Explanatory note on the day-ahead common capacity calculation methodology for Core CCR

Version September 2017

CONTENT

GLOSSARY

ACER	Agency for the Cooperation of Energy Regulators
AHC	Advanced Hybrid Coupling
BRP	Balance responsible party
CACM	Capacity allocation and congestion management
CC	Capacity calculation
CCC	Coordinated capacity calculator
CCR	Capacity calculation region
CGM	Common grid model
CGMA	Common grid model alignment
CGMAM	Common grid model alignment methodology
CHP	Combined heat and power
CNE	Critical network element
CNEC	Critical network element and contingency
D-1	Day-ahead
D-2	Two-days ahead
D2CF	Two-days ahead congestion forecast
DC	Direct current
EC	External constraint
EFB	Evolved flow-based
EMF	European merging function
ENTSO-E	European network of transmission and system operators for electricity
FAV	Final adjustment value
FB	Flow-based
F_0	Expected flow without commercial exchange within the Core region
F_{exp}	Expected flow
F_{max}	Maximum admissible power flow
F_{LTN}	Expected flow after long term nominations
F_{real}	Real flow
F_{ref}	Reference flow
FRM	Flow reliability margin
GSK	Generation shift key
HVDC	High voltage direct current
IGM	Individual grid model
I_{max}	Maximum admissible current
$LODF$	Line outage distribution factors
LT	Long term
LTA	Long term allocated capacities
LTN	Long term nominations submitted by Market Participants based on LTA
MC	Market Coupling
MCP	Market clearing point
MTU	Market time unit
NP	Net position
NRA	National regulatory authority
NTC	Net transfer capacity
OSP	Operational security policy

PNP	Preliminary net position
PPD	Pre-processing data
PST	Phase-shifting transformer
$PTDF$	Power transfer distribution factor
PTR	Physical transmission right
PX	Power exchange for spot markets
RA	Remedial action
RAM	Remaining available margin
RAO	Remedial action optimization
RES	Renewable energy sources
SA	Shadow auctions
SCED	Security constrained economic dispatch
SCUC	Security constrained unit commitment
SCUC/ED	Security constrained unit commitment and economic dispatch
SO	System operation
SoS	Security of supply
TSO	Transmission system operator
x	scalar
$\vec{x}$	vector
$\boldsymbol{x}$	matrix
Z2S	Zone-to-slack
Z2Z	Zone-to-zone

1.   INTRODUCTION

Sixteen TSOs follow a decision of the Agency for the Cooperation of Energy Regulators (ACER) to combine the existing regional initiatives of former Central Eastern Europe and Central Western Europe to the enlarged European Core region (Decision 06/2016 of November 17, 2016). The countries within the Core CCR are located in the heart of Europe which is why the Core CCR Project has a substantial importance for the further European market integration.

In accordance with Article 20ff. of the CACM Regulation, the Core TSOs are working on the implementation of the day-ahead common capacity calculation methodology Proposal (hereafter Core DA FB CCM).

The aim of this explanatory note is to provide a detailed description of the day-ahead common capacity calculation methodology Proposal and relevant processes. This paper considers the main elements of the relevant legal framework (i.e. CACM Regulation, 714/2009, 543/2013). Chapter 2 of this document covers the day-ahead common capacity calculation methodological aspects including the description of the inputs and the expected outputs, while Chapter 3 details the Core DA FB CC process.

1.1. Approach for finalization of the Core DA FB CCM

Although the Core TSOs started the development of the required Core DA FB CCM in time, it is highly challenging for the 16 TSOs (13 countries) in the Core CCR to deliver a final CCM within 10 months after the ACER CCR decision that requested the establishment of the Core CCR in deviation from TSOs' proposal to merge the formerly existing regions CWE and CEE only in a second, later step.

Therefore, Core TSOs will follow the below approach for finalization of the Core DA FB CCM:

1. Submission of the updated Approval Package to NRAs on 17 September 2017
    ● Updated Core DA FB CCM Proposal with the inclusion of all adaptations possible at this moment in time based on feedback received from Core stakeholders;
    ● Clear process steps included in the Proposal on how to determine the final values and methods for e.g. CNEC selection, harmonized risk level in the FRM calculation, Generation Shift Key methodology and Remedial Action Optimisation. These process steps include descriptions on how to close and approve the open points;
        o Core TSOs will provide a "Core TSO deliverable report" in Q1 2018 with detailed plans on how to finalize the open topics. Core TSOs shall conclude on finalization of the methodology, consult it with Market Participants and propose the updated methodology to NRAs;
        o NRAs shall approve the proposed update of the respective Articles in the Proposal.
2. In parallel of the NRA approval period (6 months until March 2018) Core TSOs will continue detailing the Proposal and Explanatory Note based on the results from experimentation and further alignment with NRAs and Market Parties

Main reasons for Core TSOs to propose this approach:

- To be able to develop a Core DA FB CCM that meets stakeholders' and NRAs' expectations as reflected in the feedback received after public consultation;
- To secure the development of a solid Core DA FB CCM, supported by experimentation results and feasibility studies, being able to provide an acceptable level of capacity to the market while ensuring security of supply;

1.2. Core TSO Deliverable Report

In Q1 2018, Core TSOs shall provide a report to the Core NRAs in which detailed plans are described on how to conclude on the following topics:

- Methodology for critical network elements and contingencies selection
- Reliability margin methodology
- Generation shift keys methodology
- Rules on the adjustment of power flows on critical network elements due to remedial actions

It should therefore be considered that this Explanatory Note describes the current status of the Core DA FB CCM (September 2017) but will be amended according to the further development of the Core DA FB CCM.

2. FLOW-BASED CAPACITY CALCULATION METHODOLOGY

2.1. Inputs – *see Article 21(1)(a) of the CACM Regulation*

2.1.1. Methodologies for operational security limits, contingencies and allocation constraints – *see Article 23 of the CACM Regulation*

2.1.1.1. Critical network elements and contingencies

According to Article 5(1) and (2) of the Proposal, a Critical Network Element (CNE) is a network element, significantly impacted by Core cross-border trades, which can be monitored under certain operational conditions, the so-called Contingencies. The CNECs (Critical Network Element and Contingencies) are determined by each Core TSO for its own network according to agreed rules, described below.

The CNECs are defined by:
- A CNE: a tie-line, an internal line or a transformer, that is significantly impacted by cross-border exchanges (see 2.2.2);
- An "operational situation": normal (N) or contingency cases (N-1, N-2, busbar faults; depending on the TSO risk policies).

A contingency can be a trip of:
- a line, cable or transformer;
- a busbar;
- a generating unit;
- a (significant) load;
- A set of the aforementioned contingencies.

CNEs were formerly known as Critical Branches (CBs), while contingencies were called Critical Outages (COs). The combination of a CB and a CO (formerly CBCO) is referred to as a CNEC.

2.1.1.2. Maximum flow & current on a critical network element

Maximum current on a Critical Branch (I_{max})

According to Article 6(1)(a)-(c) of the Proposal, the maximum admissible current ($I_{\max}$) is the physical limit of a CNE determined by each TSO in line with its operational security policy. This $I_{\max}$ is the same for all the CNECs referring to the same CNE. $I_{\max}$ is defined as a permanent or temporary physical (thermal) current limit of the CNE in kA. A temporary current limit means that an overload is only allowed for a certain finite duration (e.g. 115% of permanent physical limit can be accepted during 15 minutes). Each individual TSO is responsible for deciding, in line with their operational security policy, if a temporary limit can be used.

As the thermal limit and protection setting can vary in function of weather conditions, $I_{\max}$ is usually fixed per season. Its value can be adapted by the concerned TSO if a specific weather condition is forecasted to highly deviate from the seasonal values, e.g. when the forecasted ambient temperature significantly exceeds the temperature threshold that was used for determining the seasonal values. Insofar as

dynamic line rating is available for a given CNE, its I_{max} may vary by market time unit depending on the weather forecast. There are also CNEs with fixed I_{max} for all market time units, for example because they are equipped with modern high temperature conductor material, whose current limit is less dependent on the ambient temperature than regular conductors, or because dynamic line rating is not yet available for this CNE.

I_{max} is not reduced by any security margin, as all uncertainties in capacity calculations on each CNEC are covered by the flow reliability margin (FRM, see section 2.1.2) and final adjustment value (FAV, see section 2.1.1.3).

Maximum admissible power flow (F_{max})

According to Article 6(1)(d) of the Proposal, the value F_{max} describes the maximum admissible power flow on a CNE in MW. This F_{max} is the same for all the CNECs referring to the same CNE. F_{max} will be calculated using reference voltages.

F_{max} is calculated from I_{max} by the given formula:

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

Equation 1

with

F_{max}	maximum admissible power flow on a CNE in MW
I_{max}	maximum admissible current in kA of the CNE
U	reference voltage in kV
$cos(\varphi)$	power factor

The value for U^1 is fixed values for each CNE and $cos(\varphi)$ is set to 1 for the Core CCR which explains the Equation 1 of the Proposal.

2.1.1.3. Final adjustment value (FAV)

This section refers to Article 7 of the Proposal. With the final adjustment value (FAV), operational skills and experience, that cannot be taken into account in the flow-based parameters otherwise, can find a way into the flow-based methodology by increasing or decreasing the remaining available margin (RAM) on a particular CNE. Any usage of FAV will be duly elaborated and reported to the NRAs for the purpose of monitoring the capacity calculation.

Positive values of FAV (given in MW) reduce the available margin on a CNE while negative values increase it. The FAV can be set by the responsible TSO during the validation phase (see 3.5).

The following principles for the FAV usage have been identified:
● A negative value for FAV could simulate the effect of an additional margin due to complex Remedial Actions (RA) which was not modelled in the flow-based parameter calculation.

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1 Please note that the reference voltage can differ per TSO, but this value will at least be harmonized for tie-lines.

Instead, an offline calculation could determine how much capacity (in MW) can be released as additional margin without endangering the N-1 security of the TSO's own and also neighbouring networks. In any case, these $FAVs$ have to be agreed by neighbouring TSOs in advance before they can be applied in operations.

- A positive value for FAV could simulate the need to reduce the margin on one or more CNEs for system security reasons. Such reasons include, for example, the cases stated in section 3.5 (Validation) and the potential need to cover significant reactive power flows on certain CNEs. The overload detected on a CNE during the validation phase is the value which will be put as a FAV for this CNE in order to eliminate the risk of overload on this particular CNE.

2.1.1.4. Allocation Constraints

This section refers to Article 8 of the Proposal. Besides active power flow limits on CNEs, other specific limitations may be necessary to maintain the transmission system within operational security limits. Since such specific limitations cannot be efficiently transformed into maximum flows on individual CNEs, they are expressed as allocation constraints. More specifically, TSOs determine maximum import and/or export of bidding zones, also called external constraints (ECs). They are taken into account during the day-ahead market coupling in addition to the power flow limits on CNEs. The usage of ECs is justified by several reasons, among which:

- avoid market results which lead to stability problems in the network, detected by system dynamics studies;
- avoid market results 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, leading to a situation which could not be validated as safe by the concerned TSO during validation (see 3.5)
- needs of a minimum level of operational reserve to ensure ability decreasing or increasing of generation for balancing of specific control area and consequently guarantee the security of the system.

In other words, FB capacity calculation includes contingency analysis based on a DC load flow approach, and the constraints are determined as active power flow constraints only. Since grid security goes beyond the active power flow constraints, issues like:

- voltage and dynamic stability;
- linearization assumptions;
- available operational reserves;

need to be taken into account as well. This requires the determination of constraints outside the FB parameter computation: the so-called external constraints.

The detailed explanations of individual Core TSOs operational limits, which are provided as the external constraints are described in Appendix 1.

External constraints are crucial to ensure security of supply and are, therefore, systematically implemented as an input of the FB calculation process. To put it in another way, the TSO does not decide on including or not an EC on a given day (or even hour). Instead, the TSO will always integrate a previously determined EC in order to prevent unacceptable situations as defined above – apart from the

rare occasion of a negative outcome of the validation step (see 3.5), when manual intervention is needed.

The ECs are regularly reviewed and potentially updated at least once a year, in line with the annual review (see 2.1.5).

The design and activation of external constraints is fully transparent. The external constraints are easily identifiable in the published capacity domain data. Indeed, their $PTDFs$ are straightforward (the zone-to-slack $PTDF$ for the concerned bidding area is 1 or -1 and all the other $PTDFs$ are set to zero, the RAM being the import/export limit after long term nominations – see 2.2.1.1) and can be directly linked to the respective bidding zone. Alternatively, the external constraint can be applied directly during market coupling and not as a capacity calculation constraint. In such a case the global net position (exchanges over all borders and not only those in the CCR) will be limited by the external constraint.

External constraints versus FRM:

By construction, $FRMs$ do not allow to hedge against the situations mentioned above which can occur in extreme cases, since they only represent the uncertainty in forecasted flow of the FB model.

Therefore, FRM on one hand (statistical approach, looking "backward", and "inside" the FB model) and external constraints on the other hand (deterministic approach, looking "forward", and beyond the limitations of the FB model) are complementary and cannot be a substitute to each other. Each TSO has designed its own thresholds on the basis of studies, but also on operational expertise acquired over the years.

2.1.2. Flow reliability margin (FRM) – *see Article 22 of the CACM Regulation*

This section refers to Article 9 of the Proposal. The methodology for the capacity calculation 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.

This section describes the methodology of determining the level of reliability margin per critical network element and contingency (CNEC) – also called the flow reliability margin (FRM) – which is based on the assessment of the uncertainties involved in the FB CC process. In other words, the FRM has to be calculated such that it prevents, with a predefined level of residual risk, that the execution of the market coupling result (i.e. respective changes of the Core net positions) leads to electrical currents exceeding the thermal rating of network elements in real-time operation in the CCR due to inaccuracies of the FB CC process.

The FRM determination is performed by comparing the power flows on each CNEC of the Core CCR, as expected with the FB model used for the D-1 market coupling, with the real-time flows observed on the same CNEC. All differences for a defined time period are statistically assessed and a probability distribution is obtained. Finally, a risk level is applied yielding the FRM values for each CNEC. The FRM values are constant for a given time period, which is defined by the frequency of FRM determination process in line with the annual review requirement. The concept is depicted in Figure 1.
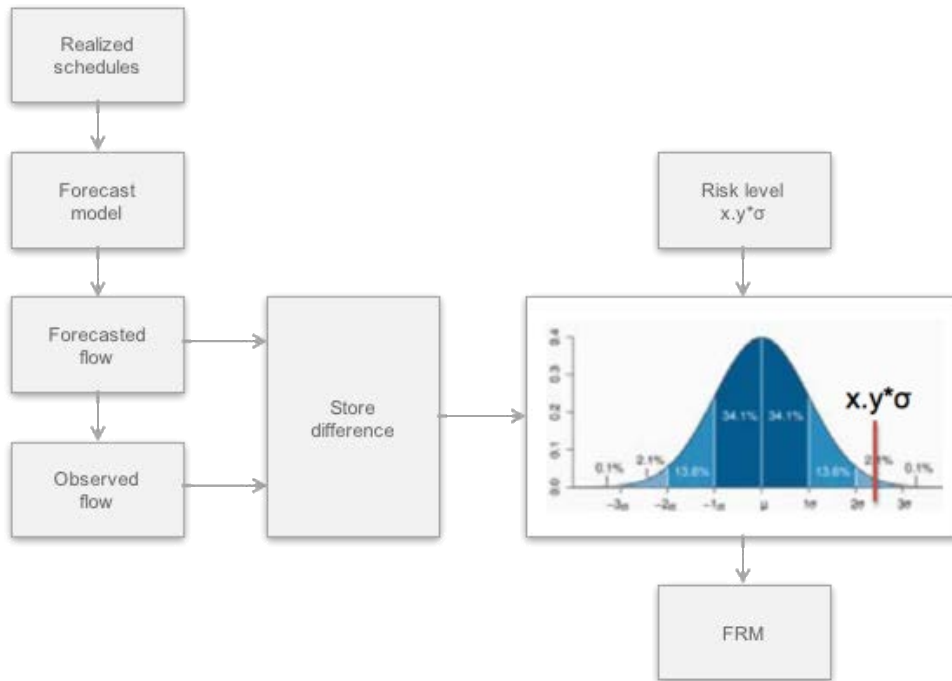
Figure 1: Process flow of the FRM determination

For all the hours within the one-year observatory period of the FRM determination, the D-2 Common Grid Model (CGM) is modified to take into account the real-time situation of some remedial actions that are controlled by the TSOs (e.g. PSTs) and thus not foreseen 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[2] inside the Core CCR with the D-2 $PTDFs$ (see section 2.2.1). Consequently, the same commercial exchanges in Core are taken into account when comparing the flows based on the FB CC model created in D-2 with flows in the real-time situation. These flows are called expected flows (F_{ref}), see Equation 2.

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

Equation 2

with

$\vec{F}_{exp}$	expected flow per CNEC
$\vec{F}_{ref}$	flow per CNEC in the modified D-2 CGM
$\boldsymbol{PTDF}$	power transfer distribution factor matrix of the modified D-2 CGM
$\overrightarrow{NP}_{real}$	realized net position per bidding zone (based on realised exchanges)
$\overrightarrow{NP}_{ref}$	net position per bidding zone in the D-2 CGM

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2 Please note that realized commercial exchanges include the trades of all timeframes (e.g. intraday) before realtime. Exchanges naturally changes

the flows in the grid from the initially forecasted flows. Hence the amount of exchanges do not lead to uncertainties itself, but the uncertainty of their

flow impact, which is modelled in the GSK, is considered in the FRM.

For the same observatory period, the realized power flows are calculated using the real time European grid models by means of contingency analysis. Then for each CNEC the difference between the real flow (F_{real}) and the expected flow (F_{exp}) from the FB model is calculated. Results are stored for further statistical evaluation.

In a second step, 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[3]:

- 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;
- 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.

The statistical evaluation, as described above is conducted centrally by the CCC. 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.

As a summary, the FRM covers the following forecast uncertainties with a certain risk level:
- Core external transactions (out of Core CCR control: both between Core region and other CCRs as well as among TSOs outside the Core CCR);
- generation pattern including specific wind and solar generation forecast;
- generation Shift Key;
- load forecast;
- topology forecast;
- unintentional flow deviation due to the operation of load frequency controls;
- FB CC assumptions including linearity and modelling of external (non-Core) TSOs' areas.

After computing the FRM following the above-mentioned approach, TSOs may potentially apply an "operational adjustment" before practical implementation into their CNE and CNEC definition. The rationale behind this is that TSOs remain critical towards the outcome of the pure theoretical approach in order to ensure the implementation of parameters which make sense operationally. For any reason (e.g. data quality issue, perceived TSO risk level), it can occur that the "theoretical FRM" is not consistent with the TSO's experience on a specific CNE. Should this case arise, the TSO will proceed to an adjustment. It is important to note here that this adjustment which can be set between 5% and 20% of the F_{max} calculated under normal weather conditions. It is not an arbitrary re-setting of the FRM but an adaptation of the initial theoretical value. The differences between operationally adjusted and theoretical values shall be systematically monitored and justified, which will be formalized in an annual report towards Core NRAs.

Eventually, the operational FRM value is determined and updated once for all TSOs and then becomes a fixed parameter in the CNE and CNEC definition until the next FRM determination.

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3 If the same CNE is shared by two TSOs, the respective TSOs will aim to align on the same FRM value.

2.1.3.   Generation Shift Key (GSK) – *see Article 24 of the CACM Regulation*

According to Article 10 of the Proposal, the generation shift key (GSK) defines how a change in net position is mapped to the generating units in a bidding zone. Therefore, it contains the relation between the change in net position of the bidding zone and the change in output of every generating unit inside the same bidding zone.

Due to the convexity pre-requisite of the flow-based domain as required by the price coupling algorithm, the GSK must be constant per MTU.

Every TSO assesses a GSK for its control area taking into account the characteristics of its system. Individual *GSKs* can be merged if a bidding zone contains several control areas.
A GSK aims to deliver the best forecast of the impact on CNEs of a net position change, taking into account the operational feasibility of the reference production program, projected market impact on generation units and market/system risk assessment.

In general, the GSK includes power plants that are market driven and that are flexible in changing the electrical power output. TSOs will additionally use less flexible units, e.g. nuclear units, if they don't have sufficient flexible generation for matching maximum import or export program or if they want to moderate impact of flexible units. Since the generation pattern (locations) is unique for each TSO and the range of the NP shifting is also different, there is no unique formula for all Core TSOs for creation of the GSK. Finally, the resulted change of bidding zone balance should reflect the appropriate power flow change on CNECs and should be relevant to the real situation.

For the application of the methodology, Core TSOs may define:
a) Generation shift keys based proportional to the actual generation 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;
c) Generation shift keys with fixed values based on the D-2 CGM for each peak and off-peak situations.

The GSK values are given in dimensionless units. For instance, a value of 0.05 for one unit means that 5 % of the change of the net position of the bidding zone will be realized by this unit. Technically, the GSK values are allocated to units in the CGM. In cases where a generation unit contained in the GSK is not directly connected to a node of the CGM (e.g. because it is connected to a voltage level not contained in the CGM), its share of the GSK can be allocated to one or more nodes of the CGM in order to appropriately model its technical impact on the transmission system.

2.1.4.   Remedial Action (RA) – *see Article 25 of the CACM Regulation*

This section refers to Article 11 of the Proposal. During flow-based parameters calculation Core TSOs will take into account Remedial Actions (RAs) in D-2 to optimize cross-zonal capacities while ensuring a secure power system operation, e.g. N-0/N-1/N-k criterion fulfilment in real-time.

Each RA is connected to one or more CNEC combination(s), while the calculation can take explicit and implicit RAs into account. Only explicit RAs are considered in the remedial action optimization (RAO).

An explicit RA can be:
- changing the tap position of a phase shifting transformer (PST);
- 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.

Explicit measures are applied during the flow-based parameters calculation and their effect on the CNECs is determined directly.

In principle, all measures can be preventive (applied before an outage occurs and hence effective for all CNECs) or curative, i.e. for defined CNECs only.

Implicit RAs can be used when it is practically not possible to explicitly express a RA by means of a concrete change in the grid model. In this case a FAV (see section 2.1.1.3) will be used as RA.

The influence of an implicit RA on CNECs is assessed by the TSO upfront and taken into account by using a FAV, which changes the available margins of the CNECs to a certain amount.

All explicit RAs applied for flow-based parameter calculation must be coordinated in line with Article 25 of the CACM Regulation.

The general purpose of the application of RAs is to modify the flow-based domain for the benefit of the market, while respecting security of supply.

A description on how the RA optimization is performed will be given in the section 3.2.5.

2.1.5.   Changes of Inputs for the capacity calculation

During the formalized flow-based capacity calculation, Core TSOs consider input parameters (described in current chapter) that can adapt the FB domain to the expected operational situations to ensure the safe operation of the transmission system.

Core TSOs will continuously monitor and report the input parameters considered. Core TSOs will evaluate the input parameters considered as part of the annual review using the latest available information and update of the Core FB capacity calculation methodology if necessary.

The following handling / communication of input-changes is foreseen[4]:
1. Daily operational changes required for grid security (ex-post communication to regulators in framework of monthly monitoring reports).
2. Possible anticipated updates after review by TSOs (ex-ante communication with possible impact assessment delivered to market parties and regulators).

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4 Please note that the approach for communication and impact assessments for the different FB input parameters changes will be further defined in the Core Transparency Framework.

2.2. Capacity calculation approach – *see Article 21(1)(b) of the CACM Regulation*

2.2.1. Mathematical description of the capacity calculation approach – *see Article 21(1)(b)(i), (v) of the CACM Regulation*

The flow-based computation is a centralized calculation which delivers two main classes of parameters needed for the definition of the flow-based domain: the power transfer distribution factors (*PTDFs*) and the remaining available margins (*RAMs*). The following chapters will describe the calculation of each of these parameters.

2.2.1.1. Power transfer distribution factor ($PTDF$)

This section refers to Article 13(1) to (4) of the Proposal. The elements of the $PTDF$ matrix represent the influence of a commercial exchange between bidding zones on power flows on the considered combinations of CNEs and contingencies. The calculation of the $PTDF$ matrix is performed on the basis of the CGM and the GSK.

The nodal $PTDFs$ are first calculated by subsequently varying the injection on each node of the CGM. For every single nodal variation, the effect on every CNE's or CNEC's loading is monitored and calculated[5] as a percentage (e.g. if an additional injection of a 100 MW has an effect of 10 MW on a CNEC, the nodal $PTDF$ is 10 %).

Then the GSK translates these nodal $PTDFs$ (or node-to-slack $PTDFs$) into zonal $PTDFs$ (or zone-to-slack $PTDFs$) as it converts the zonal variation into an increase of generation in specific nodes:

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

Equation 3

with

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

The $PTDFs$ characterize the linearization of the model. In the subsequent process steps, every change in net positions is translated into changes of the flows on the CNEs or CNECs with linear combinations of $PTDFs$. The net position (NP) is positive in export situations and negative in import situations. The Core NP of a bidding zone is the net position of this bidding zone with regards to the Core bidding zones.

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

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5 In this load flow calculation the variation of the injection of the considered node is balanced by an inverse change of the injection at the slack node.

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

Equation 4

Zone-to-zone $PTDFs$ must be transitory i.e.

$$PTDF_{A \to C,l} = PTDF_{A \to B,l} + PTDF_{B \to C,l}$$

Equation 5

The validity of Equation 5 is ensured by Equation 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:

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

Equation 6

with

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

BZ list of Core bidding zones

2.2.1.2. Reference flow (F_{ref})

In Article 13(5) of the Proposal, the reference flow is the active power flow on a CNE or a CNEC based on the CGM. In case of a CNE, the F_{ref} is directly simulated from the CGM whereas in case of a CNEC, the F_{ref} is simulated with the specified contingency. F_{ref} can be either a positive or a negative value depending on the direction of the monitored CNE or CNEC (see Figure 2 – the F_{ref} value is 50 MW for $CNE_{A \to B}$ but -50 MW for the $CNE_{B \to A}$). Its value is expressed in MW.
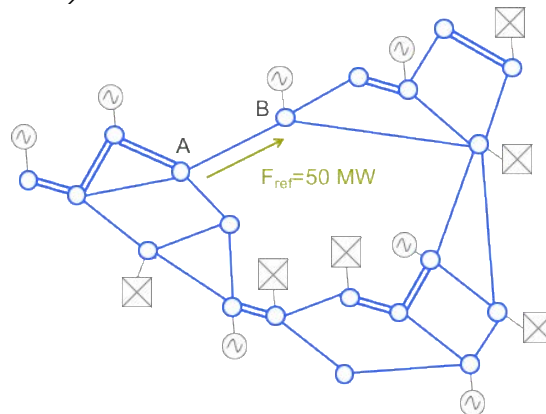

Figure 2: Example of a reference flow for the $CNE_{A \to B}$

2.2.1.3. Expected flow in a commercial situation

According to Article 13(6) of the Proposal, the expected flow F_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:

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

Equation 7

with

$\vec{F}_i$	expected flow per CNEC in the commercial situation 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 the commercial situation i
$\overrightarrow{NP_{ref}}$	Core net position per bidding zone in the CGM

As a matter of fact, in case one considers the commercial situation of the CGM, the expected flow becomes $\vec{F}_i = \vec{F}_{ref}$.

Expected flow without Core commercial exchanges

In case all the Core net positions are set to zero using the *GSK* nodes, i.e. when there is no commercial exchange within the Core region, the previous equation becomes:

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

Equation 8

with

$\vec{F}_0$	expected flow per CNEC with no commercial exchange within the Core region

Expected flow taking into account the nominations of the long-term products

In case all the Core net positions are set to the netted nominations of the long-term products for the Core bidding zone borders with Physical Transmission Rights (PTRs):

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

Equation 9

with

$\vec{F}_{LTN}$	expected flow per CNEC after long term nominations
$\vec{F}_{ref}$	flow per CNEC in the CGM
$\boldsymbol{PTDF}$	power transfer distribution factor matrix
$\overrightarrow{NP_{LTN}}$	Core net position per bidding zone resulting from long term nominations
$\overrightarrow{NP_{ref}}$	Core net position per bidding zone in the CGM

2.2.1.4. Remaining available margin in a commercial situation i

According to Article 12(7) of the Proposal, the remaining available margin 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:

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

Equation 10

2.2.2. CNEC selection *– see Article 21(1)(b)(ii) of the CACM Regulation*

Disclaimer: Please be informed that the CNEC selection process is still under development within the Core region. The sections depicted below are the current status of the methodology foreseen.

This section refers to the Article 5(3) to (7) of the Proposal. The CNEC selection process will use a three-step approach to determine the CNEC combinations which will be used for the FB computation.

As the first step an initial pool of CNEs and contingencies will be created: this pool is the result of the input from each TSO. As the second step, the CNECs for regional remedial actions optimization (RAO) will be selected. Finally, a selection will be performed to determine the final set of constraints for regional market coupling (MC).

The process requires the determination of two separate thresholds: one to assess the remedial actions relevance and the second to assess the cross border trades relevance. The differentiation of the CNEC selection between the two sub-processes (RAO and MC) is needed to monitor the impact of RAO on certain CNECs which are strongly impacted by Remedial Actions while only weakly impacted by cross border exchanges. This implies that the pool of CNECs may be different for RAO and MC. More specifically, the pool of critical CNECs for MC will always be a subset of the CNECs considered in the initial pool for RAO.

2.2.2.1. Creation of an initial pool of CNEs and Contingencies

Each TSO will be able to define a list of CNEs and contingencies which need to be monitored during the RAO process and/or the regional MC. The selection will be based on each TSO's needs and operational experience. The result of the decentralized process will be an initial pool of CNEs and contingencies to be used for RAO and MC.

The pool is defined during an offline process and will remain fixed during the computation. The list of CNEs and contingencies will be reviewed on a daily basis.

2.2.2.2. Selection of regional CNECs for the RA optimization

The second step of the process will associate the CNEs with relevant contingencies and will determine the selection of CNECs considered for RA optimization.

For the association of contingencies to CNEs, two general rules will be applied. First, the contingencies of a TSO will be associated to the CNEs of that TSO. Second, each TSO will individually associate contingencies within its observability area to its own CNEs. Currently, there is no harmonized approach to define the observability area of a TSO. In the future, this will be aligned with the criteria defined in the SO guideline. These criteria can for example be the 'influence factor' or 'line outage distribution factor'.

The result of this process is a pool of CNECs for remedial actions optimization. The CNECs of this pool can be divided in three categories:
- CNECs which are sensitive to cross border exchanges. These CNECs are considered for RAO and for the market coupling;
- CNECs which are not highly sensitive to cross border exchanges, but are significantly impacted by certain RAs. These CNECs are monitored during RAO and not considered for the market coupling;
- CNECs which are neither highly sensitive to cross border exchanges nor impacted by certain RAs are excluded from RAO.

Selection of the final constraints for regional market coupling

After RAO, the initial pool of CNECs will be filtered based on the cross-zonal network elements[6] of the Core region and internal lines from the initial pool (taken into account the final set of RAs) sensitive to cross-border exchanges. After the validation and the final FB computation i.e. after the final RAM values are known, the most constraining CNECs (presolved ones) are determined. Only these will be given to market coupling.

2.2.2.3. Remedial actions sensitivity

The sensitivity of CNECs to certain remedial actions is a key parameter for the creation of the initial pool of CNECs for RAO. For certain CNECs, two parameters could be impacted by the activation of specific RAs:
- Change in available margin due to activation of a RA e.g. a change in PST tap setting or a topological action, the margin of a CNEC could change significantly (e.g. more than X MW or Y% of F_{max}) and could even become negative (precongested);
- Change in zone to zone *PTDFs*, e.g. due to a topological RA. This implies that certain CNECs could be below the max zone to zone *PTDFs* threshold before RAO, but could pass the threshold after RAO (or vice versa).

In such a case, the CNEC could be considered as sensitive to RAs even if it does not (or at least not with certainty) fulfil the cross-border sensitivity criterion (see section 2.2.2.4). The CNEC would therefore be considered in the RAO, in addition to the CNECs fulfilling the cross-border sensitivity criterion.

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6 The term 'cross-zonal network elements' concerns 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 transformer station to which at least two internal transmission lines are connected.

2.2.2.4. Cross border sensitivity

Outline of approach

The cross-border sensitivity is a crucial criterion for selecting relevant CNECs. It is applied as the main criterion for selecting CNECs for the RAO and as the only criterion for selecting the internal CNECs[7] for the regional market coupling. The criterion is based on the maximum zone to zone *PTDF* value.

The Core TSOs adopted the maximum zone-to-zone *PTDFs* threshold of X%. TSOs want to point out the fact that the identification of this threshold is driven by two objectives:

- Bringing objectivity and measurability to the notion of "significant impact". This quantitative approach should avoid any discussion on internal versus external branches, which is an artificial notion in terms of system operation with a cross-border perspective.
- Above all, guaranteeing security of supply by allowing as much exchange as possible, in compliance with TSOs' risks policies, which are binding and have to be respected. In other words, this value is a direct consequence of Core TSOs' risk policies standards.

Practically, this X% value means that there is at least one set of two bidding zones in Core region for which a 1000 MW exchange creates an induced flow bigger than X MW (absolute value) on the branch. This is equivalent to saying that the maximum Core zone-to-zone *PTDF* of a given grid element should be at least equal to X% for it to be considered objectively "critical" in the sense of flow-based capacity calculation.

For each CNEC the maximum zone-to-zone *PTDF* value is calculated as follows:

$$PTDF_{z2z,max} = \max(PTDF_{z2s,1}, \ldots, PTDF_{z2s,N}) - \min(PTDF_{z2s,1}, \ldots, PTDF_{z2s,N})$$

Equation 11

with

$PTDF_{z2z,max}$ maximum zone-to-zone $PTDF$ of the CNEC

$PTDF_{z2s,k}$ zone-to-slack $PTDF$ of the CNEC with respect to bidding zone k

N number of Core bidding zones

If the sensitivity is above the threshold value of X%, then the CNEC is said to be significantly impacted by Core trades.

Irrespectively of their maximum zone-to-zone $PTDF$, cross-zonal elements are always deemed significant for Core trade. Therefore, cross-zonal CNEs with all defined contingencies are excluded from any filtering.

Background: Determination of zone-to-zone $PTDFs$

A set of $PTDFs$ is associated to every CNEC after each flow-based parameter calculation, and gives the influence of the variations of any bidding zone net position on the CNEC. Typically, there is only one $PTDF$ value given per bidding zone. If the $PTDF = 0.1$, this means the concerned bidding zone has 10%

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7 A CNEC is internal if its CNE is not a cross-zonal network element.

influence on the CNEC or in other words, one MW of change in net position leads to 0.1 MW change in flow on the CNEC. The change of flow is determined by increasing the net position of the bidding zone and reducing the net position of the slack by the same value.

A CNEC is a technical input that one TSO integrates at each step of the capacity calculation process in order to respect security of supply policies. The CNEC selection process is therefore performed by each TSO, who check the adequacy of their constraints with respect to operational conditions. The so-called flow-based parameters are an output of the capacity calculation associated to a CNE or CNEC at the end of the TSO operational process. As a consequence, when a TSO first considers a CNEC as a necessary input for its daily operational capacity calculation process, it does not know, initially, what the associated $PTDFs$ are.

From the calculated zone to slack $PTDFs$ (single value per bidding zone), a zone-to-zone $PTDF$ can be calculated (see Section 2.2.1.1). For example, by subtracting the zone-to-slack $PTDF$ of zone B from the one of zone A the impact of an exchange from zone A to zone B on a CNE or CNEC is determined.

In the example below where we assume the threshold is set to 5%, a typical $PTDF$ matrix is given. For each CNEC there is one zone-to-slack $PTDF$ value per bidding zone. For instance, an exchange of 1 MW between bidding zone A and the slack (which can be anywhere in the considered grid) leads to an increased loading of 0.146 MW on CNEC 3.

Zone to slack PTDFs

CNEC	Hub A	Hub B	Hub C
CNEC 1	4,9 %	4,8 %	-3,9 %
CNEC 2	4,3 %	-24,4 %	-11,5 %
CNEC 3	14,6 %	-2,7 %	-10 %
CNEC 4	0,2 %	-2,5 %	-1,5 %

Figure 3: Example zone-to-slack $PTDFs$

Since all commercial exchanges take place from one zone to the other, only the zone-to-zone $PTDF$ is a suitable indicator to determine whether a CNEC is impacted by cross border exchanges. Using the formula above, all zone-to-zone $PTDFs$ can be calculated.

It is clear that, although the zone-to-slack *PTDFs* of CNEC 1 are all below 5%, the impact of cross border exchanges is still very significant (8,8%).

Zone to zone PTDFs

CNEC	A→B	A→C	B→C	Max z2z
CNEC 1	0,1 %	8,8 %	8,7 %	8,8 %
CNEC 2	28,7 %	15,8 %	-12,9 %	28,7 %
CNEC 3	17,3 %	24,6 %	7,3 %	24,6 %
CNEC 4	2,7 %	1,7 %	-1,0 %	2,7 %

Figure 4 : Example zone-to-zone $PTDFs$

When considering the max zone-to-zone $PTDF$ of CNEC 4, it is clear that this CNEC does not meet the 5% threshold criteria. This implies that the branch will not be considered for MC unless it is a tie line or it is deemed necessary by the relevant TSOs (see "filtering and override process" below).

Filtering and override process

Although the general rule is to exclude any CNEC which does not meet the threshold on sensitivity, exceptions on the rule are allowed: if a TSO decides to keep or remove the CNEC among the presolved constraints, he has to justify it to the other TSOs, furthermore it will be systematically highlighted to the NRAs.

Minimum RAM reservation

Core TSOs are investigating the possibility to additionally ensure a minimum RAM for the CNECs limiting the cross-zonal capacity. The applicability of this approach depends on whether sufficient remedial actions are available to ensure the minimum RAM while safeguarding the operational security limits and is subject to the principles on cost sharing in line with Article 74(1) of the CACM Regulation and the recovery of the additional costs incurred by the TSOs.

2.2.3.   Long term allocated capacities (LTA) inclusion *– see Article 21(1)(b)(iii) of the CACM Regulation*

This section refers to Article 14 of the Proposal. In the current configuration of the Core region, there are 17 commercial borders which means that there are 2^{17}=131,072 combinations of net positions, that could result from the utilization of LTA values calculated under the framework of FCA guideline, to be verified against the FB domain.

The objective of the LTA check is to verify that the RAM of each CNE or CNEC remains positive in all the above-mentioned combinations. In other words, the following equation is applied to all possible combinations of net positions resulting from full utilization of LTA capacities on all commercial borders:

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

Equation 12

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 per bidding zone in the CGM

Then the following equation is checked:

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

Equation 13

If at least one of the remaining available margins RAM_i (for any CNEC and any LTA capacity utilization combination) is smaller than zero, this means the LTA values are not fully covered by the flow-based domain. In this case, one of the two following methods can be applied during the 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 and replace the CNEs or CNECs for which the RAM_i is negative (see Figure 5).
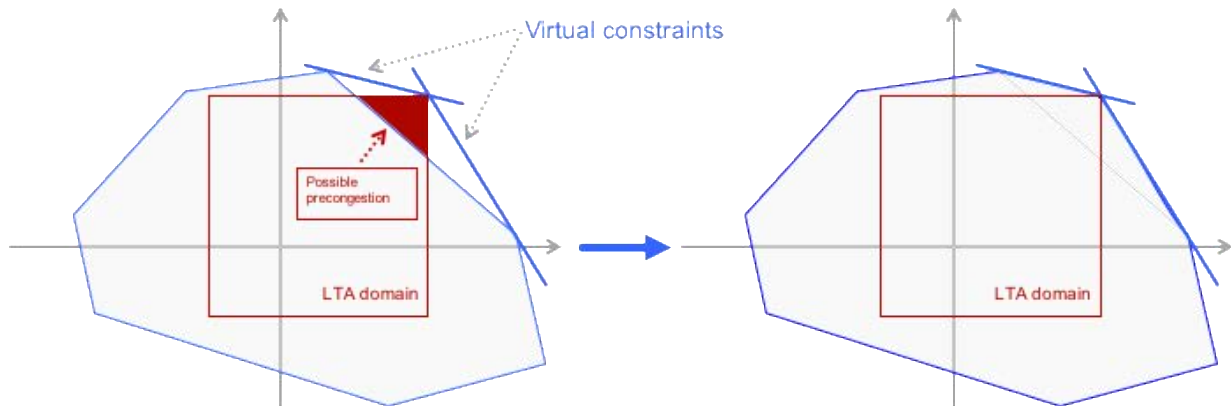

Figure 5: LTA coverage algorithm principle (2ⁿᵈ step)

This coverage is performed automatically in the final steps of the capacity calculation process before the adjustment to LT nominations.

In theory, such artefacts are not to be used. In practice, however, resorting to the "LTA coverage algorithm" can be necessary in case the FB model does not allow TSOs to reproduce exactly all the possible market conditions. For instance, the FB capacity domain is representative to the available cross-border capacities of the D-2 CGM whereas LT capacities are calculated in multiple market conditions.

In exceptional circumstances each Core TSO may, for reasons of security of supply, request a minimum import capacity for one or more MTUs. In this case, $\overrightarrow{NP_i}$ in Equation 8 will be adjusted accordingly. The acceptance of the minimum import capacity is subject to positive validation as explained in 3.5.

The usage of LTA inclusion is the object of analysis and will be monitored by Core NRAs. Obligatory monitoring items are listed and fixed in an appendix of the Proposal.

2.2.4. Rules on the adjustment of power flows on critical network elements due to remedial actions – *see Article 21(1)(b)(iv) of the CACM Regulation*

This section refers to Article 15 of the Proposal. The remedial actions (RAs) taken into account in the remedial action optimization (RAO) are defined in section 2.1.4. The output of the RAO process described in section 3.2.5 lists CNEs and Contingencies, including the selected RAs to be considered when computing the final $PTDF$ and RAM for market coupling (see 3.2.6).

2.2.5.   Integration of HVDC interconnectors located within the Core CCR in the Core capacity calculation (evolved flow-based)

This section refers to Article 16 of the Proposal. The evolved flow-based (EFB) methodology describes how to consider HVDC interconnectors on a bidding zone border within the flow-based Core CCR during Capacity Calculation and efficiently allocate cross-zonal capacity on HVDC interconnectors. This is achieved by taking into account the impact of an exchange over an HVDC interconnector on all critical network elements directly during capacity allocation. This, in turn, allows taking into account the flow-based properties and constraints of the Core region (in contrast with an NTC approach) and at the same time ensures optimal allocation of capacity on the interconnector in terms of market welfare.

There is a clear distinction between advanced hybrid coupling (AHC) and evolved flow-based. 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 FB area, implying that the influence of exchanges in one CCR (ATC or FB area) is taken into account in the FB calculation of another CCR. EFB takes into account commercial exchanges over the HVDC interconnector within a single CCR applying the FB method of that CCR.

The main adaptations to the capacity calculation process introduced by the concept of EFB are twofold.
- The impact of an exchange over the HVDC interconnector is considered for all relevant Critical Network Elements / Contingency combinations (CNECs)
- 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.

In order to achieve the integration of the HVDC interconnector into the FB process, two virtual hubs at the converter stations of the HVDC are added. These hubs represent the impact of an exchange over the HVDC interconnector on the relevant CNECs. By placing a GSK value of 1 at the location of each converter station the impact of a commercial exchange can be translated into a $PTDF$ value. This action adds two columns to the existing PTDF matrix, one for each virtual hub.

The list of contingencies considered in the capacity allocation is extended to include the 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 CNE/Contingency combinations for all relevant CNEs during the process of capacity calculation and allocation.

2.2.6.   Capacity calculation on non Core borders (hybrid coupling) – *see Article 21(1)(b)(vii)*

This section refers to Article 17 of the Proposal. Capacity calculation on non-Core borders is out of the scope of the Core FB MC project. Core FB MC just operates provided capacities (on Core to non-Core-borders), based on approved methodologies.

The standard hybrid coupling solution which is proposed today is in continuity with the capacity calculation process already applied in CWE FB MC. By "standard", we mean that the influence of "exchanges with non-Core bidding zones" on CNECs is not taken into account explicitly during the capacity allocation phase (no $PTDF$ relating to exchanges between Core and non-Core bidding zones to

the loading of Core CNECs). However, this influence physically exists and needs to be taken into account to make secure grid assessments, and this is done in an indirect way. To do so, Core TSOs make assumptions on what will be the eventual non-Core exchanges, these assumptions being then captured in the D2CF used as a basis, or starting point, for FB capacity calculations. The expected exchanges are thus captured implicitly in the RAM over all CNECs. Resulting uncertainties linked to the aforementioned assumptions are implicitly integrated within each CNECs FRM. As such, these assumptions will impact (increasing or decreasing) the available margins of Core CNECs.

After the implementation of the standard hybrid coupling in the Core region, the Core TSOs are willing to work on a target solution, in close cooperation with the adjacent involved CCRs that fully takes into account the influences of the adjacent CCR during the capacity allocation i.e. the so called advanced hybrid coupling concept.

3.   FLOW-BASED CAPACITY CALCULATION PROCESS

3.1. High Level Process flow

For day-ahead flow-based capacity calculation in the Core Region, the high-level process flow foreseen is presented in Figure 6.
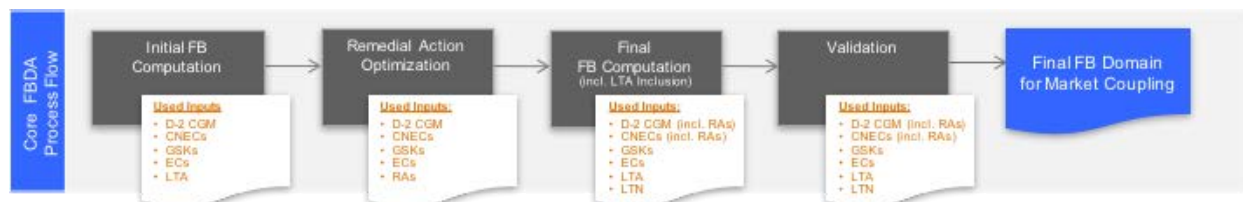

Figure 6: High level process flow for Core FB DA CC

3.2. Creation of a common grid model (CGM) – *see Article 28 of the CACM Regulation*

3.2.1.   Forecast of net positions

Forecasting of the net positions in day-ahead time-frame in Core CCR is based on a common process established in ENTSO-e: the Common Grid Model Alignment (CGMA). This centrally operated process ensures the grid balance of the models used for the daily capacity calculation across Europe. The process is described in the Common Grid Model Alignment Methodology (CGMAM)[8,] which is a part of Common Grid Model Methodology approved by all ENTSO-e TSOs NRAs in 8th May 2017.
Main concept of the CGMAM is presented in Figure 7 below:

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8 The "All TSOs' Common Grid Model Alignment Methodology in accordance with Article 25(3)(c) of the (draft) Common Grid Model Methodology" dated

17th of October 2017, can be found on ENTSO-E website:

https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/cacm/cgmm/Common_Grid_Model_Alignment_Methodology.pdf
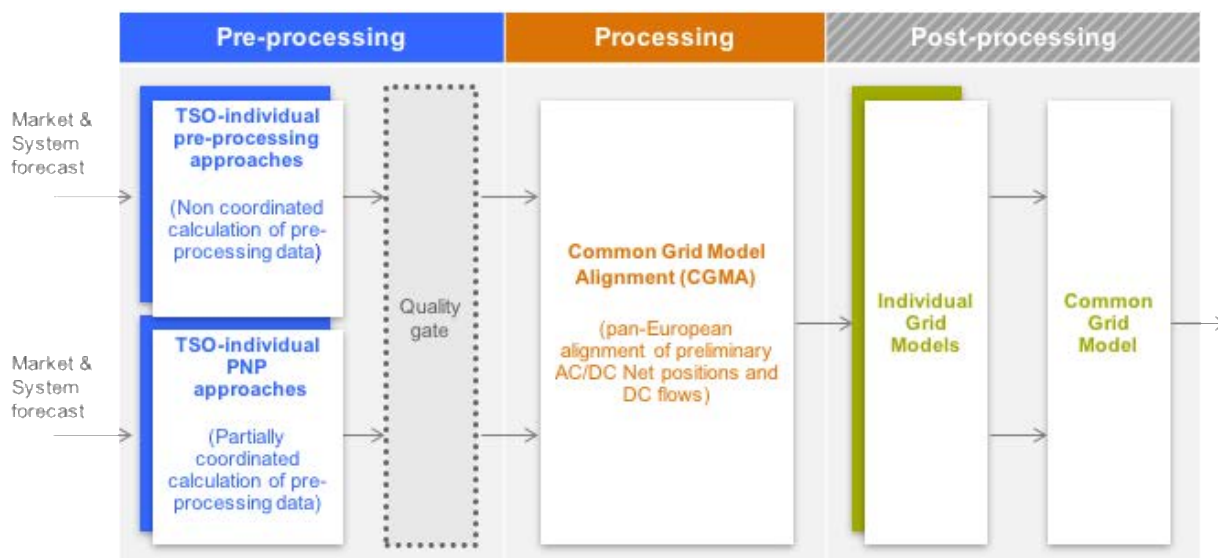
Figure 7: Main concept of the CGMAM

The CGMAM input data are created in the pre-processing phase, which shall be based on the best available forecast of the market behaviour and Renewable Energy Source (RES) generation.

Pre-processing data (PPD) of CGMA are based on either an individually or regionally coordinated forecast. Basically, the coordinated approach shall yield a better indicator about the final Net Position (NP) than an individual forecast. Therefore, TSOs in Core CCR agreed to prepare the PPD in a coordinated way.

The main concept of the coordinated approach intends to use statistical data as well as linear relationships between forecasted NP and input variables. The data shall represent the market characteristic and the grid conditions in the given time horizon. The coefficients of the linear model will be tuned by archive data.

As result of the coordinated forecast the following values are foreseen:
- NP per bidding zone
- DC flows per interconnector

Disclaimer: the details of the methodology valid for the Core CCR are under design and proof of concept is still required.

3.2.2.   Individual Grid Model (IGM)

All TSOs develop scenarios for each market time unit and establish the IGM. This means that Core TSOs create hourly D-2 IGMs for each day. The scenarios contain structural data, topology, and forecast of:
- intermittent and dispatchable generation;
- load;
- flows on direct current lines.

The detailed structure of the model for entire ENTSO-e area, as well as the content is described in the Common Grid Model Methodology (CGMM), which was approved by all ENTSO-e TSOs and regulatory authorities on 8 May 2017. In some aspects, Core TSOs decided to make the agreement more precise concerning IGMs. Additional details are presented in following paragraphs.

The Core TSOs will use a simplified model of HVDC. It means that the DC links are represented as load or generation.

D-2 IGMs are based on the best available forecast of the market and renewable energy source (RES) generation. As regards the net positions, the IGMs are compliant with the Common Grid Model Alignment (CGMA) process, which is common for entire ENTSO-e area. More specifically, the IGMs are created based on coordinated preliminary net positions (PNP), which reflect the aforementioned best available forecast.

3.2.3.   IGM replacement for CGM creation

If a TSO cannot ensure that its D-2 IGM for a given market time unit is available by the deadline, or if the D-2 IGM is rejected due to poor or invalid data quality and cannot be replaced with data of sufficient quality by the deadline, the merging agent will apply all methodological & process steps for IGM replacement as defined in the CGMM (Common Grid Model Methodology).

3.2.4.   Common Grid models

The individual TSOs' IGMs are merged to obtain a CGM according to the CGMM. The process of CGM creation is performed by the merging agent and comprises the following services:
- check the consistency of the IGMs (quality monitoring);
- merge D-2 IGMs and create a CGM per market time unit;
- make the resulting CGM available to all TSOs.

The merging process is standardized across Europe as described in European merging function (EMF) requirements.

As a part of this process the merging agent checks the quality of the data and requests, if necessary, the triggering of backup (substitution) procedures (see below).

Before performing the merging process, IGMs are adjusted to match the balanced net positions and Balanced flows on DC links according to the result of CGMA. For this purpose the GSKs are used.

Core CGM represents the entire Continental European (RG CE) transmission system[9]. It means that the CGM contains not only the Core IGMs for the respected time stamps but also all IGM of the CE TSOs

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9 Members of RG CE as follow: Austria (APG, VUEN), Belgium (ELIA), Bosnia Herzegovina (NOS BiH)), Bulgaria (ESO), Croatia (HOPS), Czech Republic (ČEPS), Denmark (Energinet.dk), France (RTE), Germany (Amprion, TenneT DE, TransnetBW, 50Hertz), Greece (IPTO), Hungary (MAVIR), Italy (Terna), Luxembourg (Creos Luxembourg), Montenegro (CGES), Netherlands (TenneT NL), Poland (PSE S.A.), Portugal (REN),

not being directly involved in the Core FB CC process. Regional calculation of cross-zonal capacity – *see Article 29 of the CACM Regulation*

3.2.5.   Optimization of cross-zonal capacity using available remedial actions

Disclaimer: Options for the RAO methodology (e.g. objective function used & algorithm) are currently being investigated via experimentations. These will be detailed when conclusions & decisions have been made.

This section refers to Article 15 of the Proposal. The coordinated application of RAs aims at optimizing power flows and thus cross-zonal capacity in the Core CCR. It is a physical property of the power system that flows can generally only be re-routed and hence a flow reduction on one CNEC automatically leads to an increase of flow on one or more CNECs. The RAO aims at managing this trade-off.

A preventive tap position on a phase-shifting transformer (PST), for example, changes the reference flow F_{ref} and thus the RAM. If set to the optimal position, the PST can be used to enlarge RAM of highly loaded or congested CNECs, while potentially decreasing RAM on less loaded CNECs. The RAO itself consists of a coordinated optimization of cross-zonal capacity within the Core CCR by means of modifying the shape of the flow-based domain in order to accommodate the expected market preferences.

The optimization is an automated, coordinated and reproducible process. TSOs individually determine the RAs that are given to the RA optimization, for which the selected RAs are transparent to all TSOs. Due to the automated and coordinated design of the optimization, it is ensured that operational security is not endangered if selected RAs remain available also after D-2 capacity calculation in subsequent operational planning processes and real time.

3.2.6.   Calculation of the final flow-based domain

This section refers to Article 18 of the Proposal. Once the optimal preventive and curative RAs have been determined by the RAO process, the RAs can be explicitly associated to the respective Core CNECs (thus altering their F_{ref} and $PTDF$ values) and the final FB parameters are computed.

When calculating the final FB parameters, the following sequential steps are taken:
1. Execution of LTA check (see section 2.2.3);
2. Determining the most constraining CNECs (see section 3.2.6.1);
3. LTA inclusion (see section 2.2.3);
4. LTN adjustment (see section 3.2.6.2).

3.2.6.1.   Determining the most constraining CNECs ("presolve")

Given the CNEs, CNECs and ECs that are specified by the TSOs in Core region, the flow-based parameters indicate what commercial exchanges or NPs can be facilitated under the day-ahead market

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Romania (Transelectrica), Serbia (EMS), Slovak Republic (SEPS), Slovenia (ELES), Spain (REE), Switzerland (Swissgrid), The former Yugoslav Republic of Macedonia (MEPSO).

coupling without endangering grid security. As such, the flow-based parameters act as constraints in the optimization that is performed by the Market Coupling mechanism: the net positions of the bidding zones in the Market Coupling are optimized as such that the day-ahead social welfare is maximized while respecting *inter alia* the constraints provided by the TSOs. Although from the TSO point of view, all flow-based parameters are relevant and do contain information, not all flow-based parameters are relevant for the Market Coupling mechanism. Indeed, only those constraints that are most limiting the net positions need to be respected in the Market 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. This "presolve" step can be schematically illustrated in the two-dimensional example below:
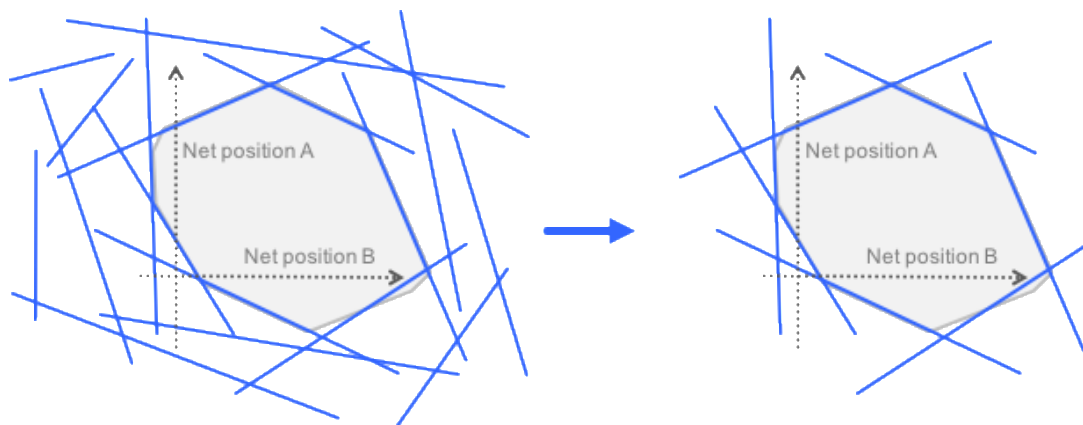

Figure 8: CNEs, CNECs and ECs before and after the "presolve" step

In the two-dimensional example shown above, each straight line in the graph reflects the mathematical representation of one constraint (CNE, CNEC or EC). A line indicates the boundary between allowed and non-allowed net positions for a specific constraint, i.e. the net positions on one side of the line are allowed whereas the net positions on the other side would violate this constraint (e.g. overload of a CNEC) and endanger grid security. The non-redundant or "presolved" CNEs, CNECs and ECs define the flow-based capacity domain that is indicated by the yellow region in the two-dimensional figure (see Figure 8). It is within this flow-based capacity domain that the commercial exchanges can be safely optimized by the Market Coupling mechanism. The intersection of multiple constraints, two in the two-dimensional in Figure 8, defines the vertices of the flow-based capacity domain.

3.2.6.2. LTN adjustment

As the reference flow (F_{ref}) is the physical flow computed from the D-2 CGM, it reflects the loading of the CNEs and CNECs given the forecast commercial exchanges. Therefore, this reference flow has to be adjusted 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 FB capacity domain is a shift in the solution space. It is schematically drawn in the following figure:
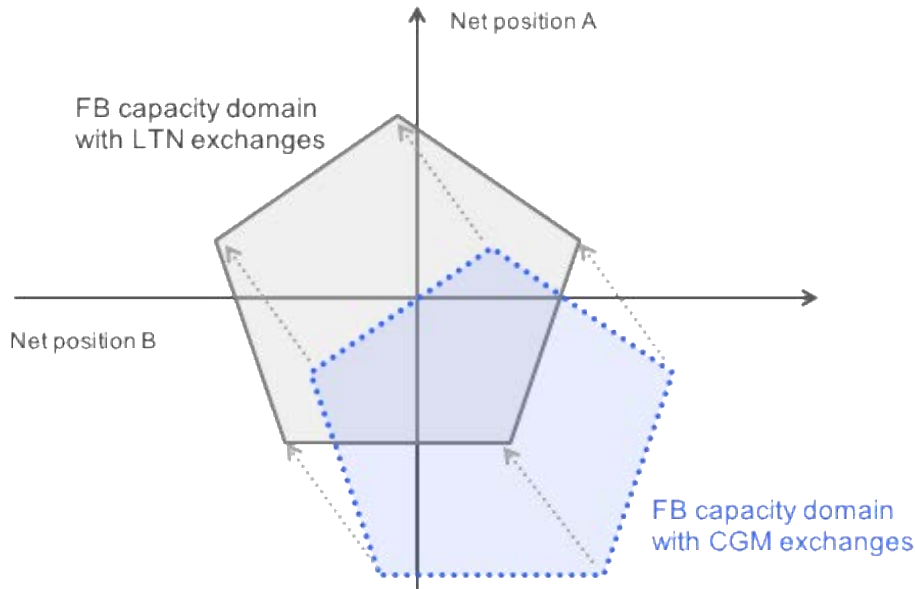
Figure 9: Shift of the FB capacity domain to the LTN

Please note that the intersection of the axes depicted in Figure 9 is the nomination point.
For the LTN adjustment, the power flow of each CNE and CNEC is calculated with the linear equation 9 described in section 2.2.1.3, repeated here for convenience:

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

Equation 14

Finally the remaining available margin per CNEC for the DA-allocation can be calculated as follows:

$$\boldsymbol{RAM}_i = \boldsymbol{F}_{max} - \boldsymbol{FRM} - \boldsymbol{FAV} - \boldsymbol{F}_{LTN}$$

Equation 15

In addition, the ECs are adjusted such that the limits provided to the Market Coupling mechanism refer to the increments or decrements of the net positions with respect to the net positions resulting from LTN.

3.3. Precoupling backup & default processes – *see Article 21(3) of the CACM Regulation*

3.3.1.   Precoupling backups and replacement process

This section refers to Article 19 of the Proposal. In some circumstances, it can be impossible for TSOs to compute flow-based Parameters according to the process and principles. These circumstances can be linked to a technical failure in the tools, in the communication flows, or in corrupted or missing input data. Should the case arise, and even though the impossibility to compute "normally" flow-based parameters only concern one or a couple of hours, TSOs have to trigger a backup mode in order to deliver in all circumstances a set of parameters covering the entire day. Indeed, market-coupling is only operating on the basis of a complete data set for the whole day (all timestamps must be available).

The approach followed by TSOs in order to deliver the full set of flow-based parameters, whatever the circumstances, is twofold:

- First, TSOs can trigger "replacement strategies" in order to fill the gaps if some timestamps are missing. Because the flow-based method is very sensitive to its inputs, TSOs decided to directly replace missing flow-based parameters by using a so-called "spanning method". Indeed, trying to reproduce the full flow-based process on the basis of interpolated inputs would give unrealistic results. These spanning principles are only valid if a few timestamps are missing (up to 2 consecutive hours). Spanning the flow-based parameters over a too long period would also lead to unrealistic results.
- Second, in case of impossibility to span the missing parameters, TSOs will deploy the computation of "default flow-based parameters".

The flowchart in

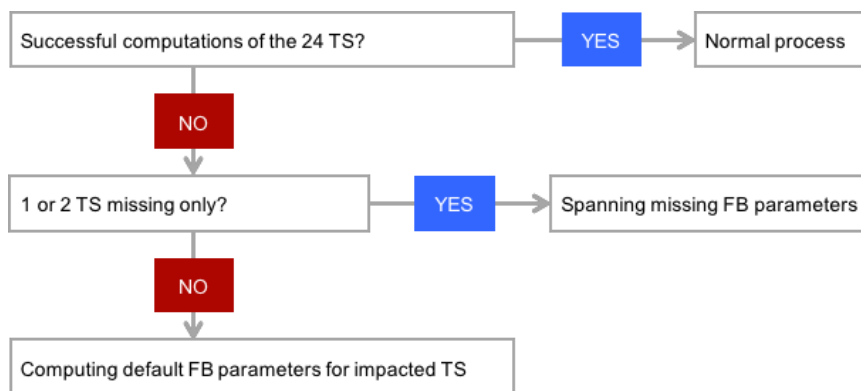Figure 10 will synthesise the general approach followed by TSOs:

Figure 10: Flowchart for application of precoupling backups or default process

Spanning

When inputs for flow-based parameters calculation are missing for less than three 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 from the previous and sub-sequent timestamps are gathered and only the most constraining ones of both timestamps are taken into consideration (intersection).
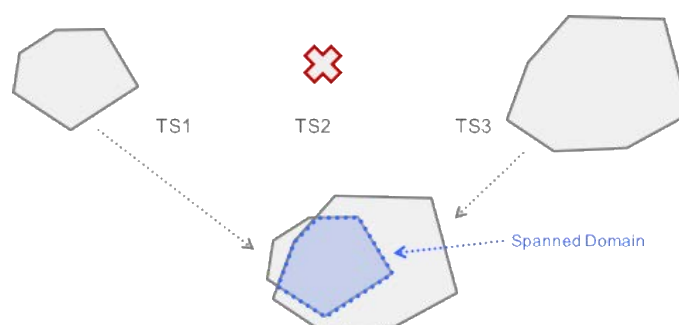
Figure 11: Forming the spanned domain

### 3.3.2. Precoupling default flow-based parameters

In case of impossibility to span the missing parameters, i.e. if more than two consecutive hours are missing, the computation of "default flow-based parameters" will be deployed.

This computation shall be based on existing long term bilateral capacities. These capacities can indeed be converted easily into flow-based external constraints (i.e. import or export), 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 direction, transformed into flow-based constraints, "n" being positive or null and computed during the capacity calculation process. Involved TSOs, for obvious reasons of security of supply, cannot commit to any value for "n" at this stage.

3.4. Market coupling fallback TSO input - ATC for Shadow Auctions – *see Article 44 of the CACM Regulation*

This section refers to Article 20 of the Proposal. In the event of unavailability of the normal or backup operation of the Core day-ahead price coupling a fallback solution will be applied. It has been designed with the aim to be easy to apply and as fail-safe as possible in order to ensure the allocation of cross zonal capacity in any case. Concretely, shadow auctions (SA) will be organized. These require the determination of bilateral ATC figures for each MTU[10].

As a result of FB CC, flow-based domains are determined for each MTU as an input for the FB MC process. In case the latter fails, the flow-based domains will serve as the basis for the determination of the ATC values that are input to the shadow auctions (SA ATC). In other words: there will not be a need for an additional and independent stage of ATC capacity calculation. As the selection of a set of ATCs from the flow-based domain leads to an infinite set of choices, an algorithm has been designed that determines the SA ATC values in a systematic way. It is based on an iterative procedure starting from the LTA domain as shown in Figure 12 below.

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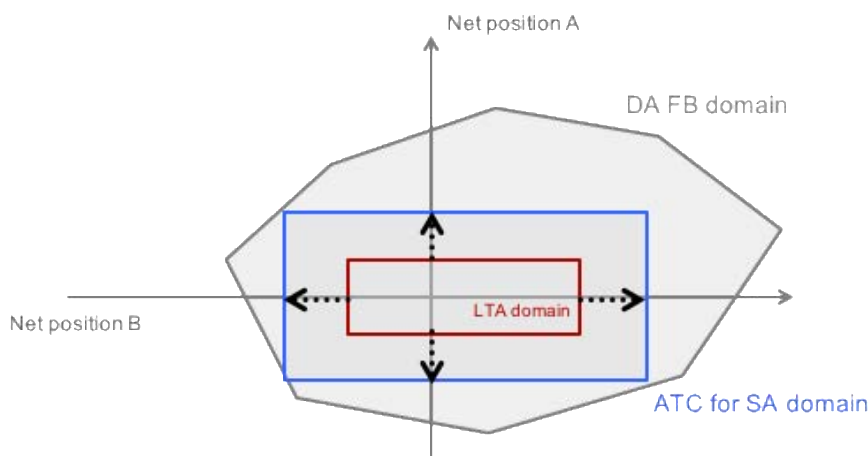
10 This is in line with the "All Core TSOs' proposal for Fallback Procedures" as submitted to the NRAs on the 17th of May 2017.

Figure 12: Creation of ATC for Shadow auctions domain

Input data:

The following input data are required for each market time unit:
- LTA values
- presolved flow-based parameters as sent to the PXs

Output data:

Following outputs are the outcomes of the computation for each market time unit:
- ATC values for Shadow Auction
- constraints with zero margin after the SA ATC computation

Algorithm:

The SA ATC computation is an iterative procedure.

Starting point: First, the remaining available margins (RAM) of the presolved constraints (CNEs, CNECs and ECs) have to be adjusted to take into account the starting point of the iteration.

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

$$pPTDF_{z2z,A \to B} = \max\left(0, PTDF_{z2s,A} - PTDF_{z2s,B}\right)$$
Equation 16

with

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

$PTDF_{z2s,k}$ 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 (e.g. $pPTDF_{DE \to NL}$). Other non neighbouring borders (e.g. $pPTDF_{PL \to HU}$) will not be taken into account.

The iterative procedure to determine the SA ATC 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 17

Iteration: The iterative method applied to compute the SA ATCs in short comes down to the following actions for each iteration step i:

For each CNE, CNEC and EC, share the remaining margin between the Core internal borders that are positively influenced with equal shares.

From those shares of margin, maximum bilateral exchanges are computed by dividing each share by the positive zone-to-zone $PTDF$, i.e. the $pPTDFs$.

The bilateral exchanges are updated by adding the minimum values obtained over all CNEs, CNECs and ECs.

Update the margins on the CNEs, CNECs and ECs using new bilateral exchanges from step 3 and go back to step 1.

These 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. The resulting SA ATCs get the values that have been determined for the maximum Core internal bilateral exchanges obtained in iteration i+1 after rounding down to integer values.

After algorithm execution, there are some CNEs, CNECs and ECs with no remaining available margin left. These are the limiting constraints of the SA ATC computation.

The computation of the SA ATC domain can be precisely described with the following pseudo-code:

NbShares = number of Core internal commercial borders

```
While max(abs(margin(i+1) - margin(i))) > StopCriterionSAATC
For each constraint
For each non-zero entry in pPTDF_z2z Matrix
IncrMaxBilExchange = margin(i)/NbShares/pPTDF_z2z
MaxBilExchange = MaxBilExchange + IncrMaxBilExchange
End for
End for
For each ContractPath
MaxBilExchange = min(MaxBilExchanges)
End for
For each constraint
   margin(i+1) = margin(i) – pPTDF_z2z * Max- BilExchange
End for
End While
SA_ATCs = Integer(MaxBilExchanges)
```

3.5. Validation of cross-zonal capacity – *see Article 26 and Article 30 of the CACM Regulation*

This section refers to Article 21 of the Proposal. The TSOs are legally responsible for the cross-zonal capacities and therefore have to validate the calculated values before the coordinated capacity calculator can send them for allocation. With the validation of the cross-zonal capacity and allocation constraints, the TSOs ensure that the results of the capacity allocation process will respect operational security requirements. Each TSO shall have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders provided by the CCC. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity relevant to the TSO's bidding zone borders for the following reasons:

1. Any change or mistake in input data or use of a back-up file (CNEC-file, GSK, D2CF, EC) that leads to too high/unsafe capacities, e.g.:
   • missing CNEC in the CNEC-file;
   • non-availability of a remedial action that was expected to be available (CNEC-file);
   • missing or wrong GSK node(s);
   • wrong topology or power infeed in the D2CF, e.g.: when an outage occurs between delivery of the file and/or during CC;

- • too high or not delivered ECs.

2. Exceptional contingency occurred

   In case of a warning for or occurrence of an exceptional contingency, i.e., a contingency of more than one element relevant for capacity calculation as e.g. icing or wind storms, occurred between the provision of inputs and the validation process, the TSOs may reduce the relevant cross-zonal capacities to the extent necessary.

3. TSOs encounter an exceptional situation where the redispatch or countertrade potential, that is needed to ensure the minimum RAM on all CNECs and/or to ensure the requested minimum import capacity as defined in 2.2.3, is not available.

   The TSOs provide a minimum RAM on CNECs in order to increase cross-zonal capacities regardless of the actual loading of the critical network elements. This could lead to overloading in the grid. To relieve the overloaded CNEs, the TSOs need to apply remedial actions (e.g. redispatch and countertrade). Therefore, the TSOs have to ensure that the redispatch and countertrade potential is available to perform these actions. In cases where the TSOs anticipate that the redispatch and countertrade potential will be exhausted, TSOs may reduce the cross-zonal capacity to ensure system security.

When performing the validation, the TSOs will consider the operational security limits, but may also consider additional grid constraints, grid models, and other relevant information. Therefore the 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.

In case of a required reduction, a TSO can use FAV for its own CNECs or adapt the external constraints to reduce the cross-zonal capacity. In this case a new final FB computation will be launched. In exceptional situations, a TSO can also request a common decision to launch the default flow-based parameters.

The regional coordinated capacity calculator will coordinate with neighbouring coordinated capacity calculators during the validation process.

Any information on decreased cross-zonal capacity from neighbouring coordinated capacity calculators will be provided to the TSOs. The TSOs may then apply the appropriate reductions of cross-zonal capacities.

3.6. Transparency framework

This section refers to Article 23 of the Proposal. The Core transparency framework is based on the current operational transparency framework in CWE day-ahead flow-based market coupling.

Initial flow-based parameters (without LTN) will 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 FB parameters all long term nominations at all Core borders are assumed as zero ($LTN = 0$). The LTN for each Core border where PTRs are applied will be published at D-1 (10:30 target time[11]) for each market time unit of the following day.

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[11] This is CET during the winter period and CEST in the summer period.

Final flow-based parameters will be published at D-1 (10:30 target time) for each market time unit of the following day, comprising the zone-to-slack power transfer distribution factors ($PTDFs$) and the remaining available margin (RAM) for each "presolved" CNEC.

Additionally, at D-1 (10:30 target time), the following data items will be published for each market time unit of the following day:

- maximum and minimum net position of each bidding zone;
- maximum bilateral exchanges between all Core bidding zones;
- ATCs for shadow auctions.

In compliance with national regulations, the following information may be published at D-1 (10:30 target time):):

- real names of CNECs and external constraints;
- CNE EIC code and Contingency EIC code;
- 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.

- Detailed breakdown of RAM per external constraint:

  - F_{max};
  - F_{LTN}.

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:

- vertical load;
- production;
- best forecast of net position.

In compliance with national regulations, the static grid model of each TSO will be published.

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 NRAs. 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.

APPENDIX 1 -   Methods for external constraints per bidding zone

The following section depicts in detail the method currently used by each Core TSO to design and implement external constraints.

Austria:

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

Belgium:

Elia uses an import limit constraint which is related to the dynamic stability of the network. This limitation is estimated with offline studies which are performed on a regular basis.

Croatia:

HOPS does not apply external constraints. Due to lack of operational experience this section is subject to change, according results of experimentations.

Czech Republic:

CEPS does not apply external constraints.

France:

RTE does not apply external constraints.

Germany:

The German[12] TSOs do not apply external constraints for the German Market area

Hungary:

MAVIR does not apply external constraints.

Netherlands:

TenneT NL 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

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12 While the text refers to Germany for the sake of readability, the area of Luxemburg is also covered by this External Constraint.

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 14 and 15. 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).
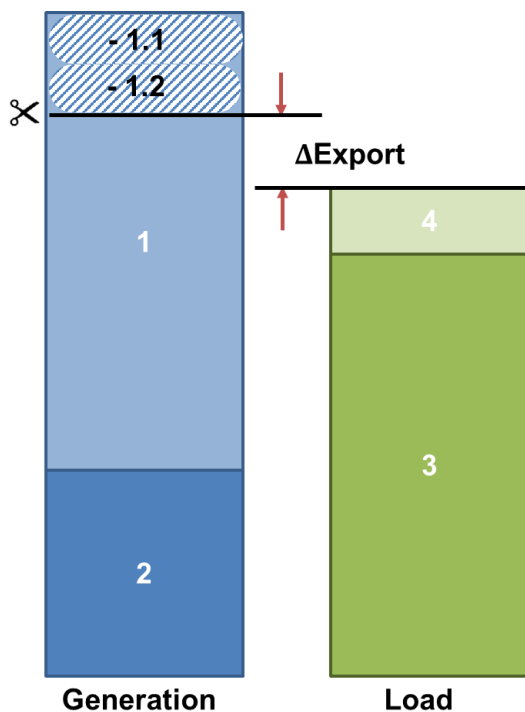
1. sum of available generating capacities of centrally dispatched units[13] as declared by generators, reduced by:
   1.1 TSO forecast of capacity not available due to expected network constraints;
   1.2 TSO assessment (based on experiences of recent days) of extra reserve to cover short term unavailabilities 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).

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13 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

Figure 14: 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).
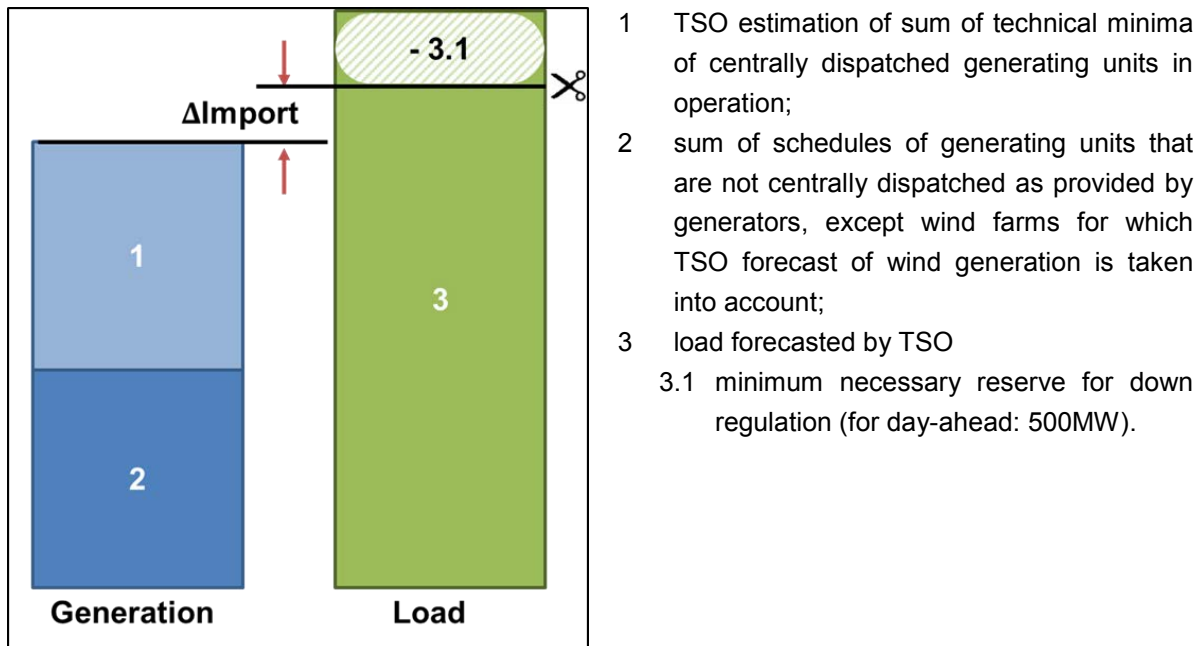
Figure 15: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day-ahead transfer capacity calculation

Romania:

Transelectrica does not apply external constraints.

Slovakia:

External constraints in form of exp/imp limit may be introduced subject to operational security assessment results.

Slovenia:

ELES does not apply external constraints.

APPENDIX 2 -   Methods for GSKs per bidding zone

The following section depicts in detail the method currently used by each Core TSO to design and implement GSKs.

Austria:

APG's method only considers market driven power plants in the GSK file which was done with statistical analysis of the market behaviour of the power plants. This means that only pump storages and thermal units are considered. Power plants which generate base load (river power plants) are not considered. Only river plants with daily water storage are also taken into account in the GSK file. The list of relevant power plants is updated regularly in order to consider maintenance or outages. Furthermore the GSK file will also be updated seasonally because in the summer period the thermal units are out of operation.

Belgium:

Elia will use in its GSK flexible and controllable production units which are available inside the Elia grid (they can be running or not). Units unavailable due to outage or maintenance are not included.

The GSK is tuned in such a way that for high levels of import into the Belgian bidding zone all units are, at the same time, either at 0 MW or at P_{min} (including a margin for reserves) depending on whether the units have to run or not (specifically for instance for delivery of primary or secondary reserves). For high levels of export from the Belgian bidding zone all units are at P_{max} (including a margin for reserves) at the same time.

After producing the GSK, Elia will adjust production levels in all 24 hour D2CF to match the linearised level of production to the exchange programs of the reference day as illustrated in Figure 16.
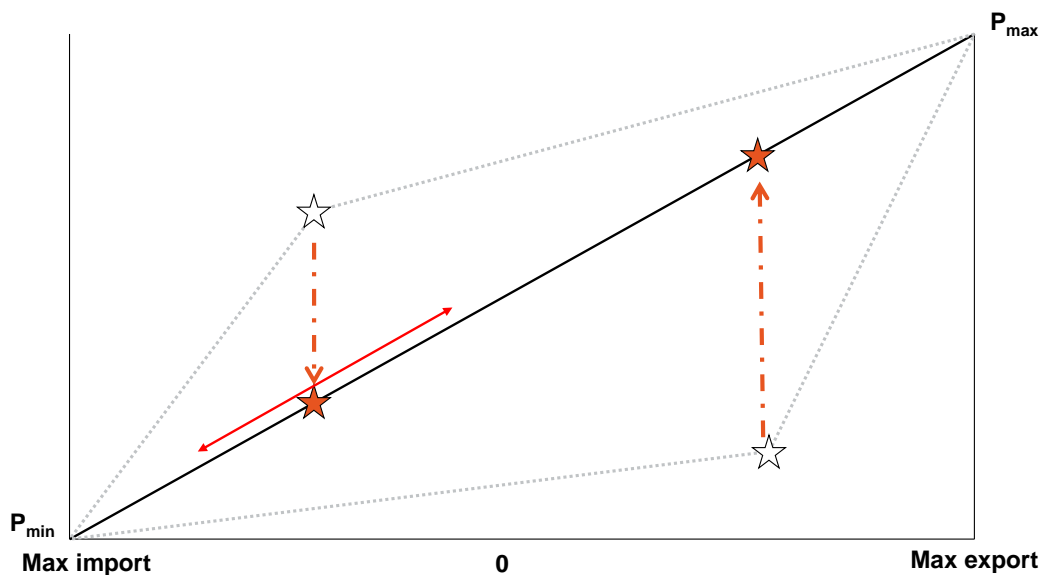

Figure 16: Belgian GSK.

Croatia:

HOPS will use in its GSK all flexible and controllable production units which are available inside the HOPS' grid (mostly hydro units). Units unavailable due to outage and maintenance are not included, but units that aren't currently running are included in GSK.

Due to different grid operation in each season of the year GSK will be updated accordingly.

Czech Republic:

The Czech GSK considers all production units which are available inside CEPS´s grid and were foreseen to be in operation in target day. Units planned for the maintenance are not included in the GSK file. The list of GSK is produced on hourly basis. The generation pattern inside GSK is shifted proportionally to the given P_{gen}.

The current approach of creation GSKs is regularly analysed and can be adapted to reflect actual situation in CEPS´s grid.

Netherlands:

TenneT B.V. will dispatch the main generators in such a way as to avoid extensive and not realistic under- and overloading of the units for extreme import or export scenarios. Unavailability due to outages are considered in the GSK. Also the GSK is directly adjusted in case of new power plants.

All GSK units (including available GSK units with no production in de D2CF file) are redispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit. The total production level remains the same.

The maximum production level is the contribution of the unit in a predefined extreme maximum production scenario. The minimum production level is the contribution of the unit in a predefined extreme minimum production scenario. Base-load units will have a smaller difference between their maximum and minimum production levels than start-stop units.

France:

The French GSK is composed of all the units connected to RTE's network in the D-2 CGM.

The variation of the generation pattern inside the GSK is the following: all the units which are in operation in the D-2 CGM will follow the change of the French net position based on the share of their nominal productions. In other words, if one unit represents n% of the total generation on the French bidding zone, n% of the shift of the French net position will be attributed to this unit.

Germany:

The German[14] TSOs provide one single GSK for the whole German bidding zone. Since the structure of the generation differs for each German TSO, an approach has been developed, which allows the single TSO to provide GSKs that respect the specific character of the generation in their own grid while ultimately yielding a comprehensive single German GSK.

In a first step, each German TSO creates a TSO-specific GSK with respect to its own control area based on its local expertise. The TSO-specific GSK denotes how a change of the net position in the forecasted market clearing point of the respective TSO's control area is distributed among the nodes of this area.

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14 The area of Luxemburg is taken into account in the contribution from Amprion.

This means that the nodal factors of each TSO-specific GSK add up to 1. Details of the creation of the TSO-specific GSKs are given below per TSO.

In a second step, the four TSO-specific GSK are combined into a single German GSK by assigning relative weights to each TSO-specific GSK. These weights reflect the distribution of the total market driven generation among German TSOs. The weights add up to 1 as well.

With this method, the knowledge and experience of each German TSO can be brought into the process to obtain a representative GSK. As a result, the nodes in the GSK are distributed over whole Germany in a realistic way, and the individual factors per node are relatively small.

Both the TSO-specific GSKs and the TSOs' weights are time variant and updated on a regular basis. Clustering of time periods (e.g. peak hours, off-peak hours, week days, weekend days) may be applied for transparency and efficiency reasons.

Individual distribution per German TSO

50Hertz:

The GSKs for the control zone of 50Hertz are based on a regular statistical assessment of the behaviour of the generation park for various market clearing points. In addition to the information on generator availability, the interdependence with fundamental data such as date and time, season, wind infeed etc. is taken into account. Based on these, the GSKs for every MTU are created.

Amprion:

Amprion established a regular process in order to keep the GSK as close as possible to the reality. In this process Amprion checks for example whether there are new power plants in the grid or whether there is a block out of service. According to these monthly changes in the grid Amprion updates its GSK. If needed Amprion adapts the GSK in meantime during the month.
In general Amprion only considers middle and peak load power plants as GSK relevant. With other words basic load power plants like nuclear and lignite power plants are excluded to be a GSK relevant node.
From this it follows that Amprion only takes the following types of power plants: hard coal, gas and hydro power plants. In the view of Amprion only these types of power plants are taking part of changes in the production.

TenneT Germany:

Similar to Amprion, TTG considers middle and peak load power plants as potential candidates for GSK. This includes the following type of production units: coal, gas, oil and hydro. Nuclear power plants are excluded upfront.
In order to determine the TTG GSK, a statistical analysis on the behaviour of the non-nuclear power plants in the TTG control area has been made with the target to characterize the units. Only those power plants, which are characterized as market-driven, are put in the GSK. This list is updated regularly.

TransnetBW:

To determine relevant generation units TransnetBW takes into account the power plant availability and the most recent available information at the time when the individual GSK-file is generated for the MTU:

The GSK for every power plant i is determined as:

$$GSK_i = \frac{P_{max,i} - P_{min,i}}{\sum_{i=1}^{n}(P_{max,i} - P_{min,i})}$$

Equation 18

Where n is the number of power plants, which are considered for the generation shift within TransnetBW's control area.

Only those power plants which are characterized as market-driven, are used in the GSK if their availability for the target hour is known.

The following types of generation units for middle and peak load connected to the transmission grid can be considered in the GSK:

- hard coal power plants
- hydro power plants
- gas power plants

Nuclear power plants as baseload units are excluded because of their mostly constant infeed.

Hungary:

MAVIR uses general GSK file listing all possible nodes to be considered in shifting the net position in a proportional way, i.e. in the ratio of the actual generation at the respective nodes. All dispatchable units, including actually not running ones connected to the transmission grid are represented in the list. Furthermore, as the Hungarian power system has generally considerable import, not only big generation units directly connected to the transmission grid are represented, but small, dispersed ones connected to lower voltage levels as well. Therefore, all 120 kV nodes being modelled in the IGM are also listed representing this kind of generation in a proportional way, too. Ratio of generation connected to the transmission grid and to lower voltage levels is set to 50-50% at present.

Poland:

PSE present in GSK file all dispatchable units which were foreseen to be in operation in day of operation. Units planned for the maintenance are not included on the list. The list is created for each hour. The generation pattern listed in the GSK is changed proportionally to the given P_{gen}.

Romania:

The Transelectrica GSK file contains all dispatchable units which are available in the day of operation. The units planned for maintenance and nuclear units are not included in the list.

Slovakia:

In GSK file of SEPS are given all dispatchable units which are in operation in respective day and hour which the list is created for. The units planned for maintenance and nuclear units are not included in the list. All mentioned nodes to be considered in shifting the net position in a proportional way.

Slovenia:

GSK file of ELES consists of all the generation nodes specifying those generators that are likely to contribute to the shift. Nuclear units are not included in the list. In additional also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators

connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). At the moment GSK file is designed according to the participation factors, which are the result of statistical assessment of the behaviour of the generation units infeeds.

APPENDIX 3 -   Determination of threshold for CNEC selection

The determination of the common maximum absolute zone-to-zone PTDF and the minimum RAM values shall be based on an analysis that assesses the volume of cross-zonal capacity made available to the market and the system costs incurred to make available this capacity. The applicability of this approach depends on whether sufficient remedial actions are available to ensure the minimum RAM while safeguarding the operational security limits and is subject to the principles on cost sharing in line with Article 74(1) of the CACM Regulation and the recovery of the additional costs incurred by the TSOs.

The threshold will be set following security assessments performed by TSOs, by the iterative process described below:

TSOs will carry out some alternative computations of flow-based parameters, using scenarios where only the threshold is set to different values. Depending of the threshold values, some critical network elements are included or not in the flow-based parameters computation, resulting in a capacity domain more or less constraining for the market. Taking some extreme "vertices" of the resulting alternative flow-based domains, TSOs will assess whether these domains are safe, and more precisely identify at which point the exclusion of CNE not respecting the threshold would lead to unacceptable situations, with respect to Core TSOs risk policies. If for one given threshold value, the analyses would conclude in unacceptable situations (because the removal of some constraints would allow an amount of exchanges that TSOs could not cope with as they would not respect standard security of supply (SOS) principles, like the standard N-1 rule), then this simply means that the threshold is too high. Following this approach and assessing different values, Core TSOs should conclude which X% is an optimal compromise, in terms of size of the domain versus risk policies.