Explanatory Note of the day-ahead and intraday common capacity calculation methodology for the SEE CCR

Version February 2019

Contents

1. Introduction

This technical document sets out the main principles for the common capacity calculation methodology for the day-ahead and intraday market time-frames (hereafter SEE day-ahead and intraday CCM) applied in the SEE CCR. It contains a description of both methodologies in compliance with the Capacity Allocation and Congestion Management guideline (hereafter referred to us "CACM Regulation").
The participating TSOs for the calculations are ADMIE (GR), ESO EAD (BG), Transelectrica (RO) and the following borders are considered GR-BG and BG-RO.

2. Coordinated NTC calculation methodology

2.1. Inputs

In order to allow the Coordinated Capacity Calculator (CCC) to perform the relevant Capacity Calculation (CC) processes, the TSOs of the SEE CCR shall provide the following relevant input data:

- Operational security limits and contingencies;
- Reliability Margins;
- Generation shift keys;
- Remedial actions.

In this chapter details about the previous data are described.
The capacity calculation is based on the unique CGMs built in accordance with Articles 17 and 28 of CACM Regulation.

2.1.1. Operational security limits, contingencies and allocation constraints

This section refers to Articles 7 and 7a of the CCM.

A Critical Network Element (CNE) is a network element either within a bidding zone or between bidding zones impacted by cross-border trades and monitored during the CC process under certain operational conditions. The CNEC (Critical Network Element and Contingency) is a CNE limiting the amount of power that can be exchanged, potentially associated to a contingency. They are determined by each SEE TSO according to agreed rules, described below.
The CNECs are defined by:

- A CNE: a line or a transformer that is significantly impacted by cross-border exchanges;
- An "operational situation": base case (N) or contingency cases (N-1, N-2, busbar faults, depending on the TSO risk policies).

A contingency is defined as the trip of one single or several network elements. A scheduled outage is not a contingency. A contingency can be a trip of:

- a line, a cable or a transformer (including phase shifter transformer);
- a generating unit;
- a load;
- a set of the aforementioned contingencies.

The association of contingencies to CNEs shall be done following the rules established in accordance with Article 75 of SO GL. The TSOs of the SEE CCR shall provide to the CCC a list of the proposed CNECs. The CCC shall merge the list of CNECs provided by all SEE CCR TSOs into a single list, which shall constitute the initial list of CNECs.

The maximum permanent admissible current/power limit means the maximum loading that can be sustained on a transmission line, cable or transformer for an unlimited duration without risk to the equipment, determined by each TSO in line with its operational security policy. The temporary current/power limit means the maximum loading that can be sustained for a limited duration without risk to the equipment (e.g. 120% of permanent physical limit can be accepted during 20 minutes). Each SEE TSO is responsible for deciding, in line with their operational security policy, if temporary limit should be used. As thermal limits and protection settings can vary in function of weather conditions, different values are calculated and set for the different seasons within a year. These values can be also adapted by the concerned TSO if a specific weather condition is forecasted to highly deviate from the seasonal values. The maximum admissible limit is not reduced by any security margin, as all uncertainties in capacity calculations are covered by reliability margin.

The TSOs of SEE CCR shall monitor only the elements from initial list of CNECs significantly impacted by cross-zonal power exchange. The CCC shall calculate the sensitivity factors for selecting the CNECs that are significantly impacted by cross-zonal power exchange.

The sensitivity factors calculated as a percentage using the relevant CGM and GSK are defined as follow:

$$SF_{CNEC} = \frac{P_f - P_i}{\Delta P} \times 100$$

with

SF_{CNEC}	Sensitivity factor for CNEC;
P_f	CNEC active power flow after ΔP;
P_i	CNEC active power flow based on the relevant CGM;
ΔP	Increase of the exchange with 100 MW through the north Greek borders, respectively south Romania borders.

SEE CCR cross-zonal network elements are by definition considered to be significantly impacted. The other CNECs from initial list shall have a sensitivity factor equal or higher than 5% to be taken into account in all of the steps of the common capacity calculation to determine the cross-zonal capacity.

SEE TSOs will not apply allocation constraints.

2.1.2. Reliability Margin (RM)

This section refers to Article 6 of the CCM.

The day-ahead and intraday common capacity calculation methodologies are based on forecast models of the transmission system. 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.

In accordance with Article 22(2) and (4) of the CACM Regulation, the Reliability Margins (RMs) cover the following forecast uncertainties:

a. cross-zonal exchanges on bidding zone borders outside SEE CCR;;
b. generation pattern including specific wind and solar generation forecast;
c. generation shift key;
d. load forecast;
e. topology forecast;
f. unintentional flow deviation due to the operation of frequency containment reserves.

The reliability margin can be considered as an indirect input to the CC process since it refers to the difference where the TTC and the NTC limits are reached for the constraint under investigation.

RMs computation is based on the analysis of the following data:

- unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;
- uncertainties which could affect capacity calculation and which could occur between the time of capacity calculation and real time, for the market time unit being considered.

Regarding the unintended deviation (UD), for control-related reasons, deviations occur between the scheduled values and the actual values during the exchange of energy between neighboring control areas. This implies that at any moment the exchange between two control areas can be significantly higher than the scheduled exchanged, endangering the security of supply.

Regarding the uncertainties (UN) the coordinated NTC calculation methodology is based on different inputs provided by TSOs, they are based on best available forecast at the time of the capacity calculation for renewable energy sources, consumption, generation or available network elements and those could differ from the real-time situation.

The RMs on the SEE CCR borders are calculated in a three-step approach:

a. in a first step, for each market time unit of the observatory period, the relevant common grid models (CGM) are updated in order to take into account the real-time situation of the remedial actions that are considered in the common capacity calculation. This step is undertaken by copying the real-time configuration of these remedial actions and applying them into the historical CGM where the capacity calculation was performed. The power flow on BG-RO and BG-GR borders of the SEE CCR, as expected with the common capacity calculation methodology is then compared with the real time power flow observed on the same borders. All differences for all market time units of a one-year observation period shall constitute the probability distribution function of deviations between the expected flows at the time of capacity calculation and realized flows in real time. In case where not all required historical snapshots are available or simultaneous, an alternative approach is based on direct application of real time recordings provided by the TSOs. The impact on the capacity shall be defined with the following equation:

$$F_{err} = \frac{F_{real} - F_{up\ CGM}}{SF_{border}}$$

with

F_{err}	Active power flow error due to *UD* and *UN*;
F_{real}	Active power flow through the border in real time;
$F_{up\ CGM}$	Active power flow through the border in the updated relevant CGM;
SF_{border}	Sensitivity factor for SEE CCR border in base case;

$$SF_{border} = \frac{F_f - F_i}{\Delta \mathrm{P}} \times 100$$

with

F_f	Active power flow through the border after ΔP;
F_i	Active power flow through the border based on the relevant CGM;
ΔP	Increase of the exchange with 100 MW through the SEE CCR border.

b. in a second step and in accordance with Article 22(3) of the CACM Regulation the 95th percentiles of the probability distributions for the BG-RO and BG-GR borders of the SEE CCR shall be calculated. This means that the TSOs apply a common risk level of 5% and thereby the RM values cover 95% of the historical forecast errors within the observation period.

c. a possible third step could be to undertake an operational adjustment on the values derived previously, by modifying the computed RM values to a value within the range which will retain system security between 1% and 20% of the TTC calculated under normal weather conditions.

The TSOs shall take into account the operational security limits, the power system uncertainties and the available remedial actions when determining the risk level for their borders to ensure the system security. TSO's considered a risk level of 5% in order to ensure the implementation of parameters that make sense operationally. The common risk level of 5%, applied at the majority of CCRs, is also considered as a justified threshold among very low values which reduce cross border capacities and high values which may endanger system security. For any reason (e.g. data quality issue, unexpected system conditions), it can occur that the "theoretical RM" is not consistent with retaining system security. In that case the RM maybe balanced within the range 1-20% of TTC calculated under normal weather conditions.

Before the first operational calculation of the *RMs* values, SEE CCR TSOs shall use the RM values already in operation in the existing capacity calculation initiatives. The *RMs* before the first operational calculation for the BG-RO and BG-GR borders shall be 100 MW for each direction.

2.1.3. Generation Shift Key (GSK)

This section refers to Article 8 of the CCM.

GSKs are needed to transform any change in the balance of one bidding zone into a change of injections in the nodes of that bidding zone. GLSKs are elaborated on the basis of the forecast information about the generating units and, if necessary, the loads.
GSK file is defined for each:

- control area: GSK is computed for each relevant network node in the same control area;
- and time interval: GSK is dedicated to individual market time unit in order to model differences between different system conditions.

In order to avoid newly formed unrealistic congestions caused by the process of generation shift, TSOs should be able to define in the generation shift key (GSK) those generators that shall contribute to the shift.
SEE TSOs have harmonized their GSK determination methodologies:

a. In its GSK, each TSO shall use flexible and controllable production units which are available inside the TSO grid
b. Units unavailable due to outage or maintenance are not included.
c. GSK is reviewed on a daily basis.

For the Greek bidding zone a proportional representation of the generation variation to the remaining capacity, based on ADMIE's best estimate of the initial generation profile, ensure the best modeling of the Greek system.
For the Bulgarian bidding zone a proportional representation of the generation variation to the remaining capacity respecting the limits of the generating units, based on ESO EAD's best estimate of the initial generation profile, ensure the best modeling of the Bulgarian system. The nuclear units are not included in the list.
The Transelectrica GSK file contains dispatchable units which are available in the day of operation. The 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.

2.1.4. Remedial Action (RA)

This section refers to Article 9 of the CCM.

During coordinated NTC calculation, SEE TSOs will take into account Remedial Actions (*RAs*), that refers to any measure applied in due time by a TSO in order to respect security principles under maximum allowed cross border exchanges of the transmission power system regarding power flows and voltage constraints.

The general purpose of the application of *RAs* is to maintain the transmission system within the operational security limits during the CC process, where maximum power exchanges are reached. The application of proper *RAs* in the context of the capacity calculation can allow an increase of NTC values released to the markets, with subsequent benefits for the system.

RAs can be classified in the following two categories:

- Preventive Remedial Actions (PRAs) are those launched to anticipate a need that may occur, due to the lack of certainty to cope efficiently and in due time with the resulting constraints once they have occurred;
- Curative Remedial Actions (CRAs) are those needed to cope with and to relieve rapidly constraints with an implementation delay of time for full effectiveness compatible with the Temporary Admissible Transmission Loading. They are implemented after the occurrence of the contingencies.

The possible types of RAs considered in the CC process are the following:

- Changing the tap position of a phase shifting transformer (PST);
- Topological measure: opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s) or switching of one or more network element(s) from one bus bar to another, connection/disconnection of reactor(s), capacitor(s).

In accordance with Article 25(6) of the CACM Regulation, the RAs taken into account are the same for day-ahead and intra-day common capacity calculation, depending on their technical availability for each capacity calculation time-frame. Only the RAs for which the technical availability is known should be taken into account at the time of capacity calculation.

In accordance with Article 25(5) of the CACM Regulation, the day-ahead and intraday common capacity calculation take non-costly RAs into account which can be explicitly modelled in the CGM.

The RAs coordination (RAC) in the day-ahead and intraday common capacity calculation shall be an automated, coordinated, and repeatable optimization process performed by the CCC. The CCC shall take into account in capacity calculation RAs to increase the cross-zonal capacity. After calculation the maximum power exchanges between bidding zones without RAs, necessary adjustment taking into account RAs are executed in the CGM and maximum power exchanges between bidding zones taking into account RAs shall be recalculated.

The RAC in the day-ahead and intraday common capacity calculation is performed in accordance with a set of pre-defined characteristics such as an objective function, constraints and variables:

a. The RAC objective is to enlarge the capacity domain around the balanced net position of the Common Grid Model Alignment process, with the objective function to minimize the overload of the CNECs and/or the violation of the nodes voltage;
b. The constraints are the operational security limits in accordance with Article 7, minimum impact on objective function value for use RAs and without negative impact on the TTC values.
c. The variables are the switching states of the topological measures and tap positions.

2.1.5. Mathematical description of the CNTC approach

This section refers to Article 11 of the CCM.

For the day-ahead and intraday market time-frames, individual values for cross-zonal capacity for each market time unit shall be calculated using the Coordinated Net Transmission Capacity (*CNTC*) approach as defined in the common capacity calculation methodology, as set forth in Article 14 and Article 21of the CACM Regulation. This approach has been selected since Article 20 (4) of CACM Regulation states that "*No later than six months after at least all South East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame*". Therefore, the flow-based method could be used only after the market coupling in the SEE CCR.

The Coordinated Net Transmission Capacity (CNTC) computation is a centralized calculation based on AC load flow which delivers the main parameter needed for the definition of CNTC domain: Total Transmission Capacity (TTC). The TTC represent the maximum power exchange on a bidding zone border and calculation shall according to the following procedure:

a. use the common grid model, generation shift keys, and list of CNECs defined in accordance with Article 7a to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;
b. adjust maximum power exchange using remedial actions in accordance with Article 9.

During the day-ahead and the intraday CC processes, the Total Transfer Capacity (TTC) for the south RO borders, BG-RO border, north Greek borders and BG-GR border shall be assessed in both border directions:

- Using Alternate Current (AC) load-flow algorithm in order to assess network security of the relevant CNECs, taking also into consideration the beneficial effects of remedial actions coordination;
- Based on:
  - two-days ahead CGMs (D2CF merged models) for day-ahead CC process;
  - day ahead or intraday CGMs (DACF or IDCF merged models) for intraday CC process;
- Applying modification of cross-zonal exchanges according to GSK files.

A first intraday common capacity calculation is performed in the end of D-1 for all MTUs of day D, and a second intraday capacity calculation is performed during intraday (i.e. day D), for the remaining MTUs of day D. First intraday capacity calculation is based on DACF CGMs available at 18.00 in D-1 (TSOs receive the schedules from market participants (15.00) and these schedules are used to build the D-1 IGM and merged D-1 CGM). The SEE TSOs shall review the frequency of re-calculations for intraday capacity calculation no later than one year after the implementation of the common capacity calculation methodology for the intraday market time-frame. TSOs need some operational experience in order to be able to determine the feasible frequency of re-calculations for intraday capacity calculation.

The *TTC* on the BG-GR direction is a ratio of the total *TTC* value calculated from all north Greek systems (power systems of Albania, FYROM, Bulgaria and Turkey) to the Greek system:

$$TTC_{BG-GR} = k_{BG-GR} \cdot TTC_{north\ GR\ systems-GR}$$

with

TTC_{BG-GR} *TTC* on the BG-GR direction

k_{BG-GR}	splitting factor for BG-GR direction
$TTC_{north\ GR\ systems-GR}$	*TTC* from all north Greek systems to the Greek system

The *TTC* on the GR-BG direction is a ratio of the total *TTC* value calculated from the Greek system to all north Greek systems (power systems of Albania, FYROM, Bulgaria and Turkey):

$$TTC_{GR-BG} = k_{GR-BG} \cdot TTC_{GR-north\ GR\ systems}$$

with

TTC_{GR-BG}	*TTC* on the GR-BG direction
k_{GR-BG}	splitting factor for GR-BG direction
$TTC_{GR-north\ GR\ systems}$	*TTC* from the Greek system to all north Greek systems

The *TTC* on the BG-RO direction is a ratio of the total *TTC* value calculated from all south Romanian systems (power systems of Bulgaria and Serbia) to the Romanian system:

$$TTC_{BG-RO} = k_{BG-RO} \cdot TTC_{south\ RO\ systems-RO}$$

with

TTC_{BG-RO}	*TTC* on the BG-RO direction
k_{BG-RO}	splitting factor for BG-RO direction
$TTC_{south\ RO\ systems-RO}$	*TTC* from all south Romanian systems to the Romanian system

The *TTC* on the RO-BG direction is a ratio of the total *TTC* value calculated from the Romanian system to all south Romanian systems (power systems of Bulgaria and Serbia):

$$TTC_{RO-BG} = k_{RO-BG} \cdot TTC_{RO-\ south\ RO\ systems}$$

with

TTC_{RO-BG}	*TTC* on the RO-BG direction
k_{RO-BG}	splitting factor for RO-BG direction
$TTC_{RO-\ south\ RO\ systems}$	*TTC* from the Romanian system to all south Romania systems

The splitting factor used for day-ahead and intraday capacity calculation in the year *Y* will be based on the NTC values from the last two years. This approach is based on the Article 3(h) of the CACM Regulation that contributes to the objective of respecting the need for a fair and orderly market and price formation and ensures a fair distribution of costs and benefits between the involved TSOs. Moreover the approach is in line with the distribution of the congestion income (as defined in the Article 73 of CACM Regulation and Article 57 of FCA Regulation) collected by the TSOs, and thus do not alter the signals for investments to TSOs given by the congestion income. The splitting factors used at the NTC computation will comply with the security operation in accordance with Article 3(c) of the CACM Regulation, will not alter the signals for investments to TSOs given by the congestion income and allow reasonable financial planning according with Article 73 of the CACM Regulation.

The splitting factor for BG-GR direction is determined with the following equation:

$$k_{BG-GR} = NTC_{BG-GR}/NTC_{north\ GR\ systems-GR}$$

where:

k_{BG-GR}	splitting factor as percentage to be applied for BG-GR direction for day-ahead and intraday capacity calculation in the year Y
NTC_{BG-GR}	Average value of the NTC for the direction BG-GR (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years
$NTC_{north\ GR\ systems-GR}$	Average value of the total NTC for the direction north GR systems -GR (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years

The splitting factor for GR-BG direction is determined with the following equation:

$$k_{GR-BG} = NTC_{GR-BG}/NTC_{GR-north\ GR\ systems}$$

where:

k_{GR-BG}	splitting factor as percentage to be applied for GR-BG direction for day-ahead and intraday capacity calculation in the year Y
NTC_{GR-BG}	average value of the NTC for the direction GR-BG (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years
$NTC_{GR-north\ GR\ systems}$	average value of the total NTC for the direction GR-north GR systems (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years

The splitting factor for BG-RO direction is determined with the following equation:

$$k_{BG-RO} = NTC_{BG-RO}/NTC_{south\ RO\ systems-RO}$$

where:

k_{BG-RO}	splitting factor as percentage to be applied for BG-RO direction for day-ahead and intraday capacity calculation in the year Y
NTC_{BG-RO}	Average value of the NTC for the direction BG-RO in the last two years
$NTC_{south\ RO\ systems-RO}$	Average value of the total NTC for the direction south RO systems-RO in the last two years

The splitting factor for RO-BG direction is determined with the following equation:

$$k_{RO-BG} = NTC_{RO-BG}/NTC_{RO-south\ RO\ systems}$$

where:

k_{RO-BG}	splitting factor as percentage to be applied for RO-BG direction for day-ahead and intraday capacity calculation in the year Y
NTC_{RO-BG}	Average value of the NTC for the direction RO-BG in the last two years
$NTC_{RO-south\ RO\ systems}$	Average value of the total NTC for the direction RO-south RO systems in the last two years

The *CCC* of the SEE CCR shall provide to the SEE TSOs with the validated *NTCs* values after application of the *RM*s defined in accordance with Article 6 for the BG-RO and BG-GR borders.

The Net Transmission Capacity (NTC) on the BG-GR border is determined with the following equations:

$$NTC_{BG-GR} = TTC_{BG-GR} - RM_{BG-GR}$$

$$NTC_{GR-BG} = TTC_{GR-BG} - RM_{GR-BG}$$

with

NTC_{BG-GR}	*NTC* on the BG-GR direction
NTC_{GR-BG}	*NTC* on the GR-BG direction
TTC_{BG-GR}	*TTC* on the BG-GR direction
TTC_{GR-BG}	*TTC* on the GR-BG direction
RM_{BG-GR}	*RM* on the BG-GR direction
RM_{GR-BG}	*RM* on the GR-BG direction

The Net Transmission Capacity (NTC) on the BG-RO border is determined with the following equations:

$$NTC_{BG-RO} = TTC_{BG-RO} - RM_{BG-RO}$$

$$NTC_{RO-BG} = TTC_{RO-BG} - RM_{RO-BG}$$

with

NTC_{BG-RO}	*NTC* on the BG-RO direction
$NTC_{RO-BG} =$	*NTC* on the RO-BG direction
TTC_{BG-RO}	*TTC* on the BG-RO direction
TTC_{RO-BG}	*TTC* on the RO-BG direction
RM_{BG-RO}	*RM* on the BG-RO direction
RM_{RO-BG}	*RM* on the RO-BG direction

In accordance with Article 21(1)(b)(iii) of the CACM Regulation, SEE TSOs shall apply the rules for taking into account the previously-allocated cross-zonal capacity. The objective of the rules is to verify that the Available Transmission Capacity (*ATC*) value of each border and direction of the SEE CCR remains non-negative in case of previously-allocated commercial capacity.

The Available Transmission Capacity (*ATC*) taking into consideration the Already Allocated Capacities (AAC) is determined with the following equations in case of BG – GR border:

$$ATC_{BG-GR} = NTC_{BG-GR} - AAC_{BG-GR} + AAC_{GR-BG}$$

$$ATC_{GR-BG} = NTC_{GR-BG} - AAC_{GR-BG} + AAC_{BG-GR}$$

with

ATC_{BG-GR}	*ATC* on the BG-GR direction
NTC_{BG-GR}	*NTC* on the BG-GR direction
AAC_{BG-GR}	*AAC* on the BG-GR direction
AAC_{GR-BG}	*AAC* on the GR-BG direction
ATC_{GR-BG}	*ATC* on the GR-BG direction
NTC_{GR-BG}	*NTC* on the GR-BG direction

The Available Transmission Capacity (*ATC*) taking into consideration the Already Allocated Capacities (AAC) is determined with the following equations in case of BG – RO border:

$$ATC_{BG-RO} = NTC_{BG-RO} - AAC_{BG-RO} + AAC_{RO-BG}$$

$$ATC_{RO-BG} = NTC_{RO-BG} - AAC_{RO-BG} + AAC_{BG-RO}$$

with

ATC_{BG-RO}	*ATC* on the BG-RO direction
NTC_{BG-RO}	*NTC* on the BG-RO direction
AAC_{BG-RO}	*AAC* on the BG-RO direction
AAC_{RO-BG}	*AAC* on the RO-BG direction
ATC_{RO-BG}	*ATC* on the RO-BG direction
NTC_{RO-BG}	*NTC* on the RO-BG direction

The Available Transmission Capacity (*ATC*) for day-ahead market time-frame and also for the intraday market time-frame is determined with the following equations in case of BG – GR border, taking into account the *NTC* values calculated before and Already Nominated Capacity (*ANC*):

$$ATC_{BG-GR} = NTC_{BG-GR} - ANC_{BG-GR} + ANC_{GR-BG}$$

$$ATC_{GR-BG} = NTC_{GR-BG} - ANC_{GR-BG} + ANC_{BG-GR}$$

with

ATC_{BG-GR}	*ATC* on the BG-GR direction
NTC_{BG-GR}	*NTC* on the BG-GR direction
ANC_{BG-GR}	*ANC* on the BG-GR direction

ANC_{GR-BG}	*ANC* on the GR-BG direction
ATC_{GR-BG}	*ATC* on the GR-BG direction
NTC_{GR-BG}	*NTC* on the GR-BG direction

The Available Transmission Capacity (*ATC*) for day-ahead market time-frame and also for the intraday market time-frame is determined with the following equations in case of BG – RO border, taking into account the *NTC* values calculated before and Already Nominated Capacity (*ANC*):

$$ATC_{BG-RO} = NTC_{BG-RO} - ANC_{BG-RO} + ANC_{RO-BG}$$

$$ATC_{RO-BG} = NTC_{RO-BG} - ANC_{RO-BG} + ANC_{BG-RO}$$

with

ATC_{BG-RO}	*ATC* on the BG-RO direction
NTC_{BG-RO}	*NTC* on the BG-RO direction
ANC_{BG-RO}	*ANC* on the BG-RO direction
ANC_{RO-BG}	*ANC* on the RO-BG direction
ATC_{RO-BG}	*ATC* on the RO-BG direction
NTC_{RO-BG}	*NTC* on the RO-BG direction

If the *ATC* values calculated for day-ahead or intraday market time-frames are negative, no capacity will be made available for day-ahead, respectively intraday market time-frame.

For the day-ahead and intraday capacity calculation the processes are depicted in Figure 1. It shows the various processes performed by entities involved.

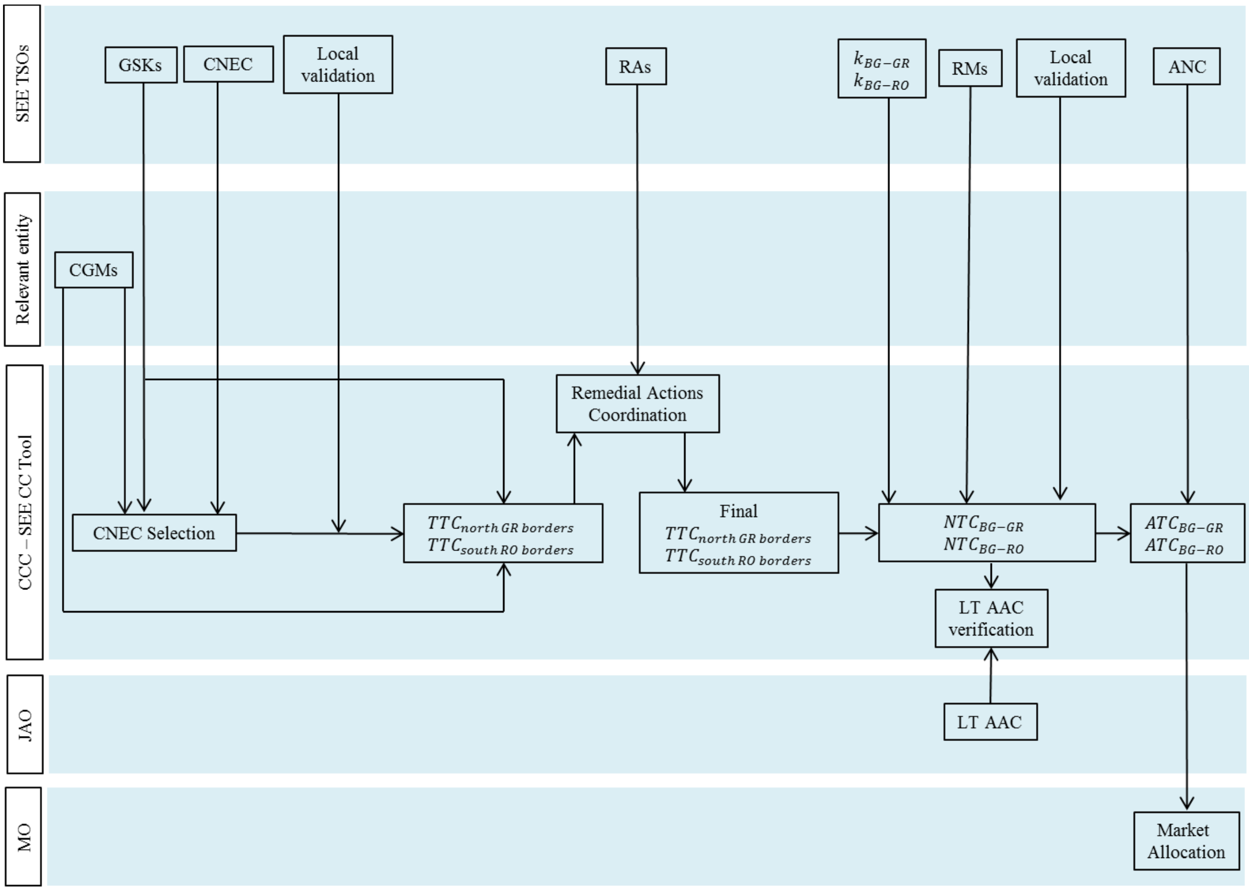

Figure 1: CNTC common capacity calculation process

The capacity calculation process in the SEE CCR shall be performed by the CCC and SEE TSOs according with the following procedure:

a. Each SEE TSO shall provide the CCC the following capacity calculation inputs: GSKs, list of proposed CNECs, operational security limits, RAs, RMs, splitting factors, ANCs;
b. The relevant entity shall provide the CGMs;
c. The CCC shall calculate the sensitivity factors for selecting the CNECs that are significantly impacted by cross-zonal power exchange;
d. SEE TSOs shall validate the list of monitored CNECs used for all steps of the common capacity calculation to determine the cross-zonal capacity;
e. The CCC shall calculate TTC for each MTU for the north Greek borders, and south Romanian borders;
f. The CCC shall perform the Remedial Actions Coordination and calculate the final TTC for each MTU for the north Greek borders, and south Romanian borders;
g. The CCC shall calculate NTC for each MTU for the BG-GR and BG-RO borders. SEE TSOs either validate the NTC values or reduce the NTC values with a reason;
h. SEE TSOs, or an entity delegated by the SEE TSOs, shall send for each market time unit the AAC and ANC to the coordinated capacity calculator. Long-term already allocated capacity could be sent by Joint Allocation Office (JAO);
i. The CCC shall verify that the ATC values of each border and direction of the SEE CCR remains non-negative in case of previously-allocated commercial capacity;
j. The CCC shall calculate ATC values of each border and direction of the SEE CCR taking into account ANC;
k. The CCC shall publish the ATC values and provide them to the relevant entity (Market Operator) for capacity allocation. Before market coupling in the SEE CCR, the capacity allocation shall be performed by the TSOs or a delegated by the TSOs auctioning office.

2.1.6. Cross-zonal capacity validation

This section refers to Article 10 of the CCM.

Regarding the final validation process, once the coordinated capacity calculator has calculated the TTC, it provides the concerned TSOs with these values. Each TSO then has the opportunity to validate the TTC value calculated centrally or can reduce the value in exceptional situations. These situations are:

a. A forced outage as defined in Article 3 of SO GL;
b. when remedial actions, that are needed to ensure the calculated capacity, are not sufficient;
c. extremely low demand of a TSO which leads to low system inertia and high voltage conditions and so require a minimum number of power plants on the grid;
d. a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective.

The TSO requesting a capacity reduction is required to provide a reason for this reduction, its location and the amount of MW to be reduced in accordance with article 26(5) of CACM Regulation.
Where the two TSOs of a bidding zone border request a capacity reduction on their common border, the coordinated capacity calculator will select the minimum value provided by the TSOs. The reason associated to this value will be the one taken into account in all report required by relevant legislation.

2.2. Backup & Fallback processes

2.2.1. Backups and replacement process

For all inputs related to the capacity calculation, standard backup communication process has to be defined among SEE TSOs and the coordinated capacity calculator. Where inputs are not available for one of the parties at the expected time, back up procedures are applied until a critical deadline is reached, in order to get the associated inputs and carry on with the original process.
Where a critical deadline is reached and the inputs could not be provided to the concerned party on time, then fallbacks are applied, meaning that SEE TSOs and the coordinated capacity calculator could use other inputs to perform their tasks. As an example, inputs from the day before, since network situations are usually stable from one day to another and could be re-used in order to complete the CC process.

2.2.2. Fallback NTC values

If the SEE TSOs and the coordinated capacity calculator could not complete a CC process within the agreed time for calculation, the last coordinated cross-zonal capacity calculated within the long-term time-frame is then used as an input for validation of cross-zonal capacities for day-ahead market time-frame. For intraday market time-frame the cross-zonal capacities calculated within the day-ahead time-frame are used as fallback NTC values.

3. Transparency

In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to the regulatory authorities and market participants, the following data items shall be published (in addition to the data items and definitions of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets) no later than 30 minutes before market gate opening time in case of day-ahead capacity calculation and no later than 15 minutes before market gate opening time in case of intraday capacity calculation, except point i):

a. NTC values determined for day-ahead and intraday market time-frames;
b. RMs for each direction of the SEE CCR borders;
c. RAs resulting from the RAC and for each RA it shall be published the type of RA, location of RA, whether the RA was curative or preventive, if the RA was curative, a list of CNEC identifiers describing the CNEC to which the RA was associated;
d. Limiting CNECs (CNEC which is limiting the maximum power exchange on a bidding zone border);
e. For each CNEC, it shall be published the methods for determining Imax in accordance with article 7 (5) a);
f. For each CNEC the EIC code of CNE and Contingency;
g. Real names of CNECs;
h. The following forecast information contained in the CGM for each MTU and bidding zone of the SEE CCR:
    i). Load
    ii). Production
    iii). Net position
    iv). exchange programs on non-SEE bidding zone borders;
i. every 6 months, publication of an up-to date static grid model by each SEE TSO.

Individual SEE TSO may withhold the publication of information disclosing the locational information referred to c), d), e), f), g), h) and i) if required by a competent regulatory authority or by relevant national legislation on the grounds of protecting the critical infrastructure. In such case, the information referred to f) shall be replaced with an anonymous identifier which shall be stable for each CNEC across all market time units. The anonymous identifier shall also be used in the other TSO communications related to the CNEC, including when communicating about an outage or an investment in infrastructure.

SEE TSOs will participate in the elaboration of the ENTSO-E biennial report on capacity calculation and allocation, which will be provided each two years and updated under request of the relevant authorities, according to Article 31 of CACM Regulation. For SEE CCR, this report will contain the capacity calculation approach used, statistical indicators of cross-zonal capacity, and, if appropriate, proposed measures to improve capacity calculation.
The Agency shall decide whether to publish all or part of this report.

4. Timescale for the CCM implementation

Article 9(9) of the CACM Regulation requires that:
"*The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation.*"
The deadline for implementing a harmonized CCM within a Capacity Calculation Region is defined in article 21(4):
"*All TSOs in each capacity calculation region shall, as far as possible, use harmonized capacity calculation inputs. By 31 December 2020, all regions shall use a harmonized capacity calculation methodology which shall in particular provide for a harmonized capacity calculation methodology for the flow-based and for the coordinated net transmission capacity approach*."
The following section provides the description of the planned implementation timeline for the SEE capacity calculation methodology.

4.1. Prerequisites

When the new Capacity Calculation (CC) goes live, the calculation will be performed by the coordinated capacity calculator based on input provided by the TSOs, and finally validated by the TSOs. Two crucial elements in this process are the Common Grid Model (CGM) and the Industrialized Capacity Calculation Tool. The CGM is being developed by a coordinated project of all EU TSOs, and the industrialized capacity calculation tool is being developed by the coordinated capacity calculator. Both shall be implemented before the "go-live" of the CCM.

4.2. Timeline for implementation of the CCM

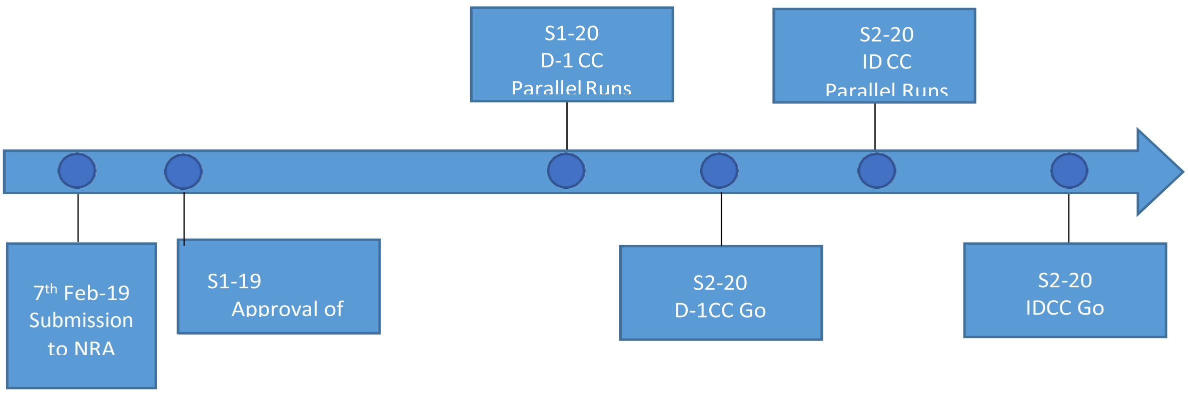

Figure 2. Timeline

The TSOs of the SEE CCR shall start the implementation process of this common capacity calculation methodology with the entry into force of this methodology and shall consist of the following steps:

a. Internal parallel run, during which the TSOs shall test the operational processes for capacity calculation inputs, capacity calculation process and capacity validation and develop the appropriate IT tools and infrastructure;
b. External parallel run, during which the TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, SEE TSOs will involve market participants to test the effects of applying this methodology on the market. In accordance with Article 20(8) of CACM Regulation, this phase shall not be shorter than 6 months.

The TSOs of the SEE CCR shall implement the day-ahead common capacity calculation methodology no later than 1st of July 2020.

The TSOs of the SEE CCR shall implement intraday capacity calculation within the following timeframes:

a. Update of cross-zonal capacities pursuant to Article 5(9)(a) by the deadline of implementation of day-ahead capacity calculation;
b. Calculation of intraday cross-zonal capacities pursuant to Article 5(9) (b) by 3 months after the implementation of day-ahead capacity calculation methodology; and
c. Re-calculation of intraday cross-zonal capacities pursuant to Article 5(9)(c) by 12 months after the implementation of calculation of intraday cross-zonal capacities pursuant to point (b) of this paragraph.

Parallel runs may start in the beginning of 2020 at the earliest due to time required for procurement, development and testing of the industrial capacity calculation tool.