ACER Decision on Core CCM: Annex I

# Day-ahead capacity calculation methodology of the Core capacity calculation region

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

**21 February 2019**

# 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.

of the operational security limits (*inter alia* frequency, voltage and dynamic stability) depend on the level of production and consumption in a given bidding zone, and these cannot be controlled by active power flow 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 these allocation 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.

(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.

# 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;
    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 resulting from the allocation of cross-zonal capacities within the Core CCR;

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"), 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"), 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;

21. '$F_{0,Core}$' means the flow per CNEC in the situation without commercial exchanges within the Core CCR;

22. '$F_{0,all}$' means the flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe and between bidding zones within Continental Europe and bidding zones of 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;

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

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

37. $LTA_{margin}$ means the adjustment of remaining available margin to incorporate long-term allocated capacities;

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 single 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. A slack node 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;
68. 'zone-to-slack $PTDF$' means the PTDF of a commercial exchange between a bidding zone and the slack node;
69. 'zone-to-zone $PTDF$' means the PTDF of a commercial exchange between two bidding zones;

70. the notation $x$ denotes a scalar;

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

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

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:

   (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);

   (b) the adjustment values for long-term allocated capacities for each Core bidding zone border to enlarge the default flow-based domain beyond the long-term allocated capacities for the purpose of calculating the default flow-based parameters; 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.

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 and individual validations, 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 initial 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.

## 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.

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 eighteen 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 thermal limits of CNEs, the Core TSOs shall use the maximum admissible current limit ($I_{max}$), which is the physical limit of a CNE according to the operational security limits in accordance with Article 25 of the SO Regulation. The maximum admissible current shall be defined as follows:

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

        i. Seasonal limit, which means a fixed limit for all 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, cables or substation equipment installed in the primary power circuit (such as circuit-breaker, or disconnector) with limits not sensitive to ambient conditions.

    (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(φ) is the power factor.

    (f) the CCC shall, by default, set the power factor cos(φ) 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. φ = 0). If the share of reactive power is not negligible, a TSO may consider this aspect during the validation phase in accordance with Article 20.

3. The Core TSOs shall aim at gradually phasing out the use of seasonal limits pursuant to paragraph 2(a)(i) and replace them with dynamic limits pursuant to paragraph 2(a)(ii), when the benefits are greater than the costs. After the end of each calendar year, each TSO shall analyse for all its CNEs for which seasonal limits are applied and have a non-zero shadow price at least in 0.1% of DA CC MTUs in the previous calendar year, the expected increase in the economic surplus in the next 10 years resulting from the implementation of dynamic limits, and compare it with the cost of

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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.

implementing dynamic limits. Each TSOs shall provide this analysis to Core regulatory authorities. If the cost benefit analysis, taking into account other planned investments, is positive, the concerned TSO shall implement the dynamic limits within three years after the end of the analysed calendar year. In case of interconnectors, the concerned TSOs shall cooperate in performing this analysis and implementation when applicable.

4. TSOs shall regularly review and update operational security limits in accordance with Article 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. For this purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone within the SDAC.

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

   (a) a constraint on the Core net position (the sum of cross-zonal exchanges within the Core CCR 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.

3. External constraints may be used by ELIA, TenneT B.V. and PSE during a transition period of two 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 external constraints as specified in Annex 1 to this methodology. During this transition period, the concerned Core TSOs shall:

   (a) calculate the value of external constraints on a daily basis for each DA CC MTU (for PSE only) or at least on a quarterly basis and publish the results of the underlying analysis (this obligation is for ELIA and TenneT B.V. only);

   (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 DA CC MTU when the external constraint had a non-zero shadow price the loss in economic surplus due to external constraint and the effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits and (ii) alternative solutions to address the underlying operational security limits. The CCC shall include this report as an annex in the quarterly report as defined in Article 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 previous paragraph, they may, by eighteen 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 external constraints indicating the underlying operational security limits and why they cannot be transformed efficiently into $I_{max}$ and $F_{max}$;

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

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

5. For the SDAC fallback procedure, pursuant to Article 23, all external constraints shall be modelled as constraints limiting the Core net position as referred to in paragraph 2(a).

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

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

## Article 8. Reliability margin methodology

1. The $FRM$s shall cover the following forecast uncertainties:

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

(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 $FRM$s 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

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

then adjusted to take into account the realised commercial exchanges inside the Core CCR. The latter adjustment shall be performed by calculating $PTDFs$ 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 which are reflected in realised power flows. This above calculation of expected power flows ($F_{exp}$) is described with Equation 2.

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

*Equation 2*

with

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

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

6. Each TSO may reduce the $FRM$ values resulting from the second step for its own CNECs if it considers that the underlying uncertainties have been over-estimated.

7. No later than eighteen 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

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

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.

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 the following $FRM$ values:.

   (a) for CNECs already used in existing flow-based capacity calculation initiatives, the $FRM$ values shall be equal to the $FRM$ values used in these initiatives at the time of adoption of this methodology; and

   (b) for CNECs not already used in existing flow-based capacity calculation initiatives, the $FRM$ values shall be equal to 10% of the $F_{max}$ calculated under normal weather conditions.

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 a bidding zone net position into a specific change of injection or withdrawal in the CGM. A GSK shall have fixed values, which means that the relative contribution of generation or load to the change in the bidding zone net position shall remain the same, regardless of the volume of the change.

2. For a given 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 take into account the available information on generation or load available in the CGM in order to select the nodes that will contribute to the GSK.

3. The GSKs shall describe the expected response of generation and/or load units to changes in the net positions. This expectation shall be based on the observed historical response of generation and/or load units to changes in net positions, clearing prices and other fundamental factors, thereby contributing to minimising the FRM.

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

4. The GSKs shall be updated and reviewed on a daily basis or whenever the expectations referred to in paragraph 3 change. The Core TSOs shall review and update the application of the generation shift key methodology in accordance with Article 24.

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

6. Within eighteen months after the implementation of this methodology in accordance with Article 28(3), all Core TSOs shall develop a proposal for further harmonisation of the generation shift key methodology and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. The proposal shall at least include:

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

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

### 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 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.

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 bidding zones net position 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; 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; 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 exchanges over HVDC interconnectors which are integrated pursuant to Article 12:

$$PTDF_{z2zmax,l} = max\left(\max_{A\in BZ}(PTDF_{A,l}) - \min_{A\in BZ}(PTDF_{A,l}), \max_{B\in HVDC}(PTDF_{B,l})\right)$$

*Equation 5*

with

| | |
|---|---|
| $PTDF_{A,l}$ | zone-to-slack $PTDF$ of bidding zone A on a CNEC $l$ |
| HVDC | set of HVDC interconnectors integrated pursuant to Article 12 |
| $BZ$ | set of all Core bidding zones |
| $\max_{A\in BZ}(PTDF_{A,l})$ | maximum zone-to-slack PTDF of Core bidding zones on a CNEC $l$ |
| $\min_{A\in BZ}(PTDF_{A,l})$ | minimum zone-to-slack PTDF of Core bidding zones on a CNEC $l$ |

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) |
| **PTDF** | power transfer distribution factor matrix |
| $\overrightarrow{NP}_i$ | Core net position per bidding zone in the commercial situation $i$ |
| $\overrightarrow{NP}_{ref}$ | Core net position per bidding zone in the reference commercial situation |

## Article 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 when including HVDC interconnectors on the bidding zone borders of the Core CCR[5]. According to this methodology, a cross-zonal exchange over an HVDC interconnector on the bidding zone borders of the Core CCR is modelled and optimised explicitly as a bilateral exchange in capacity allocation, and is constrained by the physical impact that this exchange has on all CNECs considered in the final flow-based domain used in capacity allocation.

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

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

*Equation 7*

with

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

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

[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 within a single CCR applying the flow-based method of that CCR.

4. The virtual hubs introduced by this methodology are only used for modelling the impact of an exchange through a HVDC interconnector and no orders shall be attached to these virtual hubs in the coupling algorithm. The two virtual hubs will have a combined net position of 0 MW, but their individual net position will reflect the exchanges over the interconnector. The flow-based net positions of these virtual hubs shall be of the same magnitude, but they will have an opposite sign.

## 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 with a standard hybrid coupling (SHC) and where possible also with an advanced hybrid coupling (AHC).

2. In the standard hybrid coupling, the Core TSOs shall consider the electricity exchanges on bidding zone borders outside the Core CCR as fixed input to the 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.

3. In the AHC, the CNECs of the day-ahead capacity calculation methodology shall limit not only the net positions of the Core bidding zone borders, but also the electricity exchanges on bidding zone borders of adjacent CCRs.

4. No later than eighteen months after the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly develop a proposal for the implementation of the AHC and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. The proposal for the implementation of the AHC shall aim to reduce the volume of unscheduled allocated flows on the CNECs of the Core CCR resulting from electricity exchanges on the bidding zone borders of adjacent CCRs. If before the implementation of this methodology, the AHC has been implemented on some bidding zone borders in existing flow-based capacity calculation initiatives, it may continue to be applied on those bidding zone borders as part of the day-ahead capacity calculation carried out according to this methodology until the amendments pursuant to this paragraph are implemented.

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

## Article 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.

## 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[6] over switching states (i.e. activated or not-activated) of topological measures 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

[6] A global optimisation finding the optimal solution in one iteration would also be acceptable, as long as the final optimisation result is at least as good as the one obtained through the described iterative process, i.e. would lead to a higher value of the objective function while fulfilling all constraints.

| | |
|---|---|
| $\overrightarrow{RAM}_{nrao}$ | 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) |

$$RAM_{rel} = \frac{RAM_{nrao}}{\sum_{(A,B)\,\in\, neighbouring\ Core\ bidding\ zones\ pairs} \left|PTDF_{A\rightarrow B,nrao}\right|}\ if\ RAM_{nrao} \geq 0$$

$$RAM_{rel} = RAM_{nrao}\ if\ RAM_{nrao} < 0$$ [7]

*Equation 9*

with

| | |
|---|---|
| $PTDF_{A\rightarrow B,nrao}$ | 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);

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) $\mathbf{PTDF}_f = \mathbf{PTDF}_{nrao}$ directly from the optimisation results;

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

(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 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 is first calculated by setting the Core net positions $\overrightarrow{NP}_i$ in Equation 6 to zero for all Core bidding zones, leading to the following equation:

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

*Equation 10*

with

| | |
|---|---|
| $\vec{F}_{0,Core}$ | flow per CNEC in the situation without commercial exchanges within the Core CCR |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM after the NRAO |

| | |
|---|---|
| $\mathbf{PTDF}_f$ | power transfer distribution factor matrix for the Core CCR |
| $\overrightarrow{NP}_{ref,Core}$ | Core net position per bidding zone 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, and between bidding zones within Continental Europe and bidding zones from other synchronous areas. For this calculation, the CCC shall set all exchanges on DC interconnectors between Continental Europe and other synchronous areas to zero, and then calculate the zonal PTDFs for all bidding zones within the synchronous area Continental Europe 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 $F_{0,all}$ with the following Equation 11.

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

*Equation 11*

with

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

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 $F_{uaf}$ (capacity offered outside the Core CCR) 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:

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

*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:

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

*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 |
| $F_{0,\mathrm{Core}}$ | flow in the situation without commercial exchanges within the Core CCR |
| $R_{amr}$ | 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 the $RAM$ of each CNEC remains non-negative in all combinations of net positions that could result from previously-allocated cross-zonal capacity.

   (b) previously-allocated capacities on all bidding zone borders of the Core CCR are the long-term allocated capacities (LTA) calculated and allocated pursuant to the FCA Regulation.

(c) until the implementation of long-term capacity calculation as referred to in paragraph 1(b), LTA shall be 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.

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 applying the external constraint, i.e. $NP_{ref}$ in the equation below; and

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

3. The first step in the LTA inclusion is to calculate the flow for each CNEC (including external constraints) in each combination of net positions resulting from the full utilisation of previously-allocated capacities on all bidding zone borders of the Core CCR, based on Equation 6:

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

*Equation 16*

with

| | |
|---|---|
| $\vec{F}_{LTAi}$ | flow per CNEC in LTA capacity utilisation combination $i$ |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM after the NRAO |
| $\mathbf{PTDF_f}$ | zone-to-slack power transfer distribution factor matrix |
| $\overrightarrow{NP}_{LTAi}$ | Core net position per bidding zone in LTA capacity utilisation combination $i$ |
| $\overrightarrow{NP}_{ref}$ | Core net position per bidding zone in the CGM |

4. For a given CNEC, the maximum oriented flow from the LTA inclusion is then

$$F_{LTA,max} = \max_i F_{LTAi}$$

*Equation 17*

5. The adjustment for the LTA inclusion is finally:

$$LTA_{margin} = \max(F_{LTA,max} + FRM - AMR - F_{max}; 0)$$

*Equation 18*

## 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[8] of the adjustment for minimum $RAM$ ($AMR$) according to Article 17;

(c) the calculation of the adjustment for the LTA inclusion according to Article 18;

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

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

*Equation 19*

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, described in Equation 10. For external constraints, in line with Article 18(2), this flow is equal to zero. |
| $\overrightarrow{AMR}$ | Adjustment for minimum RAM pursuant to Article 17 |
| $\overrightarrow{LTA}_{margin}$ | Flow margin for LTA inclusion, pursuant to Article 18 |
| $\overrightarrow{RAM}_{bv}$ | 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 (i.e. the $RAM_{bv}$) 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.

3. In the first step, the CCC in coordination with all Core TSOs shall validate the $RAM_{bv}$. In this process they 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 $RAM_{bv}$ on individual CNECs 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 on the use of RAs having an impact on neighbouring CCRs. For those CNECs where all available RAs are not sufficient to avoid the

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

violation of operational security, the Core TSOs in coordination with the CCC may reduce the $RAM_{bv}$ to the maximum value which avoids the violation of operational security. This reduction of the $RAM_{bv}$ is called 'coordinated validation adjustment' ($CVA$) and the adjusted $RAM$ is called '$RAM$ after coordinated validation'.

4. The coordinated validation pursuant to paragraph 3 shall be implemented gradually. During the first year 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. Subsequently, the simplified process shall gradually be replaced by a full analysis by twenty four months after the implementation of this methodology. Within eighteen months after the implementation of this methodology in accordance with Article 28(3), 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, further specifying the process and requirements for coordinated validation. The proposal shall at least include:

   (a) the CCC role in assessing and communicating available remedial actions; and

   (b) a process for assessing in a coordinated manner (between the Core TSOs and the CCC) whether there are enough RAs to avoid capacity reductions.

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 3 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 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.

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, pursuant to Article 7, 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 20:

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

*Equation 20*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bn}$ | remaining available margin before adjustment for long-term nominations |
| $\overrightarrow{RAM}_{bv}$ | remaining available margin before validation |
| $\overrightarrow{CVA}$ | 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. Pursuant to Article 18(1(a), capacity reductions through $CVA$ and $IVA$ shall ensure that the $RAM_{bn}$ remains non-negative in all combinations of nominations resulting from LTA. Such a constraint is described for each CNEC, including external constraints, by the following equation:

$$CVA + IVA \leq F_{max} - FRM + AMR + LTA_{margin} - F_{LTA,max}$$

*Equation 21*

with

| | |
|---|---|
| $CVA$ | coordinated validation adjustment |
| $IVA$ | individual validation adjustment |
| $F_{LTA,max}$ | maximum oriented flow from LTA inclusion pursuant to Equation 17 |

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) the forecasted flow in the CGM, in the D-1 CGM, and the realised flow, before (and when relevant after) contingency;

(f) 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), (c) and (e) above;

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

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

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

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; and

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

15. When a given Core TSO reduces capacity for its CNECs 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.

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 *22*:

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

*Equation 22*

with

| | |
|---|---|
| $\vec{F}_{LTN}$ | flow after consideration of LTN |
| $\mathbf{PTDF}_f$ | power transfer distribution factor matrix |
| $\overrightarrow{NP}_{LTN}$ | Core net position per bidding zone resulting from LTN |

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

$$\overrightarrow{RAM}_f = \overrightarrow{RAM}_{bn} - \vec{F}_{LTN}$$

*Equation 23*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bn}$ | remaining available margin before LTN adjustment |
| $\vec{F}_{LTN}$ | flow after consideration of LTN |
| $\overrightarrow{RAM}_f$ | final remaining available margin |

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 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

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 missing results by using one of the following two capacity calculation fallback procedures:

(a) 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). 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.

(b) 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). The calculation of default flow-based parameters shall be based on long-term allocated capacities as provided by TSOs pursuant to Article 4(4(a). An external constraint on the Core bidding zones' net positions shall be defined based on the LTA capacity for each Core oriented bidding zone border. The external constraint shall be the LTA value, increased by the minimum of the two adjustments provided by the TSO(s) on each side of the bidding zone border, pursuant to Article 4(4(b). These external constraints are then combined, and adjusted for long-term nominations pursuant to Article 21, to obtain the final flow-based domain.

## 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;

   (b) the flow-based parameters $\mathbf{PTDF}_f$ and $\overrightarrow{RAM}_{bn}$ in accordance with Article 16 and 20 respectively; and

   (c) if defined, the global allocation constraints shall be assumed to constrain the Core net positions pursuant to Article 7(5), and shall be described following the methodology described in Article 18(2). Such constraints shall be adjusted for offered cross-zonal capacities on the non-Core bidding zone borders.

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 equal to LTAs for each Core oriented bidding zone border, i.e.:

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

   with

| | |
|---|---|
| $\overrightarrow{ATC}_{k=0}$ | the initial ATCs before the first iteration |
| $\overrightarrow{LTA}$ | the LTA on Core oriented bidding zone borders |

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

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

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

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 oriented bidding zone borders with strictly positive zone-to-zone power transfer distribution factors on this CNEC;

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

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

v. go back to step i;

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

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

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

(c) positive zone-to-zone PTDF matrix ($\mathbf{pPTDF}_{zone-to-zone}$) for each Core 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):

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

*Equation 24*

with

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

# 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 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;

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

      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: $I_{max}$, $U$, $F_{max}$, $FRM$, $F_{ref,init}$, $F_{nrao}$, $F_{ref}$, $F_{0,\mathrm{core}}$, $F_{0,\mathrm{all}}$, $F_{uaf}$, $AMR$, $LTA_{margin}$, $CVA$, $IVA$, $F_{LTN}$;

      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 area Continental Europe and reference exchanges for all HVDC interconnectors within synchronous area Continental Europe and between synchronous area Continental Europe 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;

ii. flows resulting from net positions resulting from the SDAC.

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

3. Individual Core TSO may withhold the information referred to in paragraph 2(d)iv), 2(d)v) and 2(e) if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of 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(e) shall be publicly notified at least one month before its entry into force. The notification shall at least include:

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

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

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

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

## 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 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.

   (c) according to Article 16(6), 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(3), 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.

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, 20 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), 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(3), 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.

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 Agency in accordance with Article 9(12) 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 1 December 2020. The implementation process, which shall start with the entry into force of this methodology and finish by 1 December 2020, 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.

# 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: Justification of usage and methodology for calculation of external constraints

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

### 1. Belgium:

ELIA may use an external constraint to limit the import of the Belgian bidding zone.

**Technical and legal justification**

ELIA is facing voltage constraints and voltage collapse risks in case of low generation within the Belgium grid. Therefore ELIA requires to maintain a certain amount of power to be generated within Belgium to prevent violation of voltage constraints (i.e. to prevent voltage dropping below the lower safety limit). The risks of dynamic instability are also analysed to assess the amount of machines requested within the Belgium grid to provide a minimal dynamic stability to avoid transient phenomena. These analyses and results lead to the use of a maximum import constraint.

**Methodology to calculate the value of external constraints**

The value of maximum import constraint for the Belgian bidding zone shall be estimated with studies performed on a regular basis. The studies shall include a voltage collapse analysis and a stability analysis performed in line with Article 38 of the SO Regulation. The studies shall be performed and published at least on an annual basis and updated every time this external constraint had a non-zero shadow price in more than 0.1% of hours in a given quarter.

### 2. Netherlands:

TenneT B.V. may use an external constraint to limit the import and export of the Dutch bidding zone.

**Technical and legal justification**

The combination of voltage constraints and limitations following from using a linearised GSK make it necessary for TenneT B.V. to apply external constraints. Voltage constraints justify the use of a maximum import constraint, because a certain amount of power needs to be generated within the Netherlands to prevent violation of voltage constraints (i.e. to prevent voltage dropping below the lower safety limit). To prevent the deviations between forecasted and realised values of generation in-feed following from the linear GSK to reach unacceptable levels, it is necessary to make use of external constraints to limit the feasible net position range for the Dutch import and export net position. This last point is explained in more detail below.

The day-ahead capacity calculation methodology uses a Generator Shift Key (GSK) to determine how a change in net position is mapped to the generating units in a specific bidding zone. The algorithm requires that the GSK is linear and that by applying the GSK the minimum and maximum net position ('the feasibility range') of a bidding zone can be reached. TenneT B.V. applies a GSK method that aims at establishing a realistic generator schedule for every hour and which is applicable to every possible net position within the flow-based domain. In order to realise this, generators can be divided in three groups based on a merit order: (i) rigid generators that always produce at maximum power output, (ii) idle generators that are out-of-service and (iii) 'swing generators' that provide the 'swing capacity' to reach all intermediate net positions required by the algorithm for a specific grid situation. To reach the maximum net position, all 'swing generators' shall produce at maximum power. To reach the minimum net position, all 'swing generators' shall produce at minimum power. The absolute difference between the minimum and maximum net position thus determines the amount of required 'swing capacity', i.e. the total capacity required from 'swing generators'.

If TenneT B.V. would not apply external constraints, and higher import and export net positions would be possible, several generators that in practice operate as rigid generators (e.g. CHPs, coal fired power plants etc.) would need to be modelled as 'swing generators'. In some cases, a switch of a generator from 'idle' to 'swing' or from 'rigid' to 'swing' could mean a jump of roughly 50% in the power output of such a power plant, which in turn has significant impact on the forecasted power flows on the CNECs close to that power plant. This results in a reduced accuracy of the GSK as the generation of these plants is modelled less accurately and the deviations between the forecasted and realised flows on particular CNECs increase to unacceptable levels with significant impact on the capacity domain. The consequence of this would be that higher FRMs need to be applied to partly cover these deviations, which will constantly limit the available capacity for the market. To prevent too large deviations in generation in-feed, the total feasibility range, which should be covered by the GSK, thus needs to be limited with external constraints.

The Netherlands is a small bidding zone with, in comparison to other bidding zones, a lot of interconnection capacity which implies a very large feasibility range compared to the total installed capacity. E.g. TenneT B.V. has applied external constraints of 5 GW for both the import and export position in the past, already implying a feasibility range of 10 GW on a total of roughly 15 GW generation capacity included in the GSK at that point in time. For other bidding zones with a much higher amount of installed capacity or relatively less interconnection capacity, the relative amount of 'swing capacity' in their GSK is much lower and therefore also the deviations between forecasted and realised generation are lower. Or in other words, the maximum feasibility range which can be covered by the GSK without increasing deviations between forecasted and realised generation to unacceptable levels, is larger than the total installed interconnection capacity for these bidding zones, making it not necessary to use external constraints as a measure to limit these deviations.

**Methodology to calculate the value of external constraints**

TenneT B.V. determines the maximum import and export constraints for the Netherlands based on studies, which combine a voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during different extreme import and export situations in accordance to Article 38 of the SO Regulation. The studies shall be performed and published at least on an annual basis and updated every time this external constraint had a non-zero shadow price in more than 0.1% of hours in a given quarter.

## 3. Poland:

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

**Technical and legal justification**

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

The integrated scheduling process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process.[9] Therefore, one way to ensure sufficient reserve capacity within integrated scheduling process is to set a limit to how much electricity can be imported or exported in the SDAC.

The objective to limit balancing service providers to sell too much energy in the day-ahead market in order to be able to provide sufficient reserve capacity in the integrated scheduling process cannot be efficiently met by translating this limit into capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs, whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, whereas the trading of other bidding zones is unaffected.

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

**Methodology to calculate the value of external constraints**

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

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

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

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

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

[9] This conclusion equally applies for the case of lack of downward balancing capacity, which would be endangered if balancing service providers (generating units) sell too little energy in the day-ahead market, because of too high imports.

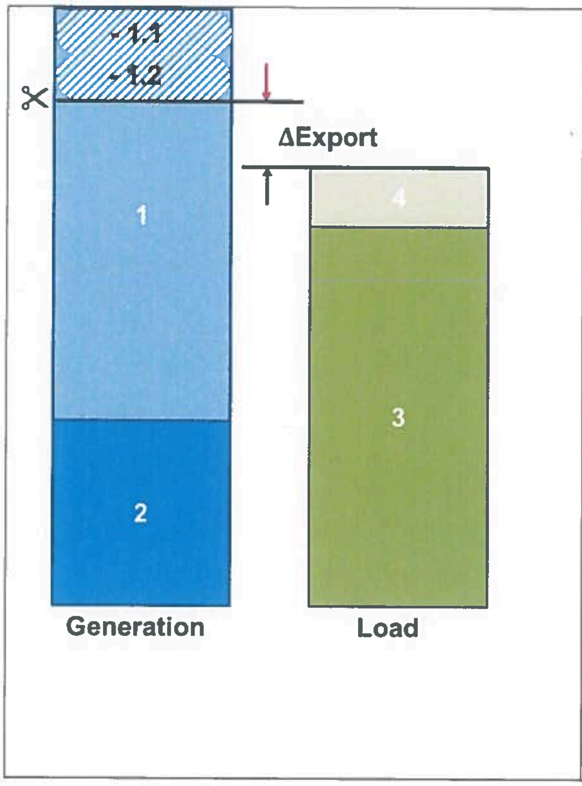
Where:

| | |
|---|---|
| $P_{CD}$ | Sum of available generating capacities of centrally dispatched units as declared by generators[10] |
| $P_{CD_{min}}$ | 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 wind farms: 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 |

For illustrative purposes, the process of practical determination of external 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 hour of the delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.

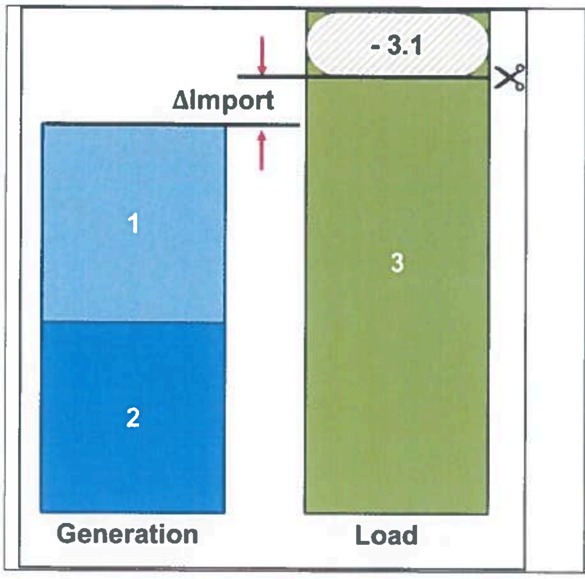
External constraint in export direction is applicable if ΔExport is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction. External constraint in import direction is applicable if ΔImport is lower than the sum of cross-zonal capacities on all Polish interconnections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

[10] 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 wind farms: forecasted by PSE)
3. Demand forecasted by PSE
4. Minimum necessary reserve for up regulation

Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of the 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 wind farms: forecasted by PSE)

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

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

**Frequency of re-assessment**

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

## Time periods for which external constraints are applied

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

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

1. 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.[11]

2. 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 |

3. The minimum RAM factor in year 2020, $R_{amr,start}$ is the average total capacity allocated on all CNECs[12] 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.

4. 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

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

[12] 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 |

5. 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 |

6. 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 24. |
| $\overrightarrow{NTC}_{fallback}(MTU)$ | 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 |

7. 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 |

8. 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 **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 **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.

# ACER Decision on Core CCM: Annex III

# Evaluation of responses to the public consultation on the amendments of the proposal for a common capacity calculation methodology for the Core capacity calculation region

## 1 Introduction

On 4 June 2018, transmission system operators ('TSOs') from the Core capacity calculation region ('CCR') submitted the amended proposals for the *'Core CCR TSOs' regional design of the intraday common capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015'* and the *'Core CCR TSOs' regional design of the day-ahead common capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015'* (the 'Amended Proposals'). The last Core CCR regulatory authority received the Amended Proposals on 19 June 2018.

The Core regulatory authorities did not reach a unanimous agreement to either approve the Amended Proposals, to request the Agency to extend the deadline for decision or to request the Agency to adopt a decision on the Amended Proposals pursuant to Article 21 et seqq. of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (the 'CACM Regulation'). In accordance with Article 9(12) of the CACM Regulation, all the Core CCR regulatory authorities referred the Amended Proposals to the Agency, for the Agency to adopt a decision. In order to take an informed decision, the Agency launched a public consultation on 4 December 2018 inviting all interested parties to express their views on potential amendments of the Amended Proposals. The closing date for comments was 24 December 2018.

More specifically, the public consultation invited stakeholders to comment on the following aspects of the capacity calculation methodology ('CCM'):

(i) The avoidance of undue discrimination between internal and of cross-zonal trade, and in particular the suggested approaches on the selection of critical network elements and contingencies ('CNECs'), as well as the minimum remaining available margin ('minRAM');

(ii) TSOs' intervention to ensure operational security, at the end of the calculation process (i.e. 'capacity validation');

(iii) The quality of the capacity calculation input parameters, and in particular the suggested approaches to the Flow Reliability Margin ('FRM') and Generation Shift Key ('GSK');

(iv) The use of allocation constraints by the Core TSOs;

(v) The calculation of intraday ('ID') capacity, and in particular the consistency between the day-ahead and the intraday methodologies, the suggested approach to the timing and the frequency of ID capacity calculation and the suggested approach to cross-zonal capacity at the intraday cross-zonal gate opening time;

(vi) The overall transparency of the CCM; and

(vii) The foreseen implementation timeline.

## 2 Responses

By the end of the consultation period, the Agency received responses from 26 respondents.

This evaluation paper summarises all received comments and responses to them. The table below is organised according to the consultation questions and provides the respective views from the respondents, as well as a response from the Agency clarifying the extent to which their comments were taken into account.

| Respondents' views | ACER views |
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| **Question 1: Please comment on the suggested approach on the selection of critical network elements and contingencies.** | |
| 22 respondents provided an answer to this question. | |
| 6 respondents share the Agency's observation that cross-zonal capacities for the market are low. 2 of these respondents further believe that TSOs manage internal congestions at the cost of cross-zonal capacity.<br>1 respondent further supports the gradual two-year approach to removing internal lines from capacity calculation, as well as the possible derogation after those 2 years, as suggested by the Agency | The Agency agrees. |
| 14 respondents object to the exclusion of internal critical network elements after two years.<br>7 of those respondents observe that in a zonal market design, cross-zonal trade, regardless of the zonal configuration, will always affect some internal network elements. 4 among those respondents observe that the flow-based methodology by design should take into account congestion on internal network elements. 7 of those respondents further suggest that inclusion be allowed based on a sound market economic efficiency analysis. | The Agency disagrees with the systematic inclusion of internal network elements into capacity calculation based only on the criteria of significant physical impact. This criteria is indeed an important one as it is mandated by Article 29(3)(a) of the CACM Regulation. However, it should not be the only one, since the reference to the rules for avoiding undue discrimination between internal and cross-zonal exchanges in accordance with Article 21(1)(b)(ii) and Article 29(7)(d) of the CACM Regulation aims to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009. This point requires that '*TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons [i.e. economic efficiency] and reasons of operational security*'. As the Agency's Decision needs to respect the applicable Union legal framework, the inclusion of internal network elements in capacity calculation therefore needs to be conditional on economic efficiency and operational security. Therefore, the Agency introduced a selection criteria for internal network elements to become critical network elements, which is based on economic efficiency and, in exceptional cases, during capacity validation, TSOs may add internal network elements to the list of CNECs due to operational security. |

| Respondents' views | ACER views |
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| 2 respondents favour limiting the inclusion of internal critical network elements based on a threshold for power transfer distribution factors ('PTDFs') (1 respondent suggests a 15% threshold); 1 among those respondents believes such threshold offers a better guarantee of compatibility between the Core CCM is and Core TSOs' system security.<br>In opposition with those respondents, 2 respondents are opposed to any derogation (and the inclusion of internal critical network elements) after two years. | Even though cross-zonal trade may indeed affect internal network elements, this fact is not a sufficient reason for these elements to limit cross-zonal trade. This is because in the zonal market model, these elements should generally be assumed as physically non-congested and if the congestion would indeed appear on those elements, they should be managed by means of equal competition and access for cross-zonal and internal exchanges and not by introducing competition only for cross-zonal exchanges while keeping the priority access for internal exchanges.<br>Further, the Agency notes that there is no requirement in the Union legislation, which would require by design that a flow-based CCM takes into account internal network elements. |
| 6 respondents believe that the CCM should set proper incentives for network investments.<br>2 respondents observe that excluding internal lines from the CCM has the opposite result, by desincentivising investment in cross-border infrastructures. 1 respondent further believes that this approach will punish those countries that have built up a significant cross-border transport infrastructure or are planning to do so. 5 respondents believe that the focus should be on network elements subject to frequent 'reductions'. 1 respondent judges the Agency's approach to be unfair and inefficient, as it does not target undue discrimination but rather forces TSOs operating large bidding zones to trigger massive amounts of redispatching and/or countertrading. | The Agency considers that a policy based on efficient congestion management can never fulfil all the energy policy objectives, namely in this case the incentives to develop cross-border infrastructure investments. Generally, a combination of measures is needed to address different policy objectives. The Agency considers that investments in interconnections should be incentivised through different regulatory measures and they should be implemented only when the networks inside bidding zones is sufficiently strong to accommodate new interconnectors or when these investments are combined with planned reconfiguration of bidding zones.<br>The Agency also notes that redispatching and/or countertrading is not the only way to address the discrimination issue (and most likely not the most efficient one). |

| Respondents' views | ACER views |
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| 4 respondents observe that the transition period of two years is too short to consider alternative measures such as splitting the bidding zones or infrastructure investments. In general, TSOs will need more time for the implementation of the CACM Regulation. 1 respondent observes that TSOs are liable for a secure system operation and will relieve overloaded lines by applying remedial actions. 2 respondents suggest to extend the initial transition period to 5 years in order to avoid an inefficient, carbon-emitting and possibly unsafe use of remedial actions, 1 suggests a specific possibility of an extension for those internal lines with significant cross-border impact (zone-to-zone PTDF >5%).<br><br>In contradiction with this observation, 1 respondent believes that the transition period of two years is unjustified, as TSOs should already have implemented solutions two years ago, in the context of the Agency's Recommendation. | The Agency considers that a transition period is needed, since it implies a significant change in how cross-zonal capacities are calculated. Even though the legal framework related to point 1.7 of Annex I to Regulation 714/2009 has been applicable for several years, this does not change the fact that immediate implementation of this solution is not feasible. The Agency considers that the proposed transition period is sufficiently long as it includes the following timeline:<br>1. at least 21 months for the implementation of the methodology<br>2. 18 months for the development of a proposal<br>3. 6 to 12 months for the approval of the proposal.<br>This should provide sufficient time to TSOs to analyse and implement, where necessary, the alternatives. |

| Respondents' views | ACER views |
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| 4 respondents discuss the issue of bidding zone configuration: 1 respondent observes that any consideration of an 'optimal bidding zone configuration' is out of the legal scope of the provisions of the CACM Regulation on capacity calculation, which another respondent supports by stating that a decision on amending or maintaining bidding zones falls within the concerned Member States. 2 respondents assume that a bidding zone reconfiguration is very unlikely to occur due to political and technical resistance. 1 respondent states that as a principle, TSOs should only be requested to do as much as they are able to, but not be sanctioned for any effects or developments beyond their powers, for example, a change in the configuration of bidding zones.<br>1 respondent, supporting bidding zone reconfiguration, considers that long-term structural congestions will necessary be solved by ensuring that bidding zones are efficiently configured, following a clearly defined review process. | The Agency agrees that bidding zone reconfiguration is out of scope of the CCM and the legal scope of the Agency's Decision. For this reason, the Agency did not impose any obligations on this subject. Rather, the Agency defined conditions under which TSOs can include internal network elements to the list of CNECs that may reduce cross-zonal capacity, which is within the scope of the Decision. Therefore, the main added-value of the Agency's Decision is to protect the interest of the internal market and to optimise the capacity of the interconnectors by making sure that reductions due to congestions on internal network elements are indeed efficient considering the legally possible alternatives. The Agency does not consider it justified to limit the cross-zonal capacities due to the unwillingness or national restrictions imposed on some TSOs to implement the alternative possibility provided by the Union legislation. |
| **Question 2: Please comment on the suggested approach to minimum remaining available margin.** | |
| 22 respondents provided an answer to this question. | |
| 4 respondents are opposed to the setting of minRAM:<br>1 respondent observes that the European energy policies in general, and the Clean Energy Package in | The Agency finds it necessary to ensure minimum capacity available for cross-zonal trade in order to avoid non-discrimination between internal and cross-zonal exchanges. |

| Respondents' views | ACER views |
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| particular, do not constitute a framework that contributes to German end-consumer welfare. In a context where German consumers face the cost of the energy transition, increased network charges due to higher redispatching costs, or any alternative are politically challenging: a split in bidding zones would result in higher tariffs in South Germany and additional investments (Süd-link) would bear the same result. This is why fixed cross-border capacity bears no positive outcome for German consumers.<br><br>1 respondent believes that artificially increased cross-zonal trade will not bring any benefit except for traders, and sees potential loss in profitability from a generator perspective, market distortion, increased costs associated to increased use of remedial actions, undermining the positive effects of scarcity pricing.<br><br>1 respondent believes that minRAM is not transparent enough.<br><br>1 respondent believes that minRAM is an artificial tool altering the mathematical soundness of the algorithm without guaranteeing that the level of capacity made available to the market is maximised up to the level of optimal welfare.<br><br>1 respondent believes that the setting of minRAM is out of scope as the intention of flow-based capacity calculation is to align operations and markets. | While the Agency shares the concerns of stakeholders about the minRAM approach (i.e. transparency, overall benefits for end consumers, overall impact on market efficiency when the costs of remedial actions are taken into account), it notes however that this approach is the only one available to the Agency to address the discrimination between internal and cross-zonal exchanges. Without such a measure, the undue discrimination between internal and cross-zonal exchanges would remain unresolved.<br><br>On the necessity of this requirement, the CCM establishes common harmonised rules for calculation of interconnection capacity serving the overall objective of establishing a fully competitive Internal Electricity Market with common harmonised rules for access to interconnection capacity. Therefore, regardless of the individual policies applicable in different Member States, these policies should not have any impact on the access rules for interconnection capacity. In the absence of such common rules, the concept of Internal Electricity Market would be seriously endangered. |

| Respondents' views | ACER views |
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| On the contrary, 9 respondents see merit in minRAM threshold.<br>7 respondents see merits in The Agency's proposal to address undue restriction of cross-zonal trades by the enforcement of minRAM. 1 respondent believes that the approach is justified if the percentage remains manageable from a system security point of view, as seen in the Core CCR and the former Central Western European region. 1 respondent believes that the approach may provide a certain level of certainty to the market. | The Agency agrees. |
| 7 respondents anticipate negative consequences from an initial setting of too high a value of minRAM. 5 respondents consider that too high a minRAM value would jeopardize economic efficiency. 4 respondents see risks for system security, and 1 sees further risks regarding security of supply for central Europe. The risk, which those respondents point at, is one of a TSO potentially facing rising levels of unscheduled flows through its system, up to a level that redispatching could not address. 3 respondents underline a specific impact for third countries sharing the same synchronous area with any Member State. 2 among those note that the problem can be more critical in bidding zones where market participants must have balanced positions in the day-ahead timeframe, therefore call for consistency between national rules and rules defined in the Agency's Decision. | As outlined above, the Agency finds it necessary to comply with the Union legislation on harmonised and efficient rules for access to interconnectors between Member States. This is essential to establish a truly competitive and non-discriminatory Internal Electricity Market. Therefore, the Union rules on access to interconnectors should not be bound or tailored to specific national markets. While specific national markets and jurisdictions may indeed face difficulties, costs or inefficiencies when implementing these rules, these are, in the Agency's view, mostly unavoidable. |

| Respondents' views | ACER views |
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| 9 respondents specifically discuss the starting threshold for the minRAM trajectory.<br><br>6 respondents suggest cautious approaches. 1 respondent observes that the setting of an initial value of minRAM at 40% would not be based on available experience, unlike the 20% minRAM suggested in the Amended Proposal, pursuant to current practices in the former Central Western European region. 2 other respondents further consider 20% as an acceptable compromise, considering that in the former Central Eastern European region, TSOs have little or no experience with flow-based capacity calculation. 1 respondent would support a starting point up to 30%. 1 respondent would support an initial range for minRAM, rather than a fixed target. Finally, 1 respondent qualifies 'any minRAM (20%)' as 'ambitious'.<br><br>On the contrary, 3 respondents would support more ambitious approaches. 1 respondent considers that 20% it is not ambitious enough. This respondent further observes that in 2018, remaining available margin ranged on average around 30% for active constraints on internal lines and close to 50% for cross-border lines, therefore an overall 30% threshold would actually be a step back, and the political signal that 70% of the cross-border could possibly be reserved for loop flows. 2 additional respondents support the last statement. | The Agency is of opinion that it is important to define the objective, which is compliant with the currently applicable Union legislation. In the Agency's understanding, the minimum RAM should be 70% of the maximum admissible flow of critical network elements and further justification of this value can be found in the Decision. The Decision also explains that this requirement is without prejudice to possible deviations as long as those are compliant with the Union legislation. |

| Respondents' views | ACER views |
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| 13 respondents suggest alternative approaches to establishing a minRAM threshold.<br>8 respondents suggest that the threshold for minRAM be based on an economic analysis aiming at welfare maximisation, further suggesting that the analysis is revised every other year.<br>1 respondent suggests that minRAM takes account the PTDFs. Based on the observation that a small RAM increase on a CNEC with a low PTDF can free up a significant amount of capacity, this respondent suggests calling for lower minRAM thresholds on critical network elements with lower PTDFs, thereby targeting the effort in a cost-efficient manner, and guaranteeing feasibility.<br>1 respondent suggests that the minRAM threshold be considered over 80% of trading hours only.<br>3 respondents suggest that the minRAM threshold should be a 'benchmark target' (i.e. non-binding). 1 among them argues that the CACM Regulation does not mandate any pre-defined goal. | The Agency considered the option to use economic efficiency as a criteria to define the minimum thresholds for cross-zonal capacities. However, as outlined above, such efficiency criteria would presently likely be impacted by specific national market aspects and would thus make the Union rules on access to interconnection capacities highly dependent on specific national market design features and thereby the potential negative impacts of national market design choices would spill over to other markets. The Agency does not see this as a proper basis for defining common Union rules for access to interconnection capacity.<br>The Agency finds the proposal of defining relative minimum RAM interesting as it would 'normalise' the minimum capacity according to the relevance of different critical network elements for cross-zonal trade. However, the Agency objects the notion that the legitimacy of capacity reductions on interconnectors or internal critical network elements due to loop flows, reliability margins and internal flows can differ in relation to the significance of the underlying network elements for cross-zonal trade. In the Agency's view, the legitimacy of those reductions should be set in absolute terms. |
| 3 respondents express concerns over the linear trajectory for increasing the minRAM: 2 respondents anticipate that it will incur significant costs. 1 respondent considers that the increase should not be automatic, but the assessment of the success of one step should condition the launching of the next one. | The Agency does not consider it legally feasible to provide discretion to TSOs to fulfil legal requirements. The fact that TSOs are not complying with the Union legislation today should not be a reason for providing them a continuous comfort for non-compliance. |

| Respondents' views | ACER views |
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| 3 respondents discuss the end-goal of reaching a threshold of 75% minRAM.<br>2 respondents consider that such threshold is not ambitious enough. 1 of them considers that it goes against European Regulations, Directives and the Treaty of Lisbon. 1 considers that it contradicts the approach to economically efficient CCMs in the draft recast Regulation. 1 respondent considers that the threshold is too ambitious. | The Agency considers that with currently available information the 70% target for minimum RAM represents an expectation that, in a bidding zone configuration, the level of loop flows, internal flows and reliability margin should not increase beyond 30%. Therefore, in the context of a zonal market design, TSOs may not be able to provide more cross-zonal capacities. Nevertheless, this assumption is currently based on best available information and it may therefore change in future once more data and information become available. |
| 2 respondents support the introduction of a loop-flow threshold (1 among them suggested a value of 10%), with the aim that loop flows considered in capacity calculation should be reduced up to this level. 1 of these respondents further requests that *'It should also be avoided that NRAO* [i.e. non-costly remedial action optimization] *creates margin on internal lines considered in capacity calculation by increasing the loop flows on the border above the agreed threshold.'* | The Agency accommodated this proposal and introduced an option for TSOs to define initial settings of remedial actions to reduce the level of loop flows below the threshold level. The Agency also defined this threshold level using the same assumptions as the ones used in the definition of the minimum RAM factor. Finally, the Agency also provided a constraint for the optimisation of non-costly remedial actions such that the latter does not lead to an increase of loop flows beyond the threshold level. |
| 2 respondents support preventive remedial actions to be taken into account in the base case when there is a certainty that they will be activated as they relieve structural constraints, in order to reflect better the actually feasible minRAM values. | The Agency considers that such an approach is not needed, since the minimum capacity (i.e. minRAM) can achieve the same result, which is to ensure the maximisation of cross-zonal capacities even if structural congestions or loop flows are present. Such an approach (i.e. defining a common grid model ('CGM') with all expected remedial actions) would also reverse the cause and effect ordering, since a CGM is needed to identify congestions that would occur without remedial actions and only then the optimal remedial actions can be chosen to address these congestions. |
| **Question 3: Please comment on the suggested approach to the validation process.** | |
| 15 respondents provided an answer to this question. | |

| Respondents' views | ACER views |
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| 10 respondents approve the process; 1 among those respondents further sees it as a guarantee for transparency and liability over recurring capacity reductions.<br>2 respondents ask further analysis to be provided when a TSO claims 'insufficient remedial actions' as a reason for reduction, namely an obligatory analysis of whether capacity contracting for remedial action by the individual TSOs is sufficient, and if increasing capacity contracting would be economically efficient. | The Agency agrees that Article 21(1) of the Amended DA Proposal and Article 19(1) of the Amended ID Proposal do not describe in sufficient detail the content of the report, which the coordinated capacity calculator ('CCC') has to issue every three months and do not require the Core TSOs to provide the CCC with all the information needed. During the consultation process, stakeholders confirmed that experience in the former Central Western European region revealed that without a clear definition of the expected information requirements, the risk was that TSOs would limit the reporting to generic and insufficient information.<br>In order to avoid such outcomes, the Agency updated the description of the report to be issued by the CCC every three months, in order to ensure that the Core NRAs receive a complete description of the situations leading to capacity reductions. Also, the Agency added additional requirements for the publication of information related to capacity reductions:<br>• the corresponding flow components calculated during capacity calculation;<br>• the forecasted physical flow and the realised physical flow;<br>• the detailed reason for violations, including the operational security limit(s) that would have been violated with the calculated cross-zonal capacities, and under which circumstances they would have been violated; and<br>• the proposed measures to avoid similar reductions in the future.<br>In order to ensure that the CCC has access to the data required for the report referred to in the previous paragraph, the Core TSOs that have reduced capacity on critical network elements ('CNEs') must provide the CCC with detailed information about these reductions, as well as the information on the measures to alleviate such reductions in the future. |

| Respondents' views | ACER views |
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| 1 respondent considers that the reporting requirements (namely the detailed action plan) are too heavy.<br>2 respondents are opposed to the threshold of reductions occurring more than 1% of market time units to trigger a detailed action plan. 1 respondent considers that the threshold is too high, as an action plan should be triggered for every instance of reduction, while 1 respondent considers that action plans will be triggered too often. | The Agency considers capacity reductions below the minimum levels required to avoid undue discrimination (i.e. minRAM) as serious violations of interconnection access rules and therefore justify significant reporting requirements such as to ensure full transparency of these reductions. Only then, the regulatory authorities and stakeholders will be able to assess whether the reductions were indeed unavoidable or whether they are the results of TSOs' negligence.<br>When these reductions occur frequently, the concerned TSOs should also provide the CCC with an action plan describing how such deviations are expected to be alleviated and solved in the future. The CCC should annex this action plan to the quarterly report.<br>Following consultation with regulatory authorities and TSOs, the Agency deems the content of the action plan and the threshold for the triggering of such action plan proportionate to the objective pursuant to Article 3(f) of the CACM Regulation. |
| 1 respondent considers that the implementation should allow for 'learning-by-doing' due to the current lack of experience in the validation step. | In order to ensure coordination of remedial actions in capacity validation and to fulfil the requirement of Article 25(2) of the CACM Regulation, the Agency split the DA capacity validation process into two main steps.<br>The first capacity validation step conducted by the CCC in coordination with the Core TSOs aims at ensuring that all available remedial actions taken into account in capacity calculation are coordinated among the Core TSOs. As this step may require a rather sophisticated coordination process that is not in practice today, the DA CCM allows for a gradual implementation ('learning-by-doing').<br>The second validation step is conducted individually by each Core TSO, and does not require gradual implementation.<br>Article 19 of the ID CCM only includes the second validation step, and does not require gradual implementation either (see also question 8 below). |
| 1 respondent is opposed to the possibility to add temporary internal network elements to capacity calculation during the validation period and considers | The Agency generally agrees with the principle that reductions of capacity during the validation process should be avoided. On the other hand, the Agency recalls that TSOs bear legal responsibility for operational security and therefore should have the necessary means to ensure such operational security, including by adding temporary internal network elements to |

| Respondents' views | ACER views |
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| that this should be subject to a formal joint approval of the Core regulatory authorities. | capacity calculation during the validation process, and without prior authorisation from the Core regulatory authorities. The Core regulatory authorities cannot issue a joint decision in time needed to address urgent operational security issues occurring on a daily basis.<br>Nevertheless, such reduction should be exceptional and temporary by nature, as otherwise the CCC would process the information as an input to the CCMs. Therefore, the CCMs request that TSOs are sufficiently transparent about such situations and their resolution (see above). |
| 6 respondents are concerned with the two-year time limit: the time needed to solve some of the problems to be tackled in the detailed action plans (e.g. investment, market configuration) is more than 2 years. | Article 20(15) of the DA CCM (respectively Article 19(12) of the ID CCM) related to detailed action plans triggered by frequent reductions of capacity during validation does not include such time limit, but is intended to ensure transparency, pursuant to Article 3(f) of the CACM Regulation. |
| 1 respondent advocates for the introduction of a 'requester pays' principle in the cost allocation of remedial actions as an incentive for TSOs to address congestions according to their detailed action plan. | The CCMs generally have no implication on the actual application of remedial actions and the related cost sharing. These two aspects are to be fully determined within the context of the redispatching and cost sharing methodologies developed pursuant to Articles 35 and 74 of the CACM Regulation. |
| 1 respondent suggest 'limitations of third countries' to be added to the list of reasons for reduction. | The Agency observes that such limitations are non-specific and may be covered by reasons listed in Articles 20(5)(a) and 20(5)(b) of the DA CCM (respectively 19(2)(a) and 19(2)(b) of the ID CCM), namely:<br>(a) an occurrence of an exceptional contingency or forced outage pursuant to Article 3 of the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation ('SO Regulation');<br>(b) when all available costly and non-costly RAs are not sufficient to ensure operational security, taking the CCC's analysis pursuant to paragraph **Error! Reference source not found.** into account, and coordinating with the CCC when necessary. |
| **Question 4: Please comment on the suggested approach to FRM.** | |
| 15 respondents provided an answer to this question. | |

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| 9 respondents overall support the Agency approach. | Answers to the Public Consultation overall confirm the approach proposed by the Agency. |
| 4 respondents explicitly support the 10% Cap, while 1 respondent objects that it may not fit the risk level that single TSOs experience now.<br>1 respondent suggests the inclusion of 'good principles' for FRM calculation, and in particular the inclusion of (i) the general objective to have FRMs as low as possible by working on improving different drivers of uncertainty, (ii) the reduction of FRM in intraday compared to day-ahead, (iii) the need to have a statistical sample which is large enough to ensure robustness of the analysis. | During early discussions with regulatory authorities and TSOs, the Agency considered applying a cap on FRM in order to mitigate the concerns that reliability margin could be very high due to inappropriately defined bidding zones. Finally the Agency decided not to follow this approach, since the rules for applying the minimum available RAM already implicitly cap all legally justified reductions of cross-zonal capacity. Hence, an additional cap on FRM would not bring any added value with respect to the final outcome.<br>Both CCMs include a temporary FRM equal to 10% of Fmax for the CNECs not already used in existing flow-based capacity calculation initiatives, for the first calculation (Article 8(10)(b) of the CCMs).<br>Finally, as regards the first calculation of FRMs, the Agency considers that a one-year historical sample period is sufficiently large, as a longer sample period would bear the risk that FRM calculation would not be responsive enough to recent changes in the network and the underlying uncertainties. |
| 9 respondents discuss the implementation timeline. 5 respondents explicitly support the timeline, with a special emphasis from 1 respondent on the need for TSOs to respect the implementation timeline, as already benefiting from a transition period of at least 2 years. 4 respondents object to the timeline, as being too short and colluding with other deliverables of the methodology, such as GSK proposal, allocation constraints, definition of relevant CNECs, plus update of the static grid model. | As a general approach, the Agency supports firm implementation timelines as ensuring firm legal responsibility and thereby enforceability. After discussion with the Core regulatory authorities and TSOs, the Agency concluded that requesting a significant review of the CCM, among them also the FRM calculation, no later than 18 months after the implementation of the methodology is not overly burdensome on TSOs. The Agency considers that these requirements for review are still relatively minor compared to the requirement to develop the original proposal for the methodology. Hence, they are not considered too challenging to be implemented within the timeframe given by the Agency. |

| Respondents' views | ACER views |
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| 1 respondent considers that TSOs should not conduct FRM calculation at CNE level. This respondent observes that calculations based on N-1 (CNEC level) lead to larger FRM than calculations based on N (CNE level); and that Article 22(1) of the CACM Regulation supports N as mentions that FRM should cover deviations between expected power flows and realised power flows, and not between expected power flows and simulated power flows. | Since the Agency currently has no evidence in support of one approach over the other, the Amended Proposals have been amended so that this choice is made once TSOs have performed the first calculation of probability distributions, and no later than 18 months after the entry into force of the methodology. This will allow comparing both approaches (see Articles 8(7) to 8(9) of the CCMs). |
| 1 respondent calls for the elaboration of principles for non-interconnector cross-zonal infrastructures and guidance on the inclusion in the CCM of cross-zonal infrastructures such as distribution, which are not included in the CGM. | The Agency notes that the legal scope of the CCMs is provided by the CACM Regulation and Regulation 714/2009, which sets out non-discriminatory rules for access conditions to the network for cross-border exchanges in electricity and, in particular, rules on capacity allocation and congestion management for interconnections and transmission systems affecting cross-border electricity flows. Further, interconnector is defined by Regulation 714/2009 as a transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member States. For this reason, the Agency understands that the scope of the CCM applies solely to transmission level and obligations can be imposed only on TSOs.<br>Furthermore, the Agency understands that distribution interconnectors have marginal impact on the cross-border flows and capacities (i.e. their PTDFs are generally very low). |
| Regarding non-Core regions, 1 respondent suggests that an appropriate change of the FRM or final adjustment value for dedicated cross-zonal elements close to non-Core borders might be one possible option to ensure grid security of non-Core grids. | See Agency's response related to third countries in Question 6. |
| **Question 5: Please comment on the suggested approach to GSK.** | |

| Respondents' views | ACER views |
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| 15 respondents provided an answer to this question. | The Agency observes that respondents generally support some degree of harmonisation. Opinions vary about the extent of the harmonisation. |
| 6 respondents recommend that TSOs define a limited set (e.g. 3) of possible methodologies for the GSK definition and select the one that leads to the smallest FRMs on the most frequently active CNECs for a representative panel of situations. The distribution of errors in forecasting relates to its quality and the ability of the GSK to show to what extent a net position shift may affect the location of generation/load within a bidding zone; therefore, harmonised GSKs could be detrimental if leading to higher FRMs on the most critical CNECs.<br>To the contrary, 2 respondents doubt about the possibility to harmonise GSKs, because the generation portfolios in Core differ considerably. | The Agency generally agrees with the observation that the Amended Proposals fail to achieve harmonisation of the approach to GSKs as they do not provide any principle or methodology specifying how the best forecast of the relation of a change in the net position of a bidding zone is achieved and only include a set of TSO-specific methodologies. Nevertheless, the Agency notes that the choice of a GSK is to some degree arbitrary as it requires deciding which generators are exporting and which are serving domestic consumption. The Agency favours the merit order principle by which the most expensive generators are participating in export and they can generally be defined by observing historical changes in generation output in relation to different underlying factors, such as net positions, prices, load, etc. The Agency established this as the main principle for defining a GSK.<br>However, the Agency has no further understanding for proposing a fully harmonised method beyond the principle described above. For this reason, the Agency provided an obligation on all TSOs to submit a proposal for further harmonisation of the GSK 18 months after the implementation of the methodology. This will allow TSOs to gain some experience on the criteria and metrics for defining the efficiency of GSKs. |
| 1 respondent suggests the inclusion of 'good principles' for GSK calculation, in particular the inclusion of (i) the objective that the selected GSK methodology results in forecasts as close as possible to load patterns observed in reality and (ii) the automation of GSK calculation. | Beyond the setting of above-mentioned principle, the Agency requested that the proposal for improvements of GSKs should define the criteria and metrics for defining the efficiency and performance of GSKs and allowing for quantitative comparison of different GSKs. This monitoring and the determination of a fully harmonised methodology will allow more automation of the GSK calculation. |

| Respondents' views | ACER views |
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| 4 respondents are concerned with the proposed timeline as they object that it is not feasible to perform all required analyses in parallel. The 18 months deadline for GSKs coincides with the FRM proposal, the allocation constraints, the definition of relevant CNECs, long-term allocated capacity ('LTA') parameter and the demand to publish an up-to-date static grid model every 6 months. | As a general approach, the Agency supports firm implementation timelines as ensuring firm legal responsibility and thereby enforceability. After discussion with the Core regulatory authorities and TSOs, the Agency concluded that requesting a significant review of the capacity calculation methodology, among them also the GSK calculation, no later than 18 months after the implementation of the methodology is not overly burdensome on TSOs. The Agency considers that these requirements for review are still relatively minor compared to the requirement to develop the original proposal for the methodology. Hence, they are not considered too challenging to be implemented within the timeframe given by the Agency. |
| 2 respondents suggest to add that rules shall be common to all GSKs of the CCR (or alternatively to add criteria for deviations by TSOs from the harmonised GSK methodology) and clear justification and publication process, in order to increase transparency towards market parties. | The Agency's proposal includes the requirement that the Core TSOs develop a harmonised methodology for GSK 18 months after the implementation (Article 9(6) of the CCMs). Further, the Agency requested that the TSOs' proposal for a harmonised methodology include rules and criteria for TSOs to deviate from the harmonised generation shift key methodology. |
| **Question 6: Please comment on any other input parameter.** | |
| 10 respondents provided an answer to this question. | |
| 1 respondent generally agrees with the proposed approach. | |
| 5 respondents encourage TSOs to provide all details about the methodology used for forecasting the reference situation and propose a similar approach as the one used for GSKs, i.e. the definition of a limited set of possible approaches and select the one that leads to smallest FRMs on the most frequently active CNECs for a representative panel of situations. | The Agency agrees with this general objective of ensuring best possible forecasts as inputs to the CCMs. Regarding FRM calculation, the CCMs ensures transparency by harmonising calculation first, then requesting that TSOs study the causes of uncertainty (see Article 8(2) of the CCMs). Nevertheless, the Agency notes that forecasting reference situations is outside the scope of CCM as it is determined within the scope of Common Grid Model Methodology. |

| Respondents' views | ACER views |
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| 1 respondent underlines that TSOs should be given a strong incentive to improve the quality of the base case and its capacity calculation parameters, to bring the base case closer to the real time grid situation and maximise the cross-zonal capacity that can be provided. | The Agency observes that this aspect of the debate is relevant in the context of the discussions about the Common Grid Model Methodology, which is outside the scope of this Decision. Nevertheless, in order to mitigate possible negative impacts on the available cross-zonal capacity, Article 10(5) of the DA CCM allows the Core TSOs to define individually the initial setting of its own non-costly and costly RAs based on the best forecast. More information on this can be found in the Decision. |
| 1 respondent is concerned that the methodology for LTA inclusion is not applicable where borders have not had any allocation before, as the methodology is based on 'historical values'. | The Agency is aware of this fact and considers that its impact is negligible. This is because the LTAs provide additional cross-zonal capacity not only on the concerned border, but on all CNECs which are impacted by such LTA. Second, and more importantly, the Agency expects that the minRAM requirement will exceed the LTA inclusion in almost all cases and therefore the lack of cross-zonal capacities due to the lack of LTAs on some borders will be replaced by the minRAM requirement, which will determine the final RAM on CNECs. |
| 1 respondent points out that the methodology does not take potential security impacts on neighboring grids into account. flow-based CCM in the Central Western European region increases N-1 violations on the Swiss grid during the increase of capacities in certain market directions as security checks with neighbouring TSOs is not part of the process. The proposal includes provisions to take into account flows originating from non-Core TSO grids (Article 17), but entirely neglects the vice versa impact on these non-Core TSOs' grids. | The scope of the Agency's Decision is the capacity calculation (and implicitly the congestion management) on the bidding zone borders of the Core CCR. The Agency understands that this may indeed have an impact on third countries. However, the Agency understands that congestion management on the borders of third countries is the responsibility of the TSOs on those borders, which may include capacity calculation and allocation as well as remedial actions to be applied on those borders. In case those would be insufficient to ensure operational security, the concerned Core TSOs may reduce cross-zonal capacities (in capacity validation process) in the Core CCR to ensure operational security on the concerned interconnectors. |
| **Question 7: Please comment on the suggested approach to allocation constraints.** | |
| 19 respondents provided an answer to this question. | The Agency observes that stakeholders' views on the use of allocation constraints are divided.<br>As a general principle, the Agency concludes that stakeholders, on the one hand, wish to have full transparency on allocation constraints, and on the other hand, wish to use allocation constraints as an efficient solution to the problem faced. |

| Respondents' views | ACER views |
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| | The Agency amended the Amended Proposal to reflect both points. |
| 4 respondents state that allocation constraints currently used are justified.<br>2 respondents state that the three Core TSOs proposing to use such constraints provided materials on the need, the computations and application of those constraints. The CACM Regulation does not seem to provide further requirements on the justification of those limits.<br>2 respondents states that Polish allocation constraints are justified due to having a central dispatch model, which requires the TSO to acquire reserves along with the energy.<br>5 respondents disagree with the proposed time limit.<br>2 respondents state that the proposed 2-year period should be extended and adjusted to the time when evaluation of solutions planned for Polish balancing market would be possible.<br>4 respondents state that allocation constraints should be allowed without a time limit, of which 2 further state that applying allocation constraints is allowed under the CACM Regulation with no phase-out after some time. It is also applied in CCR Baltic and CCR Hansa. Removing allocation constraints would result in additional TSOs' requirements on Polish generation facilities and possibly additional costs to Polish consumers without any evidence of benefits. | The Agency agrees with the principle that allocation constraints may be used when those are technically justified, but they must also be an efficient mean to address the underlying operational security issue. First, the Agency observes that TSOs propose to use allocation constraints based on Article 23(3) of the CACM Regulation, which specifies that TSOs may only apply allocation constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements.<br>The explanations provided by the concerned TSOs vary. For the Belgian and Dutch allocation constraints, the Agency recognise the validity of technical justification; however, the efficiency with respect to alternatives has not been demonstrated. For the Polish allocation constraint, nether technical validity nor economic efficiency has been demonstrated so far in the Agency's view.<br>Therefore, the Agency adopted the following approach: unless legal compliance in terms of technical and economic justification is demonstrated by the relevant TSOs and approved by the Core regulatory authorities within two years after implementation, the allocation constraint should no longer be applied (see Article 8 of the DA CCM and Article 7 of the ID CCM).<br>This approach guarantees that TSOs ensure a sufficient level of transparency over the need for such allocation constraints, and the oversight of regulatory authorities of the Core CCR. On the other hand, TSOs may prolong the use of allocation constraints as long as they demonstrate that such constraints remain the best solution to the problem faced following a yearly assessment pursuant to Article 24 of the DA CCM (respectively Article 22 of the ID CCM).<br>The Agency observes that obligations thereby set on TSOs are proportionate to the overarching requirements set by Article 23(3) and Article 3 of the CACM Regulation.<br>Further justification can be found in the Decision. |

| Respondents' views | ACER views |
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| 1 respondent does not agree on postponing the removal of allocation constraints. This respondent expresses concern over the situation in Poland, where capacities are set without taking into account economic efficiency. This respondent further observes that this is against the spirit of the CACM Regulation and Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing,. | The Agency is generally also unsupportive of those allocation constraints. However, the Agency does not consider it feasible to prohibit these allocation constraints without providing some transitional period to the concerned TSOs in order to, either improve their justification or to adjust their procedures in order to cease applying them. |
| 2 respondents state that if neighbouring network constraints are not directly handled by the algorithm, allocation constraints may be the simplest (and only) way to ensure system security in some situation by indirectly considering limitations of third countries. | See the Agency's responses with regard to the impact on third countries in Question 6. |
| 9 respondents request additional refinements concerning transparency. 5 respondents recommend a yearly TSO report on welfare losses induced by the allocation constraints, based on a parallel run for situations when allocation constraints are active. 1 respondent insists, regarding the derogation process proposed for inclusion on internal CNEC, on the need to have a clear and systematic framework where common requirements are set to assess the efficiency of allocation constraints compared to alternative solutions. 1 respondent would like to add a provision for transparency towards all stakeholders concerning the eventual justification of allocation constraints. | The Agency agrees and has provided requirements on these aspects in both CCMs. |

| Respondents' views | ACER views |
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| 1 respondent states that the complexity of network constraints taken into account as input to the SDAC algorithm used by Nominated Electricity Market Operators ('NEMOs') should be sustainable to avoid negative impact on the performance of the SDAC algorithm. NEMOs should have sufficient time to run simulations and tests. | The Agency agrees, yet this issue is outside the scope of this Decision. |
| 1 respondent states that all the Core NRAs should always agree on inclusion of any external constraints. | The Agency agrees, yet such agreement can only be made through the adoption or amendment of the CCMs, as there is no time nor legal framework for such approval within a daily capacity calculation process. |
| 1 respondent states that relevant analysis should not impose excessive obligations on TSOs and subsequently on NRAs. | The Agency disagrees. Allocation constraints, which are justified technically and legally, should indeed not impose excessive obligations on TSOs. However, when this is not the case, the TSOs should face those obligations until all doubts have been removed. |
| 2 respondents state that the transition period should be designed such that the methodology would not require any amendments. | The Agency observes that the current wording guarantees a legally robust and thereby enforceable methodology. The transition period with a possibility of extension can only be decided jointly by the Core regulatory authorities. Within the current legal framework, this can only be done through the amendment of the CCMs, since the CACM Regulation provides a clear governance for the underlying coordination of TSOs and regulatory authorities. |
| 1 respondent states that the CCM should include a provision for the possibility to introduce allocation constraints if needed. | The Agency agrees. This possibility is provided by regular reviews and the possibility for amendment of the CCMs. |
| 1 respondent questions the set threshold of tolerance for allocation constraints limiting the market at 0.1% of hours per quarter, as the presented threshold favours the CACM Regulation goal of maximising the economic surplus over the CACM Regulation goal of contributing to security of supply. | The Agency disagrees with the interpretation that the threshold referred to by the respondent induces a bias.<br>Articles 7(3)(b) of the CCMs request that *'if applicable and in case the external constraint had a non-zero shadow price in more than 0.1% of hours in a quarter, provide to the CCC a report analysing the effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits for each ID CC MTU when the external constraint had* |

| Respondents' views | ACER views |
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| | *a non-zero shadow price and analysing alternative solutions to address the underlying operational security limits.'*<br>The threshold triggers a demonstration that the use of allocation constraints is proportionate to the problem faced. During the consultation process with regulatory authorities and TSOs, one argument in favour of allocation constraints was that they seldom effectively constrain the market. However, discussions lacked quantified evidence. The threshold will allow an objective monitoring. |
| **Question 8: Please comment on the consistency between day-ahead and intraday (removal of minRAM, LTA inclusion and validation, use of RAs to increase intraday capacity).** | |
| 15 respondents provided an answer to this question. | |
| 13 respondents support increased consistency between DA and ID CCMs.<br>2 respondents consider that the ID CCM is not detailed enough. DA and ID CCMs should include the same approaches to the selection and application of CNECs, external constraints, reference programs for non-Core borders, FRMs, GSKs, calculation process etc. should applies for both day-ahead and intraday. Both methodologies should explicitly describe these approaches. | After consultation with the TSOs and regulatory authorities of the Core CCR, the Agency maximised the consistency between DA and ID CCMs such that the two differ only in the following aspects:<br>• The ID CCM does not include any requirement for the adjustment of minimum RAM and LTA inclusion. This is because the possibility to maximise cross-zonal capacities in intraday timeframe is limited by the inability to take into account the costly remedial actions, as there is no sufficient time between the end of capacity calculation and allocation and first delivery hour for coordinated application of remedial actions. Nevertheless, Article 5(10) of the ID CCM specifies, *'Core TSOs shall analyse the possibility of introducing the adjustment of a minimum RAM as applied in the day-ahead capacity calculation methodology'*.<br>• The first validation step ('coordinated validation' as described in Article 20(3) of the DA CCM) was not included in the ID CCM as the CCC and TSOs would not have sufficient time to coordinate remedial actions before the first delivery hour.<br>• The ID CCM introduces additional calculation process for updating of cross-zonal capacities remaining after the single day-ahead coupling ('SDAC'); |

| Respondents' views | ACER views |
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| 5 respondents consider that TSOs must commit to consider (costly) remedial actions (including countertrading) ahead of or during the ID capacity calculation. Otherwise, it might be impossible to design a flow-based domain that encompasses the last reported market clearing point. This allows for the early (e.g. 5 pm day-ahead) implementation of countertrading and cross-zonal redispatching necessary to secure operation of the CNECs, making it possible for TSOs to compare on an equal footing cross-zonal and internal remedial actions.<br>1 respondent considers that even though minRAM requirements may not be feasible in intraday due to timing constraints, Core TSOs must investigate all possible ways to increase cross-zonal capacity in intraday in a timely manner, given the reduced uncertainty when coming nearer to real time. | • The ID CCM introduces two (re-)calculations in contrast to DA CCM where calculation is performed only once. |
| 1 respondent claim that the ID CCM should be in line with the cross-border intraday market project XBID ('XBID project'). | The Agency agrees. Until the solution offered by XBID project is not able to allocate cross-zonal capacities in form of flow-based parameters, the TSOs should convert these to available transmission capacities. |

| Respondents' views | ACER views |
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| 1 respondent believe that basing LTA inclusion in the transitional period (i.e. before coordinated long-term capacity calculation methodology is approved) on historical values might not be appropriate, especially in the context of borders, which have not had any allocation before. To that respect, LTA values should be commonly coordinated, in an attempt to mimic to the maximal possible extent the process foreseen by long-term capacity calculation based on Commission Regulation (EU) 2016/1719 (the 'FCA Regulation'). However, if the use of the historical values is still unavoidable, we should apply also some transition period as already proposed regarding e.g. FRM, GSK, etc. | See Question 6 above with regard to the use of historical values. The Agency considers that requiring a fully coordinated long-term capacity calculation before the methodology pursuant to the FCA Regulation is implemented would not make sense as it would further delay the implementation of the CCMs (and duplicate the work on implementation of long-term capacity calculation). For this reason, the Agency considers that it is sufficient that TSOs coordinate only the changes in long-term allocated capacities until the full implementation of the long-term capacity calculation. |
| **Question 9: Please comment on the on the suggested approach to the timing and frequency of ID capacity calculation.** | |
| 15 respondents provided an answer to this question. | The majority of respondents wish that the ID CCM be more ambitious than the Amended ID Proposal. |
| 2 respondents agree with the approach. 1 respondent notes that it will leave enough time for market participants to adjust their strategy before the first allocation. 1 respondent however requests that TSOs be required to optimise processes in order to deliver ID capacity calculation results earlier in the evening, e.g. 8 or 9 p.m. | The ID CCM takes account of those comments as follows:<br>The Agency provided legal clarity on the number of calculations and their exact timings. These are aligned with the methodology for pricing intraday cross-zonal capacity established pursuant to Article 55 of the CACM Regulation, but should be reviewed after the Core TSOs gain more experience with the operation of these methodologies;<br>Article 11 of the ID CCM specifies the methodology to calculate cross-zonal capacities provided to the NEMOs before the intraday cross-zonal gate opening time.<br>The Agency is also concerned about the long period between the end of the SDAC and the time when the first ID capacity re-calculation is finished. The Agency is of opinion that TSOs |
| 8 respondents believe that the approach lacks ambition. 4 respondents observe that the proposal is the minimum acceptable. 7 respondents do not see evidence suggesting that an earlier deadline is | |

| Respondents' views | ACER views |
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| unfeasible. 3 respondents explicitly do not support the proposal as they support an earlier timing for the first allocation. 1 respondent requests first allocation at 18:00 at the latest. 1 respondent observes that based on the proposal, requirements for additional recalculation could remain undefined and thus proposes to include clear and strict timings and deadlines. | should optimise these processes, namely to adjust to parallel operation of continuous trading, operational security analysis and ID capacity calculation as discussed in Question 10.<br>Nevertheless, the Agency decided not to challenge TSOs on this aspect since the proposed timings are strongly interlinked with other methodologies (i.e. three common grid model methodologies established pursuant to CACM Regulation, FCA Regulation and SO Regulation and the intraday cross-zonal capacity pricing methodology) some of which are already established and were not adopted by the Agency. These methodologies are also European-wide and affect all European TSOs. Therefore, any change in the timelines would need to be fully coordinated with all TSOs, all regulatory authorities and across different methodologies. The Agency will focus on this problem and discuss with TSOs and regulatory authorities on the appropriate opportunity to improve these timings. |
| 1 respondent states that the operational security analysis must be performed after nomination of the day-ahead market results as a precondition for intraday capacity calculation to start. | |
| 1 respondent asks for consistency with the XBID project. | The Agency agrees. |
| **Question 10: Please comment on the on the suggested approach to the cross-zonal capacity at the intraday cross-zonal gate opening time.** | |
| 17 respondents provided an answer to this question. | |
| 5 respondents would like to make the provision of day-ahead leftovers compulsory. The reason is to ensure equal treatment through bidding zones. The Agency should reject the possibility for TSOs to withhold leftover capacities after the day-ahead clearing until intraday capacities have been recalculated, to ensure a fair and non-discriminatory treatment, improving price formation, allowing portfolio optimisation and improving efficiency of market coupling. The TSOs from all the Core CCR have not properly justified why they would not be able to follow the process of opening the market and performing the recalculation | The Agency generally agrees that this is the right solution and that TSOs should gradually implement a solution where cross-zonal trading and capacity recalculation are performed in parallel. Nevertheless, based on consultation with TSOs this currently represents a significant challenge for them, since parallel processes would require significant changes in existing processes, namely the operational security analysis and coordination and application of remedial actions. Parallel processes would require that TSOs continuously monitor the developments of the intraday market, regularly exchange information and coordinate their actions to adapt continuously their congestion management processes to the changes in the intraday market. This, in the Agency's view requires some time to improve those processes and therefore a transition period is needed for the parallel solution to be applied. Nevertheless, the Agency notes that a parallel solution would be much easier to implement if TSOs would be willing to implement a more optimal definition of bidding zones where all intraday trading |

| Respondents' views | ACER views |
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| in parallel. The Agency should allow TSOs to suspend shortly (up to 10 min) the XBID project in order to readjust capacities when finalising the capacity recalculation process. | would create much less congestion problems in the network and much less need for TSOs' actions. |
| 1 respondent explains that providing day-ahead leftovers at intraday cross-zonal gate opening time ('IDCZGOT') lessens, or even removes the rationale of conducting ID capacity calculations as it forces this process' output in a certain direction, which may not be optimal. | In the Agency's view frequent recalculation of cross-zonal capacities during the intraday timeframe essentially allows TSOs no other choice but to adapt their processes such that capacity calculation, congestion management and intraday trading can be performed in parallel. While this may indeed mean that TSOs processes may be based on information, which is continuously changing, this requires that TSOs speed up their procedures to be more adaptive to continuous trading and by this they would always need to keep track of the market changes and adapt speedily and continuously to them. Finally, TSOs will also have a last chance to ensure operational security after the intraday gate closure time where continuous trading will no longer interfere with their processes. |
| 4 respondents claim that the Agency's proposal seems to overrule implementing its own Decision 04-2018.<br>Until the implementation of the CCM for intraday, the additional exemption would make even less sense considering the TSOs' arguments: should the recalculation process prevent TSOs from releasing leftover capacities from day-ahead to the market, there would be even less reason to exonerate TSOs to release these capacities when the recalculation process is not in place.<br>Many stakeholders have developed diverging legal interpretations of the Agency's previous decision on IDCZGOT and could decide legally to challenge the Agency's Decision on this basis, which could become an obstacle to its prompt implementation. | While the Agency is committed to provide obligations (where the Agency has such competence) on TSOs to provide DA leftovers at the IDCZGOT, it cannot do so without considering the concerns of TSOs related to operational security. TSOs claim that they currently may be unable to ensure operational security, if intraday cross-zonal trading is allowed during the time when they are analysing and identifying the congestions in the network and addressing these congestions with remedial actions. The concerns of TSOs may make sense from the perspective that any trading during their congestion management processes may make those procedures ineffective, since the decisions on remedial actions are based on the forecasts of flows, yet these forecasts are constantly changing due to continuous trading. Therefore, such trading (even if based on DA leftovers) may commence once TSOs have finished the congestion management procedures.<br>While the Agency is not fully convinced about the underlying concerns, it cannot completely exclude the possibility that a legal obligation to provide DA leftovers at the IDCZGOT would indeed lead to operational security problems. Therefore, in the Agency's view the TSOs should keep the final discretion when it comes to operational security or at least be provided with sufficient transition period with regard to changes in applicable rules, which may impact |

| Respondents' views | ACER views |
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| While the amount of capacity to be made available at the gate opening time depends on the recalculation process, it seems clear that from one month after the approval of the CCM, the TSOs have to set the gate opening time at 15:00 at all borders of the CCR and release some capacity. However, the methodology assumes that TSOs would have possibility to effectively open the market and thereby allocate capacity only at 22:00. This reading contradicts the Agency´s Decision 04-2018. | operational security. The Agency decided for the latter solution as it is convinced that with proper planning and adaptation of congestion management procedures, TSOs should be able to avoid operational security problems in case of parallel processes of congestion management and intraday market.<br>The Agency also notes that a transition solution is not explicitly conditioned on the implementation of the intraday capacity calculation, yet the latter does have some impact on the transition period as it allows TSOs to test properly the parallel procedures of intraday capacity calculation, congestion management and intraday trading. |
| 3 respondents claim that the Core TSOs cannot provide leftover capacity after the day-ahead market clearing for allocation, because it would disqualify the extensive operational security analysis, as the market outcome may move away from what the day-ahead market fixed. Nevertheless, these respondents also explain that Core TSOs have the obligation to carry out a common and coordinated ID capacity calculation; therefore a solution where individual TSOs decide whether to offer leftover capacity to the day-ahead market would contradict this obligation. | The Agency provided for individual TSOs the discretion to offer zero cross-zonal capacity at the IDCZGOT in cases where such capacity is in the form of available transmission capacities' ('ATC') values. The way these values are calculated ensures that they are simultaneously feasible, which means that TSOs on the concerned bidding zone border should be able to decide on the capacity allocation of these ATCs independently from other bidding zone borders. |
| 2 respondent ask the Agency to include a clear deadline for the transition period, in order to give a clear signal to the TSOs to be ambitious enough to develop such process in the nearest possible future.<br>Every solution chosen for this methodology should clearly indicate when the capacity would be available for the market participants. | The Agency provided a clear transition period and full clarity on the applicable rules during the transition period. The latter ones are included in Annex II to the ID CCM. |

| Respondents' views | ACER views |
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| **Question 11: Please comment on the on the suggested approach to transparency.** | |
| 15 respondents provided an answer to this question. | |
| 12 respondents support the proposal from the Agency. | A majority of respondents support the suggested approach and asked for even more information to be published. |
| 9 respondents object to the derogation from transparency obligation– observing that the burden of proving that national legislation has superiority over the methodology should be left to the Members States.<br>1 additional respondent urges the Agency, NRAs, Members States and TSOs not to use this criterion unduly. | The Agency agrees that national legislation should not take precedence over a methodology established pursuant to Union law, except in cases where specific national provisions are established pursuant to Union legislation. Such is the case in Regulation (EU) No 543/2013 and Regulation (EU) No 1227/2011, which both provide an exemption for an information 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. As the scope of the information in question is the same as the one provided in those two regulations, the Agency therefore provided the same exemptions as referred to in these two regulations. |
| 1 respondents observe that the publication requirements will require a high effort from TSOs. | The Agency believes that the approach to transparency is proportionate to the objective set by Article 3(f) of the CACM Regulation. |
| 4 respondents asked for the publication of additional information:<br>1. The full flow-based domain before and after the application of the LTA patch, or any other patch (e.g. minRam). It is important that the domain as obtained without patch is published, since it reflects the physical situation.<br>2. On top of Core positions for the base case, the expected individual positions considered by TSOs of at least all direct neighbours should be published (rather than just a global view). | The Agency responded to these requests as follows:<br>1. This information is implicitly provided within the requirement to publish all the flow components for each CNEC before pre-solving. This includes components like adjustment for the minimum remaining available margin ('AMR') or LTA margin. All these components are sufficient to identify the flow-based domain during any step of capacity calculation.<br>2. The Agency added this information by requiring the reference net positions (contained in the CGM) of all bidding zones in the Synchronous Area Continental Europe as well as exchanges of high voltage direct current ('HVDC') interconnectors with other synchronous areas.<br>3. The Agency required equal information for all CNECs impacting capacity calculation regardless of whether they are internal or cross-zonal. |

| Respondents' views | ACER views |
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| 3. Assuming that no internal CNECs are selected, only information on cross-border CNECs would be published, following the Agency's transparency requirements. This would be problematic since no information on the decision to allocate capacity at the border would be available to the market. Information on grid elements influencing PTDF calculation should be available. The Agency must find a solution, for instance, by requesting TSOs to publish information (as for cross-border CNECs) for internal lines that influence the calculation. This kind of approach was in place during the flow-based parallel run in the former Central Western European region.<br>4. The transparency obligations should also detail what TSOs should publish in case they are not able to respect the minimum level of capacity imposed by the CCM. The methodology should detail:<br>(a) An exhaustive list of conditions for which the rule can be suspended.<br>(b) A clear obligation on TSOs to inform market participants about the suspension at the time of the decision, with all the details available on the reasons for the suspension at that moment.<br>(c) An obligation on TSOs to issue a yearly report to regulators and the market on the application | 4. The Agency added these requirements. On the measures to uphold higher cross-zonal capacities, the Agency notes that higher cross-zonal capacities do not necessarily require any measures to uphold them. This is because physical congestions are only identified after the SDAC and based on the polluter-pays principle, the cause is attributed to flows resulting from internal exchanges.<br>5. The Agency added these requirements.<br>6. The Agency added the requirement on vertical load and production, but finds the additional requirements on decentralized generation imbedded in the vertical load with the technology type breakdown as excessive. This information is also more related to the CGM than to the CCMs.<br>7. The Agency kept and clarified a general requirement on static grid model, but found it difficult to extend this requirement in the absence of a clear legal basis. |

| Respondents' views | ACER views |
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| of the rule, with extensive details on the reasons leading to its suspension.<br>(d) Full transparency should be ensured on measures needed to the uphold higher cross-zonal capacities. This includes inter alia internal zonal measures, redispatch, and their costs, the cross-border information on scheduled and unscheduled.<br>4 respondents suggest further clarification:<br>5. Real names of CNECs should be 'split' between CNE and Contingency.<br>6. Vertical load and production:<br>(a) TSO should provide an estimation of the decentralized generation imbedded in the vertical load (ideally with the technology-type breakdown).<br>(b) TSO should provide a breakdown of the Generation by fuel type, as some fuels play a big role in the flow-based domain.<br>7. Every six months, publication of an up-to-date static grid model by each Core TSO. The CCM should specify that the static grid model should be detailed enough. For instance, detailed substation topology (Switch/Breaker/Connected Generation) should be published. Transmission lines below 400kV and Transformers/PST should be described and published if they are modelled in the operational grid model (D2CF). | |

| Respondents' views | ACER views |
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| 1 respondent wants to see the same level as in the former Central Western European region applied to the Core CCR. | While the transparency requirements set in the former Central Western European region were used as a benchmark in the discussion, the Agency provided increased transparency requirements to ensure compliance with Article 3(f) of the CACM Regulation. |
| 1 respondent calls for a rationalisation of the format of data published and a sustainable retrieval process in the long-run. | The Agency shares the view that transparency over the data published implies a responsibility over the quality of and easy access to the data published. Therefore, the Agency introduced the following requirements:<br>• In order to guarantee accuracy, consistency and comparability of the information published on the platform, the Agency clarified the granularity of the information to be published, and, in particular, for each information item related to a CNEC.<br>• To address the requirement of Article 20(9) of the CACM Regulation, the Agency also added an obligation on the Core TSOs to 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;<br>• Finally, the Agency set a process to guarantee the quality of the data published (Article 25 of the DA CCM and Article 23 of the ID CCM). |
| 1 respondent calls for an extension of the transparency requirements to non-Core borders. | The Agency added obligations on the reference net positions for the whole Continental Europe and reference exchanges over HVDC links that are contained in the CGM. |
| **Question 12: Please comment on the on the suggested implementation timeline.** | |
| 18 respondents provided an answer to this question. | The Agency observes that stakeholders' views on the use of Allocation Constraints are divided. |
| 3 respondents support a firm and ambitious implementation deadline. | The Agency agrees and has provided such deadlines in the CCMs. |

| Respondents' views | ACER views |
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| 10 respondents find the suggested deadline challenging. 6 respondents support a firm but realistic deadline implying that the proposed deadline of 1 April 2020 is not realistic because an external parallel run should be performed at least over one year. | The Agency supports firm and legally binding deadline and firm legal responsibility ensuring clear enforceability. Article 28(3) of the DA CCM clarifies that the DA CCM should be implemented no later than 1 December 2020. This deadline has been consulted with the Core TSOs and regulatory authorities and is widely recognised to include sufficient time for:<br>1. The development of the relevant IT tools<br>2. The establishment of CCC<br>3. The testing of internal TSO and CCC procedures<br>4. The testing of the methodology with market participants and NEMOs. This period should be at least 6 months long as required by CACM Regulation.<br>5. The reasonable reserve time in case of delays in the above phases.<br>For the ID CCM, the Agency provided a relative implementation deadline, which is one year after the implementation of DA CCM for the first recalculation and one additional year after for the second recalculation. |
| 2 respondents want legally binding deadlines. These respondents call for a legally binding timeline, where delays have consequences. | The Agency agrees. The adopted CCMs have legally binding deadlines and in case of delays, the concerned regulatory authorities and the EC will be able to enforce compliance. |
| **Question 13: Please provide any further comment on the Core Capacity Calculation Methodology.** | |
| 17 respondents provided an answer to this question. | |
| 5 respondents call for legal robustness of the decision, and believe that the exclusion of internal CNECs can be legally challenged. | The Agency considers that references in the CACM Regulation to rules for avoiding undue discrimination and specific reference to point 1.7 of Annex I to Regulation 714/2009 provides a sufficient and clear legal basis for excluding internal network elements from capacity calculation except where this is needed for reasons of economic efficiency or operational security. Further justification can be found in the Decision. |

| Respondents' views | ACER views |
|---|---|
| 6 respondents call for an assessment of the compatibility of the Core CCM with CCMs of neighbouring CCRs. | While such compatibility is indeed important, the legal framework for adoption of the regional methodologies makes is difficult to ensure full consistency. Nevertheless, basic consistency is already provided by the legal framework established in the CACM Regulation and additional harmonisation will occur pursuant to the harmonisation process established in Article 21(4) of the CACM Regulation. |
| 2 respondents expressed concerns over costs triggered by the CCM. | See the Agency's response above on the efficiency criteria to address undue discrimination. |
| 1 respondent observes that TSOs do not cooperate to integrate markets and calls for an assessment of their regulatory incentives to do so. | The Agency supports harmonisation of incentives, however, they cannot be provided without a legal basis in national jurisdictions or Union legislation. |
| 1 respondent suggests adding the following requirement: '*Considering the highly meshed structure of the grid in the synchronous area Central Europe, it will be necessary to extend this methodology to non-European borders and TSOs not part of the Core Region, applying the same principles and rules and responsibilities. This will be made binding for all concerned TSOs via private contract arrangements. This is especially important for the borders between France and Switzerland, Germany and Switzerland and Austria and Switzerland.*' | The Agency is only competent to decide on rules for cross-zonal capacities on Union bidding zone borders as established in the Determination of CCRs. The interconnection rules on the borders with third countries is outside the legal scope of the Agency's Decision. |
| 1 respondent appreciate stakeholders' involvement in the Agency's drafting process. | The Agency is committed to involving all the concerned parties and to considering all stakeholders' concerns. |
| 2 respondents stress that the main objective of the CCM is to maximise cross-border capacity, 1 respondent adds transparency as the second objective. | The Agency agrees. |

| Respondents' views | ACER views |
|---|---|
| For 1 respondent, the concept of advanced hybrid coupling should be a part of the Core CCM. | The Agency tried to incorporate this concept in the CCM and to provide clear obligations on TSOs. However, when consulting TSOs on this issue, the Agency understands that the concept of advanced hybrid coupling is not yet mature enough to be defined in the CCM. Therefore, the Agency provided an obligation for an amendment of the CCMs to incorporate this concept at a later stage. |
| 1 respondent is concerned about the impact of the CCM on very small bidding zones, regarding social welfare, as because of their small sizes, overall social welfare within such zones will not be affected much by changes in capacities at their borders. | The Agency does not understand this comment. |
| 1 respondent is concerned about the various fixed thresholds in the Core CCM (FRM, unscheduled allocated flows…) in situations when Core TSOs are eventually responsible to enforce those thresholds without direct influence of them. | The Agency disagrees. TSOs are primarily and the most responsible for operating the electricity networks. They do have in their powers to affect all these underlying uncertainties. |

## 3 List of respondents

| Organisation | Type |
|---|---|
| 50Hertz Transmission GmbH | TSO |
| Austrian Power Grid | TSO |
| Bundesnetzagentur | NRA |
| CEZ, a.s. | Energy company |
| CNMC | NRA |
| Consumer Association of North-Rhine Westphalia | Association |
| Core TSOs | Transmission System Operators of the Core Region |
| CRE | NRA |
| EDF SA | Energy company |
| EFET - European Federation of Energy Traders | Association |
| Elia Group (Elia & 50Hertz) | Energy company |
| Energie AG Oberösterreich Trading GmbH | Energy company |
| Energie-Nederland | Energy company |
| Energy Regulatory Office (URE) | NRA |
| EPEX SPOT | Power exchange |
| Federation of Enterprises in Belgium (FEB) | Association |
| IFIEC Europe | Association |
| Market Parties Platform (MPP) | Association |

| Organisation | Type |
|---|---|
| Nord Pool AS /European Market Coupling Operator AS | Power exchange |
| Österreichs E-Wirtschaft (OE) - Association of Austrian Electricity Companies | Association |
| Polish Electricity Association | Association |
| Polish Power Plants Association | Association |
| PSE | TSO |
| Swiss Federal Electricity Commission ElCom | NRA |
| Swissgrid | TSO |
| TIWAG-Tiroler Wasserkraft AG | Energy company |