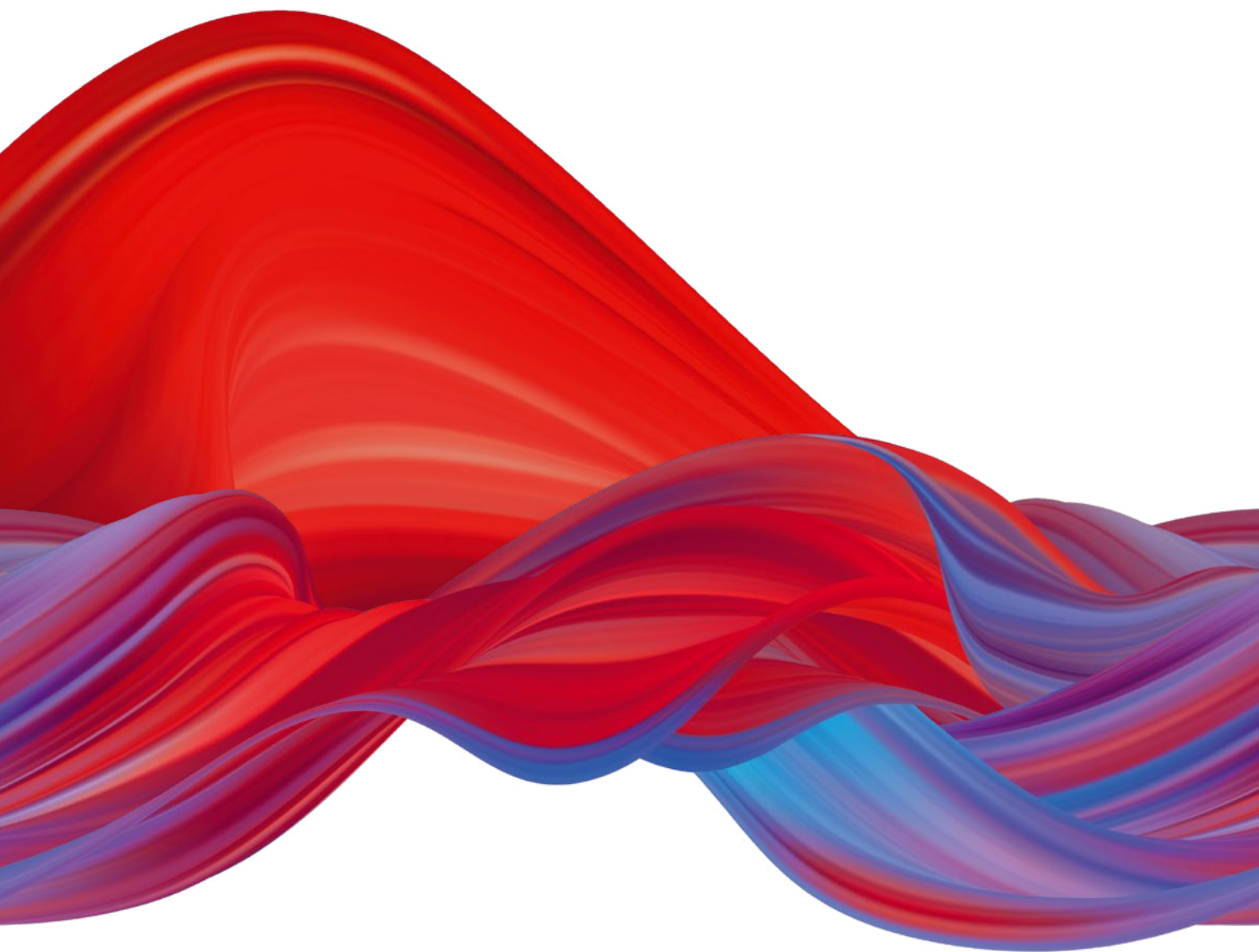
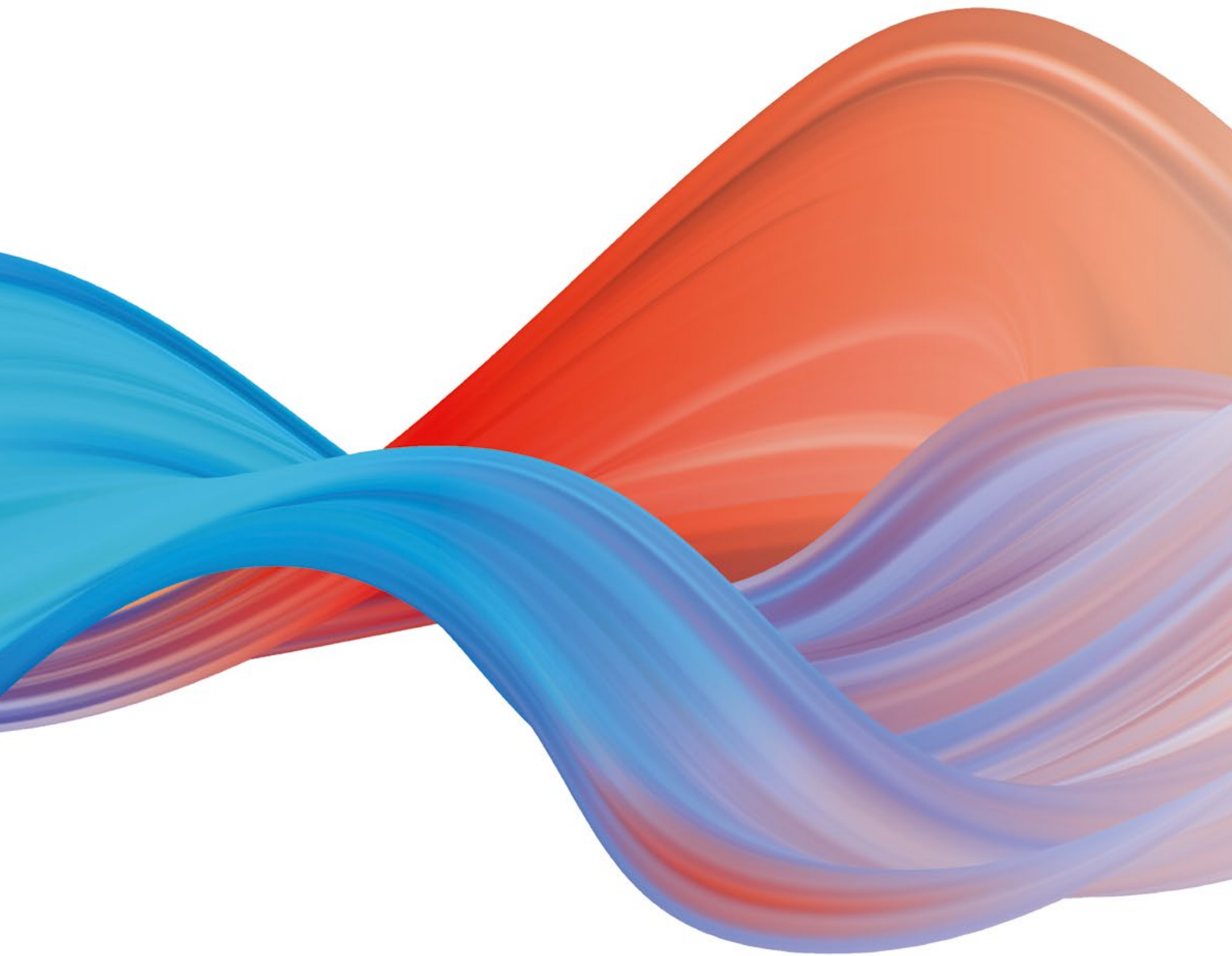


2023

**NATIONAL RESOURCE
ADEQUACY ASSESSMENT
FOR ITALY**



Driving Energy



“ We are behind the energy you use every day

We are responsible for guaranteeing the continuity of power supply, essential in making sure that electricity reaches Italian homes and businesses at all times.

We provide everyone with equal access to electricity and are working to provide clean energy for future generations. ”

PURPOSE

“ We care about the future of energy

We are committed to building a future powered by clean energy, enabling new forms of consumption and production increasingly based on renewable sources. This will allow us to achieve the goal of delivering an energy transition that is fair and inclusive, whilst also lowering costs.

Thanks to our overall vision of the electricity system and new digital technologies, we are leading the country's drive to get to net zero by 2050, in line with European climate goals. ”

VISION

“ Terna is investing in Italy's development

We guarantee energy security and balance electricity supply and demand 24 hours a day, ensuring that the system is reliable, efficient and accessible to all.

We invest and innovate every day in the development of an electricity grid capable of integrating the energy produced from renewable sources, improving links between the different areas of the country and strengthening cross-border interconnections, applying a sustainable approach that takes into account the needs of the communities and people we work with. ”

MISSION

Executive Summary

INTRODUCTION

The Italian electricity system is undergoing continuous and deep changes. Integrating growing volumes of renewable production is not only critical to achieving the decarbonization goals, but also represents an extraordinary opportunity to reduce the dependence from fossil fuels, thus minimizing the country's exposure to geopolitical risks or other risks connected to tensions on the global markets.

Both drivers have led policy-makers (national and European) to develop a series of legislative proposals such as the Fit-for-55 package (FF55, which aims to reduce GHG emissions by 55% until 2030 and to achieve “carbon neutrality” by 2050) and REPowerEU (which aims to achieve independence from Russian fossil fuels). These packages define specific objectives both for the energy sector as a whole, and also specifically for the electricity sector.

National governments have then translated these overarching EU goals into a National Energy and Climate Plan (NECP) which contains national scenarios and identifies the actions needed to make sure that these scenarios are realized. For Italy, the Ministry of the Environment and Energy Security published a new draft NECP on 19 July 2023 (updating the indications from 2019).

The draft NECP 2023 is in line with the electricity decarbonization targets and the related necessary actions identified by Terna in our 2022 Future Energy Scenarios (FES, so called *Documento di Descrizione degli Scenari*, DDS 2022) and in our 2023 Grid Development Plan. These documents describe a series of coordinated actions and measures needed to integrate growing volumes of variable renewable energy sources (vRES) and to replace fossil fuel generation, such as the development of new grid infrastructure, complemented with a further deployment of storage capacity.

Gradually replacing gas-fired generation with vRES implies the need to tackle and overcome important challenges in the electricity system operation, namely:

- **ensure system adequacy**, considering the limited predictability of vRES and properly estimating the contribution of storage and imports to system adequacy;
- **managing a gradual reduction of the regulating power and the inertia**, following the **decreasing usage of dispatchable rotating capacity**;
- **mitigating an increase in grid congestions linked to the development of vRES in areas characterized by strong winds and high solar radiations, which typically not correspond with the location of consumption centres**;
- **managing the problems related to voltage regulation** (overvoltages and voltage dips) and **frequency instabilities** (uncontrolled oscillations and grid separations).

The need to tackle an increasing instability of energy supply as a direct consequence of the geopolitical context is another challenge that, as previously mentioned, has been recently added to the current framework. This instability, which affects the entire European area, translates for Italy into the **need for an increasingly careful and targeted assessment both of using gas-fired generation for covering the energy demand and of the effective expected contribution of electricity imports** from neighboring countries, also subject to the same critical issues.

The 2022 edition of the National Resource Adequacy Assessment for Italy (NRAA, so called Rapporto Adeguatezza Italia, RAI 2022) highlighted that in the medium-term adequacy risks are significant when both high temperatures and low river levels can be observed, a situation which already occurred during the summer of 2022, determining the erosion of the adequacy margin for the North and Centre-North bidding zones.

In fact, during the summer of 2022, high temperatures and a severe drought determined: i) a much higher unavailability of thermal power plants compared to historical values, due to limitations related to the low availability of cooling water and the limitations related to the High Discharge Water Temperatures (HDWTs) for plants located near rivers or the sea and ii) a record-low hydro power generation compared to 2021.

In addition, in the first months of 2023, the water inflows were in line with the values recorded during 2022 and, consequently, far below the previous all-time lows. Therefore, to avoid the occurrence of the same conditions occurred in the summer of 2022, Italian law decree 39/2023 authorised, limited to the period from 20 June to 15 September 2023, the operation of the thermal power plants by way of derogation from the limitations related to discharge water temperatures.

Finally, in a recommendation, the Ministry asked Terna to modify the capacity market rules to promote that thermal plants equipped with water cooling systems will be upgraded to air-cooled systems. This will happen by implementing solutions to reduce the dependence of the production of these plants both on the availability and the temperatures of water in the most critical periods of the year for the system adequacy.

It is finally worth noting that the results of the adequacy analysis of the 2023 edition of the National Resource Adequacy Assessment for Italy (NRAA 2023), presented in the following chapters, are in line with those of NRAA 2022.



Objectives of the National Resource Adequacy Assessment for Italy

The present **National Resource Adequacy Assessment (NRAA)** has been prepared with the purpose of verifying the adequacy conditions of the system in the medium-long term in a context of increasing uncertainty.

The document focuses on analyzing the capability of the Italian electricity system to ensure that, over the next ten years, the available resources, such as electricity power plants, imports and storages, are sufficient to meet the hourly electricity demand in each bidding zone of the country.

The adequacy of an electricity system is commonly measured through two indicators:

**EXPECTED
ENERGY NOT
SUPPLIED**
(EENS, MWh)

the expected portion of demand not covered, in a given period, due to limitations on the generation fleet and/or on the transmission capacity;

**LOSS OF LOAD
EXPECTATION**
(LOLE, h)

the expected number of hours in which the EENS value is different from zero.

With the Ministerial Decree of 28/10/2021 the maximum value of LOLE (Reliability Standard of the system, RS) has been set at **3 h/year**. This definition is based on the study¹ performed by Terna upon request from ARERA (Resolution 507/2020/R/eel) and in compliance with the ACER methodology (Decision 23/2020).

The purpose of the analyses described in this report is two-fold:

- assess the ability of the system to respect the Reliability Standard (RS) in the considered scenarios;
- indicate the minimum necessary resources and conditions to respect the RS.

These objectives are pursued together with an assessment of the economic viability of power plants (hereinafter EVA - Economic Viability Assessment - introduced for the first time in the NRAA 2022 document), in compliance with the ACER Decision 24/2020. The analysis estimates the profit margins expected from the thermal generation fleet, assumes that the economically non-viable power plants will be gradually decommissioned, and verifies whether the remaining portion (economically viable thermal power plants) is sufficient to guarantee the adequacy standard of the system. In case of a negative result, it will be necessary to deploy specific market instruments in order to avoid the decommissioning of the power plants that are necessary for adequacy but “out-of-money”.

¹ <https://www.arera.it/allegati/docs/21/370-21studio.pdf>



To perform the analyses, the electricity system was simulated in two different states: one at medium term horizon (2028) and one at long term horizon (2033), both aligned with the 2022 Future Energy Scenarios (FES 2022)², in turn aligned with the FF55 policy goals and the 2023 National Development Plan (NDP) of the Transmission Grid.

² Drafted in compliance with Opinion 574/2020/R/eel and Resolution 539/2020/R/gas.

Main results of the analyses and needs of the electricity system

In the medium term (2028), considering the simultaneous presence of:

1) the capacity already contracted in the previous CM auctions ('22, '23 and '24);

2) the grid reinforcements provided for in the NDP (in particular the Tyrrhenian Link);

and the absence of:

3) further decommissioning of thermal generation capacity, besides the already planned coal phase-out;

4) drastic reductions of imports from the northern border,

the **Italian electricity system will be moderately adequate and will not need new capacity**.

The analyses show risks related to the following conditions:

1. prolonged periods of high temperatures that determine peaks in electricity demand, caused by summer conditioning;

2. prolonged conditions of low water inflows, due to dry months, with consequent drop in hydro energy production and in the availability of thermal capacity with closed-cycle technology (CCGT or coal power plants) located near rivers, due to the consequent limitations on the operation of cooling systems;

3. reduction in available thermal capacity in with high temperature periods, due to thermal derating phenomena, caused by constraints on river water temperatures in proximity of power plant discharges, made more difficult to comply due to the rising river temperatures (HWDTs limits).

“Extreme” weather conditions (similar to what happened in the summer 2022) pose risks to the system adequacy depending on the actual unavailability of plants. In fact, the climate conditions observed during the summer of 2022 resulted in 20 GW of thermal power plants being unavailable, bringing the Italian electricity system close to its adequacy limit. In the medium term, these risks remain and could result in even more severe situations.

Therefore, in the medium term horizon, as well as monitoring the commissioning of the already awarded capacity of the Capacity Market auctions and deploying the grid infrastructure already planned by Terna, **solutions will need to be identified to improve the availability of the current generation fleet in cases of high temperatures and low water inflows**, considering also the risk associated with the availability of imports from the northern border. While waiting for the implementation of these solutions, it is crucial to assess short-term complementary measures capable of mitigating this specific risk.

In the long-term horizon (2033), thanks to the significant increase in vRES and storage systems, and the further development of the transmission grid, part of the existing gas-fired generation fleet, together with the coal-fired power plants, would no longer be necessary to ensure the adequacy of the Italian electricity system. In this regard, it is important to remark that the remaining thermal generation capacity, still necessary to respect the adequacy standard, may not be economically viable considering only the spot markets revenues.

According to the **economic viability assessment for both the medium and the long term horizons**, the significant increase in vRES and storage capacity will determine the reduction in the running hours of fossil-fuel power plants, with consequent contraction of their profit margins. According to the simulations, the total capacity estimated “being phased out for economic unviability” is **14.8 GW in the medium term horizon and 19.7 GW in the long term horizon**. If all this capacity would be decommissioned, the available thermal capacity would fall to levels well below the **minimum necessary to ensure system adequacy in the two time horizons (approximately 39 GW compared to the 50.2 GW necessary in the medium-term horizon and approximately 33 GW compared to the 41 GW necessary in the long-term horizon)**.



Therefore, the analyses showed that, **without forward contract mechanisms, i.e. mechanisms that keep the necessary minimum capacity in operation, the system would reach an economic equilibrium** (in terms of available thermal capacity) **not compatible with the adequacy requirements, if it were to rely only on the price signals coming from the spot markets.** In this regard, although the potentially high prices reached on the spot markets during the scarcity hours (high electricity demand and low renewable generation) may provide an incentive to avoid the decommissioning of these plants, the uncertainty in the frequency and intensity of such phenomena are incompatible with the expected remuneration and risk profile of the power plant owners. Therefore, the report confirms the role of thermal capacity in the long term scenarios, which gradually moves from covering a large part of energy demand (MWh) to guaranteeing their availability to cover demand peaks (MW), in coherence with the evidence presented in the previous NRAA report (NRAA 2022).

The periods at greatest risk of inadequacy are closely related to the periods of high residual load that tend to occur at peak demand (typically in the presence of extreme temperatures in summer and winter) and/or during period of low renewable generation, (during the evening/night hours), combined with the unavailability of thermal capacity caused by adverse weather conditions (low river levels for cooling and HDWTs).



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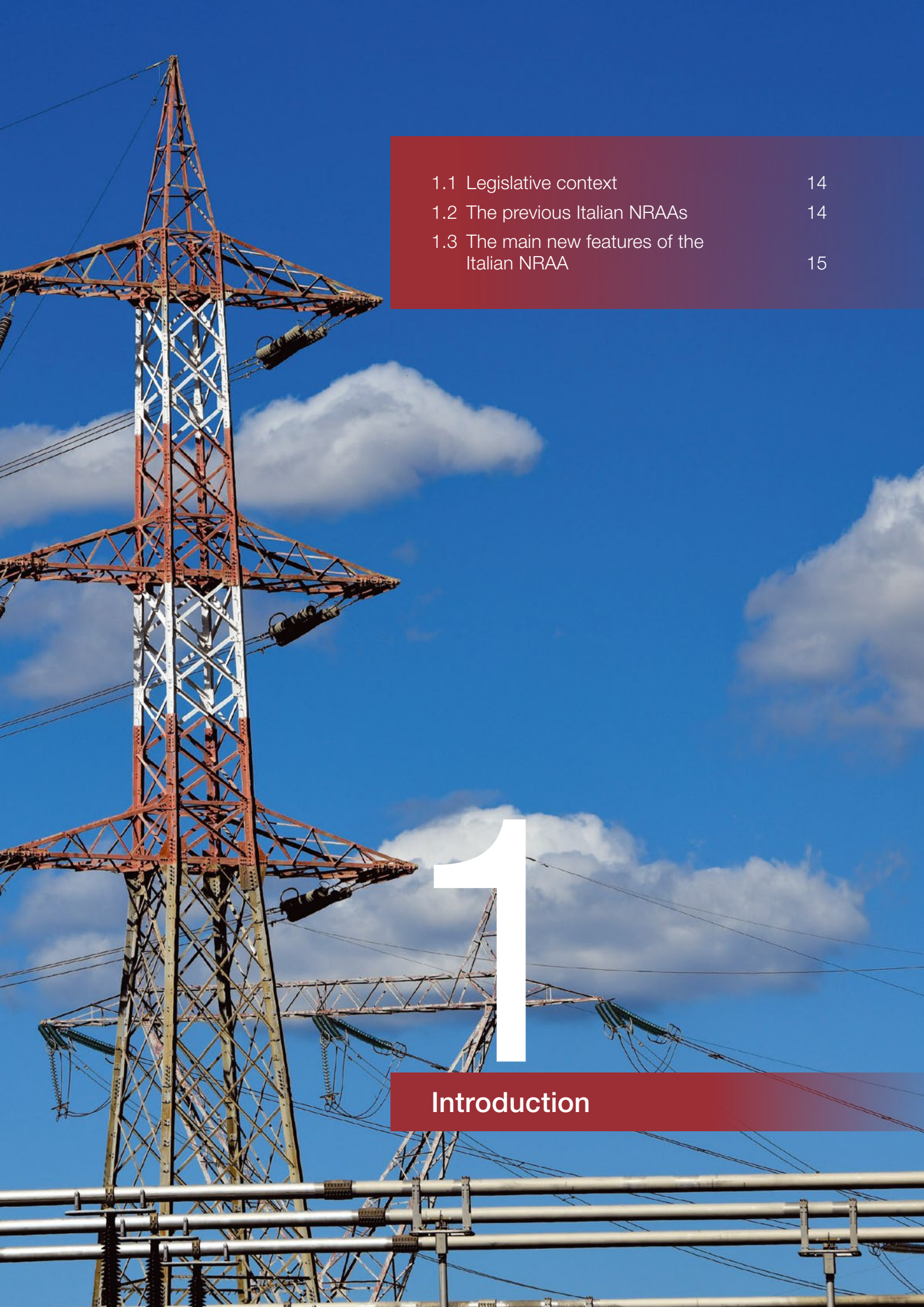
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1

Introduction

Introduction



1.1 Legislative context

In the national context, the Italian NRAA fulfills a series of regulatory requirements with reference to:

- **art.3 of the MiSE Ministerial Decree of 28/06/2019** which requires that the adequacy assessment of the electricity system should be carried out and updated yearly. This assessment, under the terms of art.2 of the same Min. Dec., takes into account the positive effects deriving from the development of the grid infrastructure and interconnections with other countries, the future scenarios and adequacy studies at regional and European level developed by ENTSO-E, and the evolution of renewable sources, distributed generation, flexible resources and storage systems, in line with the goal of developing an integrated electricity market;
- **art.53 of the Resolution 111/06 (as amended by Resolution 856/17)** which requires the publication of the adequacy report by 30 September of every year, with reference to a time horizon of not less than the six following years, which assesses the total generation capacity necessary to meet the energy demand;
- art 2.1 of the Mite Ministerial Decree of 28/10/2021 which defines a maximum LOLE value of **3h/year**.

In addition, this report complies with **art.13.5 of the Rules of the generation capacity availability remuneration mechanism** which requires, at least 60 days before each Main Auction, Terna to publish a NRAA document on with a ten-year timeframe.

1.2 The previous Italian NRAAs

The NRAA 2022 analyzed a medium-term horizon (2027-2028), considering the simultaneous presence of:

- 1) capacity already awarded** in the CM auctions ('22, '23 and '24);
 - 2) grid reinforcements planned in the National Development Plan** (in particular the Tyrrhenian link);
- and the absence of:
- 3) further decommissioning**, besides what already planned for the coal-fired plants;
 - 4) the absence of drastic reductions of electricity imports** from the northern border.

In the medium term horizon (2027-2028), there is a risk of prolonged periods of high temperatures, preceded by months of low rainfall simultaneously with the reduction in the availability of imports from bordering countries. These particularly stressful situations could determine a LOLE higher than the system Reliability Standard (3h/year).

In the long-term horizon (2030-2032), thanks to the significant increase in vRES, storage systems installed capacity, and thanks to further development of the transmission grid, the Italian electricity system – without further generation capacity being decommissioned– would be adequate. As a matter of fact, a significant part of the gas-fired plants could be decommissioned, together with the coal-fired power plants.

Assuming the fulfilment of all the scenario assumptions, the performed simulations confirm that it will be necessary to guarantee the availability of a **minimum value of 40 GW of thermal capacity**, in order to ensure the electricity system adequacy. However, according to the economic viability analysis, the significant increase in vRES and storage capacity will determine a reduction in the running hours of thermal fleet, with a consequent contraction of the earning margins. The estimated decommissioning of the thermal capacity “not in the money” would result in a reduction of the thermal fleet down to approximately 37 GW (corresponding to about 30 GW of so-called “Capacità Disponibile in Probabilità: CDP, a parameter that takes into account maintenance, outages and thermal derating of the power plant from a stochastic point of view), 3 GW below the minimum necessary to ensure adequacy standards.

1.3 The main new features of the Italian NRAA

This report follows up directly from the previous edition of the Italian National Resource Adequacy Assessment (NRAA 2022), published in February 2023. In particular, the NRAA '23 guarantees the alignment with the NRAA '22, both regarding the scenario, on which the analyses are based (aligned with FES '22 and NDP '23), and the methodological approach.

However, there are some new features that further strengthen the analyses.

Compared to the previous study, the **economic viability analysis** has been carried out on both the horizons (medium and long term horizon), in order to estimate the decommissioning risk of a portion of the thermal fleet due to economic unviability also in the medium-term horizon.

The adequacy assessment methodology is in a *continuous improvement process*, both to incorporate new elements into the modelling that will become part of the electricity system (such as storages, demand-side-response, electrolysers), and to make the representation of the electricity system increasingly accurate.

It is worth mentioning some developments deployed on the **weather variables** and on the **reduction of the available capacity of the thermal power plants** due to climate phenomena (thermal derating factor).


Related to the first aspect, a new set of **weather variables** (that considers the most updated climatic data) was adopted in order to capture with more accuracy the early effects of climate change on the electricity system.

Instead, as regards the **thermal capacity de-rating**, a modelling improvement was implemented; this makes it possible to simulate the expected correlation between the outdoor temperature (which strongly impacts peak demand) and the reduced availability of thermal generation (both related to temperature peaks). Therefore, thermal capacity de-rating profiles that reflect the behaviour of the thermal power plants in these conditions were introduced.

These methodological and modelling developments make it possible to represent the electricity system with increased accuracy. The methodology by which the demand is profiled according to the climate years was also been improved, bringing it in line with the European standards adopted in ERAA '23 (European Resources Adequacy Assessment). In brief, the Italian NRAA takes into account the methodological aspects adopted by ENTSO-E in the European study (ERAA), declining them in the national analyses with greater depth. In such a big context as the European one, the detail must necessarily be less than that adopted for the national studies, confirming the complementarity of the two reports.







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Context of the Italian electricity system

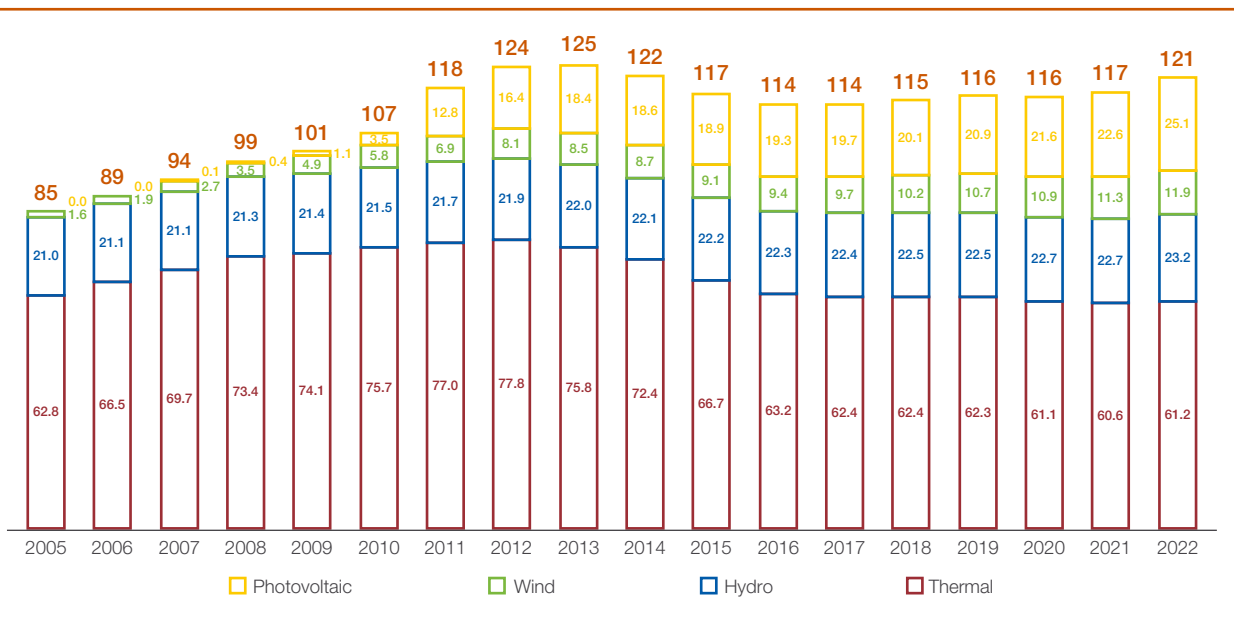
Context of the Italian electricity system

2

2.1 Electricity generation capacity

In the last few years, the generation fleet in Italy has undergone significant changes. In particular, in 2010 and 2011 two opposite trends began to be observed: the gradual growth of renewable capacity, which in 2022 reached approximately 37 GW, and at the same time the gradual reduction in the conventional thermal installed capacity, which as of today is equal to 61.2 GW. (Figure 1).

FIGURE 1 Evolution of generation capacity 2005-2022 [GW]

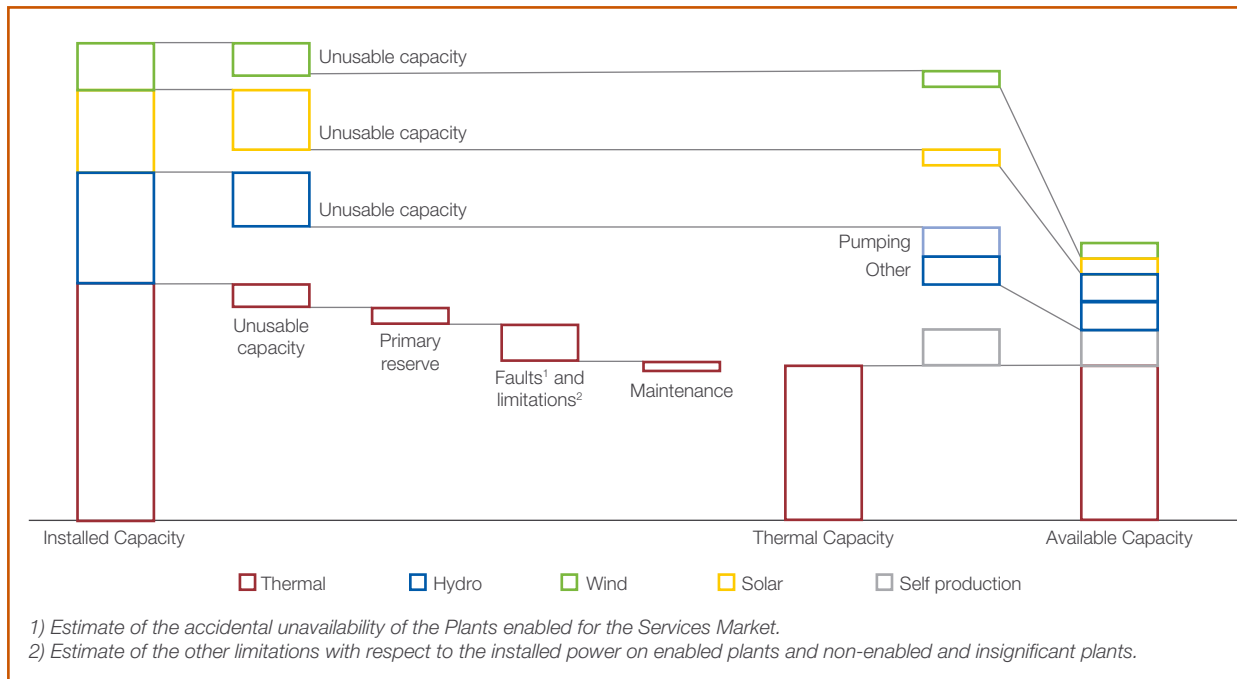


In particular, thermal power plants underwent a significant reduction, of approximately 13 GW, in the period between 2013 and 2017. This trend continued in the following years, in a more limited manner, with a further reduction of less than 2 GW between 2018 and 2021.

This trend seems to have been inverted in recent years (2021-2022) when an increase in installed thermal capacity of almost 1 GW was recorded due to the results of the capacity market auctions. Hence, the total installed capacity at the end of 2022 was approximately **121 GW**.

When analyzing the adequacy of an electrical system it is necessary to consider, rather than the installed capacity, the available generation capacity (Figure 2) which conceptually is equal to the sum of the installed capacity of the different sources, classified by technology, opportunely derated to take into account their effective availability and potential contribution to cover demand peaks.

FIGURE 2 Available generation capacity (example)

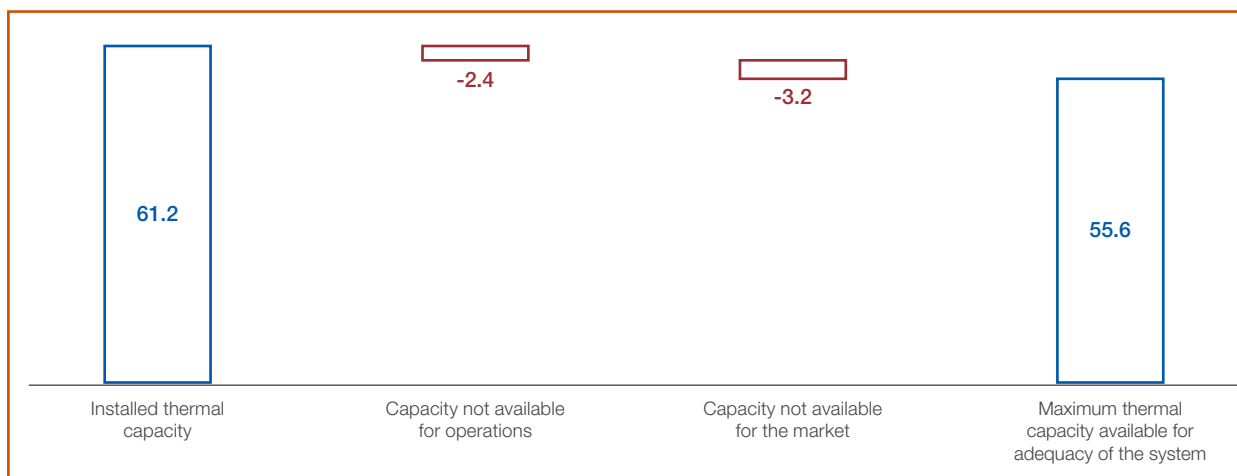


As regards the current thermal capacity (Figure 3), there are about **2.4 GW systematically not usable for covering the demand** (of which approximately 1.6 GW due to long-term unavailability and about 0.8 GW due to authorization constraints on operation) and approximately **3.2 GW** of further various limitations.

Hence, **55.6 GW** represents the maximum thermal capacity available for the system adequacy (figures updated to 31/12/2022).

However, **this capacity will never be contemporaneously available**, because it is necessary to consider also the plant unavailability associated with maintenance, outages and further reductions due to phenomena such as the derating³ and the HDWTs⁴ of thermal power plants.

FIGURE 3 Maximum thermal capacity available in support of the adequacy of the system [GW]



³ The available capacity from thermal plants decreases gradually in presence of high temperatures of the combustion air and/or of the cooling water/air necessary for their operation.

⁴ The discharge water temperature of a thermal power plant must be within a precise range in order to avoid a deterioration of the conditions of the surrounding environment.

2.2 Availability of imports for the Italian electricity system adequacy

Imports from abroad (especially from the northern border) play a fundamental role in covering the Italian electricity demand. In 2021 and 2022 imports amounted to approximately 43 TWh, corresponding to about 13.5% of the national electricity demand. The reason for this is firstly the different composition of the generation fleet compared to the bordering countries (France and Switzerland in particular), which typically have a lower variable generation cost. As a consequence of the availability of low cost energy from the northern border, the Italian electricity system structurally relies on this resource, which has become essential to cover the high demand of the North of the country.

Therefore, imports become essential in covering the demand and ensuring the national adequacy standard, especially during demand peaks and/or in periods of reduction in the availability of the national thermal generation. This critical issue involves essentially the North and Centre-North bidding zones.

The amount of energy imported depends not only on the physical availability of interconnection grids between Italy and other countries, but above all on the effective availability of the generation capacity in excess with respect to the demand in the bordering countries.

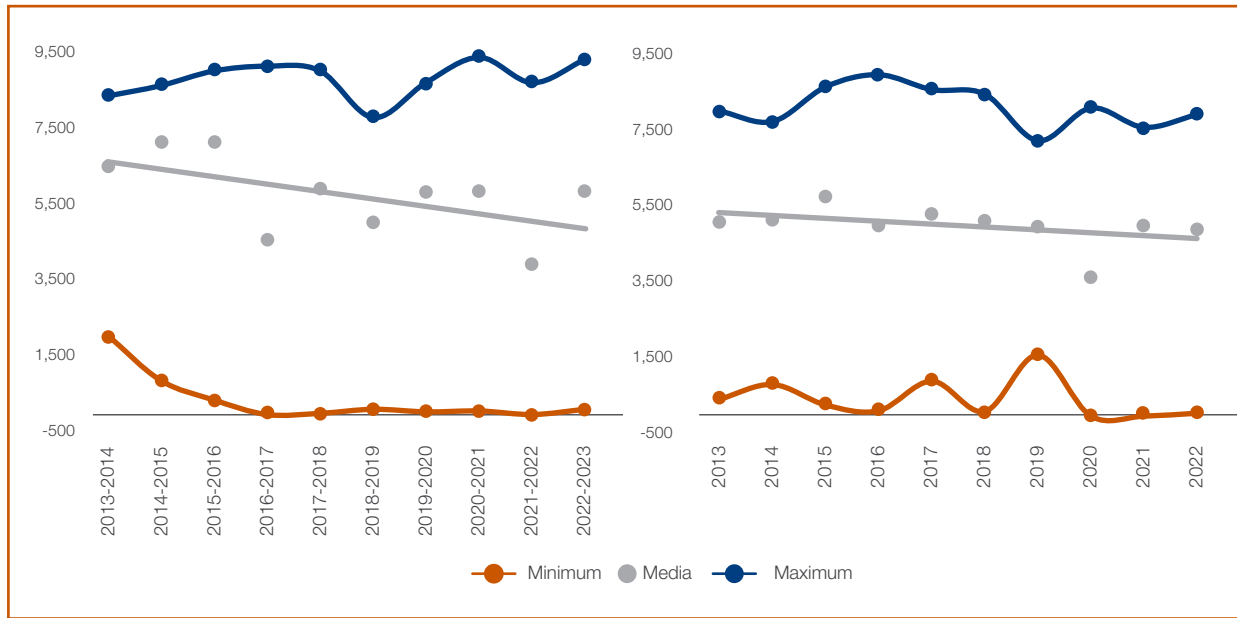
Also in the bordering countries, as it is in Italy, the generation capacity over the last few years has undergone a gradual reduction as a result of the economically-driven decommissioning, and prolonged downtimes for maintenance. On this point the most emblematic case is that of the French nuclear power plants: in 2022 the availability rate of the French nuclear power plants was approximately 54% compared to an average of about 73% from 2015 to 2019. In particular, during the autumn of 2022, only 25 GW out of the total 63 GW of the French nuclear power plants were available. This resulted in a 30% nuclear generation decrease in 2022 compared to the average of the previous 20 years. This, along with the lowest hydro generation since 1976, meant that **France in 2022 was in a net import position for the first time since 1980, compared to an average net exports of more than 45 TWh in the previous twenty years.**

This **extreme variability of imports** caused by critical conditions is destined to increase further in the future. In fact, the underlying phenomena are common to all European countries: the development of renewable sources, intrinsically dependent on the weather conditions, the decreasing economic viability of conventional power plants, the increasingly impacting effect of climate changes and the risk related to difficulties in the supply of fossil fuels from non-European countries that arose after the Russian invasion of Ukraine.

The magnitude and frequency with which these phenomena occur require a significant strategic reflection in the definition of the medium and long-term scenarios, in which the progressive electrification of consumption will make Italy increasingly dependent on the security and adequacy of the electricity systems, also to cover the basic needs (e.g. cooking, heating, mobility, etc.).

In *Figure 4* it can be noted how during the last few years imports have recorded a slight but gradual reduction both in the summer and winter period.

FIGURE 4 Imports (GW) Northern border: l) winter period, r) summer period



Therefore, it is essential to take into account these phenomena, identifying the right compromise between an overestimation of imports, which could lead to serious adequacy problems, and a more cautious approach, which could lead to excessive system expenses. For further details please see Annex II: Models and Methodologies.



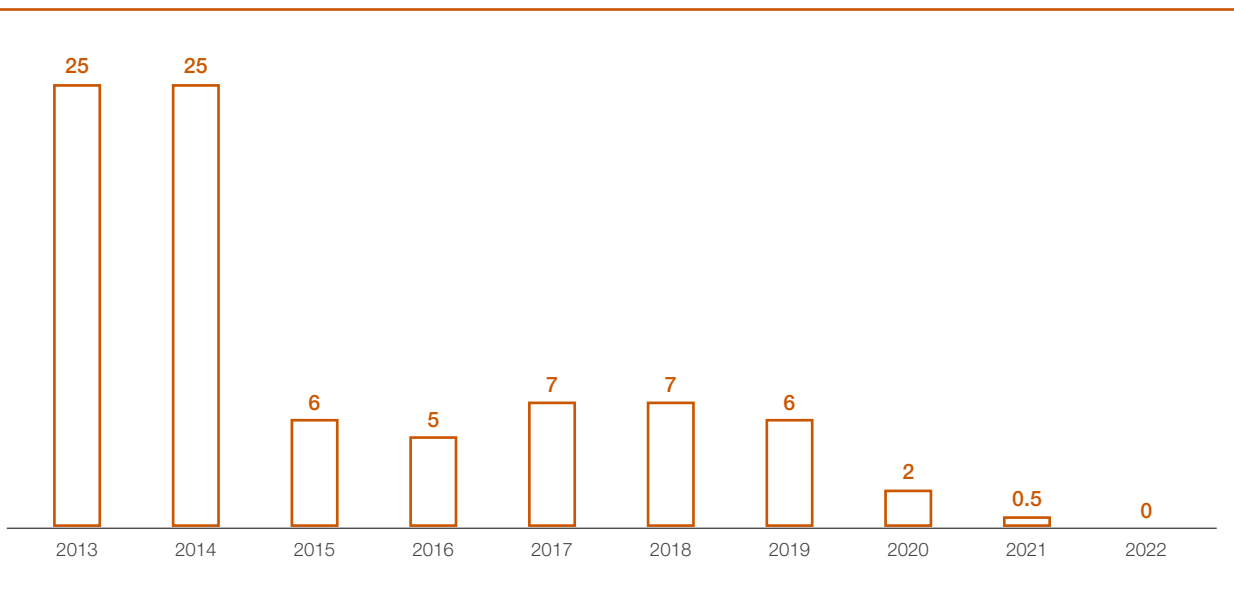
2.3 Adequacy margins of the electricity system

The adequacy margin is a deterministic parameter that identifies, for each market zone and period of analysis, the difference between:

- the sum of available domestic generation capacity and the imports from bordering market zones, including the contributions of storage facilities and demand-side response;
- the electricity demand increased by the necessary tertiary substitution reserve (defined as the generation capacity made available to the Transmission System Operator for increasing the generation of electricity for balancing purposes).

The reduction of the available capacity and the contribution of imports from neighboring countries causes the reduction of the system adequacy margin. The first significant reduction of the adequacy margin was recorded between 2014 and 2015 (-76%), subsequently, over the next four years, it remained between 5 and 7 GW, before decreasing further in 2022, when it reached a minimum value of 0 GW (Figure 5). This minimum was recorded on 25, 26 and 27 July 2022.

FIGURE 5 *Minimum adequacy margin (GW) 2013-2022*



During those days the Italian electricity system recorded:

- 1) significant demand peaks between 55 and 57 GW⁵ due to the high temperatures (confirming a strong correlation, especially in the summer period, between an increase in the average temperature and the growth in electricity consumption, caused by summer conditioning);
- 2) a significant reduction in the availability of thermal power⁶, as a result of unforeseen faults, phenomena of HDWTs and shutdowns/great limitations for power plants located along the Po river as a result of the drought that affected the area;
- 3) a reduction in the total generation surplus in the neighboring countries, mainly because of the high demand recorded all over central Europe (high temperatures) and a contraction of the available generation capacity in France (due to the prolonged maintenance of the nuclear power plants).

⁵ <https://www.terna.it/it/sistema-elettrico/transparency-report/peak-valley-load>

⁶ About a third of Italian thermal capacity (in particular in the northern area of the country) was not available to meet the demand.

The situation just described determined on 25 July an adequacy margin close to zero, and only a slightly higher value on 26 and 27 July 2022⁷.

BOX 1

THE ADEQUACY OF THE EUROPEAN SYSTEM IN THE 2023 SUMMER PERIOD

Unlike 2022, in which an adequacy margin all-time low (0 GW) was recorded on 25, 26 and 27 July, in the summer of 2023 was recorded a minimum margin of 2.3 GW.

The increase in rainfall, starting from May 2023, caused a net improvement of the water inflows; this, together with a reduction of the average summer temperature (compared to the previous year), resulted in a greater Italian electricity system adequacy despite the recorded demand peak of 59 GW.

Thanks to the higher rainfall, the power stations located near the Po' river did not face the same issues of the previous year. The lower average temperature limited slightly the HDWTs phenomena, characteristic of the summer period.

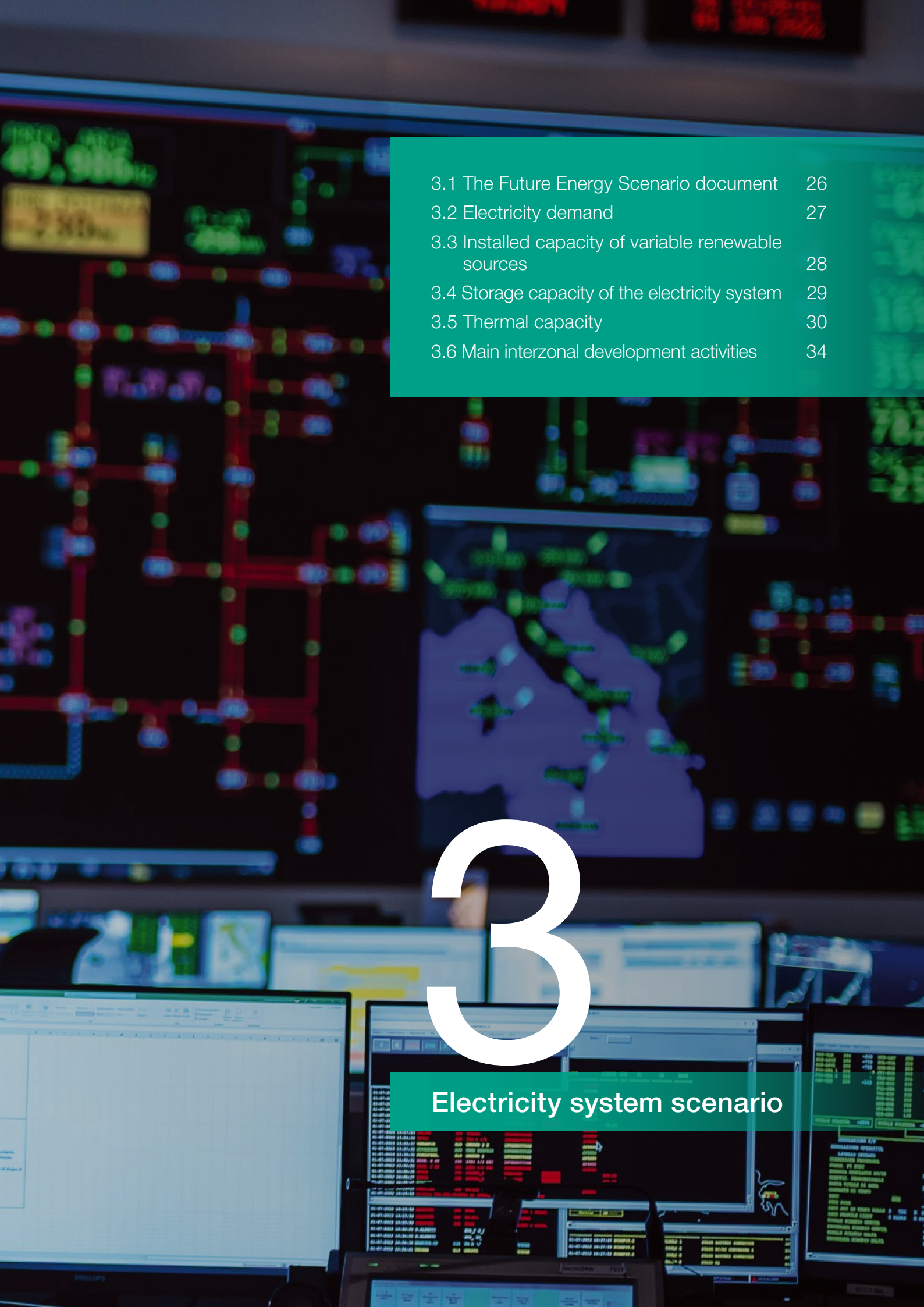
However, environmental factors, are not the only drivers of this phenomenon. In particular, the national electricity system operation is also affected by the current European economic and social context. This can be seen from the reduction in electricity demand in 2023.

Although this is favorable for the adequacy margin, attention must not be lowered. The adequacy margin trend over the years has been gradually downwards, prolonged droughts are becoming increasingly frequent and the monthly average temperatures denote an upward trend, with a consequent increase in the expected peaks of demand (together with the electrification of consumption, due mainly to the spread of electric vehicles and heat pumps).

For the first months of 2023 the water inflows were such as to expect a summer season with adequacy margins comparable to those of 2022; for this reason, Italian Law Decree 39/2023 authorised, limited to the period from 20 June to 15 September 2023, the thermal power plants to operate above the limitations related to discharge water temperatures.

⁷ To deal with this situation it became necessary for Terna to carry out a series of emergency measures, including – for the first time – the activation of the procurement service of the tertiary reserve before the day-ahead market session.





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3

Electricity system scenario

Electricity system scenario

3

3.1 The Future Energy Scenarios document

The Future Energy Scenarios 2022 (FES 2022) represents the result of the activities performed by Snam and Terna to reach a solid view of the possible future evolutions of the Italian energy system in support of the grid planning process.

The creation process of the scenarios involved:

- i. the definition of the storylines and the inputs of the scenarios;
- ii. the energy demand forecast for final uses, including both gas and electricity demand;
- iii. both the electricity and gas market analyses;
- iv. the policy targets achievement verification

The scenarios processed and described in the FES 2022 are:

- a policy scenario for 2030 (so-called Fit-For-55);
- two policy scenarios for 2040 (so-called Distributed Energy and Global Ambition) which share Fit-For-55 (hereinafter FF55) as a common starting point;
- a contrasting scenario, diverging from the policy scenarios (so-called Late Transition) for both 2030 and 2040.

For the adequacy analysis the FF55 policy scenario was considered; this was remodulated on the target years 2028 and 2033 representing respectively medium and long term time horizons, in line with the European Resource Adequacy Assessment (ERAA 2023) edited by ENTSO-E.

The FF55 scenario, the only policy scenario for 2030, achieves the European community emission reduction target of 55% through electrification and a significant expansion of renewable sources.

More details are contained in the FES 2022⁸.

⁸ https://download.terna.it/terna/Documento_Descrizione_Scenari_2022_8da74044f6ee28d.pdf

3.2 Electricity needs

Electricity needs refers to the total sum of:

- electricity for final uses;
- energy uses;
- grid losses.

The forecasting of electricity demand follows a structured process that involves multiple factors, the main ones are the correlation between GDP and electricity demand, the expected increase in the use of electric vehicles, heat pumps and in the production of green hydrogen from electrolysis, and the effect associated with the increase in the energy efficiency.

The electricity demand reaches approximately **378 TWh in the long-term horizon** (Figure 6).

Similarly, mainly due to the growth of electric vehicles and in the use of heat pumps, it is expected a concomitant increase in the peak electricity demand (Figure 7); The peak value could fluctuate within a range depending on the possible climatic conditions estimated in line with the new methodology used in the ERAA.

FIGURE 6 *Evolution of the electricity needs (TWh)*

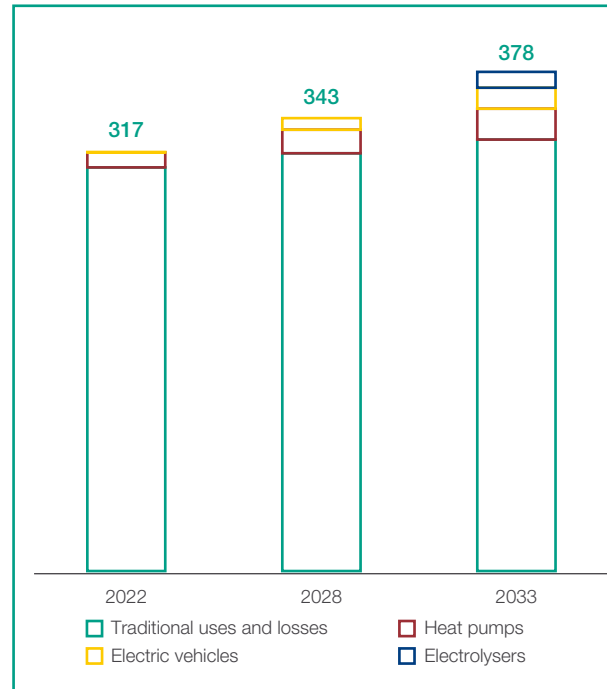
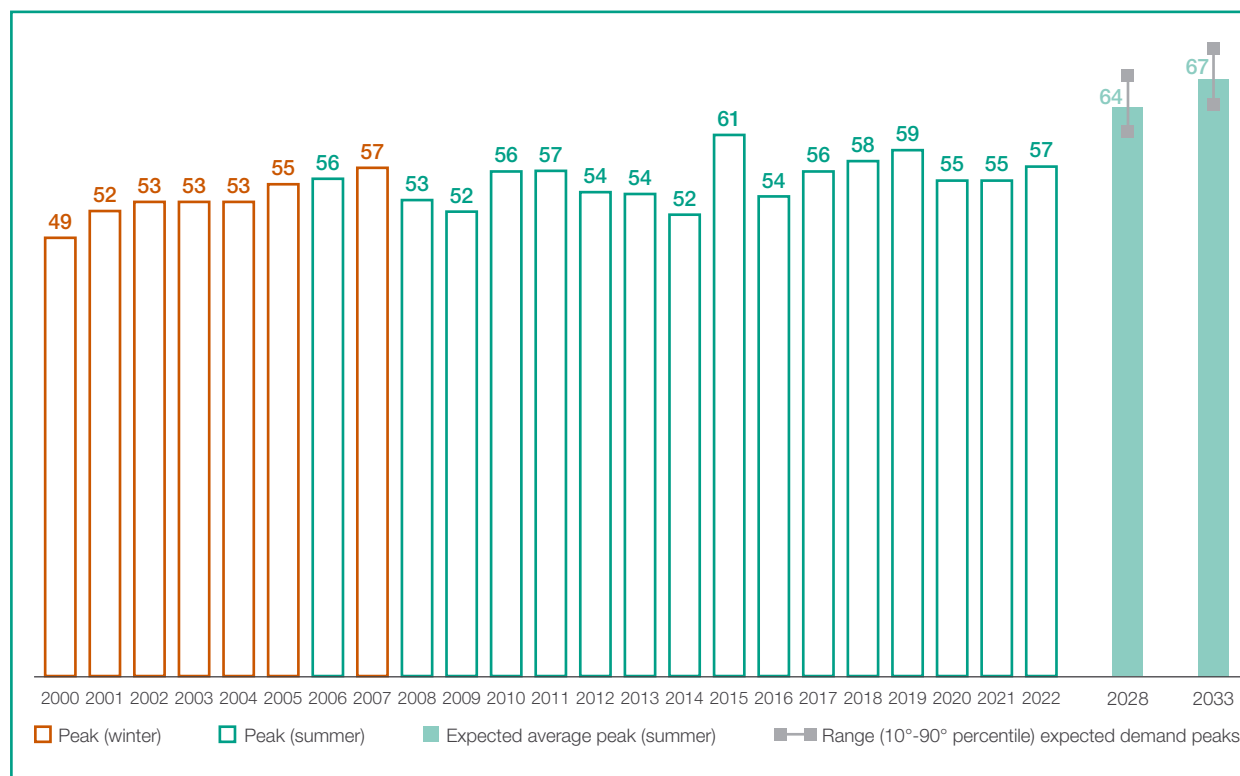


FIGURE 7 *Evolution of peak demand (GW) in the medium and long term horizons (average figure, 10° and 90° percentile between the different conditions simulated)*



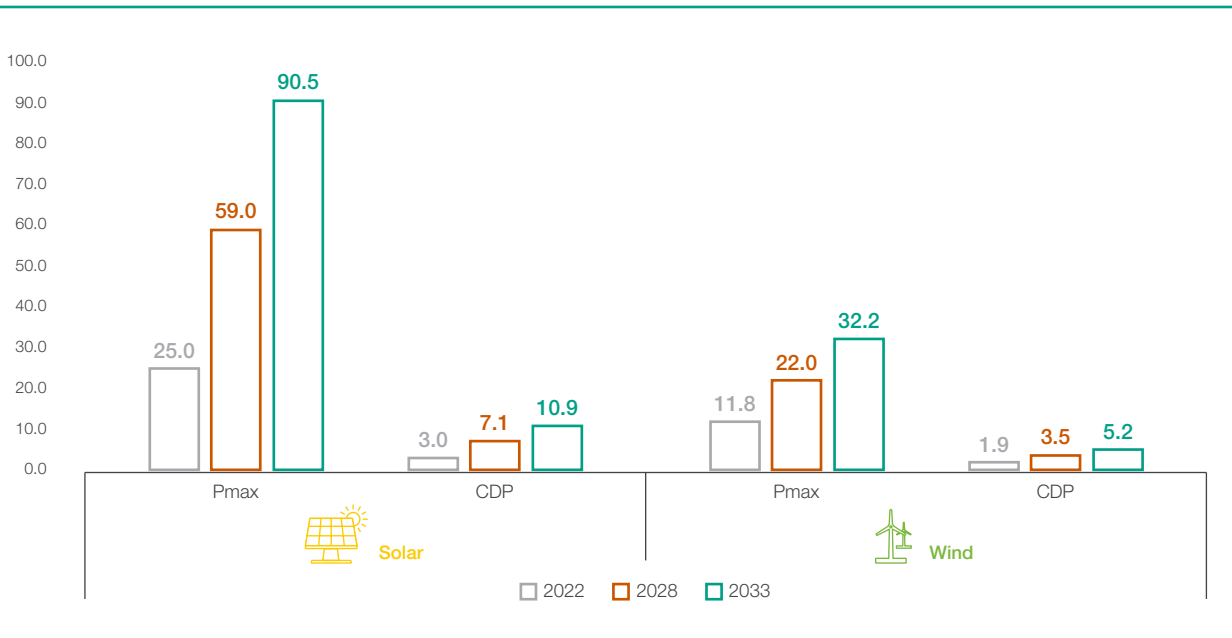
3.3 Installed capacity of non-programmable renewable sources

The FF55 scenario foresees a significant growth in vRES in order to achieve the policy targets. Therefore, in the long-term scenario (2033), are expected approximately 90 GW of solar plants (divided between rooftop and utility scale) and about 32 GW of wind power plants installed (including offshore and onshore).

To better estimate the impact of the growth of these resources on the system adequacy, the concept of Available Capacity in Probability (so called CDP) is used, calculated multiplying the installed capacity by specific de-rating coefficients that consider the effective availability of each source to cover the electricity needs. This is, therefore, a necessarily simplified approach, introduced for the Capacity Market auctions, which allows for a synthetic representation of the extreme complexity of the matter.

Applying the most up-to-date de-rating rates to the scenarios presented in this document, it becomes clear (Figure 8) that despite large installed capacities of vRES, their contribution to the system adequacy is limited.

FIGURE 8 Evolution of vRES (GW)



3.4 Electricity system storage capacity

The energy scenario with significant growth of RESs, presented in this document, is also characterized by a significant amount of storage capacity available in the long term.

The storage capacity in the scenario (*Figure 9*) is given by the sum of:

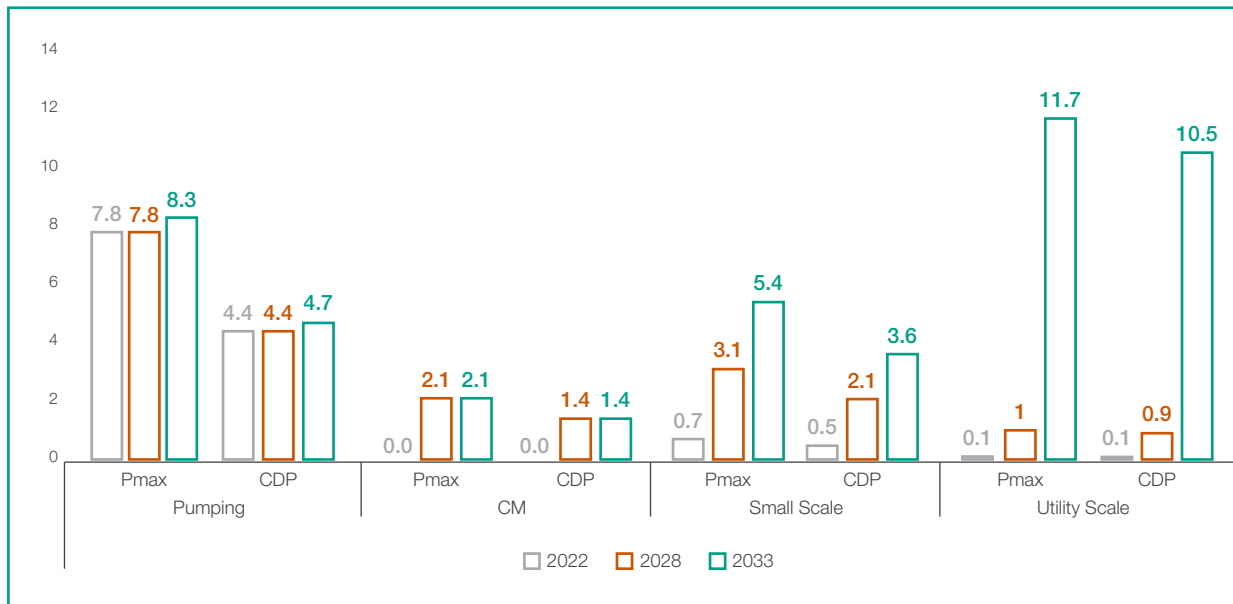
- existing storages (primarily pumped-storage plants);
- new “small-scale” storages which are electrochemical batteries with an average energy/power ratio of 4 hours, primarily designed to support the development of small-scale solar plants to maximize self-consumption;
- storages awarded during the Capacity Market auctions⁹ characterized by an energy/power ratio of 2 or 4 hours;
- new “utility-scale” storages, with a high energy/power ratio up to 8 hours, mostly assumed to be deployed in the long term scenario.

In particular, the target years 2028 and 2033 displays a total storage capacity of **13.9 GW** and **27.4 GW respectively**. These values, particularly in reference to the long term scenario, are aligned with what was defined in the policy scenario (in line with the European FF55 package) of the Future Energy Scenarios 2022 (FES '22).

Analogously to the considerations made in paragraph 4.3, also for these technologies the contribution to adequacy is reduced compared to the installed capacity and, by applying the most updated de-rating rates, it emerges that compared to the current situation (2022) the storage systems contribute for a total of 8.8 GW in 2028 and 20.2 GW in 2033.

With the approval of ARERA Resolution 247/2023, Terna was appointed to establish an auction mechanism for the procurement of new storage capacity, in order to capture efficient and integrated electricity markets for the energy transition. The establishment of this mechanism, currently under definition, would allow to award additional storage capacity, capable of contributing to the system adequacy.

FIGURE 9 Evolution of storage capacity (GW) for 2028 and for 2033



⁹ Approx. 2 GW of storage awarded in the CM23 and CM24 auctions.

PROSPECTIVE ROLE OF STORAGE CAPACITY

Storage systems will play a key role in future scenarios, characterized by an increasing deployment of renewable energy sources, as they will enable the provision of a various useful services to the electricity system, including time-shifting and dispatching services, crucial to ensure the security and the system adequacy. Storage will allow the 'structural' shifting of part of the variable Renewable Energy Sources production (vRES) from hours of high resource availability to hours of low or no availability, efficiently managing their overgeneration and adapting to the load curve, thus ensuring the achievement of the decarbonization targets.

Legislative Decree No. 210/21 provides for the introduction of a new mechanism for the forward procurement of electricity storage capacity. The system should be designed and sized to integrate renewables with an efficient level of overgeneration, considering in particular the planned grid developments.

The studies conducted by Terna and published in the 2022 Future Energy Scenarios display that, by 2030, approximately 71 GWh of utility-scale storage capacity will need to be installed, in addition to the distributed storage primarily associated with small-scale solar and storage which has already been awarded in the Capacity Market auctions.

3.5 Thermal capacity

As seen above (*Figure 3*), in 2022 the thermal capacity amounted to 55.6 GW of effectively available capacity for ensuring the system adequacy.

In the upcoming years, the main drivers guiding the evolution of the available thermal capacity will be:

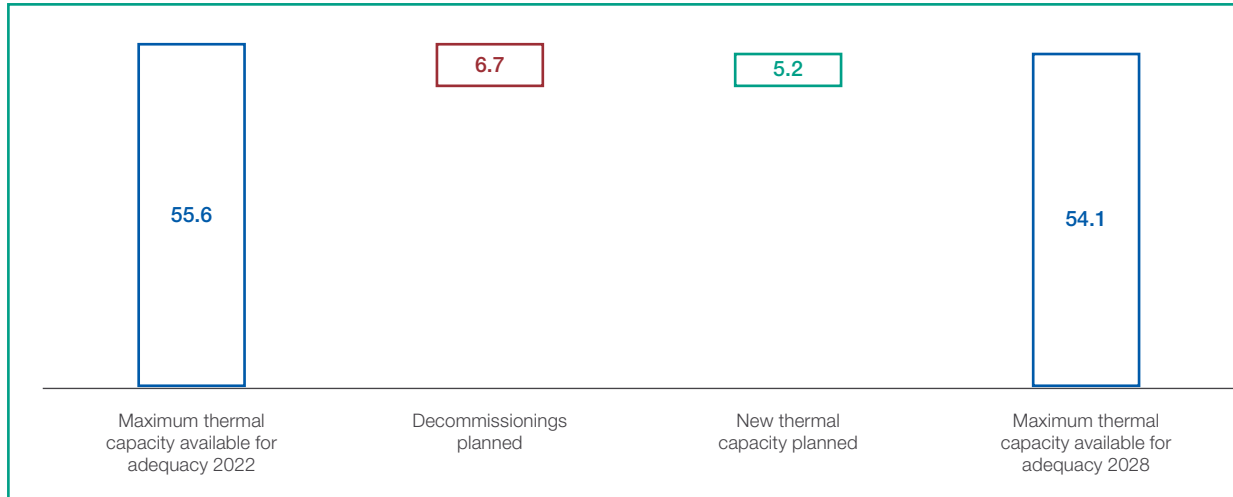
- the decommissioning of the coal/oil-fired power plants;
- the commissioning of what has already been awarded through the Capacity Market auctions held during 2019 (for the horizon years 2022 and 2023) and 2022 (for the horizon year 2024). The evolution of the thermal capacity involved in these auctions is detailed in *Table 1*;
- the commissioning of new thermal capacity resulting from connection requests to the national transmission grid.

TABLE 1 Evolution of the thermal capacity awarded in the CM auctions (GW)

HORIZON YEAR	ADDITIONAL CAPACITY AWARDED	CAPACITY IN SERVICE	CAPACITY RESOLVED	FUTURE ENTRIES
2022	2.0	2.0	-	-
2023	4.3	0.8	0.6	2.9
2024	3.0	0.0	0.9	2.1

In the absence of further unforeseen decommissioning, the maximum thermal capacity available will drop to circa 54 GW in the medium-term horizon (Figure 10).

FIGURE 10 *Maximum installed capacity (GW) for adequacy in the medium term horizon*



Instead, in the long-term horizon the thermal capacity that can contribute to the adequacy of the system will be slightly above 53 GW (Figure 11) due to the planned decommissioning of the remaining coal-fired plants (cf. Box 3).

FIGURE 11 *Maximum installed capacity (GW) for adequacy in the long term horizon*



However, it is worth emphasizing that, especially in the long term horizon, it is not guaranteed that an additional portion of the gas-fired thermal generation fleet will not be decommissioned due to the potential reduction in revenues. This potential phenomenon is captured in this report through a specific economic viability analysis that will be discussed later on.

DECOMMISSIONING OF COAL-FIRED POWER S

Already before 2019 Italy had committed to phase-out its coal-fired power plants. This objective was defined with greater accuracy, particularly regarding the **preconditions** necessary to achieve it.

Although the contribution of coal-fired plants in Italy is limited compared to other European countries, decarbonization must go hand in hand with the dimension of the security and cost-effectiveness of the supplies. Besides contributing to the adequacy of the system, in fact, coal-fired power plants also contribute:

- to stabilize the voltage profiles at specific grid nodes and portions of the grid, keeping them within the regulatory limits, both for the security and the quality of the supply;
- to provide inertia to the system, the reduction of which can lead to increased frequency variations (in terms of disturbance amplitude and rapidity), which must be mitigated through resources characterized by extremely rapid response times;
- to maintain adequate levels of short-circuit power at the grid nodes, essential for containing the severity of voltage dips and ensuring the proper operation of the protection systems and the HVDC connections.

Therefore, considering the need to maintain the above requisites, as of today the system has been able to sustain the decommissioning of approximately 1650 MW of coal-fired power plants.

The continuation of the coal phase-out process (*Table 2*) will require the fulfilment of the following enabling conditions:

- an increase in electricity needs in line with Terna's current forecasts contained in the joint Terna-Snam scenario document, so in the absence of significant increases not foreseeable as of today;
- growth of RESs in line with the targets of the NDP in 2030 (cf. chapter 2.1.2);
- development of storage capacity in line with the targets of the NDP in 2030 (cf. chapter 2.2);
- the commissioning of the generation units awarded in the Capacity Market (2022 auctions, 2023 and 2024 auctions), including those not yet authorised, whose commissioning has been estimated based on the best information to date;
- the reinforcement of the electricity grid, as described in the NDP, with particular reference to the interconnections with the major islands;

- the absence of decommissioning of gas-fired plants currently in service (for example due to economic unviability);
- the absence of significant reductions in import availability, in particular from the northern border (for example due to unavailability of the French nuclear capacity).

TABLE 2 *Decommissioning of the coal-fired capacity*

MONTH/YEAR	CAPACITY DECOMMISSIONABLE (MW)	TECHNICAL CONSTRAINTS ON DECOMMISSIONING
April 2024	1480	Commissioning of the generation and storage capacity awarded in the CM auctions
April 2025	1210	
January 2026	1845	

However, for Sardinia (*Table 3*) the development of vRES, storages and new interconnections with the mainland (Tyrrhenian link, SACOI 3) is essential for phasing out coal-fired power plants (in total approximately 1,000 MW) and there do not seem to be any conditions in place to achieve this by 2025; therefore, the hypothesis of initiating the phase-out on the island by 2025 and completing the process by 2028 appears more realistic.

TABLE 3 *Decommissioning of the coal-fired capacity in Sardinia*

MONTH/YEAR	CAPACITY DECOMMISSIONABLE (MW)	TECHNICAL CONSTRAINTS ON DECOMMISSIONING
April 2025	445	Commissioning of the storage capacity awarded in Sardinia for the 2024 CM auctions
January 2028	250	Commissioning of the Tyrrhenian Link West branch
January 2029	265	Completion of the Tyrrhenian Link connection

3.6 Main interzonal development

In order to facilitate the vRES deployment described in 3.3, as well as the storage systems outlined in section 3.4, the National Development Plan '23 calls for an increase in the transport capacity of the grid through the implementation of a specific set of projects.

The completion of the developments outlined in the NDP '23 will result in an increase in the exchange capacity from the South to the North of the country for a total of 16.6 GW.

Only a portion of these development projects has been considered within this document, consistent with the medium term (2028) and long term (2033) horizons, in the light of the best estimate based on the NDP '23.

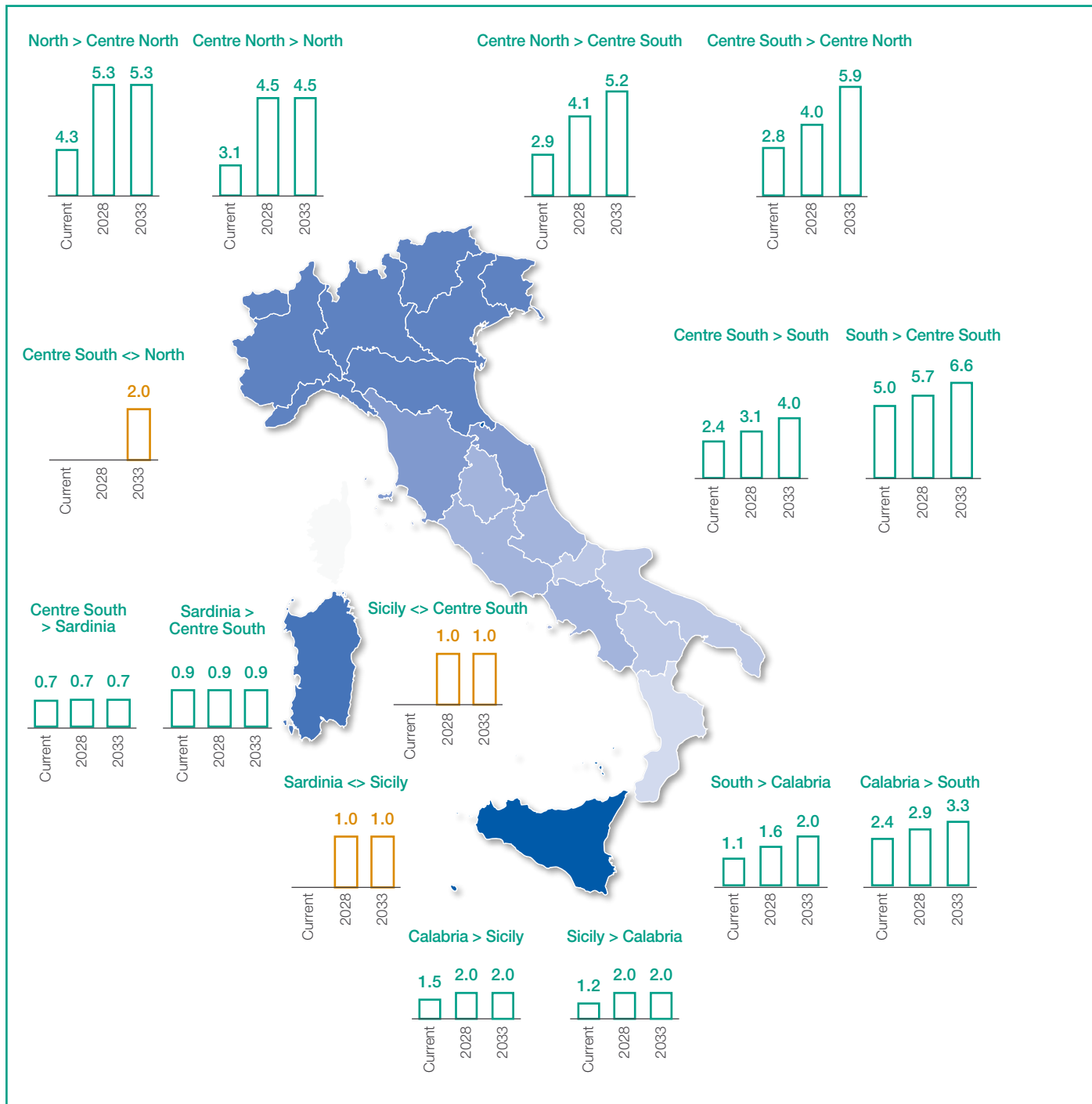
This new capacity becomes essential to enable the integration of the renewables planned in the scenarios, ensuring an acceptable level of overgeneration and enabling the transmission of energy from southern Italy (where most of the vRES growth is concentrated) to the northern regions, characterized by higher electricity consumption.



The increase in the planned transport capacity between market zones is summarized in *Figure 12*.

More details are available in the National Development Plan¹⁰.

FIGURE 12 Evolution of the exchange capacity (GW) between market zones



¹⁰ <https://www.terna.it/en/electric-system/grid/national-electricity-transmission-grid-development-plan>





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4

Main results and conclusions

Main results and conclusions

4

4.1 Reference to the modelling chain

The adequacy analysis of the Italian electricity system presented in this document refers to two time horizons, one in the medium term horizon (2028) and one in the long term horizon (2033).

This choice allows maintaining compliance with the time horizons identified by ENTSO-E within the ERAA 2023 (European Resources Adequacy Assessment).

The electricity needs, the vRES capacity and the storage capacity are consistent with the FES '22 (Future Energy Scenario, drafted by Terna and Snam) for the two analyzed time horizons.

The development of the interconnections, in the two time horizons, are in line with the 2023 National Development Plan (NDP '23).

The adequacy analyses are preceded by an economic viability assessment of the thermal power plants (EVA). These assessments aim to verify, whether the capacity of the existing thermal plants is able to cover their costs with the revenues coming from the electricity market in the time horizon.

The maximum available thermal capacity, presented in chapter 3.5, was used to obtain the perimeter of thermal power plants that can be subject to decommissioning due to the reduction of the earning margins (more details on the methodology are presented in Annex II).

The result of the EVA analysis, therefore, defines the list of the thermal plants potentially “in loss” allowing for a more accurate adequacy analysis in compliance with the standards defined by ARERA in the Resolution 370/2021/R/ELL.

In the Adequacy Analysis, therefore, it is verified whether the so-called “In the money” thermal plants are sufficient to ensure the adequacy of the Italian electricity system. If this is not the case, the maximum decommissioning is defined to maintain the adequacy of the electricity system by progressively decommissioning plants that are not profitable.

The study also includes ad-hoc sensitivity analyses with specific inputs aimed at better understanding the phenomena underlying potential risk situations for the system adequacy .

4.2 Adequacy in the medium term horizon(2028)

The analysis for the medium term horizon was conducted considering:

- the generation awarded in the previous Capacity Market auctions;
- the increase in electricity needs, in vRES and in storage capacity in line with the FF55 scenario (*Table 4*);
- the development of the exchange capacity in line with the FF55 scenario and, in particular, the full operation of the Tyrrhenian Link and Adriatic Link connections.

At the same time the following were not taken into consideration:

- additional decommissioning of the thermal generation capacity beyond what was already planned for the coal/oil-fired plants, and the refurbishment of plants awarded in Capacity Market auctions (*Figure 10*).
- analyses of extreme weather conditions similar to what occurred in the summer of 2022.

Using these assumptions the system is adequate, with a national average LOLE value of less than 3 h/year, as shown graphically in *Figure 13*.

As described in the methodological annex, the result shown represents the average value of a large number of possible system states simulated with a Monte Carlo approach. In particular, the ranges represented in *Figure 13* indicate the average result of all climatic conditions simulated.

The Italian electricity system could be subject to risks of load shedding in the event of critical circumstances, such as the decommissioning of a significant portion of the thermal power plants fleet or extreme weather conditions that simultaneously cause high demand, low water inflows and reduced thermal capacity availability as a result of HDWTs, derating or low water level in waterways.

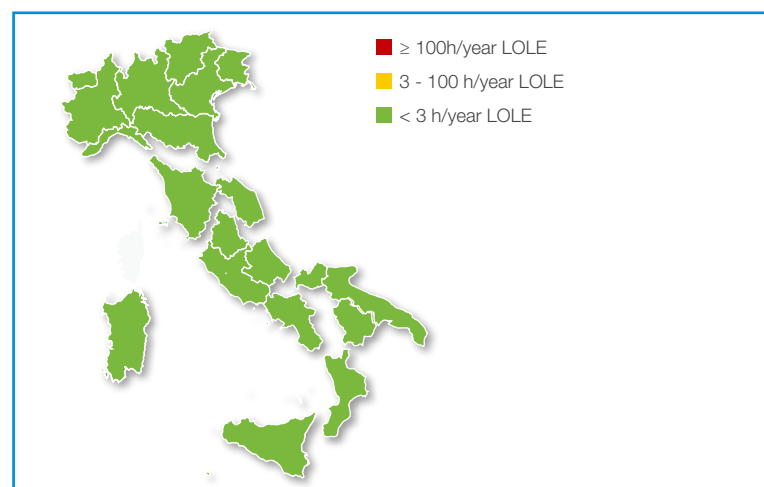
Besides the conditions just described, the medium term horizon analyses were performed considering also:

- additional decommissioning of the thermal generation capacity beyond what was already planned for the coal/oil-fired plants, and the refurbishment of plants awarded in Capacity Market auctions;
- analyses of extreme weather conditions similar to what occurred in the summer of 2022. This became necessary because the aforementioned extreme conditions are not included in the set of simulated weather conditions in the baseline analyses, thus requiring specific considerations as described in 5.2.2.

TABLE 4 *Medium-term scenario (2028), main assumptions*

	VALUE CONSIDERED IN THE SCENARIO
Demand	344.2 TWh
Photovoltaic	59 GW
Wind	22 GW
Storages	13.9 GW

FIGURE 13 *LOLE by bidding zone, medium term horizon (base scenario)*



4.2.1 Adequacy in the medium term horizon: the impact of the economic unviability

The analysis reported in the previous paragraph (4.2) indicates that, applying the described methodologies, the Italian electricity system is moderately adequate and does not require new capacity. In this scenario, however, there remain **risks linked to the decommissioning of thermal power plants due to their economic unviability**.

The increase in the installed capacity of vRES, as reported in FES '22 will, inevitably, lead to a reduction and greater irregularity in the running hours of the traditional thermal power plants. This will impact the revenues of thermal units leading to the decommissioning of those no longer able to cover their costs.

In order to assess the possible implications of the above, an Economic Viability Assessment (EVA) of the plants is conducted, with the objective of determining whether only the plants that are capable of covering their costs are sufficient to ensure the adequacy standard of the system.

FIGURE 14 *Economically unviable capacity (GW) by technology, medium term horizon (2028)*

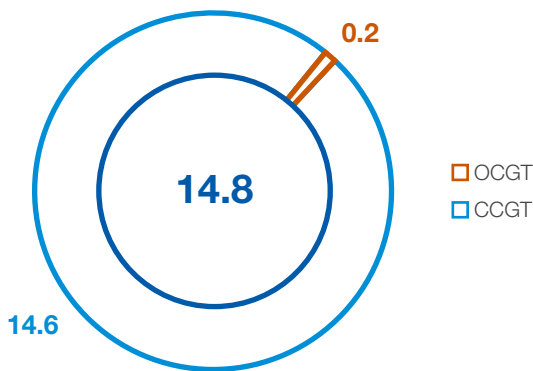
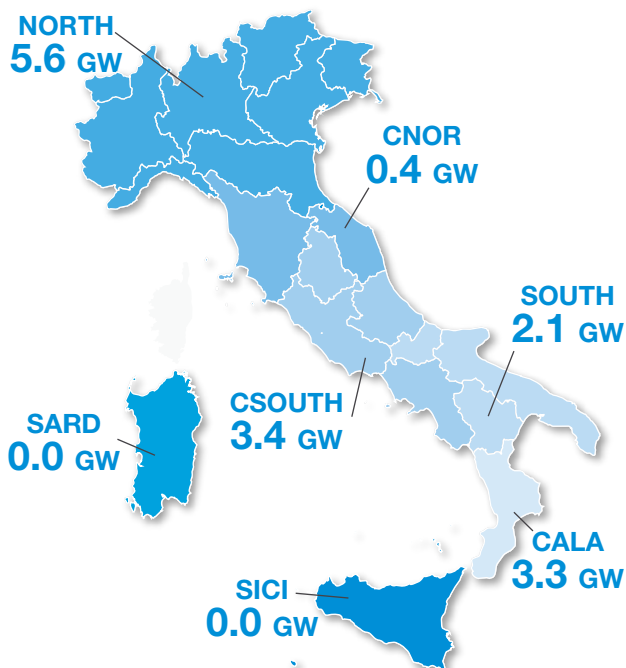


FIGURE 15 *Economically unviable thermal maximum capacity, in the medium term horizon: zonal distribution*



The analysis was performed through an iterative process aimed at simulating the effect of a gradual decommissioning of the “missing money” thermal power plants, thus allowing for an evaluation of how the decommissioning of a first group of plants could lead to an increase in the profit margin of the remaining ones, enabling, in some cases, the recover of the avoidable fixed costs.

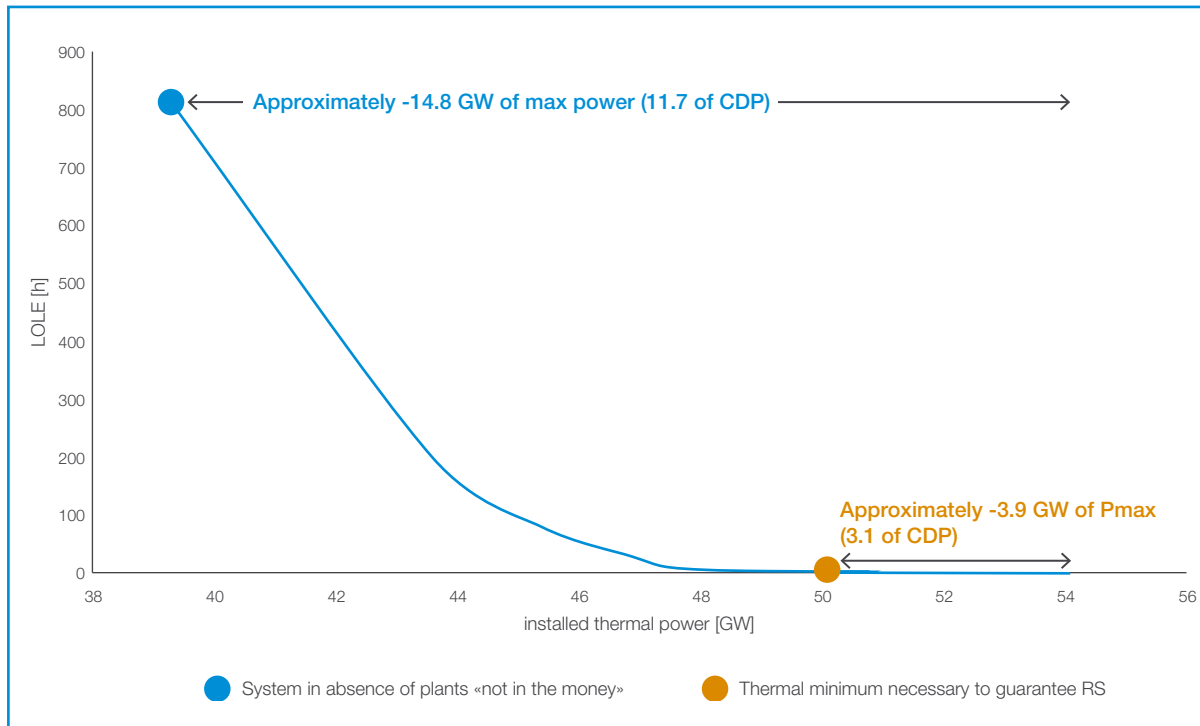
The details regarding the applied methodology are described in 5.2.1 (Analysis of the economic viability of the plants). In particular, a perimeter of plants that could be at risk of decommissioning is defined. This “missing money” perimeter excludes for example (i) cogeneration plants and/or those linked to industrial production cycles that generate additional profits beyond those related to the energy markets and (ii) all new and repowered plants which have been awarded in the Capacity Market auctions for 2022, 2023 and 2024, securing a 15-years premium. Overall, the “missing money” perimeter consists of about 20 GW compared to the total thermal capacity of around 54 GW.

The EVA analysis for the medium term horizon showed the presence of approximately **14.8 GW of thermal power plants unable to cover their avoidable fixed costs**.

Figure 14 presents the breakdown by technology, while Figure 15 shows the distribution of this capacity across the various areas of the system.

The decommissioning of these plants for economic reasons (approximately 14.8 GW) would determine a LOLE much higher than the RS (*Figure 16*) and criticalities distributed all over the system (*Figure 17*).

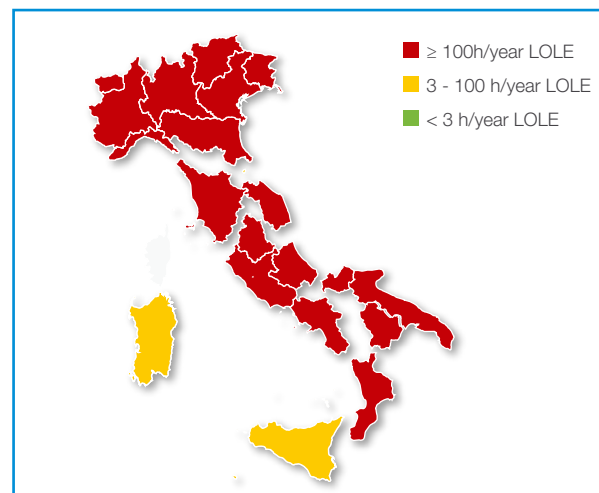
FIGURE 16 *Impact of the decommissioning of the economically unviable thermal generation. Change in Pmax - LOLE*



From the chart above it can be seen that the system becomes inadequate by decommission 3.9 GW of thermal power plants.

Therefore, even assuming that all the conditions foreseen in the scenario are effectively fulfilled, the **electricity system will need a minimum value of about 50.2 GW of maximum thermal capacity**, while the EVA analysis showed that, without opportune mechanisms to keep the necessary capacity in operation, the system would reach a point of economic balance of around 39.3 GW of maximum thermal capacity, with a gap of 11 GW and an unacceptable value of LOLE.

FIGURE 17 *Impact of the decommissioning of the economically unviable generation, LOLE value by bidding zone (39.3 GW of remaining thermal power plants)*



4.2.2 Adequacy in the medium term horizon: critical weather conditions

Despite the conditions described in paragraph 4.2 representing an adequate system, risks persist due to the occurrence of extreme weather conditions such as those experienced in 2022 (extreme and prolonged drought, high temperatures and too-low river levels). The critical situation of the summer 2022 is currently neither captured in the climatic dataset used in ERAA framework, nor in the Monte Carlo samples used in the stochastic analyses, therefore it is necessary to reconstruct such conditions *ad hoc*, based on the weather scenario that represents the summer of 2022, but applied to the future power system model in terms of resources (load, renewables, grids, etc.).

These climatic circumstances result in an increase in electricity needs in summer periods, a reduction in hydro generation (due to low water inflows) and a decrease in the available capacity of thermal plants. The latter is caused by the derating effect of HDWTs phenomena and/or by the low river levels which compromises the use of the plants cooling systems. All of these contingencies occurred simultaneously in July '22, resulting in a maximum unavailability of about 20 GW of thermal capacity. Of these, 3.1 GW were exceptionally unavailable in the North zone due to the low water level in rivers (a peculiarity not replicable in the climate database used for the base simulations).

With the aim of reproducing the situation occurred in the summer of 2022, a medium-term scenario, in which what has just been described occurs, was simulated:

- hourly electricity demand profile in line with the 2022 one, rescaled with the mid-term electricity target demand;
- hydro generation in line with what occurred in 2022;
- loss of an additional 3.1 GW of thermal capacity in the North due to HDWTs and excessively low river levels, in addition to faults and available capacity decrease due to thermal de-rating.

The stochastic analyses indicate that in a climatic condition like July 2022, the future Italian electricity system would face serious adequacy issues leading to a loss of load, even with a moderate import from the Northern border. In particular, the system reaches its adequacy limit considering the unavailability of only 2.0 GW of thermal capacity in the North zone, compared to the 3.9 GW that could be decommissioned according to the analysis conducted in 4.2.1.

Therefore, it will be necessary to identify solutions to **improve the availability** of the current generation fleet under extreme conditions of high temperatures and drought (e.g evaporative cooling towers).

4.3 Adequacy in the long term horizon (2033)

Similarly to the medium term horizon, the long-term horizon is characterized by:

- the presence of the generation awarded in previous Capacity Market auctions
- an increase in electricity needs, in vRES and storage systems in line with the FF55 scenario ([Table 5](#));
- the evolution of the exchange capacity in line with the '23 Development Plan, including the implementation of some HyperGrid projects, such as HVDC Milan-Montalto, Central Link and part of the HVDC Adriatic.

TABLE 5 Long-term scenario (2033), main assumptions

	VALUE CONSIDERED IN THE SCENARIO
Demand	378.6 TWh
Photovoltaic	90 GW
Wind	32 GW
Storages	27.4 GW

From the analyses of the reference scenario, it emerges that the long-term horizon, considering the increase in renewable installed capacity and the increase in the storage capacity while **maintaining all the thermal capacity expected** in 2033 ([Figure 11](#)), will be fully adequate with a LOLE value close to 0 h/year and less critical than the medium term horizon regarding the adequacy of the system.

Besides the conditions just described, long-term analyses were carried out considering further decommissioning of the thermal capacity due to the possible revenue reductions from energy markets ([Figure 18](#)).

4.3.1 Adequacy in the long term horizon: the impact of economic unviability

For the long term horizon (2033), in analogy to the 2028 time horizon, an economic viability analysis has been conducted to assess how many thermal plants, among those at risk of decommissioning due to the increase in the vRES generation (the "missing money" perimeter), are economically profitable and to quantify the potential decommissioning.

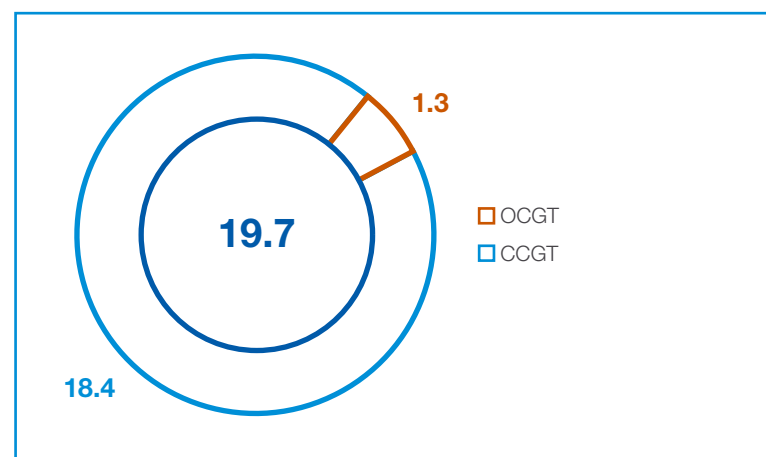
This "missing money" perimeter amounts to approximately 20 GW and, similarly to what was done for the medium term horizon, excludes for example (i) cogeneration plants and/or plants that power industrial production cycles, which make additional profit and (ii) all new and repowered plants which have participated to the auctions for the year of delivery 2022, 2023 and 2024 of the Capacity Market, awarding a 15-year premium.

The **EVA analysis for the long term horizon** showed **greater criticality compared to the medium term horizon** as regards the risk associated with the **decommissioning of thermal power plants** due to economic unviability.

In fact, the **entire thermal fleet of the EVA perimeter** was found to have lower profits than its costs and is therefore at risk of being **potentially decommissioned in the long term horizon** (Figure 18).

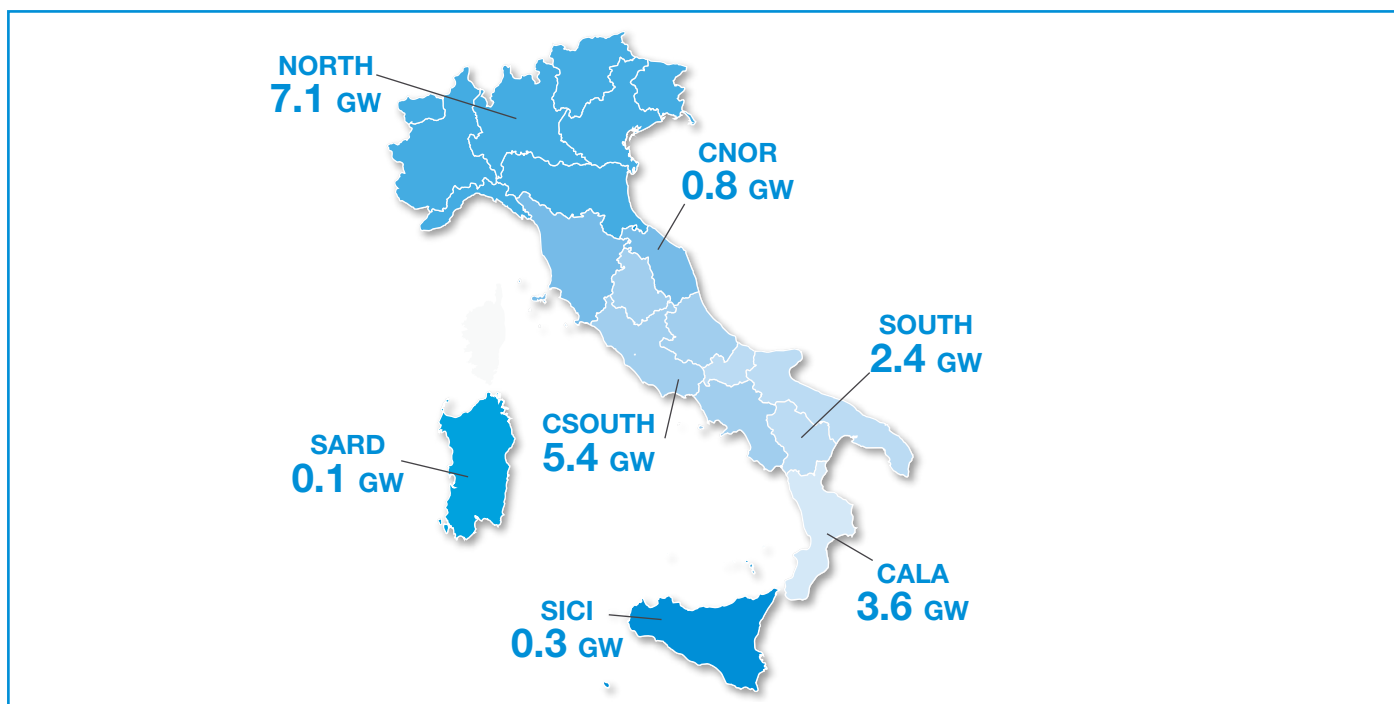
This is mainly due to the increase in the photovoltaic (90.5 GW), wind (32.2 GW) and storages (27,4 GW) expected installed capacity for 2033 which reduces the running hours of thermal power plants.

FIGURE 18 Economically unviable capacity (GW) by technology, long term horizon (2033)



In particular, the zonal distribution of the decommissioned "missing money" plants is shown in Figure 19.

FIGURE 19 Economically unviable thermal maximum capacity, in the long term horizon: zonal distribution



4. Main results and conclusions

The trend of the national LOLE value according to the gradual decommissioning of thermal capacity is shown in [Figure 20](#). In the long term horizon, the adequacy standard is met despite the decommissioning of approximately 12.8 GW¹¹ of thermal power plants (around 9 GW more than in the medium-term analyses). The decommissioning of the entire economically unviable perimeter (19.7 GW), instead, results in an unacceptable LOLE value.

FIGURE 20 *Impact of the decommissioning of the economically unavailable thermal generation fleet. change in Pmax - LOLE*

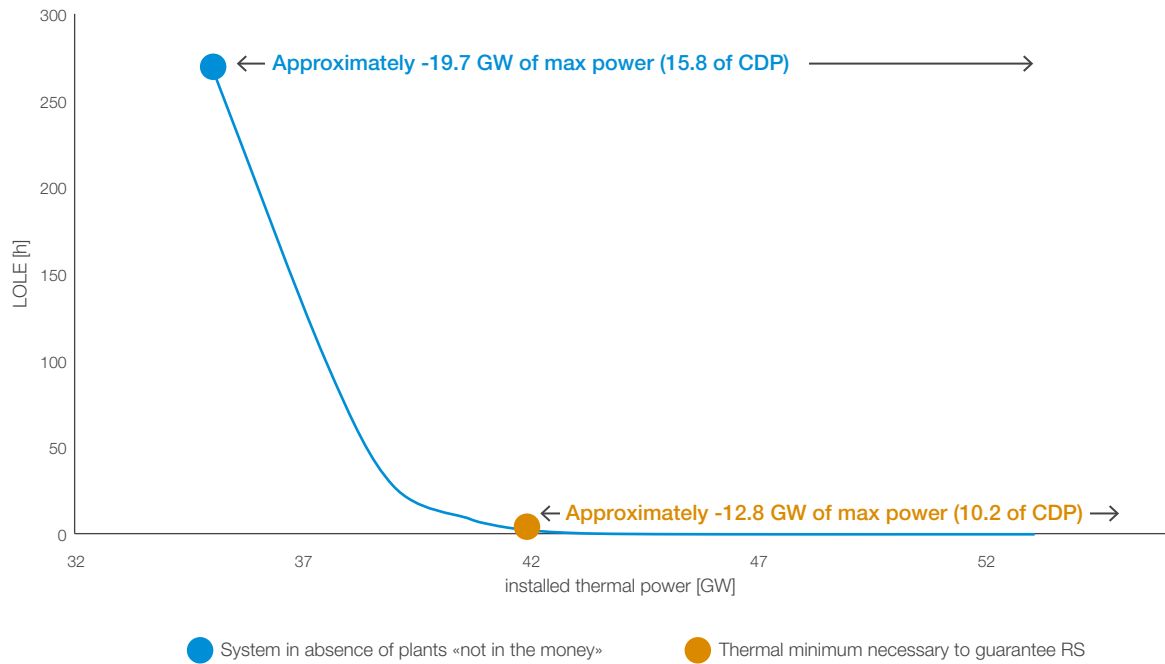
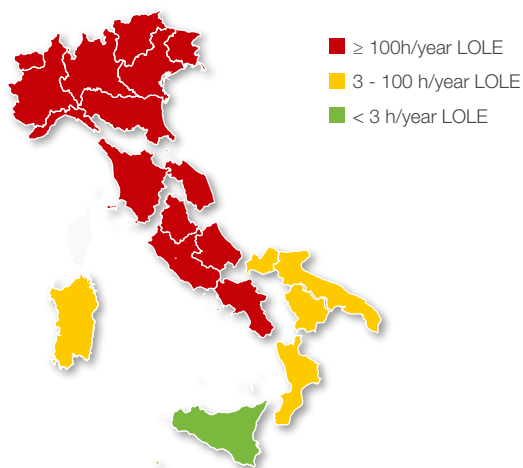


FIGURE 21 *LOLE by bidding zone, long term horizon*



In the event that all existing capacity in the EVA perimeter is decommissioned, only Sicily is able to meet its zonal load without compromising the adequacy standard ([Figure 21](#)) thanks mainly to the great expansion of vRES in the island.

¹¹ The maximum value of thermal capacity “decommissionable”, for which the Reliability Standard of 3 hours of LOLE should in any case be met, depends on multiple factors, such as the specific plant decommissioned and the market zone in which it is located.

4.4 Conclusions

In the **medium term horizon** (2028), the analyses showed that in the simultaneous occurrence of what was already awarded in the CM auctions ('22, '23 and '24), and was already planned by the NDP (in particular the Tyrrhenian link and the Adriatic Link), considering **the absence of further decommissioning besides that already planned for the coal-fired plants, the Italian electricity system would be moderately adequate** and does not require new capacity.

However, extreme climatic events, such as those that occurred in the summer of 2022 and that risked to repeat also during 2023, can compromise the availability of the Italian thermal generation fleet and, consequently, can have a significant effect on the system adequacy.

Therefore, besides maintaining the operation of a sufficient quantity of thermal power capacity through forward contractualization mechanisms, it is necessary to promote – through the Capacity Market – the upgrading of the thermal plants equipped with water cooling systems, through the implementation of solutions that reduce the dependence of the power generation on the river levels and temperatures of water, in the most critical periods of the year. With this objective, in a recommendation, the Minister of Environment and Energy Security asked Terna to modify the Capacity Market Rules.

Potential **adequacy risks are further reduced in the long term horizon** (2033) thanks to the contribution deriving from the planned development of vRES, storages and grid infrastructures, if there is no further thermal decommissioning besides that considered by the reference scenarios.

Specific analyses of the economic viability of the thermal generation fleet (EVA-Economic Viability Assessment) showed, however, that in the medium and long term horizons the expected running hours of the power plants tend to decrease leading to the potential **decommissioning** of about **14.8 GW in the medium term horizon** and **19.7 GW in the long term horizon**.

Both time horizons show an evident inadequacy in the condition in which all the thermal power plants resulting unviable from the EVA analysis are assumed to be decommissioned. In order to keep the Italian electricity system adequate, it is necessary to maintain in operation at least 50.2 GW of thermal installed capacity in the medium term horizon and at least 41 GW in the long term horizon.

This results confirm the need in the electricity system, also in the long term horizon, for a forward contractualization mechanism such as to safeguard a minimum thermal capacity.

Finally, the analyses showed that, in most of the simulations, the most critical areas results to be the North, Centre-North and Centre-South bidding zones where most of the thermal capacity is located and which are responsible for approximately 80% of the national electricity needs.

The riskiest periods are closely associated with an increase in the residual load of the system. In general they occur in correspondence with high demand, typically related to the most extreme temperatures in summer and winter, and low contribution from PV generation during evening/night periods.

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5

Annexes

Annexes

5

5.1 ANNEX I: Analogies and differences between ERAA 2023 and the Italian NRAA 2023

The ENTSO-E ERAA 2023 document (ERAA 23), currently being published, contains analyses referred to 2025, 2028, 2030 and 2033 target years. The reference scenario for the analyses was prepared starting from December 2022 and is based on the data included in the 2022 (target FF55). The Italian national transmission grid is aligned to what was published in the NDP 2023.

Unlike this report, ERAA analyses the economic viability of plants through an approach based on the minimization of the system costs instead of executing a detailed analysis of the marginality of each plant. Moreover, regarding Italy, ERAA considers a much greater availability of imports from the Northern border which in Terna's opinion is excessively optimistic.

ERAA23, in addition, does not provide, unlike the national report, indications on the thermal minimum capacity necessary to meet the RS (3 h/year), but is limited to the adequacy assessment of the system with reference to a specific generation scenario obtained through the application of the economic viability analysis briefly described above.



5.2 ANNEX II: Models and methodologies

5.2.1 Economic viability assessment of the plants

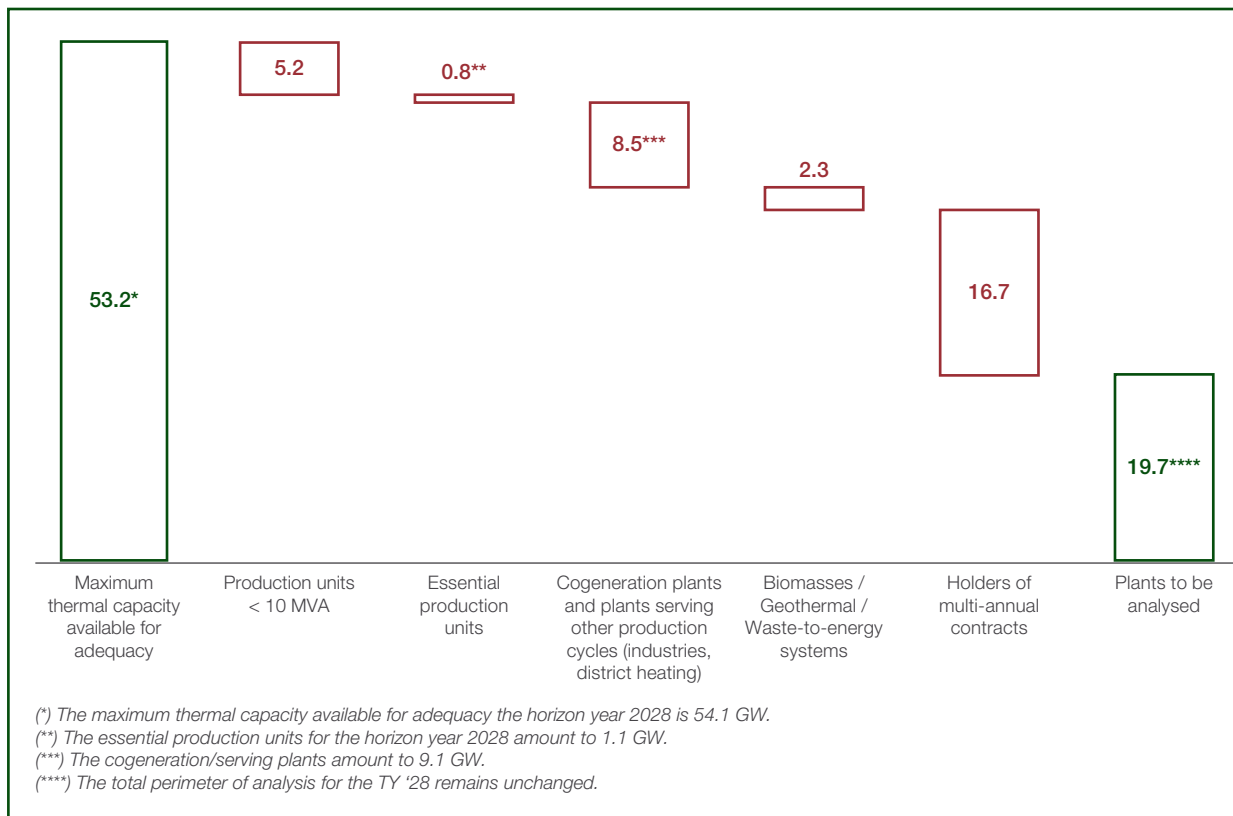
5.2.1.1 Perimeter of the analysis

The objective of the economic viability assessment (EVA) of the plants is to verify their profitability in the time horizon so as to determine the generation capacity potentially subject to decommissioning due to negative values of the profit margin.

The analysis focuses only on significant production units excluding:

- cogeneration plants and/or plants that power industrial production cycles, which make additional profits potentially crucial for the profitability of the plant itself (the expected revenues cannot be easily simulated);
- essential plants, which remain in operation regardless of their economic viability¹²;
- unavailable plants, because they are mothballed or kept as cold reserve¹³;
- new and repowered¹⁴ plants which won a 15-years premium participating to the Capacity Market auctions for 2022, 2023 and 2024.

FIGURE 22 *Economic viability assessment: perimeter*



The result is shown in *Figure 22*, where we can see that the thermal capacity considered by the analysis will be approximately 19.7 GW.

¹² Conservative assumption based on the most recent available information.

¹³ Conservative assumption based on the most recent available information.

¹⁴ Repowered plants are completely excluded from the analysis.

5.2.1.2 Analysis process

For the economic viability assessment of the plants the avoidable fixed costs were considered; these are obtained as the sum of all the costs incurred by the operator of the plant independently from its production. These costs include, in line with what is provided for in the ACER methodology¹⁵, the:

- maintenance costs: in this item includes all costs related to the routinary, preventive and predictive maintenance (during the normal operation of the plant);
- manpower costs: the costs related to the personnel employed for the maintenance of the plant;
- insurance, economic amount of the insurance entered into by the power plant operator.

The costs for gas transport are, instead, excluded. For these, in fact, great variability from plant to plant has been noted, in particular for OCGTs, which makes it difficult to identify a standard value of reference.

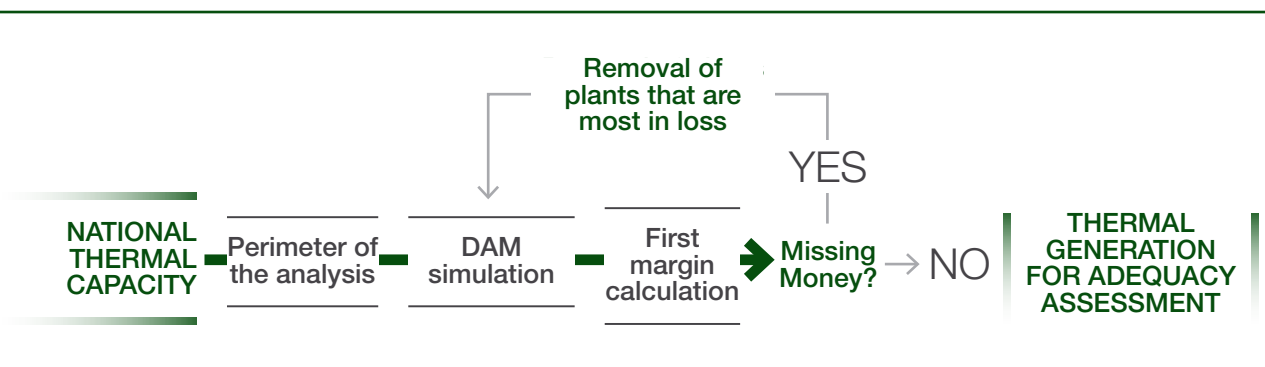
The fixed costs¹⁶ used for the analysis are shown in *Table 6*.

TABLE 6 Avoidable fixed costs

TECHNOLOGY	AVOIDABLE FIXED COSTS [k€/MW-year]
CCGT	15
OCGT	13

The analysis was conducted through an iterative process (*Figure 23*) aimed to simulate the effect of a gradual decommissioning of the loss-making thermal power plants. This process makes it possible to assess how the decommissioning of a first group of plants increases the profit margin of the remaining ones, enabling, in some cases, the recovery of the avoidable fixed costs.

FIGURE 23 Iterative analysis process



For each cycle of the iterative process, for each power plant, the following are estimated in the year of reference:

- the day-ahead-market (DAM) revenues based on the marginal market price and a further earning margin related to any conditions of shortage on the market itself;
- the variable operating costs obtained as the sum of the fuel cost, CO₂ emission cost and other operating costs (such as the variable maintenance costs, the start-up costs, etc.);
- the DAM profits as the difference between a. and b.

In this way it is possible to calculate the EBITDA («Earnings Before Interest Taxes Depreciation and Amortisation») as the first margin calculated from the DAM profits net of the avoidable fixed costs (*Table 6*). Among “missing money” plants (EBITDA<0), those making the most loss are considered decommissioned, and are not considered in the next iteration.

¹⁵ https://acer.europa.eu/sites/default/files/documents/Decisions_annex/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf

¹⁶ <https://www.arera.it/allegati/docs/21/370-21studio.pdf>

The estimation of the DAM revenues is made through a simulation of the said market, based, in addition to the scenario already described in paragraph 3, also on a series of assumptions, in particular:

- a set of weather conditions of reference;
- producibility of renewable resources;
- commodity prices;
- interconnections with other countries.

The choice of a set of different weather conditions, obviously, can determine a variation in the production profiles of the thermal power plants, increasing or reducing the related revenues. However, an operator of a thermal plant, in reality, cannot base its strategy on the occurrence or non-occurrence of specific weather conditions.

Considering, in addition, the time horizon of the analysis, 2028 and 2033, and the gradual reduction of the costs of the Dispatching Services Market (DSM) as a result of the grid development planned, it is assumed that the component of revenues coming from this segment of the electricity market is no longer significant for the purpose of determining the profit margin, and is therefore neglected.

The iterative process continues until all the thermal plants in the perimeter are “in money” ($EBITDA > 0$). Therefore, it can be considered that they will still be operating in the year of reference and will therefore be able to contribute to the adequacy of the system.

The scenario thus modified, with a reduced thermal generation fleet, is then assessed through a probabilistic approach in order to calculate the adequacy indicators.



5.2.2 Adequacy analysis

5.2.2.1 Simulation of the electricity system

The two main indicators for measuring the adequacy of an electric system are: the expected energy not served in a year (EENS), and the number of hours in a year in which the system does not manage to meet the demand (LOLE).

The estimation of these two indicators is done through the probabilistic simulation of the electricity system over a time period of one year. A simulation which requires a series of input data, including for example:

- the thermal generation installed with the related technical characteristics;
- the hydro, photovoltaic and wind installed capacity;
- the transmission grid, represented in a simplified way through the exchange capacity (expressed as the weighted average over the various periods of the year) between bordering market areas;
- the hourly profiles of “imposed” generation ¹⁷, that is the power generation not tied to the economic merit orders;
- the hourly profiles of reduction of the exchange capacity between market areas due to planned maintenance;
- the number of weeks of maintenance required by each generator;

the hourly profile of the temperature, from which the demand profile is obtained;

- the hourly profiles of wind, sunlight and rainfall, from which the hydro, photovoltaic and wind generation profiles are obtained;
- the hourly profiles of unavailability of each thermal power plant due to accidental faults;
- the hourly profiles of reduction of exchange capacity with foreign neighboring countries due to accidental outages.

Based on the aforementioned inputs the following problems of optimisation with different time horizons are resolved in order:

1. the hourly programming, on an annual time horizon, of the management of hydro reservoirs and definition of an optimised maintenance plan for the thermal generation fleet;
2. the hourly dispatching on a weekly basis which revises the previous one on the basis of the faults selected by the model.

Both optimisation problems seek the configuration which, observing the technical constraints of the simulated system, minimises the variable generation cost. In particular, the unit-commitment requires observance of the constraints related to the operating reserve and to the transport capacity between the different bidding zones of the system.

Like all models, there are a series of approximations, including:

- the resolution of the demand/generation balance occurs within a single energy market (intraday markets, and dispatching and balancing services are not considered);
- the absence of specific strategies on producers side (“perfect market” condition).

¹⁷ For example, geothermal generation, generation from biomass, and all the generation subject to operating constraints (essential plants).

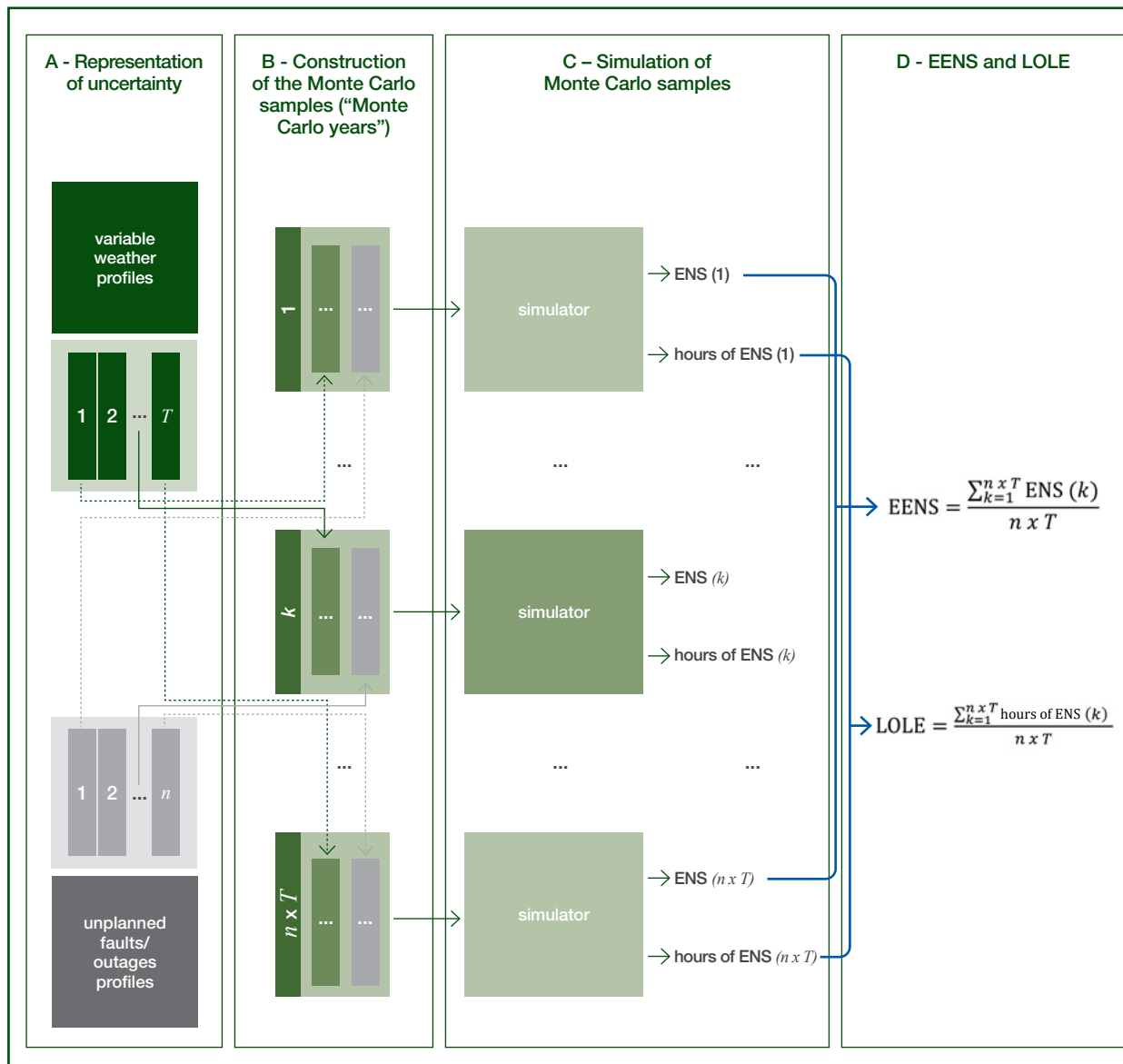
5.2.2.2 Probabilistic approach

The daily operation of the electricity system presents a series of elements which, by nature, are uncertain, including:

- the weather phenomena (temperature, wind, sunlight and rainfall);
- the availability of the generation, which depends also on the occurrence or non-occurrence of faults;
- the availability of the transmission capacity, which, as for the generation, is linked to possible faults.

This uncertainty is destined, in the next few years, to be increasingly significant: the electrification of consumption and the higher proportion of generation from renewable sources will increase the dependence of demand and generation on uncertain weather phenomena, the gradual ageing of the thermal generation fleet will make more probable the breakdown of some components, and the increase in extreme weather phenomena exposes some elements of the transmission grid to a higher probability of outages. For these reasons, a correct system adequacy assessment must involve the use of a probabilistic approach.

FIGURE 24 Probabilistic approach summary



A probabilistic approach makes it possible to consider in the simulations the intrinsic uncertainty of some input elements. Currently, the probabilistic approach most used is the so-called Monte Carlo method (*Figure 24*).

The Monte Carlo method can be summarised as the consecutive application of the following actions:

- A. a sample of possible values and/or operating conditions is considered for all the potentially uncertain elements. In producing the samples, the distribution curve of the probabilities of occurrence of each of the above statuses is taken into account;
- B. a certain number of Monte Carlo samples (also called “Monte Carlo years”) is obtained with the different values and/or operating conditions identified in A;
- C. the operation of the system considered is simulated in the different Monte Carlo samples (MC years) obtained in B and for each of them the adequacy indicators are calculated;
- D. the annual average is calculated based on the results of the simulations of the system described in C.

The four steps just mentioned are described in more detail below.

A. Uncertainty in an electricity system

In the analysis uncertainty is represented mainly:

- by using the weather variables: obtained by historical data opportunely updated to consider the phenomena of climate change. The weather variables are considered completely correlated: in the construction of a Monte Carlo sample, temperature, wind, sunlight and rainfall profiles comes always from the same “climate year”;
- by the availability of generation and of the exchange capacity between areas: assessed through a sequence of casual extractions that simulates the occurrence of faults in generators and lines.

B. Construction of the Monte Carlo samples (“Monte Carlo (MC) years”)

The various MC years to be analysed are obtained grouping together, for each market zone, the weather conditions, belonging to one climate year, with the availability profiles for each generator in the market zone and the availability profiles of the exchange capacity with the bordering countries. The Monte Carlo years thus constructed are considered all equally probable, because the probability of occurrence is considered over the total number of the simulated MC years.

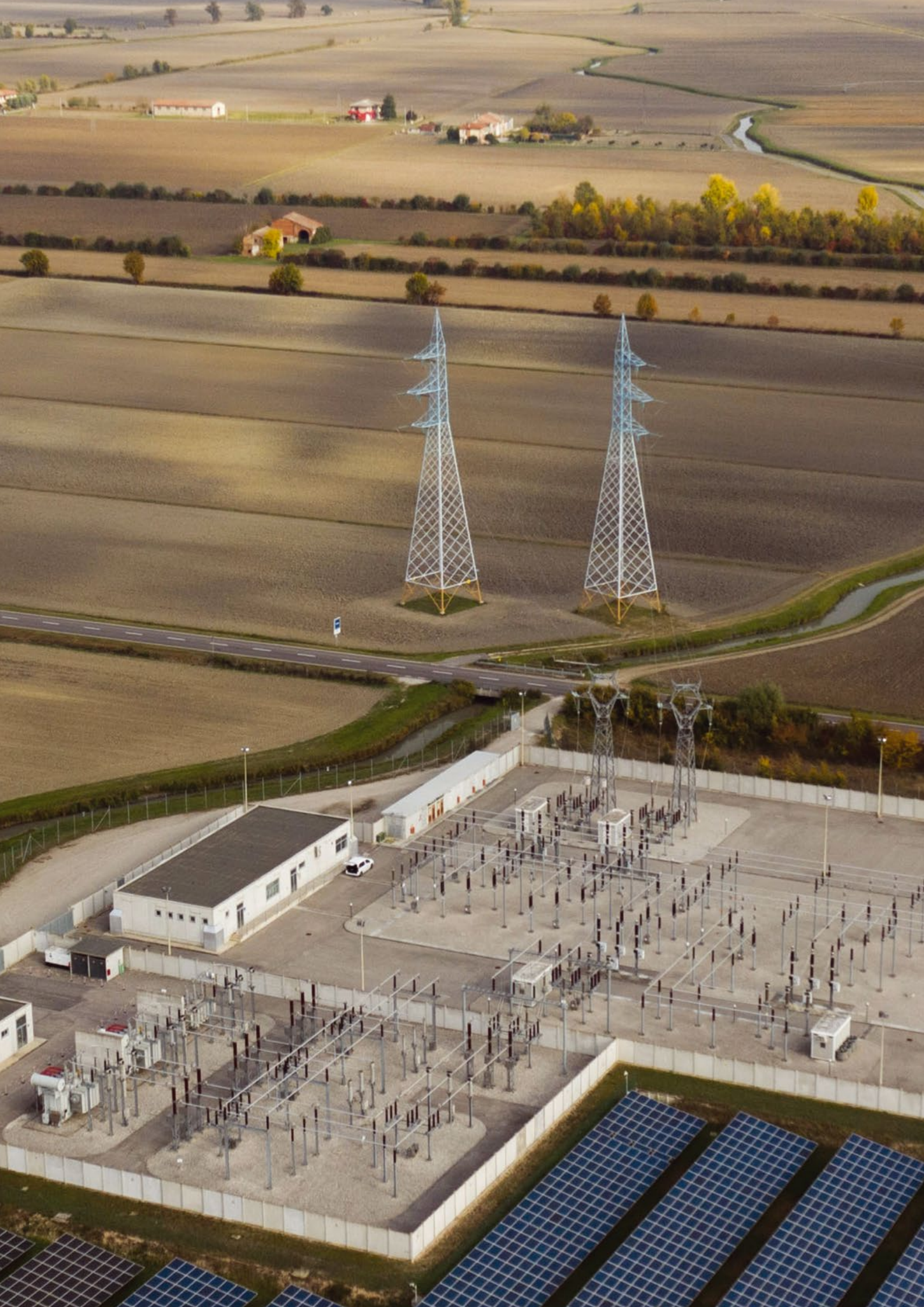
C. Simulation of the Monte Carlo samples

For each MC year generated, the operation of the electricity system is simulated and the adequacy indicators are obtained by calculating the ENS (Energy Not Served, MWh) index, representing the portion of demand not supplied, and the number of hours in which this value is different from zero.

D. EENS and LOLE

The last step of the process is the calculation of the average value of ENS of all the MC years simulated which represents the Expected Energy Not Served (EENS). Similarly, the average hours, for each MC year, in which the value of ENS is different from zero represents the Loss of Load Expectation (LOLE).

For each “climate year” a value of EENS and LOLE is obtained from the average of the MC years simulated in those given conditions of temperature, sunlight and wind. The total values of EENS and LOLE are calculated as the average of those obtained for the different weather years.



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