Fourth amendment of the Day-Ahead Capacity Calculation Methodology of the Core Capacity Calculation Region

in accordance with article 20ff. of the Commission Regulation (EU) 2015/1222 of 24^{th} July 2015 establishing a guideline on capacity allocation and congestion management

December 2025

Whereas

TSOs of the Core CCR ("Core TSOs"), take into account the following:

(1) Specification of operational security limits: These are founded on the SO Regulation. With this amendment, the Core TSOs propose to amend the existing wording to clarify and resolve an editorial inconsistency. The proposal does not alter the meaning of the stipulations regarding operational security limits. The proposed amendment is accompanied by a minor adaptation to make clear that certain aspects of operational security may, but do not have to be addressed by allocation constraints. This allows, where possible, to continue considering such aspects by operational security limits on CNEs.

(2) The Core TSOs aim to make maintaining operational security, which is a crucial condition of DA CCM, independent from the amount of long-term allocated capacities (LTA). This will allow LTA pursuant to Core LT CCM and more generally, pursuant to FCA GL, to be set without a direct link to operational security. To reach this aim, this amendment foresees that the LTA inclusion must end at the latest with the first delivery period of the long-term capacities calculated according to the LT CCM pursuant to FCA GL It is an option to do this even earlier. In addition to the inclusion of LTA as such, LTA have been used in the DA CCM for several further purposes. Therefore, besides the mere removal of LTA inclusion as such, this amendment foresees substitute solutions for all of these purposes. This includes a new approach for default flow-based parameters as part of the capacity calculation fallbacks, a revision of the determination of ATCs for SDAC fallback, and minimum level of cross-zonal capacity by introducing a floor level of 20 percent of the maximum admissible power flow in the final flow-based parameters. The latter also safeguards against small cross-zonal capacity due to LTAs that are still allocated as physical transmission rights.

Core TSOs may deviate from the RAM floor level of 20 percent of the maximum admissible power flow on their own CNECs if operational security cannot be maintained otherwise. The concerned Core TSO(s) shall communicate such deviations immediately to market participants via an Urgent Market Message (UMM) broadcasted on the JAO website[1]. The concerned Core TSO(s) shall provide to the CCC a report with a justification why the application of the RAM floor level would have led to the inability to maintain operational security and an action plan describing how such situations will be avoided in the future. This report will become an annex to the quarterly report.

(3) HVDC interconnectors within the Core CCM and with both ends in the same synchronous area require a special term in the formula for determining the maximum zone-to-zone Power Transfer Distribution Factors. With this fourth amendment the Core TSOs aim to amend the related formula to overcome two shortcomings of the present formula. Firstly, the new formulation ensures that the maximum zone-to-zone PTDF on all CNECs correctly accounts for the maximum impact of routing a zone-to-zone transfer through an HVDC interconnector. Secondly, the new formulation covers the potential future scenario in which there is more than one HVDC interconnector with both ends in the same synchronous area in the

[1] https://www.jao.eu/news?roles_target_id_group=tso

Core CCR.

(4) With this amendment the Core TSOs aim to improve the clarity and consistency of the method by correcting several minor editorial mistakes, without altering the meaning of the respective stipulations.

(5) With this amendment, PSE aims at extending the period of using AC by an additional two years. Operational experience gathered over the previous two years has proven that allocation constraints are an effective measure to maintain the transmission system within operational security limits and cannot be transferred efficiently into maximum flows on critical network elements, as prescribed by provisions of the CACM Article 23(3). Allocation constraints allowed to avoid any cases of insecure operation in Poland that could not have been resolved by operational means. Allocation constraints secure balancing reserves by limiting excess trade which could result in scarcity of available balancing capacity. To increase the available balancing capacity and limit Allocation Constraints impact on market, PSE launched an additional balancing capacity market mechanism which was implemented on 14 June 2024. Balancing capacities on the market are acquired separately for the direction of increasing the power introduced to the system and its reduction. The acquisition of balancing capacities for given day D takes place in the basic process at 8:30 on D-1 and in the supplementary process of Integrated Scheduling Process from the afternoon on D-1 until the time of delivery on D. The capacity bought by PSE in the basic process should not be offered anymore by BSPs on the SDAC and SIDC leading to significantly less frequently binding Allocation Constraints. So far, the market is not liquid enough to provide sufficient reserves despite that PSE buys all the available capacity on the market. Despite immaturity of morning balancing capacity market, the impact of retracting procured capacities on frequency of activation of Allocation Constraints is noticeable. They are the only means of ensuring sufficient regulation reserves and secure operation of the power system. They are for now the only effective measure to maintain the frequency stability. For the above reasons, the extension for using capacity allocation constraints is necessary to secure balancing re-serves until the balancing capacity market is liquid enough to reliably and systematically provide them. As the transition period started with the implementation of Day-Ahead Capacity Calculation process on 8th June 2022 the extended transition period will end in June 2028.

(6) The individual validation process is updated to allow TSOs the consideration of additional 110 kV elements to ensure operational security while the PTDF threshold of 5% is respected and the margins of the new elements are maximised for cross-zonal trade

(7) Core TSOs propose the harmonised GSK methodology alongside the “Nodal Forecasting Error” as the key metric to evaluate GSK quality and rules for monitoring GSK quality and deviating GSK methodologies. The harmonised GSK methodology is a firm methodology defined in 9(4)(a). The harmonised GSK methodology does only allow for individual TSO modifications as defined in 9(2).

(8) The Celtic interconnector will create a new bidding zone border assigned to the Core CCR once it becomes operational. Consequently, the bidding zone border between the Single Electricity Market in Ireland and Northern Ireland (‘SEM’) and France (‘FR’), attributed to EirGrid, SONI, and RTE, will be incorporated into the Core Day-Ahead CCM. To enable this integration and to accommodate the

needs of EirGrid and SONI, Core TSOs propose amendments to include EirGrid and SONI in the list of Core TSOs, update the definition of 'F0, all' and 'slack node' to cover Core bidding zones in different synchronous area, and define the 'SEM' as a single bidding zone for Ireland and Northern Ireland; to allow the delegation of a Core TSO obligation in providing capacity calculation inputs to another Core TSO; to permit the use of ramping constraints as a specific type of allocation constraints in addition to external constraints; to establish the approach of integrating Core HVDC interconnectors between synchronous areas; to update the wording in the calculation of 'F0,all' to cover Core bidding zone in different synchronous areas; to include reference exchanges between bidding zones across different synchronous areas; and to specify that the operationalization of SEM-FR border is dependent on the commissioning of Celtic cable and its readiness for commercial operation. Annex 1 is updated to include EirGrid and SONI among the list Core TSOs applying allocation constraints together with the corresponding justification and methodology.

(9) To take into account the upcoming inner-German HVDC lines as corrective measure for the NRAO these grid elements are added in this amended to the specific sections.

(10) For the purposes of this fourth amendment to the Core CCR TSOs' Day-Ahead Capacity Calculation Methodology, terms used in this document shall have the meaning of the definitions included in Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast), Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation), Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA Regulation), Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB Regulation) and Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council and the definitions set out in Article 2 Annex I of the Decision No 02/2019 of the Agency for the Cooperation of the Energy Regulators of 21 February 2019 on the Core CCR TSOs' proposal for the regional design of the day-ahead and intraday common capacity calculation methodologies.

Article 1
Whereas

1. Whereas shall be amended by updating paragraph 18 accordingly:
   "Some operational security limits can be transformed into limitations on active power flows on critical network elements, whereas some other cannot and may be modelled as allocation constraints. Some of the operational security limits (inter alia frequency, voltage, dynamic stability, and inter-synchronous area ramping re-

strictions) may depend on the level of production and consumption in a given bidding zone, and as such cannot be controlled by limitations on active power flows on critical network elements. Thus, specific limitations on production and consumption are needed, and these are expressed as maximum import and export constraints of bidding zones. External constraints are therefore a type of allocation constraints limiting the total import and export of a bidding zone. Nevertheless, given the lack of proper legal and technical justification for the external constraints, their application is considered in this methodology as a temporary solution in order to allow TSOs to explore alternative solutions to the underlying problems. If none of the alternative solutions is more efficient to tackle the underlying problems, the concerned TSOs may propose to continue applying them. In addition to external constraints, ramping constraints which limit the maximum flow change on HVDC interconnectors between synchronous areas from one MTU to the next, also constitute a specific type of allocation constraints."

2. Whereas shall be amended by updating paragraph 24 accordingly:
   "Cross-zonal capacities determined by the day-ahead capacity calculation shall ensure that all combinations of net positions that could result from previously-allocated cross-zonal capacity – Long Term Allocations (LTA) – can be accommodated. For that purpose, the TSOs proceeded to the LTA inclusion which consists in providing a single flow-based domain including LTAs for the single day-ahead coupling. The extended LTA inclusion approach differs by providing the single day-ahead coupling with LTAs and the flow-based domain without LTA inclusion separately. The market coupling algorithm then chooses which union of both domains creates most welfare. Core TSOs will cease to apply LTA inclusion at the latest when long-term capacities will be calculated and allocated pursuant to the FCA Regulation. This shall serve to decouple maintaining of operational security from the amount of LTAs"
3. Whereas shall be amended by updating paragraph 25 accordingly:
   "To enable a more accurate and efficient representation of connections with neighbouring CCRs, the advanced hybrid coupling (AHC) is foreseen in the Core DA CCM to replace the standard hybrid coupling and provide efficiency gains in the capacity calculation and allocation phase on the borders where AHC is applied. AHC principles can also rather efficiently be applied to a lowly meshed alternating alternative current (AC) border between a Core and a non-Core bidding zone, while its efficiency and accuracy of network representation diminishes with the increased meshness of AC borders. Implementation of AHC is foreseen on all borders linking Core bidding zones and bidding zones of neighbouring CCRs and which are part of SDAC, except for the common borders with Italy North CCR which is planned to be merged with the Core CCR under a future common flow-based approach and for the common borders with SWE where only a low efficiency gain is expected in comparison with the challenges imposed by AHC."

Article 2
Definitions and interpretation

1. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 13 accordingly:

"Core TSOs are 50Hertz Transmission GmbH ("50Hertz"), Amprion GmbH ("Amprion"), Austrian Power Grid AG ("APG"), CREOS Luxembourg S.A. ("CREOS"), ČEPS, a.s. ("ČEPS"), EirGrid PLC ("EirGrid"), Eles d.o.o. sistemski operater prenosnega elektroenergetskega omrežja ("ELES"), Elia System Operator S.A. ("ELIA"), Croatian Transmission System Operator Ltd. (HOPS d.o.o.) ("HOPS"), MAVIR Hungarian Independent Transmission Operator Company Ltd. ("MAVIR"), Polskie Sieci Elektroenergetyczne S.A. ("PSE"), RTE Réseau de transport d'électricité ("RTE"), Slovenská elektrizačná prenosová sústava, a.s. ("SEPS"), System Operator for Northern Ireland Ltd. ("SONI"), TenneT TSO GmbH ("TenneT GmbH"), TenneT TSO B.V. ("TenneT B.V."), National Power Grid Company Transelectrica S.A. ("Transelectrica"), TransnetBW GmbH ("TransnetBW");"

2. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 20a accordingly:
   "'external virtual hub (EVH)' means a virtual bidding zone without any buy and sell orders, used to represent the imports and exports on an AHC border as specified in Article 13 of this Methodology or exchanges on HVDC interconnectors on the bidding zone borders of the Core CCR when either end of a HVDC interconnector is in a different synchronous area as specified in Article 12 (5);"
3. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 22 accordingly:
   "'$F_{0,all}$' means the flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, between bidding zones within Continental Europe and bidding zones located in other synchronous areas, and between the island of Ireland and bidding zones located in other synchronous areas"
4. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 32 accordingly:
   "HVDC' means a high voltage direct current network element"
5. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 60 accordingly:
   "'slack node' means the reference node used for determination of the PTDF matrix, i.e. shifting the power infeed of generators up results in absorption of the power shift in the slack node. Each synchronous area has one designated slack node, which remains constant for each DA CC MTU;"
6. Article 2 [Definitions and interpretation] shall be amended by updating paragraph 73 accordingly:
   "'CZC' means cross-zonal capacity whereas this capacity is to be understood as the "flow-based parameters" (flow-based domain) or, in case the extended LTA approach pursuant to Article 18(1a) is applied, the union of the flow-based parameters and "LTA values" (LTA domain);"
7. Article 2 [Definitions and interpretation shall be amended by adding paragraph 78 accordingly:
   "'SEM' means the Single Electricity Market, the bidding zone consisting of both Ireland and Northern Ireland as a single all-island electricity market;"
8. Article 2 [Definitions and interpretation shall be amended by adding paragraph 79 accordingly:
   "'MTU' is the day-ahead market time unit, which means the time unit for the day-

ahead market;”

9. Article 2 [Definitions and interpretation shall be amended by adding paragraph 80 accordingly:
“$\|\vec{x}\|_2$ denotes the Euclidean norm of a vector.”

Article 3
Day-ahead capacity calculation process

1. Article 4 [Day-ahead capacity calculation process] shall be amended by updating paragraph 3 accordingly:
“Each Core TSO shall provide the CCC the following capacity calculation inputs by the times established in the process description document, with the reservation that a Core TSO may delegate its obligation of providing the following inputs to another Core TSO subject to prior agreement and in accordance with applicable procedures”
2. Article 4 [Day-ahead capacity calculation process] shall be amended by updating paragraph 4a accordingly:
“the long-term allocated capacities (LTA) , as long as the Core TSOs apply the rules as referred to in Article 18(1)(a);”
3. Article 4 [Day-ahead capacity calculation process] shall be amended by updating paragraph 4b accordingly:
“the adjustment values for long-term allocated capacities for each Core bidding zone border and for each AHC border to enlarge the default flow-based domain beyond the long-term allocated capacities for the purpose of calculating the default flow-based parameters, as long as the Core TSOs apply the rules as referred to in Article 18(1)(a); and”
4. Article 4 [Day-ahead capacity calculation process] shall be amended by updating paragraph 8 (step 9) accordingly:
“The CCC shall, according to Article 21, remove the redundant CNECs and redundant external constraints from final $PTDF_f$ and RAM_{bn} and publish these as pre-final flow-based parameters in accordance with Article 25.

Article 4
Methodology for operational security limits

1. Article 6 [Methodology for operational security limits] shall be amended by updating paragraph 2 accordingly:
“To take into account the operational security limits of CNEs, the Core TSOs shall use as far as applicable the maximum admissible current limit (I_{max}), which is the physical limit of a CNE according to the operational security limits in accordance with Article 25 of the SO Regulation. The maximum admissible current shall be defined as follows:”
2. Article 6 [Methodology for operational security limits] shall be amended by updating paragraph 2a(iii) accordingly:
“Fixed limits for all DA CC MTUs, in case of specific situations where the physical limit reflects the capability of overhead lines, transformers, cables or substation equipment installed in the primary power circuit (such as circuit-breaker, or

disconnector) with limits not sensitive to ambient conditions, or where operational security limits are not set by thermal rating."

Article 5
Methodology for allocation constraints

1. Every "external constraint" or "external constraints" phrase in the methodology is replaced by an "allocation constraint" or "allocation constraints" respectively.
2. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 1 accordingly:
   "In case operational security limits cannot be transformed efficiently into I_{max} and F_{max} pursuant to Article 6, the Core TSOs may transform them into allocation constraints."
3. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 2 accordingly:
   "The Core TSOs may apply allocation constraints as one of the following three options:
   a. a constraint on the Core net position (the sum of cross-zonal exchanges within the Core CCR and on AHC borders for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to its imports and/or exports to other bidding zones in the Core CCR. This option shall be applied until option (b) can be applied.
   b. a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the SDAC. This option shall be applied when: (i) such a constraint is approved within all day-ahead capacity calculation methodologies of the respective CCRs, (ii) the respective solution is implemented within the SDAC algorithm and (iii) the respective bidding zone borders are participating in SDAC.
   c. ramping constraints (flow ramping limits) that limit the maximum flow change on HVDC interconnectors between synchronous areas from one MTU to the next."
4. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 3 accordingly:
   "Allocation constraints referred to in Article 7 2(a) and 2(b) may be used by a Core TSO as listed in Annex 1 during a transition period of six years following the implementation of this methodology in accordance with Article 28(3) and in accordance with the reasons and the methodology for the calculation of allocation constraints as specified in Annex 1 to this methodology. During this transition period, the concerned Core TSOs shall:
   a. calculate the value of allocation constraints in accordance with Annex 1 and in any case at least on a quarterly basis and publish the results of the underlying analysis;
   b. in case the external constraint had a non-zero shadow price in more than 0.1% of hours in a quarter, provide to the CCC a report analysing: (i) for each MTU when the allocation constraint had a non-zero shadow price the loss in economic surplus due to allocation constraint and the

effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits and (ii) alternative solutions to address the underlying operational security limits. The CCC shall include this report as an annex in the quarterly report as defined in Article 27(5);

   c. if applicable and when more efficient, implement alternative solutions referred to in point (b)."

5. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 4 accordingly:

   "In case the concerned Core TSOs could not find and implement alternative solutions referred to in the Article 7(3), they may, by sixty-six months after the implementation of this methodology in accordance with Article 28(3), together with all other Core TSOs, submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of CACM Regulation. Such a proposal shall include the following:

   a. the technical and legal justification for the need to continue using the allocation constraints indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};
   b. the methodology to calculate the value of allocation constraints including the frequency of recalculation."

6. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 5 accordingly:

   "In case such a proposal has been submitted by all Core TSOs, the transition period referred to in Article 7(3) shall be extended until the decision on the proposal is taken by all Core regulatory authorities."

7. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 6 accordingly:

   "For the SDAC fallback procedure, pursuant to Article 23, all allocation constraints referred to in Article 7, 2(a) and 2(b) shall be modelled as constraints limiting the Core net position as referred to in Article 7 2(a)."

8. Article 7 [Methodology for allocation constraints] shall be amended by updating paragraph 7 accordingly:

   "A Core TSO may discontinue the use of an external constraints. The concerned Core TSO shall communicate this change to all Core regulatory authorities and to the market participants at least one month before discontinuation"

Article 6
Generation shift key methodology

1. Article 9 [Generation shift key methodology] shall be replaced and read accordingly:

1. Each Core TSO shall define for its bidding zone and for each DA CC MTU a GSK, which translates a change in its bidding zone net position into a specific change of nodal injection or withdrawal in the CGM. A GSK shall have fixed values, which means that for one DA CC MTU the relative contribution of generation or load to the change in the bidding zone net position shall remain the same, regardless of the volume of the change.

1a. The quality of the GSK shall be quantified by evaluating the nodal forecasting error (NFE). The NFE is defined as the sum of absolute deviations between nodal power injections or withdrawals in the DACF IGM at the Day-Ahead market clearing point (MCP) and those in the D2CF IGM shifted to the Day-Ahead MCP using the GSK.

2. For a given DA CC MTU, the GSK shall only include actual generation and/or load[2] present in the CGM for that DA CC MTU. The Core TSOs shall consider the available information on generation or load in the CGM in order to select the nodes that will contribute to the GSK. Nodes in the CGM may be excluded from the calculation of GSK values if they do not contribute to the minimisation of the NFE.

3. (deleted)

4. (deleted)

4a. Core TSOs shall implement the Country GSK methodology. The nodal GSK values shall be defined in proportion to the absolute values of power injections and withdrawals in the IGM.

4b. Core TSOs may deviate from the Country GSK methodology pursuant to paragraph 4a if the deviating strategy outperforms the Country GSK in terms of the NFE.

   (a) As part of the reporting obligation pursuant to Article 26, the CCC shall monitor on an annual basis, for each TSO applying a GSK methodology deviating from the Country GSK methodology, the difference between the NFE of the Country GSK and their applied GSK methodology.

   (b) A positive NFE difference indicates that a Core TSO's GSK outperforms the Country GSK.

   (c) In case the reported NFE difference is negative, the concerned TSOs shall apply the Country GSK methodology as soon as possible.

   (d) When switching to a deviating GSK methodology, the concerned TSOs shall provide an analysis covering a period of at least 6 months that shows that the deviating GSK methodology outperforms the Country GSK methodology.

5. The Core TSOs belonging to the same bidding zone shall jointly define a common GSK for that bidding zone and shall agree on a methodology for such coordination. For Germany and Luxembourg, each TSO shall calculate its individual GSK and the CCC shall combine them into a single GSK for the whole German-Luxembourgian bidding zone, by assigning relative weights to each TSO's GSK. The German and Luxembourgian TSOs shall agree on these weights, based on the share of the generation in each TSO's control area that is responsive to changes in net position, and provide them to the CCC.

5a. The CCC shall define GSKs for the EVHs according to Article 13 (3)(b) as follows:

[2] And other elements connected to the network, such as storage equipment.

(a) In case an EVH represents only HVDC interconnectors, the GSK shall be defined by all converter stations of the HVDC interconnectors, weighted based on the respective trans-mission capacity.

(b) In case an EVH represents only AC interconnectors, the CCC shall use the GSK of the adjacent bidding zone provided by the TSOs of that bidding zone. If this GSK is not available, the CCC shall define a GSK based on all positive injections in the IGM of the adjacent bidding zone.

(c) In case an EVH represents both HVDC interconnectors and AC interconnectors, the respective Core TSO shall define a single combined GSK based on the GSK for the HVDC and the GSK for the AC interconnectors.

Article 7
Methodology for remedial actions in day-ahead capacity calculation

1. Article 10 [Methodology for remedial actions in day-ahead capacity calculation] shall be amended by adding paragraph 7c accordingly:
   "changing the set point of a bidding zone internal HVDC line"

Article 8
Calculation of power transfer distribution factors and reference flows

1. Article 11 [Calculation of power transfer distribution factors and reference flows] shall be amended by updating paragraph 5 accordingly:

The maximum zone-to-zone $PTDF$ of a CNEC ($PTDF_{z2zmax,l}$) is the maximum influence that any Core exchange has on the respective CNEC, including the exchanges with the virtual hubs, i.e. the exchanges over HVDC interconnectors which are integrated pursuant to Article 12 and the exchanges on AHC borders which are modelled through EVH pursuant to Article 13:

$$PTDF_{z2zmax,l} = \max_{X\in\{BZ\cup EVH\}}\left(PTDF_{X,l}\right) - \min_{X\in\{BZ\cup EVH\}}\left(PTDF_{X,l}\right) + \sum_{\substack{k\in K \\ H_{1k},H_{2k}\in IVH}} \left|PTDF_{H_{1k},l} - PTDF_{H_{2k},l}\right|$$

Equation 1

with

k	a given HVDC interconnector within the Core CCR
K	set of all HVDC interconnectors within the Core CCR
$PTDF_{X,l}$	zone-to-slack $PTDF$ of a Core bidding zone or external virtual hub X on a CNEC l

BZ	set of all Core bidding zones
EVH	set of all external virtual hubs in the Core CCR
IVH	set of all internal virtual hubs in the Core CCR
$\max_{X \in \{BZ \cup EVH\}} (PTDF_{X,l})$	maximum zone-to-slack PTDF of Core bidding zones or EVHs on a CNEC l
$\min_{X \in \{BZ \cup EVH\}} (PTDF_{X,l})$	minimum zone-to-slack PTDF of Core bidding zones or EVHs on a CNEC l
$PTDF_{H1k,l}$	zone-to-slack $PTDF$ of internal virtual hub H_1 on a CNEC l, with H_1 representing the converter station at the sending end of the HVDC interconnector k
$PTDF_{H2k,l}$	zone-to-slack $PTDF$ of internal virtual hub H_2 on a CNEC l, with H_2 representing the converter station at the receiving end of the HVDC interconnector k

Article 9
Integration of HVDC interconnectors on bidding zone borders of the Core CCR

1. Article 12 [Name of Article] shall be replaced and read accordingly:

1. The Core TSOs shall apply the evolved flow-based (EFB) methodology, in accordance with paragraphs 2 to 4 below, when including HVDC interconnectors on the bidding zone borders of the Core CCR, provided that both ends of the HVDC interconnector are within the same synchronous area.[3] In the EFB, a cross-zonal exchange over an HVDC interconnector on the bidding zone borders of the Core CCR is modelled and optimised explicitly as a bilateral exchange in capacity allocation, and is constrained by the physical impact that this exchange has on all CNECs considered in the final flow-based domain used in capacity allocation and constraints modelling the maximum possible exchange of the HVDC interconnector.

2. In order to calculate the impact of the cross-zonal exchange over a HVDC interconnector pursuant to paragraph 1 on the CNECs, the converter stations of the cross-zonal HVDC shall be modelled as two internal virtual hubs, which function equivalently as bidding zones. Then the impact of an exchange between A and B, each being either a bidding zone or an external virtual hub, over such HVDC interconnector shall be expressed as an exchange from the bidding zone or external virtual hub A to the internal virtual hub representing the sending end of the HVDC interconnector plus an

[3] EFB is different from AHC. AHC imposes the capacity constraints of one CCR on the cross-zonal exchanges of another CCR by considering the impact of exchanges between two capacity calculation regions. E.g. the influence of exchanges of a bidding zone which is part of a CCR applying a coordinated net transmission capacity approach is taken into account in a bidding zone which is part of a CCR applying a flow-based approach. EFB takes into account commercial exchanges over the cross-border HVDC interconnector, provided both ends are within the same CCR and synchronous area, applying the flow-based method of that CCR.

exchange from the internal virtual hub representing the receiving end of the interconnector to the bidding zone or external virtual hub B:

$$PTDF_{A\rightarrow B,l} = (PTDF_{A,l} - PTDF_{IVH\_1,l}) + (PTDF_{IVH\_2,l} - PTDF_{B,l})$$

Equation 2

with

$PTDF_{A,l}$	zone-to-slack PTDF of a bidding zone or external virtual hub A on a CNEC l
$PTDF_{B,l}$	zone-to-slack PTDF of a bidding zone or external virtual hub B on a CNEC l
$PTDF_{IVH\_1,l}$	zone-to-slack $PTDF$ of internal virtual hub 1 on a CNEC l, with internal virtual hub 1 representing the converter station at the sending end of the internal Core HVDC interconnector
$PTDF_{IVH\_2,l}$	zone-to-slack $PTDF$ of internal virtual hub 2 on a CNEC l, with internal virtual hub 2 representing the converter station at the receiving end of the internal Core HVDC interconnector

3. The PTDFs for the two internal virtual hubs $PTDF_{IVH\_1,l}$ and $PTDF_{IVH\_2,l}$ are calculated for each CNEC and they are added as two additional columns (representing two additional internal virtual bidding zones) to the existing $PTDF$ matrix, one for each internal virtual hub.

4. The internal virtual hubs introduced by this methodology are only used for modelling the impact of an exchange through a HVDC interconnector and no orders shall be attached to these internal virtual hubs in the coupling algorithm. The two internal virtual hubs, will have a combined net position of 0 MW, but their individual net position will reflect the exchanges over the interconnector. The flow-based net positions of these internal virtual hubs shall be of the same magnitude, but they will have an opposite sign. $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ of all or only a subset of CNECs can be set to zero before the DA market coupling if $\left| PTDF_{IVH\_1,l} - PTDF_{IVH\_2,l} \right|$ is below a certain threshold. The adjustment is to be done after the NRAO optimization described in Article 16 and before the validation steps described in Article 20. This PTDF threshold shall not exceed 1% and may be applied during the transition period preceding the Go-Live of Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation. Core TSOs shall report quarterly on the initial setup and any change of this threshold together with the impact which entails from a non-zero threshold and a due justification.

5. The Core TSOs shall consider the HVDC interconnectors on the bidding zone borders of the Core CCR when either end of the HVDC interconnector is in different synchronous areas by using at least one external virtual hub (EVH) according to paragraphs (a) and (b) below.

   (a) The CNECs of the Core Day-ahead capacity calculation in one synchronous area shall not only limit the net positions of bidding zones due to exchanges within this synchronous area but also the exchanges on Core bidding zone borders between the two synchronous areas.

(b) Core TSOs may impose a limit to the net position of the external virtual hub, that considers the physical limitations of the Core HVDC cables on the border and the converter stations on either endpoint of the Core HVDC cables.

Article 10
Non-costly remedial actions optimisation

1. Article 16 [Non-costly remedial actions optimisation] shall be amended by updating paragraph 3b accordingly:
   "the optimisation process iterates over switching states (i.e. activated or not-activated) of topological measures, range of setpoints of bidding zone internal HVDC lines and PST tap positions in order to maximise this objective. Preventive RAs may jointly be associated with all CNECs, whereas curative RAs may be optimised independently for each contingency."
2. Article 16 [Non-costly remedial actions optimisation] shall be amended by updating paragraph 3d(viii) accordingly:
   "<…>"
3. Article 16 [Non-costly remedial actions optimisation] shall be amended by adding paragraph 3d(viii) accordingly:
   "the available range of setpoint of each bidding zone internal HVDC."
4. Article 16 [Non-costly remedial actions optimisation] shall be amended by updating paragraph 7d accordingly:
   "an estimate of the market clearing point (and related market welfare) which may have occurred, should the NRAO not have taken place (but including other capacity calculation steps such as minRAM, LTA inclusion [as long as the Core TSOs apply the rules as referred to in Article 18(1)(a)] and an estimate of the validation phase.)"

Article 11
Adjustment for minimum RAM

1. Article 17 [Adjustment for minimum RAM] shall be amended by updating paragraph 3 accordingly:

Then, the CCC shall calculate $F_{0,all}$, which is the flow on each CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, between bidding zones within Continental Europe and bidding zones located in other synchronous areas, and between the island of Ireland and bidding zones located in other synchronous areas. For this calculation, the CCC shall set to zero all exchanges on DC interconnectors linking Continental Europe and the island of Ireland to each other or to other synchronous areas. The CCC shall then calculate the zonal PTDFs for all bidding zones within the synchronous areas Continental Europe and island of Ireland for each CNEC. For this calculation, the CCC shall use the GSKs provided by the concerned TSOs to the Common Grid Model platform, and when these are not available, the CCC shall use a GSK where all nodes with positive injections participate to shifting in proportion to their injection. Subsequently the CCC shall calculate $\mathrm{F}_{0,\mathrm{all}}$ with the following Equation 3.

$$\vec{F}_{0,all} = \vec{F}_{ref} - \mathbf{PTDF}_{\boldsymbol{all}} \, \overrightarrow{NP}_{ref,all}$$

Equation 3

with

$\vec{F}_{0,all}$	flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, between bidding zones within Continental Europe and bidding zones located in other synchronous areas, and between the island of Ireland and bidding zones located in other synchronous areas
$\mathbf{PTDF}_{\boldsymbol{all}}$	power transfer distribution factor matrix for all bidding zones in Continental Europe and the island of Ireland, and all Core CNECs
$\overrightarrow{NP}_{ref,all}$	total net positions per bidding zone in Continental Europe and the island of Ireland included in the CGM

Article 12
Long-term allocated capacities (LTA) inclusion

1. Article 18 [Long-term allocated capacities (LTA) inclusion] shall be replaced and read accordingly:

1. In accordance with Article 21(1)(b)(iii) of the CACM Regulation, the Core TSOs shall apply the following rules for taking into account the previously-allocated cross-zonal capacity:

   (a) the rules ensure that cross-zonal capacities can accommodate all combinations of net positions that could result from previously-allocated cross-zonal capacity.

   (b) (deleted)

   (c) previously-allocated capacities on all bidding zone borders of the Core CCR and on the AHC borders shall be the long-term allocated capacities (LTA) based on historical values of long-term allocated capacities and any change shall be commonly coordinated and agreed by all Core TSOs with the support of the CCC.

   (d) the Core TSOs shall not apply the rules as referred to in paragraph 1(a) after the implementation of the Core Long Term Capacity Calculation Methodology and long-term capacity allocation pursuant to the FCA regulation.

1a. As long as the Core TSOs apply the rules set out in paragraph 1(a), these rules shall be implemented by extended LTA inclusion, whereby the cross-zonal capacities consist of a flow-based domain without LTA inclusion and a LTA domain.

2. In case an external constraint restricts the Core net positions pursuant to Article 7(2)(a), it shall be added as an additional row to the $\mathbf{PTDF}_{\boldsymbol{f}}$ matrix and to the $\vec{F}_{max}$, $\vec{F}_{ref}$, $\overrightarrow{FRM}$, and $\overrightarrow{AMR}$ vectors as follows:

(a) the $PTDF$ value in the column related to the bidding zone applying the concerned external constraint is set to 1 for an export limit and -1 for an import limit, respectively;

(b) the $PTDF$ values in the columns related to all other bidding zones are set to zero;

(c) the F_{max} value is set to the amount of the external constraint;

(d) the F_{ref} value is set to the Core net position in the CGM of the bidding zone or EVH applying the external constraint, i.e. NP_{ref} in the equation below; and

(e) the FRM and AMR values are set to zero;

Article 13
Calculation of flow-based parameters before validation

1. Article 19 [Calculation of flow-based parameters before validation] shall be replaced and read accordingly:

Based on the initial flow-based domain and on the final list of CNECs, the CCC shall calculate for each CNEC the RAM before validation, relying on the following sequential steps:

(a) the calculation of F_{ref} and $PTDF_f$ through the NRAO according to Article 16;

(b) the calculation[4] of the adjustment for minimum RAM (AMR) according to Article 17;

(c) (deleted)

(d) the calculation of RAM before validation as follows:

$$\overrightarrow{RAM}_{bv} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{0,Core} + \overrightarrow{AMR}$$

Equation 4a

with

$\vec{F}_{max}$	Maximum active power flow pursuant to Article 6
$\overrightarrow{FRM}$	Flow reliability margin pursuant to Article 8

[4] AMR, $F_{0,Core}$ and FRM do not apply to external constraints, and shall be zero for such constraints.

$\vec{F}_{0,Core}$	Flow without commercial exchanges in the Core CCR and without commercial exchanges on AHC borders, described in Equation 10. For external constraints, in line with Article 18 (2), this flow is equal to zero.[8]
$\overrightarrow{AMR}$	Adjustment for minimum RAM pursuant to Article 17
$\overrightarrow{RAM}_{bv}$	Remaining available margin before validation

Article 14
Validation of flow-based parameters

1. Article 20 [Validation of flow-based parameters] shall be replaced and read accordingly:

1. The Core TSOs shall validate and have the right to correct cross-zonal capacity for reasons of operational security during the validation process individually and in a coordinated way.

2. Capacity validation shall consist of two steps. In the first step, the Core TSOs shall analyse in a coordinated manner whether the cross-zonal capacity could violate operational security limits, and whether they have sufficient RAs to avoid such violations. In the second step, each Core TSO shall individually analyse whether the cross-zonal capacity could violate operational security limits in its own control area.

2a. The capacity validation shall be based on the flow-based domain with RAM_{bv}. As long as the Core TSOs apply the rules as referred to in Article 18(1)(a), the capacity validation shall be based on the convex hull of the flow-based domain with RAM_{bv} and the LTA domain.

3. In the process of cross-zonal capacity validation the Core TSOs shall exchange information on all expected available (non-costly and costly) RAs in the Core CCR, defined in accordance with Article 22 of the SO Regulation. In case the cross-zonal capacity could lead to violation of operational security, all Core TSOs in coordination with the CCC shall verify whether such violation can be avoided with the application of RAs. In this process, the CCC shall coordinate with neighbouring CCCs and optionally technical counterparties on the use of RAs having an impact on neighbouring CCRs and optionally on technical counterparties. For those CNECs where all available RAs are not sufficient to avoid the violation of operational security, the Core TSOs in coordination with the CCC may reduce the $RAM_{bv,LTAmargin}$ or $RAM_{bv,noLTAmargin}$ to the maximum value which avoids the violation of operational security. This reduction is called 'coordinated validation adjustment' (CVA) and the adjusted RAM is called 'RAM before individual validation' (RAM_{biv}).

4. The coordinated validation pursuant to paragraph 3 shall be implemented gradually. During the first forty-two months following the implementation of this methodology in accordance with Article 28(3), the coordinated validation may be limited to exchange of information on the available (non-costly and costly) RAs in the Core CCR and a CCC's advice to individual TSOs based on its operational experience. After the

forty-two months, the simplified process shall be replaced by a full analysis pursuant to paragraphs 4a until 4h.

4a. The coordinated validation process step in the Core CCR as set out in paragraph 4 sentence 3 shall be performed by the CCC and the Core TSOs and optionally by the technical counterparties pursuant to Article 13(2) according to the following procedure:

Step 1. The CCC shall use the inputs pursuant to paragraph 4b;

The CCC shall, pursuant to paragraph 4c, select the circumstances, being possible market outcomes, that shall be evaluated to determine whether the power system could accommodate them having regard to operational security requirements;

The CCC shall analyse the selected circumstances subject to the criteria pursuant to paragraph 4d and applying the remedial action optimisation method pursuant to paragraph 4e;

The CCC shall, in coordination with the Core TSOs and optionally technical counterparties pursuant to Article 13(2), determine CVA pursuant to paragraph 4f;

The CCC shall compute the RAM_{biv} pursuant to paragraph 4g;

The CCC shall disseminate the results of steps 2, 3, 4 and 5 pursuant to paragraph 4h to enable Core TSOs and technical counterparties pursuant to Article 13(2) to consider them in the individual validation process step;

4b. The CCC shall base the full coordinated validation on the following inputs:

(a) the CZC domain based on the flow-based parameters before validation pursuant to Article 19, and, as long as the Core TSOs apply the rules as referred to in Article 18(1)(a), the LTA domain;

(b) the CGM;

(c) all expected available (non-costly and costly) RAs in the Core CCR and optionally in control areas of technical counterparties pursuant to Article 13(2), defined in accordance with Article 22 of the SO Regulation. These may comprise RAs from bidding zones outside the Core CCR, subject to alignment with the respective connecting TSOs. The probability of RAs being available under the modelling assumptions may be taken into consideration when providing RAs;

(d) a list of network elements and contingencies to consider when assessing operational security. Each Core TSO and optionally each technical counterparty pursuant to Article 13(2) shall provide such a list to the CCC. Any network element from the CGM with a voltage level higher than or equal to 220 kV may be considered. The standard properties of these network elements are that they shall not be overloaded after coordinated validation with respect to their operational security limits. Each Core TSO and optionally each technical counterparty pursuant to Article 13(2) may define two parameters to modify the properties of each network element. Firstly, the maximum flow of a network element may be increased. Secondly, a network element may be specified as scanned network element. Scanned network elements may not be overloaded, or not incur additional overloading, pursuant to the specifications in paragraph 4d.

Core TSOs may decide for the CCC to base the full coordinated validation on further input, as long as this is within the boundaries of Article 3 (b), (c) and (d) of the CACM Regulation. Core TSOs may alter the parameters and thresholds of the input where an input would have a significant impact on the resulting CZC, as long as this is within the boundaries of Article 3 (b), (c) and (d) of the CACM Regulation. The CCC shall report quarterly on the initial setup and any change in the input or its parameters and thresholds, together with its impact and a due justification. The CCC shall also publicly announce such change at least two working days before it takes effect.

4c. The CCC shall separately select at least one circumstance for each DA CC MTU, to be analysed in the coordinated validation as set out in paragraph 4 sentence 3. The number of circumstances shall be sufficiently large having regard to the time available for conducting the coordinated validation and the complexity of the analysis per circumstance pursuant to paragraph 4e. During the implementation of the coordinated validation as set out in paragraph 4 sentence 3, the Core TSOs and optionally the technical counterparties pursuant to Article 13(2) shall:

(a) make a justified trade-off between the complexity of the analysis and the number of circumstances;

(b) define criteria for the selection of circumstances. The Core TSOs may alter the criteria after implementation to cope with the evolution of technical or market conditions, as long as this is within the boundaries of Article 3 (b), (c) and (d) of the CACM Regulation. The CCC shall report quarterly on any change in the criteria, together with its impact and due justification

Exchanges on borders to non-Core bidding zones via AHC shall be treated equally to exchanges on Core borders when defining and selecting circumstances. Exchanges on borders with technical counterparties may optionally be taken into account in the selection of circumstances.

4d. When analysing a circumstance, the CCC shall use the CGM and apply load flow calculation and contingency analysis. The net positions of the BZs in the CGM shall be shifted towards the net positions of the circumstance. This shift shall, in principle, be done using the GSK pursuant to 0. A deviation from the GSK is allowed, insofar as the injection from generators is altered, to prevent a violation of technical generator bounds. The RA potential related to redispatch shall be adjusted to reflect the dispatch modifications between the CGM and the circumstance.

For each circumstance in each DA CC MTU, the maximum admissible flow on each scanned network element shall, if necessary, be increased such that the difference between the maximum admissible flow and the post-contingency flow in the circumstance prior to the remedial action optimisation pursuant to paragraph 4e is at least as large as a threshold, which shall be set according to the process described in paragraph 4b.

4e. The CCC shall perform an RA optimisation to determine for each circumstance in each DA CC MTU, to which extent this circumstance could be realised with respect to operational security. The circumstance can be realised entirely, if all operational security violations, which might occur after shifting the CGM to the circumstance pursuant to paragraph 4c, and having regard to the network elements, contingencies and properties as specified pursuant to paragraph 4b(d), can be completely eliminated by the application of RAs. In case the circumstance cannot be realised without violating operational security constraints, the RA optimisation shall determine the extent of this violation. The RA optimisation shall further determine an alternative circumstance that is as similar as possible to the original one but can be implemented without violating operational security constraints.

The RA optimisation shall consider the same types of RAs as used in the Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation, or other congestion management planning processes of the Core TSOs or optionally technical counterparties. To limit the complexity of the RA optimisation and in accordance with the requirements and obligations set out in paragraph 4b, Core TSOs and optionally technical counterparties may adjust the inputs of the coordinated validation to reflect the estimated effect of congestion management planning procedures while adhering to operational security constraints. Such adjustments may comprise, but are not limited to, ignoring network elements or allowing a certain amount of overload. The RA optimisation shall consider preventive and curative RAs with full or partial sharing of the benefit of curative RAs.

The RA optimisation shall be specified such that use of RAs shall precede a reduction to the extent needed to which the circumstance can be realised. The RA optimisation shall be designed in consistency with the approach for determining the limitations of the CZC pursuant to paragraph 4f.

Core TSOs may apply the following means to relax or constrain the RA optimisation:

(a) To avoid unnecessarily strict limitations, Core TSOs may specify optimisation parameters. These may comprise, but are not limited to, ignoring low sensitivities of loadings on network elements with respect to RAs and/or cross-zonal exchanges;

(b) To take into account constraints of the Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation, or other congestion management planning processes of the Core TSOs or optionally technical counterparties, Core TSOs and optionally technical counterparties may specify limits on the number of RAs and/or on the total redispatch amount that can be simultaneously applied. These limits may be specified on subsets of RAs.

(c) Core TSOs may define the objective function to minimise the extent of operational security violations and/or to maximise the extent to which the cross-zonal exchanges match the circumstance.

4f. If one or more circumstances for a DA CC MTU cannot be realised to their full extent, the CCC shall limit cross-zonal capacity such that the maximum line loading on network elements that would lead to operational security violations in any circumstance is reduced to comply with operational security limits. CNECs with applied CVA shall be sufficiently effective for reducing the loading of the network elements on which operational security limits would be violated in the circumstance without CVA.

If several circumstances lead to CVA in a given DA CC MTU, the final CVA per CNEC shall be the maximum across all circumstances.

The Core TSOs shall consider a minimum capacity floor in terms of the percentage of RAM_{biv} in relation to the maximum admissible active power per CNEC (F_{max}) pursuant to Article 6(2)(d). The CVA shall be capped to respect this floor, such that any remaining operational security violations are left to the individual validation.

Subject to a previous alignment with the other Core TSOs, the CCC and optionally technical counterparties in which an attempt was made to resolve the reasons for the rejection, a Core TSO may reject with justification all of the CVA resulting from one or several circumstances in one or several DA CC MTUs. In case of such rejection the final CVA shall be recomputed as if no CVA had resulted from the rejected circumstances.

4g. The CCC shall calculate for each CNEC the RAM before individual validation as follows;

$$\overrightarrow{RAM}_{biv} = \overrightarrow{RAM}_{bv} - \overrightarrow{CVA}$$

Equation 19c

4h. The CCC shall share with each Core TSO and technical counterparty pursuant to Article 13(2) all information that is necessary to support consistency of the subsequent individual validation with the coordinated validation. This information shall at least comprise the analysed circumstances, applied RAs and, if applicable, remaining operational security violations after coordinated validation.

5. After coordinated validation, each Core TSO shall validate and have the right to decrease the RAM for reasons of operational security during the individual validation. The adjustment due to individual validation is called ‘individual validation adjustment’ (IVA) and it shall have a positive value, i.e. it may only reduce the RAM. IVA may reduce the RAM only to the minimum degree that is needed to ensure operational security considering all expected available costly and non-costly RAs, in accordance with Article 22 of the SO Regulation. The individual validation adjustment may be done in the following situations:

   (a) an occurrence of an exceptional contingency or forced outage as defined in Article 3(39) and Article 3(77) of the SO Regulation;

   (b) when all available costly and non-costly RAs are not sufficient to ensure operational security, taking the CCC’s analysis pursuant to paragraph 4 into account, and coordinating with the CCC when necessary;

   (c) a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective; and/or

   (d) a potential need to cover reactive power flows on certain CNECs.

6. If all available costly and non-costly RAs are not sufficient to ensure operational security on an internal network element, voltage level 110 kV or above, with a specific contingency, which is not defined as CNEC and for which the maximum zone-to-zone PTDF is above the PTDF threshold referred to in Article 15(1), the competent Core TSO may exceptionally add such internal network element with associated contingency to the final list of CNECs. The RAM on this exceptional CNEC shall be the highest RAM ensuring operational security considering all available costly and non-costly RAs. PTDF_{init} according to Article 14(3) shall be used to determine if the PTDF of the additional CNEC is above the PTDF threshold. When considering the additional CNEC during the computation of the final flow-based parameters, the $PTDF_f$ value from the NRAO according to Article 16 shall be considered.

6a. A technical counterparty may, subject to Article 13(2), add a network element with a specific contingency for which the maximum zone-to-zone PTDF is above the PTDF threshold referred to in Article 15(1) in conjunction with Article 11(7a) to the final list of CNECs.

7. When performing the validation, the Core TSOs shall consider the operational security limits pursuant to Article 6 (1). While considering such limits, they may consider additional grid models, and other relevant information. Therefore, the Core TSOs shall use the tools developed by the CCC for analysis, but may also employ verification tools not available to the CCC.

8. In case of a required reduction due to situations as defined in paragraph 1(a), a TSO may use a positive value for IVA for its own CNECs or adapt the external constraints, to reduce the cross-zonal capacity for its bidding zone.

9. In case of a required reduction due to situations as defined in paragraph 1(b), (c), and (d), a TSO may use a positive value for IVA for its own CNECs. In case of a situation as defined in paragraph 1(c), a Core TSO may, as a last resort measure, request a common decision to launch the default flow-based parameters pursuant to Article 22.

10. After coordinated and individual validation adjustments, the RAM_{bn} before adjustment for long-term nominations shall be calculated by the CCC for each CNEC and external constraint according to Equation 5a:

$$\overrightarrow{RAM}_{bn} = \overrightarrow{RAM}_{bv} - \overrightarrow{CVA} - \overrightarrow{IVA}$$

Equation 5a

with

$\overrightarrow{RAM}_{bn}$	remaining available margin before adjustment for long-term nominations
$\overrightarrow{RAM}_{bv}$	remaining available margin before validation pursuant to Article 19 (d)
$\overrightarrow{CVA}$	coordinated validation adjustment

$\overrightarrow{IVA}$ individual validation adjustment

11. Any reduction of cross-zonal capacities during the validation process, separately for coordinated and individual validation, shall be communicated and justified to market participants and to all Core regulatory authorities in accordance with Article 25 and Article 27, respectively.

12. (deleted)

13. Every three months, the CCC shall provide in the quarterly report all the information on the reductions of cross-zonal capacity, separately for coordinated and individual validations. The quarterly report shall include at least the following information for each CNEC of the pre-solved domain affected by a reduction and for each DA CC MTU:

    (a) the identification of the CNEC;

    (b) all the corresponding flow components pursuant to Article 25 (2)(d)(vii);

    (c) the volume of reduction, the shadow price of the CNEC resulting from the SDAC and the estimated market loss of economic surplus due to the reduction;

    (d) the detailed reason(s) for reduction, including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;

    (e) if an internal network elements with a specific contingency was exceptionally added to the final list of CNECs during validation: a justification why adding the network elements with a specific contingency to the list was the only way to ensure operational security, the name or the identifier of the internal network elements with a specific contingency, the DA CC MTUs for which the internal network elements with a specific contingency was added to the list and the information referred to in points (b) and (c) above;

    (f) the remedial actions included in the CGM before the day-ahead capacity calculation;

    (g) in case of reduction due to individual validation, the TSO invoking the reduction;

    (h) the proposed measures to avoid similar reductions in the future.

14. The quarterly report shall also include at least the following aggregated information:

    (a) statistics on the number, causes, volume and estimated loss of economic surplus of applied reductions by different TSOs;

    (b) general measures to avoid cross-zonal capacity reductions in the future;

    (c) changes to inputs, parameters or thresholds of the coordinated validation referred to in paragraph (4b).

15. When capacity is reduced for operational security limits of a given Core TSO in more than 1% of DA CC MTUs of the analysed quarter, the concerned TSO shall provide to the CCC a detailed report and action plan describing how such deviations are expected to be alleviated and solved in the future. This report and action plan shall be included as an annex to the quarterly report.

Article 15
Calculation and publication of final flow-based parameters

1. Article 21 [Calculation and publication of final flow-based parameters] shall be amended by updating paragraph 1 accordingly:

"No later than 8:00 market time day-ahead, the CCC shall publish for each DA CC MTU of the following day the flow-based parameters before long-term nominations. These parameters are the $PTDF_f$ and RAM_{bn} of pre-solved CNECs and external constraints. The CCC shall remove those RAM_{bn} and $PTDF_f$ values which are redundant and therefore may be removed without impacting the possible allocation of cross-zonal capacity. The pre-solved CNECs and external constraints shall thus ensure that the capacity allocation do not exceed any limiting CNEC or external constraint. In addition the CCC shall publish the LTA domain as long as the Core TSOs apply the rules as referred to in Article 18 (1)(a)."

2. Article 21 [Calculation and publication of final flow-based parameters] shall be amended by updating paragraph 3 accordingly:

The CCC shall calculate the final RAM_f for each CNEC and external constraint as follows:

$$\overrightarrow{RAM_f} = \max\left(\overrightarrow{RAM_{bn}} - \vec{F}_{LTN}, 0.2 \cdot \overrightarrow{F_{max}}\right)$$

Equation 6

with

$\overrightarrow{RAM_{bn}}$	remaining available margin before LTN adjustment
$\vec{F}_{LTN}$	flow after consideration of LTN
$\overrightarrow{F_{max}}$	maximum admissible power flow
$\overrightarrow{RAM_f}$	final remaining available margin

3. Article 21 [Calculation and publication of final flow-based parameters] shall be amended by updating paragraph 3a accordingly:
   "After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations), it shall also adjust the LTA domain for long-term nominations as long as the Core TSOs apply the rules as referred to in Article 18(1)(a)."
4. Article 21 [Calculation and publication of final flow-based parameters] shall be amended by adding paragraph 3b accordingly:

"Core TSOs may deviate from the calculation of the final RAM_f pursuant to paragraph 3 on their own CNECs in case operational security cannot be maintained otherwise.

In such a case, the CCC shall compute RAM_f for the CNECs of the concerned Core TSOs as follows:

$$\overrightarrow{RAM_f} = \max\left(\overrightarrow{RAM_{bn}} - \vec{F}_{LTN}, 0\right)$$

Equation 7

with

$\overrightarrow{RAM_{bn}}$	remaining available margin before LTN adjustment
$\vec{F}_{LTN}$	flow after consideration of LTN
$\overrightarrow{RAM_f}$	final remaining available margin

The concerned Core TSOs shall immediately inform market participants via a market message about such deviation. The concerned Core TSOs shall provide to the CCC a report with a justification why the calculation of RAM_f pursuant to paragraph 3 would have led to the inability to maintain operational security and an action plan describing how such situations will be avoided in the future. This report and action plan shall be added as an annex to the quarterly report as defined in Article 27(5).

5. Article 21 [Calculation and publication of final flow-based parameters] shall be amended by updating paragraph 4 accordingly:

   "The final flow-based parameters shall consist of $\mathbf{PTDF}_f$ and RAM_f for pre-solved CNECs and external constraints. In accordance with Article 46 of the CACM Regulation, the CCC shall ensure that, for each DA CC MTU, the final flow-based parameters and, as long as the Core TSOs apply the rules as referred to in Article 18(1)(a), the LTA domain adjusted for long-term nominations be provided to the relevant NEMOs as soon as they are available and no later than 10:30 market time day-ahead. The CCC shall also publish these flow-based parameters for each DA CC MTU of the following day no later than 10:30 market time day-ahead."

Article 16
Day-ahead capacity calculation fallback procedure

1. Article 22 [Day-ahead capacity calculation fallback procedure] shall be replaced and read accordingly:

1. According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA CC MTUs does not lead to the final flow-based parameters due to, inter alia, a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data, the Core TSOs and the CCC shall calculate the remaining missing results by using one of the two capacity calculation fallback procedures pursuant to paragraph 2 or paragraphs 3 to 7 respectively.

2. When the day-ahead capacity calculation fails to provide the flow-based parameters for strictly less than three consecutive hours, the CCC shall calculate the missing flow-based parameters with the spanning method. The spanning method is based on the union of the previous and subsequent available flow-based parameters (resulting in the intersection of the two flow-based domains), adjusted to zero Core net positions (to delete the impact of the reference net positions of the Core bidding zones and VHs).

All flow-based constraints from the previous and subsequent data sets are first converted into zero Core net positions. Then all previous and subsequent constraints are combined, the redundant constraints are removed, and the pre-solved constraints are adjusted for the long term nominations in accordance with Article 21. In case the extended LTA inclusion approach is applied, the LTA domain for missing hours contains for each Core border and each AHC border the minimum of the long-term allocated capacities values of the hours for which the previous and subsequent flow-based parameters are available.

3. When the day-ahead capacity calculation fails to provide the flow-based parameters for three or more consecutive hours, the Core TSOs shall define the missing parameters by calculating the default flow-based parameters. Such calculation shall also be applied in cases of impossibility to span the missing parameters pursuant to point (a) or in the situation as described in Article 20 (9).

4. The intermediate default flow-based parameters shall be determined in advance and updated at least on a monthly basis.

5. The CCC shall compute intermediate default flow-based parameters based on all historical flow-based parameters from the 12 previous months, excluding DA CC MTUs for which capacity calculation fallback procedures pursuant to this article have been applied. If there have been structural changes of the Core bidding zones, IVHs or EVHs within the time period of the historical flow-based parameters or there will be such change between this time period and the period for which the initial default flow-based parameters will be applied, the CCC may, in coordination with all Core TSOs, use an alternative basis for the computation of the initial default flow-based parameters, including but not limited to using data from a parallel run and shortening the time period of the historical data.

   (a) The CCC shall determine a list M of CNEs which are part of pre-solved CNECs in more than a predefined percentage of the historical flow-based domains pursuant to paragraph 5.

   (b) For each CNE m on the list pursuant to the previous paragraph, the CCC shall determine one “representative CNEC” described by $\overrightarrow{PTDF}_{m,rep,initial}$ and $RAM_{m,rep,initial}$, and an associated $F_{m,max}$.

      i. The CCC shall determine a list L of all pre-solved CNECs from the historical flow-based domains pursuant to paragraph 45 which are associated with the CNE m.

      ii. Each CNEC l of the list pursuant to the previous paragraph shall be adjusted for historical long-term nominations and normalised by computing $\overrightarrow{PTDF}_{l,norm}$ and $RAM_{l,norm}$, and an associated $F_{max,l,norm}$.

$$\overrightarrow{PTDF}_{l,norm} = \frac{\overrightarrow{PTDF_l}}{\left\|\overrightarrow{PTDF_l}\right\|_2}$$

$$RAM_{l,norm} = \frac{RAM_l + F_{LTN,l}}{\left\|\overrightarrow{PTDF_l}\right\|_2}$$

$$F_{max,l,norm} = \frac{F_{max,l}}{\left\|\overrightarrow{PTDF_l}\right\|_2}$$

Equation 23a

with

$\overrightarrow{PTDF_l}$	$PTDF$ of CNEC l from historical flow-based parameters
RAM_l	Final RAM of CNEC l from historical flow-based parameters
$F_{LTN,l}$	Flow after consideration of LTN in historical flow-based parameters, pursuant to Art. 21(2)
$F_{max,l}$	F_{max} of CNEC l from historical flow-based parameters

iii. The PTDFs of the representative CNEC, $\overrightarrow{PTDF}_{m,rep,initial}$, shall be computed as the normalised mean of the normalised PTDFs of all CNECs in L.

$$\overrightarrow{PTDF}_{m,mean} = \frac{1}{|L|}\sum_{l=1}^{|L|}\overrightarrow{PTDF}_{l,norm}$$
$$\overrightarrow{PTDF}_{m,rep,initial} = \frac{\overrightarrow{PTDF_{mean}}}{\left\|\overrightarrow{PTDF_{mean}}\right\|_2}$$

Equation 23b

with

$\overrightarrow{PTDF}_{m,mean}$	mean normalised PTDFs across all CNECs in L

iv. The RAM of the representative CNEC, $RAM_{m,rep,initial}$, shall be computed as the PR_{DFP}-percentile of the normalised RAMs.

$$RAM_{m,rep,initial} = Q_{PR_{DFP}\%}\left(\{RAM_{l,norm}: l \in L\}\right)$$

Equation 23c

with

PR_{DFP}	RAM percentile rank for default flow-based parameters

v. The F_{max} of the representative CNEC, $F_{m.max}$, shall be computed as the PR_{DFP}-percent quantile of the normalised F_{max} values.

$$F_{max,m,rep} = Q_{PR_{DFP}\%}\left(\{F_{max,l,norm}: l \in L\}\right)$$

Equation 23d

(c) The CCC shall form the initial default flow-based parameters by forming the union of all representative CNECs and removing redundant CNECs, thus keeping the pre-solved representative CNECs.

(d) Each Core TSO has the right to validate and, if needed to consider the effect of planned outages of network elements, reduce the RAM of the representative CNECs from the initial default flow-based parameters, where the CNEs are fully or partly located in its own control area. Such reduction shall be provided in the form of an Individual Validation Adjustment $IVA_{m,rep}$ per representative CNEC m. Any such reduction shall be communicated and justified to market participants and to all Core regulatory authorities in accordance with Article 25 and Article 27, respectively.

(e) The intermediate default flow-based parameters shall consist of the representative CNECs of the initial default flow-based parameters with unmodified $PTDF$ and modified RAM, taking into account a minimum level of 20% of the respective F_{max}.

$$\overrightarrow{PTDF}_{m,rep} = \overrightarrow{PTDF}_{m,rep,initial}$$
$$RAM_{m,rep} = RAM_{m,rep,initial} - IVA_{m,rep}$$

Equation 23a

(f) The CCC shall publish the intermediate flow-based parameters.

6. Core TSOs may alter the percentage referred to in paragraphs 5(a) and the percentile rank PR_{DFP} as long as this is within the boundaries of Article 3 (b), (c) and (d) CACM, having regard to the exceptional nature of the application of default flow-based parameters. The CCC shall report quarterly on the initial setup and any change in these percentages, together with its impact and a due justification. The CCC shall also publicly announce such change at least two working days before it takes effect.

7. For each DA CC MTU for which the default flow-based parameters are applied pursuant to paragraph (3), the intermediate default flow-based parameters shall be adjusted for long-term nominations pursuant to Article 21, to obtain the final parameters. This shall be done by using the parameters $\mathbf{PTDF}_{\boldsymbol{rep}}$, $\overrightarrow{RAM}_{rep}$ and $\vec{F}_{max,rep}$ as replacements for $\mathbf{PTDF}_{\boldsymbol{f}}$, $\overrightarrow{RAM}_{bn}$ and $\vec{F}_{max}$, respectively.

8. As long as the Core TSOs apply the rules as referred to in Article 18 (1)(a), the calculation of default flow-based parameters may be based on long-term allocated capacities as provided by TSOs pursuant to Article 4(4)(a). In this case the capacities on the bilateral Core bidding zone borders and on AHC borders shall be defined based on the LTA capacity for each oriented bidding zone border:

(a) increased by the minimum of the two adjustments provided by the TSO(s) on each side of the Core bidding zone border, pursuant to Article 4(4)(b); and

(b) adapted by the adjustment provided by the Core TSO on its adjacent AHC border, pursuant to Article 4(4)(b).

These capacities are then adjusted for long-term nominations, to obtain the final parameters.

Article 17
Calculation of ATCs for SDAC fallback procedure

1. Article 23 [Calculation of ATCs for SDAC fallback procedure] shall be replaced and read accordingly:

1. In the event that the SDAC process is unable to produce results, a fallback procedure established in accordance with Article 44 of the CACM Regulation shall be applied. This process requires the determination of available transmission capacities (ATCs) (hereafter referred as "ATCs for SDAC fallback procedure") for each Core oriented bidding zone border and each DA CC MTU.

2. The flow-based parameters shall serve as the basis for the determination of the ATCs for SDAC fallback procedure. As the selection of a set of ATCs from the flow-based parameters leads to an infinite set of choices, an algorithm determines the ATCs for SDAC fallback procedure in a systematic way.

3. The following inputs are required to calculate ATCs for SDAC fallback procedure for each DA CC MTU:

   (a) the LTA values may be used as long as the Core TSOs apply the rules as referred to in Article 18 (1)(a);

   (b) the flow-based parameters $\mathbf{PTDF_f}$ and $\overrightarrow{RAM}_{bn}$ in accordance with Article 16 and 20 respectively, replaced for DA CC MTUs for which default flow-based parameters are applied pursuant to Article 22(3) by the intermediate default flow-based parameters pursuant to Article 22(4); and

   (c) if defined, the global allocation constraints shall be assumed to constrain the Core net positions pursuant to Article 7(6) and shall be described following the methodology described in Article 18(2). Such constraints shall be adjusted for offered cross-zonal capacities on the remaining non-Core bidding zone borders, and their values should be equal to the smallest allocation constraint value among the MTUs corresponding to the considered DA CC MTU.

4. The following outputs are the outcomes of the calculation for each DA CC MTU:

   (a) ATCs for SDAC fallback procedure; and

   (b) constraints with zero margin after the calculation of ATCs for SDAC fallback procedure.

5. The calculation of the ATCs for SDAC fallback procedure is an iterative procedure, which gradually calculates ATCs for each DA CC MTU, while respecting the constraints of the final flow-based parameters pursuant to paragraph 3:

   (a) The initial ATCs are set to zero, i.e.

$$\overrightarrow{ATC}_{k=0} = \vec{0}$$

with

$\overrightarrow{ATC}_{k=0}$	the initial ATCs before the first iteration

(b) The iterative method applied to calculate the ATCs for SDAC fallback procedure consists of the following actions for each iteration step *k*:

i. for each CNEC and external constraint of the flow-based parameters pursuant to paragraph 3, calculate the remaining available margin based on ATCs at iteration *k*-1:

$$\overrightarrow{RAM}_{ATC}(k) = \overrightarrow{RAM}_{bn} - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}\,\overrightarrow{ATC}_{k-1}$$

with

$\overrightarrow{RAM}_{ATC}(k)$	remaining available margin for ATC calculation at iteration *k*
$\overrightarrow{ATC}_{k-1}$	ATCs at iteration *k*-1
$\mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}$	positive zone-to-zone power transfer distribution factor matrix

ii. for each CNEC, share $RAM_{ATC}(k)$ with equal shares among the Core and AHC oriented bidding zone borders with strictly positive zone-to-zone power transfer distribution factors on this CNEC;

iii. from those shares of $RAM_{ATC}(k)$, the maximum additional bilateral oriented exchanges are calculated by dividing the share of each Core and AHC oriented bidding zone border by the respective positive zone-to-zone PTDF;

iv. for each Core and AHC oriented bidding zone border, $\overrightarrow{ATC}_k$ is calculated by adding to $\overrightarrow{ATC}_{k-1}$ the minimum of all maximum additional bilateral oriented exchanges for this border obtained over all CNECs and external constraints as calculated in the previous step;

v. go back to step i;

vi. iterate until the difference between the sum of ATCs of iterations *k* and *k*-1 is smaller than 1kW;

vii. the resulting ATCs for SDAC fallback procedure stem from the ATC values determined in iteration *k*, after rounding down to integer values and from which LTN are subtracted;

viii. at the end of the calculation, there are some CNECs and external constraints with no remaining available margin left. These are the limiting constraints for the calculation of ATCs for SDAC fallback procedure.

(c) positive zone-to-zone PTDF matrix ($\mathbf{pPTDF}_{zone-to-zone}$) for each Core and AHC oriented bidding zone border shall be calculated from the $\mathbf{PTDF}_f$ as follows (for HVDC interconnectors integrated pursuant to Article 12, Equation 8 shall be used):

$$pPTDF_{zone-to-zone,A\to B} = \max\left(0, PTDF_{zone-to-slack,A} - PTDF_{zone-to-slack,B}\right)$$

Equation 8

with

$pPTDF_{zone-to-zone,A\to B}$	positive zone-to-zone $PTDFs$ for Core and AHC oriented bidding zone border A to B
$PTDF_{zone-to-slack,m}$	zone-to-slack $PTDF$ for Core and AHC bidding zone border m

5a. As long as the Core TSOs apply the rules as referred to in Article 18 (1)(a), the ATCs for SDAC fallback procedure are set equal to the LTAs for each Core and AHC oriented bidding zone border, reduced by LTN, i.e.:

$$\overrightarrow{ATC} = \overrightarrow{LTA} - \overrightarrow{LTN}$$

with

$\overrightarrow{ATC}$	the ATC for SDAC fallback procedure
$\overrightarrow{LTA}$	the LTA on Core and AHC oriented bidding zone borders
$\overrightarrow{LTN}$	the nomination of the long-term allocated capacity on Core and AHC oriented bidding zone borders

6. If the calculation pursuant to paragraph 5 cannot be performed during the regular day-ahead capacity calculation process, Core TSOs may re-use ATCs for SDAC fallback procedure from a previous run of the process. In this case, the global allocation constraints from the current process, processed pursuant to paragraph 3(c)shall be used to proportionally cap the ATCs of the relevant bidding zones prior to subtracting the LTN.

Article 18
Reviews and updates

1. Article 24 [Reviews and updates] shall be amended by updating paragraph 4 accordingly:
“The review of the common list of RAs taken into account in the day-ahead capacity calculation shall include at least an evaluation of the efficiency of specific PSTs, bidding zone internal HVDC setpoints and the topological RAs considered during the RAO.”

Article 19
Publication of data

1. Article 25 [Publication of data] shall be amended by updating paragraph 2d(vii) accordingly:
   "detailed breakdown of RAM for each CNEC of the final flow-based parameters before pre-solving: I_{max}, U, F_{max}, FRM, $F_{ref,init}$, F_{nrao}, F_{ref}, $F_{0,\text{core}}$, $F_{0,\text{all}}$, F_{uaf}, AMR, CVA, IVA, F_{LTN};"
2. Article 25 [Publication of data] shall be amended by updating paragraph 2d(xiii) accordingly:
   the forecast information contained in the CGM:

   - vertical load for each Core bidding zone and each TSO;
   - production for each Core bidding zone and each TSO;
   - Core net position for each Core bidding zone and each TSO;
   - reference net positions of all bidding zones in synchronous areas Continental Europe and island of Ireland and reference exchanges for all HVDC interconnectors within synchronous area Continental Europe, between synchronous area Continental Europe and other synchronous areas and between synchronous area island of Ireland and other synchronous areas; and

3. Article 25 [Publication of data] shall be amended by adding (h) to paragraph 2 accordingly:
   "the intermediate default flow-based parameters."

Article 20
Monitoring, reporting and information to the Core regulatory authorities

1. Article 27 [Monitoring, reporting and information to the Core regulatory authorities] paragraph 4 accordingly shall be replaced and read accordingly:

"The CCC, with the support of the Core TSOs where relevant, shall draft and publish an annual report satisfying the reporting obligations set in Articles 9, 10, 13, 16, 26 and 28 of this methodology:

(a) according to Article 10 (6), the Core TSOs shall report to the CCC on systematic withholdings which were not essential to ensure operational security in real-time operation.

(b) according to Article 13 (5), the Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM which are not handled through AHC. The Core TSOs shall report in the annual report to all Core regulatory authorities the accuracy of such forecasts.

(c) according to Article 16(7), the CCC shall monitor the efficiency of the NRAO.

(d) according to Article 26(3), the CCC shall monitor and report on the quality of the data published on the dedicated online communication platform as referred to in Article 25, with supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned TSOs, where relevant.

(e) according to Article 28(4), after the implementation of this methodology, the Core TSOs shall report on their continuous monitoring of the effects and performance of the application of this methodology.

(f) according to Article 9(5)(a), the Core TSOs shall report to the CCC on GSK quality.

(g) according to Article 22(4)(e) Core TSO shall report on the reductions of default flow-based parameters with due justifications."

2. Article 27 [Monitoring, reporting and information to the Core regulatory authorities] shall be amended by updating paragraph 5b accordingly:
"according to Article 20(13),(14) and (15), the CCC shall provide all information on the reductions of cross-zonal capacity, with a supporting detailed analysis from the concerned TSOs where relevant."
3. Article 27 [Monitoring, reporting and information to the Core regulatory authorities] shall be amended by updating paragraph 5c accordingly:
"according to Article 28(4), during the implementation of this methodology, the Core TSOs shall report on their continuous monitoring of the effects and performance of the application of this methodology"

Article 21
Timescale for implementation

1. Article 28 [Timescale for implementation] shall be amended by adding paragraph 8 accordingly:
"The SEM - France bidding zone border shall be integrated into the Core CCR and the respective implementation of the present capacity calculation methodology once commissioning is finalized, and the technical conditions allow commercial operations to begin. The integration of the HVDC cable connecting the two bidding zones shall be conducted in compliance with the provisions of Article 12."
2. Article 28 [Timescale for implementation] shall be amended by adding paragraph 9 accordingly:
"Core TSOs shall cease applying the rules for taking into account LTAs pursuant to Article 18(1)(a) no later than upon implementation of the Long-Term Capacity Calculation and long-term capacity allocation pursuant to the FCA regulation. Core TSOs shall announce the date of discontinuation at least one (1) month prior to its entry into force."

Article 22
List of Core TSOs and their justification of usage and methodology for calculation of allocation constraints

1. Annex 1 [List of Core TSOs and their justification of usage and methodology for calculation of allocation constraints] shall be replaced and read accordingly:

Allocation constraints may be used by the following Core TSOs:

1: Poland - PSE

2: SEM – EirGrid and SONI

The following section depicts in detail the justification of usage and methodology currently used by each Core TSO to design and implement allocation constraints, if applicable. The legal interpretation on eligibility of using allocation constraints and the description of their contribution to the objectives of the CACM Regulation is included in the Explanatory Note.

1. Poland:

PSE may use an external constraint to limit the import and export of the Polish bidding zone.

Technical and legal justification

Capacity allocation constraints are a legally prescribed means, defined by Capacity Allocation and Congestion Management Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).

These constraints limit the global net position of Polish zone and 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 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 is related to the fact that under the conditions of the integrated scheduling-based market model applied in Poland (also called central dispatching model) the responsibility of the Polish TSO on system balance is significantly extended comparing to such responsibility of TSOs in so-called self-dispatch market models. Central dispatching is one of the two dispatching models authorized by EU Commission Regulation 2017/2195. In self-dispatch markets, balance responsible parties (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 dispatching model, it is the TSO who dispatches generating units taking into account their: operational constraints, transmission constraints and reserve capacity requirements, with the aim to balance national generation, demand and cross-border exchanges while ensuring secure operation of the transmission system. When TSO is preparing generation dispatch plans for the operational day, energy and reserves in the central dispatching model are ensured simultaneously (inherent feature of central dispatching systems with accordance to EU Commission Regulation 2017/2195). Results of the wholesale market together with the results of the balancing capacity reserves market serve as a basis for the generation dispatch performed under integrated scheduling process.

In central dispatching systems, the above process is realised within an Integrated Scheduling Process (ISP) run as a single optimisation problem called security constrained unit commitment (SCUC – where generation units are being dispatch on and off) and economic dispatch (SCED – where generation output for all dispatched generation units is determined). Integrated Scheduling Process starts in the late afternoon of D-1, already well after the day-ahead capacity calculation and SDAC, and continues iteratively by recalculating the future dispatch plans for each particular hour of day D until its real-time execution (new recalculation at least every hour). Within aforementioned integrated scheduling process, generation units connected to the transmission grid are dispatched by PSE with the aim to respect power purchase agreements concluded between market participants on the wholesale market, while minimizing overall costs of dispatch adjustments and balancing energy activation to cover the residual demand (being the part of end users demand not covered by commercial contracts). When doing so, PSE is obliged to respect power system operating conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Unit capabilities, considering their inter-temporal limitations (ramping rates), are also considered in this process.

According to the national legislation, PSE is legally obliged ensure availability of sufficient level of generating reserves for the whole Polish power system in order to safeguard its secure operation in case of contingency, as well as in case of insufficient and ineffective balancing activities performed by market participants in Poland. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market in form of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process as required by national legislation. This conclusion equally applies for the case when market participants import significant amount of energy, as it could result in balancing service providers being unable to provide downward regulation capabilities due to not securing enough generation levels in the day-ahead market. The strength of the imbalance settlement pricing is also important in this process, together with the maturity and the ability market participants to maintain balanced portfolios under objectively high RES and demand uncertainties and underdeveloped intra-day markets.

This leads to implementation of allocation constraints, being the necessary means to ensure operational security of Polish power system in terms of securing generating capacities for upward or downward regulation, as well as in order to cover the national imbalances in the direction of shortage (i.e. cover the residual demand) and surplus (i.e. manage and regulate down the surplus of power during periods of oversupply). Excluding such a solution and depriving TSOs under central dispatching systems from the usage of allocation constraints to set appropriate limits to how much electricity can be imported or exported by the system as a whole may lead to insufficient balancing capacity reserves, making the provisions of Electricity Balancing Guideline void, and making it impossible or at least much more difficult to comply with System Operation Guideline.

The impact of allocation constraints is analysed and described in Quarterly and Annual Core Reports. The reports shows that the largest social welfare impact concerns Poland (order of magnitude higher than for other Core countries), resulting in a loss of social welfare in Poland due to application of allocation constraints. However, as demonstrated in the reports time after time, this apparent loss of social welfare in Poland avoids much higher welfare losses when secure operation of the Polish power system is threatened and extraordinary measures must be applied to mitigate this threat (e.g. demand curtailment or RES curtailment).

It needs to be highlighted that despite implementation of explicit balancing capacity procurement in Poland as per 14 June 2024, and despite maintaining the use of Allocation Constraints, PSE still has to apply remedial measures at large scale in order to ensure equilibrium between demand and supply in the Polish power system. These measures are mostly the non-market-based curtailment of RES (in case of energy surplus) and emergency exchanges with neighbouring TSOs (in case of energy surplus or shortage). Both aforementioned measures have severe negative consequences, such as difficulties for TSO and DSO dispatching teams to manage hundreds of operational commands issued to dispersed RES facilities in very short time, difficulties of RES facility owners to respond to dispatching commands issued with short notice, as well as depletion of operational reserves of neighbouring TSOs when asked for emergency exchanges, reducing overall European power system resilience. In many instances of time, neighbouring TSOs are unable to provide the requested support.

Balancing market reform executed on 14 June 2024 has significantly improved market price signals, so that balancing responsible parties are better reacting to dynamically changing power system situation. Nonetheless, the observed levels of balancing energy that needs to be activated by PSE under ISP is still very high, often exceeding the procured balancing capacity. This implies that the new improved balancing market prices are still unable to convey sufficient incentives for market participants to improve generation and demand planning as BRPs still do not balance their portfolios earlier on more attractive day-ahead and intraday markets. Moreover, new balancing capacity reserves procurement process is still immature and suffers from lack of liquidity, low supply and low competition. Both aforementioned items are a subject of intensive analysis on PSE side with the aim to prepare improvements and increase effectiveness of price signals.

Due to the fact that no alternatives to using allocation constraints have been identified as plausible to be implemented until two years following implementation of flow-based in Central Europe, which could both have lower overall cost while maintaining the similar level of operational security and which would not require a major overhaul of the whole market design, PSE aims at using allocation constraints AC in the Central Europe region.

The reason why allocation constraints can’t be expressed by maximum admissible power flow

This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal 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 flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. 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 – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e. transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, while the trading of other bidding zones is unaffected.Determination of allocation constraints in Poland

Allocation constrains are applied in day-ahead allocation process, with values determined day before energy delivery, per each Market Time Unit (MTU) individually based on expected generation adequacy analysis for this MTU as well as power system operation conditions and technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Allocation constrains are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border.

When determining the allocation constraints, PSE takes into account the most recent information on the 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 frames.

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

For each MTU, the constraints are calculated according to the below equations:

$$EXPORT_{constraint} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \quad (1)$$

$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \quad (2)$$

Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[5]
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)

[5] 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.

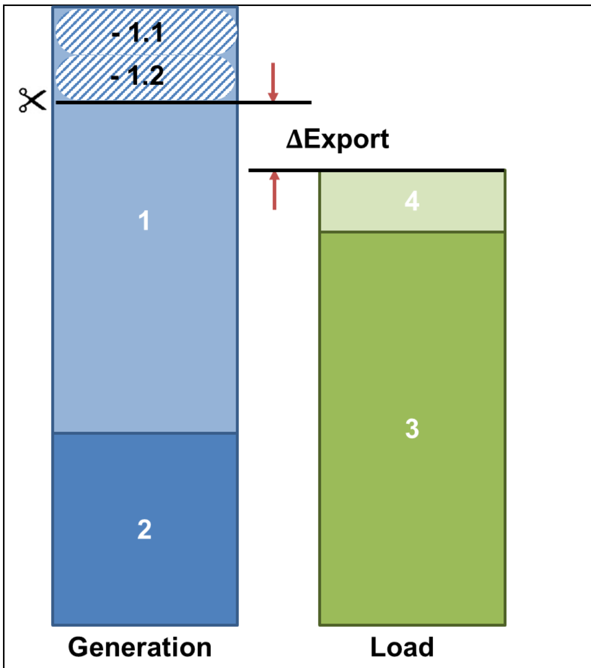
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

Equation (1) stems from requirement for system operators to maintain upward reserves to cover part of forecasted load with accordance to Polish grid codes. These reserves are a critical aspect of ensuring system reliability and stability, particularly in balancing supply and demand during unexpected events such as generation outages or sudden demand spikes. During periods of high energy demand combined with limited additional capacity from renewable sources, it becomes challenging to maintain adequate upward reserves. In such scenarios, the only viable solution to address the balancing challenge is to set the export capacity to zero.

Equation (2) refers to the need of securing the capacity that can be quickly reduced to balance supply and demand when there is an excess of power in the grid e.g. in case of loss of significant load.

For illustrative purposes, the process of practical determination of allocation constraints in the framework of the day-ahead capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each MTU of the delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.

Allocation constraint in export direction zone Polish interconnections in export direction. Allocation constraint in import direction limits import to Polish zone.



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 weather-dependent intermittent renewable generation: forecasted by PSE) 3. Demand forecasted by PSE 4. Minimum necessary reserve for up regulation

Figure 1: Determination of allocation constraints in export direction (generating capacities available for potential exports) in the framework of the day-ahead capacity calculation.

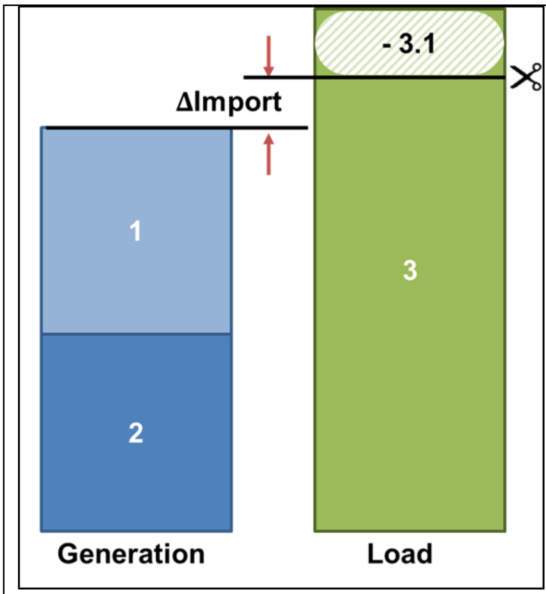
	1 Sum of technical minima of centrally dispatched generating units in operation 2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE) 3 Demand forecasted by PSE, reduced by: 3.1 Minimum necessary reserve for down regulation

Figure 2: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of the day-ahead 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 frame, from forward till day-ahead and intra-day. 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.

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 of the respective allocation day.

SEM:

Technical and legal justification

EirGrid and SONI intend to implement both external constraints on the net position of the SEM bidding zone and ramping constraints on the Celtic interconnector (HVDC) in compliance with Article 7 of Core Day-Ahead Capacity Calculation Methodology (CCM).

i) Reasons EirGrid and SONI propose using external constraints

The primary objective of external constraints is to maintain operational security standards while enabling efficient market functioning. The necessity of these constraints for the SEM bidding zone is driven by several factors. As the island of Ireland operates a relatively small power system and electricity market which constitutes a separate synchronous area, dispatching decisions by EirGrid and SONI (SEM TSOs) need to carefully consider system security and real-time balance of supply and demand.

The SEM TSOs are responsible for generation commitment and determining optimal dispatch schedules. In centralized dispatch, balancing reserve procurement and congestion management are performed concurrently, in an integrated process. This differs from self-dispatch systems, where the balance-responsible parties make commitment decisions and determine dispatch positions, based on their own economic criteria, the technical constraints of generating units and the demand elements they are responsible for balancing.

The electricity system of the island of Ireland features a high penetration of renewable energy sources, particularly wind, with the instantaneous System Non-Synchronous Penetration (SNSP) levels reaching up to the safe operational limit of 75%. In the island of Ireland, renewables accounted for 40.0% of the country's electricity generation over the year 2024, with wind energy providing 33% of total electricity demand. Moreover, 41% of the months in the year 2024 had a SNSP of 50% or higher. The large share of wind and solar introduces volatility and unpredictability into the grid, requiring system operators to balance with dispatchable generation and Battery Energy Storage Systems (BESS).

During periods of extremely low wind generation, there can be limited operational flexibility, and managing domestic system reserves becomes crucial to prevent the system from entering an alert, emergency, or blackout state. During these periods of tight system margins, limiting the total export capacity of the SEM bidding zone becomes a key remedial action. This prevents potential market-driven export flows from causing a deficit in reserve margins, thereby ensuring system generation resource adequacy and avoiding potential violations of operational security limits.

In certain situations, conventional generating units identified through system studies are required to operate to support system voltage and provide reactive power in specific parts of the grid, as well as to maintain system inertia above recommended thresholds for frequency stability. These units are treated as priority dispatch (must-run), and system operators may aim to keep them online at or above their minimum generating capability (P_{min}). Additionally, during periods of heavy rainfall, run-of-river hydro units are also prioritized to manage water levels and mitigate the risk of upstream flooding. These operational requirements may reduce the system's flexibility to lower domestic generation. To preserve adequate downward regulation capability and avoid over-supply, it may become necessary to limit the total import capacity into the SEM bidding zone. This remedial action ensures must-run units can operate as required while maintaining system balance and protecting operational security limits.

The island of Ireland operates within a synchronous area that comprises the control areas of both Ireland and Northern Ireland. This synchronous area is connected to other synchronous zones exclusively via HVDC subsea cables. While these HVDC links provide essential cross-zonal trading capacity, they offer limited synchronous support and cannot deliver services such as inertia or electromagnetic coupling. The extent of support services available from HVDC links depends on both the technical capabilities and the commercial agreements between interconnector owners and TSOs. Moreover, the relatively small size of the synchronous area restricts the ability to share reserves and balancing capacity across bidding zone borders, placing it at a disadvantage compared to larger systems like Continental Europe. These limitations may necessitate additional measures to ensure sufficient domestic operating reserves are maintained under all operating conditions.

High HVDC import levels can reduce the dispatch of local synchronous generation, which in turn lowers system inertia and increases susceptibility to frequency deviations during disturbances such as interconnector trips or local faults. The sudden loss of an HVDC interconnector also poses transient stability risks, potentially leading to significant power imbalances and rotor angle instability. Moreover, large HVDC power flows can affect local oscillatory modes, raising small-signal stability concerns in a low-inertia environment where damping is limited. When combined with the variability of intermittent renewable sources, these dynamic stability challenges may require operational management, including measures in the form of external constraints to safeguard system security.

Methodology of calculating external constraints

The methodology outlined here shows how the export and import constraints of the net position of the SEM bidding zone are calculated by evaluating the available generation, demand, and reserve requirements. It considers total dispatchable generation, forecasted wind & solar power, and operational limitations such as energy-limited resources like pumped storage, demand side units (DSU), dynamic stability, and battery energy storage. The process also accounts for reductions due to long-notice plants (long lead-time), generation unavailable because of grid constraints, and unusable hydro capacity.

The difference between net generation and the sum of demand and operating reserves for upward regulation defines the net position constraint in the export direction. On the other hand, the system demand subtracted from the sum of technical minima of dispatchable generation (required to run to maintain system inertia), non-dispatchable generation, and operating reserves for downward regulation defines the net position constraint in the import direction.

Export Constraint = Dispatchable generation (DF)

+ [Solar PV generation + Wind generation]

– [Derated generation (Demand Response, Pumped Storage, BESS)]

– Unusable generation (Long notice, TX constraints, unusable hydro)

– [Forecasted Demand + Upward Reserves]

Import Constraint = Forecasted demand

– [Non-dispatchable generation from Solar PV & Wind]

– Sum of minima of dispatchable generating units (DF)

– Downward reserves

Where:

DF - declared on fuel availability

BESS - Battery Energy Storage Systems

TX constraints - unavailable generation due to transmission constraints

Frequency of re-calculation

External constraints are determined through a continuous process for each capacity allocation time frame, based on the most recent information on the technical offer data of dispatchable generating units, forecasted wind and solar generation, forecasted system demand, and operational limitations such as dynamic stability and system constraints.

Time periods for which external constraints are applied

In the case of the day-ahead process, external constraints are calculated on the morning of D-1, resulting in bi-directional values (import and export) for each MTU of the respective trading day. However, actual capacity restrictions are applied only to those MTUs where the calculation results indicate a potential violation of system security limits.

ii) Reasons EirGrid and SONI propose using ramping constraints on Celtic interconnector

With the commissioning of the Celtic interconnector (700 MW), it will become the largest single infeed and outfeed for the all-island system, increasing the total cross-zonal trading capacity of SEM bidding zone to 2200 MW, which accounts for nearly 30% of peak system demand. To maintain system stability, particularly during imbalances caused by flow changes on HVDC interconnections between market time units (MTUs), ramping restrictions are necessary. These restrictions further mitigate the risk of abrupt shifts between (maximum) import and export limits across two MTUs. Thereby, ramping constraints, as a specific type of allocation constraints, ensure that the maximum flow change on the HVDC interconnector between MTUs remains within secure operational limits.It is important to note that the HVDC ramping constraints referred to in this description are applied within the market coupling process as a standard procedure, and do not impact the capacity calculation process.