# ENTSO-E
# Capacity Calculation and Allocation Report 2023

entsoe

# 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

# Executive Summary

Coordinated processes for capacity calculation and allocation harmonise the operation of cross-border markets in Europe to increase competitiveness and integrate renewable generation. Transmission system operators (TSOs) are working to achieve this by implementing a coordinated capacity calculation process in each capacity calculation region (CCR).

The CCRs are geographical regions in which the available cross-zonal trading capacity is determined based on forecasts of electricity flows for all market timeframes as defined in the capacity allocation and congestion management (CACM regulation; for the day-ahead [DA] and intraday [ID] timeframe) and forward capacity allocation (FCA) regulations (for the long-term timeframe). At the time of this report, most of the capacity calculation methodologies (CCMs) under the CACM regulation have been approved by the relevant regulatory authorities. Therefore, this report focuses on their implementation within the CCRs. Most of the CCMs under the FCA regulation for the long-term timeframe have been submitted but are awaiting approval, although some have already been approved.

| Capacity calculation region | Approach implemented | Coordinated capacity calculator(s) | Implementation date | |
|---|---|---|---|---|
| | | | Day-ahead | Intraday |
| Nordic | Flow-based (FB) | Nordic Regional Coordination Centre | Exp. Q1 2024 | Exp. Q1 2024 |
| Hansa | coordinated NTC (cNTC) | Nordic Regional Coordination Centre & TSCNET Services | Exp. Q2 2024 | Exp. Q2 2024 |
| Core | FB | Coreso & TSCNET Services | 9 June 2022 | Transitional solution using leftovers from the DA cross-zonal capacities: Implemented (Q2 2022)<br><br>Target solution: at earliest 2024 and subject to ACER procedure to adopt decision on 2nd and 3rd amendment of the Core ID CCM |
| Italy North | cNTC | Coreso & TSCNET Services | 1 November 2021 | 1 November 2021 |
| Greece-Italy | cNTC | Southeast Electricity Network Coordination Centre (SEleNe) capacity calculation | 3 August 2021 | 29 September 2021 (only IDCC2) |
| South-West Europe | cNTC | Coreso | Implemented (Q1 2020) | 15 March 2022 |
| Baltic | cNTC | Baltic Regional Coordination Centre | Exp. 2025 | Exp. 2025 |
| South-East Europe | cNTC | Southeast Electricity Network Coordination Centre (SEleNe) capacity calculation | 1 July 2021 | 1 October 2021 (1st ID)<br>1 October 2022 (2nd ID) |

Table 1: Implementation status of the CCMs according to the CACM Regulation per CCR

Several statistical and quality indicators have been drawn up to monitor operations after the launch of the CCMs[1]. This report presents the indicators for CCRs whose coordinated capacity calculation processes under the CACM regulation were already in use during the period it covers (i.e. 2021 and 2022). The statistical and quality indicators for CCRs whose CCMs will soon become operational can be expected to appear in the next edition of this report. Statistical and quality indicators are the basis on which TSOs assess the further harmonisation of CCMs. As this assessment requires a sufficient data basis, TSOs have proposed 2025 as the target year for this assessment. The conclusion is expected to be included in the 2025 edition of this report. In addition to the DA and ID timeframe, this report also covers the long-term timeframe. Table 2 (page 5) shows the implementation status of the CCMs according to the FCA regulation per CCR.

1 Pursuant to Article 31(3) of the CACM regulation.

| Capacity calculation region | Approach to be implemented | Status of the proposal | Implementation status | | |
|---|---|---|---|---|---|
| | | | Y-1 | M-1 | Q-1 |
| Nordic | FB | Approved in Oct 2019 | Ongoing | Ongoing | N/A |
| Hansa | cNTC | Submitted in Oct 2019 | Ongoing | Ongoing | N/A |
| Core | FB | The latest version of the Core LT CCM was approved by ACER in January 2023 | Q4 2024 | Q4 2024 | N/A |
| Italy North | cNTC | Approved in May 2020 | Q4 2021 | Q4 2021 | N/A |
| Greece-Italy | cNTC | Approved in Jan 2020 | Ongoing | Ongoing | N/A |
| South-West Europe | cNTC | Approved in Mar 2020 | Q2 2024 | Q2 2024 | Q2 2024 |
| Baltic | cNTC | Rejected by Agency for the Cooperation of Energy Regulators (ACER) in Nov 2020 | Exp. 2025 | Exp. 2025 | N/A |
| South-East Europe | cNTC | Approved in May 2020 | Q1 2023 | Q1 2023 | N/A |

Table 2: Implementation status of the CCMs according to the FCA Regulation per CCR

## CCR assessment framework

Based on a request by ACER made in their decision on the Capacity Calculation regions, All TSO are asked to assess at least CCRs Hansa, Nordic and Core. To facilitate this assessment and any future CCR configuration assessments, all TSOs are developing a three-step assessment framework:

- **Step 1**: Identification of CCR configuration(s) to be assessed in step 2 (influences for commercial exchange, remedial actions and contingencies are used).
- **Step 2**: Alternative CCR configuration(s) are assessed against the status quo based on nine parameters.
- **Step 3**: The assessments will lead to a recommendation to either keep the status quo or implement an alternative CCR configuration.

# 1 Introduction

TSOs calculate the optimal level of cross-zonal transmission capacity across various timeframes from long-term to real time. This calculation establishes the basis for the efficient performance of the European wholesale electricity markets across these timeframes. Both Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (the FCA regulation)[2], used for the long-term timeframe, and Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (the CACM regulation), used for the ID and DA timeframe, provide a framework to harmonise the manner in which cross-zonal capacity (CZC) is calculated and allocated in Europe. TSOs – in cooperation with all involved stakeholders – are working intensively on the implementation of the provisions of the FCA and CACM regulations. Capacity calculation and allocation methodologies compliant with the FCA and CACM regulations are implemented by the CCRs. CCRs stem from the need to properly consider the cross-zonal flows in capacity calculation and allocation for all the market timeframes. CCRs ensure that coordinated capacity calculation can be accurately and reliably performed to ensure optimal capacity is made available to the European market. Figure 1 (page 7) presents the current CCRs.

The FCA and CACM regulations also provide guidelines for transparent monitoring of the implementation of their provisions. The essence of these reporting activities is presented in the biennial ENTSO-E Capacity Calculation and Allocation Report. The present edition (2023) covers the period from Q1 2021 to Q4 2022. The report is being delivered to the Agency for the Cooperation of Energy regulators (ACER) and is published on ENTSO-E's website. The report is organised as follows:

- **Chapter 1** introduces the content of the report
- **Chapter 2** describes the statistical and quality indicators used to monitor capacity calculation and allocation.
- **Chapter 3** recounts the progress made to date with respect to the CCMs in all CCRs.
- **Chapter 4** presents the purpose and structure of the CCR assessment framework.
- **Annexes** provide complementary information such as legal references relevant to the report, list of tables, figures and abbreviations used.

2 See Annex I to learn more about the legal references and requirements covered in this report.

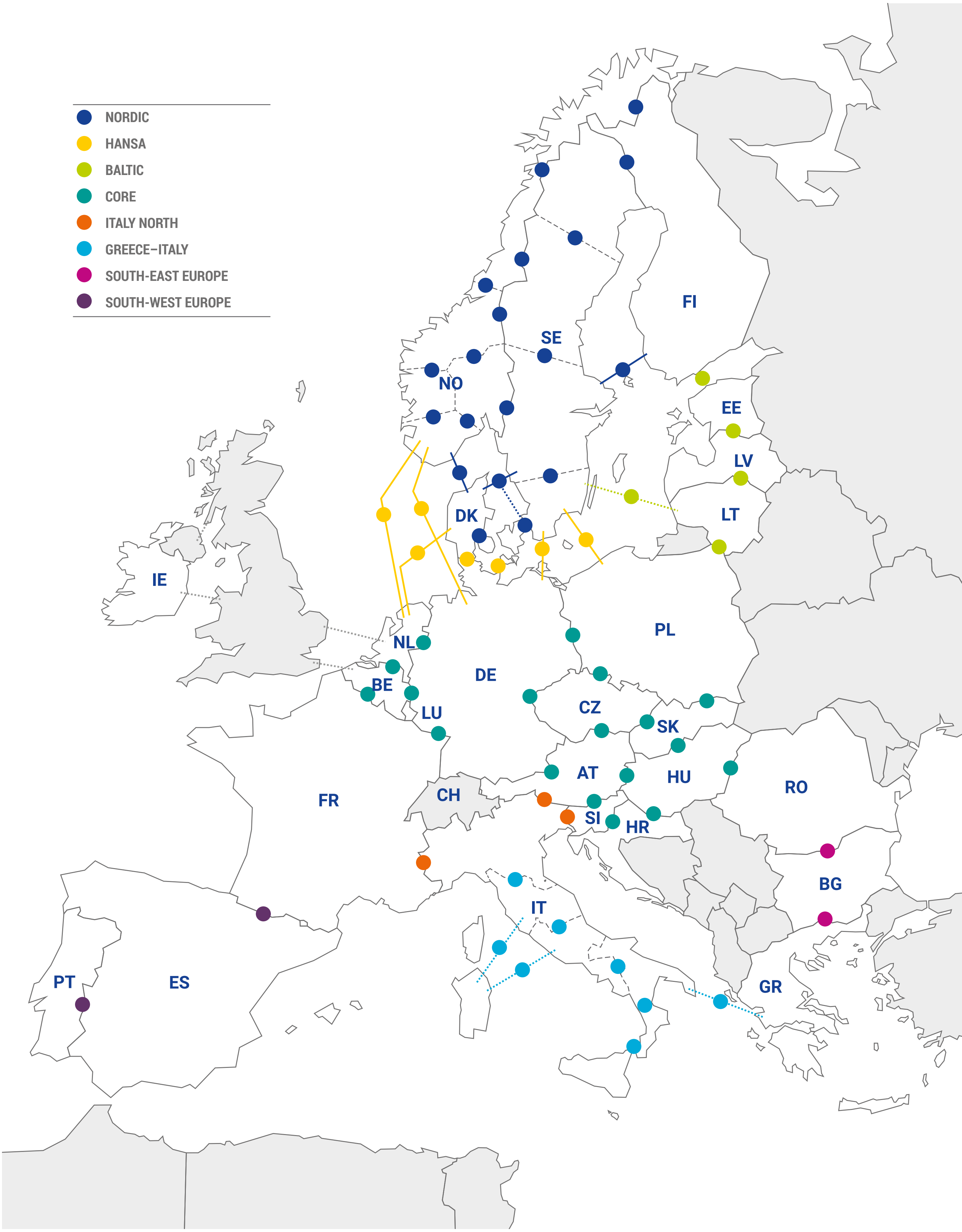



Figure 1: Current CCRs

# 2 Indicators to monitor the capacity calculation and allocation processes

This chapter describes the statistical and quality indicators developed jointly by ACER and ENTSO-E during Q1/2023 to monitor the state of capacity calculation and allocation within the CCRs[3].

The indicators cover (a) reliability margins, (b) available and allocated CZC, (c) the information used for capacity calculation and (d) indicators for assessing and following in the longer term the efficiency of single DA and ID coupling. It is important to note that this report presents the indicators for the CCRs whose coordinated capacity calculation and allocation processes compliant with the CACM and FCA regulations were already in use during the period it covers (i.e. 2021 and 2022) and for which data are available for at least 6 months during the reporting period (see table 3), and also the data for offered and allocated CZC for all CCRs.

| CCR | Intraday | Day-Ahead | Long-Term |
|---|---|---|---|
| Nordic | | | |
| Hansa | | | |
| Core | | live | |
| Italy North | live | live | live |
| Greece-Italy | live | live | live |
| South-West Europe | live | live | |
| Baltic | | | |
| South-East Europe | live | live | |

Table 3: Timeframes relevant for PIs calculation

## 1. Statistical indicators on reliability margins

These indicators aim to assess the reliability margin (RM) for capacity calculation in long-term (FCA regulation) as well as DA and ID (CACM regulation) timeframes. The RM is a key part of the capacity calculation process covering discrepancies between the forecasts of the capacity calculation process and real time to ensure system security. Therefore, the RM serves as a 'margin of error' considering uncertainties stemming from external influences that cannot be foreseen. The process for calculating the RM depends on the capacity calculation approach being implemented in the CCR: cNTC or FB calculation. For cNTC, the RM is based on the transmission reliability margin (TRM), whereas for FB, the RM is calculated based on the flow RM (FRM). To assess the RM, the following indicators have been established:

| cNTC | FB |
|---|---|
| – average TRM values per border/direction or profile/direction (if applicable) and timeframe (in MW)<br>– TRM as a percentage of Total Transfer Capacity (TTC) value (%). | – Average FRM values in MW<br>– Average FRM as a percentage of the maximum admissible power flow (Fmax) of the critical network element and contingency (CNECs) at BZ level |

Table 4: Statistical indicators on RMs

3 In accordance with Articles 31(3) of the CACM and 26(3) of the FCA regulations.

## 2. Statistical indicators on available and allocated CZC

These indicators seek to assess the level of available and allocated CZC across all timeframes. Moreover, complementary information on allocation constraints as well as maximum export and import capacities are presented, if relevant.

| cNTC | FB |
|---|---|
| – Average net transmission capacity (NTC) values<br>– Maximum export and import capacities<br>– Average External Constraints, where applied (MW)<br>– The portion of the CZC to be allocated, i.e. offered, by each timeframe<br>– The portion of the CZC allocated by each timeframe | – Average remaining available margin (RAM) values as a percentage of the maximum admissible power flow (Fmax) of the CNEC before pre-solved state, at BZ level<br>– Maximum export and import capacities for each BZ individually and matrix BZ to BZ (non-simultaneous values) |

Table 5: Statistical indicators of available and allocated CZC for each CCM approach

## 3. Quality indicators for the information used for capacity calculation

Two indicators have been developed. The first indicator assesses the quality of the input data and forecast Common Grid Model (CGM), by comparing the forecasted and realised reference flows on CNEs at FB calculation. The second indicator monitors the quality of the information used for the capacity calculation process by identifying the percentage of time when the CNEC of an NTC calculation is not determined during capacity calculation (e.g. due to stability limits).

| cNTC | FB |
|---|---|
| – percentage of time when the critical network element and contingency (CNEC) of a NTC calculation is not determined during capacity calculation (e.g. due to stability limits) | – Comparison of D-0 realised flows with D-2 forecasted flows<br>– Comparison between D2CF and DACF flows |

Table 6: Quality indicators for the information used for capacity calculation

## 4. Indicators for assessing and following in the longer term the efficiency of single DA and ID coupling.

The purpose of these indicators is to assess the efficiency of the current capacity calculation and allocation framework. This can be shown by the value of import/export per different BZs within a CCR.

# 3 Capacity calculation regions

The following chapter presents the current state of the short-term and long-term capacity calculation in each CCR.

## 3.1 Nordic

The TSOs in the Nordic CCR are Energinet (DK), Fingrid (FI), Svenska Kraftnät (SE) and Statnett (NO) whereas the Norwegian borders only got included in the CCR based on the ACER Decision No 08-2023[4]. 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 adopt their respective decisions on the CCR methodology.

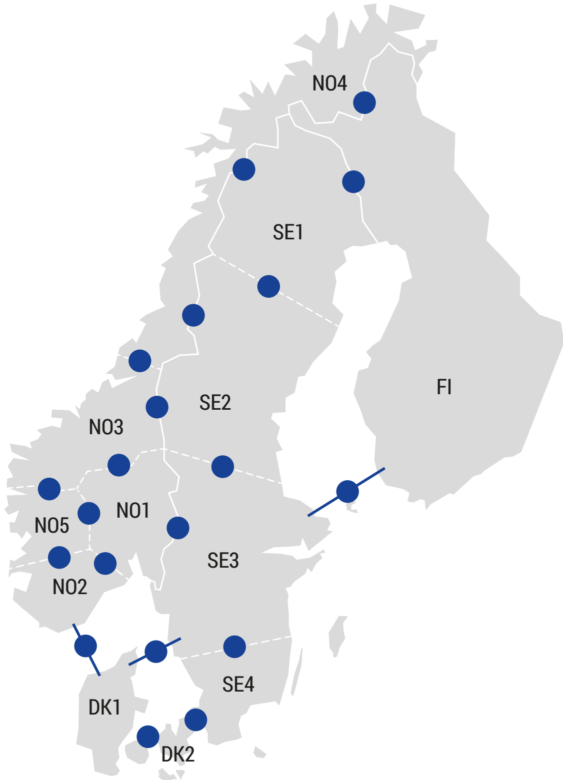



Figure 2: Nordic CCR. This CCR includes the following bidding zone borders (BZBs): Denmark 1–Sweden 3 (DK1–SE3), Denmark 2–Sweden 4 (DK2–SE4), Denmark 1–Denmark 2 (DK1–DK2), Sweden 4–Sweden 3 (SE4–SE3), Sweden 3–Sweden 2 (SE3–SE2), Sweden 2–Sweden 1 (SE2–SE1), Sweden 3–Finland (SE3–FI), Sweden 1–Finland (SE1–FI), Norway 1–Norway 2 (NO1–NO2), Norway 1–Norway 3 (NO1–NO3), Norway 1–Norway 5 (NO1–NO5), Norway 2–Norway 5 (NO2–NO5), Norway 3–Norway 5 (NO3–NO5), Norway 3–Norway 4 (NO3–NO4), Norway 1–Sweden 3 (NO1–SE3), Norway 3–Sweden 2 (NO3–SE2), Norway 4–Sweden 2 (NO4–SE2), Norway 4–Sweden 1 (NO4–SE1), Norway 4–Finland (NO4–FI), Norway 2–Denmark 1 (NO2–DK1)

### 3.1.1 Capacity calculation and allocation for the short-term

The Nordic CCM[5] for the DA and ID timeframes was approved by the Nordic national regulatory authorities (NRAs) on 14 October 2020.

- For the DA timeframe, the Nordic TSOs implement an FB capacity calculation approach.
- For the ID timeframe, the Nordic TSOs implement an FB approach as well. Until the single ID coupling is able to support the allocation of CZCs based on FB parameters, the capacity calculation coordinator (CCC) will transform the FB parameters into available transfer capability (ATC) as a transitional solution.

The Nordic FB capacity calculation and allocation is currently in an External Parallel Run (EPR) phase. The FB capacity calculation results are published daily on the JAO publication platform[6]. All other relevant information with regard to the FB methodology, FB news and updates, EPR market results and reports, ID gate opening results, can be found on the Nordic RCC website[7].

4 To be found **here** and its **annex**
5 To be found **here**
6 To be found **here**
7 To be found **here**

## Day-ahead capacity calculation process of the Nordic CCR

The capacity calculation process for the DA timeframe includes the following steps:

- Each Nordic TSO will create an IGM for its BZs and send it to the merging agent to merge the IGMs to build the CGM.

**A TSO may also transform operational security limits for dynamic stability into allocation constraints and send these as combined dynamic constraints for the calculation of Fmax.**

- Each Nordic TSO will send CNECs for its BZ(s) to the CCC to be considered in capacity calculation.
- The CCC will calculate $F_{max}$ for each CNEC applying the CGM, generation shift keys (GSKs), contingencies, operational security limits, combined dynamic constraints and CNECs submitted by each Nordic TSO.
- Each Nordic TSO will send RM, already allocated capacity and remedial action for each CNEC and combined dynamic constraint to the CCC for calculation of the RAM.
- The CCC will calculate the RAM and combined dynamic constraint for each CNEC, considering rules for sharing the power flow capabilities of CNECs among different CCRs.
- The CCC will send calculated FB parameters to each Nordic TSO for validation.
- The merging agent will send the CGM to the CCC to calculate $F_{max}$ values.
- Each Nordic TSO will send GSK strategies, contingencies and operational security limits for its BZ(s) to the CCC to calculate $F_{max}$ values.
- Each Nordic TSO will send validated FB parameters, including adjustments to FB parameters, to the CCC.
- Each Nordic TSO will send allocation constraints to the CCC. The CCC will send the validated FB parameters and allocation constraints to relevant nominated electricity market operators (NEMOs) for the purpose of allocating CZC by market coupling operator.
- Relevant NEMOs will publish validated FB parameters and allocation constraints to the market.
- The CCC will publish validated FB parameters, allocation constraints and other information requested.

A general overview of the stepwise capacity calculation process defined above is schematically represented in figure 3.

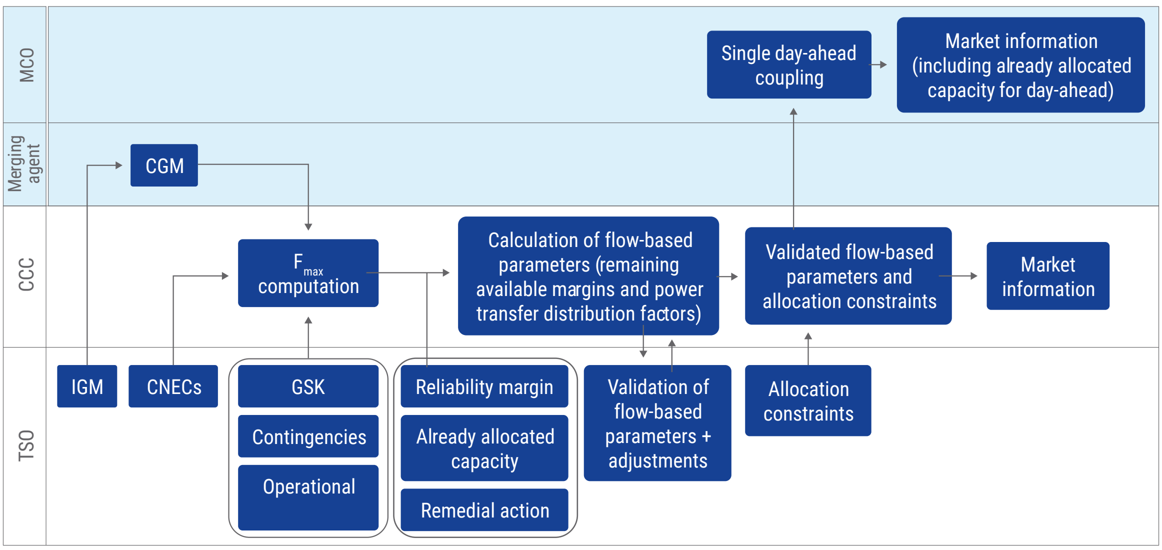



Figure 3: Nordic CCR: Input and output data and roles of the entities in the capacity calculation process for the DA time

## Reliability margin methodology

The Nordic TSOs will only determine the RM for Alternative Current (AC) grid elements and deliver these values to the CCC. The methodology used to determine the AC grid elements RM consists of two steps.

A probability distribution of the deviation between the expected and realised (observed) power flows is determined at least annually for each CNEC based on historical data. This forms the prediction error distribution for each CNEC. The prediction errors will be tailored to a statistical distribution that minimises the modelling error.

The RM value will be calculated by deriving a value from the probability distribution based on the provided TSO risk level value by each Nordic TSO, which is currently set to 95%. The risk level is defined as the area (cumulative probability) right of the RM value and frequency containment reserve margin value in their probability distribution.

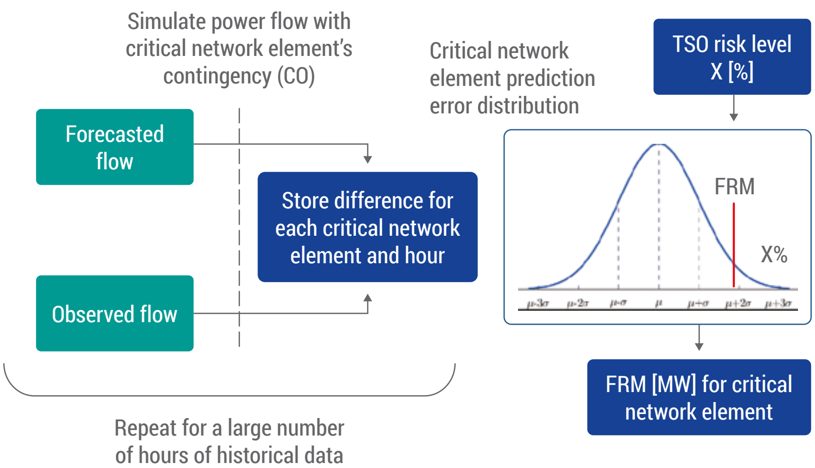



Figure 4: Nordic CCR: Determination of the reliability margin

The TSOs will calculate the RM and frequency containment reserve margin regularly and at least once a year, applying the latest information available. **The unintended deviations of the physical flows due to the adjustments made to maintain a constant frequency (frequency containment reserve margin) will be assessed separately and added to the final RM value.** Tables 7 and 8 provide an overview of the already accomplished milestones and planned timeline for the implementation of the Nordic CCR DA and ID capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q3 2018 | NRA approval of the CCR Nordic CCM proposal |
| Q4 2018 | NRA request for amendment[8] |
| Q4 2019 | NRA approval of the amended CCR Nordic CCM proposal |
| Q4 2020 | NRA approval of the second amended CCR Nordic CCM proposal |
| Q1 2022 | Start of the External Parallel Run (EPR) |

Table 7: Nordic CCR: Closed milestone(s) for short-term capacity calculation and allocation

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q2 2023 | ACER decision on Norwegian borders to CCR Nordic |
| Q1 2024 | Nordic DA CCM and ID CCM go-live window |

Table 8: Nordic CCR: Planned milestone(s) for short-term capacity calculation and allocation

8 More info to be found **here**

## 3.1.2 Indicators for the short-term

Figures 5 and 6 show the implicit offered and allocated DA capacities and Figures 7 and 8 (page 14) show the implicit ID offered and allocated capacities from January 2021 to December 2022 at Nordic CCR internal borders, which will become part of the Nordic CCR CCM in accordance with CACM regulation[9]. The values are presented in box-plot diagrams to show the distributional characteristics of the data series.

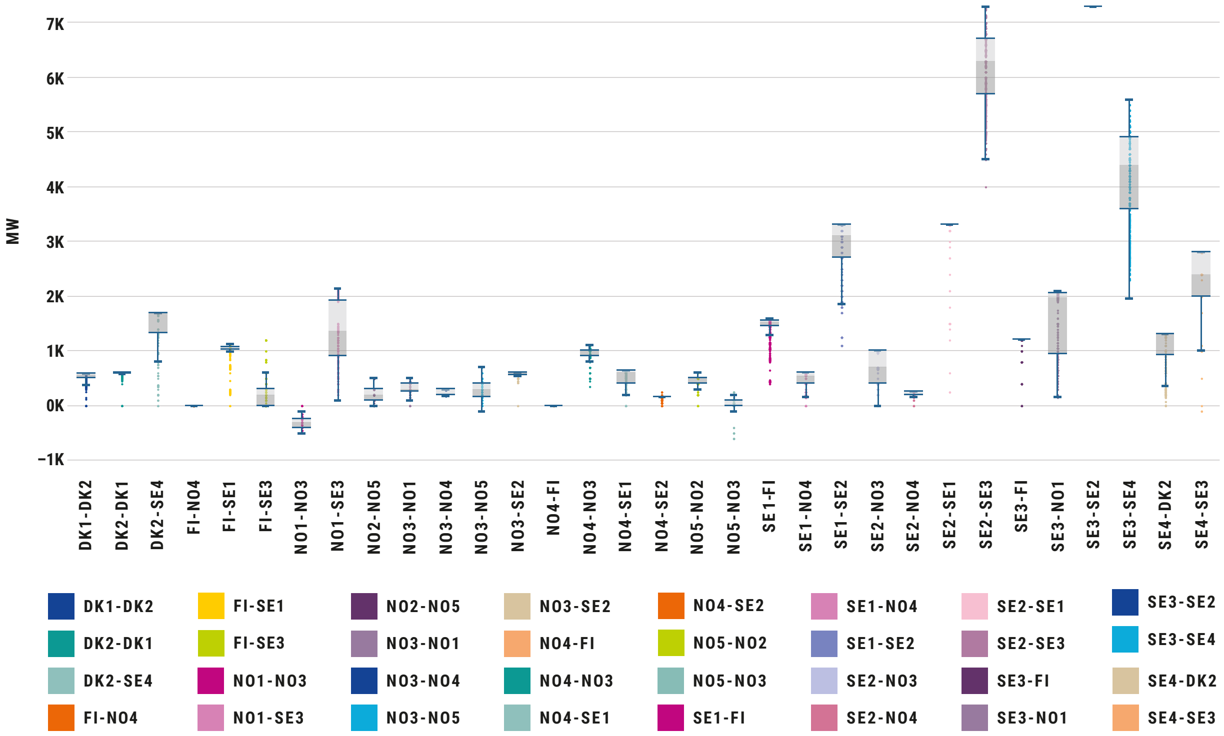



Figure 5: Nordic CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

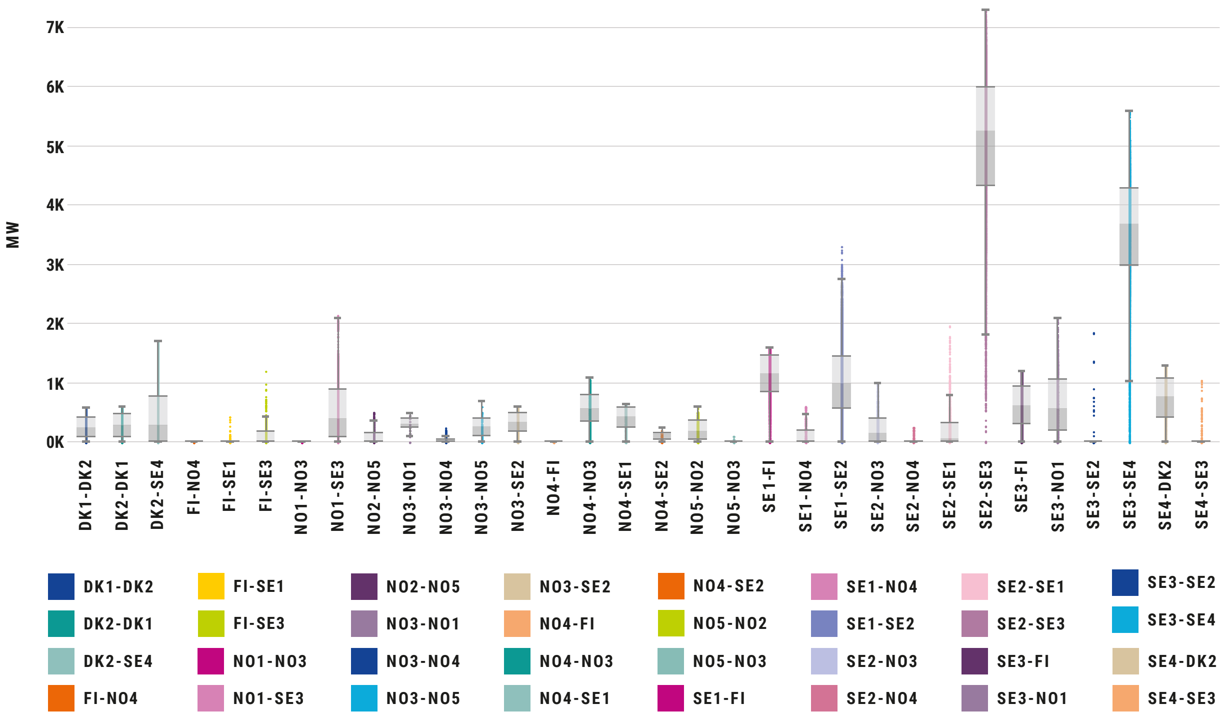



Figure 6: Nordic CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

9 Article 20 of the CACM regulation.

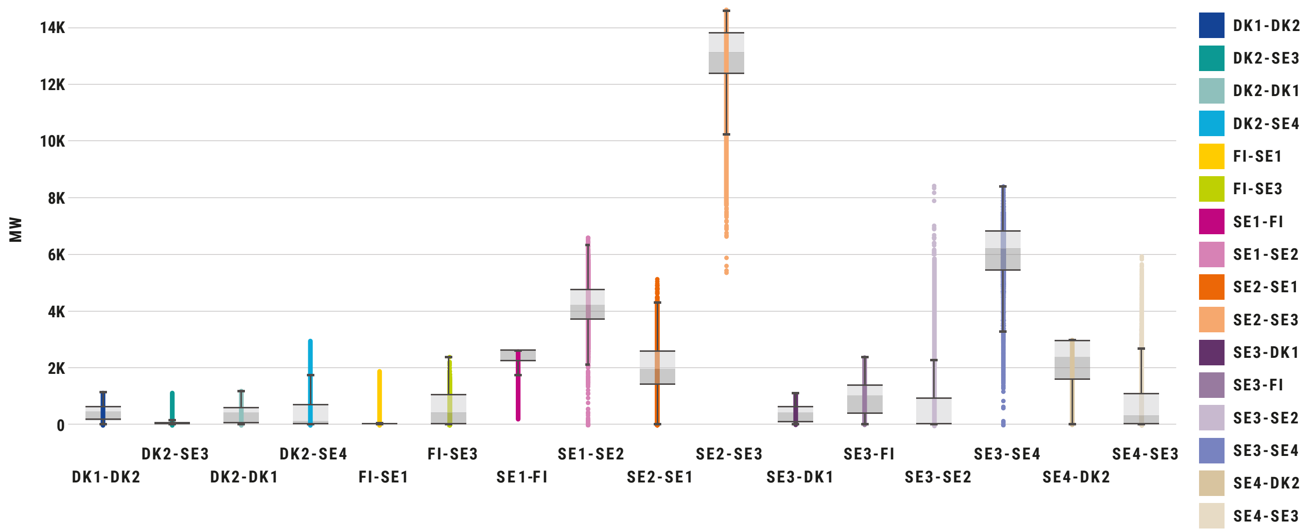



Figure 7: Nordic CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

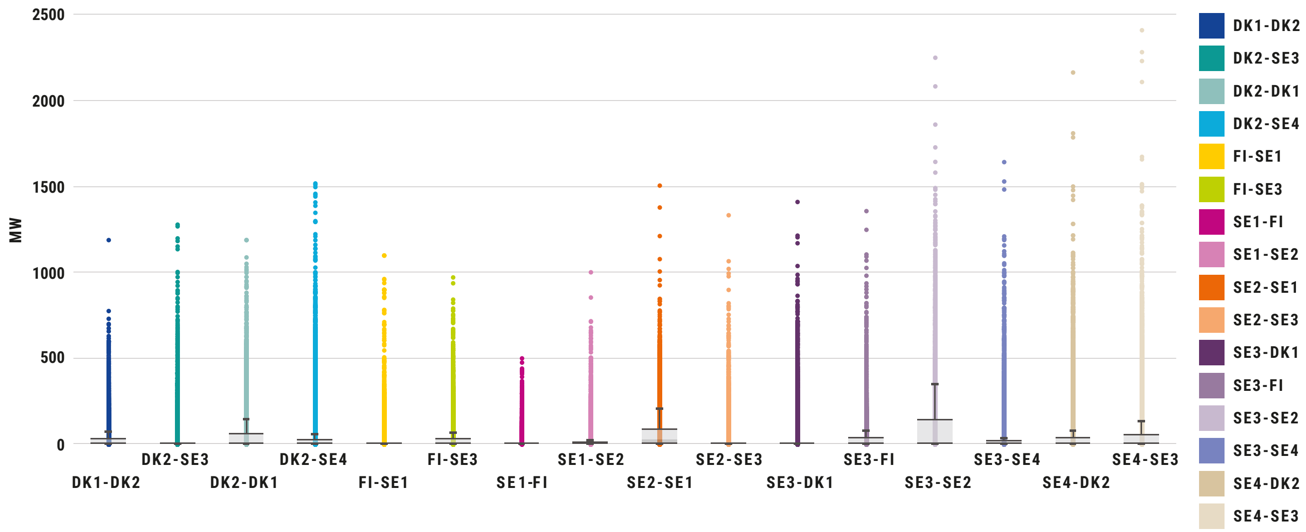



Figure 8: Nordic CCR: Implicit allocated ID capacities (2021-2022); Data source: Transparency platform

## 3.1.3 Capacity calculation and allocation for the long-term

The FCA CCM[10] for the Nordic CCR has been decided upon by ACER as presented in the closed milestones in table 9. For the long-term timeframe, the Nordic TSOs will implement a FB capacity calculation approach in Q1 2025.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2019 | The Nordic CCR TSOs submitted the long-term transmission rights CCM proposal to the NRA |
| Q2 2019 | ACER referral |
| Q4 2019 | ACER decision on the Nordic CCR long-term CCM |

Table 9: Nordic CCR: Closed milestone(s) for long-term capacity calculation and allocation

## 3.1.4 Indicators for the long-term

Figure 9 shows the offered and allocated long-term capacities during 2021 and 2022 at the Nordic CCR internal borders, which will become part of the Nordic CCR's CCM in accordance with the FCA regulation[11]. If a border is not shown in the figure, the capacity had not been offered within the long-term market timeframe represented during the reporting period.

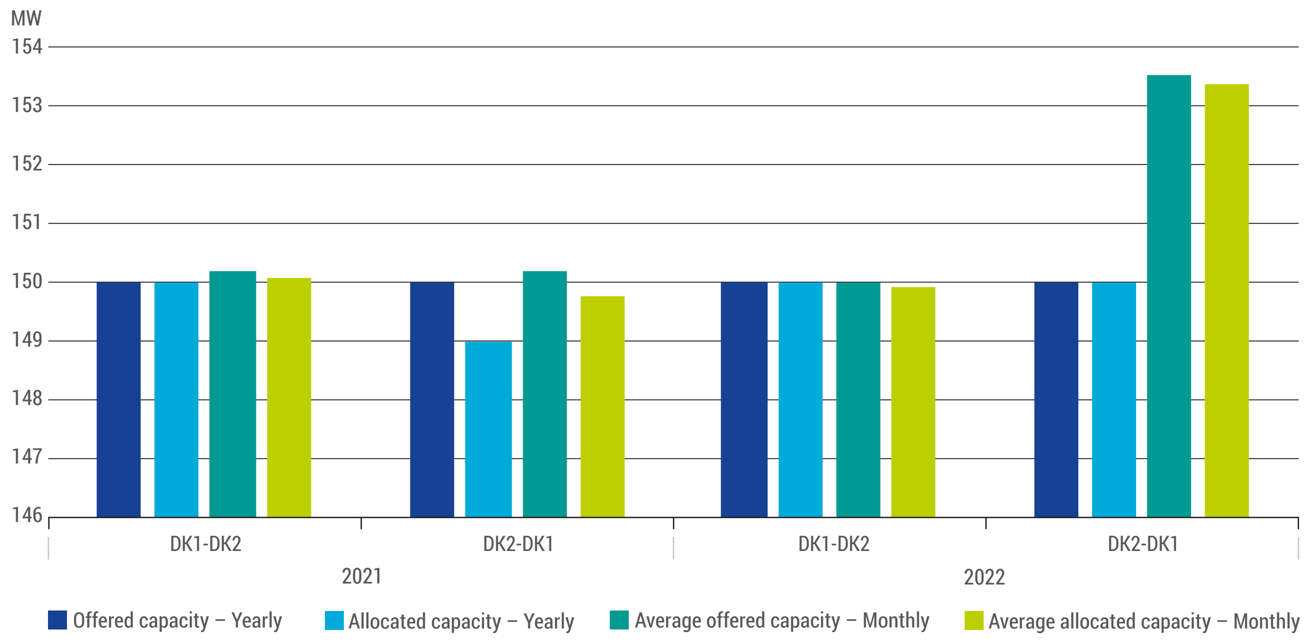



Figure 9: Nordic CCR: Offered and allocated long-term capacities during 2021 and 2022. Data source: JAO, excl. May 2022 for DK2–DK1 and DK1–DK2 directions with 0 offered/allocated capacity

10 Annex I_ACER Decision on Nordic LT CCM (entsoe.eu)

11 Article 10 of the FCA regulation

## 3.2 Hansa

The TSOs of the Hansa CCR are 50Hertz (DE/LU), Baltic Cable AB (SE4 – DE/LU), Energinet (DK), Statnett (NO), PSE (PL), TenneT DE (DE/LU), TenneT NL (NL) and Svenska Kraftnät (SE), whereas the Norwegian borders were only included in the CCR based on the ACER Decision No 08-2023[12].

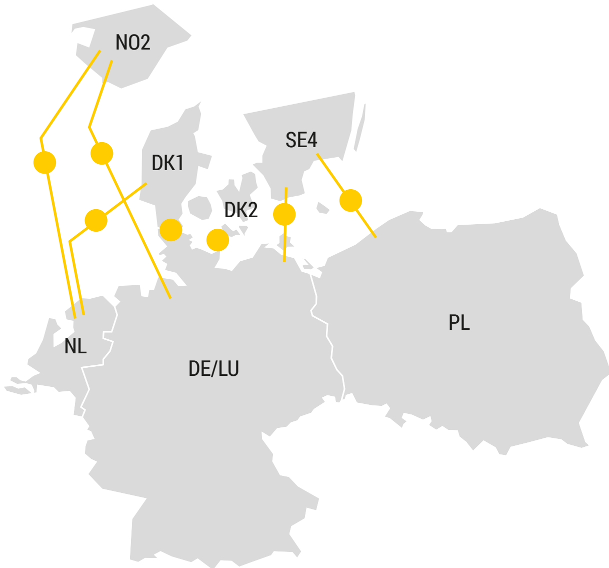



Figure 10: Hansa CCR. The Hansa CCR includes the following BZBs: Denmark 1–Germany/Luxembourg (DK1–DE/LU), Denmark 2–Germany/Luxembourg (DK2–DE/LU), Sweden 4–Poland (SE4–PL), Denmark 1–The Netherlands (DK1–NL), Sweden 4–Germany/Luxembourg (SE4–DE/LU), Norway 2–Netherlands (NO2–NL), Norway 2–Germany/Luxembourg (NO2–DE/LU)

### 3.2.1 Capacity calculation and allocation for the short-term

Tables 10 and 11 (page 17) provide an overview of the already accomplished milestones and planned timeline for the implementation of the Hansa CCR DA and ID capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| Quarter | Description |
| Q3 2017 | The Hansa CCR TSOs run a public consultation on the ID and DA CCM proposal |
| Q3 2017 | The Hansa CCR TSOs submitted the ID and DA CCM proposal for NRA approval |
| Q1 2018 | The Hansa CCR NRAs submitted Request for Amendment to the ID and DA CCM proposal |
| Q3 2018 | The Hansa CCR TSOs handed in Request for Amendments to the ID and DA CCM proposal |
| Q4 2018 | The Hansa CCR NRAs approved the amended ID and DA CCM proposal |
| Q1 2019 | ACER's amendment of the determination of CCRs, COBRAcable included |
| Q2 2019 | The Coordinated Capacity Calculators are appointed |
| Q3 2020 | The Hansa CCR NRAs submitted Requests for Amendments to the ID and DA CCM |
| Q4 2020 | The European Commission published its decision on KF CGS derogation |
| Q4 2020 | The Hansa CCR TSOs ran a public consultation on the amendment of the ID and DA CCM |
| Q4 2020 | Phase 1 of ID & DA CCM implementation completed for Hansa interconnectors (except NordLink scheduled for 2021) |
| Q1 2021 | The Hansa CCR TSOs submitted the amendments to the ID and DA CCM |
| Q2 2021 | ACER's amendment of the determination of CCRs, Baltic Cable AB included |
| Q2 2021 | Phase 1 of ID and DA CCM implementation for NordLink |
| Q1 2022 | TSOs submitted amendments to the DA fallback methodology (CACM Article 44) |
| Q1 2022 | TSOs submitted amendments to the Redispatch and Countertrading Cost Sharing methodology (CACM Article 74) |
| Q2 2022 | NRAs approved DA fallback |
| Q4 2022 | NRAs approved RCCS Art74 |
| Q4 2022 | Phase 2 of DA/IDCCM implementation |
| Q4 2022 | TSOs submitted EB CCM (EBGL Article 37) |

Table 10: Hansa CCR: Closed milestone(s) for DA and ID capacity calculation processes

12 To be found **here**

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2023 | TSO conducted public consultation on DA/ID CCM |
| Q2 2023 | ACER decision on Norwegian borders to CCR Hansa |
| Q3 2023 | EB CCM Implementation activities approved by NRAs |
| Q4 2023 | Assess readiness for ID auctions go-live |
| Q2 2024 | Phase 2 DA/ID CCM Implementation complete |

Table 11: Hansa CCR: Planned milestone(s) for DA and ID capacity calculation processes

It should be noted that the CCM for the Hansa CCR is interlinked with the CCMs being developed in the Nordic CCR and Core CCR. As the Hansa CCR has the unique feature of all BZs being currently connected by radial lines, the assessment of cross-border capacity can be split into three separate parts, which allows the TSOs to examine the impact of cross-border trade independently on each part of the grid. The methodology for the Hansa CCR is, therefore, a cNTC methodology for both DA and ID. Applying an advanced hybrid coupling (AHC) approach, the Hansa CCR's CCM takes advantage of the FB methodologies developed in Nordic and Core CCRs. This makes it possible to consider the limitations in the meshed AC grids, whereas the effective interconnector capacities are addressed individually within the Hansa CCR. Although the implementation of AHC in the Nordic CCR is expected to take place from the beginning of Nordic FB CC, it is planned to be applied in the Core CCR in an additional step after the initial launch of the Core DA CCM. This method ensures that the capacity calculation in Hansa CCR is as efficient as possible, from a market perspective and across all timeframes. Therefore, the method meets the requirements specified in Article 20(7) of CACM Regulation allowing the use of the cNTC approach. The methodology is easy to implement, and from an operational and Security-of-Supply perspective, it is coordinated with adjacent regions. Moreover, the proposed methodology is sustainable throughout the expected future changes in CCR configurations.

Due to the interdependencies with other CCRs, the CCM for the Hansa CCR will be implemented step-by-step, including:

1. appointment of CCC(s);
2. implementation of the CGM;
3. implementation of FB capacity calculation with AHC in the Nordic CCR;
4. implementation of FB capacity calculation with AHC in the Core CCR;
5. implementation of ID market coupling with FB constraints.

As soon as the ongoing implementation of new processes is complete, the TSOs will send the results of the cross-zonal CC for their respective borders and/or interconnectors to the Hansa CCR's CCC. Based on this, the Hansa CCC will perform the coordinated cross-zonal CC and calculate the minimum CZC. The resulting CZCs will be subject to validation by each Hansa CCR TSO for its BZBs. The validated CZCs and allocation constraints will be provided to the allocation mechanism by the Hansa CCR's CCC. This so-called Phase 2 implementation of the CCMs is expected to be completed in 2024.

## Determination of transmission reliability margins

The methodology to determine the TRM includes the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the CC and realised power flows in real time, and subsequently specifies the uncertainties to be considered in the CC. This only applies to the radial-connected AC border DK1–DE/LU.

The TRM calculation consists of the following high-level steps:

1. the identification of sources of uncertainty for each total transfer capacity (TTC) calculation process;
2. the derivation of independent time series for each uncertainty and determination of probability distribution of each time series; and
3. convolution of individual probability distributions and derivation of the TRM value from the convoluted probability distribution, whereas the 90$^{th}$ percentile is taken as a risk level.

An overview of the roles of the entities involved in the Hansa CCR CC for ID and DA processes in CC Phase is provided in Figure 11.

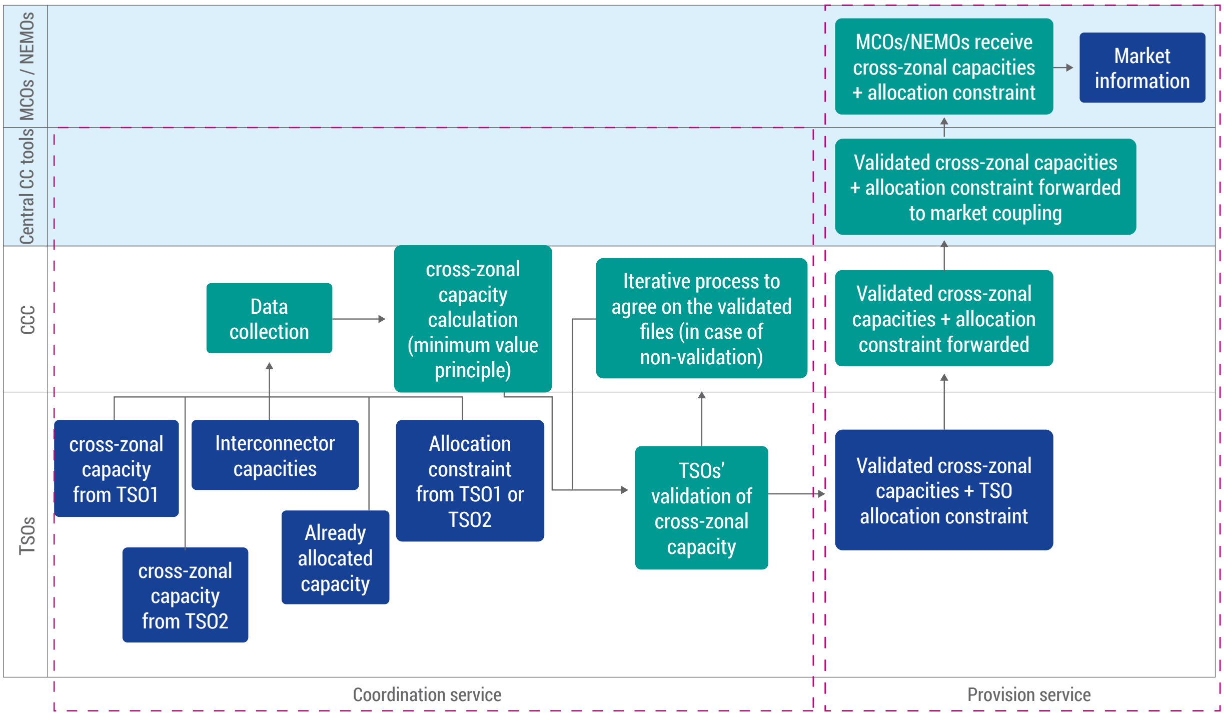



Figure 11: Hansa CCR: Input and output data and roles of the entities in the capacity calculation process for the DA and ID timeframes

## 3.2.2 Indicators for the short-term

Figures 12 and 13 (page 19) show the implicit offered and allocated DA capacities and figures 14 and 15 (page 19) show the implicit ID offered and allocated[13] capacities during 2021 and 2022 at borders, which will become part of the Hansa CCR CCM in accordance with CACM regulation[14]. The values are presented in box-plot diagrams to show the distributional characteristics of the data series.

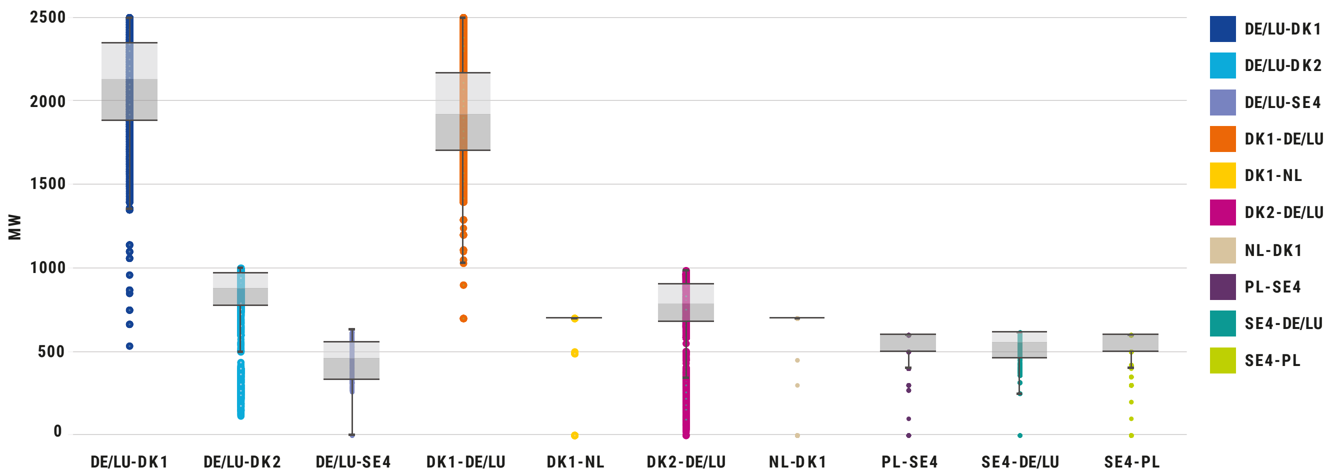



Figure 12: Hansa CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

13 In the event where the ID allocated capacity is higher than the ID offered capacity, it should be considered as a human error or IT issue

14 Article 20 of the CACM regulation

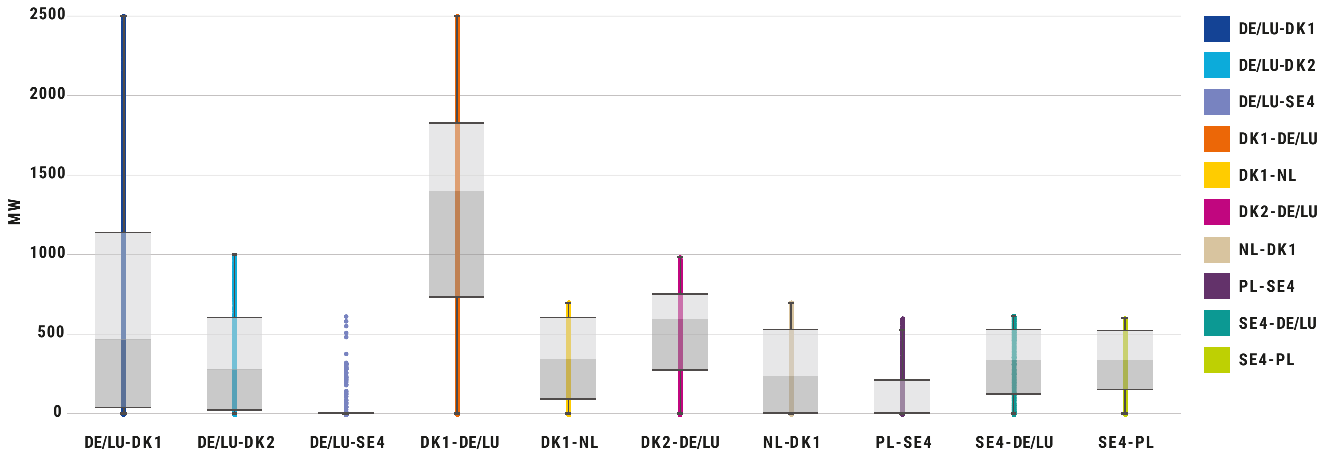



Figure 13: Hansa CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

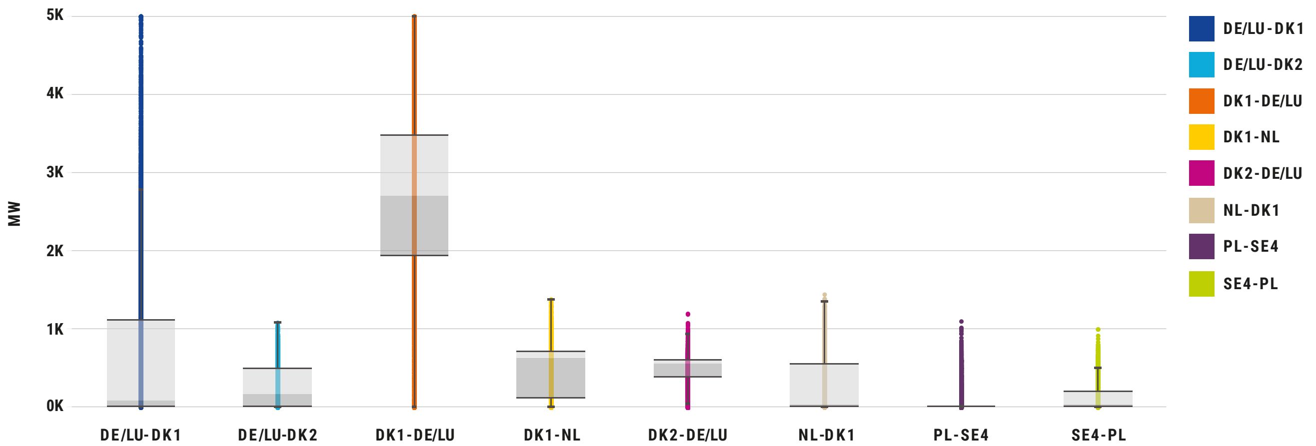



Figure 14: Hansa CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

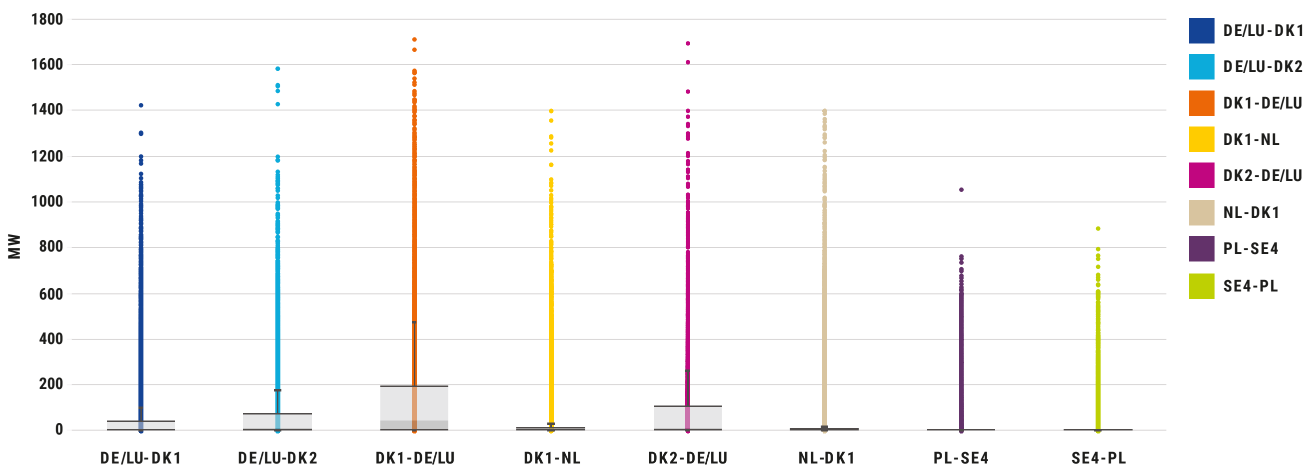



Figure 15: Hansa CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

## 3.2.3 Capacity calculation and allocation for the long-term

The Hansa long-term CCM was approved by Hansa NRAs in December 2020. At the same time, the European Commission published its decision on the Kriegers Flak combined grid solution (KF CGS) derogation[15]. Consequently, the Hansa CCR TSOs amended the FCA LTTRs CCM and launched a public consultation on the amendments. The Hansa CCR still proposes implementing a cNTC approach, and only dedicated provisions for KF CGS were added. At the time of writing, no specific timeframe has been designated for the go-live of the Hansa long-term CCM.

Figure 16 shows the process and responsibilities within the long-term CCM of the Hansa CCR in addition to the interactions with the Nordic and Core CCRs.

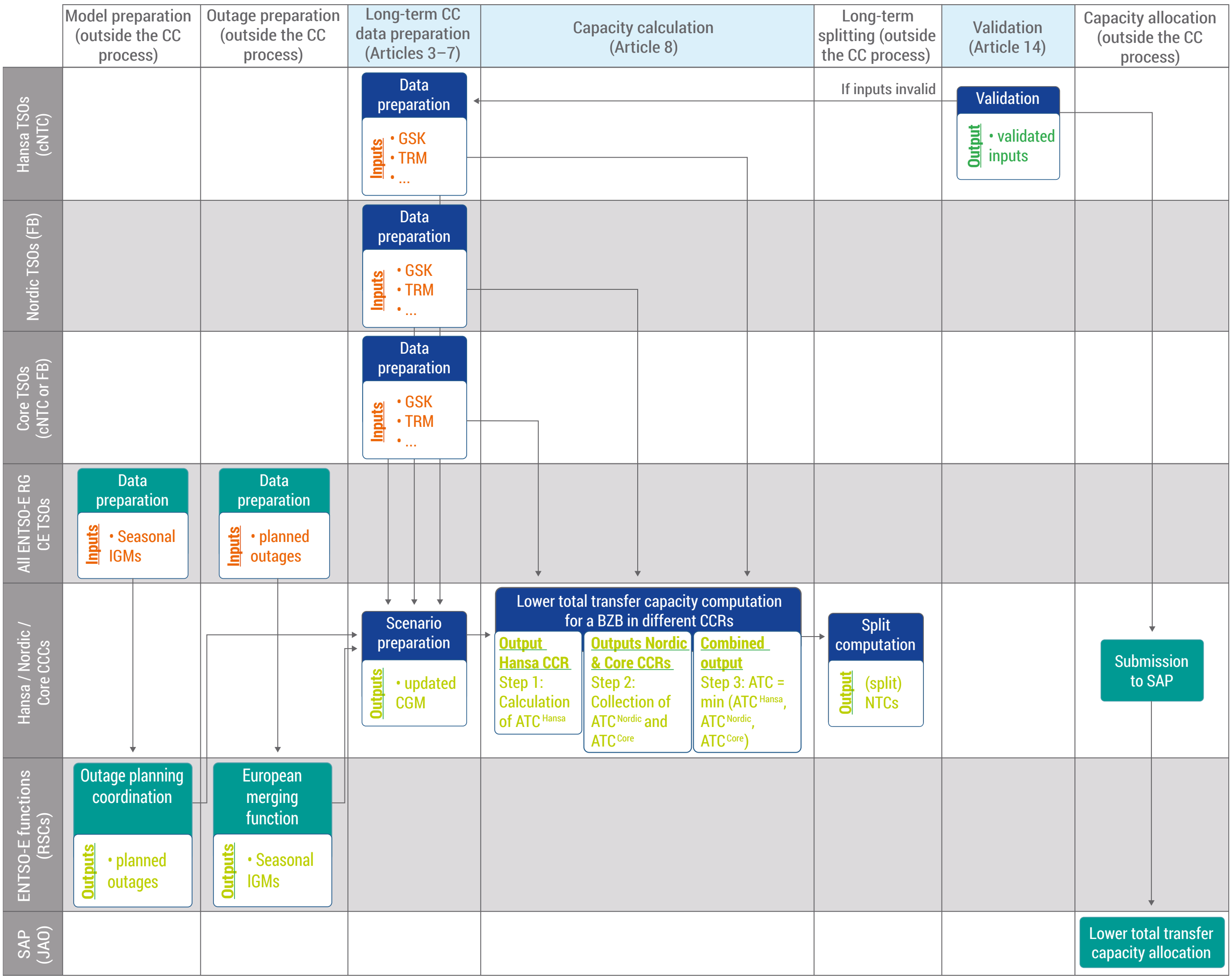



Figure 16: Hansa CCR: Input and output data and roles of entities in the capacity calculation process for the year- and month-ahead timeframes

15 See European Commission, Application of 30 June 2020 granting the Federal Republic of Germany and the Kingdom of Denmark a derogation according to Article 64 of Regulation (EU) 2019/943 of the European Parliament and of the Council for Kriegers Flak Combined Grid Solution (KF CGS), 2020

Table 12 provides an overview of the already accomplished milestones of the Hansa CCR long-term capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2018 | Regional design of LTTR was approved by the Hansa CCR NRAs |
| Q2 2019 | The Hansa CCR TSOs ran a first public consultation on the long-term CCM and long-term Splitting Rules |
| Q2 2020 | Hansa CCR NRAs approved the long-term Splitting Rules methodology |
| Q3 2020 | Hansa CCR NRAs requested an amendment to the long-term CCM submitted by the Hansa CCR TSOs |
| Q4 2020 | The Hansa CCR TSOs submitted the amended long-term CCM, after the Request for Amendment was considered |
| Q4 2020 | Hansa CCR NRAs approved the Hansa long-term CCM |
| Q4 2020 | The European Commission published its decision on KF CGS derogation |
| Q1 2021 | The Hansa CCR TSOs ran a public consultation on an amendment of the long-term CCM to consider the EC decision on KF CGS derogation |
| Q1 2021 | Long-term Splitting Rules are implemented on (relevant) Hansa borders |
| Q1 2021 | The Hansa CCR TSOs submitted the amendment to the long-term CCM |
| Q3 2021 | Hansa CCR NRAs approved submitted amendment to long-term CCM |

Table 12: Hansa CCR: Closed milestone(s) for long-term capacity calculation processes

### 3.2.4 Indicators for the long-term

Figure 17 shows the offered and allocated long-term capacities during 2021 and 2022 at borders, which will become part of the Hansa CCR Capacity Calculation Methodology in accordance with FCA regulation[16]. If a border is not shown in a figure, the capacity had not been offered within the long-term market timeframe represented during the reporting period.

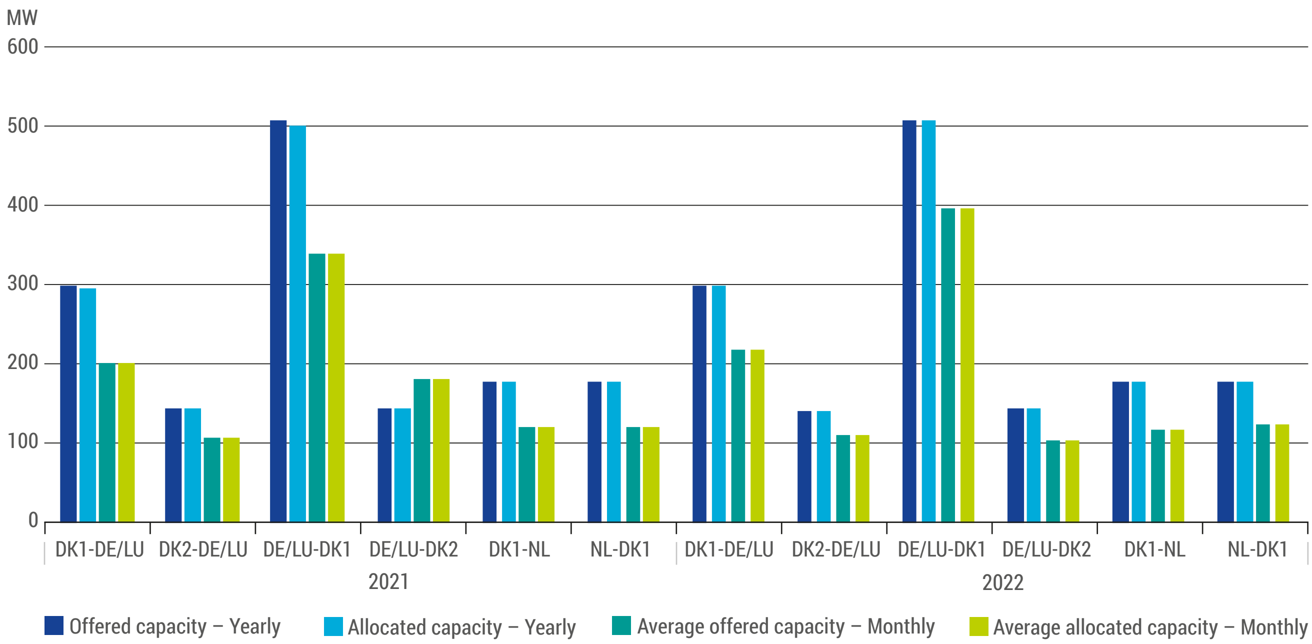



Figure 17: Hansa CCR: Offered and allocated long-term capacities during 2021 and 2022; Data source: JAO

16 Article 10 of the FCA regulation

# 3.3 Core

The 16 TSOs in Core CCR are 50Hertz, Amprion, APG, ČEPS, CREOS, HOPS, ELES, Elia, MAVIR, PSE, Transelectrica, RTE, SEPS, TenneT NL, TenneT DE and TransnetBW.

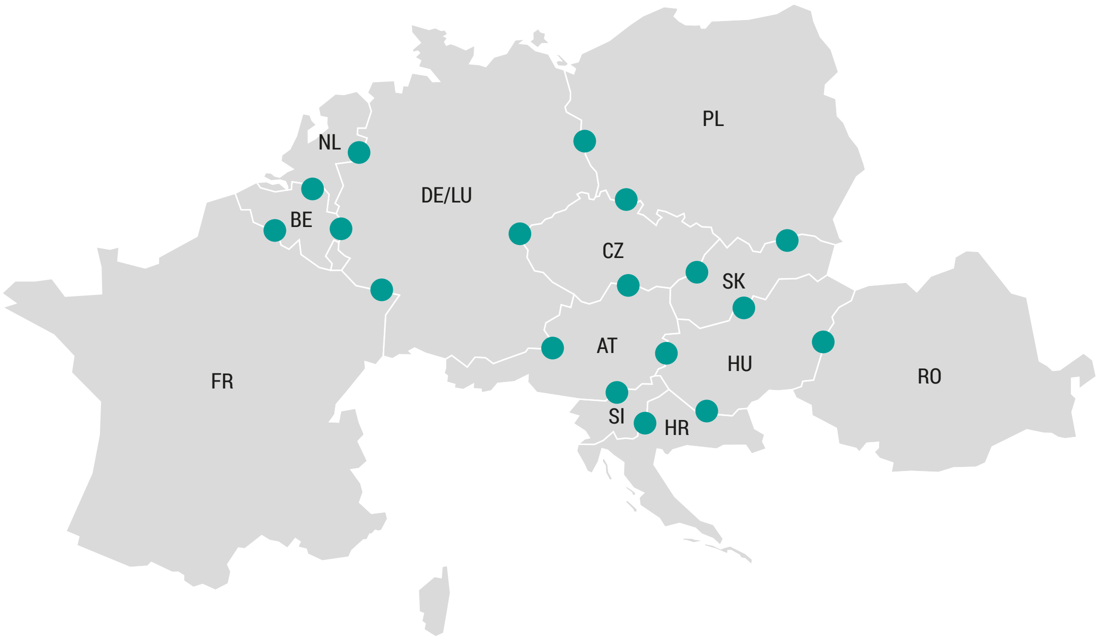



Figure 18: Core CCR. The Core CCR includes the following BZBs: France–Belgium (FR–BE), Belgium–Netherlands (BE–NL), France–Germany/Luxembourg (FR–DE/LU), Netherlands–Germany/Luxembourg (NL–DE/LU), Belgium–Germany/Luxembourg (BE–DE/LU), Germany/Luxembourg–Poland (DE/LU–PL), Germany/Luxembourg–Czech Republic (DE/LU–CZ), Austria–Czech Republic (AT–CZ), Austria–Hungary (AT–HU), Austria–Slovenia (AT–SI), Czech Republic–Slovakia (CZ–SK), Czech Republic–Poland (CZ–PL), Hungary–Slovakia (HU–SK), Poland–Slovakia (PL–SK), Croatia–Slovenia (HR–SI), Croatia–Hungary (HR–HU), Romania–Hungary (RO–HU), Hungary–Slovenia (HU–SI) and Germany/Luxembourg–Austria (DE/LU–AT).

TSOs in the Core CCR have set up a special consultative group, the Core Consultative Group[17], to keep concerned market participants up-to-date and involve them in discussions regarding the implementation of CCR deliverables within the Core CCR.

17 Find more info **here**

### 3.3.1 Capacity calculation and allocation for the short-term

Tables 13 and 14 (page 23) provide an overview of the already accomplished milestones and the planned timeline for the implementation of the Core CCR DA and ID capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q2 2021 | Approval of 1st amendment of DA CCM by Core NRAs |
| Q3 2021 | Start of the EXT//run FB DA market coupling |
| Q4 2021 | Go live of the Improved Coordination Solution |
| Q2 2022 | Adoption of decision on 1st amendment of ID CCM by ACER |
| Q2 2022 | Go-live of Core FB DA CC & MC<br>Go-live of Core ID CCM transitional solution (as depicted by the 1st amendment of the ID CCM) |
| Q4 2022 | Submission of 2nd ID CCM amendment |
| Q4 2022 | Start of EXT//run IDCC1 |
| Q1 2023 | Submission of 3rd ID CCM amendment |
| Q2 2023 | Submission of DA 2nd amendment (AHC implementation) |

Table 13: Core CCR: Closed milestone(s) for DA and ID capacity calculation processes

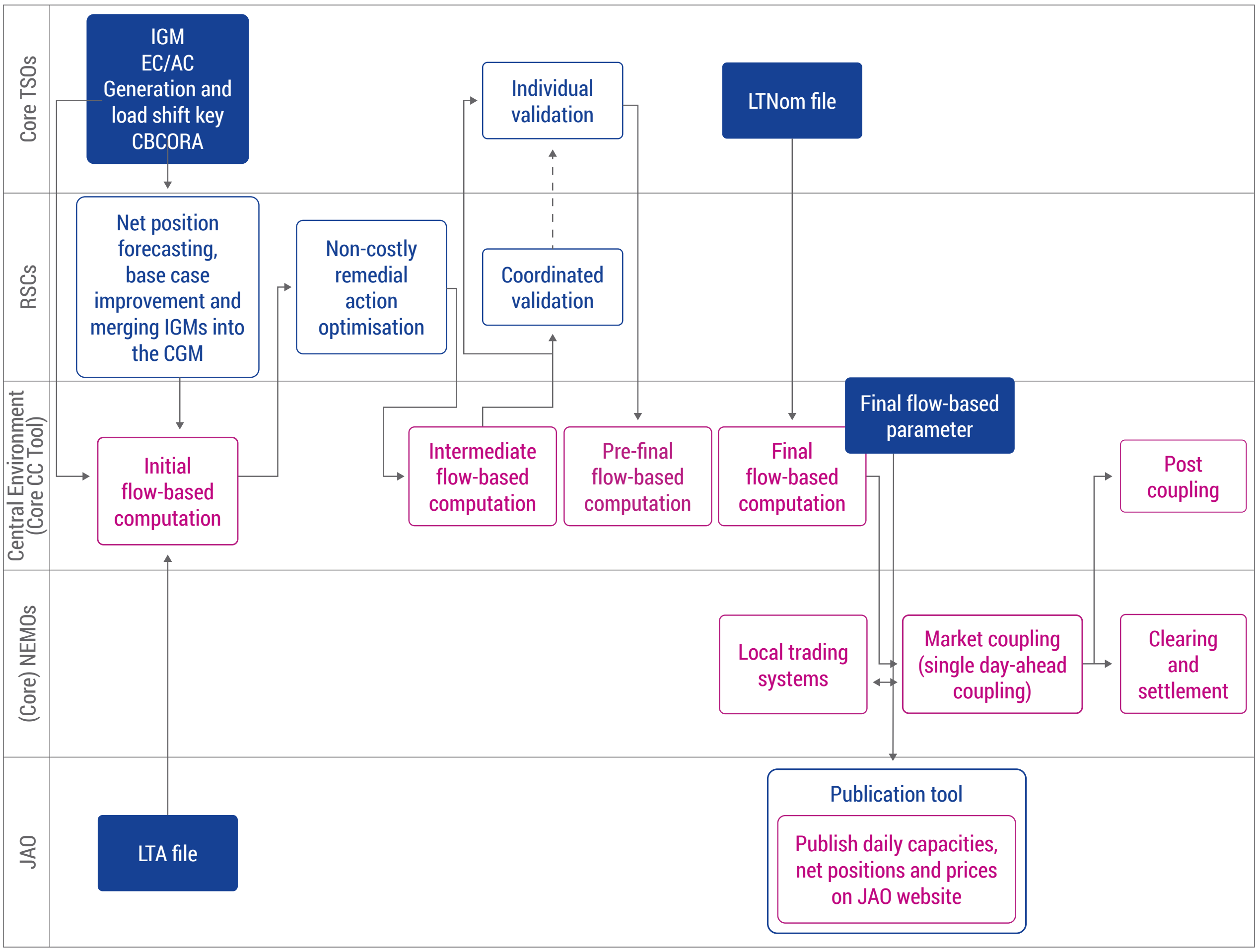
| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q4 2023 | Submission of DA 3rd amendment (Post go-live studies) |

Table 14: Core CCR: Planned milestone(s) for DA and ID capacity calculation processes

## Core DA capacity calculation methodology

There were two amendments introduced to the Core DA capacity calculation methodology during the period of scope of this report. The first amendment was approved by Core NRAs in 2021. The second amendment relates to the implementation of AHC and has been submitted to Core NRAs in Q2 2023. Figure 19 provides an overview of the Core FB DA capacity calculation process and involved entities.

Core flow-based capacity calculation and allocation




Disclaimer: This is a simplified high-level business overview for illustrative purposes only.

Figure 19: Core CCR: Input and output data and roles of the entities in the capacity calculation process for the DA timeframe

## Common Grid Models

The individual TSOs' IGMs are merged to obtain a CGM.

## Reliability margins

In the first amendment of the DA CCM, the FRM assessment establishes upper and lower estimates for the FRMs for Core TSOs, along with an obligation to justify the manner in which the final FRMs are derived from these estimates.

## Export and import thresholds (min./max.)

Specific export and import thresholds may be necessary to maintain secure grid operation. However, as such limitations cannot be efficiently transformed into operational security limits of individual critical network elements (CNEs), they are expressed as the maximum import and export constraints of BZs. Instead of including them in the DA FB calculation process, they are included as a so-called allocation constraint within the Euphemia market coupling algorithm. This is carried out as a constraint on the global net position, limiting the net position of the respective BZ compared with all BZs that are part of the single DA coupling.

## Core FB DA go-live

On 9 June 2022, the Core go-live was successfully launched. This came along with an exhaustive daily data publication in addition to several reports providing insights in how the process performs. This information is complementary, and to some extent also covering, the information contained in the section 'Indicators for the short-term'.

First, Core TSOs together with Core RCCs fulfil the obligations on daily data publications through the JAO publication tool[18]. This is a dedicated online communication platform that fulfils the publication obligations related to Article 25 of the Core DA Capacity Calculation Methodology. The online platform makes it possible to navigate various publications and download data[19]. The tool is accompanied by a Publication Handbook[20].

In addition, Core TSOs together with Core RCCs publish on JAO the following reports:

**Monthly operational KPI reports[21], covering the following indicators**

- KPI 1 – Average maximum AMR per TSO
- KPI 2 – Occurrences of RAM < 20%
- KPI 3 – Share of MTUs with intervention per TSO
- KPI 4 – Min and Max Net Positions per BZ
- KPI 5 – Relative Time Share of Applied RAs, by TSO, Type and Mode
- KPI 6 – Most limiting CNEC per TSO (NRAO)
- KPI 7 – Average variation of relative RAM before and after NRAO
- KPI 8 – Most often pre-solved CNEs (Top 20)
- KPI 9a – Most limiting CNEs (Top 20)
- KPI 9b – Allocation Constraints
- KPI 10 – Clearing prices, price spread and price convergence

For more information on these indicators, please consult the reading guide[22]

**Monthly data quality reports[23], covering the following indicators:**

- IGM replacement was performed
- Spanning was applied
- DFP was applied
- CNEC selection failed
- NRAO was not applied

**Quarterly reports[24], covering reporting obligations on:**

- Allocation constraints
- Capacity reductions
- Flows resulting from the SDAC net position

18 See **here**.
19 See **here**.
20 See **here**.
21 See **here**.
22 See **here**.
23 See **here**.
24 See **here**.

## 3.3.2 Indicators for the short-term

The Core DA FB capacity calculation methodology went live on 9 June 2022. For the indicators below, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022[25].

### Indicator for reliability margin

Table 15 shows the average FRM values in MW and its share of the maximum admissible power flow ($F_{max}$) of the CNECs at BZ level. For the first years until reliable data is collected for the FRM calculation, BZs of the former Central West Region (CWE)[26] use the FRM values used in the former CWE FB calculation and all non-CWE BZs use 10% of $F_{max}$ under normal weather conditions. The reason, that the value presented below differs from 10% is due to changed FRMs based on deviation for former CWE BZs, dynamic line rating and increase/decrease of $I_{max}$.

| Control Area | Average FRM (MW) | Percentage of Fmax of CNEC (%) |
|---|---|---|
| AT | 96.31 | 9.50 |
| BE | 176.39 | 10.39 |
| CZ | 142.66 | 10.02 |
| DE (TenneT DE) | 173.63 | 11.08 |
| DE (TransnetBW) | 185.45 | 11.50 |
| DE (Amprion) | 190.80 | 9.78 |
| DE (50Hertz) | 164.25 | 9.99 |
| FR | 220.52 | 10.66 |
| HR | 115.25 | 9.89 |
| HU | 129.46 | 9.96 |
| NL | 155.37 | 8.08 |
| PL | 119.09 | 9.99 |
| RO | 82.01 | 9.87 |
| SI | 87.28 | 10.01 |
| SK | 130.08 | 9.80 |

Table 15: Core CCR: Average FRM and percentage of Fmax for Core DA CCM (from 9 June 2022 to 31 December 2022); Data source: Core TSOs

25 After several discussions with ACER, it was agreed to exclude the indicator for the information used for capacity calculation from this year's report

26 Including the borders between the Netherlands, Belgium, Germany/Luxemburg, France and Austria

Figure 20 shows the range of RAM values as a percentage of the maximum admissible power flow ($F_{max}$) of the CNEC before pre-solved state, at BZ level. The green line in the graph indicates 20% of $F_{max}$ as this is the minimal value to be provided for capacity calculation. This an additional provision on minimal capacity within the Core region, whereas the universal minimal capacity according to article 16 of the regulation on the internal market for electricity[27] also respected flows outside of the Core region[28]. If the RAM values are below 20% of $F_{max}$, a TSO had to reduce the value as part of individual validation phase within the capacity calculation. In this step, a TSO evaluates if the capacities to be provided for market coupling would endanger system security within their control area. If that is the case, the TSO is allowed to reduce the RAM values:

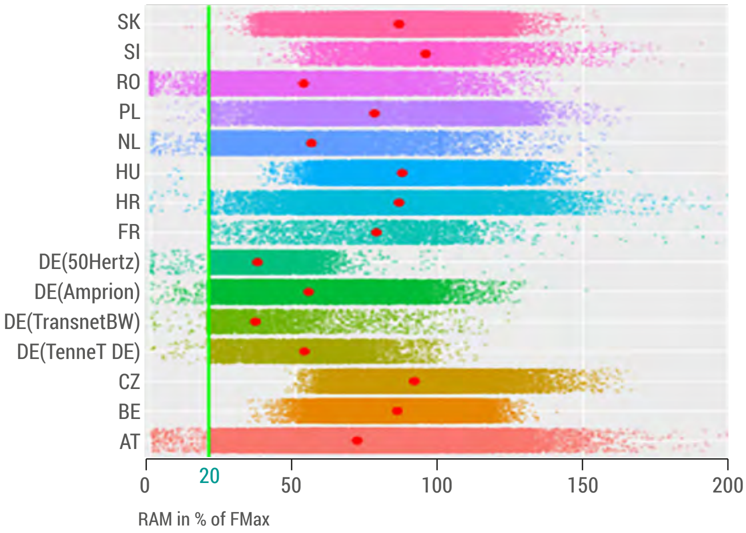



Figure 20: Core CCR: Range of RAM for DA CCM (9 June 2022 – 31 December 2022); Data source: Core TSOs

Table 16 shows the maximum bilateral exchanges between two Core BZs with the assumption that the other net positions are zero (in MW). These indicators are extracted from the union of the final FB domain and final bilateral exchange restriction which together describe the CZCs provided to the market coupling. This means that those capacities could, theoretically, have been used by the market if the prices during market coupling would indicate extreme demand in one BZ as in the case the allocation algorithm would optimise towards this BZ. In reality, capacities are lower than the values shown below.

| From/to | AT | BE | CZ | DE | FR | HR | HU | NL | PL | RO | SI | SK |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AT | | 6,181 | 7,564 | 6,315 | 6,453 | 4,670 | 4,887 | 5,879 | 4,658 | 3,112 | 4,724 | 5,429 |
| BE | 6,829 | | 6,631 | 9,142 | 8,368 | 5,404 | 5,342 | 6,500 | 3,621 | 3,115 | 5,405 | 5,633 |
| CZ | 7,006 | 7,205 | | 7,304 | 7,620 | 6,014 | 6,002 | 6,232 | 4,900 | 3,106 | 5,436 | 5,989 |
| DE | 8,080 | 8,750 | 6,502 | | 12,159 | 5,518 | 5,708 | 6,500 | 3,596 | 3,111 | 5,190 | 5,582 |
| FR | 7,226 | 10,057 | 6,963 | 12,743 | | 5,293 | 5,794 | 6,500 | 3,701 | 3,124 | 5,772 | 5,869 |
| HR | 3,998 | 3,735 | 4,623 | 3,850 | 3,628 | | 5,323 | 3,552 | 3,894 | 3,343 | 3,127 | 5,325 |
| HU | 6,119 | 7,458 | 6,875 | 7,460 | 7,311 | 5,504 | | 6,500 | 5,071 | 3,125 | 4,446 | 7,895 |
| NL | 5,750 | 5,509 | 5,750 | 6,500 | 6,385 | 4,953 | 5,544 | | 3,443 | 3,113 | 4,908 | 5,497 |
| PL | 987 | 998 | 900 | 900 | 999 | 993 | 900 | 996 | | 900 | 900 | 966 |
| RO | 3,818 | 3,730 | 4,058 | 3,770 | 3,721 | 3,518 | 3,897 | 3,734 | 3,416 | | 3,343 | 3,696 |
| SI | 5,544 | 7,112 | 6,173 | 7,780 | 7,404 | 3,962 | 5,428 | 6,087 | 4,863 | 3,199 | | 6,014 |
| SK | 5,570 | 6,301 | 6,515 | 6,956 | 6,584 | 5,692 | 6,421 | 6,071 | 5,205 | 3,179 | 4,789 | |

Table 16: Core CCR: Non-simultaneous maximum export and import capacities (from 9 June 2022 to 31 December 2022); Data source: Core TSOs

27 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

28 More Information on the minimal capacity can be found in the ENTSO-E Market Report published in 2021, 2022 and 2023

## Indicator for assessing and following in the longer term the efficiency of single DA and ID coupling

Table 17 shows the efficiency of the current capacity calculation and allocation framework by multiplying Net positions (DA) and DA price: These values give an indication about the value the net import or export of a BZ has.

| BZ | 2022<br>∑ ($NP_h$ x $DA_h$), mln EUR | BZ | 2022<br>∑ ($NP_h$ x $DA_h$), mln EUR |
|---|---|---|---|
| AT | −2,339 | HU | −2,382 |
| BE | 1,409 | NL | 1,573 |
| CZ | 2,622 | PL | 27 |
| DE | −489 | RO | −691 |
| FR | −5,817 | SI | −682 |
| HR | 303 | SK | −44 |

Table 17: Core CCR: Efficiency of the current capacity calculation and allocation framework (from 9 June 2022 to 31 December 2022); Data source: OPSCOM reports

Figures 21 and 22 (page 29) show the implicit offered and allocated DA capacities and figures 24 and 25 (page 30) show the implicit ID offered and allocated capacities from January 2021 to December 2022 at Core CCR internal borders, which will become part of the Core CCR CCM in accordance with CACM regulation[29]. Figure 23 (page 29) shows the allocated DA capacities for the timeframe from 9 June 2022 to 31 December 2022.

The values of the DA and ID timeframes are presented in box-plot diagrams to show the distributional characteristics of the data series. The borders of the CWE FB market coupling region, which will become part of the Core CCR, are not shown in the graphs below. After Core go-live on 09 June 2022, no Day Ahead capacities are shown in the graphs below due to FB market coupling.

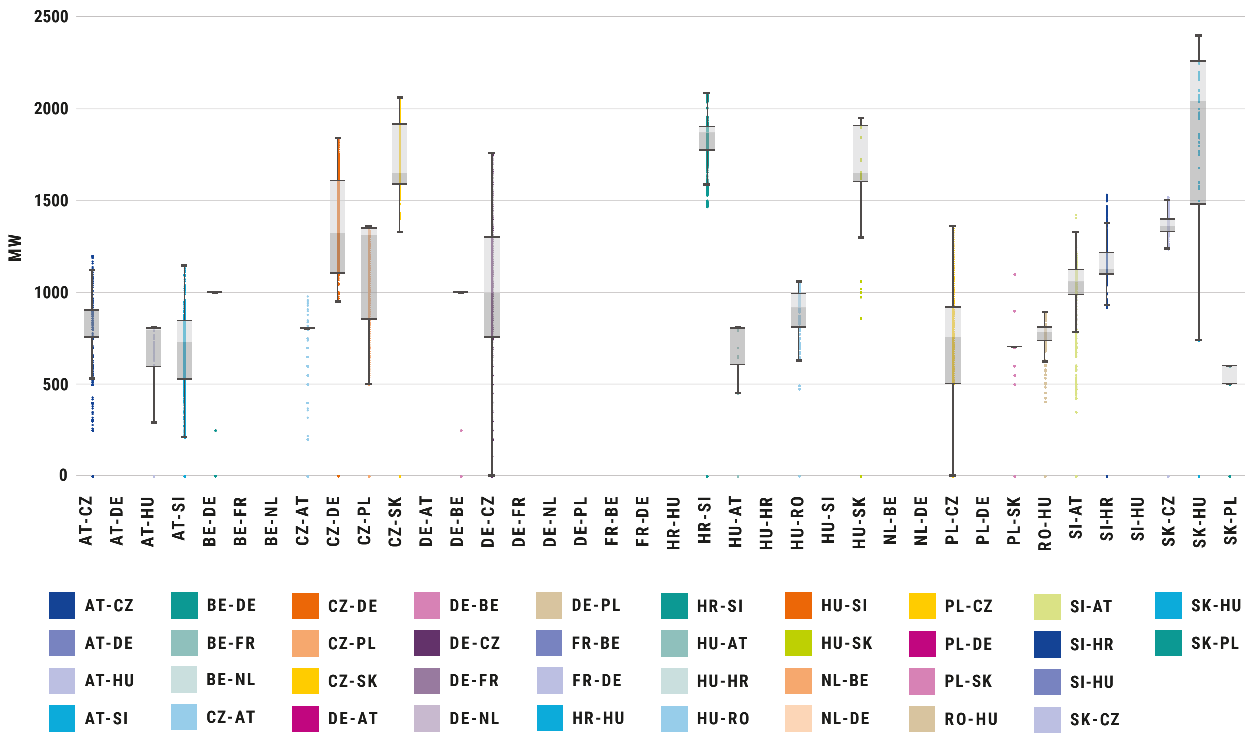



Figure 21: Core CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

29 Article 20 of the CACM regulation

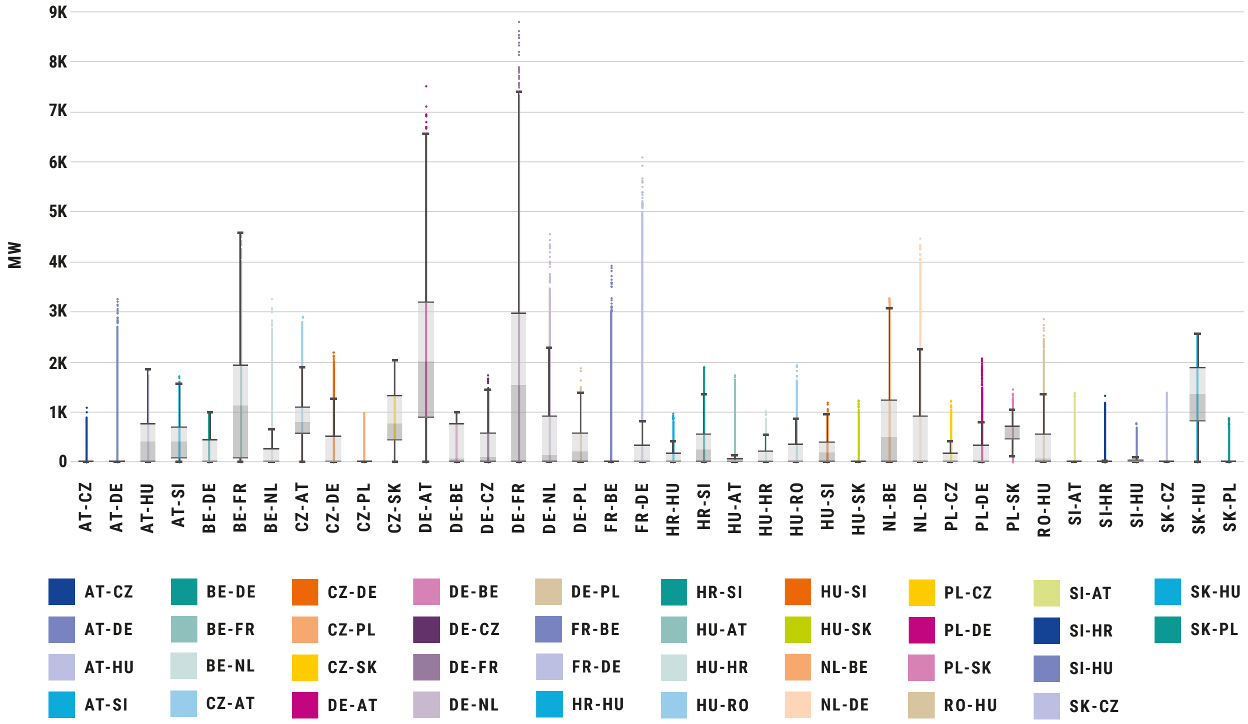



Figure 22: Core CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

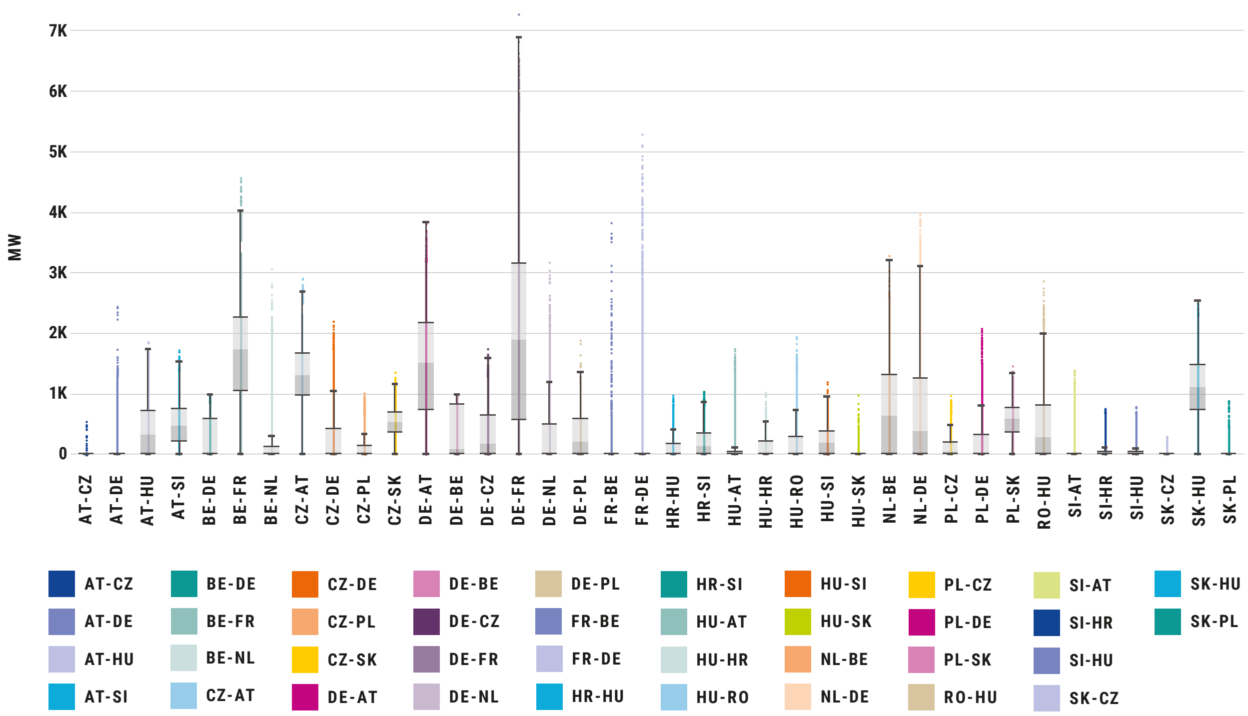



Figure 23: Core CCR: Implicit allocated DA capacities (9 June 2022 – 31 December 2022); Data source: OPSCOM reports

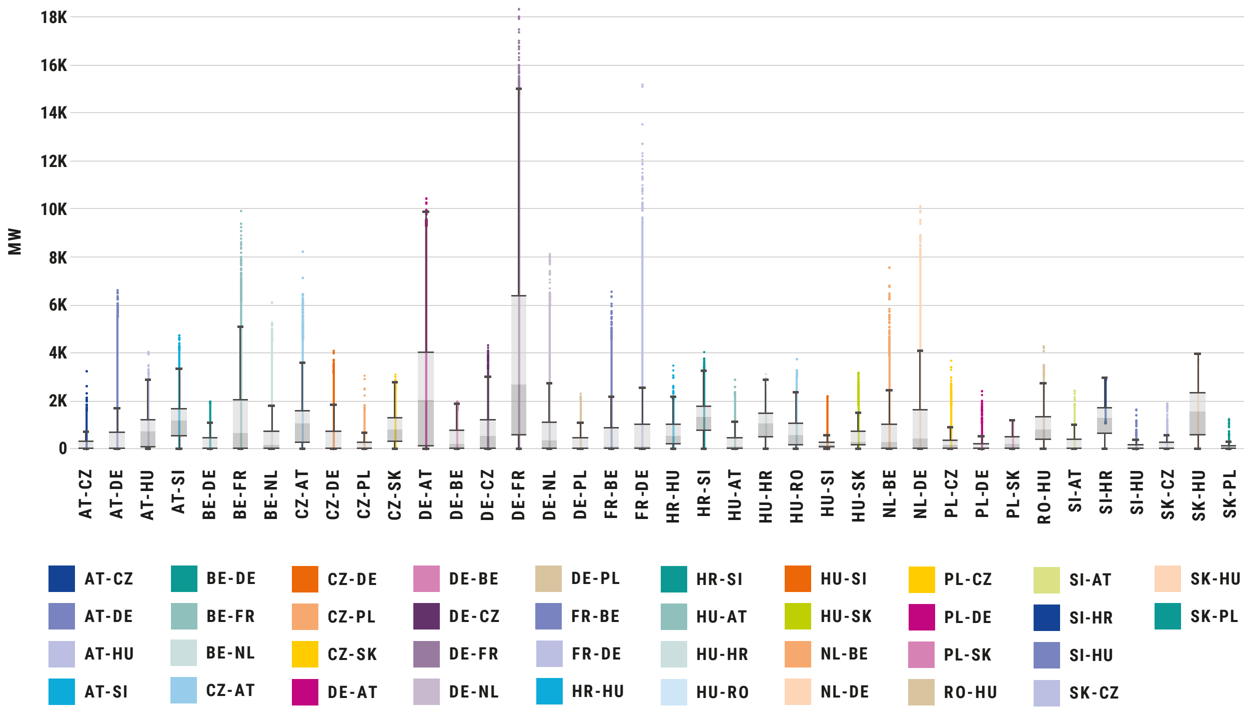



Figure 24: Core CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

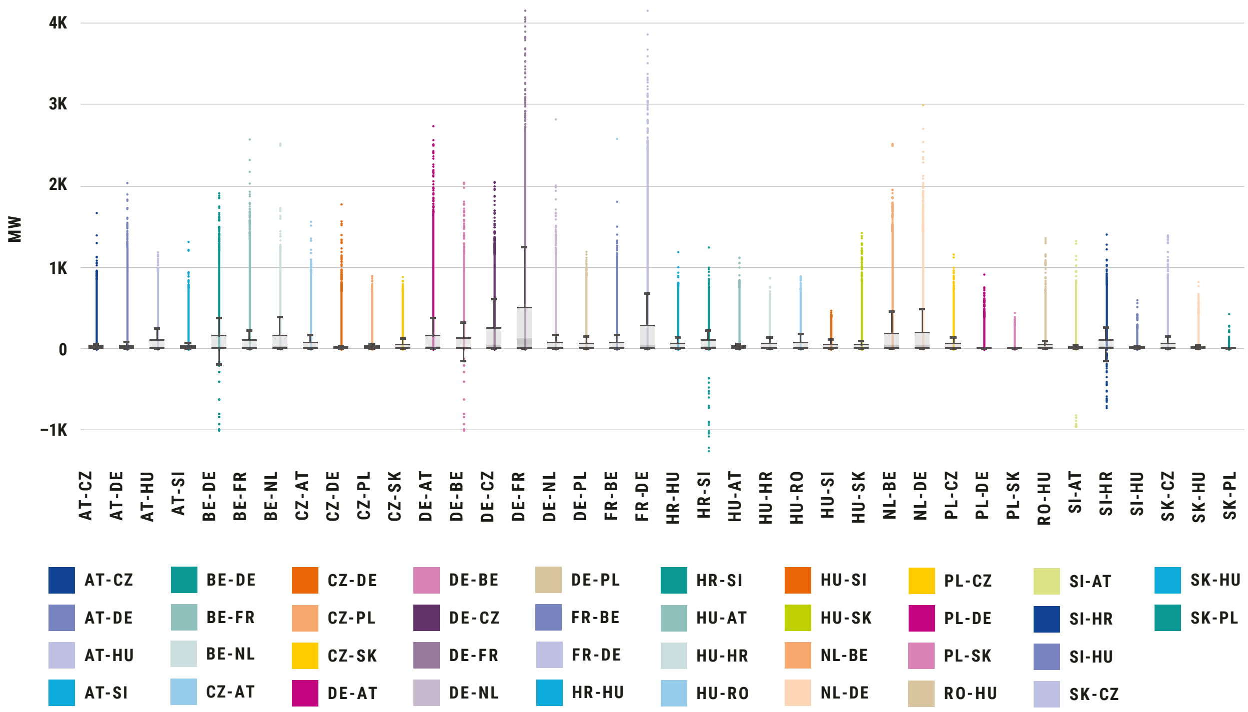



Figure 25: Core CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

## 3.3.3 Capacity calculation and allocation for the long-term

The Core Long-Term Capacity Calculation (Core LTCC) process is established under Article 10 of the FCA Regulation. Core LTCC methodology was approved by the ACER Decision 14/2021 of 3 November 2021[30]. It uses a FB approach, applies a security analysis based on multiple scenarios, and is compliant with the capacity calculation methodologies used in the DA and ID timeframes. Core LTCC project ensured the implementation of the coordinated capacity calculation process, which determines capacities for yearly and monthly timeframes which are then input to the FB explicit allocation organised by the Single allocation platform (SAP). It allows for long-term planning and provides hedging opportunities by calculating capacities and making them available to market participants at an early stage. Implementation of the FB allocation is carried out under the ENTSO-E structure together with JAO.

Core TSOs have initiated the LTCC experimentation phase in mid-2022 with the aim of validating business processes and setting up the basis for the IT implementation. In parallel, Core TSOs developed the design and functional requirements of the LTCC process to launch the IT implementation of common tooling and local IT implementation. As of January 2023, the implementation of industrialised tools was initiated. At the same time, the experimentation with an increased number of scenarios is executed with the aim of providing more accurate capacity data for subsequent allocation simulations. Core TSOs plan to finalise IT implementation and testing by the end of 2023 to launch the internal and external parallel run testing in Q1 and Q2 of 2024. The expected Core LTCC go-live is November 2024 (yearly auction for 2025), as indicated in table 19.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q3 2021 | Approval of LT CCM |

Table 18: Core CCR: Closed milestone(s) for long-term capacity calculation processes

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q2 2024 | Start EXT//run |
| Q4 2024 | LTCC go-live (yearly auction for 2025) |

Table 19: Core CCR: Planned milestone(s) for long-term capacity calculation processes

30 To be found here

### 3.3.4 Indicators for the long-term

Figures 26 and 27 show the offered and allocated long-term capacities during 2021 and 2022[31] at Core CCR internal borders, which will become part of the Core CCR CCM in accordance with FCA regulation[32].

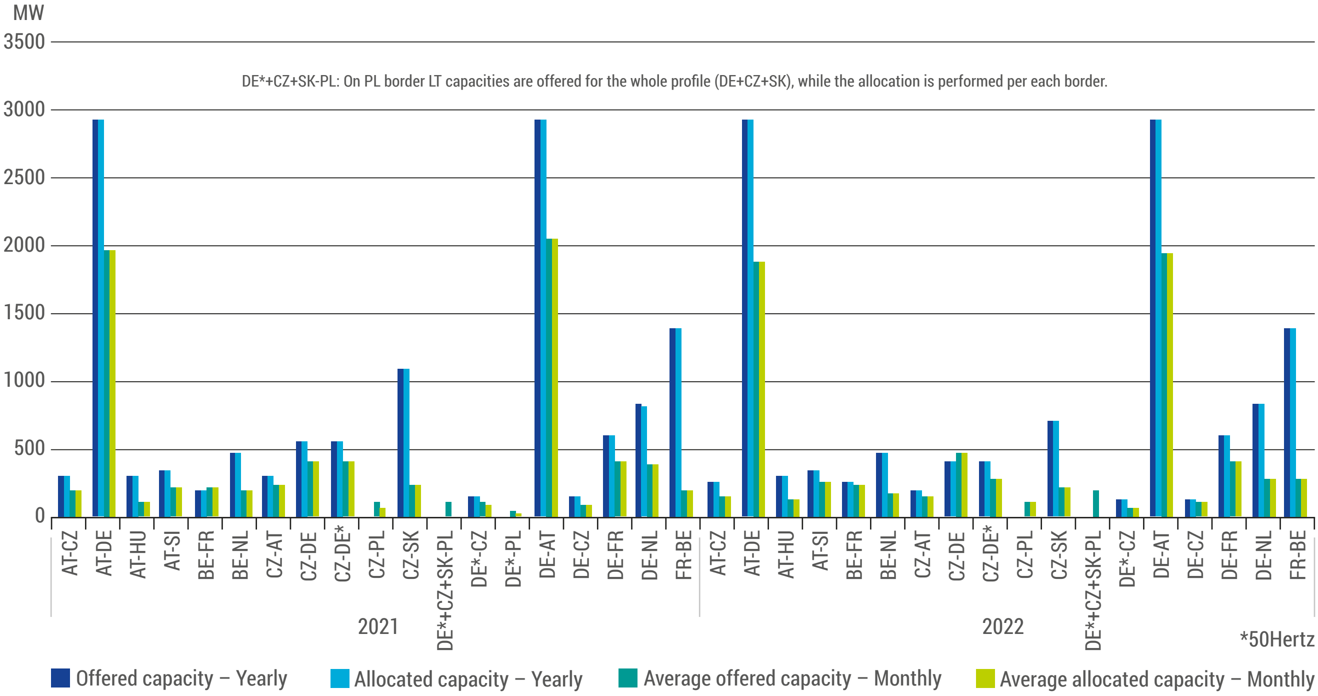



Figure 26: Core CCR: Offered and allocated long-term capacities during 2021 and 2022; Data source: **JAO**

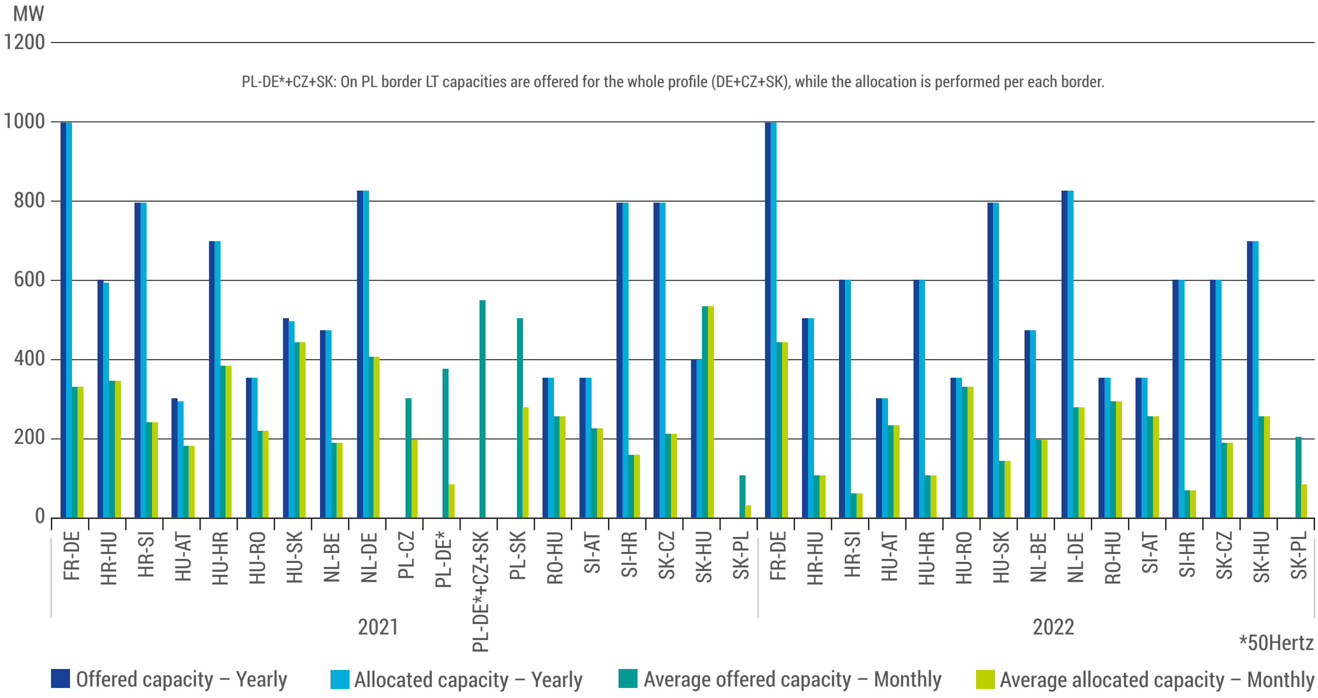



Figure 27: Core CCR: Offered and allocated long-term capacities during 2021 and 2022; Data source: **JAO**

31 Data source: **JAO**, excl. January-June 2021, September-November 2021, January-June 2022, August-December 2022, yearly 2021 and 2022 auctions for CZ-PL direction, April-June 2021, September-November 2021, January-May 2022, yearly 2021 and 2022 auctions for DE (50Hz)-PL direction, January-April 2021, June-November 2021, January-December 2022, yearly 2021 and 2022 auctions for PL-CZ direction, June-November 2021, January-May 2022, yearly 2021 and 2022 auctions for PL-DE(50Hz) direction, January-April 2021, June-November 2021, January-December 2022, yearly 2021 and 2022 auctions for PL-SK direction and January-June 2021, September-November 2021, January-June 2022, August-December 2022, yearly 2021 and 2022 auctions for SK-PL direction with 0 offered/allocated capacity.

32 Article 10 of the FCA regulation

## 3.4 Italy North

The capacity calculation process in the Italy North Region comprises the following TSOs: Austrian Power Grid AG (AT), ELES d.o.o (SI), Réseau de transport d'électricité (FR), TERNA Rete Elettrica Nazionale S.p.A (IT) and Swissgrid ag (CH).

The Italy North Region comprises the following BZBs:

- Italy NORD – France (NORD–FR), TERNA Rete Elettrica Nazionale S.p.A. and RTE– Réseau de transport d'électricité;
- Italy NORD – Austria (NORD–AT), TERNA Rete Elettrica Nazionale S.p.A. and Austrian Power Grid AG; and
- Italy NORD – Slovenia (NORD–SI), TERNA Rete Elettrica Nazionale S.p.A. and ELES d.o.o.

In addition to the abovementioned borders (constituting the Italy North CCR based on the ACER decision), the BZB Italy NORD – Switzerland (NORD–CH), TERNA Rete Elettrica Nazionale S.p.A. and Swissgrid is included in the capacity calculation of the Italy North Region.

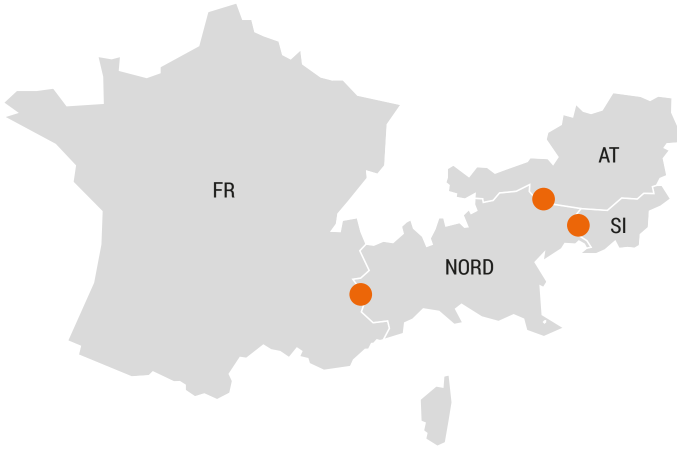



Figure 28: Italy North CCR.

### 3.4.1 Capacity calculation and allocation for the short-term

According to the CACM Regulation, the long-term objective for the Italy North Region will be to implement an FB capacity calculation methodology. In the meantime, the TSOs of the Region have developed and implemented methodologies based on the CNTC approach. In this methodology Swissgrid is technically fully included as a Technical Counterparty. This means that the border CH-IT is treated in the same manner as the other borders in the Italy North region from the technical perspective of Capacity Calculation.

#### DA market timeframe

Since February 2016, individual values for the CZC for each DA market time unit are being calculated using the coordinated capacity calculation methodology starting at day D-2.

In June 2018, the TSOs of the Region submitted a common methodology proposal to the NRAs for complementing the existing capacity calculation process in D-2. Following an amendment request from the NRAs, the TSOs submitted an amended proposal in March 2019 which was approved in October 2019. Furthermore, TSOs submitted an updated proposal compliant with the Regulation (EC) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), which was approved in July 2020.

The implementation timeline for the changes in the capacity calculation process is defined in the latest version of the methodology.

## ID market timeframe

In June 2018, the TSOs of the Region submitted a common methodology proposal to the NRAs for a coordinated capacity calculation methodology for the ID timeframe. Following an amendment request from the NRAs, the TSOs submitted an amended proposal in March 2019 which was approved in October 2019. Furthermore, TSOs submitted an updated proposal compliant with the Regulation (EC) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), which was approved in July 2020.

TSOs successfully implemented a first version of the ID Capacity Calculation process, which will be further upgraded, so that it meets the requirements defined in the ID Capacity Calculation Methodology. This process provides CZCs for the market time units 16h–24h since November 2019 and 12h–24h since February 2022. As soon as the ID coupling model developed in accordance with Articles 55 and 63 of the CACM regulation is implemented in the Italy North region, an additional capacity calculation will be implemented, which calculates the individual values for CZC for all 24 hours of the day in the evening of D-1. Further closed milestones are presented in table 21.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2016 | Go-live for the D-2 capacity calculation |
| Q2 2017 | Implementation phase and internal parallel run for the ID capacity calculation covering hours 16 h – 24 h for XBID2 auction. |
| Q3 2019 | External parallel run for the ID capacity calculation covering hours 16 h – 24 h for auction. |
| Q4 2019 | Go-live for the ID capacity calculation covering hours 16 h – 24 h for auction |
| Q4 2019 | Approval of first CCM version |
| Q3 2020 | Approval of updated CCMs including provisions from CEP by NRAs |
| Q2 2021 | Go-live of CNEC selection in D2CC and IDCC |
| Q2 2021 | Go-live of Daily Data Publication |
| Q4 2021 | Go-Live of Adjustment for Minimum Capacity in D2CC and IDCC |
| Q1 2022 | Go-Live of Allocation Constraint Removal in D2CC and IDCC |
| Q1 2022 | Go-Live of IDCCv1 Extension (12h - 24h) |
| Q4 2022 | Go-Live Handling PiSa HVDC in capacity calculation |

Table 20: Italy North CCR: Closed milestone(s) for short-term capacity calculation and allocation

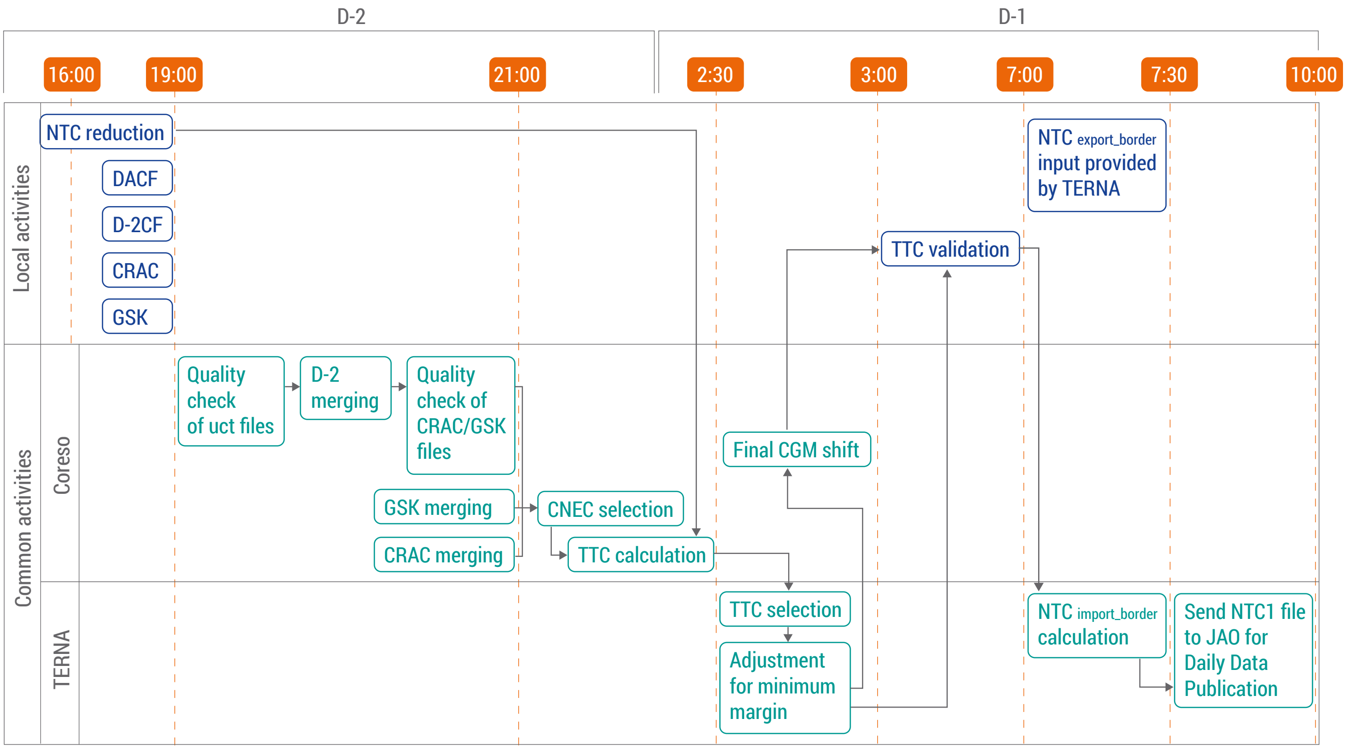
Italy North TSOs plan to restart the work on the drafting of a FB CCM after the completion of the implementation of the Export Corner[33] in the cNTC process.

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q4 2023 | Go-live of Export Corner – optimisation of CC process to include export direction |
| Q4 2024 | Go-live of IDCCv2 (additional capacity calculation in D-1 for 24h) |

Table 21: Italy North CCR: Planned milestone(s) for short-term capacity calculation and allocation

Figures 29 and 30 (page 35) are the high-level schemes with the steps needed and the roles involved in determining the capacity calculation for the DA and ID timeframes.

33 I.e. the common capacity calculation when at least one country is expected to be importing from Italy




General rule: If files are sent in the last five minutes before the deadline, the sender informs the receiver by email.

Figure 31: Italy North CCR: Roles of the entities involved, and input and output data in the capacity calculation process for D-2 and DA timeframes

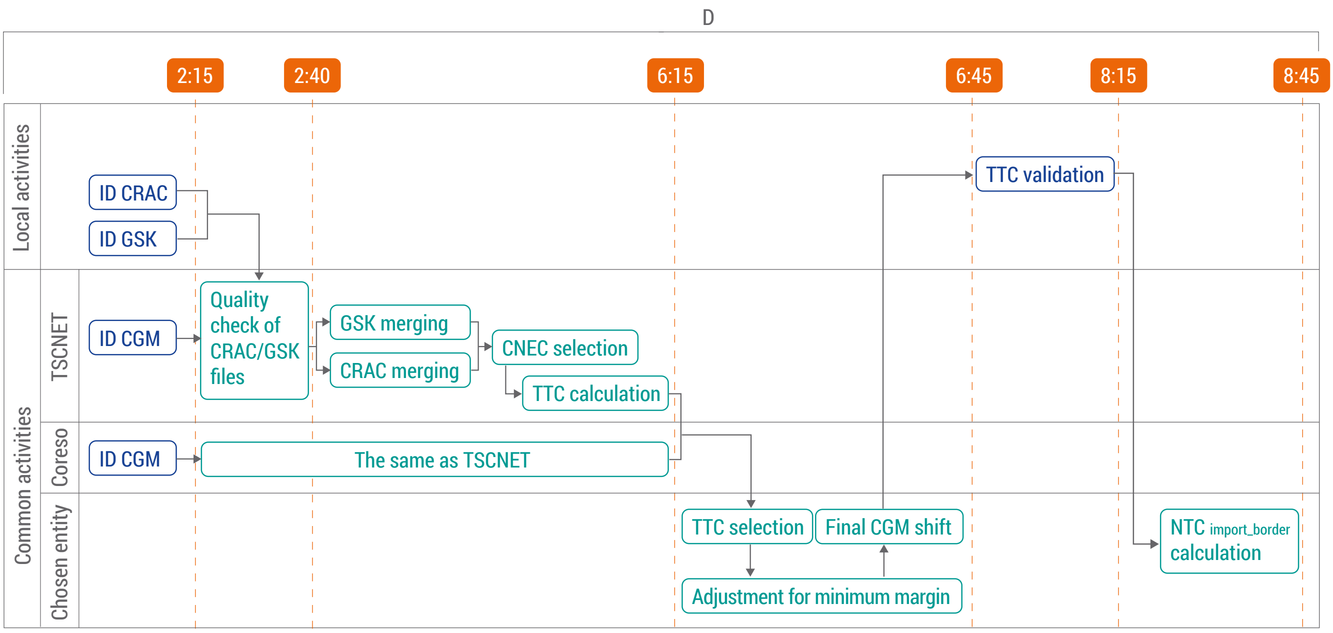



Figure 32: Italy North CCR: Roles of the entities involved, and input and output data in the capacity calculation process for ID timeframe

## Cross-zonal capacity calculation:

In this chapter a high-level description of the Italy North capacity calculation process is provided. For a more detailed explanation Italy North TSOs would like to reference the published capacity calculation methodologies and their explanatory notes[34].

### Input provision and quality check

The Italy North capacity calculation process, both for DA and ID, starts with the provision of the necessary input data by the TSOs. As input, the TSOs provide the following information to the CCC:

- IGM;
- Generation (and load) shift key (GLSK); and
- File containing all CNEs, remedial actions and additional constraints

The CCC subjects all provided input to a quality check and merges the individual files to inputs common to the regions which are then used in the subsequent processes.

### CNEC selection

The inputs are used by the CCC to compute the sensitivities with the help of the Power Transfer Distribution Factor (PTDF) for each CNEC. The list of CNECs is then filtered by removing all CNECs that do not meet the minimum Sensitivity threshold value to ensure that elements with a low sensitivity are not considered during the optimisation process. This filtered CNEC list is used for the next process steps.

### CZC calculations

The CZCs are computed by the CCC considering the following inputs:

- Outputs of the preceding sub-processes
- The TRM is a capacity margin needed for the secure operation of interconnected power systems considering the planning errors, including the errors caused by the forecast at the time the transfer capacities have been computed. Currently Italy North TSOs use a static TRM value which will be evaluated on a yearly basis and adjusted if required.

The CZCs are computed by the CCC, which performs an optimisation of the CZC considering the following constraints:

- The cross-border TTC assessment shall follow the methodological principles in the Methodical guidelines for stable operation in the Italy North CCR, as well as in national regulations and standards implemented and agreed in the Instruction for parallel operation in the Cross-Border Interconnections between TSOs involved, while considering the intra- and intersystem Operational Security.
- Methodical guidelines for stable operation in the Italy North CCR are used as a basis and reviewed by TSOs, to ensure the collective secure operation with neighbouring interconnected TSOs.
- The Cross-Border TTC shall be determined by the proceeding Contingency Analysis with respect of Operational Security Limits in the Italy North CCR and Control Area of Italy North TSOs.
- A Contingency Analysis is performed for those contingencies which are agreed among Italy North TSOs in the Contingency List. The Contingency List shall be agreed and provided among Italy North TSOs and to the CCC.
- If during the capacity calculation process the the CCCs determine different TTC values, the lowest value shall be used as a coordinated value.

34 See **here**

### Adjustment for Minimum Capacity

After computing the CZC it is checked whether they fulfil the minimum capacity according to Regulation (EU) 2019/943 (Article 16 paragraph 8), if the minimum capacity cannot be reached, counter-trading and redispatch, including cross-border redispatch, shall be used to maximise available capacities to reach the minimum capacity.

### TSO validation of CZCs

After the Adjustment for the Minimum Capacity process, the CCC submits the computed CZC to TSOs for validation. TSOs will check the system security for the proposed capacities and, in the event of an unsecure situation, perform one of the following actions to ensure the capacity is reduced to a secure value:

- Request a bilateral reduction of the CZC on one specific border; and
- Request a reduction of the total CZC calculated for the Northern Italian borders.

At the end of the validation process, the CCC considers the requests from reductions submitted by TSOs to reduce the capacity to the maximum secure value.

### Forwarding of validated CZC

After completion of the validation phase, the CZC will be forwarded to the allocation.

## 3.4.2 Indicators for the short-term

The capacity calculation methodology for ID and DA as described above has been implemented since 1 November 2021. Therefore, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022.

### Indicator for reliability margin

Table 22 shows the values of average TRM values per border for ID and DA in addition to their average percentage of TTC value (%). Those values indicate the discrepancies between the forecasts of the capacity calculation process and real time to ensure system security and uses historical data to be calculated:

| ID | | |
|---|---|---|
| Direction | Average TRM* (MW) | Percentage of TTC (%) |
| FR–IT | 219.7 | 8,32 |
| CH–IT | 217.7 | 7.71 |
| AT–IT | 15.1 | 5.61 |
| SI–IT | 47.5 | 8.5 |

| DA | | |
|---|---|---|
| Direction | Average TRM* (MW) | Percentage of TTC (%) |
| FR–IT | 219.7 | 7.57 |
| CH–IT | 217.7 | 7.2 |
| AT–IT | 15.1 | 5.24 |
| SI–IT | 47.5 | 7.47 |

Table 22: Italy North CCR: Average TRM and percentage of TTC for ID and DA timeframe (from 1 November 2021 to 31 December 2022); Data source: Italy North CCR; *bilateral values

## Indicator for available and allocated CZC

Table 23 shows average NTC values and also the values of maximum export and import capacities per BZ[35]:

| ID | | | |
|---|---|---|---|
| BZ | Average NTC [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) |
| IN | 1,079 / 454 | 1,864 / 7,664* | 2,223 / 7,670* |
| AT | 59 / 66 | 484 / 6,650* | 514 / 10,467* |
| FR | 175 / 174 | 2,223 / 15,209* | 1,864 / 18,355* |
| SI | 454 / 1,079 | 1,535 / 3,000* | 1,576 / 4,762* |

| DA | | | |
|---|---|---|---|
| BZ | Average NTC**** [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) |
| IN | –*** | 5,133 | 4,716 |
| AT | 263 / 98 | 399 / 3,515** | 146 / 3,832** |
| FR | 2,735 / 1,091 | 4,287 / 16,692** | 1,664 / 15,591** |
| SI | 603 / 642 | 966 / 3,262** | 680 / 3,532** |

Table 23: Italy North CCR: Average NTC values and maximum export/import capacity values for ID and DA timeframe; Data source: Transparency platform (ID) and OPSCOM Reports (DA); * Value includes the adjacent CCRs BZ capacities; ** Value includes the adjacent CCRs BZ capacities (from 9 June 2022 allocated capacity values were taken for Core BZBs) *** No CCR value is available due to the fact that value can be based only on joint IN–AT, IN–SI and IN–FR values. **** Considering OPSCOM reports comprise ATC values, the values provided are ATCs.

Until the end of February 2022 Italy North has considered Allocation Constraints within the DA & ID CC-processes. Since the end of February 2022, Italy North transferred the Allocation Constraint handling from DA & ID CC to the Allocation Process (Euphemia), since the Allocation process is out of scope of the DA & ID CC-processes in Italy North. Since then, TERNA sends on a daily basis an Allocation Constraint timeseries to Euphemia and DA & ID CC calculates the unconstraint capacity and provides it to Euphemia (for the coupled borders).

This update was an obligation coming from Italy North CCM[36] (and also from CACM), which defines that it is solely allowed to consider Allocation Constraints in the Allocation phase but not in the capacity calculation process. The update of the Allocation Constraint handling in February 2022 was another step towards the full CCM-compliance.

Table 24 provides the values of average external constraints in Italy North for 2 time periods: 01.11.2021–28.02.2022 and 01.03.2022–31.12.2022. An external constraint is used as an additional instrument to simulate constraints of the system that cannot be represented by CNECs used in capacity calculation.

| Period | Average External Constraints (MW) |
|---|---|
| 01.11.2021 – 28.02.2022 | 14,081 |
| 01.03.2022 – 31.12.2022 | 12,862 |

Table 24: Italy North CCR: Average external constraints for a short-term timeframe; Data source: Italy North CCR

## Indicators for the information used for capacity calculation

Table 25 (page 39) shows the percentage of time when the CNEC of a NTC calculation is not determined during capacity calculation. The reasons why this might happen are as follows:

- for DA: the main reason for the significant value is the high amount of TSO validation, which is done due to the current methodology of CGM creation. IN is currently investigating in the region the possibility of introducing a Net Position Forecast, which should then lower the amount of Validation cases once it is implemented. Expected time to be out into operation – earliest next year.
- for ID: the huge process fail rate can be explained by the fact, that IN had many issues on the RCC and TSO side. As the process timings in IDCC are much shorter than in DACC, the automation level is much higher and thus, operators frequently lack the time and possibility to fix such issues in the live process. IN is aware of that problem in the region and is working on solutions, e.g. defining default-input files in the event a TSOs fails in sending their input.

35 Directions in the table are expressed considering the perspective of the listed BZ
36 Find more info **here**

| ID | |
|---|---|
| Percentage of time, when a CNEC is not determined during capacity calculation [%] – Total | 73.37 |
| | in Details [%] |
| BackUp values due to process fail | 34.7 |
| ID Schedules | 6.66 |
| TSO Validation | 26.65 |
| Allocation Constraints (active in CC only until 14.02.2022) | 0.22 |
| Lack of remedial actions in order to ensure the requirement for minMargin | 0.15 |
| Smoothing ramp | 1.57 |
| Lack of GLSK margin | 3.42 |

| DA | |
|---|---|
| Percentage of time, when a CNEC is not determined during capacity calculation [%] – Total | 58.27 |
| | in Details [%] |
| BackUp values due to process fail | 8.93 |
| Lower TTC-cap | 10.90 |
| TSO Validation | 35.30 |
| Allocation Constraints (active in CC only until 14.02.2022) | 1.85 |
| Lack of remedial actions in order to ensure the requirement for minMargin | 0.41 |
| Smoothing ramp | 0.88 |

Table 25: Italy North CCR: Time when a CNEC is not determined during ID and DA capacity calculation (from 1 November 2021 to 31 December 2022)

## Indicator for assessing and following in the longer term the efficiency of single DA and ID coupling

Table 26 shows the efficiency of the current capacity calculation and allocation framework by multiplying Net positions (DA) and DA price: These values give an indication about the value the net import or export of a BZ has.

| BZ | 2021 | 2022 |
|---|---|---|
| | $\sum (NP_h \times DA_h)$, mln EUR | $\sum (NP_h \times DA_h)$, mln EUR |
| IN | −1,165 | −13,035 |
| AT | −996 | −3,819 |
| FR | −1,716 | −7,341 |
| SI | −101 | −867 |

Table 26: Italy North CCR: Efficiency of the current capacity calculation and allocation framework for 2021 and 2022 (from 1 November 2021 to 31 December 2022); Data source: OPSCOM reports

Figures 31, 32, 33 and 34 (page 40–41) show the implicit offered and allocated DA and ID capacities during January 2021 to December 2022 at the Italy North CCR internal borders, which are part of the Italy North CCR CCM in accordance with CACM regulation. The values are presented in box-plot diagrams to show the distributional characteristics of the data series. During the period covered in this report, Italy North borders FR–IT, AT–IT, SI–IT are coupled under SIDC since September 2021. Figures 35 and 36 (page 41) show the implicit offered and allocated ID capacities for the timeframe from 01 November 2021 to 31 December 2022.

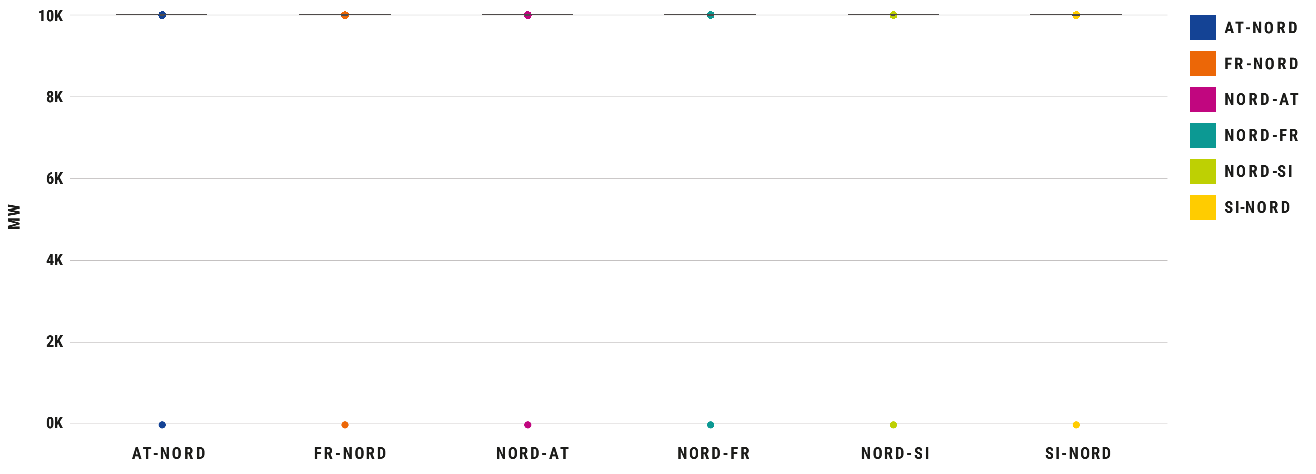



Figure 31: Italy North CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

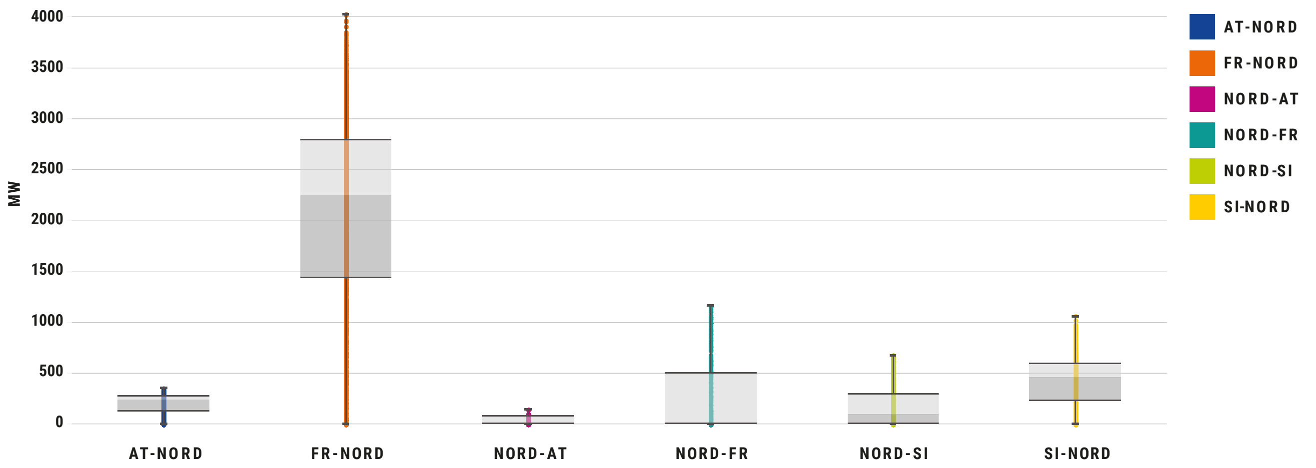



Figure 32: Italy North CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

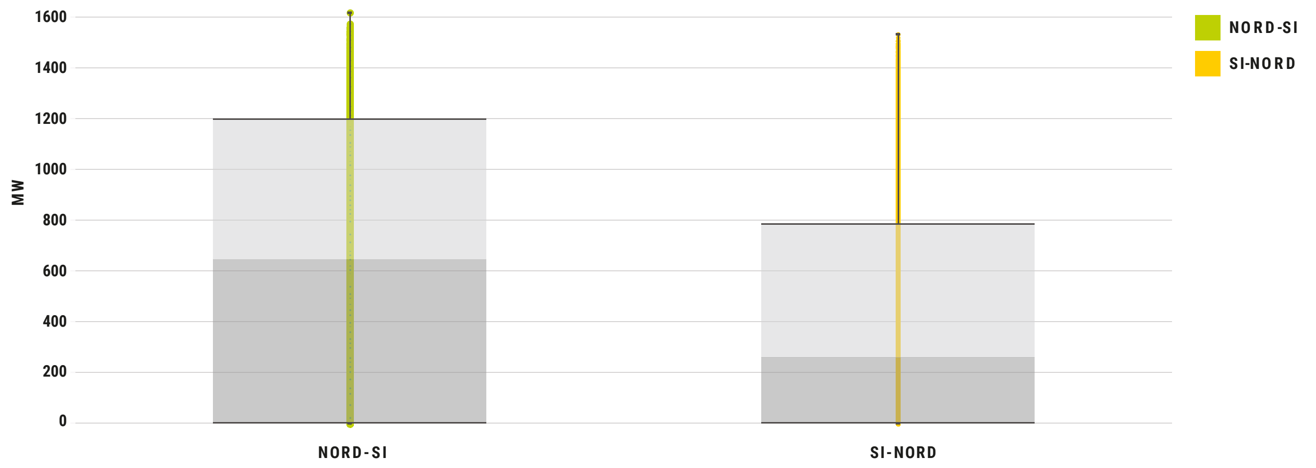



Figure 33: Italy North CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

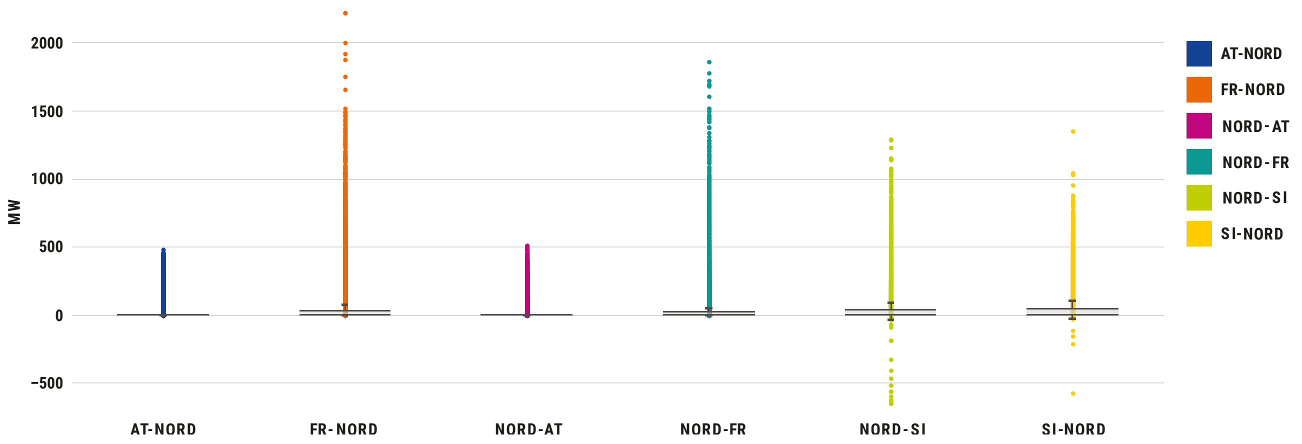



Figure 34: Italy North CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

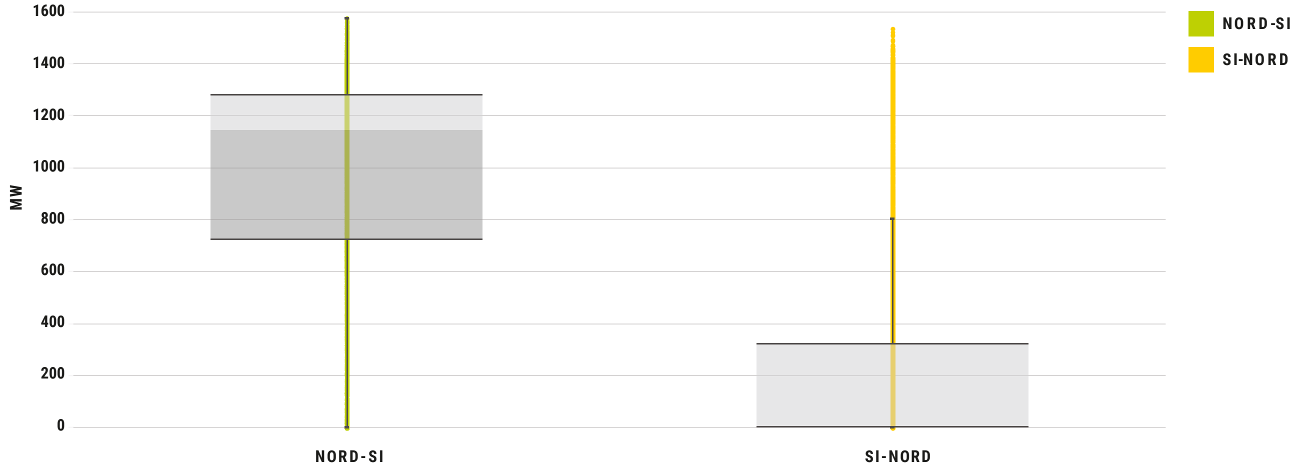



Figure 35: Italy North CCR: Implicit offered ID capacities (1 November 2021 – 31 December 2022); Data source: Transparency platform

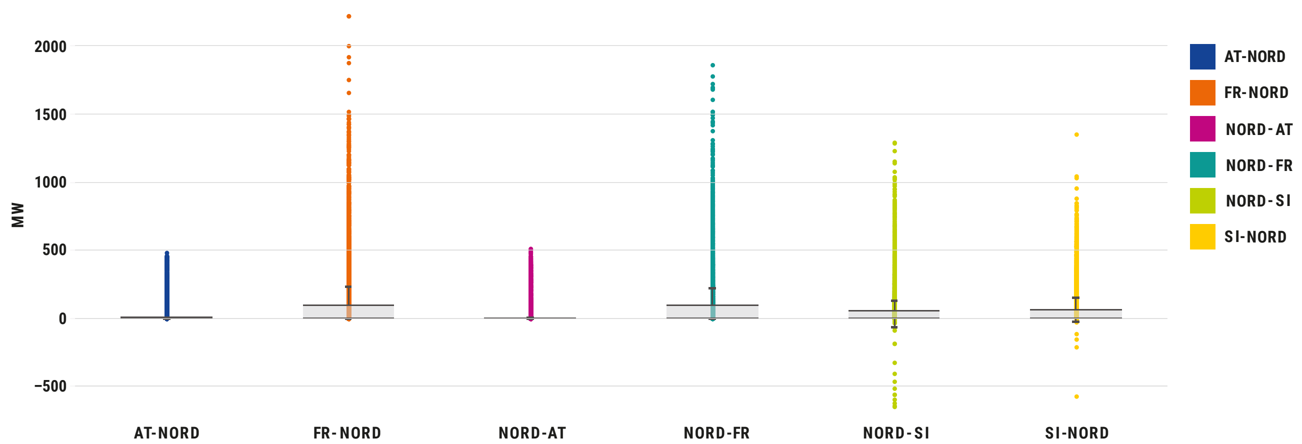



Figure 36: Italy North CCR: Implicit allocated ID capacities (1 November 2021 – 31 December 2022); Data source: Transparency platform

## 3.4.3 Capacity calculation and allocation for the long-term

In accordance with Article 10 seq. of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on Forward Capacity Allocation, Italy North has developed a methodology for long-term cross-zonal capacity calculation (LT CCM). The long term cross zonal capacity splitting rules across yearly and monthly timeframes in the export and import directions is done in accordance with Article 16 in the FCA Regulation. The process of long-term capacity splitting can be launched should the criteria defined in the Italy North Borders Long Term Capacity Splitting Methodology be met.

| Closed milestone(s) | |
|---|---|
| Quarter | Description |
| Q4 2020 | NRAs approved LTCC Methodology |
| Q4 2020 | NRAs approved LT CZC Methodology |
| Q4 2021 | LTCC yearly & monthly CC Go-Live (MVP) |

Table 27: Italy North CCR: Closed milestone(s) for long-term capacity calculation and allocation

| Planned milestone(s) | |
|---|---|
| Quarter | Description |
| Q2 2023 | IT Development & Testing of sub-module MVP |
| Q3 2023 | LTCC Monthly & Yearly Go-Live of Enduring Solution |

Table 28: Italy North CCR: Planned milestone(s) for long-term capacity calculation and allocation

Italy North uses a statistical approach based on historical CZC for DA or ID timeframes calculated in a coordinated manner, which is applied to properly consider all sources of uncertainty related to the long-term capacity calculation timeframes.

As input for the long-term capacity calculation timeframes, the latest available historical NTC values are used, coming from either the D-2 or ID CC which are based on the CNTC approach according to the D-2 & ID CCMs.

### Cross-zonal capacity calculation:

In this chapter, a high-level description of the Italy North long term capacity calculation process is provided. For a more detailed explanation, Italy North TSOs would like to reference the published capacity calculation methodologies[37]. The LTCC can be subdivided into the yearly and monthly capacity calculations.

#### Yearly Capacity Calculation Process

The yearly capacity calculation sub-process aims to define a long-term net transfer capacity value for each MTU. It is performed basing on the full-grid NTC values, one for each season, coming from the statistical analysis sub-process, which are eventually reduced according to:

- The planned outages reduction file given to the process as a conjunctural input; and
- The allocation constraints profile for each border and direction. Such reductions refer to maximum import values linked to voltage regulation and dynamic stability issues that happen during the so-called low consumption hours.

In addition, according to the criteria described in the methodology, the calculation considers the eventual New Grid Investments. This calculation shall result in an hourly profile that shall cover the entire year for which calculation is performed. The process shall be performed once a year.

37 Find more info **here**

## Input(s)

The input data for yearly capacity calculation includes:

- The yearly full grid NTC value file;
- Hourly bilateral planned outage reduction file provided by TSOs as conjunctural inputs;
- Hourly Allocation Constraints profiles for each respective border/direction; and
- The NTC reduction from the input provided by TSOs of each new grid investment that goes live in the business year.

## Yearly computation

The hourly profile for the final yearly bilateral NTCs is computed by picking the minimum between:

- The hourly bilateral NTC after the application of New Grid Investment additions and the NTC reduction file; and
- The hourly Allocation Constraints profile,

## Output(s)

For each hour and for each border/direction, the results, to be sent to TSOs for local validation, contain:

- Status of the calculation process ('failed' or 'successful');
- Value of the reference bilateral full-grid NTC for the corresponding season/period already considering the addition of New Grid Investments;
- Value of the bilateral NTC reduction according to the maintenance plan;
- Value of the corresponding allocation constraint; and
- Value of the yearly bilateral NTC.

Figure 37 depicts a high-level scheme with the steps needed and the roles involved in determining the capacity calculation for the yearly timeframe.

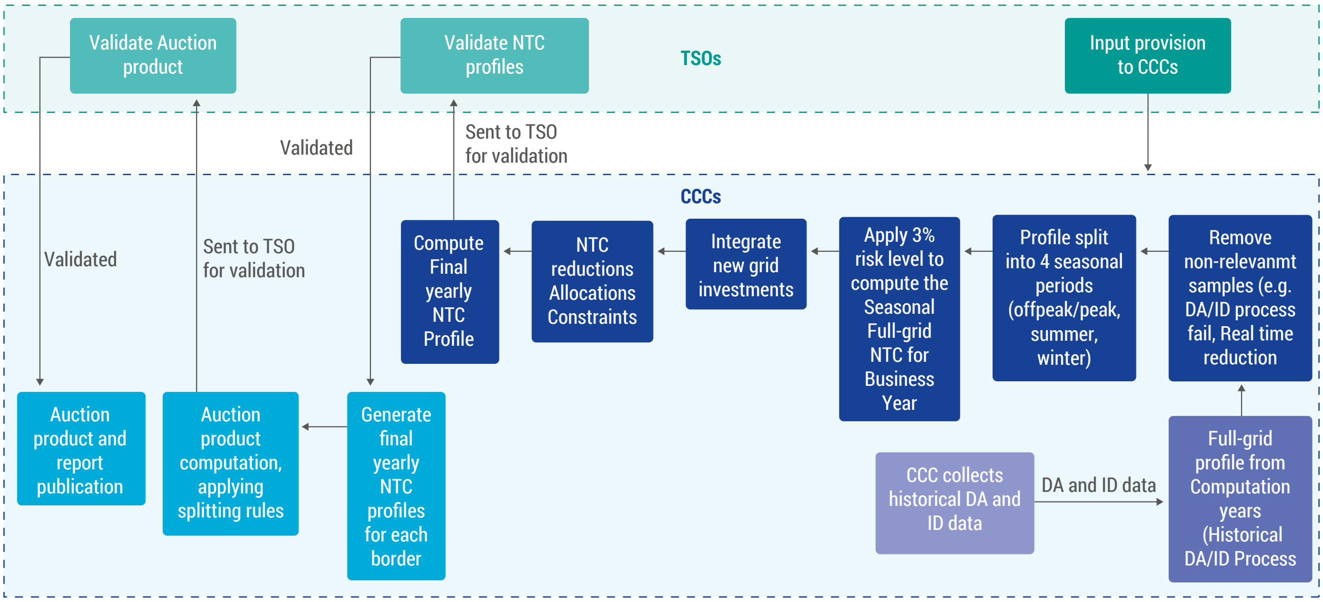



Figure 37: Italy North CCR: High-Level Business Process of the yearly capacity calculation

## Monthly capacity calculation process

The monthly capacity calculation sub-process aims to update the corresponding business month in the yearly NTC profile already calculated by the yearly capacity calculation sub-process. The full-grid NTC values from the statistical analysis sub-process are taken and reduced according to:

- The updated planned outage reduction file given to the LTCC Process as a conjunctural input, and
- The most updated allocation constraints profile for each border and direction.

In addition, according to the criteria described in the methodology, the calculation shall consider the update of eventual New Grid Investments. This process shall result in an hourly profile that shall cover the reference month, starting from the yearly. The process shall be performed for each month of the business year.

## New Grid Investment monthly computation

For each New Grid Investment that goes live in the business year on the generic border/direction, an hourly Investment Value profile is computed.

The monthly bilateral 'full grid' NTC value is computed as the value of the corresponding Seasonal Period already calculated in the yearly capacity calculation sub-process. The so-computed hourly profile for border is defined as hourly profile of the monthly NTC for each border/direction that considers the addition coming from New Grid Investments. The hourly NTC profile for border shall be modified according to the reductions per border provided as a conjunctural input.

## Monthly computation

The hourly profile for the final monthly bilateral NTCs is computed by picking the minimum between

- The hourly bilateral NTC after the application of New Grid Investment additions and the NTC reduction value
- The last updated hourly Allocation Constraints profile

## Output(s)

For each hour and for each border/direction, the results, to be sent to TSOs for local validation, contain:

- Status of the calculation process ('failed' or 'successful');
- Value of the reference bilateral full-grid NTC for the corresponding season/period S already considering the addition of New Grid Investments;
- Value of the bilateral NTC reduction according to the maintenance plan;
- Value of the corresponding allocation constraint; and
- Value of the monthly bilateral NTC.

Figure 38 depicts a high-level scheme with the steps needed and the roles involved in determining the capacity calculation for monthly timeframe.

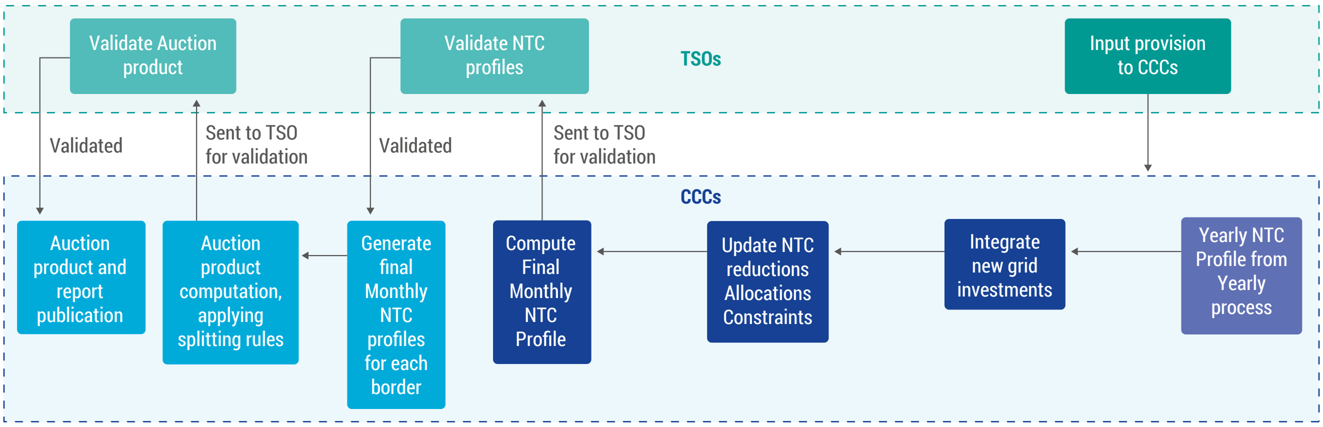



Figure 38: Italy North CCR: High-Level Business Process of the monthly capacity calculation

## Full NTC profile validation

To validate the final NTC values, TSOs will receive the output file from the CCC (treated as an input in the following flowchart). After validation, and eventually modifications and bilateral agreements on the final bilateral NTCs, each TSO shall send back to the CCC the final validated NTC profile with a proper reason for each timestamp where a reduction has been applied.

## 3.4.4 Indicators for the long-term

The capacity calculation methodology for the long-term as described above is implemented for the yearly and monthly auctions starting from January 2022. Therefore, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022.

The indicator on RM is not included in the report for the IN LTCC section. As explained in the previous section, this information is not used for the LT Capacity Calculation due to the statistical approach.

### Indicator for available and allocated CZC

Table 29 shows the values of average net transmission capacity (NTC), maximum export and import capacities (for each BZ individually):

| LONG-TERM | | | |
|---|---|---|---|
| BZ | Average NTC [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) |
| AT | 75 / 31 | 205 / 6,548* | 80 / 6,564* |
| FR | 751 / 162 | 2,168 / 7,748* | 1,190 / 4,523* |
| SI | 100 / 186 | 470 / 1,730* | 334 / 1,589* |

Table 29: Italy North CCR: Average NTC values and maximum export/import capacity values for long-term timeframe; Data source: **JAO**
* Value includes the adjacent CCRs BZ capacities

Table 30 provides an overview of the average external constraints used in Italy North. An external constraint is used as an additional instrument to model Italian import constraints of the system. Figure 39 shows the offered and allocated long-term capacities during 2021 and 2022 at Italy North CCR internal borders, which are part of the Italy North CCR Capacity Calculation Methodology in accordance with the FCA regulation.

| Month, 2022 | Average Allocation Constraint (MW) |
|---|---|
| 1 | 15,009.3 |
| 2 | 16,751.6 |
| 3 | 15,397.2 |
| 4 | 11,645.8 |
| 5 | 12,026.2 |
| 6 | 12,992.4 |
| 7 | 15,277.6 |
| 8 | 11,749.3 |
| 9 | 15,236.1 |
| 10 | 15,711.1 |
| 11 | 16,615 |
| 12 | 16,357.8 |

Table 30: Italy North CCR: External constraints values for the long-term timeframe

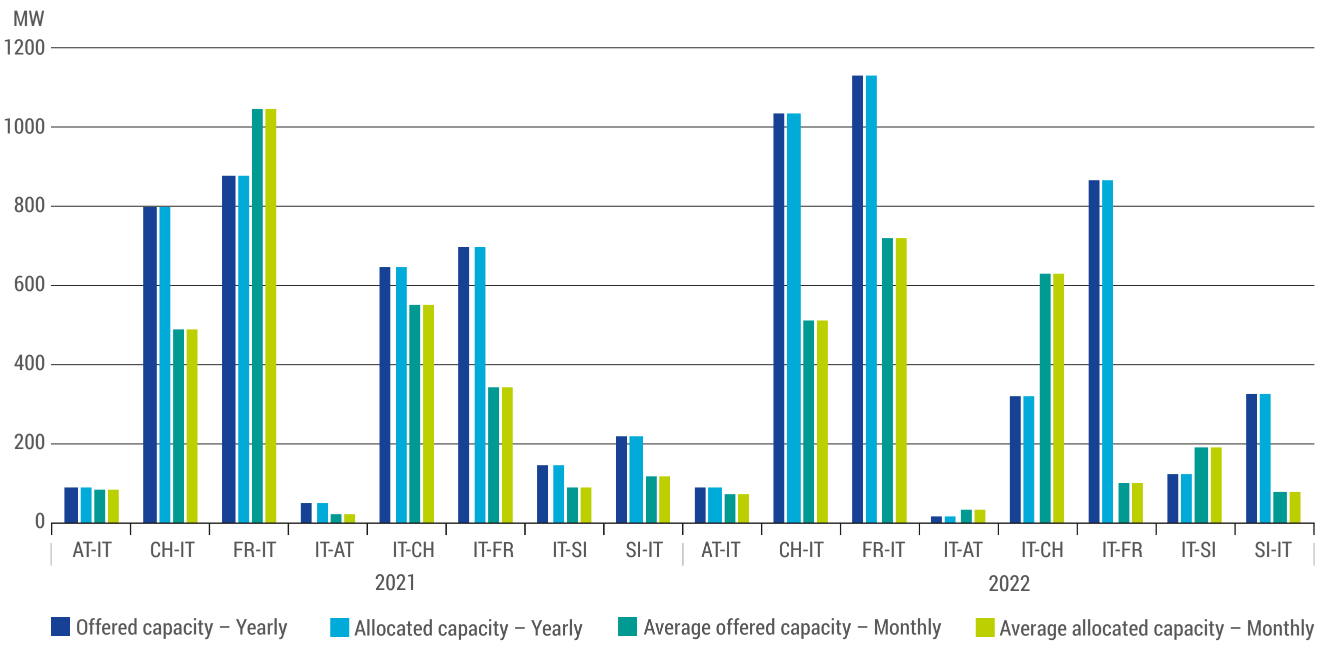



Figure 39: Italy North CCR: Offered and allocated long-term capacities during 2021 and 2022; Data source: **JAO**, excl. February–April 2022 and October 2022 for AT–IT direction and October 2022 for IT–AT direction with 0 offered/allocated capacity

# 3.5 Greece–Italy

The TSOs in Greece–Italy (hereafter referred to as 'GRIT') CCR are: Terna (IT) and IPTO (GR).


Figure 40: GRIT CCR. The Greece–Italy Region comprises the BZBs: Italy SUD–Greece (SUD–GR), Italy NORD–Italy CNOR (NORD–CNOR), Italy CNOR–Italy CSUD (CNOR–CSUD), Italy CNOR–Italy SARD (CNOR–SARD), Italy SARD–Italy CSUD (SARD–CSUD), Italy CSUD–Italy SUD (CSUD–SUD), Italy SUD–Italy CALA (SUD–CALA), Italy CALA–Italy SICI (CALA–SICI).

## 3.5.1 Capacity calculation and allocation for the short-term

The GRIT capacity calculation methodology for the DA and ID timeframes was approved by GRIT NRAs on 9 December 2020. For the DA and ID timeframes, the GRIT TSOs implement a cNTC approach.

Coherently with the 'Capacity calculation methodology for the DA and ID market timeframe for Greece-Italy CCR in accordance with Articles 20 and 21 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management' and due to the specificities of the GRIT CCR, GRIT TSOs will use the coordinated NTC approach to determine the cross-border capacities for each border of the GRIT CCR. This choice is mainly driven by the network structure of the GRIT Region, which is mainly 'non-meshed'.

Table 31 provides the overview of the already accomplished milestones timeline for the implementation of DA and ID capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q3 2017 | Submission of the GRIT DA CC methodology to the NRAs |
| Q1 2018 | Request for amendment of the CACM CC methodology for DA and ID timeframes received by the GRIT NRAs |
| Q2 2018 | The GRIT TSOs to re-submit amended CACM CC methodology proposal for DA and ID timeframes |
| Q3 2018 | The GRIT NRAs to approve the CACM DA and ID CC methodology (See **here**.) |
| Q4 2020 | The GRIT NRAs approved the CACM DA and ID CC methodology. |
| Q3 2021 | Go-Live DA capacity calculation. |
| Q4 2021 | Go-Live ID (10:00 D) capacity calculation |
| Q1 2022 | Submission of the GRIT BT CC methodology to the NRAs |
| Q4 2022 | Go-Live ID (22:00 D-1) capacity calculation. |

Table 31: GRIT CCR: Closed milestone(s) for DA and ID capacity calculation processes.

Figure 41 shows an overview of the ID and DA capacity calculation processes and responsibilities within the GRIT CCR.

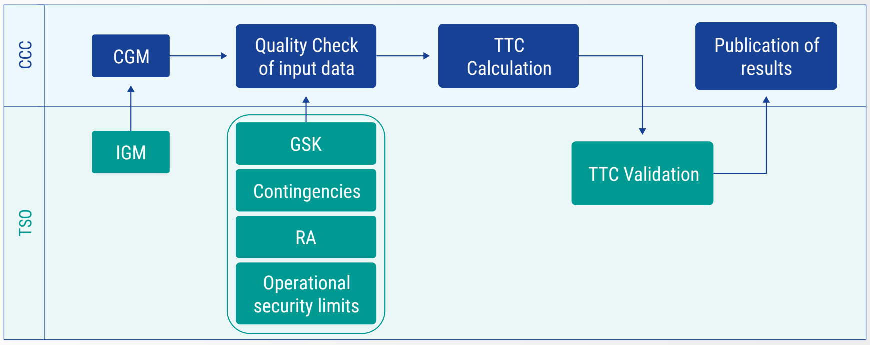



Figure 41: GRIT CCR: Data and role flow during the whole capacity calculation process for DA and ID timeframe

The cross-border TTC shall be determined by the proceeding contingency analysis complying Operational Security Limits in the GRIT CCR. If, during the capacity calculation process, the CCCs determine different TTC values, the lowest value shall be used as a coordinated value (only for the Greece – Italy SUD border).

The CCM is based on forecast models of the transmission system. Therefore, the outcomes are subject to inaccuracies and uncertainties. The TRM aims to cover these inaccuracies and uncertainties induced by those forecast errors.

Considering the technical details of the Greece-Italy border, which is an HVDC link, the TRM is considered equal to 0. Regarding the internal Italian borders, the TRM value on each border is set to 0MW as:

- Terna manages the power system using an Optimal Power Flow (hereafter 'OPF') function in real-time able to cope with potential cross-border congestions; and
- An assessment of the deviations between scheduled and realised flows confirmed that flow deviations could be reliably managed by the above-mentioned function.

After computing the CZC, the CCC submits the computed CZC to TSOs for validation. TSOs will check the system security for the proposed capacities.

At the end of the validation process the CCC considers the requests from reductions submitted by TSOs to reduce the capacity to the maximum secure value.

**Forwarding of validated CZC:** After completion of the validation phase, the CZC will be forwarded to the allocation.

## 3.5.2 Indicators for the short-term

The capacity calculation methodology for ID and day-head as described above is implemented since 3 August 2021 (DA) and 29 September 2021 (ID 2). Therefore, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022.

### Indicator for reliability margin

Considering the technical details of the GRIT border that is an HVDC link, the TRM is considered equal to 0.

Regarding the Italian internal borders, as already explained in the GRIT CCM Methodology, the TRM value on each border is set to 0 MW as the Italian TSO manages the power system using an Optimal Power Flow (OPF) function in real-time to cope with potential cross-border congestions.

## Indicator for available and allocated CZC

Table 32 shows the values of average total transmission capacity (TTC), maximum TTC and minimum TTC (for each BZB individually):

| ID (IDCC2) | | | | DA | | | |
|---|---|---|---|---|---|---|---|
| BZB | Average TTC (MW) | max TTC (MW) | min TTC (MW) | BZB | Average TTC (MW) | max TTC (MW) | min TTC (MW) |
| NORD-CNOR | 3,900 | 5,030 | 2,609 | NORD-CNOR | 3,836 | 5,133 | 2,681 |
| CNOR-NORD | 2,828 | 4,484 | 1,817 | CNOR-NORD | 2,887 | 4,716 | 1,834 |
| CNOR-CSUD | 2,483 | 3,505 | 1,005 | CNOR-CSUD | 2,531 | 3,620 | 1,058 |
| CSUD-CNOR | 2,982 | 3,937 | 1,525 | CSUD-CNOR | 3,012 | 4,103 | 1,427 |
| CSUD-SUD | 2,846 | 4,636 | 1,808 | CSUD-SUD | 2,779 | 4,707 | 1,803 |
| SUD-CALA | 1,346 | 2,216 | 300 | SUD-CALA | 1,343 | 2,299 | 300 |
| SUD-CSUD | 4,846 | 6,052 | 2,671 | SUD-CSUD | 4,845 | 5,767 | 2,589 |
| CALA-SICI | 1,352 | 1,602 | 100 | CALA-SICI | 1,364 | 1,644 | 100 |
| SICI-CALA | 1,276 | 1,707 | 100 | SICI-CALA | 1,269 | 1,843 | 100 |
| CALA-SUD | 2,220 | 2,350 | 600 | CALA-SUD | 2,229 | 2,585 | 600 |
| SUD-GREC | 443 | 500 | 0 | SUD-GREC | 420 | 500 | 0 |
| GREC-SUD | 443 | 500 | 0 | GREC-SUD | 420 | 500 | 0 |
| SARD-CSUD | 830 | 900 | 0 | SARD-CSUD | 811 | 900 | 0 |
| CSUD-SARD | 654 | 720 | 0 | CSUD-SARD | 645 | 720 | 0 |
| SARD-CNOR | 263 | 300 | 0 | SARD-CNOR | 266 | 300 | 0 |
| CNOR-SARD | 263 | 300 | 0 | CNOR-SARD | 266 | 300 | 0 |

Table 32: GRIT CCR: Average TTC values and maximum/minimum TTC values for ID and DA timeframe; Data source: GRIT TSOs

Table 33 (page 49) provides an overview of the average external constraints used in GRIT CCR. The external constraints provided refer to a max value for a certain border/direction linked to issues different from CNEC analysis.

| ID | | |
|---|---|---|
| Border | Direction | Average external constraints (MW) |
| SUD–CSUD | SUD -> CSUD | 4,491 |
| CALA–SUD | CALA -> SUD | 2,328 |
| SICI–CALA | SICI -> CALA | 518 |
| | CALA -> SICI | 481 |
| SUD–GREC | SUD -> GREC | 276 |
| | GREC -> SUD | 276 |
| CNOR–SARD | CNOR -> SARD | 240 |
| | SARD -> CNOR | 240 |
| SARD–CSUD | SARD->CSUD | 798 |
| | CSUD -> SARD | 638 |

| DA | | |
|---|---|---|
| Border | Direction | Average external constraints (MW) |
| NORD–CNOR | NORD -> CNOR | 3,722 |
| | CNOR -> NORD | 2,750 |
| CNOR–CSUD | CNOR -> CSUD | 2,551 |
| | CSUD -> CNOR | 2,674 |
| CSUD–SUD | CSUD -> SUD | 2,000 |
| | SUD -> CSUD | 4,635 |
| SUD–CALA | SUD -> CALA | 500 |
| | CALA -> SUD | 2,339 |
| CALA–SICI | CALA -> SICI | 392 |
| | SICI -> CALA | 406 |
| SUD–GREC | SUD -> GREC | 281 |
| | GREC -> SUD | 281 |
| CNOR–SARD | CNOR -> SARD | 266 |
| | SARD -> CNOR | 266 |
| SARD–CSUD | SARD -> CSUD | 811 |
| | CSUD -> SARD | 645 |

Table 33: GRIT CCR: Overview of the average external constraints for ID and DA timeframe; Data source: GRIT TSOs

## Indicators for the information used for capacity calculation

Table 34 shows the percentage of time when the CNEC of a NTC calculation is not determined during capacity calculation. The reason for this to happen is mainly linked to voltage constraints, additional constraints or IT issues.

| ID | | |
|---|---|---|
| Border | Direction | Percentage of time when CNEC is not determined ( %) |
| NORD–CNOR | NORD -> CNOR | 13.5 |
| | CNOR -> NORD | 6.5 |
| CNOR–CSUD | CNOR -> CSUD | 2.6 |
| | CSUD -> CNOR | 13.8 |
| CSUD–SUD | CSUD -> SUD | 4.3 |
| | SUD -> CSUD | 3.5 |
| SUD–CALA | SUD -> CALA | 0.7 |
| | CALA -> SUD | 87.1 |
| SICI–CALA | SICI -> CALA | 16.2 |
| | CALA -> SICI | 17.4 |
| SUD–GREC | SUD -> GREC | 0.6 |
| | GREC -> SUD | 0.6 |
| CNOR–SARD | CNOR -> SARD | 100 |
| | SARD -> CNOR | 100 |
| CSUD–SARD | CSUD -> SARD | 100 |
| | SARD -> CSUD | 100 |

| DA | | |
|---|---|---|
| Border | Direction | Percentage of time when CNEC is not determined ( %) |
| NORD–CNOR | NORD -> CNOR | 13.5 |
| | CNOR -> NORD | 4.9 |
| CNOR–CSUD | CNOR -> CSUD | 3.5 |
| | CSUD -> CNOR | 10.9 |
| CSUD–SUD | CSUD -> SUD | 3.9 |
| | SUD -> CSUD | 3.9 |
| SUD–CALA | SUD -> CALA | 1.2 |
| | CALA -> SUD | 85.2 |
| SICI–CALA | SICI -> CALA | 14.6 |
| | CALA -> SICI | 15.1 |
| SUD–GREC | SUD -> GREC | 0.5 |
| | GREC -> SUD | 0.5 |
| CNOR–SARD | CNOR -> SARD | 100 |
| | SARD -> CNOR | 100 |
| CSUD–SARD | CSUD -> SARD | 100 |
| | SARD -> CSUD | 100 |

Table 34: GRIT CCR: Time when a CNEC is not determined during ID and DA capacity calculation; Data source: GRIT TSOs

## Indicator for assessing and following in the longer term the efficiency of single DA and ID coupling

| BZ | 2021 | 2022 |
|---|---|---|
| | ∑ ($NP_h$ x $DA_h$), mln EUR | ∑ ($NP_h$ x $DA_h$), mln EUR |
| CALA | 671 | 2,718 |
| CNOR | −793 | −3,170 |
| CSUD | −1,659 | −6,247 |
| NORD | −2,640 | −13,035 |
| SARD | 221 | 1,099 |
| SICI | −381 | −274 |
| SUD | 1,388 | 5,402 |
| GR | −67 | −464 |

Table 35: GRIT CCR: Efficiency of the current capacity calculation and allocation framework (from 03 August 2021 to 31 December 2022); Data source: OPSCOM reports

Table 35 shows the efficiency of the current capacity calculation and allocation framework by multiplying Net positions (DA) and DA price: These values give an indication about the value the net import or export of a BZ has.

Figures 42, 43, 44 and 45 (page 50–51) show the offered and allocated DA and ID capacities during 2021 and 2022 at GRIT CCR internal borders, which will become part of the GRIT CCR CCM in accordance with CACM regulation. The values are presented in box-plot diagrams to show the distributional characteristics of the data series. Figures 46 and 47 (page 51–52) show the offered and allocated DA capacities during 03 August 2021 and 31 December 2022, and Figures 48 and 49 (page 52) show the offered and allocated ID capacities during 29 September 2021 and 31 December 2022.

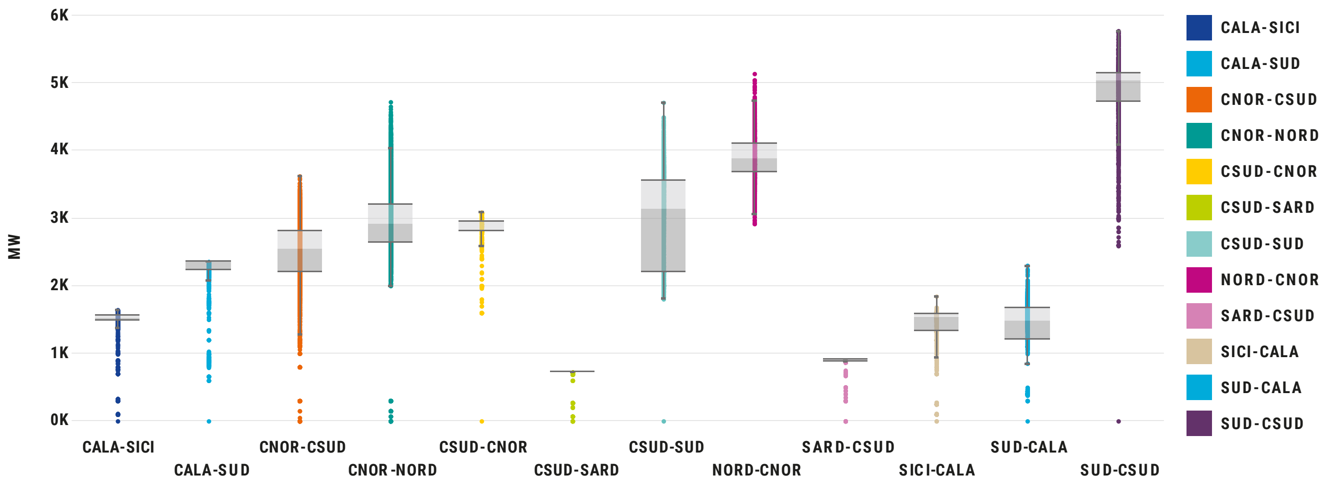



Figure 42: GRIT CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

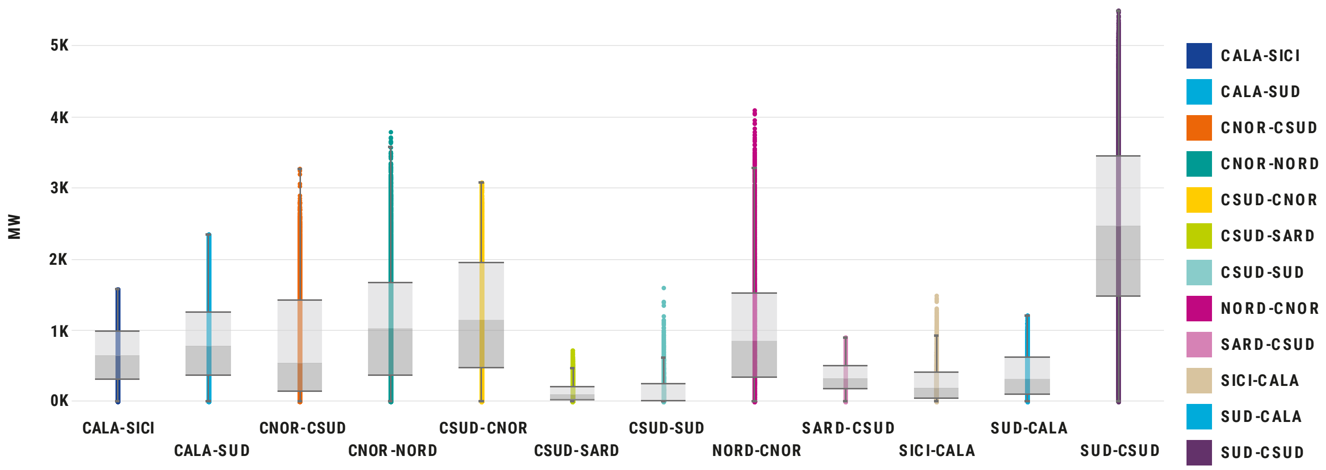



Figure 43: GRIT CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

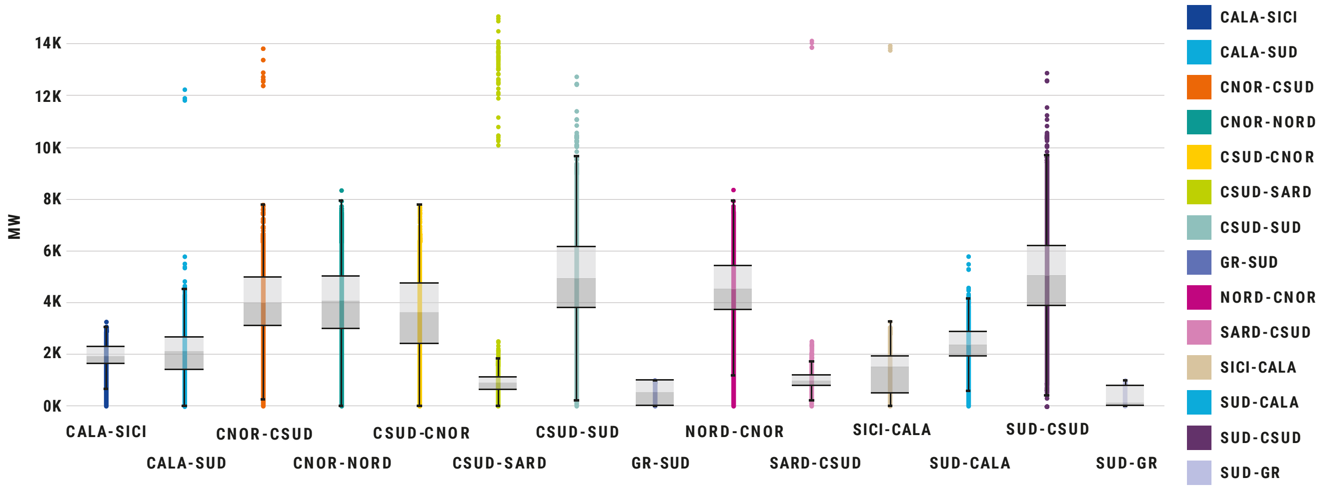



Figure 44: GRIT CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

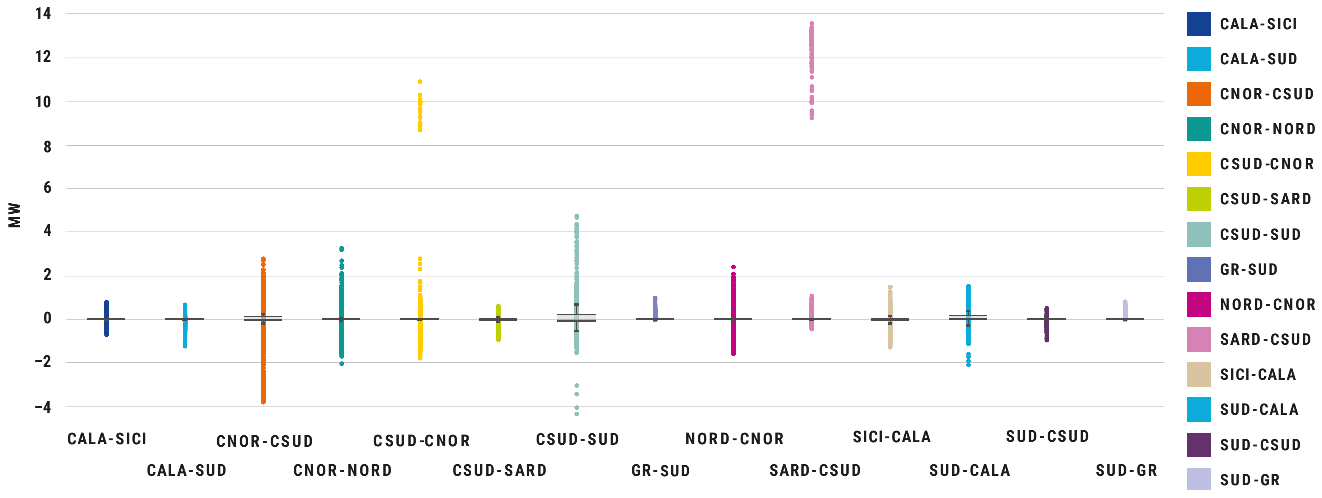



Figure 45: GRIT CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

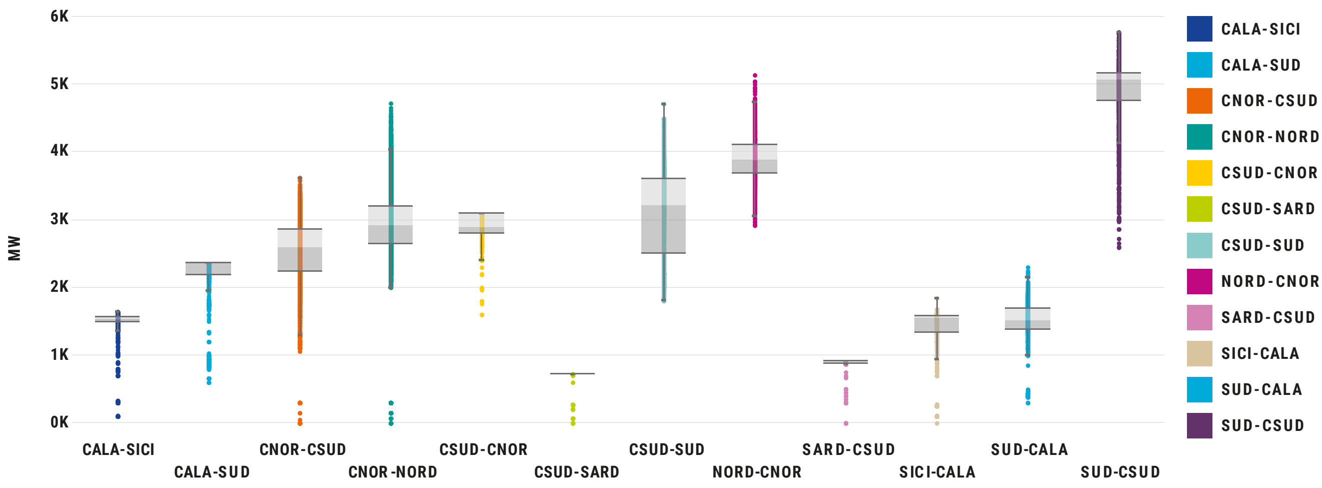



Figure 46: GRIT CCR: Implicit offered DA capacities (03 August 2021 – 31 December 2022); Data source: OPSCOM reports

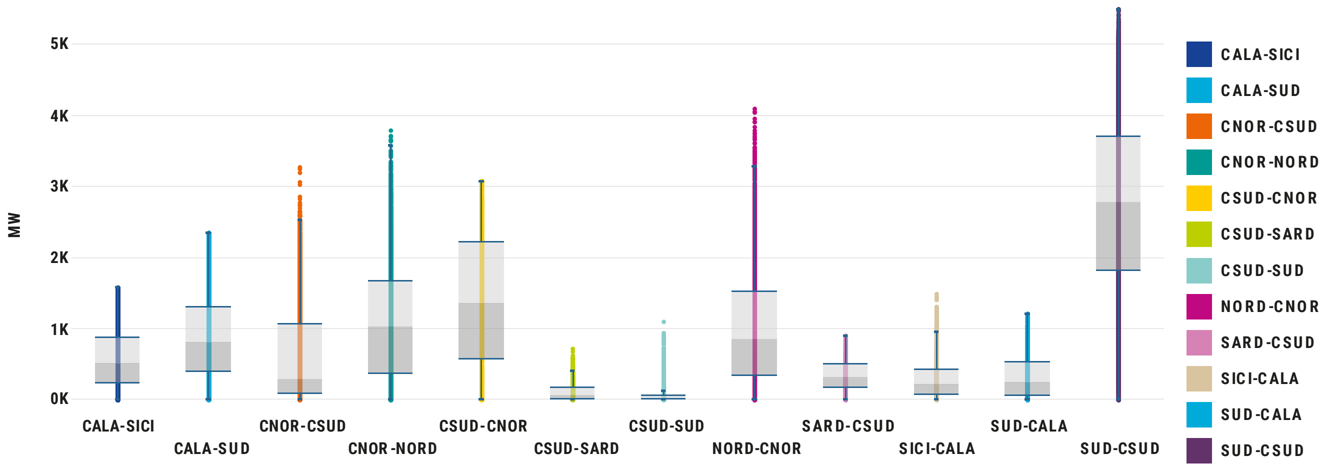



Figure 47: GRIT CCR: Implicit allocated DA capacities (03 August 2021 – 31 December 2022); Data source: OPSCOM reports

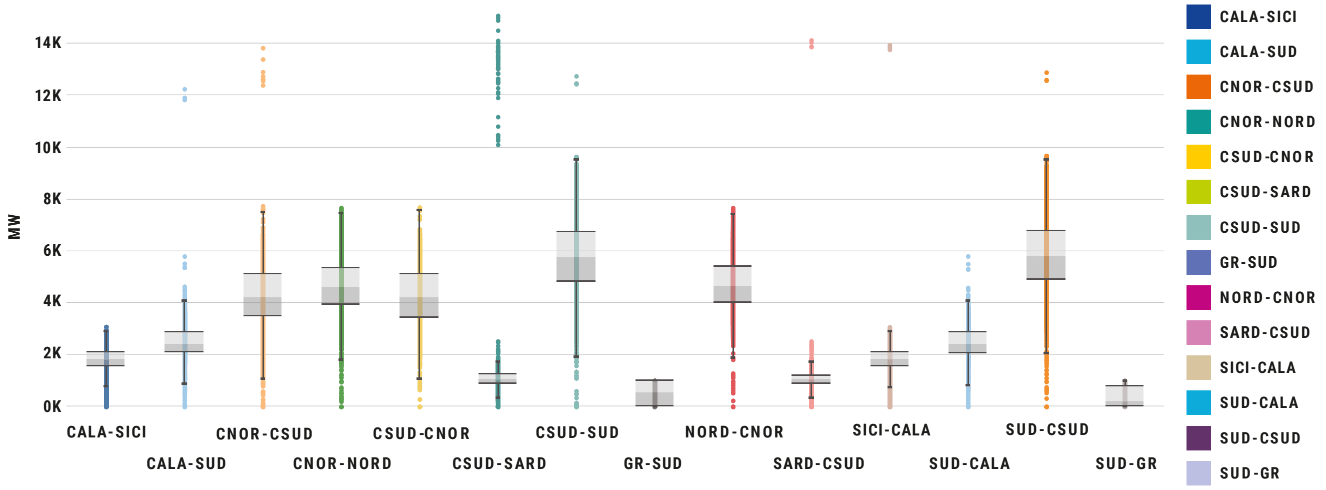



Figure 48: GRIT CCR: Implicit offered ID capacities (29 September 2021 – 31 December 2022); Data source: Transparency platform

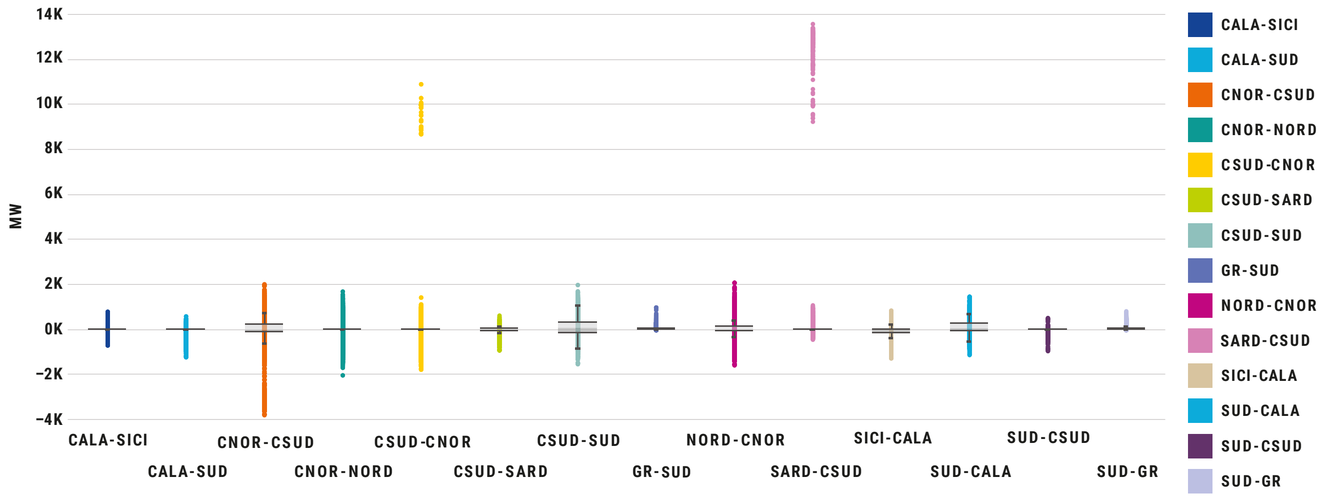



Figure 49: GRIT CCR: Implicit allocated ID capacities (29 September 2021 – 31 December 2022); Data source: Transparency platform

## 3.5.3 Capacity calculation and allocation for the long-term

The approved methodology provides that coordinated long-term capacity calculation and splitting will be go-live on 1 January of 2022. The capacity calculation methodology is based on the cNTC statistical approach.

Table 36 provides the overview of the already accomplished milestones for the implementation of the GRIT CCR long-term capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| Quarter | Description |
| Q4 2018 – Q1 2019 | Consultation of FCA long-term CC and splitting methodology based on CNTC approach (1 month) |
| Q1 2019 | Submission to GRIT NRAs of the long-term CC and splitting methodology |
| Q3 2019 | Request for amendment of the long-term CC methodology received by the GRIT NRAs. |
| Q4 2019 | The GRIT TSOs re-submitted the amended FCA LT CC methodology proposal. |
| Q1 2020 | The GRIT NRAs approved the FCA LT CC and splitting methodology. |
| Q3 2021 | Greece-Italy TSOs parallel run |
| Q4 2021 | Go-live long-term capacity calculation and allocation processes |

Table 36: GRIT CCR: Closed milestone(s) for long-term capacity calculation processes

Figure 50 provides an overview of the yearly long-term capacity calculation process:

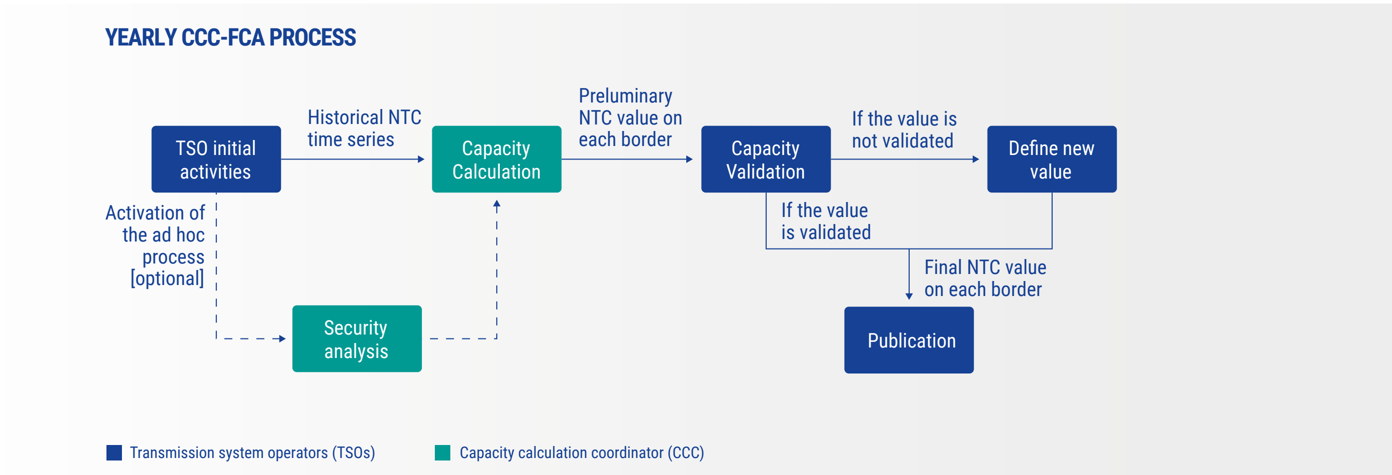



Figure 50: GRIT CCR: Data and role flow during the whole capacity calculation process for the yearly timeframe

The CCC of the GRIT CCR shall calculate two values of yearly CZC, respectively for peak and off-peak hours for the whole year for each Italian internal border/direction, corresponding to the maximum value between:

- The 50°percentile of the historical series (as a proxy of the expected value)
- The 10 % of the 95° percentile of the historical series (acting as a floor in case relevant long-lasting, exceptional events occurred in the past) increased, when relevant and if positive, of the difference between the TTC value computed according to 'Ad hoc' capacity calculation process and the 95°percentile of the historical series.

'Ad hoc' capacity calculation process is based on security analysis, activated only the event the relevant events are expected for the delivery period, which cannot be explained by historical series (e.g., multiple planned outages, commissioning of relevant new grid investments).

Figure 51 provides an overview of the monthly long-term capacity calculation process.

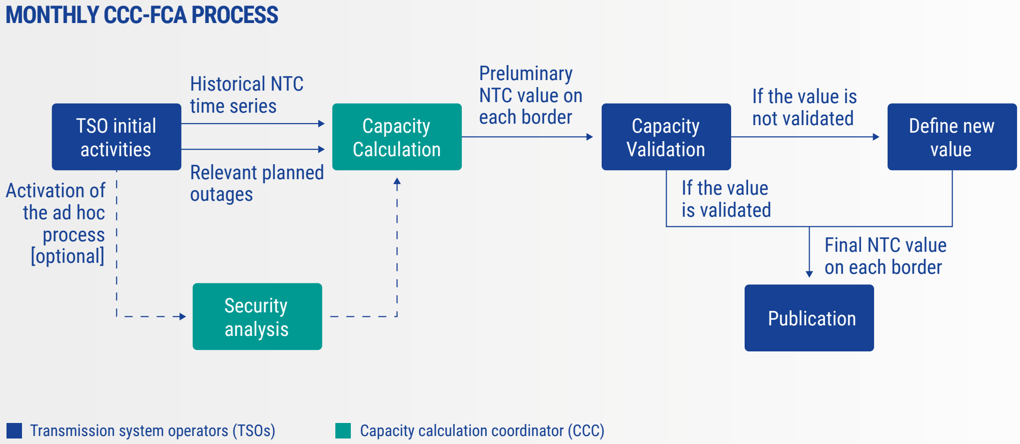



Figure 51: GRIT CCR: Data and role flow during the whole capacity calculation process for monthly timeframe

The CCC of the GRIT CCR shall calculate two values of monthly CZC for each day of the delivery month, respectively for peak and off-peak hours for each border/direction, corresponding to the minimum value between:

1. for each planned outage in the day that could impact CZC, the 50° percentile of the historical series considering only relevant hours in past when the same element was out of service;

2. the maximum value (this is a proxy of the expected maximum TTC value in case all grid elements are available) between:

   – the 95° percentile of the historical series of the hours of the same Season of the day under assessment;
   – when relevant, the TTC value computed according to 'Ad hoc' capacity calculation process.

3. when relevant, the TTC value computed according to 'Ad hoc' capacity calculation process (this act as a CAP in case multiple-outages, as never happened before, are expected)

The CCC of the GRIT CCR shall define the CZC for each hour of the delivering period (year/month) for the Greece–Italy SUD border corresponding to:

1. If the HVDC link is expected to be available, the 50°percentile of the historical series considering all hours of the last 2 years during which the cable was available.

2. If a planned outage of the HVDC link is scheduled in the delivery hour, the 50°percentile of the historical series considering all hours of the last 2 years during which the cable was unavailable.

For a more detailed explanation, GRIT TSOs would like to reference to the published Long-Term capacity calculation and splitting methodologies and their explanatory notes[37].

Once the yearly and monthly NTC profiles are computed, the validation can begin.

37 Find more info **here**

## 3.5.4 Indicators for the long-term

The capacity calculation methodology for long-term as described above is implemented for the yearly and monthly auctions starting from January 2022. Therefore, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022.

The indicators for reliability margin, average constraints and the percentage of time when the CNEC of a NTC calculation is not determined during capacity calculation are not included in the report for the GRIT LTCC section. As explained in the previous section, this information is not used for the LT Capacity Calculation due to the statistical approach.

### Indicator for available and allocated CZC

| LONG-TERM | | | |
|---|---|---|---|
| BZ | Average NTC [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) |
| GR | 418 / 418 | 500 | 500 |

Table 37: GRIT CCR: Average NTC values and maximum export/import capacity values for long-term timeframe. Data source: JAO

Table 37 shows the values of average net transmission capacity (NTC), maximum export and import capacities (for each BZ individually):

Figure 52 shows the offered and allocated long-term capacities during 2021 and 2022 at GRIT CCR internal borders, which will become part of the GRIT CCR CCM in accordance with FCA regulation.

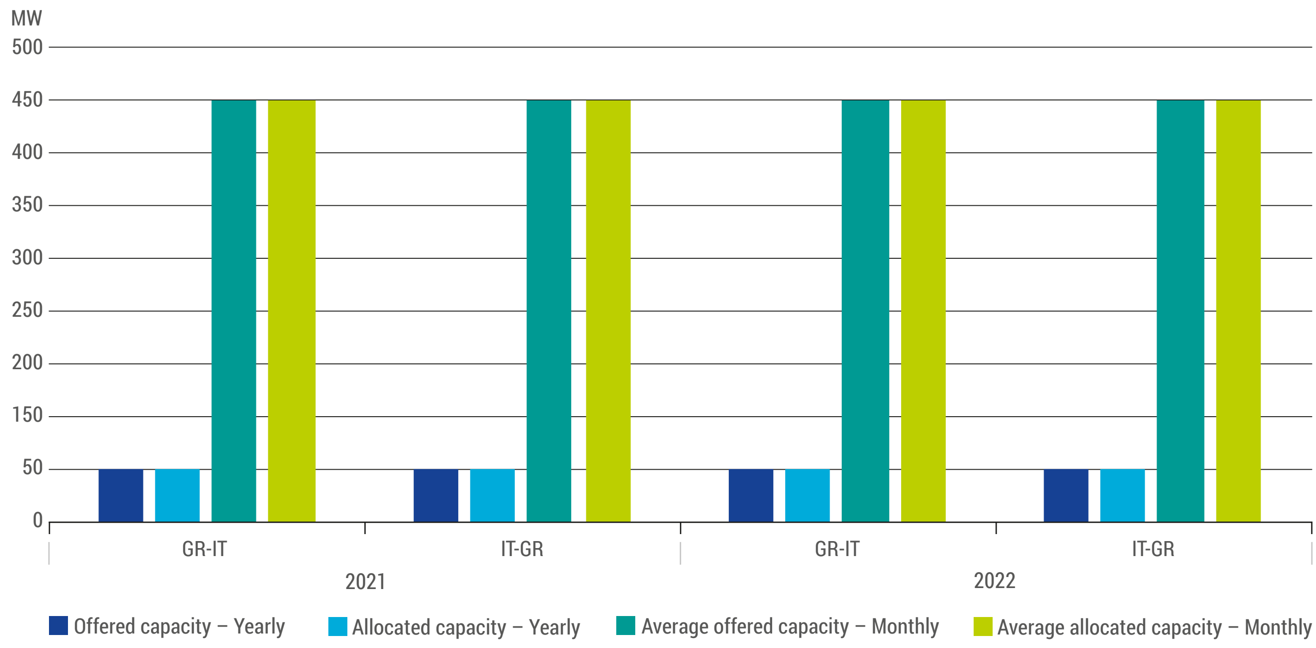



Figure 52: GRIT CCR: Offered and allocated long-term capacities during 2021 and 2022. Data source: JAO, excl. September 2021 for GR-IT and IT-GR directions with 0 offered/allocated capacity

# 3.6 South-West Europe

The TSOs in the South-West Europe (SWE) CCR are RTE (FR), REE (ES) and REN (PT).

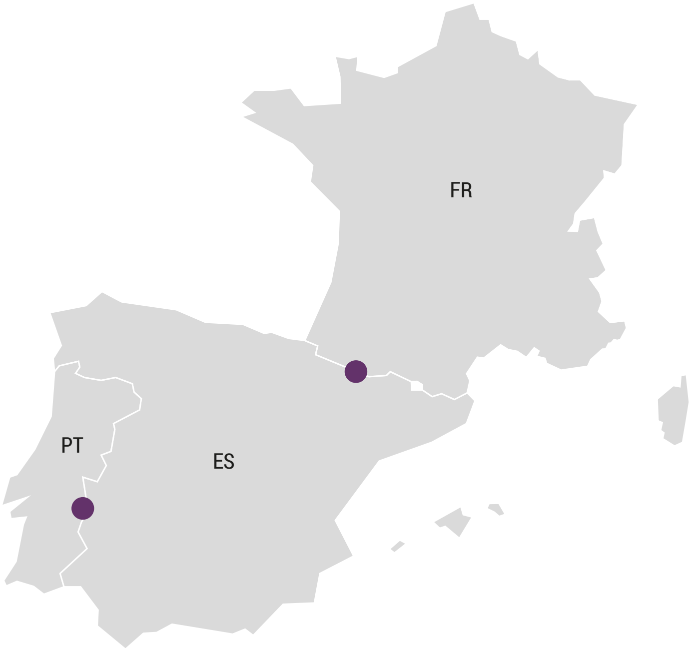



Figure 53: South-West Europe CCR. This CCR includes the following BZBs: Portugal – Spain (PT–ES) and Spain – France (ES–FR).

## 3.6.1 Capacity calculation and allocation for the short-term

SWE NRAs approved the SWE CCM for the DA and ID timeframes in November 2018.

For the DA timeframe, the SWE CCR TSOs implemented a cNTC approach in January 2020. Concerning the ID capacity calculation 1st run, the SWE CCR TSOs implemented a cNTC approach in March 2022.

The high-level capacity calculation process for the DA timeframe is shown in Figure 54 (page 57). The figure identifies the roles of the entities involved and the input and output data in the capacity calculation process. This capacity calculation process also applies on the ID timeframe.

The CGM used in the capacity calculation for this period is a SWE regional CGM, which resulted from the three TSOs merging their respective IGMs. Both the IGMs and the CGM were created using the CGMES. SWE was the first CCR to implement this format in an operational capacity calculation process.

In line with Paragraph 7 of Article 20 of the CACM regulation a study was performed in 2017 for the SWE CCR to justify the application of a cNTC methodology. This study is still considered valid as there have been no significant changes in French, Portuguese, and Spanish grids since 2017.

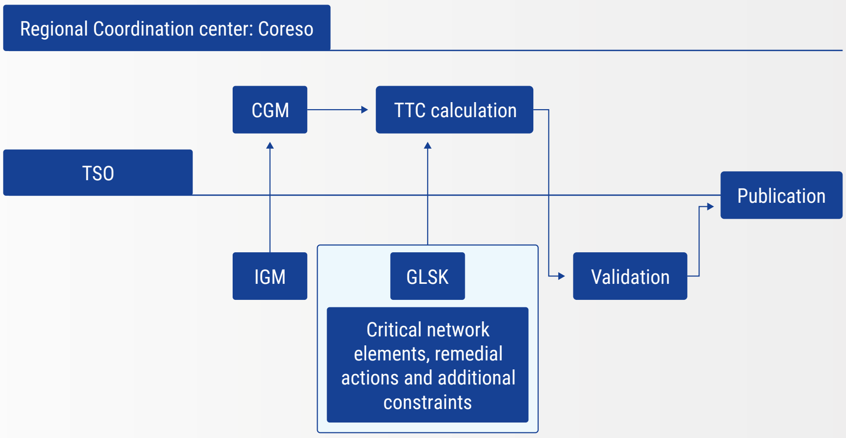



Figure 54: SWE CCR: Input and output data and roles of the entities in the capacity calculation process for the DA and ID timeframes

At the time of writing of this report, the following milestone is planned for SWE CCR:

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2024 | Go-live of the ID capacity calculation 2nd run |

Table 38: SWE CCR: Planned milestone(s)

## 3.6.2 Indicators for the short-term

The following indicators provide an evaluation of the results of the utilisation of the SWE regional CCM in the DA timeframe between 1 January 2021 and 31 December 2022.

For the ID timeframe the following indicators provide an evaluation of the results between 15 March 2022 (Go-live date) and 31 December 2022.

### Indicator for reliability margin

The following TRM values have been applied according to the SWE CCR's CCM:

- For the FR–ES border, in both directions, the RM for the capacity calculation performed on D-2 is calculated as the maximum value between 200 MW, covering the unintended deviation part of the RM, and 7.5 % of the TTC value, covering the uncertainties of the forecast part of the RM
- For the ES–PT border, in both directions, the RM for the capacity calculation performed on D-2 and on DA is calculated as the maximum value between 100 MW, covering the unintended deviation part of the reliability margin, and 10 % of the TTC value, covering the uncertainties of the forecast part of the RM

Table 39 shows the values of average TRM per border/direction or profile/direction (if applicable) and timeframe (in MW), and also as a percentage of Total Transfer Capacity (TTC) value ( %):

| ID | | | |
|---|---|---|---|
| **Border** | **Direction** | **Average TRM (MW)** | **Percentage of TTC ( %)** |
| France-Spain (FR–ES) | FR -> ES | 234 | 9 |
| | ES -> FR | 213 | 10 |
| Portugal-Spain (PT–ES) | PT -> ES | 300 | 10.2 |
| | ES -> PT | 400 | 10.1 |

| DA | | | |
|---|---|---|---|
| **Border** | **Direction** | **Average TRM (MW)** | **Percentage of TTC ( %)** |
| France-Spain (FR–ES) | FR -> ES | 244 | 8.2 |
| | ES -> FR | 219 | 9.4 |
| Portugal-Spain (PT–ES) | PT -> ES | 338 | 10.1 |
| | ES -> PT | 415 | 10.1 |

Table 39: SWE CCR: Average TRM and percentage of TTC for ID and DA timeframe; Data source: SWE CCR

## Indicator for available and allocated CZC

This indicator compares the effectively allocated capacity in relation to the offered capacity in both DA, according to the SWE CCM, and ID timeframes, considering the arithmetic mean of hourly results. Specifically, the ID timeframe indicator for the SWE CCR covers the aggregated capacity allocated within Iberian CRIDAs and net allocation within the continuous ID market. For the ID continuous market, only the hourly net allocation is considered, although for a single hour, several exchanges could have been established in both directions of the interconnection.

| Timeframe/BZB | FR–ES | PT–ES |
|---|---|---|
| DA | 84.95 % | 37.29 % |
| ID | 20.98 % | 16.14 % |

Table 40: SWE CCR: Allocated capacity in relation to offered capacity for DA and ID timeframes; Data source: SWE CCR

Tables 41 and 42 show the values of average NTC, maximum export and import capacities (for each BZ individually):

| ID | | |
|---|---|---|
| BZB | Direction | Average NTC (MW) |
| France–Spain | FR->ES | 2,657 |
| | ES->FR | 2,209 |
| Portugal–Spain | PT->ES | 2,696 |
| | ES->PT | 3,603 |

| DA | | |
|---|---|---|
| BZB | Direction | Average NTC (MW) |
| France–Spain | FR -> ES | 2,875 |
| | ES -> FR | 2,387 |
| Portugal–Spain | PT -> ES | 3,041 |
| | ES -> PT | 3,732 |

Table 41: SWE CCR: Average NTC values for ID and DA timeframe; Data source: SWE CCR

| ID – Per BZ | | |
|---|---|---|
| | Max Export (MW) | Max Import (MW) |
| Portugal | 4,545 | 5,490 |
| Spain | 8,742 | 8,111 |
| France | 3,838 | 3,792 |

| DA – Per BZ | | |
|---|---|---|
| | Max Export (MW) | Max Import (MW) |
| Portugal | 4,590 | 5,559 |
| Spain | 8,466 | 8,155 |
| France | 3,885 | 3,885 |

Table 42: SWE CCR: Maximum export and import capacity values for ID and DA timeframe; Data source: SWE CCR

## Indicators for the information used for capacity calculation

Table 43 shows the percentage of time when the CNEC of a NTC calculation is not determined during capacity calculation (e.g. due to stability limits):

| ID | | |
|---|---|---|
| Border | Direction | Percentage of time when CNEC is not determined (%) |
| France–Spain | FR -> ES | 54 |
| | ES -> FR | 27 |
| Portugal–Spain | PT -> ES | 33 |
| | ES -> PT | 38 |

Table 43: SWE CCR: Time when a CNEC is not determined during ID capacity calculation; Data source: SWE CCR

DA – Table 44 shows the number of CNEC not identified and CNEC fallback due to the following reasons:

- IT issue (lead to NTC Long term values as backup solution);
- Alternating Current load-flow divergence;
- CNE not provided (process failed); and
- Allocation constraint (only in ES–PT border).

Since 2022 a fallback CNEC has been applied for a 70 % CEP monitoring purpose to compute the MACZT as detailed in the South-West Europe TSOs common capacity calculation methodology for the DA and ID market timeframe[38].

38 Find more info **here**

| DA | | |
|---|---|---|
| Border | Direction | Percentage of time when CNEC is not determined (%) |
| France–Spain | FR -> ES | 22 |
| | ES -> FR | 10 |
| Portugal–Spain | PT -> ES | 19 |
| | ES -> PT | 17 |

Table 44: SWE CCR: Time when a CNEC is not determined during DA capacity calculation; Data source: SWE CCR

## Indicator for assessing and following in the longer term the efficiency of single DA and ID coupling

Table 45 shows the efficiency of the current capacity calculation and allocation framework by multiplying Net positions (DA) and DA price.

| BZ | 2021 | 2022 |
|---|---|---|
| | $\sum (NP_h \times DA_h)$, mln EUR | $\sum (NP_h \times DA_h)$, mln EUR |
| ES | −255 | 2,461 |
| PT | −429 | −1,237 |
| FR | 38 | −7,341 |

Table 45: SWE CCR: Efficiency of the current capacity calculation and allocation framework; Data source: OPSCOM reports

Figures 55, 56, 57 and 58 (page 59–60) show the offered and allocated capacities in the DA timeframe as well as offered and allocated capacities in the ID timeframe during 2021 and 2022 at PT-ES and FR-ES borders, which are part of the SWE CCR Capacity Calculation Methodology in accordance with CACM regulation. The values are presented in box-plot diagrams to show the distributional characteristics of the data series. Figure 59 and 60 (page 61) show the offered and allocated capacities in the ID timeframe during 15 March 2022 and December 2022.

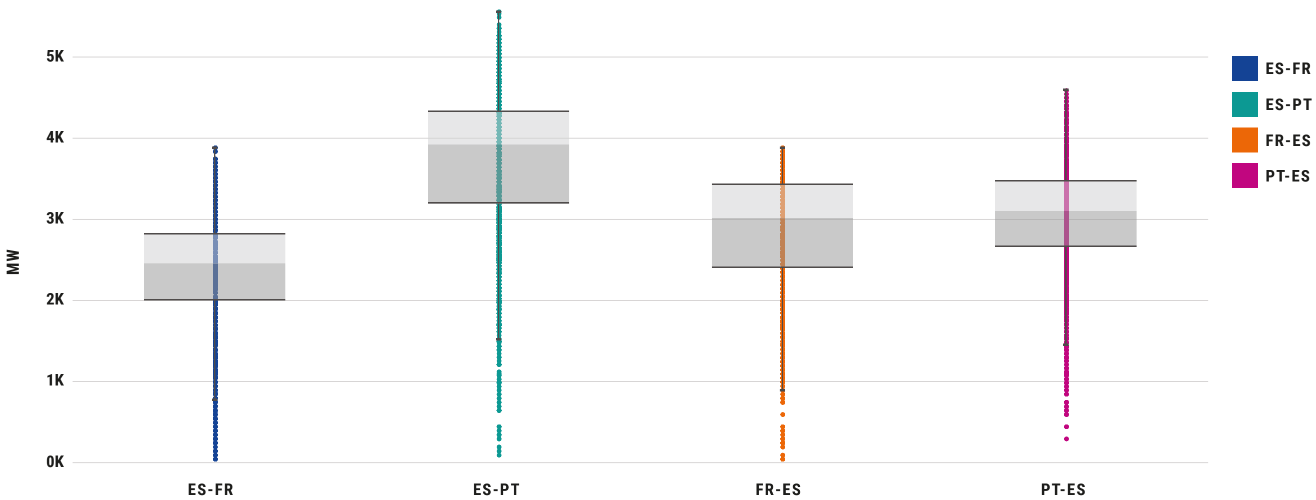



Figure 55: SWE CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

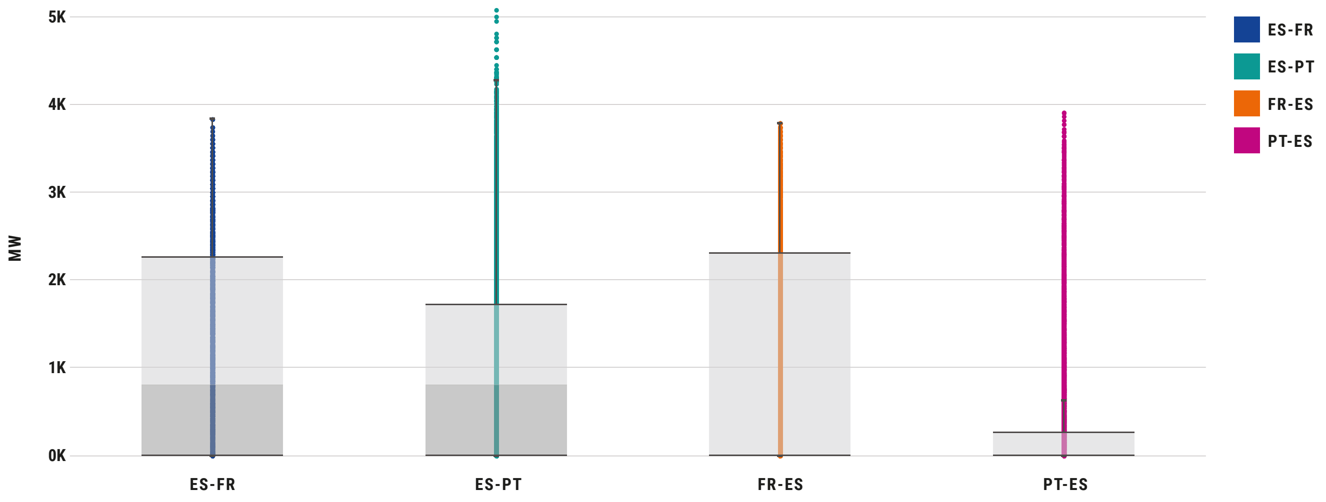



Figure 56: SWE CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

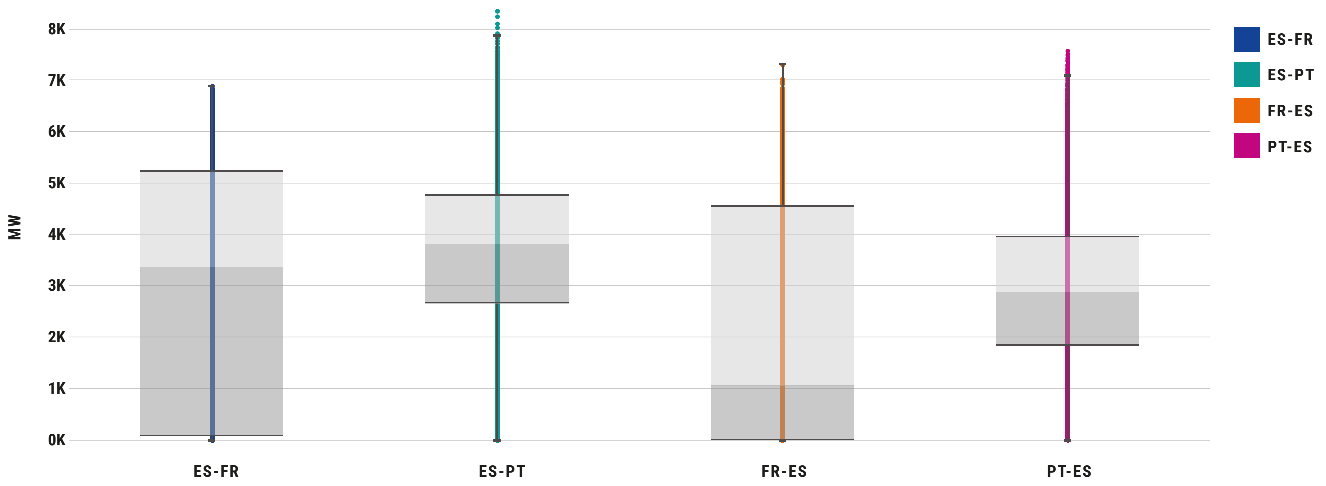



Figure 57: SWE CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

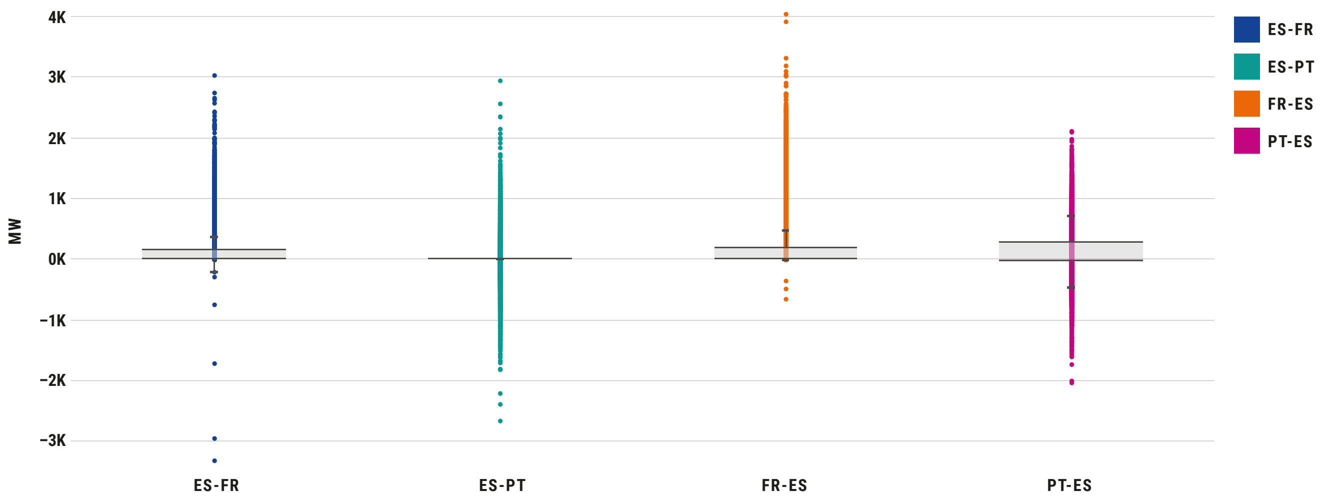



Figure 58: SWE CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

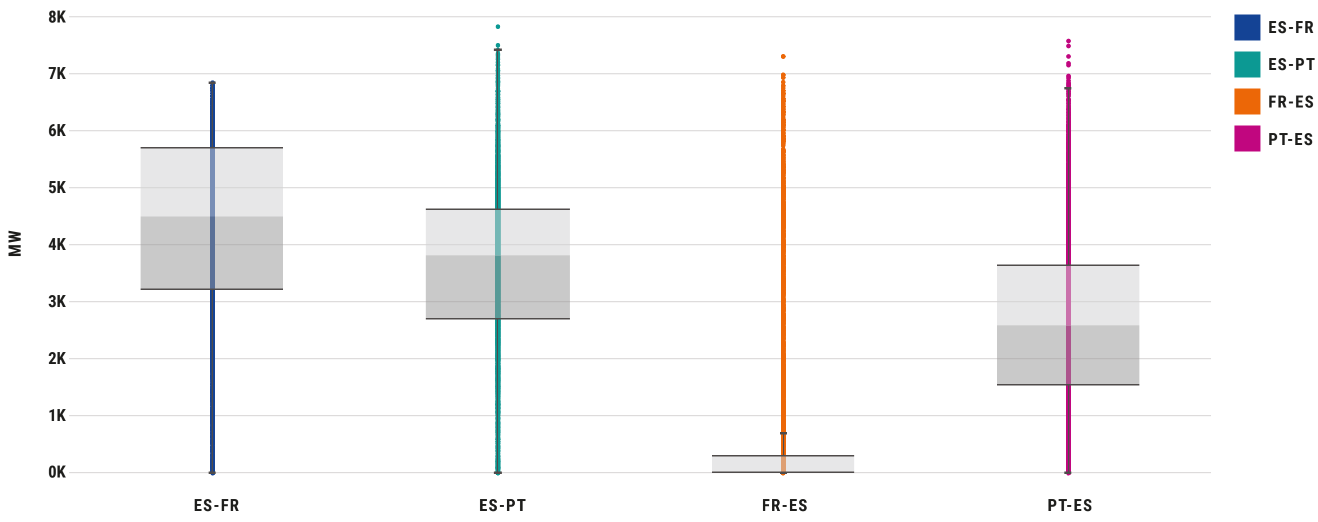



Figure 59: SWE CCR: Implicit offered ID capacities (15 March 2022 – 31 December 2022); Data source: Transparency platform

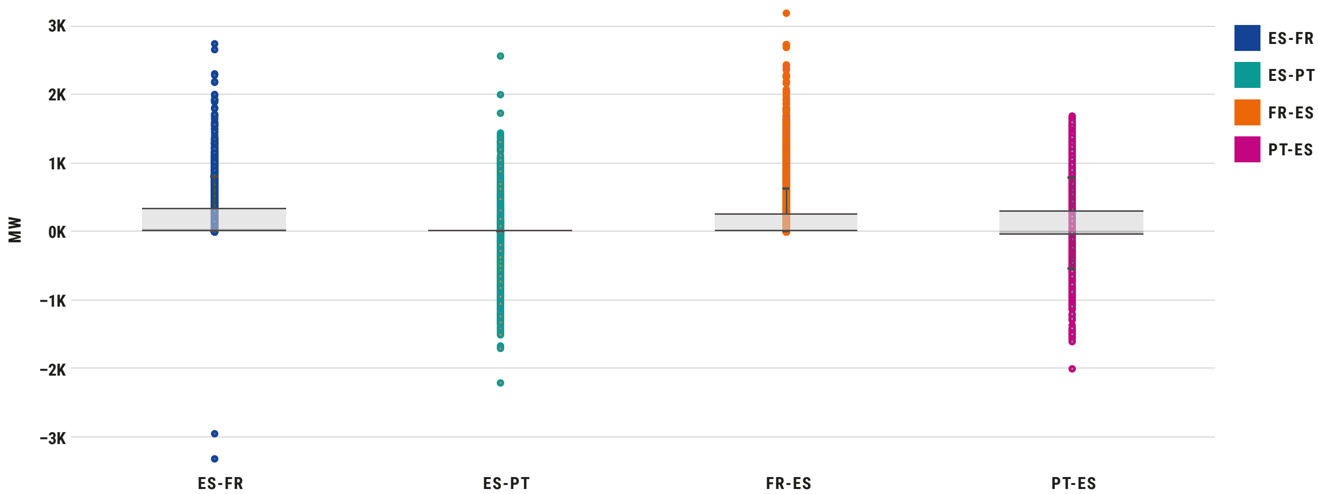



Figure 60: SWE CCR: Implicit allocated ID capacities (15 March 2022 – 31 December 2022); Data source: Transparency platform

### 3.6.3 Capacity calculation and allocation for the long-term

SWE CCR NRAs approved the SWE CCM for long-term timeframes in February 2020. At the time of writing of this report its implementation is ongoing in accordance with timeline agreed with SWE NRAs.

The methodology for long-term timeframes follows the same cNTC approach and principles already implemented for the DA, with the same tasks assigned to each role and the same CCC. The methodology will be applied to all timeframes for which there is LTTR allocation: year-ahead, month-ahead and quarter-ahead (the latter only for the ES–PT border). The most updated long-term outage plans will be considered to create the scenarios to be evaluated in each calculation. A specific sub-methodology to calculate the long-term TRM values is also included.

The high-level capacity calculation process for the long-term timeframe is shown in Figure 61, which identifies the input and output data and the roles of the entities involved in the capacity calculation process.

As a pan-European CGM is not available in CGMES format, the CGM used in the capacity calculation will be a SWE regional CGM, which resulted from the three TSOs merging their respective IGMs. Both the IGMs and the CGM will be created using the CGMES format

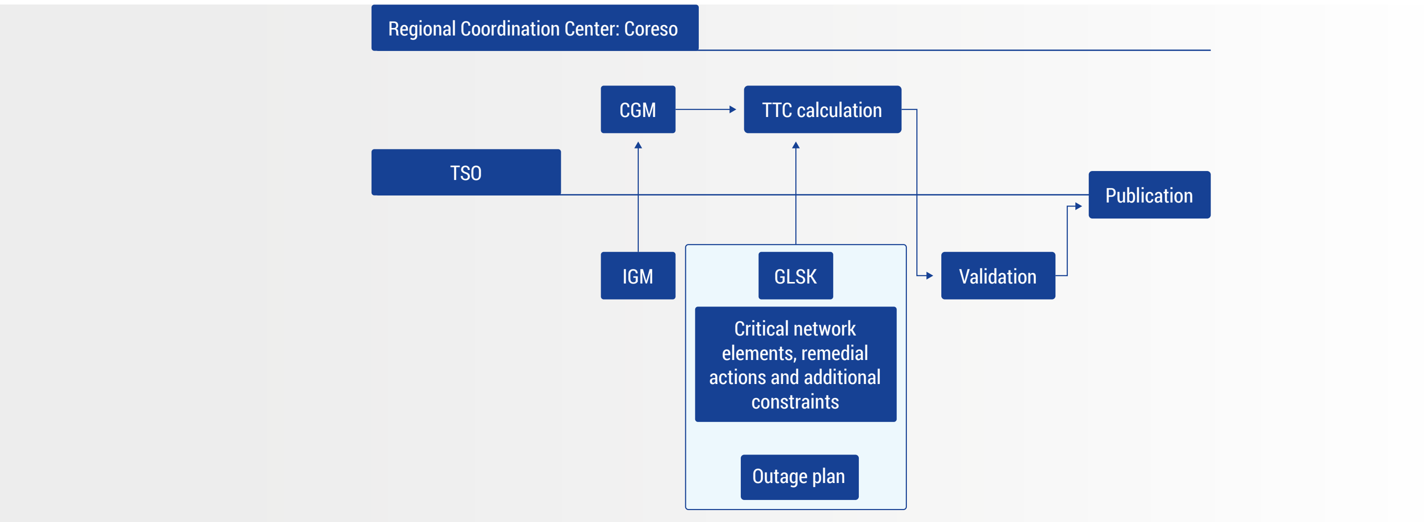



Figure 61: SWE CCR: Input and output data and roles of the entities in the capacity calculation process for the year-, month- and quarter-ahead timeframes

Tables 46 and 47 provide an overview of the already accomplished milestones and current planned timeline for the implementation of the SWE CCR long-term capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q2 2019 | SWE CCR TSOs submitted the long-term CCM proposal to the relevant NRAs |
| Q1 2020 | SWE CCR TSOs submitted an amendment to the SWE long-term CCM initial proposal |
| Q1 2020 | SWE CCR NRAs approved the SWE long-term CCM proposal |

Table 46: SWE CCR: Closed milestone(s) for long-term capacity calculation processes

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2024 | Implementation of the long-term CCM by SWE CCR TSOs and SWE RSC (Coreso) |
| Q3 2024 | Long-term CCM Go-Live covering yearly, quarterly (ES-PT) and monthly ahead capacity calculation |

Table 47: SWE CCR: Planned milestone(s) for long-term capacity calculation processes

### 3.6.4 Indicators for the long-term

Table 48 shows the values (in %) of offered capacity in relation to available capacity for long-term timeframe and allocated capacity in relation to offered.

Figure 62 shows the offered and allocated long-term capacities during 2021 and 2022 at the PT–ES and FR–ES borders, which are part of the SWE CCR CCMs in accordance with FCA regulation (Article 10).

| | FR–ES | PT–ES |
|---|---|---|
| Offered | 80 %** | 65 %*** |
| Allocated* | 99.98 % | 99.84 % |

Table 48: SWE CCR: Offered capacity in relation to allocated capacity for long-term timeframe.
*In application of article 35.5 of the Harmonised allocation rules for LTTRs, two or more participants submitted valid Bids with the same bid price that cannot be accepted in full for the total requested quantity and the SAP determined allocated quantity in a pro-rata base.
**According to Art.7.1 of SWE methodology for splitting long-term cross-zonal capacity in accordance with Article 16 of FCA, the percentage of long-term offered capacity with respect to the calculated long-term capacity average for FR–ES BZB is set at 80%.
***According to Art.6.1 of SWE methodology for splitting long-term cross-zonal capacity in accordance with Article 16 of FCA, the percentage of long-term offered capacity with respect to the calculated long-term capacity average for PT–ES BZB is set at 65%.

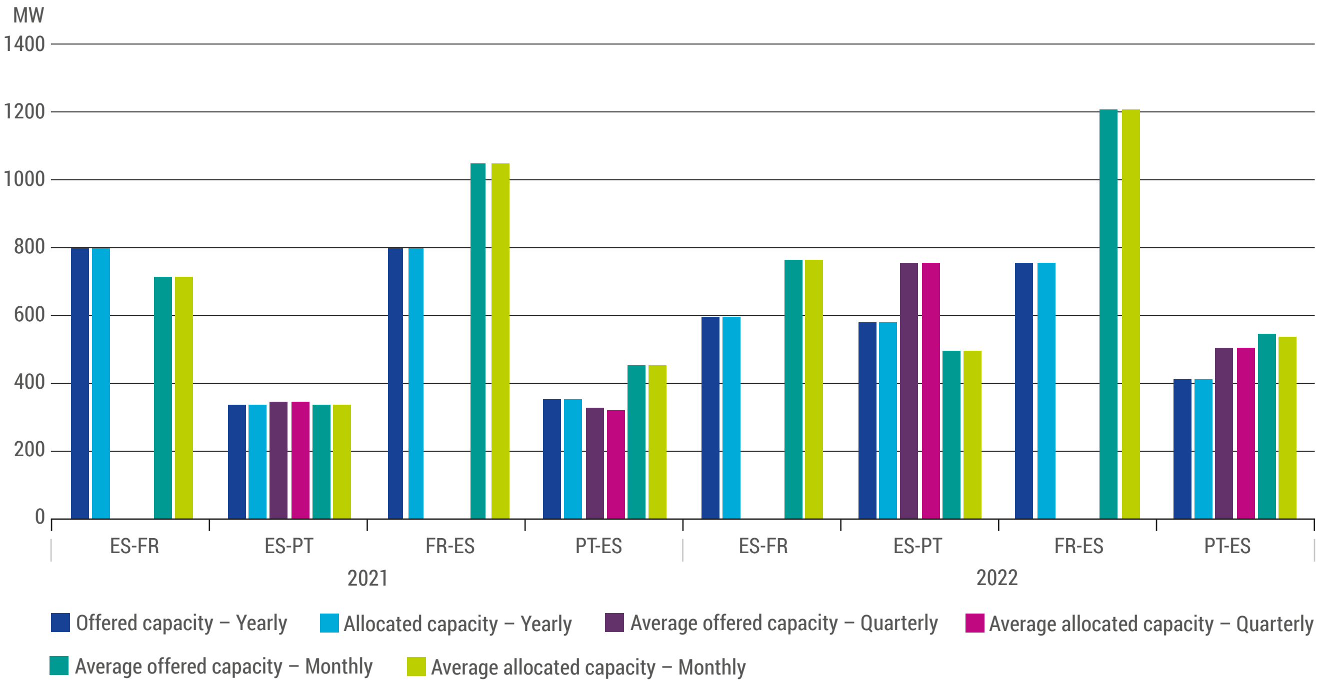



Figure 62: SWE CCR: offered and allocated long-term capacities during 2021 and 2022. Data source: **JAO**, excl. March 2021, February–March 2022 and November 2022 for ES–PT direction, and August 2022 for ES–FR direction, and September 2022 for PT–ES direction with 0 offered/allocated capacity.

## 3.7 Baltic

The TSOs in the Baltic CCR are Elering AS (EE), Litgrid AB (LT), Augstsprieguma tīkls AS (LV), Fingrid OY (FI), Svenska Kraftnät (SE) and PSE S.A. (PL).

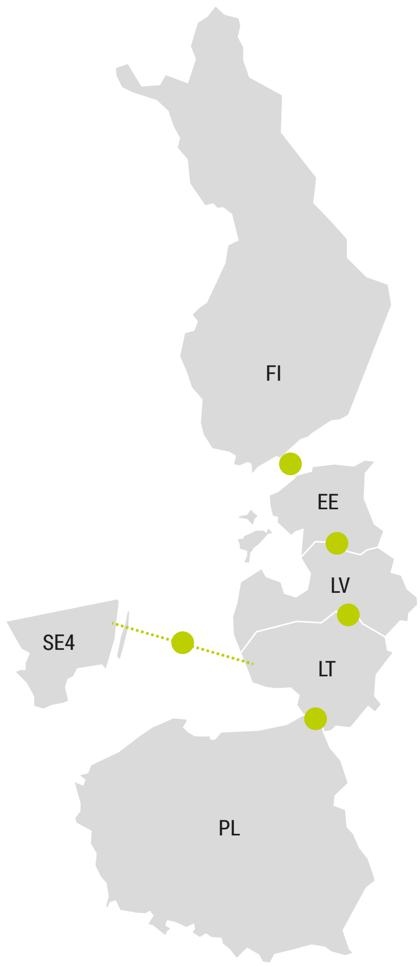



Figure 63: Baltic CCR. This CCR includes the following BZBs: Finland–Estonia (FI–EE), Estonia–Latvia (EE–LV), Lithuania–Latvia (LT–LV), Lithuania–Poland (LT–PL), and Sweden–Lithuania (SE4–LT).

### 3.7.1 Capacity calculation and allocation for the short-term

The Baltic TSO-s Elering AS, AS 'Augstsprieguma tīkls' and LITGRID AB have investigated the effectiveness of implementing the FB capacity calculation approach in the Baltic CCR with the help of consultants from E-Bridge Consulting GmbH. The other TSOs involved in the Baltic CCR, Fingrid Oyj, Svenska kraftnät and PSE S.A, connected to the Baltic TSOs via HVDC links, were also included as observers in the study, which was conducted between May 2016 and May 2017. In the study these HVDC links have been modelled as virtual bidding areas using the advanced hybrid coupling methodology, which allows to consider load flow constraints of the link itself as well as the neighbouring AC networks (on the side of Baltic TSOs). The main conclusion of the study was that the FB capacity calculation approach is technically feasible for application in the Baltic CCR. However, based on the outcome of the socioeconomic welfare and operational security assessment, it was concluded that the application of the capacity calculation methodology using the FB approach would not yet be more efficient compared to the current capacity calculation approach assuming a comparable level of operational security in the Baltic CCR. As the situation in the Baltics has not changed until the desynchronisation from BRELL, the conditions specified in CACM Article 20(7) are still fulfilled.

The Baltic CCR developed a cNTC approach for CZC calculation and allocation. By Q4 2018, the Baltic CCR TSOs received approval from the relevant NRA and started preparing to implement the Baltic CCR CCM. As preconditions for the implementation of the Baltic CCR CCM following methodologies was developed and approved by NRAs:

- the coordinated re-dispatching and countertrading methodology according to Article 35 of the CACM regulation approved by NRAs Q4 2018;
- the re-dispatching and countertrading cost-sharing methodology within the Baltic CCR required by Article 74 of the CACM regulation approved by NRAs Q2 2019;
- Q1 2019 the Baltic NRA's approved the document specifying terms, conditions and methodology on CZC calculation, provision and allocation with third countries (i.e. Estonia–Russia, Latvia-Russia, Lithuania-Belarus, Lithuania-Russia[39]) across Baltic State borders and these third countries.

Baltic CCR TSOs were in communication with Baltic CCR NRAs on the best method and timeframe to implement the Baltic CCR cNTC CCM. In parallel with the implementation planning of the Baltic CCM, the Baltic CCR LT CCM methodology was also developed. On 17 November 2020 the Baltic CCR TSOs received ACER's letter on ‚ACER Decision No 27/2020 rejecting the Baltic CCR TSOs' proposal for the long-term capacity calculation methodology'[40]. ACER concluded (Section 6.2 of the decision), the Baltic LT CCM compliant with EU law can only be implemented after de-synchronisation from BRELL, which is expected to be in 2025. Reading the ACERs assessment of LT CCM the Baltic CCR TSOs and NRAs evaluated that the Baltic CCR DA/ID CCM needs to be re-developed.

A new version of the DA/ID CCM requires considerably more time for the Baltic CCR TSOs to draft as the details of the synchronous operation with the networks of the Continental Europe Synchronous Area cannot be precisely known at the present moment and the synchronous operation mode is still under research.

39 In the Kaliningrad area

40 ACER Decision **No. 27/2020**

At the time of the writing of this report, the following milestones are planned for Baltic CCR:

| Planned milestone(s) | |
|---|---|
| Quarter | Description |
| Q4 2023 | Preparation of the new re-developed Baltic CCR cNTC CCM |
| 2025 | Implementation of Baltic CCR cNTC CCM |

Table 49: Baltic CCR: Planned milestone(s)

The CCM steps of the capacity calculation process can be described as follows:

**As an input, the CZC calculation process receives the RMs and the remedial actions.**

1. The TRM is a capacity margin, which considers planning errors, including the errors made due to imperfect information issued by third countries at the time the transfer capacities have been calculated. The TRM calculation methodology covers cross-border interconnections between Lithuanian and Latvian power systems as well as between Latvian, Russian and Estonian power systems. The TRM for HVDC interconnectors is 0 MW, whereas the TRM for the AC borders is calculated based on statistical data, i.e. the deviation of factual power flow from planned power flow over the cross-border interconnection. TRM is equal to the average arithmetic value plus one standard deviation using the above factual and planned power flow data.

2. The remedial actions are the changes in network topology and the changes in the power systems' balance, for example, changing generation.

**The TTC is the calculation for cross-borders with AC interconnectors in the Baltic TSOs' control area.**

1. The cross-border interconnection TTC assessment for AC interconnectors will follow the methodological principles in the 'Methodical guidelines for stable operation in the BRELL loop,' as well as national regulations and standards implemented and agreed in the instructions for parallel operations in the cross-border interconnections between the TSOs involved, while taking into account the intra- and intersystem operational security.

2. Methodical guidelines for stable operation in the BRELL Loop are used as a basis and reviewed by TSOs to ensure the secure and collection operation with neighbouring interconnected TSOs.

3. The TTC will be determined by the proceeding contingency analysis, complying with the operational security limits of the BRELL Loop and the Baltic TSOs' control area.

4. A contingency analysis is performed for those contingencies which are agreed upon by Baltic TSOs and thereafter placed on the contingency list. Once agreed upon, this list is provided to the CCC.

5. The list of CNEs in the Baltic TSO control area will be shared with all Baltic TSOs and the CCC. The cross-border TTC calculation will be carried out using mutually coordinated data and information as inputs. These inputs are the CGM, which includes the power transmission equipment model of the BRELL Loop and scenarios describing the net positions for each of the Baltic TSOs' control areas and the Russian/Belarusian power systems, valid for given calculation purposes.

6. When determining the TTC values, TSOs and the CCC can consider ambient temperatures for different seasonal periods within the control area as well as effective emergency power reserves within the Baltic TSOs' control areas and Russian/Belarusian power systems to ensure operational security.

7. If during the capacity calculation process, neighbouring TSOs find different TTC values for the same cross-border interconnection, the lowest value will be used as a coordinated value.

**TTC calculation for cross-borders with HVDC interconnectors.**

1. The TTC of each border that consists solely of HVDC connections is limited by the sum of ratings of HVDC interconnectors that connect the relevant BZs. To establish the TTC limitation related to adjacent AC networks, contingency analyses based on N-1 criteria (i.e. a loss of any single element of the power system) will be performed using CGMs. While performing contingency analyses after applying N-1 criteria, the following limits will not be exceeded:
   - thermal limits that correspond to the relevant ambient temperature of network elements;
   - voltage limits in network nodes;
   - rotor angle stability limits.

2. The maximum permissible capacity of a HVDC interconnector will be limited when there is a lack of available power reserves to mitigate the failure of the HVDC interconnector.

3. The relevant party performing the contingency analysis should check if the maximum capacity for each connection in each direction could be provided to the market. If the contingency analysis reveals that network security cannot be guaranteed when the HVDC interconnectors are fully loaded in any direction, then capacity on the relevant border in the relevant direction will be reduced until network parameters are within permissible limits during the analysis.

4. The TTC of the relevant HVDC interconnector is the minimum capacity value that is the outcome of the contingency analyses that the relevant parties perform on each side of the relevant interconnector.

5. For Baltic CCR TSOs, the cross-border TTC calculations will be carried out using the following data and information as inputs:

- the CGM, which includes:
  - the power transmission equipment model of the BRELL Loop and scenarios describing net positions for each of the Baltic TSOs' control areas and the Russian/Belarusian power systems, valid for given calculation purposes;
  - the model of the Polish power system from the European merging function, supplemented with the 110 kV sub-transmission grid and the scenarios reflecting the net position of the Polish BZ, valid for given calculation process;
  - the models of the Nordic power systems from European merging function;
- generation, renewable generation and load shift keys;
- critical network elements;
- planned outages;
- the contingency list;
- remedial actions; and
- operational security limits.

## ID capacity calculation and allocation

Before CZCs are provided to the ID market, the following steps need to be carried out:

1. Calculation by the TSOs and CCC of the NTC value for the DA market;

2. Provision of the DA market results by NEMO, complying with the NTCs and allocation constraints; and

3. Calculation of the ATC value for the ID market.

After the DA firmness deadline, all CZC and allocation constraints are firm for DA capacity allocation unless there is an emergency situation or a force majeure event. The DA firmness deadline is 60 minutes before the DA gate closure time unless there is another deadline. After the DA firmness deadline, the CZC that has not been allocated may be adjusted for subsequent allocations, subject to allocation constraints. The ID CZC is firm as soon as it is allocated and is subject to allocation constraints unless there is an emergency situation or a force majeure event.

If, due to the time constraints, ATC values cannot be calculated by the CCC and validated by TSOs before the ID cross-zonal gate opening time, TSOs will provide ATC capacities for their respective borders for ID market timeframe based on the DA NTCs and the results of the DA market coupling, as well as an evaluation of operational security by TSOs.

If neighbouring TSOs come up with different ATC values for provision to the respective border, the lowest value will be used as a coordinated value and will be provided to the ID market for allocations. Updated ATC values will be provided to the ID market as soon as possible after calculation and validation have been successfully finalised.

During the ID trading process, ATC values – apart from changes arising from NTC updates – will be adjusted automatically by the respective market operator/market platform after each trade affecting the respective border. The value of the ATC adjustment (increase or decrease) will be equal to the commercial flow over the respective border as a result of trade. The same refers to allocation constraints, which, apart from changes arising from their updates, will be adjusted automatically by the respective market operator/market platform after each trade affecting the respective power system. The volume of this adjustment (increase or decrease), will be equal to the change of net position of a given power system as a result of trade.

In the Baltic CCR, there is no need for rules for efficiently sharing the power flow capabilities of CNEs between different BZBs, as there is no such CNE in this CCR that would clearly and in most cases influence the power flow capabilities of several borders at once. Therefore, the methodology does not contain these rules, given that no such sharing takes place.

Currently, CZC and allocation constraints are provided to NEMOs for implicit allocation by TSOs (after TSOs have participated in the coordination process). In the future, when the CCC performs its functions, including validating the CZC, the TSOs will provide allocation constraints to the CCC, who will send them to NEMOs to allocate capacity.

Figure 64 is a high-level diagram of the steps and roles involved in determining the capacity calculation for the DA and ID timeframes.

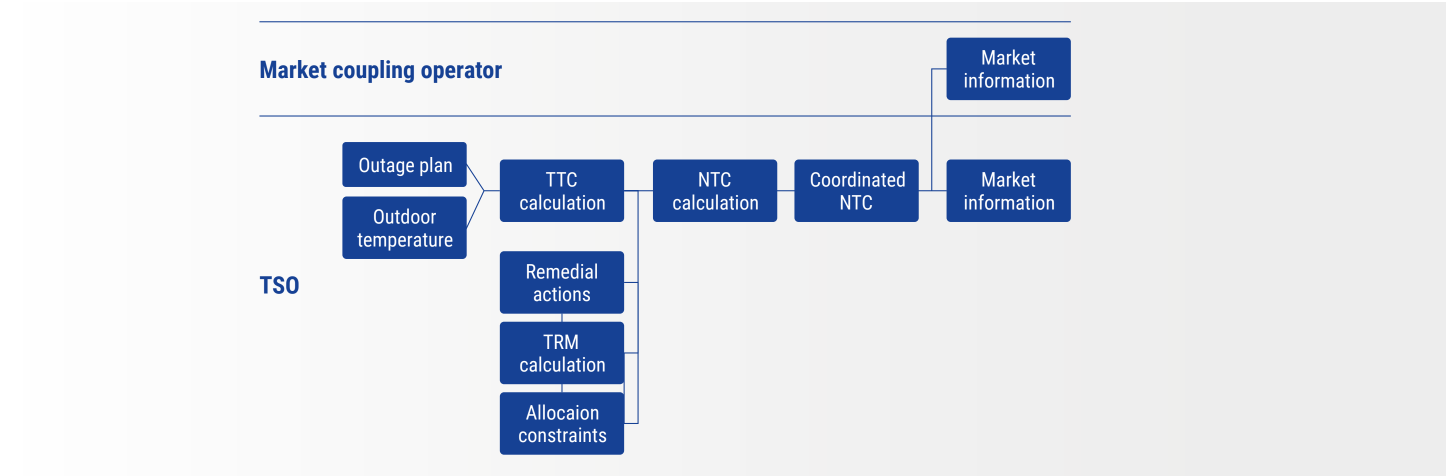



Figure 64: Baltic CCR: Input and output data and roles of the entities in the capacity calculation process for the DA and ID timeframes[41]

## 3.7.2 Indicators for the short-term

Figures 65 and 66 (page 67–68) show the implicit offered and allocated DA and Figures 67 and 68 (page 68) show the implicit ID offered and allocated capacities during 2021 and 2022 at borders, which will become part of the Baltic CCR CCM in accordance with CACM regulation[42]. The values are presented in box-plot diagrams to show the distributional characteristics of the data series:

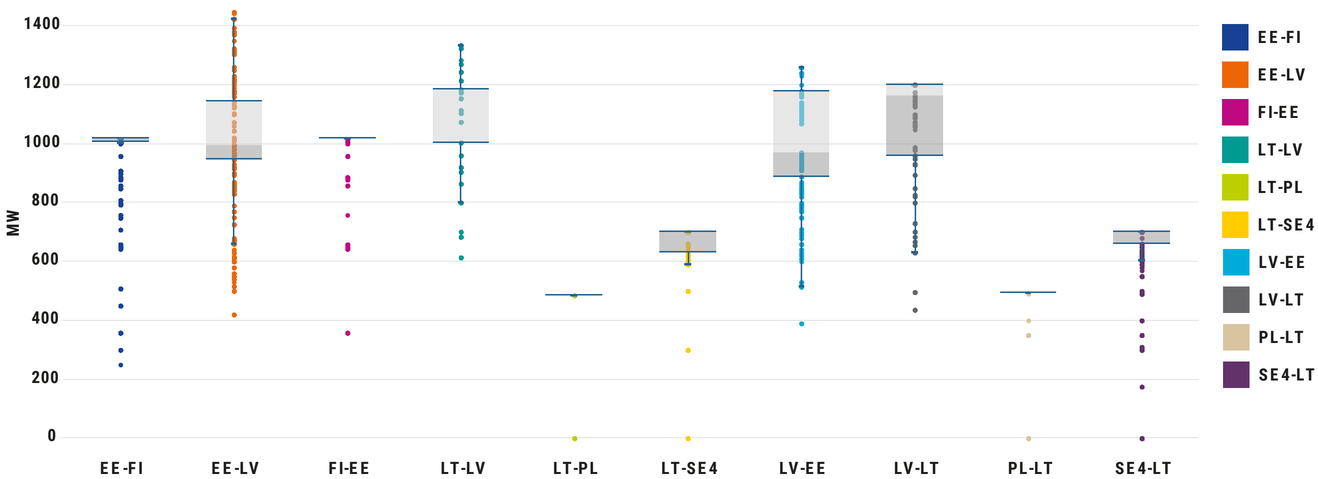



Figure 65: Baltic CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

41 Find more info **here**

42 Article 20 of the CACM regulation

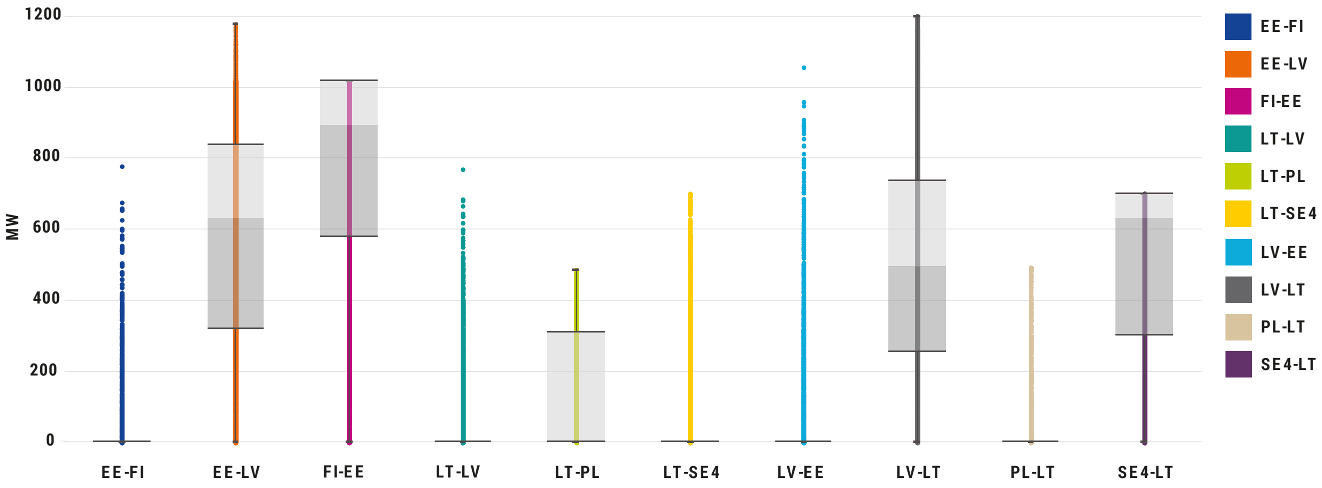



Figure 66: Baltic CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

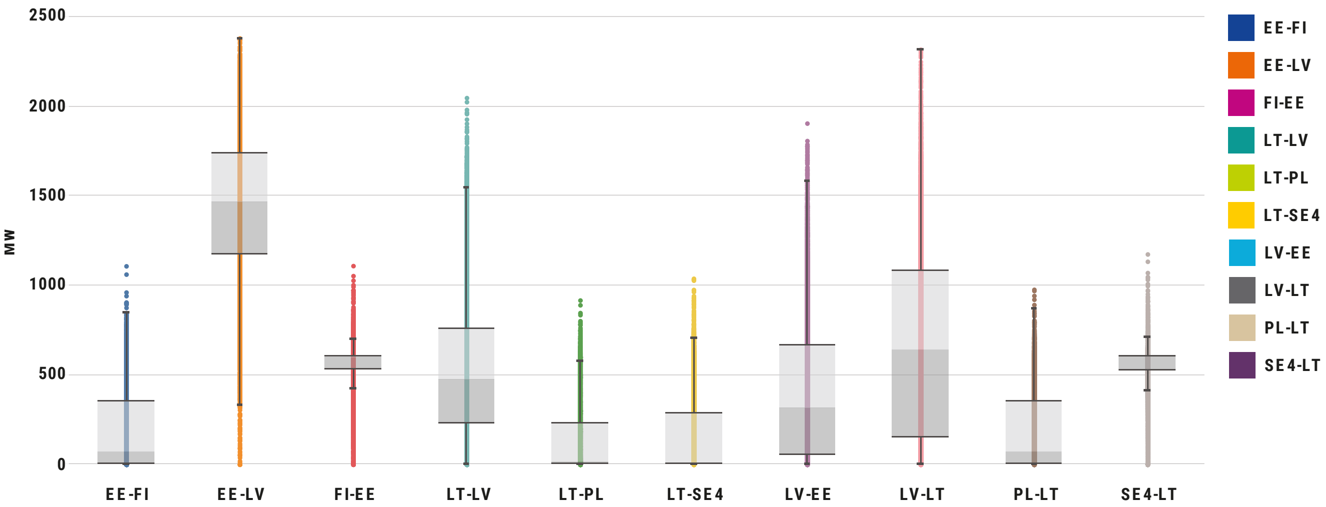



Figure 67: Baltic CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

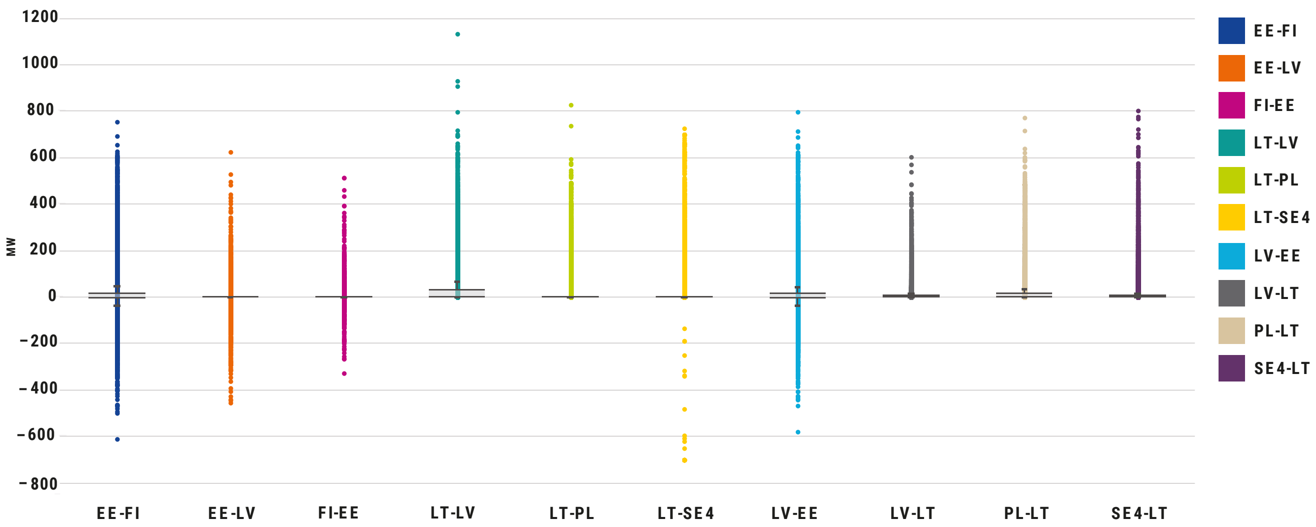



Figure 68: Baltic CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

### 3.7.3 Capacity calculation and allocation for the long-term

The FCA regulation obliges the TSOs to issue LTTRs on a BZB unless the competent regulatory authorities of the BZB have adopted coordinated decisions not to issue LTTRs on the BZB. Based on the assessments on the functioning of the wholesale electricity markets, relevant NRAs agreed the following:

- In April 2017, the Finnish and Estonian NRAs agreed that there are sufficient hedging opportunities in the Finnish and Estonian BZs and decided in accordance with Article 30(1) of the FCA Regulation that no LTTRs need to be issued on the FI-EE BZB. On 28 May 2021, Energiavirasto and Konkurentsiamet, after a new assessment of the hedging opportunities in the concerned Finnish and Estonian BZs, concluded that the market did not provide sufficient hedging opportunities in those BZs and agreed to request, in accordance with Article 30(5) of the FCA Regulation, Fingrid and Elering to issue LTTRs on the FI-EE BZB.
- In May 2017, the Latvian and Estonian NRAs agreed not to request the respective TSO to issue LTTRs or to make other cross-zonal hedging products available at the LV-EE BZB in addition to the already available EE–LV border FTR-options (then named as PTR-Limited).
- The Lithuanian, Latvian, Swedish and Polish regulators bilaterally agreed that LTTRs should not be issued on the Lithuanian–Latvian (LT–LV), Lithuanian–Swedish (LT–SE4) and Lithuanian–Polish (LT–PL) BZBs, but also that other long-term cross-zonal hedging products must be made available to support the functioning of the wholesale electricity markets within the above-mentioned BZBs

Based on a decision by the relevant NRAs, Financial Transmission Rights options are offered on the Latvian–Estonian (LV–EE) border in the direction towards Latvia and from 2023 also on the Finnish–Estonian (FI–EE) border in the direction towards Estonia.

Based on the FCA regulation, the SAP is responsible for facilitating the allocation of LTTRs at the European level.

In March 2022, ACER gave opinion No 03/2022[43] relating to the implementation of LTTRs on the FI–EE BZB. In the opinion ACER stated: until the splitting methodology according to Article 16 of Regulation (EU) 2016/1719 has been implemented, CZC may be split according to a methodology bilaterally agreed by the relevant TSOs, subject to regulatory oversight.

On 17 November 2020, ACER issued a decision (No 27/2020)[44] on the Baltic CCR's long-term CCM as the FCA and CACM regulations and the BRELL agreements[45] foresee some deviations in the capacity calculation approach. This decision does not force Baltic CCR's TSOs to implement the long-term CCM before BRELL synchronisation has taken place as this could potentially endanger the operational security of the Baltic networks. Nonetheless, a new methodology should be developed in the 24 months following the decision. It is also indicated by ACER, to ensure required compatibility in accordance with Article 10(3) of the FCA Regulation, that the LT CCM would need to be revised together with the DA/ID CCM.

The Baltic CCR TSOs started to work on the re-development of the DA/ID CCM prior to the preparation of the LT CCM. However, the new version of the DA/ID CCM requires considerably more time for the Baltic CCR TSOs to draft, as the details of the synchronous operation with the networks of the Continental Europe Synchronous Area cannot be precisely known at the present moment and the synchronous operation mode is still under the research. Preparation of the new version of the DA/ID CCM is expected to be done in year 2023. The Baltic CCR TSOs will be able to prepare and submit the revised LT CCM to the Baltic CCR NRAs after the development and approval of the new version of the DA/ID CCM by the Baltic CCR NRAs.

43 Find more info **here**

44 ACER Decision **No. 27/2020**

45 Agreements specifying the operation of three Baltic TSOs synchronously with Belarus and Russia

Tables 50 and 51 provide an overview of the already accomplished milestones and planned timeline for the implementation of the Baltic CCR long-term capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q2 2019 | Approval of the Baltic CCR long-term CCM by Baltic CCR TSO Steering Committee and launch of a public consultation |
| Q2 2019 | Approval of the Baltic splitting long-term CZC by Baltic CCR TSO Steering Committee and launch of a public consultation |
| Q3 2019 | Review of the feedback received from public consultations and approval of the Baltic CCR long-term CCM by Baltic CCR TSO Steering Committee for submission to Baltic CCR NRAs (as planned). |
| Q3 2019 | Review of the feedback received from public consultations and approval of the Baltic CCR splitting long-term CZC methodology by relevant Baltic CCR TSO Steering Committee members for submission to relevant Baltic CCR NRAs (as planned) |
| Q3 2019 | Submission of Baltic CCR long-term CCM to Baltic CCR NRAs (as planned) |
| Q3 2019 | Submission of Baltic CCR splitting long-term CZC methodology for splitting CZC to the relevant NRA (as planned) |
| Q1 2020 | Request for Amendment for Baltic CCR long-term CCM from Baltic CCR NRAs to Baltic CCR TSOs |
| Q1 2020 | Submission of the amended Baltic CCR long-term CCM to Baltic CCR NRAs |
| Q1 2020 | Approval and publication of the Baltic CCR splitting long-term CZC methodology (as planned) |
| Q2 2020 | Submission of a letter from the Baltic CCR NRAs to ACER requesting a decision on Baltic CCR long-term CCM submitted by Baltic CCR TSOs |
| Q3 2020 | ACER public consultation and hearing phase for the decision on the Baltic CCR long-term CCM |
| Q4 2020 | Publication of ACER Decision No 27/2020 on the Baltic CCR long-term CCM |
| Q3 2022 | Estonian and Finnish NRA positive opinions on the Bilateral methodology for determining and splitting the long-term CZC for the purpose of allocating LTTRs on the Finnish–Estonian BZB |

Table 50: Baltic CCR: Closed milestone(s) for long-term capacity calculation processes

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| To be determined | Development of new LT CCM |
| Q1 2025 | Expected time for implementation of the Baltic CCR long-term CCM and splitting long-term CZC |

Table 51: Baltic CCR: Planned milestone(s) for long-term capacity calculation processes

### 3.7.4 Indicators for the long-term

Figure 69 shows the offered and allocated long-term capacities during 2021 and 2022 at Baltic CCR internal borders, which will become part of the Baltic CCR CCM in accordance with FCA regulation (Article 10).

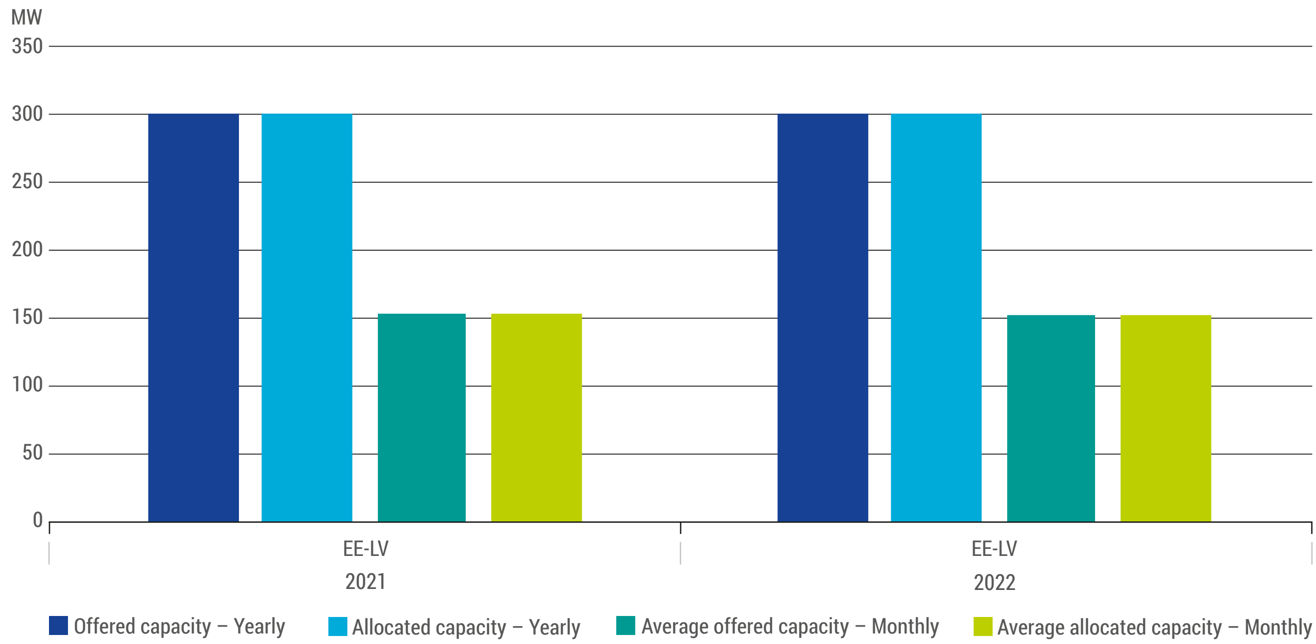



Figure 69: Baltic CCR: offered and allocated long-term capacities during 2021 and 2022. Data source: JAO

## 3.8 South-East Europe

The capacity calculation process in the South-East Europe (SEE) CCR comprises the following TSOs: ESO (BG), IPTO (GR) and Transelectrica (RO). According to Art. 20(4) of CACM 'after at least all South-East Europe Energy Community Contracting Parties participate in the single DA coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the FB approach for the DA and ID market timeframe'. However, until now the market coupling of the DA markets between the Greece–Bulgaria–Romania and the Western Balkan countries (i.e. Serbia, Kosovo*[46], Bosnia & Herzegovina, North Macedonia, Albania, Montenegro) has not been launched, so the FB approach cannot be applied and the coordinated NTC is still used.

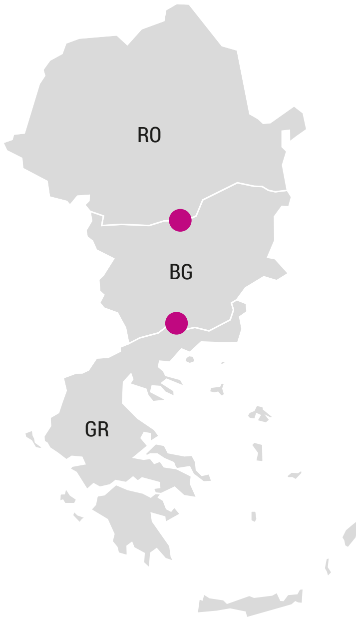



Figure 70: SEE CCR; This CCR includes the following BZBs: Greece–Bulgaria (GR–BG) and Bulgaria–Romania (BG–RO).

### 3.8.1 Capacity calculation and allocation for the short-term

SEE NRAs approved the current version of SEE CCM for the DA and ID timeframes in July 2021.

For the DA timeframe, the capacity calculation process started on 1 July 2021. Concerning the ID capacity calculation process the first ID capacity calculation started on 1 October 2021 and the second ID capacity calculation on 1 October 2022.

Both for the DA and the ID timeframe, the SEE CCR TSOs implemented a cNTC approach. The DA capacity calculation is performed in the D-2 time horizon (TH) for each MTU (24 hours of the day) of a business day (BD) D whereas there are two ID capacity calculations; the first ID where the NTC is calculated for D-1 TH for each MTU of BD D and the second ID where the NTC is calculated in BD D for the last 12 MTUs (13h – 24h) of the BD.

The high-level capacity calculation process for the DA and ID timeframe is shown in Figure 71. The figure defines the roles of the entities involved and the input and output data of the capacity calculation process.

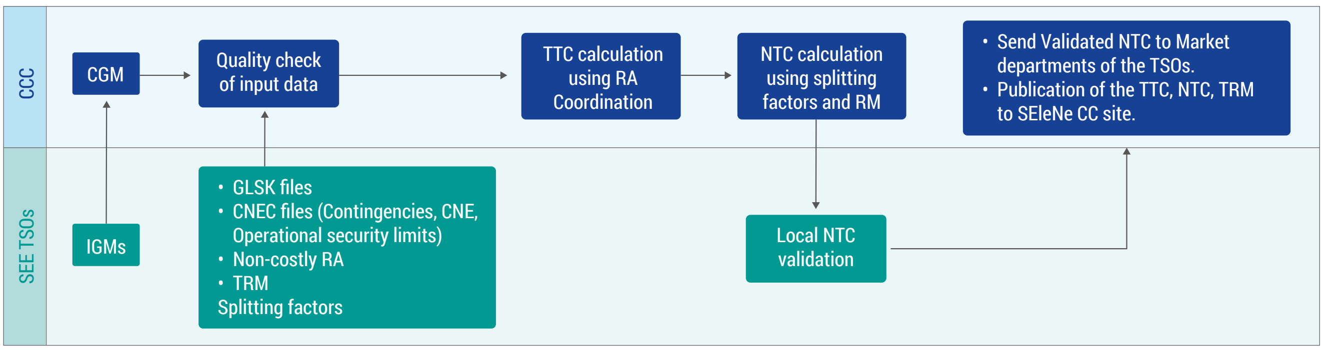



Figure 71: SEE CCR: Input and output Data and roles of entities during the whole capacity calculation process for DA and ID timeframe

46 *This designation is without prejudice to positions on status, and is in line with UNSCR 1244/1999 and the ICJ Opinion on the Kosovo declaration of independence

The capacity calculation process in the SEE CCR is performed by the CCC SEleNe CC and SEE TSOs according with the following procedure:

1. Each SEE TSO shall provide to the CCC the following capacity calculation inputs: their DACF and D2CF IGMs, the GSKs, their CNEC files (containing a list of proposed CNECs, operational security limits and RAs), TRMs, splitting factors;
2. The DACF IGMs of the Continental Europe for the CGM merging are provided from Swissgrid platform;
3. The CCC merges the IGMs to create the CGM that will be used for the capacity calculation;
4. CCC calculates the sensitivity factors for selecting the CNECs that are significantly impacted by cross-zonal power exchange;
5. SEE TSOs validate the list of monitored CNECs used for all steps of the common capacity calculation to determine the NTC;
6. CCC calculates the TTC for each MTU of the BD D for the north Greek borders and south Romanian borders. The calculation is based on AC load flow;
7. CCC performs the Remedial Actions Coordination through an optimiser and calculates the final TTC for each MTU for the north Greek borders and south Romanian borders;
8. CCC calculates the NTC for each MTU for the Greece-Bulgaria and Bulgaria-Romania borders both for import and export. SEE TSOs validate the NTC values and, in the event of reduction of the NTC, a reason is provided; and
9. The CCC shall send the validated NTC values to the Market departments of the SEE TSOs and publish them to the SEleNe CC website.

## CNEC selection

The TSOs of SEE CCR monitor only the elements from the CNEC file significantly impacted by cross-zonal power exchange. The RCC calculates the sensitivity factors for selecting the CNECs that are significantly impacted by cross-zonal power exchange. SEE CCR cross-zonal network elements are by definition considered to be significantly impacted. The other CNECs of the CNEC file with a sensitivity factor equal or higher than 5 % are considered in all of the steps of the common capacity calculation to determine the NTC.

## Transmission Reliability Margin

The DA and ID capacity calculation is based on forecast models of the transmission system. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors. The TRMs for the Greece–Bulgaria and Bulgaria–Romania borders are constant and equal to 100 MW both for import and export but will be evaluated in yearly basis and adjusted if required.

## Remedial Actions Coordination (RAC)

The RAC in the DA and ID common capacity calculation is an automated, coordinated, and repeatable optimisation process performed by the CCC. The CCC considers in capacity calculation RAs to increase the TTC. After calculation, the maximum power exchanges between BZs without RAs, necessary adjustment considering RAs are executed in the CGM and maximum power exchanges between BZs considering RAs is recalculated.

The RAC in the DA and ID common capacity calculation is performed in accordance with a set of pre-defined characteristics such as an objective function, constraints and variables:

- The RAC objective is to enlarge the capacity domain around the balanced net position of the Common Grid Model Alignment process, with the objective function to minimise the overload of the CNECs and/or the violation of the nodes voltage;
- The constraints are the operational security limits, minimum impact on objective function value for use RAs and without negative impact on the TTC values; and
- The variables are the switching states of the topological measures and tap positions.

The types of RAs considered in the CC process are non-costly and are the following:

- Changing the tap position of a phase shifting transformer (PST); and
- Topological measure: opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s) or switching of one or more network element(s) from one bus bar to another, connection/disconnection of reactor(s), capacitor(s).

Table 52 provides an overview of the already accomplished milestones of the implementation of the SEE CCR DA and ID capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q1 2018 | SEE CCR TSOs' submission of the SEE short-term CCM (DA and ID) to the SEE CCR NRAs |
| Q2 2019 | SEE CCR NRAs approval of the SEE short-term CCM (DA and ID) submitted by the SEE CCR TSOs |
| Q2 2020 | Establishment of the SEleNe capacity calculation |
| Q3 2020 | SEE CCR TSOs' submission of Version 1 of the SEE short-term CCM (DA and ID) to the SEE CCR NRAs |
| Q3 2021 | SEE CCR NRAs' approval of the SEE short-term CCM submitted by the SEE CCR TSOs |
| Q3 2021 | Go-live of the DA capacity calculation |
| Q4 2021 | Go-live of the 1st ID capacity calculation |
| Q4 2022 | Go-live of the 2nd ID capacity calculation |

Table 52: SEE CCR: Closed milestone(s) for DA and ID capacity calculation processes

| Planned milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q3 2023 | SEE NRAs is expected to provide feedback to the amendments to the DA and ID CCM |

Table 53: SEE CCR: Planned milestone(s) for DA and ID capacity calculation processes

## 3.8.2 Indicators for the short-term

The capacity calculation methodology for ID is implemented since 1 October 2021 and DA since 1 July 2021. Therefore, the following indicators provide information on the time period from go live until 31 December 2022 or the whole monitoring period of 2021 and 2022.

### Indicator for RM

Table 54 shows the values of average TRM per border for ID and DA as well as their average percentage of TTC value ( %).

For the Greece–Bulgaria and Bulgaria–Romania borders, in both directions, both for the DA (D-2 TH) and the ID capacity calculation (i.e. 1st ID and 2nd ID) the TRM is static and equals to 100 MW.

| | | 1st ID | | 2nd ID | | DA | |
|---|---|---|---|---|---|---|---|
| **Border** | **Direction** | **Average TRM (MW)** | **Percentage of TTC ( %)** | **Average TRM (MW)** | **Percentage of TTC ( %)** | **Average TRM (MW)** | **Percentage of TTC ( %)** |
| Greece-Bulgaria (GR–BG) | BG -> GR | 100 | 5.34 | 100 | 4.67 | 100 | 5.26 |
| | GR -> BG | 100 | 5.28 | 100 | 4.88 | 100 | 5.33 |
| Bulgaria-Romania (BG–RO) | BG -> RO | 100 | 4.68 | 100 | 4.14 | 100 | 4.86 |
| | RO -> BG | 100 | 5.1 | 100 | 4.38 | 100 | 5.37 |

Table 54: SEE CCR: Average TRM and percentage of TTC (1st ID, 2nd ID and DA); Data source: SEE CCR.

## Indicator for available and allocated CZC

Table 55 shows the values of average net transmission capacity (NTC), maximum export and import capacities (for each BZB individually)[47]:

| ID | | | | DA | | | |
|---|---|---|---|---|---|---|---|
| BZB | Average NTC [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) | BZB | Average NTC [EXP/IMP] (MW) | maxExp (MW) | maxImp (MW) |
| RO–BG | 1,180 / 1,219 | 1,400 | 1,870 | RO–BG | 1140 / 1197 | 1,400 | 1,870 |
| GR–BG | 570 / 631 | 636 | 742 | GR–BG | 558 / 630 | 803 | 812 |

Table 55: SEE CCR: Average NTC values and maximum export/import capacity values for ID and DA timeframe

## Indicators for the information used for capacity calculation

Table 56 below shows the percentage of time when the limiting CNEC of calculation is not determined during capacity calculation (e.g. due to stability limits). The limiting CNEC is not determined only when the TTC is not calculated, and this leads to NTC Long-term values (monthly values) as a backup solution. For the calculation of the TTC the security of the transmission network should be respected. In the event that the security is violated, the SEleNe CC tool automatically identifies the combination of pre-defined remedial actions to eliminate eventual violation (if possible). If no secure solution can be found, namely the RAs cannot alleviate the overloading of the CNECs (the loading is more than 100 %) the TTC is not calculated. A secure solution is considered when all grid limits are respected for both the base case and all defined post-contingency cases (N-x). The security analysis is based on AC load flow:

| | | 1st ID | 2nd ID | DA |
|---|---|---|---|---|
| Border | Direction | Percentage of time when CNEC is not determined ( %) | Percentage of time when CNEC is not determined ( %) | Percentage of time when CNEC is not determined ( %) |
| Greece-Bulgaria (GR–BG) | BG -> GR | 1.68 | 0.72 | 1.57 |
| | GR -> BG | 2.15 | 0.72 | 2.37 |
| Bulgaria-Romania (BG–RO) | BG -> RO | 0.49 | 0.72 | 0.69 |
| | RO -> BG | 0.77 | 0.82 | 1.13 |

Table 56: SEE CCR: Time when a CNEC is not determined (1st ID, 2nd ID and DA); Data source: SEE CCR.

47 Data sources: SELeNe capacity calculation tool module and the SEE CCR annual KPI reports for capacity calculation process

## Indicator for assessing and following in the longer term the efficiency of single DA and ID coupling

Table 57 shows the efficiency of the current capacity calculation and allocation framework by multiplying Net positions (DA) and DA price.

| BZ | 2021 | 2022 |
|---|---|---|
| | $\sum (NP_h \times DA_h)$, mln EUR | $\sum (NP_h \times DA_h)$, mln EUR |
| BG | 351 | 1,758 |
| RO | −278 | −1,042 |
| GR | −105 | −464 |

Table 57: SEE CCR: Efficiency of the current capacity calculation and allocation framework (from 1 July 2021 to 31 December 2022); Data source: OPSCOM reports

Figures 72, 73, 74 and 75 (page 76–77) show the implicit offered and allocated DA and ID capacities during 2021 and 2022 at South-East Europe CCR internal borders, which will become part of the South Easter Europe CCR Capacity Calculation Methodology in accordance with CACM regulation[48]. The values are presented by box-plot diagrams to show the distributional characteristics of the data series. Figures 76 and 77 (page 77–78) show the implicit offered and allocated DA capacities during 1 July 2021 and 31 December 2022, and Figures 78 and 79 (page 77–78) show the implicit offered and allocated ID capacities during 1 October 2021 and 31 December 2022.

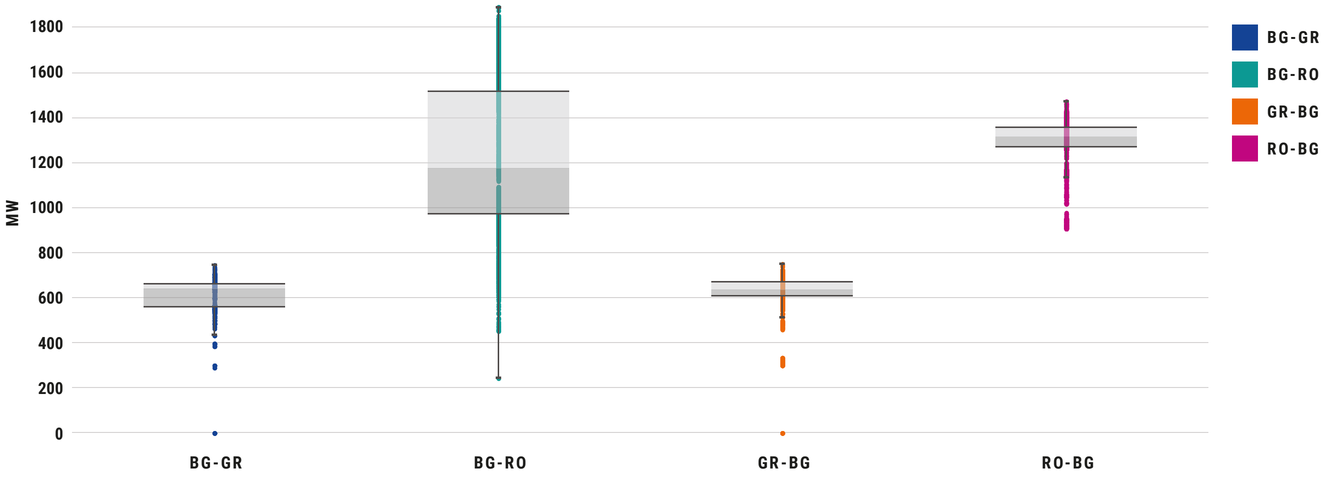



Figure 72: SEE CCR: Implicit offered DA capacities (2021–2022); Data source: OPSCOM reports

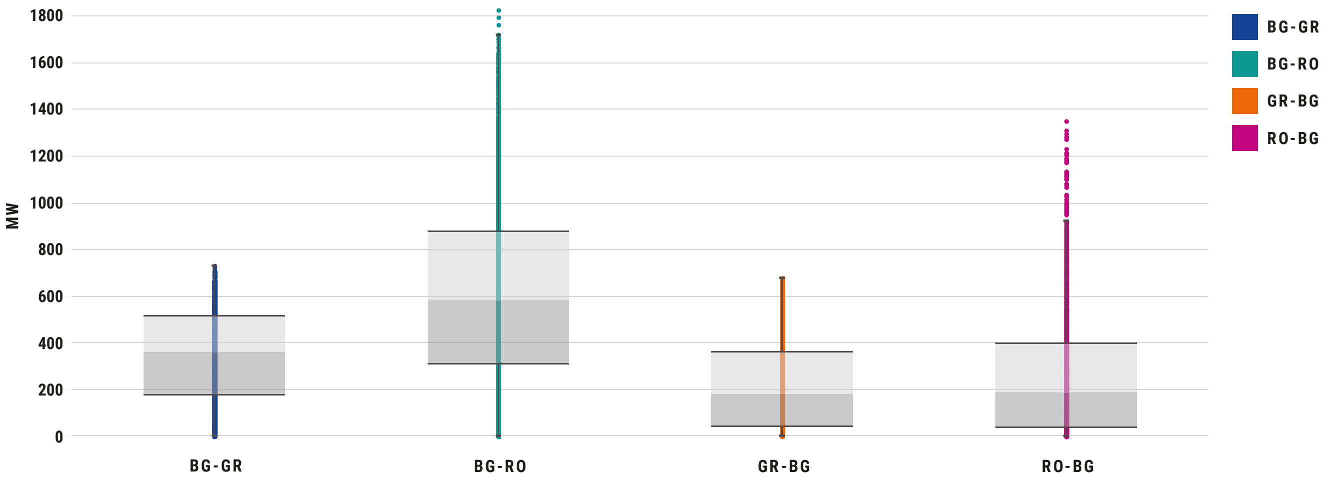



Figure 73: SEE CCR: Implicit allocated DA capacities (2021–2022); Data source: OPSCOM reports

48 Article 20 of CACM regulation

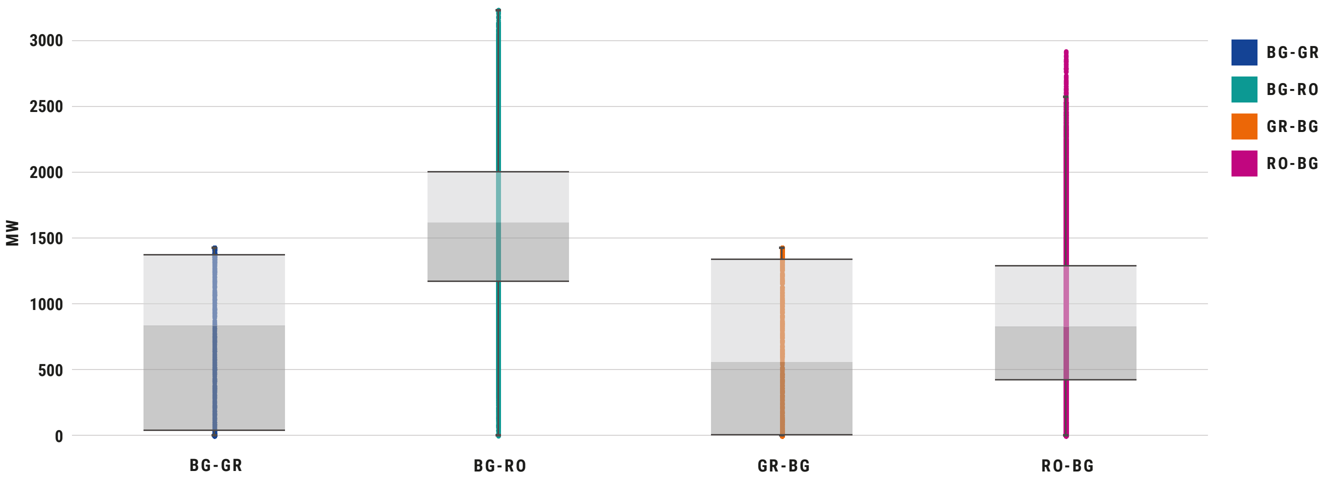



Figure 74: SEE CCR: Implicit offered ID capacities (2021–2022); Data source: Transparency platform

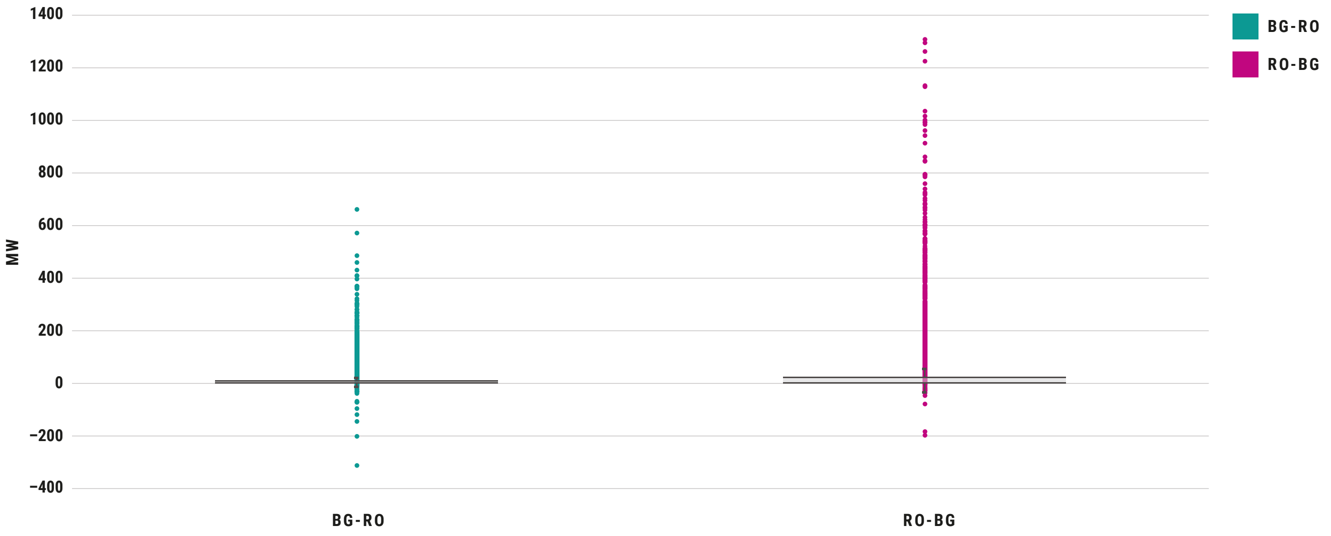



Figure 75: SEE CCR: Implicit allocated ID capacities (2021–2022); Data source: Transparency platform

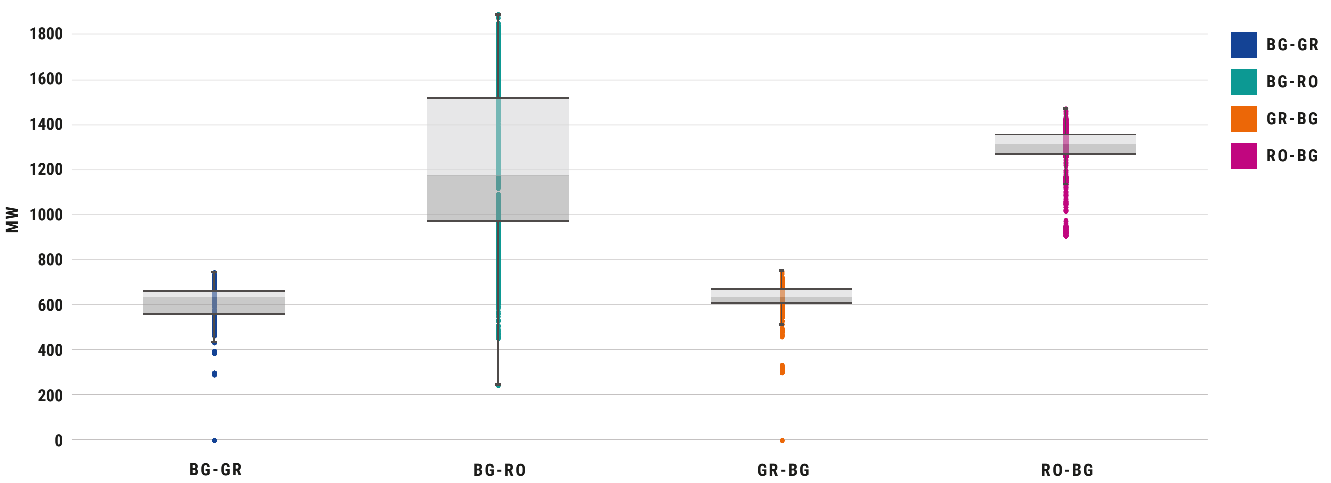



Figure 76: SEE CCR: Implicit offered DA capacities (01 July 2021 – 31 December 2022); Data source: OPSCOM reports

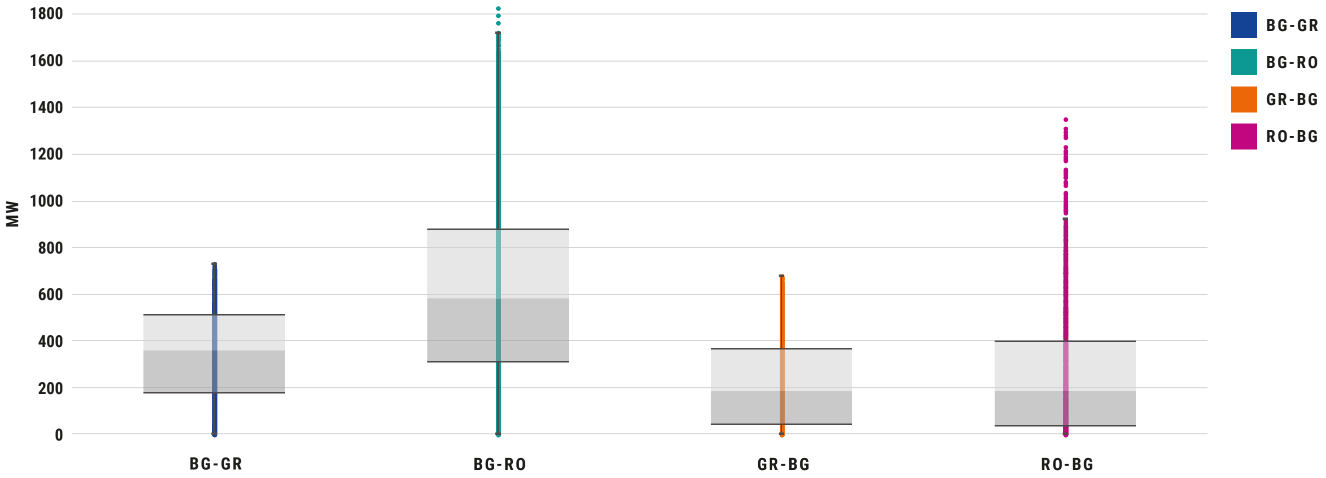



Figure 77: SEE CCR: Implicit allocated DA capacities (01 July 2021 – 31 December 2022); Data source: OPSCOM reports

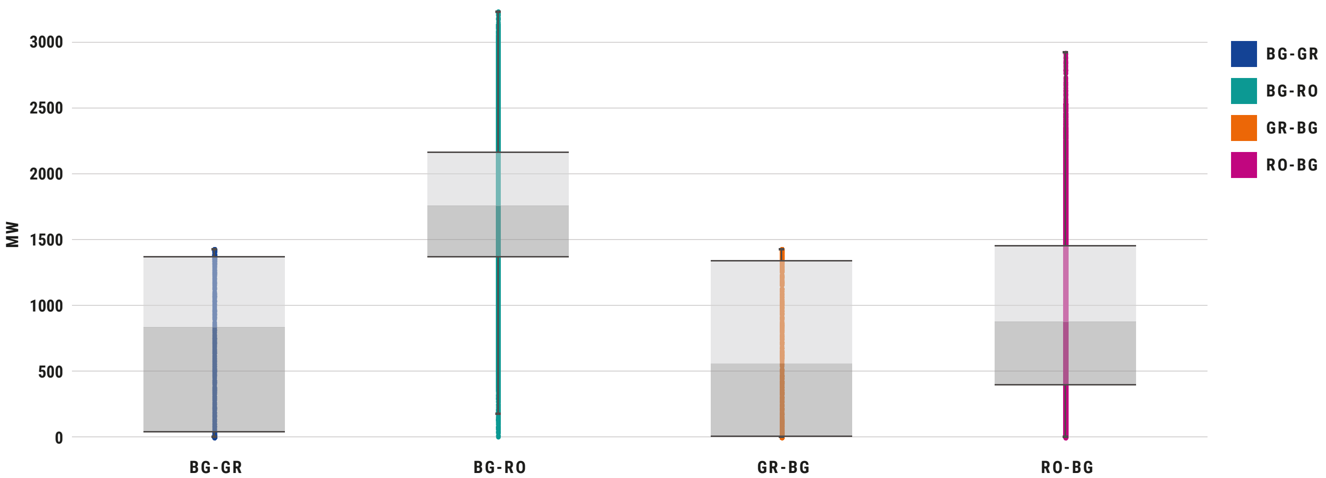



Figure 78: SEE CCR: Implicit offered ID capacities (01 October 2021 – 31 December 2022); Data source: Transparency platform

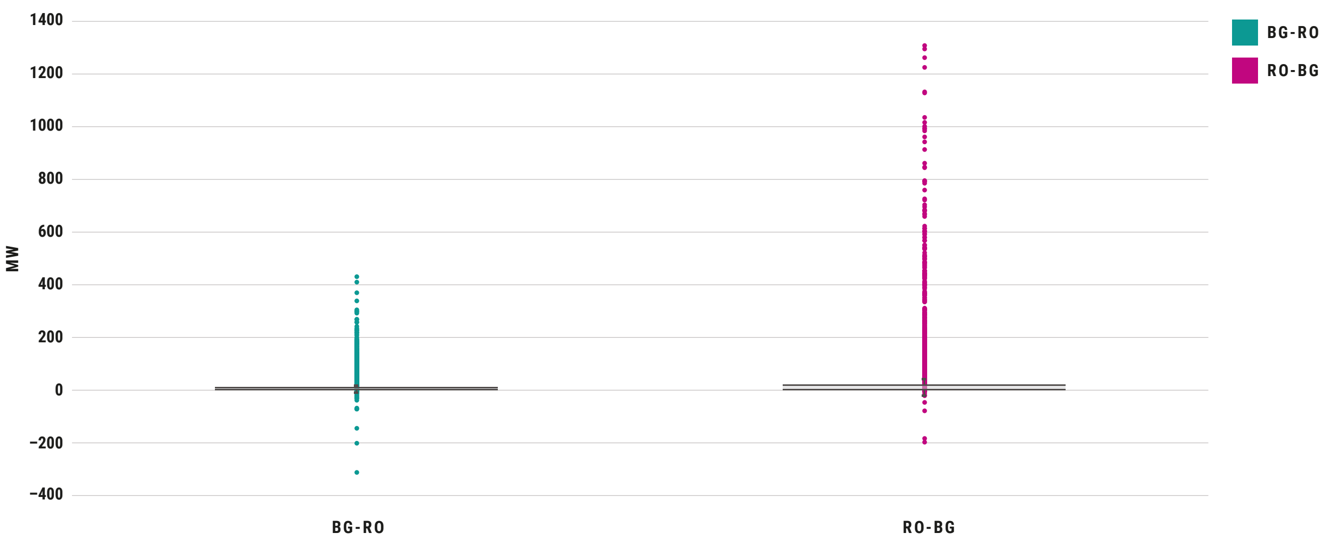



Figure 79: SEE CCR: Implicit allocated ID capacities (01 October 2021 – 31 December 2022); Data source: Transparency platform

## 3.8.3 Capacity calculation and allocation for the long-term

At the time of writing this report, the long-term CCM pursuant to Article 10 of the FCA regulation is in the drafting phase. Table 58 provides an overview of the already accomplished milestones of the SEE CCR long-term capacity calculation processes.

| Closed milestone(s) | |
|---|---|
| **Quarter** | **Description** |
| Q3 2019 | CCR submission of the SEE long-term CCM to the NRAs |
| Q3 2019 | CCR submission of the long-term Splitting Rules to the NRAs |
| Q4 2020 | NRA approval of the SEE long-term CCM submitted by the CCR |
| Q4 2020 | NRA approval of the long-term Splitting Rules submitted by the CCR |

Table 58: SEE CCR: Closed milestone(s) for long-term capacity calculation and allocation

As the drafting of the SEE CCR's long-term CCM is ongoing, the SEE CCR TSOs cannot currently provide an indication of the future use of long-term indicator(s).

## 3.8.4 Indicators for the long-term

As long-term CCM was not live in the reporting period 2021-2022, the PIs according to chapter 2 are not provided. Figure 80 shows the offered and allocated long-term capacities during 2021 and 2022 at borders, which will become part of the SEE CCR LTTR CCM. If a border is not shown, no long-term capacity had been offered during the reporting period.

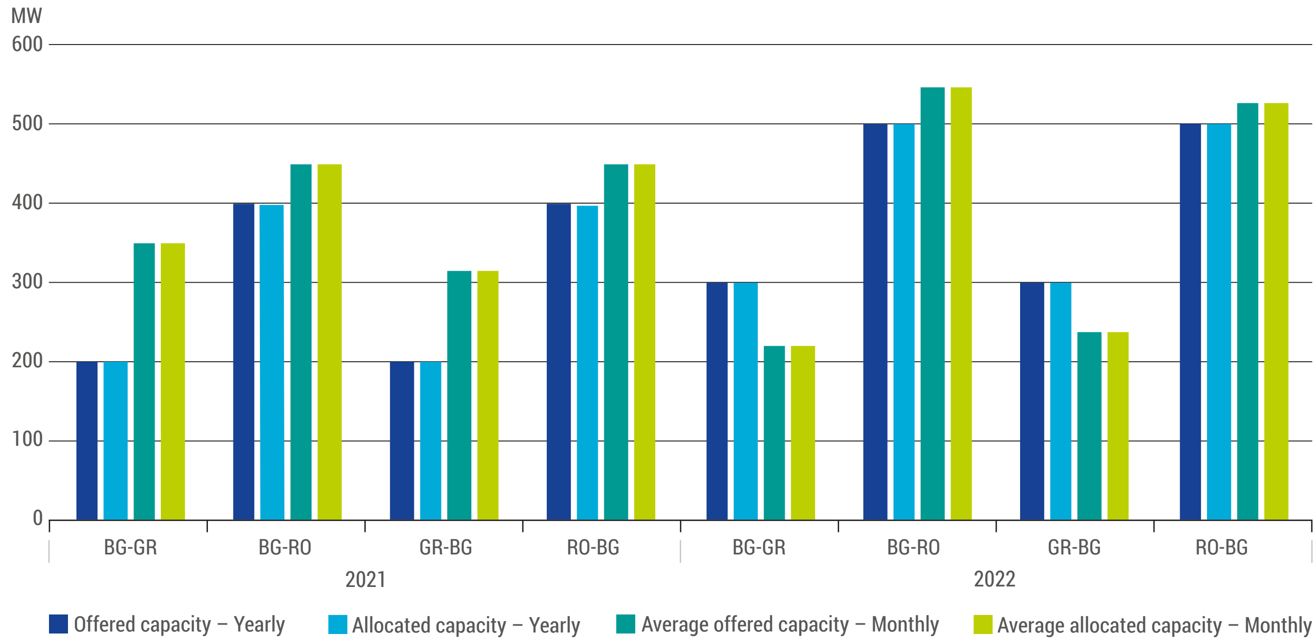



Figure 80: SEE CCR: Offered and allocated long-term capacities during 2021 and 2022. Data source: JAO, excl. January-February 2021, May–August 2021, October 2021 and December 2021, and January–February 2022, May 2022, July 2022 and December 2022 for BG-GR direction, and January-February 2021, May–August 2021 and November–December 2021, and January–February 2022, April–September 2022 and November–December 2022 for GR–BG direction with 0 offered/allocated capacity

# 4 Capacity Calculation Region Assessment Framework

All TSOs are developing a framework to outline the relevant parameters that need to be considered to achieve a comprehensive analysis of future CCR assessments. This chapter provides an overview of the current framework under development by the TSOs.

## 4.1 Background on the CCR Assessment framework

Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management[49] has defined **CCRs as 'the geographic area in which coordinated capacity calculation is applied'**. The determination of the CCRs is the basis for further implementation of terms and conditions or methodologies stemming from acts and EU Electricity Regulations of regional relevance and, therefore, **for important TSOs' coordination activities at Union and regional level, among which we find the following**:

- **methodologies for capacity calculation**, which is to be performed in a harmonised way (at least) at CCR level for **long term, day ahead and ID timeframes**[50];
- **methodology for regional operational security coordination** for agreeing and activating remedial actions in a coordinated way at CCR level[51];
- **methodology for remedial actions costs sharing** among the TSOs of a CCR[52];
- **regional coordination operational procedure for outage coordination** among TSOs of a CCR (OCR)[53]; and
- **regional adequacy assessment** for assessing week-ahead adequacy and proposing actions to reduce risks to the TSOs of a CCR[54].

TSOs' regional coordination is organised around different geographical levels, depending on the activity and on its timing. Those geographical levels can be grouped in CCRs and perimeters functional for balancing and system operation processes.

For TSOs, cooperation has always been a natural thing: electricity does not stop at borders and each country's power system is affected by its neighbours and vice-versa.

The importance of this cooperation has grown in the transition process to a net-zero economy. In fact, the clean energy transition must ensure sustainability, security of supply and energy at affordable prices for consumers. More efficient markets, more reliable system operation and the integration of renewable energy sources all require increased coordination among national electricity systems.

The management of system security and stability has gradually grown in terms of complexity and requires a stronger degree of coordination among TSOs. In light of this need, EU Electricity Regulations foster cooperation among TSOs.

49 See Article 2(3) CACM GL

50 See Article 20(2) CACM GL; Article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA GL); and Article 37 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB GL)

51 See Article 35 CACM GL; and Article 76 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (SO GL)

52 See Article 74 CACM GL; and Article 76 SO GL

53 See Article 83 of SOGL

54 See Article 81 of SOGL

The evolution of regional cooperation is shown below:

- The past century – TSOs (and the vertically integrated companies that preceded them) together built the synchronous and coordinated European network and developed voluntarily common or compatible standards based on common analysis and sharing of best practices.
- 2008 – the first regional coordination initiatives among TSOs are set up on a voluntary basis in central Europe[55].
- 2009 – 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 (Regulation (EC) 714/2009) requires TSOs to set up regional structures and to cooperate through the ENTSO to promote the internal market in electricity and to ensure the coordinated operation of the European grid. The document identifies seven regions where a common coordinated congestion management method and procedure for allocating capacity to the market should be used at least annually, monthly and DA. Allocation of interconnection capacity is coordinated and implemented through common allocation procedures by the participating TSOs. Congestion management methods shall be coordinated through a common congestion management procedure in cases where a commercial exchange between two TSOs is expected to significantly affect physical flow conditions in any third country (TSO).
- 2015 – CACM introduces the procedure for the determination of CCRs and defined it as geographic area in which coordinated capacity calculation is applied. The determination of the CCRs is the first step towards the implementation of the CACM GL, as the regulation requires the development and implementation of regional methodologies for CZC allocation and congestion management in electricity markets. CACM GL also introduces the role of the CCC as an entity which calculates transmission capacity at a regional level or above.
- Voluntary arrangements start: European TSOs and ENTSO-E sign a Multilateral Agreement which requires TSOs to participate in 'Regional Security Coordination Initiatives' (RSCIs)' or to contract a number of essential services from them. RSCIs must develop tools, standards, and methodologies in a harmonised, interoperable and standardised way under ENTSO-E's coordination.
- 2017 – Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (SO GL) formalised the Regional Security Coordinator's (RSC) role in EU law and defines in a standardised way what core services will be performed by RSCs[56]. SO GL also defines a common set of minimum requirements for Union-wide system operation to ensure the operational security of the interconnected transmission system, taking into account harmonised technical rules jointly developed by TSOs on a voluntary basis.
- 2019 – Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (Electricity Regulation) defines additional requirements for the regional coordination of TSOs, which has to be further developed via the establishment of 'Regional Coordination Centres' (RCCs)[57]
- 2020 – RSCs have successfully been set up.
- 2022 – RSCs completed the transition toward RCCs after 1 July 2022 in accordance with the Electricity Regulation.

55 Coreso, based in Brussels, and TSCNET, based in Munich. In 2015, another RSCI was created in south-eastern Europe (SEE) in Belgrade. In 2016, Nordic and Baltic RSCIs were established

56 RSCs' historically performed 5 types of services to each TSO: (1) operational planning security analysis (also known as coordinated security analysis); (2) outage planning coordination; (3) coordinated capacity allocation; (4) short- and very short-term adequacy forecasts; (5) individual and common grid modelling and data set delivery

57 With the Clean Energy Package (IEM Regulation), RSCs are relabelled as RCCs and additional tasks are added on top of the five described in the network codes and guidelines. IEM Regulation foresees that the tasks of RCCs (see art.37) should cover the tasks carried out by RSCs pursuant to the Commission Regulation (EU) 2017/1485 as well as additional system operation, market operation and risk preparedness tasks. The tasks carried out by RCCs should not include real-time operation of the electricity system

## 4.2 Legal references and requirements

CCRs were first introduced in the EU by CACM, Article 15, which defines them as 'the geographic area in which the coordinated capacity calculation is applied'[58]; the same definition is found in the Electricity Regulation[59].

CACM provides that CCRs shall be proposed by all TSOs[60] and shall be subject to approval by ACER[61]. In particular, Article 15(2) CACM indicates the requirements for the CCR definition:

- the proposal shall define the BZBs attributed to TSOs members of each CCR;
- the proposal shall consider the regions specified in point 3(2) of Annex I to Regulation (EC) No 714/2009;
- each BZB, or two separate BZBs, if applicable, through which interconnection between two BZs exists, shall be assigned to one CCR; and
- at least those TSOs shall be assigned to all CCRs in which they have BZBs.

This framework assessment considers the general principles and goals set out in the CACM as well as in the Electricity Regulation. The goal of the CACM is the coordination and harmonisation of capacity calculation and allocation in the DA and ID cross-border markets, and it sets requirements for TSOs to cooperate on the level of CCRs, on a pan-European level and across BZBs.

## 4.3 Purpose and structure of the CCR assessment framework

The following section provides an overview of the purpose and structure of the CCR assessment framework.

Article 12 'Future Assessment' of the ACER Decision on the determination of capacity calculation regions (Annex 1) of 7th May 2021[62], states as follows:

'all TSOs shall submit to ACER an assessment analysing alternative determinations of at least the CCRs Hansa, Nordic and Core in terms of:

(a) efficiency of capacity calculation and allocation in all timeframes; and

(b) efficiency of regional operational security coordination (ROSC) in accordance with Article 76(1) of the SO Regulation, coordinated redispatching and countertrading in accordance with Article 35 of the CACM Regulation and redispatching and countertrading cost sharing in accordance with Article 74 of the CACM Regulation and cross-regional operational security coordination in accordance with Article 75(1) of the SO Regulation.'

In preparation for these specific CCR assessments, all TSOs are developing a framework to outline the relevant parameters that need to be considered for achieving a comprehensive analysis. The framework document will be a 'toolbox' used by all TSOs to perform future assessments of CCR configurations. This chapter provides an overview of the current framework under development by the TSOs.

The framework applies to those CCRs, where additional efficiency might be achieved, and in particular: (1) when the concerned TSO(s) ask on a voluntarily basis to perform a CCR assessment, or (2) when there is a legal requirement to perform a CCR assessment.

The parameters considered in the framework address Article 12 (a)-(b) of ACER's Decision mentioned above. Additional parameters useful to assess the efficiency of CCRs, are included in the framework.

The assessment will be conducted by the relevant expert teams, with the objective to provide a proposal to All TSOs for a decision.

58 See Article 2(3) CACM GL

59 See Article 2(21) Electricity Regulation

60 See Article 15 CACM GL

61 The first version of CACM GL provided that the CCR proposal had to be approved by all the regulatory authorities. Commission Implementing Regulation (EU) 2021/280 of 22 February 2021 amended the Guidelines by shifting the competency of the approval to ACER

62 Found **here**.

The process of the framework is outlined with the three-step approach below:

### Step 1 – identification of CCRs for assessment:

In Step 1, the following indicators will be evaluated: (1) commercial exchange influence, (2) Influence of Remedial Actions, (3) Influence of Contingencies. Threshold values apply to each indicator. There are two cases:

1. Voluntary CCR assessment triggered by one or several TSO(s): If at least one indicator is above the threshold value, Step 2 (described below) is triggered. If no indicator reaches the threshold value, Step 2 is not triggered. However, a TSO can request a voluntary assessment, and an All TSOs decision will be taken whether or not to move forward with Step 2. In this case, a list of the best alternative CCR configurations to be assessed is proposed to All TSOs for decision.

2. Legal requirement upon CCR assessment: In case there is a clear legal requirement to assess a single CCR configuration or set of configurations, further configurations are not required to be developed and proposed. In this case, Step 2 is automatically triggered. In case there are no CCR configurations proposed in the legal requirement, a list of the best alternative CCR configurations to be assessed is proposed to All TSOs for decision. Subsequently, Step 2 is triggered.

### Step 2 – CCR configuration assessment:

Alternative CCR configurations are assessed against the status quo CCR configuration using the following parameters:

- Influence factors (as in Step 1);
- Efficiency of capacity calculation and allocation in all timeframes;
- Efficiency of ROSC;
- Efficiency of coordinated redispatching and countertrading;
- Efficiency of redispatching and countertrading cost sharing;
- Impact of CCRs on System Operation Regions (SORs);
- Transition and operational costs;
- Third-country involvement; and
- Governance.

### Step 3 – results and recommendations:

The assessment can lead to the following results:

- Keeping the status quo is more efficient than amending it. The following non-exhaustive list of solutions could be applied to improve the efficiency, where applicable:

  - Apply AHC;
  - Improve inter-CCR coordination;

OR

- An alternative configuration is more efficient than the status quo. The following could be alternative configurations if demonstrated to be more efficient than the status quo:

  - Moving a BZB from one CCR to another;
  - Merging two or more CCRs;
  - Splitting a CCR;
  - adding a BZB to a CCR; and
  - establishing a new CCR.

If step 2 is conducted, a recommendation will be made in step 3 and is subject to an all TSOs decision. If a more efficient alternative CCR configuration is identified, all TSOs shall submit to ACER a proposal for an amendment to the Determination of CCRs in accordance with Article 9(13) of CACM.

# Annexes

## Annex I – Legal references and requirements

ENTSO-E is required to draft a report on capacity calculation and allocation and to submit it to ACER in line with Articles 82(2)(b) and 31(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015, establishing a guideline on capacity allocation and congestion management (hereafter the 'CACM regulation') and Articles 26 and 63(1)(c) of Commission Regulation (EU) 2016/1719 of 26 September 2016, establishing a guideline on forward capacity allocation (hereafter 'the FCA regulation').

This report ensures the fulfilment of ENTSO-E reporting obligations as outlined in Articles 31(2) and 82(2)(b) of the CACM regulation and Articles 26(2) and 63(1)(c) of the FCA regulation.

In the letter of 9 March 2023, ACER requested that ENTSO-E deliver the CACM and FCA report on capacity calculation and allocation no later than 31 August 2023.

# Annex II – Glossary

| | |
|---|---|
| **50Hertz** | 50Hertz Transmission GmbH (1 of the 4 German TSOs) |
| **AC** | Alternating current |
| **ACER** | Agency for the Cooperation of Energy Regulators |
| **AHC** | Advanced hybrid coupling |
| **APG** | Austrian Power Grid AG (Austrian TSO) |
| **Amprion** | Amprion GmbH (1 of the 4 German TSOs) |
| **AT** | Austria |
| **ATC** | Available transfer capacity |
| **Baltic Cable** | Baltic Cable AB |
| **BE** | Belgium |
| **BG** | Bulgaria |
| **BRELL** | Belarus, Russia, Estonia, Latvia and Lithuania |
| **BZ** | Bidding Zone |
| **BZB** | Bidding zone border |
| **CACM** | Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management |
| **CC** | Capacity calculation |
| **CCM** | Capacity calculation methodology |
| **CCR** | Capacity calculation region |
| **CCC** | Capacity calculation coordinator |
| **ČEPS** | ČEPS a.s. (Czech TSO) |
| **CGM** | Common grid model |
| **CGMES** | Common grid model exchange standard |
| **CH** | Switzerland |
| **CNE** | Critical Network Element |
| **CNEC** | CNE associated with a contingency used in capacity calculation. The term CNEC also cover the case where a CNE is used in capacity calculation without a specified contingency |
| **CNOR** | Central-Northern (Italian bidding zone) |
| **cNTC** | Coordinated net transmission capacity |
| **CREOS** | Creos Luxembourg SA (Luxembourgish TSO) |
| **CRIDA** | Complementary regional intraday auctions |
| **CSUD** | Central-South (Italian bidding zone) |
| **CWE** | Central Western Europe |
| **CZ** | Czech Republic |
| **CZC** | Cross-zonal capacity |
| **D2CF** | 2-days ahead congestion forecast |
| **D-1** | Day before electricity delivery |
| **D-2** | Day two-days before electricity delivery |
| **DA** | Day-ahead |
| **DACF** | Day-ahead congestion forecast |
| **DC** | Direct current |
| **DE** | Germany |
| **DK** | Denmark |
| **EE** | Estonia |
| **EEA** | European Economic Area |
| **Elia** | Elia Transmission System Operator SA (Belgian TSO) |
| **ENTSO-E** | European Network of Transmission System Operators for Electricity |
| **Energinet** | Energinet Eltransmission A/S (Danish TSO) |
| **Elering** | Elering AS (Estonian TSO) |
| **ELES** | ELES, d.o.o. (Slovenian TSO) |
| **EPR** | External parallel run |
| **ESO** | Electroenergien Sistemen Operator EAD (Bulgarian TSO) |
| **EU** | European Union |
| **FB** | Flow-based |
| **FCA** | Forward capacity allocation |
| **FI** | Finland |
| **Fingrid** | Fingrid Oyj (Finish TSO) |
| **FR** | France |
| **FRM** | Flow Reliability Margin |
| **FTR** | Financial transmission right |
| **GLSK** | Generation and load shift key |
| **GR** | Greece |
| **GRIT** | Greece – Italy |
| **GSK** | Generation shift key |
| **HR** | Croatia |
| **HOPS** | Croatian Transmission System Operator Plc. (Croatian TSO) |

| | |
|---|---|
| **HU** | Hungary |
| **IPTO** | Independent Power Transmission Operator SA (Greek TSO) |
| **ID** | Intraday |
| **IGM** | Individual grid model |
| **IT** | Italy |
| **JAO** | Joint Allocation Office |
| **KF CGS** | Kriegers Flak combined grid solution |
| **Litgrid** | Litgrid AB (Lithuanian TSO) |
| **LT** | Lithuania |
| **LTCC** | Long-term transmission capacity |
| **LTTR** | Long-term transmission right |
| **LU** | Luxembourg |
| **LV** | Latvia |
| **MACZC** | Margin available for cross-zonal capacity |
| **MAVIR** | Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság (Hungarian TSO) |
| **MC** | Market coupling |
| **MTU** | Market Time Unit |
| **MW** | Megawatt |
| **NEMO** | Nominated Electricity Market Operator |
| **NL** | Netherlands |
| **NORD** | Northern (Italian bidding zone) |
| **NTC** | Net transfer capacity |
| **NRA** | National regulatory authority |
| **OPF** | Optional Power Flow |
| **OPSCOM** | SDAC Operations Committee |
| **PL** | Poland |
| **PSE** | Polskie Sieci Elektroenergetyczne (Polish TSO) |
| **PST** | Phase shifting transformer |
| **PTDF** | Power Transfer Distribution Factor |
| **PTR** | Physical transmission right |
| **Q1** | First quarter |
| **Q2** | Second quarter |
| **Q3** | Third quarter |
| **Q4** | Fourth quarter |
| **RA** | Remedial action |
| **RAM** | Remaining available margin |
| **REE** | Red Eléctrica de España SAU (Spanish TSO) |
| **REN** | Rede Eléctrica Nacional, SA (Portuguese TSO) |
| **RCC** | Regional Coordination Centre |
| **RM** | Reliability margin |
| **RO** | Romania |
| **RTE** | Réseau de Transport d'Electricité (French TSO) |
| **RSC** | Regional security coordinator |
| **RSCI** | Regional Security Coordination Initiatives |
| **SAP** | Single allocation platform |
| **SARD** | Sardinia (Italian bidding zone) |
| **SE** | Sweden |
| **SEE** | South-East Europe |
| **SEPS** | Slovenská elektrizačná prenosová sústava, a.s. (Slovak TSO) |
| **SI** | Slovenia |
| **SICI** | Sicily (Italian bidding zone) |
| **SK** | Slovakia |
| **Statnett** | Statnett SF (Norwegian TSO) |
| **SUD** | Southern (Italian bidding zone) |
| **Svenska** | Svenska kraftnät (Swedish TSO) |
| **SWE** | South-West Europe |
| **Swissgrid** | Swissgrid ag (Swiss TSO) |
| **TenneT NL** | TenneT TSO B.V. (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 SA (Romanian TSO) |
| **TransnetBW** | TransnetBW GmbH (1 of the 4 German TSOs) |
| **TRM** | Transmission reliability margin |
| **TSO** | Transmission System Operator |
| **TTC** | Total Transfer Capacity |

# Annex III – List of figures

# Annex IV – List of tables

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**Publisher**

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**Design**

DreiDreizehn GmbH, Berlin | www.313.de

**Images**

iStockphoto.com

**Publishing date**

30 June 2023

European Network of
Transmission System Operators
for Electricity