2025

National Resource Adequacy Assessment for Italy

Terna
Driving Energy

In this document, Terna will examine expected developments in the Italian electricity system and assess the conditions needed to guarantee resource adequacy over the next ten years, as required by art. 3 of the Ministerial Decree issued by the Ministry for Economic Development on 28 June 2019.

MISSION

"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."

PURPOSE

"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 ensure that everyone has equal access to electricity and are working to provide clean energy for future generations."

VISION

"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."

Executive Summary

Context and aims of the National Resource Adequacy Assessment for Italy

The electricity system is at the centre of a radical ongoing transformation. This is driven by the need to integrate growing volumes of energy produced from variable renewable energy sources (hereinafter "vRES"), as the number of new renewable energy plants progressively increases. Between the beginning of 2022 and the end of 2025, a total of 23.3 GW in photovoltaic and wind capacity has entered service.

On the one hand, this ongoing process is enabling us to reduce our dependence on fossil fuels and exposure to gas and CO2, price volatility, limiting the risks linked to geopolitical factors and international markets. On the other hand, it has created new challenges and complexities for electricity system operators.
The progressive replacement of gas-fired power generation with vRES poses significant challenges for management of the electricity system, including for example:

- **adequacy** in terms of the system's ability to meet demand at all times, taking into account the unpredictable nature of vRES and appropriate quantification of the contributions made by storage and imports;
- **flexibility**, in terms of the system's ability to cope with the variability and uncertainty that demand and production from vRES have introduced into the system;
- management of **overgeneration**, where production outstrips demand: a situation that in recent years has typically occurred on and around public holidays in spring, when consumption is lower and renewable production is high. Such situations are due to become more frequent in the future given the growing share of energy generated from renewable sources;
- **voltage regulation** of synchronous thermal plants ensures constant control of reactive capacity and enhances the system's robustness. A reduction in their number could accentuate the volatility of voltage profiles, making it more difficult to manage security limits and increasing the grid's exposure to changes in operating conditions and during outages;
- the stability of **frequency regulation** is dependent on **system inertia** traditionally provided by synchronous thermal plants. Their progressive reduction means that frequency levels are more susceptible to unexpected imbalances between generation and load demand, with faster and more marked oscillations. This makes it more complicated to manage the system's stability and increases the risk of grid separations;
- an increase in **grid congestion** linked to the development of vRES, the location of which does not usually correspond to consumption centres.

Given these changes and greater uncertainty, the aim of this **National Resource Adequacy Assessment for Italy (NRAA)** is to assess the adequacy conditions of the system in the medium and long term, taking into account the target years of 2030 and 2035. The basis for this assessment includes certain elements already examined in the energy scenarios set out by Terna and Snam in the 2024 Future Energy Scenarios document ("FES", so called *Documento di Descrizione degli Scenari*, or DDS 2024). These are based on the National Energy and Climate Plan (NECP) adopted by the Italian Government in July 2024.

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

Expected Energy Not Supplied

(EENS, MWh)

The expected share of unmet electricity demand in a given period due to generation fleet and/or transmission capacity constraints.

Loss of Load Expectation

(LOLE, h)

The expected number of hours when the EENS value is not zero.

Over a ten-year time horizon, the document assesses the capacity of the Italian electricity system to ensure that available resources - namely generation plants, imports and storage - are sufficient to meet electricity demand at any given time, and in any bidding zone into which the country is divided.

The adequacy assessment is preceded by an economic viability assessment (EVA), which aims to verify the capacity of existing plants to cover their costs on the energy market in the various target years under analysis. The outcome of the EVA thus defines the boundary of generation capacity that will continue to operate as it is in the money. This implies that capacity unable to cover its fixed costs will be decommissioned, allowing for a more accurate assessment of adequacy and of compliance with the standards set by the regulator, ARERA, in Resolution 370/2021/R/ELL.

Results

The major increase in the use of vRES and storage foreseen in the FES - and in part already apparent – will lead to a significant reduction in the operating hours of the gas-fired thermal fleet. This will result in a decline in the value of the thermal generation market and a greater risk that plants will be decommissioned as a part of the fleet is no longer in the money. Recent years have already recorded a progressive decline in the operating hours of thermal plants and, as a result, in thermal production which, after excluding biomass and geothermal production, has fallen from 175 TWh in 2022 to 131 TWh in 2024. This decline is particularly significant in relation to non-cogeneration gas-fired plants, representing the contestable segment of the electricity market: in 2024, this segment amounted to approximately 52 TWh, down almost 30 TWh compared with 2022, with a further decline expected over the medium to long term. Given that the generation fleet consists of units with varying degrees of efficiency, the reduction in production is more concentrated among less efficient plants.

The assessment conducted shows how overall loss-making thermal capacity, with a contribution margin below fixed costs, is expected to exceed 26 GW as early as 2030. The simulations conducted show that this capacity will operate for less than 1,000 hours a year by 2030. If this capacity were to be effectively decommissioned, available thermal capacity would fall to below the minimum needed to guarantee system adequacy. This would result in a system with hundreds of LOLE hours, when expected demand would exceed available capacity. It should also be noted that the EVA was not applied to cogeneration plants serving internal production cycles, as it is assumed that these will continue to operate, if necessary following renewal. Without this, failure to modernise cogeneration plants will worsen the issues around adequacy.

This assessment confirms that a system devoid of forward contracting mechanisms, and thus reliant solely on price signals from the spot markets, would tend towards a level of programmable capacity determined solely by short-term economic equilibrium, and therefore incompatible with adequacy standards.

These risks remain even if the assessment takes into account storage capacity arranged following the first Energy Storage Capacity Procurement Mechanism (MACSE) auction, which contracted 10 GWh of storage capacity, equal to 1.2 GW of firm capacity. This amount does not substantially alter the adequacy of the Italian electricity system. The scenario also assumes that there will be a significant increase in storage, due to reach 50 GWh in capacity by 2030. Despite this, the adequacy assessment shows that the additional marginal contribution of battery energy storage systems (BESS) to adequacy declines as their penetration of the electricity system increases. Indeed, with the progressive increase in storage capacity as a replacement for other programmable sources, BESS are no longer able to achieve loads sufficient to fully contribute to adequacy at critical times.

Finally, it should be noted that the adequacy assessments presented in this document are based on European scenarios that envisage a significant policy-led increase in new programmable capacity over the next ten years (approximately 170 GW in gas-fired capacity and storage systems), as targeted in the various NECPs to achieve decarbonization goals. However, not all Member States have also implemented policy mechanisms able to guarantee that these resources can be deployed in an effective and timely manner. The resulting mismatch between actual trajectories and those provided for in the policies designed to expand programmable capacity could result in available resources falling significantly short of expectations at European level. This will also entail tangible risks for Italy, linked to the reduced reliability of imports at critical times.

The National Resource Adequacy Assessment for Italy prudently assumes that imports across the country's northern border will contribute at least 4,000 MW at critical times, whilst European Resource Adequacy Assessments (ERAAs) show that imports contribute an average of 9 GW to the adequacy of the Italian system. Over time, it will be appropriate to assess the effective deployment of planned programmable capacity at European level, with a view to confirming the availability of future imports amounting to at least 4,000 MW under all operating conditions.

Key takeaways

As stated previously, the assessments conducted confirm that an electricity market devoid of forward contracting mechanisms, in which adequacy is reliant solely on price signals from the spot markets, would lead to an electricity system with a level of programmable capacity incompatible with adequacy standards.

To manage this issue, several European countries have introduced capacity mechanisms to ensure the availability of programmable resources. France, Poland, Belgium and Ireland now have capacity markets, in which operators secure capacity through forward contracts, thereby ensuring the availability of plants at critical times. Finland, Germany and Sweden, on the other hand, use a strategic reserve, in which contracts are concluded with certain specific plants. These resources are not available on the energy market and are only dispatched in emergency situations.

As noted, Italy has introduced a Capacity Market, with auctions conducted annually, to ensure the adequacy of the country's system. The purpose of the first auctions to be held was to support the expansion of capacity, to bridge the pre-existing adequacy gap, whilst at the same time allowing the most obsolete resources to be replaced. Capacity Market auctions have so far secured new plants providing approximately 9 GW of Firm capacity, equivalent to nameplate capacity of approximately 10.8 GW (including around 7.9 GW of new gas-fired capacity and around 2.9 GW of new storage), net of terminated contracts. In more recent auctions, the system has demonstrated that there is reduced need for new capacity, suggesting that adequacy can be secured above all by exploiting existing capacity or by replacing it when necessary. In this context, the Capacity Market plays a key role in avoiding the decommissioning of existing capacity provided by plants that are no longer in the money.

Ministry of the Environment and Energy Security ("MASE") Decree 180 of 9 May 2024 gave the green light for capacity market auctions through to the 2028 delivery year. Article 3, paragraph 2 of the same decree requires Terna, by 31 December 2026, to provide the MASE and ARERA with an assessment of the conditions under which it would be necessary to resort to capacity remuneration mechanisms for delivery years after 2028.

The adequacy assessment contained in this report indicates the need to retain a forward contracting mechanism for capacity to ensure that the electricity system continues to meet appropriate adequacy standards after 2028. We therefore propose that this document can also be used and interpreted in relation to the purposes provided for in the above decree.

Considering expected developments in the electricity system and market, the Capacity Market offers a structural mechanism for ensuring the system's adequacy. We believe it is, therefore, necessary to continue with auctions under the current mechanism with the limits indicated in European Commission Decision C(2019) 4509 of 14 June 2019, which permits the conduct of auctions through to 2028, with the last delivery year being 2032. It will also be important to secure the necessary capacity quickly and sufficiently in advance of the delivery year to provide adequate time to plan investment initiatives.

Finally, the assessments confirm that retention of an efficient Capacity Market, capable of ensuring that resources continue to be in the money, will deliver a future system that is not only adequate, but that could allow the country to phase out a part of its existing thermal capacity. The exact amount of capacity that can be decommissioned is, however, closely tied to developments in generation capacity, storage and demand, as well as to effective delivery of the development projects envisaged in the National Transmission Grid Development Plan.

An adequate capacity remuneration mechanism, including the correct definition and valuation of derating factors, and the correct interaction of these factors with the forward mechanisms used to secure storage and renewable capacity (namely the Energy Storage Capacity Procurement Mechanism, or MACSE, and forward auctions for the development of new renewable capacity conducted by Italy's Energy System Operator (GSE) will in any event play a key role in guiding the approach to decommissioning, giving operators the right economic signals.

Application of derating factors to the different generation and storage technologies through the Capacity Market, and definition of the requirements for storage systems pursuant to article 18 of Legislative Decree 210 of 8 November 2021, serve to provide a common basis for comparing the different technologies, normalizing their contribution to electricity system adequacy and the related performance.

Given the role played by forward markets in providing indications regarding future developments in electricity generation capacity, correct definition of these derating factors will enable us to manage the interaction between the different existing mechanisms. This will ensure that the future structure of the generation fleet meets the electricity system's security requirements.

The current form of the market presupposes an assessment of the need for storage systems procured through auctions on the MACSE, taking into account the development of renewables and evaluating the contribution of storage systems in assessing the benefits they provide, through the use of appropriate derating factors. Then again, in determining the quantity of resources to be procured through the Capacity Market, the contributions to adequacy from both storage systems and renewable resources is taken into account by applying derating factors

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1 Introduction

Introduction

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1.1 Legislative framework

At national and European level, the NRAA for Italy is based on a number of regulatory requirements, including:

- at **European** level, **Article 24 of Regulation (EU) 2019/943** governs National Resource Adequacy Assessments (NRAA);
- at national level, **the article in the Ministry for Economic Development (MISE) Decree of 28 June 2019** requiring an adequacy assessment of the electricity system to be carried out and updated on an annual basis. This assessment, pursuant to article 2 of the Decree, takes into account the positive effects arising from the development of grids and cross-border interconnections, regional and European adequacy scenarios and assessments developed by ENTSO. It also examines the development of generation from renewable sources, distributed generation, demand resources and storage systems, in line with the objective of developing an integrated electricity market;
- **art. 2.1 of the Minister for the Environment and Energy Security Decree 180 of 9 May 2024**, which sets a maximum LOLE value of **3 h/year**;
- **art. 3.2 of this Decree** requires Terna to submit an assessment of the conditions related to any use of the capacity remuneration system for delivery years after 2028 to the Ministry for the Environment and Energy Security and to ARERA.

Moreover, this report complies with **art. 13.6 of the Rules governing the electricity generation capacity remuneration system**, which requires Terna to publish a document containing adequacy assessments over a ten-year time horizon at least 60 days prior to each Main Auction.

1.2 Previous NRAAs for Italy

The 2024 NRAA for Italy analysed time horizons for 2028, 2030 and 2035, which revealed that the significant increase in non-programmable renewable sources and storage will lead to a substantial reduction in the operating hours of the gas-fired thermoelectric generation fleet, with a contraction in profit margins and a consequent risk of decommissioning due to not being in the money.

The total thermal capacity deemed to be “unavailable due to not being in the money” (i.e. with contribution margins below fixed costs) will amount to 20.8 GW as early as 2028, and rise to 23.6 GW in the longer term (2035).

If this were to actually occur, available thermal capacity would fall well below the minimum levels required to ensure system adequacy over the three-year time horizon.

The analyses carried out have shown that if the system were devoid of forward contracting mechanisms would reach an economic equilibrium incompatible with adequacy standards.

Over the time horizons analysed, a gradual shift in critical adequacy periods from summer to winter may be noted. This is due to the combined effect of the highly seasonal nature of photovoltaic generation, and the expected increase in the use of heat pumps for heating buildings.

In the short to medium term, simulations indicate potential risks to system adequacy, even during the summer months. However, these issues tend to diminish in the long term, due to the expected significant expansion of solar power generation, combined with adequate distribution of storage capacity. Nevertheless, even in future scenarios, peak demand is expected to occur in the summer months and, therefore, potential critical issues cannot be ruled out in the event of low water levels coinciding with peak demand and reduced availability of imports from neighbouring countries.

The analyses confirmed that, if no plants are decommissioned on economic viability grounds, and assuming that capacity already secured in previous Capacity Market auctions is still in operation, the future system will be adequate, and also able to do without some of the existing thermal capacity.

1.3 Key changes in the 2025 edition of the NRAA for Italy

This report follows on from the previous version, and further consolidates the methodology applied to the adequacy assessments, as part of a of continuous improvement process.

The economic viability assessment, which was applied to six different climate scenarios for all the 2025 European Resources Adequacy Assessment (ERAA) target years (2028, 2030, 2033 and 2035), introduced factors designed to more accurately portray real investors' risk aversion.

Elements have been introduced into the adequacy assessment that improve the characterisation of the Italian electricity system, such as unavailability of thermal power units due to high discharge water temperatures and the availability profiles of HVDC interconnectors, which model faults and maintenance of these elements more accurately.

Continuing the efforts described in the previous report regarding the northern border, modelling of the contribution of imports at the borders with Greece and Montenegro has been further enhanced to take account of developments in the European electricity system and the operating conditions affecting limits on cross-border exchange.

2 Current and future electricity system

Current and future electricity system

2

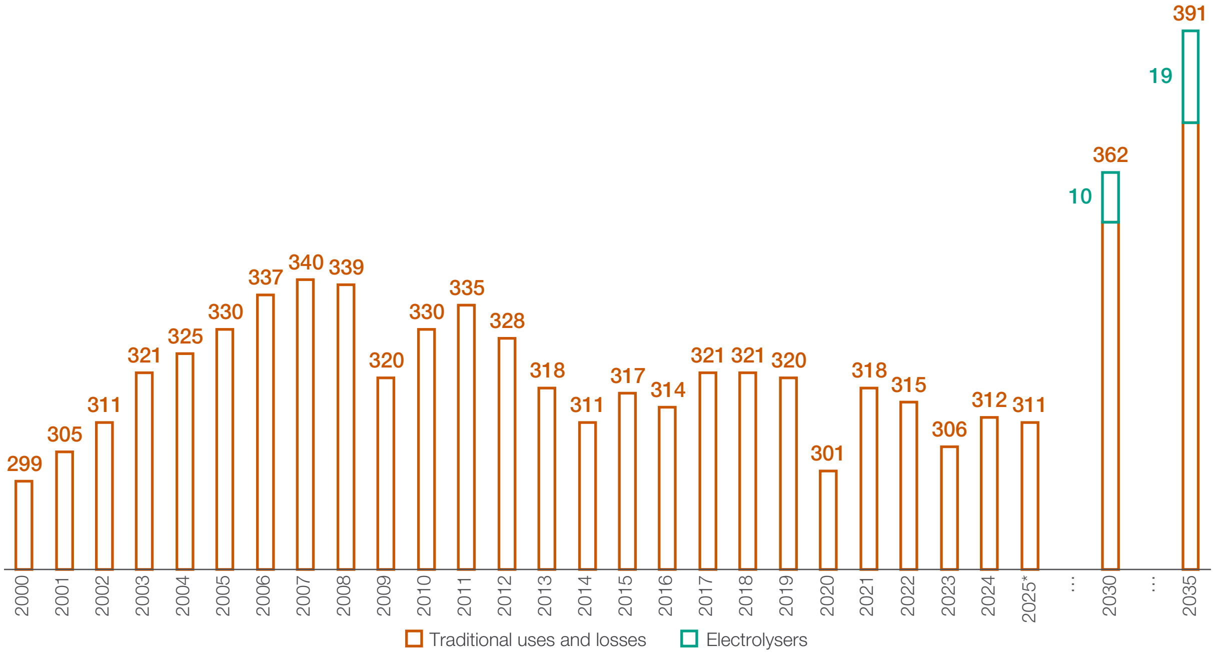
2.1 Electricity system trends

For the purposes of the assessments made in this report, the energy scenarios and the evolution of the main scenario variables set out in the 2024 Future Energy Scenarios (FES) document have been taken into account, in line with the 2024 Integrated National Energy and Climate Plan (NECP). In particular, the NECP policy scenario was used for 2030, while an average of the trajectories described in the DE-IT and GA-IT scenarios was used for 2035. The same data used for the national assessments were provided to ENTSO-E as part of the ERAA 25 data collection process.

2.1.1 Electricity demand

Figure 1 shows the electricity demand trend from 2000 until 2035. It may be noted that electricity demand grew steadily until 2008, before falling during the economic crises of 2009 and 2012, and then remained virtually constant in 2017, 2018 and 2019. In 2020, measures to combat and contain the Covid-19 pandemic brought certain economic activities to a standstill, resulting in lower electricity demand. After a revival of demand and the economy in general in 2021, 2022 and 2023 show a decoupling of economic growth from increased electricity demand.

Figure 1 ***Historical demand trends and scenario projections (TWh)***

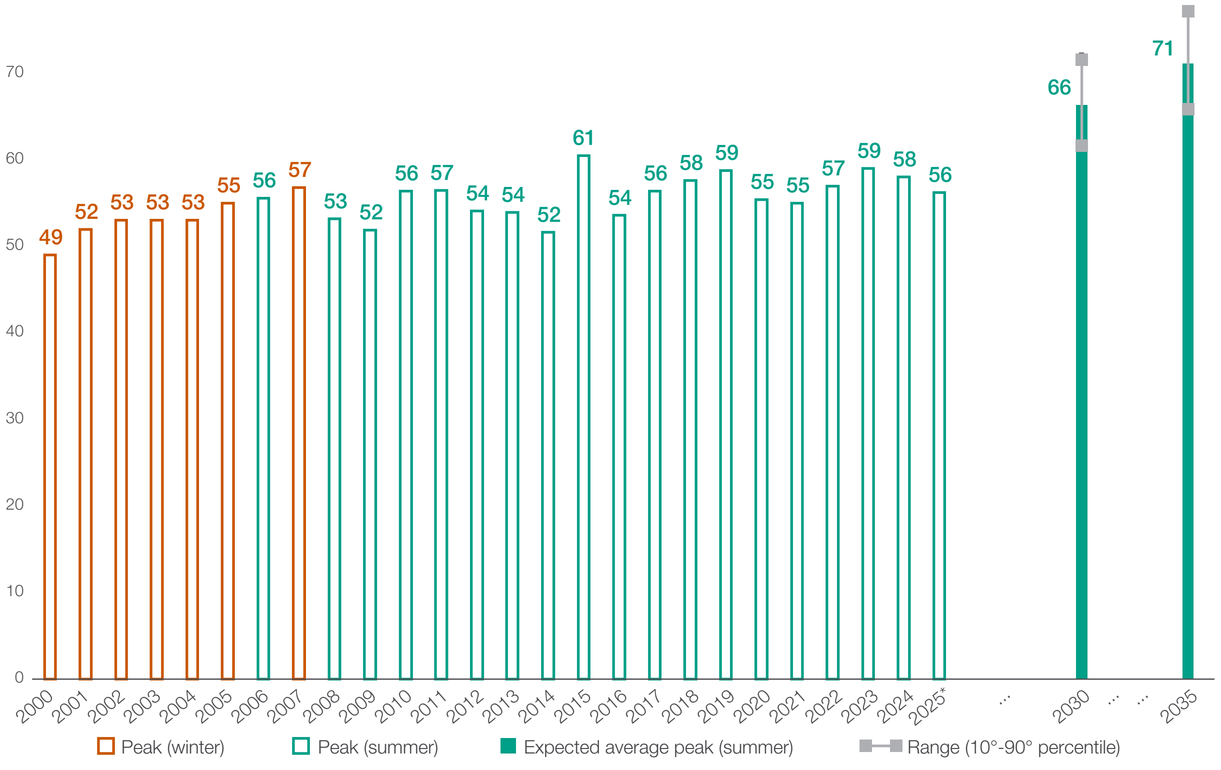


* *Provisional data.*

The future scenario takes into account increased energy efficiency and the expected growth of data centres, electric vehicles and heat pumps, and also factors in the energy consumption required for domestic production of green hydrogen via electrolysis. In the scenario analysed, electricity demand rises to around 362 TWh by 2030, before reaching approximately 391 TWh in 2035.

Similarly, primarily driven by growth in electric vehicles and the use of heat pumps, peak demand is expected to rise (*Figure 2*), with values fluctuating within a fairly wide range, depending mainly on possible climatic conditions (estimated in line with ENTSO-E methodology).

Figure 2 ***Evolution of peak demand (GW) in the medium to long term (average, 10° and 90° percentile between the different conditions simulated)***

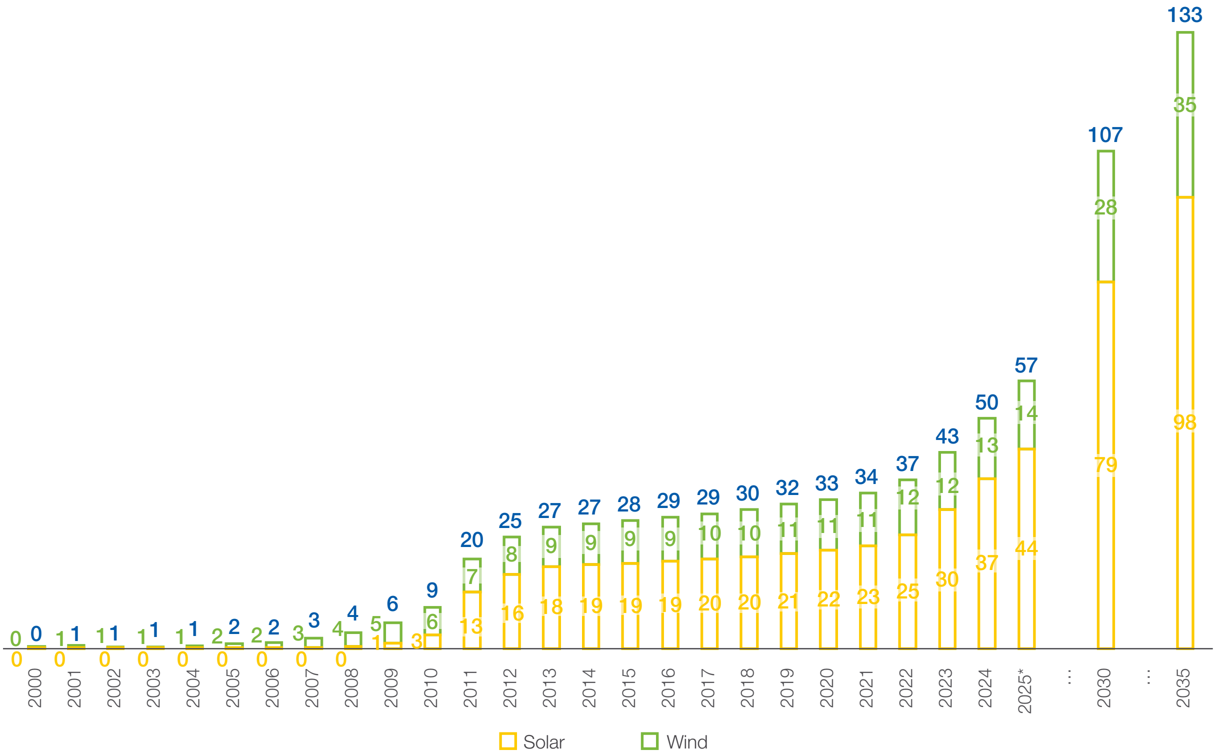


** Provisional data.*

2.1.2 Installed capacity of variable renewable energy sources

At the end of 2025, total installed wind and solar capacity had reached 57 GW, compared with the NECP target for 2030 of 107 GW. The annual rate of expansion of renewable installed capacity stands at a robust level: +7.1 GW in 2025, in line with the 2024 figure and up on the period 2021–23 (+1.4 GW in 2021, +3.0 GW in 2022 and +5.7 GW in 2023).

Figure 3 ***Historical vRES trends and scenario projections (GW)***

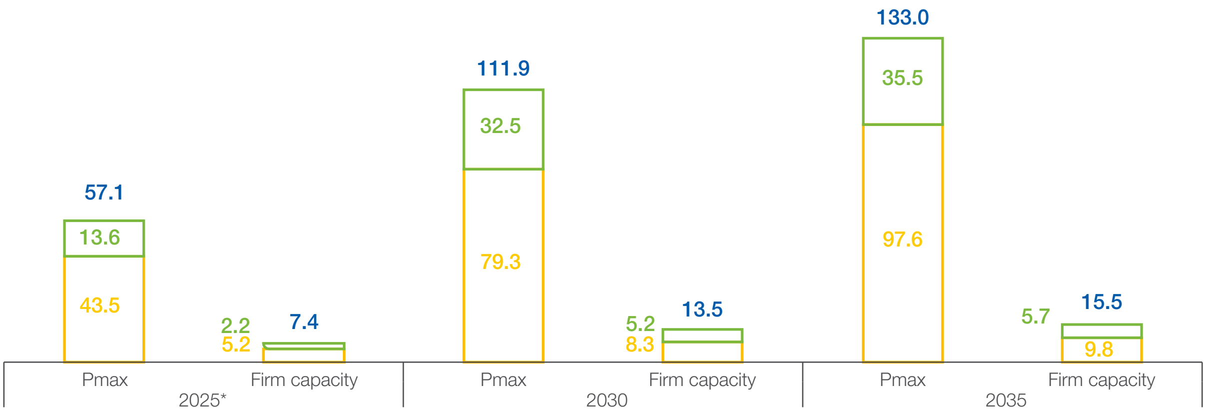


** Provisional data.*

An approximate estimate of the impact of the growth of vRES on the adequacy of the electricity system can be made by using firm capacity. This is calculated by conventionally reducing the nameplate capacity by applying specific derating factors that take into account the actual availability of each source to meet electricity demand. Application of this simplified approach to Capacity Market auctions enables concise presentation of a highly complex issue.

By applying the latest derating factors to the nominal capacity envisaged for scenarios discussed in this report, it becomes clear (*Figure 4*) that, in the presence of large installed vRES capacities, the average contribution to adequacy rises less quickly than the increase in nominal capacity.

Figure 4 ***Evolution of firm capacity vRES (GW)***



** Provisional data.*

FOCUS

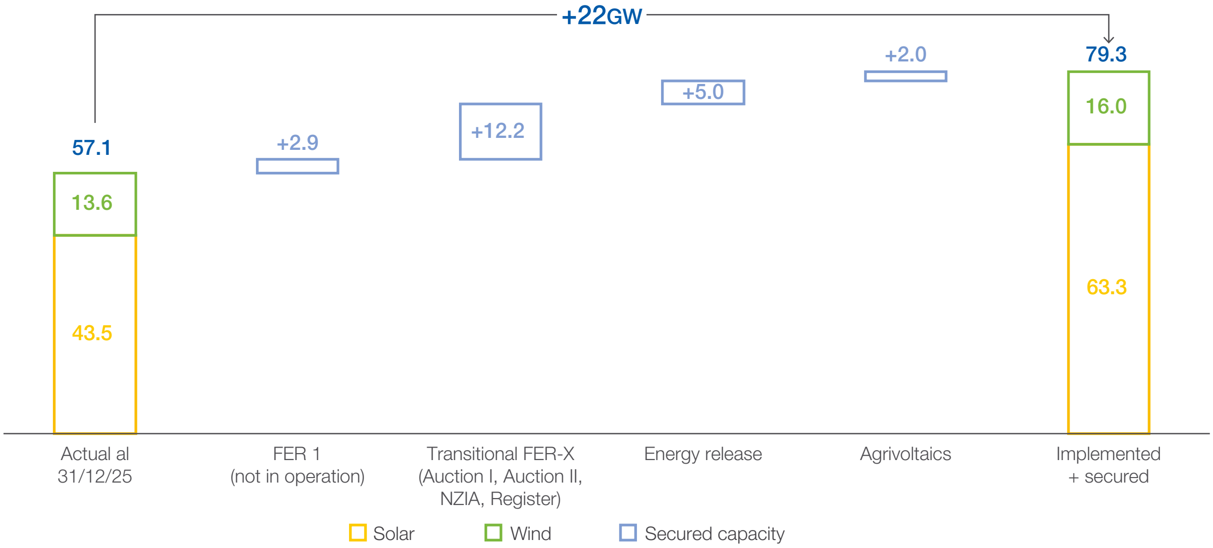
Existing vRES capacity versus secured and authorised capacity

The NECP targets envisage total capacity of variable renewable energy sources (solar and wind) of approximately 107 GW. At 31 December 2025, 57.1 GW had already been installed, with at least an additional 22 GW secured via the policy instruments currently in force, including FER1, Transitional FER-X, energy release and agrivoltaics, which are expected to come on stream in the coming years.

The latest figures show that growth is primarily driven by solar power, whilst wind power is advancing at a slower pace than expected in the set targets, mainly due to complex authorisation procedures, landscape constraints and limited availability of suitable sites. This trend is borne out by the outcome of the first Transitional FER-X auction, which saw the solar quota fully secured, whilst the wind quota was underutilised.

With regard to total capacity, the 2030 target is challenging but achievable, due to the "inertial" growth of small and medium-sized plants and thanks to future FER auctions (*Figure 5*).

Figure 5 ***Existing and secured vRES capacity (GW)***



2.1.3 Outcome of Capacity Market auctions

To date, six Capacity Market auctions have been held, relating to the start of the delivery period from 2022 to 2027.

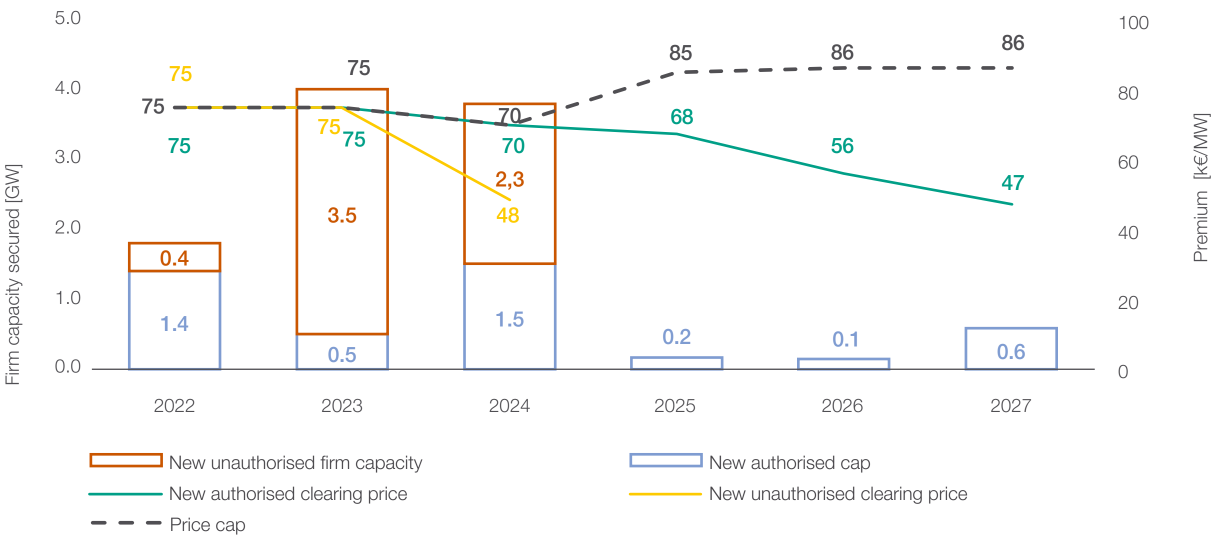
This mechanism has enabled approximately 10.5 GW in firm capacity terms (of which 1.5 in firm capacity terms were subsequently terminated) of new power plants to be secured, which, in turn, have enabled renewal of Italy's electricity generation fleet. Over the years, the capacity remuneration mechanism has thus promoted decarbonisation by securing new capacity to replace coal-fired capacity due to be decommissioned. Moreover, the Capacity Market has enabled the share of existing capacity needed to ensure adequacy to be kept in operation.

The evolution of the capacity remuneration mechanism is also reflected in *Figure 6*, which shows the amount of new capacity - authorised and unauthorised - that has been secured during auctions, and the related clearing price compared with the price cap set for each delivery year.

In particular, it may be noted that around 90% of new capacity was secured in the 2022, 2023 and 2024 auctions. During this period, the clearing prices for authorised new capacity were equal to the price cap, whilst those for unauthorised new capacity were equal to the price cap only in the first two auctions (CM22 and CM23), before falling to around €48,000/MW in the CM24 auction.

In the 2025, 2026 and 2027 auctions, more than 90% of the total capacity allocated was existing capacity, indicating that the system required less new capacity than in previous auctions. Consequently, clearing prices were significantly lower than the price cap, as reflected in a sharp downward trend. This was borne out in the 2027 auction, where the clearing price for new capacity equalled the price cap set for existing capacity. Indeed, in the 2027 auction new (authorised) was in direct competition with existing capacity, and replaced approximately 600 MW firm capacity. For the first time, not all of the existing capacity offered was awarded an annual contract.

Figure 6 ***New capacity secured through Capacity Market auctions and related price***



With regard to the data set out in *Figure 6*, it should be noted that part of the newly secured capacity was terminated due to breach of contract. Specifically, in the CM23 and CM24 auctions, part of the allocated capacity was subsequently terminated, primarily because the necessary authorisations were not obtained within the set timeframe. Overall, to date, **approximately 1.6 GW of firm capacity capacity has been terminated**, spread across the various auctions as shown in *Figure 7*. It should also be noted that new capacity did not always enter operation by the scheduled delivery year.

To date, the capacity allocated as a result of the first two auctions (2022–2023) has been fully implemented and has entered operation, whilst approximately 1.6 GW firm capacity allocated in the CM24 auction has not yet been built and is expected to come into operation this year. Furthermore, to date only one project forming part of the capacity allocated as a result of the auctions held over the last three years has come on stream, whilst the remaining projects are not expected to start up before the end of 2026.

Figure 7 ***New firm capacity by state of progress***

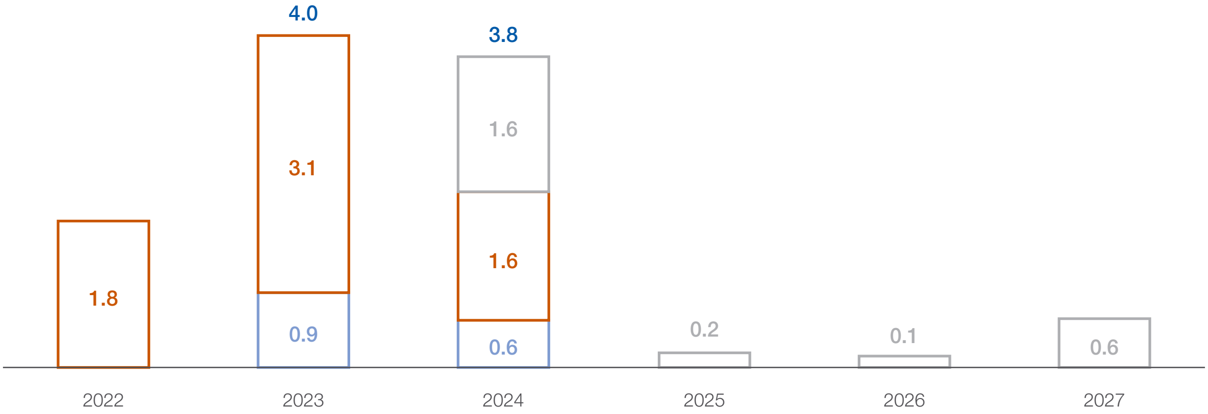
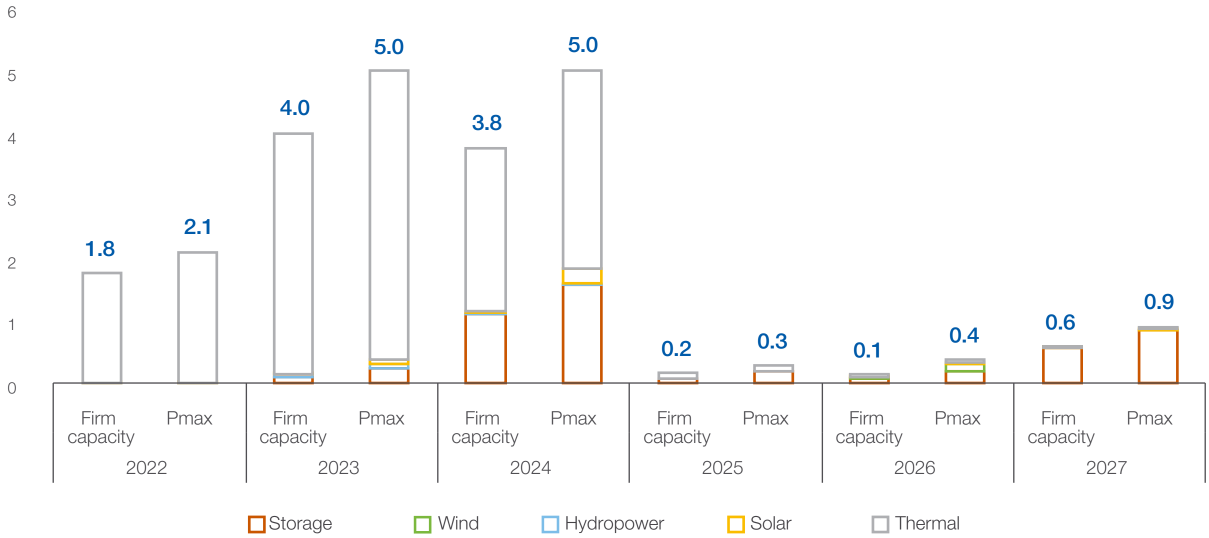


Figure 8 shows the technologies (plant types) secured at Capacity Market auctions, and also sets out a comparison between the secured firm capacity and the related installed capacity figures. It should be noted that the current obligations for operators holding Capacity Market contracts refer to the contracted firm capacity figure rather than the related installed capacity figure. Therefore, the installed capacity values shown in the figure are only indicative and do not denote any binding requirement.

Figure 8 ***New capacity secured through the CM by type [GW]***



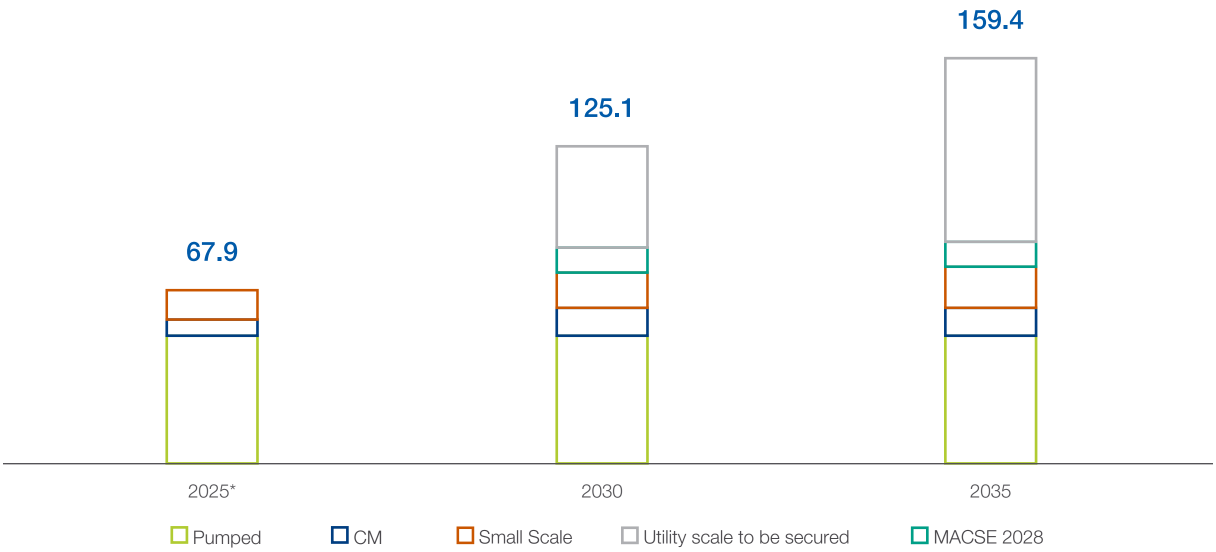
2.1.4 Storage capacity in the electricity system

To facilitate the integration of variable renewable energy sources into the electricity system, new storage capacity will need to be developed. The storage capacity shown in the scenarios (*Figure 9*) consists of: (1) existing storage facilities (mainly pumping plants); (2) new small-scale storage, comprising electrochemical batteries with an average duration of around 2 hours, primarily designed to support the development of small-scale solar photovoltaics to maximise self-consumption; (3) storage secured through Capacity Market auctions, with an average duration of around 4 hours; and (4) utility-scale storage secured or to be secured via MACSE auctions.

In line with the observations made about vRES, these technologies' contribution to adequacy is also obtained by applying derating factors to the installed capacity, which for storage systems mainly depend on their duration (see ANNEX III: Considerations on future Capacity Market auctions).

In line with the scenarios underlying this study, storage capacity will reach 159.4 GWh in 2035, as shown in *Figure 9*.

Figure 9 ***Storage capacity trends (GWh)***



** Provisional data.*

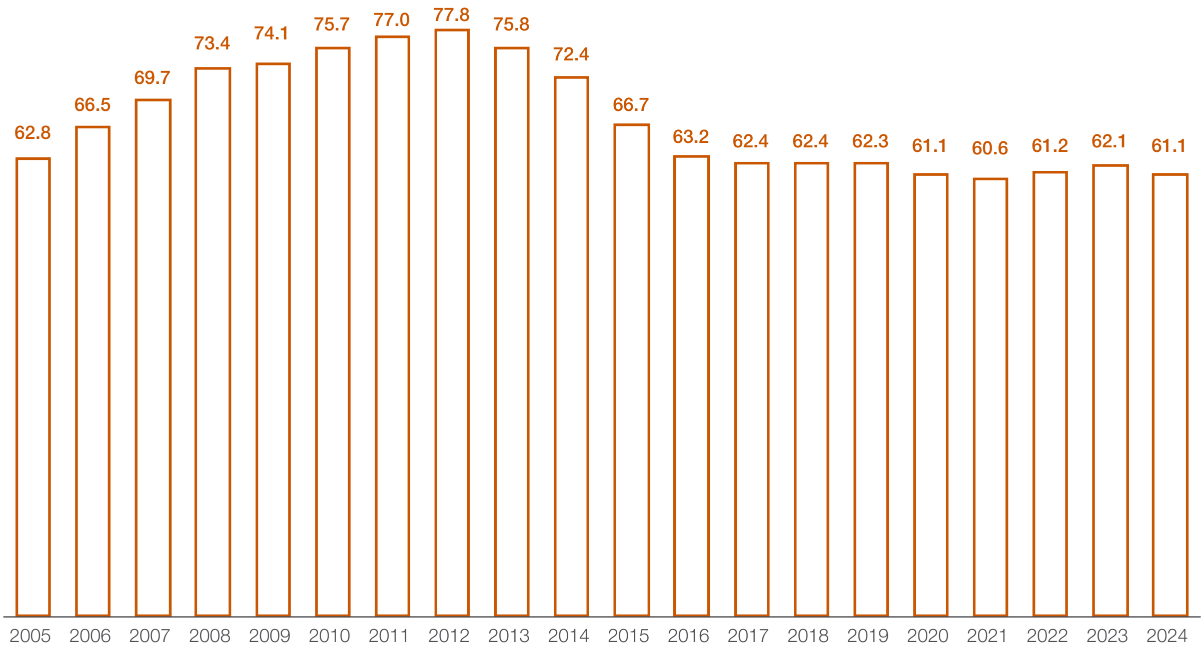
On 30 September 2025, the first MACSE auction was held for the 2028 delivery year, at which 10 GWh of storage capacity was allocated across the Central-South, Calabria, South and Islands regions, covering the entire required load. The auction resulted in allocation of capacity at a weighted average price of around €13,000/MWh-year, which is approximately one-third of the reserve premium of €37,000/MWh-year.

2.1.5 Thermal capacity

Between 2013 and 2017, the capacity of the thermal fleet fell significantly. This trend continued in the following years, albeit at a slower pace, with a reduction of just under 2 GW between 2018 and 2021 (*Figure 10*).

Since 2021, this trend has slowed, resulting in an improvement in thermal capacity, driven by the commissioning of the first plants procured through the Capacity Market. This development has occurred despite the ongoing process of decommissioning coal-fired plants, which has not yet been completed.

Figure 10 ***Thermal capacity trends 2005-2024***



As highlighted in the previous paragraph, although additional new thermal capacity has been secured via the Capacity Market, approximately 1.6 GW of CAP capacity has yet to enter service. Therefore, the overall evolution of installed capacity will be primarily driven by these factors:

- completion of the phase-out of coal- and oil-fired plants;
- the commissioning of capacity already secured but not yet operational, relating to the 2024, 2025, 2026 and 2027 auctions;
- any new capacity deriving from forward contracting mechanisms;
- potential entry into service of new merchant capacity.

It should be noted that part of installed capacity cannot actually be used to meet demand. Currently, there is approximately 3.5 GW of unusable capacity, of which around 1.5 GW is due to long-term unavailability and/or operational licensing restrictions, and around 2 GW is due to other constraints.

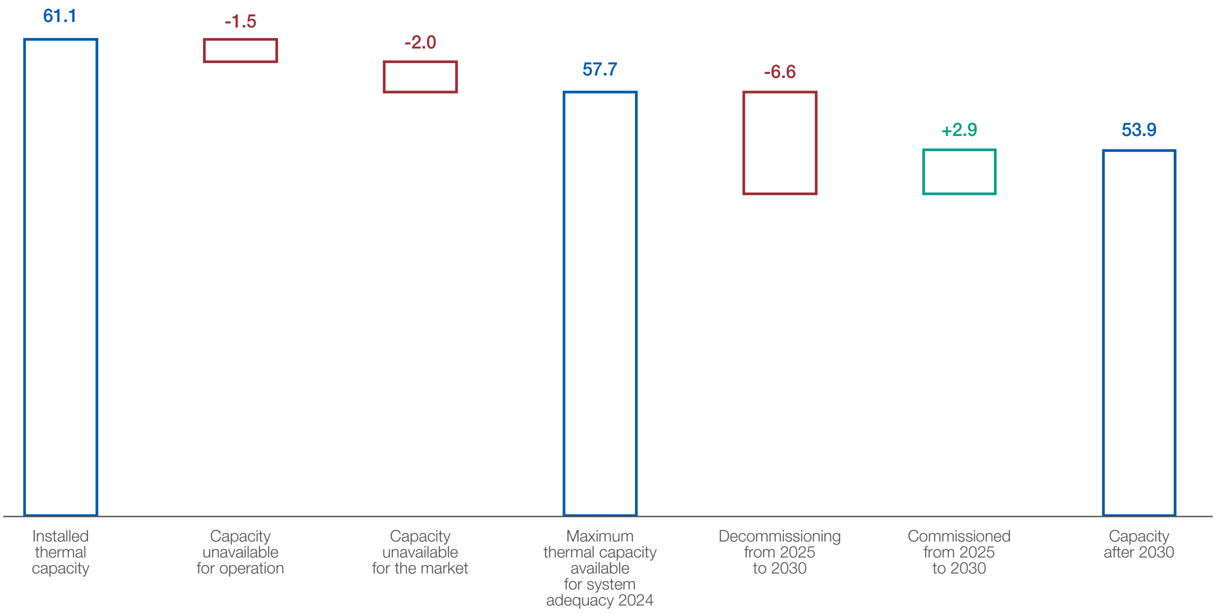
Consequently, the amount of thermal capacity currently available for adequacy purposes is approximately 57.7 GW, compared with 61.1 GW installed[1].

It should also be noted that, in practice, this capacity is never available simultaneously, as outages linked to routine maintenance, breakdowns and other reductions due to factors such as derating and high discharge water temperatures at thermal power stations must also be taken into account.

[1] Source: Terna, Statistical Yearbook 2024

If no additional decommissioning initiatives other than those already planned are undertaken (6.6 GW), and taking into account the planned expansion of capacity, maximum available thermal capacity, as shown in *Figure 11*, will fall to approximately 55.4 GW in target year 2030.

Figure 11 ***Maximum installed capacity (GW) for adequacy under the scenarios considered***



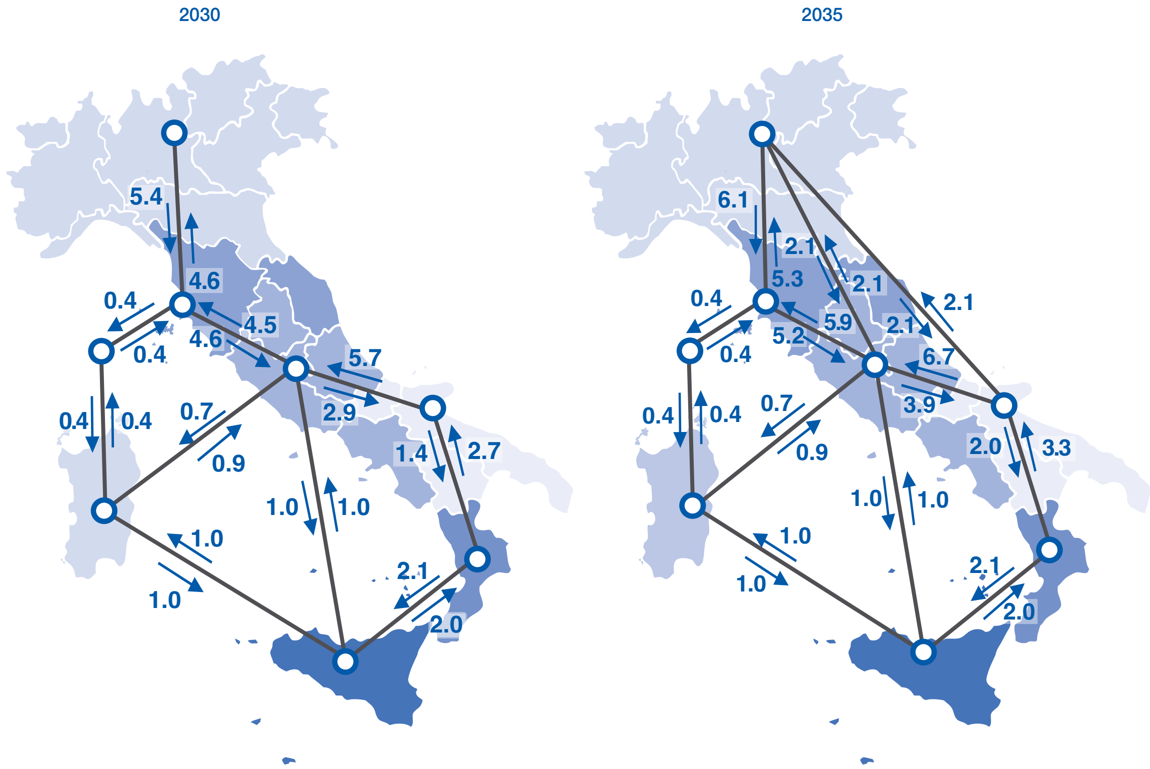
It should be noted that this chart does not include any further decommissioning of thermal power plants arising from reduced operating hours and lower profit margins. This aspect is explored in greater detail in the economic viability assessment in section 4.

2.1.6 Relevant grid and key interzonal development projects

Terna's Development Plan seeks to increase transmission capacity via construction of a specific set of grid infrastructure projects, with a view to facilitating the energy transition underpinning the FES scenarios. The expected new transmission capacity is vital for enabling the integration of renewables envisaged in the scenarios, whilst guaranteeing an acceptable level of overgeneration and enabling the transportation of energy from southern Italy (where a significant share of vRES growth is concentrated) to the northern regions where most of the demand is concentrated.

The assessments set out in this report take into account projects due to come into operation during the time horizon covered by this study (2030 and 2035). The projected evolution of transport capacity is shown in *Figure 12.*

Figure 12 ***Evolution of exchange capacity (GW) between bidding zones***



2.2 Adequacy margins in the electricity system

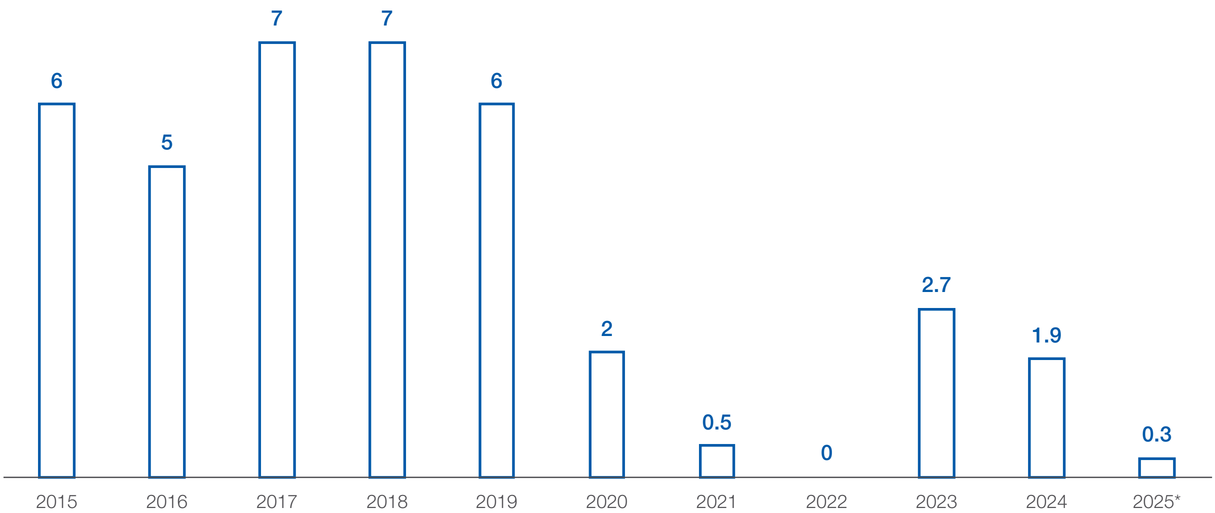
The adequacy margin is a deterministic parameter that, for each geographical area and period of analysis, identifies the difference between:

- the sum of available generation capacity (net of the primary reserve) and electricity imports from neighbouring areas, including contributions from storage and demand-side-response;
- electricity demand increased by the required tertiary replacement reserve (namely the production capacity made available to the Operator for the purposes of increasing the electricity input as part of balancing).

The minimum adequacy margin is particularly interesting. This is recorded at the most critical time of the year, which generally occurs in the summer. The period 2017–2020 saw a gradual decline in the minimum adequacy margin, due to a reduction in available generation capacity and the contribution of imports from neighbouring European countries. In particular, in 2022 a minimum margin of 0 GW was recorded, due to unforeseen events such as a prolonged drought, which caused a sharp fall in hydroelectric generation and the unavailability of several thermal power stations resulting from difficulties in operating cooling systems during periods of high demand caused by high temperatures, as well as limited availability of imports from neighbouring countries *(Figure 13)*.

After 2022, the commissioning of new capacity procured through the Capacity Market, combined with more favourable hydrological conditions, helped to improve the level of the minimum adequacy margin. However, such positive conditions are not enough to guarantee consistently high margins, as the actual value of the margin also depends on the contribution from imports. As observed in 2025, under specific market conditions at European level, flows may occur that bring the margin down to barely sufficient levels.

Figure 13 ***Minimum adequacy margin (GW) 2013-2025***



** Provisional data.*

The performance of this indicator confirms that the transformations underway across Europe (decommissioning of programmable fossil fuel plants, increased prevalence of intermittent generation, expansion of electrification) are raising the national electricity system's exposure to neighbouring countries' operating conditions and to the variability of weather patterns. These circumstances have been mitigated by the commissioning of new capacity, supplied via the

Capacity Market mechanism, which has therefore played a vital role in ensuring system adequacy. At the same time, commissioning of new plants has enabled decommissioning of the oldest ones, thereby making the power generation fleet more efficient. Together with the benefits associated with implementation of new resources secured through Capacity Market auctions, grid development also enabled the minimum adequacy margin to be maintained. The prompt delivery of development projects and shrewd management of the transition period will also be vital for the electricity system in the future, especially for Sicily (e.g. full development of the Tyrrhenian Link), which is particularly exposed to variable weather conditions, as well as to severe constraints and accidental damage to the thermal generation fleet due to high discharge water temperatures. These events are becoming increasingly common, due to rising average river and sea temperatures, which jeopardise the smooth running of thermal power plants that use open-loop cooling systems, in which water is drawn directly from an external natural source.

FOCUS

The adequacy of the European system in summer 2025 and winter 2025/26

Winter Outlook 2025-26

Given the full commissioning of the thermal generation units procured via the Capacity Market, almost constant demand, and an increase in installed renewable energy capacity, no particular critical issues are expected for the winter of 2025-26. The Winter Outlook 2025 published by ENTSO-E in November 2025 highlights a slight improvement in adequacy margins compared with previous winters, in line with national assessments.

Although the Italian electricity system is expected to be adequate this coming winter, there are still instances where exports from Italy to other countries could lead to a reduced adequacy margin. This is not due to a shortage of domestic resources, but rather to a shortage of resources across Europe.

Summer Review 2025

The summer of 2025 saw lower average temperatures than those reported in the summer of 2024. This contributed to the year-on-year decline in demand (down 1.4%). The decrease in demand, combined with good hydrological conditions and increased capacity - especially from RES and storage systems - ensured good adequacy margins throughout the summer. However, at times of peak demand in the first week of July, despite ample availability from the national thermal power fleet, export levels were substantial, reaching up to 2.8 GW. This led to a reduction in the adequacy margin, with minimum values of 0.3 GW.

However, it should be noted that, whilst the average adequacy margin may be boosted by increased generation from variable renewable energy sources, this uncertainty and dependence on weather conditions can lead to specific situations in which the minimum adequacy margin is particularly low.

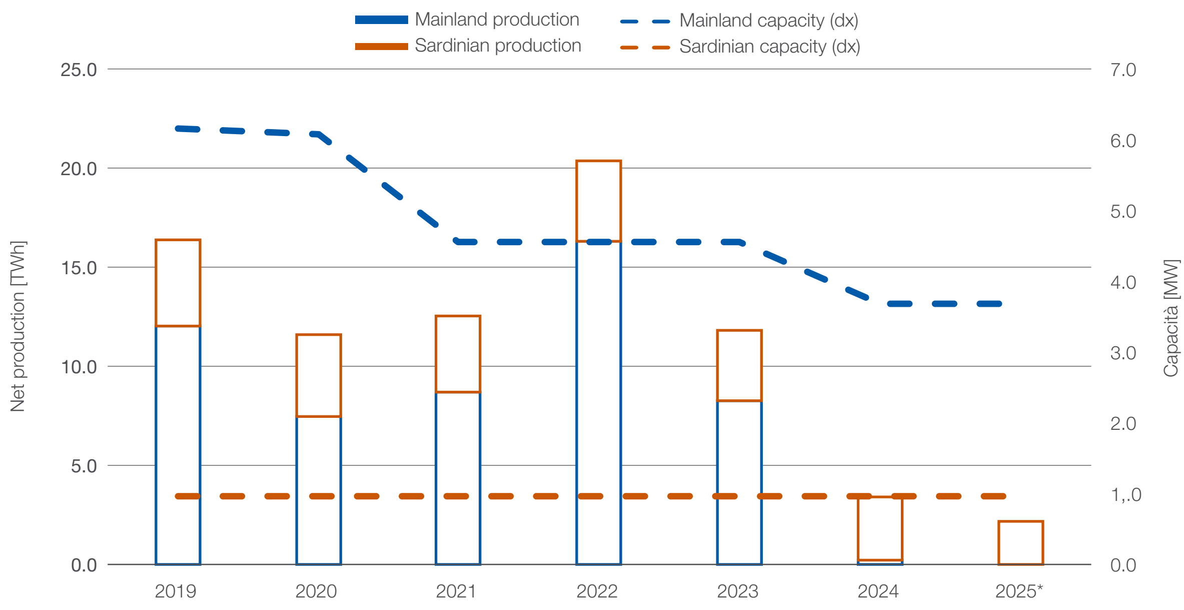
FOCUS

Coal phase-out

As envisaged in the National Energy and Climate Plan (NECP), Italy is committed to planning a gradual phase-out of coal-fired power generation.

An analysis of net coal-fired electricity production over the last six years (data for 2025 are still provisional) reveals a clear downward trend (*Figure 14*). In particular, in 2024 and 2025, coal-fired production on the mainland has virtually dropped to zero, partly because coal-fired plants are now uncompetitive compared to other available technologies for economic reasons.

Figure 14 Evolution of net coal-fired production 2019-2025



** Provisional data.*

At the end of 2025, coal-fired plants with a capacity of around 4.7 GW were still in operation, including 1.0 GW in Sardinia and 3.7 GW on the mainland. The actions already implemented and planned are adequate to enable the phase-out of the coal plants still operating on the mainland. It will then be up to the operator to start the process by submitting a phase-out request to the Ministry.

In Sardinia, the development of storage and completion of the Tyrrhenian Link are vital for enabling the coal phase-out in the island, which is currently expected in 2029, depending on the above technical conditions.

3 Economic viability assessment of plants

Economic viability assessment of plants 3

3.1 The EVA process

The Economic Viability Assessment (hereinafter also EVA, introduced for the first time in the 2022 NRAA for Italy) is a process carried out in line with ACER Decision 24/2020, which has also been adopted in European Resource Adequacy Assessments. A key difference between the national and European assessments is that, at least until the 2025 editions, the NRAA adopts an EVA using a revenue-based approach, whereas ENTSO-E has opted for an EVA that uses a cost-based approach. Both approaches are fully compliant with ERAA methodology.

In 2024, after approval of the 2023 edition of the NRAA for Italy, ACER recommended that ENTSO-E carry out a revenue-based EVA, as this methodology is better suited to representing the behaviour of a rational, risk-averse operator. Following this recommendation, the 2024 edition of the NRAA presented a case study on implementation of the revenue-based approach, based on the efforts made by Terna in its national studies from previous years. In the NRAA 2025, this methodology was further enhanced and presented in a more mature version. The resulting revenue-based approach has been applied in this document on a pan-European basis and to all the target years analysed within the ERAA 2025 framework (2028, 2030, 2033 and 2035).

In EVA simulations, bids from thermal power plants are determined on the basis of variable costs (including fuel and CO_2 costs, in terms of a plant's specific yield). Moreover, in defining bids, a scarcity function is taken into account. This stipulates that during hours when demand cannot be met or when a single plant - within its relevant bidding zone – is vital to meeting demand, the bid price is set at €1,000/MWh[2]. This approach is in line with the provisions of Article 24 of EU Regulation 2019/943, which allows for a national adequacy assessment provided that it uses the European methodology approved by ACER. In particular, Article 6 of the methodology specifies that plants' forecast revenues must be based on expected market prices. Therefore, in the draft ERAA 2025, ENTSO-E has adopted this requirement in accordance with the above terms.

Compared with the previous edition of the NRAA, the following developments have been implemented:

- modelling of faults related to generators and grid elements has been introduced;
- grid operational constraints arising from the need to maintain a day-ahead market (DAM) margin for the balancing reserve have been taken into account;
- as the EVA is conducted at European level, average investment costs have been applied across all countries to avoid introducing system distortions into the final balance[3];
- the quality of the EVA results depends on how faithfully the analysis reproduces real dynamics. To represent investors' risk aversion in the model, as well as taking into account a premium above the weighted average cost of capital (the so-called hurdle premium), which was already present in the previous edition of the NRAA, a mechanism has been introduced to mitigate the impact of the most extreme prices on investment decisions. A survey of European investors conducted by ENTSO-E in May 2025 revealed that basing a business plan mainly on the expectation of extreme prices is deemed unrealistic4. Therefore, the EVA adopts a cap on hourly revenue expectations for the valuation of new investments to reflect more plausible market scenarios.

[2] Valid for 2028. The value varies depending on the target year subject to EVA.
[3] The only exception is demand side response (DSR), which is only taken into account for certain countries and has particularly variable costs.

Therefore, this document adopts a more comprehensive EVA than the assessment carried out in the previous edition of the NRAA, whilst also incorporating certain specific features of the Italian situation that the European study does not take into account. These include, for example, the share of repowered capacity remunerated via 15-year contracts, emerging in the Capacity Market auctions for the years 2022–2027.

3.2 Results of European EVAs

The economic viability assessment of plants takes into account the entire European electricity system to obtain a coherent and consistent post-EVA scenario. Therefore, in the calculation model applied, each Member State was represented using the latest electricity demand and power generation fleet data. The interconnections planned in the various target years electrically connect the grids of the individual states.

The unit-by-unit representation of the revenue-based EVA approach allows for a more detailed analysis of the evolution of capacity, which explicitly distinguishes exogenous factors of national origin (gathered by TSOs in the data collection phase) from endogenous factors, determined by the model. In this way, it is possible to separate decommissioned and expanded capacity driven by national energy policies from those attributable to expected economic (un)viability.
Figure 15 shows the developments forecast for 2030 and 2035.

The technologies shown comprise the variable portion of installed capacity, including:

- Thermal power plants;
- Demand side response (DSR);
- Electrochemical storage.

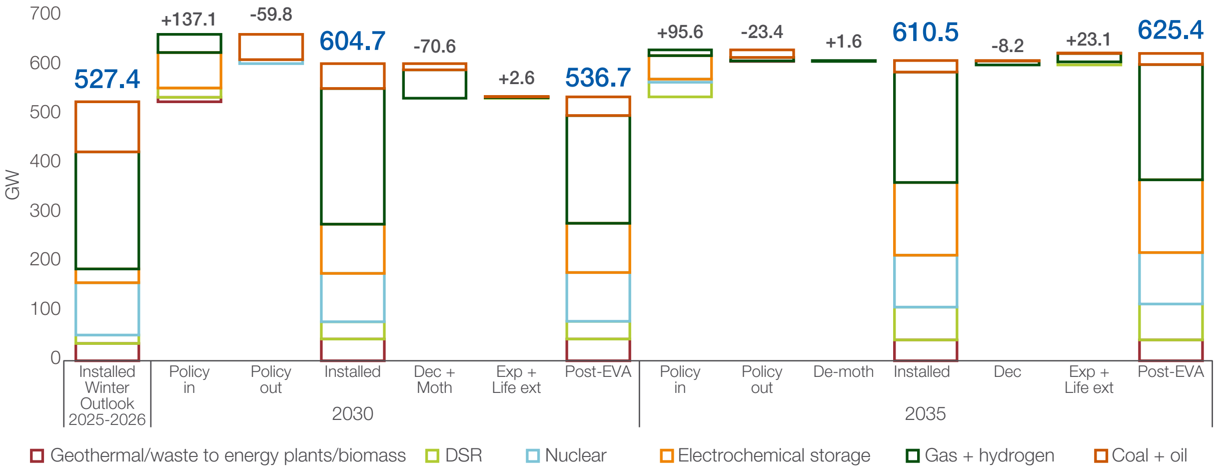
More specifically, individual Member States[4] national policies envisage the commissioning of approximately 137 GW of new variable capacity by 2030 and approximately 96 GW by 2035. Overall, around 64 GW of thermal capacity, 120 GW of electrochemical storage and 49 GW of DSR are expected to come on stream. Furthermore, according to national forecasts, around 60 GW of coal-fired power stations will be decommissioned over the next five years, having reached the end of their operational life by 2030. It should be noted that the new policy-led expansions of capacity have been identified in the various National Energy and Climate Plans (NECPs) to achieve decarbonisation targets. They include an increase in storage capacity aimed at managing the growing volume of energy produced from variable renewable energy sources. However, not all Member States have also implemented policy mechanisms to ensure that these resources actually come on stream in a timely manner. This misalignment between actual trajectories and those envisaged by policy in the development of variable capacity could result in a level of available resources that is significantly lower than European expectations. This would also entail tangible risks for Italy, due to reduced reliability of imports at critical times.

Regarding developments related to EVA, a negative net effect can be seen in 2030, with decommissioned capacity outweighing newly commissioned plants. Overall, in 2030, it is estimated that almost 71 GW of capacity will be decommissioned for economic reasons as a result of EVAs, consisting mainly of the oldest gas and coal-fired power stations. It should be noted that the above policy-led additional capacity in 2030[5] - should it actually materialise - may at best offset the decommissioned capacity but will not be sufficient to ensure adequacy against a backdrop of growing electricity demand.

[4] The results of this survey have been published on the ENTSO-E website at this link: "Investor Survey: How can ERAA better reflect real investment behaviour?"

[5] The "Policy in" and "Policy out" values shown in *Figure 15* reflect the net effect of policy-led newly commissioned and decommissioned plants using the same technologies.

Figure 15 ***Evolution of the European fleet[6] (thermal, DSR and electrochemical storage) in terms of economic performance 2026-2035***



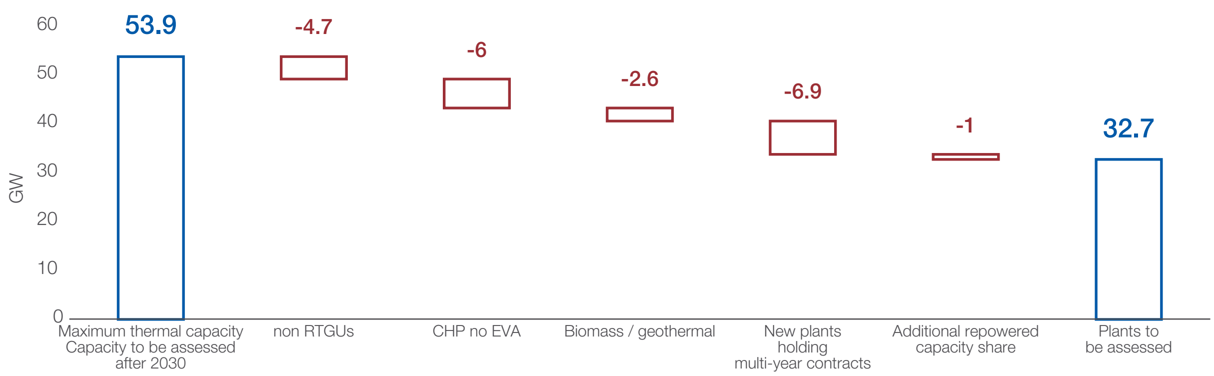
3.3 Scope of the assessment for Italy

The assessment solely focuses on the relevant thermal generating units (RTGUs) excluding:

- non-relevant generation units (<10 MVA);
- cogeneration plants that generate significant revenue in addition to electricity market earnings, such as district heating plants and cogeneration plants serving industrial facilities managed by the same producer (e.g. plants serving refineries). The underlying assumption is that the requirements of the relevant production processes lead the operator to keep the connected plants in operation. Conversely, cogeneration plants that are highly dependent on electricity market profits are included in the analysis;
- renewable thermal (biomass, geothermal and waste-to-energy units);
- new capacity secured under a 15-year contract via Capacity Market auctions for the years 2022-2027;
- repowered capacity: share of existing plant capacity that has been secured under a 15-year contract via Capacity Market auctions for the years 2022-2027.

The total capacity assessed for economic viability in this report amounts to approximately 33 GW (*Figure 16*), which is higher than the amount analysed in the previous edition of the NRAA for Italy (29.1 GW).

Figure 16 **Scope of the economic viability assessment for 2030/ 2035**



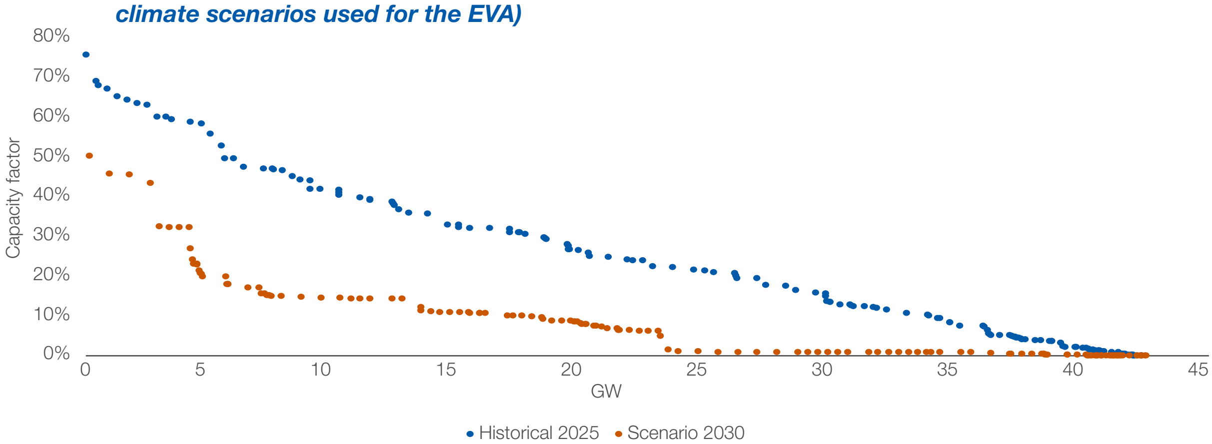
3.4 Results of the EVA for Italy

As shown in *Figure 17*, under the projected national energy scenario, the equivalent operating hours of existing gas-fired power plants would be reduced compared with the values recorded in 2025, which would result in

[6] The European scope of ERAA 25 is shown, except for Turkey and Ukraine. The scope includes the EU-27, Norway, Switzerland and Balkan countries.

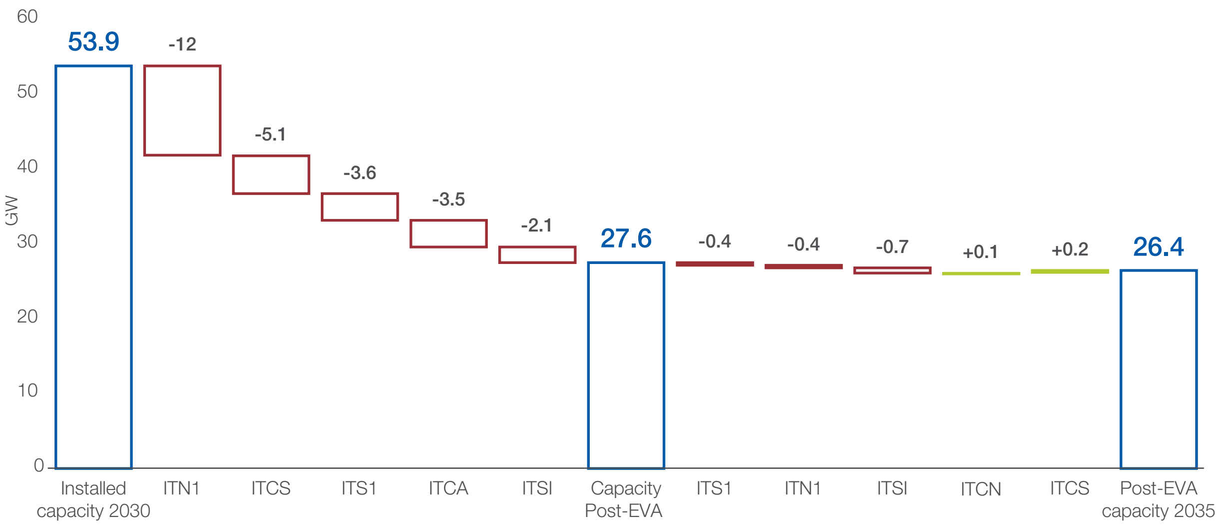
many of these plants being unable to cover unavoidable fixed costs. As a result, a significant portion of the thermal generation fleet would be at risk of being decommissioned and would be unable to contribute to system adequacy. However, it should be noted that even power generation units with a low number of operating hours play an important role in ensuring system adequacy, as they enable the system to cope with stress situations such as consumption peaks in years affected by droughts, or outages, which are sometimes multiple, in other parts of the system. To counter this risk, an adequate level of variable capacity will need to be kept in operation.

Figure 17 ***Capacity factors for gas-fired units in 2025 and in the future scenario in 2030 (average of six climate scenarios used for the EVA)***



The potential evolution of Italy's thermal power generation fleet in terms of economic performance (namely without any forward capacity contracting mechanisms) that emerged from the EVA is summarised in *Figure 18*.

Figure 18 Evolution of Italy's thermal generation fleet in terms of economic performance (2030-35)



A concentration of decommissioning risk **by 2030** may be noted. Therefore, **without any forward capacity contracting mechanism**, as much as **26.3 GW would be economically unviable and could be decommissioned**.

In subsequent years, the growing penetration of variable renewable energy generation would drive additional thermal power plants out of the market, leading to decommissioning of a further 1.5 GW for economic reasons. Moreover, central Italy has seen a 300 MW boost to installed capacity, resulting from an expected increase in the load over the long term. As regards zonal distribution of decommissioning, by 2030 much of the unprofitable capacity will be concentrated in the North, which has an ageing generation fleet in competition with imports from neighbouring countries. By 2035, the remaining decommissioning will be distributed almost equally between the North, the South and Sicily.

4 Adequacy assessment

Adequacy assessment

4

4.1 Adequacy under the reference scenarios without decommissioning

The adequacy assessments of the Italian electricity system referring to the target years 2030 and 2035 were carried out without factoring in potential decommissioning due to economic unviability, and therefore took into account:

- commissioning of all the capacity secured via the Capacity Market;
- growth in demand, vRES and storage, in line with the 2024 FES;
- evolution of inter-zonal exchange capacity, in line with the forecasts in the 2024 FES;

and excluding:

- additional decommissioning of thermal capacity, with respect to the amounts envisaged in the coal and oil phase-out plan;
- extreme conditions due to contingent events (e.g. drought conditions and a combination of particularly serious and rare events), showing that the system is adequate with a national average LOLE of less than 3 hours per year.

4.2 Impact of the risk of programmable plant decommissioning on adequacy

The results of the adequacy assessment under the post-EVA scenario - i.e. taking into account the capacity at risk of decommissioning - are set out below. The adequacy assessment is probabilistic and also takes future climate variability into account[7], by simulating 36 different, equally probable climate conditions.

The EVA applied to the 2030 target year highlighted the presence of approximately 26.3 GW of capacity not in the money. If all the capacity expected to be lost were actually decommissioned, the electricity system would be severely inadequate (over 150 LOLE hours per year), even taking into account commissioning of all the storage systems secured via the 2028 MACSE auction.

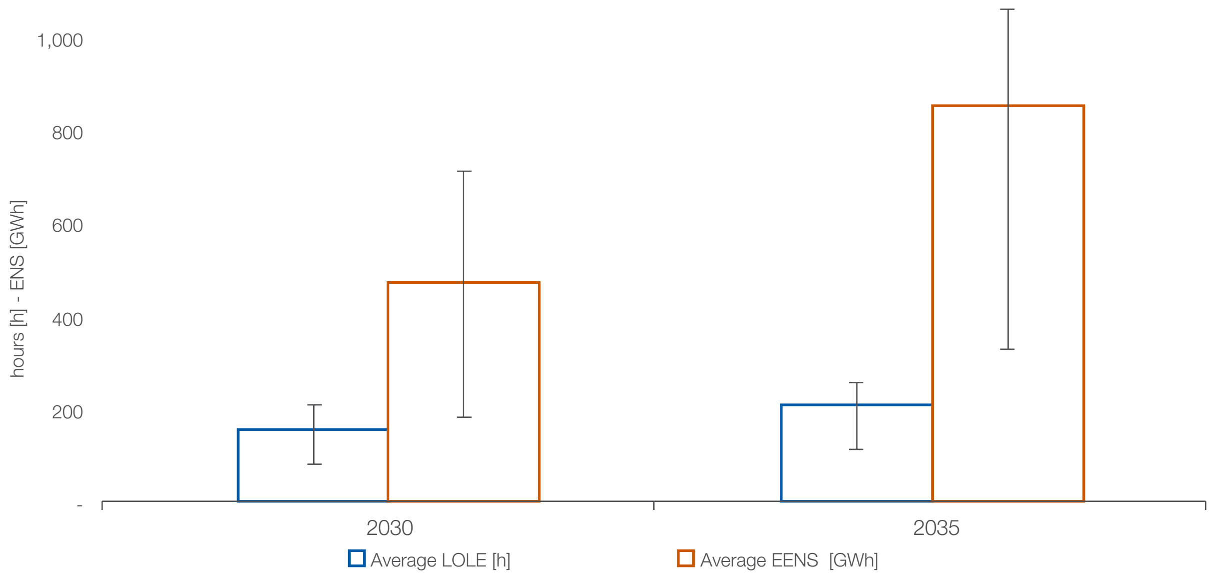
For the target year 2035, the loss of all economically unviable thermal capacity (down 27.5 GW) would put the system in a significantly inadequate situation, with over 200 LOLE hours per year.

[7] Since the 2024 edition of the NRAA for Italy, Terna has adopted the Pan-European Climate Database (PECD) for its simulations. This includes future climate projections that take global warming into account. The climate database maintains a spatial and temporal correlation of European climate variables.

Figure 19 shows LOLE hours and unmet demand (EENS) in 2030 and 2035. LOLE hours clearly exceed the adequacy standard of 3 hours per year, and it may also be noted that adequacy conditions deteriorate between 2030 and 2035. These results are influenced by the significant increase in peak demand forecast between 2030 and 2035 (linked to increased electrification of the residential sector through heat pumps and the development of data centres), as well as the additional thermal power capacity expected to be decommissioned due to missing money.

The figure also shows the dispersion of the LOLE and EENS adequacy indicators. It should be noted that, although the variability of the adequacy simulation results decreases slightly between 2030 and 2035, it remains above 60%, demonstrating that, in a system with a high level of renewable energy integration, its operating conditions will strongly depend on climatic conditions.

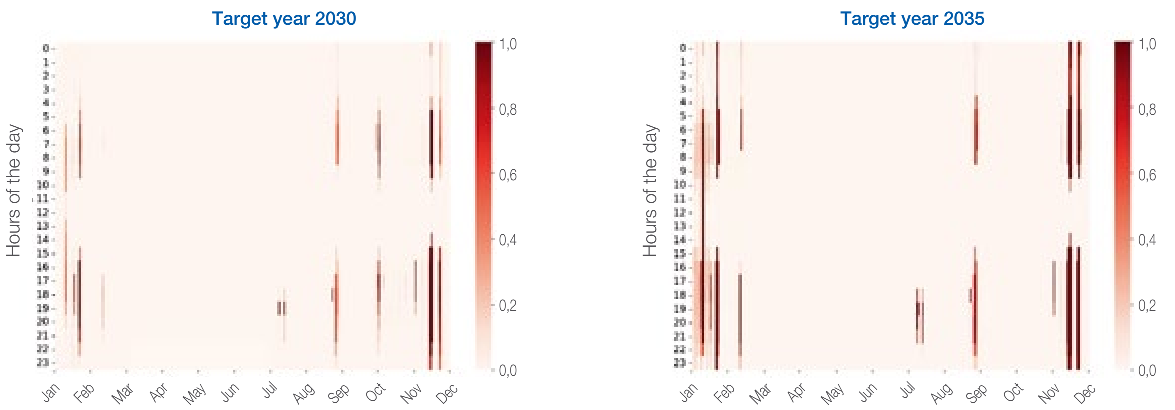
Figure 19 ***LOLE and EENS hours due to missing money caused by climate variability (2030-35)***



To better define the critical issues the electricity system might face over the timeframe analysed, and to describe the adequacy indicators in more detail, a climate scenario was selected that represents the average conditions of the entire set of 36 climate scenarios, which also turns out to have a LOLE figure close to the average. The selected climate scenario (WS 26) has a mild summer, a not particularly harsh winter, and average vRES power generation.

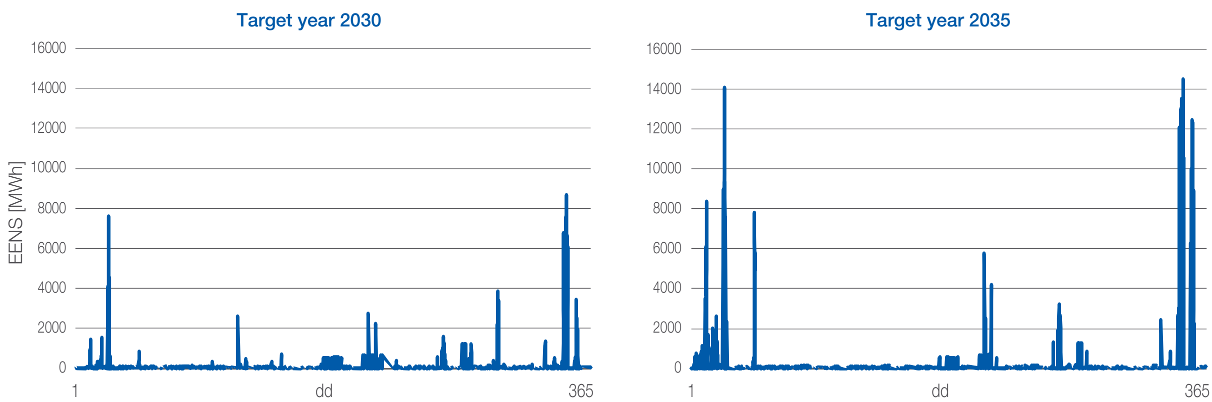
Loss Of Load Probability (LOLP) heatmaps were studied for these climate conditions, which show (*Figure 20*) that the greatest risks of energy not served occur during evening hours and in the winter and, to a lesser extent, also in the summer, when peak demand is greatest. The assessments highlight the need for storage capacity to meet the high level of residual load in the evening, especially in the absence of a significant share of thermal power.

Figure 20 ***Heatmap of Loss of Load Probability for an average scenario and target years 2030 and 2035***



On examining the evolution of the heatmaps from target year 2030 to target year 2035, it may be noted that critical issues affecting the summer are gradually diminishing, whilst still occurring in particularly critical situations (e.g. restrictions on thermal production due to high discharge water temperature), primarily due to the growing penetration of solar and storage capacity. However, in the winter, due to limited solar production capacity and increased use of heat pumps for heating, power generation and storage capacity is unable to cover the high residual load occurring during the evening and at night.

Figure 21 ***Annual distribution with hourly granularity of EENS***



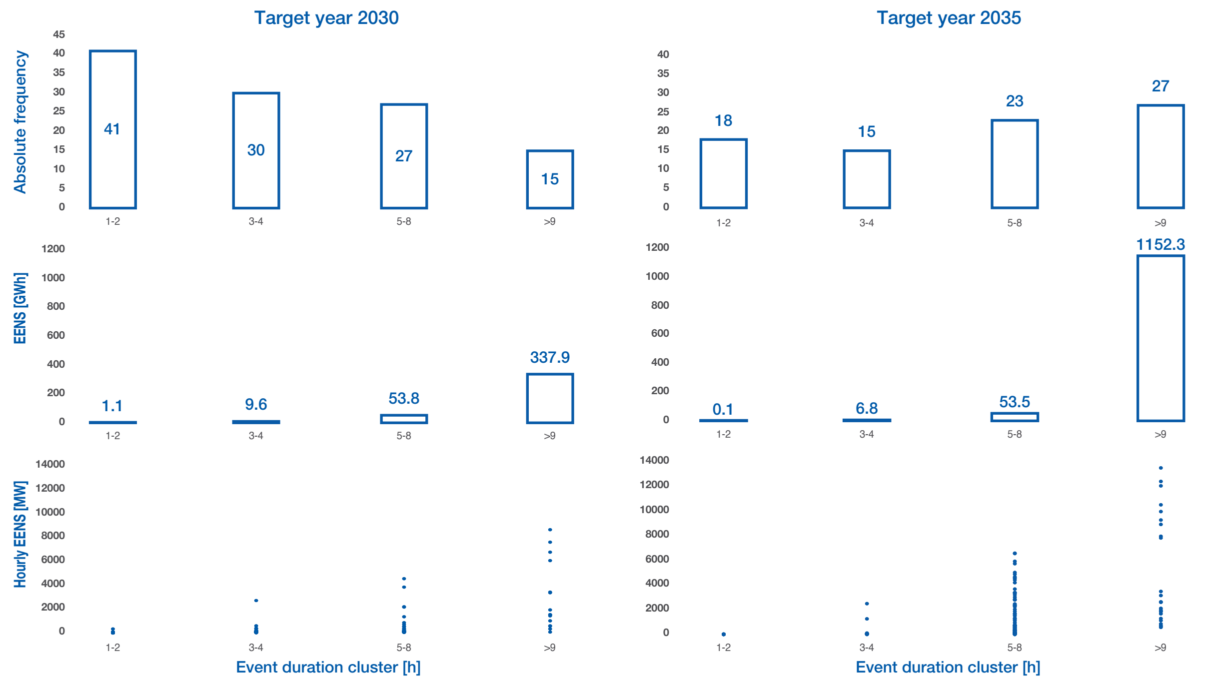
The time distribution over the year of energy not supplied (ENS) indicates that unserved energy events, given the same probability of occurrence, would generate greater impacts on the system in winter (*Figue 21*).

Energy not served events were characterised by clustering them according to their duration. Four clusters were used: 1-2 hours, 3-4 hours, 5-8 hours and over 9 hours. For each of these clusters, the following quantities were analysed:

- number of events;
- EENS;
- magnitude of the event.

Figure 22 shows the graphs of these quantities under average weather conditions (weather scenario). It may be noted that the most critical events turn out to be long ones (over 8 hours), in terms of both total energy not served and unserved instantaneous capacity. In the target year 2035, there is a gradual decrease in EENS events lasting less than 8 hours, mainly due to growing penetration of storage systems with an E/P=8h ratio. Examination of these indicators reveals that merely increasing current storage capacity to replace decommissioned thermal plants would not provide a comprehensive solution to ensure system adequacy, as the duration of the storage systems would need to be significantly longer than is feasible with current technology.

Figure 22 ***Frequency of EENS events, value of energy not supplied, maximum capacity of each event by event duration cluster***




Terna

5 Annexes

Annexes

5

ANNEX I: Comparison with ERAA 2025

The 2025 edition of the European Resource Adequacy Assessment (ERAA 2025), published by ENTSO-E in December 2025, complements the assessment described in this report through a pan-European monitoring assessment of power system resource adequacy of up to 10 years ahead.

The timing of data collection and the simplifications applied due to the Europe-wide scale of the assessment in the ERAA means that there are intrinsic differences with respect to the assessment at national level. The main differences are described in this section.

It is important to note that the national and European assessments are conducted in synergy. National resource adequacy assessments (NRAAs) are conducted by experts with solid knowledge of regional specifics and, therefore, go into far greater detail than the European assessments. This is because they take into account specific peculiarities of the electricity system, thanks to a more flexible process for updating input data and the use of more detailed modelling.

At the same time, the ERAA process enables data and scenarios relating to the various Member States to be shared within a consistent, organic framework (in terms, for example of target years and energy policies) and provides general results within an overall vision. Taken together, the NRAA and the ERAA offer a complete, integrated view of the adequacy assessment, placing the peculiarities considered in national assessments within a Europe-wide context. Despite this consistency in terms of scenarios and target years, there are differences between the NRAA and ERAA, above all with regard to the economic viability assessment which, in the European assessment, adopts a cost-based approach rather than a revenue-based approach, using the expected margins of producers. As a result, the quantitative data in the European analyses could underestimate adequacy risks, as the chosen methodological approach assumes a lower level of decommissioning of existing capacity, thus overestimating the capacity available to contribute to the system adequacy.

Target years:

As indicated in Regulation (EU) 2019/943 of the European Parliament and Council, the ERAA considers a time horizon of ten years following the year of publication, analysing a number of mid-term target years deemed to be the most significant. As a result, the time horizon used in the 2025 edition of the ERAA covers a period from 2026 to 2035 and examines the target years 2028, 2030, 2033 and 2035.

The NRAA for Italy is a strategic document that looks at the adequacy of the country's electricity system over the medium to long term. To ensure consistency with the European document, the 2025 edition analyses the years 2030 and 2035. This means that, although the economic viability assessment of plants (EVA) is carried out using the same target years as the ERAA, the adequacy assessment in the NRAA focuses on the years 2030 and 2035.

Economic viability assessment:

ERAA 2025 presents the results of two distinct approaches to assessing the economic viability of plants (EVA):

1. a cost-based approach, the results of which form the basis of the reference scenario for the adequacy assessment in the ERAA 2025;
2. a revenue-based approach, using an estimate of the expected margins of producers, the results of which are reported to highlight the maturity of this approach and the potential for its full application in future editions of the ERAA. This approach aims to identify an equilibrium condition in line with the economic criteria effectively applied by electricity market operators.

As described, this second approach is also applied in the economic viability assessment in the NRAA 2025, which, compared with the assessment conducted for the ERAA 2025, introduces the following peculiarities for the Italian assessment:

1. Secondary reserve: Procurement of reserve capacity in the NRAA 2025 is more accurately modelled, guaranteeing that the system's minimum reserve requirement is always covered using all the enabled resources (including BESS). In addition to ensuring simulation consistency by avoiding any shortage of reserves, this implies that the generation units whose economic viability is being assessed are more exposed to the risk of not being on the money as they are competing with other resources to provide reserve capacity.
2. Scope of the EVA: Italian generation capacity covered by the EVA in the ERAA 2025 amounts to 33.7 GW. In the NRAA 2025, on the other hand, this capacity amounts to 32.7 GW for the reasons detailed in section 4.3. The reduction in capacity included in the assessment scope reflects exclusion of the repowered capacity of existing plants covered by fifteen-year contracts through Capacity Market auctions.

Table 1 shows the net effects of the three EVA processes in the two years referred to in the NRAA 2025.

Table 1 ***Post-EVA scenario, net effect (Expansion - Decommissioning) [GW]***

[GW]

	2030	2035
Revenue-based NRAA 2025	-26.3	-27.5
Revenue-based ERAA 2025	-22.3	-25.0
Cost-based ERAA 2025	-18.3	-20.3

Adequacy analysis:

The main differences between the methodologies used for the adequacy analysis in the ERAA and the NRAA are described below:

- In the ERAA, the **scope of the analysis** is pan-European, while the NRAA's analysis is limited to bidding zones in Italy and Malta, which was explicitly modelled in in line with the ERAA 2025. All other bordering countries are modelled as "equivalent generators":

- countries on Italy's northern border are modelled as an equivalent node, associated with an ideal generator with hourly capacity equal to the outcome of the post-EVA simulations conducted for a pan-European scope. This node is connected to the Italian electricity system through an equivalent interconnector described below;

- the level of NTC from countries to the north was modelled with greater detail in the NRAA, to take into account the particular grid operating conditions not captured by the standard bus-bar models used in the ERAA;

- Greece and Montenegro were modelled as equivalent nodes, associated with an ideal generator with a production profile equal to import availability and a demand profile equal to exports to the above nodes resulting from the EVA.

- The **secondary reserve** requirement in the NRAA 2025 is modelled to ensure the minimum quantity needed by the system is always covered.

- The NRAA extracts and analyses **100 Monte Carlo (MC) years** whilst the ERAA looks at only 15. This difference is particularly significant, as a high number of MC years enables a fuller and more accurate assessment of a radial-type electricity system such as the Italian one, where interconnections (above all with the islands) play a key role in guaranteeing adequacy.

There are further minor differences, including the use of updated power line maintenance profiles and failure rates and more detailed modelling of the thermal fleet. For example, restrictions on high discharge water temperatures, which better characterise the operation of thermal plants with respect to external temperatures, were taken into account.

Summary of the results of the ERAA 2025

In the **ERAA 2025**, adequacy indicators for each bidding zone in the European market are shown as a **range of values**, reflecting the use of **two different models of investor behaviour** in the Economic Viability Assessment (EVA). A hurdle premium is applied in both models to incorporate increased risk aversion and, as a result, higher investment costs. However, a **Revenue Cap**, designed to limit operators' exposure to price volatility, is applied in only one of the models.

As noted in the documents on methodology and in the comparative analysis reported on in the Country Comments (Annex 6), inclusion of the Revenue Cap tends to result in more cautious outcomes: the reduced ability to capture scarcity price signals makes it more difficult for plants to be profitable, heightening the likelihood of decommissioning and thereby having a negative impact on adequacy indicators. This effect is particularly evident if the scenarios with just a hurdle premium are compared with those where there is a hurdle premium plus a revenue cap, resulting in significant reductions in economically viable conventional capacity.

Regardless of the approach used to represent investor risk aversion, the ERAA 2025 identifies **areas of inadequacy** (LOLE > 3 h/year) in Italy **across all the studied time horizons**. This result is consistent with the conclusions in the report, which states that, without adequate capacity remuneration mechanisms, the decommissioning of thermal plants not in the money would lead to ongoing difficulties throughout the next decade.

Table 2 shows, for information purposes, the value of LOLE in 2030, deriving from application of **implementation A of the revenue-based EVA approach**, already used in the **NRAA 2025** and included in Appendix 5 of the ERAA 2025 as proof of concept of shifting to a revenue-based approach on a European scale.

Table 2 ***Values for LOLE [h] published for Italy in the ERAA 2025 and compared with the NRAA 2025***

LOLE (h) UNDER THE EVA APPROACH	2030	2035
ERAA 25, cost-based EVA (partial risk aversion model)	6	5
ERAA 25, cost-based EVA (full risk aversion model)	9	10
NRAA 25, revenue-based EVA (full risk aversion model)	155	208

ANNEX II: Adequacy analysis

5.1 Electricity system simulation

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

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

- thermal installed capacity with the related technical characteristics;
- hydro, photovoltaic and wind installed capacity;
- the transmission grid, represented in a simplified way through exchange capacity (expressed as the weighted average over the various periods of the year) between bordering market areas;
- the hourly profiles of “imposed” generation[8], that is power generation not tied to considerations regarding economic viability;
- the hourly profiles of reduced exchange capacity between market areas due to planned maintenance;
- the number of weeks of maintenance required by each generator;
- the hourly profile of 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 forced outages;
- the hourly profiles of reduced cross-border exchange capacity with neighbouring countries due to forced outages.

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

1. hourly programming, over an annual time horizon, of the operation of storage systems (including hydro reservoirs), together with an optimised maintenance plan for the thermal generation fleet;
2. hourly dispatching on a weekly basis, revising the previous solution based on faults selected by the model.

Both optimisation problems require a configuration that, whilst capable of observing the technical constraints of the simulated system, can minimise the variable cost of generation. In particular, the unit-commitment requires observance of constraints related to the operating reserve and those on transport capacity between different bidding zones in the system.

[8] For example, geothermal and biomass generation and all generation subject to operational constraints (essential plants).

5.2 Probabilistic approach

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

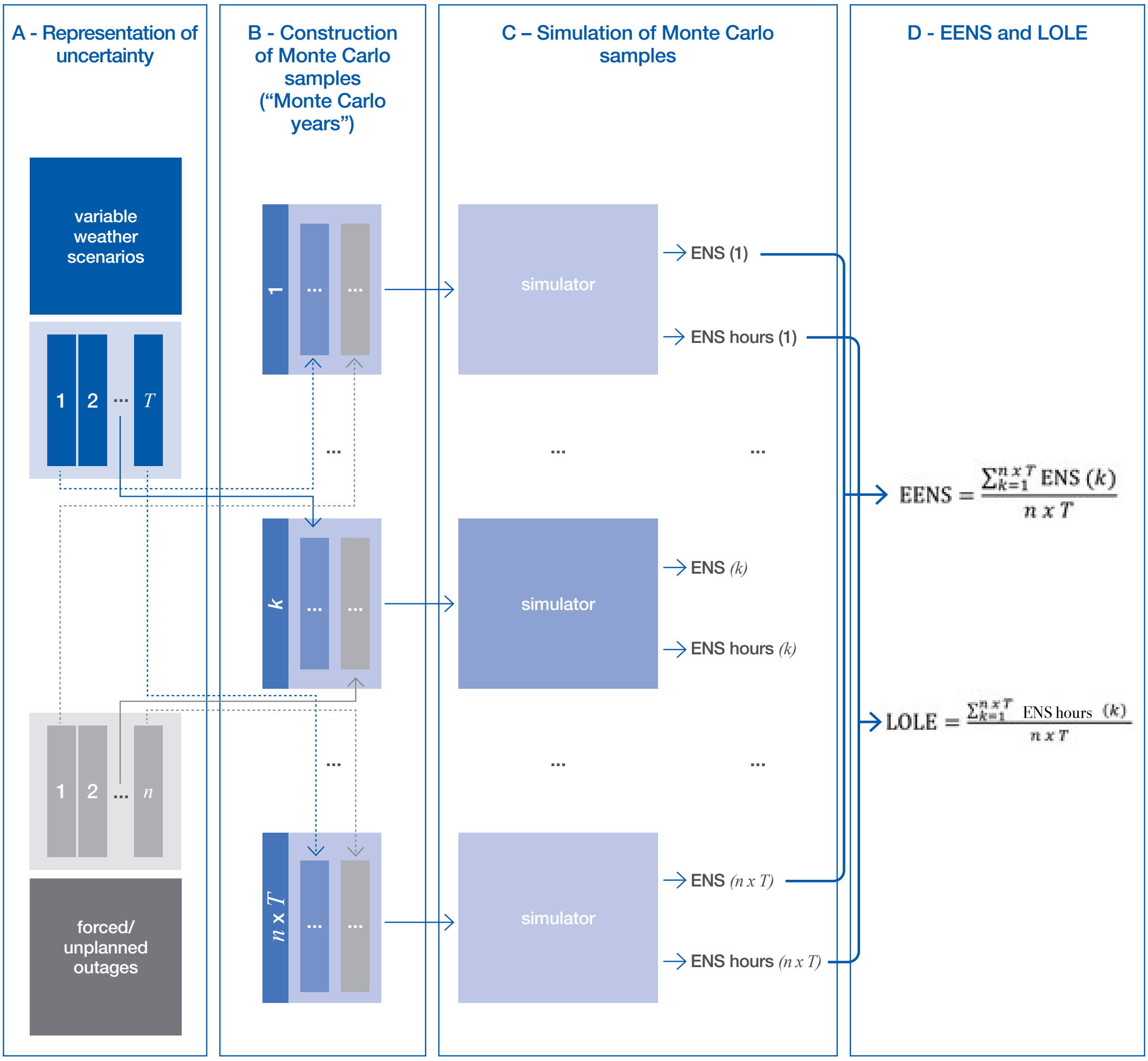
- weather (temperature, wind, sunlight and rainfall);

- the availability of generation capacity, which also depends on the occurrence or non-occurrence of outages;

- the availability of transmission capacity, which, as with generation, is also linked to the potential occurrence of outages.

This uncertainty is destined, in the next few years, to be increasingly significant: the electrification of consumption and the higher share 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 it more likely that certain components will fail, and the increase in extreme weather events will make it more likely that certain parts of the transmission grid are exposed to the risk of outages. For these reasons, a correct system adequacy assessment must involve the use of a probabilistic approach (*Figure 23*)

Figure 23 ***Summary of the probabilistic approach***



A probabilistic approach makes it possible for simulations to take into account the intrinsic uncertainty of certain inputs. Currently, the most frequently used probabilistic approach for system adequacy analysis is the Monte Carlo method (*Figure 23*).

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

A. a sample of possible values and/or operational conditions is considered for all the potentially uncertain elements. In producing the samples, the probability distribution curve for the occurrence of each of the above states 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 operational 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 the adequacy indicators are calculated for each of them;

D. the annual average is calculated based on the results of the simulations of the system described in C.

The above four steps are described in greater detail below.

A. Uncertainty in an electricity system

In the analysis uncertainty is represented mainly:

- by using climate variables: obtained from historical data appropriately updated to consider the phenomena of climate change. Climate variables are taken to be fully correlated: in the construction of a Monte Carlo sample, temperature, wind, sunlight and rainfall profiles always relate to the same "climate scenario";
- by the availability of generation and of exchange capacity between areas: assessed through a sequence of random extractions that simulates the occurrence of faults in generators and lines.

B. Construction of Monte Carlo samples ("Monte Carlo years")

The various MC years to be analysed are obtained by grouping together, for each bidding zone, the weather conditions associated with the same climate year, with the availability profiles for each generator in the bidding zone and the availability profiles for cross-border exchange capacity with neighbouring countries. The Monte Carlo years thus constructed are considered all equally probable, as the probability of occurrence is considered over the total number of the simulated MC years that include the same basic variable.

C. Simulation of the Monte Carlo samples

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

D. EENS and LOLE

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

Values for EENS and LOLE are obtained for each "climate scenario" (as described in A), based on the average of the MC years simulated under the given temperature, sunlight and wind conditions.

ANNEX III: Considerations on future Capacity Market auctions

As stated in section 3.1.3, the expansion of capacity obtained through the Capacity Market has played a key role in driving decarbonisation and guaranteeing system adequacy in recent years.

Given the role played by forward markets in predicting future trajectories for power generating capacity, the correct definition of derating factors enables the interaction between the various existing mechanisms to be managed, ensuring that developments in the structure of the generation fleet are consistent with the need to guarantee the security of the electricity system.

Upcoming Capacity Market auctions are expected to see a natural extension of the trends seen in previous auctions: capacity expansion will tend to play an increasingly marginal role, whilst growing competition – driven by the **development of vRES** and **storage**, together with moderate growth in demand – will make it unlikely that all the existing fleet will be selected at the price cap.

Update of derating factors for solar and storage

Regarding the Capacity Market, each resource's contribution to firm capacity is calculated by conventionally reducing the installed power by applying specific derating factors that take into account the actual availability of each specific resource. This provides a common basis for comparing the different technologies.

Photovoltaic technology, for example, reaches peak production in the middle of the day. With the growth in vRES in recent years, this has reduced the residual load[9] during this part of the day, on occasion to below zero. At the same time, the evening is progressively becoming the most critical time of day. This means that, as overall solar capacity expands, the incremental contribution of this technology to meeting demand is in decline.

In the case of battery energy storage systems (BESS), this factor is of particular importance as these resources supply a limited amount of power and their effective operational capacity depends on the possibility to charge themselves with energy produced by other resources (both renewable and conventional thermal). This means that they are dependent on the state of the electricity system and bidding zone in which they operate. In general, BESS are capable of replacing thermal generators, whilst only to a certain extent guaranteeing adequacy and reducing peak residual load. As their penetration of the electricity system increases, the incremental contribution of expanded storage capacity declines.

The need to update derating factors for the Capacity Market auction for the 2028 delivery year, and to define the need for storage system capacity, is primarily linked to the forecast expansion of storage systems, including those selected in the MACSE auction for delivery in 2028, compared with the storage capacity on which previous auctions were based. Moreover, the potential replacement of thermal capacity with BESS, observed in the Capacity Market auction for the 2027 delivery year, also makes an update necessary.

As in previous auctions, a national factor is to be calculated for both solar resources and BESS for the purposes of Capacity Market auction for 2028. In terms of BESS technology, a single derating factor will be calculated for all bidding zones, according to the various energy/power ratios. In this regard, to calculate the contribution made by BESS resources to adequacy on a prudent basis, the proposed rating coincides with the one attributable to the Northern bidding zone, which is the most critical from the viewpoint of adequacy.

[9] The residual load is defined as the difference between total demand for electricity and vRES production.

An iterative process was used to measure the technology rating (solar or BESS) based on availability, with the aim of identifying the rate at which BESS capacity is replacing ideal programmable capacity: starting from the expected system in 2028, solar or BESS capacity is expanded incrementally as programmable capacity is reduced in the same bidding zone, with the quantity added sufficient to ensure that the same level of system adequacy is maintained. This ideal programmable capacity thus diminishes as solar or BESS capacity expands. The derating factor is therefore calculated as the one's complement of the ratio between the reduction in ideal programmable capacity and the increase in expanded photovoltaic or storage capacity needed to guarantee adequacy.

This results in a curve (for each technology and for each time horizon) showing incremental capacity, in which each value for additional capacity is associated with the related rating.

Managing the situation in Sicily

The particular nature of the Sicilian electricity system affects robustness and reliability:

- a significant part of the programmable generation fleet still consists of outdated oil-fired plants;
- programmable generation is affected by unavailability or operational constraints linked to increasingly frequent high discharge water temperatures;
- the penetration of non-programmable renewable sources is growing rapidly, as confirmed by the results of recent FER-X auctions in which contracts for around 4.5 GW were awarded on the island;
- interconnection with other bidding zones remains limited, given that the Tyrrhenian Link will only be fully operational from 2029, following expected completion of the two branches in 2028.

These aspects make the Sicilian system particularly vulnerable, above all in the medium term, if the decommissioning of less efficient and reliable generation capacity continues, without the full support of the Tyrrhenian Link. Under these conditions, there is a real risk of being unable to meet demand, above all:

- at times of peak load (during the summer, for example);
- in the evening or at night, when there is a minimal contribution from solar;
- at times of reduced exchange capacity with Calabria, for example when maintenance of the links is taking place.

In this rapidly changing, complex scenario, the security and adequacy of the Sicilian electricity system is dependent on availability of the local programmable generation fleet.

For this reason, the Capacity Market auction for 2028 is an opportunity to ensure that the necessary capacity is provided directly in Sicily, limiting use of exchange capacity with the mainland. Terna wishes to highlight the importance of targeted procurement, guaranteeing the stability and resilience of the island's system, alongside the transition to a more sustainable energy mix.

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