European Network of
Transmission System Operators
for Electricity

European Resource Adequacy Assessment - Methodology Proposal in accordance with Article 23 of the Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)

Date: 22 April 2020

Contents

Whereas

This document is developed by the European Network of Transmission System Operators for Electricity (hereafter referred to as "ENTSO-E") regarding a European Resource Adequacy Assessment (hereafter referred to as "ERAA") Methodology (hereafter referred to as "Methodology") 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".

1. The Methodology takes into account the general principles and goals set in the Electricity Regulation as well as the European Union (EU) legal framework, in particular:
    a) 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");
    b) 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");
    c) Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as "CACM Regulation");
    d) Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO GL");
    e) 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")
2. One of the goals of the Electricity Regulation is to ensure the most effective and efficient provision of resource adequacy within the EU. A common approach—through this Methodology—in all resource adequacy assessments whether carried out at national, regional or Union level is key to achieve this goal.
3. Article 23(3) of the Electricity Regulation sets the legal basis and requirements for the Methodology developed by ENTSO-E. It shall be based on a transparent methodology which shall ensure that each assessment is in line with the provisions set in Article 23(5) of the Electricity Regulation.
4. Upon its adoption, ENTSO-E will use this Methodology, as required by Article 23(1) of the Electricity Regulation, to identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demands for electricity at Union level, at the level of the Member States and, where relevant, at the level of individual bidding zones. ERAA shall be carried out on an annual basis covering each year within a period of 10 years ahead from the date of assessment. ERAA assesses the impact of system development trends on resource adequacy. System development trends include change of generation capacity mix, change of demand patterns, network developments and others. As a result of these assessments, policy makers and other relevant stakeholders might take actions to ensure that reliability standards are satisfied. ENTSO-E and its transmission system operator (TSO) members shall not be held responsible in case the hypotheses taken in this assessment or the estimations based on these hypotheses are not realised in the future.
5. Complementary national resource adequacy assessments (hereafter referred to as "NRAA") may be conducted, shall have a regional scope and shall be based on the Methodology, in particular taking into consideration points (b) to (m) of Article 23(5) of the Electricity Regulation. Article 24 of the Electricity Regulation specifies the principles for NRAAs. Where the NRAA identifies an adequacy concern with regard to a bidding zone that was not identified in the ERAA, the NRAA shall include the reasons for the divergence between the two resource adequacy assessments, including details of the sensitivities used and the underlying assumptions.

6. Stakeholder interaction shall provide visibility and transparency on the scenarios, the assumptions, and the results as well as on the implementation of the Methodology for each ERAA report. Sufficient interaction channels shall be provided to ensure that all market participants and relevant national authorities 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 assessment.
7. In conclusion, the Methodology contributes to the general objectives of the Electricity Regulation to the benefit of all market participants and electricity consumers.

Article 1
Subject matter and scope

1. This Methodology shall be used to identify resource adequacy concerns by assessing the overall adequacy of the electricity system and its ability to supply projected demand levels for electricity at Union level, at the level of the Member States and at the level of individual bidding zones, where relevant, in accordance with Article 23(1) of the Electricity Regulation. The Annexes constitute an integral part of the Methodology and shall be read together with its provisions.
2. The Methodology shall be transparent and ensure that each assessment:
   a) is carried out on each bidding zone covering at least all Member States;
   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/flexibility, sectorial integration, demand side response, and import and export and their contribution to flexible system operation;
   e) anticipates the likely impact of the measures to eliminate any identified regulatory distortions or market failures as a part of the State aid process, as referred to in Article 20(3) of the 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 the following indicators referred to in Article 25 of the Electricity Regulation: — 'expected energy not served', and — 'loss of load expectation';
   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;

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. The Methodology, after ACER approval or amendment, shall be adopted by ENTSO-E as the basis for the ERAA.
4. The Methodology, after ACER approval or amendment, shall also serve as a reference method, without prejudice to innovation going beyond it, for NRAAs and regional adequacy assessments. NRAAs may make assumptions on the particularities of national electricity demand and supply, use tools and consistent recent data that are complementary to those used by ENTSO-E for the ERAA and, when assessing the contribution of capacity providers located in another MS to the security of supply of the bidding zones they cover, shall use the methodology as provided in point (a) of Article 26(11) of the Electricity Regulation.
5. The Methodology does not limit the geographical scope of the analysis. ERAAs performed by ENTSO-E shall have explicitly modelled systems covering at least the region composed of ENTSO-E members and other TSOs for which Articles 81, 106 and 107 of the SO GL apply. ENTSO-E (itself and its members) shall continuously engage operators of other interconnected systems to establish and foster cooperation. If tightly interconnected neighbouring regions commit to cooperation on adequacy assessments, they should be modelled in the same level of detail as the core analysed regions. Otherwise, the contribution to pan-European adequacy of those systems will be considered based on the assumptions of ENTSO-E's members having direct interconnections with those systems.
6. The temporal and spatial granularity of the ERAA and any national/regional resource adequacy assessment, shall respect at minimum the granularity defined in the Methodology.

Article 2
Definitions and interpretation

1. For the purposes of the Methodology, the terms used in this document shall have the meaning of the definitions included in Article 2 of Electricity Regulation, RPR, Electricity Directive, CACM and SO GL.
2. The following additional definitions shall also apply:

a) 'Planned outage' means a state of an asset 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.

b) 'Unplanned outage' means a state of an asset when it is not available in the power system and the outage was not planned.

c) 'Unit Commitment and Economic Dispatch' (UCED) means a mathematical optimisation model, which determines the commitment schedule of supply and demand units and their level of dispatch, in order to meet demand for every time-step of the modelling horizon. The objective function of the problem minimizes the total system operating cost, while satisfying the operational constraints of the power system. The total system operating cost is meant as the sum of all short-run operating cost (fuel costs, emission costs, variable operation and maintenance costs, unserved energy costs): the cost of unserved energy is assumed very high and load shedding is used as last resort to allow feasibility of the optimisation problem.

d) 'UCED time resolution' means the time resolution of the UCED problem is equally to the market simulation resolution, i.e. hourly.

e) 'Non-explicitly modelled systems' means electric systems which are directly interconnected with a member of the modelled power system and are modelled in a simplified way as fixed exchanges with the interconnected zone.

f) '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 this Methodology.

g) 'Market-based measures' means any supply or demand measures available in the system complying with market rules and commercial agreements and participating to the Internal Market for Electricity. This includes all measures participating in Capacity Mechanisms (CMs) which are participating to the Energy Only Market (EOM).

h) 'Zone' means either a bidding zone or a country, depending on the level of data granularity available. Note that, reliability standards are defined by country and not by bidding zone.

i) 'Loss of Load Expectation' (LOLE) means, in a given zone and in a given time period, the expected number of hours in which resources are insufficient to meet the demand.

j) 'Expected Energy Not Served' (EENS) means, in a given zone and in a given time period, the energy which is expected not to be supplied due to insufficient resources to meet the demand. In the context of this Methodology, Energy Not Served (ENS) refers to the simulated unserved energy, calculated for each hour of the simulation.

k) 'Demand' means the total load observed in the transmission system, including network losses.

l) 'Net Generating Capacity' (NGC) of a generation unit means the maximum electrical net active 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 (weather, climate etc.) and full availability of fuels;

    iii. for hydro, solar and wind units, 'normal conditions' means the usual maximum availability of primary energies, i.e. optimum water, solar or wind conditions.

m) 'Flow-based Market Coupling' (FBMC) means a mechanism to couple different electricity markets, increasing the overall economic efficiency, while considering the available transmission capacity between different bidding zones using the flow-based approach/model

n) 'Capacity calculation methodology' (CCM) means the capacity calculation methodology expected to be operational for the considered target year.

o) 'Strategic reserve' means a CM in which designated resources are not available on the EOM and are only dispatched in the case where TSOs are likely to exhaust their balancing resources to establish an equilibrium between demand and supply.

p) ‘Demand-side response’ (DSR) is defined as follows:

   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 dispatchable demand;

   ii. ‘Implicit demand-side response’ (Implicit DSR) means the change of electricity load 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.

q) ‘Revenues’ means the income that a given asset receives from the market. For the EOM, the revenues of each capacity are calculated based on the ‘inframarginal rent’. The inframarginal rent for a given capacity is defined as the difference between the revenues of the asset in the energy market (System Marginal Price [€/MWh] multiplied by the Energy Delivered [MWh]) and the variable costs defined below.

r) ‘Capital Expenditures’ (CAPEX) or ‘overnight cost’ mean the investment required to develop, construct and refurbish a plant without considering the financial costs (e.g., interest costs) or the structure of financing (equity versus debt) i.e. the investment required if the plant were to be built in a single night at the current prices.

s) ‘Annual Fixed Costs’ means costs incurred in the context of operation of a capacity resource each year once the capacity resource starts operating, independently from the generated or curtailed energy volume.

t) ‘Fixed costs’ refers to CAPEX and annual fixed costs; Further hypotheses on discount rates (see below) are considered to convert CAPEX into Annuity values in the economic viability checks.

u) ‘Variable costs’ refers to fuel costs, CO2 costs and variable Operating Expenditures (OPEX)/variable Operations and Maintenance (O&M) costs. Fuel and CO2 prices shall be defined centrally, considering available economic expertise and projections in Europe. Variable OPEX/variable O&M costs are non- fuel operations and maintenance costs that includes cost of consumable materials (ammonia, limestone, water, etc.), production by-products handling (ash, slug, etc.) and maintenance costs that may be scheduled based on the number of operating hours or start- stop cycles of the plant.

v) ‘Policy-driven asset’ means a generation, demand side response or storage asset for which investment is decided and executed based on the support from subsidies or incentives, as well as assets for which a policy is developed on a national level and for which investment decisions are therefore not solely depending on an economic trade-off and/or assets for which no new investments are possible due to e.g. a phase-out policy. An asset can be a policy-driven asset and then, after some duration of time, change its status to non-policy.

w) ‘Non-policy-driven asset’ means a generation, demand side response or storage asset for which investment is decided and executed without any consideration of support from subsidies or incentives or policy considerations, excluding support from existing Capacity Mechanisms. Hence such assets rely on expected revenues from the EOM, CMs and any other relevant additional revenues if robust estimates exist on these to ensure long-term investments.

x) ‘Economic lifetime’ means the number of years within which the initial investment cost is expected to be recovered by rational investors.

y) 'Construction time' means the number of years needed between the moment the investment decision is taken and the date of commissioning of the investment.

z) 'Discount rate' expresses the time value of money and converts future cashflows 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 after commissioning of the asset/plant. Multiplying the future cashflow by the respective discount factor k converts it to the equivalent value it would hold at the year of commissioning.

aa) 'Weighted Average Cost of Capital' (WACC) means the cost of capital of a business firm in which each category of capital is proportionally weighted. All sources of capital, including common stock, preferred stock, bonds and any other long-term debt, are included in a WACC calculation.

bb) 'Annuity' means the annualised CAPEX (considering WACC).

cc) 'Target year' (TY) means a year simulated within the ERAA.

dd) 'Publication year' (PY) means the year when resource adequacy assessment results are officially published.

3. In this Methodology Proposal, unless the context requires otherwise:
   - the singular indicates the plural and vice versa;
   - the table of contents and headings are inserted for convenience only and do not affect the interpretation of this Methodology; and
   - 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 from PY+1 until PY+10. The ERAA assessment for PY+1 shall 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. These national forecasts shall ensure quality and consistency with most recent national consultations and policies.
3. The baseline data for the ERAA are the national projected demand, supply and grid outlooks prepared by each individual TSO, considering:
   a) national objectives, targets and contributions, and other projections contained in the National Energy and Climate Plans (NECPs), as referred in Article 3 of the Governance Regulation, including trends related to coal phase-out, nuclear phase-out, renewable energy development, storage, sectorial integration, DSR and energy efficiency measures. For times between NECP publication and its subsequent updates, scenarios shall be aligned with the Ten-Year Network Development Plan (TYNDP) biennial scenario building process relying on most up-to-date data incorporating recent economic, demographic, political and technological trends;

b) best estimates regarding the state of the grid in line with the TYNDP and the most recent national development plans;

c) known trends/assumptions regarding mothballing, construction of new assets, existing contracts under current or past CM auctions and estimates on available capacity under current and planned CMs approved within State Aid rules pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union (TFEU).

4. An economic viability check shall be performed on the baseline data according to Article 6, for the Central Reference Scenarios, referred to in paragraph Article 3(5) below. Non-policy, non-viable resources, as defined in Article 6, are removed from the Scenario and, non-policy, viable new resources, as defined in Article 6, are added to the Scenario within the economic viability check. The ERAA report shall clearly show how the baseline data referred to in Article 3(3) has been modified within the economic viability check.

5. The ERAA shall be performed for the following "Central Reference Scenarios":

a) **Scenario with CMs:** this scenario considers that CMs, as approved in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union (TFEU) and applicable[1] at the time of the assessment, provide additional revenues beyond the revenues from the EOM within the 10-year period, or within part of the 10-year period, covered by the assessment and with the purpose of ensuring that the reliability standard of the country is fulfilled at least cost. Constraints such as limits on capacities available (e.g. constraints on demand response), legal and administrative hazard, hazards with impact on availability, building delays, stop-loss limits, may however justify in specific cases that the Reliability Standard is not always fulfilled at any price. Strategic reserves, despite being out-of-market resources, shall be considered under the framework of CM, when applicable. Strategic reserves shall neither affect the outcome of the economic viability assessments nor the market-based probabilistic calculations. Strategic reserve contribution shall solely relate to the calculation of the adequacy indicators after economic viability as well as after market-based probabilistic calculations and, by default, only for the country in which the strategic reserve is contracted. Cross-border contribution of strategic reserves shall be considered only if approved in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union (TFEU), but neither affect the economic viability nor the probabilistic assessment results for countries without contracted strategic reserve.

b) **Scenario without CMs:** this scenario considers that CMs, as approved in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the TFEU and applicable at the time of the assessment, do not provide additional revenues to resources, except when these already hold a CM contract granted in any previous auction of any existing or approved CM at the time of the assessment and in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the TFEU.

6. These two "Central Reference Scenarios" will be complemented by sensitivity studies with European relevance to assess the robustness of the possible identified adequacy risks within the assumptions of these Central Reference Scenarios. Criteria for the definition of such sensitivities are amongst others:

[1] taking into account relevant legislative restrictions introduced after the CM was approved, e.g. the Emission Performance Standard of 550 g CO_2/kWh.

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

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

c) assessments of the robustness of the identified investments within the economic viability check; and

d) robustness of the results through variations on fuel and/or carbon prices.

7. Input for the definition and prioritization of the relevant sensitivities shall be part of European and National public consultations, especially in relation to the views of Member States and relevant Stakeholders on the evolution of the power system and the relevance of any proposed sensitivity for the ERAA.

Article 4
European Resource Adequacy Assessment – Description

1. **General**

a) The ERAA shall simulate each year from PY+1 until PY+10 (included).

b) Adequacy shall be assessed using the following two probabilistic metrics: (1) the EENS and (2) the LOLE.

c) The adequacy metrics are assessed through a UCED model.

d) The adequacy assessment consists of three major pillars: demand, supply and grid representation among different zones.

e) Uncertainty is represented through random unplanned outage patterns of generators and different weather conditions. Uncertainty of interconnectors is also represented through random unplanned outage patterns of interconnectors between different bidding zones in the model, unless this effect is already included in the Flow-Based parameters considered within the Flow-Based approach and/or through the nominated N-1 capacity assigned to the interconnector. Data related to hydro inflows, irradiance, wind speed and temperature are consolidated in the ENTSO-E Pan-European Climate Database (PECD). The PECD comprises a set of hourly time series of climate parameters for multiple years. Frequency and magnitude of future weather and hydrological conditions shall be taken into account, also reflecting any evolution of the climate conditions under climate change. In any case, the data set shall properly consider the inter-zonal and inter-temporal correlation of those climate parameters.

f) The UCED model shall be built on a "perfect foresight" principle with respect to variable parameters. Forecast errors of wind, solar, hydro generation, of planned outages as well as of demand are ignored in the UCED model. Additionally, the occurrence of unplanned outages is assumed to be known in advance.

g) Market simulations shall be run with an hourly resolution.

h) The granularity of geographical zones shall be set at least by the smallest level between country and bidding zone, considering the official biding zone configuration and expected evolution at the moment of the assessment. In addition, the specific geographical characteristics of the assessed perimeter shall be reflected in the UCED model by explicitly modelling islands for which sufficiently qualitative and granular input data exist, for example the island of Crete.

i) Non-explicitly modelled zones are represented by fixed hourly time series of energy exchanges through existing interconnections, which represents only an estimation of the real exchange with neighbouring systems given limited data access and modelling of such systems.

2. **Probabilistic Assessment**

a) The ERAA shall use a probabilistic methodology to reflect the stochasticity of climate parameters affecting supply and demand as well as the unexpected technically or economically constrained availability of generation, storage and transmission resources.

b) The Monte Carlo (MC) method shall be used for probabilistically assessing the availability of generation and transmission resources interconnecting synchronous areas. It creates possible future states of the power system by sampling a sequence of random outages of the relevant stochastic variables. In the ERAA, random MC samples represent different availability of generation assets and transmission lines, which are subject to failures that cannot be predicted beforehand and may have significant impact on adequacy. MC sampling is based on the Law of Large Numbers, according to which the average of the results obtained by performing the same experiment for a sufficiently large number of times, should converge to the expected value.

c) Monte Carlo simulations in ERAA shall be built combining the climate-dependent variables and random outages referred to in Article 4(1e) and Article 4(2b), respectively, and shall be performed in the following way: climate years, including years considering realistic but extreme weather conditions and the effect of climate change, are first selected one-by-one. Each climate year consists of a combination of demand (accounting for the so-called "temperature-load-dependency") and also includes the effect of irradiance, wind speed and other relevant climate parameters in the form of wind, solar and hydro inflow production time series. Each set of climate conditions is further associated with a relatively large number of random outage samples, that is, randomly assigning unplanned outage patterns for thermal units, as well as for interconnections, as per Art. 4 paragraph 1(e) of this Methodology. The convolution of climate years and number of random unplanned outage patterns defines the final number of Monte Carlo years analysed. The choice of the final number of Monte Carlo years shall ensure convergence of the results.

d) The convergence of the Monte Carlo method shall be assessed by the coefficient of variation (α) of the $EENS$ adequacy metric. It describes the volatility of the EENS adequacy 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 $EENS$ is the expectation estimate of ENS over N number of Monte Carlo samples, i.e., $EENS = \frac{\sum_{i=1}^{N} ENS_i}{N}, i = 1 \dots N$ and $Var[EENS]$ is the variance of the expectation estimate, i.e., $Var[EENS_N] = \frac{Var[ENS]}{N}$.

e) A stopping criterion for the probabilistic assessment is enforced, under a sufficiently large number of Monte Carlo samples, 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 samples N of the adequacy assessment would not increase the level of accuracy considerably. Consequently, the Monte Carlo analysis can be stopped.

f) To indicate the reliability of adequacy assessment results, these parameters shall be reported along with the results:

i. the number of analysed Monte Carlo samples N;

ii. the values of α as a function of the number of Monte Carlo samples N.

3. Demand

a) Demand shall be represented as a time series with the same temporal resolution as the UCED model for each target year. It shall be calculated considering the stochasticity of climate variables, economic growth and penetration of new technologies (e.g. electric vehicles and heat pumps) at the target year, based on historical demand time series and the impact of climate change.

b) Demand is modelled considering load- temperature sensitivity using historical climate data or climate data derived from climate models. The load-sensitivity relationship might include other variables such as irradiation, wind speed or humidity, if proven relevant. While in the ERAA this data is aggregated to bidding zone level, national studies might include sensitivities that rely on climate data of higher spatial and temporal granularity.

c) Explicit and implicit DSR shall be considered in the assessment. It can consist of a potential for demand reduction as well as demand postponement or shifting. The data related to potential for reduction, postponement or shifting shall be based on assumptions considering that the relevant technology is available, mature and competitive in the modelled zone and within the concerned period of the assessment.

DSR will be split in terms of non-policy DSR (hence subject to economic viability checks) and policy DSR (exogenously defined within the scenario following policy expectations). Both policy and non-policy DSR shall consider both implicit and explicit DSR. In principle, different proportions of implicit and explicit DSR might be allocated within the different policy and non-policy DSR categories.

DSR potential shall be structured in different price and volume bands, each characterized by a maximum activation capacity (MW), maximum activation duration (h), marginal activation price (EUR/MWh) as well as economic and technical activation and energy constraints. The 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 DSR potentials and their activation curves shall be performed per bidding zone. The economic viability check shall define the economic viable amount of such potential DSR that is to be finally included in the Central Reference Scenarios capacity portfolio, taking into account the constraints referred in Article 6.

The terms ‘mature and competitive’ refer to the existence of robust data upon the data collection process which allows to define: i) the potential for DSR, ii) one or several DSR price and volume bands, iii) any technical or economical activation and duration constraints for each of the bands defined (e.g. energy constraints). Both DSR potential and DSR activation curves may either be given as input to the investment model referred to in Article 6 of the Methodology during the economic viability check, or be used to define DSR exogenously in the simulation. The choice of either option shall be based and communicated on the basis of transparent and fundamental arguments (see also Article 5(67c.7.(c)). In case implicit DSR activation is not directly linked to time-variable electricity prices but rather to permanent incentive payments associated to a certain expected behaviour of costumers at specific hours every day/week of the year (i.e. policy asset), implicit DSR shall be modelled within ENTSO-E demand prediction tool, e.g. as time-dependent flexibility bands.

d) Additional demand during charging of storage units is determined though the simulation model and shall be considered as an element responding to market signals. Such demand may result from pumped-hydro storage power plants, market-participating batteries, power-to-gas units or electric vehicles among others. It shall only be estimated for technologies that are used in practice or if there is consolidated evidence, e.g. through reports or political programs that these technologies may be mature and economically competitive and available within the analysed time-period (PY+1 to PY+10).

e) Estimates on evolution of energy efficiency and its effects on demand curves as well as demand growth are considered using annual forecasts that are collected via the ENTSO-E central data collection process together with TSOs.

4. **Supply**

a) Supply assumptions shall consider best estimates of all available generation and storage units in the system, as well as available exchanges with non-explicitly modelled neighbouring zones.

b) All market-based resources shall be considered. In addition, the scenario with capacity mechanisms, defined in Article 3, shall also consider the out-of-market strategic reserves where and when applicable within State Aid rules, and considering any cross-border contribution only if approved within State Aid rules. Under this context, strategic reserves contribute only to the adequacy of the country in which they are contracted and hence will be considered in the ERAA only after the implementation of the economic viability assessment, not affecting its outcomes. Furthermore, the impact of out-of-market resources might be further assessed within national resource adequacy assessments should Member States wish to do so, in accordance with Article 24 of the Electricity Regulation.

c) Supply shall be defined in terms of NGC.

d) Any seasonal impact on generation capacity availabilities (e.g. Combined Heat Power plant availabilities in summer and seasonal efficiencies) shall be considered, for example by introducing their availability by use of time series for the installed capacity or modelling it through the planned maintenance schedule for the periods of unavailability.

e) Wind and solar generation shall reflect modelled weather conditions, respectively irradiance and wind speed. These weather variables are also correlated with temperature, through the climate database used. This allows to build a consistent input data for the assessment, since correlations between weather-dependent generation and "temperature-dependent" demand are properly taken into account. Temperature impact on the efficiency of PV panels is only indirectly considered through the statistical information used to build the solar generation models.

f) Availability of supply sources:

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

   ii. Planned outages are modelled considering perfect foresight. Planned outage schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These shall be optimized to avoid as much as possible scheduling maintenance at critical moments of scarcity, while respecting relevant constraints such as maintenance period for each power plant, the percentage of capacity that should be maintained during winter period, as well as technology specific constraints, e.g. maximum number of nuclear units simultaneously under maintenance. Furthermore, for the short-term period of 1-3 years, the maintenance profiles shall respect data published by owners of generation units pursuant to the REMIT Regulation, as well as technology specific constraints, e.g. maximum number of nuclear units in simultaneous maintenance.

iii. Unplanned outages of supply shall be considered in a probabilistic manner and on the principle of perfect foresight, as per Article 4, par. 1. Assumptions on outage rates per technology type and mean time to repair shall build on historical outage events in Europe.

g) Supply-side technical constraints shall be considered. These might include minimum and maximum generating capacities, capacity requirements for system services (reserves, voltage support, etc), capacity reductions due to mothballing, must-run constraints, time series of derating ration, planned maintenance requirements, ramping capabilities, start-up and shut-down times.

h) Energy constraints (such as hydro) shall consider energy availability. For hydro generation modelling, the energy constraints can be related to water inflows, reservoir size or minimum energy release requirements due to environmental reasons. For bidding zones where vehicle-to grid technology is applied, energy availability shall be linked to energy storage potentials of EV battery. For bidding zones where battery technology is applied, energy availability shall be linked to energy storage potentials and charging-discharging constraints of the batteries.

i) Generation from Renewable Energy Sources (RES) shall be represented by two different elements: (1) RES net generating capacity for each technology, representing the market penetration of RES at the target year, (2) time-varying load factors reflecting the spatial and temporal dependency of RES generation on climatic variables as well as the evolution of RES technologies in the target year. The load factors are contained in the PECD database. Forecast errors are not accounted for in the PECD.

j) FCR and FRR shall be deducted from the available resources in the adequacy assessment, either by deducting their respective capacities from the available supply or by adding them to the load profile. Reserves are dimensioned to cover the unexpected imbalances resulting from second-by-second random variations of generation and load and to face in the short term a range of contingencies. Replacement Reserves (RR) shall be considered as available capacity contributing to adequacy in the ERAA adequacy assessment.

Reserve sizing for FCR shall cover at least the reference incident of a synchronous area. FCR contribution by each TSO shall be based on the sum of the net generation and consumption of the TSO's control area divided by the sum of net generation and consumption of the synchronous area over a period of 1 year as set out in the SO GL. Within the analysed time-period (PY+1 to PY+10) in ERAA, dimensioning of FCR shall be based on the latest available historical data of generation and consumption, following the relevant SO GL rules.

5. **Storage**

a) Pumped- hydro storage units are 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. More specifically, modelling pumped-hydro storage units requires an ex-ante optimization phase, with lower time resolution than the UCED model, due to the weekly resolution of the available inflow data. During this phase, hydro reservoir targets are optimized to provide the UCED model with the available energy from hydro storage within each time step of the hydro optimization

ENTSO-E AISBL • Rue de Spa 8 • 1000 Brussels • Belgium • Tel + 32 2 741 09 50 • Fax + 32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

phase. The hydro optimization model shall respect constraints related to upper and lower reservoir levels, minimum/maximum pumped energy (GWh/time granularity), minimum/maximum generated energy (GWh/time granularity), minimum/maximum generation (GW).

b) Batteries shall be considered within bidding zones, should available and robust estimates exist, so relevant battery technologies can be considered as available, mature and competitive at the modelled zone within the concerned period of the assessment. The methodology shall consider participating-in-the-market and out-of-market batteries, where the former are large-scale battery capacities that are traded in day-ahead and intraday markets, while the latter represent small-scale batteries typically managed behind the meter. Market-participating batteries are modelled similarly to pumped-hydro storage and are subject to the following constraints: maximum power (MW), maximum energy storage (MWh), state of charge (% of maximum of energy storage), charging/discharging efficiency (%). Out-of-market batteries are modelled as peak-shaving units based on predefined peak-reduction ratios, which are a direct input to tool building the demand profiles.

c) Emerging technologies (e.g. vehicle-to-grid power injection) will be modelled similarly to pumped-hydro storage and are subject to the following constraints: maximum power (MW), maximum energy storage (MWh), state of charge (% of maximum of energy storage), charging/discharging efficiency (%).

6. **Network**

a) Cross-zonal capacities shall reflect the expected CCM for each considered target year, taking operational security limits into account. In particular, cross-zonal capacities shall reflect the latest available information regarding Member State 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.

b) Within the "Coordinated Net Transmission Capacity", NTCs shall limit the bilateral exchange capacity between two zones. Within FBMC, a flow-based domain shall be computed pursuant to paragraph (e).

c) If the CCM allows for specific allocation constraints, such constraints may further restrict cross-zonal trade. In this case, the constraint value shall be computed in line with the CCM.

d) NTCs (possibly combined with allocation constraints) shall reflect cross-zonal capacities between explicitly modelled and non-explicitly modelled systems. These values shall reflect expected operational practices (including specific connection agreements) for the target year.

e) For bidding-zone borders relying on the flow-based approach, CNECs shall be defined as follows:

   i. ENTSO-E, based on TSOs input data, shall coordinate the identification of CNECs reflecting the CCM during the data collection process, following the applicable principles for identification of CNECs at the time of the assessment and as referred in Article 2 of the CACM Regulation;

   ii. Definition of relevant Power Transfer Distribution Factors (PTDFs) shall use grid models covering the flow-based area under consideration and suited for each target time of the assessment, i.e., each of the 10 target years. European grid models from the TYNDP reference grid shall be used incorporating the relevant grid modifications expected to be operational by the different target time the assessment;

   iii. 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, Phase-Shifting

Transformer (PST) settings, and other degrees of freedom that might be given to the market under FBMC, in any case in accordance with the CACM Regulation and SO GL;

iv. The capacity available for cross-zonal trade on a CNEC depends on the maximum admissible power flow at the considered capacity calculation market time unit (CC MTU) defined as $F_{\max}$. $F_{\max}$ shall be determined in accordance with the implemented CCM and, if relevant, can be implemented as a time-varying value in order to reflect varying relevant conditions;

v. The selection of Generation Shift Keys (GSKs) shall be made in a way that is in line with foreseen practices in the relevant capacity calculation region, taking into account any simplification deemed necessary for the scope of ERAA;

vi. Network constraints shall be defined further through the Remaining Available Margin (RAM) of each CNEC, with existing capacity calculation principles as referred in Article 2 of the CACM Regulation, hence including proper considerations on internal, loop and transit flows;

vii. The capacity calculation should ensure the N-1 criterion is met at all times. The calculation of the PTDF and RAM thus accounts for the N-1 principle;

viii. For all relevant CNECs, the (RAM, PTDFs) parameters define a collection of linear constraints to the variables to be optimized by the UCED model. This total set of constraints is reduced to the set of constraints limiting the exchanges within the simulation. This procedure leads to the final combination of relevant constraints forming the so-called ‘flow-based’ domain;

ix. The final set of limiting constraints, i.e. flow-based domains, shall be the linear constraints to be introduced in the UCED model tools for the ERAA assessment;

x. Weather conditions and seasonal patterns that impact network constraints shall be considered when defining the exchange constraints within the flow-based approach. Time series of climatic years within the PECD will be used to model variability of the renewable generation, electricity demand, etc. The flow-based domains referred to in paragraph 5.f.viii) shall include representative groups of linear constraints, each group linked to given climate conditions and hence to a certain level of congestions in the network. A correlation analysis between the different domain groups and relevant climate variables (e.g. renewable generation/electricity demand) shall be applied when setting up the flow-based domains referred in paragraph 5.f.viii) in the UCED model.

f) Unplanned outages of HVDC interconnections in the NTC approach shall be considered in a probabilistic manner, as per point (e) of Article 4(1) of this Methodology. Assumptions on outage rates per line and mean time to repair shall build on statistical analysis of historical outage events in Europe.

g) Load curtailment sharing principles currently applicable within the day-ahead electricity market coupling algorithm, shall be considered both for Coordinated Net Transmission Capacity regions (under NTC modelling) as well as for Flow-based areas, within the UCED model. The aim of curtailment sharing is to equalize as much as possible the curtailment ratios between those bidding zones that are simultaneously in a curtailment situation.

Article 5
Data Collection

1. The ERAA data collection shall follow the ENTSO-E data collection framework principles: i) ENTSO-E data collection guidelines are provided to each national TSO, to guarantee a coherent data collection process. Such guidelines specify the assumptions that each TSO has to use when providing data to

ENTSO-E; ii) Some of the data requested from the TSOs is used as an input for centrally prepared data at ENTSO-E level.

2. The process of data collection to prepare and consolidate all required input data shall be centrally coordinated by ENTSO-E. During this process, data is collected from the TSOs according to centrally prepared guidelines by ENTSO-E. Furthermore, the collected data is provided by TSOs by filling standard data templates prepared/provided by ENTSO-E in a coordinated manner. The established data collection guidelines guarantee a standardised data preparation process and ensure that databases are built on consistent, transparent and common assumptions.

3. Transmission system operators shall provide ENTSO-E with the data needed to carry out the ERAA. ENTSO-E shall clearly differentiate the origin of data used in its studies (TSOs, other/external, ENTSO-E assumptions). In addition, ENTSO-E shall, in case contrasting or misaligned input data from TSOs are provided, request and transparently detail the sources of TSO data and define a consolidation mechanism in order to combine such data into a consistent dataset.

4. Data used as input to the resource adequacy methodology is collected by ENTSO-E through its network of adequacy correspondents nominated at each member TSO.

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 the Electricity Regulation, respecting confidentiality and transparency, in order for TSOs to set up or benchmark the appropriate scenarios of projected demand and supply and, especially, to provide relevant technical and economic assumptions for the economic viability checks.

6. Collected data originates from combined top-down and bottom-up collection processes. It is checked for completeness and consistency and eventually consolidated into a Pan-European Market Modelling Data Base (PEMMDB) – a data base that contains information on the network and market models in annual resolution. Unless stated otherwise, data originates from TSOs. Data delivered shall be in line with any implementation plans of measures set out by Member States as a response to resource adequacy concerns, pursuant to Article 20(3). More specifically, PEMMDB contains the input dataset to the UCED model, i.e. any data processing is provided prior to the data entry in the database. The PEMMDB includes:

    a) Generation data, consisting of RES and fossil fuel net generation capacities, their predicted evolution over time, maintenance requirements, ramp capabilities, fuel consumption, conversion efficiencies, mothballing predictions among others. Thermal generation data shall be collected unit by unit, to the best availability. Wherever unit by unit granularity is not available, generation data shall be aggregated per generation technology. Thermal power plant conversion efficiencies used in the model are based on fuel subtypes. RES capacities are provided per bidding zone. Both RES and fossil fuel generator time series have hourly time resolution;

    b) Data on existing contracts for assets within the considered portfolio, which have been granted after auctions occurred within existing CMs before the data collection;

    c) Data on the potential of explicit and implicit DSR, should such split be available, and the potential of storage, etc., for which the expected realization in the market shall be assessed within the economic viability check. Such estimates should build on input from relevant national market parties and TSO data and result in values that are differentiated for each market zone. Furthermore, if available also to TSOs through national economic viability checks, input from relevant national market parties or through national consultation processes, also forecasted explicit and/or implicit demand response realized in the market shall be submitted by each TSO per bidding zone including the respective price bands (price of activation vs. capacity) and relevant activation constraints, i.e. price bands (activation price (Euro/MW), capacities (MW), and duration (h)).Such TSO forecasts are important as they shall be used to calibrate and validate the outcomes of the investment model to be used for the economic viability check of Article 6 of the Methodology when pertinent;

d) System reserve requirements, i.e. with respect to FRR, FCR and RR;

e) Demand predictions, built on historical hourly demand profiles and forecast adjustments (e.g. electric vehicles, heat pumps, energy efficiency among others; their penetration along with their properties). These components are the following:

- Bidding zone historical demand time series with at least hourly resolution shall be collected from TSOs. Such historical demand time series, together with historical climate variables, are used to build demand predictions using a software tool that is centrally applied by ENTSO-E and generating multiple time series for each target year that reflect different weather conditions observed over the past and stored in the PECD database.

- Demand forecasts further require a set of model parameters that allow for a characterization of time series:

  i. Annual demand per sector (industry, residential sector, services and transport) and per bidding zone is provided as an aggregated forecast for each year (in TWh);

  ii. Forecast additional electric vehicles with regard to the base year, average effective usage (km/EV/day) with differentiation between weekend and weekdays, average efficiency (energy forecast consumption in kWh/100 km), share of fast- and slow-charging profiles – taking into the account the geographical diversity of charging behaviour within 10 years of the assessment. EV forecast is defined by each TSO as part of the scenario building process; Vehicle-to-grid capabilities shall be reported as far as they are available to each TSO through national consultation or the data collection processes;

  iii. Forecast number of heat pumps added: thermal load increase caused by heat pump additions, Coefficient of Performance (COP), COP threshold for switching (hybrid heat pumps);

  iv. Forecast addition of out-of-market batteries: Out-of-market participating batteries behind the meter are considered with their maximum total power (MW), storage capacities (MWh), cycle efficiency (%), peak reduction (%) and ramp-rate reduction (%);

  v. Other forecast adjustments: additional other load types (e.g. data centres) in MW;

  vi. Holidays/weekdays/special days calendars;

  vii. If not included in the list above, other relevant characteristics of relevant technologies that affect demand levels and shape (e.g. energy efficiency programs).

f) NTC of bidding zone interconnections where relevant. FBMC borders are referred to in paragraph 9 below.

7. The PECD of ENTSO-E includes:

   a) Wind power and PV generation capacity factor time series used for the calculation of wind and solar generation;

b) Temperature, used for the calculation of demand time series along with irradiance, humidity and wind speed data;

c) Water inflows to reservoirs for the calculation of hydro generation;

d) The used climate data shall build on "state-of-the-art" climate and weather databases, using available re-analysis of historical data and climate projections when applicable.

8. TSOs shall use the following data, pursuant to Article 4, when setting up the flow-based modelling:

   a) List of relevant CNECs;

   b) PTDFs considering the relevant list of CNECs and all the relevant market, within the geographical area modelled within the flow-based approach;

   c) Phase Shifting Transformer settings and HVDC set position, shall be considered as possible variables if deemed relevant for the flow-based calculation;

   d) Relevant limitations not associated with CNECs but relevant for the scope of the assessment (external constraints and Long-Term Allocations and Nominations if/while applicable);

   e) Remaining Available Margin (RAM) for each CNEC, considering minimum levels of RAM on the list of relevant CNECs, in accordance with Article 16 of the Electricity Regulation and Article 4 of the Methodology;

   f) This data shall be calculated centrally within ENTSO-E, where feasible, and shall rely to the maximum extent possible on data prepared by TSO flow-based expert groups both within ENTSO-E as well as within relevant RCCs. The methodology to calculate these parameters shall follow the principles referred in Article 2 of the CACM Regulation and rules for the minimum capacity available for cross-zonal exchanges as referred in Article 16 of the Electricity Regulation.

9. Reserve requirements shall be available per zone in NGC, and dimensioned by following the applicable principles for dimensioning of reserves as referred in the SO GL. Data collections shall consist of the following:

   a) Reserve requirements separately for FRR, FCR and RR. FRR reserve requirements shall not include FCR reserve requirements. RR reserve requirements shall include neither FRR nor FCR reserve requirements;

   b) FRR requirements shall contain manually activated reserve as well as automatically activated reserve requirements. FRR requirements should be divided into FRR that needs to be available by generation or storage units, and FRR that will be procured by reservoir or pumped storage hydro.

10. Economic and technical data to perform viability assessments should be consolidated centrally by ENTSO-E based on best available information to ENTSO-E and complemented by inputs from TSOs and other relevant stakeholders and market parties. The following data categories are needed per relevant technology:

    a) CAPEX, expressed in EUR/MW;

    b) Annual fixed costs shall be expressed in EUR/MW/year and variable OPEX/ variable O&M costs in EUR/MWh;

    c) Short term variable costs (EUR/MWh) including variable OPEX/variable O&M costs, fuel costs (EUR/net GJ), efficiencies (%) and CO2 prices (EUR/ton);

d) WACC and discount rates r.

11. Best estimates regarding technical and economic parameters (carbon price developments, fuel developments, estimates of other parameters needed for the economic viability checks, assumptions on market price cap levels and the analysis of its likely evolution to the value of lost load, as referred in Article 10 of the Electricity Regulation), will be prepared centrally by ENTSO-E, based on available economical expertise at European level. This shall be consistent with the ENTSO-E scenarios prepared for the TYNDP.
12. Information on existing or planned CMs shall be considered within the collection of national data on generation, demand and storage assets and shall be provided by TSOs. This includes assumptions on capacity and time duration of the capacity mechanism and may include any form of CM (strategic reserve, capacity payment, capacity auction, capacity obligation, reliability option, etc.). This information should allow to assess the share of the capacity within the Pan-European Market Modelling Data Base (PEMMDB) relying on any type of existing or future CM as well as the expected duration of any already granted CM contract within the PY+1 – PY+10 scope of the assessment.
13. Data collection guidelines and a summary of model assumptions shall be published either in the documentation of ENTSO-E major studies or in dedicated reports for further use and validation by other stakeholders, during relevant public consultations. The provision of this material shall therefore be made available at the time of the publication of each ERAA report, in order to provide a high level of transparency. The results presented in each ERAA report should be understood in relation to the data collection guidelines and the summary of assumptions provided within each ERAA report publication and hence should not be interpreted separately from the hypotheses related to the data collection and other relevant assumptions used in each ERAA report.

Article 6
Economic viability assessments

1. The following process of the economic assessment as described in Article 6 aims to implement an ambitious, innovative but complex methodology. Hence it shall require a systematic implementation based on stepwise impact assessments of the different steps. The focus of such stepwise assessment shall be on both its feasibility as well as on the robustness and trustworthiness of the results. Its implementation will require a proof-of-concept stage according to the implementation roadmap presented in Article 10 and in any case validated by ACER and ENTSO-E.
2. “The European resource adequacy assessment *shall include an economic assessment of the likelihood of retirement, mothballing and new-build of generation assets*.” The purpose of the economic assessment shall be the minimization of the overall system cost, including operational and investment costs. Any other relevant technological or economical restrictions as well as market regulations shall be formulated as constraints of the problem.
    - The system costs consist of annualized investment costs, annual fixed costs, variable costs and the costs resulting from unserved demand. Differentiation between non-policy and policy units/technologies shall be performed when setting up the economic viability problem.
    - Policy technologies are not subject to economic viability checks and shall be defined by exogenous assumptions, e.g. following policy decisions related to coal or nuclear phase-outs, development of renewable energy sources or investment decisions regarding other relevant policy-driven supply evolutions.

- Non-policy technologies are subjected to a verification of their economic viability. The following investment candidates shall be defined:
    - Decommissioning/mothballing of existing units categorized as non-policy;
    - Investment in new units categorized as non-policy.

National projected supply outlooks prepared by each individual transmission system operator should label the assumed existing or expected new-build capacity either as ‘policy’ or ‘non-policy’. Such categorization shall be based on transparent and fundamental argumentation.

The main constraints to the economic assessment are:

- The demand;
- Existing units and their respective lifespan within the relevant period of the assessment;
- Reserve requirements;
- Constraints or side-effects resulting from heat supply in case of Combined Heat and Power (CHP) assets, when deemed relevant for electricity generation and for non-policy labelled resources;
- Constraints related to emission limits of CO_2 of fossil fuel origin per kWh, as referred to points (a) and (b) of Article 22(4) of the Electricity Regulation, if relevant;
- Relevant technological, economical, market and regulatory constraints might be further imposed in order to check the robustness of the solution found by this assessment.

When deemed appropriate within the considered scenario framework, such additional constraints might be based on relevant considerations including price restrictions, imperfect information, regulatory uncertainty, regulatory restrictions on investments, risk-averse behaviour by investors, uncertainty regarding input markets or other relevant externalities in the electricity market.

Any such considerations shall be duly founded and their impact explained upon the discussion of the results obtained.

The decision variables of the economic assessment are:

- Investment in different generation and storage units defined within the problem as investment candidates (considering the complete lifetime of all assets);
- Investment in demand-side response;
- The decision between temporary mothballing vs. final shut-downs of non-viable generation units;
- The decision variables shall assess the economic viability of the assets within the period of the assessment from PY+1 to PY+10;
- Lifetime of the units shall be considered, together with WACC, in depreciating the CAPEX both for existing and new-built capacities within the period of the assessment PY+1 to PY+10;
- The assessment shall not provide any explicit results beyond the PY+10 horizon.

3. The **Economic Viability without CMs** check shall follow the following logic:
    a) The Economic Viability procedure starts by considering exogenous assumptions based on national base line data as described in Article 3 of the Methodology.
    b) Considering the above exogenous generation, storage and demand assets, all non-policy technologies shall be considered as eligible for the economic viability check. Thus, reported

mothballed assets and proposed new-built assets by TSO shall be subject to the economic viability check, unless considered as policy assets under Article 6.2(c) of the Methodology. Technologies subject to national subsidies, support schemes, policies or incentives shall be considered as exogenous input and shall not be eligible in the ERAA economic viability check.

c) For countries with existing CMs, the economic viability assessment shall not take into account CM revenues to assets within a non-policy technology category as defined above, except when they already hold a CM contract granted in any previous auction of an existing or approved CM at the moment of the assessment.

d) The principles of the economic assessment framework of a scenario without CMs are:

For the given scenario and economic dispatch under a probabilistic simulation, the economic assessment shall assess the likelihood of retirement, mothballing and new-build of generation, storage and demand response assets, taking into account decisions based on the viability (or profitability) of the non-policy units under consideration.

Viability shall be defined as a function of the expected revenues (from EOM and any other relevant additional revenues if robust estimates exist on these), the variable costs and the fixed costs. In addition, revenues from CM shall be taken into account if the assets already hold a CM contract of an existing or approved CM at the moment of the assessment and if robust estimates exist on these revenues. In absence of such estimate, or until such estimate can be defined with proven data quality, the asset holding a CM contract of an existing or approved CM shall be considered as policy asset.

The expected revenues calculated for each asset shall reflect the current market design existing in each Member State. In particular, existing price caps on energy, including the provisions of Article 10 of the Electricity Regulation, and any existing contract within existing capacity markets shall be considered.

After economic dispatch under a probabilistic simulation, it can be observed that the distribution of revenues from all considered Monte Carlo years, including different climate conditions and outage scenarios, can be very skewed. In some cases, viability might rely on high price spikes occurring only within a small percentage of the analysed situations. To improve the viability assessment's robustness against these specific cases, the ERAA shall consider the effect of risk aversion towards price volatility and price spikes, considering state of the art experience in the industry.

Consideration of additional revenues due to scarcity pricing mechanisms shall be considered in ERAA only when a scarcity pricing mechanism is implemented and operational in a Member State. Therefore, a robust estimate exists and is provided upon the data collection on the extra revenues that such a mechanism is expected to provide through assumed backwards propagation of price signals into the day-ahead, intraday and long-term forward markets, triggered by short-term scarcity. ERAA economic viability checks will however not consider or assume any theoretical or academic scarcity pricing mechanism in any Member State beyond of what it is provided by the above-mentioned estimates relating to extra scarcity pricing related revenues.

Regarding additional revenues from for example heat-driven CHP generation or ancillary services, if a robust estimate exists on the expected extra revenues and is provided upon the data collection by a TSO, it shall be considered in the economic viability within the ERAA assessment. To the extent possible, the estimation of expected revenues shall account for realistic operation within the functioning of either the EOM or the Ancillary Services Market of the concerned Member State. For ancillary services, the estimates shall only concern the RR, these being the only part of the reserves contributing to adequacy.

ENTSO-E AISBL • Rue de Spa 8 • 1000 Brussels • Belgium • Tel + 32 2 741 09 50 • Fax + 32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Regarding the above-mentioned considerations of assets holding a contract within existing or approved CMs, scarcity pricing or extra revenues from heat-driven CHP and ancillary services, the concept of 'robust' implies here that such figures, when provided by TSO, are based on inputs from a national consultation process of data, as referred in Article 8 of the Methodology.

However, note that due to the country-specific nature of these additional revenues, notably heat-driven CHP generation or ancillary services, it might not be possible to reliably estimate these in the above-mentioned robust way needed for the ERAA. Robust estimation of such complementary revenues might be deemed a country-specific task by Member State as part of the complementary national resources adequacy assessment, therefore fulfilling the requirements of Article 24 (1a) of the Electricity Regulation of 'assumptions taking into account the particularities of national electricity demand and supply'.

e) The economic viability assessment procedure shall be integrated within the probabilistic economic dispatch assessment from the UCED model and its objective shall be to minimize the overall system costs considering operational costs and investment costs, in a probabilistic simulation.

- The economic viability assessment decisions shall keep non-policy assets in the model, if these assets are considered economically viable, i.e. they have a positive business case.
- The economic viability assessment decisions shall consider removing non-profitable non-policy assets from the model, if these assets are considered not economically viable.

  It is also possible for new assets within the different categories of non-policy technologies to be added, provided these assets are deemed viable within the economic assessment framework and feasible in the related zone.

4. The **Economic Viability with CMs** check shall follow the same logic as Article 6(3) of the Methodology, also considering:

   a) National projected supply outlooks prepared by each individual transmission system operator, indicating whether parts of the assumed existing or expected new-build capacity rely on remuneration from existing or planned and approved and applicable CMs in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the TFEU. Hereby and in the following, only capacity remuneration mechanisms that allow capacity to participate in the electricity market are considered.

   b) The economic assessment framework shall follow the principles described in Article 6(3), except for countries with existing or planned and approved and applicable CMs where the economic viability assessment shall also take into account additional revenues helping to ensure that the reliability standards are respected. Nevertheless, as referred to in Article 3(5)a, capacity limits (e.g. demand response), legal and administrative hazard, hazards with impact on availability, building delays and stop-loss limits, might justify in specific cases that the Reliability Standard is not always fulfilled at any price.

5. The stability and trustworthiness of the results of the economic viability assessment with respect to different assumptions (e.g. assumptions on costs, CO2 prices, etc.) shall be studied with the objective to test the robustness of the scenarios resulting from the economic viability assessment. ENTSO-E shall ensure that the endogenous assumptions of the model are consistent with relevant national policies, generation capacity forecasts and feedbacks from national market parties, expressed upon the national consultations as referred in Article 9. In case of non-stability of the results within the mentioned sensitivity checks, the reliability of the relevant assumptions shall be assessed and when needed revised

with non-purely economic considerations, in any case to strengthen the trustworthiness of the central scenarios proposed.

Article 7
Outputs and Results

1. Outputs of the adequacy assessment are provided in terms of EENS and LOLE for Central Reference Scenarios and their sensitivities, with a spatial granularity relevant to the Member State responsibility regarding Security of Supply, for each year from PY+1 until PY+10. For neighbouring bidding zones presenting EENS/LOLE, analysis of the different simultaneous scarcity regimes shall be performed. Different simultaneous scarcity situations at both regional and/or European level shall be indicated.
2. In addition to EENS and LOLE, the 50^{th} and 95^{th} percentile of the simulated hourly ENS and of the simulated number of hours with ENS, shall be reported.
3. The source of the adequacy concerns shall be assessed via (i) the percentage of hours corresponding to the relevant different simultaneous scarcity situations to the total amount of scarcity hours and (ii) the analysis of generation, demand and import levels of a given market zone and its connected neighbours during those scarcity events – considering all Monte Carlo years when there is scarcity.
4. The ERAA report shall strive to facilitate stakeholders' understanding regarding the inputs, data, assumptions, and scenario development. This might encompass, amongst other, detailed figures and maps on renewable energy penetration, amount of unviable capacity, import/export levels, simulated newly-built capacity, mothballing, interconnector contribution, DSR, storage, self-generation contributions, energy efficiency measures, carbon price developments, etc.

Article 8
Stakeholder Interaction

1. Developing the proposals for the ERAA methodology, scenarios, sensitivities, assumptions and the report requires close interaction with the various stakeholders, including civil society, in each step of the process in a transparent, open, accessible, inclusive, efficient, and well-structured manner. The ERAA results provide a coherent and comparable basis on a European level, give key insights into the adequacy of supply to meet demand and contribute to the discussion on whether there is a need for CMs in the medium to long term for a variety of actors such as policy makers, TSOs, market participants, ministries, regulatory bodies and other national authorities and system users (among others).
2. Pursuant to Article 23(7) of the Electricity Regulation, the ERAA methodology, scenarios, sensitivities, and assumptions as well as results of the assessment shall be subject to the prior consultation of Member States, the Electricity Coordination Group and relevant stakeholders and approval by ACER under the procedure set out in Article 27 of the Electricity Regulation.
3. ENTSO-E shall facilitate opportunities through adequate interaction channels for all relevant stakeholders, including civil society, to contribute in 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) web-based public consultations through the ENTSO-E consultation tool available on the ENTSO-E website;

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

4. Consultations shall be planned by ENTSO-E on ERAA methodology, scenarios, assumptions, sensitivities and results:

4.1. A yearly consultation on assumptions and high-level definition of scenarios with their assumptions shall be published. This shall include at least CO_2 prices, fuel cost per technology, demand, DSR potential, cross-zonal capacities and an overview of generation capacity per Member State. This process may closely align with the ENTSO-E TYNDP scenario framework biennial consultation process in the years when ERAA and TYNDP editions coincide.

4.2. The exogenous capacity assumptions estimated by the TSOs shall receive feedback from stakeholders through the processes of relevant consultations related to NECP revisions and/or within the legal framework of national grid development plans, national adequacy studies, regional plans where relevant or any other relevant national consultations which have occurred prior to the ERAA consultation. In order to ensure coherent and consistent data quality and inputs, other available statistical sources or reports may be used as relevant from various national authorities, statistical databases and industry stakeholders, in compliance with Article 5(2) of the Methodology.

4.3. The Electricity Coordination Group (ECG) shall be consulted regarding the methodology, scenarios, sensitivities and assumptions. An overview of the preliminary results of the ERAA will be presented at the ECG as soon as available and preferably before the publication of the ERAA report.

4.4. Comments received from the ECG or other stakeholders during the consultation shall be considered for improvements of the future editions of the ERAA, while not delaying the annual publication of the ERAA. ENTSO-E shall provide a reply to the stakeholders' comments received during the public consultation for each ERAA.

4.5. The results of the ERAA depend strongly on the chosen scenarios and the quality of the data collected. ENTSO-E shall ensure through its public consultation on the scenarios, assumptions and sensitivities of the ERAA that all market participants, relevant national authorities as well as civil society have the opportunity to check, compare and benchmark the data and the assumptions used in the assessment. For that purpose, they may be further asked to provide TSOs and ENTSO-E where necessary, with relevant data if deemed necessary and with the only purpose of ensuring that ENTSO-E uses robust and coherent inputs. The granularity of the data published shall be in compliance with ENTSO-E's data transparency guidelines.

4.6. The results of each ERAA, together with the assumptions on which they are based and the data related to the different scenarios, shall be made publicly available on the ENTSO-E website at the same time as the report is published.

4.7. Latest three months after approval of the ERAA Methodology, ENTSO-E shall publish a roadmap describing the implementation phase referred to in Article 10 (2). This roadmap, if needed, shall be updated on annual basis when publishing each edition of the ERAA report.

5. Regarding approval, revision or amendments to the Methodology:

ENTSO-E AISBL • Rue de Spa 8 • 1000 Brussels • Belgium • Tel + 32 2 741 09 50 • Fax + 32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

5.1. As set in Article 27(3) of the Electricity Regulation, within three months of the date of receipt of the draft proposals, ACER shall either approve or amend them. In case of amendment, ACER shall consult ENTSO-E before approving the amended proposal.

5.2. ACER may request changes to the approved proposal at any time, pursuant to Article 27(4) of the Electricity Regulation. Within six months of the date of receipt of such a request, ENTSO-E shall submit a draft of the proposed changes to ACER. Within three months of the date of receipt of the draft, ACER shall amend or approve the changes.

5.3. ENTSO-E may also submit a request for updates to ACER, in case significant evolutions or new information would require updates of the Methodology. Any subsequent proposals for amendments to the methodology shall be consulted publicly as per the requirements of Article 27 of the Electricity Regulation and submitted to ACER for approval or amendment.

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

Article 9
Process

The data collection and different stakeholder interactions, as described in Article 5 and Article 8 of the Methodology, will occur in the following order:

1. ENTSO-E provides data templates to each TSO and publishes data collection guidelines and model assumptions either in the documentation of ENTSO-E major products or dedicated reports for further use by other stakeholders;
2. TSOs fill in the data templates according to the data collection guidelines;
3. ENTSO-E collects the TSO data, executes data quality checks, centrally prepares and stores the data in the PEMMDB;
4. ENTSO-E prepares and consolidates economic and technical data to perform viability assessments centrally;
5. ENTSO-E organizes, in alignment with the TYNDP scenario framework biennial consultation process in the years when ERAA and TYNDP coincide, a consultation on yearly assumptions and high-level definition of scenarios with their assumptions before the launch of simulations for the ERAA;
6. The exogenous capacity assumptions estimated by the TSOs shall receive stakeholder feedback through the processes of relevant consultations related to NECP revisions and/or within the legal framework of national grid development plans, national adequacy studies, regional plans where relevant or any other relevant national consultations which have occurred prior to the ERAA consultation;
7. ENTSO-E consults the ECG regarding the scenarios, sensitivities and assumptions;
8. ENTSO-E executes the ERAA calculations and analyses the results;
9. ENTSO-E presents 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;

10. ENTSO-E incorporates comments received from the ECG or other stakeholders during the consultation into the respective edition of the ERAA as soon as practicable, while not delaying the annual publication of the ERAA;
11. ENTSO-E publishes 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. Each ERAA report shall:
    a) consider the most up to date information and data available regarding Member State-level plans (NECPs) in the year of publication of the report;
    b) use the current bidding zone configuration of the year of publication of the report as well as the latest available assumptions regarding potential changes to that configuration for the 10-year horizon ahead;
    c) deploy the flow-based market modelling approach where applicable (e.g. where real time flow-based market coupling is implemented);
    d) deploy/include sectorial integration assumptions and modelling where applicable;
    e) deploy a yearly granularity resolution through a stepwise approach based upon testing and tool outputs have converged towards equally robust results;
12. ACER may approve, revise or amend the ERAA results throughout the process as set in Article 27(3) of the Electricity Regulation.

Article 10
Implementation

1. The ERAA Methodology shall be used as the methodology for conducting the ERAA by ENTSO-E. The national resource adequacy assessments shall have a regional scope and shall be based on the ERAA methodology as per Article 24 of the Electricity Regulation.
2. The ERAA methodology shall be implemented through a step-by-step, gradual process, where ‘proof of concept’ testing and impact assessment of the different methodological elements shall be ensured, prior to considering that any such methodological deployment within the ERAA methodology target is mature as an integral part of the ERAA report. Such approach shall also allow to strike the balance between accuracy and feasibility of the targeted improvements and facilitate an efficient implementation based on experience gathered through this step-by-step process.
3. This ERAA methodology provides the requirements to be considered as a basis to perform the European assessment. However, different requirements may be gradually deployed in each subsequent annual ERAA based on latest capabilities and improvements with respect to technical, data and computational capabilities and resources to ensure a state-of-the-art approach is followed.
4. Regional and national adequacy assessment studies shall inter alia use most recent data and assumptions which shall be as much as possible consistent with ENTSO-E data and which if deviating shall be complementary to the data used by ENTSO-E for the ERAA. Regional and national adequacy assessment studies shall follow the same ERAA stepwise implementation and deployment approach as ENTSO-E, specified in the roadmap mentioned in Article 8(4.6). As long as a given aspect of the methodology is not implemented in the latest published ERAA, the actual methodology implemented in the latest published European adequacy report remains the baseline for regional and national studies.

Article 11
Language

1. The reference language for this Methodology Proposal shall be English.

Appendix 1
Glossary

Acronym	Definition
aFRR	Automatic Frequency Restoration Reserve
CACM	Guideline on Capacity Allocation and Congestion Management
CAPEX	Capital Expenditures
CCM	Capacity calculation methodology
CC MTU	Capacity Calculation Market Time Unit
CHP	Combined Heat and Power
CM	Capacity Mechanism
CNEC	Critical Network Elements and Contingencies
DSO	Distribution System Operator
DSR	Demand-side Response
ECG	Electricity Coordination Group
EENS	Expected Energy Not Served
ENS	Energy Not Served
EOM	Energy-Only Market
ERAA	European Resource Adequacy Assessment
FBMC	Flow-based Market Coupling
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
GSK	Generation Shift Key
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
Electricity Regulation	Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
LFC	Load-frequency block
LOLE	Loss of Load Expectation
MC	Monte Carlo

ENTSO-E AISBL • Rue de Spa 8 • 1000 Brussels • Belgium • Tel + 32 2 741 09 50 • Fax + 32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Acronym	Definition
Methodology	European Resource Adequacy Assessment Methodology in accordance with Articles 23 of the Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
mFRR	Manual Frequency Restoration Reserve
MS	Member State
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
NGC	Net Generating Capacity
NTC	Net Transfer Capacity
OPEX	Operational Expenditures
O&M	Operations and Maintenance
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Data Base
PST	Phase-Shifting Transformer
PTDF	Power Transfer Distribution Factors
PY	Publication Year
RAM	Remaining Available Margin
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable Energy Source
RPR	Regulation (EU) 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector
RR	Replacement Reserve
SO GL	System Operation Guideline
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission System Operator
TY	Target Year
TYNDP	(ENTSO-E) Ten-Year Network Development Plan
UCED	Unit Commitment and Economic Dispatch

Appendix 2
High-level information flow scheme

European Resource Adequacy Assessment (ERAA)

10-year ahead adequacy results

- Year-by-year adequacy in each zone
- Compliance with reliability standards
- Impact of different regulatory scenarios on adequacy

↓ Year-ahead adequacy results

Seasonal Adequacy Assessment

Intra-season adequacy results

- Updated adequacy
- Identification of most critical weeks and zones
- Assessment of available countermeasures
- Circumstances when risks exist

↓ Critical weeks and zones

Short-term Adequacy Assessment

Intra-week adequacy results

- Updated adequacy
- Identification of most critical moments
- Assessment of available countermeasures
- Trigger if regional assessment is needed

Appendix 3
High-level business process diagram