All TSOs' of the Nordic Capacity Calculation Region proposal for capacity calculation methodology in accordance with Article 20(2) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

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All TSOs of the Nordic Capacity Calculation Region, taking into account the following:

Whereas

(1) This document describes a common methodology developed by all Transmission System Operators (hereafter referred to as "TSOs") of the Nordic Capacity Calculation Region (hereafter referred to as "CCR Nordic") as defined in accordance with Article 15 of Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Allocation and Congestion Management (hereafter referred to as the "CACM Regulation") regarding a methodology for Capacity Calculation (hereafter referred to as "CCM") in accordance with Article 20 and Article 21 of the CACM Regulation.

(2) This CCM takes into account the general principles, goals and other methodologies set in the CACM Regulation, Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO Regulation"), and Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity (hereafter referred to as "Regulation (EC) No 714/2009").

(3) The goal of the CACM Regulation is the coordination and harmonisation of cross-zonal capacity calculation and capacity allocation in the day-ahead and intraday markets, and it sets requirements for the TSOs to cooperate on the level of capacity calculation regions (hereinafter referred to as "CCRs"), on a pan-European level and across bidding zone borders. The CACM Regulation also sets rules for establishing capacity calculation methodologies based either on the flow-based approach (hereafter referred to as "FB approach") or the coordinated net transmission capacity approach (hereafter referred to as "CNTC approach").

(4) This CCM takes into account the Common Grid Model (hereafter referred to as "CGM") methodology and assumes that the CGM developed accordingly, is available in order to execute capacity calculation for the day-ahead and intraday timeframes. Thus the frequency of the reassessment of intraday capacity depends on the availability of the CGM for the intraday timeframe.

(5) This CCM also takes into account specific situations in the Nordic power system, incorporating active and reactive power flow and voltage analyses in steady state and, where appropriate, voltage and dynamic stability analyses. This entails that, in the long term, a CGM with dynamic data is to be developed in accordance with Article 19(6) of the CACM Regulation.

(6) Article 9(9) of the CACM Regulation requires that the expected impact of the CCM on the objectives of the CACM Regulation is described. The impact is presented below (points (7) to (15) of this Whereas Section).

(7) The CCM contributes to and does not in any way hamper the achievement of the objectives of Article 3 of the CACM Regulation. In particular, the CCM serves the objectives of promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation), ensuring optimal use of the transmission infrastructure (Article 3(b) of the CACM Regulation), ensuring operational security (Article 3(c) of the CACM Regulation), optimising the calculation and allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation), ensuring and enhancing the transparency and reliability of information (Article 3(f) of the CACM Regulation), contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM

Regulation), respecting the need for a fair and orderly market and fair and orderly price formation (Article 3(h) of the CACM Regulation) and providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation).

(8) The CCM promotes effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) since the CCM supports fair and equal access to the transmission system as it applies to all market participants on all bidding zone borders in CCR Nordic. Market participants will have access to the same reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation, in a transparent way. The FB approach does not implicitly pre-select or exclude bids from market players and, hence the competitiveness of bidding is the only criteria on which bids of market players are selected during the matching, yet taking the significant grid constraints into consideration. The CCM applies remedial actions (hereafter referred to as "RAs"), increasing cross-zonal capacity and capacity on internal CNEs and PTCs in order to improve effective competition between internal and cross-zonal trades, taking operational security and economic efficiency into account.

(9) The CCM secures optimal use of the transmission capacity (Article 3(b) of the CACM Regulation) as it takes advantage of the FB approach, representing the limitations in the alternating current (hereafter referred to as "AC") grids. There is no predefined and static split of the capacities on critical network elements (hereafter referred to as "CNE"), and the flows within CCR Nordic and between CCR Nordic and adjacent CCRs are decided based on economic efficiency during the capacity allocation phase. The CCM treats all bidding zone borders within the CCR Nordic and adjacent CCRs equally, and provides non-discriminatory access to cross-zonal capacity. The CCM applies Advanced Hybrid Coupling (hereafter referred to as "AHC") for the efficient integration of HVDC interconnections into the FB CCM. The approaches aim at providing the maximum available capacity to market participants within the operational security limits. For the intraday timeframe, a CNTC approach ensures better use of transmission capacity compared to the currently-applied method until the FB approach is implemented. Non-costly RAs are taken into account if they are available.

(10) The CCM secures operational security (Article 3(c) of the CACM Regulation) as the grid constraints are taken into account in the day-ahead and intraday timeframe providing the maximum available capacity to market participants within the operational security limits, hereby not allowing for more cross-zonal exchange possibilities than can be supported by available costly RAs. This supports operational security in a short time perspective, where bidding zone re-configuration will be used in a mid-term perspective and grid investments in the long-term perspective.

(11) The CCM serves the objective of optimising the calculation and allocation of cross-zonal capacity in accordance with Article 3(d) of the CACM Regulation since the CCM is using the FB approach for the day-ahead timeframe and also for the intraday timeframe - when conditions for implementation have been fulfilled - providing optimal cross-zonal capacities to market participants. Better optimisation in the intraday timeframe, compared to current methods, can be achieved with a CNTC approach until a FB approach is implemented. Moreover, optimisation of capacity calculation is secured based on coordination between Nordic TSOs, hereby applying CGM and a Coordinated Capacity Calculator.

(12) The CCM serves the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation) as the CCM determines the main principles and main processes for the day-ahead and intraday timeframes. The CCM enables TSOs to provide market participants with the same reliable information on cross-zonal capacities and allocation constraints for day-ahead and intraday allocation in a transparent way. To facilitate transparency, the TSOs should publish data to the market on a regular basis to help market participants to evaluate the capacity calculation process. The TSOs should engage stakeholders in dialogue to specify necessary and useful data to

this effect. The publication requirements are without prejudice to confidentiality requirements pursuant to national legislation.

(13) The CCM does not hinder an efficient long-term operation in CCR Nordic and adjacent CCRs, and the development of the transmission system in the European Union (Article 3(g) of the CACM Regulation). The CCM, by taking most important grid constraints into consideration, will support efficient pricing in the market, providing the right signals from a long-term perspective.

(14) The CCM contributes to the objective of respecting the need for a fair and orderly market and price formation (Article 3(h) of the CACM Regulation) by making available in due time the cross-zonal capacity to be released in the day-ahead and intraday market.

(15) The CCM provides non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation). Application of RAs to increase capacity on internal constraints - based on operational security and economic efficiency - contributes to avoiding undue discrimination between internal and cross-zonal power exchanges. The CCM includes two tests to be fulfilled in order to increase the available margin on internal CNEs and PTCs. The test for operational security aims at quantifying available costly RAs in order to increase the available margin of internal CNEs and PTCs, without compromising operational security. The available margin of internal CNEs and PTCs will only be increased if costly RAs can be expected to be available and to have impact on the internal CNE/PTC (by applying node-to-line PTDF matrices). The test for economic efficiency aims at assessing if adding more available margin to an internal CNE/PTC, will increase social welfare. Both tests have to be fulfilled simultaneously in order to increase the available margin. The CCM also ensures a transparent and non-discriminatory approach to facilitate cross-zonal capacity allocation.

(16) In conclusion, the CCM contributes to the general objectives of the CACM Regulation to the benefit of market participants and electricity end consumers.

SUBMIT THE FOLLOWING CCM TO ALL REGULATORY AUTHORITIES OF THE CCR NORDIC:

TITLE I
General

Article 1
Subject matter and scope

1. The CCM is the common methodology of TSOs in CCR Nordic in accordance with Article 20(2) and Article 21 of the CACM Regulation.

2. This CCM applies solely to the CCR Nordic as defined in accordance with Article 15 of the CACM Regulation.

3. This CCM covers the capacity calculation methodologies for the day-ahead and intraday timeframes.

Article 2
Definitions and interpretation

1. For the purposes of the Proposal, the terms used shall have the meaning given to them in Article 2 of Regulation (EC) 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross border exchanges in electricity and repealing

Regulation (EC) no 1228/2003, Article 2 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as "CACM Regulation"), Article 3 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO Regulation"), Article 2 of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as "Balancing Regulation"), and Article 2 of Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council (hereafter referred to as "Transparency Regulation").

2. In addition, in this CCM, the following terms shall have the meaning below:
    a) "advanced hybrid coupling" (AHC) means the integration of HVDC interconnections, and AC interconnections between CCRs, in a FB approach by applying virtual bidding zones;
    b) "base case" means the CGM scenario for a specific market time unit, including the best available forecast for the state of the power system. The base case combines the expected grid topology, load and generation forecast on a nodal basis;
    c) "internal CNE" means a critical network element (CNE) that is located inside a bidding zone and that is limiting the amount of power that can be exchanged between bidding zones;
    d) "network element" means a component in the power system or several components in the power system, such as PTCs;
    e) "PTC" means power transfer corridor, being a set of several transmission lines or other grid components imposing a MW limit for operational security reasons;
    f) "snapshot" means like a photo of a TSO's power system state taken from the TSOs' control system, showing the voltage, currents, and power flows in the power system at the time of taking the photo;
    g) "unique identifier" means a consistent identifier over time; and
    h) "virtual bidding zone" means a bidding zone without any buy and sell orders from market participants.

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

4. For the sake of clarity this CCM does not affect TSOs' right to delegate their task in accordance with the Article 81 of the CACM Regulation. In this CCM "TSO" shall refer to Transmission System Operator or to a third party whom the TSO has delegated task(s) to in accordance with the CACM Regulation, where applicable. However, the delegating TSO shall remain responsible for ensuring compliance with the obligations under the CACM Regulation.

TITLE 2
Calculation of the inputs to capacity calculation for day-ahead and intraday timeframe

Article 3
Methodology for determining reliability margin

1. The TSOs shall determine the reliability margin as follows:
    a) The reliability margin is determined for AC grid elements only.
    b) A probability distribution of the deviation between the expected and realized (observed) power flows is determined annually for each CNE or AC cross-zonal interconnection, based on historical snapshots of the CGM for different market time units. The realized (observed) power flows for each CNE or AC cross-zonal interconnection are obtained from the snapshot, where also the potential contingencies associated with this CNE or AC cross-zonal interconnection are taken into account. The net positions from the snapshot are used with the FB parameters or in the CGM to compute the expected power flows. The differences between the realized and expected power flows (in MW) form the prediction error distribution for each CNE or cross-zonal interconnection. The prediction errors shall be fitted to a statistical distribution that minimizes the modelling error.
    c) The reliability margin (hereafter referred to as "RM") value shall be calculated by deriving a value from the probability distribution based on the TSOs risk level value as defined in Article 3(6).
    d) The unintended deviations of the 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 (frequency containment reserve), are not part of the reliability margin described in Article 3(1)(a) – 3(1)(c) and need to be assessed separately ("FCR margin"). The final RM value is the sum of the RM value and the FCR margin; the TSO shall send this RM values as input data to the coordinated capacity calculator (hereafter referred to as "CCC").

2. When the FB approach is applied, the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time are as follows:
    a) The methodology for RM determination described in Article 3(1)(a) – 3(1)(c) is applied on all CNEs; and
    b) Separate distributions are formed for capacities that are calculated based on CGMs for day-ahead and intraday capacity calculation timeframes.

3. When the CNTC approach is applied, the principles for calculating the probability distribution of the deviations between the expected power flows at the time of capacity calculation and realized power flows in real time are as follows:
    a) The methodology for RM determination described in Article 3(1)(a) – 3(1)(c) is applied on all cross-zonal capacities; and
    b) Separate distributions are formed for capacities that are calculated based on CGMs for day-ahead and intraday capacity calculation timeframes.

4. The uncertainties covered by the RM values, described in the Articles 3(2), and 3(3) are:
    a) Uncertainty in load forecast;
    b) Uncertainty in generation forecasts (generation dispatch, wind prognosis, etc.);
    c) Assumptions inherent in the generation shift key (hereafter referred to as "GSK") strategy;
    d) Uncertainty in external trades to adjacent synchronous areas;
    e) Application of a linear grid model (with the power transfer distribution factors (hereafter referred to as the "PTDFs")), constant voltage profile and reactive power;

f) Topology changes due to e.g. unplanned outages of network elements;

g) Internal trade in each bidding zone;

h) Grid model errors, assumptions and simplifications.

5. The margin caused by the activation of the frequency containment reserve (hereafter referred to as "FCR") shall be modelled separately and added to the RM, pursuant to Article 3(1)(d). The following approach shall be applied:

   a) The FCR power flow impact shall be computed for each CNE and cross-zonal interconnection based on historical information, forming FCR power flow distributions;

   b) The FCR margin value for each CNE and cross-zonal interconnection shall be calculated by deriving a value from the probability distribution based on the TSOs risk level value as defined in Article 3(6).

6. The TSOs shall take into account the operational security limits, the power system uncertainties and the available RAs when determining the risk level for their CNEs and cross-zonal interconnections to ensure the system security and efficient system operation. This risk level shall determine how the RM value and FCR margin value shall be derived from their probability distributions. The risk level is defined as the area (cumulative probability) right of the RM value and FCR margin value in their probability distribution. The TSOs shall use the predefined risk level of 95%.

7. The TSOs shall store the differences between the realized and expected flows in a database that allows the TSOs to make statistical analyses.

8. The probability distributions, RM values, and FCR margin values, shall be stored in a standardized data format for each CNE and cross-zonal interconnection. The RM value shall be defined and stored as an absolute value (in MW). It may be converted for comparison purposes to a percentage of the CNE's maximum flow (hereinafter referred to as "Fmax") in the FB approach or cross-zonal capacity in the CNTC approach.

9. The TSOs shall perform the calculation of the RM regularly and at least once a year applying the latest information, for the same period of analysis for the RM and FCR margins, on the probability distribution of the deviations between expected power flows at the time of capacity calculation and realized power flows in real time.

Article 4
Methodology for determining operational security limits

1. The TSOs shall apply the same operational security limits as in the operational security analysis. These limits shall be defined in accordance with Article 25 of the SO Regulation. Each TSO shall provide the operational security limits to the CCC to be used in the capacity calculation.

2. All operational security limits shall be respected both during the normal operation and in application of the N-1 criterion.

Article 5
Methodology for determining contingencies relevant to capacity calculation

The TSOs shall apply the same contingencies as in the operational security analysis. These contingencies shall be defined in accordance with Article 33 of the SO Regulation. Each TSO shall provide these contingencies to the CCC to be used in the capacity calculation.

Article 6
Methodology for determining allocation constraints

1. TSOs may apply allocation constraints according to the requirements set in Article 23(3) of the CACM Regulation. The TSOs may apply either of the following allocation constraints:
   a) The combined import or export from one bidding zone to other neighbouring bidding zones shall be limited to a threshold value;
   b) Ramping rates: Ramping rates define the maximum flow changes on HVDC interconnections between market time units. Due to imbalances generated by flows on HVDC interconnections between market time units, ramping rates are needed in order to maintain the stability of the power system. Ramping rates ensure that the maximum flow change on HVDC interconnection between market time units is kept within the available balancing power reserves or within technical limits of HVDC interconnections.
   c) Implicit loss factors: The implicit loss factors on HVDC interconnections account for the power loss on HVDC interconnections by the following equation:

   *Export quantity = (1 – "Loss Factor") * Import quantity*

   The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling. The implicit loss factor might be applied on an HVDC interconnector if an EU-wide welfare economic benefit can be demonstrated.

2. Allocation constraints may be applied in both the DA and the ID timeframe.

3. Each TSO applying the allocation constraints according to Article 6(1) shall communicate and justify application of those constraints to the market participants.

4. The relevant TSOs shall provide the allocation constraints to the CCC.

Article 7
Methodology for determining generation shift keys (GSKs)

1. GSKs shall define how a net position change in a given bidding zone shall be distributed to each production and load unit on that bidding zone in the CGM. These GSKs shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the CGM for each scenario. The forecast shall take into account the information received in accordance with Article 10 and Article 12 of the generation and load data provision methodology developed by all TSOs in accordance with Article 16 of the CACM Regulation.

2. Each TSO shall select a GSK strategy from Table 1 for each bidding zone, aiming at an optimal GSK based on the following conditions:
   a) Production and load units that are, based on historical data and experience, sensitive to changes in market situation and flexible in changing their electrical output and intake and likely to be shifted shall receive a non-zero GSK factor;
   b) Non-flexible production units shall be ignored and shall receive a zero GSK factor;
   c) The TSO shall aim to find a GSK strategy that minimizes the prediction error between the forecasted and observed flows for all production and load units in each bidding zone for a certain time span. This is the GSK strategy that minimises the overall RM for the studied period;
   d) Each of the GSK strategies may be applicable for a bidding zone and applied from a single hour until all hours of the year; and
   e) Different GSK strategies may be optimal (meeting the requirement under c) for different bidding zones, countries or hours as the generation technology mixture varies between bidding zones or as the geographical distribution of generation and generation technologies varies significantly between zones.

3. Each TSO shall define the GSK strategy for each bidding zone from Table 1, and communicate the GSK strategy transparently to the market participants.

4. The TSOs shall provide the selected GSK strategy for the CCC to be used in the capacity calculation for each bidding zone and the market time units for which the GSK strategy shall be valid.

5. The TSOs shall make ex-post analysis of GSK strategy regularly. Using the latest available information, at least once a year or if significant changes occur in the power system, review and, if necessary, change the selected GSK strategy.

Table 1. GSK strategies including both generation and load components.

Strategy number	Generation	Load	Description/comment
0	k_g	k_l	Custom GSK strategy with individual set of GSK factors for each generator unit and load for each market time unit for a TSO
1	$\max\{P_g - P_{min}, 0\}$	0	Generators participate relative to their margin to the generation minimum (MW) for the unit
2	$\max\{P_{max} - P_g, 0\}$	0	Generators participate relative to their margin to the installed capacity (MW) for the unit
3	P_{max}	0	Generators participate relative to their maximum (installed) capacity (MW)
4	1.0	0	Flat GSK factors for all generators, independently of the size of the generator unit
5	P_g	0	Generators participate relative to their current power generation (MW)
6	P_g	P_l	Generators and loads participate relative to their current power generation or load (MW)
7	0	P_l	Loads participate relative to their loading power (MW)
8	0	1.0	Flat GSK factors for all loads, independently of size of load

where

k_g : GSK factor [pu] for generator g

k_l : GSK factor [pu] for load l

P_g : Current active generation [MW] for generator g

P_{min} : Minimum active generator output [MW] for generator g
P_{max} : Maximum active generator output [MW] for generator g
P_{load}: Current active load [MW] for load l

Article 8
Rules for avoiding undue discrimination between internal and cross-zonal exchanges

1. Internal and cross-zonal flows shall be given access to transmission capacity on equal and fair conditions. Deviations from this principle can only be justified by reasons of economic efficiency and operational security in accordance with Article 11.

2. TSOs shall take actions to avoid undue discrimination between internal and cross-zonal exchanges. Undue discrimination is understood as a situation where some flows are prioritized on grounds which cannot be justified by reasons of economic efficiency or operational security.

3. In a short-term perspective, the TSOs shall, in accordance with Article 11, review the CNEs applied in capacity calculation, and which are limiting cross-zonal power exchange, at least every week to determine if inclusion of the CNEs in the capacity allocation is needed.

4. To avoid undue discrimination between internal and cross-zonal flows, RA in MWh/h shall be added to the RAM of the internal CNEs, in line with the assessment of operational security and economic efficiency in accordance with Article 9 and 11.

5. In a mid-term perspective, the TSOs shall review the existing bidding-zone configuration in accordance with Article 32 of the CACM Regulation. In this review, the TSOs shall study whether a reconfiguration of bidding zones would bring benefits in accordance with Article 33 of the CACM Regulation.

6. In a long-term perspective, the TSOs shall consider efficient investments.

7. TSOs shall perform a regular, at least annual, analysis on the amount of loop flows and internal flows on the CNEs having cross-border relevance in the Nordic power system. The analysis shall be reported to the NRAs.

Article 9
Methodology for determining remedial actions (RAs) to be considered in capacity calculation

1. Each TSO shall define RAs to be applied in capacity calculation. The relevant RAs shall be coordinated between TSOs, clearly described, and communicated to other TSOs and the CCC.

2. Each TSO shall take into account RAs in capacity calculation to allow for an increase in remaining available margin (hereafter referred to as "RAM") on CNEs in line with the equation in Article 15(1) or for increase in cross-zonal capacity due to CNEs in line with equation in Article 19(3). Costly RAs shall be applied for internal CNEs, if foreseen to be available for each capacity calculation timeframe and to contribute to an increased economic welfare at the EU-level, in accordance with Article 11.

3. TSOs shall apply any of, or a combination of, the following RAs to fulfil Article 9(2):
   a) System protection schemes, being an automatic tripping of generation, consumption or grid elements in case of fault;
   b) Topology changes, being any changes in grid topology in order to minimise the effect of faults;
   c) Redispatching; and
   d) Countertrading.

4. Each TSO shall quantify and list the RAs, according to Article 9(3), foreseen to be available in its own control area and to apply them in the capacity calculation, based on the following principles:
   a) Availability of costly and non-costly RAs shall be assessed on a daily basis and communicated to the CCC, taking into account:
      i. outage information
      ii. constraints on generation and consumption flexibility
   b) The list of RAs shall be based on information in the IGM and on historical bidding lists from the balancing market, taking into account the requirements for ancillary reserves according to Chapter 2 of Title III of the Balancing Regulation.

5. The TSOs shall regularly and at least once a year review the application of RAs in the capacity calculation in accordance with Article 27(4)(c) of the CACM Regulation.

TITLE 3
Detailed description of the capacity calculation approach for day-ahead timeframe

Article 10
Mathematical description of the applied capacity calculation approach with different capacity calculation inputs

1. Capacity calculation approach for the day-ahead timeframe shall be the FB approach. The capacity calculation shall follow the process as presented in Article 31.

2. The FB approach shall include:
   a) Simplified representation of the CNEs as a PTDF matrix, where each factor in the matrix, $PTDF_j^A$, represents the percentage of 1 MW injected in bidding zone A, and extracted from a defined slack node, that will appear on the CNE "j" in accordance with Article 14;
   b) Remaining available margin (RAM) for each CNE, which shall be the amount of transmission capacity available for capacity allocation in the market coupling process, and determined in accordance with Article 15.

3. For each CNE the single day-ahead coupling process shall apply the following constraint during the capacity allocation, i.e. the product of the NP vector and the PTDF matrix shall be less than or equal to the RAM vector:

$$\mathbf{NP} \cdot \mathbf{PTDF} \leq \mathbf{RAM}$$

   where **NP** refers to the vector of bidding zone net positions within the FB region, **PTDF** refers to the matrix of PTDFs for the bidding zones in the FB region calculated for the CNEs, and **RAM** refers to the vector of the remaining available margin for the CNEs.

4. The **PTDF** and **RAM** shall form FB parameters describing the available transmission capacity between relevant bidding zones.

5. The vector of bidding zone net positions, is calculated by the price coupling algorithm within single day-ahead coupling based on commercial offers and the FB parameters.

6. The FB parameters are calculated by the CCC according to Articles 14 and 15, and input is given by the TSOs in accordance with Article 3 – 7, 9, 11, and 31.

7. HVDC interconnections and AC interconnections between CCRs shall be managed by the advanced hybrid coupling, i.e. PTDFs and RAMs will be applied to the Nordic access node of those connections, where the Nordic access nodes shall be a virtual bidding zone.

Article 11
Impact of remedial actions (RAs) on CNEs

1. CNEs located on the bidding zone border or within a bidding zone are subject to the capacity calculation in this CCM.

2. A list including CNEs located on bidding zone borders, and internal CNEs with impact on cross border trade, shall be provided by the TSOs or a service provider on at least a weekly basis and shall be derived from operational security analyses and scenarios applying the relevant CGM.

3. The CNEs at this list are considered in capacity calculation.

4. Internal CNEs provided to the capacity allocation, shall be justified based on operational security, employing an assessment of availability of RAs, and economic efficiency.

5. If RAs are not available, or when their availability cannot be expected, according to Article 9, internal CNEs shall be taken into account in the capacity allocation without changing the RAM.

6. For non-costly RAs to be expected to be available, the extent to which these relieve the flows on the internal CNE, shall be added to the RAM.

7. For costly RAs to be expected to be available, the extent to which these relieve the flows on the internal CNE shall be added to the RAM only if the EU-wide economic efficiency of applying the costly RA can be demonstrated according to Article 11(8).

8. The assessment of economic efficiency shall be based on a comparison of the expected socio-economic cost of providing the CNE to the capacity allocation with and without the RAs added to the RAM in accordance with Article 15.

9. The socio-economic assessment in article 11(8) shall be performed in the following way:
   a) Expected price of the necessary RAs (P^r)
   b) Expected technical efficiency of the RAs (T^r)
   c) Estimated risk premium for the RAs (R^r)
   d) Expected price difference between the relevant bidding zone and the adjacent bidding zone with the lowest price difference to the relevant bidding zone (the least expensive border) (P^{cb})
   e) Expected technical efficiency of limiting the border capacity (T^{cb})
   f) Find the lowest of the marginal welfare economic cost of RAs, and the marginal welfare economic cost of potentially limiting the DA cross-border trade by the following relation:

   $$\frac{P^r}{T^r} * (1 + R^r) < \frac{P^{cb}}{T^{cb}}$$

   The right-hand side is the cost of not taking RA into account (not adding an RA element to RAM) and the left-hand side is the cost of taking RA into account (adding an RA element to RAM).
   g) If the inequality sign in f) applies, then the internal CNEs shall be submitted for capacity allocation, where the impact of RAs is reflected in the RA element in Article 15.
   h) The risk premium shall initially be set to zero. The risk premium shall be updated on a yearly basis, based on a statistical analysis of the RA application, and the uncertainty involved.

10. TSOs shall evaluate the selection process of RAs in terms of the accuracy of the information that is input to this process, at least once a year.

Article 12
Rules on the adjustment of power flows on CNEs or of cross-zonal capacity due to remedial actions (RAs)

1. TSOs shall take into account in the capacity calculation RAs as defined in Article 9 to increase the cross-zonal capacity for the day-ahead timeframe.

2. RAs shall be translated into resulting flows on each CNE by applying power system analyses for several relevant scenarios in the CGM, pursuant to Article 11. The resulting flow for each available RA on each CNE shall be added to the RAM of that CNE in accordance with Article 15(1).

Article 13
Rules for taking into account previously allocated cross-zonal capacity

1. TSOs shall take into account the previously-allocated capacity as follows:
    a) Capacity allocated for nominated Physical Transmission Rights (PTRs); and
    b) Capacity allocated for cross-zonal exchange of ancillary services, except those ancillary services in accordance with Article 22(2)(a) of the CACM Regulation.

2. Previously allocated cross-zonal capacity shall be translated into resulting flows on each CNE by applying PTDFs. The resulting flow for each CNE shall be subtracted from the RAM of that CNE to define the RAM including the previously allocated cross-zonal capacity, in accordance with Article 14 and Article 15.

Article 14
A mathematical description of the calculation of power transfer distribution factors (PTDFs) for the FB approach

1. The PTDF matrix is a linearized description of how the net position in each bidding zone impacts the flow on the CNEs. PTDFs shall be calculated by applying an AC load flow analysis software tool to the CGM with the simplifications necessary to create a linear approximation as described in this Article.

2. PTDFs shall be calculated to represent the power system state after the contingency or disconnections, taking into account RAs.

3. PTDFs shall be calculated with the following assumptions:
    a) The magnitude of voltage in each node is 1 pu;
    b) The resistance of the power system series elements are neglected (zero); and
    c) The difference between the voltage angles of adjoining nodes is small

4. Taking into account these simplifications in load flow analysis, the PTDFs can be calculated for all nodes and transmission elements as:

$$PTDF_j^\alpha = B_j * \left(Zbus_{i,\alpha} - Zbus_{k,\alpha} \right)$$

where $PTDF_j^\alpha$ is the sensitivity for the transmission element "j" connecting the nodes "i" and "k" for the power injection in node "α" that is taken out at the defined slack node. B_j is susceptance between the nodes "i" and "k" of the grid element "j", $Zbus_{i,\alpha}$ and $Zbus_{k,\alpha}$ refers to elements in the bus impedance matrix.

5. For the capacity allocation the nodal PTDFs as calculated under Article 14(4) shall be aggregated to one PTDF value for the whole bidding zone applying GSK factors for weighting each node as follows

$$PTDF_j^A = \sum_\alpha GSK^\alpha PTDF_j^\alpha \ , \quad \text{and} \qquad \sum_\alpha GSK^\alpha = 1$$

where

$PTDF_j^A$ is sensitivity of transmission element j to injection in bidding zone A;

$PTDF_j^\alpha$ is sensitivity of transmission element j of injection in node α; and

GSK^α is the weight of node α on the PTDF of bidding zone A.

Article 15
A mathematical description of RAM on CNE for the FB approach

1. The *RAM* shall provide the capacity available for allocation. The RAM shall be calculated as follows:

$$RAM = F_{max} - FRM + RA - F'_{ref} - FAV - AAC$$

   F{max} is the maximum allowed physical flow on a CNE, *FRM* is the flow reliability margin, *RA* is the impact of RAs, *F'{ref}* is the reference flow at zero net position in the linearized flow calculation applying computed PTDFs, *FAV* is the final adjustment value that may receive a positive or negative value in the validation stage in accordance with Article 17, and *AAC* is the already allocated capacity.

2. *F{max}* shall be calculated by an AC load flow analysis and, where appropriate, a dynamic analysis using the CGM or regional model to ensure the secure grid operation, in accordance with Article 32 of the SO Regulation.

3. *FRM* shall be the flow reliability margin covering the uncertainty between the expected power flow at the time of the capacity calculation and the realized power flow in real time to be calculated in accordance with Article 3.

4. *RA* shall be the RAs to increase *RAM* and defined in accordance with Article 9 and Article 11.

5. *F'{ref}* shall be the reference flow at zero net position in the linearized flow calculation applying the computed PTDFs (see Figure 1). For each CNE "j", the F'{ref,j} shall be defined as follows:

$$F'_{ref,j} = F_{ref,j} - \sum_A PTDF_j^A \cdot NP^A$$

   where *F{ref,j}* is the flow on the CNE "j" in the base case, *NP^A* is the net positions in bidding zone "A" in the base case, and $PTDF_j^A$ are the *PTDF* values for this CNE "j". *F'{ref}* may be positive and shall be subtracted from the RAM or negative and shall be added to the *RAM*.

6. The FB approach shall apply negative RAMs to the extent that the capacity allocation in the following timeframe will allow such negative values. When a negative RAM is calculated but not applied in capacity allocation, the RAM value shall be set to zero and the potential constraint shall be managed by RA.
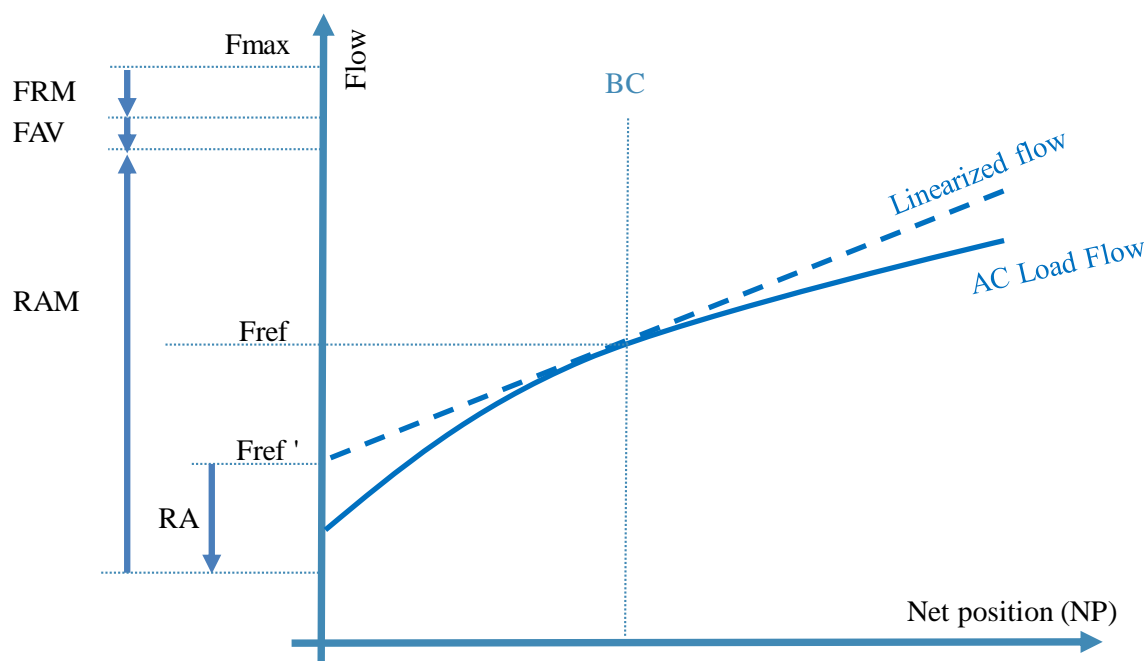
Figure 1. Relation between flow, net position, and *RAM* (assuming the *AAC* to be zero). BC refers to the base case.

Article 16
Rules for sharing the power flow capabilities of CNEs among different CCRs

1. AHC is applied for the interconnections to the neighbouring CCRs. The AHC shall expose the flows between CCR Nordic, and adjacent CCRs to competition for scarce grid resources on equal terms with other flows in CCR Nordic.

2. The access node(s) for interconnections to an adjacent CCR shall be virtual bidding zone in CCR Nordic.

3. PTDFs for the virtual bidding zone shall be calculated according to Articles 3 – 7, 9, 11, 14, and 15.

4. The virtual bidding zone and the related PTDFs shall be a part of the CCR Nordic FB capacity calculation.

TITLE 4
Methodology for the validation of cross-zonal capacity for day-ahead timeframe

Article 17
Methodology for the validation of cross-zonal capacity

1. Each TSO shall perform the validation of cross-zonal capacities on its bidding zone border(s), defined by its CNEs, to ensure that the results of regional calculation of cross-zonal capacity will ensure operational security. When performing the validation, the TSOs shall consider operational security, taking into account new and relevant information obtained during or after the most recent capacity calculation.

2. During the validation of cross-zonal capacity, each TSO may change the FB parameters on any CNE according to Article 17(1) and 17(3).

3. *RAM* defined in accordance with Article 15(1) may be adjusted during the validation by applying *FAV* to take into account relevant information known at the time of validation in accordance with Article 17(1). Each application of *FAV* needs to be justified by the TSOs applying it, by reporting on the need to apply *FAV*, and the rationale behind the *FAV*-value, towards the CCC and other TSOs.

4. Each CCC shall, every three months, report all reductions made during the validation of cross-zonal capacity to all NRAs of the Nordic CCR. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

5. The CCC shall coordinate with the neighbouring CCCs during the capacity calculation and validation.

TITLE 5
Detailed description of the capacity calculation approach for intraday timeframe

Article 18
Target capacity calculation approach

The FB approach shall be the target capacity calculation approach for the intraday timeframe. The CNTC approach shall be applied in the intraday timeframe until conditions to implement FB approach described in Article 32 have been fulfilled.

Article 19
Mathematical description of the applied capacity calculation approach with different capacity calculation inputs

1. Inputs to the CNTC approach shall be:
    a) CGM, which presents the forecasted state of the power system for the intraday timeframe;
    b) GSKs in accordance with Article 7;
    c) Contingencies in accordance with Article 5; and
    d) Operational security limits in accordance with Article 4.

2. AC load flow analysis shall reveal the voltage (magnitude and angle) on each node of the CGM, power flows (active and reactive power) and losses on each serial component of the CGM. Voltages and power flows can be calculated when load (outtake) and generation (injection) in each node of the CGM is known. The active and reactive power flows in steady state shall be calculated as follows:

$$\underline{S}_i = P_i + \mathrm{j}Q_i = (P_{\mathrm{G}i} - P_{\mathrm{L}i} - P_{\mathrm{T}i}) + \mathrm{j}(Q_{\mathrm{G}i} - Q_{\mathrm{L}i} - Q_{\mathrm{T}i})$$

where $\underline{S}_i$ is the net apparent power coming to node *i*, P_i is the net active power coming to node *i*, Q_i is the net reactive power coming to node *i*, $P_{\mathrm{G}i}$ is the active power coming to node *i* from the connected generators, $P_{\mathrm{L}i}$ is the active power from node i to the connected load, $P_{\mathrm{T}i}$ is the active power going from node *i* to the connected transmission lines, $Q_{\mathrm{G}i}$ is the reactive power coming to node *i* from the connected generators, $Q_{\mathrm{L}i}$ is the reactive power from node *i* to the connected load and $Q_{\mathrm{T}i}$ is the reactive power going from node *i* to the connected transmission lines.

3. Cross-zonal capacity shall be calculated as follows:

$$CZC = TTC - AAC - RM,$$

where *TTC* is the maximum allowed power exchange of active power between adjoining bidding zones respecting *N*-1 criteria and operational security limits taking into account RAs, rules for undue discrimination and rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders, *AAC* refers to previously allocated capacity, and *RM* refers to reliability margin.

Article 20
Rules for taking into account previously allocated cross-zonal capacity

Cross-zonal capacities shall be reduced, where appropriate, by the amount of previously allocated capacities in the day-ahead timeframe and in accordance with Article 13. In case previously allocated capacity is bigger than *CZC* on a bidding zone border, defined in accordance with Article 19(3), the relevant TSO(s) shall provide zero cross-zonal capacity for the capacity allocation and use RAs to ensure operational security.

Article 21
Rules on the adjustment of power flows on CNEs or of cross-zonal capacity due to RAs

TSOs shall take into account in the capacity calculation RAs as defined in Article 9 to increase the cross-zonal capacity for the intraday timeframe. After calculating the maximum power exchanges between bidding zones without RAs, necessary adjustments taking into account RAs are executed in the CGM and maximum power exchanges between bidding zones taking into account RAs shall be recalculated.

Article 22
A mathematical description of the calculation of power transfer distribution factors for the FB approach

Article 14 shall apply for intraday timeframe.

Article 23
A mathematical description of remaining available margins on critical network elements for the FB approach

Article 15 shall apply for intraday timeframe.

Article 24
Rules for calculating cross-zonal capacity, including rules for efficiently sharing power flow capabilities of CNEs among different bidding zone borders for the CNTC approach

1. The capacity calculation approach shall, in accordance with Article 29(8) of the CACM Regulation:
    a) use CGM, generation shift keys and contingencies 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 RAs taken into account in capacity calculation;
    c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal exchanges;

d) apply the rules for efficiently sharing the power flow capabilities of different CNEs among different bidding zone borders; and

e) calculate cross-zonal capacity, which shall equal the maximum power exchange, adjusted according to b), c), and d), and taking into account the reliability margin and previously allocated cross-zonal capacity.

2. According to Article 29(8)(a) of the CACM Regulation, the following shall apply:

a) The calculation of the maximum power exchange on a bidding zone border consists of contingency analysis taking into account relevant operational security limits as defined in Article 4 and 5.

b) The calculation of maximum power exchanges in accordance with Article 24(1)(a) for each market time unit. The contingency analyses shall investigate probable scenarios, where applicable, finding the maximum power exchanges not violating operational security limits, as defined in line with Article 4 and 5. In the contingency analyses, GSKs will be applied scaling the net positions of the bidding zones, in order to adjust the power exchange over the studied bidding zone border(s).

3. According to b) and c) of Article 29(8) of the CACM Regulation, the following shall apply:

a) The maximum power exchange from Article 24(2) shall be adjusted by using RAs as defined in accordance with Article 9

b) The maximum power exchanges from Article 24(2) shall be adjusted by applying rules for undue discrimination between internal and cross-zonal exchanges as defined in accordance with Article 8.

4. According to d) of Article 29(8) of the CACM Regulation, the following shall apply:

a) Sharing rules may be applied for interdependent bidding zone borders to share capacities efficiently among the different bidding zone borders. Zone-to-zone PTDF matrices may be used to evaluate on which bidding zone borders sharing rules may be applied; and

b) The sharing rules shall ensure the maximization of cross-zonal trading possibilities.

c) Sharing rules are defined by an iterative method adjusting the flows on interdependent cross-zonal borders in order to find simultaneously feasible maximum exchanges on those borders for each CGM scenario.

d) The iterative method shall respect operational security limits and allocation constraints

e) Re-evaluation of the interdependencies between bidding zones borders shall be carried out regularly in accordance with the timeframe set in Article 31 of the CACM Regulation, and shall be made available by the CCC together with a justification for the applied sharing rules.

5. According to e) of Article 29(8) of the CACM Regulation the following shall apply. Cross-zonal capacity shall equal the maximum power exchange calculated in accordance with Article 24(2), Article 24(3) and Article 24(4) adjusting exchanges with reliability margin calculated for each AC bidding zone border in accordance with Article 3 and previously allocated cross-zonal capacity in accordance with Article 20.

Article 25
Rules for sharing the power flow capabilities of CNEs among different CCRs

1. Adjoining bidding zones in neighbouring CCR(s) shall be taken into account in the capacity calculation in CCR Nordic. Cross-zonal capacities on bidding zone borders between CCR Nordic and neighbouring CCRs shall be calculated using CGMs and relevant information from these adjoining bidding zones in coordination with the neighbouring CCC(s).

2. If there is difference in the cross-zonal capacity on the bidding zone border to the neighbouring CCR, the lower value of the cross-zonal capacity shall be used for the capacity allocation.

TITLE 6
Methodology for the validation of cross-zonal capacity for intraday timeframe

Article 26
Methodology for the validation of cross-zonal capacity

1. Each TSO shall perform the validation of cross-zonal capacities on its bidding zone border(s) in accordance with Article 17.

2. For the CNTC approach, the rules for splitting the corrections of cross-zonal capacity shall follow the same sharing rules as described in Article 24(4). The TSOs shall reduce the cross-zonal capacity in a manner that minimizes the negative impact on the market by applying the same rules for splitting the cross-zonal capacity as is described in Article 24(4).

TITLE 7
Miscellaneous

Article 27
Reassessment frequency of cross-zonal capacity for the intraday timeframe

1. First assessment of intraday cross-zonal capacity shall be done based on CGMs for day-ahead capacity calculation timeframe and the results of the single day-ahead coupling. The cross-zonal capacity shall be released to the intraday market without undue delay. The frequency of the reassessment of intraday cross-zonal capacity shall be dependent on the availability of input data relevant for capacity calculation, as well as any events impacting the cross-zonal capacity.

2. Reassessment of intraday cross-zonal capacity shall be done at the frequency the CGM for the intraday timeframe is made available in accordance with the CGM methodology developed in line with Article 17 of the CACM Regulation and in case of a fault in the power system. The latest available CGM is applied in the reassessment of cross-zonal capacities. Any change in cross-zonal capacity due to a reassessment shall be released to the intraday market without undue delay.

Article 28
Fallback procedure if the initial capacity calculation does not lead to any results

When capacity calculation does not lead to any results, cross-zonal capacities from the annual, monthly, or more recent long-term capacity calculations are provided as cross-zonal capacity for day-ahead and intraday timeframes.

Article 29
Monitoring data to the national regulatory authorities

1. All technical and statistical information related to this CCM shall be made available upon request to the NRAs in the CCR Nordic.

2. Monitoring data shall be provided to the NRAs in the CCR Nordic as a basis for supervising a non-discriminatory and efficient congestion management in CCR Nordic, regularly at least on a quarterly basis, consisting of at least the following information:
   a. Information on the application of RAs.

b. The non-zero shadow prices of the constraints in the capacity allocation, to be provided by NEMOs.

3. Any data requirements mentioned above should be managed in line with confidentiality requirements pursuant to national legislation.

Article 30
Publication of data

1. The TSOs shall, in compliance with national legislation and in accordance with Article 3(f) of the CACM Regulation, and in addition to the data items and definitions of Transparency Regulation, publish the following on a regular basis and as soon as possible:

a) A list of all CNEs that are considered and used in the capacity allocation for each market time unit. Each CNE shall be presented with a unique identifier, and it shall be clear on which bidding zone border or which bidding zone the CNE is located;

b) Information for each market time unit which shall include the following:
   i. all components of the RAM, i.e. FRM, Fmax, Fref´, RA, AAC, and FAV, for each CNE that are provided to capacity allocation;
   ii. allocation constraints and CNEs having impact on the cross-border capacity;
   iii. zone-to-slack PTDF matrix;
   iv. The base case power flows (Fref) for each CNE that are provided to capacity allocation, on an ex-post weekly basis;

2. The above mentioned publication requirements are without prejudice to confidentiality requirements pursuant to national legislation.

Article 31
Capacity calculation process

The capacity calculation process for the day-ahead timeframe is shown in Figure 2. The figure identifies the roles of the entities involved, and the input and output data in the capacity calculation process. Same process shall apply for the intraday capacity calculation process.
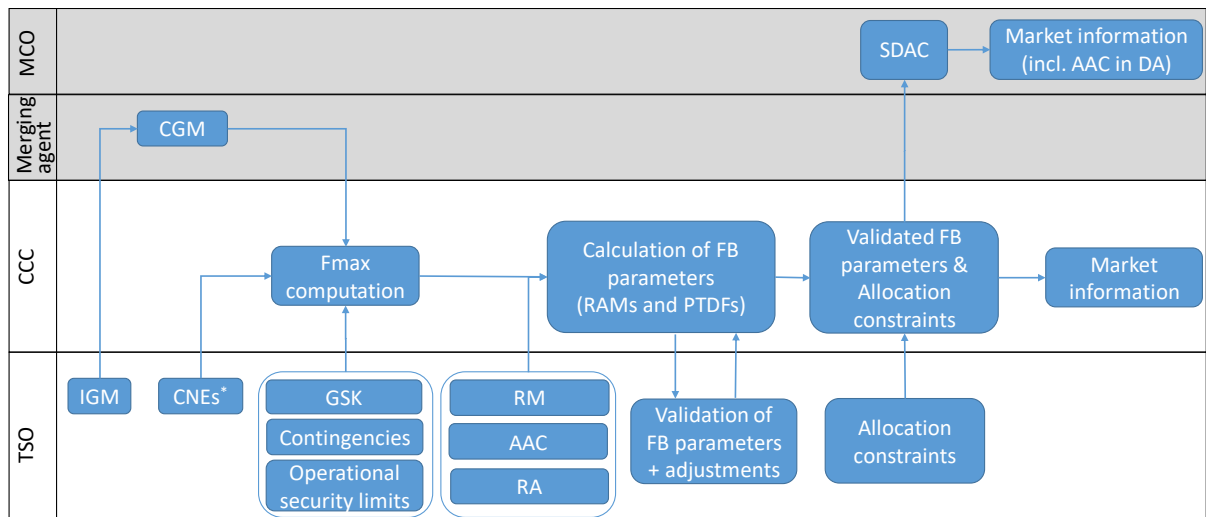

Figure 2. Roles of the entities involved, and input and output data, in the capacity calculation process for the day-ahead timeframe. MCO means Market Coupling Operator, and the Merging agent delivers the CGM.
* CNEs to be defined at least on weekly basis applying relevant historical CGMs.

TITLE 8
Final Provisions

Article 32
Publication and Implementation

1. The TSOs shall publish the CCM without undue delay after all NRAs in the CCR Nordic have approved the CCM or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(10), Article 9(11) and 9(12) of the CACM Regulation regarding the methodology.

2. The TSOs shall implement the CCM on all bidding zone borders within the CCR Nordic after the CGM methodology developed in accordance with Article 17 of the CACM Regulation, the market coupling operator function developed in accordance with Article 7(3) of the CACM Regulation, the relevant requirements set in algorithm submitted in accordance with Article 37(5), and the coordinated capacity calculator in CCR Nordic has been set up in accordance with Article 27 of the CACM Regulation, are implemented in the CCR Nordic. The milestones and the criteria for implementing the CCM are presented in Table 2 and 3. A milestone is reached after all criteria listed above in the table for that milestone are being met.

3. Parallel runs according to Article 20 of CACM Regulation may start in the beginning of 2020 at the earliest due to time required for procurement, development and testing of the industrial FB capacity calculation tool.

Table 2. Milestones and criteria for implementation of FB approach for day-ahead timeframe.

#	Milestone	Criteria to be met before moving to the next milestone
1	Market simulations in Simulation Facility using prototype FB tool (overlapping with milestone #2)	• Requirements/specifications for the industrialized tool are finished and are based on the CCM and the experience gained by using the prototype tool; • In order to increase transparency, stakeholders are involved in the development of stakeholder information tool; • NRAs have approved the CCM.

2	Investment decision - FB industrialized tool	• Minimum of one year of FB market simulations (as described under milestone #1), where:
		   o FB approach is not proven to be less efficient compared to NTC, at the same level of operational security;
		   o FB approach is not proven to decrease system security, at the same level of efficiency;
		   o FB approach is reliable in producing capacity calculation parameters and results.
		• Market simulation results are published to the stakeholders;
		• GSK and FRM methodologies are fully developed and ready for implementation;
		• CGMs are available and can be applied in the capacity calculation.
		• KPIs for a go-live of the FB approach have been specified, in dialogue with NRAs and stakeholders.

3	Parallel runs including FB and NTC	• Parallel runs are performed in real NEMO systems (single day-ahead coupling) and capacity calculation parameters are submitted to NEMOs daily as with current NTC approach:
		   o Precondition is that Euphemia is able to handle FB parameters for a larger area including CCR Nordic when performing calculations for the geographical scope of single day-ahead coupling.
		• At the minimum 12 months of continuous parallel runs, where:
		   o FB approach is not proven to be less efficient compared to NTC, at the same level of operational security;
		   o FB approach is not proven to decrease system security, at the same level of efficiency;
		   o FB approach is reliable in producing capacity calculation parameters and results.
		• Results from the parallel runs, and the KPIs, are published daily.
		• KPIs for a go-live of the FB capacity calculation have been met.
		• A final, exhaustive and binding list of all publication items, metrics and indicators, has been consulted with NRAs and stakeholders.

4	FB go-live	

Table 3. Milestones and criteria for implementation of CNTC approach and FB approach for intraday timeframe.

#	Milestone	Criteria to be met before moving to the next milestone
1	CGMs applied in capacity calculation using current NTC approach	• GSK and RM methodologies are fully developed and ready for implementation. • Coordination in capacity calculation implemented.

2	CNTC go-live	• FB approach fully developed, tested in day-ahead and intraday, and:
		  ○ not proven to be less efficient compared to NTC, at the same level of operational security;
		  ○ not proven to decrease system security, at the same level of efficiency;
		  ○ reliable in producing capacity calculation parameters and results.
		• Single intraday coupling (SIDC) ready to support FB approach.

3	FB go-live	

Article 33
Language

The reference language for this CCM shall be English. For the avoidance of doubt, where TSOs need to translate this CCM into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant TSOs shall be obliged to dispel any inconsistencies by providing a revised translation of this CCM to their relevant national regulatory authorities.