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

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

Clean version
(for informative purpose only)

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Contents

Whereas

(1) This document sets out the capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on Capacity Allocation and Congestion Management (hereafter referred to as the "CACM Regulation"). This methodology is hereafter referred to as the "day-ahead capacity calculation methodology".

(2) The day-ahead capacity calculation methodology takes into account the general principles and goals set in the CACM Regulation as well as in Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity (hereafter referred to as "Regulation (EC) No 714/2009"). The goal of the CACM Regulation is the coordination and harmonisation of capacity calculation and allocation in the day-ahead and intraday cross-border markets. It sets, for this purpose, the requirements to establish a day-ahead capacity calculation methodology to ensure efficient, transparent and non-discriminatory capacity allocation.

(3) According to Article 9(9) of the CACM Regulation, the expected impact of the day-ahead capacity calculation methodology on the objectives of the CACM Regulation has to be described and is presented below.

(4) The day-ahead capacity calculation methodology serves the objective of promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) since it ensures that the cross-zonal capacity is calculated in a way that avoids undue discrimination between market participants and since the same day-ahead capacity calculation methodology will apply to all market participants on all respective bidding zone borders in the Core CCR, thereby ensuring a level playing field amongst market participants. Market participants will have access to the same reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation, at the same time and in a transparent way.

(5) The day-ahead capacity calculation methodology contributes to the optimal use of transmission infrastructure and to operational security (Article 3(b) and (c) of the CACM Regulation) since the flow-based approach aims at providing the maximum available capacity to market participants on the day-ahead timeframe within the operational security limits.

(6) The day-ahead capacity calculation methodology contributes to avoiding that cross-zonal capacity is limited in order to solve congestion inside control areas by (i) defining clear criteria under which the network elements located inside bidding zones can be considered as limiting for capacity calculation, and (ii) ensuring that a minimum share of the capacity is made available for commercial exchanges while ensuring operational security (Article 3(a) to (c) of the CACM Regulation and Point 1(7) of Annex I to the Regulation (EC) 714/2009).

(7) The day-ahead capacity calculation methodology serves the objective of optimising the allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation), since it is using the flow-based approach, which optimises the way in which the cross-zonal capacities are allocated to market participants, and since it facilitates the efficiency of congestion management by comparing the capacity allocation with other congestion management alternatives, such as the application of remedial actions, bidding zone reconfiguration and network investments.

(8) The day-ahead capacity calculation methodology is designed to ensure a fair and non-discriminatory treatment of TSOs, nominated electricity market operators ('NEMOs'), the Agency, regulatory authorities and market participants (Article 3(e) of the CACM Regulation) since the day-ahead capacity calculation methodology has been developed and adopted within a process that ensures the involvement of all relevant stakeholders and independence of the approving process.

(9) The day-ahead capacity calculation methodology determines the main principles and main processes for the day-ahead timeframe. It requires that the Core TSOs provide market participants with reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation in a transparent way and at the same time. This includes information on all steps of capacity calculation and regular reporting on specific processes within capacity calculation. The day-ahead capacity calculation methodology therefore contributes to the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation).

(10) The day-ahead capacity calculation methodology provides requirements for efficient use of existing electricity infrastructure and facilitates competitive and equal access to transmission infrastructure in particular in case of congestions. This provides a long-term signal for efficient investments in transmission, generation and consumption, and thereby contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM Regulation).

(11) The day-ahead capacity calculation methodology also contributes to the objective of respecting the need for a fair and orderly market and price formation (Article 3(h) of the CACM Regulation) by making available in due time the information about cross-zonal capacities to be released in the market, by maximising the available cross-zonal capacities and by ensuring a backup solution for the cases where capacity calculation fails to provide flow-based parameters.

(12) The day-ahead capacity calculation methodology facilitates a level playing field for NEMOs (Article 3(i) of the CACM Regulation) since all NEMOs and all their market participants will face the same rules and non-discriminatory treatment (including timings, data exchanges, results formats etc.) within the Core CCR.

(13) Finally, the day-ahead capacity calculation methodology contributes to the objective of providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) by ensuring a transparent and non-discriminatory approach towards facilitating cross-zonal capacity allocation.

(14) In conclusion, the day-ahead capacity calculation methodology contributes to the general objectives of the CACM Regulation to the benefit of all market participants and electricity end consumers.

(15) The day-ahead capacity calculation methodology is structured into three stages: (i) the definition and provision of capacity calculation inputs by the Core TSOs, including the underlying principles and calculation methods for these inputs, (ii), the capacity calculation process by the coordinated capacity calculator in coordination with the Core TSOs, and (iii) the capacity validation by the Core TSOs in coordination with the coordinated capacity calculator. The roles and responsibilities of the Core TSOs and of the coordinated capacity calculator need to be clearly defined.

(16) The day-ahead capacity calculation methodology is based on forecast models of the transmission system. The inputs are created two days before the electricity delivery date with the available knowledge at that time. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.

(17) The methodology applies temporary solutions for reliability margins, generation shift keys and allocation constraints. As regards reliability margins, the first real calculation can only be done after some operational experience is gained with the application of this methodology. For generation shift keys, TSOs also need some operational experience in order to be able to improve them. The final definition of these capacity calculation inputs should therefore be reviewed and redefined if needed after the effective implementation of this methodology.

(18) Some operational security limits can be transformed into limitations on active power flows on critical network elements, whereas some other cannot and may be modelled as allocation constraints. Some

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

(19) To avoid undue discrimination between internal and cross-zonal exchanges (and the underlying discrimination between market participants trading inside or between bidding zones), this methodology introduces two important measures. The first measure aims to limit the situations where cross-zonal exchanges are limited by congestions inside bidding zones. The second measure aims to minimise the degree to which the flows resulting from exchanges inside a bidding zone on network elements located inside that zone (i.e. internal flows) or on network elements on the borders of bidding zones and inside neighbouring bidding zones (i.e. loop flows) are reducing the available cross-zonal capacity.

(20) In the zonal congestion management model established by the CACM Regulation, bidding zones should be established such that physical congestions occur only on network elements located on the borders of such bidding zones. The network elements located within bidding zones should therefore *a priori* not limit cross-zonal capacity and should therefore not be considered in capacity calculation. Nevertheless, at the time of adoption of this methodology, some network elements located inside the Core bidding zones are often congested and therefore TSOs need some transition period to shift gradually from limiting cross-zonal capacity, as the main method to address these internal congestions, to other methods in which internal congestions limit cross-zonal capacity only when this is the most efficient solution considering other alternatives (such as remedial actions, reconfiguration of bidding zones or network investments). Only in case those alternatives are proven inefficient, TSOs should be able to continue addressing internal congestions by limiting cross-zonal capacity beyond the transition period.

(21) In highly meshed electricity networks, exchanges inside bidding zones create flows through other bidding zones (i.e. loop flows) which can significantly reduce the capacity for trading between bidding zones. To avoid undue discrimination between internal and cross-zonal exchanges, this methodology aims to minimise the negative impact of these loop flows. This is first achieved by allowing TSOs to define initial settings of remedial actions with the aim to reduce the loop flows on their interconnectors. These remedial actions are then further coordinated within capacity calculation process with a constraint not to increase loop flows beyond a defined threshold. This measure is needed to avoid undue discrimination in situations where coordination of remedial actions would significantly increase loop flows in order to address congestions within bidding zones. Since this first measure is optional for TSOs, the second measure aims to ensure that the final outcome of the capacity calculation meets the agreed thresholds for available cross-zonal capacities, where such thresholds are established by limiting the number and size of variables which reduce cross-zonal capacities. For this purpose, at least 70% of the technical capacity of critical network elements considered in capacity calculation should be available for cross-zonal trade in all CCRs in the day-ahead timeframe. Nevertheless, in case of exceptions or deviations granted in accordance with the relevant Union legislation, the target value of 70% may temporally be replaced by a linear trajectory.

(22) Despite coordinated application of capacity calculation, TSOs remain responsible for maintaining operational security. For this reason they need to validate the calculated cross-zonal capacities to

ensure that they do not violate operational security limits. This validation is first performed in a coordinated way to verify whether a coordinated application of remedial actions can address possible operational security issues. Finally, each TSO may individually validate cross-zonal capacities. Both validation steps may lead to reductions of cross-zonal capacities below the values needed to avoid undue discrimination. Thus transparency, monitoring and reporting, as well as the exploration of alternative solutions are needed in case of reductions of cross-zonal capacities.

(23) Transparency and monitoring of capacity calculation are essential for ensuring its efficiency and understanding. This methodology establishes significant requirements on TSOs to publish the information required by stakeholders to analyse the impact of capacity calculation on the market functioning. Furthermore, additional information is required to allow regulatory authorities to perform their monitoring duties. Finally, the methodology establishes significant reporting requirements in order for stakeholders, regulatory authorities and other interested parties to verify whether the transmission infrastructure is operated efficiently and in the interest of consumers.

(24) Cross-zonal capacities determined by the day-ahead capacity calculation shall ensure that all combinations of net positions that could result from previously-allocated cross-zonal capacity – Long Term Allocations (LTA) – can be accommodated. For that purpose, the TSOs proceeded to the LTA inclusion which consists in providing a single flow-based domain including LTAs for the single day-ahead coupling. The extended LTA inclusion approach differs by providing the single day-ahead coupling with LTAs and the flow-based domain without LTA inclusion separately. The market coupling algorithm then chooses which union of both domains creates most welfare. Core TSOs will cease to apply LTA inclusion at the latest when long-term capacities will be calculated and allocated pursuant to the FCA Regulation. This shall serve to decouple maintaining of operational security from the amount of LTAs.

(25) To enable a more accurate and efficient representation of connections with neighbouring CCRs, the advanced hybrid coupling (AHC) is foreseen in the Core DA CCM to replace the standard hybrid coupling and provide efficiency gains in the capacity calculation and allocation phase on the borders where AHC is applied. AHC principles can also rather efficiently be applied to a lowly meshed alternating current (AC) border between a Core and a non-Core bidding zone, while its efficiency and accuracy of network representation diminishes with the increased meshness of AC borders. Implementation of AHC is foreseen on all borders linking Core bidding zones and bidding zones of neighbouring CCRs and which are part of SDAC, except for the common borders with Italy North CCR which is planned to be merged with the Core CCR under a future common flow-based approach and for the common borders with SWE where only a low efficiency gain is expected in comparison with the challenges imposed by AHC.

TITLE 1 - General provisions

Article 1. Subject matter and scope

The day-ahead capacity calculation methodology shall be considered as a Core TSOs' methodology in accordance with Article 20ff. of the CACM Regulation and shall cover the day-ahead capacity calculation methodology for the Core CCR bidding zone borders.

Article 2. Definitions and interpretation

1. For the purposes of the day-ahead capacity calculation methodology, terms used in this document shall have the meaning of the definitions included in Article 2 of the CACM Regulation, of Regulation (EC) 714/2009, Directive 2009/72/EC, Commission Regulation (EU) 2016/1719 (hereafter referred to as the 'FCA Regulation'), Commission Regulation (EU) 2017/2195 and

Commission Regulation (EU) 543/2013. In addition, the following definitions, abbreviations and notations shall apply:

1. '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;

1a. 'AHC border' means a border between a bidding zone within and outside of Core CCR where both bidding zones are part of Single-Day-Ahead Coupling and the AHC is applied;

2. 'AMR' means the adjustment for the minimum remaining available margin;

3. 'annual report' means the report issued on an annual basis by the CCC and the Core TSOs on the day-ahead capacity calculation;

4. '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;

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

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

7. 'CGM' means the common grid model as defined in Article 2(2) of the CACM Regulation and means a D-2 CGM established in accordance with the CGMM;

8. 'CGMM' means the common grid model methodology, pursuant to Article 17 of the CACM Regulation;

9. 'CNE' means a critical network element;

10. '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;

11. '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;

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

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

14. ‘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);

15. ‘curative remedial action’ means a remedial action which is only applied after a given contingency occurs;

16. ‘D-1’ means the day before electricity delivery;

17. ‘D-2’ means the day two-days before electricity delivery;

18. ‘DA CC MTU’ is the day-ahead capacity calculation market time unit, which means the time unit for the day-ahead capacity calculation and is equal to 60 minutes;

19. ‘default flow-based parameters’ means the pre-coupling backup values calculated in situations when the day-ahead capacity calculation fails to provide the flow-based parameters in three or more consecutive hours. These flow-based parameters are based on long-term allocated capacities;

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

20a. ‘external virtual hub (EVH)’ means a virtual bidding zone without any buy and sell orders, used to represent the imports and exports on an AHC border as specified in Article 13 of this Methodology or exchanges on HVDC interconnectors on the bidding zone borders of the Core CCR when either end of a HVDC interconnector is in a different synchronous area as specified in Article 12 (5);

21. ‘$F_{0,Core}$’ means the flow per CNEC in the situation without commercial exchanges within the Core CCR and with EVH;

22. ‘$F_{0,all}$’ 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;

23. ‘F_i’ means the expected flow in commercial situation *i*;

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

25. ‘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;

26. ‘F_{LTN}’ means the expected flow after long-term nominations;

27. ‘F_{max}’ means the maximum admissible power flow;

28. ‘F_{nrao}’means the expected flow change due to non-costly remedial actions optimisation;

29. ‘F_{ref}’ means the reference flow;

30. ‘$F_{ref,init}$’ means the reference flow calculated during the initial flow-based calculation pursuant to Article 14;

31. 'GSK' or 'GSK' means the generation shift key as defined in Article 2(12) of the CACM Regulation;

32. HVDC' means a high voltage direct current network element

33. 'IGM' means the D-2 individual grid model as defined in Article 2(1) of the CACM Regulation;

34. 'internal CNEC' means a CNEC, which is not cross-zonal;

34a. '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 12 of this Methodology;

35. 'I_{max}' means the maximum admissible current;

36. 'LTA' means the long-term allocated capacity;

37. (deleted)

38. 'LTN' means the long-term nomination, which is the nomination of the long-term allocated capacity;

39. 'merging agent' means an entity entrusted by the Core TSOs to perform the merging of individual grid models into a common grid model as referred to in Article 20ff of the CGMM;

40. 'MNEC' means a monitored network element with a contingency;

41. 'NP' or 'NP' means a net position of a bidding zone, which is the net value of generation and consumption in a bidding zone;

42. 'NRAO' means the non-costly remedial action optimisation;

43. 'oriented bidding zone border' means a given direction of a bidding zone border (e.g. from Germany to France);

44. 'pre-solved domain' means the final set of binding constraints for capacity allocation after the pre-solving process;

45. 'pre-solving process' means the identification and removal of redundant constraints from the flow-based domain;

46. 'preventive remedial action' means a remedial action which is applied on the network before any contingency occurs;

47. 'previously-allocated capacities' means the long-term capacities which have already been allocated in previous (yearly and/or monthly) time frames;

48. 'PST' means a phase-shifting transformer;

49. 'PTDF' or '$PTDF$' means a power transfer distribution factor;

50. '$\mathbf{PTDF}_{init}$' means a matrix of power transfer distribution factors resulting from the initial flow-based calculation;

51. '$\mathbf{PTDF}_{nrao}$'means a matrix of power transfer distribution factors used during the NRAO;

52. '$\mathbf{PTDF}_{f}$' means a matrix of power transfer distribution factors describing the final flow-based domain;

53. 'PTR' means a physical transmission right;

54. 'quarterly report' means a report on the day-ahead capacity calculation issued by the CCC and the Core TSOs on a quarterly basis;

55. 'RA' means a remedial action as defined in Article 2(13) of the CACM Regulation;

56. 'RAM' or 'RAM' means a remaining available margin;

57. 'reference net position or exchange' means a position of a bidding zone or an exchange over HVDC interconnector assumed within the CGM;

58. 'SDAC' means the single day-ahead coupling;

59. '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;

60. 'slack node' means the reference node used for determination of the PTDF matrix, i.e. shifting the power infeed of generators up results in absorption of the power shift in the slack node. Each synchronous area has one designated slack node, which remains constant for each DA CC MTU;

61. 'spanning' means the pre-coupling backup solution in situations when the day-ahead capacity calculation fails to provide the flow-based parameters for strictly less than three consecutive hours. This calculation is based on the intersection of previous and sub-sequent available flow-based parameters;

62. 'SO Regulation' means Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation;

63. '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;

64. 'static grid model' means a list of relevant grid elements of the transmission system, including their electrical parameters;

65. 'U' is the reference voltage;

66. 'UAF' is an unscheduled allocated flow;

67. '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;

67a. 'virtual hub' (VH) means external or internal virtual hub.

68. '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;

69. '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;

70. the notation x denotes a scalar;

71. the notation $\vec{x}$ denotes a vector;

72. the notation $\mathbf{x}$ denotes a matrix;

73. 'CZC' means cross-zonal capacity whereas this capacity is to be understood as the "flow-based parameters" (flow-based domain) or, in case the extended LTA approach pursuant to Article 18(1a) is applied, the union of the flow-based parameters and "LTA values" (LTA domain);

74. 'LTA domain' means a set of bilateral exchange restrictions covering the previously allocated cross-zonal capacities;

75. technical counterparty' means a TSO which is not a Core TSO and operates in a country which is not a Member State of the European Union;

76. 'CGMES' means the common grid model exchange specification that is developed by ENTSO-E pursuant to the CGMM;

77. 'circumstance' means a combination of net positions which is feasible according to the CZC used for the respective validation phase. A circumstance comprises at least the Core bidding zones and, where AHC is applied, the respective external virtual hubs. It may additionally contain bidding zones of technical counterparties.

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

79. 'MTU' is the day-ahead market time unit, which means the time unit for the day-ahead market;

80. $\|\vec{x}\|_2$ denotes the Euclidean norm of a vector;

81. r denotes the factor for determining the floor level of the RAM of the final flow-based parameters in case of deviations from the standard floor level.

2. In this day-ahead capacity calculation methodology unless the context requires otherwise:

   (a) the singular indicates 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 day-ahead capacity calculation methodology;

   (d) any reference to the day-ahead capacity calculation, day-ahead capacity calculation process or the day-ahead capacity calculation methodology shall mean a common day-ahead capacity calculation, common day-ahead capacity calculation process and common day-ahead 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, regulations, directive, 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 day-ahead capacity calculation methodology solely applies to the day-ahead 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 day-ahead capacity calculation methodology

Article 4. Day-ahead capacity calculation process

1. For the day-ahead market time frame, the cross-zonal capacities for each DA CC MTU shall be calculated using the flow-based approach as defined in this methodology.

2. The day-ahead capacity calculation process 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.

3. Each Core TSO shall provide the CCC the following capacity calculation inputs by the times established in the process description document, with the reservation that Core TSOs in the SEM bidding zone may delegate their obligation of providing the following inputs to each other subject to prior agreement and in accordance with applicable procedures:

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

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

   (c) 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.

4. 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 DA CC MTU of the delivery day, the following additional inputs by the times established in the process description document:

   (a) the long-term allocated capacities (LTA) , as long as the Core TSOs apply the rules as referred to in Article 18(1)1(a);

   (b) the adjustment values for long-term allocated capacities for each Core bidding zone border and for each AHC border to enlarge the default flow-based domain beyond the long-term allocated capacities for the purpose of calculating the default flow-based parameters, as long as the Core TSOs apply the rules as referred to in Article 18(1)1(a); and

(c) the long-term nominated capacities (LTN).

5. When providing the capacity calculation inputs pursuant to paragraphs 3 and 4, 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.

5a. No later than 3 months after the implementation of the common grid model methodology according to Article 17 CACM Regulation and the implementation of this methodology according to Article 28, Core TSOs shall deliver an assessment for the application of CGMES in the capacity calculation, including a planning proposal with clear milestones for each implementation step.

6. No later than six months before the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly establish a process description document as referred to in paragraphs 3 and 4 and publish it on the online communication platform as referred to in Article 25. This document shall reflect an up to date detailed process description of all capacity calculation steps including the timeline of each step of the day-ahead capacity calculation.

7. Once the merging agent receives all the IGMs established pursuant to the CGMM, it shall merge them to create the CGM in accordance with the CGMM and deliver the CGM to the CCC.

8. The day-ahead capacity calculation process 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 14;

Step 2. The CCC shall calculate the first flow-based parameters ($PTDF_{init}$ and $F_{ref,init}$) for each initial CNEC pursuant to Article 14;

Step 3. The CCC shall determine the final list of CNECs and MNECs for subsequent steps of the day-ahead capacity calculation pursuant to Article 15;

Step 4. The CCC shall perform the non-costly remedial actions optimisation (NRAO) according to Article 16 and, as a result, obtain the applied non-costly RAs, along with the final $PTDF_f$ and F_{ref} adjusted for the applied RAs;

Step 5. The CCC shall calculate the adjustment for minimum RAM (AMR) according to Article 17;

Step 6. The CCC shall calculate the adjustment for LTA inclusion according to Article 18

Step 7. The CCC shall calculate the RAM before validation (RAM_{bv}) based on the results of the previous processes pursuant to Article 19;

Step 8. The Core TSOs and the CCC shall, according to Article 20, validate the RAM_{bv} with coordinated validation, calculate the RAM before individual validation (RAM_{biv}), validate the RAM_{biv} with individual validation, and decrease RAM when operational security is jeopardised, which results in the RAM before long-term nominations (RAM_{bn});

Step 9. The CCC shall, according to Article 21, remove the redundant CNECs and redundant external constraints from final $PTDF_f$ and RAM_{bn} and publish these as pre-final flow-based parameters in accordance with Article 25;

Step 10. The CCC shall calculate the flows resulting from long-term nominations (F_{LTN}) and derive the final RAM (RAM_f) according to Article 21;

Step 11. The CCC shall publish the $PTDF_f$ and RAM_f values in accordance with Article 25 and provide them to NEMOs for capacity allocation in accordance with Article 21.

8a. The steps in Article 4(7) shall be complemented with the IGMs of technical counterparties, subject to Article 13(2).

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.

1a. 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 in Core. Such a CNE on an AHC border shall be regularly monitored only in a single CCR. Any deviation from this rule shall be subject to a sound justification.

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 24. A contingency can be an unplanned outage of:

   (a) a line, a cable, or a transformer;

   (b) a busbar;

   (c) a generating unit;

   (d) a load; or

   (e) 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. Each Core TSO may also provide to the CCC a list of monitored network elements with contingency (MNEC), which need to be monitored during the capacity calculation.

5. No later than sixty months after the implementation of this methodology in accordance with Article 28(3), 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 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.

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 24.

Article 6. Methodology for operational security limits

1. The Core TSOs shall use in the day-ahead 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 limits of CNEs, the Core TSOs shall use as far as applicable the maximum admissible current limit (I_{max}), which is the physical limit of a CNE

according to the operational security limits in accordance with Article 25 of the SO Regulation. The maximum admissible current shall be defined as follows:

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

i. Seasonal limit, which means a fixed limit for all DA CC MTUs of each of the four seasons.

ii. Dynamic limit, which means a value per DA CC MTU reflecting the varying ambient conditions.

iii. Fixed limits for all DA CC MTUs, in case of specific situations where the physical limit reflects the capability of overhead lines, transformers, cables or substation equipment installed in the primary power circuit (such as circuit-breaker, or disconnector) with limits not sensitive to ambient conditions, or where operational security limits are not set by thermal rating.

(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 individual validation phase in accordance with Article 20.

3. Core TSOs and technical counterparties 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. Core TSOs and technical counterparties shall provide the status of operational security limits in use in accordance with Article 25(2)(f). No later than 48 months after the implementation of this methodology in accordance with Article 30(2), Core TSOs and technical counterparties shall conduct an analysis on the efficiency of implementing dynamic limits for the maximum admissible current. This analysis shall include an identification of the set of CNEs where dynamic limits would bring the most value and possible solution to implement more granular operational security limits. Every two years after the end of the calendar year, all Core

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[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 20.

TSOs and technical counterparties shall analyse all CNEs which jointly collected 99% of cumulative shadow price in the period of last two calendar years.

4. TSOs shall regularly review and update operational security limits in accordance with Article 24.

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.

2. The Core TSOs may apply allocation constraints as one of the following three options:

   (a) a constraint on the Core net position (the sum of cross-zonal exchanges within the Core CCR and on AHC borders for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to its imports and/or exports to other bidding zones in the Core CCR. This option shall be applied until option (b) can be applied.

   (b) a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the SDAC. This option shall be applied when: (i) such a constraint is approved within all day-ahead capacity calculation methodologies of the respective CCRs, (ii) the respective solution is implemented within the SDAC algorithm and (iii) the respective bidding zone borders are participating in SDAC.

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

3. Allocation constraints referred to in Article 7 2(a) and 2(b) may be used by a Core TSO as listed in Annex 1 during a transition period of six years following the implementation of this methodology in accordance with Article 28(3) and in accordance with the reasons and the methodology for the calculation of allocation constraints as specified in Annex 1 to this methodology. During this transition period, the concerned Core TSOs shall:

   (a) calculate the value of allocation constraints in accordance with Annex 1 and in any case at least on a quarterly basis and publish the results of the underlying analysis;

   (b) in case the external constraint had a non-zero shadow price in more than 0.1% of hours in a quarter, provide to the CCC a report analysing: (i) for each MTU when the allocation constraint had a non-zero shadow price the loss in economic surplus due to allocation constraint and the effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits and (ii) alternative solutions to address the underlying operational security limits. The CCC shall include this report as an annex in the quarterly report as defined in Article 27(5);

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

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

(a) the technical and legal justification for the need to continue using the allocation constraints indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};

(b) the methodology to calculate the value of allocation constraints including the frequency of recalculation.

5. 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.

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

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

8. The Core TSOs shall review and update allocation constraints in accordance with Article 24.

9. If one or more Core TSOs plan to apply allocation constraints, referred to in Article 7(1), the relevant Core TSOs shall, 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 use an allocation constraint indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};

(b) the methodology to calculate the value of allocation constraints including the frequency of recalculation.

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 DA 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 DA 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 11, but using the modified CGMs and the historical GSKs. The expected power flows at the time of the capacity calculation shall therefore be calculated using the final realised commercial exchanges in the Core CCR and on AHC borders which are reflected in realised power flows. This above calculation of expected power flows (F_{exp}) is described with Equation 2.

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

Equation 2

with

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

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

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

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

5a. The Core TSOs shall repeat steps one and two pursuant to paragraphs 3 to 5 with two different implementation approaches for paragraph 3, sentence 4, where one implementation leads to an upper estimate and the other implementation leads to a lower estimate of the true FRM.

(a) For the determination of the upper estimate, the historical CGMs shall be updated such that only the RAs considered during the day-ahead capacity calculation are considered as deliberated Core TSOs' actions. This will yield an upper estimate of the FRM because some deliberated Core TSOs' actions, in particular re-dispatching, will not be considered and thus treated as source of FRM.

(b) For the determination of the lower estimate, the historical CGMs shall additionally be updated such that also the entire generation pattern of the Core CCR is considered as deliberated Core TSOs' actions. This will yield a lower estimate of the FRM because only a part of the entire generation dispatch is the result of deliberated Core TSOs' actions in the form of re-dispatching.

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.

7. No later than sixty months after the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly perform the first FRM calculation pursuant to the methodology described above and based on the data covering at least the first year of operation of this methodology. By the same deadline, all Core TSOs shall submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation as well as the supporting document as referred to in paragraph 9 below. The proposal for amendment shall include an approach and justification for selecting the FRM from the range between the lower and upper estimates as well as next possible steps for improving the process to approach as much as possible the true FRM.

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 has been approved by all Core regulatory authorities, the Core TSOs shall use FRM values equal to 10% of F_{max} pursuant to Article 6(2).

11. After the proposal for amendment of this methodology pursuant to paragraph 7 has been approved by all Core regulatory authorities, 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 DA CC MTU a GSK, which translates a change in its bidding zone net position into a specific change of nodal injection or withdrawal in the CGM. A GSK shall have fixed values, which means that for one DA CC MTU the relative contribution of generation or load to the change in the bidding zone net position shall remain the same, regardless of the volume of the change.

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

2. For a given DA CC MTU, the GSK shall only include actual generation and/or load[4] present in the CGM for that DA CC MTU. The Core TSOs shall consider the available information on generation or load in the CGM in order to select the nodes that will contribute to the GSK. Nodes in the CGM may be excluded from the calculation of GSK values if they do not contribute to the minimisation of the NFE.

3. (deleted)

4. (deleted)

4a. Core TSOs shall implement the harmonised GSK methodology where the GSK values of each node contained in a TSO's IGM shall be defined in proportion to the absolute values of power injections and withdrawals in the IGM.

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

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

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

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

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

5. The Core TSOs belonging to the same bidding zone shall jointly define a common GSK for that bidding zone and shall agree on a methodology for such coordination. For Germany and Luxembourg, each TSO shall calculate its individual GSK and the CCC shall combine them into a single GSK for the whole German-Luxembourgian bidding zone, by assigning relative weights to

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

each TSO's GSK. The German and Luxembourgian TSOs shall agree on these weights, based on the share of the generation in each TSO's control area that is responsive to changes in net position, and provide them to the CCC.

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

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

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

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

Article 10. Methodology for remedial actions in day-ahead 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 day-ahead capacity calculation.

2. In case a RA made available for the day-ahead 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 optimisation of cross-zonal capacities while ensuring operational security in real-time.

4. For the purpose of the NRAO, all Core TSOs shall provide to the CCC all expected available non-costly RAs and, for the purpose of coordinated capacity validation, all Core TSOs shall provide to the CCC all expected available costly and non-costly RAs.

5. In order to avoid undue discrimination and with the aim to reduce the amount of expected loop flows, each Core TSO may individually define the initial setting of its own non-costly and costly RAs, based on the best forecast of their application and with the aim to reduce the total loop flows on its cross-zonal CNECs below a loop flow threshold that avoids undue discrimination. This threshold shall be consistent with the assumptions made about the loop flows when defining the minimum RAM factor pursuant to Article 17(9), and shall be equal to 30% of the F_{max} of these CNECs reduced by the FRM when a TSO applies a minimum RAM factor equal to 0.7. Each TSO shall provide the CCC with the loop flow threshold for its cross-zonal CNECs to be used in the NRAO.

6. 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 day-ahead 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.

7. The day-ahead 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; and

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

8. In accordance with Article 25(6) of the CACM Regulation, the RAs taken into account are the same for day-ahead and intra-day capacity calculation, depending on their technical availability.

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

10. The optimised application of non-costly RAs in the day-ahead capacity calculation is performed in accordance with Article 16.

11. TSOs shall review and update the RAs taken into account in the day-ahead capacity calculation in accordance with Article 24.

TITLE 4 - Description of the day-ahead capacity calculation process

Article 11. 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 positions 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:

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

Equation 3

with

$\mathbf{PTDF}_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones and virtual hubs; 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 virtual hubs; 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 4

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 the exchanges with the virtual hubs, i.e. the exchanges over HVDC interconnectors which are integrated pursuant to Article 12 and the exchanges on AHC borders which are modelled through EVH pursuant to Article 13:

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

Equation 5

with

k	a given HVDC interconnector within the Core CCR
K	set of all HVDC interconnectors within the Core CCR
$PTDF_{X,l}$	zone-to-slack $PTDF$ of a Core bidding zone or external virtual hub X on a CNEC l
BZ	set of all Core bidding zones
EVH	set of all external virtual hubs in the Core CCR
IVH	set of all internal virtual hubs in the Core CCR
$\max_{X\in\{BZ\cup EVH\}}(PTDF_{X,l})$	maximum zone-to-slack PTDF of Core bidding zones or EVHs on a CNEC l
$\min_{X\in\{BZ\cup EVH\}}(PTDF_{X,l})$	minimum zone-to-slack PTDF of Core bidding zones or EVHs on a CNEC l

$PTDF_{H1k,l}$ zone-to-slack $PTDF$ of internal virtual hub H_1 on a CNEC l, with H_1 representing the converter station at the sending end of the HVDC interconnector k

$PTDF_{H2k,l}$ zone-to-slack $PTDF$ of internal virtual hub H_2 on a CNEC l, with H_2 representing the converter station at the receiving end of the HVDC interconnector k

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 6

with

$\vec{F}_i$ expected flow per CNEC in the commercial situation i

$\vec{F}_{ref}$ flow per CNEC in the CGM (reference flow)

$\mathbf{PTDF}$ power transfer distribution factor matrix

$\overrightarrow{NP}_i$ Core net positions in the commercial situation i

$\overrightarrow{NP}_{ref}$ Core net positions in the reference commercial situation

7a. For network elements with contingencies from technical counterparties pursuant to Article 20(6a) the steps referred to in paragraphs 3 to 7 above shall be performed by the CCC with the additional inclusion of the bidding zone of the technical counterparty in Equation 5, subject to Article 13(2). For the sake of computing PTDFs and flow components for such network elements with contingencies, the CCC shall use the GSK provided by the technical counterparty.

Article 12. Integration of HVDC interconnectors on bidding zone borders of the Core CCR

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

synchronous area.[5] In the EFB, a cross-zonal exchange over an HVDC interconnector on the bidding zone borders of the Core CCR is modelled and optimised explicitly as a bilateral exchange in capacity allocation, and is constrained by the physical impact that this exchange has on all CNECs considered in the final flow-based domain used in capacity allocation and constraints modelling the maximum possible exchange of the HVDC interconnector.

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

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

Equation 7

with

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

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

4. The internal virtual hubs introduced by this methodology are only used for modelling the impact of an exchange through a HVDC interconnector and no orders shall be attached to these internal virtual hubs in the coupling algorithm. The two internal virtual hubs, will have a combined net position of 0 MW, but their individual net position will reflect the exchanges over the interconnector. The flow-based net positions of these internal virtual hubs shall be of the same magnitude, but they will have an opposite sign. $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ of all or only a subset of CNECs can be set to zero before the DA market coupling if $\left| PTDF_{IVH\_1,l} - PTDF_{IVH\_2,l} \right|$ is below a certain threshold. The adjustment is to be done after the NRAO optimization described in Article 16 and before the validation steps described in Article 20. This PTDF threshold shall not

[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.

exceed 1% and may be applied during the transition period preceding the Go-Live of Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation. Core TSOs shall report quarterly on the initial setup and any change of this threshold together with the impact which entails from a non-zero threshold and a due justification.

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

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

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

Article 13. 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.

2. Where Core TSOs consider as essential to enhance coordination in day-ahead capacity calculation with a technical counterparty, such enhanced coordination shall be based on the consideration of network elements of the technical counterparty and/or network elements of (a) Core TSO(s) that is (are) significantly influenced by the exchanges with the bidding zone managed by this technical counterparty. A concept description documentation shall be jointly established between all Core TSOs and the technical counterparty. The documentation shall include at least a clear description of:

   (a) the interfaces to this methodology, including the lists and the values of network elements and of all parameters to be considered,

   (b) common and individual procedures that are performed by the Core TSOs, the CCC and the technical counterparty,

   (c) the rights and obligations of the technical counterparty and of the Core TSOs in this respect,

   (d) the monitoring of the effects and performance of the application of this enhanced coordination.

   If the technical counterparty operates in a country that applies the legal framework of the European Energy Market or has concluded an intergovernmental agreement on electricity markets with the European Union, the following provisions of Article 13(2) do not apply.

   The concept description documentation is subject to unanimous validation by all Core regulatory authorities, and it must be contractually agreed upon between all Core TSOs and the technical counterparty. Where the concept description documentation or elements thereof have not been unanimously validated by all Core regulatory authorities, the Core TSOs shall not enhance cooperation with a technical counterparty in day-ahead capacity calculation.

   The concept description documentation shall be regularly reviewed by all Core TSOs and validated by all Core regulatory authorities. The respective next date of the review and the validation shall be specified in the concept description documentation.

Upon the unanimous validation by all Core regulatory authorities, all Core TSOs shall accordingly apply and consider the results from such an enhanced coordination in the day-ahead capacity calculation.

3. In other cases, the Core TSOs shall consider using a standard hybrid coupling (SHC) or an advanced hybrid coupling (AHC).

   (a) 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 day-ahead 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.

   (b) In the AHC, the CNECs of the Core Day-ahead 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.

   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.

4. Core TSOs may impose a limit to the net position of the external virtual hubs:

   (a) 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;

   (b) Core TSOs may consider a limit in the form of an NTC value as an outcome of the capacity calculation from the neighbouring CCR.

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

Article 14. Initial flow-based calculation

1. As a first step in the day-ahead 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 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 DA CC MTU.

3. The initial flow-based parameters shall be calculated pursuant to Article 11 and shall consist of the $\mathbf{PTDF}_{init}$ and $\vec{F}_{ref,init}$ values for each initial CNEC.

3a. For network elements with contingencies from technical counterparties pursuant to Article 20(6a), the steps described in paragraphs 1 to 3 shall be carried out by the CCC in order to enable a potential submission, subject to Article 13(2), of the network elements with contingency by the technical counterparty to the final list of CNECs during coordinated and individual validation. Until then, the network elements with contingencies from technical counterparties shall not be considered as constraints to the formulation of flow-based domain, neither to the NRAO.

Article 15. Definition of final list of CNECs and MNECs for day-ahead capacity calculation

1. The CCC shall use the initial list of CNECs determined pursuant to Article 14 and remove those CNECs for which the maximum zone-to-zone $PTDF_{init}$ is not higher than 5%. The remaining CNECs shall constitute the final list of CNECs.

2. The CCC shall use the lists of MNECs submitted by the Core TSOs and merge them into a common list of MNECs, which shall be monitored during the NRAO process, based on information provided by the Core TSOs pursuant to Article 5. In accordance with Article 16(3)(d)(vi), the additional loading resulting from the application of the NRAO process on the MNECs may be limited during the NRAO process, while ensuring that a certain additional loading up to the defined threshold is always accepted.

Article 16. Non-costly remedial actions optimisation

1. The NRAO process coordinates and optimises the use and application of non-costly RAs pursuant to Article 10, with the aim of enlarging and securing the flow-based domain around the expected operating point of the grid, represented by the reference net positions and exchanges.

2. The NRAO shall be an automated, coordinated and reproducible optimisation process performed by the CCC that applies non-costly RAs defined in accordance with Article 10. Before the start of the NRAO, the CCC shall apply the initial setting of non-costly and costly RAs as determined and provided by individual TSOs pursuant to Article 10(4) and (5).

3. The NRAO shall consist of the following objective function, variables and constraints:

   (a) the objective function of the NRAO is to maximise the smallest relative RAM of all limiting CNECs. External constraints shall not be included in this objective function.

$$\min_{limiting\ CNECs}(RAM_{rel}) \rightarrow to\ be\ maximised$$

   (b) the optimisation process iterates over switching states (i.e. activated or not-activated) of topological measures, range of setpoints of bidding zone internal HVDC lines and PST tap positions in order to maximise this objective. Preventive RAs may jointly be associated with all CNECs, whereas curative RAs may be optimised independently for each contingency.

   (c) for a given state of the optimisation, the RAM_{nrao} of a CNEC takes into account flows coming from reference net positions and exchanges as well as switching states of RAs. As a result, the $PTDF_{nrao}$ and F_{nrao} are updated for each CNEC during each optimisation iteration. The calculations of RAM_{nrao} and relative RAM_{nrao} for a given CNEC are expressed in Equation 8 and Equation 9, and rely on F_{max}, FRM and $F_{ref,init}$.

$$\overrightarrow{RAM}_{nrao} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{ref,init} + \vec{F}_{nrao}$$

Equation 8

   with

$\overrightarrow{RAM}_{nrao}$	RAM per CNEC during the NRAO optimisation process
$\vec{F}_{ref,init}$	Reference flow per CNEC in the CGM in the initial flow-based calculation
$\vec{F}_{nrao}$	Flow change per CNEC due to preventive and/or curative RAs, derived from simulations conducted on the CGM (and initially zero)

$$RAM_{rel} = \frac{RAM_{nrao}}{\sum_{(A,B)\,\in\, neighbourpairs} \left|PTDF_{A\rightarrow B,nrao}\right|}\ if\ RAM_{nrao} \geq 0$$
$$RAM_{rel} = RAM_{nrao}\ if\ RAM_{nrao} < 0$$[6]

Equation 9

with

$neighbour\ pairs$	Set of two neighbouring Core bidding zones or set of a Core bidding zone and a neighbouring EVH
$PTDF_{A\rightarrow B,nrao}$	The zone-to-zone PTDFs for the current optimisation iteration

(d) The constraints of the NRAO are:

i. F_{max}, FRM and $F_{ref,init}$ per CNEC;

ii. the available range of tap positions of each PST;

iii. parallel PSTs, as defined by TSOs, shall have equal tap positions;

iv. a RA may only be associated with a CNEC, if it has a minimum positive impact on the objective function or constraint;

v. the maximum number of activated curative non-costly remedial actions per CNEC (with contingency);

vi. the RAM_{nrao} of the MNECs shall be positive. A minimum initial RAM_{nrao} (at reference point, without RAs) of 50 MW shall be applied for MNECs;

vii. the loop flow on each cross-zonal CNEC, which is equal to $F_{0,all}$ calculated pursuant to Article 17(3), shall not increase above either:

d.vii.1. the initial value of $F_{0,all}$ of the considered CNEC before the NRAO in case this value is higher than or equal to the loop flow threshold as defined in Article 10(5);

d.vii.2. the loop flow threshold as defined in Article 10(5) in case the initial value of $F_{0,all}$ of the considered CNEC before the NRAO is lower than the loop flow threshold as defined in Article 10(5); and

viii. the available range of setpoint of each bidding zone internal HVDC.

[6] RAM_{rel} ignores PTDFs for overloaded CNECs, in order to solve the largest absolute overloads first.

4. As a result of the NRAO, a set of RAs is associated with each CNEC. $PTDF$ and F_{ref} are updated as follows:

   (a) $\mathbf{PTDF}_{\boldsymbol{f}} = \mathbf{PTDF}_{\boldsymbol{nrao}}$ directly from the optimisation results;

   (b) $\vec{F}_{ref} = \vec{F}_{ref,init} - \vec{F}_{nrao}$, based on the RAs associated with each CNEC by the NRAO.

5. The non-costly RAs applied at the end of the NRAO shall be transparent to all TSOs of the Core CCR, and also of adjacent CCRs, and shall be taken as an input to the coordinated operational security analysis established pursuant to Article 75 of the SO Regulation.

6. An exchange of foreseen RAs in each CCR, with sufficient impact on the cross-zonal capacity in other CCRs, shall be coordinated among CCCs. The CCC shall take this information into account for the coordinated application of RAs in the Core CCR;

7. Every year after the implementation of this methodology in accordance with Article 28(3), the CCC, in coordination with the Core TSOs, shall analyse the efficiency of the NRAO and present the results of this analysis in the annual report. This analysis shall contain an ex-post analysis on whether the NRAO effectively increased cross-zonal capacity in the most valuable market direction. The analysis shall focus on data from the last year of operation, and shall include at least the following information:

   (a) an assessment of the availability of non-costly RAs provided by the Core TSOs, including the average number of non-costly RAs provided by each Core TSO;

   (b) for the Core TSOs which did not provide non-costly RAs, a justification why they did not do so;

   (c) for each CNEC with non-zero shadow price: $\overrightarrow{PTDF}_{init}$, $\overrightarrow{PTDF}_{f}$, $F_{ref,init}$ and F_{nrao}; and

   (d) an estimate of the market clearing point (and related market welfare) which may have occurred, should the NRAO not have taken place (but including other capacity calculation steps such as minRAM, LTA inclusion [as long as the Core TSOs apply the rules as referred to in Article 18(1)1(a)] and an estimate of the validation phase.)

8. Based on the conclusion of the analysis mentioned in the previous paragraph, the Core TSOs may propose changes to the NRAO by submitting to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation.

Article 17. Adjustment for minimum RAM

1. To address the requirement of Article 21(1)(b)(ii) of the CACM Regulation, the Core TSOs shall ensure that the RAM for each CNEC determining the cross-zonal capacity is never below a minimum RAM, except in cases of validation reductions as defined in Article 20.

2. In order to determine the adjustment for minimum RAM for a CNEC, the flow in the situation without commercial exchanges within the Core CCR and on AHC borders is first calculated by setting the net positions $\overrightarrow{NP_i}$ in Equation 6 to zero for all Core bidding zones and for all VHs, leading to the following equation:

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

Equation 10

with

$\vec{F}_{0,Core}$	flow per CNEC in the situation without commercial exchanges within the Core CCR and without commercial exchanges on AHC borders
$\vec{F}_{ref}$	flow per CNEC in the CGM after the NRAO
$\mathbf{PTDF}_{\boldsymbol{f}}$	power transfer distribution factor matrix for the Core CCR, including VHs
$\overrightarrow{NP}_{ref,Core}$	Core net positions included in the CGM

3. Then, the CCC shall calculate $F_{0,all}$, which is the flow on each CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, between bidding zones within Continental Europe and bidding zones located in other synchronous areas, and between the island of Ireland and bidding zones located in other synchronous areas. For this calculation, the CCC shall set to zero all exchanges on DC interconnectors linking Continental Europe and the island of Ireland to each other or to other synchronous areas. The CCC shall then calculate the zonal PTDFs for all bidding zones within the synchronous areas Continental Europe and island of Ireland for each CNEC. For this calculation, the CCC shall use the GSKs provided by the concerned TSOs to the Common Grid Model platform, and when these are not available, the CCC shall use a GSK where all nodes with positive injections participate to shifting in proportion to their injection. Subsequently the CCC shall calculate $\mathrm{F}_{0,\mathrm{all}}$ with the following Equation 11.

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

Equation 11

with

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

4. 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 12

with

$\vec{F}_{uaf}$	flow per CNEC assumed to result from commercial exchanges outside Core CCR excluding flows resulting from commercial exchanges on AHC borders

5. The main objective of the adjustment of the minimum RAM is to ensure that at least a specific percentage, as defined in paragraph 9, of F_{max} is reserved for commercial exchanges on all bidding zone borders, including those outside the Core CCR. This means that the sum of RAM (capacity offered within the Core CCR and on the AHC borders) and F_{uaf} (capacity offered outside the Core CCR except the AHC borders) on the Core CNECs shall be equal or higher than the specific percentage, defined in paragraph 9, of F_{max}. If the specific percentage, defined in paragraph 9, is expressed generally as a minimum RAM factor (R_{amr}), then it follows:

$$RAM + F_{uaf} \geq R_{amr} \cdot F_{max}$$

Equation 13

6. The adjustment of minimum RAM aims to ensure that the previous inequality is always fulfilled, therefore AMR is added as follows:

$$\begin{aligned} RAM + F_{uaf} + AMR &= R_{amr} \cdot F_{max} \\ RAM &= F_{max} - FRM - F_{0,Core} \end{aligned}$$

Equation 14

7. The minimum RAM available for trade on each CNEC of the Core CCR shall not be below 20% of F_{max}.

8. Combining the previous requirements, the AMR for a CNEC is finally determined with the following equation:

$$AMR = max\begin{pmatrix} R_{amr} \cdot F_{max} - F_{uaf} - \left(F_{max} - FRM - F_{0,Core}\right), \\ 0.2 \cdot F_{max} - \left(F_{max} - FRM - F_{0,Core}\right), 0 \end{pmatrix}$$

Equation 15

with

F_{max}	maximum admissible flow
FRM	flow reliability margin
F_{uaf}	flow per CNEC resulting from assumed commercial exchanges outside the Core CCR, but excluding flows resulting from commercial exchanges on AHC borders
$F_{0,\mathrm{Core}}$	flow in the situation without commercial exchanges within the Core CCR, and without commercial exchanges on AHC borders
R_{amr}	minimum RAM factor

9. The minimum RAM factor R_{amr} shall be equal to 0.7 for all CNECs, except those for which a derogation has been granted or an action plan to address structural congestions has been set in accordance with the relevant Union legislation. In case of such a derogation or action plan, the R_{amr} shall be defined by means of a linear trajectory as defined in Annex II to this methodology, unless otherwise defined by the decisions on derogations or action plans in accordance with the relevant Union legislation. In the latter case, the TSO(s) affected by such derogations or action

plans shall inform all Core regulatory authorities and the Agency about the values of R_{amr} applicable during the period for which the derogation has been granted or action plan has been set.

Article 18. Long-term allocated capacities (LTA) inclusion

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

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

   (b) (deleted)

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

   (d) the Core TSOs shall cease to apply the rules as referred to in paragraph 1(a) in accordance with the provisions in Article 28(9).

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

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

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

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

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

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

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

Article 19. Calculation of flow-based parameters before validation

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

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

(b) the calculation[7] of the adjustment for minimum RAM (AMR) according to Article 17;

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

(c) (deleted)

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

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

Equation 16a

with

$\vec{F}_{max}$	Maximum active power flow pursuant to Article 6
$\overrightarrow{FRM}$	Flow reliability margin pursuant to Article 8
$\vec{F}_{0,Core}$	Flow without commercial exchanges in the Core CCR and without commercial exchanges on AHC borders, described in Equation 10. For external constraints, in line with Article 18(2), this flow is equal to zero.[8]
$\overrightarrow{AMR}$	Adjustment for minimum RAM pursuant to Article 17
$\overrightarrow{RAM}_{bv}$	Remaining available margin before validation

Article 20. 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 individually and in a coordinated way.

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

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

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

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

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

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

Step 2. The CCC shall, pursuant to paragraph 4c, select the circumstances, being possible market outcomes, that shall be evaluated to determine whether the power system could accommodate them having regard to operational security requirements;

Step 3. The CCC shall analyse the selected circumstances subject to the criteria pursuant to paragraph 4d and applying the remedial action optimisation method pursuant to paragraph 4e;

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

Step 5. The CCC shall compute the RAM_{biv} pursuant to paragraph 4g;

Step 6. The CCC shall disseminate the results of steps 2, 3, 4 and 5 pursuant to paragraph 4h to enable Core TSOs and technical counterparties pursuant to Article 13(2) to consider them in the individual validation process step;

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

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

(b) the CGM;

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

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

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

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

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

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

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

4d. When analysing a circumstance, the CCC shall use the CGM and apply load flow calculation and contingency analysis. The net positions of the BZs in the CGM shall be shifted towards the net positions of the circumstance. This shift shall, in principle, be done using the GSK pursuant to Article 9. A deviation from the GSK is allowed, insofar as the injection from generators is altered, to prevent a violation of technical generator bounds. The RA potential related to redispatch shall be adjusted to reflect the dispatch modifications between the CGM and the circumstance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Equation 19c

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

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

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

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

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

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

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

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

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

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

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

10. After coordinated and individual validation adjustments, the RAM_{bn} before adjustment for long-term nominations shall be calculated by the CCC for each CNEC and external constraint according to Equation 17a:

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

*Equation 17*a

with

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

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

12. (deleted)

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

    (a) the identification of the CNEC;

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

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

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

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

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

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

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

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

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

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

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

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

Article 21. Calculation and publication of final flow-based parameters

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

2. After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations), it shall calculate for each CNEC and external constraint the flow resulting from these nominations (F_{LTN}). This is done by multiplying the net positions reflecting the long-term nominations with the $\mathbf{PTDF_f}$. This step is described with Equation 18:

$$\vec{F}_{LTN} = \mathbf{PTDF_f}\, \overrightarrow{NP}_{LTN}$$

Equation 18

with

$\vec{F}_{LTN}$	flow after consideration of LTN
$\mathbf{PTDF_f}$	power transfer distribution factor matrix
$\overrightarrow{NP}_{LTN}$	Core net positions resulting from LTN

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

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

Equation 19

with

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

3a. After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations), it shall also adjust the LTA domain for long-term nominations as long as the Core TSOs apply the rules as referred to in Article 18(1)(a).

3b. Core TSOs may deviate from the calculation of the final RAM_f pursuant to paragraph 3 on their own CNECs by specifying a lower factor than 0.2 for the floor level in case operational security cannot be maintained otherwise. In such a case, the CCC shall compute RAM_f for the CNECs of the concerned Core TSOs as follows:

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

Equation 20

with

$\overrightarrow{RAM_{bn}}$	remaining available margin before LTN adjustment
$\vec{F}_{LTN}$	flow after consideration of LTN
$\overrightarrow{F_{max}}$	maximum admissible power flow
$\overrightarrow{RAM_f}$	final remaining available margin
r	TSO-specific factor with $0 \leq r < 0.2$

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

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

5. When missing data prevented the calculation of the final flow-based parameters, the final flow-based domain shall be the flow-based domain resulting from the day-ahead capacity calculation fallback procedure in accordance with Article 22.

6. If the CCC is unable to provide the final flow-based parameters to NEMOs by 10:30 market time day-ahead, that coordinated capacity calculator shall notify the relevant NEMOs. In such cases, the CCC shall provide the final flow-based parameters to NEMOs no later than 30 minutes before the day-ahead market gate closure time.

Article 22. Day-ahead capacity calculation fallback procedure

1. According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA CC MTUs does not lead to the final flow-based parameters due to, inter alia, a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data,

the Core TSOs and the CCC shall calculate the remaining missing results by using one of the two capacity calculation fallback procedures pursuant to paragraph 2 or paragraphs 3 to 7, respectively.

2. When the day-ahead capacity calculation fails to provide the flow-based parameters for strictly less than three consecutive hours, the CCC shall calculate the missing flow-based parameters with the spanning method. The spanning method is based on the union of the previous and subsequent available flow-based parameters (resulting in the intersection of the two flow-based domains), adjusted to zero Core net positions (to delete the impact of the reference net positions of the Core bidding zones and VHs). All flow-based constraints from the previous and subsequent data sets are first converted into zero Core net positions. Then all previous and subsequent constraints are combined, the redundant constraints are removed, and the pre-solved constraints are adjusted for the long term nominations in accordance with Article 21. In case the extended LTA inclusion approach is applied, the LTA domain for missing hours contains for each Core border and each AHC border the minimum of the long-term allocated capacities values of the hours for which the previous and subsequent flow-based parameters are available.

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

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

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

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

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

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

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

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

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

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

Equation 23a

with

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

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

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

Equation 23b

with

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

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

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

Equation 23c

with

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

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

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

Equation 23d

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

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

(e) The intermediate default flow-based parameters shall consist of the representative CNECs of the initial default flow-based parameters with unmodified $PTDF$ and modified RAM.

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

Equation 23a

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

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

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

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

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

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

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

Article 23. Calculation of ATCs for SDAC fallback procedure

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

2. The flow-based parameters shall serve as the basis for the determination of the ATCs for SDAC fallback procedure. As the selection of a set of ATCs from the flow-based parameters leads to an

infinite set of choices, an algorithm determines the ATCs for SDAC fallback procedure in a systematic way.

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

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

   (b) the flow-based parameters $\mathbf{PTDF_f}$ and $\overrightarrow{RAM_f}$ in accordance with Article 16 and 21 respectively; and

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

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

   (a) ATCs for SDAC fallback procedure; and

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

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

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

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

   with

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

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

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

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

      with

$\overrightarrow{RAM}_{ATC}(k)$	remaining available margin for ATC calculation at iteration *k*
$\overrightarrow{ATC}_{k-1}$	ATCs at iteration *k*-1

$\mathbf{pPTDF}_{zone-to-zone}$	positive zone-to-zone power transfer distribution factor matrix

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

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

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

v. go back to step i;

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

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

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

(c) positive zone-to-zone PTDF matrix ($\mathbf{pPTDF}_{zone-to-zone}$) for each Core and AHC oriented bidding zone border shall be calculated from the $\mathbf{PTDF}_{f}$ as follows (for HVDC interconnectors integrated pursuant to Article 12, Equation 7 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 21

with

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

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

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

with

$\overrightarrow{ATC}$	the ATC for SDAC fallback procedure

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

6. If the calculation pursuant to paragraph 5, cannot be performed during the regular day-ahead capacity calculation process, Core TSOs may use ATCs for SDAC fallback procedure from a previous run of the process, but based on default flow-based parameters according to Article 22. In this case, the global allocation constraints from the current process, processed pursuant to paragraph 3(c), shall be used to proportionally cap the ATCs of the relevant bidding zones prior to subtracting the LTN.

TITLE 5 – Updates and data provision

Article 24. 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 day-ahead 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 common list of RAs taken into account in the day-ahead capacity calculation shall include at least an evaluation of the efficiency of specific PSTs, bidding zone internal HVDC setpoints and the topological RAs considered during the RAO.

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 the Agency.

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 the Agency. 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 25. 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 day-ahead 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) flow-based parameters before long term nominations pursuant to Article 21(1), which shall be published no later than 8:00 market time of D-1 for each DA CC MTU of the following day;

    (b) the long term nominations for each Core bidding zone border where PTRs are allocated, which shall be published no later than 10:30 market time of D-1 for each DA CC MTU of the following day;

    (c) final flow-based parameters pursuant to Article 21(4), which shall be published no later than 10:30 market time of D-1 for each DA CC MTU of the following day;

    (d) the following information, which shall be published no later than 10:30 market time of D-1 for each DA CC MTU of the following day:

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

        ii. maximum possible bilateral exchanges between all pairs of two Core bidding zones, pairs of two EVHs and pairs of one Core bidding zone and one EVH;

        iii. ATCs for SDAC fallback procedure;

        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, $F_{ref,init}$, F_{nrao}, F_{ref}, $F_{0,\mathrm{core}}$, $F_{0,\mathrm{all}}$, F_{uaf}, AMR, CVA, IVA, F_{LTN};

        viii. detailed breakdown of the RAM for each external constraint before pre-solving: F_{max}, F_{LTN};

        ix. indication of whether spanning and/or 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;
- in case of reduction due to individual validation, the TSO invoking the reduction;
- the volume of reduction (CVA or IVA);
- the detailed reason(s) for reduction in accordance with Article 20(5), 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, (i) the name or identifier of the internal network elements with a specific contingency;

xii. for each RA resulting from the NRAO:

- type of RA;
- location of RA;
- whether the RA was curative or preventive;
- if the RA was curative, a list of CNEC identifiers describing the CNECs to which the RA was associated;

xiii. the forecast information contained in the CGM:

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

(e) the information pursuant to paragraph 2(d)(vii) shall be complemented by 14:00 market time of D-1 with the following information for each CNEC and external constraint of the final flow-based parameters:

i. shadow prices;

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

(g) The CCC shall include in its quarterly report as defined in Article 27(5) the flows resulting from net positions resulting from the SDAC on each CNEC and external constraint of the final flow-based parameters;

(h) the intermediate default flow-based parameters.

3. Individual Core TSO may withhold the information referred to in paragraph 2(d)iv), 2(d)v) and 2(f) 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 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(d)iv) and 2(d)v) shall be replaced with an anonymous identifier which shall be stable for each CNEC across all DA 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(f) 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(d)iv), 2(d)v) and 2(f)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 the Agency. Each Core TSO may decide not to publish the additional information, which was not requested by its competent regulatory authority.

7. Core TSOs shall provide Core regulatory authorities on a monthly basis the underlying capacity calculation and market coupling data related to the quarterly reports. The reporting framework shall be developed in coordination with Core regulatory authorities and updated and improved when needed.

8. Any change in the threshold according to Article 12(4) shall be publicly notified at least two weeks before its entry into force. The notification shall at least include:

   (a) the current threshold applied;

   (b) the day of entry into force of the new threshold;

   (c) the value of the new threshold; and

   (d) a due justification of the change.

Article 26. Quality of the data published

1. No later than six months before the implementation of this methodology in accordance with Article 28(3), 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 25. 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 27. Monitoring, reporting and information to the Core regulatory authorities

1. The Core TSOs shall provide to Core regulatory authorities data on day-ahead 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 25(2)(d)(iv) and (v) shall be provided to all Core regulatory authorities on a monthly basis for each CNEC and each DA 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 25(2).

3. 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.

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

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

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

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

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

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

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

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

5. 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, 12, 20, Article 21, 25 and 28 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 20(13),(14) and (15), the CCC shall provide all information on the reductions of cross-zonal capacity, with a supporting detailed analysis from the concerned TSOs where relevant.

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

   (d) according to Article 25(2) (g), Core TSOs shall report on flows resulting from net positions resulting from the SDAC on each CNEC and external constraint of the final flow-based parameters.

   (e) according to Article 12(4), Core TSOs shall report on the economic social welfare deviation which was provoked by introducing a non-zero PTDF threshold.

   (f) according to Article 21(3b), for cases of deviation from Article 21(3) the concerned Core TSOs shall provide reports with a justification why the calculation of the final RAM pursuant to Article 21(3b) would have led to the inability to maintain operational security and an action plan describing how such situations will be avoided in the future and the CCC shall annex those to the quarterly report.

6. The published annual and quarterly reports may withhold commercially sensitive information or sensitive critical infrastructure protection related information as referred to in Article 25(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 6 - Implementation

Article 28. Timescale for implementation

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

2. No later than four months after the decision has been taken by the Agency in accordance with Article 9(12) of the CACM Regulation, all Core TSOs shall jointly set up the coordinated capacity calculator for the Core CCR and establish rules governing its operation.

3. The TSOs of the Core CCR shall implement this methodology no later than 8 June 2022. The implementation process, which shall start with the entry into force of this methodology and finish by 8 June 2022, shall consist of the following steps:

   (a) internal parallel run, during which the TSOs shall test the operational processes for the day-ahead capacity calculation inputs, the day-ahead capacity calculation process and the day-ahead 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 within the SDAC, 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, the Agency 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. The Core TSOs shall implement the day-ahead capacity calculation methodology on a Core bidding zone border only if this bidding zone border participates in the SDAC.

6. By 31 March 2025, Core TSOs shall have developed AHC. By the same deadline they shall update the explanatory note and publish an analysis that allows market participants to understand the impact of AHC.

7. By 30 June 2025, Core TSOs shall implement AHC for borders to bidding zones outside of the Core CCR insofar these bidding zones are part of SDAC, excluding common borders with Italy North CCR and with SWE CCR. The implementation is subject to the readiness of SDAC. Before

the implementation of AHC, Core TSOs shall involve Core NEMOs to test the implementation of AHC within SDAC and market participants to adapt to the effects of applying AHC via an external parallel run which shall last at least one (1) month. Core TSOs shall publish the results of this parallel run, including the resulting monitoring and performance criteria established pursuant to paragraph (4).

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 is finalized, and the technical conditions allow commercial operations to begin. The integration of the HVDC cable connecting the two bidding zones shall be conducted in compliance with the provisions of Article 12.

9. Core TSOs shall cease to apply the rules for taking into account LTAs pursuant to Article 18(1)(a) no later than as of the first delivery period of the long-term capacities calculated according to the Core Long Term Capacity Calculation Methodology pursuant to the FCA Regulation. Core TSOs shall announce the date of discontinuation at least one (1) month prior to its entry into force.

TITLE 7 - Final provisions

Article 29. Language

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: List of Core TSOs and their 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.

1. Poland:

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

Technical and legal justification

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

These constraints limit the global net position of Polish zone and reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the Polish power system to ensure secure operation. This is explained further in subsequent parts of this Annex.

Rationale behind implementation of allocation constraints on PSE side

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

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

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

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

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

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

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

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

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

This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e. transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, while the trading of other bidding zones is unaffected.Determination of allocation constraints in Poland

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

When determining the allocation constraints, PSE takes into account the most recent information on the technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time frames.

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

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

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

$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \tag{2}$$

Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[8]
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_{L}	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

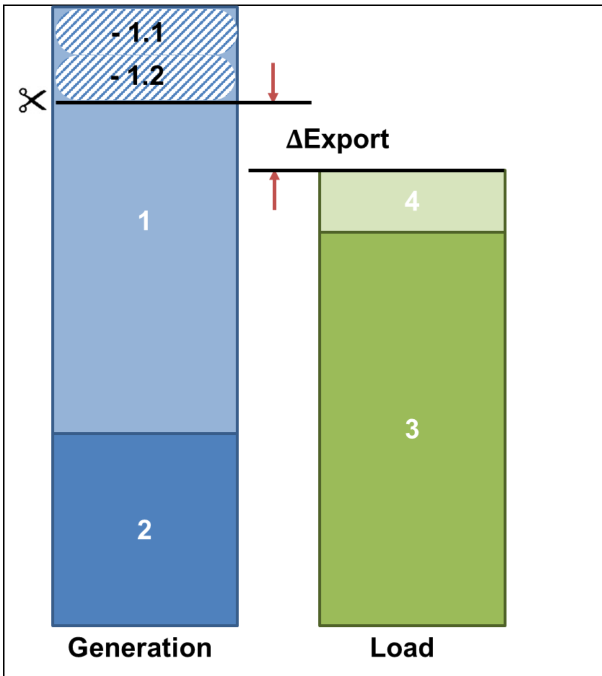
Equation (1) stems from requirement for system operators to maintain upward reserves to cover part of forecasted load with accordance to Polish grid codes. These reserves are a critical aspect of ensuring system reliability and stability, particularly in balancing supply and demand during unexpected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

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

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

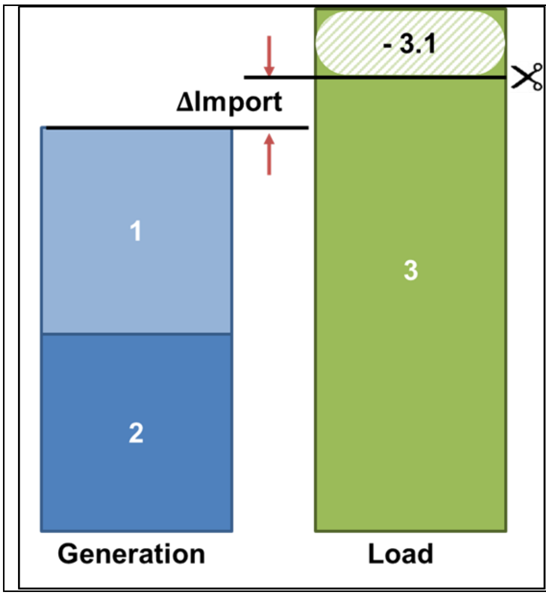
Allocation constraint in export direction zone Polish interconnections in export direction. Allocation constraint in import direction limits import to Polish zone.

[8] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
   - 1.1 Generation not available due to grid constraints
   - 1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
3. Demand forecasted by PSE
4. Minimum necessary reserve for up regulation

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



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

2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)

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

Figure 2: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of the day-ahead capacity calculation.

Frequency of re-assessment

Allocation constraints are determined in a continuous process based on the most recent information, for each capacity allocation time frame, from forward till day-ahead and intra-day. In case of day-ahead process, these are calculated in the morning of D-1, resulting in independent values for each MTU, and separately for directions of import to Poland and export from Poland.

Time periods for which allocation constraints are applied

As described above, allocation constraints are determined in a continuous process for each capacity allocation timeframe, so they are applicable for all MTUs of the respective allocation day.

a) SEM:

Technical and legal justification

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

i) Reasons EirGrid and SONI propose using net position constraints

The primary objective of allocation 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 allocation constraints to the net position to safeguard system security.

Methodology of calculating allocation constraints on net position

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. Adopting the equations from Annex 1 for continuity and clarity, the Export and Import constraints are defined as follows:

$$\boldsymbol{Export}_{\,\boldsymbol{Constraint}} = P_{CD} - P_{UG} - P_{DER} + P_{NCD} - (P_L + P_{UPres})$$

$$\boldsymbol{Import}_{\,\boldsymbol{Constraint}} = P_L - P_{DOWNres} - P_{CDmin} - P_{NCD}$$

Where:

P_{CD} : Sum of operating generating capacities of centrally dispatched units as declared on fuel availability by generators

P_{CDmin} : Sum of technical minima of centrally dispatched generating units in operation

P_{UG} : Unavailable generation due to Transmission Constraints, Long-Notice Units, Unusable Hydro

P_{DER} : Derated generation (Demand Response Units, Pumped Storage, Battery Energy Storage Systems)

P_{NCD} : Sum of schedules of generating units that are not centrally dispatched, as provided by generators

P_L : Forecasted Load

P_{UPres} : Minimum reserve for upward regulation

$P_{DOWNres}$: Minimum reserve for downward regulation

Frequency of re-calculation

Allocation constraints on net position 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 allocation constraints on net position are applied

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

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

With the commissioning of the Celtic interconnector (700 MW), it will become the largest single infeed and outfeed for the all-island system, increasing the total cross-zonal trading capacity of SEM bidding zone to 2200 MW, which accounts for nearly 30% of peak system demand. To maintain system stability, particularly during imbalances caused by flow changes on HVDC interconnections between market time units (MTUs), ramping restrictions are necessary. These restrictions further mitigate the risk of abrupt shifts between (maximum) import and export limits across two MTUs. Thereby, ramping constraints, as a specific type of allocation constraints, ensure that the maximum flow change on the HVDC interconnector between MTUs remains within secure operational limits.

Methodology of determining ramping constraints

The ramping constraint is required due to the nature of the generation stack in the SEM bidding zone rather than any technical constraints on the Celtic interconnector itself, although the constraint will appear on the interconnector since it is the only one available for cross-border flows in Core CCR. To calculate the ramping constraint, EirGrid and SONI will carry out market and system modelling analysis for all hours of the year 2028 to coincide with forecasted Celtic Interconnector go-live. This analysis will assess the ramping characteristics of the system against a range of possible ramping rates on the Celtic interconnector. These system ramps are constrained by the typical ramp characteristics of renewable generators such as wind and solar PV, and the technically feasible ramping characteristics of the conventional dispatchable generating units in the SEM. The range of acceptable ramp rates is defined by calculating the number of system frequency events that breach system security high and low frequency standards. Based on these study results and overall EirGrid and SONI system frequency control standards, the acceptable Celtic interconnector ramp rates will be defined in due course before Celtic interconnector go-live.

Annex 2: Application of linear trajectory for calculation of minimum RAM factor

One linear trajectory for calculation of minimum RAM factor shall be calculated per Member State and shall apply for all CNECs defined by TSO(s) of such Member State.[9]

1. The linear trajectory for calculation of minimum RAM factor shall define yearly values to be applied for each year between the start year and the end year. The start year shall be 2020, and the end year shall be 2026. For each year between 2020 and 2026, the minimum RAM factor R_{amr} pursuant to Article 17(9) shall be defined as follows

$$R_{amr}(year) = R_{amr,start} + \frac{year - 2020}{2026 - 2020} * (R_{amr,end} - R_{amr,start})$$

with

$R_{amr,start}$	Minimum RAM factor in year 2020
$R_{amr,end}$	Minimum RAM factor in year 2026 which is equal to 0.7

The minimum RAM factor in year 2020, $R_{amr,start}$ is the average total capacity allocated on all CNECs[10] defined by the TSO(s) of a Member State in the year 2019 or the average total capacity allocated on all CNECs defined by the TSO(s) of a Member State in the years 2017, 2018 and 2019, whatever is higher:

$$R_{amr,start} = \max(RAM_{rel,avg}\ (2019), RAM_{rel,avg}\ (2017 - 2019))$$

with

$RAM_{rel,avg}\ (2019)$	average relative total RAM ($RAM_{t,rel}$) calculated over all CNECs defined by the TSO(s) of a Member State and all market time units of 2019
$RAM_{rel,avg}\ (2017 - 2019)$	average relative RAM ($RAM_{t,rel}$) calculated over all CNECs defined by the TSO(s) of a Member State and all market time units of 2017, 2018 and 2019

The selection of CNECs for this analysis shall be defined pursuant to paragraph 8.

2. The relative total RAM ($RAM_{t,rel}$) for each CNEC and market time unit available for cross-zonal trade over all bidding zone borders of all CCRs is the ratio of the total RAM available for trade over all bidding zone borders of all CCRs to F_{max} as defined pursuant to paragraph 8.

$$RAM_{rel}(CNEC, MTU) = \frac{RAM_t(CNEC, MTU)}{F_{max}}$$

with

[9] In case a bidding zone covers a territory of more than one Member State, the common trajectory shall be applied for such bidding zone

[10] This includes all cross-zonal capacities from all bidding zones in all CCRs impacting the flow on this CNEC

$RAM_{rel}(CNEC, MTU)$	Relative total RAM ($RAM_{t,rel}$) calculated of a specific CNEC in a specific market time unit
$RAM_t(CNEC, MTU)$	Total RAM ($RAM_{t,rel}$) calculated of a specific CNEC in a specific market time unit
F_{max}	Maximum admissible flow of a specific CNEC in a specific market time unit

3. For each CNEC and market time unit, the total RAM available for cross-zonal trade over all CCRs is then the sum of contributions from bidding zone borders applying the flow-based approach and contributions from bidding zone borders applying the NTC approach:

$$RAM_t(CNEC, MTU) = RAM_{FB}(CNEC, MTU) + RAM_{NTC}(CNEC, MTU)$$

with

$RAM_{FB}(CNEC, MTU)$	The capacity (or RAM) of a CNEC available for cross-zonal trade on bidding zone borders applying the flow-based approach
$RAM_{NTC}(CNEC, MTU)$	The capacity of a CNEC available for cross-zonal trade on bidding zone borders applying the NTC approach

4. The capacity (or RAM) of a CNEC available for cross-zonal trade on bidding zone borders applying the flow-based approach ($RAM_{FB}(CNEC, MTU)$) shall be defined as follows:

   a) For CNECs which are already used in existing flow-based capacity calculation initiatives, $RAM_{FB}(CNEC, MTU)$ shall be equal to the historical DA RAM values calculated in these initiatives and offered for cross-zonal trading, without the adjustment for long-term nominations;

   b) For CNECs, which are not yet used in existing flow-based capacity calculation initiatives $RAM_{FB}(CNEC, MTU)$ shall be calculated as follows:

$$\overrightarrow{RAM}_{FB}(CNEC, MTU) = \mathbf{pPTDF_{zone-to-zone}}(CNEC, \mathrm{MTU})\, \overrightarrow{NTC}_{fallback}(MTU)$$

with

$\mathbf{pPTDF_{zone-to-zone}}(\mathrm{CNEC, MTU})$	Positive zone-to-zone power transfer distribution factor matrix for a given CNEC, bidding zone border and market time unit, pursuant to Equation 21.
$\overrightarrow{NTC}_{fallback}(MTU)$	The NTCs used for the DA fallback procedure on all oriented bidding zone borders in implemented flow-based capacity calculation initiatives for a given market time unit

5. The capacity of a CNEC available for cross-zonal trade resulting from bidding zone borders applying the NTC approach ($RAM_{NTC}(CNEC, MTU)$) shall be defined by converting for each market time unit the day-ahead NTC values on all oriented bidding zone borders applying the NTC approach with the corresponding zone-to-zone PTDFs (if positive) for the given CNEC:

$$\overrightarrow{RAM}_{NTC}(CNEC, MTU) = \mathbf{pPTDF_{zone-to-zone}}(CNEC, \mathrm{MTU})\, \overrightarrow{NTC}_{DA}(MTU)$$

with

$\overrightarrow{NTC}_{DA}(MTU)$	The day-ahead NTCs of all oriented bidding zone borders for a given market time unit

6. For the calculation of the above variables, the following assumptions shall be used:

   (a) The selection of CNECs to be used in the analysis shall be equal to the selection of CNECs that TSOs expect to use in the Core day-ahead capacity calculation.

   (b) $\vec{F}_{max}$ and $\mathbf{PTDF}$ for CNECs which are the same as the ones used in existing flow based capacity calculation initiative shall be equal to the historical values used in these initiatives. For CNECs, which have not been used in implemented flow-based capacity calculation initiatives during 2017 – 2019, $\vec{F}_{max}$ and $\mathbf{PTDF}$ shall be calculated by the concerned TSOs based on Article 6 and Article 11 respectively. When doing so, the TSOs may use representative values for more than one market time unit.

   (c) The $\overrightarrow{NTC}_{fallback}$ as referred to in paragraph 6 shall be the ATC values used for fallback procedures on the borders for which the flow-based capacity calculation approach was already implemented during the analysed period of 2017 – 2019.

   (d) The $\overrightarrow{NTC}_{DA}$ as referred to in paragraph 6 shall be the day-ahead NTC values on the borders which have been applying the NTC approach during the analysed period of 2017 – 2019.