ACER Decision on ERAA 2023: Annex I.e

To be read together with the updated results set out in Annex IV

European Resource Adequacy Assessment

2023 Edition

Annex 4: Country Comments

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Disclaimer: This Annex aims to present specific national insights linked to the present ERAA, provided by TSOs on a voluntary basis. These insights reflect only the positions of the concerned TSOs who have submitted their comments and shall not be considered as ENTSO-E's statement.

1 Austria

1.1 Adequacy Indicators

The adequacy indicators for Austria depicted in the ERAA 2023 report show non-zero values of LOLE and EENS for all the target years assessed (2025, 2028, 2030 and 2030) in both Scenarios A and B. The average LOLE values are below 1h in both scenarios for the mid-term horizon (up to 2030), while they reach higher values for the target year 2033 (1.44h for Scenario A and 2.69h for Scenario B). These results suggest that, despite the expected internal growth of RES capacity (mainly solar PV and wind onshore) and the commissioning of key strategic hydropower projects, the expected rapid growth of the electricity demand and the pervasive electrification of the heating and transportation sectors can pose significant challenges to maintain the desired level of domestic security of supply. To assess the penetration of electric vehicles and heat pumps, ad-hoc scientific work was produced which helped to identify drivers for demand growth for electric mobility and heating/cooling, as well as to refine the corresponding hourly profiles in the electricity demand forecasts. The resilience of the system needs to be supported by growing availability of flexible resources. Currently there is no legally binding Reliability Standards (RS) in Austria. Nevertheless, we see the need to closely monitor the domestic availability of resources to ensure resource adequacy in Austria in the mid- and especially long-term perspective. In fact, the P95 values of Loss of Load Duration (LLD) increase up to 8h/year and 14h/year in 2033 in scenario A and B respectively, showing high impact of some extreme but possible scenarios and the increasing sensitivity of peak-load with respect to the outdoor temperature profiles. Additionally, the development on the electrification on the demand side was not fully captured for all sectors in ERAA 2023 input data, thus it will be closely monitored and investigated in future adequacy assessments. APG (the Austrian TSO for electricity) intends to keep monitoring the national level of adequacy to provide both the TSO and the national key stakeholders with tailored and complementary insights on the domestic adequacy indicators, aside from the ones reported in the ERAA 2023 report, especially taking into account the peculiar characteristics of the Austrian power system, which could not be properly reflected in the ERAA. These include but are not limited to (i) precise modelling of complex hydropower storage systems, (ii) specificities of the internal high voltage transmission grid, (iii) additional sensitivities and scenarios on available capacity, demand, and other key input data.

1.2 Economic Viability Assessment

Another factor that affects resource adequacy is the economic viability of existing thermal generators. The EVA of ERAA 2023 indicates that in both scenarios around 800 MW of thermal generation capacity are likely to be mothballed in the mid-term perspective (2025 - 2028) and additional 100 MW are at risk of early decommissioning (as of 2025) in relation to their economic viability. The capacity at risk in the ERAA 2023 exercise represents around 20% of the ca. 4200 MW of total thermal capacity (excluding “other non-RES") expected to be available in 2025 according to the TSO data. A substantial part of Austria’s thermal generation capacity is already today maintained operational through a network reserve mechanism. APG monitors closely the availability of Austria’s thermal generation capacity, given its critical importance to ensure not only resource adequacy, but also a safe and secure operation of the national electricity grid. More conservative assumptions as well as the actual economic viability of such plants depict currently potential higher mothballing grade during the next decade, particularly during the summer period, highlighting the significance of complementary mechanisms to maintain enough flexible generation resources operational in Austria.

2 Czech Republic

The outcomes of ERAA 2023 are crucial for understanding the future European power mix and will be used in the National Resource Adequacy Assessment of the Czech Republic (MAF CZ). Following points need to be nevertheless mentioned from the Czech perspective:

1. The preparation of ERAA 2023 coincided with the update of the Czech National Energy and Climate Plan. While the updated data could not be reflected in ERAA 2023 due to data freeze, it will be incorporated into MAF CZ.

2. Investment constraints for the installation of new sources were applied in EVA in line with the current situation in the Czech Republic. In general, new (gas) capacities may be subject to different forms of support by EU Member States. In order to loosen any investment constraints within the Czech Republic, a similar support for capacity expansion will be reflected in the national assessment. From this perspective, Scenario B is thus more suited to the needs of the Czech electricity sector.

3. Reliability standard calculations for the Czech Republic in this report are based on the outdated VOLL value. The new VOLL, CONE and reliability standard values have already been determined but will not be published until 2024 in MAF CZ.

3 Finland

The Finnish adequacy indicator results presented in the report don't meet the Finnish standard for system reliability, which is currently set to LOLE 2.1 h/a. Especially in 2025 the Finnish LOLE values are higher than the set standard. However, they gradually decrease going further into 2028, 2030 and 2033. The adequacy risks identified in 2025 are highly dependent on the possible decommissioning and/or mothballing of thermal units, especially coal CHPs (-240 MW in EVA by 2025). The decreasing risks in the later years are explained by increased interconnector capacity as Aurora Line between Northern Sweden and Finland is commissioned by the end of 2025, and increased demand-side response (DSR) assumed from the industry as well as households, especially from heating. At the same time, EVA results show increase in DSR (+120 MW from 2025 onwards) but decrease in fossil thermal generation due to mothballing and decommissioning especially in long-term (-1600 MW in 2033).

Adequacy of electricity supply faces its greatest challenges during the winter season in Finland, particularly during cold and calm weather periods. This is because electricity demand is significantly influenced by outdoor temperatures, and power generation becomes increasingly reliant on wind conditions. Despite increase in domestic generation capacity, there is a necessity for importing electricity from neighbouring countries to meet peak demand, particularly when wind generation is low and/or in case of forced outages. This is witnessed in the detailed results in Annex 3, which show that the 95th percentile LOLE results are usually +10 h/a while median is 0 h/a. It's important to note that the LOLE results are averaged over 35 weather years, while it's the colder years that the adequacy challenges are usually faced.

All in all, the development regarding adequacy is highly dependent on the increase in DSR, and if it does not realise, some other type of flexibility is needed to reach sufficient electricity adequacy in Finland especially during the coldest winters. Currently Finland has a strategic reserve measure in place until 2032 but no capacity is contracted to the reserve. As a new development, National Emergency Supply Agency (NESA) has made an agreement on Meri-Pori coal power plant to reserve its production for severe disruptions and emergencies to guarantee security of supply in the electricity system. The agreement period is from 1 March 2024 until 31 December 2026 and Meri-Pori will not be available for the market during the period. The new government programme also states that a study will be conducted to create a cost-effective capacity mechanism (e.g. an auction or similar) that will ensure a sufficient amount of available electricity at all times. Fingrid views the potential well-designed capacity mechanism as a positive development to ensure adequate electricity supply in Finland.

4 France

4.1 The National Energy and Climate Plan

The new NECP draft has been presented to the European Commission late 2023. It relies on two framework documents, the National Low-Carbon Strategy and the Multiannual Energy Plan, both of which provide a roadmap for the energy sector in the coming year. The new NECP draft is also now supported by more recent work, such as RTE's latest National Resource Adequacy Assessment.
It integrates the *Fit for 55* and *RePowerEU* packages in the French energy roadmap, with ambitious RES development targets, but also carries a new nuclear strategy, with expectations of expanding lifetime of several nuclear units up to 50 years and the building of several new reactors. These developments support the target of decarbonisation through electrification to reach carbon neutrality by 2050.

4.2 Load forecast provided for 2025, 2028, 2030, 2033

After remaining stable over the past decade, the French electricity demand fell in 2022 (461 TWh, i.e. 12 TWh less than in 2019). This decrease happened after the COVID crisis and can be explained by a combination of sufficiency from consumers and high market prices. First forecasts of electricity consumption of 2023 tend to show similar figures as 2022, with a slow decrease of market prices and an optimistic 23-24 Winter Outlook.
In the medium term, French electricity demand is expected to keep on this rising trend, from 2024 onwards. The recovery of the economic activity and the development of electricity as a decarbonisation vector will more than counterbalance the effects of energy efficiency actions on the annual demand. Furthermore, to meet the *Fit for 55* target, RTE provided this ERAA with a reference load scenario, which was presented as well in the 2023 NRAA, the *Bilan Prévisionnel*[1] (published in September 2023).

Main drivers of this rising demand are:

- Approximately 9% of the French electricity demand dedicated to hydrogen production by 2035;
- Approximately 40% of the vehicle fleet and 20% of trucks will be electric by 2035;
- Increasing the share of electricity in heating systems and industrial processes

This trajectory is above that from the previous ERAA 2022~~.~~ It reflects an increased electrification, especially in transports and industry, it being a pathway to achieve Fit for 55 in 2030 and carbon neutrality by 2050.

4.3 Net generating capacity forecast provided for 2025, 2028, 2030, 2033

The scenario presented in the 2023 ERAA foreshadowed the NECPs evolutions on short term trajectories of electricity production:

- Accelerated development of RES (wind and solar capacities are multiplied by more than three in the next ten years);

[1] 2023-10-02-bilan-previsionnel-2023-principaux-resultats.pdf (rte-france.com)

- Decommissioning of the last two coal units (Cordemais power plant) is still postponed to 2024 at the earliest, for security of supply concerns;
- No commissioning of new fossil-fuelled units is authorised;
- The new Flamanville nuclear unit is expected to start-up by 2024 with nominal functioning in 2025.

Regarding nuclear availability, the recent corrosion stress crisis appears to come to an end by 2024, but still has led RTE to review its nuclear availability forecasts. The effect is still expected to be perceived on availability in 2024 with a full recovery by 2025.

4.4 National view on adequacy and economic viability

RTE produces an annual risk assessment through its national adequacy outlook on a time horizon of five to ten years.
The key messages from the NRAA (published in September 2023) regarding adequacy were:

- Security of supply in France is expected to improve in the coming years, after a setback in the last years caused by the COVID crisis and the stress corrosion of a number of nuclear reactors.
- From 2030 on: a need for new capacities has been identified, which can be fulfilled by several combinations of demand-side response and production

Levels of vigilance remain necessarily high, monitoring nuclear availability and the speeding up of electrification.

On a general basis, the ERAA 2023 numerical results, considering the complementary Scenarios A and B together, are consistent with the NRAA's conclusion on security of supply concerns, ERAA pointing them out from 2025 or 2028 on, depending on the scenario, and the *Bilan Prévisionnel* from 2026 on, taking into account the impact of the viability analysis.

RTE recognises the numerous methodological improvements that were carried out in this edition of the ERAA, on both EVA and ED studies. Moreover, the complementary analysis from *Scenario B* is very precious and essential to grasp the extent of the economic risk in Europe in general and in France in particular.

While results are consistent on security of supply concerns in France, some methodological simplifications linked to the global complexity of calculations still raise attention points, that will have to be addressed in further editions of the study. Mainly, **the very low number of Climate Years used in EVA (3)** can lead to result instability, as one of these years only carries drive for investment. The economic equilibrium output is represented by a balance of a single, low-probability, year with very high revenues, and most of the weight on years with little or negative revenues. Hence, the weighting of the year 1985[2] becomes the most prominent driver for capacity commissioning or decommissioning, as is seen between scenarios A and B. This equilibrium does not seem representative, or representative enough, of a risk-averse behavior in capacity commissioning. RTE believes that a *revenue-based* approach would better avoid these phenomena while being in line with the ACER methodology.

Consequently, the results of this ERAA for France have to be read jointly with the French NRAA *Bilan Prévisionnel*, to mitigate possible uncertainties due the sheer complexity of the ERAA exercise. The last edition of the *Bilan Prévisionnel* was published in autumn 2023, with detailed chapters having been published since. They depict a central scenario pointing towards a need for investment by 2030 to ensure fulfilment of the **2h Reliability Standard.**

[2] Which is an historically extreme outlier in the whole of Europe and in France, setting unseen-since lows for temperature.

5 Germany

5.1 Input Data

The scenario input provided by German TSOs (scenario “National Trends”) reflects the current legislation and political targets in Germany. Hard coal and lignite-fired power plants shall be shut-down by 2030 at the latest according to the ambitions of the current government. Related negotiations and revisions of the legislative framework are in progress. Renewable expansion goals result in installed capacities of 115 GW of wind onshore, 30 GW of wind offshore and 215 GW of photovoltaics in 2030.
The scenarios are in accordance with the fit-for-55 regulations. The scenarios of the national processes like the network development plan, which are approved by the national regulatory authority, are the framework for the ERAA scenarios. Further scenario sources are the German legally mandated processes on determining the demand for reserve generation capacity for congestion management called “Systemanalyse” and “Langfristanalyse”. Further national discussions about safeguarding resource adequacy (“Kraftwerksstrategie”) have not been concluded yet and therefore cannot be taken into account as part of the exogeneous input parameters of ERAA 2023.

Hydrogen power plants

Hydrogen power plants in accordance with the Renewable Energy Law EEG23 (8.8 GW in 2030) are taken into account. In addition, a gradual transition of existing gas-fired power plants to hydrogen is accounted for, which ensures consistency with the assumptions of the national grid development plan NEP. In the report, hydrogen units and natural gas units are both included in the category "gas" power plants. However, in the model, they are dispatched following the hydrogen cost assumptions.
Due to the planned subsidies for these fuel switch power plants, they are considered as "policy units"; hence they cannot be decommissioned. The endogenous expansion is based on the central assumption on investment costs and fixed operating costs of gas-fired power plants. ERAA 2023 has no endogenous hydrogen expansion option. Therefore, the capacity expansions identified in the EVA should be interpreted as follows: either, they have the same techno-economic operation as natural gas-fired power plants or have a similar cost structure similar to natural gas-fired power plants due to subsidy schemes.

Flexible Demand

It should be noted that, compared to ERAA 2022, flexibility assumptions for households in Germany have increased. In agreement with the German NRA, it is assumed for 2030 that 60-65% of household heat pumps, EVs and household batteries will react to electricity price signals. Consequently, their electricity consumption might be reduced in times of scarcity within the modelling constraints of “implicit DSR” (see Annex 2 chapter 2.3.2). An analysis of the German TSOs on ERAA 2023 results has shown that the contribution of “implicit DSR” technologies during scarcity is rather limited due to restrictive temporal redistribution potential of demand.

Home storage battery systems

Home storage battery systems are modelled as dual use entities. Most of the year, home storage systems optimize the self-consumption of electricity produced by rooftop-PV: they charge in accordance to solar irradiance and discharge during evening load peak. Since the utility of home storages is very limited during winter months, it is assumed that a share of those (e.g. 65% in 2030) is flexibly and can also react to spot market prices.

Large power-to-heat systems

Large power-to-heat systems are modelled fully price dependent. Large-scale heat pumps amount to 8.8 GW and electric boilers to 10 GW in 2030. The demand of heat for district heating networks depends on the temperature and thus the climate year.

5.2 Comments on the results

The EVA shows a net-expansion of the German power plant fleet from 2030 onwards compared to the pre-EVA national-trends scenario. The coal phase out assumed in 2030 is set exogenously. Assumed high gas prices prevent an earlier coal phase out than exogenously given. With coal power plants in the market, the peaking gas units are temporarily not economically viable. Therefore, the years prior to the coal phase-out (2025 and 2028) are marked by mothballed gas power plants. However, with increasing sector coupling and simultaneous coal phase-out previously mothballed units can be operated economically from 2030 onwards. Additionally, the coal phase-out (19 GW between 2028 and 2030) incentivizes substantial investment in gas-fired units. The EVA suggests 12.4 GW of gas expansion in 2030 and additional 10 GW in 2033 for scenario A. In scenario B the gas capacity is expanded by 6.5 GW in 2030 and by additional 8.4 GW in 2033. Those are the largest investments identified by the EVA in Europe and they have a large impact on the resulting level of security of supply. For earlier target years, the higher weighting of the climate year with scarcity situations in scenario A leads to lower mothballing rates as shown in Annex 3 chapter 3.1.1 ("EVA results"). The wide range of both EVA scenarios results is also reflected in the results of the adequacy simulation stage. In terms of adequacy result parameters, scenario A shows LOLE values of 2.2 h/a in 2025, 3.6 h/a in 2028, 4.3 h/a in 2030 and 8.1 h/a in 2033. The national reliability standard of 2.77 h/a is only met in 2025. The EVA-results of scenario B show increased LOLE values as less capacity is kept in the system and less new built capacities are realized. The German reliability standard is violated in all target years: 9.6 h/a in 2025, 12.3 h/a in 2028, 11.2 in 2030 and 21.6 h/a in 2033.

Comparison with the NRAA

In comparison to the ERAA 2023, the NRAA for Germany ("Versorgungssicherheitsmonitoring 2022[3]") does not identify resource adequacy concerns for Germany and neighboring countries until 2031 (LOLE close to 0 h/a) despite a similar level of controllable generation capacity in 2030/2031 (~80 GW in the NRAA as compared to 74-80 GW in ERAA 2023). The following key-components of ERAA 2023 should be emphasized, which – besides others – are likely to contribute to a different outcome of the security of supply situation:

- The Economic Dispatch of ERAA 2023 considers a large variety of historical climate conditions, modelled by a set of 35 climatic years.
- Temporal and regional distribution of ENS in the Economic Dispatch stage is determined according to the methodologies described in Annex 2 chapters 11.7 and 11.5. This prevents the arbitrary character of ENS allocation in spatially or temporally coupled scarcity situations. The German TSOs consider these settings as the appropriate methodological approach.
- The modeling approach and penetration of demand flexibilities (electric vehicles and heat-pumps) in the national process can lead to a greater reduction of scarcity situations.

[3] https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/versorgungssicherheit-strom-bericht-2022.html

EVA: Exclusion of all thermal power plant technologies for capacity expansion in France

In both scenarios, the exclusion of all thermal power plant technologies for EVA-based capacity expansion in France (see Annex 1 “8.1.2 Capacity data drivers” and Annex 2 “10.4 Investment Constraints”) incentivizes capacities in Germany that would have been economically expanded in France instead. Based on sensitivity calculations, it can be estimated that this assumption leads to additional power plant expansions in Germany in the order of 5-10 GW (depending on the weighting of the Climatic Years in the EVA). The German TSOs point out that this measure has resulted in significantly more capacity being located in Germany within the EVA step. Therefore, they believe that the assessed result is only valid if no new power plant capacity (apart from ~0.7 GW hydro expansion projects included in the NECP) will be built in France by 2033 neither through a capacity mechanism nor through the EOM. The security of supply level in Germany increases due to additional national capacity resulting from the expansion constraint in France. According to sensitivity calculations, capacity expansion restrictions in the Czech Republic and Poland have, in comparison, significantly less impact on German capacity expansion.

6 Great Britain

The Great Britain data was based on the 2022 Future Energy Scenarios which were published in July 2022. There has been a further annual update to the Future Energy Scenarios which were published in July 2023.

National Grid ESO analysis from both the Future Energy Scenarios 2022 and 2023 editions concluded that in all scenarios there is enough supply to meet demand out to 2050 which includes the years covered within the ERAA study. This analysis includes consideration of capacity procured through the Capacity Market in the calculations. This means all scenarios meet the reliability standard as prescribed by the Secretary of State for DESNZ – currently three hours per year Loss of Load Expectation (LOLE). The calculation of how capacity market is considered for LOLE is given in our modelling methods document [4].

National Grid ESO data has been provided as an input into this process, this data is publicly available.

7 Hungary

Due to technical problems during the data validation phase, one of our correction in the input data had not been implemented. It relates to the Hungarian wind onshore capacity: the values considered are up to 168,5 MW (depending on the target year) lower than our best estimate at the time when input data had been finalized. The impact of this on the results is estimated to be low.

8 Ireland

Ireland and Northern Ireland together comprise the Single Electricity Market (SEM.) This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support

[4] https://www2.nationalgrideso.com/document/283071/download

long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually. EirGrid inputs to the PEMMDB data collection reflect the best information available at the time of the collection (Dec. 2022 for ERAA23).

EirGrid carries out national studies of adequacy in the SEM and publishes these in the annual 'All-Island Generation Capacity Statement (GCS)'[5]. These assessments incorporate the most up-to-date information at the data freeze dates for demand forecasts (March 2023) and generation availability (May 2023). It should be noted that the GCS freeze dates take place much later than the ERAA data collection, so there can be substantial differences in input data.

There have been significant concerns in recent years regarding the security of supply outlook in Ireland. In response to the concerns, as part of the Commission for Regulation of Utilities (CRU)[6] led SOS programme and the capacity auction process, EirGrid, along with other state agencies and project developers, engage in a process for the enhanced monitoring of new projects; data from this process enables EirGrid to take a TSO risk adjusted view of project delivery i.e. will a project deliver on-time, delayed or not at all.

Since the ERAA data collection window, the risk adjusted view of new project delivery has changed and this will be reflected in our GCS. Furthermore, since the ERAA data collection, a capacity auction has taken place in which a significant amount of new gas generation was awarded for 2027/2028. New projects successful in the capacity auction have been included in the enhanced monitoring process and are included in our GCS.

The adequacy standard in Ireland is set at 8 hours of Loss of Load Expectation (LOLE). National adequacy studies show Ireland to be outside this standard across the study horizon from 2023 to 2032, indicating an increased risk to security of supply in Ireland over the coming years. The ERAA assessment is showing similar increased risk for the early years of the study horizon however the risk decreases in the latter half of the study horizon.

In 2025, there is a significantly increased risk to security of supply in Ireland, with hundreds of hours of LOLE in both the GCS and ERAA assessments. Actions are being taken to mitigate against these potential shortages. By 2028, the adequacy situation has improved, helped by the commissioning of the Celtic interconnector to France and some new thermal generating units. The adequacy situation remains tight in the GCS for 2030 and beyond, while it improves to within standard in the ERAA – these differences can be partly explained by more RES assumed in the ERAA, increased interconnection contribution and by some inaccurate reserve data in 2033[7].

EirGrid have observed a continued decline in plant performance as reflected in our GCS, resulting in an increased risk to security of supply in Ireland. The data submission for ERAA23 included 2019-unit level outage statistics for existing capacity and a 5-year technology class average for new capacity (2017-2021). The GCS applies the latest 5-year (2018-2022) technology class average outage statistics for existing and new capacity, reflecting the declining performance and increased risk to operating a reliable power system.
The peak demand for 2025 in ERAA is significantly lower than in the GCS, while the later years are more closely aligned. This will affect the closeness of the adequacy results particularly for 2025.

While the GCS and the ERAA are both analysing adequacy, there are differences in inputs and methodologies that results in the overall outcome being different. The GCS takes a pragmatic approach, incorporating current

[5] The latest GCS has been submitted to the appropriate regulatory bodies and will be published once approved on www.eirgridgroup.com

[6] CRU.ie

[7] There was a data input error which resulted in zero reserve requirement for 2033.

trends, aspirations to meeting targets and expert input. On the other hand, the inputs to ERAA (and also to TYNDP[8]) incorporate a more ambitious outlook to achieving targets from 2030 onwards.

The ERAA employs a Monte Carlo based probabilistic assessment of resource adequacy, running a large number of simulations over a variety of Forced Outage patterns and climate profiles. In contrast, the current GCS process uses a convolution based probabilistic assessment of resource adequacy, running a single simulation using a convoluted probability of forced outage and an average climate year.

The two assessments return consistent results when the inputs are consistent, however it is not possible to model interregional cross border exchanges in the current GCS process and therefore interconnection is represented using credits whilst the ERAA assessment provides distribution of possible imports and exports. The credit estimation is based on regulatory approved capacity market inputs and places a lower reliance on imports than witnessed through the pan European assessments.

Despite the differences in terms of data inputs and modelling approach, the patterns of adequacy results are broadly similar. In general, the ERAA shows lower LOLE results, particularly as its methodology incorporates flow-based interconnection, along with a wider range of weather years to capture the effect of intermittent renewables.

Following on from ACER's DECISION No 24/2020 on the methodology for the European Resource Adequacy Assessment (ERAA); EirGrid in collaboration with the CRU are currently reviewing the Generation Capacity Statement methodologies to move to towards the National Resource Adequacy Assessment (NRAA) as specified under Regulation (EU) 2019/943 Article 24. As part of this review of Ireland's reliability calculation, EirGrid will consider the impact of weather dependent renewable sources (for example: solar and wind), conventional generation, demand, operational requirements, interconnection, demand side response, storage and energy limited technologies. EirGrid is carrying out a consultation on this new methodology.

9 Italy

As required by national regulation, **Terna publishes a National Adequacy Report** every year **(Rapporto Adeguatezza Italia**[9]**). The report identifies the combination of resources that are necessary to meet the reliability standard** of 3 hours of LOLE per year.[10]
The 2023 edition of the National Adequacy Report analyses a mid-term (2028) and long-term (2033) time horizon. **The underlying scenarios** are based on the Future Energy Scenarios Report[11] prepared by Terna and the Italian gas TSO and are **coherent with the ERAA '23 scenarios**, subject to minor deviations, since the national report takes into account more updated scenario data on renewables and storage (ERAA '23 Data Collection window was closed in early 2023, while for the national report we leave more time to update the scenario data).
Both in the national report and in the ERAA '23, an **Economic Viability Assessment** (EVA) of generation units **is performed to determine those units that face the risk of being decommissioned** for economic reasons. However, while ERAA'23 uses a system-cost approach for EVA, Terna takes a revenue-based

[8] The PEMMDB data collection also gathers data for the Ten Year Network Development Plan.
[9] https://www.terna.it/it/sistema-elettrico/dispacciamento/adeguatezza
[10] The Clean Energy Package requirements were used to determine the reliability standard. In this context, Terna carried out a study to determine VOLL, CONE and RS based on the methodology outlined in the ACER Decision 23/2020. The study has been published by the NRA, see ARERA Deliberation 370/2021.
[11] Published in August 2022, see https://download.terna.it/terna/Documento_Descrizione_Scenari_2022_8da74044f6ee28d.pdf

approach to analyse the economic viability of power plants, i.e. we assess the costs & revenues of individual production units to represent the perspective of power plant operators. The revenue-based approach is in line with the Option a) of Art. 6.2 of ACER Decision 24/2020 on ERAA - Annex I.
The national report shows that the **significant increase in renewables** and storage systems **will lead to a substantial reduction in the operating hours of thermal power plants**, and consequentially in a **strong decrease of their revenues**, which in turn increases the risk of power plants being decommissioned due to economic unsustainability.
In the medium term, 14.8 GW of thermal capacity is at risk, a figure that increases to 19.7 GW in the long-term. In these conditions, the **thermal capacity remaining in the market would drop below the minimum level needed to guarantee adequacy** in both time horizons (39 GW remaining against 50 GW needed to meet the reliability standard in the medium-term, and 33 GW remaining against 41 GW needed in the long-term).
Should this capacity be decommissioned, the **LOLE of the Italian electricity system will be in the order of hundreds of LOLE hours per year**, thus **hundred times higher than the amount required by the reliability standard** (3 h per year), both in the mid-term and long-term horizon. This is in stark contrast to ERAA'23, which sees a lower risk of inadequacy (below ten LOLE hours per year). One of the reasons for this misalignment is that the EVA of ERAA'23 indicates that a significant amount of new capacity would be built in Europe, triggered by extreme market prices of several thousand euros per MWh that occur in very few hours per year. In EVA of the national report, we do not consider that rational investors would be willing to commission new capacity with a lifetime of 15-20 years, only based on a few hours of spiky prices reached in one single year and in extreme weather conditions.
The national report indicates that, **relying solely on average spot market prices, the Italian electricity system would reach an economic equilibrium** in terms of thermal installed capacity, which would **put our system adequacy at severe risk**. To hedge this risk **and ensure that the required level of thermal available capacity is kept operational** in the system, a **dedicated regulatory mechanism is needed**. Such mechanism will be required even if renewable, storage and transmission grid capacity are developed as envisaged in the scenario.
Furthermore, in the national report we highlight that the LOLE of the Italian system heavily depends on the conditions of neighbouring countries and could hence increase even further if neighbours provide little or no adequacy contribution to the Italian system (for example because of a low availability of French nuclear power). We also underline that extreme climate conditions (similar to what happened in summer 2022) show higher risks for electricity system adequacy, due to an unexpected loss of thermal generation, currently not captured by the climatic data of the PECD.

10 Lithuania

Lithuania faces the problem of aging of traditional generation. ERAA 2023 confirmed the results of the National adequacy assessment 2026-2030 for normal operation of the system and shows that the adequacy situation in Lithuania highly depends on the availability of interconnectors. The highest adequacy risk is identified in 2028, which reflects the currently delayed new interconnection between Lithuania and Poland.

Estimates of adequacy in 2030 and 2033 are built on a more conservative demand growth compared to the newest national study. Recently mid/long-term demand growth forecasts have been increasing with the ongoing rapid expansion of renewable integration in the country. Increased long-term demand will be reflected in the next ERAA.

11 Malta

It is important to note that due to its specific electricity network characteristics, Malta does not have an electricity transmission system and although the generation has been opened for competition, there is currently no liquid wholesale electricity market on the island. The Maltese electricity system has been synchronised with the Italian electricity grid since April 2015 through the 200 MW HVAC 200kV interconnector. Out-of-market resources, such as strategic reserves, are not considered within the ERAA as being available for adequacy purposes, which has a profound impact on the output of the models for Malta which yielded significant high values of LOLE and ENS. In Malta, there is as yet no real electricity market, and with just only one supplier the non-market measures are actually an integral part of the power system. A total generating capacity of 215 MW (38% of the thermal capacity in Malta),) which in the report were considered as non-market reserves and hence not included in modelling, is available for dispatching as required at any point to meet the local demand. The inclusion of these non-market measures in future editions of the ERAA study would reflect the state of Malta's power system in a more realistic manner and would inevitably decrease the risk of LOLE and ENS for Malta.

12 Netherlands

Solar PV Overplanting

In the Netherlands the buildout of renewable energy is largely incentivised via a subsidy scheme called Stimulering Duurzame Energie (SDE). In a recent update of the subsidy scheme, new requirements for the connection of (larger) solar PV installations have been introduced, forcing the limitation of the effective (AC) grid power infeed to 50 % of the installed solar PV panel capacity (DC). The aim is to avoid high power infeed in rather rare situations throughout the year (potentially harming grid stability) while the effect of this measure on yearly energy production is comparably limited. In practice, the limitation is achieved by dimensioning the DC/AC converter capacity smaller than the solar panel capacity, often also referred to as "overplanting". Besides these regulations, also for smaller solar PV installations a clear trend can be observed of market parties choosing for smaller converters (e.g. only 70% of panel capacity), mostly driven by economics like the relatively lower costs for solar panels.

While the effect of overplanting is modelled in TenneT's recent national studies, it has not been considered for the ERRA2023 study – leading to a higher solar PV production in e.g. mid-day summertime hours than would be expected. However, as the most challenging periods for adequacy are typically winter evening hours where overplanting would have much less of an impact, the overall adequacy results are not expected to be affected. There are plans to account for solar PV overplanting in future years of the ERAA. However, to allow other parties to work with profiles including the effect of overplanting, TenneT has prepared a set of alternative solar PV profiles for the ERAA scenario years (2025, 2028, 2030, 2033) which can be provided upon request to ENTSO-E or TenneT.

DSR investments in EVA

The results from this year's EVA show significant investments in DSR in the Netherlands, reaching 2.1 GW and 2.4 GW in 2033 for Scenario A and B respectively. The DSR investment potential for the Netherlands was based on a study by DNV published in 2020[12]. However, after completion of the simulations an error in the input data was identified that the activation price for this full capacity was taken as 500 €/MWh by the model, rather than separate capacities with a range activation prices both below and above 500 €/MWh. As a

[12] DNV 2020, De mogelijke bijdrage van industriële vraagrespons aan leveringszekerheid DNV

result, the investments in DSR in the Netherlands are potentially higher than they would be if the correct activation prices had been used. Nevertheless, the impact on the key adequacy findings are considered minor as:

- The LOLE in the Netherlands is (comfortably) below its reliability standard of 4 h/y in both Scenario A and B in all target years up to 2030. Thus, somewhat less DSR capacity in the Netherlands is unlikely to result in the reliability standard being exceeded in the medium term.
- More than half of the additional DSR is only invested in the period between 2030 and 2033. If the correct range of DSR activation prices had been used, the model would have invested in the cheaper DSR first, and only then in the more costly DSR.
- DSR is a so-called ‘peaking’ technology with very high marginal costs, which is typically used only rarely. Higher activation costs for DSR in the Netherlands would likely lead the EVA model to investment either in another peaking technologies such as OCGTs, or even lower-cost DSR in a neighboring country.

13 Northern Ireland

Northern Ireland and Ireland together make up the Single Electricity Market (SEM). This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually. SONI inputs to the PEMMDB data collection reflect the best information available at the time of the collection (Dec. 2022 for ERAA23).

SONI carries out national studies of adequacy in the SEM and publishes these in the annual 'All-Island Generation Capacity Statement' (GCS[13]). These assessments incorporate the most up-to-date information at the data freeze dates for demand forecasts (March 2023) and generation availability (May 2023).

Demand forecasts used for the ERAA align to the previous GCS publication (2022). The latest GCS (2023) reflects that the out-turn Total Electricity Requirement (TER) for 2022 was down compared to the initial forecast, particularly in the second half of the year, coinciding with high energy prices. The latest data has been factored into the GCS23 TER demand forecasts and results in a lower TER demand level in the short term (2023 – 2026). From 2027 onwards, the longer-term effect of high energy prices is expected to subside, and the demand forecast is comparable to that utilised in the ERAA.

The adequacy standard in Northern Ireland is set at 4.9 hours of Loss of Load Expectation (LOLE). National adequacy studies in the GCS show Northern Ireland is significantly outside of this standard in 2025, and as such the power system could be operating with an increased level of risk. The ERAA results also indicate a resource adequacy concern in 2025 – this risk is higher than shown in the GCS, likely due to the more detailed modelling of assistance available over the interconnectors to the UK and to Ireland, who are both in significant stress in 2025.

With the introduction of new capacity, the adequacy position improves so that by 2028, both the GCS and the ERAA assessments show LOLE to be within standard, and this is maintained until the 2033 study year.

[13] The latest GCS has been submitted to the appropriate regulatory bodies and will be published once approved on https://www.soni.ltd.uk/

Since the data freeze date for the GCS, SONI has carried out a further sensitivity that includes an updated risk adjusted view of the new steam turbine capacity delivery. This is referred to as the 'TSO risk adjusted scenario' and assumes non-delivery of the new steam turbine capacity which was assumed to be available from 2027 in the GCS core scenarios. In the TSO risk adjusted scenario, annual run-hour limitations are applied for the entire study period to the gas units that are due to be delivered in 2024. The core scenarios assumed the delivery of the steam turbine in 2027 established a Combined Cycle Gas Turbine at the site and removed the annual run hour limitations. This additional scenario shows an increased risk to security of supply in Northern Ireland across the study horizon.

Following on from ACER's DECISION No 24/2020 on the methodology for the European Resource Adequacy Assessment (ERAA); SONI in collaboration with the UR are currently reviewing the Generation Capacity Statement methodologies to move to towards the National Resource Adequacy Assessment (NRAA) as specified under Regulation (EU) 2019/943 Article 24. As part of this review of Northern Ireland's reliability calculation, SONI will consider the impact of weather dependent renewable sources (for example: solar and wind), conventional generation, demand, operational requirements, interconnection, demand side response, storage and energy limited technologies. SONI is carrying out a consultation on this new methodology.

14 Poland

INPUT DATA DESCRIPTION

The input data for Poland was valid during the data collection period, means January 2023. The base of this data was NECP and Energy Policy of Poland until 2040, with necessary updates regarding:

1. The dates of commissioning and decommissioning of thermal units already known to PSE.
2. Ongoing significant RES development, especially PV and observed big amount of applications for issuing connection conditions.

According to the requirements, the data provided for the ERAA 2023 process takes into account information on already concluded contracts in Polish Capacity Market (CM). It includes results of all held, until moment of data collection, CM auctions i.e. delivery periods up to 2027.It does not include results or estimations for further years especially Target Years (TY) 2028 and 2030 for which capacity auctions are already planned. The same assumption was applied to the already concluded contracts for DSR coming from CM, which means for TY 2025. Due to specific conditions of activation of Polish DSR, it was not a subject of the central simulation in ERAA 2023 process, however it was used to reduce hourly ENS and LOLE results in the post-process. For information, in national comments appendix, PSE presents the result of this post-process also for TY 2028 and 2030. Although the contracts on CM for these years are not yet concluded, PSE, observing the current interest in such DSR, expects at least to maintain the level of DSR capacity that has been already proven.

ADEQUACY RESULTS

In PSE's opinion the ERAA 2023 results of LOLE for Poland may be underestimated due to choices and methods used in analyses, which comes from the scope of ERAA 2023, where it was impossible to apply all country-specific constrains. Taking into account data used for and results of national estimations PSE has identified possible areas that may influence the results and shall be evaluated during the process of preparation of National Resource Adequacy Assessment (NRAA):

1. Restrictions in building new capacities in Economic Viability Assessment (EVA) simulations.
   he maximum levels per TYs for Poland were not modelled in ERAA 2023. The additional capacity (above the technical limit of possible new build) is participating in Economic Dispatch (ED) simulations and most probably decrease LOLE results for Poland presented in the report.
2. Flow Based (FB) domain used in ED simulations.
   In ERAA 2023 ED simulations, PSE observed very high flows between Poland and CORE BZs. Recent PSE operational experience and observations show that even during periods of tight power balance in Poland commercial import is very often not available, while availability of power outside Poland is confirmed. PSE recognises the complexity of the FB domain preparation, and PSE experts closely cooperate with ENTSO-E to investigate possible reasons of the high flows and improve FB modelling for next ERAA edition.
3. Complexity of EVA and ED models for ERAA require many assumptions which may not reflect operation of the power system entirely. For example, limited number of Forced Outage Scenarios (FOS) or excluding some technical parameters from modelling (most likely referred to the thermal units) like ramp up/down, shutdown time, start-up time, etc. Taking such limitations into account may show situations where the ED result will not be feasible and thus, in real system operation, would cause additional LOLE.

The abovementioned topics will be further investigated by PSE and, where possible, their influence on the LOLE results for Poland will be decreased in the planned NRAA.

Below, as mentioned in paragraph “INPUT DATA DESCRIPTION”, ENS / LOLE results for 2028 and 2030 affected by estimated level of DSR:

Scenario A	**Target Year 2028**		**Target Year 2030**	
	ENS [MWh]	LOLE [h]	ENS [MWh]	**LOLE [h]**
Before out of market measures implementation	**1.10**	**1.89**	**1.20**	**2.82**
After Capacity Market DSR implementation	**0.37**	**0.51**	**0.44**	**0.74**
Scenario B	**Target Year 2028**		**Target Year 2030**	
	ENS [MWh]	LOLE [h]	ENS [MWh]	**LOLE [h]**
Before out of market measures implementation	**3.65**	**5.21**	**2.97**	**4.46**
After Capacity Market DSR implementation	**1.18**	**1.42**	**1.16**	**1.36**

15 Portugal

The ERAA, the Seasonal Outlook and the Ten Year Network Development Plan (TYNDP) aim to model and analyze possible events that could adversely impact the balance between supply and demand of power system in different time horizons ahead. The seasonal adequacy assessments, such as the Winter Outlook (WO) and

Summer Outlook (SO), assess the situation in the short term period for the upcoming season (weeks to months ahead). In this way, in recent WO 2023-2024 published by ENTSO-E for the next Winter 2023-2024 (out of scope of this ERAA 2023), the Portuguese TSO (REN) presented some insights (included in the National Comments Annex) in terms of assessment of security of Supply in Portugal in 2024. The main messages were:

- The National Adequacy Assessment Monitoring Report (RMSA-E 2023) is currently under preparation and will address electricity security of supply for the horizon 2024–2040. Although not fully comparable with WO and SO in terms of methodology and assumptions, on the expected report (RMSA-E 2023), for year 2024, it is foreseen that there will be a risk of dependence of the Portuguese system on imports from Spain and a risk of noncompliance with the current national reliability standards[14]. Under these conditions, some mitigating measures may be necessary to handle operational reserve needs and ensure security of supply in the Portuguese power system, as listed below:

#	Measures
(Demand)	Load reduction market product for eligible consumers with whom there are annual contracts for the provision of this service
(Supply)	Request for the activation of a support program with the Spanish System Operator
(Demand)	Occasional load shedding of non-priority consumptions, according to the protocol between the electricity transmission and distribution network operators

- In RMSA-E 2023, load reduction needs (1st measure identified) was identified, depending on hydro conditions. For this purpose, an auction for specific market product was launched by the Portuguese NRA on 28th November 2023 (convocatoria_01_leilao_bmfrr_20231218_19.pdf (erse.pt)). According past experience in Portugal shown that less than 40% of the required capacity in this type of auctions was provided by the market.

The ERAA focuses on the medium-term horizon of 2 to 10 years ahead. The purpose of the ERAA is to identify adequacy assessment concerns and serve as an action guidance, with a moderate uncertainty up to 5 years ahead, increasing to higher uncertainty beyond the 5 years. For this ERAA 2023, the Portuguese TSO (REN) has provided input data in order to create a scenario that represents the expected best possible extent. The 'National Trends' data for the target years 2025, 2028, 2030 and 2033 is according with the ´Trajetória Ambição' scenario as assumed in the last RMSA-E 2022[15]. For this scenario, the CCGT Tapada do Outeiro is decommissioned by the end of 2029.

In RMSA-E 2022 (in ´Trajetória Ambição' similar to 'National Trends' scenario) for the target years 2025, 2027 and 2030, contributions from NTC with Spain are required up to 20%, 10% and 50%, respectively, in order to comply with current national reliability standards.

Based on this initial set of data ERAA 2023 has produced two different sets of results, being the only difference between them the weights applied in the **EVA model** to represent the climatic variability. It would be interesting to improve in future editions how the climatic conditions are represented in the EVA step. Regarding the capacity modifications proposed by the **EVA model** for the Portuguese power system applying a total system cost minimization approach, it can be observed that expansion capacity of DSR and CCGT decommissioning are proposed. In both sets of results, regarding CCGT, is identified that a part of the power

[14] The Loss of Load Expectation (LOLE) comparing with the current national reliability standard (LOLE ≤ 5h/year) is much higher if CCGT Tapada do Outeiro is decommissioned on March 2024 (when the PPA - Power Purchase Agreement between the concessionaire of the Transmission System Operator and the owner of this power plant will finished). This value is reduced, but is not enough to comply with reliable standard, requiring that CCGT Tapada do Outeiro must continue it's operation.

[15] https://www.dgeg.gov.pt/media/ck2pa4s2/rmsa-e-2022.pdf

plant capacity, up to 170 MW in 2025 and 2028, would not be economically viable (a small percentage of CCGT Tapada do Outeiro may be decommissioned in 2029 in this ERAA 2023). In terms of capacity expansion, the **EVA model** results in new DSR capacity for 2028, 2030 and 2033 (between 400 MW and 580 MW). It's important to underline that nowadays, as said before, the Portuguese power system need on short term periods more DSR capacity to face internal and interconnection operational restrictions.

Regarding **Adequacy assessment (ADQ),** the analysis of the scenarios were performed after the expansion of new capacity and the decommissioning of the economically unviable units. The results for the Portuguese power system show no adequacy issues above the current reliability standard in the horizon of this study, due to decommission of a small percentage of the capacity of CCGT Tapada do Outeiro in 2025 and 2028, the DSR expansion after 2028 and expected investments both in new renewable generation and interconnection capacities with Spain.

Surely the most relevant and impactful factors for assessing the European adequacy situation were identified in this study. Nevertheless national and regional assessments should provide deeper analysis of local constraints. The ERAA takes a pan-European approach that should be complemented by regional analysis.

Finally, REN highlights that the ERAA 2023 has been an important step forward compared to the previous ERAA editions in terms of methodological implementation and also development of capabilities, in a continuous effort to gradually improve the quality and the usefulness of the product, fruit of a collaborative framework between stakeholders, ENTSO-E and TSOs.

16 Spain

16.1 General overview of the ERAA 2023

The ERAA 2023 has been an important step forward compared to the previous ERAA editions in terms of methodological implementation and also development of capabilities, in a continuous effort to gradually improve the quality and the usefulness of the product, fruit of a collaborative framework between stakeholders, ENTSO-E and TSOs.

16.2 Spanish inputs for the ERAA 2023

Red Eléctrica has provided input data in order to create a scenario that represents the expected system reality to the best possible extent. In this sense, in the long term (2033, 2030) the scenario was set considering the best available information at the moment of the data delivery (afterwards, the draft of the updated NECP was published in June 2023 and there are some variations that could not be taken into account). For the short to mid-term (2025, 2028) the scenario is based on the best information available from the stakeholders and the recent evolution of the installed capacities and permits issued. The resulting scenario represents an adaptation of what the lineal progression to the NECP would be, gradually transforming the current system into the desired future one.

As a general tendency, in ERAA 2023 Spanish inputs include higher capacities of renewables compared with ERAA 2022 especially regarding solar photovoltaic capacity in line with the updated version of the NECP. Thermal capacities are similar to the ones used in ERAA 2022. However, in the mid-term a decrease in new storage (hydro, solar thermal, batteries) has been considered in line with the National Resource Adequacy Assessment (NRAA) that Red Eléctrica has carried out as a complement to the ERAA 2022.

In terms of demand, similar values to the ones used in ERAA 2022 have been considered, although for the short-term the demand levels are expected to grow at a slower pace, and then increase in the mid and long-term, in line with the deeper electrification considered in the reviewed NECP and grid planning requests received.

Cross-border capacities have not experienced important changes. For the Spain-France border no additional interconnectors are assumed until 2030 (only Gulf of Biscay. Navarra-Landes and Aragón-Atlantic Pyrenees are not considered to be available in the horizon in order to maintain a conservative approach for adequacy purposes). For the Spain-Portugal border, the proposed cross-border capacities already consider the future interconnector Beariz-Ponte de Lima since 2025. In addition, Balearic Islands and Ceuta have been considered in this edition as implicit regions.

Finally, reserve requirements have been updated this year, in line with operational scenarios that have recently occurred and suggest that as variability grows an increase of reserves is needed for system security.

16.3 Economic viability assessment (EVA) results

Based on this initial set of data ERAA 2023 has produced two different sets of results, being the only difference between them the weights applied in the EVA model to represent the climatic variability. It would be interesting to improve in future editions how the climatic conditions are represented in the EVA step.

Regarding the capacity modifications proposed by the EVA model for the Spanish peninsular power system applying a total system cost minimization approach, it can be observed that no expansion is proposed but only decommissioning/mothballing. Note that in this edition part of the DSR commissioning that the EVA proposed in the ERAA 2022 was already considered in the base scenario. In both sets of results, 0.56 GW of coal decommissioning would be expected to occur one year earlier than in the base scenario, similarly to the ERAA 2022. Regarding combined cycles also both scenarios identify that a part of the generators, up to 2.2 GW at the end of the horizon, would not be economically viable. Depending on the set of results this same volume would not be economically viable already at the beginning of the horizon. Also, there could be some capacity subject to mothballing and de-mothballing along the horizon. Differences in terms of assumptions and methodology explain the numerical differences in terms of EVA results comparing to ERAA 2022.

16.4 Adequacy assessment (ADQ) results

After the EVA results (decommissioning/mothballing of thermal generators) are applied to the initial set of data (Spanish input provided by Red Eléctrica), the adequacy assessment is carried out. Please note that when analyzing the adequacy results, Red Eléctrica is currently considering a binding reliability standard of LOLE < 0.94 hours/year, following the proposal for the Reliability Standard published by the Spanish Government based on the European legal framework.

In both scenarios assessed in this edition, the ERAA 2023 shows the same tendency for the Spanish peninsular power system: under the given scenarios and methodological framework following the considerations set out by the Regulation EU 2019/943, the economic viability of a part of the generation mix is not guaranteed in the short, mid and long-term. The assessment of the scenarios which would result after the decommissioning of the economically unviable units shows a risk of adequacy issues above the reliability standard in the short (2025) to mid-term (2028). The risks tend to be reduced to values below the reliability standard in the long-term (2030, 2033) due to the expected investments both in new generation and international interconnection capacities.

In view of these results, Red Eléctrica has performed additional simulations for the closest target year (2025) in the most severe scenario (Scenario B), maintaining the post-EVA scenario for the non-Spanish perimeter but considering all the existing CCGT generators in service. The simulations show that with all the existing CCGT generators in service but with a non-optimized maintenance profile, similar to the one observed in the current one-year perspective due to lack of perfect market information, adequacy risks would remain above the reliability standard. However, with mechanisms that would ensure that all CCGT generators were kept online, the adequacy indicators would fall below the reliability standard and the desired level of guarantee of supply would be achieved.

16.5 Wrap up

As a final idea, it is important to keep monitoring adequacy in future assessments, especially in the mid and long-term as the uncertainty in this time horizon is higher and faster or slower developments in terms of demand behavior and pace of investments in new capacities can have an impact on the results. This is also particularly relevant in the case of new storage investments, in which close monitoring of the measures that can bring effectively new commissioned capacity by the time horizons in the official scenarios, is required, due to the high impact it has to adequacy results as reflected in the available National Resource Adequacy Assessment (NRAA).
The conclusions derived from the ERAA 2023 are aligned with the ones obtained in the ERAA 2022 and also the ones derived in the NRAA that Red Eléctrica has performed as a complement to the ERAA 2022, despite the results in terms of economic equilibrium and adequacy indicators reasonably differ due to differences in the considered assumptions (national and international) and methodology used in each analysis.

17 Sweden

Sweden has a peak load reserve of 562 MW which is contracted until 15 March 2025. This is currently not reflected in the results. Further analysis for 2025 shows that the LOLE values for SE3 and SE4 will decrease by approximately 0,36- and 0,48 hours per year respectively.

Whilst this correction would indicate a slightly lower LOLE value, the final result still exceeds the national reliability standard for Sweden which is currently defined as 1 hour per year. The reliability standard is exceeded for all target years investigated and for all scenarios, with an increasing trend until 2030. The results for 2030 and 2033 indicate that the LOLE value stabilize after 2030, but still at a value in excess of the national reliability standard for all investigated scenarios. A driving factor resulting in the rising LOLE value observed in Sweden up to 2030 is an increasing electrification in the industrial sector in Sweden along with other factors such as increased consumption from data centers and, to some extent, electric vehicles.

18 Switzerland

Although no significant adequacy issue has been identified for Switzerland in the present exercise, the report shows that adequacy indicators will remain tight in the coming years. In order for the system adequacy not to deteriorate integration in the European grid must be ensured.

Any reductions of the cross-border capacity between Switzerland and its neighbours will have adverse impacts on Switzerland and, potentially, on the whole region. To mitigate these effects, Swissgrid entered into relevant agreements with the CCR Italy North and works on agreements with CCR Core.