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Flexibility Needs Assessment report for Finland

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Summary

This report presents the results of Finland's first national Flexibility Needs Assessment, prepared in accordance with Article 19e of Regulation (EU) 2019/943 and the methodology approved by ACER. The assessment evaluates the flexibility needs of the Finnish electricity system for the target years 2030 and 2035 and identifies potential barriers to the deployment of flexible resources in a rapidly evolving power system characterised by growing electricity demand and a declining share of dispatchable generation. The analysis is mainly based on data from ERAA 2024 and information provided by Finnish distribution system operators, complementing the ERAA assessment with an insight into national flexibility needs arising from factors not explicitly captured in adequacy assessments.

The results show that flexibility needs are expected to increase as electrification progresses and weather-dependent production continues to grow. While ERAA primarily highlights challenges related to resource adequacy during periods of high demand and low renewable generation, particularly in winter, the FNA assessment demonstrates that flexibility needs can arise throughout the year under a variety of system conditions. The analysis confirms that Finland's future flexibility needs will be dominated by situations with insufficient amount of flexible generation assets to meet variations in variable generation and demand, resulting in a growing need of flexible resources providing upward regulation.

The assessment is structured around the following complementary areas: system flexibility needs, network flexibility needs, and barriers to flexibility and the contribution of digitalisation. System flexibility needs were assessed through indicators related to renewable energy integration, ramping needs arising from changes in residual load, and short-term flexibility needs arising from forecast errors. Network flexibility needs were evaluated separately for distribution and transmission networks. In accordance with the FNA methodology, distribution system operators provided assessments of local network flexibility needs, while the transmission network assessment was limited to a preliminary cost-benefit analysis focusing on the transmission between north and south. Therefore, the report does not provide a comprehensive assessment of the transmission network flexibility needs.

Out of three system needs indicators, two of them revealed uncovered needs. No uncovered needs were identified for renewable energy integration in either target year, indicating that the renewable energy deployment assumed in the assessment is aligned with national energy and climate objectives and can be accommodated with the flexibility that is already expected to be in the system. In contrast, uncovered needs were observed for both ramping and short-term needs. Across both indicators, the uncovered needs were primarily associated with insufficient upward flexibility in 2030 and 2035, although some uncovered downward needs were also observed in 2035. Uncovered needs can reach to thousands of megawatts for both upward and downward needs during most challenging situations, indicating a need for new capacity to provide flexibility. These uncovered needs are significant compared to the projected peak demand of the Finnish power system, which has reached a maximum of 15 GW in recent years and is expected to be around 20 GW in 2030 and exceed 25 GW in 2035.

The nature of the identified flexibility needs differs between the indicators. Uncovered ramping needs last from one to three hours and occur particularly during morning peaks. By contrast, uncovered short-term needs can persist for up to 20 consecutive hours if prolonged forecast errors occur, and are most common during evening and night hours. Neither indicator exhibits a strong distinction between weekdays and weekends, and they can occur throughout the year, although certain months show a higher likelihood of uncovered events than others. The results should be interpreted in light of the limited number of weather scenarios considered, as the assessment was based on only three weather scenarios and additional weather years could influence the identified flexibility needs.

It should also be noted that the results are sensitive to the assumptions made regarding flexible resources and the extent to which different technologies are considered available to address flexibility needs. As this is the first implementation cycle of the FNA methodology, uncertainties remain regarding the practical availability and suitability of various flexibility resources across different indicators. One example relates to demand side response, which was excluded from the portfolio of flexible resources considered in the assessment due to uncertainties regarding its practical availability and utilisation. However, a sensitivity analysis indicated that if full demand side response potential were assumed to be available at all times, uncovered ramping needs would be reduced to nearly zero.

While uncovered needs were observed for both ramping and short-term flexibility, the results related to short-term needs are considered particularly relevant for Finland, as they are directly linked to forecast errors observed in historical demand and wind generation data, and it has already been seen that they can create stress to the system. The variation between weather scenarios is also less significant for short-term needs than for ramping needs, suggesting that the identified uncovered short-term needs are not driven by a single weather scenario but can emerge under a range of different system conditions.

Large forecast errors can persist for several consecutive hours, and their impact may become more significant as weather-dependent production and demand continue to grow. In the upcoming years, forecast errors can create prolonged upward flexibility needs that may be challenging to cover with available resources, underlining the need of new resources capable of supporting system balancing during extended periods. These resources would support both adequacy during challenging winter conditions and the broader flexibility needs identified in this assessment.

At distribution network level, the results indicate that flexibility needs vary considerably between network areas and that many distribution system operators do not currently identify any flexibility needs. Nevertheless, a limited number of distribution system operators with larger local challenges account for a significant share of the reported needs, which are identified in both 2030 and 2035 for both upward and downward regulation.

Flexible connection agreements were identified as the most important contractual mechanism for enabling flexibility at distribution network level, reflecting their potential to support efficient utilisation of grid capacity and facilitate the integration of new demand and generation. However, the survey responses indicate that the wider deployment of flexibility remains constrained by several barriers. The most frequently identified challenges relate to the limited economic attractiveness of flexibility solutions compared to traditional network investments due to insufficient regulatory incentives, and uncertainties related to the practical implementation and effectiveness of emerging flexibility markets.

1. Introduction

1.1. Purpose and scope of the national report

The purpose of this report is to assess the flexibility needs of the national electricity system over a forward-looking time horizon. The assessment aims to identify the amount and types of flexibility required to ensure the secure, reliable and cost-efficient operation of Finland's electricity system, while supporting the integration of renewable energy sources and the achievement of decarbonisation objectives. While European Resource Adequacy Assessment (ERAA) evaluates the adequacy of electricity across Europe to identify risks to security of supply, Flexibility Needs Assessment (FNA) focuses on the flexibility needs arising from imbalances and on the ability of the national power system to manage variations.

The report is intended to support national decision-making, including the setting of indicative national objectives for non-fossil flexibility and to provide a basis for potential policy and market measures enabling the efficient use of flexible resources. The assessment considers a time horizon of 5 to 10 years and includes the evaluation of different drivers of flexibility needs, such as variability of renewable generation, demand fluctuations and forecast uncertainties.

This report represents the first implementation cycle of the Flexibility Needs Assessment at national level. As such, it reflects an initial application of the newly adopted methodology, with certain assumptions, data constraints and practical arrangements still evolving. The experience gained from this first assessment will support further development of the adaptation of the methodology, data collection processes and analytical approaches in subsequent reporting cycles, improving the robustness and comparability of the results over time.

1.2. Legal and regulatory context

This report is prepared in the context of the European Union (EU) legal framework governing electricity market design and system adequacy. Article 19e of Regulation (EU) 2019/943 (Electricity Regulation) requires Member States to ensure that a national flexibility needs assessment is carried out periodically and reported at national level.

The assessment is conducted in accordance with the FNA methodology[1] approved by ACER (Agency for the Cooperation of Energy Regulators). This methodology defines the required data, formats and analytical approach for assessing flexibility needs by transmission system operators (TSOs) and distribution system operators (DSOs), ensuring consistency and comparability of results across Member States. The FNA process forms part of the broader EU framework for ensuring security of supply, facilitating the integration of renewable energy, and supporting the transition towards a decarbonised electricity system.

[1] Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis in accordance with Article 19e(4) of Regulation (EU) 2019/943: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER-Decision-05-2025-FNAM-Annex-I.pdf

1.3. Governance: designated bodies involved in the FNA report

Fingrid as the transmission system operator has been named as the designated entity by the Ministry of Economic Affairs and Employment of Finland and is therefore responsible for coordinating the assessment, collecting and consolidating inputs from distribution system operators, and preparing the national report. Energy Authority as the regulatory authority is responsible for reviewing and approving the report. Fingrid has been using modelling results from ENTSO-E (the European Network of Transmission System Operators for Electricity), data provided by the Finnish distribution system operators and Fingrid's own data in making of the report.

Distribution system operators have provided their data to Fingrid and have had the possibility to delegate parts of their analytical tasks to external consultants. The final data submissions were delivered by 29 May 2026, while preliminary data was requested earlier in order to support the timely progress of the assessment. The scope and content of the data to be provided by DSOs were jointly agreed between the Energy Authority, Fingrid, and the distribution system operators at the end of 2025.

2. Methodological aspects

2.1. Main definitions, data and methodological framework

Flexibility needs assessment consists of system needs and network needs, which are further divided into different indicators, as illustrated in Figure 1. System needs assess the characteristics of the Finnish electricity system, whereas network needs concentrate on constraints arising in both transmission and distribution networks.

FIGURE 1 Structure of Flexibility Needs Assessment.

The assessment of flexibility needs in this report is based on a harmonised European modelling framework, in line with the FNA methodology, which emphasises the use of consistent and transparent data sources across different system levels. To ensure consistency with European adequacy assessments and comparability of results, dataset from European Resource Adequacy Assessment 2024[2], later referred as ERAA 2024, has been chosen as the primary input for this report. Given the tight reporting schedule and the timing of ACER's approval of ERAA 2025, ERAA 2024 was chosen as the latest available dataset that could be consistently incorporated into the assessment.

ERAA dataset has been used for system needs as well as for cost-benefit analysis (CBA) conducted within the TSO network needs assessment. It should be noted that the ERAA 2024 dataset reflects assumptions from earlier years and may not fully align with the current view on the development of the Finnish electricity system. For example, the dataset assumes higher cross-border transmission capacity for 2035 and lower storage capacities than are currently expected, affecting both the availability and utilisation of flexible resources in the system. At the distribution level, DSOs have relied on their distribution network development plans (DNDPs) of 2026 to assess network needs. To define forecast errors for short-term needs, Fingrid's own historical forecast data has been used.

In accordance with FNA requirements, the assessment horizon must cover at least the next 5 to 10 years. For the first iteration of the FNA report, 2030 is defined as a common reference year across Europe. Consequently, the target years (TYs) considered in this report are 2030 and 2035. Both years are available in the ERAA 2024 dataset, and 2030 also aligns with the timeline of Finland's National Energy and Climate Plan (NECP), ensuring consistency with national policy targets.

[2] ERAA 2024 input data and results are available on ENTSO-E's website: https://www.entsoe.eu/eraa/2024/

The analysis has been carried out with post-processing approach based on ERAA 2024 results, in line with the FNA methodology, which allows flexibility needs to be assessed without modifying the underlying market model. The data has been provided as hourly time series and therefore the analysis uses hour as market time unit (MTU) for system needs evaluation, enabling a detailed representation of system variability and operational flexibility requirements.

To capture the impact of weather variability, three weather scenarios of ERAA 2024 were analysed: WS14, WS25 and WS28. These scenarios were selected from the 36 weather scenarios available in ERAA 2024 and correspond to those used for the Economic Viability Assessment. They are representative of different meteorological conditions, including variations in temperature, wind and precipitation, affecting demand and generation.

For each weather scenario, 15 simulations with different outage patterns have been performed, resulting in 45 simulations for each target year. The results presented in this report are derived from an average of these simulations and thus reflecting a broad range of possible system states. In total, the analysis is based on 90 simulations across both target years. This approach ensures that the assessment captures not only expected system conditions but also variability arising from weather and outage uncertainties, which is essential for a robust evaluation of flexibility needs in accordance with the FNA methodology.

2.2. Approach to system needs

The methodological approach for assessing system needs in this report follows the principles defined in the FNA methodology, which emphasises a consistent and data-driven evaluation of system behaviour under varying conditions. The objective is to quantify the need for flexibility in the power system by analysing how imbalances between supply and demand emerge and how large and frequent these imbalances are over time. To capture different dimensions of system behaviour, system needs are evaluated using three indicators: RES integration, ramping and short-term needs. Together, these indicators reflect structural changes in the system, predictable variations and short-term uncertainties.

2.2.1. Quantification of RES integration needs

RES integration indicator concentrates on periods of excess energy generation resulting in curtailment of renewable energy sources (RES). The main goal is to provide information on flexibility needs required to reduce curtailment and enable efficient integration of RES, thereby supporting the achievement of national RES targets in the electricity sector.

Curtailment refers to the intentional reduction of electricity generation of wind and solar power, typically due to system constraints or market conditions. It therefore acts as an indicator of insufficient flexibility in the system, reflecting limitations in demand response, storage, cross-border capacity, or transmission infrastructure. It is worth noting that not all wind and solar capacity is flexible due to technological or contractual constraints, such as household solar installations or certain wind turbines operating under power purchase agreements.

Curtailment time series were extracted from ERAA 2024 dataset. It shall be noted that in ERAA 2024 modelling nuclear and combined heat and power (CHP) plants shut down before wind or solar power is curtailed which does not reflect real-world operational behaviour. As a result, the timing and magnitude of curtailment may differ from real system operation and should be interpreted with caution.

RES integration targets for considered target years are based on Finland's Integrated National Energy and Climate Plan Update from 2024. The plan defines a target for final energy consumption for the electricity sector for 2030 but not for 2035. The target for 2030 is 65 %, and based on the increase of the target during 2025 – 2030, the target for 2035 was determined as 69 % in agreement with the Energy Authority and in accordance with the FNA methodology. Generation of wind turbines, solar panels, hydro power plants and CHP plants using biomass as their fuel are included to fulfil the target.

Uncovered RES integration needs are discovered if RES target is not met and are defined as the amount of RES curtailment exceeding the maximum level of RES curtailment compatible with the RES integration target.

2.2.2. Quantification of ramping needs

Ramping needs describe the ability of the power system to respond to changes in residual load over time. In line with the FNA methodology, ramping requirements are analysed based on changes in residual load between consecutive MTUs, capturing predictable variations driven by demand patterns, and generation of renewables and must-run units. This approach allows the identification of the magnitude and frequency of required system adjustments in both upward and downward directions.

Residual load refers to the portion of electricity demand that must be met by dispatchable generation resources after accounting for non-dispatchable and must-run sources. High residual load typically means there is low share of renewables in the system and a high need for dispatchable capacity. In this report, residual load is defined as following:

$$Demand - (Wind\ Power + Solar\ Power + CHP_{must\text{-}run} + Nuclear_{must\text{-}run})$$

Ramps are defined as the variation of residual load between consecutive MTUs, being one hour in this study. Positive ramps refer to a situation where residual load increases, indicating a growing need for dispatchable generation, whereas negative ramps, occur when residual load decreases, leading to a reduced need of dispatchable generation.

Uncovered ramping needs are discovered if flexible resources cannot meet the ramps and are calculated as the difference between the ramps and flexible resources. This reveals situations where the system lacks sufficient ramping capability to maintain balance.

2.2.3. Quantification of short-term needs

To define short-term flexibility needs, the forecasting errors of residual load are analysed based on the FNA methodology. There is no historical timeseries for Finland's residual load, and therefore the analysis was done by combining separate demand and production time series to produce a simplified residual load, defined as the difference of demand and wind production.

The available data for this analysis was the realised demand, forecast for demand, realised wind production and forecast for wind production. For all of these, the timeseries include data from a time period of 1.1.2023 – 20.4.2026. Forecast errors were calculated by comparing realised values with forecasts produced on the previous day after the publication of day-ahead prices, thereby capturing the influence of price information on the forecasts. The FNA methodology requires at least a two-year time series, preventing the use of forecast for solar production due to lack of sufficient data. Solar forecast will be included at the next cycle of Finland's FNA reporting.

To determine forecast errors for 2030 and 2035, historical forecast errors for demand and wind generation were first calculated for each hour and subsequently combined. The relative forecast error was then expressed with respect to the simplified residual load. The resulting forecast errors were grouped into ten bins based on the level of the simplified residual load over the analysed period. For each bin, the 0.1 and 99.9 percentiles of the forecast error were determined. These percentile values were then used to derive forecast errors for the target years 2030 and 2035 by constructing corresponding ten-bin classifications based on the residual load levels in the ERAA 2024 time series. Even though forecasting improvements can be expected for the upcoming 10-year period, they were not included in this study.

Uncovered short-term needs are discovered if flexible resources cannot meet the forecast errors and are calculated as the difference between the forecast error and flexible resources. Uncovered periods reveal lack of flexible resources in the intraday time horizon.

2.2.4. Flexible resources

Flexible resources are used for determining uncovered ramping and short-term needs. The electricity system requires both upward and downward flexibility to maintain balance under varying operating conditions. In this report, the available resources to provide flexibility at each hour are referred to as flexible resources. Flexible resources are based on the availabilities of different resources in ERAA 2024 data, including generation capacity, storage and exchange capacity, which represents available cross-border capacity between bidding zones. The analysis uses hourly time series data, with flexible resources also defined at an hourly resolution.

Availability of flexible resources are presented for both target years, and upwards and downwards regulation, separately in Figures 2, 3, 4 and 5. The resources considered for both ramping and short-term indicators remain identical in downward regulation while there is difference in upward regulation. Wind generation is not considered in short-term needs for upward regulation, as the short-term needs are highly driven by wind forecast errors and thus not expected to be able to contribute.

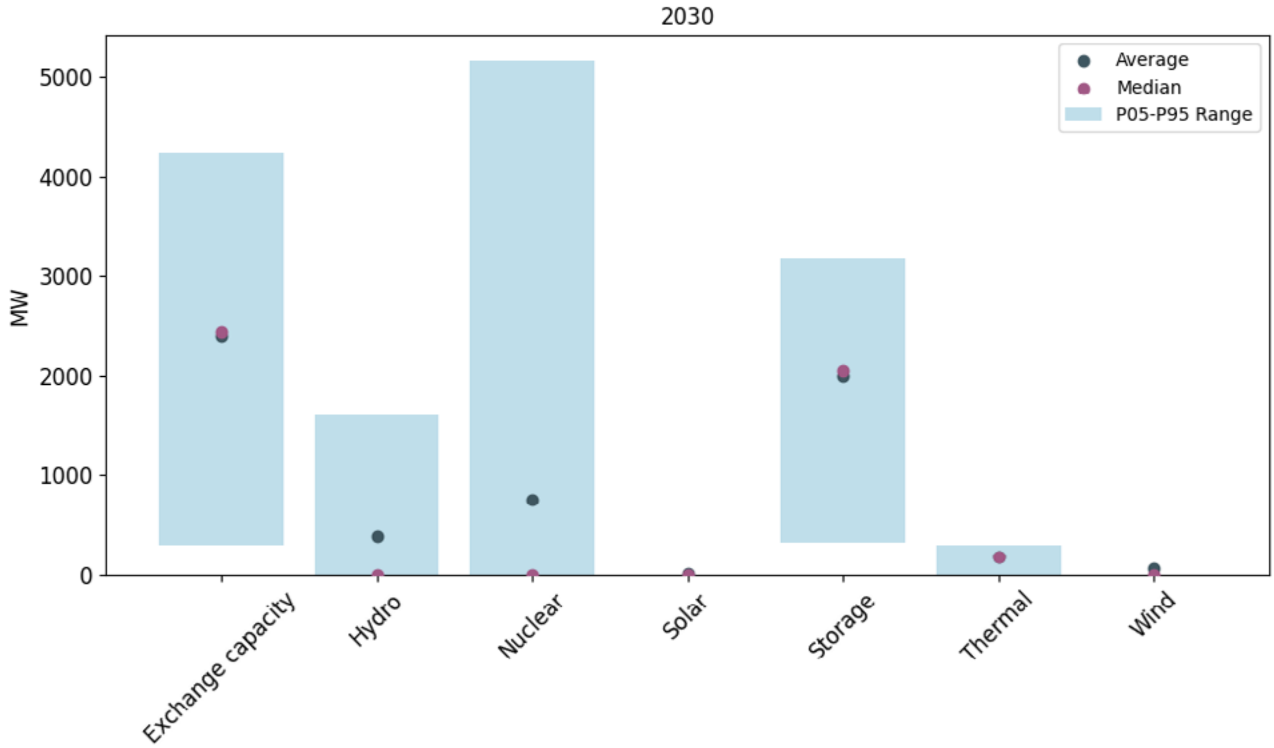


FIGURE 2 Hourly availabilities of flexible resources in 2030 for upward regulation.

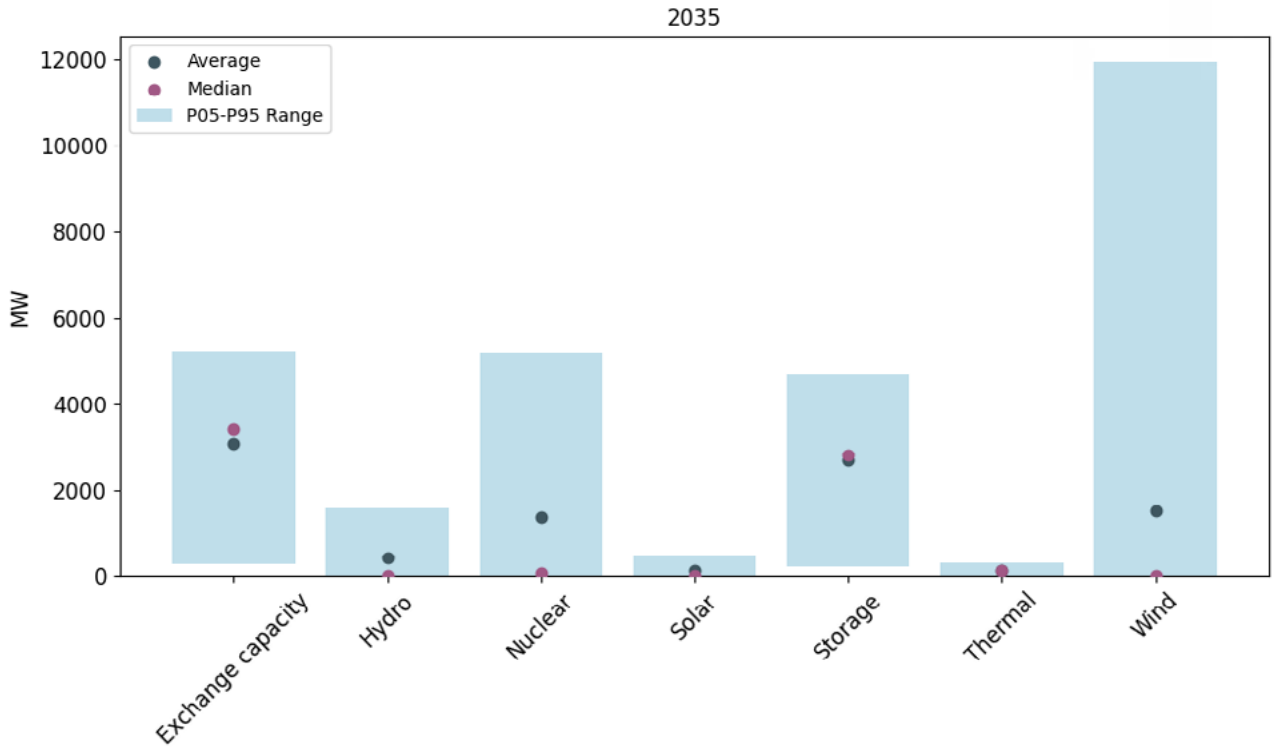


FIGURE 3 Hourly availabilities of flexible resources in 2035 for upward regulation.

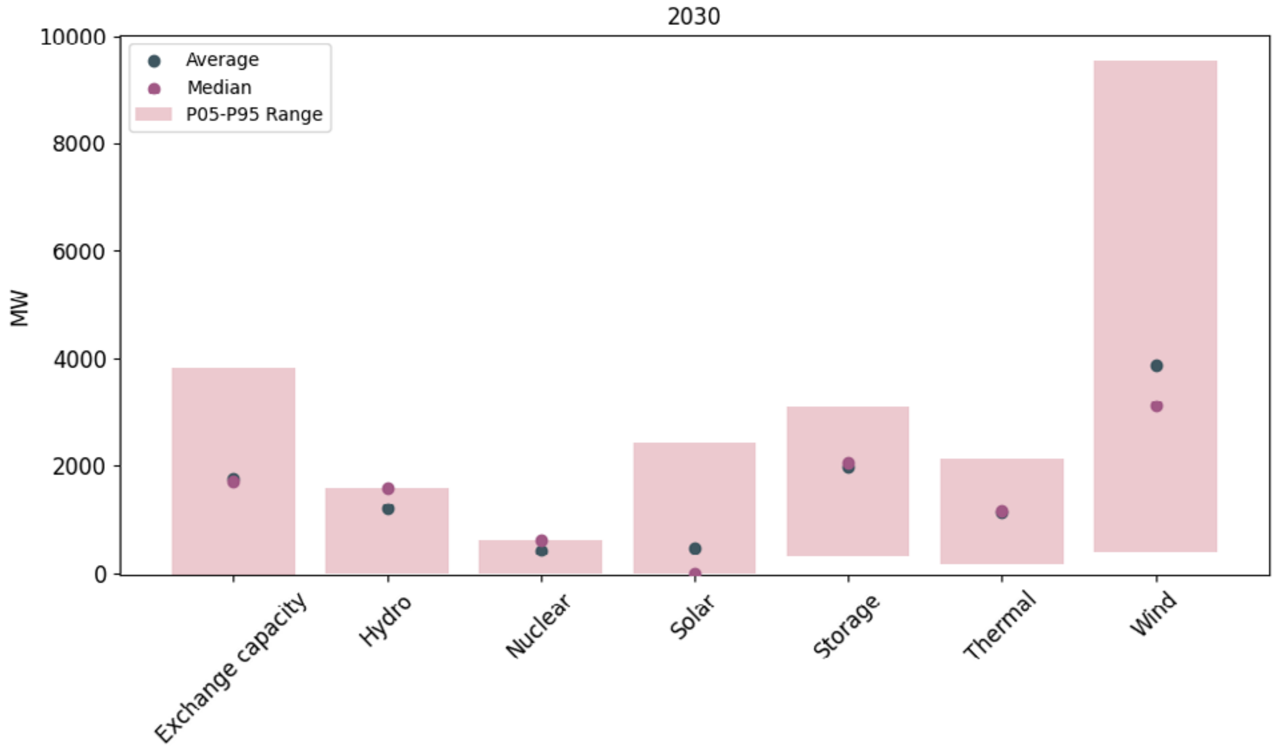


FIGURE 4 Hourly availabilities of flexible resources in 2030 for downward regulation.

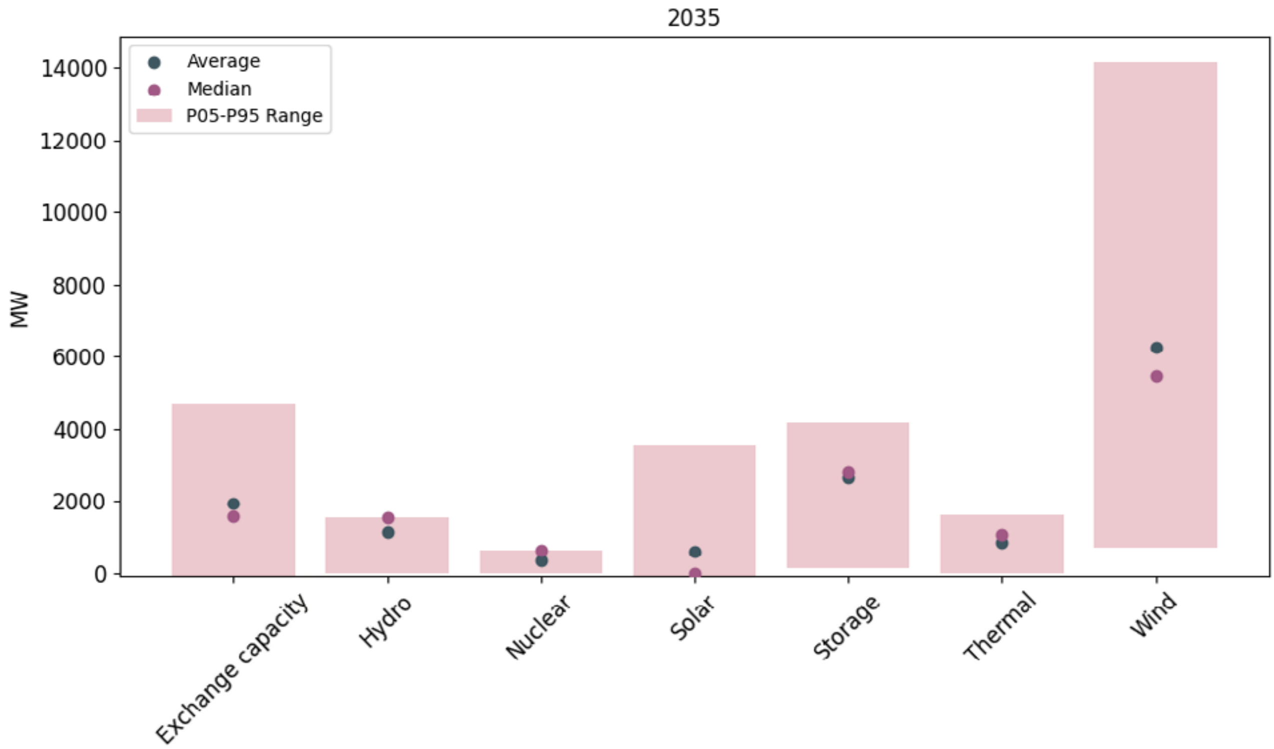


FIGURE 5 Hourly availabilities of flexible resources in 2035 for downward regulation.

The determination of flexible resources is subject to a number of assumptions and constraints, as outlined below.

- Exchange capacity is considered zero in case of extreme price situation in neighbouring bidding zones. This assumption is based on the FNA methodology, allowing reductions in the periods with 1% lowest and 99% highest price of the economic dispatch model results. There is no further assessment of resource availability in neighbouring bidding zones, and therefore the flexible resources may be overestimated at certain times.

- Hydropower, nuclear and thermal availability is simplified and is expected to be able to ramp up full capacity in MTU despite possible real-world restrictions.

- A thermal power plant is not considered as flexible resource when it is not in operation due to their start-up time constraints.

- Most Finnish nuclear power capacity is not flexible in real-world operation. However, due to modelling challenges in ERAA explained below, all five nuclear power plants are included in upward regulation but only one in downward regulation.

- Only part of the wind turbines and solar panels on industrial sites are expected to participate in balancing due to technological and contractual limitations. Both technologies can be used in downward regulation, and also in upward regulation if they have been curtailed.

- As the ERAA 2024 dataset does not include the state of charge of batteries, the estimated ability of batteries to provide upward and downward regulation may be overestimated in certain hours.

- Demand response is expected to only participate in day-ahead market and it is not included as flexible resource due to lack of data and uncertainties

The assessment of flexibility availability is influenced by ERAA modelling regarding the dispatch order of generation units. In the ERAA framework, prior to curtailment of renewable generation, conventional generation including nuclear and other thermal power plants are reduced to levels that do not reflect realistic system operation. This affects the distribution and availability of flexibility across technologies besides the level of RES curtailment in the system.

For downward flexibility, this assumption has a relatively limited impact on the total available capacity. While the allocation of downward flexibility may shift between technologies, the overall magnitude of downward flexibility remains broadly unchanged. As a result, the modelling primarily affects how downward flexibility is distributed rather than the total volume available.

For upward flexibility, however, the impact is more significant. As conventional units are reduced instead of renewable generation being curtailed, these units may not be able to provide upward regulation in subsequent hours due to start-up time constraints. This can lead to a reduction in the total available upward flexibility. In contrast, if curtailment was applied to renewable generation, the curtailed RES capacity could potentially be used for upward regulation, thereby increasing the total upward flexibility available to the system.

For upward flexibility, the data shows that in 2030 the system relies primarily on exchange capacity and storage, with moderate contributions from other technologies including hydro, nuclear and thermal. In 2035, exchange capacity and storage provide still a high share of flexibility with growing capacities while the contribution of hydro, nuclear and thermal is staying at rather same level. The main difference between the target years is the contribution of wind power. In 2030, its contribution is nearly zero while in 2035 it becomes the main contributor of flexible resources. For downward flexibility, wind power provides the highest amount of flexibility in both 2030 and 2035, followed by storage, exchange capacity and hydro.

2.3. Approach to network needs

The assessment of network-related flexibility needs in this report focuses on identifying potential constraints in the transmission and distribution grids that may limit the efficient use of flexible resources. The evaluation of network needs distinguishes between transmission and distribution systems, reflecting their different roles and data sources.

For the transmission system, the assessment is limited to a simplified analysis of north–south transmission across the Cross-section Central Finland. At the distribution level, network needs are assessed by each DSO based on their DNDPs of 2026. These provide a perspective on local grid constraints and expected developments, allowing the identification of location-specific challenges that may not be visible in system-wide modelling.

2.3.1. Quantification of TSO network needs

The quantification of TSO network needs is based on the cost-benefit analysis, comparing the usage of flexible resources as an alternative to new grid investments. The following simplified methodology to perform the CBA was agreed with the Finnish Energy Authority. Similar methodology has been already used as part of ENTSO-E's Ten-Year Network Development Plan (TYNDP) in the cycle of 2024 to calculate the CBA for the Finnish internal project.

The analysis was performed with averaged datasets, representing all 15 outage patterns, for all three weather scenarios and two target years, six analyses in total. The basis of the analysis is the transmission across Finland in North-South direction, more specifically, over the Cross-section Central Finland, also called Cut P1[3]. Cross-sections are virtual boundaries defined on electrotechnical bases. The transmission of electricity on power lines passing through cross-sections is closely monitored. Grid reinforcements increasing the capacity in Cross-section Central Finland are a major part of Fingrid's investment plan. The approximate geographical location of the Cross-section Central Finland is presented in the Figure 6.

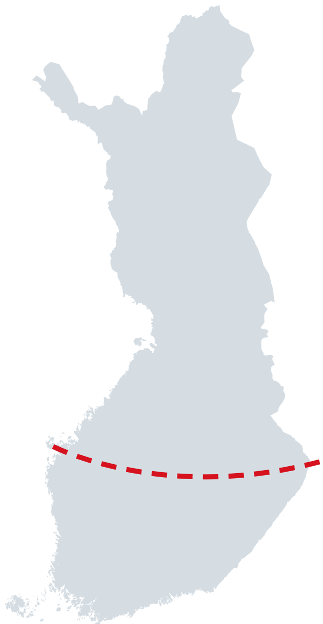


FIGURE 6 Approximate location of the Cross-section Central Finland (Cut P1).

[3] Continuously updated measurement and capacity on the transmission over Cross-section Central Finland can be found on Fingrid's webpage: https://www.fingrid.fi/en/electricity-market-information/history-data-from-cut-p1/

For the majority of hours during a year, the direction of transmission is from north to south and if the capacity in Cross-section Central Finland is not sufficient for transmission need during some hours, the redispatch of generation assets might be required to fulfil the electricity demand in the southern part of the country. The analysis was inspecting the alternative of using flexible generation assets instead of expanding grid. The assets included in CBA modelling were demand side response, gas turbines, small part of nuclear capacity[4] and some of the capacity of CHP plants. All these assets would participate in redispatch based on merit order, determined by their short-run marginal cost taking into account fuel, CO_2 and operational costs for generation assets and threshold price for demand side response.

Given the limitations of the available data and resource constraints, modelling of actual load flows across the Cross-section Central Finland was not seen as a feasible option. Therefore, CBA utilised a rough approach based on simple energy balances calculated for both northern and southern part of the country, split by Cross-section Central Finland. The flow of electricity between two balance areas was assumed to be simply the sum of domestic generation and import, subtracted by the sum of domestic consumption and exports. The resulting transmission can be calculated for either of balance areas, north or south, with the equation below.

Generation + Import – Consumption – Export = Transmission between North and South

2.3.2. Quantification of DSO network needs

The quantification of distribution network needs is based on structured input collected from DSOs who were requested to provide their assessment of network needs using a standardised table provided in the FNA methodology, ensuring consistency and comparability of results across different distribution networks. However, it should be noted that the level of detail and the underlying methodologies used by DSOs may vary, as the inputs are based on their respective network development plans and planning practices. Therefore, DSOs were required to provide supporting information on the data and assumptions underlying their assessment.

The table used for data collection captures key attributes of network constraints and the associated flexibility needs. DSOs were asked to report flexibility needs separately for both target years and for upward and downward directions. They were also given the option to provide information on the geographical location and voltage level of the constraint, although this was not mandatory. In addition, they were able to indicate the expected contractual arrangements or mechanisms through which flexibility could be procured.

Flexibility needs were required to be quantified both in terms of maximum power and total energy. In addition, DSOs were asked to specify a time block indicating when the flexibility need occurs, such as the time of day or period of the year. For downward flexibility needs, DSOs were further requested to estimate the share attributable to RES curtailment.

[4] Part of the capacity of one of Finland's nuclear reactors, Olkiluoto 3, can be considered flexible and available for redispatch.

2.4. Approach to fine-tuning

Fine-tuning refers to an additional step in system needs calculation, where the flexibility needs are adjusted to include network limitations and to better reflect real-word constraints on the availability of flexible resources. According to the FNA methodology, three criteria are used to determine whether fine-tuning is required. These criteria are the following:

1. The annual RES curtailment due to network constraints at transmission level shall be higher than 10 % of the RES curtailment.

2. The annual RES curtailment due to network constraints at distribution level provided by the DSOs shall be higher than 10 % of the RES curtailment.

3. The maximum hourly unavailability of flexible resources due to prequalification and temporary limits shall be higher than 10 % of the installed capacity of flexible resources.

Transmission network need assessment includes only the CBA on this preliminary round of FNA and therefore no explicit quantification of downward network needs is carried out, distribution network constraints are less than 10% of the RES curtailment on both target years as described in Table 1, and due to lack of data and uncertainties, prequalification or temporary limits are decided to be neglected. Therefore, none of the criteria above is met and no fine-tuning is carried out.

TABLE 1 Assessment of the distribution level fine-tuning criterion.

TY	RES curtailment due to distribution network constraints	RES curtailment	Distribution network constraint contribution to RES curtailment
2030	40 GWh	700 GWh	6%
2035	20 GWh	14 300 GWh	0.1%

3. Results of flexibility needs assessment

3.1. System needs

This section presents the results of the system flexibility needs assessment for the selected target years. The results are structured according to the three indicators defined in the methodology: RES integration, ramping and short-term needs. For ramping and short-term needs, the analysis distinguishes between upward and downward flexibility requirements, reflecting different operational conditions and challenges in maintaining system balance, while RES integration needs describe the structural evolution of the system.

3.1.1. RES integration needs

RES integration indicator provides an overview of the expected evolution of renewable energy generation in the system. Finland's RES integration target is 65 % for 2030 and 69 % for 2035. This means approximately 86 TWh of RES generation for 2030 and 115 TWh for 2035 based on demand of three used weather scenarios of ERAA 2024.

3.1.1.1. Characterisation of residual load time series

Residual load time series have been extracted from the ERAA 2024 dataset to support the subsequent analysis. Based on these time series, hourly, daily and seasonal flexibility needs were calculated and the results are presented in Figure 7 as annual flexibility needs in TWh. The indicators are defined as following:

1. Hourly indicator: sum of positive variations between the hourly residual load and its daily average, flexibility needs driven mostly by the daily variation of demand and RES generation.

2. Daily indicator: sum of positive variations between the daily residual load and the weekly average, flexibility needs driven mostly by wind regimes and variation in demand between weekdays and weekends.

3. Seasonal indicator: sum of positive variations between the monthly residual load and the annual average, flexibility needs driven mostly by seasonal variation of both RES generation and demand.

In the hypothetical case where residual load remained constant over time, no flexibility would be required. However, the results show variability across all timeframes, indicating a need for flexibility in the system. The analysis highlights that flexibility needs are highest at the daily level, suggesting that day-to-day variability, particularly driven by wind production patterns, is the dominant source of system stress. This reflects the expected increase in wind power capacity in Finland in the 2030s. In addition, all indicators show a clear increase from 2030 to 2035, pointing to a growing requirement for flexibility as the system evolves.

The relatively high daily flexibility needs indicate that the system will increasingly depend on resources capable of managing multi-day variations, such as demand response and flexible generation. At the same time, the increase in hourly flexibility needs suggests that intraday balancing requirements will become more demanding, highlighting the need for sufficient fast-reacting flexibility to respond to short-term fluctuations.

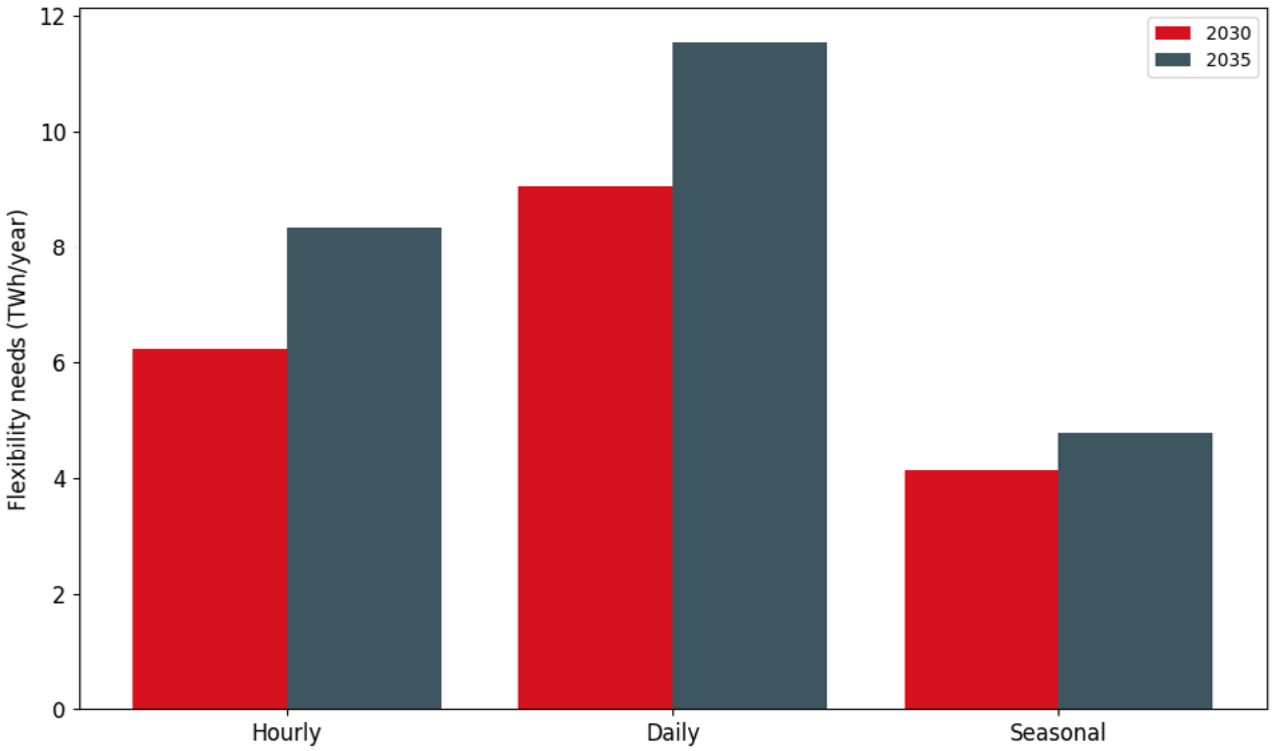


FIGURE 7 Hourly, daily and seasonal flexibility needs as an annual average.

3.1.1.2. Characterisation of RES curtailment

Curtailment was analysed across hourly, daily and seasonal timeframes in terms of energy, duration and interval. Figure 8 presents the cumulative energy of curtailment over the year for 2030 and 2035, while Tables 2 and 3 summarise the curtailment levels across different timeframes. Renewable generation capacity grows through the years resulting in growing curtailment from 2030 to 2035 in all timeframes. Curtailment occurs especially during the weekends and during the months of May, November and December. During the day, curtailment is rather even between the day and nighttime. In Annex 1, more detailed graphs of curtailment are presented indicating how curtailment occurs during different hour of the day, day of the week and month of the year, and also in which kind of system conditions in terms of wind generation, solar generation and demand.

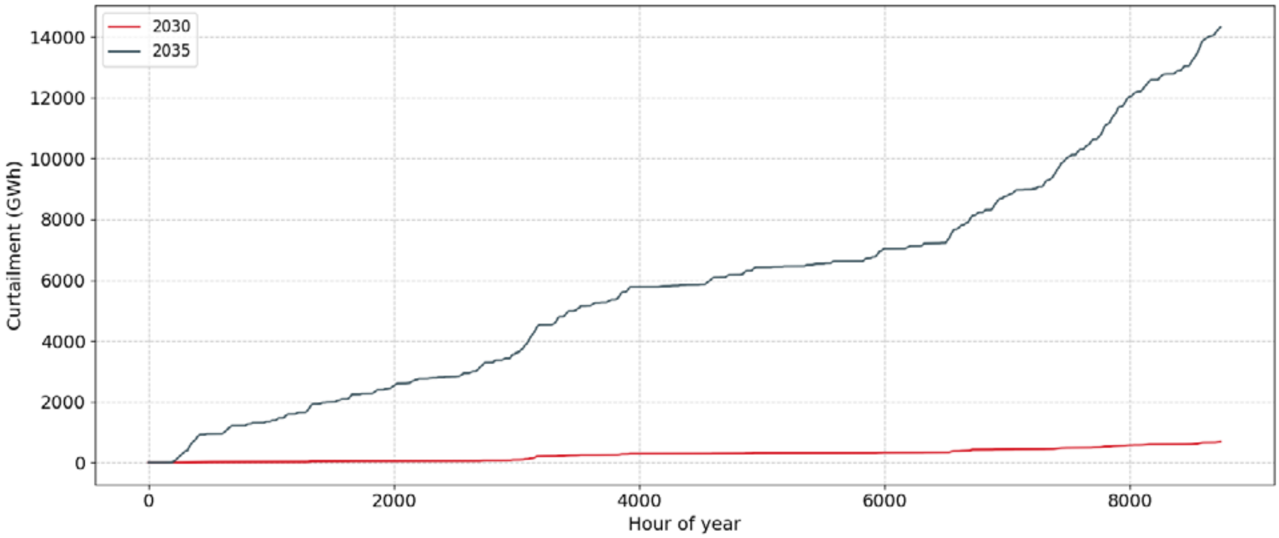


FIGURE 8 Annual cumulative curtailment in 2030 and 2035.

TABLE 2 Curtailment levels in MWh.

Timeframe	TY	Minimum curtailment	Average curtailment	Maximum curtailment
Hourly	2030	0	80	14 700
	2035	0	1 600	33 600
Daily	2030	0	1 900	155 700
	2035	0	39 400	517 500
Seasonal	2030	0	56 900	457 700
	2035	19 100	1 194 000	5 118 000

TABLE 3 Curtailment percentiles across timeframes in MWh.

Timeframe	TY	P50	P90	P95
Hourly	2030	0	0	0
	2035	0	7 600	11 800
Daily	2030	0	900	9 600
	2035	0	147 000	219 800
Seasonal	2030	26 000	144 600	211 100
	2035	745 000	3 117 000	3 700 000

Duration characteristics are presented in Table 4, where it can be seen how the duration of curtailment events increases significantly from 2030 to 2035, indicating that excess generation occurs not only more frequently but also persists for longer periods. Consecutive curtailment describes the duration of continuous curtailment events, indicating how long periods of excess generation persist without interruption. In contrast, interval describes the time between such events and therefore reflects how frequently curtailment occurs in the system. As shown in Figure 9, on average around 20 % of hours have curtailment in 2035 and only few percentages in 2030. Daily and monthly exceedance curves are found in Annex 1.

TABLE 4 Duration characteristics of curtailment in hours.

Timeframe	TY	Average consecutive	Maximum consecutive	Average interval	Maximum interval
Hourly	2030	6	59	101	2 728
	2035	15	190	58	1 440
Daily	2030	2	8	13	114
	2035	3	19	6	60
Seasonal	2030	4	12	3	4
	2035	12	12	0	0

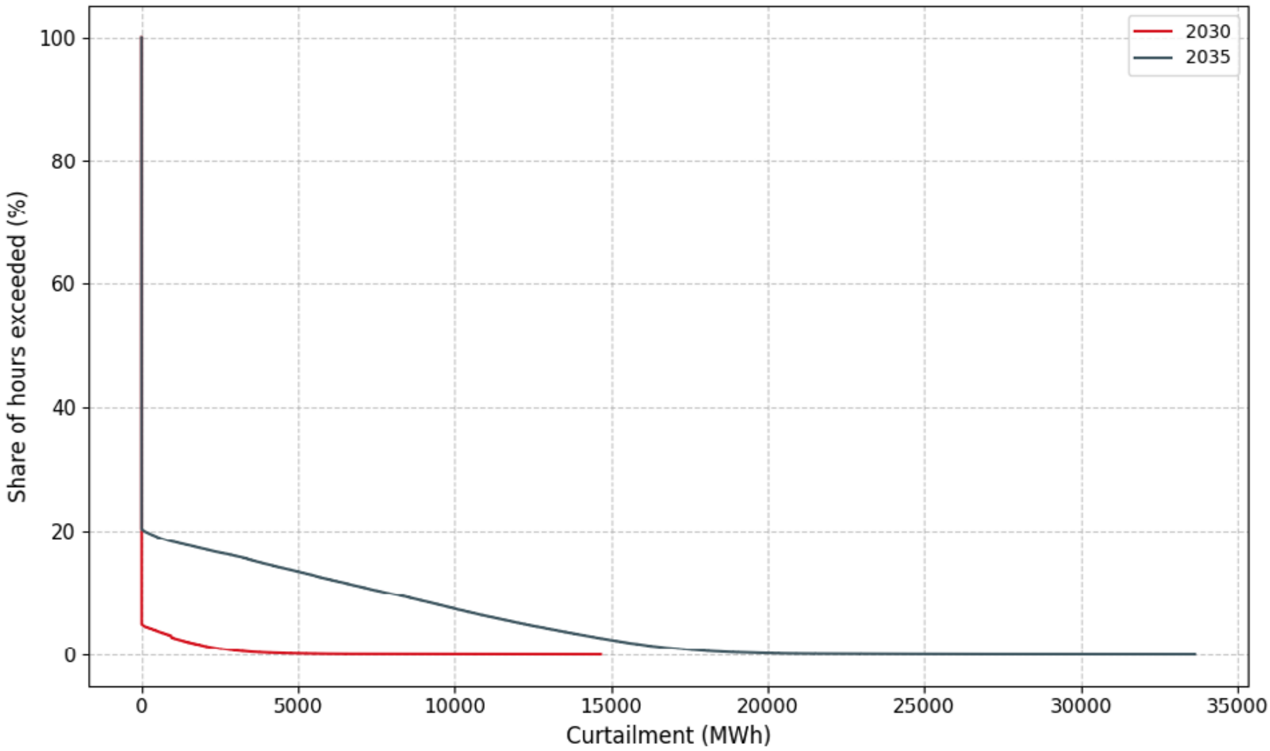


FIGURE 9 Exceedance curves of hourly curtailment.

3.1.1.3. Uncovered RES integration needs

On both target years, the level of RES generation surpasses the RES integration targets and therefore uncovered RES integration needs were not discovered, as shown in Table 5. Although no needs were identified, the curtailment levels projected especially for 2035 indicate that additional flexible resources and network development could enable the utilisation of a larger share of renewable generation. Generation of wind turbines, solar panels, hydro power plants and CHP plants using biomass as their fuel were considered as RES in this analysis and are included in the RES integration shares.

TABLE 5 The fulfilment of RES integration targets.

TY	RES integration target	RES integration based on ERAA 2024
2030	65 %	79 %
2035	69 %	90 %

3.1.2. Ramping needs

The ramping needs indicator reflects the magnitude and frequency of changes in residual load and the corresponding need for system response. This describes the required adjustments in dispatchable resources between consecutive MTUs with the use of available flexible resources.

3.1.2.1. Characterisation of ramps

Hourly ramps were computed for 2030 and 2035 and Table 6 summarises ramping levels, where minimum ramping represents the largest downward ramp and maximum ramping the largest upward ramp. The results indicate that highest upward ramps are clearly larger than highest downward ramps, and the average ramp is positive in both target years.

However, the percentile analysis provided in Table 7 and Figure 10 show a different perspective. The median (P50) is close to zero, while P25 and P75 are of similar magnitude on opposite sides of zero. This indicates that although extreme upward ramps are larger, the overall distribution of ramps is relatively symmetric around zero.

For both directions, there is a slight increase in the magnitude of the ramp both in the morning and the evening. No clear differences are observed across days of the week, and even though some variation exists between months, there is no distinct seasonal pattern. In Annex 1, more detailed graphs of ramps are presented indicating how ramps occur during different hour of the day, day of the week and month of the year, and also in which kind of system conditions in terms of wind generation, solar generation and demand.

TABLE 6 Ramping levels in MW.

TY	Minimum	Average	Maximum
2030	-5 600	460	7 500
2035	-8 000	840	12 700

TABLE 7 Ramping percentiles in MW.

TY	P10	P25	P50	P75	P90
2030	-700	-300	-6	300	700
2035	-1 400	-500	-7	500	1 600

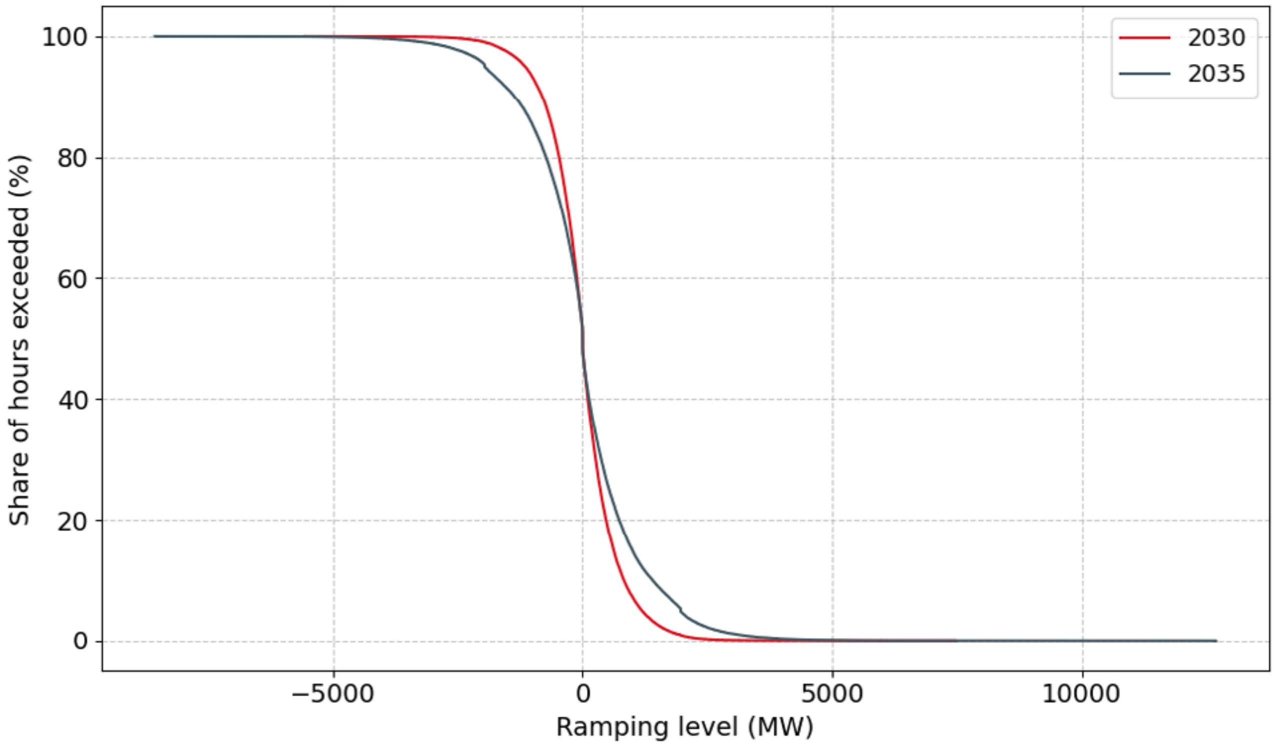


FIGURE 10 Exceedance curves of ramps.

The consecutiveness of ramps was also analysed to understand their behaviour. When analysing consecutive ramps, only changes in residual load greater than 1 MW are classified as ramps. Figure 11 and Figure 12 illustrate the magnitude of consecutive ramps in terms of total ramp energy, as well as the duration of these ramping events in consecutive hours.

The results for 2030 and 2035 show broadly similar characteristics in terms of both total ramp energy and duration. A similar pattern can be observed for upward and downward ramps, with similar distributions across consecutive hours and maximum total ramp energies reaching roughly 15 000 MWh in both directions. However, in 2030 the distribution shows a somewhat wider spread, particularly for longer-duration events, and some extreme values extend beyond 25 consecutive hours, whereas in 2035 the ramp durations remain more concentrated and typically below 20 consecutive hours.

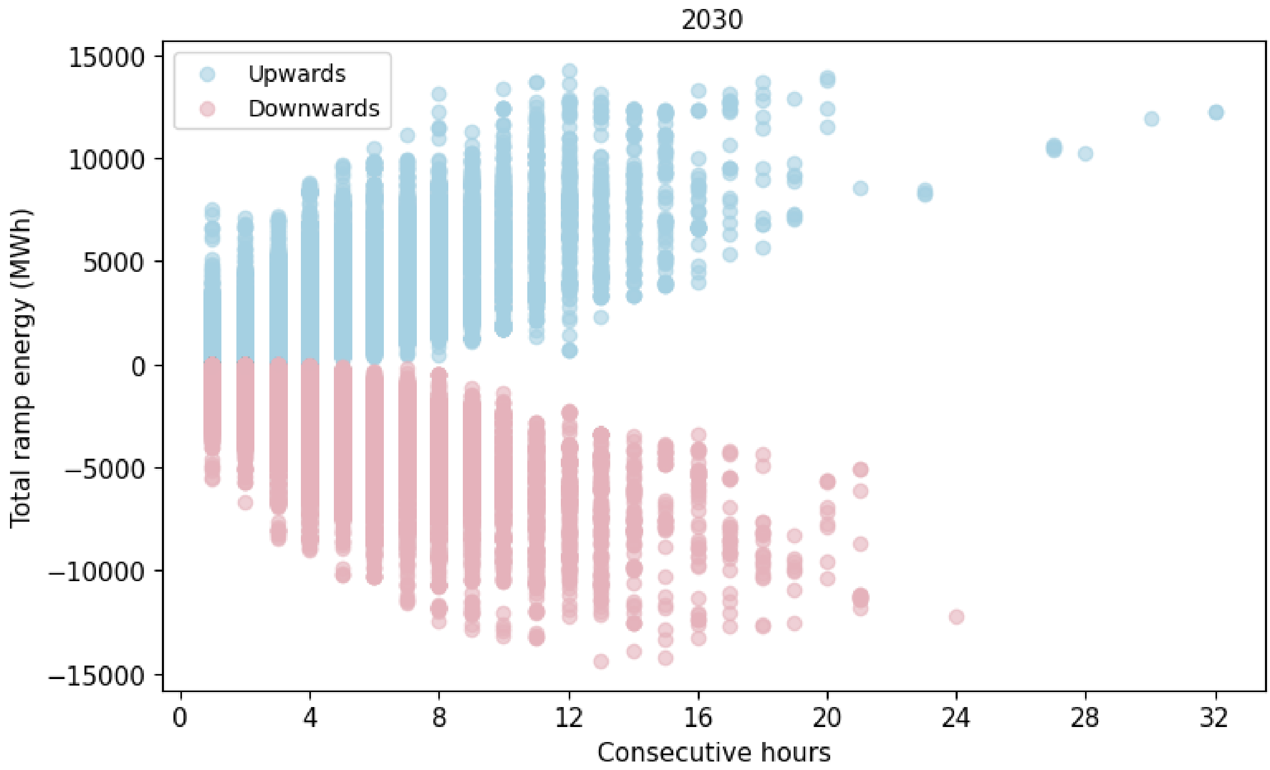


FIGURE 11 Consecutive ramps and their total energy in 2030.

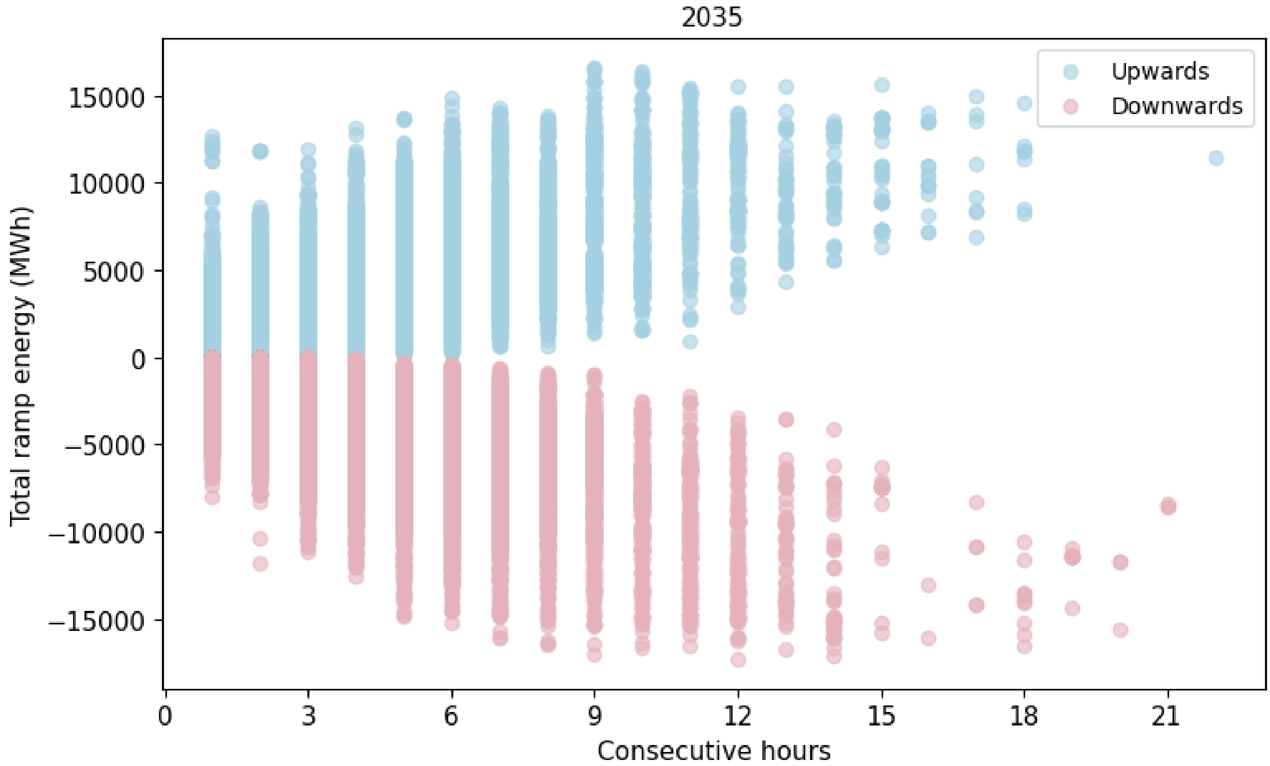


FIGURE 12 Consecutive ramps and their total energy in 2035.

3.1.2.2. Uncovered ramping needs

Uncovered ramping needs were determined to investigate how the system can manage variations in residual load. The hourly variation of residual load was compared to the available flexible resources, described in section 2.2.4. The assessment of uncovered ramping needs is sensitive to the assumption of available flexible resources and the results are highly dependent on it. Therefore, the identified uncovered ramping needs should be interpreted as indicative, reflecting the assumed flexibility portfolio rather than exact representation of future system capabilities.

Uncovered ramping needs were discovered upwards for both target years and downwards for 2035. The uncovered needs are presented in Figure 13 as annual average of uncovered hours and expected uncovered energy. Uncovered ramping needs increase clearly towards 2035, especially for upward regulation. Upward needs rise from an annual average of around 9 uncovered hours in 2030 to nearly 15 hours in 2035, with the expected uncovered energy increasing from 3 700 to 7 700 MWh. The increase in uncovered ramping needs is driven by the growing size of the system and higher shares of renewable generation, which lead to higher variations of residual load and consequently higher ramping requirements. Downward needs are not observed in 2030 but appear in 2035, although at a clearly lower level than upward needs, with expected uncovered energy of 2 100 MWh. If DSR would have been considered as a flexible resource, uncovered ramping needs upwards would decrease to an annual average of nearly zero hours in all cases.

Weather variability has a significant influence on the results of the assessment. The analysis was carried out using three weather scenarios and the values presented in this report represent averages across those scenarios. There is a clear variation between the weather scenarios and for ramping needs upwards, the expected uncovered energy ranges from 800 to 5 500 MWh in 2030, while in 2035 the results are more consistent, ranging from 6 000 to 9 000 MWh. The corresponding number of uncovered hours ranges from 3 to 14 hours in 2030 and from 12 to 18 hours in 2035. For downward ramping needs, the results vary from no uncovered energy to approximately 5 600 MWh depending on the weather scenario, with the number of uncovered hours ranging from zero to three.

The magnitudes of uncovered ramping needs are presented in Figure 14. While upward needs are much more frequent, they are lower in size compared to downward needs. For both target years the average uncovered upward need is around 500 MW while for downward needs it is around 1 500 MW. Even though the median and average of upward needs stay at the same range in 2030 and 2035, the highest percentiles grow towards 2035. Uncovered ramping needs are mostly one-hour periods, although two- and three-hour periods also occur for both upward and downward directions as described in Table 8. In addition, the table presents the average interval between consecutive events, showing that the number of hours between occurrences of uncovered needs decreases from 2030 to 2035.

Uncovered needs upwards exhibit clear temporal patterns across hours, days, and months. In both 2030 and 2035, higher shares are observed during specific hours of the day, particularly in the morning, with additional peaks in the evening. Weekly patterns show a relatively even distribution, although certain mid-week days have higher shares. Seasonally, uncovered ramping needs are spread across the year with high shares for both target years in January, May, July, August, September and October. In contrast, downward needs are most common in afternoon hours, over weekends and during the months of May and June.

When analysing system conditions, uncovered ramping needs upwards tend to occur during periods of relatively low wind production, while no clear relationship with solar production or demand is observed. In contrast, uncovered downward needs are discovered during periods of high wind production in combination with no solar production. More detailed graphs of uncovered ramping needs are presented in Annex 1, indicating how uncovered periods occur during different hour of the day, day of the week and month of the year, and also in which kind of system conditions in terms of wind generation, solar generation and demand.

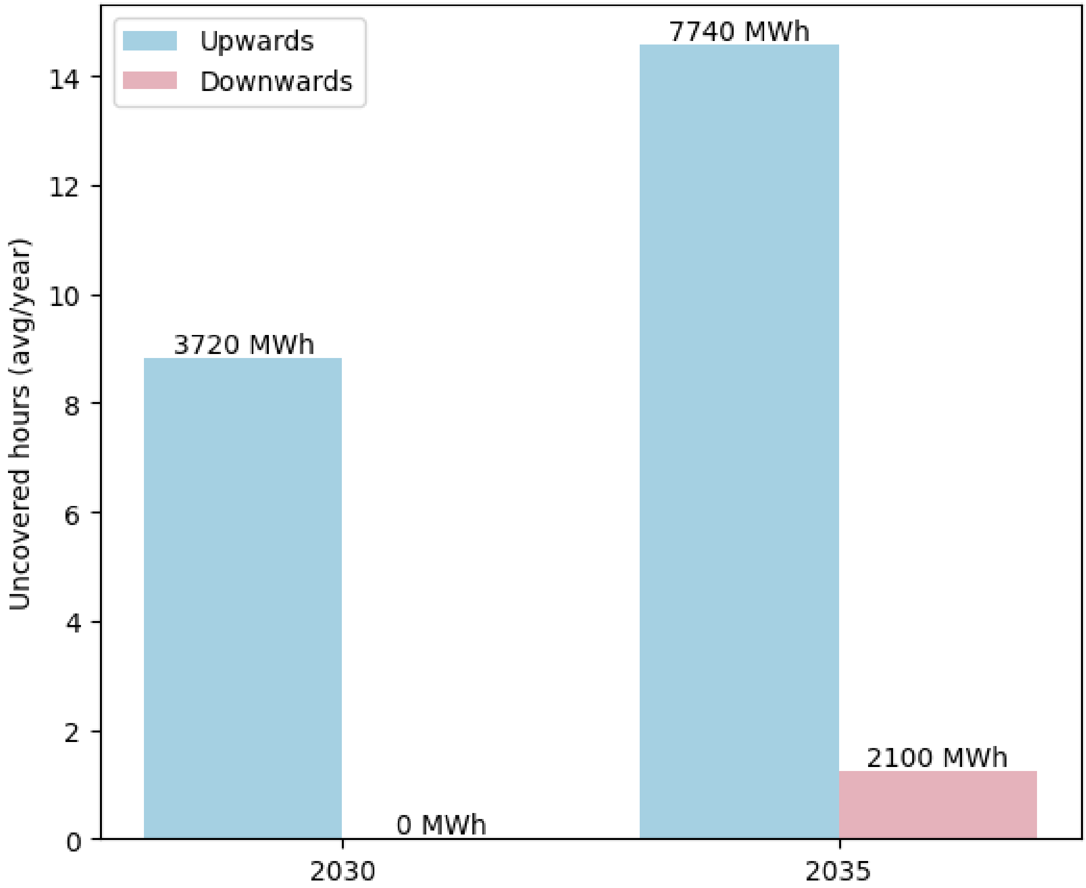


FIGURE 13 Uncovered ramping needs as annual average of uncovered hours (bars) and expected uncovered energy (MWh).

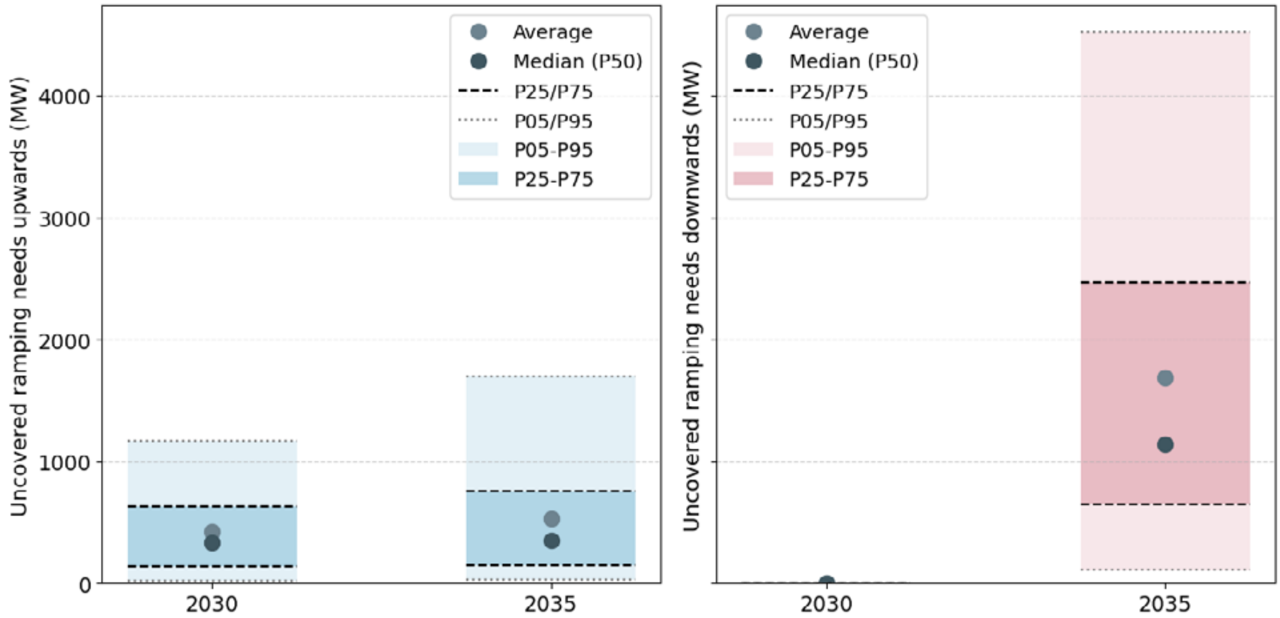


FIGURE 14 Percentile ranges of uncovered ramping needs.

TABLE 8 Duration characteristics of uncovered ramping needs in hours.

TY	Direction	Average consecutive	Maximum consecutive	Average interval	Maximum interval
2030	Upwards	1	3	729	6387
	Downwards	-	-	-	-
2035	Upwards	1	3	508	2758
	Downwards	1	3	27	483

3.1.3. Short-term needs

Short-term needs describe the required dispatchable resources to manage deviations between forecasted and realised conditions within the intraday timeframe, using the available flexible resources described in section 2.2.4. Short-term flexibility needs are investigated by analysing variations in demand and wind generation through their forecast errors. Uncovered short-term needs occur when the available flexible resources are not sufficient to cover these forecast errors.

3.1.3.1. Characterisation of forecast errors

As described in section 2.2.3, short-term needs were assessed as the forecast error of simplified residual load, using the 0.1 and 99.9 percentiles under different system conditions. Based on historical data, the forecast error is expressed as a proportion of the simplified residual load, ranging from 0.05 to 0.50 in periods requiring downward regulation and from 0.10 to 0.57 in periods requiring upward regulation. These coefficients were used to define forecast errors for each hour of the ERAA simulations for 2030 and 2035.

3.1.3.2. Uncovered short-term needs

Uncovered short-term needs occur when flexible resources cannot cover the forecast errors. The system was tested with high and rare forecast errors for every hour of the year for every weather scenario and outage pattern. On average, in 2030 there were 831 hours where system could not handle the error and did not have enough upward flexible resources, and the number of uncovered hours decreases to 696 in 2035, representing nearly 10 % of the hours in a year. No uncovered downward needs were identified for 2030, and in 2035 downward resources are not sufficient for less than one hour on average.

By taking into account the probability of such rare forecast error, the annual uncovered hours and expected uncovered energy are defined and presented in Figure 15. The identified uncovered upward needs are 0.8 hours annually for 2030 and 0.7 hours for 2035. Even though the average annual hours decrease towards 2035, the expected uncovered energy rises from 540 to 630 MWh. Uncovered downward needs for 2035 were as little as 0.0004 hours, with expected uncovered energy of 0.6 MWh, indicating that available downward flexibility appears to be sufficient in almost all cases.

The analysis was carried out using three weather scenarios, and the values presented in this report represent averages across those scenarios. The weather conditions had smaller impact on the expected uncovered energy of short-term needs compared to ramping needs, suggesting that based on these three weather scenarios the likelihood of uncovered needs due to forecast errors is relatively similar despite the weather conditions. Discovered expected uncovered energy upwards range from 300 to 800 MWh in 2030, and from 550 to 800 MWh in 2035. The number of uncovered hours shows little variation between weather scenarios especially in 2035, ranging from 0.6 to 1.1 hours in 2030 and differing by only 0.1 hours in 2035. Downward needs were extremely rare and were only observed in one weather scenario for one target year.

The magnitudes of uncovered short-term needs are presented in Figure 16. In 2030, upward needs are observed, with average uncovered need around 650 MW. By 2035, the average uncovered upward need rises to 900 MW, and the highest percentiles also increase, indicating more extreme short-term requirements. Downward needs emerge only in 2035, and although they occur significantly less frequently than upward needs, they are larger in magnitude, with average reaching nearly 1 500 MW. However, due to very low occurrence of such events, the results of their magnitude should be interpreted with caution.

The duration characteristics of uncovered needs are presented in Table 9. The maximum consecutive hours indicate that in case of prolonged forecast error, uncovered upward needs can last around 20 hours. On the other hand, the reasonably low average interval for uncovered needs upwards indicates that flexible resources are insufficient relatively often in case of a high and rare forecast error. Interval is defined as the number of MTUs between uncovered events within one weather scenario and outage pattern and for downward needs, it leads to a limited number of interval observations and consequently low interval values. The low downward interval values reflect the fact that uncovered needs occur mainly as single events within a given weather scenario and outage pattern or within few hours from the last event in case of multiple events within one simulation.

Uncovered short-term needs upwards vary over the course of the day, week, and year. In both 2030 and 2035, higher levels are observed during late evening and night hours, with lower values during daytime hours. Across the week, upward needs are relatively evenly distributed, although slightly higher levels are observed during weekdays compared to weekends. At the seasonal level, short-term needs occur throughout the year but tend to be higher particularly in January, April, May and August. Even though there is a clear distribution in expected energy of uncovered needs across hours, days and months, the magnitude of individual event remains relatively constant despite the time of its occurrence. Downward needs are absent in 2030 and remain minimal in 2035, appearing only on a Saturday around mid-day in May.

Uncovered short-term needs upwards seem to occur across a higher variety of system conditions compared to ramping needs, although they appear more frequently during periods of relatively low level of wind and solar production. However, uncovered short-term needs downward follow a similar pattern to ramping needs, occurring at relatively high wind production level combined with no solar production. More detailed graphs of uncovered short-term needs are presented in Annex 1, indicating how events occur during different hour of the day, day of the week and month of the year, and also in which kind of system conditions in terms of wind generation, solar generation and demand.

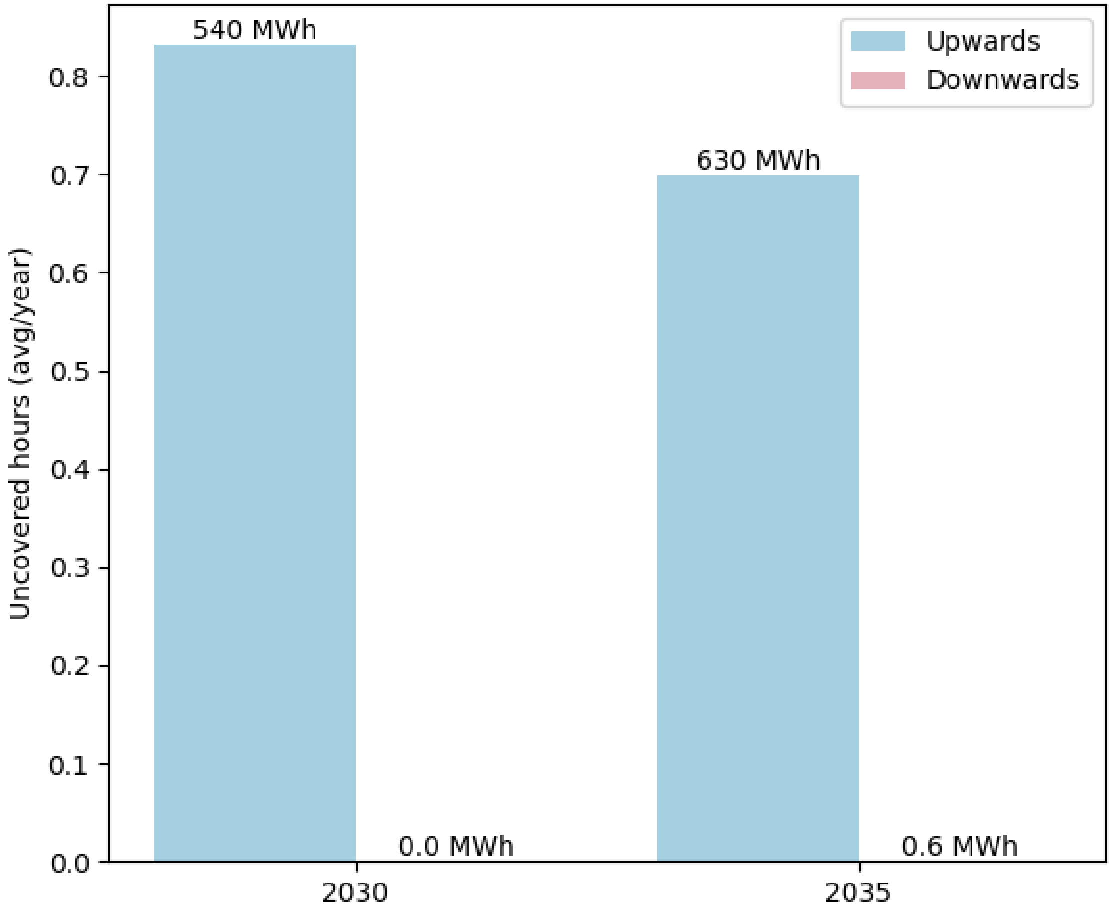


FIGURE 15 Uncovered short-term needs as annual average of uncovered hours (bars) and expected uncovered energy (MWh).

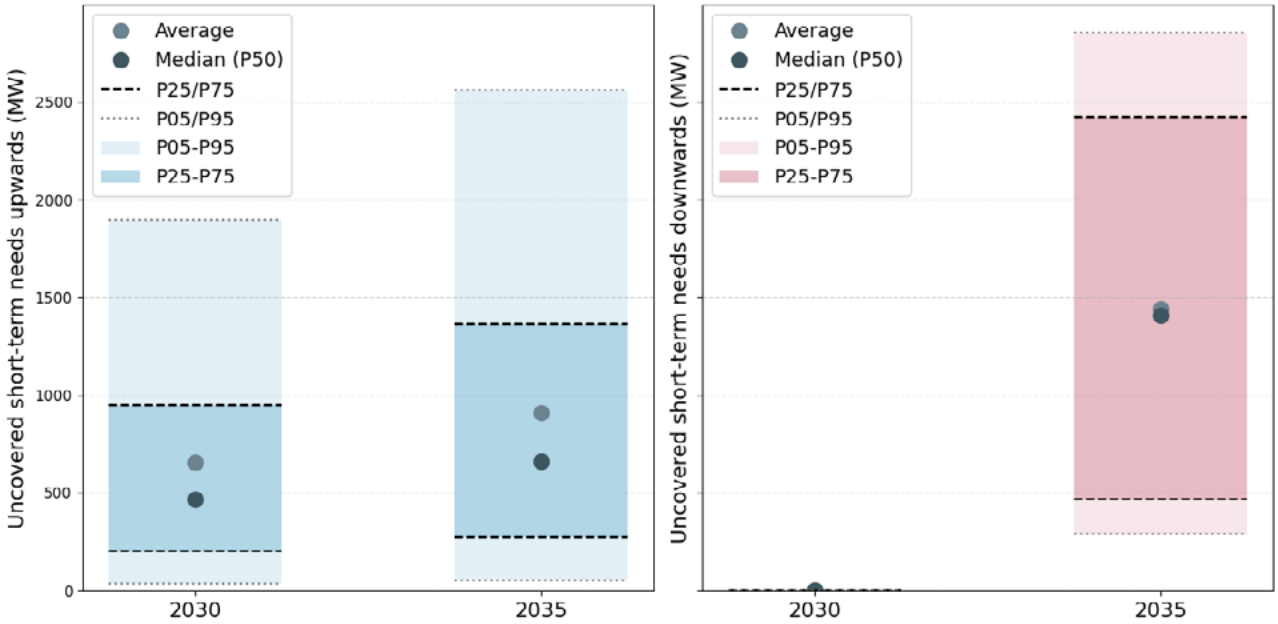


FIGURE 16 Percentile ranges of uncovered short-term needs.

TABLE 9 Duration characteristics of uncovered short-term needs in hours.

TY	Direction	Average consecutive	Maximum consecutive	Average interval	Maximum interval
2030	Upwards	2	22	10	385
	Downwards	-	-	-	-
2035	Upwards	2	19	12	487
	Downwards	2	3	1	2

3.2. Network needs

This section presents the identified network needs required to support the operation and development of the power system. The analysis distinguishes between transmission and distribution perspectives, reflecting differences in system roles and available solutions, as assessed by the respective parties. While section 3.1 focuses on system-level requirements, network need analysis translates these requirements into implications for network capacity and operational constraints.

3.2.1. TSO network needs

The underlying idea in cost-benefit analysis was to compare the required redispatch using flexible generation assets as an alternative to grid expansion. Capacity increases reinforcing the Cross-section Central Finland scheduled in Fingrid's investment plan until 2035 are presented in Table 10. The current transmission capacity across Cross-section Central Finland has been 4 500 MW on average during the first half of 2026. However, the available capacity is highly dependent on grid usage situation and external conditions such as temperature and wind. The capacity in Cross-section Central Finland is anticipated to increase to 7 400 MW on average by 2029 with the completion of new 400 kV overhead lines Järvilinja 2 and Lakeuslinja. By 2035, the capacity further increases to 11 400 MW with several grid investments.

TABLE 10 Grid reinforcements adding the transmission capacity in Cross-section Central Finland.

Planned year	Capacity (MW)	Reinforcement name
Current (2026)	4 500	
2029	7 400	Järvilinja 2, Lakeuslinja
2031	9 100	Hirvisuo-Seinäjoki
2033	10 400	Harjulinja
2035	11 400	Reinforcements elsewhere in grid and compensation investments

The cost-benefit analysis was performed using the methodology presented in section 2.3.1, used previously also in TYNDP process. The results of the CBA performed as part of the study are presented below in Tables 11 and 12.

TABLE 11 Use of flexible assets for redispatch in 2030.

		Transmission capacity (MW)		
	Weather scenario	**4 500 (2026 level)**	**7 400 (2029 level)**	**9 100 (2031 level)**
Redispatch generation (MWh)	WS14	890 000	39 000	0
	WS25	5 524 000	315 000	0
	WS28	4 000	400	0

TABLE 12 Use of flexible assets for redispatch in 2035.

		Transmission capacity (MW)		
	Weather scenario	**9 100 (2031 level)**	**10 400 (2033 level)**	**11 400 (2035 level)**
Redispatch generation (MWh)	WS14	259 000	9 000	0
	WS25	888 000	71 000	0
	WS28	1 170 000	175 000	4 000

Results indicate that without grid reinforcements redispatch of flexible assets would be required. In 2030, redispatch requirements are not observed if all the grid reinforcements scheduled by the end of that year are completed, adding the transmission capacity up to 9 100 MW. If the capacity would remain at the level of 2029, redispatch would be needed in amounts ranging from 400 to 315 000 MWh per year, highly depending on the weather scenario. If the capacity would remain at the current level, redispatch requirements are naturally even higher. The peak transmission in 2030 ranges between 8 400 and 9 100 MW.

In 2035, the scheduled reinforcements, adding up to 11 400 MW of transmission capacity, are sufficient to cover all situations in north-south transmission and redispatch is not needed, except for some very rare cases in WS28. Without the investments scheduled for 2035, the capacity would be 10 400 MW and redispatch would be needed in amounts ranging from 9 000 to 175 000 MWh per year in the analysed weather scenarios. Without previous grid reinforcements, redispatch requirements would reach even higher levels. The range in peak transmission is narrower than observed in 2030, ranging between 11 400 and 11 800 MW.

The flexible assets participating in redispatch were set into merit order based on their marginal cost in case of generation assets or their threshold price in case of demand side response. The availability of flexible assets is constrained by several factors such as maximum amount of hours in demand side response or must-run constraints in CHP plants. The usage of DSR is uncertain and therefore both situations, with and without DSR participating in redispatch, were evaluated resulting in a difference of few thousand megawatts in the amount of available assets.

In cases where all planned grid reinforcements are completed, there are only very minor redispatch requirements in one of the weather scenarios in 2035, which do not pose any challenge to the usage of redispatch resources. In 2030, even the highest redispatch requirements (i.e. WS25, with capacity at 4 500 MW) could be covered without participation of DSR. In 2035, the situation could become tight if DSR does not participate in redispatch and planned grid reinforcements are not completed.

It must be noted that transmission calculated in CBA does not represent actual load-flow calculations which are performed at Fingrid as part of long-term grid planning but rather a more simplified approach based on energy balances. The simplified methodology was used due to quality of available data and resource constraints as discussed in section 2.3.1. Therefore, the current CBA approach and results should be interpreted as indicative.

3.2.2. DSO network needs

Distribution system operators assessed their flexibility needs for 2030 and 2035, and the aggregated results are presented in Table 13. Given the large number of DSOs in Finland, the flexibility needs of an individual DSO typically remain relatively low, and a large portion of DSOs do not identify flexibility needs at all. However, a limited number of DSOs with significantly higher demand can drive higher flexibility needs at the DSO level, which is reflected in the average values.

Overall, total flexibility needs in terms of energy decrease towards 2035 for both downward and upward regulation. Upward flexibility needs remain around 70 GWh, whereas downward needs decrease from 58 GWh in 2030 to approximately half of that level by 2035. In terms of capacity, DSOs estimated the maximum power required during flexibility events. For downward needs, the average maximum power per DSO decreases from 40 MW in 2030 to 22 MW in 2035, and the median increases slightly from 15 to 19 MW. For upward needs, the required capacity increases significantly, with the average maximum power per DSO rising from 35 to 67 MW by 2035, and the median increasing from 5 to 27 MW. These values are calculated by assigning equal weight to each DSO regardless their energy volume. If the results were instead weighted by the reported energy volumes of flexibility needs, the average peaks would remain at relatively similar level.

Contractual means to access flexibility were also identified by DSOs and the responses indicate that flexible connection agreements are by far the most commonly expected contractual mechanism to enable flexibility. These agreements allow network users to connect under conditions where their capacity or operation may be limited or controlled, thereby supporting efficient use of grid capacity. Although flexible connection agreements were widely recognised as an important enabler of flexibility, several DSOs also highlighted barriers related to their implementation. In addition to flexible connections, local flexibility services and markets are frequently mentioned. These include locally procured services or market-based solutions that enable distribution system operators to manage congestion and balance the system.

TABLE 13 Flexibility needs of distribution system operators.

	2030		2035	
	Downwards	**Upwards**	**Downwards**	**Upwards**
Total flexibility needs of all DSOs (MWh)	58 000	83 000	27 000	77 000
Average of peak flexibility need per DSO (MW)	40	35	22	67
Median of peak flexibility need per DSO (MW)	15	5	19	27

4. Barriers for flexibility and contribution of digitalisation

4.1. Barriers for flexibility

Barriers to flexibility were evaluated separately by Fingrid and the DSOs in accordance with the FNA methodology. The assessment focused on six categories identified by ACER as potential barriers to the deployment and utilisation of non-fossil flexibility resources which are listed below.

1. Lack of proper legal framework for market access to new entrants and small actors
2. Lack of enablers and incentives to provide flexibility
3. Restrictive requirements to provide balancing services
4. Restrictive requirements to provide congestion management
5. Complex, lengthy, and discriminatory administrative requirements
6. Lack of regulatory incentives to system operators to consider non-wire alternatives

4.1.1. TSO barrier evaluation

ACER's recommendation on barriers for non-fossil flexibility[5] was used as guideline for Fingrid's evaluation. It focuses on identifying potential regulatory, market-based, and operational barriers that may limit the participation of non-fossil flexible resources in electricity markets. The responses are mainly structured around and aligned with the questions set out in the recommendation.

4.1.1.1. Lack of proper legal framework for market access to new entrants and small actors

Energy storage behind the meter

Regarding energy storage facilities which are combined with different facilities, such as renewable generation facilities, electric vehicle recharging points or final customers' demand facilities, there are no explicit technology-specific or combination-specific restrictions. Constraints are determined by grid capacity, voltage level, and system strength considerations. Energy storage facilities may be combined with any other assets, and all combinations are generally permitted, provided that the connection point voltage level supports the required power transfer capability.

The applicable limitations are primarily related to connection capacity and voltage level. At the 110 kV connection level, the maximum total active power exchange capacity at a single connection point shall not exceed ±250 MW for switchyard connections. This includes up to 125 MW of battery energy storage system (BESS) connected via the switchyard, as well as any DSO network connected to the TSO network through a single connection point. For direct power line connections, the maximum total active power exchange capacity shall not exceed ±60 MW, including up to 30 MW of BESS. This limitation also applies to DSO networks connected to the TSO network via a single connection point. At the 400 kV connection level, generation capacity behind a single connection point shall be permitted up to 1.3 GW, corresponding to the system's dimensioning fault.

[5] Recommendation No 01/2026 of the European Union Agency for the cooperation of energy regulators of 19 March 2026 on NRAs' reporting on barriers for non-fossil flexibility: https://www.acer.europa.eu/sites/default/files/documents/Recommendations/ACER-Recommendation-01-2026-NRAs-reporting-barriers-to-flexibility.pdf

Aggregation and market access restricted due to lack of legal eligibility

Aggregation of consumption, generation, and storage is legally allowed in all electricity markets in Finland, and several aggregation models are in use. Aggregation and independent aggregator are included in the national legislation in Finland. The Electricity Market Act (588/2013) in Finland states that further regulation on independent aggregation may be given as a government decree. The government decree is pending.

An integrated aggregation model, i.e. the aggregator is the balance responsible party (BRP) or supplier of the resource, is in use in all electricity markets in Finland. A contractual balancing service provider (BSP) model is in use in all balancing markets (FCR-D, FCR-N, FFR, aFRR, mFRR). Implementation of independent aggregation has been carried out in FCR-D, FCR-N, FFR and aFRR. Independent aggregation is currently not possible in day-ahead, intraday and mFRR markets. In June 2026, Fingrid published a questionnaire to gather market participants' and other stakeholders' views on the future development of independent aggregation model in all electricity markets in Finland. As part of the questionnaire[6], Fingrid published material describing the concept of a future independent aggregation model for all electricity markets.

There is an on-going pilot market (FinFlex project) to test the operation of a common TSO-DSO congestion management market. At the moment, Fingrid and one DSO (Helen Electricity Network Ltd.) are participating in the project. In FinFlex, integrated model and contractual flexibility service provider model are in use.

It is legally allowed for final customers (household, commercial, industrial), renewable producers, and energy storage operators to participate in wholesale markets and system operation services following the same principles as aggregators and other electricity market participants. Citizen energy communities and renewable energy communities are not yet fully implemented in national legislation.

Unclear framework for access to final customer data

Non-discriminatory and transparent procedures for access to metering and consumption data by final customers and eligible parties have been implemented through the central information exchange system (Fingrid datahub) and mapped to the reference model established in Commission Implementing Regulation (EU) 2023/1162. The mapping has been reported to the European Commission by the Ministry of Economic Affairs and Employment, and the report has been published at the repository website at data-interoperability.eu. This establishes a clear and transparent framework for access to final customer data.

The charges imposed by the operator of the central information exchange system on the eligible parties must be non-discriminatory and transparent, and they must be based on the services provided to the eligible parties and other market participants. The charges can only be used to cover operating costs and a reasonable allowed return for investment, as regulated by the national regulation authority.

[6] More information about the questionnaire (available in Finnish) can be found on Fingrid's website: https://www.fingrid.fi/ajankohtaista/tiedotteet/2026/kysely-itsenaisen-aggregoinnin-tulevaisuuden-kehityksesta/

Ownership restrictions for energy storage and electro-mobility
The Electricity Directive prohibits TSOs from owning, developing, managing or operating energy storage facilities. There are currently no effective derogations for TSOs for owning, developing, managing or operating energy storage facilities.

Restrictions on trade in day-ahead and intraday markets
There are no special restrictions for trading in day-ahead nor intraday markets in Finland. The smallest minimum bid size is the same as in the rest of the area, 0.1 MW according to the common SDAC and SIDC rules. The imbalance settlement period is 15 minutes, and it is possible for market participants to trade on 15 minutes.

4.1.1.2. Lack of enablers and incentives to provide flexibility

Majority of Finnish retail electricity customers, over 99 %, live in households equipped with smart metering. The share has remained the same since at least 2021. Therefore, Finland has very strong prerequisites for offering dynamic price contracts to retail customers. Only few of the Finnish retail electricity suppliers have more than 200 000 final customers, and all of them offer dynamic price contracts.

By 31.12.2024, shares of retail customers with different contract types were the following: fixed-term 45 %, open-ended 22 %, and dynamic 33 %. The share of dynamic price (i.e. spot price) contracts has increased rapidly during recent years from 9 % in 2021. Overall, dynamic price contracts and optimization of consumption to match the cheapest hours have gained a lot of public interest among household customers in Finland, regardless of the increased volatility in electricity prices since 2022.

In addition, number of customers with a network service contract for partial self-generation has increased rapidly to 113 700 (of which 101 600 are households) in 2024 from 41 800 in 2021. Number of energy communities in distribution grids was 280, housing 3 300 consumption places in 2024.

Regarding grid tariffs, Fingrid and many DSOs are currently applying static time-of-use grid tariffs for consumers. A typical time-based distribution service offered by DSOs is composed of a basic fee, a power fee (EUR/kW/mo), distribution fees which are different at night and day, and electricity tax. Some DSOs offer seasonal distribution contracts, which generally have higher prices during daytime in winter months (e.g. Nov-Mar). At least five largest DSOs in Finland, serving nearly 2 million customers, offer contracts with such time-of-use elements.

4.1.1.3. Restrictive requirements to provide balancing services

Large minimum eligible capacity and non-market based balancing products
Minimum bid size is 0.1 MW for FCR-N and 1 MW for all other reserve products. Fingrid does not have local balancing products or non-standard balancing products, and purchasing of balancing capacity and balancing energy is market based. Balancing capacity for all products is purchased via daily capacity markets. Balancing energy is purchased via continuous aFRR and mFRR energy markets.

Restrictions in the prequalification of reserve providing groups
Prequalification of reserve providing groups is allowed for all reserve products. Generation, demand and storage units are allowed to be combined under the same reserve providing group in all reserve products. Separate prequalification for provision of balancing capacity and balancing energy is not required.

Unregulated duration or long prequalification process
Prequalification process follows the requirements stated in System Operation Guideline. Within 8 weeks from receipt of FCR or FRR application, the reserve connecting TSO or the designated TSO shall confirm whether the application is complete. Where the reserve connecting TSO or the designated TSO considers that the application is incomplete, they shall request additional information and the potential FCR/FRR provider shall submit the additional required information within 4 weeks from the receipt of the request. Within 3 months after the reserve connecting TSO or the designated TSO confirms that the application is complete, the reserve connecting TSO or the designated TSO shall evaluate the information provided and decide whether the potential FCR/FRR providing units or FCR/FRR providing groups meet the criteria for a FCR/FRR prequalification.

4.1.1.4. Restrictive requirements to provide congestion management

Unjustified lack of market-based TSO congestion management
Fingrid has several tools to address physical congestion. The choice of the tool is made based on the type of congestion and the lead time before the congestion may cause issues.

The main market-based measure is mFRR special regulation. It can be utilized in faults of intra-zonal components or cross-zonal ones. Other market-based measures include a congestion management agreement (bilaterally pre-agreed price for activation) and a TSO-DSO congestion management market FinFlex which can be utilized to release the mFRR capacity in persisting congestion situations. FinFlex is still in pilot phase and has not been actively used yet. For interconnection faults Fingrid utilities also intraday market countertrade with neighboring countries.

For planned maintenance outages Fingrid has the possibility to limit generation or consumption of its customers based on the connection agreement. Congestions outside of the planned outage situations are still rare in the Finnish transmission system.

Constraints in local markets for TSO/DSO congestion management
The foreseen congestion management needs can be significant in terms of power but they occur seldom. This characteristic of the demand causes challenges for development of an efficient market and increase of liquidity requires time.

Fingrid has been piloting a TSO/DSO congestion management market FinFlex with one of the Finnish DSOs. The market is still in its infancy, and the liquidity is being built gradually. During the first year of its operation (May 2025 to May 2026) there were no realized activations. Market parties are still entering the market and onboarding their flexible resources, and after one year the capacity available on the market has reached a level that is relevant for the congestion management on the high voltage grid. The pilot lasts until the end of 2027.

The regulatory model of the TSO in Finland does not incentivize the use of market-based flexibility. Thus, Fingrid utilizes first the OPEX-neutral alternatives which often also bring the best social welfare benefit.

4.1.1.5. Complex, lengthy, and discriminatory administrative requirements

Inefficient grid connection procedures

Fingrid publishes online up-to-date information on available grid capacity for connections. Capacities are given separately for power production, power consumption and for battery energy storage systems.

Obtaining a grid connection permit starts with the connection agreement. Requirements for connection agreement are provided online and connection agreement application can be filled in electronic form. Connection agreements are signed electronically. Connection agreements are usually signed about 1-3 years before the connection.

Obtaining the connection permit means fulfilling Fingrid's general connection terms, grid code specifications and other requirements. These requirements are provided online and the process of fulfilling the required requirements is carried out in Fingrid's extranet service My Fingrid. Connection process in My Fingrid informs the customer about the required steps and deadlines. Different procedures can and should be run parallel to each other to fulfil the different requirements and to ensure a fast and efficient connection process.

Disproportionate procedures and requirements for market access

Currently, in the TSO/DSO congestion management pilot it is only possible for small actors to utilise contractual aggregation. For some market participants this has presented a barrier, since the BSPs of the assets are not obliged to engage in contractual aggregation with the flexibility service providers.

On the day-ahead and intraday markets independent aggregation is not currently possible. Small actors and new entrants can act through becoming a BRP or agreeing on a service with an existing BRP.

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

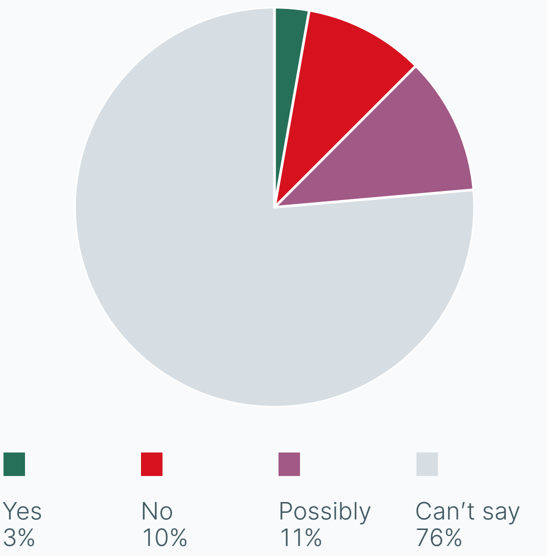
The Finnish regulatory framework allows the TSO to procure flexibility services. Flexibility procurement and grid expansion alternatives are considered when preparing network development plans and making investment decisions. Network development should follow the most technically and economically advantageous option. The regulatory framework also provides for cost recovery, but no incentives are currently in place for procuring flexibility services or using smart grid solutions or innovative technologies.

4.1.2. DSO barrier evaluation

DSOs were asked to indicate whether the predefined categories constitute barriers to flexibility in their point of view. In addition, an open-ended field was provided, allowing respondents to further elaborate on their assessments and provide additional insights. Out of 81 DSOs, 70 of them answered to all categories and 2 answered to only category one. It shall be noted that some DSOs used the same consultant to prepare their answers, which resulted in several identical assessments of barriers. This has influenced the distribution of responses across categories and reduced the diversity of viewpoints.

The questionnaire was distributed to DSOs prior to ACER's publication of Recommendations on barriers to non-fossil flexibility. As a result, most DSOs responded to the questions based solely on the title of each barrier category. In four categories out of six, "can't say" was the most common response, suggesting either limited awareness of the barriers or uncertainty in interpreting the question.

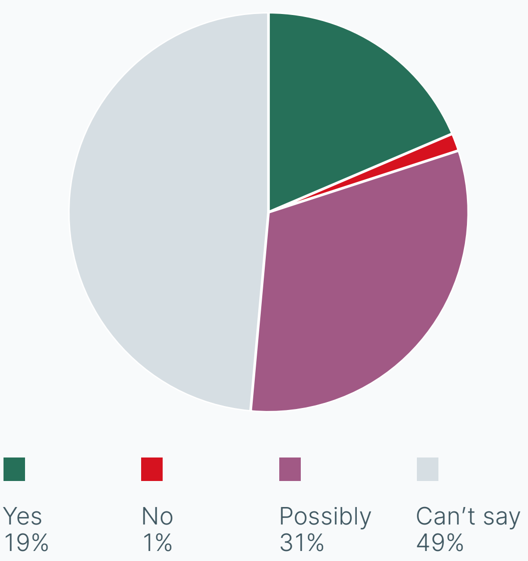
Lack of proper legal framework for market access to new entrants and small actors



The existence of legal barriers affecting market access seems to be unclear based on the survey responses, as a large share of respondents selected "Can't say". However, the open-ended responses revealed differing views among DSOs. While some respondents did not find legal restrictions relevant, others indicated that they had not analysed the issue in sufficient detail. Several respondents noted that legal barriers do not necessarily prevent the utilisation of flexibility but may make it more difficult.

The responses indicate that regulatory interpretations can create uncertainty and encourage a cautious approach among stakeholders. According to the responses, legal barriers may increase costs, hinder market access, and slow down technological development. In addition, it was stated that the possibilities are uncertain because DSOs may not participate in the electricity markets.

Lack of enablers and incentives to provide flexibility

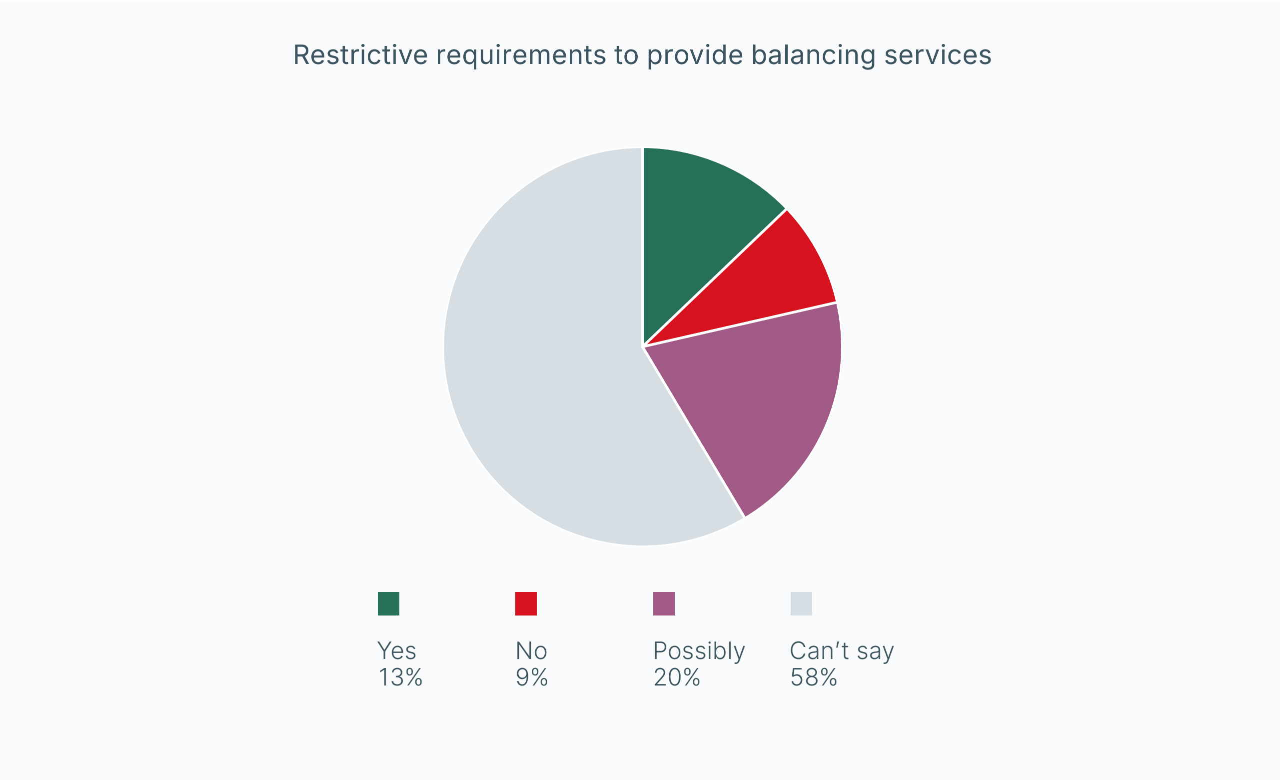


The lack of enablers and incentives to provide flexibility was identified as a potential barrier by a notable share of respondents and only a few respondents indicated that they had not observed any lack of enablers for flexibility. The open-ended responses suggest that the main challenge is not the technical feasibility but rather its uncertain economic viability.

Several respondents highlighted that the financial incentives for both network operators and flexibility providers are often weak. Under the current regulatory framework, DSOs may have limited economic incentives to utilise flexibility, while the benefits gained from flexibility can be small compared to alternative network investments. The information systems and operational capabilities required to utilise flexibility require both fixed and operational costs even when the actual use of flexibility remains limited.

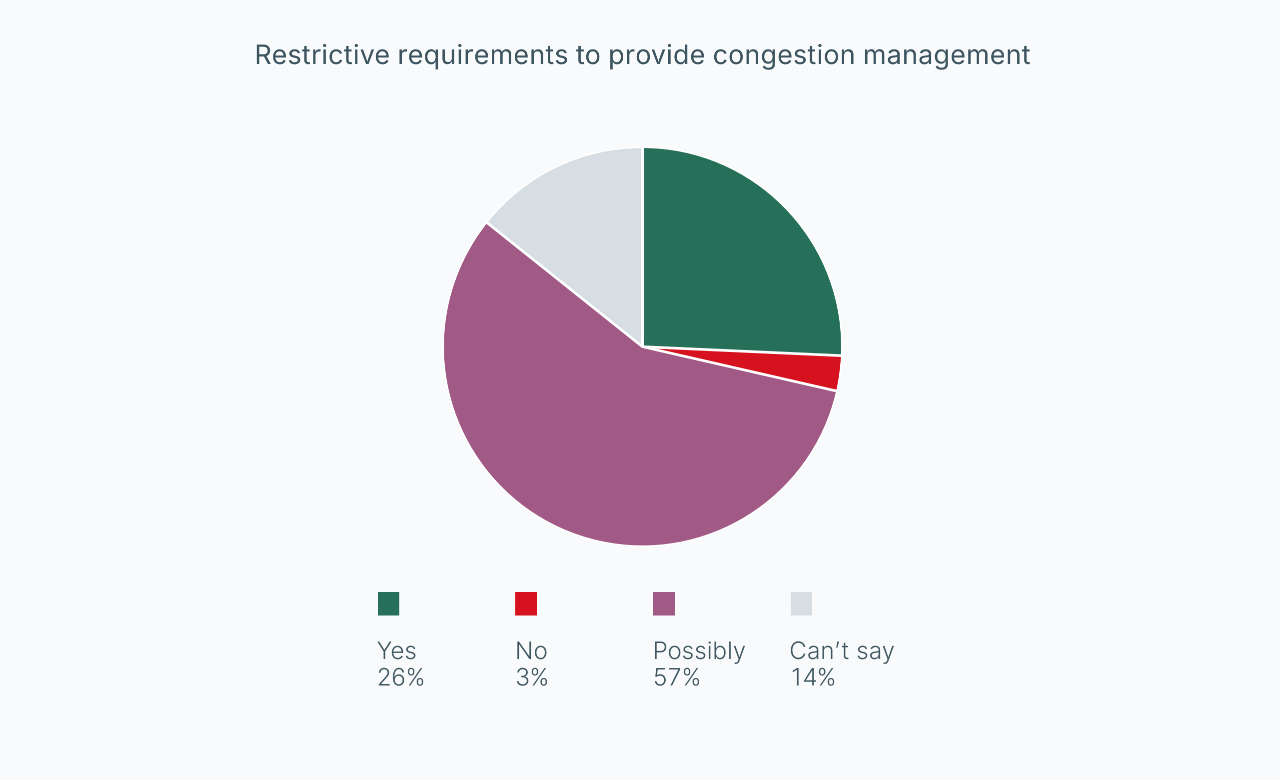
Respondents raised concerns about the high uncertainty regarding future revenue streams and the profitability of investments required to enable flexibility. The lack of long-term predictability in market conditions, uncertain payback periods, and limited financial benefits from flexibility were seen as factors reducing the willingness of both customers and service providers to participate. Several respondents noted that the need for flexibility in distribution networks is often highly local and infrequent, resulting in small market volumes and rare activations, which further weakens the business case for flexibility solutions.

Other challenges identified included the lack of standardised national data exchange solutions for controlling generation and demand, limited availability of technical solutions capable of providing reliable flexibility services, and low customer interest in offering flexibility. Overall, the responses indicate that uncertainty around economic viability and practical implementation of flexibility remain key factors limiting flexibility.



While uncertainty remains high among respondents, the responses reveal identifiable concerns related to balancing service requirements, indicating that barriers are perceived by at least a portion of DSOs, although some did not identify such barriers. Several respondents highlighted that the technical and administrative requirements for participation in reserve markets may limit the participation of smaller flexible resources. In particular, minimum bid sizes, technical requirements, and qualification processes were considered challenging for many low-voltage and medium-voltage flexible resources. Even though aggregation can help overcome these limitations, respondents noted that the practical implementation of aggregation is still evolving and may be subject to legal uncertainties.

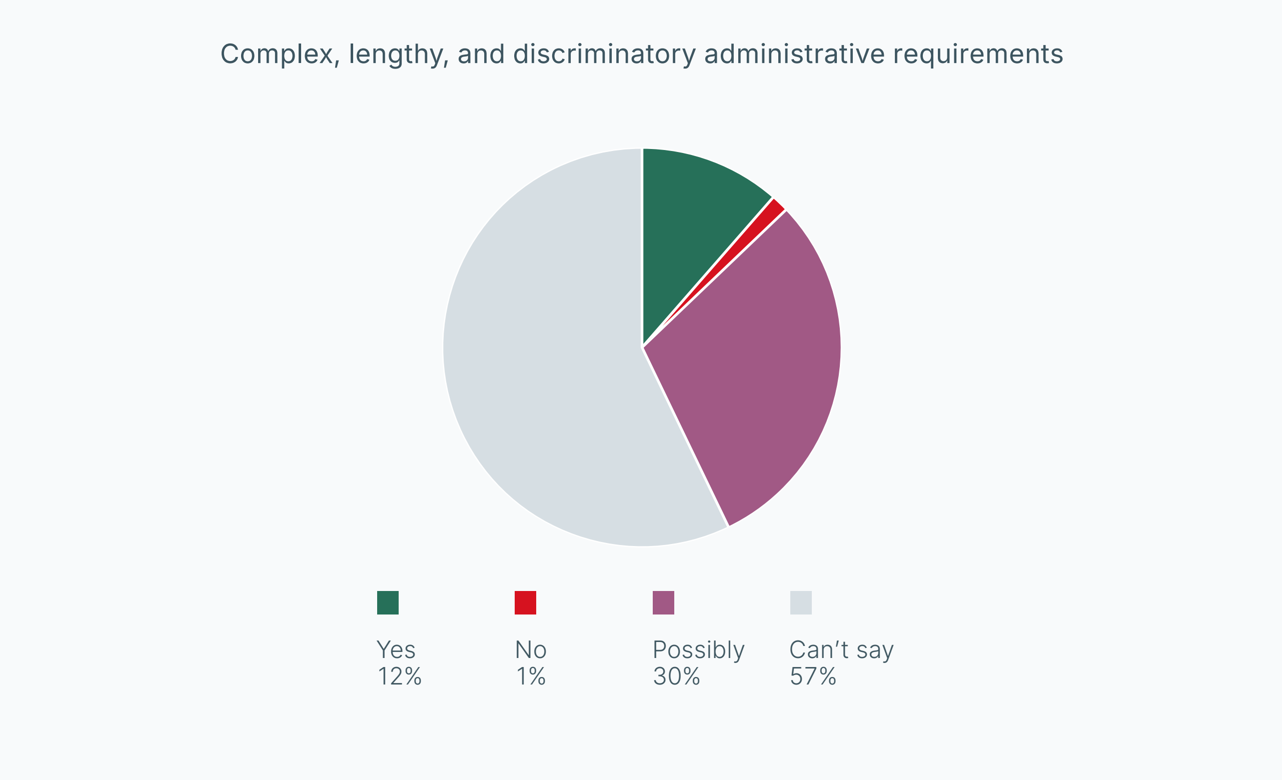
Respondents further indicated that reserve market requirements may reduce the commercial attractiveness of flexibility services and exclude potential providers from the market. In addition, some questioned whether flexibility markets can become sufficiently attractive if participation in reserve markets remains difficult due to requirements. Technical criteria related to response times, reliability, and performance were also identified as factors limiting the participation of certain resources. While several respondents acknowledged that these requirements are justified from a power system reliability perspective, they nevertheless noted that they may slow the development of flexibility services and limit the utilisation of available flexible resources.



The survey responses suggest that restrictive requirements for providing congestion management are perceived as a potential barrier by many DSOs and the large share of "Yes" and "Possibly" answers indicates that respondents generally recognise challenges related to the use of flexibility for congestion management. The comments primarily highlighted the immaturity of local flexibility markets and the uncertainty surrounding their practical implementation. Several respondents noted that market mechanisms, contractual arrangements, and operating models for congestion management are still under development, making their effectiveness difficult to assess. In addition, respondents raised concerns regarding the division of responsibilities between DSOs and the TSO, particularly in situations where both parties may require the same flexible resource simultaneously for different purposes.

Respondents also emphasised that the successful use of flexibility for congestion management requires sufficient availability of geographically targeted flexibility, together with well-functioning market platforms and supporting information systems. The availability of flexibility in specific low-voltage and medium-voltage network areas was considered particularly challenging, and several respondents noted that flexibility cannot always be targeted with sufficient geographical and voltage-level precision to address local network constraints.

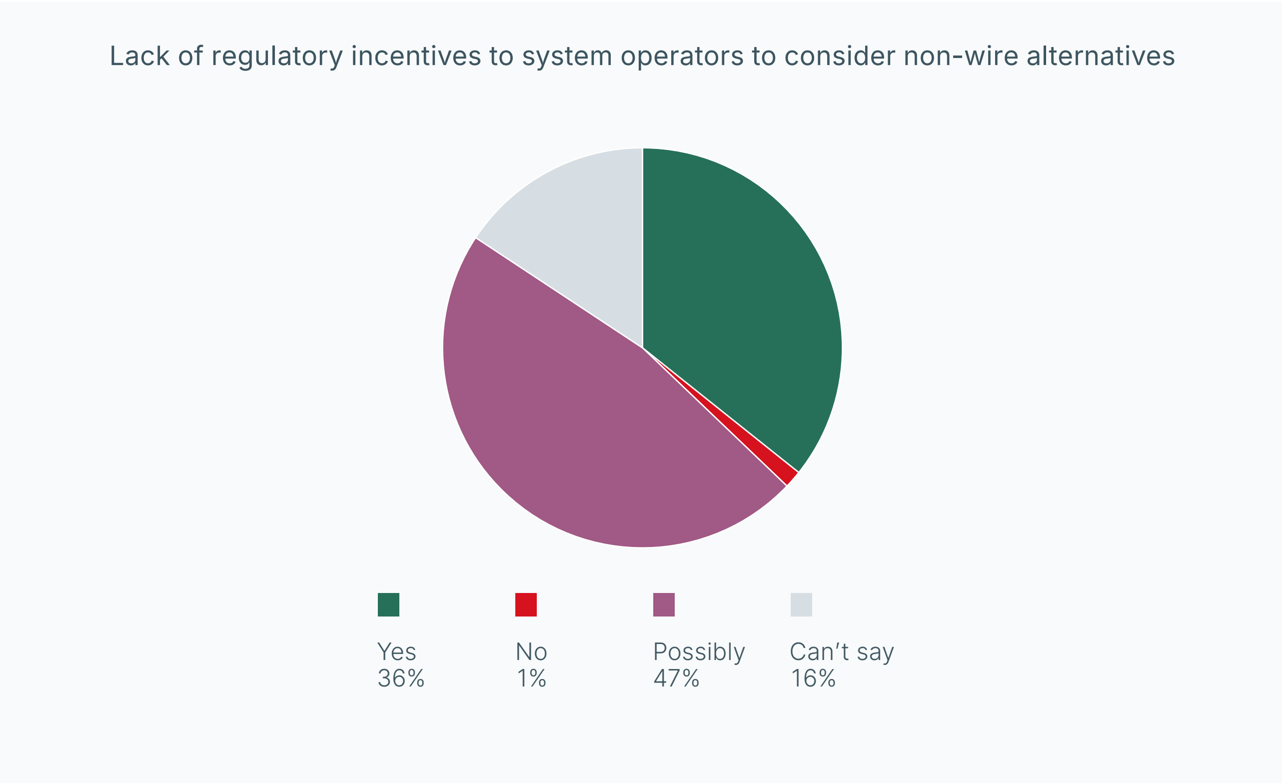
Some respondents expressed uncertainty regarding the long-term reliability of flexibility as a congestion management solution. Unlike network reinforcements, flexibility is dependent on market participants and therefore cannot always be relied upon as a permanent solution. In particular, respondents noted that flexibility markets may not be suitable for long-lasting network constraints, such as reduced substation capacity following equipment failures that can persist for several months. As a result, traditional network investments are in many cases still considered the primary option for addressing congestion.



Despite the high share of "Can't say" responses, the survey results suggest that complex, lengthy, and potentially burdensome administrative requirements may constitute a barrier to the provision of flexibility services. Only a few respondents indicated that no such barriers exist, while the comments provided by other respondents highlighted a range of administrative and regulatory challenges.

Respondents noted that administrative procedures may create additional barriers for adopting flexibility solutions, reduce the number of participating actors, and increase overall costs. Several comments highlighted that the implementation of flexibility services often requires new contractual arrangements, metering solutions, information system integrations, and coordination between multiple parties, including customers, aggregators, DSOs, and data exchange platforms. The resulting complexity was considered disproportionate to the potential benefits, particularly for smaller flexible resources.

A recurring theme in the responses was the uncertainty associated with developing regulatory frameworks, contractual arrangements, and operating procedures. Contractual models, operating procedures, and market arrangements were described as still evolving, resulting in unclear responsibilities and administrative burdens. In particular, the regulatory framework and approval processes related to flexible connection agreements were considered overly complex by some respondents. Several comments referred to Energy Authority regulations and guidance concerning flexible connection agreements, which were perceived as administratively burdensome and, in some cases, involving costly permitting processes without providing certainty regarding the long-term availability of flexibility. Some respondents emphasised that flexible connection agreements may be necessary to ensure reliable access to flexible resources, as market-based flexibility alone cannot always be relied upon as an alternative to network investments.



The survey responses indicate that a lack of regulatory incentives for system operators to consider non-wire alternatives is widely perceived as a barrier. The large share of "Yes" and "Possibly" responses suggests that many DSOs view the current regulatory framework as favouring traditional network investments over flexibility solutions.

A recurring theme in the comments was that the current regulatory and incentive framework provides stronger incentives for conventional network reinforcements than for the utilisation of flexibility services. Several respondents noted that investments in network infrastructure generate regulated returns, whereas flexibility solutions are typically treated as operational expenditures and therefore do not receive comparable regulatory treatment. As a result, flexibility is often perceived as a less attractive option from an economic perspective.

While a dedicated flexibility incentive exists within the regulatory framework, several respondents considered it temporary, limited in scope, or insufficient to fundamentally change network development practices. The uncertainty regarding the long-term continuity of incentives was also identified as a challenge, particularly as flexibility solutions often require long-term planning and investments in information systems, processes, and contractual arrangements.

Respondents further noted that the costs and benefits of flexibility solutions remain uncertain, making traditional network reinforcement a more predictable and lower-risk option. Several comments indicated that the economic risks and uncertainties associated with flexibility tend to fall on DSOs, while the regulatory framework continues to favour investment-based solutions. Some respondents also highlighted the obligation of network operators to provide connection capacity and maintain network reliability, which may limit the extent to which flexibility can be relied upon as an alternative to network expansion.

In addition, respondents pointed out that flexibility solutions may not be suitable in all situations, such as in rural distribution networks, where congestion issues are often highly localised and caused by individual large consumption or generation connections. Overall, the responses indicate that although flexibility is recognised as a potentially valuable complement to traditional network development, the current regulatory framework does not yet treat it equally with conventional grid investments.

4.2. Contribution of digitalisation

Fingrid uses Dynamic Line rating (DLR) in the 400 kV network. In case the thermal limitations are the reason behind curtailment needs, DLR can provide mitigation by incorporating real-time weather conditions into capacity assessment. There is potential for increased thermal capacity under weather conditions more favourable to conductor cooling than which are assumed in calculating the seasonal line ratings. The utilization of this additional capacity is integrated into Fingrid’s operational systems.

5. Conclusions

This first cycle of Finland's Flexibility Needs Assessment provides an overview of the flexibility needs expected in the Finnish power system in 2030 and 2035 and the ability of available flexible resources to respond to those needs. The results highlight the growing importance of flexibility in a power system with increasing shares of weather-dependent generation and electrification, while also demonstrating that the magnitude, timing, and duration of flexibility needs vary considerably. The results presented in this report provide a basis for further monitoring and development of flexibility solutions.

In recent years, discussions on adequacy of electricity in Finland have primarily focused on prolonged cold winter periods combined with low wind generation. While these situations remain important from an adequacy perspective, the results of the Flexibility Needs Assessment demonstrate that flexibility needs can arise throughout the year and are not limited to winter peak demand conditions. The analysis shows that significant balancing needs can emerge under a variety of system conditions, reaching several thousand megawatts in the most challenging situations, and are driven by forecast errors, renewable generation variability, and changes in demand. The results also indicate that flexibility needs in Finland are dominated by upward needs, reflecting the importance of ensuring sufficient flexible capacity during periods when demand exceeds available generation.

Meeting future flexibility needs will require a diverse portfolio of flexible resources. While uncovered ramping needs do not last for more than a few hours, prolonged forecast errors may create uncovered flexibility needs for more than ten consecutive hours. Ensuring adequate flexible resources require not only resources capable of providing a rapid response, but also technologies capable of providing sustained upward flexibility over extended periods, which also support adequacy of electricity during winter peak demand. The results indicate that future flexibility needs cannot be met solely with the resources currently assumed to be available, highlighting the potential need for additional flexible capacity in the Finnish power system.

Although this assessment primarily focuses on flexibility needs from a system perspective, the responses received from DSOs indicate that flexibility needs are also emerging at the distribution network level. While the identified needs vary between network areas, several DSOs recognised flexibility, and particularly flexible connection agreements, as a potential tool for managing local network constraints. However, the survey results highlight that the wider utilisation of flexibility in distribution networks is currently constrained by several barriers. One of the most significant challenges identified by DSOs relate to the limited economic attractiveness and insufficient regulatory incentives to consider flexibility as an alternative to network investments.

Similar challenges can also be identified from the TSO perspective. The effective utilisation of flexibility requires the regulatory model to economically favour the use of flexibility instead of OPEX neutral alternatives and sufficient predictability regarding the availability of flexible resources, particularly when flexibility is expected to contribute to the security of supply and system operation. For example, allowing permanent flexible connection agreements could improve the reliability and predictability of flexibility resources, thereby supporting both network planning and operational decision-making. At the same time, maximising the amount of generation and demand that can participate as flexible resources should be a key objective. Wherever possible, barriers limiting the participation or utilisation of flexibility should be reduced, as broader participation would increase the volume of available flexibility and strengthen the ability of the power system to respond to future flexibility needs.

The results of this assessment are highly influenced by both the underlying data and the assumptions applied to the availability and utilisation of flexible resources. During the first assessment cycle, several uncertainties were identified regarding the availability and utilisation of different flexible resources and particular attention should be given in future FNA cycles to ensure that both the input data and assumptions reflect the realistic operation of the power system as accurately as possible. Improved understanding of the characteristics and availability of the resources would increase the robustness of future assessments and support more informed decision-making regarding the development of network planning and power system operation.

ANNEX 1 – Detailed flexibility needs results

This annex provides additional results for the three system needs indicators: RES integration, ramping, and short-term needs. The figures complement the main results presented in the report by providing a more detailed characterisation of system operation and flexibility needs. In accordance with the FNA methodology, the annex includes analyses of the temporal distribution of curtailment, ramping and uncovered needs, and their relationship with system conditions.

RES integration needs

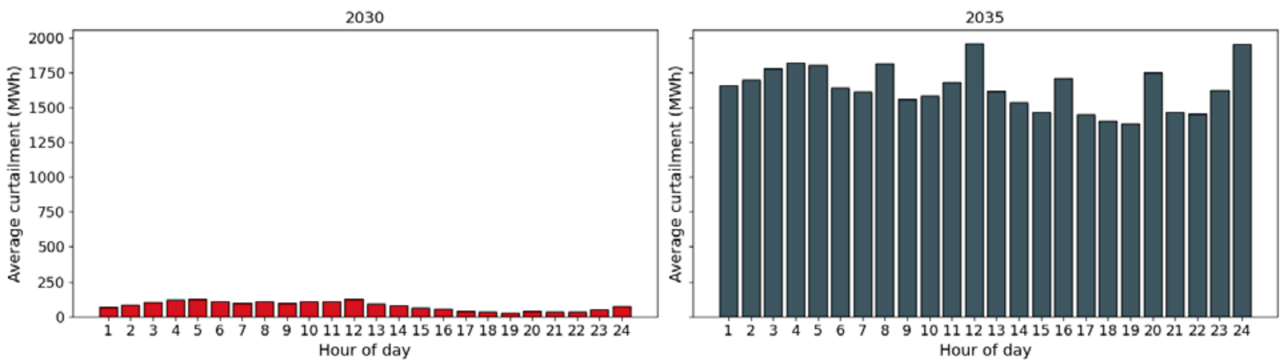


FIGURE 1 Average curtailment by hour of day.

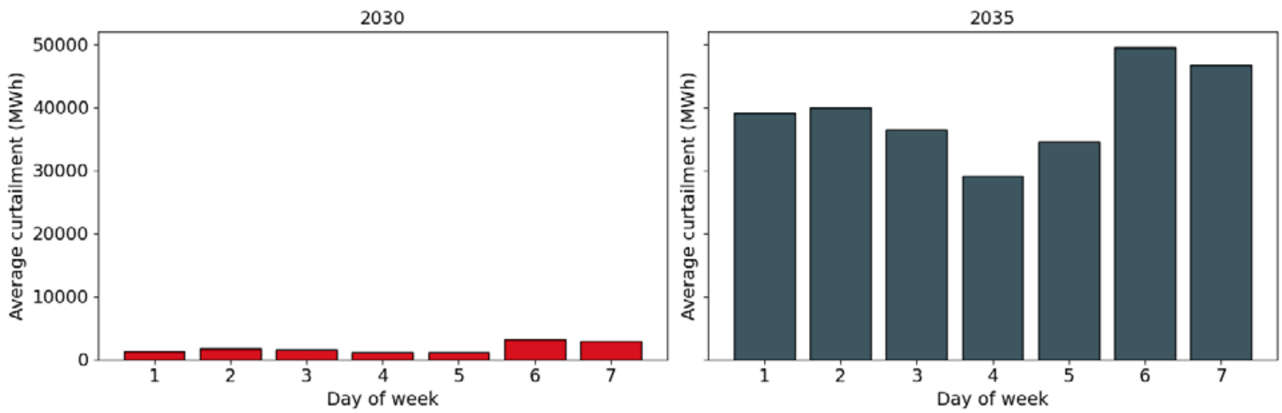


FIGURE 2 Average curtailment by day of week.

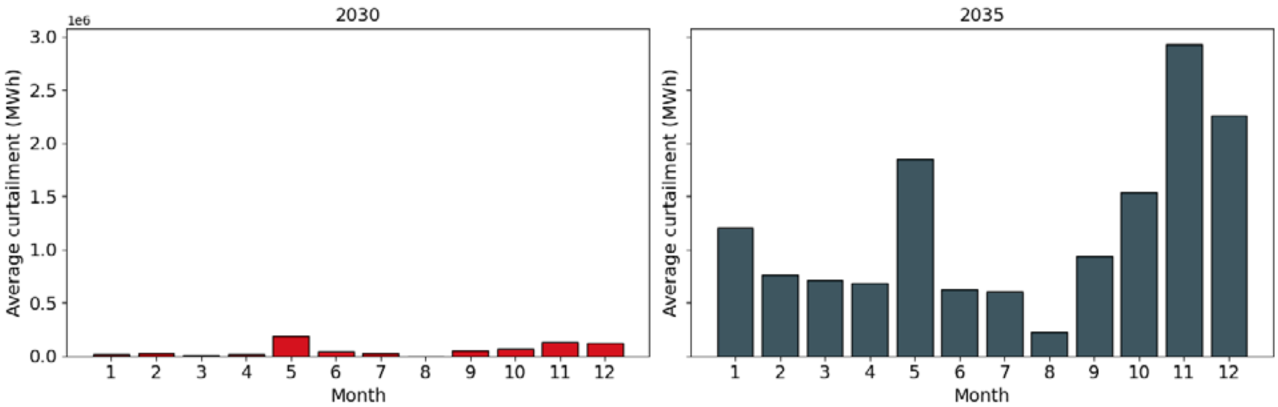


FIGURE 3 Average curtailment by month.

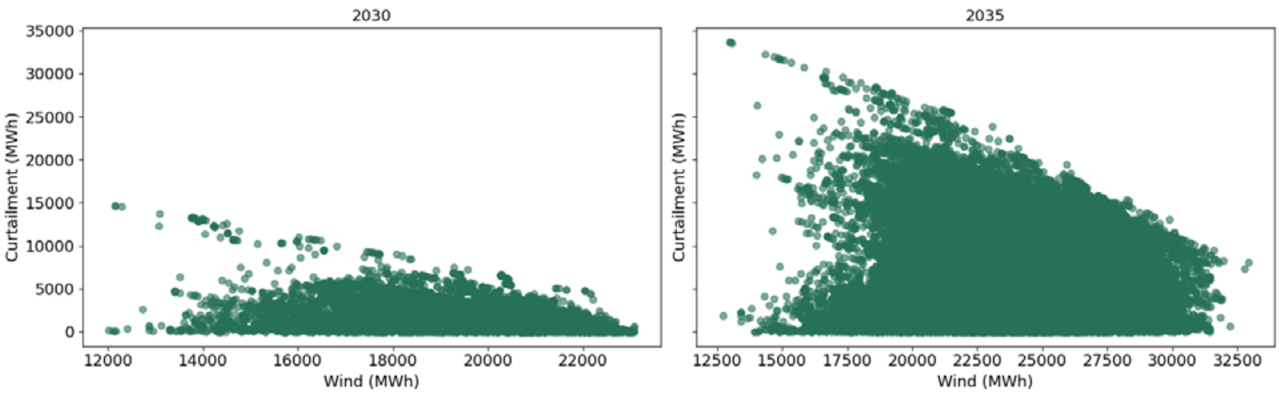


FIGURE 4 Curtailment behaviour across wind generation levels.

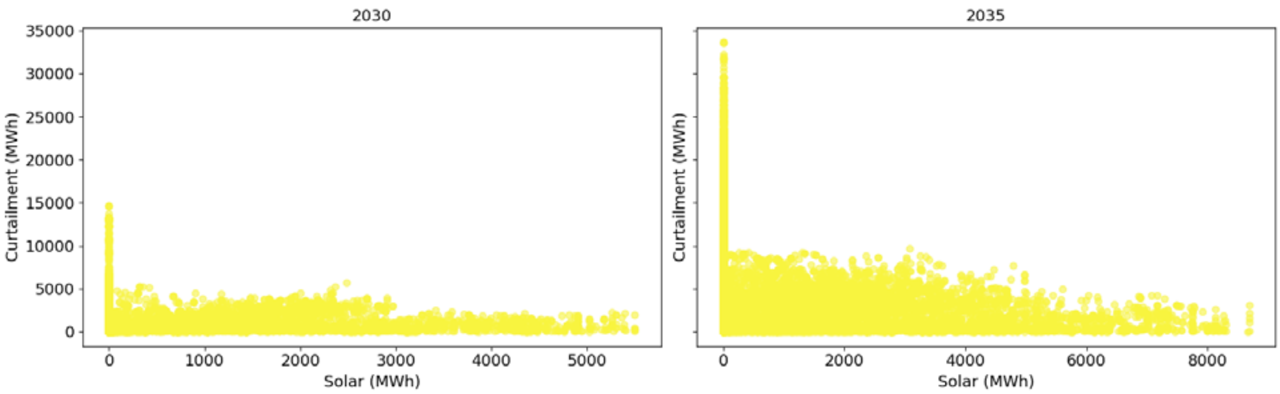


FIGURE 5 Curtailment behaviour across solar generation levels.

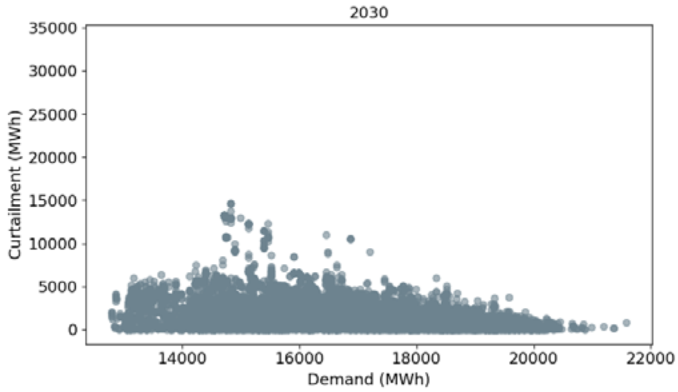


FIGURE 6 Curtailment behaviour across demand levels.

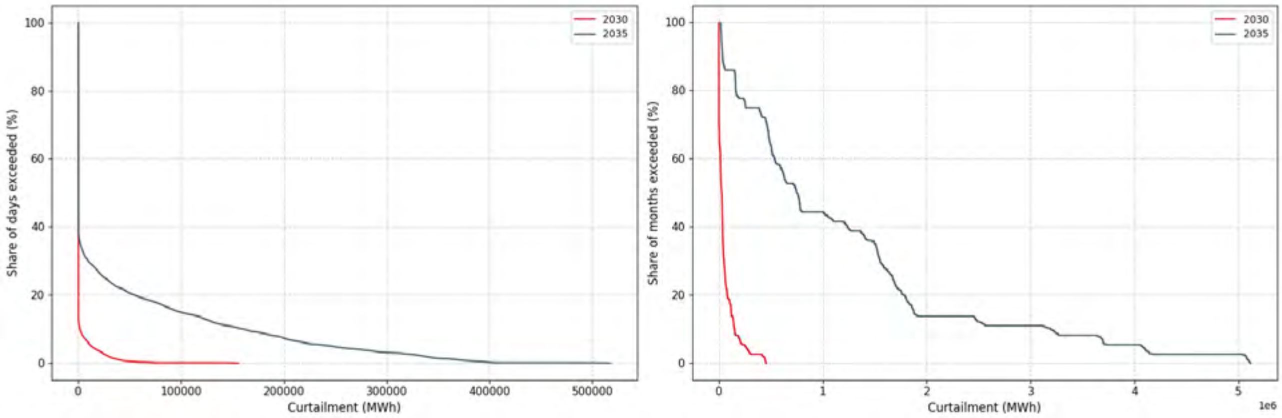


FIGURE 7 Exceedance curves of daily and monthly curtailment.

Ramping needs

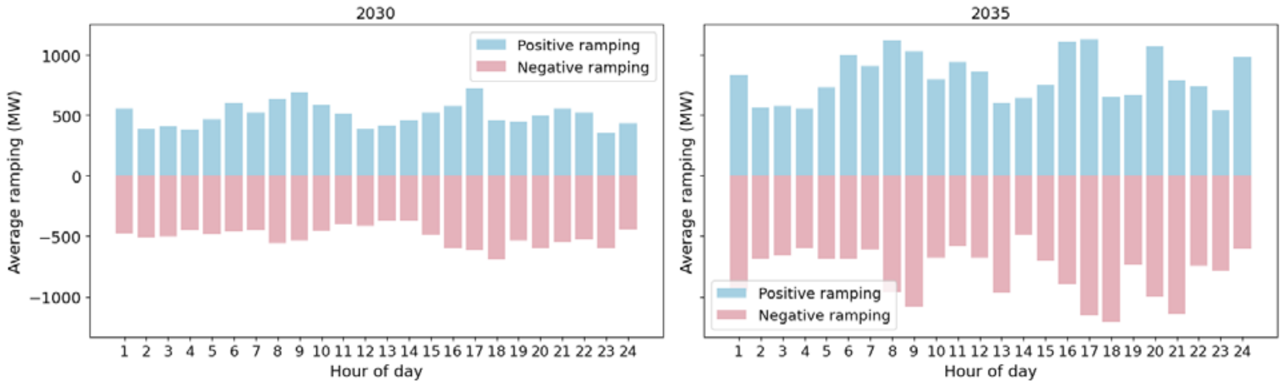


FIGURE 8 Average ramping by hour of day.

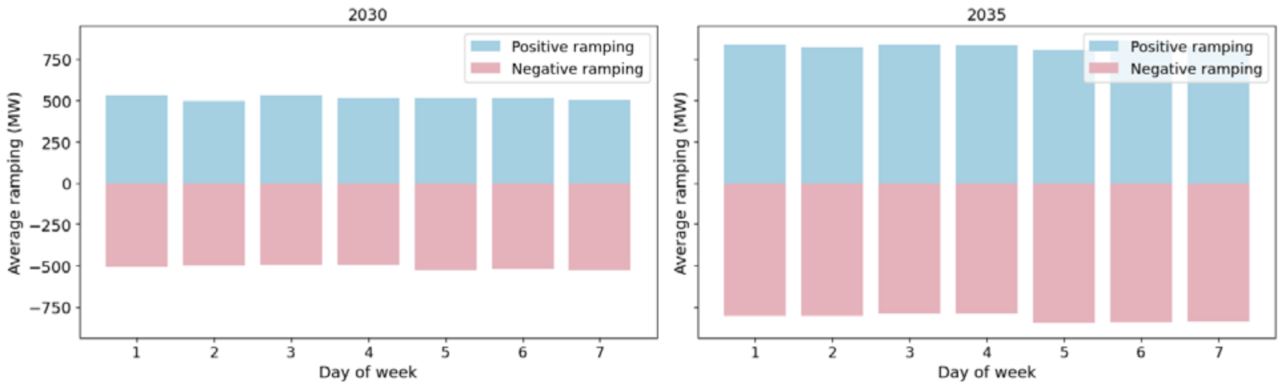


FIGURE 9 Average ramping by day of week.

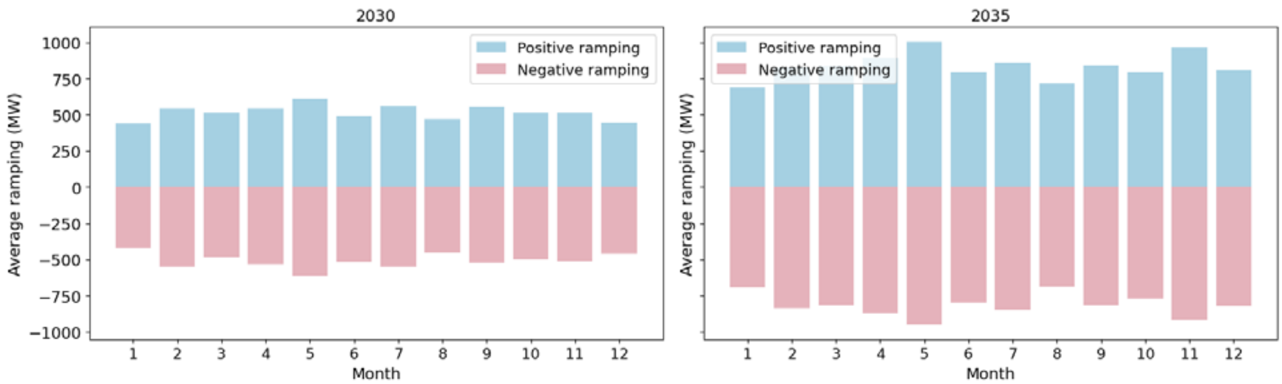


FIGURE 10 Average ramping by month.

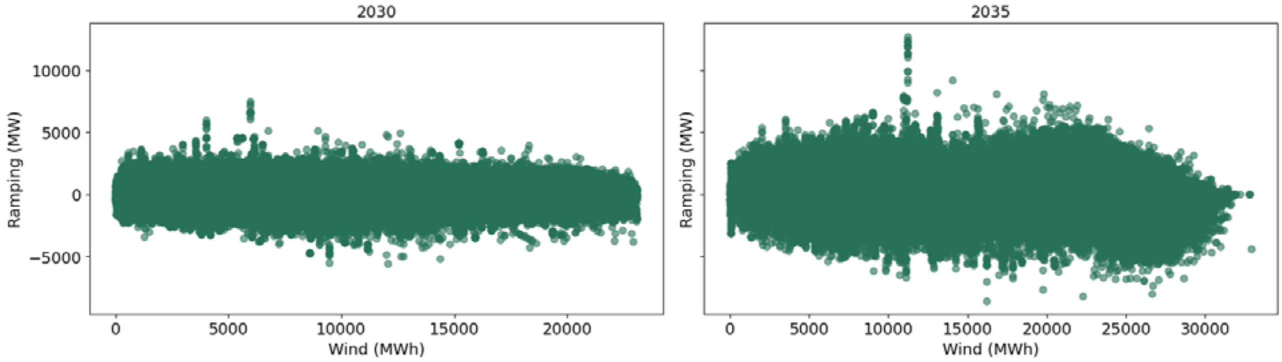


FIGURE 11 Ramping behaviour across wind generation levels.

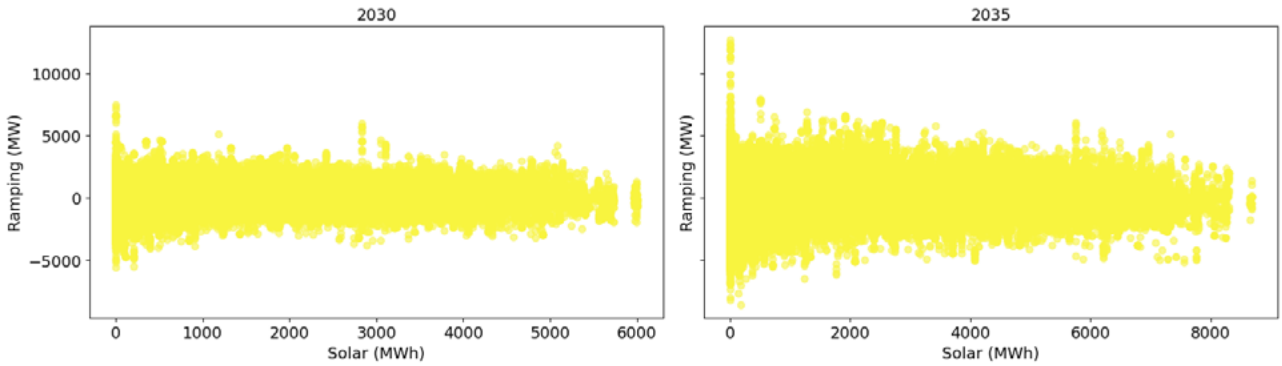


FIGURE 12 Ramping behaviour across solar generation levels.

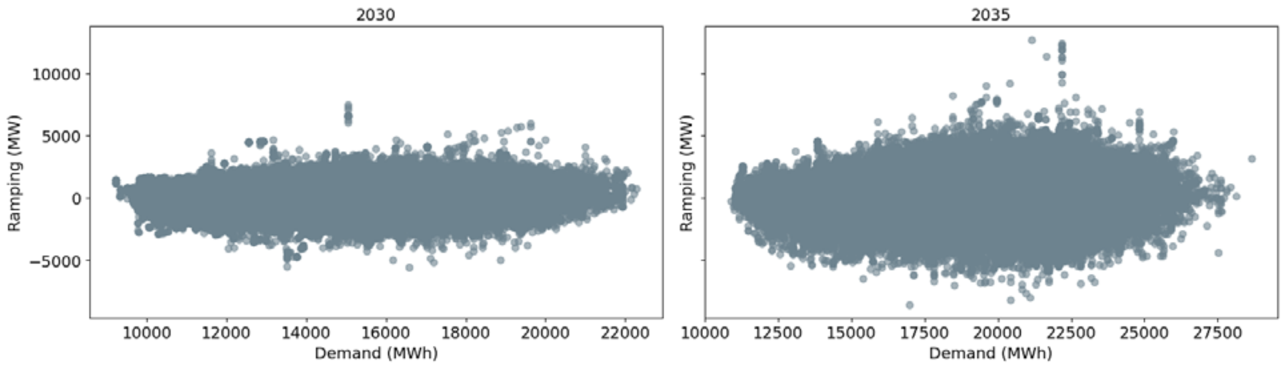


FIGURE 13 Ramping behaviour across demand levels.

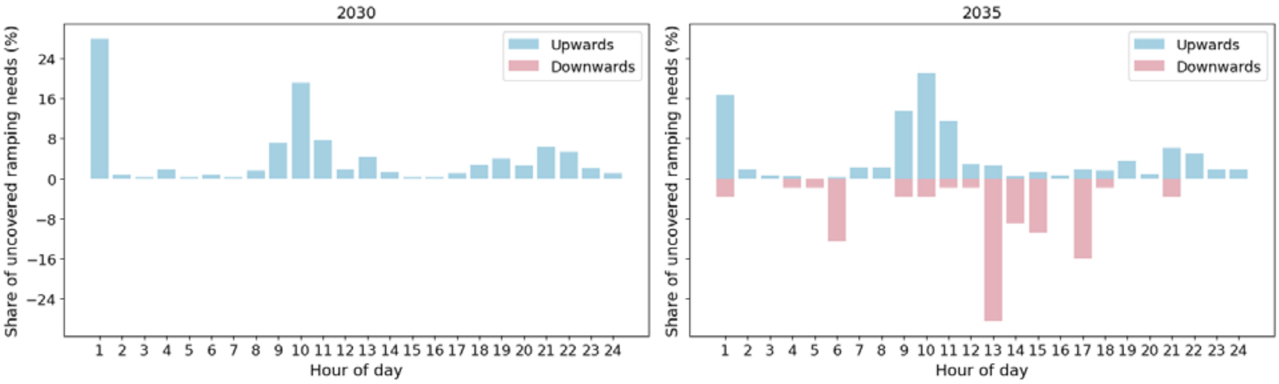


FIGURE 14 Share of uncovered ramping needs by hour of day.

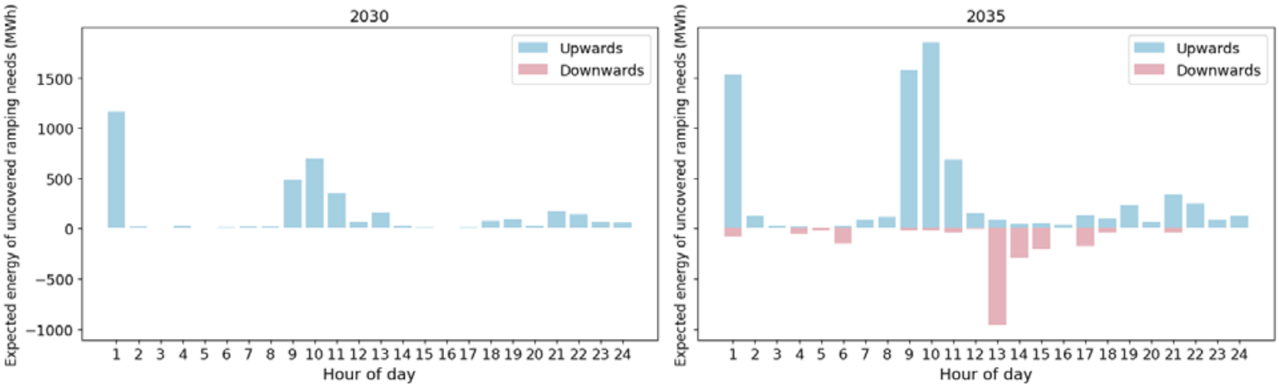


FIGURE 15 Expected energy of uncovered ramping needs by hour of day.

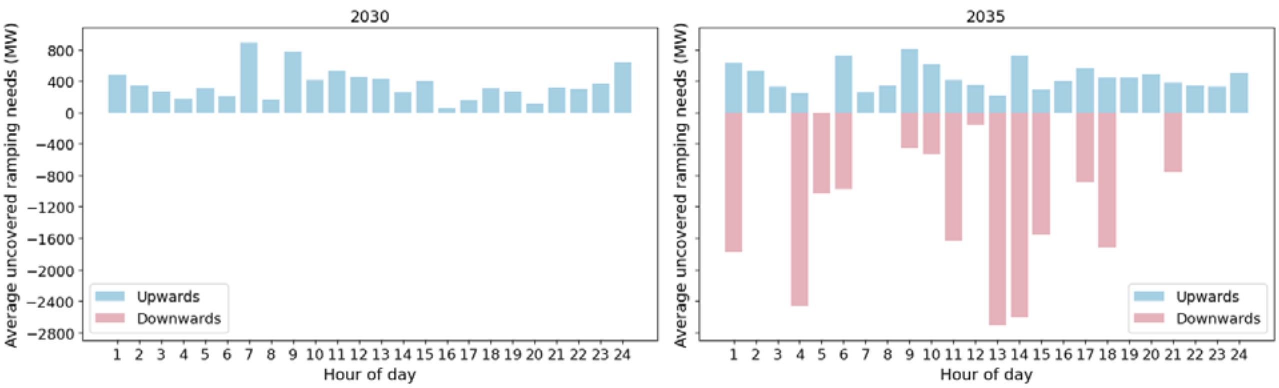


FIGURE 16 Average uncovered ramping needs by hour of day.

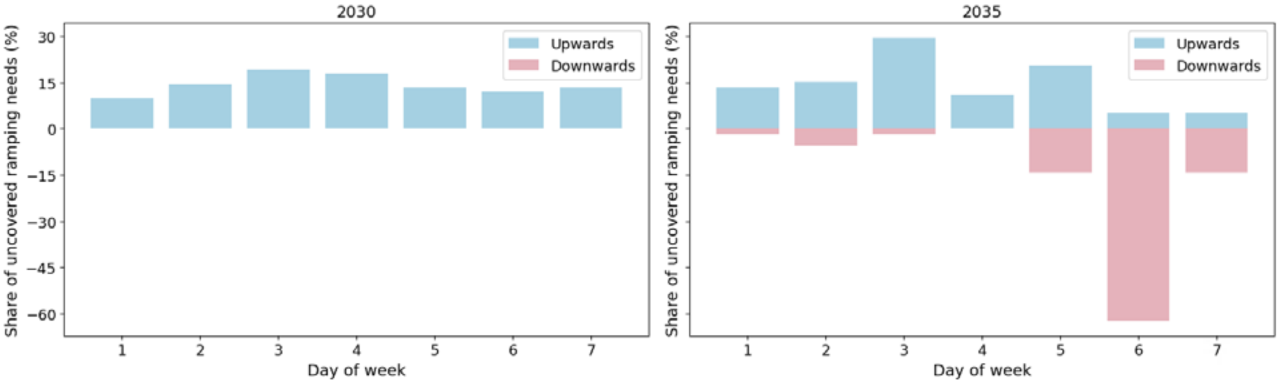


FIGURE 17 Share of uncovered ramping needs by day of week.

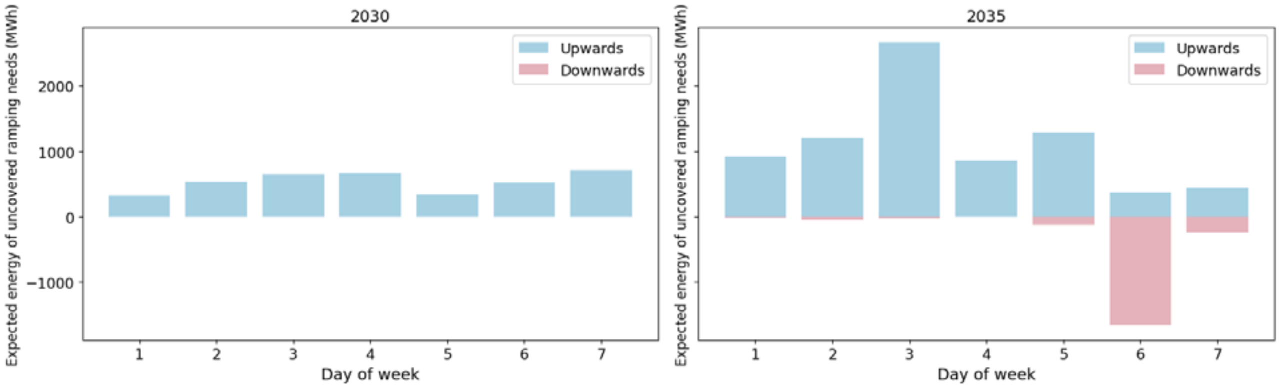


FIGURE 18 Expected energy of uncovered ramping needs by day of week.

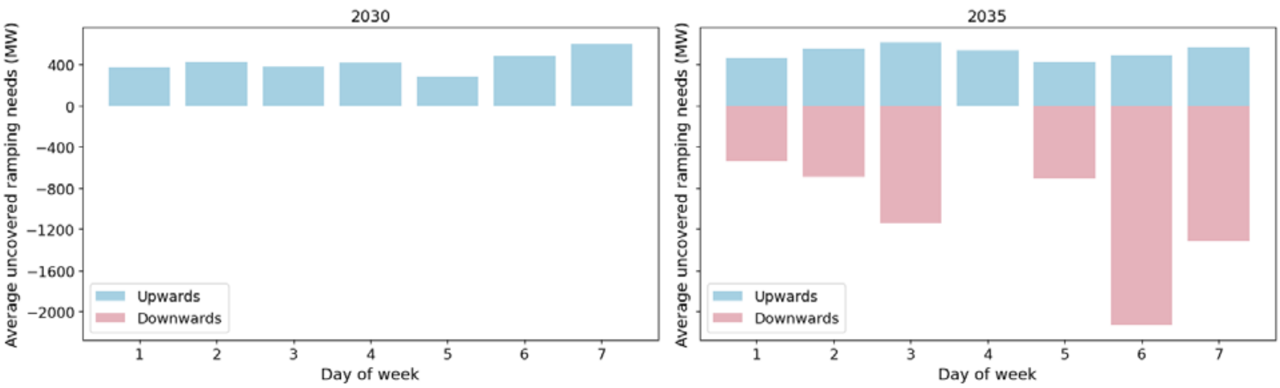


FIGURE 19 Average uncovered ramping needs by day of week.

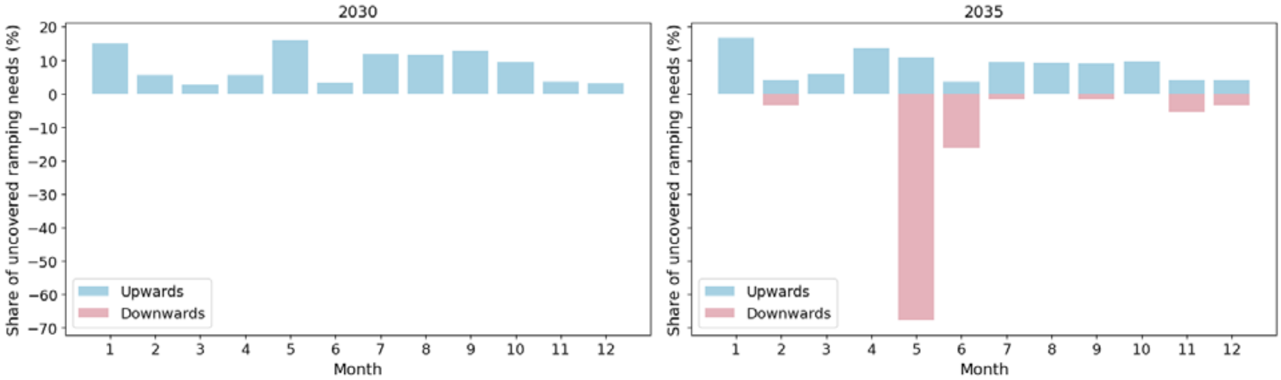


FIGURE 20 Share of uncovered ramping needs by month.

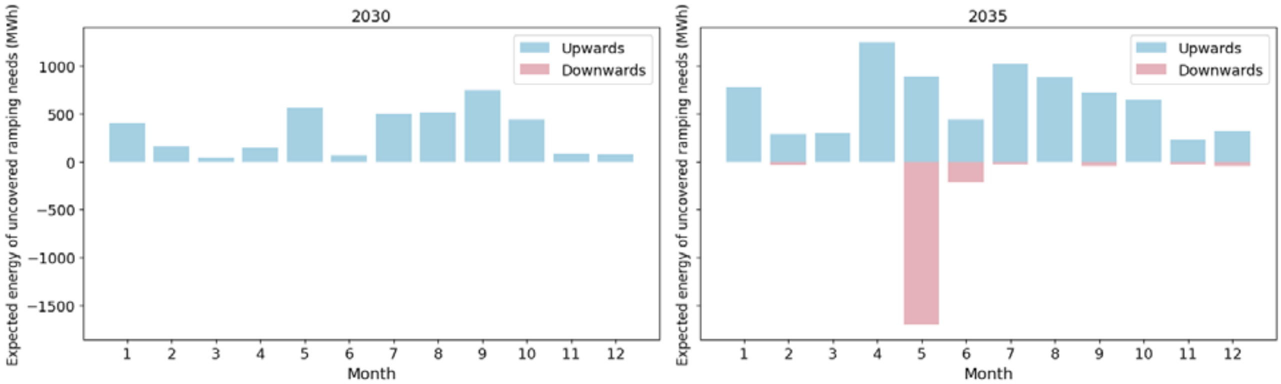


FIGURE 21 Expected energy of uncovered ramping needs by month.

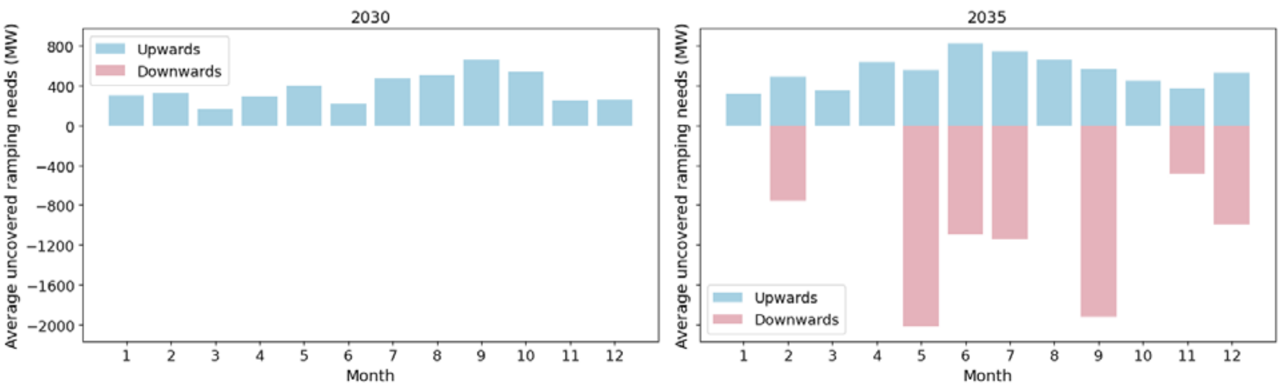


FIGURE 22 Average uncovered ramping needs by month.

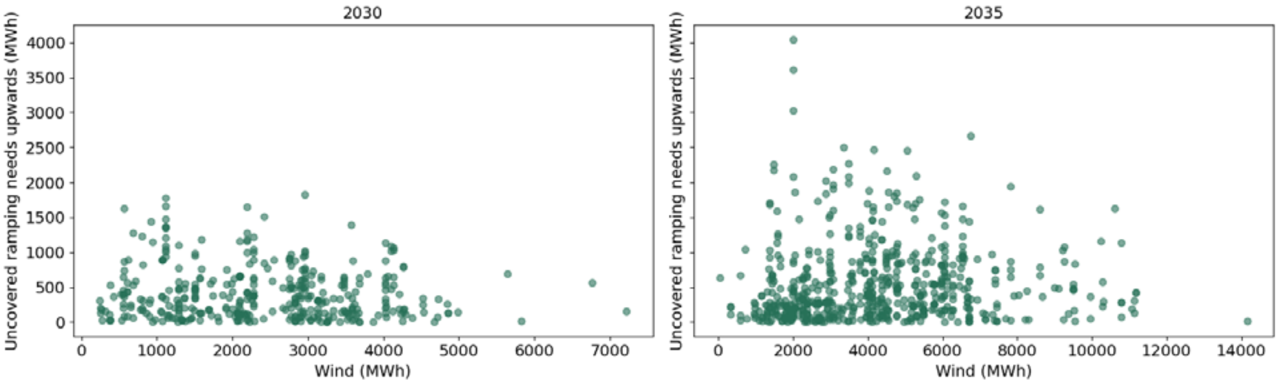


FIGURE 23 Uncovered ramping needs upwards across wind generation levels.

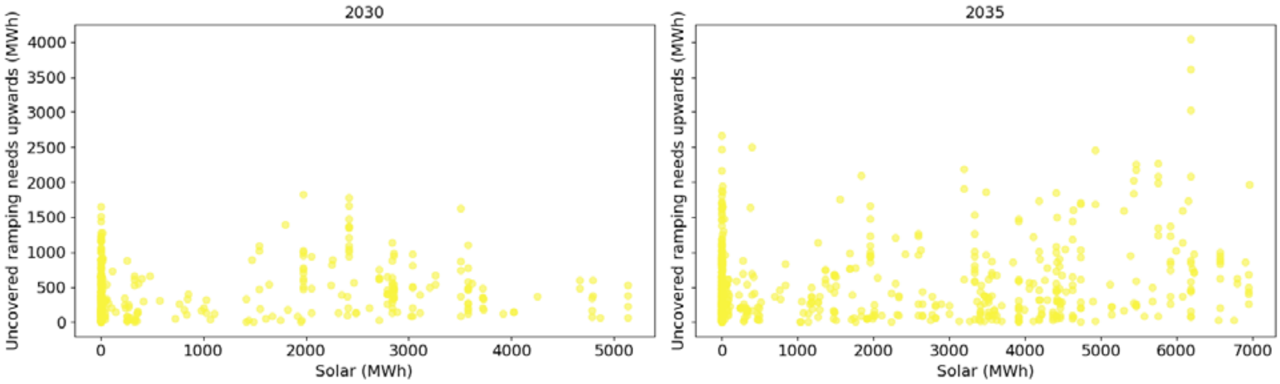


FIGURE 24 Uncovered ramping needs upwards across solar generation levels.

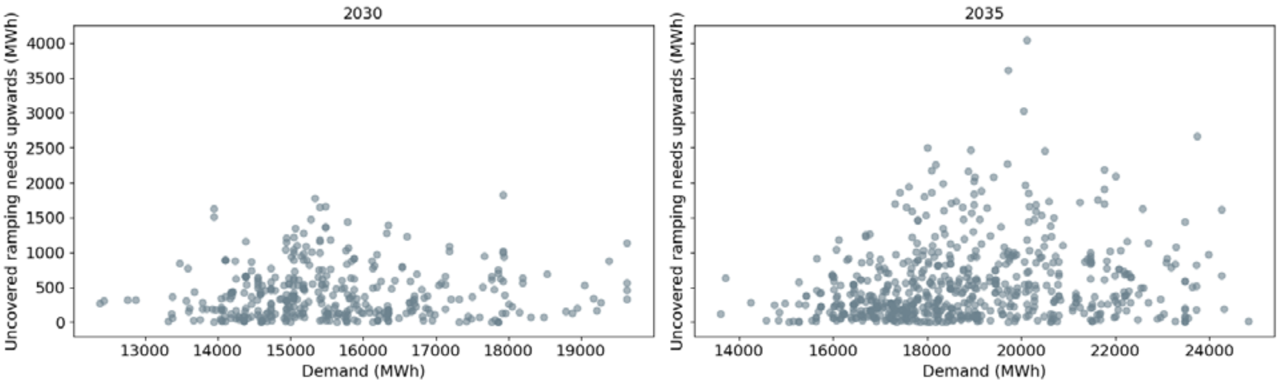


FIGURE 25 Uncovered ramping needs upwards across demand levels.

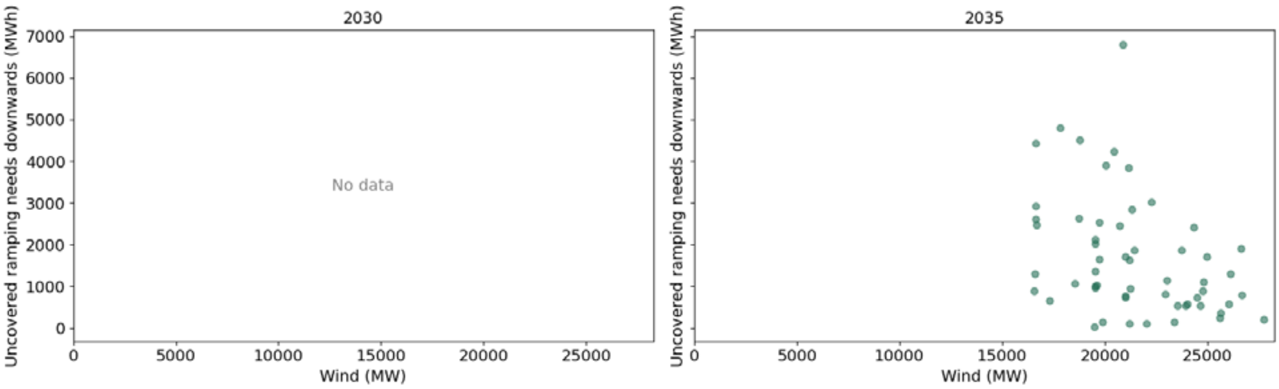


FIGURE 26 Uncovered ramping needs downwards across wind generation levels.

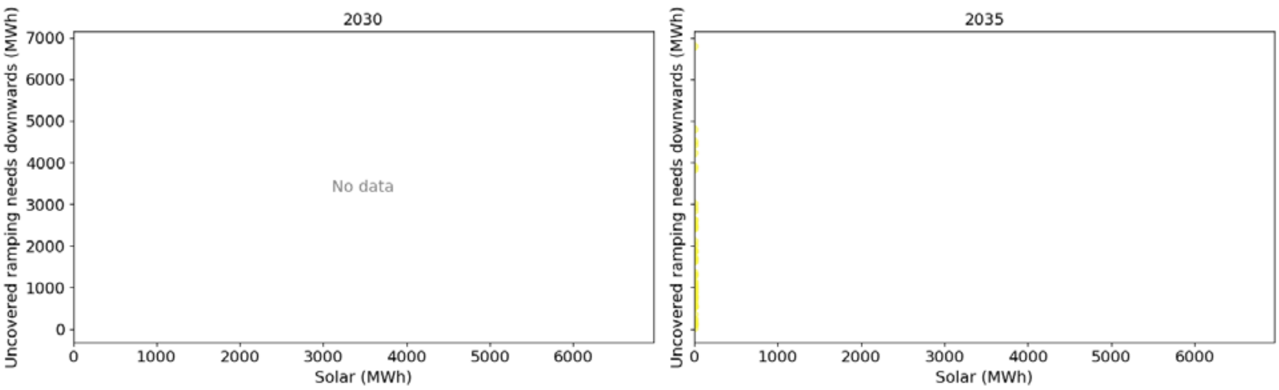


FIGURE 27 Uncovered ramping needs downwards across solar generation levels.

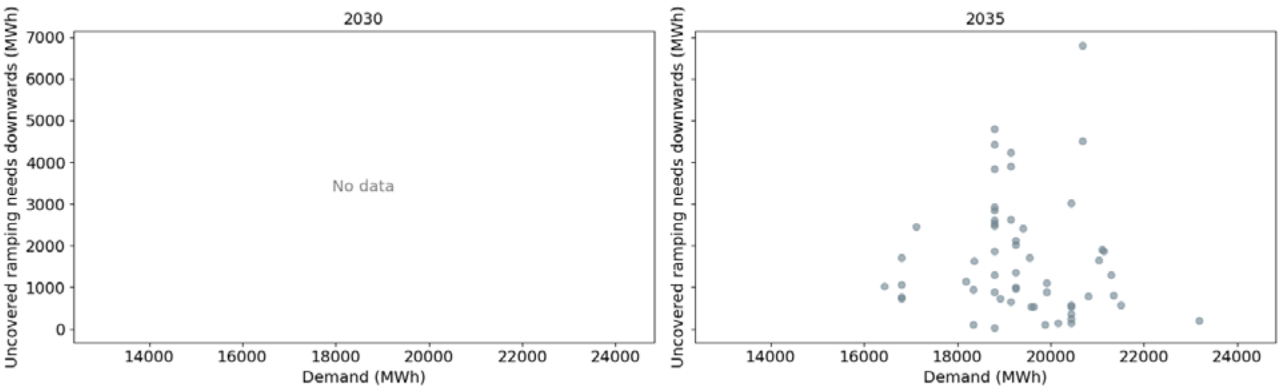


FIGURE 28 Uncovered ramping needs downwards across demand levels.

Short-term needs

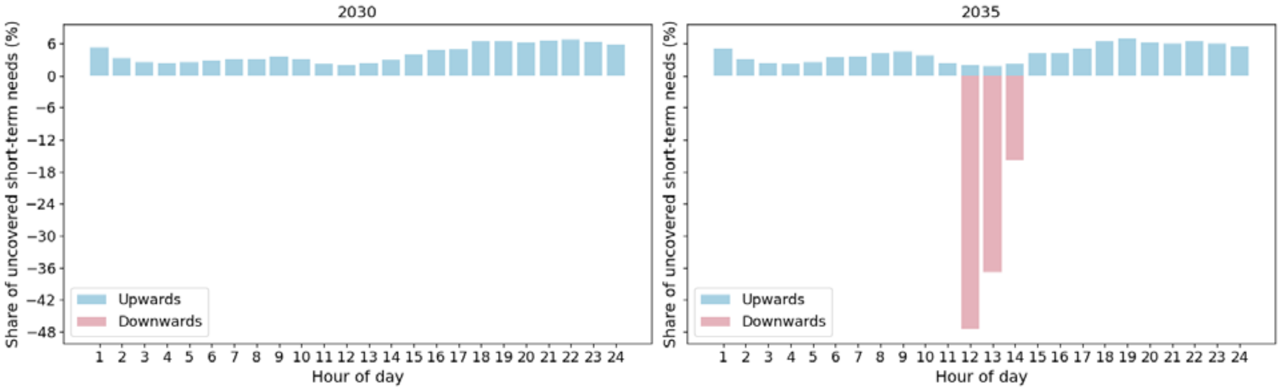


FIGURE 29 Share of uncovered short-term needs by hour of day.

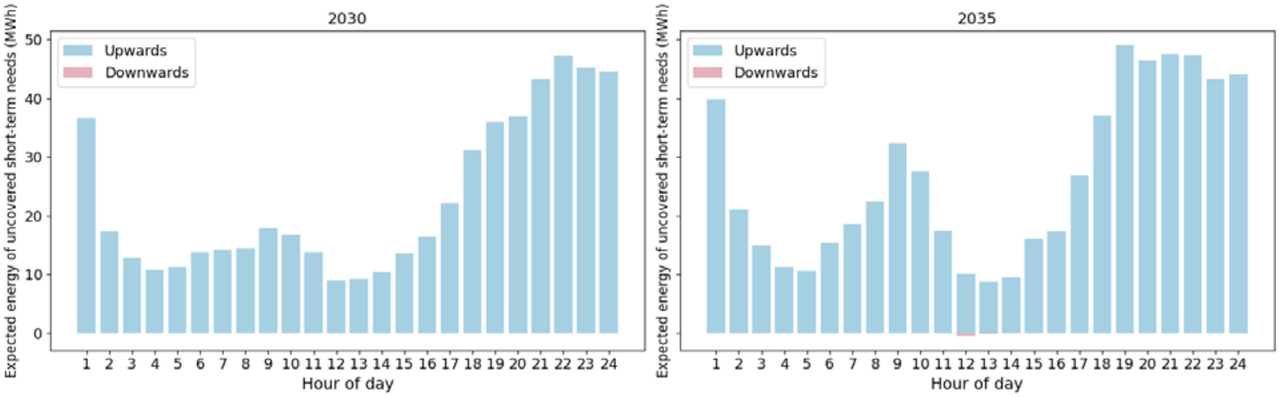


FIGURE 30 Expected energy of uncovered short-term needs by hour of day.

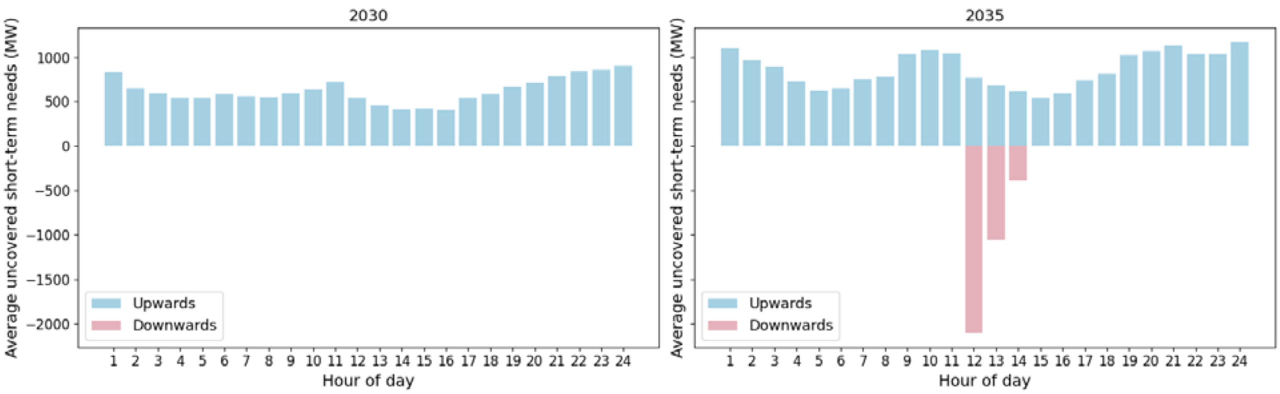


FIGURE 31 Average uncovered short-term needs by hour of day.

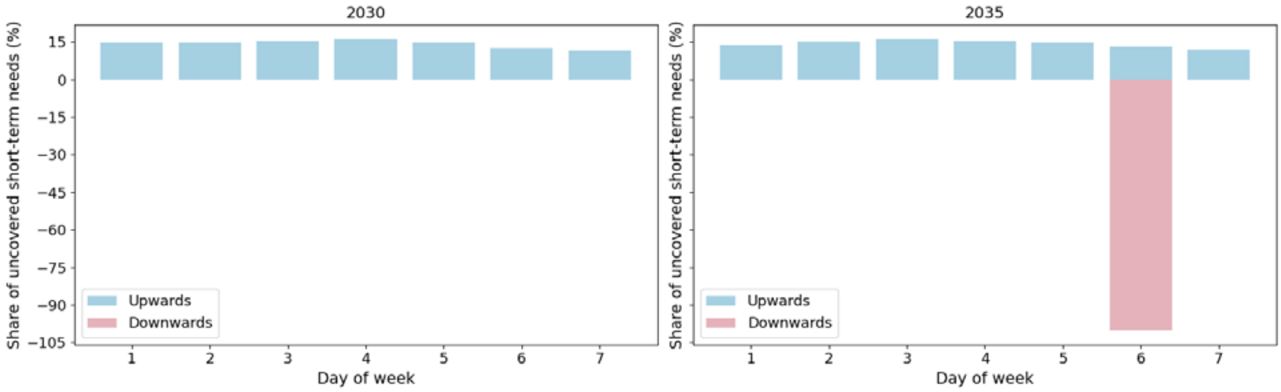


FIGURE 32 Share of uncovered short-term needs by day of week.

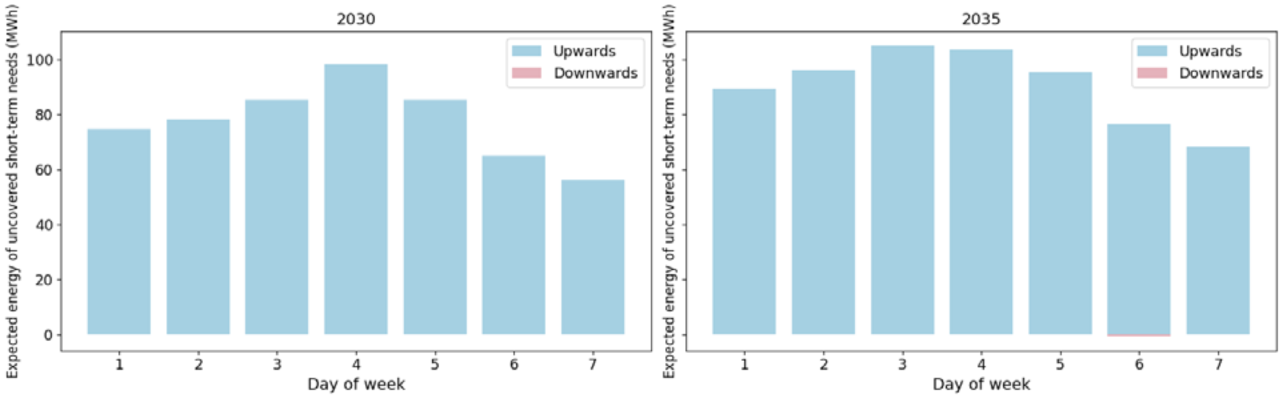


FIGURE 33 Expected energy of uncovered short-term needs by day of week.

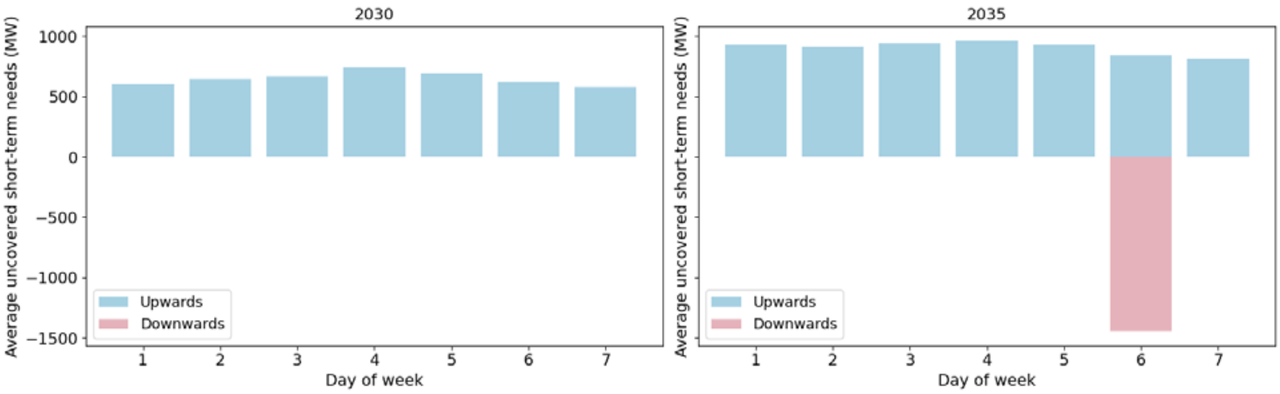


FIGURE 34 Average uncovered short-term needs by day of week.

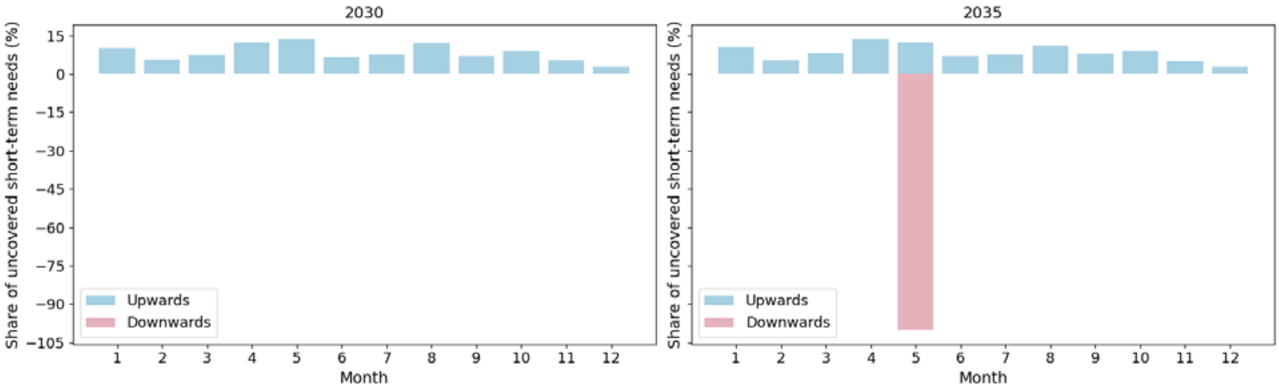


FIGURE 35 Share of uncovered short-term needs by month.

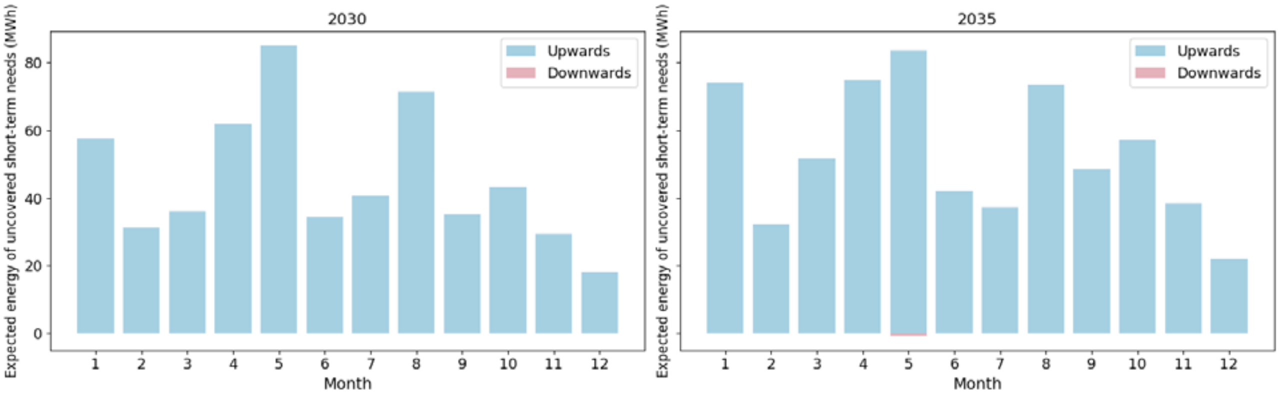


FIGURE 36 Expected energy of uncovered short-term needs by month.

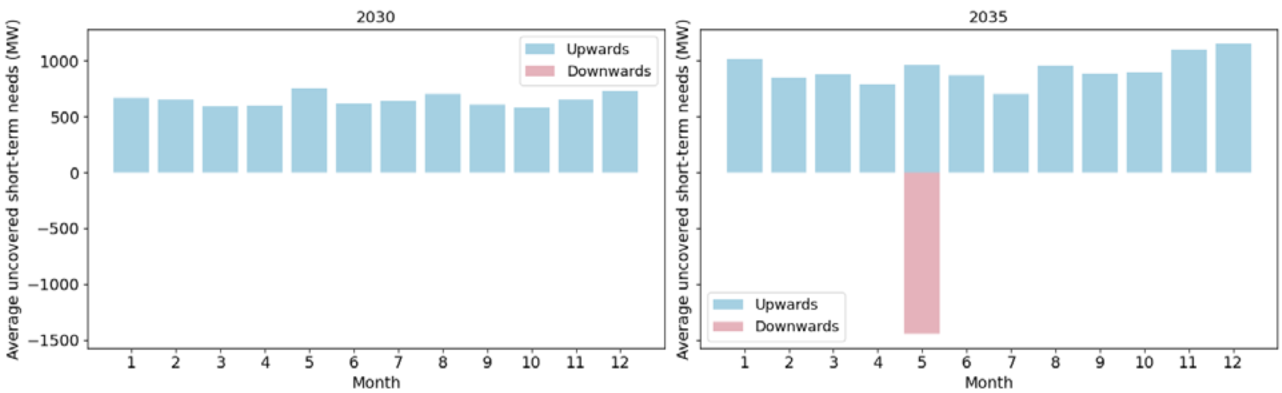


FIGURE 37 Average uncovered short-term needs by month.

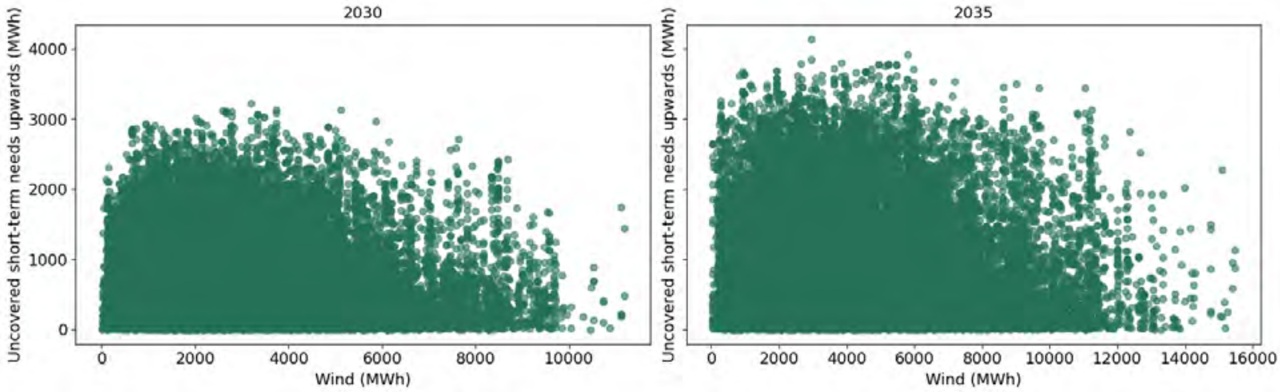


FIGURE 38 Uncovered short-term needs upwards across wind generation levels.

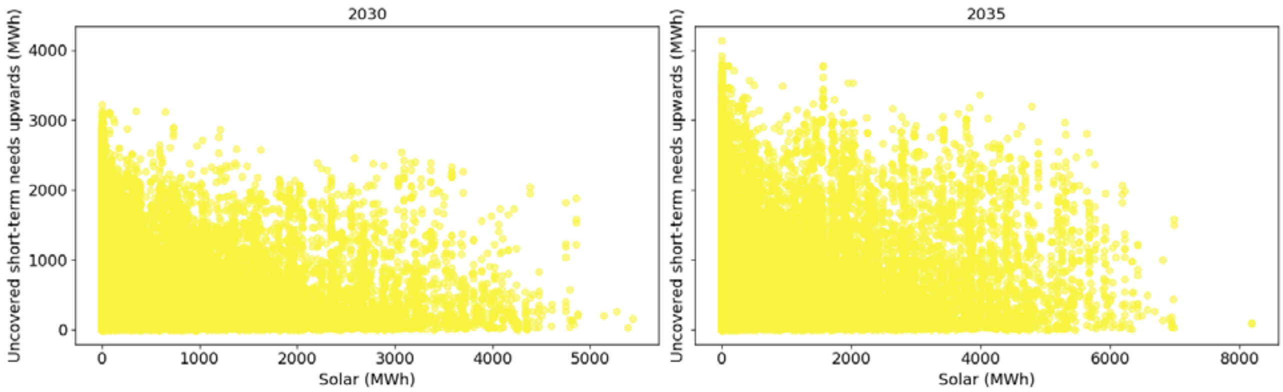


FIGURE 39 Uncovered short-term needs upwards across solar generation levels.

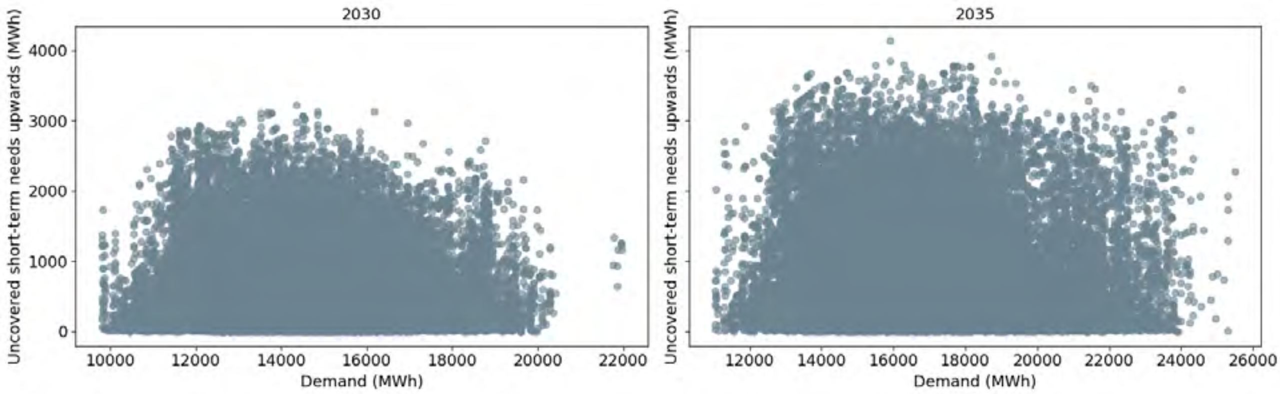


FIGURE 40 Uncovered short-term needs upwards across demand levels.

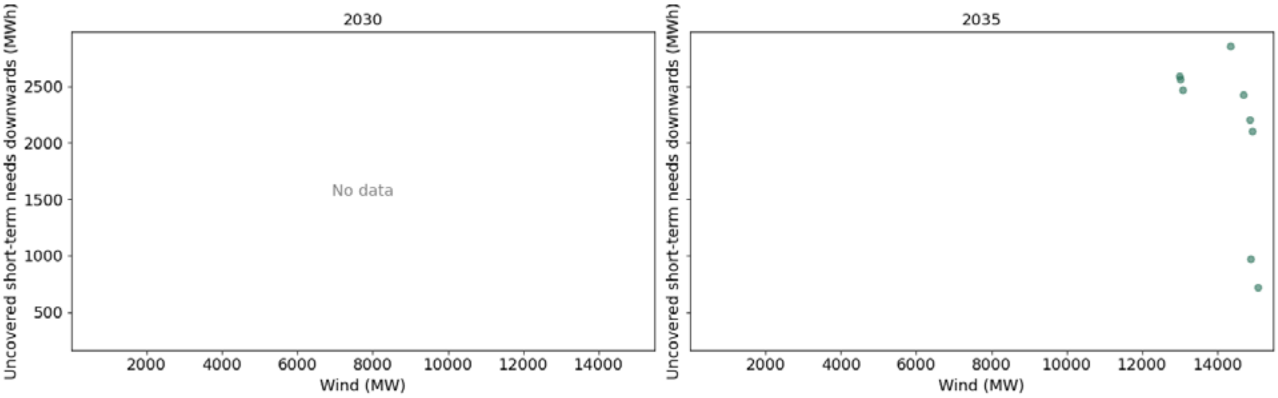


FIGURE 41 Uncovered short-term needs downwards across wind generation levels.

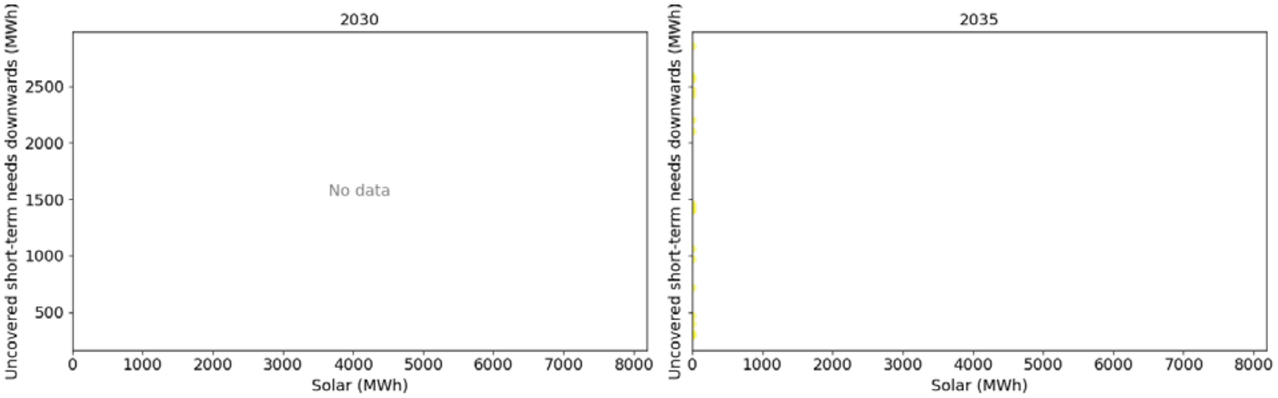


FIGURE 42 Uncovered short-term needs downwards across solar generation levels.

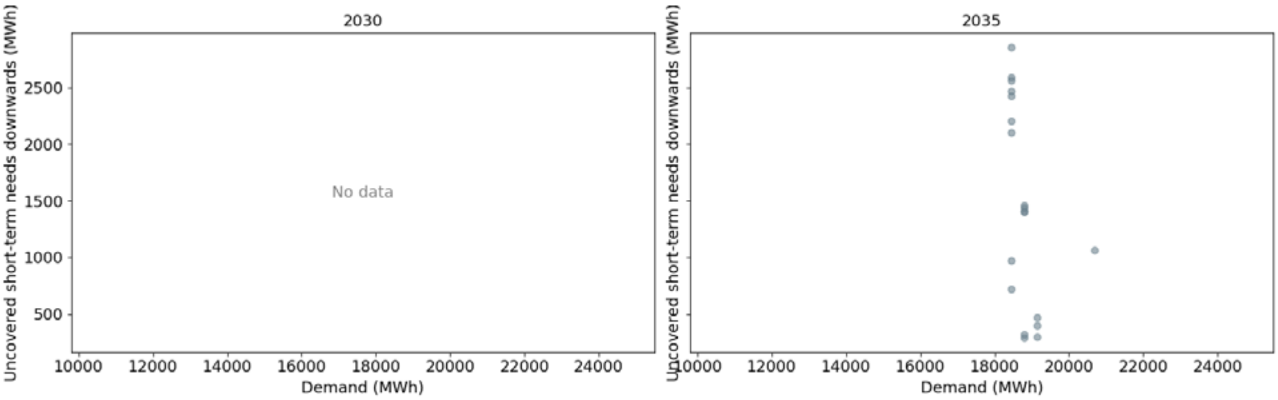


FIGURE 43 Uncovered short-term needs downwards across demand levels.