ERSE
ENTIDADE REGULADORA
DOS SERVIÇOS ENERGÉTICOS

REPORT

FLEXIBILITY NEEDS ASSESSMENT FOR PORTUGAL

2026

July 2026

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

Article 19e (1) of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019, as currently in force, foresees that the regulatory authority, or another authority or body designated by a Member State, shall adopt a report on the estimated flexibility needs at national level, covering at least the next five to ten years.

With a view to the sector's decarbonisation objective, this study must take into account the need to ensure the security and reliability of the electricity supply in a cost-effective manner, taking into account the expected integration of generation from variable renewable energy sources (RES), the necessary integration of sectors, as well as the interconnected nature of the electricity market, including interconnection targets and the potential availability of cross-border flexibility.

Furthermore, in accordance with the European Regulation, this flexibility needs assessment forms the basis for the Member State to set an indicative national target for non-fossil flexibility, including the specific contributions of demand response and storage towards achieving that target (see Article 19f). This target must be reflected in a future update of the National Energy and Climate Plan (NECP)[1], and may be achieved by realising the identified flexibility potential, by removing the identified market barriers, or through support schemes for non-fossil flexibility (see Article 19g).

As provided for in European Regulation, the aim of this study was to estimate future flexibility needs in mainland Portugal, with a view to ensuring security of supply and the operational security of the National Electric System (SEN).

In line with the methodology approved by the European Union Agency for the Cooperation of Energy Regulators (ACER) for this purpose (Flexibility Needs Assessment Methodology – FNAM[2]), and taking into account the objectives set out in the NECP, this study assesses different types of flexibility needs:

a) System flexibility needs, which include i) RES integration; ii) ramping; and iii) short-term flexibility; and

[1] PNEC 2030

[2] Flexibility Needs Assessment Methodology – FNAM

b) Network flexibility needs, which are divided into i) transmission network flexibility and ii) distribution network flexibility.

System flexibility needs reflect the flexibility needed for the power system to adjust to the variability of generation and demand patterns. In turn, network flexibility needs reflect the flexibility needed to ensure network availability by preventing or resolving congestion or voltage control issues. Flexibility needs are categorised as upward needs when an increase in generation or a reduction in demand is required, and as downward needs when a reduction in generation or an increase in demand is required.

Flexibility also has a temporal dimension, in that the resources required to respond, for example, to the need to adjust production/demand patterns in an intraday, short-term context (e.g., storing surplus energy during solar hours for subsequent consumption at peak times), will differ from those required to address the seasonality of these patterns (e.g., storing surplus energy in the summer for subsequent consumption in the winter). In this regard, flexibility needs are characterised in terms of both power and energy.

Although the European Regulation provides for an analysis of needs over a period of five to ten years, the FNAM stipulates that, in this first exercise, at least two target years must be considered. Accordingly, this analysis focused on the years 2030 and 2035, and, regarding system flexibility needs, it was carried out based on the results of the economic dispatch from the ERAA[3] 2025, for three of the weather scenarios for each of these years[4]. To better align the scenarios with the specific characteristics of the SEN, it was necessary to make some adjustments to the annual electricity consumption of pumped storage, limiting this demand – as derived from the ERAA 2025 simulation – to the highest annual figure ever recorded in the SEN (around 5.5 TWh).

To this end, ERSE coordinated the drafting of this report, that involved REN – Rede Elétrica Nacional, S.A., in its capacity as the national transmission system operator (TSO), and E-REDES - Distribuição de Eletricidade, S.A., in its capacity as the national distribution system operator (DSO), as well as the Directorate-General for Energy and Geology (DGEG), given its remit at national level, particularly with regard to security of supply and the drafting and revision of the NECP.

[3] European Resource Adequacy Assessment – ERAA

[4] The weather scenarios considered most representative within the scope of the cost-minimisation exercise for the economic viability assessment of ERAA 2025 (WS 23, 27 and 35) were selected.

SYSTEM FLEXIBILITY NEEDS

The main indicator analysed in the study concerns the system flexibility needs for RES integration, which are linked to reducing RES curtailment[5], with a view to meeting energy policy objectives.

In accordance with Article 8 of the FNAM, the TSO estimated the flexibility needs for integrating RES. The figures presented in Table 1 correspond to the range of RES curtailment values identified for the different scenarios assessed.

Table 1 – RES curtailment

Type	Indicator	Target year	RES curtailment [TWh]	RES curtailment [%[6]]
System	RES integration	2030	2.7 – 4.3	3 – 5.5
		2035	1.4 – 6	1.2 – 5.8

As mentioned in sections 3.4 and 4.1, the NECP does not define a maximum acceptable value for RES curtailment, and it was not possible to identify this value by other means. Consequently, flexibility needs have been defined as the amount of energy that the system will need to absorb in order to offset this curtailment. Thus, the results obtained represent an upper bound on the system's flexibility needs for RES integration, insofar as allowing for some level of curtailment may be a more cost-effective solution.

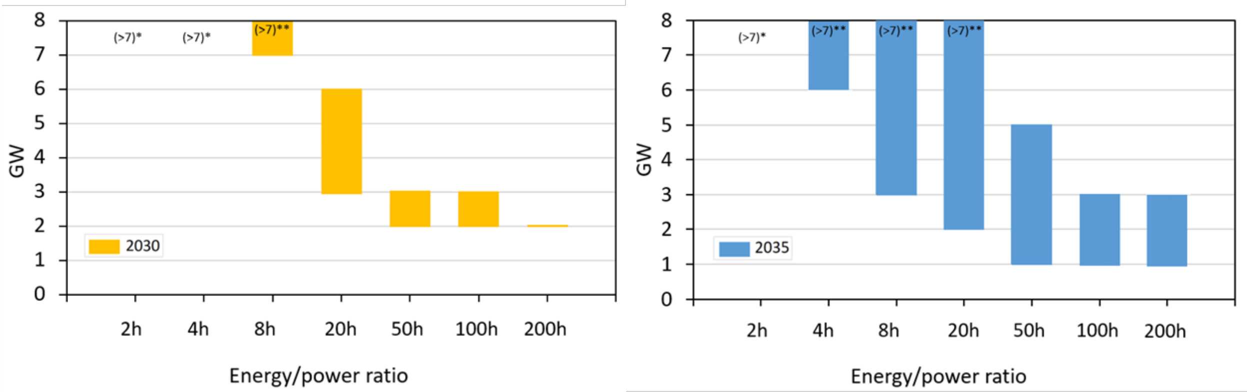
When it comes to characterising the identified RES curtailment, it should be noted that it occurs mainly between 8 am and 6 pm, which correspond to the periods with the highest proportion of solar power in the generation portfolio. In terms of percentage, the identified curtailment is consistently less than 6% of total RES generation across the various scenarios.

Subsequently, in accordance with the provisions of the FNAM, the TSO assessed the resources required to meet the identified needs. To this end, flexibility resources with energy-to-power ratios of 2h, 4h, 8h, 20h, 50h, 100h and 200h were considered, and the additional capacity that would need to be installed to reduce RES curtailment to zero or to values very close to zero was identified.

[5] Waste is defined as renewable generation that is curtailed due to grid or system constraints or a lack of equivalent demand, and which cannot be stored locally.

[6] Percentage of RES curtailment as a share of total RES production in each scenario.

Figure 1 – Ranges of additional capacity required (GW), by resource type, for 2030 and 2035[7]



* For all scenarios, a need for additional capacity of > 7 GW was identified.
** At least one scenario was identified in which additional capacity of more than 7 GW is required.

Compared to the baseline scenario (target year 2030), it was concluded that, using resources with energy-to-power ratios between 2 and 8 hours[8], in most cases, additional installed capacity of more than 7 GW would be needed to meet the identified flexibility needs. Assuming technologies with a ratio of 50 hours[9], it is estimated that by 2030, with additional installed capacity ranging from 2 GW to 3 GW, RES curtailment would be virtually eliminated. This value decreases when considering resources with higher ratios, but even when considering a resource with a ratio of 200 hours[10], for both scenarios considered, the installation of additional capacity between 1 GW and 3 GW[11] will always be necessary. The resources analysed here should be viewed from a technologically neutral perspective and are not limited to the most common storage technologies, such as electrochemical batteries or hydro storage.

It should be emphasised that the approach used in this analysis does not allow for the complementarity of the various flexibility resources to be taken into account. The identified needs should be met through the

[7] For the purposes of creating this figure, it was considered the additional capacity needed to reduce curtailment to 250 GWh.

[8] Typically, electrochemical batteries, but demand response can also be considered, e.g., changes in the charging profile of electric vehicles or the use of heat pumps.

[9] Among others, given the characteristics and specific features of the SEN, hydroelectric projects with significant storage capacity could be considered.

[10] Examples of such resources could include the hypothetical use of electrolysers and green hydrogen storage capacity.

[11] These were the capacity values identified to reduce curtailment to levels very close to zero (250 GWh). However, it should be noted that the analysis conducted makes it possible to identify the additional capacity required should a maximum acceptable level of RES curtailment be established, which would be lower than the values identified here.

simultaneous use of a diverse portfolio of resources that enables the benefits and added value of each technology to be realised.

The results presented are strongly influenced by the assumptions underlying the scenarios used in this assessment. These scenarios are subject to a significant degree of uncertainty, both due to the long-term nature of the analysis and to the actual developments that have occurred in the SEN, compared to the objectives established in the updated NECP on which they were based. Accordingly, two sensitivity analyses were conducted on the baseline scenarios. The first sensitivity analysis considered a lower interconnection capacity compared to that assumed in the baseline scenarios, limiting it to 10% of the total capacity initially projected. The second sensitivity analysis considered a lower installed capacity of electrolysers and offshore wind power than that projected in the NECP.

The first sensitivity analysis sought to assess the system's flexibility needs in a scenario close to that of an isolated system. The very significant increase in the identified flexibility needs demonstrates the importance of the interconnection as a source of flexibility for the system. The second sensitivity analysis sought to assess the impact of a slower-than-expected development of generation and demand compared to the NECP scenarios. Despite considering a lower installed renewable capacity, this sensitivity analysis resulted in an increase in flexibility needs, since the reduction in electrolyser capacity has a greater impact in the demand side, given that the study's assumptions treat them as flexible loads.

In terms of system flexibility needs, the TSO also identified needs related to generation ramps[12], which are presented in Table 2.

The system's inability to respond to these generation ramps and to absorb their impacts may, amongst other things, lead to the need to increase the curtailment of renewable power to ensure system balance.

[12] Significant variations in generation capacity over short periods of time, caused by the output profiles of RES and the technical characteristics of these technologies, particularly solar and wind power.

Table 2 – Ramping flexibility needs

Type	Indicator	Target year	Direction	Average value of uncovered needs[13] [MW]	Uncovered needs[14] [MWh]
System	Ramping needs	2030	Upward	0 – 0.17	0 – 1,484
			Downward	0	0
		2035	Upward	0 – 0.03	0 – 293.4
			Downward	0	0

FNAM also stipulates that short-term flexibility needs must be identified, relating to the ability to respond to generation forecast errors. Given the approach taken in this study, and the assumptions and data used, the TSO considered that applying the methodology would not yield representative results. Consequently, no such needs were determined.

NETWORK FLEXIBILITY NEEDS

The TSO has not identified any network flexibility needs at transmission network level, as its planning exercises were based on the allocation of firm capacity to the new connections, with no expected network constraints. In this context, TSO has not identified any instances of RES curtailment due to network congestion.

The DSO identified distribution network flexibility needs, which are reflected in the values in Table 3.

[13] According to FNAM, the uncovered flexibility needs relating to RES generation ramps concern the power required at each hour to respond to a RES generation ramp, minus the technical margins of the remaining existing generation assets, in other words, the capacity of the remaining generation assets to increase or decrease their output relative to their operating point at that hour. The values presented here are the average of the values calculated for each hour, in each scenario.

[14] The values presented here relate to the annual power needs resulting from the sum of the identified hourly needs.

Table 3 – Network flexibility neds

Type	Indicator	Target year	Direction	Sum of maximum power [MW]	Expected average energy value [MWh]
Network	Transmission network needs	2030	Upward	0	0
			Downward	0	0
		2035	Upward	0	0
			Downward	0	0
	Distribution network needs	2030	Upward	48.7	57.3
			Downward	0	0
		2035	Upward	56.8	66.9
			Downward	0	0

Although it is subject to a number of assumptions and methodological limitations, the assessment carried out helps to quantify flexibility needs in a different and complementary context to those currently analysed in the context of security of supply studies, namely the ERAA and the RMSA[15]. The conclusions of this report should contribute to the establishment of the indicative targets set out in Article 19f of Regulation (EU) 2019/943, without prejudice to the conclusions of other relevant studies or other energy policy instruments that may contribute to a better identification of the flexibility needs of the SEN, thereby providing a basis for the Member State's decision on this matter.

BARRIERS TO FLEXIBILITY

As mentioned, the identified flexibility needs can be met by the market as a natural response to the economic mechanisms of the power system. To this end, it is important to remove the barriers to the provision of such flexibility. In addition, specific incentive mechanisms may be established to encourage the provision of additional flexibility resources.

In line with ACER Recommendation No. 01/2026, an assessment was carried out to determine whether there were any barriers to the entry of flexibility resources into the system. Overall, it was concluded that, amongst the aspects that could be assessed, although some opportunities for improvement were identified, there are no significant barriers to the entry of flexibility resources into the system that are not

[15] Relatório de Monitorização da Segurança de Abastecimento, the Portuguese National Resource Adequacy Assessment (NRAA).

already being addressed by measures aimed at mitigating them. In this context, the following measures are highlighted:

- Pilot project for the development of the market for aggregated ancillary services;
- Development and expansion of pilot projects relating to local congestion management markets, such as the FIRMe project[16];
- Implementation of standardised balancing products.

These considerations are set out in detail at section 5 and Annex IV presents a summary table relating to this assessment.

[16] FIRMe – Integrated flexibility under a market-based regime

1. INTRODUCTION

1.1 LEGAL AND REGULATORY CONTEXT

Article 19e(1) of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 (Regulation (EU) 2019/943), as currently worded by Regulation (EU) 2024/1747, of the European Parliament and of the Council of 13 June 2024[17], establishes that the regulatory authority, or another authority or body designated by a Member State, shall adopt a report on estimated flexibility needs at national level, covering at least the next five to ten years, no later than one year after ACER has approved a methodology for that purpose.

This methodology was adopted by ACER on 25 July 2025, thereby setting 25 July 2026 as the deadline for the submission of this study, which must be repeated every two years.

With a view to the sector's decarbonisation objective, this study must take into account the need to ensure the security and reliability of the energy supply in a cost-effective manner, considering the expected integration of generation from variable RES, the necessary integration of sectors, as well as the interconnected nature of the power market, including interconnection targets and the potential availability of cross-border flexibility.

Although this obligation is not set out in Portuguese national legislation, it was on the basis of this legal and regulatory framework at European level that the study leading to this report was carried out.

[17] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02019R0943-20240716

1.2 OBJECTIVE AND SCOPE OF THE NATIONAL REPORT

As provided for in European Regulation, the aim of this study was to estimate future flexibility needs in mainland Portugal[18], taking into account the objectives of decarbonisation and the RES integration, with a view to ensuring security of supply and the operational security of the National Power System (SEN).

In line with the methodology approved by ACER for this purpose[19] (Flexibility Needs Assessment Methodology – FNAM), this study aimed to assess the different types of flexibility needs identified (system and network needs), with a view, amongst other aspects, to integrating electricity generated from renewable sources into the SEN, taking into account the objectives set out in the National Energy and Climate Plan[20] (NECP). Having estimated the flexibility needs, the study also sought to identify the potential of non-fossil flexibility resources to meet them.

Finally, an assessment was made of any barriers or obstacles to market entry of flexibility solutions and the potential contribution of the digitalisation of electricity transmission and distribution networks to increasing the flexibility of the SEN.

Among other aspects, pursuant to Article 19f of Regulation (EU) 2019/943, the results, analyses and conclusions of this report should contribute to the setting of an indicative national target for non-fossil flexibility, which, in turn, should be reflected in a future update of the NECP.

1.3 ENTITIES INVOLVED IN THE STUDY

Under paragraphs 1 and 2 of Article 19e of Regulation (EU) 2019/943, ERSE, as the national regulatory authority, is responsible for submitting the report on the analysis of flexibility needs at national level.

To this end, ERSE coordinated the preparation of this report, involving REN – Rede Elétrica Nacional, S.A. (REN), in its capacity as the national TSO, E-REDES - Distribuição de Eletricidade, S.A. (E-Redes), in its

[18] As this is the first edition of this report and given the lack of experience with studies of this type, it was decided to take into account only the transmission and distribution networks in mainland Portugal.

[19] Flexibility Needs Assessment Methodology – FNAM

[20] PNEC 2030

capacity as the national distribution system operator (DSO), and the DGEG, given its remit at national level, particularly in relation to the preparation and revision of the NECP 2030.

These bodies set up a working group which met periodically throughout the course of the study. At an early stage, and pursuant to Article 4(1) of the FNAM, the details of the national implementation of the methodology were agreed, including:

a) The scope of the data and analyses to be provided by the TSO and the DSO at national level;

b) The roles and responsibilities of the TSO and DSO;

c) Target years for the analysis;

d) Temporal, spatial and voltage-level granularity of the data for the purpose of identifying flexibility needs in the distribution network;

e) Data required to assess potential barriers to flexibility in the markets and the contribution of digitalisation.

Following the submission of the data and analyses by the network operators, meetings were held to discuss and validate the results, with close collaboration between all entities involved in the preparation of the report.

As this is the first edition of this study and given the complexity of the exercise, it was not possible to involve external *stakeholders* in a timely manner. This has been identified as an area for improvement in future updates to this work.

2. METHODOLOGY

2.1 DATA USED

SYSTEM FLEXIBILITY NEEDS

Regarding system flexibility needs analysis, FNAM stipulates that at least one scenario consistent with the reference scenarios of the European Resource Adequacy Assessment (ERAA) must be considered. Given that the ERAA 2025 was expected to be approved in the first quarter of 2026[21], and the availability of scenarios and results that are more up-to-date than those contained in the latest ERAA approved at the start of the work[22], as well as to ensure better alignment with developments in European systems and the specific characteristics of the SEN, it was decided to use the central scenario of the ERAA 2025[23] and the respective results of the Economic Viability Assessment (EVA[24]) for the energy generation centres relevant to this analysis.

NETWORK FLEXIBILITY NEEDS

In assessing network flexibility needs, the assumptions and scenarios used in the planning and investment exercises for the transmission and distribution networks were taken into account.

With regard to the transmission network, the conclusions, which are set out later in this report, were based on the assumptions and criteria used in the planning exercises for this network.

With regard to the distribution network, the analysis was based on the data contained in the Distribution Network Development and Investment Plan – PDIRD-E 2024[25], as the main reference document for

[21] The ERAA 2025 was approved by ACER Decision No. 06/2026 on 24 April 2026.

[22] ERAA 2024.

[23] The lower range of the central scenario of the ERAA 2025 was taken into account, which is in line with ACER Decision No. 06/2026.

[24] EVA – Economic Viability Assessment.

[25] Proposed PDIRD-E 2024, public consultation documents and ERSE's opinion on the proposal are available here.

characterising the network and identifying flexibility needs, taking into account, in particular, the characterisation of HV/MV substations and the flexibility needs identified in this context[26] .

Data from the national resource adequacy study was also taken into account, namely the Electricity Sector Monitoring and Security of Supply Report – RMSA-E 2024[27], particularly with regard to the forecast of synchronous peak loads in the SEN for the years under review, in order to ensure consistency between the characterisation of the network and macro trends in load development.

2.2 Target years

The FNAM stipulates that data and analyses must be made available for the ERAA's target years. In this first exercise, at least two target years must be considered, at least one of which must correspond to a policy year[28].

The target years for ERAA 2025 are 2028, 2030, 2033 and 2035. Accordingly, as 2030 is the only policy year in this set, it was designated as one of the common target years for this analysis.

Given the exploratory nature of this initial exercise and the need to ensure the robustness of the results at an early stage, it was decided that the choice of the additional year would always be between 2028 or 2035. However, the possibility of analysing all three years (2028, 2030 and 2035) was also assessed, and it was concluded that this would not be feasible within a reasonable timeframe.

Subsequently, as the work progressed, both operators agreed on the year 2035 as the second year of analysis. Consequently, this study considers the years 2030 and 2035.

[26] Further details in Annex I.

[27] Available here.

[28] In line with the targets and objectives set out in subparagraph (iii) of paragraph (a) of Article 19e(4) of Regulation (EU) 2019/943.

2.3 Methodological approach

2.3.1 System flexibility needs

With regard to the assessment of system flexibility needs, the FNAM stipulates that at least one of the scenarios to be used must be consistent with the ERAA reference scenarios. This assessment must be based on the results of the economic dispatch from an ERAA or a national resource adequacy study, or, alternatively, on an economic dispatch simulation carried out independently by the TSO[29].

During the development of this study, work was still underway to adapt the national resource adequacy methodology to the European methodology defined for the ERAA, and the TSO did not have the necessary tools to carry out an economic dispatch that complied with the criteria established at European level. In this context, it was decided to use the results of the ERAA 2025 economic dispatch.

In view of this decision, and given the complexity of the exercise, it was also necessary to select the weather scenarios (WS) to be considered. Following the methodology applied in the ERAA 2025, the WS considered most representative for the EVA cost-minimisation exercise were selected. Accordingly, the results of the ERAA 2025 were processed for WS 23, 27 and 35[30].

In addition, it was deemed necessary to introduce adjustments to ensure greater alignment with the reality and specific characteristics of the SEN, namely an adjustment to the annual electricity consumption of the hydro pumping system, limiting the consumption resulting from the ERAA 2025 simulation to the highest annual figure ever recorded in the SEN (approximately 5.5 TWh)[31].

In accordance with the FNAM[32] , the assessment of system flexibility needs focused on three distinct areas: i) needs associated with the RES integration; ii) needs arising from RES generation ramps; and iii) short-term flexibility needs.

---

[29] In accordance with Article 7(3) of the FNAM.

[30] In accordance with the provisions of Article 6(5) of the FNAM.

[31] It should be noted that this limitation had already been identified by the Portuguese TSO in the 'Country Comments' document for ERAA 2025, available in [Annex 6 – Country Comments ERAA 2025](#).

[32] Articles 8, 9 and 10 of the FNAM.

FLEXIBILITY NEEDS FOR RES INTEGRATION (ARTICLE 8 OF THE FNAM)

To quantify the flexibility needs for RES integration, TSOs must base their calculations on the characterisation of the time series for expected RES curtailment and residual load, extracted from the ERAA's economic dispatch, for each target year and selected WS[33].

The residual load was determined from net demand and non-dispatchable RES generation, which made it possible to identify the periods in which there is expected RES curtailment for each hour and for each target year and WS, using the formula:

$$Residual\ load = net\ demand - (wind, solar\ and\ other\ RES + mini - hydro + run - of - river\ hydro \\ + cogeneration\ technical\ minimum)$$

The results relating to RES curtailment were analysed at different timeframes (hourly, daily and seasonal), enabling an assessment of the variability of the residual load, an analysis of differences between timeframes, and the identification of the system's flexibility needs.

For the baseline scenario and its sensitivities, across all WS, the benefit of adding new flexibility resources to the system[34] was assessed to enable the absorption of the renewable power forecast in the NECP. In order to ensure technological neutrality, the additional flexibility resources were characterised in terms of power, energy capacity, availability, full-cycle efficiency[35], and energy-to-power ratio, with ratios of 2, 4, 8, 20, 50, 100 and 200 hours being analysed.

The methodology used makes it possible, depending on the maximum acceptable level of RES curtailment, to determine the quantity of flexibility resources required to meet this requirement.

[33] In accordance with Article 8(1) of the FNAM.

[34] In accordance with the provisions of Article 8(10) of the FNAM.

[35] round-trip efficiency.

RAMPING FLEXIBILITY NEEDS (ARTICLE 9 OF THE FNAM)

To calculate the flexibility needs for responding to generation ramps, for each WS and target year, the TSOs must determine the upward flexibility needs[36] and downward flexibility needs[37], calculated as the difference between the variations in residual load and the capacity of the residual ramp margins[38].

Based on the results of the ERAA 2025 economic dispatch, the shortfalls in generation flexibility resulting from residual load ramp-ups and ramp-downs were quantified over a period of up to 60 minutes, taking into account the technical constraints of the available generating units[39].

The analysis was based on hourly data, modelling five natural gas generating units representing different operational scenarios (although seven natural gas generating units are planned for 2030, the five generating units analysed result from decisions taken at EVA level in the ERAA 2025 study). The maximum capacity of the generating units, technical minimums, start-up conditions and minimum shutdown and generation periods were taken into account to ensure operational security (4 hours).

A comparison was made between the required ramping rates and the achievable ramping rates to identify flexibility shortfalls that could potentially affect system security. In order to contribute to the gradual reduction of the identified flexibility needs, flexibility resources were introduced sequentially, using the various available technologies, in the following order: combined-cycle thermal power stations, reservoir hydroelectric power centres, pumped storage, batteries and, finally, electrolysers demand.

SHORT-TERM FLEXIBILITY NEEDS (ARTICLE 10 OF THE FNAM)

To identify short-term needs, the TSOs must analyse the system's capacity to respond to residual load forecasting errors, i.e., the deviation between what was forecast the previous day and what actually occurs[40].

---

[36] Increase in generation or decrease in demand.

[37] Decrease in generation or increase in demand.

[38] In accordance with Article 9 of the FNAM.

[39] Five natural gas-fired generating units were considered, representing different operating scenarios.

[40] In accordance with Article 10 of the FNAM.

Based on a historical analysis of forecasts and observed load values[41], the distribution functions of the forecast errors were determined for each month and hour. By calculating the convolution of the three distribution functions for each month and hour, the distribution function of the residual load forecast error was determined. The results were subsequently projected for the selected target years, using the load profiles derived from ERAA 2025 for each year and the relevant WS.

2.3.2 NETWORK FLEXIBILITY NEEDS

2.3.2.1 TRANSMISSION NETWORK FLEXIBILITY NEEDS

According to FNAM, network flexibility needs must reflect the flexibility needed to prevent or solve congestion or voltage constraints, and exhibit specific local and temporal characteristics, depending on local generation and consumption patterns.

In the case of the transmission network, the network studies carried out as part of the planning exercises are conducted in strict compliance with the Safety Standards for Planning set out in the Transmission Network Code. Consequently, REN's issuance of favourable opinions for connection to the Public Service Electricity Grid (RESP) was based on the allocation of firm capacity to the new connections, with no expected grid constraints. In this context, the TSO has not identified any instances of RES curtailment or unserved energy resulting from network congestion.

2.3.2.2 DISTRIBUTION NETWORK FLEXIBILITY NEEDS

Assessing the flexibility needs of the distribution network presents challenges arising from the local nature of the constraints and the high level of uncertainty associated with the development of connections for decentralised generation and new demand.

The increasing level of uncertainty as the forecasting horizon lengthens – resulting from the evolution of multiple structural and cyclical factors – influences the behaviour of the power system, making it more complex to produce a robust estimate of flexibility volumes in the medium to long term.

---

[41] Wind power generation and solar power generation over the last 3 years.

In particular, as the analyses of flexibility needs already carried out under the PDIRD-E 2024 do not include the selected target years (2030 and 2035), the DSO considered it necessary to develop a specific, high-level methodology for that horizon, based on extrapolations.

To this end, the DSO began by defining the average quantities of power and energy characteristic of a flexibility scenario within the context of the PDIRD-E. It then estimated the evolution of the utilisation of HV/MV substations for the period in question through an iterative load-increase process. By defining a lower and upper limit of utilisation, between which the DSO acknowledges the existence of network constraints that can be managed through the use of flexibility, the DSO counted the number of identified cases where the constraints were deemed manageable through the use of flexibility. Finally, it calculated the distribution network's flexibility needs by multiplying the number of identified cases by the average quantities initially determined.

This methodology is detailed in Annex I.

2.3.3 Approach to fine-tuning

The FNAM provides that, when certain conditions are met, the system's flexibility needs shall be reassessed, taking into account the data resulting from the identified network needs.

In accordance with Article 14(2) of the FNAM, the fine-tuning process must take into account downward network needs that result in RES curtailment.

With regard to the transmission network, as mentioned in section 2.3.2.1, no flexibility needs were identified. On the other hand, with regard to the distribution network, as described in sections 2.3.2.2 and 4.2.1, only upstream network flexibility needs were identified. Consequently, in accordance with the provisions of the FNAM, no *fine-tuning* process was required.

3. DESCRIPTION OF SCENARIOS AND ASSUMPTIONS

3.1 CURRENT STATUS OF THE NATIONAL POWER SYSTEM

In 2025, energy demand totalled 53 TWh, representing a 3.2% increase compared with 2024, and marking the highest figure ever recorded in the SEN, 1.6% above the all-time high recorded in 2010[42]. Peak demand reached 9,395 MW, around 500 MW below the all-time high recorded in 2021, whilst maximum power generation capacity stood at 11,474 MW, 400 MW below the all-time high recorded in 2023.

Installed capacity in the SEN totalled 23.8 GW at the end of 2025, of which 16.3 GW (68.5%) was connected to the transmission network, representing an increase of around 1 GW compared with 2024, corresponding almost entirely to photovoltaic installations. Renewable capacity totalled 19.4 GW, with a notable increase in solar photovoltaic capacity (+954 MW), whilst non-renewable capacity remained broadly stable. Storage totalled 3.6 GW, mainly associated with pumped storage. This installed capacity within the SEN was divided between 13 GW of dispatchable capacity[43] and 10.8 GW of non-dispatchable capacity.

In 2025, domestic renewable energy production met 68% of consumption, with hydroelectric power[44] playing a significant role, accounting for 27% of demand, alongside significant contributions from wind power (25%), solar power (11%) and biomass (5%). Natural gas, including combined cycle and cogeneration, supplied 15% of demand. The balance of trade via the interconnections with Spain remained in favour of imports[45], supplying the remaining 17% of domestic demand.

In terms of the flow of power through the network, power generation centres connected directly to the transmission network fed 31.9 TWh into the network (+3.5 TWh compared with 2024). Power generation centres connected to the distribution network produced 16.3 TWh, of which 3.1 TWh was fed into the transmission network, highlighting insufficient local consumption within the distribution network.

---

[42] Information on the state of the SEN in 2025 taken from REN's Technical Data 2025.

[43] Power generation centres authorised to provide ancillary services.

[44] In 2025, the productivity index was 1.31 – the ratio of the power actually generated to the power that would be generated in an average year.

[45] Situation observed over the last 7 years

As at December 2025, the cross-border electricity interconnection between Portugal and Spain consisted of six 400 kV lines and three 220 kV lines, making a total of nine interconnection lines. In terms of transmission capacity, these lines – whose thermal limits depend on ambient temperature and operating conditions as determined by the operators of the interconnected networks – have a total minimum thermal capacity of 9,627 MVA.

In 2025, there was an increase in the maximum values of the interconnection capacity available for commercial purposes, both in the import direction – reaching 5,310 MW, still some way short of the maximum recorded in 2022 – and in the export direction, with a value of 4,950 MW, representing a new all-time high[46]. However, average values remained stable, with a slight increase in the export direction, whilst minimum values were zero in both directions, as was the case in the previous year.

Furthermore, with regard to the interconnector's performance, in 2025 there were 938 hours of congestion, accounting for around 10.7% of the year, with the highest incidence in May and June. This performance was influenced by restrictions on the Portugal–Spain interconnection capacity, introduced following the Iberian blackout on 28 April 2025 for reasons of operational security, with a more significant impact on import capacity, and which largely account for the performance observed.

Annex II provides further details on the current situation of the SEN.

3.2 SCENARIOS FOR SYSTEM NEEDS ANALYSES

As described in section 2.3.1 , this analysis took into account the ERAA 2025 scenarios for the target years 2030 and 2035. Within the framework of ERAA 2025, REN, as the Portuguese TSO, provided the input data based on the '*Trajetória Ambição*' scenario of RMSA-E 2024, which envisages the fulfilment of the installed renewable generation capacity targets set out in the NECP for 2030 and 2035.

This scenario envisages a strengthening of national energy policies, within a moderate economic context, with more significant progress in the implementation of energy efficiency measures, the electrification of

[46] From 2007 – the year in which the Iberian Electricity Market (MIBEL) came into operation on 1 July 2007 – until 2025.

transport, the production of green hydrogen and other major consumption sectors, and an increase in decentralised generation, consistent with a greater impact of self-consumption.

Set out below are the input data used in the ERAA 2025, for each target year, which led to the results of the economic dispatch considered for the analysis of system flexibility needs.

Target year 2030

For 2030, the scenario considered forecasts a total installed capacity of 48.8 GW, of which 12.4 GW relates to wind generation and 21.1 GW to solar generation.

The total annual demand considered amounts to 75.3 TWh, with a peak demand of 13.1 GW. This scenario also takes into account 4.4 GW of installed electrolysers capacity and 2 GW of installed capacity from large power consumers. For storage, the scenario forecasts 2 GW of batteries and 3.9 GW of pumped-storage.

With regard to interconnection capacity, taking into account the commissioning of the new Minho-Galicia electrical interconnection[47], this scenario assumes, at all times, an export capacity of 3.5 GW and an import capacity of 4.2 GW. It should be noted that these figures are significantly higher than the average figures described in section 3.1.

Taking into account the specific characteristics of the SEN and recent developments, it was also deemed appropriate to carry out two sensitivity analyses on the results obtained in the ERAA 2025 economic dispatch:

a) **Sensitivity 1** – It was assumed that the interconnection would not always be available, and a value of 10% interconnection capacity was used. This sensitivity analysis sought to assess system flexibility needs in a scenario approximating an isolated system and, at the same time, the importance of the interconnection as a source of flexibility for the system.

b) **Sensitivity 2** – To assess the impact of a slower-than-expected growth in installed electrolysers capacity compared with the NECP scenarios, a reduction in this capacity was considered, based on the results of the ERAA 2025 economic dispatch, from 4.4 GW to 430 MW, in line with the ERAA 2026 proposal. A

[47] The new Minho-Galicia electricity interconnector came into operation in July 2026.

reduction in the installation of 2 GW of offshore wind power was also analysed, on the assumption that these are projects related to green hydrogen production. In this sensitivity analysis, the interconnection capacity was maintained at the levels considered in the base case scenario.

TARGET YEAR 2035

For 2035, the scenario envisages a total installed capacity of 58.9 GW, of which 27.8 GW relates to solar generation and 16 GW to wind generation.

Total annual demand is estimated at 82.5 TWh, with a peak demand of 14.5 GW. This scenario also takes into account 7.4 GW of installed electrolysers capacity and 2 GW of installed capacity for large power consumers. For storage, the scenario forecasts 2.5 GW of battery storage and 3.9 GW of pumped-storage hydroelectricity.

As no further development of electricity interconnections is anticipated beyond 2030 in this scenario, interconnection capacities remained at 3.5 GW for exports and 4.2 GW for imports.

For 2035, as part of the analysis of flexibility needs for RES integration, only a sensitivity analysis of the results of the ERAA 2025 economic dispatch was considered:

a) **Sensitivity 2 –** As with the sensitivity analysis carried out for the target year 2030, a reduction in installed electrolysers capacity was considered, based on the outcome of the ERAA 2025 economic dispatch, from 7.4 GW to 1.5 GW, in line with the ERAA 2026 proposal. A reduction in installed offshore wind capacity to 940 MW was also taken into account. In this sensitivity analysis, the interconnection capacity was also maintained at the levels considered in the baseline scenario.

3.3 SCENARIOS FOR NETWORK NEEDS ANALYSES

3.3.1 SCENARIOS FOR DISTRIBUTION NETWORK NEEDS ANALYSES

As mentioned in section 2.1, the scenario for analysing flexibility needs at distribution network level was based on the scenarios considered in the PDIRD-E 2024 and the RMSA-E 2024.

According to the DSO, in terms of network planning, the strategy outlined for the PDIRD-E 2024 seeks to ensure alignment with national energy policy objectives, namely those defined in the NECP, as well as with European guidelines. This strategy seeks to address the needs of the expected energy transition and network expansion, and to prepare the distribution network for the proliferation of distributed generation based on renewable technology, and for new services related to demand management and the promotion of energy efficiency.

To this end, for the purposes of the methodology applied, the scenario used in this study took into account the characterisation of the distribution network forecast for 2030 in the PDIRD-E 2024. Compared with the current situation, developments are expected, for example, in terms of the number of HV/MV substations, the number of transformers and the installed transformer capacity, with a view, amongst other aspects, to enabling the RES integration targets to be met.

In this context, given the methodology used to analyse the flexibility needs of the distribution network, the operational scenario envisaged for HV/MV substations was of particular relevance. Projections from the PDIRD-E 2024 for the year 2030 were used, specifically regarding installed transformer capacity, peak load, natural peak load and the estimated maximum utilisation over this time horizon[48].

Furthermore, with regard to demand trends, the PDIRD-E 2024 sets out the expected evolution of demand and loads for the period 2024–2030, without, however, specifying demand growth rates for later time horizons.

Consequently, to support the demand trend scenario beyond 2030, the DSO drew on the RMSA-E 2024, in particular Annex 3, which presents the projected trend for the SEN peak demand.

For the purposes of this exercise, the DSO assumed that the evolution of the distribution network peak load follows that of the SEN peak load, assuming consistency between the overall dynamics of the system and the evolution of demand at distribution network level.

Given that the RMSA-E provides figures for the SEN peak demand for the years 2030, 2035 and 2040, the DSO used the average annual growth rate between the different periods, subsequently applying these

[48] Further details can be found in Annex B.1.3.2 of the PDIRD-E 2024.

same rates to project the evolution of the peak demand at HV/MV substations at national level over the analysis horizons considered.

3.3.2 SCENARIOS FOR TRANSMISSION NETWORK NEEDS ANALYSES

As described and justified in section 2.3.2.1, no flexibility needs for the transmission network were taken into account in this exercise.

3.4 OBJECTIVE/TARGET FOR RES INTEGRATION

The NECP has set a target for 2030, of a 93% RES share in the electricity sector's demand satisfaction[49]. Both this target and those relating to the growth in installed renewable power capacity are reflected in the scenarios that formed the basis of this study.

The FNAM stipulates that, when assessing system flexibility needs, a target for renewable power integration must be taken into account, that corresponds to the maximum acceptable RES curtailment, so that energy policy objectives can be met. This indicator is not set out in the NECP. In these circumstances, FNAM stipulates that this indicator should be calculated on the basis of the RES integration target set out in the PNEC. However, in this exercise, the TSO was unable to carry out this calculation as the necessary data were not available[50].

Accordingly, for the purposes of this study, it was assumed that RES curtailment should tend toward zero, whilst acknowledging that this would inevitably lead to the results obtained overestimating the system flexibility needs for RES integration. In future editions of this study, efforts will be made to develop an approach that allows for a more robust analysis of these needs

[49] The PNEC does not set a target for 2035.

[50] The PNEC sets a target for the integration of renewables as a share of renewable power in meeting the electricity sector's demand (as a percentage). According to the FNAM, as the NECP does not specify the maximum acceptable RES curtailment, this indicator should be derived from the established target for RES integration. However, in the present exercise, the TSO did not have all the information and data necessary to apply the formula for calculating the share of renewables in the electricity sector, as used in the NECP, based on the results of the ERAA 2025 economic dispatch, therefore it was not possible to calculate this indicator.

4. RESULTS OF FLEXIBILITY NEEDS ASSESSMENT

4.1 SYSTEM FLEXIBILITY NEEDS

4.1.1 RES INTEGRATION

4.1.1.1 RESIDUAL LOAD CHARACTERISATION

As described above, the time series for the residual load for the defined target years, 2030 and 2035, were taken from the results of the ERAA 2025 economic dispatch, applying the formula described in section 2.3.1. These time series were calculated for the three WS analysed. The hourly, daily and seasonal diagrams resulting from this calculation for WS 35 (considered an average climatic year), for each target year, are presented in Figure 2 and Figure 3, as examples. The remaining WS are presented in Annex III[51].

[51] In this exercise, the TSO did not calculate some of the indicators provided for in Article 8 of the FNAM, given that, by considering only three WS per target year, the respective analyses would be unrepresentative.

Figure 2 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 economic dispatch for 2030 (WS 35)

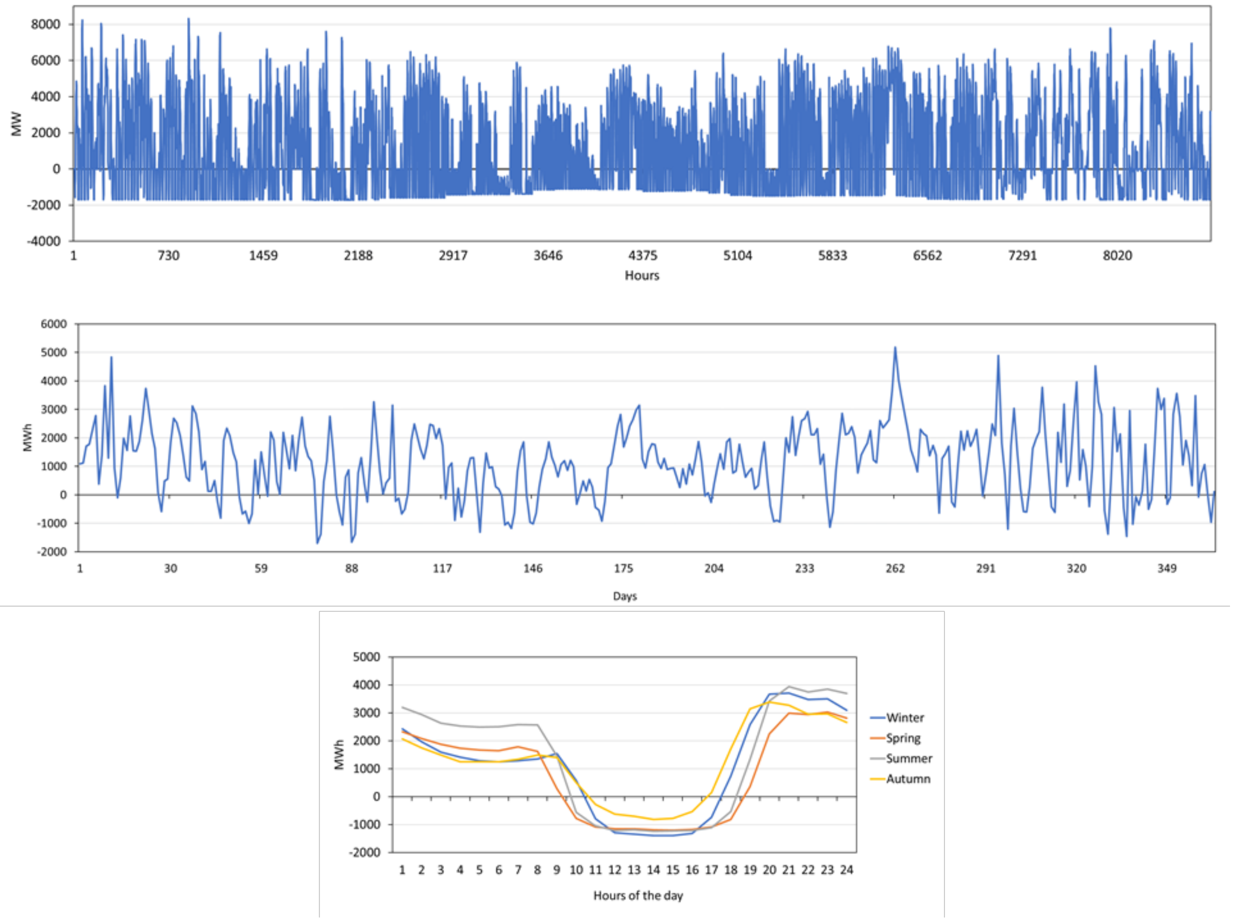
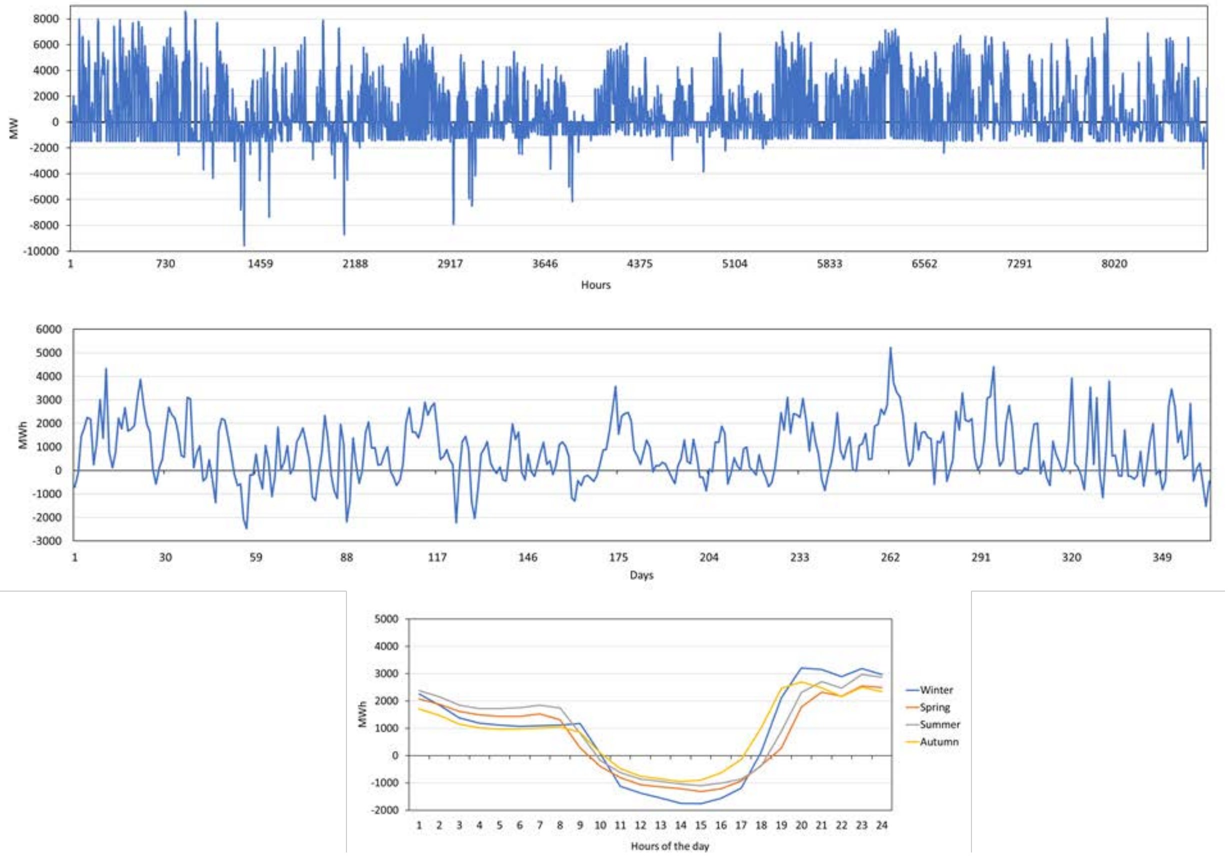


Figure 3 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 economic dispatch for 2035 (WS 35)



Analysis of the figures presented shows negative residual load values in both target years, thus indicating the occurrence of RES curtailment. This curtailment occurs mainly between 8 am and 6 pm, i.e., during periods of peak solar generation.

4.1.1.2 RES CURTAILMENT CHARACTERISATION

As mentioned previously, the expected RES curtailment for each hour and for each target year and WS was characterised based on the calculation of the residual load.

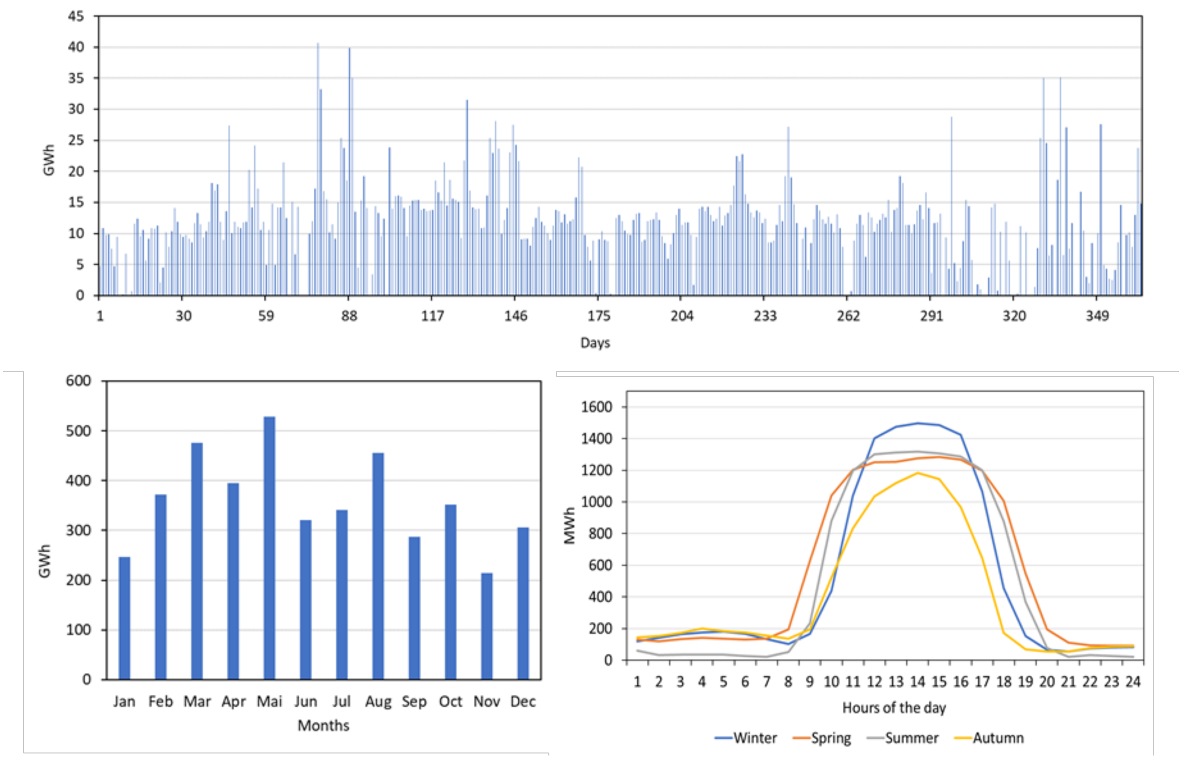
As an example, Figure 4 and Figure 5 present, the RES curtailment diagrams on a daily, monthly and seasonal basis for WS 35, for each target year considered. The remaining WS are presented in Annex IIIIII.

ANALYSIS OF THE RESULTS FOR THE TARGET YEAR 2030

Analysing the results relating to RES curtailment for the scenario defined for the year 2030, and for WS 23, 27 and 35, it was concluded that:

- Annual RES curtailment ranges from approximately 2.7 TWh to 4.3 TWh;
- Curtailment occurs mainly between 8 am and 6 pm, reaching an average of 1,500 MW;
- The winter months show a lower level of RES curtailment.

Figure 4 – RES curtailment on a daily, monthly and seasonal basis (2030, WS 35)



With regard to the sensitivity analyses:

- In sensitivity analysis 1, annual RES curtailment increases, ranging between 7.2 TWh and 12.7 TWh;
- In sensitivity analysis 2, annual RES curtailment also increases, ranging between 5.4 TWh and 5.8 TWh.

The results of the sensitivity analyses clearly highlight the influence of the scenarios considered on the outcomes. Taking sensitivity analysis 2, described in more detail in section 3.2, as an example it can be seen that if the roll-out of electrolysers and offshore wind capacity is slower than forecast in the NECP, the expected RES curtailment increases significantly. Despite the fact that a lower installed renewable capacity was considered, this sensitivity analysis resulted in an increase in RES curtailment, as the reduction in electrolyser capacity has a greater impact, given that the study's assumptions treat them as flexible loads.

The results of sensitivity analysis 1, in turn, clearly demonstrate the importance of interconnection capacity as a source of flexibility for the system. Assuming an interconnection capacity of 10% – which is recognised as an extreme scenario – the range of RES curtailment rises from 2.7 TWh to 4.3 TWh, to 7.2 TWh to 12.7 TWh, in other words, figures three times higher.

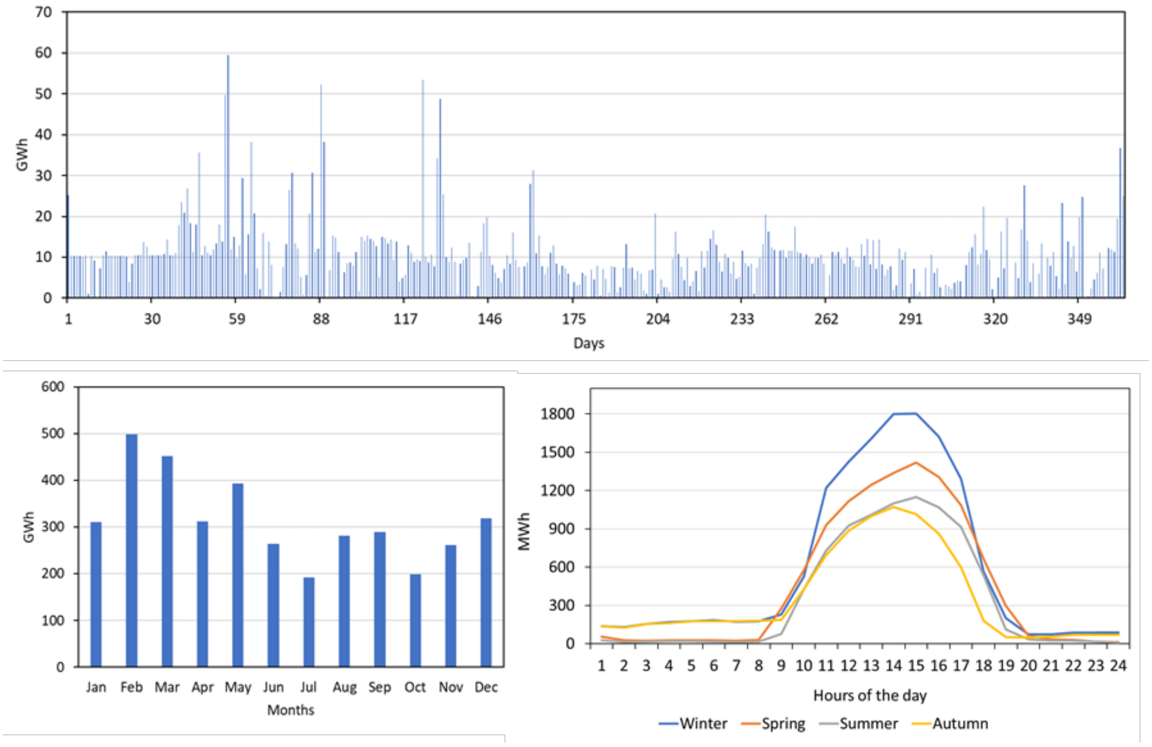
ANALYSIS OF THE RESULTS FOR THE TARGET YEAR 2035

Taking into account the scenario defined for the year 2035, and for WS 23, 27 and 35, it was concluded that:

- Annual RES curtailment ranges from around 1.4 TWh to 6 TWh;
- Curtailment occurs mainly between 8 am and 6 pm, reaching an average of 1,800 MW;
- The winter months show a lower level of RES curtailment.

For the year 2035, only sensitivity analysis 2 was carried out, and a further significant increase was observed in the range of RES curtailment, rising to values between approximately 6.7 TWh and 8.1 TWh.

Figure 5 – RES curtailment on a daily, monthly and seasonal basis (2035, WS 35)



The FNAM also provides for RES curtailment to be characterised on the basis of a set of indicators expressed in terms of power, duration and interval, with the aim of assessing the system's capacity to cope with periods of excess generation that result in such curtailment.

Given that only three WS per target year were analysed, some of these indicators were not determined, namely the probability distribution and relevant percentiles, and the correlation of the results with system conditions, as these analyses would be unrepresentative.

4.1.1.3 FLEXIBILITY NEEDS

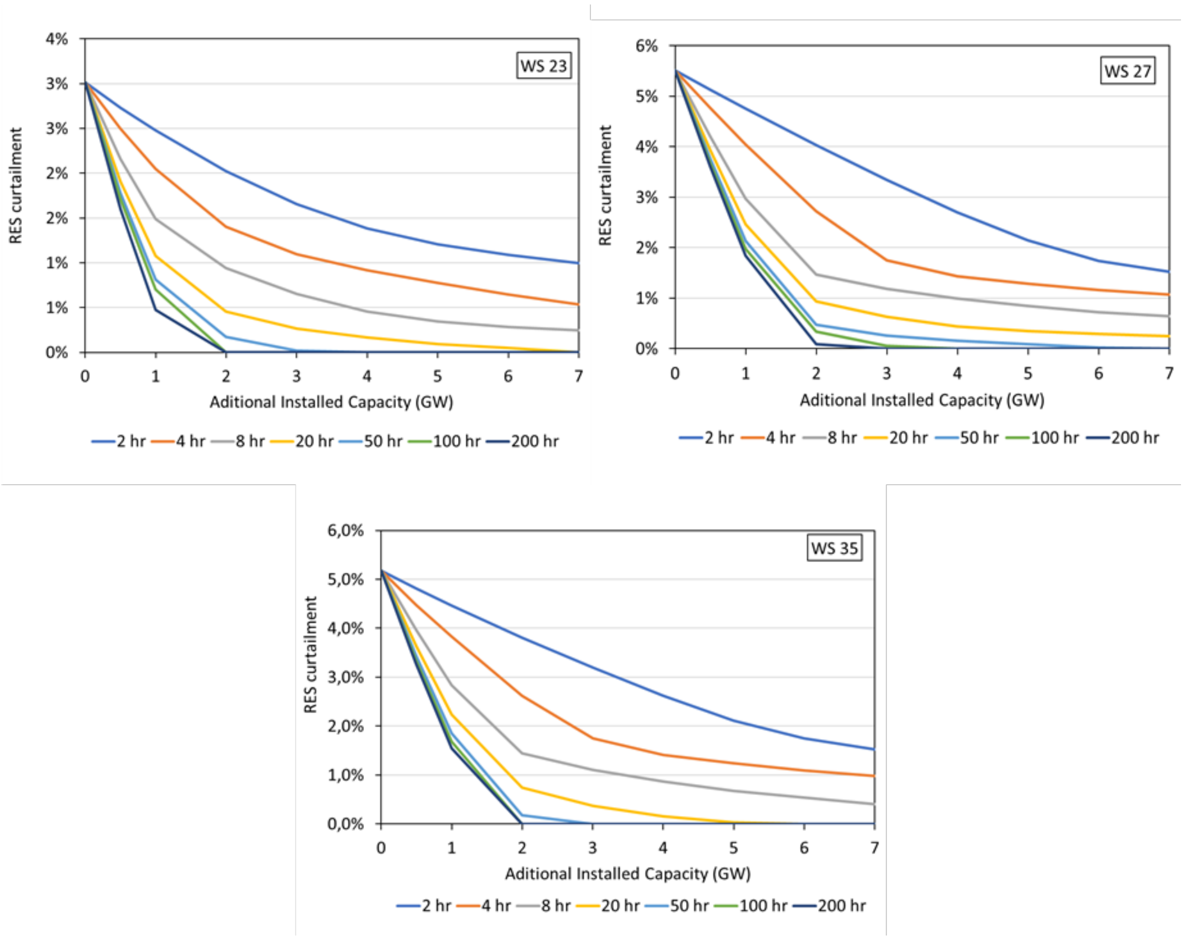
Within the scope of this study, as described in the section 3.4, the TSO assumed that meeting the RES integration target implies a RES curtailment equal or very close to zero. Accordingly, as a more robust approach was not possible for the reasons identified, the TSO considered that the flexibility needs to be met would be equal to or very close to the figures for RES curtailment described in the previous section.

Article 8(10) of the FNAM provides that, should any uncovered flexibility needs be identified, the TSO must analyse the benefits of adding new flexibility resources to the system in each target year. In this context, flexibility resources with a power-to-energy ratio of 2, 4, 8, 20, 50, 100 and 200 hours must, at a minimum, be considered.

TARGET YEAR 2030

For the year 2030, an analysis of WS 23, 27 and 35 concluded that, for a flexibility resource with a ratio of between 2 and 8 hours, additional installed capacity of more than 7 GW will always be required to reduce RES curtailment to zero. Taking, for example, a resource with a ratio of 4 hours, for an additional installed capacity of 7 GW, renewable power wastage would still be between 0.5 TWh and 0.8 TWh. However, for a resource with a 50 hour ratio and around 3 GW of new installed capacity, renewable power waste is virtually eliminated. The results can be seen at Figure 6 for the three WS, for 2030.

Figure 6 – RES curtailment[52] taking into account the energy-to-power ratio of flexibility resources for 2030, WS 23, 27 and 35



The results obtained from the sensitivity analyses for the target year 2030 once again highlighted the significant influence of the factors considered in these analyses. These can be viewed in greater detail in Annex III .

For sensitivity analysis 2, for example, to eliminate RES curtailment considering resources with a 50 hour ratio, additional installed capacity of around 5 GW would be required (compared with 3 GW in the baseline scenario).

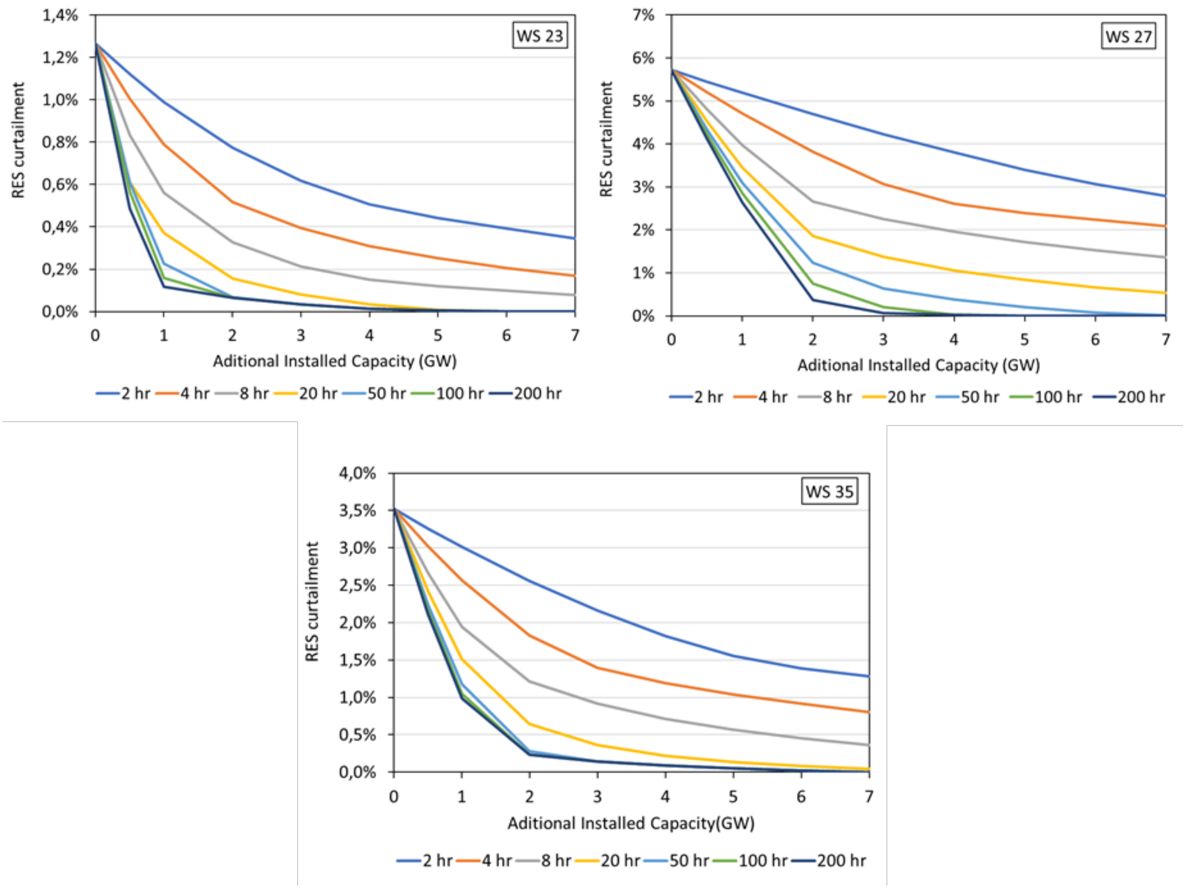
[52] RES curtailment as a percentage of total RES generation in each scenario. Figures with values in energy units presented in annex III.

For sensitivity analysis 1, in WS 23 and WS 35, RES curtailment is not eliminated, even when taking into account resources with a 200 hour ratio. In WS 27, however, to eliminate RES curtailment, it would be necessary to install an additional 6 GW of capacity from resources with a 200 hour ratio.

TARGET YEAR 2035

For the year 2035, analysing WS 23, 27 and 35 it was possible to conclude that, for a flexibility resource with a ratio of between 2 and 8 hours, in order to achieve a total reduction in RES curtailment – as is the case for the target year 2030 – additional installed capacity of more than 7 GW will always be required. Taking, for example, a flexibility resource with a ratio of 4 hours, for an additional installed capacity of 7 GW, renewable power waste would still range between 0.2 TWh and 2 TWh. In contrast, for a flexibility resource with a ratio of 50 hours and around 3 GW of new installed capacity, renewable power waste would reach a maximum of 0.6 TWh. The results can be seen at Figure 7, for the three WS, for 2035.

Figure 7 – RES curtailment[53] taking into account the energy-to-power ratio of flexibility resources for 2035, WS 23, 27 and 35



For the target year 2035, only sensitivity analysis 2 was carried out. Once again, the results of this sensitivity analysis differ significantly from the baseline scenario. In WS 23, to eliminate RES curtailment, it would be necessary to install around 6 GW of additional resources with a 50 hour ratio. In WS 27 and WS 35, to eliminate RES curtailment, it would be necessary to install around 7 GW of resources with a 100 hour ratio. These results can be viewed in greater detail in Annex III.

As mentioned, these were the capacity figures identified to reduce curtailment to zero or to values very close to zero. However, it should be noted that the analysis carried out makes it possible to identify the

[53] RES curtailment as a percentage of total RES generation in each scenario. Figures with values in energy units presented in annex III.

additional capacities required should a maximum acceptable level of RES curtailment be determined. These figures will be lower than those identified here.

In light of the results obtained, it is important to characterise the possible flexibility resources with characteristics that enable compliance with the energy/power requirements and ratios referred to above, within the context of the SEN. In this regard, and taking into account the estimated evolution of the SEN, the following technologies may be considered:

- **2h, 4h and 8h** – Electrochemical batteries, but also demand-side response, e.g., adjusting the charging profile of electric vehicles or the use of heat pumps;
- **20h** – Hydro power plants with pumped-storage with a storage capacity of up to 20h (such as the Gouvães power plant);
- **50 hours** – Hydroelectric systems with a total storage capacity of up to 50 hours (such as the Alto Rabagão and Baixo Sabor pumped storage systems);
- **100h and 200h** – Hypothetical use of electrolysers and green hydrogen storage capacity of 100h or 200h.

Finally, it is also important to emphasise that the approach used in this analysis does not allow for the complementarity of the various flexibility resources to be taken into account. The SEN future flexibility needs should, naturally, be met through the simultaneous use of a varied portfolio of resources that allows the benefits and added value of each technology to be harnessed.

4.1.2 Ramping

4.1.2.1 Characterisation of current response capacity to ramping needs

Article 9(3) of the FNAM provides for the characterisation of the capacity of existing assets to respond to ramping needs, based on their technical characteristics. In this regard, it was assumed that, for all target years and WS considered, the available assets followed the reference values identified in Table 4, Table 5 and Table 6.

Table 4 – Reference values for a combine cycle gas turbine (CCGT) power plant

Technology	Cold	Warm	Hot
CCGT	Start-up time [hours]		
	2	1,5	1
	Start-up conditions[54] [hours]		
	120 a 56	56 a 8	< 8

Table 5 – Reference values for CCGT ramping limits

Technology	Ramping limit	MW/min		
CCGT	Downward	From the maximum power output to 200 MW		
		16		
		From 200 MW to 0 MW		
		12		
	Upward	Up to the technical limit (0 a 200 MW)		
		Cold	Warm	Hot
		78	58	34
		From tech. limit to maximum power (200 MW to máx.)		
		14		

Table 6 – Reference values for a hydro power plant

Technology	Run-of-river	Reservoir	Pumping
Hydro	Start-up time [min]		
	16	7	6

4.1.2.2 FLEXIBILITY NEEDS

Article 9 of the FNAM stipulates that, for each target year and for each WS, flexibility needs must be calculated as the difference between variations in residual load and the capacity of residual ramping margins to manage these variations.

[54] Time from the last grid disconnection to the next parallel connection.

To identify these needs, the incremental introduction of flexibility resources was analysed, considering the following order for the deployment of technologies: CCGT, reservoir hydro power plants, pumped storage, batteries, and, finally, electrolysers.

TARGET YEAR 2030

For 2030, in WS 23, maximum values of 1,597 MW and 1,274 MW were identified for upward and downward flexibility needs, respectively. For this WS, the identified needs are virtually met after taking pumped storage into account, and are fully met by utilising the batteries considered in this scenario.

WS 27 corresponds to the most critical scenario among those considered, recording maximum upward flexibility needs of 1,676 MW and maximum downward flexibility needs of 1,800 MW. In this scenario, even after mobilising all the technologies considered to be available, there remains a residual upward flexibility need of around 1.5 GWh/year, corresponding to an average power of 0.17 MW.

In WS 35, a maximum upward flexibility need of 863 MW and a maximum downward flexibility need of 1,672 MW were identified. As with WS 23, the identified flexibility needs are fully met following the introduction of batteries.

In summary, for the year 2030, it is evident that, for all WS, there is a greater need for downward flexibility (higher maximum values). Nevertheless, the system appears to have a lower capacity to respond to upward flexibility needs. Even so, for this target year, no significant uncovered ramping flexibility needs were identified.

In terms of the technologies considered, the sequential introduction of hydro reservoirs, pumped storage, batteries and electrolysers significantly reduces the identified flexibility needs, particularly for downward flexibility. Among these, pumped storage is the technology with the greatest structural impact on reducing flexibility needs, whilst the contribution of batteries and electrolysers proves to be negligible or non-existent in the scenarios presented.

TARGET YEAR 2035

For 2035, in WS 23, maximum upward flexibility needs of 540 MW and maximum downward flexibility needs of 1,833 MW were identified. For this WS, the system was found to behave stably, with few events requiring flexibility. After taking into account all available flexibility resources, a residual upward flexibility need of approximately 293 MWh/year remains, corresponding to an average power of 0.03 MW.

In WS 27, maximum flexibility needs were identified as 751 MW for upward flexibility and 1,861 MW for downward flexibility. In this WS, even when making use of all available flexibility resources, a residual upward flexibility need of 271 MWh/year remains, corresponding to an average power of 0.03 MW.

In WS 35, the maximum upward and downward flexibility needs identified were 765 MW and 1,560 MW, respectively. In this WS, the simulations identified high variability in generation ramps, requiring a faster and more robust response from flexibility resources. Nevertheless, after utilising all available flexibility resources, a residual upward flexibility need of 58 MWh/year remains, corresponding to an average power of 0.01 MW.

As observed for the year 2030, for the year 2035 there was, across all WS, greater downward flexibility needs, whilst a lower capacity to respond to upward flexibility needs continued to be identified. Although uncovered flexibility needs were identified in all WS, the values identified are residual.

As with the year 2030, flexibility needs are concentrated primarily on the mobilisation of hydro resources (reservoirs and pumping), with the contribution from batteries and electrolysers being marginal.

The results of this analysis are presented in greater detail in Annex III.

4.1.3 SHORT-TERM FLEXIBILITY NEEDS

4.1.3.1 CHARACTERISATION OF CURRENT RESPONSE CAPACITY TO SHORT-TERM NEEDS

Article 10(3) of the FNAM provides for the characterisation of the capacity of the residual margins of assets to provide upward and downward flexibility, for each year and WS considered, based on the technical constraints of the available assets. The assets considered in this analysis were those already characterised in section 4.1.2.1.

4.1.3.2 FLEXIBILITY NEEDS

Article 10(1) of the FNAM stipulates that TSOs must determine short-term flexibility needs based on the 0.1 and 99.9 percentiles of the probability distribution of residual load forecast errors for each target year. Upward flexibility needs are determined by the maximum and minimum values of percentile 99.9, whilst downward flexibility needs are determined by the maximum and minimum values of percentile 0.1.

For 2030, and for the WS under consideration, maximum upward flexibility needs ranging from 2,154 MW to 2,223 MW and minimum upward flexibility needs ranging from 433 MW to 439 MW were identified. For downward flexibility needs, the maximum values ranged from 2,757 MW to 2,842 MW and the minimum values from 516 MW to 526 MW.

For 2035, and for the WS under consideration, maximum upward flexibility needs ranging from 2,406 MW and 2,465 MW and minimum upward flexibility needs ranging from 482 MW to 488 MW were identified. For downward flexibility needs, the maximum values ranged from 3,080 MW to 3,156 MW and the minimum values from 576 MW to 585 MW.

The calculation of flexibility needs was based on the processing of the results of the ERAA 2025 economic dispatch, with the residual load being obtained directly from these results for each target year and WS. Consequently, the residual load constitutes a deterministic value, and it is not possible to explicitly simulate the respective forecasting errors.

In accordance with Article 10 of the FNAM, short-term flexibility needs relate to the system's capacity to respond to forecasting errors, that is, to the deviations between the residual load forecast the previous day[55] and the residual load actually observed. In this study, these deviations were projected by taking into account the statistical distribution of the forecasting error, expressed as a percentage of the residual load calculated for each target year and the relevant WS.

However, it is important to note that the TSO considers that forecasting errors merely represent an upper bound on flexibility needs. For the effective application of the determined distribution functions for residual load forecasting error, simulations of these random variables should be carried out using the Monte Carlo method, enabling alternative demand profiles (forecast demand + simulated error) to be obtained, on the basis of which new economic dispatch calculations would be performed to assess, in each case, the flexibility needs in terms of power, energy, and the times at which these occur. Alternatively, in a less ambitious approach, it would be possible to determine an average forecast error profile based on the error distribution functions, and simply carry out a new economic dispatch to assess the existing flexibility needs.

In this study, as the methodology applied was based on the processing of the results of the ERAA 2025 economic dispatch, it was not possible to apply any of the approaches described to carry out new economic dispatch simulations. For this reason, the TSO considered that the methodological conditions were not met to identify, with the required degree of robustness, the uncovered flexibility needs associated with residual load forecasting errors, consequently, no uncovered flexibility needs were determined.

4.2 NETWORK FLEXIBILITY NEEDS

4.2.1 DISTRIBUTION NETWORK NEEDS

Article 11 of the FNAM stipulates that DSOs must detail the network flexibility needs identified by direction and, where applicable, by scenario, using, preferably, the sum of the maximum local power (MW) and total energy (MWh) for representative time periods of each target year. If this is not possible, the annual sum of the maximum local power and total energy must be provided as a minimum data set.

[55] One-day time horizon, with a maximum breakdown to quarter-hourly intervals.

In accordance with the methodology described in section 2.3.2.2 and in Annex I, and as previously agreed, the results regarding the flexibility needs of the distribution network were calculated taking into account the following levels of granularity:

- Temporal Granularity – Annual;
- Spatial Granularity – the entire distribution network;
- Voltage-level granularity – HV/MV substations[56].

The results obtained for the target years 2030 and 2035 are summarised in Table 7 .

The analysis carried out concludes that only upward flexibility needs were identified. For 2030, the sum of the maximum local upward power needs is 48.7 MW, corresponding to an expected average energy value of 57.3 MWh. For 2035, the DSO identified upward network flexibility needs characterised by a sum of local peak powers of 56.8 MW and an expected average energy value of 66.9 MWh.

Table 7 – Distribution network flexibility needs, for 2030 and 2035

Direction of need	Target year	Temporal Granularity	Spatial Granularity	Voltage level	Unit	Need	% RES curtailment	Expected contractual means
Upward	2030	Annual	RND	0,4 kV - 60 kV	Sum of maximum power [MW]	48.7	0	Procurement of Services Local Markets
					Expected average energy value [MWh]	57.3		
Downward					Sum of maximum power [MW]	0		
					Expected average energy value [MWh]	0		
Upward	2035	Annual	RND	0,4 kV - 60 kV	Sum of maximum power [MW]	56.8	0	Procurement of Services Local Markets
					Expected average energy value [MWh]	66.9		
Downward					Sum of maximum power [MW]	0		
					Expected average energy value [MWh]	0		

The identified needs are primarily justified by the emergence of constraints in the distribution network, namely situations of congestion or the network assets approaching their operational limits, both in terms

[56] Notwithstanding the fact that, given the methodology used, the study was carried out at the HV/MV substation level, it should be noted that, on the one hand, constraints may arise at other voltage levels, such as a specific MV feed from the HV/MV substation, and, on the other hand, generally speaking, the provision of flexibility services may also be carried out by customers connected at a voltage level lower than that of the identified constraint (e.g. LV customers can provide flexibility services to mitigate constraints in the MV network).

of thermal capacity and voltage control. This stems from changes in load profiles within the distribution network, resulting from growth in electricity demand and the progressive electrification of consumption.

The projected evolution of peak load reflects the assumptions underlying the SEN's electricity demand projections, as defined in the RMSA-E 2024, including favourable macroeconomic trends, the impact of energy efficiency policies and the increased penetration of new electricity loads, such as electric mobility and distributed generation (self-consumption).

In this context, the main objective of utilising flexibility solutions will be to defer network investments, particularly in an initial phase where constraints are limited and potentially manageable by the network operator through the use of flexibility.

With regard to meeting these needs, given their nature and the experience the DSO expects to gain in this context – which already falls within the use cases envisaged in the PDIRD-E 2024 – it is anticipated that the preferred procurement method will be through local flexibility markets.

4.2.2 TRANSMISSION NETWORK NEEDS

As mentioned in section 2.3.2.1, in the various analyses carried out as part of the transmission network planning exercises, conducted in accordance with the Security Standards set out in the Transmission Network code, the TSO has not identified any instances of RES curtailment or unserved energy resulting from network congestion.

Accordingly, and pursuant to the FNAM, the TSO has not identified any need for transmission system flexibility within the scope of this analysis.

5. BARRIERS TO FLEXIBILITY AND THE CONTRIBUTION OF DIGITALISATION

Subparagraphs (c) and (d) of paragraph 2 of Article 19e of Regulation (EU) 2019/943 stipulate that this study must assess barriers to market flexibility, propose relevant mitigation measures and incentives, and evaluate the potential contribution of the digitalisation of electricity transmission and distribution networks.

In this regard, Article 15 of the FNAM provides that this assessment shall be carried out on the basis of six categories of barriers:

a) Lack of proper legal framework for market access to new entrants and small actors;

b) Lack of enablers and incentives to provide flexibility;

c) Restrictive requirements to provide balancing services;

d) Restrictive requirements to provide congestion management;

e) Complex, lengthy, and discriminatory administrative requirements;

f) Lack of regulatory incentives to system operators to consider non-wire alternatives.

To support this assessment, ACER issued Recommendation No 01/2026[57], which examines in greater depth the set of barriers identified in the FNAM and provides guidance on their assessment in each Member State. To this end, ACER sets out a list of 24 indicators to be assessed, along with the relevant aspects to be analysed.

This report has sought to follow this recommendation as far as possible, and the points considered to be the most relevant in this analysis are set out below. Annex IV presents a summary table of the assessment carried out for each indicator[58].

---

[57] *Recommendation No 1/2026 of 19 March 2026 on NRAs' reporting on barriers to non-fossil flexibility* .

[58] On 29 June 2026, Decree-Law No. 130/2026 was published, which partially transposed Directive (EU) 2023/2413 on the promotion of power from renewable sources, transposed Directive (EU) 2024/1711, on improving the design of the Union's electricity market, and partial transposed Directive (EU) 2023/1791 on energy efficiency. This analysis does not take into account the publication of this Decree-Law, as it was published at a late stage of the study's preparation and because national regulations have not yet incorporated the legal amendments introduced.

5.1 ENABLERS AND INCENTIVES TO PROVIDE FLEXIBILITY

ACER Recommendation No. 01/2026 considers the degree of smart meters roll-out as one of the key indicators for assessing the existence of conditions favourable to the development of flexibility[59].

In Portugal, Order No. 14064/2022[60], dated 6 December, approved the timetable for the installation of smart meters and their integration into smart network infrastructure, ensuring full coverage of end customers connected to the low-voltage (LV) power distribution network by the end of 2024.

There is currently no disaggregated information on the percentage of domestic and non-domestic consumers with smart meters. Nevertheless, by the end of 2025, around 6.50 million LV customers in mainland Portugal (i.e., 99.5%) had a smart meter installed and around 6.47 million (i.e. 99.0%) were integrated into the smart network. The process of installing smart meters and integrating them into the smart network in mainland Portugal is, for the most part, complete, in line with the objectives set out in national legislation.

With regard to their functionalities, in Portugal, smart meters are defined as those that meet the needs set out in Ministerial Order No. 231/2013[61] of 22 July, which are consistent with those identified in ACER Recommendation No. 01/2026. Thus, the current level of smart meter deployment does not appear to be a barrier to the development of flexibility solutions in mainland Portugal.

The analysis of this indicator also envisages an assessment of the use of sub-meters or specific metering devices, a practice which, to date, is not common in Portugal. However, relevant regulatory developments are currently underway.

On the one hand, it is important to note that, with regard to the legal framework at national level, the transposition of Directive (EU) 2024/1711[62] has very recently been completed, in particular the provisions

[59] This analysis considers the percentage of smart meters installed in domestic and non-domestic end-user households.

[60] https://diariodarepublica.pt/dr/detalhe/despacho/14064-2022-204338646

[61] https://diariodarepublica.pt/dr/detalhe/portaria/231-2013-498106

[62] Decree-Law No. 130/2026 of 29 June

relating to the free choice of suppliers and the right of customers to have more than one metering point at the same premises with a single connection to the network.

Furthermore, Decree-Law No 93/2025 of 14 August[63], which establishes the legal framework applicable to electric mobility following the publication of Regulation (EU) 2023/1804 of the European Parliament and of the Council of 13 September 2023, already enshrines the right to freely choose a supplier for charging points connected to demand facilities not exclusively dedicated to electric mobility. Exercising this right requires the conclusion of a supply contract separate from that associated with the connection point to the public network.

In this regard, ERSE has already laid down this principle in its codes, with effect from the end of 2025, allowing, amongst other things, for electric vehicle charging points connected to demand installations not exclusively dedicated to electric mobility to request that the relevant network operator establish an internal metering point to segregate demand at those charging points. These internal metering points are managed by the respective network operators in a similar way to metering points connected to the public network, ensuring the correct collection of data underlying the various contracts in the electricity sector (network use and supply contracts). It should be noted that this model assumes that each metering point has only one supply contract. In other words, multiple supply contracts for the same metering point are not permitted (for example, one contract for weekdays and another for weekends).

With regard to specific metering devices which, as set out in Regulation (EU) 2019/943, can be used for the purposes of observability, settlement of demand response services and flexibility services, particularly in the absence of smart meters (which is not the case in Portugal), discussions on the regulatory rules applicable to such devices are expected in the near future, building on the ongoing work towards the adoption of the demand response network code and the final results of pilot projects in the field of flexibility services.

Finally, initiatives are currently underway to develop the potential of smart meters, in support of demand-side response and customer flexibility.

[63] Decree-Law No. 93/2025, of 14 August

Among these, the Smartmetering Plus pilot project[64], developed by E-REDES, stands out. It aims to digitalise access to data in near real time by virtualising the HAN interface of smart meters via an API, which can be used directly by customers or shared with third parties. This project aims to develop case studies relating to the management of domestic power systems and access to distributed power resources for future flexibility management.

Also worth highlighting is the FlexC project[65], also developed by E-Redes, which utilises the concept of flexible power, dynamically adjusted based on the building's total demand. The available power is monitored and directed towards charging electric vehicles, enabling an increase in charging capacity without altering the infrastructure that supplies the building.

In conclusion, it is considered that the metering systems currently in place in mainland Portugal, as well as ongoing regulatory and technological developments, facilitate the development of flexibility, with no significant barriers identified in this area.

5.2 BALANCING SERVICES REQUIREMENTS

Currently, there is no FCR market in Portugal[66]. This is a mandatory, unpaid ancillary service provided by generation facilities and other operational installations, wherever technically feasible.

Nevertheless, paragraph 10 of Article 49 of the Network Operation Code[67] (ROR) stipulates that the National Network Operator should submit a proposal for market rules governing the procurement of the FCR service. To this end, a pilot project is currently underway aimed at defining the technical needs applicable to FCR, in particular with regard to monitoring compliance with the provision of the service. It is expected that the conclusions and results of this project will support the possible creation of a market for this service.

[64] Smartmetering Plus Project, 6 May 2025.

[65] FlexC – Innovative Solution for Charging Electric Vehicles in Multi-occupancy Buildings.

[66] Frequency Containment Reserve.

[67] Network Operation Code.

With regard to the provision of balancing services, another point to be assessed concerns any restrictions on pre-qualification for the provision of reserve services to the system.

With regard to aFRR[68], although the regulations provide for the possibility of pre-qualification for reserve supply groups, only reserve supply units are currently pre-qualified. Consequently, to date, there has been no pre-qualification for reserve supplier groups. Conversely, for the provision of mFRR[69], bids are submitted by groups of physical units. It should also be noted that two pilot projects are currently being prepared in the field of aggregation, which envisage the pre-qualification of reserve supply groups for aFRR and also for the aggregation of small physical units via an aggregator.

It is also worth noting that the needs for providing aFRR and mFRR services are quite different. Whilst aFRR is based on 4-second optimisation cycles, mFRR provides for a total activation time of 12.5 minutes. Consequently, reserve supply units in Portugal undergo separate qualification processes for each of the aFRR and mFRR services.

In summary, although some regulatory developments remain to be finalised, particularly with regard to the FCR service, it is considered that relevant initiatives are underway to reduce these barriers and to promote wider participation in balancing services.

5.3 REQUIREMENTS FOR CONGESTION MANAGEMENT SERVICES

5.3.1 TSO CONGESTION MANAGEMENT

With the aim of resolving physical congestion on the transmission network, the TSO carries out a technical validation of the physical flows of scheduled generation resulting from the day-ahead and intraday markets. Should congestion be identified during this analysis, the TSO may resort to redispatching procedures, replacing the schedule of generation units causing constraints with others whose power flow does not jeopardise the operational security of the system.

[68] Frequency restoration reserves with automatic activation.

[69] Manual Frequency Restoration Reserve.

This is a market-based process that utilises specific bids per unit submitted by the BSPs[70] to be activated during the congestion management process. However, these constraints may be local in nature, thereby reducing the number of resources to be allocated in this process. Whenever congestion occurs in real time, procedures similar to those described above are applied.

5.3.2 DSO CONGESTION MANAGEMENT

To date, the main tool for resolving situations of structural physical congestion in the distribution network, from a medium to long-term perspective, has been investment in strengthening and developing the network. In real-time operation, the ORD has solutions at its disposal such as network reconfiguration, voltage control, curtailment of generation and, in more extreme cases, load shedding.

The use of market-based solutions to address congestion is still at an early stage of development in Portugal. In this context, Article 78(12) of the ROR stipulated that the operator of the MV and HV distribution networks (E-Redes) should submit a pilot project to ERSE that included, at a minimum, the procurement of these services.

Accordingly, E-Redes submitted the FIRMe pilot project[71] to ERSE, which began in 2022, with two main objectives: i) to develop local flexibility markets, promoting the participation of market participants as providers of flexibility services to the DSO; and ii) to adapt network planning methodologies, incorporating flexibility alternatives as a complement to investment. The project comprises three standard products – Dynamic, Restore and Secure – designed, respectively, to mitigate constraints arising from scheduled outages of network assets, to support network restoration following sporadic events resulting from network failures in contingency situations and to manage demand peaks at specific points on the network to support normal network operation.

In the first phase of this pilot project, on 14 March 2024, ten contracts were signed with nine different entities for the provision of flexibility services. In June 2025, E-Redes proposed to ERSE the launch of a second phase of the pilot project (FIRMe 2.0), for the period 2026–2027, retaining the structure of the initial project and the products established for contracting, but introducing adjustments to the rules and

[70] Market participant authorised to participate in balancing services and other ancillary services, or Balancing Service Provider.

[71] FIRMe – Integrated flexibility in a market-based system

procedures associated with the tender process and the provision of services, incorporating the lessons learnt from the first phase. This new phase currently covers 17 use cases.

It is also worth noting that this pilot project has fulfilled the objective of generating interest and increasing the involvement of market participants in this type of service. Between July 2023 (the date of the first auction) and June 2025, the number of registered potential flexibility service providers rose from 29 to 75, whilst the number of associated assets increased from 31 to around 830.

With regard to flexible connection agreements, these are enshrined in national legislation, specifically in Decree-Law No. 15/2022 and the Access to Networks and Interconnections Code[72] (RARI). In the case of consumer installations, their application is currently limited to pilot projects, and the implementation of this type of solution in Portugal remains limited.

Finally, it is worth noting that there are still relevant regulatory developments which have not yet begun, in particular, the drafting of the Manual of Procedures for the Technical Management of Electricity Distribution Networks (MPGTRD), as provided for in the ROR. This manual is expected to set out, amongst other aspects, i) technical specifications for flexibility services, non-frequency-related ancillary services and standardised market products for these services; ii) the pre-qualification process and requirements for the provision of flexibility services and non-frequency-related ancillary services; and iii) rules applicable to the contracting, use, compliance verification and settlement of flexibility services and non-frequency-related ancillary services. It is hoped that the drafting of this MPGTRD will benefit from the results and lessons learnt from the ongoing pilot projects and from the adoption of the demand response network code at European level.

In conclusion, although flexibility services for congestion management are still at an early stage of development in Portugal, significant regulatory and operational progress is being made, supported by pilot projects that have enabled market-based solutions to be tested.

[72] RARI.

5.4 NETWORK CONNECTION PROCEDURES

The first aspect to be assessed under this indicator concerns the existence of network connection procedures for renewable energy self-consumption installations, energy storage installations and heat pump installations, specifically with regard to the public availability of information on these procedures and the possibility of carrying them out electronically.

In Portugal, Article 15 of Decree-Law No. 15/2022 provides for a single electronic platform, managed by the DGEG, as the licencing entity, through which electronic forms, application requirements, the status of procedures, decisions and issued licences are made available as part of the prior review process.

The implementation of this platform is currently underway for installations with a capacity of over 1 MW, and is the responsibility of the Task Force for the Licensing of Renewable Power Projects 2030 (EMER 2030)[73]. For installations with an installed capacity of less than 1 MW, registrations and prior notifications are already carried out on a digital platform created for this purpose[74].

In addition, the applicable legislation and guidance are published on the DGEG official website and a form for the processing of applications is also available[75], contributing to greater transparency in administrative procedures.

Another aspect to be assessed concerns the application of the concept of simple-notification by the DSO. In Portugal, this is provided for in relation to certain types of installation, in accordance with paragraphs 4 and 5 of Article 11 and Article 59 of Decree-Law No. 15/2022.

In particular, the national framework provides for prior notification procedures and exemption from prior control for small-scale installations, namely:

- low-power UPACs (below 800 W) and those between 800 W and 30 kW;

[73] EMER 2030 – A framework established by Council of Ministers Resolution No. 50/2024 of 26 March, with the remit to ensure compliance with the objectives of the NECP and to accelerate the implementation of renewable energy projects. One of the objectives of this Mission Structure is "to develop, implement and manage the One-Stop Shop for the Licensing and Monitoring of Renewable Power Projects, based on a digital One-Stop-Shop model".

[74] Power Portal – DGEG.

[75] Power Generation – DGEG.

- certain installations without feed-in to the RESP.

In these cases, the network operator’s involvement is waived or limited, bringing the system functionally closer to the ‘simple-notification’ model, as provided for in European legislation.

With regard to the publication of up-to-date information on available network connection capacity, the DSO, E-Redes, publishes this information on its website. At the transmission network level, this information is made available by the DGEG, under paragraphs 1 and 2 of Article 19 of Decree-Law No. 15/2022, which publishes online the available feed-in capacity for both the transmission and distribution network. However, this information does not distinguish between firm capacity and flexible capacity, and is not dynamically updated in line with allocations, expiries and network reinforcements.

In summary, it is considered that Portugal currently has a largely digitalised framework for network connection procedures. However, there is still room for improvement, particularly in terms of the dynamic updating of information on available connection capacity and the provision of more detailed information on the actual conditions of access to the networks.

5.5 REGULATORY INCENTIVES FOR NETWORK OPERATORS TO CONSIDER NON-WIRE ALTERNATIVES

ACER Recommendation No. 01/2026 also provides for the assessment of existing regulatory incentives to enable operators to procure flexibility services or invest in smart networks, network optimisation and innovative technologies as an efficient alternative to network expansion.

In Portugal, the regulation of power transmission and distribution activities is based on a revenue cap-type incentive-based regulatory approach applied to total controllable costs (TOTEX), supplemented by a mechanism for sharing gains and losses between companies and consumers.

The adoption of this regulatory methodology increases the flexibility of the cost structures for these activities, minimising the distinction between capital expenditure (CAPEX) and operating expenditure (OPEX), and promoting more efficient investment decisions, as it is technology-neutral, which will yield medium- and long-term gains for both companies and consumers.

In particular, the TOTEX methodology in the power distribution activity[76], by not favouring physical investment options, implicitly encourages the adoption of demand-side participation mechanisms, such as network operators' use of flexibility procurement, rather than traditional investments in expanding network capacity, where this option proves to be effective and more efficient.

This methodology is in line with the recommendations discussed at European level, which identify this methodology as an important component of regulation geared towards the objectives of decentralisation, digitalisation and decarbonisation of the sector.

The profit-and-loss-sharing mechanism reinforces these incentives for investment efficiency and the potential adoption of flexibility solutions. Through this mechanism, if a network operator resolves a constraint on its network by using a flexibility solution (which initially involves a lower cost), rather than expanding the network (which involves a higher cost), the national tariff methodology allows part of these cost savings to be shared with the operator (as additional profit) and the other part to be passed on to consumers (lower electricity tariffs).

Furthermore, in terms of explicit incentives, the 'Incentive for innovation and new services in LV installations – INS' was also approved by the Smart Network Services Code (RSRI)[77].

This incentive aims to make the regulatory framework more flexible to enable adequate investment in the development of new services in the electricity sector, notably with a view to influencing and fostering new behaviours amongst stakeholders in the electricity sector. Among other things, the potential benefits of this type of investment include improved management of network areas with high levels of RES integration, the possibility of implementing demand-side flexibility mechanisms, facilitating the integrated management of electric vehicle charging, and the local provision of ancillary services, which will enable a reduction in operating costs and deliver further benefits for consumers and other stakeholders.

Whilst not directly classified as an incentive, national regulations also provide for pilot projects, with provision for the acceptance of costs associated with innovative projects (e.g., active network management) which, despite carrying higher risk, bring long-term benefits for system efficiency. In this

[76] In Portugal, the TOTEX methodology is applied to both power distribution and transmission activities.

[77] Smart Network Services Code (RSRI).

context, it should be noted that the latest PDIRD-E already incorporates flexibility solutions as an alternative to investment in network development, drawing on the experience gained from the FIRMe pilot project, referred to above.

In conclusion, it is considered that the national regulatory framework already incorporates relevant mechanisms to incentivise the use of flexibility solutions and non-wire alternatives. However, the consolidation of these mechanisms will depend on the continued regulatory development and the flexibility markets currently being implemented.

6. CONCLUSIONS

This study assesses the different types of flexibility needs identified, with a view, amongst other aspects, to integrating electricity generated from renewable sources into the SEN, taking into account the objectives set out in the NECP 2030 (updated version).

The study follows the methodology for assessing flexibility needs approved by ACER in 2025 (FNAM), pursuant to Regulation (EU) 2019/943, in its current wording.

The FNAM defines two main types of flexibility needs: system flexibility needs and network flexibility needs.

The study was coordinated by ERSE, involving the TSO and DSO, as well as the DGEG.

6.1 RESULTS OF FLEXIBILITY NEEDS ASSESSMENT

SYSTEM FLEXIBILITY NEEDS

The main indicator analysed in the study concerns the system flexibility needs for RES integration, which are linked to reducing RES curtailment, with a view to meeting energy policy objectives.

In accordance with Article 8 of the FNAM, the TSO estimated the flexibility needs for integrating RES. The figures presented in Table 8 correspond to the range of RES curtailment values identified for the different scenarios assessed.

Table 8 – RES curtailment

Type	Indicator	Target year	RES curtailment [TWh]	RES curtailment [%[78]]
System	RES integration	2030	2.7 – 4.3	3 – 5.5
		2035	1.4 – 6	1.2 – 5.8

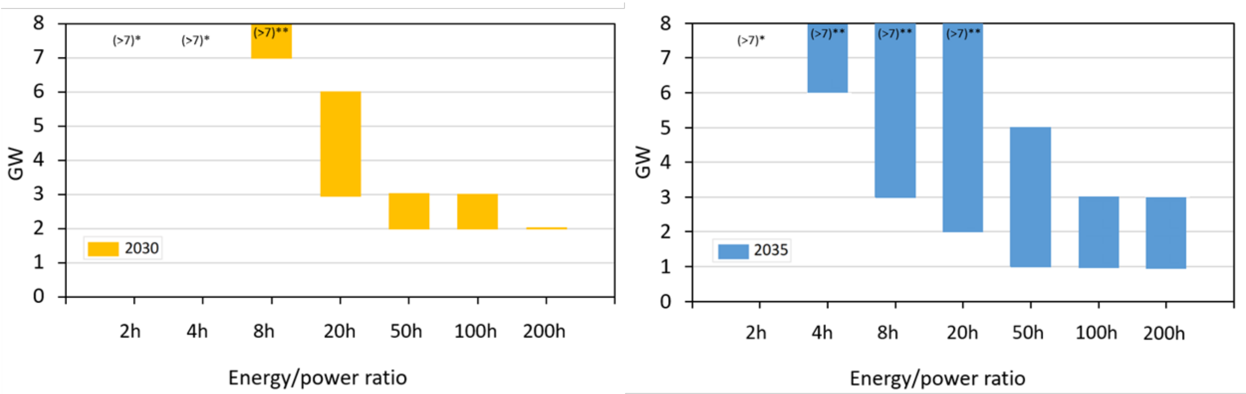
[78] Percentage of RES curtailment as a share of total RES production in each scenario.

As mentioned in sections 3.4 and 4.1, the NECP does not define a maximum acceptable value for RES curtailment, and it was not possible to identify this value by other means. Consequently, flexibility needs have been defined as the amount of energy that the system will need to absorb in order to offset this curtailment. Thus, the results obtained represent an upper bound on the system's flexibility needs for RES integration, insofar as allowing for some level of curtailment may be a more cost-effective solution[79].

When it comes to characterising the identified RES curtailment, it should be noted that it occurs mainly between 8 am and 6 pm, which correspond to the periods with the highest proportion of solar power in the generation portfolio. In terms of percentage, the identified curtailment is consistently less than 6% of total RES generation across the various scenarios.

Subsequently, in accordance with the provisions of the FNAM, the TSO assessed the resources required to meet the identified needs. To this end, flexibility resources with energy-to-power ratios of 2h, 4h, 8h, 20h, 50h, 100h and 200h were considered, and the additional capacity that would need to be installed to reduce RES curtailment to zero or to values very close to zero was identified.

Figure 8 – Ranges of additional capacity required (GW), by resource type, for 2030 and 2035[80]



* For all scenarios, a need for additional capacity of > 7 GW was identified.
** At least one scenario was identified in which additional capacity of more than 7 GW is required.

[79] An example of this is the participation of RES generation in ancillary services markets. This flexibility, which is necessary for system management, will result in some waste of renewable power, but in certain situations it may be the most efficient solution.

[80] For the purposes of creating this figure, it was considered the additional capacity needed to reduce curtailment to 250 GWh.

Compared to the baseline scenario (target year 2030), it was concluded that, using resources with energy-to-power ratios between 2 and 8 hours, in most cases, additional installed capacity of more than 7 GW would be needed to meet the identified flexibility needs. Assuming technologies with a ratio of 50 hours, it is estimated that by 2030, with additional installed capacity ranging from 2 GW to 3 GW, RES curtailment would be virtually eliminated. This value decreases when considering resources with higher ratios, but even when considering a resource with a ratio of 200 hours, for both scenarios considered, the installation of additional capacity between 1 GW and 3 GW will always be necessary[81]. As mentioned, these were the capacity figures identified to reduce curtailment to zero or to levels very close to zero. However, it should be emphasised that the analysis carried out makes it possible to identify the additional capacities required should a maximum acceptable level of RES curtailment be determined. These figures will be lower than those identified here.

It should also be emphasised that the approach used in this analysis does not allow for the complementarity of the various flexibility resources to be taken into account. The identified needs should, naturally, be met through the simultaneous use of a varied portfolio of resources that allows the benefits and added value of each technology to be harnessed.

The results presented are strongly influenced by the assumptions underlying the scenarios used in this assessment. These scenarios are subject to a significant degree of uncertainty, both due to the long-term nature of the analysis and to the actual developments that have occurred in the SEN, compared to the objectives established in the updated NECP on which they were based. Accordingly, two sensitivity analyses were conducted on the baseline scenarios. The first sensitivity analysis considered a lower interconnection capacity compared to that assumed in the baseline scenarios, limiting it to 10% of the total capacity initially projected. The second sensitivity analysis considered a lower installed capacity of electrolysers and offshore wind power than that projected in the NECP.

The first sensitivity analysis sought to assess the system's flexibility needs in a scenario close to that of an isolated system. The very significant increase in the identified flexibility needs demonstrates the importance of the interconnection as a source of flexibility for the system. The second sensitivity analysis

[81] The resources analysed here should be viewed from a technologically neutral perspective and are not limited to the most common storage technologies, such as electrochemical batteries or hydro storage.

sought to assess the impact of a slower-than-expected development in generation and demand compared to the NECP scenarios. Despite considering a lower installed renewable capacity, this sensitivity analysis resulted in an increase in flexibility needs, since the reduction in electrolyser capacity has a greater impact, given that the study's assumptions treat them as flexible loads.

Table 9 – RES curtailment – sensitivity analyses

Type	Indicator	Target year	Sensitivity analysis	RES curtailment [TWh]
System	RES Integration	2030	Sensitivity 1	7.2 – 12.7
			Sensitivity 2	5.4 – 5.8
		2035	Sensitivity 2	6.7 – 8.1

In terms of system needs, flexibility needs relating to generation ramps were also identified. The system's inability to respond to these generation ramps and to absorb their impacts may, amongst other things, lead to the need to increase RES curtailment to ensure system balance.

As can be seen from the Table 10, the uncovered flexibility needs are not significant. This implies that, given the scenarios and assumptions adopted in this study, the flexibility resources expected to be available in the selected target years will be sufficient to meet the ramping needs.

Table 10 – Ramping flexibility needs

Type	Indicator	Target year	Direction	Average value of uncovered needs [MW]	Uncovered needs [MWh]
System	Ramping needs	2030	upward	0 – 0.17	0 – 1,484
			downward	0	0
		2035	upward	0 – 0.03	0 – 293.4
			downward	0	0

FNAM also stipulates that short-term flexibility needs must be identified, relating to the ability to respond to generation forecast errors. Given the approach taken in this study, and the assumptions and data used, the TSO considered that applying the methodology would not yield representative results. Consequently, no such needs were determined.

NETWORK FLEXIBILITY NEEDS

With regard to network flexibility needs, it was concluded that no such needs were identified at the transmission network level.

As regards the flexibility needs of the distribution network, the DSO analysis, based on a high-level methodology described in section 2.3.2.2 and in Annex I, resulted in the figures presented in Table 11.

Table 11 – Network flexibility neds

Type	Indicator	Target year	Direction	Sum of maximum power [MW]	Expected average energy value [MWh]
Network	Transmission network needs	2030	Upward	0	0
			Downward	0	0
		2035	Upward	0	0
			Downward	0	0
	Distribution network needs	2030	Upward	48.7	57.3
			Downward	0	0
		2035	Upward	56.8	66.9
			Downward	0	0

The needs identified in the distribution network are mainly due to the emergence of network constraints, namely the worsening of congestion or network assets approaching their operational limits, both in terms of thermal capacity and voltage control, particularly at specific points in the distribution network. This stems from changes in load profiles within the distribution network, resulting from growth in electricity demand and the progressive electrification of consumption.

It should be noted that, although this study is subject to a number of methodological assumptions and limitations that prevent it from achieving the desired level of robustness and detail, it contributes to quantifying flexibility needs in a distinct and complementary scope to those analysed in the context of resource adequacy studies, namely the ERAA and the RMSA, thereby enabling a better identification of the actual flexibility needs of the SEN.

BARRIERS TO FLEXIBILITY

In line with ACER Recommendation No. 01/2026, an assessment was carried out to determine whether there were any barriers to the entry of flexibility resources into the system. Overall, it was concluded that, amongst the aspects it was possible to assess, although some opportunities for improvement were identified, there are no significant barriers to the entry of flexibility resources into the system that are not already being addressed by measures aimed at mitigating them.

6.2 NEXT STEPS

Article 19f of Regulation (EU) 2019/943 stipulates that, no later than six months after the submission of this report, each Member State must set an indicative national target for non-fossil flexibility, including the specific contributions from demand response and storage towards achieving that target. This target must also be reflected in the integrated national power and climate plans.

Thus, the completion of this report marks the start of the deadline[82] for setting these targets, which must take into account the conclusions of this report, without prejudice to the conclusions of other relevant studies or other energy policy instruments that may contribute to a better identification of flexibility needs, thereby underpinning the Member State's decision in this matter[83]. In this context, it is important to emphasise that, in accordance with the methodology approved for this purpose, the results presented in this report are based on the ERAA 2025 scenarios, which do not fully capture the specific characteristics of SEN.

Given the limited experience with this type of analysis – this being the first edition of this exercise – a number of opportunities for improvement have been identified for future editions:

- Develop an approach that enables the identification of a maximum acceptable level of RES curtailment, with a view to identifying RES integration flexibility needs in a more robust manner, that takes into account the dimension of economic efficiency;

[82] In accordance with Article 19f of Regulation (EU) 2019/943, considering the date of submission of this report, the deadline for setting these targets is 25 January 2027.

[83] In this scope Its relevant to highlight, for example, the future National Storage Strategy.

- Assess the feasibility of conducting the study based on the economic dispatch of a national resource adequacy study or by considering a greater number of ERAA weather scenarios, thereby increasing the representativeness of the analysis and enabling, amongst other things, the identification of short-term flexibility needs;
- Develop the methodology for identifying distribution network needs, with a possible adjustment to the temporal, spatial and voltage-level granularity, to enable a more disaggregated and detailed analysis;
- Develop an approach to identifying and describing potential flexibility resources capable of meeting the identified flexibility needs;
- Monitor the evolution of the actual participation of different types of resources in flexibility markets;
- Develop the analytical methodologies used, drawing on the results of the assessment to be carried out by ACER at European level and on examples of good practice to be gathered from the reports of other Member States;
- Encourage the involvement of the various stakeholders in the preparation of the study, something which was not possible in this first edition.

ANNEX

I. METHODOLOGY FOR DISTRIBUTION NETWORK FLEXIBILITY NEEDS

The assessment of distribution network flexibility needs presents challenges arising from the local nature of the constraints, the high level of uncertainty associated with the connection of new consumers, and decentralised generation.

The increasing level of uncertainty as the forecasting horizon lengthens – resulting from the evolution of multiple structural and cyclical factors – influences the behaviour of the power system, making it more complex to produce a robust estimate of long-term flexibility volumes, which is necessary for assessing needs in the target years selected for this study (2030 and 2035).

In particular, as the analyses of flexibility needs already carried out under the PDIRD-E 2024 do not include the selected target years, the DSO considered it necessary to develop a specific, high-level methodology for this horizon, based on extrapolations.

DEFINING THE SCOPE OF THE FLEXIBILITY NEEDS ASSESSMENT

The exercise to estimate the distribution network flexibility needs focused on situations falling within the scope of the PDIRD-E, where the need for intervention arises from overloads, voltage problems or other constraints associated with increased power flows through the network. In these cases, flexibility may constitute a cost-effective alternative to traditional network reinforcement investments, in line with the principles established by Decree-Law No. 15/2022 of 14 January, which promotes the adoption of efficient solutions and the consideration of alternatives to conventional network development.

It should be added that connections subject to restrictions were not taken into account when quantifying flexibility needs, as these relate to network access conditions defined at the time of connection, which are already factored into the planning process. Furthermore, as they are assessed on a case-by-case basis, it is difficult to identify, in advance and systematically, flexibility needs directly associated with this type of access. Consequently, these were not considered as additional flexibility needs as set out in the FNAM methodology.

Outlook for the evolution of flexibility needs in the context of network development

The quantification of flexibility needs depends, in each period, on the network's utilisation status. However, in this analysis, the DSO did not consider that the use of flexibility solutions could indefinitely sustain the postponement of structural investments in the network, given that load trends tend to progressively exacerbate the magnitude and frequency of network constraints, as well as the risk associated with their management. In this study, the DSO considered that, beyond a certain threshold, this risk becomes incompatible with the required levels of safety and service quality, and mitigating it solely through flexibility mechanisms is no longer acceptable. Indeed, flexibility is understood as a transitional tool for managing constraints, enabling specific network situations to be accommodated as the network evolves over time.

Thus, the constraints identified, which may initially be addressed through flexibility solutions, must be resolved structurally through the natural development of the network, supported by the progressive implementation of investments to reinforce it.

Flexibility needs associated with reduced generation/increased demand

Although the national legal framework, namely Decree-Law No. 15/2022, provides for the possibility of limiting the injection of generation into the network, whenever this proves necessary to ensure the safety and efficient operation of the power system, in this analysis, the DSO did not consider the identification of flexibility needs to mitigate constraints arising from the injection of generation, specifically in terms of reducing injection or increasing demand (downward needs).

This approach is justified by the current context of the distribution network, insofar as network capacity has, to date, been dimensioned and planned to fully accommodate the injection of power from renewable sources.

UNCERTAINTY ASSOCIATED WITH FORECASTING FLEXIBILITY VOLUMES AT THE DISTRIBUTION NETWORK LEVEL (TEMPORAL AND SPATIAL)

Constraints in the distribution network tend to be highly local in nature and exhibit a high degree of spatial granularity. They may occur within a small geographical area, such as the partial area of influence of a substation or even a medium-voltage circuit.

Consequently, flexibility volumes are highly sensitive, depending on factors such as the natural evolution of load (and its territorially asymmetric nature), the location of new network connections, the technical characteristics of the existing infrastructure, and the associated temporal profiles of demand and generation. This challenge is not intrinsic to flexibility itself, but rather to the network planning process, highlighting the importance of developing load evolution forecast models that incorporate high levels of temporal and spatial granularity.

From the perspective of specifying flexibility needs, this characteristic generally entails conducting studies with a detailed characterisation of the network and its constraints, supported by computationally intensive probabilistic methods, using a case-by-case approach (a procedure adopted in the context of the PDIRD-E). Given the inherent complexity of this type of analysis, and considering that the aim is to project medium- and long-term needs across the distribution network — in a context characterised by increasing levels of uncertainty as the time horizon extends — the DSO opted for an extrapolative approach to estimating flexibility needs, drawing on its accumulated experience.

METHODOLOGICAL DETAILS

Given the uncertainty inherent in the evolution of operating conditions and the high spatial variability of the identified needs, the DSO opted for a more aggregated (high-level) analytical approach:

I. As part of the preparation of the PDIRD-E 2024, flexibility needs were characterised to eliminate constraints as an alternative to network reinforcement investment projects. These projects have different scopes and are classified into specific investment sub-programmes (Network Development, Security of Supply to District Capitals and Asset Rehabilitation), consequently, their flexibility needs have different characteristics.

II. Building on this characterisation, the DSO assessed the average volumes (power and energy) of the flexibility scenarios considered in the PDIRD-E. For the needs in each sub-programme, the maximum power volumes of the largest needs in each flexibility scenario were summed, and this value was divided by the number of scenarios. The same procedure was followed for the expected activation energy of each case. In this way, the ORD established the typical average quantities of power and energy characteristic of a flexibility case within the context of the PDIRD-E.

III. Furthermore, the PDIRD-E 2024 also includes a characterisation of the distribution network for the year 2030, at the HV/MV substation level, comprising the installed transformer capacity, the annual peak load, the natural peak load and the maximum utilisation of these facilities.

IV. Based on the underlying assumptions of the RMSA-E 2024, namely the expected evolution of the SEN peak load from 2025 to 2040, the DSO calculated the average annual growth rates for the periods 2030–2035 (CAGR[84] = 1.4%) and between 2035 and 2040 (CAGR = 0.6%).

V. Using these rates, the DSO projected the utilisation of HV/MV substations, taking 2030 as the starting point. The natural peak load of each substation is multiplied by the rate for the respective period, yielding the forecast peak for the following year. The peak for the following year is expected to increase by the same absolute value as the natural peak load for that year. Once the peak for the following year has been determined, it is possible to estimate the forecast utilisation of the HV/MV substations.

VI. The DSO then carried out the analysis based on the estimated utilisation calculated for the HV/MV substations. It defined upper and lower utilisation limits, between which it acknowledges the existence of network constraints that can be managed through the use of flexibility. Following this iterative process, when a substation reaches a utilisation level above the defined upper limit, the DSO assumes that a level of constraints would be reached which could not be managed through the use of flexibility solutions. Tehrefore, in that year, the completion of the traditional network reinforcement investment must be ensured.

VII. Finally, for each year, the DSO recorded the number of identified cases where the constraints were deemed manageable through the use of flexibility, and calculated the distribution network's flexibility needs by multiplying these by the standardised average volumes determined in II.

[84] Compound Annual Growth Rate (CAGR).

II. CURRENT STATUS OF THE NATIONAL ELECTRIC SYSTEM

This annex provides further details on the current status of the national power system, through the following Tables and Figures.

Table 12 – Installed capacity in the SEN in 2024 and 2025 [MW][42]

	2025	2024	Change
Total	**23,800**	**22,836**	**964**
Renewable	**19,360**	**18,385**	**975**
Hydropower	8,385	8,385	0
Wind	5,444	5,408	36
Biomass	692	707	-15
Cogeneration	343	352	-9
Solar	4,839	3,885	954
Waves	0	0	0
Non-renewable	**4,421**	**4,444**	**-23**
Natural gas	4,396	4,419	-23
Cogeneration	567	590	-23
Other	25	25	0
Cogeneration	25	25	0
Batteries	**19**	**7**	**12**
Total storage	**3,604**	**3,592**	**12**
Pumping	3,585	3,585	0
Batteries	19	7	12
Dispatchable power plants[85]	**12,989**	**12,126**	**863**
Non-dispatchable power plants	**10,811**	**10,711**	**100**

[85] Power plants authorised to provide ancillary services.

Figure 9 – Breakdown of generation in 2025[42]

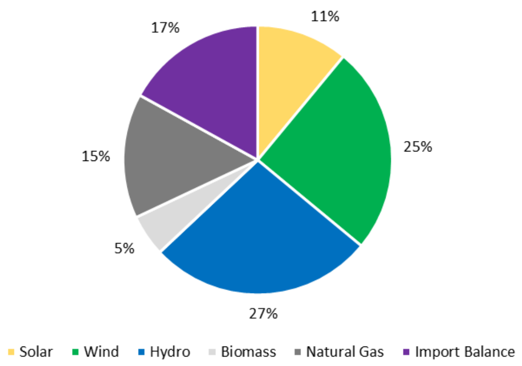
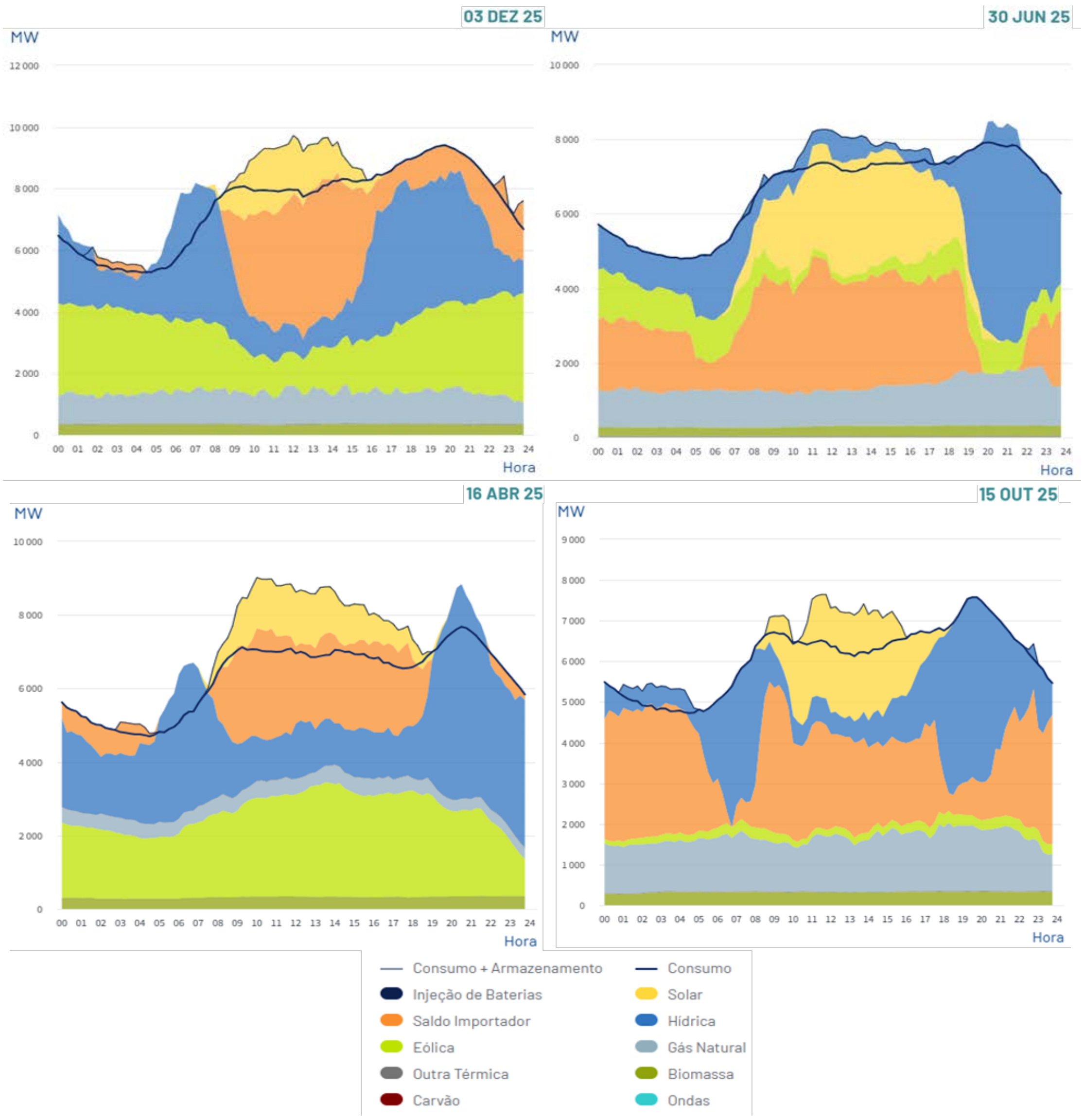


Table 13 – Domestic demand supply in 2024 and 2025 [GWh] [42]

	2025	2024	Change (%)
Total generation	**48,878**	**45,685**	**7**
Renewable generation	**36,916**	**36,747**	**0**
Hydropower	14,504	14,540	0
Wind	13,473	14,143	-5
Biomass	2,807	3,156	-11
Cogeneration	1,188	1,334	-11
Solar	6,132	4,908	25
Waves	0	0	-
Non-renewable generation	**7,874**	**5,114**	**54**
Natural Gas	7,644	4,871	57
Cogeneration	1,222	1,547	-21
Other	230	243	-5
Cogeneration	23	28	-18
Generation from storage	**4,088**	**3,824**	**7**
Pumping	4,081	3,824	7
Batteries	7	0	-
Demand for storage	**5,126**	**4,744**	**8**
Pumping	5,117	4,744	8
Batteries	9	0	-
Import Balance	**9,301**	**10,429**	**-11**
Imports	11,378	13,081	-13
Exports	2,077	2,652	-22
Total demand	**53,053**	**51,370**	**3**
Dispatchable Generation	**24,939**	**20,666**	**21**
Non-dispatchable generation	**23,939**	**25,020**	**-4**

Figure 10 – Load diagrams for peak days in winter, summer, spring and autumn 2025[86]

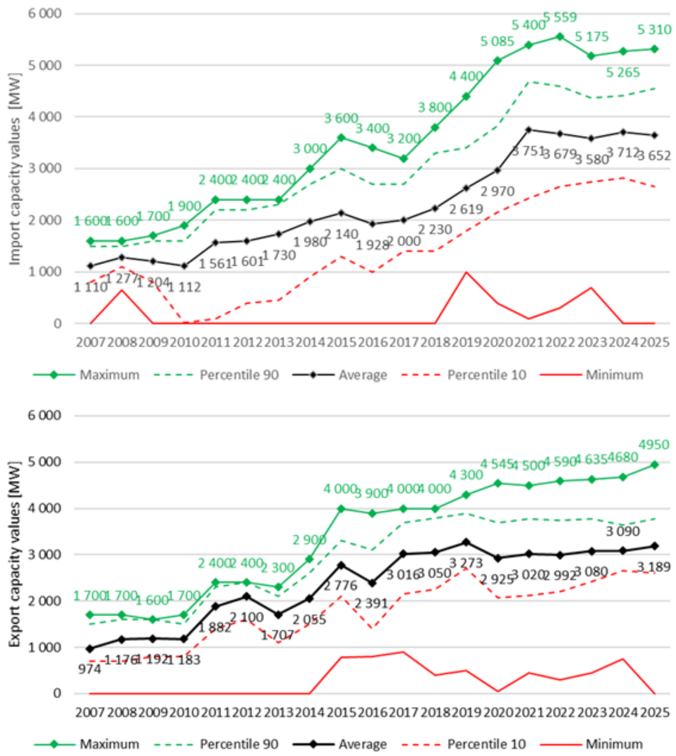


[86] Diagrams taken from [REN's Datahub](#).

Figure 11 – Interconnection lines between Portugal and Spain and the thermal capacities of the lines[87]

Linha	Capacidade térmica mínima [MVA]
Linhas a 400 kV:	
Alto Lindoso – Cartelle 1	1499
Alto Lindoso – Cartelle 2	1499
Lagoaça – Aldeadávila	1469
Falagueira – Cedillo	1386
Alqueva – Brovales	1280
Tavira – Puebla de Guzman	1386
Linhas a 220 kV:	
Pocinho – Aldeadávila 1	374
Pocinho – Aldeadávila 2	374
Pocinho – Saucelle	360
Total	9627

Figure 12 – Trends in available interconnection capacity – Imports and Exports



[87] Taken from the document describing the interconnections as at 31 December 2025.

III. FLEXIBILITY NEEDS – RESULTS AND ADDITIONAL DETAILS

System flexibility needs – RES integration, Article 8 of the FNAM

Year 2030

Figure 13 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 ED for 2030 (WS 23)

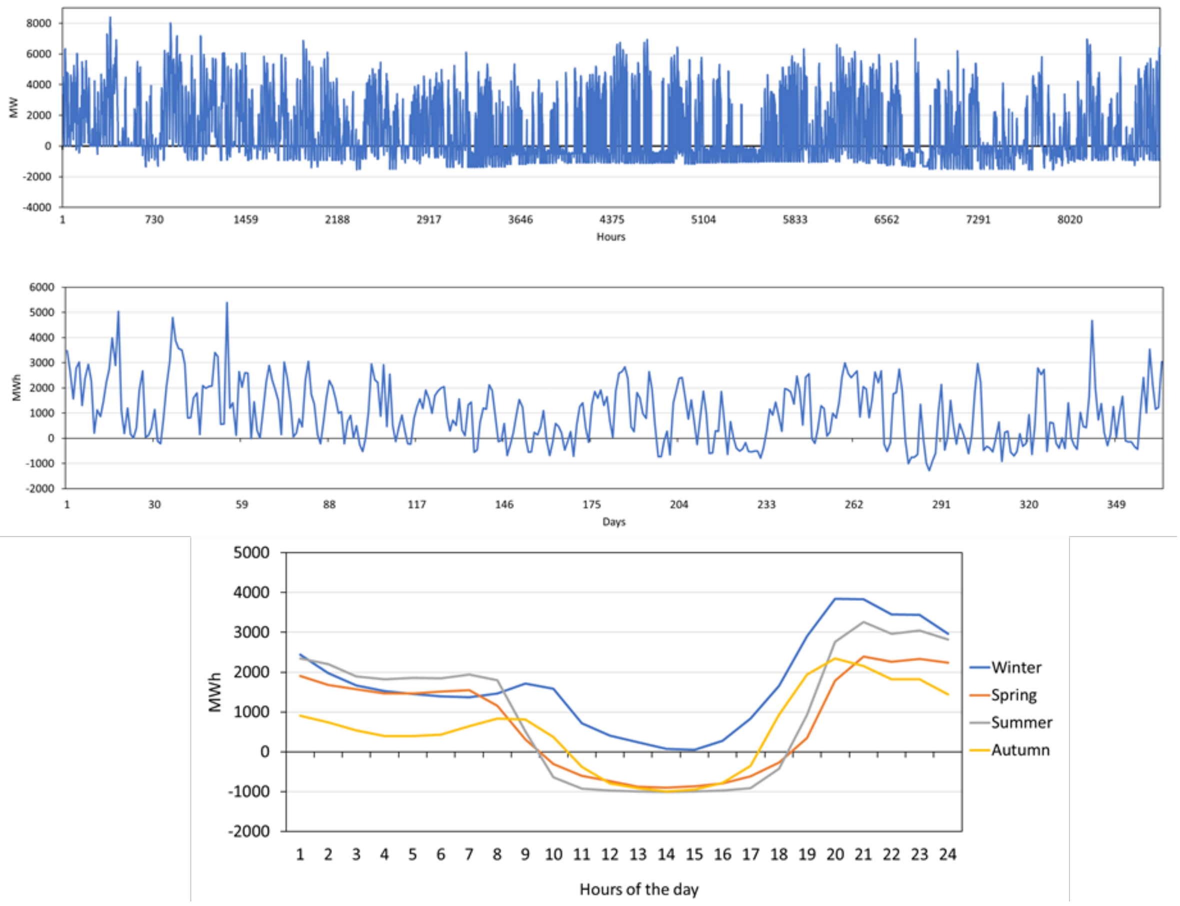


Figure 14 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 ED for 2030 (WS 27)

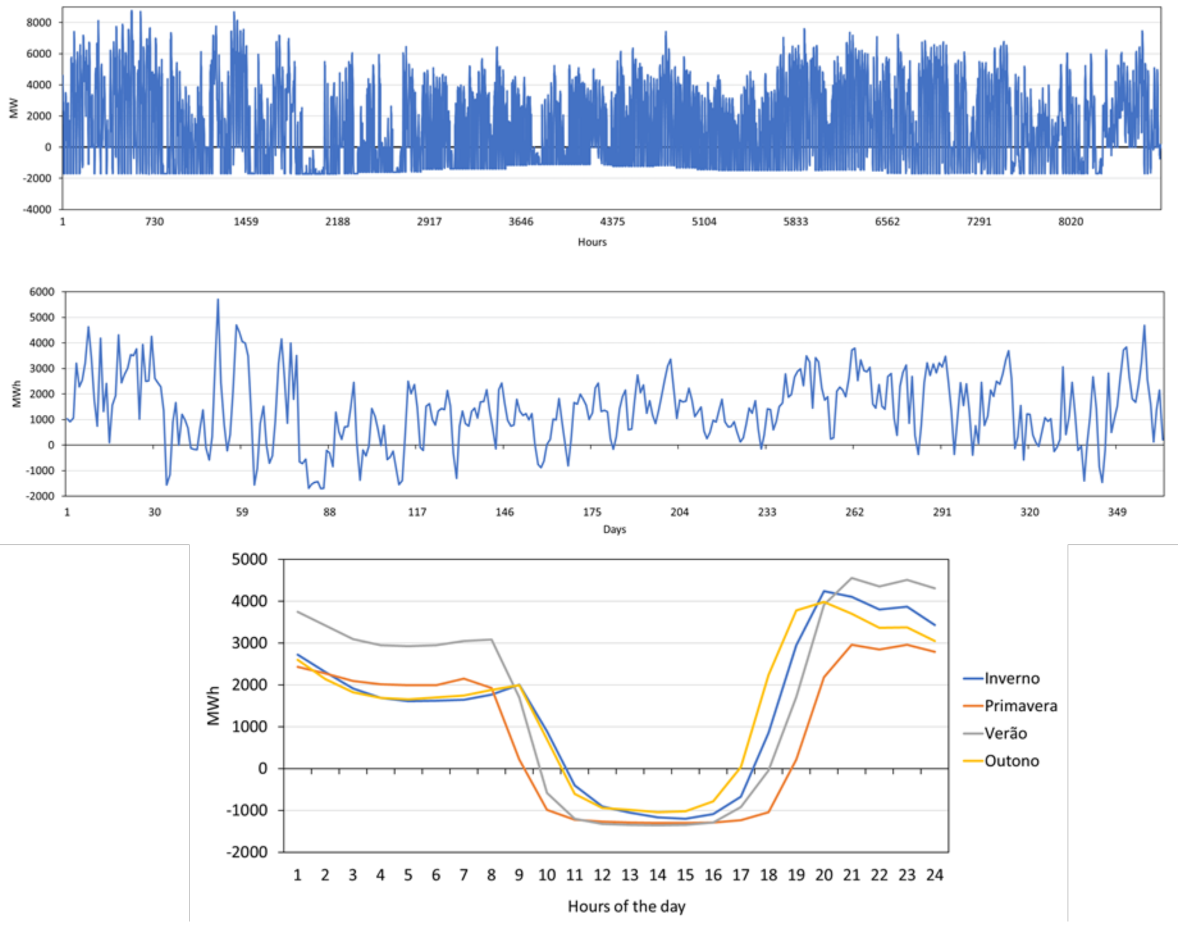


Figure 15 – Daily, monthly and seasonal RES curtailment (2030, WS 23)

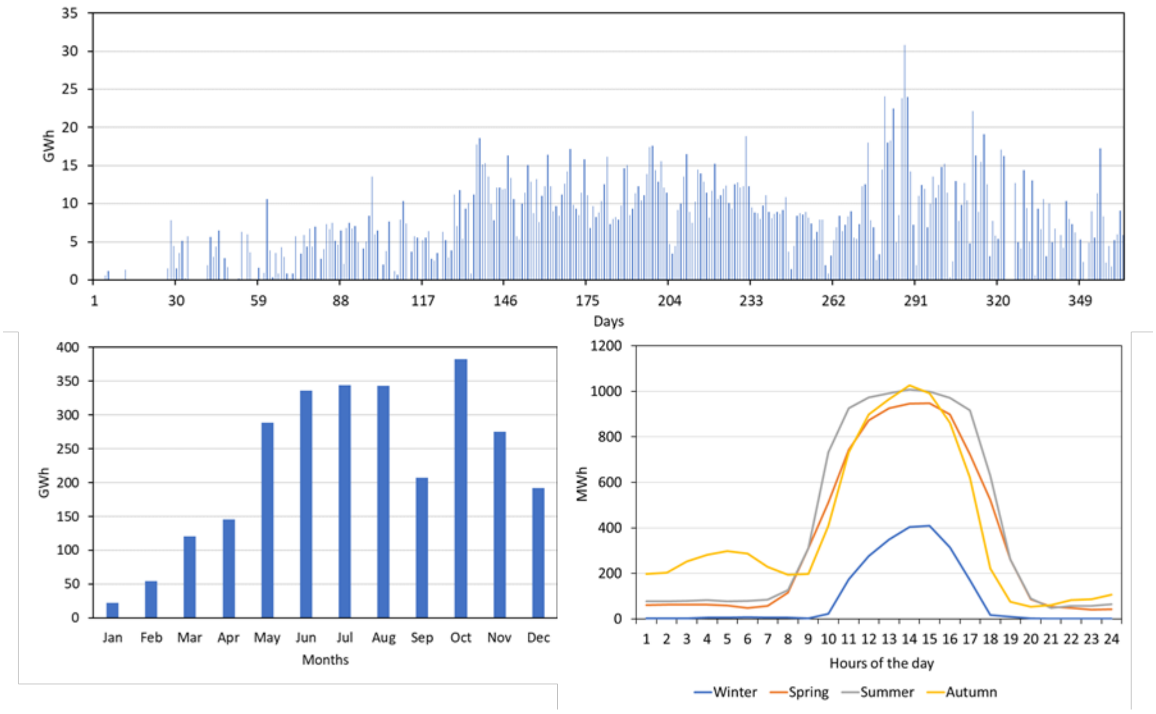


Figure 16 – Daily, monthly and seasonal RES curtailment (2030, WS 23, sensitivity 1)

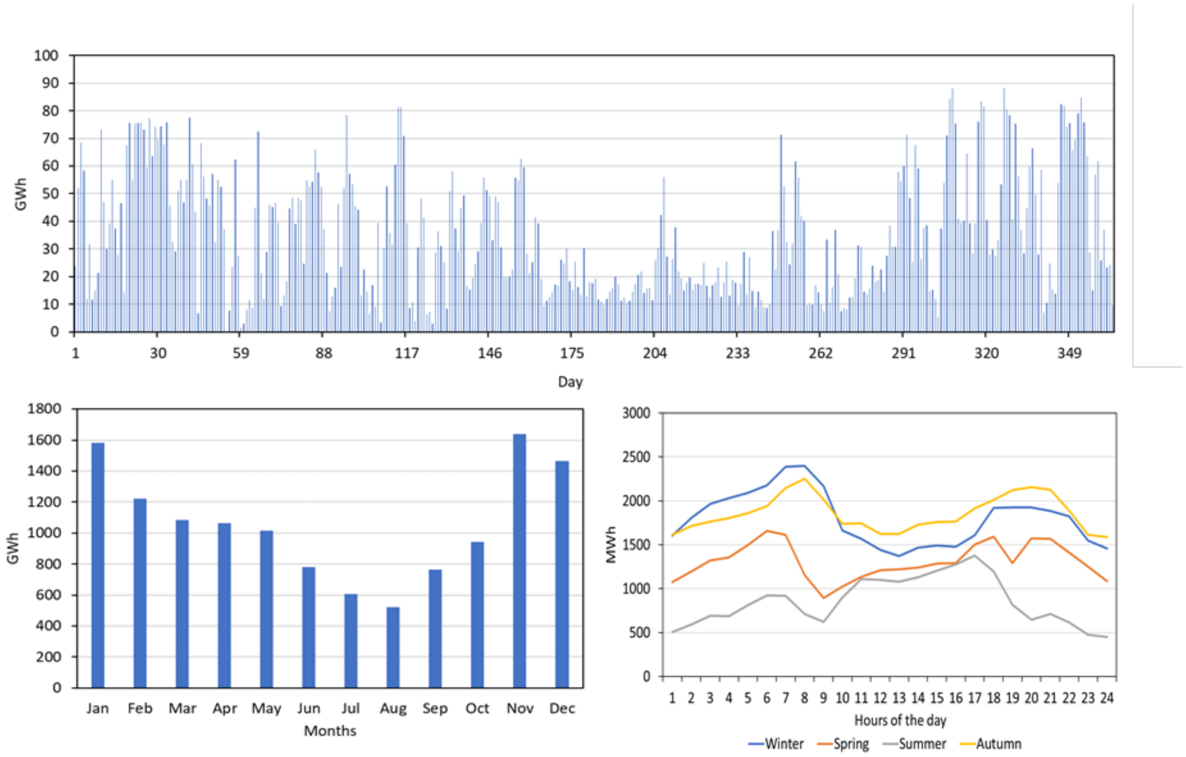


Figure 17 – Daily, monthly and seasonal RES curtailment (2030, WS 23, sensitivity 2)

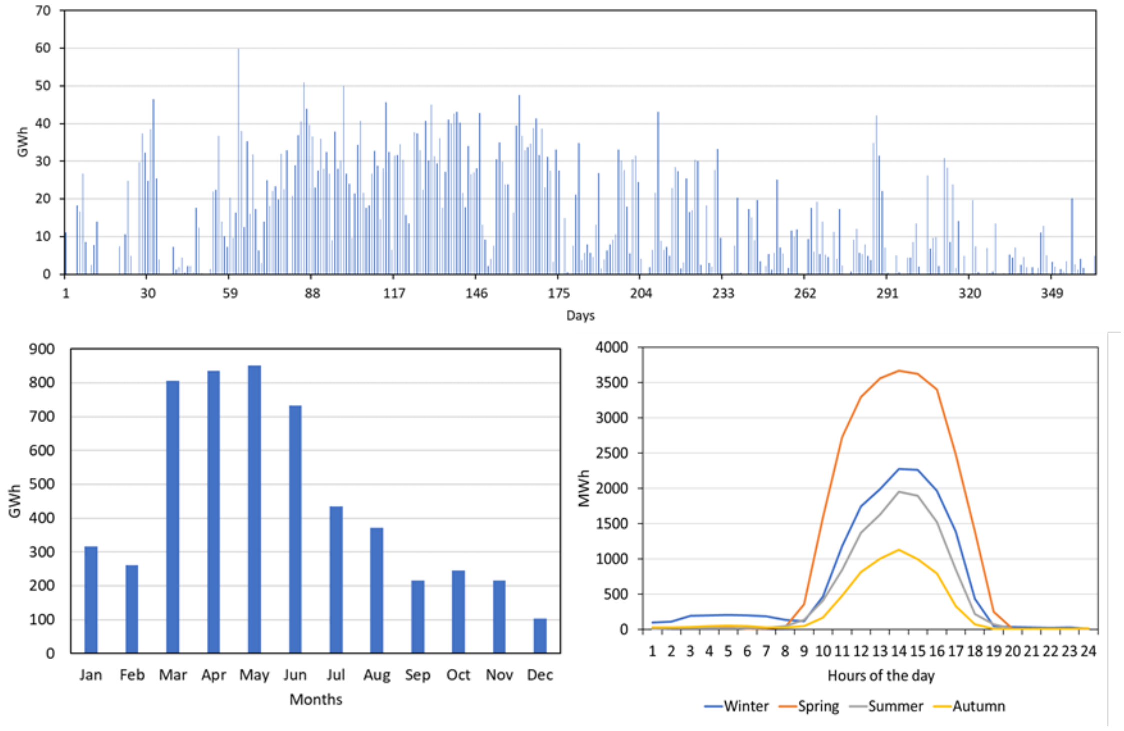


Figure 18 – Daily, monthly and seasonal RES curtailment (2030, WS 27)

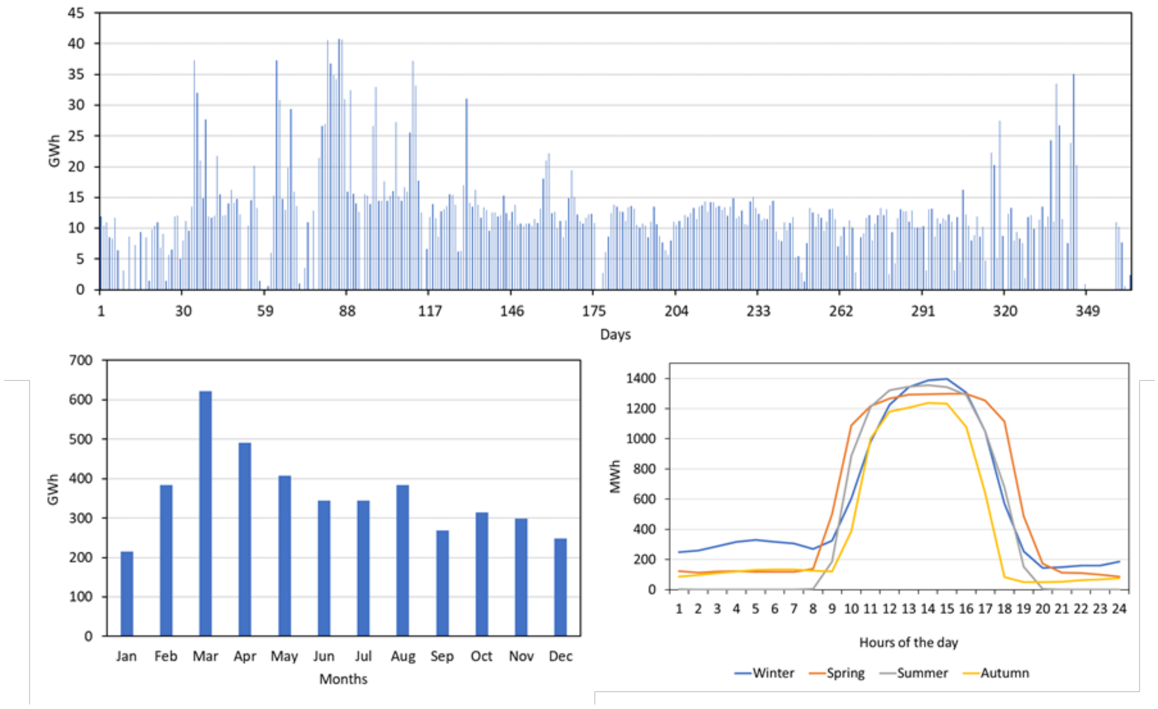


Figure 19 – Daily, monthly and seasonal RES curtailment (2030, WS 27, sensitivity 1)

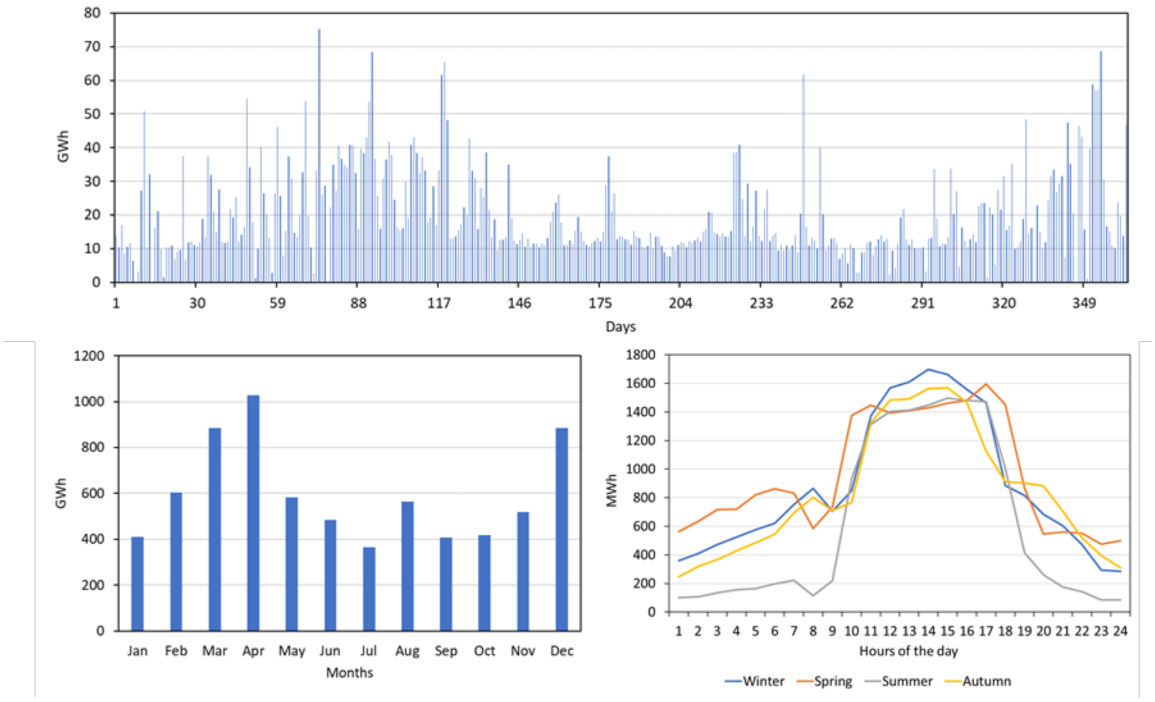


Figure 20 – Daily, monthly and seasonal RES curtailment (2030, WS 27, sensitivity 2)

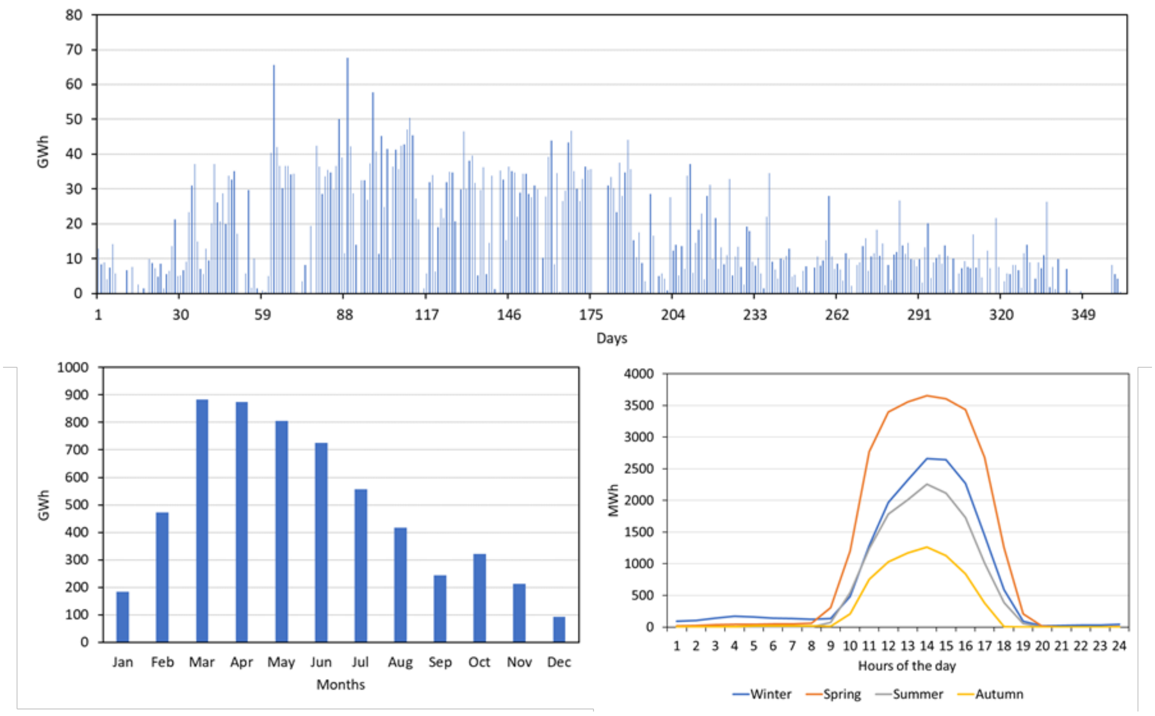


Figure 21 – Daily, monthly and seasonal RES curtailment (2030, WS 35, sensitivity 1)

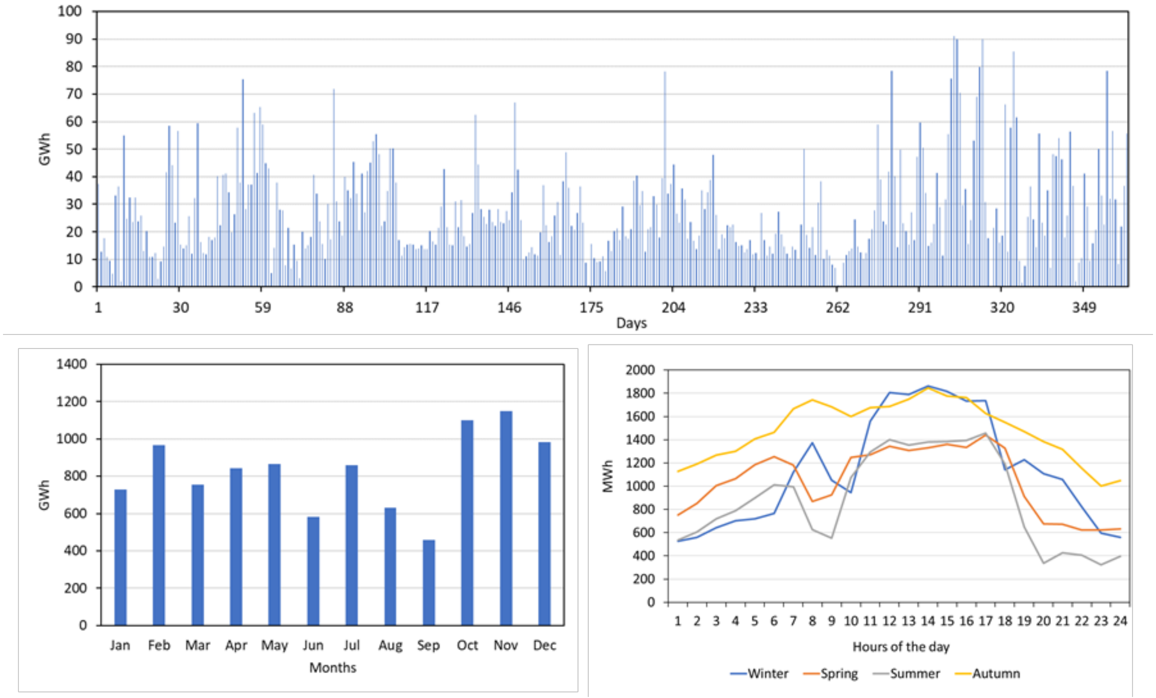


Figure 22 – Daily, monthly and seasonal RES curtailment (2030, WS 35, sensitivity 2)

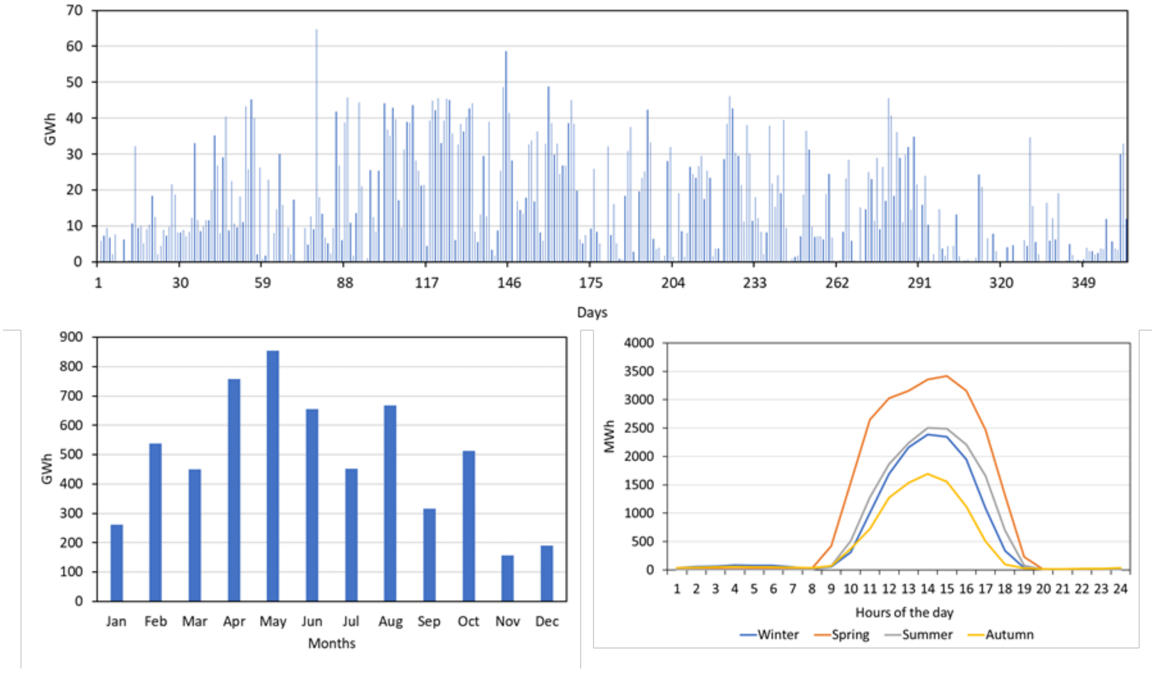
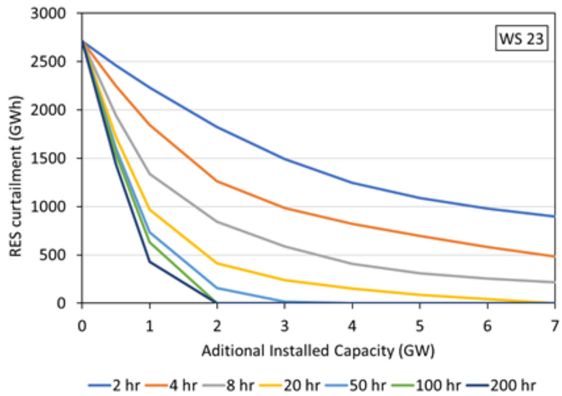
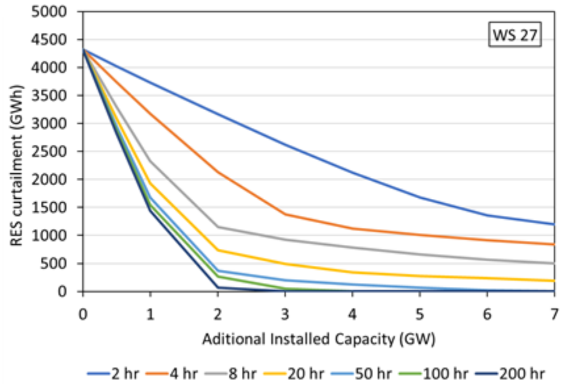


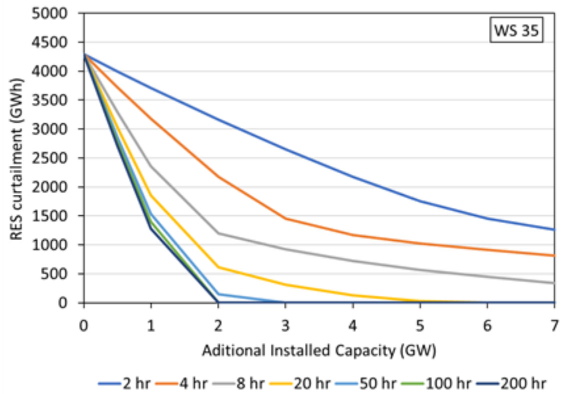
Figure 23 – RES curtailment taking into account the energy-to-power ratio of flexibility resources for 2030, scenarios WS 23, 27 and 35



Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	2711	2711	2711	2711	2711	2711	2711
0,5	2460	2245	1941	1719	1601	1537	1437
1,0	2230	1843	1338	970	734	629	429
2,0	1821	1261	846	413	157	0	0
3,0	1492	986	586	237	17	0	0
4,0	1246	823	410	152	0	0	0
5,0	1087	696	312	86	0	0	0
6,0	981	581	256	44	0	0	0
7,0	896	482	220	0	0	0	0

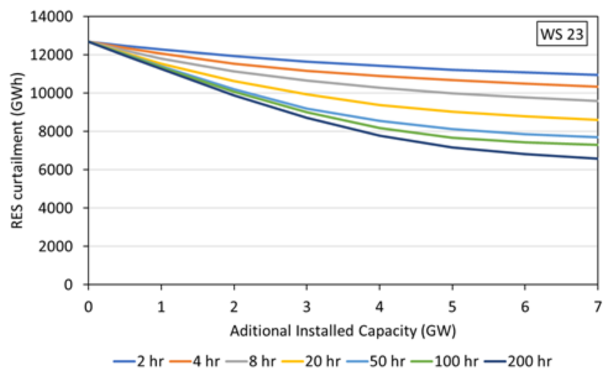


Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	4324	4324	4324	4324	4324	4324	4324
0,5	4022	3738	3294	3089	2952	2878	2826
1,0	3729	3175	2327	1936	1678	1547	1447
2,0	3162	2132	1154	733	371	267	67
3,0	2619	1372	927	496	203	47	0
4,0	2118	1122	783	343	126	0	0
5,0	1681	1008	663	275	70	0	0
6,0	1362	910	568	234	19	0	0
7,0	1195	837	503	194	0	0	0

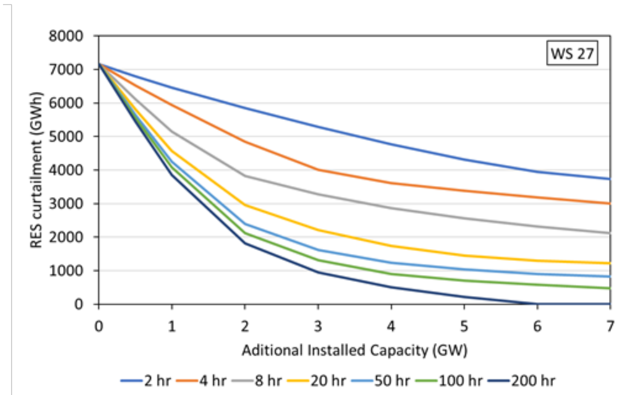


Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	4293	4293	4293	4293	4293	4293	4293
0,5	3993	3717	3288	3022	2848	2766	2707
1,0	3707	3177	2358	1854	1535	1395	1279
2,0	3163	2179	1201	614	147	0	0
3,0	2653	1455	919	310	0	0	0
4,0	2172	1166	720	127	0	0	0
5,0	1756	1025	564	24	0	0	0
6,0	1449	911	444	0	0	0	0
7,0	1262	811	337	0	0	0	0

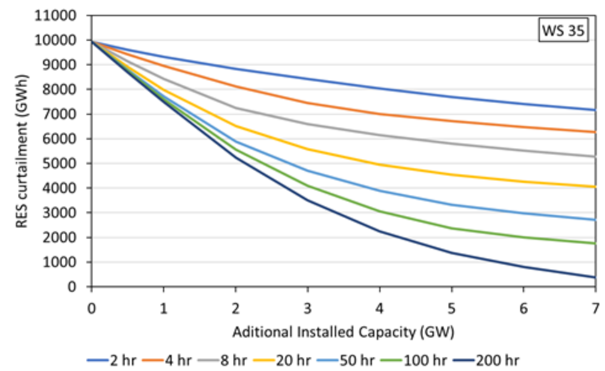
Figure 24 – RES curtailment taking into account the energy-to-power ratio of flexibility resources for 2030, scenarios WS 23, 27 and 35, sensitivity 1



GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	12 691	12 691	12 691	12 691	12 691	12 691	12 691
0,5	12 480	12 373	12 231	12 094	12 046	12 021	11 971
1,0	12 284	12 077	11 802	11 527	11 409	11 359	11 259
2,0	11 932	11 545	11 144	10 629	10 200	10 081	9 881
3,0	11 652	11 164	10 656	9 928	9 202	9 000	8 700
4,0	11 419	10 890	10 282	9 380	8 545	8 172	7 772
5,0	11 226	10 674	9 998	9 021	8 133	7 676	7 176
6,0	11 072	10 485	9 769	8 793	7 854	7 423	6 823
7,0	10 950	10 333	9 591	8 618	7 693	7 289	6 589

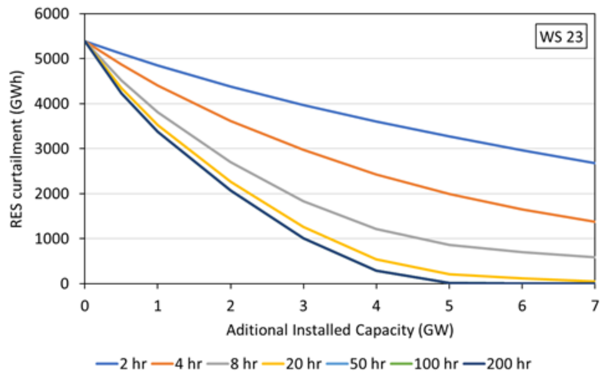


GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	7152	7152	7152	7152	7152	7152	7152
0,5	6792	6523	6111	5809	5639	5551	5443
1,0	6462	5935	5142	4568	4258	4081	3860
2,0	5855	4850	3822	2951	2388	2124	1812
3,0	5293	4003	3279	2211	1610	1310	949
4,0	4770	3611	2869	1741	1243	902	502
5,0	4310	3378	2556	1453	1031	709	209
6,0	3953	3180	2311	1292	899	585	0
7,0	3730	2998	2114	1219	828	478	0

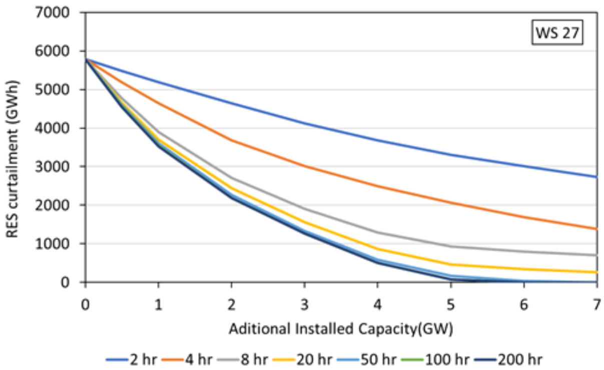


GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	9922	9922	9922	9922	9922	9922	9922
0,5	9603	9413	9142	8912	8791	8739	8686
1,0	9324	8950	8418	7969	7703	7598	7485
2,0	8831	8118	7251	6503	5883	5564	5227
3,0	8416	7442	6601	5577	4702	4101	3501
4,0	8037	7004	6139	4945	3891	3049	2249
5,0	7698	6720	5793	4531	3319	2364	1364
6,0	7401	6480	5507	4263	2968	1998	798
7,0	7160	6266	5272	4051	2720	1767	367

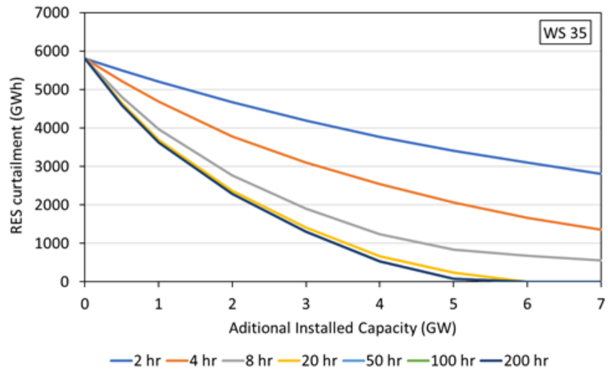
Figure 25 – RES curtailment taking into account the energy-to-power ratio of flexibility resources for 2030, scenarios WS 23, 27 and 35, sensitivity 2



GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	5390	5390	5390	5390	5390	5390	5390
0,5	5108	4865	4519	4340	4236	4226	4226
1,0	4848	4403	3809	3522	3369	3369	3369
2,0	4384	3619	2701	2270	2075	2075	2075
3,0	3972	2975	1829	1254	1012	1012	1012
4,0	3604	2428	1209	539	283	283	283
5,0	3271	1991	864	206	12	12	12
6,0	2965	1647	700	112	0	0	0
7,0	2682	1370	583	52	0	0	0



GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	5785	5785	5785	5785	5785	5785	5785
0,5	5477	5195	4779	4653	4603	4572	4547
1,0	5189	4642	3892	3698	3602	3545	3517
2,0	4638	3684	2706	2433	2268	2182	2182
3,0	4124	3012	1908	1555	1326	1258	1258
4,0	3678	2495	1288	865	586	501	501
5,0	3309	2060	925	467	165	75	75
6,0	3007	1696	797	347	40	0	0
7,0	2735	1383	710	266	0	0	0



GW \ Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	5810	5810	5810	5810	5810	5810	5810
0,5	5500	5219	4805	4644	4597	4597	4597
1,0	5208	4683	3960	3681	3619	3619	3619
2,0	4673	3776	2768	2369	2291	2291	2291
3,0	4191	3099	1907	1410	1309	1309	1309
4,0	3767	2546	1243	664	527	527	527
5,0	3406	2061	836	240	81	81	81
6,0	3094	1661	671	0	0	0	0
7,0	2812	1355	559	0	0	0	0

Table 14 – Detailed results for RES integration flexibility needs in 2030 (WS 23)

<table>
<tr><th>Type</th><th>Flexibility Needs</th><th>Indicator</th><th>Sub-Indicator</th><th></th><th>Value</th><th>Unit</th><th>Target Year</th><th>Scenario</th></tr>
<tr><td rowspan="20">System needs</td><td rowspan="20">RES integration</td><td>RES integration target</td><td>-</td><td rowspan="8"></td><td>0,0</td><td>TWh</td><td rowspan="20">2030</td><td rowspan="20">WS23</td></tr>
<tr><td rowspan="19">RES generation curtailment</td><td>RES generation curtailment</td><td>2,7</td><td>Total in TWh</td></tr>
<tr><td rowspan="3">Hourly timeframe</td><td>310,3</td><td>Average in MW</td></tr>
<tr><td>1552,5</td><td>Maximum in MW</td></tr>
<tr><td>0,0</td><td>Minimum in MW</td></tr>
<tr><td rowspan="3">Daily timeframe</td><td>7448,0</td><td>Average in MWh</td></tr>
<tr><td>30810,5</td><td>Maximum in MWh</td></tr>
<tr><td>0,0</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="12">Seasonal timeframe</td><td rowspan="3">Winter</td><td>91,2</td><td>Average in MWh</td></tr>
<tr><td>409,4</td><td>Maximum in MWh</td></tr>
<tr><td>0,0</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Spring</td><td>352,7</td><td>Average in MWh</td></tr>
<tr><td>948,2</td><td>Maximum in MWh</td></tr>
<tr><td>41,6</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Summer</td><td>405,3</td><td>Average in MWh</td></tr>
<tr><td>1008,4</td><td>Maximum in MWh</td></tr>
<tr><td>48,5</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Autumn</td><td>388,8</td><td>Average in MWh</td></tr>
<tr><td>1025,8</td><td>Maximum in MWh</td></tr>
<tr><td>53,9</td><td>Minimum in MWh</td></tr>
</table>

Table 15 – Detailed results for RES integration flexibility needs in 2030 (WS 23 – sensitivity 1)

Type	Flexibility Needs	Indicator	Sub-indicator		Value	Unit	Target years	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS23 - Sens. 1
		RES generation curtailment	RES generation curtailment		12,7	Total in TWh		
			Hourly timeframe		1452,8	Average in MW		
					4608,5	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		34866,4	Average in MWh		
					88297,5	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	1800,3	Average in MWh		
					2398,6	Maximum in MWh		
					1372,5	Minimum in MWh		
				Spring	1310,0	Average in MWh		
					1657,4	Maximum in MWh		
					891,1	Minimum in MWh		
				Summer	856,4	Average in MWh		
					1376,2	Maximum in MWh		
					450,0	Minimum in MWh		
				Autumn	1854,8	Average in MWh		
					2250,5	Maximum in MWh		
					1588,4	Minimum in MWh		

Table 16 – Detailed results for RES integration flexibility needs in 2030 (WS 23 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicador		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS23 - Sens. 2
		RES generation curtailment	RES generation curtailment		5,4	Total in TWh		
			Hourly timeframe		617,0	Average in MW		
					5437,3	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		14807,7	Average in MWh		
					59821,9	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	639,5	Average in MWh		
					2276,9	Maximum in MWh		
					9,7	Minimum in MWh		
				Spring	1107,7	Average in MWh		
					3667,1	Maximum in MWh		
					1,7	Minimum in MWh		
				Summer	463,5	Average in MWh		
					1956,2	Maximum in MWh		
					4,6	Minimum in MWh		
				Autumn	259,2	Average in MWh		
					1133,7	Maximum in MWh		
					7,3	Minimum in MWh		

Table 17 – Detailed results for RES integration flexibility needs in 2030 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS27
		RES generation curtailment	RES generation curtailment		4,3	Total in TWh		
			Hourly timeframe		495,0	Average in MW		
					1731,1	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		11879,5	Average in MWh		
					40775,2	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	565,8	Average in MWh		
					1397,7	Maximum in MWh		
					143,4	Minimum in MWh		
				Spring	569,3	Average in MWh		
					1297,5	Maximum in MWh		
					87,3	Minimum in MWh		
				Summer	451,5	Average in MWh		
					1354,5	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	85,5	Average in MWh		
					1236,7	Maximum in MWh		
					48,8	Minimum in MWh		

Table 18 – Detailed results for RES integration flexibility needs in 2030 (WS 27 – sensitivity 1)

Type	Flexibility Needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS27 - Sens. 1
		RES generation curtailment	RES generation curtailment		7,2	Total in TWh		
			Hourly timeframe		818,6	Average in MW		
					4855,2	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		19647,4	Average in MWh		
					75149,3	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	879,4	Average in MWh		
					1696,8	Maximum in MWh		
					285,0	Minimum in MWh		
				Spring	958,4	Average in MWh		
					1595,1	Maximum in MWh		
					474,8	Minimum in MWh		
				Summer	605,8	Average in MWh		
					1497,0	Maximum in MWh		
					83,7	Minimum in MWh		
				Autumn	833,9	Average in MWh		
					1569,0	Maximum in MWh		
					246,6	Minimum in MWh		

Table 19 – Detailed results for RES integration flexibility needs in 2030 (WS 27 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS27 - Sens. 2
		RES generation curtailment	RES generation curtailment		5,8	Total in TWh		
			Hourly timeframe		662,2	Average in MW		
					5713,1	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		15893,0	Average in MWh		
					67644,5	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	712,2	Average in MWh		
					2659,6	Maximum in MWh		
					19,6	Minimum in MWh		
				Spring	1100,6	Average in MWh		
					3652,4	Maximum in MWh		
					1,1	Minimum in MWh		
				Summer	550,5	Average in MWh		
					2256,5	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	287,2	Average in MWh		
					1264,7	Maximum in MWh		
					1,0	Minimum in MWh		

Table 20 – Detailed results for RES integration flexibility needs in 2030 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS35
		RES generation curtailment	RES generation curtailment		4,3	Total in TWh		
			Hourly timeframe		491,4	Average in MW		
					1724,0	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		491,4	Average in MWh		
					40671,6	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	506,4	Average in MWh		
					1496,2	Maximum in MWh		
					56,3	Minimum in MWh		
				Spring	569,7	Average in MWh		
					1285,7	Maximum in MWh		
					90,6	Minimum in MWh		
				Summer	490,4	Average in MWh		
					1316,7	Maximum in MWh		
					20,6	Minimum in MWh		
				Autumn	399,1	Average in MWh		
					1182,8	Maximum in MWh		
					54,4	Minimum in MWh		

Table 21 – Detailed results for RES integration flexibility needs in 2030 (WS 35 – sensitivity 1)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS35 - Sens. 1
		RES generation curtailment	RES generation curtailment		9,9	Total in TWh		
			Hourly timeframe		1135,8	Average in MW		
					4866,6	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		27259,3	Average in MWh		
					90973,0	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	1134,4	Average in MWh		
					1862,5	Maximum in MWh		
					525,9	Minimum in MWh		
				Spring	1049,3	Average in MWh		
					1440,3	Maximum in MWh		
					622,5	Minimum in MWh		
				Summer	883,0	Average in MWh		
					1456,4	Maximum in MWh		
					321,7	Minimum in MWh		
				Autumn	1479,2	Average in MWh		
					1845,5	Maximum in MWh		
					1000,2	Minimum in MWh		

Table 22 – Detailed results for RES integration flexibility needs in 2030 (WS 35 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2030	WS35 - Sens. 2
		RES generation curtailment	RES generation curtailment		5,8	Total in TWh		
			Hourly timeframe		665,1	Average in MW		
					5680,2	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		15962,8	Average in MWh		
					64791,7	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	578,3	Average in MWh		
					2389,2	Maximum in MWh		
					2,6	Minimum in MWh		
				Spring	1038,0	Average in MWh		
					3417,1	Maximum in MWh		
					4,7	Minimum in MWh		
				Summer	650,4	Average in MWh		
					2507,1	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	393,0	Average in MWh		
					1693,0	Maximum in MWh		
					15,3	Minimum in MWh		

<u>Year 2035</u>

Figure 26 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 ED for 2035 (WS 23)

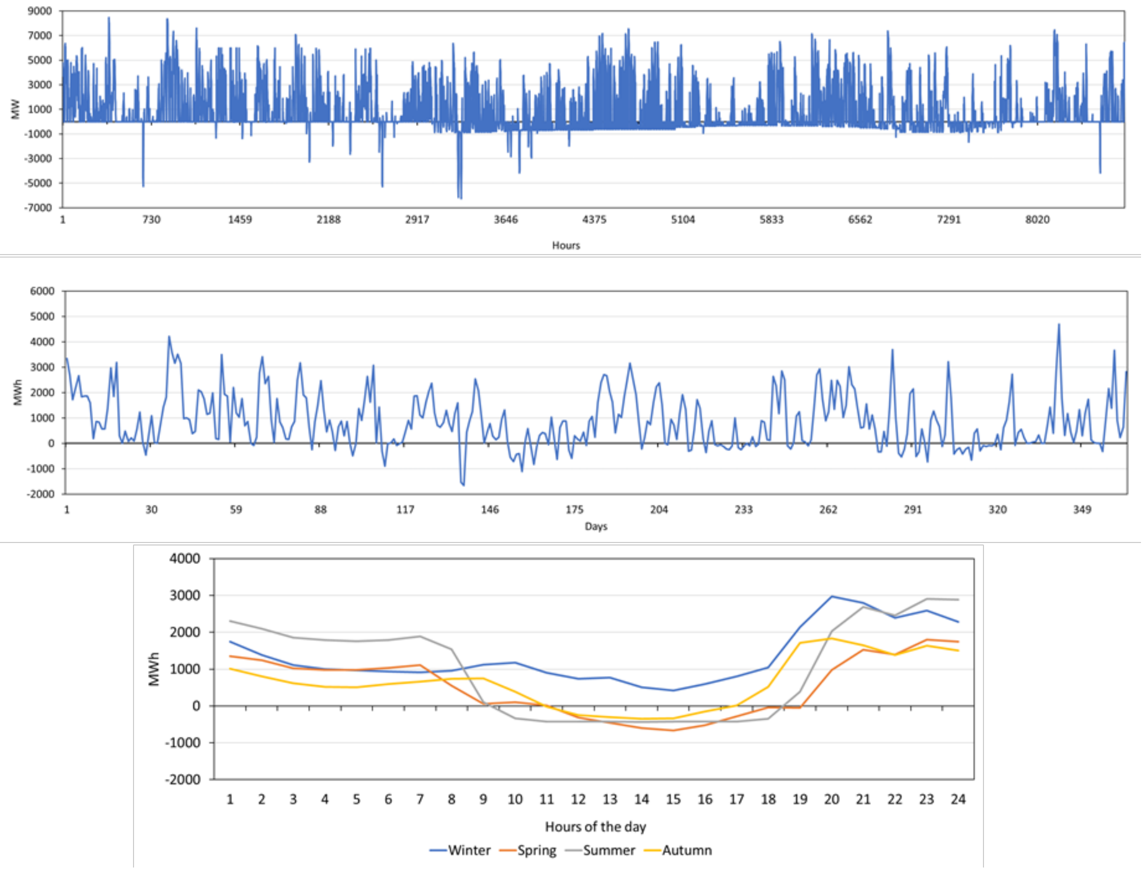


Figure 27 – Hourly, daily and seasonal residual load resulting from the ERAA 2025 ED for 2035 (WS 27)

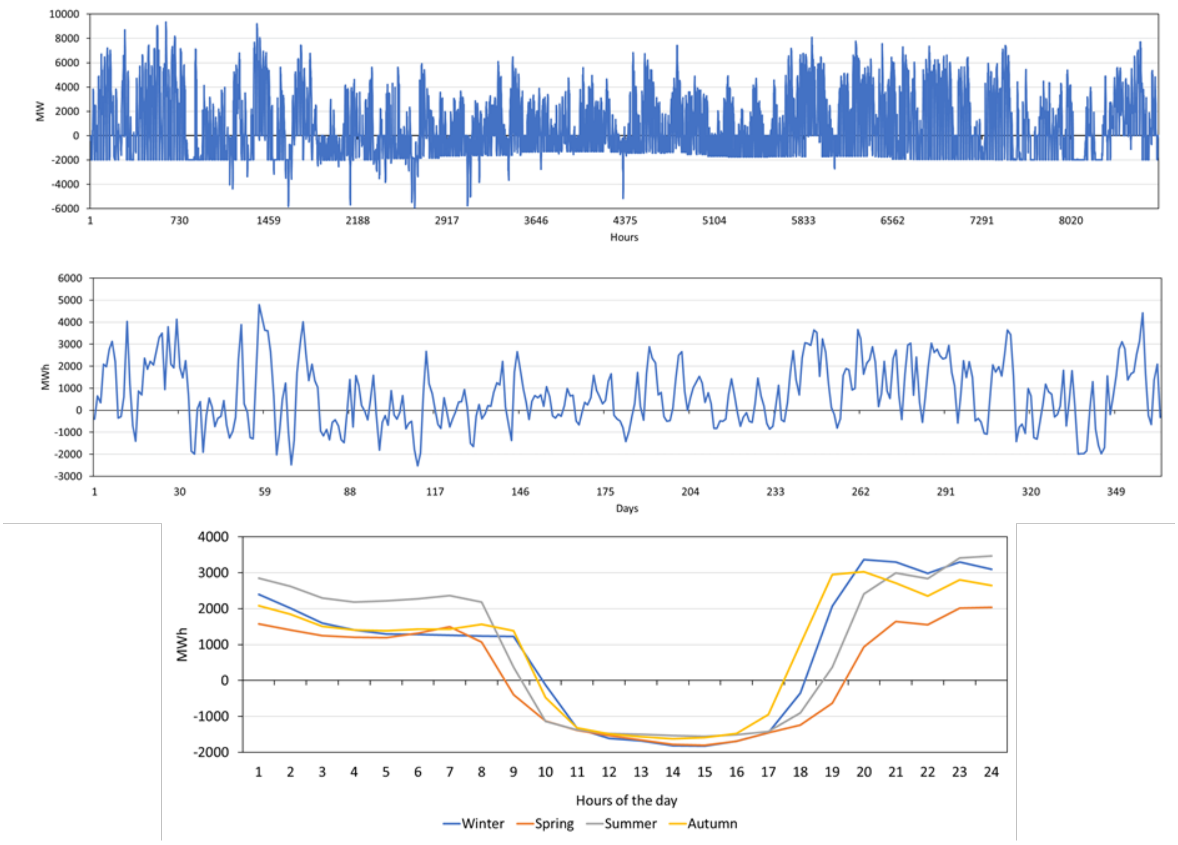


Figure 28 – Daily, monthly and seasonal RES curtailment (2035, WS 23)

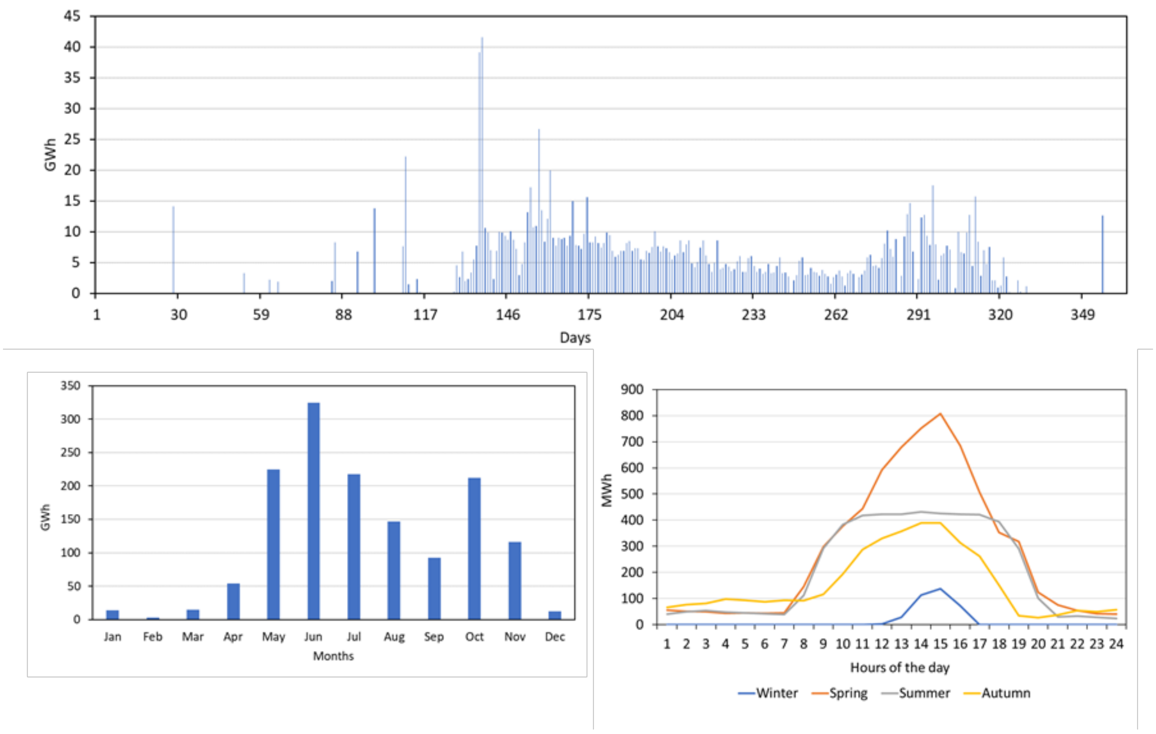


Figure 29 – Daily, monthly and seasonal RES curtailment (2035, WS 23, sensitivity 2)

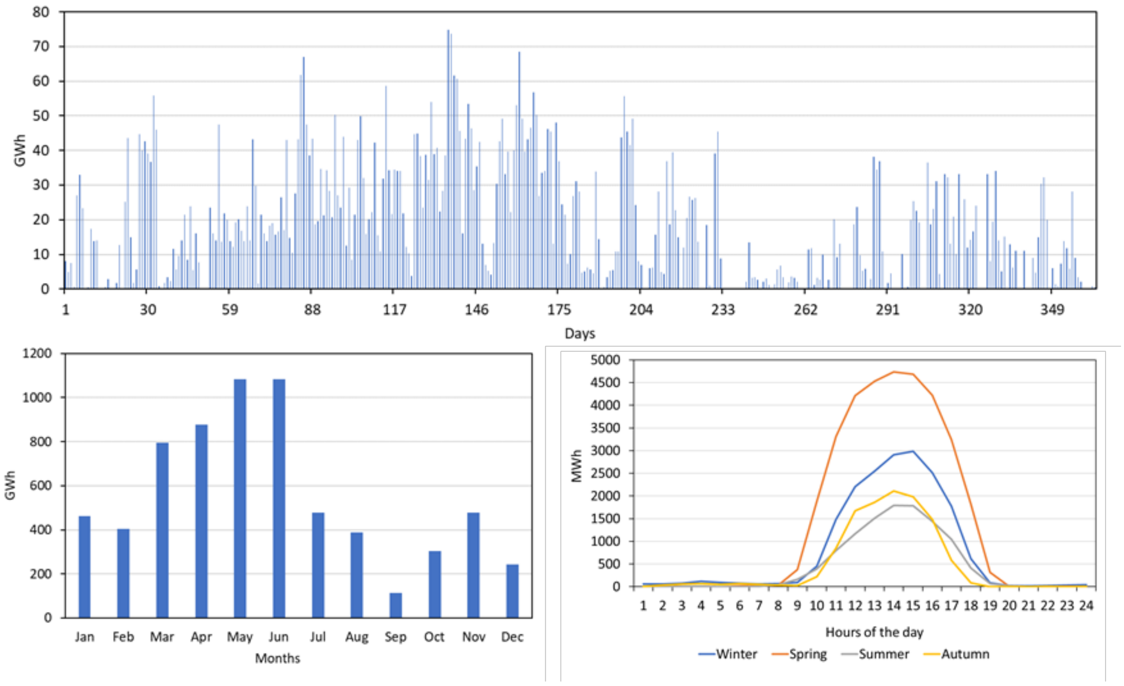


Figure 30 – Daily, monthly and seasonal RES curtailment (2035, WS 27)

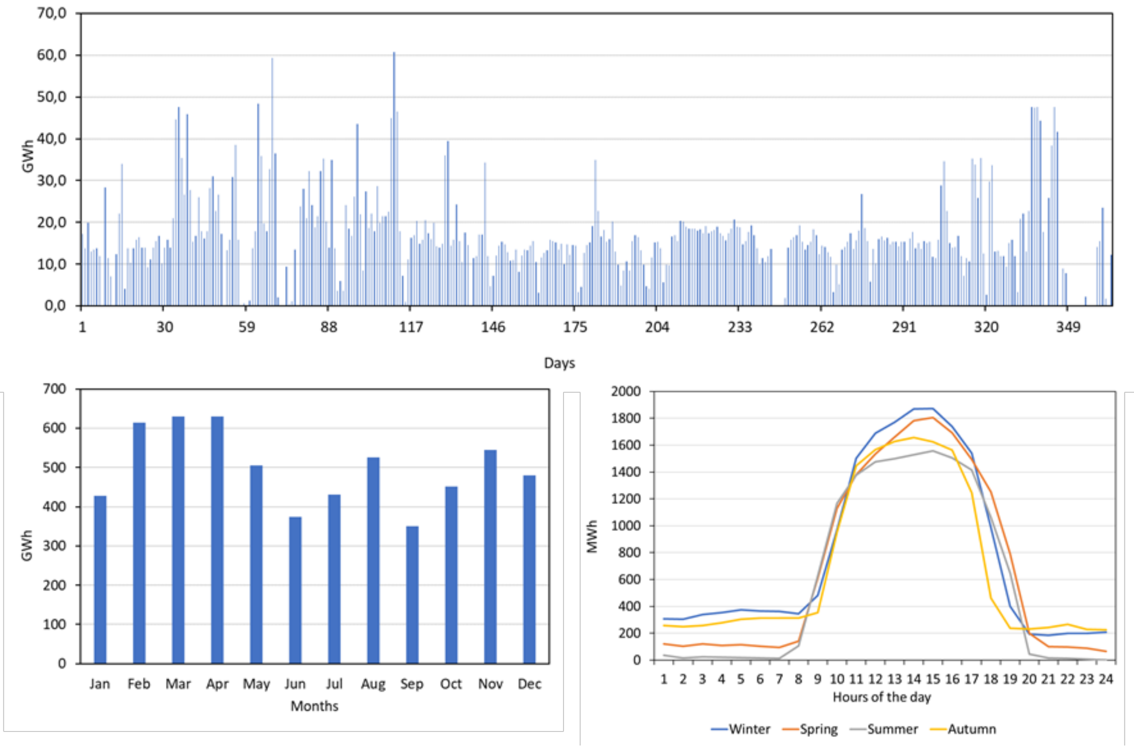


Figure 31 – Daily, monthly and seasonal RES curtailment (2035, WS 27, sensitivity 2)

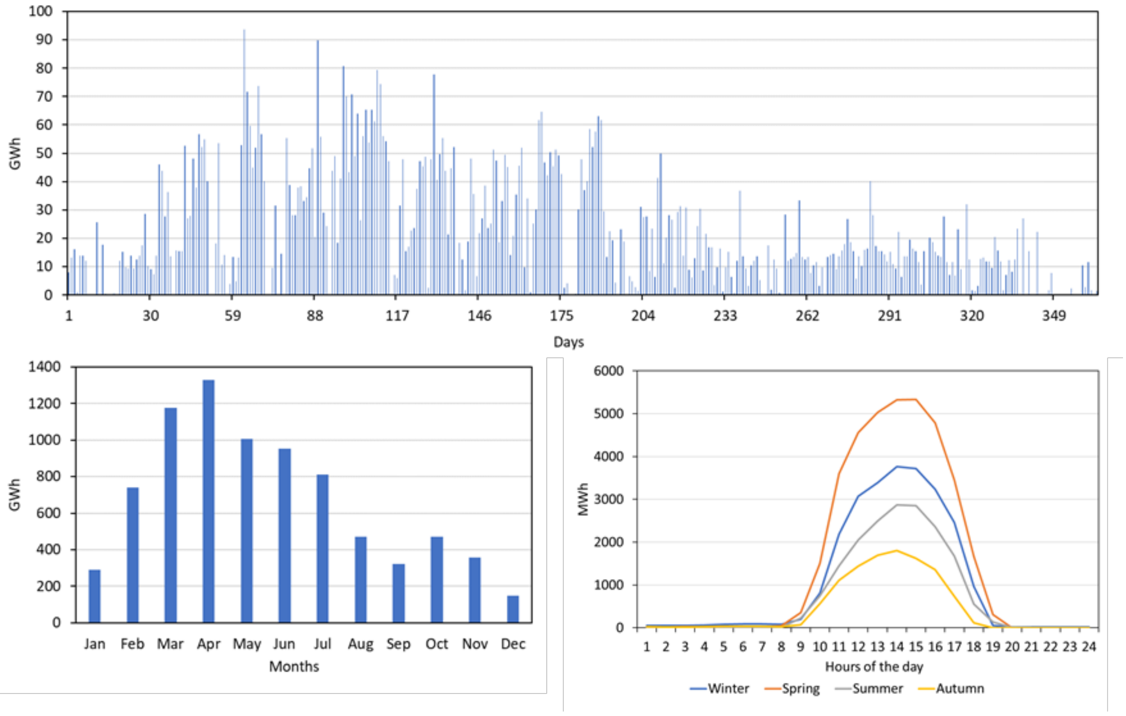


Figure 32 – Daily, monthly and seasonal RES curtailment (2035, WS 35, sensitivity 2)

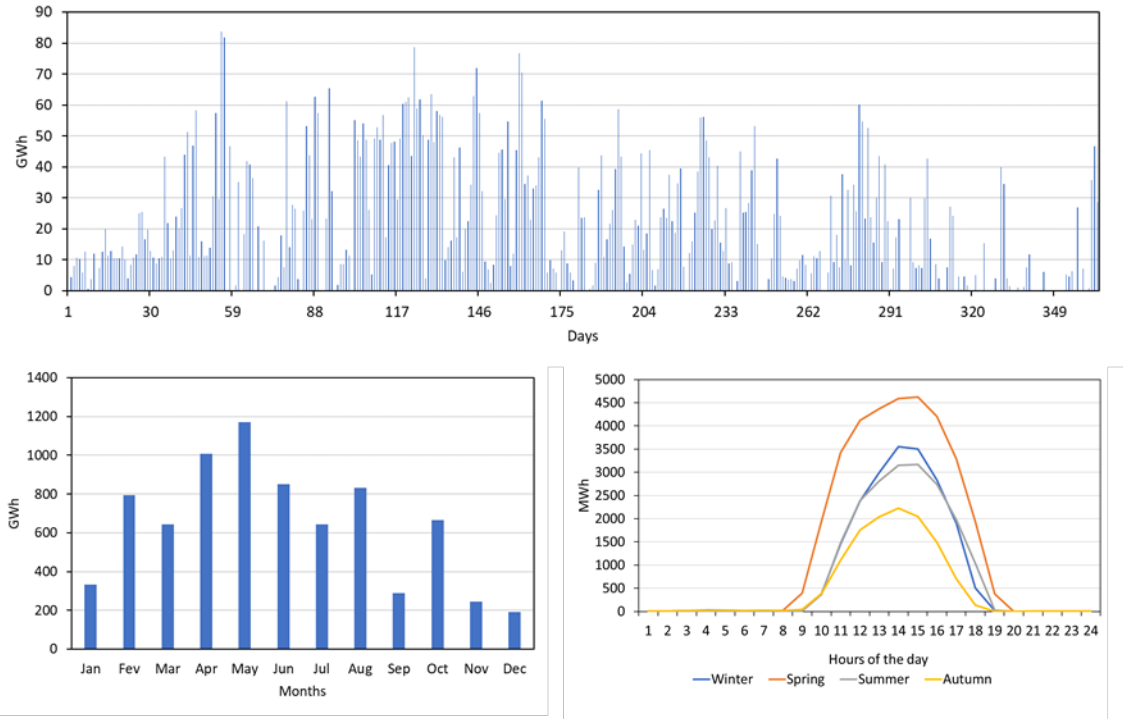
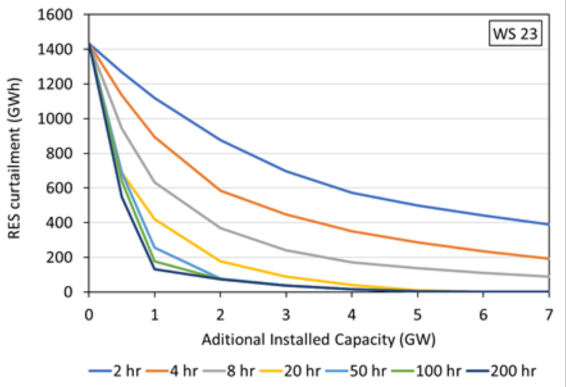
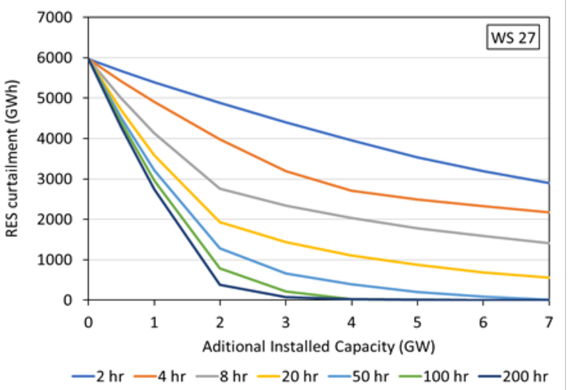


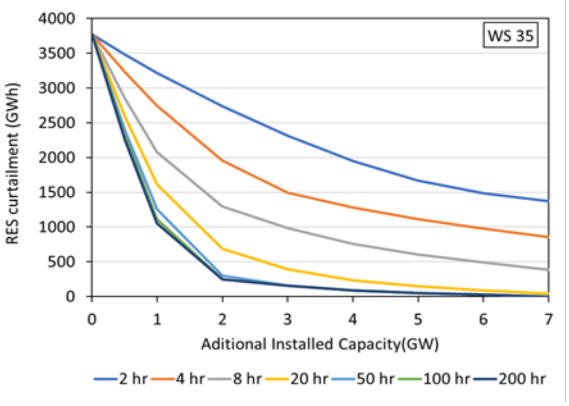
Figure 33 – RES curtailment taking into account the energy-to-power ratio of flexibility resources for 2035, scenarios WS 23, 27 and 35



GW / Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	1433	1433	1433	1433	1433	1433	1433
0,5	1269	1134	942	689	689	639	549
1,0	1118	893	633	420	255	178	131
2,0	876	585	369	177	76	74	74
3,0	697	447	241	90	38	38	38
4,0	573	350	170	40	16	16	16
5,0	499	286	136	8	5	5	5
6,0	442	233	112	0	0	0	0
7,0	389	192	88	0	0	0	0

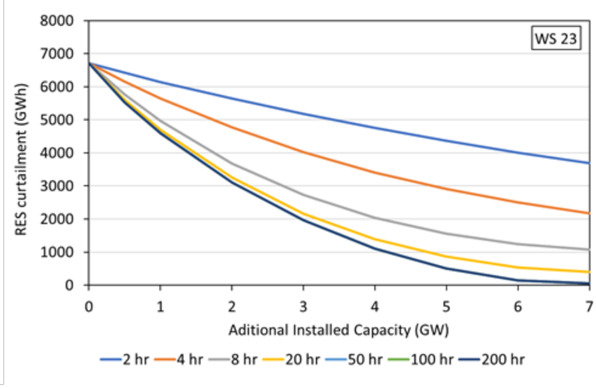


GW / Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	5963	5963	5963	5963	5963	5963	5963
0,5	5674	5417	5001	4710	4521	4395	4286
1,0	5398	4904	4134	3592	3218	2962	2748
2,0	4883	3975	2766	1937	1282	787	380
3,0	4403	3197	2341	1436	663	210	71
4,0	3954	2714	2039	1101	395	27	27
5,0	3542	2492	1783	872	206	6	6
6,0	3187	2327	1583	692	85	0	0
7,0	2901	2174	1415	560	11	0	0

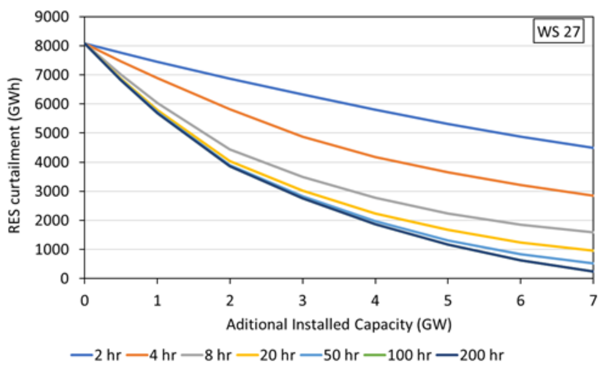


GW / Ratio	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	3770	3770	3770	3770	3770	3770	3770
0,5	3484	3228	2849	2592	2398	2310	2259
1,0	3220	2744	2075	1612	1258	1116	1053
2,0	2738	1953	1295	690	301	246	246
3,0	2310	1489	983	389	153	153	153
4,0	1946	1276	759	230	91	91	91
5,0	1666	1113	608	146	51	51	51
6,0	1488	977	488	87	25	25	25
7,0	1372	857	388	45	0	0	0

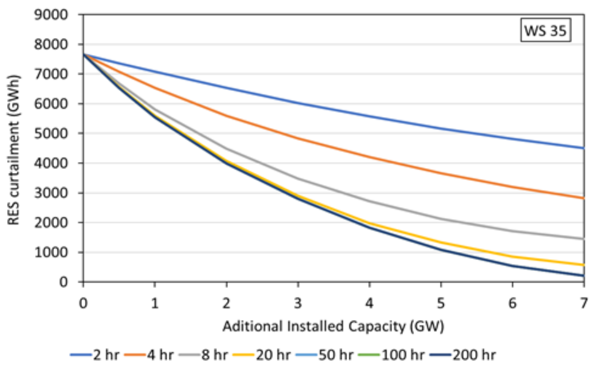
Figure 34 – RES curtailment taking into account the energy-to-power ratio of flexibility resources for 2035, scenarios WS 23, 27 and 35, sensitivity 2



Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	6710	6710	6710	6710	6710	6710	6710
0,5	6418	6154	5769	5593	5531	5519	5519
1,0	6144	5650	4975	4701	4604	4597	4597
2,0	5640	4768	3682	3251	3103	3103	3103
3,0	5178	4019	2726	2159	1964	1964	1964
4,0	4754	3407	2036	1386	1113	1113	1113
5,0	4362	2903	1552	862	511	511	511
6,0	4009	2500	1248	542	152	152	152
7,0	3688	2172	1078	399	51	51	51



Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	8078	8078	8078	8078	8078	8078	8078
0,5	7758	7464	7005	6865	6828	6816	6816
1,0	7453	6886	6030	5782	5710	5686	5686
2,0	6878	5812	4434	4031	3900	3853	3853
3,0	6327	4881	3493	3023	2834	2765	2765
4,0	5800	4184	2785	2242	1965	1873	1873
5,0	5312	3653	2241	1668	1305	1165	1165
6,0	4872	3214	1849	1239	836	623	623
7,0	4491	2845	1595	961	528	246	246



Ratio / GW	2 hr	4 hr	8 hr	20 hr	50 hr	100 hr	200 hr
0,0	7663	7663	7663	7663	7663	7663	7663
0,5	7362	7082	6681	6565	6537	6537	6537
1,0	7073	6536	5810	5587	5537	5537	5537
2,0	6527	5589	4483	4079	3996	3996	3996
3,0	6028	4827	3486	2902	2795	2795	2795
4,0	5575	4201	2711	1984	1828	1828	1828
5,0	5169	3657	2130	1329	1082	1082	1082
6,0	4814	3192	1707	857	546	546	546
7,0	4495	2825	1443	565	215	215	215

Table 23 – Detailed results for RES integration flexibility needs in 2035 (WS 23)

<table>
<tr><th>Type</th><th>Flexibility needs</th><th>Indicator</th><th>Sub-indicator</th><th></th><th>Value</th><th>Unit</th><th>Target year</th><th>Scenario</th></tr>
<tr><td rowspan="20">System needs</td><td rowspan="20">RES integration</td><td>RES integration target</td><td>-</td><td rowspan="8"></td><td>0,0</td><td>TWh</td><td rowspan="20">2035</td><td rowspan="20">WS23</td></tr>
<tr><td rowspan="19">RES generation curtailment</td><td>RES generation curtailment</td><td>1,4</td><td>Total in TWh</td></tr>
<tr><td rowspan="3">Hourly timeframe</td><td>164,0</td><td>Average in MW</td></tr>
<tr><td>6220,2</td><td>Maximum in MW</td></tr>
<tr><td>0,0</td><td>Minimum in MW</td></tr>
<tr><td rowspan="3">Daily timeframe</td><td>3936,3</td><td>Average in MWh</td></tr>
<tr><td>41628,0</td><td>Maximum in MWh</td></tr>
<tr><td>0,0</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="12">Seasonal timeframe</td><td rowspan="3">Winter</td><td>14,8</td><td>Average in MWh</td></tr>
<tr><td>138,2</td><td>Maximum in MWh</td></tr>
<tr><td>0,0</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Spring</td><td>276,1</td><td>Average in MWh</td></tr>
<tr><td>808,0</td><td>Maximum in MWh</td></tr>
<tr><td>40,7</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Summer</td><td>207,1</td><td>Average in MWh</td></tr>
<tr><td>432,1</td><td>Maximum in MWh</td></tr>
<tr><td>24,2</td><td>Minimum in MWh</td></tr>
<tr><td rowspan="3">Autumn</td><td>155,9</td><td>Average in MWh</td></tr>
<tr><td>389,8</td><td>Maximum in MWh</td></tr>
<tr><td>26,2</td><td>Minimum in MWh</td></tr>
</table>

Table 24 – Detailed results for RES integration flexibility needs in 2035 (WS 23 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2035	WS23 - Sens. 2
		RES generation curtailment	RES generation curtailment		6,7	Total in TWh		
			Hourly timeframe		768,1	Average in MW		
					12121,2	Maximum in MW		
					0,0	Minimum in MW		
			Hourly timeframe		18433,3	Average in MWh		
					74824,5	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	768,6	Average in MWh		
					2983,6	Maximum in MWh		
					19,2	Minimum in MWh		
				Spring	1393,5	Average in MWh		
					4734,5	Maximum in MWh		
					0,0	Minimum in MWh		
				Summer	444,2	Average in MWh		
					1789,9	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	469,5	Average in MWh		
					2106,9	Maximum in MWh		
					0,0	Minimum in MWh		

Table 25 – Detailed results for RES integration flexibility needs in 2035 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2035	WS27
		RES generation curtailment	RES generation curtailment		6,0	Total in TWh		
			Hourly timeframe		682,6	Average in MW		
					5916,2	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		16381,4	Average in MWh		
					60747,1	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	773,3	Average in MWh		
					1871,7	Maximum in MWh		
					184,9	Minimum in MWh		
				Spring	691,3	Average in MWh		
					1805,3	Maximum in MWh		
					64,6	Minimum in MWh		
				Summer	591,8	Average in MWh		
					1557,7	Maximum in MWh		
					1,8	Minimum in MWh		
				Autumn	675,9	Average in MWh		
					1656,8	Maximum in MWh		
					224,3	Minimum in MWh		

Table 26 – Detailed results for RES integration flexibility needs in 2035 (WS 27 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2035	WS27 - Sens. 2
		RES generation curtailment	RES generation curtailment		8,1	Total in TWh		
			Hourly timeframe		924,6	Average in MW		
					11592,1	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		22191,4	Average in MWh		
					93555,7	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	1021,4	Average in MWh		
					3764,2	Maximum in MWh		
					15,7	Minimum in MWh		
				Spring	1506,1	Average in MWh		
					5336,4	Maximum in MWh		
					0,0	Minimum in MWh		
				Summer	726,5	Average in MWh		
					2869,7	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	447,7	Average in MWh		
					1806,9	Maximum in MWh		
					0,0	Minimum in MWh		

Table 27 – Detailed results for RES integration flexibility needs in 2035 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2035	WS35
		RES generation curtailment	RES generation curtailment		3,8	Total in TWh		
			Hourly timeframe		431,6	Average in MW		
					9551,6	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		10357,4	Average in MWh		
					59454,5	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	583,5	Average in MWh		
					1802,6	Maximum in MWh		
					71,8	Minimum in MWh		
				Spring	443,1	Average in MWh		
					1419,6	Maximum in MWh		
					11,5	Minimum in MWh		
				Summer	345,3	Average in MWh		
					1147,9	Maximum in MWh		
					9,6	Minimum in MWh		
				Autumn	356,9	Average in MWh		
					1071,5	Maximum in MWh		
					49,5	Minimum in MWh		

Table 28 – Detailed results for RES integration flexibility needs in 2035 (WS 35 – sensitivity 2)

Type	Flexibility needs	Indicator	Sub-indicator		Value	Unit	Target year	Scenario
System needs	RES integration	RES integration target	-		0,0	TWh	2035	WS35 - Sens. 2
		RES generation curtailment	RES generation curtailment		7,7	Total in TWh		
			Hourly timeframe		877,1	Average in MW		
					15452,6	Maximum in MW		
					0,0	Minimum in MW		
			Daily timeframe		21051,4	Average in MWh		
					83623,5	Maximum in MWh		
					0,0	Minimum in MWh		
			Seasonal timeframe	Winter	819,1	Average in MWh		
					3555,5	Maximum in MWh		
					0,0	Minimum in MWh		
				Spring	1387,3	Average in MWh		
					4626,1	Maximum in MWh		
					0,0	Minimum in MWh		
				Summer	798,4	Average in MWh		
					3168,7	Maximum in MWh		
					0,0	Minimum in MWh		
				Autumn	504,0	Average in MWh		
					2224,4	Maximum in MWh		
					0,0	Minimum in MWh		

System flexibility needs – Ramping, Article 9 FNAM

Year 2030

Table 29 – Detailed ramping flexibility needs results for 2030 (WS 23)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	3,82	MW	2030	WS23	Annual value
			Maximum (upward)	1596,59	MW			Hourly value
			Minimum (upward)	0,00	MW			Hourly value
			Average (downward)	3,94	MW			Annual value
			Maximum (downward)	1274,38	MW			Hourly value
			Minimum (downward)	0,00	MW			Hourly value
			Relevant percentile - upward (99,9%)	821,98	MW			Hourly value
			Relevant percentile - downward (99,9%)	688,46	MW			Hourly value
		Upward uncovered ramping needs	Average	0,00	MW			After activation of hydro, pumping and batteries.
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			
		Downward uncovered ramping needs	Average	0,00	MW			
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			

Table 30 – Detailed ramping flexibility needs results for 2030 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	33,02	MW	2030	WS27	Annual value
			Maximum (upward)	1675,78	MW			Hourly value
			Minimum (upward)	0,00	MW			Hourly value
			Average (downward)	36,89	MW			Annual value
			Maximum (downward)	1800,00	MW			Hourly value
			Minimum (downward)	0,00	MW			Hourly value
			Relevant percentile - upward (99,9%)	1489,12	MW			Hourly value
			Relevant percentile - downward (99,9%)	1740,25	MW			Hourly value
		Upward uncovered ramping needs	Average	0,17	MW			After activation of hydro, pumping, batteries and electrolysers
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	1484,00	MWh			
		Downward uncovered ramping needs	Average	0,00	MW			
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			

Table 31 – Detailed ramping flexibility needs results for 2030 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	6,52	MW	2030	WS35	Annual value
			Maximum (upward)	862,76	MW			Hourly value
			Minimum (upward)	0,00	MW			Hourly value
			Average (downward)	9,00	MW			Annual value
			Maximum (downward)	1671,95	MW			Hourly value
			Minimum (downward)	0,00	MW			Hourly value
			Relevant percentile - upward (99,9%)	597,99	MW			Hourly value
			Relevant percentile - downward (99,9%)	914,05	MW			Hourly value
		Upward uncovered ramping needs	Average	0,00	MW			After activation of hydro, pumping and batteries.
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			
		Downward uncovered ramping needs	Average	0,00	MW			
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			

Year 2035

Table 32 – Detailed ramping flexibility needs results for 2035 (WS 23)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	1,21	MW	2035	WS23	Annual value
			Maximum (upward)	539,05	MW			Hourly value
			Minimum (upward)	0,00	MW			Hourly value
			Average (downward)	2,71	MW			Annual value
			Maximum (downward)	1833,00	MW			Hourly value
			Minimum (downward)	0,00	MW			Hourly value
			Relevant percentile - upward (99,9%)	326,38	MW			Hourly value
			Relevant percentile - downward (99,9%)	789,25	MW			Hourly value
		Upward uncovered ramping needs	Average	0,03	MW			After activation of hydro, pumping, batteries and electrolysers
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	293,37	MWh			
		Downward uncovered ramping needs	Average	0,00	MW			
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			

Table 33 – Detailed ramping flexibility needs results for 2035 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	5,13	MW	2035	WS27	Annual value
			Maximum (upward)	750,62	MW			Hourly value
			Minimum (upward)	0,00	MW			Hourly value
			Average (downward)	16,84	MW			Annual value
			Maximum (downward)	1860,53	MW			Hourly value
			Minimum (downward)	0,00	MW			Hourly value
			Relevant percentile - upward (99,9%)	591,50	MW			Hourly value
			Relevant percentile - downward (99,9%)	1730,49	MW			Hourly value
		Upward uncovered ramping needs	Average	0,03	MW			After activation of hydro, pumping, batteries and electrolysers
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	270,51	MWh			
		Downward uncovered ramping needs	Average	0,00	MW			
			Relevant percentile (99,9%)	0,00	MW			
			Equivalent total uncovered energy	0,00	MWh			

Table 34 – Detailed ramping flexibility needs results for 2035 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Ramping needs	Ramping flexibility needs	Average (upward)	2,70	MW	2035	WS35	Annual value
System needs	Ramping needs	Ramping flexibility needs	Maximum (upward)	765,27	MW	2035	WS35	Hourly value
System needs	Ramping needs	Ramping flexibility needs	Minimum (upward)	0,00	MW	2035	WS35	Hourly value
System needs	Ramping needs	Ramping flexibility needs	Average (downward)	3,79	MW	2035	WS35	Annual value
System needs	Ramping needs	Ramping flexibility needs	Maximum (downward)	1559,65	MW	2035	WS35	Hourly value
System needs	Ramping needs	Ramping flexibility needs	Minimum (downward)	0,00	MW	2035	WS35	Hourly value
System needs	Ramping needs	Ramping flexibility needs	Relevant percentile - upward (99,9%)	431,97	MW	2035	WS35	Hourly value
System needs	Ramping needs	Ramping flexibility needs	Relevant percentile - downward (99,9%)	764,08	MW	2035	WS35	Hourly value
System needs	Ramping needs	Upward uncovered ramping needs	Average	0,01	MW	2035	WS35	After activation of hydro, pumping, batteries and electrolysers
System needs	Ramping needs	Upward uncovered ramping needs	Relevant percentile (99,9%)	0,00	MW	2035	WS35	After activation of hydro, pumping, batteries and electrolysers
System needs	Ramping needs	Upward uncovered ramping needs	Equivalent total uncovered energy	58,38	MWh	2035	WS35	After activation of hydro, pumping, batteries and electrolysers
System needs	Ramping needs	Downward uncovered ramping needs	Average	0,00	MW	2035	WS35	After activation of hydro, pumping, batteries and electrolysers
System needs	Ramping needs	Downward uncovered ramping needs	Relevant percentile (99,9%)	0,00	MW	2035	WS35	After activation of hydro, pumping, batteries and electrolysers
System needs	Ramping needs	Downward uncovered ramping needs	Equivalent total uncovered energy	0,00	MWh	2035	WS35	After activation of hydro, pumping, batteries and electrolysers

System flexibility needs – Short-term, Article 10 FNAM

Year 2030

Table 35 – Detailed short-term flexibility needs results for 2030 (WS 23)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2220	MW	2030	WS23	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	438	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	2835	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	521	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

Table 36 – Detailed short-term flexibility needs results for 2030 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2223	MW	2030	WS27	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	439	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	2842	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	526	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

Table 37 – Detailed short-term flexibility needs results for 2030 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2154	MW	2030	WS35	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	433	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	2757	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	516	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

Year 2035

Table 38 – Detailed short-term flexibility needs results for 2035 (WS 23)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2451	MW	2035	WS23	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	486	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	3138	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	581	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

Table 39 – Detailed short-term flexibility needs results for 2035 (WS 27)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2465	MW	2035	WS27	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	488	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	3156	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	585	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

Table 40 – Detailed short-term flexibility needs results for 2035 (WS 35)

Type	Flexibility needs	Indicator	Sub-indicator	Value	Unit	Target year	Scenario	Comments
System needs	Short-term needs	Upward residual load forecast errors	Relevant percentile of the forecast error: p99,9% (maximum)	2406	MW	2035	WS35	D-1 forecast; gross needs
			Relevant percentile of the forecast error: p99,9% (minimum)	482	MW			
		Downward residual load forecast errors	Relevant percentile of the forecast error: p0,1% (maximum)	3080	MW			
			Relevant percentile of the forecast error: p0,1% (minimum)	576	MW			
		Uncovered short-term flexibility needs	Upward uncovered needs		MW			Uncovered needs calculation not possible in the ED processing option
			Downward uncovered needs		MW			
			Upward uncovered needs total energy		MWh			
			Downward uncovered needs total energy		MWh			
			Number of hours with uncovered needs		-			

IV. BARRIERS TO FLEXIBILITY

Barrier 1 - Lack of proper legal framework for market access to new entrants and small actors

Indicator 1.1 - Main roles and responsibilities of new actors not defined[88]

Active customers		
Aspects	**Evaluation**	**Comments**
1. Is all necessary primary and secondary legislation in effect to ensure that final customers are entitled to act as active customers and exercise the following rights:		
a. Consume and store electricity generated within their premises located within confined boundaries or self-generated or shared electricity within other premises	Yes	DL no. 15/2022 and the Self-consumption Code
b. Operate directly or through aggregation	Yes	DL no. 15/2022 and the Commercial Relations Code
c. Sell self-generated electricity, including through power purchase agreements	Yes	DL no. 15/2022 and Self-consumption Code
d. When they own an energy storage facility, they have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled	Yes	DL n.º 15/2022 and Access to Networks and Interconnections Code
1.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.	NAP	

[88] The tables below include the abbreviations NA – Not Assessed, and NAP – Not Applicable.

Aggregation		
Aspects	**Evaluation**	**Comments**
2. Please indicate if and how the following activities and actors are defined in national legislation:		
a. ‘Aggregation’, if defined differently compared to the Electricity Directive	Defined in accordance to the Directive (EU) 2019/944 on common rules for the internal market for electricity	Article 143(1) of DL no. 15/2022
b. ‘Independent aggregator’, if defined differently compared to the Electricity Directive	There is no direct definition for "Independent aggregator" in Portuguese legislation	Although there is no explicit definition of independent aggregators in Portuguese legislation, the national legal framework allows aggregation activities to be carried out in accordance with the provisions of the Electricity Directive applicable to independent aggregators.
c. ‘Aggregator’, if defined, or ‘market participant engaged in aggregation’, if defined differently compared to the Electricity Directive	DL no. 15/2022 contains a dedicated chapter on aggregation activities. The Commercial Relations Code defines an 'Aggregator' as an entity that, in accordance with the law, aggregates electricity and/or natural gas consumption and/or generation.	
3. Is all necessary primary and secondary legislation in effect to ensure that final customers:		
a. Can conclude an aggregation contract with any market participant engaged in aggregation, without the consent of the final customer's electricity undertakings (i.e. its supplier or its BRP)	NA	
b. When they have an aggregation contract, they are not subject to undue payments, penalties or other undue contractual restrictions by their suppliers	NA	
c. Are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier based on whether they have an aggregation contract	NA	
3.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.	NA	

Energy Communities		
Aspects	**Evaluation**	**Comments**
4. Is all necessary primary and secondary legislation in effect to ensure that citizen energy communities:	Yes	DL no. 15/2022, the Self-consumption Code, and the Commercial Relations Code
a. Can engage in generation, including from renewable energy sources, supply, consumption, aggregation, energy storage and charging services for electric vehicles	-	
b. Can access all electricity markets directly or through aggregation in a non-discriminatory manner	-	
c. Are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers or market participants engaged in aggregation	-	
4.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.	-	
5. Is all necessary primary and secondary legislation in effect to ensure that renewable energy communities:	Yes	Under DL No. 15/2022, at the regulatory level, energy communities are treated in the same way as any other market participant and may engage in existing market activities, provided that they obtain the necessary accreditation.
a. Can produce, consume, store and sell renewable energy, including through renewables power purchase agreements	-	
b. Can access all suitable energy markets directly or through aggregation in a non-discriminatory manner.	-	
c. Are not subject to discriminatory treatment regarding their activities, rights and obligations as final customers, producers, suppliers or as other market participants.	-	
5.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.	-	

Energy storage behind-the-meter		
Aspects	**Evaluation**	**Comments**
6. Are energy storage facilities permitted to be combined with the following facilities and connected to the same grid access point:		
a. Facilities producing renewable energy, as "co-located energy storage"	Yes	DL No. 15/2022, Order No. 1859/2025 and the Self-consumption Code
b. Electric vehicle recharging points	Yes	Article 15(1)(f) of DL No. 93/2025
c. Final customers' demand facilities	Yes	Although permitted, there is no simplified procedure for installing small-scale storage systems. Storage systems of 1 MW or less must be registered.
6.1. Please explain any combinations that are not allowed, as well as any conditions or restrictions that may apply to allowed combinations (e.g. size or type of energy storage or combined facilities, restrictions to the operation of the energy storage or the combined facilities, etc.).	-	

Aggregation models		
Aspects	**Evaluation**	**Comments**
7. Please indicate and briefly describe the aggregation model(s) with more than one balance responsible party per connection point that are implemented in your country for each wholesale electricity market and system operation service/product:	NA	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
	-	
7.1. Please indicate if any of the implemented aggregation models are not available to certain types of system users (e.g., system users connected to specific voltage levels, active customers with co-located energy storage, etc.) or are available subject to any specific conditions or restrictions.	-	

Indicator 1.2 - Market access restricted due to lack of legal eligibility

Aggregation		
Aspects	**Evaluation**	**Comments**
8. Are any of the following market participants not legally allowed to participate24 in wholesale markets and system operation services/products:	NA	
a. Market participants engaged in aggregation, excluding independent aggregators	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
b. Independent aggregators	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
8.1. Please explain any restrictions (e.g., market participant XX is not legally eligible to access YY markets/services/products because of ZZ reasons etc.).	-	

Direct participation		
Aspects	**Evaluation**	**Comments**
9. Are any of the following actors not legally allowed to participate directly25 in wholesale markets and system operation services:	NA	
a. Household final customers	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
b. Commercial final customers	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
c. Industrial final customers	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
d. Renewable producers	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
e. Energy storage operators	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
f. Citizen energy communities	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
g. Renewable energy communities	-	
- Day-ahead	-	
- Intraday	-	
- FCR	-	
- aFRR	-	
- mFRR	-	
- TSO congestion management	-	
- DSO congestion management	-	
9.1. Please explain any restrictions (e.g. actor XX is not allowed to participate directly in market YY for ZZ reasons)	-	

Indicator 1.3: Unclear framework for access to final customer data

Aspects	Evaluation	Comments
10. Has your Member State implemented the reference model for metering and consumption data access, including the various roles, information exchanges, and procedures, in line with Article 3 of Commission Implementing Regulation (EU) 2023/1162?	Yes	
10.1. If so, please indicate if the national practices on implementing the interoperability requirements and procedures for access to data are reported in line with Article 10 of Commission Implementing Regulation (EU) 2023/1162.	Yes	https://www.erse.pt/en/electricity/energy-data-access-procedures/
11. If any charges are imposed by regulated entities providing data services to eligible parties for access to data, please explain how your Member State ensures that these are reasonable and duly justified.	No charges apply	

Indicator 1.4: Ownership restrictions for energy storage and electro-mobility

Aspects	Evaluation	Comments
12. The Electricity Directive prohibits DSOs from owning, developing, managing or operating energy storage facilities except for specific derogations:		
12.1. If derogations exist to allow DSOs to own, develop, manage or operate energy storage facilities considered as either fully integrated network components or when they meet the conditions in points (a) to (c) of Article 36(2) of the Electricity Directive, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to fully integrated network components or to other energy storage facilities? does the derogation refer to one or more DSOs? does the derogation refer to specific energy storage facilities?).	No derogations apply	
12.2. If derogations for fully integrated network components exist, please indicate if any open and transparent criteria or process have been defined based on which an energy storage facility owned and operated by a DSO can qualify as a fully integrated network component.	No derogations apply	
12.3. If derogations for energy storage facilities fulfilling the conditions in points (a) to (c) of Article 36(2) of the Electricity Directive exist, please indicate if any public consultations have been performed pursuant to article 36(3) of the Electricity Directive and whether a decision has been taken to phase out the respective DSO activities.	No derogations apply	
13. The Electricity Directive prohibits TSOs from owning, developing, managing or operating energy storage facilities except for specific derogations:		
13.1. If derogations exist to allow TSOs to own, develop, manage or operate energy storage facilities considered as either fully integrated network components or when they meet the conditions in points (a) to (c) of Article 54(2) of the Electricity Directive, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to fully integrated network components or to other energy storage facilities? does the derogation refer to one or more TSOs? does the derogation refer to specific energy storage facilities?).	No derogations apply	
13.2. If derogations for fully integrated network components exist, please indicate if any open and transparent criteria or process have been defined based on which an energy storage facility owned and operated by a TSO can qualify as a fully integrated network component	No derogations apply	
13.3. If derogations for energy storage facilities fulfilling the conditions in points (a) to (c) of Article 54(2) of the Electricity Directive exist, please indicate if any public consultations have been performed pursuant to article 54(4) of the Electricity Directive and whether a decision has been taken to phase out the respective TSO activities.	No derogations apply	
14. The Electricity Directive prohibits DSOs from owning, developing, managing or operating recharging points for electric vehicles except where distribution system operators own private recharging points solely for their own use.		
14.1. If derogations exist to allow DSOs to own, develop, manage or operate recharging points for electric vehicles that are not solely for their own use, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to one or more DSOs? does the derogation refer to specific facilities?).	No derogations apply	
14.2. If such derogations exist, please indicate if any public consultations have been performed pursuant to article 33(4) of the Electricity Directive and whether a decision has been taken to phase out the respective DSO activities.	No derogations apply	

Indicator 1.5: Restrictions on trade in day-ahead and intraday markets

Aspects	Evaluation	Comments
15. What is the smallest minimum bid size of products for trading in the day- ahead and intraday markets?	NA	
16. What is the imbalance settlement period? If this is different than 15 minutes, has the regulatory authority granted a derogation or exemption. Please explain that derogation.	15 minutes	Article 55 of the Network Operation Code
17. Do NEMOs enable market participants to trade in energy in time intervals which are at least as short as the imbalance settlement period for the day- ahead and intraday markets?	NA	

Barrier 2 – Lack of enablers and incentives to provide flexibility

Indicator 2.1: Lack of adequate metering systems

Low roll-out of smart meters – Lack of sub-meters and dedicated measurement devices		
Aspects	**Evaluation**	**Comments**
1. What is the percentage share of household and non-household final customers equipped with smart meters?	This level of disaggregation is not available	See Section 5.1 of the report
2. Are sub-meters or dedicated measurement devices31 used by TSOs, DSOs, and market participants, including independent aggregators and, if defined, aggregators?	This is not common practice in Portugal	See Section 5.1 of the report
a. If they are used, please explain the uses	-	
b. If they are not needed, please explain why (e.g. no need for data about specific end-uses inside final customers' facilities, no practical use cases exist for DMDs, all metering needs are covered by main utility meters or other systems/arrangements)	-	
c. If they are not used although they are needed or could be used, please describe the needs or potential uses and explain why they are not used	-	

Lack of smart meters with minimum functionalities		
Aspects	**Evaluation**	**Comments**
3. For the following minimum functionalities of smart metering systems, what is the percentage share of household and non-household final customers equipped with smart meters for which the functionality is available/in use?	All smart meters in Portugal comply with the requirements below; however, this level of disaggregation is not available.	See Section 5.1 of the report
a. Provision of information on actual electricity consumption and actual time of use.	-	
b. Access to non-validated near real-time consumption data at no additional cost, through a standardised interface or through remote access	-	
c. Access to validated historical consumption data, including visualisation, on request and at no additional cost	-	
d. Accounting separately for electricity fed into the grid and electricity consumed from the grid by active customers' premises	-	
e. Data on final customers' electricity consumption and the electricity that they fed into the grid is made available to them on request or to a third party acting on their behalf at no additional cost, through a standardised communication interface or through remote access	-	
f. Final customers are metered and settled at the same time resolution as the imbalance settlement period in the national market	-	

Other functionalities and services enabling flexibility and demand response		
Aspects	**Evaluation**	**Comments**
4. Are there any other functionalities or ICT services, related to or supported by smart metering data, that are available to final customers in your Member State, and considered helpful for enabling demand response and customer flexibility?	Yes	See Section 5.1 of the report

Indicator 2.2: Absence of price signals

Limited availability/uptake of retail electricity contracts with time differentiation and dynamic electricity price contracts		
Aspects	**Evaluation**	**Comments**
5. Do all suppliers with more than 200,000 final customers offer dynamic price electricity contracts for all types of final customers with a smart meter?		
a. Household customers	There are five suppliers with more than 200,000 customers, and all of them offer dynamic price contracts.	
b. Non-household customers	There are five suppliers with more than 200,000 customers, and only one of them does not offer dynamic price contracts.	
6. What is the availability to and uptake by household and non-household customers of different types of retail electricity contracts (market-based / regulated):		Data from 2025. Regulated tariffs are based on fixed prices and fixed-term contracts.
a. Time-of-use fixed-price, fixed-term contracts	**Market-based:** Domestic – 21 suppliers / 247 offers / 4.9% uptake; Non-domestic – 19 suppliers /107 offers / 14.2% uptake. **Regulated:** Domestic – 13 suppliers /2 offers / 2.1% uptake; Non-domestic – 13 suppliers /2 offers / 6.2% uptake.	
b. Variable price contracts with one single price that varies between quarters / months / days	**Market-based:** Domestic - 21 suppliers/41 offers/ 0,7% uptake; Non-domestic - 25 suppliers/40 offers/ 3,5% uptake	
c. Variable price contracts with time-of-use pricing that varies between quarters / months / days	**Market-based:** Domestic - 20 suppliers/ 38 offers/0,1% uptake; Non Domestic - 25 suppliers/42 offers/ 5,1% uptake	
d. Dynamic price contracts	**Market-based:** Domestic - 8 suppliers/41 offers/ 0,3% uptake; Non Domestic - 5 suppliers/12 offers/ 4,1% uptake	

e. Hybrid contracts (i.e. contracts combining elements of fixed and variable or dynamic contracts, contracts targeting consumers with specific assets, such as heat pumps or electric vehicles, or specific consumption profiles)	**Market-based:** Domestic - 0 Non domestic - 1 supplier/0,4% uptake	
f. Other (please describe)	**Market-based:** Domestic - 21 suppliers/247 offers/ 4,9% uptake; Non domestic - 19 suppliers/107 offers/ 14,2% uptake **Regulated:** Domestic - 13 suppliers/2 offers/2,1% uptake; Non-domestic - 13 suppliers/2 offers/6,2% uptake	Fixed price and fixed contract terms. A single tariff (with no differentiation between time periods).
7. What is the estimated percentage share of household and non-household customers under collective metering and billing schemes or similar arrangements that do not allow final customers to be exposed to time-of-use or dynamic price signals (e.g. retail contracts, network tariffs, local flexibility markets etc.)?	0%	Smart meter deployment is virtually 100%.

Lack of consideration of network tariffs with time differentiation		
Aspects	**Evaluation**	**Comments**
8. Are network tariffs with time-of-use (static or dynamic) elements applied to any customer categories connected to the transmission or the distribution system?	Yes	
8.1. If no time-of-use signals (static or dynamic) are introduced in network tariffs for any customer types connected to the transmission or distribution system, despite the presence of physical congestion in the system and the availability of fit-for-purpose metering systems, please indicate if there was an assessment to support this decision and explain the reasons for deciding against introducing time-of-use signals in network tariffs.	NAP	
8.2. If time-of-use signals are introduced in network tariffs, are these tariffs mandatory for network users to whom they apply (i.e. no possibility to opt-out and select a different tariff that does not include such signals)?	Yes, except for low-voltage customers with a contracted power equal to or below 20.7 kVA. These customers may choose either not to have time-of-use tariffs or to adopt a tariff scheme with two or three time periods.	
8.3. If time-of-use signals are introduced in network tariffs, are suppliers allowed to 'bundle' charges related to the network component into fixed electricity price contracts with no flexible elements that they may offer to customers to which time-of-use network tariffs apply?	Yes, regarding the final price paid by consumers; however, this practice has not been observed to date. In any case, for customers with mandatory time-of-use tariffs, the bill must specify the quantities and prices associated with network tariffs.	

Barrier 3 – Restrictive requirements to provide balancing services

Indicator 3.1: Non-market-based balancing products

Aspects	Evaluation	Comments
1. If any TSO uses non-market-based procurement for balancing capacity or balancing energy:		
a. For which reserves (i.e. FCR, aFRR, mFRR) and types of products (i.e. capacity, energy) is this the case?	mFRR	A specific product is used, based on scheduled mFRR bids, to support the response to significant variations in the interconnection capacity allocated in the day-ahead and intraday markets.
b. How does the TSO procure/cover its balancing needs for these reserves and what is the current planning for implementing market-based procurement?	The TSO meets these balancing needs by using the available mFRR bids submitted by Balancing Service Providers.	The TSO was requested to define a new product that is more closely aligned with the standard products.

Indicator 3.2: Restrictions in the prequalification of reserve providing groups (RPGs)

Aspects	Evaluation	Comments
2. Do all TSOs allow prequalification of reserve providing groups for FCR, aFRR and mFRR?	No	See Section 5.2 of the report
3. For reserves where at least one TSO allows prequalification of reserve providing groups, are there any combinations of generation (G), demand (D) and storage (S) units under the same reserve providing group that are not allowed by one or more TSOs?	Currently, prequalification is not possible for aggregated groups.	See Section 5.2 of the report
a. FCR	-	
G&D&S	-	
G&S	-	
D&S	-	
G&D	-	
b. aFRR	-	
G&D&S	-	
G&S	-	
D&S	-	
G&D	-	
c. mFRR	-	
G&D&S	-	
G&S	-	
D&S	-	
G&D	-	
3.1. Please explain why certain combinations are not allowed (e.g. aggregation of XX units is not allowed in YY reserve by WW TSO for ZZ reasons) and describe any specific restrictions that may apply with regard to any allowed combinations (e.g. locational or connection voltage level restrictions, restrictions on the type or size of facilities/units that can be aggregated, etc.) and the reasons for these restrictions.	-	See Section 5.2 of the report
4. Are reserve providing units or reserve providing groups required to pass separate prequalification to provide balancing capacity and balancing energy for FCR, aFRR or mFRR? If so, please explain the reasons for requiring separate prequalification.	Yes. The requirements for providing aFRR and mFRR services are substantially different (4-second cycles compared with a full activation time of 12.5 minutes), resulting in separate prequalification processes.	No FCR market exists in Portugal.

Indicator 3.3: Large minimum eligible capacity

Aspects	Evaluation	Comments
5. What is the minimum capacity (MW) required by each TSO in the prequalification process to be allowed to participate in the different local or standard and specific balancing products used for FCR, aFRR and mFRR?	1 MW for aFRR and mFRR	The provision of FCR is mandatory and legally established; therefore, this restriction does not apply in the same manner.

Indicator 3.4: Unregulated duration or long prequalification process

First time prequalification		
Aspects	**Evaluation**	**Comments**
6. If a reserve providing unit (RPU) or reserve providing group (RPG) is required to pass a first-time prequalification to provide FCR, aFRR or mFRR, what is the regulated maximum duration (weeks), if any, for the following intermediate steps of the prequalification process for each reserve?	These conditions are not defined at national level.	An ACER Decision defining these parameters is expected as part of the implementation framework for aFRR and mFRR.
a. From receipt of a formal application by a reserve provider, for the TSO to confirm if the application is complete	-	
b. From receipt of a request by the TSO for additional information, for the reserve provider to submit the additional information	-	
c. From confirmation of the completeness of the application, for the TSO to confirm to the reserve provider if the reserve providing unit/group has been prequalified	-	

Re-prequalification		
Aspects	**Evaluation**	**Comments**
7. If a prequalified RPG is required to pass a new prequalification process for FCR, aFRR or mFRR due to the following changes, what is the maximum regulated duration (weeks) of the re-prequalification process, if any?	These conditions are not defined at national level.	An ACER Decision defining these parameters is expected as part of the implementation framework for aFRR and mFRR.
7.1. After adding new connection points, adding new generation/demand/storage units in the existing connection points and/or increasing the capacity of existing units or their contribution to the prequalified capacity of the RPG.	-	
7.2. After removing some connection points, removing some generation/demand/storage units in the existing connection points and/or decreasing the capacity of existing units or their contribution to the prequalified capacity of the RPG.	-	
7.3. After changes to the composition or distribution of units	-	
8. If a prequalified RPU or RPG is required to pass a new prequalification process for FCR, aFRR or mFRR due to being switched to a different BSP for the same balancing product and without having undergone any changes, what is the maximum regulated duration (weeks) of this re-prequalification process, if any?	These conditions are not defined at national level.	An ACER Decision defining these parameters is expected as part of the implementation framework for aFRR and mFRR.

Indicators 3.5 to 3.9

In case products other than standard products are used, indicate if there are local or specific			Local / Specific	Local / Specific	Local / Specific	Local / Specific
Product or market design element	**EU target model requirement**	**FCR**	**aFRR Capacity**	**aFRR Energy**	**mFRR Capacity**	**mFRR Energy**
a. Minimum bid size	**≤ 1 MW**	NAP	NAP	NAP	NAP	NAP
b. Validity period of balancing energy bids	**15 min**	**NAP**	**NAP**	NAP	**NAP**	NAP
c. Procurement of upward /downward capacity	**Separate**	NAP	NAP	**NAP**	NAP	**NAP**
d. Price settlement rule	**Marginal pricing**	**NAP**	**NAP**	NAP	**NAP**	NAP
e. Non-contracted balancing energy bids	**Allowed**	**NAP**	**NAP**	NAP	**NAP**	NAP

Indicator 3.10: Too short predefined minimum duration between consecutive activations

Aspects	**Evaluation**	**Comments**
10.What is the shortest and the longest minimum duration (minutes) between the end of deactivation period and the following activation defined for local or standard and specific balancing energy products used by each TSO at national level for aFRR and mFRR.	The deactivation period for aFRR and mFRR is, respectively, 5 minutes and 10 minutes. The maximum activation time defines the maximum duration for the next activation.	

Indicator 3.11: Long procurement lead time and long duration of balancing capacity contracts

Aspects	**Evaluation**	**Comments**
11. Has the regulatory authority issued a decision for any of the following?		
a. To grant a derogation concerning the time between contracting and provision of balancing capacity, pursuant to article 6(9) of the Electricity Regulation.	No	
b. To grant a derogation concerning the contractual period of capacity contracts, pursuant to article 6(9) of the Electricity Regulation.	No	
c. To approve an extension of the contractual period of the balancing capacity that is contracted more than one day ahead of delivery, pursuant to article 6(10) of the Electricity Regulation, following a derogation granted pursuant to article 6(9) of the Electricity Regulation.	No	
12. What is the percentage of balancing capacity contracted within 'X' time before its provision, for all balancing reserves and balancing capacity products used at national level?	aFRR - 100% "one day ahead or less" mFRR - Currently, there is a specific product featuring auctions with different maturities, which are held depending on the TSO needs. Starting in 2027, there will be a standard product with contracts entered into "one day ahead or less."	
a. One day ahead or less.	-	
b. Between one day and one week ahead.	-	
c. Between one week and one month ahead.	-	
d. Between one month and one year ahead.	-	
e. More than one year ahead.	-	
13. What is the percentage of balancing capacity contracts with a contractual period no longer than 'X' time, for all balancing reserves and balancing capacity products used at national level?	There are no balancing capacity contracts.	
a. No longer than one day.	-	
b. Between one day and one week.	-	
c. Between one week and one month.	-	
d. Between one month and one year.	-	
e. More than one year ahead.	-	

Barrier 4 – Restrictive requirements to provide congestion management

Indicator 4.1: Unjustified lack of market-based TSO congestion management

Aspects	Evaluation	Comments
1. Please explain the main congestion management measures taken by TSOs to address physical congestions. When a TSO uses redispatching to solve physical congestions in its transmission grid, please explain the type of procurement, i.e., market-based, non-market-based or a combination and under which conditions the TSO applies each procurement method.	TSO uses a technical validation of physical flows derived from the daily and intraday markets. TSO uses redispatching.	See Section 5.3.1 of the report
2. If a TSO uses non-market-based redispatching, please explain the reasons for applying this type of procurement:	TSO only uses market-based redispatching.	See Section 5.3.1 of the report
a. No market-based alternative is available.	-	
b. All available market-based resources have been used.		
c. The number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located.	-	
d. The current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned has adopted an action plan to address this congestion.	-	
e. The current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8) of the Electricity Regulation.	-	
f. Other (please explain).		
3. If a TSO uses non-market-based redispatching, please explain if this type of procurement only applies to solving physical congestions in specific grid areas or voltage levels, to specific congestion management products, to specific types of system users or technologies, time periods or other criteria.	TSO only uses market-based redispatching.	See Section 5.3.1 of the report
4. If a TSO uses non-market-based redispatching, please explain the assessment process to set this type of procurement, including the following aspects:	TSO only uses market-based redispatching.	See Section 5.3.1 of the report
a. Initiation: who initiated the process.	-	
b. Evaluation: type of evaluation, scope, who made the evaluation.	-	
c. Stakeholders involvement: how the stakeholders were involved.	-	
d. Decision: who approved the deviation from market-based procurement.	-	
5. If a TSO uses non-market-based redispatching, please explain the process to reassess whether reasons to set non-market redispatching become no longer applicable.	TSO only uses market-based redispatching.	See Section 5.3.1 of the report
6. If a deviation from market-based redispatching is not approved for a TSO, is there some primary or secondary legislation that needs to be approved or to enter into force in your country to ensure that the TSO can redispatch resources based on a market-based mechanism?	NAP	

Indicator 4.2: Unjustified lack of market-based DSO congestion management

Aspects	Evaluation	Comments
7. Please explain how DSOs solve physical congestions in their distribution grid. Please explain if all or some DSOs:	DSO uses network reconfiguration, voltage control, curtailment and load shedding.	See Section 5.3.2 of the report
a. use market-based redispatching	-	
b. implement non-market-based congestion management measures (e.g. non-market-based redispatching, flexible connection agreements50, interruptible network tariffs, etc.) and/or	-	
c. take other measures, except network reinforcement and expansion or requesting the TSO to solve the physical congestion (please explain these measures).	-	
8. If a DSO uses non-market-based congestion management, please explain the reason(s) for applying this type of procurement:	DSO does not use non-market-based congestion management	See Section 5.3.2 of the report
a. Market-based procurement is not economically efficient.	-	
b. Market-based procurement would lead to severe market distortions.	-	
c. Market-based procurement would lead to higher congestion.	-	
d. Other (please explain).	-	
9. If a DSO uses non-market-based congestion management, please explain if this type of procurement only applies to solving physical congestions in specific grid areas or voltage levels, to specific congestion management products, to specific types of system users or technologies, time periods or other criteria.	DSO does not use non-market-based congestion management	See Section 5.3.2 of the report
10. If a DSO uses non-market-based congestion management, please explain the assessment process to set this type of procurement, including the following aspects:	DSO does not use non-market-based congestion management	See Section 5.3.2 of the report
a. Initiation: who initiated the process.	-	
b. Evaluation: type of evaluation, scope, who made the evaluation.	-	
c. Stakeholders involvement: how the stakeholders were involved.	-	
d. Decision: who approved the deviation from market-based procurement.	-	
11. If a DSO uses non-market-based congestion management, please explain the process to reassess whether reasons to set non-market redispatching become no longer applicable.	DSO does not use non-market-based congestion management	See Section 5.3.2 of the report
12. If a deviation from market-based congestion management is not approved for a DSO, is there some primary or secondary legislation that needs to be approved or to enter into force in your country to ensure that the DSO can use congestion management services based on a market-based mechanism?	Yes	See Section 5.3.2 of the report

Indicator 4.3: Constraints in local markets for TSO/DSO congestion management

Aspects	Evaluation	Comments
13. If local markets for congestion management (for TSOs and/or DSOs) are operational in your country, please describe whether you have identified any barrier to entry or participation of non-fossil flexibility resources and new entrants, such as flexible renewable generation, demand response, energy storage and aggregation, in the prequalification process (if applicable), product design and/or market design, e.g.:	In Portugal, local congestion management markets in the distribution network only exist in the scope of the pilot-project FIRMe.	See Section 5.3.2 of the report
a. Restrictions in the prequalification of service providing groups (e.g. aggregation of generation/demand/storage under the same service providing group is not allowed, locational or connected voltage level restrictions in the aggregation of different units/resources, restrictions to facilities combining different types of units/resources such as demand or generation combined with storage, unjustified or disproportionate restrictions to aggregators' portfolio management, verification/testing requirements not justified by product requirements, etc.)	-	
b. Restrictive product or market design requirements (e.g. long validity period of congestion management bids, increasing demand response not allowed, long procurement lead time and long duration of congestion management capacity contracts, etc.)	-	
c. Unjustified or disproportionate restrictions applicable to resources with limited network access, such as resources connected with flexible connection agreements.	-	
d. Other (please explain)	-	

Barrier 5 – Complex, lengthy, and discriminatory administrative requirements

Indicator 5.1: Inefficient grid connection procedures

Aspects	Evaluation	Comments
1. As regards the procedures to obtain a grid connection permit for renewables self-consumers, energy storage facilities (front-of-the-meter, behind-the-meter including co-located energy storage) and installation of heat pumps:		See Section 5.4 of the report
a. Is information about the procedures provided online?	Yes, up to 1 MW. Above 1 MW, the platform is under development.	See Section 5.4 of the report
b. Can the procedures be carried out entirely in electronic form?	Only possible up to 1 MW	See Section 5.4 of the report
c. Can the procedures run in parallel to other required authorisations to help speed up the overall permit-granting process?	Yes	Article 24 (3) of DL No. 15/2022
d. Are there clearly defined deadlines for all steps of the procedures?	Yes	Articles 14, 25, 26, 55 and 59 of DL No. 15/2022
2. Do DSOs apply a simple-notification procedure for grid connections in accordance with article 17 of the Renewable Directive?	Yes, for certain types of installations.	See Section 5.4 of the report
3. Do system operators publish online up-to-date information on available grid capacity for connections?	The DSO does.	See Section 5.4 of the report
4. Are there any measures in place to simplify grid connection procedures for renewables self-consumers, electric vehicle recharging points and for renewable generation and energy storage owned by renewable and citizen energy communities?	Yes	DL No. 15/2022

Indicator 5.2: Disproportionate procedures and requirements for market access

Aspects	Evaluation	Comments
5. As regards procedures and requirements to access wholesale electricity markets and local markets for congestion management:	NA	
a. Have you identified or been made aware of any potentially unjustified differences in these procedures or requirements between new entrants and smaller actors (such as market participants engaged in aggregation, including independent aggregators, operators of energy storage, energy communities) and traditional market participants (such as producers and suppliers)?	-	
b. Are there any access options designed with smaller participants in mind (e.g. offering alternative collateral arrangements, reduced infrastructure requirements, proportionate market access fees, etc.)?	-	

Barrier 6 - Lack of regulatory incentives to system operators to consider non-wire alternatives

Indicator 6.1: Lack of incentives for SOs to consider non-wire alternatives

Aspects	Evaluation	Comments
1. Does the regulatory framework in your country ensure that TSOs and DSOs are able to procure flexibility services, including congestion management in their areas, in particular from generation, demand response or energy storage facilities, as needed for an efficient and secure system operation? If no, please explain why.	Yes, but there are still some gaps in the secondary regulations governing the distribution network.	See Section 5.5 of the report
2. Is there a legal or regulatory requirement for TSOs and DSOs to assess the procurement of flexibility services as an alternative to grid expansion when preparing the network development plans? If so, please explain the requirements (e.g. do they apply to certain types of grid expansion, do they apply to investments above a certain threshold, type of assessment, assessment criteria etc.)	Yes. This requirement is set forth in Article 123(5) of Decree-Law 15/2022. It is a requirement that is independent of both the type of investment and the amounts involved.	The latest distribution network development plan incorporated some flexibility solutions as an alternative to investment in network development.
3. Does the regulatory framework in your country ensure that TSOs and DSOs can fully recover the reasonable costs efficiently incurred when procuring flexibility services or investing in digitalisation of the system, including any related CAPEX or OPEX costs?	Yes. The national regulatory model allows for efficient cost recovery, which may include CAPEX or OPEX costs related to contracting flexibility or to the digitization of the system.	
4. Does the regulatory framework in your country provide incentives to TSOs and DSOs:	Yes	See Section 5.5 of the report
a. to procure flexibility services, including congestion management in their areas, in particular from generation, demand response or energy storage facilities, as an efficient alternative to grid expansion?	-	
b. to invest in smart grids, grid optimisation and other innovative technologies (e.g. active network management), as an efficient alternative to grid expansion?	-	
5. If incentives are provided, please explain:	See Section 5.5 of the report	
a. The type of incentives (e.g. expenditure allowances, TOTEX approach, cost efficiency targets, performance targets, reward/penalty schemes, benefit sharing schemes, etc.)	-	
b. The main purpose of the incentives (e.g. establish sandbox or pilot applications, increase system observability and digitalisation, promote efficient system utilisation, increase overall system efficiency, address CAPEX bias, etc.)	-	
c. In which year were the incentives introduced?	-	
d. How would you assess the results of the incentives so far?	-	
e. If there are limited or no positive results, what are the main factors to which you would attribute this?	-	

ERSE - Entidade Reguladora dos Serviços Energéticos

Rua Dom Cristóvão da Gama, 1 – 3.º
1400 - 113 Lisboa

+351 213 033 200
erse@erse.pt
www.erse.pt