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 24 July 2015 establishing a guideline on capacity allocation and congestion management

Tracked change version

September 2025

Contents

TITLE 1 – General provisions

Article 1. Subject matter and scope

1. The intraday capacity calculation methodology is the Core TSOs' methodology in accordance with Article 20ff. of the CACM Regulation and covers the intraday capacity calculation methodology for the Core CCR bidding zone borders.

2. This methodology is without prejudice to the TSOs' rights and obligations under Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation, such as taking any remedial actions pursuant to this Regulation to maintain operational security and ensure that the system operates in a normal state. Accordingly, the management of cross-zonal capacities by the TSOs after their delivery to the allocation process is beyond the scope of this methodology.

Article 2. Definitions and interpretation

1. For the purposes of the intraday capacity calculation methodology, terms used in this document shall have the meaning of the definitions included in Regulation (EU) 2019/943, Directive (EU) 2019/944, Commission Regulation (EU) 2015/1222, Commission Regulation (EU) 2016/1719, Commission Regulation (EU) 2017/2195, Commission Regulation (EU) 543/2013, the definitions set out in Article 2 Annex I of ACER Decision No 02/2019 on the Core CCR TSOs' proposal for the regional design of the day-ahead and intraday common capacity calculation methodologies and the definitions set out in Article 2 Annex I of ACER Decision No 33/2020 on the methodology for regional operational security coordination for the Core capacity calculation region ("Core ROSC methodology"). In addition, the following definitions, abbreviations and notations shall apply:

   (a) 'AAC_{ID}' is the already allocated capacity which has been allocated in SIDC;

   (b) 'AHC' means the advanced hybrid coupling, which is a solution to take fully into account the influences of the adjacent CCRs during the capacity allocation;

      (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);

   (c) 'AMR_{DA}' means the adjustment for the minimum remaining available margin in accordance with the day-ahead capacity calculation methodology of the Core CCR;

   (d) 'annual report' means the report issued on an annual basis by the CCC and the Core TSOs on the intraday capacity calculation;

   (e) 'ATC' means the available transmission capacity, which is the transmission capacity that remains available after the allocation procedure and which respects the physical conditions of the transmission system;

   (f) 'CCC' means the coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation, of the Core CCR, unless stated otherwise;

(g) 'CCR' means the capacity calculation region as defined in Article 2(3) of the CACM Regulation;

(h) 'CGM' means the common grid model as defined in Article 2(2) of the CACM Regulation and means the intraday CGM established in accordance with the CGMM;

(i) 'CGMM' means the common grid model methodology, pursuant to Article 17 of the CACM Regulation;

(j) 'CNE' means a critical network element;

(k) 'CNEC' means a CNE associated with a contingency used in capacity calculation. For the purpose of this methodology, the term CNEC also cover the case where a CNE is used in capacity calculation without a specified contingency;

(l) 'Core DA CCM' means the Core day-ahead capacity calculation methodology;

(m) 'Core CCR' means the Core capacity calculation region as established by the Determination of capacity calculation regions pursuant to Article 15 of the CACM Regulation;

(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;

(o) 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");

(p) 'cross-zonal CNEC' means a CNEC of which a CNE is located on the bidding zone border or connected in series to such network element transferring the same power (without considering the network losses);

(q) 'curative remedial action' means a remedial action which is only applied after a given contingency occurs;

(r) 'D-1' means the day before electricity delivery;

(s) 'D-2' means the day two-days before electricity delivery;

(t) 'DACF' means day ahead congestion forecast;

(u) 'default flow-based parameters' means the pre-coupling backup values calculated in situations when the intraday capacity calculation fails to provide the flow-based parameters in three or more consecutive hours. These flow-based parameters are based on previously calculated flow-based parameters;

(v) ‘external constraint’ means a type of allocation constraint that limits the maximum import and/or export of a given bidding zone;

(w) ‘$F_{0,all}$’ 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;

(x) ‘F_i’ means the expected flow in commercial situation i;

(y) ‘flow-based domain’ means a set of constraints that limit the cross-zonal capacity calculated with a flow-based approach;

(z) ‘FRM’ or ‘FRM’ means the flow reliability margin, which is the reliability margin as defined in Article 2(14) of the CACM Regulation applied to a CNE;

(aa) ‘F_{max}’ means the maximum admissible power flow;

(bb) ‘F_{ref}’ means the reference flow;

(cc) ‘GSK’ or ‘GSK’ means the generation shift key as defined in Article 2(12) of the CACM Regulation;

(dd) ‘HVDC’ means a high voltage direct current network element;

(ee) ‘'IDA’ means intraday auction;

(ff) ‘ID CC MTU’ is the intraday capacity calculation market time unit, which means the time unit for the intraday capacity calculation and is equal to 60 minutes;

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

(hh) ‘IGM’ means the intraday individual grid model as defined in Article 2(1) of the CACM Regulation;

(ii) ‘internal CNEC’ means a CNEC, which is not cross-zonal;

(jj) ‘I_{max}’ means the maximum admissible current;

(kk) ‘IVA’ means individual validation adjustment;

(ll) $LTA_{margin,DA}$ means the adjustment of remaining available margin to incorporate long-term allocated capacities in accordance with the day-ahead capacity calculation methodology of the Core CCR;

(mm) ‘NP’ or ‘NP’ means a net position of a bidding zone, which is the net value of generation and consumption in a bidding zone;

(nn) ‘$NP_{AAC,DA}$’ means net position resulting from already allocated capacities in SDAC;

(oo) $NP_{AAC,ID}$’ means net position resulting from already allocated capacities in SIDC;

(pp) ‘oriented bidding zone border’ means a given direction of a bidding zone border (e.g. from Germany to France);

(qq) ‘pre-solved domain’ means the final set of binding constraints for capacity allocation after the pre-solving process;

(rr) ‘pre-solving process’ means the identification and removal of redundant constraints from the flow-based domain;

(ss) ‘preventive remedial action’ means a remedial action which is applied on the network before any contingency occurs;

(tt) ‘PST’ means a phase-shifting transformer;

(uu) ‘PTDF’ or ‘$PTDF$’ means a power transfer distribution factor;

(vv) ‘$\mathbf{PTDF}_{\boldsymbol{Core}}$’ means a matrix of power transfer distribution factors resulting from the intraday flow-based calculation for Core bidding zones;

(ww) ‘$\mathbf{PTDF}_{\boldsymbol{all}}$’ means a matrix of power transfer distribution factors resulting from the intraday flow-based calculation for all bidding zones of Continental Europe, and connection points of the bidding zones of Continental Europe with the bidding zones of other synchronous areas;

(xx) $\mathbf{PTDF}_{\boldsymbol{f,DA}}$’ means a matrix of power transfer distribution factors describing the final day-ahead flow-based domain;”

(yy) ‘quarterly report’ means a report on the intraday capacity calculation issued by the CCC and the Core TSOs on a quarterly basis;

(zz) ‘RA’ means a remedial action as defined in Article 2(13) of the CACM Regulation;

(aaa) ‘RAM’ or ‘RAM’ means a remaining available margin;

(bbb) ‘RCC’ means Regional Coordination Centre;

(ccc) ‘reference net position or exchange’ means a position of a bidding zone or an exchange over HVDC interconnector assumed within the CGM;

(ddd) ‘SDAC’ means the single day-ahead coupling;

(eee) ‘SIDC’ means the single intraday coupling;

(fff) ‘shadow price’ means the dual price of a CNEC or allocation constraint representing the increase in the economic surplus if a constraint is increased by one MW;

(ggg) ‘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;

(hhh) ‘SO Regulation’ means Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation;

(iii) ‘standard hybrid coupling’ means a solution to capture the influence of exchanges with non-Core bidding zones on CNECs that is not explicitly taken into account during the capacity allocation phase;

(jjj) ‘static grid model’ means a list of relevant grid elements of the transmission system, including their electrical parameters;

(kkk) ‘U’ is the reference voltage;

(lll) ‘UAF’ is an unscheduled allocated flow;

(mmm) ‘vertical load’ means the total amount of electricity which exits the transmission system of a given bidding zone to connected distribution systems, end consumers connected to the transmission system, and to electricity producers for consumption in the generation of electricity;

(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;

(ooo) ‘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;

(ppp) the notation x denotes a scalar;

(qqq) the notation $\vec{x}$ denotes a vector;

(rrr) the notation $\mathbf{x}$ denotes a matrix;

(sss) ‘LTA domain’ means a set of bilateral exchange restrictions covering the previously allocated cross-zonal capacities;

(ttt) ‘Extended LTA inclusion approach’ is an LTA inclusion approach in the Core DA CCM. When this approach is applied in the day ahead capacity calculation, the day ahead cross-zonal capacities consist of a flow-based domain (containing flow-based parameters) without LTA inclusion and a separate LTA domain (including LTA values);

(uuu) ‘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;

(vvv) ‘XNEC’ means cross-border relevant network element with contingency, as defined in the Core ROSC methodology.

(www) ‘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;

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

(yyy) ‘virtual hub’ (VH) means external or internal virtual hub.

2. In this intraday capacity calculation methodology unless the context requires otherwise:

   (a) the singular also includes the plural and vice versa;

   (b) the acronyms used both in regular and italic font represent respectively the term used and the respective variable;

(c) the table of contents and the headings are inserted for convenience only and do not affect the interpretation of this intraday capacity calculation methodology;

(d) any reference to the intraday capacity calculation, intraday capacity calculation process or the intraday capacity calculation methodology shall mean a common intraday capacity calculation, common intraday capacity calculation process and common intraday capacity calculation methodology respectively, which is applied by all Core TSOs in a common and coordinated way on all bidding zone borders of the Core CCR; and

(e) any reference to legislation, regulation, directive, decision, order, instrument, code, or any other enactment shall include any modification, extension or re-enactment of it when in force.

Article 3. Application of this methodology

This intraday capacity calculation methodology solely applies to the intraday capacity calculation within the Core CCR. Capacity calculation methodologies within other CCRs or for other time frames are not in the scope of this methodology.

TITLE 2–- General description of the capacity calculation methodology

Article 4. Intraday capacity calculation process

1. For the intraday market time frame, the cross-zonal capacities shall be calculated using the flow-based approach as defined in this methodology.

2. The intraday cross-zonal capacity calculation shall be performed in the following sequence, by the times established in the process description document as referred to in paragraph 7:

   (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.

The reference to ID CC MTUs in the remainder of this methodology shall mean the MTUs as established in this paragraph.

3. Each calculation or re-calculation of cross-zonal capacities pursuant to paragraphs 2(b) to (2)(e), shall consist of three main stages:

    (a) the creation of capacity calculation inputs by the Core TSOs;

    (b) the capacity calculation process by the CCC; and

    (c) the capacity validation by the Core TSOs in coordination with the CCC. Capacity validation may also be applied for the update of capacities pursuant to paragraph 2(a).

4. 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:

    (a) individual list of CNECs in accordance with Article 5;

    (b) operational security limits in accordance with Article 6;

    (c) external 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.

5. In addition to the capacity calculation inputs pursuant to paragraph 3, the Core TSOs, or an entity delegated by the Core TSOs, shall send to the CCC, for each ID CC MTU of the delivery day, the following additional inputs by the times established in the process description document:

    (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.

    If the Core TSOs provided to the CCC the already allocated capacities on the Core biding zone borders instead of the Core net positions, the CCC shall convert them into Core net positions.

6. When providing the capacity calculation inputs pursuant to paragraphs 4 and 5, the Core TSOs shall respect the formats commonly agreed between the Core TSOs and the CCC while fulfilling the requirements and guidance defined in the CGMM.

7. No later than six months before the implementation of this methodology in accordance with Article 25(3)(b), the Core TSOs shall jointly establish a process description document as referred to in paragraphs 2, 4 and 5 and publish it on the online communication platform as referred to in Article 22. This document shall reflect an up-to-date detailed process description of all capacity calculation steps including the timeline of each step of the intraday capacity calculation.

8. The Core RCCs, acting as the CCC shall use the latest available CGMs, proposed and coordinated XRAs from the day ahead and intraday CROSAs, in accordance with the CSAM. During the interim period until ROSC CROSA process is implemented in accordance with Article 37 of Core ROSC methodology, only the latest available CGM shall be delivered.

9. In case the necessary outputs of the ROSC ICS/CROSA process cannot be provided within the foreseen timeframe, the delivery of the CGMs and XRAs pursuant to paragraph 8, and subsequent intraday capacity calculation and delivery of intraday capacities may be delayed only up to a point in time at which the target start of allocation pursuant to paragraphs 2(b), 2(c), 2(d) and 2(e) is not yet affected. If the target start of allocation becomes affected by such a delay, the fallback procedure pursuant to Article 19 applies.

10. The intraday capacity calculation process pursuant to paragraphs 2(b), 2(c), 2(d) and 2(e) and validation in the Core CCR shall be performed by the CCC and the Core TSOs according to the following procedure:

    Step 1. The CCC shall define the initial list of CNECs pursuant to Article 15;

    Step 2. The CCC shall calculate the first flow-based parameters ($PTDF_{init}$ and $F_{ref,init}$) for each initial CNEC pursuant to Article 15;

    Step 3. The CCC shall determine the final list of CNECs for subsequent steps of the capacity calculation pursuant to Article 16;

    Step 4. The CCC shall calculate the RAM before validation (RAM_{bv}) based on the results of the previous processes pursuant to Article 17;

    Step 5. The Core TSOs shall, according to Article 18, validate the RAM_{bv} with individual validation, and decrease RAM when operational security is jeopardised, which results in the final RAM_f;

    Step 6. The CCC shall, according to Article 18, remove the redundant CNECs and redundant external constraints from final $PTDF_f$ and RAM_f;

    Step 7. The CCC shall publish the $PTDF_f$ and RAM_f values in accordance with Article 22 and provide them to NEMOs for capacity allocation in accordance with paragraph 2.

11. All capacity updates, calculations and re-calculations pursuant to paragraph 2, including all steps pursuant to paragraph 3, shall be performed per ID CC MTU. Cross-zonal capacities shall be provided to the NEMOs for each ID CC MTU, but for capacity allocation they may be converted into a higher time resolution in accordance with the market time unit applicable on specific bidding zone border(s).

TITLE 3 – Capacity calculation inputs

Article 5. Definition of critical network elements and contingencies

1. Each Core TSO shall define a list of CNEs, which are fully or partly located in its own control area, and which can be overhead lines, underground cables, or transformers. All cross-zonal network elements shall be defined as CNEs, whereas only those internal network elements, which are defined pursuant to paragraph 6 or 7 shall be defined as CNEs. Until 30 days after the approval of the proposal pursuant to paragraph 6, all internal network elements may be defined as CNEs.
   (a) 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

2. Each Core TSO shall define a list of proposed contingencies used in operational security analysis in accordance with Article 33 of the SO Regulation, limited to their relevance for the set of CNEs as defined in paragraph 1 and pursuant to Article 23(2) of the CACM Regulation. The contingencies of a Core TSO shall be located within the observability area of that Core TSO. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the Core TSO, pursuant to Article 21. A contingency can be an unplanned outage of:
   (b) a line, a cable, or a transformer;
   (c) a busbar;
   (d) a generating unit;
   (e) a load; or
   (f) a set of the aforementioned elements.

3. Each Core TSO shall establish a list of CNECs by associating the contingencies established pursuant to paragraph 2 with the CNEs established pursuant to paragraph 1 following the rules established in accordance with Article 75 of the SO Regulation. Until such rules are established and enter into force, the association of contingencies to CNEs shall be based on each TSO's operational experience. An individual CNEC may also be established without a contingency.

4. Each Core TSO shall provide to the CCC a list of CNECs established pursuant to paragraph 3.

5. 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.

6. The list pursuant to the previous paragraph shall be updated at least every two years. For this purpose, no later than eighteen months after the approval by all Core regulatory authorities of the proposal for amendment of this methodology pursuant to previous paragraph and this paragraph, all Core TSOs shall jointly develop a new proposal for the list of internal 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 replace the relevant annex to this methodology.

7. The proposed list of internal CNECs pursuant to paragraph 5 and 6 shall not include any internal network element with contingency with a maximum zone-to-zone PTDF below 5%, calculated as the time-average over the last twelve months. An exception is applied for CNECs that are considered in accordance with Article 16(2) to (3) and Article 18(4).

8. The proposal pursuant to paragraphs 5 and 6 shall include at least the following:

   (a) a list of proposed internal CNECs with the associated maximum zone-to-zone PTDFs referred to in paragraph 7;

   (b) an impact assessment of increasing the threshold of the maximum zone-to-zone PTDF for exclusion of internal CNECs referred to in paragraph 7 to 10% or higher; and

   (c) for each proposed internal CNEC, an analysis demonstrating that including the concerned internal network element in capacity calculation is economically the most efficient solution to address the congestions on the concerned internal network element, considering, for example, the following alternatives:

      i. application of remedial actions;

      ii. reconfiguration of bidding zones;

      iii. investments in network infrastructure combined with one or the two above; or

      iv. a combination of the above.

   Before performing the analysis pursuant to point (c), the Core TSOs shall jointly coordinate and consult with all Core regulatory authorities on the methodology, assumptions and criteria for this analysis.

9. The proposals pursuant to paragraphs 5 and 6 shall also demonstrate that the concerned Core TSOs have diligently explored the alternatives referred to in paragraph 8 sufficiently in advance taking into account their required implementation time, such that they could be applied or implemented by the time that the decisions of the Core regulatory authorities on the proposal pursuant to paragraphs 5 and 6 are taken.

10. The Core TSOs shall regularly review and update the application of the methodology for determining CNECs as defined in Article 21.

Article 6. Methodology for operational security limits

1. The Core TSOs shall use in the intraday capacity calculation the same operational security limits as those used in the operational security analysis carried out in accordance with Article 72 of the SO Regulation.

2. 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.

(b) when applicable, I_{max} shall be defined as a temporary current limit of the CNE in accordance with Article 25 of the SO Regulation. A temporary current limit means that an overload is only allowed for a certain finite duration. As a result, various CNECs associated with the same CNE may have different I_{max} values.

(c) I_{max} shall represent only real physical properties of the CNE and shall not be reduced by any security margin.[1]

(d) the CCC shall use the I_{max} of each CNEC to calculate F_{max} for each CNEC, which describes the maximum admissible active power flow on a CNEC. F_{max} shall be calculated by the given formula:

$$F_{max} = \sqrt{3} \cdot I_{max} \cdot U \cdot cos(\varphi)$$

Equation 1

(e) where I_{max} is the maximum admissible current of a critical network element (CNE), U is a fixed reference voltage for each CNE, and $\cos(\varphi)$ is the power factor.

(f) the CCC shall, by default, set the power factor $\cos(\varphi)$ to 1 based on the assumption that the CNE is loaded only by active power and that the share reactive power is negligible (i.e. $\varphi = 0$). If the share of reactive power is not negligible, a TSO may consider this aspect during the validation phase in accordance with Article 18.

3. 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. If applicable, after the end of each calendar year, each TSO shall analyse for all its CNEs for which seasonal limits are applied and have a non-zero shadow price at least in 0.1% of ID CC MTUs in the previous calendar year, the expected increase in the economic surplus in the next 10 years resulting from the implementation of dynamic limits, and compare it with the cost of implementing dynamic limits. Each TSOs shall provide this analysis to Core regulatory authorities. If the cost benefit analysis, taking into account other planned investments, is positive, the concerned TSO shall implement the dynamic limits within three years after the end of the analysed calendar year. In case of interconnectors, the concerned TSOs shall cooperate in performing this analysis and implementation when applicable.

4. TSOs shall regularly review and update operational security limits in accordance with Article 21.

[1] Uncertainties in capacity calculation are covered on each CNEC by the flow reliability margin (FRM) in accordance with Article 8 and adjustment values related to validation in accordance with Article 18.

Article 7. Methodology for allocation constraints

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) 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.

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:

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

   (b) 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);

   (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 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.

Article 8. Reliability margin methodology

1. The FRMs shall cover the following forecast uncertainties:

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

   (b) generation pattern including specific wind and solar generation forecast;

   (c) generation shift key;

   (d) load forecast;

   (e) topology forecast;

   (f) unintentional flow deviation due to frequency containment process; and

   (g) flow-based capacity calculation assumptions including linearity and modelling of external (non-Core) TSOs' areas.

2. The Core TSOs shall aim at reducing uncertainties by studying and tackling the drivers of uncertainty.

3. 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[2]. 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

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

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

4. The expected power flows on each CNEC of the Core CCR shall then be compared with the realised power flows observed on the same CNEC. When calculating the expected (respectively realised) flows for CNECs, the expected (resp. realised) flows shall be the best estimate of the expected (resp. realised) power flow which would have occurred, should the outage have taken place. Such estimate shall take curative remedial actions into account where relevant. All differences between these two flows for all ID CC MTUs of the observation period shall be used to define the probability distribution of deviations between the expected power flows at the time of the capacity calculation and the realised power flows;

5. In the second step, the 90th percentiles of the probability distributions of all CNECs shall be calculated[3]. This means that the Core TSOs apply a common risk level of 10% and thereby the FRM values cover 90% of the historical forecast errors within the observation period. Subject to the proposal pursuant to paragraph 6, the FRM value for each CNEC shall either be:

    (a) the 90th percentile of the probability distributions calculated for such CNEC;

    (b) the 90th percentile of the probability distributions calculated for the CNEs underlying such CNEC.

6. Each TSO may reduce the FRM values resulting from the second step for its own CNECs if it considers that the underlying uncertainties have been over-estimated. For CNECs used within both the Core day-ahead and intraday capacity calculations, the FRM values calculated pursuant to this methodology shall not be higher than the FRM values for the same CNECs used within the Core day-ahead capacity calculation.

7. 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

[3] This value is derived based on experience in existing flow-based market coupling initiatives.

with Article 9(13) of the CACM Regulation as well as the supporting document as referred to in paragraph 9 below.

8. The proposal for amendment of this methodology pursuant to the previous paragraph shall specify whether the FRM value shall be calculated for each CNEC based on the underlying probability distribution, or whether all CNECs with the same underlying CNE shall have the same FRM value calculated based on the probability distribution calculated for the underlying CNE. In case the proposal suggests calculating the FRMs at CNEC level, the proposal shall describe in detail how to estimate the expected and realised flows adequately, including the RAs that would have been triggered in order to manage the contingency when relevant.

9. The supporting document for the proposal for amendment of this methodology pursuant to paragraph 7 above shall include at least the following:

   (a) the FRM values for all CNECs calculated at the level of CNE and CNEC; and

   (b) an assessment of the benefits and drawbacks of calculating the FRM at the level of CNE or CNEC.

10. Until the proposal for amendment of this methodology pursuant to paragraph 7 is approved, the Core TSOs shall use the following FRM values:

   (a) if and as long as all Core TSOs apply FRM for the day-ahead capacity calculation equal to 10% of Fmax, the FRM value for intraday capacity calculation for each CNEC shall be min {5% of Fmax, FRM at day-ahead level};

   (b) as soon as the Core TSOs start applying the FRM calculation for the day-ahead capacity calculation pursuant to Article 8 of Core DA CCM, the FRM value for intraday capacity calculation shall be equal or lower than the FRM value at the day ahead level.

11. After the proposal for amendment of this methodology pursuant to paragraph 7 is approved, the FRM values shall be updated at least once every year based on an observation period of one year in order to reflect the seasonality effects. The FRM values shall then remain fixed until the next update.

Article 9. Generation shift key methodology

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

2. For a given ID CC MTU, the GSK shall only include actual generation and/or load[4] present in the CGM for that ID CC MTU. The Core TSOs shall take into account the available information on generation or load available in the CGM in order to select the nodes that will contribute to the GSK.

3. The GSKs shall describe the expected response of generation and/or load units to changes in the net positions. This expectation shall be based on the observed historical response of generation

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

and/or load units to changes in net positions, clearing prices and other fundamental factors, and thereby contributing to minimising the FRM.

4. The GSKs shall be updated and reviewed on a daily basis or whenever the expectations referred to in paragraph 3 change. The Core TSOs shall review and update the application of the generation shift key methodology in accordance with Article 21.

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

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

      i. 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.

      ii. 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.

      iii. 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.

6. 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. The proposal shall at least include:

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

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

Article 10. Methodology for remedial actions in intraday capacity calculation

1. In accordance with Article 25(1) of the CACM Regulation and Article 20(2) of the SO Regulation, the Core TSOs shall individually define the RAs to be taken into account in the intraday capacity calculation.

2. In case a RA made available for the intraday capacity calculation in the Core CCR is also made available in another CCR, the TSO having control on this RA shall take care, when defining it, of a consistent use in its potential application in both CCRs to ensure operational security.

3. In accordance with Article 25(2) and (3) of the CACM Regulation, these RAs will be used for the coordinated calculation of cross-zonal capacities while ensuring operational security in real-time.

4. RAs used for intraday capacity calculation shall be aligned as much as technically feasible with the most recent ROSC CROSA. The latest version of coordinated RAs available at the time of starting step 2 according to Article 4(9) shall be used. Such RAs will be only available once ROSC CROSA is implemented in accordance with Article 37 of Core ROSC methodology.

5. In accordance with Article 25(4) of the CACM Regulation, a TSO may withhold only those RAs, which are needed to ensure operational security in real-time operation and for which no other (costly) RAs are available, or those offered to the intraday capacity calculation in other CCRs in which the concerned TSO also participates. The CCC shall monitor and report in the annual report on systematic withholdings, which were not essential to ensure operational security in real-time operation.

6. The intraday capacity calculation may only take into account those non-costly RAs which can be modelled. These non-costly RAs can be, but are not limited to:

   (a) changing the tap position of a phase-shifting transformer (PST); and

   (b) a topological action: opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s), or switching of one or more network element(s) from one bus bar to another.

7. In accordance with Article 25(6) of the CACM Regulation, all RAs taken into account for day-ahead capacity calculation are also considered during the intraday timeframe, depending on their technical availability.

8. The RAs can be preventive or curative, i.e. affecting all CNECs or only pre-defined contingency cases, respectively.

9. TSOs shall review and update the RAs taken into account in the intraday capacity calculation in accordance with Article 21.

TITLE 4 – Update of intraday cross-zonal capacities

Article 11. Update of intraday cross-zonal capacities remaining after the SDAC

1. The CCC shall use 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.

   For the updated intraday flow-based parameters, the PTDF values shall be the final PTDFs resulting from the day-ahead capacity calculation, 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
$\overrightarrow{RAM}_{f,DA}$	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

2. 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.

3. Irrespective of the options provided to each TSO pursuant to this paragraph, each TSO shall ensure that on each bidding zone border, the long-term capacities that are in effect taken into account in the $LTA_{m\arg in,DA}$, are between 0.001 MW and 1500 MW

4. 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.

    (c) 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.

5. 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.

TITLE 5 - Description of the intraday capacity calculation process

Article 12. Calculation of power transfer distribution factors and reference flows

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 Article 13:

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

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

Article 13. Integration of HVDC interconnectors on bidding zone borders of the Core CCR

2) The Core TSOs shall apply the evolved flow-based (EFB) methodology, in accordance with paragraphs 2 to 4 below, when including HVDC interconnectors on the bidding zone borders of the Core CCR, provided that both ends of the HVDC interconnector are within the same synchronous area[5]. 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

[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.

considered in the final flow-based domain used in capacity allocation and constraints modelling the maximum possible exchange of the HVDC interconnector.

3) 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

4) 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.

5) 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.

6) 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 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.

Article 14. Consideration of non-Core bidding zone borders

1. Where critical network elements within the Core CCR are also impacted by electricity exchanges outside the Core CCR, the Core TSOs shall take such impact into account with a standard hybrid coupling (SHC) or with an advanced hybrid coupling (AHC).

2. In the standard hybrid coupling, the Core TSOs shall consider the electricity exchanges on bidding zone borders outside the Core CCR as fixed input to the intraday capacity calculation. These electricity exchanges, defined as best forecasts of net positions and flows for HVDC lines, are defined and agreed pursuant to Article 19 of the CGMM and are incorporated in each CGM. They impact the F_{ref} and $F_{0,Core}$ on all CNECs and thereby increase or decrease the RAM of the Core CNECs in order for those CNECs to accommodate the flows resulting from those exchanges. Uncertainties related to the electricity exchanges forecasts are implicitly integrated within the FRM of each CNEC.

3. 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.

4. 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.

5. Until the AHC is implemented, the Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM. The Core TSOs shall report in the annual report to all Core regulatory authorities the accuracy of such forecasts.

Article 15. Initial flow-based calculation

1. As a first step in the intraday capacity calculation process, the CCC shall merge the individual lists of CNECs provided by all Core TSOs in accordance with Article 5(4) into a single list, which shall constitute the initial list of CNECs.

2. 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.

3. The initial flow-based parameters shall be calculated pursuant to Article 12 and shall consist of the **PTDF** values and $\vec{F}_{ref}$ values for each initial CNEC.

Article 16. Definition of final list of CNECs for intraday capacity calculation

1. The CCC shall use the initial list of CNECs determined pursuant to Article 15 and remove those CNECs, for which the maximum zone-to-zone $PTDF_{init}$ is below 5%. The remaining CNECs shall constitute the final list of CNECs.

2. In the first twelve months following the implementation of the ROSC methodology in accordance with Article 76(1) of the SO Regulation, the concerned Core TSO may also add an XNEC to the final list of CNECs, with no PTDF threshold, provided that:

    (a) It was loaded 100% or more before the latest CROSA and for which cross-border redispatch or countertrading were applied during that CROSA;

    (b) Its RAM shall be at least the difference between its Fmax and its loading after the CROSA.

   After twelve months following the implementation of the ROSC methodology, the PTDF threshold of 5% shall apply to the XNEC to CNEC conversion, unless the amendment pursuant to paragraph (4) is approved and implemented.

3. The Core TSOs shall study the effects and needs for the XNEC to CNEC and may propose an amendment to this methodology, which shall at least include:

    (a) the proposed PTDF threshold for XNEC to CNEC conversion;

    (b) rules for avoiding undue discrimination between internal and cross zonal exchanges for such XNECs, which shall include limitations of such exchanges in proportion to the burdening effect of their consequential flows (internal flows and allocated flows, respectively).

Article 17. Calculation of flow-based parameters before validation

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:

    (a) 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

(b) 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.

(c) 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

2. Based on the initial flow-based domain and on the final list of CNECs, the Core CCC shall calculate for each CNEC the RAM before validation, according to the equation:

$$\overrightarrow{RAM}_{bv} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{ref}$$

Equation 12

$\vec{F}_{max}$ Maximum active power flow pursuant to Article 6

$\overrightarrow{FRM}$ Flow reliability margin pursuant to Article 8

$\overrightarrow{RAM}_{bv}$ Remaining available margin before validation

3. 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 $\mathbf{PTDF_f}$ 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 RAMvalue is set to the amount of the external constraint, corrected for the net position included in the CGM.

Article 18. Validation of flow-based parameters

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

2. Each Core TSO shall validate and have the right to decrease the RAM for reasons of operational security during the individual validation. The adjustment due to individual validation is called 'individual validation adjustment' (IVA) and it shall have a positive value, i.e. it may only reduce the RAM. IVA may reduce the RAM only to the minimum degree that is needed to ensure operational security, and only after all the expected available costly and non-costly remedial actions pursuant to Article 22 of the SO Regulation are considered. In case certain remedial actions are not implemented, such as countertrading, Core TSOs shall ensure their implementation within twelve months following the application of IDCC(b) pursuant to Article 4(2)(b).

3. The individual validation adjustment may be done in the following situations:

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

(b) when all available costly and non-costly RAs are not sufficient to ensure operational security;

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

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

4. 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 network 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 in 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.

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

6. In case of a required reduction due to situations as defined in paragraph 3(a), a TSO may use a positive value for IVA for its own CNECs or adapt the external constraints, pursuant to Article 7, to reduce the cross-zonal capacity for its bidding zone.

7. In case of a required reduction due to situations as defined in paragraph 3(b), (c), and (d), a TSO may use a positive value for IVA for its own CNECs. In case of a situation as defined in paragraph 3(c), a Core TSO may, as a last resort measure, request a common decision to launch the default flow-based parameters pursuant to Article 20.

8. After individual validation adjustments, the remaining available margin before validation ($\overrightarrow{RAM_{bv}}$) shall be adjusted for the flows resulting from net positions or already allocated capacities resulting from the SIDC in accordance with Article 4(5)c. The final RAM_f shall be calculated by the CCC for each CNEC and external constraint according to Equation 13.

$$\overrightarrow{RAM_f} = \overrightarrow{RAM_{bv}} - \overrightarrow{IVA} - \mathbf{PTDF}_{\boldsymbol{Core}}\ \overrightarrow{NP}_{AAC,IDadd}$$

Equation 13

with

$\overrightarrow{RAM_f}$	final remaining available margin
$\overrightarrow{RAM_{bv}}$	remaining available margin before validation
$\overrightarrow{IVA}$	individual validation adjustment

$\mathbf{PTDF}_{Core}$	final power transfer distribution factor matrix resulting from the intraday capacity calculation
$\overrightarrow{NP}_{AAC,IDadd}$	Core net positions resulting from SIDC which are not already included in the CGM

9. The CCC shall remove those $\overrightarrow{RAM_f}$ and $\mathbf{PTDF}_f$ values which are redundant and may therefore be removed without impacting the possible allocation of cross-zonal capacity. The pre-solved CNECs and external constraints shall thus ensure that the capacity allocation shall not exceed any limiting CNEC or external constraint.

10. Any reduction of cross-zonal capacities during the validation process shall be communicated and justified to market participants and to all Core regulatory authorities in accordance with Article 22 and Article 24, respectively.

11. Every three months, the CCC shall provide in the quarterly report all the information on the reductions of cross-zonal capacity and exceptional additions of internal network elements. The quarterly report shall include at least the following information for each CNEC of the pre-solved domain affected by a reduction and for each ID CC MTU:

    (a) the identification of the CNEC;

    (b) all the corresponding flow components pursuant to Article 22(2)(b)(vii);

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

    (d) the detailed reason(s) for reduction, including the operational security limit(s) that would have been violated without reductions, specifying network elements on which these limits would have been violated, and under which circumstances they would have been violated, as well as the list of remedial actions with their detailed information, considered prior to the reduction;

    (e) the forecast flow in the CGM used for D-1 capacity calculation, in the CGM considered for the intraday capacity calculation within which the capacity reduction occurred, in the first CGM established after the considered intraday calculation and the realised flow, before (and when relevant after) contingency;

    (f) if an internal network element with a specific contingency was exceptionally added to the final list of CNECs pursuant to Article 16 and Article 18(4):

        i. a justification why adding the network element with a specific contingency to the list was the only way to ensure operational security;

        ii. the name or the identifier of the internal network element with a specific contingency;

        iii. the ID CC MTUs for which the internal network element with a specific contingency was added to the list;

        iv. the maximum zone-to-zone PTDF calculated on the basis of the methodology in Article 12, calculated on the CGM for MTUs defined in paragraph iii;

v. for the cases under Article 16(2), the amount of total, internal, loop and allocated flows at the considered exceptionally added XNEC; and

vi. the information referred to in paragraphs (b), (c) and (e) above.

(g) the remedial actions included in the CGM before the intraday capacity calculation;

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

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

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

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

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

13. When a given Core TSO reduces capacity for its CNECs in more than 1% of ID CC MTUs of the analysed quarter, the concerned TSO shall provide to the CCC a detailed report and action plan describing how such deviations are expected to be alleviated and solved in the future. This report and action plan shall be included as an annex to the quarterly report.

14. The final flow-based parameters shall consist of $\mathbf{PTDF}_{\boldsymbol{f}}$ and $\overrightarrow{RAM}_{f}$ for CNECs and external constraints of the pre-solved domain.

Article 19. Intraday capacity calculation fallback procedure

1. 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.

2. 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 20. ATC extraction for SIDC

1. 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.

2. The flow-based parameters shall serve as the basis for the determination of the ATCs for SIDC without flow-based. As the selection of a set of ATCs from the flow-based parameters leads to an infinite set of choices, the algorithm provided in paragraph 5 determines the ATCs for SIDC without flow-based.

3. The following inputs are required to calculate ATCs for SIDC without flow-based for each ID CC MTU:

   (a) final flow-based parameters ($\mathbf{PTDF}_{\boldsymbol{f}}$ and $\overrightarrow{RAM_f}$) as calculated pursuant to Article 20 or final flow-based parameters ($\mathbf{PTDF}_{\boldsymbol{f,DA}}$ and $\overrightarrow{RAM_{UID}}$) as calculated pursuant to Article 11;

   (b) if defined, the global allocation constraints shall be assumed to constrain the Core net positions pursuant to Article 7(5), and shall be described following the methodology described in Article 17(3). Such constraints shall be adjusted for offered cross-zonal capacities on the non-Core bidding zone borders.

4. the final PTDFs ($\mathbf{PTDF}_{\boldsymbol{f}}$ and $\mathbf{PTDF}_{\boldsymbol{f,DA}}$) of all or only a subset of CNECs can be adjusted before the ID ATC extraction by setting the positive zone-to-zone PTDFs below a certain threshold to zero. The following outputs are the outcomes of the calculation for each MTU:

   (a) ATCs for SIDC without flow-based; and

   (b) constraints with zero margin after the calculation of ATCs for SIDC without flow-based.

   (c) An ATC limitation on specific borders as set by relevant TSOs as output of the local validation as defined in Annex 2: $ATC_{A \rightarrow B \text{ validated}}$

5. The calculation of the ATCs for SIDC without flow-based is an iterative procedure, which gradually calculates ATCs for each DA CC MTU, while respecting the constraints of the final flow-based parameters pursuant to paragraph 3:

   (a) The initial ATCs are set equal to zero for each Core oriented bidding zone border, i.e.:

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

   with

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

   (b) the remaining available margin at iteration zero is either equal to the final remaining available margin ($\overrightarrow{RAM_f}$) according to Article 18(8) or the updated remaining available margin for intraday cross-zonal capacities (RAM_UID) according to Article 11(1):

$$\overrightarrow{RAM}_{ATC}(0) = \overrightarrow{RAM_f}$$
$$\text{or } \overrightarrow{RAM}_{ATC}(0) = \overrightarrow{RAM}_{UID}$$

Equation 14

   with

$\overrightarrow{RAM}_{ATC}(0)$	remaining available margin for ATC calculation at iteration *k*=0

$\overrightarrow{RAM}_f$	remaining available margin of the flow-based parameters pursuant to paragraph 3.
$\overrightarrow{RAM}_{UID}$	updated remaining available margin for intraday cross-zonal capacities

(c) In the case when there are negative RAMs, negative ATCs are calculated for CNECs with negative $RAM_{ATC}(0)$ according to the following procedure:

i. Per CNEC with negative remaining available margin for ATC calculation at iteration *k*=0 ($RAM_{ATC}(0)$) negative ATCs are calculated for all oriented bidding zone borders with positive PTDFs according to Equation 14a:

$$ATC_{A\to B,CNEC\,i} = \frac{pPTDF_{A\to B,CNEC\,i}}{\sum_{(A,B)\in\,Core\ contract\ paths\ with\ positive\ z2zPTDFs} PTDF_{A\to B}^2} RAM_{ATC,CNEC\,i}(0)$$

Equation 14a

with

$ATC_{A\to B,CNEC\,i}$	negative ATC for the oriented bidding zone border A to B determined by CNEC i
A, B	Core bidding zones
$RAM_{ATC,CNEC\,i}(0)$	remaining available margin for ATC calculation at iteration *k*=0 of CNEC i
$pPTDF_{A\to B,CNEC\,i}$	Final positive zone-to-zone PTDF of the oriented bidding zone border A to B

ii. In case for an oriented Core bidding zone border more than one negative ATC has been calculated according to Equation 14athen for each oriented Core bidding zone border the most negative ATC is determined over all CNECs with negative remaining available margin.

$$\overrightarrow{ATC}_{A\to B} = min\left(\overrightarrow{ATC}_{A\to B,CNEC\,i}\right)$$

Equation 14b

iii. After extraction of negative ATCs a scaling factor (*SF*) is calculated for each CNEC with negative remaining available margin:

$$SF_{CNEC\,i} = \left|\frac{RAM_{ATC,CNEC\,i}(0)}{\sum_{(A,B)\in\,Core\ contract\ paths\ with\ positive\ z2zPTDFs} PTDF_{A\to B,CNEC\,i}\ ATC_{A\to B}}\right|$$

Equation 14c

The final scaling factor (SF_{final}) is the maximum of all calculated scaling factors:

$$SF_{final} = max(SF_{CNEC\,i})$$

Equation 14d

iv. The final negative ATCs are calculated by scaling the negative ATCs with the final scaling factor:

$$\overrightarrow{ATC}_{negative,final} = \overrightarrow{ATC}_{A \to B}\, SF_{final}$$

Equation 14e

(d) Before starting the iterative method applied to calculate the positive ATCs for SIDC fallback all the remaining available margins for ATC calculation at iteration k=0 ($\overrightarrow{RAM}_{ATC}(0)$) shall be adjusted to be non-negative:

$$\overrightarrow{RAM}_{ATC}(0) = \max\left(0, \overrightarrow{RAM}_{ATC}(0)\right)$$

Equation 14f

with

$\overrightarrow{RAM}_{ATC}(0)$	remaining available margin for ATC calculation at iteration *k*=0

The iterative method applied to calculate the positive ATCs for SIDC without flow-based consists of the following actions for each iteration step *k*:

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

$$\overrightarrow{RAM}_{ATC}(k) = \overrightarrow{RAM}_{ATC}(0) - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}\, \overrightarrow{ATC}_{k-1}$$

Equation 14g

with

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

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

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

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

v. $\overrightarrow{ATC_k}$ is limited to a maximum value of $ATC_{A\rightarrow B\ \mathrm{validated}}$ if such value has been introduced by TSOs on the border A→B as a result of the ATC validation phase as described in Annex 2. Then go back to step i;

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

vii. the resulting positive ATCs for SIDC without flow-based stem from the ATC values determined in iteration k, after rounding down to integer values;

viii. at the end of the calculation, there are some CNECs and external constraints with no remaining available margin left. These are, together with the CNECs and external constraints with initially negative $RAM_{ATC}(0)$, the limiting constraints for the calculation of ATCs for SIDC without flow-based.

(e) positive zone-to-zone PTDF matrix ($\mathbf{pPTDF}_{zone-to-zone}$) for each Core oriented bidding zone border shall be calculated from the $\mathbf{PTDF}_{Core}$ as follows (for HVDC interconnectors integrated pursuant to Article 13, Equation 8 shall be used):

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

Equation 15a

with

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

(f) The final ATCs per Core oriented bidding zone border are the minimum from positive and negative ATCs:

$$\overrightarrow{ATC}_{final} = \min\left(\overrightarrow{ATC_k}, \overrightarrow{ATC}_{negative,final}\right)$$

Equation 15b

TITLE 6 – Updates and data provision

Article 21. Reviews and updates

1. Based on Article 3(f) of the CACM Regulation and in accordance with Article 27(4) of the same Regulation, all TSOs shall regularly and at least once a year review and update the key input and output parameters listed in Article 27(4)(a) to (d) of the CACM Regulation.

2. If the operational security limits, critical network elements, contingencies and allocation constraints used for intraday capacity calculation inputs pursuant to Article 5 and Article 7 need to be updated

based on this review, the Core TSOs shall publish the changes at least 1 week before their implementation.

3. In case the review proves the need for an update of the reliability margins, the Core TSOs shall publish the changes at least one month before their implementation.

4. The review of the list of RAs taken into account in the intraday capacity calculation, as defined in Article 10(4), shall include at least an evaluation of the efficiency of specific PSTs and the topological RAs considered from the CROSA process.

5. In case the review proves the need for updating the application of the methodologies for determining GSKs, critical network elements and contingencies referred to in Articles 22 to 24 of the CACM Regulation, changes have to be published at least three months before their implementation.

6. Any changes of parameters listed in Article 27(4) of the CACM Regulation shall be communicated to market participants, all Core regulatory authorities and ACER.

7. The Core TSOs shall communicate the impact of any change of allocation constraints and parameters listed in Article 27(4)(d) of the CACM Regulation to market participants, all Core regulatory authorities and ACER. If any change leads to an adaption of the methodology, the Core TSOs shall make a proposal for amendment of this methodology according to Article 9(13) of the CACM Regulation.

Article 22. Publication of data

1. In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to all regulatory authorities and market participants, all Core TSOs and the CCC shall regularly publish the data on the intraday capacity calculation process pursuant to this methodology as set forth in paragraph 2 on a dedicated online communication platform where capacity calculation data for the whole Core CCR shall be published. To enable market participants to have a clear understanding of the published data, all Core TSOs and the CCC shall develop a handbook and publish it on this communication platform. This handbook shall include at least a description of each data item, including its unit and underlying convention.

2. The Core TSOs and the CCC shall publish at least the following data items (in addition to the data items and definitions of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets):

   (a) cross-zonal capacities in accordance with Article 4(2) by the deadlines set therein;

   (b) the following information for intraday cross-zonal capacity calculation and re-calculation pursuant to Article 4(2)(b) to (e) shall be published by the deadlines established therein:

      i. maximum and minimum possible net position of each bidding zone;

      ii. maximum possible bilateral exchanges between all pairs of Core bidding zones;

      iii. if applicable, ATCs for SIDC without flow-based;

      iv. names of CNECs (with geographical names of substations where relevant and separately for CNE and contingency) and external constraints of the final flow-based parameters before pre-solving and the TSO defining them;

v. for each CNEC of the final flow-based parameters before pre-solving, the EIC code of CNE and Contingency;

vi. for each CNEC of the final flow-based parameters before pre-solving, the method for determining I_{max} in accordance with Article 6(2)(a);

vii. detailed breakdown of RAM for each CNEC of the final flow-based parameters before pre-solving: I_{max}, U, F_{max}, FRM, F_{ref}, $F_{0,\text{core}}$, $F_{0,\text{all}}$, $F_{\text{ref,core}}$, F_{uaf}, IVA;

viii. value of each external constraint before pre-solving;

ix. indication of whether default flow-based parameters were applied;

x. indication of whether a CNEC is redundant or not;

xi. information about the validation reductions:

- the identification of the CNEC;
- the TSO invoking the reduction;
- the volume of reduction (IVA);
- the detailed reason(s) for reduction in accordance with Article 18(2) and 18(3), including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;
- if an internal network elements with a specific contingency was exceptionally added to the final list of CNECs during validation: (i) a justification of the reasons of why adding the internal network elements with a specific contingency to the list was the only way to ensure operational security, (ii) the name or identifier of the internal network elements with a specific contingency, along with the calculated set of PTDFs;

(c) the following forecast information contained in the CGM for each ID CC MTU shall be published by the deadlines established in Article 4(2):

i. vertical load for each Core bidding zone and each TSO;

ii. production for each Core bidding zone and each TSO;

iii. Core net position for each Core bidding zone and each TSO;

iv. 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

(d) as soon as the SIDC directly applies the flow-based parameters, in case of intraday auctions, two hours after the auction, the information pursuant to paragraph 2(b)(vii) shall be complemented by the following information for each CNEC and external constraint of the final flow-based parameters.

i. shadow prices;

ii. flows resulting from net positions obtained at intraday auctions.

(e) every six months, the publication of an up-to-date static grid model by each Core TSO.

(f) The CCC shall include in its quarterly report as defined in Article 25(6) the flows resulting from net positions resulting from intraday auctions on each CNEC and external constraint of the final flow-based parameters. This requirement is valid after the SIDC will directly apply the flow-based parameters.

3. Individual Core TSO may withhold the information referred to in paragraph 2(b)(iv), 2(b)(v) and 2(e) if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of the Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. In such a case, the information referred to in paragraph 2(b)(iv) and 2(b)(v) shall be replaced with an anonymous identifier which shall be stable for each CNEC across all ID CC MTUs. The anonymous identifier shall also be used in the other TSO communications related to the CNEC, including the static grid model pursuant to paragraph 2(e) and when communicating about an outage or an investment in infrastructure. The information about which information has been withheld pursuant to this paragraph shall be published on the communication platform referred to in paragraph 1.

4. Any change in the identifiers used in paragraphs 2(b)(iv), 2(b)(v) and 2(e) shall be publicly notified at least one month before its entry into force. The notification shall at least include:

(a) the day of entry into force of the new identifiers; and

(b) the correspondence between the old and the new identifier for each CNEC.

5. Pursuant to Article 20(9) of the CACM Regulation, the Core TSOs shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones. The tool shall be developed in coordination with stakeholders and all Core regulatory authorities and updated or improved when needed.

6. The Core regulatory authorities may request additional information to be published by the TSOs. For this purpose, all Core regulatory authorities shall coordinate their requests among themselves and consult it with stakeholders and ACER. Each Core TSO may decide not to publish the additional information, which was not requested by its competent regulatory authority.

Article 23. Quality of the data published

1. No later than six months before the implementation of this methodology in accordance with Article 25(2)(b), the Core TSOs shall jointly establish and publish a common procedure for monitoring and ensuring the quality and availability of the data on the dedicated online communication platform as referred to in Article 22. When doing so, they shall consult with relevant stakeholders and all Core regulatory authorities.

2. The procedure pursuant to paragraph 1 shall be applied by the CCC, and shall consist of continuous monitoring process and reporting in the annual report. The continuous monitoring process shall include the following elements:

(a) individually for each TSO and for the Core CCR as a whole: data quality indicators, describing the precision, accuracy, representativeness, data completeness, comparability and sensitivity of the data;

(b) the ease-of-use of manual and automated data retrieval;

(c) automated data checks, which shall be conducted in order automatically to accept or reject individual data items before publication based on required data attributes (e.g. data type, lower/upper value bound, etc.); and

(d) satisfaction survey performed annually with stakeholders and the Core regulatory authorities.

The quality indicators shall be monitored in daily operation and shall be made available on the platform for each dataset and data provider such that users are able to take this information into account when accessing and using the data.

3. The CCC shall provide in the annual report at least the following:

   (a) the summary of the quality of the data provided by each data provider;

   (b) the assessment of the ease-of-use of data retrieval (both manual and automated);

   (c) the results of the satisfaction survey performed annually with stakeholders and all Core regulatory authorities; and

   (d) suggestions for improving the quality of the provided data and/or the ease-of-use of data retrieval.

4. The Core TSOs shall commit to a minimum value for at least some of the indicators mentioned in paragraph 2, to be achieved by each TSO individually on average on a monthly basis. Should a TSO fail to fulfil at least one of the data quality requirements, this TSO shall provide to the CCC within one month following the failure to fulfil the data quality requirement, detailed reasons for the failure to fulfil data quality requirements, as well as an action plan to correct past failures and prevent future failures. No later than three months after the failure, this action plan shall be fully implemented and the issue resolved. This information shall be published on the online communication platform and in the annual report.

Article 24. Monitoring and reporting

1. The Core TSOs shall provide to the Core regulatory authorities data on intraday capacity calculation for the purpose of monitoring its compliance with this methodology and other relevant legislation.

2. At least, the information on non-anonymized names of CNECs for final flow-based parameters before pre-solving as referred to in Article 22(2)(b)(iv) and (v) shall be provided to all Core regulatory authorities on a monthly basis for each CNEC and each ID CC MTU. This information shall be in a format that allows easily to combine the CNEC names with the information published in accordance with Article 22(2).

3. In addition, each month, starting in January 2025 with data for December 2024, the Core TSOs shall provide the Core regulatory authorities and ACER with the following data for each MTU and each CNEC:

   (a) final zone-to-hub PTDF values for all modelled bidding zones;

   (b) Core net positions pursuant to Article 4(5); and

   (c) flow components, consisting of the internal flow, loop flows (total loop flow and particular loop flows created by each bidding zone) and PST flow.

4. The Core regulatory authorities may request additional information to be provided by the TSOs. For this purpose, all Core regulatory authorities shall coordinate their requests among themselves. Each Core TSO may decide not to provide the additional information, which was not requested by its competent regulatory authority.

5. The CCC, with the support of the Core TSOs where relevant, shall draft and publish an annual report satisfying the reporting obligations set in Articles 10, 14, 23 and 25 of this methodology:

    (a) according to Article 10(5), the Core TSOs shall report to the Core CCC on systematic withholdings which were not essential to ensure operational security in real-time operation.

    (b) according to Article 14(5), the Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM.

    (c) according to Article 23(3), the CCC shall monitor and report on the quality of the data published on the dedicated online communication platform as referred to in Article 22, with supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned TSOs, where relevant.

    (d) according to Article 25(4), after the implementation of this methodology, the Core TSOs shall report on their continuous monitoring of the effects and performance of the application of this methodology.

6. The CCC, with the support of the Core TSOs where relevant, shall draft and publish a quarterly report satisfying the reporting obligations set in Articles 7, 19 and 26 of this methodology:

    (a) according to Article 7(3)(b), the CCC shall collect all reports analysing the effectiveness of relevant allocation constraints, received from the concerned TSOs during the period covered by the report, and annex those to the quarterly report.

    (b) according to Article 18(10), the CCC shall provide all information on the reductions of cross-zonal capacity, with a supporting detailed analysis from the concerned TSOs where relevant.

    (c) according to Article 25(4), during the implementation of this methodology, the Core TSOs shall report on their continuous monitoring of the effects and performance of the application of this methodology.

    (d) according to Article 22(2)(f), Core TSOs shall report on flows resulting from net positions resulting from the intraday auctions, on each CNEC and external constraint of the final flow-based parameters. This requirement is valid after the SIDC will directly apply the flow-based parameters.

7. The published annual and quarterly reports may withhold commercially sensitive information or sensitive critical infrastructure protection related information as referred to in Article 22(3). In such a case, the Core TSOs shall provide the Core regulatory authorities with a complete version where no such information is withheld.

TITLE 7 - Implementation

Article 25. Timescale for implementation

1. The TSOs of the Core CCR shall publish this methodology without undue delay after the decision has been taken by ACER in accordance with Article 9(12) of the CACM Regulation.

2. The TSOs of the Core CCR shall implement this methodology within the following timeframes:

   (a) IDCC(a): update of cross-zonal capacities pursuant to Article 4(2)(a) by the deadline for the implementation of day-ahead capacity calculation methodology as established in the day-ahead capacity calculation methodology of the Core CCR;

   (b) IDCC(b): calculation of intraday cross-zonal capacities pursuant to Article 4(2)(b) by **4 months** after the adoption of ACER Decision 03/2024 approving the related amendments;

   (c) IDCC(c): re-calculation of intraday cross-zonal capacities pursuant to Article 4(2)(c) by **13 months** after the implementation of calculation of intraday cross-zonal capacities pursuant to point (b) of this paragraph;

   (d) 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

   (e) 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.

3. The implementation process, which shall start with the entry into force of this methodology and finish by the deadlines established in paragraph 2, shall consist of the following steps:

   (a) internal parallel run, during which the TSOs shall test the operational processes for the intraday capacity calculation inputs, the intraday capacity calculation process and the intraday capacity validation and develop the appropriate IT tools and infrastructure;

   (b) external parallel run, during which the TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, the Core TSOs will involve the Core NEMOs to test the implementation of this methodology, and market participants to test the effects of applying this methodology on the market. In accordance with Article 20(8) of CACM Regulation, this phase shall not be shorter than 6 months.

4. During the internal and external parallel runs, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. For this purpose, they shall develop, in coordination with the Core regulatory authorities, ACER and stakeholders, the monitoring and performance criteria and report on the outcome of this monitoring on a quarterly basis in a quarterly report. After the implementation of this methodology, the outcome of this monitoring shall be reported in the annual report.

5. 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.

6. 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.

7. If required, following the expected amendments to the CACM Regulation, this methodology shall be revised accordingly.

8. 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.

TITLE 8 - Final provisions

Article 26. Language

1. The reference language for this methodology shall be English. For the avoidance of doubt, where TSOs need to translate this methodology into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant TSO shall, in accordance with national legislation, provide the relevant Core regulatory authorities with an updated translation of the methodology.

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

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.

0) 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.

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

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

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

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

Where:

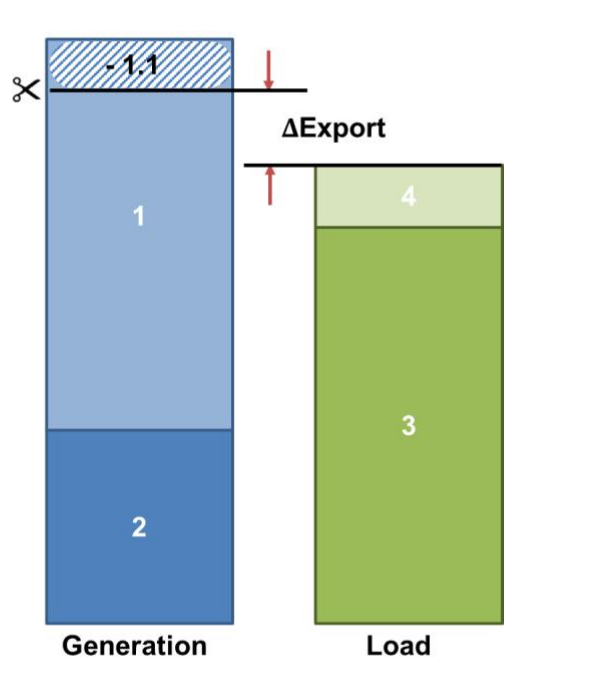
P_{CD}	Sum of operating generating capacities of centrally dispatched units as declared by generators
P_{CDmin}	Sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for 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.

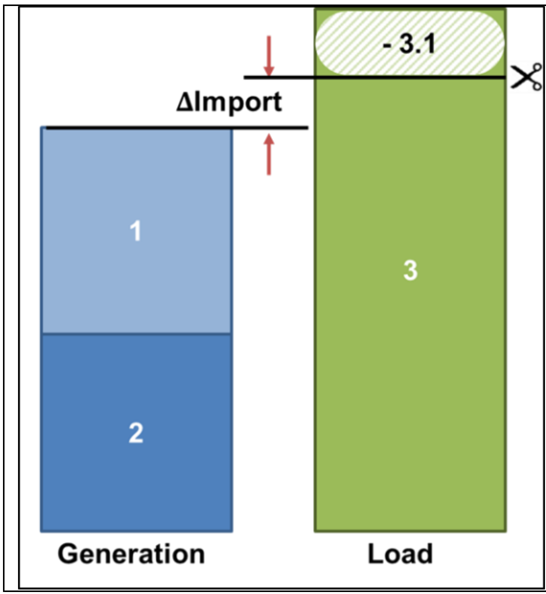
Equation (2) refers to the need of securing the capacity that can be quickly reduced to balance supply and demand when there is an excess of power in the grid e.g. in case of loss of significant load.

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:
   1.1 Generation not available due to grid constraints
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
3. Demand forecasted by PSE
4. Minimum necessary reserve for up regulation

Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of the intraday capacity calculation.



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

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

3 Demand forecasted by PSE, reduced by:
3.1 Minimum necessary reserve for down regulation

Figure 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).

i) **Reasons EirGrid and SONI propose using external constraints**

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

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

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

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

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

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

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

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

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

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.

Annex 2: ATC based validation process

1. Each Core TSO has the right to perform an ATC based validation in order to ensure operational security. This is an additional process, next to the existing validation process described in Article 18 as IVA validation. Pursuant to this validation, each Core TSO can set a maximum ATC value for its own oriented border.
2. The ID ATC on a bidding zone border shall always be the lowest value of all ID ATCs set by all TSOs for this bidding zone border.

$$ATC_{A\text{à}B\ validated} = \min\left(\overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ 1}, \overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ 2}, \overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ x}\right)$$

Equation 16

with

$ATC_{A\text{à}B\ validated}$	Minimum of validated ATCs for border A→B by all Core TSOs adjacent to this border
$\overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ x}$	Validated ATC for border A→B by TSO x

3. The ATC limitation may be done only in the following situations:

   (a) an occurrence of an unexpected contingency impacting a CNE after the beginning of the related IDCC process;

   (b) as a fallback, in case IVA validation cannot be performed fully in time or if it faces IT issue; or

   (c) a mistake in input data that leads to an overestimation of cross-zonal capacity from an operational system security perspective.

4. In addition to the publication described in Article 22, Core TSOs and the CCC shall publish at least the following information and data items with regard to the ATC based validation for each IDCC MTU:

   (a) The TSO invoking the limitation;

   (b) The ATC limitation per border;

   (c) The situation applicable as per the previous paragraph; and

   (d) The detailed reason for the limitation of the ATC with the same level of information as IVA validation following the reasonings developed in Article 18(2), including the operational security limits (when relevant) that would have been violated without the reductions, and under which circumstances they would have been violated.

5. Every three months, the CCC, with the support of Core TSOs where relevant, shall provide in the quarterly report the data items given under paragraph 4(a), 4(b), 4(c) and 4(d), with regard to the ATC based validation for each IDCC MTU.