Fifth 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

September 2025

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 Flowbased 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, GLSK and FRM have been extended to align with ROSC go-live and developments of the Day-Ahead timeframe.

9. The article describing the requirements for the Capacity Improvement Study is removed as the study has been submitted to NRAs by Core TSOs.

10. The deadline for the ATC based validation is extended until the start of Flowbased 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.

15. With this amendment, PSE aims at extending the period of using AC by 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 Art. 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. Unfortunately, so far the market isn't 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 reserves until the balancing capacity market is liquid enough to reliably and systematically provide them.

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, nnn and ooo, 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;"

   (nnn) "'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;"

   (yyy) "'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
$\mathbf{PTDF}$	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"

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

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.

(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

$\mathbf{PTDF}_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones and VHs; rows: CNECs)

$\mathbf{PTDF}_{node-to-slack}$	matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)
$\mathbf{GSK}_{node-to-zone}$	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 $PTDF_{A\rightarrow B,l}$ 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 $PTDF_{A\rightarrow B,l}$ 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
$\max_{X\in\{BZ \cup EVH\}}\left(PTDF_{X,l}\right)$	maximum zone-to-slack PTDF of Core bidding zones or EVHs on a CNEC l
$\min_{X\in\{BZ \cup EVH\}}\left(PTDF_{X,l}\right)$	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)
$\mathbf{PTDF}$	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:

    "1. 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.

    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 25. 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. Before the implementation of AHC, Core TSOs shall involve the Core NEMOs to test the implementation of AHC within the 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)(w) 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)(ggg) 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 MTU;”

4. Article 2. Definition and interpretation shall be amended by updating paragraph (1)(www) 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)(xxx) 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. A Core TSO may delegate its obligation of providing the inputs to another Core TSO subject to prior agreement of concerned Core TSOs and in accordance with applicable procedures:”

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 area5. In the EFB According to this 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 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."

10. 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

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

Equation 8b

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

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

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"

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

“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 the $\overrightarrow{RAM}_{bv}$ vector 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; and

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

12. 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”

13. Article 25 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 finalised, 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 13. ”

Article 3
Polish and SEM allocation constraints

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

    “(gg) ‘MTU’ is the intraday market time unit, which means the time unit for the intraday market;”

2. 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."

3. 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. For this purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone within the SIDC pursuant to Article 7(2), and ramping constraints pursuant to Article 7(9).

2. The Core TSOs may apply external constraints as one of the following two options:

   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.

   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.

3. External constraints 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 external constraints as specified in Annex 1 to this methodology. During this transition period, the concerned Core TSOs shall:

   calculate the value of external constraints in accordance with Annex 1;

if applicable and 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 DA CC MTU when the external constraint had a non-zero shadow price the loss in economic surplus due to external 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);

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 external 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 external 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 external 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 external 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.

8. In addition to the external constraints defined in Article 7(2), Core TSOs may use ramping constraints (flow ramping limits) that limit the maximum flow change on HVDC interconnectors between synchronous areas from one MTU to the next."

4. 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 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 external constraints on PSE side

Implementation of external 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 and intraday 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 markets. 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 intraday markets.

This leads to implementation of external 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 external 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 external 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 external 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 External 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 external 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 external constraints in the Core region.

The reason why external 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 external 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 external 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 external constraints in Poland

External constrains are applied in intraday allocation process, with values determined before every capacity calculation process for the energy delivery day, 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. External 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 external 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.

$$EXPORT_{\mathrm{constraint}} = P_{\mathrm{CD}} - P_{\mathrm{NA}} + P_{\mathrm{NCD}} - (P_{\mathrm{L}} + P_{\mathrm{UPres}}) \qquad (1)$$

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

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

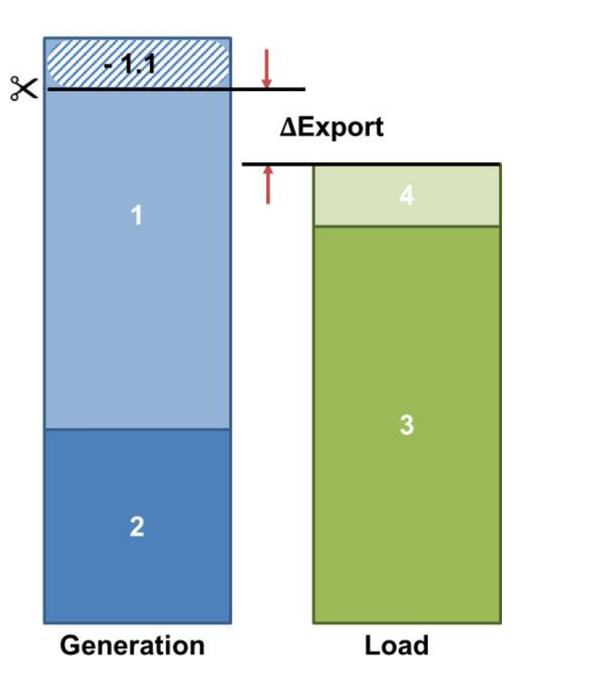
The calculated values of Allocation Constraints are then adjusted to take into consideration already allocated capacities on Polish borders (current global net position of Poland including non-SDAC exchange): in case of export constraints their values are reduced by the global net positions and in case of import constraints their values are increased by the global net positions. Published values of Allocation Constraints are therefore relative to global net position value in the time they were calculated.

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.

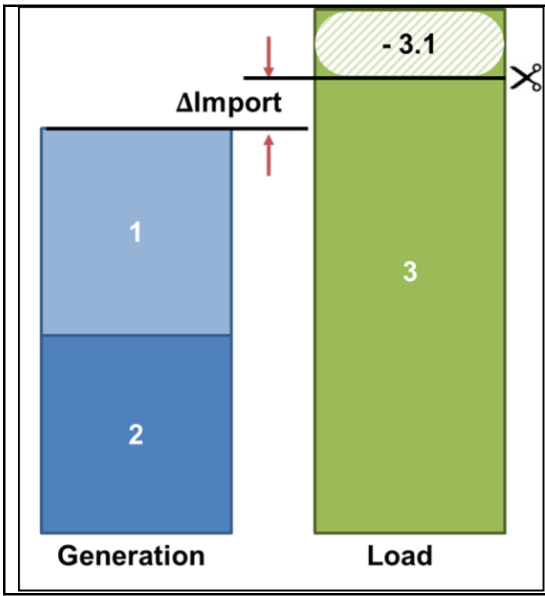
The process of practical determination of external constraints in the framework of the intraday capacity calculation is illustrated below in Figures 1 and 2. The figures show how a forecast of the Polish power balance for each Market Time Unit of the delivery day is developed by PSE in the morning of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

External constraint in export direction is limits export from Polish zone. External 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:
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 external 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 external constraints in import direction (reserves in generating capacities available for potential imports) in the framework of intraday capacity calculation.

Frequency of re-assessment

External 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, external 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.

$$
\begin{aligned}
\textbf{Export Constraint} \quad = \ & \text{Dispatchable generation (DF)} \\
& + [\text{Solar PV generation} + \text{Wind generation}] \\
& - [\text{Derated generation (Demand Response, Pumped Storage, BESS)}] \\
& - \text{Unusable generation (Long notice, TX constraints, unusable hydro)} \\
& - [\text{Forecasted Demand} + \text{Upward Reserves}]
\end{aligned}
$$

$$
\textbf{Import Constraint} \quad = \text{Forecasted demand}
$$

– [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 MTU. 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 paragraph 2 accordingly:

"For each CNEC, each TSO may decrease the $RAM_{f,DA}$ by decreasing the AMR_{DA}, and optionally $LTA_{margin,DA}$, 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."

2. Article 11. Update of intraday cross-zonal capacities remaining after the SDAC shall be amended by introducing paragraph 5accordingly:

   "The Core TSOs shall apply the rules referred as optional to in paragraph 2, and should apply paragraph 3, only until the implementation of the Core Long Term Capacity Calculation Methodology and Long-term flow-based allocation pursuant to the FCA regulation."

3. 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 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, 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 hour is first converted to zero Core balance. The RAM on each CNEC (including allocation constraints) is then decreased by the adjustments for minRAM, and optionally 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"

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

   "The Core TSOs shall apply the rules referred as optional in the previous paragraph only until the implementation of the Core Long Term Capacity Calculation Methodology and Long-term flow-based allocation pursuant to the FCA regulation,"

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;

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 only after the implementation of the list of internal network elements 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 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 only the implementation of the FRM calculation 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."

3. 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 25(2) and only after the implementation of the updated GSK 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."

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

1. Article 25. 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 25. 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 10
New wording for ATC extraction for SIDC without flow-based

1. Article 20. ATC extraction for SIDC shall be amended by updating paragraph 1 accordingly:

   "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 MTU. 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 11
ID FB computation on shifted CGM

1. 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."

2. 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 MTU."

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.”