

ACER Decision on the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered: Annex I

Methodology and assumptions that are to be used in the bidding zone review process

in accordance with Article 14(5) of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

24 November 2020

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Whereas

- (1) This document sets out the methodology and assumptions that are to be used in the bidding zone (hereinafter referred to as ‘BZ’) review process pursuant to Article 14(5) of Regulation (EU) 2019/943 of the European Parliament and Council of 5 June 2019 on the internal market for electricity (recast) (hereinafter referred to as the ‘Electricity Regulation’). This methodology is hereinafter referred to as the ‘BZR Methodology’.
- (2) The present BZR Methodology refers to alternative BZ configurations to be considered as if they were approved, pursuant to Article 14(5) of the Electricity Regulation; however, these alternative BZ configurations will be only approved in another decision to be issued separately from the present BZR Methodology, at a later stage.
- (3) The BZR Methodology is based on structural congestions which are not expected to be overcome within the following three years, taking due account of tangible progress on infrastructure development projects that are expected to be realised within the following three years as set forth in Article 14(5) of the Electricity Regulation.
- (4) The BZR Methodology takes into account the general principles and goals set in the Electricity Regulation and in Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (hereinafter referred to as the ‘CACM Regulation’).
- (5) The BZR Methodology describes how to assess the ability of BZs to:
 - (a) maximise economic efficiency and cross-zonal trading opportunities in accordance with Article 16 of the Electricity Regulation, while maintaining security of supply, as set forth in Article 14(1) of the Electricity Regulation;
 - (b) create a reliable market environment, including for flexible generation and load capacity, which is crucial to avoiding grid bottlenecks, balancing electricity demand and supply and securing the long-term security of investments in network infrastructure. as set forth in Article 14(3) of the Electricity Regulation;
 - (c) reflect supply and demand distribution, ensure market liquidity, efficient congestion management, overall market efficiency, and operational security as set forth in Recital 19 of the Electricity Regulation; and
 - (d) provide effective price signals for new generation capacity, demand-side response (DSR) and transmission infrastructure as set forth in Recital 30 of the Electricity Regulation.
- (6) The BZR Methodology takes into account the need to ensure that BZs reflect structural congestions and that in particular, cross-zonal capacity is not reduced in order to resolve internal congestions, as set forth in Recital 30 of the Electricity Regulation. In order to ensure this, the BZR Methodology takes into account the objective of finding a common solution on how to best address congestions as set forth in Recital 31 of the Electricity Regulation.
- (7) The BZR Methodology takes into account the criteria for reviewing BZ configurations set out in Article 33 of the CACM Regulation.
- (8) The BZR Methodology takes into account the need to involve and consult stakeholders and the relevant authorities as set forth in Article 14(3) of the Electricity Regulation, and Article 12 and Article 32(4)(b) of the CACM Regulation.
- (9) The BZR Methodology ensures that relevant information is made transparent for stakeholders, to enable them understand and prepare for potential changes of the BZ configuration, and that detailed results are made available to MSs with a view to enable them to take an informed decision on whether to maintain or amend the BZs.

- (10) The BZR Methodology recognises the need to protect confidential information in accordance with Article 13 of the CACM Regulation.

Article 1. Subject matter and scope

1. This BZR Methodology specifies the methodology and assumptions which the TSOs shall use in the BZR process.

Article 2. Definitions and interpretation

1. For the purposes of this BZR Methodology, the terms used shall have the meaning given to them in Article 2 of the Electricity Regulation, in Article 2 of the CACM Regulation, in Article 2 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation, in Article 3 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereinafter referred to as the ‘SO Regulation’) and in Article 2 of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.
2. In addition, the following definitions and acronyms shall apply. In the event of any inconsistency between the following definitions and the definitions pursuant to paragraph 1, the latter shall prevail.
 - (a) AC: Alternating Current;
 - (b) ACER: Agency for Cooperation of Energy Regulators;
 - (c) AMR: Adjustment for the minimum remaining available margin;
 - (d) ‘approval year’ means the year when the configurations for a given BZR Region is approved;
 - (e) BRP: Balancing Responsible Party;
 - (f) BSP: Balancing Service Provider;
 - (g) BZR: BZ Review;
 - (h) BZRR: BZ Review Region means a set of BZs defined for the purpose of the BZR;
 - (i) CCM: Capacity Calculation Methodology;
 - (j) CCR: Capacity Calculation Region, pursuant to Article 2 of Electricity Regulation;
 - (k) CGM: Common Grid Model;
 - (l) CNE: Critical Network Element;
 - (m) CNEC: Critical Network Element and Contingency means a CNE associated with a contingency used in capacity calculation. For the purpose of this BZR Methodology, the term CNEC also covers the case where a CNE is used in capacity calculation without a specified contingency;
 - (n) Core DA CCM: means the common day-ahead capacity calculation methodology for the Core CCR¹;
 - (o) ‘cross-zonal’ network element means a network element located on the BZ border or connected in series to such network element transferring the same power (without considering the network losses);
 - (p) DC: Direct Current;

¹ Pursuant to ACER’s Decision No 02/2019, available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2002-2019%20on%20CORE%20CCM.pdf

- (q) DSR: Demand-Side Response;
- (r) EC: European Commission;
- (s) EENS: Expected Energy Not Served means, in a given modelled zone and in a given time period, the expected ENS;
- (t) ENS: Energy Not Served means, for a given MTU and modelled zone, the energy which is not supplied due to insufficient capacity resources to meet the demand;
- (u) ENTSO-E: European Network of Transmission System Operators for Electricity;
- (v) ERAA: European Resource Adequacy Assessment;
- (w) EU: European Union;
- (x) FB: Flow-Based means the flow-based approach pursuant to CACM Regulation;
- (y) FCR: Frequency Containment Reserve pursuant to SO Regulation;
- (z) Fmax: Maximum flow on a critical network element;
- (aa) Fref: Reference flow;
- (bb) FRM: Flow Reliability Margin means the Reliability Margin as defined in Article 2(14) of the CACM Regulation applied to a CNEC;
- (cc) FRR: Frequency Restoration Reserve pursuant to SO Regulation;
- (dd) GSK: Generation Shift Keys pursuant to CACM Regulation;
- (ee) HHI: Herfindahl-Hirschman Index;
- (ff) HVDC: High Voltage Direct Current network element;
- (gg) LMP: Locational Marginal Pricing;
- (hh) LOLE: Loss Of Load Expectation means, in a given modelled zone and in a given time period, the expected number of hours in which resources are insufficient to meet the demand;
- (ii) MACZT: Margin Available for Cross-Zonal Trade, i.e. the portion of capacity of a CNEC available for cross-zonal trade;
- (jj) MACZT Recommendation: Recommendation of ACER on the implementation of MACZT²;
- (kk) MTU: Market Time Unit means the market time unit used for the modelling chain;
- (ll) ‘new BZ’ refers to a BZ which does not coincide with any of the BZs of the status quo BZ configuration;
- (mm) ‘non-costly remedial action’ refers to a remedial action without cost, e.g. changing PST tap positions and other topological actions, or changing HVDC active (or reactive) power flow, in line with Article 25(5) of the CACM Regulation;
- (nn) NTC: Net Transfer Capacity means the cross-zonal capacity calculated using the coordinated NTC (cNTC) calculation approach, as defined in Article 2(8) of the CACM Regulation;

² Recommendation no 01/2019 of the European Union Agency for the Cooperation of Energy Regulators of 08 August 2019 on the implementation of the minimum margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943, available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf

- (oo) OSL: Operational Security Limit (including thermal rating);
- (pp) PEMMDB: Pan-European Market Modelling Database means detailed ENTSO-E data following the National Trends scenario designed for the TYNDP;
- (qq) PSI: Pivotal Supplier Index;
- (rr) PST: Phase Shifting Transformer;
- (ss) PTDF: Power Transfer Distribution Factor means an indicator which describes the impact of a BZ net position or of a commercial exchange between two BZs on a CNEC;
- (tt) RAM: Remaining Available Margin means margin of a CNEC available for cross-zonal trade within a CCR;
- (uu) RAO: Remedial Actions Optimisation;
- (vv) RES: Renewable Energy Sources;
- (ww) RR: Replacement Reserve pursuant to SO Regulation;
- (xx) RSI: Residual Supply Index;
- (yy) ‘socio-economic welfare’ means the aggregation of the economic surpluses of electricity consumers, producers, and transmission network owners (congestion revenue);
- (zz) ‘status quo configuration’ means the BZ configuration which is expected to apply for the target year based on previously-adopted decisions³;
- (aaa) ‘target year’ means the year for which the BZ configurations are evaluated and compared;
- (bbb) TRM: Transmission Reliability Margin means the Reliability Margin as defined in Article 2(14) of the CACM Regulation on a BZ border;
- (ccc) TSO: Transmission System Operator;
- (ddd) TYNDP: Ten-year network development plan means the 2020 edition of ENTSO-E’s ten-year network development plan;
- (eee) UCED: Unit Commitment Economic Dispatch refers to the problem that determines the commitment and schedule of individual generation, storage and DSR units in order to minimise operating costs while supplying demand and meeting technical and security constraints of both network and units; and
- (fff) VOLL: Value Of Lost Load.

3. In the BZR Methodology, 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 the BZR Methodology;
 - (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; and
 - (d) any reference to an Article without an indication of the document shall mean a reference to the BZR Methodology.

³ For example, as Italy decided to update its BZ configuration, which is expected to be implemented in 2021 (as described in footnote 4), this new configuration shall be considered as status quo for the target year.

Article 3. Overview of the BZR process

1. The TSOs shall perform a BZR consisting of the following steps:
 - (a) TSOs shall define the scenario and assumptions pursuant to Article 4.
 - (b) TSOs shall perform the modelling chain in accordance with Article 5 for the scenario, for all the alternative BZ configurations and for the status quo BZ configuration.
 - (c) TSOs shall evaluate the relative performance of all the alternative BZ configurations according to Article 13.
 - (d) TSOs shall publish the results of the BZR which shall include a proposal to the relevant MS on maintaining or amending the BZ configurations.
2. TSOs may conduct the specific tasks described in Article 5 to Article 15 at the BZRR level, except when specified otherwise in the said articles. When performing tasks at the BZRR level, the following BZRRs and BZs shall be considered:
 - (a) the BZRR Central Europe comprises the BZs: France, Belgium, The Netherlands, Germany/ Luxembourg, Austria, Czech Republic, Poland, Slovakia, Hungary, Slovenia, Croatia, Romania, Denmark 1, and Italy 1 (Nord);
 - (b) the BZRR Nordic comprises the BZs: Finland, Sweden 1, Sweden 2, Sweden 3, Sweden 4, and Denmark 2;
 - (c) the BZRR South-East Europe comprises the BZs: Bulgaria and Greece;
 - (d) the BZRR Central Southern Italy comprises the BZs: Italy 2 (Cnor), Italy 3 (Csud), Italy 4 (Sud), Italy 5 (Sici), Italy 6 (Sard), and Italy 7 (Rosn/Cala)⁴;
 - (e) the BZRR Iberian Peninsula comprises the BZs: Spain and Portugal;
 - (f) the BZRR Baltic comprises the BZs: Estonia, Latvia and Lithuania;
 - (g) the BZRR Ireland comprises the BZ: Ireland Single Electricity Market; and
 - (h) the BZRR Great Britain comprises the BZ: Great Britain.

Article 4. Scenario, sensitivities, and assumptions

1. Scenario and target year: The scenario shall reflect the best forecast of TSOs for the target year. The target year shall be three years after the approval year. The TSOs may build this scenario based on the TYNDP data set. In this case, TSOs shall adapt, where needed, the TYNDP data set to reflect the latest available information, e.g. concerning network elements expected to be operational in the target year pursuant to point 2(e) of this article. The scenario assumptions shall align with paragraphs 2 to 9 of this article.
2. Network: The network model shall reflect the European power grid, and shall fulfil the following minimum requirements:
 - (a) TSOs of a BZRR shall rely on the same network model(s) to reflect a given BZRR, both within and outside the considered BZRR, subject to the following simplification outside the considered BZRR. To model the network beyond the considered BZRR, TSOs shall rely on network data provided by neighbouring TSOs, which may be simplified consistently across all BZRRs to ensure feasibility of the BZ review. In case of simplification, for each neighbouring BZRR with a simplified network model, the simplified network model shall behave similarly to the detailed network model, at least

⁴ This BZRR reflects the BZ configuration approved by the Italian NRA on 19 March 2019 (ARERA Decision 103/2019/R/EEL). This BZ configuration is expected to be implemented in 2021.

with respect to electricity impedances, flows and operational security limits within the considered BZRR.

- (b) Contingencies and OSLs related to network elements operating at nominal voltage higher than or equal to 380 kV shall be included. Contingencies and OSLs related to network elements operating at nominal voltage levels below 380 kV shall be excluded (and these network elements shall thus not be considered as CNEs in Article 6.7), unless TSOs are able to justify properly why different BZ configurations would significantly affect either:
 - i. the impact of contingencies in lower voltages on violation of OSLs on 380 kV network elements;
 - ii. violations of OSLs on lower voltage network elements; or
 - iii. the remedial actions available to solve the violations of OSLs on lower voltage network elements or on 380 kV network elements.

Such a justification may rely on:

- i. a simplified network analysis highlighting the impact of alternative BZ configurations on flows and operational security limits of specific network elements or voltage levels; and
 - ii. a consultation of regulatory authorities on the topic pursuant to Article 17.2 and Article 17.3.
- (c) The availability and activation of non-costly remedial actions shall reflect the best expected operational practices for the target year. In case non-costly remedial actions are expected to solve or alleviate the impact of specific contingencies or OSLs, TSOs may individually remove or increase some OSLs or remove some contingencies from the list defined in point 1(b) of this article, properly justifying such an approach and consulting regulatory authorities on the topic pursuant to Article 17.2 and Article 17.3.
- (d) In this case, these non-costly remedial actions shall be unavailable within the modelling chain, and the updated contingencies and OSLs shall apply throughout the modelling chain.
- (e) Only network elements expected to be operational during the target year, based on the latest available information, shall be included. Changes in the network, which are expected to be commissioned after the target year, shall be ignored. TSOs may model new network elements based on either of the following options:
 - i. define multiple network models appropriately reflecting the gradual commissioning of new network elements throughout the target year; or
 - ii. where the definition of network models according to point 2(e)i of this article is not possible, include, in all network models, all new network elements expected to be commissioned by 30 June of the target year.
- (f) TSOs may individually change the network topology, e.g. by opening or closing circuit breakers or busbar breakers. These topological changes shall reflect the best expected operational practices for the target year, and shall aim at maximising cross-zonal capacity while safeguarding operational security for each BZ configuration. TSOs shall jointly describe to regulatory authorities the changes applied, and the reasons for the main changes applied, pursuant to Article 17.2 and Article 17.3.
- (g) Generation and demand pursuant to paragraphs 5 and 6 of this article shall be connected to the node where they are expected to be located during the target year, in line with the disaggregation of zonal values into nodal values pursuant to paragraph 9 of this article.

- (h) The network model shall include information about the net position of each BZ. The net position shall be consistent with load and generation forecasts pursuant to paragraphs 5 and 6 of this article.
 - (i) If the TSOs build the grid model for the target year by adapting the latest available reference grid model from the TYNDP data set that represents the reference grid of the closest year to the target year, they shall describe to regulatory authorities the changes they applied, and shall justify how such changes fulfil the previous requirements.
- 3. Reserve requirements: Reserve requirements shall be set separately for FCR, FRR and RR.
 - (a) For each target year, the dimensioning of FCR, FRR and RR, and the related contribution of each TSO, shall reflect reserve needs to cover imbalances in line with Articles 153, 157 and 160 of SO Regulation.
 - (b) The assignment of these balancing reserves to generation, demand and storage shall reflect expected operational practices for the target year.
- 4. Climate years: TSOs shall jointly select three reference climate years to assess BZ configurations. These three years shall be selected among the thirty most recent available climate years. The reference climate years shall be consistently used across all BZRRs and BZ configurations. A BZRR may select additional climate years, which shall be justified and published before the modelling chain starts, pursuant to the publication requirements described in Article 16, and consulted with regulatory authorities and ACER pursuant to Article 17.2 and Article 17.3. Unless stated otherwise and duly justified, all selected reference climate years shall have the same weight in the assessment and conclusions made for each criterion and configuration. Additional climate years may also be used as a sensitivity analysis as described in paragraph 10 of this article.
- 5. Load: Zonal load data shall be based on the demand from the PEMMDB for the target year, as follows:
 - (a) TSOs shall generate a realistic time series of zonal load curves for each climate year pursuant to paragraph 4 of this article.
 - (b) TSOs shall build a time series of zonal load curves by combining:
 - i. a pre-set zonal load forecast at the expected day-ahead price pursuant to point 5(c) of this article; and
 - ii. demand elasticity pursuant to point 5(g) of this article.
 - (c) TSOs shall consider the pre-set zonal load forecast, for each MTU of the target year, as follows:
 - i. if detailed wholesale price forecasts are available for each MTU of the target year at the beginning of the BZ review, the pre-set zonal load forecast shall be equal to the load at the expected day-ahead prices for the considered MTU;
 - ii. as a simplification, the pre-set zonal load forecast may be equal to the load forecast for the considered MTU at the average day-ahead price of the three years before the approval year; or
 - iii. an alternative approach to match the pre-set zonal load forecast with a price for each MTU of the target year, provided that TSOs properly justify why the alternative approach is more relevant, and highlight the main assumptions underlying the alternative approach.
 - (d) TSOs shall spread the time series of zonal load curves among electric nodes pursuant to paragraph 9 of this article.

- (e) DSR shall be represented by both:
- i. explicit DSR units which respond at specific activation prices, including interruptible demand units, pursuant to point 5(f) of this article; and
 - ii. implicit DSR based on the demand elasticity estimated pursuant to point 5(g) of this article,
- as follows:
1. By default, demand shall be assumed to at least respond to price signals with day-ahead notice, i.e. in day-ahead markets.
 2. By default, demand shall be inelastic when notice is shorter than in day-ahead markets. When specific means of DSR may be able to respond with shorter than day-ahead notice, the demand parameters shall reflect the shorter notice period.
- (f) Each explicit DSR unit shall be described through the following parameters:
- a. maximum power which may respond, in MW;
 - b. minimum price at which the response is triggered, in €/MWh;
 - c. if applicable, maximum activation duration, i.e. the maximum number of consecutive MTUs of DSR, in h; and
 - d. if applicable, maximum activated energy per day, in MWh.
- (g) Implicit DSR shall be considered as follows:
- i. For each BZ, TSOs shall estimate the elasticity of the remaining load, i.e. of the load which is not represented through explicit DSR units. TSOs shall compute at least one estimate per BZ; they may compute more values to reflect the change in demand elasticity as a function of the day-ahead price. Each estimate shall be equal to either of the following:
 1. the average elasticity of the day-ahead market demand curve near the day-ahead clearing price, over all hours of the year before the approval year, or over hours where the day-ahead is close to a given value if multiple elasticity values are estimated;
 2. the average elasticity of the whole demand, based on a robust and recent study forecasting demand elasticity for the target year; or
 3. -0.2 or an average value based on a robust and recent EU study.
 - ii. As far as technically possible, day-ahead demand elasticity shall be modelled as a parameter(s) that can be explicitly considered by the modelling tool. Alternatively, TSOs may model demand elasticity as a set of equivalent generation units, pursuant to point 5(f) of this article, subject to the following conditions:
 1. the parameters that describe these equivalent generation units shall be aligned with the estimated demand elasticity, pursuant to point 5(e)ii.1 and 5(g) of this article; and
 2. this simplified modelling shall be compatible with the estimation of socio-economic welfare pursuant to Article 7.2.
 - iii. The elasticity of the remaining load shall only be available for market dispatch pursuant to Article 7, and shall be unavailable for remedial actions optimisation pursuant to Article 9.

- (h) Demand which remains when the day-ahead price reaches the day-ahead price cap may be shed only when prices are greater than or equal to VOLL or the day-ahead price cap, whichever is higher. TSOs shall ensure consistency with the VOLL methodology pursuant to Article 11 of the Electricity Regulation, and shall ensure that VOLL reflects at least the impact of pre-notification of consumers before load shedding.
6. Generation: Zonal generation data shall be based on the generation data from the PEMMDB for the target year, as follows:
- (a) For each climate-dependent generation unit and for each climate year pursuant to paragraph 4 of this article, TSOs shall generate a realistic generation time series. This generation time series may be calculated as a combination of:
 - i. installed generation capacities; and
 - ii. generation factors time series for each climate year, i.e. how much 1 MW would generate for each MTU of the climate year.
 - (b) TSOs shall spread zonal climate-dependent generation data among electric nodes pursuant to paragraph 9 of this article.
 - (c) Technical generation constraints shall be considered. These constraints shall at least include minimum and maximum generating capacities, must-run constraints, ramping capabilities, minimum run-time, start-up and shut-down times. These constraints may also include capacity requirements for system services, such as reserves or voltage support, capacity reductions due to mothballing, time series of derating ratio, due to constraints which are not explicitly modelled pursuant to Article 7 and Article 9, or planned maintenance requirements.
 - (d) TSOs may apply simplifications to the modelling of technical constraints subject to the conditions laid out in the relevant articles of this BZR methodology.
7. Storage: Zonal storage data shall be based on the storage data from the PEMMDB for the target year. The modelling of storage assets shall reflect expected operational practices for the target year, and shall include at least the following aspects:
- (a) pumped-hydro storage shall respect constraints related to upper and lower reservoir levels, minimum and maximum pumped energy, minimum and maximum generated energy and minimum and maximum generation capacity; and
 - (b) the energy availability of batteries shall be based on energy storage capacities and charging and discharging constraints.
8. Other assumptions: Fuel and CO₂ prices shall be equal to the forecast used for the latest available TYNDP data set for the closest year to the target year, or, if available, equal to a forecast which is better than the one used for the latest available TYNDP.
9. Disaggregation to nodal level: TSOs shall disaggregate the zonal load and generation forecasts into nodal forecasts, i.e. they shall spread the zonal value into one value per node included in the network model pursuant to paragraph 2 of this article. To disaggregate zonal values to nodal level, TSOs shall either:
- (a) follow the disaggregation methodology applied in the TYNDP; or
 - (b) follow an alternative disaggregation methodology which leads to load and generation forecasts at least as detailed as the TYNDP disaggregation methodology.
10. Sensitivity analysis:
- (a) To enable the assessment of the ‘Stability and robustness of BZs over time’ criterion, pursuant to Article 15.16, TSOs shall at least perform one sensitivity analysis, while it is recommended that TSOs perform at least three sensitivity analyses.

- (b) All sensitivities shall reflect appropriate and foreseeable variations, in any of the input data or grid infrastructure, of the scenario defined pursuant to paragraph 1 of this article.
- (c) Except for the assessment of the ‘Stability and robustness of BZs over time’ criterion, the results of the sensitivity analyses shall be clearly separated from the results of the ‘main study’, as described in Article 13.2(d).

Article 5. Modelling chain

1. In order to assess the criteria described in Article 13, the TSOs shall develop a series of consecutive steps in a modelling chain to represent, for each BZRR, scenario and sensitivities described under Article 4, the following:
 - (a) cross-zonal trade within the EU and with third countries; and
 - (b) the flows of electricity through the BZRR electricity grid.
2. The modelling chain shall rely on the following steps:
 - (a) TSOs shall run cross-zonal capacity calculation pursuant to Article 6, leading to cross-zonal capacities for each BZ border and MTU;
 - (b) starting from available generation, demand, including DSR, and cross-zonal capacities, TSOs shall jointly simulate the market dispatch of generation and demand pursuant to Article 7, for each MTU;
 - (c) based on the grid model pursuant to Article 4.2, and on the market dispatch, a load flow calculation shall determine flows and operational security violations pursuant to Article 8 throughout the electricity network, for each MTU;
 - (d) in order to solve all operational security violations detected in the previous step, a redispatching simulation/analysis shall optimise remedial actions pursuant to Article 9, for each MTU; and
 - (e) based on the outcome of the remedial action optimisation, TSOs shall estimate the flows not induced by cross-zonal trade, to determine the effects of internal trade on other BZs.
3. The MTU shall be one hour.
4. The steps pursuant to paragraph 2 of this article may be internal to the modelling tool, but the results shall be available for each step.

Article 6. Capacity calculation

1. For a given BZ border, MTU and scenario (including climate year), TSOs of a CCR shall jointly calculate cross-zonal capacity. For a given BZ border, the same cross-zonal capacity shall as much as possible be used across all BZRRs. For BZ borders outside the synchronous area of a considered BZRR, simplified cross-zonal capacities may be used; in this case, the simplified cross-zonal capacities shall be consistent with grid model simplifications pursuant to Article 4.2(a).
2. For each BZ border, cross-zonal capacity calculation shall rely on either:
 - (a) the flow-based approach, on BZ borders which belong to a CCR with an adopted flow-based CCM for the day-ahead timeframe pursuant to the CACM Regulation; or
 - (b) the cNTC approach, for the other BZ borders.
3. Capacity calculation shall ensure the 70% requirement pursuant to Article 16(8) of the Electricity Regulation unless derogations or action plans are expected to apply for the target

year. Derogations may only apply provided they have been consulted with regulatory authorities and agreed, for the target year, pursuant to Article 16(9) of the Electricity Regulation. The list of agreed derogations shall be published pursuant to Article 16 of this methodology. The application of the 70% requirement shall be consistent with the MACZT Recommendation.

4. TSOs shall at least compute seasonal cross-zonal capacities for each BZ border. If seasonal values are computed, the definition of the seasons used for capacity calculation shall match the expected operational practices of the target year. TSOs shall refine cross-zonal capacities when cross-zonal capacities are expected to vary significantly within a given season.
5. TSOs shall compute cross-zonal capacities based on the network model pursuant to Article 4.2.
6. GSKs shall reflect expected operational capacity calculation practices for the target year, as described in the CCM approved pursuant to the CACM Regulation in the considered CCR. For a given BZ, if those GSKs are too complex to estimate, TSOs may rely on a GSK proportional to the generation in the grid model for the target year, and MTU or season. Such a simplification shall be reported and justified to regulatory authorities and ACER pursuant to Article 17.2 and Article 17.3.
7. TSOs of a CCR shall jointly define CNECs. All cross-zonal network elements shall be considered as CNEs. The definition of internal CNEs shall rely on an economic efficiency analysis, e.g. considering the option to manage congestion through remedial actions or network investment. The definition of contingencies shall align with the CCM approved pursuant to the CACM Regulation, and shall be a subset of the contingencies considered in Article 8.3.
8. Upon agreement of all TSOs, TSOs of a CCR may simplify the definition of internal CNECs as follows. TSOs of a CCR may include as CNE all internal network elements whose maximum zone-to-zone PTDF is at least equal to a PTDF threshold. The PTDF threshold shall be the same for all TSOs, and shall not be lower than any PTDF threshold used in any CCM approved pursuant to the CACM Regulation. As default value, the PTDF threshold shall be 10%. If TSOs of a CCR use a different PTDF threshold, they shall justify why it better reflects an economic efficiency analysis for the whole EU. All internal network elements which do not have a maximum PTDF above the PTDF threshold shall not be defined as CNE.
9. For each CNEC and MTU, or season, F_{max} shall reflect the expected operational practices of the target year, and shall be computed based on the network model pursuant to Article 4.2. F_{max} shall reflect a subset of the operational security limits pursuant to Article 8.4.
10. For each CNEC, TSOs shall estimate the FRM. Within a given CCR, each TSO shall follow a uniform methodology when estimating the FRM on all CNECs which are located within its territory. The FRM shall be:
 - (a) preferably computed individually for each CNEC in line with the CCM approved pursuant to the CACM Regulation in the considered CCR. In this case, network models reflecting the forecast D-2 grid and the real time situation (stemming from a market simulation reflecting the cross-zonal capacities of the alternative BZ configurations) for each MTU shall be used; or
 - (b) where the computation pursuant to point 10(a) of this article is not technically possible, set to a fixed value. This value shall be 10% of F_{max} for each CNEC, or any other fixed value if agreed by all TSOs of the relevant CCR. This fixed value shall be consistently applied across all alternative BZ configurations.
11. The same approach may apply to define the TRM on a BZ border, if TSOs are unable to define CNECs in capacity calculation. If TSOs define NTCs based on thermal ratings pursuant to point 17(a) of this article, they may set the FRM to zero on the HVDC interconnectors on this border.
12. For each CNEC and MTU, or season, TSOs shall compute PTDFs based on the network model pursuant to paragraph 5 of this article, relying on GSKs described in paragraph 6 of this article.

13. For each CNEC and MTU, or season, the flow without commercial exchanges within the whole system shall be⁵:

$$\vec{F}_{0,all} = \vec{F}_{ref} - \text{PTDF}_{all} \overline{NP}_{ref,all}$$

with

$\vec{F}_{0,all}$	flow per CNEC in a situation without any commercial exchange between EU BZs, and with selected non-EU BZs. Cross-zonal exchanges with non-EU BZs shall only be included if and where an agreement with the non-EU country (as described in the MACZT Recommendation 2019 section 4.1) is expected to apply for the target year;
PTDF_{all}	power transfer distribution factor matrix for all BZs pursuant to paragraph 12 of this article;
$\overline{NP}_{ref,all}$	net positions per BZ included in the network model pursuant to Article 4.2. Only the share of the net position related to exchanges with EU BZs and BZs for which an agreement is expected to apply pursuant to Article 4.1 of the MACZT Recommendation shall be considered.

14. For each CNEC, a minimum RAM requirement shall be fulfilled in line with paragraph 3 of this article. For example, for CNECs for which the minimum margin available for cross-zonal trade is 70%, the adjustment for minimum RAM shall be:

$$\text{AMR} = \max(0, F_{0,all} + \text{FRM} - 0.3 * F_{max})$$

15. The flow without cross-zonal exchanges within the considered CCR shall be for each CNEC⁶:

$$\vec{F}_{0,CCR} = \vec{F}_{ref} - \text{PTDF}_f \overline{NP}_{ref,CCR}$$

with

$\vec{F}_{0,CCR}$	flow per CNEC in the situation without commercial exchanges within the considered CCR;
\vec{F}_{ref}	flow per CNEC in the CGM, taking preventive remedial actions and topological actions into account;
PTDF_f	power transfer distribution factor matrix for the CCR (submatrix of PTDF_{all});
$\overline{NP}_{ref,CCR}$	net position per BZ of the CCR included in the CGM.

16. Finally, the margin available on each CNEC shall be:

$$\text{RAM} = F_{max} - \text{FRM} - F_{0,CCR} + \text{AMR}$$

with

\vec{F}_{max}	maximum active power flow pursuant to paragraph 9 of this article;
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⁵ See equation 11 of the Core DA CCM.

⁶ See equation 10 of the Core DA CCM

\overline{FRM}	flow reliability margin pursuant to paragraph 10 of this article;
$\vec{F}_{0,CCR}$	flow without commercial exchanges in the CCR, described in paragraph 15 of this article;
\overline{AMR}	adjustment for minimum RAM pursuant to paragraph 14 of this article;
\overline{RAM}	remaining available margin without exchanges within the CCR.

17. TSOs of a CCR which does not rely on the flow-based approach shall jointly select one of the following approaches for all the BZ borders of the CCR in order to reflect expected operational practices for the target year:

- (a) cNTC approach based on thermal ratings, for already existing DC borders only.
 - i. On each BZ border which was operational during at least one year prior to the approval of the alternative BZ configurations, the sum of the thermal ratings of cross-zonal network elements and the day-ahead NTCs shall be computed for all market time units when the considered BZ border was present, excluding time periods when exceptional contingencies affected the considered BZ border. The average ratio between the NTC and the sum of thermal ratings of cross-zonal network elements shall be the ‘historical relative NTC’.
 - ii. The ‘historical relative NTC’ shall then be corrected to take expected operational changes and paragraph 10 of this article into account, leading to ‘relative NTC’. The ‘relative NTC’ shall be greater than or equal to 70%, unless a derogation or action plan applies for the considered BZ border during the target year.
 - iii. For each BZ border and MTU of the target year, the relative NTC shall be combined with the thermal ratings of cross-zonal network elements to lead to the NTC.
- (b) cNTC approach based on CNECs and GSKs.
 - i. TSOs shall determine GSKs and CNECs pursuant to paragraphs 6 and 7 of this article. For each CNEC, TSOs shall compute RAM consistently with paragraphs 9 to 16 of this article.
 - ii. TSOs shall jointly define different representative situations of cross-zonal exchanges.
 - iii. TSOs shall maximise cross-zonal capacity, while subject to the RAM on each CNEC defined in point 17(b)i, in line with paragraph 16 of this article. As a simplification, TSOs may check the fulfilment of the minimum RAM requirement only on the CNEC(s) which were identified as limiting at the capacity calculation stage. The flow impact on the CNEC is either computed by updating the grid model based on GSKs and performing a load-flow, or by combining cross-zonal exchanges with PTDFs. The same flow impact calculation shall be used on all BZ borders within a CCR. When conducting this step, TSOs shall share the power flow capability of CNECs in line with the CCM approved pursuant to the CACM Regulation in the considered CCR.
 - iv. This calculation shall be carried out on a set of timestamps selected by TSOs to reflect possible grid situations. At least one calculation per season shall be conducted.
- (c) cNTC approach based on TYNDP for existing BZ borders which are not impacted by a change in BZ configuration, and for BZ borders with, or between, third countries. TSOs may use NTC values calculated as part of the latest TYNDP process. In this case, TSOs

shall ensure that these NTCs reflect the requirements set forth in Article 16(8) of the Electricity Regulation, adapted for derogations or action plans.

18. Flow-based approach: On borders where the flow-based approach is chosen, the initial flow-based domain shall be computed in line with paragraphs 6 to 16 of this article. The NTC values for the NTC base case shall be computed in line with one of the methods described in paragraph 17 of this article. Non-costly remedial actions may be taken into account to increase the size of the initial flow-based domain in the directions which are likely to be valuable for the market for the considered MTU. In this case, these remedial actions shall also be modelled pursuant to Article 9.2(a).
19. Allocation constraints: When approved CCMs explicitly allow allocation constraints for the target year, TSOs may introduce such constraint within capacity calculation. The constraint value shall reflect operational practices for each MTU when such a constraint applies. In case a change in BZ configurations would allow to phase out the allocation constraint, the allocation constraint shall be removed when modelling capacity calculation for this BZ configuration. Furthermore, for a given allocation constraint, the methodology to compute the allocation constraint shall be the same among all studied BZ configurations for which the allocation constraint is necessary. The kinds of allocation constraints introduced shall be published pursuant to Article 16. The detailed allocation constraints shall be consulted with regulatory authorities and ACER pursuant to Article 17.2 and Article 17.3.
20. Output: The capacity calculation leads to the following outputs for scenario, BZ configuration, BZ border and MTU:
 - (a) for cNTC BZ borders: one NTC value per direction;
 - (b) for flow-based BZ borders: a list of CNECs with zonal PTDFs and RAM;
 - (c) where applicable, allocation constraints;
 - (d) for all BZ borders: the list of remedial actions applied during capacity calculation; and
 - (e) the network model as an outcome of capacity calculation, i.e. the network model pursuant to paragraph 5 of this article, updated to reflect preventive remedial actions in line with point 20(d) of this article.

Article 7. Day-ahead market dispatch

1. In order to estimate the EU generation dispatch resulting from the market for a scenario and given BZ configuration, TSOs shall run a UCED, assuming perfect forecast of demand and generation availability.
2. The UCED shall maximise the socio-economic welfare, which shall be equal to the difference between:
 - (a) the utility function of supplied demand (including DSR), as described in point 6(b) of this article; and
 - (b) the total generation and storage cost, including at least start-up and short-run marginal costs. In case short-run marginal costs are very close for few power plants within a BZ, and to ensure a more robust simulation outcome, TSOs shall add a small random hourly mark-up on top of the short-run marginal cost to define an hourly short-run marginal cost per power plant. The random mark-up shall lie within the range $[-1; 1]$ €/MWh, and shall be larger than the numerical tolerance of the UCED.
3. In order to fully reflect the impact of intertemporal constraints on the UCED, the UCED shall jointly optimise all MTUs within a week, or within a longer time period.
4. The UCED shall reflect the following constraints:

- (a) available generation, including storage, per BZ and MTU, including technical constraints pursuant to Article 4.6 and Article 4.7; where technical limitations apply to the consideration of technical constraints, simplifications analogous to the ones described in Article 9.8(b) may be applied as follows:
 - i. only for units with nominal generating capacity lower than 100 MW; and
 - ii. subject to a maximum of 400 MW per node and to a maximum of 50% of the installed thermal generation capacity in a given BZ.
 - (b) demand to supply, including DSR, per BZ and MTU pursuant to Article 4.5 and further described in paragraph 6 of this article;
 - (c) available cross-zonal capacity per BZ border and MTU pursuant to Article 6; and
 - (d) reserves and balancing requirements, as described in Article 4.2(i).
5. The UCED shall reflect the following generation and storage behaviour:
- (a) Thermal power plants bid according to their start-up costs and short-run marginal costs, including fuel costs, CO₂ costs, variable operation and maintenance costs. Technical constraints pursuant to Article 4.6 shall be considered.
 - (b) The short-run marginal cost of wind and solar power plants shall be 0 €/MWh by default. However, other factors related to subsidy schemes or technical restrictions may also be considered.
 - (c) Unregulated, i.e. run-of-river, hydro power shall be modelled as an unregulated inflow pursuant to Article 4.6(a)ii.
 - (d) Regulated, i.e. reservoir or pumped, hydro power plants shall be subject to constraints set in power plant data. The time horizon over which the injections and withdrawal of these hydro power plants are optimised shall reflect expected operational practices for the target year. The withdrawals related to hydro pumping shall not be inputs; instead, the UCED shall optimise these variables. The hydro stock shall be optimised either:
 - i. based on the expected marginal cost during future hours when the hydro stock is expected to be used, i.e. ‘water value calculation’; or
 - ii. based on perfect foresight, i.e. optimising the hydro stock over the whole target year to maximise socio-economic welfare.
 - (e) Biomass power plants may be represented either as conventional power plants similar to the category indicated in point 5(a) of this article, if the output depends on marginal costs, or fixed infeed time series if the output is price-independent.
 - (f) Other non-renewable power plants not included under category indicated in point 5(a) of this article shall be represented with infeed time series and a marginal cost that reflects the projected bidding price of the units.
 - (g) Other renewable power plants not specifically modelled are represented with load factor time series combined with forecasted installed capacity.
 - (h) Storage assets shall be modelled in line with Article 4 (7). In particular, withdrawals shall not be inputs, but shall be optimised by the UCED.
 - (i) Any other technologies shall be represented in accordance with expected operational practices and with market design aspects which impact their behaviour.
 - (j) For each MTU, capacity affected to FCR or FRR in accordance with Article 4.2(i) shall be considered unavailable.
6. Representation of load:

- (a) The definition of load included in Article 2 applies.
 - (b) DSR shall be considered as described in Article 4.5. For implicit and explicit DSR, the utility shall be equal to the bid price. The utility of inelastic demand shall be equal to VOLL, assuming pre-notification of consumers one day before the load is shed, as variable cost.
7. For each BZRR, the market dispatch simulation shall provide the following results for the EU, for each MTU:
- (a) the total socio-economic welfare in €;
 - (b) the utility of supplied demand in €;
 - (c) the total generation cost in €;
 - (d) the overall congestion revenue in €;
 - (e) for each generation unit, the production in MW;
 - (f) for each storage unit, the injection or withdrawal in MW;
 - (g) for each DSR unit, the activated DSR in MW;
 - (h) the change in load due to demand elasticity in MW;
 - (i) for each BZ, the amount of load-shedding in MW;
 - (j) for each BZ, the short-run marginal cost in €/MWh;
 - (k) for each BZ, the net positions in MW;
 - (l) for each BZ border, the cross-zonal exchange in MW; and
 - (m) for each CNEC, the flow in MW, and the shadow price in €/MW.

Article 8. Operational security analysis

1. For a given scenario, BZ configuration and MTU, TSOs shall combine the network model pursuant to Article 6.20(e) and the generation and demand schedules pursuant to Article 7.7 to define the network model resulting from the day-ahead market dispatch.
2. Based on the network model derived from paragraph 1 of this article, TSOs shall run an operational security analysis in order to assess whether contingencies pursuant to paragraph 3 of this article lead to violations of OSLs described in paragraph 4 of this article. To this end, TSOs may either run, as long as technically possible:
 - (a) an AC load-flow calculation; or
 - (b) a DC load-flow calculation whereby network losses have been accounted for; or
 - (c) as a fall-back, a DC load-flow calculation.However, within a BZRR, all load-flow calculations shall be run in only one of the three above-listed methods.
3. First, the TSOs of a BZRR shall jointly establish a contingency list for the operational security analysis for that BZRR. The list shall be identical among all climate years and configurations, except if network elements are added or removed from the network model. In this case, the contingency list may reflect these additions or removals. The list shall be based on the following principles:
 - (a) the chosen set of contingencies to investigate for operational security analysis shall at least include the contingencies considered in capacity calculation;

- (b) network elements monitored and used to define contingencies shall be defined in accordance with Article 4.2. No other network element shall be monitored; and
 - (c) occurrences of a loss of (a) power generating module(s) may also be included as contingency in the contingency list.
4. For each contingency, TSOs shall run a load-flow calculation to assess whether the following OSLs are violated:
- (a) corrected thermal ratings of network elements for the considered MTU⁷, before remedial actions if applicable. For each network element⁸, the corrected thermal rating shall be the difference between the thermal rating defined in line with Article 4.2 and the FRM estimated pursuant to Article 6.10; and/or
 - (b) OSLs underlying an allocation constraint, when such a constraint was introduced pursuant to Article 6.19; and/or
 - (c) other limits e.g. related to voltage magnitude or phase angle, if and where relevant.
5. The operational security analysis shall provide the following results for each scenario, BZ configuration, MTU and violation of an OSL:
- (a) the precise network configuration(s) when the violation occurs;
 - (b) the kind of OSL violated;
 - (c) the network element affected by the violation;
 - (d) the OSL of the network element; and
 - (e) the value of the violation.

Article 9. Consideration of remedial actions

1. For each scenario, BZ configuration and day for which at least one violation of OSL was detected pursuant to Article 8.4, TSOs shall run a RAO simultaneously covering all MTUs within the day in order to solve all operational security violations. Starting from the day-ahead market dispatch pursuant to Article 7.7, the remedial actions to activate shall minimise the additional cost to fulfil all OSLs. The additional cost shall include:
- (a) cost induced by change in generation schedule pursuant to paragraph 4 of this article; and
 - (b) cost induced by DSR, and socioeconomic loss from load-shedding pursuant to paragraph 5 of this article.
2. The RAO shall optimise the following preventive and curative remedial actions:
- (a) non-costly remedial actions (pursuant to Article 4.2(c));
 - (b) change in generation dispatch; and
 - (c) change in activation of explicit demand-response, or load-shedding.
3. The remedial action optimisation shall be subject to the following constraints;
- (a) conditions for activation of non-costly remedial actions pursuant to paragraph 6 of this article;
 - (b) generation constraints pursuant to paragraph 7 of this article;
 - (c) DSR and load-shedding constraints pursuant to paragraph 9 of this article;

⁷ At least seasonal line ratings shall be computed.

⁸ i.e. not only for CNECs.

- (d) operational security limits pursuant to Article 8.4, both without contingency and for all contingencies pursuant to Article 8.3; and
 - (e) the expected level of coordination of remedial actions among BZs, which shall follow paragraph 10 of this article.
4. Generation costs shall include at least start-up and variable costs.
- (a) The variable cost for increasing generation shall be equal to the sum of:
 - i. the short-run marginal cost used for day-ahead dispatch pursuant to Article 7.5(a);
 - ii. an additional cost to reflect start-up cost, as a simplification if start-up costs are not explicitly modelled. In this case, the additional cost shall be equal to the start-up cost divided by the minimum technical power; and
 - iii. the readiness cost, which reflects additional costs related to the short notice of redispatching, the opportunity cost, which reflects lost opportunity on other markets such as the intraday and balancing markets, and any other additional costs inherently related to the participation of generation or demand in the redispatching timeframe, if such costs are not incurred in the day-ahead timeframe.
 - (b) These costs shall be calculated, per generation unit, as follows:
 - i. In BZs which are expected to rely on market-based redispatching for the target year, these costs shall be equal to the average relative difference, over the year before the approval year, between:
 - 1. the upward bid price of the unit in the redispatching mechanism, excluding profit margin, but including opportunity cost and other costs described in point 4(a)iii of this article; and
 - 2. the estimated bid price in the day-ahead market, based on the short-run marginal cost used for day-ahead dispatch pursuant to Article 7.5(a).
 - ii. In BZs which are expected to rely on non-market-based redispatching for the target year, these costs shall be equal to the regulated additional cost allowed for upward redispatching bids, provided that the regulated additional cost covers, at least, opportunity and readiness costs.
 - iii. If TSOs are unable to estimate the cost pursuant to points 4(b)i and 4(b)ii of this article, they shall rely on the average relative difference calculated for BZs which meet the conditions described in point 4(b)ii of this article, over the BZRR, or over the EU.
 - (c) The variable cost for decreasing generation shall be equal to the difference between:
 - i. the short-run marginal cost used for day-ahead dispatch as described in point 4(a)i of this article; and
 - ii. the cost to reflect readiness cost and opportunity cost, and any other additional costs that are inherently related to the participation in the redispatching timeframe, as described in points 4(a)ii and 4(a)iii of this article, but reflecting downward redispatching opportunity cost.
 - (d) As a simplification, e.g. if data is missing, the above described variable costs may be computed jointly for each generation technology.
5. The activation cost of DSR shall be greater than or equal to the activation cost used for the day-ahead market dispatch. An additional cost may be added to reflect the decreased notification time before the activation of DSR, and/or lost opportunity on other markets which are not explicitly modelled. The socio-economic loss coming from load-shedding shall be equal to the

VOLL of the consumers most likely to be disconnected during a load-shedding event taking place during the considered MTU(s). This VOLL shall assume a pre-notification time of at most one hour.

6. The availability and activation of non-costly remedial actions shall reflect the expected operational practices of TSOs for the target year. Non-costly remedial actions shall be assumed to lead to no cost.
7. TSOs shall assess for each generation technology or generation unit within their control area whether it is available for the redispatching simulation, considering the expected practices in their respective control area for the target year. For each MTU, capacity affected to FCR or FRR in accordance with Article 4.3 shall be considered unavailable.
8. All technical generation constraints pursuant to Article 4.6 shall be fulfilled as much as possible. In particular:
 - (a) Hydro power plants shall not change the net⁹ total amount of energy used during the whole day, in order to ensure consistency with the day-ahead market dispatch.
 - (b) As a simplification, TSOs may reflect start-up and shutdown time as follows:
 - i. Generation units which are not running during the last hour of the day before the simulated day, based on the outcome of the day-ahead market dispatch, shall be considered as unavailable at the beginning of the day during the time duration equal to sum of start-up and shutdown time of the considered unit.
 - ii. Generation units which are not running during the first hour of the day after the simulated day, based on the outcome of the day-ahead market dispatch, shall be considered as unavailable at the end of the day during the time duration equal to the sum of start-up and shutdown time of the considered unit.
9. DSR shall be considered as described in Article 4.5. In particular, demand elasticity shall be unavailable for the RAO and explicit DSR may be available, if it reflects expected operational practices, and provided its activation time is short enough to allow for its participation in the RAO. All technical DSR constraints pursuant to Article 4.5 shall be fulfilled.
10. Coordination of remedial actions activation shall reflect the expected level of coordination of redispatching among TSOs for the target year. In particular, the RAO shall reflect:
 - (a) the geographical scope of perfect coordination of remedial actions, if and where such perfect coordination is expected to apply for the target year;
 - (b) the geographical scope of imperfect coordination, if and where such imperfect coordination is expected to apply for the target year;
 - (c) when such coordination of remedial actions is expected to be (gradually) implemented; and
 - (d) the impact of imperfect coordination of remedial actions on the availability and cost of remedial actions.
11. TSOs may run additional studies to calibrate the model and ensure that it leads to realistic costs of remedial actions.
12. TSOs may reduce the number of days to simulate to reduce computation time. In this case, TSOs shall select at least 50 representative days to simulate, the selection of which shall be duly justified, and simulate this reduced sample. TSOs shall then affect each day to a

⁹ i.e. the difference between the used and stored hydro energy.

representative day, and shall assume that the additional cost for each day is consistent with the additional cost derived for the representative day.

13. For each scenario, BZ configuration and geographic scope, and based on RAO results, TSOs shall also estimate the cost of ensuring availability of units for redispatching purposes, i.e. associated to the procurement of capacity or any other mechanism aimed at ensuring that sufficient redispatching reserves are available when needed.
14. By default, the cost of ensuring availability of units for redispatching purposes shall be assumed to be proportional to the activated redispatching energy over a full year, and shall thus be equal to:

$$\begin{aligned} & \text{cost for RD availability (year}_{target}\text{)} \\ &= \text{cost for RD availability (year}_{historical}\text{)} \\ & \quad \frac{\text{RD energy activated (year}_{target}\text{)}}{\text{RD energy activated (year}_{historical}\text{)}} \end{aligned}$$

with

- year_{target}* the target year of the BZR pursuant to Article 4.1;
- year_{historical}* the latest year for which full historical data related to redispatching is available within the BZRR;

cost for RD availability (year_{target}) the cost of ensuring availability of units for redispatching purposes for the target year over the BZRR, excluding MSs for which the option in paragraph 15 of this article applies;

cost for RD availability (year_{historical}) the cost of ensuring availability of units for redispatching purposes for the historical year over the BZRR, excluding MSs for which the option in paragraph 15 of this article applies;

RD energy activated (year_{target}) the total upward dispatch change over the target year over the BZRR, excluding MSs for which the option in paragraph 15 of this article applies;

RD energy activated (year_{historical}) the total upward dispatch change over the historical year over the BZRR, excluding MSs for which the option in paragraph 15 of this article applies.

15. Alternatively, TSOs may estimate the cost of ensuring availability of units for redispatching purposes in their respective MS, as proportional to the peak hourly activated redispatching energy over a full year, as follows:

$$\begin{aligned} & \text{cost for RD availability (year}_{target}\text{)} \\ &= \text{cost for RD availability (year}_{historical}\text{)} \\ & \quad \frac{\text{peak RD energy activated (year}_{target}\text{)}}{\text{peak RD energy activated (year}_{historical}\text{)}} \end{aligned}$$

with

- year_{target}* the target year of the BZR pursuant to Article 4.1;
- year_{historical}* the latest year for which full historical data related to redispatching is available within the BZRR;
- cost for RD availability (year_{target})* the cost of ensuring availability of units for redispatching purposes for the target year, per MS;
- cost for RD availability (year_{historical})* the cost of ensuring availability of units for redispatching purposes for the historical year, per MS;
- peak RD energy activated (year_{target})* the hourly peak upward dispatch change over the target year, per MS;
- peak RD energy activated (year_{historical})* the hourly peak upward dispatch change over the historical year, per MS.
16. For each scenario, BZ configuration, geographic scope and day, TSOs shall calculate the total additional cost of fulfilling all OSLs. The total additional cost shall be the sum of:
- the additional cost from the RAO pursuant to paragraph 1 of this article; and
 - the cost of ensuring availability of redispatching units, in line with paragraph 14 and 15 of this article.
17. For each scenario, BZ configuration, geographic scope of the RAO and MTU, the RAO shall yield:
- the total upward¹⁰ dispatch change, in MW;
 - the total downward dispatch change, in MW;
 - for each unit, the new dispatch, and the change in dispatch, in MW;
 - for each BZ, the new net position, in MW; and
 - the grid model from Article 8.1 updated to include all preventive remedial actions.
18. If the TSOs simulate a reduced number of days pursuant to paragraph 12 of this article, the data listed in paragraph 17 of this article shall be provided only with respect to the days effectively simulated. Additionally, information on the representative days associated to each of the non-simulated days and the resulting total costs for the non-simulated days shall be provided.

Article 10. Estimate of flows not induced by cross-zonal trade

- The TSOs of a BZRR shall calculate the flows not induced by cross-zonal trade after the day-ahead market dispatch and after operational security analysis based on the network models pursuant to Article 6.20(e) and Article 9.17(e), respectively. The flow calculation shall either:

¹⁰ i.e. increase of injections or decrease of withdrawals.

- (a) follow the flow decomposition methodology applicable to share redispatching and countertrading costs in line with Article 74 of the CACM Regulation (if any); or
 - (b) follow assumptions similar to the ACER Recommendation 01/2019. In this case, DC interconnectors shall be modelled as additional BZs with a GSK of 1 on each side of the DC interconnector, and the flow without commercial exchanges shall be $\vec{F}_{0,all}$ from Article 6.13 (taking the net positions of all BZs into account).
2. The following flow contributions not induced by cross-zonal trade shall at least be computed:
 - (a) oriented flows in the same direction as the flow resulting from the day-ahead market dispatch, pursuant to Article 7.7(m), for all CNECs considered in capacity calculation pursuant to Article 6; and
 - (b) oriented flows in the same direction as the flow in the CGM, for all CNECs for which at least one violation of OSL was detected pursuant to Article 8.

Article 11.LMP analysis

1. The TSOs shall jointly carry out a LMP analysis, for the scenario described under Article 4. TSOs may decide to perform the LMP analysis separately for each of the synchronous areas that are expected to exist in Europe for the target year.
2. For this purpose, the TSOs shall run a UCED at nodal level, assuming perfect forecast of demand and generation availability.
3. The UCED shall maximise the socio-economic welfare defined according to the same assumptions used for the day-ahead market dispatch pursuant to Article 7; where technical limitations apply, TSOs may reduce the optimization period of the UCED to one day.
4. The LMP analysis shall cover at least all the nodes at nominal voltage level greater than or equal to 220 kV that are included in the grid model pursuant to Article 4.2.
5. The UCED shall use the network model pursuant to Article 4.2 and shall reflect the following constraints:
 - (a) available generation and storage per node and MTU, including technical constraints, pursuant to Article 4.6 and Article 4.7 respectively. As far as technically possible, these constraints shall be consistent with the ones adopted for the day-ahead market dispatch according to Article 7.4(a). Alternatively, simplifications analogous to the ones described in Article 9.8(b) may be applied as follows:
 - i. only for units with nominal generating capacity lower than 400 MW; and
 - ii. subject to a maximum of 400 MW per node and to a maximum of 50% of the installed thermal generation capacity in a given BZ.
 - (b) demand to supply, including DSR, per node and MTU pursuant to Article 4.5 and Article 7.6;
 - (c) security constraints based on OSLs and contingencies identified according to Article 4.2. As far as technically possible, these constraints shall be consistent with the assumptions adopted for the operational security analysis pursuant to Article 8. Alternatively, the two following options may be considered:
 - i. including only the most significant contingencies not fully resolved by means of non-costly remedial actions; or
 - ii. performing an iterative analysis where OSLs are progressively included in the UCED.

As far as technically feasible, the LMP analysis shall make use of the same AC or DC load-flow calculation as the one selected for the operational security analysis pursuant to Article 8.

- (d) reserves and balancing requirements, as described in Article 4.3; these constraints shall be consistent with the ones adopted for the day-ahead market dispatch according to Article 7.4; and
 - (e) energy balance at each node.
6. Disaggregation at nodal level shall be performed according to the scenario and assumptions reported in Article 4.
 7. TSOs shall endeavour to include all non-costly remedial actions in the UCED. Where technical limitations apply, the UCED shall at least take into account the following non-costly remedial actions: PSTs taps and HVDCs active power flow. The non-costly topological remedial actions not taken into account by the UCED shall reflect the expected operational practices of TSOs for the combination of target and climate years. For each MTU, TSOs shall highlight any difference between the non-costly remedial actions used for LMP analysis according to this paragraph and the non-costly remedial actions resulting from the remedial action optimisation pursuant to Article 9. TSOs shall qualitatively estimate the impact of these differences on the results.
 8. As far as technically possible, TSOs shall perform the LMP analysis for all MTUs of the target year. Where technical limitations apply, TSOs may limit the time horizon to a minimum of eight weeks, ensuring that this limited time horizon is representative of the entire target year.
 9. The following output shall at least be provided:
 - (a) nodal price for each node and MTU, in €/MWh;
 - (b) cleared generation, storage and demand volumes for each node and MTU, in MW;
 - (c) flows on all considered network elements for each MTU, in MW;
 - (d) active network constraints for each MTU if any;
 - (e) shadow prices associated to the active network constraints, €/MW;
 - (f) overall socio-economic welfare resulting from the optimization, in €; and
 - (g) any other information deemed relevant by the TSOs.

Article 12. List of evaluation criteria

1. TSOs of a BZRR shall assess the status quo BZ configuration and each alternative BZ configuration studied within the BZRR and compare these configurations by using the criteria listed below, which includes the minimum list of criteria set out in Article 33 of the CACM Regulation.
2. The TSOs in every BZRR shall use the following evaluation criteria:
 - (a) To assess network security:
 - i. operational security;
 - ii. security of supply; and
 - iii. degree of uncertainty in cross-zonal capacity calculation.
 - (b) To assess market efficiency:
 - i. increase or decrease in economic efficiency;

- ii. firmness costs;
 - iii. market liquidity and transaction costs;
 - iv. market concentration and market power, analysed separately for:
 - 1. the various market timeframes, from long-term to short-term markets; and
 - 2. the TSOs' mechanism to resolve physical congestions.
 - v. effective competition, differentiating between:
 - 1. short-term competition;
 - 2. long-term competition; and
 - 3. competition for cross-zonal capacity.
 - vi. price signals for building infrastructure;
 - vii. accuracy and robustness of price signals;
 - viii. transition costs;
 - ix. infrastructure costs;
 - x. market outcomes in comparison to corrective measures;
 - xi. adverse effects of internal transactions on other BZs; and
 - xii. impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.
- (c) To assess stability and robustness of BZs:
- i. stability and robustness of BZs over time;
 - ii. consistency across capacity calculation time frames;
 - iii. assignment of generation and load units to BZs; and
 - iv. location and frequency of congestion, market and grid.
- (d) To assess energy transition:
- i. short-term effects on CO₂ emissions;
 - ii. short-term effects on RES integration; and
 - iii. long-term effects on low-carbon investments.

Article 13. Evaluation: General approach and outcome of the BZ review

1. TSOs shall assess the performance of alternative BZ configurations in accordance with the following steps:
 - (a) Step 1: Monetised benefits
 - i. TSOs shall assess the monetised benefit of each alternative configuration which shall be equal to the sum of:
 1. the change in economic efficiency, as defined in Article 15.4; and
 2. as far as technically possible, the benefits, or losses, derived from other criteria that can be potentially monetised, such as the security of supply criterion pursuant to Article 15.2 or the sub-criterion related to the operation and efficiency of the

balancing mechanisms pursuant to Article 15.15(a). The aggregation of benefits, or losses, derived from various criteria shall be done consistently to avoid double counting.

- ii. The TSOs shall take the monetised value related to the ‘transition costs’ criterion separately into account to calculate the minimum lifetime of a BZ configuration, as described in point 1(d) of this article.
 - iii. Based on the monetised benefits of each alternative BZ configuration, compared to the status quo, the TSOs shall proceed as follows:
 1. If the monetised benefit compared to the status quo is negative, then TSOs may:
 - a. decide not to proceed with the next steps of the overall process, thus rejecting the said alternative BZ configuration; or
 - b. decide to proceed with next steps of the assessment if they can duly justify that further assessment is needed.
 2. If the monetised benefit compared to the status quo is not negative, then TSOs shall proceed to evaluate the alternative BZ configuration according to Step 2.
 3. To reflect the benefits from combining alternative BZ configurations, TSOs of a BZRR may generate additional alternative BZ configurations which simultaneously reflect the changes, with respect to the status quo, of two or more of the approved alternative BZ configurations. When doing so, TSOs shall combine alternative BZ configurations with positive monetised benefits compared to the status quo. TSOs shall then estimate the monetised benefits of the additional, combined, alternative BZ configurations compared to the status quo, and proceed with all other steps of the evaluation as for any other alternative BZ configuration.
 4. TSOs may also reject alternative BZ configurations that do not meet the requirement of unique and unambiguous assignment of generation and load units to BZs, pursuant to Article 15.18.
- (b) Step 2: Assessment of all other criteria
- i. For the BZ configurations that remain following Step 1, TSOs shall assess all other criteria, i.e. those not considered in Step 1, according to the evaluation approaches described in Article 15.
 - ii. Based on this assessment, TSOs shall conclude, for each criterion, on the performance on each alternative BZ configuration with regard to the status quo configuration. TSOs shall at least specify whether each alternative BZ configuration performs better, worse or the same¹¹ than the status quo BZ configuration. TSOs may jointly agree on a more detailed scale to grade the performance of the alternative BZ configurations which shall be consistently used for all other criteria, alternative BZ configurations and BZRRs.
 - iii. For each criterion and alternative configuration, TSOs shall provide a justification for the outcome of the individual assessment, including the following items:
 1. the quantitative values, related to the indicators defined in Article 15, that support the conclusions;

¹¹ E.g. respectively using the scale +/-0.

2. where applicable, a brief description of any qualitative analysis or considerations which complement the quantitative analysis, and how such analysis or considerations support the conclusions; and
 3. the identification of practical considerations, which need to be balanced with the need for expeditiousness when deciding on a BZ configuration change, as set forth in Article 14(10) of the Electricity Regulation.
- (c) Step 3: Acceptability assessment of the alternative BZ configurations
- i. In case for a given alternative BZ configuration all other criteria are assessed to perform better or the same as the status quo configuration pursuant to Step 2, the said alternative BZ configuration shall be deemed acceptable.
 - ii. For alternative BZ configurations that perform worse than the status quo configuration for at least one criteria pursuant to Step 2, TSOs shall perform an assessment of the acceptability of each of these configurations as follows:
 1. TSOs shall first perform an assessment aiming at identifying alternative BZ configurations that potentially perform below 'acceptable' levels. When performing this assessment, TSOs shall at least consider the following:
 - a. the relative performance of alternative configurations with regard to the status quo configuration, in light of the indicators envisaged in Step 2;
 - b. the relative performance of individual BZs (or BZRRs) of alternative BZ configurations compared to the BZs (or BZRRs) of the status quo, across the EU, in light of the indicators envisaged in Step 2; and
 - c. the need to consider all criteria assessed in Step 1 and Step 2, taken together, rather than considering each criterion individually.
 2. Based on the above-described assessment, TSOs shall draw a list of potentially 'unacceptable' configurations.
 3. Based on the aforementioned list, TSOs shall consult the relevant authorities. The consultation shall aim at collecting the relevant authorities' views on at least the following aspects:
 - a. whether the BZ configurations identified by TSOs as potentially performing below 'acceptable' levels should be deemed 'unacceptable', after considering possible measures to mitigate negative impacts related to certain criteria; and
 - b. whether, in light of the information provided by TSOs, other BZ configurations should be deemed as 'unacceptable', after considering possible measures to mitigate negative impacts related to certain criteria.
 4. As an input for the consultation to the relevant authorities, TSOs shall provide:
 - a. the outcome of the TSOs' assessment of each criterion pursuant to Step 1 and 2, including all justifications provided in point 1(b)iii of this article;
 - b. stakeholders' replies to the relevant aspects of the public consultation pursuant to Article 17.4; and
 - c. justifications on why certain configurations are considered as potentially 'unacceptable'.

- iii. TSOs shall draw a list of 'unacceptable' configurations, which shall be duly justified. Such a justification shall include the views of the relevant authorities and how those views have been taken into account.

(d) Step 4: Consolidation of the results of the BZR

- i. TSOs shall consolidate the results in one joint report for all BZRRs, and they shall publish the joint report according to Article 16 and Article 18 of this BZR Methodology.
- ii. TSOs shall include a recommendation on whether to maintain or amend the BZs, for each BZRR, in the joint report.

iii. When making the recommendation, the TSOs shall proceed as follows:

1. TSOs shall recommend to maintain the status quo BZs if there is no 'acceptable' alternative BZ configuration which leads to positive monetised benefits compared to the status quo; or
2. TSOs shall recommend to amend the BZs if at least one 'acceptable' alternative BZ configuration leads to positive monetised benefits compared to the status quo. This configuration shall be among the list of 'acceptable' configurations with positive monetised benefits compared to the status quo, and shall be, by default, the one with the highest monetised benefits compared to the status quo, for each BZRR.
3. Alternatively, TSOs may:
 - a. recommend an alternative BZ configuration, among the 'acceptable' ones but different from the one with the highest monetised benefits compared to the status quo, if they can duly justify the recommendation; or
 - b. recommend to maintain the status quo configuration, if they can duly justify that this is a better option than any of the 'acceptable' alternative BZ configurations.

iv. The results shall be consolidated in three different tables per BZRR, as follows:

1. A first table displaying all BZ configurations ranked according to decreasing monetised benefits compared to the status quo as calculated in Step 1. This table shall include the following information for all alternative BZ configurations:
 - a. the monetised benefits from the alternative BZ configuration as calculated in Step 1; and
 - b. additionally, for all 'acceptable' alternative BZ configurations:
 - the related transition costs as defined in Article 15.11; and
 - the minimum lifetime, in years, of the BZ configuration that would be needed to pay back the transition costs, in light of the monetised benefits compared to the status quo, and considering a discount rate.
2. A second table with the assessment of all other criteria that mainly refer to short-term effects of all alternative BZ configurations and that cannot be monetised pursuant to Step 2. This table shall at least include the following criteria and sub-criteria: *Operational security, market liquidity and transaction costs, market concentration and market power (from long-term to short-term markets), market concentration and market power (redispatching mechanism), facilitation of effective competition (short-term), adverse effects of internal transactions on other BZs, short-term effects on CO₂ emissions, and short-term effects on RES integration.*

3. A third table with the assessment of all other criteria that mainly refer to long-term effects of all alternative BZ configurations and that cannot be monetised pursuant to Step 2. This table shall at least include the following criteria and sub-criteria: *Facilitation of effective competition (long-term), facilitation of effective competition (relative access to cross-zonal capacity), price signals for building infrastructure, accuracy and robustness of price signals, infrastructure cost, impact on the imbalance settlement processes, stability and robustness of BZs over time¹², location and frequency of congestion (market and grid), and long-term effects on low-carbon investments.*
 4. Tables two and three shall at least include a conclusion on whether each alternative BZ configuration performs better, worse or the same, or a more detailed scale if agreed by all TSOs, than the status quo BZ configuration, as described in Step 2. A summarised justification for the outcome of the assessment of each criterion, as described in Step 2, may also be included.
 5. The above results shall refer to the results of the ‘main study’, i.e. considering the scenario and the reference climate years, as envisaged in Article 4.
 6. As far as technically possible, a breakdown of the results per MS shall also be provided.
 7. Annex Ib includes a template which may be used to consolidate the results of the BZR, for each BZRR.
2. When assessing the alternative BZ configurations in accordance with the steps 1 to 4 of paragraph 1 of this article:
 - (a) TSOs shall consider market design changes that are expected to be in place for the target year, in particular market design changes which may mitigate negative impacts of specific alternative BZ configurations with regard to any of the evaluation criteria. Those market design changes may be complemented with potential measures derived from the consultation among stakeholders and the relevant authorities pursuant to Step 3.
 - (b) TSOs shall assess alternative BZ configurations by mainly considering the scenario and the reference climate years pursuant to Article 4.4. In particular, the assessment shall lead to a single outcome per criterion, as defined in Article 15, and alternative BZ configuration, which constitute the results of the ‘main study’. Unless stated otherwise during the process to select reference climate years pursuant to Article 4.4, all reference climate years shall have the same weight in the single outcomes per criterion and configuration.
 - (c) TSOs shall present the results of all sensitivity analyses, conducted pursuant to Article 4.10, together with the final conclusions of the study, although clearly separated from the results of the ‘main study’.
 - (d) TSOs may conduct external studies, to perform or complement the evaluation of certain criteria. Criteria that may require external advice are suggested in Article 15.
 - (e) TSOs shall determine the geographical scope and granularity of the evaluation criteria pursuant to Article 14.
 - (f) TSOs shall evaluate each individual criterion in accordance with Article 15.

¹² The ‘Accuracy and robustness of price signals’, ‘Impact on the imbalance settlement processes’, and the ‘Stability and robustness of BZs over time’ criteria may be included in both the ‘short-term’ and ‘long-term’ effects table.

Article 14. Evaluation criteria: Geographical delimitation

1. Before assessing the alternative BZ configurations, the TSOs shall jointly agree on how to categorise the criteria according to the two following dimensions:
 - (a) The geographical scope of the assessment of the alternative BZ configurations with regard to each criterion, as follows:
 - i. for the ‘Economic efficiency’ criterion, the geographical scope shall be the EU; and
 - ii. for all other criteria, the geographical scope shall be, either:
 1. the EU; or
 2. the BZRR, if an alternative BZ configuration is deemed not to have significant impacts outside the BZRR.
 - (b) The granularity of the assessment with regard to each criterion, i.e. the level of disaggregation of the indicators associated to each criterion pursuant to Article 15, which shall be:
 - i. the entire geographical scope of the BZR, i.e. the EU, if one aggregated value is sufficient to reach conclusions for a given criterion; or
 - ii. the BZRR, if one aggregated value is sufficient to reach conclusions for a given criterion; or
 - iii. the BZ, if a value per BZ needs to be estimated to reach conclusions for a given criterion; or
 - iv. a combination of points 1(b)ii and 1(b)iii of this article, if e.g. a value per BZ inside the BZRR shall be given, while for BZs outside the BZRR, only one aggregated value shall be given; or
 - v. any of the above options and optionally a higher level of granularity to complement the analysis.
2. The categorisation agreed upon by the TSOs shall be the same for all BZRRs, except otherwise duly and jointly justified by TSOs.

Article 15. Evaluation approach per criterion

1. The ‘Operational security’ criterion shall be evaluated as follows:
 - (a) The assessment of the impact of alternative BZ configurations on operational security shall be based on the security analysis as described in Article 8 and shall consider the following two indicators:
 - i. the aggregated number of N and N-1 operational security violations before considering remedial actions; and
 - ii. a physical congestion index calculated as follows:

$$Cong.index(BZc) = \sum_{h=1}^H \sum_{i=1}^I (physical\ congestion_{i,h}),$$

with

BZc the zonal configuration under consideration;

h the hour under consideration;

H	the total number of hours in a year;
i	the network element under consideration whose forecasted flow before the application of remedial actions is above the thermal rating;
I	the number of network elements whose forecasted flow before the application of remedial actions is above the thermal rating for the considered hour;
$physical\ congestion_{i,h}$	any physical congestion identified pursuant to Article 8.5. It shall be calculated as the difference between the forecasted flows before the application of remedial actions and the thermal rating of the relevant network element, for the network element i during hour h, expressed in MW.

- (b) Interpretation of the results: A given BZ configuration is expected to:
- i. Perform better (respectively worse) than the status quo configuration with regard to the ‘Operational security’ criterion when either the two above described indicators show a lower (respectively higher) value for the said configuration than for the status quo one, or at least one of the two indicators shows a lower (respectively higher) value for the said BZ configuration while the other is the same as for the status quo configuration.
 - ii. Perform the same as the status quo configuration with regard to the ‘Operational security’ criterion in any other case.
2. The ‘Security of supply’ criterion shall be evaluated as follows:
- (a) The evaluation should at least be based on the following indicators:
- i. ‘LOLE’;
 - ii. ‘EENS’; and
 - iii. the monetised impact of the ENS, which should be calculated by combining the EENS and the VOLL, as envisaged in Article 11 of the Electricity Regulation.
- (b) The calculation process to estimate the above indicators should be probabilistic. Additionally, it should:
- i. Consider the network within and between BZs, i.e. the grid within BZs should not be considered as copper-plate networks. In particular, the assessment shall reflect the probabilistic EENS which may occur due to physical congestion in the internal network.
 - ii. Except for the consideration of the network, be aligned with the latest methodology of the European Resource Adequacy Assessment Methodology¹³.
 - iii. Be progressively implemented based on experienced gained from upcoming ERAAs and BZR.
- (c) Interpretation of the results:
- i. As far as technically possible, the ‘Security of supply’ criterion shall be monetised as above described, and therefore considered together with all other monetised criteria.

¹³ Envisaged in Article 23 of the IME Regulation.

- ii. Otherwise, and until the modelling tools to estimate the above described indicators are developed, the alternative BZ configurations may be considered to perform the same as the status quo with regard to the ‘*Security of supply*’ criterion.
3. The ‘*Degree of uncertainty in cross-zonal capacity calculation*’ criterion shall be evaluated as follows:
 - (a) The degree of uncertainty in cross-zonal capacity calculation shall relate to the FRMs of CNECs used in capacity calculation as described in Article 6.10.
 - (b) Interpretation of the results: As the FRMs are inputs for the capacity calculation process, which is in itself an input for the calculation of the ‘*Economic efficiency*’ criterion, pursuant to paragraph 4 of this article, the ‘*Degree of uncertainty in capacity calculation*’ criterion shall be considered as implicitly monetised, and therefore considered together with all other monetised indicators.
4. The ‘*Economic efficiency*’ criterion shall be evaluated as follows:
 - (a) The assessment of the economic efficiency shall be based on the change of socio-economic welfare, as follows:
 - i. For each alternative BZ configuration, the change in socio-economic welfare shall be calculated. This change refers to the difference between socio-economic welfare of the said BZ configuration and of the status quo BZ configuration, both calculated at the EU level.
 - ii. The change in socio-economic welfare shall be equal to the sum of:
 1. the change in the socio-economic welfare derived from the market dispatch, pursuant to Article 7; and
 2. the change in total additional costs derived from the RAO pursuant to Article 9.16.
 - iii. A breakdown of socio-economic welfare into producer surplus, consumer surplus and congestion revenue shall also be provided.
 - iv. As far as technically possible, a breakdown of socio-economic welfare per MS shall also be provided.
5. The ‘*Firmness cost*’ criterion shall be evaluated as follows:
 - (a) The assessment of firmness costs shall be based on the costs of guaranteeing that the cross-zonal capacity allocated to market participants remains unchanged.
 - (b) As the remedial action optimisation described in Article 9 assumes that the allocated cross-zonal capacity is always guaranteed by applying the necessary remedial actions, the firmness costs shall be considered as implicitly monetised in the ‘*Economic efficiency*’ criterion described in paragraph 4 of this article.
 - (c) Interpretation of the results: The ‘*Firmness cost*’ criterion is indirectly monetised as part of the ‘*Economic efficiency*’ criterion described in paragraph 4 of this article and therefore considered together with all other monetised indicators.
6. The ‘*Market liquidity and transaction costs*’ criterion shall be evaluated as follows:
 - (a) The assessment of the expected evolution of market liquidity and its impacts, including potential impacts on transaction costs, shall be performed for both the long-term timeframe, i.e. before the day-ahead timeframe, and the short-term timeframes, i.e. day-ahead and closer-to-real-time timeframes.
 - (b) The analysis of liquidity and transaction costs in long-term timeframes shall be based on a study, conducted for the whole EU, that aims to capture the impacts of long-term markets

liquidity, in particular on whether liquidity changes impact the existence of sufficient hedging opportunities for market participants. The analysis shall, at least, consider the following elements:

- i. A descriptive analysis of liquidity aiming to describe the starting point of market liquidity in the concerned BZs. The analysis shall at least include the following indicators:
 1. the volume of trade in organised and non-organised markets; and
 2. average of the lowest bid-ask spread per period that is relevant for market participants with hedging needs¹⁴, for the most frequently traded product(s).

Market depth indicators may also be used for the analysis.

- ii. A correlation analysis, aiming to describe the correlation of average day-ahead prices of the concerned BZ with average day-ahead prices of other BZs or BZ combinations. The correlation analysis shall at least be performed based on simple correlation indicators between the monthly average simulated day-ahead prices for the alternative BZ configurations and the status quo BZ configuration.
 - iii. To describe possible liquidity impacts because of expected changes in competition, the analysis shall also consider indicators related to the '*Market concentration and market power*' criterion, e.g. Herfindal-Hirschman-Index or the Residual Supply/ Pivotal Supplier Indexes, and to the organisation of retail markets, such as the number of retailers.
 - iv. A holistic analysis of the above numerical results shall be carried out in order to conclude whether a BZ reconfiguration is likely to result in increased/reduced hedging opportunities. In particular, an assessment of the impacts of changed hedging opportunities in a 'new' BZ may be based on a comparison with existing BZs of comparable characteristics. Where relevant, the assessment shall also consider the evolution of long-term markets liquidity, including hedging opportunities, in areas subject to recent changes of BZ configuration in Europe.
 - v. The analysis shall also identify practical considerations which may need to be considered in case of a possible BZ configuration change as set forth in Article 14(10) of the Electricity Regulation, including possible timescales for implementation of alternative BZ configurations. In doing so, the outcome of the public consultation conducted pursuant to Article 17.4 shall be considered.
 - vi. The perceived effects of alternative BZ configurations on market liquidity and transaction costs, based on the public consultation conducted pursuant to Article 17.4.
- (c) The analysis of liquidity and transaction costs in short-term markets timeframes shall be based on a study conducted at EU level. The analysis shall, at least, consider the following elements:
- i. Relevant liquidity indicators, which shall include:
 1. traded volumes; and
 2. churn ratios.

¹⁴ For example, the average of the lowest bid ask spread per week, or the average of the lowest bid-ask spread per month, depending on the period that is deemed as relevant for market participants' hedging needs.

- ii. Where relevant, the evolution of short-term markets liquidity in areas subject to recent changes of BZ configuration in Europe.
 - i. The possible effect of intra-company transactions on short-term liquidity following a BZ configuration change.
 - ii. The above mentioned study shall be conducted at least for the day-ahead timeframe. Additional short-term timeframes may also be studied.
- (d) In order to conclude on the effects of alternative BZ configurations on market liquidity and transaction costs, TSOs may request regulatory authorities' opinion on the matter, as part of the consultation pursuant to Article 17.2 and Article 17.3. If the relevant authorities are consulted, TSOs shall take their opinion duly into account.
- (e) Interpretation of the results: A given BZ configuration is expected to:
- i. Perform better (respectively worse) than the status quo configuration with regard to the 'Market liquidity and transaction costs' criterion when the analysis of liquidity for both long-term and short-term timeframes suggests that either:
 - 1. the two timeframes perform better (respectively worse) than the status quo configuration with respect to liquidity; or
 - 2. at least one of the two timeframes performs better (respectively worse) than the status quo configuration, while the performance of the other timeframe remains the same as for the status quo configuration.
 - ii. Perform the same as the status quo configuration with regard to the 'Market liquidity and transaction costs' criterion in any other case.
7. The 'Market concentration and market power' criterion shall be split into the following sub-criteria: i) 'Market concentration and market power in the wholesale markets (from long-term to short-term markets)' and ii) 'Market concentration and market power in the TSOs' mechanisms to resolve physical congestions'. The analysis of the two sub-criteria shall be made as follows:
- (a) The evaluation of market concentration shall be made by using, at least, one of the following two types of indicators:
- i. Herfindal-Hirschman-Index (HHI). For each BZ, an annual HHI shall be calculated as a time-weighted average HHI, considering that the relevant market price area may be different during each hour. For each hour, the relevant market price area shall be equal to the largest set of BZs which are interconnected and whose day-ahead price is identical. The index shall be calculated using the following formula:

$$HHI_{BZ i}^{year y} = \frac{\sum_{h=1}^{8760} HHI_{price\ area\ of\ BZ i}^{hour h}}{8760}$$

with

HHI calculated for a given price area as $\sum_{i=1}^n Si^2$;

Si the market share of installed capacity for firm i, over total installed capacity and interconnector capacity; moreover, the interconnector capacity shall be considered as a set of firms with the same concentration as in the neighbouring market.

- ii. Residual Supply/ Pivotal Supplier Indexes (RSI/PSI). RSI shall be calculated, at least, for the largest player per hour, as follows:

$$RSI_{player\ i}^{hour\ t} = \frac{\text{Total capacity} - \text{Company } i\text{'s relevant capacity}}{\frac{\text{Total demand}}{\sum_{player\ j \neq i} \text{ProductionCapacity}_j \times \text{Availability}_j + \text{Import capacity}}} \times \frac{\text{Load}^t + \text{TSO reserve Requirement}^t}{\text{Load}^t + \text{TSO reserve Requirement}^t}$$

Based on the above hourly index, two annual indicators shall then be derived for at least the largest player I, as follows:

$$RSI_{player\ i}^{year\ y} = \frac{\sum_{t=1}^T RSI_{player\ i}^{hour\ t}}{T}$$

$PSI_{player\ i}^{year\ y}$: estimated as the % hours when $RSI < 1$ for a certain player i.

- (b) Interpretation of the results: The interpretation of the results shall be as follows:
- i. The above indicators shall be used to identify the timeframes where it is more likely that market power issues might arise, i.e. either in the organised markets or in the TSOs' processes to resolve physical congestions.
 - ii. For each alternative BZ configuration, two conclusions, one for each of the sub-criteria mentioned above, shall be obtained.
 1. When the HHI values tend to be higher (lower) for a BZ configuration than for the status quo configuration; or
 2. When the RSI/PSI values tend to be lower (higher) for a BZ configuration than for the status quo configuration;

it shall be concluded that:

 - a. higher (respectively lower) levels of market concentration and, potentially, scope for market power can be expected in the wholesale markets (from long-term to short-term markets) than in the status quo configuration; and
 - b. lower (respectively higher) levels of market concentration and, potentially, scope for market power can be expected in the TSOs' mechanisms to resolve physical congestions, i.e. in the redispatching mechanisms, than in the status quo configuration.
8. The 'Facilitation of effective competition' criterion shall be split into the following three different sub-criteria, which shall be separately assessed: 'Short-term competition', 'Long-term competition' and 'Competition for cross-zonal capacity'.
- (a) The assessment of short-term competition shall be based on the comparison of the results of two other criteria:
 - i. 'Market liquidity and transaction costs'; and
 - ii. 'Market concentration and market power'.
 - (b) The assessment of long-term competition shall be based on the comparison of the results of two other criteria:
 - i. 'Accuracy and robustness of price signals'; and
 - ii. 'Price signals for building infrastructure'.

- (c) The assessment of competition for cross-zonal capacity shall aim to analyse whether structural differences in zonal PTDFs may lead to competitive disadvantages for certain BZs. In order to perform the analysis, the following indicator shall be used:

$$\sigma \left[\mu \left| PTDF_{BZ_i-BZ_j} \right| \right]$$

with

σ	the standard deviation over all pairs of BZs within the CCR;
μ	the arithmetic average over all CNECs considered in capacity calculation within a CCR for a given pair of BZs;
$\left PTDF_{BZ_i-BZ_j} \right $	the absolute value of the zone-to-zone PTDF for two given BZs i and j and for a given CNEC;
i, j	pair of BZs within a CCR.

The above described indicator shall be at least calculated for all CCRs where PTDFs are computed for the purpose of capacity calculation.

- (d) Interpretation of the results: A given BZ configuration shall be expected to:
- i. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Short-term competition*’ sub-criterion when the analysis of the criteria i) ‘*Market liquidity and transaction costs*’ and ii) ‘*Market concentration and market power*’ suggest that either a BZ configuration performs better (respectively worse) with respect to both these criteria or that at least it performs better (respectively worse) with regard to one of the two criteria while the performance of the other criterion remains the same as for the status quo configuration. In any other case, it shall be expected to perform the same as the status quo configuration.
 - ii. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Long-term competition*’ sub-criterion when the analysis of the criteria: i) ‘*Accuracy and robustness of price signals*’ and ii) ‘*Price signals for building infrastructure*’ suggest that either a BZ configuration performs better (respectively worse) with respect to both criteria or that at least it performs better (respectively worse) with regard to one of the two criteria while the performance of the other criterion remains the same as for the status quo configuration. In any other case, it shall be expected to perform the same as the status quo configuration.
 - iii. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Competition for cross-zonal capacity*’ sub-criterion, when the indicator associated to the relevant sub-criterion shows a lower (respectively higher) value for the said configuration than for the status quo one.
9. The ‘*Price signals for building infrastructure*’ criterion shall be evaluated as follows:
- (a) Infrastructure refers both to
 - i. generation or demand assets; and
 - ii. network infrastructure.
 - (b) In order for prices to give relevant signals to build generation and demand assets in a cost-efficient manner, prices shall be accurate and robust. Therefore, the ability of prices to promote efficient investments in generation and demand assets shall be based on the results

of the ‘*Accuracy and robustness of price signals*’ criterion, pursuant to paragraph 10 of this article.

- (c) In order for prices to give relevant signals to build network infrastructure, physical congestions should be preferably dealt with in the market. This shall be evaluated by using the following indicator:

Percentage of time when the physical congestion was not previously detected in the day-ahead market, i.e. the percentage of time when physical congestion (or no remaining physical capacity) was detected in a given network element, following the operational security analysis pursuant to Article 8, while market congestion, for the said network element, was not identified following the day-ahead market dispatch pursuant to Article 7.

‘Market congestions’ refers to Article 2(17) of the CACM Regulation, i.e. to market time units when there is a least one constraint, with a shadow price, which actively limits cross-zonal exchanges during capacity allocation. Such a constraint may be a cross-zonal or internal line, or an allocation constraint, based on the day-ahead market simulations, pursuant to Article 7.

- (d) Interpretation of the results: In order to conclude on this criterion, the two aspects included in points 9(b) and 9(c) of this article shall be considered, as follows:

- i. A given BZ configuration shall be expected to perform better (respectively worse) with regard to the indicator included in point 9(c) of this article, when the said indicator shows a lower (respectively higher) value for the said configuration than for the status quo one.
- ii. A BZ configuration shall be expected to perform better (respectively worse) than the status quo configuration with regard to the ‘*Price signals for building infrastructure*’ criterion when it performs better (respectively worse) with regard to both the above mentioned aspects or that at least it performs better (respectively worse) with regard to one of the aspects while the performance of the other aspect remains the same as for the status quo configuration.
- iii. In any other case, it shall be expected to perform the same as the status quo configuration.

10. The ‘*Accuracy and robustness of price signals*’ criterion shall be evaluated as follows:

- (a) Prices are accurate and robust when a majority of market participants, i.e. participating to day-ahead markets and/or using the day-ahead price as the main price reference, perceive the benefits of reacting to the actual needs of the system at the precise location and point in time.
- (b) The accuracy and robustness of price signals shall be measured by using the following indicator:

For the geographical areas comprised within ‘new’ BZs of each alternative BZ configuration, the correlation between volume-weighted average nodal prices, pursuant to Article 11 and the zonal day-ahead market prices in the said area. The correlation shall be then compared to the correlation for the same geographical area in the status quo, i.e. the nodal prices used for the former correlation would be the same as for the latter, but the zonal prices would differ.

- (c) Interpretation of the results: A given BZ configuration shall be expected to:
 - i. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Accuracy and robustness of price signals*’ criterion when the indicator above described

shows a higher (respectively lower) value for the said configuration than for the status quo one.

ii. In any other case, it shall be expected to perform the same as the status quo configuration.

11. The '*Transition costs*' criterion shall be evaluated as follows:

(a) Transition costs refer to the one-off costs expected to be incurred in case the BZ configuration is amended. In particular, transition costs:

i. Shall relate to adaptations that are inherently and unambiguously related to a specific BZ configuration change.

ii. Shall include an estimation of the cost of amending existing contractual obligations incurred by market participants, NEMOs and TSOs. Such estimation shall reflect the expected implementation timeline for an eventual BZ change, and the fact that when deciding on the implementation date, MSs are required to balance the need for expeditiousness with practical considerations, including forward trade of electricity.

iii. Shall not relate to adaptations that are, in general, necessary to ensure sufficient flexibility of the systems to cope with a variable number of BZs due to a potential amendment of the BZ configuration in the future.

iv. In order to identify and possibly estimate transition costs, a study shall be jointly performed for all BZRRs. The study shall aim to provide an overview of necessary adaptations and possibly a range of related cost estimates. The study shall also consider stakeholders' replies to the public consultation conducted pursuant to Article 17.4.

(b) The resulting estimates shall be considered to calculate the minimum 'lifetime', in years, of a BZ configuration, as described in Step 4 in Article 13.1(d).

12. The '*Infrastructure cost*' criterion shall be evaluated as follows:

(a) Infrastructure costs should preferably be estimated by modelling the effect of BZ configurations on investment decisions, e.g. on generation or demand assets, and on the need to build, or not, network infrastructure to address congestions in a cost-efficient manner.

(b) In the absence of modelling tools able to robustly assess the aspects mentioned in point 12(a) of this article, the assessment of the '*Infrastructure cost*' criterion shall be based on the comparison of the results of two other criteria: i) '*Accuracy and robustness of price signals*' and ii) '*Price signals for building infrastructure*'.

(c) Interpretation of the results: A given BZ configuration is expected to:

i. Perform better (respectively worse) than the status quo configuration with regard to the '*Infrastructure cost*' criterion when the analysis of the criteria i) '*Accuracy and robustness of price signals*' and ii) '*Price signals for building infrastructure*' suggest that either a BZ configuration performs better (respectively worse) with respect to both these criteria or that at least it performs better (respectively worse) with regard to one of the two criteria while the performance of the other criterion remains the same as for the status quo configuration.

ii. In any other case, it shall be expected to perform the same as the status quo configuration.

13. The '*Market outcomes in comparison to corrective measures*' criterion shall be evaluated as follows:

- (a) Corrective measures refer to the remedial actions that are applied to solve all operational security violations pursuant to Article 8.5.
 - (b) Consequently, the evaluation of the '*Market outcomes in comparison to corrective measures*' criterion shall be performed by calculating the total remedial action costs as envisaged in Article 9 and shall be evaluated together with the socio-economic welfare derived from the market dispatch as envisaged in Article 7. This joint evaluation corresponds to the assessment of the '*Economic efficiency*' criterion, as described in paragraph 4 of this article.
14. The '*Adverse effects of internal transactions on other BZs*' criterion shall be evaluated as follows:
- (a) The adverse effects of internal transactions on other BZs shall be assessed based on:
 - i. The analysis of flows not induced by cross-zonal trade as described in Article 10. In particular, the assessment of these adverse effects shall be estimated by using the following two indicators:
 - 1. *Average share of loop flows on network elements*, with either a market congestion following the day-ahead market dispatch, or with physical congestion during the operational security analysis following the day-ahead market dispatch pursuant to Article 7.
 - 2. *Number of occurrences (hours) with loop flows, on all network elements, higher than a given threshold*, expressed as a percentage of Fmax, and agreed upon by all TSOs of a CCR.

Loop flows shall be calculated according to the flow decomposition methods and on the CGMs pursuant to Article 10.1.
 - ii. Impacts derived from inaccurate price signals, due to flows not induced by cross-zonal trade, potentially leading to inefficient investments in other BZs. These impacts are assessed through the '*Accuracy and robustness of price signals*' and the '*Price signals for building infrastructure*' criteria.
 - (b) Interpretation of the results:
 - i. A given BZ configuration is expected to:
 - 1. Perform better (respectively worse) than the status quo configuration with regard to '*Adverse effects of internal transactions on other BZs*' criterion when, either the two above described indicators show a lower (respectively higher) value for the said configuration than for the status quo one, or at least one of the two indicators shows a lower (respectively higher) value for the said BZ configuration, while the other is the same as for the status quo configuration.
 - 2. Perform the same as the status quo configuration with regard to the '*Adverse effects of internal transactions on other BZs*' criterion in any other case.
 - ii. The presence, or lack, of adverse impacts related to the '*Accuracy and robustness of price signals*' criterion shall also be included as 'other considerations', when justifying the outcome of the assessment of the '*Adverse effects of internal transactions on other BZs*' criterion, pursuant to Article 13.1(b)iii.2.
15. The '*Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes*' criterion shall be split into two different sub-criteria which shall be separately assessed: i) '*Operation and efficiency of the balancing mechanisms*' and ii) '*Imbalance settlement processes*'.

- (a) The assessment of the operation and efficiency of the balancing mechanism should be based on the calculation of the socio-economic welfare in the balancing timeframe as follows:
- i. For each alternative BZ configuration, the change in socio-economic welfare in the balancing timeframe shall be calculated. This change shall refer to the difference between socio-economic welfare of the said BZ configuration and of the status quo BZ configuration.
 - ii. The estimation of socio-economic welfare in the balancing timeframe shall consider the following elements:
 1. The estimated balancing capacity reservation costs, which shall be based on the expected reserve requirements for each alternative BZ configuration and be equal to the sum of the expected opportunity costs reflected in the capacity bids of BSPs to cover the reserve requirements.
 2. The socio-economic welfare related to the co-optimisation of balancing capacity and day-ahead energy, i.e. that cross-zonal capacity for the exchange of balancing capacity is allocated based on a comparison of the day-ahead market curves and balancing capacity bids in each BZ.
 3. The costs related to the activation of balancing energy, defined as the costs incurred by BSPs when they are activated by TSOs to keep the system in balance. This analysis requires making an assumption on the system imbalance volumes and their geographical distribution, per MTU, for the target year. In case TSOs are unable to estimate system imbalance volumes, TSOs may consider all BRPs to be always in balance according to the results of the day-ahead market dispatch pursuant to Article 7.
 4. The effects on remedial actions, and related costs, to consider how the geographical distribution of the reserves impacts the need for TSOs' actions to prevent violations of OSLs. To enable this analysis, TSOs shall:
 - a. First, estimate how the reservation of balancing capacity impacts the amount of capacity available on network elements to accommodate flows from commercial exchanges. Such an estimation implies that in order to quantitatively assess the operation and efficiency of the balancing mechanism sub-criterion, FRMs on CNECs shall not be considered as uniform as envisaged in Article 6.10(b), but rather computed as envisaged in Article 6.10(a).
 - b. Second, use such information as an input for the modelling chain described in Article 5 to Article 9.
 - iii. The assessment of the '*Imbalance settlement processes*' sub-criterion shall consider the following:
 1. It shall refer to the accuracy and robustness of imbalance prices to incentivise BRPs to support an efficient balancing of the system when and where they are needed.
 2. The above mentioned assessment shall be based on the results of the '*Accuracy and robustness of price signals*' criterion.
- (b) Interpretation of the results:
- i. With respect to '*Operation and efficiency of the balancing mechanisms*' sub-criterion: As far as technically possible, this sub-criterion is expected to be monetised as above described, and therefore considered together with all other monetised indicators.

Otherwise, and until the process to estimate the above-described indicators is in place, the alternative BZ configurations may be considered to perform the same as the status quo configuration with regard to operation and efficiency of the balancing mechanisms sub-criterion.

- ii. With respect to ‘*Imbalance settlement processes*’ sub-criterion: A given BZ configurations is expected to perform better (worse, or the same) than the status quo configuration when it performs better (respectively worse or the same) with regard to the ‘*Accuracy and robustness of price signals*’ criterion.
16. The ‘*Stability and robustness of BZs over time*’ criterion shall be evaluated as follows:
- (a) The assessment of the ‘*Stability and robustness of BZs over time*’ criterion shall be based on, at least, the evaluation of the ‘*Economic efficiency*’ criterion in line with paragraph 4 of this article, for each of the sensitivity analyses pursuant to Article 4.10.
 - (b) Interpretation of the results: A given BZ configuration shall be expected to:
 - i. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Stability and robustness of BZs over time*’ criterion when:
 1. the evaluation of the ‘*Economic efficiency*’ criterion leads to a positive change in socio-economic welfare compared to the status quo configuration for the majority of sensitivities considered; or
 2. having analysed all criteria, TSOs conclude that the said BZ configuration performs better (respectively worse) than the status quo configuration for the majority of sensitivities considered.
 - ii. Performs the same as the status quo configuration with regard to the ‘*Stability and robustness of BZs over time*’ criterion in any other case.
17. The ‘*Consistency across capacity calculation time frames*’ criterion shall be evaluated as follows: The impact of alternative BZ configurations on this criterion shall not be considered as dependant on the BZ configuration since the consistency across capacity calculation timeframes is a regulatory requirement. Alternative BZ configurations shall thus perform the same as the status quo configuration with regard to this criterion.
18. The ‘*Assignment of generation and load units to BZs*’ criterion shall be evaluated as follows: The impact of alternative BZ configurations on this criterion shall be considered as a prerequisite for the effective operation of a given BZ configuration. In this respect, the unique and unambiguous assignment of generation and load units to a BZ should be addressed when proposing alternative BZ configurations to be studied in the BZR. In order to confirm that all alternative BZ configurations meet this prerequisite, the fulfilment of this criterion shall be assessed during the BZR; in case this requisite is not met, then the alternative BZ configuration may be ‘rejected’ as part of Step 1 of the assessment, pursuant to Article 13.1(a)iii.4; otherwise, an alternative BZ configuration shall be considered to perform the same as the status quo configuration with regard to this criterion.
19. The ‘*Location and frequency of congestion (market and grid)*’ criterion shall be evaluated as follows:
- (a) The evaluation of the ‘*Location and frequency of congestion (market and grid)*’ criterion shall be made by using the following two indicators:
 - i. *Percentage of time when the physical congestion was not previously detected in the day-ahead market*, pursuant to point 9(c) of this article; and
 - ii. the share of market congestions which occurred on cross-zonal network elements over the total market congestions on internal and cross-zonal network elements, as follows:

$$\begin{aligned} & \text{Share of market congestions on BZ borders} \\ &= \frac{\sum_1^N \text{number of market congestions on cross – zonal lines}}{\sum_{t=1}^{8760} \text{total number of market congestions}} \end{aligned}$$

with

N, the number of simulated MTUs.

- (b) Interpretation of the results: A given BZ configuration is expected to:
- i. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Location and frequency of congestion (market and grid)*’ criterion when the two indicators above described show:
 1. a better (respectively worse) performance for the two indicators, compared to the status quo configuration, meaning a lower (respectively higher) value for the ‘*Percentage of time when the physical congestion was not previously detected in the day-ahead market*’ indicator and a higher (respectively lower) value for the share of market congestions which occurred on cross-zonal network elements over the total market congestions on internal and cross-zonal network elements; or
 2. one of the two indicators shows a better (respectively worse) performance, while the other indicators shows the same performance as for the status quo configuration.
 - ii. Perform the same as the status quo configuration with regard to the ‘*Location and frequency of congestion (market and grid)*’ criterion in any other case.
20. The ‘*Short-term effects on CO₂ emissions*’ criterion shall be evaluated as follows:
- (a) The assessment of the ‘*Short-term effects on CO₂ emissions*’ criterion shall be based on the simulated overall volume of CO₂ emissions, after optimisation of remedial actions, for the different BZ configurations under investigation.
 - (b) Interpretation of the results: A given BZ configuration shall be expected to perform better (respectively worse) than the status quo configuration with regard to the ‘*Short-term effects on CO₂ emissions*’ criterion when the overall volume of CO₂ emissions for the said BZ configuration is lower (respectively higher) than for the status quo one. If the overall volume of CO₂ emissions is the same as in the status quo configuration, the said configuration shall be considered to perform the same as the status quo configuration.
21. The ‘*Short-term effects on RES integration*’ criterion shall be evaluated as follows:
- (a) The assessment of the ‘*Short-term effects on RES integration*’ criterion shall be based on the total amount of simulated fed-in energy from RES, after optimisation of remedial actions, for the different BZ configurations under investigation.
 - (b) Interpretation of the results: A given BZ configuration shall be expected to perform better (respectively worse) than the status quo configuration with regard to the ‘*Short-term effects on RES integration*’ criterion when the total amount of simulated fed-in energy quantities from RES for the said BZ configurations is higher (respectively lower) than for the status quo one. If the fed-in energy quantities from RES are the same as in the status quo configuration, the said configuration shall be considered to perform the same as the status quo configuration.
22. The ‘*Long-term effects on low-carbon investments*’ criterion shall be evaluated as follows:
- (a) The assessment of the ‘*Long-term effects on low-carbon investments*’ criterion shall be based on the comparison of the results of two other criteria: i) ‘*Accuracy and robustness of price signals*’ and ii) ‘*Price signals for building infrastructure*’.

- (b) Interpretation of the results: A given BZ configuration shall be expected to:
- i. Perform better (respectively worse) than the status quo configuration with regard to the ‘*Long-term effects on low-carbon investments*’ criterion when the analysis of the criteria i) ‘*Accuracy and robustness of price signals*’ and ii) ‘*Price signals for building infrastructure*’ suggest that either a BZ configuration performs better (respectively worse) with respect to both these criteria or that at least it performs better (respectively worse) with regard to one of the two criteria while the performance of the other criterion remains the same as for the status quo configuration.
 - ii. Performs the same as the status quo configuration with regard to the ‘*Long-term effects on low-carbon investments*’ criterion in any other case.

Article 16. Transparency

1. TSOs shall jointly ensure the publication of all relevant information concerning the BZR, including scenario, assumptions, input and output data, parameters and all other relevant information, quantitative or qualitative, used or generated during the BZR, with the exception of confidential information according to paragraph 3 of this article.
2. A list of the minimum set of data to be published pursuant to this article is included in Annex Ia.
3. Any confidential information received, exchanged or transmitted pursuant to this BZR methodology shall be managed in accordance with Article 13 of the CACM Regulation and the procedure to ensure its protection.
4. Where information is confidential under a given jurisdiction, this shall not prevent that information from being published in other jurisdictions.
5. Confidential information under a given jurisdiction shall be published, for that jurisdiction, with the minimum level of aggregation, protecting confidentiality interests.
6. All information concerning a given jurisdiction shall be disclosed to the respective regulatory authorities, and to ACER.
7. The following deadlines for the publication of data, shall apply:
 - (a) all inputs for the BZR shall be published no later than 4 months after the BZR starts; and
 - (b) all outputs of the BZR shall be published no later than one month after the BZR ends.

Article 17. Stakeholder involvement and consultation

1. TSOs shall involve stakeholders during the BZR. This shall include scheduling regular meetings with stakeholders to inform on the progress of the BZR, including on the difficulties encountered during the process, and collecting feedback from stakeholders. These meetings shall not replace the stakeholder consultations in accordance with this Article.
2. Two months after the BZR starts, TSOs shall submit all information used as an input for the BZR, pursuant to Article 16, to regulatory authorities and to ACER. The TSOs shall submit:
 - (a) all detailed information of their respective jurisdictions, including input data, scenario, sensitivities, assumptions, parameters, etc.; and

- (b) information of all other jurisdictions, including input data, scenario, sensitivities, assumptions, parameters, etc., subject to a minimum level of aggregation in case of confidentiality concerns pursuant to applicable legislation.
- 3. Following the submission of information pursuant to paragraph 2 of this article, regulatory authorities and ACER may submit comments on the submitted data to TSOs within six weeks. TSOs shall duly consider the comments of regulatory authorities and ACER. TSOs shall provide a clear and robust justification on how the comments were taken into account. Such a justification shall be published in a timely manner before or simultaneously with the publication of all information used as an input for the BZR, pursuant to Article 16.7(a).
- 4. No later than six months after the start of the BZR, TSOs of a BZRR shall hold a public consultation regarding at least the following aspects of the BZR:
 - (a) the impacts of alternative BZ configurations on at least the following criteria: ‘*Market liquidity and transaction costs*’ and ‘*Transition costs*’;
 - (b) possible measures to mitigate negative impacts of specific alternative BZ configurations with regard to at least the criteria listed in point 4(a) of this article; and
 - (c) the identification of practical considerations which may need to be considered in case of a possible BZ configuration change as set forth in Article 14(10) of the Electricity Regulation, including possible timescales for implementation of alternative BZ configurations.
- 5. The responses related to points 4(a) and 4(b) of this article, linked to the above-mentioned public consultation, shall be used for the assessment on the acceptability of alternative BZ configurations to be performed by the relevant authorities, in accordance with Article 13.1(c)ii.3.
- 6. The responses related to point 4(c) of this article, linked to the above-mentioned public consultation, shall be used as an input for TSOs to identify practical considerations when deciding on a BZ configuration change, as described in Article 13.1(b)iii.3.

Article 18. Coordination among BZRRs

- 1. The TSOs shall jointly ensure coordination among the different BZRRs when performing the BZR, in particular the TSOs shall perform the following activities in a coordinated manner:
 - (a) When performing consultations, TSOs shall:
 - i. conduct such consultations simultaneously for all BZRRs;
 - ii. use the same platform for all BZRRs; and
 - iii. define the same scope and use a harmonised structure and format of the consultations for all BZRRs.
 - (b) When publishing or disclosing data, TSOs shall:
 - i. publish or disclose such data simultaneously for all BZRRs; and
 - ii. use the same publication formats for all BZRRs.
 - (c) When publishing the final report, which shall include the proposals to amend or maintain the BZ configuration, TSOs shall:
 - i. consolidate the results of the BZ review in one single report for all BZRRs;
 - ii. use for all BZRRs the same structure and layout of the different parts of the final report referring to different BZRRs; and

- iii. include in the report all the elements described in Article 13.1(d).
- (d) TSOs shall jointly agree on at least the following aspects of the BZR:
 - i. on the three reference climate years to assess BZ configurations, pursuant to Article 4;
 - ii. on the definition of internal CNECs used in capacity calculation, pursuant to Article 6;
 - iii. on the geographical scope of perfect and imperfect coordination of remedial actions and when such coordination of remedial actions is expected to be (gradually) implemented, pursuant to Article 9;
 - iv. on the scale adopted to grade the performance of alternative BZ configurations, pursuant to Article 13;
 - v. on the geographical scope and the geographical granularity of the assessment of the alternative BZ configurations with regard to each criterion, pursuant to Article 14; and
 - vi. on any other aspect throughout this BZR Methodology for which the joint agreement of TSOs is required.
- (e) With regard to the assessment of criteria pursuant to Article 15, TSOs shall:
 - i. jointly ensure the harmonised use of the indicators for each criterion across all BZRRs; and
 - ii. when relevant, jointly conduct or commission studies at the EU level.

Article 19. Publication of the BZR Methodology

The TSOs shall publish the BZR Methodology without undue delay after the BZR Methodology has been approved in accordance with Article 14(5) of the Electricity Regulation.

Article 20. Miscellaneous

The reference language for the BZR Methodology shall be English. For the avoidance of doubt, where the relevant TSOs need to translate the BZR Methodology into their national language(s), in the event of inconsistencies between the English version and any version in another language, the relevant TSOs shall dispel any inconsistencies by providing a revised translation of the BZR Methodology to their relevant regulatory authorities.

ACER Decision on the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered: Annex Ia

List of minimum data to be published

At least the following data shall be published in accordance with Article 16 of the BZR methodology as per Annex I of Decision No 29/2020:

A. Input data

Where the same input data, or the same assumptions, and disaggregation methods per node are not used for both the modelling chain to assess BZ configurations and for the LMP simulations, any differences between these two set of simulations shall be highlighted when publishing the input data.

1. Scenario (Article 4)

- a. List of all climate years used as a basis for the study.
- b. Description of the sensitivities used to complement the scenario of the ‘main study’.
- c. Network model for the scenario and sensitivities¹.
- d. List of additional infrastructure projects for the target year compared to the year when the BZR starts. Alternatively, the main changes applied to the TYDNP latest available reference grid model, if the latter is used as a starting point to reflect the target year.
- e. Assumptions on how different voltage levels were considered or not, per bidding zone.

2. Generation

Data item	Level of granularity ²	Corresponding article in the methodology
a. Generation time series for weather-dependent generation units	Climate year, MTU, generation unit (or the maximum level of disaggregation available)	Article 4
b. Minimum and maximum generating capacities	Generation unit	Article 4
c. Must-run constraints	Generation unit	Article 4
a. Ramping capabilities	Generation unit	Article 4
b. Minimum run-time	Generation unit	Article 4
c. Start-up and shut-down times	Generation unit	Article 4

¹ Individual TSOs may withhold the information on network models if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. In such a case, the information on network models shall be replaced with an anonymous identifier which shall be stable across all MTUs and all network models used throughout the BZR.

² Generation and load data shall at least be published with a level of aggregation per technology and per bidding zone. Upon request, the level of granularity described in the respective generation and load tables shall apply.

d. Start-up costs	Generation unit	Article 7, 9
e. Breakdown of short-run marginal costs used for the market dispatch, including at least fuel costs, CO2 costs and variable operation and maintenance costs	Generation unit	Article 7, 9
f. Additional costs used for the redispatching mechanism including specific opportunity costs, readiness costs and any other cost related to the participation to redispatching	Generation unit	Article 7, 9

3. Load

Data item	Level of granularity	Corresponding article in the methodology
a. Load time series	Climate year	Article 4
b. Day-ahead demand elasticity ³ .	Implicit DSR, bidding zone	Article 4
c. Maximum power [MW] which may respond	Explicit DSR unit	Article 4
d. Minimum price [€/MWh] at which the response is triggered	Explicit DSR unit	Article 4
e. Maximum activation duration [h]	Explicit DSR unit	Article 4
f. Maximum activated energy per day [MWh]	Explicit DSR unit	Article 4
g. Average amount of DSR [MW] available for the market dispatch	Bidding zone	Article 7
h. Average amount of explicit DSR [MW] not available for redispatching after considering market dispatch and technical constraints	Bidding zone	Article 9
i. Average amount of DSR [MW] available for neither of them	Bidding zone	Article 4,7,9

4. Reserves (Article 4)

- a. Per reserve type, per technology and per bidding zone:
 - i. FCR requirement [MW];

³ In case of several elasticities, also price ranges for which each elasticity value applies.

- ii. FRR requirement [MW]; and
- iii. RR requirement [MW]

5. Capacity calculation (Article 6)

- a. Capacity calculation methodology per border.
- b. List of action plans and derogations for the target year considered pursuant to the IME Regulation.
- c. Average FRM over all CNECs, per BZ.
- d. PTDF thresholds used by each TSO and, if different from default value, why the adopted threshold better reflects an economic efficiency analysis.
- e. Allocation constraints per border/BZ.

6. Miscellaneous

- a. List and brief description of the main characteristics of the modelling tools used for the analysis.
- b. All other assumptions and parameters set at pan-European or BZRR level with an impact on the results of the BZR.

B. Output data

Output data shall be published for each BZ configuration, including the status quo.

1. Capacity calculation (Article 6)

Data item	Level of granularity
a. NTC value [MW] per direction	Scenario, NTC BZ border and MTU
b. List of CNECs with zonal PTDFs and RAM	Scenario, flow-based BZ border and MTU
c. Allocation constraints	Scenario, BZ border and MTU
d. List of remedial actions applied during capacity calculation and the network model resulting from their implementation	Scenario, BZ border and MTU

2. Day-ahead market dispatch (Article 7)

Data item	Level of granularity
a. The total socio-economic welfare [€]	The whole EU, MTU
b. The utility of supplied demand [€]	The whole EU, MTU
c. The total generation cost [€]	The whole EU, MTU
d. The overall congestion revenue [€]	The whole EU, MTU

e. The production [MW]	The whole EU, MTU, generation unit
f. Average amount of generation [MW] available for the market dispatch	Bidding zone
g. Average amount of generation [MW] not available for redispatching after considering market dispatch and technical constraints	Bidding zone
h. Average amount of generation [MW] available for neither of them (e.g. due to mothballing or planned maintenance)	Bidding zone
i. The injection or withdrawal [MW]	The whole EU, MTU, storage unit
j. The activated DSR [MW]	The whole EU, MTU, DSR unit
k. The change in load due to demand elasticity [MW]	The whole EU, MTU
l. The amount of load-shedding [MW]	Bidding zone, MTU
m. The short-run marginal cost [€/MWh]	Bidding zone, MTU
n. The net positions [MW]	Bidding zone, MTU
o. The cross-zonal exchange [MW]	The whole EU, MTU, bidding zone border
p. The flow [MW] and the shadow price [€/MW]	The whole EU, MTU, CNEC

3. Operational security analysis (Article 8)

Data item	Level of granularity
a. The precise network configuration(s) when the violation occurs	Scenario, MTU and violation of an OSL
b. The kind of OSL violated	Scenario, MTU and violation of an OSL
c. The network element affected by the violation	Scenario, MTU and violation of an OSL
d. The OSL of the network element	Scenario, MTU and violation of an OSL
e. The value of the violation	Scenario, MTU and violation of an OSL

4. Remedial action optimisation (Article 9)

Data item	Level of granularity
a. The additional cost from the RAO	Scenario, geographic scope and day

b. The cost of ensuring availability of redispatching units	Scenario, geographic scope and day
c. The total upward dispatch change [MW]	Scenario, geographic scope of the RAO and MTU
d. The total downward dispatch change [MW]	Scenario, geographic scope of the RAO and MTU
e. The new dispatch [MW] and the change in dispatch [MW]	Scenario, geographic scope of the RAO, MTU and unit
f. The new net position [MW]	Scenario, geographic scope of the RAO, MTU and bidding zone
g. The network model updated to include all preventive remedial actions	Scenario, geographic scope of the RAO and MTU

5. LMP analysis (Article 11)

Data item	Level of granularity
a. Nodal price [€/MWh]	Node, MTU
b. Cleared generation, storage and demand volumes [MW]	Node, MTU
c. Flows on all considered network elements [MW]	MTU
d. Active network constraints	MTU
e. Shadow prices associated to the active network constraints [€/MW]	MTU
f. Overall socio-economic welfare [€]	MTU

6. Results of the evaluation, for each indicator and criterion assessed in the BZR (Article 15)

7. Outcome of the BZR (Article 13)

- a. Final results consolidated in one joint report for all BZRRs.
- b. Results of the sensitivity analyses.

ACER Decision on the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered: Annex Ib

Template to consolidate the results of the BZR

1.1. Table I – Ranking and acceptability of BZ configurations

BZ configuration	Monetised benefits [€/year]	Transition costs [€]	Minimum lifetime [years]	Accepted/Rejected	Justification
1	10	20	2	Accepted	
2	15	30	2	Rejected	
...					
n					

1.2. Table II – Short-term effects

Criterion BZ configuration	Operational security		Market liquidity and transaction costs		...	Short-term integration of RES	
	Performance	Justification (or reference to it)	Performance	Justification (or reference to it)		Performance	Justification (or reference to it)
1	+/0/- or a more detailed scale						
2							
...							
n							

1.3. Table III – Long-term effects

Criterion BZ configuration	Facilitation of effective competition (long-term)		Facilitation of effective competition (relative access to cross-zonal capacity)		...	Long-term integration of RES	
	Performance	Justification (or reference to it)	Performance	Justification (or reference to it)		Performance	Justification (or reference to it)
1	+/0/- or a more detailed scale						
2							
...							
n							

ACER Decision on the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered: Annex II

Technical specifications and timeline of the data request for LMP analysis

24 November 2020

1. The Transmission System Operators (TSOs) shall provide the following data items resulting from a Locational Marginal Pricing (LMP) simulation in line with Article 11 of Annex I of Decision No 29/2020:
 - a. nodal price for each node and MTU, in €/MWh;
 - b. cleared generation, storage and demand volumes for each node and MTU, in MW;
 - c. flows on all considered network elements for each MTU, in MW;
 - d. active network constraints for each MTU if any;
 - e. shadow prices associated to the active network constraints, €/MW;
 - f. overall socio-economic welfare resulting from the optimization, in €;
 - g. network model(s) used for the simulations; and
 - h. geographical coordinates of all nodes included in the network model(s).
2. The TSOs shall provide the data items listed in point 1 above in three steps, as follows:
 - a. templates detailing the specific formats to be used by TSOs when delivering the data to ACER and at least one network model used for the simulations, per synchronous area;
 - b. provisional results, covering the number of MTUs specified in Article 11 of Annex I of Decision No 29/2020; and
 - c. final results, covering the number of MTUs specified in Article 11 of Annex I of Decision No 29/2020.
3. The TSOs shall provide the data items listed in point 1 above according to the following deadlines:
 - a. 28 February 2021, for the delivery of templates and at least one network model used for the simulations, per synchronous area;
 - b. 31 May 2021, for the delivery of provisional results; and
 - c. 31 October 2021, for the delivery of the final results of the analysis.
4. In order to ensure robust and timing delivery of the data request, TSOs are recommended to organise, during the LMP simulations, frequent interactions with regulatory authorities and ACER, including:
 - a. discussions and brief consultation on the input data;
 - b. discussions to agree on the specific formats to be used by TSOs when delivering the data to ACER;
 - c. clarifications on the modelling assumptions; and
 - d. discussion and brief consultation on metrics to assess reliability and robustness of the results.