

Mid-term Adequacy Forecast Appendix 2

Methodology
2020 Edition



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1 Mid-term adequacy forecast methodology

Adequacy studies aim to evaluate a power system's available resources and projected electricity demand to identify supply/demand mismatch risks under a variety of scenarios. In an interconnected power system such as the European system, this scope should be extended by considering the supply and demand balance under a defined network infrastructure, which can have a considerable impact on adequacy results. In this context, the focus of a pan-European Mid-Term Adequacy Forecast (MAF) - as presented in the current report by ENTSO-E - assesses the adequacy of supply to meet demand in the mid-term time horizon while considering the connections between different power systems across the European perimeter, as illustrated in Figure 1.

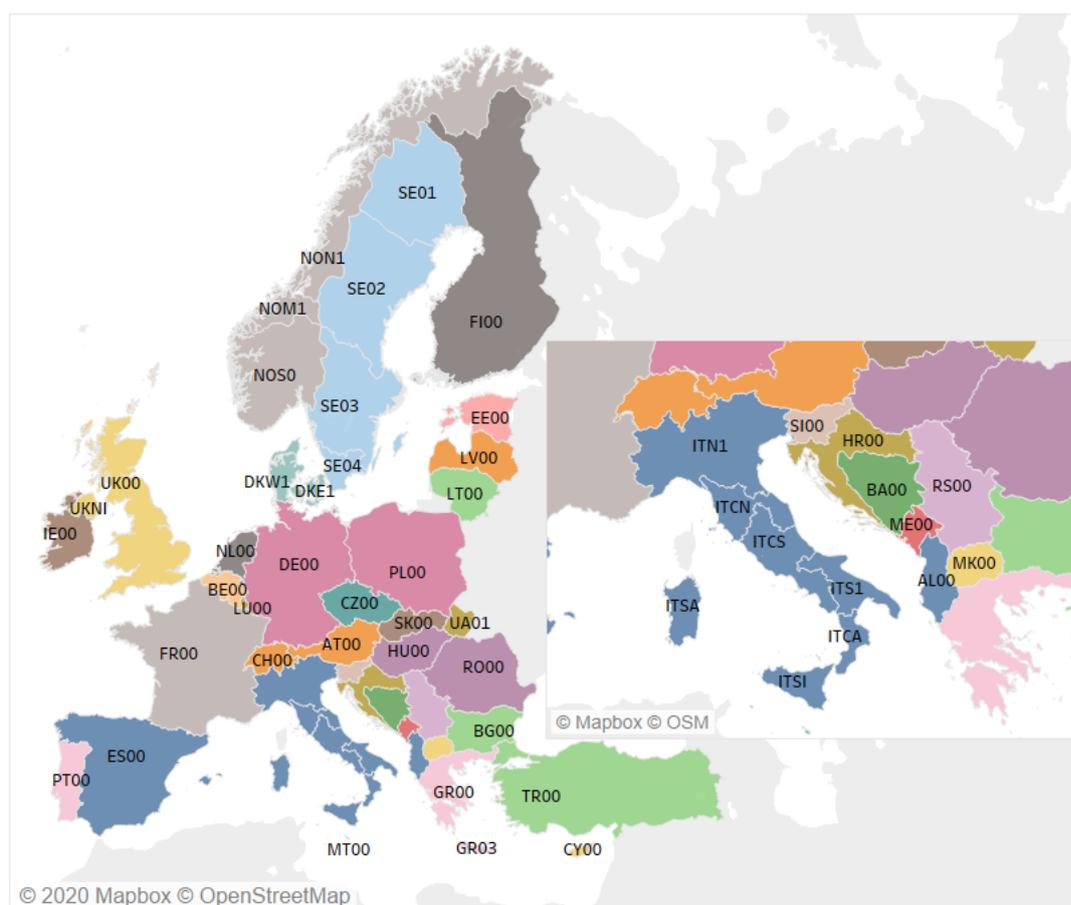


Figure 1: The interconnected European power system modelled in MAF 2020 (Note: Burshtyn Island in Ukraine is also explicitly modelled in MAF 2020)

The present MAF probabilistic methodology is considered a reference within Europe. However, the methodology followed in each MAF report up to the present should be understood as not yet aligned with the ENTSO-E's European Resource Adequacy Assessment (ERAA) under the "Clean Energy for all Europeans" legislative package (see Section 4). Notably, both the MAF 2020 scenarios and results should not be interpreted or utilised under this new legal framework. The present analysis is not a forecast of actual scarcity situations, but rather an indication of a range of possible realisations. As such, the actual realisation of future scarcity events could be very different.

1.1 Time horizon and resolution

A mid-term assessment of adequacy can focus on a single year or multiple years in the future to highlight supply shortage risks and thus assist stakeholders in making well-informed investment decisions. Notably, it considers techno-economic trends and policy decisions (e.g. a massive phase-out of certain generation technologies). The MAF 2020 focuses on target years (TYs) 2025 and 2030.

An hourly resolution has been adopted for the simulations of both TYs, meaning that all input time series data for the unit commitment and economic dispatch (UCED) model (e.g., RES generation, demand profiles and net transfer capacities) are expressed in hourly intervals.

1.2 Geographical scope

The present study focuses on the pan-European perimeter and neighbouring zones connected to the European power system. Zones can be modelled either **explicitly**, either **non-explicitly**. Explicitly modelled zones are represented by market nodes that consider complete information using the finest available resolution of input data (e.g., information regarding generating units and demand). Non-explicitly modelled zones are market nodes for which detailed power system information is not available to ENTSO-E, meaning that only expected hourly exchanges between these market nodes and adjacent explicit nodes are considered.

Only connections between market/bidding zones are modelled in the MAF model, while intrazonal grid topology is not. However, some countries have been divided into multiple zones to reflect the effect of certain critical grid elements (e.g. Greece, Denmark and Italy). Table 1 presents both the explicitly and non-explicitly modelled zones in MAF 2020, while the explicitly modelled zones are illustrated in Figure 1.

Table 1: Explicitly and non-explicitly modelled zones

Explicitly modelled member countries/regions			
Albania (AL00)	Finland (FI00)	Republic of North Macedonia (MK00)	Slovenia (SI00)
Austria (AT00)	France (FR00)	Malta (MT00)	Spain (ES00)
Belgium (BE00)	Germany (DE00)	Montenegro (ME00)	Sweden (SE01, SE02, SE03, SE04)
Bosnia and Herzegovina (BA00)	Greece (GR00, GR03)	Netherlands (NL00)	Switzerland (CH00)
Bulgaria (BG00)	Hungary (HU00)	Norway (NON1, NOM1, NOS0)	Turkey (TR00)
Croatia (HR00)	Ireland (IE00)	Poland (PL00)	Ukraine Burshtyn Island (UA01)
Cyprus (CY00)	Italy (ITN1, ITCN, ITCS, ITS1, ITCA, ITSA, ITSI)	Portugal (PT00)	United Kingdom (UK00, UKNI)
Czech Republic (CZ00)	Latvia (LV00)	Romania (RO00)	
Denmark (DKW1, DKE1)	Lithuania (LT00)	Serbia (RS00)	
Estonia (EE00)	Luxembourg (LU00)	Slovakia (SK00)	
Non-modelled member countries/regions			
Iceland (IS00)			
Implicitly modelled neighbouring countries/regions			
Belarus	Morocco	Russia	

1.3 Main assumptions

The MAF model is a simplified representation of the pan-European power system that - like any model - is based on a set of assumptions, which include:

- 1) **Central planning for generation dispatch:** The modelling tools dispatch the generation units for specified time horizons based on their marginal production cost and other plant parameters. For more details, see Section 1.5.2.
- 2) **Perfect information during the UCED problem:** RES available energy, thermal, demand-side response (DSR) and grid capacities and demand are known in advance with perfect accuracy; therefore, there are no deviations from the forecast during their realisation. As such, balancing reserves are not needed, which is why they are subtracted from the available capacity in the assessment. Furthermore, perfect foresight is assumed for variables affecting optimal hydro dispatch.
- 3) **Demand is aggregated by region:** Individual end users or end-user groups are not modelled.
- 4) **Demand elasticity regarding climate and price:** Demand levels are partly correlated to the weather. For example, temperature variations will affect demand levels due to the use of electrical heating/cooling devices. A portion of the demand is modelled as DSR, in which load can be reduced if energy prices are higher than the activation price. The remaining share of energy demand is regarded as inelastic to price and will thus hold regardless of the energy price.
- 5) **Focus on energy markets only:** Capacity markets are not modelled in the MAF. Adequacy is evaluated from a day-ahead/intraday market perspective. Lack of adequacy, the primary focus of MAF, should reflect the expectation that the system is not structurally balanced, at least in some hours and/or days. Additionally, no forward/futures markets or forward/futures contracts between market players are modelled. As such, these do not influence modelled resource capacities. However, the effect of capacity markets will be assessed in the context of the ERAA (see Section 4.1).
- 6) **Value of Lost Load (VoLL) is equal among all market areas:** Thus, costs associated with unserved energy (= VoLL) do not differ between market areas. Moreover, it is ensured that the VoLL is higher than the most expensive production unit/demand flexibility unit in the system.
- 7) **RES production depends on climate:** Solar, wind and hydro power generation directly depend on climate conditions.
- 8) **Forced/unplanned outages only affect thermal generation and grid assets:** Thus, a power plant's net generating capacity (NGC) and a grid's net transmission capacity (NTC) are not continuously guaranteed in a given TY. As seen in Section 1.5.2, forced outages are randomly generated for thermal assets and grid elements within each modelling tool, while planned grid outages are included in NTCs provided by the Transport System Operators (TSOs). Lastly, forced outages do not impact planned outages in any way.
- 9) **Maintenance/planned outages for thermal units are optimised within the modelling tools:** While forced outages occur randomly over time, planned thermal unit maintenance periods are scheduled during less critical periods (i.e., periods with likely supply surplus rather than supply deficit). The maintenance optimisation considers country-specific restrictions such as the maximum number of units simultaneously under maintenance.
- 10) **Some technical parameters of thermal generators are modelled in a simplified manner:** Technical parameters considered to have a low impact on adequacy are modelled in a simplified manner or neglected (e.g., minimum up/down time [h] restrictions that represent economical restrictions are not considered). Technical limitations (e.g., maximum ramping [MW/h]) are only

considered immediately after the occurrence of a unit outage. Lastly, marginal costs are assumed to be constant and independent of the generation level.

- 11) **NTC approach:** Electricity exchanges between market nodes are optimised as part of UCED model optimisation and limited by the respective NTC between the nodes. The NTC approach considers only bilateral power flows without considering the impact of flows in neighbouring regions. A more sophisticated approach that also considers the impact of exchanges in neighbouring regions is explained in Section 4.2 and will be implemented in the context of the ERAA.

1.4 Main inputs and uncertainties

To optimise and forecast a power system’s operation, a large amount of detailed data and information is required. However, even with the best available data, the results are subject to considerable uncertainty, thereby resulting in a difficult decision-making process for market players. Fortunately, the impact of such uncertainty can be reduced thanks to probabilistic market modelling methodologies.

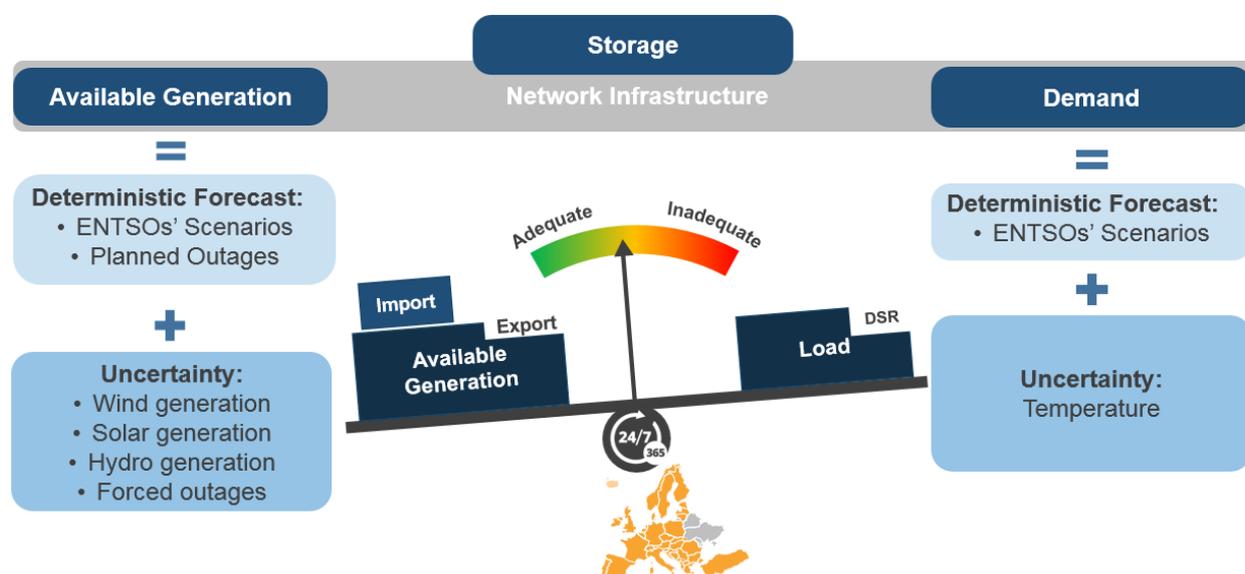


Figure 2: Overview of the methodological approach

Figure 2 illustrates the main elements of the MAF 2020 methodology and their impact on adequacy. The three pillars of an adequacy assessment include **available generation**, **demand** and **network infrastructure**.

1.4.1 Generation side

In MAF, the forecasted net generation capacities (NGCs) for thermal assets are provided by the TSOs. In this methodology, thermal generation depends on deterministic planned outages optimised within the MAF (see Chapter 1.5) and random forced outages that account for plant breakdowns. Planned outage periods for thermal generation assets are usually scheduled during periods of high expected adequacy (i.e., periods of low demand). To avoid adequacy risks, planning must respect a certain number of criteria, which include a maximum number of days per year of maintenance, a ratio of winter vs summer maintenance durations and the maximum number of thermal units in simultaneous maintenance. A single maintenance planning profile for each plant is generated and fed into the models.

In MAF, the RES generation levels depend on climate variable profiles and the RES NGCs provided by TSOs. Solar, wind and hydro generation depend on solar irradiance, wind conditions and hydro inflows,

respectively (see Section 1.5.1). However, hydro assets with storage are a unique case and their operation schedule is the result of an optimisation (see Section 1.5.2).

Balancing reserves (or ancillary services) are power reserves contracted by TSOs that help stabilise or restore the grid's frequency following minor or major disruptions due to factors such as unforeseen plant outages or higher loads. While they are fundamental to a power system's stability, only replacement reserves are modelled in the MAF. Indeed, the MAF measures structural inadequacies that manifest in time steps of 1 hour or longer and does not analyse what occurs within each hour. To avoid scheduling operational reserves (FCR and FRR) for time steps of 1 hour or longer - thus making them unavailable for their initial purpose - the latter are not modelled. Doing otherwise would result in severe violations of the frequency quality criteria outlined in legislation.

From a modelling perspective, reserves can be considered in two ways: by reducing the respective thermal generation capacity or increasing the demand by adding the hourly reserve capacity requirements. For practical reasons, the reserves were considered by adding them to consumption rather than applying a thermal capacity reduction, thereby making it easier to implement the market models. However, doing so has the disadvantage of distorting the reported energy balance since 'virtual consumption' has been added. In some countries, reserves are provided by hydro generation. In these cases, they are implemented as a constraint on the maximum hydro generation. In special cases (e.g., where a TSO has agreements with large electricity users regarding demand reduction when needed or dedicated back-up power plants), the reserve specifications were directly coordinated with the TSO data correspondent. On the other hand, replacement reserves (RRs) are considered in the MAF adequacy calculations (i.e., RRs are available to meet demand).

1.4.2 Grid side

Similar to thermal capacities, the forecasted available net transfer capacities are provided by the TSOs with an hourly resolution. Planned maintenance for the transmission lines was not centrally optimised in MAF 2020 but was considered integrated into the NTC hourly availability, as provided by TSOs. Transmission levels depend on deterministic planned outages and random forced outages, which are modelled in the same manner as the generation elements. Interconnectors between the market zones can consist of multiple poles, which are also explicitly modelled in the MAF. Random outages on these interconnectors are drawn per pole (i.e., at borders with multiple poles, an outage of one pole does not reduce the NTC to zero).

1.4.3 Demand side

Demand level forecasts are provided by TSOs based on their best estimates regarding electric vehicle penetration, heat pumps, annual demand levels, etc. The hourly time series, which are required as an input for the UCED model, are then calculated by ENTSO-E considering the dependence of demand on temperature. For more information on the generation of the demand time series, see Section 2.2.

In modern unbundled power systems, evaluating adequacy also involves the contribution of elasticity of demand with respect to prices. Furthermore, the effect of storage facilities (including their market-driven operation), electric vehicles and heat pumps, along with their corresponding impacts on demand profiles, are considered.

The DSR is modelled in a simplified manner as a generator that participates in the market. Since each DSR unit is characterised by an offer quantity and offer price, it can thus be dispatched as part of the merit order curve. Additionally, the number of hours that the units can operate per day can be limited. Prices, quantities and operational constraints are delivered by the TSOs and can consist of multiple bands where a price differentiation is requested. In most countries, DSR units have relatively high prices, which ensures that they are the last dispatchable services before energy not served (ENS) occurs. However, in some countries, DSR

units can be dispatched before the price-setting generator. Finally, it is ensured that the dispatch price of a DSR unit is set lower than the VoLL.

1.5 Putting the pieces together

The main feature of the MAF probabilistic methodology is the use of Monte Carlo (MC) sampling to combine different climate conditions through climate-dependent variables and random forced outages on generation assets and interconnections for a given TY, as visualised in Figure 3.

Initially, climate years from 1982 to 2016 are selected one-by-one (N climate years). These include temperature-dependent demand time series, wind and solar load factor time series and hydro inflow time series. Each set of climate conditions is further associated with a relatively large number of random forced outage realisation samples (M outage samples) (i.e., randomly assigning forced outage patterns to thermal generating units and interconnections (high-voltage direct current (HVDC) and some high-voltage alternating current (HVAC))). Notably, random forced outages do not affect planned outages in the models. The number of random forced outage patterns M is not known until model convergence has been reached (more details on the convergence can be found in Section **Fehler! Verweisquelle konnte nicht gefunden werden.**).

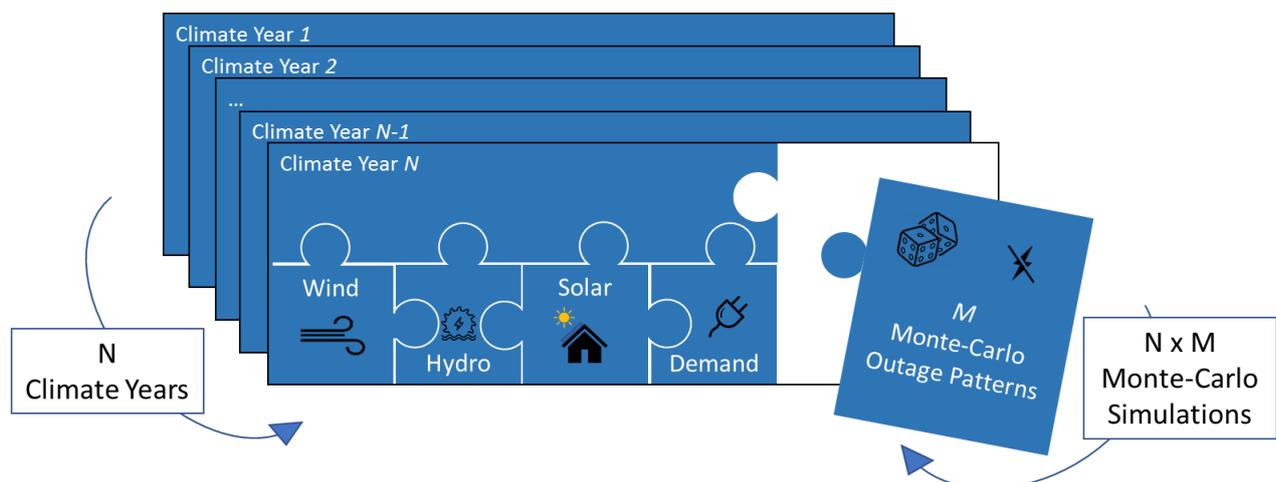


Figure 3: Monte Carlo simulation principles for a given target year

As will be shown further below, the MAF methodology uses five modelling tools to improve results reliability and robustness. Each tool solves its own system cost minimisation problem for a given TY (also known as a UCED problem) and derives the marginal energy market price. Each tool also attempts to find the least-cost solution while respecting operational constraints such as minimum stable feed-in level, transfer capacity limits and so on. Most optimisation solvers and computers are capable of solving single large-scale mixed-integer linear programming (MILP) problems within acceptable computation times; however, the very large number of MC simulations ($N \times M$) makes the MAF a time-intensive and challenging task. Since integer constraints are simplified in MAF 2020, the final problem to be solved is a linear programming (LP) problem.

1.5.1 General workflow

Figure 4 and Figure 5 illustrate the current MAF workflow to build and combine model inputs with the optimisation and convergence workflow.

Briefly, Figure 4 below illustrates the following elements:

- All required data are stored/generated in three databases/tools, namely the pan-European market modelling data base (PEMMDB), pan-European climate database (PECD) and TRAPUNTA. For more information, see Sections 2.
- Some data depend on the TYs, while other data depend on climate years or both.
- A single modelling tool is used to optimise planned maintenance profiles for the thermal assets of each modelled node (for unplanned maintenance, see Figure 5). Notably, planned maintenance for grid assets is already included in the NTC availability by the TSOs.
- Thermal capacity can be dispatched at will, while wind and Photovoltaic (PV) capacities depend on the climate conditions during their operation. As such, the available wind and PV (power) generation can be injected at no cost (or curtailed following the optimisation model’s decision).
- The datasets are fed into the models in a specific way to obtain results.

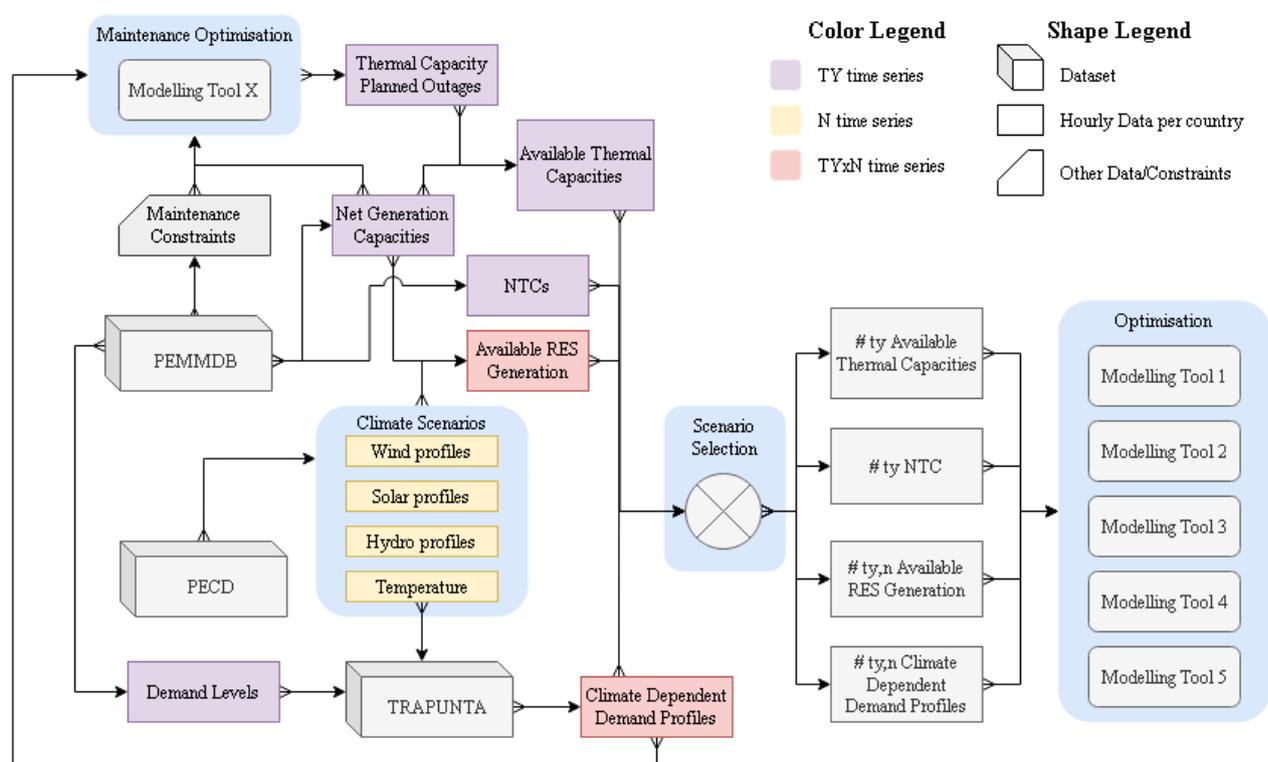


Figure 4: Model input building and combination. The simulations are performed using the following market modelling software: ANTARES¹, BID3², GRARE³, PLEXOS⁴ and POWRSYM⁵.

Figure 5 below illustrates the following elements:

- The start of the simulations is carried out by feeding the five modelling tools with datasets for the first TY and climate year. Convergence is calculated ex-post for each tool separately, meaning that the calculation occurs after $N * M$ simulations for each TY.

¹ <https://antares-simulator.org>

² <https://www.poyry.com/BID3>

³ https://www.cesi.it/news_ideas/ideas/Pages/System-Adequacy-and-Market-Modelling.aspx

⁴ <https://energyexemplar.com/solutions/plexos/>

⁵ <http://www.powrsym.com/index.htm>

- Reaching model convergence for a given TY is an iterative process. Initially, the modellers must decide on an initial amount of random outage patterns M to be generated by each modelling tool. Each tool generates its own distinctive patterns respecting a set of criteria and optimises the model for each pattern. If convergence is not reached, M is increased for the models that did not converge.

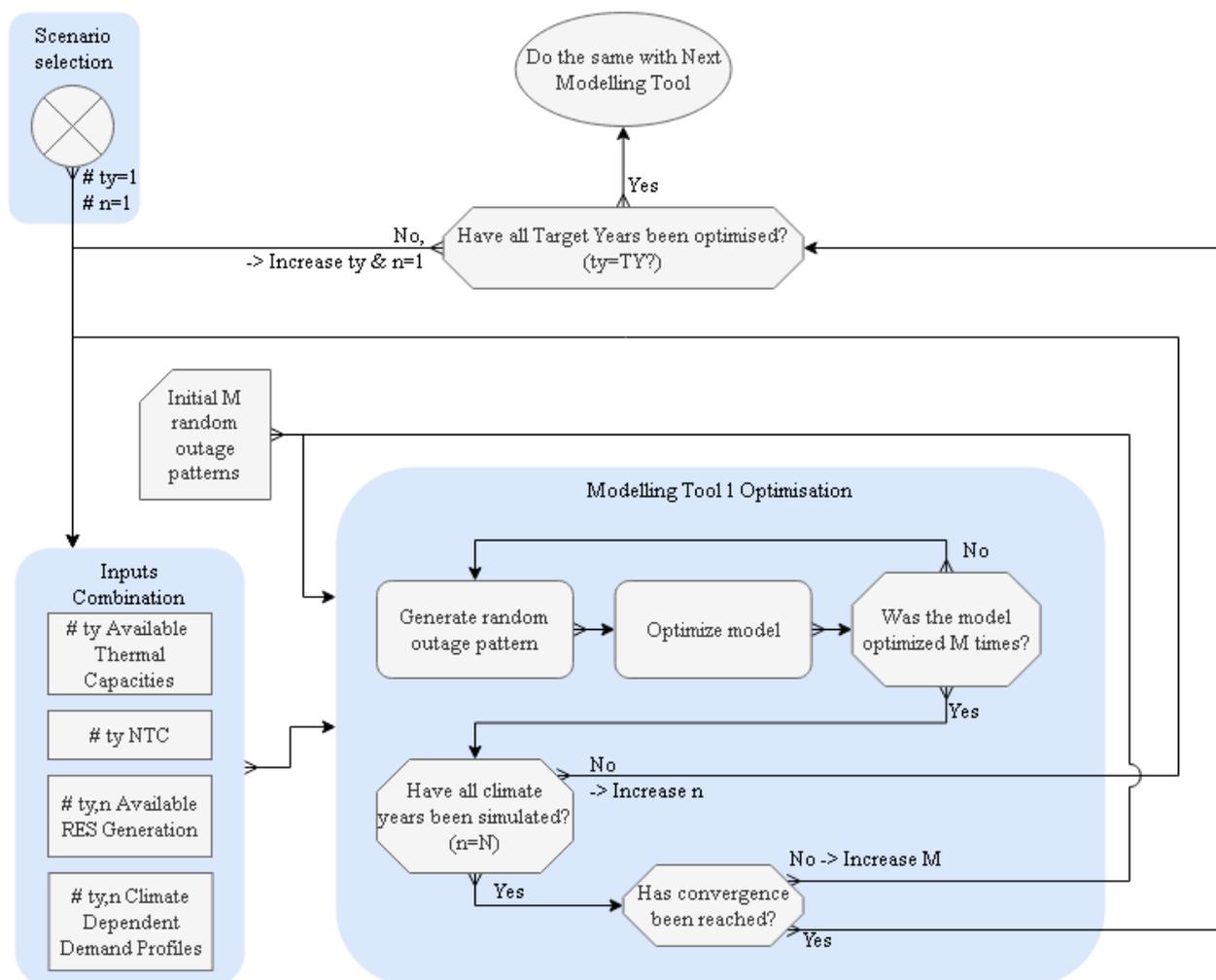


Figure 5: Model optimisation and convergence process.

1.5.2 Optimisation

An additional optimisation step for hydro storage assets occurs within each modelling tool after forced outage pattern generation and before the UCED optimisation. The available energy profile of hydro storage assets is optimised in weekly or monthly resolution steps so that energy is available for turbinng in times of simultaneous high demand and low available generation, while it is pumped (in the case of pump storage units) or stored (in the case of hydro storage units without a pumping facility) in times of oversupply. Simultaneously, exogenously provided weekly or monthly energy targets constrain the optimisation.

The UCED optimisation is then performed in smaller time steps (e.g., one day) to determine which units are dispatched at each hour of the optimisation horizon and the respective dispatch level. For the optimisation, a given TY is divided into several UCED optimisation time steps/horizons. Each resulting UCED problem is

optimised based on its profiles of available thermal NGC, RES available energy, grid NTCs and demand. Then, each UCED problem is given the final system state of the preceding UCED problem (used as the initial dispatching state for the current UCED problem). Indeed, optimising a given UCED problem with a different initial dispatching state while keeping other parameters unchanged may yield different results. Similarly, dividing a TY into a different number of UCED problems may yield different results.

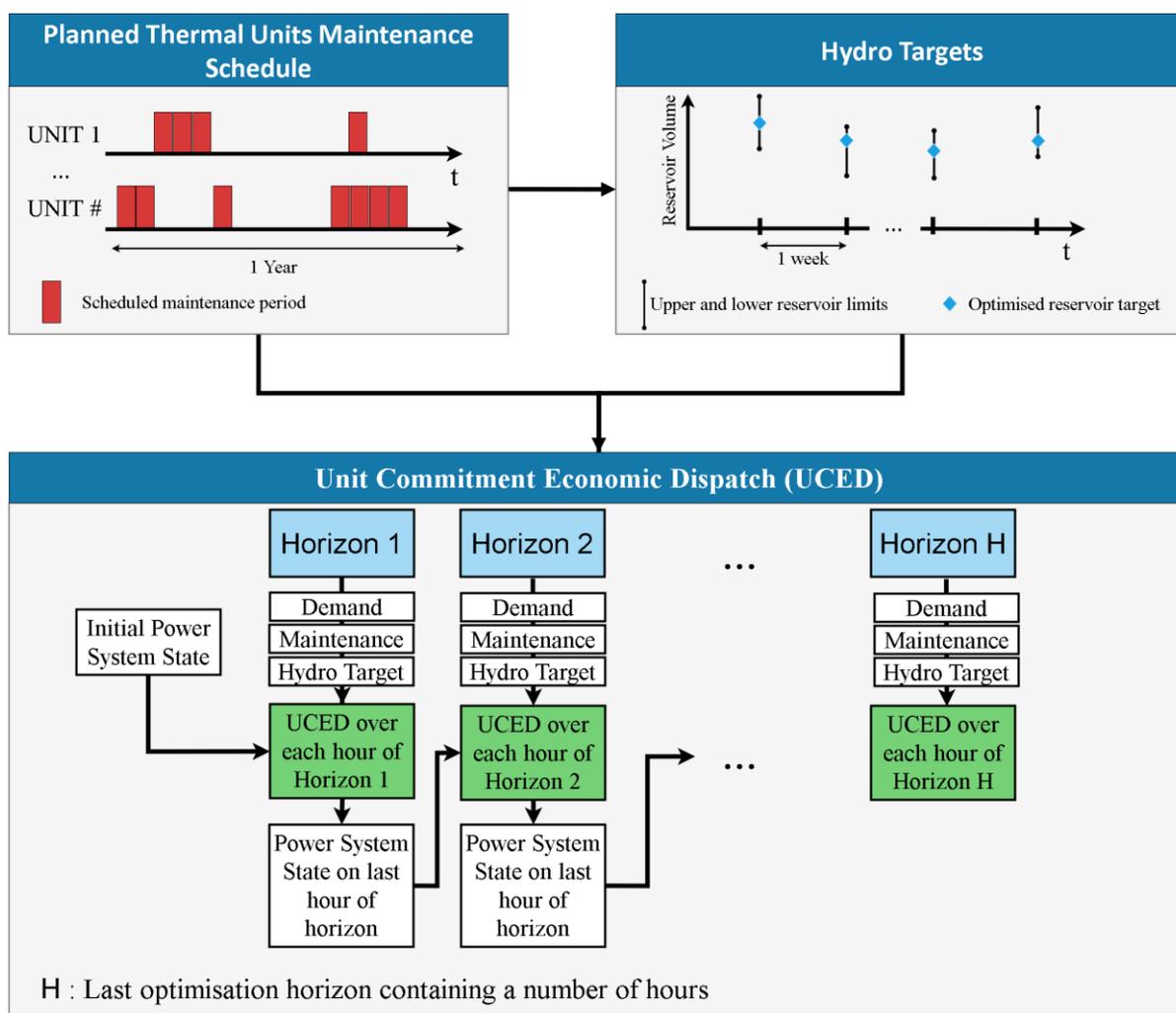


Figure 6: Illustration of the MAF modelling process

Currently, the network modelling approach for pan-European or regional market studies is based on NTC market coupling (a zonal model), which implies that the network constraints between market nodes are modelled not as physical limits, but as commercial exchange limits at the border (i.e., the available capacity for commercial exchanges as opposed to the total transfer capacity). This approach is also followed in the current study, while the value of NTC can differ throughout the year and comprises an hourly time series of NTC for each interconnection throughout each modelled TY.

1.6 Adequacy and convergence

1.6.1 Adequacy indices

System adequacy refers to the existence of sufficient resources to meet consumers' demands and the operating requirements of the power system. The so-called adequacy indicators can be deterministic or probabilistic metrics, according to the methodologies used for the adequacy assessments.

Regarding the definitions and scope of the indices used in adequacy studies, three main functional zones of power systems are involved in the adequacy evaluation:

- **Generation adequacy level** (hierarchical level I), which considers the total system generation and the effects of transmission constraints in the form of NTCs.
- **Transmission adequacy level** (hierarchical level II), which includes both the generation and transmission facilities.
- **Overall hierarchical adequacy level** (hierarchical level III), which involves all three functional zones, from the generating points to the individual consumer load points, which are typically connected at the distribution level.

Traditionally, the adequacy indices can have different designations depending on the hierarchical levels involved in the adequacy study. In MAF 2020, the focus is on hierarchical level I (i.e., the generation adequacy level).

In probabilistic MC adequacy studies, the typical indicators for adequacy (simulation results) are either the expected (average) values of a set of a random variable's outcomes or a percentile of that set, such as expected unserved energy or the 95th percentile of unserved energy. The set population is equal to $M * N$ or a given region, simulation horizon and simulation tool.

The following indices are used to assess the adequacy levels for a given geographical scope and for a given time horizon (referred to as a simulation year).

- **Loss of load event [h]** – Represents an hour in a given MC simulation during which the demand after consideration of demand flexibilities exceeds the available generation and import capacity.
- **ENS [GWh/year]** – For a single node, the energy not supplied during a single MC sample/simulation year due to the demand in the node exceeding the combination of available resource capacity and electricity imports. For a geographical area with multiple nodes, its ENS is the total ENS of all its nodes. A null ENS suggests that there are no adequacy concerns.
- **Expected energy not served (EENS) [GWh/year]** – For a given geographical area the mathematical average of the ENS calculated over the total number of MC sample/simulation years. It is calculated according to Eq. (1):

$$EENS = \frac{1}{MC_{tot}} \sum_{j=1}^{MC_{tot}} ENS_j, \quad (1)$$

where ENS_j is the energy not supplied in the j^{th} -MC simulation and MC_{tot} is the total number of MC simulations.

- **Loss of Load Duration (LLD) [h/year]** - For a single node, the number of hours during which the node experiences ENS during a single MC sample/simulation. Notably, the LLD of an MC simulation

can only be reported as an integer number of hours due to the hourly resolution of the simulation. Thus, it does not indicate the severity of the deficiency or the duration of the loss of load within that hour.

- **Loss of load expectation (LOLE) [h/year]** - For a given geography, the mathematical average of the LLDs over the total number of MC sample/simulation years. It is calculated according to Eq. (2):

$$LOLE = \frac{1}{MC_{tot}} \sum_{j=1}^{MC_{tot}} LLD_j, \quad (2)$$

where LLD_j is the loss of load duration in the j^{th} -MC simulation and MC_{tot} is the total number of MC simulations.

1.6.2 Model Convergence

To obtain confidence in the results, the latter should remain unchanged with an increasing number of MC simulations. At that point, it can be said that the model has converged. With the number of climate years N available being finite, a large number of random outage patterns may be required for the model to converge. In MAF 2020, the convergence of the model is calculated in several steps. Following a set of simulations, the model's convergences are assessed and additional simulations using new forced outage patterns are launched. This process continues until convergence is reached.

While the results provided in the Executive summary and Appendix 1 are presented for each region separately, the convergence of the model is assessed based on the results of the entire geographical scope. MAF 2020 uses the coefficient of variation α derived from the ENS of the entire geographical scope, as defined by Eq. (3):

$$\alpha = \frac{\sqrt{\text{Var}[EENS]}}{EENS}, \quad (3)$$

where $EENS$ is calculated over all MC simulations completed at the moment of assessment and $\text{Var}[EENS]$ is the variance of the expectation estimate (i.e., $\text{Var}[EENS] = \frac{\text{Var}[ENS]}{N}$).

Figure 7 illustrates an example of an MC model's α evolution and its relative change with an increasing number of MC simulations. In Figure 7, one can expect no significant changes in α past a certain number of simulations. With no significant changes in α expected, thus in the results, no additional simulations are required. No explicit α targets are set to stop the MC simulations. Instead, the decision of whether or not to launch additional simulations is a compromise between the expected α evolution and the required computational time.

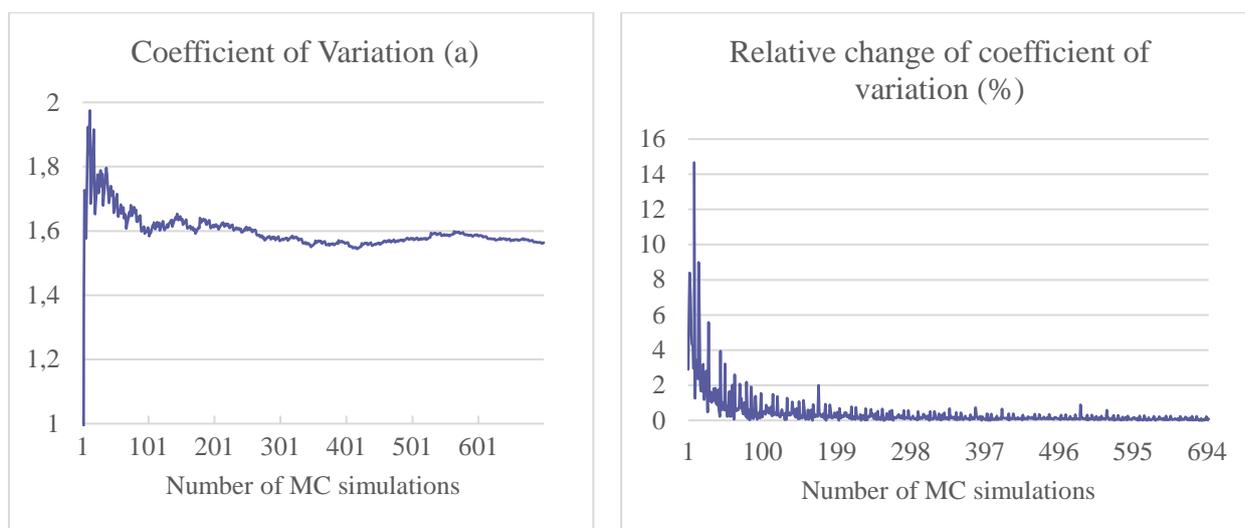


Figure 7: Example of α evolution and its relative change with an increasing number of MC samples for a converging model

Notably, certain inputs and parameters can have a significant impact on the results of these indices and their convergences, including:

- Hydro power modelling;
- NTCs;
- The use/absence of extreme, yet realistic, historical climatic years (e.g., 1985);
- Outages and their modelling, including both maintenance and forced outages⁶.

1.6.3 National reliability standards

Table 2 presents an overview of the national reliability standards that the individual EU Member States have applied to assess their national grid adequacy as of the end of 2019. Countries that are not listed do not have reliability standards in place.

Table 2: National reliability standards applied by EU Member States as of the end of 2019⁷

⁶ To understand the impact of forced outages, which are random by definition, it is important for all of the tools to use one commonly agreed upon maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

⁷ 2019: ACER Market Monitoring Report 2019 – Electricity Wholesale Markets Volume, p. 60, https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202019%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf

Member state	Type of reliability standard	Value	Binding (B)/non-binding (NB)
BE ⁸	LOLE	3 h/year	B
	P95	20 h/year	B
CY	Reserve margin	189 MW	B
DE	LOLE	5 h/year	NB
DK ⁸	Outage minutes	5 minutes	B
FR	LOLE	3 h/year	NB
GR	LOLE	3 h/year	NB
IE	LOLE	8 h/year	B
IT	LOLE	3 h/year	B
LT	LOLE	8 h/year	NB
NL	LOLE	4 h/year	NB
PT ⁸	LOLE	5 h/year	B
	Load supply index	≥ 1	B
PL	LOLE	3 h/year	NB
ES	Reserve margin/LOLE	(see note)	NB
UK	LOLE	3 h/year	B

Some notes regarding Table 2 are provided based on the ACER Market Monitoring Report⁷:

- Loss of load probability (LOLP) is the probability that available capacity will not be able to cover demand.
- Load supply index in Portugal refers to the risk of inadequacy at the day-ahead market only.
- The reserve margin in Cyprus is the level of additional capacity readily available during the peak period of capacity demand.
- In Denmark, the reliability standard is set in ‘outage minutes (OM)’, which are defined as $OM = 8760 * 60 * EUE / Demand$, where Demand is the annual load and EUE is the expected unserved energy (i.e., the EENS adjusted to account for the fact that real load shedding occurs at predefined blocks of energy). OM indicates the expected proportion of the annual load (converted to minutes) that cannot be delivered due to a lack of adequacy. OM and LOLE are different measures and are thus not comparable.
- For Germany, the reliability standard has been derived from a threshold presented in the 2019 security of supply monitoring report⁹. Herein, a LOLP of 0.06 % has been calculated using the cost of new entry (CONE) and VOLL ($CONE/VOLL=50,000$ euro/MW/year/10,000 euro/MWh \approx 0.06%). Thus, the calculated LOLE is 0.06% of 8760 hours \approx 5 hours.
- The value for Ireland refers to the I-SEM¹⁰ and is used for the current capacity mechanism (CM).
- In Spain, a 10% reserve margin (not legally established) was recently used, while a LOLE indicator is currently under discussion. For the non-mainland territories, there is a requirement of a maximum LOLP of one day every 10 years, equivalent to a LOLE of 2.4 hours/year.
- The value for the United Kingdom refers to Great Britain only.

⁸ Reliability standards for BE, BG, DK and PT have been updated to the table contained in the ACER Market Monitoring Report⁷ based on more up-to-date data provided by the corresponding TSOs.

⁹ 2019: Definition and monitoring of security of supply on the European electricity markets, p. 39, https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/definition-and-monitoring-of-security-of-supply-on-the-european-electricity-markets-from-2017-to-2019.pdf?__blob=publicationFile&v=9

¹⁰ I-SEM stands for integrated single electricity market, a wholesale electricity market where electricity is traded in bulk across the island of Ireland.

LOLE (h/year) is the most common reliability indicator used by EU Member States, with targets typically in the range of 3–8 h/year. Setting such reliability targets is a sensitive issue since it requires the consideration of both economic and technical aspects. For instance, these targets could be determined by comparing the VoLL against the costs of increasing adequacy. According to the methodology requirement for the future pan-European Resource Adequacy Assessment, LOLE standards will be defined based on this approach from the ERAA 2021 onward for all European market zones.

2 Databases and tools used for the MAF

The MAF methodology uses data collected from TSOs or generated by internally developed tools, while also using assumptions collected by TSOs. The following sections describe the databases and tools used in the MAF assessment.

2.1 PEMMDB

ENTSO-E uses a single source of supply-side and grid data across all of its assessments (i.e., the PEMMDB containing data collected by TSOs on plant net generation capacities, interconnection capacities, generation planned outages, etc.). The database is aligned with national development plans and contains data about the power system according to the best knowledge of the TSOs at the time of data collection. The PEMMDB contains a highly granular unit-by-unit resolution of European power plants, their technical and economical parameters, their expected decommissioning dates and the forecasted development of RES capacities. Moreover, it provides an hourly time series of must-run obligations and the derating of thermal units. Compared to MAF 2019, a major improvement to the PEMMDB involves a more detailed representation of batteries and (partly) flexible consumers (i.e., electric vehicles, heat pumps and new technologies).

The aforementioned data was collected for TYs 2020 to 2030 with a yearly resolution.

2.2 TRAPUNTA

To create the forecasted hourly load profiles for each region, ENTSO-E (and thus MAF) uses a single tool named TRAPUNTA. This tool builds hourly load profile forecasts for all regions (with some exceptions) by combining information from historical load time series, historical temperature and other climate variables as well as additional historical data. This methodology incorporates the decomposition of time series into basic functions using singular value decomposition (SVD). In the second phase, the tool adjusts the forecasted load time series using bottom-up scenarios provided by the TSOs that reflect the future evolution of the market (e.g., penetration of heat pumps, electric vehicles and batteries). More information regarding the methodology for calculating demand time series is provided in the report “Demand forecasting methodology”¹¹.

2.3 PECD

ENTSO-E developed the PECD, which consists of re-analysed hourly weather data and load factors for variable generation (i.e., wind and solar). PECD datasets are prepared by external experts using industry best practices, thus ensuring a representative estimation of demand, variable generation and other climate-dependent variables. Since 2019, the PECD has been extended to include hydro generation data. Based on re-analysed data concerning hydro inflows, a standardised central methodology has been designed to map historical inflows of generation data and build a model to project hydro generation, including hydro run-of-river, hydro reservoirs and pump storage. In 2020, a further improvement was achieved by introducing a

¹¹ Demand methodology document:

<https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/2019/Demand%20forecasting%20methodology.pdf>

higher granularity of north-sea offshore zones and updating the zone configuration in Belgium. More information regarding the methodology and relevant assumptions are included in the corresponding document “Hydro Power Modelling”¹².

3 Current methodology: Limitations of MAF 2020

The current MAF methodology relies on an advanced probabilistic market modelling approach. However, like every modelling approach, it has its inherent limitations. These limitations are presented as follows:

- **Upcoming forced outages considered in UCED:** Forced outages are randomly generated but are known at the time of the UCED, with a look-ahead horizon ranging from 1 to 7 days ahead (depending on the market modelling tool). As such, the units are dispatched accordingly to avoid/minimise loss of load.
- **Thermal asset planned maintenance optimisation:** Planned maintenance optimisation of thermal generation assets is performed independently for isolated market nodes (i.e., it does not yet include the grid infrastructure).
- **DSR limitations:** DSR is only modelled as demand reduction potential in the case of high prices, while shiftable load is not yet considered in the simulations. Shiftable load enables the re-scheduling of demand from a period with high prices to a period with lower prices (i.e., from a period with higher adequacy concerns to a period with lower adequacy concerns). Moreover, the current methodology considers that part of the demand is elastic regarding price but no other criteria (e.g., the generation mix of a given moment).
- **VoLL:** Different end-user groups may be characterised by different loss of load values within a region and across regions.
- **Thermal and grid assets are not affected by climate conditions:** In reality, thermal and grid assets capacities may vary with air temperature and humidity, for example.
- **Internal grid limitations within a bidding zone are not considered:** However, they have been further investigated in a flow-based study conducted as a sensitivity analysis (explained further in Section 4.2. This topic requires further development and also needs to consider possible evolutions of the European market. The future ERAA—to be developed by ENTSO-E pursuant to article 23 of EU Regulation 2019/943—will need to be based on a methodology that inter-alia provides for the use of a market model using the flow-based approach, where applicable.
- **No forced outages are assumed for RES¹³ assets:** Since MAF 2019, thermal units have assigned unit-specific forced outages. However, no random outage draws are considered for RES.
- **Forced outages are assumed to not affect planned outages:** Generation units’ planned outages are usually scheduled months or years in advance. However, they may still change depending on the operational/contractual constraints of each plant owner/operator. In reality, if a forced outage occurs very close to a planned outage, the latter may be moved at a different moment or even merged with the forced outage.

¹² Hydro methodology document:

[https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/2019/Hydropower Modelling New database and methodology.pdf](https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/2019/Hydropower%20Modelling%20New%20database%20and%20methodology.pdf)

¹³ This includes hydro generation units.

- **Sub-hourly fluctuations of demand and RES are not considered:** Demand and RES penetration are currently modelled with an (averaged) hourly resolution so that sub-hourly variations (e.g., demand peaks) of these parameters cannot be modelled.
- **Economic viability:** Assumptions regarding available resource capacity for each TY are only the best estimate of TSOs for their area of operation, collected following a bottom-up approach. In MAF 2020, the economic performance of generation units is not assessed with respect to either their economic viability in the TY or the opportunity for expansion (see Section 4.1 for more information).
- **Use of NTCs and not flow-based:** See Section 4.
- **Sectoral Integration:** See Section 4.

4 ERAA methodology and gap analysis

The Clean Energy Package (CEP) brings several changes and updates to the methodology used for adequacy assessment, while the scope of the assessment is significantly extended. However, implementation of the complete set of changes will gradually occur over the coming years. An overview of the gap analysis regarding the target methodology and the current status of further developments in the MAF methodology is shown in Figure 8.

Topic	MAF 2020	ERAA Methodology	Status
Modelling approach	Probabilistic	Probabilistic	100%
Publication frequency	Annual	Annual	100%
Network	NTC approach. Testing Flow-Based approach since 2018	Compliance with Flow-Based approach	50%
Target years and time horizon	2 target years within a 10 year horizon	10 target years within a 10 year horizon	25%
Available resource capacity	Bottom-up expectations	Bottom-up expectations followed by Economic Viability Assessment	25%
Capacity mechanisms	No explicit considerations	Effect of Capacity Mechanism integrated	25%
Sectoral integration	None	Integration of Power to Gas, Power to Hydrogen, etc.	0%

Figure 8: The MAF methodology gap analysis upon considering the legal requirements for the Clean Energy Package

The main features affected by the CEP implementation are summarised below:

- 1) **Probabilistic market modelling approach (MC):** The core of the MAF methodology (i.e., probabilistic market modelling) already complies with most requirements of the ERAA. The future adequacy assessment will be required to present more detailed results followed by the level of convergence of the probabilistic metrics based on a single modelling tool.
- 2) **TYs and temporal resolution:** MAF 2020 focuses on two TYs, while the target ERAA methodology will request to simulate each of the 10 years ahead, while significantly increasing the workload.

- 3) **Impact of climate change:** The current methodology uses historical climate data for its probabilistic assessment. These historical data do not account for the impact that climate change could have on climate variables in the years to come. Thus, the ERAA climate change impact on the climate variables will be considered an update to the PECD.
- 4) **CMs:** Existing, approved or planned CM assets may be included in the assessment as part of the NGC forecasts of some TSOs. The ERAA will require the impacts of approved, existing and planned CM assets on adequacy to be studied separately.
- 5) **Sectoral integration:** Sectoral integration technologies, such as technologies for power-to-gas and power-to-hydrogen conversions or power conversions to other mediums, are not accounted for in the MAF but will be required in the ERAA.
- 6) **Economic viability:** The MAF is based on top-down scenarios for installed capacities and does not consider the economic viability of the fleet. Only expected or official commissioning and decommissioning dates of thermal generation plants are considered when building the MAF scenarios. The CEP requires the incorporation of an investment module, which will assess the economic viability of capacity resources and their potential exit from the market (see Section 4.1).
- 7) **Flow-based:** The MAF is built on the NTC approach for the representation of grid elements. However, it will be replaced by flow-based market coupling (FBMC), which is one of the target features of the future adequacy assessments (see Section 4.2).

4.1 Economic viability assessment

4.1.1 Economic viability assessment: Methodology and proof of concept

An economic viability assessment (EVA) is a methodological element in the target ERAA methodology that aims to identify changes in the capacity mix stemming from economic reasons that could affect the likelihood of retirement, mothballing and new investments in capacity. In the current MAF state of play, TSOs provide their best estimates of available units for each of the simulated TYs based on national plans and/or ambitions and the best available knowledge at the time of data collection. However, the economic rationale that would ensure that these capacities would indeed materialise is not verified, rendering such assumptions intrinsically uncertain. Additionally, even if these estimates could be realised, they may represent a non-optimal asset mix with regard to profitability. The EVA aims to identify assets that, under perfect competition, would likely be decommissioned or mothballed while simultaneously identifying potential new generation investments. Additionally, under the ERAA, the ability of existing CMs to improve adequacy for a given TY is taken into account by assessing the results of two separate scenarios including and excluding CM, respectively.

ENTSO-E is working intensively on defining the details of the EVA assumptions and methodology as well as its future implementation under the context of the ERAA. From the proof of concept investigations conducted at ENTSO-E by the MAF experts, it was concluded that building robust results via the EVA process requires a two-step methodology:

- **Step 1 - Overall cost minimisation:** The target of this initial step is to provide an initial estimate of the results.
- **Step 2 - Iterative process:** The goal of this second step is to refine the results to assess the robustness of and confidence in the results of the first step while confirming that the capacities maintained are economically viable (e.g., by accounting for the effect of risk management towards price volatility and price spikes and by considering the state-of-the-art experience in the industry).

In the following paragraphs, the two-step approach is further elaborated upon.

The **first step** in EVA aims to simulate a long-term cost minimisation model (LT model) to identify units that will be decommissioned and new investments that will be made. This will be done under consideration of the so-called policy units, which are exogenously defined by the respective TSOs and are not available for commissioning/decommissioning (e.g., units that are part of a coal phase-out plan). The overall costs to be minimised are formulated by summing up the investment costs of new generation and demand-side resources, fixed and variable costs of operating units, the cost of activating DSR as well as the costs (welfare loss) of unserved energy.

Notably, the LT model is a large model that is computationally difficult to solve because the generation assets are no longer passive parameters of the optimisation problem but take the status of active variables. To make this model computationally feasible to solve, some simplifications are necessary. These simplifications are summarised as follows:

- **Lower time resolution:** Since LT plan optimisation is complex, the temporal resolution of the simulation is lowered. Instead of simulating 8760 hours in a year (as in MAF UCED simulations), the EVA simulation approximates the hourly demand time series with a set of representative blocks that are fit to represent the complete time series using the weighted least-squares technique. Moreover, in this approach, it is possible to retain several peaks in the Load Duration Curve (LDC) for peak load hours to ensure that the most challenging periods are retained. Nevertheless, this approximation still leads to simplification of the demand time series.
- **Reduced number of MC years:** Another source of complexity is the number of MC years considered. Since the LT model should consider all MC years stochastically, the number of MC sample years is traded off with the convergence of the model. Therefore, to ensure the convergence of the LT model in this methodology, the EVA currently assumes a limited number of climatic years to represent different weather conditions. Moreover, random/forced generator outages are modelled using the effective load approach (i.e., modifying the load with respect to the convoluted capacity outages), and no forced outage rates are assumed for cross-border capacities.

Due to the aforementioned simplifications, the results of the LT plan may not fully reflect a least-cost equilibrium solution in which the cost of unserved energy is equal to the marginal cost of new capacity. Notably, the definition of the methodology and the respective simplifications remain a work in progress.

To confirm the robustness and validity of the results of the first step, a second step is required to evaluate the solution of the cost minimisation problem solved in step 1. This is necessary due to the limitations of the first step optimisation problem, which are listed as follows:

- Total cost minimisation does not necessarily guarantee the profitability of all resources.
- The temporal resolution is relaxed.
- The long-term optimisation can only account for a limited number of climate years.
- The impact of risk on revenues is not considered. If the revenues of a resource unit primarily come from relatively few climatic years, the average of these revenues is not a good proxy to estimate profitability. Risk aversion needs to be considered.
- Real investment or retirement decisions are not based on revenues and profitability for only one year. Thus, it might be necessary to analyse several years to make an investment or retirement decision.

To ensure the robustness of results, it is proposed to complement the total cost minimisation step with an iterative process to refine the results and ensure that units which are finally maintained are indeed profitable (i.e., once the effect of risk management towards price volatility and price spikes are duly considered according to state-of-the-art experience in the industry).

4.1.2 Additional revenues

According to the ERAA methodology, the EVA should also consider additional revenue streams for different technologies aside from revenues derived from the wholesale energy-only electricity market. The revenues can include (i) government subsidies, (ii) the sale of heat/steam in district heating networks or to industrial customers (for combined heat and power (CHP) plants only), (iii) the provision of ancillary services, (iv) capacity remuneration mechanisms and (v) trading on futures/forwards markets. In the 2020 internal tests, these revenues have not been included; nevertheless, some proposals on how these could be included have been submitted and are being explored.

4.1.3 Preliminary simulations and next steps

In 2020, some internal tests for the LT model (i.e., the first step of the methodology) were performed at ENTSO-E. In these tests, must-run units were assumed to be policy units together with coal, lignite and nuclear units. Notably, according to the ERAA methodology, policy units shall not be decommissioned. The TY considered for the tests was 2025 and the model used for performing the test simulation was the MAF 2019 model. The source of the economic parameters of fixed cost and investment cost was the Price-Induced Market Equilibrium System (PRIMES) energy system model¹⁴ whenever possible; otherwise, they were retrieved from the Energy Technology Reference Indicators (ETRI)¹⁵ report for TY 2025. In the stochastic LT model, the climatic years for these tests had to be limited. Thus, the years 1982, 1984 and 2007 were selected by sorting climatic years based on their LOLE levels (i.e., low LOLE, average LOLE and high LOLE). This selection of climate years was completed before the LT plan, and only for TY 2025. Additional simplifications were applied the hourly load duration curve of 2025 (i.e., 900 blocks and 400 peaks instead of the complete hourly time series). Finally, decision variables of investment and retirement were linearised and a single value of VoLL was assumed to represent the utility loss of involuntary load shedding.

However, the initial results of these tests are only meaningful under the assumptions and implementation simplifications undertaken, some of which were previously mentioned. Thus, it is of no added value to the reader to present results at this stage. The work on EVA will continue in the context of ERAA 2021 through refinements of the methodology and further testing during the proof of concept phase. In particular, the methodologies for modelling the scenario with CM, details on the iterative process, improving overall cost minimisation, incorporating mothballing decisions and considering additional revenues need to be further investigated.

4.2 Implementation of flow-based market coupling: Definition of the target methodology and proof of concept

In the European day-ahead market for electricity, energy is traded within and across bidding zones. While the market assumes no grid restrictions within a bidding zone, there are limitations to the amount of power that can be traded across borders. For certain capacity calculation regions (CCR), the NTC approach is used to define the available trading capacity. Here, a commercial capacity available for bilateral trades between zones is assumed. Per the definition, the trade across one border does not affect the trading capacity of other borders. Optimising a market model integrating the NTC approach can thus be classified as a classical transportation problem. This capacity calculation method is valid for several CCRs in the European day-ahead market. For these CCRs, NTCs are estimated on a daily basis in the capacity calculation process. While the MAF does not apply this level of detail, it is worth mentioning that in MAF 2020 seasonal NTC values

¹⁴ The PRIMES model is an EU energy system model which simulates energy consumption and the energy supply system. It is a partial equilibrium modelling system that simulates an energy market equilibrium in the European Union and each of its Member States. (https://ec.europa.eu/clima/policies/strategies/analysis/models_en#PRIMES)

¹⁵ The ETRI 2014 report presents a comprehensive and up-to-date cost and performance overview of the European energy technology portfolio for the period 2010 to 2050. (<https://ec.europa.eu/jrc/en/science-update/etri>)

were applied in the pan-European market model used for the main simulations. Another capacity calculation approach considers the power flow on individual critical network elements and contingencies (CNECs). Therefore, it considers the physical reality of the grid. Referencing this principle, the method is known as FBMC. In Central-Western Europe (CWE), FBMC has been operational in the day-ahead market since 2015 and the method will be extended to the CCR of the Core by mid-2021.

One goal of the ERAA is to capture the key characteristics of the European day-ahead market for a reliable resource adequacy assessment. FBMC is an essential part of the electricity market regulatory framework; thus, FBMC is planned for inclusion in the report by 2021. In the preparation of the ERAA, the principle of FBMC was applied to probabilistic market simulations as a proof of concept. Flow-based domains, consisting of processed historical domains, were introduced in the MAF 2019 model with updated input data corresponding to the simulated year of 2021. Using historical Flow Based (FB) domains for TYs close to the present is a valid approach since the underlying power system specifications change rather slowly. However, the further the look-ahead horizon, the less significant the simulation results become when obtained from historical FB domains. Therefore, it is not advisable to apply this methodology to TYs that are over two years in the future. For this reason, the FBMC implementation at ENTSO-E investigates an advanced methodology that computes FB domains based on planning datasets for market data and grid models. The current status of this work is presented in the following paragraphs.

4.2.1 Methodology description

In principle, FBMC relies on a linearised load flow model. Based on power transfer distribution factors (PTDF), the individual net positions of bidding zones and setpoints of relevant HVDC interconnectors and phase-shifting transformers (PSTs), the active power flow can be calculated for monitored network elements. The resulting power flow must not exceed the available transmission margin, which depends on the individual physical transmission capacity, reliability margins and effective legal requirements. Exchanges with countries outside of the CCR are modelled as NTCs and thus assume standard hybrid coupling (SHC). Two different implementation approaches are investigated in this proof of concept study of ENTSO-E and are briefly introduced in the following paragraphs.

4.2.1.1 First implementation approach

The general FBMC approach has been implemented by the Belgian TSO ELIA¹⁶ based on the grid model of the Ten-Year Network Development Plan (TYNDP) for which flow-based models were developed for the years 2020, 2023, 2025, 2028 and 2030. This approach is described in the steps illustrated in Figure 9.

¹⁶ “Adequacy and flexibility study for Belgium 2020–2030”, https://www.elia.be/en/news/press-releases/2019/06/20190628_press-release-adequacy-and-flexibility-study-for-belgium-2020-2030.

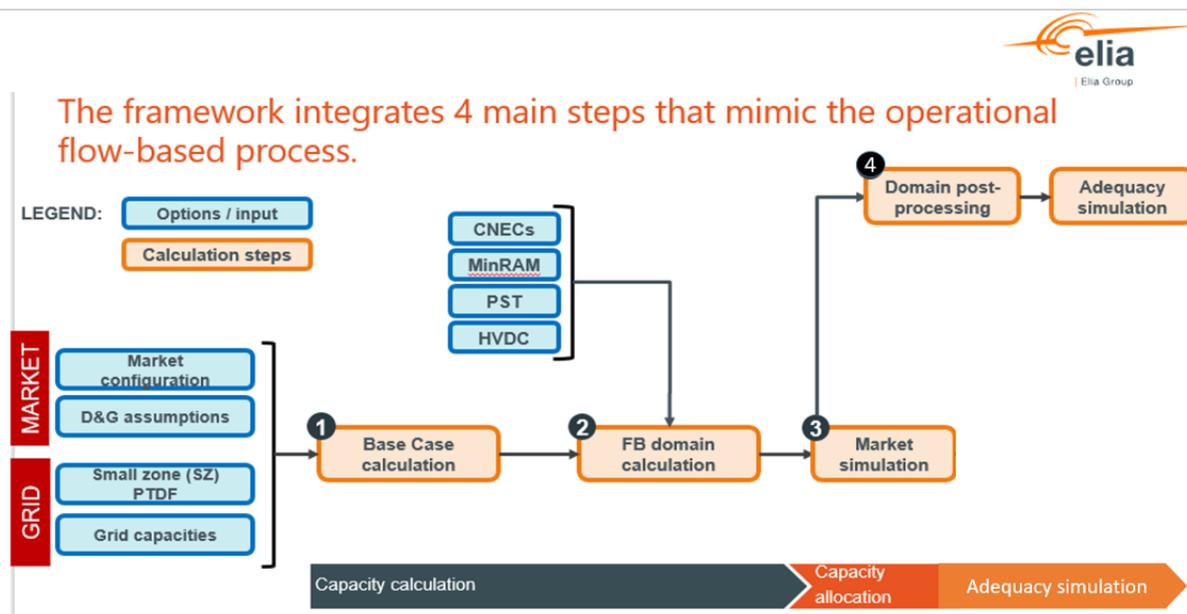


Figure 9: FBMC methodology steps based on ELIA’s document “Adequacy and flexibility study for Belgium 2020–2030”

An initial market simulation is performed with flow-based domains based on the linearised grid model, which considers the physical reality of the grid. The admissible flow of each grid element equals the entire seasonal rated transmission capacity. This market simulation estimates the dispatch within the CCR to determine realistic initial loadings of all grid elements, including critical network element and contingency (CNECs).

By combining geographical information on the location of load and generation with the initial hourly market dispatch, the loadings of grid elements can be determined for each hour. Using the bidding zone generation shift keys (GSK), which are based on dispatchable generation inside each bidding zone, the net position of each of the bidding zones is then scaled to zero. Hereby, commercial exchanges between bidding zones are cancelled, and the remaining flow on grid elements equals the initial loadings accounting for internal flows and loop flows.

The above process for determining the initial loading of network elements is performed in the absence of commercial exchange between the CCR bidding zones. However, the CCR region might also be connected to external bidding zones that do not apply the FBMC methodology. Therefore, the framework also considers these external flows (EFs) and their contribution to the loop flow calculation. Following the aforementioned approach using GSKs, the global net position of the entire bidding zone is scaled back to zero and also considers the contribution of EFs feeding into each corresponding bidding zone.

Finally, in the base case calculation, relevant PSTs and HVDC systems are optimised by the market simulation. The loop flow associated with these PSTs and HVDC systems is also duly considered in addition to the previously calculated contributions.

Once the initial loading of grid elements is determined, the remaining available margin (RAM) is calculated. The effect of the flows on HVDC lines and PSTs in this approach can be considered in two ways: i) SHC or ii) advanced hybrid coupling (AHC). In SHC, the resulting base case flows through HVDC lines and PSTs provide an ‘injection’ into the meshed AC grid. For each critical network element (CNE), this is considered in the calculation of the RAMs to account for the estimated base case flows from the HVDC interconnection and PSTs. In AHC, the power flows from the HVDC lines and PSTs become a part of the FB approach within a CCR and are thus treated the same as all other power flows competing for the available transmission

capacity of the AC meshed grid. Therefore, the RAM for the affected CNEs in the AC transmission grid is not further reduced by the HVDC and/or PST base case power (loop -) flow contribution, as in SHC.

Furthermore, in line with the CEP target for 2025, a minimum margin for trade is applied to the RAM calculation of each grid element determining the flow-based domains. Notably, this value is 70% for 2025 onwards. Since the initial market simulation has an hourly resolution, it would result in 8760 flow-based domains for a year. To obtain feasible computation times, a clustering algorithm based on the geometrical shape of the domains is thus applied, resulting in a specified number of clusters. Next, a representative domain is selected for each clustered set to be used in the FBMC model. In the final step, a correlation analysis between the domain clusters and several input parameters is applied to link a given market situation to the FB domain to be applied. Currently, the selection of German wind infeed and French demand are chosen for this proof of concept in MAF 2020 as the most relevant parameters in determining the selection of the domain. This choice is being assessed with respect to the extended geographical scope foreseen from CWE to the Core region. In any case, the principle remains the same: the hourly choice of the applied domain is based on the correlation with relevant external parameters and climate variables.

4.2.1.2 Second implementation approach

Another FBMC methodology implementation for the proof of concept in MAF 2020 is based on a methodology introduced by the French TSO RTE (illustrated in Figure 10). For the initial market simulation, an NTC approach is chosen. The output of this simulation is then projected on a grid model representing the expected future grid situation for the time horizon of the study. The result of this step is a nodal model describing generation, load and power flows for one or multiple time steps. For this nodal model, a remedial action optimisation is conducted based on a list of CNECs provided for the study. This step ensures that cross-border exchanges can be maximised. Although this step of the methodology was not performed in the proof of concept, it is planned to be implemented at a later stage. The next step is then to apply the CWE/core FBMC methodology to calculate flow-based domains from the CNEC list and the associated remedial actions. The result is a list of hourly flow-based domains. An optional additional step involves introducing a feedback loop that delivers the calculated flow-based domains back to the initial market simulation, thereby replacing the initial NTCs. The process chain can then be re-run for a more robust result. Finally, the set of flow-based domains resulting from this process can be reduced by geometrical clustering. The clusters are sets of computed days with a similar shape at hourly resolution. A representative typical day is then selected from each cluster and can be applied in probabilistic adequacy simulations depending on their correlation with simulation variables related to adequacy. In this proof of concept, these variables consist of load and power generation.

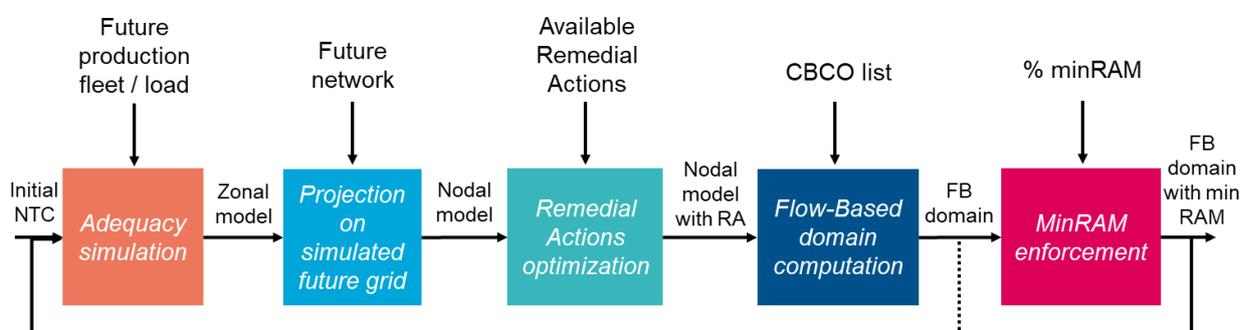


Figure 10: RTE FBMC methodology steps.

4.2.2 Preliminary simulations

Based on the two aforementioned FBMC methodology implementations, two sets of FB domains were provided for probabilistic adequacy studies. The first implementation approach consists of domains prepared by ELIA, which cover a geographical area very similar to the core CCR, whereas the geographical scope of the second implementation approach covers the CCR of CWE. For this proof of concept, the first approach uses domains calculated based on a TYNDP 2018 grid model, whereas the second approach uses domains obtained from a TYNDP 2020 model. Notably, both sets of domains do not use the same CNEC list since they were calculated using different grid models. Both domain sets have been implemented for the adequacy market model of MAF 2019.

The retrieved domains were compared against each other by comparing the vertices in several two-dimensional representations for CWE countries. This visual comparison showed that even though the two implementation approaches are different in some respects, the resulting flow-based domains for CWE are consistent overall.

The two sets of flow-based domains have been integrated into two market simulation tools. Utilising more than one piece of software helps to validate the simulation results if the outcome for relevant quantities is aligned. The preliminary results show values for LOLE and EENS that are in the same range for both market simulation tools. However, certain differences in results are still present and are under investigation.

4.2.3 Conclusions and outlook

FBMC is an established capacity calculation method for inter-zonal trade in the European energy market for electricity in the CWE region. With its introduction in core CCR, the method becomes even more relevant to the entire European market and demands a proper representation in mid- and long-term studies. Therefore, FBMC is planned to be included in the ERAA starting in 2021. As a preparational step, an internal proof of concept has been performed and reported here in MAF 2020 for information. This proof of concept has introduced two implementations of the general FBMC methodology that apply to mid- and long-term studies. While the practical implementations differ on certain points, the resulting FB domains were sufficiently consistent and affirm the validity of the chosen approaches. The work performed within this ENTSO-E proof of concept will thus provide the basis for the implementation of FBMC within the ERAA.

For the next steps, the two developed tool chains for domain calculation will be adapted to capture the entire Core as a CCR. As part of this development, updated market and grid model databases will also be included in the domain calculations and market simulations. Furthermore, the results of the proof of concept highlight the importance of considering the effect of curtailment minimisation and curtailment sharing (“adequacy patch”) in the market simulations once the FBMC approach is fully implemented in the ERAA simulations. Based on the results obtained, it is observed that once scarcity is present in one or several bidding zones, ‘flow factor competition’¹⁷ could lead to situations where order curtailment occurs non-intuitively/unfairly. For example, this could mean that some buyers (order in the market) that are ready to pay any price to import energy would be rejected while lower buy bids in other bidding areas are selected instead. Two situations tend to occur prior to the “adequacy patch” being considered: i) ENS can be created for net exporting countries to identify the lowest ENS for the FB area as a whole; ii) Countries with low ‘flow factors’ are penalised with ENS to the benefit of countries with high ‘flow factors’, even if all of these countries are simultaneously at the maximum market price cap. These are the situations that the adequacy patch must

¹⁷ If two possible market transactions generate the same welfare, the one having the lowest impact on the scarce transmission capacity will be selected first within FBMC. This also means that, in order to optimize the use of the grid and to maximize the market welfare, some buy (demand) bids with higher prices than other buy (demand) bids located in other bidding zones, might not be selected within the flow-based allocation. This is a well-known and intrinsic property of flow-based referred to as “flow factor competition”.

mitigate by correcting flow factor competition while being compliant with the principles of capacity allocation for the 'single price coupling' (EUPHEMIA) algorithm.