The Public Utilities Commission of Latvia

LATVIAN SYSTEM FLEXIBILITY NEEDS ASSESSMENT

RIGA – 2026

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Regulatory framework for preparation of Flexibility Needs Assessment

The European Parliament and the Council on 13 June 2024 adopted REGULATION (EU) 2024/1747 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL with amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design. The Regulation 2024/1747 Article 19e asks EU countries to prepare Flexibility needs assessment (FNA), where European Agency for the Cooperation of Energy Regulators (ACER) is nominated to prepare FNA. Regulation 2024/1747 Article 19e, point 1 says that no later than one year after the approval by ACER of the methodology pursuant to paragraph 6, and every two years thereafter, the regulatory authority or another authority or entity designated by a Member State, shall adopt a report on the estimated flexibility needs for a period of at least the next 5 to 10 years at national level, in view of the need to cost effectively achieve security and reliability of supply and decarbonise the electricity system, taking into account the integration of variable renewable energy sources and the different sectors, as well as the interconnected nature of the electricity market, including interconnection targets and potential availability of cross-border flexibility. The ACER decision No 05/2025 was done on 25 July 2025 on the type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis. Based on ACER decision and EU Regulation 2024/1747 Article 19e point 1, FNA for Latvia should be prepared by Public Utilities Commission (PUC), as National Regulative Authority (NRA) of Latvia, till 25 July 2026 and afterwards submitted to ACER.

The preparation of FNA in each country could be delegated to another company with future submission to NRA. FNA preparation in Latvia is delegated to electricity Transmission System Operator (TSO) AS "Augstsprieguma tīkls", what is approved in the amendments to the Electricity Market Law. FNA should consist of transmission and distribution part assessment, therefore, considering mentioned above and necessity to assess pan-European energy system capabilities to handle high generation variability, Latvian TSO and Distribution System Operator (DSO) prepared analysis of energy system capabilities, based on ERAA 2024 market modelling results performed by ENTSO-E.

Based on the Latvian national regulatory authority – Public Utilities Commission of Latvia (PUC) delegation to AS "Augstsprieguma tīkls" (AST) and AS "Sadales tīkls" (ST), as TSO and DSO in Latvia to prepare FNA report, the analysis has prepared by AST and ST based on "ACER Decision on the FNA methodology: Annex I, "Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis" which is in accordance with Article 19e(4) of Regulation (EU) 2019/943 (ACER methodology).

TSO Flexibility Needs Assessment

1.1 Introduction

The European Commission identified goals for climate neutrality and reduction of CO_2 emission became main exercise and challenge for the power systems trends in coming years. Dramatic increase of requests from renewable energy sources (RES) for connections to the transmission network became top priority questions in whole Europe and asked TSO to pay a lot of attention to the long-term transmission system planning issues, as well as RES generation impact to the power system operation.

Latvian power system generation mix as in majority of European Union countries is going into direction of variable generation sources and RES, like solar, onshore wind and offshore wind. With increase of RES installed capacity, system becomes more unpredictable, covering of demand might be challenging due to unfavourable weather conditions like low wind speed or low solar irradiation. This question became essential for power system planning and transmission network planning in all EU countries.

Current FNA analysis is based on ERAA 2024 market modelling results of 2030 and 2035 target years (TY), weather scenarios (WS) number 14, 25 and 28. Specific scenarios were selected to be compliant with methodology and to not overwhelm with amount of data that TSO and DSO need to post-process since the main target of first FNA edition is getting insight into Latvian power system capability to handle variability caused by weather conditions, consumers behaviour and forecasting errors. During process of preparation FNA, AST and ST have gained valuable experience during preparation of such analysis. Within this analysis, according to ACER methodology, three main system needs indicators which reflect flexibility aspects have been calculated: RES integration, Ramping needs and Short-term flexibility needs.

FNA report can be broken down into four main chapters which are described in the separate parts: RES integration needs, Ramping needs, Short-term flexibility needs, Market barriers in implementation of flexible solutions and conclusions part, based on the results of the prepared analysis. First three are based on post processing of ERAA 2024 simulation results focusing on Latvian electricity system flexibility for the next 10 years ahead. In essence FNA required analysis has opened new approach to assess already performed ERAA study data particularly for Latvian electricity system and gave impression whether we can adjust the changes in Latvian electricity system in certain development conditions. Market barriers chapter gives insight into Latvian digital part of electricity system and describes state for electricity market participants.

1.2 RES integration needs

Variable renewable energy sources production is inherently uncertain, it highly depends on weather conditions like wind speed and solar irradiation, creating a challenge in system operation due to its variability and unpredictable production. RES production levels may be low due to poor solar irradiation or in case of low wind speed, or too high during intense solar irradiation and too high wind speed cases. On the other hand, end-consumption is more predictable and needs to be covered at any given moment of the bidding time step around a year. In the hours of insufficient RES generation, it should be covered by dispatchable and fast run-up generation. When lack of RES is prolonged and demand is particularly high and close to peak load, like in winter peaks, the system can drain water reserves in reservoirs and become even more reliant on combined cycle gas turbines (CCGT), in other words, dispatchable generation. During such instances it is essential to know how often load can be covered solely by RES and how much conventional generation is necessary to cover demand in hours of low RES production.

RES curtailment becomes important as well, as it can show how much of generation could not be used or transferred due to lack of load or having generation while load is not even close to maximum values. In other words, having generation from solar power plants in mid-day, when irradiation is at highest values, but the demand is rather low and certain amount of generation must be limited and interrupted. To address and show these issues in exact numbers, RES curtailment and residual load of ERAA 2024 (ENTSO-E) modelling results were analysed.

1.2.1 RES curtailment

The RES curtailment is the intentional, involuntary reduction of power output from wind or solar farms to maintain electrical grid stability. It typically occurs when renewable generation exceeds local demand or exceeds the transmission capacity of the grid, requiring grid operators to "dispatch down" generation to avoid grid overloads or even blackouts.

In Figure 1.1 below, can be observed that Latvian curtailment in both target years is almost identical, difference appears between multiple weather scenarios, but from one time horizon (2030) to other time horizon (2035) change is negligible. Main reason behind this is input data similarity and minor changes in future development, between two mentioned target time horizons. Latvian RES generation has changed just by adding extra 50 MW of onshore wind. Couple years ago, the development of RES in Latvia was not so optimistically due to economic reasons but to assume huge growth after first wave of RES generation deployment and an assumption was made that development could stagnate. In the next FNA report edition after two years results will be calculated based on ERAA 2026 or ERAA 2027 results, which will represent much more actual and progressive vision of last year's RES development pace increase.

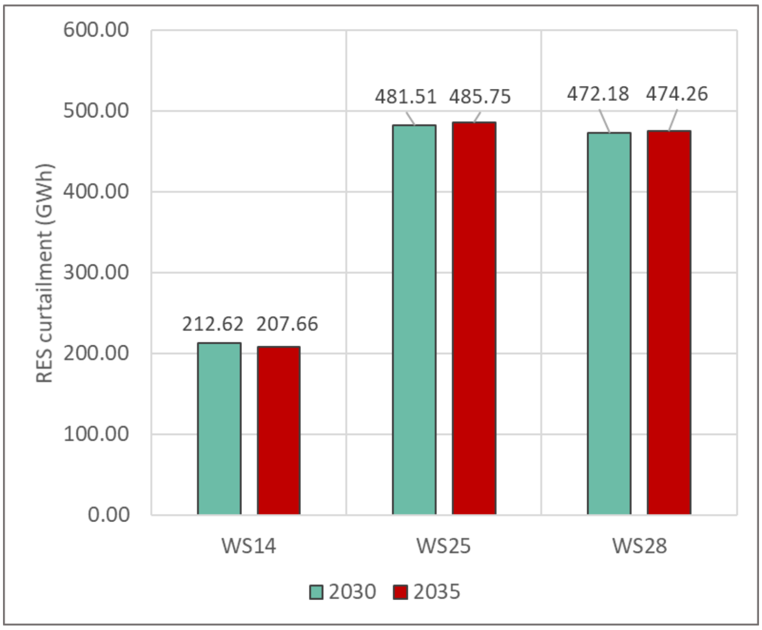

Figure 1.1 Total RES curtailment in 2030 and 2035 (GWh)

Hourly RES curtailment boxplots in Figure 1.3 illustrate the distribution of events, when curtailment occurs on hourly bases, it only includes the hours when curtailment happened. Across all weather scenarios, the results indicate increase in curtailment intensity from 2030 to 2035, it can be observed in WS14 where total curtailment value in Figure 1.1 differs by 5 GWh, but in Figure 1.3 extremes and upper 25th percentile almost doubles.

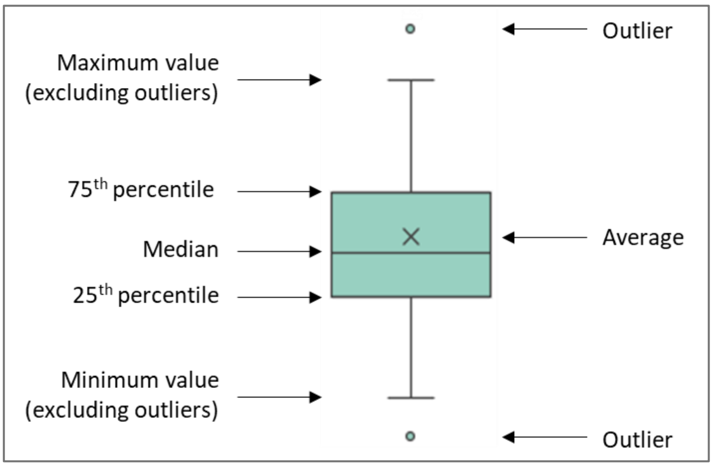

Figure 1.2 Explanation of boxplot elements

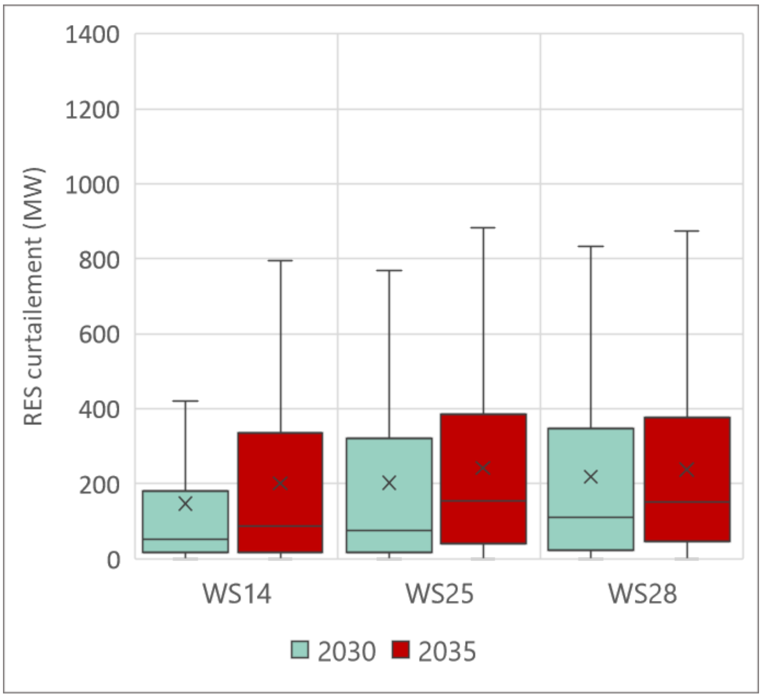

Figure 1.3 Hourly RES curtailment boxplots (MW)

Daily maximum RES curtailment shown in Figure 1.4 represents the highest hourly curtailment observed within each day, day with maximum curtailment of 0 MW were excluded. Maximum daily curtailment in both target years is similar, and maximum values are higher than 1200 MW, while upper 25th percentile fluctuate around 600 MW in most of weather scenarios. The graph demonstrates that average of daily maximums is higher than in Figure 1.3, since it includes only highest value per day and ignores value with lower RES curtailment within observed day.

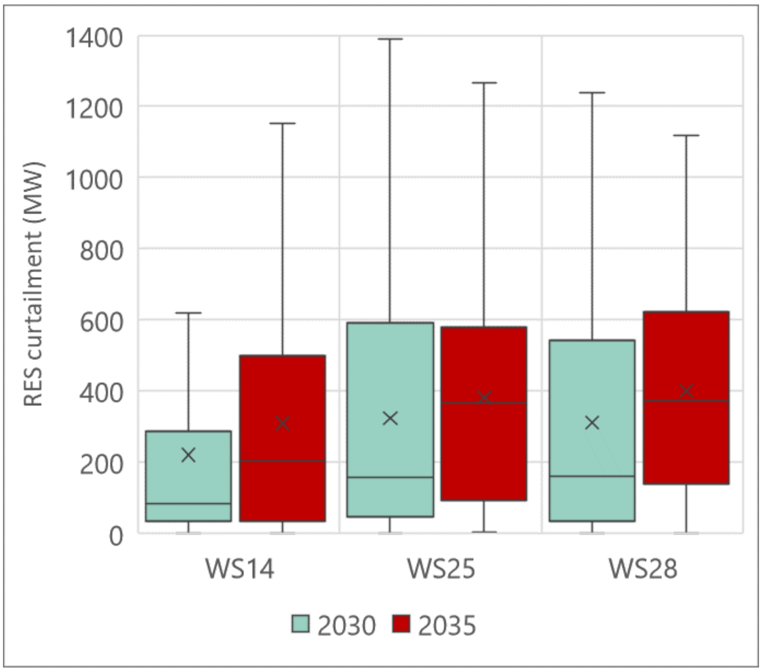

Figure 1.4 Daily maximum RES curtailment (MW)

In the Figure 1.5 presented the highest RES curtailment value, lowest value and average a year. In previous Figure 1.4 the maximum value was close to 1400 MW in 2030 WS25, because it does not include outliers which are one and a half times higher than 75th percentile. Maximum values shift depending on climatic year and out of three WS25 has highest curtailment peaks, which is almost twice as big in comparison to lowest peak, showing how much changes might happen when observing different weather scenarios.

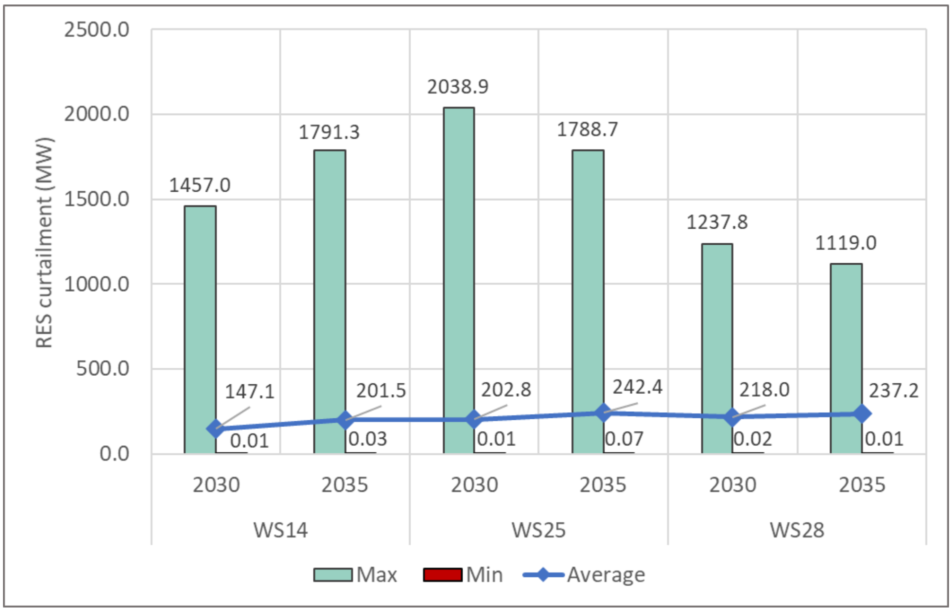

Figure 1.5 Average, maximum, minimum RES curtailment per scenario (MW)

Tables 1.1 to 1.3 shows two probability distribution tables and percentiles of RES curtailment within each WS, of the hours with curtailment higher than 0 MW.

Probability illustrates that around 50% of time the curtailment hours do not exceed 100 MW. Across all time horizons and WS above 95th percentile values are similar and the biggest deviations are in range between 25th and 75th percentile, sometimes having even two or three times higher values between studied WS.

Table 1.1 Probability distribution of RES curtailment (% of total hours)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
0 to 100 MW	64.8%	55.7%	48.7%	52.8%	42.9%	41.6%
100 to 250 MW	15.8%	14.3%	18.8%	16.4%	17.5%	20.6%
250 to 500 MW	10.4%	15.7%	16.9%	18.1%	24.8%	22.2%
500 to 1000 MW	8.4%	12.2%	15.1%	11.7%	13.2%	15.3%
1000 to 1500 MW	0.5%	1.9%	0.6%	1.0%	1.4%	0.5%
1500+ MW	0.0%	0.2%	0.0%	0.1%	0.2%	0.0%

Table 1.2 Probability distribution of RES curtailment (hours)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
0 to 100 MW	936	1322	1055	545	860	831
100 to 250 MW	229	340	407	169	351	411
250 to 500 MW	151	373	365	187	497	443
500 to 1000 MW	122	289	326	121	264	305
1000 to 1500 MW	7	45	13	10	28	9
1500+ MW	0	5	0	1	4	0

Table 1.3 Probability distribution of RES curtailment (MW)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
P1	1	1	1	1	1	1
P5	3	3	3	3	5	5
P25	16	17	23	16	40	47
P50	51	74	110	88	153	151
P75	179	320	347	335	385	377
P95	649	704	761	683	716	710
P99	932	1183	931	1012	1089	893

RES curtailment heat map for 2030 and 2035 is presented in Figures 1.6 and 1.7. It is made using RES curtailment cap of 150 MW to have better visual representation of when curtailment happens the most during different hours of day throughout the year. Both years have similar picture, RES curtailment appears mostly during mid-day in April, May – most significant production of solar. Looking towards end of the year curtailment appears more at nighttime and early morning hours. It is interesting to figure out that the highest mid-day curtailment does not happen in summer months but rather in spring, temperature is not hot enough to impact PV efficiency, but irradiation still strong.

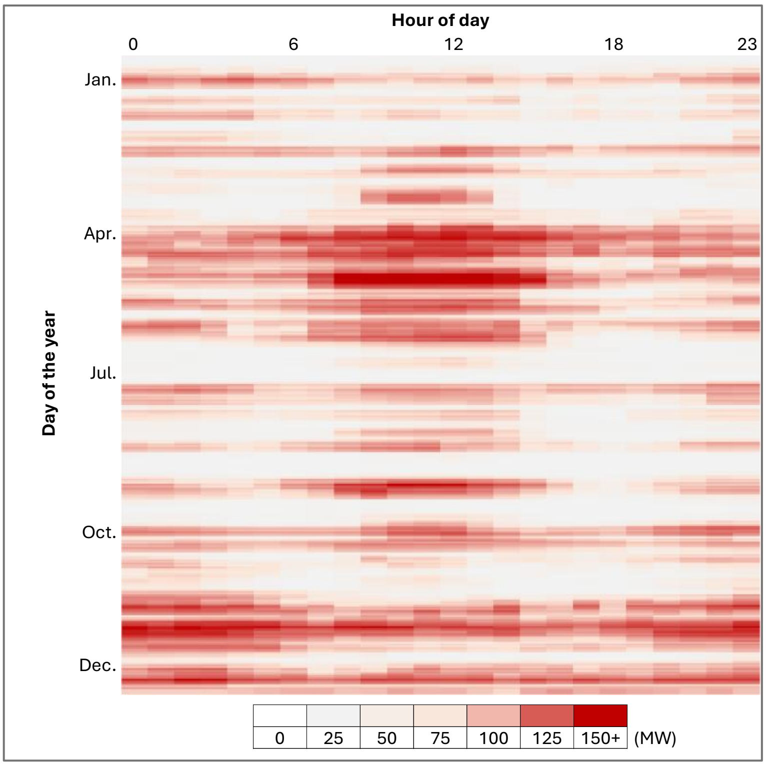

Figure 1.6 Heat map of RES curtailment in 2030 averaging three weather scenarios

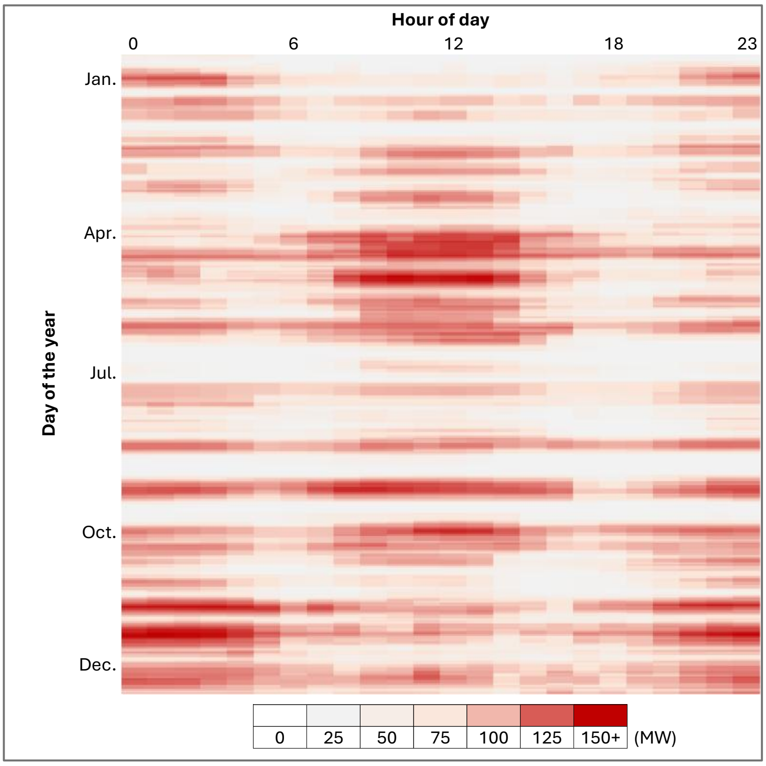

Figure 1.7 Heat map of RES curtailment in 2035 averaging three weather scenarios

In Figures 1.8 and 1.9 the seasonal analysis provides an insight into distribution of curtailment events, similarly to Figures 1.6 and 1.7, but with more focus on values during different seasons of the year rather than on the visual pattern of it. Outcome results indicates that curtailment is not evenly distributed across the year but has fair amount of variability across the seasons. Higher curtailment intensity and wider distribution have been observed during spring and summer seasons, while winter shows a smaller distribution. Variation between weather scenarios remains significant with higher distribution ranges observed in WS14 and WS28.

Looking specifically at end of the year in Figures 1.8, RES curtailment in WS25 and WS28 have higher values than in Autumn. It is connected to higher wind production overall with increase of curtailment. Figure 1.6 show more instances of RES curtailment in nighttime, when solar generation is not present.

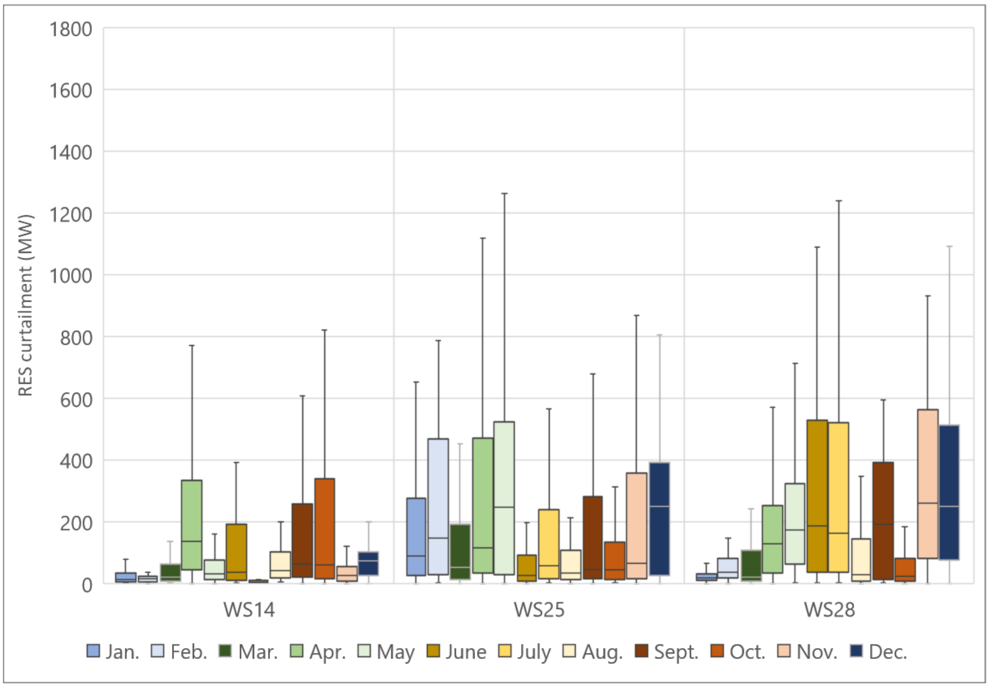

Figure 1.8 Seasonal hourly RES curtailment 2030 (MW)

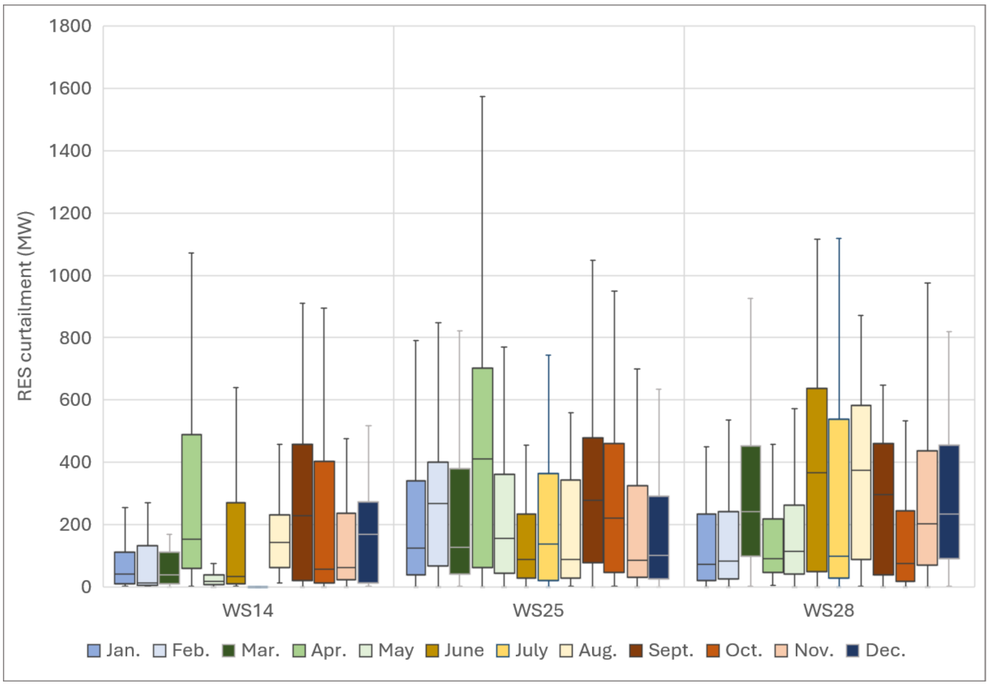

Figure 1.9 Seasonal hourly RES curtailment 2035 (MW)

Latvian RES curtailment is mostly impacted by offshore wind capacity in such a way, that when offshore wind capacity increases, RES curtailment increases the most as observed from Table 1.4. Onshore wind and Solar impacts are less significant, because these values fluctuate around 0. On the other hand, increase of load helps to decrease the RES curtailment and can be assumed as a good condition to decrease RES curtailment.

Table 1.4 Correlation between RES curtailment and different system conditions

		Wind onshore	Wind offshore	Solar	Load
2030	**WS14**	0.0151	0.1835	0.0511	-0.0656
	WS25	-0.0691	0.1566	0.0403	-0.0535
	WS28	-0.0412	0.1971	-0.051	-0.0929
2035	**WS14**	0.0035	0.2455	-0.0181	-0.0574
	WS25	0.0001	0.2623	-0.0006	-0.0763
	WS28	0.0104	0.2997	-0.0572	-0.1356

Figure 1.10 shows duration of curtailment events. It represents how many hours in a row curtailment appears until an hour without any curtailment. From the graph it is visible that curtailment lasts, on average, approximately 10 hours, however median or 50th percentile of duration is closer to 5 hours. In some cases, curtailment duration can exceed even 24 hours. Figure 1.11 represents maximum duration which occasionally can exceed even 100 hours.

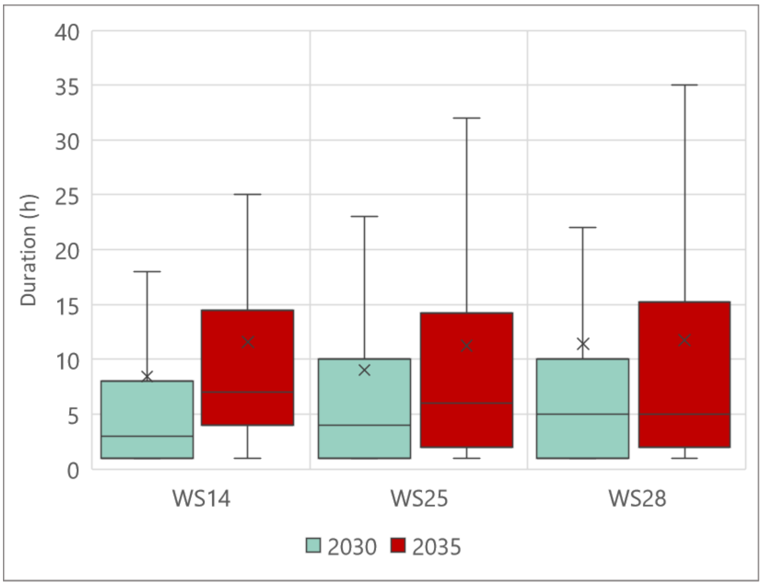

Figure 1.10 Duration of RES curtailment events (hours)

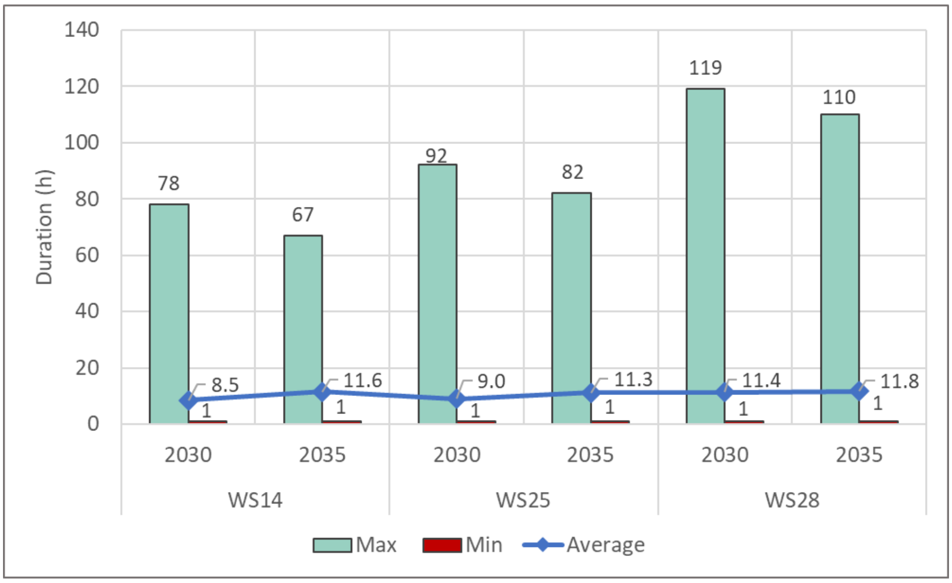

Figure 1.11 Average, maximum, minimum RES curtailment duration per scenario (hours)

Figures 1.12 and 1.13 show intervals between curtailment events, or how many hours in a row curtailment does not appear. Trend can be observed that in WS14 intervals between curtailment events are the lowest but looking at graph above duration of curtailment is similar to other WS. This creates the conclusion that WS with higher curtailment do not have much longer duration of events but have higher values of curtailment overall.

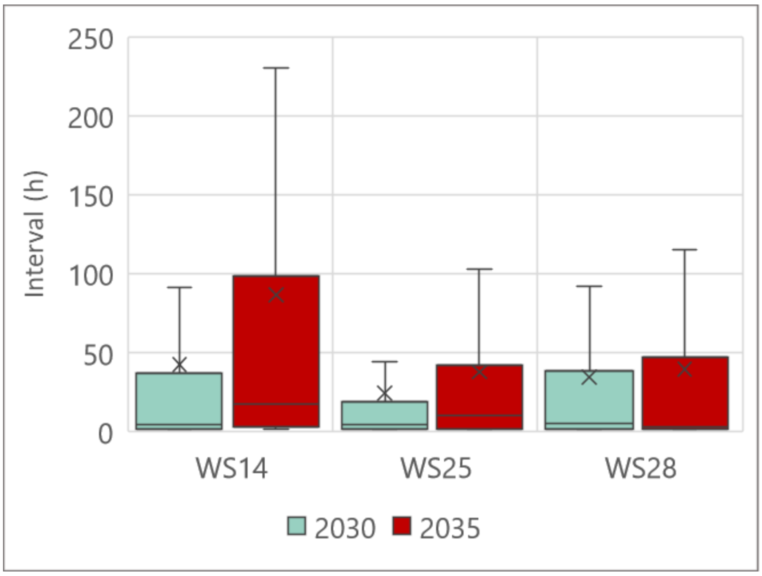

Figure 1.12 Interval between RES curtailment events (hours)

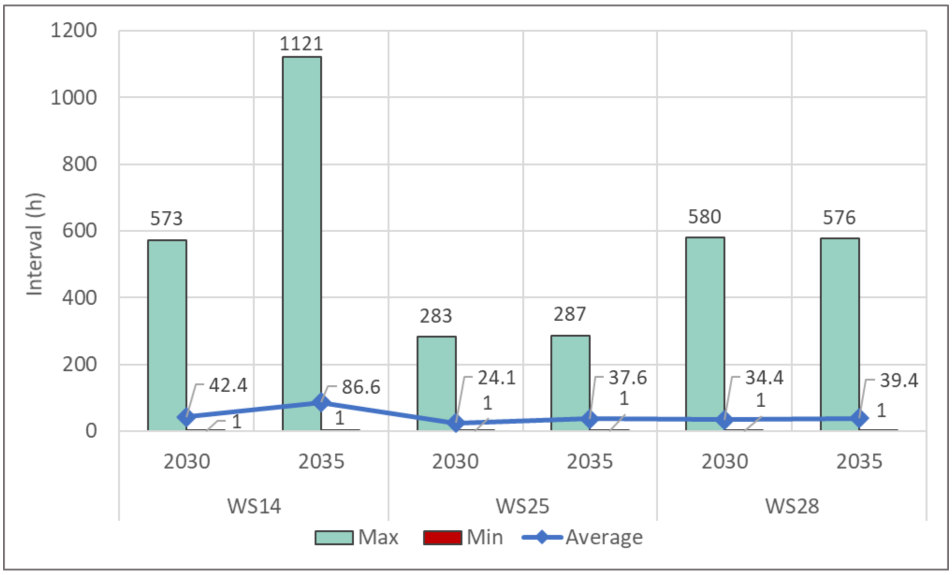

Figure 1.13 Average, maximum, minimum RES curtailment duration per scenario (hours)

RES integration target from simulation results was compered to National Energy and Climate plan. Based on latest edition of NECP[1] from spring of 2024, Latvia should have at least 80% of electricity generated from renewable energy sources by 2030 for its in end consumption, which was determined according to Article 4(a)(2) of Regulation 2018/1999. Simulation results for RES integration were calculated using Equation 1.1.

$$RES\ integration\ target = \frac{RES\ production}{consumption}$$

Equation 1.1 RES integration target

where:

- RES production – represents production from solar, wind and hydro energy, excluding biomass,
- consumption – covers only Latvian electricity consumption.

[1] Aktualizētais Nacionālais enerģētikas un klimata plāns 2021.–2030. gadam

Table 1.5 Comparison of RES integration targets

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
RES integration target from NECP (%)	>80%	>80%	>80%	N/A	N/A	N/A
RES integration from simulation results, with hydro (%)	108.1%	120%	115.9%	89%	99%	96%
RES integration from simulation results, without hydro (%)[2]	70.3%	79%	73.8%	58%	66%	61%

Values from Table 1.5 above show that Latvia complies with NECP RES integration target of having at least 80% of electricity in end consumption generated from renewables. For 2035, NECP does not have target value, since the latest target year is 2030. However, after applying same target of 80% to 2035, Latvia continuous complying with it. Latvia does not require any additional RES curtailment decrease measures and none of them will be analysed in this FNA edition as measures to decrease RES curtailment are increasing the compliance with NECP targets.

1.2.2 Residual load

Residual load is a great representation of how load is affected by RES variability. Any hour of the year load can be higher or lower than potentially produced electricity by RES generation. For context, load in particular hour is 1000 MW at the same time RES production is reaching 800 MW, in the end residual load is only 200 MW, see that equation shown below. This resulting value is an amount of electricity that should be produced by another source of electricity generation, like natural gas, hydro etc., or imported from neighbouring countries via the grid interconnections. In cases when load is lower than RES generation, additional electricity should be stored using utility scale batteries, pumped storage, etc., or transmitted using grid interconnection to other countries. Reduction of dispatchable generation is another solution, but only if such generation is producing electricity during the necessary periods of time, which is unlikely during high solar and wind generation periods.

$$Residual\ load = Load - RES\ generation$$

Equation 1.2 Calculation of Residual load

where:

- Load – all load in Latvian bidding zone;

[2] RES integration results without hydro are informative, to see how much solar and wind capacity contribute to RES integration target.

- RES generation – generation from variable RES generation sources like wind and solar.

In Figure 1.14 can be observed that during the year residual load can reach more than 1500 MW of load in peak hours, on other end negative residual can reach -750 MW or RES production covers all Latvian load and still has 750 MW of electricity available for export to other countries or for storage to cover load peaks during the other parts of the day.

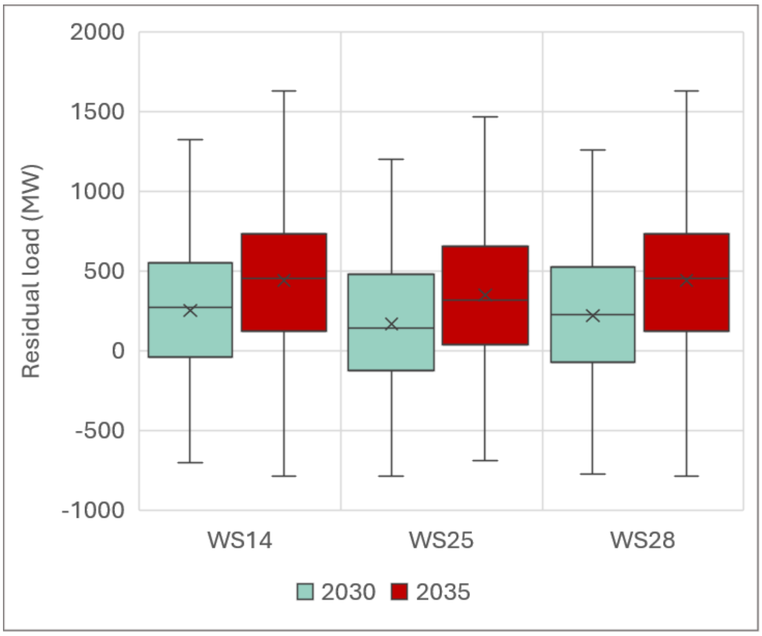

Figure 1.14 Hourly residual load (MW)

Figures 1.15 and 1.16 are showing residual load deviation for three different time intervals: hourly, daily and monthly. Hourly graphs show how much value of each hour deviates from daily average residual load. Daily shows daily deviation from weekly average residual load. Monthly data represents monthly average deviation from annual average residual load. Results for 2030 and 2035 have similar patterns, 2035 having slightly higher average values, shown as "X" in figures. Hourly and daily deviations medians are at least twice as big as yearly value showing that Latvian electricity system has more short-term and mid-term balancing challenges rather than long-term ones. Big spread, especially in WS28 daily values, illustrates the challenges which occur due to high variability of renewables.

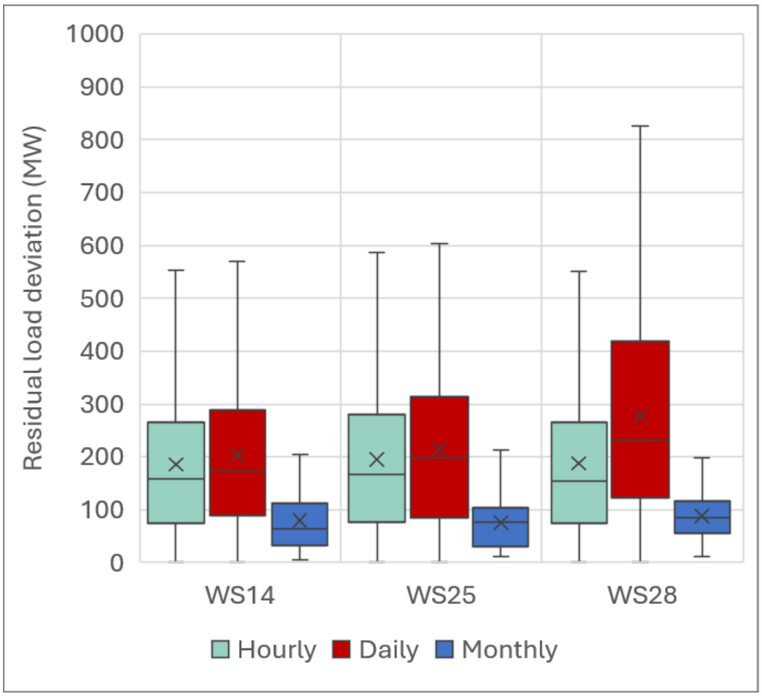

Figure 1.15 Residual load deviation in 2030 (MW)

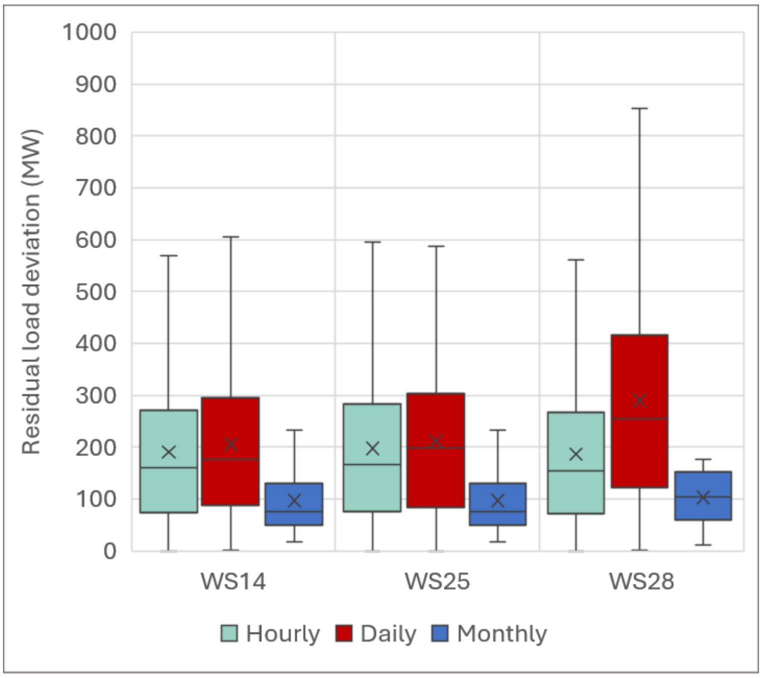

Figure 1.16 Residual load deviation in 2035 (MW)

1.3 Ramping needs

1.3.1 Residual load variation

Residual load variation is the difference in residual load between two market time units. It describes how much residual load can change within an hour. Variation shows how much generation upwards or downwards regulation can be necessary to keep system balance from one market time unit to another.

Figure 1.17 demonstrates residual load variation for the whole year, in most cases residual load shifts up to +/- 50 MW from previous market time units, which does not require big shifts in generation and interconnections flows. Looking at the extremes in Figure 1.18 variation can even reach a level, which is close to Baltic countries reference incident of 700 MW, or above. Average value of residual load variation is zero, because throughout of the year load changes every hour and by the end of it reaches the initial point.

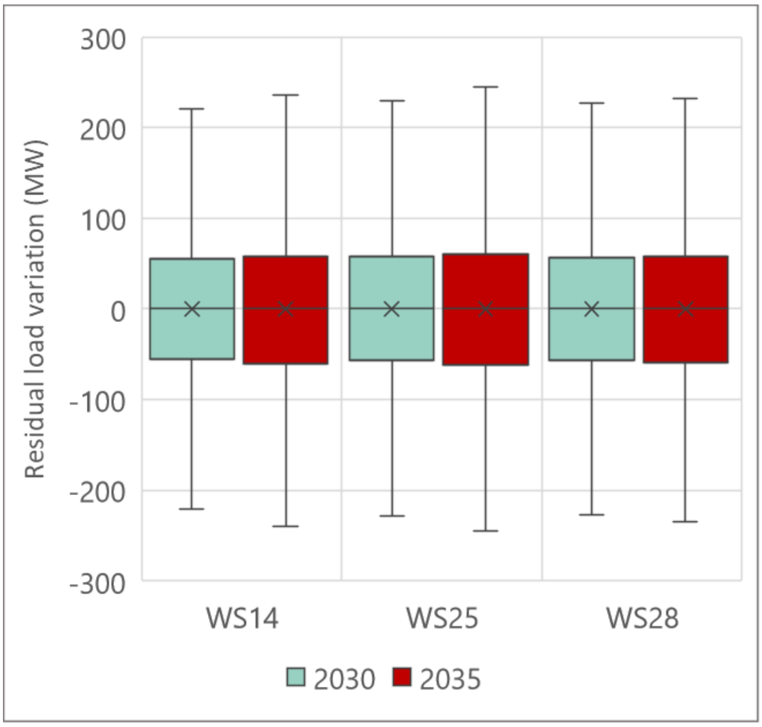

Figure 1.17 Hourly residual load variation (MW)

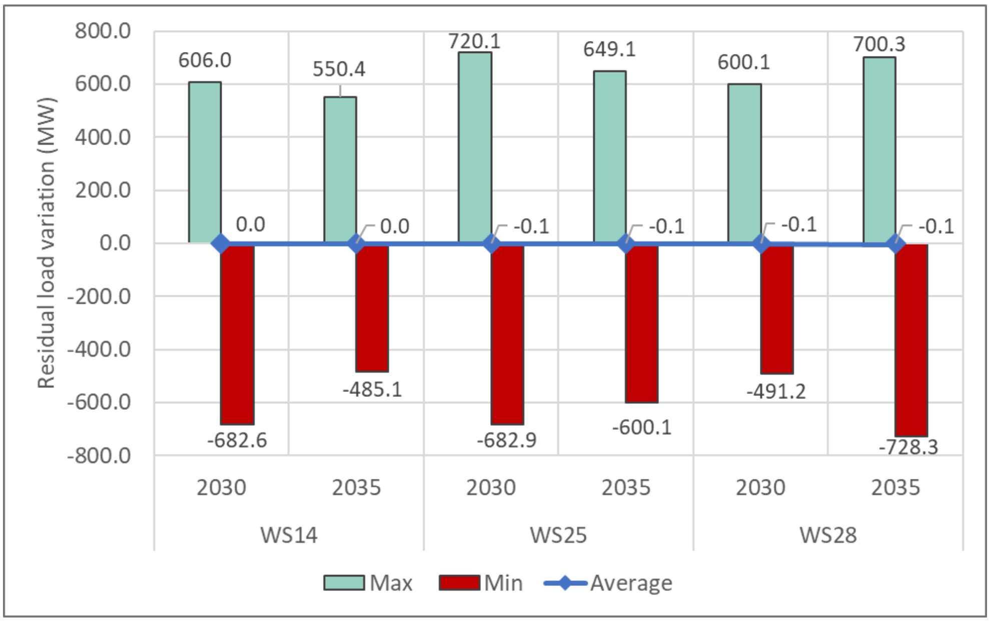

Figure 1.18 Average, maximum, minimum residual load variation per scenario (MW)

Just like observed previously in Figure 1.17, Table 1.6 shows similar behaviour, having almost 80% of residual load variation in the range between -100 and +100 MW. In case of Latvian electricity system load variation there is not high variation in 95th and 99th percentiles, reaching 150 MW and 250 MW respectively. In comparison to residual load deviation, which has strong impact of RES variability to deviation from daily and weekly values, residual load variation changes from hour to hour in a more manageable manner. Extremely high values like in Figure 1.18 can occur few times per year, looking at 99th percentile in Table 1.8 variation is up to 250 MW.

Table 1.6 Probability distribution of residual load variation (%)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
<–500 MW	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
–500 to –250 MW	0.4%	0.9%	1.0%	0.4%	1.0%	0.6%
–250 to –100 MW	10.8%	11.7%	11.7%	13.0%	13.2%	13.2%
–100 to –50 MW	16.1%	14.8%	14.6%	15.7%	14.2%	14.3%
–50 to 0 MW	23.0%	23.2%	22.6%	21.6%	22.1%	22.7%
0 to 50 MW	23.0%	21.9%	23.0%	21.8%	20.9%	21.6%
50 to 100 MW	14.8%	14.0%	13.9%	14.0%	13.8%	13.2%
100 to 250 MW	11.3%	12.5%	12.2%	13.1%	13.6%	13.5%
>250 MW	0.5%	0.8%	0.9%	0.4%	1.1%	0.8%

Table 1.7 Probability distribution of residual load variation (hours)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
<–500 MW	4	2	0	0	1	2
–500 to –250 MW	39	76	88	32	91	56
–250 to –100 MW	945	1026	1022	1134	1155	1150
–100 to –50 MW	1405	1297	1275	1370	1243	1252
–50 to 0 MW	2009	2028	1977	1885	1933	1981
0 to 50 MW	2006	1917	2012	1905	1830	1890
50 to 100 MW	1295	1227	1216	1225	1204	1155
100 to 250 MW	988	1090	1066	1146	1185	1179
>250 MW	45	73	80	39	94	71

Table 1.8 Percentiles of residual load variation (MW)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
P1	-214	-246	-250	-214	-252	-235
P5	-139	-161	-158	-145	-166	-157
P25	-56	-57	-57	-61	-62	-59
P50	0	0	0	0	0	0
P75	55	58	57	58	61	58
P95	141	157	154	149	165	157
P99	218	243	244	225	253	240

Residual load variation does not have variability during the year. In Figures 1.19 and 1.20 it is visible that variation does not have a seasonal pattern unlike RES curtailment analysed in Chapter 1.2, with clear high and low curtailment months, variability has almost the same peaks in all 12 months of the year. Only visible change is that the median in some months can be negative, while in other months positive, but this change does not have strong patterns that could be clearly observed.

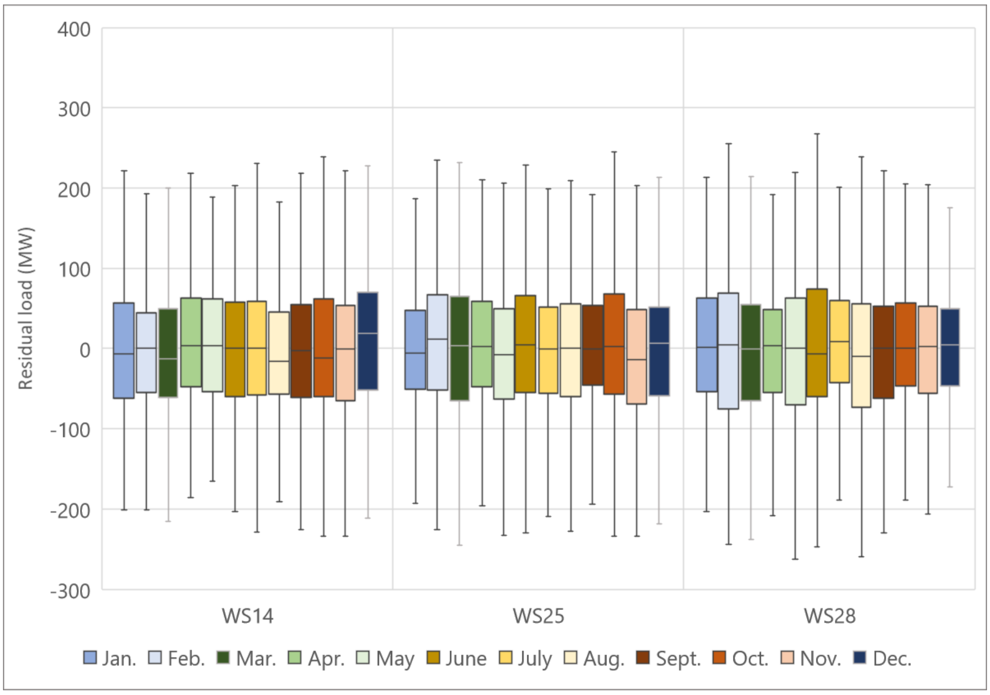

Figure 1.19 Seasonal residual load variation 2030 (MW)

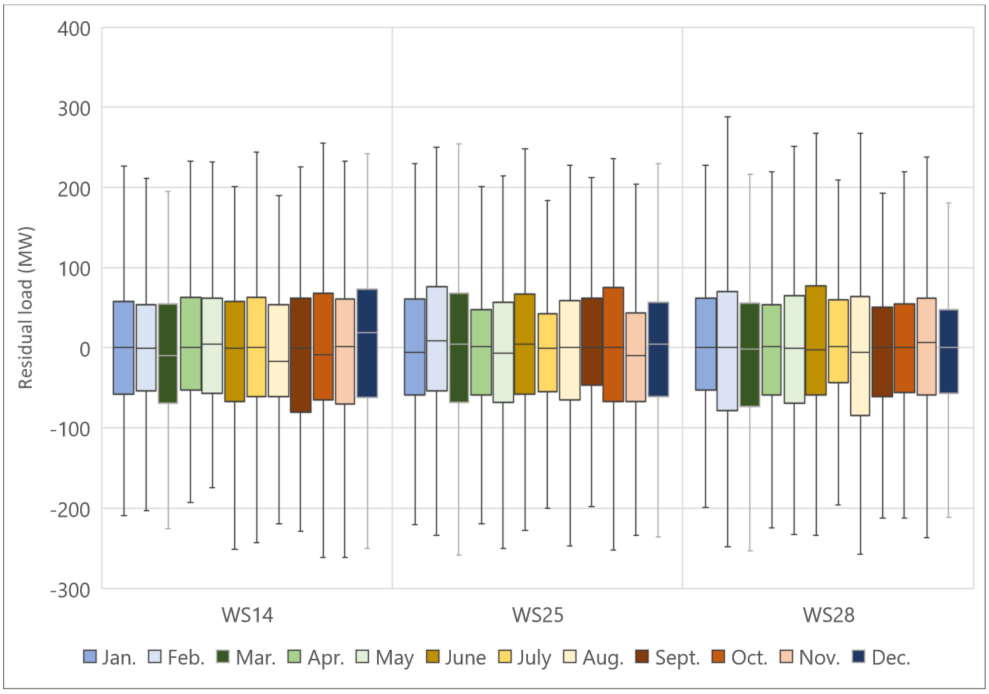

Figure 1.20 Seasonal residual load variation 2035 (MW)

Residual load variation heat maps shown in Figures 1.21 and 1.22. Residual load does not have any visible changes within the comparison period. But these heat maps discover an interesting pattern of how residual load shifts during the year. Heat maps have two colours: red represents rise of demand or decrease of RES production, blue shows decrease of demand or increase of RES production. For residual load itself during hours with positive values dominates load and hours with negative values has more renewable energy source in it.

Heat maps show that positive variations are primary observed during early morning and afternoon hours, while negative variation dominate in morning, until mid-day, and evening periods. Seasonality affects how long variation is in specific zone, in winter morning positive values are longer, in evening negative values begin earlier.

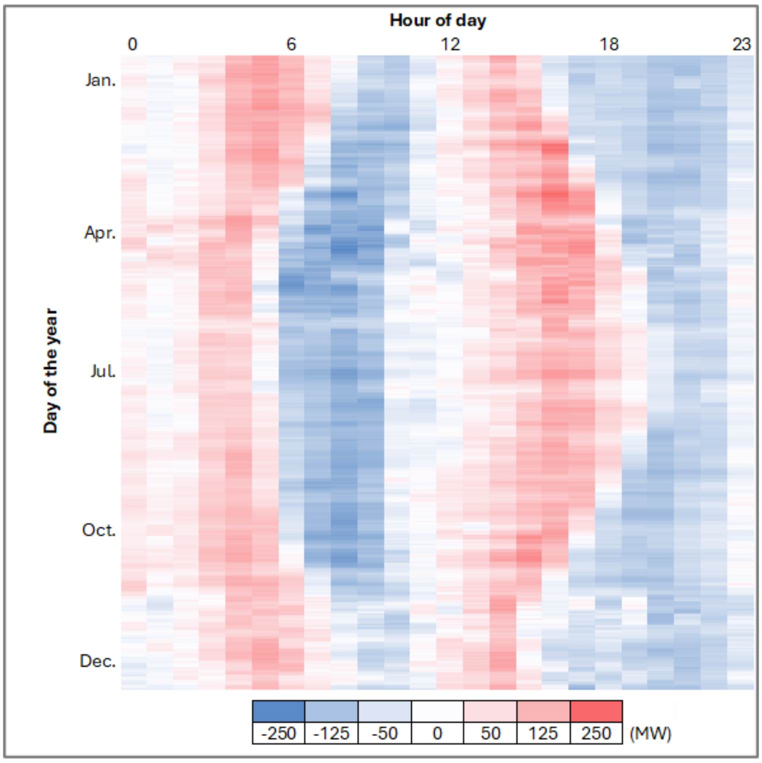

Figure 1.21 Heat map of Residual load variation 2030 averaging three weather scenarios (MW)

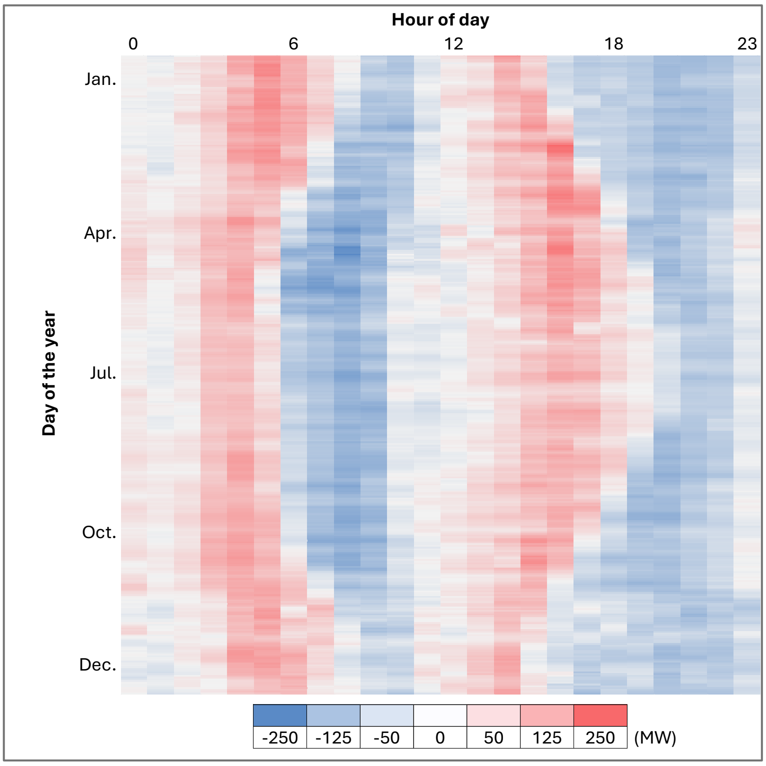

Figure 1.22 Heat map of Residual load variation 2035 averaging three weather scenarios (MW)

Table 1.19 below shows correlation between residual load variation and different system conditions, results demonstrates that onshore wind, offshore wind and load almost don't have any correlation with variation, only solar production has some type of correlation with tendency to decrease variation when production increases. This can be connected to fact that solar production is happening during day-hours with clear growth phase and decrease phase making the variation predictable.

Table 1.9 Correlation between residual load variation and different system conditions

		Wind onshore	Wind offshore	Solar	Load
2030	**WS14**	0.0273	-0.0421	-0.1711	-0.026
	WS25	0.0297	-0.0597	-0.1633	-0.0434
	WS28	-0.0148	-0.0701	-0.1302	-0.0264
2035	**WS14**	0.0221	-0.037	-0.168	-0.0101
	WS25	0.0273	-0.0572	-0.1639	-0.0268
	WS28	-0.0044	-0.0611	-0.1334	-0.0084

1.3.2 Ramping residual margin

Ramping residual margins (RRM) calculated as the difference between current generation in a particular hour and maximum capacity to get RRM Up, RRM Down is the difference between current generation and minimum stable level.

Generators can be offline in specific hour, the contribution to any type of RRM is zero, this assumption is made to account for start-up time. Other generators specific properties such as start down time, minimum up time, minimum down time, were included into ERAA market model. Figure 1.23 shows available RRM from dispatchable generation in Latvia, which are natural gas and hydro. During calculation of RRM contribution for generators, one should account for ramping rates, but it is not a case for this analysis, because the market time unit used in analysis is 1 hour and all dispatchable generators in Latvia can reach maximum values within one hour.

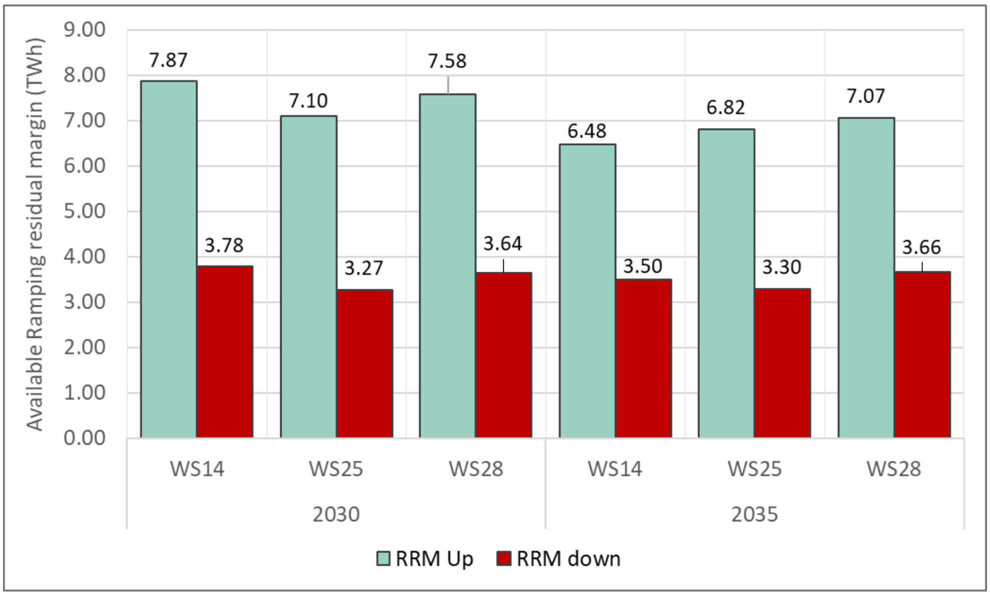

Figure 1.23 Annual available ramping residual margins from generators (TWh)

Figure 1.24 shows how much natural gas and hydro are contributing to RRM, where hydro is contributing to major part of RRM. There are two reasons for such tendencies, first one is installed capacity itself. In Latvian electricity system the Riga Combined heat and power (CHP) plant installed capacity is a bit over 1000 MW, while installed capacity of hydro generation cascade on Daugava River is reaching almost 1600 MW. Second reason is a way how generator contributes towards RRM, since only when generator has at least 1 MW of production it is eligible to provide RRM, therefore, natural gas CHP's usually works more when electricity price is higher.

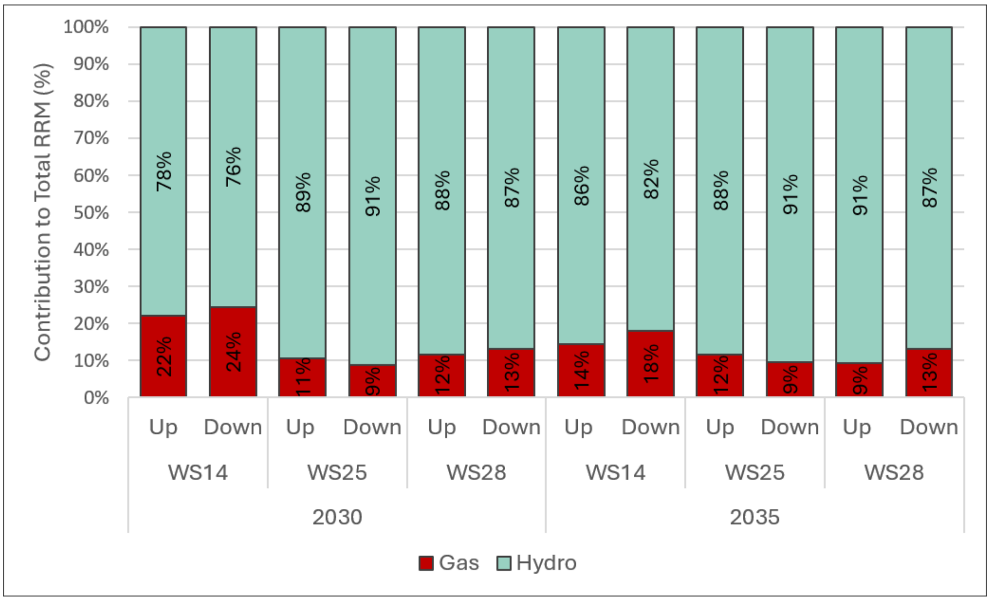

Figure 1.24 Contribution to RRM from gas and hydro generation (%)

Interconnections have an essential role in regulation of energy system and their contribution to RRM. When interconnection has room for import, it contributes to RRM Up and when it has available capacity to export it contributes to RRM Down. During the calculation two things where considered, maximum and minimum Net Transfer Capacity (NTC) of interconnection and the liquidity constraint. NTC was taken according to input data to ERAA market model. To account for liquidity constraint, when electricity price exceeded 99th percentile, NTC decreased by 50%. Figure 1.25 shows RRM from interconnection and their contribution is two times higher than from generators.

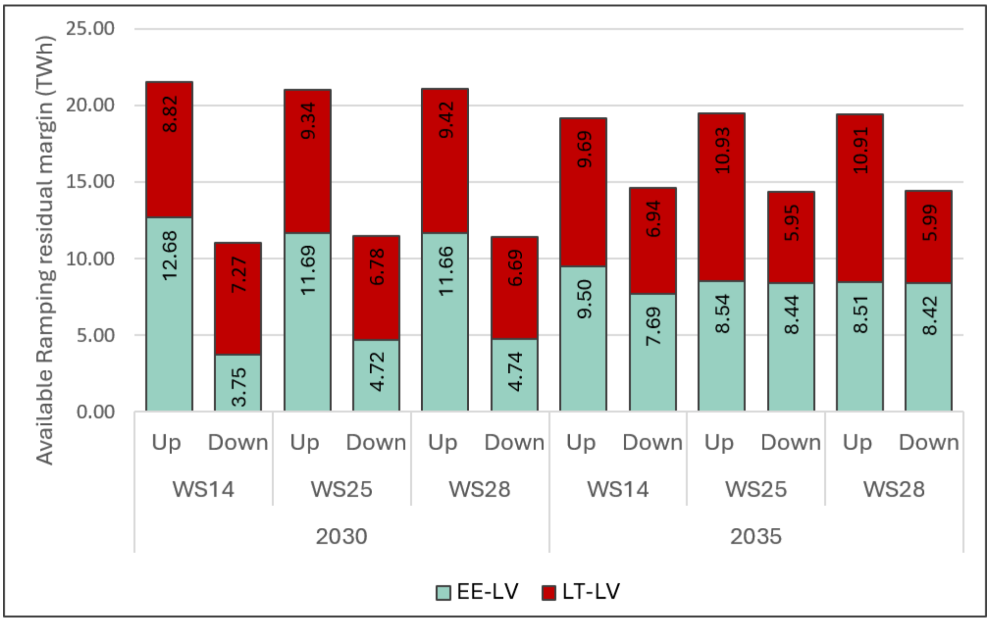

Figure 1.25 Available RRM from interconnection (TWh)

1.3.3 Uncovered residual load variation

Residual load variation should be covered by RRM from generation and interconnection. Values of residual load variation were observed in chapter 1.3.1., but to have a clear view how much of it needs to be covered, Figure 1.26 shows total RRM Up and total RRM Down for each scenario.

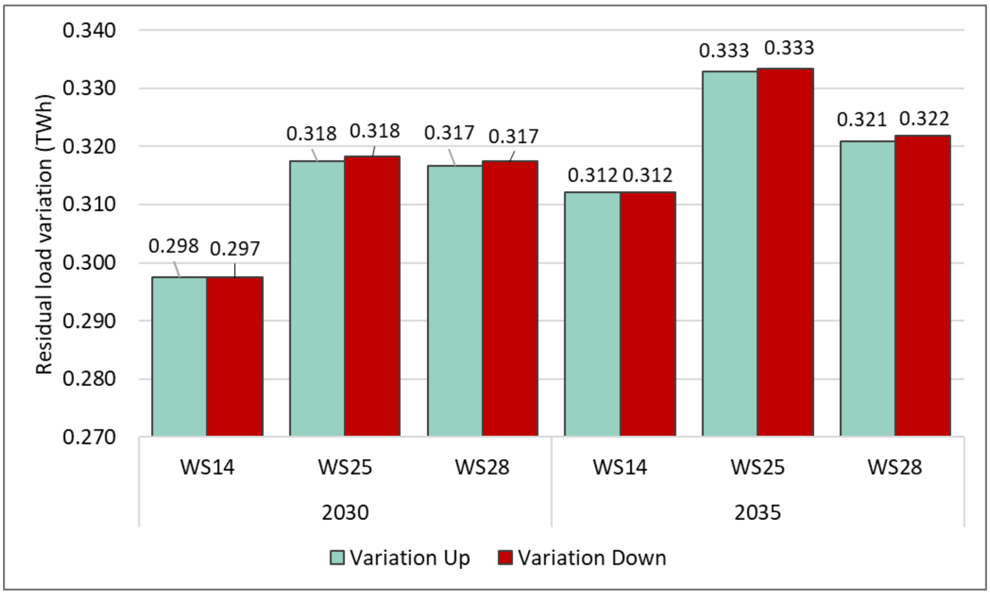

Figure 1.26 Total residual load variation (TWh)

Residual load variation mostly is in the range between -250 MW and 250 MW, in total 0.6 TWh. For the Latvian electricity system dispatchable generation and interconnection capacities are enough to cover all of it. During analysis there was not even 1 hour with uncovered variation in all scenarios.

Table 1.10 Summary of uncovered residual load variation

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
Number of uncovered ramping events	0	0	0	0	0	0
Average duration, h	0	0	0	0	0	0
Max event capacity, MW	0	0	0	0	0	0

1.4 Short-term flexibility needs

For the analysis of short-term flexibility needs the residual load forecast error was calculated, based on historical D-1 forecast and real-time observations for two years: 2024 and 2025. To have consistency with data for forecast error calculations ENTSO-E transparency platform[3] data were used. Total load, solar and wind generation values for Day-ahead and Actual categories were extracted from it.

During preparation of forecast error calculation, time series were calculated in relative units for load, solar and wind generation. For the load, day-ahead value was subtracted from actual load and divided by actual load. For wind and solar day-ahead values were subtracted from actual values but divided by installed capacity for each of historical years. Then data of two years of historical forecast error was stacked into one timeseries, ERAA simulation results were duplicated once to have values against each point of forecast error. Before application of forecast errors, following forecasting improvement factors were used – for load 5%, for solar 25% and for wind 15%. There is no one regulation or methodology stating exact ranges for forecasting improvement factors to be used, therefore TSO assumed values based on NREL study "Wind Power Forecasting error distribution: an international comparison"[4] and ISO New England "Solar power forecast error statistics"[5].

1.4.1 Historical residual load forecast errors

Table 1.11 shows residual load percentiles on different days of the week during the year. All days of the week have similar percentiles without any significant outliers even for 0.01 and 99.9 percentiles. Forecast errors are leaning into negative part stronger, showing that predicting of RES generation is harder and it is more unpredictable. Reason for this can be low values of installed RES capacity in overall energy mix of Latvia, according to data in ENTSO-E transparency platform solar installed capacity in 2024 was 303 MW and 450 MW in 2025. In the end, result with few hundred megawatts mismatch can cause forecasting error to exceed 50% in relative units.

[3] ENTSO-E Transparency Platform
[4] The Distribution of Wind Power Forecast Errors from Operational Systems
[5] a04_etwg_2024_04_30_solar_forecast_statistic_preview.pdf

Table 1.11 Percentiles of residual load error for different days of the week

	P0.1	P1	P5	P25	P50	P75	P95	P99	P99.9
Monday	-71.8%	-42.2%	-17.1%	-3.4%	1.0%	4.5%	10.7%	16.2%	21.7%
Tuesday	-66.8%	-34.1%	-15.9%	-3.6%	0.7%	4.0%	9.1%	15.5%	23.2%
Wednesday	-91.5%	-53.3%	-19.2%	-4.2%	-0.1%	3.6%	8.6%	12.2%	15.9%
Thursday	-70.9%	-44.0%	-18.1%	-2.0%	1.3%	4.4%	8.5%	11.9%	20.5%
Friday	-66.3%	-40.7%	-16.7%	-2.3%	1.4%	4.3%	8.6%	12.7%	17.2%
Saturday	-72.9%	-37.2%	-14.7%	-2.1%	1.2%	3.8%	8.1%	12.2%	17.6%
Sunday	-74.3%	-39.4%	-15.8%	-2.2%	0.8%	3.5%	7.7%	14.5%	22.0%

Figure 1.27 shows that most data points in all months throughout the year are similar, being under +/- 15% of forecast error. However, from March till October error outliers exceed -60% and in some cases can reach almost -100%. Main cause of such a big error is thought to be solar forecast and actual production mismatch. Data on onshore wind is not represented strongly enough, because installed capacity is 136 MW and only with further growth in installed capacity of onshore wind a stronger conclusion could be made in the future.

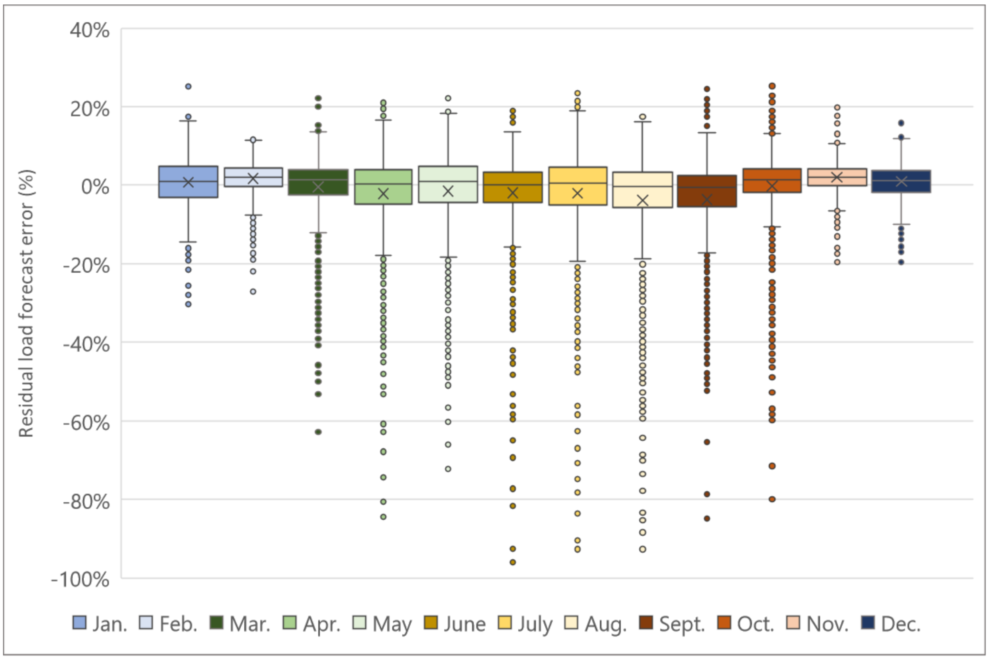

Figure 1.27 Seasonal residual load forecast error (%)

1.4.2 Short-term residual margins

According to the methodology used, residual margins are calculated in exactly same way as residual ramping margins, described in chapter 1.3.2. of this report. Therefore, assumption was made that short-term residual margins are identical to RRM. Residual load variation and forecasting error are different types of system flexibility needs, where first one is driven by changes in residual load due to changes in load of the system and RES generation variation. Second one is more focused on system operator and market participants to forecast actual load and

RES generation for the next day. That's why coverage of residual load variation from generation and electricity grid interconnections does not subtract these resources for margins to cover residual load forecast error. Graphs with available margins can be seen in chapter 1.3.2 Figures 1.23 to 1.25.

1.4.3 Uncovered short-term flexibility needs

In target year 2030 and 2035 uncovered short-term flexibility needs were relatively low to system sizes. Therefore, any measures to reduce 2.1 GWh and 0.1 GWh of uncovered needs do not justify costs of implementation. Additionally, as described above forecast error appear due to solar generation miss match between D-1 and actual generation, where even 200-300 MW difference create almost 100% forecast error.

Table 1.12 Uncovered short-term flexibility needs

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
Average capacity of uncovered ST flexibility needs, MW	75	122	101	38	76	0
Total amount of expected energy across all WS, GWh	2.086			0.102		
Number of hours with uncovered ST flexibility needs, h	18	27	16	4	2	0

Table 1.14 shows that values are up to 200 MW in most hours with uncovered short-term flexibility needs. Uncovered needs slightly over 350 MW is happening only in 2030 WS25. Creating over all scenarios, with two historical years applied to each of them, around 70 hours with uncovered needs, which after application of associated probability have 2.2 GWh of expected energy.

Table 1.13 Probability distribution of uncovered short-term flexibility needs (% of total hours)

	2030			2035		
	WS14	**WS25**	**WS28**	**WS14**	**WS25**	**WS28**
0-50 MW	56%	22%	44%	50%	50%	0%
50-100 MW	11%	26%	13%	50%	0%	0%
100-150 MW	17%	26%	19%	0%	50%	0%
150-200 MW	11%	7%	6%	0%	0%	0%
200-250 MW	6%	4%	6%	0%	0%	0%
250-300 MW	0%	7%	6%	0%	0%	0%
300-350 MW	0%	4%	6%	0%	0%	0%
350+ MW	0%	4%	0%	0%	0%	0%

Table 1.14 Probability distribution of uncovered short-term flexibility needs (hours)

	2030			2035		
	WS14	WS25	WS28	WS14	WS25	WS28
0-50 MW	10	6	7	2	1	0
50-100 MW	2	7	2	2	0	0
100-150 MW	3	7	3	0	1	0
150-200 MW	2	2	1	0	0	0
200-250 MW	1	1	1	0	0	0
250-300 MW	0	2	1	0	0	0
300-350 MW	0	1	1	0	0	0
350+ MW	0	1	0	0	0	0

From heat maps in Figures 1.28 and 1.29 can be observed that short-term flexibility appears only during mid-day. Target year 2030 has more hours during the year with uncovered needs, almost all of them happen during August-October period. Target year 2035 only has few hours with uncovered needs, which occur in the end of April and September. These heat maps cover requirement to show representation of the uncovered short-term flexibility needs per hour and day. Heat map with representation of the expected energy resulting from uncovered needs will look exactly same. Because it is calculated as average uncovered needs across all three weather scenarios, only difference will be units in MWh rather than MW.

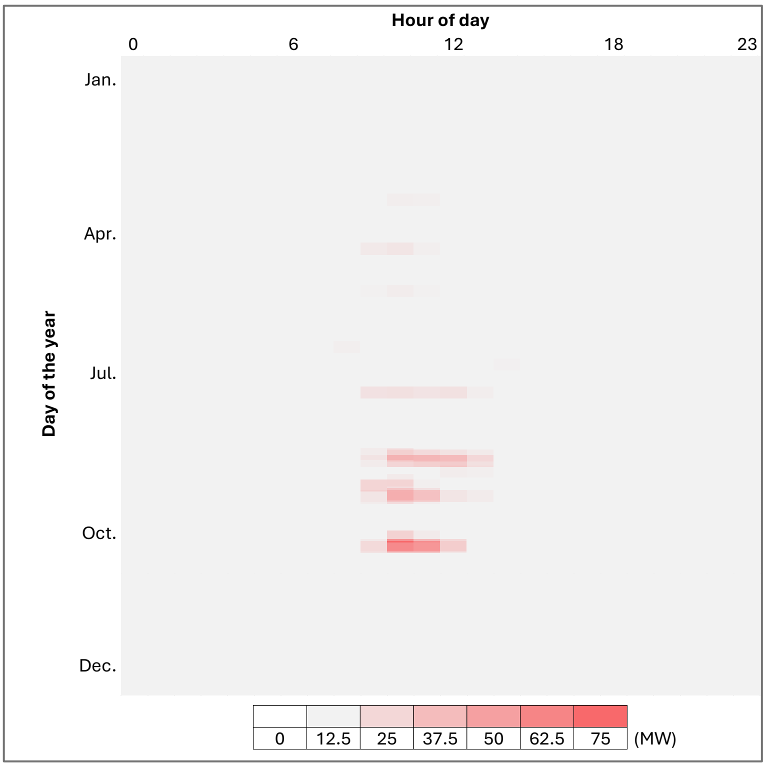

Figure 1.28 Heat map of average uncovered short-term flexibility needs in 2030 averaging three weather scenarios (MW)

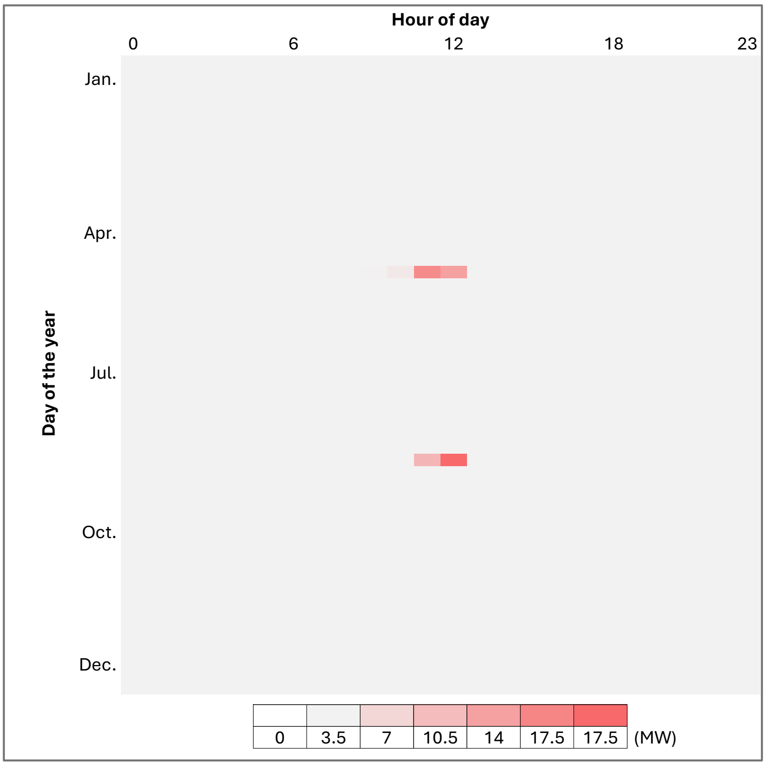

Figure 1.29 Heat map of average uncovered short-term flexibility needs in 2035 averaging three weather scenarios (MW)

1.5 Market barriers and contribution of digitalisation

This chapter describes the main barriers affecting the participation of flexibility resources in the Latvian electricity market and the contribution of digitalisation to reducing of those barriers.

Overall, Latvia along other development in energy market and flexibility sector has made significant progress in opening balancing markets and enabling digital, near-real-time operation of the power system. Marginal pricing and standard balancing products and therefore participation in European balancing platforms and short-term capacity procurement via Baltic balancing capacity market create transparent price signals and lower several traditional market-entry barriers. At the same time, some areas remain where the framework is still developing and where further regulatory and digitalization developments are needed.

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

A complete legal framework is a prerequisite for participation of new actors such as independent aggregators, active end-users, energy communities, storage operators and others. While in Latvia, the legal framework is supporting active customers, energy communities, storage operators the legal basis for independent aggregation is incomplete.

Independent aggregation remains the most significant identified regulatory barrier for new entrants and small-scale flexibility resources. Work on this regulation improvements for independent aggregators is still ongoing and progress on this topic is foreseen in future. However, current framework allows aggregation only under limited conditions, and fully independent aggregation is not implemented yet as a complete market model. This limits the possibility for consumers, distributed generation, storage and other small assets to participate in the market through an aggregator that is independent from the electricity supplier.

The barriers are both legal and technical.

- The relevant issues from legal framework include the definition of the aggregator role, the relationship between the aggregator, the balance responsible party and supplier, settlement and compensation principles, access to metering and baseline data, and procedures for verifying delivered flexibility. Until these elements are fully defined, potential aggregators face uncertainty regarding market access, portfolio composition, data exchange and settlement responsibilities.
- A flexibility register or similar data exchange solution would help identify which assets are available for aggregation, who controls them, in which market they participate and whether they are subject to technical or contractual limitations. This is especially important for small actors, because manual processes and bilateral data exchange increase

transaction costs and make aggregation less attractive. Therefore, even if the legal framework might be developed swiftly it does not enable independent aggregation if there are no appropriate digital solutions for data exchange and administration.

1.5.2 Lack of enablers and incentives to provide flexibility

Latvia's close to 100% smart metering coverage is an important enabler for flexibility and digitalisation. Smart meters allow customers to observe consumption patterns, react to wholesale price signals through dynamic-price contracts and participate in implicit demand side response. This reduces the metering barrier that exists in many markets and creates a foundation for more advanced flexibility services, including explicit demand response and aggregation.

Latvia has implemented several important market-design elements that act as enablers for flexibility participation rather than barriers.

- The balancing market is based on standard balancing products and organised in a regional framework. The balancing energy market has moved towards 15-minute market time units and is integrated with the European mFRR and aFRR balancing energy platforms, enabling Latvian balancing service providers to participate in wider European balancing energy markets. The balancing capacity market is organised through short-term procurement, with daily auctions for capacity products, which reduces long-term lock-in and supports competition among providers. These markets are important not only because they provide access to balancing products, but also because they are the place where the value of flexibility is revealed through price formation.
- At the same time, flexibility providers are able to use not just balancing markets but other wholesale markets and trade in day-ahead, intra-day auctions and intra-day markets.
- Since 2026 intra day trading is allowed up to 30 minutes before the delivery, previously it was 60 minutes, this is a significant improvement for flexible and variable assets.

1.5.3 Restrictive requirements to provide balancing services

The use of marginal pricing in balancing energy and capacity markets provides transparent price signals and incentivises participation by resources, whose are able to respond to system needs. Standard product requirements, 1 MW bidding granularity, bid attributes (linking, divisibility, others), standard prequalification procedures, non-contracted bids along with contracted bids, automated data exchange and the possibility to use aggregated reserve providing units support the entry of new technologies, including batteries, distributed generation and demand-side response. These arrangements reduce barriers that would otherwise arise from non-standard products, long procurement lead times, non-transparent activation rules or bilateral procurement practices.

Digitalisation is a key precondition for these market improvements. AST's implemented solutions ensure automated message exchange with balancing service providers, integration with MARI and PICASSO processes, and publication of balancing market information through regional and Europe scale transparency tools, therefore improving operational efficiency, reducing possibility of error and increasing market transparency. These digital solutions also support the integration of new resources by enabling automated bid submission, activation, verification and settlement related processes.

Since April 2025 Baltic TSOs have finalized major balancing market development, where regional market for balancing energy was integrated with European balancing energy platforms MARI and PICASSO and Baltic TSOs developed a regional capacity market. All this supports competition and new opportunities for market participants offering flexibility.

1.5.4 Restrictive requirements to provide congestion management

The rapid growth of renewable generation, particularly solar and wind, increases the risk of internal network constraints. This issue has become increasingly relevant in recent years and is expected to materialise further in the coming years. Therefore, Latvia is actively developing a framework and implementing the necessary solutions for forecasting, preventing and managing internal grid congestion. The proposed approach aims to maintain a high level of renewable energy integration while limiting curtailment to what is strictly necessary for secure system operation. In the process of framework development stakeholders are involved to provide their feedback via public consultations, therefore facilitating early recognition of potential barriers or other problematic aspect.

1.6 TSO Flexibility needs assessment conclusions

- RES integration target simulation results were compared to Latvian National Energy and Climate plan (NECP). Latvia reaches integration target of having at least 80% consumption covered by RES. Depending on the scenario, RES integration targets calculated from simulation results in range from 89% up to 120%.
- According to simulation results RES curtailment does not exceed 150 MW in 50% of times it appears, however extreme values can reach even 2000 MW depending on the scenario. RES curtailment has strong seasonality, most of the peaks happening on mid-day in spring and summer periods. In winter peak shift towards night hours, late evening, early morning.
- Duration of curtailment events in all scenarios is similar, however interval between curtailment events changes by growing in scenarios with lower overall curtailment. Showing that in different weather scenarios increases curtailment amplitude rather than increasing amount of hours with curtailment.
- Hourly and daily residual load deviation medians are at least twice as big as yearly deviation median showing that Latvian power system has more short-term and mid-term fluctuations rather than long-term.
- Residual load variation between two continuous market time units in 80% of hours are in range between -100 MW and +100MW. Only few hours are with extreme variation reaching +/- 700 MW. Low variation changes in most hours indicates good conditions for short-term regulation of the electricity system without big challenges.
- In all scenarios electricity system of Latvia do not have any uncovered residual load variation, showing that natural gas power plants, hydro powerplants (HPP) and electricity transmission interconnections capacities are sufficient to maintain reliable and stable electricity system operation for target years 2030 and 2035, without any risks of lacking flexibility.
- Latvian forecast error has strong negative outliers during months with higher solar generation, reaching almost -100% miss match between D-1 and actual residual load, this is connected to low solar and wind installed capacity, where 300 MW miss-match can lead to almost -100% forecast error. In other cases, forecast error is in ranges from -20% to 20%.
- Latvia has some uncovered short-term flexibility needs, which happen during mid-day due to solar forecast miss-match impact to residual load forecast error. Total expected energy from uncovered needs reach 2.2 GWh. On average capacity of uncovered needs are around 80 MW over 70 hours combined in all WS over two target years with 2 historical years application in comparison to system size can be neglectable.

- Latvia electricity system in recent years have made significant steps towards digitalisation. Prerequisite to have access for flexible entrants have been met with Baltic balancing capacity market improvements, integration with European balancing energy platforms MARI and PICASSO, 100% smart metering implementation with flexibility to implement 15 minutes market time unit and overall better integration of market participants on digital side of electricity system. Latvia as electricity market still have room for improvement like better regulation for independent aggregators, precise grid constraints localisation and its further management.
- ERAA market simulations have shown annual onshore wind and solar curtailment fluctuations from 133 GWh up to 310 GWh depending on weather scenario, representing 7% to 13% of total onshore wind and solar generation. Considering 1 GW of installed offshore wind capacity RES curtailment reach up to 486 GWh. To mitigate such RES curtailment and maximize amount of electricity produced by wind and solar in end consumption, Latvia needs broad battery energy storage systems (BESS) integration into electricity system. Highlighting that without flexibility solutions unlocking full potential of RES generation will not be possible.
- FNA analysis has shown that having dispatchable generation like Daugava cascade HPPs, Riga CHP 1 and Riga CHP 2 have crucial role in covering variability of wind and solar generation. Flexible solutions like BESS should not be underestimated, but dispatchable generation is key to cover low-RES production period, especially during winter, when electricity shortage is more critical for consumers.
- In all analysed scenarios, no issues were identified that would compromise the reliable operation of the power system.

DSO Flexibility Needs Assessment

2.1 Introduction

2.1.1 Scope of the assessment

This assessment covers the 20kV distribution network operated by the DSO.

The assessment is performed at the level of primary substations (110kV/20kV), which represent the geographical granularity adopted for identifying future flexibility needs. Each primary substation is assessed individually based on its historical loading, projected future electricity demand and planned network development.

The assessment evaluates future network utilisation under the assumptions defined in the national Energy Strategy and considers the expected evolution of the electricity system throughout the assessment period.

Future electricity demand is estimated using historical operational data together with the Base scenario of the National Energy Strategy[6]. Planned network reinforcement projects are incorporated into the assessment to determine the period during which flexibility may be required before additional network capacity becomes available.

2.1.2 Objectives of the assessment

The purpose of the assessment is to identify where, when and to what extent flexibility is expected to be required within the distribution network under projected future operating conditions.

More specifically, the assessment aims to:

- identify primary substations where future network constraints are expected to occur;
- estimate in which primary substations flexibility becomes necessary for target years 2030 and 2035;
- quantify the required flexibility in terms of power (MW) and energy (MWh) compared to total load of primary transformers;
- provide standardized input for the national Flexibility Needs Assessment in accordance with the ACER methodology.

The assessment is intended to support long-term network planning by identifying situations where flexibility may complement conventional network reinforcement. The reported flexibility needs do not represent procurement decisions or commitments to acquire flexibility services. Instead, they provide a

[6] Energy strategy of Latvia 2050

planning-based estimate of future network requirements under the assumptions described in this report.

2.2 Long-term forecasting methodology

2.2.1 General overview

The identification of future distribution network flexibility needs requires a combination of historical operational data, nationally adopted planning assumptions and information on future network development. These datasets provide the basis for estimating future network utilisation and identifying locations where flexibility may be needed before network reinforcement is implemented.

The assessment presented in this report has been developed using three principal sources of information:

- Historical electricity demand measured at each 110 kV primary substation;
- Base scenario of the National Energy Strategy prepared by the Ministry of Climate and Energy;
- Distribution System Operator's planned network reinforcement programmes.

Together, these inputs enable a consistent assessment of future network loading and provide the necessary information to quantify flexibility needs in accordance with the ACER Flexibility Needs Assessment Methodology.

2.2.2 Historical electricity demand

Historical electricity demand measured at each 110 kV primary substation represents the baseline of the assessment.

The use of historical measurements ensures that future projections are based on actual network utilisation rather than theoretical assumptions. Since electricity demand varies considerably between different regions and network areas, each primary substation has been assessed individually.

The historical dataset provides information on:

- existing network utilisation;
- annual peak demand;
- demand development trends;
- differences in loading between primary substations.

These measurements form the reference against which future electricity demand is projected using the assumptions defined in the National Energy Strategy.

Historical operational data are considered the most reliable representation of current network conditions and therefore sets the starting point of the flexibility needs assessment.

2.2.3 National energy strategy

To ensure consistency with national energy policy and long-term planning objectives, future electricity demand has been projected using the Base Scenario defined in the National Energy Strategy prepared by the Ministry of Climate and Energy.

The Base Scenario represents the official reference scenario describing the expected development of Latvia's electricity sector (Transmission and Distribution system operators) over the coming decades. It reflects needed changes in electricity consumption resulting from the electrification of transport, heating, industry and other sectors of the economy.

Unlike historical operational data, which describe the current state of the electricity system, the National Energy Strategy provides the assumptions required to estimate how electricity demand is expected to increase during for target period.

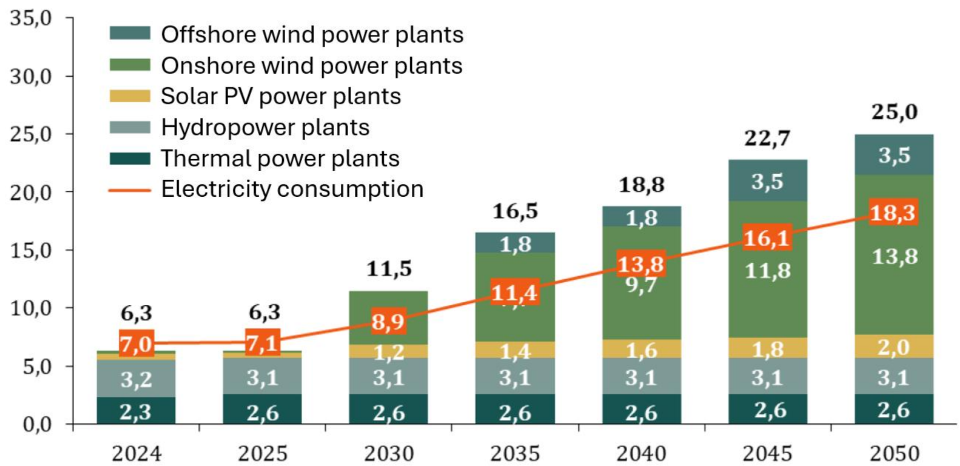

Figure 2.1 Electricity production and demand forecast according to Base Scenario (TWh)

As shown in Figure 2.1 the Base Scenario projects an increase in annual electricity demand from 7 TWh in 2024 to 11,4 TWh in 2035, representing an overall increase for more than 40%. During the same period, installed photovoltaic capacity is projected to increase from 660 MW to 1400MW. In 2026, installed photovoltaic capacity in DSO grid has already reached around 1000 MW and total capacity connected to Latvian grid (Distribution and Transmission grids) projection is around 1900 MW, corresponding to around 135% of the Base Scenario target for year 2035 as shown in Figure 2.2.

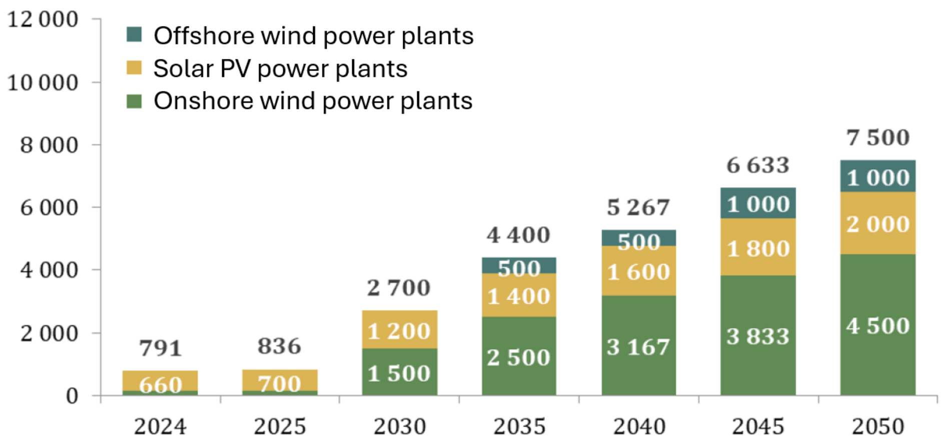

Figure 2.2 Distributed energy resources (DER) capacity installation forecast in Base Scenario, MW

The comparison indicates that the deployment of photovoltaic generation has reached already 2030 target defined in the Base Scenario.

For this reason, the assessment presented in this report primarily evaluates flexibility needs associated with projected demand growth while remaining consistent with the renewable generation assumptions defined in the National Energy Strategy.

2.2.4 Planned network reinforcement

Future network reinforcement projects have been incorporated into the assessment to reflect the expected increase of available network capacity. Rather than evaluating flexibility needs against the existing network configuration only, the assessment considers the timing of planned reinforcement projects and identifies the period during which flexibility may provide an alternative to, or defer, conventional network expansion.

The planned reinforcement programme is therefore used to determine:

- the year in which additional network capacity becomes available;
- the duration for which flexibility is required before reinforcement is commissioned;
- the residual flexibility need after planned reinforcement has been completed.

This approach ensures that flexibility is assessed only where it provides additional value within the planned development of the distribution network.

2.2.5 Forecasting model

The forecasting methodology combines historical operational measurements, statistical data processing and machine learning techniques to generate hourly demand forecasts while maintaining consistency with the assumptions of the National Energy Strategy.

The forecasting process consists of four consecutive stages: preparation of historical measurements, calculation of historical network indicators, development of the forecasting model and generation of long-term demand scenarios. Each stage produces intermediate datasets that are retained throughout the calculation process, ensuring that the complete forecasting workflow remains transparent and reproducible.

2.2.5.1 Data preprocessing

The primary input dataset consists of hourly active and reactive power measurements recorded for each primary substation. Measurements include active and reactive power in both import and export directions together with the installed transformer capacities. Prior to model development, the historical measurements undergo data quality checks. Records containing missing values are removed from further analysis, while measurements exceeding the 99th percentile of any measured variable are excluded to minimise the influence of abnormal operating conditions and measurement anomalies on the forecasting model.

To represent the loading of each primary substation independently of the direction of power flow, the apparent load is calculated using the larger active and reactive power components measured during each observation.

$$\mathrm{St} = \sqrt{\max(\mathrm{P}+, \mathrm{P}-)2 + \max(\mathrm{Q}+, \mathrm{Q}-)}$$

Equation 2.1 Hourly apparent load

where:

- St – hourly apparent load;
- P_+, P_- – imported and exported active power;
- Q_+, Q_- – imported and exported reactive power.

Since electricity demand exhibits a seasonal pattern, the month variable is transformed using cyclic sine and cosine functions. This prevents the forecasting model from interpreting December and January as unrelated periods and enables the model to preserve seasonal continuity throughout the forecasting horizon.

$$m_{sin} = sin\left(\frac{2\pi m}{n12}\right), m_{cos} = cos\left(\frac{2\pi m}{n12}\right)$$

Equation 2.2 Cyclic representation of seasonality

where m represents the calendar month.

2.2.5.2 Historical indicators, capacity utilisation and modelling

Following data preparation, historical network indicators are calculated for every assessed primary substation. These include annual peak consumption, annual peak generation, maximum apparent load and average apparent load. Historical loading is subsequently compared with the installed transformer capacities to determine transformer utilisation under existing operating conditions.

$$U_1 = \frac{S_{peak}}{ST_1} \; X \; 100\%, \qquad U_{12} = \frac{S_{peak}}{ST_1 + ST_2} \; X \; 100\%,$$

Equation 2.3 Transformer utilisation

where ST_1 and ST_2 denote the nominal capacities of the installed transformers.

Long-term forecasts are developed independently for each primary substation using a Gradient Boosting regression model. The model is trained using historical measurements and temporal variables describing the year, month, day, hour and seasonal characteristics. Model performance is evaluated using an 80/20 training and testing split with the Mean Squared Error (MSE) used as the primary performance indicator.
As tree-based machine learning models are not intended to extrapolate long-term trends beyond the historical observation period, a long-term growth component is introduced separately. The annual growth rate is estimated from the historical average loading observed between 2020 and 2024 and is constrained within predefined upper and lower limits to avoid unrealistic extrapolation.

$$g = \left(\frac{S_{2024}}{S_{2020}}\right)^{1/10} - 1$$

Equation 2.4 Compound annual growth rate

where $g \in [-0{,}10; 0{,}10]$

Hourly forecasts for the full 2025-07 – 2035-12 period are obtained by applying the substation-specific trend factor, relative to the last historical year, to the model's baseline prediction:

$$\hat{y}_t = f(x_t) \times (1 + g)^{y(t) - y_{hist}}$$

Equation 2.5 Long-term hourly forecast

2.2.5.3 Aggregation, capacity limits and scenarios

Hourly forecasts are aggregated to monthly resolution, mean and maximum per substation, and combined with the identically aggregated historical data via an outer join, forming a continuous time series. For each substation, a two-panel chart is generated, monthly average and monthly maximum load, with transformer capacities drawn as horizontal reference lines, making it possible to read off the year in which the forecast approaches the capacity limit. A growth scenario with a compound factor from the forecast base year is additionally applied (r = 0.05 for averages, r = 0.04 for maxima):

$$k_{NR}(y) = (1 + r)^{y - y_{base}}, r = 0{,}05$$

Equation 2.6 Scenario scaling

The Base scenario in Latvian Energy Strategy applies the same scaling with r = 0.05 at the hourly level to selected substations, where the base year is each substation's first forecast year. The scenario is validated with three comparison charts (hourly profile for 2035, monthly averages and maxima for 2025–2035) and exported to comma-separated values(.csv) file format.

For system-level analysis, the monthly forecasts of all substations are summed into a single time series from 2026 onwards, and cumulative compound growth is estimated from month-over-month changes:

$$c_T = \prod_{t=1}^{T} (1 + \Delta_t) - 1,\ \Delta_t = \frac{s_t - s_{t-1}}{s_{t-1}}$$

Equation 2.7 System level cumulative growth

2.2.5.4 Technology stack and limitations

Pandas and NumPy stack are used for data processing, scikit-learn for modelling, matplotlib for visualisation; data exchange between stages via .csv format (Parquet is worth considering for larger volumes). Key methodological limitations are that the model uses only calendar features, without meteorological data. The trend and scenarios are deterministic scaling factors without uncertainty intervals. In the 2020-2024 window includes Covid and energy-crisis effects and the random 80/20 split of time-series data creates a leakage risk between training and test sets. That is why a chronological split is recommended for stricter validation. These aspects should be kept in mind when interpreting the absolute forecast values in long-term investment decisions.

2.3 Assessment results

This chapter presents the results of the distribution network flexibility needs assessment for the target years 2030 and 2035. The assessment results are based on the long-term load forecasts described in Chapter 2.2 and are reported in accordance with Article 11 of the ACER Flexibility Needs Assessment Methodology[7]. The identified flexibility needs are presented for each primary substation together with the needed annual energy and maximum congestion power.

2.3.1 Electricity demand assessment

The assessment identified flexibility needs only in a limited number of primary substations. Their geographical distribution is presented in Figure 2.3. The size of each marker is proportional to the total energy (MWh) requirements identified for the corresponding primary substation.

[7] Flexibility needs assessment methodology

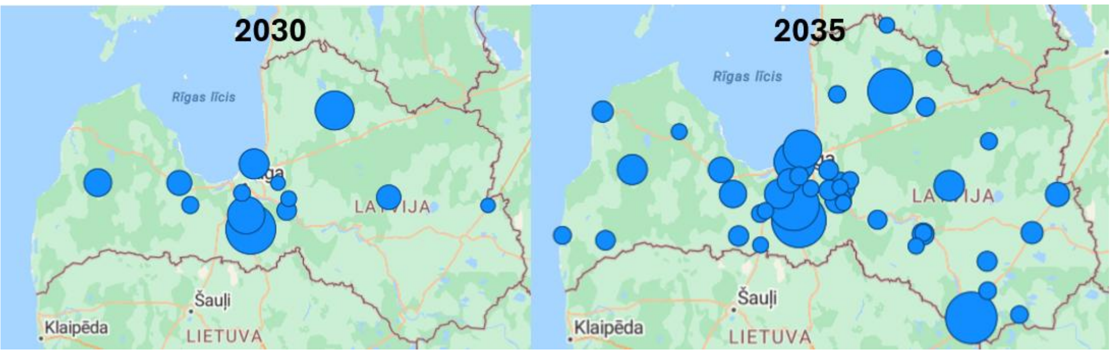

Figure 2.3 Map of flexibility needs by total energy (MWh) in 2030 and 2035

In Table 2.1 is summary of the flexibility needs identified for all assessed primary substations. The information is presented using the reporting structure specified in Article 11 of the ACER Flexibility Needs Assessment Methodology and includes the direction of flexibility, target year, assessment period, spatial granularity, voltage level, flexibility metric and quantified flexibility requirement.

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
1	Upward	2030	Entire year	210	20kV	Total energy over the year, MWh	4.11
2						Maximum power, MW	0.56
3	Upward	2030	Entire year	94	20kV	Total energy over the year, MWh	3.79
4						Maximum power, MW	0.21
5	Upward	2030	Entire year	141	20kV	Total energy over the year, MWh	46.68
6						Maximum power, MW	2.16
7	Upward	2030	Entire year	8	20kV	Total energy over the year, MWh	17.40
8						Maximum power, MW	0.73
9	Upward	2030	Entire year	2	20kV	Total energy over the year	221.91
10						Maximum power	1.34
11	Upward	2030	Entire year	212	20kV	Total energy over the year, MWh	2 018.56
12						Maximum power, MW	10.32
13	Upward	2030	Entire year	150	20kV	Total energy over the year, MWh	894.11
14						Maximum power, MW	3.60
15	Upward	2030	Entire year	89	20kV	Total energy over the year, MWh	832.66
16						Maximum power, MW	3.24

17	Upward	2030	Entire year	164	20kV	Total energy over the year, MWh	1 452.48
18						Maximum power, MW	3.75
19	Upward	2030	Entire year	149	20kV	Total energy over the year, MWh	4 383.08
20						Maximum power, MW	9.79
21	Upward	2030	Entire year	70	20kV	Total energy over the year, MWh	4 970.33
22						Maximum power, MW	4.38
23	Upward	2030	Entire year	45	20kV	Total energy over the year, MWh	10 488.60
24						Maximum power, MW	6.81

Table 2.1 Flexibility needs summary per identified substation in 2030

The reported annual energy and maximum power values represent the minimum flexibility capability required to avoid forecast network congestion under the assumptions described in Chapter 2.2.

It is important to note that the flexibility needs presented in Table 2.1 for 2030 and Table 2.2 for 2035 have been assessed against the primary installed transformer capacity available at each primary substation even if there are two transformers installed.

Under this assessment approach, flexibility needs have been identified in 12 primary substations in 2030 and 42 substations in 2035. If the assessment was performed against the capacity of a two transformers installed in substations (where applicable) the number of substations requiring flexibility would decrease, having no assessed flexibility needed in 2030 and seven substations with possible need of flexibility in 2035. The approach adopted in this report reflects the normal operating configuration of the distribution network and provides a realistic basis for long-term flexibility planning.

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
1	Upward	2035	Entire year	163	20kV	Total energy over the year, MWh	0.27
2						Maximum power, MW	0.26
3	Upward	2035	Entire year	79	20kV	Total energy over the year, MWh	0.06
4						Maximum power, MW	0.04
5	Upward	2035	Entire year	49	20kV	Total energy over the year, MWh	0.39
6						Maximum power, MW	0.17

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
7	Upward	2035	Entire year	77	20kV	Total energy over the year, MWh	0.81
8						Maximum power, MW	0.27
9	Upward	2035	Entire year	62	20kV	Total energy over the year, MWh	1.64
10						Maximum power, MW	0.41
11	Upward	2035	Entire year	14	20kV	Total energy over the year, MWh	1.00
12						Maximum power, MW	0.14
13	Upward	2035	Entire year	25	20kV	Total energy over the year, MWh	5.15
14						Maximum power, MW	0.63
15	Upward	2035	Entire year	46	20kV	Total energy over the year, MWh	27.87
16						Maximum power, MW	1.80
17	Upward	2035	Entire year	159	20kV	Total energy over the year, MWh	40.00
18						Maximum power, MW	1.15
19	Upward	2035	Entire year	64	20kV	Total energy over the year, MWh	268.37
20						Maximum power, MW	3.25
21	Upward	2035	Entire year	80	20kV	Total energy over the year, MWh	93.19
22						Maximum power, MW	1.27
23	Upward	2035	Entire year	20	20kV	Total energy over the year, MWh	127.82
24						Maximum power, MW	1.88
25	Upward	2035	Entire year	273	20kV	Total energy over the year, MWh	148.92
26						Maximum power, MW	2.14
27	Upward	2035	Entire year	43	20kV	Total energy over the year, MWh	201.39
28						Maximum power, MW	2.60
29	Upward	2035	Entire year	17	20kV	Total energy over the year, MWh	165.90
30						Maximum power, MW	1.57

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
31	Upward	2035	Entire year	33	20kV	Total energy over the year, MWh	209.84
32						Maximum power, MW	1.75
33	Upward	2035	Entire year	231	20kV	Total energy over the year, MWh	206.31
34						Maximum power, MW	1.52
35	Upward	2035	Entire year	208	20kV	Total energy over the year, MWh	513.56
36						Maximum power, MW	3.16
37	Upward	2035	Entire year	210	20kV	Total energy over the year, MWh	1 013.31
38						Maximum power, MW	3.87
39	Upward	2035	Entire year	71	20kV	Total energy over the year, MWh	606.19
40						Maximum power, MW	3.59
41	Upward	2035	Entire year	11	20kV	Total energy over the year, MWh	1 427.48
42						Maximum power, MW	6.42
43	Upward	2035	Entire year	4	20kV	Total energy over the year, MWh	634.07
44						Maximum power, MW	2.97
45	Upward	2035	Entire year	160	20kV	Total energy over the year, MWh	1 862.24
46						Maximum power, MW	5.41
47	Upward	2035	Entire year	48	20kV	Total energy over the year, MWh	1 241.42
48						Maximum power, MW	3.64
49	Upward	2035	Entire year	66	20kV	Total energy over the year, MWh	886.41
50						Maximum power, MW	3.41
51	Upward	2035	Entire year	141	20kV	Total energy over the year, MWh	4 173.65
52						Maximum power, MW	10.95
53	Upward	2035	Entire year	90	20kV	Total energy over the year, MWh	2 486.21
54						Maximum power, MW	5.32

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
55	Upward	2035	Entire year	232	20kV	Total energy over the year, MWh	1 085.58
56						Maximum power, MW	2.51
57	Upward	2035	Entire year	150	20kV	Total energy over the year, MWh	5 831.70
58						Maximum power, MW	8.51
59	Upward	2035	Entire year	28	20kV	Total energy over the year, MWh	2 476.74
60						Maximum power, MW	3.98
61	Upward	2035	Entire year	41	20kV	Total energy over the year, MWh	11 869.66
62						Maximum power, MW	17.12
63	Upward	2035	Entire year	8	20kV	Total energy over the year, MWh	12 222.30
64						Maximum power, MW	9.68
65	Upward	2035	Entire year	2	20kV	Total energy over the year, MWh	7 130.22
66						Maximum power, MW	6.39
67	Upward	2035	Entire year	164	20kV	Total energy over the year, MWh	13 229.66
68						Maximum power, MW	9.78
69	Upward	2035	Entire year	89	20kV	Total energy over the year, MWh	13 801.86
70						Maximum power, MW	11.13
71	Upward	2035	Entire year	212	20kV	Total energy over the year, MWh	33 372.09
72						Maximum power, MW	31.92
73	Upward	2035	Entire year	94	20kV	Total energy over the year, MWh	4 530.70
74						Maximum power, MW	3.01
75	Upward	2035	Entire year	112	20kV	Total energy over the year, MWh	42 114.28
76						Maximum power, MW	25.74
77	Upward	2035	Entire year	30	20kV	Total energy over the year, MWh	82 276.06
78						Maximum power, MW	27.52

Line number	Direction of need	Target year	Time block	Spatial granularity, 110kV / 20kV substation	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs
79	Upward	2035	Entire year	149	20kV	Total energy over the year, MWh	79 659.44
80						Maximum power, MW	39.67
81	Upward	2035	Entire year	45	20kV	Total energy over the year, MWh	96 492.08
82						Maximum power, MW	24.55
83	Upward	2035	Entire year	70	20kV	Total energy over the year, MWh	55 557.02
84						Maximum power, MW	12.52

Table 2.2 Flexibility needs summary per identified substation in 2035

2.3.2 Generation assessment

Although the assessment methodology considers both electricity demand and generation increase, no flexibility needs with generation-driven congestion have been identified within the distribution network.

The National Energy Strategy Baseline Scenario projects continued growth of renewable electricity generation. However, approximately 1 GW of photovoltaic generation capacity has already been installed within the distribution network, representing a level that is broadly consistent with the development pathway assumed in the assessment.

Furthermore, the Distribution System Operator applies network connection procedures that require available network capacity before new generation facilities are connected. Generation connections are therefore not based on overbooking principles, and each new connection is assessed against the available network capacity at the point of connection.

Consequently, the assessment does not indicate significant additional flexibility needs resulting from renewable generation growth. The flexibility needs identified in this report are primarily driven by projected increases in electricity demand.

Nevertheless, the Distribution System Operator is aware of one primary substation where the continued growth of microgeneration may result in local generation-related congestion and the need of local flexibility services. This situation is being monitored through normal network planning processes and is considered a location-specific operational issue rather than an indication of a broader distribution network flexibility need. Consequently, it does not materially affect the overall conclusions of this assessment.

Glossary

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AST	AS "Augstsprieguma tīkls"
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbines
CHP	Combined Heat and Power
D-1	Day Ahead
DER	Distributed Energy Resources
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission Operators for Electricity
ERAA	European Resource Adequacy Assessment
FNA	Flexibility Needs Assessment
HPP	Hydro Power Plant
ISO	International Organization for Standardization
MARI	Manually Activated Reserves Initiative
mFRR	Manual Frequency Restoration Reserve
MSE	Mean Squared Error
NECP	National Energy and Climate Plan
NRA	National Regulative Authority
NREL	National Renewable Energy Laboratory
NTC	Net Transfer Capacity
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PUC	Public Utilities Commission
PV	Photovoltaic

RES	Renewable Energy Sources
RRM	Ramping Residual Margins
ST	AS "Sadales tīkls"
TSO	Transmission System Operator
TY	Target Year
WS	Weather Scenario