Core CCR TSOs' proposal for the 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

15 September 2017

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

WHEREAS

1. This document is the proposal developed by the transmission system operators of the Core CCR (hereafter referred to as “Core TSOs”) regarding the development of 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 proposal is hereafter referred to as “day-ahead common capacity calculation methodology Proposal”.
2. The day-ahead common capacity calculation methodology Proposal 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 proposal for a day-ahead common capacity calculation methodology to ensure efficient, transparent and non-discriminatory capacity allocation.
3. Article 20(2) of the CACM Regulation stipulates “all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region.”
4. According to Article 9(9) of the CACM Regulation, the expected impact of the day-ahead common capacity calculation methodology Proposal 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.
5. The day-ahead common capacity calculation methodology Proposal 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.
6. The day-ahead common capacity calculation methodology Proposal 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 day-ahead timeframe within the operational security limits.
7. The day-ahead common capacity calculation methodology Proposal 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 Proposal 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 after the consultation period where applicable.

9. Regarding the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation), the day-ahead common capacity calculation methodology Proposal determines the main principles and main processes for the day-ahead timeframe. The day-ahead common capacity calculation methodology Proposal 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 Proposal 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 Proposal, 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 Proposal 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 Proposal contributes to the general objectives of the CACM Regulation to the benefit of all market participants and electricity end consumers.
14. The foreseen timeframe of 10 months in the CACM Regulation to come up with a day-ahead and intraday common capacity calculation methodology Proposal covering 16 TSOs from 13 countries is highly challenging. The Core TSOs need more time to further develop and perform experimentations on the day-ahead and intraday common capacity calculation methodologies. This day-ahead common capacity calculation methodology Proposal is submitted as an initial deliverable since further work is required in accordance with Article 20 of the CACM Regulation. The Core TSOs also would like to highlight that experimentation results from the parallel run with market participants are required to ensure both the well-functioning and acceptability of the day-ahead common capacity calculation methodology. After finalizing the methodology and analyzing the experimentation results, the Core TSOs will submit an improved day-ahead common capacity calculation methodology Proposal to the Core regulatory authorities after having consulted market participants.

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

GENERAL PROVISION

Article 1 Subject matter and scope

The day-ahead common capacity calculation methodology Proposal shall be considered as a proposal of Core TSOs in accordance with Article 20(2) 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 Proposal, 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:

a. '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;
b. 'available transmission capacity' (hereinafter 'ATC') means the transmission capacity that remains available after allocation procedure and which respects the physical conditions of the transmission system;
c. 'balance responsible party' (hereinafter 'BRP') means a market participant or its chosen representative responsible for its imbalances;
d. 'CCC' is coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation;
e. 'CCR' is the capacity calculation region as defined in Article 2(3) of the CACM Regulation;
f. '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;
g. 'CGM' is the common grid model as defined in Article 2(2) of the CACM Regulation;
h. 'CGMM' is the common grid model methodology as submitted to all regulatory authorities by all TSOs on 27 May 2016 as amended;
i. 'CNE' is a critical network element;
j. 'CNEC' is a critical network element with a contingency;
k. '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;
l. Core TSOs are 50Hertz Transmission GmbH ("50Hertz"), Amprion GmbH ("Amprion"), Austrian Power Grid AG ("APG"), CREOS Luxembourg S.A. ("CREOS"), ČEPS, a.s. ("ČEPS"), Eles, d.o.o., sistemski operater prenosnega elektroenergetskega omrežja ("ELES"), Elia System Operator S.A. ("ELIA"), Croatian Transmission System Operator Ltd. (HOPS d.o.o.) ("HOPS"), MAVIR Hungarian Independent Transmission Operator Company Ltd. ("MAVIR"), Polskie Sieci Elektroenergetyczne S.A. ("PSE"), RTE Réseau de transport d'électricité ("RTE"), Slovenská elektrizačná prenosová sústava, a.s. ("SEPS"), TenneT TSO GmbH ("TenneT GmbH"), TenneT TSO B.V. ("TenneT B.V."), National Power Grid Company Transelectrica S.A. ("Transelectrica"), TransnetBW GmbH ("TransnetBW")
m. '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;
n. '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;
o. 'external constraint' (hereinafter 'EC') means the maximum import and/or export constraints of given bidding zone;
p. '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;

q. ‘D-1’ means day-ahead;
r. ‘D-2’ means two-days ahead;
s. ‘FAV’ is the final adjustment value;
t. ‘flow-based domain’ means the set of constraints that limits the cross-zonal capacity calculated with a flow-based approach;
u. ‘F_{max}’ is the maximum admissible power flow;
v. ‘F_i’ is the expected flow in commercial situation i;
w. ‘F_{ref}’ is the reference flow;
x. ‘F_{LTN}’ is the expected flow after long term nominations;
y. ‘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;
z. ‘GSK’ is the generation shift key as defined in Article 2(12) of the CACM Regulation;
aa. ‘HVDC’ is a high voltage direct current transmission system;
bb. ‘IGM’ is the individual grid model as described in Article 2(1) of the CACM Regulation;
cc. ‘I_{max}’ is the maximum admissible current;
dd. ‘LTA’ are the long term allocated capacities;
ee. ‘LTN’ are the long term nominations submitted by market participants based on LTA ;
ff. ‘merging agent’ as defined in Article 20 of the CGMM;
gg. ‘neighbouring bidding zone pairs’ means the bidding zones which have a common commercial border;
hh. ‘MTU’ is the market time unit;
ii. ‘MP’ is the market party;
jj. ‘NP’ is the net position;
kk. ‘presolved domain’ means the final set of binding constraints for capacity allocation after pre-solving process ;
ll. ‘presolving process’ means that the redundant constraints are identified and removed from flow-based domain by CCC;
mm. ‘previously allocated capacities’ means the long term capacities which have already been allocated in previous (yearly and/or monthly) time frames;
nn. ‘PST’ is a phase shifting transformer;
oo. ‘$PTDF$’ is the power transfer distribution factor;
pp. ‘PTR’ is the physical transmission right;
qq. ‘RA’ means a remedial action as defined in Article 2(13) of the CACM Regulation;
rr. ‘RAM’ is the remaining available margin;
ss. ‘RAO’ is the remedial action optimization;
tt. ‘SA’ is a shadow auction as defined in the Core CCR TSOs’ fallback procedures proposal in accordance with Article 44 of the CACM Regulation;
uu. ‘slack node’ means the reference node used for determination of the $\boldsymbol{PTDF}$ matrix, i.e. shifting the power infeed of generators up results in absorption of the power shift in the slack node;
vv. ‘spanning’ means the precoupling backup solution in situation 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;
ww. ‘SO GL’ is the System Operation Guideline (Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation);

xx. ‘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;

yy. ‘static grid model’ is a list of relevant grid elements of the transmission system, including their electrical parameters;

zz. ‘U’ is the reference voltage;

aaa. ‘vertical load’ means the total amount of electricity which exits the national transmission system to connected distrubutions systems, end consumers connected to transmission system and to electricity producers for consumption in the generation of electricity;

bbb. ‘zone-to-slack $PTDF$’ means the power transfer distribution factor of a commercial exchange between a bidding zone and slack node;

ccc. ‘zone-to-zone $PTDF$’ means the power transfer distribution factor of a commercial exchange between two bidding zones;

ddd. ‘preventive’ remedial action means a remedial action which is applied before a contingency occurs;

eee. ‘PX’ is the power exchange for spot markets;

fff. ‘curative’ remedial action means a remedial action which is applied after a contingency occurs;

ggg. the notation x denotes a scalar;

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

iii. the notation $\boldsymbol{x}$ denotes a matrix.

2. In this day-ahead common capacity calculation methodology Proposal, 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 Proposal; 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 then in force.

Article 3 Application of this proposal

This day-ahead common capacity calculation methodology Proposal 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 proposal.

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 20(3) of the CACM Regulation.
2. For the day-ahead common capacity calculation in the Core CCR, the high level process flow includes four steps until the final flow-based domain for the single day-ahead coupling process is set:
   a. first of all, the input as defined in Article 12 is delivered for the inital flow-based computation leading to preliminary results of capacity calculation;
   b. after the initial flow-based computation, the second process step selects remedial actions (RAs) resulting from the remedial action optimization as defined in Article 15;

c. the third process step takes additionally the previously allocated capacities from long term auctions (LTA) and nominations (LTN) including remedial actions (RAs) into account which are the inputs for the final flow-based computation;
d. the fourth and last step is the validation of the final cross-zonal capacities.

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.
   A CNE can be:
   - a cross-zonal network element;
   - an internal line; 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.
   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 critical network elements shall be done from the list of CNEs defined in Article 5(1) and from the list of contingencies as defined in Article 5(2). Besides, it shall follow the rules established in Article 75 of SO GL, which means that the contingencies of one TSO can be associated to another TSO. The outcome of this association is the initial pool of CNECs.
4. Core TSOs shall distinguish between:
   a. the CNECs of the initial pool that are significantly influenced by the changes in bidding zone net positions. 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 13 higher than a common threshold to be considered as significantly influenced by the changes in bidding zone net positions, in accordance with Article 29(3) of the CACM Regulation. The CNECs of this category will be taken into account in all the steps of the common capacity calculation and will determine the cross-zonal capacity;
   b. the CNECs of the initial pool that are significantly influenced by the RAs defined in Article 11, but are not significantly influenced by the changes in bidding zone net positions. The CNECs of this category may only be monitored during the RAO and will not limit the cross-zonal capacity;
   c. the CNECs of the initial pool that are neither described in Article 5(4)(a) nor Article 5(4)(b). The CNECs of this category will not be taken into account in the day-ahead common capacity calculation.
5. In case a TSO decides to keep a CNEC within the list described in Article 5(4)(a) which is not significantly influenced by the changes in bidding zone net positions, the respective TSO shall

provide Core regulatory authorities with a clear description of the specific situation that led to this decision in the monitoring report defined in Article 24.

6. In case a TSO decides to exclude a CNEC within the list described in Article 5(4)(a) which is significantly influenced by the changes in bidding zone net positions, the respective TSO shall provide to Core regulatory authorities with a clear description of the specific situation that led to this decision in the monitoring report defined in Article 24.
7. In response to Article 21(1)(b)(ii) of the CACM Regulation, Core TSOs shall ensure a minimum RAM for the CNECs determining the cross-zonal capacity before allocating commercial exchanges, in addition to applying the common threshold set in Article 5(4)(a).
8. Core TSOs shall further detail the open issues related to the methodology for CNEC selection (such as maximum zone-to-zone $PTDF$ and the minimum RAM values, etc.) as follows:
    a. Core TSOs shall submit a 'Core TSOs' deliverable report' to regulatory authorities in Q1 2018 describing a detailed approach for finalization of the open issues related to CNEC selection (such as the common maximum zone-to-zone $PTDF$ and the minimum RAM values, etc.);
    b. the following steps shall be included and specified in the Core TSOs' deliverable report:
        i. assessment and definition of options, safeguarding the capacities provided to the market and reflecting TSOs obligations related to security of supply;
        ii. time line and method(s) for conducting experimentation and studies resulting in a feasibility report;
            1. the feasibility report shall be discussed with and concluded upon between Core TSOs and Core regulatory authorities and shall be shared afterwards with the market participants in the respective stakeholder meetings.
    c. Core TSOs shall conclude on finalization of the methodology, consult it with market participants and propose the updated *Methodology for critical network elements and contingencies selection* to regulatory authorities;
    d. regulatory authorities shall approve the proposed update of this Article.

Article 6 Methodology for operational security limits

1. In accordance with Article 23 of the CACM Regulation, Core TSOs shall determine the operational security limits at the level used in operational security analysis carried out in line with Article 72 of the SO GL which also means that 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;
        ii. fixed limits for all market time units of a specific season;
        iii. a value per market time unit depending on the weather forecast.
    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} describes the maximum admissible power flow on a CNE. F_{max} is calculated from I_{max} by the given formula:

$$F_{max} = \sqrt{3} \times I_{max} \times U$$

Equation 1

where I_{max} is the maximum admissible current in kA of a critical network element (CNE). The values for the reference voltage U (in kV) are fixed values for each CNE.

Article 7 Final Adjustment Value

1. The maximum admissible power flow 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;
    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 to 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) of the CACM Regulation, besides active power flow limits on CNEs, other specific limitations may be necessary to maintain the secure grid operation. Since such specific limitations cannot be efficiently transformed into operational security limits of individual CNEs, they are expressed as maximum import and export constraints of bidding zones. These allocation constraints are called external constraints.
    a. external constraints are determined by Core TSOs and taken into account during the single day-ahead coupling in addition to the power flow limits on CNECs.
    b. this external constraint can be modelled either
        i. within the Core cross-zonal capacity, thus limiting the Core net position of the respective bidding zone, or
        ii. as a constraint on the global net position, thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of the single day-ahead coupling.
2. A TSO may use external constraints in order to avoid situations which 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.
3. 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 linearilized GSK, leading to a situation which could not be validated as safe by the concerned TSO. This is applicable for TenneT B.V.
4. A TSO may use external constraints in case of a central dispatch model that needs a minimum level of operational reserve for balancing. In central dispatch systems, BRPs do not need to submit balanced schedules. Instead, the TSO acts as the BRP responsible for the power system balance. In order to execute this task, the TSO in a central dispatch system needs to ensure the availability of sufficient upward or downward regulation reserves for maintaining secure power system operation.

The external constraint introduced varies depending on the foreseen balancing situation. This is applicable for PSE.

5. The details for the use of external constraints as described in Article 8(2), 8(3) and 8(4) are set forth in Appendix 1.
6. A TSO may discontinue the usage of an external constraint as described in Article 8(2), 8(3) and 8(4). The concerned TSO shall communicate this change to the Core regulatory authorities and to the market participants at least one month before its implementation.

Article 9 Reliability margin methodology

1. The day-ahead common capacity calculation methodology Proposal is based on forecast models of the transmission system. The inputs are created two days before the delivery date of electricity 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 two-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 computed (F_{ref}) and then adjusted to realised commercial exchanges inside the Core CCR with the $PTDF$s calculated during the day-ahead common capacity calculation as described in Article 13. 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.

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

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)
$\boldsymbol{PTDF}$	power transfer distribution factor matrix
$\overrightarrow{NP}_{real}$	Core net position ber bidding zone in the realised commercial situation
$\overrightarrow{NP}_{ref}$	Core net position ber 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, 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 on the associated contingency;
    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;
    iii. or undertake an operational adjustment on the values derived from Article 9(2)(b)(i) or 9(2)(b)(ii), which can set the FRM values between 5% and 20% of the F_{max} calculated under normal weather conditions.

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 will either use the FRM values already in operation in existing flow-based market coupling initatives or 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:
    a. Core external transactions (out of Core CCR control: both between Core CCR and other CCRs as well as among TSOs outside the Core CCR);
    b. generation pattern including specific wind and solar generation forecast;
    c. generation shift key;
    d. load forecast;
    e. topology forecast;
    f. unintentional flow deviation due to the operation of load frequency controls; and
    g. 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 further detail and justify the reliability margin methodology considering the justification of the common risk level applying the following procedure:
    a. Core TSOs shall submit a 'Core TSOs deliverable report' to regulatory authorities in Q1 2018 describing amongst others the justification of the common risk level;
    b. the following steps shall be included and specified in the deliverable report:
        i. assessment and definition of options, safeguarding the capacities provided to the market and reflecting TSOs obligations related to security of supply;
        ii. time line and method(s) for conducting experimentation and studies resulting in a feasibility report;
            1. the feasibility report shall be discussed with and concluded upon between Core TSOs and Core regulatory authorities and shall be shared afterwards with the market participants in the respective stakeholder meetings.

c. Core TSOs shall conclude on finalization of the methodology, consult it with market participants and propose the updated *Reliability margin methodology* to regulatory authorities;
d. regulatory authorities shall approve the proposed update of this Article.

Article 10 Generation shift keys methodology

1. In accordance with Article 24 of the CACM Regulation, Core TSOs developped the following methodology to determine the common generation shift key:
   a. 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;
   b. each Core TSO shall aim to find a GSK that minimizes the error of dispatch forecast;
   c. Core TSOs shall define a constant generation shift key per market time unit;
   d. Core TSOs belonging to the same bidding zone shall determine a common methodology that translates a change in the net position to a specific change of generation or load in the common grid model.
2. For the application of the methodology, Core TSOs may define:
   a. generation shift keys proportional to the actual generation and potentially consumption in the D-2 CGM for each market time unit;
   b. generation shift keys for each market time unit with fixed values based on the D-2 CGM and based on the maximum and minimum net positions of their respective bidding zones; or
   c. generation shift keys with fixed values based on the D-2 CGM for each market time unit.
3. During the different implementation phases the application of the current GSK methodology shall be continuously tested and improved with the future target of harmonization as far as possible.
4. Core TSOs shall further detail the harmonized approach for the generation shift keys methodology applying the following procedure:
   a. Core TSOs shall submit a ‘Core TSOs deliverable report’ to regulatory authorities in Q1 2018 describing amongst others a detailed TSO-specific overview of each GSK;
   b. the following steps shall be included and specified in the deliverable report:
      i. assessment and definition of options, safeguarding the capacities provided to the market and reflecting TSOs obligations related to security of supply;
      ii. time line and method(s) for conducting experimentation and studies resulting in a feasibility report;
         1. the feasibility report shall be discussed with and concluded upon between Core TSOs and Core regulatory authorities and shall be shared afterwards with the market participants in the respective stakeholder meetings.
   c. Core TSOs shall conclude on finalization of the methodology, consult it with market participants and propose the updated *Generation shift keys methodology* to regulatory authorities;
   d. regulatory authorities shall approve the proposed update of this Article.

Article 11 Methodology for remedial actions in capacity calculation

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

3. 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;
4. In accordance with Article 25(5) of the CACM Regulation, the day-ahead common capacity calculation takes non-costly RAs into account. 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.
5. In accordance with Article 25(6) the RAs taken into account are the same for day-ahead and intra-day common capacity calculation, depending on their technical availability.
6. The RAs can be preventive or curative, i.e. affecting all CNECs or only pre-defined contigency cases, respectively.
7. The optimized application of RAs is performed in accordance with Article 15.

Article 12 Provision of the inputs

1. The TSOs of the Core CCR shall provide the coordinated capacity calculator before a certain deadline commonly agreed between the TSOs and the coordinated capacity calculator the following 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.
2. 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.
3. When applicable, 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.
4. Core TSOs shall send for each time unit of the day the long term allocated capacities (LTA) and nominated capacities (LTN) to the CCC.

DETAILED DESCRIPTION OF THE CAPACITY CALCULATION APPROACH

Article 13 Mathematical description of the capacity calculation approach

1. In accordance with Article 21(b)(i) of the CACM Regulation, for each CNEC defined in Article 5(3), Core TSOs shall calculate the influence of the bidding zone net position changes on its power flow. This influence is called 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.
2. 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:

$$\boldsymbol{PTDF}_{zone-to-slack} = \boldsymbol{PTDF}_{node-to-slack} \cdot \boldsymbol{GSK}_{node-to-zone}$$

Equation 3

with

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

3. $PTDFs$ 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 $PTDF_{A\to B,l}$ represents the influence of a variation of a commercial exchange from A to B on a CNE or CNEC l. The zone-to-zone $PTDF_{A\to B,l}$ can be linked to zone-to-slack $PTDFs$ as follows:

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

Equation 4

4. The maximum zone-to-zone $PTDF$ of a CNE or a CNEC is the maximum influence that a Core exchange can have on the respective CNE or CNEC:

$$\text{maximum zone-to-zone } \boldsymbol{PTDF} = \max_{\boldsymbol{A\in BZ}}(\boldsymbol{PTDF}_{\boldsymbol{A,l}}) - \min_{\boldsymbol{A\in BZ}}(\boldsymbol{PTDF}_{\boldsymbol{A,l}})$$

Equation 5

with

$PTDF_{A,l}$	zone-to-slack $PTDF$ of bidding zone A on a CNE or CNEC l
BZ	list of Core bidding zones

5. The reference flow (F_{ref}) is the active power flow on a CNE or a CNEC based on the CGM. In case of a CNE, F_{ref} is directly simulated from the CGM whereas in case of a CNEC, F_{ref} is simulated with the specified contingency.
6. 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 CGM (reference commercial situation) and the commercial situation i:

$$\vec{F}_i = \vec{F}_{ref} + \boldsymbol{PTDF} \times \left(\overrightarrow{NP}_i - \overrightarrow{NP}_{ref}\right)$$

Equation 6

with

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

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

7. 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 reliability margin (FRM), the final adjustment value (FAV) and the expected flow (F_i) with the following equation:

$$\boldsymbol{RAM_i = F_{max} - FRM - FAV - F_i}$$

Equation 7

Article 14 Long term allocated capacities (LTA) inclusion

1. In accordance with Article 21(b)(iii) of the CACM Regulation, Core TSOs developed the following rules for taking into account the previously allocated cross-zonal capacity:
   a. The objective of the rule is to verify that the RAM of each CNE or CNEC remains positive 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.
2. The following equation is applied to all possible combinations of net positions resulting from full utilization of previously allocated capacities on all commercial borders:

$$\vec{F}_i = \vec{F}_{ref} + \boldsymbol{PTDF} \cdot \left(\overrightarrow{NP}_i - \overrightarrow{NP}_{ref}\right)$$

Equation 8

with

$\vec{F}_i$	flow per CNEC in LTA capacity utilization combination i
$\vec{F}_{ref}$	flow per CNEC in the CGM
$\boldsymbol{PTDF}$	power transfer distribution factor matrix
$\overrightarrow{NP}_i$	Core net position per bidding zone in LTA capacity utilization combination i
$\overrightarrow{NP}_{ref}$	Core net position ber bidding zone in the CGM

Then the following equation is checked:

$$\boldsymbol{RAM_i = F_{max} - FRM - FAV - F_i}$$

Equation 9

3. If at least one of the remaining available margins RAM_i is smaller than zero, this means the previously allocated capacities are not fully covered by the flow-based domain. In this case one of the two following methods can be applied during final flow-based computation: a TSO can either decide to increase the RAM of limiting CNEs using the FAV concept to compensate the negative RAM_i, or create virtual constraints which replace CNEs or CNECs for which the RAM_i is negative.
4. In exceptional circumstances each Core TSO may, for reasons of security of supply and pursuant to Article 76 of the SO GL, request a minimum import capacity for one or more MTUs. In this case $\overrightarrow{\mathrm{NP}_\mathrm{i}}$ in Equation 8 will be adjusted accordingly. The acceptance of the minimum import capacity is subject to positive validation in accordance with Article 21. Costs stemming from accommodating the request shall be covered by the methodology to be developed according to Article 74(1) of the CACM Regulation.

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 Proposal shall describe the rules on the adjustment of power flows on critical network elements due to remedial actions:
    a. the coordinated application of RAs shall aim at optimizing cross-zonal capacity in the Core CCR. The remedial action optimization (RAO) itself consists of a coordinated optimization of cross-zonal capacity within the Core CCR by means of enlarging the flow-based domain ;
    b. the optimization shall be an automated, coordinated and reproducible process that applies RAs defined in accordance with Article 11; and
    c. the applied RAs should be transparent to all TSOs, also of adjacent CCRs.
2. Core TSOs shall further detail and justify the remedial action optimization methodology applying the following procedure:
    a. Core TSOs shall submit a ‘Core TSOs deliverable report’ to regulatory authorities in Q1 2018 describing amongst others the remedial action optimization methodology and the objective function;
    b. the following steps shall be included and specified in the deliverable report:
        i. assessment and definition of options, safeguarding the capacities provided to the market and reflecting TSOs obligations related to security of supply;
        ii. time line and method(s) for conducting experimentation and studies resulting in a feasibility report;
            1. the feasibility report shall be discussed with and concluded upon between Core TSOs and Core regulatory authorities and shall be shared afterwards with the market participants in the respective stakeholder meetings.
    c. Core TSOs shall conclude on finalization of the methodology, consult it with market participants and propose the updated *Rules on adjustment of power flows on critical network elements due to remedial actions* to regulatory authorities;
    d. regulatory authorities shall approve the proposed update of this Article.

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 flow-based Core CCR.

2. Core TSOs shall take into account the impact of an exchange over an cross border HVDC interconnector on all CNEs within the process of capacity 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 considers the impact of exchanges between two capacity calculation regions (as the case may be belonging to two different synchronous areas) e.g. an ATC area and a flow-based area, implying that the influence of exchanges in one CCR (ATC or flow-based area) is taken into account in the flow-based calculation of another CCR. 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 will be added. These 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.
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 will 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 captured in the D-2 CGM and underlying schedules, which are used as a starting point for 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 6 and 7). 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 allocation of capacities. The feasibility of AHC will be studied in accordance with Article 24(5).

4. In accordance with Article 20(5) of the CACM Regulation, future merging of adjacent CCRs that apply a flow-based capacity calculation will, in addition to advanced hybrid coupling, facilitate a more efficient sharing of power flow capabilities among different borders.

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. execution of the rules for previously allocated capacity in Article 14;
   b. only the constraints that are most limiting the net positions need to be respected in the single day-ahead coupling: the non-redundant constraints (or the “presolved” domain). As a matter of fact, by respecting this “presolved” domain, the commercial exchanges also respect all the other constraints. The redundant constraints are identified and removed by the CCC by means of the so-called “presolve” process;
   c. 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 of the reference day. Therefore, this reference flow has to be adjusted to take into account the effect of the LTN (Long Term Nominations) of the MTU (Market Time Unit) instead. The $PTDFs$ remain identical in this step. Consequently, the effect on the flow-based capacity domain is a shift in the solution space.
   For the LTN adjustment, the power flow of each CNE and CNEC is calculated with the linear equation described in Article 14:

$$\vec{F}_{LTN} = \vec{F}_{ref} + \boldsymbol{PTDF} \cdot \left(\overrightarrow{NP}_{LTN} - \overrightarrow{NP}_{ref}\right)$$

Equation 10

with

$\vec{F}_{LTN}$	flow per CNEC after consideration of LTN
$\vec{F}_{ref}$	flow per CNEC in the CGM
$\boldsymbol{PTDF}$	power transfer distribution factor matrix
$\overrightarrow{NP}_{LTN}$	Core net position per bidding zone resulting from LTN
$\overrightarrow{NP}_{ref}$	Core net position ber bidding zone in the CGM

   d. finally the remaining available margin for the day-ahead single coupling can be calculated as follow:

$$\boldsymbol{RAM_{LTN} = F_{max} - FRM - FAV - F_{LTN}}$$

Equation 11

   e. in addition, the external constraints are 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.

Article 19 Precoupling backup and default processes

1. In accordance with Article 21(3) of the CACM Regulation, this proposal includes a fallback procedure for the case where the initial capacity calculation does not lead to any results. Possible cases 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 flow-based parameters 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 20(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 easily 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 will 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. Involved TSOs, for reasons of security of supply, cannot commit to any value for "n" at this stage.

Article 20 ATCs for shadow auctions

1. According to Article 44 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 shadow auctions") for each market time unit, what is in line with the "Core TSOs' Proposal for Fallback Procedures"[1].

2. The flow-based domains will serve as the basis for the determination of the ATCs for shadow auctions. 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 shadow auctions 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.
4. The following outputs are the outcomes of the computation for each market time unit:
   a. ATCs for shadow auctions;
   b. constraints with zero margin after the ATCs for shadow auctions computation.
5. The computation of the ATCs for shadow auctions is part of the final flow-based computation step as described in Article 4 and thus is realised for each market time unit.
6. The computation of the ATCs for shadow auctions 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 external constraints) have to be adjusted to take into account the starting point of the iteration which is the LTA domain:

[1] Submitted to the Core regulatory authorities on the 17th of May 2017.

i. from the zone-to-slack $PTDFs$ ($PTDF_{z2s}$), one computes zone-to-zone $PTDFs$ (p$PTDF_{z2z}$), where only the positive numbers are stored:

$$pPTDF_{z2z,A\rightarrow B} = \max\left(0, PTDF_{z2s,A} - PTDF_{z2s,B}\right)$$

Equation 12

with

$pPTDF_{z2z,A\rightarrow B}$	zone-to-zone $PTDF$ of a CNEC with respect to exchange from Core bidding zone A to B, only taking into account positive values
$PTDF_{z2s,\mathrm{k}}$	zone-to-slack $PTDF$ of the CNEC with respect to bidding zone k

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 shadow auctions 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:

$$\overrightarrow{Margin}(0) = \overrightarrow{RAM}_{LTN} - \boldsymbol{pPTDF}_{z2z} * \left(\overrightarrow{LTA} - \overrightarrow{LTN}\right)$$

Equation 13

b. The iterative method applied to compute the ATCs for shadow auctions comes down to the following actions for each iteration step i:
    i. for each CNE, CNEC and external 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 $PTDF$;
    iii. the bilateral exchanges are updated by adding the minimum values obtained over all CNEs, CNECs and external constraints. Update the margins on the CNEs, CNECs and external constraints using new bilateral exchanges from step 3 and go back to step 1;
    iv. 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;
    v. the resulting ATCs for shadow auctions get the values that have been determined for the maximum Core internal bilateral.

Article 21 Capacity validation methodology

1. Each TSO will, 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;
    b. an exceptional situation where sufficient redispatch or countertrade potential, that is needed to ensure the minimum RAM on all CNECs and/or to ensure the requested minimum import capacity pursuant to Article 14(4), may not be available;

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

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) and 21(1)(b), 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 his market area, and may request a common decision to launch a new final flow-based computation. 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.
4. Any reduction of cross-zonal capacities during the validation process will be communicated to market participants and justified to regulatory authorities in accordance with Article 23 and Article 24, respectively.
5. The regional coordinated capacity calculator shall coordinate with neighbouring coordinated capacity calculators during the validation process. 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 decribed in Article 21(3).

UPDATES AND DATA PROVISION

Article 22 Reviews and updates

1. 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.
2. If the operational security limits, contingencies and allocation constraints used for the common capacity calculation need to be updated based on this review, Core TSOs shall publish the changes early in advance before the implementation.
3. In case the review proves the need of an update of the reliability margins, Core TSOs shall publish the changes early in advance before the implementation.
4. The review of the 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.
5. 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 before the final implementation.

Article 23 Publication of data

1. The data as set forth in Article 22(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 publicated 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);
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 shadow auctions.
e. in compliance with national regulations, 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 permament or temporary limits;
        - F_{LTN};
        - I_{max};
        - FRM;
        - FAV.
    iv. detailed breakdown of RAM per external constraint:
        - F_{max};
        - F_{LTN}.
f. in compliance with national regulations, 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. in compliance with national regulations, 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 decribed in Article 25(2).

[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. Monitoring data shall be treated as confidential by the Core regulatory authorities and shall not be disclosed to the public.
4. 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. hourly intraday ATCs for all Core borders;
    e. maximum bilateral exchanges for each Core bidding zone border (hourly);
    f. usage of the final adjustment value FAV;
    g. external constraints;
    h. hourly shadow auction ATCs for all Core-borders;
    i. overview of timestamps where spanning is applied (per month);
    j. overview of timestamps for which default flow-based parameters were applied (per month);
    k. hourly non-anonymized presolved CNECs, disclosing $PTDF$, F_{max}, FRM, FAV, RAM and F_{max};
    l. key aggregated figures per country and border:
        - number of presolved CNEs;
        - number of precongested cases in D-2 CGM;
        - number of CNEs exceeded by LTA;
        - number of of presolved CBs with RAs applied;
        - number of presolved CNEs without RAs applied;
        - number of presolved CNEs, breaching the max zone-to-zone $PTDF$ threshold;
        - number of hours using the FAV;
        - number of hours, spanning technology was applied;
        - number of hours, default flow-based parameters were applied;
        - GSK.
    m. in case of occurrence: justification when FAV is applied;
    n. in case of occurrence: justification when the max zone-to-zone $PTDF$ threshold is breached of presolved CNECs;
    o. reductions made during the validation of cross-zonal capacity in accordance with Article 26 (5) of the CACM Regulation.
5. The final, exhaustive and binding list of all monitoring items (Article 24(4)), 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 decribed in Article 25(2).

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 Proposal 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. Subject to several dependencies (e.g. progress of the internal parallel run, implementation, proposed changes to the concept, regulatory approval of the methodology), the TSOs of the Core CCR shall implement the day-ahead common capacity calculation methodology to launch the external parallel run 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, and have S1-2020 as the go-live window for the market.
3. 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 (including those from external parallel run) and no later than the end of 2019.
4. For this transitional period, according to Article 25(3), the FRM shall be determined in accordance with Article 9.
5. 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.
6. The deadlines defined in the above Article 23(2), Article 23(3), and Article 23(4) 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 after the day-ahead market coupling operator function is implemented in accordance with Article 7(3) of the CACM Regulation.

LANGUAGE

Article 26 Language

The reference language for this proposal shall be English. For the avoidance of doubt, where TSOs need to translate this proposal 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 proposal.

APPENDIX 1: USE OF EXTERNAL CONSTRAINTS

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.

Netherlands

TenneT B.V. determines the maximum import and export constraints for the Netherlands based on off-line studies, which include voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during different import and export situations. The study can be repeated when necessary and may result in an update of the applied values for the constraints of the Dutch network.

Poland

Capacities on PSE side may be reduced due to so called external constraints, defined in Commission Regulation (EU) 2015/1222 of 24 July 2015, (CACM Regulation) as "constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation". These potential constraints reflect in general the ability of all Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical constraints of individual generating units as well as minimum reserve margins required in the whole Polish power system to ensure secure operation. This is related to the fact that under the conditions of central dispatch market model applied in Poland responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in self dispatch market models – see further explanations in this respect.

Thus, capacity in export direction is reduced if the export of the PSE exceeds generating capacities left available within Polish power system taking into account necessary reserve margin for upward regulation.

Similarly, capacity in import direction is reduced if the import exceeds downward regulation available within Polish power system taking into account necessary reserve margin for downward regulation.

Rationale behind implementation of allocation constraints on PSE side

Implementation of allocation constraints on PSE side is related to the fact that under the conditions of central dispatch market model applied in Poland responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in 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) and medium (up to year-ahead) terms. 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 sometimes lead to implementation of allocation constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation. In self dispatch markets BRPs themselves are supposed to take care about their generating reserves, while TSO shall ensure them just for dealing with contingencies in the time frame of up to one hour ahead. Thus these two approaches ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view. It is worthwhile to note that infeasibilities in this respect lead to counter trade actions and appear only if faults out of dimensioning criteria occur. In order to better explain the above issue the following subchapters elaborate more on the differences between central and self-dispatch market models as well as on PSE's role in system balancing.

Central vs self-dispatch market models

Market operation in Europe is carried out in several different ways. However, they can be basically grouped in two families: self-dispatch model and central-dispatch model.

In a self-dispatch market, market design produces a balance between generation and demand (including external exchanges) by requiring that market parties (balance responsible parties - BRPs) are in a balanced position to participate in the balancing market (e.g. one hour before energy delivery). Imbalance charges/penalties are levied on market parties which deviate from the balanced position. Commitment decisions, which take into account generating unit constraints, are made by the generators in conjunction with the demand elements they are balancing with. Generators alter their output to maintain the balance between generation and served demand. To be able to maintain balanced position they keep the given amount of reserves in their internal portfolios for compensation of their deviations. Before real time, generators submit bids to TSO which correspond with self-schedules of their units. Bids are used by TSO to dispatch additional generation needed to balance and secure the system in real time. Most of the electricity markets in Europe are based on the self-dispatch principle.

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 process as an optimisation problem called security constrained unit commitment and economic dispatch (SCUC/ED). The main distinguishing feature of a central dispatch model is that balancing, congestion management and reserve procurement are performed simultaneously and they start day before and continuing until real time. This involves dispatch instructions being issued several hours ahead of real time, to start up units (SCUC), as well as real time instructions for dispatching on line units (SCED). In central dispatch model market participants do not need to be in a balanced position. The existing central-dispatch markets in Europe currently are the Greek, the Italian, the Irish and the Polish electricity markets.

PSE role in system balancing

PSE directly dispatches generating units taking into account their operational constraints and transmission constraints in order to cover the expected load having in mind adequate reserve requirements, which is also forecasted by PSE itself. To fulfil 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 security constrained unit commitment (SCUC) and economic dispatch (SCED). 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 reserve margin of 18% (over forecasted load including already allocated capacities on interconnections, if any) is kept on average in each month. The monthly and weekly updates aim to keep this reserve margin on each day at the level of 17% and

14% respectively, if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

The day-ahead SCUC process aims to achieve 9% of spinning reserve (or quickly activated, in Polish reality only units in pumped storage plants) margin for each hour of the next day. 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 other generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE itself (like a system demand) and relevant uncertainty margins are included (90% for yearly and monthly time horizons referring to installed generation and 20% day ahead referring to forecasted generation). 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.

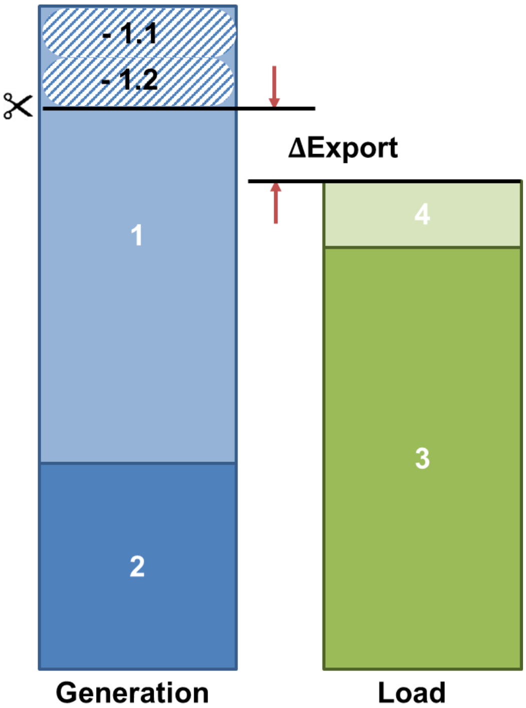
The further updates of SCUC/SCED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.) and aim to keep at minimum 7% of spinning reserve for each hour (as described above) in a time frame corresponding to the start-up times of the remaining thermal generating units (in practice 6 to 8 hours). Such an approach usually allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW (i.e. potential loss of the largest generating unit of 850 MW and 150 MW of primary control reserve being PSE's share in RGCE).

Practical determination of allocation constraints within the Polish power system

As an example the process of practical determination of allocation constraints in the framework of day-ahead transfer capacity calculation is illustrated on the below figures 1 and 2. They 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 find reserves in generating capacities available for potential exports and imports, respectively.

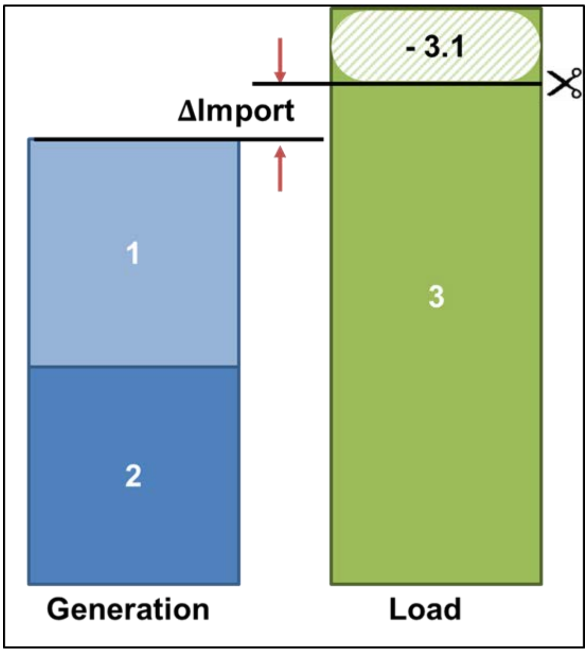
Allocation constraint in export direction occurs if generating capacities left available on centrally dispatched units within Polish power system for export are lower than the sum of export ATCs on all three interconnections (synchronous cross section, SwePol Link and LitPol Link).

Allocation constraint in import direction occurs if downward regulating capacities left available on centrally dispatched units in operation within Polish power system for imports (ΔImport) are lower than the sum of import ATCs on all three interconnections (synchronous cross section, SwePol Link and LitPol Link).



1. sum of available generating capacities of centrally dispatched units[3] as declared by generators, reduced by:
   1.1 TSO forecast of capacity not available due to expected network constraints;
   1.2 TSO assessment (based on experiences of recent days) of extra reserve to cover short term unavailabilities not declared by generators day ahead (limitations coming from e.g. cooling conditions, fuel supply, etc.) and prolonged overhauls and/or forced outages.
2. sum of schedules of generating units that are not centrally dispatched as provided by generators, except wind farms for which generation is forecasted by TSO;
3. load forecasted by TSO;
4. minimum necessary reserve for up regulation (for day-ahead: 9% of forecasted load).

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



1 TSO estimation of sum of technical minima of centrally dispatched generating units in operation;

2 sum of schedules of generating units that are not centrally dispatched as provided by generators, except wind farms for which TSO forecast of wind generation is taken into account;

3 load forecasted by TSO

3.1 minimum necessary reserve for down regulation (for day-ahead: 500MW).

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

3 note that generating units, which have very limited working hours left due to environmental restrictions are not taken into account in power balance for determining export allocation constraints: most of these units are still in operation only thanks to special contracts with TSO (thus being out of the market) – otherwise they would have already been decommissioned as not profitable; currently also all pumped storage units in Poland are also operated by TSO out of market (for the same reason), however these units are taken into account in power balance for determining export allocation constraints as their operation is not limited environmentally