Sixth amendment of the Intraday capacity calculation methodology of the Core capacity calculation region

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

December 2025

History of ID CCM

Core TSOs submit the 5th amendment of the Core IDCCM. Below a summary of the history of the Core IDCCM

- 1st amendment: context to extended LTA inclusion & ATC extraction methodology
- 2nd amendment: alignment with core ROSC DA CROSA process including the interim solution & ATC extraction methodology for negative ATCs
- 3rd amendment: ATC validation method.
    - 2nd and 3rd amendment where combined escalated to ACER
- 4th amendment: Update delivery and implementation time for IDCC(c)
- 5th amendment: Proposal for extension of the PL AC.

Whereas

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

1. With this amendment, Core TSOs aim to improve capacities computed in the IDCC process and provide legal certainty regarding the go-live date for IDCC(d) and IDCC(e). The following changes fulfil the objectives set out in Article 3 CACM. In particular, an improvement will be made in relation to Article 3 (b), (d), (e) and (j).

2. The integration of the Celtic interconnector extends the Core region to Ireland and the updated amendment shall ensure legal certainty for its consideration after the technical go-live of the new interconnector.

3. The removal of LTA inclusion from the Day-Ahead Capacity Calculation is considered for IDCC(a) to prepare the ID methodology for the operational changes of the Day-Ahead capacity calculation process.

4. 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

5. The procedure to manage and update ID capacities after the introduction of Flow-based allocation for Intraday Auctions in SIDC has been integrated to prepare the ID CCM for the upcoming changes in ID capacity allocation.

6. The quality of the input of the initial Flowbased computation is improved by using a shifted common grid model considering the latest market results from SDAC and SIDC respectively.

7. The IDCC process and its deadlines have been updated to clarify the operational interaction between the CCC and NEMOs as well as the availability of recomputed ID capacities in SIDC.

8. The deadlines for the post go-live studies for CNEC and FRM have been extended to align with ROSC go-live and developments of the Day-Ahead timeframe. For

the CNEC PGLS study the deadline has been updated related to the DA developments.

9. The article describing the requirements for the Capacity Improvement Study is updated to include a recital to the study and Core TSOs focus on further improving ID capacities.

10. The deadline for the ATC based validation is extended until the start of Flow based for Intraday Auction to allow more time for the transition of the individual validation processes to the flow based approach.

11. A corrected go-live date for IDCC(d) and IDCC(e) shall ensure legal certainty with go-live dates, which are feasible and independent from ROSC, considering extensive pre-go-live testing requirements set by the legal framework.

12. Hybrid coupling refers to the combined use of Flow-Based (FB) and Available Transmission Capacity (ATC) constraints in one single capacity allocation mechanism. There are two forms of hybrid coupling: Standard Hybrid Coupling (SHC) and Advanced Hybrid Coupling (AHC). The difference between SHC and AHC is how power flows on interconnectors between the Core CCR and adjacent CCRs are mapped onto Core CNECs. The SHC grants access to the scarce CNEC capacity by reserving capacity on the Core CNECs based on the forecasted power flows on the interconnectors. On the other hand, in AHC, the power flows on the interconnectors between the Core CCR and adjacent CCRs shall be subject to non-discriminatory competition for CNEC capacity with all other power flows within the Core CCR. Besides ensuring a non-discriminatory competition for the scarce CNEC capacity, the expectation is that Core FB ID MC will benefit from the implementation of AHC in terms of socio-economic welfare;

13. With this amendment, as the specifics for AHC in the ID timeframe need to be further detailed and investigated before going live with ID AHC, Core TSOs aim to both set a timeline for the technical readiness of their tools and to include a study on developing ID AHC considering the special requirements set by a combined use of flow-based and ATC-based capacity allocation in the ID timeframe;

14. The following changes fulfil the objectives set out in Article 3 CACM. In particular, an improvement will be made in relation to Article 3 (b), (d) and (j) improving the allocation of capacity at borders to other CCRs. The aim of the measures is to create a level playing field in Single Intra Day Coupling (‘SIDC’) with regard to flows resulting from intra-CCR trade and flows resulting from trade with bidding zones outside the core CCR.

Article 1
Advanced Hybrid Coupling including an Implementation Study

1. Article 2. Definitions and interpretation shall be amended by introducing a new number b1 and b2 accordingly:

   “(b1) ‘AHC border’ means a border between a bidding zone within and outside of Core CCR where both bidding zones are part of Single-Intraday-Coupling and the AHC is applied;

(b2) 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 14 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 13 (5);

2. Article 2. Definitions and interpretation shall be amended by updating ,n, lll and mmm, yyy accordingly:

(n) "'Core net position' means a net position of a bidding zone or VH in Core CCR resulting from the allocation of cross-zonal capacities within the Core CCR and on AHC borders;"

(lll) "'zone-to-slack $PTDF$' means the PTDF of a commercial exchange between a bidding zone and the slack node or between a VH and the slack node;

(mmm) 'zone-to-zone $PTDF$' means the PTDF of a commercial exchange between two bidding zones, between two VHs or between a VH and a bidding zone;"

(uuu) "'virtual hub' (VH) means external or internal virtual hub."

3. Article 5. Definition of critical network elements and contingencies shall be amended by adding a paragraph 1(a)accordingly:

"CNEs pursuant to paragraph 1 shall additionally include those elements on AHC borders. In case the capacity constraints resulting from cross-zonal network elements on an AHC border are already considered in another CCR, a Core TSO may decide not to define such network elements as CNE or CNEC in Core. Such a CNE or CNEC on an AHC border shall be regularly monitored only in a single CCR. Any Core TSO willing to deviate from this rule shall justify such deviation to other Core TSOs "

4. Article 8. Reliability margin methodology shall be amended by updating paragraph 1a accordingly:

"(a) cross-zonal exchanges on bidding zone borders outside the Core CCR excluding AHC borders;"

5. Article 8. Reliability margin methodology shall be amended by updating paragraph 3 accordingly:

"The FRMs shall be calculated in two main steps. In the first step, the probability distribution of deviations between the expected power flows at the time of the capacity calculation and the realised power flows in real time shall be calculated. To calculate the expected power flows (F_{exp}), for each ID CC MTU of the observation period, the historical CGMs and GSKs used in capacity calculation shall be used. The historical CGMs shall be updated with the deliberated Core TSOs' actions (including at least the RAs considered during the capacity calculation) that have been applied in the relevant ID CC MTU[1]. The power flows of such modified CGMs shall be recalculated (F_{ref}) and then adjusted to take into account the realised commercial exchanges inside the Core CCR and on AHC borders. The latter adjustment shall be performed by calculating $PTDF$s according to the methodology as described in Article 12, but using the modified CGMs and the historical GSKs. The expected power flows at the time of the capacity calculation shall therefore be calculated using the final realised commercial exchanges in the Core CCR and on AHC borders which are reflected in realised power flows. This above calculation of expected power flows (F_{exp}) is described with Equation 2.

$$\vec{F}_{exp} = \vec{F}_{ref} + \mathbf{PTDF}\left(\overrightarrow{NP}_{real} - \overrightarrow{NP}_{ref}\right)$$

Equation 2

with

$\vec{F}_{exp}$	expected power flow per CNEC in the realised commercial situation in Core CCR
$\vec{F}_{ref}$	flow per CNEC in the CGM updated to take deliberate TSO actions into account
PTDF	power transfer distribution factor matrix calculated with updated CGM
$\overrightarrow{NP}_{real}$	Core net position in the realised commercial situation
$\overrightarrow{NP}_{ref}$	Core net position in the updated CGM"

6. Article 9. Generation shift key methodology shall be amended by adding a new paragraph 5(a) accordingly:

"The CCC shall define GSKs for the AHC EVHs according to Article 14 (3) b as follows:

(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.

[1] These actions are controlled by the Core TSOs and thus not considered as an uncertainty.

(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."

7. Article 12. Calculation of power transfer distribution factors and reference flow shall be replaced and read accordingly:

1. "The flow-based calculation is a centralised calculation, which delivers two main classes of parameters needed for the definition of the flow-based domain: the power transfer distribution factors ($PTDFs$) and the remaining available margins ($RAMs$).

2. In accordance with Article 29(3)(a) of the CACM Regulation, the CCC shall calculate the impact of a change in the net position of bidding zones and of VHs on the power flow on each CNEC (determined in accordance with the rules defined in Article 5). This influence is called the zone-to-slack $PTDF$. This calculation is performed from the CGM and the GSK defined in accordance with Article 9.

3. The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ for each node defined in the GSK. These nodal PTDFs are derived by varying the injection of a relevant node in the CGM and recording the difference in power flow on every CNEC (expressed as a percentage of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ by multiplying the share of each node in the GSK with the corresponding nodal PTDF and summing up these products. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\text{zone-to-slack}} = \mathbf{PTDF}_{\text{node-to-slack}}\,\mathbf{GSK}_{\text{node-to-zone}}$$

Equation 4

with

$\mathbf{PTDF}_{\boldsymbol{zone-to-slack}}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones and VHs; rows: CNECs)
$\mathbf{PTDF}_{\boldsymbol{node-to-slack}}$	matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)
$\mathbf{GSK}_{\boldsymbol{node-to-zone}}$	matrix containing the $GSKs$ of all bidding zones (columns: bidding zones and VHs; rows: nodes; sum of each column equal to one)

4. The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$. A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a net position of bidding zone A on a CNEC l and assumes a commercial exchange between a bidding zone and a slack node. A zone-to-zone $PTDF_{A\to B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on CNEC l. The zone-to-zone $PTDF_{A\to B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

$$PTDF_{A\rightarrow B,l} = PTDF_{A,l} - PTDF_{B,l}$$

Equation 5

5. 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 exchanges over HVDC interconnectors which are integrated pursuant to **Error! Reference source not found.**:

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

Equation 6

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
$\max_{X\in\{BZ\cup EVH\}}(PTDF_{X,l})$	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

6. The reference flow (F_{ref}) is the active power flow on a CNEC based on the CGM. In case of a CNEC without contingency, F_{ref} is simulated by directly performing the direct current load-flow calculation on the CGM, whereas in case of a CNEC with contingency, F_{ref} is simulated by first applying the specified contingency and then performing the direct current load-flow calculation.

7. The expected flow F_i in the commercial situation i is the active power flow of a CNEC based on the flow F_{ref} and the deviation between the commercial situation considered in the CGM (reference commercial situation) and the commercial situation i:

$$\vec{F}_i = \vec{F}_{ref} + \mathbf{PTDF}\left(\overrightarrow{NP}_i - \overrightarrow{NP}_{ref}\right)$$

Equation 7

with

$\vec{F}_i$	expected flow per CNEC in the commercial situation i
$\vec{F}_{ref}$	flow per CNEC in the already shifted CGM (reference flow)
PTDF	power transfer distribution factor matrix
$\overrightarrow{NP}_i$	Core net position per bidding zone in the commercial situation i
$\overrightarrow{NP}_{ref}$	Core net position per bidding zone in the reference commercial situation"

8. Article 13. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating paragraph 4 accordingly:

   "The PTDFs for the two internal virtual hubs $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ 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."

9. Article 13. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating paragraph 5 accordingly:

   "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 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 virtual hubs shall be of the same magnitude, but they will have an opposite sign."

10. Article 14. Consideration of non-Core bidding zone borders shall be amended by adding paragraph 3 accordingly:

    " In the AHC, the CNECs of the Core Intraday capacity calculation region shall not only limit the net positions of Core bidding zones due to exchanges on bidding zone borders of the Core CCR but also the exchanges on bidding zone borders between the Core CCR and respective adjacent bidding zones.

    In the AHC, the CNECs of the Core Intraday capacity calculation region shall not only limit the net positions of Core bidding zones due to exchanges on bidding zone borders of the Core CCR but also the exchanges on bidding zone borders between the Core CCR and respective adjacent bidding zones.

(a) The AHC shall only be applied in case it can be simultaneously considered in both intraday-auctions and the intraday continuous trade. In case the AHC can only be implemented in intraday auction but not yet to the intraday continous trade, the restrictions inherent to the AHC shall be considered in the intraday continuous trade through an ATC extraction that incorporates Core and non-Core borders.

(b) Core TSOs applying AHC shall introduce at least one external virtual hub for each AHC border, meaning that multiple interconnectors (be it HVDC or AC interconnectors) at a single AHC border can be assigned to separate EVHs.

(c) In the AHC, Core TSOs may impose a limit to the net position of the external virtual hubs:

   i. for HVDC interconnectors, the limit takes into account the physical limitations of the HVDC cables on the border, and the converter stations on the Core side;

   ii. Core TSOs may consider a limit in the form of an NTC value based on the capacity calculation by the neighbouring CCR."

11. Article 14. Consideration of non-Core bidding zone borders shall be amended by updating number 4 accordingly:

    "No later than June 2026 the Core TSOs shall jointly provide a concept including a study of its effects in intraday-capacities for the implementation of the AHC in ATC-based allocation and submit it by the same deadline to all Core regulatory authorities. The study shall allow for a proposal for the implementation of the AHC simultaneously in both intraday-auctions and the intraday continuous trade and consider that the intraday continuous trade might be based on ATC-based allocation. The ID AHC shall aim to reduce the volume of unscheduled allocated flows on the CNECs of the Core CCR resulting from electricity exchanges on the bidding zone borders of adjacent CCRs. If before the implementation of this methodology, the AHC has been implemented on some bidding zone borders in existing flow-based capacity calculation initiatives, it may continue to be applied on those bidding zone borders as part of the day-ahead capacity calculation carried out according to this methodology until the amendments pursuant to this paragraph are implemented."

12. Article 26. Timescale for implementation shall be amended by added paragraph 5 accordingly:

    "Core TSOs shall have developed the intraday AHC, allowing for simultaneous consideration on both intraday-auctions with flow-based allocation and intraday continuous trade with ATC-based allocation, and propose an implementation deadline subject to readiness of SIDC, by June 2026. Core TSOs shall implement AHC by 30 June 2027, subject to the readiness of the SIDC. Before the implementation of AHC, Core TSOs shall involve the Core NEMOs to test the implementation of AHC within the SDAC-SIDC and market participants to adapt to the effects of applying AHC. This phase shall last at least three (3) months. Core TSOs shall publish an analysis that allows market participants to understand the impact of AHC."

Article 2
Inclusion of Celtic Interconnector and SEM-FR Bidding Zone Border

1. Article 2. Definition and interpretation shall be amended by updating paragraph (1)(o) 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 Plc (HOPS d.d.) ("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. Definition and interpretation shall be amended by updating paragraph (1)(v) 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;"

3. Article 2. Definition and interpretation shall be amended by updating paragraph (1)(eee) 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 single slack node, which remains constant for each ID CC TU;"

4. Article 2. Definition and interpretation shall be amended by updating paragraph (1)(sss) accordingly:

"‘‘internal virtual hub (IVH)’ means a virtual bidding zone without any buy and sell orders, used to represent the commercial exchanges on an internal Core HVDC interconnector, where the evolved flow based approach is applied as specified in Article 13 of this Methodology;"

5. Article 2. Definition and interpretation shall be amended by adding paragraph (1)(ttt) accordingly:

   "‘SEM’ means the Single Electricity Market, the bidding zone consisting of both Ireland and Northern Ireland as a single all-island electricity market; "

6. Article 4. Intraday capacity calculation process shall be amended by updating paragraph 4 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 Core TSOs in the SEM bidding zone may delegate their obligation of providing the following inputs to each other, subject to prior agreement and in accordance with applicable procedures:

   a) individual list of CNECs in accordance with Article 5;
   b) operational security limits in accordance with Article 6;
   c) allocation constraints in accordance with Article 7;
   d) FRMs in accordance with Article 8;
   e) GSKs in accordance with Article 9; and
   f) non-costly and costly RAs in accordance with Article 10.

7. Article 13. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating paragraph 1 accordingly:

   "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 area2. In the EFB methodology, 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."

8. Article 13. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating Footnote 5 to paragraph 1 accordingly:

"5 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."

9. Article 13. Integration of HVDC interconnectors on bidding zone borders of the . Core CCR shall be amended by updating paragraph 2 accordingly:

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

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

Equation 8

with

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

10. Article 13. Integration of HVDC interconnectors on bidding zone borders of the . Core CCR shall be amended by adding paragraph 6 accordingly:

" 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 Intraday 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."

11. Article 17. Calculation of flow-based parameters before validation shall be amended by updating paragraph 1 accordingly:

"1. The flows assumed to result from commercial exchanges outside the Core CCR (F_{uaf}) shall be calculated in the following steps. First, the flows on CNECs in situations without commercial exchanges are calculated by setting the corresponding net positions $\overrightarrow{NP_i}$ to zero:

The flows without Core exchanges including exchanges on AHC borders are calculated as:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \vec{F}_{ref,Core}$$

Equation 8a

$$\vec{F}_{ref,Core} = \mathbf{PTDF_{Core}}\ \overrightarrow{NP}_{ref,Core}$$

Equation 8b

The flows without exchanges in the whole Continental Europe and on its links towards other synchronous areas, are calculated as:

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

Equation 8c

For this calculation, the CCC shall use the GSKs provided by the concerned TSOs, and when these are not available, the CCC shall use a GSK where all nodes with positive injections participate in shifting in proportion to their injection.

The flow assumed to result from commercial exchanges outside the Core CCR (F_{uaf}) is then calculated for each CNEC as follows:

$$\vec{F}_{uaf} = \vec{F}_{0,Core} - \vec{F}_{0,all}$$

Equation 8d

with

$\vec{F}_{0,Core}$	flow per CNEC in a situation without commercial exchanges within the Core CCR and on the AHC borders
$\vec{F}_{ref}$	flow per CNEC in the CGM (which already contains the flows originated by SDAC process, and partially from the SIDC process)

$\vec{F}_{ref,Core}$ flow originated from the Core net positions including VHs which are already included in the CGM

$\mathbf{PTDF}_{\boldsymbol{Core}}$ power transfer distribution factor matrix for all bidding zones and VHs of the Core CCR

$\mathbf{PTDF}_{\boldsymbol{all}}$ power transfer distribution factor matrix for all bidding zones and VHs of Continental Europe, and connection points of the bidding zones of Continental Europe with the bidding zones of other synchronous areas

$\overrightarrow{NP}_{ref,Core}$ Core net position per bidding zone and VH included in the CGM (resulting from SDAC and the SIDC exchanges already included in the CGM), excluding the net positions' changes resulting from the application of remedial actions in the previous CROSA process

$\overrightarrow{NP}_{ref,all}$ total net positions included in the CGM, of: all bidding zones and VHs of Continental Europe and the island of Ireland, and connection points of the bidding zones of Continental Europe with the bidding zones of other synchronous areas

$\vec{F}_{0,all}$ flow per CNEC in a situation without any commercial exchange between bidding zones and VHs within Continental Europe, and any commercial exchange 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

$\vec{F}_{uaf}$ unscheduled allocated flow, i.e. the flow per CNEC resulting from commercial exchanges outside Core CCR excluding the AHC borders"

12. Article 17. Calculation of flow-based parameters before validation shall be amended by updating paragraph 3 accordingly:

"In case an allocation 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 the $\overrightarrow{RAM}_{bv}$ vector as follows:

a) the $PTDF$ value in the column related to the bidding zone applying the concerned allocation 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; and

c) The RAM value is set to the amount of the allocation constraint, corrected for the net position included in the CGM."

13. Article 22 Publication of data shall be amended by updating paragraph 2(c)iv. accordingly:

"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"

14. Article 25 Timescale for implementation shall be amended by adding paragraph 9 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 of the relevant interconnector is finalised, and the technical conditions allow commercial operations to begin. The integration of the HVDC cable connecting the two bidding zones into the present capacity calculation methodology shall be conducted in compliance with the provisions of Article 13. "

Article 3
SEM 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 2. Definitions and interpretation shall be amended accordingly, a new definition shall be introduced:

"(gg) 'TU' is the intraday time unit, which means the time unit for the intraday market;

(3) Article 6. Methodology for operational security limits shall be amended by updating paragraph 2 accordingly:

"To take into account the operational security of CNEs, the Core TSOs shall use 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:

(a) the maximum admissible current can be defined as:

i. Seasonal limit, which means a fixed limit for all ID CC MTUs of each of the four seasons.
ii. Dynamic limit, which means a value per ID CC MTU reflecting the varying ambient conditions.
iii. Fixed limits for all ID 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.”

(4) Article 7. Methodology for allocation constraints shall be amended by updating the whole article accordingly

1. “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.

2. 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 SIDC), 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 SIDC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the SIDC. This option shall be applied when: (i) such a constraint is approved within all intraday capacity calculation methodologies of the respective CCRs, (ii) the respective solution is implemented within the SIDC algorithm and (iii) the respective bidding zone borders are participating in SIDC.

   c) ramping constraints (flow ramping limits) that limit the maximum flow change on HVDC interconnectors between synchronous areas from one TU to the next.

3. Allocation constraints referred to in Article 7 2(a) and 2(b) may be used by a concerned Core TSO as listed in Annex 1 during a transition period of four years following the implementation of this methodology in accordance with Article 25(2)(b) 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;

   b) if applicable and in case the allocation 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 DA CC TU 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 24(5);

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

4. In case the concerned TSOs could not find and implement alternative solutions referred to in the previous paragraph, it may, by fourty two months after the implementation of this methodology in accordance with Article 25(2)(b), 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.

   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.

5. For the SIDC ATC extraction procedure, pursuant to Article 20, all allocation constraints, shall be modelled as constraints limiting the Core net position as referred to in Article 7(2)(a).

6. A concerned Core TSO may discontinue the use of an allocation constraint. In such a case, a concerned Core TSO shall communicate this change to all Core regulatory authorities and to the market participants at least one month before discontinuation.

7. The Core TSOs shall review and update allocation constraints in accordance with Article 21."

(5) ANNEX 1 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 allocation constraint to limit the import and export of the Polish bidding zone.

Technical and legal justification

Implementation of allocation constraints as applied by PSE is related to integrated scheduling process applied in Poland (also called central dispatching model) and the way how reserve capacity is being procured by PSE. In a central dispatching model, in order to balance generation and demand and ensure secure energy delivery, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve capacity requirements. This is realised in an integrated scheduling process as a single optimisation problem called security constrained unit commitment (SCUC) and economic dispatch (SCED).

The integrated scheduling process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance and in effect not removed from the wholesale market and SIDC. However, if balancing service providers (generating units) would already sold too much energy in the previous market timeframes because of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process. Therefore, one way to ensure sufficient reserve capacity within integrated scheduling process is to set a limit to how much electricity can be imported or exported in the SIDC.

The objective to limit balancing service providers to sell too much energy in the intraday market in order to be able to provide sufficient reserve capacity in the integrated scheduling process cannot be efficiently met by translating this limit into 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, whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, whereas the trading of other bidding zones is unaffected.

Allocation constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border (i.e. Core, Baltic and Hansa). This solution is the most efficient application of external constraints. Considering allocation constraints separately in each CCR would require PSE to split global external constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward reserve capacity requirements, or when Poland is unable to export any more power due to insufficient upward reserve capacity requirements, Polish transmission infrastructure is still available for cross-border trading between other bidding zones and between different CCRs.

Methodology to calculate the value of allocation constraints:

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 ID CC MTU, and separately for directions of import to Poland and export from Poland.

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

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

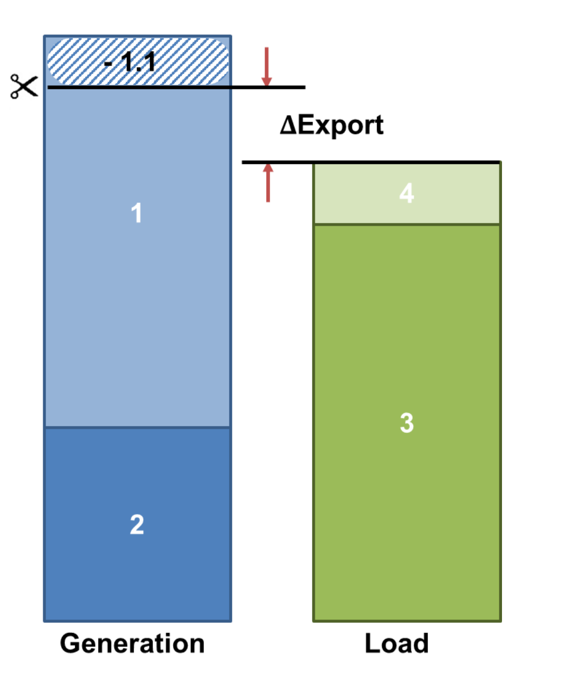
$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CDmin} - P_{NCD} \quad (2)$$

Where:

P_{CD}	Sum of operating generating capacities of centrally dispatched units as declared by generators[6]
P_{CDmin}	Sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

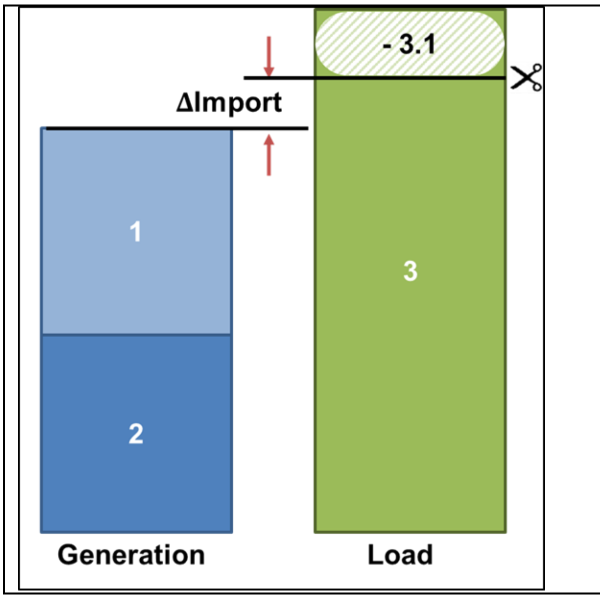
For illustrative purposes, the process of practical determination of allocation constraints in the framework of the intraday capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the delivery day is developed by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

Allocation constraint in export direction is applicable if ΔExport is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction. External constraint in import direction is applicable if ΔImport is lower than the sum of cross-zonal capacities on all Polish interconnections in import direction.



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
2. Generation not available due to grid constraints
3. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
4. Demand forecasted by PSE
5. 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 intraday capacity calculation.



6. Sum of technical minima of centrally dispatched generating units in operation
7. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
8. Demand forecasted by PSE, reduced by:
9. 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 intraday 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 intraday. In case of intraday process, these are calculated for each intraday capacity calculation timeframe in accordance with Article 4(2), resulting in independent values for each MTU, and separately for directions of import to Poland and export from Poland.

Time periods for which external 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.

2. 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 Intraday Capacity Calculation Methodology (CCM).
Capacity allocation constraints are a legally prescribed means, defined by CACM Regulation (Art. 23(3) and Art. 21(1)(a)(ii).

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 recalculation

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 DA CC 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."

Article 4
Flow-based in IDA

1. Article 20. ATC extraction for SIDC shall be amended by updating paragraph 1, in addition to replacing 'ATCs for SIDC fallback procedure' with 'ATCs for SIDC without flow-based' accordingly in the complete article. The latter applies to article 22 as well.

   "In case the SIDC is unable to accommodate flow-based parameters, the CCC shall convert them into available transmission capacities (hereafter referred as "ATCs for SIDC without flow-based") for each Core oriented bidding zone border and each ID CC TU. SIDC without flow-based cannot open as long as this conversion towards available transmissions capacities is done. The Core TSOs may delegate this responsibility to a third party.

Article 5
Implementation of the Core Long Term Capacity Calculation Methodology and LTA allocation and impact in IDCC(a) capacities without LTA inclusion and LTA domain

1. Article 11. Update of intraday cross-zonal capacities remaining after the SDAC shall be amended by updating the ful article to

"The CCC shall use or recalculate the flow-based parameters resulting from day-ahead capacity calculation and the net positions resulting from already allocated capacities in the SDAC to calculate the updated day-ahead cross-zonal capacities, in the form of flow-based parameters, to be used as intraday cross-zonal capacities at the intraday cross-zonal gate opening time.

The CCC may recalculate the flow-based parameters resulting from day-ahead capacity calculation, provided that the provisions of the Core day-ahead capacity calculation methodology are applied, where such recalculation is necessary to reflect changes in the market topology between day-ahead and intraday time frame or where it constitutes a technically more efficient solution.

For the updated intraday flow-based parameters, the PTDF values shall be the final PTDFs resulting from the day-ahead capacity calculation or the recalculation, and the RAM shall be derived as:

$$\overrightarrow{RAM}_{UID} = \overrightarrow{RAM}_{f,DA} - \mathbf{PTDF}_{\boldsymbol{f,DA}}\, \overrightarrow{NP}_{AAC,DA}$$

Equation 3

with

$\overrightarrow{RAM}_{UID}$	updated remaining available margin for intraday cross-zonal capacities
$\overrightarrow{RAM}_{f,DA}$	Recalculated or final remaining available margin resulting from the day-ahead capacity calculation
$\mathbf{PTDF}_{\boldsymbol{f,DA}}$	final power transfer distribution factor matrix resulting from the day-ahead capacity calculation
$\overrightarrow{NP}_{AAC,DA}$	net positions resulting from already allocated capacities in SDAC

10. For each CNEC, each TSO may decrease the $RAM_{f,DA}$ by decreasing AMR_{DA} and $LTA_{margin,DA}$ insofar as calculated pursuant to the day-ahead capacity calculation methodology while ensuring that there is no undue discrimination between internal and cross-zonal exchanges in line with Article 21(1)(b)(ii) of the CACM Regulation.

11. Irrespective of the options provided to each TSO pursuant to this paragraph, the CCC shall ensure that on each CNEC $\overrightarrow{RAM}_{UID}$ is non-negative.

Until the implementation of intraday auctions at 15:00 market time of day D-1, the Core TSOs may set to zero the cross-zonal capacities calculated pursuant to Article 4(2)(a), including those calculated pursuant to a transitional solution for updating the cross-zonal capacities remaining after the day-ahead capacity allocation pursuant to Article 26(5). In case the final cross-zonal capacities, calculated in accordance with this Article and taking into account Article 20(1), are in the form of ATCs, such a decision may be made per bidding zone border by the competent TSOs. In case the final cross-zonal capacities, calculated in accordance with this Article and taking into account Article 20(1) are in the form of flow-based parameters, such a decision shall be coordinated among all Core TSOs."

2. Article 19: Intraday capacity calculation fallback procedure shall be updated by amending paragraph 1 accordingly

"According to Article 21(3) of the CACM Regulation, when the intraday capacity calculation for specific ID CC TUs 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, missing or delayed input data, the Core TSOs and the CCC shall define the missing parameters by calculating the default flow-based parameters. The calculation of default flow-based parameters shall be based on previously calculated flow-based parameters for the same delivery market time unit. The latest (intraday or day-ahead) available flow-based domain, which may be corrected during local validation in accordance with Article 18, for the considered delivery ID CC TU is first converted to zero Core balance. The RAM on each CNEC (including allocation constraints) is then decreased by the adjustments for minRAM and LTA inclusion if present. The redundant constraints are removed, and pre-solved constraints are adjusted for the Core net positions resulting from the SDAC and the SIDC."

Article 6
110kV network elements in final CNEC list

1. Article 18: Validation of flow-based parameters shall be amended by introducing paragraphs 3 and 4 accordingly:
   "If all available costly and non-costly RAs are not sufficient to ensure operational security on an internal network element with a specific contingency, which is not defined as a CNEC, the concerned Core TSO may exceptionally add such internal element to the final list of CNECs, provided that:
   (a) Its maximum zone-to-zone PTDF is equal or above the threshold of 5% referred to Article 16(1);
   (b) Its voltage level must be 110 kV or above;

   (c)Its RAM shall be the highest RAM ensuring operational security considering all available costly and non-costly RAs, with the floor of zero."

Article 7
New deadline for post go-live studies

1. Article 5. Definition of critical network elements and contingencies shall be amended by updating paragraph 5 accordingly:

   "No later than twelve months after the full implementation of the ROSC methodology and as soon as the list of internal network elements is established in DA, all Core TSOs shall jointly develop a list of internal network elements (combined with the relevant contingencies) to be defined as CNECs and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. After its approval in accordance with Article 9 of the CACM Regulation, the list of internal CNECs shall form an annex to this methodology"

2. Article 5 (11) shall be added by and read accordingly

   "The Core TSOs shall submit an amendment proposal reconsidering the list of internal CNECs, in order to comply with the legal findings of the General Court in the Case BNetzA v ACER (T-600/23) in so far as those legal findings are applicable to the Intraday capacity calculation methodology of the Core Europe capacity calculation region. In case this methodology is already compliant with the legal findings of the General Court, no such amendment proposal is required."

3. Article 5 (11) shall be added by and read accordingly
   "The Core TSOs shall aim at gradually phasing out the use of seasonal limits pursuant to paragraph 2(a)(i) and replace them with dynamic limits pursuant to paragraph 2(a)(ii) when the benefits are greater than the costs. Each Core TSOs shall provide annually the status of operational limits in place. No later than 24 months after the implementation of this methodology in accordance with Article 24(2,e), Core TSOs shall conduct an analysis on the efficiency of implementing dynamic limits for the maximum admissible current. This analysis shall include an identification of the CNECs where dynamic limits would bring the most value and possible solution to implement more granular operational security limits. Every two years after the end of the calendar year, all Core TSOs shall analyse all CNEs which jointly collected 99% of cumulative shadow price in the period of last two calendar years. "

4. Article 8. Reliability margin methodology shall be amended by updating paragraph 7 accordingly:

   > "No later than twelve months after the full implementation of the ROSC methodology and as soon as the FRM calculation is done in DA , the Core TSOs shall jointly perform the first FRM calculation pursuant to the methodology described above and based on the data covering at least the first year of operation of this methodology. By the same deadline, all Core TSOs shall submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation as well as the supporting document as referred to in paragraph 9 below."

5. Article 9. Generation shift key methodology shall be amended by updating paragraph 6 accordingly:

   "Within 38 months after the implementation of this methodology in accordance with Article 24(2)(b) and as soon as the updated GSK is implemented in DA all Core TSOs shall develop a proposal for further harmonisation of the generation shift key methodology and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. The proposal shall at least include:

(a) the criteria and metrics for defining the efficiency and performance of GSKs and allowing for quantitative comparison of different GSKs; and

(b) a harmonised generation shift key methodology combined with, where necessary, rules and criteria for TSOs to deviate from the harmonised generation shift key methodology.

(c) Changing the set point of a bidding zone internal HVDC line"

Article 8
New implementation deadlines for IDCC(d) and IDCC(e)

1. Article 26. Timescale for implementation shall be amended by updating paragraph 2(d)(e) accordingly:

   "IDCC(d): re-calculation of intraday cross-zonal capacities pursuant to Article 4(2)(d) by 23 months after the implementation of calculation of intraday cross-zonal capacities pursuant to point (b) of this paragraph; and

   IDCC(e): re-calculation of intraday cross-zonal capacities pursuant to Article 4(2)(e) by 36 months after the implementation of calculation of intraday cross-zonal capacities pursuant to point (b) of this paragraph.;."

Article 9
Extension of ATC validation deadline

1. Article 26. Timescale for implementation shall be amended by updating paragraph 6 accordingly:

   "In parallel to IVA validation and as long as SIDC is not able to directly apply flow-based parameters, the Core TSOs may also perform ATC based validation pursuant to Annex 2. The ATC based validation shall no longer be allowed after the implementation of flow-based in IDA."

Article 11
ID FB computation on shifted CGM

1. Article 2. shall be amended by updating paragraph1 (qqq)) accordingly:
   "'SEC_{DA}' means scheduled exchange resulting from already allocated capacities in the single day ahead coupling (SDAC). The parameter is provided by the SDAC based on the all TSO methodology for calculating scheduled exchanges resulting from single day-ahead coupling according to Article 43 of CACM Regulation;

2. Article 4. shall be amended by updating paragraph 5(a-c) accordingly:

   (a) "the Core net positions or, alternatively, the already allocated capacities on the SDAC bidding zone borders resulting from the SDAC;"

(b) "the Core net positions or, alternatively, the already allocated capacities on the SIDC bidding zone borders resulting from the SIDC which are already included in the CGM;"

(c) the Core net positions or, alternatively, the already allocated capacities on the SIDC bidding zone borders resulting from the SIDC not already included in the CGM."

3. Article 15. Initial flow-based calculation shall be amended by updating paragraph 2 accordingly:

> "Subsequently, the CCC shall use the initial list of CNECs pursuant to paragraph 1, the CGM (including the latest SIDC NP) pursuant to Article 4(7) and the GSK for each bidding zone in accordance with Article 9 to calculate the initial flow-based parameters for each ID CC TU."

Article 12: Capacity provision deadlines

1. Article 4. Intraday capacity calculation shall be amended by updating paragraph 2 (a-d) accordingly:

(a) "IDCC(a): updating of cross-zonal capacities remaining after the SDAC for all ID CC MTUs between 00:00 and 24:00 of day D and providing them as intraday cross-zonal capacities to relevant NEMOs with a target end of time of 15 minutes before the intraday cross-zonal gate opening time, at 15:00 market time of day D-1. In case intraday cross-zonal capacities cannot be provided before the intraday cross-zonal gate opening time, the intraday cross-zonal capacities can be provided to the continuous trading platform until 17:20;"

(b) "IDCC(b): calculation of intraday cross-zonal capacities for all ID CC MTUs between 00:00 and 24:00 of day D. The cross-zonal capacities resulting from this calculation shall be published and submitted to NEMOs with a target end of time of 15 minutes before the target start of allocation at 22:00 market time of day D-1. In case intraday cross-zonal capacities cannot be provided before the target start of allocation at 22:00 market time of day D-1, the intraday cross-zonal capacities can be provided until 22:30 D-1 to the continuous trading platform; "

(c) "IDCC(c): re-calculation of intraday cross-zonal capacities for all ID CC MTUs between 06:00 and 24:00 of day D. The cross-zonal capacities resulting from this calculation shall be published and submitted to NEMOs no later than 04:30 on day D for immediate use on the continuous trading platform;"

(d) "IDCC(d): re-calculation of intraday cross-zonal capacities for all ID CC MTUs between 12:00 and 24:00 of day D. The cross-zonal capacities resulting from this re-calculation shall be published and submitted to NEMOs with a target end of time of 15 minutes before the target start of allocation at 10:00 market time of day D. In case intraday cross-zonal capacities cannot be provided before the target start of allocation at 10:00 market time of day D, the intraday cross-zonal capacities can be provided until 10:30 D to the continuous trading platform; and”

(e) “IDCC(e): re-calculation of intraday cross-zonal capacities for all ID CC MTUs between 18:00 and 24:00 of day D. The cross-zonal capacities resulting from this calculation shall be published and submitted to NEMOs no later than 16:00 on day D for immediate use on the continuous trading platform.”

Article 13: TSOs analyses

1. Article 25. TSOs analyses shall be amended by updating the full article accordingly:

   “1. Based on the results of the Capacity Improvement Study, which was conducted pursuant to Article 25 of the 4th Core IDCCM Amendment as a common assessment, the Core TSOs shall optimise process timings in order to utilise the latest possible Common Grid Models (CGMs).

   2. Core TSOs shall continue to analyse possible measures to improve cross-zonal capacities in the intraday timeframe. This may include the study of a minimum RAM (minRAM) approach, which takes into account that grid security has to be maintained.

   Core TSOs shall monitor on an annual basis for each CNEC the level of MACZT in the Intraday timeframe and include it to the Annual reports”

2. Article 26. Timescale for implementation shall be amended by added paragraph 7-8 accordingly:

   “ 7. If required, by 1 November 2026, the Core TSOs shall propose amendments to this methodology based on the outcomes of their analyses pursuant to Article 25(1). If required, following the expected amendments to the CACM Regulation, this methodology shall be revised accordingly.

   8. Core TSOs shall analyse measures to increase cross-zonal capacities in the intraday timeframe according to article 25. Core TSOs shall aim to reach, over time, a minimum capacity threshold of 70%”