



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

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TSOs OF THE CORE CCR, TAKING INTO ACCOUNT THE FOLLOWING,

WHEREAS

1. This document is the methodology developed by the transmission system operators of the Core CCR (hereafter referred to as “Core TSOs”) regarding the common 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 “day-ahead common capacity calculation methodology”.
2. The day-ahead common capacity calculation methodology takes into account the general principles and goals set in the CACM Regulation as well as 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 cross-border markets. It sets for this purpose requirements to develop a day-ahead common 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 common capacity calculation methodology on the objectives of the CACM Regulation has to be described and is presented below. The proposed day-ahead common capacity calculation methodology generally contributes to the achievement of the objectives of Article 3 of the CACM Regulation.
4. The day-ahead common 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 the same day-ahead common 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 respective 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 common capacity calculation methodology contributes to the optimal use of transmission infrastructure and operational security (Article 3(b) and (c) of the CACM Regulation) since the flow-based mechanism aims at providing the maximum available capacity to market participants on the day-ahead timeframe within the operational security limits.
6. The day-ahead common capacity calculation methodology contributes to avoiding that cross-zonal capacity is limited in order to solve congestion inside control areas by defining criteria for cross-zonal relevance of critical network elements and contingencies and ensuring a minimum margin made available for commercial exchanges while ensuring operational security (Article 3(a) to (c) of the CACM regulation and Article 1.7 of Annex I to the Regulation (EC) 714/2009).
7. The day-ahead common capacity calculation methodology serves the objective of optimising the allocation of cross-zonal capacity in accordance with Article 3(d) of the CACM Regulation since the common capacity calculation methodology is using the flow-based approach which provides optimal cross-zonal capacities to market participants.
8. The day-ahead common capacity calculation methodology is designed to ensure a fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities, and market participants (Article 3(e) of the CACM Regulation) since the day-ahead common capacity calculation methodology is performed with transparent rules that are approved by the relevant national regulatory authorities.

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9. Regarding the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation), the day-ahead common capacity calculation methodology determines the main principles and main processes for the day-ahead timeframe. The day-ahead common capacity calculation methodology enables Core TSOs to provide market participants with the same reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation in a transparent way and at the same time.
 10. The day-ahead common capacity calculation methodology also contributes to the objective of respecting the need for a fair and orderly market and price formation (Article 3(h) of the CACM Regulation) by making available in due time the cross-zonal capacity to be released in the market.
 11. When preparing the day-ahead common capacity calculation methodology, Core TSOs took careful consideration of the objective of creating a level playing field for NEMOs (Article 3(i) of the CACM Regulation) since all NEMOs and all their market participants will have the same rules and non-discriminatory treatment (including timings, data exchanges, results formats etc.) within the Core CCR.
 12. Finally, the day-ahead common capacity calculation methodology contributes to the objective of providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) by ensuring a transparent and non-discriminatory approach towards facilitating cross-zonal capacity allocation.
 13. In conclusion, the day-ahead common capacity calculation methodology contributes to the general objectives of the CACM Regulation to the benefit of all market participants and electricity end consumers.

SUBMIT THE FOLLOWING DAY-AHEAD COMMON CAPACITY CALCULATION METHODOLOGY TO REGULATORY AUTHORITIES OF THE CORE CCR:

GENERAL PROVISION

Article 1 Subject matter and scope

The day-ahead common 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 common capacity calculation methodology for the Core CCR bidding zone borders.

Article 2 Definitions and interpretation

1. For the purposes of the day-ahead common 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 and Commission Regulation (EU) 543/2013. In addition, the following definitions, abbreviations and notations shall apply:
 1. 'advanced hybrid coupling' (hereinafter 'AHC') means a solution to fully take into account the influences of the adjacent capacity calculation regions during the capacity allocation;
 2. 'AMR' is the adjustment for minimum *RAM*, i.e. the adjustment for the minimum remaining available margin;
 3. 'available transmission capacity' (hereinafter 'ATC') means the transmission capacity that remains available after the allocation procedure and which respects the physical conditions of the transmission system;

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4. 'balance responsible party' (hereinafter 'BRP') means a market participant or its chosen representative responsible for its imbalances;
 5. 'CCC' is coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation;
 6. 'CCR' is the capacity calculation region as defined in Article 2(3) of the CACM Regulation;
 7. 'central dispatch model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process;
 8. 'CGM' is the common grid model as defined in Article 2(2) of the CACM Regulation;
 9. 'CGMAM' is the the common grid model alignment methodology;
 10. 'CGMM' is the common grid model methodology, pursuant to Article 17 of the CACM regulation;
 11. 'CNE' is a critical network element;
 12. 'CNEC' is a critical network element with a contingency;
 13. 'Core CCR' is the Core capacity calculation region as given by the Agency for the cooperation of energy regulators No 06/2016 on 17 November 2016;
 14. 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 Transeletrica S.A. ("Transeletrica"), TransnetBW GmbH ("TransnetBW");
 15. 'cross-zonal network element' means in general only those transmission lines which cross a bidding zone border. However, the term 'cross-zonal network elements' is enhanced to also include the network elements between the interconnector and the first substation to which at least two internal transmission lines are connected;
 16. 'default flow-based parameters' means the precoupling backup values computed in situations when inputs for flow-based parameters are missing for more than two consecutive hours. This computation is done based on existing long term bilateral capacities;
 17. 'external constraint' (hereinafter 'EC') means the maximum import and/or export constraints of a given bidding zone;
 18. 'evolved flow-based' (hereinafter 'EFB') means a solution that takes into account exchanges over all cross-border HVDC interconnectors within a single CCR applying the flow-based method of that CCR;
 19. 'D-1' means day-ahead;
 20. 'D-2' means two-days ahead;
 21. 'FAV' is the final adjustment value;
 22. 'flow-based domain' means the set of constraints that limits the cross-zonal capacity calculated with a flow-based approach;
 23. ' F_{max} ' is the maximum admissible power flow;
 24. ' F_i ' is the expected flow in commercial situation i;
 25. ' F_0 ' is the flow per CNEC in the situation without commercial exchanges within the Core CCR;
 26. ' F_{ref} ' is the reference flow;

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27. ' F_{LTN} ' is the expected flow after long-term nominations;
 28. 'flow reliability margin' (hereinafter ' FRM ') means the reliability margin as defined in Article 2(14) of the CACM Regulation applied to a critical network element in a flow-based approach;
 29. ' GSK ' is the generation shift key as defined in Article 2(12) of the CACM Regulation;
 30. 'HVDC' is a high voltage direct current transmission system;
 31. 'IGM' is the individual grid model as described in Article 2(1) of the CACM Regulation;
 32. ' I_{max} ' is the maximum admissible current;
 33. 'LTA' are the long-term allocated capacities;
 34. LTA_{margin} is the margin for LTA inclusion;
 35. 'LTN' are the long-term nominations submitted by market participants based on LTA;
 36. 'merging agent' as defined in Article 20 of the CGMM;
 37. 'neighbouring bidding zone pairs' means the bidding zones which have a common commercial border;
 38. 'MTU' is the market time unit;
 39. 'MP' is the market party;
 40. 'NP' is the net position;
 41. 'presolved domain' means the final set of binding constraints for capacity allocation after the pre-solving process;
 42. 'presolving process' means that the redundant constraints are identified and removed from the flow-based domain by the CCC;
 43. 'previously-allocated capacities' means the long-term capacities which have already been allocated in previous (yearly and/or monthly) time frames;
 44. 'PST' is a phase-shifting transformer;
 45. ' $PTDF$ ' is the power transfer distribution factor;
 46. 'PTR' is the physical transmission right;
 47. 'RA' means a remedial action as defined in Article 2(13) of the CACM Regulation;
 48. ' RAM ' is the remaining available margin;
 49. 'RAO' is the remedial action optimization;
 50. 'SDAC' means single day-ahead coupling;
 51. '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 per MTU calculation;
 52. 'spanning' means the precoupling backup solution in situations when inputs for flow-based parameters are missing for less than three consecutive hours. This computation is based on the intersection of previous and sub-sequent available flow-based domains;
 53. 'SO GL' is the System Operation Guideline (Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation);
 54. '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;
 55. 'static grid model' is a list of relevant grid elements of the transmission system, including their electrical parameters;
 56. ' U ' is the reference voltage;

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57. 'vertical load' means the total amount of electricity which exits in the national transmission system to connected distribution systems, end consumers connected to the transmission system, and to electricity producers for consumption in the generation of electricity;
 58. 'zone-to-slack *PTDF*' means the power transfer distribution factor of a commercial exchange between a bidding zone and the slack node;
 59. 'zone-to-zone *PTDF*' means the power transfer distribution factor of a commercial exchange between two bidding zones;
 60. 'preventive' remedial action means a remedial action which is applied before a contingency occurs;
 61. 'curative' remedial action means a remedial action which is applied after a contingency occurs;
 62. the notation x denotes a scalar;
 63. the notation \vec{x} denotes a vector;
 64. the notation \mathbf{x} denotes a matrix.
2. In this day-ahead common capacity calculation methodology unless the context requires otherwise:
 - a. the singular indicates the plural and vice versa;
 - b. the table of contents and headings are inserted for convenience only and do not affect the interpretation of this day-ahead common capacity calculation methodology; and
 - c. 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 common capacity calculation methodology solely applies to the day-ahead capacity calculation within the Core CCR. Common capacity calculation methodologies within other capacity calculation regions or other time frames are not in scope of this methodology.

Article 4 Cross-zonal capacities for the day-ahead market

1. For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated using the flow-based approach as defined in the day-ahead common capacity calculation methodology, as set forth in Article 20ff of the CACM Regulation.
2. The TSOs of the Core CCR shall provide the coordinated capacity calculator (CCC) sufficiently in advance of the day-ahead firmness deadline as defined in accordance with Article 69 of CACM Regulation the following initial inputs:
 - a. D-2 IGMs respecting the methodology developed in accordance with Article 19 of the CACM Regulation;
 - b. critical network elements (CNEs) and contingencies in accordance with Article 5;
 - c. operational security limits in accordance with Article 6;
 - d. allocation constraints in accordance with Article 8;
 - e. flow reliability margin (*FRM*) in accordance with Article 9;
 - f. generation shift key (GSK) in accordance with Article 10; and
 - g. remedial actions in accordance with Article 11.
3. Core TSOs, or an entity acting on behalf of Core TSOs, shall send for each market time unit of the day the long term allocated capacities (LTA) and nominated capacities (LTN) to the coordinated capacity calculator, without undue delay.

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4. When providing the inputs, the TSOs of the Core CCR shall respect the formats commonly agreed between the TSOs and the coordinated capacity calculators of the Core CCR, while respecting the requirements and guidance defined in the CGMM.
 5. Once D-2 IGMs have been received, the merging agent shall merge the D-2 IGMs to create the D-2 CGMs respecting the methodology developed in accordance with Article 17 of the CACM Regulation.
 6. For the day-ahead common capacity calculation in the Core CCR, performed by the CCC, the high-level process flow includes seven steps until the final flow-based domain for the single day-ahead coupling process is set:
 - a. First, the provided inputs as defined in Article 4(2) are taken for the initial flow-based computation as defined in Article 12, taking into account the reference commercial situation, leading to preliminary results of capacity calculation;
 - b. after the initial flow-based computation, the second process step is to determine the relevant CNECs for subsequent steps of the common capacity calculation based on the preliminary results as defined in Article 5;
 - c. after the determination of relevant CNECs, the third process step selects remedial actions (RAs) resulting from the remedial action optimization as defined in Article 15;
 - d. the fourth process step is the intermediate flow-based computation where:
 - i. a new flow-based computation is performed as defined in Article 12, taking into account the reference commercial situation and the updated inputs resulting from steps described in Article 4(6)(b) and Article 4(6)(c);
 - ii. the following step is the determination of the adjustment for minimum *RAM (AMR)* as defined in Article 13;
 - iii. and finally the execution of the rules for previously-allocated capacities from long-term auctions (LTA) are taken into account as defined in Article 14.
 - e. after the intermediate flow-based computation the resulting cross-zonal capacities are validated by the TSOs of the Core CCR as defined in Article 21. During this validation process the CCC shall coordinate with CCCs of neighbouring CCRs as defined in Article 21(6);
 - f. the sixth process step is the pre-final flow-based computation where:
 - i. a new flow-based computation is performed as defined in Article 18, taking into account no commercial exchange for the Core region and the updated inputs resulting from steps described Article 4(6)(d) and Article 4(6)(e);
 - ii. the following step is performing the presolve process as defined in Article 18(1)(d);
 - iii. the next step is to remove the reference commercial situation as defined in in Article 18(1)(e);
 - iv. as a final step the remaining available margin is calculated as defined in Article 12(10).
 - g. the seventh and final process step is the final flow-based computation where:
 - i. a new flow-based computation is performed as defined in Article 18, taking into account no commercial exchange for the Core region and the updated inputs resulting from steps described Article 4(6)(d) and Article 4(6)(e);
 - ii. the following step is performing the presolve process as defined in Article 18(1)(d);
 - iii. the next step is to remove the reference commercial situation as defined in in Article 18(1)(e);
 - iv. afterwards the LTN adjustment is performed as defined in Article 18(1)(f);
 - v. as a next step the external constraints are adjusted with respect to the net positions resulting from LTN, as defined in Article 18 (2)(c);

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- vi. finally, the remaining available margins for the day-ahead single coupling are calculated as defined in Article 18(1)(g).
7. In accordance with Article 46 of CACM Regulation, the CCC and TSOs of the Core CCR shall ensure that cross-zonal capacity shall be provided to relevant NEMOs before the day-ahead firmness deadline as defined in accordance with Article 69 of CACM Regulation.

METHODOLOGIES FOR CALCULATION OF THE INPUTS

Article 5 Methodology for critical network elements and contingencies selection

1. Each Core TSO shall provide a list of critical network elements (CNEs) of its own control area based on operational experience. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the TSO, pursuant to Article 22. A CNE is a network element, significantly impacted by Core cross-zonal trades, which are supervised under certain operational conditions, the so-called contingencies. A CNE can be:
 - a cross-zonal network element; or
 - an internal network element.Those elements can be an overhead line, an underground cable, or a transformer.
2. In accordance with Article 23(1) of CACM Regulation, Core TSOs shall provide a list of contingencies used in operational security analysis in line with Article 33 of the SO GL, limited to their relevance for the set of CNEs as defined in Article 5(1) and pursuant to Article 23(2) of the CACM Regulation. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the TSO, pursuant to Article 22.

A contingency can be a trip of:

 - a line, a cable, or a transformer;
 - a busbar;
 - a generating unit;
 - a load; or
 - a set of the aforementioned contingencies.
3. The association of contingencies to CNEs shall be done from the list of CNEs established in Article 5(1) and from the list of contingencies established in Article 5(2). It shall follow the rules established in Article 75 of SO GL.
4. Until a compliant methodology for Article 75 SO GL enters into force, and pursuant to Article 23(2) of the CACM regulation, the association of contingencies to CNEs will be based on each TSO's needs and operational experience. The contingencies of a TSO will be associated to the CNEs of that TSO, and each TSO will individually associate contingencies within its observability area to its own CNEs.
5. The result of the process according to Article 5(3) or Article 5(4) will be an initial pool of CNECs to be used for RAO and in all subsequent steps of the common capacity calculation. This pool shall remain fixed during the computation. The initial pool of CNECs will be reviewed on a daily basis before the initial flow-based computation pursuant to Article 5(6).
6. Core TSOs shall distinguish between:
 - a. the CNECs of the initial pool that are marked by the CCC to be significantly influenced by the changes in bidding zone net positions in accordance with Article 29(3) of the CACM Regulation. A cross-zonal network element is always considered as significantly influenced. The other CNECs shall have a maximum zone-to-zone *PTDF*, as described in Article 12, higher than a common threshold of 5 percent. The value of this threshold is defined in

conjunction with the adjustment for minimum *RAM* according to Article 13, both being a measure to mitigate possible discrimination between the treatment of internal and cross-zonal transactions, in response to Article 21(1)(b)(ii) of the CACM Regulation and Article 1.7 of Annex I to the Regulation (EC) 714/2009 and in line with Article 3(a), 3(b) and 3(e) of the CACM Regulation, with the aim to promote social welfare.

The CNECs of this category will be taken into account in all the subsequent steps of the common capacity calculation and will determine the cross-zonal capacity;

- b. the CNECs of the initial pool that, based on experience are expected to be influenced by the RAs defined in Article 11, but are not significantly influenced by the changes in bidding zone net positions, pursuant to Article 5(6)(a). The CNECs of this category may only be monitored during the RAO and shall not limit the cross-zonal capacity.

In accordance with Article 15(2)(b) the additional loading, resulting from the application of RAs, of CNECs of this category may be limited during the RAO, while ensuring that a certain additional loading up to the defined threshold is always accepted.

The differentiation of the CNEC selection between the two sub-processes (RAO and the subsequent steps of the common capacity calculation) is needed to monitor the impact of RAO on certain CNECs which are strongly impacted by RAs while only being weakly impacted by cross-border exchanges, in line with Article 3(c) of the CACM Regulation. The pool of CNECs for RAO and for subsequent steps of the common capacity calculation may differ. However, the pool of CNECs for the subsequent steps of the common capacity calculation shall be a subset of the CNECs considered for RAO;

- c. the CNECs of the initial pool not mentioned in Article 5(6)(a) or Article 5(6)(b). The CNECs of this category shall not be taken into account in the day-ahead common capacity calculation.
- 7. In an exceptional situation, such as extreme weather conditions, untypical flow conditions or topology or grid situation, a TSO may decide to modify the CNEC list described in Article 5(6)(a) for one or several market time units covering the expected period of presence of the exceptional situation.
 - a. In case a TSO decides, in an exceptional situation, to keep a CNEC within the list described in Article 5(6)(a) which is not significantly influenced by the changes in bidding zone net positions, the respective TSO shall inform Core national regulatory authorities without undue delay and provide in the monitoring report defined in Article 24 a clear description of the specific situation providing detailed information such as the specific topology or grid situation that led to this decision.
 - b. In case a TSO decides, in an exceptional situation, to exclude a CNEC from the list described in Article 5(6)(a) which is significantly influenced by the changes in bidding zone net positions, the respective TSO shall inform Core national regulatory authorities without undue delay and provide in the monitoring report defined in Article 24 a clear description of the specific situation providing detailed information such as the specific topological or grid situation that led to this decision.
 - 8. TSOs shall further study the value of the common threshold referred to in Article 5(6)(a), including social welfare based analysis, and potentially adapt it in accordance with the results of the internal parallel run pursuant to Article 25.
 - 9. TSOs shall review and update methodologies for determining CNECs in accordance with Article 22.

Article 6 Methodology for operational security limits

- 1. In accordance with Article 23(1) of the CACM Regulation, Core TSOs shall respect the operational security limits used in operational security analysis carried out in line with Article 72 of the SO GL. The operational security limits used in the common capacity calculation are the same as those used

in operational security analysis, therefore any additional descriptions pursuant to Article 23(2) of the CACM Regulation are not needed. In particular:

- a. Core TSOs shall respect the maximum admissible current (I_{max}) which is the physical limit of a CNE according to the operational security policy in line with Article 25 of the SO GL. The maximum admissible current can be defined with:
 - i. fixed limits for all market time units in the case of transformers and certain types of conductors which are not sensitive to ambient conditions. This is applicable for all Core TSOs;
 - ii. fixed limits for all market time units of a specific season; This is applicable for Amprion, APG, CREOS, ČEPS, ELIA, HOPS, MAVIR, RTE, SEPS, TenneT GmbH, TenneT B.V., Transelectrica, and TransnetBW;
 - iii. a value per market time unit depending on the weather forecast. This is applicable for ČEPS, PSE, ELIA, TenneT GmbH, TenneT B.V., APG, ELES, 50Hertz, Amprion, and RTE;
 - iv. fixed limits for all market time units, in case of specific situations where the physical limit reflects the capability of substation equipment (such as circuit-breaker, current transformer, or disconnecter). This is applicable for a subset of lines of the following TSOs: MAVIR, Transelectrica, PSE, SEPS, ČEPS, TransnetBW, APG, ELES, Amprion, HOPS, TenneT GmbH, TenneT B.V., and 50Hertz.
- b. when applicable, I_{max} shall be defined as a temporary current limit of the CNE in accordance with Article 25 of the SO GL. A temporary current limit means that an overload is only allowed for a certain finite duration.
- c. I_{max} is not reduced by any security margin, as all uncertainties in the common capacity calculation are covered on each CNEC by the flow reliability margin (FRM) in accordance with Article 9 and final adjustment value (FAV) in accordance with Article 7.
- d. the value F_{max} in MW, describes the maximum admissible power flow on a CNE. F_{max} is calculated by the CCC from I_{max} by the given formula:

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

Equation 1

where I_{max} is the maximum admissible current in kA of a critical network element (CNE), U is a fixed reference voltage in kV for each CNE, and $\cos(\varphi)$ the power factor. Core TSOs shall assume that the share of the CNE loading by reactive power is negligible (i.e. the angle $\varphi = 0$). Thus, factor $\cos(\varphi)$ equals 1, which means that the element is assumed to be loaded only by active power. Any significant deviation from this assumption shall be covered by FAV pursuant to Article 21(1)(d);

2. Core TSOs shall aim towards determining the maximum admissible current using at least seasonal limits pursuant to Article 6(1)(a)(ii) and ideally dynamic line rating pursuant to Article 6(1)(a)(iii), save for cases where the conditions pursuant to Article 6(1)(a)(i) or Article 6(1)(a)(iv) apply.
3. TSOs shall review and update operational security limits in accordance with Article 22.

Article 7 Final Adjustment Value

1. The remaining available margin (RAM) on a CNE may be increased or decreased by the final adjustment value (FAV), where:
 - a. positive values of FAV (given in MW) reduce the available margin on a CNE while negative values increase it;

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- b. *FAV* can be set by the responsible TSO during the validation process in accordance with Article 21;
 - c. in case a TSO decides to use *FAV* during the day-ahead common capacity calculation, the respective TSO shall provide the Core regulatory authorities with a clear description of the specific situation that led to this decision in the monitoring report defined in Article 24.

Article 8 Methodology for allocation constraints

1. In accordance with Article 23(3)(a), and respecting the objectives described in Article 3 of the CACM Regulation, besides active power flow limits on CNEs, allocation constraints may be necessary to maintain a secure grid operation. As defined in Article 2(6) of the CACM Regulation, allocation constraints constitute measures defined to the purpose of keeping the transmission system within operational security limits. Some of the transmission system parameters, defined in Article 2(7) of CACM Regulation, used for expressing operational security limits (*inter alia* frequency, voltage and dynamic stability) depend on production and consumption in a given system, and these specific limitations can be related to generation and load. Since such specific limitations cannot be efficiently transformed into maximum active power flows on individual CNEs, these have to be included as allocation constraints in capacity calculation expressed as maximum import and export constraints of bidding zones. These kinds of allocation constraints are called external constraints.
2. External constraints are determined by Core TSOs and taken into account during the single day-ahead coupling in addition to the active power flow limits on CNECs.
3. These external constraints shall be modelled as a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the single day-ahead coupling), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the single day-ahead coupling.
4. In case implementation of an external constraint on the global net position in the single day-ahead coupling is technically unfeasible, the external constraint shall be implemented by constraining the cross-zonal capacity calculation in the Core CCR as described in Article 18(2), thus limiting the Core net position of the respective bidding zone.
5. For the fallback process, pursuant to Article 20, the allocation constraints, being external constraints, shall be modelled as constraints limiting the Core net position.
6. A TSO may use external constraints in order to avoid situations that lead to stability problems in the network, detected by at least yearly reviewed system dynamics studies. This is applicable for ELIA and TenneT B.V., for all MTUs.
7. A TSO may use external constraints in order to avoid situations which are too far away from the reference flows going through the network in the D-2 CGM, and which, in exceptional cases, would induce extreme additional flows on grid elements resulting from the use of a linearized GSK, leading to a situation which could not be validated as safe by the concerned TSO. This is applicable for TenneT B.V., for all MTUs.
8. A TSO may use external constraints in case of a central dispatch model for ensuring a minimum level of operational reserve for balancing. The external constraints introduced are bi-directional, with independent values for directions of import and export, depending on the foreseen balancing situation. This is applicable for PSE, for all MTUs.
9. The details, justifications for use, and the methodology for the calculation of external constraints as described in Article 8(6), 8(7), and 8(8) are set forth in Appendix 1.
10. A TSO may discontinue the usage of an external constraint as described in Article 8(6), 8(7), and 8(8). The concerned TSO shall communicate this change to the Core regulatory authorities and to the market participants at least one month before its implementation.

11. TSOs shall review and update allocation constraints in accordance with Article 22.

Article 9 Reliability margin methodology

1. The day-ahead common capacity calculation methodology is based on forecast models of the transmission system. The inputs are created two days before the delivery date of energy with available knowledge. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.
2. In accordance with Article 22(1) of the CACM Regulation, the reliability margins for critical elements (hereafter referred to as “*FRM*”) are calculated in a three-step approach:
 - a. in a first step, for each market time unit of the observatory period, the D-2 common grid model (CGM) are updated in order to take into account the real-time situation of at least the remedial actions that are considered in the common capacity calculation and defined in Article 11. These remedial actions are controlled by Core TSOs and thus not considered as an uncertainty. This step is undertaken by copying the real-time configuration of these remedial actions and applying them into the historical D-2 CGM. The power flows of the latter modified D-2 CGM are re-computed (F_{ref}) and then adjusted to realised commercial exchanges inside the Core CCR with the *PTDF*s calculated based on the historical GSK and the modified D-2 CGM according to the methodology as described in Article 12. Consequently, the same commercial exchanges in the Core CCR are taken into account when comparing the power flows based on the day-ahead common capacity calculation with flows in the real-time situation. These flows are called expected flows (F_{exp}), see Equation 2.

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

Equation 2

with

\vec{F}_{exp}	expected flow per CNEC in the realised commercial situation
\vec{F}_{ref}	flow per CNEC in the CGM (reference flow)
\mathbf{PTDF}	power transfer distribution factor matrix
$\overrightarrow{NP}_{real}$	Core net position per bidding zone in the realised commercial situation
$\overrightarrow{NP}_{ref}$	Core net position per bidding zone in the CGM

The power flows on each CNEC of the Core CCR, as expected with the day-ahead common capacity calculation methodology are then compared with the real time flows observed on the same CNEC. All differences for all market time units of a one-year observation period are statistically assessed and a probability distribution is obtained;

- b. in a second step and in accordance with Article 22(3) of the CACM Regulation, based on experience in existing flow-based market coupling initiatives, the 90th percentiles of the probability distributions of all CNECs are calculated. This means that the Core TSOs apply a common risk level of 10% i.e. the *FRM* values cover 90% of the historical errors. Core TSOs can then either:
 - i. directly take the 90th percentile of the probability distributions to determine the *FRM* of each CNEC. This means that a CNE can have different *FRM* values depending

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- on the associated contingency; this principle will be applied by the following Core TSOs: 50Hertz, Amprion, APG, CEPS, MAVIR, PSE, SEPS, Transelectrica, TenneT GmbH, TenneT BV, and TransnetBW;
- ii. only take the 90th percentile of the probability distributions calculated on CNEs without contingency. This means that a CNE will have the same *FRM* for all associated contingencies; this principle will be applied by the following Core TSOs: ELES, Elia, CREOS, HOPS, and RTE;
- c. a possible third step is to undertake an operational adjustment on the values derived from Article 9(2)(b)(i) or 9(2)(b)(ii), which can be applied to reduce the computed *FRM* values to a range between 5% and 20% of the F_{max} calculated under normal weather conditions.
- d. TSOs shall further study the value of the common risk level referred to in Article 9(2)(b) and potentially adapt it pursuant to Article 25.
3. The *FRM* values will be updated every year based upon an observatory period of one year so that seasonality effects can be reflected in the values. The *FRM* values are then fixed until the next update.
4. Before the first operational calculation of the *FRM* values, Core TSOs shall use the *FRM* values already in operation in existing flow-based market coupling initiatives. In case these values are not available, Core TSOs shall determine the *FRM* values as 10% of the F_{max} calculated under normal weather conditions.
5. In accordance with Article 22(2) and (4) of the CACM Regulation, the *FRMs* cover the following forecast uncertainties:
- Core external transactions (out of Core CCR control: both between Core CCR and other CCRs as well as among TSOs outside the Core CCR);
 - generation pattern including specific wind and solar generation forecast;
 - generation shift key;
 - load forecast;
 - topology forecast;
 - unintentional flow deviation due to the operation of frequency containment reserves; and
 - flow-based capacity calculation assumptions including linearity and modelling of external (non-Core) TSOs' areas.
6. Core TSOs shall assess the possible improvements of the inputs of the day-ahead common capacity calculation in the annual review as defined in Article 22.
7. Core TSOs shall publish a study, based on the first and second annual *FRM* assessments and the quality improvements on the input data and process of the flow-based capacity calculation, two and a half years after the go-live of the Core flow-based day-ahead capacity calculation.

Article 10 Generation shift keys methodology

1. In accordance with Article 24 of the CACM Regulation, Core TSOs developed the following methodology to determine the common generation shift key:
- Core TSOs shall take into account the available information on generation or load available in the common grid model for each scenario developed in accordance with Article 18 of the CACM Regulation in order to select the nodes that will contribute to the generation shift key;
 - Each Core TSO shall aim to apply a GSK that resembles the dispatch and the corresponding flow pattern, thereby contributing to minimizing the flow reliability margins;
 - Core TSOs shall define a constant generation shift key per market time unit;

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- d. Core TSOs belonging to the same bidding zone shall determine a common methodology that translates a change in the bidding zone net position to a specific change of generation or load in the common grid model.
 2. For the application of the methodology, Core TSOs shall define, for the capacity calculation process, generation shift keys with fixed values, impacted by the actual generation and/or load present in the D-2 CGM, for each market time unit.
 3. Core TSOs have harmonized their GSK determination methodologies whilst including some dedicated features to take into account specific production patterns within their grids.
 - a. Common rules to establish generation shift keys shared by all Core TSOs
 - i. In its GSK, each TSO shall use flexible and controllable production units which are available inside the TSO grid (they can be running or not within D-2 CGM).
 - ii. Units unavailable due to outage or maintenance are not included.
 - iii. GSK is reviewed on a daily basis
 - b. Specific methodologies have been developed by some TSOs that are facing a limited amount of flexible production and consumption units within their grid. These methodologies are applied to avoid unrealistic under- and overloading of the units in extreme import or export scenarios.
 - i. For Belgium, the GSK is defined in such a way that for high levels of import into the Belgian bidding zone all GSK units are, at the same time, either at 0 MW or at their minimum production level (including a margin for reserves). For high levels of export from the Belgian bidding zone all GSK units are at their maximum production level (including a margin for reserves) at the same time.
 - ii. For the Netherlands, all GSK units are redispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit to prevent infeasible production levels at foreseen extreme import and export scenarios.
 - iii. For Croatia, Hungary, Slovakia, and Slovenia, small dispersed units connected to lower voltage levels are considered in the GSK in order to achieve more realistic flow patterns when the net position shifts.
 - c. Germany and Luxembourg
 - i. The German and Luxembourgian TSOs provide one single GSK for the whole German-Luxembourgian bidding zone;
 - ii. Each single TSO provides GSKs that respect the specific characteristics of the generation in their own grid;
 - iii. the TSO-specific GSKs are combined into a single GSK by assigning relative weights to each TSO-specific GSK. These weights reflect the distribution of the total market-driven generation among TSOs.
 4. TSOs shall further study the GSK methodology referred to in Article 10(2) and Article 10(3) and potentially adapt it in accordance with the results of the internal parallel run pursuant to Article 25. Potential improvements shall be done in a progressively harmonized way.
 5. TSOs shall review and update the application of the methodology for determining GSK in accordance with Article 22.

Article 11 Methodology for remedial actions in capacity calculation

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

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2. In case a remedial action made available for the capacity calculation in the Core CCR is also one which is made available in another capacity calculation region, the TSO taking control of the remedial action shall take care, when defining it, of a consistent use in its potential application in both regions to ensure a secure power system operation.
 3. In accordance with Article 25(2) and (3) of the CACM Regulation, these RAs will be used for coordinated optimization of cross-zonal capacities while ensuring secure power system operation in real time.
 4. In accordance with Article 25(4) of the CACM Regulation, a TSO may refrain from considering a particular remedial action in capacity calculation in order to ensure that the remaining remedial actions are sufficient to ensure operational security;
 5. In accordance with Article 25(5) of the CACM Regulation, the day-ahead common capacity calculation takes only non-costly RAs into account which can be explicitly modelled in the D-2 CGM. These RAs can be:
 - a. changing the tap position of a phase-shifting transformer (PST);
 - b. topological measure: 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.
 6. In accordance with Article 25(6) of the CACM Regulation, the RAs taken into account are the same for day-ahead and intra-day common capacity calculation, depending on their technical availability.
 7. The RAs can be preventive or curative, i.e. affecting all CNECs or only pre-defined contingency cases, respectively.
 8. The optimized application of RAs in the day-ahead common capacity calculation is performed in accordance with Article 15.
 9. TSOs shall review and update remedial actions taken into account in capacity calculation in accordance with Article 22.

DETAILED DESCRIPTION OF THE CAPACITY CALCULATION APPROACH

Article 12 Mathematical description of the capacity calculation approach

1. The flow-based computation is a centralized 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 21(b)(i) of the CACM Regulation, for each CNEC defined in Article 5(5), Core TSOs shall calculate the influence of the bidding zone net position changes on its power flow. This influence is called the zone-to-slack power transfer distribution factor (*PTDF*). This calculation is performed from the D-2 CGM and the *GSK* defined in accordance with Article 10.
3. The nodal *PTDFs* can be first calculated by subsequently varying the injection of each node defined in the *GSK* in D-2 CGM. For every single nodal variation, the effect on every CNE's or CNEC's loading is monitored and calculated as a percentage. The *GSK* shall translate these node-to-slack *PTDFs* into zone-to-slack *PTDFs* as it converts the bidding zone net position variation into an increase of generation in specific nodes as follows:

$$PTDF_{zone-to-slack} = PTDF_{node-to-slack} \cdot GSK_{node-to-zone}$$

Equation 3

with

$PTDF_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones, rows: CNECs)
$PTDF_{node-to-slack}$	matrix of node-to-slack $PTDFs$ (columns: nodes, rows: CNECs)
$GSK_{node-to-zone}$	matrix containing the $GSKs$ of all bidding zones (columns: bidding zones, rows: nodes, sum of each column equal to one)

4. $PTDFs$ may be defined as zone-to-slack $PTDFs$ or 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 CNE or CNEC l . 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 a CNE or CNEC l . The zone-to-zone $PTDF_{A \rightarrow B,l}$ can be linked to zone-to-slack $PTDFs$ as follows:

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

Equation 4

5. A low value of the zone-to-zone value $PTDF_{A \rightarrow B,l}$ as in Equation 4, being a value close to zero percent, means that a commercial exchange between the bidding zone A and bidding zone B does impact the flow on the CNE or CNEC l , yet not to a large extent. In a flow-based SDAC, all commercial exchanges that do have an impact on the flow of CNE or CNEC l , even when it is low, are competing to make use of its capacity. When it is this CNE or CNEC l that is congested, it implies that the commercial exchange between the bidding zones A and B is restricted as well. TSOs shall monitor the impact of small zone-to-zone $PTDFs$, as defined in Article 24. In case of an undesirable impact, the TSOs shall take appropriate actions to investigate the mitigation of those effects.
6. The $PTDF$ for an exchange between two bidding zones A and B over a HVDC interconnector within the Core CCR following the EFB methodology pursuant to Article 16 shall be expressed as an exchange from bidding zone A to the sending end of the HVDC interconnector plus an exchange from the receiving end of the interconnector to bidding zone B:

$$PTDF_{A \rightarrow B,l} = (PTDF_{A,l} - PTDF_{VH_1,l}) + (PTDF_{VH_2,l} - PTDF_{B,l})$$

Equation 5

with

$PTDF_{VH_1,l}$	zone-to-slack $PTDF$ of Virtual hub 1 on a CNE or 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 CNE or CNEC l . With Virtual hub 2 representing the converter station at the receiving end of the HVDC interconnector located in bidding zone B

The impact of the exchange over the HVDC interconnector on the flow of the CNEs and CNECs can hence be computed as a function of the net positions of the virtual hubs and the corresponding zone-to-slack $PTDFs$, in accordance to Article 16.

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7. The maximum zone-to-zone $PTDF$ of a CNE or a CNEC ($PTDF_{z2zmax,l}$) is the maximum influence that any Core exchange can have on the respective CNE or CNEC:

$$PTDF_{z2zmax,l} = \max_{A \in BZ}(PTDF_{A,l}) - \min_{A \in BZ}(PTDF_{A,l})$$

Equation 6

with

$PTDF_{A,l}$	zone-to-slack $PTDF$ of bidding zone A on a CNE or CNEC l
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 CNE or CNEC l
$\min_{A \in BZ}(PTDF_{A,l})$	minimum zone-to-slack $PTDF$ of Core bidding zones on a CNE or CNEC l

8. The reference flow (F_{ref}) is the active power flow on a CNE or a CNEC based on the D-2 CGM. In case of a CNE, F_{ref} is directly simulated from the D-2 CGM whereas in case of a CNEC, F_{ref} is simulated with the specified contingency.
9. The expected flow F_i in the commercial situation i is the active power flow of a CNE or CNEC based on the flow F_{ref} and the deviation of commercial exchanges between the D-2 CGM (reference commercial situation) and the commercial situation i :

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

Equation 7

with

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

10. The remaining available margin (RAM) of a CNE or a CNEC in a commercial situation i is the remaining capacity that can be given to the market taking into account the already allocated capacity in the situation i . This RAM_i is then calculated from the maximum admissible power flow (F_{max}), the adjustment for minimum RAM (AMR), the margin for LTA inclusion (LTA_{margin}), the reliability margin (FRM), the final adjustment value (FAV), and the expected flow (F_i) with the following equation:

$$RAM_i = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_i$$

Equation 8

Article 13 Adjustment for minimum *RAM*

1. In response to Article 21(1)(b)(ii) of the CACM Regulation, in addition to applying the common maximum zone-to-zone *PTDF* threshold set in Article 5(6)(a), Core TSOs shall ensure a minimum *RAM* for the CNECs determining the cross-zonal capacity before allocating commercial exchanges, save for reasons of operational security.
2. The margin made available on each CNEC for flows stemming from the sum of all commercial exchanges within the Core CCR shall not be lower than 20 percent of the maximum admissible power flow F_{max} , without prejudice to the right for exclusion of specific CNECs according to Article 13(5) and for adjustment of cross-zonal capacity during validation in accordance with Article 21.
3. In order to determine the adjustment for minimum *RAM*, the situation without commercial exchanges within the Core CCR is considered. The flows on all CNECs in this commercial situation are determined by setting \overrightarrow{NP}_i to zero in equation 7, which leads to the following equation:

$$\vec{F}_0 = \vec{F}_{ref} - \mathbf{PTDF} \cdot \overrightarrow{NP}_{ref}$$

Equation 9

with

\vec{F}_0	flow per CNEC in the situation without commercial exchanges within the Core CCR
\vec{F}_{ref}	flow per CNEC in the CGM (reference flow)
\mathbf{PTDF}	power transfer distribution factor matrix
$\overrightarrow{NP}_{ref}$	Core net position per bidding zone in the CGM

4. The adjustment for minimum *RAM* (*AMR*) per CNEC is determined with the following equation:

$$AMR = \max(0.2F_{max} - (F_{max} - FRM - F_0); 0)$$

Equation 10

with

F_{max}	Maximum admissible flow
FRM	Flow reliability margin
F_0	Flow in the situation without commercial exchanges within the Core CCR

5. A TSO may decide to not apply the *AMR* in certain circumstances on specific CNECs, justified to regulatory authorities pursuant to Article 24(3)(o). The exclusion can be performed:
 - a. before the initial flow based parameter computation when the TSO identifies the necessity when providing the CNEC list, pursuant to Article 4(2); or
 - b. during the validation process as described in Article 21, and pursuant Article 4(6)(e).
6. The exclusion of the application of *AMR* for a given CNEC as described in Article 13(5) can be triggered in situations when there are insufficient available remedial actions, costly or not, in order to ensure the security of supply and system security.

Article 14 Long-term allocated capacities (LTA) inclusion

1. In accordance with Article 21(1)(b)(iii) of the CACM Regulation, Core TSOs shall apply the following rules for taking into account the previously-allocated cross-zonal capacity:
 - a. The objective of the rules is to verify that the *RAM* of each CNE or CNEC remains non-negative in all combinations of previously-allocated commercial net positions.
 - b. “Previously-allocated capacities” on all commercial borders of the Core CCR are the long-term allocated capacities (LTA). LTA shall be calculated under the framework of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation in accordance with the therein foreseen respective timelines.
 - c. As long as the long-term capacity calculation according to Article 14(1)(b) has not been established, LTA will be commonly coordinated on an annual basis during an all Core TSOs meeting. Core TSOs will commonly coordinate on any proposed deviation from the historical values on the basis of security assessment.
2. The following equation shall be applied to all possible combinations of net positions resulting from full utilization of previously-allocated capacities on all commercial borders:

$$\vec{F}_{LTA_i} = \vec{F}_{ref} + \mathbf{PTDF} \times (\vec{NP}_{LTA_i} - \vec{NP}_{ref})$$

Equation 11

with

\vec{F}_{LTA_i}	flow per CNEC in LTA capacity utilization combination i
\vec{F}_{ref}	flow per CNEC in the CGM (reference flow)
\mathbf{PTDF}	power transfer distribution factor matrix
\vec{NP}_{LTA_i}	Core net position per bidding zone in LTA capacity utilization combination i
\vec{NP}_{ref}	Core net position per bidding zone in the CGM

Then the following equation shall be checked:

$$RAM_{LTA_i} = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_{LTA_i}$$

Equation 12

with

RAM_{LTA_i}	RAM per CNEC in LTA capacity utilization combination i
LTA_{margin}	the margin for LTA inclusion

3. If at least one of the remaining available margins RAM_{LTA_i} is smaller than zero, it implies that the previously-allocated capacities are not fully covered by the flow-based domain. In this case the RAM of limiting CNEs shall be increased using the LTA_{margin} parameter to compensate the negative RAM_{LTA_i} .

Article 15 Rules on adjustment of power flows on critical network elements due to remedial actions

1. In accordance with Article 21(1)(b)(iv) of the CACM Regulation, this day-ahead common capacity calculation methodology shall describe the rules on the adjustment of power flows on critical network elements due to remedial actions:
 - a. An exchange of foreseen remedial actions in each CCR, with sufficient impact on the cross-zonal capacity in other CCRs, should be coordinated among CCCs. The Core CCC shall take this information into account for the coordinated application of RAs in the Core CCR;
 - b. the coordinated application of RAs shall aim at optimizing cross-zonal capacity in the Core CCR in accordance with Article 29(4) of the CACM Regulation. The remedial action optimization (RAO) itself consists of a coordinated optimization of cross-zonal capacity within the Core CCR by means of securing and enlarging the flow-based domain in the foreseen operating point of the grid. The foreseen operating point of the grid shall be expressed by the balanced net positions for each bidding zone obtained from the Common Grid Model Alignment process, pursuant to the Common Grid Model Alignment Methodology.
 - c. The RAO shall be an automated, coordinated, and reproducible process, performed by the CCC, that applies RAs defined in accordance with Article 11; and
 - d. the applied RAs should be transparent to all TSOs, also of adjacent CCRs, and shall be an input to the coordinated operational security analysis established under SO GL Article 75.
2. The RAO methodology contains a set of pre-defined characteristics such as an objective function, constraints, and optimization variables:
 - a. The RAO objective is to enlarge the capacity domain around the balanced net positions of the Common Grid Model Alignment process, with the objective function $\min(RAM_{rel}) \rightarrow \max$, i.e. maximizing the minimum relative *RAM* of all optimized CNECs in accordance with Article 5(6)(a). The term relative refers to a weighting of *RAM* determined by the reciprocal of the sum of all absolute zone-to-zone *PTDFs* on Core bidding zone borders, see Equation 13.

$$RAM_{rel} = \frac{RAM}{\sum_{(A,B) \in \text{Pairs of Core bidding zones with commercial border}} |PTDF_{A \rightarrow B}|}$$

Equation 13

As long as the *RAM* on at least one CNEC is less than zero, the objective function changes to the maximization of the minimum *absolute* margin of all optimized CNECs in accordance with Article 5(6)(a), until all CNECs have a *RAM* equal to or larger than zero.

- b. The constraints, in accordance with Article 25(4) of the CACM Regulation, are:
 - operational security limits of optimized CNECs in accordance with Article 6;
 - the provided range of tap positions of each PST as preventive or curative remedial actions;
 - minimum impact on objective function value for use of remedial actions;
 - equal tap positions for pre-defined parallel PSTs;
 - limitations on the number of activated curative remedial actions;
 - maximum loading of monitored (i.e. not optimized) CNECs in accordance with Article 5(6)(b), limiting the additional flow due to the RAO to the maximum of 50 MW and the CNEC's *RAM* prior to the RAO.

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- c. The optimization variables are the switching states of topological measures and PST tap positions.

Article 16 Integration of cross-border HVDC interconnectors located within the Core CCR

1. Core TSOs shall apply the evolved flow-based (EFB) methodology when including cross-border HVDC interconnectors within the Core CCR.
2. Core TSOs shall take into account the impact of an exchange over a cross-border HVDC interconnector located within the Core CCR on all CNECs within the process of capacity calculation and allocation. The flow-based properties and constraints of the Core CCR (in contrast to an NTC approach) and at the same time optimal allocation of capacity on the interconnector in terms of market welfare shall be taken into account.
3. Core TSOs shall distinguish between AHC and EFB. 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 main adaptations to the day-ahead common capacity calculation process introduced by the concept of EFB are twofold:
 - a. the impact of an exchange over the cross-border HVDC interconnector is considered for all relevant CNECs;
 - b. the outage of the HVDC interconnector is considered as a contingency for all relevant CNEs in order to simulate no flow over the interconnector, since this is becoming the N-1 state.
5. In order to achieve the integration of the cross-border HVDC interconnector into the flow-based process, two virtual hubs at the converter stations of the cross-border HVDC shall be added. These virtual hubs represent the impact of an exchange over the cross-border HVDC interconnector on the relevant CNECs. By placing a GSK value of 1 at the location of each converter station, the impact of a commercial exchange can be translated into a *PTDF* value. This action adds two columns to the existing *PTDF* matrix, one for each virtual hub. The virtual hubs introduced by this process in Article 12(6) are only used for the modelisation of the impact of an exchange, and do not contain any bids during market coupling. As a result, the virtual hubs will have a global net position of 0 MW, but their FB net position will reflect the exchanges over the interconnector. The flow-based net positions of these virtual hubs will be the same value, but they will have an opposite sign.
6. The list of contingencies considered in the capacity calculation will be extended to include the cross-border HVDC interconnector. Therefore, the outage of the interconnector has to be modelled as a N-1 state and the consideration of the outage of the HVDC interconnector creates additional CNEC combinations for all relevant CNEs during the process of capacity calculation and allocation.

Article 17 Consideration of non-Core CCR borders

1. In accordance with Article 21(1)(b)(vii) of the CACM Regulation, Core TSOs take into account the influences of other CCRs by making assumptions on what will be the future non-Core exchanges in accordance with Article 18(3) of the CACM Regulation and Article 19 of the Common Grid Model Methodology.

2. The assumptions of non-Core exchanges are implicitly captured in the D-2 CGM by the non-Core TSOs' best forecasts of net positions and flows for HVDC lines, according to Article 18(3) of CACM Regulation, which are used as the basis for the common capacity calculation. In Core CCR, this constitutes the rule for sharing power flow capabilities of Core CNECs among different CCRs. The expected exchanges are thus captured implicitly in the *RAM* via the reference flow F_{ref} over all CNECs (see also Equations 7 and 8 of Article 12). As such, these assumptions will impact (increase or decrease) the *RAMs* of Core CNECs. Resulting uncertainties linked to the aforementioned assumptions are implicitly integrated within each CNEC's *FRM*. This concept is usually referred to as standard hybrid coupling.
3. In contrast, advanced hybrid coupling (AHC) would enable Core TSOs to explicitly model the exchange situations of adjacent CCRs within the flow-based domain and thus in the single day-ahead coupling. This would reduce uncertainties in the D-2 CGM regarding forecast of non-Core exchanges, and increase the degree of freedom for the single day-ahead coupling in terms of optimal allocation of capacities. The feasibility of AHC will be studied in accordance with Article 25(7).
4. AHC is considered to be the target solution to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain and will be discussed with adjacent involved CCRs.
5. Core TSOs shall monitor the accuracy of non-Core exchanges in the D-2 CGM. Core TSOs shall report on at least an annual basis.

Article 18 Calculation of the final flow-based domain

1. After the determination of the optimal preventive and curative RAs, the RAs are explicitly associated to the respective Core CNECs (thus altering their reference flow F_{ref} and *PTDF* values) and the final flow-based parameters are computed in the following sequential steps:
 - a. determination of the adjustment for minimum *RAM* (*AMR*) according to Article 13;
 - b. execution of the rules for previously-allocated capacity in Article 14;
 - c. application of a possible *FAV* in accordance with Article 21;
 - d. only the constraints that are most limiting the exchanges need to be respected in the single day-ahead coupling: the non-redundant constraints (or the "presolved" domain). The redundant constraints are identified and removed by the CCC by means of the so-called "presolve" process. The principle of the "presolve" is to give, one after the other, each flow-based constraint a very high *RAM* and check whether the flow on this line can be higher than its original *RAM* value by changing the net position values and taking all the other constraints into account. If the flow on this line is able to exceed the original *RAM* value, by a certain set of net positions without violating any of the other constraints, the flow-based constraint is not redundant and remains with its original *RAM*. If the flow on this line remains below the original *RAM* value, the flow is limited by other constraints and the flow-based constraint is redundant and will be removed ("presolved") from the flow-based domain. By respecting this "presolved" domain, the commercial exchanges also respect all the redundant constraints;
 - e. as the reference flow (F_{ref}) is the physical flow computed from the D-2 CGM, it reflects the loading of the CNEs and CNECs given the forecast commercial exchanges. Therefore, this reference flow has to be adjusted firstly to remove the effect of these commercial exchanges. The *PTDFs* remain identical in this step. Consequently, the effect on the flow-based capacity domain is a shift in the solution space. It is computed using equation 7 pursuant to Article 12(9) for the commercial situation without Core commercial exchanges:

$$\vec{F}_0 = \vec{F}_{ref} + \mathbf{PTDF} \cdot (\vec{0} - \vec{NP}_{ref})$$

Equation 14

with

\vec{F}_0	flow per CNEC in the commercial situation without Core commercial exchanges
\vec{F}_{ref}	flow per CNEC in the CGM (reference flow)
PTDF	power transfer distribution factor matrix
$\vec{0}$	Zero vector
\vec{NP}_{ref}	Core net position per bidding zone in the CGM

- f. next, the flow has to be adjusted to take into account the effect of the LTN (Long-Term Nominations) of the market time unit. The *PTDFs* remain identical in this step. Consequently, the effect on the flow-based capacity domain is another shift in the solution space:

$$\vec{F}_{LTN} = \vec{F}_0 + \mathbf{PTDF} \cdot \vec{NP}_{LTN}$$

Equation 15

with

\vec{F}_{LTN}	flow per CNEC after consideration of LTN
\vec{F}_0	flow per CNEC in the commercial situation without Core commercial exchanges
PTDF	power transfer distribution factor matrix
\vec{NP}_{LTN}	Core net position per bidding zone resulting from LTN

- g. Finally, the remaining available margin for the single day-ahead coupling shall be calculated as follows:

$$RAM_{LTN} = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_{LTN}$$

Equation 16

2. In case an external constraint is modelled as a constraint within the Core cross-zonal capacity calculation according to Article 8(4), it shall be added as an additional row to the final flow-based domain as follows:
 - a. The *PTDF* value in the column relating to the concerned bidding zone is set to 1 for an export limit and -1 for an import limit, respectively;
 - b. the *PTDF* values for all other bidding zones are set to zero;
 - c. the *RAM* value is set to the amount of the external constraint and adjusted such that the limits provided to the single day-ahead coupling mechanism refer to the increments or decrements of the net positions with respect to the net positions resulting from LTN.
3. In case costly remedial actions are needed to maintain the calculated cross-zonal capacity, these remedial actions shall be coordinated.

Article 19 Precoupling backup and default processes

1. In accordance with Article 21(3) of the CACM Regulation, this methodology includes a fallback procedure for the case where the initial capacity calculation does not lead to any results. Possible

causes can be linked, but are not limited, to a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data.

- a. When inputs for the flow-based capacity calculation are missing for less than three consecutive hours, it is possible to compute spanned flow-based parameters with an acceptable risk level, by the so-called spanning method. The spanning method is based on an intersection of previous and sub-sequent available flow-based domains, adjusted to zero balance (to delete impact of reference program). For each TSO, the CNEs and CNECs from the previous and sub-sequent timestamps are gathered and only the most constraining ones of both timestamps are taken into consideration (intersection).
- b. In case of impossibility to span the missing parameters or in the situation as described in Article 21(1)(c), Core TSOs can deploy the computation of “Default flow-based parameters”. This computation shall be based on existing Long-Term bilateral capacities. These capacities can be converted into flow-based cross-zonal capacities, via a simple linear operation. In order to optimize the capacities provided in this case to the allocation system, involved TSOs shall adjust the long-term capacities during the capacity calculation process. Eventually, delivered capacities will be equal to “LTA value + n” for each border and each direction, transformed into flow-based constraints, “n” being positive or null and computed during the capacity calculation process.

Article 20 ATCs for fallback process

1. According to Article 21(3) of the CACM Regulation, in the event that the single day-ahead coupling process is unable to produce results, a fallback solution will be applied. This process requires the determination of bilateral ATCs (hereafter referred as “ATCs for fallback process”) for each market time unit, in line with the “Core TSOs’ Proposal for Fallback Procedures”¹ as requested in Article 44 of the CACM Regulation.
2. The flow-based domains will serve as the basis for the determination of the ATCs for fallback process. As the selection of a set of ATCs from the flow-based domain leads to an infinite set of choices, an algorithm was designed that determines the ATCs for fallback process in a systematic way.
3. The following input data are required for each market time unit:
 - a. LTA values;
 - b. the final flow-based domain as described in Article 18;
 - c. the allocation constraints pursuant to Article 8(5).
4. The following outputs are the outcomes of the computation for each market time unit:
 - a. ATCs for fallback process;
 - b. constraints with zero margin after the ATCs for fallback process computation.
5. The computation of the ATCs for fallback process is part of the final flow-based computation step as described in Article 4 and thus is realised for each market time unit.
6. In the computation of the ATCs for fallback process each allocation constraint pursuant to Article 20(3)(c) is modelled as an additional row to the final flow-based domain as follows:
 - a. The *PTDF* value in the column relating to the concerned bidding zone is set to 1 for an export limit and -1 for an import limit, respectively;
 - b. the *PTDF* values for all other bidding zones are set to zero;

¹ Submitted to the Core regulatory authorities on the 26th of January 2018.

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- c. the *RAM* value is set to the amount of the allocation constraint, reduced by the sum of the ATCs on the non-Core CCR borders of the respective bidding zone.
 - 7. The computation of the ATCs for fallback process is an iterative procedure which aims at increasing the LTA domain while respecting the constraints of the final flow-based domain calculated for each market time unit as described in Article 18.
 - a. first, the remaining available margins (*RAM*) of the final flow-based domain (CNEs, CNECs, and allocation constraints) have to be adjusted to take into account the starting point of the iteration which is the LTA domain:
 - i. from the zone-to-slack *PTDFs* ($PTDF_{zone-to-slack}$), one computes zone-to-zone *PTDFs* ($pPTDF_{zone-to-zone}$), where only the positive numbers are stored:

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

Equation 17

with

$pPTDF_{zone-to-zone,A \rightarrow B}$	zone-to-zone <i>PTDF</i> of a CNE, CNEC or allocation constraint with respect to exchange from Core bidding zone <i>A</i> to <i>B</i> , only taking into account positive values
$PTDF_{zone-to-slack,k}$	zone-to-slack <i>PTDF</i> of the CNE, CNEC or allocation constraint with respect to bidding zone <i>k</i>

Only zone-to-zone *PTDFs* of Core internal borders i.e. of neighbouring bidding zone pairs are needed.

- ii. the iterative procedure to determine the ATCs for fallback process starts from the LTA domain. As such, with the impact of the LTN already reflected in the *RAMs*, the *RAMs* need to be adjusted in the following way:

$$\overrightarrow{Margin}(0) = \overrightarrow{RAM}_{LTN} - pPTDF_{zone-to-zone} * (\overrightarrow{LTA} - \overrightarrow{LTN})$$

Equation 18

with

$\overrightarrow{Margin}(0)$	Margin at the starting point, being iteration 0
$\overrightarrow{RAM}_{LTN}$	Remaining available margins after the LTN, pursuant to Article 18(1)(g)
$pPTDF_{zone-to-zone}$	matrix of zone-to-zone <i>PTDFs</i> of all CNEs, CNECs and allocation constraints with respect to exchange between all pairs of neighbouring Core bidding zones, only taking into account positive values

- b. The iterative method applied to compute the ATCs for fallback process comes down to the following actions for each iteration step i:
 - i. for each CNE, CNEC and allocation constraint of the final flow-based domain, share the remaining margin between the Core internal borders that are positively influenced with equal shares;
 - ii. from those shares of margin, maximum bilateral exchanges are computed by dividing each share by the positive zone-to-zone *PTDF*;

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- iii. the bilateral exchanges are updated by adding the minimum values obtained over all CNEs, CNECs, and allocation constraints.
 - iv. Update the margins on the CNEs, CNECs, and allocation constraints using new bilateral exchanges from step iii and go back to step i;
 - v. iterations continue until the maximum value over all constraints of the absolute difference between the margin of iterations $i+1$ and i is smaller than a stop criterion;
 - vi. the resulting ATCs for fallback process get the values that have been determined for the maximum Core internal bilateral exchanges obtained in iteration $i+1$ after rounding down to integer values;
 - vii. After algorithm execution, there are some CNEs, CNECs, and allocation constraints with no remaining available margin left. These are the limiting constraints of the ATCs for fallback process computation.

Article 21 Capacity validation methodology

1. Each TSO shall, in accordance with Article 26(1) and 26(3) of the CACM Regulation, validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders for reasons of operational security during the validation process. In exceptional situations cross-zonal capacities can be decreased by TSOs. These situations are:
 - a. an occurrence of an exceptional contingency or forced outage as defined in Article 3 of SO GL;
 - b. when costly remedial actions and non-costly remedial actions, pursuant to Article 11, that are needed to ensure the calculated capacity pursuant to Article 4(6)(d) on all CNECs, are not sufficient;
 - c. a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective;
 - d. a potential need to cover reactive power flows on certain CNECs;
2. When performing the validation, Core TSOs may consider the operational security limits, but may also consider additional grid constraints, grid models, and other relevant information. Therefore Core TSOs may use, but are not limited to, the tools developed by the CCC for analysis and might also employ verification tools not available to the CCC.
3. In case of a required reduction due to situations as defined in Article 21(1)(a), a TSO may use a positive value for *FAV* for its own CNECs or adapt the external constraints to reduce the cross-zonal capacity for its market area.
4. In case of a required reduction due to situations as defined in Article 21(1)(b), (c), and (d), a TSO may use a positive value for *FAV* for its own CNECs. In case of a situation as defined in Article 21(1)(c), a TSO may also request a common decision to launch the default flow-based parameters. In case of a situation as defined in Article 21(1)(b), a TSO may also decide not to apply the *AMR* on specific CNECs pursuant to Article 13(5).
5. Any reduction of cross-zonal capacities during the validation process shall be communicated to market participants and justified to regulatory authorities in accordance with Article 23 and Article 24, respectively. The CCC shall issue a three-monthly report for regulatory authorities that shall include the amount of reduction in cross-zonal capacity, location, and reason for reduction, pursuant to Article 26(5) of CACM. In cases of reduction due to situations as defined in Article 21(1)(c) the report shall contain measures to prevent similar mistakes.
6. The regional coordinated capacity calculator shall coordinate with neighbouring coordinated capacity calculators during the validation process, where at least the reductions in cross-zonal capacity are shared among them. Any information on decreased cross-zonal capacity from neighbouring

coordinated capacity calculators shall be provided to Core TSOs. Core TSOs may then apply the appropriate reductions of cross-zonal capacities as described in Article 21(3).

UPDATES AND DATA PROVISION

Article 22 Reviews and updates

1. Based on Article 3(f) of the CACM Regulation and in accordance with Article 27(4) of the CACM 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.
 - a. If the operational security limits, critical network elements, contingencies and allocation constraints used for the common capacity calculation need to be updated based on this review, Core TSOs shall publish the changes at least 1 week before the implementation.
 - b. Core TSOs shall include the re-assessment of the further need of allocation constraints.
2. In case the review proves the need of an update of the reliability margins, Core TSOs shall publish the changes at least 1 month before the implementation.
3. The review of the common list of remedial actions taken into account in capacity calculation shall include at least an evaluation of the efficiency of specific PSTs and the topological RAs considered during RAO.
4. In case the review proves the need for updating the application of the methodologies for determining generation shift keys, critical network elements, and contingencies referred to in Articles 22 to 24 of the CACM Regulation, changes have to be published at least 3 months before the final implementation.
5. Any changes of parameters listed in Article 27(4) of the CACM Regulation have to be communicated to market participants and Core NRAs.
6. The impact of any changes of allocation constraints and parameters listed in Article 27(4)(d) of the CACM Regulation have to be communicated to market participants and Core NRAs. If any change leads to an adaption of the methodology, Core TSOs will amend the methodology according to Article 9(13) of the CACM Regulation.

Article 23 Publication of data

1. The data as set forth in Article 23(2) will be published on a dedicated online communication platform representing all Core TSOs. To enable market participants to have a clear understanding of the published data, a handbook will be prepared by Core TSOs and published on this communication platform.
2. In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to the regulatory authorities and market participants, at least the following data items shall be published 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. initial flow-based parameters (without LTN) shall be published at D-1 before the nominations of long-term rights for each market time unit of the following day. For this set of initial flow-based parameters all long-term nominations at all Core bidding zone borders are assumed as zero (LTN=0);

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- b. the LTN for each Core border where PTRs are applied shall be published at D-1 (10:30 target time)² for each market time unit of the following day;
 - c. final flow-based parameters shall be published at D-1 (10:30 target time) for each market time unit of the following day, comprising the zone-to-slack *PTDFs* and the *RAM* for each “presolved” CNEC;
 - d. additionally, at D-1 (10:30 target time), the following data items shall be published for each market time unit of the following day:
 - i. maximum and minimum net position of each bidding zone;
 - ii. maximum bilateral exchanges between all Core bidding zones;
 - iii. ATCs for fallback process.
 - e. the following information may be published at D-1 (10:30 target time):
 - i. real names of CNEC and external constraint;
 - ii. CNE EIC code and Contingency EIC code;
 - iii. detailed breakdown of *RAM* per CNEC:
 - F_{max} , including information if it is based on permanent or temporary limits;
 - F_{LTN} ;
 - I_{max} ;
 - FRM ;
 - AMR ;
 - LTA_{margin} ;
 - FAV .
 - iv. detailed breakdown of *RAM* per external constraint:
 - F_{max} ;
 - F_{LTN} .
 - v. For each RA resulting from the RAO:
 - Type of RA;
 - Location of RA.
 - f. the following information of the D-2 CGM for each market time unit, for each Core bidding zone and each TSO may be published ex-post at D+2:
 - i. vertical load;
 - ii. production;
 - iii. best forecast of net position.
 - g. publication of the static grid model.
3. The final, exhaustive and binding list of all publication items, respective templates and the data-access points shall be developed in dedicated workshops with the Core Stakeholders and regulatory authorities. The refinement shall keep at least the transparency level reached in the operational CWE flow-based market coupling. An agreement between Stakeholders, Core regulatory authorities and Core TSOs shall be reached not later than three months before the go-live window as described in Article 25(4).

² This is CET during the winter period and CEST during the summer period.

Article 24 Monitoring and information to regulatory authorities

1. With reference to the Whereas and Article 26(5) of the CACM Regulation, monitoring data shall be provided towards the Core regulatory authorities as basis for supervising a non-discriminatory and efficient Core congestion management.
2. The provided monitoring data shall also be the basis for the biennial report to be provided according to Article 27(3) of the CACM Regulation.
3. At least, the following monitoring items related to the Core common capacity calculation shall be provided to the Core regulatory authorities on a monthly basis:
 - a. results of the hourly LTA checks;
 - b. maximum zone-to-zone *PTDF* check;
 - c. hourly Min/Max Net Positions per bidding zone;
 - d. maximum bilateral exchanges for each Core bidding zone border (hourly);
 - e. usage of the final adjustment value *FAV*;
 - f. external constraints;
 - g. hourly ATCs for the fallback process for all Core-borders;
 - h. overview of timestamps where spanning is applied (per month);
 - i. overview of timestamps for which default flow-based parameters were applied (per month);
 - j. hourly non-anonymized presolved CNECs, disclosing *PTDF*, F_{max} , *FRM*, *AMR*, LTA_{margin} , *FAV*, *RAM* and F_{ref} ;
 - k. hourly non-anonymized active CNECs, disclosing associated net positions and shadow prices;
 - l. key aggregated figures per bidding zone, for each MTU:
 - number of presolved CNECs;
 - if the *RAM* after initial computation, pursuant to Article 4(6)(a), on at least one CNEC is less than zero;
 - number of CNECs impacted by LTA inclusion;
 - number of presolved CNECs with RAs applied;
 - number of presolved CNECs without RAs applied;
 - number of presolved CNECs, breaching the max zone-to-zone *PTDF* threshold;
 - number of presolved CNECs, breaching the max zone-to-zone *PTDF* threshold due to the application of RAO;
 - number of presolved CNECs using the *FAV*;
 - number of presolved CNECs where *AMR* has not been applied, pursuant to Article 13(5);
 - if spanning technology was applied;
 - if default flow-based parameters were applied;
 - m. the impact of small zone-to-zone PTDFs;
 - n. in case of occurrence: justification when *FAV* is applied;
 - o. in case of occurrence: justification when *AMR* is not applied;
 - p. in case of occurrence: justification when the max zone-to-zone *PTDF* threshold of presolved CNECs is breached due to decisions pursuant to Article 5(7);
 - q. reductions made during the validation of cross-zonal capacity in accordance with Article 26(5) of the CACM Regulation;
 - r. the list of CNEs with the I_{max} definitions used and a justification for that, in accordance to Article 6(1);

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- s. new CNEs and contingencies that have been added to the lists, in accordance to Article 5(1) and Article 5(2), provided by the TSOs to the capacity calculation, including a justification.
 4. The final, exhaustive and binding list of all monitoring items, respective templates and the data-access point shall be developed in dedicated workshops with the regulatory authorities. An agreement between the Core regulatory authorities and Core TSOs shall be reached not later than three months before the go-live window as described in Article 25(4).

IMPLEMENTATION

Article 25 Timescale for implementation of the Core flow-based day-ahead capacity calculation methodology

Below, in accordance with Article 9(9) of the CACM Regulation, a proposed timescale for implementation is presented:

1. The TSOs of the Core CCR shall publish the day-ahead common capacity calculation methodology without undue delay after all national regulatory authorities have approved the proposed methodology or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(10), (11), and (12) of the CACM Regulation.
2. TSOs shall continue to monitor the effects and the performance of the proposed day-ahead flow-based methodology. This will be done under dedicated internal and external parallel run as well as in continuous manner once the methodology is operational. Monitoring criteria / KPIs will be defined in alignment with Core NRAs and other stakeholders (see also Table 1 – Appendix 2).
3. Before implementation of the CCM an analysis shall be made of information required to be published for each country, that sees a conflict of Article 23 with national as well as international regulations or directives (e.g. EU 114/2008, EU 1227/2011, EU 72/2009). The results of this conducted analysis by respective TSO(s) in cooperation with respective national regulatory authorities shall be presented to all Core NRAs and data publication (Article 23) shall be done in accordance to these national analysis.
4. The TSOs of the Core CCR aim to implement the day-ahead common capacity calculation methodology in order to be operationally ready for launching an external parallel run together with Core NEMOs no later than S1-2019 in accordance with Article 20(8) of CACM Regulation, except the execution of the methodology for *FRM* in line with Article 22 of the CACM Regulation. The external parallel run will be followed by an SDAC integration phase and go live preparations aiming for S1-2020 as the go-live window for the market. The milestones and the criteria for implementing the CCM are presented in Table 1 – Appendix 2. The duration of the external parallel run will be depending on the market experiences, economic welfare results, as well as the duration of the NRA approval process.
5. For the day-ahead common capacity calculation, the *FRM* defined in accordance with Article 9 shall be implemented 3 months after collecting 1 year of data since the Core flow-based day-ahead market coupling go-live.
6. For this transitional period, according to Article 25(4), the *FRM* shall be determined in accordance with Article 9.
7. After the implementation of the day-ahead common capacity calculation methodology, Core TSOs are willing to work on supporting a solution, in addition to standard hybrid coupling, that fully takes into account the influences of the adjacent CCRs during the capacity allocation i.e. the so called advanced hybrid coupling (AHC) concept, in close cooperation with adjacent involved CCRs. Core TSOs aim to be operationally compatible two (2) years after the Core flow-based day-ahead market

coupling go live for the market. The implementation of the AHC concept will be decided together with the adjacent involved CCRs.

8. The deadlines defined in the above Article 25(), Article 25(4), and Article 25(5) can be modified on request of all TSOs of the Core CCR to their national regulatory authorities, where testing period does not meet necessary conditions for implementation.

Core TSOs will implement the day-ahead common capacity calculation methodology on a Core bidding zone border only if this bidding zone border is operated in implicit allocation sessions together with all other bidding zone borders of the Core CCR.

LANGUAGE

Article 26 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 national regulatory authorities with an updated translation of the methodology.

APPENDIX 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 CACM objectives is included in the Explanatory Note.

Austria:

APG does currently not apply external constraints. Due to lack of operational experience this section is subject to changes and further amendments at a later stage.

Belgium:

Elia uses an import limit constraint which is related to the dynamic stability of the network. This limitation is estimated with offline studies which are performed on a regular basis. The offline study includes a voltage collapse analysis and a stability analysis performed in line with Article 38 of SO GL. Indeed, as a small hub, Elia is facing voltage constraints and voltage collapse risks in case of low generation within 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 Elia grid to provide a minimal dynamic stability to avoid transient phenomena. These analysis and results lead to the use of a maximum import position.

Croatia:

HOPS does not apply external constraints. Due to lack of operational experience this section is subject to change, and further amendments at a later stage.

Czech Republic:

CEPS does not apply external constraints. Due to lack of operational experience, this section is subject to change, and further amendments at a later stage.

France:

RTE does not apply external constraints.

Germany and Luxembourg:

The German and Luxembourgian TSOs do not apply external constraints for the German-Luxembourgian bidding zone.

Hungary:

MAVIR does not apply external constraints.

Netherlands:

The combination of voltage constraints and limitations following from using a linearized GSK make it necessary for TenneT TSO B.V. to apply external constraints. Voltage constraints justify the use of a maximum import position, 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 that deviations between forecasted and realized values of generation in-feed following from the linear GSK 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 Core DA FB CCM 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 TSO 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 FlowBased domain. In order to realize this, production generators can be divided in three groups based on a merit order: rigid generators that always produce at maximum power output, idle generators that are out-of-service and '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 TSO 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.) 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 forecasted power flows on 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 realized flows on particular CNECs increase to unacceptable levels with significant impact on the capacity domain. 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.

TenneT TSO B.V. understands that it may seem odd that only TenneT TSO B.V. justifies the use of external constraints based on the argument above. However, it has to be pointed out that the Netherlands is a small hub with, in comparison to other hubs, a lot of interconnection capacity which implies a very large feasibility range compared to the total installed capacity. E.g. TenneT TSO 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 the GSK at that point in time. For other hubs 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 realized generation are lower. Or in other words, the maximum feasibility range which can be covered by the GSK without increasing deviations between forecasted and realized generation to unacceptable levels, is larger than the total installed interconnection capacity for these hubs, making it not necessary to use external constraints as a measure to limit these deviations.

TenneT TSO B.V. determines the maximum import and export constraints for the Netherlands based on an off-line study, which combines a voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during extreme import and export situations in

accordance to Article 38 of SO GL. The study takes several months to be performed, shall be repeated when necessary (e.g. on the introduction of a new interconnector) but at least once a year and may result in an update of the applied values for the external constraints of the Dutch network.

Poland:

External constraints in Poland are applied as stipulated in Article 8(8) of the CCM methodology. These constraints reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the whole Polish power system to ensure secure operation. This is explained further in subsequent parts of this document.

Rationale behind implementation of external constraints on PSE side

Implementation of external constraints as applied by PSE side is related to the fact that under the conditions of integrated scheduling based market model applied in Poland (also called central dispatch system) responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in so-called self dispatch market models. The latter is usually defined up to hour-ahead time frame (including real time operations), while for PSE as Polish TSO this is extended to short (intraday and day-ahead). Thus, PSE bears the responsibility, which in self-dispatch markets is allocated to balance responsible parties (BRPs). That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which leads to implementation of external constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand³. In self-dispatch markets BRPs are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the time frame of up to one hour ahead. In a central dispatch market, in order to provide generation and demand balance, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve requirements. This is realized in an integrated scheduling process as an optimization problem called security constrained unit commitment (SCUC) and economic dispatch (SCED). Thus these two approaches (i.e. self and central dispatch market) ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

It was noted above that systemic interpretation of all network codes is necessary to ensure their coherent application. In SO GL, the definitions of specific system states involve a role of significant grid users (generating modules and demand facilities). To be in the 'normal' state, a transmission system requires sufficient active and reactive power reserves to make up for occurring contingencies (Art. 18) – the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO GL are also not defined as a closed set, as Article 25 requires each TSO to *specify the operational security limits for each element of its transmission system, taking into account **at least the following physical characteristics (...)***. The CACM definition of contingency (*identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security*) is therefore consistent with the abovementioned SO GL framework, and shows that CACM application should involve circumstances related to generation and load.

³ Residual demand is the part of end users' demand not covered by commercial contracts (generation self-schedules).

As regards the way PSE procures balancing reserves, it should be noted that the Guideline on Electricity Balancing (EB GL) allows TSOs to apply integrated scheduling process in which energy and reserves are procured simultaneously (inherent feature of central dispatch systems). In such a case, ensuring sufficient reserves requires setting a limit to how much electricity can be imported or exported by the system as a whole (explained in more detail below). If CACM is interpreted as excluding such a solution and mandating that a TSO offers capacity even if it may lead to insufficient reserves, this would make the provisions of EB GL void, and make it impossible or at least much more difficult to comply with SO GL.

Specification of security limits violated if the external constraint is not applied

With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch systems), there may be a sustained deviation from scheduled exchanges of the TSOs in question. These deviations may lead to an imbalance in the whole synchronous area, causing the system frequency to depart from its nominal level. Even if frequency limits are not violated, as a result, deviation activates frequency containment reserves, which will thus not be available for another contingencies, if required as designed. If another contingency materializes, the frequency may in consequence easily go beyond its secure limits with all related negative consequences. This is why such a situation can lead to a breach of operational security limits and must be prevented by keeping necessary reserves within all bidding zones, so that no TSO deviates from its schedule in a sustained way (i.e. more than 15 minutes, within which frequency restoration reserve shall be fully deployed by given TSO). Finally, the inability to maintain scheduled area balances resulting from insufficient operational reserves will lead to uncontrolled changes in power flows, which may trigger lines overload (i.e. exceeding the thermal limits) and as a consequence can lead to system splitting with different frequencies in each of the subsystems. The above issue affects PSE in a different way from other Core TSOs due to reasons explained in the subsequent paragraph.

PSE role in system balancing

PSE directly dispatches all major generating units in Poland taking into account their operational characteristics and transmission constraints in order to cover the load forecasted by PSE, having in mind adequate reserve requirements. To fulfill this task PSE runs the process of operational planning, which begins three years ahead with relevant overhaul (maintenance) coordination and is continued via yearly, monthly and weekly updates to day-ahead SCUD and ED. The results of this day-ahead market are then updated continuously in intraday time frame up to real time operation.

In a yearly timeframe PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that on average the minimum year ahead generation reserve margin⁴ over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day⁵, if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

⁴ The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point II.4.3.4.18). It is subject to change depending on the results of the development of operational planning processes.

⁵ The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point II.4.3.4.18) and currently set at 17% and 14% respectively.

The day-ahead SCUC process aims to achieve a set value of spinning reserve⁶ (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except CHP plants as they operate mainly according to heat demand). The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.

The further updates of SCUC/ED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.). It allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW, i.e. potential loss of the largest generating unit, currently 850 MW (subject to change as new units are commissioned) and ca. 150 MW of primary control reserve (frequency containment reserve) being PSE's share in RGCE.

Determination of external constraints in Poland

When determining the external constraints, the Polish TSO takes into account the most recent information on the aforementioned 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 horizons.

External constraints are bidirectional, with independent values for each market time unit, and separately for directions of import to Poland and export from Poland.

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

$$\text{EXPORT}_{\text{constraint}} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \quad (1)$$

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

Where:

P_{CD} Sum of available generating capacities of centrally dispatched units as declared by generators⁷

⁶ The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change – see footnote 2.

⁷ 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.

P_{CDmin}	Sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions).
P_{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 up regulation
$P_{DOWNres}$	Minimum reserve for down regulation

For illustrative purposes, the process of practical determination of external constraints in the framework of day-ahead transfer capacity calculation is illustrated below: figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the next day is developed by TSO day ahead in the morning in order to determine reserves in generating capacities available for potential exports and imports, respectively, for day ahead market. For the intraday market, the same method applies *mutatis mutandis*.

External constraint in export direction is applicable if $\Delta Export$ is lower than the sum of transfer capacities on all Polish interconnections in export direction. External constraint in import direction is applicable if $\Delta Import$ is lower than the sum of transfer capacities on all Polish interconnections in import direction.

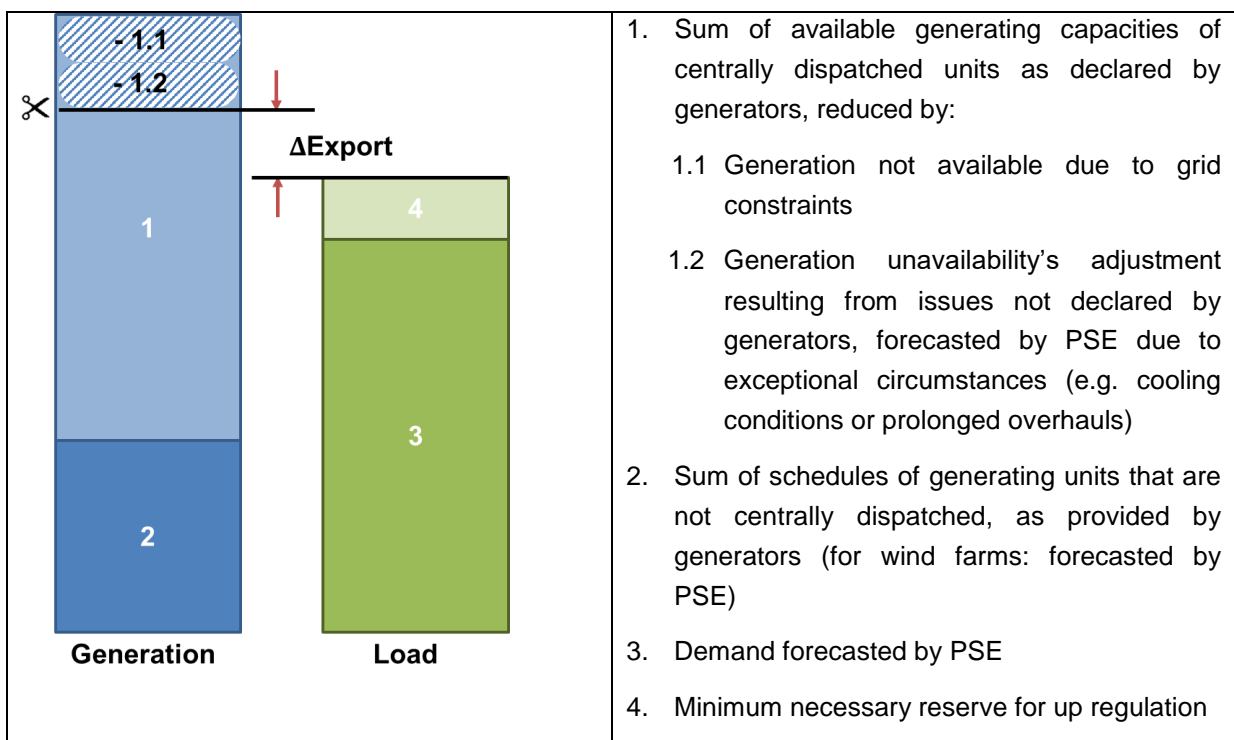


Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of day-ahead transfer capacity calculation.

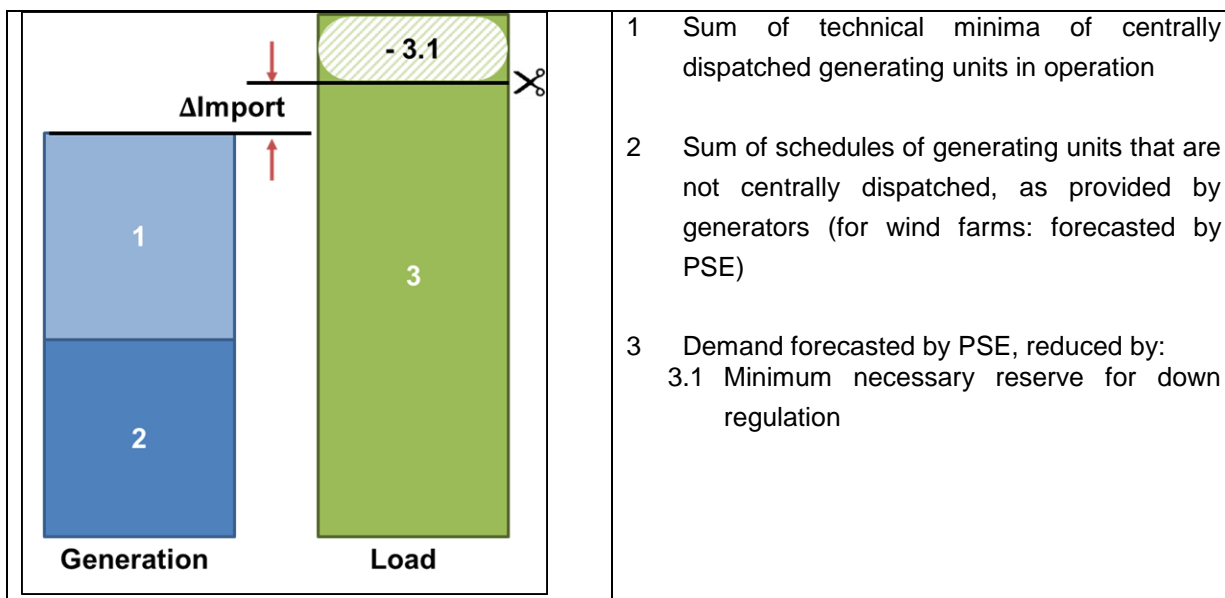


Figure 2: Determination of external constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day-ahead transfer capacity calculation.

Frequency of re-assessment

External constraints are determined in a continuous process based on the most recent information, for each capacity allocation time horizon, 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 market time unit, and separately for directions of import to Poland and export from Poland.

Impact of external constraints on single day-ahead coupling and single intraday coupling

Allocation constraints in form of external constraints as applied by PSE do not diminish the efficiency of day-ahead and intraday market coupling process. Given the need to ensure adequate availability of generation and generation reserves within Polish power system by PSE as TSO acting under central-dispatch market model, and the fact that PSE does not purchase operational reserves ahead of market coupling process, imposing constraints on maximum import and export in market coupling process – if necessary – is the most efficient manner of reconciling system security with trading opportunities. This approach results in at least the same level of generating capacities participating in cross border trade as it is the case in self-dispatch systems, where reserves are bought in advance by BRPs or TSO, so they do not participate in cross-border trade, either. Moreover, this allows to avoid competition between the TSO and market participants for generation resources.

It is to be underlined that external constraints applied in Poland will not affect the ability of any CORE country to exchange energy, since these constraints only affect Polish export and/or import. Hence, transit via Poland will be possible in case of external constraints applied.

Impact of external constraints on neighboring CCRs

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 border (i.e. Core, Baltic and Hansa).

It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global

allocation 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 generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.

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 market time units (hours) of the respective allocation day.

Why the allocation constraints cannot be efficiently translated into capacities of critical network elements offered to the market

Use of capacity allocation constraints aims to ensure economic efficiency of the market coupling mechanism on these interconnectors while meeting the security requirements of electricity supply to customers. If the generation conditions described above were to be reflected in cross-border capacities offered by PSE in form of an appropriate adjustments of border transmission 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 FB approach, this would need to be done on each critical branch in a form of RAM reductions. 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 – overstated on one interconnection and underestimated on the other, or vice versa. Consequently, application of allocation constraints to tackle the overall Polish system constrains separately from the capacities on individual lines allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.

Romania:

Transelectrica does not apply external constraints.

Slovakia:

SEPS does currently not apply external constraints. Due to lack of operational experience this section is subject to changes and further amendments at a later stage.

Slovenia:

ELES does not apply external constraints.

APPENDIX 2 - Implementation milestones and criteria for implementation of the day-ahead CCM

Table 1. Implementation milestones and criteria for implementation of the day-ahead CCM.

#	Milestone	Criteria to be met before moving to the next milestone
1	Internal parallel run	<ul style="list-style-type: none">• Industrial tool is ready to be used;• The flow-based capacity calculation process is a close-to-operational process, that will be performed by TSO operators;• Market simulation results can be published for the stakeholders on a daily basis.
2	External parallel run	<ul style="list-style-type: none">• Minimum of six months of external parallel runs, where:<ul style="list-style-type: none">◦ flow-based is reliable in producing capacity calculation parameters and results.
3	Day-ahead CCM go-live	<ul style="list-style-type: none">• Operational readiness to introduce advanced hybrid coupling in the daily capacity calculation and allocation process;• Alignment and agreement among the relevant CCRs.
4	Day-ahead CCM compatibility with Advanced Hybrid Coupling	<ul style="list-style-type: none">• Go live is to be decided in alignment with neighboring CCRs