR, aFRR in upward and downward direction respectively) can be shared or exchanged on a DA basis. In parallel to the HCZCAM, TSOs submitted the proposals that address both the future balancing capacity procurement and sizing facilitating tasks for the Regional Coordination Centers (RCCs) to ACER in March 2023. The ACER decisions on all three proposals (HCZCAM plus RCC´s procurement/sizing ones) are expected in July 2023. Once approved, the TSOs' proposal for the HCZCAM foresees a period of one year to develop the set of requirements for the cross-zonal capacity allocation optimization function (CZCAOF) serving as a blueprint for all regional balancing capacity platforms intending to apply the market-based allocation process sets out in the methodology. Furthermore, the proposal submitted by TSOs foresees the development of this blueprint comprising the basic software with all harmonised features necessary to warrant a unique CZCAOF for all regional Balancing Capacity platforms. The foreseen deadline for the development of the blueprint is one additional year after the development of the set of requirements.

1 Introduction

Every year, ENTSO-E monitors the progress of electricity markets[1]. This monitoring covers the different time periods for which electricity is traded, ranging from long-term to day-ahead (DA) markets and intraday (ID) to balancing markets. The 2023 version of ENTSO-E's annual Market Report covers the period from June 2022 to May 2023. The report is formally submitted to the Agency for the Cooperation of Energy Regulators (ACER) and published on ENTSO-E's website after the reporting period.

Electricity markets from long-term to real-time

Electricity is a non-storable good which needs to be produced at the time in which it is to be consumed (in real time). The trading of electricity occurs before and after this point in time. Figure 1 gives an overview of the current trading time frames of the internal electricity markets. Transmission system operators (TSOs) establish the basis for the efficient performance of European electricity markets across these time frames by offering the optimal level of transmission capacity. Integrated cross-border markets across all time frames lead to a more efficient European market overall, which will ultimately lead to benefits for all European customers.

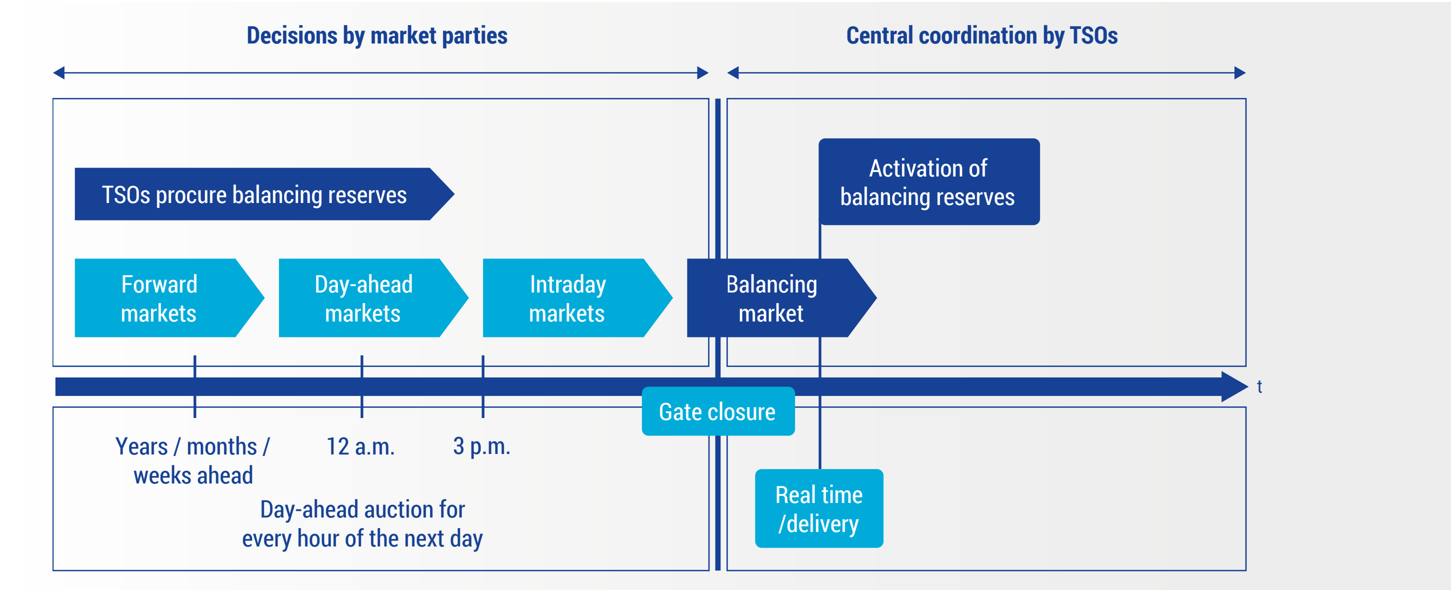


Figure 1: Overview of different time frames of the wholesale and balancing markets

Long-term capacity calculation

Up to one year in advance of the actual delivery date, TSOs determine the appropriate level of long-term transmission capacity at the borders they manage. Based on this calculation, long-term transmission rights (LTTRs) are offered at explicit auctions on the **Single Allocation Platform** (JAO). Calculating the appropriate level of long-term transmission capacity is a complex and challenging task given the high degree of uncertainty around long lead times. TSOs must make assumptions and ensure that the allocated LTTRs can be guaranteed at all times of the product period. Risks such as potential outages of transmission lines and varying generation and load patterns must be considered in this context. Given these uncertainties, the long-term capacity calculation process greatly differs from capacity calculation processes

1 For legal references, please see the annex.

that are closer to real-time, as more relevant information is available. The Commission Regulation (EU) 2016/1719 (guideline on forward capacity allocation, FCA), which entered into force on 17 October 2016, sets out harmonised rules for the calculation and allocation of LTTRs, in addition to how LTTR holders are compensated if their right is curtailed due to capacity recalculations before teh DA timeframe. The overarching goal is to provide market participants with the ability to hedge their risk associated with cross-border electricity trading where the electricity forward market does not provide sufficient hedging opportunities.

Short-term day-ahead and intraday capacity calculation

TSOs can perform more reliable forecasts of a grid's situation closer to the electricity's actual delivery date. The available electricity transmission capacity between Bidding Zones (BZs) is determined by translating physical transmission constraints into commercial transaction constraints. These commercial transaction constraints are then considered in the market clearing algorithm, which determines market prices and cross-zonal exchanges between BZs. These calculations are performed between one day prior to the delivery date (e. g.: DA capacity calculation and first ID capacity calculation) and within the delivery date (second ID capacity calculation and continuous capacity assessment). Congestions occurring after capacity allocation resulting from the different short-term markets require remedial actions (e. g.: countertrading or redispatching measures), which are coordinated between all affected TSOs during real-time grid operation.

The rules set by the Commission Regulation (EU) 2015/1222 (guideline on capacity allocation and congestion management, CACM) provide the basis for implementing a single energy market across Europe in DA and ID time frames. They also establish the methods for allocating capacity in DA and ID time frames and outline how capacity will be calculated across the different BZs.

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** (Electricity Balancing [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, 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 the financial imbalance settlement that have to be implemented through terms and conditions for balance responsible parties (BRPs).

The EB Regulation lays down the guidelines for creating an integrated balancing market in different timeframes, in which TSOs can share their resources to ensure that generation equals demand at all times. The final goal of the EB Regulation is to integrate balancing markets and promote the possibilities 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]), replacement reserves (RR), and a common methodology for the exchange and sharing of reserves and 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 earlier:

- **Chapter 2** provides insights 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 described previously.
- **Chapter 4** provides a detailed overview of the common European processes of long-term electricity trading and transmission capacities according to the FCA Regulation.
- **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 the market process overview of FCA, CACM, EB Regulation, in addition to 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

In parallel to the drafting of this report, The European Commission (EC) initiated an Electricity Market Design reform process[2], which could help making the market design fit for a climate neutral future. Parts of the reform could affect the processes described in this report and are addressed in chapters 2.3 and 2.4 ENTSO-E is active in proposing its expert views on how the market functioning could be further improved. ENTSO-E positions are available on the website.[3]

2.1 Trade development with Ukraine and Moldova

Sequence of events

On 27 February 2022, the Ukrainian TSO Ukrenergo requested to accelerate the synchronisation with Continental Europe following the war initiated by Russia. On 28 February 2022, considering Ukrenergo's request, the Moldavian TSO Moldelectrica requested to be synchronised as well. On 11 March 2022, Regional Group Continental Europe (RG CE) of ENTSO-E approved the start of emergency trial synchronisation without comm77ercial exchange. **On 16 March 2022, the power systems of Ukrenergo and Moldelectrica were successfully synchronised with the Continental Europe synchronous area.**[4]

Between March and June, RG CE worked on developing a set of pre-conditions for allowing the increase of the cross-border capacity available for commercial exchange between Ukraine/Moldova Control block and Continental Europe. All preconditions were completed by Ukrenergo and, as of 30 June 2022, commercial cross-border exchange began.

2 See **here**.

3 See **here** and **here**.

4 More details to be found **here**.

Trade developments

Since June 2022 until the present day, a well-defined procedure, consisting of two main principles, as outlined below, has been followed for gradual increase of the cross-border capacity values:

1. The **maximum capacity** that can be made available between Ukraine/Moldova and Continental Europe **is determined by RG CE decision**.
2. RG CE up to date sets the **capacity limit without calculation based on a stepwise approach** and monitoring of system behavior.

The sequence of RG CE approvals and increase of cross-border capacity values is outlined as follows:

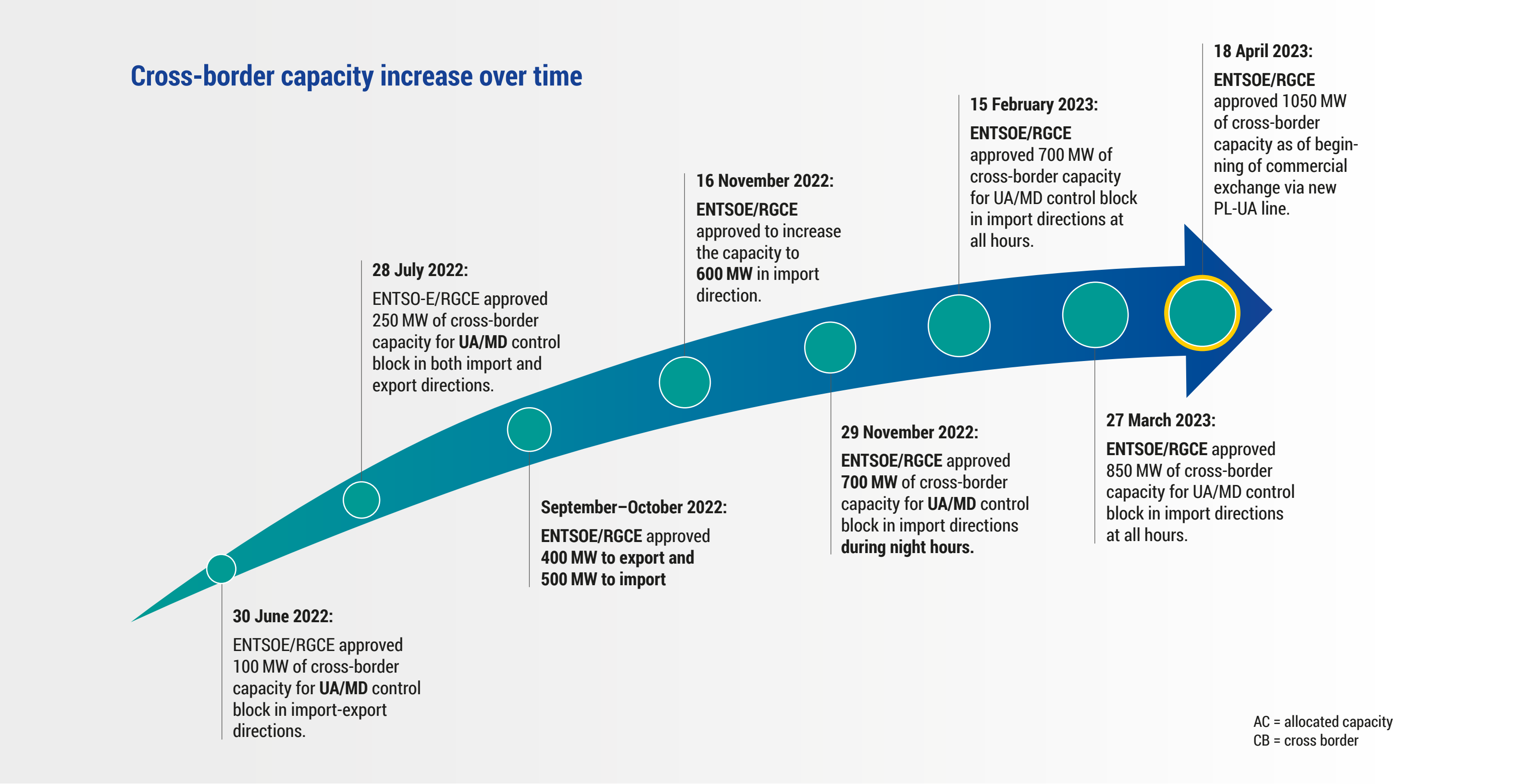


Figure 2: Timeline with gradual increase of cross-border capacity allocation from start trading date.

The cross-border capacity allocated on the Ukrainian–Slovak and Ukrainian–Romanian borders was unilateral, such that each side of the border sells the capacity separately. In the period June 2022 and February 2023, on average between 5 and 8 market participants took place in the auctions on the Ukrainian side. The trade slowed down since October 2022 on the Ukrainian–Romanian border; at the same time in October 2022, harmonised trade allocation began on the Moldovan–Romanian border.

On 16 January 2023, the capacity allocation between Ukraine and Romania was stopped. Currently, negotiations regarding the bilateral allocation on the Ukrainian-Romanian border are ongoing. It is the process of deciding which allocation platform will be used for joint capacity allocation. On 10 October 2022, the Ukrainian authorities decided to ban export operations on all cross-border profiles due to the deterioration in the energy balance of the Ukrainian power system caused by Russia's massive missile attacks on the energy infrastructure. Since 15 April 2023, daily auctions on the UA–SK border have begun, allocated cross-border capacity is 200 MW. However, as of 21 April 2023, the allocated cross-border capacity in the direction Ukraine to Slovakia has stopped.

ENTSO-E is a key player in maintaining European electricity grid stability and ensuring trade progress between Ukraine/Moldova and Continental Europe

Since the beginning of the Russian invasion of Ukraine in February 2022, **ENTSO-E has played a key role in maintaining stability of the European electricity grid while simultaneously providing support to Ukrenergo and Moldelectrica**. To that end, ENTSO-E Market Committee provides support and ensures the continuity of trade development.

ENTSO-E Market Committee is closely working with the concerned TSOs and external stakeholders towards enabling harmonised daily allocation on four borders: Ukrainian–Slovak, Ukrainian–Hungarian, Ukrainian–Polish and Ukrainian–Romanian. Different market challenges have been identified and categorised to be timely tackled.

ENTSO-E acts in the role of a facilitator for communication between the TSOs and external stakeholders, in particular: the EC, EnCS, JAO and various national institutions. The ENTSO-E team has monitored the progress of the cross-border capacity allocation and trade development over 2022. The key challenges addressed up-to-date are outlined below:

SHORT TERM (IMMEDIATELY)	MID TERM (Q4/22 – Q1 – Q2/23)	REGULATORY TOPICS to be managed by EnCS, NRAs. MS and EC
› Bilatereal agreements to govern trade details (time horizons, auction rules ans nominations). › Short term solution is subject to individual TSO/NRA decision. › One auction per border is strongly preferred.	› Hamonised auction rules › Single auction per border or per profile › Common solution subject to consesus	› Level playing field › Approvals of national, bilateral and multi-lateral documents › Use of allocation platform

Figure 3: Overview of market trading principles and challenges from electricity trade with Ukraine and Moldova.

The synchronisation of Continental Europe TSOs with Ukrenergo and Moldelectrica under extremely difficult circumstances was a major milestone. ENTSO-E and Continental Europe TSOs will continue to support Ukrenergo and Moldelectrica in maintaining the stability of their power system and working towards achieving another major milestone: go-live of common daily coordinated capacity allocation between Ukrenergo, Moldelectrica and neighbouring Continental Europe TSOs.

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

2.2 Prioritisation of further developments

With the entry into force of legislations such as CACM, FCA and EB Regulation, TSOs and NEMOs as project parties were tasked with the implementation of a variety of projects aiming at the integration of European electricity markets. Along the implementation process, regulators, ACER, stakeholders and project parties observed delays for some projects. One key aspect of the delays is the high number of projects the regulatory framework requires project parties to implement in parallel. Deliverables by the regulatory framework are often set without coordination of considering workload of project parties for existing or planned project and sometimes even within unrealistic timings set on short notice by legal deadlines. This leads to overloading and frequent reallocation of resources resulting in inefficiencies and consequently delays.

After a broad discussion with TSOs, NEMOs and market participants on the deliveries and respective implementation timelines running in parallel on the local, regional and pan-European level, NEMOs and TSOs appreciate that the task for prioritisation was initiated by ACER. TSOs and NEMOs welcome this as a tool to provide a more stable framework for mid to long term planning. Coordination and prioritisation of the legal deadlines set in the legal framework will help to (1) bring more robustness in the project pipeline, (2) allow for a better plan of resources and deadlines, (3) reduce delays, and (4) increase overall efficiency. It is agreed with ACER that for the short term, well-advanced projects shall be finalised first.

The key projects are

- Implementation of the FB capacity calculation methodologies for the DA and ID timeframe in the CCRs Nordic and Core
- Introduction of 15 minute products for the DA and ID markets; and
- Implementation of ID auctions.

For the upcoming years, resources shall be focused on those projects.

In a second step the real prioritisation exercise begins; all projects to be delivered in the mid-term planning after 2025 as well as project parties' capacities in terms of the number of projects to be worked on in parallel, should be identified. Furthermore, project parties shall align and agree on a process on how the prioritisation of those projects will be done and which objective criteria will be used to assess their benefit for stakeholders and society while also considering the dependencies of other projects. After the application of the agreed process and defining the priorities on existing and future projects, legal implementation deadlines are to be set by regulators and ACER consistent with the outcome of the priority list. In that manner, TSOs and NEMOs, but also market participants, can allocate resources accordingly in their project pipelines. Ideally, the same process shall be applied at the regional level and also coordinated to ensure efficiency and consistency among themselves as well as avoiding errors from the past which would lead to conflicts that result in the same implementation issues. Hence, the objective of the priority exercise should be, ultimately, to not only focus on each regulation on its own but include projects across regulations (CACM, FCA and EB Regulation).

2.3 Development and role of forward markets

Forward markets are envisaged as playing a key role in helping to achieve the EU's Green Deal ambitious objectives. Increased price volatility in the electricity system, due to the acceleration of renewable energy source (RES) deployment and current exceptional geopolitical circumstances, is accelerating the focus on these markets to help market participants to manage their risks. However, forward markets are not sufficient to support investments in low-carbon generation nor to ensure resource adequacy in a rapidly evolving market and policy environment, also considering the absence of liquidity on longer durations products (> 10 years), which is likely to persist. To manage a rapid energy transition in a secure manner TSOs thus see Capacity Mechanisms necessary in most markets to ensure sufficient dispatchable resources in the system. These should complement Contracts for Difference (CfDs) and Power Purchase Agreements (PPAs) for investment signals in low-carbon generation resources.

Focusing on forward markets, different levels of liquidity can be observed, ranging from highly liquid ones to the majority of BZs being illiquid. Whereas illiquidity can be caused by different sources ranging from hidden barriers hampering the development of such markets, regulatory provisions incentivising Over-The-Counter trading, lack of generators interest in participating in the organised forward market or a small number for market participants in a BZ. If aiming at an increase of liquidity, policy makers should carefully analyse all potential barriers of entry and find solutions having cost-efficiency and the interest of end consumers in mind. As the forward market is a commodity market first, many of the issues resulting in illiquidity are outside of the TSOs' influence and cannot be solved by LTTRs. Furthermore, the liquidity of BZs is just one indicator to look at. For market participants to be able to hedge themselves efficiently, liquidity in all BZs is not necessarily needed. Nevertheless, TSOs see the potential of re-evaluating the current market design for LTTRs to make it fit-for-purpose and to ensure the better protection of market participants, retail suppliers and consumers.

Discussions over a new proposal on forward market design

In December 2022, ENTSO-E published a Policy Paper on EU's Electricity Forward Markets[5] assessing the current forward markets from a comprehensive perspective and providing additional insights from the TSOs' experiences. It provides an initial analysis and views on two alternative policy options. The two policy options from ENTSO-E's Policy Paper (1) TSOs as providers of hedging opportunities, either improved FTR Options or Obligations or 2) Purely financial forward markets) have subsequently been developed into one common ENTSO-E position for the forward market. The combined position better reflects the recent Electricity market reform proposal from the European Commission. The necessity to review the current long-term market models are acknowledged by other key players beyond the TSO community, in particular, the EC, who also see a need to tackle challenges in the forward market. The EC has proposed a regional virtual hub model for the forward market in their electricity market reform proposal.

Leading up to this, the EC included several questions related to forward markets in their public consultation on Electricity Market Design in January 2023 and ACER/CEER published a

5 See **here**.

policy paper on the 'Further development of the EU Electricity forward market' in February 2023.[6]

The regional virtual hub approach would mean that TSOs offer FTR Obligations between BZs and hubs with high price correlation up to three years in advance in the hope of improving the forward market. Furthermore, the EC proposed more frequent auctions and LTTR maturities up to three years ahead. In other words, the proposal aims to significantly change the forward markets as we know it today. This approach was already suggested by ACER in their paper on forward markets and ACER's response to the EC's public consultation on the Electricity Market Design[7].

From the TSOs' perspective, the current shortcomings of forward markets such as limited liquidity could be addressed with practical evolutions of the current set-up (e. g. more frequent auctions, improved products, etc.). The proposal of Regional Virtual Hubs is a disruptive approach with long implementation times (5 – 10 years). It is based on untested solutions and with significant uncertainties on cost and risks for both TSOs and market participants whose interest in such Virtual Hub arrangements is far from evident. Furthermore, the adoption of Financial Transmission Rights (FTR) obligations, the extension of the maturity and potentially full firmness bares very significant financial risks for TSOs (due for instance to a malfunction of an interconnector). Cash-flow measures and regulatory cost-recovery comfort are essential to mitigate such risk. In addition, it is unclear to ENTSO-E how this development impacts commercial power exchanges organising derivatives trading.

All potential solutions for the forward market, including practical solutions fit for market parties' hedging needs or the virtual zone to hub model, should be thoroughly assessed. Based on the conclusions of such an assessment, All TSOs are willing to propose amendments to the existing FCA Regulation.

Nonetheless, any improvements of TSOs' products could have an impact on liquidity on the forward market, but the hidden barriers and disincentives to market participants need to also be carefully addressed and reduced.

Assessment of the Shadow Auction Mechanism

In addition to the discussions, ENTSO-E also published the final version of the econometric study[8] which assesses the question of whether the remuneration of LTTRs based on market spreads reduces incentives to allocate capacity in the shadow auctions and, thus, reduces its efficiency. The results of the study, requested to a group of researchers from Ulm University in 2022, highlight two aspects that need to be changed: the fallback procedures and the price reference for remuneration of LTTRs in the event of decoupling. Therefore, the TSOs will still aim to improve the remuneration of LTTRs in the event of decoupling in the ongoing debate on forward markets and long-term hedging opportunities.

Beyond the focus of this study, the development of alternatives to the shadow allocation process should be considered. After their implementation, ID Actions could be worth considering as an alternative fallback and could replace shadow auctions.

Long Term Flow Based Allocation

In parallel to the on-going discussions on how to improve the FCA Regulation, TSOs together with JAO, are also involved in making a significant change to the allocation process by the adoption of the Long-Term FB following the NRAs and ACER's decisions. Go-live on long-term FB capacity calculation methodologies in Core CCR is planned at the end of 2024 and in Nordic CCR at beginning of 2025. FB capacity calculation should allow allocation of the scarce transmission capacity more efficiently as cross-zonal capacities between BZs are highly interdependent.

However, it is not only positive effects that can be linked with this improvement. Instead, some negative impacts of LTFBA (some of which are currently being investigated by the TSOs and JAO) are listed below:

- **Potential zero allocation at some BZBs**: Due to the direct competition between BZ borders during the flow-based capacity allocation, results with zero allocated rights at a BZ border despite existing demand can be achieved;
- **Auction timings:** The flow-based capacity calculation and allocation processes will both require a longer time and be more complex than the previous process which will have various impacts on the auctions; and

---

6 See **here**, **here** and **here**.

7 See **here**.

8 See **here**.

- **Collateral requirements:** As all BZBs in a CCR will be linked together and will run as one single auction, the level of collateral requirements is expected to be higher as of today, whereby auctions for individual BZBs take place at different times. Consequently, the entry barrier for market participants could be much higher.

All these challenges have been addressed in different workshops with market participants, regulators and other relevant stakeholders. The implementation of the proposed improvements as part of the expected revision of the FCA Regulation would be subject to the impact of LTFBA.

2.4 Development of short-term markets

The CACM 2.0 process was frozen on the EC's side in 2022 but developments in the short-term market continue nonetheless.

In the Market Stakeholder Committee[9] end of 2022 meeting, EFET and Neuroelectric presented a joint paper[10] to propose some quick wins to improve the CACM 2.0 Regulation. The proposed improvements aimed at improving

- the efficiency of DA market coupling and continuous ID trading;
- the transparency of DA and ID markets; and
- limiting some other projects that are seen as not to be prioritised from the market participants perspective (ID Auctions, governance of the MCO function, non-uniform pricing).

TSOs and NEMOs have to carefully consider the proposal from the market participants and the Market coupling Steering Committee agree to provide an answer on each of the item raised.

In line with the prioritised projects presented in chapter 2.3, NEMOs and TSOs are dedicated to achieving big implementation steps in the delivery of the 15-min products on Day Ahead and Intraday by 2025 without endangering the already available functionalities and services of the DA and ID algorithms. On the question of the Intraday cross zonal Gate opening time, TSOs and NEMOs are working on robust solutions which respect system operation's needs. An update of the available capacity is expected to be available for the implementation of the first Intraday auction at 14:45 (D-1). To ensure a smooth implementation of the intraday Auction (IDA), NEMOs and TSOs aim for the shortest possible interruption time, the actual cross-border allocation interruption time will be 20 minutes before Gate Closure Time (GCT) and 20 minutes after GCT during the IDA regular process.

The EC has in the electricity market design reform proposed to shorten the ID cross-zonal gate closure to 30 minutes ahead of real time by 2028. ENTSO-E sees that those issues need to be addressed by methodologies stemming from the CACM and the decision of the Intraday gate closure time should be accompanied by an impact assessment to avoid negative consequences concerning system security, costs and CO_2 emission. Shorter Intraday Gate Closure Times could be introduced where necessary – provided this is compatible with operational constraints which also depend on the different balancing approaches by TSOs.

Furthermore, TSOs and NEMOs increased the level of transparency throughout the last year to support market participant's understanding for the short-term markets.

In this regard, the NEMOs publish the aggregated bidding curve[11] presenting electricity supply and demand curves as well as the volume and price of the market clearing point of every MTU. Furthermore, NEMOs are committed to improve the public description of the Day ahead algorithm.

TSOs publish the information about LTTR curtailments[12], which are the basis for LTA-inclusion in the day-ahead capacity calculation. Alongside the go-live of the flow-based market coupling in the Core region on 9 June 2023, market participants can find a variety of data on the Core capacity calculation like the validation reduction on a dedicated publication tool[13]. On the Nordic side, until the go live of the Flow based capacity calculation, the result of the parallel runs is made public.[14]

In addition of the information already available in the transparency platform, the TSOs also publish an overview of the SDAC and SIDC allocation constraints.[15]

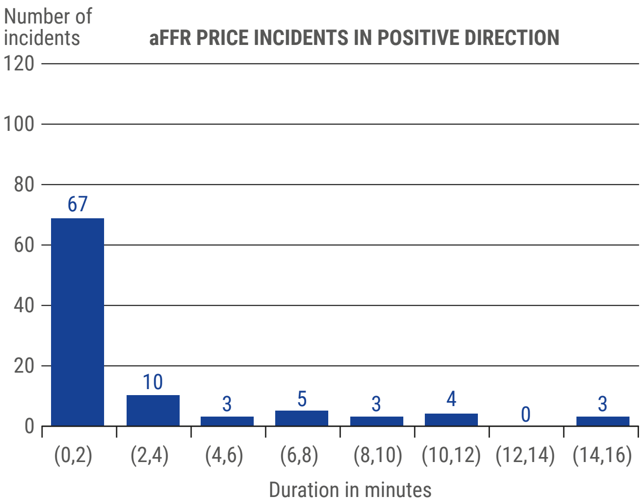
9 See **here**.
10 See **here**.
11 See **here**.
12 See **here**.
13 See **here**.
14 See **here**.
15 See **here** and **here**.

2.5 High prices at balancing platforms

Discussion on high price spikes in the European balancing markets

Since the first cross-border exchanges between Austria, Germany and the Czech Republic on the European platform for the exchange of aFRR (PICASSO) on 22 June 2022, TSOs have observed a significant amount of high clearing prices. In total 235 aFRR pricing incidents, as defined in the amended pricing methodology[16], took place during the operational months of PICASSO in 2022. This affected 1.27 percent of all operational quarter hours. On the MARI platform, facilitating the cross-border exchange of mFRR, two price incidents happened during its operational period in 2022. No price incidents took place at the TERRE platform. The provisions in this chapter are therefore limited to the PICASSO platform as the low number of price incidents are not a suitable basis for drawing any conclusions for MARI.

Root causes for the price spikes observed can be identified on both, the demand and the supply side as well as in the way that cross-border marginal prices (CBMP) on the balancing platforms are formed. High TSO demand in combination with low liquidity and high priced bids placed at the end of the merit order list will lead to the selection of these bids. For the time being most of the price incidents have been of short duration (see figure 4). These incidents as well as incidents of longer durations but with a low CBMP have no severe impact on the imbalance settlement prices which are in general calculated based on the volume weighted average price of the aFRR CBMPs in the countries connected to the platform. Nevertheless, TSOs identified the need to initiate a discussion with ACER and NRAs on the causes of the recurring price spikes and potential mitigation measures.



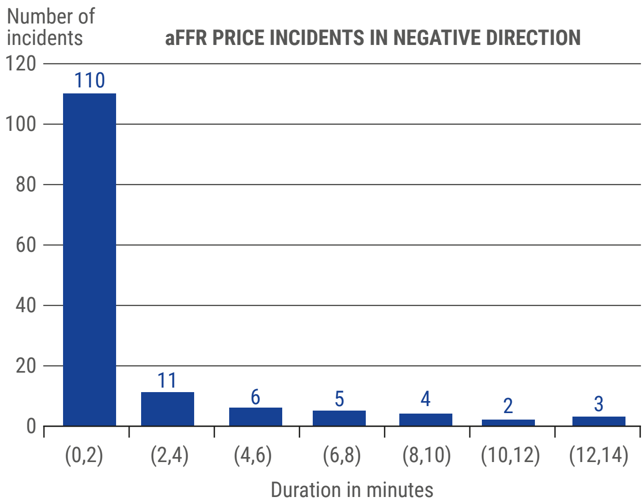


Figure 4: Duration of aFRR price incidents from 22 June to 31 December 2022

One of the main arguments of TSOs used during the discussions to introduce a price limit was the substantial risks resulting from applying marginal pricing in the balancing energy markets, especially during the transitional phase with only a few TSOs being connected to the platforms but also at moments when local markets are isolated due to only little or unavailable transmission capacities (ATCs). The limited liquidity together with the heterogeneous structures of the (local) balancing energy markets, different balancing service provider (BSP) bidding behaviors and conditions in the connected countries as well as high market shares of a small number of BSPs add to the fact that the issue will probably not diminish with more TSOs joining the platforms.

Although TSOs do not see any realistic mitigation measures on the demand side and are of the strong opinion that issues on the market side should not be tackled by changes to the technical design, they consider that the CBMP for aFRR does not reflect the true value of energy for the market at all times. BSP bids, in particular the ones at the end of the merit order, may be exaggerated. In addition, the introduction of the new market design for the balancing markets has not yet increased the incentive for new participants to enter the market and place additional bids at the beginning of the merit order. For their national markets, the majority of TSOs have been establishing tools to monitor the local bidding behavior and detect any market abuse at national level.

16 ACER decision 03/2022 on the amendment to the methodology for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy or operating the imbalance netting process obliges TSOs to prepare and submit a report to ACER and the NRAs each time the cross-border marginal price of the balancing platform reaches 50 % of the transitional price limit of +/– 15,000 EUR/MWh.

In conclusion, TSOs strongly support the European target model for the integrated balancing energy markets and see significant potential advantages resulting from it. To further improve it they invite ACER and NRAs to have an open and constructive discussion with TSOs and market participants on possible actions both in the short as well as in the long term. Two points in particular are important to consider from the TSOs' perspective. First, based on the current price formation on the platforms there may arise national concerns and reservations regarding the timely connection to the balancing platforms. Second, a discussion on the definition of a price incident as currently described in the amended pricing methodology might be necessary. Reporting on a short term CBMP spike is of limited informative value with regard to the impact it may have on the Volume-Weighted Average Price (VWAP)-based imbalance settlement price.

2.6 Transposition of EU regulations in Energy Community

The Energy Community is an international organisation that aims to extend the EU internal energy market to neighbouring countries in South East Europe, the Black Sea region and beyond. The Energy Community Treaty provides for the transposition of EU energy legislation into the legal frameworks of its Contracting Parties.

As for the transposition of EU regulations into the Energy Community legal framework, this process involves adapting EU regulations to the specific needs and circumstances of the Energy Community Contracting Parties. The aim is to ensure that the regulatory framework is coherent and consistent across the region in scope of EnC, promoting the development of a stable and integrated energy market.

The Energy Community has made significant progress in transposing EU energy legislation, particularly in the areas of electricity and gas market regulation, renewable energy, and energy efficiency.

On 15 December 2022, the Energy Community Ministerial Council adopted Decision 2022/03/MC-EnC[17] on the incorporation of the European Union's electricity market acquis in the Energy Community together with Procedural Act 2022/01/MC-EnC[18] on fostering regional energy market integration in the Energy Community. Consequently, the Contracting Parties obliged themselves to bring into force the laws, regulations and administrative provisions necessary to comply with the new provisions by 31 December 2023.

The adopted electricity package enables full market integration of Energy Community Contracting Parties into the single European market for electricity, based on the principle of reciprocity.

Encompassing nine acts, the package aims at making the markets fit to deliver on cost-efficient clean energy transition while ensuring secure and affordable electricity supply to the citizens.

There are four acts which are part of the CEP:

- Electricity Directive (EU) 2019/944 (recast);
- Electricity Regulation (EU) 2019/943;
- Risk-preparedness Regulation (EU) 2019/941 (recast); and
- ACER Regulation (EU) 2019/942.

The five Network Codes and Guidelines establish detailed rules related to different market segments and system operation:

- Forward Capacity Allocation Guideline;
- Capacity Allocation and Congestion Management Guideline;
- Electricity Balancing Guideline;
- System Operation Guideline; and
- Network Code on Emergency and Restoration.

The Energy Community has made significant strides in aligning its regulatory framework with that of the EU, paving the way for a more integrated and efficient energy market. While there are still challenges to be overcome, the future looks promising for the Energy Community, as it moves towards full integration into the EU market. With continued cooperation and dedication, the Energy Community will undoubtedly play an important role in shaping the future of energy in the region and beyond.

17 See **here**.

18 See **here**.

2.7 Update to Transparency Platform

Transparency is essential for the implementation of the Internal Electricity Market and for the creation of efficient, liquid and competitive wholesale markets. It is also critical for creating a level playing field between market participants and avoiding the scope for market power (if it exists) to be abused. Since its launch in 2015, the ENTSO-E Transparency Platform has contributed to those objectives by providing electricity market information for the future and further facilitating the development of efficient and competitive energy markets across Europe.

Ever since its launch, the increase in users accessing the ENTSO-E Transparency Platform has regularly shown the interest and importance of the platform. By January 2023, the number of registered TP users reached nearly 50,000 with around 4,000 daily active users, as presented in figure 5.

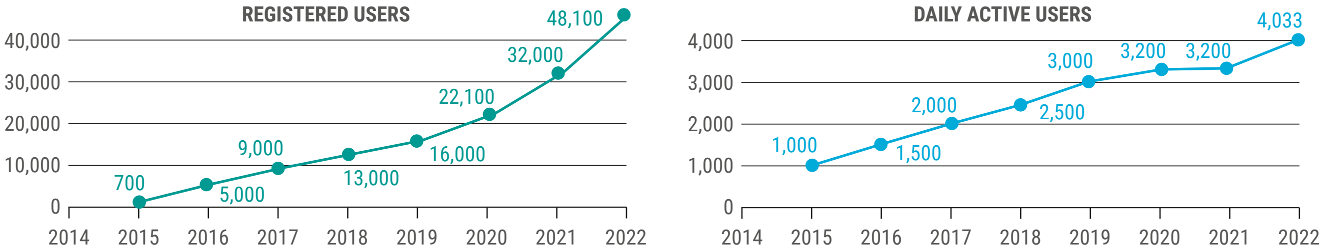


Figure 5: Yearly average of registered users and daily active users of the ENTSO-E transparency platform

Following the ever-growing publication requirements stemming from regulations such as System Operations Guidelines (SOGL), balancing Implementation Frameworks, and REMIT regulation, ENTSO-E kept adopting the platform and adding more relevant data. The relevant development milestones include:

- The data publications stemming from System Operations Guidelines (SOGL) were implemented (14/12/2022) with new rich & standard data items replacing and updating the existing SOGL data publications.
- The TP was enhanced and went-live (21/07/2022) with the IFs of European balancing platforms data publications related to standard imbalance netting, aFRR and mFRR products.
- The work on TP becoming an Inside Information Platform (IIP) was initiated and is ongoing. Sub-set of TSOs chose to disclose their inside information as required by REMIT Regulation on the TP.

As a next step of evolution, the ENTSO-E Transparency Platform is being equipped with a new user friendly and interactive interface.

The new interface[19] enables users to select areas on a map and view the respective data in a graphic as well as tabular form, including the option to adopt and merge information. This aims to help the user to get graphs to be used readily from the platform that could be essential during the energy crises and the energy transition. As part of the TP's new Graphical User Interface (GUI) Update implementation scope:

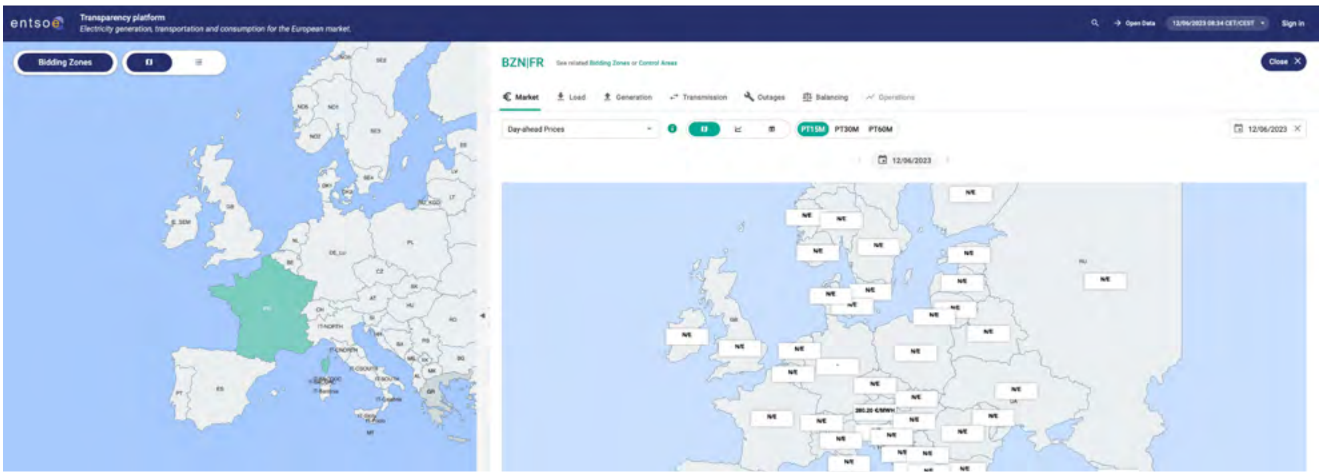


Figure 6: Example for the new interface

19 See **here**.

- Implementation of the Day-ahead Prices went live in the beginning of Nov-22. The Day-ahead Prices (Transparency Regulation art.12.1. D) data item, was successfully launched on the new TP GUI in full scope with graphical, tabular and map views. The new TP interface view example is shown in figure 6.

Upon a successful completion of the development, by the end of August, implementation scope is planned to be finalised and a transition period will begin to publicly announce that the current GUI will be decommissioned by the end of 2023.

2.8 Implementation of CEP 70 % minimum capacity targets

The CEP entered into force on 4 July 2019. As one of the main provisions of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (EU Electricity Regulation), from 1 January 2020, at least 70 % of the transmission capacity must be made available for cross-zonal electricity trading (Article 16(8). For borders that use an FB approach, 70 % of the transmission capacity respecting operational security limits after deductions of contingencies needs to be made available. For borders that use a cNTC approach) the minimum capacity shall be 70 % of the transmission capacity per border respecting operational security limits after deduction of contingencies. The inclusion of 'derogations'[20] and 'action plans'[21] in the EU Electricity Regulation provides temporary exemptions, which can be applied to achieve the 70 % (CEP70) target via a transitionary phase. During the legislative process, ENTSO-E raised concerns as to whether a general minimum cross-zonal trading margin would be an appropriate instrument to enhance European market integration. Although ENTSO-E fully supports the general optimisation of the use of trading capacities, the economic and technical impact of the CEP70 target needs further analysis and discussion. Such an assessment should particularly focus on system security, economic efficiency and decarbonisation targets.

Nevertheless, TSOs and ENTSO-E continue to invest significant efforts and apply the appropriate tools to implement the existing CEP70 provisions and achieve compliance with the legal provisions, while also accommodating fallback options to ensure system security at all times.

In 2022, the implementation of Core Day-Ahead Flow Based Market Coupling on 8 June for the delivery day 9 June 2022 led to a harmonised and more efficient application of minimum cross-zonal trading capacities on 19 borders in Central Europe. This is a further step to enhance a more integrated and efficient European electricity market. The methodology will ensure that the allocation of cross-zonal capacity is fair and transparent especially for integrating the RES on the road to a carbon-free electricity power production.

According to the EU Electricity Regulation, the NRAs are responsible for assessing TSOs' compliance with the CEP70 provisions. This report provides an overview of the national assessments for external stakeholders. The main findings are displayed in this chapter. In addition, the annex provides detailed country-by-country assessments including explanations of the respective monitoring methodologies.

CEP70: the situation in 2022

Table 1 presents the status of CEP70 provisions from 2022. As a central performance indicator for TSOs, the share of MTUs where the minimum capacity is reached (considering action plans or derogations) is shown. The underlying methodological assumptions for these figures can also be found in the annex. Acknowledging that NRAs are responsible for assessing TSOs' compliance with the CEP70 provisions, a reference to the respective NRA report is provided when applicable. Where an NRA has not made an official decision or an NRA's decision has not been published at the time of publication of this report, it is referred to as 'N/A' (not applicable). Table 1 provides an overview; further information and detailed graphs of the analysis performed by TSOs can be found in Annex IV of this report. Due to the large amount of supporting information provided by TSOs, this is also provided in the Annex IV.

20 Option to deviate from the minimum cross-zonal capacity target for a predefined period of time. In 2022 applied by Austria, Belgium, Bulgaria, Czech Republic, Spain, Hungary, Italy, the Netherlands, Poland, Portugal and Romania.

21 Option to achieve the 70 % minimum cross-zonal trading capacity via a linear trajectory by 31 December 2025 in case of internal structural congestions. In 2022 applied by Austria, Germany, Croatia, Hungary, the Netherlands, Poland and Romania.

Country	TSO	Border/region	% of MTUs in which minimum target was reached (considering action plans and/or derogations[22]	Compliance decision by relevant NRA	Exemption clause applied
AT	APG	CWE (AT < > DE)	99.99 %	Compliant	Derogation and Action Plan
		cNTC(AT < > CZ/HU/SI)	98.32 %		
		CORE (AT < > DE/CZ/HU/SI)	100.00 %		
		Italy North (AT < > IT)	100.00 %		
BE	ELIA	CWE	69.88 %		Derogation
		CORE	81.80 %		
		ALEGRO	98.47 %		
BG	ESO	SEE BG < > GR	100.00 %	Compliant	No
		SEE BG < > RO	100.00 %		No
CZ	ČEPS	CZ > (AT+DE+PL+SK)	90.61 %	N/A	Derogation target 90 % of MTUs
		(AT+DE+PL+SK) > CZ	92.71 %		
		CORE	100.00 %		
DE	Amprion	CWE	99.98 %	Compliant	Action Plan
		ALEGrO (CWE) – HUB AL_DE	100.00 %		
		CORE	99.5 %		
		ALEGrO (CORE) – HUB AL_DE	100.00 %		
	Transnet-BW	CWE	100.00 %		
		CORE	100.00 %		
	50 Hertz	CORE	99.51 %		
		DK2 < > DE	100 %		
	50Hertz/TenneT	DE < > PL/CZ	100 %		
	TenneT	CWE	99.96 %		
		CORE	99.49 %		
DK	Energinet	SE3 > DK1	98.41 %	N/A	
		DK 1 > SE3	98.88 %		
		DE < > DK2	100.00 %		
		DK1 > DK2	98.97 %		
		DK2 > DK1	99.98 %		
		DK1 < > NL	100.00 %		
		DK 1 > NO2	99.14 %		
		NO2 > DK 1	99.99 %		
		DK2 > SE4	82.73 %		
		SE4 > DK2	82.59 %		
		DK1 > DE	73.86 %		
		DE > DK1	72.97 %		
EE	Elering	EE < > FI	100.00 %		
		EE < > LV	N/A		
EL	IPTO	SEE	97.00 %	15 % of MCCC	Yes
		GRIT	100.00 %	Compliant	No

22 The underlying assumptions can be found in the Annex IV. Please note that the assessment of compliance is complex and therefore considers much more than the calculation of percentages of MTUs in which targets where reached. TSOs can be compliant with the CEP70 provisions, even if they did not reach the minimum target in all hours.

Country	TSO	Border/region	% of MTUs in which minimum target was reached (considering action plans and/or derogations[22]	Compliance decision by relevant NRA	Exemption clause applied
ES	REE	ES < > FR	100.00 %	N/A	Derogation
		ES < > PT	100.00 %		
FI	Fingrid	FI < > SE1	100.00 %	100.00 %	
		FI < > SE3	100.00 %	100.00 %	
		FI < > EE	100.00 %	100.00 %	
FR	RTE	SWE (FR > ES)	87.10 %	NRA appreciation	Derogation
		SWE (ES > FR)	93.80 %		
		IN	99.70 %		-
		CWE	63.00 %		
		CORE	87.00 %		
HR	HOPS	CORE	100.00 %	Compliant	Action plan[23]
		HR < > SI	100.00 %		Action plan and derogation
		HR < > HU	100.00 %		
HU	MAVIR	AT > HU	129.00 %	N/A	Action plan with 25 % minimum capacity level
		RO > HU	25.61 %		Action plan with 33 % minimum capacity level
		CORE	98.69 %		Action Plan with 25 % and 33 % minimum capacity level
IE	Eirgrid	no information provided			
IT	Terna	IN	98.96 %	N/A	Derogation
		GR < > IT	100.00 %	N/A	-
LT	Litgrid	LT < > SE4	97.74 %	N/A	-
		LT < > PL	100.00 %		
		LT < > LV	N/A		
LV	AST	LV < > LT	N/A	N/A	-
		LV < > EE	N/A		
NL	Tennet BV	CWE	99.00 %		Action Plan and Derogation
		CORE	100.00 %		
		Nordlink	100.00 %		
NO	Statnett	No information provided			
PL	PSE	PL < > (CZ-DE-SK)	100.00 %		Action Plan and Derogation
		PL < > LT	100.00 %		Action Plan
		PL < > SE4	100.00 %		Action Plan
		CORE	100.00 %		
PT	REN	PT < > ES	100.00 %		Derogation
RO	Transelectrica	RO < > BG	N/A	N/A	Action Plan
		RO < > all borders	N/A	N/A	Action Plan
		CORE	80.00 %		Action Plan and Derogation

23 Action plan started with NTC approach (25/02/2022) with starting value 20 %. From FB DA MC Go-Live (09/06/2022), HOPS uses FB approach.

Country	TSO	Border/region	% of MTUs in which minimum target was reached (considering action plans and/or derogations[22]	Compliance decision by relevant NRA	Exemption clause applied
SE	Svenska kraftnät	SE1 > FI	99.66 %		No
		FI > SE1	99.54 %		
		SE1 < > SE2	100.00 %		
		SE1 > NO4	83.35 %		
		NO4 > SE1	97.67 %		
		SE2 > SE3	99.16 %		
		SE3 > SE2	100.00 %		
		SE2 > NO3	98.52 %		
		NO3 > SE2	100.00 %		
		SE2 > NO4	96.97 %		
		NO4 > SE2	97.74 %		
		SE3 > NO1	98.87 %		
		NO1 > SE3	99.41 %		
		SE3 > DK1	98.79 %		
		DK1 > SE3	100.00 %		
		SE3 > SE4	99.51 %		
		SE4 > SE3	99.47 %		
		SE3 > FI	100.00 %		
		FI > SE3	97.75 %		
		SE4 > DK2	99.55 %		
		DK2 > SE4	99.79 %		
		SE4 < > DE	100.00 %		
		SE4 < > PL	100.00 %		
		SE4 > LT	99.98 %		
		LT > SE4	99.93 %		
SI	ELES	CORE	97.00 %	N/A	
SK	SEPS	CORE	96.00 %	N/A	Derogation

Table 1: TSOs' performance regarding the CEP70 provision from 2022

3 Implementation progress of the FCA, CACM and EB Regulations

3.1 FCA Regulation

The FCA Regulation, which entered into force on 17 October 2016, sets out rules for the type of LTTRs that can be allocated via explicit auction, and the way in which holders of transmission rights are compensated if their right is curtailed. Annex II outlines the implementation progress of this regulation including links to all relevant documents such as TSO proposals and ACER decisions.

Long-Term flow-based allocation assessment

The long-term flow-based allocation (LTFBA) project, the go-live of which is expected by the end of 2024 (first for the yearly auction of market period 2025, shortly followed by the January monthly auction), required the amendment of four All TSOs methodologies already in 2022/2023 for a timely implementation of the new allocation approach in the concerned CCRs (Core and Nordic). In 2021, ACER requested that ENTSO-E submits proposals for amendment of the following FCA methodologies:

- Harmonised Allocation Rules (HAR) in accordance with Article 51 of the FCA Regulation;
- Single Allocation Platform (SAP) requirements in accordance with Article 49 of the FCA Regulation;
- Congestion Income Distribution (CID) methodology in accordance with Article 57 of the FCA Regulation; and
- Methodology for ensuring firmness and remuneration of long-term transmission rights (FRC) in accordance with Article 61 of the FCA Regulation.

The amendment of the four methodologies was performed in parallel with the implementation of the long-term Capacity Calculation methodologies for the Nordic and Core CCRs. More details on the project and on the collaboration with JAO to make it possible can be found in chapter 4.4.3.

Single Allocation Platform requirements methodology and SAP cost-sharing methodology (Articles 49 and 59 of the FCA Regulation)

In September 2022, all TSOs submitted the proposal for amendment of the establishment of the SAP and for the Cost Sharing to ACER. The revision of this methodology with the set of requirements for the establishment and run of the SAP is driven by the changes required due to the introduction of the LTFBA principles. The main changes consist of the formulation of the new allocation algorithm for LTFBA regions in addition to the new requirements. The NTC allocation algorithm has also been included to complement the methodology, not amended since its approval in 2017. ACER approved TSOs' submitted proposal on 24 March 2023.

Congestion Income Distribution (Article 57 of the FCA Regulation)

In September 2022, all TSOs submitted the proposal for amendment of the methodology for sharing congestion income from forward capacity allocation to ACER. The revision of this methodology is driven by the changes required due to the introduction of the LTFBA principle which requires an alignment of the FCA CID methodology processes, so it is more suitable for this kind of allocation. ACER approval TSOs' submitted the proposal on 24 March 2023.

Cost of ensuring firmness and remuneration of LTTRs (Article 61 of the FCA Regulation)

In September 2022, all TSOs submitted the cost of ensuring firmness and remuneration of LTTRs (FRC) proposal to ACER. The revision of this methodology is driven by the changes required due to the introduction of the long-term FB allocation principle. To ensure the consistency of the FRC methodology with the FCA CID methodology, a new article on sharing the remuneration costs of eligible LTTRs among BZBs for CCRs with long-term FB capacity calculation was added. ACER approved TSOs' submitted proposal on 24 March 2023.

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 HAR and in line with ACER's request to update the necessary FCA methodologies to adapt to the LTFBA project. HAR should be periodically reviewed by the SAP and the relevant TSOs (at least every two years involving the Registered Participants). All TSO submission to ACER was done 1 March 2023 according to the biennial update. A second submission containing elements related to LTFBA not solved in the first submission, is due 1 June, and the final ACER approval expected by end of October 2023, in time for the 2024 auction. Further information on the specific changes made in the methodology can be found in chapter 4.4.2.

3.2 CACM Regulation

The rules set by the CACM Regulation provide the basis for implementing a single energy market across Europe in DA and ID time frames. All the Terms and Conditions deriving from the CACM Regulation have been submitted, and the implementation of these Terms and Conditions is still ongoing. Annex II provides tables showing the implementation progress of this regulation.

3.2.1 Main developments in all TSOs' deliverables

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

As of August 2021, Norway was formally bound by the CACM Regulation. Therefore, a new proposal for the amendment of the determination of CCRs methodology has been prepared to allocate the Norwegian BZs to the relevant CCRs, namely CCR Nordic and CCR Hansa.

Following the certification of Statnett mid-2022, All TSOs submitted to ACER, on 13 October 2022, the amendment of the Capacity Calculation Region definition (CACM Art 15). On 14 April 2023, ACER approved the TSOs' proposal. The decision becomes applicable when the EFTA Surveillance Authority (ESA), responsible for the application of European Economic Area (EEA) rules in Iceland, Liechtenstein and Norway, and the Norwegian NRAs adopted their respective decisions on the CCR methodology.

Day Ahead Scheduled Exchanges Methodology (Article 43 of the CACM Regulation)

The scheduled exchange calculation methodology is a regional methodology according to CACM Regulation Art. 9(7). All TSOs submitted to All NRAs, on 19 December 2022, the amendment to the Day Ahead Scheduled Exchanges Methodology for optimising the NEMO trading hub flows calculation. The amendment proposal allows for changes to the so-called inter-NEMO flow calculations, which is a post-coupling process that does not impact the scheduled exchanges between BZs or between Scheduling areas that are relevant for TSO's post-coupling processes. The purpose of this part of the calculation (and methodology) is to minimise flows and thus financial exposures between NEMOs. The methodology has been referred by All NRAs to ACER in January 2023 and was approved by ACER on 30 May 2023.

Congestion Income Distribution ('CID') (Article 73 of the CACM Regulation)

According to ACER's decision from December 2021, TSOs are to develop a new amendment within 18 months including mature solutions to address the transfer of congestion income among different CCRs in the event of non-intuitive flows[24]. The final submission date is expected for mid-2023.

Core flow-based market coupling project

2022 has seen a major milestone in the implantation journey with the go-live of the Core FB market coupling (8 June 2022 for the delivery day 9 June 2022). The flow-based capacity calculation developed by the TSOs of the Core Region laid the foundations for the Core Flow-Based Market Coupling Project which is an excellent example of the potential of pan-European cooperation for delivering social welfare benefits by improving grid utilisation and reducing the overall cost for customers. Since the go-live, the capacity calculation has been running almost without fault, and there have been very few operational and process issues with it.

Since introducing FB market coupling in the Core CCR[25] some tentative studies have been carried out to extract the benefits of flow-based from the market data. Those benefits are calculated by comparing data from 6 months after flow-based go-live with the same period the previous year. Comparing data over this time span will contain systematic errors resulting from the changed dynamics in the energy system and energy markets over the past year.

Investigating the market results, capacity allocation volumes and price development in the 6 months after flow-based go-live compared to the same period the year before in 2021, provides some useful insights, but cannot lead to firm conclusions.

Figure 7 compares price spreads and shows higher values in 2022 than in 2021. In theory, the use of flow-based should lead to a higher degree of price convergence and lower price spreads due to a better use of the underlying grid but the clearing price level in 2022 overall was high. A more accurate impact of flow-based market coupling on price convergence could only be provided by comparing actual market results with simulated market coupling results for the same time period but based on the former NTC allocation method.

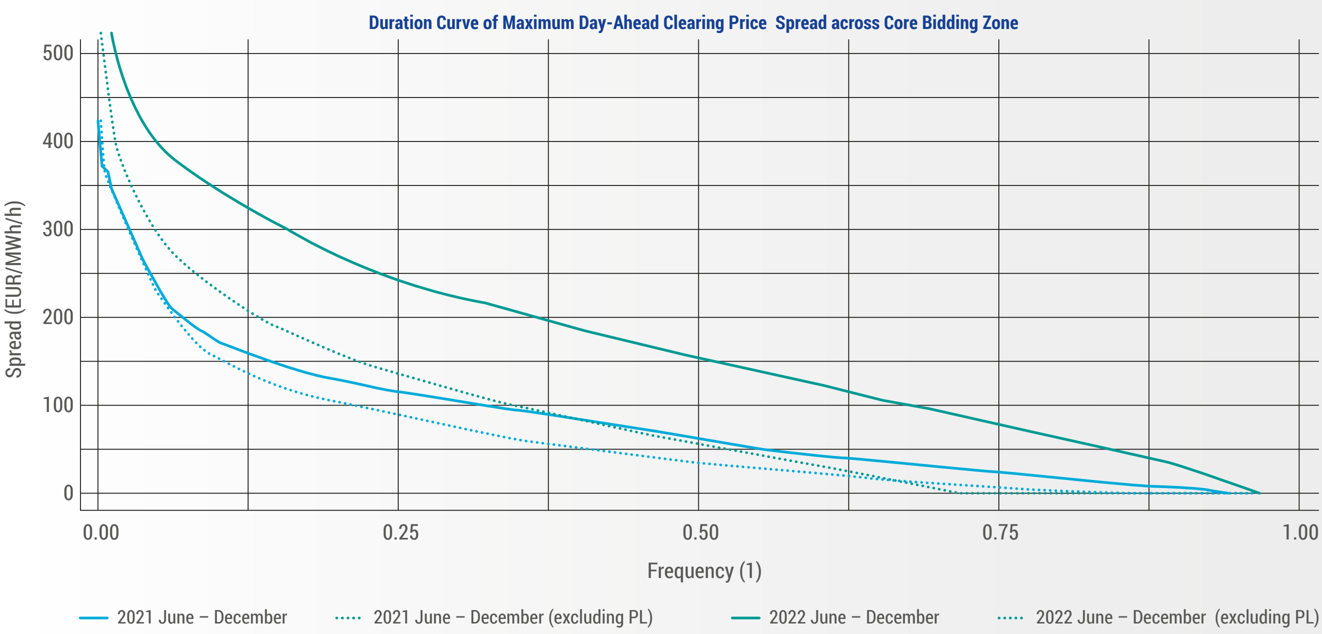


Figure 7: Price spread distribution for compared periods. The graph shows higher price spreads in over FB borders in 2022 compared to same period in 2021. Graph was produced by Magnus Energy.

24 Non-intuitive flows are physical cross-zonal electricity flows in the opposite direction of a cross-zonal price difference.

25 It should be noted that the borders between the Netherlands, Belgium, France, Germany/Luxemburg, and Austria applied a FB market coupling approach since 2015.

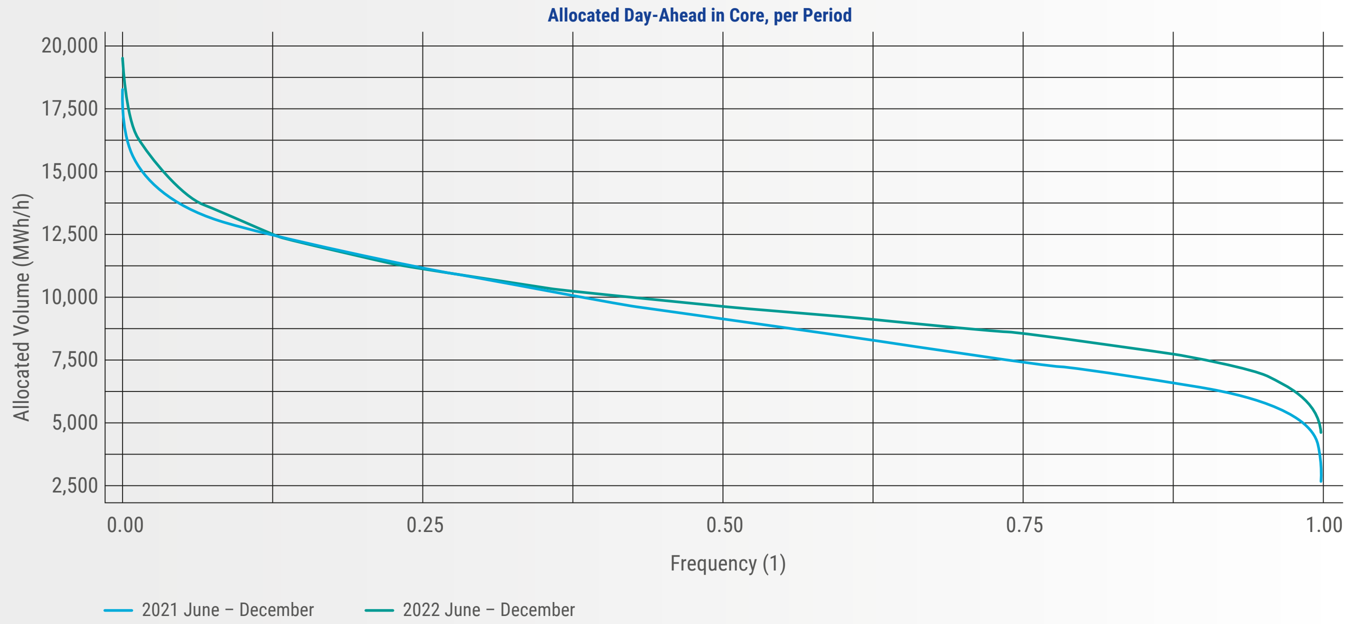


Figure 8: Distribution of allocated volumes on FB borders for compared periods. The graph shows a greater volume of exchange after introduction of FB. Graph was produced by Magnus Energy.

Figure 8 compares the allocated volumes pre and post coupling. Indeed greater volumes of cross border trade have been observed, although the larger volumes compared to the year before could also be explained by the increased price volatility, increasing demand for imports.

Quantifying the exact benefits of FB market coupling is complicated. The energy mix is constantly changing. The exogenous drivers of the changing market conditions include load, wind and solar generation, generation of nuclear, gas and coal power plants, unavailability of nuclear, gas and coal power capacity, coal, gas and carbon prices, and temperatures, as well as exchanges with non-flow-based bidding zones.

To get an insight into the benefit of FB capacity calculation, several scientific studies for the FB approach since 2015 at the borders between the Netherlands, Belgium, France, Germany/Luxemburg and Austria (known as Central West Europe [CWE]) can be consulted. Most recently a study published in 2023 concluded after controlling for exogenous market conditions, that FB increased surplus in the day-ahead markets of CWE by on average 134 M euros per year in the first 2.5 years following the introduction in 2015, and FB market coupling led to a persistent increase of cross-border exchange with around 1,150 MWh/h over all participating borders.[26]

Nordic flow-based market coupling project

The NRAs of CCR Nordic have agreed on a number of conditions/KPIs to be fulfilled over a 3-month reporting period, followed by another 6 months parallel run, before go-live of CCR Nordic flow based.

The three months reporting period was concluded in March 2023. Given a continued stable parallel run during the last days of the 3-months reporting period, the Nordic TSOs will provide a report describing the results from the 3-months, which the Nordic NRAs will approve before the start of the last 6 months of external parallel run. With the current results of the parallel run, a Go-live in Q1 2024 is very likely.

The market reports, containing the comparison of the FB and NTC market results for W50 2022 and onwards are available on the Nordic RCC website. The FB data are published daily (before 11.00 CET) on the JAO Publication Tool, on the custom site for the Nordic CCR.[27]

26 See **here**.

27 See **here** and **here**.

3.2.2 Main developments in the NEMOs' deliverables

CACM Annual Report

On 28 September 2022, the All NEMO Committee, together with ENTSO-E organised a webinar[28] to present the key findings from the 'CACM Annual Report 2021' that was delivered on 1 July 2022. The webinar focused on the first 100 days of operation of the Core Flow based Market coupling and featured a policy discussion about the upcoming changes and challenges for 2023. Participants included the Head of the Electricity Department of ACER, the Chairwoman of ACER Board of Regulators, the Deputy Director of FSR and the Vice-chair of ENTSO-E Market Committee. The opening remarks were delivered by the Director for Green Transition and Energy System Integration, from the European Commission.

Harmonised Minimum and Maximum Prices methodology

All NEMOs consulted from May to July 2022 on the methodologies in accordance with Art. 41(2) and Art. 54 (2) of CACM determining the harmonised minimum and maximum clearing prices (HMMCP) to be applied in all BZs for SDAC and for SIDC. After this consultation, ACER urged the NEMOs to amend both methodologies to limit the frequency of increases of the maximum clearing price in the spot markets, allowing consumers and market participants to adapt to the scarcity situation gradually and better.

All TSOs provided their views on the amendment proposal from ACER advocating for having stricter rules for the triggering of the increase of the price limit and for a mechanism to decrease the price limit as well. TSOs have also recommended providing sufficient time for the implementation if the methodologies are amended in order to perform all the necessary tests on the Algorithm and also to provide sufficient time for the market participants to adjust to the new processes. All NEMOs provided their proposal to ACER on 16 September 2022[29] and ACER approved it on 11 January 2023.

Day Ahead Products (CACM Article 40)

All NEMOs have ran a public consultation (4 January to 10 February 2023) on the SDAC products methodology in line with the CACM Regulation. After review there are no proposed amendments to the products and all NEMOs are therefore proposing not to amend the content of the current list of SDAC products.

3.2.3 Single Day-Ahead and Intraday Coupling Observership and Non-Disclosure Agreement

The CACM Regulation requires that TSOs, ENTSO-E, power exchanges (PXs) and market operators or PXs in their quality of NEMO cooperate and exchange information to fulfil the obligations described in the CACM GL for the completion of the single day-ahead and intraday coupling. To protect the exchange of confidential information, the Single Day-Ahead and Intraday Coupling Observership and Non-Disclosure Agreement (CACM Global NDA) came into effect on 23 February 2016. At the time, the CACM Global NDA replaced individual NDAs from early implementation projects prior to the date the CACM GL entered into force.

Following up on the information presented in previous editions of this report (ENTSO-E Market Report 2020 and 2019)[30], this section provides an update on the new parties that have joined the CACM Global NDA between August 2020 and May 2023. Importantly, in accordance with article 8 of the CACM Global NDA, the parties must give their consent to the adherence of a new party.

On the basis of above-mentioned article 8, on 17 July 2021, MEMO became part of the CACM Global NDA; on 13 August 2021, Baltic Cable did; on 2 August 2022 ETPA joined and on 17 November 2022, JSC "Market Operator" also joined.

Table 2 lists all the parties under the CACM Global NDA (as of March 2023) and the date upon which each party became part of this agreement.

28 See **here**.

29 See **here**.

30 See **here** and **here**.

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

Name of party	Member since
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
LAGIE, Operator of Electricity Market S.A	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 Pieței de Energie Electrică și 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

Table 2: Overview of global non-disclosure agreement signatories (in chronological order, as of March 2023)

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 to integrate balancing energy markets across the Union. It sets out rules for the procurement of balancing capacity, the allocation of cross-zonal transmission capacity for cross-border trades, the activation of balancing energy, and the financial settlement of BRPs and BSPs. This part of the report describes the main achievements regarding the EB Regulation roadmap, with emphasis on the cross-border balancing capacity procurement development, the imbalance settlement harmonisation process, and the implementation of the FSkar process (focused on financial settlement of unintended exchanges). Special focus lies on the key achievements accomplished in 2022 related to the European Balancing Platforms particularly the go-lives of the PICASSO- and MARI platforms.

3.3.1 Regulatory developments regarding procurement of balancing capacity and allocation of cross-zonal transmission capacity for cross-border trades

All TSOs' submission of Article 38(3)

On 16 December 2022, All TSOs submitted the proposal for a harmonised allocation process of cross-zonal capacity methodology (HCZCAM) for the exchange of balancing capacity or sharing of reserves per timeframe in accordance with Article 38(3) of EB Regulation, together with explanatory document and answers to public consultation responses document to ACER and published the document on the ENTSO-E website[31]. This methodology for a harmonised allocation process per timeframe includes the co-optimised allocation process pursuant to Article 40 and the market-based allocation process pursuant to Article 41 of the EB Regulation and consisting of cross-border procurement processes taking place day ahead of the provision of the balancing capacity pursuant to Article 6(9) of Regulation (EU) 2019/943. Approval of the methodology by ACER is expected in July 2023. Until then, bilateral meetings between ACER/NRAs and TSOs are organised to discuss and align on the content of the methodology.

The market-based allocation defined in the methodology proposes a decentralised manner of managing multiple balancing capacity (BC) platforms. This means that different regions (e. g. CCRs) can build their own BC platforms, with, however, one unique CZCAOF for all BC platforms. Therefore, the set of business requirements for the CZCAOF blueprint will be drafted by and agreed with all TSOs. In this way, the CZCAOF blueprint remains the same for all BC platforms in the EU, while the implementation and operation of BC platforms remains regional and considers regional specificities.

In addition, the HCZCAM assigns some tasks to the RCCs regarding forecast validation for the market-based allocation process. Therefore, in 2023, together with the ENTSO-E project developing the proposals for the RCC Procurement and Sizing tasks, there are alignments with RCCs to clarify their tasks, including the forecast validation proposed in the HCZCAM.

3.3.2 Regulatory developments regarding Imbalance Settlement Harmonisation

This section assesses the progress of harmonisation of the main features of the imbalance settlement proposal that entered into force in January 2022 as well as the consequences and possible distortions due to non-harmonisation. Overall, there is good progress although not all TSOs are currently applying 15-minute Imbalance Settlement Period (ISP). Several derogations are still in place until 2025.

The EB Regulation and recast EU Electricity Regulation[32] establish a 15-minute ISP for which BRPs' imbalances must be calculated. It also sets the minimum time interval for NEMOs by which they shall provide market participants with the opportunity to trade in energy, for both DA and ID markets. The 15-minute ISP is either already implemented within three years of the EB Regulation's entry into force (January 2021), subject to derogation (until 1 January 2025 at the latest), or subject to an exemption for the whole of a synchronous area, in which case the ISP shall be 30 minutes (1 January 2025 at the latest).

31 See **here**.

32 See **here**.

The implementation of Imbalance Settlement Harmonisation Methodology (by January 2022) requires each TSO to apply a self-dispatching model to use the single final position of each BRP to calculate imbalance volumes, and limits the number of additional price components each TSO may apply in its imbalance price calculation and limits the number of conditions for the application of dual imbalance pricing. Further information on the implementation status can be found in Chapter 4 of the Balancing Report 2022.

3.3.3 Regional implementation of FSkar process

One of the main developments in the implementation of the EB Regulation regarding regional implementations is the start of the financial settlement of exchange of energy between the TSOs of the Continental Europe Synchronous Area because of ramping among TSOs, the frequency containment process, or unintended exchange (FSkar).

Starting per June 2021 with 29 TSOs representing 26 countries, including part of Ukraine, during early 2022 Ukraine (and Moldova) became fully synchronised with SA CE. DK1 became a separate Load Frequency Control Block and accounting and settlement party in FSkar in June 2022.

A review of the FSkar process and methodology was initiated late 2022, the results will be presented to the relevant NRAs and to ACER.

3.3.4 Overview of European and regional implementation of the EB Regulation

This section summarises the status of the balancing energy procurement and activation deliverables (Table 3), the status of the balancing capacity procurement and CZC allocation deliverables (Table 4), and the status of the imbalance settlement and other settlements deliverables (Table 5).

Type	Proposal	EB Art	First TSOs' submission	NRAs approval/ 1st request for amendment/ Referral to ACER	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
All-TSOs	Implementation framework for the European RR platform	19	**18 Jun 2018**	**15 Jan 2019 (approval)**				
All - TSOs	1st Amendment of the Implementation framework for the European RR platform	19	**16 Mar 2021**	18 Oct 2021[33]				
All - TSOs	2nd Amendment of the Implementation framework for the European RR platform	19	**31 Mar 2022**					
All-TSOs	Implementation framework for the European mFRR platform	20	**11 Feb 2019**	**24 Jul 2019** (referred to ACER)				**24 Jan 2020**
All-TSOs	1st Amendment of the Implementation framework for the European mFRR platform	20	**31 Mar 2022**					
All-TSOs	2nd Amendment of the Implementation framework for the European mFRR platform	20	**31 Mar 2022**					**30 Sep 2022**
All-TSOs	Implementation framework for the European aFRR platform	21	**11 Feb 2019**	**24 Jul 2019** (referred to ACER)				**24 Jan 2020**
All-TSOs	1st Amendment for the Implementation framework for the European aFRR platform	21	**31 Mar 2022**					**30 Sep 2022**

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

Type	Proposal	EB Art	First TSOs' submission	NRAs approval/ 1st request for amendment/ Referral to ACER	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
All-TSOs	Implementation framework for the European IN platform	22	**18 Jun 2018**	9 Nov 2018 (RfAs by individual NRAs)	**23 Jan 2019**	19 Jul 2019 (2nd RfA[34]) **16 Jan 2020** (referred to ACER)	**10 Sep 2019**	**24 Jun 2020** Corrigendum: **8 Dec 2020**
All-TSOs	1st Amendment for the Implementation framework for the European IN platform	22	**31 March 2022**					**30 Sep 2022**
All-TSOs	Classification of the activation purposes of balancing energy bids	29	**11 Feb 2019**	23 Jul 2019 (RfAs by individual NRAs)	**11 Nov 2019**	19 Jul 2019 (2nd RfA[35]) **16 Jan 2020** (referred to ACER)		**15 Jul 2020**
All-TSOs	Pricing method for all products	30	**11 Feb 2019**	**24 Jul 2019** (referred to ACER)				**24 Jan 2020**
All-TSOs	Amendment – Pricing method for all products	30	**28 Aug 2021**					**25 Feb 2022**

Table 3: Status of the balancing energy procurement and activation deliverables

Type	Proposal	EB Art	First TSOs' submission	NRAs approval/ 1st request for amendment/ Referral to ACER	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
All-TSOs	List of standard balancing capacity products for FRR and RR	25	**18 Dec 2019**					**17 June 2020**
All-TSOs	Methodology for the allocation of cross-zonal capacity based on the co-optimisation allocation process	40	**18 Dec 2019**					**17 June 2020**
All-TSOs	Cross-Zonal Capacity Allocation Harmonised Methodology (HCZCA)	38	17 Dec 2022					
All-TSOs	ENTSO-E Proposals for the Regional Coordination Centres' (RCCs) Procurement and Sizing		17 Mar 2023					
Regional	Methodology for the allocation of the cross-zonal capacity market-based allocation process	41	Baltic: **18 Dec 2019**	**18 Jun 2020**	**28 Aug 2020**	**30 Oct 2020** (2nd RfA)	**30 Dec 2020** (NRAs forwarded for decision to ACER on 19 Feb 2021)	ACER approved on **13 Aug 2021**
Regional			CORE: **18 Dec 2019**	**12 Aug 2020**	**6 Dec 2020**	NRAs forwarded for decision to ACER on 22 Feb 2021		ACER approved on **13 Aug 2021**
Regional			GR/IT: **18 Dec 2019**	**1 Jul 2020**	**24 Sep 2020**	**1 Dec 2020** (2nd RfA)	**1 April 2021**	NRAs approved on **22 Jun 2021**
Regional			Hansa: **18 Dec 2019**	**24 Jul 2020**	**13 Oct 2020**	Withdrawn by respective TSOs on **12 May 2021**		
Regional			IT North: **18 Dec 2019**	**29 Jun 2020**	**4 Sep 2020**	**15 Dec 2020** (2nd RfA)	**26 March 2021**	NRAs approved on **1 Jun 2021**
Regional			Nordic: **7 April 2019**	**17 Oct 2019**	**17 Dec 2019**	**28 Feb 2020** (referred to ACER)		**5 Aug 2020**

34 2nd RfAs are not available (same as 1st RfAs) as those requests were made by each NRA to their respective TSO.

35 2nd RfAs are not available (same as 1st RfAs) as those requests were made by each NRA to their respective TSO.

Type	Proposal	EB Art	First TSOs' submission	NRAs approval/ 1st request for amendment/ Referral to ACER	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
Regional	Methodology for the allocation of cross-zonal capacity based on an economic analysis	42	CORE: **18 Dec 2019**	**12 Aug 2020**	**4 Dec 2020**	Withdrawn by respective TSOs on **24 May 2021**		
Regional			GR/IT: **18 Dec 2019**	**1 Jul 2020**	**24 Sep 2020**	**1 Dec 2020** (2nd RfA)	**9 April 2021**	NRAs approved on **22 June 2021**
Regional			Hansa	Did not submit.				
Regional			IT North: **18 Dec 2019**	**29 Jun 2020**	**4 Sep 2020**	**15 Dec 2020** (2nd RfA)	**26 Mar 2021**	Withdrawn by corresponding TSOs on **27 May 2021**
Regional			Nordic:	Did not submit.				

Table 4: 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	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
All-TSOs	TSO-TSO settlement of intended exchanges of energy as a result of the RRP, FRP and INP	50.1	**18 Dec 2018**	**23 Jul 2019**	**11 Nov 2019**	**16 Jan 2020** (referred to ACER)		**16 Jul 2020**
All-TSOs	TSO-TSO settlement of intended exchanges of energy due to ramping restrictions and FCR between synchronous areas	50.4	**18 Jun 2019**	**4 Dec 2019**	**27 Mar 2020**	**22 May 2020** (NRAs' approval)		
All-TSOs	TSO-TSO settlement of unintended exchanges between synchronous areas	51.2	**18 Jun 2020**			**4 Dec 2019** (NRAs' approval)		
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 Jun 2019**	**4 Dec 2019**	**15 Mar 2020**	**27 May 2020** (NRAs' approval)		
Regional		51.1	**18 Jun 2019**	**4 Dec 2019**	**15 Mar 2020**	**27 May 2020** (NRAs' approval)		
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 Jun 2019**	**18 Dec 2019**	**18 Feb 2019**	**31 Mar 2020** (NRAs' approval)		
Regional		51.1b						
All-TSOs	Imbalance settlement harmonisation	52	**11 Feb 2019**	11 Jul 2019		**16 Jan 2020** (referred to ACER)		**15 Jul 2020**

Table 5: Status of the imbalance settlement and other settlements deliverables

4 Forward capacity allocation

All TSOs have appointed a JAO in accordance with Article 49 of the FCA Regulation[36], to act as the SAP for the FCA as of 1 November 2018. JAO is a joint service company currently owned by 25 TSOs[37] that hosts SAP services for TSOs.

SAP enables long-term auctions of transmission capacity and currently serviced 25 TSOs from 21 EU countries. The IT system is scalable border by border, allowing for annual, non-calendar annual, half-yearly, quarterly, monthly, weekly, weekend, daily and intraday auctions.

4.1 Governance

In accordance with Article 1 of the approved SAP methodology, all TSOs and regulatory authorities[38] bound to the FCA Regulation agreed to appoint JAO as the SAP operator. Consequently, the SAP Cooperation Agreement ('SAP CA'), according to Article 2(3)(g) of the SAP methodology, was developed and signed by all TSOs that issue long-term transmission rights (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 fulfilment of SAP tasks, in accordance with the FCA Regulation[39].

Figure 9: Countries whose TSOs are obliged to be part of the SAP Council and are part of the SAP CA (as of May 2023)[40]

36 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.

37 Includes TSOs/companies operating undersea cable interconnectors as well. 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.

38 Some Regulatory Authorities (the Regulatory Authorities of Finland, 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 part of the SAP CA yet.

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

40 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 SAP Council.

4.2 Operations

JAO performs all tasks in compliance with the SAP CA, the SAP methodology and the HAR.[41]

As of 2023, the SAP operator organises forward capacity rights auctions at 67 BZ directional borders and provides services by use of a common IT system for more than 400 registered market participants[42]. Only yearly, quarterly and monthly products are being allocated at EU borders in 2023.

A gradual shift is being observed of 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 1.33 % of allocated rights. A broad transition to FTRs happened in the context of the launch of FB day-ahead coupling in CCR Core, when a vast majority of remaining BZBs in the region switched to FTRs.

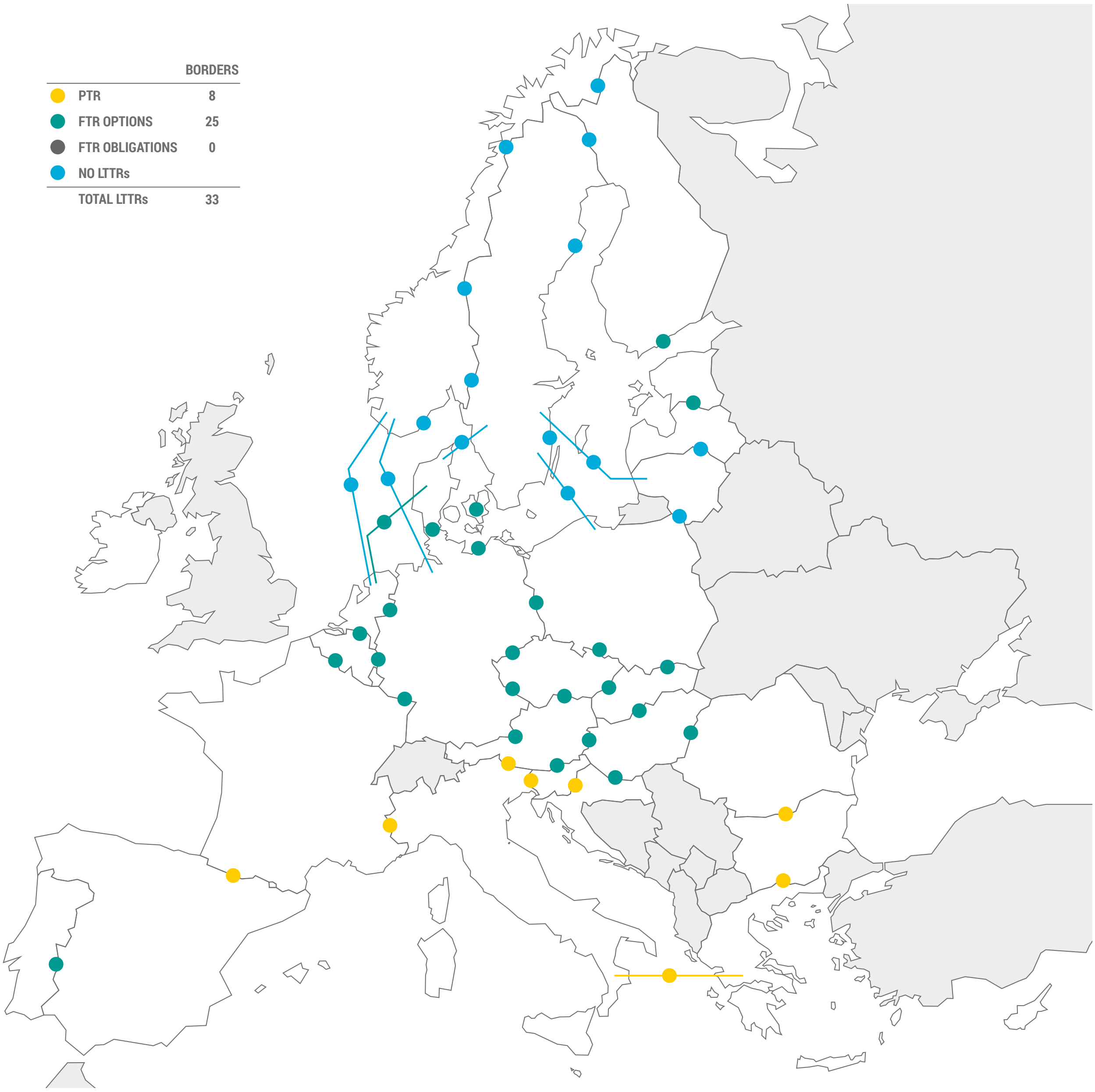


Figure 10: Overview of products offered at SAP (as of 2023)[43]

On the above mentioned borders, the SAP operator organised in 2022 more than 778 auctions with LTTRs and similar amounts are anticipated for 2023.

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

42 A detailed description of the common IT System e-cat can be found in the ENTSO-E Market Report 2019.

43 At the border DE-CZ FTR Options are offered for CZ-DE (TenneT) and CZ-DE (50Hertz), at the borders EE-LV and FI-EE FTR Options are only offered for the directions EE to LV and FI to EE.

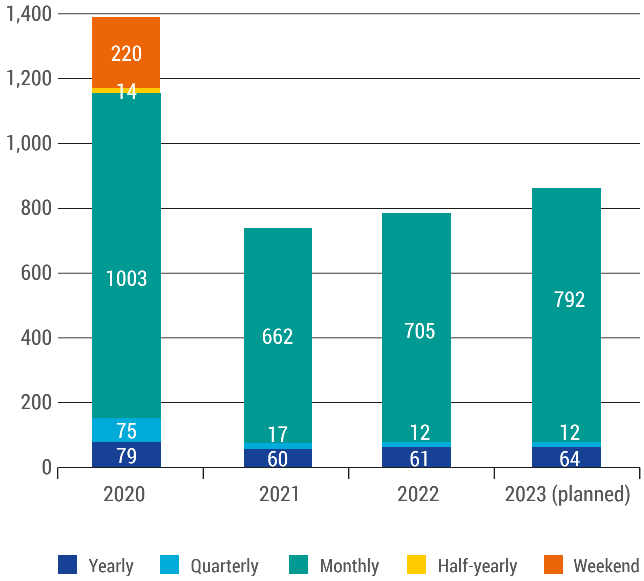


Figure 11: Overview of auctions

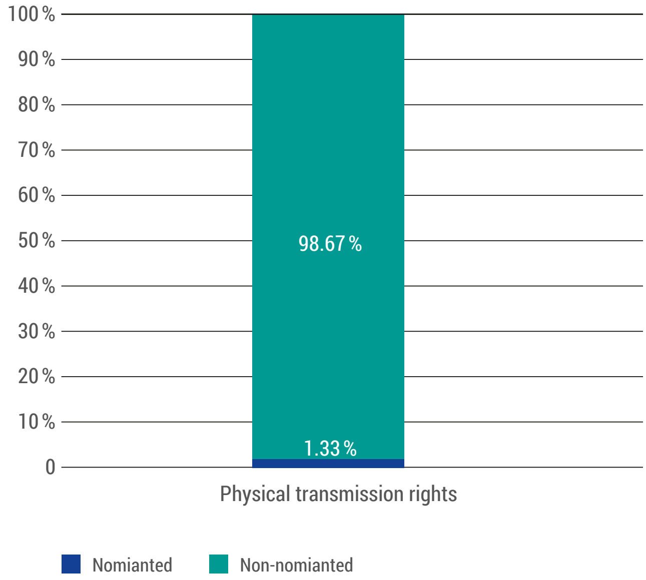


Figure 12: Usage (nomination) rate of long-term transmission rights

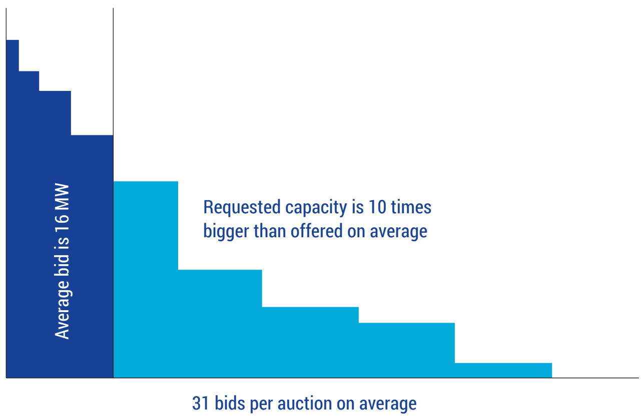


Figure 13: Average long-term capacity rights auction structure

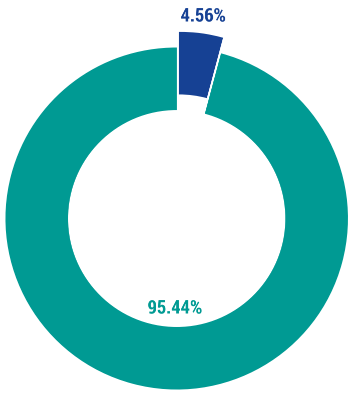


Figure 14: Rate of return of long-term capacity rights for reallocation at subsequent long-term auction

Figure 15: Number of participants in every auction versus number of participants that win the capacity during 2022 and 2023

4.2.1 Quality of operations

The SAP Council regularly monitors the quality of operations performed by the SAP operator. More than 4,200 auctions have taken place since SAP operations began. As for last year, no incidents occurred.

To monitor the SAP operator's operation quality, the TSOs of the SAP Council calculate 23 detailed key performance indicators (KPIs) which are merged into three meta-KPIs[44] (see table 6).

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 16: SAP key performance indicators

Month	Fulfilling reporting Obligations	Operational Effectiveness	Customer Satisfaction	TOTAL	Quarterly Score
Jan-22	9.50	10.00	6.00	8.50	
Feb-22	9.50	10.00	9.00	9.50	9.06
Mar-22	9.50	10.00	8.00	9.17	
Apr-22	9.50	10.00	9.00	9.50	
May-22	9.50	10.00	9.00	9.50	9.17
Jun-22	9.50	10.00	6.00	8.50	
Jul-22	9.50	8.00	9.00	8.83	
Aug-22	9.50	10.00	9.00	9.50	8.83
Sep-22	10.00	10.00	8.00	9.33	
Oct-22	10.00	8.00	8.00	8.67	
Nov-22	10.00	10.00	8.00	9.33	9.22
Dec-22	10.00	10.00	8.00	9.33	
Jan-23	10.00	10.00	8.00	9.33	
Feb-23	10.00	8.00	8.00	8.67	9.11
Mar-23	10.00	10.00	8.00	9.33	

Table 6: Overview operation Meta-KPIs of single allocation platform (as of March 2023)

Customer interaction and satisfaction

JAO has created a platform to gather the 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. According to the SAP operator annual survey that took place early 2022 and is being repeated in 2023, market participants rated SAP operator's performance as very good. We witness stable scores as the general satisfaction value from the last survey was 4.0 points out of 5.0. The SAP Council continuously works with the JAO to identify key elements for improvement and which are incorporated in the SAP operator workplan.

44 See here.

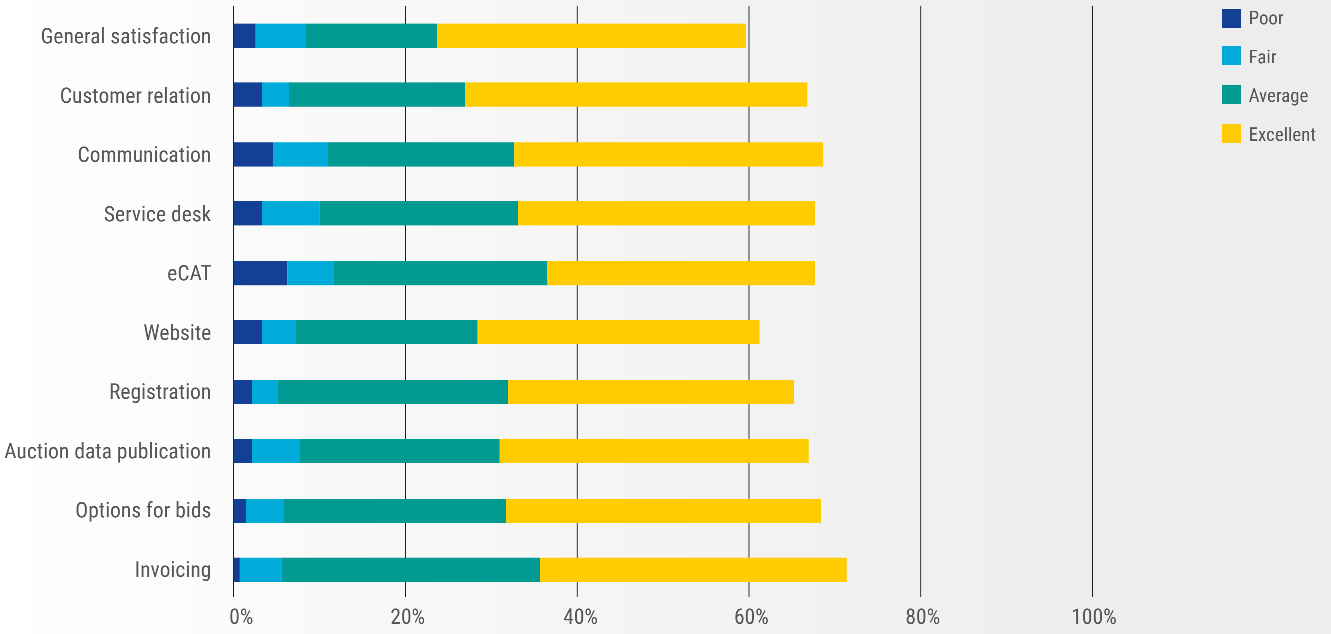


Figure 17: SAP customer interaction and satisfaction

4.3 Expenditures

This report provides a summary of TSOs' common costs of establishing, amending and operating the SAP. In the figure below, the planned and actual costs since 2018 are depicted[45]. Larger investment costs are anticipated due to changes needed for FB DA and long-term allocation.

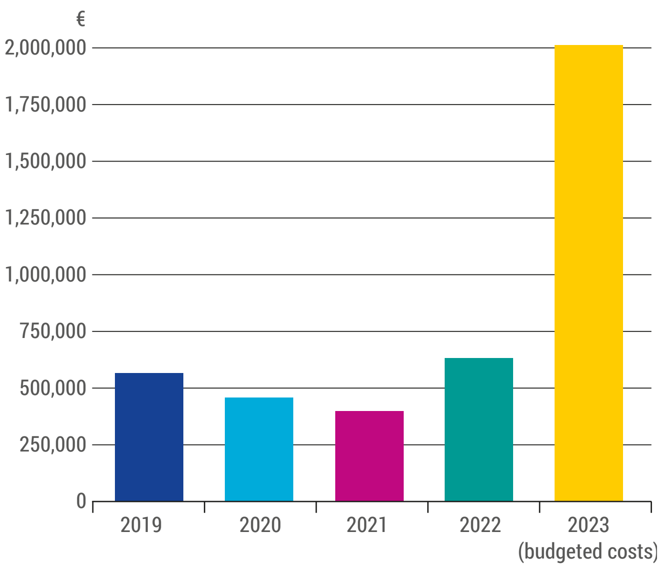


Figure 18: Overview of the single allocation platform for establishing and amending costs

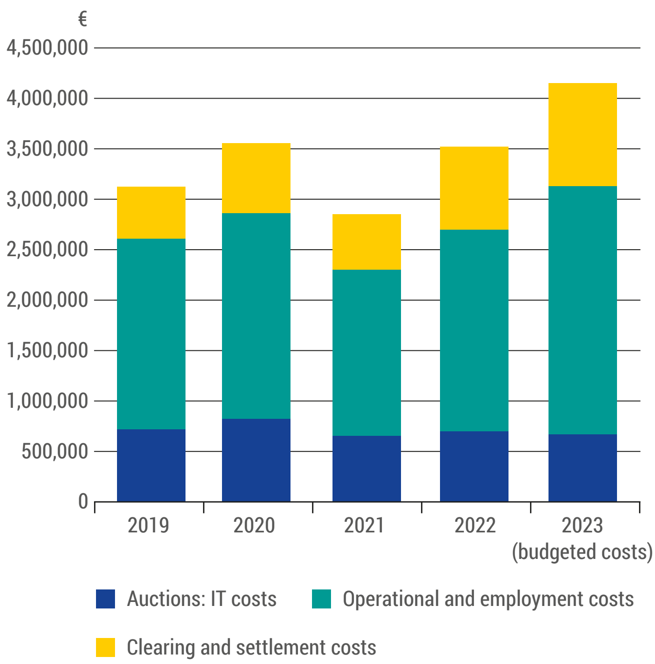


Figure 19: Overview of the single allocation platform operating costs

45 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.

The reported establishment and development costs consist of annual depreciation and amortisation of investments to establish and develop SAP on top of existing tools in JAO. The operational costs for SAP consist of annual depreciation and amortisation of the tools and other assets used for LT auctions. Furthermore, they consist of 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 whole business chain for capacity allocation to market participants. The organisation and meeting of SAP Council did not cause any direct costs.

The fee principles for the SAP are defined based on the SAP methodology, which is derived from the 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 FCA Regulation.

The SAP methodology is applicable to costs of running the 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).

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 FB market coupling in the Core CCR, a shift from PTR to FTR options happened for the majority of the Core CCR BZBs.

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 Harmonised Allocation Rules update

In 2023, the HAR were reviewed especially in view of the introduction of LTFBA:

The changes relate to:

1. Introduction of LTFBA
2. 15 Min MTU
3. Remuneration in case of decoupling
4. Remuneration of LTTRs
5. General changes related to:

- Corporate Accounts
- Erroneous invoice and Prefinancing
- Change of collateral in case of payment incident
- Liability
- Suspension (due to sanctions)
- Termination of dormant accounts
- SWIFT message

4.4.3 Long-term Flow-Based Allocation

The preparations for the go-live of the LTFBA project in the Core and Nordic CCRs continue to progress with the aim to reach the go-live dates:

- For Core CCR, the go-live is foreseen for the end of 2024 starting with the yearly auction for market period 2025 followed by the monthly auction for January 2025.
- For Nordic CCR, the go-live has been delayed and currently foreseen to be started with the monthly auctions in Q1 2025 for the border DK1–DK2 that would be followed up with the yearly auction at the end of the year for market period 2026.

Regulatory-wise, the necessary amendments are expected to be finalised in 2023 with ACER’s Decision on the latest review of the HAR, the remaining methodology to be updated to allow Long-Term Flow-Based. See chapter 3.1 FCA Regulation for more details.

In terms of operations, JAO established a Project Board with the supervision of the SAP Council, aimed to monitoring and coordinating the launch of LTFBA as required by both the the Capacity Calculation Methodologies of the Core and Nordic CCRs, with a special focus on the update of the impacted processes and tools. The LTFBA Project Board prepared in 2022 an extended project charter based on the then available information and scope and included an estimation of the project budget, an initial version of the project plan, main constraints, and risks as well as a list of key deliverables. This was approved by the SAP Council in April 2022.

The introduction of LTFBA will affect significantly the SAP operator's main IT tools (e.g: auction system and web pages), market rules and operational procedures, among other things. Figure 20 provides an overview of the allocation process and main processes, and Figure 21 the latest timeline of the project (timings may slightly vary throughout the process).

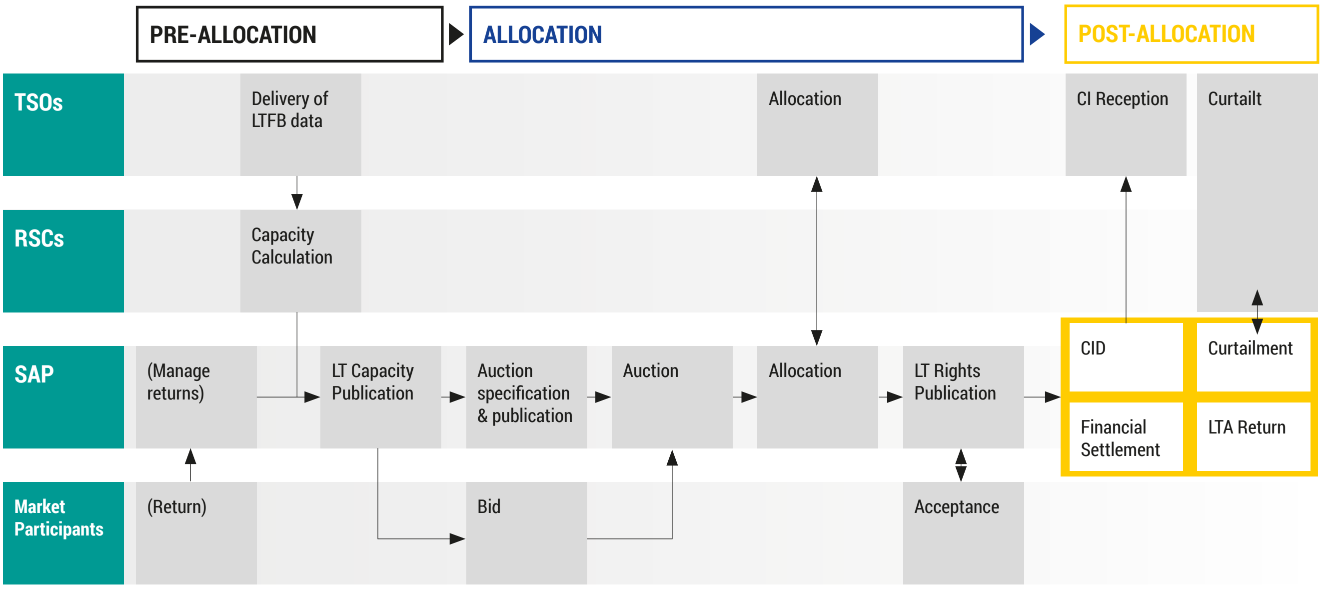


Figure 20: LT Flow-Based Allocation Process overview Process overview

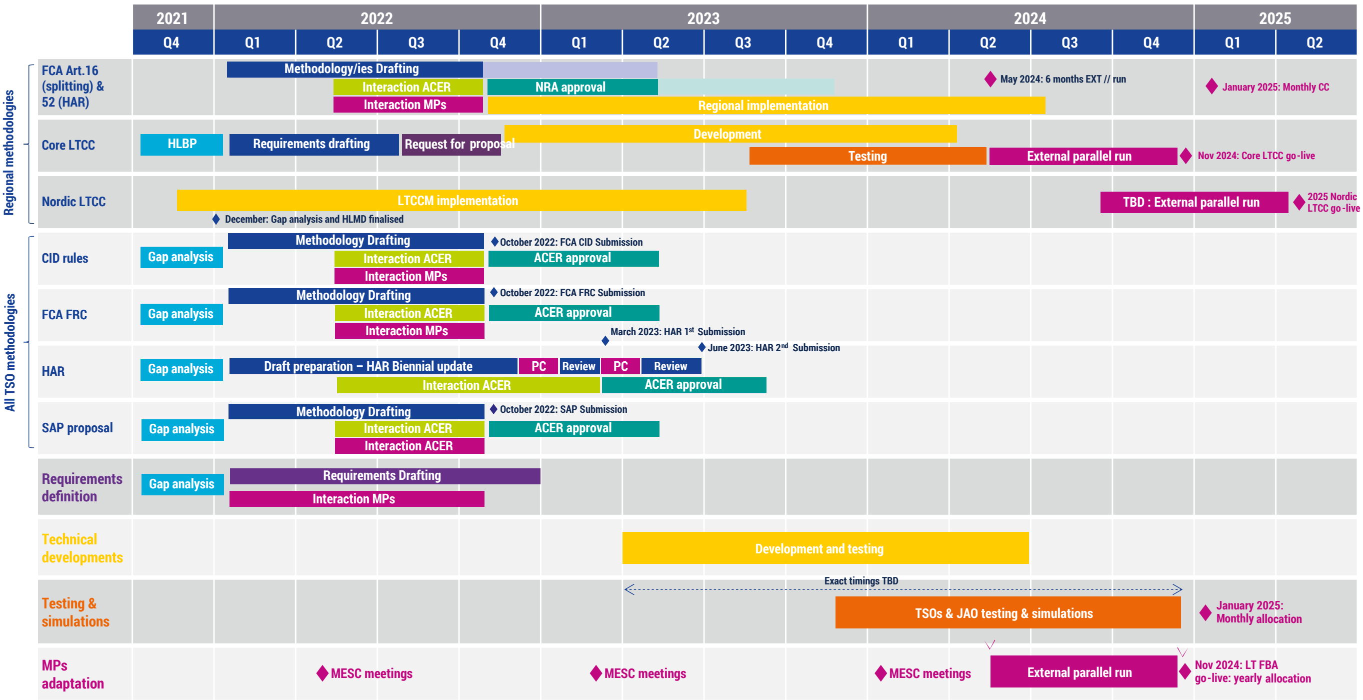
The use of FB capacity calculation requires changing the auction set up to only one auction per timeframe for a whole region (e. g. all borders being part of Core), which entirely changes current operations, both for the SAP operator but also for market participants. The provision of input data in a transparent manner before the auction starts or the allocation optimisation system itself are only some examples of the affected processes and tools.

Given the scope of the changes, there is an ongoing cooperation with market participants to design the system as close as possible to their preferences. For this purpose, five workshops were co-organised by ENTSO-E and ACER on the Long Term Flow-Based Capacity Calculation and Allocation on 27 January 2022, 24 May 2022, 29 September 2022, 15 February 2023 and on 4 May 2023[46] where JAO also participated in their preparation. In addition, to handle external communication, JAO created a new section[47] on their web page dedicated to the LTFBA project.

From a procedural perspective, the main changes foreseen are linked to auction timings currently in place (e. g. regarding the returns, the availability of the offered capacity, length of the contestation period), the creation of a new Long-term Publication tool and the credit limit and collateral approach used. The decision on the latter could result in additional significant changes, including updates in the bidding screen as well as impacting other crucial parts of the systems and processes that are currently in place. No changes are foreseen currently regarding the processes and file exchanges of the Long-Term capacity rights results. In addition, TSOs' preliminary simulation results show there is a possibility that the allocation algorithm could provide some borders with 0 MW or low values of allocation. The possible reasons could be: historical market participants' bids designed for NTC allocation, the size of the FB domain respectively available RAM, the switch from NTC to FB, the objective function or the competition among borders (see materials from the workshop of 4 May 2023 for more information).

46 The workshops links: Presentation and Recording Jan 2022, Presentation and Recording May 2022, Presentation and Recording Sep 2022, Presentation and Recording Feb 2023, Presentation May 2023

47 See here.



*Timings may slightly vary from the planning above

Figure 21: LT FB Allocation Timeline planning

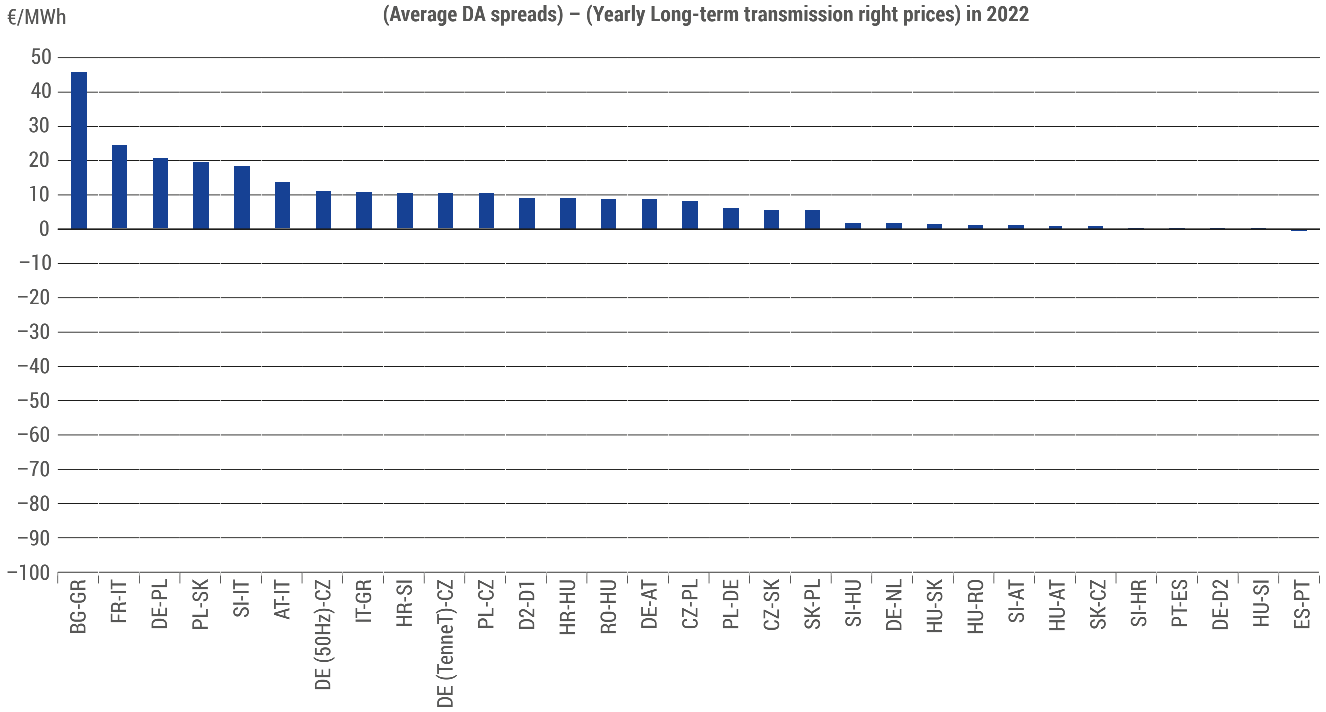
4.4.4 Analysis of auction prices

In November 2022, JAO as SAP shared a high-level comparison between the Average DA price spreads and the yearly auction prices in 2019, 2020, 2021 and 2022. The reports on it can be found in the Market Opportunities section[48] of the jao.eu website. In addition, from May 2023 onwards, JAO continues the initiative by the publication of a monthly report on the comparison between the Average DA price spreads and the monthly auction prices.

Figure 22 shows the difference between the average DA market spread and LTTR auction price for each border. A positive value indicates that TSOs would have been better off financially if they had not sold LTTR and instead would have kept their DA congestion income. This is the case for most borders in 2022.

Very preliminary calculations for 2023 show that the difference between average DA market spread and LTTR prices are smaller compared to 2022.

48 See here.



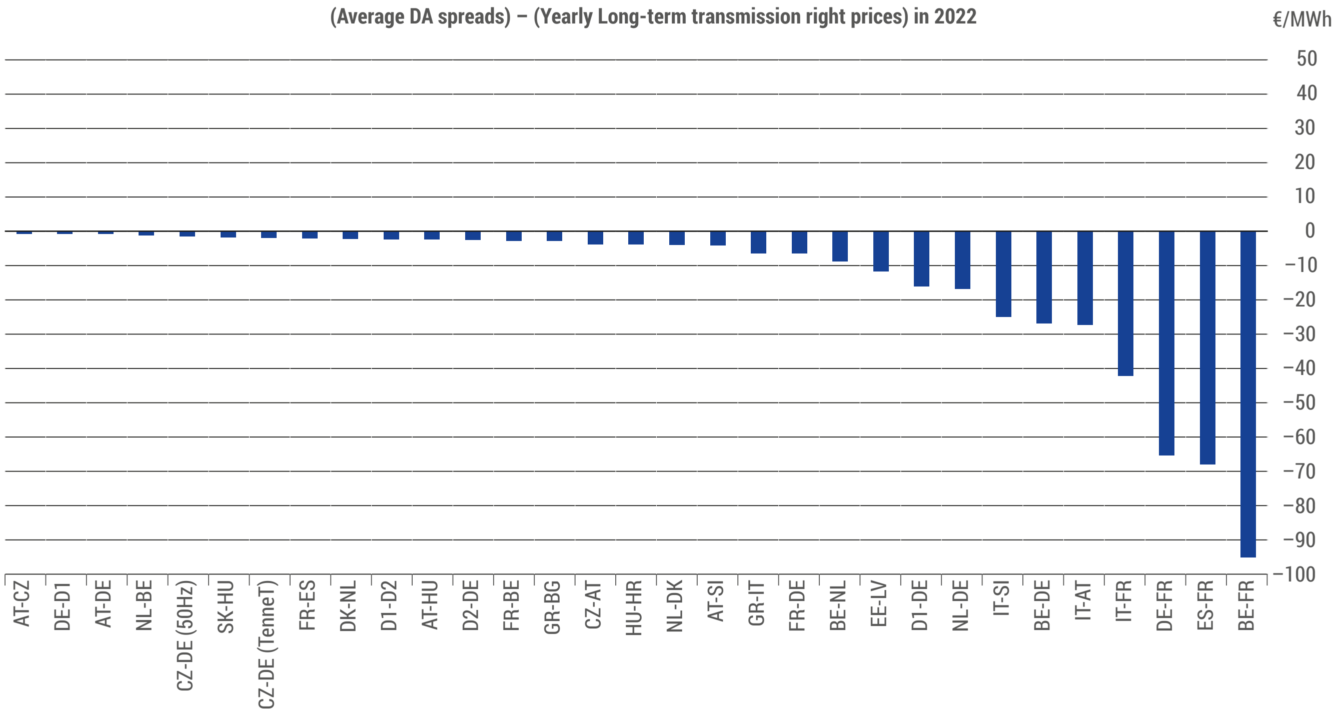


Figure 22: Difference between the average DA price spread and the yearly long-term transmission right prices in €/MWh for 2022 and the yearly long-term transmission right prices in €/MWh for 2022

5 Market Coupling

This chapter has been prepared in cooperation with the All NEMO Committee. The All NEMO Committee 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 2023 to be released by All TSOs and All NEMOs in Q3 2023.

SDAC utilises the DA 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 EUPHEMIA.

SIDC so far enables continuous cross-border trading across Europe. Intraday Auctions (IDAs) are expected to be implemented in 2024. SIDC is based on a common IT system with an SOB, a CMM and a SM. This common IT system facilitates the continuous matching of orders from market participants from several BZs, provided that CZC is available. The IT system also enables multiple NEMOs to participate per country.

5.1 Governance

Following the entering into force of the new joint governance of SDAC and SIDC on 14 January 2022, the joint MCSC was established. The way of working has undergone further optimisation throughout the period covered by this report. The new organigram[49] was approved in September 2022, formalising the establishment of the Joint TSO and NEMOs governance in all Working Groups and Task Forces. The set-up of the Working Groups has been mirrored between SDAC and SIDC to ensure efficiency and to secure synergies between the projects.

A dedicated Market Coupling Consultative Group (MCCG) for market participants with regular meetings was established in February and held its first meeting in June 2022[50]. For the implementation of organisational improvements the Governance TF was set up in early 2023. Moreover, certain responsibilities such as the preparation of the annual CACM Cost Report and the CACM Annual Report were delegated to MCSC from 'All TSOs' governance bodies and the NEMO Committee. To further optimise and harmonise the governance structure of MCSC and to ensure coordinated system provider interactions in the DA cooperation, the SDAC QARM was established at the very beginning of 2023.

In terms of voting principles, QMV was introduced at the steering committee level as of the September 2022 MCSC meeting.

As a next step in the governance optimisation, a single Project Management Office (PMO) team was established in March 2023 to support the integrated governance.

49 See **here**.

50 See **here**.

5.1.1 Single Day-Ahead Coupling

There have been no changes in the membership of SDAC compared to the time of writing of the 2022 market report. As such, SDAC continues to serve 27 countries. In total, 32 TSOs and 17 NEMOs[51] cooperate under the agreement that aims to govern SDAC, namely the DAOA. The agreement was amended in September 2022 in order to implement QMV.

5.1.2 Single Intraday Coupling

In total, 30 TSOs and 15 NEMOs from 27 countries cooperate under the IDOA, the agreement aimed at governing SIDC. With the go-live of the 4th wave of SIDC in November 2022, 25 counties[52] are operational with at least one border. IDOA governs the pan-European SIDC and regulates the cooperation of TSOs and NEMOs regarding the establishment, amendment and operation of the market coupling. As is the case for the DAOA, the IDOA was amended in September 2022 to implement QMV.

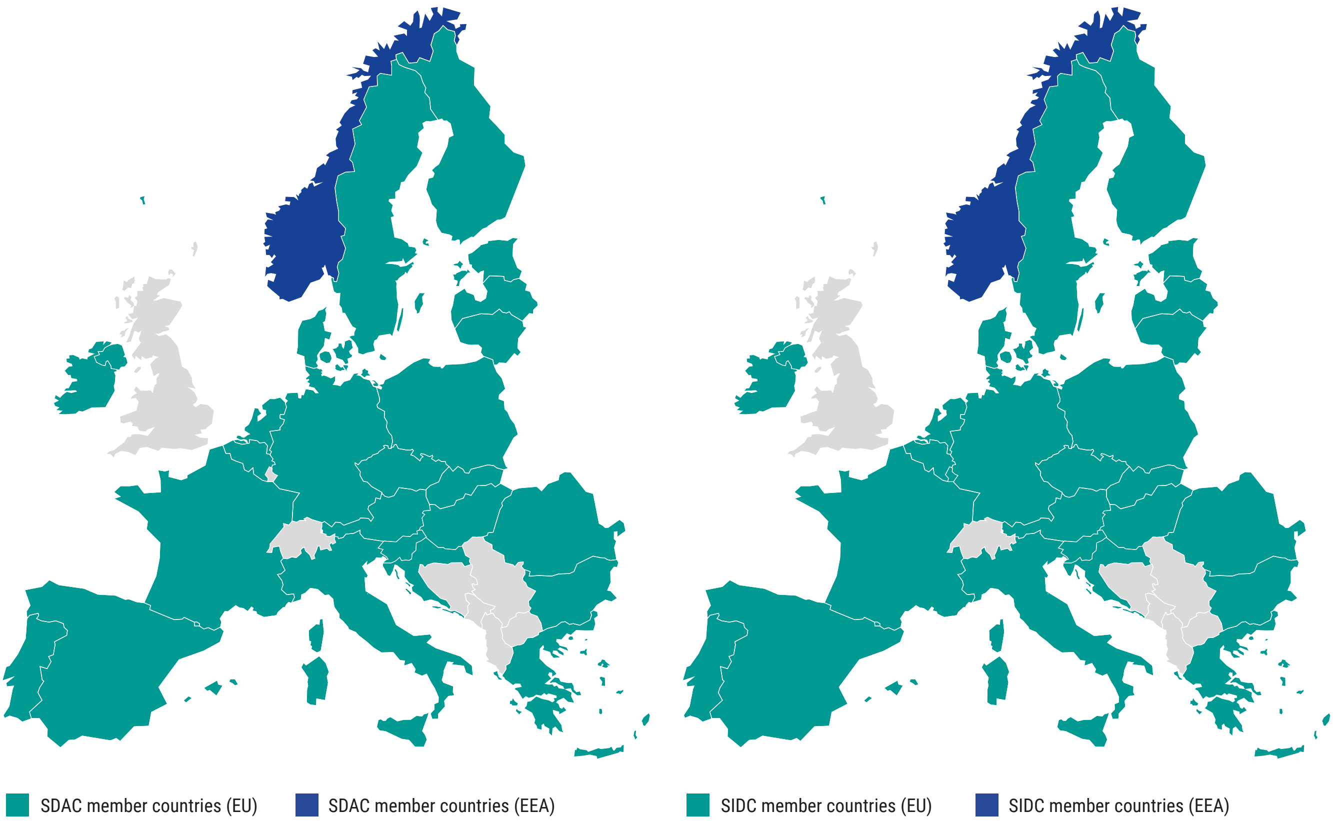


Figure 23: Countries of SDAC (left) and SIDC (right) (as of June 2023)

51 **TSOs:** 50Hertz, Amprion, APG, AST, Baltic Cable, ČEPS, Creos, HOPS, EirGrid, ESO, Elering, ELES, Energinet, Elia, Fingrid, IPTO, Kraftnät Åland, Litgrid, MAVIR, Transelectrica, PSE, REE, REN, RTE, SEPS, SONI, Statnett, Svenska Kraftnät, TenneT NL, TenneT DE, Terna, and TransnetBW.
NEMOs: BSP, SouthPool, CROPEX, EirGrid and SONI acting jointly as SEMOpx, EPEX SPOT, EXAA, GME, HEnEx, HUPX, IBEX, Nasdaq, Nord Pool EMCO, OMIE, OTE, OKTE, OPCOM, and TGE.

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

5.2 Operations

In the context of the energy crisis, the market coupling projects have seen robust operations over the course of 2022 with a continuous roll-out, and optimised interactions between SIDC and SDAC on a project level.

5.2.1 Single Day-Ahead Coupling

The go-live of DA FB market coupling in the Core capacity calculation region (CCR) on 8 June 2022 (for delivery on 9 June)[53] constitutes a major milestone in implementing the CACM Guideline and its target model. In the project leading up to this go-live, 16 TSOs and 7 NEMOs worked together, supported by system providers, IT experts and other professional service delivery firms. Flow-based market coupling in Core – a region spanning from France to Romania and from Croatia to the Netherlands – allows for more efficient utilisation of transmission infrastructure and increased levels of exchange possibilities.

At the same time as Core FB market coupling was introduced, the Multi-NEMO Arrangement (MNA) on the Italy North CCR BZBs was implemented. Italy has a single monopoly; Austria and France, however, have multiple NEMOs operating in their DA and ID markets. The implementation of the MNA on the Italy North CCR BZBs allows for immediate clearing and settlement processes between NEMOs active in Austria and France and the monopoly NEMO in Italy in both SDAC and SIDC.

At the time of this report, SDAC integrates 27 countries, 98,6 % of the EU electricity consumption is coupled and averaging circa 1,530 TWh/year, in one market solution.

Despite generally higher power prices, two events stick out concerning SDAC clearing prices:

- On 4 April 2022, the French power price cleared at close to 3000 EUR/MWh for two consecutive hours (MTU 8 at 2,712.99 EUR/MWh and MTU 9 at 2,987.78 EUR/MWh). This price level was the hereto highest level observed and almost reached the technical limit of 3,000 EUR/MWh/h. As required by the SDAC Harmonised Minimum and Maximum Clearing Prices (HMMCP) methodology[54], the maximum clearing price was increased from 3,000 EUR/MWh to 4,000 EUR/MWh on 10 May 2022.
- On 17 August 2022, the Lithuanian, Latvian and Estonian power price cleared at 4,000 EUR/MWh during MTU 18. Thereby, the technical price limit implemented in May 2022 was reached.

Following Lithuania's power price reaching 4,000 EUR/MWh, ACER requested the NEMOs to amend the HMMCP methodologies for SDAC and SIDC. These amended methodologies were approved by ACER on 10 January 2023[55].

Due to the winter season and an enduring period of high electricity prices, the NEMOs involved in the SDAC in the most affected countries decided to increase the threshold that triggers the second auction procedure from EUR 1,500 to EUR 2,400 per MWh. This change was implemented of 7 December.[56]

SDAC continues to operate successfully without full decoupling. In fact, no full decoupling of markets has occurred since the operation began in February 2014. However, there have been four partial decoupling during this period. The first two occurred on 7 June 2019 and 4 February 2020. The third occurred on 13 January 2021 while the fourth occurred on 10 May 2022 due to technical issues of a local NEMO trading platform.

Other minor operational incidents have occurred since the previous report, some of which have been communicated actively to market participants in line with the SDAC operational procedures. All operational incidents are monitored and analysed on a regular basis. Updates of the processes are introduced via the SDAC operational steering committee (OPSCOM) to mitigate relevant risks. The figure below depicts these two types of incidents.

Details on the incidents can be found in the annual CACM reports.[57]

53 See **here**.

54 See **here**.

55 See **here** and **here**.

56 See **here**.

57 See CACM reports of **2018**, **2019**, **2020**, **2021**, 2022.

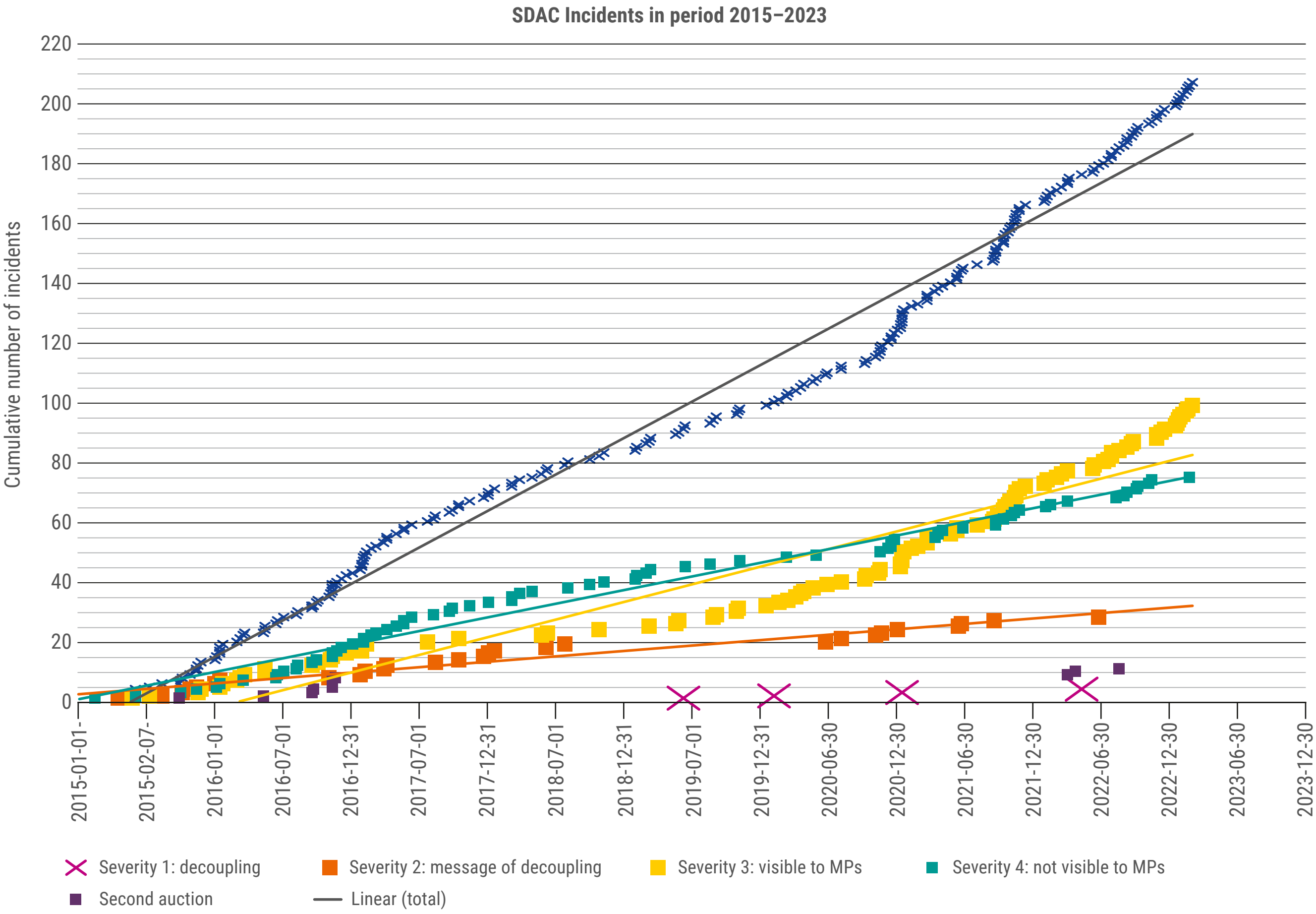
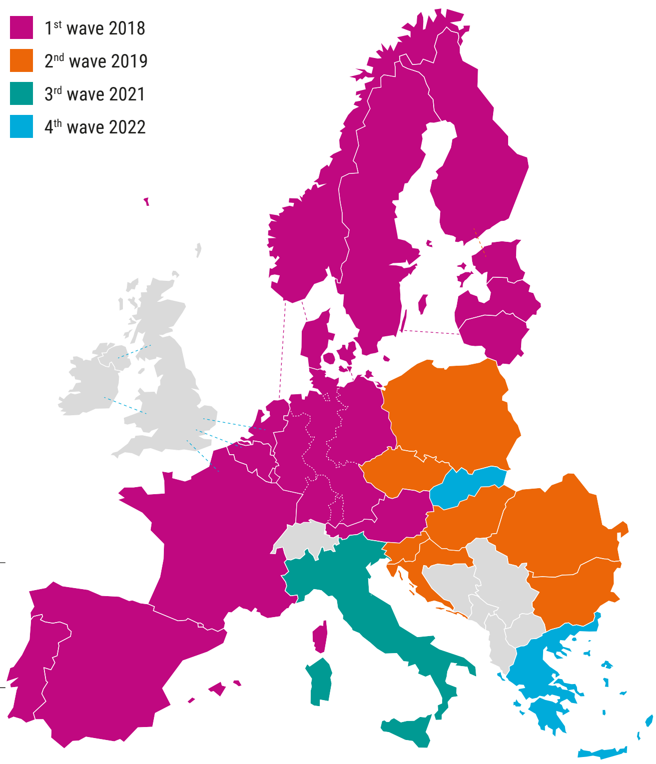


Figure 24: SDAC Incidents in period 2015–2023

5.2.2 Single Intraday Coupling

SIDC has been operational in 15 countries since 12 June 2018. The first delivery was on 13 June 2018[58] and it was subsequently extended by the second go-live wave to seven additional countries (Bulgaria, Croatia, Czechia, Hungary, Poland, Romania and Slovenia), with the first deliveries taking place on 20 November 2019[59]. The third go-live wave[60] on 21 September 2021 integrated the Northern Italian borders (IT–FR, IT–AT and IT–SI) as well as the Italian internal BZBs into the already coupled ID region. The fourth go-live wave[61] took place in November 2022 with Greece and Slovakia. Figure 25 shows the current status of SIDC markets. A new NEMO will soon join the SIDC in Netherlands – preparation for the fifth wave is on-going, with testing campaign and aim for Q2 2023 go-live.

Figure 25: Current Status SIDC Markets



58 See here.
59 See here.
60 See here.
61 See here.

The joint TSOs and NEMOs single ID coupling IT system with one SOB, a CMM and a SM continue to perform operationally robustly[62]. In total, almost 242 million trades have been executed within SIDC since its inception in June 2018 (counting until end of February 2023) (see Figures 26 and 27).

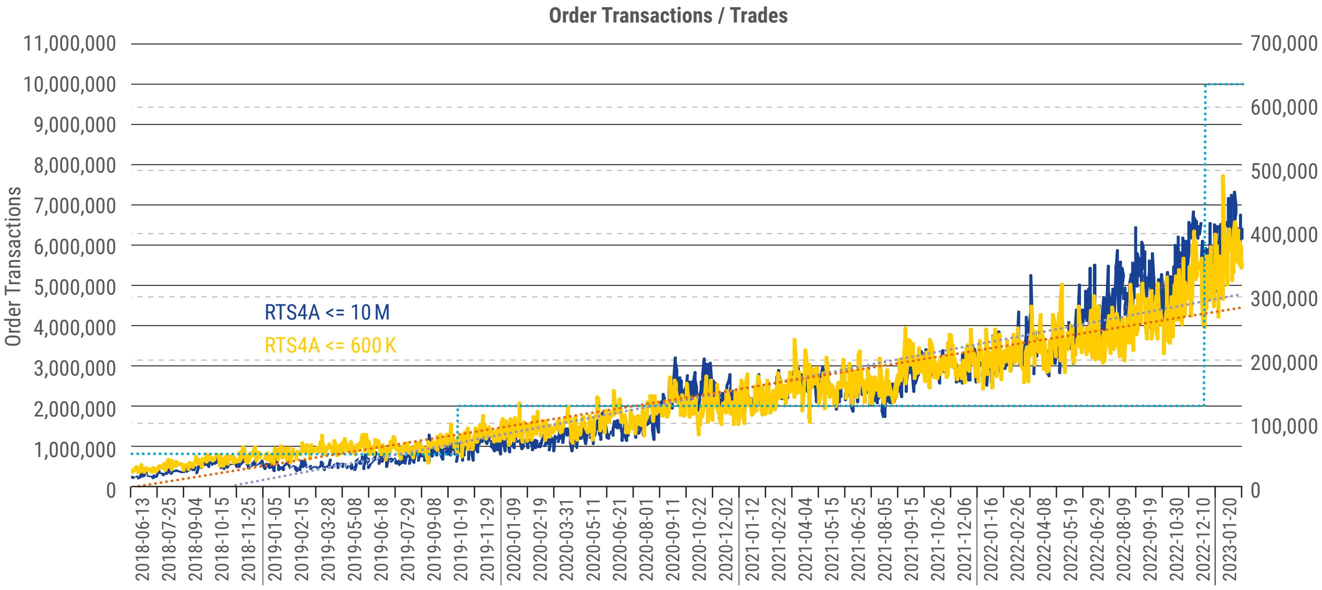


Figure 26: SIDC daily order transactions/trades since 2018

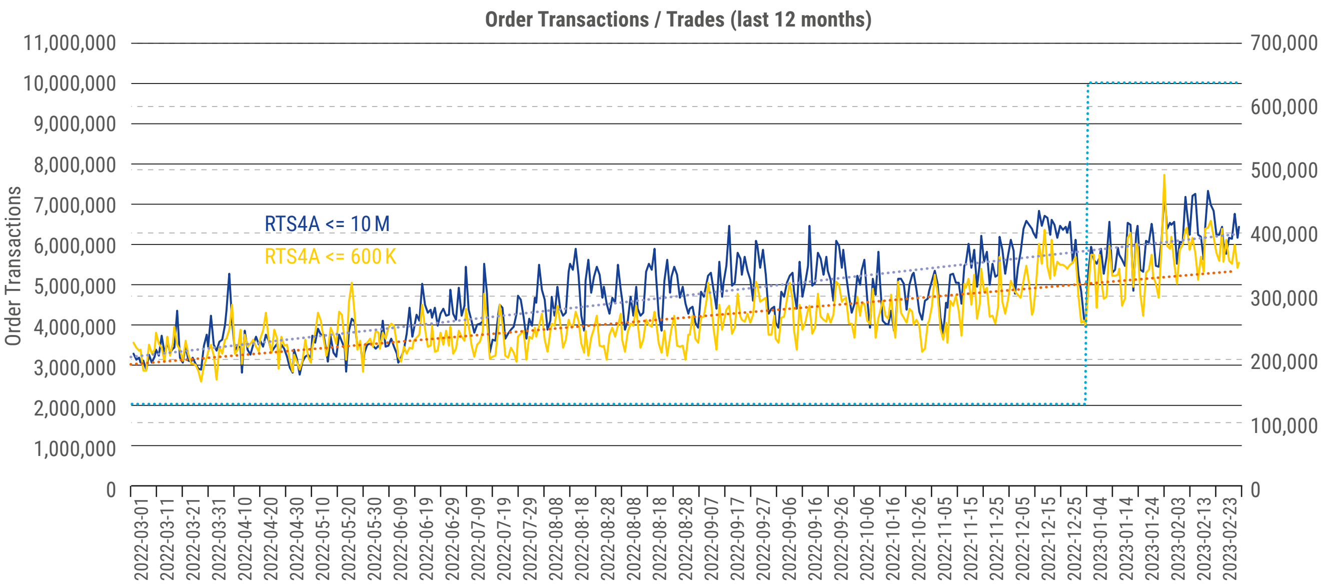


Figure 27: SIDC daily order transactions/trades last 12 months

62 See **here**.

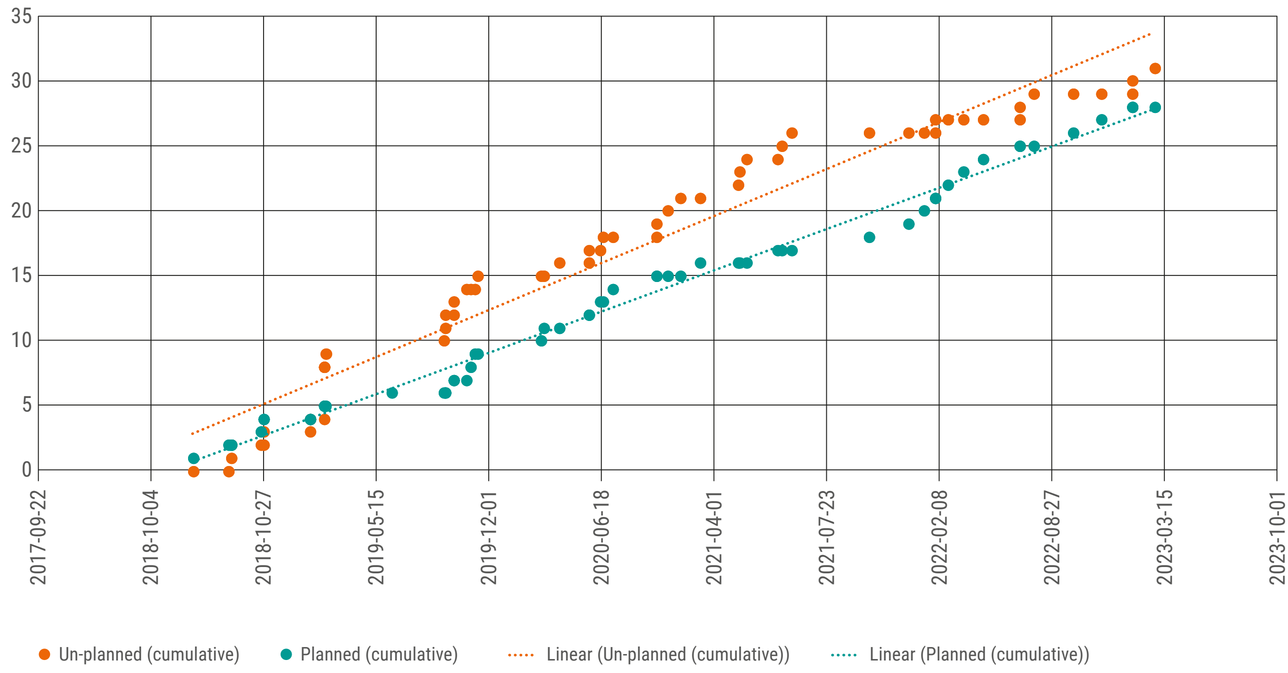


Figure 28: Number of unplanned and planned non-availabilities of SIDC (as of February 2023)

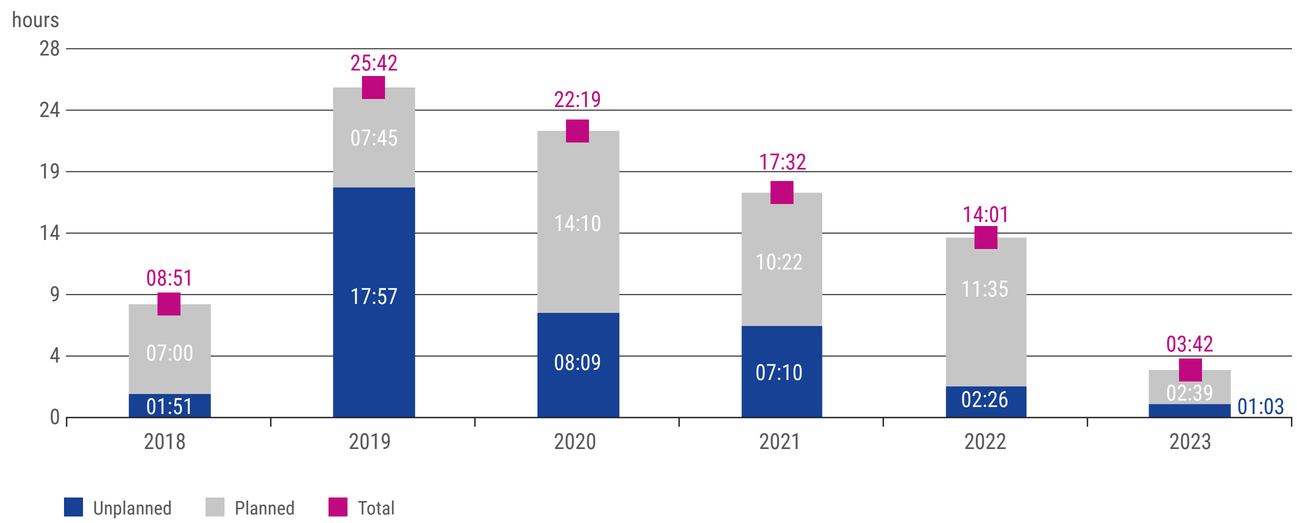


Figure 29: Time of unplanned and planned non-availabilities of SIDC (as of December 2021)

One global critical incident took place[63] on 27 February 2023, when a core failover in the SIDC common IT system occurred due to an issue in the primary data centre leading to a Market Halt. Another global critical incident took place[64] on 25 July 2022 after a message from XBID core failover was received and the SOB WebGUI was not accessible.

Other minor operational incidents have occurred since the previous report, some of which have been communicated actively to market participants in line with the SDIC operational procedures. All operational incidents are monitored and analysed on a regular basis. Updates of the processes are introduced via the SDIC operational steering committee (OPSCOM) to mitigate relevant risks.

In the period covered by this report, two releases were used for production. This concerned the fifth and sixth release, respectively release 3.2 and 3.3. The fifth release (Release 3.2) was focussed on necessary technical updates and was in use for the forth go-live wave. The sixth release (Release 3.3) was developed, tested and approved in 2022 and deployed on 18 January 2023 and covered all performance optimisation measures to fully support the geographical extension of SIDC and newly agreed with the provider Service Level Agreements (SLAs).

63 See here.

64 See here.

CCR	Bidding zone border	GOT as of 2nd go-live wave	Cross-border capacities published at GOT	Point in time cross-border capacity is made available after GOT (effective GOT)	GCT as of 2nd go-live wave
Baltic	EE–FI, EE–LV, LV–LT, LT–SE4,	15:00 CET D-1	0	As soon as possible after GOT	One hour before delivery of MTU
	PL–LT			18:00 CET D-1	
Core	DE–NL, FR–BE, BE–NL, BE–DE, DE–FR, DE–AT, DE–PL, DE–CZ, CZ–PL, CZ–AT, AT–HU, SI–AT, HR–SI, HR–HU, HU–RO, HU–SI, SK–CZ, SK–PL, SK–HU	15:00 CET D-1	0	22:00 CET D-1	
Hansa	DE–DK1, DK1–NL, DE–DK2, NO2–NL, PL–SE4, DE–NO2, DK1–DK2	15:00 CET D-1	0	18:00 CET D-1	
SEE	RO–BG	15:00 CET D-1	0	16:00 CET D-1	
	MA_IT-GR-GR	15:00 CET D-1	0	15:30 CET D-1	
	GR–BG	15:00 CET D-1	0	16:00 CET D-1	
SWE	FR–ES	15:00 CET D-1	0	22:00 CET D-1	
	ES–PT	15:00 CET D-1	Calculated cross-border capacity	N/A	
Nordic	DK1–DK2, DK1–NO2, DK1–SE3, DK2–SE4	15:00 CET D-1	Calculated cross-border capacity	N/A	
	FI–SE1, FI–SE3, NO1–NO2, NO1–NO3, NO1–NO5, NO1–SE3, NO2–NO5, NO3–NO4, NO3–NO5, NO3–SE2, NO3–SE4, NO4–SE1, NO4–SE2, SE1–SE2, SE2–SE3, SE3–SE4	15:00 CET D-1	Calculated cross-border capacity	N/A	
Italy North	MA_IT–CP-FR, MA_IT–CP-AT	15:00 CET D-1	0	22:00 CET D-1	
	MA_IT–CP-SI	15:00 CET D-1	0	22:30 CET D-1	
Italy	Italian internal bidding zones	15:00 CET D-1	0	15:30 CET D-1	

Table 7: Opening times of all currently operational borders

5.3 Expenditures

TSOs and NEMOs provide an annual detailed cost report[65] to ACER and the NRAs in accordance with Article 80 of the CACM Regulation.

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 (all TSOs and all NEMOs). Figures 30 and 31 show the budgeted and actual costs since 2017[66].

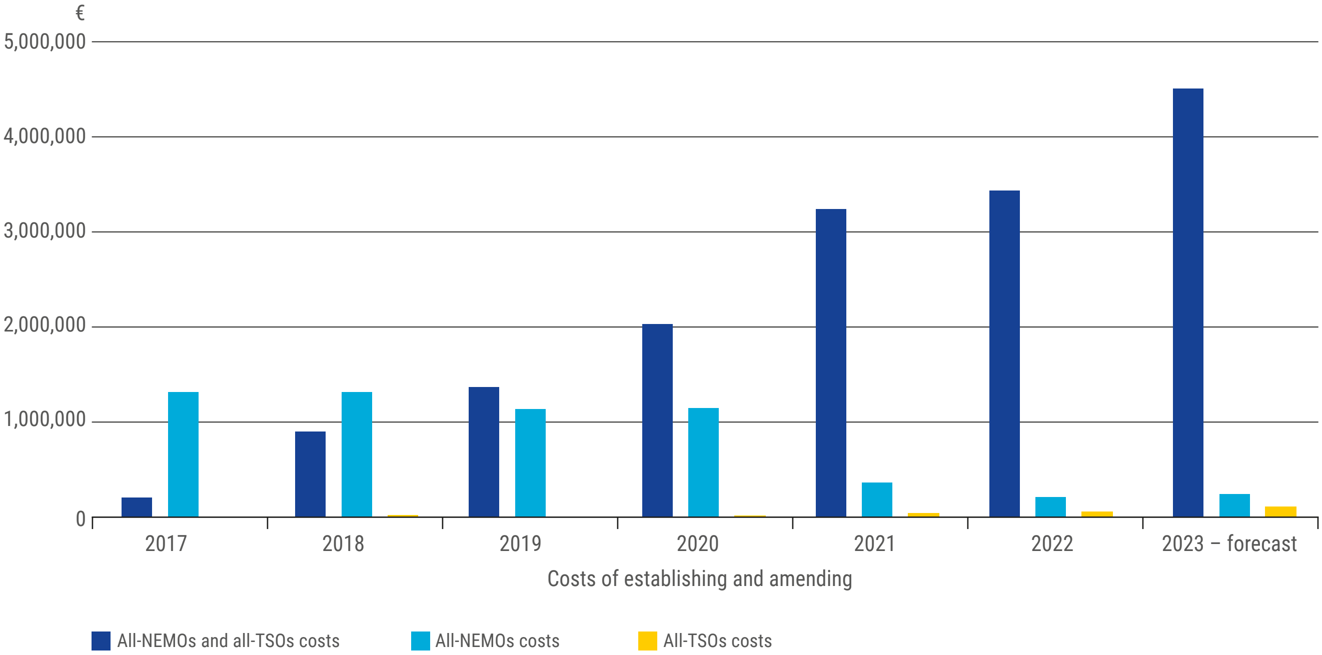


Figure 30: Overview of SDAC for 'all-TSOs costs', 'all-NEMOs costs' and 'all-NEMOs and all-TSOs costs' of establishing and amending

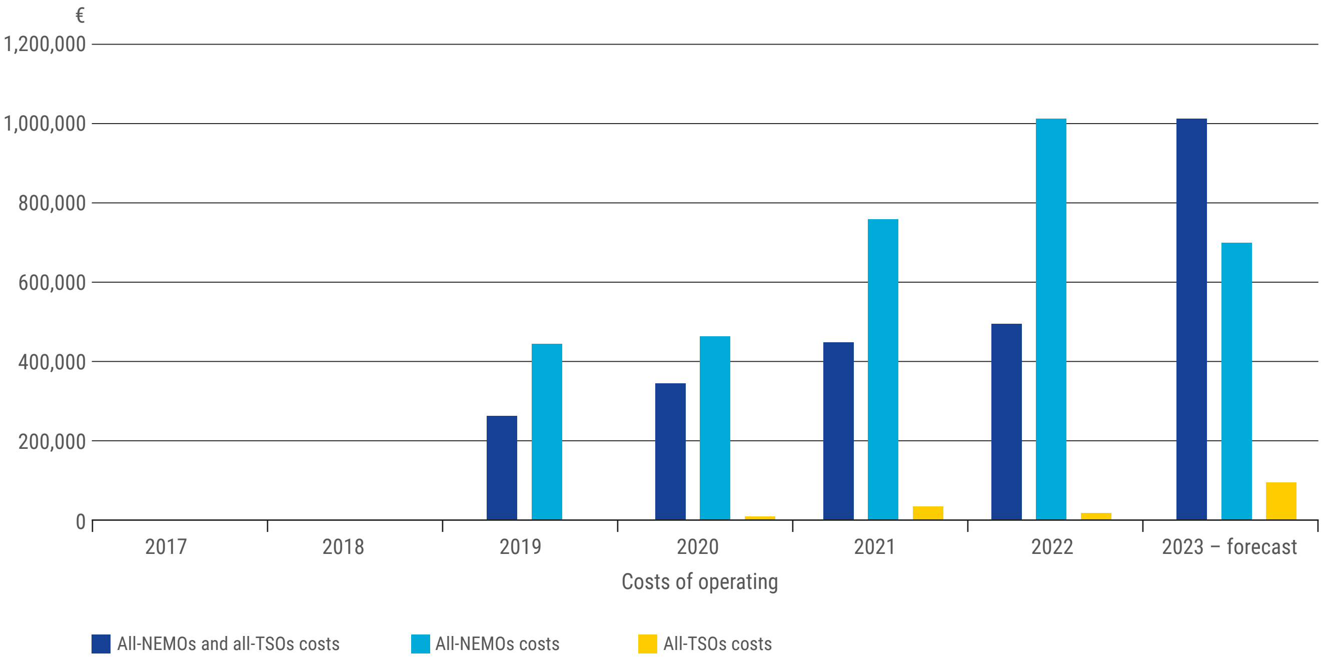


Figure 31: Overview of SDAC for 'all-TSOs costs', 'all-NEMOs costs' and 'all-NEMOs and all-TSOs costs' of operating

65 See CACM reports of **2018**, **2019**, **2020**, **2021**, 2022.

66 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.

All-TSOs costs (e. g. external TSO support), all-NEMOs costs (e. g. third-party services) and all-TSOs and all-NEMOs cost are governed by the respective cooperation agreements (i. e. Transmission Cooperation Agreement [TCID], All NEMO Cooperation Agreement [ANCA) and Single Day-ahead Coupling Operations Agreement [DAOA]).

5.3.2 Single Intraday Coupling

This section provides a summary of common costs of establishing, amending and operating the SIDC, categorised by TSO-only costs, NEMO-only costs and joint costs. Figures 32 and 33 show the budgeted and actual costs since 2017[67].

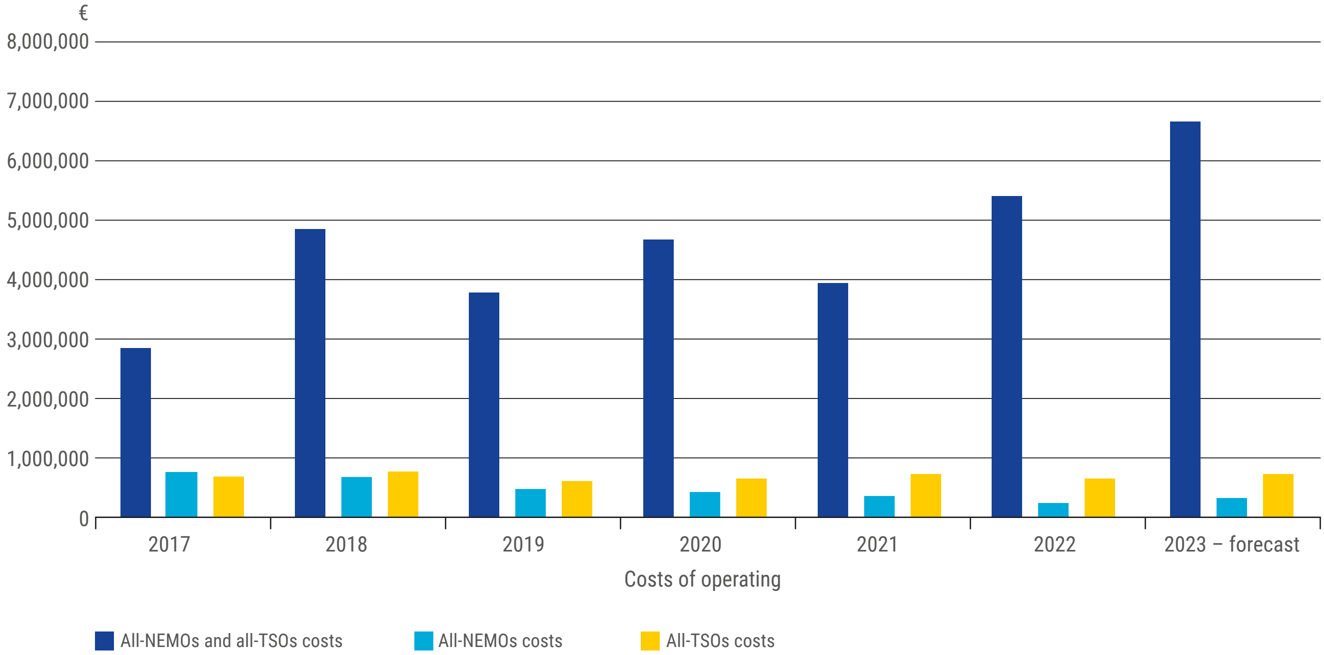


Figure 32: Overview of SIDC for 'all-TSOs costs', 'all-NEMOs costs' and 'all-NEMOs and all-TSOs costs' of establishing and amending

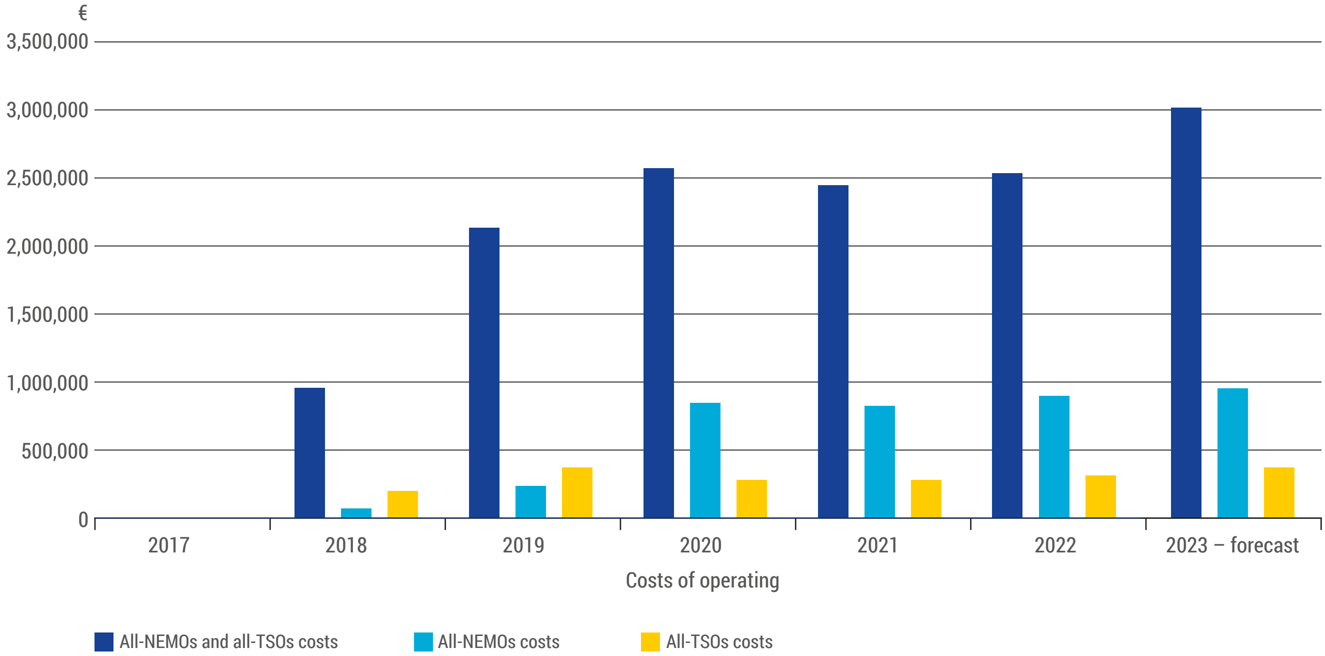


Figure 33: Overview of SIDC for 'all-TSOs costs', 'all-NEMOs costs' and 'all-NEMOs and all-TSOs costs' of operating

67 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.

All-TSOs costs (e. g. external TSO support), all-NEMOs costs (e. g. third-party services) and all-TSOs and all-NEMOs cost (e. g. advanced SIDC solution) are governed by the respective cooperation agreements (i. e. TCID, ANCA and IDOA).

5.4 Evolution of services

5.4.1 Single Day-Ahead Coupling

The SDAC is continuously being developed with respect to topology and system functionalities. Over the current reporting period, the following SDAC functional projects went live:

1. Technological update of PMB and various new releases of both PMB and the EUPHEMIA algorithm. The PMB releases entailed PMB 11.3 (in January 2023) and PMB 12.0 (in March 2023). 11.3 version included technological upgrades only. 12.0 contained needed updates for enabling 15 min MTU, plus some improvements dedicated to NEMOs.

2. Regional implementations of the second auction in case of threshold limits (high, +2,400€/MWh) or low, -150 €/MWh) were reached in the Day-Ahead Market Clearing Prices in Croatia, Estonia, Latvia as well as Lithuania.

3. Improvement of algorithm performance by implementing Scalable Complex Orders for SEMOpx in Ireland.

The remaining planned go-live regards the FR–SEM (representing the joint BZ of Ireland and Northern Ireland) BZB with the Celtic Cable project is planned to go live in 2026. Functional projects that are currently in the pipeline are Hansa CCR 2.0, Baltic MNA, MNA on the FR–ES border, the enduring solution on MNA on the Slovenia–Austria border, 15 min MTU implementation and Nordic Flow-Based, and Advanced Hybrid Coupling in CORE CCR.

Technical advancements were planned and implemented within the period covered by this report, as part of the SDAC research and development programme.

Algorithm improvements are made through the change control procedure and the Algorithm Methodology[68]. Both frameworks aim to address changes efficiently with minimal disruption and controlled risk: the change control procedure sets out the process for implementing changes in the SDAC operations, whereas the NEMO algorithm methodology sets out transparent rules and principles for the management (submission, evaluation, decision and implementation) of requests for changes related to the SDAC algorithm (EUPHEMIA).

Since its launch, EUPHEMIA has been continuously developed further. With the latest releases, changes such as functionalities to support Core FB MC, and the calculation of aggregated curves have been implemented.

Multi-NEMO arrangement

The functionality of handling multiple NEMOs in and between BZs was first utilised in the CWE CCR in July 2019. Since then, this functionality has been sequentially introduced in the Nordics (June 2020), for the Hansa CCR (for NorNed in November 2020; for the Cobra cable and the Danish borders in June 2021), in Poland (for the SwePol cable and LitPol Link in February 2021 and for the remaining borders in June 2021), and the Italian Borders Working Table (IBWT) (June 2022). The Baltic CCR is also a multiple-NEMO region. However, so far only one NEMO is active in this region.

68 See **here**.

Implementation of a 15-minute market time unit considering the granted 15-minute imbalance settlement period derogations

According to the EB Regulation, TSOs should apply an ISP of 15 minutes in all scheduling areas. The deadline for introducing this ISP in all scheduling areas was 1 January 2021, unless regulatory authorities had granted a derogation or an exemption. Article 8 of the EU Electricity Regulation[69] obliges NEMOs to provide market participants with the opportunity to trade energy in time intervals that are at least as short as the ISP for both DA and ID markets. The NEMO algorithm methodology (Article 4(14) (d)) states that NEMOs are obliged to implement 15-minute products together with other future requirements by August 2022. Consequently, a project was established under the SDAC Joint Steering Committee to coordinate implementation of 15-minute products in the DA time frame across the EU (15-minute MTU implementation).

Figure 34: current status of ISP readiness/derogations in each country

Originally, NRAs decided on the gradual implementation of 15- or 30-minute ISPs, which also requires cross-matching (product crossmatching and network cross-matching). Given the impact on the whole 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 with the new go-live expected in Q1 2025. The new updated design and planning were elaborated in September 2022.

The Big bang 15-minute MTU implementation approach means there is one single go-live where every BZ and BZ border in SDAC needs to switch from 60 min MTU data to 15 min MTU data jointly at the same time. The target approach is then that all BZs (and all its TSOs and NEMOs) and BZBs will jointly switch to the final expected MTU setup in Q1 2025, with member testing on SDAC level being foreseen for Q4 2024. An exemption is granted to Ireland where the finest granularity will be 30 min MTU.

From a product design perspective, within a Bidding Zone the Big Bang Approach can still be with products in multiple MTUs, or 15 min MTU products only. SDAC is currently assessing both multiple MTU products and 15 min MTU products only as separate scenarios. The final product set up to be clarified during the second half of 2023.

69 See here.

SDAC is already working on the following measures that are 'must haves' for the 15 min MTU implementation:

- Removal of PUN product from SDAC.
- Transition from Complex order to Scalable complex order.
- Additional time to the algorithm in DA MC process.
- Deployment of the Distributed Computing environment.

Research and development programme

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 carried out under the umbrella of the EUPHEMIA Lab programme, which shows positive results overall and is leading to the industrialisation of promising improvements in the algorithm.

The improvements to be implemented over the next few years will be challenging and require SDAC to revisit the current design. This applies, in particular, to the 15-minute MTU, cross-matching functionality, the implementation of a co-optimisation balancing allocation, increased volume of trades and flow-based in the Nordic CCR. Heuristics or distributed computing are considered an intermediary mid-term solution but are not expected to improve performance up to the required level to handle the 15-minute MTU implementation. Ongoing discussions within SDAC foresee a disruptive solution to meet these and other challenges in the long term.

Flow-based capacity allocation

In line with the legal requirements, flow-based market coupling (FBMC) will be sequentially extended beyond the CWE CCR, where it went live in May 2015. On 8 June 2022, the Core CCR, comprising the former CWE CCR and CEE CCR, introduced FBMC. It is expected that the Nordic CCR will commence operation of DA FB market coupling in 2024. The Core CCR is currently working on the implementation of advanced hybrid coupling (AHC) and Nordic FB is expected to go-live with AHC on the Hansa CCR BZBs and internal borders (comprising the HVDC interconnector and the AC border DE-DK1).

5.4.2 Single Intraday Coupling

Extensions

The SIDC is continuously being developed with respect to topology and system functionalities. In November 2022, the fourth wave went live which integrated the Greek borders (GR–IT and GR–BG)[70] and Slovak borders (SK–CZ, SK–HU and SK–PL)[71].

New functionalities

The development of the market and a geographical extension contribute to an increase in system performance needs. The 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 R3.3 developed and validated at the end of 2022 and released to production in January 2023. From that moment, new improved SLAs were also agreed with the system provider. SIDC is also developing and preparing the testing of the next release (R4.0) which shall be deployed into production towards the beginning of 2024 to support the introduction of IDAs.

70 Terna, ESO and IPTO, and Gestore dei Mercati Energetici SpA (GME), IBEX and HEnEx.

71 ČEPS, MAVIR, PSE and SEPS, and EPEX SPOT, EMCO, HUPX, OKTE, OTE and TGE.

(a) European Intraday Auctions

The current SIDC continuous trading mechanism does not allow for the efficient allocation of CZC when congestion takes place as it is based on first come the first serve principle. Hence, the CZC is not priced. With the implementation of IDAs, SIDC will incorporate implicit auctions, similar to the DA market, leading to a more efficient allocation of CZC when congestion occurs.

Implementation of IDAs is a prioritised project by ACER and Market Coupling Steering Committee. The technical design has been concluded, the first conceptual tests were completed and the testing of central modules and regional systems are ongoing (incl. Euphemia's performance tests). The go-live of IDAs is currently planned for Q2 2024. The main challenges are the coordination of implementation, testing between SDAC and SIDC assets, testing between SIDC project and the different regions, and the performance impact of IDAs and parallel projects.

(b) Cross-product matching

The 60-minute cross-border products are available by default. Several BZs have implemented additional border adaptations to extend cross-border trading opportunities for smaller granularity – 15- and 30-minute cross-border products (see figure 35). The purpose of the cross-product matching feature was to enable products with different delivery periods to be matched and involves matching one order with several others. It enables the matching of 15-minute and 60-minute products, 30-minute and 60-minute products, 15-minute and 30-minute products, and any combination of these (such as two 15-minute products and one 30-minute product with one 60-minute product).

The design of this feature was finalised in 2021 and a prototype in the form of a minimum viable product (MVP) was realised in 2022. However, the results of this MVP have showed several technical and, performance challenges which would negatively impact the system. Such a backdrop in performance and necessary investments were considered significant. The reason why it was agreed with ACER to put this implementation on hold, was to avoid compromising the other developments in the planning (such as IDAs)

Figure 35: Cross-product matching

(c) Flow-based allocation in continuous trading

Two CCRs within the SIDC are currently implementing FB capacity calculation in ID: Core and Nordics. In accordance with the Algorithm Methodology, the allocation of capacity in IDA could stay in ATC until flow-based allocation is implemented in the XBID platform for the continuous trading. This implementation is also a priority of SIDC after the implementation of IDA. Design work has started, including concept and performance analysis with the IT provider. To efficiently address the performance impact, the design and implementation will continue in 2023 with the realisation of a minimum viable product.

(d) Implicit intraday losses

In line with algorithm methodology requirements, the continuous trading matching algorithm shall consider losses on interconnectors between BZs during capacity allocation. Applying the losses will, in most cases, require regulatory approval. Implicit losses prevent electricity from flowing on the interconnector if the price difference between adjacent bidding zones is lower on the losses on the interconnector. Design of Losses are currently on hold, similarly to cross product matching, due to the significant negative performance impact and the necessary technical complex investments needed.

6 Balancing markets

The following sections provide an overview of the main achievements regarding balancing markets accomplished between June 2022 and May 2023 as set out in EB Regulation. The first section focuses on the main features of the implementation of the European balancing energy platforms.

An update on the main accomplishments and new accessions to the already operational platforms TERRE and IGCC is provided. In the case of the new platforms that went live during 2022 (PICASSO and MARI), the chapter provides information about the go-live and initial performance experience at both platforms. In addition, the main features of the cross-platform XB capacity management module (CMM), which is still under development, are provided. The second section addresses the development of regional platforms/applications for reserve sharing or the exchange of balancing capacity purposes. Finally, the third section displays the balancing performance indicators (PIs) calculated for the calendar year 2022, focused on balancing energy and capacity, both on a national and regional level. The source of data for the PI calculation is either data stored at Transparency Platform (TP), inputs received directly from the respective balancing energy and reserve platforms (limited to those platforms which had at least four months of operation in 2022), or data directly provided by TSOs.

6.1 Procurement and Activation of Balancing Energy

The most important achievement accomplished in 2022 is that since October last year all four European balancing platforms are in operation. The go-live of PICASSO took place in June 2022, MARI went live in October 2022, whereas TERRE and IGCC have already been in operation some years. With the go-live of the platforms, the European target model has also been introduced by the already connected TSOs, including the full usage of standard balancing products as the main resource to balance TSOs' systems. Several TSOs must join the MARI and PICASSO platforms in the upcoming years, so further information can be found in the respective accession roadmaps.

In general, there is good progress by TSOs using standard products in Europe by connecting to the different balancing platforms or by previously adapting their local market designs prior to their planned connections.

6.1.1 RR Platform (led by TERRE Project)

The TERRE project is the European implementation project for exchanging replacement reserves in line with EB Regulation[72] (Article 19). The EB Regulation which entered into force on December 18, 2017, provides the technical and operational framework and defines the market rules to govern the functioning of balancing markets. It sets out rules for the procurement of balancing capacity and for the allocation of cross-zonal transmission capacity for cross-border trades, for the activation of balancing energy and the financial settlement of BRPs.

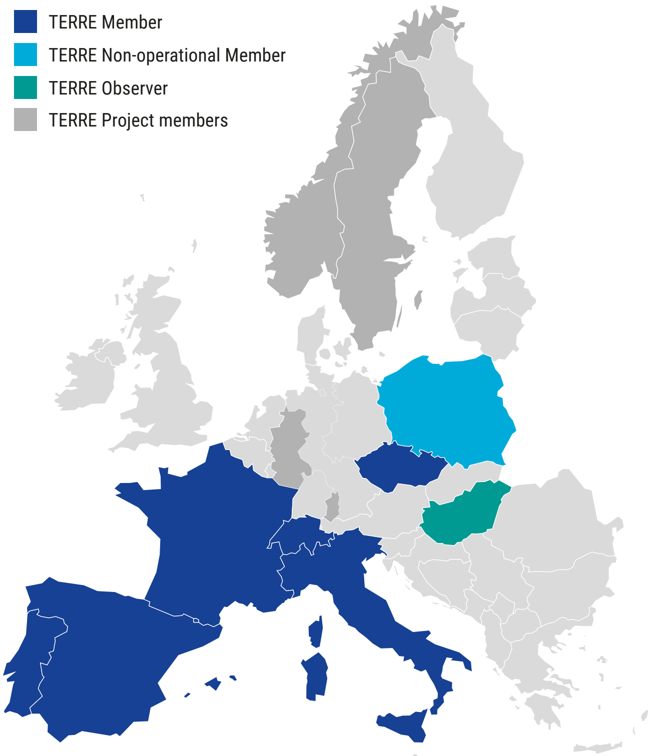
72 See **here**.

Governance of RR Platform

The TERRE project comprises seven TSO members, namely ČEPS, PSE, REE, REN, RTE, Swissgrid and Terna and one Observer: MAVIR

The RR platform (TERRE) has been operational since January 2020. Since then, six TSOs have connected to the platform (ČEPS, REE, REN, RTE, Terna and Swissgrid). PSE will connect in Q2 2024. In April 2021, the TSO National Grid ESO (Great Britain) has given notice to the TERRE Steering Committee on their desire to exit the TERRE project, as part of the decision on Brexit and in line with the provision included in the Cooperation Agreement. After the settlement of all operational, financial, and legal terms including the contractual framework, National Grid ESO will officially exit the TERRE project in December 2022 through an official decision from the project's Steering Committee.

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 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. The LIBRA Platform Management Board (LPMB) is the joint body enabling the cooperation between TERRE, MARI and the Nordics.



TERRE Members (7 TSOs)	
Czech Republic	čeps, a.s.
France	Rte Réseau de transport d'électricité
Italy	Terna
Poland	PSE
Portugal	REN
Spain	RED ELÉCTRICA CORPORACIÓN
Switzerland	swissgrid
TERRE Observers (1 TSO + ENTSO-E)	
Hungary	MAVIR
ENTSO-E	entsoe
Project Members (3 TSOs)	
Germany	amprion
Norway	Statnett
Sweden	SVENSKA KRAFTNÄT

Figure 36: RR platform – TSO part of the TERRE project (as of January 2023)

The TERRE Steering Committee (TSC) is the decision-making body of the TERRE project, granted the ability to make a binding decision on any matter or question related to the TERRE project. Each of the TERRE Members and Observers has a representative in the TSC; however, only TERRE Members, through their representatives, have voting rights.

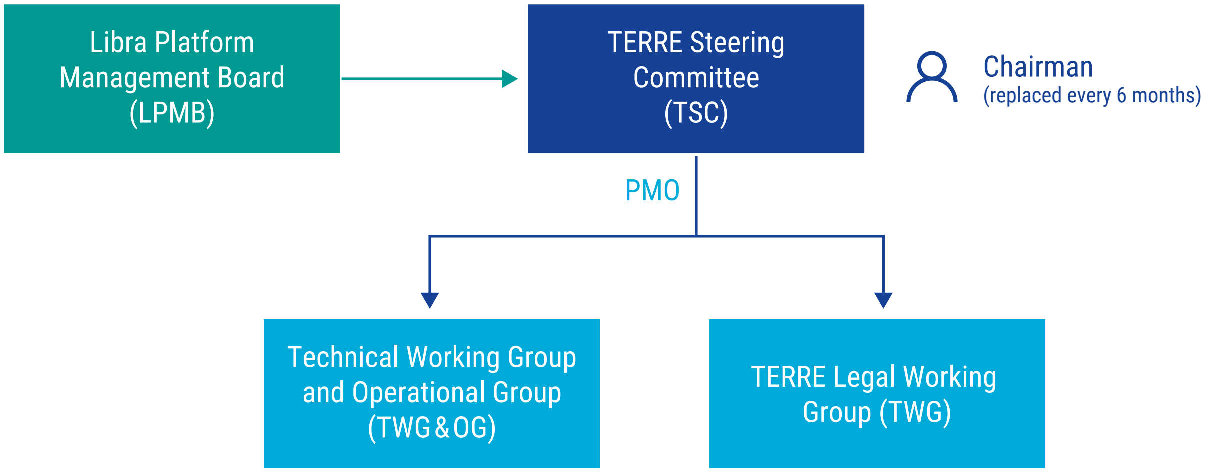


Figure 37: TERRE Governance structure

RR Operation: Market Development

In January 2020, the RR platform went live but it was only until January 2021 that the current six TSOs were connected to the platform. Therefore, the year 2021 marks the first full year of operations with five TSOs exchanging RR products in Region 1 (comprising REE, REN, RTE, Swissgrid and Terna and one TSO (ČEPS) still in isolated mode in Region 2 until the connection of PSE expected in 2024.

The LIBRA platform has proven to be a robust and reliable IT solution. In 2022, there were only 1 critical incident affecting usage of the platform. The bidders on the platform submitted 11.8 million bids amounting to 257,164,919 MWh (monthly offered volumes per direction and per TSO see figure 38).

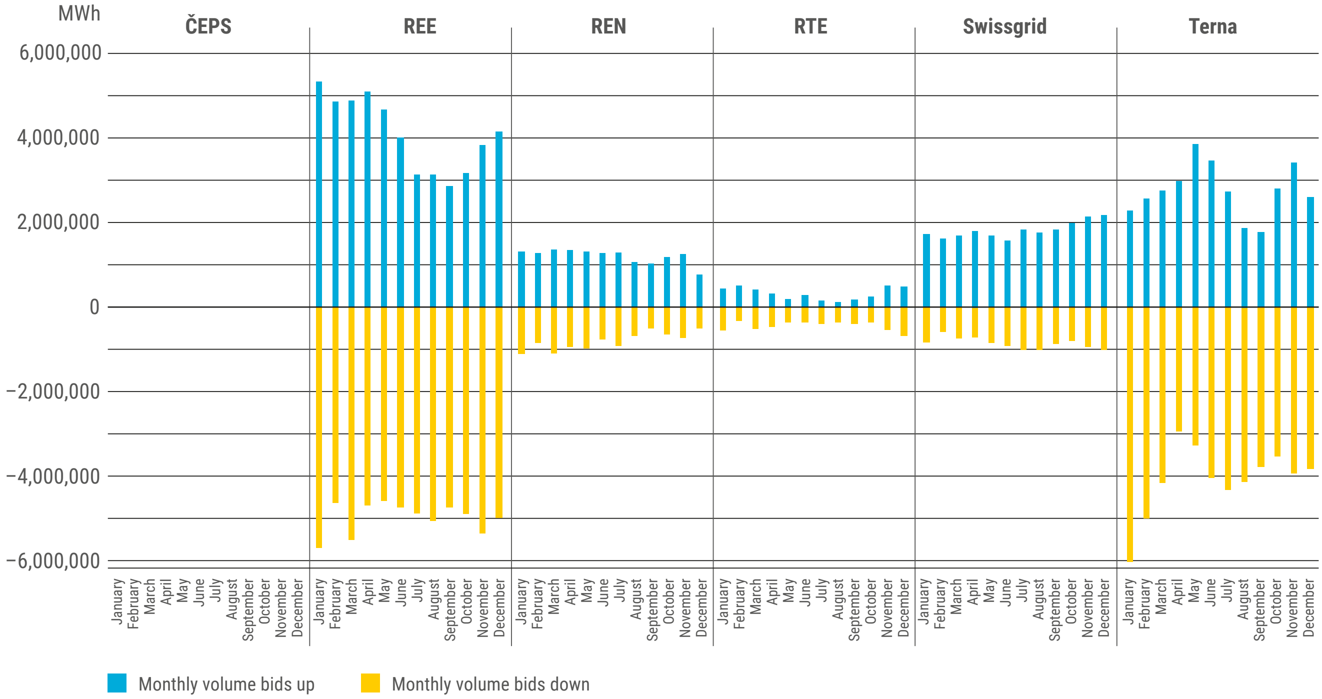


Figure 38: Monthly offered volumes of submitted bids per TSO in 2022 (MWh)

On average, the hourly activations represent 839 MWh (monthly activation volumes per direction and per TSO see figure 39).

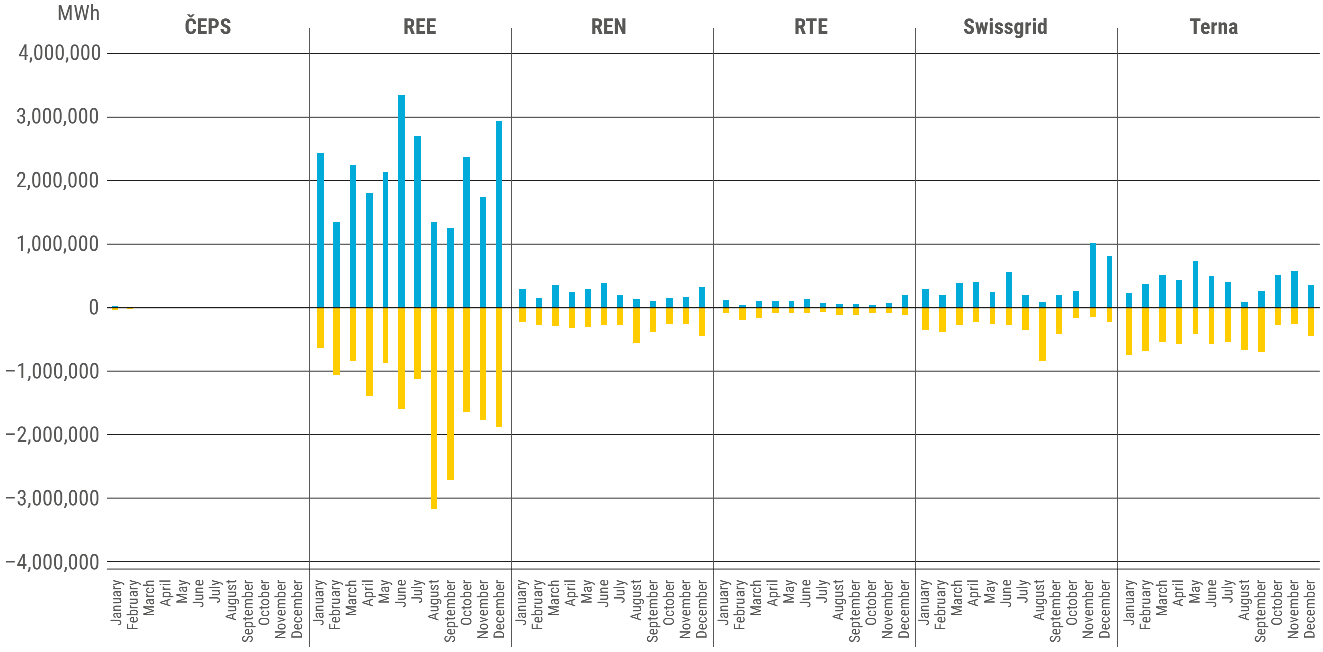


Figure 39: Monthly volumes of selected bids per TSO in 2022 (MWh)

During the previous year, the LIBRA platform allowed some significative financial savings thanks to all RR exchanges registered between TERRE TSOs. Indeed, the global amount saved thanks to these exchanges is estimated to be around 760 million EUR with monthly records in April and June due to high prices and large volumes of demand.Further information on the high-level architecture of the platform can be found in the Market Report 2020[73].

Evolution: Accession and Project Timelines

The accession of the TSO PSE (Poland) is scheduled for the middle of next year, which will effectively enable cross-country exchanges in Region 2. As mentioned previously, National Grid exit the TERRE project as the end of year 2022 following the Brexit. The next steps within the TERRE project implementation are depicted in Figure 40.

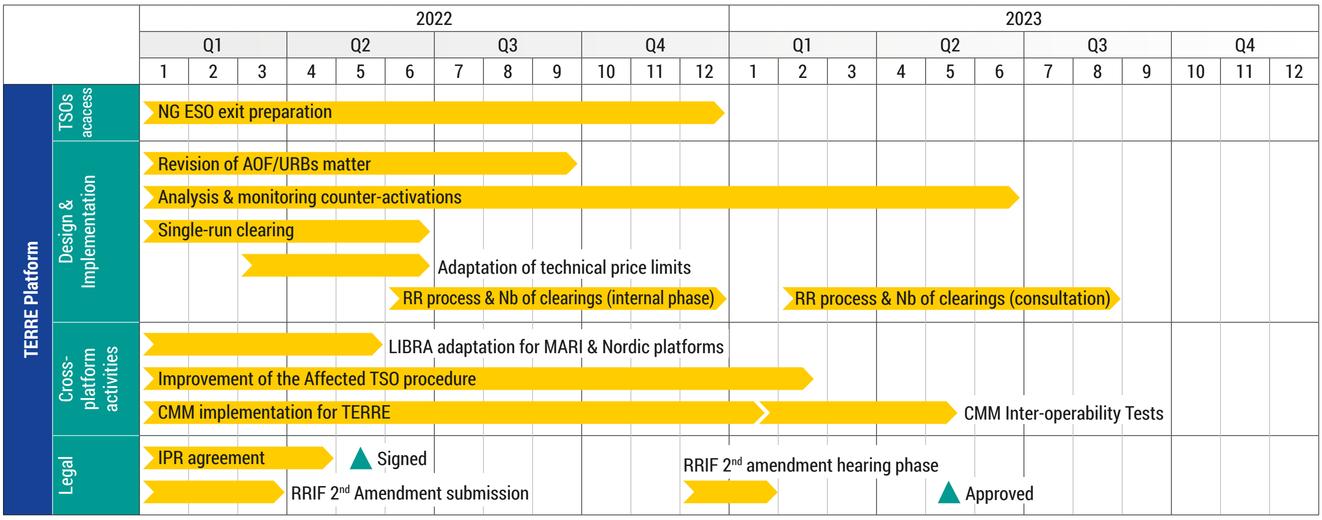


Figure 40: Project planning of TERRE project

73 See here, page 18–21.

The main workstreams, illustrated in figure 40 of the TERRE project can be summarised as follows:

- **NG ESO exit preparation:** legal, financial and operational work to finalise NG ESO exit from the TERRE project.
- **Revision of AOF:** Design and implementation of measures to optimise the algorithm.
- **Analysis & monitoring counter-activations:** Monitoring, evaluation and reporting of the impact of counter-activations on balancing energy prices and on the efficient functioning of the RR Platform.
- **Single run clearing:** Design and implementation of the change following the Pricing and Settlement Methodologies approval by ACER in 2020.
- **Adaptation of technical price limits:** Implementation by 1 July 2022 of the change consisting in applying price limits +/– 15,000 €/MWh, following the Pricing Methodology approval by ACER in February 2022.
- **RR process & number of clearings:** Study and implementation of a Cross-border Scheduling Step to 15 mn in TERRE region and evaluation of the increase of daily gates/clearings. At the beginning of 2023, a public consultation will be launched to gather feedback from market parties on the preferred options.
- **LIBRA adaptation for MARI & Nordic platforms:** Cooperation between TERRE project with MARI and Nordic projects to exchange best practices and identify synergies in the design and adaptations of the LIBRA branches.
- **Improvement of the Affected TSO procedure:** Design and implementation of the Affected TSO procedure (red button functionality) aligned with MARI and PICASSO projects.
- **CMM implementation for TERRE:** Preparation of the connection of the Capacity Management Module to the TERRE platform.
- **IPR (Intellectual Property Rights) agreement:** Drafting, approval and signature of the agreement covering the co-ownership of Intellectual Property Rights for both the MARI and the Fifty (Nordic LIBRA) projects.
- **Second Replacement Reserve Implementation Framework (RRIF) amendment:** Drafting, public consultation, hearing phase and approval of the RRIF amendment.

TERRE Expenditures

The annual expenditures on establishing, amending, and operating the RR platform from 2018 to 2022 are shown in figure 41.

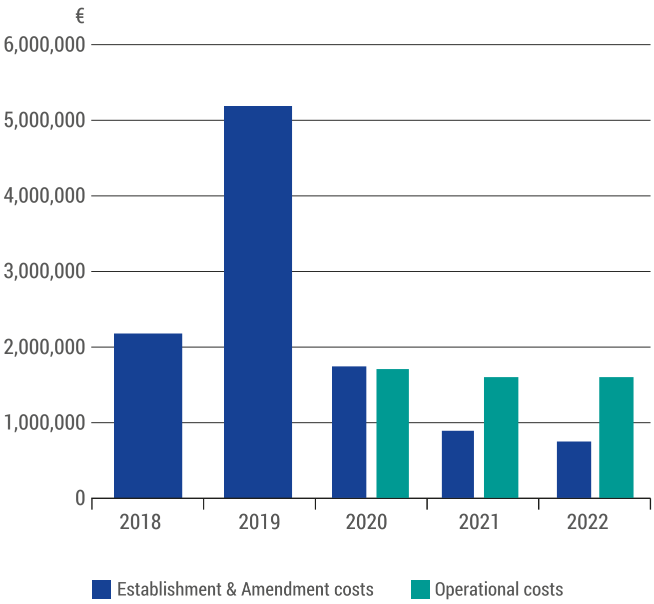


Figure 41: Overview of costs for establishing and operating the RR platform (EUR)

6.1.2 mFRR Platform (led by the MARI Project)

Manually **A**ctivated **R**eserves **I**nitiative (MARI) is the European implementation project for the creation of the European mFRR platform. On 5 April 2017, 19 TSOs signed a Memorandum of Understanding (MoU) that outlines the major cornerstones of the cooperation; this MoU was replaced by a second one in 2018, with two additional TSOs[74]. Three additional TSOs[75] and ENTSO-E have joined the project as observers. In addition, the Ukrainian TSO Ukrenergo is in a process of becoming an observer.

The German TSO Amprion is the Common Service Provider (CSP)[76] for MARI and in this role operates the MARI AOF and TSO–TSO settlement function on behalf of all MARI TSOs.

A major milestone was reached on 15 September 2022, when the MARI platform was launched. The first TSOs then connected on 5 October 2022. The operation of the platform has been stable with few incidents.

The major share of the investment costs for the platform has been incurred in 2021 and 2022 with an accumulated cost of establishment by the end of 2022 of 17.3 million EUR.

As it can be seen in section 6.1.3.4, the majority of the TSOs are planning to connect close to the legal deadline of 24 July 2024 (with derogation).

Governance

The legal governance of MARI is based on EB Regulation Article 20, the implementation framework for mFRR platform (IF), a common Principal Agreement (joint with PICASSO) and subordinate agreements regulating the MARI and PICASSO platforms and the obligations of the CSPs of the platforms.

The governance of the MARI platform is further specified in the IF Article 14 requires that MARI is governed by a Steering Committee (SC) with at least one representative from each TSO. In addition, there shall be one (or more) expert group(s). The following Working Groups (WG) report directly to the MARI SC: IT WG, TSO Testing WG, Technical WG, Legal WG (joint with PICASSO) and Capacity Management Module (CMM) WG.

On 3 May 2022, an Operational Committee (OC) was established by the MARI SC. All participating TSOs[77] have the right to vote. All MARI member TSOs must appoint a representative for this OC. An Operational WG will report to the OC and this will be part of the OC report to SC. Incidents in operation are handled by an Incident Committee.

In addition to the WGs under MARI, there is a budget Task Force (TF) and two joint TFs with TERRE and PICASSO: Stakeholder Management TF and IT Security TF.

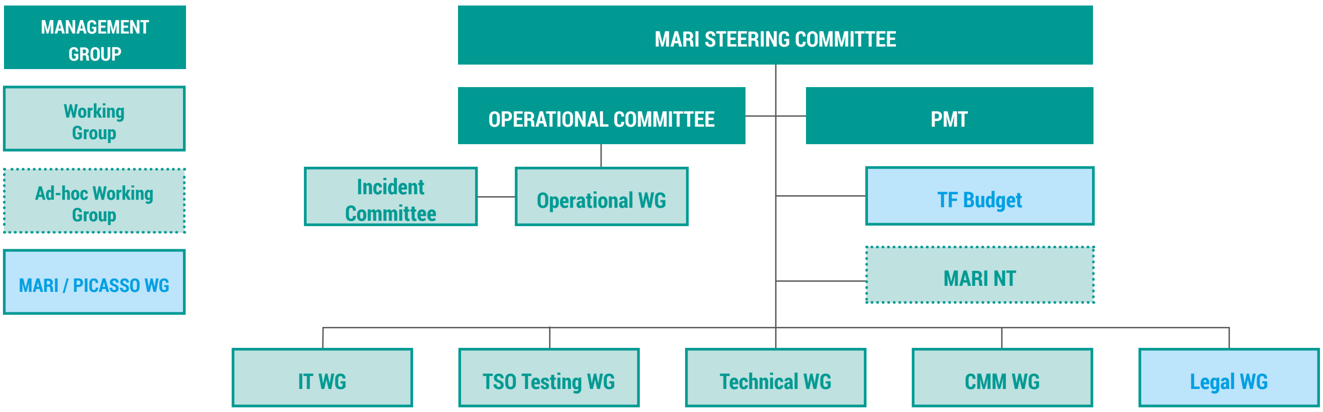


Figure 42: MARI governance structure

74 Member TSOs: 50Hertz, IPTO (ADMIE), Amprion, APG, AST, ČEPS, CREOS, ELERING, ELES, Elia, Energinet, ESO, FINGRID, HOPS, LITGRID, MAVIR, PSE, Red Eléctrica, REN, RTE, SEPS, Statnett, Svk, Swissgrid, TenneT DE, TenneT NL, Terna, Transelectrica and TransnetBW.

75 Observer TSOs: EirGrid, SONI, MEPSO.

76 A CSP means the common service provider of the Common Service Provider Agreement.

77 Participating TSOs means TSOs connected to the MARI platform or that will connect within the next 6 months.

Implementation of the mFRR Balancing Energy Market

According to the EB Regulation, 24 July 2022 was the legal deadline for the go-live of the platform. The daily process on the MARI platform was successfully launched as of 15 September 2022, whereas the German TSOs and ČEPS have been using the platform operationally since 5 October 2022. The war in Ukraine was an indirect reason for the delayed Go-Live of the platform as it led to urgent shifts in prioritisation among TSOs as well as capacity issues for the IT supplier Unicorn, partly based in Kiev. The regulators were duly informed about the delay.

All TSOs connected to the MARI platform submit mFRR balancing energy bids and demands for the joint activation optimisation and exchange of mFRR balancing energy.

Due to the participation of all EU TSOs from all synchronous areas, as requested by the EB Regulation, the MARI project is the largest implementation project in terms of the number of TSOs involved.

Between June 2022 and May 2023, the following main goals have been achieved in the scope of the MARI project:

- Technical Go-Live of the platform on 15 September 2022;
- Market Go-Live of the German TSOs and ČEPS on 5 October 2022;
- Establishment of an operational committee and an operational organisation;
- Release of new versions of the MARI platform with new functionalities and adjustments based on operational experience; and
- Transparency reporting in line with the mFRR IF, EB Regulation and Transparency Regulation.

Expenditures

2021 saw a steep increase in expenditures from 2020, as development activities ramped up significantly. Development activities continued at a high level in 2022 keeping development costs high. The implementation costs were 6.1 million EUR in 2022 with an accumulated establishment cost of 17.3 million EUR by the end of the year. 2022 was the first year with operational costs due to the technical and market Go-Live on 15 September and 5 October respectively. Operational costs reached 0.7 million EUR in 2022.

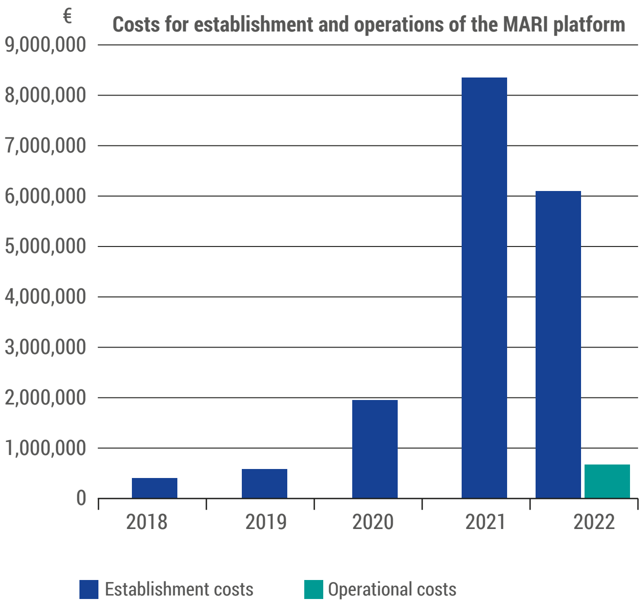


Figure 43: Costs for establishment and operations of the MARI platform

Evolution: Implementation Timeline and TSOs Accession Roadmap

According to Article 5.4.(b) of the IF, all TSOs shall establish the roadmap for the implementation of the mFRR platform and update it at least twice per year: In April and October (until all TSOs are connected).

This roadmap, including national derogation details can be found in the sixth accession roadmap[78] developed by the TSOs.

mFRR-Platform Accession Roadmap

Last updated on 20 April 2023 based on latest information available.

	mFRRIF		2023: 1 2 3 4 5 6 7 8 9 10 11 12	2024: Q1 Q2 Q3 Q4
mFRR-Platform	5.4.(b)(ii)	AOF		
	5.4.(b)(ii)	TSO-TSO Settlement		
	5.4.(b)(vi)	Testing functions & mFRR operation		
	5.4.(b)(iii)	TSOs Interoperability tests		
	5.4.(b)(iv)	Operational tests (parallel run)		
	5.4.(b)(v)	TSOs Connection / Go-live		
	5.4.(b)(vi)	mFRR-Platform Go-live		

Country	Derogation deadline[1]	TSO	2023: 1 2 3 4 5 6 7 8 9 10 11 12	2024: Q1 Q2 Q3 Q4
Germany		50Hz/Amprion/ TenneT Gmbh/ TransnetBW		
Greece	24.7.2024	IPTO[2]		
Austria		APG		
Latvia	24.7.2024	AST[3]		
Czech republic		ČEPS		
Estonia	24.7.2024	ELERING[3]		
Slovenia		ELES		
Belgium	24.7.2024	Elia[4]		
Denmark	24.7.2024	Energinet[5]		
Bulgaria	30.6.2024	ESO[6]		
Finland	24.7.2024	Fingrid[3]		
Croatia	24.7.2024	HOPS[7]		
Lithuania	24.7.2024	LITGRID[3]		
Hungary	24.7.2024	MAVIR[8]		
Poland	24.07.2024	PSE[9]		
Spain	24.07.2024	RE[10]		
Portugal	24.07.2024	REN		
France	24.07.2024	RTE[11]		
Slovakia	24.07.2024	SEPS[12]		
Sweden	24.07.2024	SVK[3]		
Netherlands		TenneT BV[13]		
Italy	24.7.2024	Terna[14]		
Romania	01.03.2024	Transelectrica[15]		
EEA				
Norway	24.07.2024	Statnett[3]		
Non-EU Member State				
Switzerland		Swissgrid[16]		

78 See **here**.

- 5.4.(b)(i) / National terms and conditions development
- 5.4.(b)(iii) / Interoperability tests between TSO and mFRR-Platformforce
- 5.4.(b)(vii) / EBGL Article 62 Derogation considered / requested / granted
- 5.4.(b)(i) / National terms and conditions entry into force
- 5.4.(b)(v) / TSO connection to mFRR-platform / Go-live

1 The technical Go Live of the MARI plattform was 15 September 2022, while the first TSOs connected 5 October.
2 IPTO was granted a derogation by the NRA until 24.7.2024. The plan presented in this roadmap shall be regarded as a preliminary, non-binding estimate.
3 Derogation request submitted by Baltic TSOs is approved by the Baltic NRAs. According to the NRAs decision, the planned connection time will be aligned with the Nordic TSOs, expected in Q2 - Q3 2024, but not later than 24.07.2024.
4 Elia was granted a derogation by the NRA until 24.7.2024
5 The plan presented in this roadmap shall be regarded as a preliminary, non-binding estimate. The planned connection time is expected in Q2 2024.
6 ESO – derogation was granted by local NRA until 30.06.2024.
7 HOPS – derogation was granted by local NRA until 24.7.2024.
8 MAVIR – derogation was granted by local NRA until 24.7.2024.
9 PSE derogation was granted by local NRA until 24.7.2024.
10 RE derogation has been granted by the NRA until 24.7.2024.
11 RTE was granted a derogation by the French NRA until 24.7.2024. However, at least one additional year will be required for RTE to connect to the MARI platform in order to ensure the operational security of the French electrical system. RTE will make its best effort to share its ATC before 24.7.2024.
12 SEPS – derogation was granted by local NRA until 24.7.2024.
13 TenneT NL aims for implementation and go-live by July 2024 and has a requested a derogation until then. However, there is a real riks that the final derogation will take place even later than the requested derogation period. If TenneT takes these risks into account, TenneT expects to participate in the summer of 2025 to participate in the mFRR platform and TenneT will enter into discussions with relevant stakeholders if it becomes clear that the risks already in the planning manifest themselves.
14 TERNA – derogation was granted by local NRA until 24.07.2024.
15 Transelectrica – derogation granted by local NRA until 01.03.2024.
16 The technical readiness of Swissgrid has been acknowledged. The participation of Switzerland in the mFRR-Platform is regulated based on article 1.6 and 1.7 of the EB Regulation and currently the subject of litigation by Swissgrid at the Court of Justice of the European Union.

Table 8: Sixth mFRR-Platform Accession roadmap

6.1.3 aFRR Platform (led by the PICASSO Project)

The PICASSO project is leading the design and implementation of the aFRR platform, which comprises 26 TSO members and 4 observers. Since 2017, the PICASSO project was responsible for TSOs implementing the aFRR European platform. On 1 June 2022 the platform has been brought successfully into operation (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 PICASSO project leads the development of the aFRR platform in close coordination with other implementation projects via ENTSO-E and International Grid Control Cooperation (IGCC) project (see subsection 4.4 of this report).

Further information on the governance and the high-level design can be found in previous reports, such as in the ENTSO-E Market Report 2021 or Balancing Report 2022.[79]

Main achievements

Especially in the time frame between June 2022 and May 2023 the go-live preparation and the go-live itself on 1 June 2022 were in the focus of the project group. With ČEPS accession on the go-live date and the accession of APG and the four German TSOs later, on 22 June these TSOs were the first with a national market for balancing energy from aFRR in operation and that are connected to PICASSO in accordance with the EB Regulation.

Furthermore, following points can be highlighted:

- Creation and revision of main documents such as an implementation guide;
- Finalisation of the design of the AOF setup, constituting the go-live release;
- Design, implementation and testing of Non-Real-Time communication interface;

79 ENTSO-E **Market Report 2021**: Chapter 6.1.4.2 for high-level design of the platform / ENTSO-E **Balancing Report 2022**: Chapter 3.1.2 for governance structure

- Security approach and business impact analysis;
- Completion of Factory Acceptance Testing, Site Acceptance Test of AOF together with different interoperability tests;
- PICASSO approved the TSO–TSO Invoicing Agent Agreement (which was signed in 2022 by MARI on behalf of the MARI, PICASSO and IGCC projects); and
- Development of a transparency and reporting concept for stakeholders.

PICASSO expenditures

The annual expenditures on establishing, amending, and operating the aFRR platform from 2018 to 2022 are graphed and shown in figure 44. The 'Costs for establishing and amending' include general project costs (such as project management costs for Project Management Office (PMOs), convenors and secretary), costs for the development of the algorithm (including developing, software and hardware costs), third party costs (like for the invoicing process) and finally other common costs (like change requests).

From 2021 to 2022 the general project costs stayed nearly constant. The significant increase of costs for 2022 can be explained by the fact that in this year the costs for the development of the IT and algorithm were included as well as (in comparison minor) costs for third parties and other common costs in the values. In particular, the IT development costs can be seen as one-time costs so it is expected that the costs will sharply decline in the following years.

Note: Since the platform went 2022 into operation, there are no operating costs for the years before.

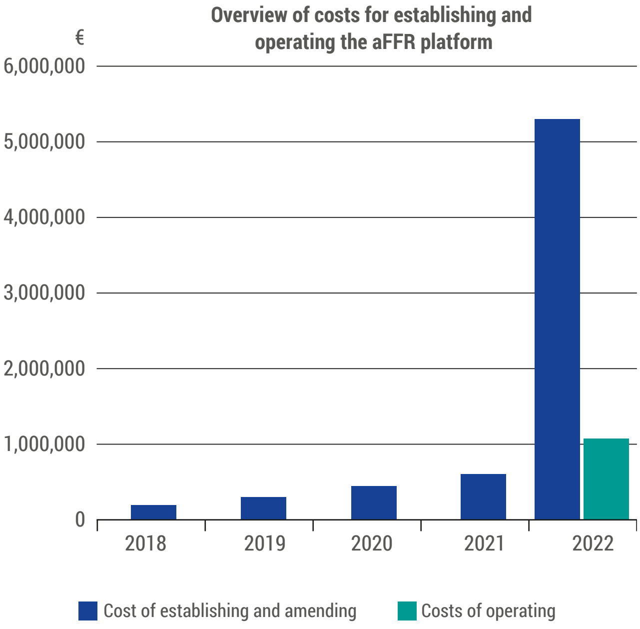


Figure 44: Overview of costs for establishing and operating the aFRR platform

PICASSO Evolution: Implementation Timeline and TSOs Accession Roadmap

According to the aFRR implementation framework, the TSOs must develop and update the platform's implementation timeline (Table 1). The accession of new PICASSO TSO members to the aFRR platform is planned in accordance with the accession roadmap. Further detailed information can be found in the sixth accession roadmap[80] developed by TSOs that are members of the aFRR platform. This accession roadmap is updated at least twice a year to provide stakeholders with current information on the developments. Compared to the last report, the following dates represent a much more accurate estimate of the go-live and derogation dates.

80 Sixth aFRR-Platform Accession roadmap, published April 2023

aFRR-Platform Accession Roadmap

Last updated on 28/04/2023 based on latest information available.

	mFRRIF		
mFRR-Platform	5.4.(b)(ii) 5.4.(b)(ii) 5.4.(b)(vi) 5.4.(b)(iii) 5.4.(b)(iv) 5.4.(b)(v) 5.4.(b)(vi)		AOF (done) TSO-TSO settlement (done) Testing functions & aFRR operation (done) TSOs Interoperability test (done) Operational test (parallel run) (done) TSOs Connection to aFRR platform / Go-live aFRR-Platform Go-live (done)

Country	Derogation deadline[1]	Connection date	TSO
Austria		22.06.22	APG
Belgium[1]	24.07.24	12.06.24	Elia
Bulgaria	30.06.24	31.03.24	ESO
Croatia	24.07.24		HOPS
Czech republic		01.06.22	ČEPS
Denmark[2]	24.07.24		Energinet
Finland[2]	24.07.24	01.06.24	Fingrid
France	24.07.24		RTE
Germany		22.06.22	50Hz, AMP, TNG,TTG
Greece	24.07.24	01.07.24	ADMIE
Hungary	24.07.24		MAVIR
Italy	24.07.23	24.07.23	Terna
Netherlands[3]	24.07.24		Tennet BV
Poland	24.07.24		PSE
Portugal			REN
Romania	01.03.24		Transelectrica
Slovakia	24.07.24	01.06.24	SEPS
Slovenia		01.07.24	ELES
Spain	24.07.24		REE
Sweden[2]	24.07.24		SVK
EEA			
Norway[2]	24.07.24		Statnett
Non-EU Member State			
Switzerland[4]			Swissgrid

5.4.(b)(i) / National terms and conditions development

5.4.(b)(i) / National terms and conditions entry into force

5.4.(b)(iii) / Interoperability tests between TSO and mFRR-Platformforce

5.4.(b)(v) / TSO connection to mFRR-platform / Go-live

5.4.(b)(vii) / EBGL Article 62 Derogation considered / requested / granted

1 A first version of the T&C has entered into force early May when local bidding has been adapted and a second one will enter into force when ELIA will connect to PICASSO.

2) The plan presented in this roadmap shall be regarded as a preliminary, non-binding estimate. The planned connection time is expected in Q2 2024.

3) TenneT NL aims for implementation and go-live by July 2024 and has been granted a derogation until then. However, there is a real risk that the final derogation will take place even later than the requested derogation period. If TenneT takes these risks into account, TenneT expects to participate in the summer of 2025 to participate in the aFRR platform and TenneT will enter into discussions with relevant stakeholders if it becomes clear that the risks already in the planning manifest themselves.

4) The technical readiness of Swissgrid has been acknowledged. The participation of Switzerland in the aFRR-Platform is regulated based on article 1.6 and 1.7 of the EB Regulation and currently the subject of litigation by Swissgrid at the Court of Justice of the European Union.

Table 9: Accession Road map of the aFRR platform (as of April 2023)

6.1.4 IN Platform (led by the IGCC Project)

The International Grid Control Cooperation (IGCC) is the implementation project chosen by ENTSO-E in February 2016 to become the European Platform for the imbalance netting process (IN-Platform) as defined by EB Regulation Article 22 and established in the Implementation Framework for a European platform for the Imbalance Netting process (IN IF)[81].

IGCC was launched in October 2010 as a regional project and has grown to cover 26 countries (29 TSOs) across continental Europe, including all those that need to implement the IN-Platform according to the EB Regulation.

IN Governance

The design and implementation of the IN platform is led by the IGCC implementation project which counts 29 TSO members and observers in 26 countries[82]. Two TSOs were connected to IGCC until April 2023: EMS (Serbia) in October 2022 and ESO (Bulgaria) in March 2023. Ukrenergo (Ukraine) has officially approached the project to become an observer at the end of the 2022 year.

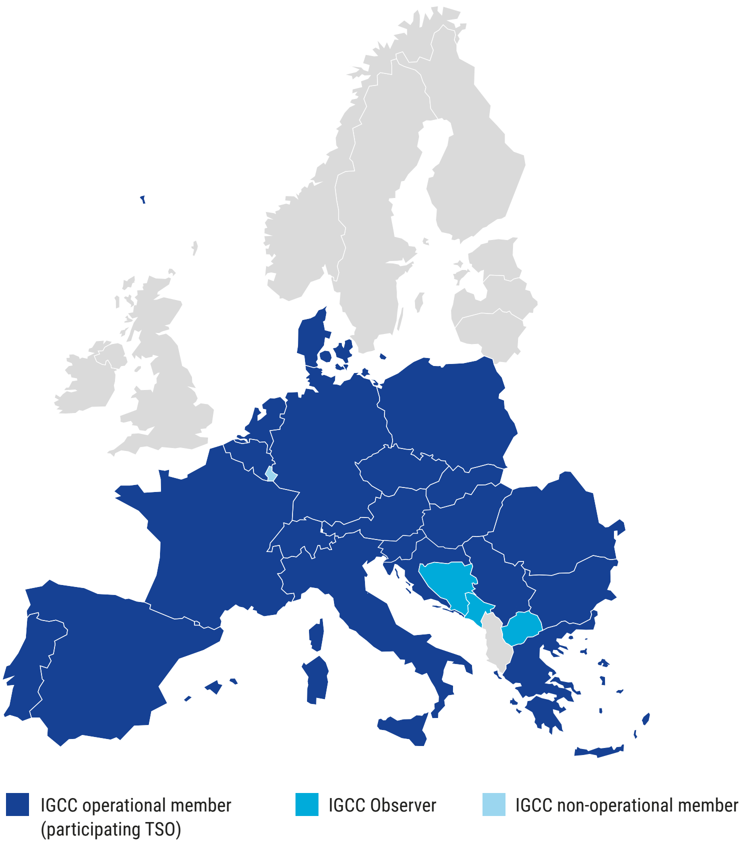


Figure 45: IN platform: TSO members of the IGCC implementation project

81 See **here**.

82 23 TSOs are operational members: 50Hertz, Amprion, APG, ČEPS, HOPS, Elia, Energinet, ELES, EMS, ESO, IPTO, MAVIR, PSE, REE, REN, RTE, SEPS, Swissgrid, TenneT NL, Transelectrica, TransnetBW, TenneT DE and Terna; 1 TSO is a non-operational member: Creos; and 3 TSOs serve as observers: Crnogorski elektroprenosni sistem, NOS BiH and MEPSO along with ENTSO-E.

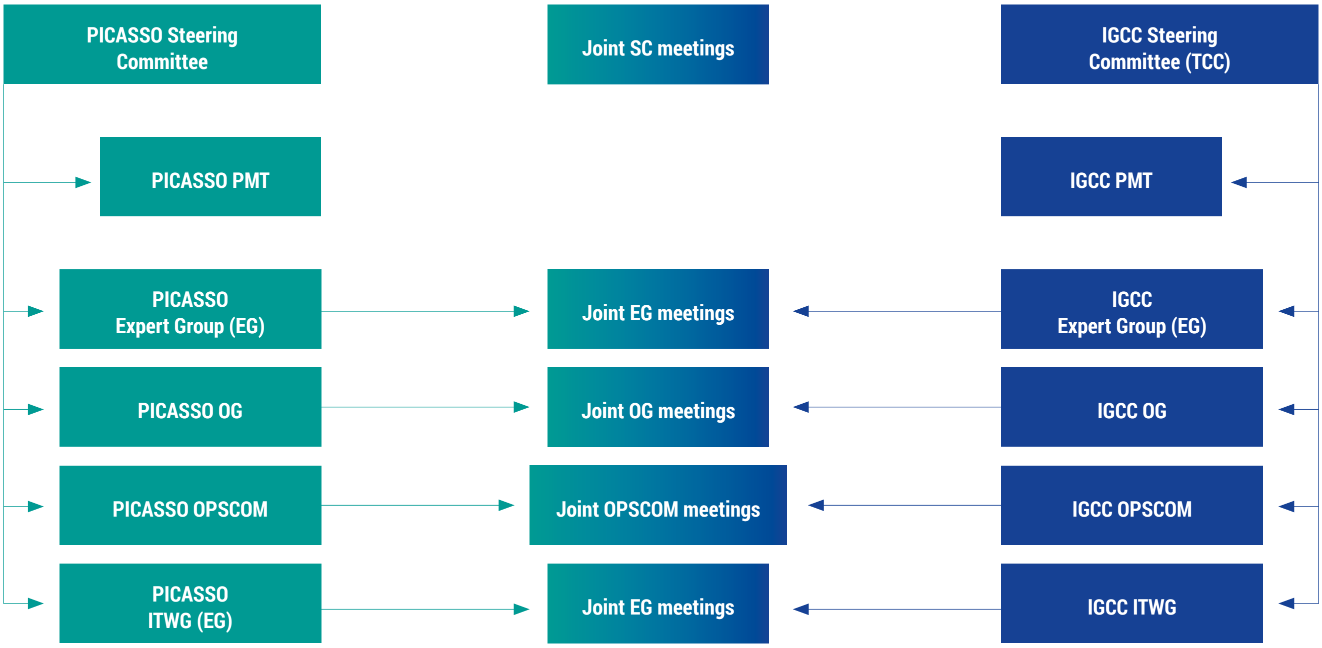


Figure 46: PICASSO and IGCC governance structure

At end of Q1 2022, PICASSO and IGCC projects launched a common project management and meetings organisation capitalise on the numerous similarities of both projects. Governance structures and decisions processes remain separated.

Operation of the IN Platform

Further information on the high-level design of the IN-platform can be found in the ENTSO-E Balancing Report 2020[83].

- Performance indicators on Monetary saving due to imbalance netting

The increase in the participation of TSOs in the imbalance netting process has enabled energy savings to reach a record of more than 1 TWh in March 2022, corresponding to a value of monthly savings of nearly 80 million EUR. Not only does this have a positive effect on the more efficient energy usage, but the additionally available aFRR capacity leads to an increase in the security of the European electricity transmission system.

The quarterly evolution of volumes and financial savings on the netted imbalances (figure 46) shows a decorrelation between both indicators and the impact of PICASSO go-live during Q3 2022.

The cumulative savings generated through international cooperation by IGCC since the start of the project in October 2011 up until Dec 2022 have surpassed 1 billion EUR. The data related to the IN-platform has been published on the Transparency Platform since June 2021.

The reports on imbalance netting volumes are published on a dedicated site at ENTSO-E[84].

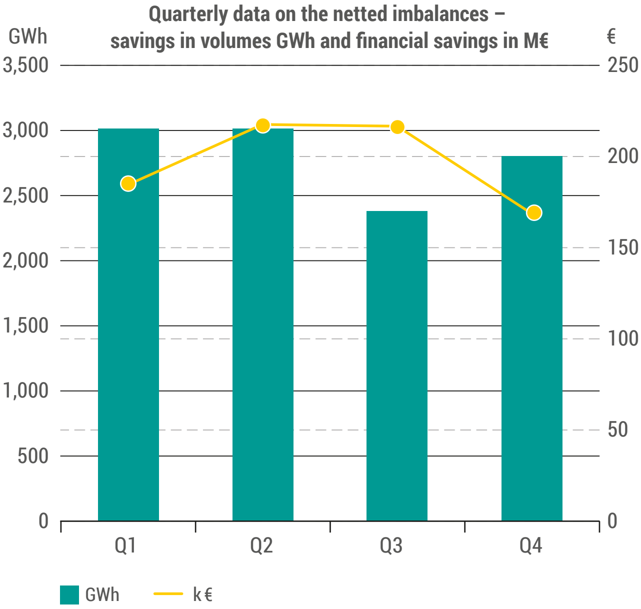


Figure 47: IN Platform quarterly savings in volumes GWh and financial savings in Euro

83 See here, page 29.
84 See here.

IGCC Evolution: TSOs Accession Roadmap

Serbia (EMS) became operational on 20 October 2022 and Bulgaria (ESO) on 1 March 2023.

IGCC Expenditures

The annual expenditures on establishing, amending, and operating the IN platform from 2018 to 2022 are shown in the graph below.

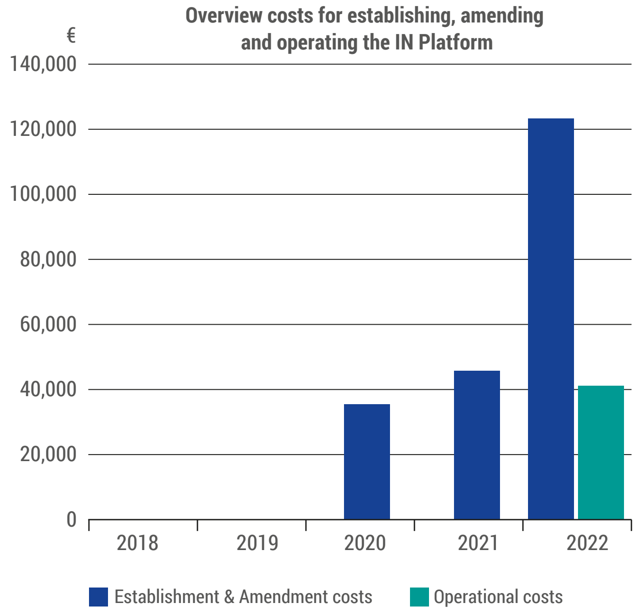


Figure 48: Overview costs for establishing, amending, and operating the IGCC platform (reflecting the development of the IGCC project into the IN platform)

6.1.5 Capacity Management Module

All the European balancing platforms must be provided in real time with the available cross-zonal capacity limits (CZCL) to optimise the cross-border activation of balancing energy. It is the responsibility of the TSOs of the respective border to provide and manage the capacities while respecting the operational security limits. TSOs have agreed to implement a centralised approach to capacity management via dedicated IT tool, that would allow TSOs to provide, manage and amend the CZCLs for all balancing platforms.

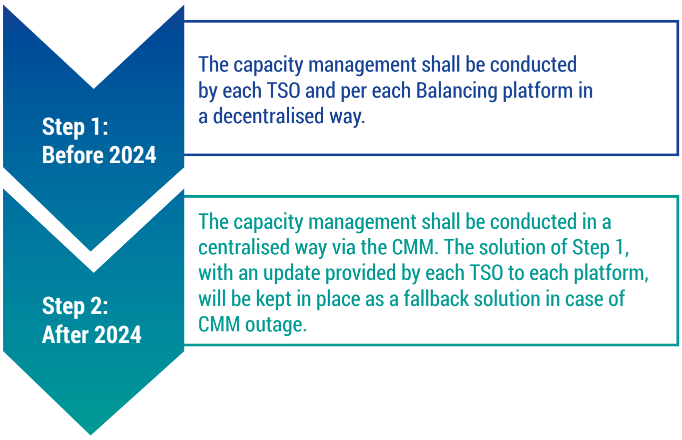


Figure 49: Capacity Management approach

Through the year 2022, TSOs were developing the Capacity Management IT tool, with the aim of testing and going live with the so-called minimum viable solution by the end of 2023. The following figure represents the high-level design of the Capacity Management Information Technology (CM IT) tool:

- Each TSO sends the information about the CZC calculated for the ID timeframe and the information about the already allocated capacity during the previous timeframes (long-term, DA, ID) for the relevant borders;
- Each TSO in a balancing capacity cooperation, or a dedicated TSO per a balancing capacity cooperation sends the information per border about the already allocated capacity for exchange of balancing energy in relation with exchange or sharing of balancing capacity;
- In addition, each TSO may submit additional limits to the available capacity (in the form of CZC limit max or net position limits), according to operational conditions.
- The CM IT tool determines the CZCL after ID for each border and sends the information on the relevant borders to the RR platform;
- The CM IT tool receives the optimised flows on the borders from the RR platform and determines the CZCL to be sent to the mFRR platform on the relevant borders;
- The CM IT tool receives optimised flows on the borders from the mFRR platform and determines the CZCL after each mFRR AOF run (either direct or scheduled);
- The CMM forwards the CZCL on the relevant borders to the aFRR and IN platforms. As the same IT system is used for aFRR and IN platforms, the CMM sends the data for both platforms at the same time. The updates between aFRR and IN processes are managed by the platforms IT solution;

› At any point in time, the TSOs can update their operational situation data (for example, in the case of an application of the affected TSO procedure[85]); and

› The CMM stores all the data related to capacity management.

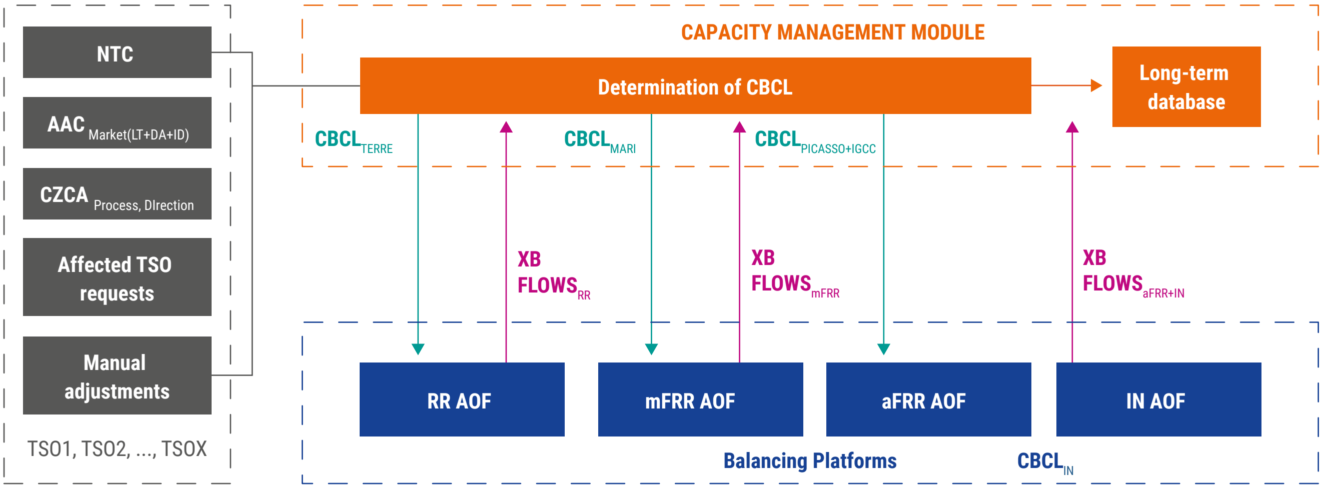


Figure 50: CMM high level design

6.2 Reserve Platforms Development

This section provides an overview of the existing reserve platforms in Europe which are operating on a voluntary basis.

6.2.1 Nordic aFRR Market

Several CCRs submitted market-based (EB Regulation Article 41(1)) methodologies to their respective NRAs in 2019, including the Nordic countries, which were approved in the case of Nordic initiative, by ACER in 2020, as is shown in table 10.

Region	Submitted methodology	Current status	Details
Baltic	Market-based (Art. 41)	Approved	Final approval of methology by ACER received 13.8.2021
Nordic			Final approval of methology by ACER received 13.8.2021
Core			Final approval of methology by ACER received 8.5.2020
Greece & Italy			Final approval of methology by NRAs (with amendments) received 22.6.2021

Table 10: market-based (EB Regulation Article 41(1)) methodologies

The harmonisation of the general principles of allocation methodologies among all CCRs was done through the harmonised CZCA methodology, which eventually replaced all previous CCR methodologies.

The Nordic TSOs successfully launched the Nordic aFRR capacity market according to plan, 7 December 2022, and will switch to the harmonised CZCA methodology as soon as it is available. The Nordic TSO will assess the market results when sufficient data are available. The results will be presented for market participants/stakeholders via the NORDIC BALANCING MODEL web and/or locally by each TSO.

The next projects during 2023 will be the first step in the launch of 15 min imbalance settlement and a common mFRR capacity market between DK1 and DK2 in Denmark. The mFRR capacity market is built on the same platform as the aFRR capacity market and will later be expanded to the whole Nordic.

85 The input data that can be updated at any time is the one provided by each TSO for their borders (NTC, AAC (Already Allocated Capacity), CZCA, CZCL (cross-zonal capacity limits), NPL (net position limit), etc.). Furthermore, the affected TSO procedure enables a TSO to establish limitations to the available capacity on a border to which is not directly connected.

6.2.2 German–Austrian aFRR Balancing Capacity Cooperation

The cooperation called 'AT–DE–BCC' was created end of 2017 with the intention to allocate not more than 80 MW of CZC for the exchange of aFRR between Germany and Austria. German TSOs and Austrian TSO APG want to extend the current cooperation to other TSOs (including Czech TSO ČEPS) for the common procurement of aFRR BC through a BC platform called 'ALPACA'. The initial interest concerned the application of the CORE market-based methodology as a basis. However, since the implementation of the CORE-market-based allocation method takes longer than initially expected, ALPACA is pursuing the application of the probabilistic method in accordance with Article 33(6) EB Regulation. It should be noted that ALPACA and AT–DE–BCC are two independent cooperations, but both focused on the common procurement of aFRR. The AT-DE-BCC actually allocates CZC and, therefore, a firm CZC allocation for balancing capacity exchange is the result. In ALPACA, however, the probabilistic methodology is applied, with no CZC allocation and no fixed balancing capacity exchange.

Market Development in 2022

The cooperation has defined a maximum of 80 MW for the allocation of CZC. As already stated in the Market Report 2020, the optimisation will be performed on both a monthly and weekly basis. The result of the monthly optimisation will be considered in the monthly capacity auction by JAO for the upcoming month. The result of the weekly optimisation will be limited by the monthly result which it re-evaluates. In the event the result of the weekly optimisation is smaller than the monthly result, the difference will be returned to the energy market within the ID increase or decrease process. The monthly and weekly optimisation uses the same methodology, but the weekly optimisation is based on more recent data. The result of the weekly optimisation is used as a limit for the common procurement optimisation.

This process was not changed in 2022. However, due to the connection to PICASSO and the introduction of balancing energy markets with 15-minute products in Germany and Austria the optimisation algorithm had to be slightly adjusted according to the validity period of the balancing energy market as well as the change from the pay-as-bid regime to pay-as-cleared for balancing energy.

Furthermore, six TSOs (ČEPS, APG and German TSOs) have formed the ALPACA cooperation (**A**llocation of CZC and **P**rocurement of **a**FRR **C**ooperation **A**greement), with TenneT NL, MAVIR, ELES and HOPS observing the progress. Within ALPACA, the TSOs intends to commonly procure the aFRR balancing capacity, by the application of the probabilistic methodology according to Art. 33 (6) EB GL. This cooperation will complement the ongoing DE–AT aFRR capacity cooperation which firmly allocates CZC for the exchange of balancing capacity between Germany and Austria which will remain after the go-live of ALPACA.

In 2023, the ALPACA cooperation intends to implement the probabilistic methodology by the second half of 2024 on the borders between AT–CZ and DE–CZ, to start the common procurement of aFRR balancing capacity in 2024. The application of the probabilistic methodology is an intermediate step and will most likely result in an application of the harmonised market-based allocation process proposed in the all TSOs methodology submitted pursuant to Article 38(3) of EB Regulation. ALPACA TSOs intend to apply this methodology and are therefore supporting the amendment of CORE methodologies (DA/ID capacity calculation methodology, congestion income distribution methodology, regional operation security coordination methodology) and processes as well as the definition of a blueprint of the harmonised market-based allocation process.

Evaluation of the Benefits

German and Austrian TSOs have commonly procured aFRR balancing capacity since February 2020. The reduction in procurement costs, which we saw in the previous years was also reached in 2022. The total balancing capacity costs of the cooperation was 123.7 million EUR (114 million EUR for Germany and 9.7 million EUR for Austria) in 2022, while the costs without cooperation would have been 127,7 million EUR compared to 2021. Figure 52 shows the savings per month due to the cooperation in comparison to 2021.

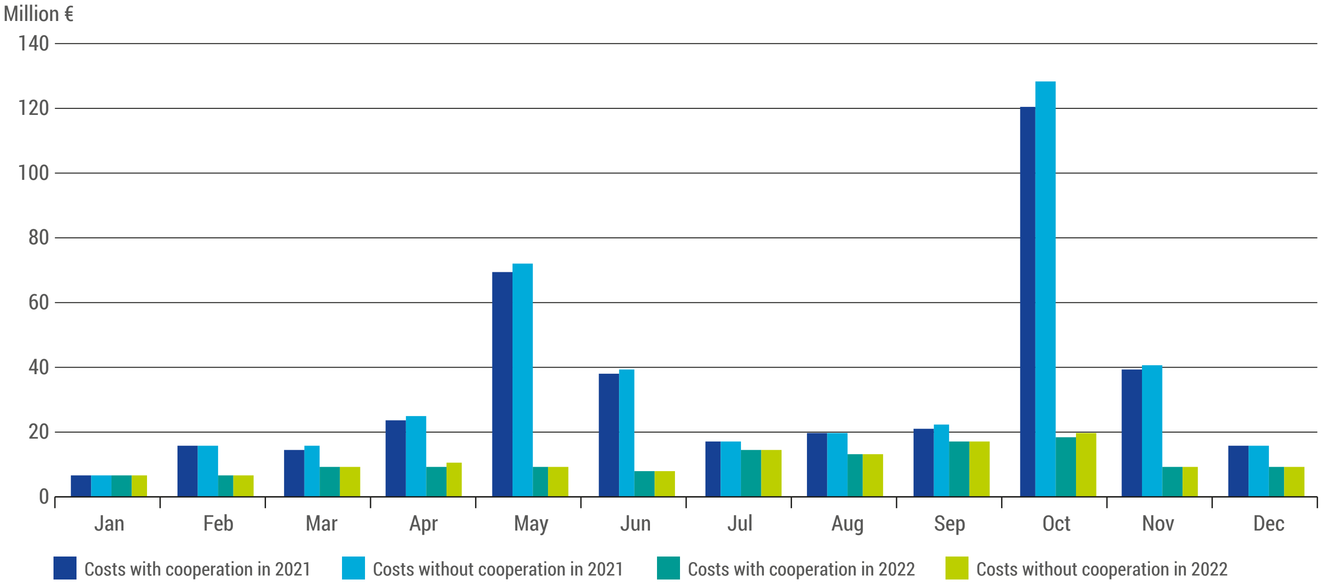


Figure 51: Comparison of procurement cost with and without the aFRR cooperation

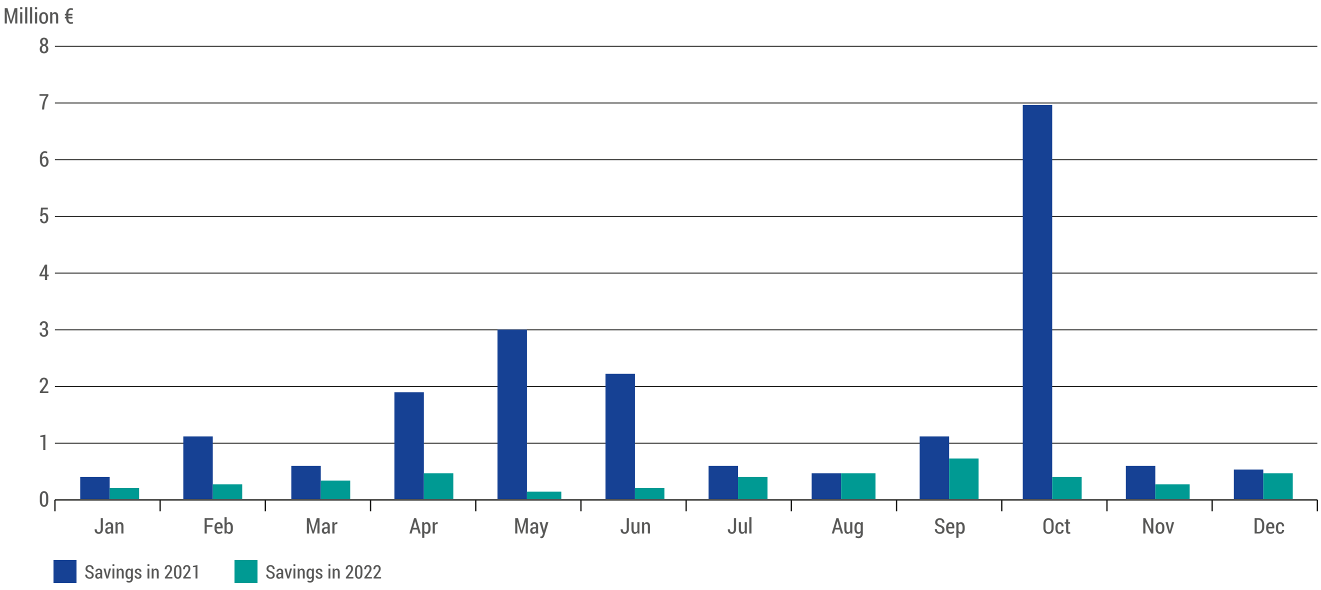


Figure 52: Savings of the aFRR cooperation

6.2.3 Frequency Containment Reserve Cooperation

General information

In accordance with the objectives of the EB regulation, the FCR cooperation, a voluntary common market for procurement and exchange of FCR capacities, currently involves 12 TSOs from 9 countries. The main principles, governance and decision-making process did not change in 2022. A detailed overview can be found in the ENTSO-E Balancing Report 2020 and Market Report 2021.[86]

Figure 53: Map of countries participating in common procurement of FCR through the FCR Cooperation

ČEPS accession to FCR Cooperation

After becoming an Observing TSO of the FCR Cooperation in 2021 and an Applicant TSO in 2022, ČEPS completed its accession on 1 March 2023, by participating in the common procurement of FCR for the first time.

The FCR demand of ČEPS is 76 MW for 2023. ČEPS will procure its entire demand within the FCR Cooperation and will also be allowed to export up to 100 MW to other FCR Cooperation members in accordance with Annex VI of SO Regulation. It is expected that the accession of ČEPS will lead to further socioeconomic benefits for the FCR Cooperation countries and allow costs to be further lowered for the procurement of FCR.

Integration of western Denmark into the German–Danish–Luxembourgish LFC Block

As of 7 September 2022, the situation whereby West Denmark is a separate LFC Area in the German–Danish–Luxembourgish LFC Block is correctly reflected in the FCR Cooperation procurement. In this new setting, there is no Danish core share. There is a common Danish-German-Luxembourgish total demand, a common core share and a common export limit. In addition, West Denmark has a Control Block internal transfer limit between Denmark and Germany. This means that in West Denmark, only the Danish obligation plus the internal transfer limit can be awarded. The internal transfer limit from Western Denmark to Germany was raised to 100 MW.

Change of GOT to D-7

The Gate Opening Time (GOT) has been moved from D-14 to D-7 as of first delivery date 07 September 2022. This change was publicly consulted on between 25 May and 25 June 2021 as part of the Amended TSOs' proposal for the establishment of common and harmonised rules and processes for the exchange and procurement of Balancing Capacity for FCR in accordance with Article 33 of Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing and approved by all respective regulatory authorities.

The change to D-7 was implemented to increase the flexibility for maintenance, patching and releasing of updates or fixes for FCR TSOs' IT systems. With a D-14 GOT, any fix effectively took 13 days to come in effect, when the last tender at the time of the fix is closed. A very long GOT was established when the auctions for the daily product were taking place during working days only: for a delivery on Monday and Tuesday, the auction had to take place on the Friday before. To cover the Christmas and long holiday periods, which extended the gap between the auction day and delivery day, a GOT at D-14 was deemed necessary to offer the flexibility to the BSPs to participate to the auction. As from 1 July 2020, the auction is performed daily, with no exception for holidays. Long GOT are therefore no longer needed.

The implementation of this change was successful. The go-live proceeded without incidents.

86 ENTSO-E **Balancing Report 2020**: page 31 / ENTSO-E **Market Report 2021**: page 101–108

FCR platform price evolution

The analysis of the evolution of the annual prices for FCR procured by the FCR Cooperation shows a significant decrease of the prices between 2017 and 2020, except for Belgium and the Netherlands where the transition to marginal pricing seems to have broken the downward trend over the past years. The overall downward trend until 2020 can be linked to the accession of new entrants in the market, associated with increased competition due to the exchange of FCR capacities. The evolution of the market design (for example, auctions in D-2/D-1, marginal pricing) also contributed to the improvement of conditions for new market participants. However, in 2021 the prices rose, explicable by the overall high energy prices in Europe. For 2022, the price increase has overall significantly slowed down or even decreased in the case of Germany. In the case of Denmark, the price rose in 2022 due to low competition on the FCR market between May and September but decreased to a normal high subsequently.

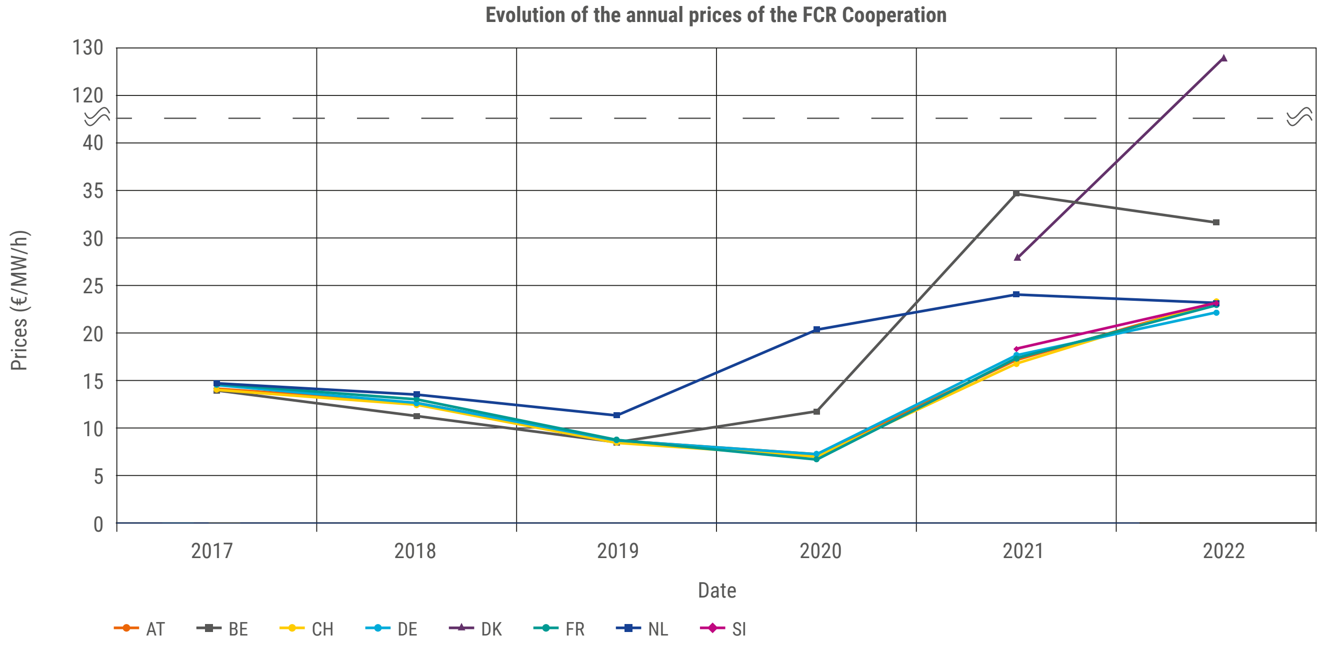


Figure 54: Evolution of the annual prices of FCR Cooperation

Note: As the price level courses of several countries are very close to each other or even the same, it is not possible to distinguish them from each other.

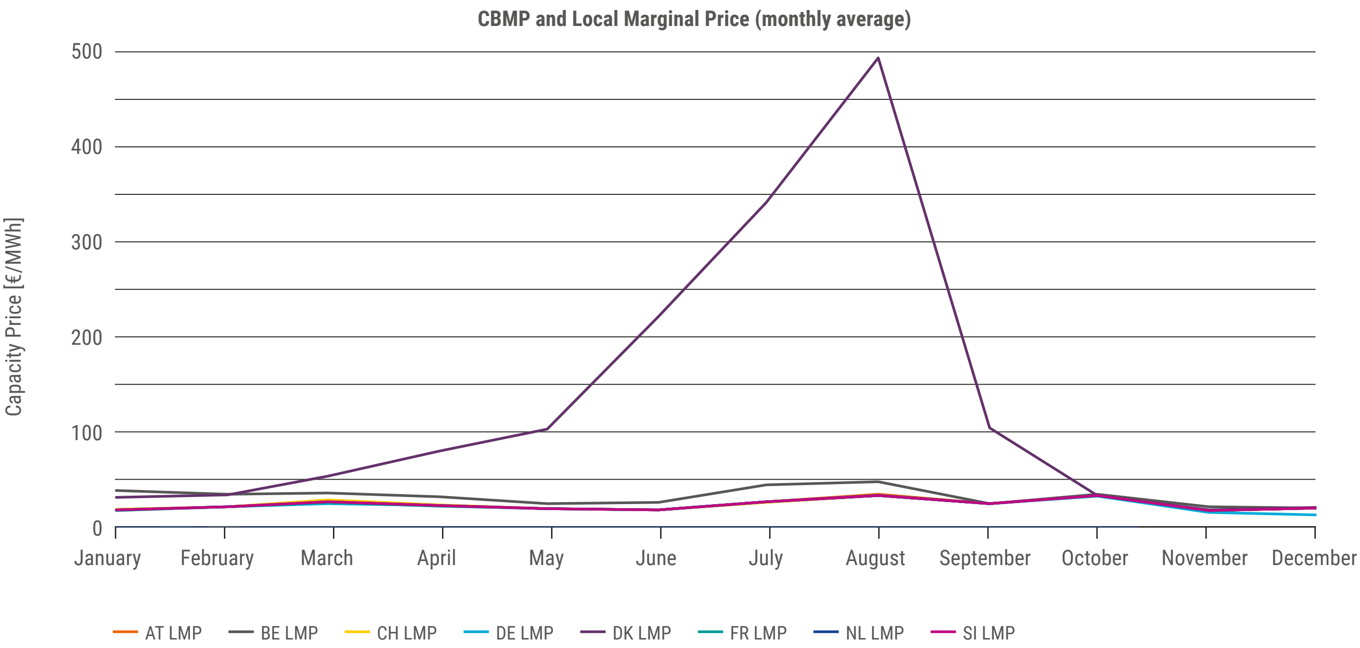


Figure 55: Evolution of CBMP and (monthly) local marginal prices, 2022 (EUR/MWh)

Note: As the CBMP and most LMPs (Austria, Germany, Switzerland, France, The Netherlands and Slovenia) are very close to each other or even the same, it is not possible to distinguish the corresponding lines on this graph.

Figure 55 shows the monthly prices for each country of the FCR cooperation for 2022, and the level of convergence of prices. The price converges when the LMP is equal to the CBMP. This is usually the case when no constraints were hit (e. g. import or export limit) which could influence the LMP.

Austria, France, the Netherlands, Slovenia and Switzerland had a very high convergence of prices, followed by Germany with 97–100 % and 90 % of the price convergence respectively. On the other hand, Belgium and Denmark often reached their import limits, resulting in prices decoupled from the rest of the cooperation and a price convergence which is comparably lower than for other countries.

The following figure shows in monthly resolution the prices (CBMP and LMP per TSO) for 2022.

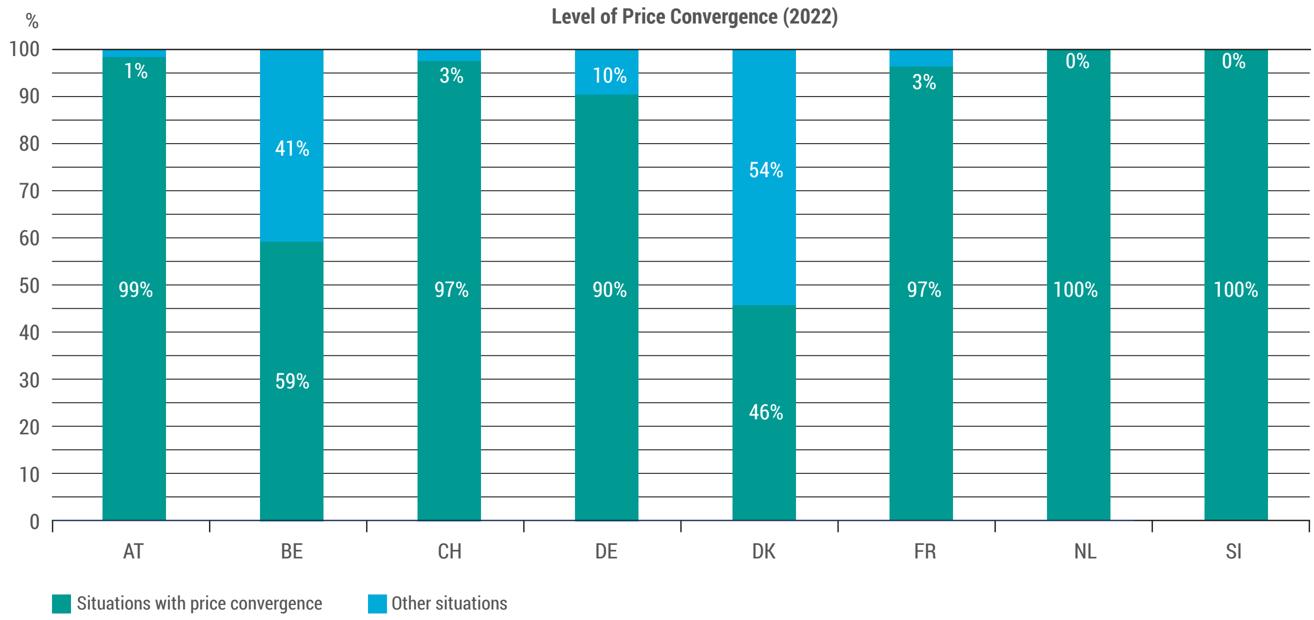


Figure 56: Level of price convergence, 2022

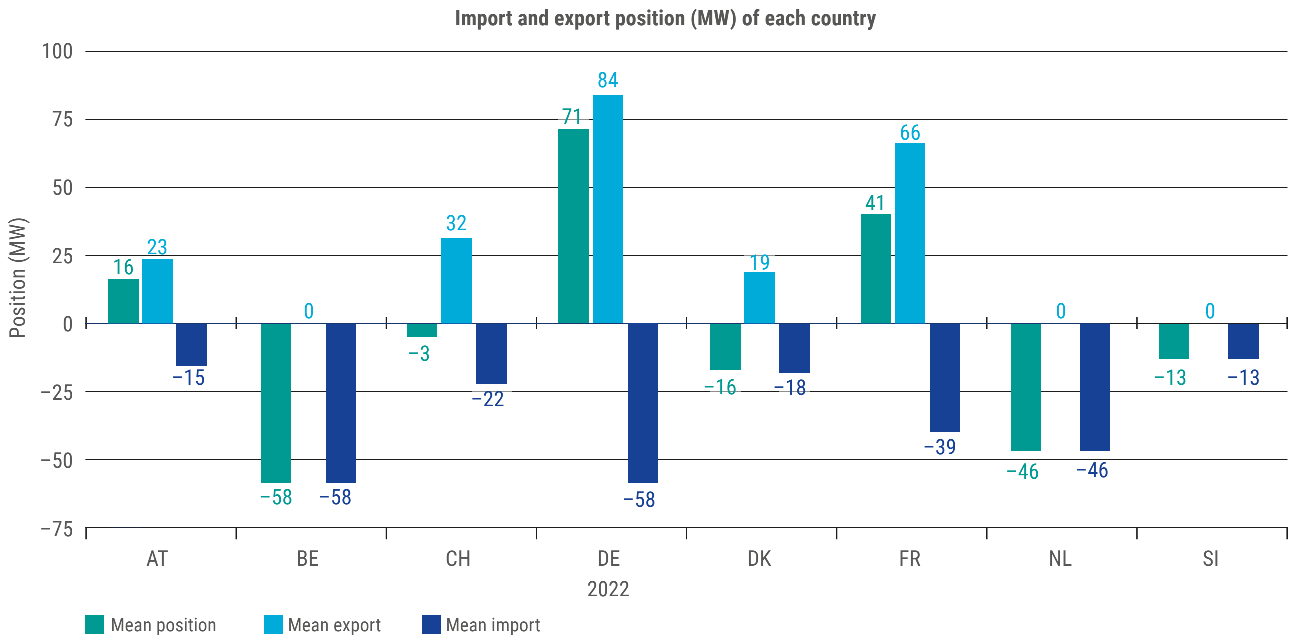


Figure 57: Import and export positions of each country, 2022 (MW)

Figure 57 shows the mean import and export positions of each country. Austria, France and Germany were mainly exporting countries, whereas Belgium, Switzerland, Denmark, The Netherlands and Slovenia were mainly importing FCR to fulfil their demand.

Note: Because import and export positions are calculated on a different number of occurrences, the mean positions are not the average of the mean import and export.

Evaluation of the Benefits

Benefits of the FCR Cooperation are evaluated based on a comparison between two situations (table 11).

Situation A	Situation B
Each country procures its FCR demand seperately	Current situation, i. e. a joint procurement and coupled markets

Table 11: Two situations for benefit evaluation

These scenarios are analysed for a 1-year period from January 2022 to December 2022. In both scenarios, the same FCR demand and same bids from the BSPs are used. In reality, it is likely that the different conditions of the scenarios would affect the bids. In situation B, the core share of each country and the export limits are considered.

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. In simulation A, there is a significant volume of under-procurement (i. e. 116 MW on average per auction). Under-procurement occurs in a country where there are insufficient local bids to cover the demand for that country; this is not a problem in the current situation, as imports are possible. This under-procurement reveals the limit of this analysis, in particular as identical sets of bids have been used for the simulation of both situations. It is likely indeed that the cooperation discouraged some BSPs to bid their entire FCR flexibility, as the most expensive bids were unlikely to be selected. It can be concluded that, without FCR cooperation, more assets would have been offered in the market. The results are summarised in table 12.

Simulation	Procurement costs (Million EUR p.a.)	BSP surplus (Million EUR p.a.)	Under procurement	Impact on social welfare (Million EUR p.a.)
Simulation A	296	185	116 MW	
Simulation B	291	247	0 MW	
B-A	–5	+62		67

Table 12: Evaluation of the benefits of the FCR Cooperation

The impact of the FCR cooperation on the procurement costs is a decrease of 5 million EUR (for a lower volume contracted, considering the under-procurement issue). This creates a significant positive impact for the tariff payers. The global optimisation has also an impact on the BSP surplus (i. e. the difference between marginal prices and bids prices) which creates a BSP surplus of 62 million EUR. Under the limitations of the simulation analysis described above, the impact on social welfare is estimated at over 67 million EUR per year. The calculated benefit for 2022 is at a similarly high level as in recent years (e. g. 2021 with 60 million EUR).

6.3 Electricity Balancing Performance Indicators

The EB performance indicators are a tool which allows the analysis and assessment of the results of the integration of balancing markets, following the EB Regulation. This section of the Market Report has been created based on data available on the Transparency Platform, provisions from voluntary reserve exchange TSO cooperation, and the balancing platforms which are currently operational.

6.3.1 Indicator on the availability of balancing energy bids, including the 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)* as collected by TSOs.

The indicator includes per TSO/load frequency control (LFC) area/BZ/LFC Block:

1) Available upward balancing energy bids for each type of processes and each type of product;

2) Available downward balancing energy bids for each type of process and each type of product;

3) Unavailable upward balancing energy bids for each type of processes; and

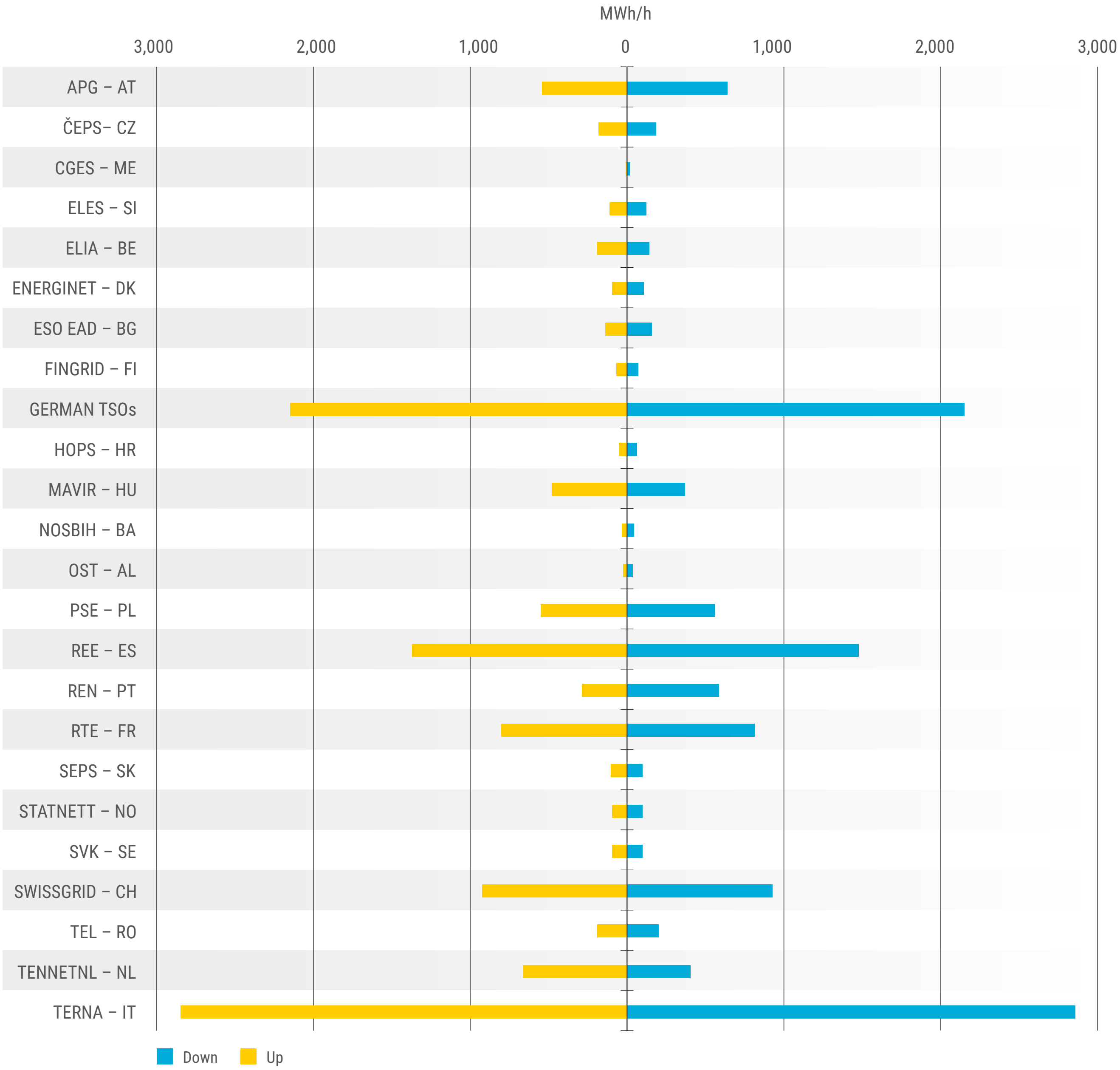
4) Unavailable downward balancing energy bids for each type of processes.

Legal reference	Article 59(4)(a) of the EB Regulation
Time reference	Yearly

Table 13: Indicator 6.3.1 on the availability of balancing energy bids (* with specific including both specific and local products)

KPI 6.3.1.1: Available upward/downward balancing energy bids (standard/non-standard incl. specific) for aFRR (MWh/h)

Disclaimer: ADMIE could not report on aFRR product due to data problems.



KPI 6.3.1.1: Available upward/downward balancing energy bids (standard/non-standard incl. specific) for mFRR (MWh/h)

Definition

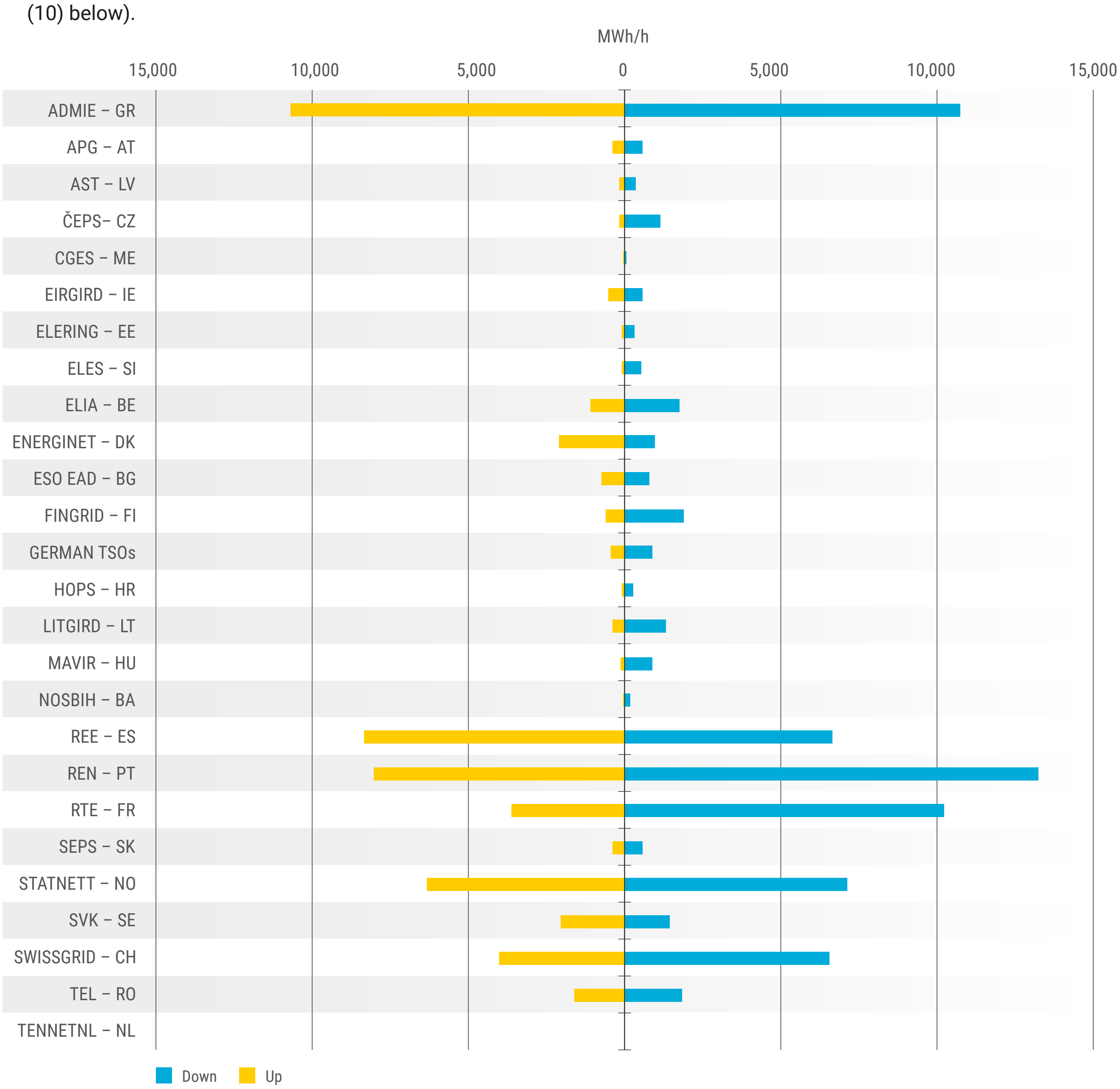
a) Social welfare impact: The social welfare increment for each exchange balancing energy market is calculated by comparing coupled/decoupled clearings. The social welfare positive increments for balancing energy activation are calculated by comparing coupled and decoupled market results. The social 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.

b) Besides social welfare impact, it will be also evaluated (in MWh-year) the potential upward/downward inelastic balancing energy not supplied at decoupled run compared to coupled run (coupled run addressed at indicator 6.3.4 (10) below).

Legal reference	Articles 59(4)(b) and 59(4)(c) of EB Regulation
Time reference	Yearly

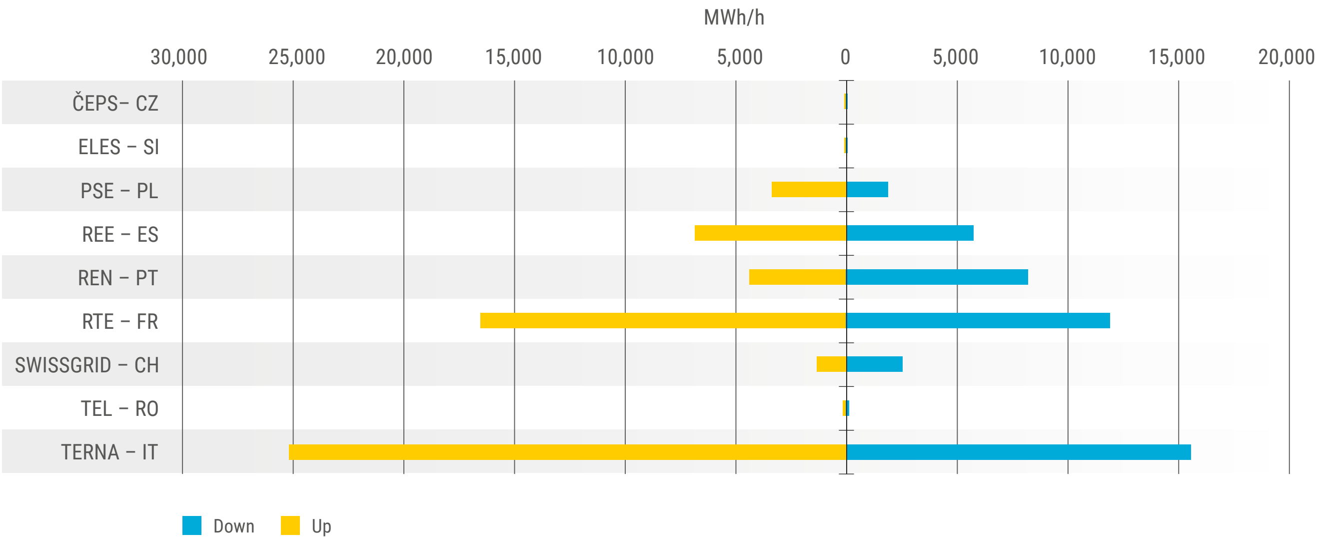
Table 14: Indicator 6.3.2.1 on balancing energy activation social welfare impact

Disclaimer: ADMIE: In the graph Integrated Scheduling Process Bids for balancing energy are reported for ADMIE. Actual available bids in real time are less than the reported values.



KPI 6.3.1.1: Available upward/downward balancing energy bids (standard/non-standard incl. specific) for RR (MWh/h)

Disclaimer: EIRGRID / SONI were not included due to a low count of ISP.



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

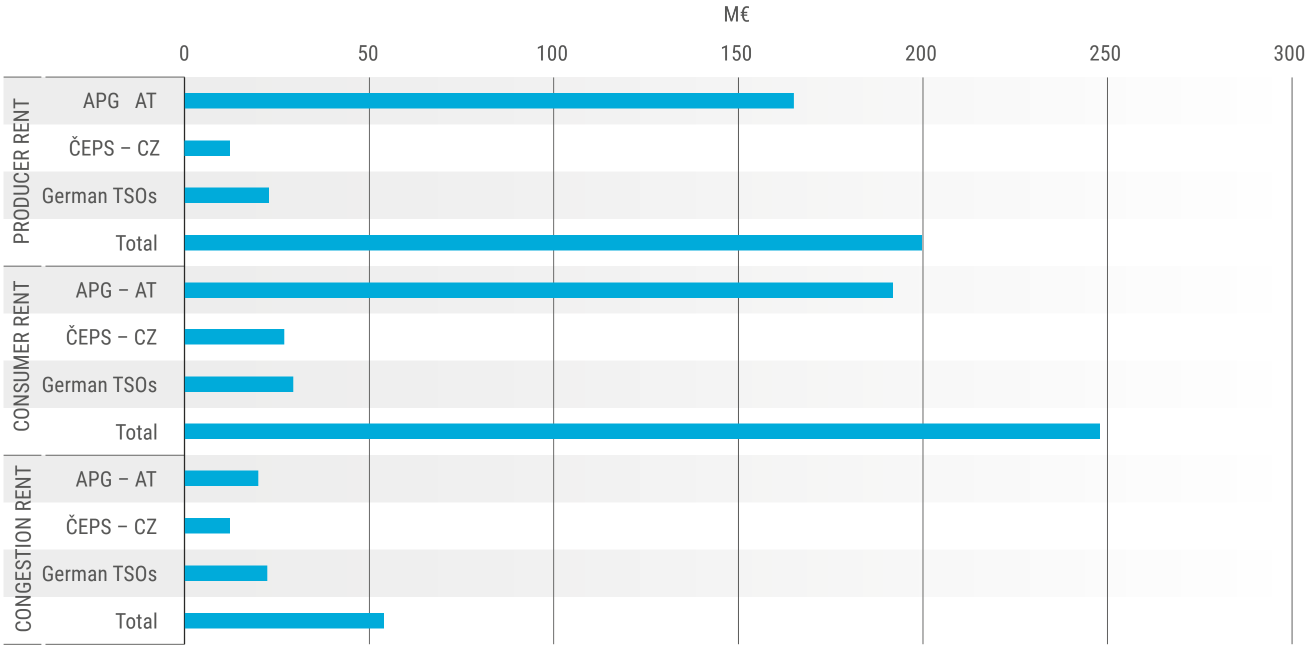
Definition

The monetary saving for IN is calculated based on the difference between respective TSO's aFRR opportunity prices and respective TSO's IN settlement prices, for imported or exported energy.

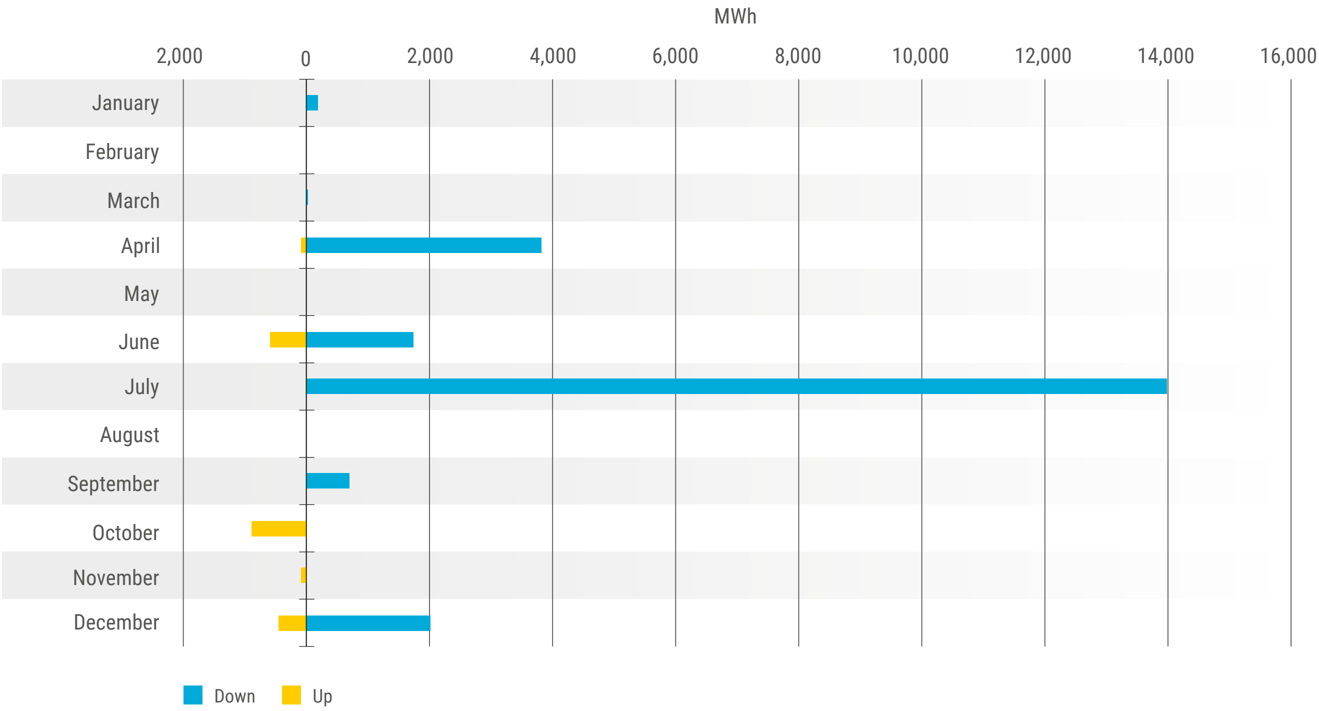
Legal reference	Articles 59(4)(b) and 59(4)(c) of EB Regulation
Time reference	Yearly

Table 15: Indicator 6.3.2.2 on imbalance netting (IN) savings

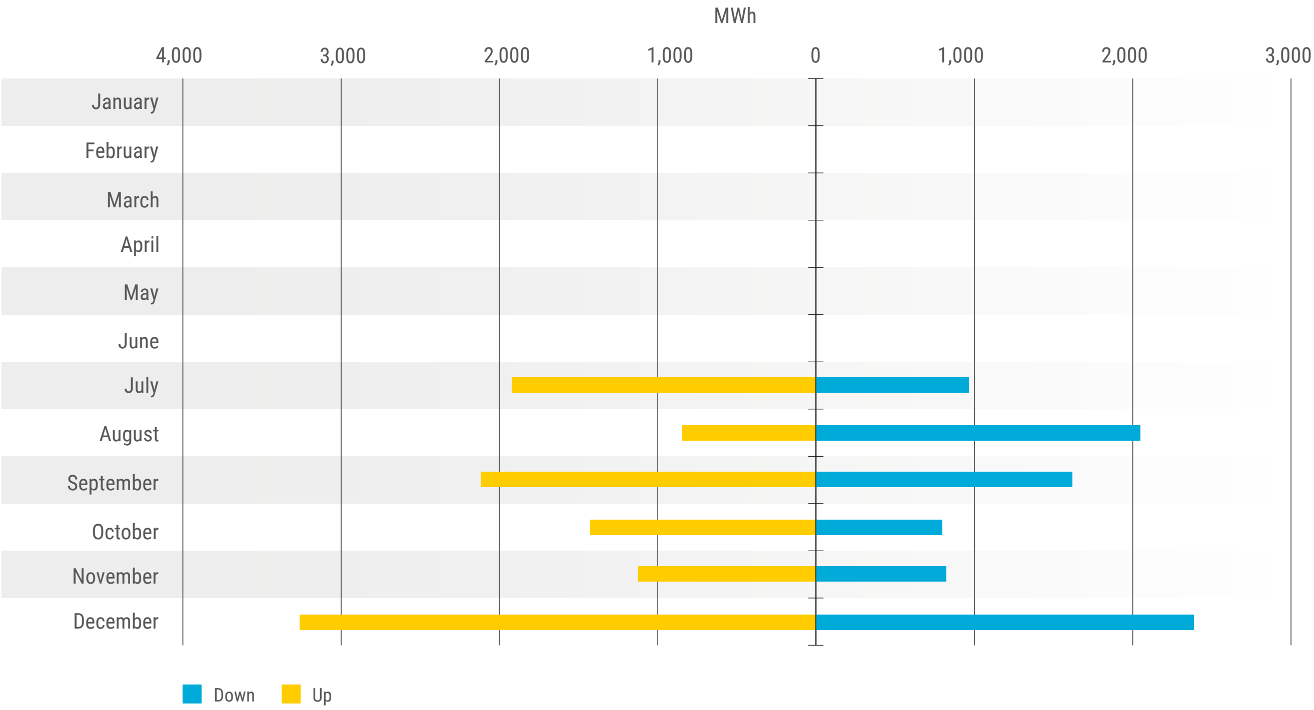
KPI 6.3.2.1: aFRR platform: social welfare impact: Producer rent, consumer rent, and congestion rent (M EUR)



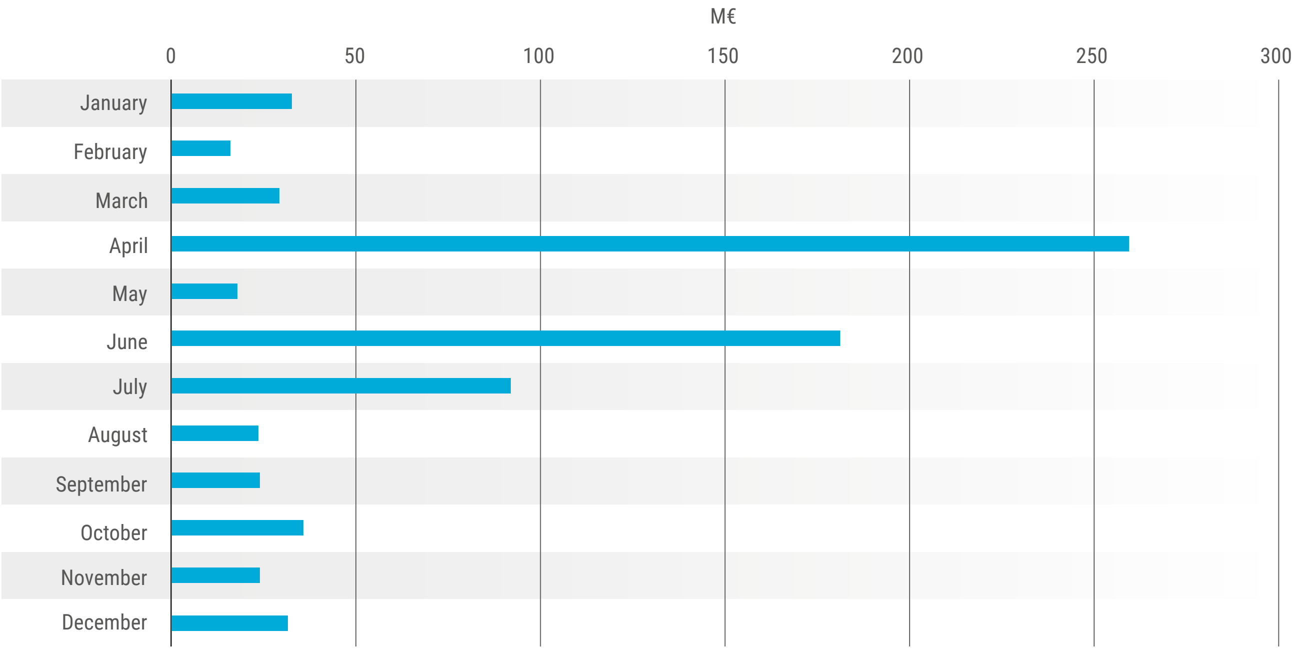
KPI 6.3.2.1: RR platform: potential upward/downward inelastic balancing energy not supplied at decoupled run compared to coupled run (MWh)



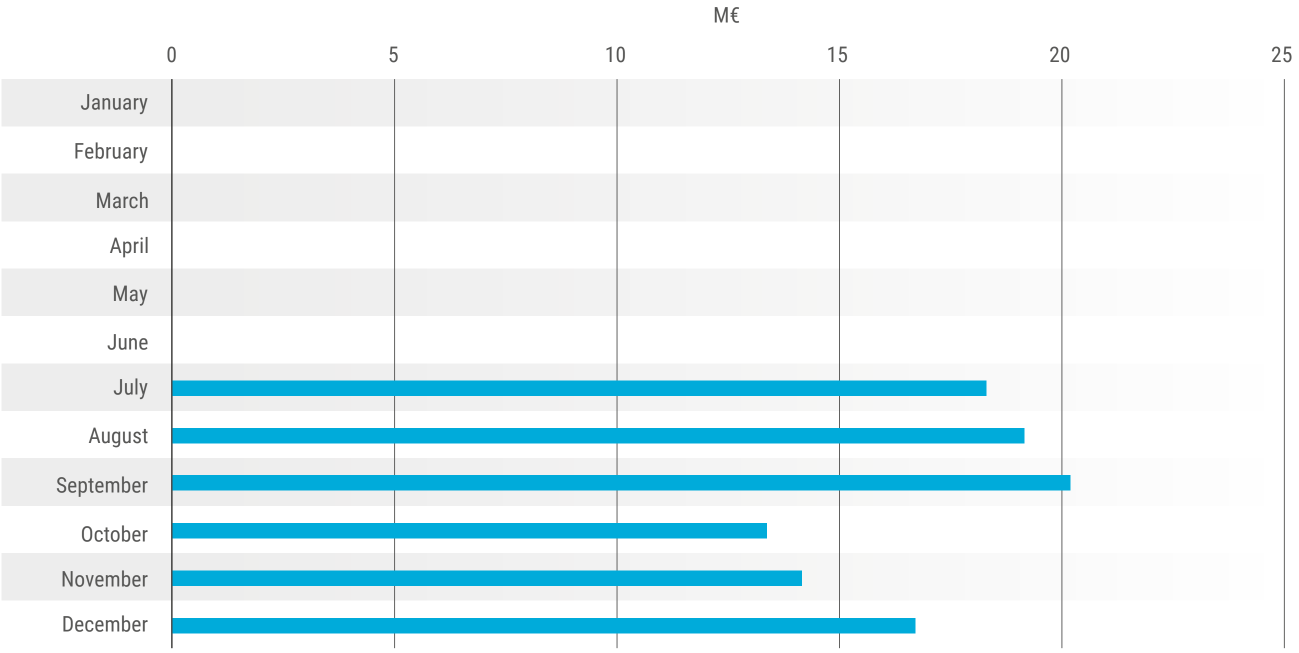
KPI 6.3.2.1: aFRR platform: potential upward/downward inelastic balancing energy not supplied at decoupled run compared to coupled run (MWh)



KPI 6.3.2.1: RR platform: differential Final vs DC (Social Welfare Final – Social Welfare decoupled run) (M EUR)



KPI 6.3.2.1: aFRR platform: differential Final vs DC (Social Welfare Final – Social Welfare decoupled run) (M EUR)



6.3.2.2 Imbalance netting (IN) savings

Definition

The social welfare increment is calculated by comparing coupled and decoupled clearings for each market sharing and exchange balancing reserve market.

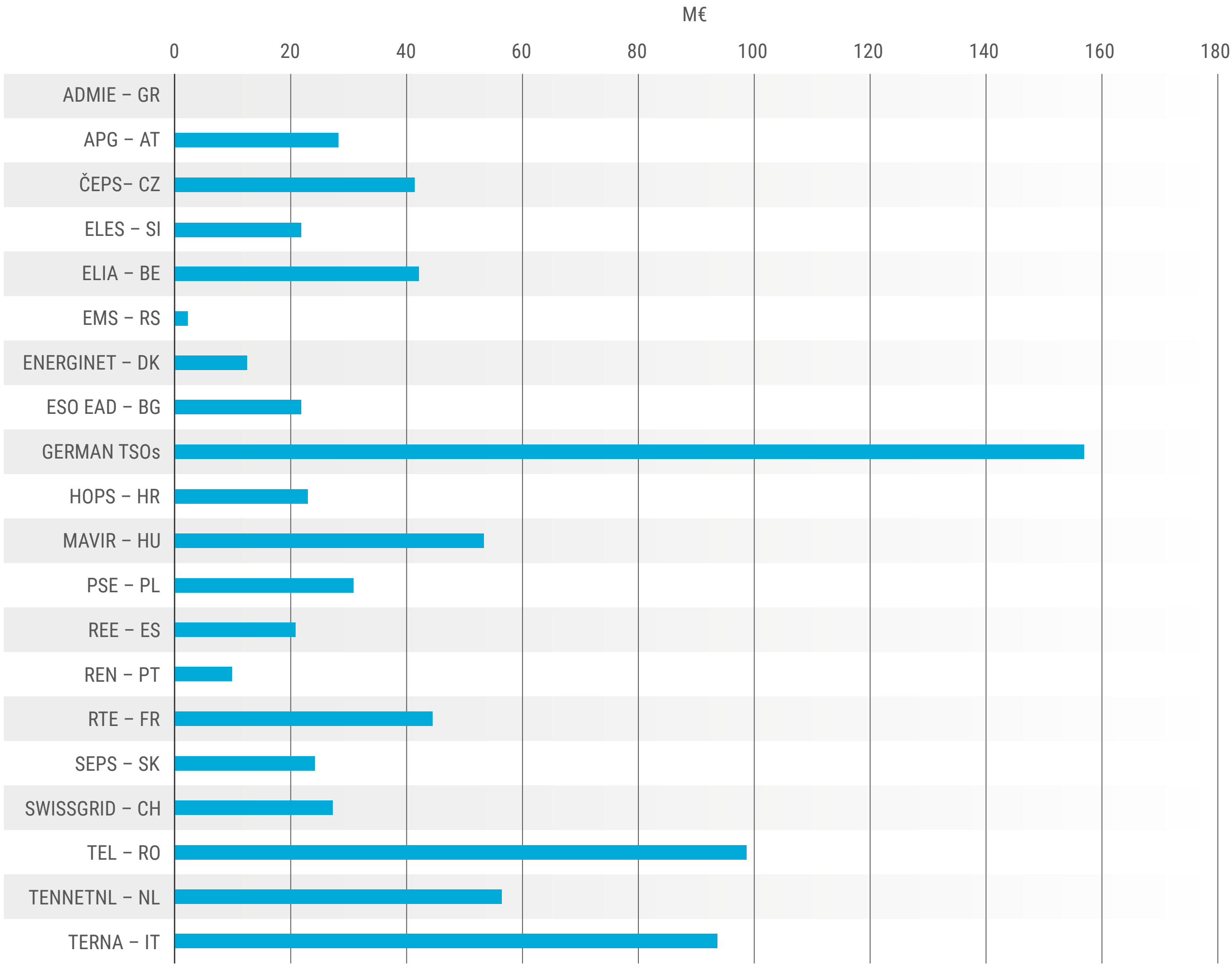
The social welfare in each market is understood as: BSPs surplus and TSO's savings, and TSO's congestion incomes. In the case of exchange/sharing of balancing capacity with CZC allocation, the potential negative impact on the day-ahead market coupling social welfare will be considered. In the market-based approach, the forecasted data of energy market will be used. In the case of inverted market-based approach, the forecasted data of the capacity market will be used.

Legal reference	Article 59(4)(d) of the EB Regulation
Time reference	Yearly

Table 16: Indicator 6.3.2.3 on the sharing and exchange of reserves

KPI 6.3.2.2 Imbalance netting (IN) savings – IN platform: monetary annual savings per TSO (M EUR)

Disclaimer: ADMIE: The operational participation of ADMIE (Greece) in the IN platform – IGCC initiated on 22 June 2021, nevertheless due to the lack of physical border for the netting of imbalances, the productive operation of ADMIE was made possible on 29 March 2023, following the accession of ESO EAD (Bulgaria).



KPI 6.3.2.3 Sharing and exchange of reserves – DE-AT cooperation

Included in the balancing section.

KPI 6.3.2.3 Sharing and exchange of reserves – Overview of demand, core share and export limit for FCR cooperation

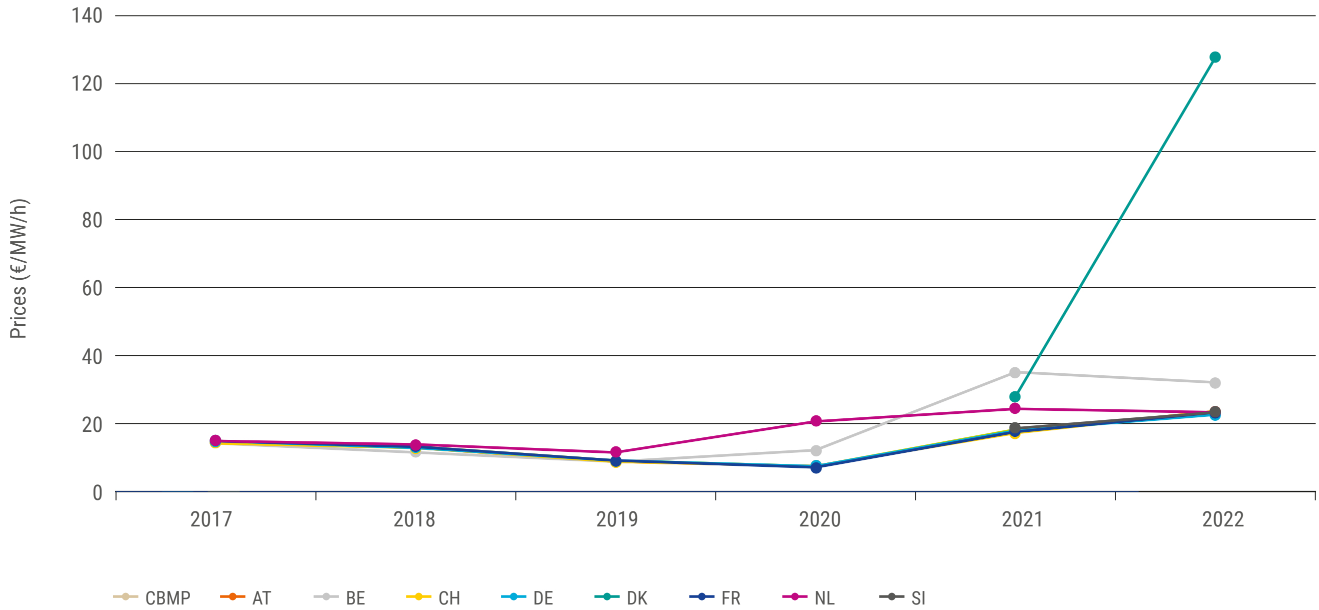
Included in the balancing section.

KPI 6.3.2.3 Sharing and exchange of reserves – Evaluation of the benefits of the FCR cooperation

Included in the balancing section.

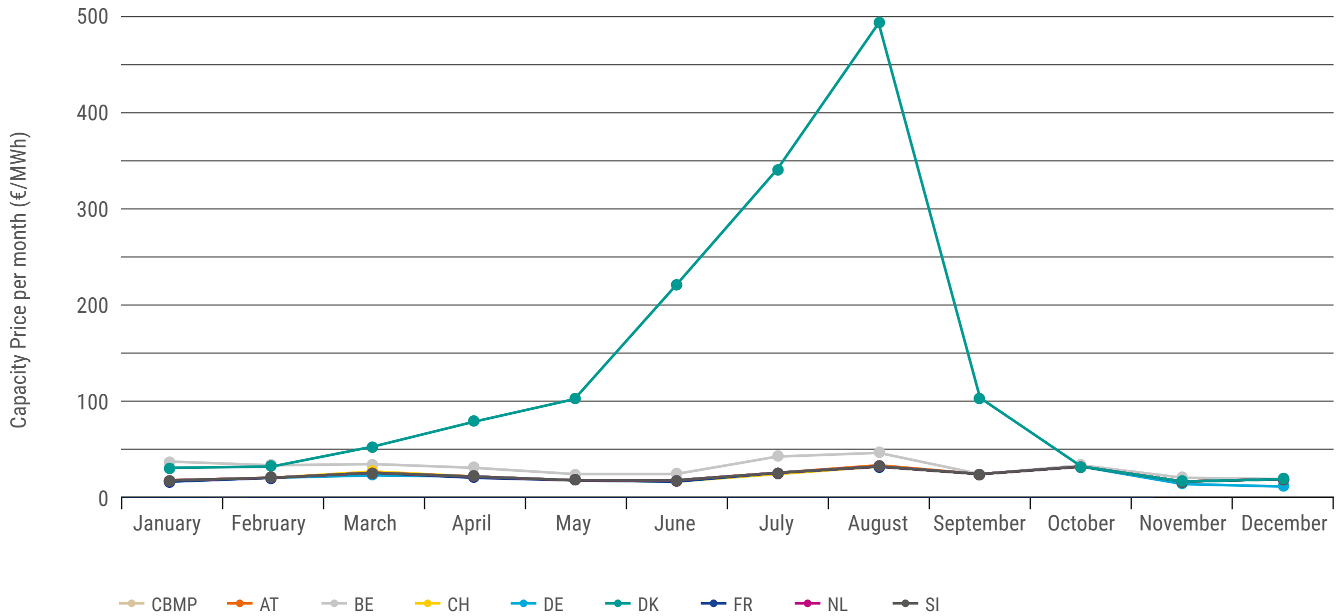
KPI 6.3.2.3 Sharing and exchange of reserves – Evolution of the annual prices of FCR cooperation (EUR/MW/h)

Disclaimer: DK1 entering FCR Corporation and due to low availability of local volumes, prices were initially higher than seen in the rest of the FCR Corporation. Changes in the market design later resulted in price levels comparable to other members.

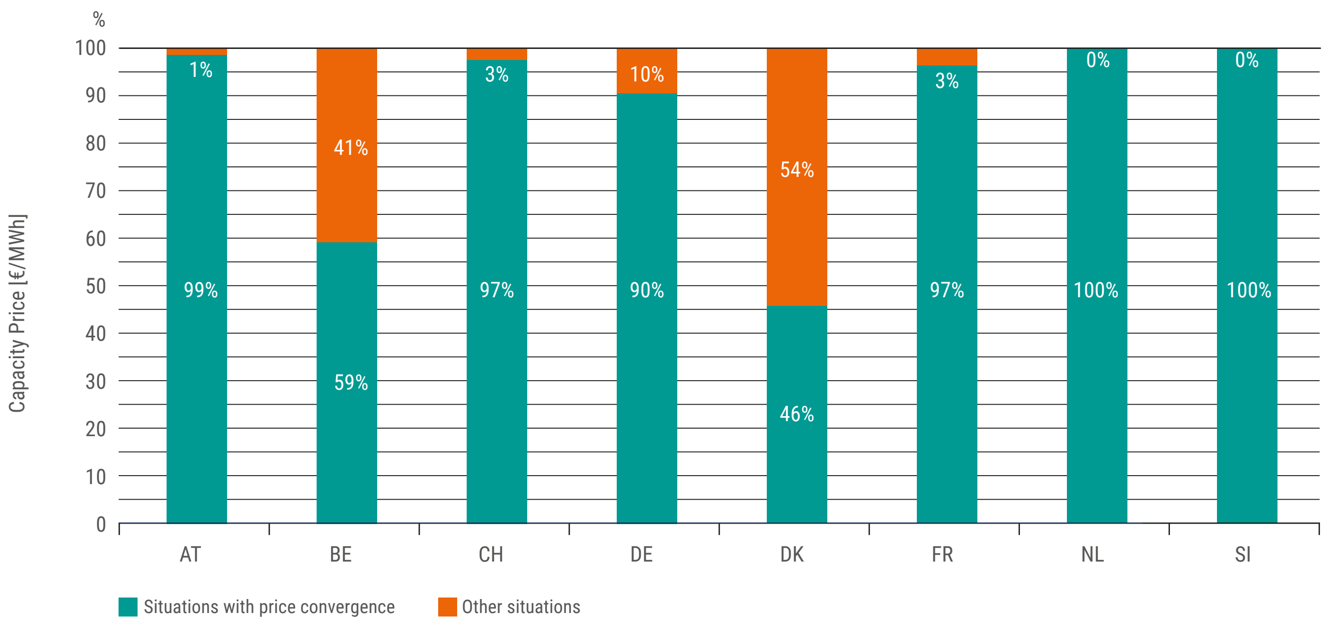


KPI 6.3.2.3 Sharing and exchange of reserves – Evolution of CBMP and local marginal monthly prices (EUR/MWh)

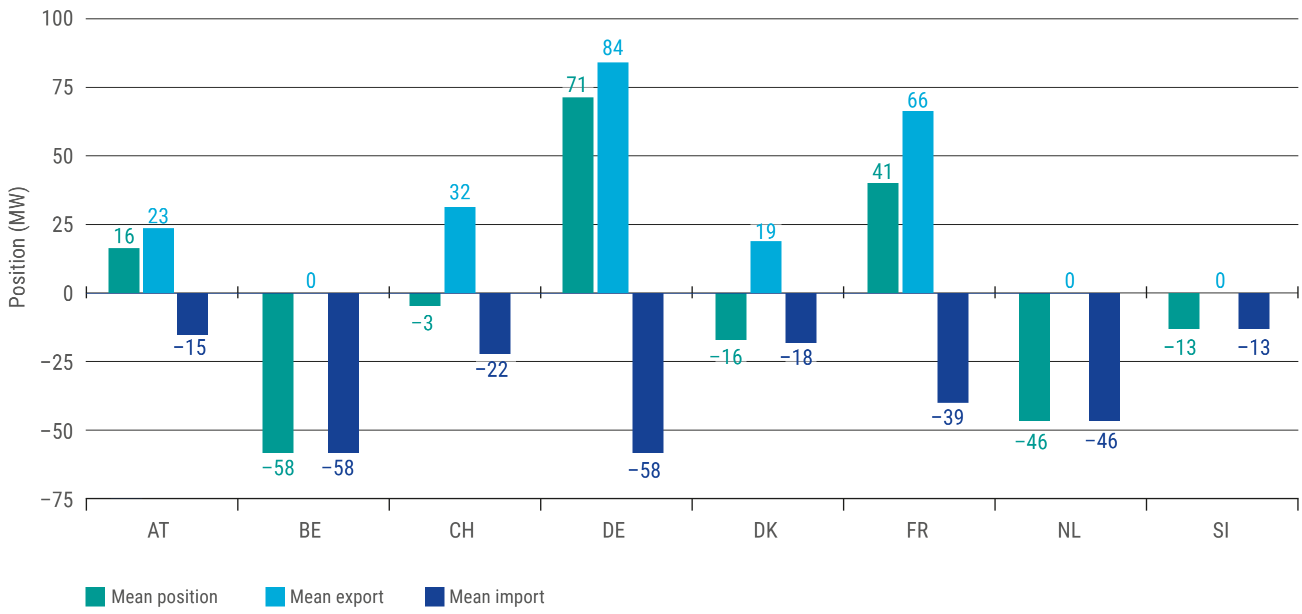
Disclaimer: DK1 entering FCR Corporation and due to low availability of local volumes, prices were initially higher than seen in the rest of the FCR Corporation. Changes in the market design later resulted in price levels comparable to other members.



KPI 6.3.2.3 Sharing and exchange of reserves – FCR Cooperation – Level of price convergence (%)



KPI 6.3.2.3 Sharing and exchange of reserves – FCR Cooperation – Import and export positions of each country (MW)



6.3.3 Total cost of balancing

Definition

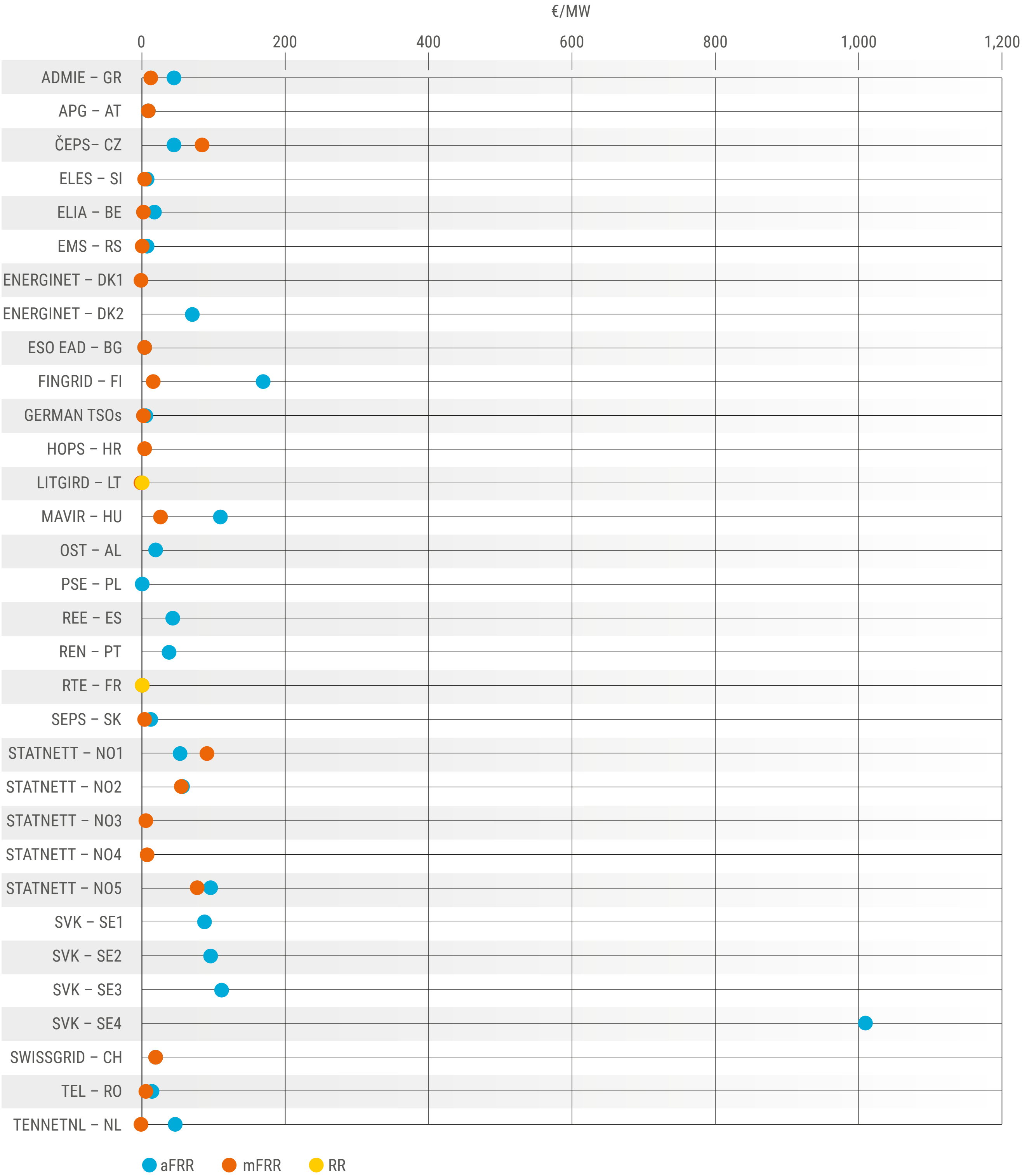
This indicator calculates the annual costs (EUR-year) for each TSO for specific and standard products (both balancing energy activation and reserve procurement costs).

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 BSP’s minus incomes from BSP’s),* adjusted when applicable with the results of TSO-TSO settlements of balancing energy, and c) the net result (cost) of TSO-IGCC settlement of Imbalance Netting. Regarding TSO-TSO settlement in the case of balancing energy platforms, congestion rents of non-participating countries should not be considered.

Legal reference	Article 59 (4)(d) of the EB Regulation
Time reference	Yearly

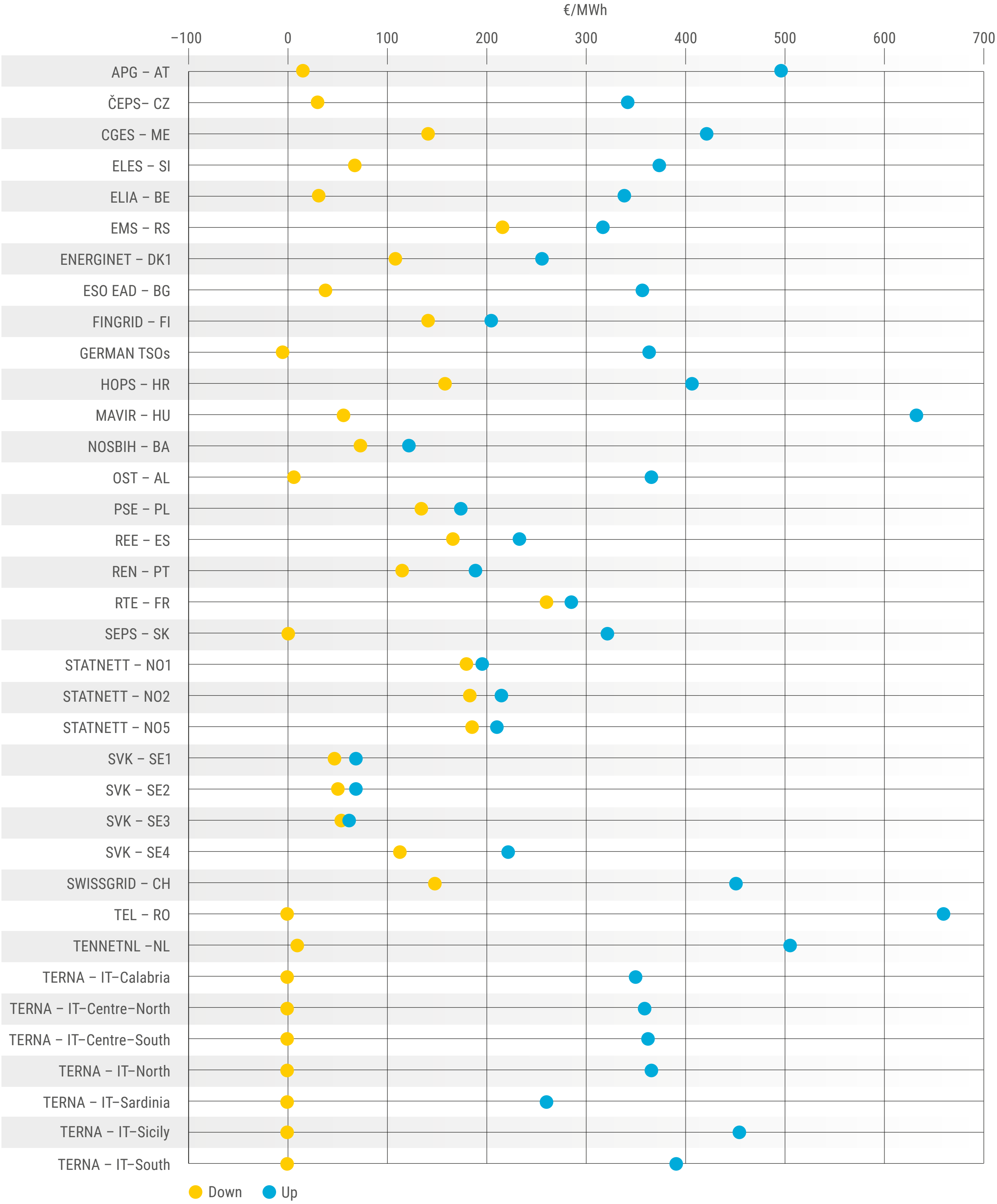
Table 17: Indicator 6.3.3 on the total cost of balancing
(* Payment to BSP’s (comprised of upward activation in case of positive prices plus downward activation in case of negative prices minus incomes from BSP’s (comprised of downward activation in case of positive prices plus upward activation in case of negative prices))

KPI 6.3.3.1: Volume-weighted average price for the procured capacities (upward/downward) across balancing products (EUR/MW)

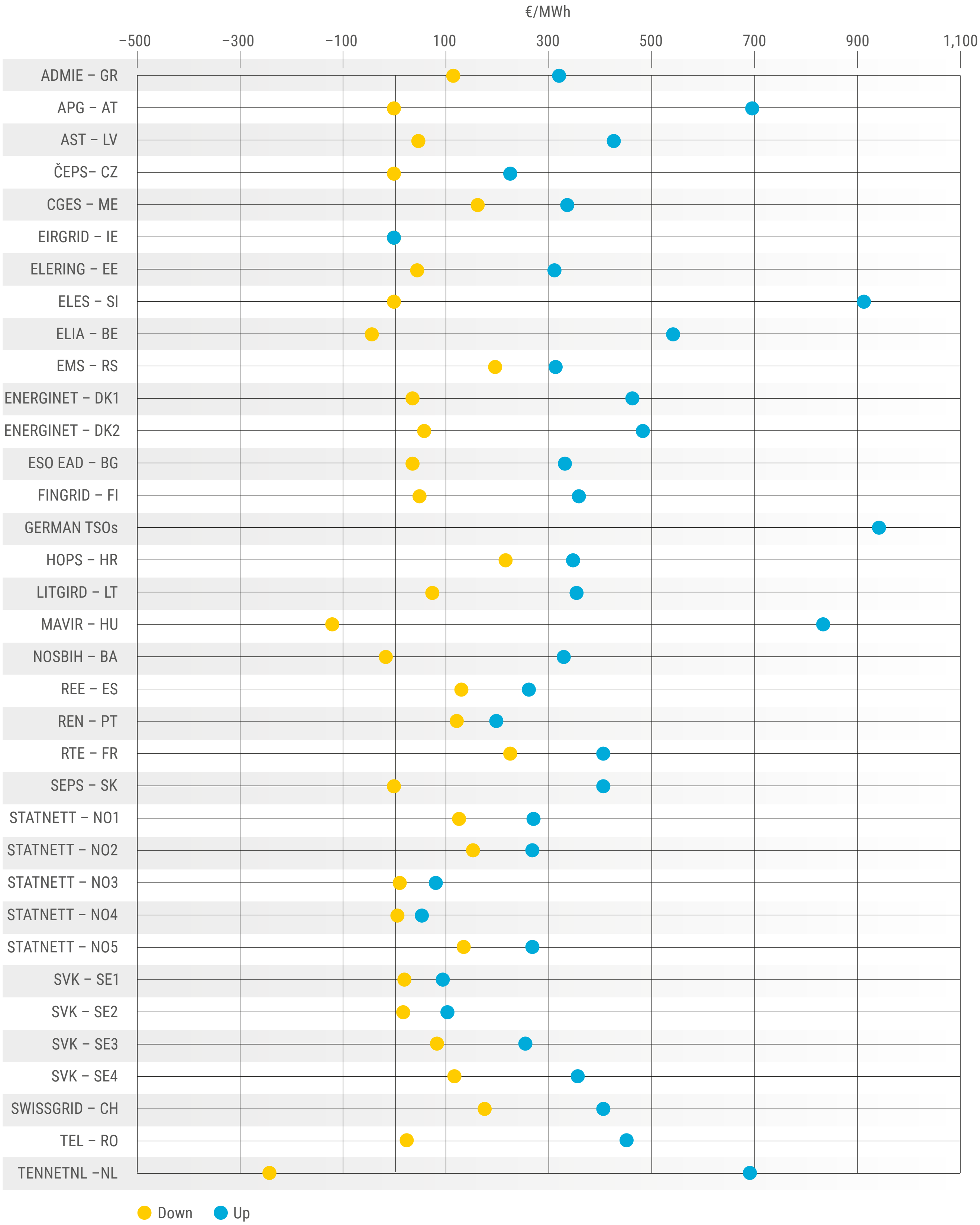


KPI 6.3.3.2/6.3.3.3: Volume-weighted average price of balancing energy activation (upward/downward) for aFRR (EUR/MWh)

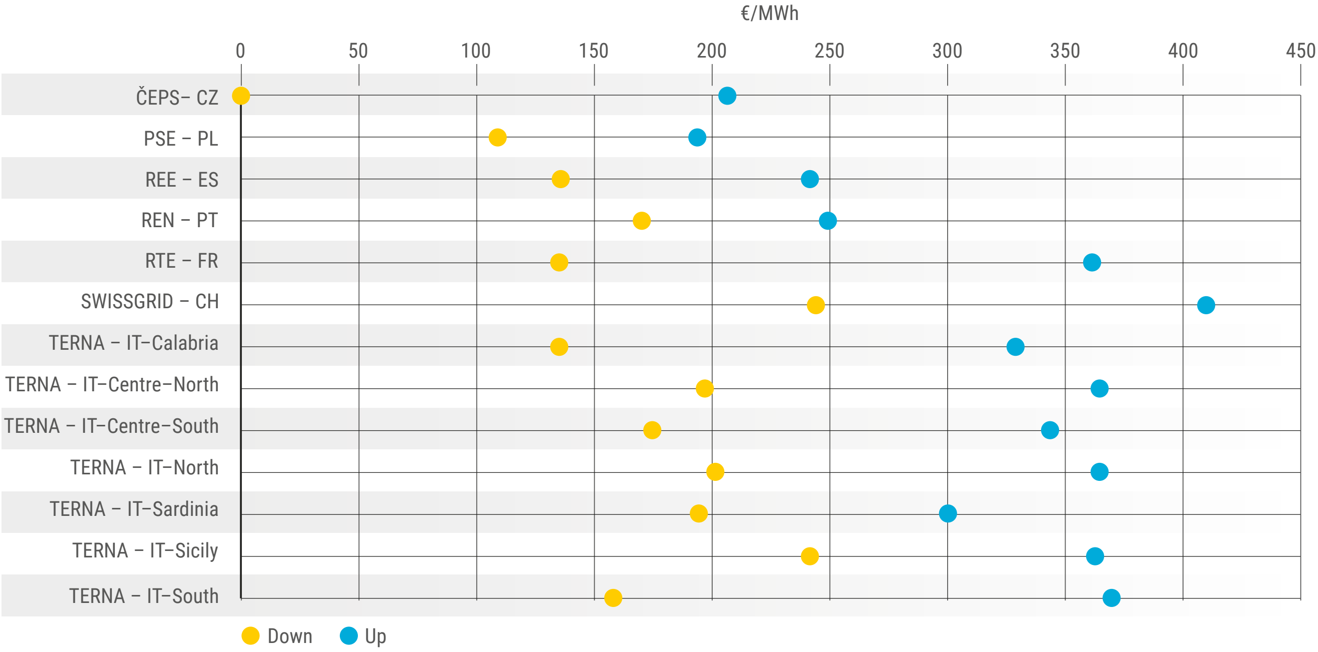
Disclaimer: ADMIE: no reporting on aFRR due to data problems.



KPI 6.3.3.2/6.3.3.3: Volume-weighted average price of balancing energy activation (upward/downward) for mFRR (EUR/MWh)

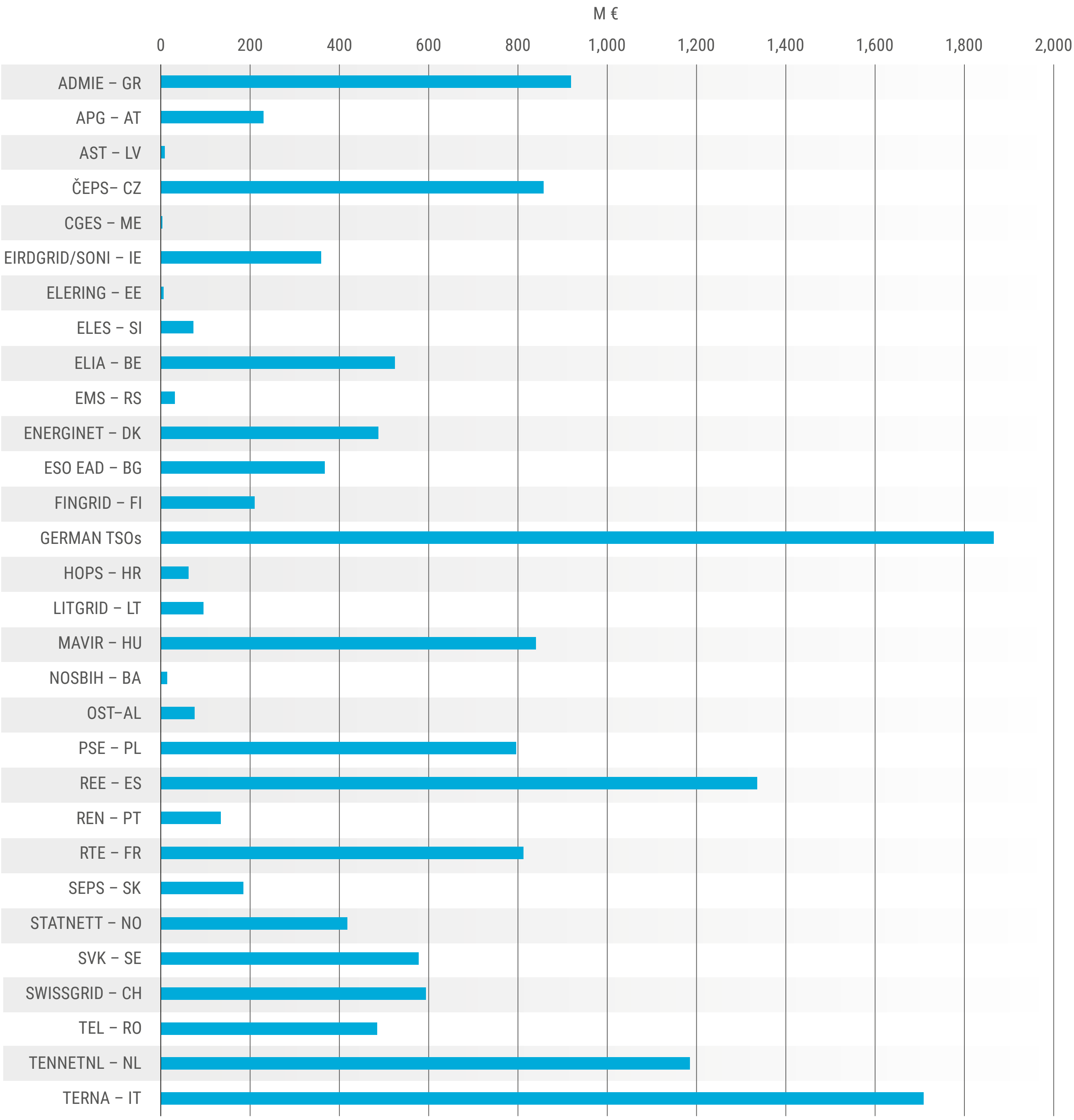


KPI 6.3.3.2/6.3.3.3: Volume-weighted average price of balancing energy activation (upward/ downward) for RR (EUR/MWh)



KPI 6.3.3.4 – Total cost of balancing

Disclaimer: ADMIE: the Total Cost of Balancing includes also cost of redispatching. EIRGRID / SONI note in the excel file: The figures presented below refer to one market only the SEM, which stands for the Single Electricity Market. This is the market shared between Ireland and Northern Ireland. This market uses the Integrated Scheduling Process.



6.3.4 The 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.

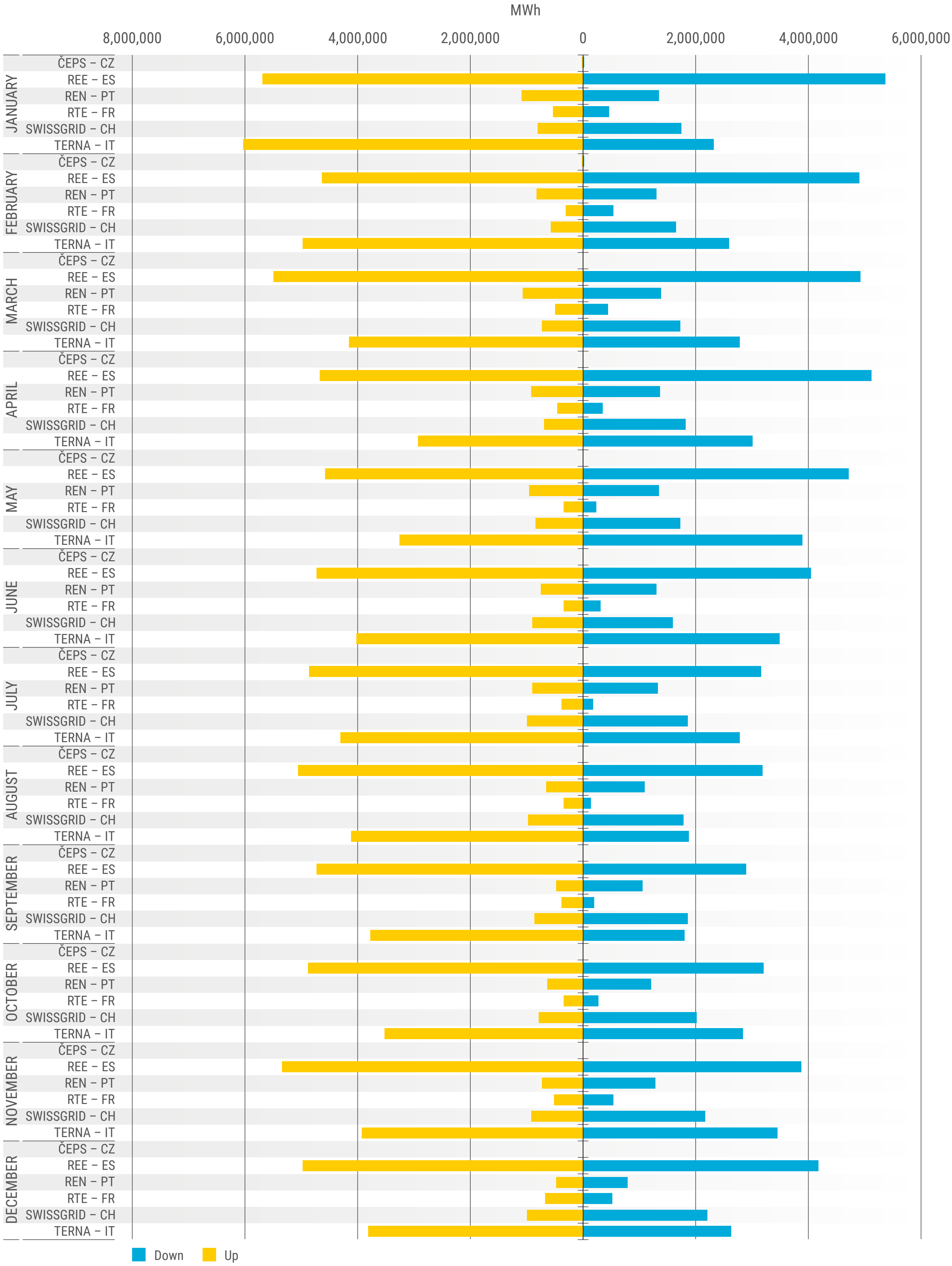
This PI includes the following for each balancing platform:

1. Monthly volume (MWh) and volume weighted average prices (EUR/MWh) of submitted bids per direction and per TSO;
2. Monthly volume of demand per direction and per TSO (MWh);
3. Monthly volume of selected bids per direction and per TSO (MWh);
4. Monthly volumes of exports per TSO (MWh);
5. Monthly volumes of imports per TSO (MWh);
6. Repartition of the use of inelastic and elastic need per TSO (% of share of total demand that is being covered by elastic and inelastic demand);
7. Monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1 %; 5 %, 10 %, 90 %, 95 %, 99 %);
8. Monthly average value of the available and used CZC per BZ border and per direction (MW);
9. Monthly average value of the number of uncongested areas;
10. Number of occurrences (% of MTU) of unsatisfied inelastic need/TSO and its volume (MWh); and
11. Incident overview.

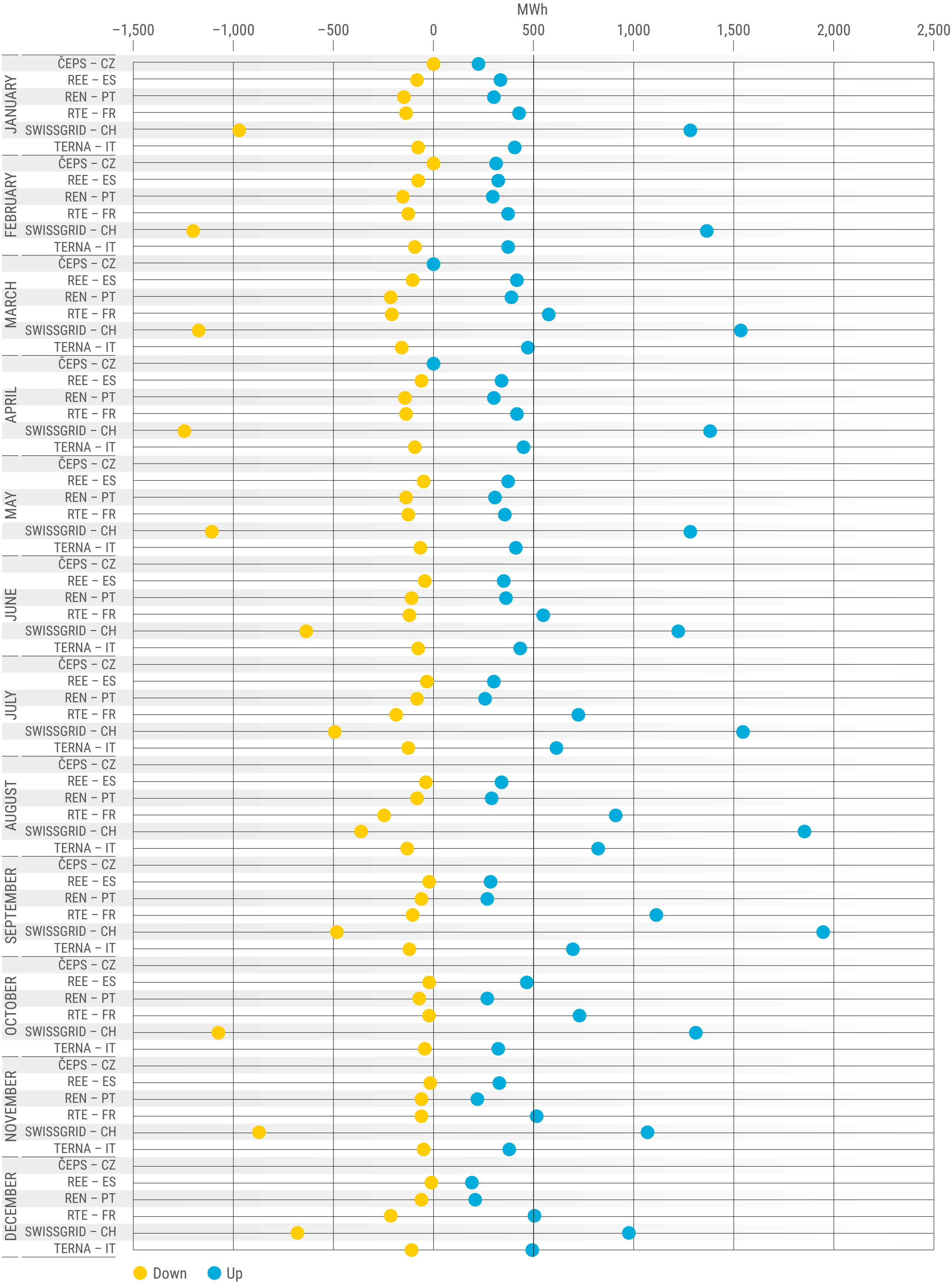
Legal reference	Article 59 (4)(e) of the EB Regulation
Time reference	Yearly

Table 18: Indicator 6.3.4 on the economic efficiency and reliability of the balancing markets

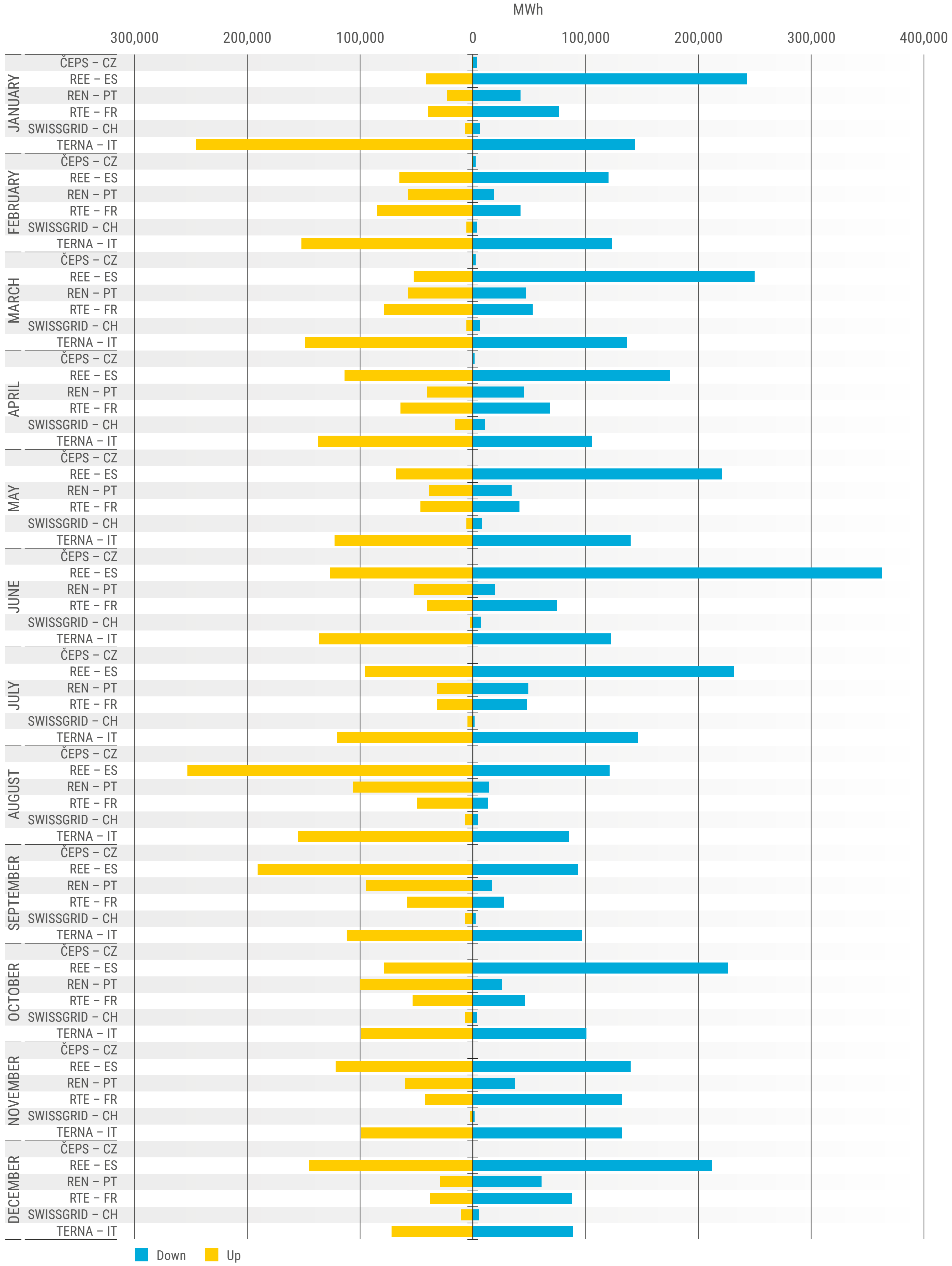
KPI 6.3.4.1 – RR platform: monthly volume (MWh) of submitted bids per direction and per TSO



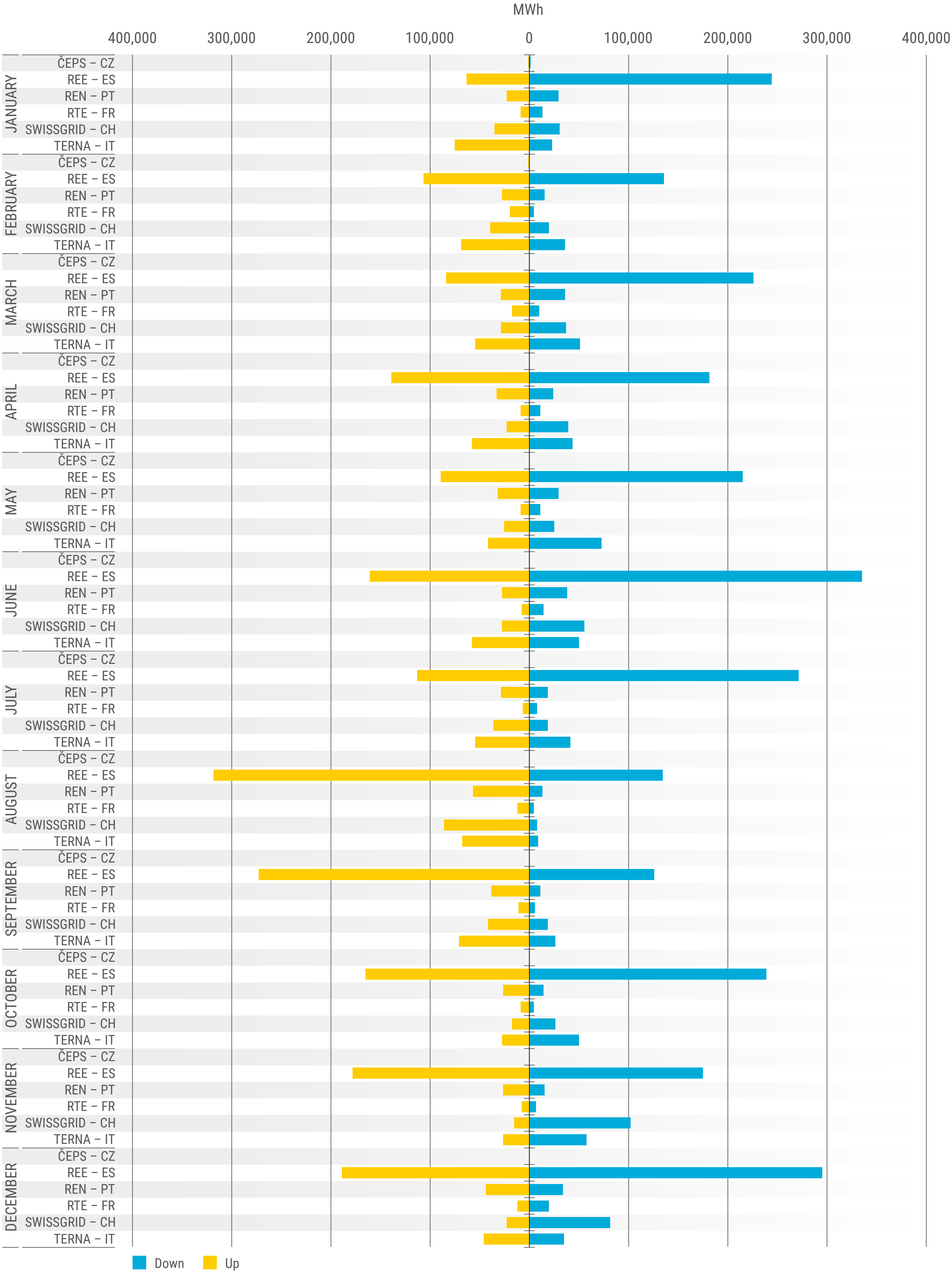
KPI 6.3.4.1 – RR platform: volume weighted average prices (EUR/ MWh) of submitted bids per direction and per TSO



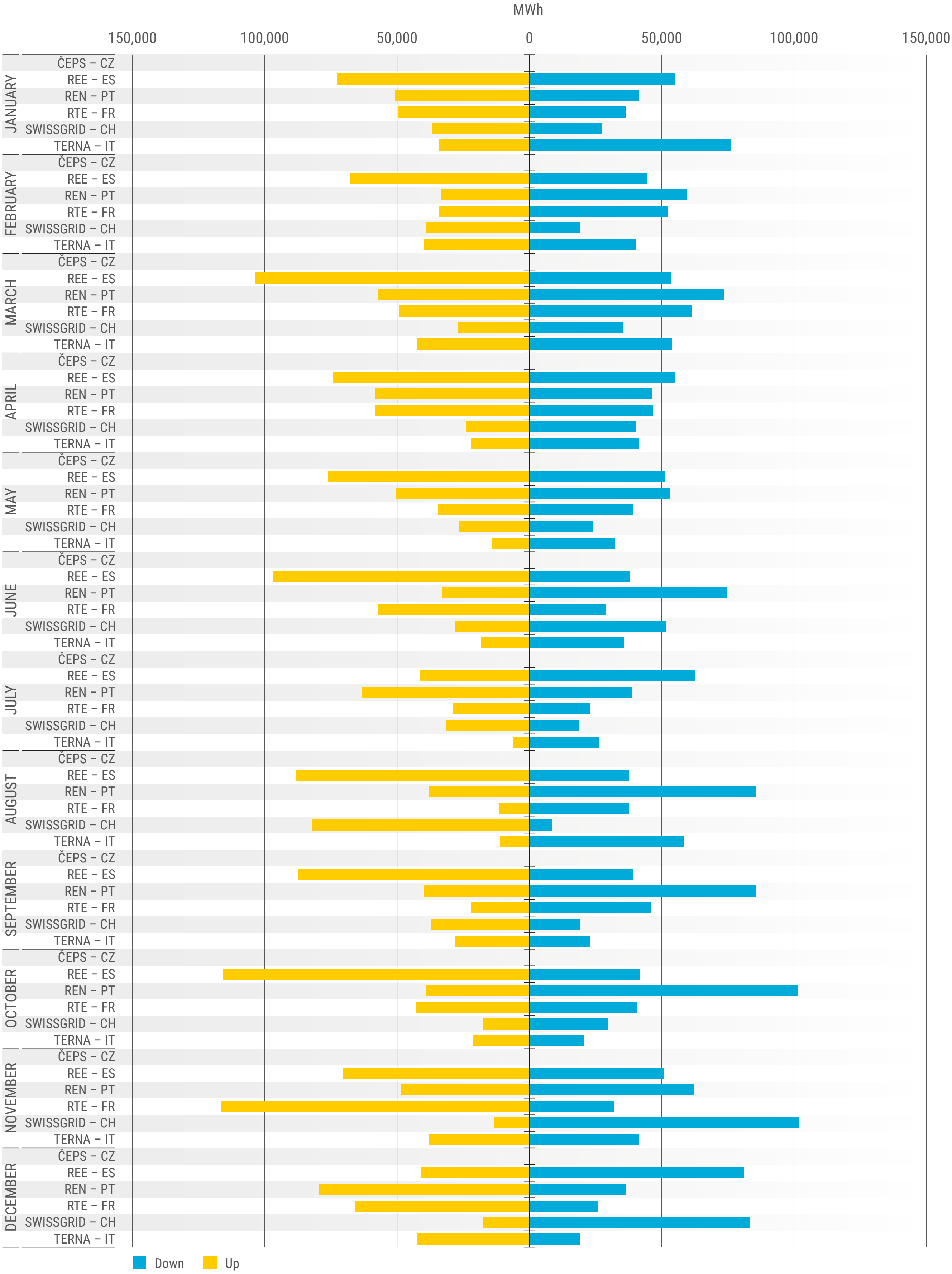
KPI 6.3.4.2 – RR platform: monthly volume of demand per direction and per TSO (MWh)



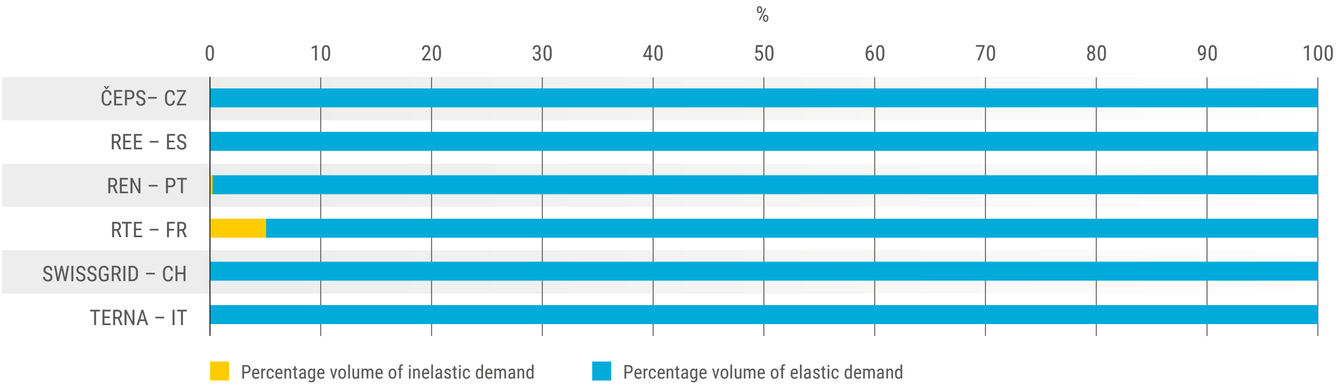
KPI 6.3.4.3 – RR platform: monthly volume of selected bids per direction and per TSO (MWh)



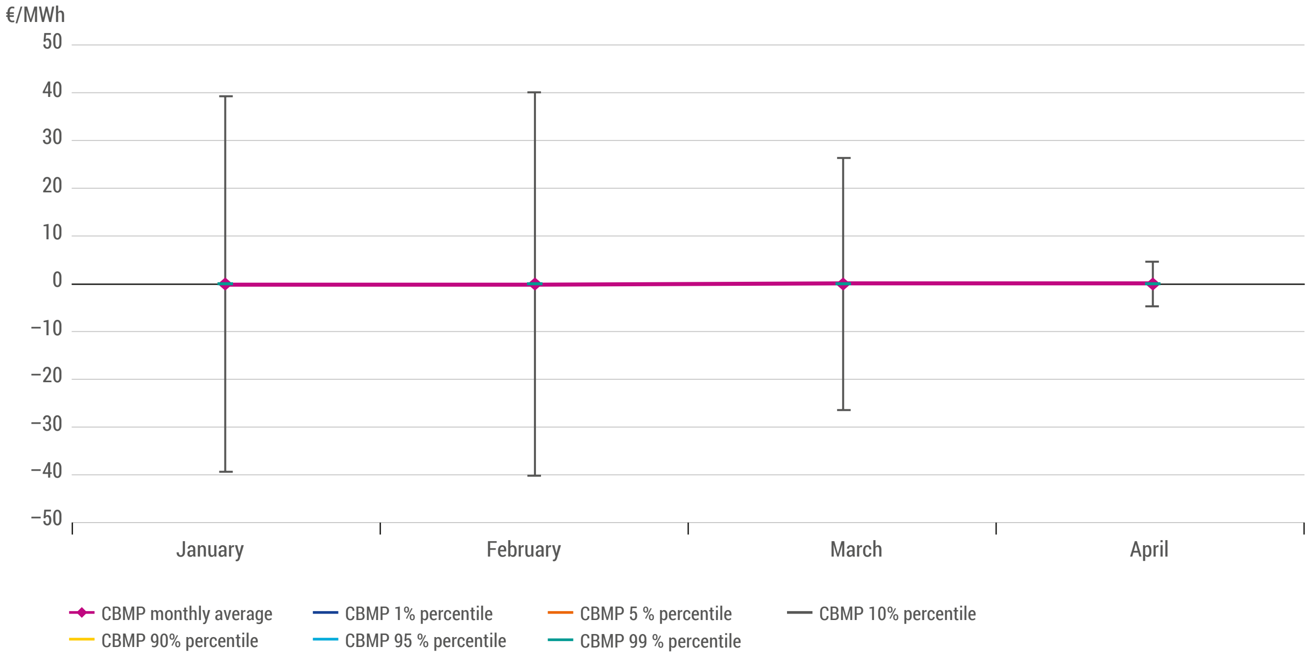
KPI 6.3.4.4/6.3.4.5 – RR platform: monthly volumes of imports / exports per TSO (MWh)



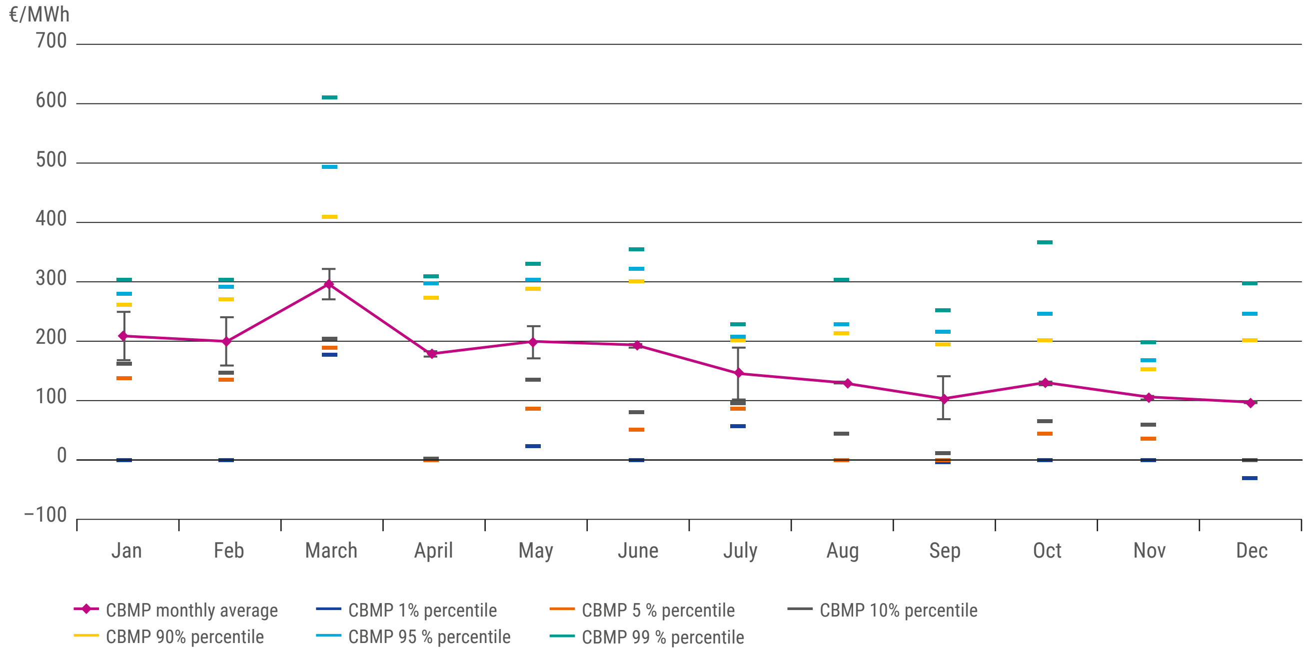
KPI 6.3.4.6 RR platform: repartition of the use of inelastic and elastic need per TSO (% of share of total demand that is being covered by elastic and inelastic demand)



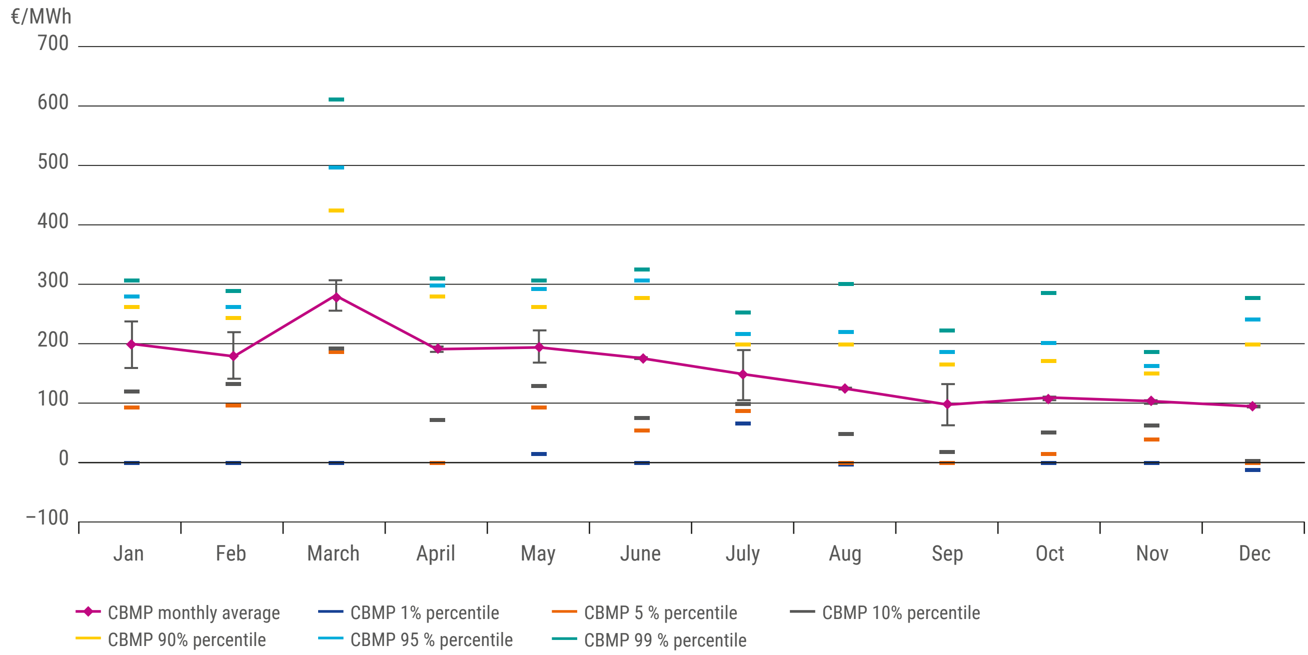
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – ČEPS (EUR/MWh)



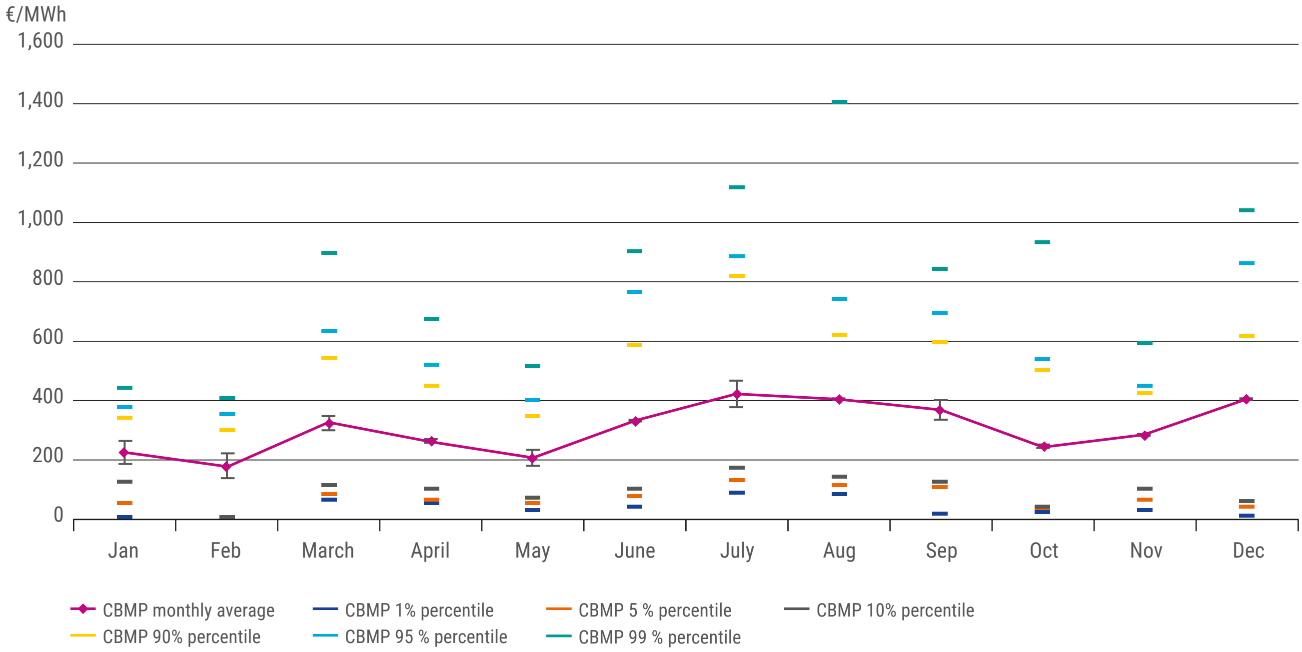
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – REE (EUR/MWh)



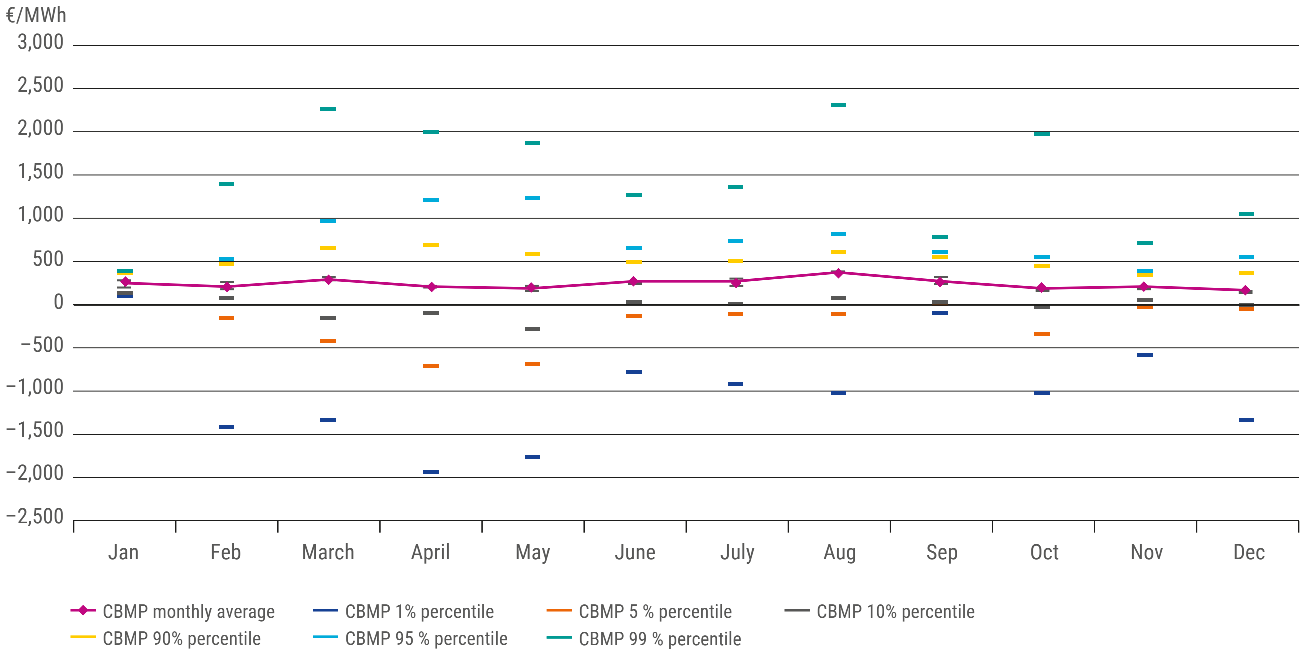
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – REN (EUR/MWh)



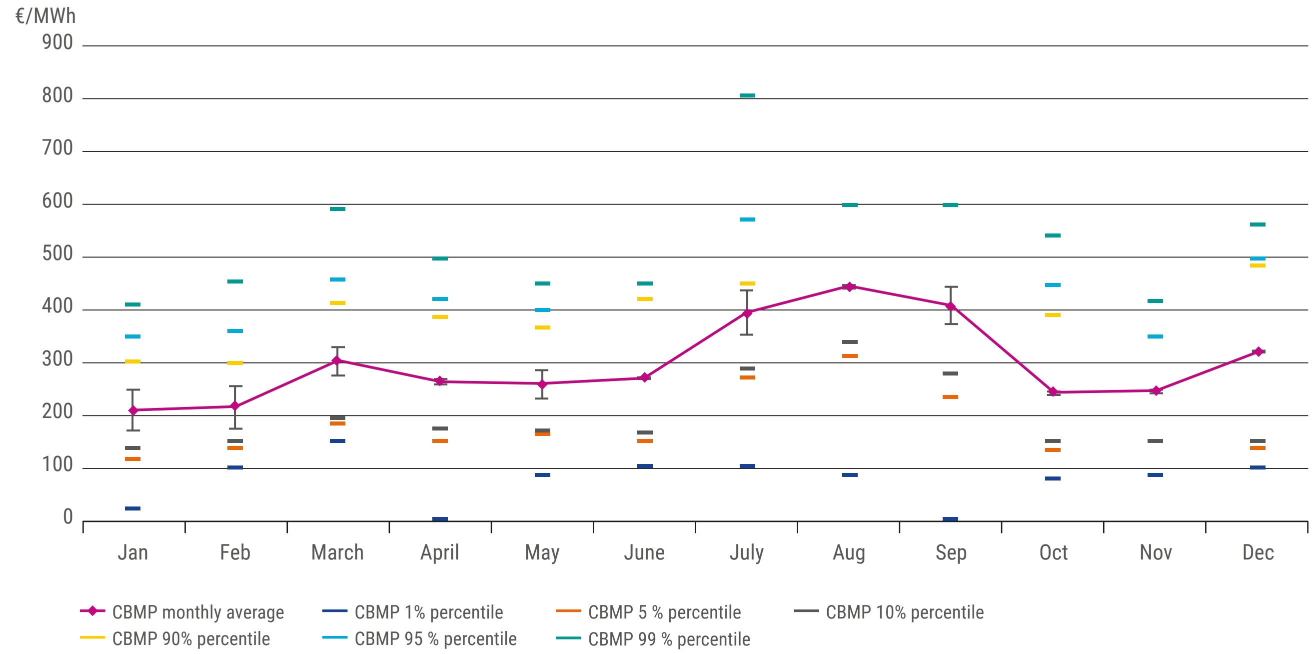
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – RTE (EUR/MWh)



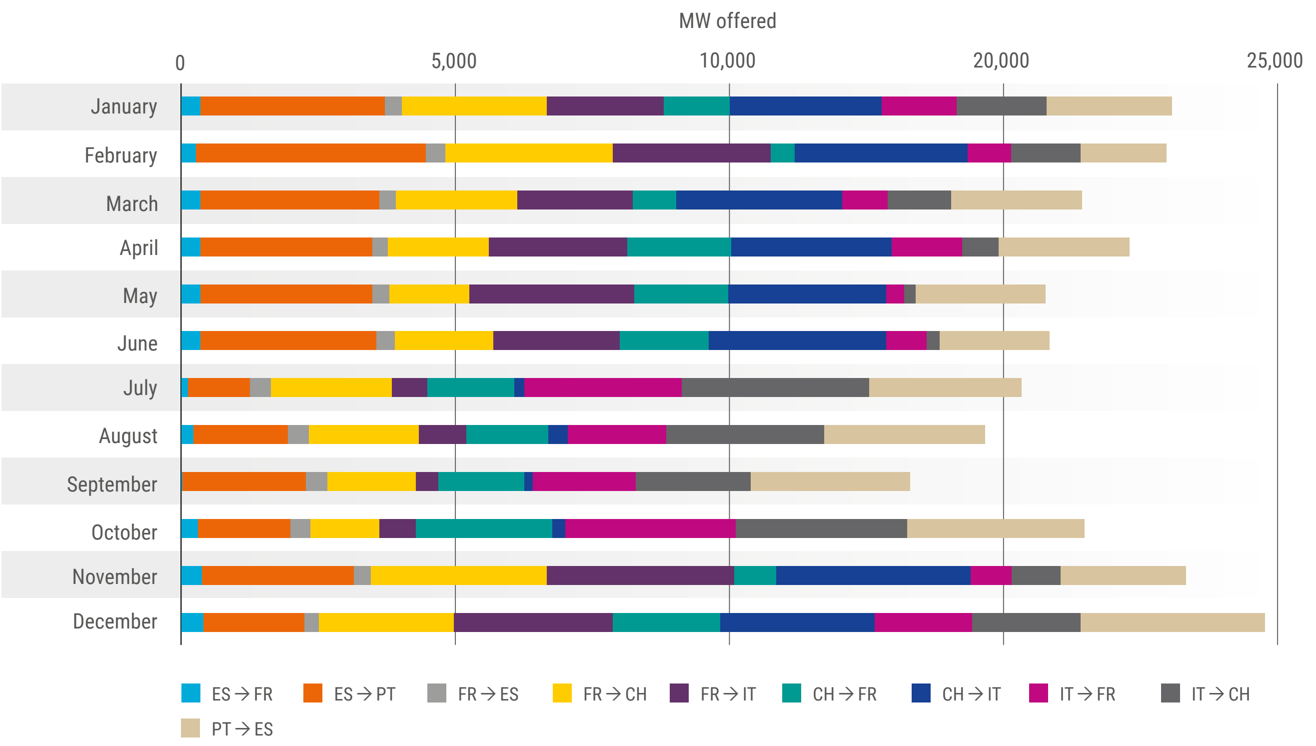
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – SWISSGRID (EUR/MWh)



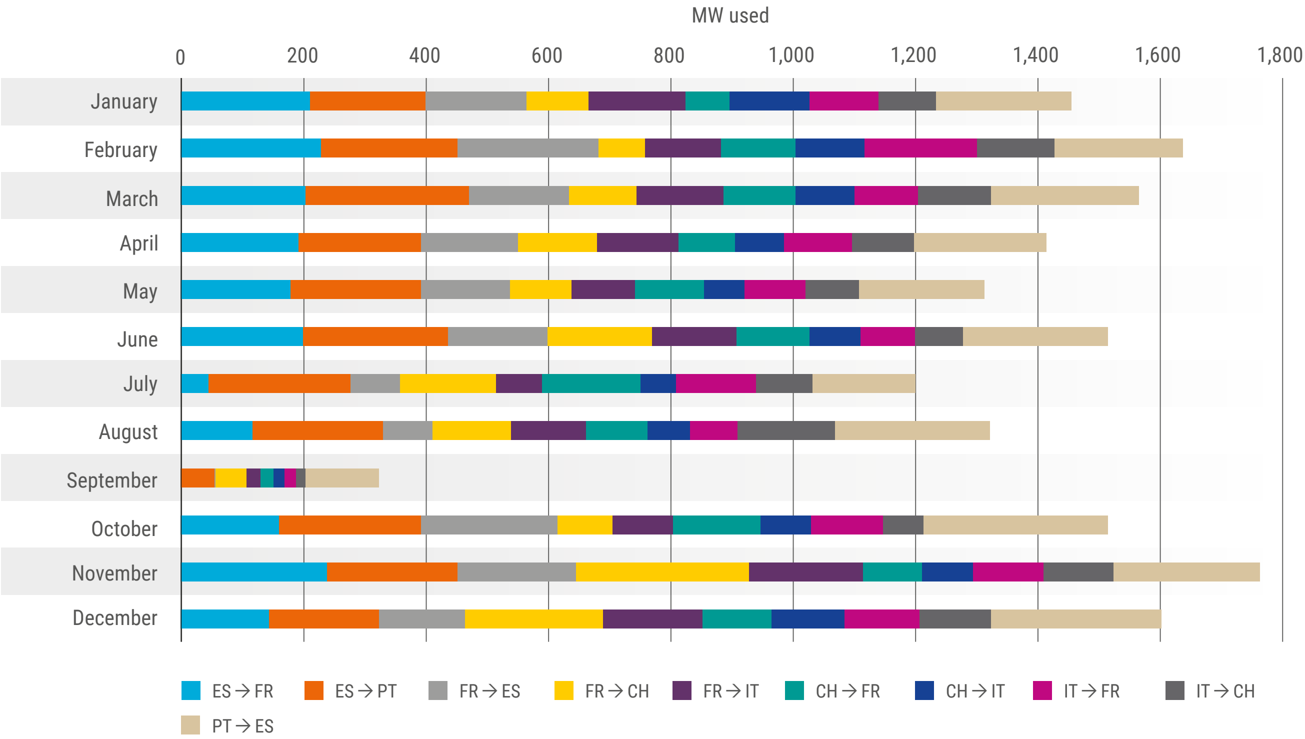
KPI 6.3.4.7 – RR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – TERNA (EUR/MWh)



KPI 6.3.4.8 – RR platform: monthly average value of the available CZC per bidding zone border and per direction (MW)



KPI 6.3.4.8 – RR platform: monthly average value of the used CZC per bidding zone border and per direction (MW)

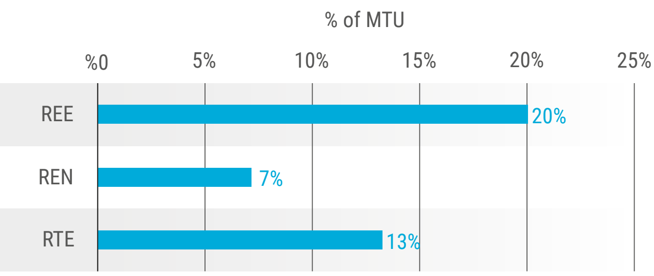


KPI 6.3.4.9 – RR platform: monthly average value of the number of uncongested areas

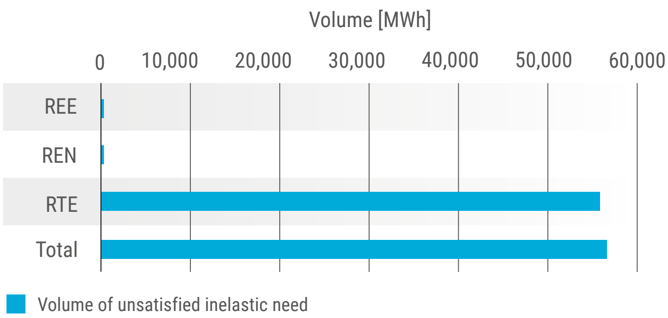
Month	Average value of uncongested LFC areas (max. 14)	Month	Average value of uncongested LFC areas (max. 14)	Month	Average value of uncongested LFC areas (max. 14)	Month	Average value of uncongested LFC areas (max. 14)
January	3.18	April	4.69	July	5.64	October	5.05
February	4.55	May	5.43	August	5.27	November	5.13
March	4.95	June	5.59	September	5.09	December	5.26

The maximum number of uncongested LFC areas is 14.

KPI 6.3.4.10 – RR platform: number of occurrences (% of MTU) of unsatisfied inelastic need / TSO and its volume (MWh)



Number of occurrences (% of MTU) of unsatisfied inelastic need

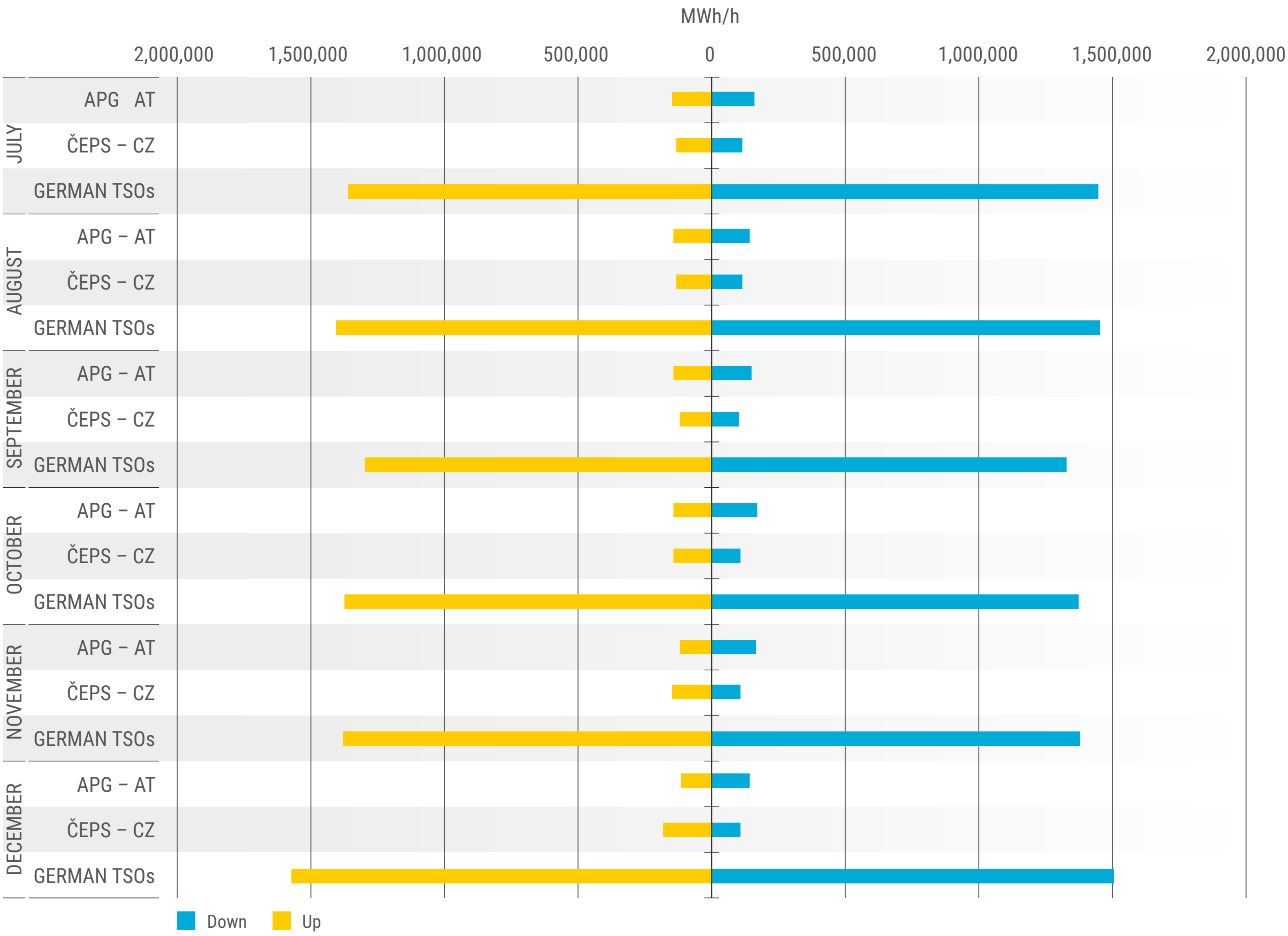


Volume of unsatisfied inelastic need (MWh)

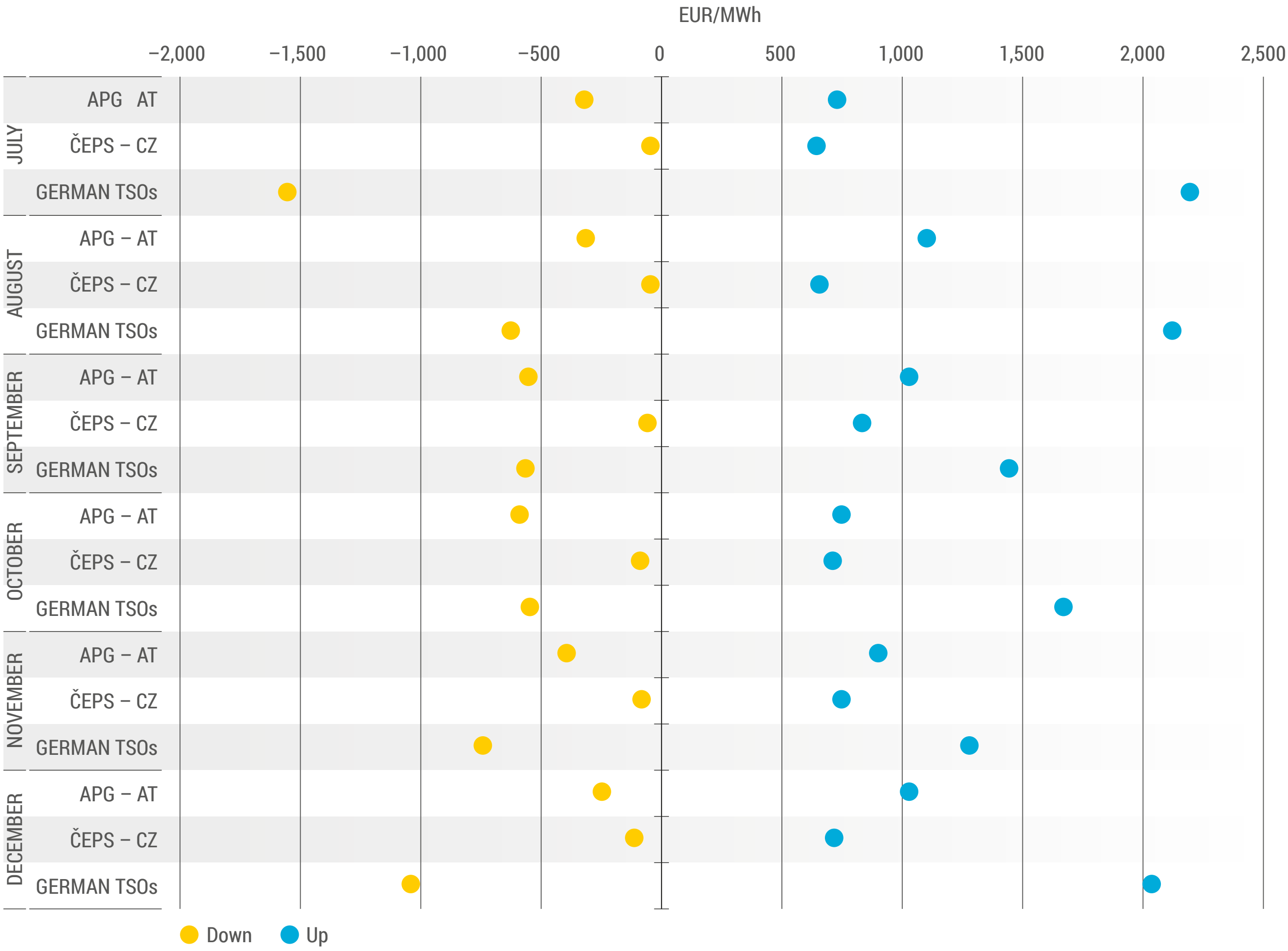
KPI 6.3.4.11 – RR platform: incident overview.

No incidents occurred.

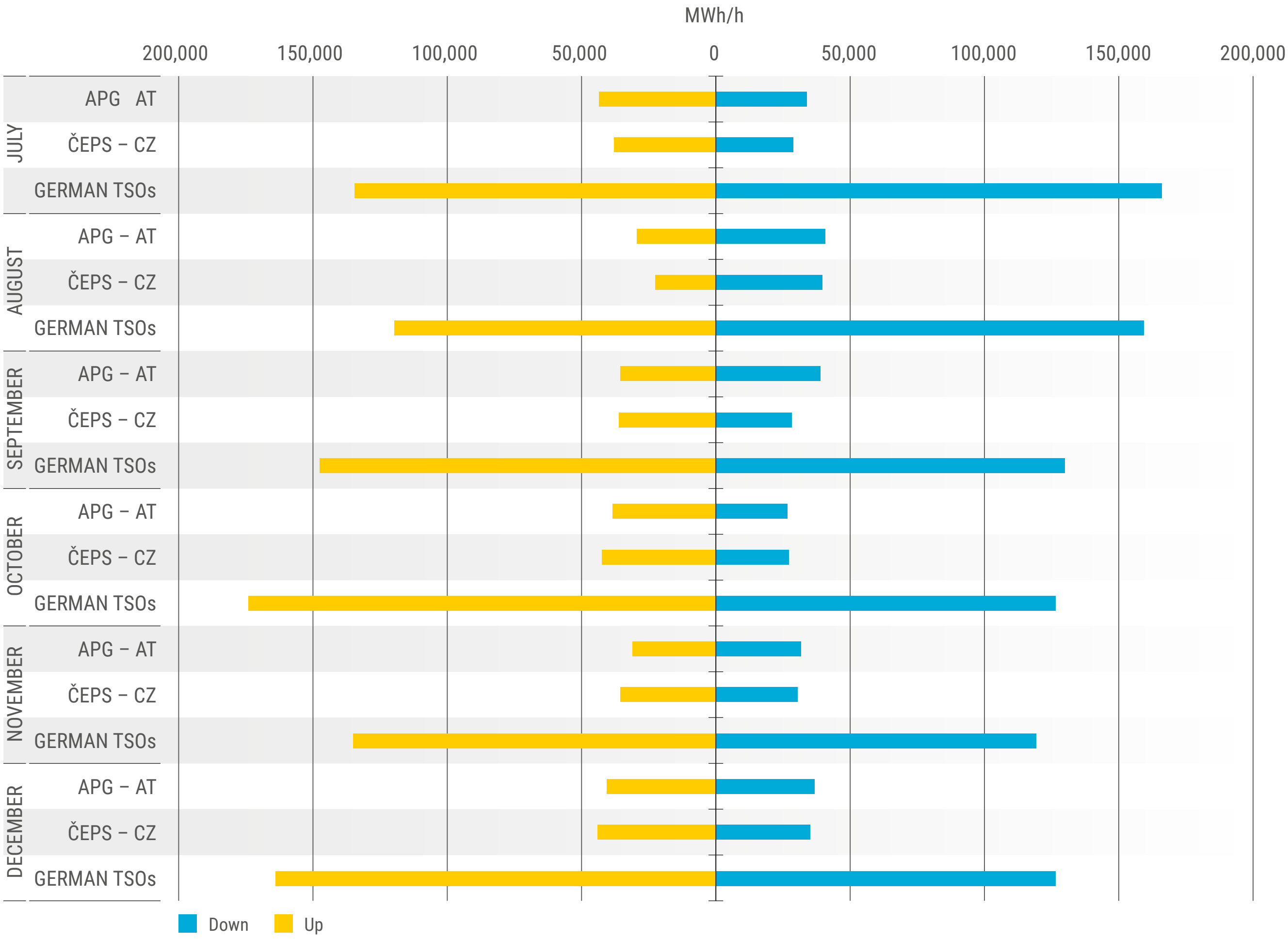
KPI 6.3.4.1 – aFRR platform: monthly volume (MWh) of submitted bids per direction and per TSO



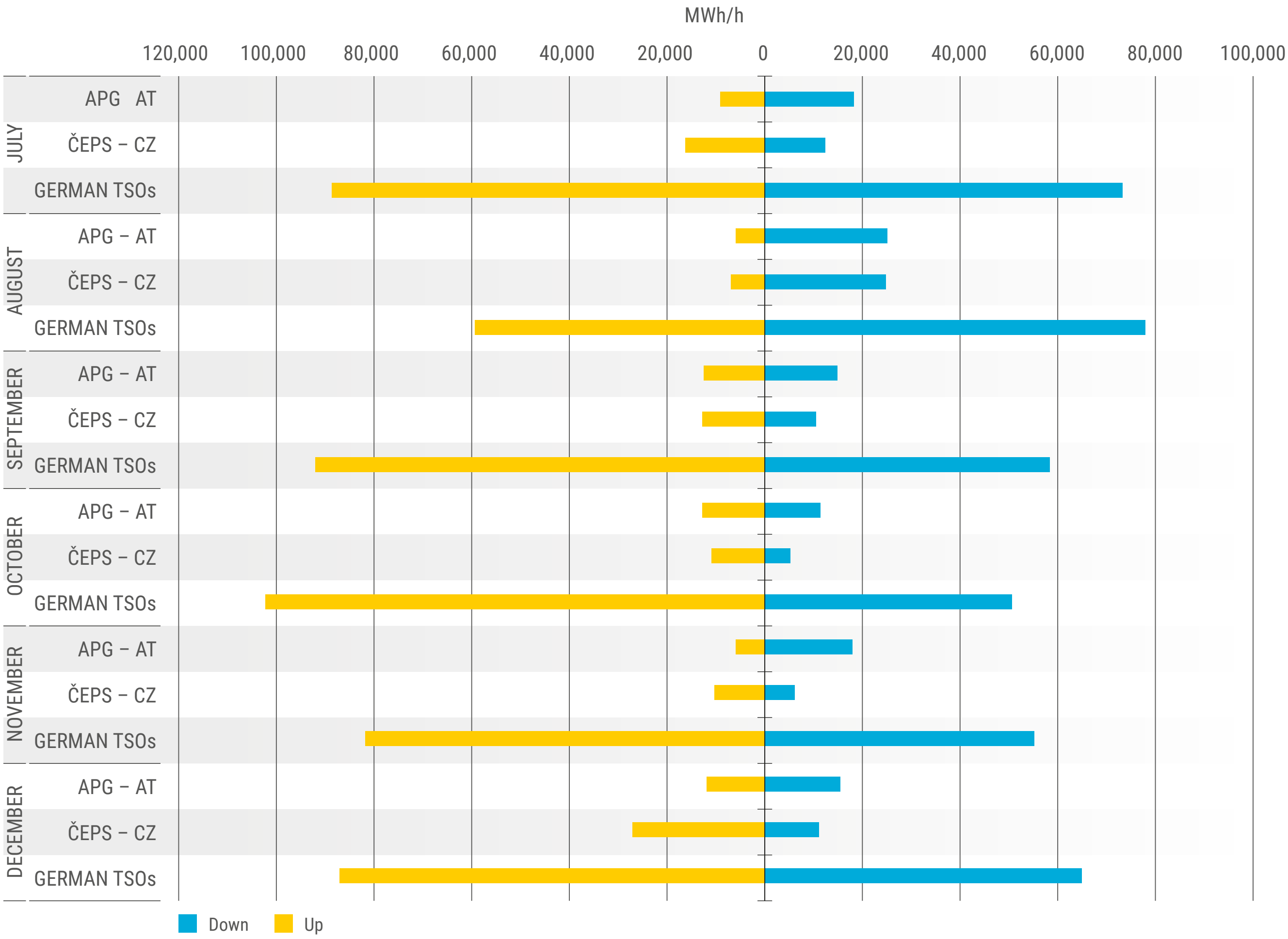
KPI 6.3.4.1 – aFRR platform: volume weighted average prices (EUR/MWh) of submitted bids per direction and per TSO



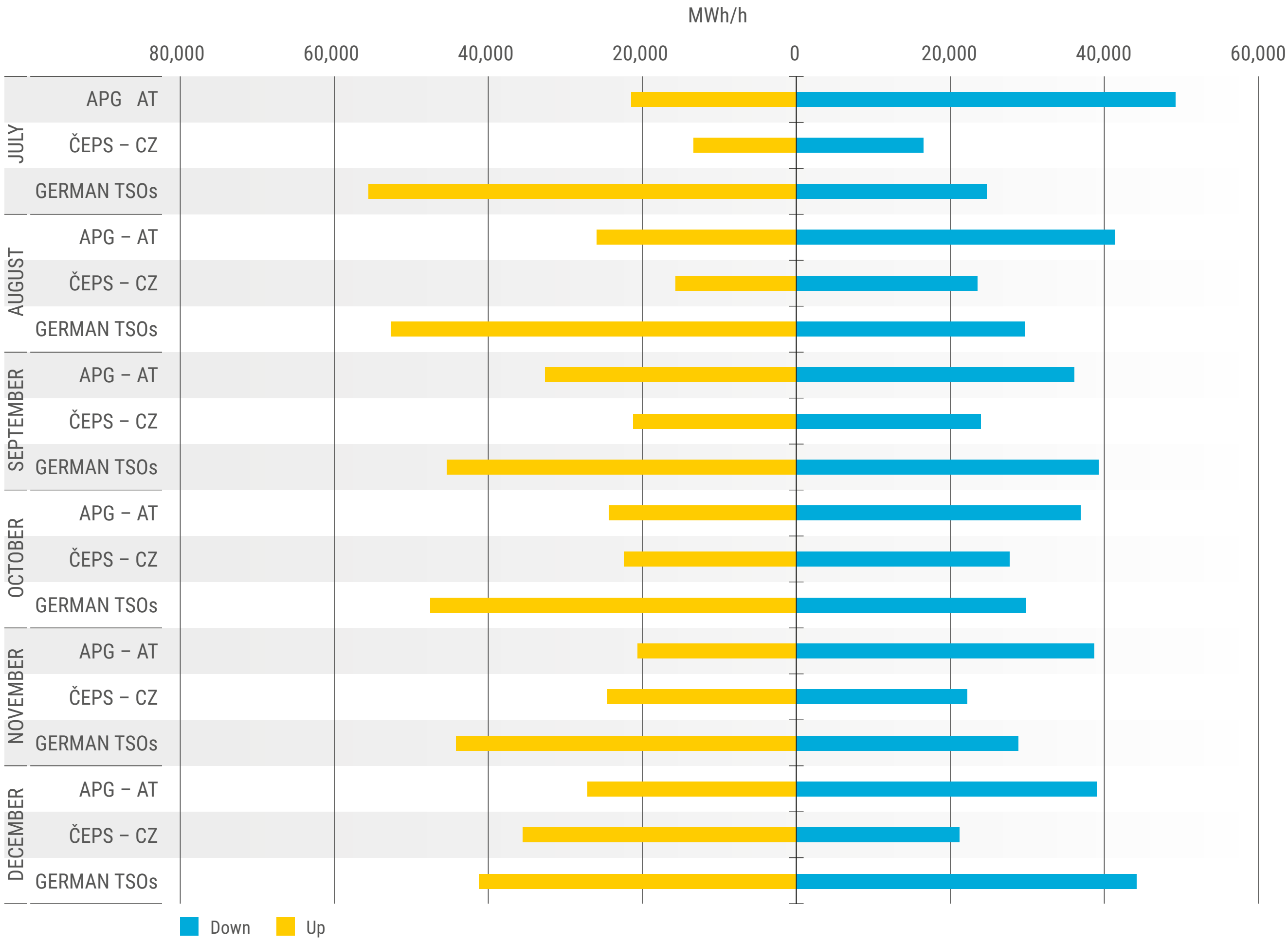
KPI 6.3.4.2 – aFRR platform: monthly volume of demand per direction and per TSO (MWh)



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



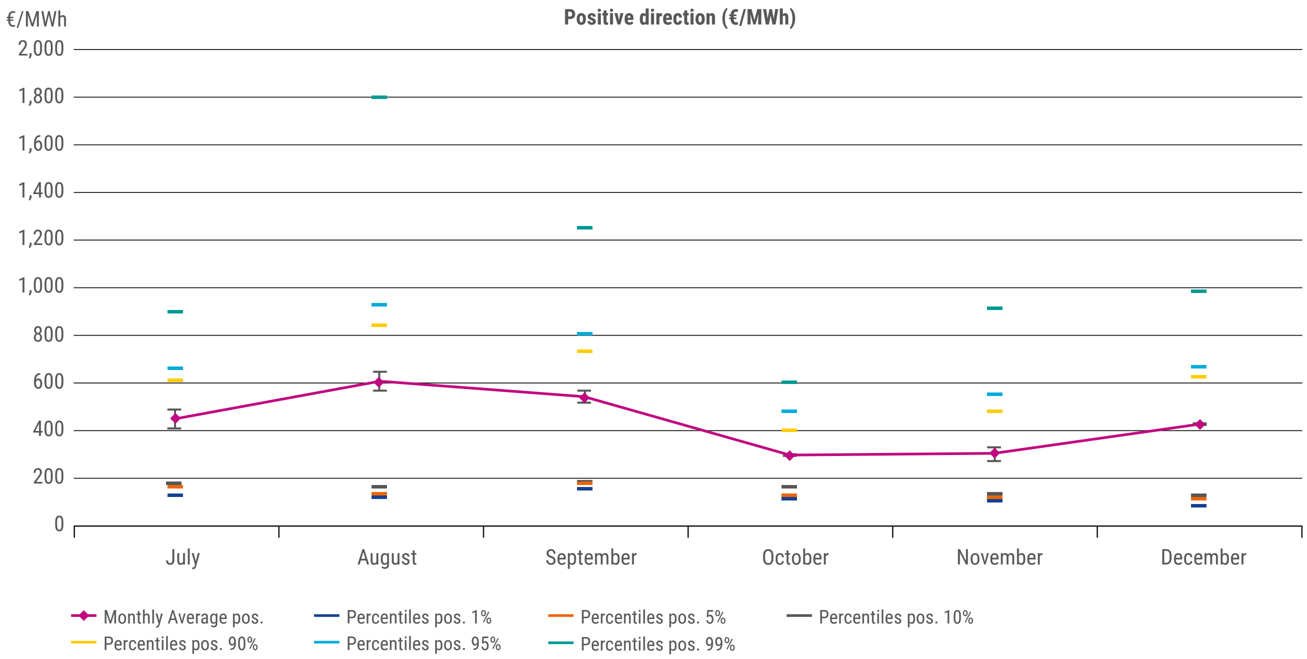
KPI 6.3.4.4/6.3.4.5 – aFRR platform: monthly volumes of imports / exports per TSO (MWh)

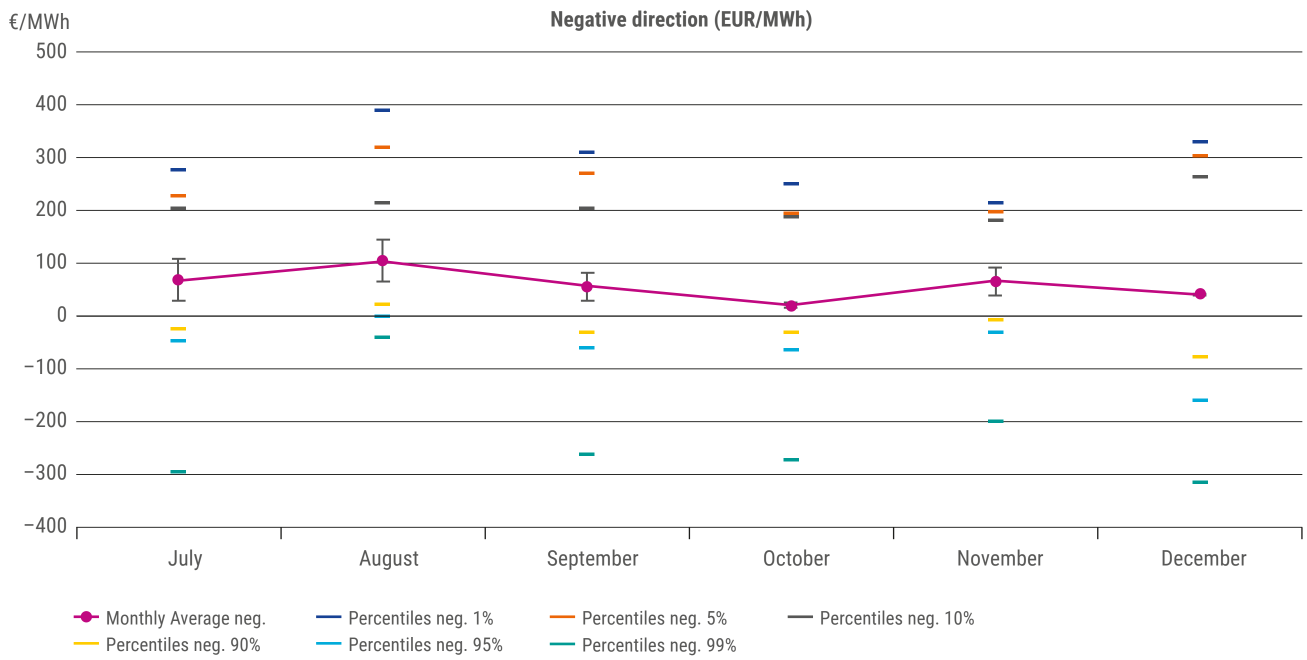


KPI 6.3.4.6 aFRR platform: repartition of the use of inelastic and elastic need per TSO

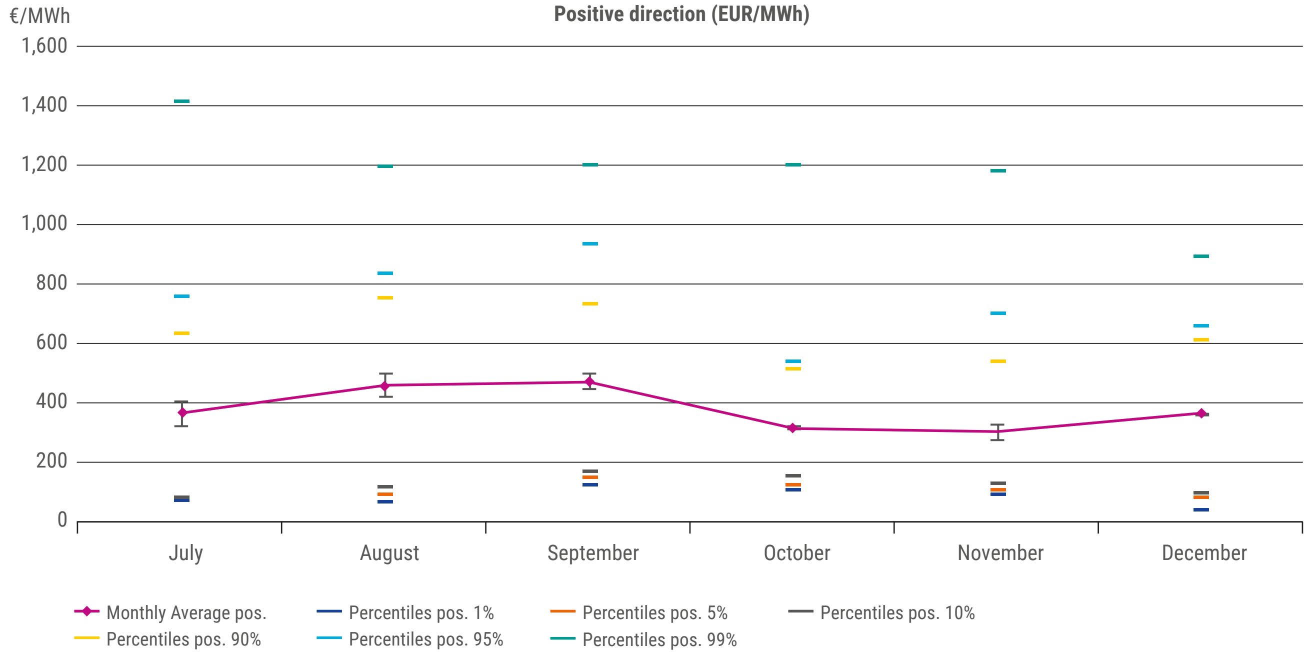
Not used.

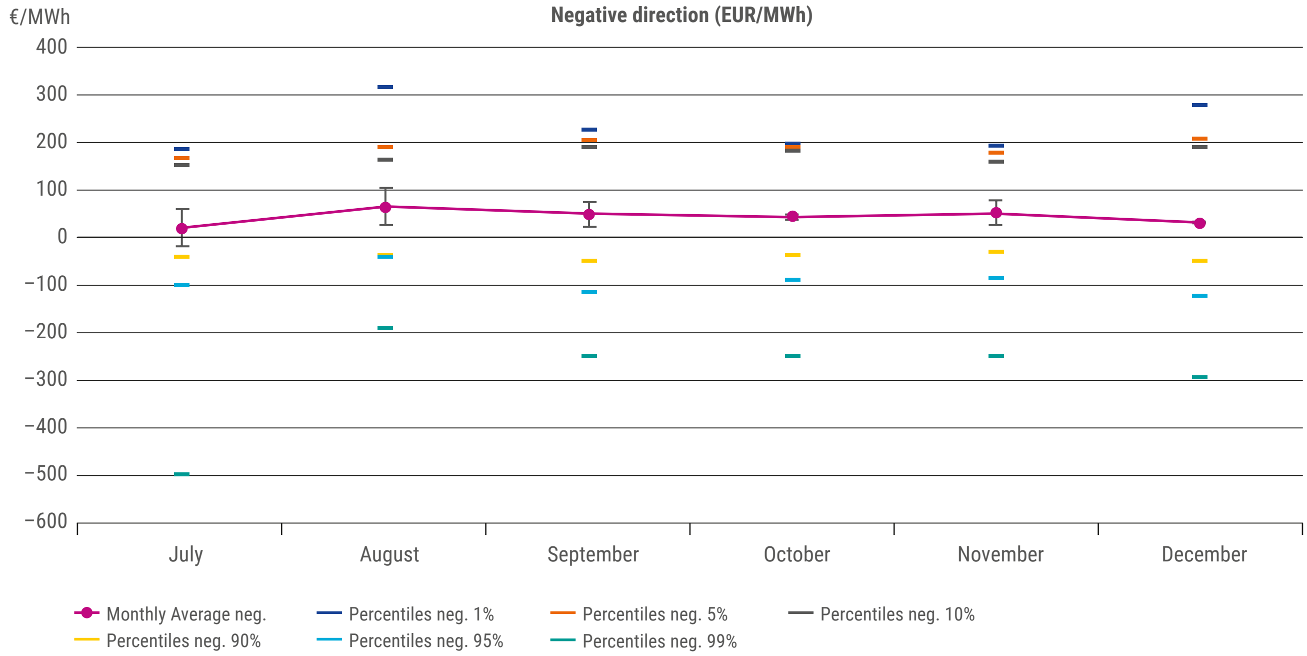
KPI 6.3.4.7 – aFRR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – APG (EUR/MWh)



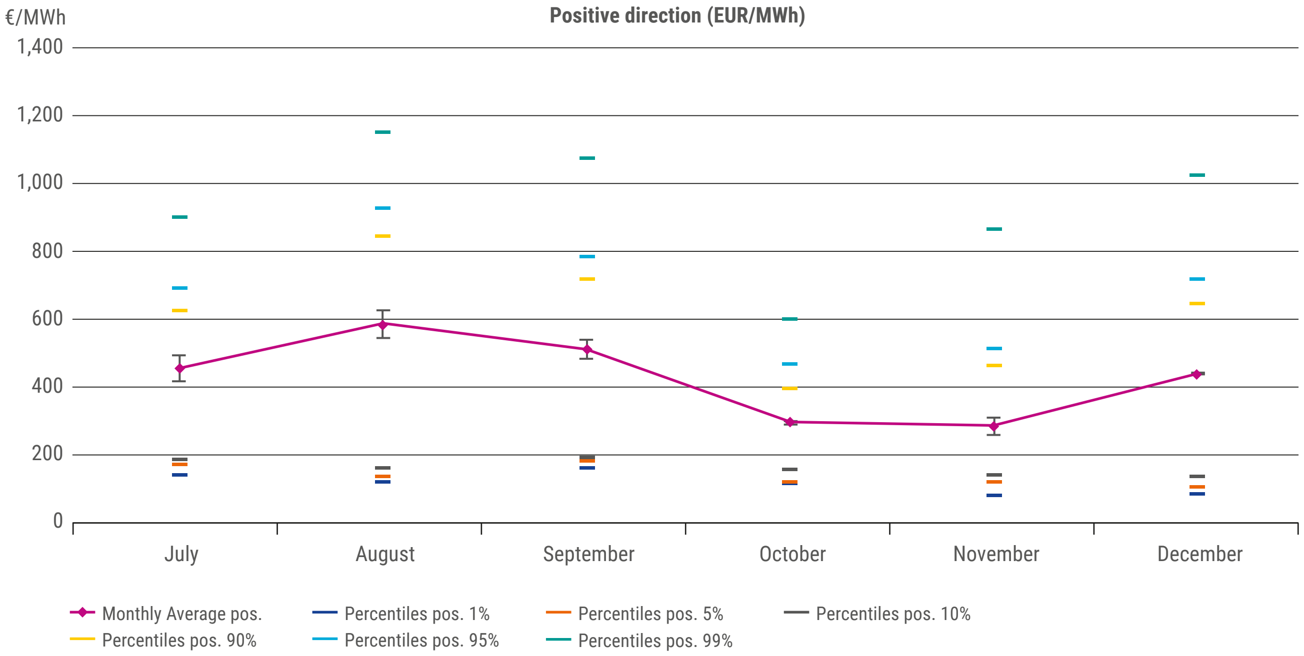


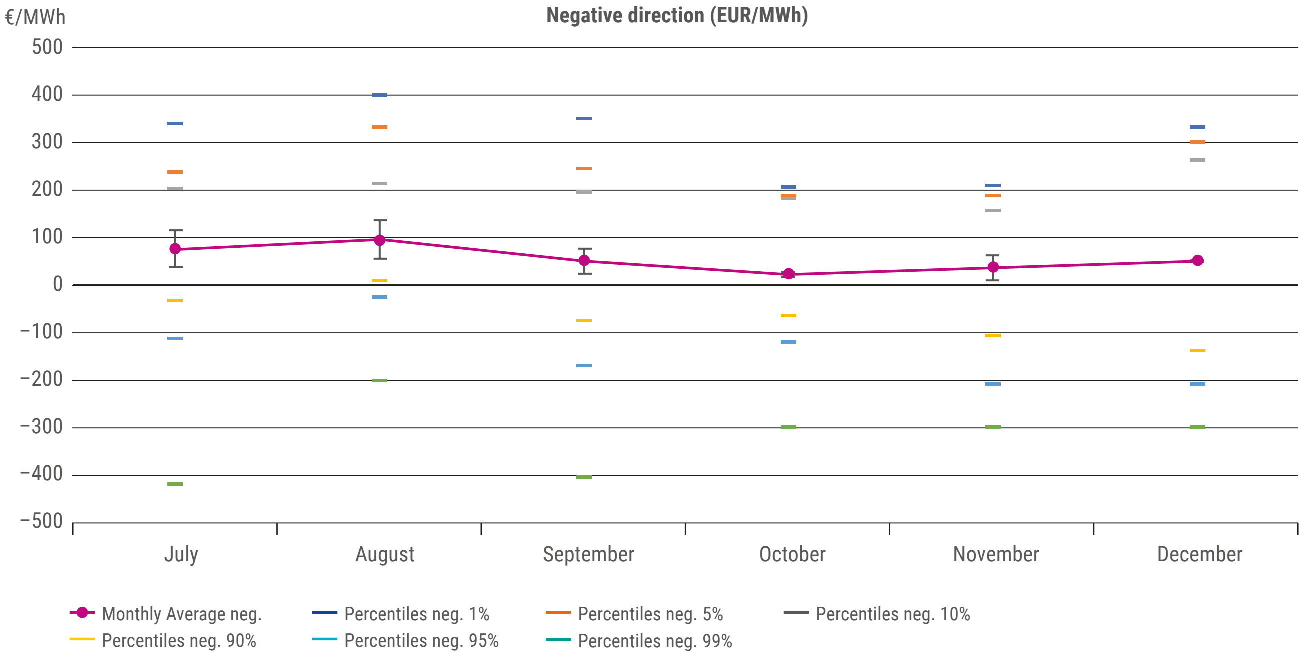
KPI 6.3.4.7 – aFRR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – ČEPS (EUR/MWh)



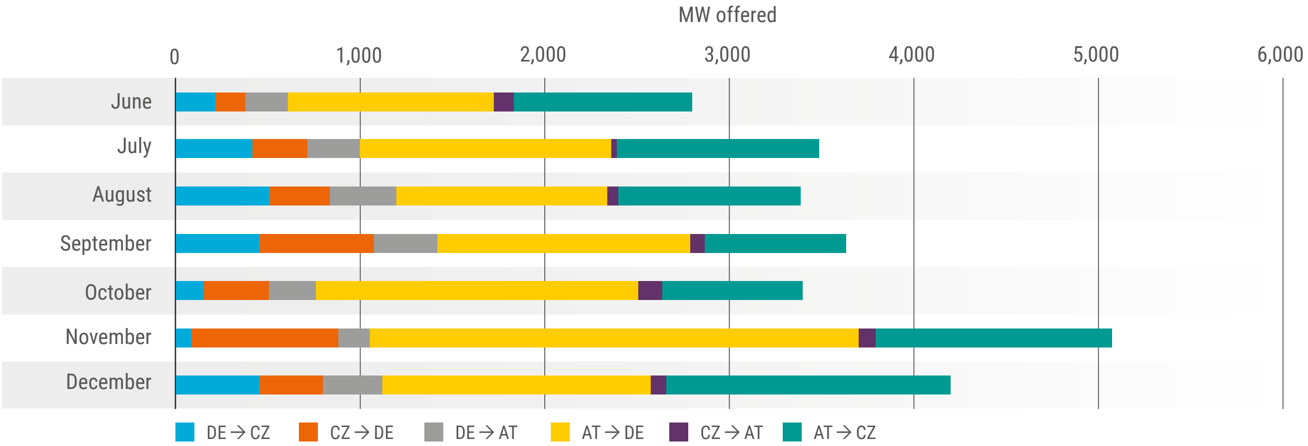


KPI 6.3.4.7 – aFRR platform: monthly average and standard deviation values and distribution of the CBMP per TSO (percentiles 1%; 5%, 10%, 90%, 95%, 99%) – GERMAN TSOs (EUR/MWh)

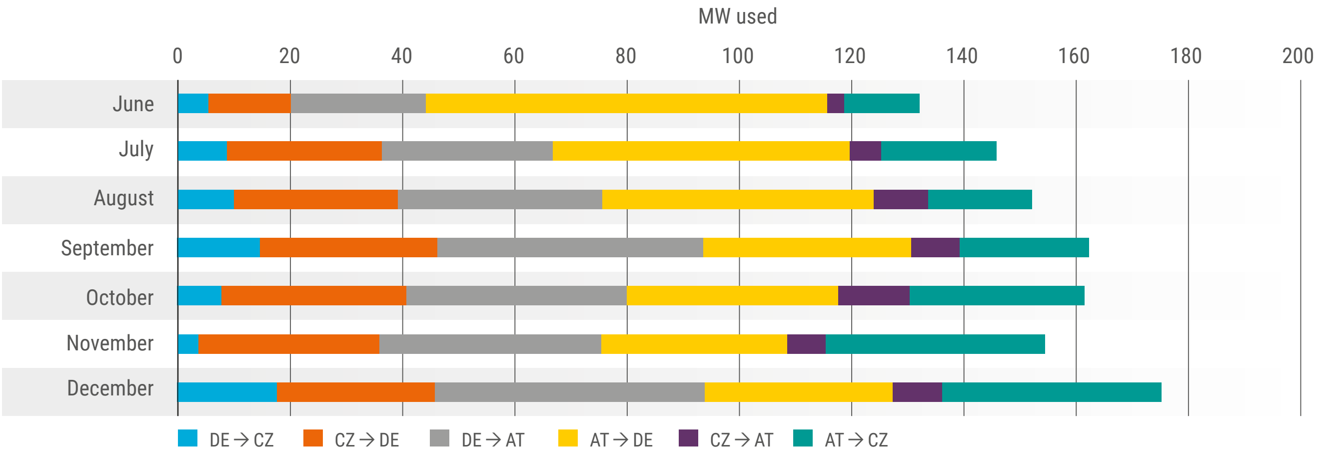




KPI 6.3.4.8 – aFRR platform: monthly average value of the available CZC per bidding zone border and per direction (MW)



KPI 6.3.4.8 – aFRR platform: monthly average value of the used CZC per bidding zone border and per direction (MW)

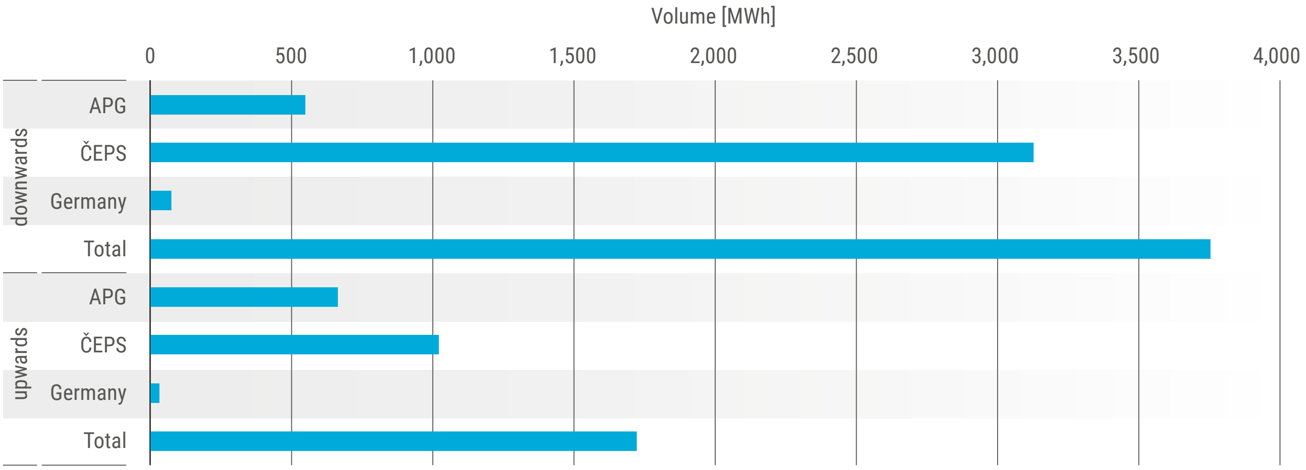


KPI 6.3.4.9 – aFRR platform: monthly average value of the number of uncongested areas

Month	Average value of uncongested LFC areas (max. 3)	Month	Average value of uncongested LFC areas (max. 3)
July	1.98	October	1.64
August	1.75	November	1.74
September	1.71	December	1.75

The maximum number of uncongested LFC areas is three.

KPI 6.3.4.10 – aFRR platform: number of occurrences (% of MTU) of unsatisfied inelastic need / TSO and its volume (MWh)



Volume of unsatisfied inelastic need (MWh)

KPI 6.3.4.11 – aFRR platform: incident overview

No incidents occurred.

6.3.5 The possible inefficiencies and distortions on balancing markets[87]

Definition

This indicator assesses the following data for each balancing platform and for each month:

- Cross-zonal capacity available and used by the balancing energy platform. Each balancing energy platform needs to report four values per BZ border: the CZC initially (considering remaining capacity after the consecutive previous processes that affect each border: 1) 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 to be calculated for each balancing energy platform per each 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.

Legal reference	Article 59(4)(f) of the EB Regulation*
Time reference	Yearly with monthly granularity

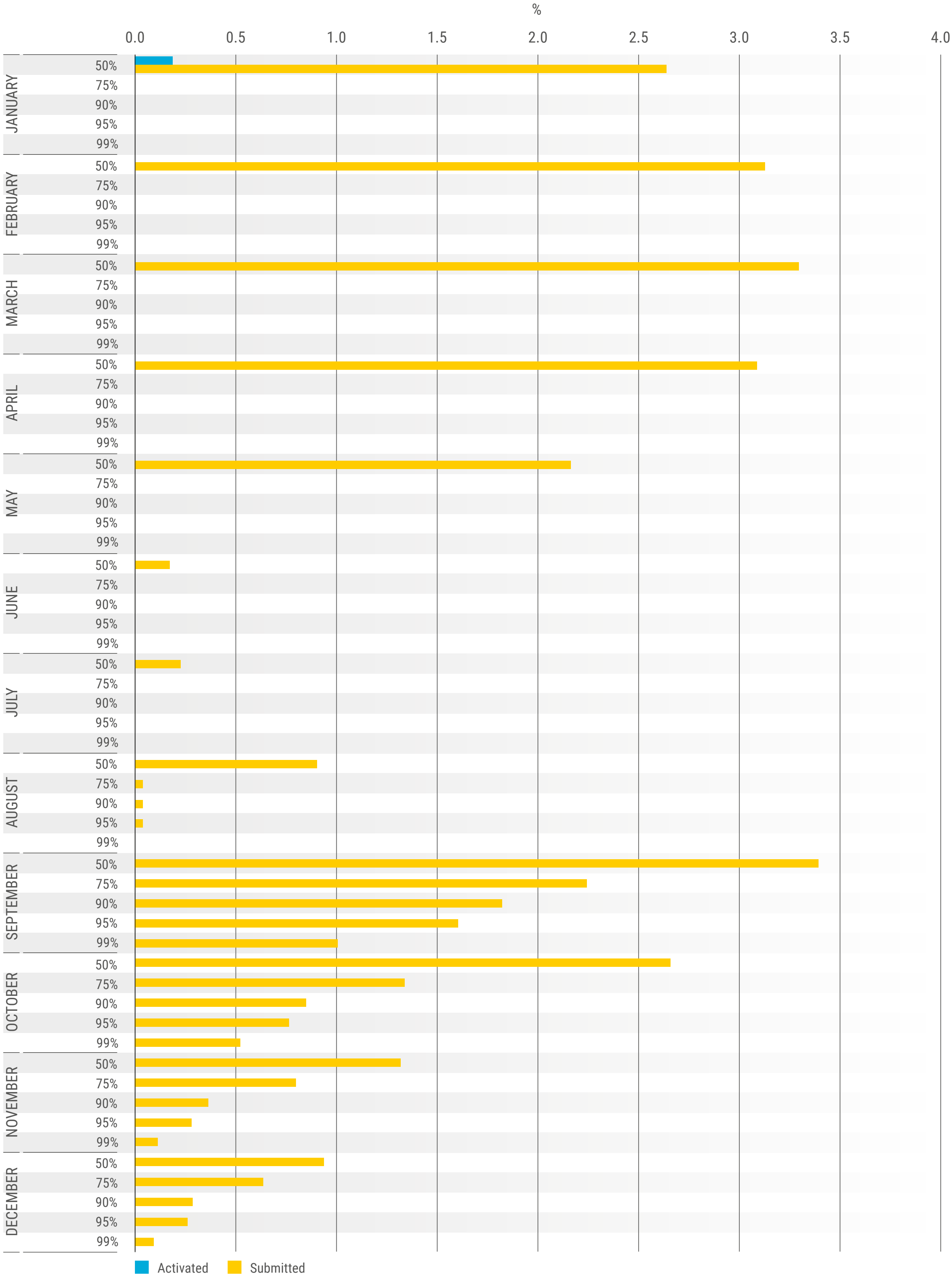
Table 19: Indicator 6.3.5 on the possible inefficiencies and distortions on balancing markets (* After the going operational of the approved implementation frameworks for the European platforms pursuant to Articles 19(5), 20(6), 21(6) and 22(5) of the EB Regulation. Further changes shall be done in accordance with Article 59(9) of the EB Regulation.)

KPI 6.3.5.1: Cross-zonal capacity available and used

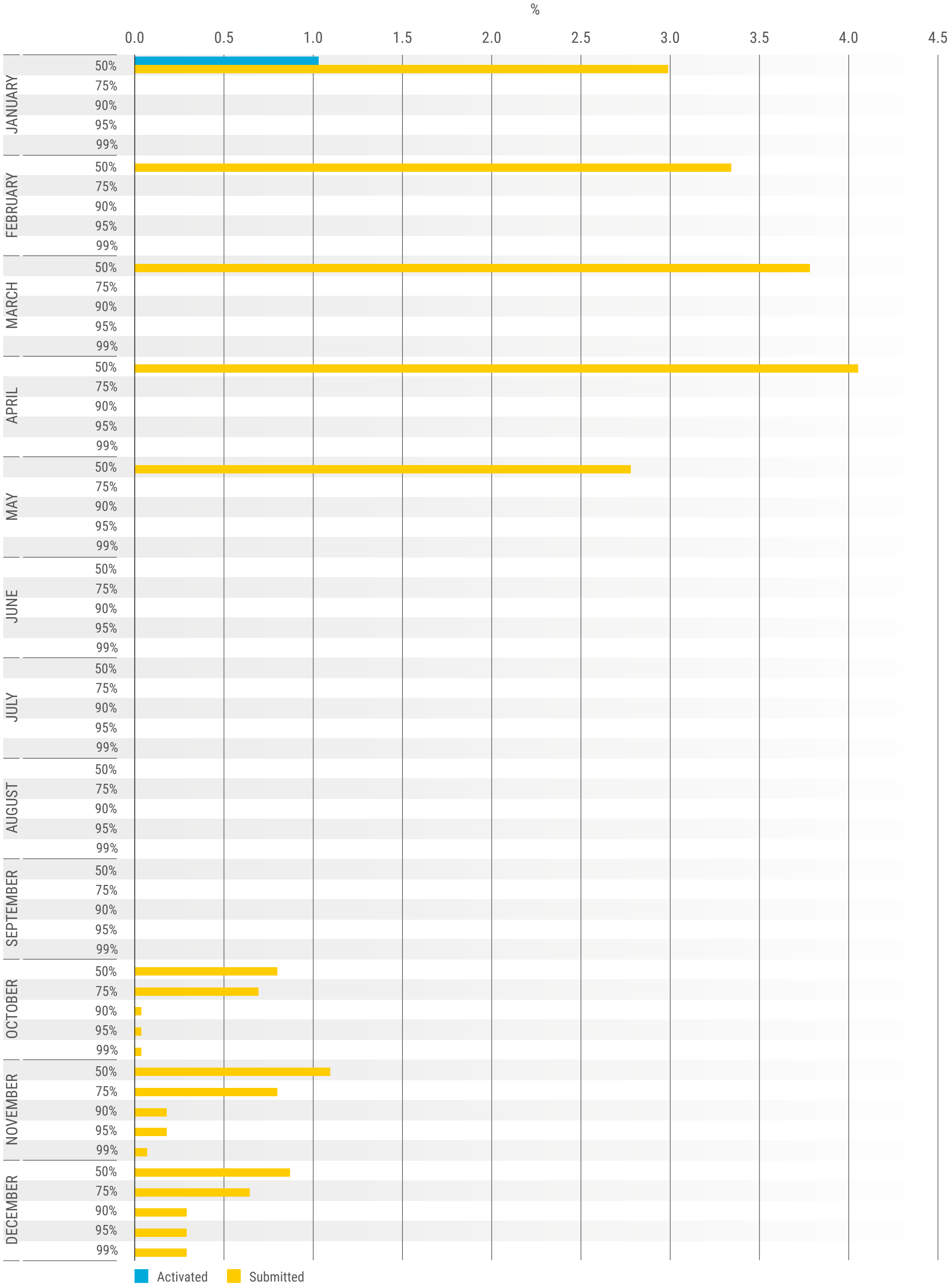
87 The annual and bi-annual reports will include links to the quarterly reports arising from the pricing methodology, where a higher level of analysis of price incidents are accomplished.

KPI 6.3.5.2 – RR platform: 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

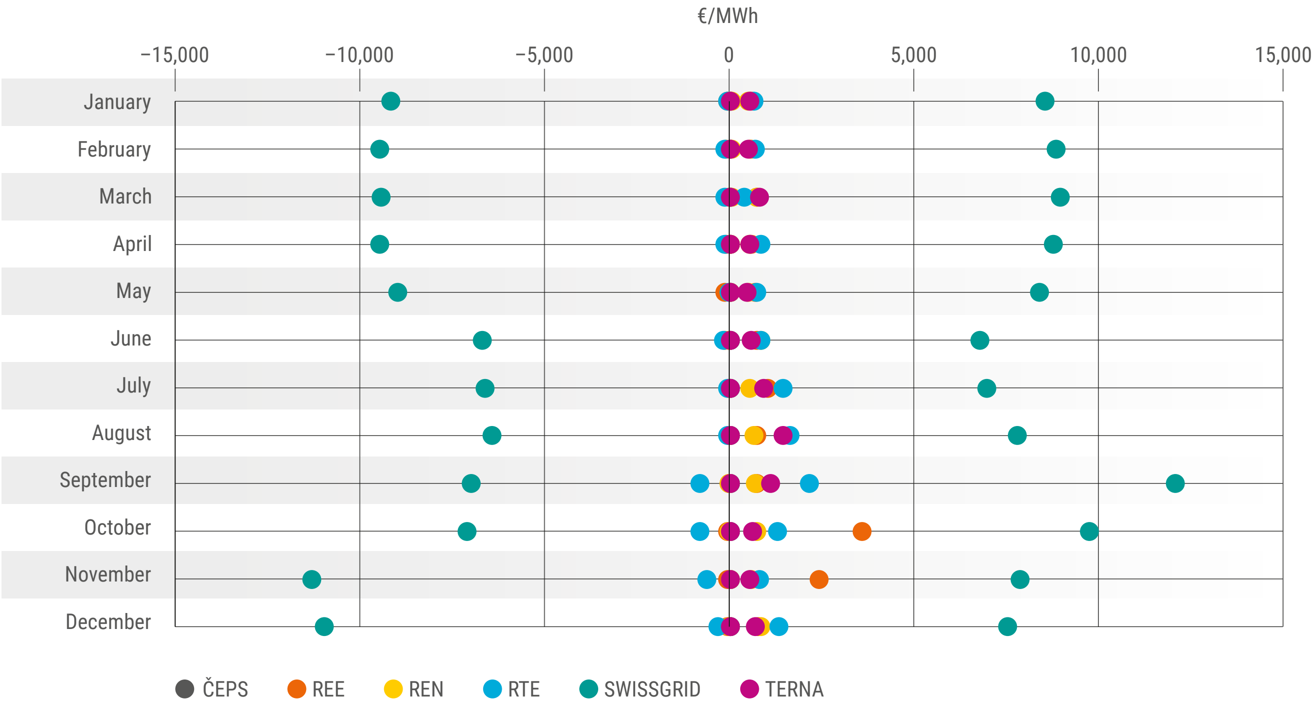
Average percentage per month of both submitted and activated standard balancing energy bids in positive direction with prices higher than 50 %, 75 %, 90 %, 95 % and 99 % of the upper or lower transitory price limit



Average percentage per month of both submitted and activated standard balancing energy bids in negative direction with prices higher than 50 %, 75 %, 90 %, 95 % and 99 % of the upper or lower transitory price limit

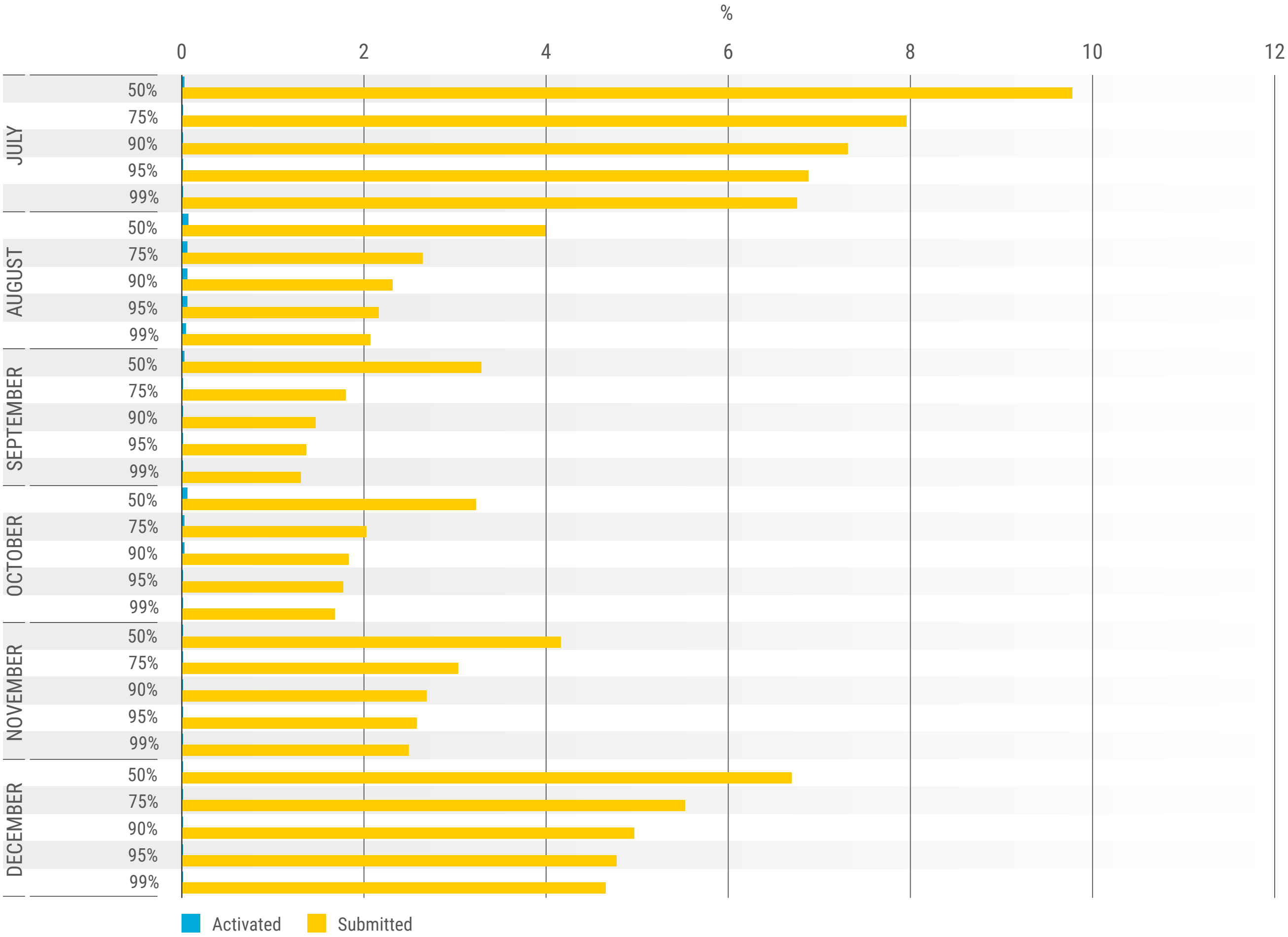


KPI 6.3.5.3 – RR platform: monthly volume weighted average price of the last (most expensive) 5% of the volume of submitted standard balancing energy bids per direction and per participating TSO – downward direction to the left side, upward direction to the right side (EUR/MWh)

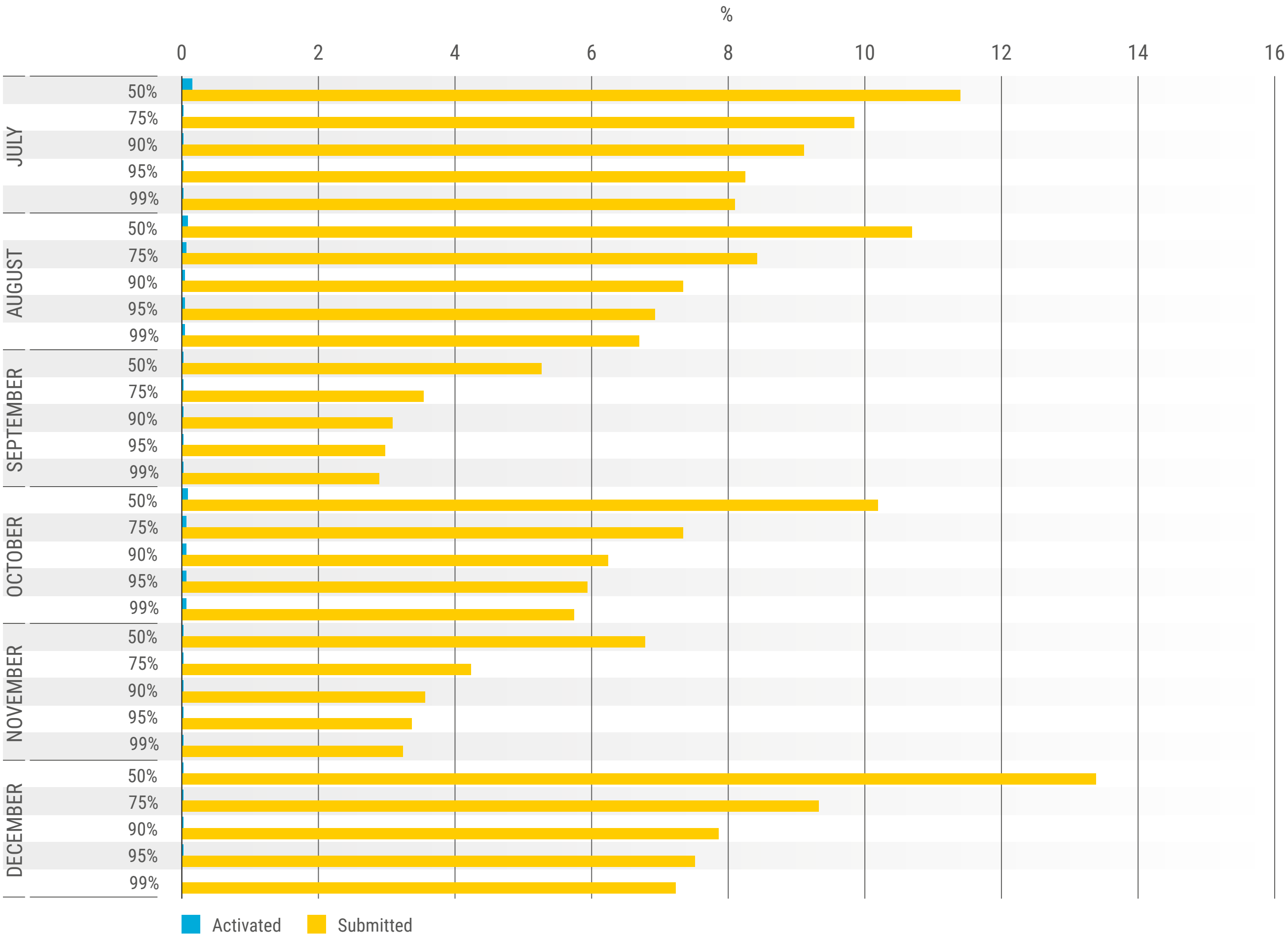


KPI 6.3.5.2 – aFRR platform: the average percentage of both submitted and activated standard balancing energy bids per product and per direction with prices higher than 50%, 75%, 90%, 95% and 99% of the upper or lower transitory price limit

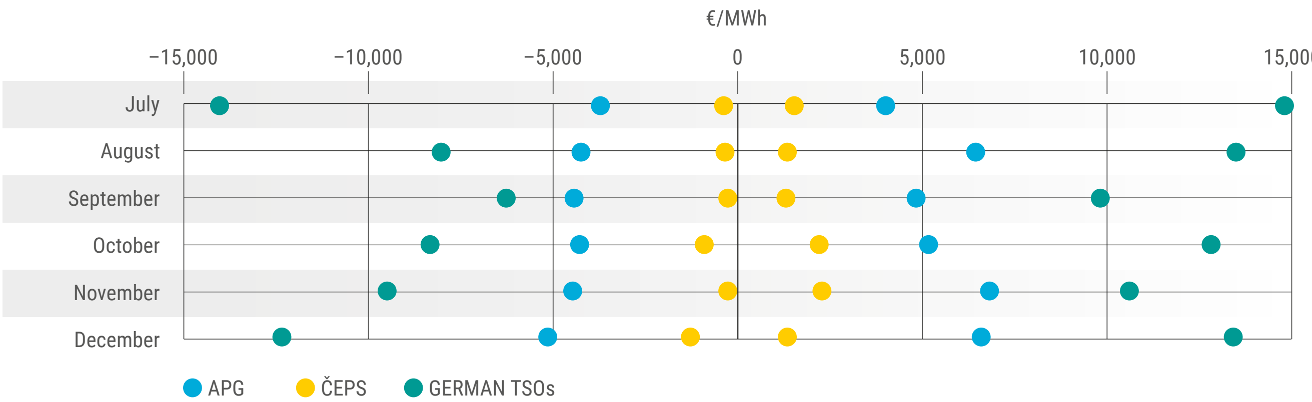
Average percentage per month of both submitted and activated standard balancing energy bids in positive direction with prices higher than 50 %, 75 %, 90 %, 95 %and 99 % of the upper or lower transitory price limit



Average percentage per month of both submitted and activated standard balancing energy bids in negative direction with prices higher than 50 %, 75 %, 90 %, 95 %and 99 % of the upper or lower transitory price limit



KPI 6.3.5.3 – aFRR platform: monthly volume weighted average price of the last (most expensive) 5% of the volume of submitted standard balancing energy bids per direction and per participating TSO – downward direction to the left side, upward direction to the right side (EUR/MWh)



6.3.6 The 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.

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

Definition

This indicator[88] displays:

- The yearly activated and available volume of balancing energy which is used for balancing purposes per BZ, per process (if applicable per product type), and per direction (GWh).
- The yearly time-average price of the activated balancing energy per BZ, per process (if available, per product type), and per direction (EUR/MWh).

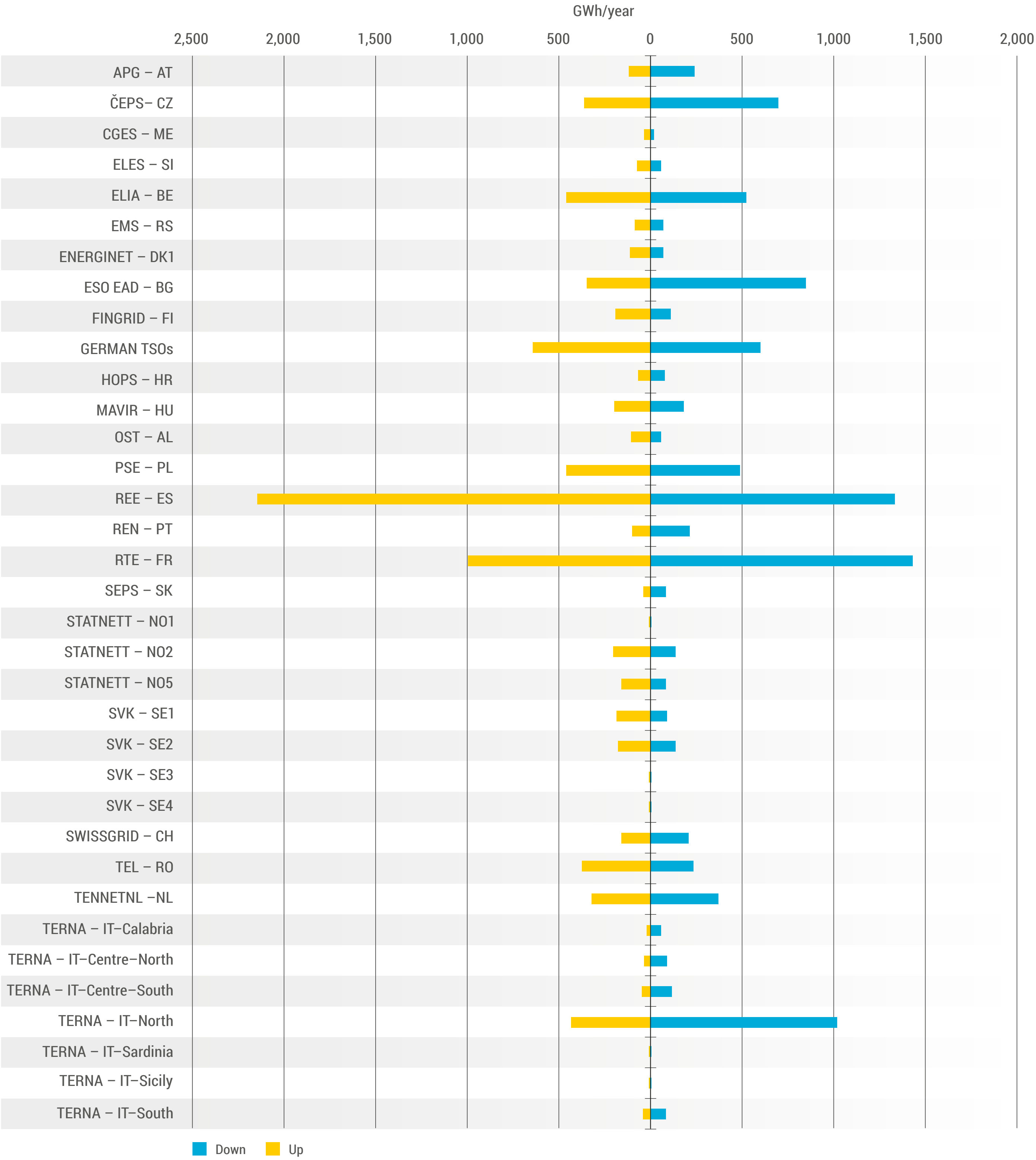
Legal reference	Article 59(4)(h) of the EB Regulation
Time reference	Yearly

Table 20: Indicator 6.3.7 on the volume and price of balancing energy used for balancing purposes

88 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).

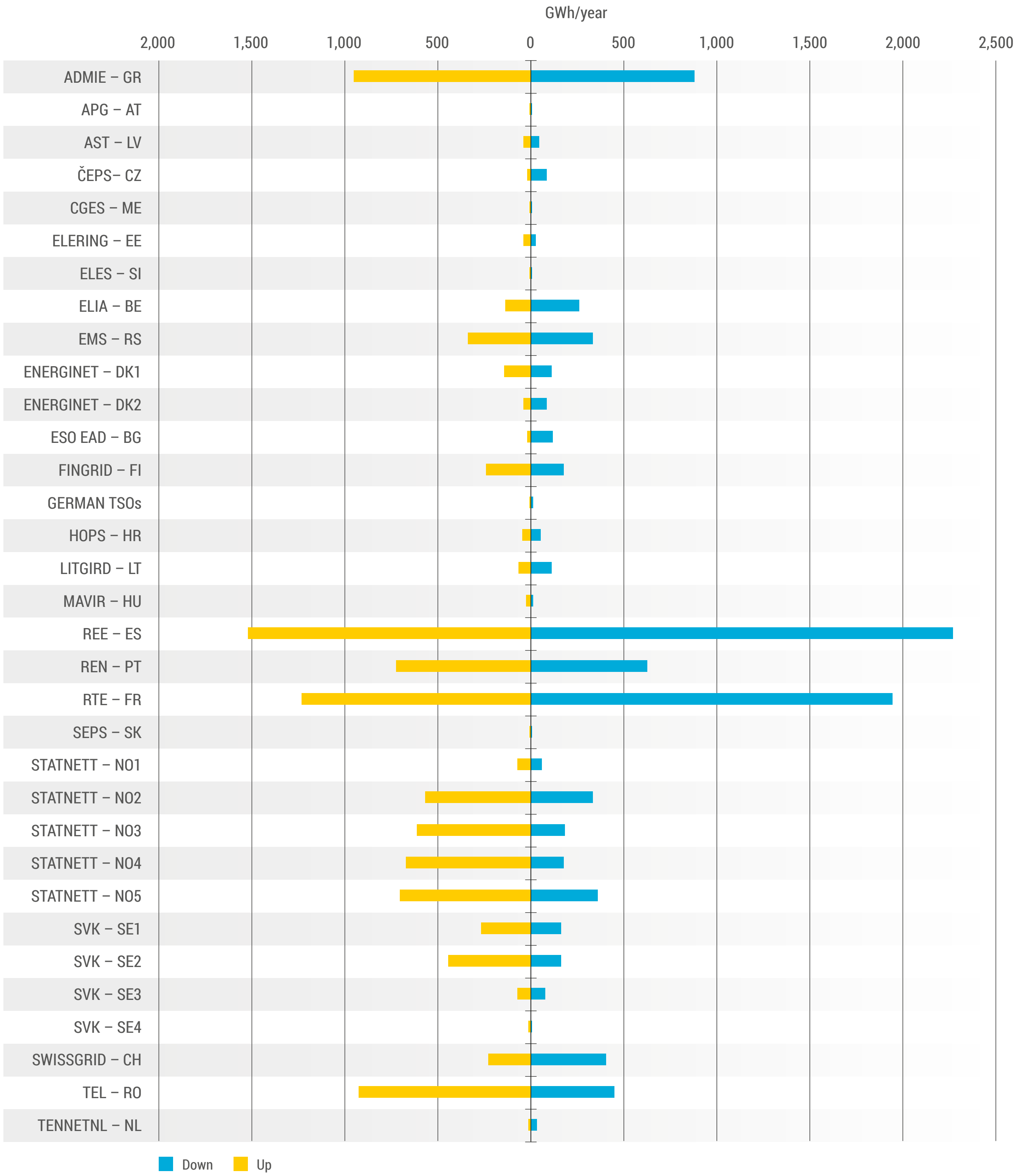
KPI 6.3.7.1 Yearly activated volume of balancing energy which is used for balancing purposes: aFRR (GWh/year)

Disclaimer: ADMIE: no reporting on aFRR due to data problems.

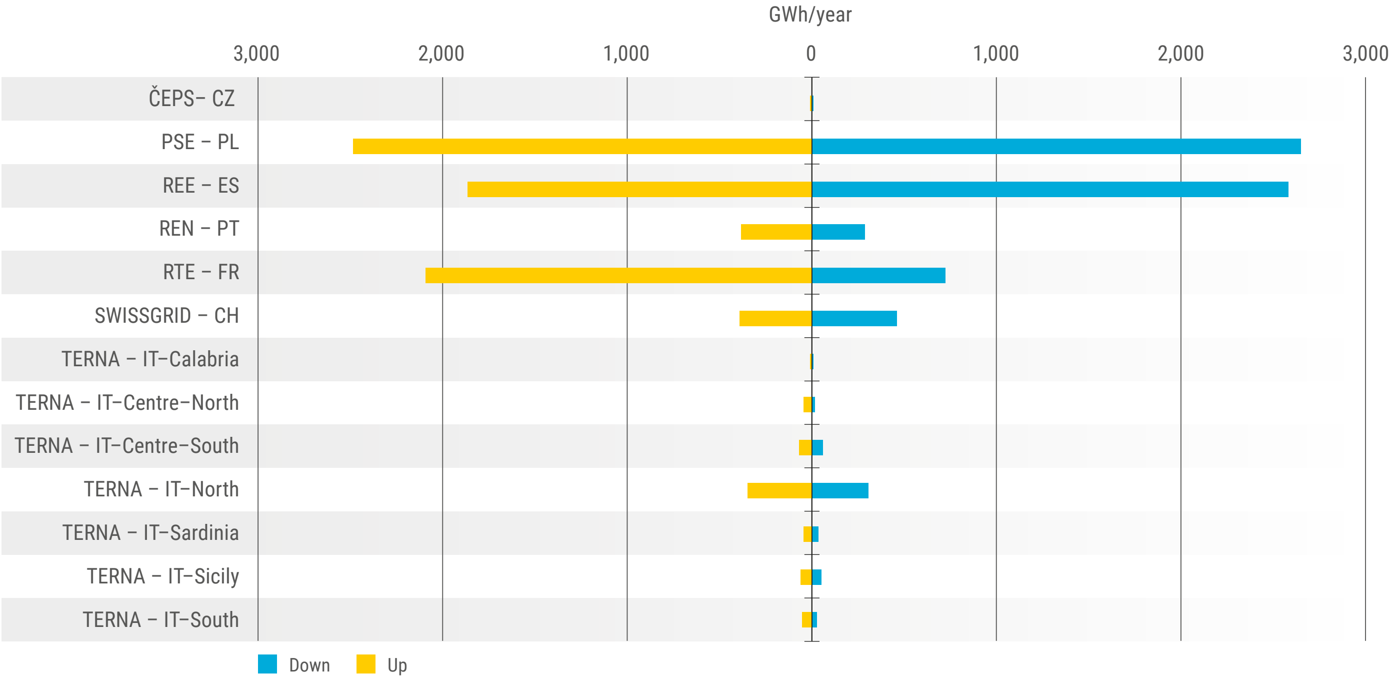


KPI 6.3.7.1 Yearly activated volume of balancing energy which is used for balancing purposes: mFRR (GWh/year)

Disclaimer: ADMIE: The values for ADMIE have been adjusted in order to include only balancing activations.

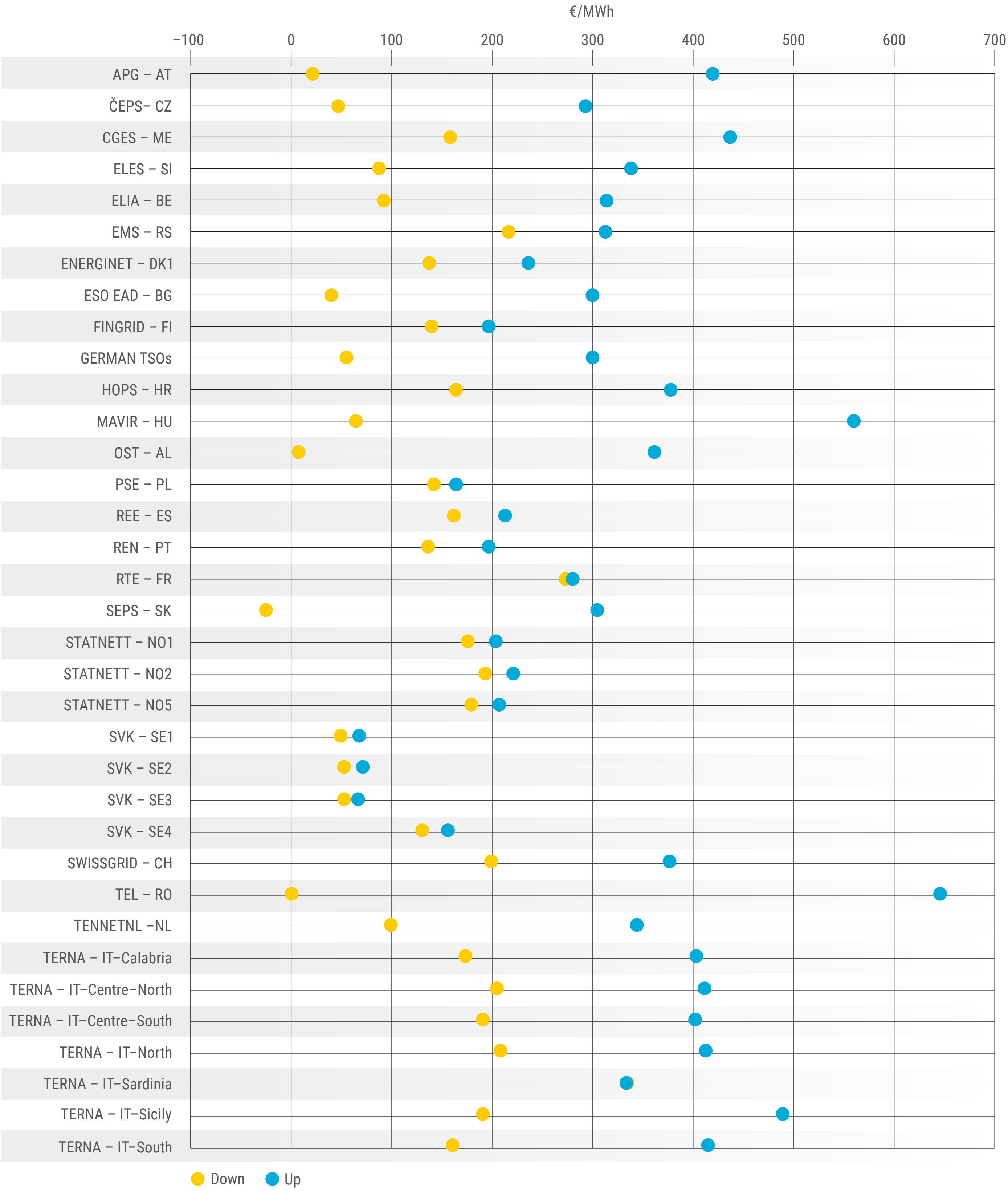


KPI 6.3.7.1 Yearly activated volume of balancing energy which is used for balancing purposes: RR (GWh/year)

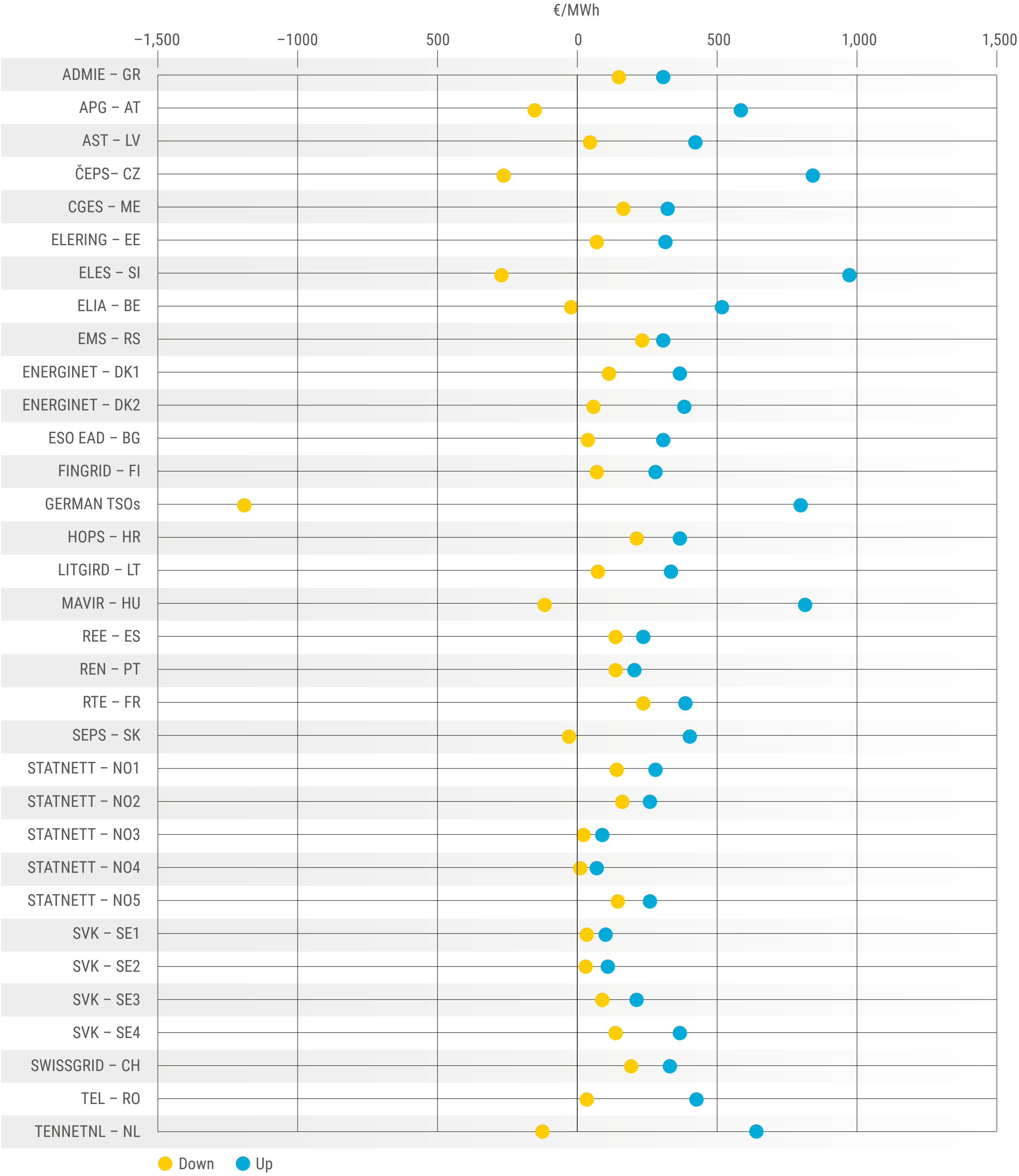


KPI 6.3.7.2: Time-average price of activated balancing energy: aFRR (EUR/MWh)

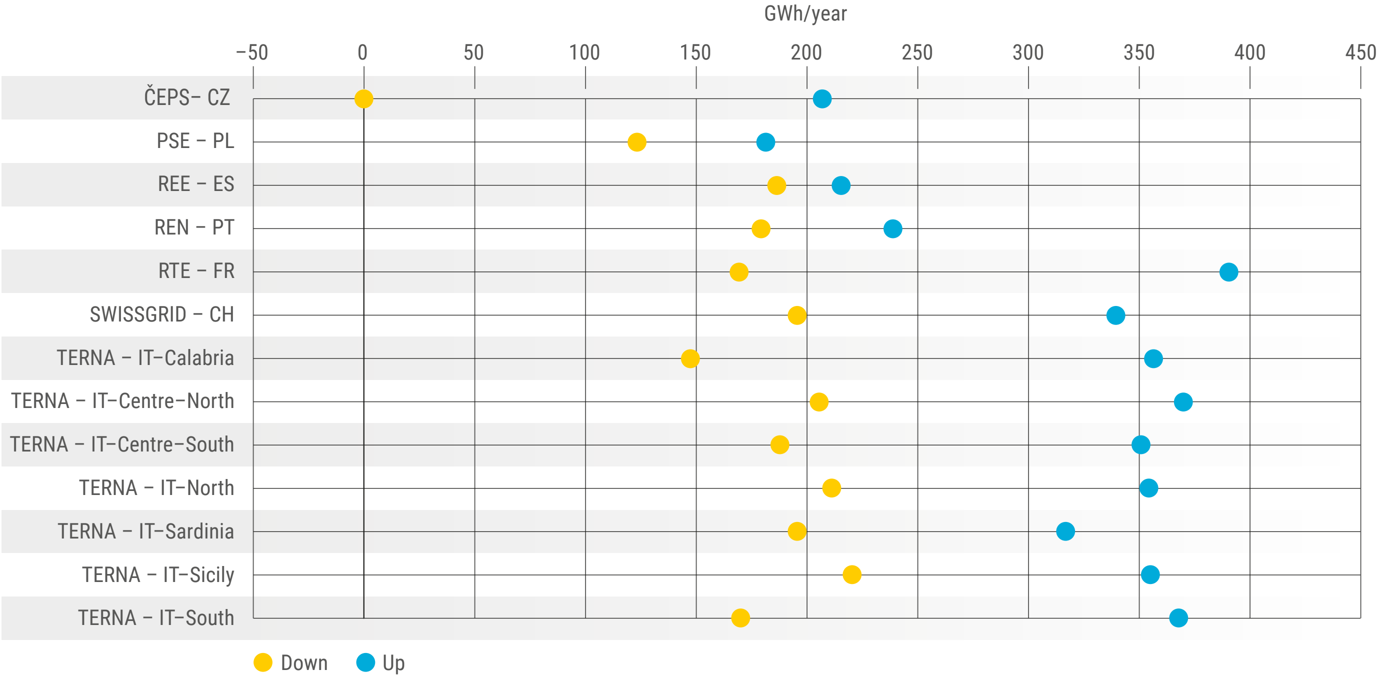
Disclaimer: ADMIE: No reporting on aFRR due to data problems.



KPI 6.3.7.2: Time-average price of activated balancing energy: mFRR (EUR/MWh)



KPI 6.3.7.2: Time-average price of activated balancing energy: RR (EUR/MWh)



6.3.8 The imbalance prices and the system imbalances

Definition

This indicator is based on the imbalance prices and the system imbalances. It indicates whether or not 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. Average prices for BRP shortage over ISPs when system imbalance indicates short;
5. Average prices for BRP surpluses over ISPs when system imbalance indicates long; and
6. Percentage of ISPs with positive respectively negative system imbalance.

Some points to consider for this indicator:

- In case 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 given 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, in order 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.

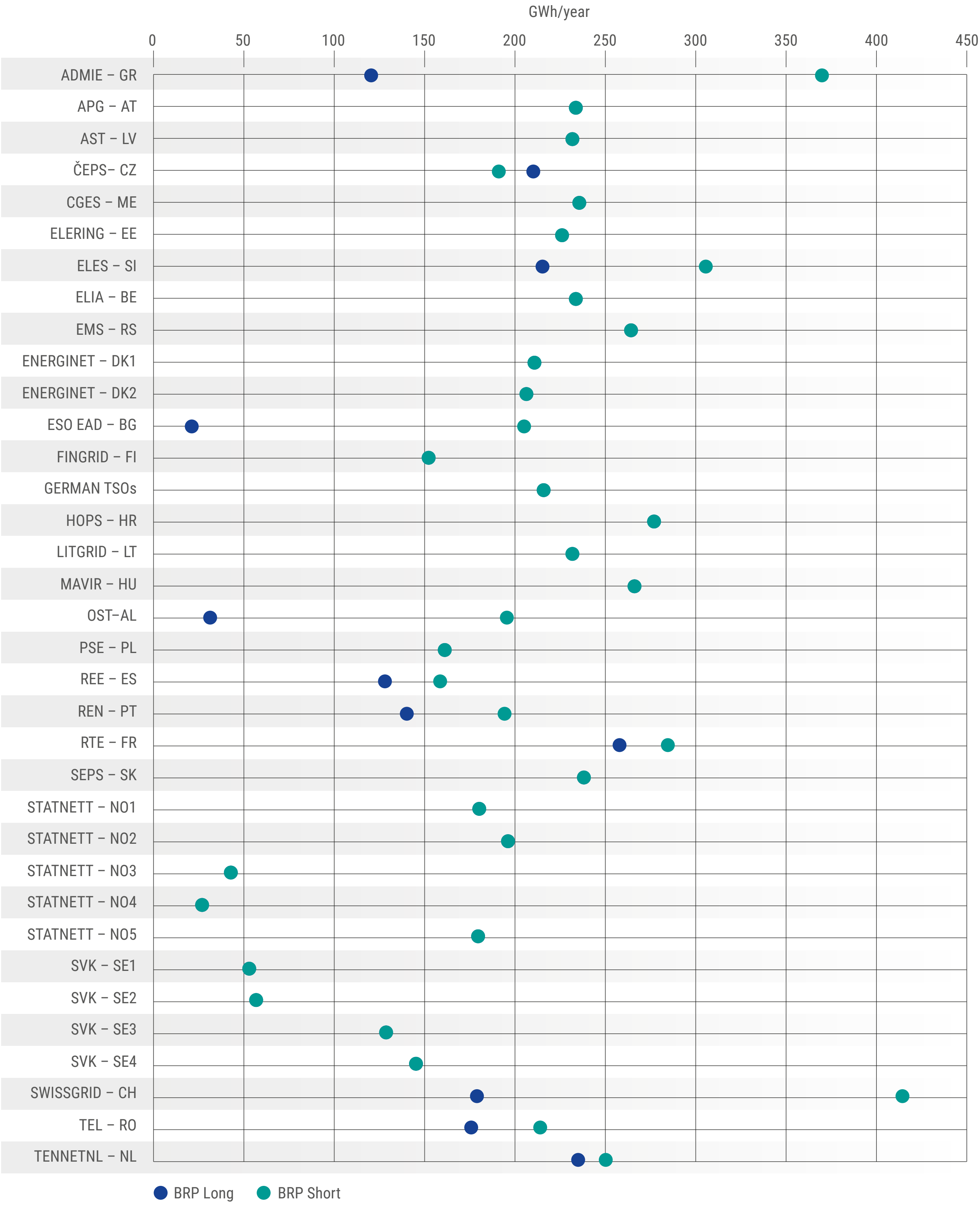
Legal reference	Article 59(4)(i) of the EB Regulation
Time reference	Yearly

Table 21: Indicator 6.3.8 on the imbalance prices and the system imbalances

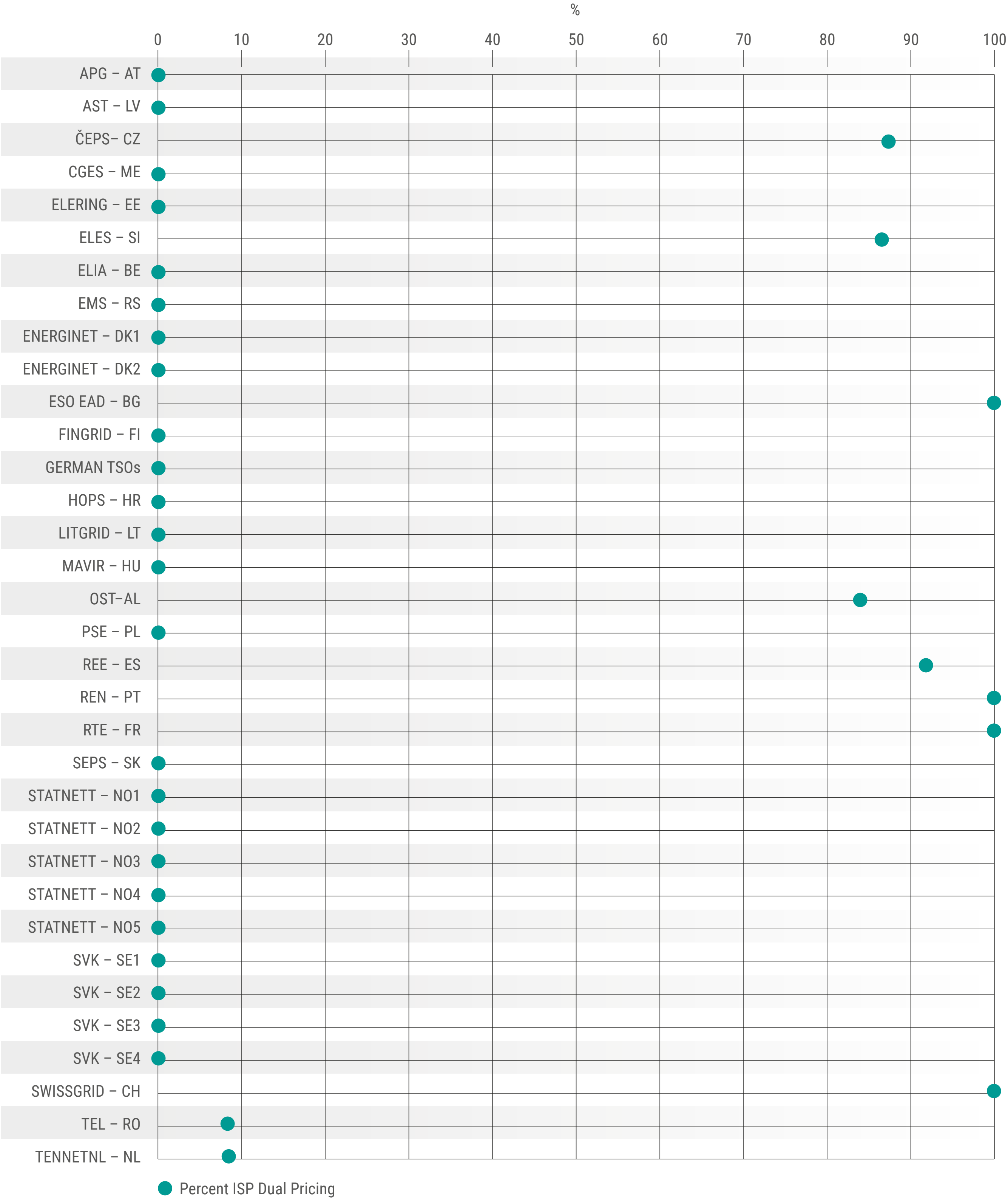
Disclaimer: EIRGRID was not included due to a low count of ISP.

KPI 6.3.8.1 / 6.3.8.2 Average price for BRP shortage and surplus over all ISPs (EUR/MWh)

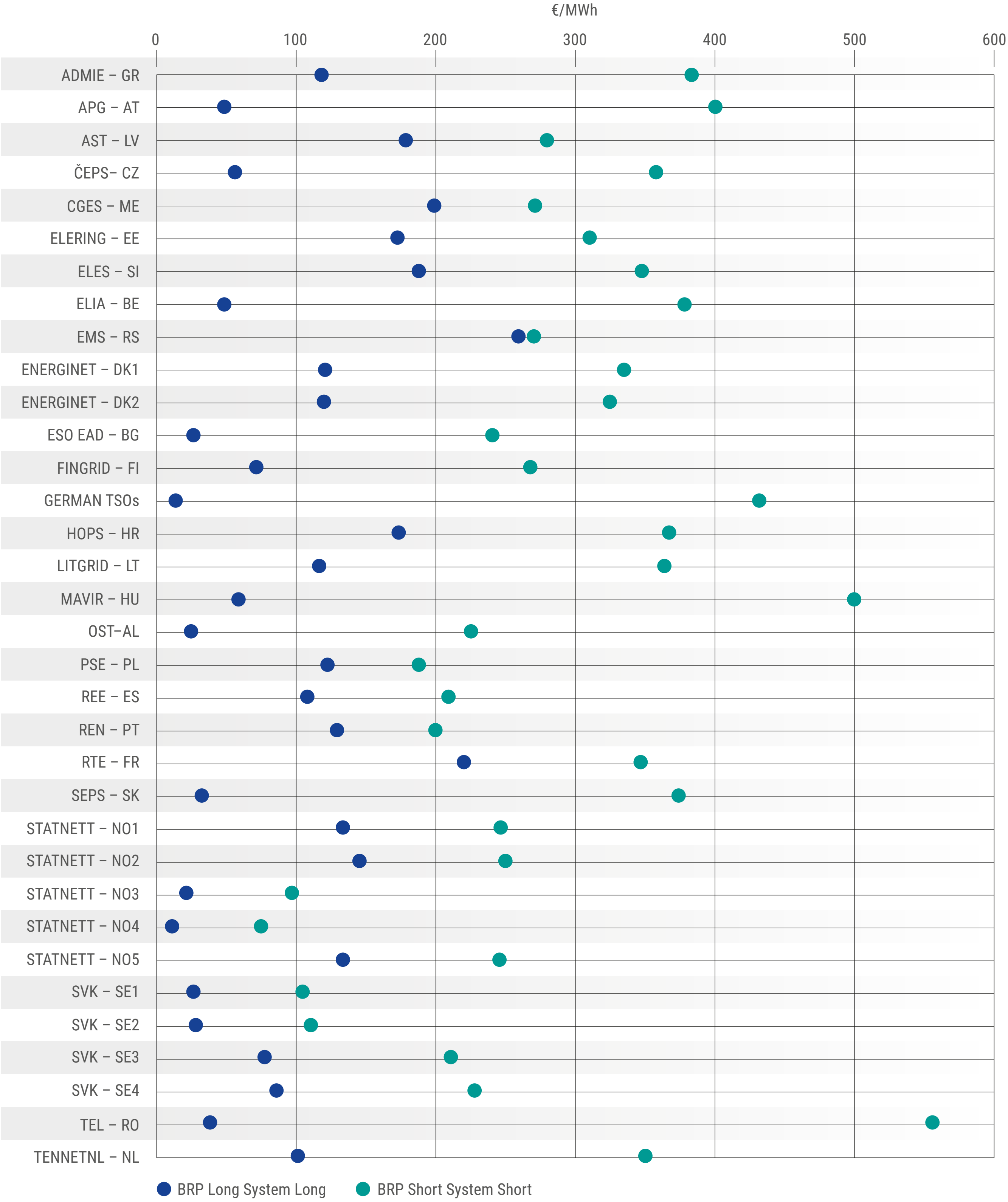
Diclaimer: PSE data was converted using NBP (Polish National Bank) exchange rate.



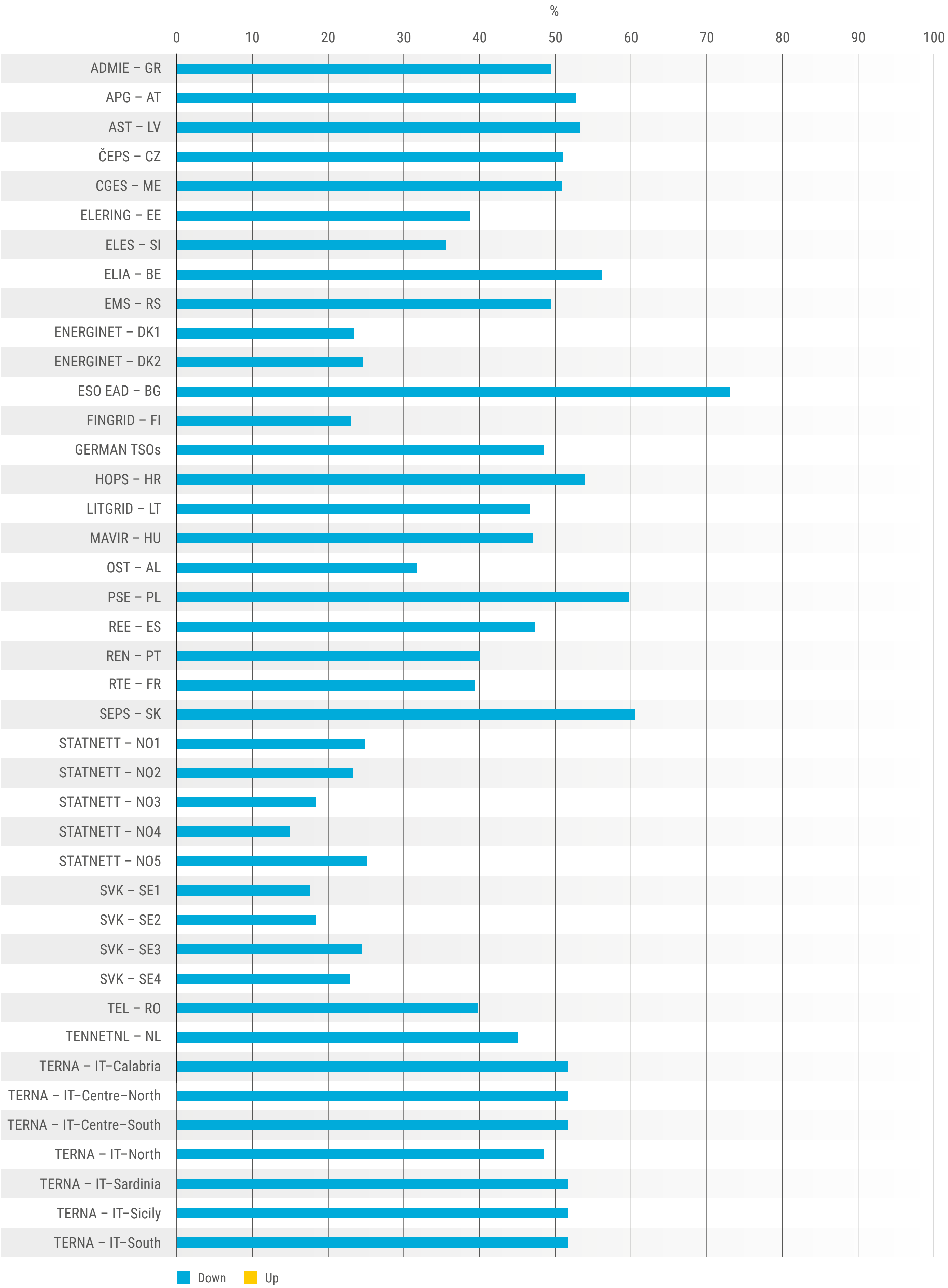
KPI6.3.8.3 Percentage of ISPs where price shortage and surplus are unequal (incidence of dual pricing)



KPI 6.3.8.4 / 6.3.8.5 Average prices for BRP shortage over all ISPs when system imbalance indicates short, and average prices for BRP surpluses over all ISPs when system imbalance indicates long (EUR/MWhISP all)



KPI 6.3.8.6 Percentage of ISPs with negative system imbalance



6.3.9 Evolution of balancing service prices of the previous years

Definition

This indicator displays the evolution of the annual average prices for the balancing services over the past 3 years (whenever data are available).

This PI includes the following:

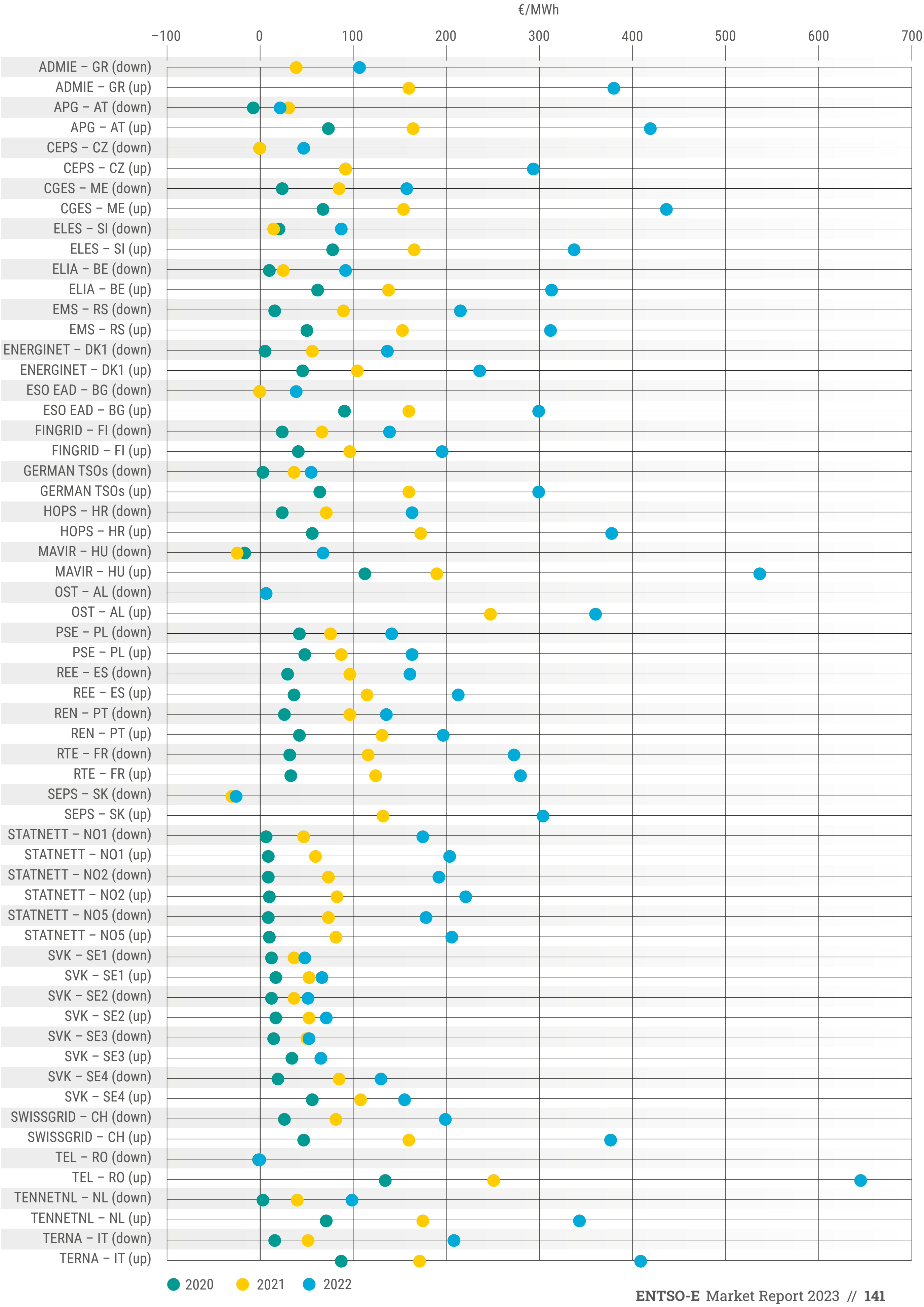
1. Evolution of balancing energy prices at the European balancing energy platforms (standard products only);
2. Evolution of balancing energy prices at each TSO and where available, per BZ (including specific products); and
3. Evolution of balancing capacity procurement prices aligning these prices with a capacity procurement time of one hour.

Legal reference	Article 59(4)(j) of the EB Regulation
Time reference	Yearly

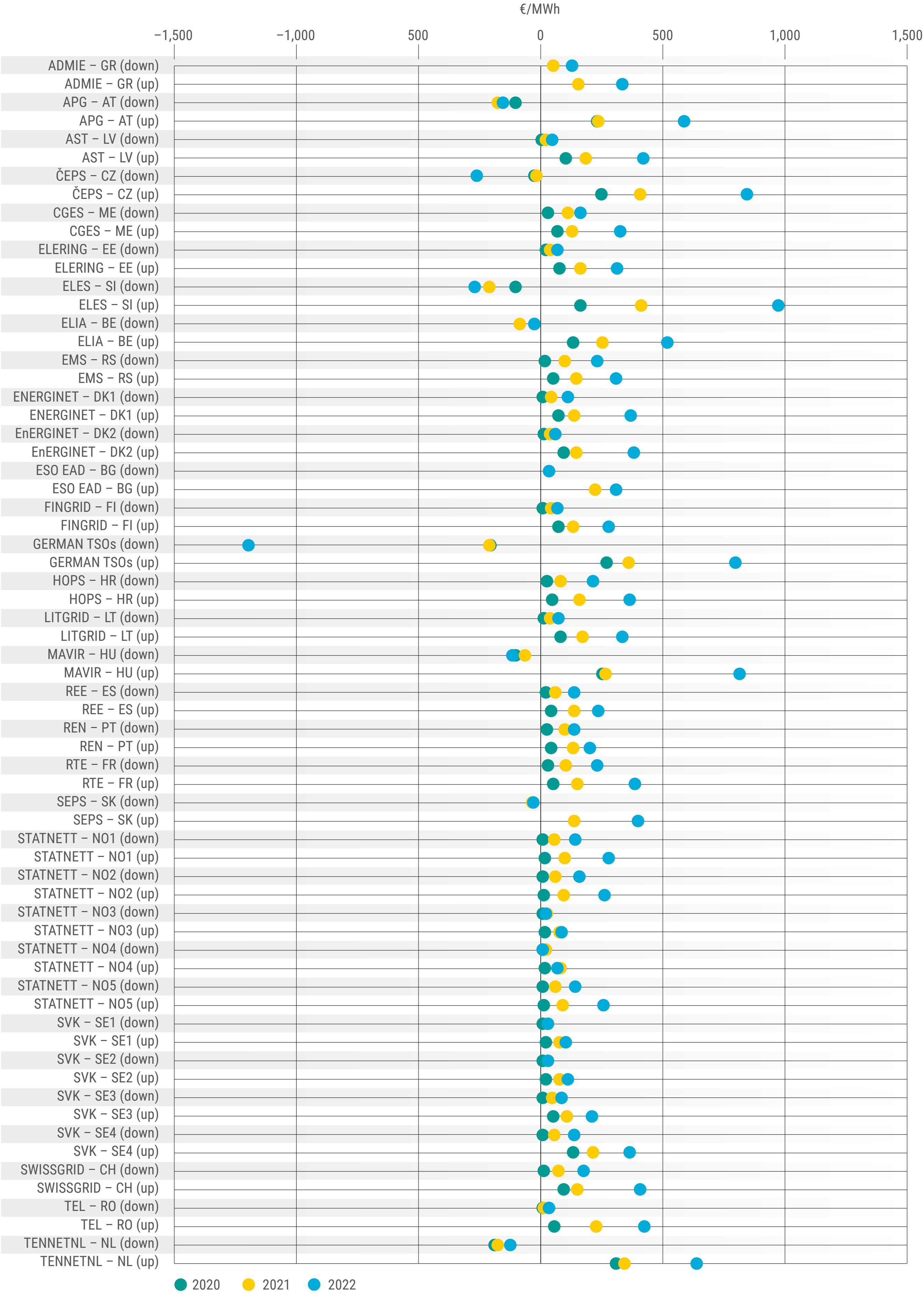
Table 22: Indicator 6.3.9 on the evolution of balancing service prices of the previous years

KPI 6.3.9.1 – Evolution of balancing energy prices at the European balancing energy platforms (standard products only) – RR (EUR/MWh)

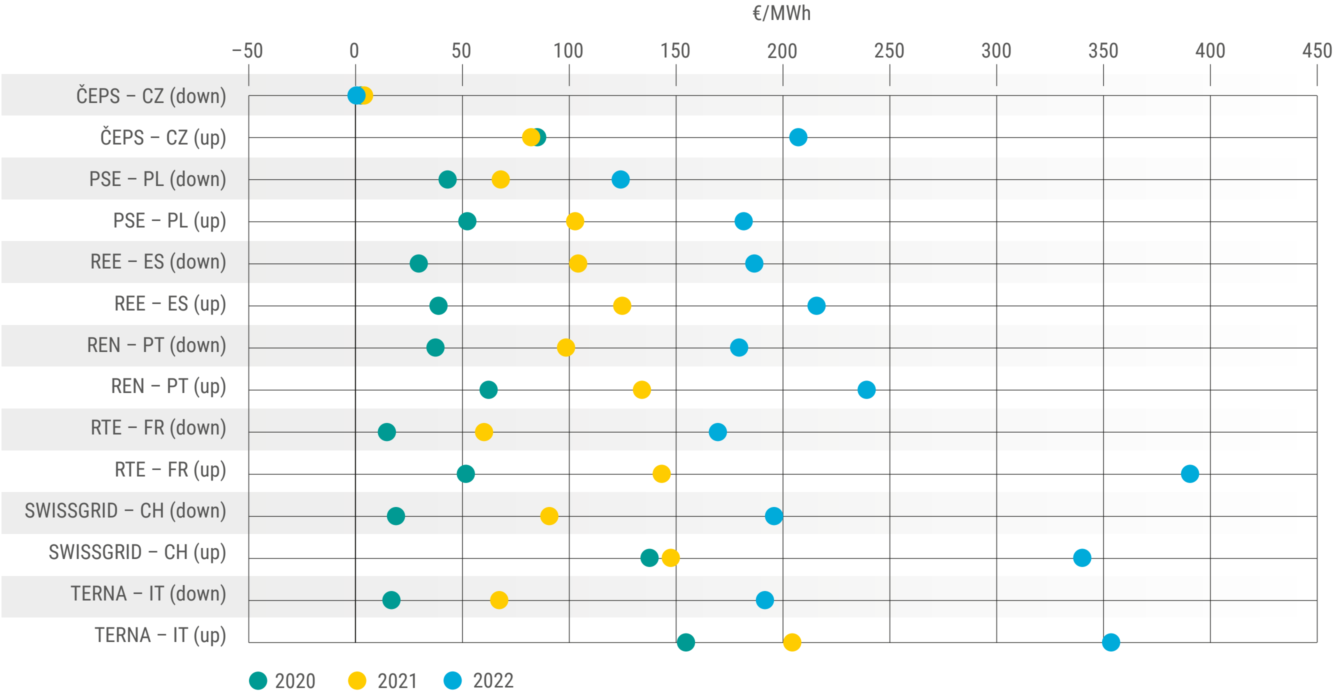
KPI 6.3.9.2 Evolution of balancing energy prices at each TSO and where available, per bidding zone (including specific products) – aFRR (EUR/MWh)



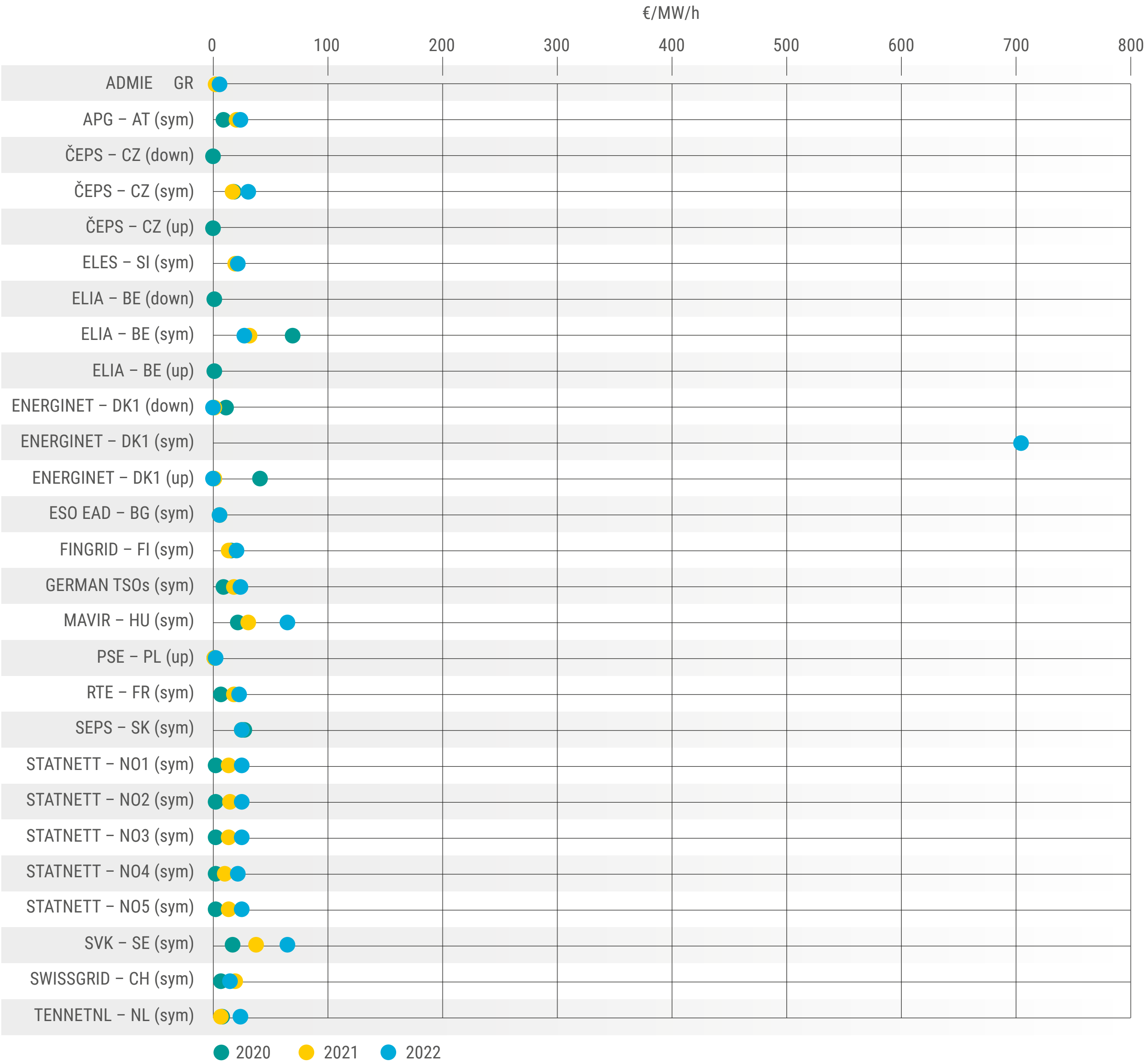
KPI 6.3.9.2 Evolution of balancing energy prices at each TSO and where available, per bidding zone (including specific products) – mFRR (EUR/MWh)



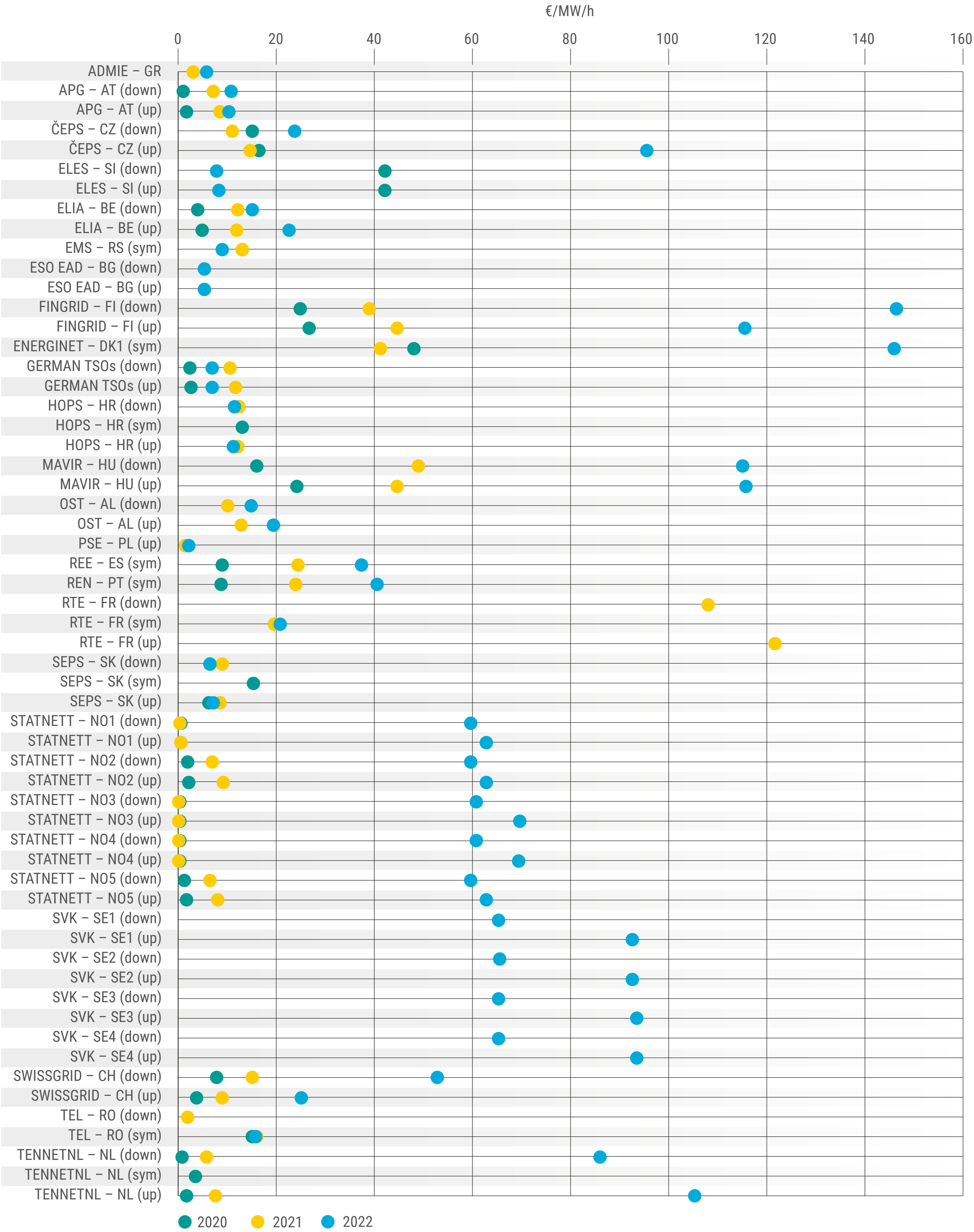
KPI 6.3.9.2 Evolution of balancing energy prices at each TSO and where available, per bidding zone (including specific products) – RR



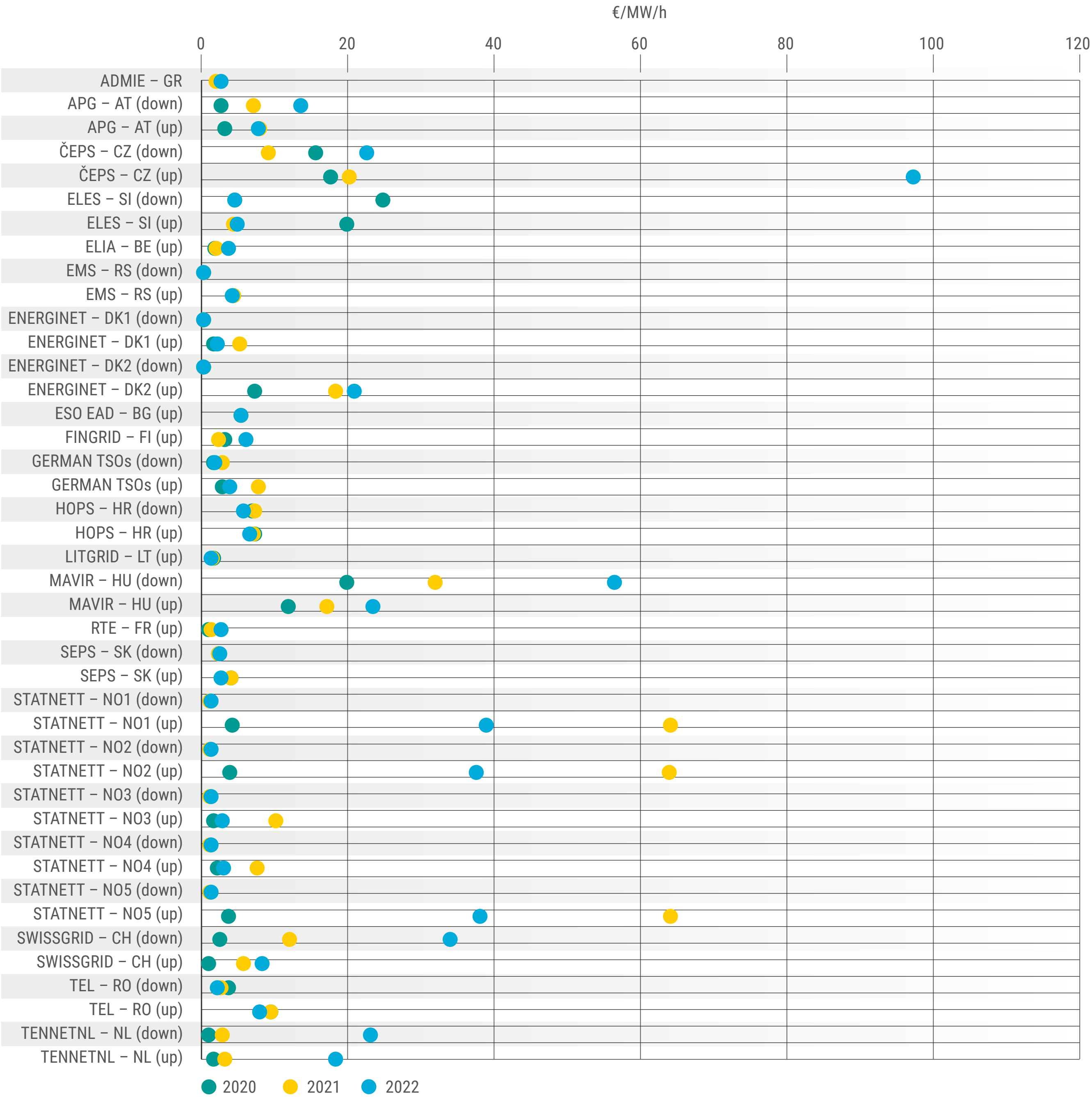
KPI 6.3.9.3 Evolution of balancing capacity procurement prices aligning these prices with a capacity procurement time of one hour – FCR (EUR/MW/h)



KPI 6.3.9.3 Evolution of balancing capacity procurement prices aligning these prices with a capacity procurement time of one hour – aFRR (EUR/MW/h)

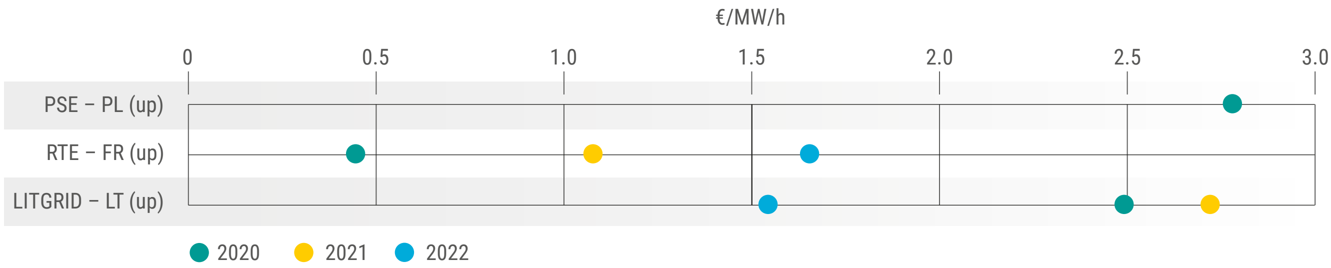


KPI 6.3.9.3 Evolution of balancing capacity procurement prices aligning these prices with a capacity procurement time of one hour – mFRR (EUR/MW/h)



KPI 6.3.9.3 Evolution of balancing capacity procurement prices aligning these prices with a capacity procurement time of one hour – RR (EUR/MW/h)

Disclaimer: PSE: 6.3.9.3 – RR: Since 01.01.2021 the service reflected in this position (Operational Capacity Reserve) has been terminated, hence no data for 2021 and 2022.



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

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 day-ahead energy market bids).*

This PI includes:

1. For market-based application (Art. 41(1) of EB Regulation), compute the social welfare by considering the forecasted day-ahead energy bids and real reserve capacity bids.

2. For inverted market-based application (Art. 41(1) of EB Regulation), compute the social welfare by considering the real day-ahead energy bids and forecasted reserve capacity bids.

Legal reference	Article 59(4)(k) of the EB Regulation
Time reference	Yearly

Table 23: Indicator 6.3.10 on the comparison of expected and realised costs and benefits from all allocations of cross-zonal capacity for balancing (* Once CZC allocation methodology and RCC procurement methodology will entry into force, PI 3.10 will be provided by RCCs purposes)

For this report, indicator 6.3.10 was not computed since there is no data available for the year 2022. This is because no go-live, whether of market-based or inverted market-based allocation of balancing capacity, took place in 2022.

Annexes

Annex I – Legal references and requirements

The report is based on previous ENTSO-E legal monitoring obligations pursuant to **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** (previous EU Electricity Regulation). Nevertheless, the entry into force of the **Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity** (recast EU Electricity Regulation) repealed the previous EU Electricity Regulation.

The recast EU Electricity Regulation does not include an equivalent of Article 8(8) of the previous EU Electricity Regulation and does not foresee new monitoring tasks of network codes and guidelines implementation for ENTSO-E. Therefore, general monitoring obligations in the network codes and guidelines linked to the previous EU Electricity Regulation cannot be considered binding after the recast Electricity Regulation enters 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 on forward capacity allocation (FCA Regulation); and Article 63(3) 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 and CACM deliverables

The following Table A-provides an overview of all TSOs' deliverable based on FCA.

Proposal	FCA Regulation article(s)	First submission	NRAs' request for amend-ments	TSO Submission after Request for Amendment	NRAs approval or ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision
Common Grid Model (CGM)	17[1] 18[2]	May 2017 Jun 2017	- Feb 2018	- May 2018	Oct 2017 Jun 2018						
Harmonised Allocation Rules (HAR)[3]	51	Apr 2017			Oct 2017[4] Oct 2017[5] Oct 2017[6]	July 2019	Oct 2019[7] Oct 2019[8]	Jun 2021	Nov 2021 Nov 2021	Mar 2023 Jun 2023	
Single Allocation Platform (SAP)	49 59	Apr 2017			Sep 2017	Sep 2022	Mar 2023 Mar 2023				
Congestion Income Distribution (CID)	57	May 2018	Nov 2018	Mar 2019	May 2019	Sep 2022	Mar 2023 Mar 2023				
Cost of ensuring firmness and remunera-tion of LTTRs (FRC)	61	April 2020			Oct 2020 Oct 2020		Oct 2021 Oct 2021	Sep 2022	Mar 2023 Mar 2023		
Capacity calculation Regions	15(1)	Oct 2015	Nov 2016[9]	Jun 2017[10]	Sep 2017	Mar 2018[11]	Apr 2019[12]	Nov 2020[13]	May 2021	Oct 2022	Apr 2023 Apr 2023

Table A-1: Regulatory process of the proposal for the determination of capacity calculation regions

1 Generation and load data provision methodology for long-term time frames

2 CGM methodology for long-term time frames

3 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**.

4 On 17 August 2017, all NRAs referred to ACER to adopt a decision

5 On 2 October 2017, ACER took a decision (No 03/2017)

6 HAR 2017 approved methodology

7 On 29 October 2019, ACER adopted a decision (No 14/2019)

8 HAR 2019 approved methodology

9 **Referral to ACER from all NRAs**

10 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).

11 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.

12 **Referral to ACER from all NRAs**

13 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.

Type	Proposal	CACM Regulation Art.	First submission	NRAs request for amendment	First Submission after the request for amendment	NRAs approval(s) or ACER decision	Request for amendment	ACER decision
All-TSOs (II)	Common grid Model	16 17	May 2016	Dec 2016	Apr 2017	May 2017		
	ID cross zonal GOT ID cross zonal GCT	59	Dec 2016	Jun 2017	Aug 2017	Apr 2018[14] Apr 2018		
	Scheduled exchange	43 56	Feb 2018[15] Feb 2018	Sep 2018	Dec 2018[16] Dec 2018[17]	Feb 2019[18] Feb 2019[19]	Dec 2022	May 2022 May 2022
	ID cross zonal capacity pricing	55(3)	Aug 2017	Referred to ACER	Jan 2019			
	Congestion income distribution	73	Jun 2016	Jan 2017	Apr 2017	Dec 2017[20]	Jul 2021	Dec 2021 Dec 2021

Table A-2: Overview of All TSOs CACM Regulation deliverables (as of May 2022)

Type	Proposal	CACM Regulation Art.	First submission	NRAs request for amendment	First Submission after the request for amendment	NRAs approval(s) or ACER decision	Request for amendment	ACER decision
All-TSOs & All-NEMOs	DA and ID algorithm	37	Feb 2017[21]	Jul 2017	Nov 2017	Jul 2018[22]	Aug 2019	Jan 2020
	Max/min price	41 54	Feb 2017 Feb 2017	Referred to ACER	Nov 2017 Nov 2017 Nov 2017 Nov 2017	DA: Sep 2022 ID: Sep 2022	DA: Jan 2023 Jan 2023 ID: Jan 2023 Jan 2023	

Table A-3: Overview of All TSO and All NEMO CACM Regulation deliverables (as of May 2022)

Type	Proposal	CACM Regulation Art.	First submission	NRAs request for amendment	First Submission after the request for amendment	NRAs approval(s) or ACER decision	Request for amendment	ACER decision
All-NEMOs	Plan of the market coupling operator	7(3)	Apr 2016	Sep 2016	Dec 2016	Jun 2017		
	Back-up methodology	36	Feb 2017	Jul 2017	Nov 2017	Jan 2018		
	Products accommodated	40 53(4)	Feb 2017 Feb 2017	Jul 2017 Jul 2017	Nov 2017 Nov 2017	Jan 2018 Jan 2018	Jun 2020[23] Aug 2019	Dec 2020[24] Dec 2020[25] Jan 2020[26] Jan 2020[27]

Table A-4: Overview of All NEMOs CACM Regulation deliverables (as of May 2022)

14 **Referral to ACER from all NRAs**
15 For DA and ID proposals, only the TSOs, which intended to calculate scheduled exchanges
16 DA proposal
17 ID proposal
18 DA Costs coefficients – **2021 update**
19 ID Costs coefficients – **2021 update**
20 **All-NRAs referral to ACER**
21 DA and ID requirements as annexes
22 **Referral to ACER from all NRAs**
23 All NEMOs' request for amendment
24 On 22 December 2020 ACER took a decision (No 37/2020)
25 SDAC Products
26 On 30 January 2020 ACER took a decision (No 05/2020)
27 SIDC Products

Annex III – Market
Process overview of FCA, CACM and EB Regulation

Abbreviations and legend used in the following process overview:

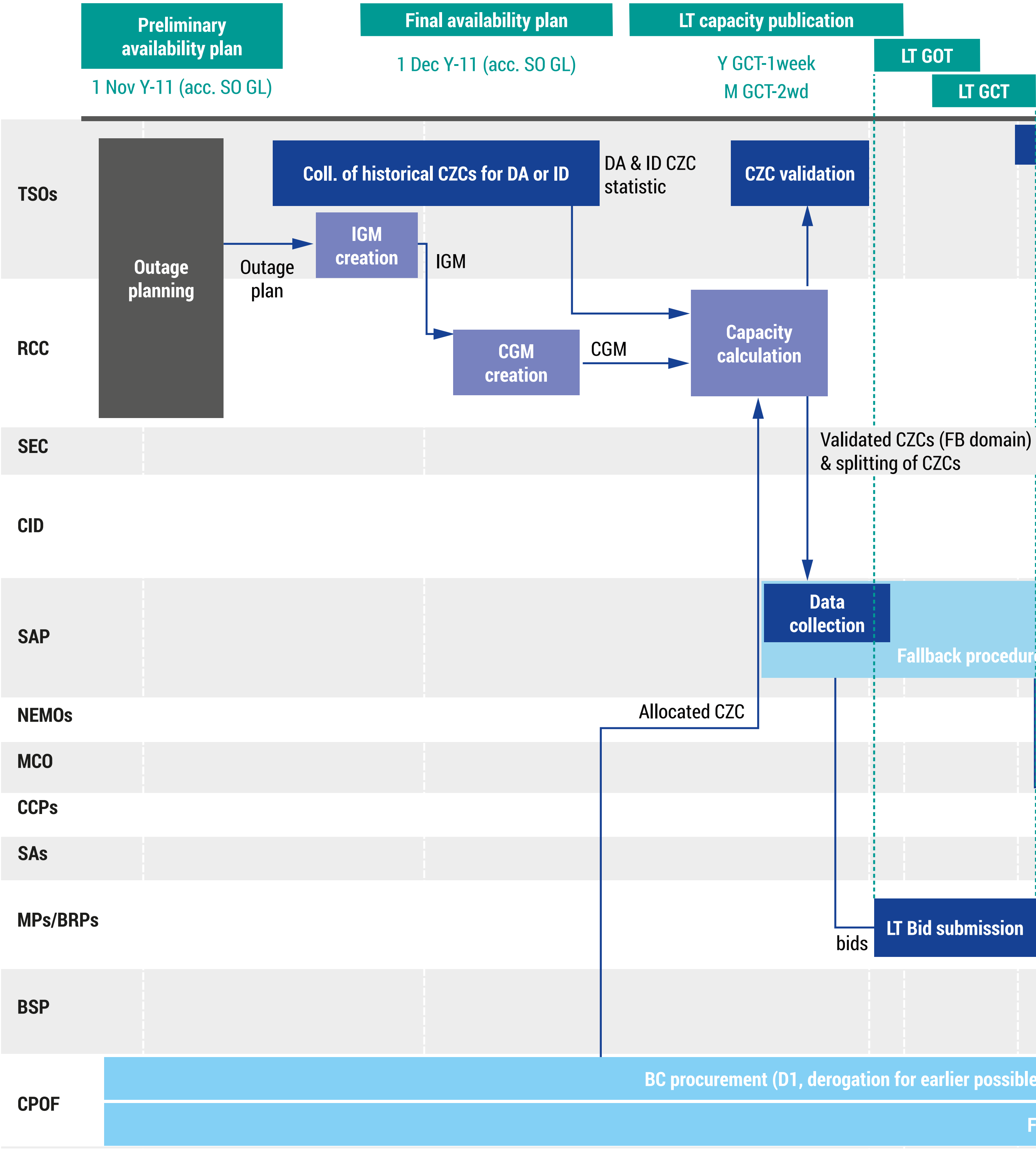
AC	Allocation Constraint
AOF	Activation Optimisation Function
aFRP	Automatic Frequency Restoration Process
aFRR	Automatic Frequency Restoration Reserves
BC	Balancing Capacity
BE	Balancing Energy
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CCC	Central Capacity Calculator
CCP	Central Counter Party
CET	Central European Time
CGM	Common Grid Model
CI	Congestion Income
CID	Congestion Income Distributor
CNEC	Critical Network Element with a Contigency
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

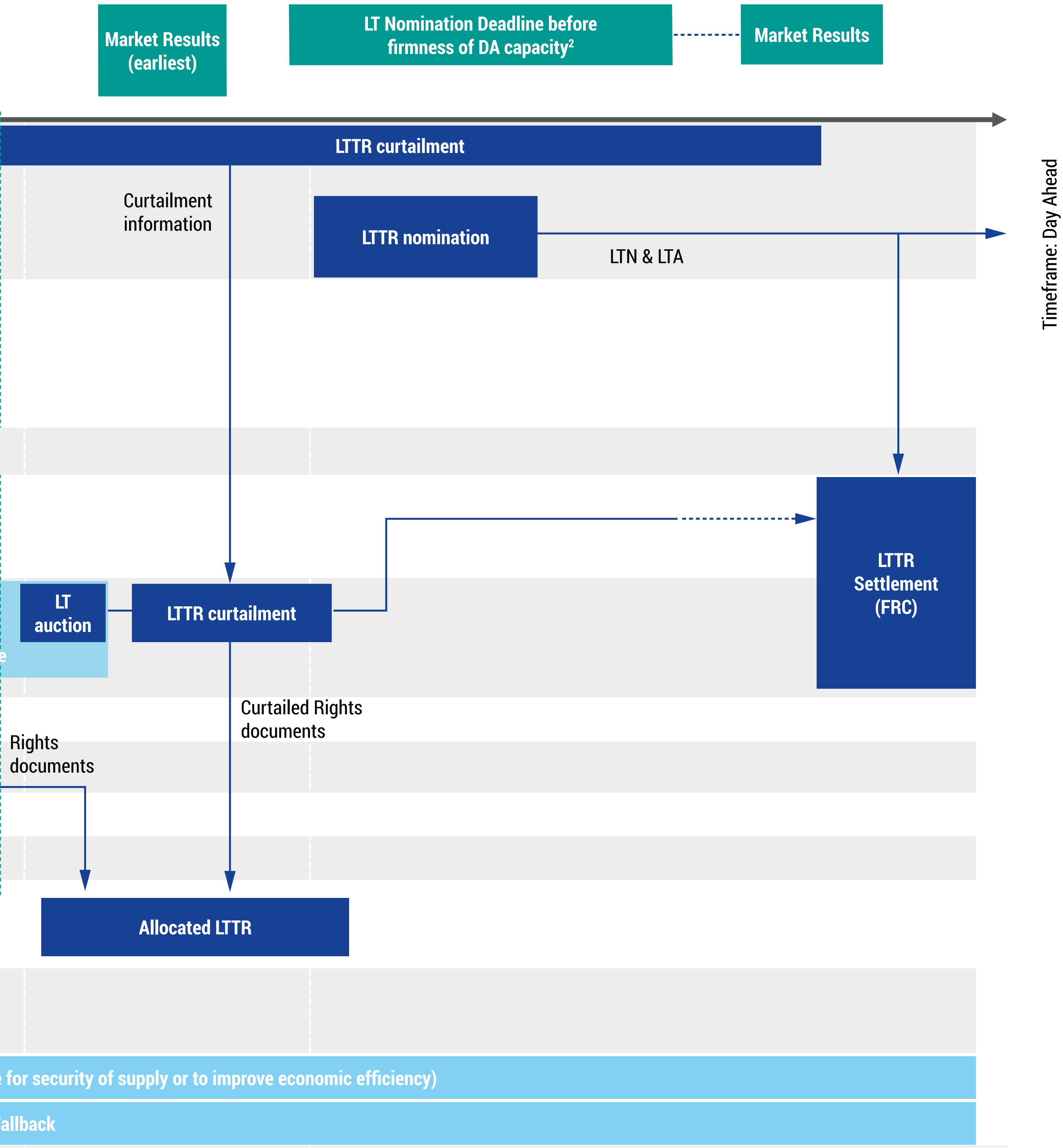
MP	Market Participant
MR	Market Result
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PTR	Physical Transmission Rights
RA	Remedial Action
RRP	Reserve Restoration Process
RR	Restoration Reserves
RCC	Regional Coordination Centre
SA	Shipping Agent
SAO	Shadow Auction Organiser(s)
SAP	Single Allocation Platform
SEC	Scheduled Exchange Calculator
T&C	Terms and conditions for BSPs / BRPs
TSO	Transmission System Operator
UIOSI	Use it or sell it

Legend

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

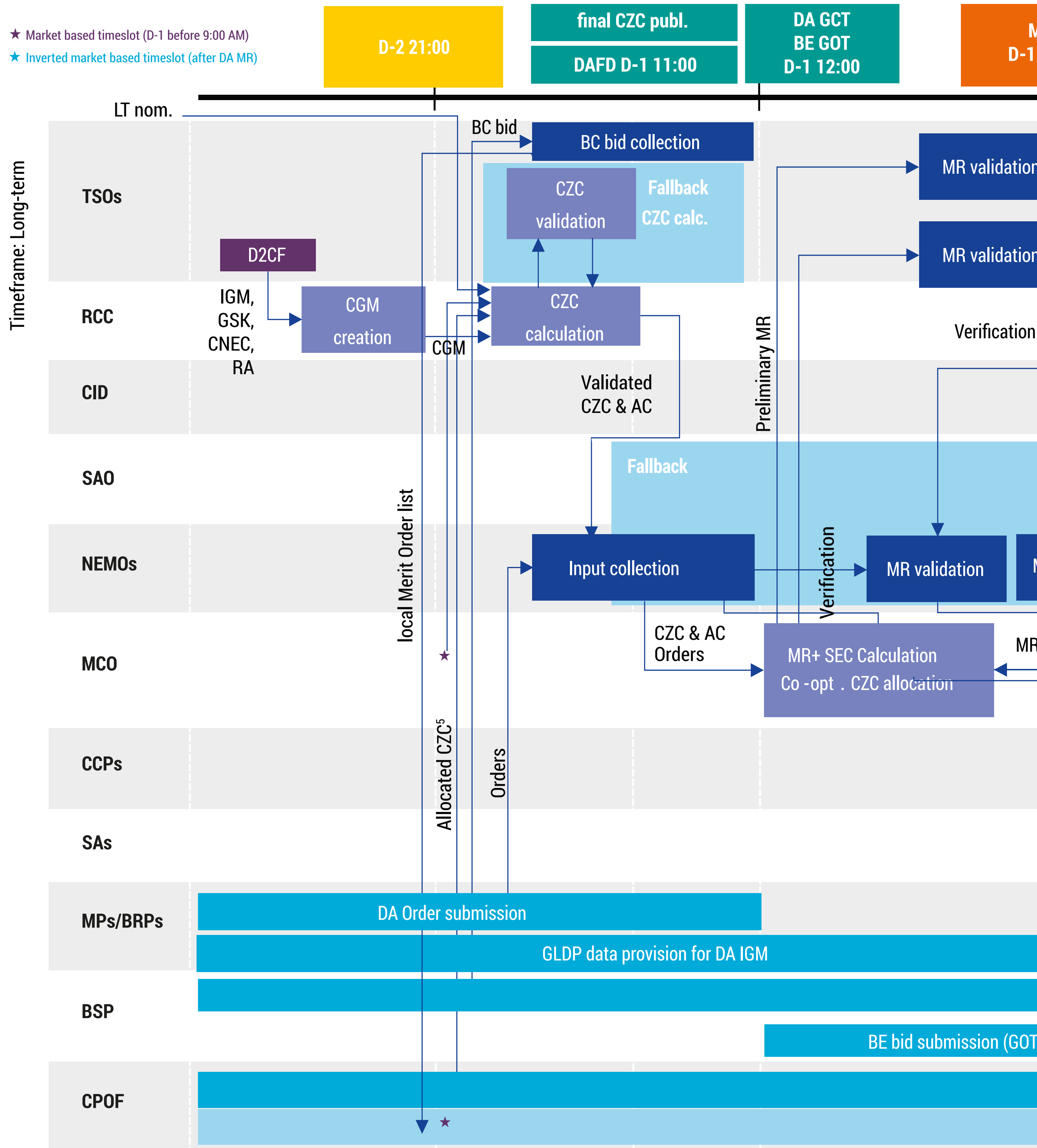
Forward capacity allocation process



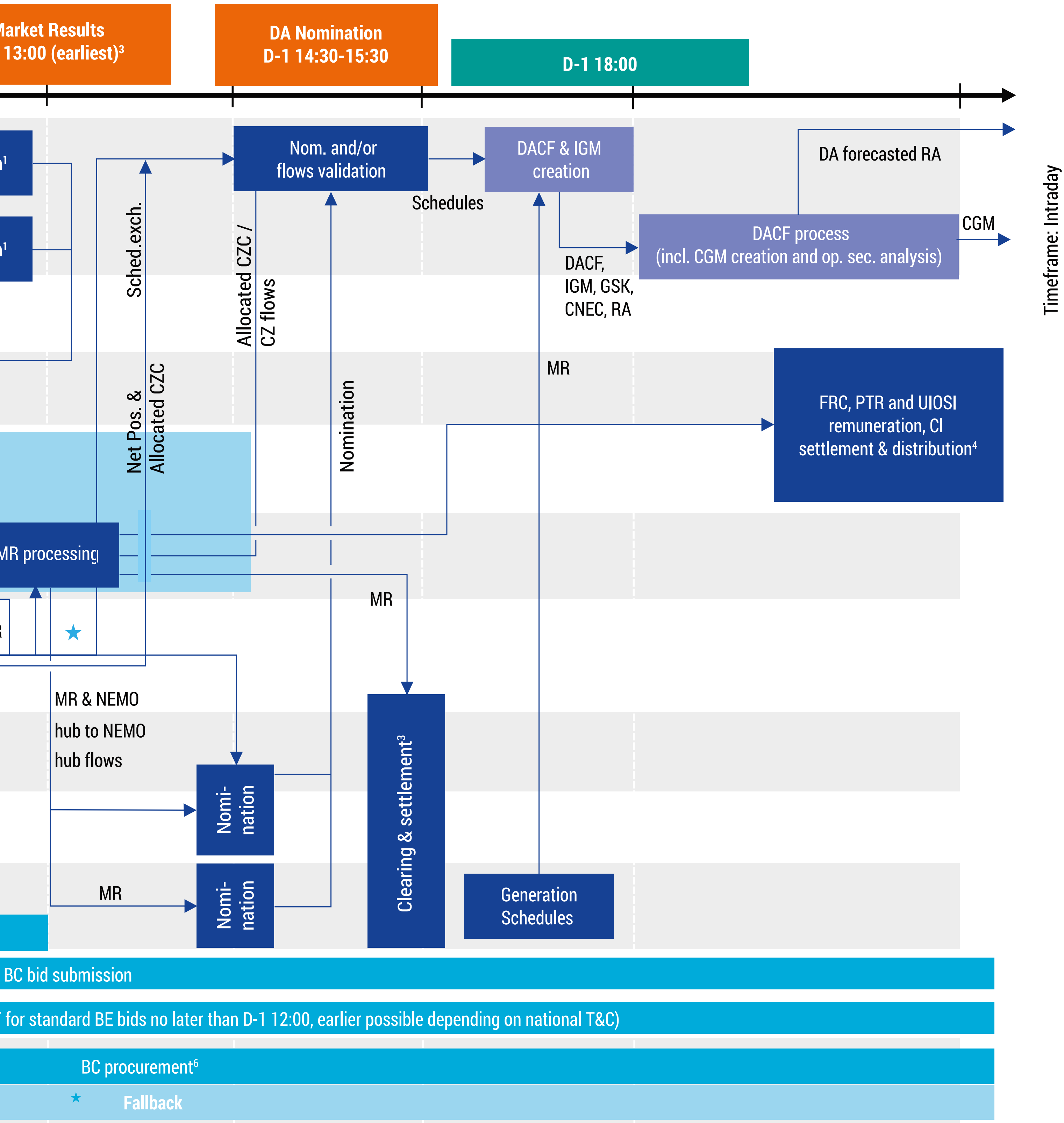


Market Results (earliest)
LT Nomination Deadline before firmness of DA capacity[2]
Market Results
LTTR curtailment
Curtailment information
LTTR nomination
LTN & LTA
Timeframe: Day Ahead
LTTR Settlement (FRC)
LT auction
LTTR curtailment
Curtailed Rights documents
Rights documents
Allocated LTTR
for security of supply or to improve economic efficiency)
allback

Day-Ahead Capacity Allocation Process

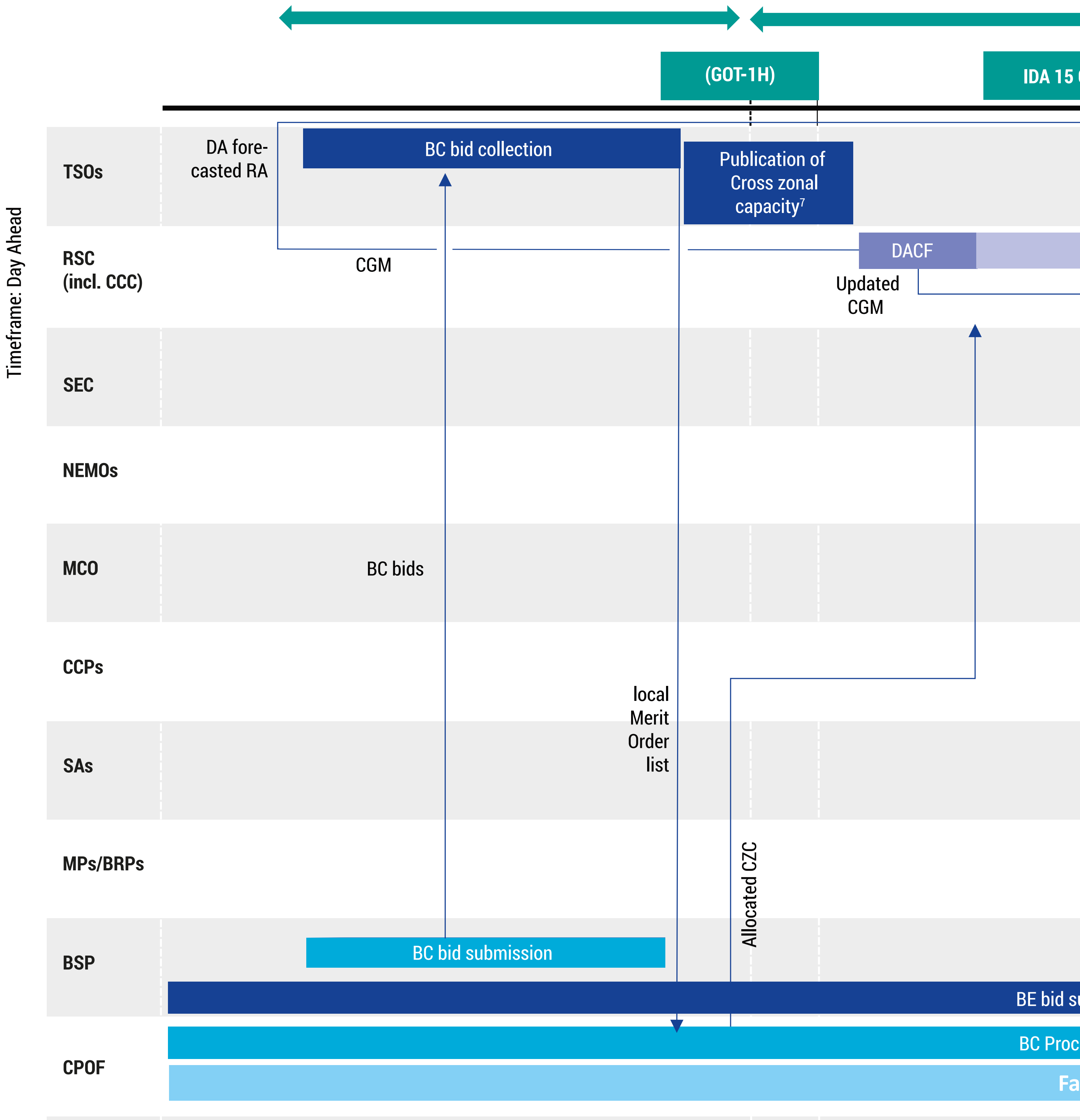


1) No parallel processes, solution depends on the regional design. **2)** Only in case of market-based allocation and economic efficiency analysis based allocation.
4) This processes are performed close to the delivery date or even after delivery. **5)** The implementation design of the co-optimized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

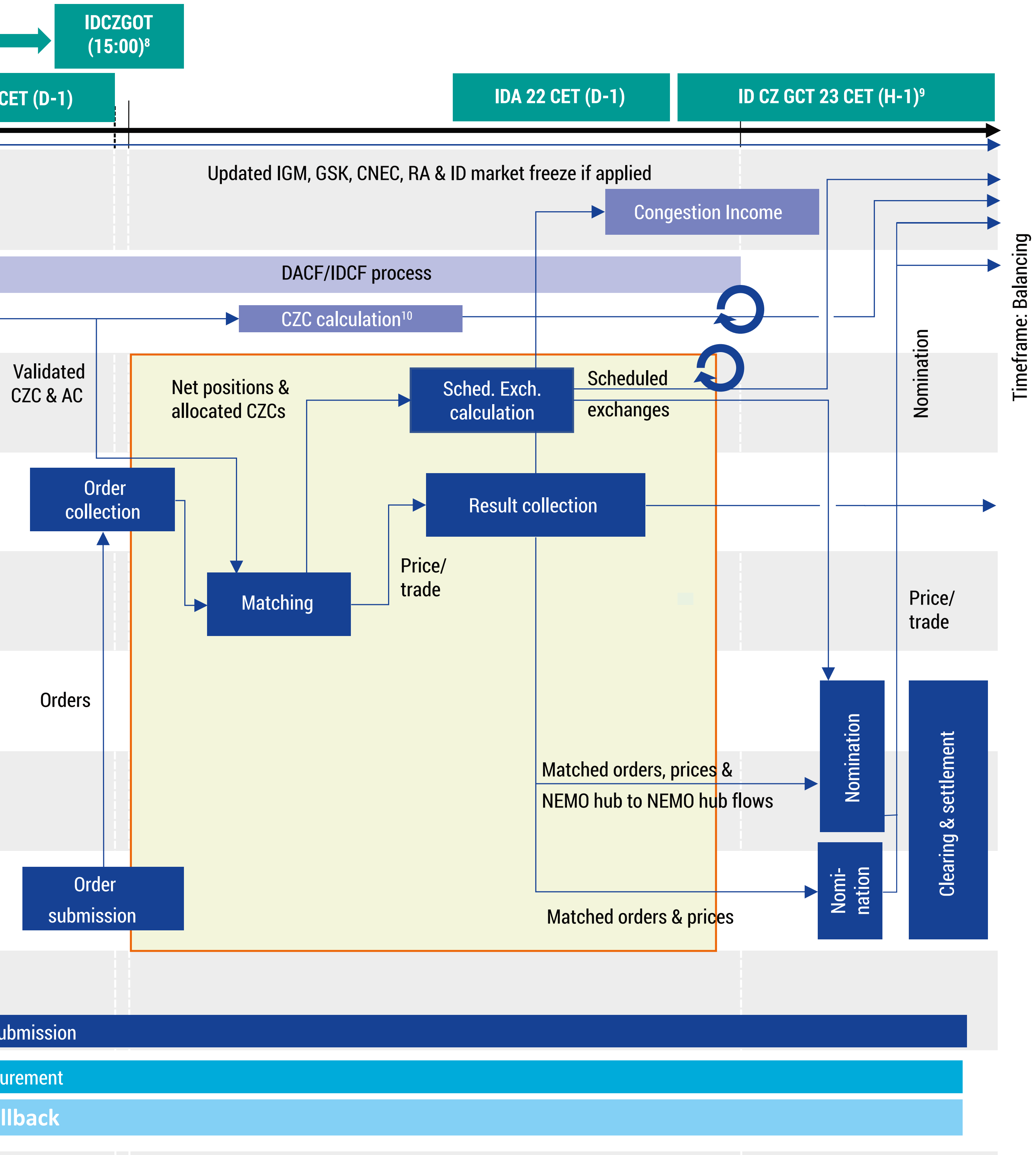


Please note that co-optimization is not shown on the slide. **3)** The latest possible time of market results publication is D-1 15:30 (in fallback situations).
EB Art. 40 and its respective methodology is under discussion until mid-2022. **6)** Some TSOs' capacity procurement takes place after day ahead energy market

Intraday capacity allocation

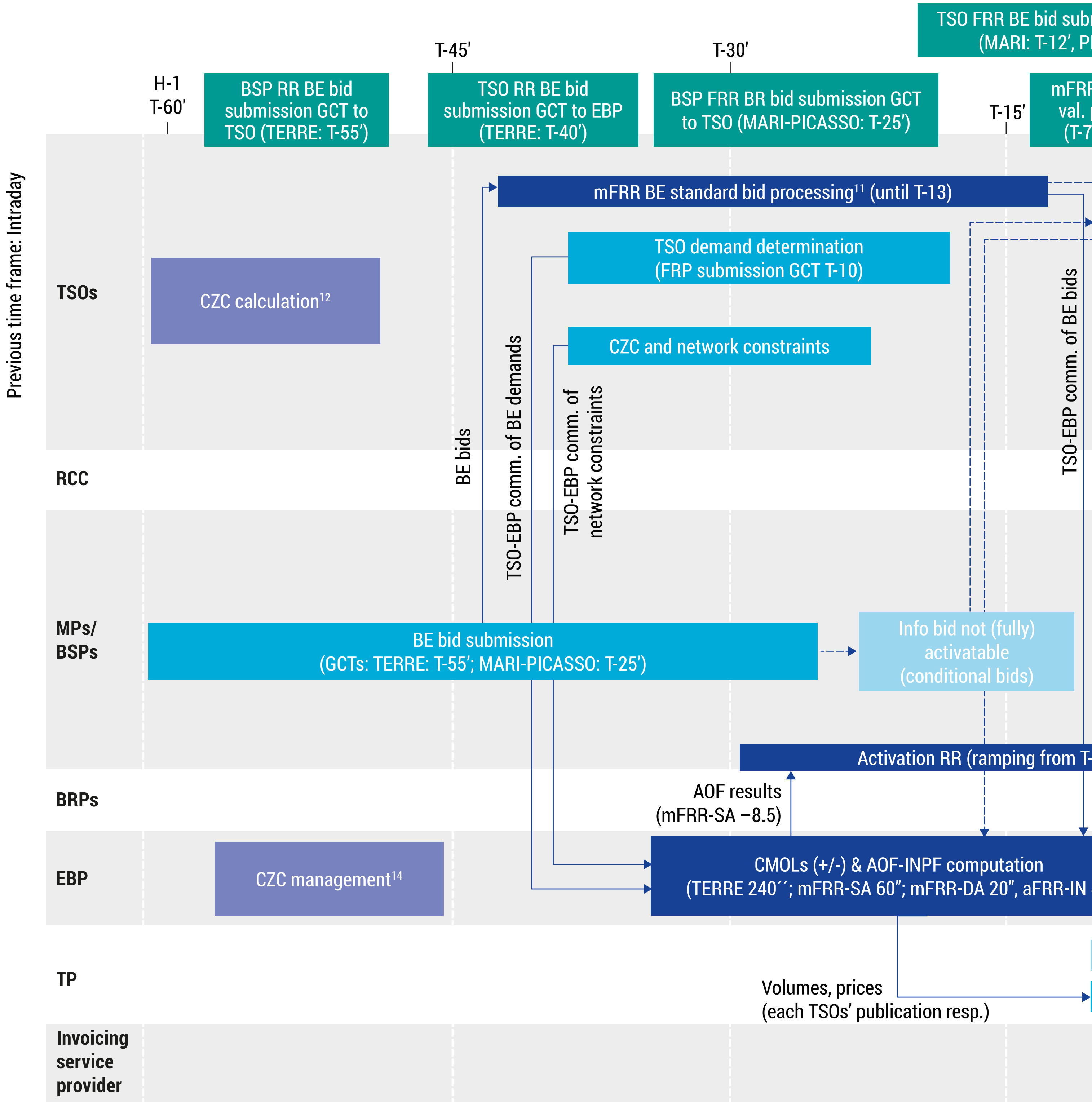


7) Preparation of CGM might be completed close or even after publication deadline. 8) IDCZGOT-15:00 D-1, IDCZ capacity might not be available at IDCZGOT on some int
Time suspension of the continuous trading for IDAs is 40 min in the target model and one hour in an interim phase of one year 9) first GCT for the first MTU of the next

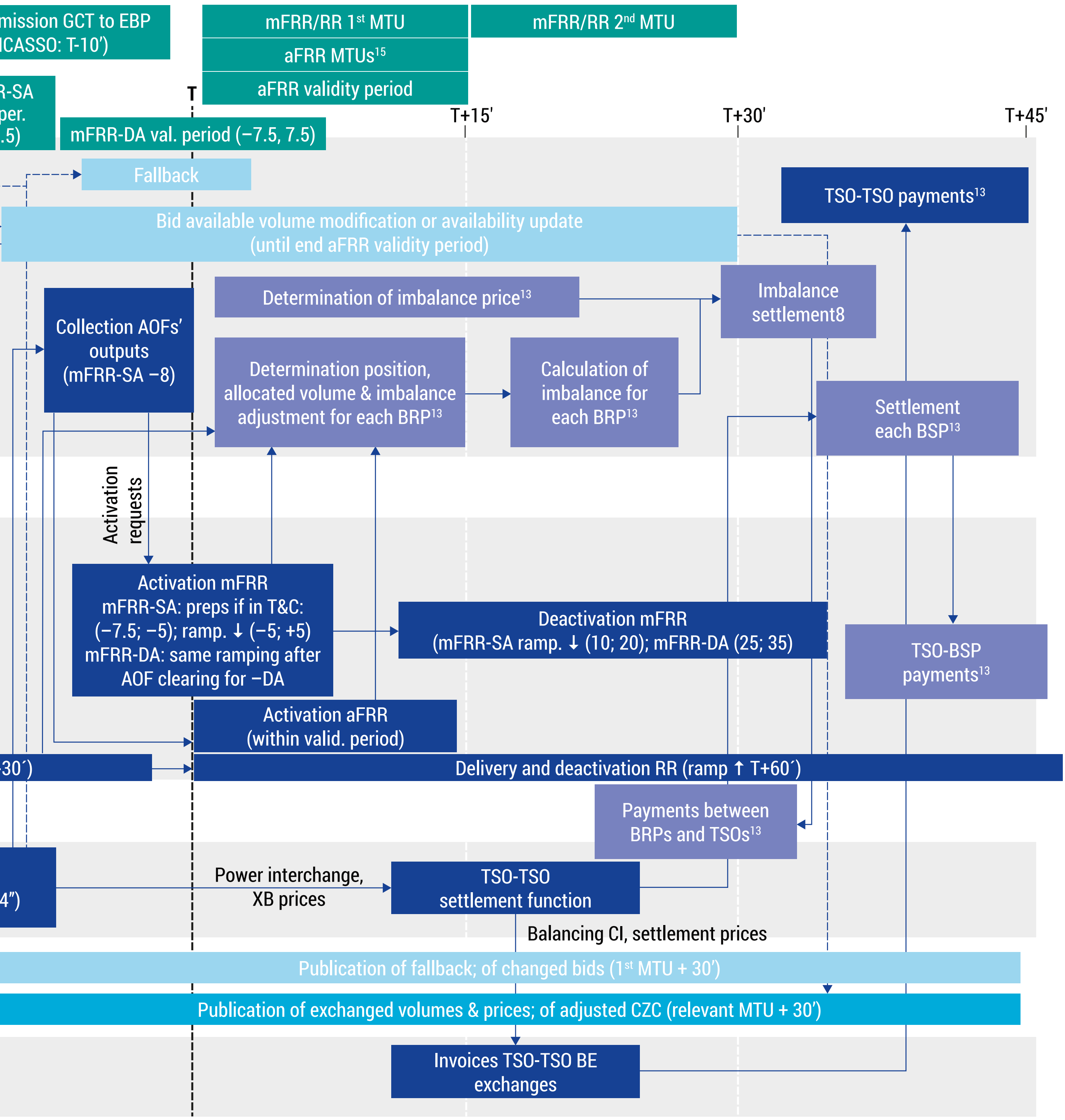


erconnections and might be provided only at 22:00 D-1 depending on CCR.
day is 23 D-1 **10)** first IDCC is carried out ahead of IDA at 10

Cross-zonal Balancing Energy Processes



11) Including collecting, conversion integrated scheduling process bids and specific BE bids to standard BE bids, modification bids EB 29(9), update availability of bids E
12) 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, RCCs, TSO
13) 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 not repre
14) A new capacity management function is being designed to manage the updates of CZC usage of all balancing platforms.
15) Each aFRR MTU corresponds to an optimisation cycle of the AOF of the aFRR-Platform (four seconds).



B 29(14), validation, preparation for submission and submission of standard BE bids to EBP.
Ds...)
esent actual timings.

Annex IV – Additional assessments of the state of CEP70

In section 2 of this report, TSOs provided an overview on their performance in regards to the CEP70 provision from 2022 (cf. Table A-1).In the following, the underlying assumptions (Table A-1), further information and detailed graphs of the analysis performed by TSOs are provided. The information in the annex is organised by country/TSO and provides (x.1) some more detailed information on the current status of the implementation of the CEP70 requirements, (x.2) further information on the assessment methodology (if needed in addition to the information in Table A-x), (x.3) assessment results and (x.4) additional information provided by the relevant TSO.

Country	TSO	Border/region	Grid elements considered	Third countries considered	Hours considered	Time frames considered
AT	APG	CWE (AT < > DE)	All CNECs of the final FB Domain except virtual ones	Yes	All hours in the timeframe 1 Jan 2022 – 8 Jun 2022 (except 2 hours with failure (one with common and one with local failure))	DA
		cNTC(AT < > CZ/HU/SI)	All limiting CNECs	Yes	All hours in the timeframe 1 Jan 2022 – 8 Jun 2022 (except 48 hours with local failure for both directions, and 3 hours with local failure for one direction)	DA
		CORE (AT < > DE/CZ/HU/SI)	All CNECs of the final FB Domain	Yes	All hours in the timeframe 9 Jun 2022 – 31 Dec 2022 (except 8 (of total 12) hours with common failure)	DA
		IN (AT < > IT)	All limiting CNECs	Yes	All hours in the timeframe 1 Jan 2022 – 31 Dec 2022 (except 11.4 % hours with common failure)	DA
BE	ELIA	CWE	All CNECs	Yes	All hours	DA
		CORE				
		ALEGRO				
BG	ESO	SEE BG < > GR	All limiting CNECs	Yes	All hours	DA
		SEE BG < > RO				
CZ	ČEPS	CZ- > (AT+DE+PL+SK)	Only cross-border CNEs and CNECs	No	3,537 hours (92.71 %) were taken into account according to the derogation.	DA
		(AT+DE+PL+SK)- > CZ	Only cross-border CNEs and CNECs	No	3,537 hours (92.71 %) were taken into account according to the derogation.	DA
		CORE	All CNECs	Yes	All hours	DA
DE	Amprion	CWE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 3,815 hours of CWE FBMC operation except one hour of failure of capacity calculation.	Only DA.*
		ALEGrO (CWE)	Only capacity offered on the German Hub AL_DE is being monitored	No	All 3,815 hours of CWE FBMC operation except one hour of failure of capacity calculation.	DA
		CORE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 4,945 hours of Core FBMC operation except for 12 hours of failure of capacity calculation.	DA
		ALEGrO (CORE)	Only capacity offered on the German Hub AL_DE is being monitored	No	All 4,945 hours of Core FBMC operation except for 12 hours of failure of capacity calculation.	DA

Country	TSO	Border/region	Grid elements considered	Third countries considered	Hours considered	Time frames considered
	Transnet-BW	CWE	CNEC per CNE and MTU with the lowest MACZT	Yes	All 3,815 hours of Core FBMC operation except for 1 hours of failure of capacity calculation	DA
		CORE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 4,945 hours of Core FBMC operation except for 12 hours of failure of capacity calculation	DA
	50 Hertz	CORE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 4,945 hours of Core FBMC operation except for 12 hours of failure of capacity calculation	DA
		DK2 < > DE	All CNECs	No	All hours	DA
	50Hertz/ TenneT	DE < > PL/CZ	All limiting CNECs are provided	Yes	All hours before Core FB MC go-live	DA
	TenneT	CWE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 3,815 hours except 1 hour(s) of failure of capacity calculation	Only DA [28]
		CORE	All CNEs (for each CNE and MTU the CNEC with the lowest MACZT is taken into account)	Yes	All 4,945 hours of Core FBMC operation except for 12 hours of failure of capacity calculation	DA
DK	Energinet	SE3 - > DK1	All limiting CNECs	No	All hours	DA
		DK 1 - > SE3		No		
		DE < > DK2		No		
		DK1 - > DK2		No		
		DK2 - > DK1		No		
		DK1 < > NL		Yes		
		DK 1 - > NO2		No		
		NO2 - > DK 1		No		
EE	Elering	EE < > FI				
		EE < > LV				
EL	IPTO	SEE	All limiting CNECs	Yes	All hours with the tie line BG-GR in operation	DA
		GRIT	N/A	Yes	All hours with the GRIT tie line in operation	DA
ES	REE	ES < > FR	All limiting CNECs	No	All hours	DA
		ES < > PT				
FI	Fingrid	FI < > SE1	All CNECs	N/A	All hours	DA
		FI < > SE3				
		FI < > EE				
FR	RTE	SWE (FR - > ES)	Only limiting CNECS	No	All hours	DA
		SWE (ES - > FR)				
		IN		Yes		
		CWE		Yes	All MTU from 1 January – 8 June 2022	DA
		CORE		Yes	All MTU from 9 June – 31 December 2022	
HR	HOPS	CORE	All limiting CNECS	Yes	All hours	DA

28 Please note that this does not include allocated long-term capacities included in the final DA capacity via LTA inclusion.

Country	TSO	Border/region	Grid elements considered	Third countries considered	Hours considered	Time frames considered
HU	MAVIR	HU < > AT	All CNECs	Yes	All hours	DA
		HU < > HR				
		HU < > RO				
		HU < > SK				
		CORE				
IE	Eirgrid	No information provided				
IT	Terna	IN	All limiting CNECs	Yes	All hours	DA
		GR < > IT	N/A	N/A	All hours	All except LT
LT	Litgrid	LT < > SE4	No CNECs	No	All hours	DA
		LT < > PL				
		LT < > LV	No	N/A	N/A	N/A
LV	AST	LV < > LT	No[29]	N/A	N/A	DA
		LV < > EE				
NL	Tennet BV	CWE	Flowbased subset	Yes	All hours	DA
		CORE				
		Nordlink	All	Yes	All hours	DA
NO	Statnett	No information provided				
PL	PSE	PL < > (CZ-DE-SK)	All limiting CNECs	Yes	All hours	DA
		PL < > LT	Monitoring NTC provided on the DC link	N/A		
		PL < > SE4		N/A		
		CORE		N/A		
PT	REN	PT < > ES	All limiting CNECs	No	All hours	DA
RO	Trans-electrica	CORE	All CNECs, but percentages are calculated considering the CNECs with the lowest RAM.	Yes	All hours starting from 9 June 2023	DA
		RO < > BG	Limiting CNECs per TS and direction	Yes	All hours starting from 9 June 2023	DA
		RO < > all borders	Limiting CNECs per TS and direction	Yes	All hours starting from 9 June 2023	DA
SE	Svenska kraftnät	All borders	The CNE or CNEC which was considered to be the most limiting when defining the NTC is assessed for each hour	No	All hours	DA
SI	ELES	CORE	All CNECs	No	All hours	DA
SK	SEPS	CORE	All CNECs	No	All hours	DA

Table A-5: Underlying assumption

29 According to approved CACM CCM in Baltic CCR, capacity calculation process does not foresee daily capacity calculation process with CGM and therefore CNEs cannot be efficiently identified and thus data related to CNEs cannot be provided

1 Austria

1.1 Current status of the implementation of CEP70 requirements

In December 2020, an action plan was adopted by the Austrian government, which is in force from 1 January 2021 onwards. In addition to improvements and projects to increase the available capacity for cross-zonal trade, it also includes a linear trajectory for reaching 70 % MACZT by the end of December 2025. According to this action plan, the MACZT-target for 2022 is 28.7 % for the relevant coordination areas of APG [CWE (AT<> DE), cNTC (AT<> CZ/HU/SI), Core (AT<> DE/CZ/HU/SI and IN (AT<> IT)].

Furthermore, APG requested a derogation regarding foreseeable grounds affecting the security of system operation when applying the MACZT criterion for the CCR Core. The derogation was granted by the Austrian regulatory authority E-Control and allows for the application of a margin reflecting the uncertainties of MNCC flows ('MNCC Margin') due to the lack of a joint forecast and strong mutual influence of the neighboring CCRs as well as the possible reduction of the MACZT target in case of excessive loop- and PST flows exceeding a predefined threshold. In addition, it also allows the consideration of trade flows from third countries in the MNCC. These mitigations are necessary as the transmission system of APG is located centrally in the interconnected system between the two CCRs Core and Italy North (IN), in the direct neighborhood of third countries and is being exposed to high loop and PST-flows.

In line with this granted derogation, the minimum capacity target for cross zonal trade according to the Austrian action plan was applied on each relevant CNEC, considering the permitted mitigation measures.

As a result of the go-live of the flow-based day ahead capacity calculation in the CCR Core with business day 9 June 2022, different coordination area configurations are relevant for different time periods of the year 2022. Therefore, the compliance with the minimum capacity criterion was assessed for each relevant coordination area in the relevant timeframe:

CWE (AT<> DE): 01.01.2022 – 08.06.2022
cNTC (AT<> CZ/HU/SI): 01.01.2022 – 08.06.2022
Core (AT <> DE/CZ/HU/SI): 09.06.2021 – 31.12.2022
IN (AT<> IT): 01.01.2022 – 31.12.2022

1.2 Assessment methodology

The assessment is performed for each coordination area listed in chapter 1.1 and focuses on the DA timeframe only. For CWE, as a coordination area with flow-based capacity calculation, all real CNECs of the final domain of each hour in the relevant time period are considered. For Core, a similar approach applies (but different to CWE, there are no virtual CNECs in Core). For cNTC and IN, only the limiting CNECs of each hour in the listed time period are relevant. Under consideration of the approved derogations, the MACZT of each relevant CNEC entry is calculated. The distribution of the MACZT for all relevant CNEC entries can be found in Figure A-1.

For the assessment of compliance, those values are compared with the MACZT target in the dedicated report according to article 15(4) of the Regulation (EU) 2019/943, which was submitted to the Austrian NRA on 30 March 2023 for approval. The compliance values of each coordination area are:

CWE (AT<>DE): 99.99 %
cNTC (AT<>CZ/HU/SI): 98.32 %
Core (AT <> DE/CZ/HU/SI): 100.00 %
IN (AT<>IT): 100.00 %

1.3 Assessment results

Figure A-1 shows the distribution of MACZT for all relevant CNECs. Figure A-2 provides an overview on process stability.

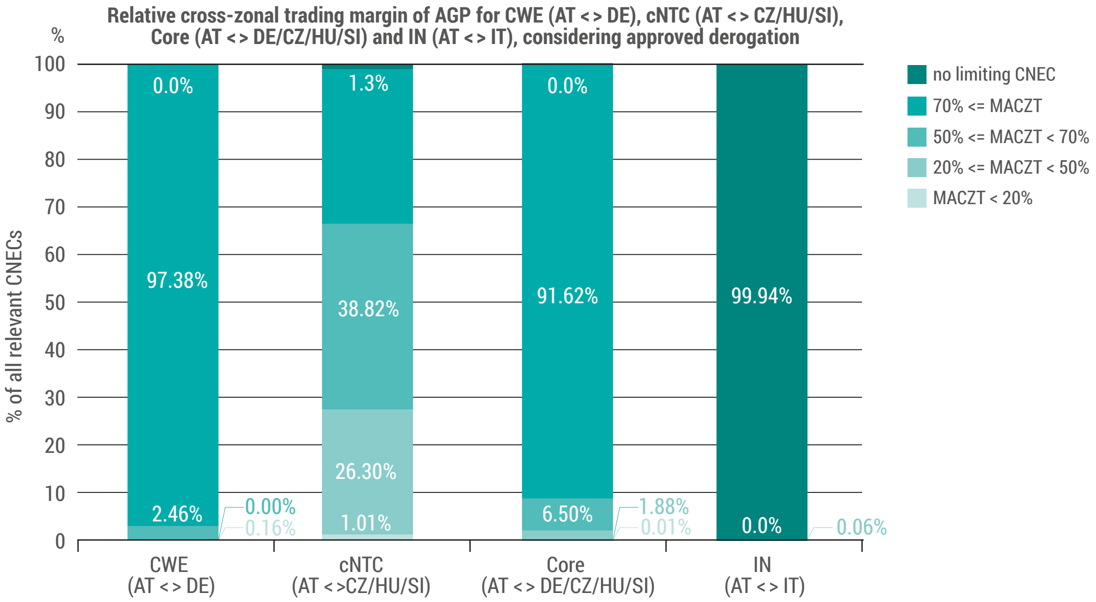
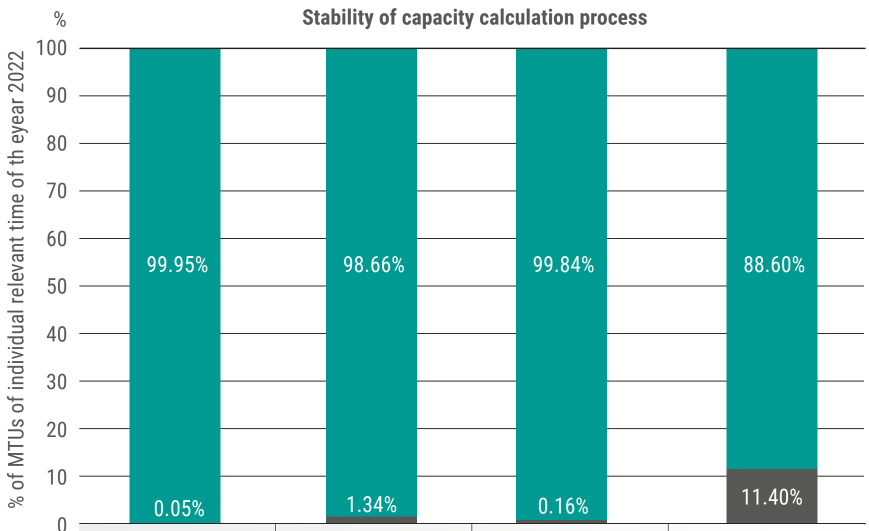


Figure A-1: Relative cross-zonal trading margin of Austria taking into account all CNECs in the respective timeframe and the approved derogation.

Figure A-1 shows a high percentage of CNECs having a MACZT >= 70 % in the FB capacity calculation areas CWE and Core (the values are based on all CNECs of all relevant hours except those with process failure, leaving all CNECs of 3,813 relevant hours in CWE and all CNECs of 4,937 relevant hours in Core). In the coordination area IN, we see that APG almost never limited this border. Just in five hours of the year 2022, with respective five CNEC entries (where all five CNEC entries have a MACZT >= 70 %), APG network elements where limiting. The coordination area cNTC shows, that the performance of the coordinated NTC capacity calculation in terms of MACZT is not as good as in areas with FB capacity calculation. This shortcoming was improved with the implementation of the Core DA FB capacity calculation on 9 June 2022. The percentages for cNTC are based on the assumption, that normally there are two limiting CNECs for each hour (import and export). Due to tool issues, APG was able to only calculate 7,531 of 7,630 limiting CNECs for the period where the coordination area cNTC was operational, leading to 1.30 % with no limiting CNEC.



	CWE (AT <> DE)	cNTC(AT <>CZ/HU/SI)	Core (AT <> DE/CZ/HU/SI)	IN (AT <> IT)
Normal state	99.95 %	98.66 %	99.84 %	88.60 %
Failure of capacity calculation/Fallback	0.05 %	1.34 %	0.16 %	11.14 %

Figure A-2: Overview on the process stability in the relevant time period of 2022 of each coordination area

The bars in Figure A-2 show that overall, the capacity calculation stability is quite high (except for IN where it is around 11.4 % of all 8,760 hours of the year 2022). In CWE, there was one hour with common and one hour with local issues, leading to a non-consideration of 0.05 % of hours of the relevant time period (3,815 h). In the coordination area cNTC, for 48 hours both (import and export) and for another three hours one limiting CNEC (export) could not be calculated due to tool issues. This leads to a non/partly consideration of 51 hours, which is 1.34 % of MTUs in the relevant time period. In the coordination area Core, twelve hours had a common fallback, but only eight of them where not considered in the relevant time period, as there were no CNECs available in those hours (0.16 % of the relevant timer period of 4,945 hours).

2 Belgium

2.1 Current status of the implementation of CEP70 requirements

Elia has been granted a derogation for excessive loop flows for its AC CNECs in the CWE region from the 1 January 2022 to the 8 June 2022 and in the CORE region from the 9 June 2022 to the 31 of December 2022.

2.2 Assessment methodology

Elia applies ACER's recommendation, complementing the 'lowest MACZT per MTU' view expressed in the main Table A-above with an 'All CNECs' view for which the assessment results are shown below. In this manner a complete picture is devised.

In November 2020, Amprion and Elia put into operation the first direct electricity interconnection between Germany and Belgium, called 'ALEGrO'. ALEGrO is integrated as a DC interconnection into the CWE/CORE capacity calculation via the 'Evolved Flow Based Methodology', enabling the allocation to optimise the exchanges over ALEGrO. The relevant metric for assessing the margin available for cross-zonal trades is the maximum transmission capacity made available on the ALEGrO interconnector, upon which the allocation then performs its optimisation.

Please note that the overview on the underlying assumptions of the assessment methodology is in the Table at the beginning of the annex.

2.3 Assessment results

ALEGrO

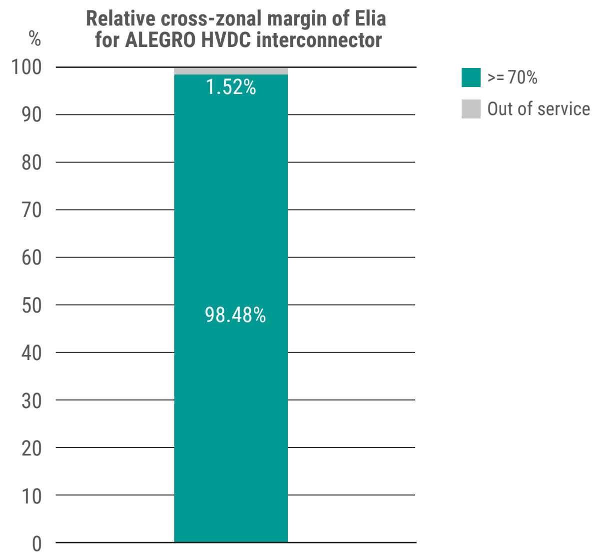


Figure A-3: Relative cross-zonal trading margin of Belgium's HDVC link on BE-DE border in CWE and CORE

Based on the above assessment methodology, the following results are obtained for Belgium. Figure A-3 illustrates that for all hours where ALEGrO was in operation at least 70 % capacity of the 1,000 MW capacity is provided. In fact, both Elia and Amprion provided in these hours the full 1000 MW capacity of the interconnector to the allocation. And this both for exchanges in the direction Belgium to Germany as well as in the direction Germany to Belgium.

CWE & CORE

This section depicts the results of the Belgian AC CNECs participating in the CWE FB DA capacity calculation.

For 1 January 2022 till 8 June 2022, the basis are all hours from the CWE DA CC process from which the following hours have been excluded:

- 0 hours where the CWE DA CC process resulted into DFPs
- 25 hours for which a local tooling issue prevented the calculation of the min MACZT target. In the event of a local tooling issue, Elia applies a minimum of 20 % RAM for CWE exchanges as fallback approach.

For 9 June 2022 till Dec 31st 2022, the basis are all hours from the CORE DA CC process from which the following hours have been excluded:

- 8 hours where the CORE DA CC process resulted into DFPs
- 4 hours for which a local tooling issue prevented the calculation of the min MACZT target. In the event of a local tooling issue, Elia applies a minimum of 20 % RAM for CORE exchanges as fallback approach.

The target of minMACZT is defined as per the rules embedded in the derogation on excessive loopflows that was granted to Elia. Hereby 70 % is taken as a starting point and reduced only for the amount of excessive loopflows observed during the capacity calculation on that particular CNEC in that particular MTU. With the transition from CWE to Core, it became possible for Core TSOs to apply remedial actions to reduce excessive loopfows. Elia makes use of this possibility by optimising the settings of its PSTs, hereby further reducing the extent of the derogation.

From figures A 4 and A 5 it can be observed that:

- For more than 92 % of CNECs in CWE and 97 % of CNECs in CORE Elia provides already the minimum 70 % of capacity;
- During ~70 % of time in CWE and ~83 % of the time in CORE the minimum target is reached on all CNECs, or in other words in ~30 % of time in CWE and ~17 % of the time in CORE the minimum target is not reached on the worst performing CNEC in a given MTU.

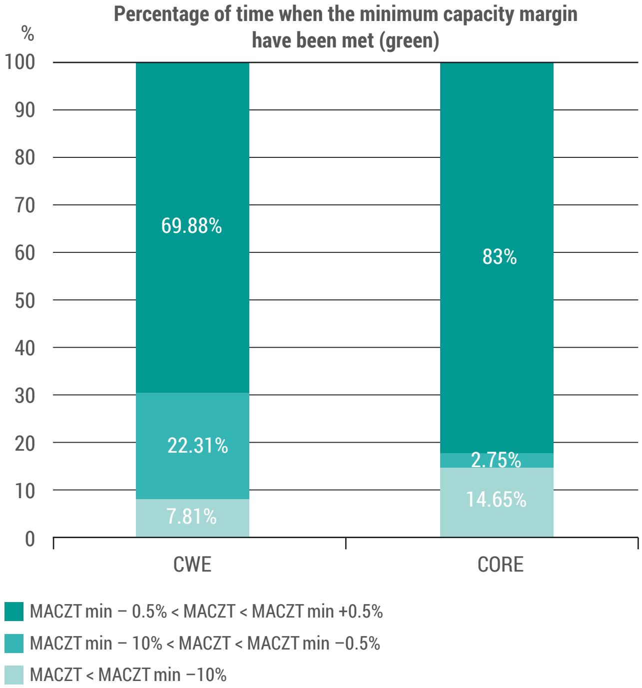
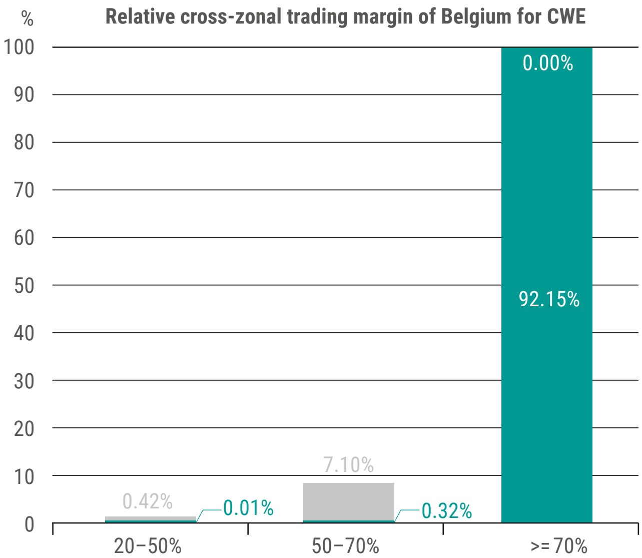


Figure A-4: Percentage of time when the relative MACZT of the least performing BE CNEC per MTU is above its minimum MACZT or within a certain range below its minimum MACZT. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges.



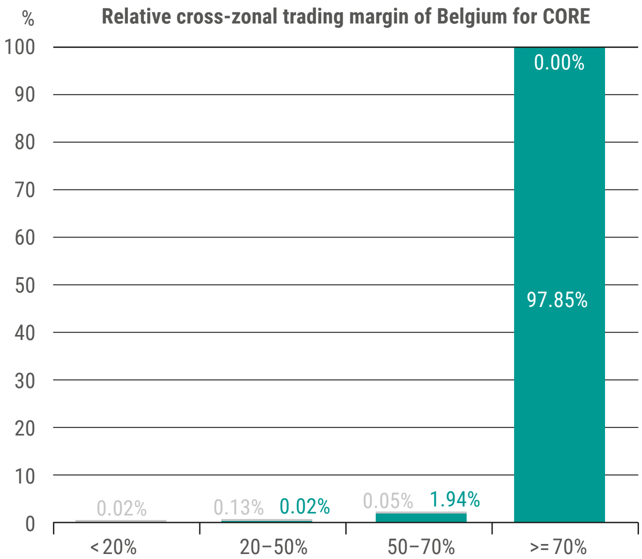


Figure A-5 & 6: Categorises for all Belgian CNECs the margin made available for cross-zonal trade.

At the time of writing the CREG report for 2022 has not been released.

3 Bulgaria

3.1 Current status of the implementation of CEP70 requirements

According to a decision Nr. 2 from Report Nr.223 from 28.10.2020 of Bulgarian NRA, ESO has been granted a derogation without a minimum capacity until 28 October 2022. Nevertheless considering all the explanations and results below, we are stating that we are compliant with the 70 % rule.

3.2 Assessment methodology

The MACZT data in this report are based on the results received from the ACER calculations. The results are based on limiting CNECs from DA capacity calculation provisions received from the SELENE RSC.

3.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Bulgaria.

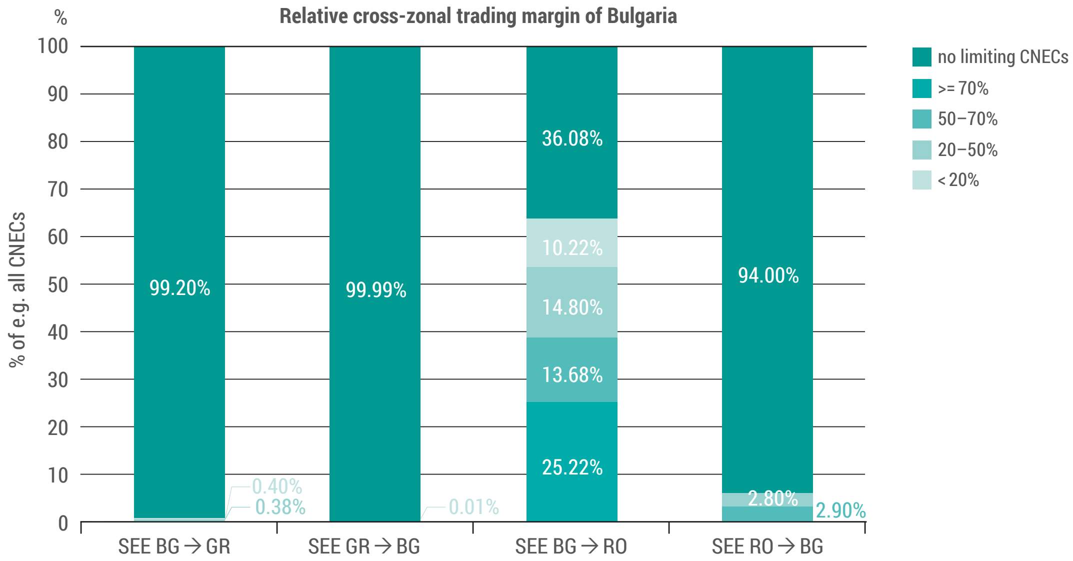
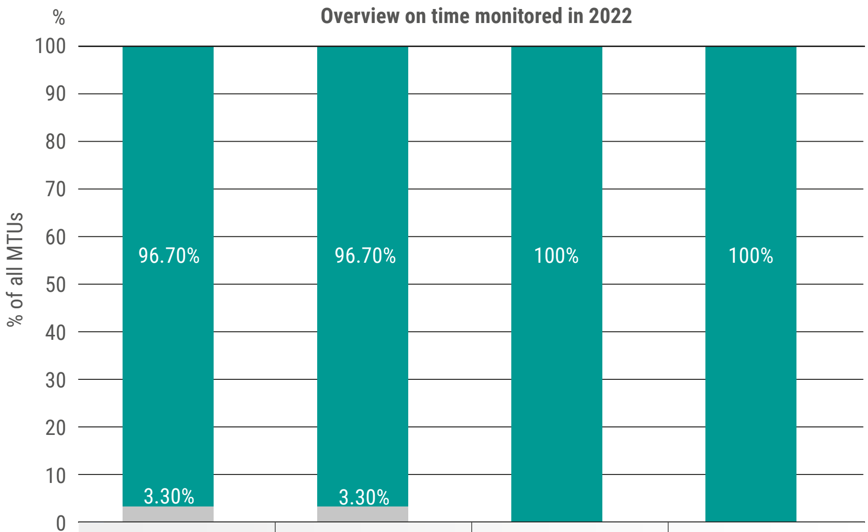


Figure A-7: Relative cross-zonal trading margin of Bulgaria



	SEE BG → GR	SEE GR → BG	SEE BG → RO	SEE RO → BG
Normal operation / process	96.70 %	96.70 %	100.00 %	100.00 %
No IC capacity available	3.30 %	3.30 %	0.00 %	0.00 %
Application of fallback procedure	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-8: Overview on time monitored in 2022

3.4 Additional information

The reason for the values of MAZCT below 70 % can be found inthe way that the flows with third countries in our region are currently threatened according to the current version of the SEE coordinated capacity calculation methodology. According to the ACER recommendation, the calculation of MACZT is determined by margin from coordinated capacity calculation MCCC and from non-coordinated capacity calculation MNCC. According to the ACER calculations, MNCC for part of our timestamps is negative (due to the fact that the flows from the non-EU member states are considered to be non-coordinated calculated), which leads to extremely low MACZT values for these cases. Three from our five borders are with non EU members, which are not obliged to comply with EU Regulations and, considering this from our perspective, the only way to fully reach the 70 % requirement according to the ACER recommendations is to have agreements signed with third countries in the region (Serbia, North Macedonia and Turkey). The three SEE TSOs have already made first steps toward the initiative for concluding agreements with third countries in the region (Serbia, North Macedonia and Turkey) considering the EU Commission letter regarding the capacity calculation and third countries flows sent to ENTSO-E and ACER on 16 September 2019. On 5 October 2020, a letter was sent on behalf of the three SEE EU TSOs (Bulgaria, Romania and Greece) to the non-EU TSOs of Albania, Turkey, North Macedonia and Serbia. Taking into account the recommendations given by the EC, it was proposed to conclude agreements with neighboring countries to address in a common coordinated way the treatment of the capacity calculation constraints and the cost sharing of remedial actions in the region. The signing of such agreements with neighboring non EU-countries would have been a good starting point for an amendment of the Methodology for calculating cross zonal capacity for the DA and ID timeframe, already adopted by National regulators in the South East Europe region. By changing the existing methodology and including the BG–MK, BG–SR, BG–TR, GR–AL, GR–MK, GR–TR and RO–SR borders, a balance will be achieved between a more efficient CZC calculation and considering all the peculiarities while maintaining the secure operation of the electricity systems in the region. So far it is not clear whether the above mentioned countries are willing to join the requirement of at least 70 % for their borders with Bulgaria, Romania and Greece. Nevertheless, in connection with the need to include the requirements to reach a minimum threshold of 70 % of the transmission capacity between commercial zones, respecting the safety standards for the secure operation of the network under Article 16(8) of REGULATION (EU) 2019/943 in the SEE CCM at the end of 2021, preliminary discussions with experts from the operators of Greece and Romania have been launched. At the end of July 2022, the draft methodology was developed where, to reach the 70 % requirement in the capacity calculation process, the borders with non-EU borders were incorporated. After public consultations the methodology was sent for approval to SEE NRAs in the end of February 2023. Unfortunately, without the consent of these parties, we can not implement the amended Methodology for the calculation of cross-zonal transmission capacity and adequately calculate the MACZT according to the ACER recommendations. We must also note that there are no internal limiting elements in our network and in normal operation conditions, the limiting elements from our perspective are the inreconnection lines with neighboring countries or elements in the networks of neighboring TSOs. Therefore, the net transfer capacity values with the member state countries proposed and validated by us in the DA CC process are respecting the 70 % requirement, taking into account the ratings of the interconnection lines. Considering all the above, and as we filled out in the previous columns, we confirm that we are 100 % compliant with the 70 % rule.

4 Croatia

4.1 Current status of the implementation of CEP70 requirements

As in 2020, Croatia has been granted a derogation for 2021. A derogation with no minimum capacity is applied in 2020. For the duration of the derogation in 2021, HOPS was committed to allocating capacities no less than the minimum capacity allocated for each market unit in the period 2018 to 2020, and no less than the capacity that corresponds to 20 % of the load for each CNEC. A structural congestion report was approved at the end of 2021. During the submission of the structural congestion report by means of an action plan, acknowledging the time needed for adopting the action plan from receiving the notification by Ministry of the Economy and Sustainable Development, Croatia submitted a request to the Croatian Energy Regulatory Agency (HERA) for derogation for 2022 or until the entry into force of the action plan adopted in accordance with Article 14(7) of the Regulation, whichever comes first. For the duration of the derogation in 2022, HOPS was committed to allocating capacities no less than the minimum capacity allocated for each market unit in the period 2019 to 2021, and no less than the capacity that corresponds to 20 % of the load for each CNEC.

The action plan was approved by Ministry of the Economy and Sustainable Development and in force from 25 February 2022.

The action plan contains a specific timeline for the adoption of measures to reduce structural congestion identified within four years of the Decision.

The action plan consists of the following elements:

- Determination of the starting point and linear trajectory of the increase of the minimum cross-border capacity available for cross-zonal trading until 31 December 2025;
- Measures that would allow the reduction of the structural congestion identified in the structural congestion report; and
- Provisions of monitoring implementation of action plan.

According to this action plan, the MACZT-target for 2022 (starting point of the linear trajectory) is 20.4 % for FB approach, while the starting point using the NTC approach before the operational start of Core Flow Based DA MC is based on the average value of MACZT between 2019 and 2021, which expects at least 7.6 % with a recommended starting point of at least 20 % at Core borders after the start of the action plan.

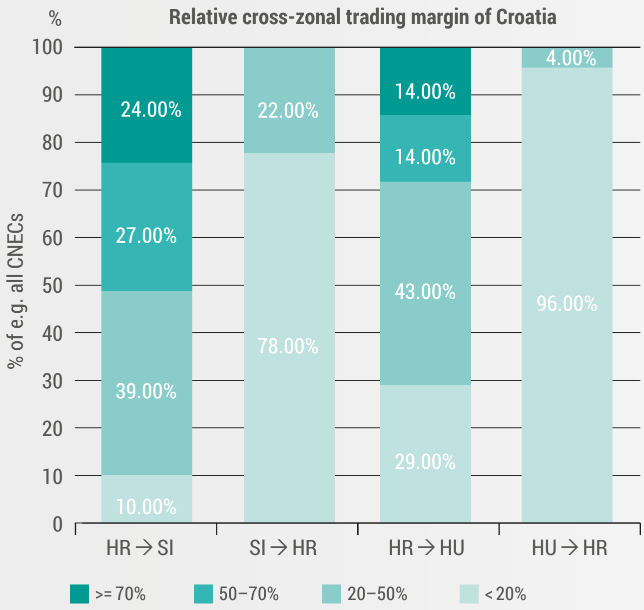
4.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied. Croatia uses the (un)coordinated unilateral NTC approach for calculating CZCs on all borders until 9 June 2022, with which Core FB DA MC starts operational working, after which HOPS applies FB approach for calculation CZCs at Core borders, in the sense of application to the borders between Croatia and Slovenia, and between Croatian and Hungary, to all critical transmission network elements.

Please note that the overview on the underlying assumptions of the assessment methodology of Croatia is provided in the Table at the beginning of the annex.

4.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Croatia. Results of the MACZT include exchanges with third countries.



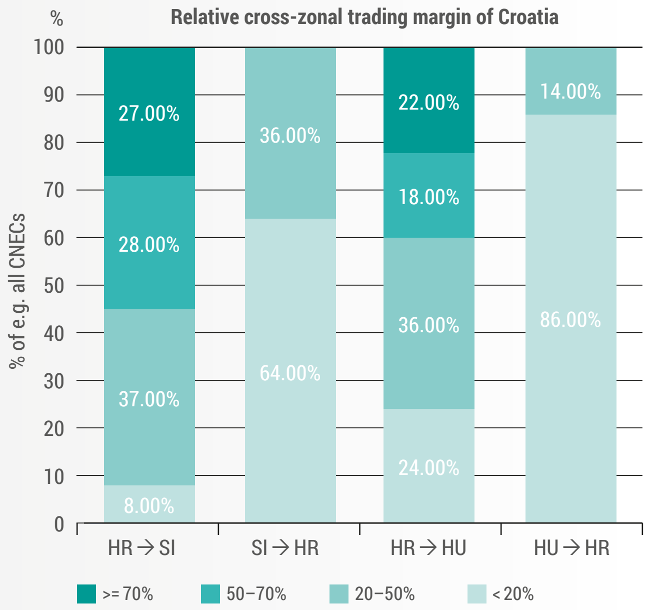


Figure A-9: Relative cross-zonal trading margin of Croatia (Left: NTC approach before action plan until 25.02.22; Right: NTC approach after action plan until 08.06.22)

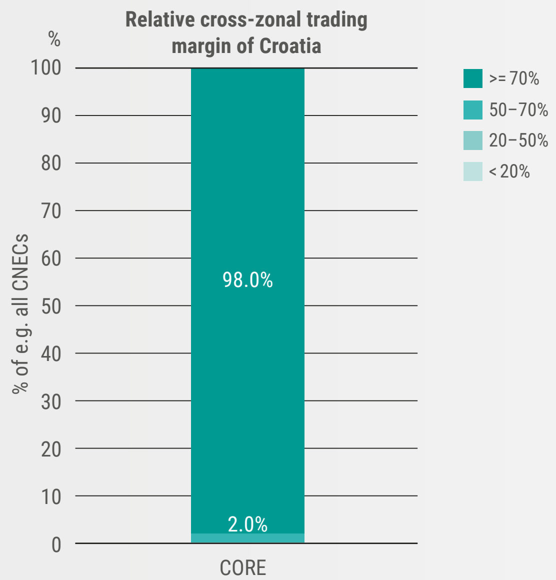


Figure A-10: Relative cross-zonal trading margin of Croatia (FB approach from 9.06.22)

5 Czech Republic

5.1 Current status of the implementation of CEP70 requirements

ČEPS derogation in 2022 (until CORE DA FBMC go-live) was set to reach a 60 % threshold in at least 90 % of MTUs in the export direction and to reach a 40 % threshold in at least 90 % of MTUs in the import direction. This applies to MTUs which are not considered as a special operational state, for which no minimum capacity applies. ČEPS was compliant with the approved derogation in both directions in 2022. After CORE DA FBMC go-live, minRAM parameter was set to 70 % which makes ČEPS fully compliant with CEP70 requirements.

5.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied.

Please note that the overview on the underlying assumptions of the assessment methodology of the Czech Republic is provided in the Table at the beginning the annex.

5.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Czech Republic.

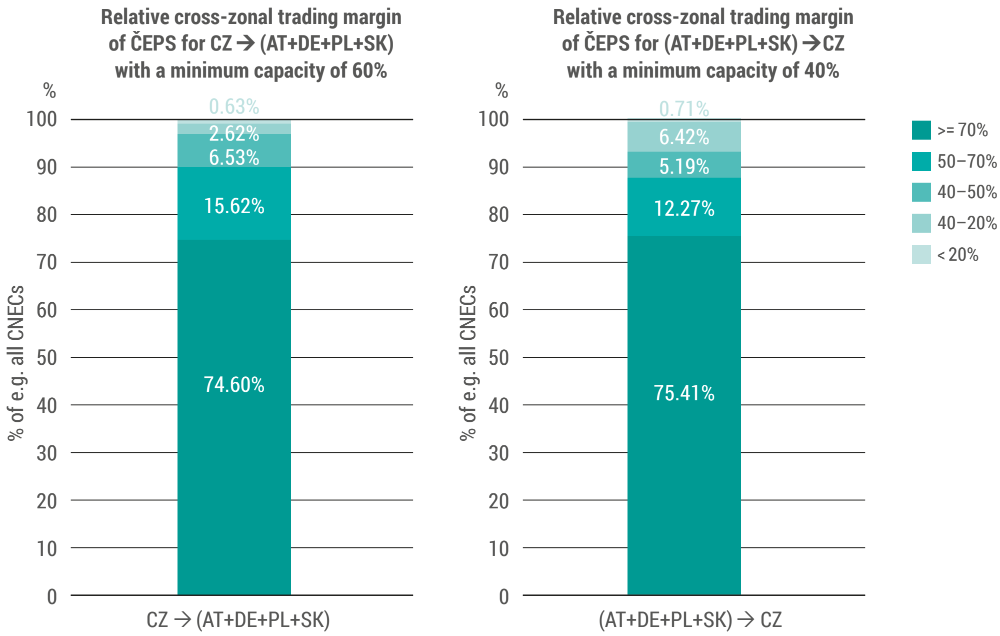


Figure A-11: Relative cross-zonal trading margin of Czech Republic until FB DA CC

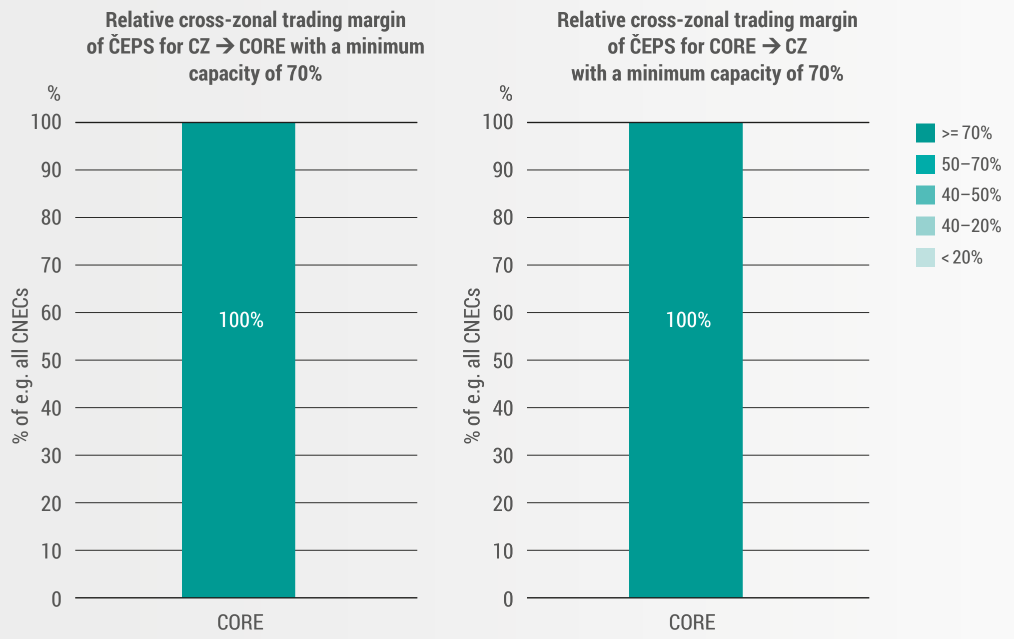
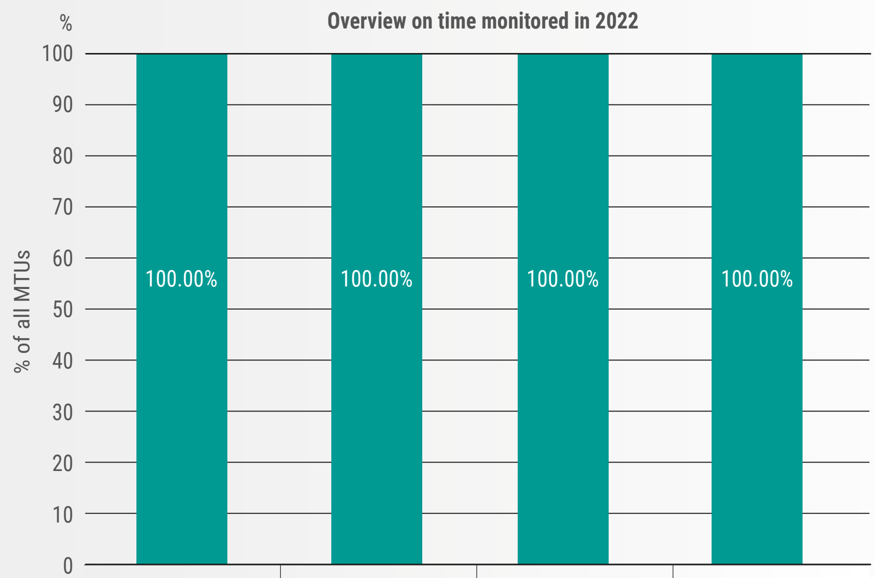


Figure A-12: Relative cross-zonal trading margin of Czech Republic after FB DA CC



	CZ → (AT+DE+PL+ SK)	(AT+DE+PL+ SK) → CZ	CORE	CORE
Normal operation / process	100.00 %	100.00 %	100.00 %	100.00 %
No IC capacity available	0.00 %	0.00 %	0.00 %	0.00 %
Fallback or failure of CC	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-13: Overview on time monitored in 2022 for Czech Republic

6 Denmark

6.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

6.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied.

Please note that the overview on the underlying assumptions of the assessment methodology of Denmark is provided in the Table at the beginning of the annex.

6.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Denmark.

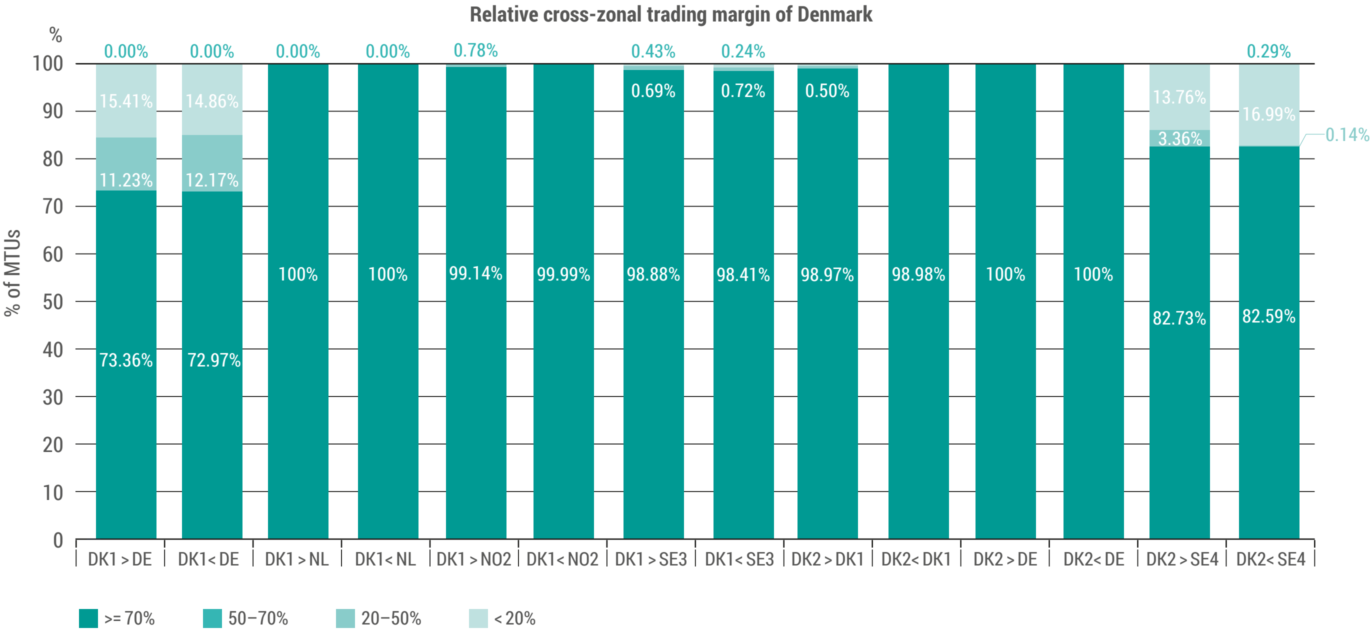
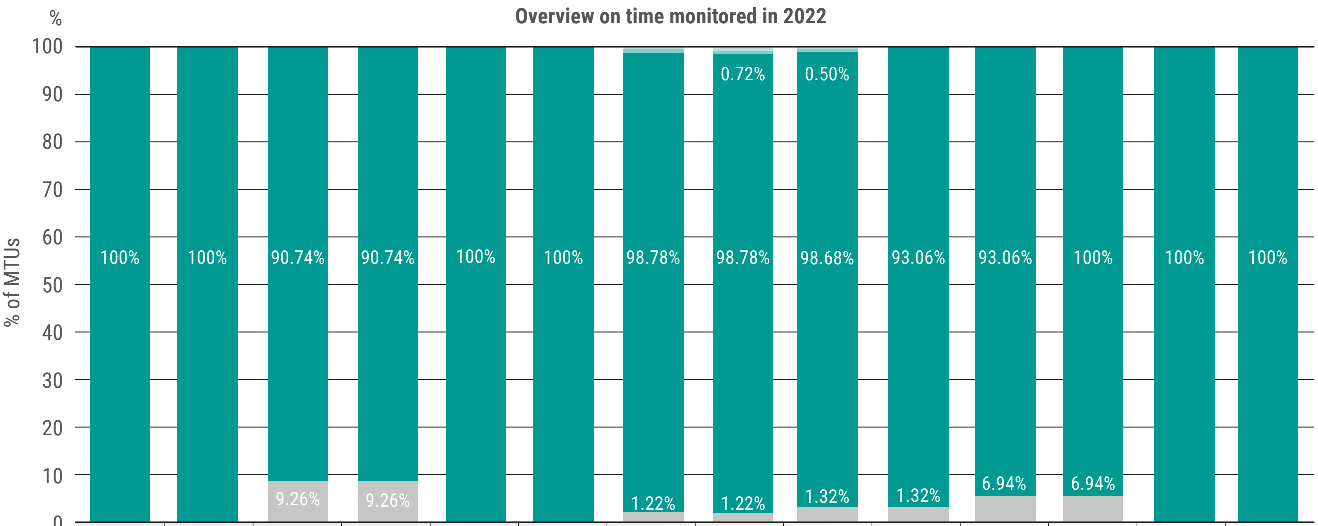


Figure A-14: Relative cross-zonal trading margin of Denmark



	DK1 > DE	DK1 < DE	DK1 > NL	DK1 < NL	DK1 > NO2	DK1 < NO2	DK1 > SE3	DK1 < SE3	DK2 > DK1	DK2 < DK1	DK2 > DE	DK2 < DE	DK2 > SE4	DK2 < SE4
Normal operation / process	100.00 %	100.00 %	100.00 %	90.74 %	100.00 %	100.00 %	98.78 %	98.78 %	98.68 %	98.68 %	93.06 %	93.06 %	100.00 %	100.00 %
No IC capacity available	0.00 %	0.00 %	0.00 %	9.26 %	0.00 %	0.00 %	1.22 %	1.22 %	1.32 %	1.32 %	6.94 %	6.94 %	0.00 %	0.00 %
Application of fallback procedure	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %

Normal operation / process ■ No IC capacity available ■ Application of fallback procedure

Figure A-15: Overview on time monitored in 2022 for Denmark

7 Estonia

7.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

7.2 Assessment methodology

The 70 % rule according to Article 16(8) of Regulation (EU) 2019/943 and ACER recommendation is applied. Please note that the overview on the underlying assumptions of the assessment methodology of Estonia is provided in the Table at the beginning of the annex.

7.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Estonia.

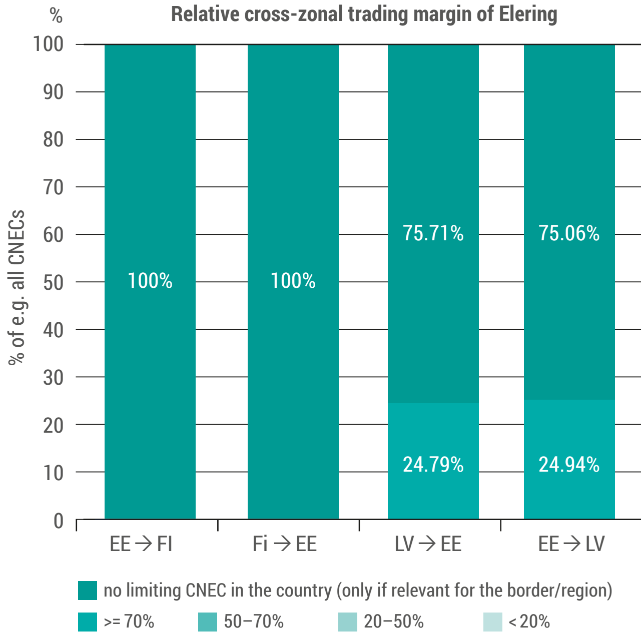


Figure A-16: Relative cross-zonal trading margin of Estonia

8 Finland

8.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

8.2 Assessment methodology

For the border FI–SE1, AC-tielines include 100 MW TRM as a market constraint. Below 70 % would be reached only with lower than 240 MW NTC. For the borders FI–SE3 and FI–EE, Fingrid does not apply any market constraints to DC-tielines. Please note that the overview on the underlying assumptions of the assessment methodology of Finland is provided in the Table at the beginning of the annex.

8.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Finland.

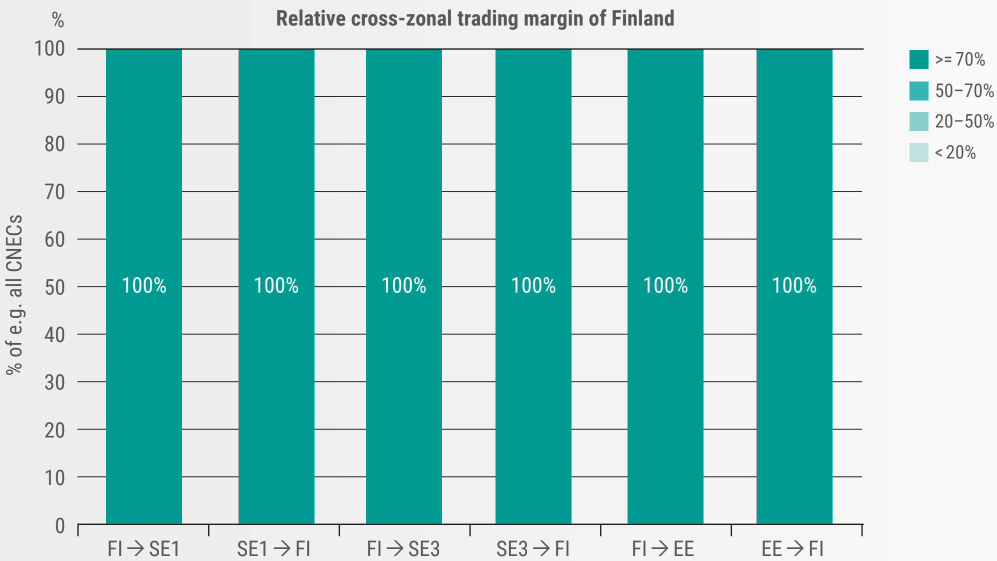


Figure A-17: Relative cross-zonal trading margin of Finland

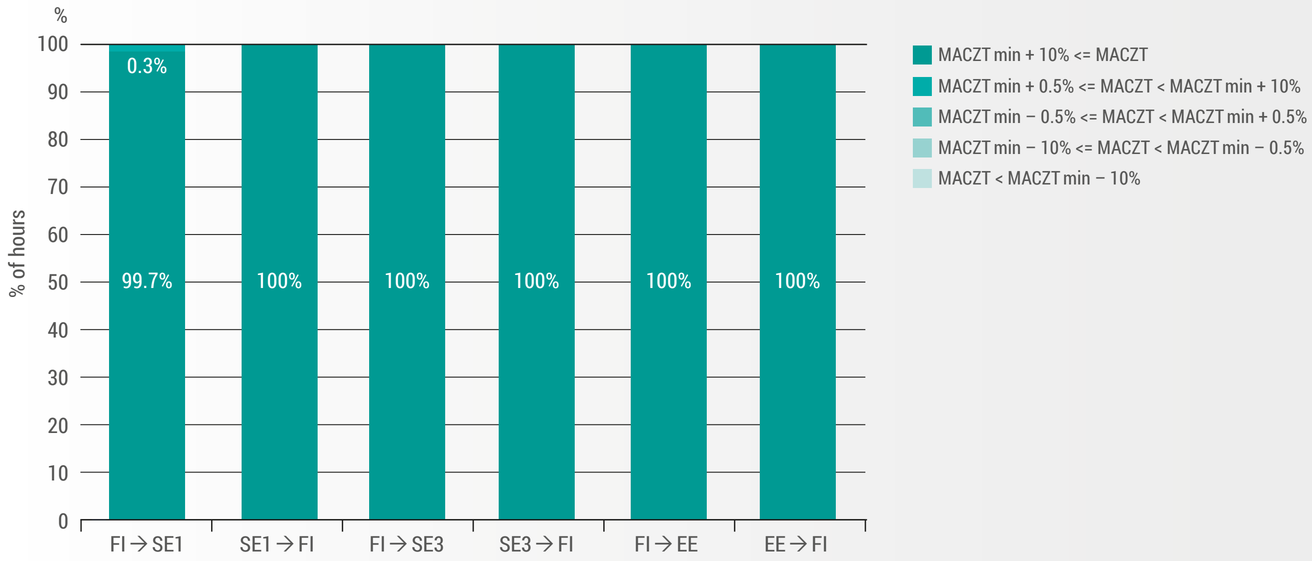


Figure A-18: Percentage of time when the relative MACZT of the least performing FI CNEC per MTU is above its minimum MACZT or within a certain range below its minimum MACZT. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges.

8.4 Additional information

Dynamic angle and voltage stability limits are considered for the border FI–SE1. Export capacity from Sweden to Finland is limited by dynamic angle stability due to long-distance transmission path between southern Finland and southern Sweden. This is done to limit undamped oscillation between large production units (e.g. nuclear power plants) in southern Finland and southern Sweden via AC-network. This phenomenon limits the transmission capacity below thermal limit of the cross-border line.

Import capacity from Finland to Sweden is limited due to voltage stability. After major production contingency, voltage has to remain on the predefined level (>370 kV). This is quite close to the thermal limit of the cross-border lines.

9 France

9.1 Current status of the implementation of CEP70 requirements

On 9 June, there was the Go-live of Core CC, thus, for 2022, we will present the data for CWE between 1 January to the 8th of June and for Core for the rest of the year.

There was no derogation for RTE in Core, SWE and Italy North in 2022.

The Go-Live of CEP Implementation finally took place at the beginning of February 2022. In the event, a CNEC does not respect the CEP 70 % threshold, RTE provides some costly remedial action to improve the MACZT (and consequently the capacity).

9.2 Assessment methodology

RTE applies ACER's recommendation to determine MACZT by taking into account Third Countries. Regarding the compliance with the 70 % rule, all French non limiting CNECs & MTUs with price convergence with cross border countries are deemed as compliant.

All MTUs where the capacity calculation process was a success were considered in the analysis. Those where a process failed occurred are also presented below.

Please note that the overview on the underlying assumptions of the assessment methodology of France is provided above.

9.3 Assessment results

Based on the above assessment methodology, the following results are obtained for France.

The MTUs where RTE was not 70 % compliant regarding the methodology described above correspond to cases where:

- For the Italy north region, there is a lack of redispatching margin to achieve the 70 % criteria; and
- For SWE, congestion management is quite hard due to network constraints.

Figure A-21 provides an overview of the time monitored in 2022 for CWE, Core and Italy North.

Please note that for CWE and Core, the category 'failure of capacity calculation' considers the application of fallback capacities (so-called default flow-based parameters) or spanning. For Italy North, a fallback procedure was applied to offer capacity to the DA market.

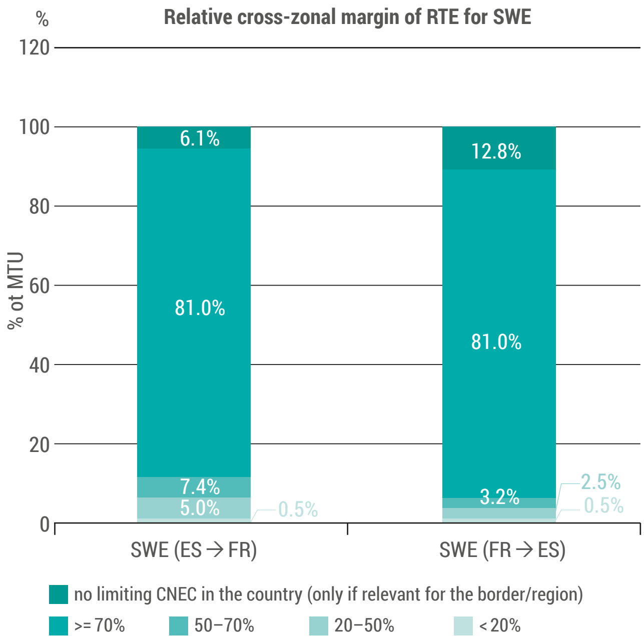


Figure A-19: Relative cross-zonal trading margin of France for SWE with a minimum capacity of 70 % in 2022

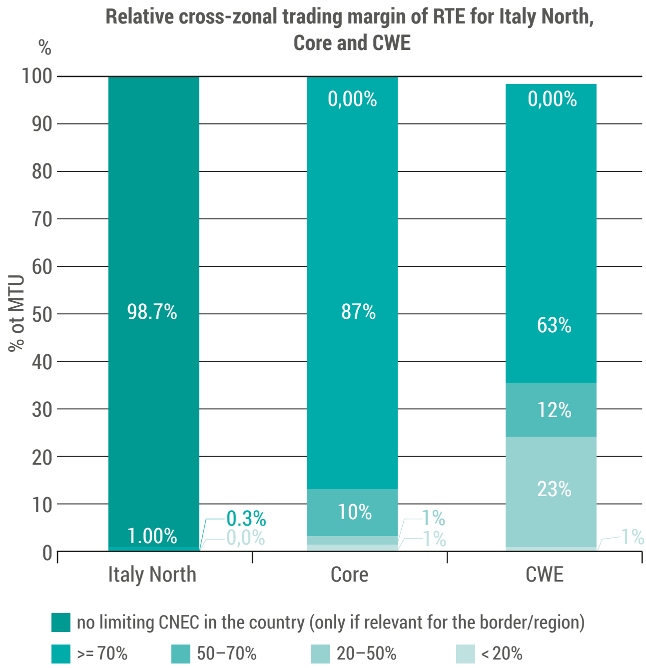


Figure A-20: Relative cross-zonal trading margin of France for CWE, Core and Italy North in 2022

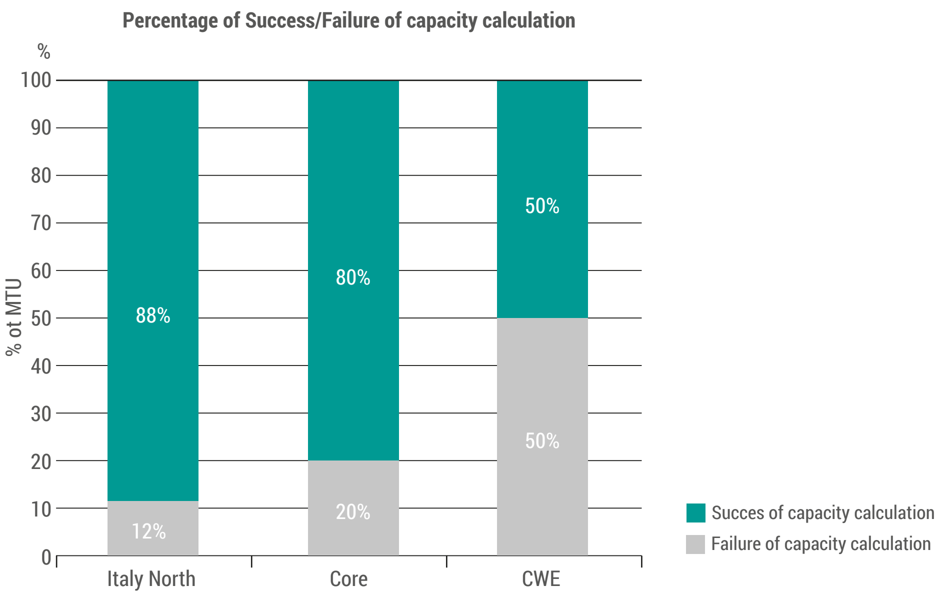


Figure A-21: Time monitored in 2022 for CWE, Core and Italy North.

10 Germany

10.1 Current status of the implementation of CEP70 requirements

Pursuant to Art. 15 (1) of the EU Electricity Market Regulation (EU) 2019/943, EU member states with identified structural grid congestion can submit an action plan to reduce this congestion. This leads to a situation where the minimum capacity of 70 % must be achieved via a linear trajectory by 31 December 2025 (Art. 15, § 2). In this context, the Federal Republic of Germany – after prior consultation with stakeholders and member states – submitted the Action Plan Bidding Zone to the EC and ACER on 28 December 2019.

The Action Plan Bidding Zone contains concrete measures through which Germany will counteract the previously identified structural bottlenecks and gradually achieve the minimum capacity for cross-bidding zone electricity trading of 70 % by 31 December 2025.

In 2022, the action plan, the respectively minimum target, could be fulfilled. All lower deviations of the minimum target were justified by risks for the operational security.[30]

10.2 Assessment methodology

The applied methodology for monitoring the compliance in regards to the available margin for cross-zonal electricity trade is based on the Electricity Market Regulation (EU) 2019/943 and the specifications for the German National Regulation Authority Bundesnetzagentur (BNetzA).

Accordingly, for borders using a flow-based approach, the available margin is determined per critical network element with the respective contingency (CNEC) and must respect the applicable minimum value (in line with the German action plan) per market time unit (MTU), i.e. in each hour, and in both directions. For borders using a coordinated net transmission capacity approach, the available margin is determined per border (for borders with AC network elements on the limiting CNEC) and must respect the applicable minimum value per MTU and in both directions. This minimum value defines the minimum capacity which should be made available/offered to the market.

The available margin offered to the market consists of two components. The first is the coordinated margin, which represents the offered capacity on the analyzed CNE or border with the respective capacity calculation region. In practical terms for CWE and CORE, the coordinated margin is at least equal to the RAM offered in the DA capacity calculation for cross-zonal trade. The second component reflects the uncoordinated margin, which depicts the impact of capacity offered on borders that do not participate in the capacity calculation region. In practical terms, the uncoordinated margin is calculated by multiplying the corresponding burdening Power Transfer Distribution Factors (PTDFs) with the respective NTCs to determine the impact of these NTCs on the respective CNEC. The total uncoordinated margin of a specific CNEC equals the sum of the individual uncoordinated margins of the different NTC borders.

The first direct electricity interconnection between Germany and Belgium, ‘ALEGrO’, is integrated as a DC interconnection into the CWE and Core capacity calculation and allocation via the ‘Evolved Flow Based Methodology’ and is thus subject to a special monitoring methodology. The relevant metric for monitoring the compliance of Amprion is the maximum transmission capacity provided in the Flow-Based Market Coupling process on the German Hub ‘AL_DE’ of ALEGrO.[31] This metric must be at least equal to the minimum percentage value according to the Action Plan multiplied by the available thermal capacity of ALEGrO. In the event of an outage or reduced thermal capacity of ALEGrO, the minimum value for cross-zonal trading capacity of ALEGrO will also be reduced. As congestions may occur in the AC grid, the actual trading capacity via ALEGrO may differ from the capacity offered directly on ALEGrO. However, this does not affect the monitoring results of ALEGrO.

More detailed information about the methodology applied and the compliance monitoring can be found in the national monitoring report[32].

Please note that the overview on the underlying assumptions of the assessment methodology of Germany (all TSOs) is in the Table at the beginning of the annex.

30 Except for 2 CNE of TenneT Germany in hour 21 of 15 November 2022, where a differences in the MNCC calculation between the German monitoring methodology and the Core CCM (applying the ACER monitoring approach) resulted in a minor lower deviation. The Core CCM assumed a higher MNCC (thus applied a lower MCCC/AMR (Adjustment for Minimim RAM) based on a forecasted schedule of Cobra Cable of 700 MW while the Germany monitoring applied the actual offered NTC of Cobra Cable, which was zero (0) MW resulting in a lower MNCC. As TenneT Germany cannot adjust the AMR during in the Core process, TenneT Germany is not responsible for such deviations.

31 This is modeled within the framework of ‘Evolved Flow-Based’ via so-called ‘virtual hubs’ of the converter stations Lixhe and Oberzier. These form their own hubs with their own PTDFs in the capacity calculation and allocation. The maximum or minimum net positions of the virtual hubs are generally limited to the available thermal capacity of ALEGrO and thus also form the basis for the assessment for the present compliance monitoring.

32 See **here**.

10.3 Assessment results

10.3.1 50Hertz

Based on the above assessment methodology, the following results are obtained for 50Hertz.

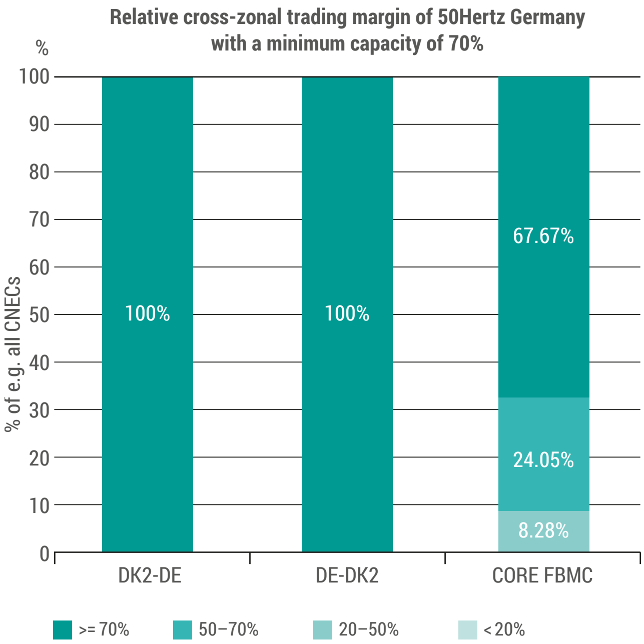


Figure A-22: Relative cross-zonal trading margin of 50Hertz for DK2-DE and DE-DK2 with a minimum capacity of 70 % and for Core FBMC with a minimum capacity of 31.0 %

10.3.2 50Hertz/TenneT Germany

Based on the above assessment methodology, for the border to PL/CZ the following results are obtained for 50Hz and Tennet Germany.

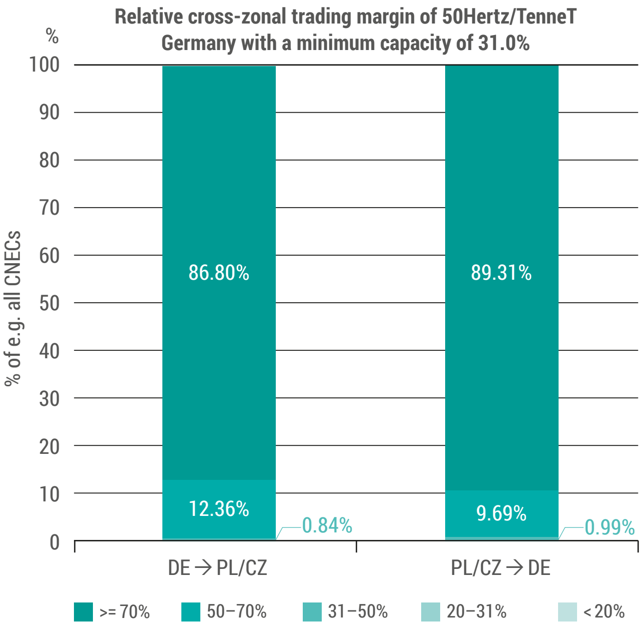
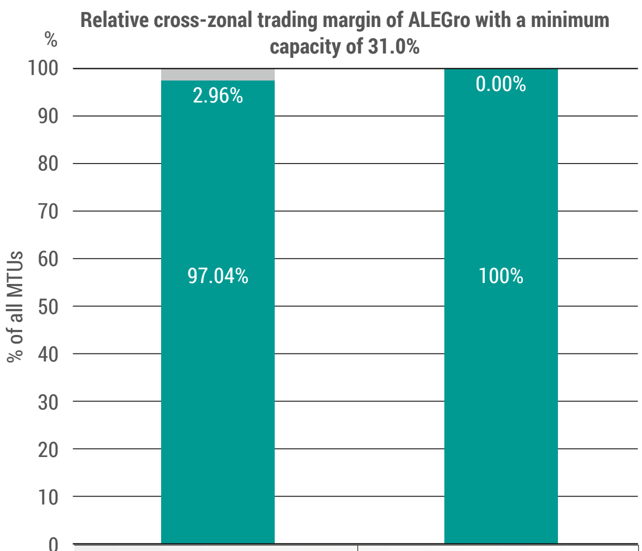


Figure A-23: Relative cross-zonal trading margin of 50Hertz/TenneT Germany for DE-PL/CZ and PL/CZ-DE with a minimum capacity of 31.0 %

10.3.3 Amprion

Based on the above assessment methodology, the following results are obtained for Amprion.



	ALEGrO (CWE)	ALEGRrO (CORE)
Out of Service	2.96 %	0.00 %
>= 70 %	97.04 %	100.00 %
50–70 %	0.00 %	0.00 %
31–50 %	0.05 %	0.00 %
<31 %	0.00 %	1.34 %

Figure A-24: Relative cross-zonal trading margin of Amprion for ALEGrO for the German Hub 'AL_DE'

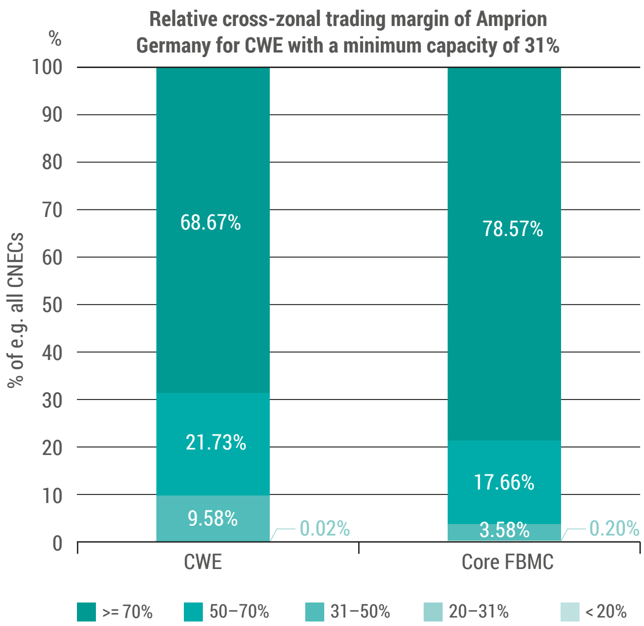


Figure A-25: Relative cross-zonal trading margin of Amprion with a minimum capacity of 31.0 %

10.3.4 TenneT Germany

Based on the above assessment methodology, the following results are obtained for TenneT Germany.

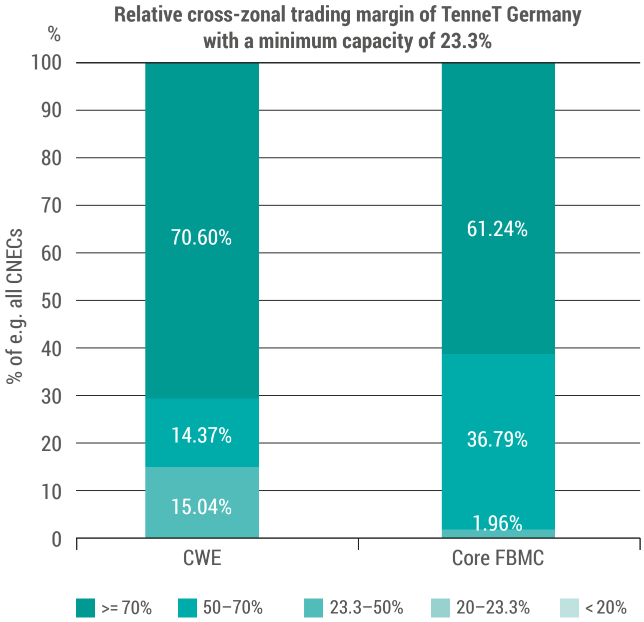


Figure A-26: Relative cross-zonal trading margin of TenneT Germany for DE-NO2 and NO2-DE with a minimum capacity of 23.3 %

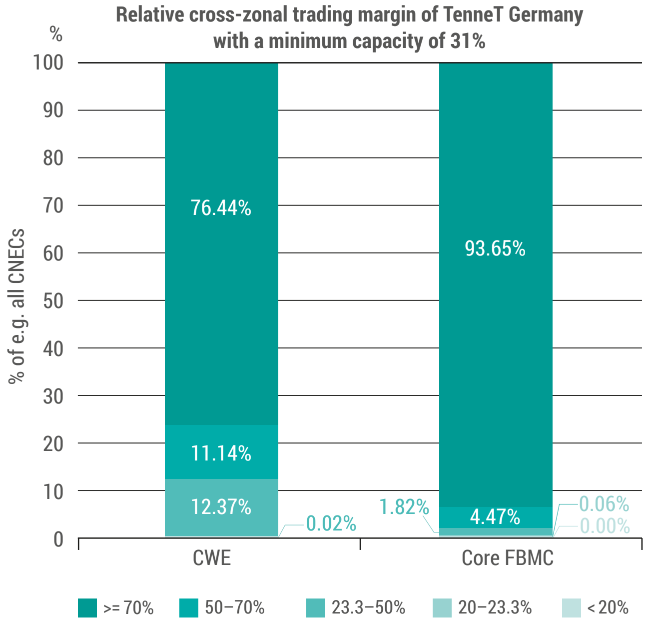


Figure A-27: Relative cross-zonal trading margin of TenneT Germany for CWE with a minimum capacity of 31.0 %

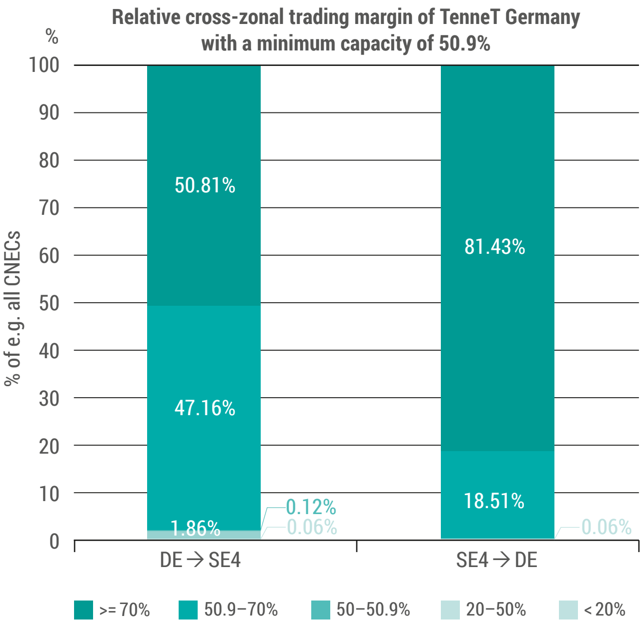


Figure A-28: Relative cross-zonal trading margin of TenneT Germany for DE-SE4 and SE4-DE with a minimum capacity of 50.9 %

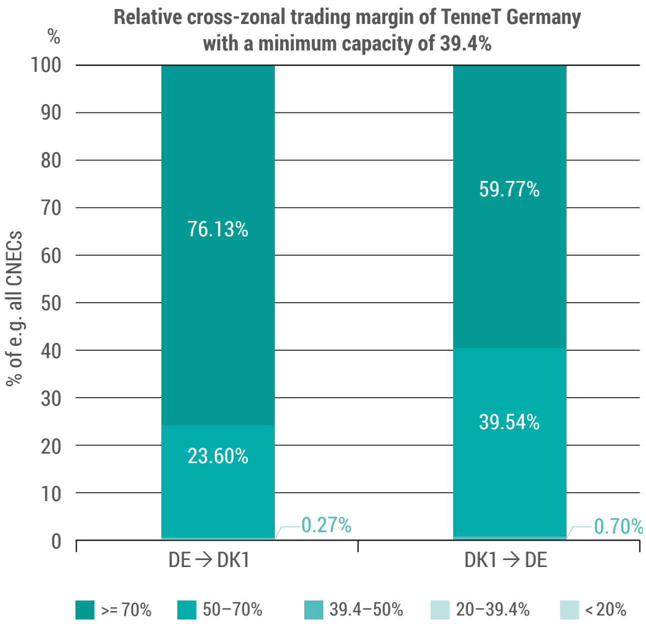


Figure A-29: Relative cross-zonal trading margin of TenneT Germany DE-DK1 and DK1-DE with a minimum capacity of 39.4 %

10.3.5 TransnetBW

Based on the above assessment methodology, the following results are obtained for TransnetBW.

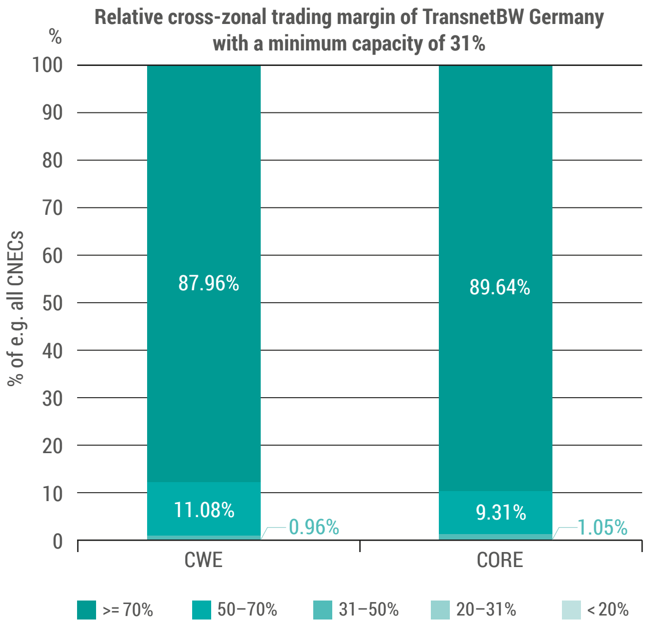
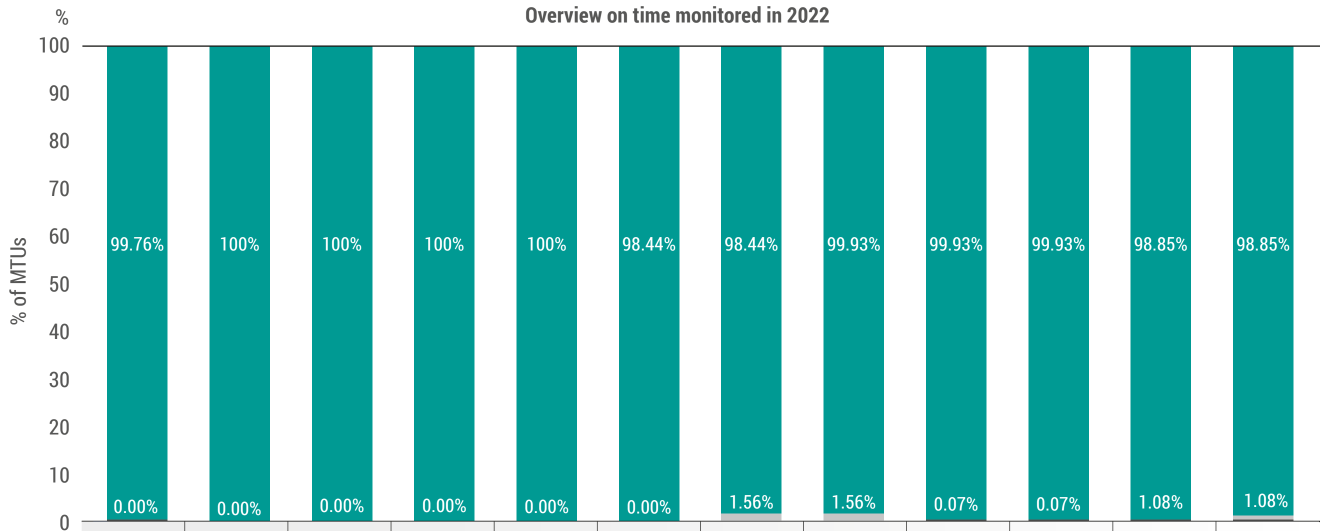


Figure A-30: Relative cross-zonal trading margin of TransnetBW for CWE with a minimum capacity of 31.0 %

10.4 Additional information

The following Figure A-31 provides an overview of the time monitored in 2022 for Germany. The category 'Normal operation/process' represents all MTUs of 2022 that have been monitored. The category 'No IC capacity available' indicates the amount of MTUs during which no interconnector capacity has been available in 2022. However, it should be noted that for FB borders, this category will be always empty as it cannot happen that no IC capacity in the entire FB system is available. However, the category is kept for the sake of comparability to other borders. The third category 'application of fallback procedure' represents the amount of MTUs during which MTUs have not been monitored due to problems in the capacity calculation.

Please note that for CWE Flow-Based Market Coupling and Core Flow-Based Market Coupling, the category 'Application of fallback procedure' considers the application of fallback capacities (so-called default flow-based parameters) or spanning.



	CORE	CWE	DK2-DE	DE-DK2	DE > PL/CZ	PL/CZ > DE	DE > SE4	SE4 > DE	DE > DK1	DK1 > DE	DE > NO2	NO2 > DE
Normal operation / process	99.76 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	98.44 %	98.44 %	99.93 %	99.93 %	98.85 %	98.85 %
No IC capacity availablea	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	1.56 %	1.56 %	0.00 %	0.00 %	1.08 %	1.08 %
Fallback or failure of CC	0.24 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.07 %	0.07 %	0.07 %	0.07 %

Figure A-31: Overview on time monitored in 2022 for Germany

11 Greece

11.1 Current status of the implementation of CEP70 requirements

For 2022, IPTO has been granted a derogation from the minimum capacity equal to 15 % of MCCC.

11.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied. In order to estimate the % of compliance to the 70 % rule, the results from ACER were considered.

Please note that the overview on the underlying assumptions of the assessment methodology of Greece is provided in the Table at the beginning of the annex.

11.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Greece. Please note that the figures below do not include the number of cases where the line BG-GR was out of operation and where there is a failure in the process of getting results.

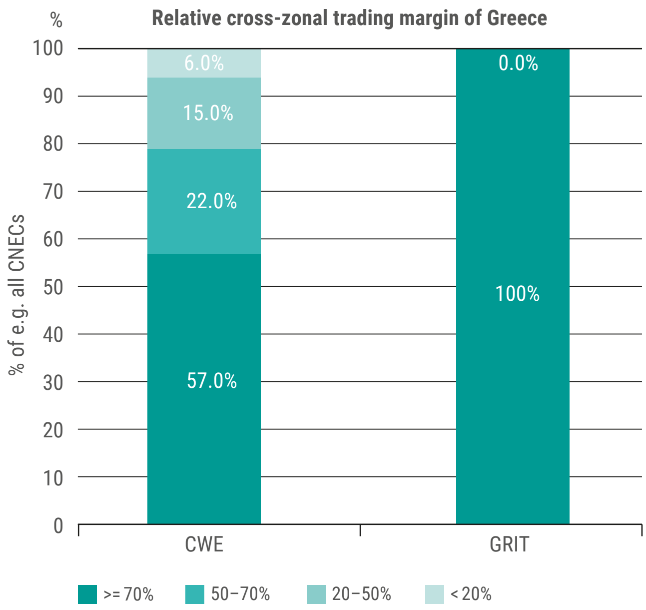


Figure A-32: Relative cross-zonal trading margin of Greece

12 Hungary

12.1 Current status of the implementation of CEP70 requirements

Hungary adopted an action plan in December 2021, pursuant to Article 15 (1) of the Electricity Market Regulation (EU) 2019/943 in order to eliminate the congestions by 31 December 2025. The action plan includes the necessary investments to be made in addition to the developments included in the Network Development Plan of the Hungarian electricity system as well as other congestion management measures that will make it possible to ensure the compliance with the provision for the minimum capacity by the deadline of 31 December 2025 at the latest.

12.2 Assessment methodology

We perform our assessment by calculating PTDFs on the merged DACF models, simulating the potential flows for the case when all available capacities offered to the market was scheduled. This is the worst case scenario from the perspective of the security of supply, and shall be considered by a TSO. The methodology according to ACER's Recommendation No 01/2019 is applied for the flow based capacity calculation assessment.

Please note that the overview on the underlying assumptions of the assessment methodology of Hungary is provided in the Table at the beginning of the annex.

12.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Hungary.

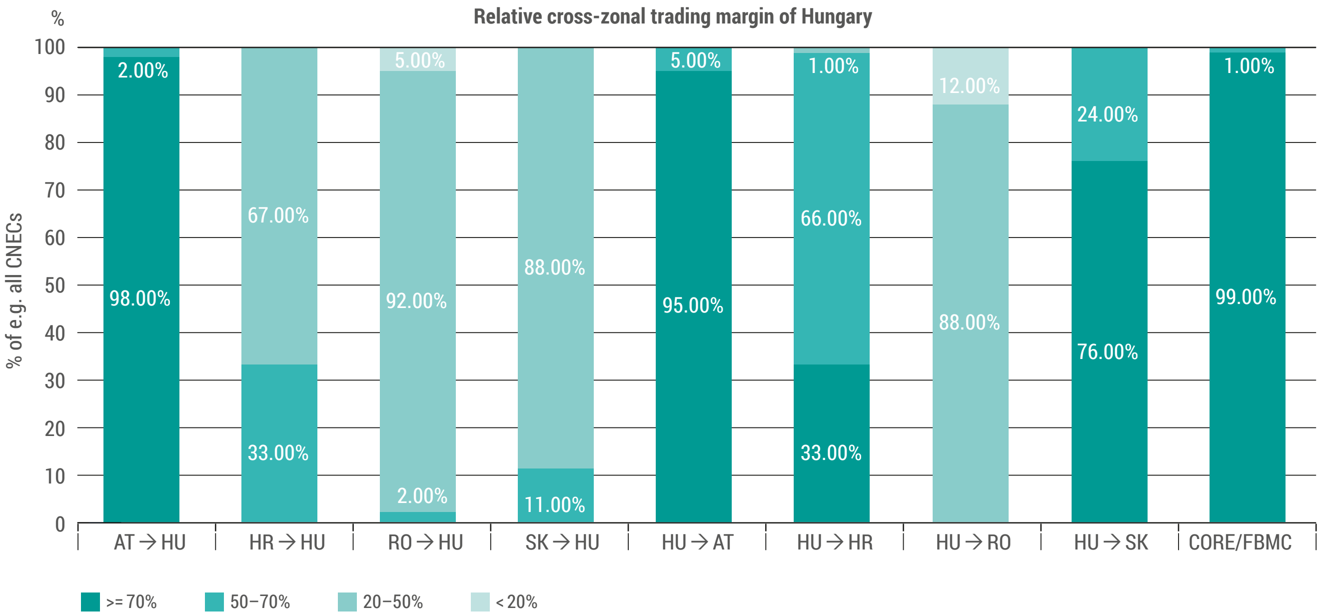


Figure A-33: Relative cross-zonal trading margin of Hungary

13 Italy

13.1 Current status of the implementation of CEP70 requirements

For Italy North, a derogation was in place for 2022, for all MTUs where allocation constraints are applied and for all MTUs until the entry into operation of the 'coordinated adjustment for minimum capacity' process. No minimum capacity target was defined.

13.2 Assessment methodology

Terna applies ACER's recommendation to determine MACZT by considering Third Countries. Regarding the compliance with the 70 % rule, in the presence of a coordinated capacity calculation for the CCR, the MACZT target is assessed only on the limiting CNEC(s).

Please note that the overview on the underlying assumptions of the assessment methodology of Italy is provided in the Table at the beginning of the annex.

13.3 Assessment results

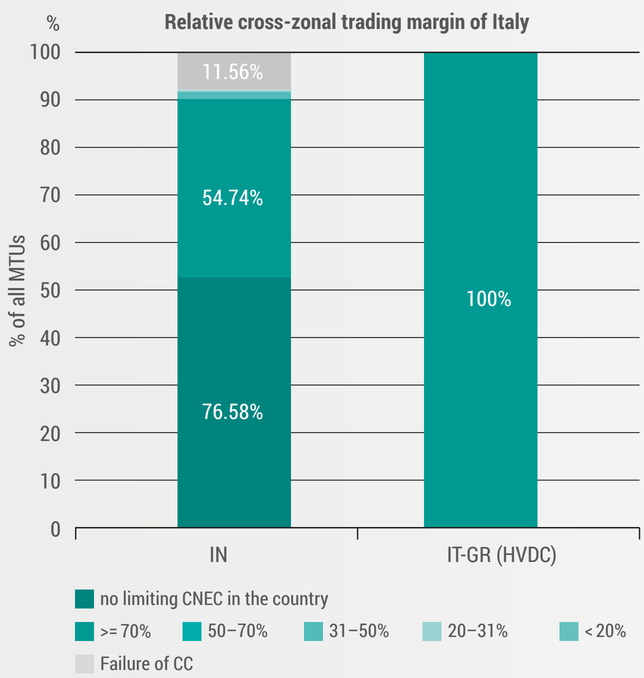
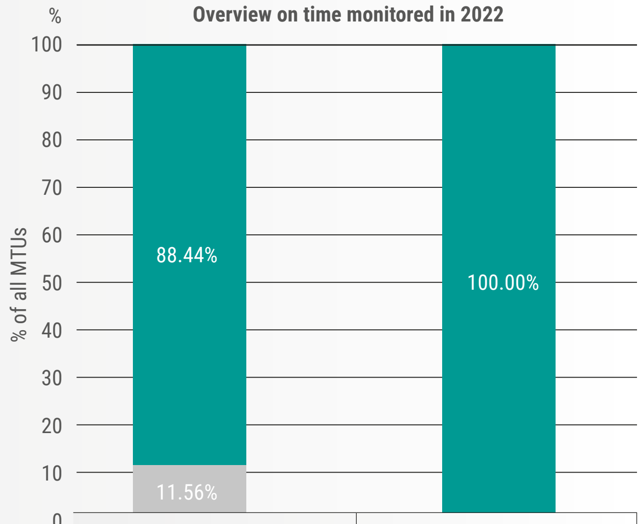


Figure A-34: Relative cross-zonal trading margin of Italy.



	IN	IT-GR (HVDC)
Normal operation / process	88.44 %	100.00 %
No IC capacity availablea	0.00 %	0.00 %
Application of fallback procedure	11.56 %	0.00 %

Figure A-35: Overview on time monitored in 2022 for Italy

14 Latvia

14.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

14.2 Assessment methodology

70 % rule according to Article 16(8) of Regulation (EU) 2019/943 and ACER recommendation.

Please note that the overview on the underlying assumptions of the assessment methodology of Latvia is provided in the Table at the beginning of the annex.

14.3 Assessment results

Based on the above assessment methodology, the results are obtained in Figure A-36 for Latvia.

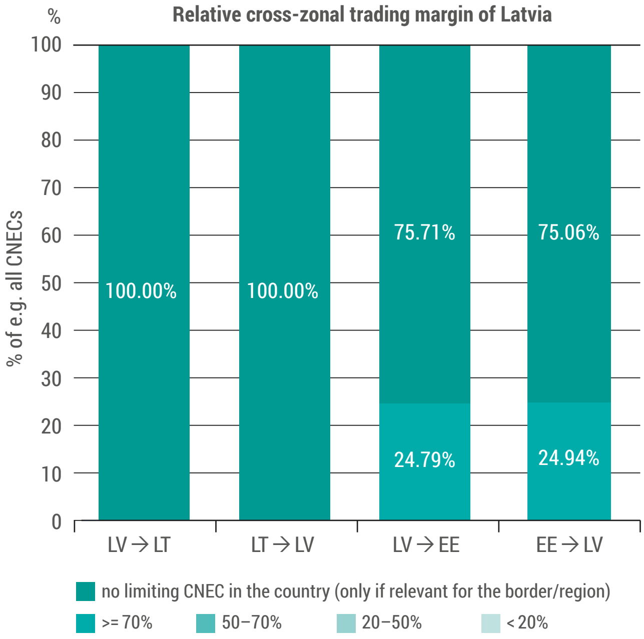
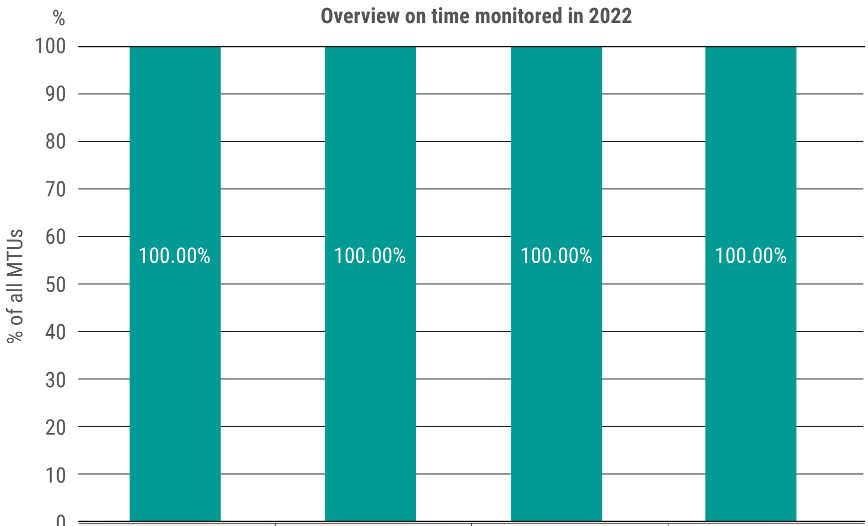


Figure A-36: Relative cross-zonal trading margin of Latvia

14.4 Additional information



	LV → LT	LT → LV	LV → EE	EE → LV
Normal operation / process	100.00 %	100.00 %	100.00 %	100.00 %
No IC capacity availablea	0.00 %	0.00 %	0.00 %	0.00 %
Fallback or failure of CC	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-37: Overview on time monitored in 2022 for Latvia

15 Lithuania

15.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

15.2 Assessment methodology

The 70 % rule according to Article 16(8) of Regulation (EU) 2019/943 and ACER recommendation. Please note that the overview on the underlying assumptions of the assessment methodology of Lithuania is provided in the Table at the beginning of the annex.

15.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Lithuania.

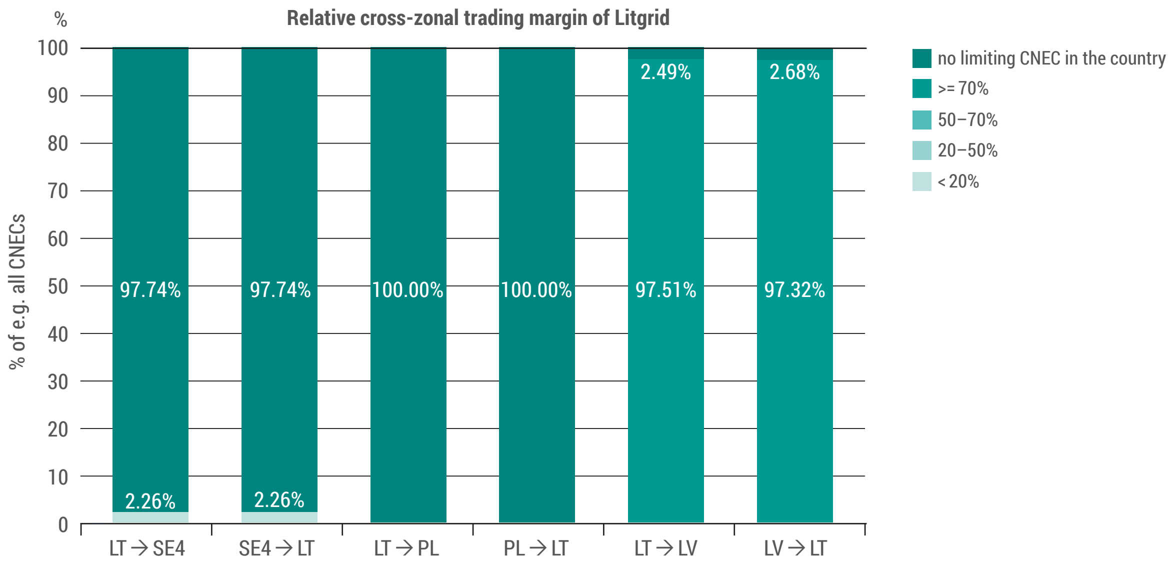
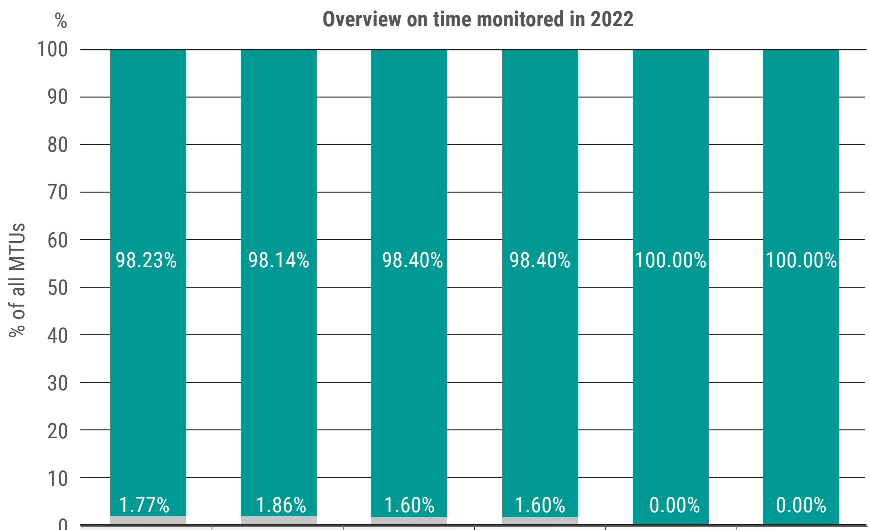


Figure A-38: Relative cross-zonal trading margin of Lithuania

15.4 Additional information



	LT → SE4	SE4 → LT	LT → PL	PL → LT	LT → LV	LV → LT
Normal operation / process	98.23 %	98.14 %	98.40 %	98.40 %	100.00 %	100.00 %
No IC capacity availablea	1.77 %	1.86 %	1.60 %	1.60 %	0.00 %	0.00 %
Fallback or failure of CC	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-39: Overview on time monitored in 2022 for Lithuania

16 Poland

16.1 Current status of the implementation of CEP70 requirements

Poland adopted an action plan in December 2019, pursuant to Article 15 (1) of the Electricity Market Regulation (EU) 2019/943. The Polish action plan foresees several transmission investments that are to be carried out to ensure that the 70 % obligation is fulfilled by 31 December 2025. The action plan foresees that the level of CZCs available for trade between BZs shall be gradually increased from 2020 through 2025 by means of a linear trajectory, until the level foreseen by Article 16 (8) of Regulation 2019/943 is met.

In addittion, Poland has obtained a derogation for 2022 based on foreseeable grounds affecting the security of system operation in accordance with Article 16(9) of Regulation 2019/943. The derogation granted covers two different reasons to deviate from the CEP70 requirement: (i) excessive loop flows through the Polish grid and lack of coordinated redispatching and countertrading (until the end of 2021) and (ii) uncertainties in uncoordinated transits (to introduce a method for capacity calculation of the Core region). The derogation obtained concerns the borders belonging to the CORE CCR (synchronous AC borders: DE–PL, CZ–PL, and SK–PL).

Finally, both planned and unplanned outages in transmission elements affect the level of cross-zonal capacities that can be safely offered to the market. In case of prolonged outages of transmission elements impacting the ability to meet the CEP70 requirement, especially when they are required to perform necessary grid reinforcements or modernisation works, cases with such outages are not treated as non-compliance with Article 16(8) of the Regulation 2019/943.

16.2 Assessment methodology

PSE calculates CZCs according to the NTC methodology approved by the Polish NRA. Capacity calculations are based on the D2CF file prepared by PSE using the latest available ID models within the CEE region. When calculating capacities to be made available for the DA market, PSE carefully monitors the calculated NTC and transit flows against the required minimum capacities from the linear trajectory obligations. When the CZCs (including transits through the Polish grid) do not fulfil the criterion of minMACZT, the offered DA capacities are increased to the required minimum threshold, upon assessing the availability of remedial actions. Please note that the overview on the underlying assumptions of the assessment methodology of Poland is provided in the Table in the annex.

16.3 Assessment results

The following section presents the monitoring results obtained for Poland. Hours where the minimal required MACZT levels were fulfilled are marked as fulfilled. Similarly, hours in which the minimal MACZT levels were considered as conditionally fulfilled due to legitimate reasons (outages, derogations, lack of redispatching potential) as also marked as fulfilled.

It is to be highlighted that in its assessment, PSE considered the applicable market design in Poland, and in particular the application of capacity allocation constraints. Detailed information on the usage and application of capacity allocation constraints is available in the regional capacity calculation methodologies for the CORE, HANSA and BALTIC CCRs. For borders belonging to the CORE CCR, where uncoordinated NTC is applied and the allocation mechanism is based on explicit auctions, the capacities offered for the market are verified to account for allocation constraints. However, for the purpose of CEP70 monitoring, PSE checks the linear trajectory based on calculated NTC capacities that are not verified for allocation constraints. In the light of Regulation 2019/943 and the 2015/1222 Regulation (CACM), allocation constraints serve to maintain the system within operational security limits, while minimal capacity obligations consider the percentage of capacity that respects operational security limits. Hence, the application of allocation constraints cannot be considered to cause a reduction of the capacities offered by PSE to below the trajectory thresholds.

16.3.1 Assessment results before CORE FB DA CC

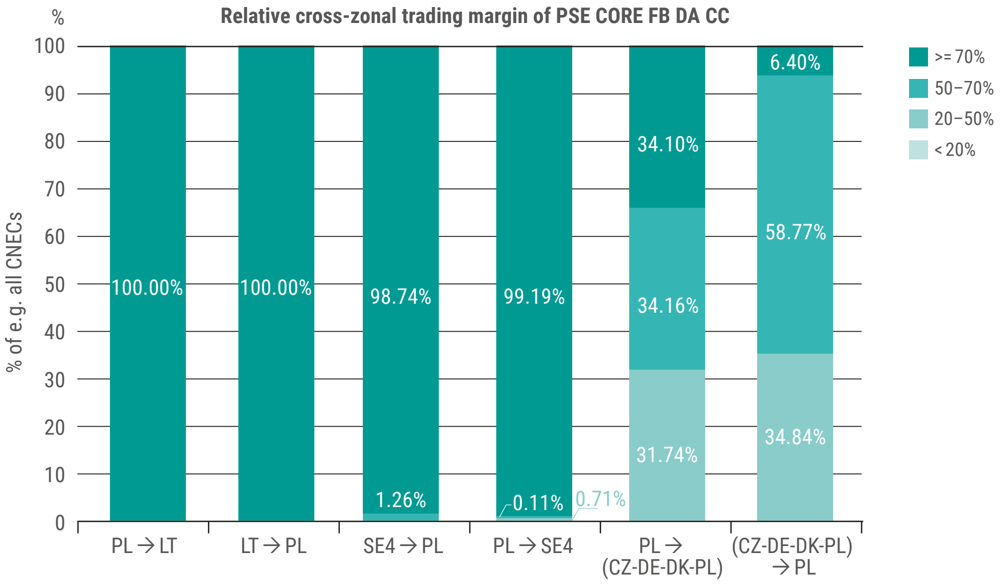


Figure A-40: Relative cross-zonal trading margin of Poland before CORE FB DA CC (For PL → SE4 a minimum capacity of 50 % is set)

16.3.2 Assessment results after CORE FB DA CC

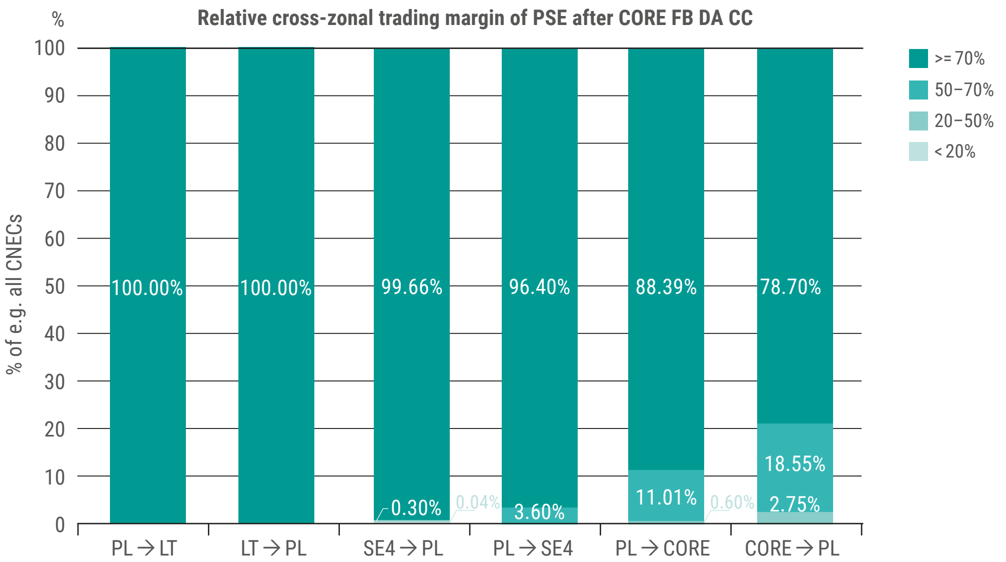


Figure A-41: Relative cross-zonal trading margin of Poland after CORE FB DA CC

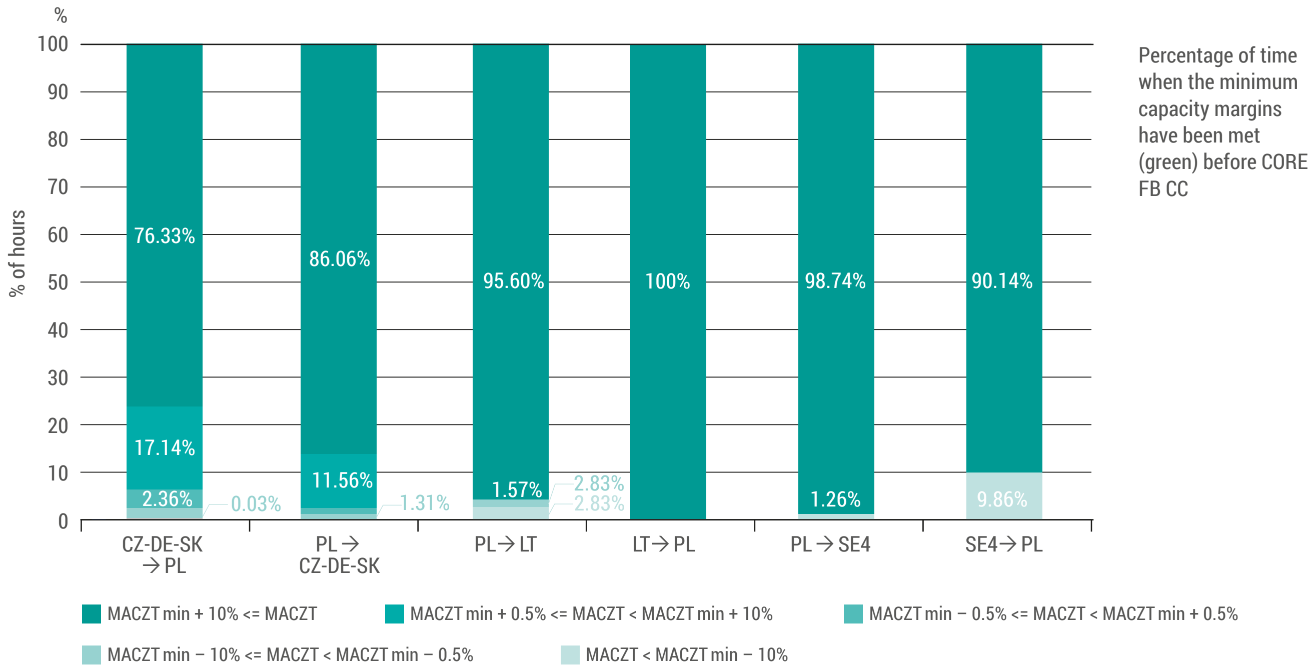


Figure A-42: Percentage of time when the relative MACZT of the least performing CNEC in the coordination area is above its minimum MACZT or within a certain range below its minimum MACZT before CORE FB DA CC. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges.

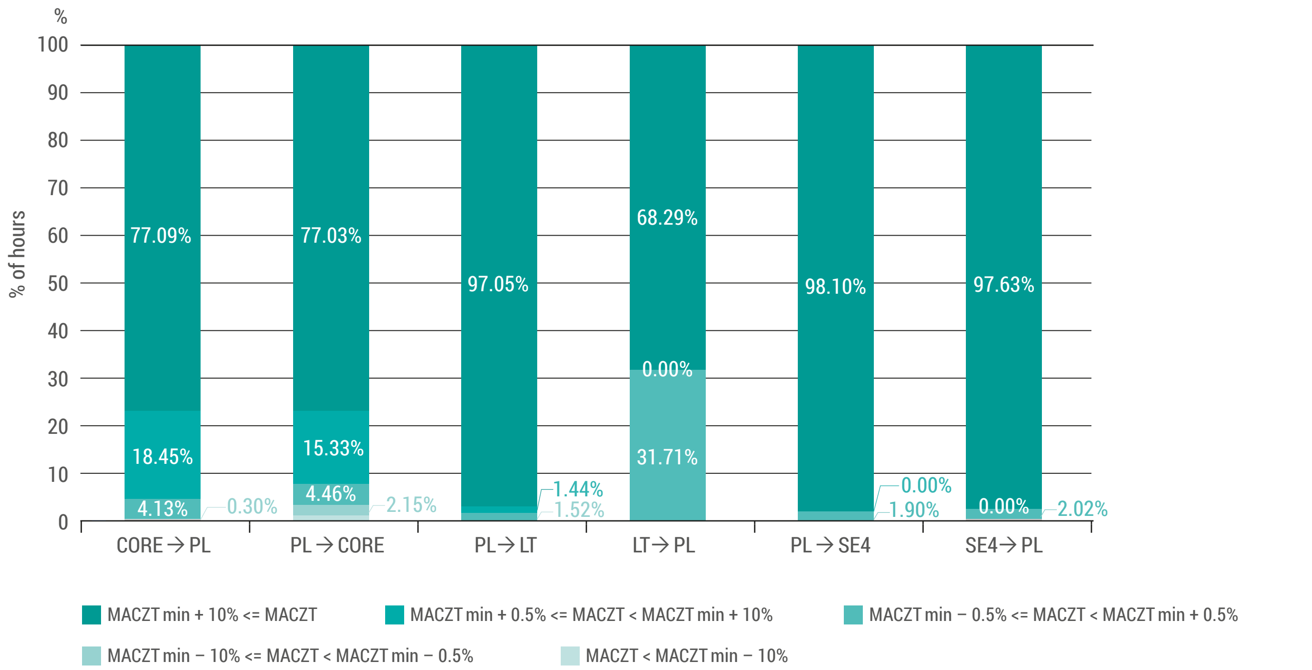
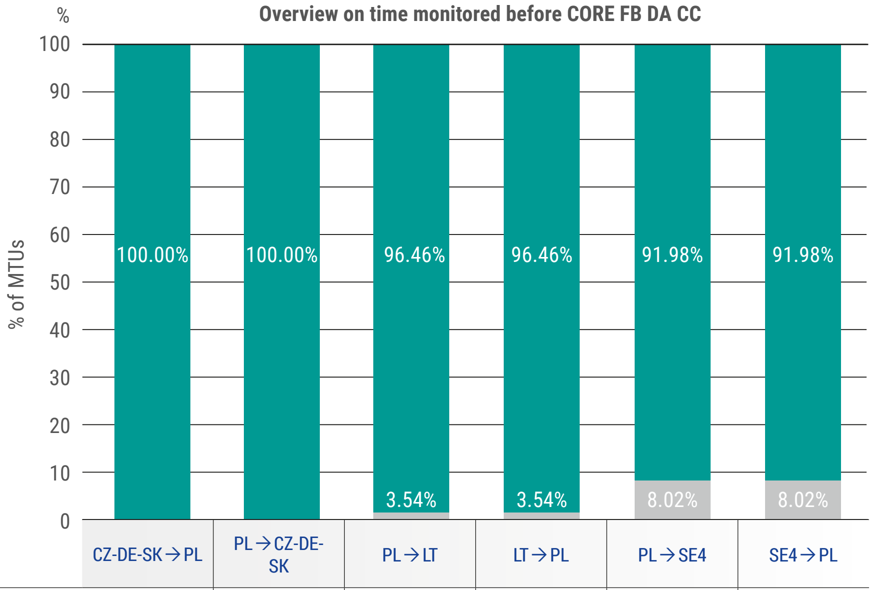


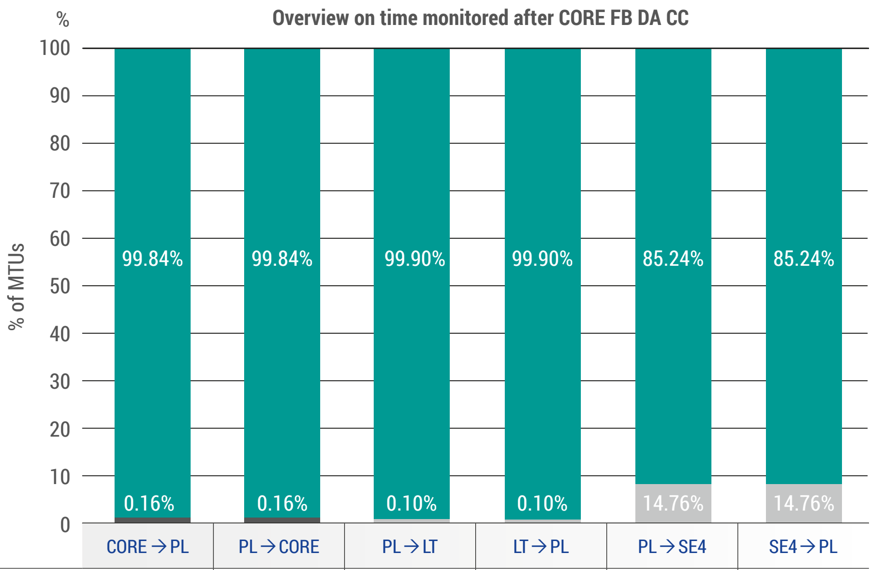
Figure A-43: Percentage of time when the relative MACZT of the least performing CNEC in the coordination area is above its minimum MACZT or within a certain range below its minimum MACZT after CORE FB DA CC. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges.

16.4 Additional information



	CZ-DE-SK→PL	PL→CZ-DE-SK	PL→LT	LT→PL	PL→SE4	SE4→PL
Normal operation / process	100.00 %	100.00 %	96.46 %	96.46 %	91.98 %	91.98 %
No IC capacity availablea	0.00 %	0.00 %	3.54 %	3.54 %	8.02 %	8.02 %
Fallback or failure of CC	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-44: Overview on time monitored for Poland before CORE FB DA CC



	CORE→PL	PL→CORE	PL→LT	LT→PL	PL→SE4	SE4→PL
Normal operation / process	99.84 %	99.84 %	99.90 %	99.90 %	85.24 %	85.24 %
No IC capacity availablea	0.00 %	0.00 %	0.10 %	0.10 %	14.76 %	14.76 %
Fallback or failure of CC	0.16 %	0.16 %	0.00 %	0.00 %	0.00 %	0.00 %

Figure A-45: Overview on time monitored for Poland after CORE FB DA CC

When ensuring fulfilment of the CEP70 trajectory, PSE was guided by the methodology adopted by the Agency. However, some minor details of the monitoring calculations might differ from the ACER approach due to differences between the ex-ante operational process as applied by PSE when calculating capacities and ensuring trajectories on limiting CNECs, and the ex-post monitoring process as applied by the Agency.

However, one important difference from the approach applied by the Agency is the treatment of allocation constraints, which are defined as 'constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation'. As minimal capacity obligations consider the percentage of capacity that respects operational security limits, the application of allocation constraints cannot be considered to reduce capacities below the trajectory thresholds. However, in its monitoring report, ACER has recalculated the cross-zonal capacity 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 assuming such an interpretation is not clear as the applicable legal framework undoubtedly allows for the application of allocation constraints. Apart from having the purpose of keeping the system within operational security limits, allocation constraints are not listed in Regulation 2019/943 as factors to be included within the 30 % margin that is foreseen for inter alia loop flows. It is to be emphasised that for hours marked by ACER as not fulfilled, the respective DC borders were used for transits though Poland (often to the full capacity of the links), thus contributing to European social welfare. The above are reasons for differences between the PSE assessment and the one shown by ACER.

17 Portugal

17.1 Current status of the implementation of CEP70 requirements

Some improvements implemented in SWE region regarding 70 %:

1. Regional monitoring process done by SWE RCC since April 2021.

2. CZC recalculation using countertrading since February 2022

3. Use of a fallback-CNEC to be able to compute the MACZT when the CNEC is not available (since 2022).

For 2022, there was a derogation for REN. During this period, REN applied the amendment capacity calculation methodology proposal in the SWE CCR for the operational DA coordinated capacity calculation process (approved by SWE NRA in January 2022), in this way ensuring the maintenance of the operational security in the SWE CCR. REN offered to this process at least the minimum levels of capacity in accordance with article 16(8)(a) of Regulation 2019/943 during 75 % of the hours on which this 1-year derogation was applied. The minimum levels were provided in accordance with article 16(8)(a) of Regulation 2019/943 and with paragraphs 4.2 and 5.1 of ACER Recommendation 01/2019 on the limiting CNECs.

In addition, the SWE capacity calculation methodology includes the use of a CNEC-fallback, which let assess the compliance of CEP 70 % when the CNEC is not available within the allotted time for the calculation process.

For 2023 there is a new derogation for REN, under the same terms as the 2002 derogation, but REN will offer at least the minimum levels of capacity in accordance with article 16(8)(a) of Regulation 2019/943 during 82,5 % of the hours for which the 1-year derogation applies.

17.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied. Please note that the overview on the underlying assumptions of the assessment methodology of Portugal is provided in the Table at the beginning of the annex.

17.3 Assessment results

Based on the above assessment methodology, the results are obtained in Figure A-46 and Figure A-47 for Portugal.

17.4 Additional information

For the assessment of the 70 % rule in the previous chapter, the following criteria have been applied:

- MTUs with limiting CNEC outside Portugal are deemed as compliant.

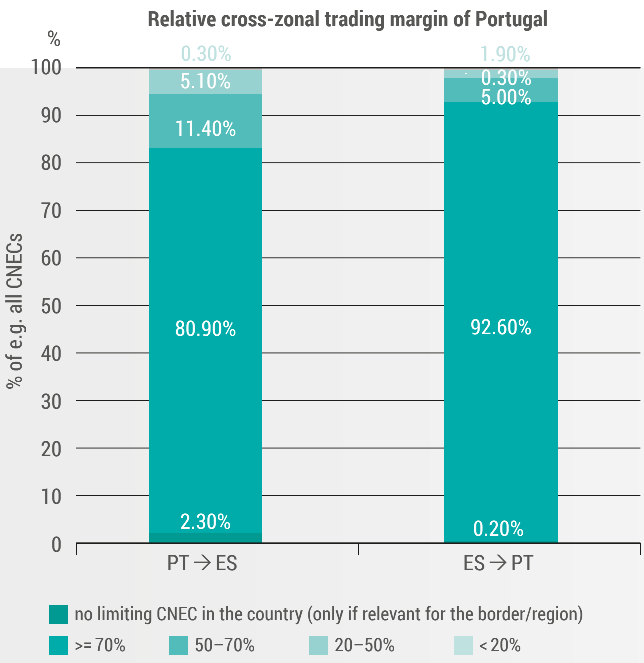
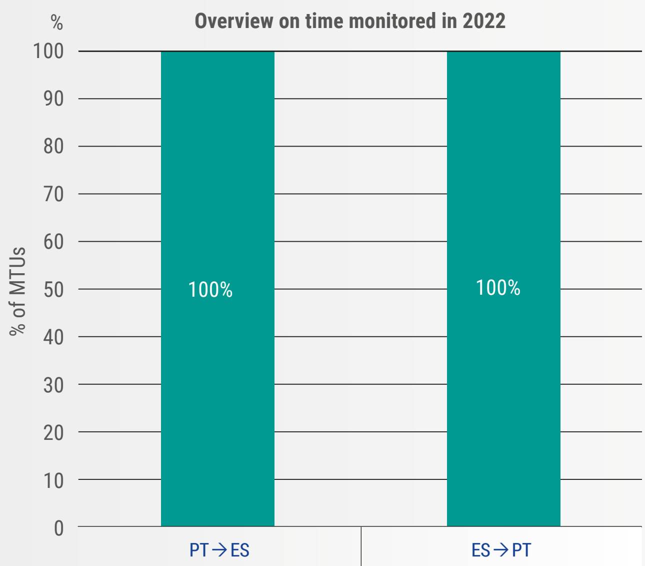


Figure A-46: Relative cross-zonal trading margin of Portugal



	PT → ES	ES → PT
Normal operation / process	100.00 %	100.00 %
No IC capacity availablea	0.00 %	0.00 %
Application of fallback procedure	0.00 %	0.00 %

Figure A-47: Overview on time monitored for Portugal

18 Romania

18.1 Current status of the implementation of CEP70 requirements

In 2022 Transelectrica has an Action Plan to reach the 70 % capacity. For this year, there is a derogation in place for RO–HU border with a minimum capacity of 33 %. For RO–BG border there is a minimum capacity of 34 %, with no request of derogation.

18.2 Assessment methodology

Transelectrica applies ACER's recommendation. Third countries are included and values are given as a percentage of time for all limiting CNECs which have a positive MACZT. Please note that the overview on the underlying assumptions of the assessment methodology of Romania is provided in the Table at the beginning of the annex.

18.3 Assessment results

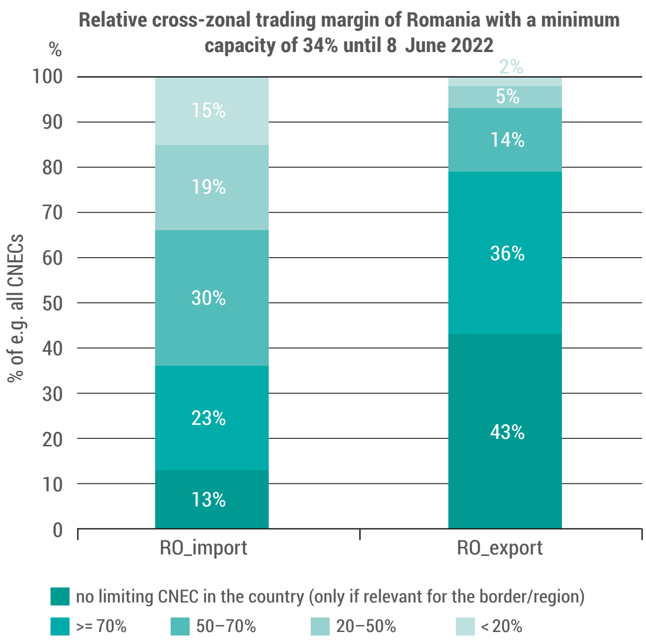


Figure A-48: Relative cross-zonal trading margin of Romania with a minimum capacity of 34 % until 8 June

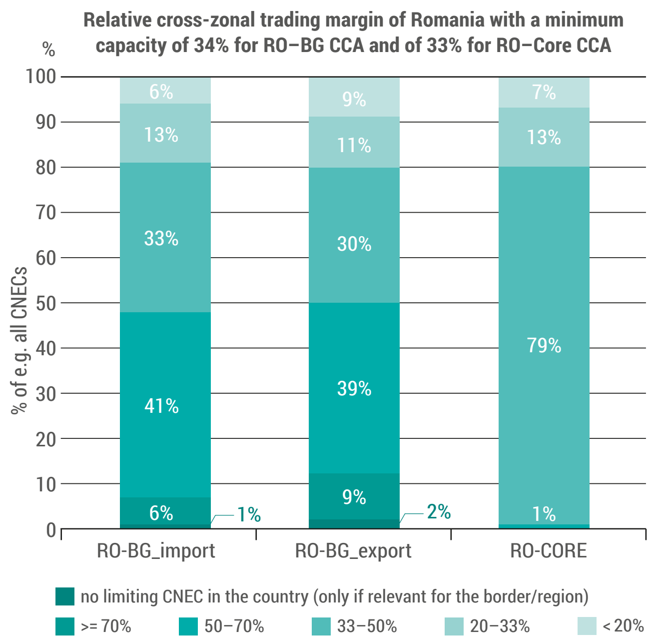


Figure A-49: Relative cross-zonal trading margin of Romania with a minimum capacity of 34 % from 9 June

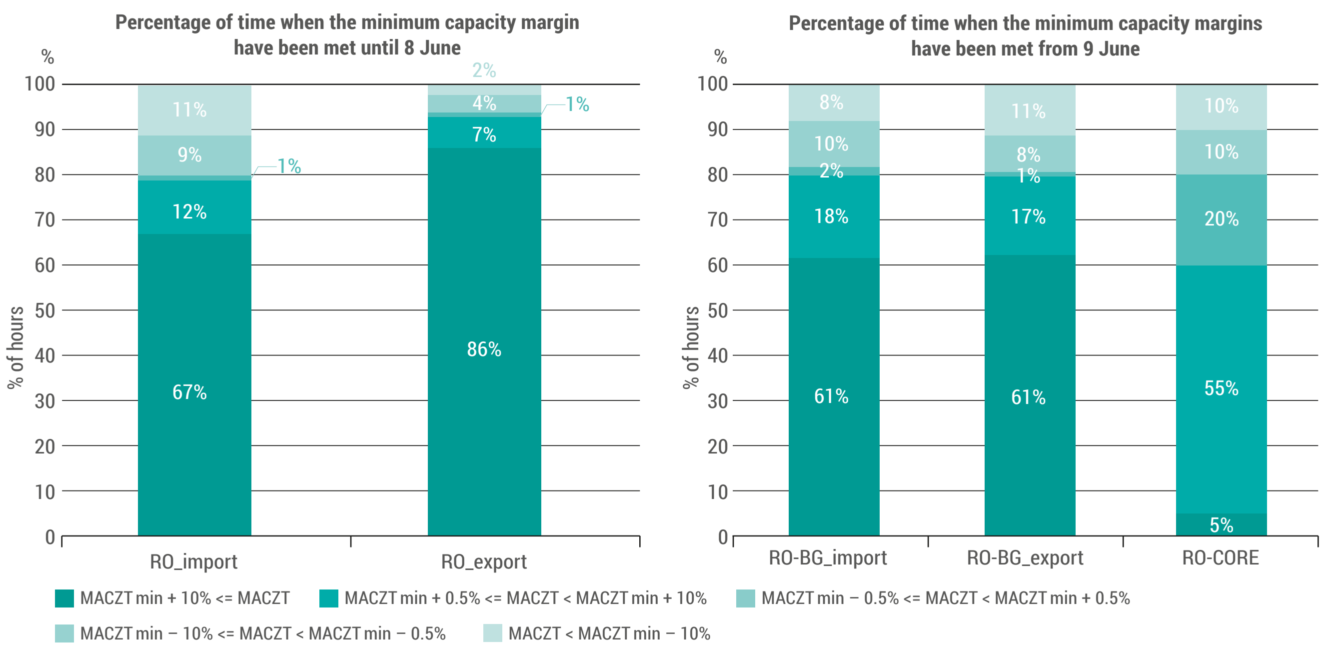


Figure A-50: Percentage of time when the relative MACZT of the least performing CNEC in the coordination area is above its minimum MACZT or within a certain range below its minimum MACZT. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges until 8 June and from 9 June.

19 Slovakia

19.1 Current status of the implementation of CEP70 requirements

Slovakia has been granted a derogation for year 2022. In accordance with this derogation, SEPS is committed to provide at least 40 % MACZT for both import and export on SK–CZ, SK–HU and SK–PL borders in at least 80 % of MTUs if security of the power system is secured. This is applicable until the start of the Core FB DA Capacity calculation. After successful go-live of FB DA there will be different minRAM factors per CNEC that can be flexible but the minRAM 20 % shall be always maintained.

19.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied.

Please note that the overview on the underlying assumptions of the assessment methodology of Slovakia is provided in the Table at the beginning of the annex.

19.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Slovakia.

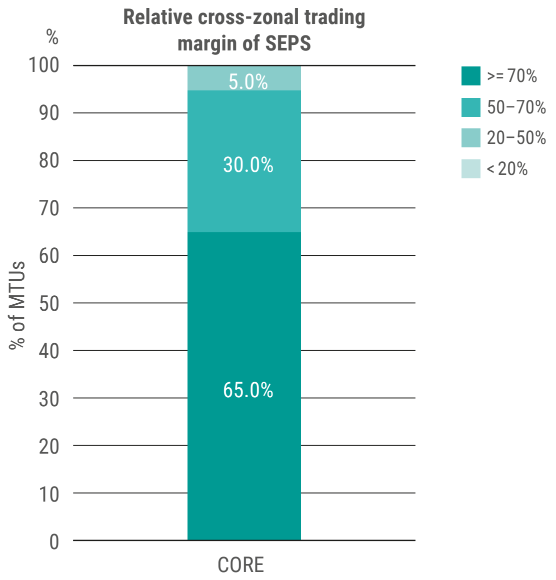


Figure A-51: Relative cross-zonal trading margin of Slovakia

20 Slovenia

20.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

20.2 Assessment methodology

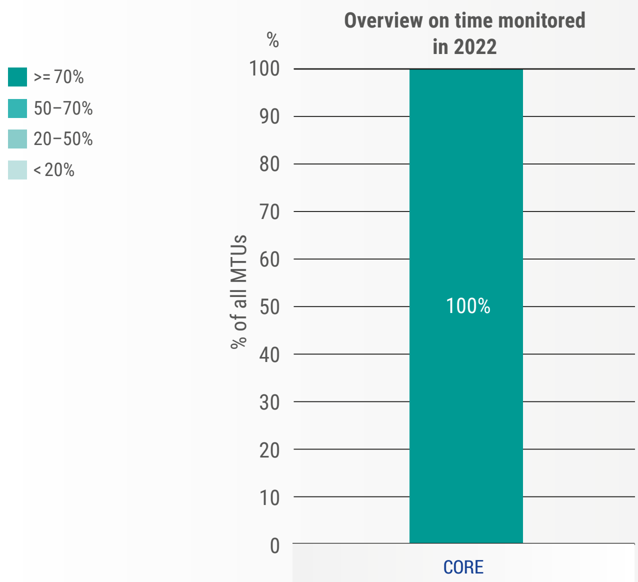
The methodology according to ACER's Recommendation No 01/2019 is applied.

20.3 Assessment results

Based on the above assessment methodology, the results are obtained in Figure A-52 for Slovenia.

20.4 Additional information

As the PSTs are used to increase overall capacities, PST flows can be considered as market flows; however, ACER does not consider them as such in the MACZT monitoring (see Figure A-53).



	CORE
Normal operation / process	100.00 %
No IC capacity availablea	0.00 %
Fallback or failure of CC	0.00 %

Figure A-52: Overview on time monitored in 2022 for Slovenia

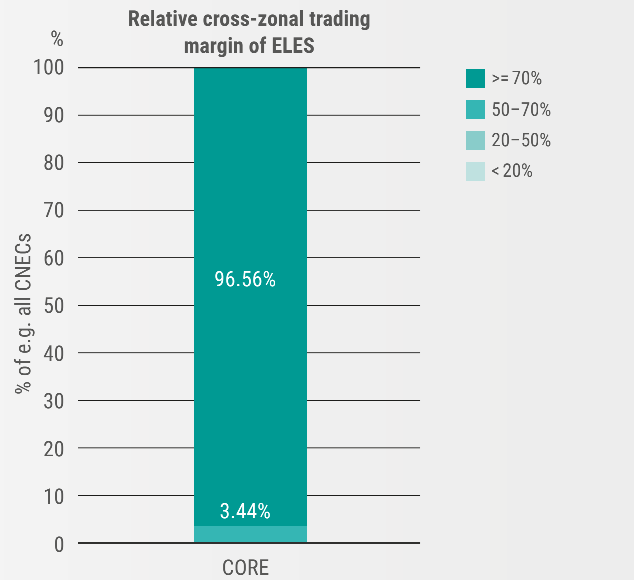


Figure A-53: Relative cross-zonal trading margin of Slovenia

21 Spain

21.1 Current status of the implementation of CEP70 requirements

Some improvements implemented in SWE region regarding 70 %:

1. Regional monitoring process done by SWE RCC since April 2021.
2. CZC recalculation using countertrading since February 2022
3. Use of a fallback-CNEC to compute the MACZT when the CNEC is not available (since 2022).

There was a derogation for Red Eléctrica in SWE region for 2022. For 2023, there is no longer any derogation.

Since February 2022, SWE region applies the amended capacity calculation methodology in SWE CCR for the operational DA coordinated capacity calculation process (approved by SWE NRA in January 2022). The mentioned amendment introduces the principles and goals set in EU Regulation to fulfill the minimum capacity requirements according to Article 16 of the Electricity Regulation, taking into account the availability of Costly Remedial Actions. Thus, in the event a CNEC is not respecting the CEP 70 % threshold, Red Eléctrica provide some costly remedial action (using countertrading) to improve the MACZT and consequently the capacity.

In addition, the SWE capacity calculation methodology includes the use of a CNEC-fallback which allows the compliance of CEP 70 % to be assessed when the CNEC is not available within the allotted time for the calculation process.

21.2 Assessment methodology

The methodology according to ACER's Recommendation No 01/2019 is applied.

Please note that the overview on the underlying assumptions of the assessment methodology of Spain is provided in the Table in the beginning of this annex.

21.3 Assessment results

Based on the above assessment methodology, the following results are obtained for Spain.

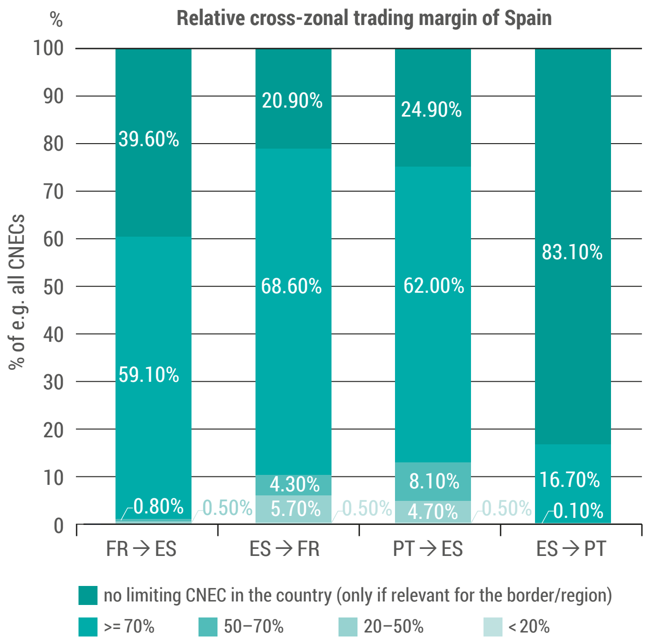


Figure A-54: Relative cross-zonal trading margin of Spain

21.4 Additional information

For the assessment of the 70 % rule in the previous chapter, the following criteria have been applied:

- MTUs with limiting CNEC outside Spain are deemed as compliant; and
- MTUs where SWE capacity calculation process did not provide a limiting CNE, the SWE capacity calculation methodology includes the use of a CNEC-fallback which allows the assessment of the compliance of CEP 70 %.

22 Sweden

22.1 Current status of the implementation of CEP70 requirements

The 70 % rule is applied in 2022.

During 2021, Svenska kraftnät identified a risk of not meeting the 70 % threshold for all MTUs 2022. The problems were mainly expected during periods of overlapping outages in large production plants (nuclear reactors in the south of Sweden).

Svenska kraftnät submitted a request for derogation for interconnectors between the following BZs: DK1–SE3, DK2–SE4, DE/LU–SE4, PL–SE4, LT–SE4, SE3–SE4, SE2–SE3 and SE3–NO for 2022. The Swedish regulatory authority, Energimarknadsinspektionen was of the view that Svenska kraftnät should be granted a derogation for interconnectors on two BZBs (FI–SE3 and SE3–DK1). The Finnish and Danish regulatory authorities, Energiavirasto and Danish Utility Regulator, which were consulted, disagreed with granting a derogation on any border. Consequently, Energimarknadsinspektionen referred the derogation request to ACER for a decision on the FI–SE3 and SE3–DK1 border. ACER decided in October 2022 to not grant Svenska kraftnät a derogation.

22.2 Assessment methodology

The current NTC capacity calculation process at Svenska kraftnät was not established with the 70 % rule in mind. During 2021 and 2022 Svenska kraftnät has improved its' processes' for evaluating its' compliance of the 70 % rule based on the ACER recommendation 01/2019.

For the assessment Svenska kraftnät follows ACER recommendation No 01/2019 as much as possible given that the coordinated capacity calculation methodology for the Nordics is not yet implemented. The current assessment of the requirement is done as close as possible to the recommendation and uses data from the Nordic parallel run for implementing FB in the Nordics. The models used in the parallel run are under development and improvements have been made continuously.

22.3 Assessment results

Based on the assessment methodology described above the following results are achieved.

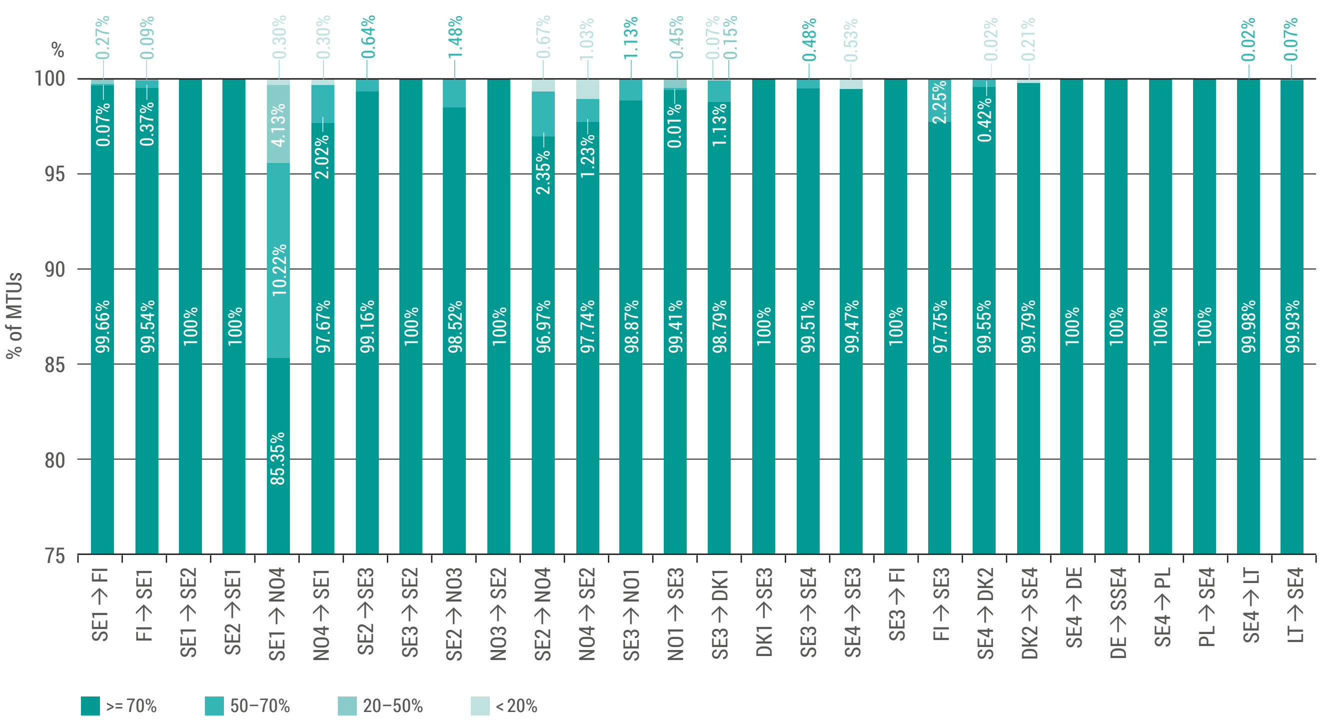


Figure A-55: Relative cross-zonal trading margin of Sweden

23 The Netherlands

23.1 Current status of the implementation of CEP70 requirements

For the Netherlands, an action plan and a derogation were adopted as transitory measures to gradually reach the minimum capacity margin of 70 % on the CNEs included in CWE and Core flow-based DA capacity calculation.

TenneT Netherlands has submitted an assessment of available cross-zonal capacity for the Netherlands in 2022, in accordance with article 15(4) of the Electricity Market Regulation (EU) 2019/943. This will be published on the ACM website later this year. The report contains an assessment of the transmission capacity made available within the CWE and Core region, as well as on the transmission capacity made available on the BZBs with Norway and Denmark, which are not part of the action plan and on which the target capacity margin of 70 % already applies.

Within the assessment report, TenneT clarifies what specific provisions related to minimum capacities apply for the Netherlands, how it implemented those specific provisions in operations and how it has monitored its compliance against those provisions. Furthermore, the report contains various analyses and additional insights obtained from the assessment of capacity calculation data.

23.2 Assessment methodology

For region CWE and Core: For each MTU, the CNEC with the lowest MACZTmargin (difference between the provided MACZT and required minimum MACZT) is selected. The MTU is deemed compliant when this margin is equal to or above 0 %.

For borders DK1-NL, NL-DK1, NO2-NL, NL-NO2: For each MTU, the relative capacity in a certain direction on HVDC cable is calculated (capacity made available by TenneT / total capacity).

Please note that the overview on the underlying assumptions of the assessment methodology of the Netherlands is in the Table at the beginning of the annex.

23.3 Assessment results

Based on the above assessment methodology, the following results are obtained for the Netherlands.

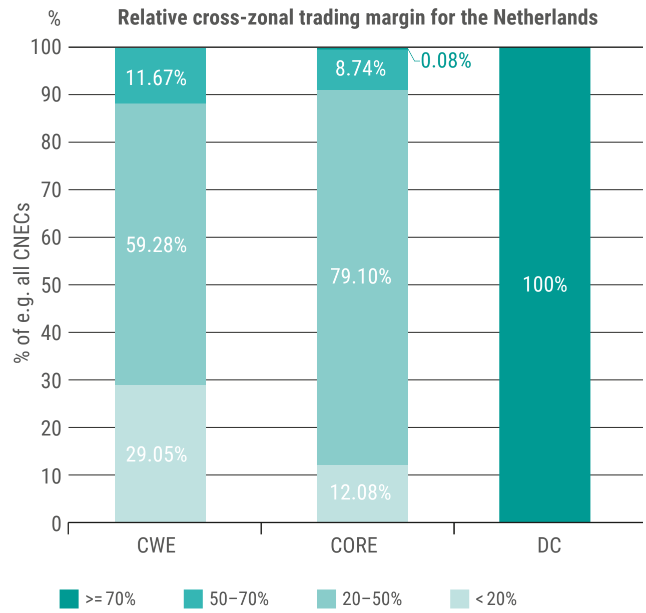


Figure A-56: Relative cross-zonal trading margin for the Netherlands

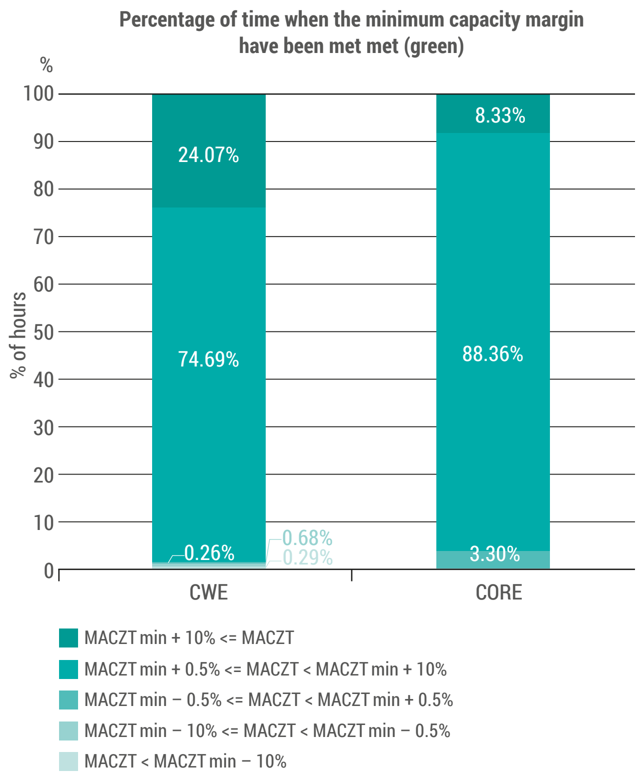


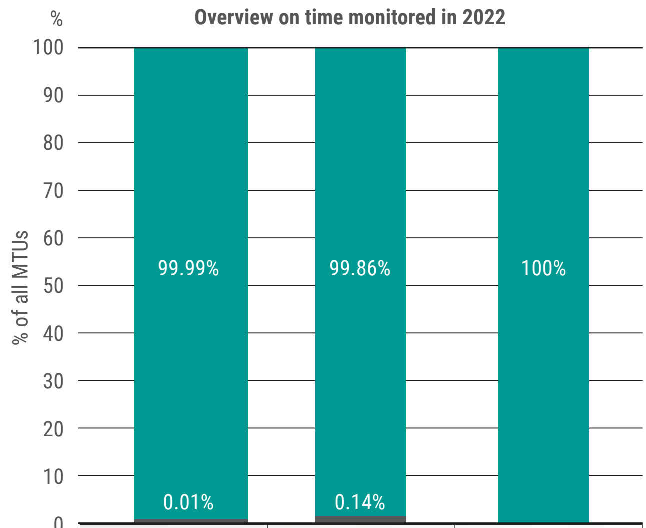
Figure A-57: Percentage of time when the minimum capacity margins have been met (green), and how much capacity was provided above or below the minimum MACZT, for the Netherlands. For each MTU, the CNEC with the lowest MACZTmargin was selected and categorised to one of the ranges.

23.4 Additional information

For a detailed assessment and further information, we refer to the 2022 Assessment of available cross-zonal capacity for the Netherlands.

The following Figure A-58 provides an overview on the time monitored in 2022 for the Netherlands. The category 'Normal operation/process' represents all MTUs of 2022 that have been monitored. The category 'No IC capacity available' indicates the amount of MTUs during which no interconnector capacity has been available in 2022. However, it should be noted that for flow-based borders, this category will always be empty as it cannot be the case that no IC capacity in the entire FB system is available. However, the category is kept for the sake of comparability to other borders. The third category 'Fallback or failure of CC' represents the amount of MTUs during which MTUs have not been monitored due to problems in the capacity calculation.

Please note that for CWE, the category 'application of fallback procedure' considers the application of fallback capacities (so-called default flow-based parameters) or spanning.



	CWE	CORE	DC
Normal operation / process	99.99 %	99.86 %	100.00 %
No IC capacity availablea	0.00 %	0.00 %	0.00 %
allback or failure of CC	0.01 %	0.14 %	0.00 %

Figure A-58: Overview on time monitored in the Netherlands

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
AOF	Activation Optimisation Function
AL	Albania
ANIDOA	All NEMOs Intraday Operational Agreement
ANDOA	All NEMOs Day-Ahead Operational Agreement
APG	Austrian Power Grid AG
Amprion	Amprion GmbH (1 out of 4 German TSOs)
AST	AS Augstsprieguma tikls (Latvian TSO)
AT	Austria
ATC	Available transfer capability
BA	Bosnia and Herzegovina
BE	Belgium
BEPP	Balancing Energy Pricing Periods
BG	Bulgaria
BRP	Balance Responsible Party
BSP	Balancing Service Provider
BZB	Bidding Zone Border
CA	Cooperation Agreement
CACM	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CGES	Crnogorski Elektroprenosni Sistem AD
CGM	Common Grid Model
CGMM	Common Grid Model Methodology
CH	Switzerland
CID	Congestion Income Distribution
CEE	Central Eastern Europe
CMM	Capacity Management Module
CMOL	Common Merit Order List
CNTC	Coordinated Net Transmission Capacity
CWE	Central Western Europe
CZ	Czech Republic
CZC	Cross-Zonal Capacity
DAOA	Day-Ahead Operational Agreement
DC	Direct Current
DE	Germany
DK	Denmark
EE	Estonia
EB	Commission Regulation (EU) 2017/2195 of 23 November
ELIA	ELIA Elia System Operator SA
ESO	Electroenergien Sistemen Operator EAD
EMS	Joint Stock Company Elektromreža Srbije
ENTSO-E	European Network of Transmission System Operators for Electricity
ES	Spain
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
FTR	Financial Transmission Right
FR	France
FRR	Frequency Restoration Reserves
GB	Great Britain
GCT	Gate Closure Time
GOT	Gate Opening Time
GR	Greece
HAR	Harmonised Allocation Rules
HOPS	Croatian Transmission System Operator Plc.
HR	Croatia
HU	Hungary
HVDC	High-Voltage Direct Current
IBWT	Italian working table
IDOA	Intraday Operational Agreement
IDSC	Intraday Steering Committee
IFA	Interconnexion France-Angleterre
IGCC	International Grid Control Cooperation
IE	Ireland
IGM	Individual Grid Model
IN	Imbalance Netting
IPTO	Independent Power Transmission Operator S.A.
ISP	Imbalance Settlement Period
IT	Italy
JAO	Joint Allocation Office
KPI	Key Performance Indicator
LIP	Local Implementation Project
LFC area	Load-Frequency Control area
LTTR	Long-Term Transmission Rights
LU	Luxembourg
MC	Market Coupling
MARI	Manually Activated Reserves Initiative
MAVIR	Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság
MCO	Market Coupling Operator
ME	Montenegro
MEMO	Electricity Market Operator of North Macedonia
MEPSO	Macedonian Transmission System Operator AD
mFRR	Frequency Restoration Reserves with manual activation
MNA	Multiple NEMOs Arrangement
MRC	Multi Regional Coupling
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator or Power Exchange
NDA	Non-disclosure agreement
NL	Netherlands
NO	Norway
NOS BiH	Nezavisni Operator Sustava u Bosni i Hercegovini
NRA	National Regulatory Authority
OPSCOM	Operational Committee

OST	OST sh.a – Albanian Transmission System Operator
PCR	Price Coupling of Regions
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and STable A-System Operation
PL	Poland
PMB	PCR Matcher and Broker IT system
PSE	Polskie Sieci Elektroenergetyczne
PT	Portugal
PTR	Physical Transmission Right
R&D	Research and Development
RA	Regulatory Authorities
REE	Red Eléctrica de España S.A.U.
REN	Rede Eléctrica Nacional, S.A.
RO	Romania
RS	Serbia
RR	Replacement Reserves
RTE	Réseau de Transport d'Electricité
SAFA	Synchronous Area Framework Agreement
SA	Synchronous Areas
SAP	Single Allocation Platform
SAP CA	Single Allocation Platform Cooperation Agreement
SDAC	Single Day-Ahead Coupling
SE	Sweden
SEPS	Slovenská elektrizačná prenosová sústava, a.s. (Slovakian TSO)
SI	Slovenia
SIDC	Single Intraday Coupling
SEE	South-East Europe
SK	Slovakia
Statnett	Statnett SF (Norway TSO)
SM	Shipping Module
SOB	Shared Order Book
SONI	System Operator for Northern Ireland Ltd.
Svenskä	Svenskä kraftnät (Swedish TSO)
SWE	South-Western Europe
Swissgrid	Swissgrid ag (Swiss TSO)
TCDA	TSO Cooperation Operational Agreement
TCID	TSO Co-operation Agreement for Single Intraday Coupling
TCOA	TSO Co-operation Agreement for Day-ahead Coupling
TenneT NL	TenneT TSO NV (Dutch TSO)
TenneT DE	TenneT TSO GmbH (1 out of 4 German TSOs)
Terna	Rete Elettrica Nazionale SpA (Italian TSO)
Transelectrica	National Power Grid Company Transelectrica S.A. (Romanian TSO)
TransnetBW	TransnetBW GmbH (1 out of 4 German TSOs)
TERRE	Trans-European Restoration Reserves Exchange
TSO	Transmission System Operator
XBID	Cross-Border Intraday project

The terms used in this document have the meaning of the definitions included in Article 2 of the CACM, FCA and EB Regulations.

List of Figures

Annex VII – List of Tables

Drafting team

Avramiotis, Iason (Swissgrid)

Cur, Alexander (Amprion)

de Chambure, Cyprien (Sia Partners)

De La Fuente Leon, Jose Ignacio (REE)

Estermann, André (50Hertz)

Fosse, Lars Olav (Statnett)

Granli, Tore (Statnett)

Grügelsiepe, Ramona (Amprion)

Grüneberg, Axel (TenneT)

Klönhammer, Maria (Magnus Energy)

Maier, Sarah (TransnetBW)

Nobel, Frank (TenneT)

Nousios, Dimitrios (Swissgrid)

Pantazi, Sotiria (ADMIE)

Schwartzmann, Julie (JAO)

Schlosser, Ilona (MAVIR)

Šebesta, Karel (ČEPS)

Tošić, Nikola (EMS)

Van Den Broucke, Thomas (Elia)

Vilsson, Jim (Energinet)

Winkler Mogensen, Henrik (Energinet)

Vonk, Tom (Magnus Energy)

Watzlawik, Julia (Amprion)

Zajac, Tomáš (ČEPS)

Aliyev, Sultan (ENTSO-E)

Belichenko, Dmitry (ENTSO-E)

Brandauer, John (ENTSO-E)

Brauner, Mathias (ENTSO-E)

Marcenac, Ludivine (ENTSO-E)

Mendoza-Villamayor, Marta (ENTSO-E)

Shemov, Gjorgji (ENTSO-E)

Zubieta Ochoa, Ignacio (ENTSO-E)

Publisher

ENTSO-E AISBL
8 Rue de Spa | 1000 Brussels | Belgium
www.entsoe.eu | info@ entsoe.eu

Design

DreiDreizehn GmbH, Berlin | www.313.de

Images

iStockphoto.com

Publishing date

30 June 2023

European Network of
Transmission System Operators
for Electricity

entsoe