Explanatory document to the proposal for the common coordinated capacity calculation methodology for Capacity Calculation Region Hansa in accordance with Article 20 (2) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management

15th of September 2017

Abbreviations:

AAC	Already Allocated and nominated Capacity
AC	Alternating Current
AHC	Advanced Hybrid Coupling
ATC	Available Transfer Capacity
CA	Capacity Allocation
CACM	Capacity Allocation and Congestion Management
CC	Capacity Calculation
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CGM	Common Grid Model
CNE	Critical Network Element
CNEC	Critical Network Element Contingency
CNTC	Coordinated Net Transmission Capacity
DA	Day Ahead
DC	Direct Current
FB	Flow-Based
GSK	Generation Shift Key
ID	Intraday
IGM	Individual Grid Model
NEMO	Nominated Electricity Market Operator
NTC	Net Transfer Capacity
NP	Net Position
PTDF	Power Transfer Distribution Factor
RA	Remedial Action
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
XBID	Single intraday market coupling

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1. Introduction

This document contains explanations for the proposal for a common coordinated capacity calculation methodology for the day-ahead and intraday timeframe for the capacity calculation region of Hansa (CCR Hansa) in accordance with Article 20 (2) of the Commission Regulation (EU) 2015/1222 of 24 July 2015[1] establishing a guideline on capacity allocation and congestion management (CACM Regulation). Transmission system operators (TSOs) are obliged to consult stakeholders on proposals for terms and conditions or methodologies required by the CACM Regulation[2].

The CCR Hansa covers three bidding zone borders and is placed between two larger CCRs, CCR Nordic and CCR Core. This document has been written with aim to ensure 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.

The CCR Hansa proposes a capacity calculation methodology based on a coordinated NTC methodology with a strong link to the adjacent CCRs which have chosen flow-based capacity calculation methodologies. By utilising the flow-based capacity calculation methodologies of CCR Nordic and CCR Core in representing the AC meshed grids and using Advanced Hybrid Coupling for representing the CCR Hansa bidding zone borders in the flow-based methodologies, the capacity calculation on the the CCR Hansa borders is optimised to the fullest extent possible. This means implicitly that CCR Hansa assumes that, if possible, all AC grid limitations outside the CCR Hansa interconnectors are respected in the capacity calculations within CCR Nordic and CCR Core. The combination of the capacity calculation inputs from the adjacent CCR Nordic and CCR Core flow-based methodologies together with the capacity calculation results within CCR Hansa determine the cross-zonal capacity of each the CCR Hansa interconnector, which shall be respected during the allocation process.

This document is structured as follows. Chapter 2 contains a description of the relevant legal references. Thereafter, chapter 3 defines CCR Hansa and the borders that are subject to this proposal. Chapter 4 and 5 contain the explanation for the capacity calculation methodology for the day-ahead and intraday timeframes presented in the legal proposal. The methodologies are described according to the requirements set in the CACM Regulation. A description of the proposed validation methodology is given in chapter 6, while chapter 7 contains an evaluation of the proposal against the objectives of the CACM Regulation. A planning for the implementation of this can subsequently be found in chapter 8. Public consultation responses are shown and commented on in chapter 9.

[1] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, OJ 25-7-2015, L 197/24.

[2] Article 12 of the CACM Regulation.

2. Legal requirements

According to Article 20 (2) of the CACM Regulation, each CCR is required to submit a common capacity calculation methodology for approval by the relevant national regulatory authority (NRA) for each capacity calculation time-frame. This is to be done no later than 10 months after approval of the CCRs for the day-ahead and intraday timeframe.

According to the CACM Regulation, the approach to be used in the capacity calculation methodology (CCM) for both the day-ahead and intraday timeframe is the flow-based approach.[3] However, according to Article 20 (7) of the CACM Regulation, TSOs may jointly request the NRAs to apply the coordinated net transmission capacity approach (CNTC) in regions and on bidding zone borders if the TSOs are able to demonstrate that the application of the CCM using the flow-based approach would not yet be more efficient compared to the CNTC approach and assuming the same level of operational security in the concerned region.

In regards to the application of the flow-based approach, the preamble of the CACM Regulation, in point (7) states the following:
"*The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The flow-based approach should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value*."

First, a number of relevant definitions from the CACM Regulation are stated below.

"*´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*".[4]

"*´flow-based approach' means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements*."[5]

"*'reliability margin' means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation*."[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*;"[7]

"'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits;"[8]

[3] Article 20 (1) of CACM Regulation.
[4] Article 2 (8) of the CACM Regulation.
[5] Article 2 (9) of the CACM Regulation.
[6] Article 2 (14) of the CACM Regulation.
[7] Article 2 (6) of the CACM Regulation.
[8] Article 2 (7) of the CACM Regulation.

"'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;"[9]

"´coordinated capacity calculator' means the entity or entities with the task of calculating transmission capacity, at regional level or above;"[10]

"´generation shift key' means a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the common grid model;"[11]

"´remedial action' means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security."[12]

Secondly, the CACM Regulation sets in Article 21 further requirements for the proposal for a CCM.

"1. *The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include at least the following items for each capacity calculation time-frame:*

a) methodologies for the calculation of the inputs to capacity calculation, which shall include the following parameters:
   I. a methodology for determining the reliability margin in accordance with Article 22;
   II. the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23;
   III. the methodology for determining the generation shift keys in accordance with Article 24;
   IV. the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25.

b) detailed description of the capacity calculation approach which shall include the following:
   I. a mathematical description of the applied capacity calculation approach with different capacity calculation inputs;
   II. rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;
   III. rules for taking into account, where appropriate, previously allocated cross-zonal capacity;
   IV. rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;
   V. for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;
   VI. for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;
   VII. where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.

[9] Article 2 (10) of the CACM Regulation.
[10] Article 2 (11) of the CACM Regulation.
[11] Article 2 (12) of the CACM Regulation.
[12] Article 2 (13) of the CACM Regulation.

c) a methodology for the validation of cross-zonal capacity in accordance with Article 26.

2. For the intraday capacity calculation time-frame, the capacity calculation methodology shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency.

3. The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results."

The methodologies to be included in the proposal are further described in Articles 22 to 26 of the CACM Regulation.

According to Article 21 (4) of the CACM Regulation, all TSOs in each CCR shall, as far as possible, use harmonised capacity calculation inputs. Therefore, the common capacity calculation methodology for the CCR Hansa should include compatible tools and principles suitable to be processed by the coordinated capacity calculator (CCC) in order to calculate the cross-zonal capacity values.

As a general point, all methodologies and proposals developed under the CACM Regulation should align with the objectives of Article 3 of the CACM Regulation. More specifically, Article 9(9) of the CACM Regulation requires that:
"The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation."

3. Definition of CCR Hansa

As stated above, this proposal relates to the CCR Hansa. According to Article 4 of ACER's decision[13] on the determination of capacity calculation regions, CCR Hansa consists of the bidding zone borders stated below as attributed to the referred TSOs (see Figure 1):

a) Denmark 1 - Germany/Luxembourg (DK1-DE/LU), Energinet.dk and TenneT TSO GmbH;
b) Denmark 2 - Germany/Luxembourg (DK2-DE/LU), Energinet.dk and 50Hertz Transmission GmbH; and
c) Sweden 4 - Poland (SE4 – PL), Svenska Kraftnät and PSE S.A.

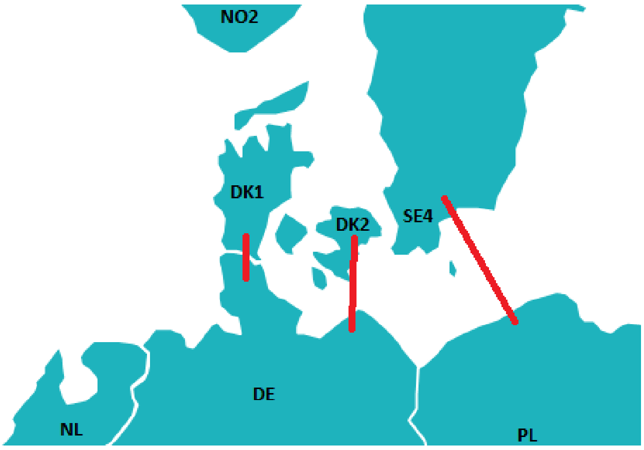


Figure 1: The bidding zone borders covered by CCR Hansa are DK1-DE/LU, DK2-DE/LU and SE4-PL

At present, the owner of Baltic cable (SE4-DE/LU) is not a certified TSO and is subsequently not in scope of the CCR work. Additionally, it is expected that NorNed (NO2-NL) will be added to CCR Hansa once Norway ratifies the 3rd EU liberalisation package, EU Regulation No. 713-714/2009.

13 ACER decision 06-2016 of 17 November 2016.

4. Capacity calculation methodology for the day-ahead timeframe

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

4.1 Description of the capacity calculation methodology in CCR Hansa

The capacity calculation methodology proposed for the day-ahead timeframe unifies 3 congestion-relevant parts. It takes advantage of the flow-based methodologies with the AHC approach developed in CCR Nordic and CCR Core in order to represent the limitations in the AC grids, while the actual interconnector capacities are addressed individually within CCR Hansa.

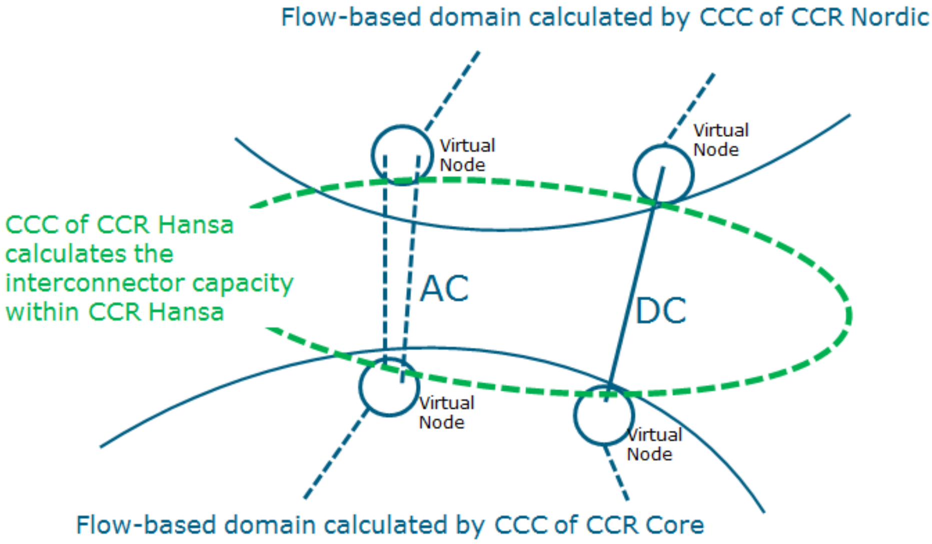


Figure 2: Capacity calculation in CCR CORE, CCR Nordic, and CCR Hansa

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 cross-border interconnector on the exporting side;
2. The cross-border interconnector itself;
3. The AC grid sensitive to the trade surrounding the cross-border interconnector on the importing side.

This holds true for all cross-border trade, irrespective of the type of 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 TSOs to look at the impact of cross-border trade independently on each part of the grid.

The methodology is thus based on three parts, as depicted in Table 1**Fejl! Henvisningskilde ikke fundet.**:

1. The actual interconnector capacity within the CCR Hansa;
2. The limitations on the interconnectors from the AC grid handled by AHC in CCR Core;
3. The limitations on the interconnectors from the AC grid handled by AHC in CCR Nordic.

These three contributions together deliver the limits on flow on the interconnectors in CCR Hansa and can be represented as in Table 1. The flexibility the methodology allows for, is to contain both flow-based restrictions as well as CNTC restrictions at the same time.

	Core AHC	Actual Interconnector Capacity	Nordic AHC
TSO1→TSO2		1400MW	
TSO2→TSO3		600MW	
TSO1→TSO4		1000MW	
	Part of Core CC	Part of Hansa CC	Part of Nordic CC

Table 1: An example of the capacity calculation in CCR Core, CCR Nordic, and CCR Hansa

In a CNTC methodology, the following terminologies are used. The NTC is the maximum total exchange program between two adjacent bidding zones compatible with security standards, and taking into account the technical uncertainties on future network conditions: NTC = TTC - TRM. In case the TRM equals zero, the NTC equals the TTC. The ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses: ATC = NTC – AAC. In case the AAC equals zero, the ATC equals the NTC.

The capacity calculation is done for each day-ahead and intraday market time unit, currently set at a one-hour resolution.

4.1.1 Mathematical description of the applied approach

The calculation of the actual interconnector capacity, as shown in Figure 3, is based mainly on the physical properties of the cross border lines and stations on each end. As CCR Hansa contains both DC and AC borders this has to be addressed separately in an ex-ante process. The following aspects should be taken into account when calculating the actual interconnector capacity for the AC and the DC borders.

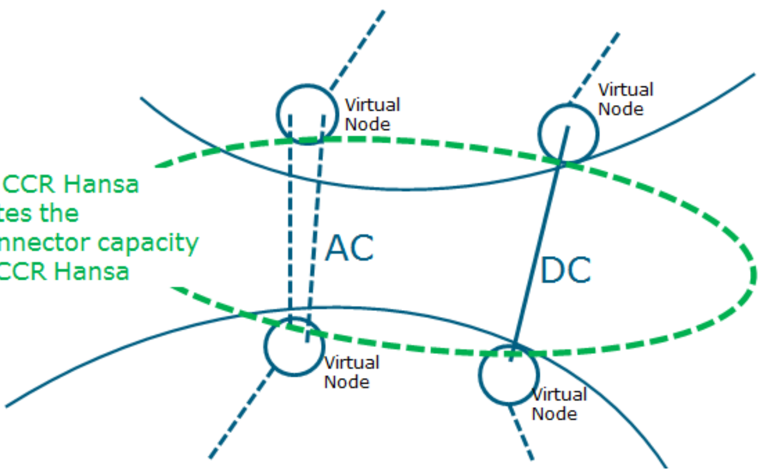


Figure 3: The actual interconnector capacity which is the responsibility of CCR Hansa to determine

TSOs calculate capacity on a bidding zone border connected with DC lines on a line per line basis, in the following named DC line i. On a bidding zone border with AC connections, the transfer capacity on the whole bidding zone border is computed, as it is not possible to control the division of flow between AC lines, in the case that there are more than one across the border.

The available transfer capacity $\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$ on a DC line i in the direction A→B is calculated from:

$$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}} = \mathrm{TTC}_{\mathrm{i,A\rightarrow B}} - \mathrm{AAC}_{\mathrm{i,A\rightarrow B}} + \mathrm{AAC}_{\mathrm{i,B\rightarrow A}}$$

Where:

A := Bidding zone A.

B := Bidding zone B.

$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$:= Available Transfer Capacity on a DC line i in direction A→B provided to the day-ahead market.

$\mathrm{TTC}_{\mathrm{i,A\rightarrow B}}$:= Total Transfer Capacity of a DC line i in direction A→B, on the receiving end. The TTC corresponds to the full capacity of the DC line, in case of no failure on the interconnector, including converter stations.

The TTC for a DC line i is defined as follows:

$$\mathrm{TTC}_{\mathrm{i,A\rightarrow B}} = \alpha_{\mathrm{i}} \cdot \mathrm{P}_{\mathrm{i,max\,thermal}} * \left(1 - \beta_{\mathrm{i,Loss,A\rightarrow B}}\right)$$

$\mathrm{AAC}_{\mathrm{i,A\rightarrow B}}$:= Already Allocated and nominated Capacity for a DC line i in direction A→B.

On the day-ahead stage, this capacity consists of the long term nominated capacity for a DC line i in direction A→B.

For Kriegers Flak (KF) Combined Grid Solution between DE-DK2, the AAC also consists of the wind infeed in the offshore wind farms, located within the interconnector:

$\mathrm{AAC}_{\mathrm{KF,A\rightarrow B}} = \mathrm{P}_{\mathrm{Wind\,forecast}}$ + already allocated and nominated capacity

Where $P_{\mathrm{Wind\,forecast}}$ represents the offshore wind forecast on the interconnector. It already incorporates a risk level, therefore no TRM is required on KF.

$\mathrm{AAC}_{\mathrm{i,B\rightarrow A}}$:= Already Allocated and nominated Capacity for a DC line i in direction B→A.

On the day-ahead stage, this capacity consists of the long term nominated capacity for a DC line i in direction B→A.

α_{i} := Availability factor of equipment defined through scheduled and unscheduled outages, α_{i}, being a real number in between and including 0 and 1.

$\mathrm{P}_{\mathrm{i,max\,thermal}}$:= Thermal capacity for a DC line i.

$\beta_{\mathrm{i.Loss,A \rightarrow B}}$:= Loss factor for a DC line i in direction A→B, which can be a different value depending on α_{i}.

The available transfer capacity $\mathrm{ATC}_{\mathrm{AC,A \rightarrow B}}$ on a bidding zone border that is connected by AC lines in the direction A→B is calculated from:

$$\mathrm{ATC}_{\mathrm{AC,A \rightarrow B}} = \mathrm{TTC}_{\mathrm{A \rightarrow B}} - \mathrm{TRM}_{\mathrm{A \rightarrow B}} - \mathrm{AAC}_{\mathrm{A \rightarrow B}} + \mathrm{AAC}_{\mathrm{B \rightarrow A}}$$

Where:

A := Bidding zone A.

B := Bidding zone B.

$\mathrm{ATC}_{\mathrm{AC,A \rightarrow B}}$:= Available Transfer Capacity of a bidding zone border in direction A→B, provided to the day-ahead market.

$\mathrm{TTC}_{\mathrm{A \rightarrow B}}$:= Total Transfer Capacity of a bidding zone border in direction A→B.

$\mathrm{TRM}_{\mathrm{A \rightarrow B}}$:= Transmission Reliability Margin for a bidding zone border in direction A→B.

$\mathrm{AAC}_{\mathrm{A \rightarrow B}}$:= Already Allocated and nominated Capacity for a bidding zone border in direction A→B.
On the day-ahead stage, this capacity consists of the long term nominated capacity for a bidding zone border in direction A→B.

$\mathrm{AAC}_{\mathrm{B \rightarrow A}}$:= Already Allocated and nominated Capacity for a bidding zone border in direction B→A.
On the day-ahead stage, this capacity consists of the long term nominated capacity for a bidding zone border in direction B→A.

4.1.2 Capacity limitations originating from the AC grid handled by AHC in CCR Nordic

The capacity of a DC line (being a fully controllable active power flow) is a NTC by nature. CCR Nordic has decided to handle the power flows of DC lines with the AHC approach, see Annex 2. This means that the flows on the DC lines are competing for the scarce capacity on the AC grid, like the exchanges from any of the other Nordic bidding zones (SE1, SE2, NO1, FI, and so on).
The converter stations of the DC interconnectors are modelled as 'virtual' bidding zones in the flow-based system (however a bidding zone, without production and consumption), having their own PTDF factors reflecting how exchanges on the DC lines are impacting the AC grid elements. Radial AC connections can be handled in the same way. This is illustrated in Figure 4.

CCR Nordic provides a flow-based representation of the AC grid in the Nordic area, which is imposing AC grid limitations on the commercial exchanges over the Hansa lines as well.

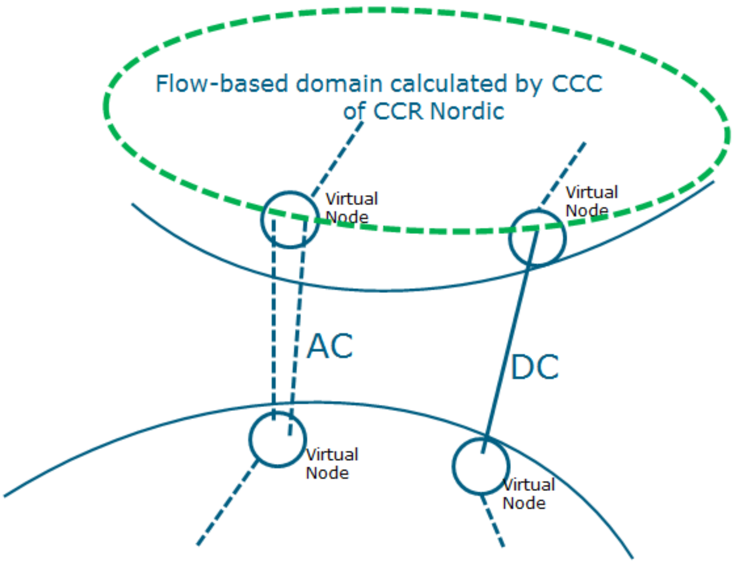


Figure 4: Advanced hybrid coupling in CCR Nordic

4.1.3 Capacity limitations originating from the AC grid handled by AHC in CCR Core

The capacity of a DC line (being a fully controllable active power flow) is a NTC by nature. CCR Core decided to handle the power flows of DC lines with the AHC[14] approach as target model. This means that the flows on the DC lines are competing for the scarce capacity on the AC grid, like the exchanges from any of the other Core bidding zones (NL, DE, PL, FR, and so on). The converter stations of the DC interconnectors are modelled as 'virtual' bidding zones in the flow-based system (a bidding zone, without production and consumption), having their own PTDF factors reflecting how exchanges on the DC lines are impacting the AC grid elements. Radial AC connections can be handled in the same way. This is illustrated in Figure 5.

CCR Core provides a flow-based representation of the AC grid in the Core area, which is imposing AC grid limitations on the commercial exchanges over the Hansa lines as well.

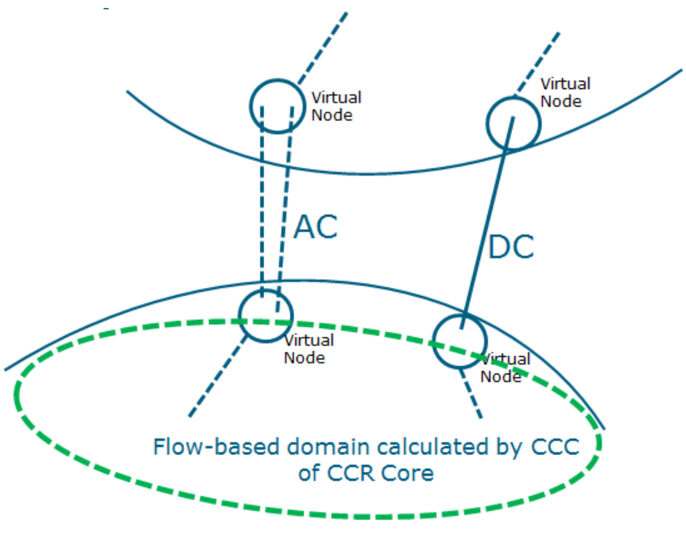


Figure 5: Advanced hybrid coupling in CCR Core

[14] See Annex 2 for explanation of AHC

4.1.4 Further requirements from Article 21 (1) (b) of the CACM Regulation

In the following section, the requirements set out in Article 21(1)(b) of the CACM Regulation for a detailed description of the capacity calculation approach, are listed and it is explained how the CCM of CCR Hansa fulfils these requirements.

***(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009*;**
As the internal flows in the bidding zones are to be handled via flow-based allocation in the adjacent CCRs, along with the representation of the CCR Hansa interconnectors with AHC, the allocation of capacity to the interconnectors will be based on a mathematical optimisation in the allocation process. Thus there is no possibility to discriminate one type of flow to another within CCR Hansa.

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;
The previously-allocated cross-zonal capacity can be subtracted from the actual interconnector capacity which is described in section 4.1.1.

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;
The impact of remedial actions such as phaseshifters meant to influence the flow distribution on the tie-lines on the AC border shall, if available, be considered in the determination of the TTC value. Remedial actions found in bidding zones will be taken into account in the flow-based methodologies of CCR Nordic and CCR Core.

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;
Not applicable, as this will be handled in the flow-based methodologies of CCR Nordic and CCR Core.

(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;
As the methodology chosen utilises flow-based domains from the two adjacent CCRs to ensure optimal market efficiency when handling constraints from the AC grids, there is not an ex-ante split of capacity on CNEs.

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.
The use of AHC in CCR Core and CCR Nordic ensures that an economic optimisation determines where capacities are allocated between borders and different capacity calculation regions.

4.2 Methodology for determining the reliability margin

Article 22 of the CACM Regulation requires the CCM to include a methodology for determining the 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 taken into account in the capacity calculation, being the TRM, mentioned in section 4.1.1. 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 does therefore only apply 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 calculation of this value the TSOs apply the TRM in order to hedge against risks inherent in the calculation. The methodology for the TRM is determined by the TSOs and reflects the risks that the 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 time- frame 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.

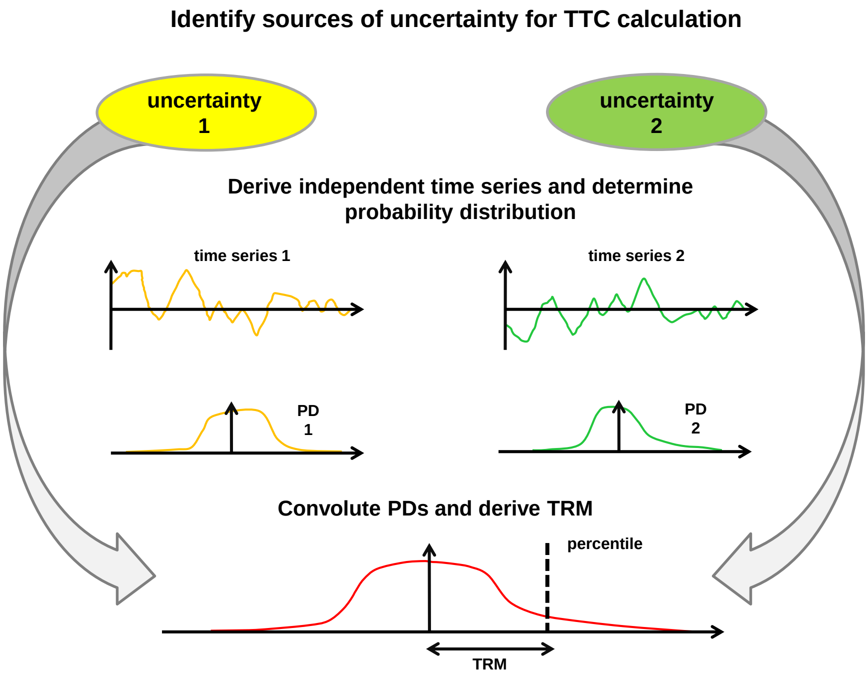


Figure 6: Illustration of the concept to calculate the TRM

Hereunder, 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 a network model, 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 concrete 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
In 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 normalized. The convoluted PD is the basis for the determination of initial TRM values. From the convoluted PD a certain percentile is taken.

4.3 Methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints

According to Article 23(1) of the CACM Regulation each TSO shall respect the operational security limits and contingencies used in operational security analysis.
According to Article 23(2) of the CACM Regulation, if the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

In the operational security analysis, the following operational security limits and contingencies can be used, but are not limited to:

- steady-state thermal limits
- voltage stability
- dynamic transient stability
- short-circuit ratio (SCR)
- security of supply (interaction with distribution network)
- identified and possible or already-occurred fault of the transmission system element
- identified and possible or already-occurred fault of the significant grid users if relevant for the transmission system operational security
- identified and possible or already-occurred fault of the distribution network element if relevant for the transmission system operational security
- balancing constraints

The actual capacity resulting from steady-state thermal limits of CCR Hansa interconnectors themselves are calculated according to the methodology described in the Chapter 4.1.1. The steady-state thermal limits and contingencies of adjacent AC networks are handled by the flow-based capacity calculation methodologies in CCR Core and CCR Nordic.

The other abovementioned operational security limits, influencing the exchange capacity over the bidding zones borders belonging to CCR Hansa (i.e. voltage stability, dynamic stability, etc.), which cannot be evaluated in the frame of flow-based calculations, are assessed by individual CCR Hansa TSOs who perform the simulations in their offline tools using a CGM. The results are translated into cross-zonal capacity constraints as the external constraints of particular virtual bidding zones representing CCR Hansa interconnectors and respected during capacity allocation.

Further, TSOs, according to CACM Regulation article 23(3), may apply allocation constraints which means constraints to be respected during capacity allocation to maintain the transmission system within operational security limits, or that are needed to increase the efficiency of capacity allocation, and that cannot not be translated into cross-zonal capacity limitations, including but not limited to:

- The production in a bidding zone shall be above a given minimum production level
- The combined import or export from one bidding zone to other neighbouring bidding zones shall be limited in order to ensure adequate level of generation reserves required for secure system operation
- Maximum flow change on DC-lines between MTUs (ramping restrictions)
- Implicit loss factors on DC-lines.

A minimum production level may need to be applied in a bidding zone in order to guarantee a minimum number of machines running in the system that are able to supply reactive power needed for voltage support.

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 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 TSO in central dispatch systems needs to ensure the availability of sufficient upward or downward regulation reserves for maintaining secure power system operation. This takes 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 maximize social welfare. For details see Annex 1.

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 (currently not implemented).

A ramping restriction is an instrument of system operation to maintain system security (frequency management purposes). This sets the maximum change in DC flows (Max MW/h per interconnector) on an hour to hour basis.

The allocation constraints are included during the capacity allocation process and one allocation constraint can influence the interconnections belonging to the different CCRs.

4.4 Methodology for determining the generation shift keys

The generation shift key used to calculate the NTC values in CCR Hansa represents the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model. Due to the unique nature of the interconnections in CCR Hansa, the generation shift key applied to calculate the NTC value of bidding zone borders connected by DC interconnections and AC interconnections differs.

On the radial AC connection between DK1 and DE, the GSK is modelled to represent the distribution of the power flow between the different cross-border lines.

Any interaction between the CCR Hansa interconnections and the adjacent AC grids, as described in 4.1, is modelled in the corresponding flow-based methodologies of CCR Core and CCR Nordic and is therefore not a part of this methodology.

4.5 Methodology for determining remedial actions to be considered in capacity calculation

In CCR Hansa there is currently phaseshifters in operation on the 220kV lines between DK1 and DE. These are planned to be removed when the 220kV grid is upgraded to 400kV. After this there will be no remedial actions available in CCR Hansa which can be utilised to influence the flow distribution on the cross border tielines. The impact of remedial actions that become available in the future will be considered in the determination of the TTC value as shown in section 4.1.1. Furthermore, it is important to note that the remedial actions found in bidding zones, in general, will be taken into account in the flow-based methodologies of CCR Nordic and CCR Core to enlarge the overall flow-based domains in the favoured market direction. This will in turn also positively impact the cross-border capabilities of CCR Hansa if it increases the European economic welfare.

4.6 Fallback procedure for day-ahead capacity calculation

According to Article 21(3) of the CACM Regulation the capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

As mentioned in chapter 4.1, the capacity calculation takes into account three different parts of the grid. This also implies that the fallback procedure for capacity calculation should be applied in cooperation with the adjacent CCRs.

In case the capacity calculation cannot be performed by the CCC, the concerned TSOs will bilaterally calculate and agree on cross-zonal capacities. TSOs will individually apply the CCM and the results will be selected by TSOs by using the minimum value of adjacent TSOs of a bidding zone border. The concerned TSOs shall submit the capacities to the relevant CCC and to the other TSOs of CCR Hansa.

5. Capacity calculation methodology for the intraday timeframe

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

5.1 Description of the capacity calculation methodology in CCR Hansa

The capacity calculation methodology for the intraday timeframe in CCR Hansa is equal to the one described for the DA timeframe, in Section 4.1. This implies that CCR Hansa calculates the capacity for the interconnectors, while the limitations from AC grids, in the possible extent, are handled by adjacent CCRs. For CCR Hansa the target model is reached when XBID is able to handle flow-based constraints.

5.1.1 Mathematical description of the applied approach

The only difference with the mathematical description for the DA timeframe (Section 4.1.1), is in the Already Allocated and nominated Capacity (AAC), as explained hereunder.

The available transfer capacity $\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$ on a DC line i in the direction A→B is calculated from:

$$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}} = \mathrm{TTC}_{\mathrm{i,A\rightarrow B}} - \mathrm{AAC}_{\mathrm{i,A\rightarrow B}} + \mathrm{AAC}_{\mathrm{i,B\rightarrow A}}$$

Where:

A := Bidding zone A.

B := Bidding zone B.

$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$:= Available Transfer Capacity on a DC line i in direction A→B provided to the intraday market

$\mathrm{TTC}_{\mathrm{i,A\rightarrow B}}$:= Total Transfer Capacity of a DC line i in direction A→B, on the receiving end. The TTC corresponds to the full capacity of the DC line, in case of no failure on the interconnector, including converter stations.

The TTC for a DC line i is defined as follows:

$$\mathrm{TTC}_{\mathrm{i,A\rightarrow B}} = \alpha_{\mathrm{i}} \cdot \mathrm{P}_{\mathrm{i,max\,thermal}} * \left(1 - \beta_{\mathrm{i,Loss,A\rightarrow B}}\right)$$

$\mathrm{AAC}_{\mathrm{i,A\rightarrow B}}$:= Already Allocated and nominated Capacity for a DC line i in direction A→B.

On the intraday stage, this capacity consists of the capacity that is nominated at the long term and day-ahead stage, and capacity that is already nominated at the intraday stage for a DC line i in direction A→B.

For Kriegers Flak (KF) Combined Grid Solution between DE-DK2, the AAC also consists of the wind infeed in the offshore wind farms, located within the interconnector:

$\mathrm{AAC}_{\mathrm{KF,A\rightarrow B}} = \mathrm{P}_{\mathrm{Wind\,forecast}}$+ already allocated and nominated capacity

Where $P_{\mathrm{Wind\,forecast}}$ represents the offshore wind forecast on the interconnector. It already incorporates a risk level, therefore no TRM is required on KF.

$\mathrm{AAC}_{i,B\to A}$:= Already Allocated and nominated Capacity for a DC line i in direction B→A.

On the intraday stage, this capacity consists of the capacity that is nominated at the long term and day-ahead stage, and capacity that is already nominated at the intraday stage for a DC line i in direction B→A.

α_i := Availability factor of equipment defined through scheduled and unscheduled outages, α_i, being a real number in between and including 0 and 1.

$P_{i,\max\,\mathrm{thermal}}$:= Thermal capacity for a DC line i.

$\beta_{i.\mathrm{Loss},A\to B}$:= Loss factor for a DC line i in direction A→B, which can be a different value depending on α_i.

The available transfer capacity $\mathrm{ATC}_{AC,A\to B}$ on a bidding zone border that is connected by AC lines in the direction A→B is calculated from:

$$\mathrm{ATC}_{AC,A\to B} = \mathrm{TTC}_{A\to B} - \mathrm{TRM}_{A\to B} - \mathrm{AAC}_{A\to B} + \mathrm{AAC}_{B\to A}$$

Where:

A := Bidding zone A.

B := Bidding zone B.

$\mathrm{ATC}_{AC,A\to B}$:= Available Transfer Capacity of a bidding zone border in direction A→B, provided to the intraday market.

$\mathrm{TTC}_{A\to B}$:= Total Transfer Capacity of a bidding zone border in direction A→B.

$\mathrm{TRM}_{A\to B}$:= Transmission Reliability Margin for a bidding zone border in direction A→B.

$\mathrm{AAC}_{A\to B}$:= Already Allocated and nominated Capacity for a bidding zone border in direction A→B.

On the intraday stage, this capacity consists of the capacity that is nominated at the long term and day-ahead stage, and capacity that is already nominated at the intraday stage for a bidding zone border in direction A→B.

$\mathrm{AAC}_{B\to A}$:= Already Allocated and nominated Capacity for a bidding zone border in direction B→A

On the intraday stage, this capacity consists of the capacity that is nominated at the long term and day-ahead stage, and capacity that is already nominated at the intraday stage for a bidding zone border in direction B→A.

5.1.2 Capacity limitations originating from adjacent AC grid

The same rules and conditions stated in chapter 4.1.2 and 4.1.3 for day-ahead will apply for intraday. It is up to CCR Nordic and CCR Core to represent the flow limitations in the AC grids, while the actual interconnector capacities are addressed individually within CCR Hansa. Together these three inputs will constitute the limitations on the interconnectors to be respected in the capacity allocation process.

5.1.3 Further requirements from Article 21 (1) (b) of the CACM Regulation

In the following section, the requirements set out in Article 21(1)(b) of the CACM Regulation for a detailed description of the capacity calculation approach are listed and a description is given how these are taken into account.

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;
As the internal flows in the bidding zones are to be handled via flow-based allocation in the adjacent CCRs along with the representation of the CCR Hansa interconnectors with AHC, the allocation of capacity to the interconnectors will be based on a mathematical optimisation in the allocation process. Thus, there is no possibility to discriminate one type of flow to another within CCR Hansa.

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;
The previously-allocated cross-zonal capacity can be subtracted from the actual interconnector capacity which is described in section 5.1.1

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;
The impact of remedial actions such as phaseshifters meant to influence the flow distribution on the tie-lines on the AC border shall, if available, be considered in the determination of the TTC value Remedial actions found in bidding zones will be taken into account in the flow-based methodologies of CCR Nordic and CCR Core.

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;
Not applicable, as this will be handled in the flow-based methodologies of CCR Nordic and CCR Core.

(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;
As the methodology chosen utilises flow-based domains from the two adjacent CCRs to ensure optimal market efficiency when handling constraint from the AC grids, there is not an ex-ante split of capacity on CNEs.

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.
The use of AHC in CCR Core and CCR Nordic ensures that an economic optimisation determines where capacities are allocated between borders and different capacity calculation regions.

5.2 Methodology for determining the reliability margin

The same methodology for the determination of the reliability margin applies, as described for the day-ahead timeframe in section 4.2.

5.3 Methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints

The methodologies for the intraday timeframe for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints are the same as for the day-ahead timeframe, see section 4.3.

5.4 Methodology for determining the generation shift keys

The methodology for the intraday timeframe for determining the generation shift keys is the same as for the day-ahead timeframe, see section 4.4.

5.5 Methodology for determining remedial actions to be considered in capacity calculation

The impact of remedial actions such as phaseshifters meant to influence the flow distribution on the tie-lines on the AC border shall, if available, be considered in the determination of the TTC value. Please refer to Section 4.5.

5.6 Intraday reassessment frequency

The frequency of the reassessment of intraday capacity shall be dependent on the availability of input data relevant for capacity calculation, as well as any events impacting the capacity on the cross-zonal lines.

According to Article 29 of the CACM Regulation, the capacity for the intraday timeframe must be calculated by the CCC based on a common grid model (CGM). This can lead to both an increase or a decrease of capacity.

The availability of input data for the common grid model, wind forecasts and measurements of wind generation in relation to Krieger's flak, as well as events, e.g unscheduled outages, influence the cross-zonal capacity and are therefore likely to influence the intraday capacity reassessment frequency.

All TSOs in each capacity calculation region shall ensure that cross-zonal capacity is recalculated within the intraday market time-frame based on the latest available information, including unexpected events and taking into consideration efficiency and operational security. The CCC shall ensure that the adjusted capacities are submitted without undue delay to the MCO.

5.7 Fallback procedure for intraday capacity calculation

The fallback procedure for capacity calculation for the intraday timeframe is the same as for the day-ahead timeframe, see section 4.6.

6. Methodology for the validation of the cross-zonal capacity for both day-ahead and intraday according to Article 26

The target model of the capacity calculation for CCR Hansa limits the scope of CCR Hansa to the interconnections themselves. Therefore, this section only describes the methodology for validating the part of the cross-zonal capacity that is actually calculated by the CCR Hansa.

The TSOs are legally responsible for the cross-zonal capacities. The validation of the interconnection capacity, which is calculated by the CCC, will be performed by each concerned TSO in CCR Hansa. Each TSO sends its capacity validation result and allocation constraints to the relevant CCC and to the other TSOs in CCR Hansa. The validation of cross-zonal capacity and allocation constraints ensure that the results of the capacity allocation process will respect operational security requirements.

The TSOs will consider the operational security limits when performing the validation, but may also consider additional grid constraints, grid models, and other relevant information. The TSOs may use, but are not limited to, the tools developed by the CCC for analysis. Thus, the TSOs might also employ verification tools not available to the CCC.

Validation of the results can be done by checking if the correct data provided by TSOs was used by the CCC in the capacity calculation process. The CCC of CCR Nordic and CCR Core can for example deliver minimum and maximum net positions for each virtual bidding zone, which will allow for CCR Hansa TSOs to compare restrictions imposed on the Hansa interconnectors from the AC grids with the capacity calculation made by the CCR Hansa CCC. Moreover, each TSO can perform its own calculations using the common grid model in order to verify the results.

In accordance with Article 26(1,3) each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders provided by the CCC. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity relevant to the TSO's bidding zone borders for reasons of operational security.

According the CACM Article 26(2) the CCM shall include a rule for splitting the correction of cross-zonal capacity between the different bidding zones when using a coordinated NTC methodology. As the CCR Hansa CCM does not include any ex-ante splitting of capacity due to the utilisation of AHC, there will be no need to split a correction of cross-zonal capacity either.

The CCC will coordinate with neighbouring CCCs during the capacity calculation and validation process to ensure that the correct input data has been used, and subsequently that the capacities are within a plausible solution space in line with Article 26(4).
Any information on increased or decreased cross-zonal capacity from neighbouring CCCs will be provided to the TSOs to be taken into account during the validation.

7. Evaluation of the CCM in light of the objectives of the CACM Regulation

This chapter contains a description of how the draft proposal meets the aims of the CACM Regulation, as stated in Article 3.

The CACM Regulation has the objective to ensure optimal use of the transmission infrastructure, operational security and optimising the calculation and allocation of cross-zonal capacity.

The Advanced Hybrid Coupling methodology for CCR Hansa secures optimal use of the transmission capacity as it takes advantage of the flow-based methodologies developed in CCR Nordic and CCR Core in order to represent the limitations in the AC grids, while the actual interconnector capacities are addressed individually within CCR Hansa. The use of interconnector capacity and AC grid capacity is fully integrated in this way, thereby providing a fair competition for the scarce capacities in the system and an optimal system use. Indeed, there is no predefined and static split of the CNE capacities, and the flows through CCR Hansa from CCR Core and CCR Nordic are decided based on economic efficiency during the capacity allocation phase.

The CCM treats all borders in CCR Hansa and adjacent CCRs equally, and thus provides non-discriminatory access to cross-zonal capacity. It creates a basis for a fair and orderly market and fair and orderly price formation by implementing a simple CCM solution which is integrated with the methodologies of the adjacent CCRs.

The methodology complies with all requirements for operational security, and defines methodologies for determining reliability margins, generation shift keys, and operational security limits.

The proposal for capacity calculation and allocation in CCR Hansa, takes advantage of flow-based capacity calculation for the AC grids while also ensuring full transparency of the calculation of actual interconnector capacity. This will in turn result in a better understanding, and increase the transparency and reliability of information on the CCR Hansa borders.

The capacity calculation methodology has no negative consequences on the development of capacity calculation methodologies in CCR Nordic and CCR Core, and can evolve dynamically with the development and merger of CCRs in the future. The methodology therefore does not hinder an efficient long-term operation in CCR Hansa and adjacent CCRs, and the development of the transmission system in the Union.

8. Timescales for implementation

Due to their location and the radial structure, the interconnections between DK1-DE/LU, DK2-DE/LU and SE4-PL can be considered independent from another. This allows the CCR Hansa TSOs to initially continue to use their current processes, and implement the new CCM in a stepwise manner in order to improve the capacity calculation whenever possible.
The first improvements are in terms of input and process coordination, while the second set of improvements utilises the flow-based projects of CCR Nordic and CCR Core in order to reflect the limitations from the AC grids on CCR Hansa interconnectors.
The implementation of the CCM in CCR Hansa will be done in parallel with the implementation of the CCMs (with AHC) in CCR Nordic and CCR Core.

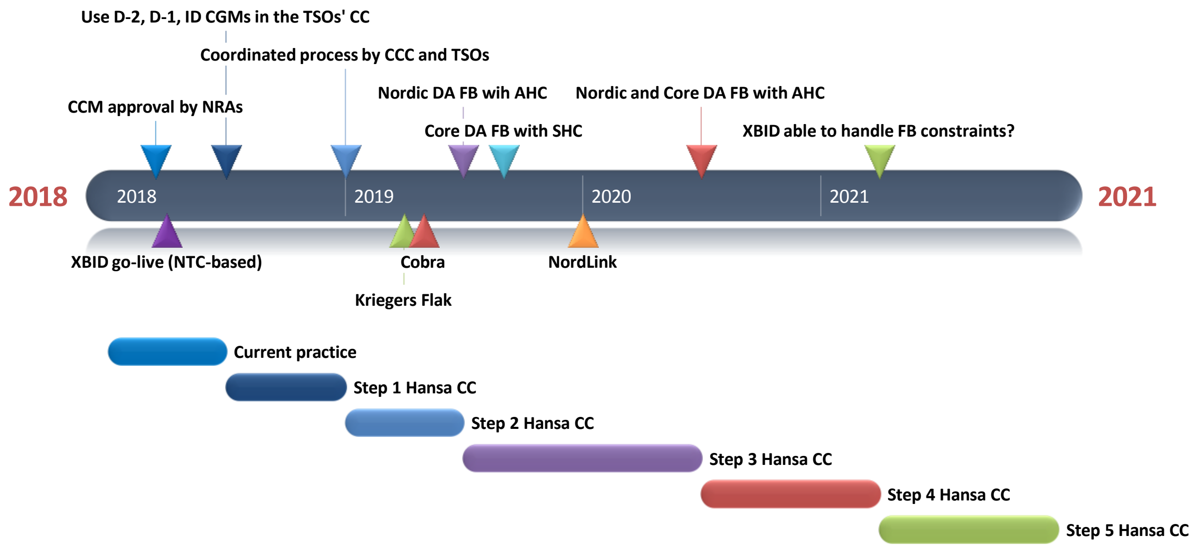


Figure 7: Indicative timeline for the implementation of the CCR Hansa CCM

<u>Current practice:</u>
Following the approval of the capacity calculation methodology by the relevant NRAs, the CCR Hansa TSOs will start the implementation of improvements of the current processes to ensure a smooth and efficient transition towards one common capacity calculation process in coordination with the CCRs Nordic and Core. Up to the introduction of the D-2, D-1, and ID CGMs, the current capacity calculation applied in the Hansa region continues as is.

Implementation of CCM for CCR Hansa consists of following steps:

<u>Step 1:</u>
With the introduction of the D-2, D-1, and ID CGMs, as a first improvement, all TSOs in CCR Hansa will use the same common grid model as input in their CCR Hansa related capacity calculation processes. This will ensure that the forecast of demand, generation and line availability is the same, thus increasing the coordination on the capacity calculation.

<u>Step 2:</u>
In a second step, the CCR Hansa TSOs will use the appointed CCC to further coordinate the capacity calculation process. The CCC will calculate the interconnector capacity while the TSOs will send the results from their capacity calculations on the AC grid to the CCC. The minimum value will prevail and will be calculated by the CCC. The resulting cross-zonal capacities are subject to validation by each TSO for its bidding zone borders. The CCC provides the validated cross-zonal capacities to the allocation mechanism.

Step 3:
The third step of the CCR Hansa capacity calculation implementation comes with the go-live of the Nordic flow-based capacity calculation. The power flows in the surrounding AC grid on the Nordic side stemming from the CCR Hansa lines will be taken into account by the AHC in the flow-based capacity calculation of CCR Nordic. This replaces the NTC calculation done by the TSOs on the Nordic side of the Hansa lines. Possible interdependencies between trade on CCR Hansa borders and trade on CCR Nordic borders are represented in the flow-based domains. At this point in the implementation of the CCR Hansa CCM, a testing phase of 6 months of data will be coordinated with CCR Nordic.

It is assumed that the capacity calculation for the Nordlink interconnector will be the responsibility of the CCR Hansa. In the Nordic flow-based capacity calculation the impact of Nordlink on the AC grid in the Nordic region is modelled with AHC. However, until the operation of AHC in the Core region, the impact of Nordlink on the AC grid in the Core region will be modelled in the capacity calculation process of the responsible TSO. Therefore the previous bilateral NTC process is changed to a C-NTC process, coordinated between all affected TSOs.

Step 4:
Step four in the CCR Hansa CC implementation is the introduction of AHC in CCR Core. At this point CCR Nordic and CCR Core model the impact of the CCR Hansa interconnectors on the AC grid in the Nordic and the Core region with AHC in the respective flow-based capacity calculation processes. Operational security limits (e.g. voltage and dynamic stability), which cannot be evaluated in the frame of flow-based calculations, are assessed by individual CCR Hansa TSOs as the external constraints of particular virtual bidding zones representing CCR Hansa interconnectors and respected during capacity allocation. The CCR Hansa CCC is responsible for calculating the capacity of the CCR Hansa interconnectors themselves and cooperation with the neighbouring CCCs of CCR Nordic and CCR Core. At this point in the implementation of the CCR Hansa CCM, a testing phase of 6 months of data will be coordinated with CCR Core.

Step 5:
In the implementation of XBID there will, in the beginning, not be any possibility to utilise flow-based constraints. This means that flow-based constraints will have to be translated to NTC constraints in intraday, but it is expected that in a later stage, flow-based constraints will be utilised in the ID CC as well. At this point in the implementation of the CCR Hansa CCM, a testing phase of 6 months of data is expected to be done within the XBID project.

9. Results from consultation

Comment number	Reviewer (Organisation)	Comments received	Hansa TSOs' reply
1	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	The methodology for the DA timeframe is not sufficiently well described in Chapter 1. It starts with a "mathematical description" in Article 3. However, then the article 5 contains a general description of some issues that seem to incline that the capacities can be reduced, but that are not covered by the mathematical description. Article 5.2 allows TSOs to reduce the capacity based on individual assessment. There is no method described that explains how these reductions are calculated. The impact of article 5.1 on the capacity is unclear. However, article 5.2 refers to article 5.1 and therefore it seems that article 5.1. can also result in reductions of the capacities. In particular, it seems that the CCM for the CCR Hansa is made subordinate to the CCM of the CCRs Core and Nordic. Which could mean that available capacities in the CCR Hansa are reduced to manage congestions in the Core and Nordic region. Moreover, article 5 does not contain precise methods to calculate capacities. The title of Article 7 says that it describes the methodology for determining remedial actions, however it does not. It only says that the CCC can consider remedial actions	In order to increase transparency, the reasoning behind Article 5 has been rewritten including clear examples. Whereas numbers 7 and 8 have been rewritten to clearly state that the application of AHC ensures that CCR Hansa bidding zone borders will be treated equally to bidding zone borders in the flow-based capacity calculation methodologies, thus ensuring that the CCR Hansa bidding zone borders are not given preferential treatment nor are they discriminated against compared to CCR Core or CCR Nordic bidding zone borders. As CCR Hansa consists of only radial lines, and because the methodology aims at giving maximum capacity to the market, remedial actions are only taken into account when they can influence the flow distribution on the tielines on the AC border. Article 7 has been rewritten to clarify this.
2	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	The definition of "Advanced Hybrid Coupling" in Article 2(1.a) is unclear. The term AHC is only used in Article 13. Article 13(c) suggests that the capacity for the lines in the CCR Hansa are determined by the CCM of CCR Nordic and CCR Core. It suggests that congestions in the Core and Nordic region are managed by limiting cross-zonal trade through the Hansa interconnectors. This is	In order to minimise concerns about discrimination of flows, which is not the case of AHC, CCR Hansa has prepared an additional annex to the explanatory document, which explains AHC in depths and its benefits for capacity calculation in CCR Hansa. As well, the capacity will be reassessed in ad-hoc basis, in case of unexpected events.

Comment number	Reviewer (Organisation)	Comments received	Hansa TSOs' reply
		not acceptable. In the Whereas, number 12 (page 3) it is mentioned that AHC is needed to avoid undue discrimination between flows within CCR Hansa or adjacent regions and between bidding zone borders within CCR Hansa. However, there is no justification for this statement. Actually the opposite seems true. By applying AHC, cross-zonal trade between the Nordic and Core regions is discriminated against trades within the Nordic CCR and against trades within the Core CCR.	
3	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	The methodology for the ID timeframe has similar shortcomings as for the DA timeframe. It starts with a mathematical description in Article 8. But then article 10 introduces the same possibilities to reduce capacities without a method being described.	Similar changes as proposed for day-ahead have also lead to adjustments in the intraday section.
4	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	Article 9 does not specify the frequency of reassessment of capacity in the intraday timeframe. This is not compliant with Article 21(2).	Article 9 is rewritten, to make this more clear.
5	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	Article 11 gives additional possibilities to TSOs to reduce the capacities. Again there is no method described.	CACM Regulation gives the TSOs the obligation to validate the cross-zonal capacity calculated by the CCC, and the TSOs do also have the right to correct the cross-zonal capacities.
6	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	Article 3 (top of page 5) mentions the application of a TRM for a DC line. Article 4 however mentions that the methodology for determining the TRM applies solely to the AC lines. This is unclear.	This is an unfortunate mistake, and Article 3 and 8 have been rewritten.
7	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	In conclusion: The proposed CCM is a general description of the status quo. Approving this proposal would mean a formal endorsement of the current “black-box” approach in calculation capacities in the	With the corrections/ adjustments made to the methodology, and together with a new annex to explain AHC, the TSOs of CCR Hansa seek to de-mystify the "black-box" and to provide a more transparent

Comment number	Reviewer (Organisation)	Comments received	Hansa TSOs' reply
		Hansa region. This method entails a clear risk that TSOs will "calculate" low capacities in order to manage internal congestions. There is no indication at all that the proposed "method" will result in justified (in terms of efficiency and non-discrimination) results. This proposal could even be labelled as "misleading" as the mathematical description with formulas in articles 3 and 8 does not cover the full calculation process. Finally the proposal is not sufficiently detailed. The proposal does not meet the CACM requirements.	capacity calculation methodology. The CCR Hansa TSOs are aiming at giving as much capacity as possible to the market.
8	EFET/Eurelectric/Nordenergi/Market parties platform/Statkraft	This method must be completely revised and needs elaborated. It is proposed to take a similar principle as proposed by the Channel region. In this approach, the capacity is set as the "MPTC" (maximum permanent technical capacity which is the maximum continuous active power which a network element (interconnector/HVDC system) is capable of transmitting). Basically, this would mean that Articles 3 and 8 are kept, but that most other articles (like 5 and 11) are removed.	The TSOs of CCR Hansa have prepared a methodology which will seek to maximise the cross-border capacity and in close coordination with the capacity calculation methodologies of CCR Core and CCR Nordic. CCR Hansa TSOs do not see a significant difference in the treatment of DC cross zonal capacity in CCR Hansa and CCR Channel.
9	EFET/Eurelectric/Nordenergi/Market parties platform	General comments as stated in chapter 1 of the reviewers' consultation document.	CCR Hansa TSOs believe that the methodology consulted on is in compliance with the CACM Regulation, but there may be areas of the methodology which are not sufficiently explained and therefore, was in need of elaboration and adjustment. To overcome this the CCR Hansa TSOs have, to the greatest extend, taken the comments on board where they are found to be helpful in the endeavour to submit a capacity calculation methodology for the bidding zone borders in CCR Hansa which fulfills the objectives and meets

Comment number	Reviewer (Organisation)	Comments received	Hansa TSOs' reply
			the requirements as set out in the CACM Regulation. CCR Hansa finds that a significant part of the comments received are justified and will lead to improvements of the methodology described. Some comments are found to be caused by misunderstandings of the legal proposal which means that CCR Hansa TSOs improved and elaborated on the descriptions and explanations given.

Annex 1: Balancing of the Polish system

Capacities on the Polish borders may be reduced by the use of allocation constraints, defined in Commission Regulation (EU) 2015/1222 of 24 July 2015, (CACM Regulation) as "constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation". These potential constraints reflect in general the ability of all Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical constraints of individual generating units as well as minimum reserve margins required in the whole Polish power system to ensure secure operation. This is related to the fact that under the conditions of the central dispatch market model applied in Poland, the responsibility of Polish TSO (PSE) of system balancing is significantly extended compared to the standard responsibility of TSOs in self dispatch market models – see further explanations below. Thus, the capacity in the export direction is reduced if the export of the PSE exceeds generating capacities left available within Polish power system taking into account the necessary reserve margin for upward regulation. Similarly, the capacity in the import direction is reduced if the import exceeds downward regulation available within the Polish power system taking into account the necessary reserve margin for downward regulation.

Rationale behind the implementation of allocation constraints on the PSE side

Implementation of allocation constraints on the PSE side is related to the fact that under the conditions of the central dispatch market model applied in Poland, the responsibility of the Polish TSO on system balancing is significantly extended compared to the standard responsibility of TSO in self dispatch market models. The latter is usually defined up to hour ahead time frame (including real time operations), while for PSE this is extended to short (intraday and day ahead) and medium (up to year ahead) terms. 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 sometimes lead 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. In self dispatch markets BRPs themselves are supposed to take care about their generating reserves, while TSO shall ensure them just for dealing with contingencies in the time frame of up to one hour ahead. Thus these two approaches ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view. It is worthwhile to note that infeasibilities in this respect lead to counter trade actions and appear only if faults out of dimensioning criteria occur. In order to better explain the above issue the following subchapters elaborate more on the differences between central and self-dispatch market models as well as on PSE's role in system balancing.

Central vs self-dispatch market models

Market operation in Europe is carried out in several different ways. However, they can be basically grouped in two families: self-dispatch model and central-dispatch model.

In a self-dispatch market, market design produces a balance between generation and demand (including external exchanges) by requiring that market parties (Balance Responsible Parties - BRPs) are in a balanced position to participate in the balancing market (e.g. one hour before energy delivery). Imbalance charges/penalties are levied on market parties which deviate from the balanced position. Commitment decisions, which take into account generating unit constraints, are made by the generators in conjunction with the demand elements they are balancing with. Generators alter their output to maintain the balance between generation and served demand. To be able to maintain balanced position they keep the given amount of reserves in their internal portfolios for compensation of their deviations. Before real time, generators submit bids to TSO which correspond with self-schedules of their units. Bids are used by TSO to dispatch additional generation needed to balance and secure the system in real time. Most of the electricity markets in Europe are based on the self-dispatch principle.

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 process as an optimization problem called Security Constrained Unit Commitment and Economic Dispatch (SCUC/ED). The main distinguishing feature of a central dispatch model is that balancing, congestion management and reserve procurement are performed simultaneously and they start day before and continuing until real time. This involves dispatch instructions being issued several hours ahead of real time, to start up units (SCUC), as well as real time instructions for dispatching on line units (SCED). In central dispatch model market participants do not need to be in a balanced position. The existing central-dispatch markets in Europe currently are the Greek, the Italian, the Irish and the Polish electricity markets.

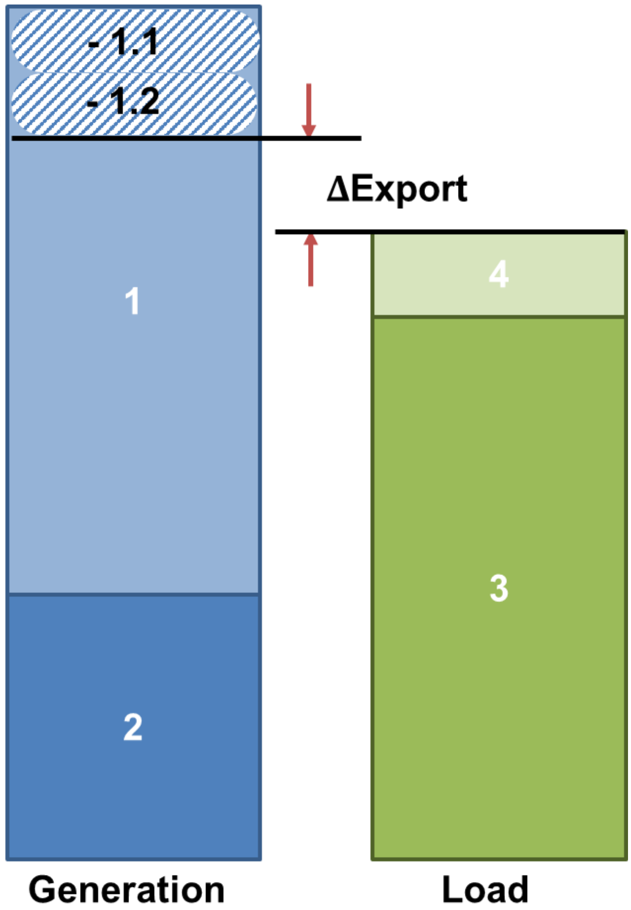
PSE role in system balancing

PSE directly dispatches generating units taking into account their operational constraints and transmission constraints in order to cover the expected load having in mind adequate reserve requirements, which is also forecasted by PSE itself. 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 security constrained unit commitment (SCUC) and economic dispatch (SCED). The results of this day ahead market are then updated continuously in intraday time frame 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 on average the minimum year ahead reserve margin of 18% (over forecasted load including already allocated capacities on interconnections, if any) is kept on average in each month. The monthly and weekly updates aim to keep this reserve margin on each day at the level of 17% and 14% respectively, 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 9% of spinning reserve (or quickly activated, in Polish reality only units in pumped storage plants) margin for each hour of the next day. 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 CHP plants as they operate mainly according to heat demand). The other generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE itself (like a system demand) and relevant uncertainty margins are included (90% for yearly and monthly time horizons referring to installed generation and 20% day ahead referring to forecasted generation). 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.) and aim to keep at minimum 7% of spinning reserve for each hour (as described above) in a time frame corresponding to the start-up times of the remaining thermal generating units (in practice 6 to 8 hours). Such an approach usually allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW (i.e. potential loss of the largest generating unit of 850 MW and 150 MW of primary control reserve being PSE’s share in RGCE).

Practical determination of allocation constraints within the Polish power system

As an example the process of practical determination of allocation constraints in the framework of day ahead transfer capacity calculation is illustrated on the below Figure 8 and Figure 9. They 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 find reserves in generating capacities available for potential exports and imports, respectively.

Allocation constraint in export direction occurs if generating capacities left available on centrally dispatched units within Polish power system for export are lower than the sum of export ATCs on all three interconnections (synchronous cross section, Swepol Link and Litpol Link). Allocation constraint in import direction occurs if downward regulating capacities left available on centrally dispatched units in operation within Polish power system for imports (ΔImport) are lower than the sum of import ATCs on all three interconnections (synchronous cross section, Swepol Link and Litpol Link).



1. sum of available generating capacities of centrally dispatched units[15] as declared by generators, reduced by:

1.1. TSO forecast of capacity not available due to expected network constraints

1.2. TSO assessment (based on experiences of recent days) of extra reserve to cover short term unavailabilities not declared by generators day ahead (limitations coming from e.g. cooling conditions, fuel supply, etc.) and prolonged overhauls and/or forced outages

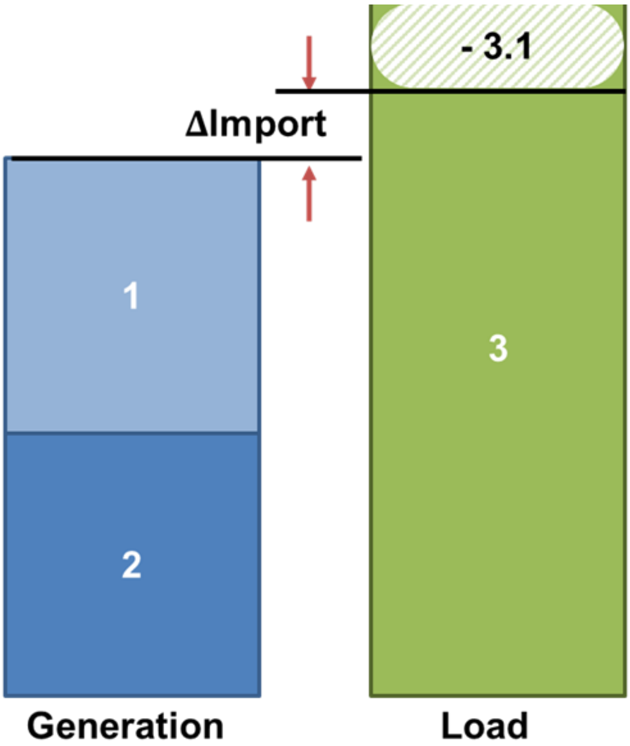
2. sum of schedules of generating units that are not centrally dispatched as provided by generators, except wind farms for which generation is forecasted by TSO

3. load forecasted by TSO

4. minimum necessary reserve for up regulation (for day ahead: 9% of forecasted load)

Figure 8: Determination of allocation constraints in export direction (reserves in generating capacities available for potential exports) in the framework of day ahead transfer capacity calculation

[15] note that generating units, which have very limited working hours left due to environmental restrictions are not taken into account in power balance for determining export allocation constraints: most of these units are still in operation only thanks to special contracts with TSO (thus being out of the market) – otherwise they would have already been decommissioned as not profitable; currently also all pumped storage units in Poland are also operated by TSO out of market (for the same reason), however these units are taken into account in power balance for determining export allocation constraints as their operation is not limited environmentally



1. TSO estimation of 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, except wind farms for which TSO forecast of wind generation is taken into account.

3. load forecasted by TSO
3.1 minimum necessary reserve for down regulation (for day ahead: 500MW)

Figure 9: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day ahead transfer capacity calculation

Annex 2: Advanced Hybrid Coupling (AHC) – a short explanation

Hybrid coupling stands for the combined use of flow-based and Available Transmission Capacity (ATC) constraints in one single allocation mechanism[16], and is found in the shapes of "Standard" and "Advanced". Though the use of ATC capacity in a flow-based world may not be limited to DC lines only, this explanatory note focuses on this application only, for the sake of clarity.

An ATC sets a limit to a commercial exchange of power between two bidding zones. These ATCs do not physically exist in the grid; indeed, they are the results of scenarios, assumptions, and computations. DC lines between bidding zones are an exception to this statement though: being fully controllable devices, a commercial exchange of 1000 MW between the two bidding zones will result in a physical flow of exactly 1000 MW on the DC line. In a way, DC lines are the physical reality or representation of an ATC. In short: where an AC grid can be modelled by using the flow-based capacity calculation approach, DC lines interconnecting the AC grids are to be modelled by means of ATCs in order to work in the European market coupling, thereby requiring a hybrid coupling approach.

In the next section the interlink between the AC and DC grid is described. Later the difference between Standard and Advanced Hybrid Coupling is explained, followed by a more in-depth description of the capacity calculation and allocation under an Advanced Hybrid Coupling approach.

Interlink DC link and AC grid

The power that is traded over the DC link can be produced and consumed anywhere in the AC grid. Therefore the interaction of the AC grid and the DC grid needs to be modelled.
A DC link is an element, integrated in the AC networks on both sides of the link. Indeed, in the converter stations, where the DC power is transformed into AC power and vice versa, the DC link absorbs its power from, and feeds its power into, the AC grid. From the AC grid point of view, the converter station acts as a source or sink of AC power.

In Figure 10, a DC link is depicted that is interconnecting two AC grids. The white lines represent the AC lines connected to the converter station.

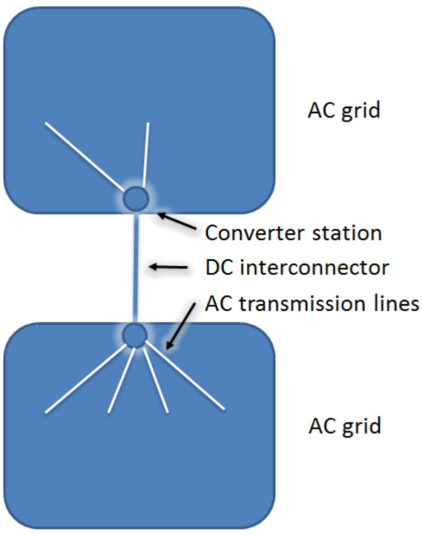


Figure 10: Interlink DC line and AC grid

A power flow on the DC interconnector has a physical impact on the AC grid. If we assume that the power flow on the DC line distributes evenly on the four white AC lines, it implies that 25 % of the flow on the DC line appears as a physical flow on every white AC line.

If during the capacity calculation stage, each of these AC lines has a capacity of 500 MW that can be used by the market, it implies that a maximum DC flow could be allowed of 500 MW / 0.25 = 2000 MW.

If we assume the DC interconnector has a nominal capacity of 1000 MW, it boils down to a maximum physical flow being induced on the AC lines of 1000 MW * 0.25 = 250 MW. The remaining 250 MW of capacity can then be used for other market transactions, besides the one on the DC line.

[16] C. Müller, A. Hoffrichter, H. Barrios, A. Schwarz, A. Schnettler: *Integration of HVDC-Links into Flow-Based Market Coupling: Standard Hybrid Market Coupling versus Advanced Hybrid Market Coupling*, CIGRE Symposium Dublin, May/June 2017.

Hybrid Coupling: Standard and Advanced

As indicated in the introduction, Hybrid Coupling stands for the combined use of flow-based and ATC constraints in one single allocation mechanism. There are two types of hybrid coupling: Standard Hybrid Coupling (SHC) and Advanced Hybrid Coupling (AHC). The difference between those two approaches is highlighted in this section.

Let us consider our example AC transmission line, with a capacity of 500 MW, as introduced above. In a SHC approach, the DC line receives a "priority access" to the AC grid. Simply put: the DC line can transport 1000 MW (it's full capacity) in both directions, and may use 25% * ±1000 = ±250 MW on the AC transmission line. Under the SHC approach, this capacity is reserved to facilitate the flows on the DC interconnector and cannot be used by other market transactions ("what is used by one cannot be used by another"). This is different under the AHC approach, where all capacity on the AC transmission line is available to be shared among the grid users in the most optimal way. This is depicted in Figure 11.

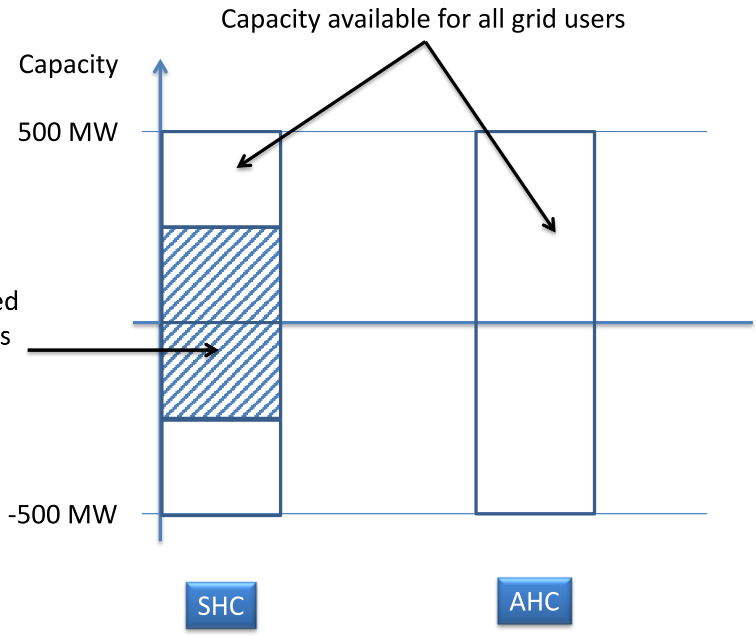


Figure 11: Standard Hybrid Coupling and Advanced Hybrid Coupling

The question how the DC interconnector is modelled under AHC, and how the capacity on the AC transmission line can be shared among the grid users in the most optimal way is touched upon in the following section.

Capacity calculation and capacity allocation

In the AHC concept, the capacity on the DC line is by default set to its nominal value, which is equal to the full capacity of the DC line[17]. In our example above, it means that the ATC = 1000 MW for the DC line (assuming the Already Allocated Capacity (AAC) to be zero: AAC = 0).

[17] For more details please refer to section 4.1.1

The impact of the DC line on the AC grid is taken into account in the flow-based capacity calculation of the AC areas. The converter station is treated as a so-called virtual bidding area in the flow-based capacity calculation of the AC area: a bidding zone, without production and consumption. In this way, the impact of having import or export of this virtual bidding area (being a commercial exchange over the DC line) on the critical network elements in the AC grid are properly taken into account.

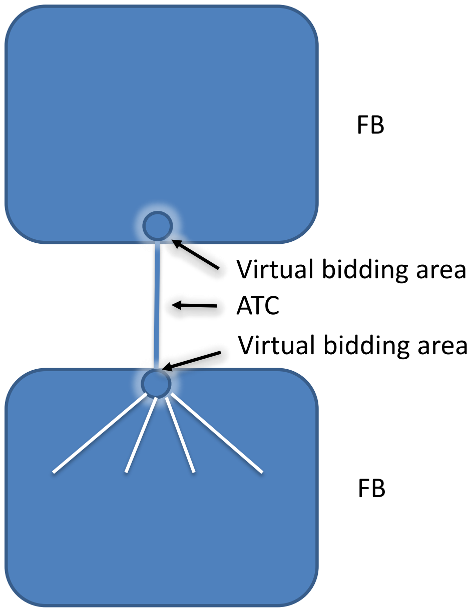


Figure 12: AHC

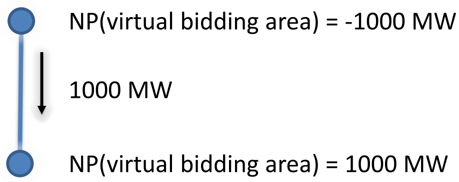


Figure 13: Flow on the DC interconnector and the net position of the virtual bidding area

The example from Figure 10 then translates into the situation depicted in Figure 12. The flow on the DC interconnector has a one-to-one link to the net position (import/export position) of the virtual bidding area, as demonstrated in Figure 13.

In the example case, the impact of having an export of the virtual bidding area on the critical network element (the AC transmission line that we are focussing on) in the AC grid, amounts to an increase of the line loading of 25 % (and -25 % when the virtual bidding area is in an import position). The so-called power transfer distribution factor (PTDF) in the flow-based methodology equals 0.25. Indeed, the PTDF is a number that translates the amount of export / import to a flow on a critical network element.

In the flow-based methodology, the impact of the virtual bidding area is assessed and quantified in exactly the same way as any other bidding area. Or in other words: when using the AHC, the flow-based methodology specifies the amount of MW available on the different critical network elements, and it determines the amount of MW used when having an import or export from one of the bidding zones and virtual bidding areas. When we zoom in on one of the flow-based areas in Figure 12, we get the image in Figure 14.

The flow-based constraint of critical network element 1 (CNE1) in Figure 14, may then look as follows:

$$\alpha * NP(A) + \beta * NP(B) + \gamma * NP(C) + 0.25 * NP(\text{virtual bidding area}) \leq 500 \text{ MW}$$

Where:

NP: Net position (import or export position of the bidding zone; export being a positive value)
α,β,γ: PTDF factors, translating the net positions of the bidding zones A, B, and C into expected physical flows on CNE1

Of course, the net position of the virtual bidding area cannot exceed the ATC capacity of the DC line.

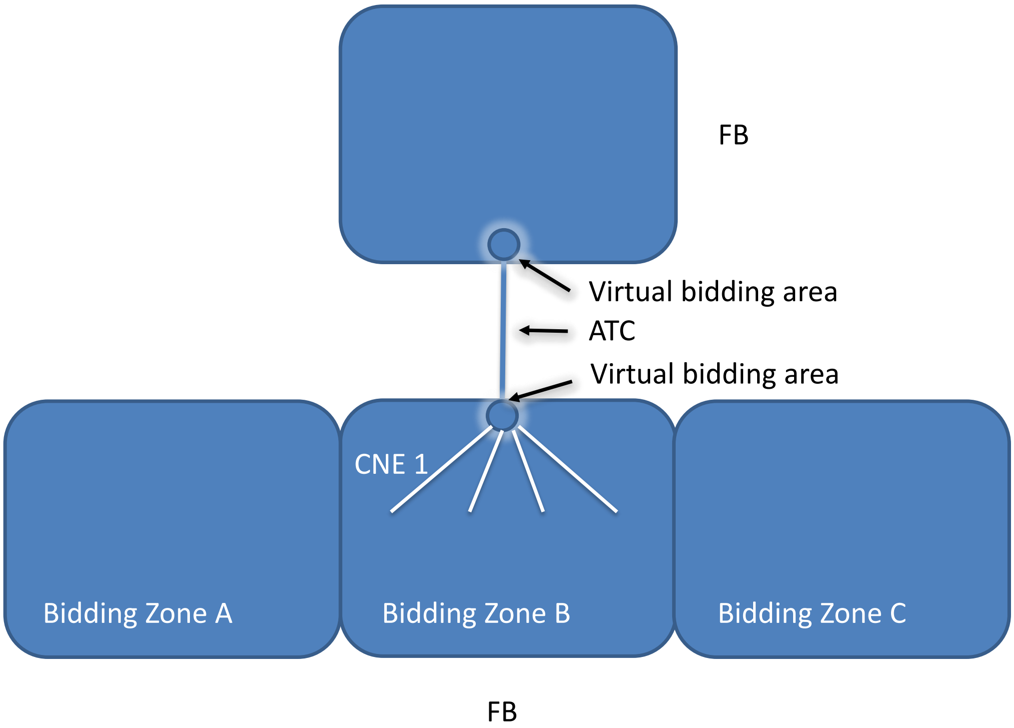


Figure 14: Zoom of the flow-based area

It is the flow-based information from the AC areas and the ATC information from the DC lines that is being provided to the allocation mechanism. It is in the allocation mechanism, where the actual import and export positions (and thereby the exchanges on the DC lines) are determined in the most optimal way given the grid restrictions and the order books.

The allocation – being a European-wide optimisation of the matching of demand and supply, given the grid and allocation constraints – allows all market participants to compete over the scarce resource that is the capacity of a line. This then may result in having a 1000 MW exchange over the DC line, but may also result into a 800 MW exchange on the DC line if this specific outcome leads to a socio-economic optimum in the overall system. Or in other words: although as a result of the capacity calculation stage, the nominal capacity (1000 MW) on the DC line is provided to the allocation mechanism, the European-wide optimal use of the whole connected transmission grid (given the order books provided) can be a solution where not the full capacity on one specific DC line is utilised in all hours.

AC grid limitations restricting the capacity on the DC line

An exceptional situation may arise in which the surrounding local AC grid, where the converter station is located, is facing some operational challenges due to the power transfer of the DC line. When these challenges cannot be handled by the flow-based methodology, for example when it is related to restrictions located in grids at lower voltage levels or voltage or dynamic issues (that are not modelled in the flow-based system), and the flow on the DC line needs to be limited in order to secure a safe grid operation, the TSO of that AC grid can impose a constraint in the flow-based methodology to do so.

In this example, the ATC capacity of the DC line will remain 1000 MW. The TSO facing operational issues, can only allow a maximum flow on the DC line of 750 MW to guarantee the safe operation in the AC grid. He can impose this limit, by adding the following constraint to the virtual bidding area in the flow-based domain:

NP(virtual bidding area) ≤ 750 MW

With the ATC capacity of the DC line being 1000 MW, and the export position of the virtual bidding area being restricted to a maximum of 750 MW, the net position of the virtual bidding area can be in between -1000 MW and 750 MW.

In this way, it is not for a technical reason linked to the DC line itself, that the capacity is limited (thereby leaving its ATC untouched), but due to operational challenges in the AC grid, and as such expressed in the flow-based capacity constraints from the AC grid.