Core TSOs common coordinated long-term capacity calculation methodology in accordance with article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

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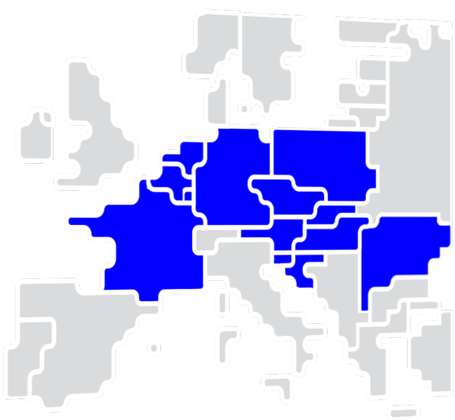

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ALL TSOS OF THE CORE CCR TAKING INTO ACCOUNT THE FOLLOWING,

Whereas

1. This document sets out the common coordinated capacity calculation methodology in accordance with article 10 seq. of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on Forward Capacity Allocation (hereafter referred to as the “FCA Regulation”). This methodology is hereafter referred to as the "Long-Term Capacity Calculation Methodology" (LT CCM).
2. The LT CCM takes into account the general principles and goals set in the FCA Regulation as well as Regulation (EC) No 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (hereafter referred to as "Regulation (EC) No 2019/943”.
3. According to article 4(8) of the FCA Regulation, the expected impact of the LT CCM on the objectives of the FCA Regulation has to be described and is presented below.
4. The LT CCM serves the objective of promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants (article 3(a) of the FCA Regulation) by taking into account the hedging needs of market participants by calculating reliable capacities at an early stage and making them available to market participants, which makes long-term planning possible since it ensures that the cross-zonal capacity is calculated in such a way that the same LT CCM will apply to all market participants on all respective bidding zone borders in the Core CCR, thereby ensuring a level playing field amongst market participants.
5. The LT CCM contributes to the optimal calculation of long-term capacity (article 3(b) of the FCA Regulation) since it takes into account all critical network elements, coordinates the timings of delivery of inputs, provides a calculation approach and coordinates validation requirements of the capacity calculation between Core TSOs and the Coordinated Capacity Calculator of Core (Core CCC).
6. The LT CCM contributes to the objective of providing non-discriminatory access to long-term cross-zonal capacity (article 3(c) of the FCA Regulation) by adhering to the rules of JAO and by publication of the results, hence ensuring non-discrimination between market participants.
7. The LT CCM is designed to ensure a fair and non-discriminatory treatment of Core TSOs, the Agency, regulatory authorities and market participants (article 3(d) of the FCA Regulation) since it has been developed and adopted within a process that ensures the involvement of all relevant stakeholders and independence of the approving process.
8. In August 2019, the Core TSOs reached the situation described on the article 4(4) of the FCA Regulation. Starting from this date, an iterative process took place, involving Core TSOs, NRAs, the Agency, the EC for designing an acceptable methodology for all parties. Following the guidance of the Agency, this LT CCM considers the flow-based calculation as a target.
9. In accordance with article 10(5) of the FCA Regulation, the CCM applies the flow-based approach to capacity calculation. In capacity calculation regions characterised by meshed networks and physically interdependent bidding zone borders, the flow-based approach by default leads to an increase in economic efficiency with the same level of system security. This is because, when a network element, which is considered in capacity calculation as critical network element is significantly impacted by cross-zonal exchanges on two or more bidding zone borders (which makes

those borders interdependent), then it is by default more efficient that requests for cross-zonal exchanges on these interdependent borders equally compete for the capacity of such critical network element. This competition between borders is the intrinsic advantage of the flow-based approach compared to the coordinated net transmission capacity ('NTC') approach. In the latter approach, the capacity of such critical network elements needs to be first split into portions reserved for each of the interdependent borders and then converted into NTC values for each border. These NTCs are then allocated independently on each interdependent border, which essentially limits the competition between interdependent borders for the capacity of such critical network elements. Lack of competition between borders for the capacity of network elements, which these borders are significantly impacting inevitably, leads to loss of economic efficiency in allocating the capacity of such network elements.

10. This LT CCM also contributes to the objective of respecting the need for a fair and orderly forward capacity allocation and orderly price formation (article 3(e) of the FCA Regulation) by making available in due time the information about cross-zonal capacities to be released in the market, and by ensuring a backup solution when capacity calculation fails to provide results.
11. The LT CCM enables Core TSOs to provide market participants with reliable information on cross-zonal capacities and import/export limits for year and month ahead allocation in a transparent way and at the same time. This includes regular reporting on specific processes within capacity calculation. The LT CCM therefore contributes to the objective of transparency and reliability of information (article 3(f) of the FCA Regulation).
12. Finally, the LT CCM provides a long-term signal for efficient investments in transmission, generation and consumption, and thereby contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (article 3 (g) of the FCA Regulation).
13. In conclusion, the LT CCM contributes to the general objectives of the FCA Regulation to the benefit of all market participants and electricity end consumers.
14. The LT CCM covers the annual and monthly long-term time frames (pursuant to article 9 of the FCA Regulation).
15. The LT CCM is structured in three consecutive stages: (i) the definition and provision of capacity calculation inputs by the Core TSOs, (ii) the capacity calculation process by the Core CCC in coordination with the Core TSOs, and (iii) the capacity validation by the Core TSOs in coordination with the Core CCC.
16. Core TSOs determine the final capacity values to meet the form of product regulated in the Core Design of Long-Term Transmission Rights (in accordance with article 31.3 of the FCA Regulation). Those capacity values are subject to the Core Methodology for splitting long-term cross-zonal capacity (in accordance with article 16 of the FCA regulation).
17. The LT CCM is based on forecast models of the transmission system. The inputs of the LT CCM are determined more than a year, respectively more than a month, before the electricity delivery date taking into account the available knowledge at that time. Therefore, the outcomes are subject to inaccuracies and uncertainties that are higher than the inaccuracies and uncertainties of the day-ahead capacity calculation methodology. The aim of the reliability margin is to cover the risk induced by these forecast errors.

18. The LT CCM shall be compatible with the day-ahead and intraday capacity calculation methodologies (article 10 (3) of the FCA Regulation).
19. Core TSOs remain responsible for maintaining operational security regardless of whether there is a coordinated application of capacity calculation or not. For this reason, they need to validate the calculated capacities to ensure that they do not violate operational security limits. This step may lead to reductions of the values given by the LT CC process. In order to avoid undue discrimination these measures of reduction have to be performed in a coordinated way. In case of missing coordination, the results might be that a Core TSO might have more capacities to the detrimental effect (operational security issues) of another Core TSO.
20. Transparency and monitoring of capacity calculation are essential for ensuring its efficiency and understanding. This methodology establishes significant requirements for Core TSOs to publish the information required by market participants, to report the information to regulatory authorities and to analyse the impact of capacity calculation on the market functioning.

SUBMIT THE FOLLOWING LT CCM TO THE NATIONAL REGULATORY AUTHORITIES OF THE CORE CCR:

TITLE 1: GENERAL PROVISIONS

Article 1 Subject, Matter and Scope

1. The long-term common capacity calculation methodology as determined in this LT CCM is the common proposal of all Core Transmission System Operators (hereafter referred to as “Core TSOs”) in accordance with article 10 seq. of the FCA Regulation and shall cover the bidding zone borders of the Capacity Calculation Region Core (hereafter referred to as “the Core CCR” – as described in the decision of the Agency for the cooperation of energy regulators n° 06/2016 of 17 November 2016 on the electricity transmission system operators proposal for the determination of capacity calculation regions).
2. This LT CCM applies solely to the long-term capacity calculations within the Core CCR and covers the annual and monthly long-term time frames pursuant to article 9 of the FCA Regulation. Common capacity calculation methodologies within other capacity calculation regions or other timeframes are outside the scope of this proposal.
3. The methodology for splitting long-term capacity is out of scope of this LT CCM, but in the scope of the methodology pursuant to article 16 of the FCA Regulation.

Article 2 Definitions and Interpretation

1. For the purposes of the LT CCM, the terms used shall have the meaning given to them in article 2 of Regulation (EC) 2019/943, article 2 of Regulation (EC) 2013/543 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 2019/943 of the European Parliament and of the Council, article 2 of Commission Regulation (EC) 2015/1222 establishing a guideline on Capacity Calculation and Congestion Management (hereafter referred to as the “CACM Regulation”) and article 2 of the FCA Regulation.
2. In addition, the following definitions, abbreviations and notations shall apply:

ACER	Agency for the Cooperation of Energy Regulators

AHC	Advanced Hybrid Coupling
AMR	Adjustment of Minimum RAM
BZB	Bidding Zone Border standing also for set of BZB
C	Contingency
CACM	Capacity Allocation and Congestion Management
CC	Capacity Calculation
CCC	Coordinated Capacity Calculator, as defined in article 2(11) of the CACM Regulation
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region, as defined in article 2(3) of the CACM Regulation
CHP	Combined Heat and Power plant
CGM	Common Grid Model, as defined in article 2(2) of the CACM Regulation
CGMM	Common Grid Model Methodology
CNE	Critical Network Element
CNEC	Critical Network Element and Contingency
DA	Day-Ahead, as defined in article 2(34) of the CACM Regulation
DA CCM	Day-Ahead Capacity Calculation Methodology
DC	Direct Current
EC	European Commission
EIC	Energy Identification Code
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FCA	Forward Capacity Allocation
FB	Flow Based
F_{max}	Maximum Allowable Power Flow
F_{ref}	Reference Flow
$F_{0, Core}$	Flow without commercial exchanges within Core CCR
FRM	Flow Reliability Margin
GSK	Generation Shift Key, as defined in article 2(12) of the CACM Regulation
HVDC	High-Voltage Direct Current
IGM	Individual Grid Model, as defined in article 2(1) of the CACM Regulation
$I_{\max}$	Maximum Admissible Current
JAO	Joint Allocation Office
LT	Long-Term
LTCC	Long-Term Capacity Calculation
LT CCM	Common Coordinated Long-Term Capacity Calculation Methodology
kA	Kilo Ampère
kV	Kilo Volt
minRAM	Minimum Remaining Available Margin
MPTC	The Maximum Permanent Technical Capacity represents the maximum continuous active power an HVDC element is capable of transmitting,

	taking into account potential reduced availability due to planned outages of the interconnector asset. This parameter is defined by the interconnector's asset operators.
MTU	Market Time Unit
MW	Megawatt
NP	Net Position
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OPC	Outage Planning Coordination
OPDE	Operational Planning Data Environment, as defined in article 3(74) of the SO GL Regulation
PTDF	Power Transfer Distribution Factor
PST	Phase-Shifting Transformer
R_{amr}	Minimum RAM factor
RA	Remedial Action, as defined in article 2(13) of the CACM Regulation
RAM	Remaining Available Margin
RG CE	Regional Group Continental Europe
RM	Reliability Margin
SAP	Single Allocation Platform
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SO GL	Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.
TSO	Transmission System Operator

3. In this LT CCM, unless the context requires otherwise:
   a. the singular indicates the plural and vice versa;
   b. headings are inserted for convenience only and do not affect the interpretation of this LT CCM; and
   c. any reference to legislation, regulations, directives, orders, instruments, codes or any other enactment shall include any modification, extension or re-enactment of it when in force.

Article 3 Long-Term Capacity Calculation Process

1. The capacity calculation process for the long-term time frame in Core CCR shall apply the flow-based approach.
2. The year-ahead and month-ahead capacity calculation process shall consist of three main stages:
   a. the creation of capacity calculation inputs by the Core TSOs, in accordance with Title 2;
   b. the capacity calculation process by the CCC, in accordance with Title 3; and
   c. the capacity validation by the Core TSOs in coordination with the CCC, in accordance with Title 4.
3. In accordance with article 24 of the FCA Regulation, each Core TSOs shall validate the results.
4. Detailed process steps are described in the related articles of this methodology.

TITLE 2: TREATMENT OF INPUT

Article 4 Reliability Margin Methodology

1. The Core TSOs shall use the latest available FRM from the DA timeframe. The latest available FRM are the yearly updated FRMs as defined per CNEC in article 8(11) of the DA CCM. The updated FRMs are applied for all yearly and monthly capacity calculations until the next yearly update. In case the FRM considered in the DA CC have been updated between the yearly and the monthly capacity calculation, the latest FRM is considered in the monthly capacity calculation. The Core TSOs use one FRM per CNEC which is updated yearly according to article 8(11) of the Core DA CCM. As stated in the Core DA CCM, the FRM is a percentage of F_{max} which covers the uncertainties.
2. The Core TSOs shall regularly review the FRMs and if needed change the FRMs in order to ensure at least the consistency with their neighbouring CCRs and to ensure an adequate consideration of the higher uncertainties in the capacity calculation for the long-term timeframes.

Article 5 Methodologies for Operational Security Limits

1. In accordance with article 12 of the FCA Regulation, referring to 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 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as the “SO GL”). The operational security limits used in the LT CCM are the same as those used in operational security analysis. In particular:
   a. Core TSOs shall respect the maximum admissible current (I_{max}) which is the seasonal limit on a CNE according to the operational security policy in line with article 25 of the SO GL. The maximum admissible current can be defined by:
      i. fixed limits for all timestamps in the case of transformers and certain types of conductors which are not sensitive to ambient conditions;
      ii. fixed limits for all timestamps of a specific season. Fixed limits are determined separately for each of the seasons.
   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 LT CCM are covered on each CNEC by the reliability margin in accordance with Article 4.
   d. The value F_{max} in MW, describes the maximum admissible active power flow on a CNEC. F_{max} is calculated by the Core CCC from I_{max} by the given formula:

$$\mathrm{F_{max}} = \sqrt{3} \cdot \mathrm{I_{max}} \cdot \mathrm{U} \cdot \cos(\varphi) \qquad (1)$$

   where I_{max} is the maximum admissible current in kA of a 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.

2. Core TSOs shall aim towards determining the maximum admissible current using seasonal limits pursuant to Article 5(1)(a)(ii). If a Core TSO uses the seasonal limits of Imax, this Core TSO has to insert this information into the list of CNECs where I_{max} of CNE is defined.
3. The Core TSOs shall review and update the methodology for operational security limits in accordance with Article 18.

Article 6 Methodology for Allocation Constraints

1. In case operational security limits cannot be transformed efficiently into I_{max} and F_{max} pursuant to Article 5, the Core TSOs may transform them into allocation constraints. For this purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone.

2. For the implementation of the LT CCM, external constraints are applied by TenneT TSO B.V. and PSE during a transition period of two years following the implementation of this LT CCM in accordance with Article 22(2) and in accordance with the reasons and the methodology for the calculation of external constraints as specified in Annex 1 to this LT CCM. During the transition period for allocation constraints, the concerned Core TSOs shall calculate the value of external constraints on a yearly and monthly basis for all allocation period (for PSE only) or at least on a quarterly basis and publish the results of the underlying analysis (this obligation is for TenneT TSO B.V. only).

3. In case Core TSOs could not find and implement alternative solutions referred to in the previous paragraphs, they may, by eighteen months after the implementation of this LT CCM in accordance with Article 22(2), together with all other Core TSOs, submit to all Core regulatory authorities a proposal for amendment of this LT CCM in accordance with article 4(12) of FCA Regulation. Such a proposal shall include the following:

   a. the technical and legal justification for the need to continue using the external constraints or introducing external constraints indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};
   b. the methodology to calculate the value of external constraints including the frequency of recalculation.

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

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

5. The Core TSOs shall review and update the methodology for allocation constraints in accordance with Article 18.

Article 7 Methodology for Critical Network Elements and Contingencies Selection

1. Each Core TSO shall provide a list of critical network elements (CNEs), including by default all cross zonal network elements and a list of associated contingencies (Cs) of its own control area based on operational experience. The result of the process will be an initial pool of CNECs in all subsequent steps of the common long-term capacity calculation.
2. Only those CNECs of the initial pool are considered by each Core TSO for the common long-term capacity calculation that are marked by the Core CCC to be significantly influenced by the changes in bidding zone net positions in accordance with article 29(3) of the CACM Regulation.
3. The CNECs shall have a maximum zone-to-zone PTDF higher than a common threshold of 5%. The CNECs of this category will be taken into account by the Core TSOs in all subsequent steps of the common capacity calculation and will determine the long-term capacity.
4. The list of CNEs and the associated contingencies can be updated monthly by the respective Core TSOs.

Article 8 Generation Shift Keys Methodology

1. In accordance with article 13 of the FCA Regulation, Core TSOs developed the following methodology to determine the common GSK:

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

   b. Core TSOs shall take into account the actual information on generation and/or load available in the common grid model for each scenario developed in accordance with article 19 of the FCA Regulation in order to select the nodes that will contribute to the generation shift key;

   c. 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;

   d. Core TSOs shall define generation shift key for the calculation period. Each Core TSO is allowed to use one GSK for multiple timestamps;

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

2. When the proposal for further harmonization of the GSK methodology as listed in article 9(6) of the Core DA CCM is approved, then the Core TSOs shall use this GSK methodology as a basis to submit to all Core regulatory authorities a proposal for amendment of this LT CCM in accordance with article 4(12) of FCA Regulation. The proposal shall at least include:

a. the criteria and metrics for defining the efficiency and performance of GSKs and allowing for quantitative comparison of different GSKs; and
b. a harmonised generation shift key methodology combined with, where necessary, rules and criteria for TSOs to deviate from the harmonised generation shift key methodology.

Article 9 Methodology for Remedial Actions in Capacity Calculation

1. Each Core TSO may define a set of available RAs, which is located in its control area. For transparency reasons, all Core TSOs have to be informed about this set of RAs in advance.
2. Only the following RAs are considered:
   - opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s);
   - switching of one or more network element(s) from one bus bar to another;
   - transformer and PST tap adjustment.
3. The Core TSOs shall only use coordinated RAs during long-term capacity calculation.
4. Only RAs confirmed by a common procedure that includes rules and pre-defined criteria will be considered and have to be approved by all Core TSOs.
5. The initial step of the common procedure is a comparison of calculation results by each Core TSO based on its best practice and experience on the combination of the results and the contingencies. This step is followed by improvement of calculation results based on a common set of coordinated remedial actions, in case a Core TSO decides in the initial step that the result is not in line with its best practice and experience.

Article 10 Scenarios

1. In accordance with article 19 of the FCA Regulation, referring to article 10 of the FCA Regulation, all TSOs in the CCRs shall jointly develop a common set of scenarios to be used in the common grid model for each long-term capacity calculation time frame.

2. In order to meet the above requirements, the Core TSOs shall use the annually created ENTSO-E year-ahead reference scenarios (i.e. default scenarios), in accordance with article 3(1) of CGMM for FCA in conjunction with article 65 of the SO GL Regulation. This Pan-European process is based on the CGMM as developed in accordance with article 18 of the FCA Regulation and respecting the merging and alignment processes developed in accordance with article 27 of the CACM Regulation.

3. In case of a considerable change, compared to the IGM for the ENTSO-E year-ahead reference scenario, in the grid of a Core TSO, this Core TSO shall update its IGM by incorporating the latest available information as regard to the generation pattern and topology (due to grid element commissioning or decommissioning), while the net position of the bidding zone is maintained unchanged when changing the generation pattern/topology. This updating process with the latest available data is performed in the month-ahead capacity calculation timeframe by Core TSOs as there is no such a process at ENTSO-E level.

4. For each calculation timestamp the Core CCC shall generate a CGM based on the (updated) ENTSO-E CGM by implementing the latest available outage plans, together with the associated topological switches related to a planned outage using the OPC database (foreseen to be replaced by the Operational Planning Data Environment [OPDE] in accordance with Title 7 of the SO GL Regulation), where all ENTSO-E RG CE TSOs' planned outages and the associated topological

switches are stored and regularly updated pursuant to the articles 99 and 100 of the SO GL Regulation.

5. Based on the database mentioned in the previous paragraph the selection of calculation timestamp is as follows:
   a. two timestamps will be selected per granularity of the concerned period, one peak and one valley. This granularity is fixed in advance and is as following:
      i. 1 month for the year-ahead timeframe;
      ii. 1 week for the month-ahead timeframe.
   b. the selected timestamps are the ones with the biggest simultaneous amount of planned relevant grid element outages within the Core CCR.

6. Core TSO may require to include additional planned outages to the calculation process if they are critical and not contained within the set of outages selected based on the Article 12(5).

7. The Core CCC shall generate, after each long-term calculation, a reporting of the base case quality of the CGM for each calculation timestamp after the application of the planned outages pursuant Article 10(4) and Article 10(6). This report shall consist of and include at least the following CNECs per calculated timestamp:
   i. the overloaded CNE(C)s and its level of overload in base case before the application of minRAM, i.e. the negative RAM occurred pursuant TITLE 3:Article 14 but before application of minRAM pursuant TITLE 3:Article 14(4);
   ii. the limiting CNEC per direction that were not subject to minRAM in the base case situation.
8. Each Core TSOs shall monitor this reporting and shall, when this report maintains a significant amount of CNECs, take necessary actions together with all Core TSOs and in a timely manner to improve the base case quality.
9. This improvement of this base case may be achieved by adjusting the following settings, based on a coordinated agreement among Core TSOs:
   i. the minRAM threshold pursuant to TITLE 3:Article 14;
   ii. the application of RA pursuant to Article 9;
   iii. the sensitivity threshold pursuant to TITLE 3:Article 13(3);
   iv. the topological switches related to a planned outage pursuant Article 10(4).

Article 11 Integration of Cross-Zonal HVDC Interconnectors Located within the Core CCR

1. Core TSOs shall determine the capacity of each HVDC interconnector located within the Core CCR at long-term timeframe. The aforementioned capacity may be constrained by the maximum permanent technical limit (MPTC) of the HVDC and by the physical impact this exchange has on all CNECs considered in the calculation.

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

$$PTDF_{A\rightarrow B,l} = (PTDF_{A,l} - PTDF_{VH\_1,l}) + (PTDF_{VH\_2,l} - PTDF_{B,l}) \tag{2}$$

With:

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

3. The PTDFs for the two virtual hubs $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ are calculated for each CNEC considered during the calculation and they are added as two additional columns (representing two additional virtual bidding zones) to the existing PTDF matrix, one for each virtual hub.
4. In case of a planned outage of the respective HVDC interconnector, the MPTC will be set to zero.

TITLE 3: DESCRIPTION OF THE CAPACITY CALCULATION PROCESS

Article 12 Description of the CC inputs and outputs

1. For each calculation timestamp the Core TSOs shall provide the Core CCC the following inputs:
    a. GSKs in accordance with Article 8;
    b. MPTC of HVDC inside the Core CCR in accordance with Article 11;
    c. CNEs and Contingencies in accordance with Article 7;
    d. Reliability Margin in accordance with Article 4;
    e. maximum current on a CNE ($Imax$) / maximum admissible active power flow ($Fmax$) in accordance with Article 5;
    f. RAs in accordance with Article 9;
    g. allocation constraints in accordance with Article 6.
2. For each calculation timestamp the Core CCC shall provide the following inputs:
    a. CGMs for each selected timestamp and the outage planning from OPC in accordance with Article 10;
    b. the already allocated capacities from JAO.
3. For each calculation timestamp the Core CCC shall use the following parameters:
    a. the minRAM threshold pursuant to Article 14;
    b. the sensitivity threshold pursuant to Article 13(3).
4. When providing the capacity calculation inputs pursuant to Article 12(1), the Core TSOs shall respect the formats commonly agreed between the Core TSOs and the Core CCC while fulfilling the requirements and guidance defined in the CGMM developed in accordance with Section 2 of the FCA Regulation.
5. For each calculation timestamp the CCC shall provide the flow-based parameters, RAM and PTDFs, computed in accordance with Article 13 and Article 14 correspondingly, for TSOs validation in accordance with TITLE 4:Article 17.

Article 13 Computation of Power Transfer Distribution Factors

1. For each calculation timestamp using the associated CGM, CNECs and GSKs, the Core CCC shall calculate PTDFs for each Core BZB. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\text{zone-to-slack}} = \mathbf{PTDF}_{\text{node-to-slack}} * \mathbf{GSK}_{\text{node-to-zone}} \tag{3}$$

With:

$\mathbf{PTDF}_{zone-to-slack}$ matrix of zone-to-slack $PTDFs$ (columns: bidding zones; rows: CNECs)

$\mathbf{PTDF}_{node-to-slack}$ matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)

$\mathbf{GSK}_{node-to-zone}$ matrix containing the $GSKs$ of all bidding zones (columns: bidding zones; rows: nodes; sum of each column equal to one).

The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$.
A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a net position of bidding zone on a CNEC l and assumes a commercial exchange between a bidding zone and a slack node.
A zone-to-zone $PTDF_{A\to B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on CNEC l. The zone-to-zone $PTDF_{A\to B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

$$PTDF_{A\to B,l} = PTDF_{A,l} - PTDF_{B,l} \tag{4}$$

2. Using zone-to-zone PTDFs, the Core CCC shall determine flow on a CNEC in the situation without commercial exchanges within the Core CCR as follows:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF_f}\ \overrightarrow{Exchanges}_{ref,Core} \tag{5}$$

With:

$\vec{F}_{0,Core}$	flow per CNEC in the situation without commercial exchanges within the Core CCR
$\vec{F}_{ref}$	flow per CNEC in the CGM with commercial exchanges as mentioned in the reference program associated with the CGMs of the ENTSO-E scenarios
$\mathbf{PTDF_f}$	zone-to zone power transfer distribution factor matrix for CNECs of the Core CCR
$\overrightarrow{Exchanges}_{ref,Core}$	Core commercial exchanges between the bidding zones as mentioned in the reference program associated with the CGMs of the ENTSO-E scenarios

3. The Core CCC shall apply the common threshold for minimum sensitivity of CNECs in accordance with Article 10 using the following formula:

If $PTDF_{A\to B,l} \leq threshold$ then the $PTDF_{A\to B,l}$ is set to zero before starting the calculation process.

Article 14 Computation of the available margins on critical network elements

1. Following the PTDFs' computation of the Article 13, the Core CCC shall compute the RAM based on CNEC maximum admissible power flow in accordance with Article 5 at Core zero-balance situation. The uncertainties of flows by using a Reliability Margin in accordance with Article 4 should be taken into account. The RAM calculation is mathematically described as follows:

$$RAM_l^+ = Fmax_l - FRM_l^+ - \vec{F}_{0,Core} \tag{6}$$

$$RAM_l^- = Fmax_l - FRM_l^- + \vec{F}_{0,Core} \tag{7}$$

With:

RAM_l^+ and FRM_l^+	RAM and FRM of CNEC l in one direction of monitoring (direction is defined by TSO)
RAM_l^- and FRM_l^-	RAM and FRM of CNEC l in direction of monitoring opposite to the previous direction (direction is defined by TSO).

2. The Core TSOs shall commonly define the minimum RAM factor (R_{amr}), i.e. a specific percentage value for calculation of minimum RAM in accordance with paragraph 4. The minRAM factor is subject to a regular review by all Core TSOs.

3. The Core CCC shall check if the RAM for each CNEC determining the cross-zonal capacity is not less than a defined minimum RAM.

4. In case the RAM determined according to paragraph 1 is below the minimum RAM, the Core CCC shall increase the RAM according to the following process:

   a. The main objective of the minimum RAM is to ensure that at least a specific percentage, a minimum RAM factor (R_{amr}) as defined in paragraph 4.c, of F_{max} is reserved for the commercial exchanges. Therefore, the following equation needs to apply for each CNEC l:

   $$RAM_l \geq R_{amr} * F_{max_l} \quad (8)$$

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

   $$RAM_l + AMR = R_{amr} * F_{max_l} \quad (9)$$

   c. The AMR for a CNEC is determined with the following equation:

   $$AMR = \max\left(R_{amr} * F_{max_l} - \left(F_{max_l} - FRM - F_{0,Core}\right),\ 0\right) \quad (10)$$

   d. Finally, the RAM will be adjusted due to the following equation:

   $$RAM_l = F_{max_l} - FRM - F_{0,Core} + AMR \quad (11)$$

Article 15 Consideration of Non-Core CCR Bidding Zone Borders

1. Where CNEs within the Core CCR are impacted by electricity exchanges outside the Core CCR, Core TSOs shall take this impact into account.

2. Core TSOs shall consider the electricity exchanges on BZBs outside the Core CCR as fixed input to the LT CCM, as prepared in the common set of ENTSO-E year-ahead reference scenarios, with unchanged NPs. These electricity exchanges, defined as best forecasts of net positions and flows in the LTCC models, are defined and agreed based on the CGMM as developed in accordance with article 18 of the FCA Regulation and are incorporated in the CGM. Uncertainties related to the electricity exchanges forecasts are implicitly considered within the reliability margin.

3. In close cooperation with adjacent CCRs, non-Core BZBs approach in LT CCM will be studied by the Core TSOs in order to take into account non-Core BZBs and to heed article 21(1)(b)(vii) of the CACM Regulation. The Core TSOs will start to study non-Core CCR bidding zone borders immediately after implementation of Advanced Hybrid Coupling (AHC) in DA CCM.

Article 16 Fallback Procedures

1. In accordance with article 10(7) of the FCA Regulation, referring to article 21(3) of the CACM Regulation, and in the event that a LTCC process is unable to produce results, a fallback procedure shall be applied.

2. In case the initial capacity calculation does not lead to any results, the CCC shall try to solve the problem and perform the long-term capacity calculation again within a new agreed timeframe to make such calculation.

3. If the CCC is not able to deliver the long-term FB parameters to SAP within the new timeframe in accordance with TITLE 6:Article 19(2), Core TSOs shall bilaterally agree on NTC values for the relevant time frame(s). The Core TSOs shall commonly coordinate and validate these bilaterally agreed NTC values.

4. The Core CCC shall send the NTC values following TITLE 6:Article 19(3) to the SAP.

TITLE 4: VALIDATION PROCESS

Article 17 Validation Methodology

1. In accordance with article 15 of the FCA Regulation, referring to article 26 of the CACM Regulation, the Core TSOs shall have the right to correct long-term capacity relevant to the Core TSO's BZBs for reasons of operational security during the validation process. In exceptional situations long-term capacities can be reduced by all Core TSOs. These potential situations are at least:
   a. an occurrence of an exceptional contingency or forced outage as defined in article 3 of the SO GL Regulation;
   b. when RAs, pursuant to TITLE 2:Article 9, that are needed to ensure the calculated capacity on all CNECs, are not sufficient;
   c. a mistake in the input data, that leads to an overestimation of long-term capacity from an operational security perspective, occurred;
   d. a potential need to cover reactive power flows on certain CNECs.
2. The validation process refers to the outcomes of the long-term capacity calculation process within the Core CCR. The validation process is composed of two parts and explained in more detail in Article 17(3) and (4):
   a. individual verification of the calculated capacities for each calculated timestamp after the change of input parameters in accordance with Article 17(3);
   b. coordinated validation of the final capacities.
3. The Core TSOs shall analyse individually whether the calculated capacity could violate operational security limits, and whether they have sufficient measures to avoid such violations. The verification is performed before splitting of capacities, such that Core TSOs may require a change in the input parameters of the calculation to correct the calculated capacities:

   a. in case of a required reduction due to situations as defined in Article 17(1) (a), (b) and (d), a Core TSO may correct its initial FRM in accordance with Article 4, for its own CNECs;
   b. in case of a situation as defined in Article 17 (1) (a), Core TSOs may also request to adapt the external constraints to reduce the capacity for its BZBs;
   c. in case of a situation as defined in Article 17(1) (c), Core TSOs may also request a common decision to calculate capacities with the correct input data.

4. When the process of individual verification of the calculated capacities is completed, then the final capacity validation process takes place in a coordinated way, whereby Core TSOs may require a reduction in calculated capacities for reasons of operational security. When performing the steps of the validation, Core TSOs shall consider the operational security limits, but may also consider additional grid constraints, grid models, and other relevant information. Therefore, Core TSOs shall use the tools developed by the Core CCC for analysis but may also employ verification tools not available to the Core CCC.

TITLE 5: UPDATES

Article 18 Review and Updates

1. Based on article 3(f) of the FCA Regulation and in accordance with article 21(3) of the FCA Regulation, referring to article 27 of the CACM Regulation, all Core 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. Should the operational security limits, CNEs, contingencies and import/export limits used for the common capacity calculation need to be updated based on this review, Core TSOs shall publish the changes simultaneously with the update and publication as mentioned in article 24 of the Core DA CCM.

2. In case the review proves the need of an update of the reliability margins, Core TSOs shall publish the updated values of reliability margin at least one month before their implementation.

3. The review of the methodology for allocation constraints by the Core TSOs, shall take place before the start of each LT capacity calculation timeframe; in case the review results in an update of the allocation constraints, the new values shall be communicated to the market participants, the Agency and the Core NRAs.

4. The review by the Core TSOs of the set of RAs taken into account in capacity calculation, in accordance with TITLE 2:Article 9 shall include at least an evaluation of the efficiency of the RAs applied.

5. In case the review proves the need for updating the application of the methodologies for determining GSKs, CNEs, and contingencies referred to in articles 12 and 13 of the FCA Regulation, referring respectively to the articles 23 to 24 of the CACM Regulation, changes made in the methodologies have to be published at least three months before their implementation.

6. Any changes of parameters listed in article 27(4) of the CACM Regulation have to be communicated to market participants, the Agency and Core NRAs.

7. The impacts of any changes of parameters listed in article 27(4)(d) of the CACM Regulation and of import/export limits have to be communicated to market participants, the Agency and Core NRAs. If any change leads to an adaption of the methodology, the Core TSOs shall make a proposal for amendment of this methodology according to article 4(12) of the FCA Regulation and submit it for approval to the Core NRAs.

8. Core TSOs shall publish updated set of calculation parameters three months before their application.

TITLE 6: REPORT AND LANGUAGE

Article 19 Publication of Data

1. The data as set forth in Article 19(2) shall be published by the Core CCC on a dedicated online communication platform representing all Core TSOs. To enable market participants to have a clear understanding of the published data, the handbook that has been prepared and published by Core TSOs on this communication platform in the framework of article 25(1) of the DA CCM, shall be extended with the information related to the LTCC, using the same format and data platform.
2. In accordance with article 3(f) of the FCA Regulation, at least the following data items shall be published for each scenario by the CCC 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. CNECs names;
    b. CNECs EIC codes;
    c. detailed breakdown of the final FB parameters per CNEC: RAM, Fmax, Fref, $F_{0,Core}$, respective reliability margin, zone-to-slack PTDFs;
    d. allocation constraints.
3. Any change in the identifiers used in paragraphs 2(a) and 2(b) of Article 19 shall be publicly notified at least one month before its entry into force.
4. An individual Core TSO may withhold the information referred to in paragraph 2(a) and 2(b) of Article 19 if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. In such a case, the information referred to in paragraph 2(a) and 2(b) of Article 19 shall be replaced with an anonymous identifier which shall be stable for each CNEC across all LTCC timeframes. The anonymous identifier shall also be used in the other TSO communications related to the CNEC and when communicating about an outage or an investment in infrastructure. The information about which information has been withheld pursuant to this paragraph shall be published on the communication platform referred to in paragraph 1 of Article 19.
5. The Core regulatory authorities may request additional information to be published by the Core TSOs. For this purpose, all Core regulatory authorities shall coordinate their requests among themselves and consult it with stakeholders and the Agency. Each Core TSO may decide not to publish the additional information, which was not requested by its competent regulatory authority.

Article 20 Monitoring and Information to Regulatory Authorities

1. The Core TSOs shall provide to Core NRAs data on LTCC for the purpose of monitoring its compliance with this methodology and other relevant legislation.
2. At least, the information on non-anonymized names of CNECs as referred to Article 19(2)(a)(b) shall be provided to all Core regulatory authorities on a yearly basis for each CNEC after the yearly calculations and on a monthly basis for each CNEC after each monthly calculation. This information shall be in a format that allows easily to combine the CNEC names with the information published in accordance with Article 19(2).

3. Core NRAs may request additional information to be provided by Core TSOs. For this purpose, all Core NRAs shall coordinate their requests and forward the coordinated request to Core TSOs. Each Core TSO may decide not to provide additional information that was not requested by its competent regulatory authority.

4. The Core CCC, with the support of the Core TSOs where relevant, shall draft and submit an annual report containing:
   a. the RAs in accordance with Article 9 on capacity calculation and in accordance with Article 10 on increasing base case quality;
   b. additional planned outages with requesting TSO names applied in accordance with Article 10(6);
   c. the quality of the data published on the dedicated online communication platform as referred to in Article 19, with supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned Core TSOs, where relevant;
   d. the Core TSOs´ report on their continuous monitoring of the effects and performance of the application of this methodology;
   e. the monitoring of the accuracy of non-Core exchanges in the CGM.

5. The Core CCC shall issue a quarterly report on capacity validation to the Core NRAs after approval by the Core TSOs. In each quarterly report, the Core CCC shall provide all the information on the reductions of calculated capacity after coordinated validation of capacities according to Article 17(4). The quarterly report shall include at least the following information for each reduced capacity and for each timestamp:
   a. the identification of the CNEC;
   b. the volume of reduction of capacity;
   c. the detailed reason(s) for reduction, including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;
   d. the proposed measures to avoid similar reductions in the future.

6. The quarterly report shall also include at least the following aggregated information:
   a. statistics on the number, causes, volume and estimated loss of economic surplus of applied reductions by different TSOs; and
   b. general measures to avoid capacity reductions in the future.

7. Core TSOs shall report to the Core NRAs in the situation when no capacity is offered by the Core TSOs via the monthly timeframe. This report shall contain:
   a. a justification for the difference between the predicted monthly capacity in the yearly timeframe and the actual allocated monthly capacity;
   b. the collection by the CCC of all reports analysing the effectiveness of relevant allocation constraints, received from the concerned TSOs during the period covered by the report;
   c. the continuous monitoring of the effects and performance of the application of this methodology.

Article 21 Language

1. The reference language for this LT CCM shall be English.

2. For the avoidance of doubt, where Core TSOs need to translate this LT CCM into their national language(s), in the event of inconsistencies between the English version published by Core TSOs in accordance with article 4(13) of the FCA Regulation and any version in another language, the relevant Core TSOs shall be obliged to dispel any inconsistencies by providing a revised translation of this LT CCM to their relevant Core NRAs.

TITLE 7: IMPLEMENTATION

Article 22 Timescale for Implementation

1. Core TSOs shall publish this methodology without undue delay after it has been approved by the relevant NRAs or a decision has been taken by ACER in accordance with article 4(9) of the FCA Regulation.
2. Core TSOs shall implement the FB capacity calculation approach described in this methodology allowing a FB allocation for Long Term timeframe within a period of 3.5 years to 5 year after approval of this methodology. The implementation process shall start on the date of approval of this methodology. The Core coordinated Long Term capacities are the ones resulting from the FB Capacity Calculation process after the implementation of this methodology.
3. During the implementation phase of the FB methodology, the Core TSOs will continue the NTC allocation and will improve the coordination at Core CCR level. A TSOs committee, consisting of one representative from each Core TSOs, shall act as a body for settlement of disputes among TSOs regarding the coordination of LT capacities during the implementation period of the FB methodology.
4. The implementation process of the FB approach shall include an internal test, during which the Core TSOs shall test the operational processes for the long-term capacity calculation inputs, the long-term capacity calculation process and the long-term capacity validation and develop the appropriate IT tools and infrastructure.
5. The implementation process of the FB calculation and allocation approach shall also include an external parallel run, to allow all Market Participants to adapt and develop appropriate IT Tools to be able to proceed to Flow Based Allocations for Long Term time frames.
6. During the internal parallel run, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. During the external parallel run TSOs shall publish the monitoring and performance criteria. After the implementation of this methodology, the outcome of this monitoring shall be summarized in an annual report.

ANNEX 1: JUSTIFICATION FOR CALCULATION OF EXTERNAL CONSTRAINTS AND ITS APPLICATION

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

1. **Netherlands:**

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

Technical and legal justification

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

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

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

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

Methodology to calculate the value of external constraints

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

2. **Poland:**

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

Technical and legal justification

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

The integrated scheduling process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process1. Therefore, one way to ensure sufficient reserve capacity within integrated scheduling process is to set a limit to how much electricity can be imported or exported in the SDAC.

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

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

Methodology to calculate the value of external constraints

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

The constraints are calculated according to the below equations:

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

$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \quad (2)$$

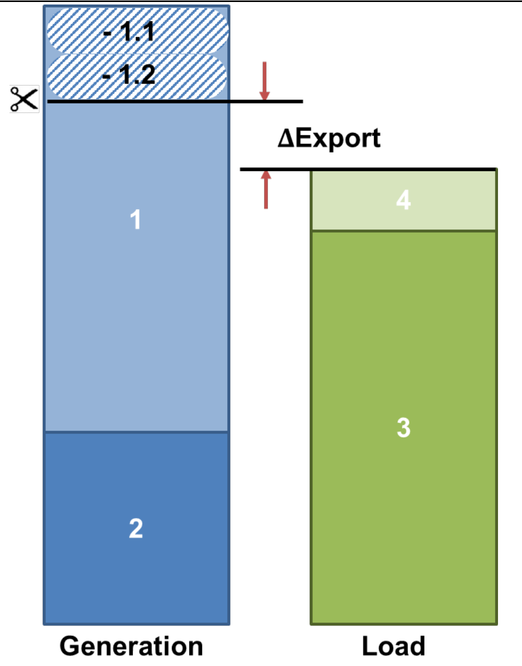
Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators2
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_{ER}	Generation unavailability’s adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

[2] 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.

For illustrative purposes, the process of practical determination of external constraints in export direction in the framework of the long-term capacity calculation is illustrated below in Figure 1. The figure illustrate how a forecast of the Polish power balance for the delivery period is developed by PSE in order to determine reserves in generating capacities available for potential exports, for the long-term market.

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



1 Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
  - 1.1 Generation not available due to grid constraints
  - 1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)

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

3 Demand forecasted by PSE

4 Minimum necessary reserve for up regulation

Figure 1 Determination of External constraint in export direction (generating capacities available for potential exports) in the framework of the long-term capacity calculation.

Frequency of review

External constraints are determined in a continuous process based on the most recent information, for each capacity allocation time frame.