Explanatory document to the Capacity Calculation Methodology for the Balancing Timeframe for Capacity Calculation Region Hansa in accordance with Article 37(3) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

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9th of October 2024

Abbreviations:

AAC	Already Allocated and nominated Capacity
AC	Alternating Current
AHC	Advanced Hybrid Coupling
ATC	Available Transfer Capacity
BP	Balancing Platform
CACM	Capacity Allocation and Congestion Management
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CGM	Common Grid Model
CMF	Capacity Management Function
CMM	Capacity Management Module. CMM is the TSO Project to implement the CMF.
CNTC	Coordinated Net Transmission Capacity
DA	Day-ahead
DC	Direct Current
HVDC	High Voltage Direct Current
ID	Intraday
IDCZGCT	Intraday Cross-Zonal Gate Closure Time
KF CGS	Kriegers Flak Combined Grid Solution
MARI	Manually Activated Reserves Initiative
MTU	Market Time Unit
NTC	Net Transfer Capacity
OWF	Offshore Wind Farm
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
ROSC	Regional Operational Security Coordination
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
XBID	Single intraday market coupling

Contents

1 Introduction

This document contains explanations for the proposal for a common coordinated capacity calculation methodology for the balancing timeframe for the capacity calculation region of Hansa (CCR Hansa) in accordance with Article 37(3) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB Regulation). CCR Hansa Transmission system operators (TSOs) are obliged to consult stakeholders on proposals for terms and conditions or methodologies required by the EB Regulation.

The CCR Hansa covers bidding-zone borders connecting two CCRs: CCR Nordic and CCR Core. This document has been written with the aim of ensuring that the methodology developed in the CCR Hansa is as efficient as possible from a market point of view and that it is easily implementable from an operational and security of supply point of view when coordinating with adjacent regions. Moreover, the methodology proposed is aimed at being sustainable for future changes in CCR configurations.

According to Article 37(3) of the EB regulation this CCM "shall be consistent with the cross-zonal capacity calculation methodology applied in the intraday timeframe". The Hansa TSOs interpret this in a way that the BT CCM and DA/ID CCM are as similar as possible, while still taking into account all the differences between the two timeframes. There are many differences between balancing timeframe and intraday, but some of the points that make the balancing timeframe distinct from day-ahead and intraday are:

- The main legal framework for the balancing timeframe is to be found in the EB regulation,
- The data input from the capacity calculation should be provided to the CMF.
- The timeframe to perform the capacity calculation is relatively short.
- Balancing timeframe is closer to real time operations, meaning that operational security and technical constraints are of very high priority.

With these differences, the Hansa TSOs have assessed that it is not feasible to have a CCM that is exactly the same for balancing timeframe and intraday. In this explanatory note the choices for the methodology are explained in order to highlight the reasoning for differences between the DA/ID CCM and the BT CCM.

The CCR Hansa proposes a capacity calculation methodology where the remaining capacity after the intraday gate closure time, together with the allocation constraints and the capacity reserved for ancillary services in the balancing timeframe, is used in the balancing timeframe. Using the residual capacity after the intraday trading reflects the minimum value principle from Hansa CCR and the adjacent CCRs and respects the capacity calculations performed in the intraday and day-ahead timeframe. If there is any new information such as unscheduled outages or new wind forecast and consequently new measurement of wind generation in relation to KF SGS, then the cross-zonal capacities will be reassessed by the relevant TSO and recalculated according to Article 4 in the Hansa CCM.

This document is structured as follows: Chapter 2 contains a description of the relevant legal references. Chapter 3 defines CCR Hansa and the borders that are subject to this proposal. Chapter 4 contains the explanation for the capacity calculation methodology for the balancing timeframe presented in the legal proposal. Chapter 5 contains the time plan for implementing the CCM. The last public consultation was carried out in September 2022 and no comments were given.

2 Legal Requirements

According to Article 37(3) of the EB Regulation, each CCR is required to submit a common capacity calculation methodology for approval by the relevant national regulatory authority (NRA) for each cross-zonal capacity calculation within the balancing timeframe. This is to be done no later than five years after the Article 37(3) of the EBGL Regulation enters into force. This capacity calculation methodology (CCM) shall avoid market distortions and shall be consistent with the cross-zonal capacity calculation methodology applied in the intraday timeframe established under Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM). Therefore, the CCM will follow the principle established under CACM.

Firstly, a number of relevant definitions from the CACM Regulation are stated below, which are applicable for this CCM as well.

"*´coordinated net transmission capacity approach' means the capacity calculation method based on the principle of assessing and defining ex ante a maximum energy exchange between adjacent bidding zones*".[1]

"*'reliability margin' means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation*."[2]

"*'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation*;"[3]

"'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency, dynamic stability limits, amount of polarity reversals, minimum flow on DC lines and maximum flow changes;"[4]

"*'contingency' means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security*;"[5]

"*´remedial action' means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security."*[6]

As a general point, all methodologies and proposals developed under the EB Regulation should align with the objectives of Article 3 of the EB Regulation.

In accordance with Article 5(5) EB Regulation this balancing timeframe capacity calculation methodology is compliant with the objectives mentioned in Article 3(1) EB Regulation as set out below. This CCM is drafted in accordance with:

- Article 3(1) (b) EB Regulation enhances efficiency of balancing as well as efficiency of European and national balancing markets by maximizing capacities for the balancing timeframe by

[1] Article 2(8) of the CACM Regulation.
[2] Article 2(14) of the CACM Regulation.
[3] Article 2(6) of the CACM Regulation.
[4] Article 2(7) of the CACM Regulation.
[5] Article 2(10) of the CACM Regulation.
[6] Article 2(13) of the CACM Regulation.

considering the latest market allocations and if necessary, recalculating capacities for the balancing timeframe after the IDCZGCT.

- Article 3(1) (c) EB Regulation integrates balancing markets and promotes the possibilities for exchanges of balancing services while contributing to operational security by providing maximum capacities within the operational security limits.
- Article 3(1) (d) EB Regulation contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union while facilitating the efficient and consistent functioning of day-ahead, intraday and balancing markets by ensuring consistency with the intraday capacity calculation methodology. Due to the alignment and reuse of principles among the different capacity calculation methodologies, synergies in IT development and operational processes are created aiming for maximum efficiency for the long-term operation of all timeframes. The balancing timeframe methodology ensures coherency with the ROSC process by facilitating a sequential process chain.
- In Article 5(5) EB Regulation this balancing timeframe capacity calculation methodology is compliant with the regulatory aspects mentioned in Article 3(2) EB Regulation as set out below. This balancing timeframe capacity calculation methodology
- In accordance with Article 3(2) (a) EB Regulation applies the principles of proportionality and non-discrimination as set out in Recital 5(a).
- In accordance with Article 3(2) (b) EB Regulation has been developed and adopted within a process that ensures the involvement of all relevant stakeholders.
- Article 3(2) (e) EB Regulation ensures that the development of the forward, day-ahead and intraday markets is not compromised by fostering the development of the markets as set out in Recital 5(a) and the fact that the balancing capacity updates are made after the IDCZGCT and thus independent from the day-ahead and intraday processes which prevents compromising those.
- Article 3(2) (f) EB Regulation respects the responsibility assigned to the relevant TSO in order to ensure system security, allowing an individual validation before capacities are provided to the balancing platforms where each TSO can check its own network.
- Article 3(2) (h) EB Regulation takes into consideration agreed European standards and technical specifications by building the balancing capacity calculation process up on established processes, principles and mechanisms that are used in the day-ahead and intraday capacity calculation methodologies and in sequence to the regional operational security coordination that creates the grid model inputs for this process.

Secondly, a number of relevant definitions from the EB Regulation are stated below:
'balancing' means all actions and processes, on all timelines, through which TSOs ensure, in a continuous way, the maintenance of system frequency within a predefined stability range.

'balancing market' means the entirety of institutional, commercial and operational arrangements that establish market-based management of balancing;

'balancing services' means balancing energy or balancing capacity, or both;

'balancing energy' means energy used by TSOs to perform balancing and provided by a balancing service provider;

'balancing capacity' means a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract;

'balancing service provider' means a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs;

'exchange of balancing energy' means the activation of balancing energy bids for the delivery of balancing energy to a TSO in a different scheduling area than the one in which the activated balancing service provider is connected;

Finally, the definition of the balancing platforms which are one of the main goals of this methodology are stated as following:

MARI (Manually Activated Reserves Initiative) is the European platform for the exchange of balancing energy from frequency restoration reserves with manual activation (mFRR). MFRR IF means the Implementation framework for the European platform for the exchange of balancing energy from frequency restoration reserves with manual activation in accordance with Article 20 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation) is the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation or aFRR-Platform. aFRR IF means Implementation framework for the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

3 Definition of Bidding-Zone Borders in CCR Hansa

This methodology relates to the bidding-zone borders of CCR Hansa. In line with Article 4 of ACER's decision[7] on the determination of capacity calculation regions, CCR Hansa currently consists of the following bidding-zone borders:

1. Denmark 1 - Germany/Luxembourg (DK1-DE/LU)
   Energinet.dk and TenneT TSO GmbH; via onshore AC-grid connection
   Additional information on the DK1-DE/LU border is given in section 3.1

2. Denmark 2 - Germany/Luxembourg (DK2-DE/LU)
   Energinet.dk and 50Hertz Transmission GmbH; and via the Kontek HVDC interconnector and the Kriegers Flak Combined Grid Solution, a hybrid interconnector consisting of interconnected offshore wind farms in the DK2 and DE/LU bidding zone.

3. Sweden 4 - Poland (SE4 – PL)
   Svenska Kraftnät and PSE S.A; via the SwePol HVDC interconnector

4. Denmark 1 – the Netherlands (DK1-NL)
   Via the COBRAcable HVDC interconnector

5. Sweden 4 - Germany/Luxembourg (SE4-DE/LU)
   Via the Baltic Cable HVDC interconnector

[7] ACER decision No 04/2024 of 19 March 2024.

6. <u>Norway 2 – the Netherlands (NO2-NL)</u>
   Via the NorNed HVDC interconnector

7. <u>Norway 2 - Germany/Luxembourg (NO2-DE/LU)</u>
   Via the NordLink HVDC interconnector

As is apparent from the list, CCR Hansa largely consists of fully controllable HVDC interconnectors. There are two exceptions to this, the AC-grid border DK1-DE/LU and the Kriegers Flak CGS attributed to the DK2-DE/LU border, of which an additional description will be given in the next sections.

3.1 Description of the Denmark 1 – Germany/Luxembourg AC border

CCR Hansa consists of several DC-connected borders and one AC-connected radial border. To understand the capacity calculation methodology and the related methodologies for remedial actions it is important to know the current topology of the AC border which is shown in Figure 1. The border DK1-DE/LU consist of two 380/400kV lines fully parallel which are connected into the same substation "Kassø" on the Danish side and "Audorf (South)" at the German side. Additionally, a third interconnector, the West-Coastline (WCL), is currently under construction.

At present, there are two phase-shifting transformers placed in Denmark at the substations where the 380/400kV lines connect. The aim of these is to equalize the distribution of flows between the lines and therefore to ensure the lines are not overloaded in operation.

There is no synchronous connection from DK1 to DK2 or Scandinavia. DK1 is only connected with AC lines to the German grid. This means that currently all exchanges between DK1 and DE have to flow from Kassø to Audorf until the connection of the Danish grid to the WCL is realized. Only the grid between Kassø and Audorf is represented within the capacity calculation of CCR Hansa. Due to historic reasons, significant parts of Flensburg are supplied from Denmark and is part of the market in DK1.

Figure 1: Topological overview of the Denmark West (DK1) – Germany (DE/LU) AC connection within CCR Hansa. Each red line represents a 380/400kV interconnector, consisting of a double circuit across the onshore border between Denmark (DK1)

and Germany (DE/LU). The West Coastline from Klixbül to Endrup is not commissioned yet.

Since all three cross-border connections run in parallel, the DK1-DE/LU border is considered radial, and no loop flows can occur.

3.2 Description of Kriegers Flak Combined Grid Solution

Since 2020, two separate connections make up the DK2-DE/LU bidding-zone border. The existing KONTEK DC interconnector and the Kriegers Flak Combined Grid Solution (KF CGS).

KF CGS is a novel type of CCR Hansa interconnector, being a hybrid with interconnector and offshore wind farm (OWF) grid connection.

Due to the fact that the transmission grids in Eastern Denmark and Germany, respectively, belong to different synchronous areas and thus are operated non-synchronously, KF CGS, in case it being solely an CCR Hansa interconnector between Eastern Denmark and Germany with no OWFs connected to it, would have been set up as an ordinary DC line. For both technical and economic reasons, KF CGS is set up as an AC line, however with a back-to-back converter which is located at one of its ends and converts AC into DC and back into AC and thus enables the connection of the Nordic synchronous area with the one in continental European synchronous areas.

KF CGS is comprised of

- a back-to-back converter station at the German terminal of KF CGS.
- two German OWFs that feed into the German bidding zone through an AC radial grid connection.
- an AC cable connecting the grid connection of the German OWFs with the grid connection of the Danish OWFs.
- one Danish OWF that feeds into the DK2 bidding zone through an AC radial grid connection.

Despite its technical setup, KF CGS behaves in operational terms like an ordinary DC link and therefore is to be treated as such.

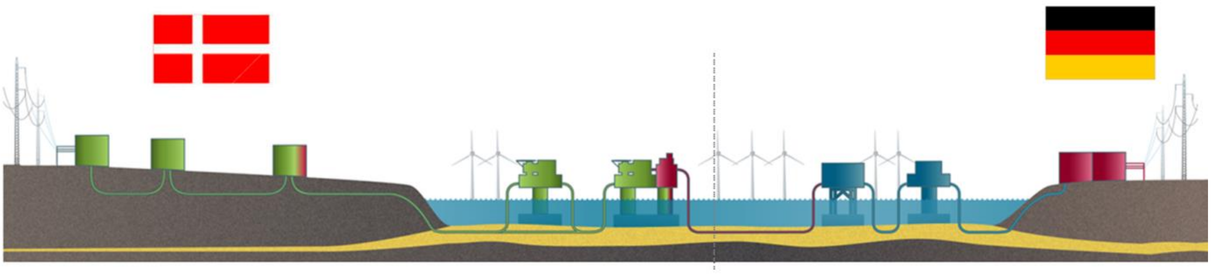


Figure 2 Conceptual sketch of KF CGS that is constituted of parts from a Danish OWF (with two offshore substations), two German OWFs, a connecting cable between the OWFs, and a back-to-back converter station. Green colours indicate parts of KF CGS stemming from the Danish OWF, blue colours show parts stemming from the German OWFs, and red colours show parts stemming from the CCR Hansa interconnector.

As such, KF CGS is not directly comparable to a traditional interconnector, regardless of it being a DC or an AC connection but is instead a hybrid. When the capacity for the DK2-DE/LU bidding-zone border is calculated, the hybrid nature of KF CGS means that special considerations have to be made in the capacity calculation methodology.

The hybrid nature of KF CGS has two concrete implications for the possibility of transmitting energy between the DK2 and DE/LU bidding zones.

1. The expected generation of the German OWF(s) [of the Danish OWF(s)] reduces the import capacity of the German bidding zone [of the Danish bidding zone] over KF CGS.
2. The expected generation of the German OWF(s) [of the Danish OWF(s)] can in some cases increase the export capacity of the German bidding zone [of the Danish bidding zone] over KF CGS.

Regarding point 1, the capacity that can be given to the market depends on the expected generation of the OWFs since the KF CGS can only utilise the share in the transmission capacity on KF CGS which is not needed to transmit the electricity generation of the German and Danish OWFs to the respective national transmission grid.

OWF generation has prioritised access to the transmission capacity towards its home market which directly reduces the capacity available for the electricity markets. This is reflected in the mathematical description of the capacity calculation methodology as a forecast term related to already allocated capacity.

Regarding point 2, the fact that generation units are physically located on the KF CGS implies that wind generation can supplement the flow on the KF CGS. In the case where the sending end terminal constitutes a binding constraint (a bottleneck) for the capacity calculation, wind generation at the sending OWF can compensate for the transmission loss between the constraint and the OWF to allow a higher market capacity. In the mathematical description of the capacity calculation methodology this is introduced as a KF CGS-specific forecast term related to the loss factor that is central to determining the NTC (Net Transfer Capacity). This is especially relevant for the northbound market capacity.

Conceptually, KF CGS consists of three sections, as shown in Figure 3, with section 1 being the radial grid connection of the Danish OWF to DK2 (capacity of 600 MW), section 2 being the cable connection between the Danish OWFs and the German OWFs (capacity of about 400 MW), and section 3 being the radial grid connection of the Germans OWFs to Germany (capacity of about 400 MW).

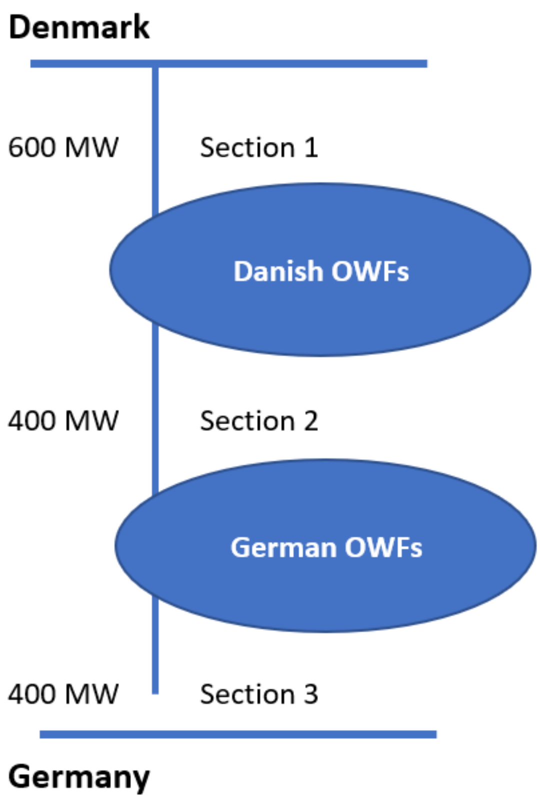


Figure 3 Conceptual illustration of transmission capacity of different sections of KF CGS

For the northbound capacity, transmission losses imply that section 3 is a bottleneck, such that the transmission capacity of about 400 MW can never be fully utilised with northbound flow.

Using the generation of the German OWFs located physically at the interface between section 2 and 3 partly, or if so, completely for covering the grid losses on section 3 moves the bottleneck from section 3 to section 2. This means that the market capacity can be increased by the equivalent of the full load grid losses of section 3.

For the southbound capacity, section 2 is the bottleneck from the outset, since the transmission capacity of section 1 is higher than that of section 2. Only in case of an outage on section 1 can this section make up a bottleneck, in which case expected generation on the Danish OWFs can increase the market capacity.

4 Capacity Calculation Methodology for the Balancing Timeframe

This chapter describes the target capacity calculation methodology which will be applied for CCR Hansa bidding-zone borders in the balancing timeframe.

4.1 Rules for Calculating Cross-Zonal Capacity

Article 3 in the BT CCM for CCR Hansa describes the rules for calculating cross-zonal capacity in CCR Hansa.

As Article 37(3) of the EBGL requires this CCM to be consistent with the ID CCM, the capacity calculation approach for CCR Hansa follows the coordinated net transfer capacity (CNTC) approach which is adjusted to fit in the tight time window of the balancing timeframe.

The rules for calculating cross-zonal capacity in the capacity calculation methodology for CCR Hansa states that the latest ATC & AAC values will be retrieved from XBID after the IDCZGCT. In case a recomputation is needed and performed for the NTC value, this shall be executed in accordance with Article 4 of the BT CCM.

Based on the current timelines, flow-based capacity calculation and allocation in intraday timeframe as well as AHC in CCR Core and CCR Nordic, might be implemented before the go-live of this methodology. If this occurs, CCR Hansa TSOs will not be able to retrieve any NTC data covering the limitation on AC CNECs impacting Hansa interconnectors (from the adjacent CCRs) from XBID.
CCR Hansa TSOs, or entities acting on their behalf, might then:

- Extract NTCs from the intraday flow-based domain of the relevant adjacent CCR after intraday gate-closure including the additions from the capacity reservations for the balancing timeframe.
- Investigate a new definition for Hansa CNEs to explore the possibility of incorporating the AC grids near the Hansa border into the Hansa capacity calculation process.

Additionally, where more than one interconnector meets on a CCR Hansa bidding-zone border, the NTC and AAC values shall be summed to a total NTC and AAC of the CCR Hansa bidding-zone border.

Regardless of the selected way to extract the NTC, the (re-)calculation is carried out by the TSOs and not by the CCCs. This is the preferred option due to the short timeframe, as it allows the NTCs to be calculated, coordinated and validated. In contrast to the DA/ID methodology, the NTC is not calculated by the CCC, which is why the corresponding input data for the calculation does not have to be communicated in accordance with the specified formulas. This results in the significantly shorter specification of Article 3 compared to the same article in the DA/ID methodology.

In the scenario that the capacity management function (CMF) is not able to calculate the ATC value, the fallback procedure for capacity calculation according to Article 10 of this CCM will enter into force.

4.2 Principle of the Recalculation of the Capacity in the Balancing Timeframe

The capacity calculation methodology proposed for the balancing timeframe unifies 3 congestion-relevant parts. It takes advantage of the methodologies developed in CCR Nordic and CCR Core in order to represent the limitations in the AC grids, while the actual CCR Hansa interconnector capacities are addressed individually within CCR Hansa. Hansa TSOs are currently investigating a CNE definition which is non-contradictory between both CCMs while taking into account the individual characteristics of the different timeframes at the same time.

Cross-border trade between bidding zones always affects at least three different parts of the grid:

1. The AC grid sensitive to the trade surrounding the CCR Hansa interconnector on the exporting side;
2. The CCR Hansa interconnector itself;
3. The AC grid sensitive to the trade surrounding the CCR Hansa interconnector on the importing side.

This holds true for all cross-border trade, irrespective of the type of CCR Hansa interconnector (AC or DC) or the applied capacity calculation methodology (NTC or flow-based).
Years of experience with capacity calculation have shown that a congestion resulting from a cross-border trade can occur in each of these three parts of the grid. In order to maintain system security, it is therefore necessary to take all three parts into account in the capacity calculation.

Since CCR Hansa has the unique feature that all bidding zones are currently connected by means of radial lines, the assessment of cross-border capacity can be split into three separate parts. This allows the CCR Hansa TSOs to look at the impact of cross-border trade independently on each part of the grid.

CCR Nordic and CCR Core will compute ATC for the virtual areas (so called virtual Hubs) that connect the respective neighbouring CCR to the Hansa-interconnector in order to reflect the AC-grid limitations therein. These ATCs will be delivered to the RCCs for the CCR Hansa.

4.3 Reassessment & Validation of Capacity in the Balancing Timeframe

The target model of the capacity calculation for CCR Hansa limits the scope of the capacity calculation for CCR Hansa to the interconnectors themselves. Therefore, this section only describes the methodology for reassessment and validation of the cross-zonal capacity that are actually performed by the CCR Hansa TSO or an entity acting on their behalf.

After intraday cross-zonal gate closure time (IDCZGCT), TSOs perform an ATC extraction from the CC tool “XBID”. Since CMM cannot receive ATC values at this point in time, TSOs are required to recalculate the NTC values based on the next formula: NTC = ATC + AAC. TSOs then send NTCs and AAC~~s~~ values to the CMM, which recalculates the ATCs, based on the previous values, for each 4 MTUs of each hour as an input to the Balancing Platforms. The cross-zonal capacities are the inputs for provision to the balancing platforms (BPs). However, if there is any new information such as new wind forecast and consequently new measurement of wind generation in relation to KF CGS as well as events, e.g., unscheduled outages, then the cross-zonal capacities will be reassessed by the relevant TSO and recalculated according to Article 4 of the BT CCM. The cross-zonal capacity is provided 96 times a day (for each MTU) in the balancing timeframe to the CMF/BPs based on the latest available information, taking into consideration operational security. The TSO shall ensure that the reassessed capacities are submitted without undue delay to the CMF/BPs.

Before the deadline for cross-zonal capacities provision to the balancing platforms, each CCR Hansa TSO may perform individual validation. The way to validate the capacity is specific to each Hansa TSO. The validation can be done locally or commonly in the CCR. Each CCR Hansa TSO may reduce cross-zonal capacity during the individual validation of cross-zonal capacity relevant to the CCR Hansa TSO’s bidding-zone borders for reasons of operational security. Each CCR Hansa TSO should also have the possibility to decrease capacities at any time after the capacities provision deadline to the balancing platforms, however it must be done directly within the balancing platforms themselves. Additionally, each CCR Hansa TSO has the right to propose increases in the cross-zonal capacity. Any increase in capacity following this validation process shall be coordinated by the TSO and commonly agreed upon by the affected CCR Hansa TSOs. The affected CCR Hansa TSO will normally mean the CCR Hansa TSOs directly involved on the specific bidding-zone border in question.

The CCR Hansa TSOs will consider the operational security limits when performing the validation, but may also consider additional grid constraints, grid models and other relevant information.

If capacities on a given bidding-zone border are regularly corrected by CCR Hansa TSOs, the CCR Hansa TSOs shall jointly evaluate the capacity calculation process and the capacity calculation methodology and investigate how to reduce the need for corrections.

Results from the validation process shall be sent from each CCR Hansa TSO to all CCR Hansa TSOs within a time limit to be agreed upon by all CCR Hansa TSOs. All such decisions from CCR Hansa TSOs on reduction of capacity and proposals for increase of capacity shall include an explanation and justification. The CCR Hansa TSOs shall report all reductions made during the validation of cross-zonal capacity to all CCR Hansa NRAs. The report shall include the location and amount of any reduction in cross-zonal capacity and shall give reason for the reductions.

4.4 Methodology for Allocation Constraints

In accordance with Article 58(4)(a) and (b) of the EB Regulation, all algorithms operated by the activation optimisation functions, imbalance netting process functions and capacity procurement optimisation functions shall respect operational security constraints, take into account technical and network constraints and, if applicable, take into account the available cross-zonal capacity. In order to ensure consistency with the cross-zonal CCM applied in the intraday timeframe in accordance with Article 37(3) of the EB Regulation, CCR Hansa TSOs may apply the constraints as allocation constraints during the capacity allocation phase.

According to CACM Art. 6, "'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation". Due to the capacity allocated in the balancing timeframe being used for cross-border exchange of balancing services which are one of the means to ensure system security, the allocation constraints need to reflect all operational security constraints as well as technical and network constraints.

The list of allocation constraints is to be considered as a list of options that can be applied, partially or in full, to each of the individual interconnectors. However, particular allocation constraints will only be applied on those interconnectors that requires them due to reasons stated above, and only if these are deemed absolutely necessary by the respective TSOs. If a TSO or an entity acting on their behalf assess that one or more allocation constraints are necessary for a given interconnector, they must inform the other Hansa TSOs, market participants, and relevant regulatory authorities at the latest 2 months before the implementation. This information will include a justification for applying the allocation constraint(s), a description of the allocation constraint(s) and when the application of the allocation constraint(s) will be initiated.

The list of allocation constraints in Hansa BT CCM is aligned with the list of allocation constraints in Hansa DA/ID CCM. However, allocation constraints in the balancing timeframe are justified by EB regulation Article 58, whereas CACM is the regulatory framework for allocation constraints in the DA/ID CCM.

4.4.1 Allocation Constraint removed: Minimum production in a bidding zone

This allocation constraint was removed because no TSO is intending to apply the allocation constraint to any Hansa interconnectors. It was decided to not include allocation constraints, that is not foreseen to be used. The allocation constraint was originally included in the BT CCM, because during the first drafting round it was not yet decided which allocation constraints are necessary. As mentioned above, the list of allocation constraints is to be considered as a list of options. Furthermore, the allocation constraint was removed in order to ensure alignment with the Hansa DA/ID CCM.

4.4.2 Allocation Constraint a: Import/Export Limits

Allocation constraints may include balancing constraints (import/export limits) that are determined for those systems where a central dispatch market model is applied, i.e., where the CCR Hansa TSO acts as the balance responsible party for the whole control area and procures reserves in an integrated scheduling process run after the day-ahead market closure. In order to execute this task, the CCR Hansa TSO in central dispatch systems needs to ensure the availability of sufficient upward or downward regulation reserves for maintaining secure power system operation. This will be done in form of allocation constraints that vary depending on the foreseen balancing situation. Application of allocation constraints to reflect balancing constraints in capacity allocation process ensures efficiency in distribution of balancing constraints on interconnections and maximise social welfare.

4.4.3 Allocation Constraint b: Maximum flow change on DC lines and KF CGS between and within MTUs in the balancing timeframe

A maximum flow change is an instrument of system operation to maintain system security (frequency management purposes) or to ensure that the maximum change on HVDC interconnections between market time units is kept within technical limits of HVDC interconnections. In the balancing timeframe, it may be necessary to apply maximum flow change restrictions both between and within MTUs. The exchange of balancing energy can occur both between and within MTUs. While mFRR scheduled activations are activated between MTUs and mFRR direct activations are activated within MTUs according to mFRR IF whereas aFRR is activated between or within the MTUs according to aFRR IF.
As the activation of balancing energy must take place considering a very short lead time and the respective demand is subject to strong fluctuations, high power gradients can occur. A coordinated optimization could increase this effect at certain borders and at certain times if the bidding structure result in a high amount of exchange. In addition, depending on the technical design, the speed at which the exchange on an interconnection can take place physically, varies from the known behaviour of balancing power plants. In order to ensure both the system security as well as the technical applicability on both sides of a border, it is imperative to limit the maximum flow change based on the technical limits of the interconnection and the operational limits of the respective grid operators.

4.4.4 Allocation Constraint c: Implicit Loss Factor

Incorporating the Implicit loss factor on DC lines during capacity allocation ensures that the DC line will not flow unless the welfare gain of flowing exceeds the costs of the corresponding losses. If the loss factor would not be considered, this could result in activation of bids from the common merit order list (CMOL) which initially appear to have lower marginal price but after accounting for costs of the losses, these bids would turn out to be more expensive to activate compared to bids which wouldn’t be activated. This situation would contradict the requirement of the Article 31(9) and (10) of the EB Regulation to balance the system in the most efficient way. Currently Implicit Loss Factor is not applied on any of the Hansa interconnectors in the balancing timeframe, though it is applied in DA. In the future, however, Implicit Loss handling might also be applied in the balancing timeframe which is why it is already included in the list of possible allocation constraints. Currently the balancing timeframe algorithms (MARI, PICASSO, CMM) cannot handle implicit losses like Euphemia does, which is why is will not be applied from the beginning. Once implicit loss handling will be applied on interconnectors in the balancing timeframe, they will go through the same process that is used today with the submission of a document that explains the grid loss management and the demonstration of social economic welfare.

With implicit loss handling, the losses incurred along the HVDC are to be taken into account in the allocation. This achieves a more efficient market result that deviates less from the physical flow and prevents flows that are disproportionate to the losses incurred. The exact form of loss consideration is determined in the respective optimization for market clearing, in this case PICASSO and MARI.
In the balancing time frame, this already complex process is very limited in time. The best possible technical implementation is therefore essential. How exactly this will look like cannot be precisely defined at the present time. In a broader sense, however, implicit loss procurement always follows the principle of implicit loss factors. The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling. The implicit loss factors on HVDC interconnections account for the power loss on HVDC interconnections by the following equation:

Import quantity = (1 – Loss Factor) x Export quantity

4.4.5 Allocation Constraint d: Minimum Flow

Considering a minimum flow on each DC line during capacity allocation ensures that the DC line will not be operated outside its technical capabilities. This creates a so-called dead-band in the feasible range of power flow on the individual interconnector.

4.4.6 Allocation Constraint e: Polarity Reversals

Older HVDC systems were built for the market conditions at the time with quite stable operational patterns. In systems with line commutated converters polarity reversals cause increased electrical stress in the cable insulation, which can in the long run reduce the life expectancy of the cable. The sensitivity to polarity reversals differs by cable and technology type. For example, one of the cable suppliers of mass-impregnated HVDC cables recommends keeping the number of polarity reversals below 1000 per year (the exact value is depending on the technical characteristics of each cable).This is also in line with the operating experience from many of the mass-impregnated cables systems in service today.

4.4.7 Allocation Constraint f: Maximum Flow

The maximum flow might be limited on some DC lines where cable technologies are sensitive to changing cable temperature and pressure. The control systems of these DC lines can impose real-time restrictions to the operating voltage, which is set at a reduced value compared to the nominal voltage.

This reduced voltage mode is triggered when cable temperature and pressure thresholds are exceeded, e.g., in case of polarity reversal or steep flow changes of the DC line and is only released/reset to nominal voltage when the control system deems it safe to do so. This is an in-built feature of the control system responsible for the DC line, to ensure the integrity of the cable is preserved and the effect of rapidly changing temperature and/or pressure does not negatively impact the cable's service life. The impact of a reduced voltage is a reduced maximum power flow for a period of time. Previous allocations within the balancing timeframe will determine the eventual physical flow on the DC line (and whether the polarity is reversed, or the DC line is ramped-up from 0MW), which will in turn determine whether a maximum flow limitation is required. It is for this reason that this limitation must be considered as an allocation constraint e.g. within the CMF.

4.4.8 General considerations regarding allocation constraints

Functionality for several of the allocation constraints described above are not yet implemented in the CMF and/or balancing platforms, and it is currently not known how or when such functionality will be implemented, as the implementation on ACs are being performed outside of CCR Hansa's governance. These allocation constraints are nevertheless included in the CCR Hansa BT CCM such that they can be applied when the functionality becomes available.

4.5 Capacity Reservations for the Balancing Timeframe

There is currently no reservation of transmission-capacity for balancing services for the Hansa interconnectors. If, and when, reservations are introduced, these will be kept from the DA and ID market timeframes and released as cross-border capacity for the balancing timeframe.

4.6 Rules for Taking into Account Already Allocated Cross-Zonal Capacity in the Balancing Timeframe

For the capacity reserved or allocated for cross-zonal exchange of ancillary services following Article 40,41 or 42 of the EB Regulation in terms of the Balancing Timeframe to be made available in the balancing platforms, it has to be not included in the AAC value.

It is important to consider that the mathematical description indicates that AAC can both be added or subtracted from the cross-border capacity depending on the direction of the AAC.

4.7 Methodology for Determining Operational Security Limits and Contingencies Relevant to Capacity Calculation

In accordance with Article 23(1) of the CACM Regulation, CCR Hansa TSOs shall respect the operational security limits used in operational security analysis in line with Article 72 of the SO Regulation. The operational security limits used in the common capacity calculation are the same as those used in operational security analysis, therefore no additional descriptions pursuant to Article 23(2) of the CACM Regulation are needed. In particular, CCR Hansa TSOs shall respect the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits. Other operational security limits relevant for the balancing timeframe are defined in Article 6, Methodology for Allocation constraints in the CCR Hansa EB methodology, and elaborated upon in chapter 4.4 in the explanatory document.

Thermal limits of CCR Hansa interconnectors are considered in the TTC calculation process described in Article 4 in the methodology. Operational security limits and contingencies of adjacent AC grid elements, reflecting interactions between CCR Hansa interconnectors and the adjacent AC grids, are expected to be handled by the flow-based capacity calculation methodologies in CCR Core and CCR Nordic.

4.8 Fallback for Capacity Calculation

The following risk cases could trigger the fallback procedure for the capacity calculation in the balancing timeframe:

1. Non-availability of the capacities from XBID or inability to retrieve those from XBID.
2. Non-availability of CMF or the communication with CMF.
3. A TSO that is not connected to the CMF.

In case the remaining capacities after the IDCZGCT are not available, the concerned CCR Hansa TSOs will bilaterally calculate and agree on cross-zonal capacities by applying the formulas in the CCM. The final cross-zonal capacity will be determined by using the minimum value of the calculated capacities.

In case of non-availability of the CMF or the communication with the CMF, the capacity would need to be set to zero or adjusted to a value respecting the system security and provided as ATC directly to the balancing platforms. However, there are several functions of the CMF which could not be replicated in the capacity calculation. These are, amongst others:

- Distributing the cross-border capacity available for the balancing timeframe consecutively to the individual platforms based on the usage of the cross-border capacity by the individual balancing services activated prior to the respective service, i.e., the capacity available for both platforms (MARI & PICASSO) are mutually dependent on the capacity used by either platform.
- Application of the allocation constraints, including maximum flow change restriction and technical limitation of the HVDC interconnectors, if not applied by the balancing platforms. Currently the CMM HVDC TF is discussing some allocation constraints (maximum flow change, minimum flow and polarity reversals), though nothing has been implemented yet. It is up to the CMM HVDC TF and the CMM WG with their respective steering committee to decide what ACs will be applied in the CMF. Introduction of ACs in the BPs will be decided by the project governance around PICASSO and MARI.). However, technical limitations of the HVDC Interconnectors can still have an effect on the determination of the ATC that is sent directly to the balancing platforms, as these can be applied as external constraints. External constraints define the maximum export and import on a specific DC border.

As the above-mentioned functions carried out in the CMF cannot be carried out in the capacity calculation itself, the capacities need to be set to zero or to a value which would ensure system security.

4.9 Methodology for determining the Transmission Reliability Margin

The methodology to determine the reliability margin, for cross-zonal capacity in CCR Hansa, includes the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation, and realised power flows in real time, and subsequently specifies the uncertainties to be considered in the capacity calculation, being the TRM mentioned in Article 4 in the CCM. The following description sets out common harmonised principles for deriving the reliability margin from the probability distribution, as required in Article 22(3) of the CACM Regulation.

Due to the controllability of the power flow over DC interconnections, the determination of a reliability margin does not need to be applied on bidding-zone borders only connected by DC interconnections. Therefore, on the borders SE4-PL and DK2-DE/LU no reliability margin is currently applied. The methodology described here therefore only applies to the radial-connected AC border DK1-DE/LU.

In general, the cross-border capacity derived for the AC border in CCR Hansa is expressed as an NTC value. During the capacity calculation, the CCR Hansa TSOs apply the TRM in order to hedge against risks inherent in the calculation. The methodology for the TRM is determined by the CCR Hansa TSOs and reflects the risks that the CCR Hansa TSOs are facing. As demanded by Article 22(2) of the CACM Regulation, the presented methodology in particular takes into account:

"(a) Unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;
(b) Uncertainties which could affect capacity calculation and which could occur between the capacity calculation timeframe and real time, for the market time unit being considered."

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

1. Identification of sources of uncertainty for each TTC calculation process.
2. Derivation of independent time series for each uncertainty and determination of probability distributions (PD) of each time series.
3. Convolution of individual PDs and derivation of the TRM value from the convoluted PD.

The method is illustrated in the figure below.

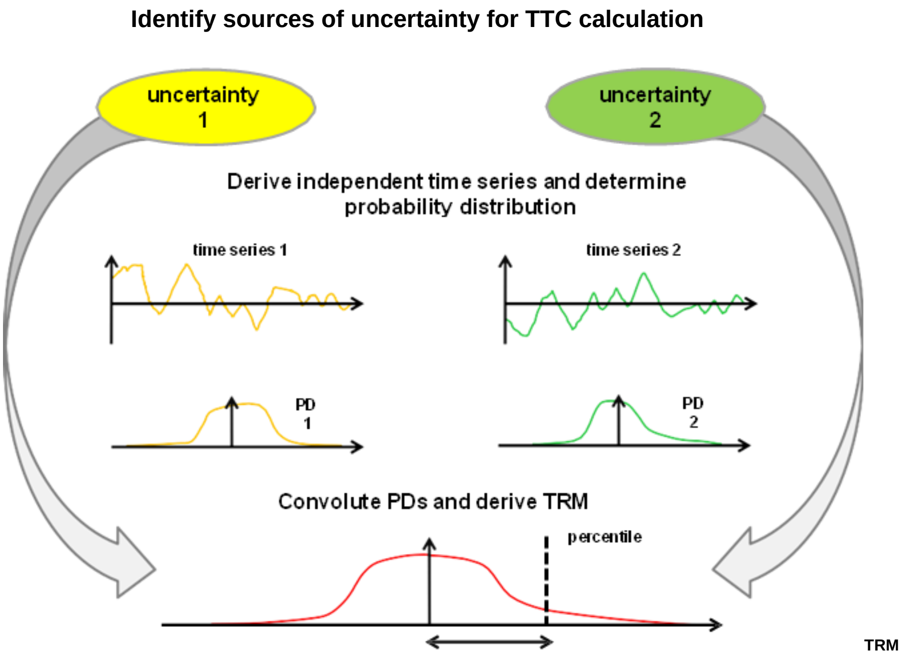


Figure 4: Illustration of the concept used to calculate the TRM

Below, the individual steps are described in more detail.

Step 1: Identification of sources of uncertainty

In the first step, the corresponding uncertainties are identified. In general, the TTC calculation is based on the CGM, which includes assumptions and forecasts for the generation and load pattern as well as for the grid topology. This is the starting point to identify specific sources of uncertainty. For the AC border in CCR Hansa, typical sources of uncertainty at the capacity calculation stage are:

1. Inaccuracy of forecasts for wind, load and solar infeed, which impact the load and generation pattern in the network model.
2. Assumptions of cross-border exchange between third countries which are not part of the TTC profile.
3. Exchange of frequency containment reserve (FCR).

Step 2: Determination of appropriate probability distributions

The second step of the TRM calculation is the determination of appropriate time series that measure or estimate the effect of each uncertainty on the TTC calculation. Depending on the nature of the uncertainty, the determination of such time series can differ. In general, generic time series from an already existing data base can be used as a starting point. The time series cover an appropriate timespan from the past in order to get a significant and representative amount of data. After performing quality checks, the impact of the uncertainty on the TTC calculation is determined.

Step 3: Convolution and TRM calculation
At the beginning of this step, the individual PDs are convoluted to get the overall PD for an event. The convolution of the PDs of the relevant uncertainties merges the individual independent factors into one common PD for one TRM. Before the convolution is made, each PD is normalised. The convoluted PD is the basis for the determination of initial TRM values. From the convoluted PD, a certain percentile is taken.

5 Timescales for implementation

The CCR Hansa TSOs shall implement this methodology by 12 months after the approval by the relevant regulatory authorities took place and all necessary (technical) requirements are fulfilled. Therefore, in order to safeguard a seamless implementation of this methodology the following milestones need to be achieved as these serve as a prerequisite for the application of this CCM:

a) All Hansa TSOs with a control area responsibility need to be connected to the balancing platforms MARI and PICASSO
b) All Hansa TSOs are connected to the CMF either directly or via an entity on their behalf

a) The CCR Hansa TSOs with a control area responsibility must go live on the relevant balancing platforms (specifically on MARI and PICASSO developed pursuant to Articles 20 and 21 of EB Regulation) before an exchange of balancing energy can occur requiring the BT CCM. Based on the current planning all Hansa TSOs with control area responsibility will be connected to both MARI and PICASSO in Q4 2026 (cf. Figure 5).

   In case that both/all TSOs of a shared border are connected to the balancing platforms and if all technical requirements for using the balancing platforms are fulfilled, without the Hansa BT CCM being live, partly or in full, the respective Hansa TSOs shall provide the remaining cross-zonal capacities after IDCZGCT, as indicated in EB Regulation Aart.37(2). In this case, TSOs shall calculate ATC (= NTC - AAC) and send it directly to the balancing platform(s). For this instance, the application of allocation constraints shall be done directly by the relevant TSO(s) during the capacity calculation according to Article 10 of this CCM.

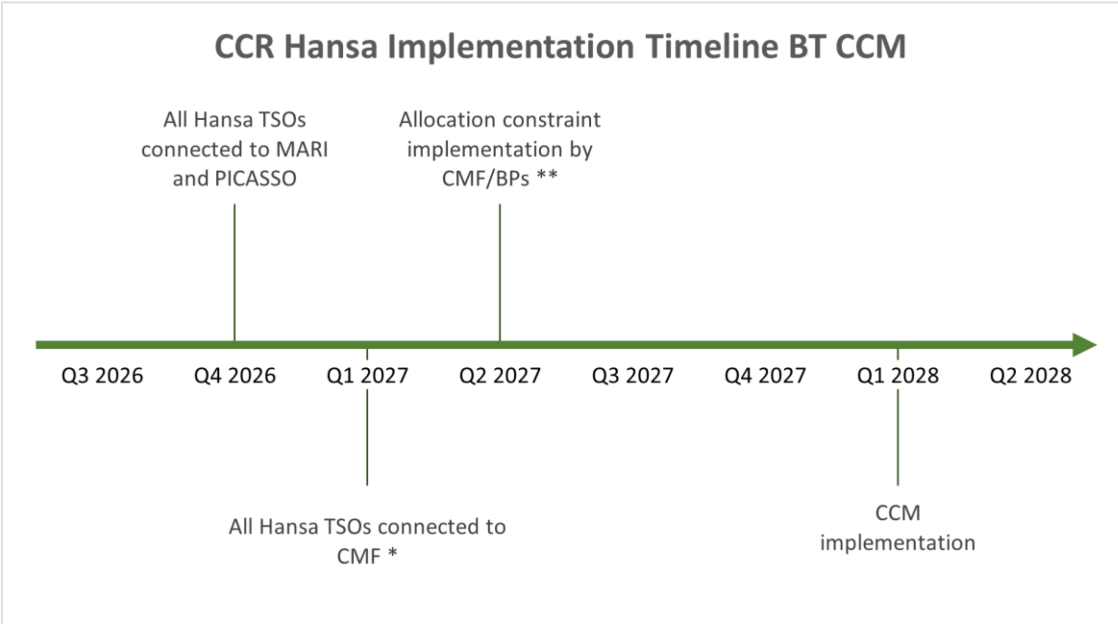
   In particular for KF CGS, the updated remaining cross-zonal capacity after IDCZGCT shall be used according to the Commission Decision (EU) 2020/2123 of 11 November 2020 on the derogation for Kriegers Flak Combined Grid Solution (KF CGS) following Article 64 of Regulation.

b) Before the BT CCM can fully go live, additionally each TSO needs to establish a connection to the CMF (Capacity Management Function), either directly via their TSO systems or alternatively via an entity on their behalf (such as e.g.an RCC). This connection is crucial for the successful implementation of the Hansa BT CCM as the CMF caters for the central alignment and management of available cross-border capacities for each of the Hansa interconnectors. Furthermore, the CMF, being an algorithm based on the CMM (Capacity Management Module), allows for consideration of TSO's individual allocation constraints in order to determine the CZCL (Cross Zonal Capacity Limits) necessary for any exchange of balancing energy. At this point in time the CMM is only operating with few TSOs while an accession of the remaining Hansa TSOs is planned to occur from mid-2024 and onwards. It is expected that TSOs will prioritize connecting to MARI and PICASSO before establishing a connection to CMF.

The final step required for the full implementation of this CCM, is the consideration of applied allocation constraints defined by Article 6(1) directly by the CMF.

Unlike both hard requirements mentioned in a) and b) this step does not necessarily hinder the implementation of the BT CCM in the eyes of the Hansa TSOs as ACs alternatively can be accounted for by the TSOs during the 'manual' capacity calculation. Although this naturally comes at the expense of higher operational as well as coordination efforts, Hansa TSOs concluded that an early implementation of the BT CCM has priority and therefore did not render this part as preconditional.

The milestones for each step described above are displayed in Figure 5. The timing of the milestones is based on the latest available information. Since the timeline is highly dependent on projects that are outside the governance of Hansa CCR, the timings are subject to change based on potential delays in preceding projects.



** Either directly or via an entity on behalf of a Hansa TSO (e.g. RCC)*
***The deadline for implementation of Hansa allocation constraints (ACs) in CMF/BPs is currently still unclear*

Figure 5: CCR Hansa Implementation Timeline BT CCM

The main reason for the long timeline for full implementation, is because many Hansa TSOs are delayed in the accession to the balancing platforms (MARI and PICASSO). As explained in step 1 above, the balancing platforms are required for the exchange of balancing energy, and with that also the need for the capacity calculation methodology, however this step is an external dependency that cannot be controlled by Hansa, but rather other TSO project dealing with balancing platform implementation.

6 Results from consultation

No comments were made in the public consultation that took place during September 2022.

7 Annex 1: Justification of usage and methodology for calculation of allocation constraints in PSE

Allocation constraints in Poland are applied as stipulated in Article 6(2) of the CCM. These constraints reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the whole Polish power system to ensure secure operation. This is explained further in subsequent parts of this Annex.

Rationale behind implementation of allocation constraints on PSE side

Implementation of allocation constraints as applied by PSE side is related to the fact that under the conditions of integrated scheduling-based market model applied in Poland (also called central dispatch system) responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in so-called self-dispatch market models. The latter is usually defined up to hour-ahead timeframe (including real time operations),while for PSE as Polish TSO this is extended to short (balancing timeframe, intraday and day-ahead).Thus, PSE bears the responsibility, which in self-dispatch markets is allocated to balance responsible parties (BRPs).That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which leads to implementation of allocation constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand. Residual demand is the part of end users demand not covered by commercial contracts (generation self-schedules). In self-dispatch markets BRPs are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the timeframe of up to one hour ahead. In a central dispatch market, in order to provide generation and demand balance, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve requirements. This is realized in an integrated scheduling process as an optimization problem called security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED). Thus, these two approaches (i.e., self and central dispatch market) ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

It was noted above that systemic interpretation of all network codes is necessary to ensure their coherent application. In SO Regulation, the definitions of specific system states involve a role of significant grid users (generating modules and demand facilities). To be in the 'normal' state, a transmission system requires sufficient active and reactive power reserves to make up for occurring contingencies (Article 18) – the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO Regulation are also not defined as a closed set, as Article 25 requires each TSO to specify the operational security limits for each element of its transmission system, taking into account at least the following physical characteristics (…).The CACM Regulation definition of contingency (identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security) is therefore consistent with the abovementioned SO Regulation framework, and shows that CACM Regulation application should involve circumstances related to generation and load.

As regards the way PSE procures balancing reserves, it should be noted that the EB Regulation allows TSOs to apply integrated scheduling process in which energy and reserves are procured simultaneously (inherent feature of central dispatch systems).In such a case ,ensuring sufficient reserves requires setting a limit to how much electricity can be imported or exported by the system as a whole (explained in more detail below).If CACM Regulation is interpreted as excluding such a solution and mandating that a TSO offers capacity even if it may lead to insufficient reserves, this would make the provisions of EB Regulation void, and make it impossible or at least much more difficult to comply with SO Regulation.

Specification of security limits violated if the allocation constraint is not applied
With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch systems), there may be a sustained deviation from scheduled exchanges of the TSOs in question. These deviations may lead to an imbalance in the whole synchronous area, causing the system frequency to depart from its nominal level. Even if frequency limits are not violated, as a result, deviation activates frequency containment reserves, which will thus not be available for other contingencies, if required as designed. If another contingency materializes, the frequency may in consequence easily go beyond its secure limits with all related negative consequences. This is why such a situation can lead to a breach of operational security limits and must be prevented by keeping necessary reserves within all bidding zones, so that no TSO deviates from its schedule in a sustained way (i.e., more than 15 minutes, within which frequency restoration reserve shall be fully deployed by any given TSO). Finally, the inability to maintain scheduled area balances resulting from insufficient operational reserves will lead to uncontrolled changes in power flows, which may trigger lines overload (i.e., exceeding the thermal limits) and as a consequence can lead to system splitting with different frequencies in each of the subsystems. The above issue affects PSE in a different way from other CCR Hansa TSOs due to reasons explained in the subsequent paragraph.

PSE role in system balancing
PSE directly dispatches all major generating units in Poland taking into account their operational characteristics and transmission constraints in order to cover the load forecasted by PSE, having in mind adequate reserve requirements. To fulfil this task PSE runs the process of operational planning, which begins three years ahead with relevant overhaul (maintenance) coordination and is continued via yearly, monthly and weekly updates to day-ahead SCUC and SCED. The results of this day-ahead market are then updated continuously in intraday timeframe, balancing timeframe up to real time operation.

In a yearly timeframe PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that the minimum year ahead generation reserve margin[8] over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day[9], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

The day-ahead SCUC process aims to achieve a set value of spinning reserve[10] (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except Combined Heat and Power (CHP) plants as they operate mainly according to heat demand).The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its

[8] The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point 10.2.11(3)). It is subject to change depending on the results of the development of operational planning processes.

[9] The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point 10.2.11(2) and (3)).

[10] These values are regulated by the Polish grid code (point 10.2.11(1)) and subject to change.

volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.

The further updates of SCUC/SCED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.). It allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW, which corresponds to the size of the largest unit in the system.

Determination of allocation constraints in Poland

When determining the allocation constraints, the Polish TSO takes into account the most recent information on the aforementioned technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time horizons.

Allocation constraints are bidirectional, with independent values for each MTU, and separately for directions of import to Poland and export from Poland.

For each hour, the constraints are calculated according to the below equation:

$$\mathrm{EXPORT}_{constraint} = \mathrm{P}_{CD} - (\mathrm{P}_{NA} + \mathrm{P}_{ER}) + \mathrm{P}_{NCD} - (\mathrm{P}_{L} + \mathrm{P}_{UPres}) \quad (1)$$

$$\mathrm{IMPORT}_{constraint} = \mathrm{P}_{L} - \mathrm{P}_{DOWNres} - \mathrm{P}_{CD_{min}} - \mathrm{P}_{NCD} \quad (2)$$

Where:

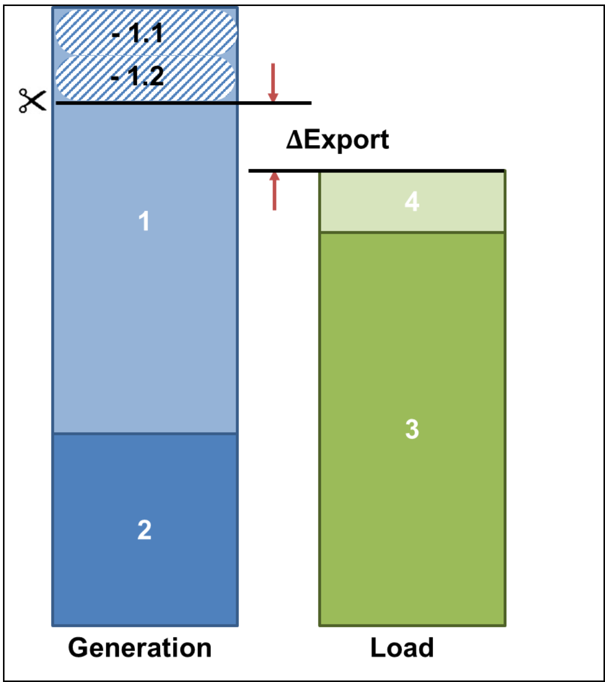
P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[11]
$\mathrm{P}_{CD_{min}}$	Sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions).
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
P_{L}	Demand forecasted by PSE
P_{UPres}	Minimum reserve for up regulation
$\mathrm{P}_{DOWNres}$	Minimum reserve for down regulation

For illustrative purposes, the process of practical determination of allocation constraints in the framework of day-ahead transfer capacity calculation is illustrated below: Figures A1 and A2. The Figures illustrate how a forecast of the Polish power balance for each hour of the next day is developed by TSO day-ahead in the morning in order to determine reserves in generating capacities available for potential exports and imports, respectively, for day-ahead market. For the intraday and balancing timeframe market, the same method applies mutatis mutandis.

Allocation constraint in export direction is applicable if Export is lower than the sum of transfer capacities on all Polish interconnections in export direction. Allocation constraint in import direction is

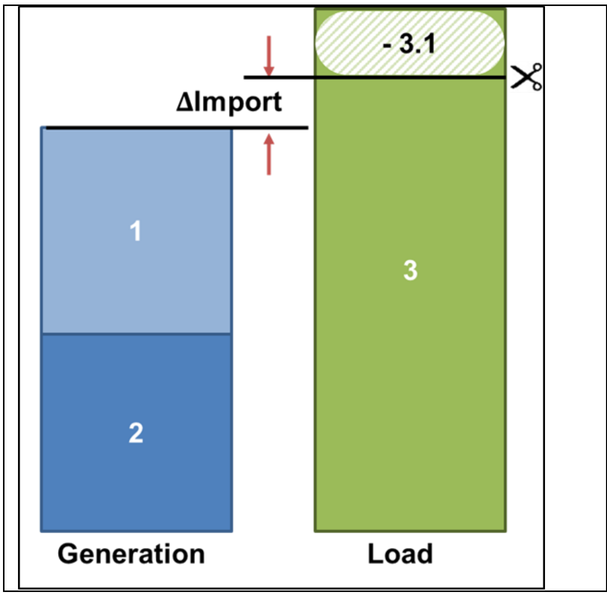
[11] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.

applicable if Import is lower than the sum of transfer capacities on all Polish interconnections in import direction.



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
   1.1 Generation not available due to grid constraints
   1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
3. Demand forecasted by PSE
4. Minimum necessary reserve for up regulation

Figure A1: Determination of allocation constraints in export direction (generating capacities available for potential exports) in the framework of day-ahead transfer capacity calculation.



1 Sum of technical minima of centrally dispatched generating units in operation

2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)

3 Demand forecasted by PSE, reduced by:

3.1 Minimum necessary reserve for down regulation

Figure A2: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day-ahead transfer capacity calculation.

Frequency of re-assessment
Allocation constraints are determined in a continuous process based on the most recent information, for each capacity allocation time horizon, from forward till day-ahead, intraday and balancing

timeframe. In case of day-ahead process, these are calculated in the morning of D-1, resulting in independent values for each MTU, and separately for directions of import to Poland and export from Poland.

Impact of allocation constraints on single day-ahead coupling and single intraday coupling
Allocation constraints in form of allocation constraints as applied by PSE do not diminish the efficiency of day-ahead, intraday and balancing timeframe market coupling process. Given the need to ensure adequate availability of generation and generation reserves within Polish power system by PSE as TSO acting under central-dispatch market model, and the fact that PSE does not purchase operational reserves ahead of market coupling process, imposing constraints on maximum import and export in market coupling process – if necessary – is the most efficient manner of reconciling system security with trading opportunities. This approach results in at least the same level of generating capacities participating in cross-border trade as it is the case in self-dispatch systems, where reserves are bought in advance by BRPs or TSO, so they do not participate in cross-border trade, either. Moreover, this allows to avoid competition between the TSO and market participants for generation resources.
It is to be underlined that allocation constraints applied in Poland will not affect the ability of any Hansa country to exchange energy, since these constraints only affect Polish export and/or import. Hence, transit via Poland will be possible in case of allocation constraints applied.

Impact of allocation constraints on adjacent CCRs
Allocation constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one border (i.e., Core, Baltic and Hansa). It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global allocation constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.

Time periods for which allocation constraints are applied
As described above, allocation constraints are determined in a continuous process for each capacity allocation timeframe, so they are applicable for all MTUs (hours) of the respective allocation day.

Why the allocation constraints cannot be efficiently translated into capacities of individual borders offered to the market
Use of capacity allocation constraints aims to ensure economic efficiency of the market coupling mechanism on these interconnectors while meeting the security requirements of electricity supply to customers. If the generation conditions described above were to be reflected in cross-border capacities offered by PSE in form of an appropriate adjustments of border transmission capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the CNTC approach, this would need to be done in a form of ATC reduction per border. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overstated on one interconnection and underestimated on the other, or vice versa. Consequently, application of allocation constraints to tackle the overall Polish balancing constrains at the allocation phase allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.