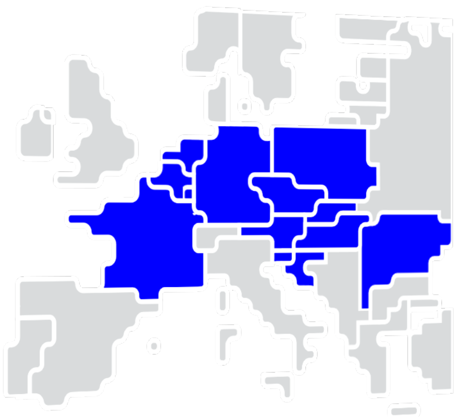
Explanatory document to the Core CCR TSOs common coordinated long-term capacity calculation methodology in accordance with article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

November 2020



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1. INTRODUCTION

Sixteen Transmission System Operators (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 CCR (Decision 06/2016 of November 17, 2016). The countries within the Core CCR are located in the center of Europe which is why the Core CCR Project has a substantial importance for the further European market integration.

In accordance with article 10 of the FCA Regulation, the Core TSOs have developed a common long-term capacity calculation methodology proposal (hereafter Core LT CCM or Proposal).

The aim of this explanatory document is to provide a detailed description of the Core LT CCM and relevant processes. This paper considers the main elements of the relevant legal framework (i.e. FCA and CACM Regulation, 2019/943, 543/2013).

Title 2 of this document covers the input aspects, Title 3 describes the capacity calculation process, Title 4 details the validation methodology, Titles 5 deals with updates and publication and Title 6 mentions the implementation timeline.

1.1 Approach for Finalization of the Core LT CCM

Although the Core TSOs started the development of the required Core LT CCM in an early stage, it is highly challenging for the 16 TSOs (13 countries) in the Core CCR to deliver a final CCM.

Therefore, the Core TSOs follow the approach for finalization of the Core LT CCM mentioned hereafter:

1. The publication of the first draft of the Approval Package accompanying the public consultation from September 16, 2020 to October 16, 2020. This first draft contains the Core LT CCM and its accompanying explanatory document, including a high level description of all the steps mentioned in the High Level Business Process (HLBP) on how to determine the final values and methods for e.g. Scenarios, CNEC selection, GSK methodology and the treatment of RAs and Scenarios (including outages).
2. Submission of the final Approval Package for Core NRA approval of the Core LT CCM Proposal ultimately by November 2020.
3. This final package contains:
    - Core LT CCM, including updates based upon Core NRAs' and stakeholders' comments, if any;
    - explanatory document, including a description of all the steps mentioned in the HLBP on how to determine the final values and methods for e.g. CNEC selection, GSK methodology and the treatment of RAs and Scenarios (including outages), as well as updates based upon Core NRAs' and stakeholders' comments, if any.

Main reasons for Core TSOs to propose this approach:

- to be able to develop a Core LT CCM that meets stakeholders’ and Core NRAs’ expectations as reflected in feedback, if any, received after public consultation.

1.2 Core TSO Deliverable Report

Currently no deliverable reports are foreseen.

1.3 High Level Business Process

This section refers to Article 3 of the Core LT CCM.

See below Figure 1 depicting the Core Long-Term Capacity Calculation (LTCC) HLBP:

Core LTCC High Level Business Process (FB LTCC)

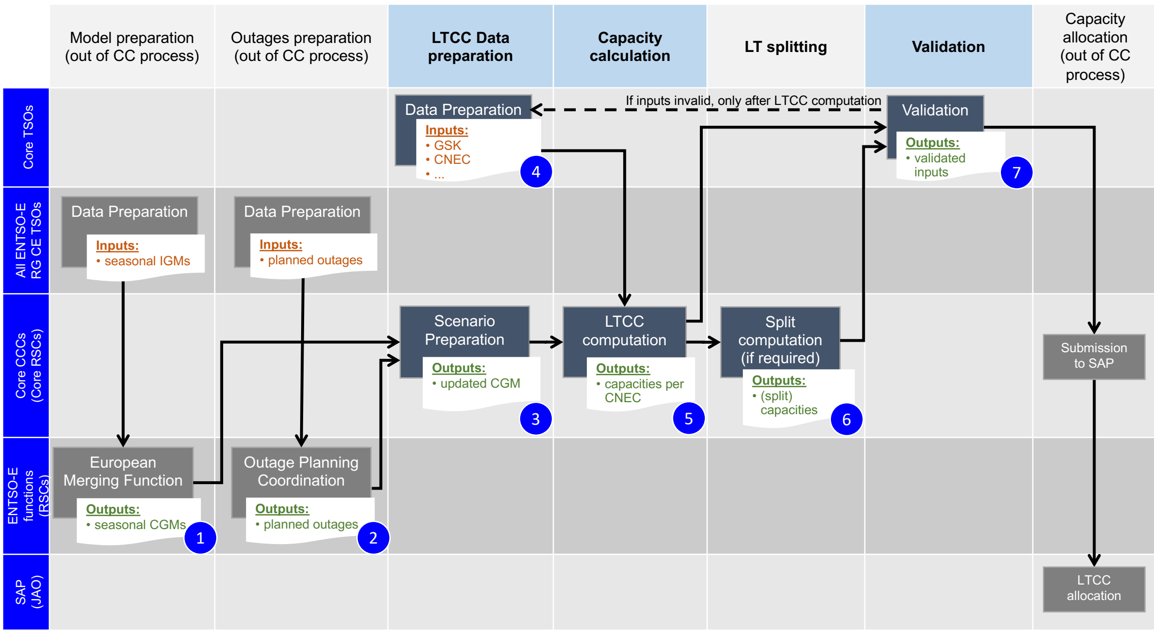

Figure 1: High Level Business Process

There are 6 steps shown (numbered); the steps dedicated to the Core LTCC process are shown in the three columns, marked light blue (LTCC Data preparation, Capacity calculation and Validation). The rows indicate which role is responsible for the process.

Data preparation for Core LTCC relies on all TSOs' European Network of Transmission System Operators for Electricity (ENTSO-E) processes. These all TSOs' data preparation steps are shown in the first two columns.

Herewith follows a description of the 6 steps:

1. The step 1 is related to an all TSOs' ENTSO-E process (article 67 of the SO GL Regulation and the FCA-CGMM). Each Core TSO provides an IGM for each seasonal CGM. IGMs are merged into seasonal default CGMs by the Core CCC each year for the next calendar year.
2. The step 2 is also related to an all TSOs´ ENTSO-E process (Title 3 of the SO GL Regulation). Availability plans (outage plans) are provided by each Core TSO to a common database. This database and the communication between the database and the Core TSOs are managed by the Core CCC. Preliminary outage plans of ENTSO-E TSOs are available in the OPC database from 1 November for the next calendar year (article 97 of the SO GL Regulation).

Planned Core processes:

3. Based on default CGMs (see step 1) and the preliminary outage plans of all Core TSOs for the whole year (see step 2), in the step 3 the Core CCC shall create the forecasted network models for any of the selected time stamps; this is achieved by incorporating the relevant outages (see Article 10 on Scenarios) in the CGMs.

4. In the step 4, each Core TSO provides to the Core CCC the necessary input data: these are e.g. GSK and CNEC files (see Article 12(1) presenting all relevant inputs for calculation).
5. During the step 5, the Core CCC performs the actual capacity calculation based on the Core LT CCM. This step represents all necessary calculations performed by the Core CCC and is described in Title 3: the step delivers results of FB CC (RAM per CNEC).
6. In the step 6, the capacity calculation outcomes can be subject to LT Splitting Rules Methodology pursuant to article 16 of FCA Regulation. For further details, please see the LT Splitting Rules Methodology.
7. During the 7th step, the Core TSOs validate the capacity calculation results obtained before and after splitting (see Article 17 on Validation), upon which the (splitted) results of the step 6 are submitted to the SA) by the Core CCC. This procedure is set in accordance with the article 24 of FCA Regulation. In case a Core TSO declares CC results obtained before splitting as invalid, a new calculation round could be triggered with necessary adjustment of input data.

These briefly described relevant steps and related methodologies are explained more in detail in the next sections.

2 TREATMENT OF INPUT

2.1 Reliability Margin Methodology

This section refers to Article 4 of the Core LT CCM.

Article 11 of the FCA Regulation requires a methodology for reliability margin (RM), meeting the requirements set out in article 22 of the CACM Regulation.

In article 2(14) of the CACM Regulation the following definition is given:

"Reliability Margin means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation". FRM means the margin reserved on the permissible loading of a CNE or cross zonal capacity to cover uncertainties of power flows in the period between the capacity calculation and real time, taking into account the availability of RA.

The uncertainties covered by the FRM values are among others:

a. Core external transactions (out of Core CCR control: both between Core region and other CCRs as well as among TSOs outside the Core CCR);

b. generation pattern including specific wind and solar generation forecast;

c. GSK;

d. load forecast;

e. topology forecast;

f. unintentional flow deviation due to the operation of load frequency controls.

Compared to the DA time frame, there are further uncertainties in the LT timeframe which are not explicitly mentioned in the list above. These are in particular the knowledge about the availability of topological measures or redispatch measures. Such further LT uncertainties cannot be considered in the FRMs calculated for the DA timeframe. Yet, taking into account the complexity of determining such additional uncertainties (whose determination is in fact also subject to a certain level of uncertainty), Core TSOs decided to cover these additional uncertainties approximately by the the consideration of several selected scenarios, which shall be the annually created ENTSO-E year-ahead reference scenarios (those scenarios are created in accordance to article 65 of the SO GL Regulation, see the paragraph on scenarios).

Therefore, considering that the additional uncertainty in the LT timeframes can approximately be adressed by the consideration of different scenarios, Core TSOs use the same FRMs in the LTCC as defined in article 8(11) of the DA CCM. Yet, if Core TSOs note after implementation of the Core LT CCM, that the described simplified approach is not sufficient to adequately cover the uncertainties in the Core LT CCM, they will review the applied approach and might request a Request for Amendment (RfA) for Core NRAs' approval.

The values technically applied in the LT capacity calculation are the FRMs (as defined in article 8(11) of the DA CCM). By referring to the DA CCM in this LT CCM, all the relevant stipulations therein, e.g. that the FRM is a percentage of the maximum admissible power flow (Fmax), apply for the Core LT CCM as well.

The reliability margin methodology shall be reviewed and if necessary, updated in order to keep full consistency with the methodology and its evolution in the Core CCR and, as aforementioned, to ensure that the higher uncertainties in the capacity calculation for the LT time frames is adequately considered.

Since a DC interconnection is not a critical branch, a reliability margin is not applicable here.

2.2 Methodologies for Operational Security Limits

This section refers to Article 5 of the Core LT CCM.

According to article 12 of the FCA Regulation the proposal for a Core LT CCM shall include methodologies for operational security limits and contingencies and it shall meet the requirements set out in articles 23(1) and 23(2) of the CACM Regulation. This methodology for operational security limits is in accordance with article 25 on operational security limits of the SO GL Regulation and with article 72 on operational security analysis in operational planning of the SO GL Regulation.

According to Article 5, the maximum admissible current ($I_{\max}$) is the physical limit of a CNE determined by each Core TSO in line with its operational security policy. The physical limit reflects the capability of a transmission element (e.g. 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 kilo ampère (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 Core TSO is responsible for deciding, in line with their operational security policy, if a temporary limit can be used. All Core TSOs will use seasonal limits or constant limits depending on the assets for LT capacity calculations. Seasonal limits are fixed limits in accordance with article 25 on operational security limits of the SO GL Regulation. The calculation of yearly capacities is carried out using 4 (winter, spring, summer, autumn) seasonal CGMs. In function of the selected timestamp the seasonal criteria will be applied conform per each Core TSO policy. No dynamic rating will be used in Core CCR for LT capacity calculations due to absence of the required forecast parameter. It is not possible in the LT capacity calculation timeframe to sufficiently forecast weather conditions like it can be done in the DA and intraday time frames. This fact is not a restriction to the use of dynamic limits in DA and ID time frames and will allow maximal available capacity utilization in short term capacity calculations.The most reliable possibility to forecast weather conditions in LT capacity calculation is by application of seasonal limits.

Generally, the methodology for operational security limits and contingencies for LT included in the proposal for a common capacity calculation methodology shall:

- meet the requirement of respecting the operational security limits used in operational security analysis (as foreseen in article 23(1) of the CACM Regulation);
- describe the particular method and criteria that are used to determine the operational security limits used for capacity calculation (in case the operational security limits used in capacity calculation are not the same as those used in operational security analysis), as foreseen in article 23(2) of the CACM Regulation.

Article 75 of the SO GL Regulation foresees development of a proposal for a methodology for coordinating operational security analysis that is applicable by Core TSO when performing a coordinated operational security analysis (article 72 of the SO GL Regulation). This methodology shall aim at the standardization of operational security analysis at least per synchronous area and shall include in the light of article 75(1) of the SO GL Regulation at least (inter alia):

- principles for common risk assessment, covering at least, for the contingencies referred to in article 33 of the SO GL Regulation: (i) associated probability; (ii) transitory admissible overloads; and (iii) impact of contingencies;
- principles for assessing and dealing with uncertainties of generation and load, taking into account a reliability margin in line with article 22 of the CACM Regulation.

2.3 Allocation Constraints

This section refers to Article 6 of the Core LT CCM.

In case operational security limits cannot be transformed efficiently into I_{max} and F_{max}, the Core TSOs may transform them into allocation constraints as foreseen in article 29(1) of the CACM Regulation, which article 23(2) of the FCA Regulation refers to. For this purpose, the Core TSOs may only use external constraints as a specific type of Allocation Constraints pursuant to Article 6 that limits the maximum import and/or export of a given Core bidding zone. Reasons and the methodology for the calculation of external constraints is specified in detail in Annex 1 to the Core LT CCM.

2.4 Critical Network Elements and Contingencies

This section refers to Article 7 of the Core LT CCM.

In the Central Western European Region (CWE), CNEs are known as Critical Branches (CBs), while contingencies are called Critical Outages (COs). Yet, in the Core CCR, the combination of a CB and a CO (in CWE known as CBCO) is referred to as a CNEC (in line with the nomenclature applied in the Core DA CCM).

The list of CNEs is determined by each Core TSO for his own bidding zone/ control area and the respective scenarios used in the Core LT CCM. A CNE is a network element, significantly impacted by Core cross-zonal trades, which is supervised under certain operational conditions, the so-called contingencies (see below). A CNE can be a cross-zonal or internal network element. Those elements can be an overhead line, an underground cable, or a transformer.

For each CNE within a certain scenario, Core TSOs provide a list of contingencies limited to their relevance for the respective CNE. A contingency can be a trip of a line, a cable, or a transformer; a busbar; a generating unit; a load; or a set of the aforementioned contingencies.

The cross-zonal sensitivity is the criterion for selecting the CNECs that are significantly impacted by cross-zonal trade and shall therefore be considered in the LTCC. Cross-zonal network elements are by definition considered to be significantly impacted. All other (i.e. non-cross-zonal) CNECs shall have at least one zone-to-zone $PTDF$ that exceeds the threshold of 5%. Due to the high complexity of LT capacity calculation and the strong interdependencies between different methodological parameters, it is difficult to derive conclusions on specific values of single methodology parameters. Given this and the general acknowledgement, that the uncertainty in the LT time frame is higher than in the short-term (like DA), Core TSOs agree on a threshold of 5%. If the operational experience after the go-live of DA CCM in Core CCR for the LTCC shows that a different threshold would be more appropriate, this will be forwarded to the Core NRAs as a RfA for their approval.

The mechanism of the CNEC selection is illustrated in Figure 2 below.

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 2: CNEC Selection Threshold Example

In the last column of Figure 2 the maximum zone-to-zone PTDF per CNEC is shown. Investigating the sensitivity of CNEC 1 for instance, out of three cross-border exchanges, exchange A →C holds the maximum zone-to-zone PTDF by 8.8%, indicating that 1 MW of A →C exchange imposes 0.088 MW on CNEC 1. When considering the maximum zone-to-zone PTDF of CNEC 4, it is clear that this CNEC 4 does not meet the 5% threshold criterion. This implies that the branch (CNEC 4) will not be considered for the calculation of LT capacities.

The impact of this CNEC selection threshold can only be assessed in conjunction with the notion of RAM, according to Article 14 of the Core LT CCM. This is clarified in the following example.

A CNEC 1 with a maximum zone-to-zone $PTDF$ of 5% and a Remaining Available Margin (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 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 cannot be limiting for the exchange between the two bidding zones in the presence of CNEC 2. Increasing the maximum zone-to-zone $PTDF$ threshold value would essentially imply setting the RAM of those CNECs, which then fall below the threshold, to an infinite value.

As described in Article 7 of the Core LT CCM, the Core TSOs have adopted the following method to select the CNEC list to be used during capacity calculation.

Firstly, each Core TSO provides a list of critical network elements and a list of associated contingencies of its own control area. Core TSOs make their decision based on their operational experience. Operation experience refers here to the experience of grid dispatchers that, when a specific contingency is relevant for a specific critical network element as in case of an outage (i.e. contingency) the specific critical network element would be considerably impacted (i.e. by a higher loading).

Secondly, based on this initial pool of CNECs, the Core CCC selects a final list of CNECs to be used in the LTCC, based on the principle that a CNEC in the final list must meet the criterion to be significantly influenced by changes in the net position. This is in accordance with article 29(3) of the CACM Regulation. It must be stated that a cross-zonal critical network element is always considered as being significantly influenced. As defined in Article 7 of the Core LT CCM, the threshold for the CNEC selection shall be a at least one zone-to-zone PTDF of 5%. Finally, the Core TSOs can update both the initial and the final list of CNECs on a monthly basis. By this possibility, Core TSOs are able to update the list with updated information before the start of a monthly capacity calculation e.g. with an updated outage planning. The publication requirements are to be found in Article 19(2).

The Core TSOs did not harmonise the methodology of the CNEC selection with the CNEC selection methodology in the Core DA CCM, due to the fact that there are significant differences between LT and DA capacity calculation. The reliability of information available one year ahead of the real-time situation is considerably lower than the information available on DA. As explained before, this is also the reason why Core TSOs foresee the possibility to update the information considered in the month-ahead capacity calculation (e.g. by consideration of the updated outage planning). In light of the considerable uncertainty one-year ahead, Core TSOs do not see it justified to limit the CNEC selection for the LT capacity calculation as foreseen in the DA CC, as the latter one requires to limit the amount of CNECs mainly to cross-zonal network elements.

2.5 Generation Shift Keys

This section refers to Article 8 of the Core LT CCM.

Article 8(2) mentions specific situations that Core TSOs can face. An example is having hardly any hydro power due to an extraordinary dry season. It must be explicitly stated that since the generation pattern (locations) is unique for each Core 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: the GSKs in the Core CCR are determined by each Core TSO individually on the basis of the latest available information about the generating units and loads; to be calculated for each scenario seperately. Each 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. The GSK created by each Core TSO can be different for each timestamp or can be same for all timestamps. If only a reference GSK file is provided, it is used for all scenarios. If no GSK file is provided, a proportional shift is implicitly applied to all generating nodes (load nodes will not be included). 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 NP 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 will be allocated to one or more nodes of the CGM in order to appropriately model its technical impact on the transmission system.

Appendix 1 describes the GSK creation per Core TSO.

2.6 Methodology for Remedial Actions in Capacity Calculation

This section refers to Article 9 of the Core LT CCM.

The use of RAs during capacity calculation is not obligatory. The purpose of RA application is to alleviate possible local constraints and not to optimize capacities.

After first capacity calculation results are available, Core TSOs may draw a conclusion that the capacity values are not in line with Core TSO's best practice and experience. In order to improve calculation results, the Core TSOs will create a common set of coordinated RAs to be applied in accordance with predefined criteria. The set will be validated and approved by each Core TSO based on coordinated capacity calculation results. The Core TSOs can initiate updates of the set.

Each Core TSO assesses the impact of RAs proposed by other Core TSOs on its grid. In case of negative influence to capacity or the (n-1) criteria is violated, then a Core TSO may refuse the proposed RA.

During the calculation process the Core CCC will apply the RAs based on the predefined criteria and deliver results to the Core TSOs. Both the application of RAs and the final capacity calculation during the validation phase has to be confirmed by all Core TSOs.

For the LTCC within the Core CCR, only the following RAs are considered:

- opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s);
- switching of one or more network element(s) from one bus bar to another;
- transformer and Phase-Shifting Transformer (PST) tap adjustment.

The Core TSOs shall not apply RAs optimization, because the optimization with the aim of enlarging and securing the long-term capacity around the expected operating point of the grid is not possible so far in advance of the real time grid situation.

2.7 Scenarios and Calculation Timestamps

This section refers to Article 10 of the Core LT CCM.

In accordance with article 19 of the FCA Regulation, the Core TSOs shall jointly develop a common set of scenarios to be used in the CGM for each LT capacity calculation timeframe; this applies for the situation where security analysis based on multiple scenarios pursuant to article 10(4)(a) of the FCA Regulation is applied, which is the case for the Core CCR.

For the LTCC for both timeframes, the Core TSOs shall use the annually created ENTSO-E year-ahead reference scenarios (i.e. default scenarios), in accordance with article 3(1) of Common Grid Model Methodology (CGMM) for FCA in conjunction with article 65 of the SO GL Regulation. This Pan-European process is based on the common grid methodology as developed in accordance with article 18 of the FCA Regulation[1]. The description of these scenarios is available ultimately 15 July each year; the accompanying CGMs are available ultimately 15 September each year[2]. The creation of the year-ahead scenarios are bound by the stipulations in article 65 of the SO GL Regulation and article 3(1) of the CGMM for FCA Regulation, which is an ENTSO-E responsibility. When Core TSOs use the resulting ENTSO-E CGMs and only apply on these CGMs the relevant outage information, the Core TSOs are not bound by the CGMM for FCA Regulation. The SO GL Regulation does not require the creation of monthly scenarios and accompanying CGMs. Therefore, ENTSO-E does not create monthly scenarios that could be used by the Core TSOs.

The current CGMM for FCA Regulation differentiates for the four seasons; for each season a scenario is created for peak and valley, hence resulting in 8 final scenarios for each year. This is based on the assumption that ENTSO-E provides 8 CGMs. Please be reminded that ENTSO-E decides annually how many CGMs are created.

The ENTSO-E OPC process also uses these scenarios (CGMs) as starting points for security assessments. Therefore, the main quality issues in the CGMs are solved by the Core CCC, on request of the Core TSOs. The main issues of preliminary year-ahead availability plans provided by all TSOs before

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[1] The Common Grid Model Methodology (“CGMM”) of article 18 of the FCA Regulation has been approved by all NRAs on 04.07.2018 (*All TSOs’ proposal for a common grid model methodology in accordance with Article 18 of Commission Regulation EU 2016/1719 of 26 September 2016 establishing a Guideline on forward capacity allocation*).

[2] Article 22(1)g CGMM SO GL Regulation: 1 September + 10 business days.

1st November (pursuant to article 97 of the SO GL Regulation), are solved by ENTSO-E and the relevant CCCs early November each year (4-5 November).

The Core TSOs use these pieces of information and the accompanied updated CGMs for the LT capacity calculation process for the yearly timeframe.

The related year-ahead seasonal scenarios used for yearly capacity calculation may be updated for monthly capacity calculation. Core TSOs may initiate a scenario update for any predictable change, compared to the year-ahead seasonal scenarios, associated with a specific measure concerning the grid topology or generation pattern, such as for example a change in generation pattern following untypical climate and hydrological conditions.

If this is the case, the Core TSOs may update:

- the generation pattern; and/or
- the topology due to grid element commissioning or decommissioning;

in its own IGM, and may provide one updated IGM for each default seasonal scenario for the referred calculation time-frame, while the NPs in the IGMs shall remain the same as given in the year ahead CGMs.

Accordingly, the Core CCC updates the CGM by replacing the initial IGM with the newly updated single Core TSOs' IGM: the Core CCC does this when a Core TSO provides a new monthly IGM that respects the NP of the respective default seasonal scenario; all in accordance with timing described in the beginning of this paragraph.

The Core CCC applies the planned outages for the monthly capacity calculations for the selected timestamps on the above mentioned updated CGM. Also for the monthly capacity calculations the Core TSOs will work in coordination with the OPC project group on the OPC process.

2.7.1 Outage Selection and Resulting Capacity Products

All ENTSO-E Regional Group Continental Europe (RG CE) TSOs’ planned outages and the associated topological switches are stored and regularly updated in the OPC database (foreseen to be replaced by OPDE). The Core CCC will use this database for downloading the most actual set of planned outages not only for the Core CCR, but for the whole synchronous area. According to the SO GL Regulation, preliminary year-ahead availability plans, i.e. planned outages of all TSOs', are available in OPC database as from 1st November for the next year, and final year-ahead availability plans as from 1st December.

According to the OPC process time schedule, the quality check of preliminary availability plans regarding tie-line inconsistencies is first performed by the Core CCC, upon which the availability plans are corrected by the Core TSOs ultimately on 4 November of each year. The year-ahead capacity calculation shall be performed using the latest outage data amended in OPC data base.

Month-ahead capacity calculation shall be performed using the latest outage data updated by Core TSOs in the OPC database. Theoretically, any timestamp with the planned outages can be selected for LTCC. In order to keep the regular workload of Core TSOs and Core CCC within a reasonable boundary the selection of planned outages for scenarios of year-ahead and month-ahead capacity calculation is determined as follows.

Year-ahead:

For each month of the year two timestamps are selected: one valley timestamp and one peak timestamp, resulting in 24 timestamps. The following selection criterion is applied on these timestamps: the largest number of simultaneously planned outages in Core CCR in the respective valley and peak periods of the month. Then all planned outages available in the OPC database for the selected timestamps of the synchronous area of Continental Europe are applied on the related default seasonal scenarios: the outages of the valley timestamp for the default valley scenario and the outages of the peak timestamp for the default peak scenario.

Note: OPC database may store planned outages of any grid element of TSOs. TSOs may mark any other TSO's grid element in OPC database as relevant for outage coordination according to SO GL Regulation. Timestamp selection considers and counts only relevant grid element outages of Core TSOs, but then all planned outages available in OPC database in the selected timestamp are applied on CGM for CC.

If any of the Core TSOs considers that a selected timestamp with all its planned outages does not represent the most critical network condition in the related period, such TSO may require to add any of the planned outages from the related period to the related set of outages. This may happen if the timestamp with the largest number of e.g. peak period outages in January does not include a certain outage (considered by a Core TSO as critical), that is planned in other peak timestamp(s) in January, as that outage is simultaneous with less other planned outages. Therefore, a critical outage may fall out from the automatic selection. Simply adding any further planned outage to the related set of outages, as decribed above, does not increase the calculation cases.

Added outages considered as critical by a TSO are individual considerations of single TSOs, and intend to serve for avoiding high cross-zonal capacities jeopardizing the system security.

Based on the 24 timestamps (i.e. the network models including the planned outages), capacity calculations are performed (as described in following sections), upon which the lowest capacity of the two capacity calculations of each month are selected, resulting in 12 values per. This is the calculated year-ahead capacity for the related monthly subperiod as the grey columns (#1) in Figure 3 below.

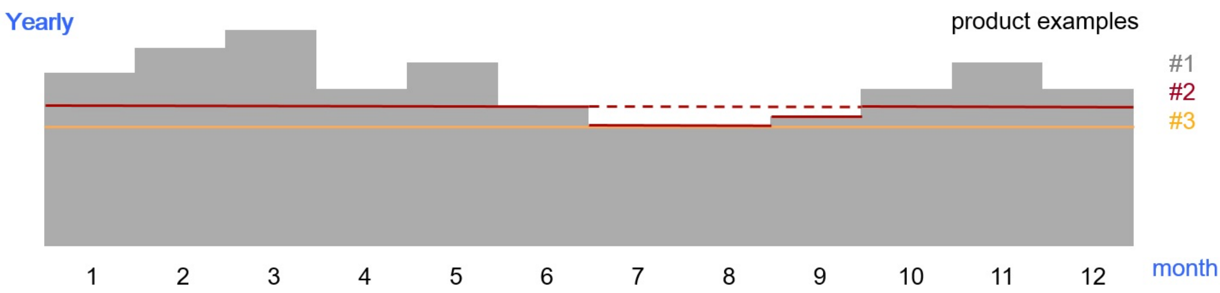


Figure 3

Based on this so-called profile different year-ahead capacity products (e.g. year-ahead capacity with 12 monthly subperiods represented by #2 or a stable bound year-ahead capacity adjusted to the lowest calculated capacity represented by #3) can be defined upon which forms of products could be applied. As the allocation algorithm is still under development, the definition of yearly products is to be confirmed by all parties.

Month-ahead:

Analogue to the monthly granularity approach for year-ahead outage selection and capacity product possibility, a weekly granularity is applied for the month-ahead CC process, resulting in 4 or 5 times 2 timestamps (valley and peak). Hence, 8-10 timestamps are selected, and 8-10 calculations are performed using the most actual planned outages information available in the OPC database. Similarly to the year-ahead process, further planned outages can be added to the related set of outages at any Core TSO's request. Resulting calculated capacities look like the grey columns in Figure 4 below. As the allocation algorithm is still under development, the definition of monthly products is to be confirmed by all parties.

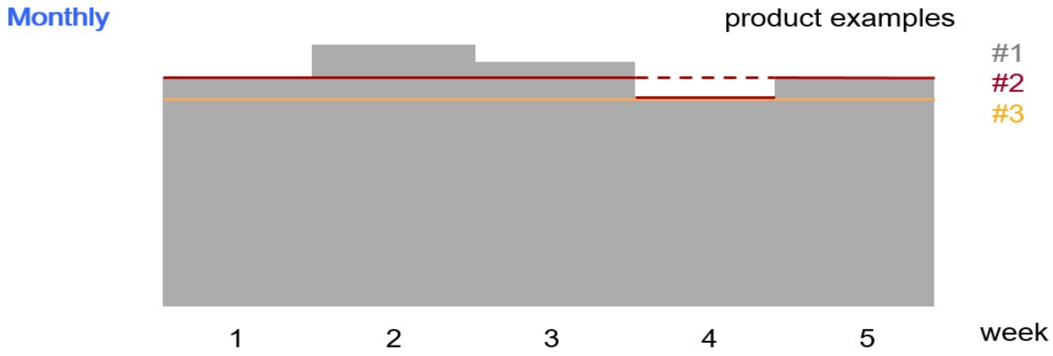


Figure 4

Also for this profile different month-ahead capacity products (e.g. month-ahead capacity with 4-5 weekly subperiods or a stable bound month-ahead capacity adjusted to the lowest calculated capacity) can be defined.

Summary

The Core TSOs use the ENTSO-E year-ahead scenarios for both long-term capacity calculation time frames as starting points. Assuming that ENTSO-E creates 8 CGMs for a specific year (4 seasons; 2 timestamps (peak and valley) per season), the Core TSOs plan to use these CGMs for LTCC. Based on these CGMs, the Core TSOs create the so-called timestamps: this is the year-ahead CGMs *plus* the selected outages as described above. For the monthly time-frame the latest available information for a TSO IGM could be incorporated under specific conditions explained above.

For the yearly calculation, the Core TSOs select per month 2 timestamps: one peak and one valley, resulting in 24 timestamps. Capacity calculation is performed based on these 24 timestamps.

For the monthly calculation, the Core TSOs select per week 2 timestamps: one peak and one valley, resulting in 8-10 timestamps. The capacity calculation is performed based on these 8 timestamps.

Based on these results, the final set of FB parameters are chosen after the validation process taking into account the product requirements pursuant to the Regional Design of Long-Term Transmission Rights (LTTRs) in accordance with article 31 of the FCA Regulation.

Based on later experiences, Core TSOs in coordination with Core CCC may modify the above selection approach, in accordance with the existing legislation.

2.7.2 Base Case Quality

Upon receiving the yearly CGMs and before the actual capacity calculation process, the Core LT CCM foresees two additional process steps yielding the necessity to check the base case quality:

1. Mapping of the planned outages against CGMs before LTCC computation

For each timestamp for which the capacity will be calculated, the grid elements that are in planned outage are searched in the CGM and the planned outages of the found elements are applied (see previous paragraph). The outage of the grid element combined with the eventual topological switches will lead to different loading of the elements compared to the loading of those elements in seasonal CGMs. It is expected that all LTCC planned outages could be found in seasonal CGMs to properly simulate system loading.

2. Congestion Check in CGMs with zero balance net position in the Core CCR

While it can be expected that overloading of the grid elements will be avoided in the year-ahead reference scenarios, it is still possible that certain grid elements after planned outages application and transition of CGM net position to zero balance, will be loaded to such an extent (e.g. 99.9%) that results will end in low capacities.

Therefore the condition for minRAM on each CNEC can be verified and imposed as the first step of capacity calculation for each timestamp as described in Article 14(3) and Article 14(4).

Yet, in order to systematically improve the base case quality on the long run, the Core TSOs will constantly monitor the base case quality pursuant to Article 10(7). Improvement of the base case may be achieved by adjusting the following settings, based on a coordinated agreement among Core TSOs:

i. the minRAM threshold pursuant to Article 14(2);
ii. the application of RA pursuant to Article 9;
iii. the sensitivity threshold pursuant to Article 13(3);
iv. the topological switches related to a planned outage pursuant Article 10(4).

Finally, after each long-term calculation an overview of the base case quality shall be provided by Core CCC to Core TSOs in a corresponding report. This report shall consist of and include at least the following CNECs per calculated timestamp:

i. the overloaded CNE(C)s and its level of overload in base case before the application of minRAM, i.e. the negative RAM occurred pursuant Article 14 but before application of minRAM pursuant Article 14(4);
ii. the pre-solved branches that were not subject to minRAM, where pre-solved branches represent the final set of binding constraints for capacity allocation after identification and removal of redundant constraints from the FB domain (based on definitions of the DA CCM).

Core CCC will also reflect the measures related to improvement of base case quality of each calculated timestamp pursuant to Article 20(4)(5).

2.8 Integration of Cross-Border HVDC Interconnectors Located within the Core CCR

This section refers to Article 15 of the Core LT CCM.

This document details the methodology for the integration of the High-Voltage Direct Current (HVDC) interconnector in the Core LT CCM. In fact, this document describes the general integration of a HVDC grid element.

2.8.1 Introduction

The integration of a HVDC grid element in an alternating current (AC) meshed grid is very particular as its flow is constant and independent of the situation on the surrounding AC meshed grid, contrasting AC elements that are directly impacted by the situation on the surrounding HVDC grid element(s).

Nevertheless, the goal is to integrate the HVDC grid elements in such a way that they are compatible with the existing calculation methodologies for an AC grid. The case of Alegro is also particular because the DE <> BE border is the only fully DC interconnector within the Core CCR.

2.8.2 Philosophy

In the Core LT CCM for the Core region, an AC-line is characterized by its zone-to-zone PTDFs and its RAM. An AC-line can be a CNEC. The idea is to give the same parameters to a HVDC element so it can be integrated in the calculation tool.

RAM

The available margin on an HVDC element is defined in the same way as on an AC-line, being the difference between the Fmax – Reference flow (Fref). The Fmax of the HVDC will be equal to the MPTC (Maximum Permanent Transfer Capability).

PTDF

An HVDC element has no zone-to-zone PTDF except between the two virtual hubs to which it is connected.

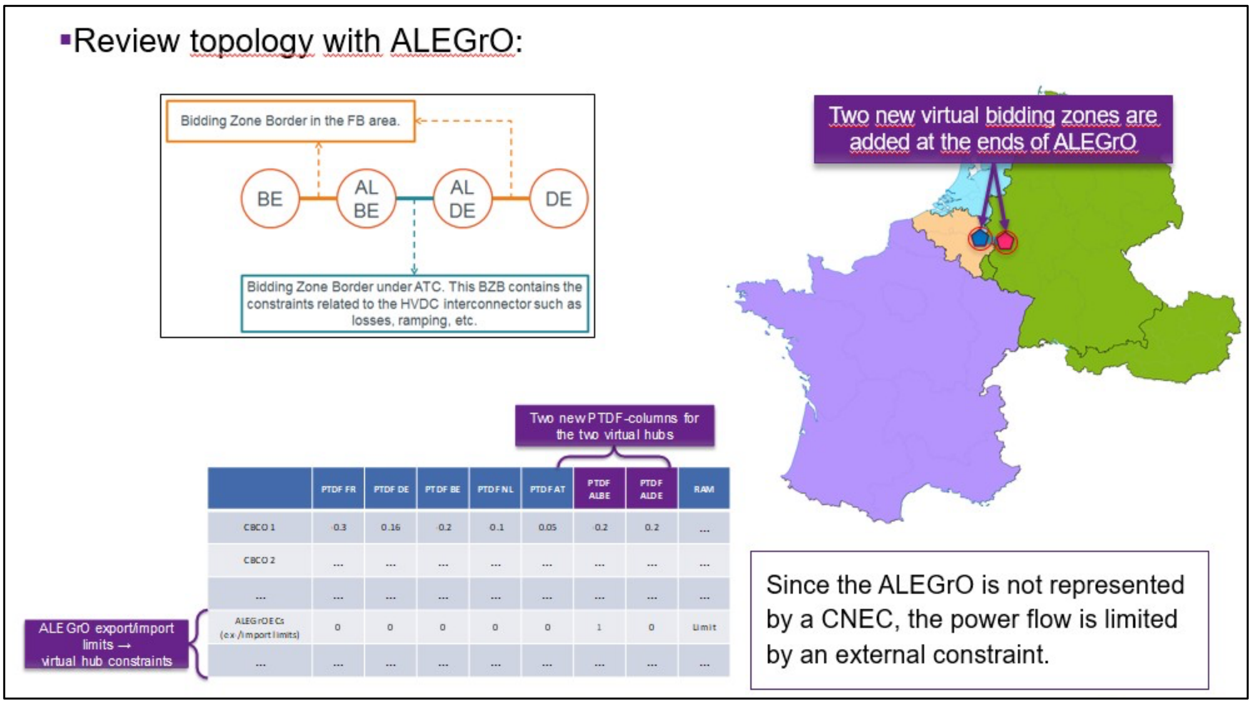
Contingency (C)
An HVDC element is a C, this means that the impact on other AC elements on the loss of an HVDC element has to be taken into account.

Critical Network Element (CNEC)
An HVDC element is not a critical branch because the flow on an HVDC is not influenced by the surrounding grid situation (e.g. exchanges on other BZBs). Consequently, Alegro will not have any FRM (see Reliability Margins section).

Operation of the HVDC
The HVDC will be operated with fixed flows (set point), which would be equal to the commercial flows. The adjustment of the flow for the base case improvement will not be considered, due to the fact that the starting position of the calculation is zero-balance.

Methodology
Amprion and Elia foresee to integrate the HVDC interconnector Alegro by adding two virtual hubs in order to represent the exchange over the DC link. Each virtual hub is modelled as one load/generation node. The PTDFs of the CNECs concerning the virtual hubs can be calculated and integrated in the Core LT CCM.

The HVDC interconnector Alegro will be considered in the inputs of Core TSOs as a CO, but not as a CB according to the particularities of the HVDC technology (fixed flows so no change in flow due to exchanges on other BZB, no overload possible). In addition, the MPTC, for which the BE <> DE long-term capacity will be capped in any case, will be an input provided by Core TSOs for the computation. This method is general and could also be applied for any other future HVDC interconnector within the Core CCR.



	PTDF FR	PTDF DE	PTDF BE	PTDF NL	PTDF AT	PTDF ALBE	PTDF ALDE	RAM
CBCO 1	0.3	0.16	0.2	0.1	0.05	0.2	0.2	...
CBCO 2	...	...	...	...	...	...	...	...
...	...	...	...	...	...	...	...	...
ALEGrOECs (ex-/import limits)	0	0	0	0	0	1	0	Limit
...	...	...	...	...	...	...	...	...

Figure 5

Some consequences:

- the long-term capacity on the BE <> DE border will be limited by the Alegro MPTC or by a limiting AC CNEC;
- the long-term capacity on AC BZB will never been limited due to an overload on an HVDC.

2.8.3 Additional Remarks

- This proposal is meant to be used only for any cross border HVDC connection within the Core Region. Therefore, if an AC connection exists on the same border as the HVDC interconnector, then the general AC calculation, as described in Article 12(5) will be used for this AC connection.

3 DESCRIPTION OF THE CAPACITY CALCULATION PROCESS

3.1 Technical Description of the Capacity Calculation Method

This section refers to Title 3 of the Core LT CCM.
The principles under which the calculation algorithm has been developed are the following:

- full compliance with the FCA Regulation – the algorithm offers a clear, transparent and scenario based methodology with FB approach. It has been developed with the objective to benefit from Core TSOs' experiences in both LT and DA capacity calculations;
- network security – the calculated figures must allow Core TSOs to effectively limit cross-border power exchanges in such a way that the relevant network security criteria are fulfilled;
- coordination and maximization of trade opportunities – within the limits of network security and taking into consideration of Core TSOs experience and best practice in internal capacity calculation risks policies, the procedure shall allow for a high utilization of the grid infrastructure by the network users;
- transparency – the procedure shall be highly transparent, i.e. with a comprehensive methodology as well as clear information on the input and the output side:
    - input: the provided data and assumptions made by each Core TSO shall be transparent to all other Core TSOs;
    - output: the procedure shall allow for the identification of input parameters necessary for the FB allocation;
- non-discriminatory and common – the LT capacity calculations for each BZB are done by the Core CCC considering the same grid model, the same scenario and applying the same calculation method.

3.1.1 Main Characteristics of the LTCC Algorithm

Before the calculation algorithm is explained in more technical detail the following set of characteristics, that are forming the basis of the LTCC algorithm, need to be introduced:

- all Core TSOs apply a commonly agreed threshold for making CNECs insensitive for "enough far away" electrical distance between the CNECs and the BZB: the so called common threshold for minimum sensitivity of CNECs or "Rule No 1". Further analysis will be performed both on the volume and on whether it could be an individual Core TSO threshold. As this is an important parameter on which the Core TSOs do not have much experience yet, the Core TSOs will review and agree on this threshold before the start of each LT capacity calculation;
- the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0) to avoid netting effect in LT CC;
- the algorithm will apply a minimum RAM threshold for each CNEC.

In order to calculate the long-term capacity respecting the system security, the following parameters are to be calculated for each CNEC **for each timestamp**:

- zone-to-zone PTDFs for each bilateral exchange direction;
- RAMs.

In accordance with Article 12 these parameters should be provided as flow based domain for allocation. Detailed explanation on how to obtain these parameters is given below.

3.1.2 PTDF Calculation

In accordance with article 29(3)(a) of the CACM Regulation, the Core CCC shall calculate the impact of a change in the bidding zones NP on the power flow on each CNEC (determined in accordance with the rules defined in Article 7 on CNEC). This influence is called the zone-to-slack $PTDF$. This calculation is performed with the CGM and the GSK defined in accordance with Article 8 on GSK.

The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ for each node defined in the GSK. These nodal PTDFs are derived by varying the injection of a relevant node in the CGM and recording the difference in power flow on every CNEC (expressed as a percentage of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ by multiplying the share of each node in the GSK with the corresponding nodal PTDF and summing up these products. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\mathrm{zone-to-slack}} = \mathbf{PTDF}_{\mathrm{node-to-slack}}\, \mathbf{GSK}_{\mathrm{node-to-zone}} \qquad (1)$$

with

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

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

$$PTDF_{A\to B,l} = PTDF_{A,l} - PTDF_{B,l} \qquad (2)$$

In order to determine the flow on a CNEC in the situation without commercial exchanges within the Core CCR the following equation is used:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF_f}\ \overrightarrow{Exchanges}_{ref,Core} \qquad (3)$$

with

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

In order to ensure consistency with DA CC, DC loadflow is used to compute $\vec{F}_{ref}$. The slack reaction of the grid is compensated by adjusting the load. Usage of DC loadlow allows a consistent use of variables in Formula 3 above (with PTDFs and exchanges) and in the RAM computation in Formula 4 and 5 in section

3.1.3. Moreover, the DC loadlflow provides a stable convergance of loadflow and enhances the computation time.

Additionally, the use of DC loadflow will ensure the fact that:

- Core TSOs will be compatible with the DA CC methodology to manage load flow investigations and improvements if any, and to ensure the compatibility between LT CC and DA CC;
- The implementation of the LT CCM requires stable assumptions in order to achieve a process fulfilling all TSO obligations.

Further investigations can be launched after Go Live in order to assess the need to include AC load flows at this step of the process.

CNEC selection described in the section 2.4 is also applied to the CNECs based on their PTDFs.

A common threshold for minimum sensitivity of CNECs in accordance with Article 13(3) may be applied to the computed zone-to-zone PTDFs using the following formula:

If $PTDF_{A\rightarrow B,l} \leq threshold$ then the $PTDF_{A\rightarrow B,l}$ is set to zero.

As a starting point the threshold will be set as 0%. Core TSOs can jointly change the value of the threshold if it is supposed to increase economic efficiency and does not harm the system security. The threshold allows to discard influence of electrically distant CNECs on exchange directions.

3.1.3 RAM Calculation

Based on the definition of PTDF described above, the RAM of a CNEC l is calculated in accordance with the definition of Fmax in Article 13 and in accordance with the definition of FRM in Article 4 on Reliability Margins as follows:

$$RAM_l^+ = Fmax_l - FRM_l^+ - F_{0,Core} \quad (4)$$

$$RAM_l^- = Fmax_l - FRM_l^- + F_{0,Core} \quad (5)$$

with

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

The non-Core BZB exchanges should be maintained in accordance with the Article 15 on Consideration of non-Core CCR bidding zone borders.

Assuming that the procedures for RAM and PTDF calculations have been used, a set of values has been created for an educative grid that contains a set of 3 CNECs: Table 1 gives an overview of the mentioned values.

Input CNECs	PTDF (A>B)	PTDF (A>C)	PTDF (D>B)	PTDF (D>C)	initial RAM
CNEC1	-0,5	0,18	-0,06	0,09	1200
CNEC2	0,27	0,05	0,13	-0,1	600
CNEC3	0,12	0,27	-0,12	0,05	2000

Table 1

Applying the CNEC selection threshold of 5% and threshold for minimum sensitivity of 5% provides the following PTDFs:

Input CNECs	PTDF (A>B)	PTDF (A>C)	PTDF (D>B)	PTDF (D>C)	initial RAM
CNEC1	0	0,18	0	0,09	1200
CNEC2	0,27	0,05	0,13	0	600
CNEC3	0,12	0,27	0	0,05	2000

Table 2

These vaues will be used for the purpose of explanation of LTCC algorithm described in the next section.

3.1.4 Application of minimum RAM

This is referring to the Article 14 of the CCM and explains how and why the TSOs of Core CCR apply a threshold in order to retrieve a minimum value of RAM.

To avoid insufficient value of RAM after computation, all TSOs have agreed on a minimum value R_{amr} which is a percentage of F_{max} that allows to retrieve a minimum RAM above this specific threshold:

$$RAM \geq R_{amr} * F_{max}$$

The previous equation can be fulfilled by adding a new parameter AMR which describe the amount of artificial RAM added to the initial RAM (defined in eq. 4-5) in the following equation:

$$RAM + AMR = R_{amr} * F_{max}$$

In order to retrieve a final value of AMR for each CNEC the following equation is used:

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

The final RAM of a CNEC l is therefore corrected by AMR value as follows:

$$RAM = F_{max} - FRM - F_{0,Core} + AMR$$

The minRAM factor is set on the level of 20% as a working assumption based on performed experimentations and will be subject to a review according to Article 14 of the LTCCM 2 years after Go Live of the methodology. The two first yearly auctions will be performend based on FB parameters computed using a 20% minRAM factor, while for the third yearly auction after Go Live, Core TSOs will use a reviewed minRAM factor. The review will take into consideration the lessons learned during all the yearly and monthly computations occurred during these 2 years.

3.2 Form of products

In accordance with article 31 of the FCA Regulation, the Core TSOs developed a proposal for the Regional Design of LTTRs to be issued on each BZB within the CCR. The application of form of products is taking into account a foreseen specific network situation (e.g. planned maintenance, long-term outages).

The harmonised allocation rules (HAR) for LTTRs developed in accordance with article 51 of the FCA Regulation, also supports the use of form of products.

In accordance with article 48 of the FCA Regulation, all TSOs established the SAP. The SAP requires that the SAP Operator shall receive the amount of LT capacity to be offered in the respective auction directly from the TSOs or the coordinated capacity calculator where relevant. The SAP Operator shall publish the offered capacity including form of products (if applicable) in accordance with the HAR.

The application of form of products is legally possible for each individual hour, which ensures that a minimum amount of capacity will be reduced. However, from a LTCC perspective, this level of detail is very challenging indeed, because in that case all timestamps representing outages causing reduction need to be considered (see Article 10 on Scenarios).

In order for the Core TSOs to facilitate the LT capacity calculation process, reduction hours are considered in default timestamps as follows:

- for the yearly long-term calculations, a monthly timestamp is chosen;
- for the monthly long-term calculation, a weekly timestamp is chosen.

As a result of this approach, capacities would be reduced for the whole respective period represented by timestamp. The results of the yearly calculation in monthly timestamps, is shown in Figure 6 below:

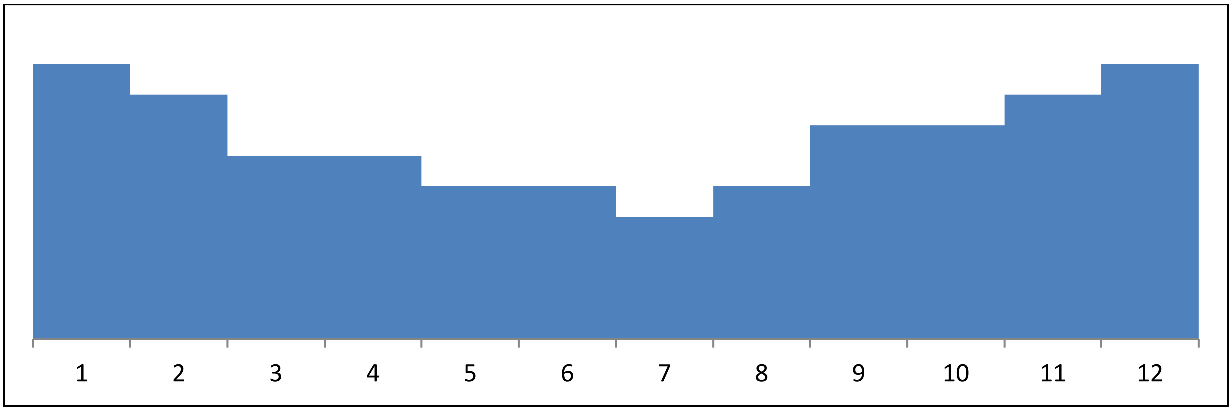


Figure 6

Analogue results can be imagined for monthly calculation, using weekly timestamps. Based on these results as a next step the coordinated long-term capacity for the respective yearly and monthly products need to be determined.

The form of any product as regulated in the regional market design pursuant to article 31 of the FCA Regulation, gives the possibility to use calculated results in order to offer capacities to the maximum amount possible. This maximum amount is represented by the red line in Figure 7.

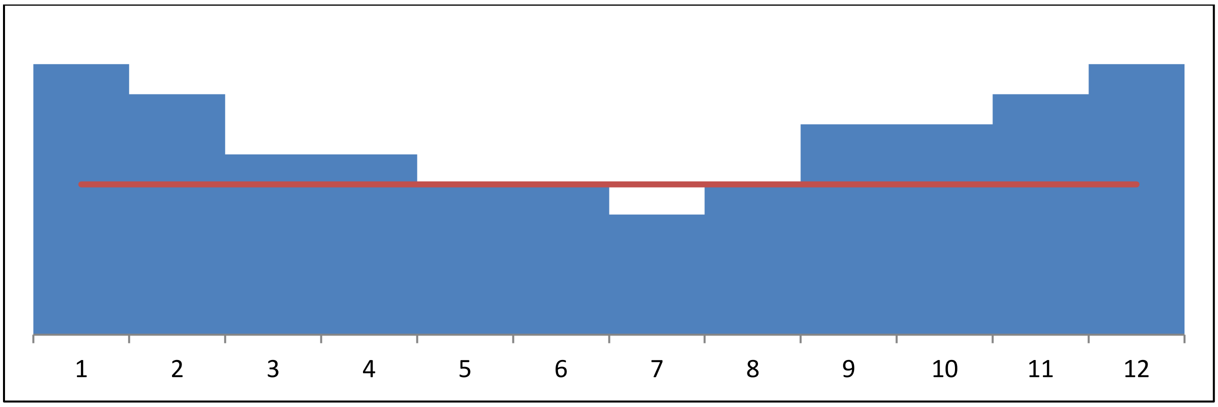


Figure 7

Core TSOs will finalize calculation results to meet the form of product regulated in the Regional Design of LTTR including reduction periods if applicable. The outcome results can vary amongst BZBs. Therefore it is inefficient to set fixed rules how to come from the calculation result to capacity products. On the one hand Core TSOs are striving to offer maximum available capacity, but on the other hand the form of product regulated in the Regional Design of LTTRs, established based on article 31 of FCA Regulation, needs to be respected. To balance those two requirements, flexibility is needed on Core TSO side in order to meet market participants expectations to the extent possible.

3.3 Consideration of non-Core Bidding Zone Borders

This section refers to Article 15 of the Core LT CCM.

Capacity calculation on non-Core borders is out of the scope of Core LT CCM. Based on approved methodologies from the relevant capacity calculation regions, JAO auctions the provided long-term capacities on Core to non-Core borders.

However, the impact of exchanges between CCRs physically exists and needs to be taken into account to ensure viable secure grid assessments, and this is done implicitly as is explained in the following lines.

As a basis or starting point for LTCC, the prepared scenarios (CGMs) include assumptions on the exchanges on non-Core BZBs. During the capacity calculation process, these exchanges are untouched and remain fixed. This is done as this is in line and compatible with the DA CCM. The expected exchanges with the Core CCR are captured implicitly (in the RAM over all CNECs). The resulting uncertainties to the aforementioned assumptions are implicitly integrated within the reliability margin (see section 2.1 in this document). As such, these assumptions will impact the available margins of Core CNECs, and consequently long-term capacity. It must be noted that it is called implicit. An explicit integration would mean incorporating exchanges between Core and non-Core bidding zones in a dedicated, seperated calculation step, which is not the case. At this stage, during the calculation step, relevant CNECs between Core and non-Core zones will be included in LTCC for the purpose of Core TSOs security of the long-term capacities (exchanges within the Core CCR).

The Core TSOs work on a target solution, in close cooperation with the adjacent involved CCRs, that fully takes into account the influences of the adjecent CCRs during the long-term capacity calcuation process and therefore less reliance on Core TSOs assumptions on non-Core exchanges. The base for non-Core approach in the Core LT CCM will be article 21(1)(b)(vii) of the CACM Regulation.

The proposal is that the Core LT CCM can update its method when the Core DA CCM fulfill article 13(4) of the DA CCM. This article 13(4) of the DA CCM deals with the implementation of Advanced Hybrid Coupling (AHC); unfortunately it is not possible to give a deadline for this implemention as the AHC is not mature enough yet. It should be noted that the final DA CCM method is considered to be the target solution to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain which will be discussed with adjacent involved CCRs, according to article 17(4) of the DA CCM. How this would impact the Core LT CCM must be explored and decided upon when the DA target solution is finalized.

3.4 Fallback Procedures

This section refers to Article 16 of the Core LT CCM.

In accordance with article 10(7) of the FCA Regulation, referring to article 21(3) of CACM Regulation, a fallback procedure needs to be in place in case the initial capacity calculation does not lead to any results.

First of all the Core TSOs would like to emphasize that the LT capacity calculation process is not under such time pressure as the DA capacity calculation process. This means that the Core TSOs have some leeway to deal with any issue that could delay the calculation process.

In case of force majeur situations, the Core TSOs will firstly, together with JAO, to the extend possible for JAO, postpone the relevant yearly or monthly auction for which the Core TSOs can not provide results. In this situation, the Core TSOs and JAO will agree on a new deadline for the submission of the results.

Secondly, in case the postponement of the auction is not possible, or the new deadline has been reached, the Core TSOs foresees the following fallback process:

1. The Core TSOs shall bilaterally agree on NTC values for the relevant timeframe.
2. The Core TSOs shall commonly coordinate, validate these bilaterally agreed NTC values and send it to the Core CCC.
3. The Core CCC shall send the NTC values to the SAP.

4 VALIDATION

4.1 Validation Methodology

This section refers to Article 17 of the Core LT CCM.

The Core TSOs are legally responsible for the long-term capacities and therefore have to validate the calculated values, in accordance with article 15 of the FCA Regulation, before the coordinated capacity calculator can send them to SAP for allocation. The Core TSOs have the right to correct their set of FB parameters provided by the Core CCC and then the Core CCC shall coordinate the validation.

After the first LT CC computation a re-assessment might be necessary to respect operational security requirements:

a. an occurrence of an exceptional contingency or forced outage as defined in article 3 of the SO GL Regulation;

b. when RAs, pursuant to Article 9, that are needed to ensure the calculated capacity on all CNECs, are not sufficient;

c. a mistake in the input data, that leads to an overestimation of long-term capacity from an operational security perspective, occurred;

d. a potential need to cover reactive power flows on certain CNECs;

and imply changes in the CGM used in calculation for that timeframe.

If one of the above situations occur, then the relevant Core TSO will send new input data and may request based on a common decision the Core CCC to launch a new calculation.

Each Core TSO may reduce the long-term capacity for reasons of operational security as soon as it is justified. The reduction and justification will be monitored according to Article 20(5).

Hence, the splitting of the correction of long-term capacity between the different BZBs is always ensured and that is why Core TSOs do not explicitly refer to article 26(2) of the CACM Regulation.

Each reduction of the capacity has to be monitored with at least an identification of the limiting CNEC and the explanation of the unforseen event. Article 15 of the FCA Regulation refers to article 26 of the CACM

Regulation, where it is stipulated that any reduction during the validation stage shall be reported to the Core NRAs every three months.

It must be clarified that the iterations on the results are not part of the final validation process, but they are part of the calculation process.

5 UPDATES AND PUBLICATION

5.1 Review and Updates

This section refers to Article 18 of the Core LT CCM.

The Core TSOs foresee to review and update the necessary parameters in conjunction with the same process as for the Core DA CCM.

5.2 Publication of Data

This section refers to Article 19 of the Core LT CCM.

The Core TSOs foresee to publish the information as described in Article 19(2). This enhances transparency for market parties and also facilitates the Core NRAs need for monitoring compliance.

5.3 Monitoring and Information to Regulatory Authorities

This section refers to Article 20 of the Core LT CCM.

The Core TSOs consider that the transparency framework as provided in this section on reporting in general to the Core NRAs, provides all necessary information to the Core NRAs enabling them to monitor compliance with this Core LT CCM and other relevant legislation.

The Core TSOs and Core CCC foresee to send the information described in Article 20 to the Core NRAs for the purpose of monitoring compliance.

6 IMPLEMENTATION

6.1 Timescale for Implementation of the methodology

This section refers to Article 21 of the Core LT CCM.

In accordance with article 10ff. of the FCA Regulation, the Core TSOs are working on the implementation of the Core LT CCM. The Core LT CCM may go-live either with yearly or monthly calculation and allocation.

Core TSOs will implement the approach described in the LT CCM within a maximum period of 5 years after approval of this methodology. Such a timescale for implementation would give Core TSOs and RSCs the chance to deal with all obligations and projects within Core CCR. There are numerous projects running in parallel (e.g. short-term flow-based capacity calculcation, redispatch and countertrading, regional operational security coordination). The simultaneous implementation of these methodologies requires a high amount of resources both from Core TSOs and RSCs and makes a priorisation of projects inevitable.

As allocation will change from NTC to FB, the implementation of this LT CCM requires the amendment of different other methodologies and IT developments:

- amendments to other methodologies, such as but not limited to HAR, LTTR and LT Splitting, and their respective approval through NRAs;
- adaptation by market parties;
- implementation of the new FB allocation platform at the SAP, which is currently not existing.

Having said this, the above mentioned timeline for implementation of LT CCM assumes a timely amendment and approval of the other methodologies. Nevertheless, the Core TSOs will try to shorten the implementation timeline as much as possible in order to achieve an earlier go-live date.

The implementation process of the FB approach shall include an internal test, during which the Core TSOs shall test the operational processes for the long-term capacity calculation inputs, the long-term capacity calculation process and the long-term capacity validation and develop the appropriate IT tools and infrastructure. The implementation process of the FB calculation and allocation approach shall also include an external parallel run, to allow all market participants to adapt and develop appropriate IT tools to be able to proceed to FB allocations for long term time frames. This step requires an already finished implementation of an explicit FB allocation at the SAP operator.

During the internal parallel run, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. During the external parallel run TSOs shall publish the monitoring and performance criteria. After the implementation of this methodology, the outcome of this monitoring shall be summarized in an annual report.

The Core coordinated Long Term capacities are the ones resulting from the FB capacity calculation process after the implementation of this methodology. Until the implementation of this FB methodology, Core TSOs will continue the NTC allocation and will improve the coordination at Core CCR level.

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 Pmin (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 Pmax (including a margin for reserves) at the same time.

After producing the GSK, Elia will adjust production levels in all datasets to match the linearised level of production to the exchange programs of the reference day

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. Units planned for the maintenance and nuclear units are not included in the GSK file. The units inside the GSK will follow the change of the Czech net position proportionally to the share of their production. In other words, if one unit represents n% of the total generation on the Czech bidding zone, 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 situation in CEPS´s grid.

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 four German 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. This means that the nodal factors of each TSO-specific GSK sum 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 sums 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 market time unit (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 needs to be created.

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

$$\mathrm{GSKi} = \frac{\mathrm{Pmax,i} - \mathrm{Pmin,i}}{\sum_{i=1}^{n}(\mathrm{Pmax,i} - \mathrm{Pmin,i})}$$

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 to be market-driven, are used in the GSK if their availability for the MTU is known.

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.

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.

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 scenario. The units planned for maintenance and nuclear units are not included in the list. The fixed participation factors of GSK are impacted by the generation present in the IGM.

Slovak Republic:

In GSK file of SEPS are given all dispatchable units which are in operation in respective time frame 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.