Framework for Assessing the Configuration of Capacity Calculation Regions

18 December 2023

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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 using 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

Following Article 12 of Annex I of Agency for the Cooperation of Energy Regulators (ACER) Decision 04/2021 that asked for an assessment of, at least, Capacity Calculation Regions (CCRs) Hansa, Core and Nordic, **Transmission System Operators (TSOs) decided to develop this CCR assessment framework on a voluntary basis.** The purpose is to apply this framework to any CCR assessments in the future, including assessments resulting from a legal requirement (e.g. Article 12 of Annex I ACER Decision 04/2021) in addition to any other CCR assessment TSOs wish to perform.

The assessment framework proposes a three-step approach to analysing CCRs

- **Step 1: identify alternative CCR configuration(s);**
- **Step 2: assess the alternative CCR configuration(s) against the status quo; and**
- **Step 3: Either maintain the current status quo of CCRs in the event it is more efficient than the alternative CCR configuration(s) assessed or provide a recommendation to amend the CCRs configuration in the event a different scenario is found to be more efficient than the status quo.**

Due to the nature of applying the framework to different cases, the framework considers the concepts of flexibility and adaptability. For this reason, both mandatory and optional indicators are proposed for assessing certain parameters in Step 2, and data sources and computation approaches are deliberately left out of the scope of this framework as these might differ from case to case and vary over time.

The adaptable stepwise structure of the framework and the flexibility proposed in the parameters are expected to simplify the CCR assessments over the coming years while giving a consistent structure, ensuring TSOs consistently consider all relevant factors.

1 Introduction

Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM GL)[1] has defined **CCRs as "the geographic area in which coordinated capacity calculation is applied".** The determination of the CCRs is **the basis** for the further implementation of terms and conditions or methodologies (TCMs) stemming from acts EU Electricity Regulations of regional relevance and, therefore, **for important TSOs' coordination activities at the pan-European and regional level, among which we find the following:**

- **methodologies for capacity calculation**, which is to be performed in a harmonised manner (at least) at CCR level for **long term, day ahead and intraday timeframes[2];**
- **methodologies for regional operational security coordination (ROSC)** for agreeing and activating remedial actions (RAs) in a coordinated manner at CCR level[3]; and
- **methodologies for RAs costs sharing** among the TSOs of a CCR[4];
- **regional coordination operational procedure for outage coordination** among TSOs of a CCR (OCR)[5]; and
- **regional adequacy assessment** for assessing week-ahead adequacy and proposing actions to reduce risks to the TSOs of a CCR[6].

TSOs' regional coordination is organised around different geographical levels, depending on the activity and on its timing. Those geographical levels are grouped into CCRs, System Operation Regions (SORs) and balancing cooperation services.

TSOs have always cooperated as electricity flow 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 regarding complexity and requires a stronger degree of coordination among TSOs. In light of this need, European Union (EU) electricity regulations foster and mandate cooperation among TSOs.

1 See Article 2(3) CACM GL.

2 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).

3 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).

4 See Article 74 CACM GL; and Article 76 SO GL.

5 See Article 83 of SOGL.

6 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 up the synchronous and coordinated European network and developed voluntarily common or compatible standards based on common analysis and the sharing of best practices.

- **2008:** the first regional coordination initiatives among TSOs are set up on a voluntary basis in Europe[7].

- 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 cooperate through ENTSO-E to promote the internal market in electricity and 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 day-ahead. Allocation of cross-zonal 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 GL introduces a procedure for the determination of CCRs and defined them as geographic areas in which coordinated capacity calculation is applied. The determination of the CCRs was the first step towards the implementation of the CACM GL as the regulation requires the development and implementation of regional methodologies for cross-zonal capacity allocation and congestion management in electricity markets. CACM GL also introduces the role of the coordinated capacity calculator as an entity which calculates transmission capacity at a regional level or above.

  Voluntary arrangements begin: European TSOs and ENTSO-E signed 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 manner 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 role of the Regional Security Coordinator (RSC) in EU law and defines in a standardised manner what services will be performed by RSCs[8]. 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, considering 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)

- **2020:** RSCs are successfully set up.

- **2022:** RSCs completed the transition toward RCCs after 1 July 2022 in accordance with the Electricity Regulation.

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7 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.

8 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; and (5) individual and common grid modelling and data set delivery.

1.1 Legal references and requirements

CCRs were first introduced in the EU by CACM GL, Article 15, which defines them as *"the geographic area in which the coordinated capacity calculation is applied"*[9]; the same definition is found in the Electricity Regulation[10].

CACM GL provides that CCRs shall be proposed by all TSOs[11] and shall be subject to approval by ACER. In particular, Article 15(2) CACM GL indicates the requirements for CCR definition:

- the proposal shall define the bidding zone borders (BZBs) attributed to TSOs that are 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 bidding zones (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 GL as well as in the Electricity Regulation. The goal of the CACM GL is the coordination and harmonisation of capacity calculation and allocation in the day-ahead and intraday cross-border markets, and it sets requirements for TSOs to cooperate on the level of CCRs, on a pan-European level and across BZBs.

1.2 Purpose and structure of the assessment framework

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

Article 12 "Future Assessment" of ACER Decision 04/2021 on the determination of capacity calculation regions (Annex 1) of 7th May 2021, 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 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 a CCR assessment, all TSOs have developed this framework to outline the relevant parameters that require consideration to achieve a comprehensive analysis. The framework document is a "toolbox" to be used by all TSOs when performing any future assessments of CCR configurations.

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 CCR assessment will not be performed on a regular basis.

The parameters considered in the framework address Article 12(a) – (b) of ACER's Decision mentioned above. Additional parameters useful for assessing the efficiency of CCRs are included in the framework.

The assessment will be conducted by the relevant TSO expert teams, with the objective of providing a proposal to All TSOs for a decision to request an amendment of the Determination of CCRs, which will then be submitted to ACER for approval.

9 *See* Article 2(3) CACM GL.

10 See Article 2(21) Electricity Regulation.

11 See Article 15 CACM GL.

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

› Step 1: identification of CCRs for assessment

The objective of Step 1 is to determine the alternative CCR configurations to be analysed against all the criteria described in Step 2. For this purpose, a *list of needs* will be established based on quantitative indicators (Market flow crossing from one CCR flowing through another CCR, Influence of RAs, Influence of contingencies) and also other needs (e.g. request from ACER and NRAs to assess a specific area). From this *list of needs*, alternative CCR configuration(s) will be proposed for further study. If the *list of needs* is empty, no further study will be required.

› Step 2: CCR configuration assessment

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

1. Influence factors (as in Step 1);
2. Efficiency of capacity calculation and allocation in all timeframes;
3. Efficiency of ROSC;
4. Efficiency of coordinated redispatching and countertrading;
5. Efficiency of redispatching and countertrading cost sharing;
6. Impact of CCRs on SORs;
7. Transition and operational costs;
8. Third-country involvement; and
9. Governance.

The parameters will be assessed depending on the configuration under consideration; therefore, not all parameters may always be assessed/calculated in an assessment. This could, for example, be the case for CCRs with radial connections or High Voltage Direct Current interconnectors (HVDCs) only where not all parameters are applicable.

› Step 3: results and recommendations

The assessment can lead to the following results:

1. Keeping the status quo is more efficient than amending it. For example, the application of advanced hybrid coupling (AHC) could be recommended as a solution to improve the efficiency of the status-quo CCR.

   OR

2. An alternative configuration is more efficient than the status quo. The following reconfiguration could take place if demonstrated to be more efficient than the status quo:
   (a) Moving a BZB from one CCR to another;
   (b) Merging two or more CCRs;
   (c) Splitting a CCR;
   (d) Adding a BZB to a CCR; and
   (e) Establishing a new CCR.

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

The CCR configuration should be sufficiently stable. A change of the CCR configuration could require the amendment to TCMs to avoid uncertainties or inconsistencies. The CCR configuration should therefore not be amended frequently.

The general assessment framework presented in this document offers a general guidance and enables a flexible approach when reassessing the CCR configurations. As such, there might be additional aspects that require consideration for a certain alternative CCR.

To perform some of the analysis described in this assessment framework, it may be necessary to access data classified as secret/confidential according to national legislation. Depending on the specific circumstances, a TSO may, therefore, not be able to share some data that may be necessary to perform some of the analysis described in this assessment framework if the data are classified as secret/confidential data according to national legislation.

1.3 AHC as an alternative to improving the efficiency of the status quo CCR

One of the main tasks of a CCR is to compute the capacities that will be offered to market mechanisms. Some of the other tasks include the efficient coordination, activation and cost-sharing of RAs.

For most CCRs, during the capacity calculation process, the TSOs of one CCR are considering the capacity that will be used by other CCRs. This capacity is then reserved and not directly offered to the market mechanisms. This is known as Standard Hybrid Coupling (SHC). To solve the inefficiencies present with SHC, AHC can be applied. AHC is an enhancement of the flow-based (FB) CCM, representing a more detailed modelling of the influence of the Coordinated Net Transmission Capacity (cNTC) BZB on the AC network flows. Thus, this allows these borders to compete for the scarce capacity within the FB area and vice versa, thereby enabling a non-discriminatory economic optimisation. In AHC, no forecast is needed. The effect of an exchange over an external border is mathematically calculated and used as an input for the welfare optimisation of the implicit market coupling.

As the efficiency of capacity calculation and allocation processes is one of the key criteria for evaluating and determining the configuration of CCRs, applying AHC can be viewed as an alternative. Efficiency can, in this context, be understood as how to maximise cross-zonal capacities and welfare when allocating the cross-zonal capacity.

- SHC can be a source of inefficiencies. The best forecast of the exchange on the external border is seen as a fixed feed in/feed out, thus the capacity of a grid element is ex-ante split between how much is used by external borders and how much is available for the BZBs inside the CCR. In the market coupling, however, the exchange across the external border is a parameter which can vary between 0 and 100 % of the available transfer capacity (ATC) of the border. This means that the allocated amount of exchange can be different from what was forecasted:
  - If best forecast < allocated (underestimation): risk of overloading of the grid elements which may require redispatching.
  - If best forecast > allocated (overestimation): unused capacity causing welfare losses might remain.

With AHC, it is not necessary to make an ex-ante split of the capacity based on forecasts. The capacity calculation now also includes the mathematical representation of how much capacity of each grid element is used by market exchanges over the external borders with AHC. The market coupling now has all the information required to decide how to allocate the available capacity most efficiently across all borders in order to maximise the welfare.

The application of AHC has some limitations:

- AHC is applicable for a CCR that applies an FB capacity calculation methodology. If the commercial exchange influence threshold has flagged a cNTC CCR, then cross-border influence can be addressed with AHC in the adjacent FB regions;
- In a situation where two CCRs are being influenced by each other's borders, with one CCR applying FB and the other one applying cNTC, AHC can – in some situations – address the need for efficient allocation of scarce capacities across borders in a non-discriminatory manner; and
- AHC does not address the issues after the process of capacity calculation and allocation, such as ROSC.

2 Step 1 – Identification of CCR(s) for assessment

2.1 Process

The objective of Step 1 is to determine the alternative CCR configurations to be analysed against all the parameters described in Step 2. If no need arises, no alternative CCR configuration will be analysed.

First, a *list of needs* has to be created. Graphically, if the *list of needs* is displayed on a map, it looks like an European map with highlighted areas. These areas are either grid elements linked to CCR influence or additional highlighted zone (e.g. legal requirements to assess an area).

Three quantitative indicators (*market flow crossing from one CCR flowing through another CCR, influence of RAs outage transfer distribution factor*) are defined in sub-section 2.2. When a defined threshold is reached for at least one simulation, the grid element will be included in the *list of needs*. When the threshold is not reached, the TSOs have the possibility to still include the grid element in the *list of needs*. Indeed, only a limited number of timestamps will be computed and might not represent future changes in the network, or flow pattern (new consumption, new production etc.). It is then important for the TSOs to review and add possible needs to propose representative alternative CCR configurations (for example, in the event of a radial connection between BZs, or a set of HVDC-only BZBs). In addition, some requirements can come from decisions from regulators, application of the legal framework or a new BZB being created. All these extra requirements would have to be included in the *list of needs*.

Based on the *list of needs,* alternative configurations have to be proposed. For example, if in an area between two present CCRs, many elements are identified, a merge of the CCRs could be proposed. As soon as the *list of needs* is not empty, a CCR reconfiguration should be proposed for assessment.

The output of Step 1 shall be a set of alternative CCR configurations addressing the *list of needs.* The proposals will not include all BZBs. For example, in the event of a merge of two CCRs, all other CCRs could remain unchanged. The proposed set of alternative CCR configurations should aim to propose alternative CCRs for all the *needs* in a reasonable number of alternative CCR configurations.

2.2 Influence Factor indicator

The geographical scope of the Influence Factor study needs to be limited to the existing CCR interfaces where cross-regional influence is expected or where analysis is requested, among the below described parameters. This means that such a study is to be realised on the borders where such interaction between CCRs is expected from an expert perspective. If so, then a list of Critical Network Elements and Contingencies (CNECs) and RAs, to be identified by experts, will be relevant for the study.

For the purpose of CCR reconfiguration, a study on all borders, or all CNECs from the European grid, is not relevant.

2.2.1 Market flow crossing from one CCR flowing through another CCR

The high-level concept aims to evaluate the commercial exchanges influence on a cross-zonal border over CNECs appointed to a neighbouring BZ or a neighbouring CCR. The Influence Factor which is evaluated is a PTDF zone-to-zone factor, from a BZ belonging to a different CCR to the one the monitored CNEC is appointed to. Such flows can be identified in any BZ, but especially in BZs belonging to several CCRs. In the event this commercial exchange influence is higher than the predefined threshold, the assessment of considered CCRs will be further investigated. The threshold for this indicator is 10 %.

For this study, when assessing these flows on one CNEC belonging to CCR A, it is necessary to use the Generation Shift Key (GSK) files from the BZs belonging to the neighbouring CCR B (BZ1, BZ2, etc...) to evaluate this commercial exchange influence from CCR B towards CNEC belonging to CCR A. Such a computation will be run on CNECs (cases with outage) from CCR A. As such, the GSK method per BZ located in CCR B might be different (e.g. proportionally to generation, proportionally to reserve), but the actual calculation is done by increasing generation in BZ 1 (belonging to CCR B) for X (e.g. 1 MW) while simultaneously decreasing the generation in BZ 2 (belonging also to CCR B) for the same amount of 1 MW and by observing the changes of flows on a relevant CNEC in CCR A. This is done sequentially by using the same MW shift amount (e.g. 1 MW) for all possible BZ from-to combinations in CCR, considering BZBs attributed to CCR B. The computation has to be performed for every external border and then summed (only positive values count; negative values are set to zero) to evaluate if the threshold is reached. As such, a worst-case influence is assessed of loading per CNEC (located in CCR A) and caused by CCR B.

HVDC cables have to be considered in this influence factor. For example, in the event 2 BZs are interconnected by one HVDC cable only, the same reasoning as the one above applies, but in addition it will be also necessary to adapt the schedule of HVDC cable according to the increase and decrease of generation in the two BZs.

2.2.2 Influence of RAs (topological, PST, and costly)

In addition to commercial exchange influence on capacity of other BZB, the influence of RAs, identified as relevant for this cross-zonal border should be considered.

For this study, when assessing the RA influence factor towards one CNEC belonging to CCR A, it is necessary to use RAs appointed to a BZ belonging to the neighbouring CCR B. Only the individual RA will be considered for this computation, meaning no combinatory for RAs will be considered (this is arbitrary but necessary to reduce the computation complexity). Only appointed RAs from CCR B will be individually monitored on the considered CNEC from CCR A. For Phase Shifting Transformer (PSTs), the activation of the full range from neutral position will be modelled.

The threshold for this indicator is 10 % and is in line with the Coordinated Security Analysis (CSA) methodology.

2.2.3 Influence of outages (Outage Transfer Distribution Factor)

The influence of the contingency of a Critical Network Element (CNE) appointed to a different BZ/CCR over a cross-zonal border is also a relevant parameter to be evaluated when assessing CCRs, if the contingency of a CNE appointed to a neighbouring CCR has an influence higher than 25 %. The 25 % threshold is a maximal value in line as defined in Annex 1 of the CSA methodology (AI.2.1, equation for the calculation of the power flow identification influence factor of an external contingency list).

For this study, when assessing the Contingency influence towards one CNEC belonging to CCR A, an outage (contingency located in CCR B) needs to be set on the considered Network Element to evaluate its influence on the monitored CNEC from CCR A.

3. Step 2 – CCR configuration assessment

The assessment of any CCR configuration and the assumptions of the status quo should consider the expected market and system conditions for a medium-to-long term future time horizon.

The assessment framework should be feasible to execute. Performing full-scale simulations mimicking capacity calculation, market coupling and operational security processes is considered out of the scope of this assessment framework. Thus, regarding the evaluation of the efficiency of capacity calculation and allocation, and the efficiency of ROSC, the quantification of these indicators is oriented towards assessing the technical interdependencies between CCRs and not on quantifying socioeconomic welfare, nor on quantifying the volume/cost of redispatch. Notwithstanding, the assessment framework gives the possibility for a TSO to raise a flag in the event it considers and demonstrates a particular need for a more detailed analysis of some indicators.

Some of the parameters explained below might be considered irrelevant in an actual assessment depending on the proposed CCR configurations for assessment as there is no added value of assessing such indicators for some cases, including (but not limiting to) CCRs with radial connections or HVDCs only, for example.

Within all the parameters described below, the option is given to assess the additional indicator "regional specificities" (see Annex 1 for elaboration) under all parameters, if deemed relevant. The relevance of such an indicator is highly dependent on the CCR configuration(s) assessed, and this indicator is therefore optional. Regional specificities are not strictly related to the current status quo of the CCRs, but instead they are distinctive peculiarities due to the pure geographical/network specificities of the regions and the determining characteristics of the electricity system in those areas. Indeed, these specificities are relevant and to be considered in any type of analysis – not only for a CCR revision.

3.1 Influence Factors

With the assessment using influence factors, a change of mutual influence between CCRs in an alternative configuration compared to the status quo shall be assessed.

Mandatory Indicators

Influence Factors - Quantitative

Application of the indicators

The calculation of different values for status quo is already done in Step 1. A re-evaluation of results will be performed in Step 2 as the results from Step 1 would need to be aggregated differently to replicate the alternative CCR structure(s). A lower number of cross-CCR network elements when comparing the different CCR configurations shall be considered as positive (gain in market efficiency). A positive outcome of this parameter will also be the complete removal of a cross-CCR influence on some network elements (no loss of efficiency due to uncertainties from different CCRs) as some network elements, for example in the case of the merge, would be fully integrated in the new CCR. At the same time, a mutual influence between CCRs in the new configuration(s) will need to be kept at the acceptable level.

3.2 Efficiency of capacity calculation and allocation

The efficiency of the capacity calculation and allocation process is highly linked to the CCR configuration and the methodologies applied in such CCRs. Changes to CCR configurations therefore need to consider the impact on the efficiency of the capacity calculation and allocation process to ensure the optimal use of the capacity given to the market in the relevant timeframes. Ideally, changes to the status quo CCR configuration should not lead to reducing the cross-zonal capacity offered to the market.

One mandatory indicator: impacts on capacity provision. Two optional indicators – (1) level of margin from non-coordinated capacity calculation (MNCC) in the different CCR configurations, and (2) flow distribution on CNECs on a BZB depending on the applied capacity calculation methodologies – are provided due to the regional specificities.

Mandatory indicator

Impacts on capacity provision – qualitative indicator

Relevance of the indicator

A change of CCR configuration could impact the amount of cross-zonal capacity provided to the market. The purpose of this parameter is to identify the various reasons for why capacity provision might be impacted and to provide a qualitative analysis of this impact.

Application of the indicator

For each alternative CCR configuration, a list of reasons for why capacity provision might be impacted shall be provided. For each item in this list, an assessment shall be made specifying which BZBs and capacity calculation time-frames are likely to be most affected and whether the impact on capacity provision is likely to be positive or negative. The assessment will be based on capacity calculation expertise.

Optional indicators

Depending on the actual CCR configuration assessed, some optional indicators can be assessed. Regarding the efficiency of capacity calculation and allocation, where feasible the optional indicators below can be assessed:

(1) Indicator

Level of MNCC in the different CCR configurations.

Relevance of the indicator

With the change of CCR configuration, for example, in the event of a merge, the level of MNCC per CNE will be changed as some of the market flows which used to be non-coordinated (created outside of a native CCR) will now be coordinated (MCCC) within the new CCR. Increasing the MCCC will lead to a more efficient capacity calculation and allocation process.

The limitation of this indicator is the use of scheduled exchanges. Scheduled exchanges are not meant to be used per border but as a regional net position (e.g. North Italian border, CORE).

Application of the indicator

Quantitative: A simple re-evaluation of MNCC values using the historical data sets for the different CCRs. Decrease in MNCC and increase of MCCC values (per CNE) is a positive parameter for the efficiency of capacity calculation and allocation.

(2) Indicator

Flow distribution on CNECs on a BZB depending on the applied capacity calculation methodologies:

Relevance of the indicator:

Analysis of the flow distribution on CNECs on a BZB depending on the applied methodologies for capacity calculation and allocation processes. This indicator is only relevant in the event the CCRs assessed apply different capacity calculation processes.

Application of the indicator:

Quantitative/qualitative: Based on a load flow simulation of different scenarios and power flow on the BZB, the flow distribution of CNECs on the BZB is assessed regarding:

1. How this potentially can be impacted by change of CCM; and
2. How this impacts loop flows on/including the border.

3.3 Efficiency of ROSC (SO GL Article 76)

The efficiency of the ROSC process depends on many factors, including the CCR configuration. Inefficiency might be caused in the event two CCRs are mutually strongly interconnected but also due to the sequential optimisation steps (first CCR and only subsequently cross-CCR optimisation), as described in chapter 3.3.1. The size of a CCR where ROSC is performed has a direct impact on the duration of the process, as described in chapter 3.3.2. The number of CCRs impacts the necessity of coordination between CCRs and the time needed to perform the coordination, as described in 3.3.3. It must be recognised that different approaches might currently apply from one CCR to another CCR and, therefore, when assessing the efficiency of ROSC, such differences across CCRs which could be affected by changes to the ROSC process should also be considered, as described in section 3.3.4.

The indicators in this section intend to capture the trade-off between:

- the size of CCRs
- enabling an optimum regarding the efficiency on a greater scale within a CCR to be found (section 3.3.1),
- taking more computing time to find that optimum (section 3.3.2);
- the number of CCRs, affecting the time needed for cross-CCR coordination (section 3.3.3); and
- the impacts of CCR configurations on ROSC processes (section 3.3.4).

3.3.1 Inefficiencies in the phase of the (regional) coordinated security analysis process

Optional indicator

Impact of RAs in one BZ on elements in another BZ

Relevance of the indicator

Each ROSC implementation optimises the use of RAs to solve contingencies within that region. To avoid overlaps, each RA and each overlapping Cross-border Relevant Network Element (XNE) can only be assigned to one CCR, while the contingencies are assigned to both CCRs. It is up to the TSOs which are part of multiple CCRs to decide which of their XNEs and RAs belong to which CCR.

To ensure that all contingencies, even those near CCR borders, are solved in the CSA process, the ROSC is followed by a coordinated cross-regional operational security assessment. This is a process of coordinating RA use between CCRs to relieve the remaining congestions on overlapping XNEs in one CCR with RAs from another CCR.

Inefficiencies in the ROSC process may arise if RAs in one CCR have a significant impact on another CCR. While the RA use in a CCR is based on optimisation and, therefore, selects a set of RAs with the highest social welfare, the cross-regional process is based on simplified assumptions.

Application of the indicator

Considering results from the Influence Factor in Step 2 (Section 3.1), this indicator assesses whether there is **an increase or a decrease of the mutual cross-zonal influence** when comparing the status quo with the proposed alternative CCR configurations.

3.3.2 Potential tool limitations due to the size of a CCR

Optional indicator

Duration of a Coordinated Regional Operational Security Assessment (CROSA) run in a CCR

Relevance of the indicator

The size of a CCR is highly correlated with the size of the problem to be optimised in both Capacity Calculation and CSA processes.

It is very important to keep a good balance between tool optimisations and the size of a CCR. Steps advocating for a potential merge of BZBs with already existing CCRs require balancing with an analysis of such a potential tool limitation. Keeping a problem sufficiently simple by keeping separated CCRs or borders is also one argument for not merging CCRs and BZBs. On the other hand, as explained in the other chapters, this potential simplification has to be compared with e.g. the eventual loss of economic efficiency (e.g. sub-optimal results of RAs optimisation) if CCRs remain separated. If the CCRs are enlarged, the problem stated above will still remain, but the outcome of the optimisation might be different (i.e. a larger pool of RAs is available for optimisation, allowing for greater efficiency).

In ROSC, the size of the CCR significantly affects the duration of regional calculation – optimisation of RAs. The binding times for each step of the process are defined in legislation[12] and must therefore be respected unless the methodologies are amended. The size of the CCRs shall therefore allow for the optimising algorithm run time to fit with the time constraints (*T1 and T2*) defined in the legislation.

Application of the indicator

As the ROSC optimising algorithms are still in development, the time needed for their runs is not known. A qualitative analysis shall be done, at least until CSA is fully implemented.

3.3.3 Potential tool limitations due to the number of CCRs

Optional indicator

Duration of cross-CCR coordination

Relevance of the indicator

The number of CCRs affects the duration of cross-regional coordination process. These processes follow regional runs. Similar to regional processes, the time constraints of the cross-regional process are defined in the legislation.

The higher the number of CCRs, the longer the coordination takes. Therefore, the number of CCRs shall allow for the cross-regional coordination process to fit with the time constraints defined in the legislation (*T4 and T5*). Nonetheless, if there is a lower number of CCRs due to their merge, the necessity for a highly sophisticated cross-CCR coordination process shall need to be challenged. This might allow more time to be given to the main optimisation run.

Application of the indicator

As the cross-CCR coordination process is still in development, the time needed for their runs is not known. Instead, the number of CCR pairs requiring coordination shall be compared.

12 Article 33 of Methodology for coordinating operational security analysis, available here.

3.3.4 Qualitative assessment of the impact on ROSC processes

Mandatory indicator

Impacts of CCR configurations on ROSC processes – qualitative indicator

Relevance of the indicator

A change of CCR configuration would have an impact on the ROSC processes in the affected CCRs. The purpose of this parameter is to identify the various ways in which ROSC processes might be impacted and to provide a qualitative analysis of this impact.

An assessment of the change of the CCRs should, among others, assess the differences in balancing and short-term markets. As ROSC processes are activating redispatching and countertrading, these impacts should be analysed. For example, the impact on the liquidity of the short-term market should not be significantly impacted as it could lead to high inefficiency.

Application of the indicator

For each alternative CCR configuration, a list of foreseen changes to ROSC processes shall be provided. For each item in this list, an assessment shall be made which describes which aspects of operational security coordination are likely to be most affected, and – if possible – whether these changes are likely to have a positive or negative impact on overall operational security. The assessment will be based on operational security expertise.

3.4 Efficiency of coordinated redispatching and countertrading (CACM GL Article 35)

Coordinated redispatching and countertrading represents another key field to consider when conducting a CCR assessment. Indeed, changing the configuration of one or more CCRs, instead of keeping the status quo, can lead to a positive or negative impact on the effectiveness and efficiency in redispatching and countertrading processes. The scope of a CCR assessment is to assess the effect that the different alternative configurations have both on the effectiveness and the efficiency of these processes, as described below.

Mandatory Indicator

The number of overlapping XNEs and their location in the different BZs, with a possibility to shift flows (congestion) from one CCR to another.

Relevance of the indicator

A security analysis (that includes Remedial Action Optimisation – RAO) is performed in two sequential steps: a first regional step, followed in some cases by a second inter-CCR step. Possible overloads on an overlapping XNE are addressed in a first step at a regional level and only in the native CCR. This means that the overload over an overlapping XNE requires solving in the regional optimisation only in one CCR where it belongs, although the congestion might be caused by applying the cross-border relevant remedial action (XRA) in the other CCRs. As such, there might be a shift of flows (congestions) between at least two CCRs, and the most affected TSOs are usually those at the edge of them. This can lead to inefficiencies, especially if the CCRs are defined as such that the actions from one CCR strongly influence the elements in the other CCR and vice-versa.

Application of the indicator

A quantitative evaluation of the total number of overlapping XNEs between two CCRs and their location in the different BZs in addition to the possibility of shifting the congestion from one CCR to another one. A lower number of overlapping XNEs (calculated in line with methodology outlined in Article 75 of SO GL) when comparing the different CCR configurations shall be considered as a positive parameter (gain in efficiency of network usage due to lower uncertainties from different CCRs) as some network elements e.g. in the event of the merge, would be fully integrated into the new CCR. A positive outcome of this parameter will also be a non-ability (partially or fully) to shift a congestion from one CCR to another one. At the same time, a mutual influence between CCRs in the new configuration will need to be kept at the acceptable level.

Optional indicator

Impact of the modification of the CCR(s) on RD&CT (including but not limited to activated costly RAs, volumes, costs)

Relevance of the indicator

The effectiveness in coordinated redispatching and countertrading processes depends on how all TSOs in each capacity calculation region can relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not, also addressing the fact that the application of the above methodology may significantly influence flows outside the TSO's control area. In other words, the problem of coordinated redispatching and countertrading shall be solved ensuring service continuity (no need for load shedding).

In multiple interconnected systems, such as more BZs that are part of one or two CCRs, the net efficiency in redispatching and countertrading operations depends on the product between volumes of operations and relative costs and on the total amount of capacity offered to the market. An increase in efficiency could be achieved by reducing this product without strongly reducing the capacity offered to the market.

Application of the indicator

A qualitative assessment of the impact on the RD&CT chain.

3.5 Efficiency of redispatching and countertrading cost sharing (CACM GL Article 74)

Article 74 of the CACM Guidelines states that the TSOs of a CCR shall develop a common methodology for redispatching and countertrading cost sharing, including cost-sharing solutions for actions of cross-border relevance. Moreover, costs eligible for cost sharing between relevant TSOs shall be determined in a transparent and auditable manner. Article 74 also describes many principles the methodology has to respect to be compliant with the Guidelines and to guarantee efficiency in cost-sharing (e.g. provide incentives to manage congestion, including RAs and incentives to invest effectively; be consistent with the responsibilities and liabilities of the TSOs involved; ensure a fair distribution of costs and benefits between the TSOs involved; facilitate the efficient long-term development and operation of the pan-European interconnected system and the efficient operation of the pan-European electricity market).

The CACM GL and SO GL, in addition to the Electricity Regulation (EU) 2019/943, set the requirements for the regional RD&CT cost sharing methodologies. According to Article 16(13) of Regulation 2019/943, *"when allocating costs of remedial actions between transmission system operators, regulatory authorities shall analyse to what extent flows resulting from transactions internal to bidding zones contribute to the congestion between two bidding zones observed, and allocate the costs based on the contribution to the congestion to the transmission system operators of the bidding zones creating such flows except for costs induced by flows resulting from transactions internal to bidding zones that are below the level that could be expected without structural congestion in a bidding zone"*. As the loop flows are a natural consequence of a zonal system, some loop flows can be accepted up to a certain level (up to the certain threshold) which could be expected without structural congestion in a BZ.

Therefore, regional RD&CT cost sharing methodologies shall account for the level of loop-flows. Depending on the level of loop-flows, the methodologies could also be based on other regional conditions in line with the All-TSOs harmonisation assessment and guidance document following CACM GL Article 74(7).

Mandatory indicator

Level of loop flows on CNECs external to the CCRs

Relevance of the indicator

With this indicator, it will be estimated to what extent flows resulting from transactions internal to BZs contribute to the line loadings outside of the CCR of those BZs. The loop flow is to be computed for the BZ of CCR A on the elements of CCR B. This would assess if CCR B could request some payment for the RAs to solve the congestions of their elements due to excessive loop flows originated by CCR A. The loop flows of the BZ of CCR B and the elements of CCR A also have to be evaluated (a vice-versa calculation). In the event of a CCR configuration change and in the event the RD&CT cost-sharing concept is based on loop flows at least in one of CCRs, this would cause the re-distribution of some costs among some BZs.

Application of the indicator

Quantitative: In the event of a merge between CCRs that are stronger mutually influenced (that is, a higher level of cross-CCR loop flows present), this indicator shall be considered as a positive parameter as the possibility for free-riding would be decreased (e.g. some BZs that caused loop flows were not punished before the merge) and discrimination among BZs – when applying the same concept within CCR – would be avoided.

Optional Indicator

Impacts on redispatching and countertrading cost sharing – qualitative indicator

Relevance of the indicator

As the methodologies for RD&CT cost sharing are developed at a CCR level, a change of CCR configuration could have an impact on the ability to reach a fair and effective cost-sharing solution for the involved TSOs. The purpose of this parameter is to identify the various ways in which RD&CT cost sharing might be impacted and to provide a qualitative analysis of this impact.

Application of the indicator

For each alternative CCR configuration, a list of commonly recurring RD&CT situations for which the cost sharing will be significantly affected shall be provided. For each item in this list, an assessment shall be made describing whether the cost sharing leads to a fair distribution of costs and benefits and provides appropriate incentives for congestion management. The assessment will be based on RD&CT expertise.

3.6 Impact of CCRs on defined SORs

The following clarifies how CCRs relate to the defined SOR, how a CCR reconfiguration could influence the SOR definitions, and how the impact on the SORs should be considered when proposing a CCR reconfiguration proposal.

Mandatory Indicator

CCRs are the geographic area in which coordinated capacity calculation is applied, and they are also the geographic scope for the performance of other processes, e.g. the ROSC foreseen by the System Operation Guideline.

SORs are the geographical scope for regional coordination established by the Electricity Regulation. Article 36 of the Electricity Regulation states that SORs comprise CCRs and TSOs, in addition to BZs and outage coordination regions. Article 37 lists the services which must be performed by the RCCs in each SOR, which, among additional tasks, **include all the services to be performed at CCR level** which were already entrusted to the RSCs and the coordinated capacity calculator foreseen by CACM GL and SO GL.

The SORs have been defined by ACER Decision 05/2022, which outlines that:

- all CCRs are included in one SOR, except for Hansa CCR, which is an interface region between the CE SOR and Nordic SOR, and SEE CCR, which is an interface region between the CE SOR and SEE SOR; and
- all CCRs are kept as a whole, meaning that all BZBs are included in the defined SORs, except for the defined interface region of Hansa BZBs.

The Decision provides the general rules for coordinating the CCRs between each pair of adjacent SORs:

- if the CCR is included in a SOR, the RCC established for that SOR shall coordinate it in accordance with applicable TCMs at CCR level (e.g. capacity calculation methodologies) which have been developed, approved and implemented pursuant to CACM, FCA and SO Guidelines by all the TSOs belonging to the CCR.
- If the CCRs is not included in a SOR (Hansa CCR), the RCCs established for the adjacent SORs (Nordic SOR and Central Europe SOR) shall coordinate to perform the tasks at CCR level according to the conditions and methodologies developed, approved and implemented pursuant to CACM, FCA and SO Guidelines.

Moreover, for several SORs, a distinction is made between:

1. the so-called *tasks of regional relevance*, which need to be performed by the RCC of the SOR in cooperation with the TSO outside of the SOR. The latter TSO must have a contractual relationship with the RCC of the SOR; and
2. the so-called *tasks of cross-regional relevance*, which need to be coordinated by both the RCCs of the adjacent SORs, as necessary. That RCC shall allow the latter TSO neighbouring the SOR to participate in the coordination of the borders through the RCC in the adjacent SOR. These two RCCs shall develop cooperative processes between them and with the TSOs involved.

The regional coordination framework of the Electricity Regulation preserves the CCRs and the established coordination at CCR level. All the applicable methodologies and processes for the existing CCRs shall keep on being used by the TSOs of the CCR and the relevant RCCs. The Electricity Regulation strengthens and expands the scope of regional coordination by assigning new tasks to the RCCs (compared to RSCs) but leaves untouched all the developments made so far for implementing the CAM GL and SO GL.

In essence, RCCs will have to cooperate on borders adjacent to SORs based on existing procedures without any requirement to change the regulatory methodologies or the governance arrangements for CCR tasks. SORs governance should not overrule CCR governance and needs to ensure that services at CCR level are properly performed by considering the regional specificities of the CCR.

Relevance of the indicator

The reconfiguration of CCRs could de-facto trigger the reconfiguration of the approved SOR setup as the SOR decision provides that any changes to the CCR configuration should also be reflected in the SOR definitions[13].

Although the SOR decision reflects that the methodologies under the current CCR setup will be respected, changing the current CCR configuration could influence and change the geographical scope of the area in which the RCCs perform their tasks, meaning that methodologies for RCC tasks would have to be adjusted and new implementation efforts (also nationally) would be needed without potentially bringing added value to the tasks compared to the present situation.

13 Moreover, Regulation 2019/943, Art 36(1) requires that SORs should include “full CCRs”: if CCRs are bigger than the SORs decided by ACER, SORs should be amended.

The added value of the reconfiguration of the CCRs must therefore be considered by taking into account the impact on the SOR definition, and any associated impact on processes, transitional costs and operational costs.

Application of the indicator

The following criteria for a proper determination of CCRs can be identified: **Any reconfiguration proposal of the CCRs must consider the influence on the current SOR setup and any effect it would have on the further implementation in the SORs/RCC and affected TSOs.**

The following should at least be applied when assessing to what extent a CCR reconfiguration impacts the SORs:

- To what extent does a CCR reconfiguration trigger SOR adjustments?
- To what extent does a CCR reconfiguration impact (positively/negatively) the performance and implementations of concerned RCCs and TSOs of the relevant SOR(s)?

It will be the prerogative of the concerned TSOs of the relevant SORs to provide input/arguments to the assessment.

3.7 Transition and operational costs

Transition costs

Transitional costs are the one-off cost of change from one CCR configuration to another. In the event that RCC and TSO operational processes and systems are already in place, the reconfiguration may require significant re-implementation projects. If implementations are still underway, projects may be stopped before the original benefits can be realised. It may not be possible to conduct a full economic assessment on the transitional costs from one arrangement to another, as the costs are a result of changing methodologies, rather than the CCR reconfiguration itself. However, where possible, an assessment should be made to consider the scale of change.

Transition costs can include the costs of RCC systems and processes, the potential combination of two CCRs resulting in transferring RCC processes to a different RCC, and TSO costs for change. In addition, there is a resulting regulatory burden for the redevelopment/adaption of legally required methodologies.

Amending the status quo CCR configuration will lead to transition costs, which are to be considered when assessing the list of alternative CCR configurations.

Mandatory Indicator

The list of transition costs to be assessed are given below:

Cost indicator	Definition	Transition cost examples (non-exhaustive)
Changes to TSO and RCC **business processes and IT systems**	Costs incurred by changes to organisation and coordination specifically attributable to CCR re-configuration	Adapting existing IT systems to specific CCR configurations Costs associated with the efforts linked to the changing of processes Setting up new RCC
Adjustment to or termination of contracts	Costs incurred by amending existing agreements to CCR re-configuration including legal costs	Changes in all legal contracts (potentially also in existing CCR if a split is proposed)
Additional costs	Any costs directly related to the CCR configuration not covered by the two categories above	Any examples not covered above

Operational costs

Amending the status quo CCR configuration will lead to a change in operational costs for performing regional services, which are to be considered when assessing the list of alternative CCR configurations.

Mandatory Indicator

A list of operational costs to be assessed is given below:

Cost indicator	Definition	Operational cost examples (non-exhaustive)
Cost related RCC(s) operational services	Cost incurred in terms of RCC services for the daily operation of the grid. Should be compared to current costs in the status quo CCRs	Costs regarding operational RCC services
TSO costs related to operating the internal grid	Costs incurred in relation to the TSOs daily operation of the internal transmission grid. Should be compared to current costs in the status quo CCRs	Costs related to operational processes Cost related to procurement of reserves Cost related to emergency responses
TSO cost related to participation in CCR(s)	Costs incurred when participating in activities within the CCR. Should be compared to current costs in the status quo CCRs	Costs to develop/amend methodologies in the different CCRs (in case of merge, no parallel processes in place) Costs related to participation in different CCR groups, sharing data, and collaborating with other TSOs within the CCR
TSO costs related to efforts for cross-CCR coordination	Costs related to cross-CCR coordination. Such costs can decrease/increase depending on the specific CCR configuration. Should be compared to current costs in the status quo CCRs	Costs related to cross-CCR operational processes, TSO coordination, optimizations etc.

3.8 Third-country involvement

Third countries can be part of the regional processes and CCRs respectively and subsequently, of the market integration projects if they have introduced reciprocally the relevant EU legislation imposing identical rules, obligations and functioning of the electricity market.

The adoption of reciprocal legislation should be subject to the conclusion of relevant agreements with the EU, such as intergovernmental, multilateral, etc., which would guarantee the emergence of the necessary commitments and obligations.

However, even in the absence of or pending the application of European legislation to these third countries, the possibility of increased cooperation and inclusion in the processes is permitted at the CCR level on the basis of agreements concluded with the CCRs *(inter-TSOs agreement*) in compliance with the legislative framework.

In this regard, the letter from the EU Commission to ACER and ENTSO-E dated 19 July 2019 on capacity calculation and third countries, stated that *"the Commission is fully aware that it is of utmost importance to preserve a smooth and efficient system of electricity exchanges with third countries, which safeguards against any security of supply risk in the EU or in neighbouring countries. The Commission therefore considers that consideration of third country flows in capacity calculation should be possible on the condition that an agreement has been concluded by all TSOs of a CCR with the TSO of a third country. With an agreement, third country flows could also be recognised as counting towards the 70 % target for capacity available for cross-border trade in the Electricity Regulation…"* while the conclusions of the Florence Forum of December 2020 on RCCs stated that *"the Forum takes note of the Commission's position on the need for proper interfaces and information exchange with 3rd country TSOs, which should be established via contractual framework to ensure operational security in the system. The Forum acknowledges that the secure operation of the European power system requires strong cooperation of both EU and non-EU TSOs*."

Article 13 of SO GL allows and requires EU TSOs to endeavour to conclude agreements with third country TSOs for the compliance of common rules concerning secure system operation, beyond the obligations related to CCRs "*Where a synchronous area encompasses both union and third country TSOs, within 18 months after entry into force of this Regulation, all Union TSOs in that synchronous area shall endeavour to conclude with the third country TSOs not bound by this Regulation an agreement setting the basis for their cooperation concerning secure system operation and setting out arrangements for the compliance of the third country TSOs with the obligations set in this Regulation."*

For these reasons, the CCR assessment framework considers an indicator for properly considering the influence of neighbouring third countries.

Mandatory Indicator

Influence of eventual neighbouring third countries on CCRs processes is properly tackled (Y/N)

Relevance of the indicator

Although third countries are not included in EU CCRs, capacity calculation approaches in CCRs, redispatching and countertrading processes, market processes and other processes related to operational security need to consider third countries' flows to be technically sound. Different CCRs may need to consider this influence to a different extent. For this reason, an indicator for defining a good CCR might be that the size, composition and features of the CCR allow the development of agreements and methodologies and decisional processes which are fit for properly addressing third countries' treatment.

Application of the indicator

Any reconfiguration proposal of a CCR must consider the indicators defined in this section.

3.9 Governance

The adoption of a changed CCR configuration will result in impacts to the governance and administrative arrangements in place within the affected CCR(s). These factors must be assessed to ensure the proposed reconfiguration's benefit is proportional to the impact. These factors are not quantitatively assessed and are intended to support decision making.

3.9.1 Terms and Conditions or Methodologies

TCMs are required by the CACM GL, FCA GL, EBGL and SO GL, and a number of these are required on a CCR level to formalise regional approaches. The development and implementation of TCMs is therefore impacted by the CCR configuration.

TCMs to be developed at CCR level or which include requirements at CCR level in the CACM GL, FCA GL, EB GL and SO GL.

CACM GL TCMs

Article 9(7) of CACM GL provides the list of TCMs and any amendments thereof to be proposed and approved at CCR level:

- the common capacity calculation methodology in accordance with Article 20(2);
- decisions on the introduction and postponement of FB calculation in accordance with Article 20(2) to (6) and on exemptions in accordance with Article 20(7);
- the methodology for coordinated redispatching and countertrading in accordance with Article 35(1);
- the common methodologies for the calculation of scheduled exchanges in accordance with Articles 43(1) and 56(1);
- the fallback procedures in accordance with Article 44;
- complementary regional auctions in accordance with Article 63(1);
- the conditions for the provision of explicit allocation in accordance with Article 64(2);
- the redispatching or countertrading cost sharing methodology in accordance with Article 74(1).

SO GL TCMs

SO GL provides the following TCMs to be developed by all TSOs of each CCR:

- Pursuant to Article 76, all TSOs of each capacity calculation region shall jointly develop a proposal for common provisions for ROSC, to be applied by the RSCs and the TSOs of the capacity calculation region. The proposal shall respect the methodologies for coordinating operational security analysis developed in accordance with Article 75(1) and complement where necessary the methodologies developed in accordance with Articles 35 and 74 of CACM GL.
- Pursuant to Article 77, the proposal of a CCR for common provisions for ROSC shall also include common provisions concerning the organisation of ROSC, and notably the appointment of RSC(s) for the CCR, rules concerning the governance and operation of RSC(s) and specific rules where the TSOs propose to appoint more than one RSC in a CCR

EB GL TCMs

Article 5(3) of EB GL provides the list of TCMs and any amendments thereof to be proposed and approved at CCR level:

- The cross-zonal capacity calculation methodology for each capacity calculation region pursuant to Article 37(3);
- For each CCR, the methodology for a market-based allocation process of cross-zonal capacity pursuant to Article 41(1); and
- For each CCR, the methodology for an allocation process of cross-zonal capacity based on an economic efficiency analysis and the list of each individual allocation of cross-zonal capacity based on an economic efficiency analysis pursuant to paragraphs 1 and 5 of Article 42;

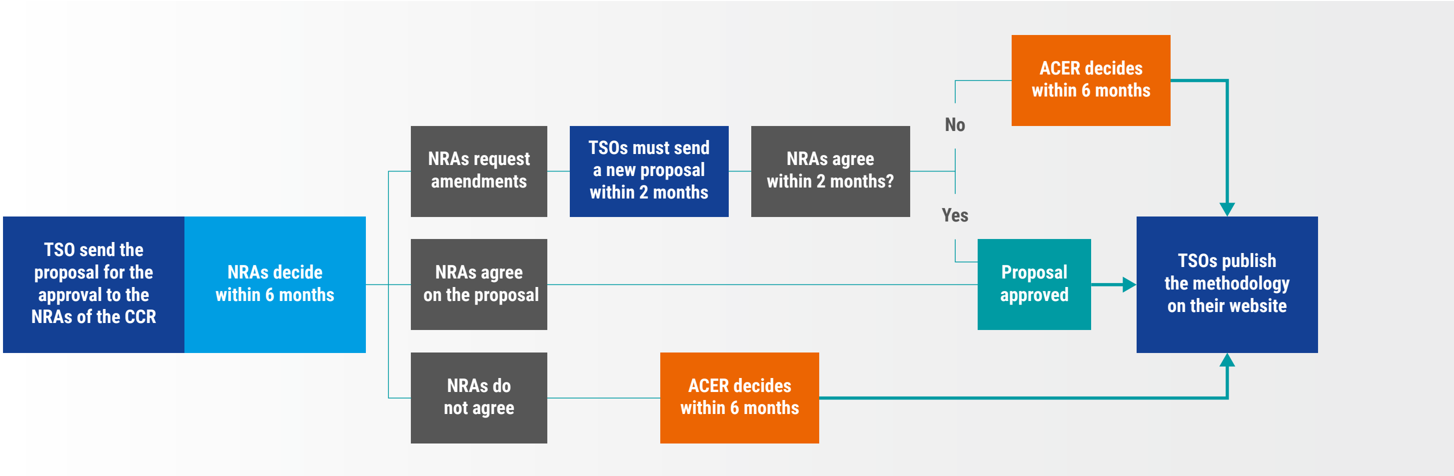
FCA GL TCMs

Article 4(7) of FCA GL provides the list of TCMs and any amendments thereof to be proposed and approved at CCR level:

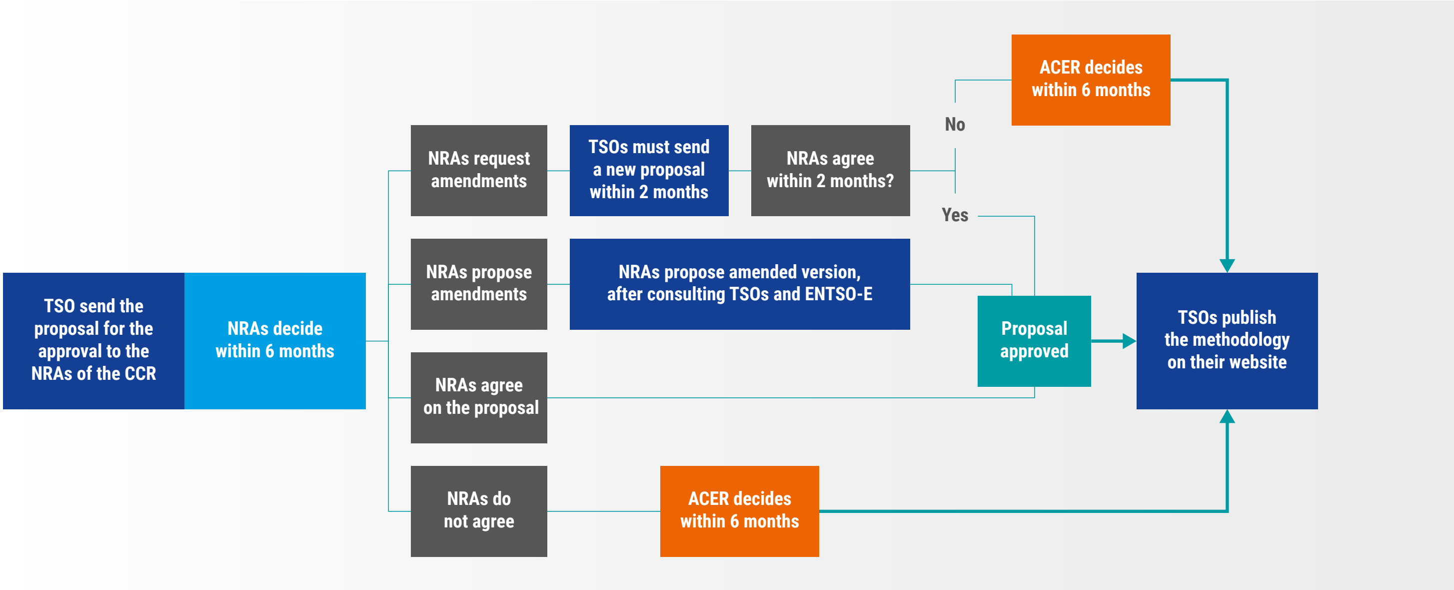
- the capacity calculation methodology pursuant to Article 10;
- the methodology for splitting cross-zonal capacity pursuant to Article 16;
- the regional design of long-term transmission rights pursuant to Article 31
- the establishment of fallback procedures in accordance with Article 42; and
- the regional requirements of the harmonised allocation rules pursuant to Article 52, including the regional compensation rules pursuant to Article 55.

The process for the drafting, submission, approval and implementation foreseen by the CACM GL, FCA GL, EBGL and SO GL.

The relevant articles of the CACM GL, FCA GL, EBGL and SO GL[14] provide the following approval process for regional TCMs:



The process changed after the entry into force of the Electricity Regulation (EU) 2019/943 and the ACER Regulation (EU) 2019/942[15] and the adoption of Commission Implementing Regulation (EU) 2021/280. This is shown in the following picture:



14 See Article 9 CACM GL; Article 6 SO GL; Article 5 EBGL; and Article 4 FCA GL.

15 See Article 5(6) ACER Regulation.

Mandatory indicator

The common view among CCR TSOs that methodologies fit the needs of the CCR; limited need for subsequent amendments due to a badly configured CCR.

Relevance of the indicator

From a governance perspective, a good CCR configuration ensures that the local/subregional particularities are not overruled by the majority (i.e. the risk that particularities of an area cannot be considered because of the qualified voting majority rules is minimised).

From a technical perspective, regional methodologies should reflect the physical power system characteristics at a regional level, in addition to the requirement for coordination. Another fundamental aspect that methodologies should tackle is the mutual impact of EU and non-EU power systems, which should be considered in the regional processes to ensure smooth and secure system operations.

Moreover, a good CCR configuration should make it possible to value and reuse specialised knowledge or pre-existing specialised processes in methodologies that may be concentrated in a single CCR (for example, 1 CCR with offshore BZs, or processes to consider the impact of and facilitate [primarily] direct current connections between independently operated CCRs [so-called "interface CCRs"]).

Application of the indicator:

An indicator when assessing the CCR configuration, therefore, is a qualitative assessment conducted on each affected CCR with an assessment on whether the change will result in negative effects on processes contained within regional methodologies. This assessment should conclude whether the change will result in a generally positive, negative or neutral effect on the processes, and should reflect:

- Whether required changes to regional methodologies will aid or hinder the appropriate representation of the physical power system in ongoing operational processes;
- Whether required changes are likely to detriment secure system operations regarding the impact of third country power systems;
- Whether the changes to methodologies will improve or detriment the status quo regarding specialised or bespoke processes within the methodologies relating to the integration of offshore BZs, direct current connections and/or the interface between independently operated CCRs or synchronous areas; and
- Future expected grid and generation evolutions in the CCR, for example offshore BZs to facilitate the integration of offshore renewables or new interconnectors between BZs.

Mandatory indicator

Convergence of current methodologies or next step of development (implementation of FB) across multiple CCRs.

Relevance of the indicator

The methodologies described above contain descriptions of the processes conducted within a CCR. An alignment of processes (and therefore methodologies) across multiple CCRs may demonstrate an ability for processes to be conducted jointly, increasing efficiency.

CACM GL Article 20(5) requires that when two or more adjacent capacity calculation regions in the same synchronous area both implement an FB capacity calculation methodology for day-ahead and intraday, then this shall be considered as one region for this purpose. They shall then be merged according to CACM GL Article 15(3) as long as merging them is more efficient than keeping them separate.

In addition to day-ahead and intraday capacity calculation, other processes may be assessed as more or less efficient if carried out in a joint manner between multiple CCRs.

Application of the indicator

For the different alternative configurations proposed, an analysis of the regional processes conducted, as detailed in the methodologies described above, should be carried out to examine the scale of change. A positive indicator is a close coherence among the methodologies applicable in the status quo and the alternative configuration, and a potential efficiency in carrying out such processes under the different alternative configurations.

3.9.2 Impact of CCR Size on decision making

Within ACER's decision 04/2021, Annex I, it was noted that the determination aimed to *"…strike a balance between 2 aspects larger where currently possible, smaller where currently necessary" concerning the size of CCRs*.

Concerning the size of CCRs, Article 15(3) of CACM GL also provides for the merger of neighbouring CCRs which both apply FB capacity calculation methodologies when a) their transmission systems are directly linked to each other; b) they participate in the same single day-ahead or intraday coupling area; and c) merging them is more efficient than keeping them separate.

Mandatory indicator

The size of the CCR(s) allow(s) for lean/efficient decisional processes for both TSOs and NRAs, cost efficiency and a reasonable timeline of the technical tasks in charge to RCCs, while achieving the stated aim of ACER to strike a balance between being larger where possible and smaller where necessary.

Relevance of the indicator

The CCR geography has a tremendous impact on the technical processes, which may in turn have effects on the CCR governance (e.g. when HVDC borders are involved, when CCRs connect more synchronous areas), as detailed in the paragraphs above.

The size of a given CCR relates to many other factors (e.g. voting, costs, technical indicators) on which there is a different impact depending on the case under consideration, to take into account when assessing the size of a CCR. This criterion seeks to identify the benefits or detriments of CCR size on governance and decision-making only, and the impact of size on the other elements is indicated by other parameters in this framework.

There cannot be a standard size for CCRs or general principles advocating unidirectionally larger or smaller size. Each individual configuration should be evaluated on a case-by-case basis to ensure that CCRs are sized to be fit for purpose. In this case-by-case analysis, it is essential to strike the right balance to ensure the above objectives (*lean/efficient decisional processes, cost efficiency and reasonable timeline)*, considering that smaller CCRs normally ensure operational efficiency and the better coordination of regional features, while larger CCRs are normally more appropriate where high coordination among TSOs – under the governance/decisional processes as well as in technical processes – is necessary.

Application of the indicator

An individual assessment should be carried out by the CCRs affected, in addition to a cross-CCR assessment, on the impact of any change on decision-making processes, cost efficiency and timeline for RCC tasks, to determine if the size of potential CCRs is positive or negative from a governance and decision-making perspective.

In principle, a progressive increase of the CCR's size should be evaluated as a positive indicator for this criterion only if it is functional for achieving better management coordination and where technical requirements make high technical coordination among TSOs necessary and possible.

4 Step 3 – Recommendation based on assessment results

Process

Once the assessment in Step 2 has been carried out, the outcomes of each parameter analysed by the individual indicators must be considered all together to form a recommendation.

This recommendation is made up of both quantifiable and unquantifiable indicators, and so the recommendation is not based purely on a combination of calculable factors. Each indicator will be assessed, and an indication made as to whether the indicator demonstrates a positive or negative marker of the CCR configuration under evaluation when compared to the status quo.

A recommendation on the future CCR configuration, to maintain or amend the status quo, will be made to All TSOs, who shall take any relevant decisions. In the situation whereby All TSOs decide to amend the CCR configuration, a proposal will be made to amend the Determination of CCRs, as defined in accordance with Article 15 of CACM GL. This will then be submitted to ACER.

In the situation where the Determination of CCRs is amended, ENTSO-E shall include the outcome of the assessment and the reasoning for the decision taken by All TSOs in the relevant explanatory note. In the situation where the assessment is undertaken to fulfil the request of a regulatory authority or ACER, a report on the assessment undertaken will be provided to the relevant regulatory authority or ACER.

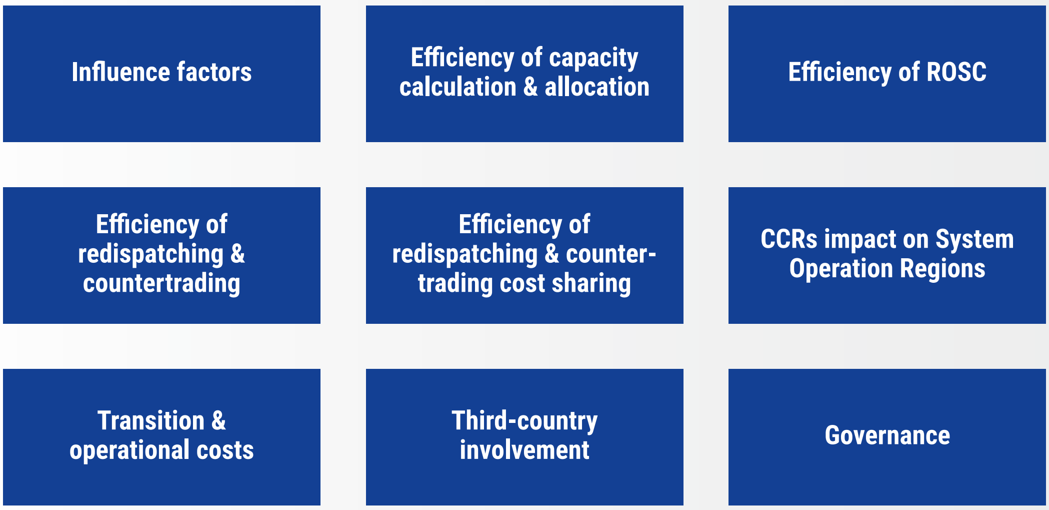
Assessment

The indicators considered were selected to demonstrate the impact of the CCR configuration on the following parameters. Each parameter shall be compared against the other CCR configurations under assessment, in addition to the status quo.

In some cases, the indicator cannot be quantifiably compared against another scenario (e. g. transition and operational costs may need be estimated to consider the impact of a potential CCR [re-]configuration). In other cases, the parameter is reliant on the view of relevant experts. For these parameters, an assessment is made on whether an alternative CCR configuration under consideration performs better than, worse than, or the same as the status quo CCR configuration, using the indicators contained within this framework. For parameters where the outcome is quantifiable, this framework details whether the CCR configuration under consideration is a positive marker (i. e. the indicator shows a better situation than the status quo) or a negative one.

It should be noted that for one CCR, the outcome for a given parameter may be different from another (i. e. the assessment of an indicator may appear beneficial for one CCR, yet detrimental to another) and so the outcome for all CCRs should be considered by the expert group to consider the wider view and benefit to each part of the European power system and to the electricity market. The recommendation will be mindful of situations where multiple indicators, due to the specifics of the configuration under assessment, could result in the double counting of some factors, which should be avoided.

The following parameters are assessed as part of this framework, and will form the basis of the recommendation to All TSOs. It should be noted that each parameter may be assessed with more than one indicator. Each assessed indicator shall contribute to the overall recommendation.



Annex

A1: Regional specificities

Some regions have market or grid specificities due to different geographical factors. Specificities such as these shall duly be considered when defining CCRs as they are an influencing factor in shaping the market, the Capacity Calculation process and/or the CSA processes. Considering such specificities shall not be confused with being an obstacle to changing the CCR definitions but rather considered a must for a detailed analysis, so that when considering that the CCR change is overall beneficial, all the pros and cons are well-addressed. Among the most critical considerations is the security of supply in each grid area (to avoid jeopardising the security of supply is a key analysis) and, consequently, in the bulk system.

Within all the parameters described in this framework, the option is given to assess the regional specifics under all parameters, if deemed relevant. The regional specifics may stem from the factors below, and to reflect these factors, a specific indicator may be chosen or not chosen. The diversity of configurations that this framework is intended to assess requires such flexibility and the ability to value technical and non-technical indicators and parameters differently for different assessments.

a) Geographical factors (island, peninsula, mainland) may affect:

b) grid topology: radial, meshed, fully meshed;

c) distribution of generation and load: uniform, non-uniform;

d) flow direction: mostly in an import/export market direction, level of import from one BZ and re-export to another BZ;

e) type of connections: mainly/exclusively HVDCs;

f) penetration of non-dispatchable generation: high/medium/low uniform penetration, high/medium/low non-uniform penetration; and

g) influence of a non-EU country: high/medium/low level of interconnection with a Third Country.

Especially for regions where geographical factors determine:

- a radial grid topology, more specifically power systems that are not fully meshed within the bulk grid, but are only interconnected in one of their sections;
- a synchronous area arrangement where two synchronous areas are linked by HVDC connections or radial AC connections;
- A low level of interconnection with other synchronous areas;
- a non-uniform distribution of generation and load that leads to sustained longitudinal flows along the system;
- flows mainly developed along a long path, with a prevailing direction;
- a high non-uniform penetration of non-dispatchable generation; and
- a high level of interconnection with a Third Country that is crucial for the security of the system.

An assessment which puts the focus on two individual CCRs shall not disregard the above specificities. This is also particularly true because, in some cases, the impact of a CCR review may also occur outside the perimeter of the CCRs under analysis; this impact could affect each of the indicators considered in this Step 2 (Efficiency of CACM processes, of ROSC, of RD&CT and the cost-sharing). A theoretical approach in the analysis is likely to overlook this influence.

Usually, the above-listed specificities are typical for the area at the external border of a given region, and the criticality is emphasised for islands and peninsulas, which are also directly exposed to oscillations and perturbations more than the central area – as they are at the borders – and to the risk of forming electrical islands. Therefore, the need to preserve the security of the interconnected sections must be properly addressed in the Capacity Calculation and CSA methodologies. In the event a Third Country is part of these sections, it is then fundamental for the security of the system to efficiently and effectively include it in the coordinated processes and methodologies.

Furthermore, specificities such as "interface regions" should also be considered if relevant depending on the CCR configuration(s) assessed. An "interface region" is one which sits between two CCRs at the interface of two synchronous areas. The synchronous areas can have different characteristics of their operation, balancing philosophies, security principles and governance arrangements. Consequently, an interface region can facilitate good cooperation and enable harmonisation. The benefits of such an arrangement can include the ability to harmonise and align on operational principles, including capacity calculation. The governance structure can facilitate this close cooperation. When considering the indicators that can be used for the assessment of a CCR configuration, consideration will be given to whether the continuation or creation of such interface regions support or detriment the overall objective, to promote fair and efficient competition and cross-border trade, and coordination between TSOs.

Abbreviations

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
AHC	Advanced Hybrid Coupling
ATC	Available Transmission Capacity
BZ	Bidding Zone
BZB	Bidding Zone Border
CACM GL	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CCR	Capacity Calculation Region
CE SOR	Central Europe System Operation Region
CNE	Critical Network Element
CNEC	Critical Network Element and Contingency
cNTC	Coordinated Net Transmission Capacity
CROSA	Coordinated Regional Operational Security Assessment
CSA	Coordinated Security Analysis
EB GL	Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FB	Flow-Based
FCA GL	Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation
GSK	Generation Shift Keys
HVDC	High Voltage Direct Current
MCCC	Margin from Coordinated Capacity Calculation
MCSC	Market Coupling Steering Committee
MNCC	Margin from Non-coordinated Capacity Calculation
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
NTC	Net Transmission Capacity
OCR	Outage Coordination Region
PST	Phase Shifting Transformer
PTDF	Power Transfer Distribution Factor
RA	Remedial Action
RAO	Remedial Action Optimisation
RCC	Regional Coordination Center
RD&CT	Redispatching and Countertrading
ROSC	Regional Operational Security Coordination
RSC	Regional Security Coordinator
RSCI	Regional Security Coordination Initiative
SEE CCR	South East Europe Capacity Calculation Region
SEE SOR	South East Europe System Operation Region
SHC	Standard Hybrid Coupling
SO GL	Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation
SOR	System Operation Region
TCMs	Terms and Conditions or Methodologies
TSO	Transmission System Operator
XNE	Cross-border Relevant Network Element
XRA	Cross-border Relevant Remedial Action

Contributors

Vincent Protard	Amprion
Milan Vukasovic	APG
Andy Paton	Baltic Cable
Martin Pistora	CEPS
Shane Duane	EirGrid
Francesco Rossetto	EirGrid
Jonas Peter Hasselblom Jacobsen	Energinet
Majura Thaya Ponnampalam	Energinet
Carla Rubi Caellas	ENTSO-E
Gjorgji Shemov	ENTSO-E
Francois-Xavier Detraz	RTE
Fanny Norén	SvK
Hjalmar Pihl	SvK
Federico Retrosi	TERNA

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8 Rue de Spa | 1000 Brussels | Belgium
www.entsoe.eu | info@ entsoe.eu

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