MID-TERM ADEQUACY FORECAST
2017 Edition

entsoe
Reliable Sustainable Connected

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1 Introduction to the MAF

What is the purpose of the 'MAF'?

The Mid-term Adequacy Forecast (MAF) is a Pan-European assessment of power system adequacy spanning the timeframe until 2025. It is based upon a state-of-the-art probabilistic analysis conducted using sophisticated market modelling tools. It will provide stakeholders with comprehensive support to take qualified decisions which are driven and affected by the level of adequacy in the European power system.

Resource adequacy is an increasingly prominent issue that requires advanced methodologies to capture and analyse rare events with adverse consequences for the supply of electric power. It describes the continuous balance between net available generation on the one hand, and net load levels on the other, as shown in Figure 1.

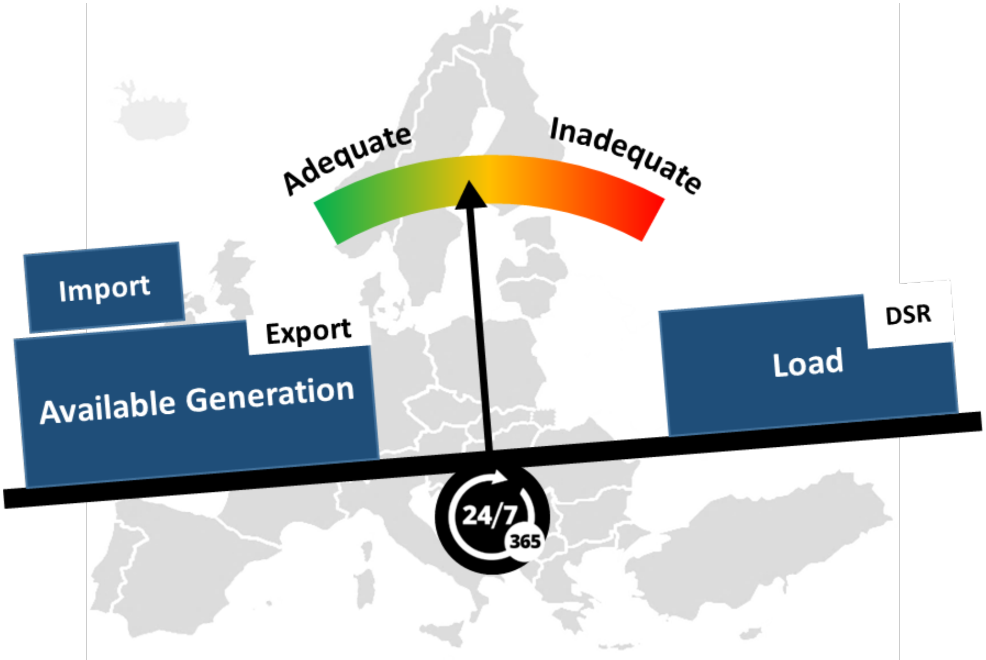

Figure 1: Resource adequacy: balance between net available generation and net load

Due to the increasing level of variable renewable energy sources in the European power system and the enhanced related challenges for system development and operation, a Pan-European analysis of resource adequacy has become ever more important. Cooperation across Europe in developing such methodologies is necessary to speed up the methods development process and ensure common methodological standards, i.e. a common 'language'.

Over the past decade, ENTSO-E has been continuously improving its methodologies and forecasts, and will continue to ensure that further progress is made. In response to recommendations by the Electricity Coordination Group (ECG) in 2013 and further stakeholder consultation during 2014, ENTSO-E has invested important resources in the development and dissemination of a common 'Adequacy Target Methodology'.[1]

[1] ENTSO-E System Adequacy Methodology

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ENTSO-E is also embracing the newest legislative proposals by the European Commission that aim to harmonise resource adequacy methodologies across Europe with the help of ENTSO-E's contribution.[2] In fact, most of the proposed features are already in place in the MAF 2017 report, such as the probabilistic market modelling and related reliability metrics (LOLE, ENS)[3], an appropriate forecast horizon, and the construction of consistent scenarios[4].

The MAF satisfies the need for a Pan-European adequacy assessment for the coming decade. As such, it provides stakeholders with comprehensive support to take qualified decisions, and will help to develop the European power system in a reliable, sustainable and connected way.

The various stakeholders may find the prospective nature of the MAF, as well as its extensive Pan-European coverage, particularly useful. In fact, the MAF is the most comprehensive Pan-European assessment of adequacy so far attempted, based on market-based probabilistic modelling approaches undertaken in a collaborative effort of representatives from TSOs covering the whole Pan-European area under the coordination of ENTSO-E. Four different modelling tools have been calibrated with the same input data and benchmarked against each other to increase the consistency, robustness, and – fundamentally – trust for the complex analytical results presented in the report.

Still, it should also be noted that the present pan-European assessment inevitably faces limitations. Higher granularity of National/Regional Adequacy assessments might detect resource constraints not identified by Pan-European assessments. Conversely, as the examples of the cold spell in winter 2017 and the winter outlook show, the European assessment may fail to capture some particular elements and interdependencies necessary to forecast and assess in sufficient detail all the potential tense situations. Hence, the MAF cannot be the sole source for regulatory and/or legislation decisions. For instance, once a capacity mechanism is implemented, its implementation lasts de facto over several years and therefore several assessment periods, and for the sake of non-distortion it cannot flash in or out depending on the results of the yearly MAF report. Hence, the MAF is not meant to replace national assessments; rather, together with regional assessments it should complement national analyses and challenge them in order to enhance the overall quality of adequacy analyses and the corresponding decisions.

What are the main improvements compared to the MAF 2016?

Since the publication of last year's report, activities have been consolidated, improved and standardised. New developments have emerged, and the prospective database has been updated with the support of national TSOs. In addition, modelling features have been added and improved, especially in the field of demand side response, and the extension of the sample of climatic conditions. Therefore, the new results correspond to an updated and improved best estimate of future adequacy conditions.

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[2] Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity (recast) COM/2016/0861 final/2 - 2016/0379 (COD)

[3] Loss Of Load Expectation (LOLE) and Energy Not Served (ENS) are two widely used metrics to describe the adequacy of a system. Further explanations are provided in Sections 2 and 3.

[4] ENTSO-E and ENTSO-G are together developing future scenarios for the European gas and electricity system. The document 'Overview of the selected / proposed gas and electricity TYNDP 2018 – 2040 story lines' was published on 19 September 2016

Last year, MAF introduced for the first time state-of-the-art modelling tools for the Pan-European probabilistic assessment of adequacy. While broadly following this approach, the MAF 2017 aims to further consolidate, improve and standardise the activities in order to establish a Pan-European standard and 'common language' regarding power system adequacy. To this end, extensive collaborative effort has been made by representatives from TSOs covering the whole Pan-European area under the coordination of ENTSO-E. The same four modelling tools have been used and further developed to conduct a comprehensive market-based probabilistic assessment of adequacy throughout Europe. Further alignment of the four different modelling tools has been achieved, thus yielding additional insights and knowledge acquisition, while simultaneously enhancing the consistency and robustness of the results. Specifically, improvements have been made in the modelling approach compared to last year's report in the following fields:

- ➔ **Hydro-optimisation and thermal plants' forced-outage modelling:** The last edition of the MAF stressed the impact of different assumptions regarding the foresight horizon of hydro scheduling and forced outage rates (FOR) of thermal units between the different modelling tools. These assumptions are now better aligned.

- ➔ **Objective function of the models:** Compared to the MAF 2016, all models involved have been aligned with respect to the objective function, i.e. costs of supply over a week to be minimised are identical across all models and subject to several techno-economic restrictions.

- ➔ **Representation of demand side response (DSR):** Based on the information collected by the TSOs, DSR has been modelled with different price bands to allow for a more detailed representation, e.g. of industrial and domestic DSR.

In addition to these modelling-related improvements, an enhanced set of input data was collected with the help of all European TSOs, and carefully implemented in the different models. Several aspects are worth highlighting:

- **Consolidation and standardisation of the database:** The format and content of the data collection made for this year's report is in full alignment with ENTSOs' Scenarios. It serves as an input for the Mid Term Adequacy Forecast as well as for the assessment performed in the framework of the Ten Year Network Development Plan (TYNDP). A comprehensive report and dataset covering the development and status of ENTSOs' scenarios[5] will be published in its first draft for consultation, together with the MAF.

- **Extension of climate sample data:** Deploying a comprehensive climate dataset is crucial to enable appropriate modelling and a statistical assessment of extreme climate and calendar events such as cold spells, heat waves, extreme low wind conditions or solar eclipse. Compared to last year's report, the database has been extended to comprise 34 years of wind, solar and temperature data at an hourly basis. Furthermore, interdependencies (i.e. correlation) between hydrological conditions and other climate parameters were considered.

- **Mothballing data:** As an additional sensitivity scenario, data were collected regarding the number and size of generation units which may be at risk of being mothballed for economic reasons. For example, mothballing could be expected in the absence of a capacity market and/or unfavourable market conditions (such as the 'missing money' problem).

[5] Scenarios developed together by ENTSO-E and ENTSO-G, with the contribution of external stakeholders.

Noticeably, the above mentioned improvements, both in the input data and in the modelling tools, naturally entail the fact that the new results presented in the MAF 2017 do not always align with those obtained and reported in the MAF 2016. Therefore, the new results should be seen as an updated and improved best estimate of future adequacy conditions.

What are the new lessons learnt?

Our report highlights the importance of cross-border cooperation in fostering adequacy throughout the Pan-European power system. These effects are caused by complex interdependencies between supply, demand and interconnection capacities. Meanwhile, the latest expectations regarding the mothballing of power plants appear to lack a comprehensive Pan-European examination, as they may severely impact adequacy in various regions.

Based upon activities and simulations conducted for the MAF 2017, several new insights were gained:

- **Climate severely impacts adequacy:** Power systems are increasingly affected by climate conditions, such as wind, solar radiation and temperature. In order to realistically forecast possible future events of system adequacy, it is necessary to deploy a comprehensive set of climate data, covering a large range of possible outcomes, including 'normal' as well as 'extreme' conditions. The 34 years of hourly data used for this report comply with this requirement. Especially interesting are the data from January 1985 which contain an extreme cold spell of long duration. Such data are crucial to cover a large and realistic scope of risks and adequacy levels in power systems.

- **Estimated reliability levels throughout Europe are extremely heterogeneous:** Limited capacities in the transmission grid impede the full deployment of balancing support throughout Europe. Consequently, expected shortages are substantially exceeding generally envisaged targets, in particular in the periphery of the simulated power system (see Figure 4 and Figure 7).

- **Strong system interdependencies call for a Pan-European perspective:** Our analysis demonstrates complex and strong system interdependencies and their impact on system adequacy, schematically shown in Figure 2. Specifically, we find temporal and spatial dependencies in load and generation patterns from variable renewable energies, as well as in the availability of hydro and thermal power (e.g. driven by hydrological inflows or maintenance schedules). However, beneficial balancing effects to support systems in times of scarce generation capacity may only be deployed if sufficient grid infrastructures are present. In a similar vein, measures to overcome adequacy problems may be allocated to the supply, demand or grid sector. Therefore, decision-makers will need to coordinate their activities to ensure an efficient deployment of (partially) complementary measures. For instance, additional interconnection may supersede the need to enhance the generation capacity within a country.

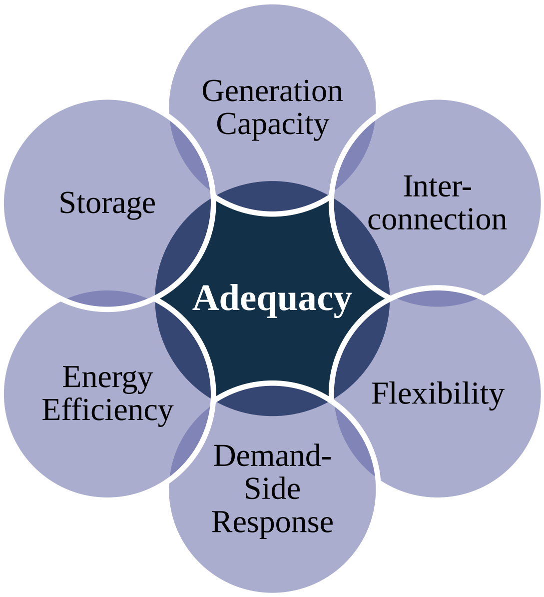

Figure 2: Interdependencies between measures impacting resource adequacy

- **Substantial capacities at risk of being mothballed, with far-reaching consequences for adequacy:** In our data collection, 45% of the countries reported generation capacities at risk of being mothballed, representing a reduction of thermal generation capacity by 15% compared to the base case (best estimate). In a sensitivity simulation analysing adequacy in Europe without these capacities, significant impacts are observed. In fact, these mothballing activities would imply tightened adequacy margins in 82% of the countries, thus having a substantial effect far beyond national borders. It will therefore be crucial to monitor mothballing activities on a broader European scale.

- **Common standard needed for data, models and metrics:** Compared to last year's report, the MAF 2017 has made various improvements regarding data collection and the deployment and alignment of the modelling tools. This process revealed that some of the results may be sensitive to the specific data and modelling approach used for quantification. In addition, large variations may be observed in the reliability standards and thresholds applied by the various Member States (for a detailed discussion, see ACER/CEER Market Monitoring Report 2015[6]). Therefore, additional efforts should be directed towards the development of common standards for data requirement, models and reliability metrics.

- **Adequacy assessments require substantial coordinated efforts:** To conduct and improve the complex probabilistic assessment of power system adequacy, continuous and coordinated activities and efforts will be necessary. Specifically, adequacy assessments require a substantial amount of resources to collect reliable data from multiple stakeholders, and to run the complex models with the necessary high level of precision and care. This holds true for the Pan-European assessment, but naturally extends to regional and national studies as well. Future efforts should thus be streamlined and supported by all stakeholders (MSs, NRAs, EC, ACER, Market Operators, etc.) to ensure consistent and reliable results for qualified decision-making.

[6] ACER – Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015, Page 61

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What are the upcoming challenges and future steps?

Despite the considerable efforts already made to arrive at the MAF 2017, future activities will need to target three dimensions: data, modelling and common standards.

The probabilistic assessment introduced in last year's MAF represented a cornerstone for system adequacy assessments in Europe. For the MAF 2017, the new direction has successfully been followed, with several remarkable improvements and findings, as described previously. Nevertheless, further efforts will be necessary to ensure the continued high quality contribution of the MAF to adequacy-related decision-making in Europe. Specifically, further improvements may be made with respect to four dimensions:

First, additional **data collection** will lead to an even better representation of the full complexity of adequacy in the power system. The greatest potential for further improvement is seen in the context of hydro power and the flexibility of generation assets, as well as economic parameters of the system (e.g. the country-specific values of lost load).

Second, the different **modelling tools** will need to be further developed, to address the full complexity of adequacy. For future editions of the MAF, we will aim for a more detailed representation and analysis of interdependencies within the system, e.g. regarding the (partial) substitutability of demand, storage and supply-side measures and interconnectors. The representation of grid infrastructure development and operation will be further developed towards a more accurate flow-based representation. Flexibility and ramping restrictions are foreseen as another area of future improvement. Noticeably, these activities will also help to further align the modelling approaches and obtain more robust results.

Third, a major challenge consists in converging to **common standards in terms of data and methodology**. We will strive to establish the MAF methodology as a reference for other studies (e.g. in relation to the TYNDP, Seasonal Outlook, regional or national adequacy studies, etc.). This includes enhanced and more standardised interaction with member TSOs and other stakeholders regarding data and modelling interfaces. In line with the proposals in the EU Clean Energy Package, the outcome will be reported in a 'Methodology Guideline', including a stakeholder consultation phase and corresponding amendments. This document will provide an important contribution to a standardised framework for adequacy assessments in Europe.

Last but not least, the MAF will be **embedded in a broader set of stakeholder activities**. Within a continuous forward-moving cycle, the yearly process mainly consists of five steps, as shown in Figure 3. The MAF itself mainly covers the three first parts, i.e. data collection, European modelling and analysis, and the stakeholder consultation. However, to realise the full potential of the MAF, these steps need to be complemented by regional and national analyses, thus providing a sound basis to adopt measures to eliminate regulatory distortions hindering the realisation of an adequate system state. Learnings and new developments will then be fed into the next edition of the MAF to ensure continuity and consistent improvements.

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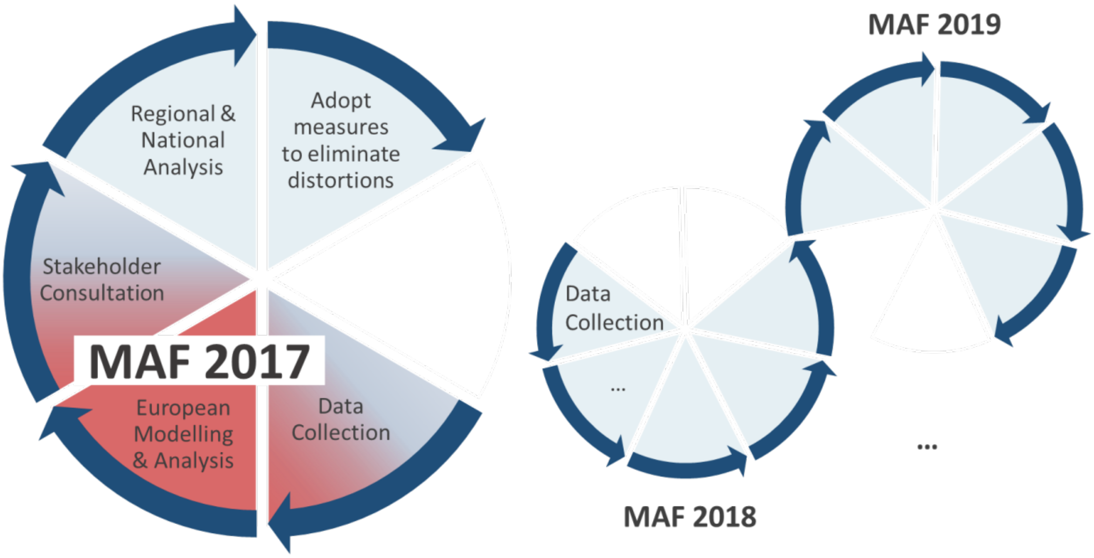


Figure 3: Process of activities in the adequacy domain

Importantly, in the process depicted in Figure 3, regional and national studies should share the same probabilistic methodology with the MAF to enable consistent analyses and comparisons. In contrast, however, it should be noted that due to the different and complementary scope and usage of Pan-European, regional and national studies, some differences in the methodological assumptions and data might be considered. The table below highlights some of the main differences observed between different adequacy assessments in Europe.

Table 1: Features of regional and national analyses

Report	Time horizons	Geographical perimeter	Climate DataBase	DSR	Flow Based method
MAF 2017	2020, 2025	EU	ENTSO-E PECD	DSR input from TSOs	Not in 2017
PLEF 2017	2017/2019, 2023/2024	Focus on adequacy within PLEF region. MAF data provides the basis for setting up the study	ENTSO-E PECD	DSR input from TSOs + use of flexibility tool	Usage of flow based approach from CWE TSOs, combined with NTC approach for PLEF countries not within the CWE FB region

Probabilistics national studies by TSOs, comparable to MAF 2017	Different up to 10 years	Single unit resolution within focus perimeter relevant for the study. Dataset consistent with MAF for rest of the simulation perimeter	ENTSO-E PECD + Hydro specific databases for all climatic years	Extensive consultation with market parties on national assumptions (e.g. DSR assumptions)	Flow based approach based on historical domains from the CWE FB tool

How to avoid erroneous take-aways?

The calculated reliability indicators are not a forecast of future outages. Specifically, the adequacy analysis presented in this report is (and can only be) a best possible estimate of future developments, given today's expectations.

It must be noted that the conclusions in this report cannot be separated from the hypotheses described and can only be read in reference to these. The hypotheses were gathered by the TSOs according to their best knowledge at the time of the data collection and validated by ENTSO-E's relevant committees.

ENTSO-E and the participating TSOs have followed accepted industry practice in the collection and analysis of data available. While all reasonable care has been taken in the preparation of this data, ENTSO- E and the TSOs are not responsible for any loss that may be attributed to the use of this information. Prior to taking business decisions, interested parties are advised to seek separate and independent opinions in relation to the matters covered by this report and should not rely solely upon data and information contained herein. Information in this document does not amount to a recommendation in respect of any possible investment. This document does not intend to contain all the information that a prospective investor or market participant may need.

ENTSO-E emphasises that ENTSO-E and the TSOs involved in this study are not responsible in the event that the hypotheses presented in this report or the estimations based on these hypotheses are not realised in the future.

2 The main findings of the MAF 2017

For the MAF 2017, five European electricity market models were calibrated and run based on comprehensive datasets for 2020 and 2025. The main findings are presented in this Section, while the more detailed results are contained in Section 4. As a preliminary remark, it should be noted that although the same time horizon as last year's MAF has been studied, the careful reader will find several differences between the results. These should be examined with care due to several changes and improvements that were made with respect to data and methodology. While a one-to-one comparison is difficult due to the large number of interdependent assumptions and highly complex models, the results presented hereafter should be seen as an updated and improved best estimate of future adequacy conditions.

2.1 Adequacy in 2020

The estimated levels of resource adequacy for the year 2020 in the base case scenario are shown in Figure 4 by means of country-by-country average Loss of Load Expectation (LOLE), i.e. a risk indicator derived from probabilistic market modelling tools. It should be noted that LOLE indicated in this report refers to the market resource adequacy, without considering ENS due to transmission or distribution faults. More specifically, for each bidding zone, two concentric circles are shown: the inner one for the average LOLE, and the outer (more conservative) one for the 95th percentile. For more information about the methodology and probabilistic indicators, please see the illustrative infoboxes presented in Figure 5 and Figure 6, as well as the detailed descriptions in Section 3. Moreover, readers should also consider the country comments (Section 5.2: National view on resources adequacy concerns identified & highlighted (or not identified) in MAF 2017) to understand country-specific characteristics and modelling assumptions before jumping to any conclusions.

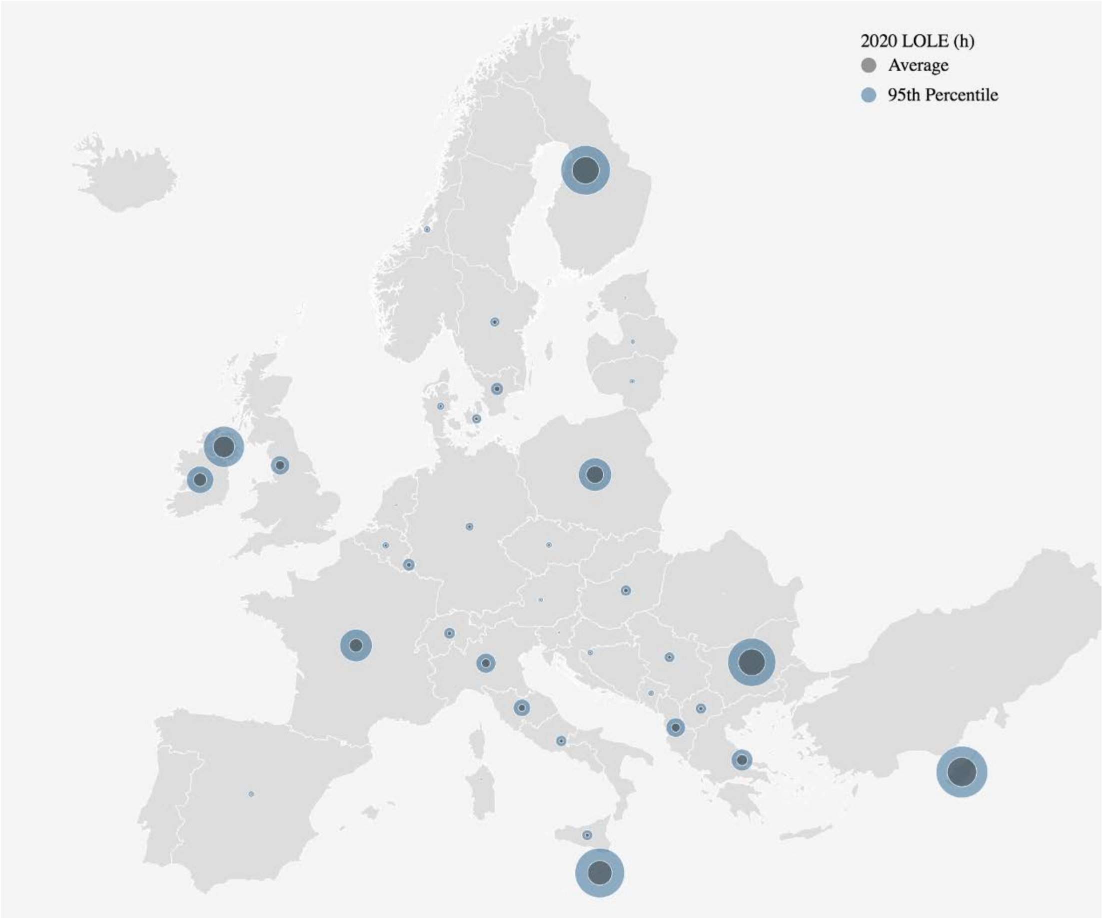


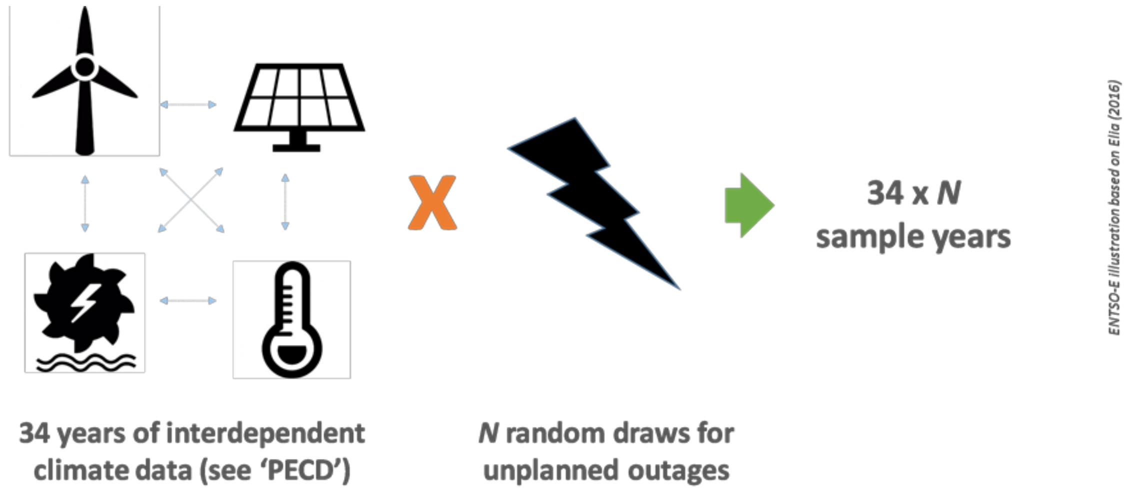
Figure 4: Adequacy in the 2020 base case scenario

As depicted in Figure 4, our results indicate that resource adequacy in 2020 remains high in most countries, even for the 95th percentile. However, in several countries severe risk of resource scarcity has been identified (threshold LOLE ≥ 10 hours/year), mainly for islands (Cyprus, Malta, Ireland and Northern Ireland) and, more generally, at the periphery of the simulated countries (e.g. Albania, Bulgaria, Greece and Finland). Besides structural developments on the demand and supply side, this finding confirms the role of interconnection in helping countries to get support in critical situations. In addition, however, reliability concerns may also arise within continental Europe: in France and Poland, as well as in Italy North and Italy Central-North, the reliability index LOLE 95th percentile value is high, indicating around 35 hours per year.

Monte Carlo:
State-of-the-art technique to assess resource adequacy

The modern Monte Carlo method was developed by scientists working on the atomic bomb in the 1940s, who named it for the city in Monaco famed for its casinos and games of chance. Its core idea is to use random samples of parameters or inputs to explore the behavior of a complex system or process. Since that time, Monte Carlo methods have been applied to an incredibly diverse range of problems in science, engineering, and finance and business applications in virtually every industry.

The high number of aleatory input variables which influence the outcomes of an adequacy assessment in power systems makes Monte Carlo very suitable for the current report. Specifically, it is a state-of-the-art technique to represent probabilistic variables such as climate data and unplanned outages in electricity market models, as illustrated below.



For each hour of our simulations, a reliability indicator is calculated, namely the Energy Non Served (ENS), indicating whether there is an adequacy problem or not. This value can be either:

ENS = 0 (no adequacy problem)

or

ENS ≠ 0 (adequacy problem found)

For each area of interest, the number of times with non zero ENS is counted and stored. This number divided by the total number of simulations provides an estimate of the probability of adequacy issues. Bookkeeping of the number of counts of ENS allows us to construct the so-called Probability Distribution (PD) function, and to derive the Loss of Load Expectation (LOLE), i.e. the expected number of hours with adequacy issues within a certain area. It is important to recall that our analysis must not be understood as a forecast of actual scarcity situations. The actual realisation of scarcity events in a particular hour in the future will – of course – depend upon the actual realisation of all the variables impacting a power system, and could be very different compared to our analysed situations. Meanwhile, our analysis provides a sound indication for the range of possible realisations (see next infobox).

Figure 5: Monte Carlo: State-of-the-art technique for assessing resource adequacy

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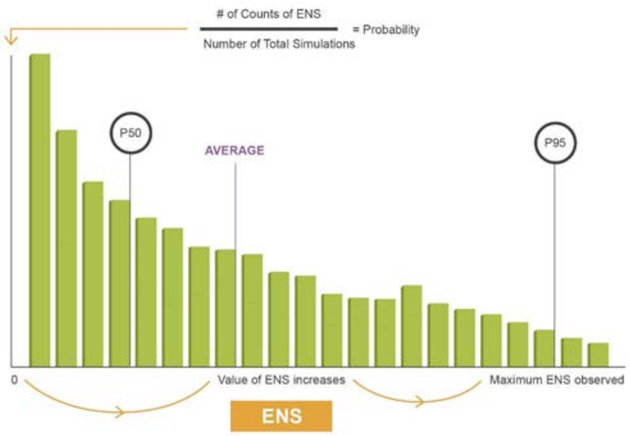
Probability Distributions:
How to derive clear messages from a complex analysis

The Probability Distribution (PD) function for ENS typically resembles the figure below. Most of the time, the records find that ENS = 0, i.e. that the resources are adequate enough to cover the load. However, a certain set of critical hours may be found where ENS is > 0, indicating particularly stressful situations where the system might – with a certain probability - be unable to serve the load.



To extract the main messages from the wealth of data comprised in the PD function, three key values are commonly computed:

- ***Average (mean)**: This is the average value of ENS found among all the situations*
- ***Median (P50):** This is the value of ENS for which there is an equal number of simulations reporting ENS > P50 than ENS < P50. The area covered by the PD on the left and on the right hand side of the P50 value are therefore equal. Note that ONLY with a symmetric PD, would P50 and Average coincide. The fact that P50 < Average indicates that the PD is not symmetric, and that there are a number of so called low-probabilility high-impact events (fat tails).*
- ***'1-in-20 years' (P95):** This is the value of ENS for which 95% of the values found are lower than P95 (ENS < P95 95% of the times). Only 5% of values found are higher than this value. P95% gives a measure of high values of ENS which are likely to occur with a very low but still finite probability of occurrence. P95 gives a measure of the 'low probability – high impact: worst case 1-in-20 years' situations observed.*

For this study, the full probability distribution as well as the 3 values above (P50, Average and P95) were computed on a country-by-country basis with 4 probabilistic European electricity market modelling tools to enable a benchmarking comparison. An exemplary result in shown in the figure below.

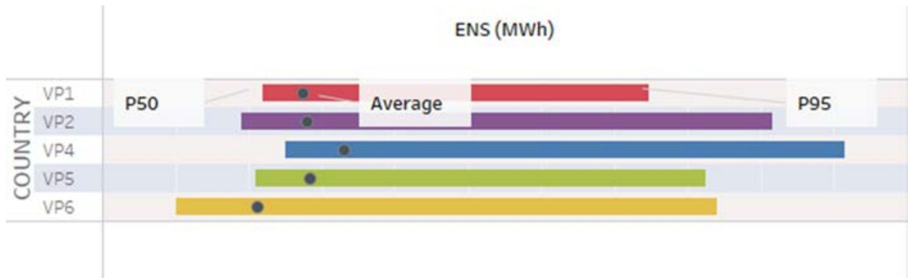


Figure 6: Probability Distributions: How to derive clear messages from a complex analysis

2.2 Adequacy in 2025

The same analysis conducted for 2020 was performed for the base case 2025 scenario. Figure 7 shows the probabilistic market modelling results for the key resource adequacy indicator LOLE on a country-by-country basis.

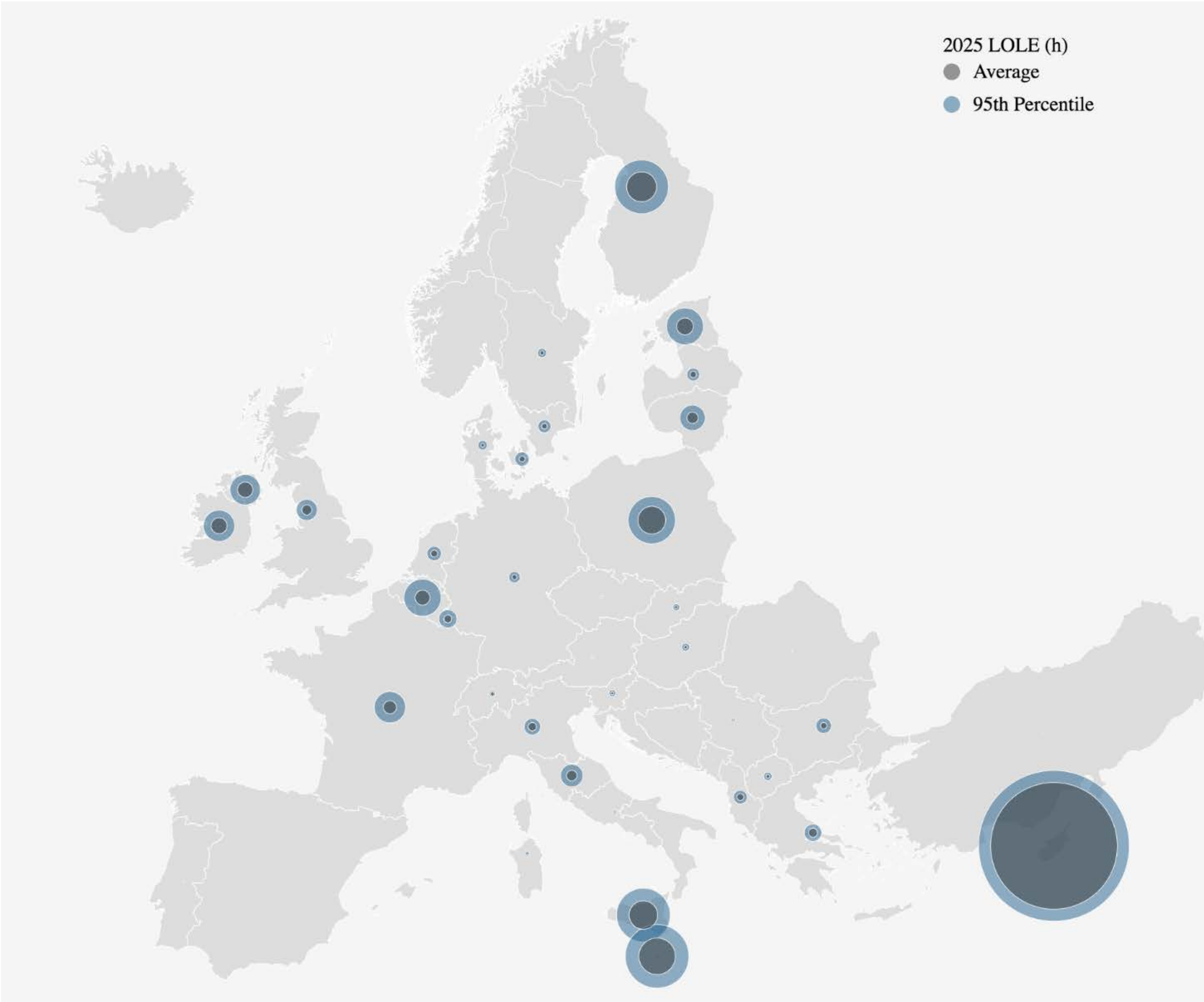


Figure 7: Adequacy in the 2025 base case scenario

Even though the resource adequacy concerns found for 2025 are broadly in line with the ones in the 2020 base case scenario (compare Figure 4 and Figure 7 and the similar adequacy risk magnitude in France, Italy North, Italy Central-North and Ireland), various differences should be noted. First, the situation is aggravated in the Baltic area, especially in Estonia and Lithuania where several old power plants are assumed to drop out of the system and in Poland, where forecasted demand growth does not correspond with investment needed. In this context, given the simultaneous occurrence of scarcities in the area, interconnections are then unable to cope with the difficult situations. Meanwhile, it will be interesting to follow actual developments to observe whether decommissioning plans will indeed be realised, or whether other distortions leading to high risks of resource inadequacy will be addressed. Noticeably, LOLE also increases for Belgium, due to various changes on the supply side as well as strong interdependencies on neighbouring countries (e.g. high LOLE in France).

A second remarkable difference relates to the degradation of adequacy conditions on the Mediterranean islands (Malta, Sicily and Cyprus). It is important to note that the European assessment may fail to capture some particular elements that are essential for assessing in sufficient detail the reliability of the power system of these islands. With respect to Sicily and Malta, the increase of LOLE could be partially explained by the simplified method of modelling the AC interconnections towards the Continent. With respect to Cyprus, the island is assumed to be isolated throughout the entire time horizon. The commissioning of the interconnection between Cyprus and the mainland would, of course, significantly impact reliability indicators. Further details about these specificities and how they are seen from a national viewpoint may be found in the country comments in Section 5.2.

A third difference is that resource adequacy is expected to improve between 2020 and 2025 in Bulgaria (due to the envisaged commissioning of new CCGT plants) and Northern Ireland (second North-South Interconnector to be commissioned in 2021).

2.3 Adequacy in 2020 and 2025 – A closer look

In addition to the base case scenarios 2020 and 2025 depicted above, a large number of additional analyses were carried out while preparing the MAF 2017. The main insights are presented hereafter, while the detailed model results are contained in Section 4.

2.3.1 Impact of extreme climate conditions

In the process of preparing the results delivered in this report, another important finding relates to the impact of climatic conditions on the adequacy of power systems. For the MAF 2017, a detailed analysis was enabled by the improvement of our Pan-European Climate Database (PECD) which now covers 34 instead of the previous 14 years of climatic data (i.e. wind speeds, solar radiation and precipitation, as well as temperature). This database covers a wider range of possible climatic conditions, including some rare but extreme events. Even though weather conditions cannot be predicted precisely for any future point in time, using such a broad range of possible historic realisations helps to develop a solid idea of potential future risks.[7] While further details about the data are presented in Section 3.2.3, let us consider one specific example, namely the impact of cold spell waves on resource adequacy. Cold spells can have a dramatic influence on the balance between generation and demand, especially if low temperatures cause demand to increase (i.e. if electricity is used for heating purposes). We cover this temperature-load dependency in our model through a detailed methodological approach (see Section 3.2.2 for details).

France is known to have a comparatively high temperature-demand dependency, and is thus an interesting and important case for studying this effect. Figure 8 shows the occurrence and severity of all cold spells in France within the period 1947-2016. Therefore, within the timeframe covered by our climate database (i.e. 1982 to 2015), two important cold spell events are contained: 1985 and 1987.[8]

[7] Note that this approach does not overcome the risk of seeing other realisations than the ones considered in this report. Specifically, we would like to stress that possible realisations with a very high impact could be missed with the approach presented (sometimes referred to as 'Black Swan' scenarios).

[8] Data availability prevents us from covering the extreme events of 1956 and 1963.

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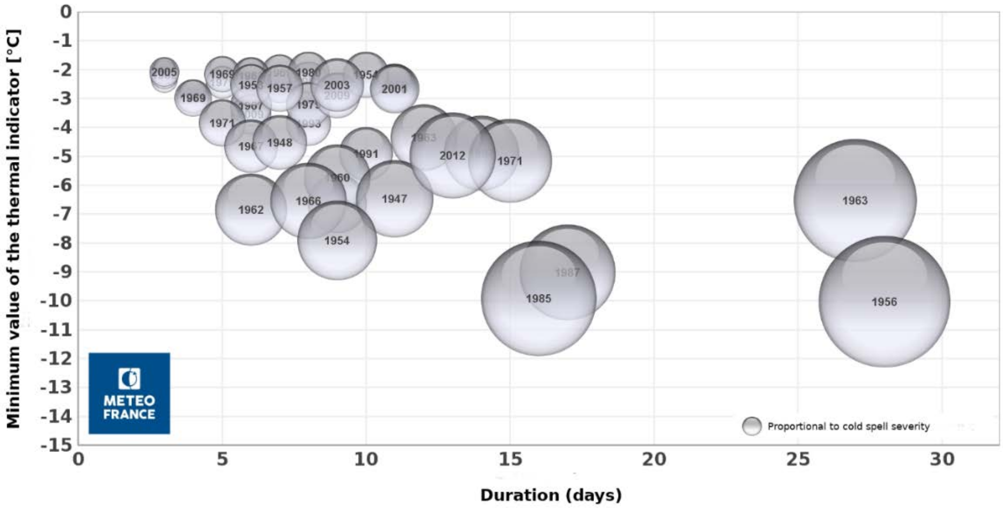

Figure 8: Cold spell experienced in France between 1947 and 2016 (© Météo-France)

In our market modelling results the effect of these extreme temperatures is clearly visible. Figure 7 shows Energy-Not-Served (ENS) on a country-by-country and year-by-year basis in the 2020 Base Case Scenario. France, for which the load-temperature dependency is known to be high, experiences extreme scarcities in the years 1985 and 1987. Additionally, countries such as Finland, Italy or Sweden have much higher levels in those years compared to mild winters. It is noteworthy that such events also impact neighbouring countries in a highly interconnected system. For instance, the exclusion of the climatic year 1985 from the 2020 base case calculations reduced the overall expected ENS by more than 50% for France, and between 20% and 50% for Luxembourg, Italy and Switzerland. This highlights the importance of carefully selecting the input database that is used to derive the reliability indicators. Meanwhile, Figure 7 also reveals that other countries face more structural challenges, with less spiky behaviours (e.g. in the case of Finland or Poland).

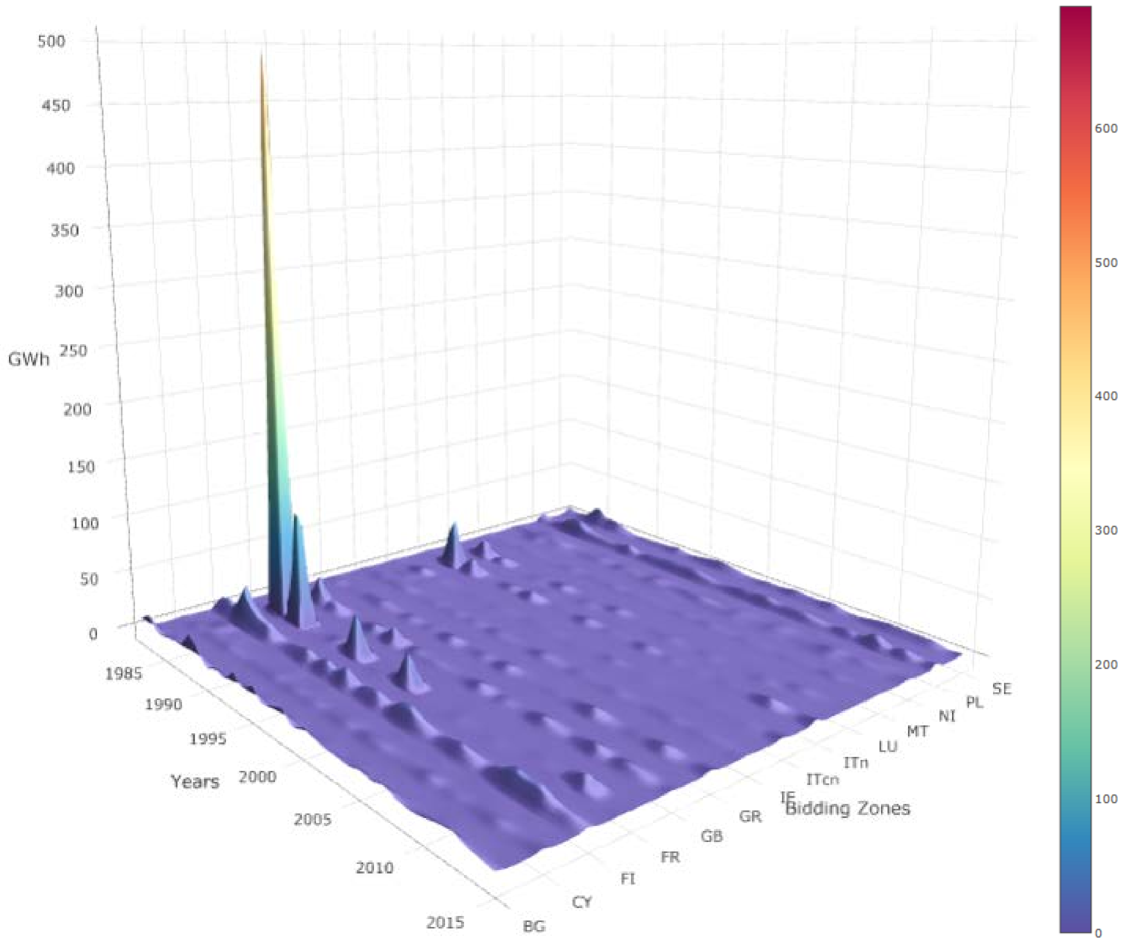

Figure 9: ENS for a selection of bidding zones and all climatic years 1982-2015 in the 2020 Base Case Scenario

2.3.2 The risk of mothballing

In addition to the base case scenarios, data were collected about the number and size of generation units which may be at risk of being mothballed in 2020 and 2025. For example, mothballing could be expected in the absence of a capacity market and/or unfavourable market conditions (such as price caps and the resulting 'missing money' problem).[9] Figure 10 shows the numbers in relative terms for 2020 and 2025 (a more detailed description of the numerical data can be found in Section 3.2.9). Relative values (%) are based on the scenario year and the total thermal generation capacity.[10] Example: 4% of Belgium's thermal generation capacity that was stated for 2020 is at risk of being mothballed in 2020.

As observed, a significant number of countries face the risk of generator mothballing.

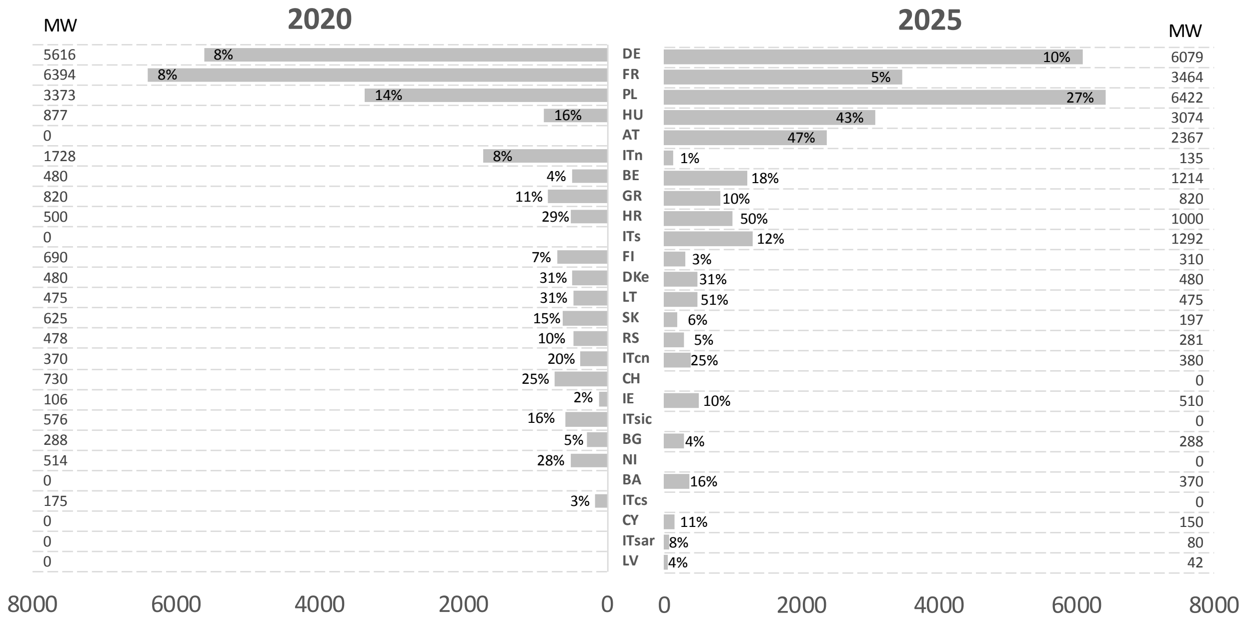

Figure 10: Generation Capacity at risk of being mothballed, absolute [MW] and relative [% of the thermal generation capacity]

We ran our adequacy analysis for these data in an additional sensitivity scenario. This sensitivity should be understood as a more conservative view of the net generating capacity, and can – by definition – only result in inferior generation adequacy levels. In fact, our analysis reveals that even though mothballing only affects 45% of the countries analysed, 82% of the them are affected in terms of a significant increase in their risk indicators (LOLE). This effect is illustrated in Figure 11, where the inner circles represent the bidding zone's base case LOLE, and the outer circle represents the LOLE after the mothballing takes place.
The country most affected by mothballing risk is Poland, where 3.4 GW of thermal capacity may be decommissioned in 2020 (6.4 GW in 2025).

[9] Even though detailed projections about mothballing activities are hardly available, TSOs are typically among the first to learn about such plans.

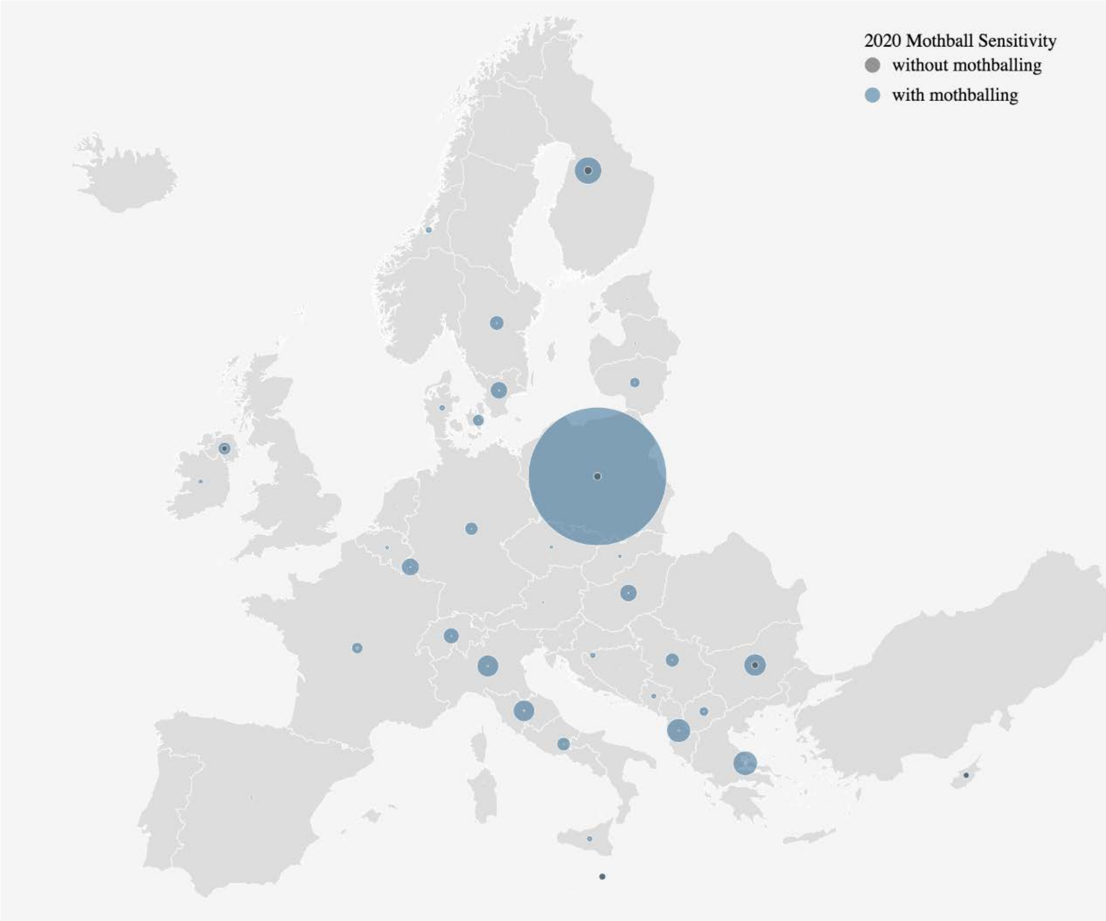

Figure 11: The impact of average mothballing on LOLE in 2020

Several lessons can be learned from this analysis. First, mothballing has a significant impact on adequacy in larger regions: even countries without any capacity considered at risk of being mothballed could see an important increase of a reliability indicator (e.g. LOLE, ENS) in the event of the degradation of adequacy conditions in neighbouring countries. Thanks to the mothballing data collected for the MAF 2017, it was possible to quantify these interdependencies.

Second, it becomes clear that coordinated studies and monitoring activities are highly important for depicting the system-wide effects. In the same vein, measures to address this risk should be coordinated to avoid inefficient overcapacities (e.g. participation of cross-border capacities to capacity mechanisms).

Third, to ensure reliable predictions of future adequacy levels, it is crucial to obtain reliable and consistent data from the supply-side of the system. For instance, European utilities could be asked to announce (de)commissioning as well as mothballing plans 3-5 years ahead. This would help to get a clearer picture of future system conditions.

2.3.3 Revision and effect of maintenance schedules – the case of Poland

Significant thermal capacity in Poland requires modernisation to fulfil Best Available Techniques (BAT) standards. The Polish TSO (PSE), based on preliminary information from producers collected in 2016, prepared a conservative estimation of the additional time required for modernisation. Provided at the beginning of 2017, the number of maintenance days was much higher than the ENTSO-E average. Simultaneously to ongoing initial analysis performed for the 2020 horizon, PSE initiated bilateral meetings with producers and began intensive work on the revision of the maintenance level for years 2019-2021. The work showed a window for the revision of the maintenance schedule. At the beginning of summer 2017, preliminary MAF results, benchmarked by several models, showed structural adequacy problems in Poland. Keeping in mind the possible window for revision, PSE decided to decrease the number of days of maintenance, which is now approximately twice as high as the ENTSO-E average. The final MAF simulations improved Polish reliability levels dramatically. Nevertheless, the updated Polish average LOLE remain high, suggesting the need for further assessment. For further information, see the detailed results in Section 4 as well as the national comments in Section 5.2.25.

2.3.4 The importance of interconnections

Interconnections are crucial for supporting adequacy in large systems. Specifically, interconnections can help to balance supply and demand on a broader geographical scope, thus allowing the deployment of benefits from statistical balancing effects in load and variable renewable generation. Intuitively speaking, when considering two interconnected countries, there is a high chance that these two countries do not face the most critical ramp at the exact same time.[11] This can be explained by climatic conditions and habitual differences between countries. A simple example could be different mealtimes among countries leading to different times for the start of the preparation (ramp-up) and end of the preparation (ramp-down). Another factor can be time zone differences that cause time shifts of demand peaks.

Therefore, interconnected countries may support each other in critical situations. To this end, sufficient interconnection capacity is essential. To investigate the importance of interconnection for adequacy in the European power system, we have performed the following hypothetical sensitivity analysis: The base case 2025 scenario, assuming that only NTC capacities from 2020 are available, i.e. disregarding the NTC enhancements between 2020 and 2025.[12]

The effect of the reduced NTC capacity in terms of increasing LOLE and ENS is shown in Figure 12. While some countries are affected less (mostly those that have large capacity margins or that do not see much grid expansion between 2020 and 2025), the effect for numerous countries is very substantial. For instance, Poland would see an increase in LOLE of around 290 hours per year. This is due to the fact that the import capacity on the common synchronous Polish profile with Germany, Czech Republic and Slovakia forecasted in 2020 amounts to 0.5 GW only, which is the result of limitations caused by the unscheduled flows through the Polish system (for more detail see paragraph 5.2.25). For 10 countries, the increase in LOLE will be greater than 10 hours per year if the NTC enhancements cannot be realised. These results highlight the importance of grid expansions in the future.

[11] Technically speaking, this is true as long as the correlation between the country data is not 1.
[12] For details about the numerical assumptions, the reader is referred to ENTSO-Es' scenario report.

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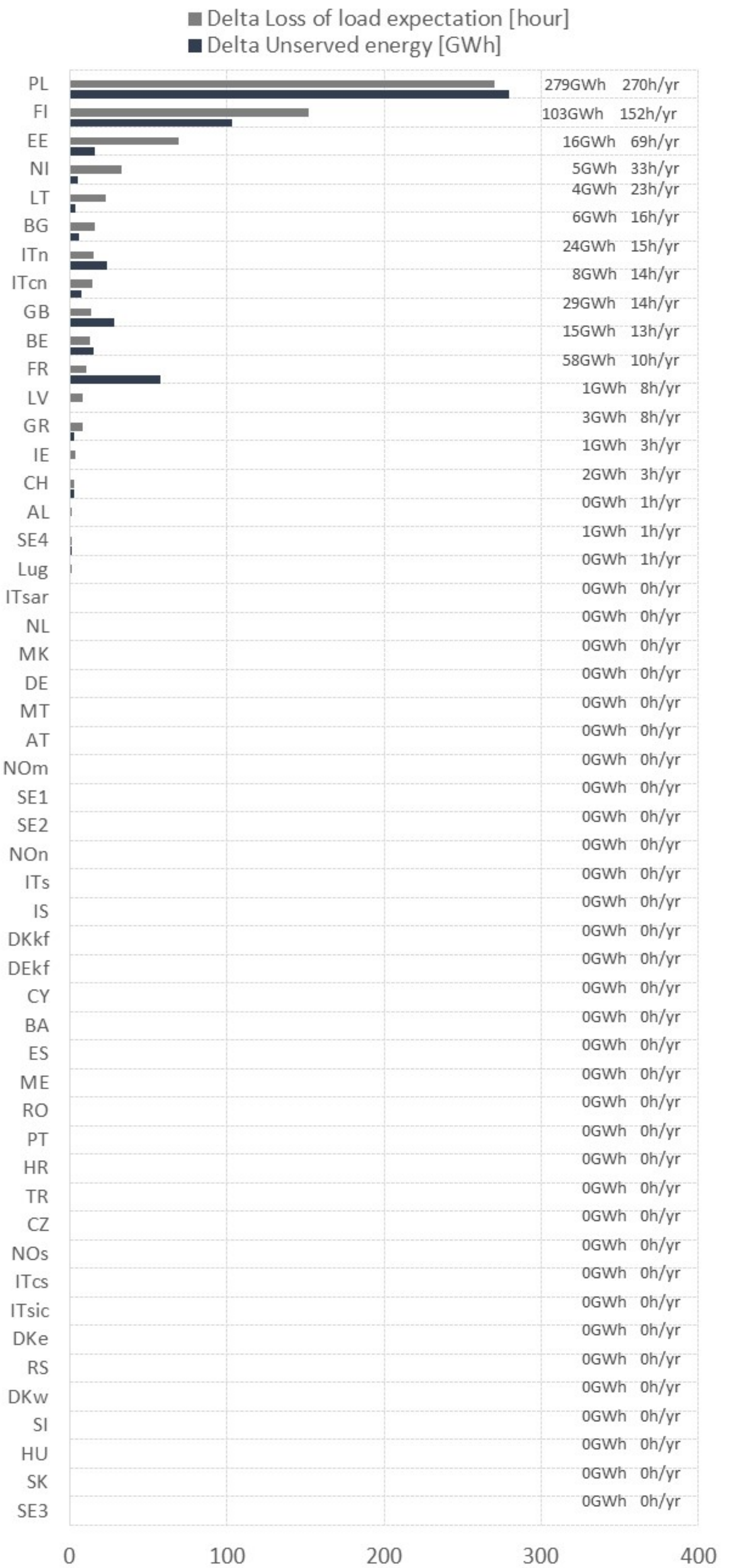

Figure 12: Delta in LOLE and ENS between the Base Case Scenario with NTCs in 2020 and 2025

2.4 System flexibility

Adequacy is not only related to the total amount of capacities being installed in the system, but also to these capacities' ability to adjust flexibly to the ever increasing dynamics of dispatch situations in Europe (mainly driven by increasing amounts of variable renewable energies). Figure 13 shows the hourly residual load ramps (i.e. the hourly changes in load minus variable renewable energy generation) that are requested from dispatchable generation units when considering each market node independently.

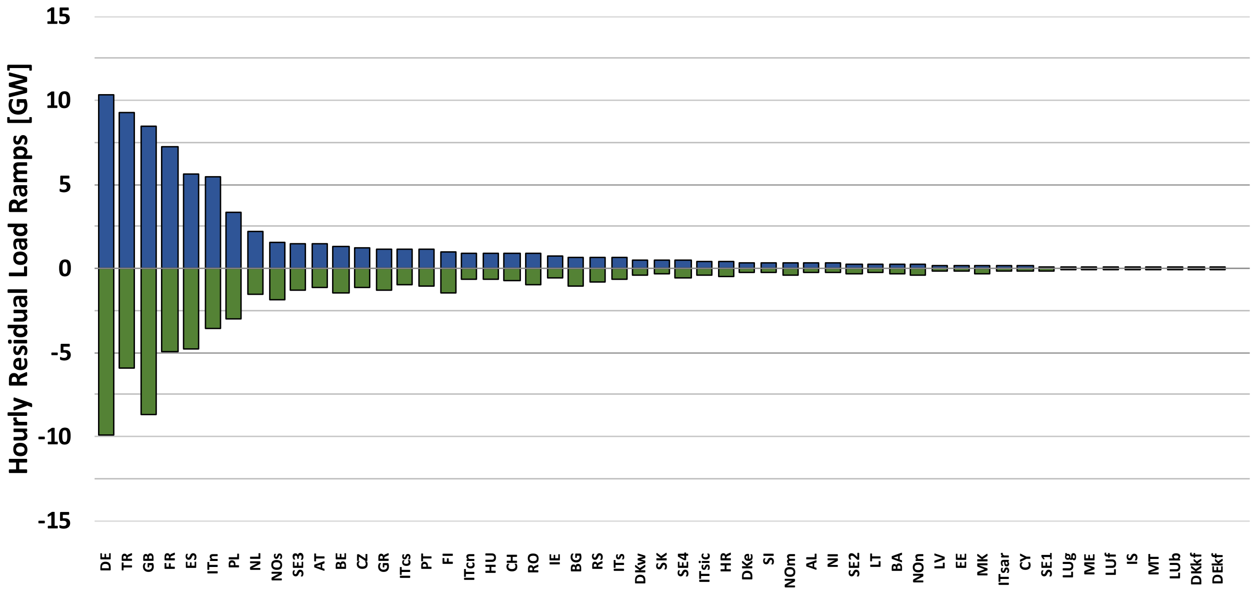

Figure 13: Hourly residual load ramps on a national basis (99.9th Percentile)

In an interconnected system, however, a national viewpoint ignores the potential benefits from spatial aggregation created through statistical balancing effects in load and variable renewable generation, as already discussed in the previous section.

The beneficial effect of spatial aggregation is shown in Figure 14, for three different system boundaries (i.e. Germany + France, the Penta-Lateral Energy Forum[13], as well as the entire European perimeter considered in this study). As observed, both the absolute and the relative benefit increases with the geographical scope, due to the increasing variance and lower levels of correlation in the data (i.e. load, wind and solar). For instance, on a European level, the hourly ramping requirements can be reduced by 22.2 GW, i.e. by roughly 30%, when spatial aggregation is considered.

Noticeably, the beneficial effect of interconnection not only applies to the hourly ramps, but also to the peak residual demand to be met by flexible generation units (see Section 2.3.4). In fact, the benefits from spatial aggregation by means of statistical balancing have been one of the main reasons for creating large interconnected electricity systems.[14]

[13] The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe (BENELUX-DE-FR-AT-CH) towards improved electricity market integration and security of supply

[14] Of course, additional benefits arise from interconnections, especially from the more efficient use of resources in the energy market.

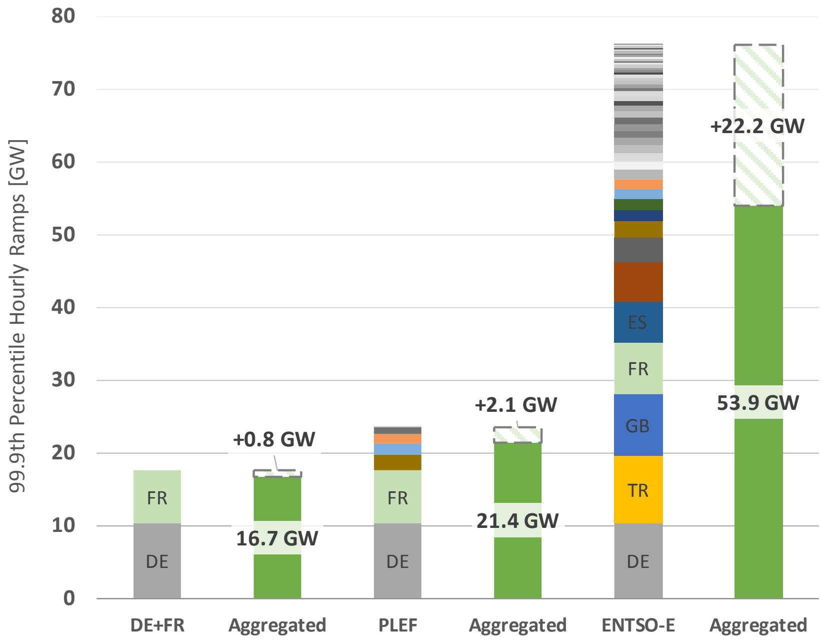

Figure 14: Benefit from spatial aggregation

3 Methodology and assumptions

‘Great things are done by a series of small things brought together’

(Vincent Van Gogh)

The methodology for adequacy assessments has been successfully implemented in four different market tools[15] working alongside each other. All tools cover the same geographic perimeter (i.e. the whole of Europe, as depicted in Figure 1 and listed in the results in Section 0), as well as the same time horizon (i.e. the target years 2020 and 2025). In the same vein, all tools deploy the same methodological approach, i.e. probabilistic fundamental electricity market modelling. This approach has enabled a thorough analysis and benchmarking of the different models, and thus substantial improvements in terms of consistency and trust. Moreover, compared to the deployment of one tool only, our approach allows for a more reliable detection and analysis of a wider range of different extreme situations.

Figure 15 provides an overview of the overall approach that has been chosen and followed for the MAF 2017. Broadly speaking, adequacy refers to the relationship of available generation and load which is balanced via network infrastructure. In our analysis, we represent all these parts in great detail. Specifically, the supply and demand side are composed by a deterministic forecast, combined with stochastic uncertainty. The deterministic forecast is in line with ENTSOs’ Scenarios which are published as a separate document. Stochastic uncertainty, driven by the climate and the risk of unplanned generator and line outages, is accommodated by means of Monte Carlo simulations, as explained in the infobox in Figure 5 and hereafter.

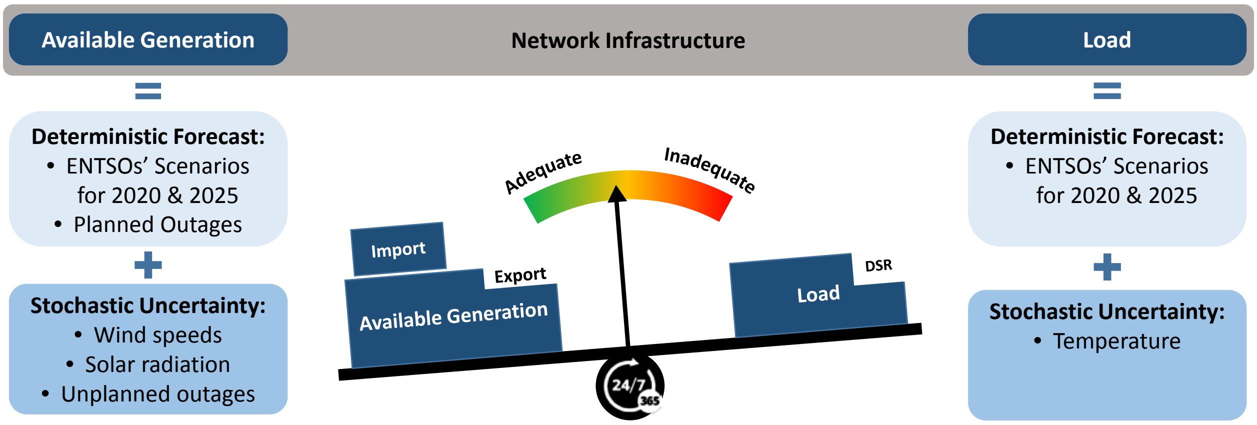

Figure 15: Overview of the methodological approach

3.1 Methodology – advanced tools for probabilistic market modelling

Our methodology compares supply and demand levels in an interconnected European power system by simulating the market operations on an hourly basis over a full year. In each of the scenarios for 2020 and 2025, we build upon ENTSOs’ scenarios forecasting – among further details – net generating capacity (NGC),

[15] ANTARES, BID, GRARE, PLEXOS. See Section 5.3 for a short presentation of the individual tools.

cross-border transmission capacity and annual level of demand forecast. In addition, the simulations consider the main stochastic contingencies capable of threatening security of supply, including:

1. **Outdoor temperatures** (which result in load variations, principally due to the use of heating in winter and cooling in summer)
2. **Wind and photovoltaic power production**
3. **Unscheduled outages** of thermal generation units and relevant HVDC interconnectors
4. **Maintenance schedules**
5. **Extended hydro database**, including **dry and wet hydro conditions** in addition to **normal hydro conditions**, and the different probabilities of the occurrence of these three

For each of these contingencies, all market modelling tools have performed Monte Carlo simulations (up to 2000), built by the combinatorial stochastic process schematically depicted in the figure below.

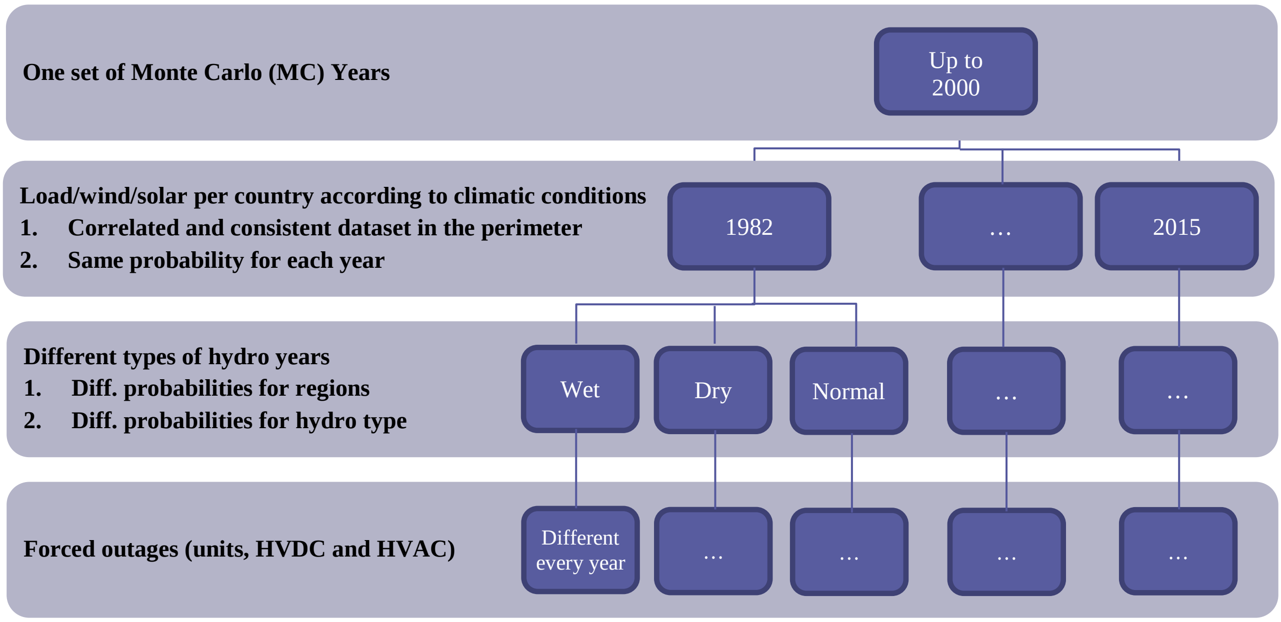

Figure 16: Graphical illustration of the number of Monte-Carlo years required for convergence of the results

<u>Each Monte Carlo simulation is built as follows</u>: All climate years (1982-2015) are chosen one-by-one. Each climate year, meaning each combination of load (accounted temperature sensitivities), wind and solar time series, is combined with the three possible hydro conditions (wet, dry, normal). Each set of climate + hydro condition is further combined with up to 300 Monte Carlo realisations of Force Outages for thermal units and HVDCs/HVACs interconnections.

In general, the tools employed are built upon a market simulation engine. Such an engine is not meant for modelling or simulating the behaviour of market players, e.g. gaming, explicit capacity withdrawal from markets, etc., but rather meant for simulating marginal costs (not prices) of the whole system and the different market nodes. Therefore, the main assumption is that the markets function perfectly.

The tools calculate the marginal costs as part of the outcome of a system-wide costs minimisation problem. Such a mathematical problem, also known as 'Optimal Unit Commitment and Economic Dispatch', is often formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem. In other words, the program attempts to find the least-cost solution while respecting all operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc.). In order to avoid unfeasible solutions, very often the constraints

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are modelled as 'soft' constraints, which means that they could be violated, but at the expense of a high penalty, i.e. high costs. Most mathematical solvers nowadays are capable of solving large-scale LP problems with little computation time. However, with the presence of integer variables it is still common in commercial tools to solve the overall problem by applying a combination of heuristics and LP. Moreover, the extensive number of Monte Carlo simulations makes the computation a work-intensive and challenging task.

In the MAF study, the size of the problem, i.e. the number of variables and constraints is immense: thousands of each. The size increases with the optimisation time horizon and the resolution. The time horizon of the optimisation objective and / or constraints, e.g. hydro optimisation, maintenance or fault duration, etc., is a week, and the resolution of the simulation is hourly, i.e. given the constraints and boundary conditions the total system costs are minimised for each week of the year on an hourly basis. The weekly optimisation horizon means that the optimal values for each hour of the whole year are calculated, with the optimisation problem broken up on a weekly basis, to reduce the computation time. A weekly optimisation horizon is also a common practice for market simulations at many TSOs for network planning. The latter means that the results such as generation output of the thermal and hydro plants, marginal costs, etc. are given per hour. This setting of the parameters is also the common practice for the market simulations which are conducted for ENTSO-E TYNDP and PLEF Generation Adequacy Assessment.

These tools also have the functionality to include the network constraints to a different degree. Nowadays the status-quo approach for pan-European or regional market studies is based on NTC/ATC-Market Coupling (NTC/ATC MC). This means that the network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border. This approach is used in this study.

The EU Internal Energy Market target model is based on Flow-Based Market Coupling (FBMC). In this model, the network constraints are modelled as real physical limits on selected 'critical branches'. Most TSO tools nowadays can perform FBMC, even though they have not been thoroughly tested for large-scale applications. There are also tools which can model the physical network explicitly including all the technical constraints such as contingencies, and thermal and voltage constraints, therefore supporting what is commonly known as OPF (Optimal Power Flow). Such a feature is not yet common in Europe since there is no agreement or plans for a regional scale application of nodal pricing. The possibility of including FBMC for future MAF reports is being evaluated currently within ENTSO-E.

For this study, five different models (referred to later in the report as either Simulator# or VP# Voluntary Party) were used in parallel. A comparison of results between the different tools ensures the quality and robustness of the inputs and the calculations, as well as the results. Meanwhile, it should be noted that a full alignment of the results between different tools is not possible due to differences in the intrinsic optimisation logic of the 'Optimal Unit Commitment and Economic Dispatch' used by the different tools. These different features of the different tools are also exploited in the simulations to understand the sensitivity of the results to the different optimisation objectives, *while the input data is identical* for all tools. The aim of the use of different models and the comparison of the model outputs is to obtain consolidated, representative and reliable results, while understanding their sensitivity to assumptions and modelling choices. The process is shown in Figure 17.

The comparison of the results was performed in four steps:

a) Preparation of aggregated output data of the models
b) Visualisation of the output data in the form of comparison charts
c) Discussions and analyses within the MAF group
d) Specification of actions regarding model or input data improvement

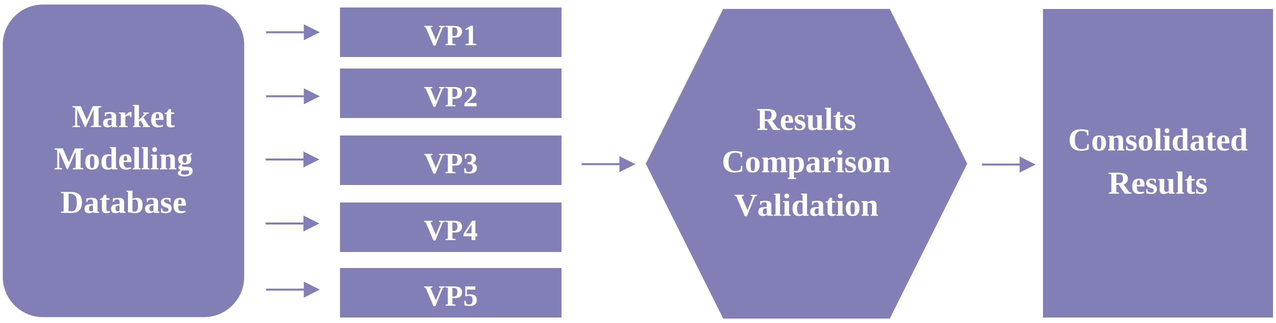

Figure 17: Use of multiple models (principle)

The current MAF probabilistic methodology is considered as a reference at pan-European perimeter one. Still, the methodology in each MAF report should be understood as an '*implementation release'* of ENTSO-E's Target Methodology, which is in itself subject to constant evolution and further improvements. The expected major improvements in future reports worth mentioning are: the implementation of flow based modelling and the extension of the climate database to cover hydrological conditions.

3.1.1 Adequacy Indices

System adequacy is concerned with the existence of sufficient resources to meet the customer demand and the operating requirements of the power system. As a metric, so-called adequacy indices are used. These indices can be quantified as deterministic indicators (capacity margins) or as probabilistic indicators, according to the methodologies used for the adequacy assessments.

With respect to the definition and scope of the indices of adequacy studies, three main functional zones of power systems are involved in the adequacy evaluation:

- Generation adequacy level (or hierarchical level I), which considers the total system generation including the effect of transmission constraints as NTCs.
- Transmission adequacy level (or hierarchical level II), which includes both the generation and transmission facilities in an adequacy evaluation.
- The overall hierarchical level (or hierarchical level III), which involves all three functional zones, from the generating points to the individual consumer load points, 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 this edition of the MAF 2017 report, the focus is on the hierarchical level I, generation adequacy level and the results of the simulation are expressed in terms of the following indices:

- **Energy Not Supplied or Unserved Energy (ENS)** [MWh/y or GWh/y] *ENS* is the energy not supplied by the generating system due to the demand exceeding the available generating and import capacity.

$$\mathrm{ENS} = \frac{1}{N}\sum\nolimits_{j\in S} ENS_j \qquad (1)$$

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where ENS_j is the energy not supplied of the system state j ($j \epsilon S$) associated with a loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered.

ENS, when referring to assessments performed for future forecasted scenarios of the power system evolution, is often referred to in the literature as Expected Energy Non-Served (EENS). Although we omit the *Expected* from our nomenclature definition, the ENS reported here should be understood as an Expectation or Forecast value and **not** as actual ENS observed in the historical statistics of actual power systems' behaviour.

- **Loss Of Load Expectation**[16] (h/y) *LOLE* is the number of hours in a given period (year) in which the available generation plus import cannot cover the load in an area or region.

$$\mathrm{LOLE} = \frac{1}{N}\sum_{j\in S} LLD_j \qquad (2)$$

where, LLD_j is the loss of load duration of the system state j ($j \epsilon S$) associated with the loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered. It should be noted that *LOLE* can only be reported as an integer of hours because of the hourly resolution of the simulation outputs. *LOLE* does not indicate the severity of the deficiency or the duration of the loss of load within that hour.

The proposed metrics above are quantified by probabilistic modelling of the available flexible resources. Additional indices to measure, for example, the frequency and duration of the *ENS* or the power system flexibility can be considered in future evolutions.

3.1.2 Reliability indices and model convergence

With respect to the relationship of the probabilistic indices and convergence of the models, when multiple Monte-Carlo simulations are conducted, these indices can also be expressed in average, minimum and maximum values accordingly. Any annual values can also be plotted to construct a probability distribution curve.

[16] When reported for a single Monte-Carlo simulation as the sum of all the hourly contributions with ENS, this quantity refers to the number of *hours (events)* within one year for which ENS occurs/is observed and this quantity should be referred to as a *Loss of Load Event*. The quantity calculated in Eq. (2) refers to the *average over the whole MC ensemble of Events* and it therefore provides the statistical measure of the expectation of the number of hours with ENS over that ensemble.

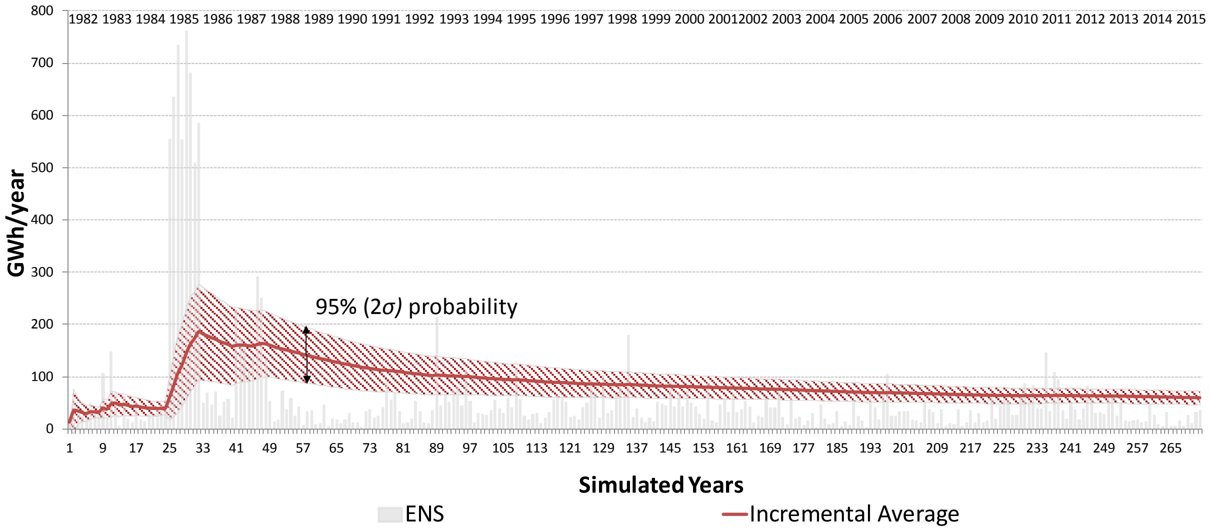

Figure 18: Example of ENS convergence on selected Monte Carlo years

The trend of the moving average of ENS against the total number of Monte-Carlo simulations (N) performed provides a good indication of the convergence of the simulations (example shown in Figure 18). When N is sufficiently large (i.e. when The Strong Law of Large Numbers and Central Limit Theorem hold), the error between the expected value and its average exhibits a Gaussian distribution and its upper bound with a probability of 95% can be calculated using the following formula, where ε_n is the error at n iterations, and σ the standard deviation:

$$|\varepsilon_n| \leq 1.96\frac{\sigma}{\sqrt{n}} \qquad (4)$$

Correspondingly, the confidence interval can be calculated using the following formula, with $\overline{X}_N$ the sample average:

$$\left[\overline{X}_N - 1.96\frac{\overline{\sigma_N}}{\sqrt{N}}, \overline{X}_N + 1.96\frac{\overline{\sigma_N}}{\sqrt{N}}\right] \qquad (5)$$

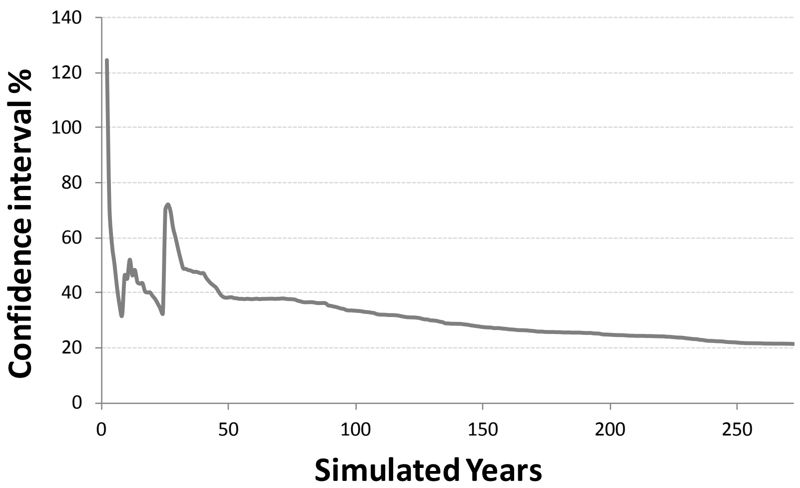

Figure 19: Example of confidence interval achieved by the simulations

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Noticeably, some inputs and parameters can have a significant impact on the numerical results of these indices and their convergence, such as

- **Hydro power data usage and modelling**
- **Net Transfer Capacities (NTC)**
- **Extreme historical climatic years (e.g. 1985)**
- **Outages and their modelling**: this refers to both maintenance and forced outages. To understand the impact of forced outages, which are random by default, it is important for all the tools to use one commonly agreed maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

In order to obtain a satisfactory analysis of the influence of different inputs, parameters, outages and modelling with the use of different tools, various sensibility analyses have been conducted in this report, as presented in Section 0.

3.1.3 Reliability indices in practice

	RELIABILITY STANDARD	LOLE (h/y)	ENS	RESERVE MARGIN METHOD	CAPACITY MARGIN	OTHER
AT	No					
BE	Yes	3				
BG	N.S.					
CH	No					
CY	N.S.					
CZ	No					
DE	No					
DK	No					
EE	No					
ES	Yes				10%	
FI	No					
FR	N.S.	3				
GB	Yes	3				
GR	Yes	24				
HR	N.S.					
HU	Yes					
IE	N.S.	8				
IT	No					
LT	No					
LU	N.S.					
LV	N.S.					
MA	No					
NL	No	4				
NO	No					
PL	No				9%	
PT	Yes	5*				
RO	N.S.					
SE	No					
SI	N.S.					
SK	No					

*Value updated in coordination with the adequacy correspondent

Figure 20: Situation of metrics used in EU Member States to assess generation adequacy at national levels in 2015 (N.S. = not specified)
Source: ACER/CEER (2015). Monitoring report of the internal energy market.

Relating the various reliability indices introduced in the previous section to European practice, the following table presents a comprehensive overview of the different metrics that EU Member States apply to assess their national generation adequacy.

As is evident, half of the countries analysed do not have a reliability standard. In all other countries, the most relevant indices are the ENS and LOLE, which are also the main indicators used in this report. Target reliability levels in terms of LOLE are typically in the range of 3-8 hours/year, but can be as high as 24 hours/year as in the case of Greece. It should be noted that setting such reliability targets is a highly sensitive issue which needs to consider economic, technical and political aspects. For instance, these targets could be determined by means of counterbalancing the value of lost load (VoLL) against the costs related to maintaining a reliable generation capacity.

Missing Capacity

Comparing our modelling results with the above discussed reliability target values raises a natural question: If the target is met beyond the national legal requirement, how large is the related capacity margin 'surplus' available for the neighbouring area or even system wide? Vice-versa, if the target is not met, by how much would the available capacity need to increase to meet the target? While the question is straightforward, obtaining the answer is rather challenging. This is due to the various interdependent options that influence generation adequacy, as was shown in Figure 2. For instance, increased interconnection capacity, storage, demand side response as well as (reliable) generation capacity, are all options which could be chosen to fill the identified gap of missing power to reach the above mentioned target. These choices require careful consideration of national or even regional specificities and regulatory frameworks and should exploit in any case the complementarities and synergies of the respective options possible/available. These are subject to intense research and discussion at the national / regional level and are beyond the scope of the present report.

Nevertheless, the MAF still aims to provide a view on the missing capacity required to reach the adequacy target by using an heuristic approach, as shown in Figure 21.

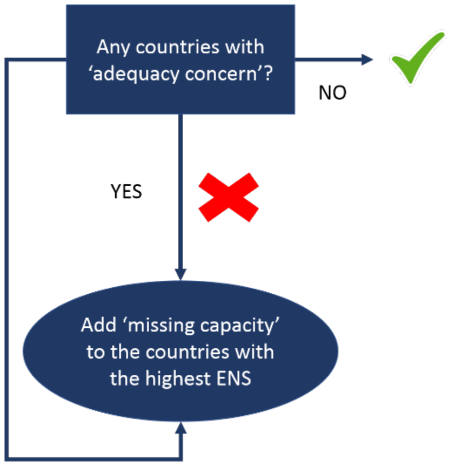

Figure 21: Heuristic approach for determining the missing capacity in a country to reach the reliability target

This exercise is performed for the horizon 2025 and focuses on areas comprising one or more countries with high values of ENS linked to values of LOLE higher than the adequacy standard for (some of) those countries.

An iterative process is followed so additional capacity is provided to these areas in steps of few hundreds of MWs beginning with countries with a higher level of ENS/LOLE and considering the effect of the additional capacity on neighbouring ones. Several possibilities of splitting the total identified capacity between the countries inside that area might lead to comparable adequacy results and should be considered at each step to ensure the robustness of the results. The results presented in this edition of MAF have explored this possibility, but only partially, since the number of possibilities and options to be explored is large. Future editions of MAF might further explore this approach in a more systematic way. In any case, as mentioned above, the goal of this exercise is not to determine the exact capacity and type of capacity that each country will need to reach its adequacy target, but rather give a view of the level of capacity that a certain region might need, without further specifying whether this capacity is interconnection capacity, storage capacity, demand side response or generation capacity and which country it needs to be assigned to.

The results of this analysis are presented in Section 4.4.

3.2 Assumptions – comprehensive datasets for all parts of the system

All models use the same data input for their calculations. In order to have a consistent data set, a common scenario framework is agreed upon. Therefore, a harmonised and centralised Pan-European Market Modelling Data Base (PEMMDB) for market studies has been prepared based on national generation adequacy data and outlooks provided to ENTSO-E by each individual TSO. The focus of the study is on the calibration of the models for two time horizons: 2020 and 2025. This section describes the most important numerical assumptions and how they are used by the different tools to run the Pan-European market simulations.

3.2.1 Scenarios and Pan-European Market Modelling Data Base (PEMMDB)

The PEMMDB is the main source of data for the MAF. The PEMMDB contains collected data from TSOs for bottom-up scenarios as well as centrally analysed data for top-down scenarios.

Scenarios were defined together with ENTSOG and Stakeholders at different time horizons (2020, 2025, 2030, 2040) and are summarised in the following figure.

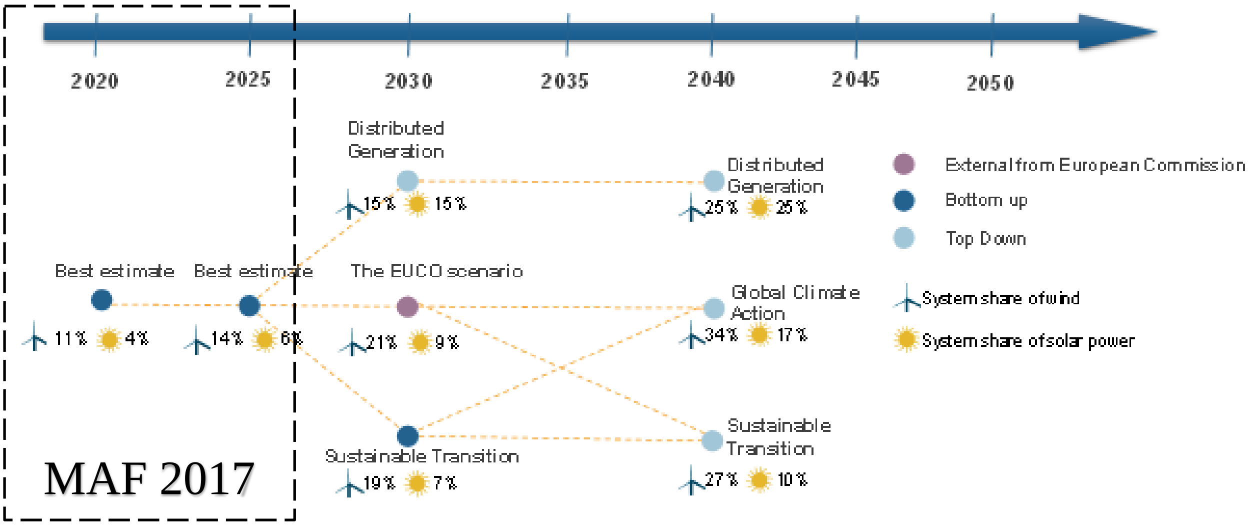

Figure 22: ENTSOs' Scenarios for TYNDP18 and MAF17

These different scenarios were used as reference input to compute different products, mainly TYNDP and MAF. The MAF framework uses collected data for 2020 and 2025 (i.e. bottom-up scenarios). TYNDP focuses on horizons from 2025 onwards, i.e. the 2025 scenario is common between TYNDP and MAF. Even though a detailed description of the PEMMDB is provided in the ENTSOs' scenario report, Figure 23 and Table 2 provide an overview of the most important data characteristics, i.e. shares of the different electricity generation sources for 2020 and 2025.

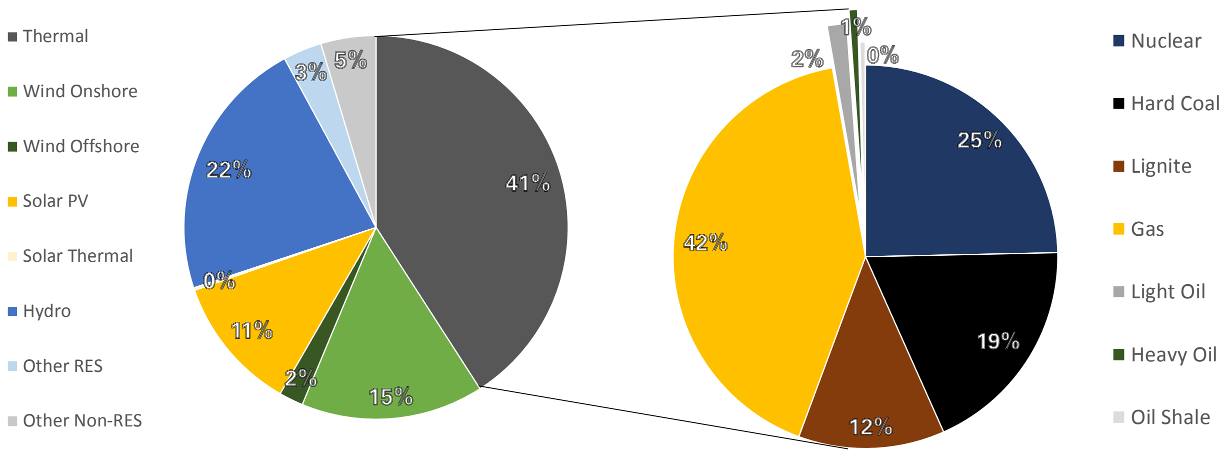

Figure 23: Distribution of generation capacity for all ENTSO-E zones (2020 Best Estimate)

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Table 2: Generation capacity in the ENTSO-E perimeter as specified in the PEMMDB for MAF2017

		2020		2025	
		GW	%	GW	%
Thermal		489.2	40.8%	446.9	35.1%
	Nuclear	120.7		100.5	
	Hard Coal	91.4		74.1	
	Lignite	60.2		58.3	
	Gas	203.5		204.7	
	Light Oil	7.9		6.1	
	Heavy Oil	3.4		2.4	
	Oil Shale	2.1		0.8	
Wind Onshore		183.8	15.3%	220.0	17.3%
Wind Offshore		24.4	2.0%	44.6	3.5%
Solar PV		138.5	11.6%	189.6	14.9%
Solar Thermal		2.6	0.2%	2.8	0.2%
Hydro		265.6	22.2%	271.8	21.3%
Other RES		39.0	3.3%	41.3	3.2%
Other Non-RES		55.5	4.6%	56.7	4.5%
TOTAL		1198.7	100.00%	1273.7	100.00%

In addition to the above figures, the PEMMDB covers further elements important for the modelling of electricity markets, such as

e) Demand and Demand-Side Response
f) Information on thermal generation units
g) Information on hydro generation units
h) Information on renewable generation capacities
i) Information on units at risk of mothballing
j) Reserves and exchanges with non ENTSO-E countries

For further details and information on all scenarios please refer to the ENTSO-E Scenario report and datafiles which will be published in parallel to the MAF 2017.

3.2.2 Load time series - Temperature dependency of load

The electrical load is dependent on different weather conditions. Besides precipitation and wind, the most important influencing factor is the temperature. Especially in the commercial and domestic sector, the widespread use of electrical heating and cooling has a significant impact on the electrical demand. The general change of temperature throughout the year leads to fluctuating demands. In addition, cold spells in winter and heat waves in summer represent extreme events that lead to extraordinary loads. It is crucial to integrate these exceptional conditions into the probabilistic models. Based on a refined sensitivity analysis of load and temperature, time series of electrical demand are created that are fundamental inputs into the MAF.

Quantifying the impact of heating and cooling

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Heating and cooling devices allow us to maintain a comfortable temperature in the rooms where we stay. Many of these devices work either directly or indirectly with electrical energy. This dependency of electrical demand and temperature can be illustrated as follows:

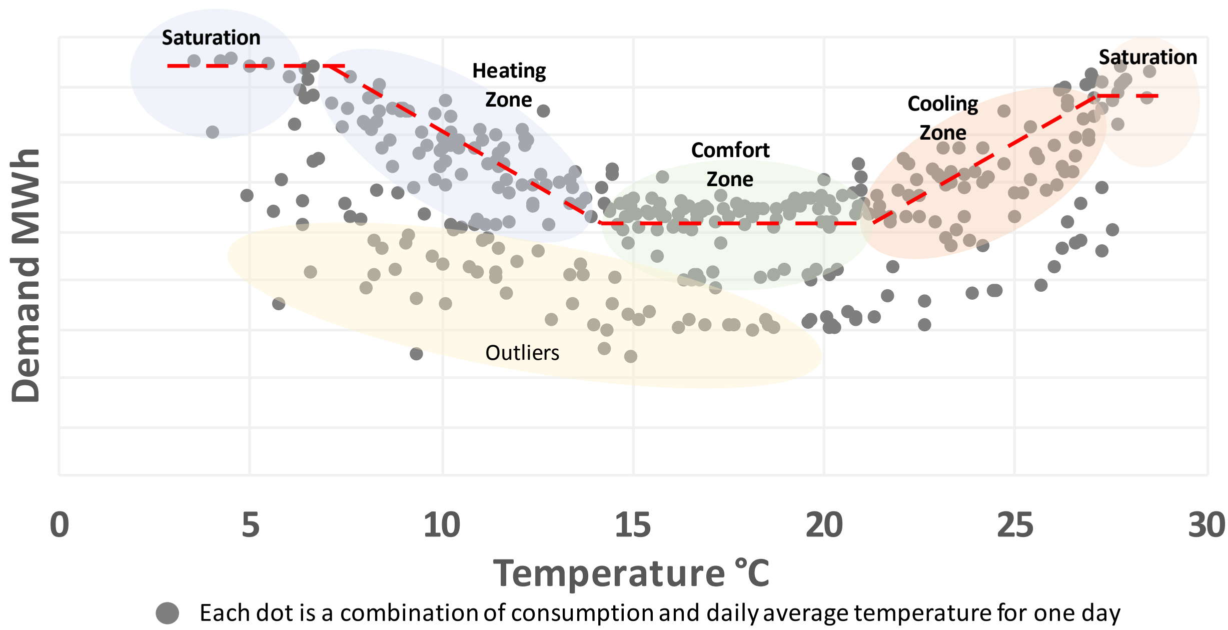


Figure 24: Temperature dependency of consumed energy

For very low temperatures, a lot of energy is consumed for heating (heating zone). When we feel comfortable, we need neither heating nor cooling and therefore the extra energy consumed by the devices is low. With rising temperatures, an increasing number of cooling devices are turned on which in turn leads again to higher electrical demand (cooling zone).

For a Pan-European assessment such as the MAF, it is crucial to observe what impact the heating and cooling has on the total consumption of electrical energy. Furthermore, it is important to quantify this effect for different assessed areas. By finding mathematical correlations between the ambient temperature in an area and its consumption, the load – temperature sensitivity can be calculated. This cubical polynomial approximation is the basis for creating synthetic hourly load profiles for each area.

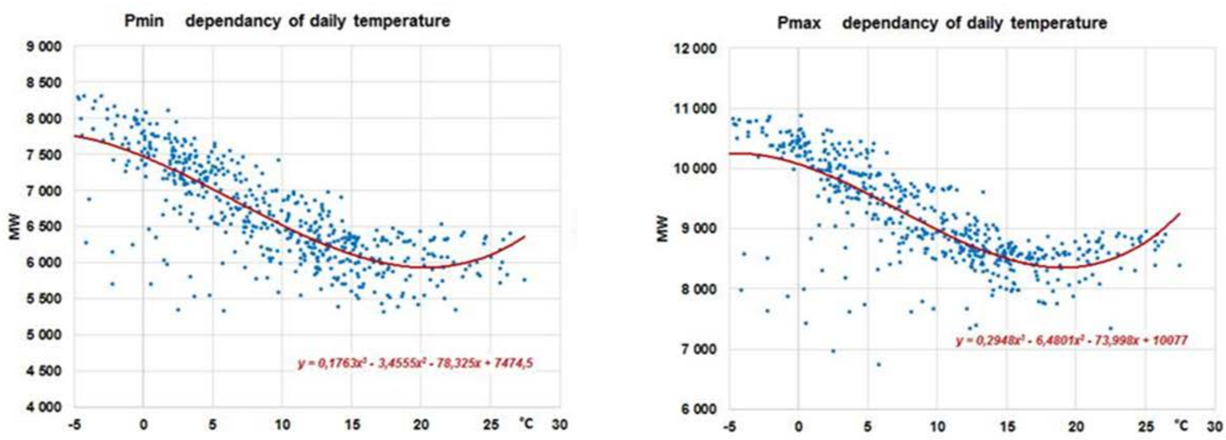


Figure 25: Cubical approximation of electrical load to daily average temperature

Figure 26 shows such cubical approximations (red lines). The blue dots represent the daily minimum or maximum load for a certain daily average temperature. It can be observed that most of the blue dots are clustered around the approximation. Only a couple of outliers with significant lower loads can be found. These points are bank and school holidays for which a majority of the commercial and industrial demand is lower. The outliers are not considered in the cubical approximations. The described analysis is carried out for all assessed market zones for the year 2015. The daily average temperature is calculated from 34 years' worth of meteorological data.

A load profile for average temperatures

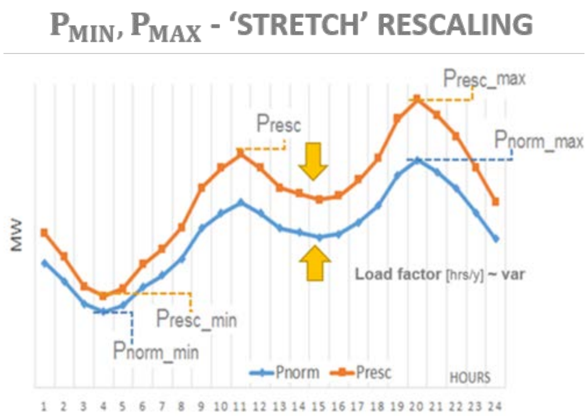
The next step is to calculate a load profile under normal temperature conditions. The previously described polynomials are applied onto the measured load profile of 2015. The outcome is an hourly profile that represents the load of the market zones as if the daily temperature would be equal to the 34-year average.

Summing up every hour of this normalised load would result in the total electrical demand of 2015 of each zone. It is now necessary to up- or downscale this to a specified demand for the targeted years. The targeted annual consumption of 2020 or 2025 is part of the PEMMDB (see Section 3.2.1).

Creating a synthetic load profile on historical temperatures

The last step is to calculate a synthetic load profile for each available year of temperature measurement. See the following example for clarification:

Day 358 of year 1999 had an average temperature of 6.5°C. By observing all 34 years, we know that the temperature of this day on average was 8.5°C. We therefore know that it is 2°C colder than average. We can also assume that the electrical load will be slightly higher than usual (since we need to heat more). To quantify this, we use the polynomial with the temperature difference and calculate the *expected* daily maximum and minimum load. With these two values, we can now rescale our load profile for that day by stretching it.



$$\frac{(P_{norm} - P_{norm\_min})}{(P_{norm\_max} - P_{norm\_min})} = \frac{(P_{resc} - P_{resc\_min})}{(P_{resc\_max} - P_{resc\_min})}$$

Figure 26: Stretch rescaling of a daily load profile

This approach is applied for every day of 34 years of available temperature data for all market zones.

Changing the shape of the load profiles

The structure of the load and consumers will change in the future. In particular, electric vehicles (EV) and heat pumps (HP) are considered as changing the shape of the daily load profile. Therefore they are treated separately. The following factors are considered to represent the electrical energy consumed by these devices:

1. Number of devices	2. Daily load profile	3. Seasonality
PEMMDB data collection		

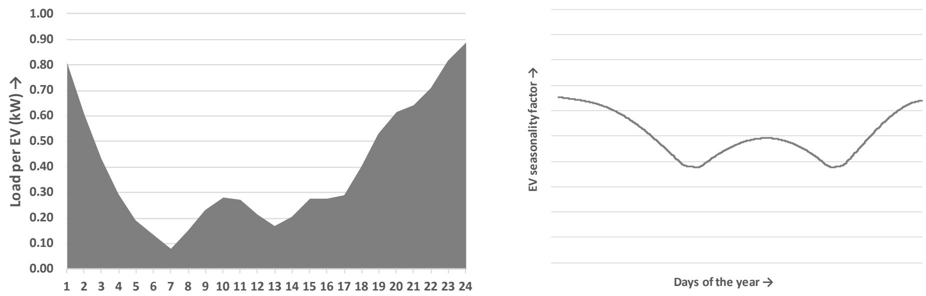
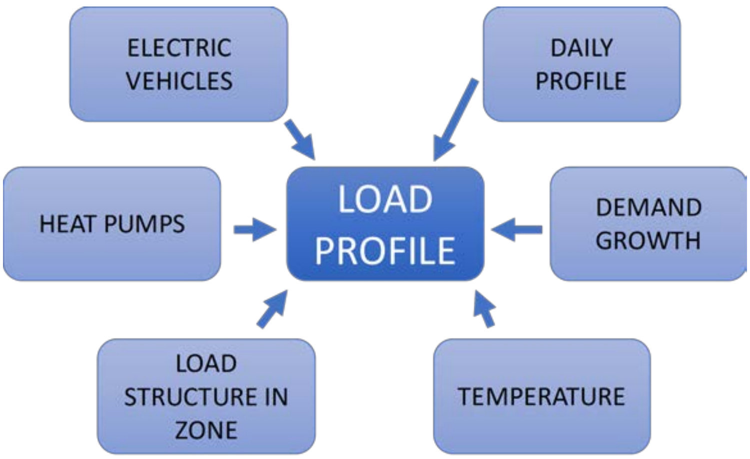


Figure 27: Factors influencing electricity load profiles

The outcomes are 34 load profiles to inputted into the MAF. They were produced with a tested and confirmed mathematical approach to ensure consistency.

MAF load in a nutshell

1. *Hourly load profiles for 34 years representing a large range of realistic temperature conditions*
2. *Scaled to the targeted annual consumption of each zone in each scenario (2020, 2025)*
3. *Electrical vehicles and heat pumps considered*
4. *Consistent approach for all MAF zones*



3.2.3 Climate data - Pan-European Climate Database (PECD)

According to the climatic correlations provided by ENTSO-E's Pan-European Climate Data Base (PECD), a consistent set of load / wind / solar production time series are used in the simulations. Furthermore, different types of hydro conditions, the available capacity of units generating supply and reflecting various possible outcomes are created for each of the phenomena considered above. These series are then combined in sufficient numbers to give statistically representative results including shortages/scarcity situations (risk of demand not being met due to a lack of generation).

The use of the PECD was an important methodological improvement achieved by ENTSO-E since the TYNDP 2014 framework.

Since the level of wind and solar energy exploitation is widely different across European countries, the availability of retrospective time series derived from measurements is limited to a few countries. In addition, there is a need for modelling input covering the projected new installations for which no measurements are available, in order to include their output in the prospective studies.

PECD load factor and temperature datasets (synthetic hourly time series derived from climate reanalysis and Weather Research and Forecast [WRF] models) enable a coherent simulation of variable RES production and weather-dependent load variation. The first set of time series delivered by Technical University of Denmark (DTU) covered the period 2000-2013.

For adequacy assessment purposes, the modelling of extreme events with potential impacts on security of supply is of key importance. Considering the evolution of the energy mix (i.e. growing development of renewable energy sources and the increased reduction of conventional power plants) the need to extend the PECD to cover more representative samples of the climatic variations has been identified. In particular, higher statistical representativeness of extreme climate and calendar events is needed, such as cold spell, heat waves, extreme low wind conditions, solar eclipses, etc.

ENTSO-E therefore decided to procure a new Pan-European Climate Database (PECD 2.0) extended by a number of additional countries and climate years, available from existing global climate reanalysis models and consisting of hourly data for 1982 to 2015. As foreseen in the MAF 2016 report, the PECD 2.0 was used for the probabilistic runs in the MAF 2017. The enhanced time series serve as important inputs for further ENTSO-E reports including the Winter and Summer Outlook reports and TYNDP 2018.

It should be noted that the extension from 14 years of climate conditions to 34 years caused a significant increase in the computational requirements of the probabilistic simulations required to be performed, whereby the additional efforts should not be underestimated. Meanwhile, the step significantly improved the range of possible weather patterns that were investigated.

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ENTSO-E PECD 2.0 consists of the following data sets:

Wind speed, radiation and nebulosity time series

- Hourly average reference wind speed at 100 m for each market node [m/s], to be calculated according to the formula provided:

$$Average\ reference\ wind\ speed\ (t, market\ node) = \sqrt[3]{\frac{1}{n}\sum_{i=1}^{n}\left(\sqrt{{U_{t,i}}^2 + {V_{t,i}}^2}\right)^3}$$

t: time [hour]
U: Zonal component of the wind speed at 100m height (west-east direction) [m/s]
V: Meridional component of the wind speed at 100m height (north-south direction) [m/s]
n: total number of grid points in the market node
i: grid point

- Hourly average global horizontal irradiance for each market node [W/m^2]
- Hourly average cloud cover (nebulosity) for each market node [okta]

Onshore, offshore wind and solar PV load factor time series

- Hourly normalised load factor time series for onshore and (if applicable) offshore wind production for each market node [-]
- Hourly normalised load factor time series for solar PV production for each market node [-]

Load factor: Percentage of production compared to installed capacity, expressed as a dimensionless ratio.

Concentrated Solar Power (CSP) load factor time series

- Hourly normalised load factor time series for concentrated solar power (CSP) for each market node where relevant [-]

Temperature time series

- Hourly city temperature time series [°C]

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3.2.4 Net Transfer Capacities (NTC)

Assumptions on NTC for each scenario 2020 and 2025 are based on TSO expertise (bottom up data collection). The transfer capacity between borders/ bidding zones, agreed between the respective TSOs, will be available within the dataset published together with the present report.

TSOs were also asked to propose values for **simultaneous importable / exportable capacities**. For adequacy simulations, these constraints should be considered since they might be imposed for some borders (e.g. in the flow based market coupling area) for reasons linked to internal grid stability and operational constraints.

Although the flow based market coupling is already in place in some parts of the ENTSO-E zone, it is not considered in the MAF 2017. On the one hand, this is due to modelling difficulties (i.e. all utilised tools ought to have similar flow based modelling approaches). On the other hand, net transfer capacities represent a more conservative approach.

In the MAF 2017, forced outages such as unexpected failures of a line resulting in unavailability have been considered for all High-Voltage Direct Current (HVDC) interconnection and some High Voltage Alternating Current (HVAC) interconnection. It has been calculated that a forced outage of these lines will occur with a chance of 6% for a period of 7 consecutive days (based on CIGRE data).

3.2.5 Thermal generation maintenance profile

The maintenance is understood as programmed out of service network elements and in this case refers to thermal generating units.

In PEMMDB it is possible to specify the number of days for maintenance and the percentage of maintenance that should be planned in winter/summer; additional constraints can be specified providing the maximum number of units for typology (nuclear, coal, ..) contemporary in maintenance for each week of the year.

An automatic procedure has been adopted for the definition of the maintenance schedule of thermal generators for each areas of the electrical system, based on the principle of ‘constant reserve’; for each week of the year the difference between available thermal generation and residual load to be covered is calculated, a wider margin is used for units with a larger size and the maintenance of each generator is never broken into discontinuous weeks.

A single maintenance schedule was calculated for each year horizon (2020, 2025) to be adopted from all the tools involved. Furthermore, maintenance schedules were not varied for the various climatic years. This is conservative, however, and in line with the limited possibilities of adjusting planned maintenance work in reality (which is typically fixed between 6 and 12 months in advance).

It was verified that the use of a constant maintenance schedule for all climatic years does not significantly affect the adequacy evaluations. For a year with a high risk of unserved energy due to climatic reasons, a special maintenance profile has been tailored. Both evaluations with the common and the special maintenance schedule have shown similar results.

3.2.6 Reserve

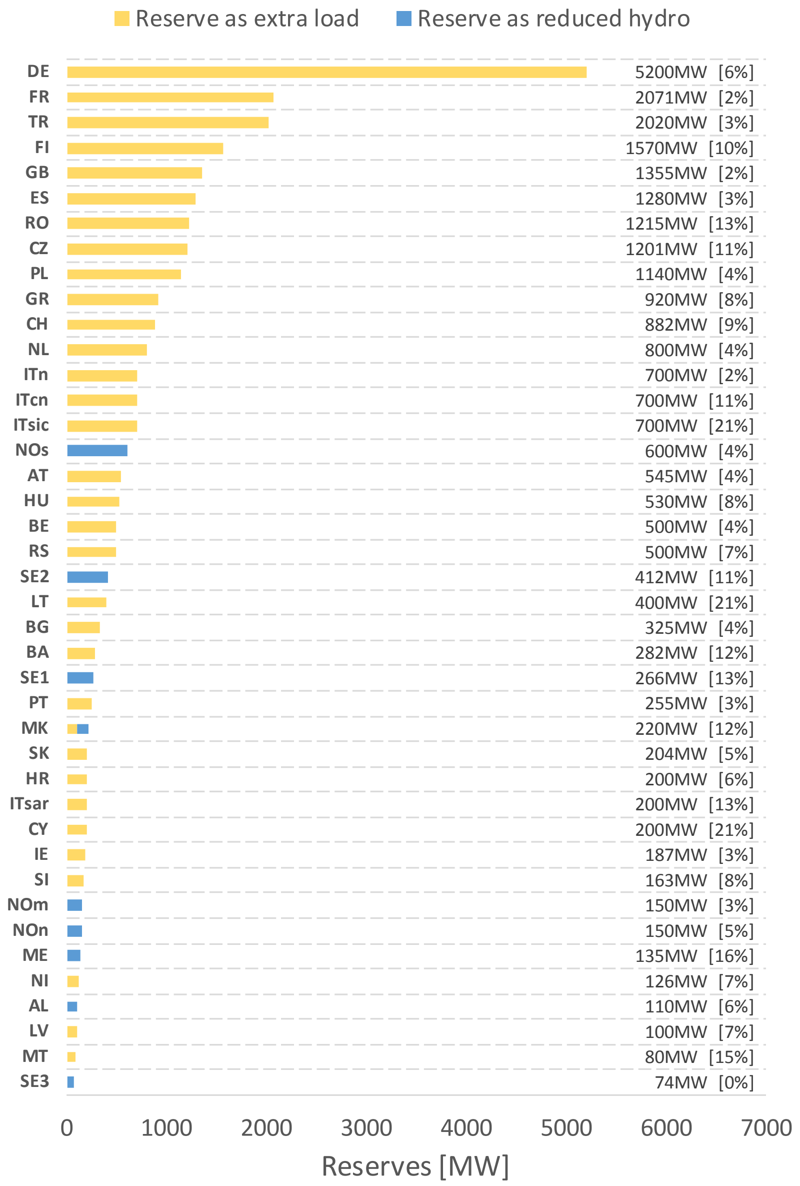


Figure 29: Reserves for 2020 as specified in the PEMMDB. Values in MW and in % of total peak load

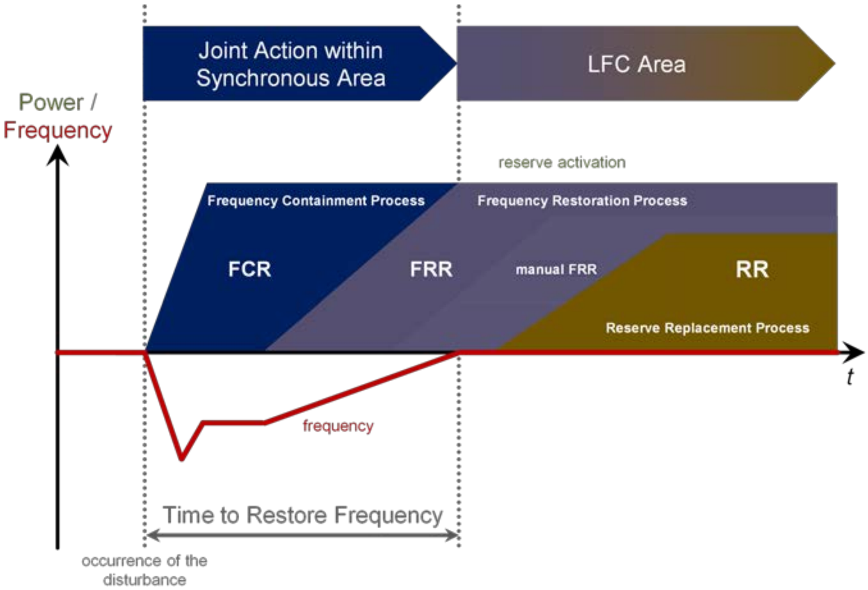
Balancing reserve or ancillary services are fundamental to a power system. As foreseen in the **Electricity Balancing Guideline**, each TSO should contract/procure ancillary services to ensure a secure, reliable and efficient electricity grid. These are agreements with certain producers and consumers to increase or decrease production or demand of certain sites to compensate for the unbalance that could be caused by the unforeseen loss of a production unit or load/renewable forecasting error. This already indicates that balancing reserves are not responsible for maintaining the large-scale adequacy, as evaluated in the MAF.

The market simulations are not real time and have a resolution of one hour. Balancing reserves are assigned to deal with the hazards that can occur within this time step. They must therefore be removed from the available generation capacity.

From a modelling perspective this can be implemented in two ways: reducing the respective thermal generation capacity or increasing the demand by the hourly reserved capacity. In order to facilitate the data collection, it was preferred to take reserves into account by adding them to consumption rather than applying a thermal reduction. While this is easier to implement into the market models, it has the disadvantage of distorting the reported energy balance since 'virtual consumption' is added. Noticeably, in some countries, reserves are provided by hydroelectrical generation. In these cases, the maximum possible hydro generation is reduced by the reserved value. Furthermore, in special cases (e.g. where a TSO has agreements with large electricity users on demand reduction when needed or dedicated back-up power plants) the reserve specifications were directly coordinated with the data correspondent of the TSO.
Further assumptions regarding the modelling of operational reserves might be considered in future reports, in line with the implementation of the pertinent Network Codes and further considerations regarding the impact of sharing operational reserves on a real time basis, across synchronously-connected countries in ENTSO-E.

Reserves

To permanently guarantee the balance between demand and generation of electrical energy, the TSO has to maintain certain levels of reserves. The reserve capacity is then requested when the electrical frequency deviates from its nominal value. Typically, fast acting conventional power plants are suitable for providing reserve capacity. In some cases, hydro power plants and interruptible loads are contracted.



In case of major frequency deviations, the restoration process is guided by three reserve products:

1. *Frequency Containment Reserve (FCR)*
   means the active power reserves (automatically activated) available to contain system frequency after the occurence of an imbalance.
2. *Automatic Frequency Restoration Reserve (aFRR)*
   should stabilise the frequency and ensure the availability of the FCR is guaranteed again. It is also utilised to maintain the balance of power imports and exports of a control area.
3. *Manual Frequency Restoration Reserve (mFRR)*
   should guarantee the availability of the aFRR. It is manually activated (e.g. by ramping up/down generators) and is mostly used when there is a major disruption of the grid operation (e.g. failure of a generator).

3.2.7 Demand Side Response

For the first time, DSR modelling has been performed for the MAF 2017. Based on the information specified in the PEMMDB, DSR is considered not as reduction of load, but as a set of flexible generators with discretely specified parameters. This modelling approach is valid because the Long-Term Adequacy Correspondents provided hourly availabilities of DSR assets in several price bands. The four distinctly modelled price bands enable more detailed simulations by considering, for example, industrial DSR and domestic DSR differently. Price bands are defined by a price (€/MWh) and a maximum number of hours of continuous availability of typical DSR installations.

Since no economic analyses of the findings are carried out in the MAF framework[17], the price for the entirety of DSR assets is set to 500€/MWh while the maximum number of available hours is respected in each band. The high price ensures its activation before loss of load, while not interfering with the rest of the merit order dispatching. Thorough tests were conducted with all market tools to ensure that this modelling approach is valid.

3.2.8 Other relevant parameters

To allow for a more accurate reflection of the diversity of generation technologies and bring the simulation's behaviour, especially the behaviour of simulated power plants and HVDC lines, closer to the operation in practice, basic parameters such as Net Generation Capacity (NGC), Number of Units and other additional technical parameters have been considered in the data collection. Some of these parameters present boundary conditions or thresholds that the simulators must fulfil during the simulations.

Availability of the power system elements is included in the simulation in two ways: i) Forced Outages and ii) Planned Outages. In the MAF, availability is considered on thermal power plants active in the market and HVDC lines.

- ➔ **Planned outages** refer to maintenance, and are defined as the number of days, on an annual basis, that a given unit (blocks of-) is expected to be offline due to maintenance. In the MAF 2016, further restrictions regarding the minimum percentage of the outages which can occur in each season of the year, with a focus on winter and summer, as well as the maximum number of simultaneously offline thermal units allowed within each month of the year, was specified by TSOs. Within these restrictions, an optimised maintenance schedule, common to all modelling tools, is prepared. Optimisation of the maintenance schedule refers to the minimisation of the number of units (simultaneously) in maintenance and the optimal distribution of the maintenance schedules to reduce the occurrence of potential adequacy problems, while respecting the constraints on their national power system provided by TSOs.

- ➔ **Forced outages** are represented by the parameter *Forced Outages Rate* (FOR) which defines the annual rate of forced outages occurrences of thermal power plants or grid elements. Forced outages are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined. Simulated random forced outages are useful for assessing the impact of the availability of base-load thermal generation and its relationship with the available flexible thermal and hydro generation, renewable generation and the ability of areas under adequacy problems to also cope with problems by means of imports. Simulating the forced outages allows the resilience of a given area to be tested subject to such contingencies, potential adequacy problems that might occur and the ability of the area to share power (*via* spot market power and/or reserves).

[17] Note that investigations of economic indicators are foreseen for future editions of the MAF.

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Minimum stable generation (MW) is a parameter defining the technical minimum of the power output of a unit. The simulation does not allow the unit to run under this limit. It is defined by a percentage of the maximal power output of the unit.

Ramp up/down rates (MW/h) define the ability of the thermal power plant, which is already in operation, to increase/decrease its generation output within the range of its stable working area, which is limited from the bottom by the minimum stable generation parameter, and from the top by the maximum power output.

Minimum Up Time parameter defines the minimum number of hours a unit must stay in operation before it can be idled.

Minimum Down Time parameter defines the minimum number of hours a unit must remain idle before it can be restarted. These parameters guarantee the units will not be simulated one hour in operation and the next hour out of operation to put it back into operation the following hour, if this kind of operation is not natural for the unit.

In addition to the main characteristics, other thermal characteristics have also been defined in the PEMMDB to allow for a more accurate reflection of the diversity of the different generation technologies.

Fuel and CO2 price assumptions

A global set of values for fuel and CO_2 prices, as shown in the table below, is used for the whole Pan-European parameter. These values are taken from the World Energy Outlook 2016 for the year 2020 for the IEA 'Current Policies' scenarios.

Table 3: Fuel and CO_2 prices according to World Energy Outlook 2016

YEAR	2020 €/GJ	2025 €/GJ
NUCLEAR	0.47	0.47
LIGNITE	1.1	1.1
HARD COAL	2.3	2.5
GAS	6.1	7.4
LIGHT OIL	15.5	18.7
HEAVY OIL	12.7	15.3
OIL SHALE	2.3	2.3
	€/TON	€/TON
CO2 PRICE	18.0	25.7

It is important to emphasise that ENTSO-E highly welcomes interaction with relevant stakeholders to further improve the level of detail of the above mentioned data for future releases of the MAF report.

3.2.9 Mothballing

The collected information on existing and available thermal generation units should be seen as a best estimate of future system states. The fundamental sources of these data are mostly national assessments and outlooks which are detailed and thoroughly researched. Nevertheless, especially for older thermal generation units, there is a risk that policy changes or economic developments will push certain generation units out of the market.

In the MAF 2017 we have quantified this as ‘generation capacity at risk of being mothballed’. With the valuable TSO expertise, the collected data helps us to build a sensitivity scenario for the 2020 and 2025 base cases. Noticeably, mothballed capacities should here always be understood as generation capacity that is at risk of being unavailable due to economic or policy reasons.[18]

Figure 10 shows the result of this data collection. In addition, Figure 31 and Figure 32 illustrate the spatial distributions of the mothballing data which will have a crucial effect on reliability indicators, as will be shown in Section 4.2. Especially in the central European countries with a high number of aged power plants, there is a significant risk of premature retirement of generation capacity.

[18] Note that we intend to investigate economic viability indicators in much more detail in future editions of the MAF.

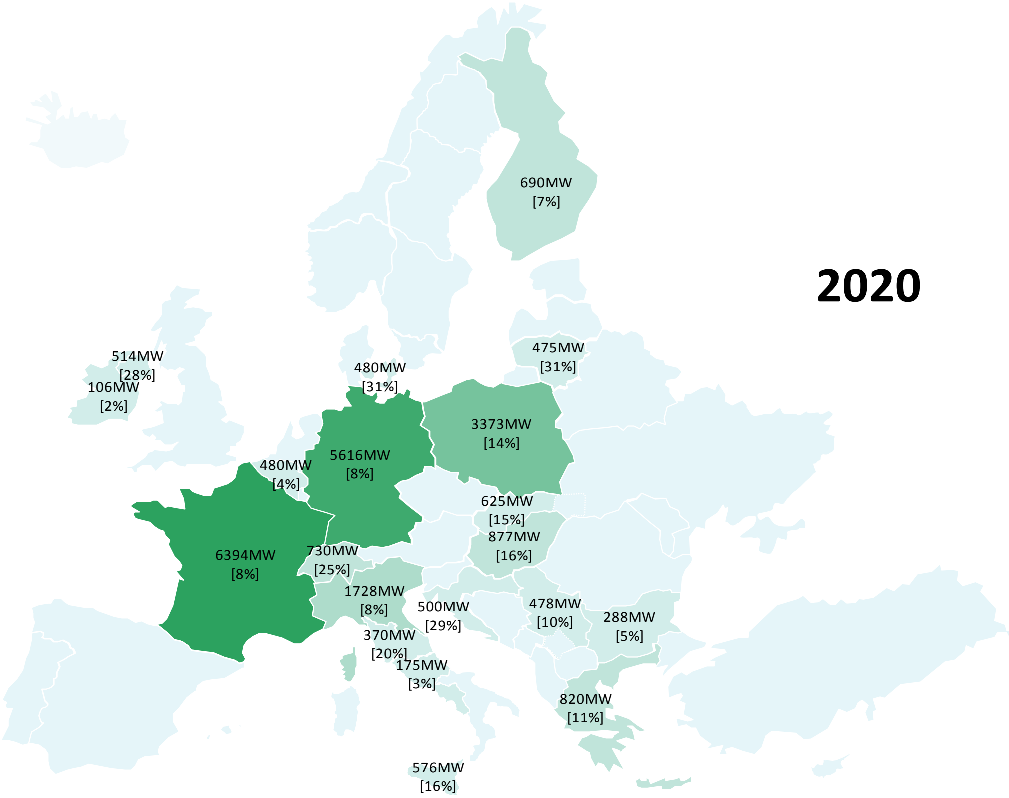


Figure 30: Generation Capacity at risk of being mothballed, absolute [MW] and relative [% of the 2020 total thermal generation capacity]

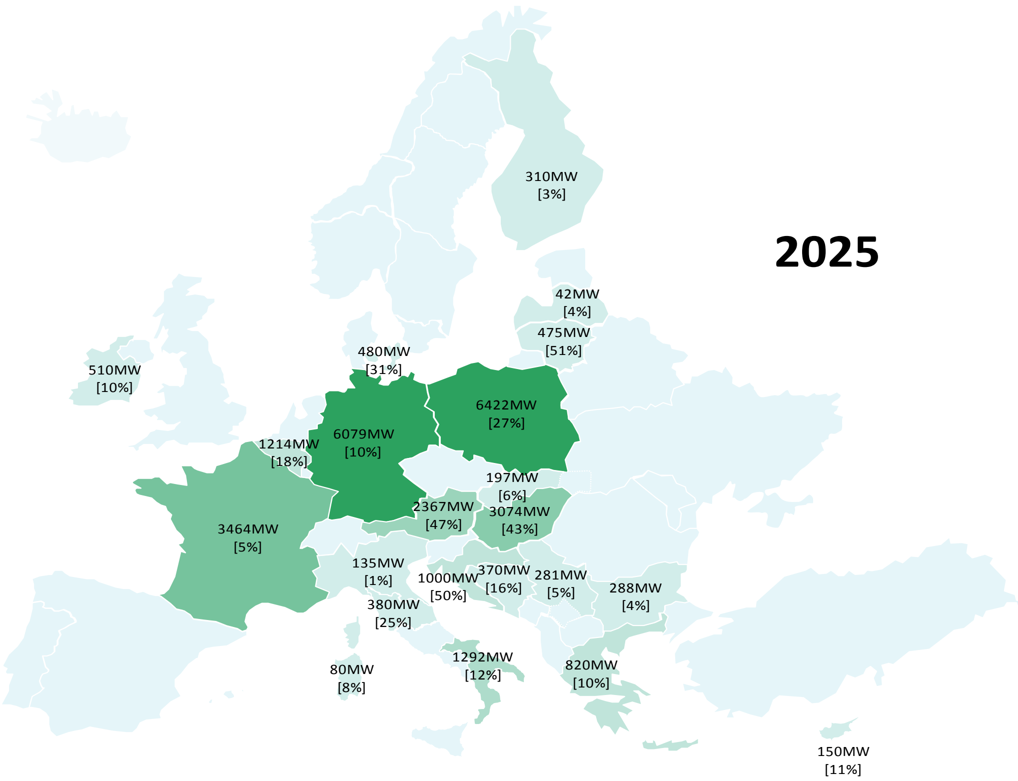


Figure 31: Generation Capacity at risk of being mothballed, absolute [MW] and relative [% of the 2025 total thermal generation capacity]

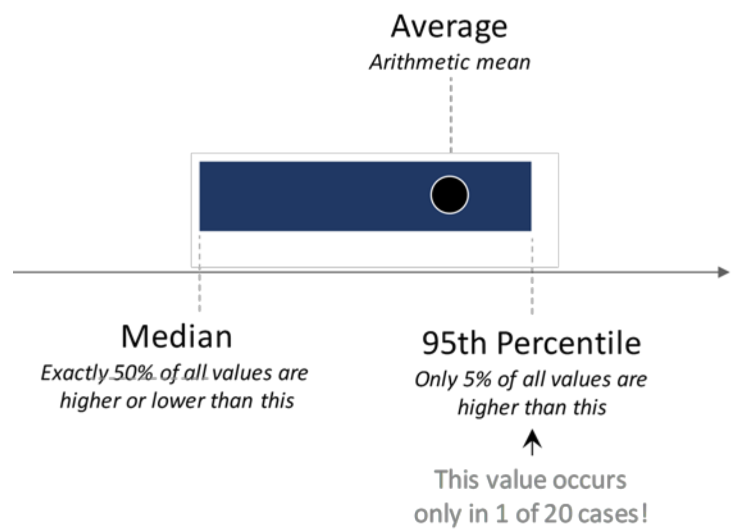
4 Detailed Model Results

This Section contains the detailed results of the market modelling studies for the Mid-term Adequacy Forecast 2017. Primarily, it contains the detailed results of the base case scenario in 2020 and 2025 (for clarification, the infobox below recalls how most of the probabilistic results are presented). In addition, several sensitivities and complementary results are presented. The Section is divided into the following parts:

1. Section 4.1 outlines the results of the base case scenario for 2020 and 2025
2. Section 4.2 describes the results of the mothballing sensitivity
3. Section 4.3 summarises the enhanced alignment of utilised market modelling tools
4. Section 4.4 covers the missing capacity calculations
5. Section 4.5 presents the findings of the flexibility analysis of residual demand

How to read the results?

The most important results are shown in bar charts. One bar represents multiple numbers which are explained below:



Example:
A market modelling tool simulates LOLE for 100 Monte Carlo years. The 95th percentile (often abbreviated P95) of the results is the 5th highest value. This corresponds to a chance of '1 in 20'.

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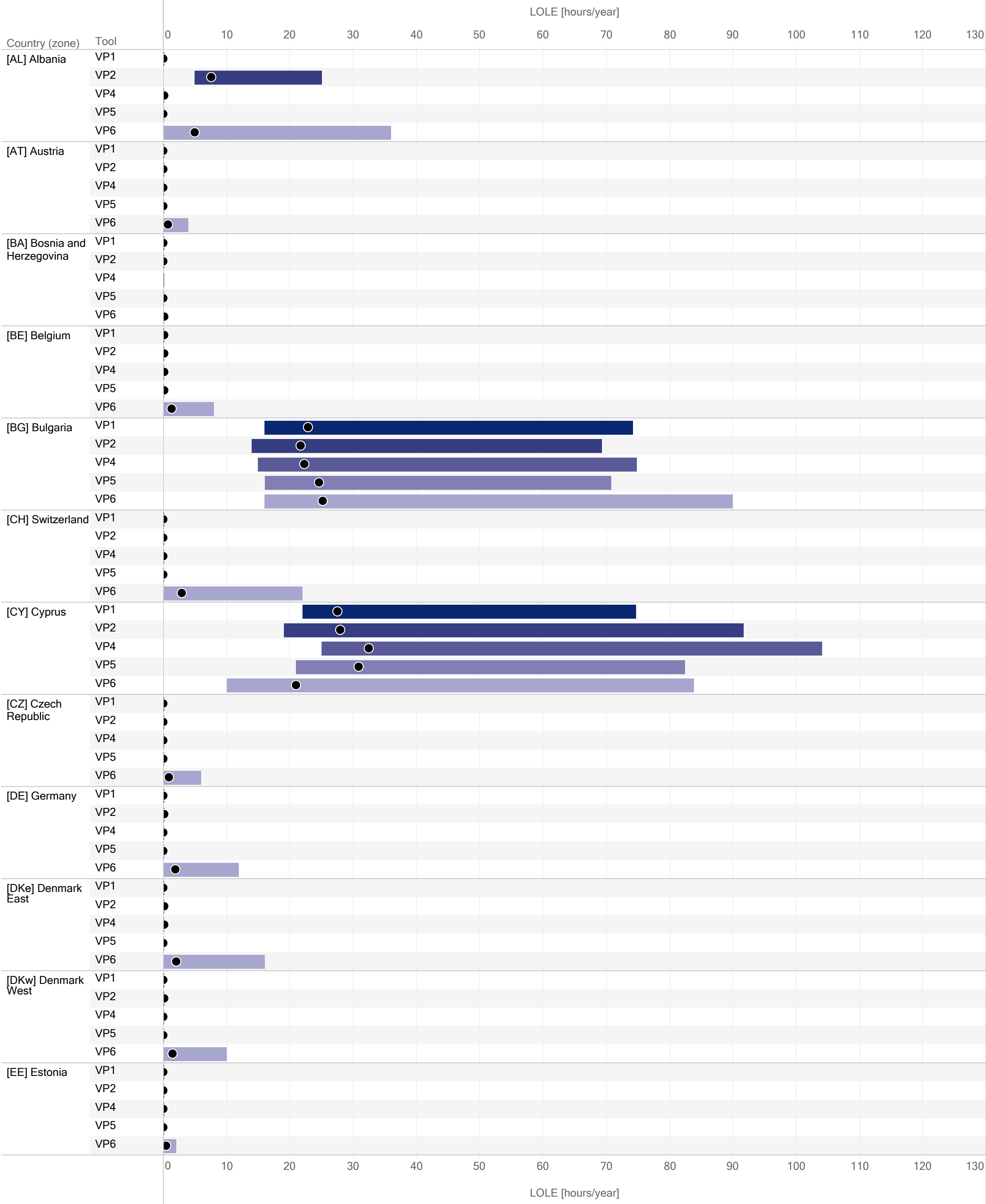
4.1 Base case results

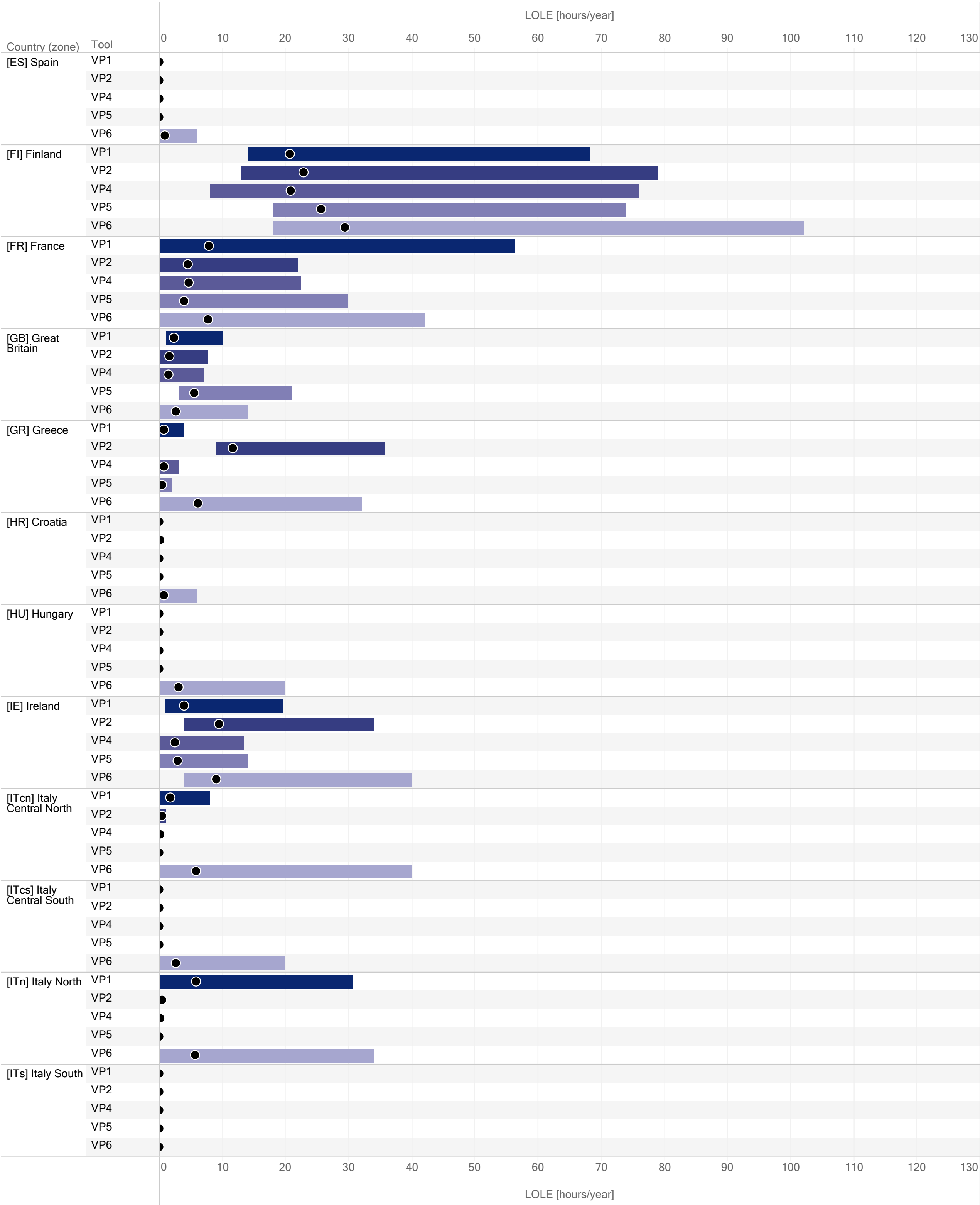
In this section, detailed simulation results of LOLE are represented in bar charts as well as ENS and LOLE, along with numerical values of LOLE and ENS in Table 3 and Table 4. Individual results of all simulation tools are represented in the figures found in Section 4.1.1 and Section 4.1.2, whereas arithmetical average values of results can be found in the tables of Section 4.1.3. More specifically, detailed results of all simulation tools are provided in the figures found in Sections 4.1.1 for 2020 and 4.1.2 for 2025, whereas arithmetical average values of results obtained by the different tools can be found in Section 4.1.3.

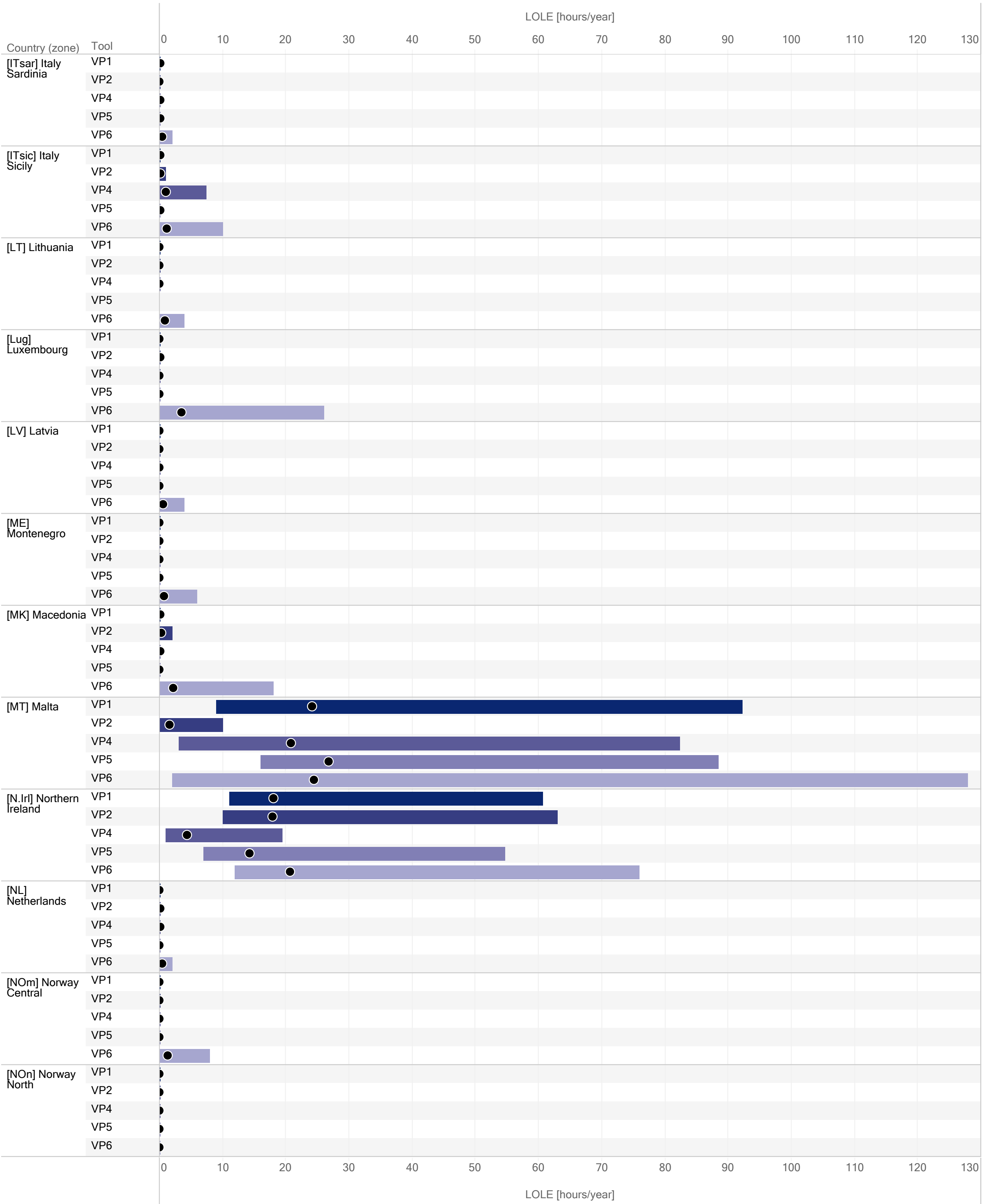
4.1.1 Adequacy in 2020

Bar charts in Section 4.1.1 indicate the probabilistic range of the adequacy index LOLE in 2020, namely the 50th and 95th percentiles of the distributions of simulation results (or in other words, the results for the risk of 1 in 2 years to 1 in 20 years). Moreover, average values of adequacy indices of all climatic simulation years are represented as dots for all simulation tools.

Figure 30: 2020 base scenario LOLE results by tool




LOLE [hours/year]
Country (zone)
Tool
0
10
20
30
40
50
60
70
80
90
100
110
120
130
[ES] Spain
[FI] Finland
[FR] France
[GB] Great Britain
[GR] Greece
[HR] Croatia
[HU] Hungary
[IE] Ireland
[ITcn] Italy Central North
[ITcs] Italy Central South
[ITn] Italy North
[ITs] Italy South
VP1
VP2
VP4
VP5
VP6


LOLE [hours/year]
Country (zone)
Tool
[ITsar] Italy Sardinia
[ITsic] Italy Sicily
[LT] Lithuania
[Lug] Luxembourg
[LV] Latvia
[ME] Montenegro
[MK] Macedonia
[MT] Malta
[N.Irl] Northern Ireland
[NL] Netherlands
[NOm] Norway Central
[NOn] Norway North
VP1
VP2
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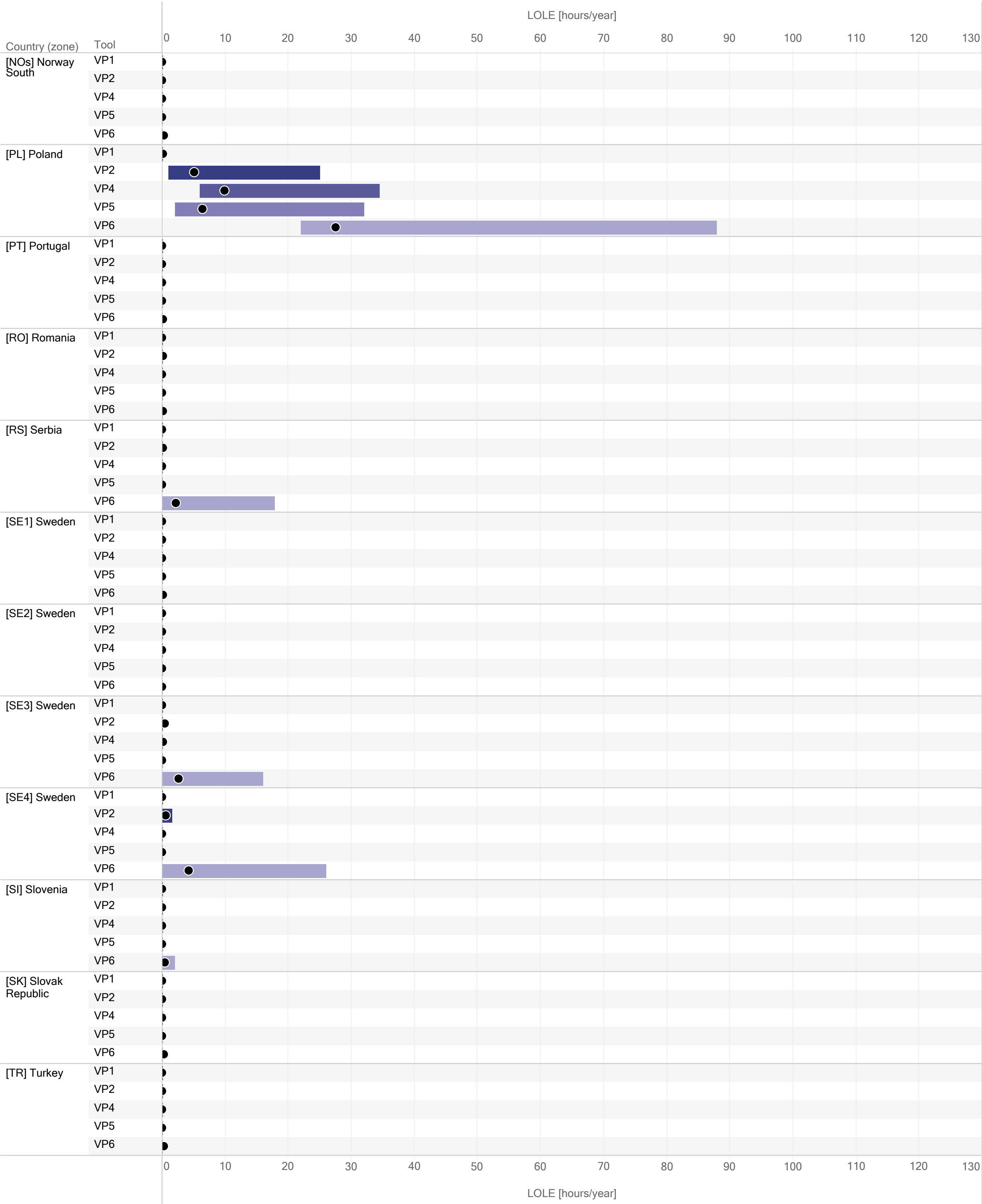
VP5
VP6
0 10 20 30 40 50 60 70 80 90 100 110 120 130


LOLE [hours/year]
Country (zone)
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110
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130
[NOs] Norway South
[PL] Poland
[PT] Portugal
[RO] Romania
[RS] Serbia
[SE1] Sweden
[SE2] Sweden
[SE3] Sweden
[SE4] Sweden
[SI] Slovenia
[SK] Slovak Republic
[TR] Turkey
VP1
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VP5
VP6

4.1.2 Adequacy in 2025

As described in Section 2.2, results for 2025 are broadly in line with 2020, however, with some important changes. First, the situation is aggravated in the Baltic area, especially in Estonia, Lithuania and Poland where several old power plants are assumed to be unavailable in the system. Second, there is a remarkable difference between the adequacy conditions on the Mediterranean islands (Malta, Sicily, Cyprus) due to simplified modelling assumptions: with respect to Sicily and Malta and the neglection of the foreseen new interconnection in Cyprus. Finally, resource adequacy is expected to improve between 2020 and 2025 in Bulgaria (due to the envisaged commissioning of new CCGT plants) and Northern Ireland (due to the second North-South Interconnector to be commissioned in 2021).

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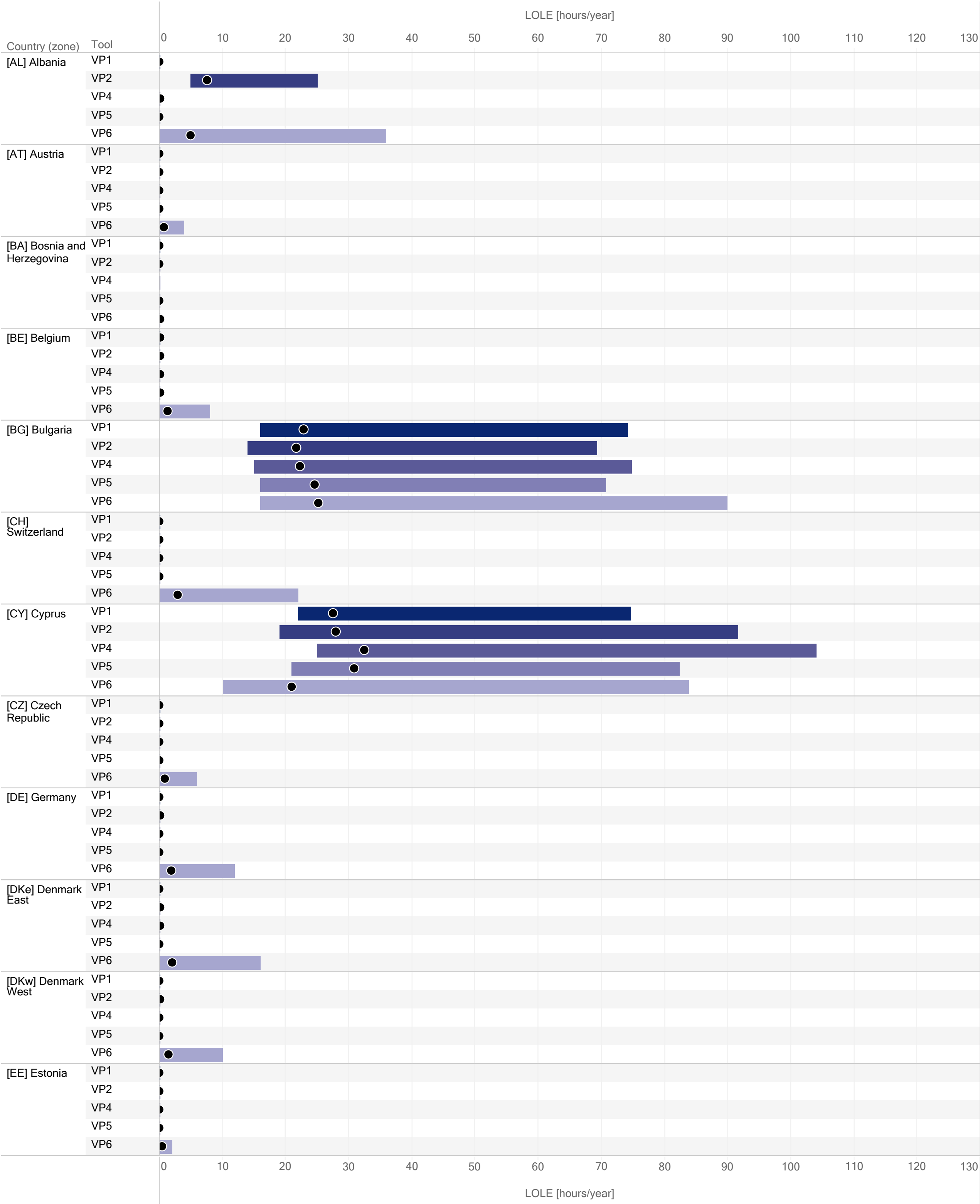
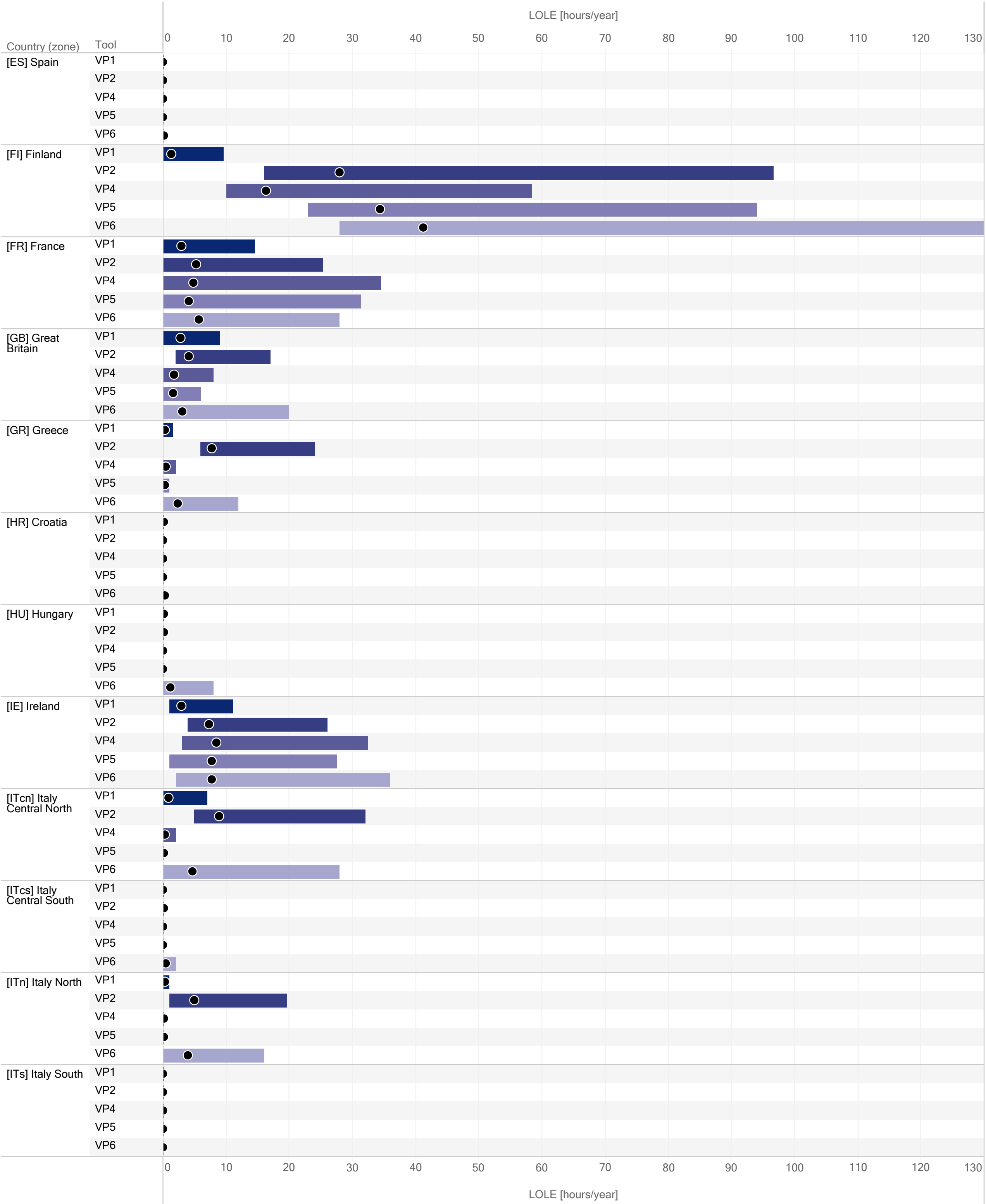
Figure 32 - 2025 base scenario LOLE results by tool




LOLE [hours/year]
Country (zone)
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100
110
120
130
[ES] Spain
[FI] Finland
[FR] France
[GB] Great Britain
[GR] Greece
[HR] Croatia
[HU] Hungary
[IE] Ireland
[ITcn] Italy Central North
[ITcs] Italy Central South
[ITn] Italy North
[ITs] Italy South
VP1
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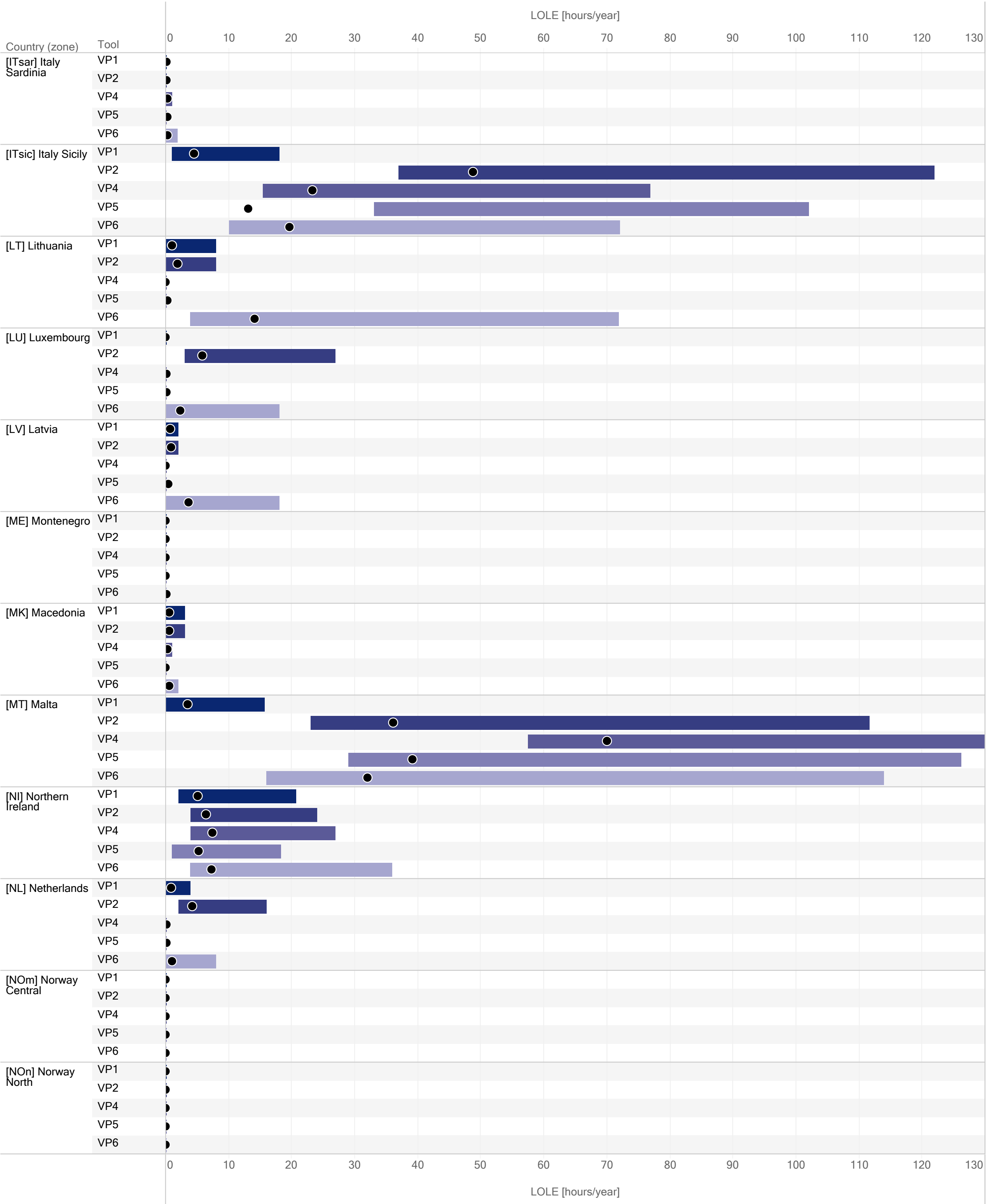
LOLE [hours/year]
Country (zone)
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[ITsar] Italy Sardinia
[ITsic] Italy Sicily
[LT] Lithuania
[LU] Luxembourg
[LV] Latvia
[ME] Montenegro
[MK] Macedonia
[MT] Malta
[NI] Northern Ireland
[NL] Netherlands
[NOm] Norway Central
[NOn] Norway North
VP1
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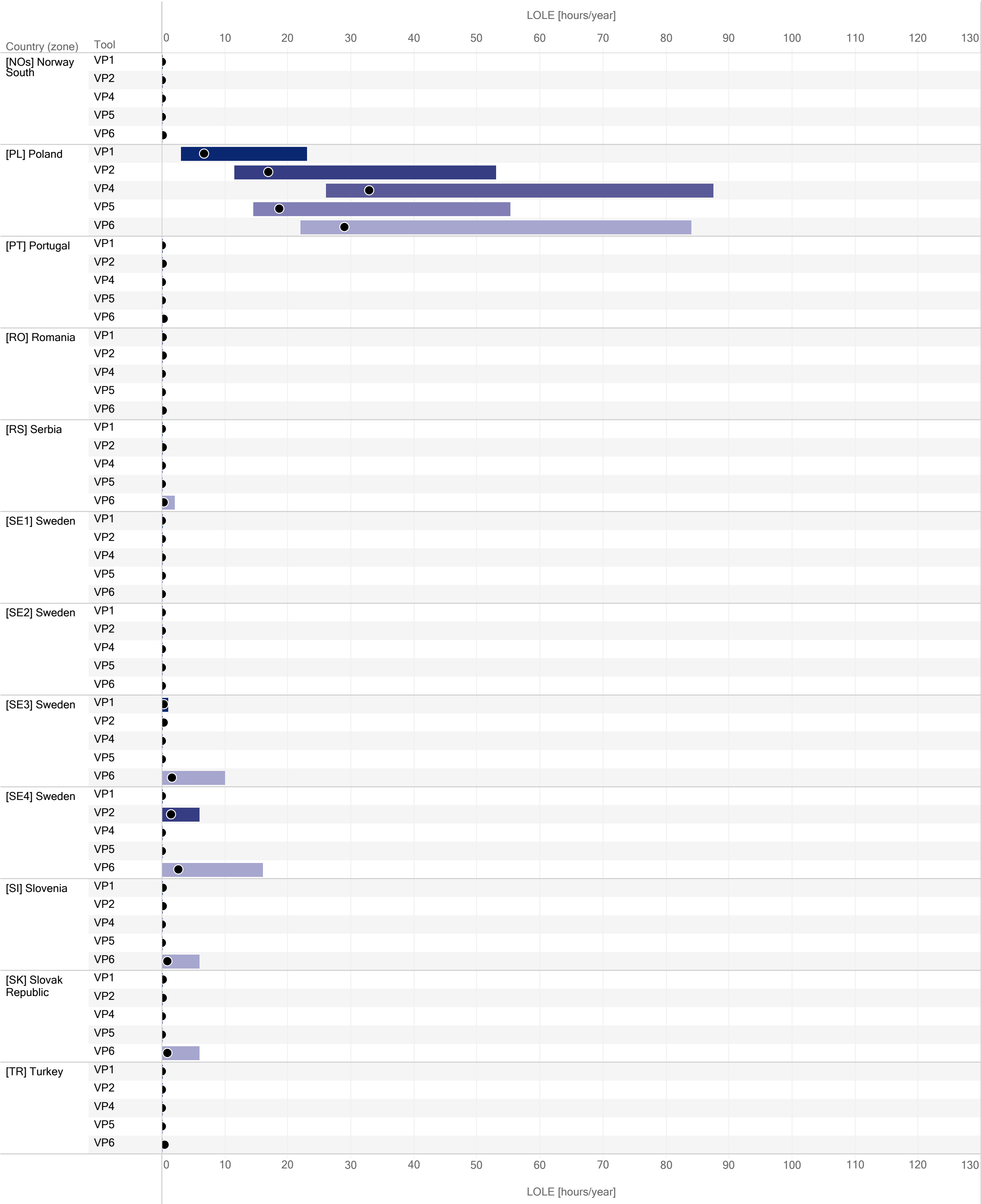
LOLE [hours/year]
Country (zone)
Tool
0 10 20 30 40 50 60 70 80 90 100 110 120 130
[NOs] Norway South
[PL] Poland
[PT] Portugal
[RO] Romania
[RS] Serbia
[SE1] Sweden
[SE2] Sweden
[SE3] Sweden
[SE4] Sweden
[SI] Slovenia
[SK] Slovak Republic
[TR] Turkey
VP1
VP2
VP4
VP5
VP6

4.1.3 Adequacy in numbers – ENS and LOLE in 2020 and 2025

In this section, base case scenario results can be found. Results presented in the following tables correspond to the average values of parameters procured from simulations by all simulation tools, e.g. in base scenario 2020, the P50 value of Albania represents the average value of all P50 values of Albania considering all tools presented in Section 4.1.1. Result data are provided for base scenarios in 2020 and 2025 of ENS and LOLE.

Table 4 Average ENS [GWh] values of all simulation tool results

Country	Base scenario 2020			Base scenario 2025		
	average	*P50*	*P95*	*average*	*P50*	*P95*
AL	0.54	0.16	2.47	0.24	0.09	0.97
AT	0.08	0.00	0.22	0.05	0.00	0.15
BA	0.00	0.00	0.00	0.00	0.00	0.00
BE	0.19	0.00	0.43	10.97	0.97	71.39
BG	8.55	3.38	32.19	0.34	0.00	1.87
CH	0.20	0.00	1.05	0.45	0.00	1.93
CY	1.82	0.82	6.84	42.93	40.27	73.38
CZ	0.00	0.00	0.02	0.02	0.00	0.15
DE	0.12	0.00	0.72	0.91	0.00	5.08
DKe	0.04	0.00	0.16	0.30	0.00	1.48
DKw	0.03	0.00	0.10	0.09	0.00	0.28
EE	0.00	0.00	0.01	2.18	0.18	11.35
ES	0.02	0.00	0.08	0.01	0.00	0.00
FI	10.19	2.96	43.85	13.24	4.55	54.03
FR	27.31	0.00	109.08	22.39	0.00	84.31
GB	3.48	0.51	17.05	5.82	0.46	27.27
GR	1.55	0.61	6.21	0.98	0.40	3.75
HR	0.03	0.00	0.06	0.03	0.00	0.00
HU	0.22	0.00	0.91	0.13	0.00	0.14
IE	1.40	0.16	6.78	1.81	0.25	8.48
ITcn	0.73	0.00	3.53	1.96	0.67	8.66
ITcs	0.13	0.00	0.78	0.05	0.00	0.04
ITn	3.47	0.00	17.22	3.79	0.16	14.78
ITs	0.00	0.00	0.00	0.00	0.00	0.00
ITsar	0.01	0.00	0.00	0.01	0.00	0.01
ITsic	0.11	0.00	0.51	5.34	3.46	26.44
LT	0.05	0.00	0.05	0.73	0.03	3.45
LU	1.08	0.00	5.89	1.85	0.40	9.02
LV	0.01	0.00	0.01	0.24	0.00	0.52
ME	0.01	0.00	0.03	0.00	0.00	0.00
MK	0.06	0.00	0.25	0.10	0.00	0.50
MT	0.96	0.15	4.50	2.05	1.13	7.26
NI	2.07	0.66	8.89	1.25	0.39	5.19
NL	0.11	0.00	0.02	1.51	0.66	5.93
NOm	0.01	0.00	0.07	0.00	0.00	0.00

Country	Base scenario 2020			Base scenario 2025		
	average	*P50*	*P95*	*average*	*P50*	*P95*
NOn	0.00	0.00	0.00	0.00	0.00	0.00
NOs	0.02	0.00	0.00	0.04	0.00	0.00
PL	7.22	2.71	29.30	17.20	8.78	61.66
PT	0.01	0.00	0.00	0.05	0.00	0.00
RO	0.01	0.00	0.00	0.01	0.00	0.00
RS	0.06	0.00	0.31	0.01	0.00	0.00
SE1	0.00	0.00	0.00	0.00	0.00	0.00
SE2	0.00	0.00	0.00	0.00	0.00	0.00
SE3	0.49	0.00	2.42	0.16	0.00	0.73
SE4	0.44	0.00	2.09	0.60	0.00	2.50
SI	0.00	0.00	0.00	0.02	0.00	0.02
SK	0.01	0.00	0.00	0.03	0.00	0.05
TR	0.04	0.00	0.00	0.08	0.00	0.00

Table 5 Average LOLE [hours/year] values of all simulation tool results

Country	Base scenario 2020			Base scenario 2025		
	average	*P50*	*P95*	*average*	*P50*	*P95*
AL	2.53	1.00	12.20	1.27	0.60	5.00
AT	0.13	0.00	0.80	0.06	0.00	0.20
BA	0.01	0.00	0.00	0.00	0.00	0.00
BE	0.31	0.00	1.60	5.97	0.60	37.47
BG	23.42	15.40	75.85	1.09	0.00	6.42
CH	0.61	0.00	4.40	0.34	0.00	1.00
CY	28.05	19.40	87.35	435.87	425.70	616.80
CZ	0.18	0.00	1.20	0.05	0.00	0.20
DE	0.40	0.00	2.40	0.63	0.00	3.40
DKe	0.44	0.00	3.20	0.92	0.00	5.40
DKw	0.30	0.00	2.00	0.34	0.00	2.40
EE	0.09	0.00	0.40	7.64	1.80	36.81
ES	0.15	0.00	1.20	0.00	0.00	0.00
FI	23.98	14.20	79.86	24.29	15.40	78.53
FR	5.82	0.00	34.51	4.59	0.00	26.72
GB	2.78	0.80	11.93	2.73	0.40	12.00
GR	3.88	1.80	15.33	2.15	1.20	8.13
HR	0.12	0.00	1.20	0.05	0.00	0.00
HU	0.64	0.00	4.00	0.26	0.00	1.60
IE	5.63	1.80	24.22	6.88	2.20	26.58
ITcn	1.60	0.00	9.80	2.98	1.00	13.80
ITcs	0.55	0.00	4.00	0.07	0.00	0.40
ITn	2.41	0.00	12.93	1.86	0.20	7.33
Its	0.00	0.00	0.00	0.00	0.00	0.00

Country	Base scenario 2020			Base scenario 2025		
	average	*P50*	*P95*	*average*	*P50*	*P95*
ITsar	0.11	0.00	0.40	0.14	0.00	0.58
ITsic	0.54	0.00	3.69	21.96	19.30	78.18
LT	0.19	0.00	1.00	3.49	0.80	17.58
LU	0.71	0.00	5.20	1.65	0.60	9.00
LV	0.11	0.00	0.80	1.09	0.00	4.40
ME	0.14	0.00	1.20	0.01	0.00	0.00
MK	0.52	0.00	4.00	0.37	0.00	1.80
MT	19.64	6.00	80.22	36.22	25.10	109.85
NI	15.14	8.20	54.76	6.35	3.00	25.20
NL	0.09	0.00	0.40	1.25	0.40	5.60
Nom	0.27	0.00	1.60	0.00	0.00	0.00
Non	0.00	0.00	0.00	0.00	0.00	0.00
Nos	0.04	0.00	0.00	0.02	0.00	0.00
PL	9.82	6.20	35.89	20.89	15.40	60.56
PT	0.02	0.00	0.00	0.03	0.00	0.00
RO	0.04	0.00	0.00	0.03	0.00	0.00
RS	0.45	0.00	3.58	0.05	0.00	0.40
SE1	0.00	0.00	0.00	0.00	0.00	0.00
SE2	0.00	0.00	0.00	0.00	0.00	0.00
SE3	0.65	0.00	3.20	0.43	0.00	2.20
SE4	0.97	0.00	5.53	0.84	0.00	4.40
SI	0.07	0.00	0.40	0.21	0.00	1.20
SK	0.05	0.00	0.00	0.21	0.00	1.20
TR	0.05	0.00	0.00	0.06	0.00	0.00

4.2 Mothballing sensitivity

In this section, the results of the mothballing sensitivity study are presented. As described in Section 2.3.2, additional simulations were run considering that generating capacity under risk of being mothballed will not be available in the system. This sensitivity should be understood as a more conservative view of the net generating capacity, and can – by definition – only result in inferior generation adequacy levels. In fact, our analysis reveals that even though mothballing only affects 45% of the countries analysed, 82% of them are affected in terms of a significant increase in their risk indicators (LOLE). This effect is illustrated in Figure 33 for 2020 and in Figure 34 for 2025[19], where the inner circles represent the bidding zone's base case LOLE, and the outer circle the LOLE after the mothballing takes place.

However, it has to be stressed that the simulation has been performed considering that all generation capacity under risk of being mothballed will not be available in the system for the respective study years (i.e. no individual country analysis has been conducted). Considering the cross-border effect of a reduction of generating capacity, it should be noted that the avoidance of mothballed capacity in a specific country would

[19] Results presented in Figure 33 and Figure 34 should be taken *cum grano salis* as impacts for Poland and Cyprus are represented with a cap on size for visualisation reasons

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contribute to the relief of adequacy issues inside the country in question as well as in some other countries. This also applies vice-versa; avoiding all the capacity of being mothballed in a specific country does not guarantee that adequacy indices in the concerned country would reach a system state with no mothballing (results presented in Section 4.1), because mothballing in neighbouring countries contributes to adequacy in the country in question as well.

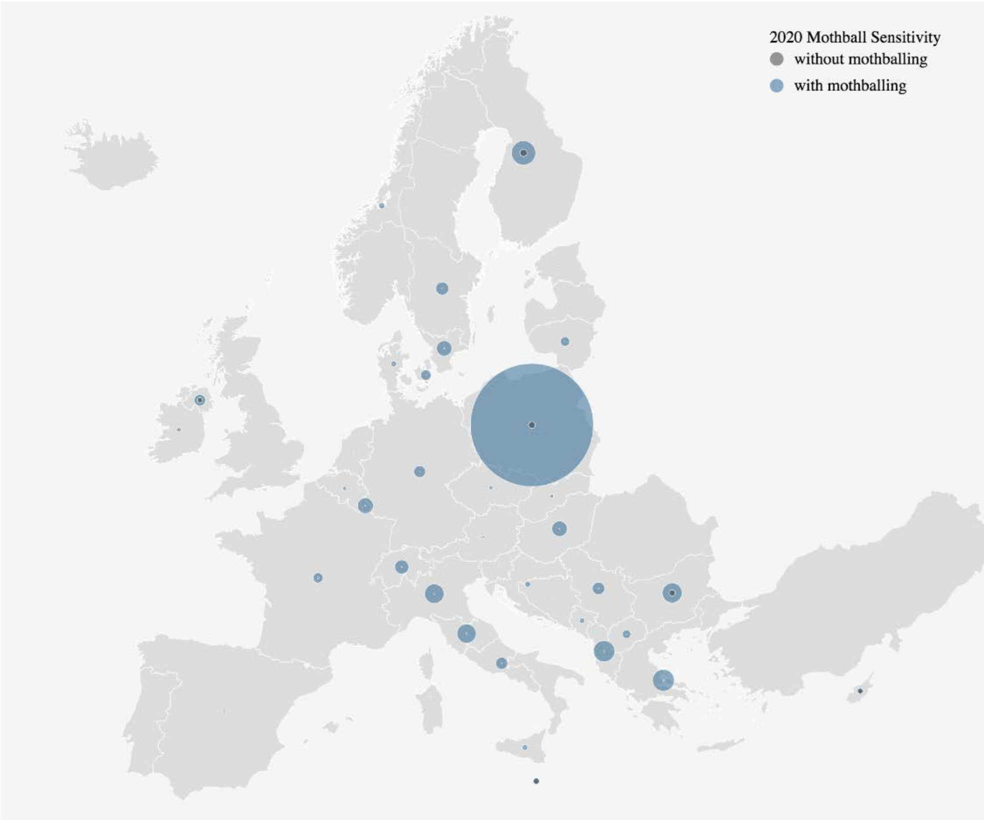

Figure 33 LOLE sensitivity to mothballing in 2020 results

As mentioned in paragraph 2.3.2, Poland is the most affected by mothballing risk in 2020. 3.4 GW of thermal capacity may be decommissioned (6.4 GW in 2025). Current unfavourable market conditions are generally preventing modernisation thermal units from fulfilling BAT standards. A capacity market, which is currently being developed by the Polish government, is therefore a crucial solution to ensure a proper adequacy level.

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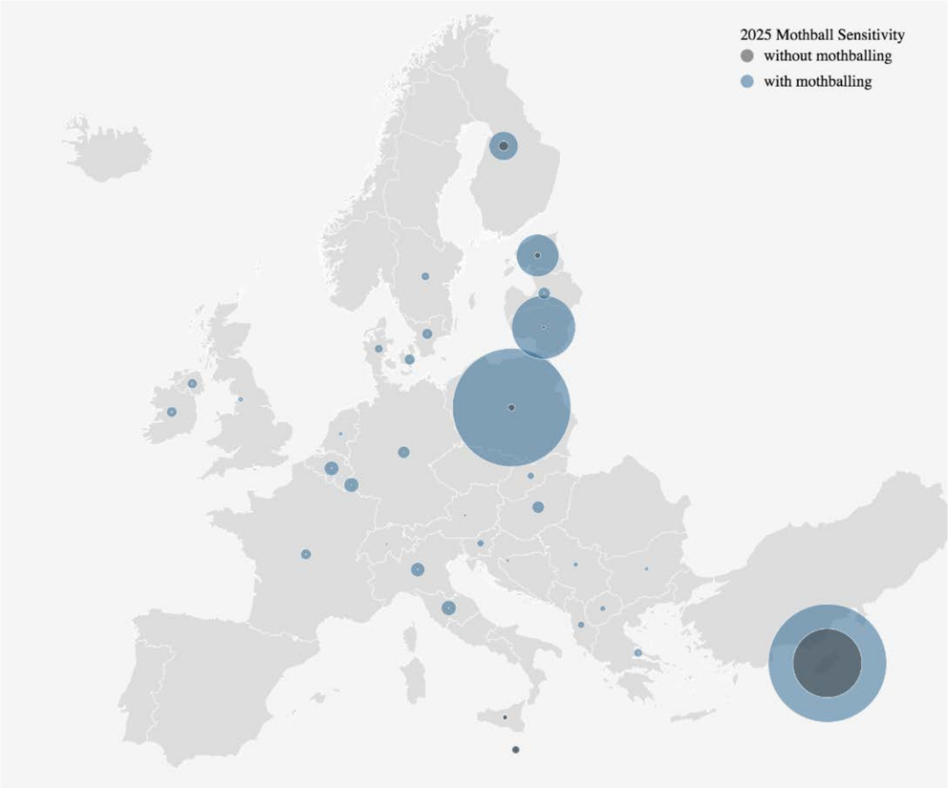

Figure 34 LOLE sensitivity to mothballing in 2025 results

4.3 Improvement in the alignment of the tools

'All models are wrong, some models are useful' (*George Box)*

Simulation models used for the mid-term adequacy forecast in 2016 have been revised to increase simulation result quality. The improved alignment of simulation results of different tools has been achieved, as presented in the figure below. The simulated LOLE values of each tool for a specific country are represented in relation to the average of the simulated LOLE for a specific country of all tools. The figure should be interpreted as follows: as the relative simulated LOLE value of a specific tool for a specific country is closer to unit, the tool simulation result is closer to the average of all tools. An improved alignment of results cause curves of simulated LOLE to shift towards a higher order of symmetry, which is observed in the LOLE result graph of 2017 compared to the one for 2016.

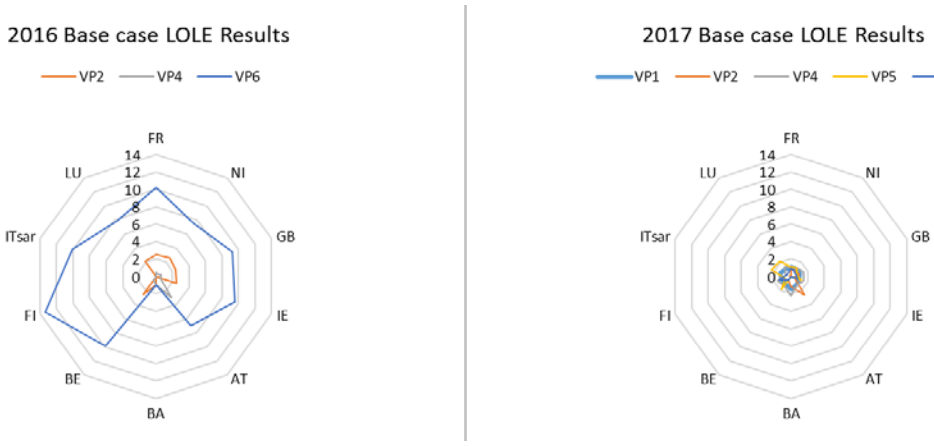

Figure 35: Base case simulation LOLE result alignment comparison

A sufficient number of independent simulation tools is crucial to ensure simulation result reliability and robustness. Experience has shown that a good robustness can be reached from three simulation tools, especially as these tools have been aligned and calibrated starting from the MAF 2016 edition. Result alignment quality can also be checked in Section 4.1 and Section 4.2.

4.4 Missing Capacity / Capacity Margin

Additional capacity findings are reported in Table 6 below. It is identified, e.g. that for the CWE area encompassing AT, BE, CH, DE, FR, IT and NL, there is a need for approximately 5000 MW of capacity, so an adequacy standard average LOLE =3 is reached for the countries inside this area. The same logic applies for the Baltic countries plus Poland, with an associated volume of 1500 MW, whereas for the Nordic area the volume is around 1300 MW. Finally, the needs for the two semi isolated countries MT and CY add up to 500 MW.
The figures provided in Table 6 should be understood as *necessary additional capacity with respect to the assumptions of generation, demand and interconnection capacity considered in the MAF 2025 base case scenario* and *as regional estimates* rather than specific country needs. It should be stressed that this is **NEITHER** a statement by ENTSO-E or its TSO member on the need for capacity renumeration mechanisms for any of the countries inside the areas considered, **NOR** on which type of capacity the reported MW refers to. These volumes should be further analysed in more detailed national and/or regional studies in order to define their type and ratio among the different relevant options, e.g. increased interconnection capacity, storage and demand side response as well as (reliable) generation capacity, which need to be chosen carefully to fill the identified gap of missing power to reach the respective national standard targets. These choices require careful consideration of national or even regional specificities and regulatory frameworks and should exploit in any case the complementarities and synergies of the respective options possible/available. These are subject to intense research and discussion at the national / regional level and are beyond the scope of this present report.

Table 6 Necessary additional capacity per area considering the 2025 base case scenario

Area	Additional Capacity [MW]	Countries
Area 1	5000	AT, BE, CH, DE, FR, IT, NL
Area 2	1500	EE, LT, LV, PL
Area 3	1300	FI, NO, SE
Area 4	500	CY, MT

4.5 Flexibility

In an energy system mainly driven by renewable energy sources, the fluctuating weather conditions directly impact the balance of generation and consumption of electrical energy. This balance is the main requirement for a safe and consistently working power supply and must not be violated.
Therefore, it is crucial to quantify the fluctuation of the renewable power generation as well as the demand volatility.

Although weather forecasts have become increasingly accurate, a 100% safe prediction is not possible. This automatically leads to uncertainty in the power generation prognoses of solar and wind generators. On the demand side, climatic conditions play a minor role in the investigations of flexibility. A more significant impact is caused by the individual load profiles of each area. The natural behaviour, e.g. a demand peak in the evening caused by the simultaneous processes of all consumers in a region (cooking, heating, switch-on of electrical consumers) leads to a very pronounced change in consumption from one hour to the next.

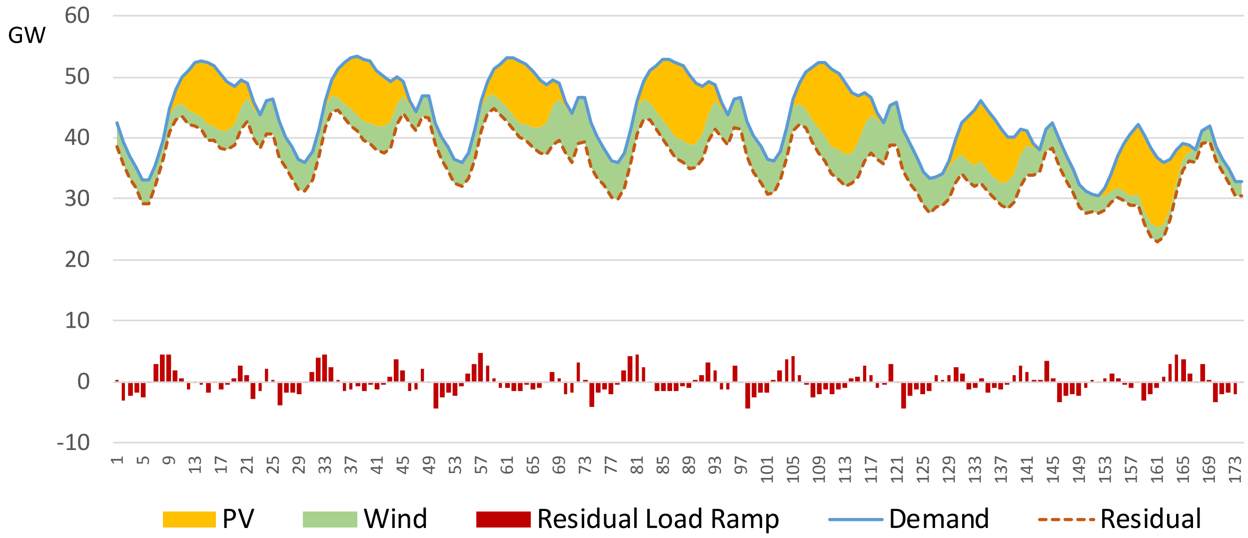

Figure 36: Demand, renewable generation and residual load during one week (hourly resolution)

By subtracting the fluctuating generation from the demand curve, the **residual load** is calculated. The residual load describes the load that is required to be covered by conventional and flexible power plants.

$$RL(h_i) = D(h_i) - W(h_i) - S(h_i)$$

$D(h_i)$ … Demand in hour i

$W(h_i)$ … Wind generation (offshore and onshore) in hour i

$S(h_i)$ … Solar generation (PV and CSP) in hour i

A further analysis of the residual load quantifies the change from one hour to another.

$$R(h_{i,i+1}) = RL(h_{i+1}) - RL(h_i)$$

This **residual load ramp** is already indicated in Figure 36. The graph presents a demand curve with a pronounced peak around noon and a smaller peak in the evening. It also shows the strong PV generation gradients and the fluctuations in wind generation. The positive ramps (load is rising faster than renewable generation does) are distributed around the morning hours when there is a very small PV infeed.

The calculation of the residual load and its ramps is carried out for 34 years of hourly values. From the demand time-series as described in Section 0 the renewable generation (Section 3.2.3) is subtracted. The 99.9th percentile of the positive and negative load ramps are shown in Figure 37. This means that, on average, only 9 hours per year (0.1%) experience higher residual load ramps.

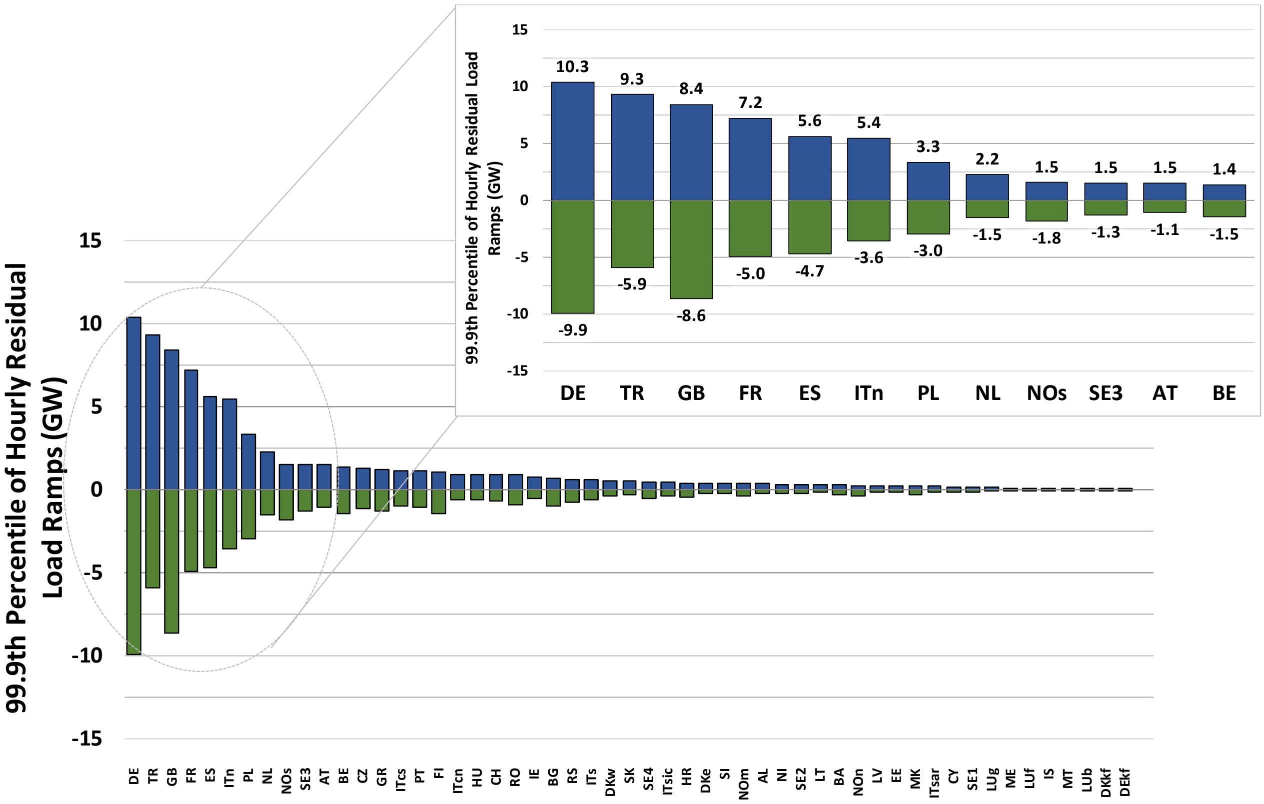

Figure 37: Load ramps

As depicted before, a system with many renewable energy generators is more likely to experience strong ramps especially when the system size is limited and therefore abrupt weather changes apply to a large number of generators.

Figure 38 confirms the correlation of residual load ramps with installed renewable capacity.

The sudden load changes require power plants to ramp up or down in a short amount of time. Due to limitations this is not possible for most of the power plants. Power plants such as hydro power plants and open cycle gas turbines have the potential to start up and generate electrical energy within a very short time. Another possibility to procure flexible power is to use cross-border capacities with countries that have excess renewable energy or experience a contrary load change.

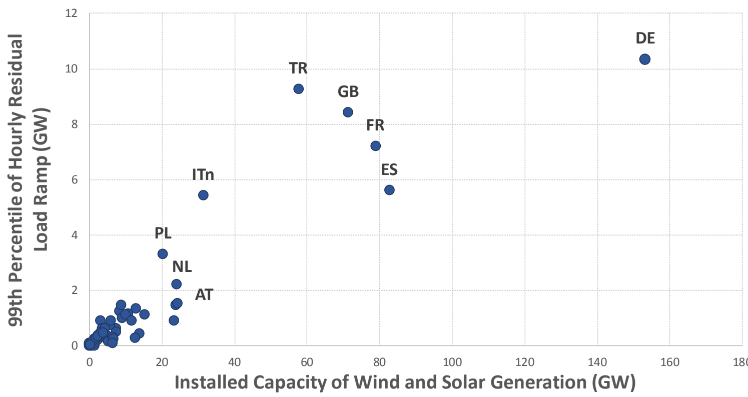

Figure 38: Residual load ramps vs installed renewable capacity

Figure 38 shows the effect of area aggregation on load ramps. An aggregated area is a virtual zone which has no transmission capacity limits. The calculation is identical to the ramping assessment as described before but two or more countries are aggregated. Before calculating the ramps, two or more residual load time series are summed up. Figure 39 compares the cases when each country is on its own and when the described regions are aggregated.

The aggregation has a balancing effect on the residual load. While in one country the residual load increases, in another it potentially decreases and thus the region can be balanced via transmission of energy. By doing this for three cases (Germany and France, the PLEF region and then full ENTSO-E) the impact of this aggregation can be analysed.

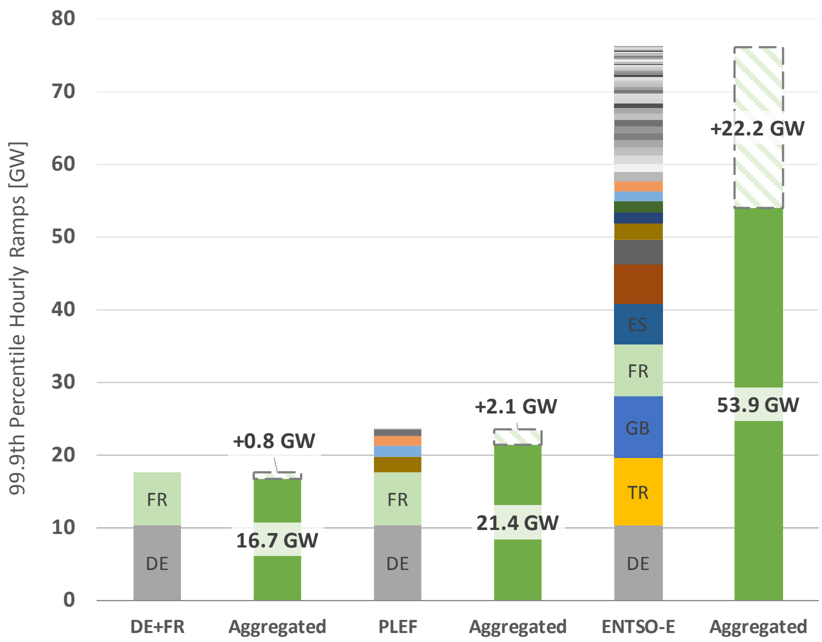

Figure 39: Benefits from spatial aggregation for hourly ramps on different geographical scopes

The differences between aggregated and individual ramps for the DE+FR case are small. This is mainly due to the regional proximity of Germany and France. The effects are limited even for the PLEF (DE, FR, AT, CH, BE, NL, LU).

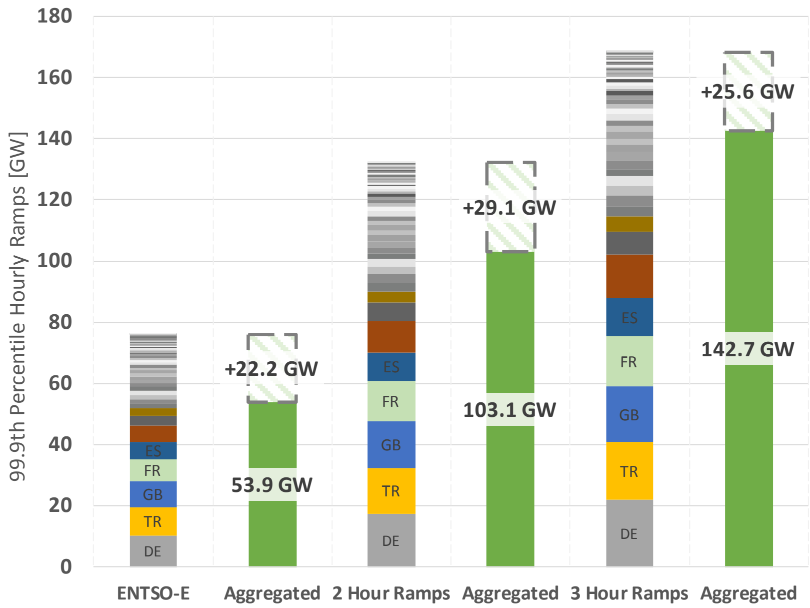

Figure 40: Benefits from spatial aggregation for different ramps on different geographical scopes

Another picture is drawn when examining and aggregating all ENTSO-E areas. The 'saving' in residual load ramp when aggregating all zones as one is enormous. The main reason for this large difference is the significant variety of weather conditions because of the spatial expansion of the ENTSO-E zones. While there is a considerable amount of solar generation in southern Europe, it is possible that middle Europe is experiencing a fall-off. In addition, due to the time shift, the critical hours around noon and in the evening are shifted slightly.

The residual load ramp from one hour to the next requires a short term response from generating facilities. Also, two and three hour ramps can be difficult to compensate, since the ramp-up and down specifications of large thermal power plants are significant. Figure 39 compares one, two and three hour ramps also showing the effect of spatial aggregation.

With the given operating limitations (see Section 3.2.8) the market modelling tools can reproduce the ramping behaviour of power plants. Therefore, the findings outlined in this section are already included in the simulations that lead to the results of previous sections.

Conclusion Flexibility

It is important to acknowledge that a possible generation deficit is conceivably caused by lack of flexibility. This dimension of adequacy has to be considered when finding solutions to detected problems. While flexible generating units are able to cope with ramping issues, this section shows that interconnection between different market zones is also a suitable way to resolve fast-changing demand situations.

5 Appendices

5.1 Glossary

ARM	Adequacy Reference Margin
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DSR	Demand Side Response
ENS	Energy not Served
FBMC	Flow-Based Market Coupling
IEA	International Energy Agency
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant directive
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAF	Mid-term Adequacy Forecast
MILP	Mixed-Integer Linear-Programming
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum incl. (AT, BE, CH, DE, FR, LU, NL)
SO&AF	Scenario Outlook & Adequacy Forecasts
VP	Voluntary Parties

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5.2 National view on resources adequacy concerns identified & highlighted (or not identified) in MAF 2017

5.2.1 Austria

For the load forecast, we assume an annual increase of 0.56% until 2020. Beyond 2020, due to energy efficiency we took into account an increase of 0.25% per year.

A further increase of renewables (wind and solar power plants) is expected. For the sensitivity analyses for 2025, we quoted a possible mothballing capacity of hard coal (246 MW) and of gas power plants (approx. 2100 MW).

5.2.2 Belgium

Elia - beyond its active involvement in the ENTSO-E MAF report - is also actively contributing to the regional PLEF GAA study as well as currently publishes every year an adequacy assessment covering the next 3 winters. Last year, at the request of the Minister of Energy, Elia published an adequacy study covering 10 years:

1. **Adequacy Study for Belgium: Need of strategic reserve capacity for the next winters:** This study is a recurrent document delivered to the Minister and the Federal Public Service every year for the 15th of November.
    1. **Edition - Winters 2017-18, 2018-19 and 2019-20 (SR17-20)** published on December 2016. This study evaluated the need of strategic reserve capacity as defined by the law based on the most recent forecasts of production and demand in Belgium and neighboring countries. The yearly update of this study is going to be published in December 2017 and covering one additional winter (2020-21, **SR18-21**).
    2. **Adequacy & Flexibility study for 2017-2027 (AdeqFlex2017-27)**. This study was requested by the Minister of Energy to Elia in order to assess the adequacy and flexibility requirements of the Belgian system for the next 10 years. The study was published on April 2016 *[http://www.elia.be/en/about-elia/newsroom/news/2016/20-04-2016-Adequacy-study-flexibility-Belgian-electricity-system]*. An addendum to the study was published in September 2016.

Load and annual demand forecast provided for 2020 and 2025

The demand forecast provided for 2020 and 2025 assumes a stable demand (excluding additional electrification of heat and transport and additional baseload) as described in the base case scenario of the AdeqFlex2017-27 study. Additional contribution to the demand from EV and heat pumps was considered based on external studies (e.g. global EV Outlook 2016). Concerning additional baseload, Elia takes into account information reported by its national grid users. This results in a slightly higher demand growth than the base case scenario of the AdeqFlex2017-27 study.

For 2020

The DSR assumptions are described in the Market Response study performed during 2017 within the preparations of the SR18-21 report.

For 2025

The DSR assumptions are the same as those described in AdeqFlex2017-27 study.

Net generating capacity forecast provided for 2020 and 2025

The hypotheses for Belgium in MAF, in terms of RES, Nuclear, CHP, biomass, pump storage, were taken into account from the SR17-20 study. A best estimate in terms of installed gas capacity was made for 2020 and 2025 based on decommissioning figures, technical lifetime as well as indications of the target for Belgium's structural block needed to ensure adequacy from the AdeqFlex2017-27 study. Strategic reserves contracted for the winters 2015, 2016 are considered out of the market and are not part of the data submitted for MAF. Regarding mothballing assumptions, some technologies of the generation park might be exposed to mothballing due to unfavorable economic conditions.

For 2020
The generation capacity is in line with the national studies SR17-20 and to be published SR18-21.

For 2025
By the end of 2025, a complete nuclear phase-out is planned in Belgium according to the law. In order to assess the effect of such phase-out, no nuclear generation capacity is considered in 2025 for MAF.

All existing biomass and gas units were considered as part of the production park. Furthermore new OGCT units were considered, in order to increase the thermal capacity of Belgium and to ensure adequacy (but there is no guarantee that such capacity will be available in 2025 nor that new capacity will be built). Regarding the additional capacity sensitivity performed in MAF, analysis of the results indicate that of the 5000 MW additional capacity identified for the area including Belgium, no more than 500 MW could be associated with a need in Belgium, to reach the national standard of LOLE = 3h/yr, with respect to the original assumptions considered for the generation park (see below for further explanations). These results are in line with the AdeqFlex2017-27 study (see below).

Net Transfer Capacity forecast provided for 2020 and 2025

The Net Transfer Capacity assumptions considered are in line with the AdeqFlex2017-27 study.

For 2020
Nemo Link®, the HVDC connection with Great Britain, is taken into account for 2020 as the current date of finalization is in 2019. This connection has an exchange capability of 1000 MW between Belgium and Great Britain. The planned HVDC interconnection with Germany (ALEGrO project) has a targeted commissioning date of 2020 and is also considered.
For 2025
The NTC evolution from 2020 towards 2025 for Belgium takes into account projects that are already underway/planned, namely:

- i) The upgrade of the high-voltage lines between the Mercator substation in Kruibeke and the Horta substation in Zomergem by installing HTLS conductors;
- ii) the construction of phase shifting transformers in Aubange;
- iii) the phases II & III of the Brabo project as well as;
- iv) the further reinforcement between the Netherlands and Belgium via the installation of additional phase shifting transformers and an HTLS upgrade. Besides these reinforcements, the NTC increase on the Belgian-Dutch border is also linked with the planned phase-out of the nuclear plants in Doel.

National view on resources adequacy concerns identified & highlighted (or not identified) in MAF 2017

The AdeqFlex2017-27 study uses a similar probabilistic approach as MAF, in order to identify the needed additional generation capacity, demand response or storage capacity needed on top of the capacity already considered as available (nuclear, RES, existing pump storage, CHP, existing demand side response on the market and planned interconnection capacity).

Based on the national criteria for adequacy (LOLE average <3 hours and LOLE P95 < 20 hours), the results for BE in MAF 2017 show:

For 2020:
MAF results show no significant LOLE for Belgium in 2020. This is in line with the results of the *base case* scenario considered by Elia in its AdeqFlex2017-27 and SR17-20 studies.

For 2025:
By the end of 2025, the nuclear phase-out is planned in Belgium. MAF results for Belgium in 2025 show that the LOLE indicators are above the national criteria of Belgium.

This can be explained by:

1. The different hypotheses within neighboring countries in terms of adequacy levels (mainly in France where adequacy criteria are not met in MAF). In the base case of Elia national studies, big countries are considered as adequate within their criteria (if existing), assuming these will take the necessary actions to remain adequate (when taking into account energy exchanges and within their national criteria). Adequacy in Belgium is very dependent on France's adequacy. In MAF 2025 FR is also above their adequacy standard. When an additional sensitivity on the available capacity in France was evaluated in the Elia national study on the need of strategic reserve for the next winters, the results showed that a reduction of 2.3 GW of capacity in France for winter 2016-17 leads to 400-500 MW additional capacity required in Belgium. It is also observed in MAF 2017 that Italy presents some adequacy problems which also might affect France and indirectly Belgium in times of scarcity.

2. According to the sensitivities performed in MAF 2017, it is expected that no more than 500MW could be associated with an extra need in BE with respect the assumptions considered for 2025 (note that the assumptions for 2025 already take into account some needed new built units to ensure adequacy). **It can be concluded that the national criteria for adequacy would be met for Belgium with a thermal capacity of 5.9GW (on top of existing CHP and biomass), including the above mentioned 500MW. This result is in line with the AdeqFlex2017-27 study given that**:

   a. No new biomass projects are considered for 2025 (this was the case in the AdeqFlex2017-27 study);

   b. This capacity is considered with outages. In the AdeqFlex2017-27, the so called "structural block" was calculated as theoretic capacity without outages;

   c. A slight increase of the demand is considered driven by additional electrification. The base case in the AdeqFlex2017-27 was based on zero growth consumption.

3. Finally, a sensitivity was performed on the 2025 case by imposing the 2020 NTC values (see Figure 12 in the main report). The NTC evolution towards 2025 for Belgium takes into account projects that are already underway/planned so the results presented in the above mentioned sensitivity for Belgium should be understood as a hypothetical sensitivity analysis to stress the importance of these infrastructure projects. The value of LOLE > 10 h/yr found does not necessarily relate to real adequacy concerns for Belgium.

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5.2.3 Bosnia and Herzegovina

In Bosnia and Herzegovina, we do not expect adequacy problems in periods until 2020 and 2025.

5.2.4 Bulgaria

National view on Generation and System Adequacy forecast for 2020 and 2025 identified in the MAF 2017 results

The LOLE base case results for Bulgaria in the MAF 2017 for 2020 are more or less in line with the current (2017-2018) levels (if not slightly less). This may be due to the fact that the predicted moderate growth in demand is heavily weather dependent, as household gasification in Bulgaria is very poor and the tendency is expected to remain the same in the near decade. The more favourable LOLE results for 2025 could in part be attributed to the strengthening of the interconnection capacity between BG and Greece [new 400kV power line Maritsa Iztok (BG) – Nea Santa (GR)].

5.2.5 Croatia

At the moment, Croatia is dependent on imports of electricity during the whole year, which is especially noticeable during the winter months. The capacity of interconnections is sufficient for Croatia to be always able to import enough electricity to cover domestic needs.

In the future, the increased construction of power plants is expected which will reduce dependence on imported electricity. However, in the coming decade Croatia will still be dependent on the import of electricity, especially during the winter months.

Finally, no significant adequacy problems are expected in periods until 2020 and 2025.

5.2.6 Cyprus

Load and annual demand forecast provided for 2020 and 2025

2020: Load 1265 MW, annual demand 5865 MWh
2025: Load 1490 MW, annual demand 6905 MWh
Please see attached the approved forecast for 2017-2026:
http://www.dsm.org.cy/nqcontent.cfm?a_id=2990&tt=graphic&lang=l2

Net Generating Capacity forecast provided for 2020 and 2025

2020: 1480MW conventional units, 175MW Wind Parks, 258MW Photovoltaics, 15MW biomass and 50MW solar thermal. These values are defined by the national action plan for RES penetration (revised) as can be found on the website of the Ministry of Energy (unfortunately only in Greek):
http://www.mcit.gov.cy/mcit/mcit.nsf/69d21a78b5ca690ac2256e67002bb48d/789553c60b9df658c225777d0033353d?OpenDocument

2025: 1520MW conventional units, 200MW Wind Parks, 350MW photovoltaics, 25MW biomass and 100MW solar thermal. Since there is no official action plan until 2025, these values are scenarios estimated by TSO.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

It should be stated that by 2025, the first phase of the construction of the EuroAsia interconnector (Israel -> Cyprus -> Greece) will be operational, providing an additional 500MW to the available capacity of Cyprus.

5.2.7 Czech Republic

No significant adequacy problems are expected in the 2020 to 2025 horizon.

The interconnection capacity is sufficient and therefore in the event of any sudden outage, the Czech Republic could import the necessary amount of electricity to cover domestic needs. We do not expect a change in the availability of interconnection capacity or any issues related to the risk of power plants mothballing during this period.

You can find more information in the ČEPS generation adequacy report.

https://www.ceps.cz/ENG/Cinnosti/Dispecerske_rizeni/generation_adequacy/Pages/default.aspx

5.2.8 Denmark

The current adequacy situation in Denmark is overall among the best in Europe. However, expectations are that reductions in thermal capacity over the coming years will worsen the market adequacy situation.

Both the national risk assessment and the MAF show that the expected adequacy is different for the two price zones. For Western Denmark, the increase in the lack of power adequacy is very low before 2025, while Eastern Denmark has a greater risk of adequacy issues.

The TSO continuously monitors the capacity situation and while not all details may be considered in the MAF, every year the TSO publishes a national security of supply report with greater detail on the Danish adequacy expectations.

5.2.9 Estonia

Although Estonian generation capacity is projected to be reduced in the 2020s, the MAF results identify considerably higher adequacy concerns compared to the national adequacy assessment. The national assessment does not identify the significant potential for unserved energy. The reasons for discrepancies are unclear, but are likely dependent on details of modelling tools and data used for the MAF. Furthermore, in the case of high unserved energy values, the electricity market prices would give clear signals to invest in market-based demand side response and generation. From the results, it is apparent that the Estonian adequacy level is correlated with Finnish adequacy, therefore, the Finnish national comments should also be referred to.

5.2.10 Finland

While the Finnish adequacy situation has tightened significantly during recent years and the trend is projected to continue, the level simulated in the MAF 2017 is considerably above national projections, and far above the level that is generally considered acceptable. National studies have projected LOLE generally around 3 h/a in a mid-2020s situation where 3rd AC interconnection between Finland and Sweden, expected by 2025, is complete. This is also the basis of the generation capacity projection. It is also presumed that other actions, such as peak load capacity reserves, would be economically justified long before >10 h/a LOLE levels were to be reached. Furthermore, very high LOLE values would also improve the profitability of market-based investments on the demand side response and flexible generation. Differences are assumed primarily to depend on details in data, simulation tools and techniques.

5.2.11 France

Load and annual demand forecast provided for 2020 and 2025

Over the past several years, RTE has observed a stabilisation of power demand in France, mainly due to energy efficiency measures and moderate economic growth. These efficiency measures will be further developed in the coming years, such that power demand is likely to contract in spite of sustained demographic growth, an uptick in economic activity and environment stimulating electricity-based solutions. Peak power demand should follow a similar decreasing trend.

Since 2015, a new legal framework known as ‘loi de transition énergétique pour la croissance verte’ with its planification document ‘programmation pluriannuelle des énergies’ supports new tools to optimise energy consumption in the country and set ambitious targets aimed at reducing the multi-energy consumption.

Every year, the generation adequacy report of RTE provides extensive information about electrical consumption in France.
Related links :
https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000031044385&categorieLien=id
http://www.developpement-durable.gouv.fr/programmation-pluriannuelle-energie
http://www.rte-france.com/sites/default/files/bp2016_complet_va.pdf

Net Generating Capacity forecast provided for 2020 and 2025
The net generating capacity forecast was mainly inspired by the new French energy transition bill entitled ‘Loi de la transition énergétique pour la croissance verte’. It forecasts a decrease in the nuclear power fleet in the mid 2020s to achieve a mix of production composed of 50% nuclear energy. At the horizon of 2030, this bill outlines the objective to complete this mix of production by 40% of renewables mainly driven by the development of wind and solar technologies. In addition to this deep transformation, coal power plants are expected to shut down at the horizon of 2023.
https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000031044385&categorieLien=id
http://www.developpement-durable.gouv.fr/programmation-pluriannuelle-energie

National view on the Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results
RTE produces an annual risk assessment through its national generation adequacy report on an horizon of five years. MAF results seem to be globally in line with national elements even if the LOLE is slightly greater, which is probably linked to a more stressful European context and a higher simulated consumption in France. The predominance of the 1985 years in the 34 climatic years may also impact the result in the second order.

The LOLE is expected to increase with the closing of numerous nuclear power plants at this time alongside coal units. However, this increase is limited mainly thanks to the reduction of energy consumption and the development of interconnectors.

The results associated with the mothballed units variant seem irrelevant due to the amount of unsupplied energy identified in the original simulation. Those units should find economic outputs in this context and stay on line.

http://www.rte-france.com/sites/default/files/bp2016_complet_va.pdf

5.2.12 FYR of Macedonia
At the moment, Macedonia depends on imports of electricity during the whole year. The cross-border capacity of interconnections is sufficient for the FYR of Macedonia to be always able to import enough electricity to cover domestic needs.

In the future, the increased production of domestic production capacities is expected which will reduce the dependence on imported electricity. Finally, no significant adequacy problems are expected in periods until 2020 and 2025. No need for specific comments has been identified.

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5.2.13 Germany

As a result of the strong growth of renewable energies and the expected reduction of conventional capacities due to economic and ecological reasons, system adequacy assessment has also become a central focus in Germany. The capacity situation in Germany is monitored periodically by the TSOs and the regulator. Instruments like a grid reserve and a capacity reserve have already been set up to avoid possible bottlenecks in the future. The amount and configuration of necessary reserve capacity is periodically identified within legal processes. At the same time, the amount and configuration is, particularly with a view to 2025, subject to several uncertainties.

The reserve capacity has an enormous impact on the system adequacy situation in Germany. It is important to understand that this capacity is not part of the simulations and not included in the results of the MAF 2017.

For the mothballing sensitivities 2020 and 2025, the German power plants were again revised. To build up a worst-case-scenario for Germany, power plants whose further operation in the market can be doubted based on new information (e.g. from the plant operator) have been removed from the sensitivities.

5.2.14 Great Britain

Load and annual demand forecast provided for 2020 and 2025

The load and annual demand forecasts for 2020 are based on the Base Case that was developed for the 2016 Electricity Capacity Report. Further details of this can be found on our Electricity Market Reform (EMR) Delivery Body website at the following link:
https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf

The load and annual demand forecasts for 2025 are based on the National Grid's Slow Progression scenario from the 2016 Future Energy Scenarios (FES). Further details of this scenario can be found on our FES website at the following link: http://fes.nationalgrid.com/

There are many different factors driving changes in electricity demand over the next 10 years. Generally, we have assumed that demand will decrease compared with today in the scenarios we have used in the MAF. However, other scenarios in the FES show a wider range, reflecting the uncertainty that demand could rise or fall over the period. The demand reductions assumed in the MAF are mainly driven by reductions in industrial and commercial demand, as well as energy efficiency gains in the residential sector. Increases in electric vehicles and low carbon heating technologies are assumed to partly offset this reduction.

The values provided by the National Grid have been adjusted in line with the ENTSO-E definition. This will explain any differences between the demand values used in the MAF and those in the National Grid reports.

Net Generating Capacity forecast provided for 2020 and 2025

The energy landscape in Great Britain is changing. There are a number of factors driving changes to decarbonise the electricity system in a way that is affordable for consumers without compromising security of supply. We expect this will lead to continued growth in renewable generation, particularly for more established technologies such as wind and solar. In addition, we are also expecting new capacity from CCGTs and interconnectors. This will help to offset the closures of existing, less efficient thermal plants and the decommissioning of nuclear power stations that reach the end of their lifespan.

The generation assumptions for 2020 and 2025 are based on the corresponding scenarios that were used for the demand (i.e. 2020 is based on the 2016 EMR Base Case and 2025 is based on Slow Progression 2016 – see the links above for further details). It may be worth pointing out that ENTSO-E use more conservative assumptions in the MAF for interconnector capacity compared to our national reports. This means that some of the interconnector capacity assumed to be available in our national studies has been excluded from the MAF. We have therefore replaced this capacity with additional thermal generation. This ensures that the adequacy results in the MAF are better aligned to our national reports and is justified on the grounds that if new interconnectors were unavailable, alternative capacity would be secured via the GB Capacity Market.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Great Britain has established a Capacity Market (CM) to ensure that we have sufficient available capacity to meet our Reliability Standard of 3 hours/year loss of load expectation (LOLE). The results for the MAF are in line with these expectations and we are not anticipating adequacy concerns in Great Britain.

Recent experience of the CM auctions has seen extra capacity being bought due to the low clearing prices. If this trend continues, then we expect the base case LOLE to be nearer 1 hour/year, well within the Reliability Standard. The generation assumptions in the MAF have not been updated to reflect this.

We have not proposed to model any additional mothballing for GB as the generation assumptions from the 2016 FES have already allowed for units at risk of mothballing. However, we recognise that such units in neighbouring markets could impact adequacy in Great Britain through reduced imports. We already allow for these risks in our modelling that supports the determination of interconnector de-rating factors used in the CM.

5.2.15 Greece

Increased RES penetration, namely photovoltaics, in the Greek generation system, as well as the shift of consumers to electricity for heating, has altered significantly the load patterns observed in the past. Adequacy concerns in the past were always concentrated on the peak loads during midday in the summer months. The last couple of years have shown that, while the total peak loads still occur in those hours, due to the operation of the photovoltaics (over 2.5 GW), peak loads faced by the transmission system now appear during evening hours and annual peaks are shifted to the winter months.

IPTO, the Greek TSO, recently notified the national Adequacy Study for the period 2017 – 2027 to the Regulatory Authority for Energy. Assumptions made regarding the evolution of demand and net generating capacity are very similar, if not in most cases identical to those used in the MAF 2017. For the evaluation of adequacy, IPTO calculates on an annual basis the probabilistic indices LOLE and EUE through probabilistic simulation (convolution techniques). A threshold of 3 hours/year for LOLE is considered satisfactory.

Based on the findings of the national study, it appears that generation adequacy over the next decade will be highly dependent on imports. Should current import levels remain feasible over the next years, the adequacy level of Greece should be satisfactory in most cases. Serious adequacy concerns are raised for the period 2020 – 2021 due to the simultaneous retirement of the lignite-fired units of Kardia and Amyndeo. The introduction of the new lignite-fired unit in Ptolemaida in 2022 seems to compensate for the loss of the other units and LOLE values from then on are, in most examined cases, below the set target. In 2025, however, the retirement of another lignite-fired unit and the assumption of the load of Crete by the generating system of the mainland leads to new adequacy concerns and increased dependency on imports. The MAF 2017 results validate the concerns identified.

In the MAF 2017, the hypothetical assumption of 2 CCGTs mothballing was examined. While plans for the early retirement of CCGT units have not been announced or suggested, the well-known missing money problem of this type of unit raises concerns over such an event. The results of the national adequacy study as well as of the MAF 2017 show that the early retirement of 2 CCGT units would have a detrimental effect on the adequacy level of Greece.

5.2.16 Hungary

The assessment shows that Hungary will continue to rely heavily on imported electricity due to the lack of new domestic investments in the mid-term. However, the overall adequacy situation depends to a great extent on the availability of excess generation capacity in the region that is highly influenced by the overall economic and market framework.

The future commissioning of the first new unit of Paks Nuclear Power Plant (NPP) could contribute to the improvement of the overall adequacy situation in Hungary.

The risk of exposure to premature decommissioning or mothballing was evaluated using a simplified approach that considered remaining lifetime, present annual average capacity factor, and other relevant information from power plant operators. As the projected commissioning date of the new unit of Paks NPP is very close to 2025, a slight delay could have a large impact on the adequacy situation. Therefore this has also been included in one sensitivity case.

5.2.17 Ireland

Load, annual demand and Net Generating Capacity forecast provided for 2020 and 2025

In the short term, Ireland has sufficient generation to adequately meet the forecast demand. We expect the continued expansion of renewable generation, mostly wind and biomass, to meet Ireland's 40% RES-E target in 2020. The completion of the second North-South Interconnector with Northern Ireland will contribute to the increased security of supply for both jurisdictions.

Demand is growing, and is expected to continue to grow, mainly driven by new large users such as data centres. Even though some older plants are due to be decommissioned because of emissions restrictions (IED), it is likely that there will be sufficient generation to meet this growing demand by 2025. However, if an additional plant closes due to further emissions restrictions, then it is likely that there will be a need for new generation or additional demand side measures as we look forward to 2025.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017

The electricity market in Ireland, the Integrated Single Electricity Market (ISEM), operates in conjunction with Northern Ireland. As part of the electricity market there are annual capacity auctions to procure sufficient generation or demand-side responses to meet the adequacy standard. Therefore it can be expected that, even with the older generation shutting down, the 4-year-ahead capacity auction will procure a new generation or demand-side response sufficient to ensure a security of supply.

The 2025 Mothball scenario in the MAF 17 provides an indication of what could happen in the absence of the ISEM capacity market. In this scenario, some plants are assumed to be unable to recover their costs through the energy-only market and are thus forced to mothball or close. The resulting LOLE would be outside the Adequacy Standard of 8 hours.

5.2.18 Italy

Load and annual demand forecast provided for 2020 and 2025

Load and annual demand forecasts are in line with the lastest TERNA publications:

- National Development Plan 2017: https://www.terna.it/it-it/sistemaelettrico/pianodisviluppodellarete/pianidisviluppo.aspx
- Italian Forecast Demand 2016-2026 http://www.terna.it/it-it/sistemaelettrico/statisticheeprevisioni/previsionidelladomandaelettrica.aspx

Net Generating Capacity forecast provided for 2020 and 2025

Generation portfolio assumptions are in line with the fastest National Development Plan published by TERNA (see https://www.terna.it/it-it/sistemaelettrico/pianodisviluppodellarete/pianidisviluppo.aspx).

In recent years, the Italian Power System has faced a significant reduction of the conventional (thermoelectric) power fleet; between 2012 and 2016, about 15 GW installed generation was phased out. The impact of an additional decommissioning of 5 GW has been considered in this report in the mothballing sensitivity, see paragraph 4.2.

As the above mentioned trend has already created a scarcity situation, in order to prevent further shut-downs and keep the power system adequate, a capacity mechanism has been proposed by the Italian decision maker (Ministry and NRA): the consultation process is at an advanced status.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017

With regards to the 2025 scenario, even in the base case (less conservative than the 'mothballing' sensitivity) the MAF's outcomes show a risk of resource adequacy scarcity in the north of Italy (market nodes Italy North and Italy Central-North) that are strongly inter-linked with the simultaneous adequacy scarcity issue identified in neighbouring countries (e.g. France and Switzerland). Moreover, the MAF's results show the potential impact of stressful climate conditions (such as the cold spell events faced by France in 1895 and 1987, and - more recently – in January 2017) on the national reliability indicators: namely, considering such rare but possible extreme climate events result in an increase of 50% of Loss of Load Expectation.

Due to the peculiarity of their system, the generation adequacy of the two main Islands – Sicily and Sardinia – are subject to regular monitoring from TERNA via ad-hoc sensitivity simulations. With regards to Sicily, the adequacy risk identified in the MAF 2017 confirms the need for further sensitivity to account for the specificity of the AC interconnections towards the Continent and to fine tune the modelling of the Italy-Tunisia interconnection (to assess the possible benefits in case of imports from Tunisia.). With regards to Sardinia, considering the adequacy concern identified in the National Adequacy studies performed following the publication of the MAF 2016, TERNA has decided to anticipate the commissioning of the PCI's candidate 'SA.CO.I 3' project.

5.2.19 Latvia

Load and annual demand forecast provided for 2020 and 2025

The TSO forecasts that annual peak load will increase by 2% from year to year on average up to 2025. The very rapid increase of demand is not expected, therefore the demand has to be covered without load shedding and according to the planned annual load increase rate.

Net Generating Capacity forecast provided for 2020 and 2025

The total installed capacity for the Latvian power system will be around 3.12 GW in 2020 and 3.29 GW in 2025. It is planned that around 42 MW could be mothballed in 2025 due to inefficiency reasons and the change in the subsidy scheme for energy production from fossil fuels in the area of Latvia. In this case, the total capacity will be reduced to 3.24 GW respectively.
The base power plants will be fossil power plants with an installed capacity of 1.08 GW in 2020 and 2025. The installed capacity on hydro power plants (run of river) is around 1.62 GW in 2020 and 2025, but only the part of capacity could be available for the load and cover demand due to water inflow limits on Daugava river. The rest of the capacity is from other RES (wind, bio fuels and solar) – 0.27 GW in 2020 and 0.36 GW in 2025. Some off-shore wind turbines are expected in the year 2025 which will help to cover the load and overall system demand. In the Latvian power system there are other-non RES generation plants around 0.12 GW which are small CHPs distributed within the area of Latvia and these will help to cover the load and demand in 2020 and 2025.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

According to the MAF's outlook, the generation for 2020 will be adequate during the whole year and Latvian TSO expects that the available capacity can cover the load and demand without load shedding. In 2025, the TSO is expecting to cover the load during the whole year, but some unexpected problems regarding fossil fuel generation can occur which can lead to problems with power system adequacy, as was identified in the MAF study.

5.2.20 Lithuania

Load, annual demand and Net Generating Capacity forecast provided for 2020 and 2025
Load and annual demand forecast for 2020 and 2025 for Lithuania is presented following the data collection guidelines for the Mid-term Adequacy Forecast.

Annual demand is forecasted with regards to the most likely projections of economic growth, development of electric vehicles and heat pumps in Lithuania. Energy efficiency measures are also considered. The annual demand growth is expected to be faster until 2020 and slower after 2020.

Net Generating Capacity forecast (for RES and thermal power plants) is prepared according to producers' information, the National Energy Independence Strategy of the Republic of Lithuania, National Renewable Energy Action Plan and other legal documents. A decrease in gas fuel capacity and an increase of RES capacity (mainly wind capacity) is foreseen during the whole period from 2017 to 2025.

National view on resources adequacy
The results of the National Generation Adequacy forecast show that Lithuania does not have enough internal capacity to cover demand during the whole analysed period. Therefore, a large amount of the Lithuanian power system demand is covered by imported electricity. The available capacity of interconnections ensures technical possibilities to import a sufficient amount of electricity to cover the lack of generating capacity.

5.2.21 Luxembourg

Load and annual demand provided for 2020 and 2025 for Luxembourg are expected to grow. Renewable generation capacity, especially wind and solar, is expected to increase in the next few years. Other generation capacity, mostly gas cogeneration units, are expected to be decommissioned due to a reduction of the support schemes.

5.2.22 Montenegro

Load and demand forecast in Montenegro will highly depend on the aluminium and steel industry power demand forecast which significantly decreased during the period of the financial crisis. The electricity consumption forecast is based on the national highest estimations of energy consumption growth until 2025, along with efficiency measures according to the Energy Development Strategy.

The NGC is expected to be increased. Generation expansion planning is based on the National Energy Strategy Development of Montenegro until 2030. There are plans for several new hydro power and thermal plants. There is also expected to be an increase in capacity from renewable sources from 2020, primarily from wind and hydro. The trend of construction of renewable energy sources will continue in 2025.

For the considered transmission period, Montenegro fulfils the criteria of adequacy. The Simultaneous Import and Export Capacities are assumed to be at the maximum NTC. This could not be possible without the new interconnection lines. Montenegro will be interconnected with Italy by HVDC undersea cables and also by foreseen projects of 400 kV interconnections with the neighbouring countries. The new interconnections will increase security of supply and also capacities for transit and across border markets.

5.2.23 Northern Ireland

Load, annual demand and Net Generating Capacity forecast provided for 2020 and 2025

The load in Northern Ireland is expected to grow modestly. We expect a continued expansion of renewable generation, mostly wind, solar and biomass over the next few years. In the short term, some plants are expected to close because of emissions restrictions. This, coupled with the expected delay to the second North-South Interconnector with Ireland, could lead to a shortage of plants by 2020.

The second North-South Interconnector with Ireland is expected to be available from 2021 – this will improve the security of supply situation, as plants in one jurisdiction can fully contribute to the security of supply in the other.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017

The electricity market in Northern Ireland, the Integrated Single Electricity Market (I-SEM), operates in conjunction with Ireland. As part of the electricity market, there are annual capacity markets to procure sufficient generation or demand-side response to meet the adequacy standard. The commissioning of the second North-South Interconnector is important for the secure and efficient operation of the I-SEM.

5.2.24 Norway

Compared with Statnett's Long-Term Analysis, the expected exports are somewhat lower in most of the MAF 2020 and 2025 scenarios/sensitivities. This may be caused by some double counting of heat pumps in the MAF scenarios. In addition, hydro generation dry years may be 15-20% lower than the normal generation. Regardless, this does not cause any problems, and ENS and LOLE are low in these years in Norway.

5.2.25 Poland

Demand

For the MAF 2017, PSE used a new demand forecast prepared by the third party at the end of 2016. This forecast assesses the level of annual demand growth until 2025, amounting to about 2%. An increase in the forecast is based on the following premises:

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1. High energy increase recent years – more than 2%.
2. The planned continuation of economic growth (and even acceleration) in Poland, which will trigger the higher consumption.
3. Lower saturation of electricity in Poland in comparison to other countries in Western Europe - consumption (kWh/person) in Poland is about two times lower than in France or Germany – PSE expects to be closer in the future.

In addition to the forecast there is an ambitious plan for electro mobility, strongly supported by the Polish Government.

NGC

Net Generating Capacity (NGC) data for the MAF 2017, based on Best Estimate scenarios for 2020 and 2025, were delivered in October 2016 and based on information from producers collected until the end of April 2016.

There are eight new commissioned big fossil fuel units considered with projected gross installed capacity as follows:

1. hard coal: 5 units with total NGC amounting to c.a. 4450 MW,
2. lignite: 1 unit 450 MW,
3. gas: 3 units with the total NGC amounting to c.a. 1510 MW.

The estimated NGC of these units amounts to 6.4 GW. All of these units are expected to be commissioned before 2020, except for the lignite unit, which is forecasted to be commissioned during 2020 and is not considered for the 2020 scenario. A development of RES is assumed until 2025 up to 11.6 GW (including the renewable part of hydro and other renewable sources).

The development of thermal NGC (both commissioning and decommissioning of generation resources) considers the influence on Best Available Techniques (BAT) Conclusions. Due to the fact that most of the fossil fuel generation resources in Poland will be affected by BAT standards, PSE prepared two scenarios:

1. Modernisation scenario, where favourable economic conditions allow the necessary investments in generations resources to be carried out in order to fulfil BAT standards. In practice it means capacity market implementation in the form of initial legislation has been already prepared by the Government.
2. Decommissioning scenario, in which a part of capacity will not be adjusted to fulfil BAT standards due to unfavourable economic conditions. The level of decommissioning already assessed in the modernisation scenario will be enlarged by an additional 3.4 GW of power until 2020 and 6.4 GW until 2025 (in fact until the end of 2021). It is worth mentioning that 6.4 GW amounts to 27% of the total thermal dispatchable power units from the modernisation scenario in 2025.

The development of RES NGC was done on the basis of the draft documents and Government statements regarding the new Energy Policy of Poland until 2050.

NTC

PSE forecasts that the following NTC will be available in 2020 and 2025:

NTC 1) [MW]	2020	2025
PL → DE+CZ+SK 2)	2500	3000
PL → SE	300	600
PL → LT 3)	500	500
PL → UA 4)	0	500
DE+CZ+SK 2) → PL	500	2000
SE → PL	600	600
LT → PL 3)	500	500
UA → PL	220	720
PL export	3300	4600
PL import	1820	3820

1. Values presented in the table are NTC values forecasted in the yearly horizon at peak time. This is the state as of January 2017. Capacity offered to the market, especially for monthly / daily auction, may differ from the values shown above.
2. PSE S.A. gives aggregated data for the PL synchronous profile with DE+CZ+SK based on the NTC method. The import capacity on Polish synchronous profile has partially considered the possible congestion resulting from unscheduled flows through Poland from the west to the south. Nevertheless, a situation may occur when the forecasted level of import capacity will not be fully available to cover tight power balance periods / hours due to the high level of unscheduled flows. Values may change after the implementation of the correct coordination of capacity calculation and allocation process in the meshed centre of the Continent.
3. Back-to-back connection.
4. Radial connection using 220kV Zamość-Dobrotvir line at the moment. For the MAF 2017 simulations, possible imports from Ukraine were not considered.

Adequacy results

Base Case scenario

As can be found in the report, simulations prepared for the MAF 2017 demonstrated a material hours of LOLE in the base case scenario for both 2020 and 2025. Adequacy results from the MAF 2017 are the subject of careful analysis, however the following information has to be provided in the report:

1. Increase of import capacity is a key issue for Poland. Available import capacities on synchronous The Polish profile with DE, CZ and SK is very low, even though Poland is strongly connected with the CE synchronous region using 10 HV tie-lines, of which 6 refer to voltage 400 kV. For years, the Polish power system has been affected by unscheduled flows through Poland from the west towards the southern border. The reason for these flows are market transactions concluded outside of Poland, which are the result of the development of subsidised (thus attractive from the cross-border trading point of view) renewable energy sources in the northern part of Continental Europe (CE). PSE takes the position that currently there is no proper coordination of capacity calculation and allocation process in Continental East Europe (CEE), therefore the unscheduled flows from the northern part of CE to the south resulting from above-mentioned transactions frequently result in a violation of the N-1 criteria. The real sustainable solution for the unscheduled flows problem is the implementation of the correct coordination of capacity calculation and allocation in the meshed centre of the Continent, i.e. a flow-based approach in the proper region, which means Continental Europe East, West and South with properly configured bidding zones (control blocks at least).

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2. DSR potential was not fully considered. This is due to fact that DSR in Poland is being procured as a service of interventional load reduction (upon the TSO's request) provided to the TSO by individual final users or load aggregators. Activation decisions are based on curtailment price offers which can be significantly above the current balancing market cap. Therefore it cannot be treated as a fully market measure according to MAF methodology. Currently, PSE has contracted 362 MW of DSR, which may be activated in case of inadequacy. As of the first half of 2018, the Polish TSO is planning to increase the DSR level to at least 500 MW.
3. As mentioned in the report, the maintenance level in Poland in 2020 was an important issue during the ongoing simulations. The level was relieved and finally decreased, however it is still much higher than the ENTSO-E average. This is the result of the required modernisation of units to fulfil BAT standards. For PSE the maintenance schedule in years 2019-2021 is still the substantial issue being constantly coordinated and optimised.

Mothballing scenario
An extremely significant adequacy threat appeared in the mothballing both for the years 2020 and 2025. This is due to fact that a huge amount of thermal capacity requiring modernisation to fulfil BAT standards is the subject of economic decommissioning due to current unfavourable market conditions. Based on the information from plant operators, PSE assesses that the decommissioning level may reach 6.4 GW in 2025 (3.4 GW till 2020).

Poland takes the view that concurrent to the ongoing work on the implementation of the European common market (which should significantly increase the capacity towards Poland), a supplementary solution to the Energy Only Market means a capacity market should be introduced. A capacity market will reduce the missing capacity problem (limited amount of reliable capacity being currently commissioned in EU causing serious adequacy threats) and will address current market distortions or failures caused by, e.g. extensive RES support, EU ETS and a lack of proper scarcity price signals. The Polish government has announced capacity auctions model implementation and proposed draft legislation.

5.2.26 Portugal

Load and annual demand forecast provided for 2020 and 2025
The electricity demand in Portugal provided for the MAF 2017 in 2020 and 2025 is based on national 'central' growth estimations with efficiency measures as defined in the revised 'National Energy Efficiency Action Plan'. The projected number of additional electric vehicles is estimated according to the 'National Renewable Energy Action Plan'. No Load Management is assumed.
These forecasts correspond to long-term estimations performed in 2016 for the national adequacy report that were published by the Portuguese Directorate-General for Energy and Geology (http://www.dgeg.pt?cr=15695). According to the 'central scenario' specified in this report, annual demand in Portugal is expected to reach nearly 50 TWh in 2020 and 51 TWh in 2025, corresponding to an average annual growth of 0.4% compared to the 2016 annual demand of 49.3 TWh.

Net Generating Capacity forecast provided for 2020 and 2025
The current Portuguese electricity system is characterised by high penetration levels of renewable energy that are already able to supply more than 50% of the annual electricity demand. National strategies for energy development support the further growth of RES by setting new goals for 2020 and beyond, mainly by increasing pumped-storage hydro, wind and solar capacity.
The MAF expected scenario of generating capacity for 2020 and 2025 is based on national energy policy drivers defined by the Portuguese government (as foreseen in 2016), whereas studies developed by REN have assessed the compliance of national Security of Supply standards.
Main developments in generation include the increase of renewable energy sources until 2020, particularly wind power, reaching a total of 5500 MW, solar power with a total of 1800 MW, as well as large hydro power plants exceeding 7000 MW (of which 2700 MW is pumped storage). Additional large hydro (+1 155 MW)

is foreseen between 2020 and 2025, most of it increasing pumping capacity (+880 MW), which is necessary to compensate for the volatility of intermittent generation from wind and solar. Decommissioning of some old coal and gas power plants (1570 MW) is expected between 2020 and 2024.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017
In both 2020 and 2025, foreseen generation capacity is expected to comply with Portuguese Security of Supply standards that comprise two equally binding parts related to Adequacy and Security aspects: LSI (probabilistic Load Supply Index) >= 1 with 95% and 99% exceeding probability (Adequacy) and LOLE ≤ 5 hours/year that also considers operational reserve requirements (Security).
Therefore, results from the national assessment of security of supply in 2020 and 2025 are consistent with the MAF 2017 indicators (for the Base Case and Sensitivities), confirming the LOLE and ENS that are nearly zero.

5.2.27 Romania

Load and Generation estimates provided for 2020 and 2025 in MAF are in line with the expected national forecasts.

5.2.28 Serbia

Load and annual demand forecast provided for 2020 and 2025
In the period 2016-2020, an increase of electricity demand is estimated with an average annual rate of 1.05 %, corresponding to a consumption of 41.8 TWh in 2020. The forecast of the annual demand increase is around 1.1 % for the period 2021-2025 and amounts to a consumption of 43.5 TWh in 2025.

Net Generating Capacity forecast provided for 2020 and 2025
Main developments in generation include the increase of renewable energy sources until 2020, particularly wind power, reaching 850 MW. The most significant increase in NGC is expected due to the commissioning of three coal units (approximately 950 MW) and three gas units (approximately 160 MW).
The increase of the capacity from renewable sources until 2025 is expected to come primarily from wind power, reaching around 200 MW. The net generating capacity of TPP on fossil fuel is expected to decrease, mainly because of the Industrial Emissions Directive and Large Combustion Plant Directive of the EU. The decommissioning of old coal and gas power plants (800 MW) is expected between 2017 and 2025.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017
The national adequacy analysis shows that no problems are expected in the period until year 2025, because NGC is higher than demand and there is a large number of interconnection borders (eight). These results can be proven by the results of particular MAF probabilistic simulations, and confirmed by Adequacy Indicators (ENS and LOLE). MAF results show that expected values for ENS are an extremely small percentage of the forecast demand for 2020 and 2025.

5.2.29 Slovakia

The conclusion of the MAF 2017 base scenario (no mothballing considered) that the generation in Slovakia is expected to be adequate to cover the Slovak demand for the time horizons 2020 and 2025, fully confirms the conclusion of The Slovak National Development Plan (NDP) provided by SEPS. This MAF 2017 scenario considers the on-time realisation of all planned development projects, where the main projects are the commissioning of two units of the new nuclear power plant EMO 3,4 (approximately 995 MW netto) and the increase of the SK - HU cross-border capacity by the commissioning of the new SK – HU lines. It is important to note that the MAF 2017 and The Slovak NDP conclusions are valid only if the evolution of the national demand does not exceed the expected values[20].

Concerning units under potential risk of mothballing (625 MW netto) it is necessary to note that 411 MW in gas-fired technology is already out of operation in the present time and the 214 MW is in restricted operation mode. In the 2020 time horizon, all of these generating units are included in the NGC as capable of operation. It is difficult to predict the future operation of these gas-fired units, as it mainly depends on the future evolution of the market prices (electricity, fuel, CO2, etc.). Therefore these gas-fired units are included in the category 'units at risk of being mothballed' in 2020. In the 2025 time horizon, these units are considered as decommissioned.

Hard-coal fired units (approximately 197 MW netto) are at risk of mothballing in the 2025 time horizon due to uncertainty, similar to that described above for the gas-fired units.

Considering the above mentioned mothballed capacities, SEPS does not assume problems for the generation adequacy in both time horizons, even if the MAF 2017 results show a negligible deterioration of ENS and LOLE values.

In case of any SK generating unit accidental outage, it will be possible to cover the missing amount of electricity through the imports from abroad, which proves the sufficiency of the import capacity on the SK cross-border profiles in 2020 and 2025.

Based on The Slovak NDP analysis, SEPS assumes a possible inadequacy in the system reserves, when mothballing (or decommissioning) the above mentioned units in 2020 and 2025 under severe conditions is considered, as these units represent an essential part of the flexible NGC able to provide the system reserves.

5.2.30 Slovenia

National TSO studies on generation adequacy show that Slovenia currently meets the LOLE recommendations, considering around 350 MW of import. Furthermore, in the most optimistic scenario LOLE is expected to slowly decrease from 2017 onwards, which is due to new hydro power plant units on the Sava River and a new pump-storage unit on the Drava River. However, if for any reason all planned investments do not meet the expected time limit, it is still expected that LOLE will remain at the same level.

The unavailable capacity is higher in winter than in summer because of the unavailability of PV generation at that time and insufficient hydrology. It should be noted that hydro power plants hold a 27% share of all installed power in Slovenia. This share has dropped due to the new lignite thermal unit in Šoštanj with 553 MW, which obtained its operating license last year. It should be further noted that the Slovenian power sector is relatively small in comparison to most other ENTSO-E countries, thus an installation of a bigger unit has a higher influence on the energy production mix.

In contrast, interconnectors also have an important role in terms of electricity exports. Until 2025, the interconnection capacities will increase because of the new interconnection lines with Hungary and Italy (new interconnectors to Italy are still under consideration) and also because of the reinforcement of the internal grid. The effective integration of the Slovenian transmission network into the ENTSO-E system through all four neighbouring countries minimises the adequacy risks.

[20] See the Ten Year Network Development plan of SEPS

5.2.31 Spain

The present analysis does not show adequacy problems for Spain and their ENS and LOLE should be understood as being zero/negligible. But our concern is the coal installed capacity considered for the two horizons. Considering the recent input from the agents about the investments in the thermal units (mainly coal units) to adapt the plants to the European Emissions Directive requirements, it is likely that more units than were expected for 2020 will be decommissioned for that period. This could mean a reduction of 50% in respect to the coal installed capacity included in the present analysis. Also, it could affect the thermal installed capacity foreseen in 2025.

5.2.32 Sweden

Sweden has a strategic reserve of currently 750 MW, of which 25% should be demand response. The procurement of the generation part until 2020 was finalised this spring. The results show that one of the units expected to be decommissioned remains available until 2020. The strategic reserve is said to be a temporary solution and the ambition is that it should be phased out by 2025, but if there are adequacy concerns the strategic reserve may be prolonged.

Sweden also has a high share of power intensive industry. Some of these industries are active in both spot and FRR markets. In periods with a tight capacity margin and high price, they may reduce consumption.

5.2.33 Switzerland

Load and annual demand forecast provided for 2020 and 2025

The annual load for Switzerland is consistent with the Swissgrid's 'Strategic Network 2025' (published in 2015) network planning scenario 'On Track', which in turn was constructed to be in line with the Swiss 'Energy Perspectives 2050 New Energy Policy Scenario'. Effectively, it means that the values for MAF were either directly taken from the scenario when available or derived in a consistent way when not available or published.

Net Generating Capacity forecast provided for 2020 and 2025

The installed generation capacity for Switzerland is consistent with Swissgrid's 'Strategic Network 2025' (published in 2015) network planning scenario 'On Track', which in turn was constructed to be in line with the Swiss 'Energy Perspectives 2050 New Energy Policy Scenario'. Effectively, it means that the values for the MAF were either directly taken from the scenario when available or derived in a consistent way when not available or published.

National view on resources adequacy concerns identified & highlighted (or not identified) in the MAF 2017

The 2020 results in the MAF 2017 were as expected, i.e. one would not expect adequacy problems for Switzerland, based on the methodology and the underlying modelling assumptions.

The 2025 results show some possible scarcity situations. However, the modelling of the reserves exaggerates the amount of energy to be used for balancing in Switzerland and thus increases the adequacy risk. Currently, the reserves are modelled by adding them as a constant load to the load time series to ensure that there is always enough energy (water) available for the dispatch of reserves. Since Swiss reserves are mainly hydro power stations, this approach reserves too much water which is normally used for peak hours rather than for base load. It is too pessimistic to assume that the reserves are fully used in every hour of the year.

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In general, it should be noted that the modelling of hydro power stations and especially the modelling of water availability is crucial for the assessment of the Swiss adequacy situation.

5.2.34 The Netherlands

TenneT issues a National generation adequacy report every year, with the 2017 edition to be published this October.
The 2016 report can be found here:
https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/Rapport_Monitoring_Leveringszekerheid__2015-2031_.pdf

In addition, TenneT is actively involved in the bi-annual PLEF adequacy study, where the adequacy developments expected in the PLEF Region (Austria, Belgium, France, Germany, Luxemburg, Switzerland and the Netherlands) in the upcoming seven years are addressed. The next PLEF report is expected to be published at the end of 2017.

TenneT uses the same starting points regarding the developments on the supply and demand side in the Netherlands for the analyses related to the National, Regional and Pan European reports. The outcomes of the MAF 2017 report are in line with the other studies, showing no adequacy issues for the Netherlands, but with tighter adequacy margins occurring in the longer (> 3 years) term.

5.3 Market tools used

5.3.1 ANTARES

ANTARES - A New Tool for the generation Adequacy Reporting of Electric Systems – is a sequential Monte-Carlo multi-area adequacy and market simulator developed by RTE. The rationale behind an adequacy or market analysis with a Monte-Carlo sequential simulator is the following: situations are the outcome of random events whose possible combinations form a set of scenarios so large that their comprehensive examination is out of the question. The basis of the model is an optimiser connected in output of random simulators.

Antares has been tailored around the following specific core requirements:

a) Representation of large interconnected power systems by simplified equivalent models (at least one node per country, at most #500 nodes for all Europe)
b) Sequential simulation throughout a year with a one hour time-step
c) For every kind of 8760-hour time-series handled in the simulation (fossil-fuel plants available capacity, wind power, load, etc.), use of either historical/forecasted time-series or of stochastic Antares-generated time-series
d) Regarding hydro power, definition of local heuristic water management strategies at the monthly/annual scales. Explicit economic optimisation comes into play only at the hourly and daily scales (no attempt at dynamic stochastic programming)
e) Regarding intermittent generation, development of ***new stochastic models*** that reproduce correctly the main features of the physical processes (power levels statistical distribution, correlations through time and space)

At its core, each Monte-Carlo (MC) year of simulation calls for two different kinds of modelling, the first one being devoted to the setting up of a ***'MC scenario'*** made up from comprehensive sets of assumptions regarding all technical and meteorological parameters (time-series of fossil fuel fleet availability, of hydro inflows, of wind power generation, etc.), while the second modelling deals with the economic response expected from the system when facing this scenario.
The latter involves necessarily a layer of market modelling which, ultimately, can be expressed under the form of a tractable ***optimisation problem***.
The former 'scenario builder' was designed with a concern for openness, that is to say to ensure the use of different ***data pools***, from a 'ready-made' time-series to an entirely 'Antares-generated' time-series.
The figure below describes the general pattern that characterises Antares simulations.

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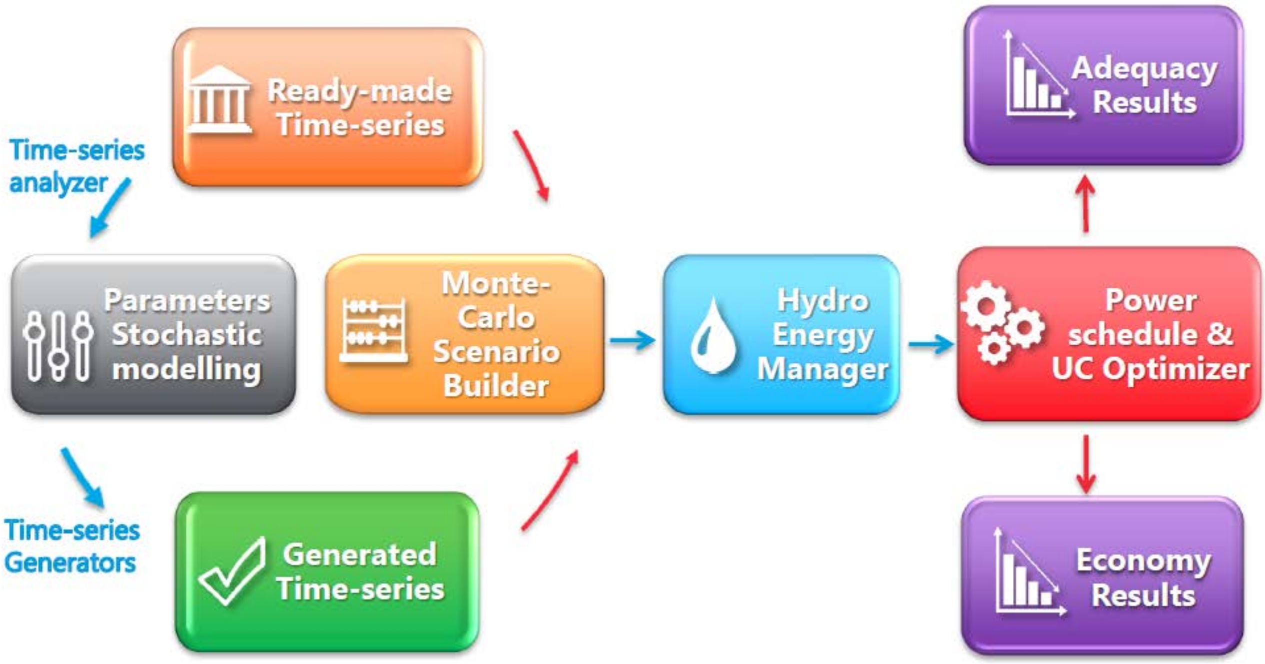

Time-series analysis and generation

When ready-made time-series are not available or too scarce (e.g. only a handful of wind power time-series) for carrying out proper MC simulations, the built-in Antares time-series generators aim to fill the gap. The different kinds of physical phenomena to model call for as many generators:

- The daily thermal fleet availability generator relies on the animation of a most classical three-state Markov chain for each plant (available, planned outage, forced outage)
- The monthly hydro energies generator is based on the assumption that, at the monthly time scale, the energies generated in each area of the system can be approximated by Log Normal variables whose spatial correlations are about the same as those of the annual rainfalls.
- The hourly wind power generator is based on a model [5] in which each area's generation, once detrended from diurnal and seasonal patterns, is approximated by a stationary stochastic process.

The different processes are eventually simulated with the proper restitution of their expected correlations through time and space. The identification of the parameters that characterise at best the stochastic processes to simulate can be made outside Antares but this can also be achieved internally by a built-in historical time-series analyser.

Economy simulations

When simulating the economic behaviour of the system in a 'regular' scenario (in the sense that generation can meet all the demand), it is clear enough that the operating costs of the plants disseminated throughout the system have a heavy bearing on the results of the competition to serve the load. As is known, the most simple way to model the underlying market rationale is to assume that competition and information are both perfect,

in which ideal case the system's equilibrium would be reached when the overall operating cost of the dispatched units is minimal.
Altogether different is the issue of the time-frame for the economic optimisation: realism dictates that optimisation should neither attempt to go much further than one week (leaving aside the specific case of the management of hydro resources) nor be as short-sighted as a one-hour snapshot.
Put together, these assumptions lead, for economic simulations, to the formulation of a ***daily/weekly linear program***, whose solution can be found using the standard simplex algorithm.
Yet, since a very large number of weekly simulations are carried out in a row (52 for each MC year, several hundreds of MC years for a session) and considering the fact that many features of the problems to be solved may be transposed from one week to the next (e.g. grid topology), it proved very efficient to implement in Antares a variant of the ***dual-simplex algorithm*** instead of the standard algorithm. For each area of the system, the main outcomes of economy simulations are the estimates at different time scales (hourly, daily, weekly, monthly, annual) and through different standpoints (expectation, standard deviations, extreme values) of the main economic variables:

- Area-related variables: operating cost, marginal price, GHG emissions, power balance, power generated from each fleet, unsupplied energy, spilled energy.
- Interconnection-related variables: power flow, congestion frequency, congestion rent (flow multiplied by the difference between upstream and downstream prices), congestion marginal value (CMV - decrease of the overall optimal operating cost brought by 1MW additional transmission capacity).

<u>Grid modelling</u>

The tool offers different features which, combined together, give a versatile framework for the representation of the grid behaviour.

- Interconnectors (actual components or equivalent inter-regional corridors) may be given hourly transfer/transmission asymmetric capacities, defined with a one-hour time step.
- Asymmetric hurdle costs (cost of transit for 1MW) may be defined for each interconnector, again with a one-hour time-step.

An arbitrary number of either equality, two-side bounded or one-side bounded linear constraints may be defined on a set of hourly power flows, daily energy flows or weekly energy flows. In parts of the system where no such constraints are defined, power is deemed to circulate freely (with respect to the capacities defined in [a]). In other parts, the resulting behaviour depends on the constraints definition. A typical choice consists in obtaining DC flows by using either PTDF-based or impedance-based hourly linear constraints. Note that the latter is a usually more efficient way to model the grid because it is much sparser than the former. Other constraints may be defined to serve quite different purposes, such as, for instance, the modelling of pumped-storage power plants operated on a daily or weekly cycle.

5.3.2 BID

BID3 is Pöyry Management Consulting's power market model, used to simulate the dispatch of all supply and demand in electricity markets. Equally capable of covering both short-term analyses for trading and long-term scenarios, BID3 is a fast, powerful and flexible tool that provides comprehensive price projections in an intuitive and user-friendly interface.

What is BID3?

BID3 is an economic dispatch model based around optimisation. It models the hourly generation of all power stations on the system, considering fuel prices and operational constraints such as the cost of starting a plant. It accurately models renewable sources of generation such as hydro, reflecting the option value of water, and intermittent sources of generation, such as wind and solar, using detailed and consistent historical wind speed and solar radiation.

What is BID3 used for?

BID3 provides a simulation of all the major power market metrics on an hourly basis – electricity prices, dispatch of power plants and flows across interconnectors. BID3 can be run for both short term market forecasts and long term scenario analysis. It is the perfect tool to assess the market value of power plants under a range of situations, through outputs like market revenue, load factor, fuel and CO2 costs, or the number of starts per year. These results can be computed for a single plant, or for an entire project portfolio for planning and investment purposes, assessing the effect of both internal decisions and a large range of external factors. BID3 can be used for the economic assessment of interconnectors, outlining flows and congestion rent, as well as socioeconomic and other commercial benefits. BID3 has a very detailed description of intermittent renewable sources, basing generation on historically observed wind speed and solar irradiation data.

BID3 combines state-of-the-art simulation of thermal-dominated markets, reservoir hydro dispatch under uncertainty, demand-side response and scenario-building tools.

Key features:

i. Sophisticated hydro modelling, incorporating stochastic Dynamic Programming to calculate the option value of stored water.
ii. Detailed modelling of intermittent generation, such as wind and solar, allowing users to understand the impact of renewables and requirements for flexibility.
iii. Advanced treatment of commercial aspects, such as scarcity rent and bidding above short-run marginal cost.

5.3.3 GRARE

GRARE, Grid Reliability and Adequacy Risk Evaluator, is a powerful computer-based tool of Terna, developed by CESI[21], that evaluates reliability and economic operational capability using a probabilistic Monte Carlo analysis.
GRARE has been developed to support medium and long-term planning studies and is particularly useful for evaluating the reliability of large power systems, modelling in detail the transmission networks.
The tool is developed to take advantage of a high performance multi-threaded code and it is integrated in the SPIRA application that is designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) and is based on a network database of the system being analysed.

[21] www.cesi.it/grare

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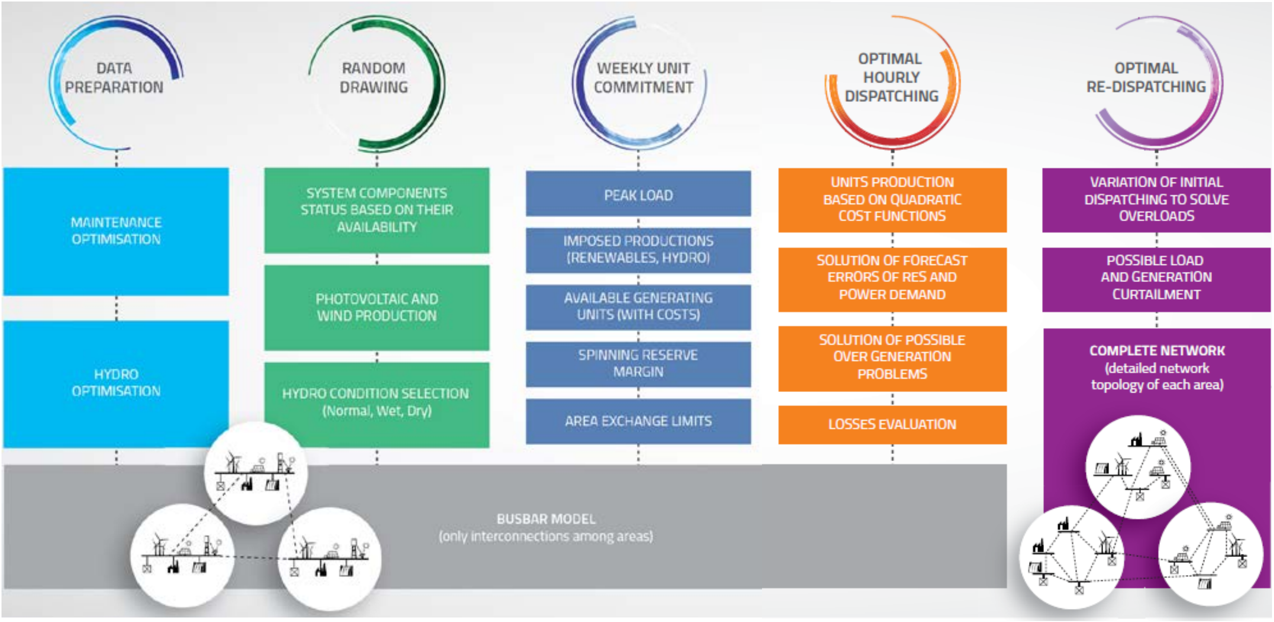
The calculation process is performed as a series of sequential steps starting from a high-level system representation and drilling down to low-level network details. Thanks to the ability to couple the economic dispatch of the generation with the complete structure of the electrical network, GRARE is able to offer a unique support for the planning and evaluation of the benefits related to network investments.



The **complete network model** (lines, generators, transformers, etc.) includes different voltage level detail and the power flow derived from generation dispatching to feed the load is obtained by applying a DC load flow with the possibility to obtain power losses and voltage profile estimation. Starting from a complete network model, GRARE is able to automatically obtain a simplified bus-bar models to complete unit commitment and market analyses where the network detail is not needed. The analysis of the full network model allows for the feasibility of the economic dispatching to be verified and the necessity to apply a re-dispatching or load shedding to operate the network in accordance with security criteria.

Algorithm and main optimisation process

- The time horizon is a single year with a minimum time unit of one hour. Many Monte Carlo Years (MCYs) can be simulated, each one being split into 52 weeks with each week independently optimised.
- The Probabilistic Monte Carlo method uses statistical sampling based on a ‘Sequential’ or ‘Non Sequential’ approach.
- Monte Carlo convergence analysis to verify the accuracy of the results obtained.
- Optimised Maintenance schedule based on residual load distribution over the year.
- Reservoir and pumping Hydro optimisation mindful of water value as an opportunity cost for water in respect to other generation sources.
- Different hydro conditions managed (dry, normal, wet).

System model

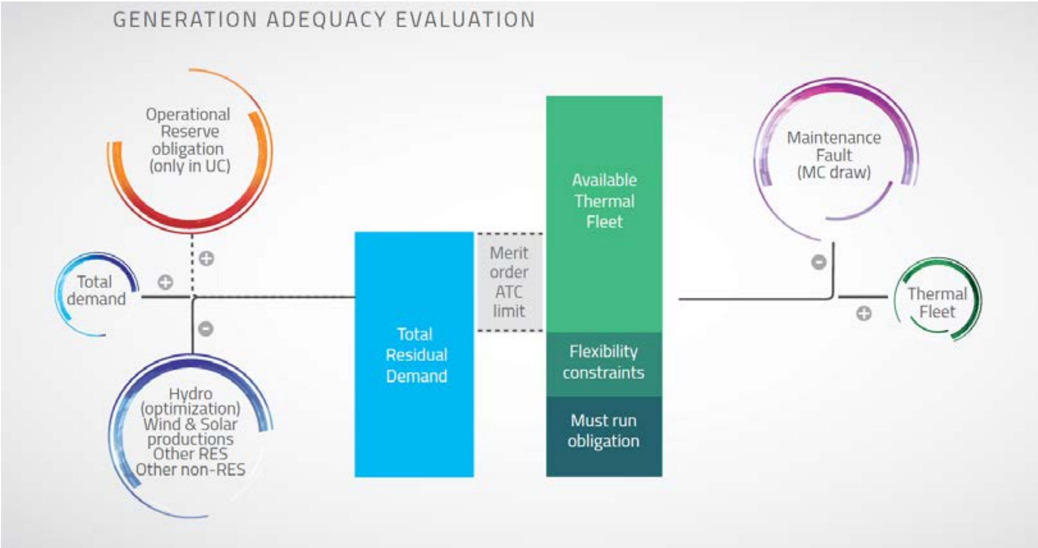
- Network detail to represent each single area (grid dimension up to 5,000 buses). A DC load flow is calculated and an estimate of voltage level can be obtained using the Sauer algorithm.
- Area modelling to optimise Unit commitment and Dispatching consistent with transfer capacities.
- Unit Commitment and Dispatching with Flow or ATC based approach.

Market analyses

- Single year day-ahead Market analysis with area modelling detail, but with no Monte Carlo drawings.
- The general restrictions of the Unit Commitment such as minimal uptime and downtime of generation units are considered for each optimisation period.
- Dispatchable units characterised by power limits, costs, must-run or dispatching priority, power plants configurations, start-up and shutdown flexibility and CO2 emissions.

Adequacy analyses

- System adequacy level measured with Reliability Indexes (ENS, LOLE, LOLP).
- Renewable production calculated by a random drawing starting from producibility figures.
- Operational reserve level evaluation considering the largest generating unit, uncertainty of load and RES forecast, and possible aggregation of Area and fixed percentage of load.
- Demand side management as rewarded load to be shed with priority without any impact on adequacy.
- Over-generation management with possible priority on generation to be reduced.



Main applications

The high level of versatility and flexibility of the GRARE tool has been appreciated in Europe first and then in several countries globally. The program has been developed to be applied in the design phase for the Italian framework and it is now used for ENTSOE-E adequacy studies. Various TSO/Institutions have benefited from the potentiality of the tool by using it directly or through specialist consultancy services.

- Designed for technical analyses of large electric systems.
- Evaluation of electric systems
- Generation & Transmission adequacy.
- Optimal level of RES integration.
- Cost Benefits Analysis for network reinforcements and storage, which factors in Security of Supply, network overloads, RES integration, network losses, CO2 emissions and over-generation.
- Calculation of Total Transfer Capacity of interconnections.

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- Generation reward evaluation for the Capacity Remuneration Mechanism.
- Point Of Connection and sizing for new power plants.

5.3.4 PLEXOS

PLEXOS, developed by Energy Exemplar, is a sophisticated power systems modelling tool. It uses mixed integer optimisation techniques to determine the least cost unit commitment and dispatch solution to meet demand, while respecting generator technical-economic constraints.
Advanced Mixed Integer Programming (MIP) is the core algorithm of the simulation and optimisation.

PLEXOS 4.0 was first released in 2000. It is used by utilities, system operators, regulators and consulting firms for:

1. Operations
2. Planning and Risk
3. Market Analysis
4. Transmission (Network) Analysis

PLEXOS features:

1. State-of-the-art optimisation-based engine using latest theories in mathematical modelling and game-theory
2. Co-optimises thermal and hydro generation, transmission and ancillary services given operational, fuel and regulatory constraints
3. Dispatch and pricing solutions are mathematically correct, robust and defensible
4. Applies optimisation across multiple timeframes
5. Benchmarked against real market outcomes and existing large-scale models

Solving UC/ED using MIP

Unit Commitment and Economic Dispatch can be formulated as a linear problem (after linearisation) with integer variables representing generator on-line status.

Minimise Cost = *generator fuel and VOM cost + generator start cost*
+ contract purchase cost –contract sale saving
+ transmission wheeling
+ energy / AS / fuel / capacity market purchase cost
–energy / AS / fuel / capacity market sale revenue

Subject to:

1. Energy balance constraints
2. Operation reserve constraints
3. Generator and contract chronological constraints: ramp, min up/down, min capacity
4. Generator and contract energy limits: hourly / daily / weekly / …
5. Transmission limits
6. Fuel limits: pipeline, daily / weekly/ …
7. Emission limits: daily / weekly / …
8. Others

Hydro-Thermal planning

Particularly important for the MAF studies was the co-ordination of Hydro-Thermal planning. The goal of the hydro-thermal planning tool is to minimise the expected thermal costs along the simulation period. The PLEXOS Integrated Energy Model offers a seamless integration of phases, making it possible to determine:

1) An optimal planning solution in the medium-term
2) Then use the obtained results in a detailed short-term unit commitment and economic dispatch problem with increased granularity.
E.g. weekly targets as constraints filter down to produce hourly electricity spot prices.

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