ACER Decision on the ERAA methodology: Annex I

Methodology for the European resource adequacy assessment

in accordance with Article 23 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

2 October 2020

Contents

Whereas

(1) This document sets out the methodology for the European resource adequacy assessment (hereafter referred to as “ERAA”) in accordance with Article 23(3) of Regulation (EU) 2019/943 of the European Parliament and Council of 5 June 2019 on the internal market for electricity (recast) (hereafter referred to as “Electricity Regulation”). This methodology is hereafter referred to as the “ERAA methodology”.

(2) The ERAA methodology takes into account the general principles and goals set out in the Electricity Regulation as well as in a broader EU legal framework, in particular:

a. Regulation (EU) 2019/942 of the European Parliament and of the Council of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators (hereinafter referred to as “ACER Regulation”);

b. Directive (EU) 2019/944 of the European Parliament and Council of 5 June 2019 on common rules for the internal market for electricity (hereafter referred to as “Electricity Directive”);

c. Regulation (EU) 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector (hereinafter referred to as “RPR”);

d. Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as “CACM Regulation”);

e. Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as “EB GL”);

f. Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as “SO GL”);

g. Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration (hereafter referred to as “E&R NC”);

h. Regulation (EU) 2018/1999 of the European Parliament and of the Council on the Governance of the Energy Union and Climate Action (hereafter referred to as “Governance Regulation”);

i. Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (hereafter referred to as “REMIT”); and

j. Commission Regulation (EU) 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council (hereafter referred to as “Transparency Regulation”).

(3) The responsibility to determine the general structure of its own level of security of supply is a Member State’s right, pursuant to Article 194(2) of the Treaty on the Functioning of the European Union. The freedom for a Member State to set its own desired level of security of supply is also recalled in recital (46) of the ‘Whereas’ section of Electricity Regulation.

(4) The ERAA methodology contributes to an efficient achievement of the objectives of the Energy Union set out in Article 1(a) of Electricity Regulation, in particular with respect to security of supply, by providing an objective methodological basis for the assessment of resource adequacy concerns.

The ERAA methodology ensures a realistic assessment, by requiring that the best forecast of the expected system state be used to assess resource adequacy.

(5) The ERAA methodology has been developed in line with the principles of the electricity market operation outlined in Article 3 of Electricity Regulation. In particular, the ERAA helps to ensure that safe and sustainable generation, energy storage and demand response participate on equal footing in the market (pursuant to Article 3(j) of Electricity Regulation), by requiring that all resources which contribute to resource adequacy be modelled.

(6) The ERAA aims to best reflect system development trends, including change of generation capacity mix, change of demand patterns, network development and others. The ERAA also aims to best reflect the expected trends in market design.

(7) The ERAA aims to provide reliable results and to reflect the realistic conditions of market and electric system operation.

(8) The ERAA aims to provide a consistent and comparable basis on a European level, gives key insights into the adequacy of supply to meet demand, and identifies resource adequacy concerns (and their causes). The ERAA results should help to inform the EU Member States, national regulatory authorities (hereafter referred to as “NRAs”) and stakeholders about the forecast level of security of supply in the EU. The ERAA results may also serve as a basis to consider different market design options pursuant to Articles 20 and 21 of Electricity Regulation.

(9) In line with Article 24 of Electricity Regulation, complementary national resource adequacy assessments may be conducted. National resource adequacy assessments have a regional scope and are based on the ERAA methodology (in particular for points (b) to (m) of Article 23(5) of Electricity Regulation). National resource adequacy assessments may include additional sensitivities.

(10) Transparency and monitoring are essential for ensuring accountability of the European Network of Transmission System Operators for Electricity (hereafter referred to as “ENTSO-E”) in carrying out the ERAA and increasing stakeholders’ understanding of this exercise. To this aim, the ERAA methodology includes specific data publication and public consultation requirements, thereby not only enhancing transparency of the ERAA but also promoting transparent operation of ENTSO-E as mandated by Article 41(2) of Electricity Regulation. Furthermore, the ERAA methodology envisages information-sharing with the relevant NRAs to facilitate their joint regional oversight on cross-border issues pursuant to Electricity Directive.

(11) The ERAA methodology envisages suitable stakeholder engagement channels to ensure that all stakeholders and NRAs have the opportunity to provide transmission system operators (hereafter referred to as “TSOs”) and ENTSO-E, where necessary, with the relevant data to enable ENTSO-E to complete, compare and benchmark the data and assumptions used in the ERAA.

(12) ENTSO-E may choose to implement ERAA through a gradual process allowing to strike a balance between accuracy of the assessment and feasibility of the targeted improvements. This approach, while allowing some temporary (and properly justified) methodological simplifications, might help ENTSO-E to continuously learn and gain experience over time and thus ensure efficient implementation of the ERAA in the longer run.

Article 1. Subject matter and scope

1. The ERAA methodology shall be used to identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demand levels for electricity at Union level, at the level of the MSs, and at the level of individual bidding zones, where relevant, in accordance with Article 23(1) of Electricity Regulation.

2. The ERAA methodology shall fulfil the requirements of Article 23(5) of Electricity Regulation, i.e. the ERAA:

   (a) is carried out on each bidding zone level covering at least all MSs;

   (b) is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments;

   (c) contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address;

   (d) appropriately takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;

   (e) anticipates the likely impact of the measures referred in Article 20(3) of Electricity Regulation;

   (f) includes variants without existing or planned capacity mechanisms and, where applicable, variants with such mechanisms;

   (g) is based on a market model using the flow-based approach, where applicable;

   (h) applies probabilistic calculations;

   (i) applies a single modelling tool;

   (j) includes at least EENS and LOLE indicators;

   (k) identifies the sources of possible resource adequacy concerns, in particular whether it is a network constraint, a resource constraint, or both;

   (l) takes into account real network development; and

   (m) ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.

3. ERAAs shall have explicitly modelled systems covering at least the region composed of TSOs (i.e. at least the EU). ENTSO-E shall continuously engage operators of other interconnected systems to establish and foster cooperation. If tightly interconnected neighbouring regions commit to cooperate on resource adequacy assessments, they should be modelled as explicitly modelled systems. Otherwise, the contribution of these systems to pan-European resource adequacy shall be considered through non-explicitly modelled systems.

4. The temporal and spatial granularity of the ERAA shall respect at minimum the granularity defined in the ERAA methodology. ENTSO-E shall carry out the ERAA on an annual basis in line with Article 23(4) of Electricity Regulation.

Article 2. Definitions and interpretation

1. For the purpose of the ERAA methodology, the definitions in Article 2 of Electricity Regulation, Article 2 of RPR, Article 2 of CACM Regulation, Article 3 of SO GL, Article 2 of EB GL, Article 2 of Transparency Regulation as well as Article 2 of Electricity Directive shall apply.

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) 'annual fixed costs' means costs incurred each year in the context of operation of a capacity resource once the capacity resource starts commercial operation, independently from the generated or curtailed (in case of DSR) energy volume;

   (b) 'capacity calculation methodology' (CCM) means the capacity calculation methodology expected to apply for the considered target year;

   (c) 'capacity resource' means any generation, storage or DSR asset which may bring resource adequacy benefit;

   (d) 'capital expenditures' (CAPEX) means the investment required to develop, construct or refurbish a capacity resource without considering the financial costs (e.g. interest costs) or the structure of financing (equity versus debt), i.e. the investment required if the capacity resource were to be built overnight at the current prices;

   (e) 'central reference scenarios' means the main scenarios defined pursuant to Article 3(5), in line with Article 23(5)(b) of Electricity Regulation;

   (f) 'CHP' means combined heat and power;

   (g) 'CM' means capacity mechanism pursuant to Electricity Regulation;

   (h) 'CNEC' means critical network element associated with a contingency used in the CCM. For the purpose of the ERAA methodology, the term CNEC also covers the case where a critical network element is used in the CCM without a specified contingency;

   (i) 'CONE' means cost of new entry in line with the CONE methodology;

   (j) 'CONE methodology' means the methodology for calculating the cost of new entry pursuant to TITLE 3 of the VOLL CONE RS methodology;

   (k) 'CORP' means cost of renewal or prolongation pursuant to Article 2 of the VOLL CONE RS methodology;

   (l) 'demand' means the total instantaneous electricity consumption observed in the transmission system, including transmission network losses;

   (m) 'DSR' means demand response pursuant to the Electricity Directive. In addition,

      i. 'explicit demand-side response' (explicit DSR) means the change of electric demand pursuant to an accepted offer to sell demand reduction or increase in an organised market, either directly or through aggregation. Explicit DSR may consist of either foregone or time-shifted demand;

ii. 'implicit demand-side response' (implicit DSR) means the change of demand by final customers from their normal or current consumption patterns, in response to time-variable electricity prices or incentive payments. Implicit DSR can either be self-directed or directed by an energy management service provider;

(n) 'discount rate' expresses the time value of money and converts future cash flows to their equivalent present value via a discount factor, $k = \frac{1}{(1+r)^n}$, where r is the discount rate and n is the number of years;

(o) 'ECG' means electricity coordination group;

(p) 'economic dispatch' (ED) means a mathematical optimisation model as described in Article 7;

(q) 'economic lifetime' means economic lifetime pursuant to the CONE methodology;

(r) 'economic viability assessment (EVA)' means a model assessing the profitability of capacity resources, informing decisions on retirement, mothballing and re-entry, renewal/prolongation and new-build of capacity resource as described in Article 6;

(s) 'energy-only market' (EOM) means the markets for electricity, including over-the-counter markets and electricity exchanges, markets for the trading of energy, balancing and ancillary services in all timeframes, including forward, day-ahead and intraday markets, but excluding CMs;

(t) 'energy not served (ENS)' means, for a given MTU and modelled zone, the energy which is not supplied due to insufficient capacity resources to meet the demand;

(u) 'expected energy not served' (EENS) means, in a given modelled zone and in a given time period, the expected ENS;

(v) 'explicitly modelled systems' means electric systems which are modelled in detail. These systems shall be modelled considering each element of the probabilistic model set in the ERAA methodology;

(w) FCR means frequency containment reserves pursuant to SO GL;

(x) 'fixed costs' means the sum of the CAPEX (annualised based on WACC) and the annual fixed costs of a capacity resource;

(y) 'flow-based' means the flow-based approach pursuant to CACM Regulation;

(z) 'flow-based domain' means a set of constraints that limit the flow-based cross-zonal capacity;

(aa) FRR means frequency restoration reserves pursuant to SO GL;

(bb) 'GSK' means generation shift key pursuant to CACM Regulation;

(cc) 'load factor' means the power generated (respectively consumed) by a given generation (respectively consumption) unit, divided by the installed capacity of the generation unit (respectively the maximum demand consumed);

(dd) 'loss of load expectation' (LOLE) 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;

(ee) 'MC' means Monte Carlo (i.e. related to the Monte Carlo method);

(ff) 'MC sample year' means one realisation of possible future states of the modelled power system resulting from the combination of sampling different stochastic variables;

(gg) 'market-based capacity resource' means any capacity resource available in the system complying with market rules and commercial agreements and participating to the Internal Market for Electricity. This includes inter alia all capacity resources participating in CMs which are allowed to participate to the EOM;

(hh) 'modelled zone' means either a bidding zone, a country or another geographic area that is explicitly modelled in the ED. A modelled zone cannot be larger than a bidding zone or a country;

(ii) 'MS' means EU Member State;

(jj) 'MTU' means market time unit pursuant to Transparency Regulation;

(kk) 'NECP' means an integrated national energy and climate plan pursuant to the Governance Regulation;

(ll) 'net generating capacity' (NGC) of a generation unit means the maximum net active electrical power it can produce continuously throughout a long period of operation in normal conditions, where:

i. 'net' means the difference between, on the one hand, the gross generating capacity of the alternator(s) and, on the other hand, the auxiliary equipment load and the losses in the main transformers of the power station;

ii. for thermal plants, 'normal conditions' means average external conditions (climate etc.) and full availability of fuels; and

iii. for hydro, solar and wind units, 'normal conditions' means the nominal availability of primary energies (i.e. water, solar or wind conditions).

(mm) 'net transmission capacity (NTC)' means the coordinated net transmission capacity approach pursuant to CACM Regulation;

(nn) 'non-explicitly modelled systems' means electric systems which are not explicitly represented in the modelling framework in detail, and which are directly interconnected with an explicitly modelled system;

(oo) 'out-of-market capacity resource' means any capacity resource which is not market-based. Out-of-market capacity resources include capacity resources of strategic reserves, but do not include ENS;

(pp) 'PECD' means pan-European climate database;

(qq) 'PEMMDB' means pan-European market modelling database;

(a) 'planned outage' means a state of a capacity resource when it is not available in the power system and the outage was planned in advance. These outages include maintenance, mothballing and any other non-availabilities known at the time of data collection for the resource adequacy assessment;

(rr) ‘PST’ means phase-shifting transformer;

(ss) ‘PTDF’ means power transfer distribution factor;

(tt) ‘RCC’ means regional coordination centre pursuant to Electricity Regulation;

(uu) ‘remaining available margin’ (RAM) means the available margin of a CNEC, pursuant to CACM Regulation;

(vv) ‘RES’ means energy from renewable sources pursuant to Electricity Directive;

(ww) ‘revenue’ means any income that a given capacity resource receives;

(xx) ‘RR’ means replacement reserves pursuant to SO GL;

(yy) ‘RS methodology’ means the methodology for calculating the reliability standard pursuant to Title 4 of the VOLL CONE RS methodology;

(zz) ‘scenario’ means the quantitative description of a plausible future of the power generation, transmission and demand systems;

(aaa) ‘sensitivity’ means a change in a scenario stemming from the variation of one (or very few) input parameter(s) that would not involve significant changes in other input parameters. Sensitivities are defined pursuant to Article 3(6) and (7);

(bbb) ‘strategic reserve’ means a type of CM in which designated capacity resources are not available in the EOM and are only dispatched when TSOs are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;

(ccc) ‘study time period’ means the time period covered by the ERAA;

(ddd) ‘submission year’ (SY) means the year when ENTSO-E submits the ERAA results to ACER for approval, in line with Article 10(2);

(eee) ‘TFEU’ means Treaty on the functioning of the European Union;

(fff) ‘target year’ (TY) means a year simulated within the ERAA;

(ggg) ‘TYNDP’ means ENTSO-E’s ten-year network development plan;

(hhh) ‘unplanned outage’ means a state of a capacity resource when it is unavailable in the power system and the unavailability was not planned;

(iii) ‘variable cost’ means variable cost pursuant to Article 2 of the VOLL CONE RS methodology;

(jjj) ‘VOLL CONE RS methodology’ means Annex I of ACER Decision No 23/2020;

(kkk) ‘VOLL methodology’ means the methodology for determining a single estimate of the value of lost load pursuant to Title 2 of the VOLL CONE RS methodology;

(lll) ‘WACC’ means WACC pursuant to Article 2 of the VOLL CONE RS methodology.

3. In the ERAA methodology, unless the context requires otherwise,

   (a) the singular indicates the plural and vice versa;

   (b) the table of contents and headings are inserted for convenience only and do not affect the interpretation of the ERAA methodology; and

   (c) any reference to legislation, regulations, directive, order, instrument, code or any other enactment shall include any modification, extension or re-enactment of it then in force.

Article 3. Scenario framework

1. The ERAA shall be based on projected demand and supply covering each year of the study time period. The ERAA assessment for SY+1 may refer to the results of the seasonal adequacy assessment pursuant to Article 9 of RPR.

2. ENTSO-E shall collect data to define the projected demand, supply and grid assumptions according to the requirements set out in Article 5.

3. The baseline data for the ERAA stems from the national projected demand, supply and grid outlooks prepared by each individual TSO. These national forecasts shall be consistent with existing and planned national policies, including:

   (a) national objectives, targets and contributions, and other projections contained in the NECPs, as referred in Article 3 of Governance Regulation, including trends related to coal phase-out, nuclear phase-out, RES development, storage, electric vehicles, sectoral integration, DSR and energy efficiency measures. Scenario assumptions shall align with the latest NECP-based TYNDP scenario. In line with Article 23(5)(e) of Electricity Regulation, the assessment shall anticipate the likely impact of the measures referred in Article 20(3) of Electricity Regulation. To this aim, the assumptions of the central reference scenarios shall align with the measures and actions defined by MSs pursuant to Article 10(5) of Electricity Regulation and with implementation plans pursuant to Article 20(3) of Electricity Regulation;

   (b) best estimates regarding the state of the grid, taking into account the TYNDP and the most recent national development plans; and

   (c) known trends and assumptions regarding mothballing, development of new capacity resources, already awarded CM contracts and estimates on available capacity under existing or planned CMs, provided these have been approved under Union State aid rules pursuant to Articles 107, 108 and 109 of the TFEU.

4. For all central reference scenarios, the EVA shall be performed on the baseline data described in the previous paragraph. The ERAA report shall clearly show whether and how the baseline data has been modified by the EVA. To ensure consistency, the EVA may also be performed for the other scenarios and sensitivities.

5. The ERAA shall rely on the following central reference scenarios:

   (a) **With CMs**: this scenario considers CMs approved in accordance with the Union State aid rules pursuant to Articles 107, 108 and 109 of the TFEU and applicable at the time of the assessment. Cross-border participation in CMs shall be considered where technically feasible and applicable pursuant to Article 26 of Electricity Regulation; and

(b) **Without CMs**: this scenario excludes CM revenues, except for CM contracts already awarded at the time of the assessment.

6. ENTSO-E may complement the central reference scenarios with additional scenarios and/or sensitivities with European relevance, e.g. to assess the robustness of the identified resource adequacy concerns. Such scenarios and/or sensitivities may be based on inter alia the following elements:

(a) different assumptions related to input data and scenario uncertainties, including different economic and policy trends relevant for resource adequacy;

(b) impact of uncertainty in the deployment of grid investments;

(c) assessments of the robustness of the identified investments within the EVA;

(d) variations on fuel, wholesale prices and/or carbon prices;

(e) consideration of extreme weather events and hydrological conditions;

(f) variations on cross-zonal capacities;

(g) pursuant to Article 23(5)(f) of Electricity Regulation, variations with CMs, including e.g.

i. adding or removing CMs for some modelled zones;

ii. postponing the implementation of CMs, or prolonging CMs for some modelled zones;

iii. changing the type of CM for some modelled zones;

(h) presence of indirect restrictions to wholesale price formation pursuant to Article 7(8) and (9).

7. If ENTSO-E identifies any resource adequacy concern pursuant to Article 8(1), and if any indirect restriction to wholesale price formation pursuant to Article 10(4) of Electricity Regulation is modelled in ERAA, ENTSO-E shall conduct an additional sensitivity without any indirect restriction to price formation, to identify whether indirect restrictions to price formation may constitute possible sources of resource adequacy concerns in line with Article 23(5)(k) of Electricity Regulation. ENTSO-E may also conduct additional sensitivity analyses adding or removing some indirect restrictions to price formation in some modelled zones. All these sensitivities do not affect the MSs' prerogatives pursuant to Article 20(1), (2) and (3) of Electricity Regulation.

8. Definition and prioritisation of any additional scenarios and/or sensitivities pursuant to paragraph (6) shall be subject to public consultation by the ENTSO-E. In particular, views of MSs and relevant stakeholders on the evolution of the power system and the relevance of any proposed scenario and/or sensitivity shall be duly taken into account.

Article 4. Resource adequacy assessment

1. Modelling framework

(a) The resource adequacy metrics are estimated through the ED. Market entry and exit are modelled through the EVA. The ERAA shall apply a single modelling tool, in line with Article 23(5)(i) of Electricity Regulation.

(b) The ERAA shall simulate each target year from SY+1 until SY+10, i.e. the study time period shall start from SY+1 until SY+10 (included).

(c) Resource adequacy shall be assessed using the following two probabilistic resource adequacy metrics: EENS and LOLE.

(d) The ERAA consists of the following major pillars: demand, supply, storage, and grid representation among different modelled zones.

(e) Uncertainty is represented through the availability of capacity resources and network, and climate conditions.

i. Availability of capacity resources is represented through random unplanned outage patterns. Uncertainty of interconnectors is also represented through random unplanned outage patterns of interconnectors between different modelled zones, unless this effect is already included in the flow-based parameters considered within the flow-based approach and/or through the thermal capacity assigned to interconnectors.

ii. Data related to climate variables (i.e. hydro inflows, irradiance values, wind speeds and temperatures) are consolidated in the ENTSO-E PECD. The PECD comprises a set of hourly time series of climate variables for multiple years. The data set shall properly consider the inter-zonal and inter-temporal correlation of those climate parameters.

(f) The expected frequency and magnitude of future climate conditions shall be taken into account in the PECD, also reflecting the foreseen evolution of the climate conditions under climate change. To this effect, the central reference scenarios shall either

i. rely on a best forecast of future climate projection;

ii. weight climate years to reflect their likelihood of occurrence (taking future climate projection into account); or

iii. rely at most on the 30 most recent historical climatic years included in the PECD.

Other scenarios and sensitivities may rely on climate data beyond the one used for the central reference scenarios, e.g. pursuant to Article 3.6(e).

(g) Unless the modelling framework allows for a proper characterisation of unforeseen imbalances, the ED shall rely on a "perfect foresight" principle: under this assumption, forecast errors of wind, solar, hydro generation, of planned outages as well as of demand are ignored in the ED. Additionally, unplanned outages are assumed to be known in advance with the perfect foresight principle.

(h) The MTU shall be smaller than or equal to an hour.

(i) The spatial granularity of modelled zones shall be set at least by the smallest level between country and bidding zone, considering the bidding zone configuration expected for each target year. In addition, the specific geographical characteristics of the assessed perimeter shall be reflected in the ED model by explicitly modelling islands for which sufficiently qualitative and granular input data exist, for example the island of Crete.

(j) Non-explicitly modelled zones are represented by fixed time series of energy exchanges through interconnections.

2. Probabilistic assessment

(a) The ERAA shall use a probabilistic methodology to reflect the stochasticity of climate variables affecting supply and demand, as well as the expected availability of generation, storage and transmission resources.

(b) The MC method shall be used for probabilistically assessing the availability of capacity resources and transmission resources. It creates possible future states of the modelled power system by sampling a sequence of random outages of the relevant stochastic variables. Random outages represent different availability of capacity resources and transmission lines, which are subject to failures that cannot be predicted beforehand and may have a significant impact on resource adequacy.

(c) Modelling of outages shall reflect, where possible and applicable, the attractiveness for capacity resources to be available during MTUs when ENS is likely to occur.

(d) MC sample years shall combine the climate-dependent variables and random outages referred to in paragraph 1(e), as follows:

i. Climate years, are first selected one-by-one;

ii. Each climate year is associated with random outage samples, i.e. randomly assigned unplanned outage patterns for thermal units, as well as for interconnectors;

iii. The combination of the climate years and the random unplanned outage patterns defines the MC sample years analysed. The number of MC sample years shall ensure convergence of the results, pursuant to paragraph 2(e).

(e) The convergence of the Monte Carlo method shall be assessed by the coefficient of variation (α) of the $EENS$ metric. It describes the volatility of the EENS metric in the Monte Carlo assessment. The coefficient of variation is defined by the equation below:

$$\alpha_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

where $EENS\ _N$ is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}, i = 1 \ldots N$ and $Var[EENS_N]$ is the variance of the expectation estimate, i.e. $Var[EENS_N] = \frac{Var[ENS]}{N}$.

(f) A stopping criterion for the probabilistic assessment shall be enforced, under a sufficiently large number of Monte Carlo years, by comparing the relative increment of α with a given threshold value Θ. In particular, for N sufficiently large, if

$$\frac{|\alpha_N - \alpha_{N-1}|}{\alpha_{N-1}} \leq \Theta$$

then increasing the number of Monte Carlo years would not increase the level of accuracy considerably. Consequently, the Monte Carlo analysis can stop.

(g) To indicate the reliability of resource adequacy assessment results, the following parameters shall be reported along with the results:

i. The number of analysed Monte Carlo years N;

ii. The value of α as a function of N.

3. Demand:

(a) For each target year, demand shall be represented as a time series with a temporal resolution equal to the MTU. Demand shall be available at least at modelled zone-level, and may be available with a higher level of spatial detail. It shall be calculated based on historical demand time series and considering the stochasticity of climate variables, the impact of climate change, and projections of economic growth and penetration of new technologies (e.g. electric vehicles and heat pumps) for each target year.

(b) With respect to climate, demand shall be modelled considering at least load-temperature sensitivity using historical climate data or climate data derived from climate models. The demand sensitivity to climate may include other variables such as irradiation, wind speed or humidity, if proven relevant.

(c) Explicit and implicit DSR shall be considered in the assessment. The data related to potential for demand reduction, postponement or shifting shall be based on the best forecast in the modelled zone and within the concerned time period of the assessment.

i. Explicit DSR potential shall be structured in different price and volume bands, each characterised by a maximum activation capacity, maximum activation duration, unit activation price, as well as economic and technical activation and energy constraints. The activation price and volume bands indicate the minimum price required to activate the corresponding volumes of DSR, hence constituting a DSR activation curve. The estimation of explicit DSR potentials and their activation curves shall be performed at least per modelled zone.

ii. Implicit DSR potential shall reflect the demand elasticity of the day-ahead market expected for the considered target year, based on best forecast.

iii. DSR shall be defined as either

1. DSR potential and initial installed capacity (for various activation prices) to allow the EVA to define the installed capacity and activation curve based on market entry and exit of DSR; or

2. Exogenous installed DSR capacity and activation curve.

iv. The choice of either option shall be properly justified and transparently communicated (see also Article 5.11(c)). In case implicit DSR activation is not directly linked to time-variable electricity prices but rather to permanent incentive payments associated with a certain expected behaviour of costumers at specific hours every day/week of the year, implicit DSR shall be modelled within ENTSO-E's demand prediction process, e.g. as time-dependent flexible demand bands.

(d) The proportion of each consumer's demand which is price-responsive, and which is excluded from calculating the single VOLL for RS pursuant to Article 7(2)(a) of the VOLL methodology, shall be included as DSR in the ERAA.

(e) Demand during charging of storage units shall be determined separately through the ED and shall be assumed to be price-responsive.

(f) Estimates on evolution of energy efficiency and its effects on demand curves as well as demand growth due to economic, technological and social developments shall be considered using annual best forecasts.

4. Supply

(a) Supply assumptions shall consider current status and best estimates of all available generation units in the system.

(b) All capacity resources and their contribution to flexible system operation shall be considered, in line with Article 23(5)(d) of Electricity Regulation.

(c) Supply shall be defined in terms of NGC. Any seasonal impact on generation capacity availabilities (e.g. CHP availabilities in summer and seasonal efficiencies) shall be considered (e.g. by introducing time series of availability or by modelling unavailability through the planned maintenance schedule). Constraints related to supply of other services (e.g. must-run of CHP) shall also be considered.

(d) Climate-dependent electricity generation, such as wind, solar and hydro generation, shall be based on modelled climate conditions, assuming perfect foresight in line with Article 4.0. The climate conditions used for climate-dependent generation and for climate-dependent demand shall be consistent. Temperature impact on climate-dependent electricity generation (e.g. on the efficiency of PV panels, temperature sensitivity of thermal generation to air temperature, need of cooling water…) may be indirectly considered through the statistical information used to build the climate-dependent electricity generation models. Non dispatchable climate-dependent electricity generation shall be modelled by combining:

i. NGC for each technology, representing the expected market penetration of climate-dependent electricity generation for the target year; and

ii. time-varying load factors reflecting the spatial and temporal dependency of climate-dependent electricity generation, as well as the evolution of technical characteristics of the relevant generation technologies in each target year.

(e) Availability of supply sources:

i. Availability of power generation sources shall account for planned and unplanned outages, as well as system reserve requirements.

ii. Planned outages are modelled assuming perfect foresight in line with Article 4.0.

1. For the time period SY+1 - SY+3, planned outage schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These maintenance profiles may be calibrated using data published by owners of generation units pursuant to the REMIT, as well as technology-specific constraints (e.g. maximum number of nuclear units in simultaneous maintenance);

2. For the time period SY+4 – SY+10, planned outage schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These planned outage schedules shall be optimised to avoid scheduling maintenance when ENS is likely to occur, while respecting relevant constraints such as maintenance period for each power plant, percentage of capacity that should undergo maintenance during winter period, as well

as technology specific-constraints (e.g. maximum number of nuclear units simultaneously under maintenance).

iii. Unplanned outages of supply shall be considered in a probabilistic manner and assuming perfect foresight in line with Article 4.0, pursuant to paragraph 1(e)i of this Article. Assumptions on outage rates per technology type and mean time to repair shall build on historical outage events in Europe. These assumptions may be refined to reflect how outage rates correlate with market signals.

(f) Supply-side technical constraints shall be considered. These constraints may include minimum and maximum generating capacities, capacity requirements for system services (such as reserves or voltage support), capacity reductions due to mothballing, must-run constraints, time series of de-rating ratio (due to constraints which are not explicitly modelled in the ED), planned maintenance requirements, ramping capabilities, minimum run-time, start-up and shut-down times and, as long as relevant for the generation technology and consistent with the climate modelling approach, constraints on temperature dependency of thermal generation and constraints related to the need for cooling water.

(g) Energy constraints (such as for hydro) shall consider energy availability. For hydro generation modelling, the energy constraints may relate to water inflows, reservoir size or minimum energy release requirements due to environmental reasons, and may require an ex-ante optimisation consistent with paragraph 5 of this Article.

5. Reservoir and storage

(a) Pumped-hydro storage capacity resources shall be divided into open-loop and closed-loop pump storage, with the latter not having natural inflows to their reservoirs but only a closed loop of pumping and generating from the available reservoir. Modelling pumped-hydro storage units shall rely on an ex-ante optimisation phase, the time resolution of which might be longer than in the ED model, depending on the time resolution of the available inflow data. During this phase, hydro reservoir targets shall be optimised to provide the ED model with the available energy from hydro storage within each time step of the hydro optimisation phase. The hydro optimisation model shall respect constraints related to upper and lower reservoir levels, minimum/maximum pumped energy, minimum/maximum generated energy, minimum/maximum generation capacity. The hydro optimisation shall reflect:

i. the expected operational principles applied for each target year by market participants which own and operate hydro storage; and

ii. environmental constraints (e.g. on potable and agriculture uses) on the water resource.

(b) Batteries (including vehicle-to-grid) shall be considered within each modelled zone, based on best estimates for the concerned period of the assessment. Energy availability shall be based on energy storage capacities and charging-discharging constraints of the batteries. The ERAA shall consider:

i. in-the-market batteries, which are large-scale battery capacities that are traded in day-ahead and intraday markets. In-the-market batteries shall be modelled similarly to pumped-hydro storage and shall be subject to the following constraints: maximum power, maximum energy storage, state of charge, charging/discharging efficiency; and

ii. out-of-market batteries, which represent small-scale batteries typically managed behind the meter. Out-of-market batteries shall be modelled as peak-shaving units based on predefined peak-reduction ratios, which are a direct input to the demand prediction process.

6. Network

(a) For each target year, cross-zonal capacities shall reflect the expected CCM, taking operational security limits into account. In particular, cross-zonal capacities shall reflect the latest available information regarding MS action plans for a linear trajectory pursuant to Article 15 or the minimum capacity pursuant to Article 16(8), as well as any temporary derogations granted as per Article 16(9) of the Electricity Regulation. Cross-zonal capacities for the central reference scenarios shall also reflect the measures decided to reach electricity interconnection targets, according to the information available to the TSOs.

(b) Within NTC capacity calculation, NTCs shall limit the bilateral exchange between two explicitly modelled zones. These values shall reflect expected operational practices (which may include specific connection agreements) for the target year.

(c) Within flow-based capacity calculation, a flow-based domain shall be computed as follows, in line with the expected CCM:

i. ENTSO-E, based on TSOs' input data, shall coordinate the identification of CNECs during the data collection process pursuant to Article 5;

ii. definition of relevant node-to-hub PTDFs shall use grid models covering the flow-based area under consideration. At least one grid model per target year shall be used. European grid models from the TYNDP reference grid shall be used. These European grid models shall incorporate the relevant grid modifications expected to be operational by the different target times of the assessment;

iii. node-to-hub PTDFs shall be defined for each of the different CNECs and for the relevant variables representing the net positions of each bidding zone under consideration, relevant HVDC flows, PST settings, and other degrees of freedom expected to be reflected in capacity calculation;

iv. the capacity available for cross-zonal trade on a CNEC depends on the maximum admissible power flow at the considered MTU, defined as $F_{\max}$. $F_{\max}$ may be implemented as a time-varying value in order to reflect varying relevant conditions;

v. the selection of GSKs shall be in line with foreseen practices in the relevant capacity calculation region, taking into account any simplification necessary for the ERAA;

vi. zone-to-hub PTDFs shall be defined, combining node-to-hub PTDFs with GSKs for each MTU;

vii. RAM of each CNEC shall be estimated, including proper considerations on internal, loop and transit flows, as well as applicable minimum RAM requirements. The impact of coordinated validation of cross-zonal capacity on RAM should be taken into account;

viii. for all relevant CNECs, the (RAM, PTDFs) parameters shall define a collection of linear constraints for the ED. This total set of constraints shall be reduced to the set of constraints limiting the exchanges within the simulation. The reduced combination of relevant constraints shall form the final flow-based domain;

ix. The final flow-based domains shall be the linear constraints introduced in the ED model.

(d) Climate conditions and seasonal patterns that impact network constraints shall be considered when defining cross-zonal capacities. In particular, for each target year, cross-zonal capacities shall at least be estimated for winter and summer (following the seasons defined operationally by TSOs). For each MTU of each MC sample year, a set of cross-zonal capacity values shall be set based on the relevant variables (including climate, RES generation and demand) of the MC sample year for the considered MTU. A correlation analysis between the different cross-zonal capacities and the relevant variables shall be applied.

(e) If the CCM allows for specific allocation constraints, such constraints may further restrict cross-zonal trade (on top of the flow-based domains or NTCs). In this case, the constraint value shall be computed in line with the expected CCM.

(f) In the NTC approach, unplanned outages of HVDC interconnections shall be considered in a probabilistic manner, as per paragraph 1(e)i.[1] Assumptions on outage rates per line and mean time to repair shall build on statistical analysis of historical outage events in Europe.

(g) Reserve requirements shall be set separately for FCR, FRR and RR.

i. For each target year, the dimensioning of FCR and FRR, and the contribution of each TSO, shall reflect reserve needs to cover imbalances in line with Articles 153 and 157 of SO GL.

ii. Unless the modelling framework described in paragraph 1(g) is able to model the use of balancing reserves in relation to unforeseen imbalances, FCR and/or FRR (or a part of these balancing reserves) may be deducted from the available capacity resources in the ED, either by deducting their respective capacities from the available supply or by adding them to the demand profile. However, the modelling of FCR and FRR shall comply with Article 7(7).

iii. RR shall be considered as capacity resource available in the ED. For each target year, the dimensioning of RR shall be consistent with Article 160 of SO GL.

7. Non-explicitly modelled systems

(a) Non-explicitly modelled systems shall be modelled as exogenous best estimates of cross-zonal exchanges on all borders with explicitly modelled zones. The cross-zonal exchanges shall be provided by TSOs having direct interconnections with those systems. The cross-zonal exchanges shall reflect expected market conditions and expected operational practices (including specific connection agreements) for the MTUs of each target year.

Article 5. Data collection

1. The ERAA data collection shall follow the ENTSO-E data collection framework principles:

[1] In flow-based, unplanned outages of HVDC interconnectors are considered when computing the flow-based domain.

(a) ENTSO-E shall provide data collection guidelines to each TSO, to guarantee a coherent data collection process. Such guidelines shall specify the assumptions (including data template) to follow when providing data, in order to guarantee a standardised data preparation process and ensure that databases are built on consistent, transparent and common assumptions;

(b) Some of the data requested from the TSOs is used by ENTSO-E as an input to generate centrally prepared datasets for the ERAA.

2. ENTSO-E shall coordinate the data collection process to prepare and consolidate the TSO input.

3. During the data collection process, ENTSO-E shall communicate with TSOs through delegated adequacy correspondents.

4. TSOs shall provide ENTSO-E with the data needed to carry out the ERAA, pursuant to Article 23(4) of Electricity Regulation. ENTSO-E shall clearly differentiate the origin of data used in its studies (MSs, TSOs, ENTSO-E assumptions, NRAs, DSOs, NEMOs, other/external, etc.). In addition, in case of inconsistency in the collected data, ENTSO-E shall request the relevant TSOs to disclose their data sources and shall define a consolidation mechanism in order to combine such data into a consistent dataset.

5. Producers and other market participants shall provide the TSOs with the relevant data regarding expected utilisation of the generation resources, pursuant to Article 23(4) of Electricity Regulation and respecting confidentiality of such data where required, in order for TSOs to set up or benchmark the scenarios of projected demand and supply and to provide relevant technical and economic assumptions for the EVAs.

6. For calibration purposes, ENTSO-E may also rely on other data collected in line with Transparency Regulation, such as e.g. historical wholesale prices.

7. In line with paragraph (4), to set up the flow-based modelling, TSOs shall either

(a) Provide ENTSO-E with the input data required to compute centrally the flow-based domain pursuant to Article 4.6(c); or

(b) Define a list of relevant CNECs with PTDFs, Fmax and RAM pursuant to Article 4.6(c).

8. Reserve requirements data collection per modelled zone shall consist of separate time series for FCR, FRR and RR, pursuant to Article 4.6(g).

9. General economic parameters, such as evolution of fuel prices and CO_2 emission allowance price under the EU ETS (where applicable), shall be prepared centrally by ENTSO-E based on best available economic expertise at European level. These assumptions shall be consistent with the ENTSOs' scenarios prepared for the TYNDP, and may lead to different parameter values among modelled zones.

10. Economic and technical data to perform EVAs shall be consolidated centrally by ENTSO-E based on best information available to ENTSO-E. The following data items shall be estimated per relevant technology and modelled zone:

(a) CAPEX, expressed in EUR/MW;

(b) Annual fixed costs, expressed in EUR/MW/year;

(c) Short-term variable costs (EUR/MWh), efficiencies (%) and emission factors of CO_2 (t/MWh);

(d) WACC and discount rates; and

(e) (remaining) economic lifetime.

For the technologies used in ERAA which are also reference technologies for CONE or CORP, the economic and technical data used for ERAA (except for WACC) shall be identical to the latest available best estimate used in the most recent CONE and CORP calculations pursuant to the CONE and RS methodologies. In particular, the EVA shall at least consider all reference technologies and all reference renewals/prolongations considered pursuant to Article 18 of the RS methodology.

For technologies, for which the CONE or RS methodology did not define technical and economic parameters, best estimates regarding technical and economic parameters required for the EVA shall be prepared centrally by ENTSO-E, based on best available economic expertise at European level.

11. Collected data shall originate from combined top-down and bottom-up collection processes. It shall be checked for completeness and consistency and eventually consolidated into a PEMMDB. The PEMMDB shall contain information on the network and market models for each modelled zone and target year. The PEMMDB shall at least include technical and economic data at modelled zone level for all the reference technologies considered during the calculation of CONE and CORP (according to the CONE and RS methodologies). More specifically, the PEMMDB shall contain the generic input dataset to the ED model. The PEMMDB shall include:

(a) Generation data, consisting of, among others, RES and thermal generation NGCs, their predicted evolution over time, maintenance requirements, technical capabilities, fuel consumption, conversion efficiencies, mothballing predictions, RES and non-dispatchable fossil fuel generation time series. Thermal generation data shall be collected unit by unit, to the best availability. Wherever unit by unit data is not available, generation data shall be aggregated following the data collection guidelines and according to the standard data templates referred to in paragraph 1. Thermal power plant conversion efficiencies used in the model shall be based on fuel subtypes. RES capacities shall be provided per modelled zone, or using a more detailed geographic granularity. Both RES and non-dispatchable fossil fuel generation time series shall have a time resolution equal to the MTU;

(b) Data on already awarded CM contracts, consisting of at least the type and volume of capacity resource contracted, the duration of the contract, the description of the delivery period and the annual amount payed to the contracted capacity during the whole duration of the contract;

(c) Data on the current installed capacity and potential of (explicit and implicit) DSR and storage. Such estimates should build on input from relevant market parties and TSO data, and shall result in values that are differentiated for each modelled zone;

(d) System reserve requirements separately provided for FCR, FRR and RR for each modelled zone, target year and MTU;

(e) Demand predictions, built on historical hourly demand profiles and forecast adjustments. These components are the following:

i. Historical demand time series (with a time resolution at least equal to the MTU) shall be collected from TSOs per modelled zone. ENTSO-E shall combine these historical demand time series with historical climate variables, in order to build demand predictions centrally. The predictions are then used to generate multiple time series for each target year to reflect different climate conditions.

ii. A set of model parameters that allow for a characterisation of time series per modelled zone, target year and MTU where applicable. These include:

1. Annual demand per sector (industry, residential, services and transport) and per modelled zone shall be provided by TSOs as an aggregated forecast for each target year;

2. current and forecast number of electric vehicles for each target year, average effective usage with time differentiation, where possible (e.g. between seasons, months, weekends and weekdays), average efficiency (forecast consumption), share of fast and slow charging profiles (taking into the account the geographical diversity of charging behaviour within the study time period). Deployment forecast of electric vehicles shall be defined by each TSO as part of the scenario building process, while vehicle-to-grid capabilities shall be based on best forecast;

3. current and forecast number of heat pumps, increase in thermal demand caused by heat pump additions, average values of coefficients of performance, threshold of coefficient of performance for switching (hybrid heat pumps);

4. current and forecast number of out-of-market batteries, their maximum total power, storage capacities, cycle efficiency, peak reduction and ramp-rate reduction;

5. other forecast adjustments: other additional demand types (e.g. data centres);

6. calendars of holidays/weekdays/special days per target year;

7. other characteristics of relevant technologies that affect demand levels and shape (e.g. energy efficiency programs).

(f) NTC of bidding-zone borders between explicitly modelled systems, and allocation constraints pursuant to Article 4.6(e).

(g) Flow-based domains as described in Article 4.6(c).

12. The PECD of ENTSO-E shall include, at least per modelled zone level, the following data:

(a) temperature, irradiance, humidity and wind speed time series;

(b) wind power and PV load factor time series; and

(c) water inflows to hydro reservoirs.

The PECD shall build on “state-of-the-art” climate databases, using available re-analysis of historical data and climate projections where applicable. ENTSO-E shall periodically update the PECD within a timeframe compatible with the “state-of-the-art” to include re-analysis of recent historical data and/or synthetic data. The PECD shall be updated before the first ERAA implementation and then at least every 5 years, to account for the most recent climate data (e.g. more recent climate years).

13. ENTSO-E shall estimate harmonised limits on maximum and minimum clearing prices (pursuant to Article 10(1) and (2) of Electricity Regulation), based on best available economic expertise at European level.

14. TSOs shall provide ENTSO-E with their best forecast on any indirect restrictions to price formation which are expected to significantly impact the ED or EVA as well as any related mitigating measures or actions pursuant to Articles 10(4) and (5) and 20(3) of Electricity Regulation. For each declared restriction or mitigating measure, the TSO shall provide the timeline during which the restriction or measure is expected to apply, in line with measures and actions defined by MSs pursuant to Article 10(5) of Electricity Regulation and with implementation plans pursuant to Article 20(3) of Electricity Regulation.

15. TSOs shall provide ENTSO-E with information on existing or planned CMs. This information shall include assumptions on the type of CM, amount of de-rated capacity procured or expected to be procured and time duration of the CM. This information should allow to assess the share of the capacity within the PEMMDB relying on any CM, as well as the expected duration of any already granted CM contract within the study time period.

Article 6. Economic viability assessment

1. Pursuant to Article 23(5)(b) of Electricity Regulation, the EVA shall assess the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency.

2. Subject to the constraints described in paragraph (8), and relying on the decision variables pursuant to paragraph (7), the EVA shall either

   (a) assess economic viability of (groups of) capacity resources, pursuant to paragraphs (4) and (5); or

   (b) minimise the overall system cost, pursuant to paragraph (6).

3. The evolution of capacity resources based on exogenous assumptions according to the national baseline data as described in Article 3 may be excluded from the EVA, i.e. the EVA may abstain from affecting these exogenous assumptions.

4. If the EVA assesses the economic viability of capacity resources within the study time period, for each capacity resource and target year, economic viability shall be defined based on the difference between revenues pursuant to paragraph (9) and costs pursuant to paragraph (10). A capacity provider shall be viable if (and only if) its revenues are higher than or equal to its costs.

5. Based on the economic viability of each capacity resource, the EVA shall

   (a) keep existing economically viable capacity resources in the market;

   (b) consider re-entry of previously mothballed capacity if the mothballed capacity is viable;

   (c) consider removing or mothballing non-viable capacity resources from the model;

   (d) consider renewing or prolonging viable existing capacity resources (if applicable); and

   (e) consider adding new viable capacity resources.

6. As a simplification, and assuming perfect competition, the EVA may minimise overall system costs, i.e. the sum of:

(a) fixed costs (consistent with the CONE and CORP values used within the RS methodology) based on data from Article 5(10); and

(b) total operating costs resulting from the ED.

In this case, the entry and exit decisions shall be assessed together for all capacity resources (as substitutional effects between capacity resources may occur).

7. For each target year and modelled zone, the EVA shall include the following decision variables:

(a) decommissioning/mothballing of existing capacity resources;

(b) investment in new capacity resources (such as generation, storage or DSR);

(c) re-entry of mothballed capacity resources; and

(d) renewal/prolongation of existing capacity resources.

8. For each target year, the EVA shall fulfil the following constraints:

(a) the demand pursuant to paragraph (11);

(b) the capacity resources and their technical constraints pursuant to paragraph (12);

(c) the network constraints (including reserve requirements) pursuant to paragraph (13);

(d) the market and regulatory constraints expected to apply pursuant to paragraph (14);

9. For each scenario and sensitivity, and for each considered target year, the revenues of a capacity provider shall be equal to the sum of all revenues expected to be collected by the capacity resources of the capacity provider, i.e.:

(a) expected revenues from the wholesale electricity market. Expected revenues from the wholesale electricity market shall be based on the expected prices (or expected marginal costs) of the relevant modelled zone(s) based on ED results according to Article 7(10) (and on actual prices from forward markets when applicable). The expected ED prices shall be consistent with the probability-weighted average of the simulated prices over the MC sample years (without risk premium). In particular,

i. for target years for which forward market sessions took place during or before SY, actual prices from forward markets may be assumed to reflect expected prices.

ii. for target years (after the considered target year) for which hedging products are expected to be available (i.e. for the next few target years after the considered target year), expected ED prices may be used to determine expected revenues from electricity markets.

iii. for target years (after the considered target year) for which hedging products are expected to be unavailable or unable to fulfil the hedging needs of the capacity resources[2],

1. additional approaches (such as "value at risk") may be used to account for the price risk due to this lack of forward products. Such additional

[2] The need for hedging products may differ depending on the type of capacity resource.

approaches shall be elaborated with ACER and other relevant stakeholders, including market parties and investors and following the consultation process described in Article 9; or

2. a market-conform and transparent increase in the WACC for these target years may be used to account for this price risk; the principles underlying the WACC increase shall be consistent with the WACC calculation guidelines from the CONE methodology.

These revenues shall only be included for capacity resources expected to participate in the wholesale electricity market;

(b) expected revenues from other electricity-related services. In particular, revenues from ancillary services (including FCR, FRR and RR where these services are remunerated) shall be considered, based on best forecast. To the extent possible, the estimation of expected revenues shall account for realistic network operation within the considered scenario for the concerned modelled zone. Revenues from other electricity-related services which are already modelled in the ED shall be estimated pursuant to paragraph (a)[3]. The expected revenues from other electricity-related services shall anticipate the likely impact of the measures referred in Article 20(3) of Electricity Regulation. These revenues shall only be included for capacity resources expected to provide other electricity-related services (e.g. revenues from ancillary services shall not be considered for capacity resources procured for strategic reserves);

(c) expected revenues from services outside the electricity sector. Additional revenues (e.g. from heat supply) shall be considered based on best forecast;

(d) expected revenues from subsidies. Expected revenues stemming from subsidies, support schemes, policies or incentives shall be considered. As a simplification, when specific installed capacity targets are defined for some technologies pursuant to paragraph 14(c), expected revenues stemming from subsidies, support schemes, policies or incentives may be assumed to ensure that the installed capacity target is reached, hence EVA may not be performed in such cases for these technologies; and

(e) expected revenues from CMs. All scenarios and sensitivities shall reflect revenues coming from CM contracts already awarded at the time of the assessment. In the central reference scenario (or sensitivity) with CM in the considered modelled zone for the considered target year, additional CM revenues shall be considered based on best forecast of the expected CM functioning in line with Article 5(15). These revenues may be assumed to ensure that the reliability standard set in the considered modelled zone (pursuant to Article 25 of Electricity Regulation) is fulfilled.

10. For each scenario, modelled zone and target year, the costs of capacity resources shall be equal to the sum of all costs expected to be incurred by the capacity resources, consistently with the CONE and CORP calculation process according to the CONE and RS methodologies. These costs shall be computed based on the data described in Article 5(10). For scenarios with CM in the considered modelled zone, if EVA relies on economic viability pursuant to paragraphs (4) and (5) and if the capacity resource receives CM payments pursuant to paragraph 9(e), the WACC may be reduced (if properly justified) to reflect the lower risk premium perceived by the capacity resource (due to a different risk allocation).

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[3] For example, only revenues coming from the activation of RR for duration shorter than one MTU (if any) shall be included pursuant to this paragraph, as other revenues related to RR activation are endogenously modelled in the ED.

11. The demand for EVA shall reflect demand (excluding DSR) for each target year and modelled zone pursuant to Article 4(3).

12. The generation, DSR and storage constraints shall be modelled in line with Article 4(3), (4) and (5). Furthermore, a maximum potential of NGC may be defined per technology, modelled zone and target year. In this case, the maximum potential of NGC shall be consistent with the capacity potential estimated for the new entrant and renewal/prolongation in the RS methodology.

13. The network constraints (including modelling of balancing reserves, when relevant) shall be modelled pursuant to Article 4(6).

14. The EVA shall reflect the following market and/or regulatory constraints:

    (a) in modelled zones with CM for a considered target year, constraints related to CM payments for units exceeding the CO_2 emission limits, as referred to in Article 22(4) of Electricity Regulation;

    (b) phase-out or restrictions of specific technologies (e.g. coal or nuclear);

    (c) binding targets for the integration of specific technologies (e.g. RES or energy efficiency); and

    (d) other market and/or regulatory constraints which are expected to apply in a target year, and which are expected to impact significantly the overall system costs or the economic viability of capacity providers. These constraints may include, inter alia, price restrictions, regulatory or policy restrictions on investments, regulatory or policy uncertainty.

15. The EVA may be refined to consider the effect of risk management towards price volatility and price spikes, considering the state-of-the-art experience in the industry. In this case, the risk management strategy (regarding revenues) should be consistent with the assumptions underlying EENS and LOLE.

16. The remaining economic lifetime (beyond the end of the study time period) of the capacity resources shall be considered, together with WACC, in depreciating the CAPEX (both for existing and new-built capacities) within the period of the assessment. The EVA may take boundary conditions into account, to reflect the expected costs and benefits of a capacity resource beyond the study time period.

17. ENTSO-E shall study the stability and trustworthiness of the EVA results. ENTSO-E shall ensure that the assumptions of the model are consistent with relevant national policies, generation capacity forecasts and feedbacks from national market parties, e.g. expressed within the national consultations as referred in Article 9. In case of instability or untrustworthiness of the results, the reliability of the assumptions shall be assessed and when needed revised appropriately to strengthen the EVA. ENTSO-E may use the data collected pursuant to Article 5 to calibrate the EVA.

18. Until 2023, ENTSO-E may simplify the EVA by manually assessing market entry and exit. In this case, the manual EVA shall reflect the main requirements set out in paragraphs (1) to (17).

19. ENTSO-E shall experiment with the EVA described in paragraphs (1) to (17) through a proof-of-concept stage, and shall publish a report (no later than the end of 2021) describing at least:

    (a) the experiment conducted, including the methodologies tested and the results obtained;

    (b) the issues faced; and

(c) the suggested target implementation of a full-fledged EVA.

Article 7. Economic dispatch

1. For each MC sample year (based on a given scenario or sensitivity), ENTSO-E shall run an ED to estimate ENS and to inform the EVA.

2. The ED shall assume perfect foresight of generation, storage and demand availability in line with Article 4.0. The window over which perfect foresight is assumed may depend on the considered technology.

3. The ED shall determine the dispatch of generation, storage and demand units in order to meet demand for every MTU of the MC sample year, while minimising the total system operating cost. The ED shall at least model individually each modelled zone; it may rely on a higher level of spatial detail. In this case, the input data shall be refined accordingly.

4. The total system operating cost shall include:

   (a) generation cost, including at least short-term variable cost, pursuant to Article 5(10);

   (b) DSR activation cost and demand elasticity;

   (c) storage operating cost; and

   (d) cost of ENS pursuant to paragraph (8).

5. The ED shall reflect the following constraints:

   (a) technical constraints of generation per modelled zone and MTU, pursuant to Article 4(4). The ED may reflect start-up and switch off decisions in detail, i.e. it may reflect a unit commitment economic dispatch, in order to improve the quality of the simulated dispatch;

   (b) demand (including DSR) per modelled zone and MTU, pursuant to Article 4(3);

   (c) available storage, including technical constraints, pursuant to Article 4(5);

   (d) planned and unplanned outages per modelled zone and MTU, pursuant to Article 4.2(d)ii;

   (e) available cross-zonal capacity per modelled zone border and MTU, pursuant to Article 4(6);

   (f) reserves and balancing requirements per modelled zone and MTU, pursuant to Article 4.6(g); and

   (g) exchanges with non-explicitly modelled systems, pursuant to Article 4(7).

6. The ED shall consider that forced demand disconnection, as a non-market-based measure, is a measure of last resort, which shall be activated if all options provided by the market have been exhausted, or where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation, in line with Article 16 of the RPR and with Articles 11(5)(b)(v) and 22 of the E&R NC and any other relevant national legislation related to load-shedding procedures.

7. In line with Article 22(2) of Electricity Regulation, the ED shall reflect that strategic reserves are to be dispatched only if a TSO is likely to exhaust its balancing resources to establish an equilibrium between demand and supply, without prejudice to the activation of capacity resources before actual

dispatch in order to respect the ramping constraints and operating requirements of these capacity resources.

8. To ensure consistency with the EVA, the cost of ENS shall reflect price formation during hours when ENS occurs in a considered modelled zone, and shall be equal to the harmonised limit on maximum clearing price (pursuant to Article 10(1) and (2) of Electricity Regulation) unless indirect restrictions to wholesale price formation (pursuant to Article 10(4) and (5) of Electricity Regulation) impact price formation during MTUs with ENS in the considered modelled zone.

9. The ED should reflect price formation to estimate a price for each modelled zone and each MTU. In this case, the following elements shall be reflected, if they are expected to impact significantly the EVA or the ED:

   (a) harmonised limits on maximum and minimum clearing prices pursuant to Article 10(1) and (2) of Electricity Regulation;

   (b) indirect restrictions to wholesale price formation (and mitigating measures) pursuant to Article 10(4) and (5) of Electricity Regulation

   (c) pursuant to Article 23(5)(c) of Electricity Regulation, the likely impact of measures adopted pursuant to Articles 10(5) and 20(3) of Electricity Regulation, including e.g. shortage pricing function for balancing energy; and

   (d) the impact of cross-zonal capacity allocation (e.g. flow-based, adequacy patch or other demand-curtailment sharing expected to apply in single day-ahead coupling), in line with CACM Regulation.

   The modelling of these elements may be simplified to ensure a feasible implementation.

10. The ED simulation shall provide the following results for each MC sample year and MTU:

   (a) the total operating cost in EUR;

   (b) for each (group of) generation unit, the production in MW;

   (c) for each (group of) storage unit, the injection or withdrawal in MW;

   (d) for each (group of) DSR unit, the activated DSR in MW;

   (e) the change in demand due to demand elasticity in MW;

   (f) for each modelled zone, the ENS before activation of out-of-market capacity resources, in MW;

   (g) for each modelled zone, the ENS after activation of out-of-market capacity resources, in MW;

   (h) for each modelled zone, the short-term marginal cost in EUR/MWh;

   (i) for each modelled zone, the price in EUR/MWh (if price formation is modelled for the considered MTU according to paragraphs (8) and (9));

   (j) for each modelled zone, the net position in MW;

   (k) for each modelled zone border, the commercial cross-zonal exchange in MW; and

(l) for each CNEC, the physical flow in MW, and the shadow price in EUR/MW.

11. The ED simulations shall at least provide the following results for each target year:

    (a) the EENS before activation of out-of-market capacity resources, in MWh;

    (b) the EENS after activation of out-of-market capacity resources, in MWh;

    (c) the LOLE before activation of out-of-market capacity resources, in h; and

    (d) the LOLE after activation of out-of-market capacity resources, in h.

12. For each modelled zone, the activation of out-of-market capacity resources shall reflect scenario assumptions (e.g. related to presence of strategic reserve), expected operational TSO practices and applicable legal framework for the considered target year. The modelling of out-of-market capacity resources may be simplified to ensure a feasible implementation.

13. ENTSO-E may use the data collected pursuant to Article 5 to calibrate the ED.

Article 8. Identifying a resource adequacy concern

1. For a given target year and modelled zone, ENTSO-E shall identify a resource adequacy concern if (and only if):

    (a) the relevant MS or competent authority designated by the MS (or MSs or competent authorities designated by the MSs in the case of cross-border modelled zones) has set a reliability standard for the target year and modelled zone pursuant to Article 25 of Electricity Regulation, based on the RS methodology; and

    (b) the reliability standard is not fulfilled for the target year for at least one central reference scenario. Where the reliability standard is defined solely as $LOLE_{RS}$ by the relevant MS (or MSs in the case of cross-border modelled zones), the reliability standard is not fulfilled for a target year and modelled zone, if the LOLE after activation of out-of-market capacity resources pursuant to Article 7.11(d) is higher than the $LOLE_{RS}$ (in at least one central reference scenario). When other criteria are used in the definition of the RS, the fulfilment of the RS should be established accordingly in a transparent manner.

2. For a given target year, scenario or sensitivity and modelled zone, ENTSO-E may separately assess whether the reliability standard is fulfilled, following the approach set out in paragraph 1(b).

3. Pursuant to Article 23(5)(k) of Electricity Regulation, for each resource adequacy concern identified pursuant to paragraph (1), ENTSO-E shall identify the possible source(s) of the resource adequacy concern. The possible source(s) of the resource adequacy concerns shall be assessed at least via:

    (a) the impact of indirect restrictions to price formation assessed in line with Article 3(7);

    (b) the percentage of MTUs corresponding to ENS occurring simultaneously in multiple neighbouring modelled zones, to the total amount of MTUs with ENS; and

    (c) the analysis of generation, demand, cross-zonal capacity and cross-zonal exchanges of a modelled zone and its connected neighbouring systems during MTUs with ENS.

Article 9. Stakeholder interaction

1. While complying with the methodology framework, the ERAA shall, to the extent possible, take advantage of the latest innovations and improvements in terms of data accuracy, data granularity and computing power, in order to maintain a state-of-the-art approach. ENTSO-E shall strive to keep abreast of the latest innovations in Europe and globally, especially through interactions with academia, research institutions, industry experts and financial experts.

2. Pursuant to Article 23(7) of Electricity Regulation, the ERAA methodology, scenarios, sensitivities, and assumptions as well as results of the assessment shall be subject to the prior consultation of MSs, the ECG and relevant stakeholders and approval by ACER under the procedure set out in Article 27 of Electricity Regulation.

3. ENTSO-E shall establish adequate interaction channels for all relevant stakeholders, including civil society, to contribute to each step of developing the proposals for the ERAA methodology, the scenarios, the assumptions, and results, through a transparent, open, accessible, inclusive, efficient, and well-structured process. Such channels shall include:

    (a) stakeholder workshops and webinars to gather inputs and suggestions ahead of finalizing the proposals for the ERAA methodology and the report, and to address stakeholder questions;

    (b) public consultations; and

    (c) visibility on forward planning for the next steps through the ENTSO-E Annual Work Program for each year ahead.

4. ENTSO-E shall hold the following consultations on the ERAA methodology, scenarios, assumptions, sensitivities and results:

    (a) A yearly public consultation on assumptions and high-level definition of scenarios with their assumptions. This consultation shall be published and shall include at least prices of CO_2 emission allowance, fuel prices, demand, DSR potential, storage, cross-zonal capacities and an overview of generation capacity by type of technology per MS. In particular, exogenous assumptions shall be properly consulted. This yearly public consultation may align with the biennial consultation the ENTSOs' TYNDP scenario framework.

    (b) The ECG shall be consulted regarding the ERAA methodology, scenarios, sensitivities and assumptions. ENTSO-E shall present an overview of the preliminary results of the ERAA to the ECG as soon as available and before the publication of the ERAA report.

    (c) Comments received from the ECG or other stakeholders during the public consultation shall be considered in improving the ERAA. These comments should not delay the annual publication of the ERAA, unless they seriously challenge the credibility or acceptance of the ERAA results. ENTSO-E shall provide a reply to the stakeholders' comments received during the public consultation for each ERAA.

    (d) The results of the ERAA depend heavily on the chosen scenarios and the quality of the data collected. During the public consultation on the scenarios, assumptions and sensitivities of the ERAA, ENTSO-E shall ensure that all stakeholders have the opportunity to check, compare and benchmark the data and the assumptions used in the assessment.

    (e) In line with Article 11, the results of each ERAA, together with the assumptions on which they are based and the data related to the different scenarios and sensitivities, shall be published on ENTSO-E's website alongside the ERAA report.

5. All ENTSO-E's consultations shall comply with Article 31 of Electricity Regulation.

Article 10. Assessment process

1. The data collection and different stakeholder interactions, as described in Article 5 and Article 9, shall occur in the following order:

   (a) ENTSO-E shall publish data collection guidelines and model assumptions and shall provide them along with data templates to each TSO;

   (b) TSOs shall fill in the data templates according to the data collection guidelines;

   (c) ENTSO-E shall collect the TSO data, execute data quality checks, prepare and store the data in the PEMMDB;

   (d) ENTSO-E shall prepare and consolidate economic and technical data to perform EVAs;

   (e) ENTSO-E shall publicly consult on a yearly basis, pursuant to Article 9.4(a);

   (f) ENTSO-E shall consult the ECG regarding the scenarios, sensitivities, input variables and assumptions;

   (g) ENTSO-E shall execute the ERAA calculations and analyse the results;

   (h) ENTSO-E shall present an overview of the preliminary results of the ERAA to the ECG and relevant stakeholders as soon as available and preferably before the publication of the ERAA report;

   (i) ENTSO-E shall incorporate comments received from the ECG or other stakeholders during the consultation into the relevant edition of the ERAA, pursuant to Article 9.4(c);

   (j) ENTSO-E shall publish the report containing the results of each ERAA on the ENTSO-E website, together with the assumptions on which they are based and the data related to the different scenarios, pursuant to Article 11.

2. By 1 November each year, ENTSO-E shall submit the scenarios, sensitivities, assumptions and results of the ERAA to ACER for approval pursuant to Article 23(7) of Electricity Regulation.

Article 11. Transparency requirements

1. In line with ENTSO-E's obligation to operate in full transparency towards stakeholders and the general public pursuant to Article 41(2) of Electricity Regulation, ENTSO-E shall ensure full transparency of the ERAA. In particular, the ERAA report shall strive to facilitate stakeholders' understanding regarding the inputs, data, assumptions, and scenario (and sensitivity) development. The ERAA report shall also include an executive summary.

2. For each ERAA, ENTSO-E shall publish on its website the ENTSO-E data collection guidelines pursuant to Article 5.1(a);

3. For each ERAA, ENTSO-E shall publish on its website at least the following input data for each scenario and sensitivity:

   (a) high level assumptions, economic and technical data to perform the EVA pursuant to Article 6, with relevant temporal granularity and at least per modelled zone;

(b) high level assumptions, economic and technical data to run the ED pursuant to Article 7, with relevant temporal granularity and at least per modelled zone;

(c) the PECD pursuant to Article 5(12);

(d) the main assumptions underlying the modelling of the harmonised limits on maximum and minimum clearing prices pursuant to Article 10(1) and (2) of Electricity Regulation, in line with Article 5(13); and

(e) The indirect restrictions to wholesale price formation and mitigating measures pursuant to Articles 10(4) and (5) and 20(3) of Electricity Regulation, which were quantitatively modelled pursuant to Article 5(14), and the main assumptions underlying the modelling.

4. For each ERAA, ENTSO-E shall publish on its website at least the following output data for each scenario and sensitivity:

(a) aggregated outputs from EVA, at least with yearly temporal granularity and per modelled zone;

(b) for each MC sample year and modelled zone, the prices (if generated by ED), marginal costs, net positions and ENS per MTU, upon request of any stakeholder;

(c) for each MC sample year and modelled zone border, the cross-zonal exchanges per MTU, upon request of any stakeholder;

(d) EENS and LOLE before and after activation of out-of-market capacity resources pursuant to Article 7(11) for the study time period, for each modelled zone with yearly temporal granularity;

(e) for each target year and modelled zone, the distribution (including the average) of total ENS and LOLE over all considered MC sample years;

(f) for each target year and modelled zone, the distribution (including the average) of net position of the modelled zone during hours when ENS is positive over all considered MC sample years, pursuant to Article 7(10), upon request of any stakeholder;

(g) for each target year, the number of analysed MC sample years and the value of the coefficient of variation (α) of the EENS metric pursuant to Article 4.2(e); and

(h) for neighbouring modelled zones with a positive EENS or LOLE, an analysis of the different situations when ENS simultaneously occurs in modelled zones. Different simultaneous ENS situations at both regional and/or European level shall be indicated.

5. In case of instability or untrustworthiness of EVA results, ENTSO-E shall clearly describe and justify in the ERAA report the additional (or revised) assumptions enforced to strengthen the trustworthiness of the EVA, as referred to in Article 6(17). Similarly, if ENTSO-E relies on a manual EVA pursuant to Article 6(18), the main assumptions describing the manual process shall be published.

6. Each ERAA report shall include any policies, measures or actions which, while not modelled in the ERAA, are expected to significantly impact resource adequacy concerns. These shall include:

(a) indirect restrictions to wholesale price formation, pursuant to Article 10(4) of Electricity Regulation;

(b) actions to eliminate or, if not possible, to mitigate the impact of that policy or measure on bidding behaviour, pursuant to Article 10(5) of Electricity Regulation ; and

(c) measures to eliminate any identified regulatory distortions or market failures, as defined by MSs pursuant to Article 20(3) of Electricity Regulation.

The ERAA report shall qualitatively assess how the aforementioned elements not modelled in the ERAA may impact ERAA results.

7. The level of detail of published data shall be consistent with the level of implementation of the ERAA methodology at the time of publication, in line with Article 12. The published data shall include the list of additional data items available upon request.

8. Within 3 months of the approval of the ERAA methodology, ENTSO-E shall publish a roadmap describing the implementation phase referred to in Article 12. This roadmap shall be updated on an annual basis, following the publication of each edition of the ERAA report. ENTSO-E shall publicly consult any significant change in the roadmap.

9. Where ENTSO-E identified as confidential a set or a subset of data (or information) to publish, ENTSO-E may publish the relevant data (or information) in such aggregated form which still preserves their confidentiality. When publishing the aggregated data (or information), ENTSO-E shall explain why publishing the data (or information) required would cause harm.

10. Upon request and for each ERAA, ENTSO-E shall provide ACER with all the information necessary for the purpose of carrying out ACER's tasks pursuant to Article 23(7) of Electricity Regulation, unless ACER has already requested and received such information, in line with Article 3(2) of the ACER Regulation.

11. Upon request, for each ERAA and for each central reference scenario, ENTSO-E shall provide all the relevant information to MSs and to the bodies that are responsible for the national resource adequacy assessments, for example for the execution of the tasks pursuant to Article 24 of Electricity Regulation.

12. ERAA data shall be shared between ENTSO-E and RCCs. In particular, for each ERAA, ENTSO-E shall provide RCCs with all the relevant information for the calculation, on annual basis, of the maximum entry capacity available for cross-border participation in capacity mechanisms pursuant to Article 26(7) of Electricity Regulation.

13. Upon request and for each ERAA, ENTSO-E shall provide the NRAs with all the information necessary for the purpose of carrying out regional cooperation tasks pursuant to Article 61(2)(c) of Electricity Directive.

Article 12. Implementation of the methodology

1. The ERAA methodology shall be used as the methodology for conducting the ERAA by ENTSO-E. The ERAA methodology shall be fully implemented by the end of 2023.

2. The ERAA methodology may be implemented through a gradual process, whereby ‘proof of concept’ testing and impact assessment of the different methodological elements should ensure that they are mature enough before they become an integral part of the ERAA. Such an approach strikes a balance between accuracy and feasibility of the targeted improvements.

3. ENTSO-E should assess whether the implementation of the ERAA methodology may lead to cybersecurity risks. If it is the case, ENTSO-E shall report on such risks (and potential mitigation measures) to ACER without undue delay.

4. ENTSO-E may suggest potential improvements of the ERAA methodology to ACER. Irrespective of any suggestion from ENTSO-E, ACER may request amendments to the ERAA methodology pursuant to Article 27(4) of Electricity Regulation.

Article 13. Language

1. The official language for the ERAA methodology shall be English.