Explanatory note on the day-ahead and intraday common capacity calculation methodologies for the Core CCR

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GLOSSARY

AC	Allocation constraint
ACER	Agency for the Cooperation of Energy Regulators
AHC	Advanced Hybrid Coupling
AMR	Adjustment for Minimum RAM
CACM	Capacity allocation and congestion management
CC	Capacity calculation
CCC	Coordinated capacity calculator
CCR	Capacity calculation region
CE	Continental Europe(an)
CGM	Common grid model
CGMA	Common grid model alignment
CGMAM	Common grid model alignment methodology
CNE	Critical network element
CNEC	Critical network element and contingency
CWE	Central Western Europe(an)
DA	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
ID	Intraday
IGM	Individual grid model
I_{max}	Maximum admissible current
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
OSL	Operational security limit
PNP	Preliminary net position
PPD	Pre-processing data
PST	Phase-shifting transformer
$PTDF$	Power transfer distribution factor
RA	Remedial action
RAM	Remaining available margin
RAO	Remedial action optimization
RES	Renewable energy sources
SA	Shadow auctions
SAP	Single allocation platform
TS	Timestamp
TSO	Transmission system operator
x	scalar
$\vec{x}$	vector
$\boldsymbol{x}$	matrix

1. INTRODUCTION

Sixteen TSOs follow the 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 and intraday common capacity calculation methodology (hereafter the DA CCM and ID CCM respectively). Unless otherwise stated, the description covers the day-ahead methodology and is equally valid for the intraday methodology where indicated.

The aim of this explanatory note is to provide additional information with regard to the day-ahead and intraday common capacity calculation methodology and relevant processes only. 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.

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

This section refers to Article 5 of the DA CCM and Article 6 of the ID CCM.

Critical network elements (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 Critical Network Element and Contingency (CNEC).

2.1.1.2. Operation security limits

This section refers to Article 6 of the DA CCM and Article 7 of the ID CCM.

According to Article 6(1)(a)-(c) of the DA CCM, the maximum admissible current ($I_{\max}$) is the physical limit of a CNE determined by each TSO in line with its operational security policy. The physical limit reflects the capability of a transmission element (such as line, circuit-breaker, current transformer or disconnector). 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 represents a loading that is allowed for a certain finite duration only (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, the $I_{\max}$ can be dynamic as described in Article 6(1)(a). Dynamic Line Rating can therefore be taken into account insofar as the necessary equipment is installed; this is perceived as being the target. For lines where this not yet the case, seasonal variations of the $I_{\max}$ can be applied. When the equipment limiting the $I_{\max}$ of a CNE is not the line itself, but another installed element physically connected to the CNE (such as current transformer, circuit breaker, disconnector) or when the line is equipped with modern high temperature resistant conductor material, which current limit is not dependent on the ambient temperature, a constant $I_{\max}$ needs to be applied on all market time units.

2.1.1.3. Allocation Constraints

This section refers to Article 8 of the DA CCM and Article 9 of the ID CCM.

It is the target to have the external constraint applied directly during market coupling (MC). 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. The concept of a global net position is illustrated in Figure 1. In this example the global net position of bidding zone A equals: 1000 (net position in bidding zone A in CCR 1) + 500 (export to CCR 2) + 500 (export to CCR 3) = 2000 MW.

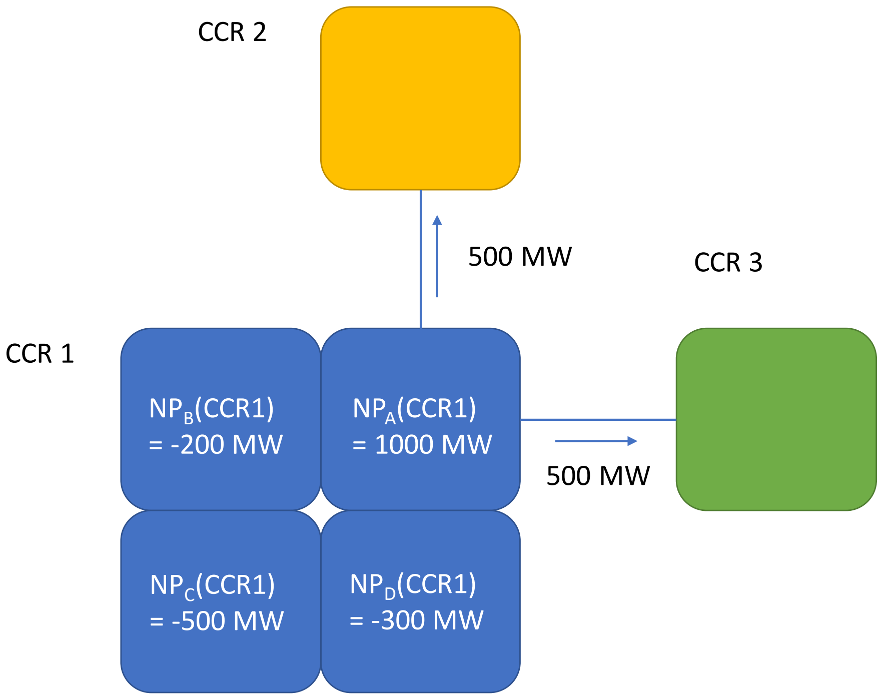


Figure 1 Illustration of global net position

If it is not feasible to apply the external constraint directly in the MC, the external constraint will be modelled as a constraint during flow-based (FB) capacity calculation. In this case, the external constraints are easily identifiable in the published FB parameters. 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) and can be directly linked to the respective bidding zone. This is demonstrated in Figure 2.

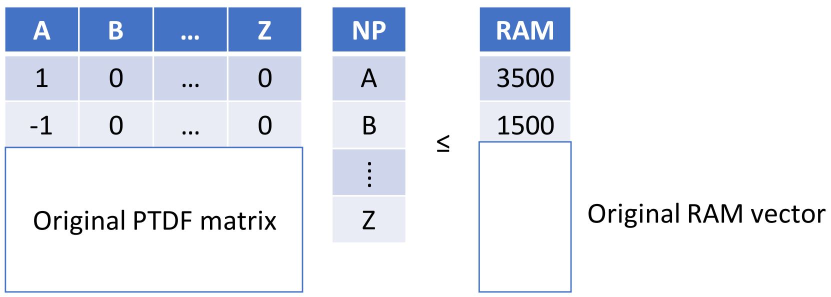


Figure 2 External constraints in the FB parameters

In this example the net position of bidding zone A cannot be higher than 3500 MW (export limit), whereas the net position of bidding zone B cannot be lower than -1500 MW (import limit).

External constraints versus FRM

By construction, the flow reliability margin (FRM) does not allow to hedge against the situations mentioned in Article 8 of the DA CCM and Article 9 of the ID CCM, since they only represent the uncertainty in forecasted flow of the FB model.

Therefore, FRM on the 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.

Legal interpretation: eligible grounds for applying allocation constraints

Under CACM, allocation constraints are understood as *constraints needed to keep the transmission system within operational security limits,* which are in turn defined as *acceptable operating boundaries for secure grid operation*. The definition of the latter (Article 2(7) of CACM Regulation) lists *inter alia* frequency limits, thermal limits and voltage limits as some of the boundaries that can be taken into account.

CACM does not enumerate allocation constraints (ACs) in a form of a list that would allow for checking whether a specific constraint is allowed by the Regulation. Thus, the application of provision on allocation constraints requires further interpretation.

CACM was issued based on Regulation 714/2009 and complements that Regulation. The general principle in Regulation 714/2009 (Art. 16.3) is that TSOs make available the maximum capacity allowed under secure network operation standards. Operational security is explained in a footnote to annex I *as keeping the transmission system within agreed security limits*. CACM rules on AC and operational security limits ('OSLs') seem to regulate the same matter as Article 16.3 in greater detail. The definition of ACs relates to OSLs, so to define what is an allocation constraint, we first need a clear idea of OSLs.

Similarly to the 'open' notion of allocation constraints in the CACM, the definition of OSLs (*the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits*) does not include an enumerative catalogue (a closed set), but an open set of system operation characteristics defined as to their purpose – ensuring secure grid operation. The list is indicative (using the words 'such as'). The open-set character of the definition is also indicated by systemic interpretation, i.e. by the usage of the term in other network codes and guidelines.

In the Core TSOs' point of view, systemic interpretation allows for consistent implementation of all network codes. In this specific case, understanding operational security limits under CACM can be complemented by applying SO GL provisions. These, in turn, require the TSOs to apply specific limitations to ensure that generation and load schedules resulting from cross-zonal trade do not endanger secure system operation. In sum, operational security limits cover a broad set of system characteristics to be respected when defining the domain for cross-zonal trade. With regard to generation and load, this is done by applying external constraints in form of import/export limits, constituting a sub-type of allocation constraints.

How import and export limits contribute to meeting the CACM objectives

Recital 2 of CACM Regulation preamble draws a reciprocal relationship between security of supply and functioning markets. Thanks to grid interconnections and cross-zonal exchange, member states do not have to fully rely on their own assets in order to ensure security of supply. At the same time, however, the internal market cannot function properly if grid security is compromised, as market trade would constantly be interrupted by system failures, and as a result potential social welfare gains would be lost. Recital 18 can be seen as a follow-up, drawing boundaries to ensure a Union-wide price coupling process, namely to respect transmission capacity and allocation constraints.

For the above reasons, one of the aims of the CACM Regulation, as expressed in Article 3, is to ensure operational security. This aim should be fulfilled insofar it does not prejudice other aims. As explained in this methodology, allocation constraints applied by Core TSOs do not undermine other aims of CACM Regulation.

In line with Article 23 of CACM Regulation, allocation constraints are only used to maintain the system within operational security limits. As the transmission system parameters used for expressing operational security limits depend on production and consumption in a given system, these specific limitations can be related to generation and load. As such, several assumptions that are required to assess the allocation constraints are based on local (bidding-zone) specific parameters. Since such specific limitations cannot be efficiently transformed into maximum active power flows on individual CNEs, these are expressed as maximum import and export constraints of bidding zones. The inability to efficiently transform these constraints into maximum flows on CNEs is explained in the Appendix 1 of the methodology with regard to specific external constraints.

The data on the application of external constraints will be provided to the Core NRAs in accordance with Article 24(3)(f) of the methodology. The final list of monitoring items, possibly containing parameters used to determine the external constraints, will be defined before the go-live in accordance with Article 24(4).

2.1.2. Flow reliability margin (FRM)

This section refers to Article 9 of the DA CCM and Article 10 of the ID CCM.

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 CNEC – also called the FRM – which is based on the assessment of the uncertainties involved in the FB Capacity Calculation (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 MC 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 DA MC, 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 3.

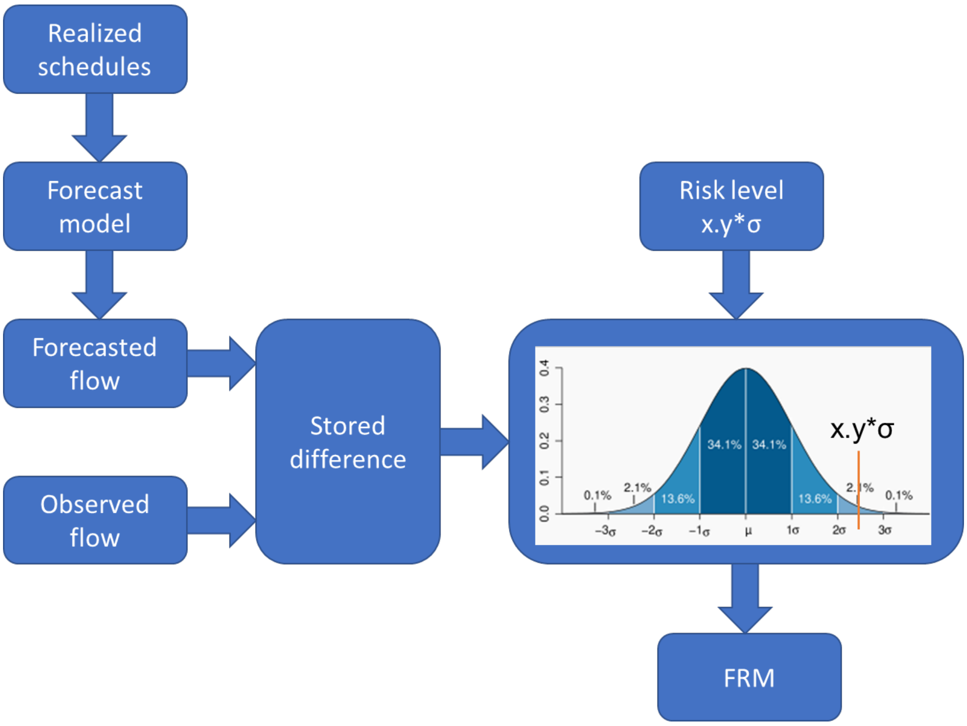


Figure 3: Process flow of the FRM determination

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[1] 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 model created in D-2 with flows in the real-time situation. These flows are called expected flows (F_{exp}), see Equation 1.

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

Equation 1

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
$\overrightarrow{NP}_{real}$	realised net position per bidding zone (based on realised exchanges)
$\overrightarrow{NP}_{ref}$	net position per bidding zone in the D-2 CGM

1 Please note that realised commercial exchanges include the trades of all timeframes (e.g. intraday) before realtime. Exchanges naturally change 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 realised power flows are calculated using the real-time European grid models by means of a contingency analysis. Then for each CNEC the difference between the realised 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 percentile 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. In order to let Core TSOs have an option to reflect their attitude towards risk acceptance, Core TSOs can then either[2]:

- 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; the FRM values are then fixed until the next update. Before the first operational calculation of the FRM values, Core TSOs will determine FRM values as 10% of F_{max} calculated under representative weather conditions, unless Core TSOs can use the FRM values already in operation in existing FB MC initatives, in which case Core TSOs shall use those values.

In case a new CNE is added, 10% of F_{max} is used as FRM. In this approach it is estimated that the 10% common risk level corresponds to the FRM value being 10% of F_{max} calculated under representative weather conditions, as shown in Figure 4. This approach may not necessarily reflect actual risks for all CNECs but is considered a conservative estimation before the first calculation of the FRM using above described statistical evaluation.

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

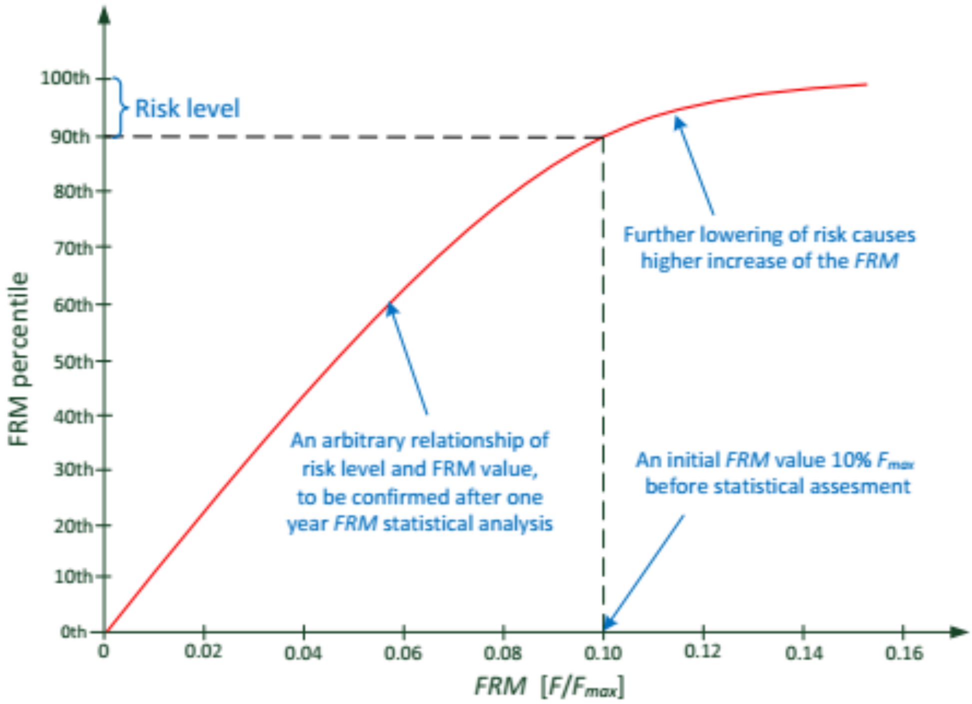


Figure 4: An example of the relationship between accepted risk level and the FRM value

The FRM values are evaluated on a yearly basis. By doing so, no seasonal variations can be captured. It is worth noting that computing FRM values on a seasonal basis rather than a yearly basis would induce other issues. Indeed, reducing the number of the statistical samples will reduce the validity of the model. Besides, the smaller the sample size, the larger the impact of marginal situations will be, like atypical grid topology / production distribution. It is foreseen that the seasonal variations potentially captured in the calculation might be overshadowed by these undesirable impacts. A solution though to allow to capture seasonal FRM values while maintaining a large number of samples would be to compute FRM values on seasonal data over several years. However, the grid is forever evolving and changing, and the FRM values would no longer have a real link to the grid situation over a long simulation period.
As a conclusion it is preferred to compute FRM values over a large number of samples – hourly samples of a year – in order to avoid introducing a high variability in the results. This allows to maintain the performance of the capacity calculation and to capture realistic grid conditions.

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 described above, in order to ensure the implementation of parameters that 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 can only be a reduction of the FRM value, to a value 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.

TSOs will publish a study on the development of the FRM based on the first two annual FRM assessments. The internal and external parallel run data cannot be used for this purpose, as this is simulated data only, including a simulated market outcome. Or in other words: the basis of the FRM determination, being a comparison between a realised and forecasted flow is not possible before the FB capacity calculation and allocation is live.

This implies that for some Core TSOs, only two years after go-live two annual FRM datasets are available to perform this study, and only 2.5 years after go-live the study can be published. While the study aims to support the TSOs in their effort to reduce the FRM values over time, new grid utilities and the increasing share of renewables in the electricity production will impact the FRM values, potentially leading to their increase.

2.1.3. Generation Shift Key (GSK)

This section refers to Article 10 of the DA CCM and Article 11 of the ID CCM.

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 FB domain, as required by the price coupling algorithm, the GSK must be constant per market time unit (MTU).

Since the generation pattern (locations) is unique for each TSO and the range of the NP shift is also different, there is no unique formula for all Core TSOs for the creation of the GSK. This is elaborated upon in Appendix 1.

The GSK values are unitless. For instance, a value of 0.05 for one generating unit means that 5% of the change of the net position of the bidding zone will be realised by this unit. Technically, the GSK values are allocated to units in the CGM. In case 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 in the CGM in order to appropriately model its technical impact on the transmission system.

The TSOs' aim is to apply a GSK that resembles the dispatch and the corresponding flow pattern, thereby contributing to minimizing the FRM.

2.1.4. Remedial Action (RA)

This section refers to Article 11 of the DA CCM and Article 12 of the ID CCM.

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

Some remedial actions used in the Core CCR can have an impact on other CCRs. This is applicable to TSOs which are part of several different CCRs. If this case shall arise, the TSO defining the RA is responsible for coordinating its use between the different CCRs for which it is provided. This coordination will result in an efficient use of remedial actions across CCRs.

2.2. Capacity calculation approach

2.2.1. Mathematical description of the capacity calculation approach

The FB computation is a centralized calculation which delivers two main classes of parameters needed for the definition of the FB 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 ($\boldsymbol{PTDF}$)

This section refers to Article 12(1-7) of the DA CCM and Article 13 of the ID CCM.

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.

A set of $PTDFs$ is associated to every CNEC after each FB parameter calculation, and gives the influence of the variations of any bidding zone net position on the CNEC. If the $PTDF = 0.1$, this means the concerned bidding zone has 10% 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.

From the calculated zone-to-slack $PTDFs$ (single value per bidding zone), a zone-to-zone $PTDF$ can be calculated. 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, a typical zone-to-slack $PTDF$ matrix is given. For each CNEC there is one zone-to-slack $PTDF$ value per bidding zone. For instance, CNEC 3 has a bidding zone(A)-to-slack $PTDF$ of 14.6%. It indicates that an exchange of 1 MW from bidding zone A to 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 5: Example zone-to-slack $PTDFs$

Since all commercial exchanges take place from one bidding zone to the other, only the zone-to-zone $PTDF$ is a suitable indicator to determine how much a CNEC is impacted by cross-border exchanges.

Using CNEC 1 as an example, its zone(A)-to-slack $PTDF$ is 4.9% and its zone(B)-to-slack is 4.8%. The zone(A)-to-zone(B) $PTDF$ is computed by 4.9% - 4.8%, yielding 0.1%. Subsequently, all zone-to-zone $PTDFs$ can be calculated, as shown in Figure 6.

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 6 : Example zone-to-zone $PTDFs$

The last column of Figure 6 selects the maximum zone-to-zone $PTDF$ per CNEC. Investigating CNEC 1 for instance, out of three cross-border exchanges, exchange A->C holds the maximum zone-to-zone $PTDF$ of 8.8%, indicating that 1 MW of A->C exchange imposes 0.088 MW on this CNEC. Please note that one may also use Equation 6 in Article 12 in the DA CCM to directly compute the maximum zone-to-zone $PTDFs$. For example, the maximum zone-to-zone $PTDF$ of CNEC 1 can be computated directly by 4.9% - (-3.9%) = 8.8%, being the maximum of its zone-to-slack $PTDF$ minus its minimum zone-to-slack $PTDF$. Comparing to the classical full computation of the zone-to-zone $PTDFs$ and subsequent selection of the maximum value as indicated in Figure 6, Equation 6 in Article 12 offers higher computational efficiency to compute maximum zone-to-zone $PTDFs$.

CNEC 1, in Figure 6, has a relatively low zone-to-zone $PTDF$ factor for exchanges from bidding zone A to bidding zone B: 0.1%. If CNEC 1 has 100 MW of RAM available for the allocation to be used, all the bids and offers submitted to the allocation mechanism are competing for the scarce capacity on CNEC 1. When all the capacity on CNEC 1 is used (and the CNEC is congested after MC), additional exchanges from bidding zone A to bidding zone B are blocked – like all other exchanges that lead to a further loading and congestion of the CNEC -, although a 100 MW exchange from bidding zone A to bidding zone B induces only a 0.1 MW flow on CNEC 1.

2.2.1.2. Reference flow (F_{ref})

This section refers to Article 12(8) of the DA CCM and Article 13(8) of the ID CCM.

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 7 – the F_{ref} value is 50 MW for $CNE_{A \rightarrow B}$ but -50 MW for the $CNE_{B \rightarrow A}$). Its value is expressed in MW.

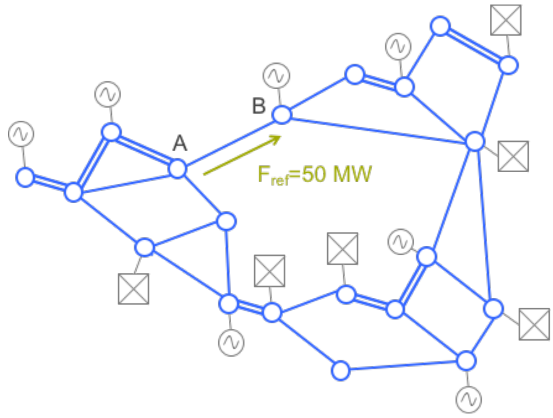


Figure 7: Example of a reference flow for the $CNE_{A\rightarrow B}$

2.2.2. Adjustment for minimum RAM (AMR)

This section refers to Article 13 of the DA CCM.

Core TSOs apply an adjustment to have a minimum RAM available for commercial exchanges. The application of the minimum RAM adjustment kicks in when the RAM – in a situation without any commercial exchanges in the Core region – is lower than 20% of the CNEC's F_{max}. This is illustrated in the examples below.

Let's imagine a CNEC with the following values

$F_{max} = 2000\ MW$	Maximimum admissible flow
$FRM = 200\ MW$	Flow reliability margin
$F_0 = 500\ MW$	Flow in the situation without commercial exchanges within the Core CCR

The AMR for the CNEC is determined with the following equation:

$$AMR = max(0.2F_{max} - (F_{max} - FRM - F_0); 0) = max(400 - (2000 - 200 - 500); 0) = 0$$

Indeed, the RAM in the situation without commercial exchanges in the Core region amounts 1300 MW and well exceeds the boundary value of 20% of the CNEC's F_{max} (being 400 MW). As such, the RAM of the CNEC is not enlarged: *AMR* = 0.

In case the $F_0 = 1500\ MW$, the AMR for the CNEC equals:

$$AMR = max(0.2F_{max} - (F_{max} - FRM - F_0); 0) = max(400 - (2000 - 200 - 1500); 0)$$
$$= max(400 - 300; 0) = 100$$

In this situation, the RAM in the situation without commercial exchanges in the Core region amounts 300 MW and is below the boundary value of 20% of the CNEC's F_{max} (being 400 MW). As such, the RAM of the CNEC is enlarged to 400 MW by applying an *AMR* of 100 MW.

The impact of the notion of minimum RAM, can only be assessed in conjunction with the CNEC selection threshold. This is elaborated upon in section 2.2.3.

2.2.3. CNEC selection

This section refers to Article 5 of the DA CCM and Article 6 of the ID CCM.

CNEC selection for capacity calculation process

This section refers to Article 5(6)(a) of the DA CCM and Article 6(6)(a) of the ID CCM.

The cross-zonal sensitivity is the criterion for selecting the CNECs that are significantly impacted by cross-zonal trade. Cross-zonal network elements are by definition considered to be significantly impacted. The other CNECs shall have a maximum zone-to-zone $PTDF$ that exceeds the threshold of 5%.

The last column of Figure 6**Error! Reference source not found.** selects the maximum zone-to-zone $PTDF$ per CNEC. Investigating CNEC 1 for instance, out of three cross-border exchanges, exchange A->C holds the maximum zone-to-zone $PTDF$ of 8.8%, indicating that 1 MW of A->C exchange imposes 0.088 MW on this CNEC. Comparing with the zone-to-slack $PTDF$s of CNEC 1, it is clear that, although the zone-to-slack $PTDF$s of CNEC 1 are all below 5%, the impact of cross border exchanges is still considered significant (being 8,8%, larger than 5% CNEC selection threshold). When considering the maximum zone-to-zone $PTDF$ of CNEC 4, it is clear that this CNEC does not meet the 5% threshold criterion. This implies that the branch will not be considered for the allocation unless it is a tie line or is deemed necessary by the relevant TSOs.

The impact of this CNEC selection threshold can only be assessed in conjunction with the notion of minimum RAM, according to Article 13 of the DA CCM. This is clarified in the following example.
A CNEC 1 with a maximum zone-to-zone $PTDF$ of 5% and a minimum RAM of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.05 = 4000 MW. The wording “at least” refers to the exchange for which the maximum zone-to-zone $PTDF$ holds, i.e. for other exchanges even higher exchanges would be feasible.
A CNEC 2 with a maximum zone-to-zone $PTDF$ of 10% and an identical minimum RAM of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.10 = 2000 MW.
Assuming that we are referring to the same pair of bidding zones for the two CNECs, the example shows that CNEC 2 is more restrictive for the potential exchange between those two bidding zones. Or in other words: CNEC 1 can not be limiting for the exchange between the two bidding zones in the presence of CNEC 2.

Generally speaking, the minimum RAM ensures that CNECs with lower maximum zone-to-zone $PTDFs$ are less likely to become presolved than CNECs with higher maximum zone-to-zone $PTDF$s.
Increasing the maximum zone-to-zone $PTDF$ threshold value would essentially imply setting the minimum RAM of those CNECs, which then fall below the threshold, to an infinite value. Allowing for a higher minimum RAM, or for a higher maximum zone-to-zone threshold, is likely to lead to a higher amount of costly remedial actions required in order to maintain operational security. At the same time, the less-constrained capacity domain is supposed to allow for a higher socio-economic welfare. The balance between those two numbers is hard to quantify.

As indicated above, in a zonal market model, the balance in between the two extremes, touched upon below, is hard to find:

- No internal CNECs are used in the capacity calculation and allocation.
  This extreme scenario seems to optimize a day-ahead (DA) market without taking internal constraints into account. Physical reality is however, that those internal constraints are there and need to be coped with by the TSOs. Neglecting internal CNECs in the DA market would lead to an “optimized” dispatch of generation and load, that to a large extent needs to be redispatched

afterwards in order to deal with the internal congestions resulting from this "optimized" market outcome.
- All internal CNECs are used in the capacity calculation and allocation.
  This extreme scenario would take the whole grid into account in the capacity calculation and allocation. Internal congestions, though not impacted by cross-border trade whatsoever, would block the cross-border trade.

The CNEC selection process, as proposed in the CCR Core, tries to find a proper balance in this respect, with the introduction of both the notion of minimum RAM and maximum zone-to-zone $PTDF$ threshold, and is considered to be in line with Regulation 714, Annex I, Article 1(7).

It is the belief of the Core TSOs that the proposed CNEC selection process contributes to, and does not in any way hamper the achievement of the objectives stated in Article 3 of the CACM Regulation.

Monitored CNEC selection for Remedial Action Optimization (RAO)
This section refers to Article 5(6)(b) of the DA CCM and Article 6(6)(b) of the ID CCM.

In order to prevent overloading of non-market relevant network elements (i.e. their maximum zone-to-zone $PTDF$ falls below the 5% threshold value) due to the RAO, these network elements can be included as monitored CNECs in the RAO. A quantitative selection criterion for these RAO-monitored CNECs is not necessary as explained in section 2.2.5.

2.2.4. Long term allocated capacities (LTA) inclusion

This section refers to Article 14 of the DA CCM.

In order to guarantee that the LTA are possible to be realised on the DA market, Core TSOs ensure that the FB domain as determined during the capacity calculation process includes the LTAs. This is exactly the goal of the LTA inclusion process, which boils down to increasing the RAM on some CNECs to accommodate possible day-ahead transactions equivalent to the amount of LTA (denoted by LTA_{margin} in Equation 12 in Article 14). The LTA inclusion process reflects the TSOs' need to assure that the congestion income collected from the day ahead is sufficient to remunerate the holders of LTA.

The type of long term transmission rights, i.e. physical or financial transmission rights, has no impact on the LTA inclusion algorithm. It does, however, have an impact on the FB domain for the single DA coupling, because long-term nominations, to be considered through Long term nominations (LTN) adjustment according to Article 18(1)(f) of the DA CCM (see section 3.3.1.2), only exist on borders with physical long-term transmission rights.

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 the FCA guideline, to be verified against the FB domain.
The method of creating virtual constraints, as applied in the CWE FB MC, and replacing the CNEs or CNECs for which the RAM_i is negative will not be applied because no algorithm is known for the creation of virtual constraints in the scope of the Core CCR (12 bidding zones, i.e. 11-dimensional problem) with acceptable computational time.

The LTA inclusion is performed automatically in the intermediate, pre-final, and final FB computations.

In theory, such artifacts are not to be used. In practice, however, resorting to the “LTA inclusion 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.

2.2.5. Rules on the adjustment of power flows on critical network elements due to remedial actions

This section refers to Article 15 of the DA CCM and Article 14 of the ID CCM.

The coordinated application of RAs aims at optimizing 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 other 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 enlarging the FB domain in the foreseen market direction. The foreseen market direction derives from the CGMA Methodology (section 3.2.1) and will be the result of a transparent and coordinated process that will be agreed upon amongst Core TSOs. With this process, Core TSOs aim to minimize the risk of a possible market intervention in case the actual market direction differs from the foreseen one. The enlargement of the domain will be performed by the RAO on one forecasted MCP given that currently there is no algorithm which is able to combine the results of RAO on multiple sets of net positions.

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 provided that selected RAs remain available also after D-2 capacity calculation in subsequent operational planning processes and real time. The RA optimisation does not use a specific order in selecting RAs.

All optimization constraints for curative remedial actions are applied individually for each contingency. Core TSOs foresee to use the following constraints for curative remedial actions:

- At most two TSOs can be involved per contingency;
- At most eight curative remedial actions can be selected per contingency;
  - Limited to three curative remedial actions for RTE, due to security policy.
  - Limited to two curative remedial actions for PSE, due to security policy.
- At most one topological curative remedial action can be selected per contingency respectively for Elia, MAVIR and PSE.

As a result there is no limit regarding the maximum number of curative remedial actions on the entire set of CNECs.

When evaluating a curative remedial action for a certain contingency, all CNEs corresponding to this contingency will be linked with this curative remedial action. Some of these CNEs may be assigned to a TSO which does not use curative remedial actions due to local TSO risk policy. In these cases, the curative remedial action will only be applied if it respects all CNEs security limits in the contingency situation.

In order to prevent overloading of non-market relevant network elements due to RAO, these network elements can be included as RAO-monitored CNECs. For each RAO-monitored CNEC i, the following has to hold:

$$\mathrm{RAM}_{\mathrm{after\ RAO,i}} \geq \min \begin{cases} 0 \\ \mathrm{RAM}_{\mathrm{before\ RAO,i}} - \mathrm{Threshold} \end{cases}$$

In words:

- If $RAM_{before\ RAO}$ is positive and higher than the threshold, $RAM_{after\ RAO}$ cannot become negative;
- If $RAM_{before\ RAO}$ is positive but smaller than the threshold, or $RAM_{before\ RAO}$ is negative, $RAM_{after\ RAO}$ shall not decrease by more than the threshold. The threshold is set at 50MW per CNEC.

The inclusion of monitored CNECs should be based upon a qualitative and experience-based assessment of the impact of the RAO, on the flow of each CNEC, by the TSO. Should a CNEC be included in this list whilst having a low sensitivity towards remedial actions, it won't have any effect on the optimization as a threshold is used to relax the optimization problem, and the variations in (relative) margin will be smaller than this threshold, which will be transparent as the CNEC will not be a binding constraint during RAO. In the opposite case, if a CNEC has a significant sensitivity towards remedial actions, it will rightfully impact the RAO as the variations in its (relative) margin will likely exceed the threshold.
This structural shadowing effect is taken advantage of in order to ensure that the RAO-monitoring function does not hinder the RAO result in case the qualitative assessment led to a wrongly-included CNEC in the RAO-monitored element list.

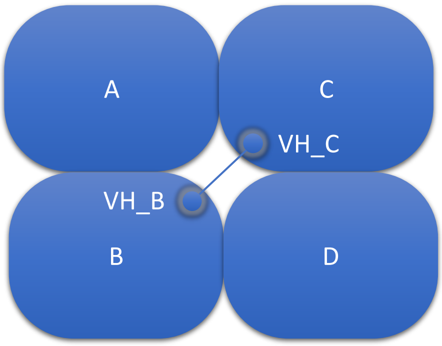
2.2.6. Integration of HVDC interconnectors located within the Core CCR in the Core capacity calculation (evolved flow-based)

This section refers to Article 16 and Article 12(6) of the DA CCM and Article 15 and Article 13(6) of the ID CCM.

The evolved flow-based (EFB) methodology describes how to consider HVDC interconnectors on a bidding zone border within the FB 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 CNEs directly during capacity allocation. This, in turn, allows taking into account the FB properties and constraints of the Core region (in contrast to 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 EFB. AHC considers the impact of exchanges between two capacity calculation regions (as the case may be belonging to two different synchronous areas) e.g. an ATC area and a 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.

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. This is illustrated in Figure 8.



A	B	C	D	VH_B	VH_C	NP		RAM
…	…	…	…	…	…	A		…
…	…	…	…	…	…	B	≤	…
…	…	…	…	…	…	C		…
…	…	…	…	…	…	D		…
…	…	…	…	…	…	VH_B		…
						VH_C		…

PTDF matrix RAM vector

Figure 8 EFB applied to an HVDC interconnector between bidding zones B and C within the CCR

The virtual hubs introduced by this process are only used for the modelisation of the impact of an exchange and will not contain any bids during MC. As a result, the virtual hubs will have a global net position of 0 MW, but their FB net position will reflect the exchanges over the interconnector.

The 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.

2.2.7. Capacity calculation on non-Core borders (hybrid coupling) – *see Article 21(1)(b)(vii) of the CACM Regulation*

This section refers to Article 17 of the DA CCM and Article 16 of the ID CCM.

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 D-2 CGM 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 AHC concept.

3. FLOW-BASED CAPACITY CALCULATION PROCESS

3.1. High Level Process flow

This section refers to Article 4 of the DA & ID CCM.

For DA FB capacity calculation in the Core Region, the high-level process flow foreseen is depicted in Figure 9. It shows the various processes performed by the entities involved.

Process step	Day	Sub-process	Non Core TSOs	Core TSOs	CCC	SAP	Merging Entities
1	**D-2**	**D-2 merging preparation**	**(X)**	**X**			**X**
	D-2	Perform NP forecasting	(X)	X			X
	D-2	Prepare IGMs	(X)	X			X
2	**D-2**	**D-2 merging**	**(X)**	**X**			**X**
	D-2	Send individual TSOs data for merging	(X)	X			
	D-2	D-2 IGM merging					X
3	**D-2**	**Initial data preparation**		**X**	**X**		**X**
	D-2	Prepare GSK		X			
	D-2	Prepare initial list of CNECs		X	X		
	D-2	Prepare external constraint		X			
	D-2	Prepare list of remedial actions available		X			
	D-2	Provide LTA		X		X	
	D-2	Fallback input file delivery if reqiuired		X	X		X
4	**D-2**	**Initial Data Gathering**		**(X)**	**X**	**X**	**X**
	D-2	Receive initial data prepration inputs		(X)	X	X	X
	D-2	Merging of received inputs			X		
5	**D-2**	**Initial FB computation**		**(X)**	**X**		
	D-2	Perform initial Flow Based computation			X		
	D-2	Perform CNEC selection			X		
	D-2	Update list of CNECs			X		
	D-2	Initate Fallback(s) if required		(X)	X		
6	**D-2 / D-1**	**Remedial Action optimization**			**X**		
	D-2 / D-1	Perform Remedial optimization			X		
	D-2 / D-1	Remedial actions selected for Core DA FB CC			X		
7	**D-1**	**Intermediate data gathering**		**X**			
	D-1	Provide LTN		X			
8	**D-1**	**Intermediate FB computation**			**X**		
	D-1	Determination adjustment for minimum RAM in list of CNECs			X		
	D-1	Execution of rules for including previously allocated capacities			X		
	D-1	Perform intermediate Flow Based computation			X		
9	**D-1**	**Validation**		**X**	**X**		
	D-1	Validate cross-zonal capacties		X			
	D-1	Coordinate cross-zonal capacties with other CCRs			X		
	D-1	Application of FAV		X			
	D-1	Update list of CNECs and/or external constraint		X			
	D-1	Early publication of data		X	X		
10	**D-1**	**Final FB computation**			**X**		
	D-1	Perform Final FB computation			X		
	D-1	Provide cross-zonal capacties to Market coupling			X		
	D-1	Initate Fallback(s) if required		X	X		
11	**D-1**	**Publication**		**X**	**X**		
	D-1	Publication of data		X	X		

Figure 9: High level process flow for Core FB DA CC
CCC means coordinated capacity calculator, and SAP means single allocation platform

For Intraday FB capacity calculation in the Core Region, the high-level process flow will be very similar to the foreseen process flow for DA FB capacity calculation as depicted in Figure 9. Based on experience in the Central West Europe (CWE) region, it is expected that the total process flow for an intraday capacity calculation will have a duration in the range of 1 to 3 hours. However, it is not clear yet how this will be impacted due to the increase of bidding zones in the Core CCR which may have a negative impact on the computation time.

Next to this the process can only be started once all required inputs can be gathered. As the TSOs individual IGMs may not be available at intraday gate opening, TSOs may refrain from providing any capacity until the intraday capacity calculation process has been finilized.

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 DA 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)[3], which is a part of the Common Grid Model Methodology approved by all ENTSO-e TSOs' NRAs in 8th May 2017.
The main concept of the CGMAM is presented in Figure 10 below:

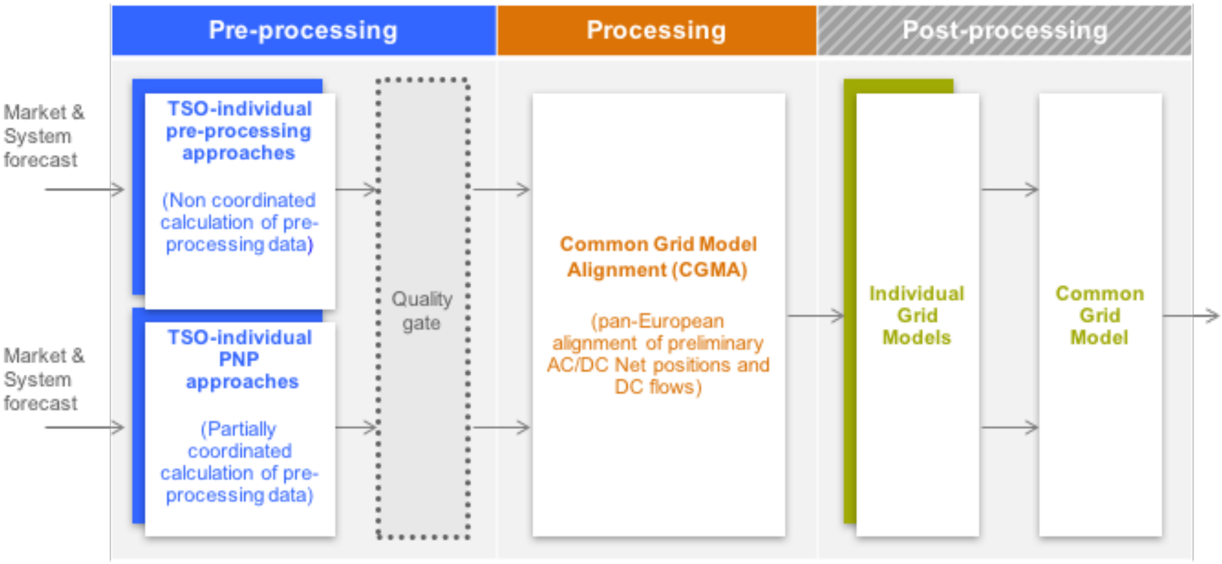


Figure 10: Main concept of the CGMAM

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.

3 The "All TSOs' Common Grid Model Alignment Methodology in accordance with Article 24(3)(c) of the Common Grid Model Methodology", dated 29th of November 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

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 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 mathematical 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 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 the 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 RES generation. As regards the net positions, the IGMs are compliant with the CGMA process, which is common for the 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.

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 the 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 section 3.4 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 $GSKs$ are used.

The Core CGM represents the entire Continental European (RG CE) transmission system[4]. It means that the CGM contains not only the Core IGMs for the respected time stamps but also all IGMs of the CE TSOs not being directly involved in the Core FB CC process.

3.3. Regional calculation of cross-zonal capacity – *see Article 29 of the CACM Regulation*

3.3.1. Calculation of the final flow-based domain

This section refers to Article 18 of the DA CCM.

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. Determination of the adjustment for minimum RAM (*AMR*, see section 2.2.2);
2. LTA inclusion (see section 2.2.4);
3. Determining the most constraining CNECs (see section 3.3.1.1);
4. LTN adjustment (see section 3.3.1.2).

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

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

This section refers to Article 17 of the ID CCM as well.

Given the CNEs, CNECs and ECs that are specified by the TSOs in the Core region, the FB parameters indicate what commercial exchanges or NPs can be facilitated under the DA MC without endangering grid security. As such, the FB 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 so that the DA social welfare is maximized while respecting the constraints provided by the TSOs. Although from the TSO point of view, all FB parameters are relevant and do contain information, not all FB 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 redundant 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 depicted in Figure 11.

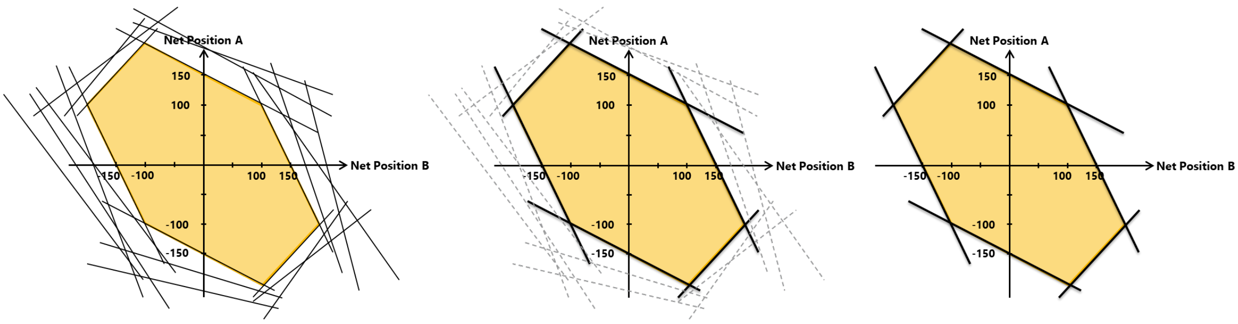


Figure 11: CNEs, CNECs and ECs before and after the "presolve" step

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 FB capacity domain that is indicated by the yellow region in the two-dimensional figure (see Figure 11). It is within this FB capacity domain that the commercial exchanges can be safely optimized by the Market Coupling mechanism. The intersections of multiple constraints (two in the two-dimensional graph in Figure 11) define the vertices of the FB capacity domain.

3.3.1.2. 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 commercial exchanges in the D-2 CGM. Therefore, this reference flow has to be adjusted to take into account the effect of the LTN of the MTU instead. The $PTDFs$ remain identical in this step. Consequently, the effect on the FB capacity domain is a shift in the solution space, as depicted schematically in Figure 12.

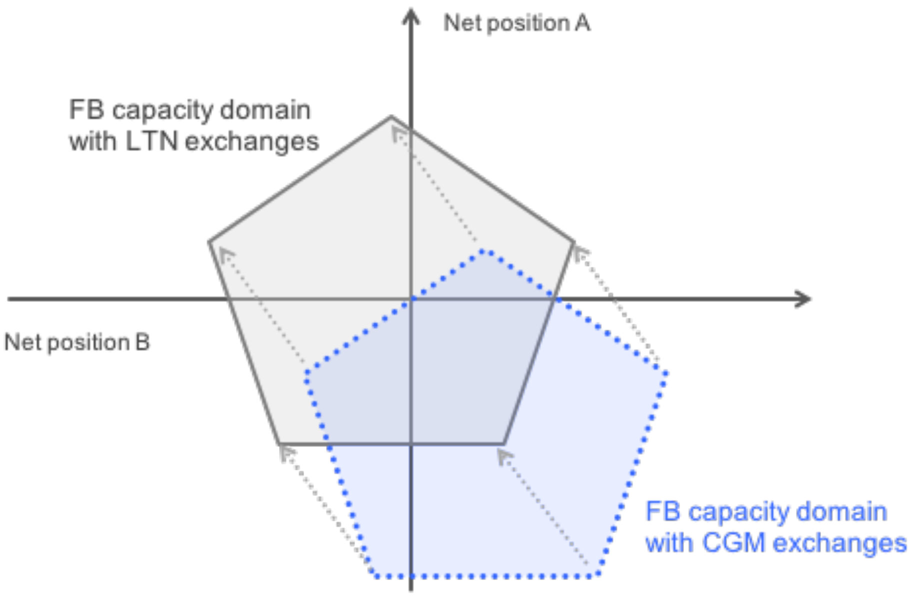


Figure 12: Shift of the FB capacity domain to the LTN

Please note that the intersection of the axes depicted in Figure 12 is the nomination point.

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

3.4.1. Precoupling backups and replacement process

This section refers to Article 19 of the DA CCM.

In some circumstances, it can be impossible for TSOs to compute FB 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" FB parameters only concerns 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 FB 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 FB method is very sensitive to its inputs, TSOs decided to directly replace missing FB parameters by using a so-called "spanning method". Indeed, trying to reproduce the full FB 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 FB parameters over a too long period would lead to unrealistic results.
- Second, in case of impossibility to span the missing parameters, TSOs will deploy the computation of "default FB parameters".

The flowchart in Figure 13 captures the general approach followed by TSOs:

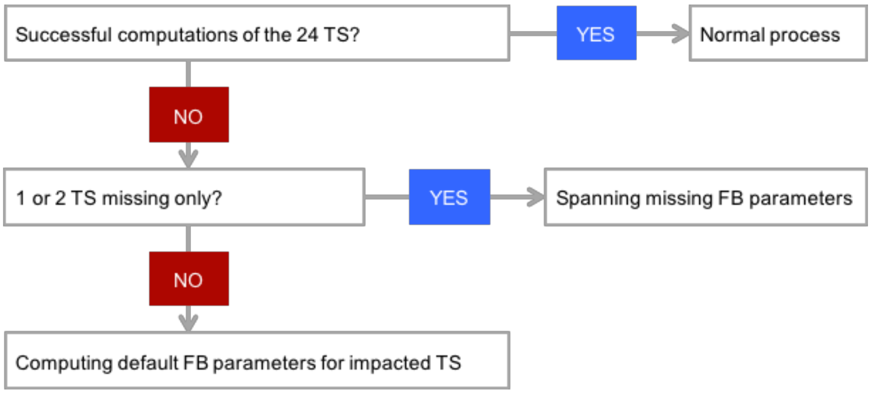


Figure 13: Flowchart for the application of precoupling backup and default processes

3.4.2. Spanning

When inputs for FB parameters calculation are missing for less than three hours, it is possible to compute spanned FB 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 FB domains, adjusted to zero balance (to delete the impact of the 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). This is illustrated in Figure 14.

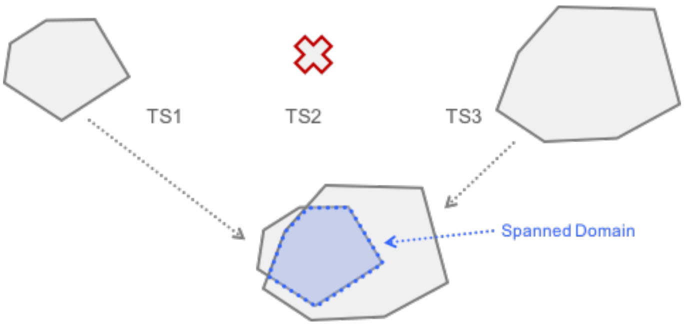


Figure 14: Forming the spanned domain for the missing timestamp 2

3.4.3. Precoupling default flow-based parameters

When it is not possible to span the missing parameters, i.e. if more than two consecutive hours are missing, the computation of "default FB parameters" will be deployed.

3.5. Market coupling fallback TSO input - ATC for fallback process – *see Article 44 of the CACM Regulation*

This section refers to Article 20 of the DA CCM.

As a result of FB CC, FB domains are determined for each MTU as an input for the FB MC process. In case the latter fails, the FB domains will serve as the basis for the determination of the ATC values that are input to the fallback process (ATCs for fallback process). 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 FB domain leads to an infinite set of choices, an algorithm has been designed that determines the ATC values in a systematic way. It is based on an iterative procedure starting from the LTA domain as shown in Figure 15 below.

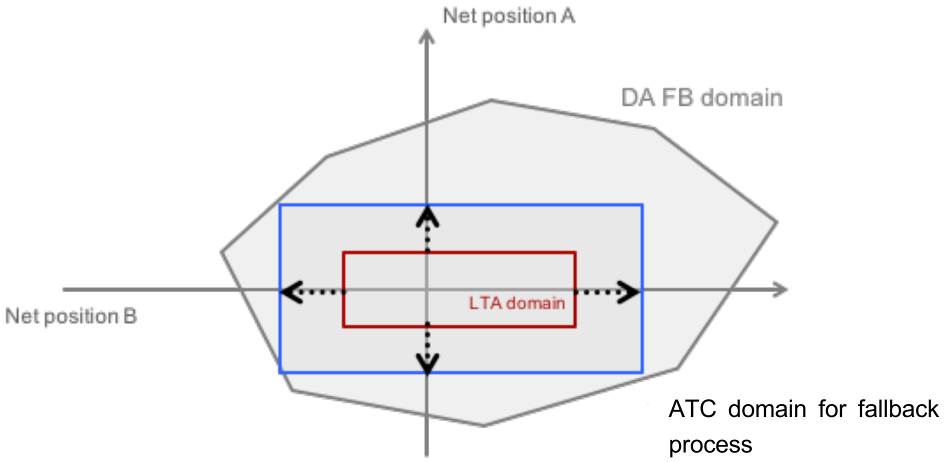


Figure 15: Creation of an ATC domain for the fallback process

The computation of the ATC for fallback process 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)
```

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

This section refers to Article 21 of the DA CCM and Article 19 of the ID CCM.

One potential necessity for TSOs to apply an FAV value during the validation of the cross-border capacity – thereby decreasing the cross-zonal capacity – may be the need to cover significant reactive power flows on certain CNECs. This is elaborated upon below.
Indeed, the Core TSOs explain in Article 6 of the DA CCM that they assume the share of the CNEC loading by reactive power to be negligible. In such a case, the power factor $\cos(\varphi) = 1$, which means that the element is assumed to be loaded by active power only:

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

This assumption is rather progressive and does not hold true by definition on AC grids. Normally, on the high-voltage grids, this assumption should not pose an issue though. However, when a reactive power flow takes substantial magnitudes, the power factor will drop according to the following equation:

$$cos(\varphi) = \frac{P}{\sqrt{P^2 + Q^2}}$$

with

P	Active power in MW
Q	Reactive power in Mvar

A too low value of the power factor may require the TSO to set a FAV value in the validation stage. This is illustrated in the example below.
By assuming a power factor $\cos(\varphi) = 1$, a certain CNEC has the following F_{max} to be applied in the capacity calculation and allocation:

$$F_{max} = 1000\, cos(\varphi)\ MW = 1000\ \ MW$$

If the reactive power flow becomes substantial, and the power factor drops e.g. to a value $\cos(\varphi) = 0.8$, the same CNEC can only handle 800 MW of active power flow:

$$F_{max} = 1000\, cos(\varphi)\ MW = 1000 \times 0.8\ \ MW = 800\ \ MW$$

When the TSO is not able to handle this difference of 200 MW in operations, he is able to set a FAV value in the validation stage.

3.7. Publication of data

This section refers to Article 23 of the DA CCM and Article 21 of the ID CCM.

The Core transparency framework is based on the current operational transparency framework in CWE DA FB MC.

3.8. Monitoring and information to regulatory authorities

This section refers to Article 24 of the DA CCM and Article 22 of the ID CCM.

The Core transparency framework is based on the current operational transparency framework in CWE DA FB MC.

4. IMPLEMENTATION

4.1. Timescale for implementation of the Core flow-based day-ahead capacity calculation methodology

This section refers to Article 25 of the DA Proposal.

According to Article 8(1) of the CACM Regulation, all European TSOs are obliged to participate in the single day-ahead and in the single intraday coupling, thus in common implicit allocation sessions. Thus, whilst taking into account Article 20(1) of the CACM Regulation, the target model for the TSOs of the CCR Core is flow-based market coupling both in the day-ahead and intraday time frame. Core TSOs strive to implement both the flow-based capacity calculation and market coupling in one single step on all bidding zone borders.

Every other approach is neither designed yet in the current CCM proposal framework nor would it be compliant to the aims of the CACM Regulation to ensure efficient, transparent and non-discriminatory capacity allocation. Any approach where a capacity allocation using both implicit and explicit allocations based on capacity domains derived out of a FB CC would need sequential approaches both in the calculation (as net positions must be adjusted) and allocation (implicit and explicit allocations cannot be run at the same time whilst using the same flow-based capacity inputs) that would either lead to a potential discrimination of market actors participating in implicit allocations in the CCR or of the ones participating in explicit auctions. Also from timing aspects such sequential solution is not feasible and also not required by TSOs.

APPENDIX 1 - 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.

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.

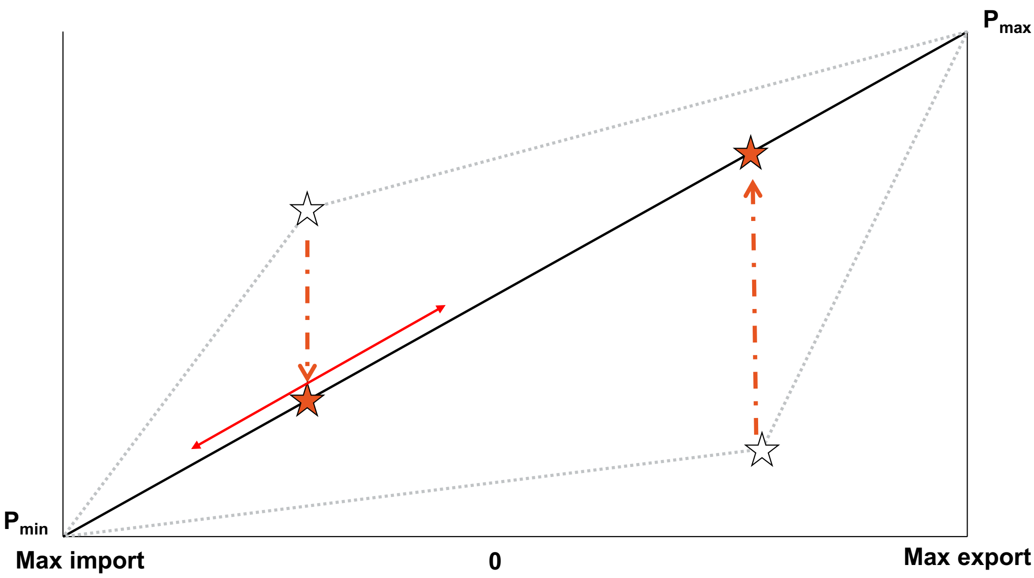


Figure 16: Belgian GSK.

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. In addition 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). All mentioned nodes are considered in shifting the net position in a proportional way.

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 and nuclear units are not included in the GSK file. The list of GSK is produced on hourly basis. The units inside the GSK will follow the change of the Czech net position proportionally to the share of their production in the D-2 CGM. In other words, if one unit represents n% of the total generation on the Czech bidding zone in the D-2 CGM, n% of the shift of the Czech net position will be attributed to this unit.
The current approach of creation GSKs is regularly analysed and can be adapted to reflect actual situation in CEPS´s grid.

Netherlands:

TenneT TSO B.V. will dispatch controllable generators in such a way as to avoid extensive and not realistic under- and overloading of the units for foreseen 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 in order to prevent unfeasible production levels.

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

TenneT TSO B.V. will continue fine-tuning their GSK within the methodology shown above.

France:

The French GSK is composed of all the flexible and controllable production 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 productions in the D-2 CGM. In other words, if one unit represents n% of the total generation on the French bidding zone in the D-2 CGM, n% of the shift of the French net position will be attributed to this unit.

Germany:

The German[5] 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.

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

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. 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 GSK for the control area of 50Hertz is 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 GSK for every MTU is 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 base 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 the 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 from the independent power producer at the time when the individual GSK-file is created.

The GSK for every considered generation node i is determined as:

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

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 MTU is known.

The following types of generation units connected to the transmission grid can be considered in the GSK:

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

Nuclear power plants are excluded.

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 are 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 units inside the GSK will follow the change of the Polish net position proportionally to the share of their production in the D-2 CGM. In other words, if one unit represents n% of the dispatchable generation on the Polish bidding zone in the D-2 CGM, n% of the shift of the Polish net position will be attributed to this unit.

Romania:

The Transelectrica GSK file contains flexible and controllable units which are available in the day of operation. The units planned for maintenance and nuclear units are not included in the list. The fixed participation factors of GSK are impacted by the actual generation present in the D-2 CGM.

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. In addition 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). 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 addition 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.