Summer Outlook 2025

Winter Outlook 2024-2025 Review

entsoe

Summer Outlook 2025

Report

28 May 2025

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 40 member TSOs, representing 36 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the inter-connected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Contents

Executive summary

ENTSO-E Summer Outlook 2025: No adequacy risk is identified in Continental Europe, Nordics and Great Britain. Islands that are isolated or scarcely interconnected (Ireland[1], Malta[2], and Cyprus) will require close monitoring.

The adequacy risk identified in Ireland at the end of the summer season is driven by multiple overlapping planned large dispatchable generator outages and the lack of new dispatchable generation entering the market to replace old units that have closed and to cover the increase in demand. The actual adequacy situation in Ireland will depend on the operational conditions, namely unplanned outages of the ageing generation fleet and especially wind generation. Non-market resources (1.4 GW) are now available and will significantly alleviate the risks.

Some **residual risks** are identified in the rather isolated Mediterranean **islands** of Malta and Cyprus. These risks might emerge in the event of high unplanned outages of the generation fleet and unfavourable weather conditions when demand is high and renewable energy source (RES) generation is low. Malta relies on non-market resources to ensure security of supply.

The surplus generation from variable renewable energy sources is expected to exceed demand during periods of high renewable generation combined with low demand, thus increasing countries' export needs. However, neighbouring countries are also likely to face challenges of **excess of renewables** during the same period, leading to an increased **risk of negative electricity prices** across Europe. The impact of negative pricing and overproduction includes potential financial losses for generators and market distortions, necessitating careful management and strategic planning to mitigate these effects.

The Summer Outlook is accompanied by a retrospect of the previous winter. In general, no adequacy issues were observed during the past winter of 2024–2025 due to mild temperatures and favourable hydrological conditions, although some countries experienced challenges. Some countries reported higher-than-expected consumption on record. Notably colder-than-average temperatures were recorded in February in the South-eastern part of Europe, while the Northern part experienced above-average temperatures during the same month.

Preparations for next winter 2025–2026 have begun. The TSOs' feedback as well as the gas situation show a confident picture, with no specific concern identified. Preparedness and close cooperation with the European Commission, TSOs and Member States will continue in the coming weeks.

Since March 2022, **Ukraine and Moldova** have been synchronised with the Continental European power system. The situation in Ukraine remains uncertain due to potential attacks on energy infrastructure, according to national experts. As of May 2025, European transmission system operators enable the electricity export capacity to Ukraine and Moldova at 1.7 GW, while the electricity import from Ukraine and Moldova has been increased to 650 MW.

Soon after 12h30 CET on 28 April 2025, a **major incident occurred in the power systems of Spain and Portugal**, unrelated to an adequacy issue and resulting in a black-out in the power system of both countries. Some areas of France close to the border with Spain were also affected by the incident, albeit for a very limited duration. The established procedures and protocols for restoring the voltage of the electricity system were activated immediately and the system was successfully restored, with support from the French TSO RTE and the Moroccan utility ONEE. In accordance with European legislation for such an exceptional and grave incident, ENTSO-E established an Expert Panel to investigate the causes of this event, in accordance

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[1] *Comprising EIRGRID and SONI.*
[2] *In Malta, adequacy issues identified in the market simulations of Summer Outlook 2025 are entirely covered by the out-of-market capacity on the island.*

with the "Incident Classification Scale Methodology"[3]. The Expert Panel will investigate the root causes, produce a comprehensive analysis, and make recommendations in a final report, which will be publicly available. National Regulatory Authorities and the Agency for the Cooperation of Energy Regulators (ACER) are invited to participate in this panel. Prior to the publication of the final report, ENTSO-E will publish a comprehensive report with full technical details on the incident. Furthermore, ENTSO-E will provide regular updates to the EU Commission and EU Member States, including progress reports of the investigation to the Electricity Coordination Group. Data so far have yielded that starting at 12:32:57 CET and within 20 seconds, presumably a series of different generation trips were registered in the south of Spain, accounting for an initially estimated total of 2200 MW. No generation trips were observed in Portugal and France. As a result of these events, the frequency decreased, and a voltage increase was observed in Spain and Portugal.

[3] https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Incident_Classification_Scale/IN_USE_FROM_JANUARY_2020_191204_Incident_Classification_Scale.pdf

Overview of the power system in summer 2025

Generation overview

Installed renewable capacity in Europe has increased by more than 90 GW compared to the previous summer (Figure 1). Most of this increase comes from the massive installation of rooftop, industrial, and utility-scale photovoltaic production across Europe, with total installed capacity increasing by 31% over one year.

Battery energy storage system capacity more than doubled (increased by 127%) compared to the previous summer but remains very small in scale, with only 25 GW of installed capacity throughout Europe.

High carbon-footprint power units such as hard coal, lignite, and oil have seen a combined decrease of installed capacity by 14 GW (-11%). On the other hand, the more flexible gas power plants are slightly expanding with an installed capacity increase of 12 GW compared to the previous summer.

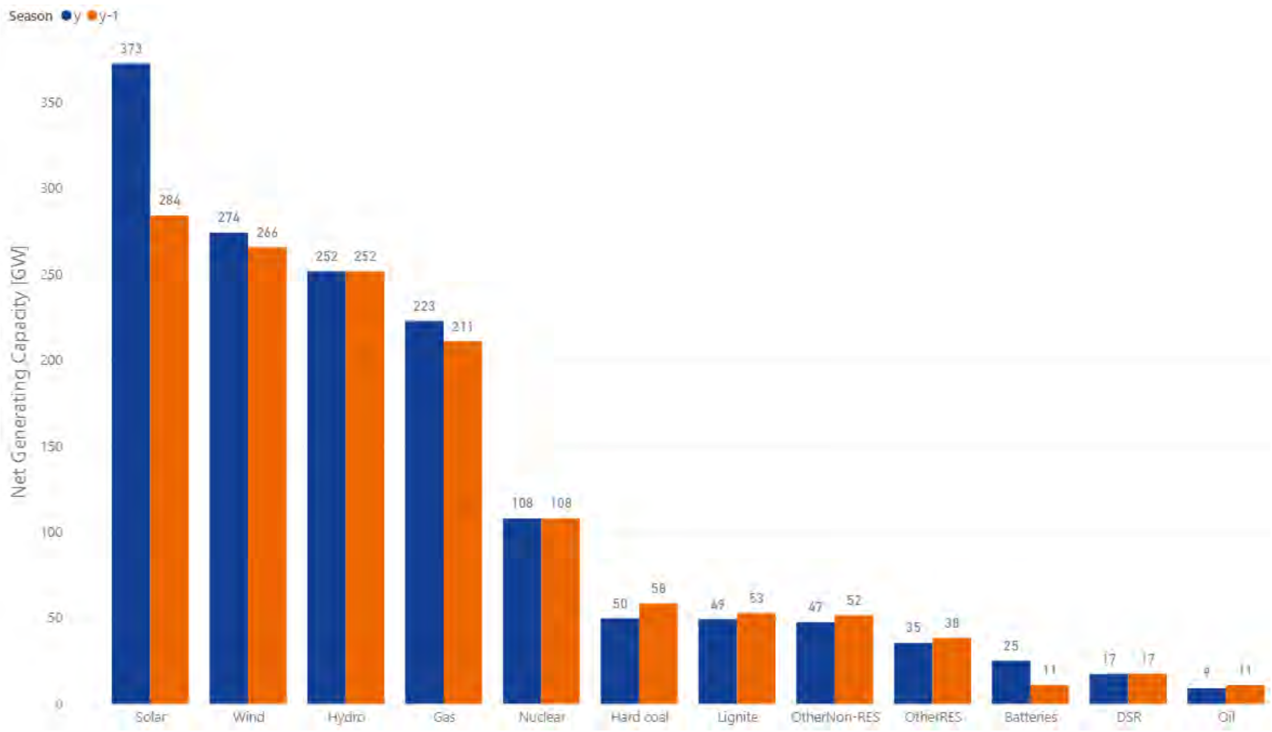

Figure 1: Generation capacity change over one year: Summer Outlook 2025 vs Summer Outlook 2024

Figure 2 shows the net generating capacity compared to the highest expected demand for every European study zone. This overview shows that sufficient generation capacity to supply consumers is available in most countries. However, generation unavailability (planned or unforeseen) and actual renewable generation infeed have an impact, and some countries might rely more strongly on imports. For example, Central Northern Italy (ITCN) and Southern Sweden (SE04) are especially dependent on imports when renewable generation is low.

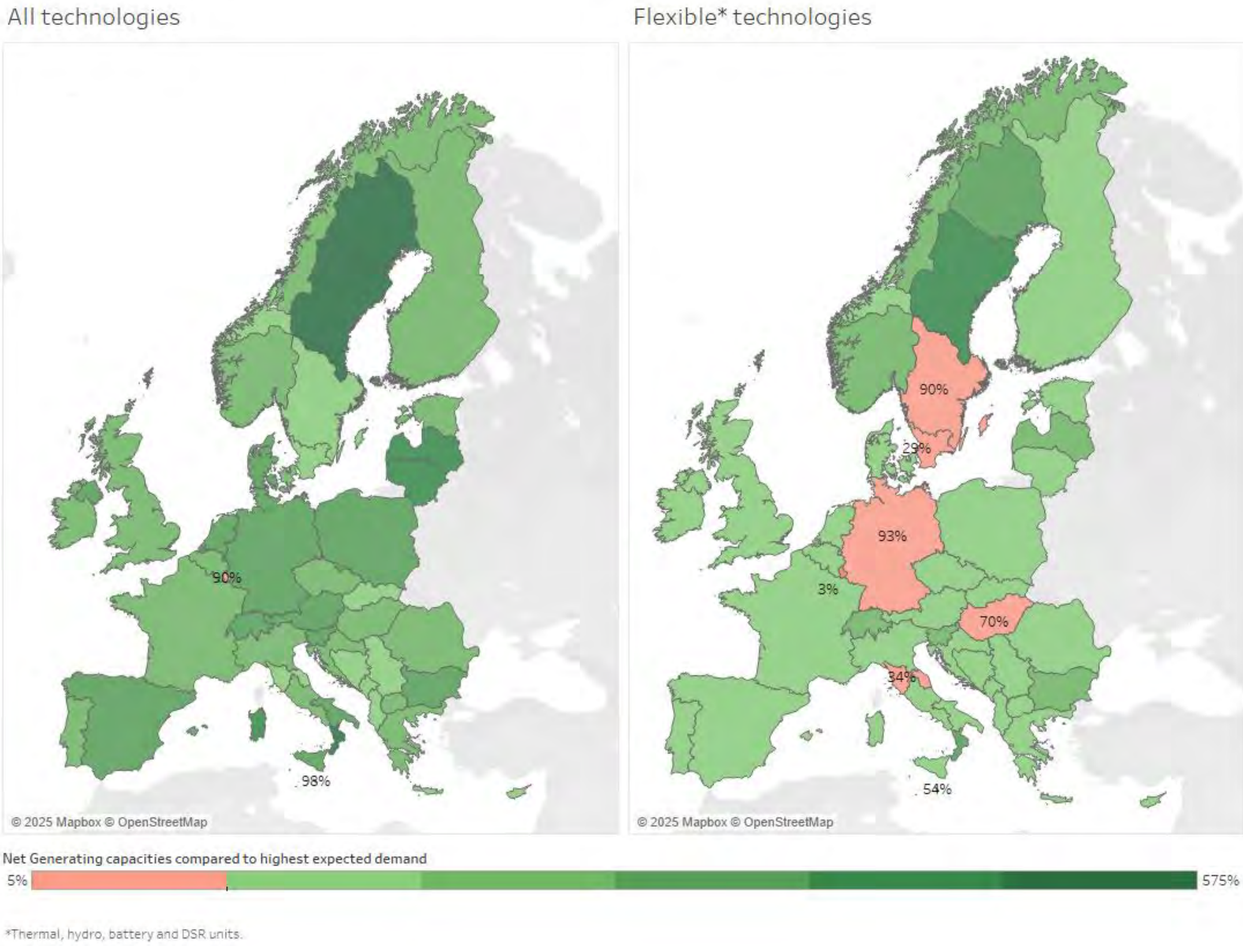

Figure 2: Ratio between the net generating capacity and the highest expected demand

According to Figure 3, thermal net generating capacity (NGC) available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of summer 2025. This is followed by hydro, wind and solar capacities, which constitute the remainder. In addition, the highest expected demand[4] is depicted with a small black square, and its value is given as a percentage of each study zone's NGC.

The thermal NGC share is below 60% in most of the study zones. This is especially noticeable in those zones with high hydro capacities. Nevertheless, the thermal NGC share is low despite insignificant hydro capacities in some study zones (e.g. Germany [DE00], Southern Sweden [SE04], central Italy [ITCN]), characterised by a high share of wind and solar generation capacities. In periods of low RES production, these countries will rely on imports to cover their peak loads.

While Demand Side Response (DSR) resources are gaining volume in Europe, DSR might only be available for a limited period (e.g. few hours in a day) or at varying capacity. More DSR is likely to be available during peak times, although this is not guaranteed.

[4]*The highest expected demand is computed by taking the highest value of the hourly demand 95th percentiles. However, the Seasonal Outlook assessment also considers that demand might even exceed the expected highest value as occasionally new peak demand records are registered in Europe.*

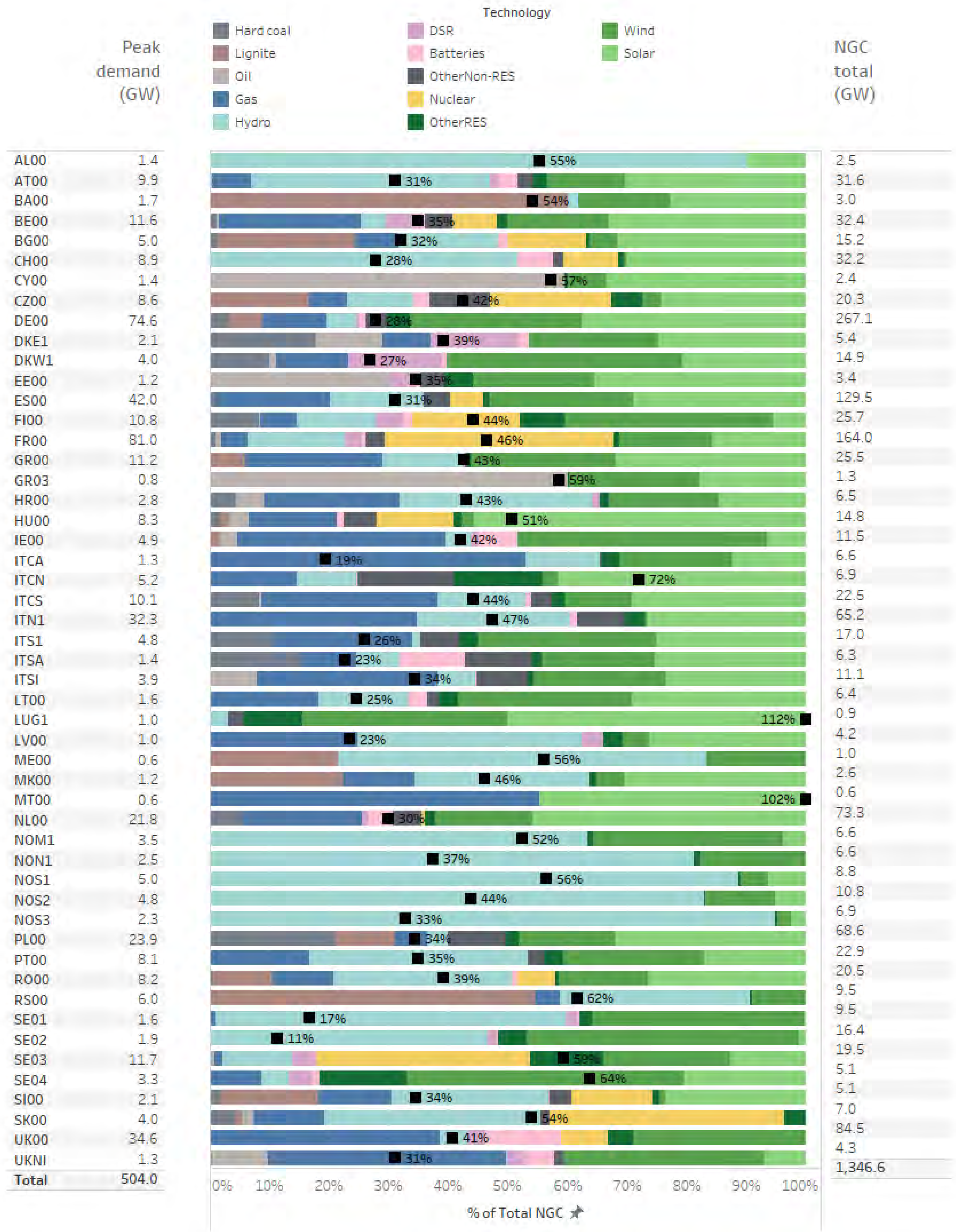

Figure 3: Generation capacity mix at the beginning of summer 2025 per study zone[5,6]

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[5] *In Figure 3, load is compared with production, and hence offshore nodes are not displayed. However, it should be noted that DEKF_OFF has 336 MW of wind capacity and DKKF_OFF has 605 MW of wind capacity.*

[6] *The peak demand for NL00 was overestimated by around 5-6 GW for Summer Outlook 2025.*

Figure 4 shows which study zones have non-market resources (NMR) available in addition to the corresponding NGC. In the event of a lack of supply in the market, the activation of dispatchable NMR can help to address the adequacy challenges. Ten countries utilise NMR. From largest to smallest NGC, these are Germany, Austria, Ireland, two southern bidding zones (BZs) of Sweden, Finland, Switzerland, Malta, Albania, and Luxembourg. This report also assesses whether these resources are sufficient to address identified adequacy issues (c.f. 'Adequacy situation in summer 2025' section).

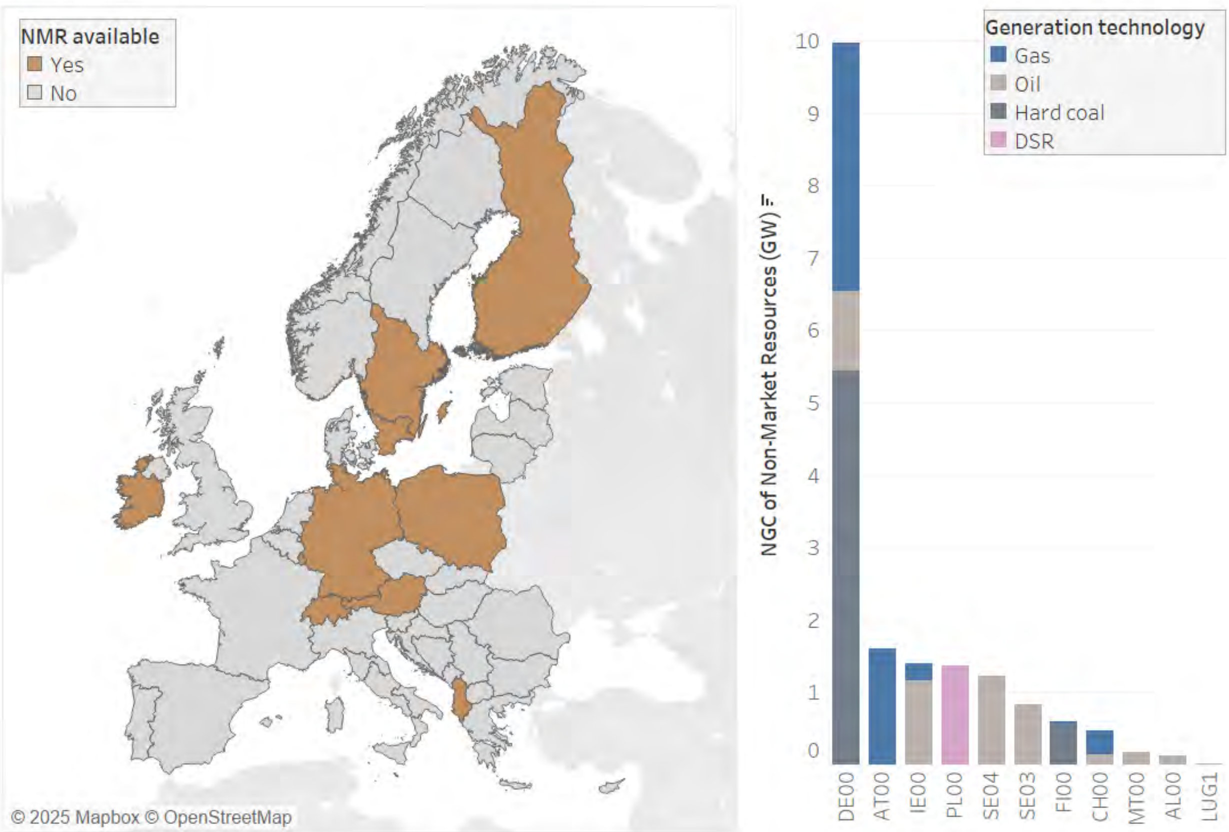

Figure 4: Non-market resources for coping with adequacy challenges in Europe[7]

Planned unavailability of generation

Figure 5: Planned unavailability of thermal units presents the planned unavailability of thermal and nuclear generation units considered in the assessment, including planned outages for maintenance purposes and mothballing. Total planned unavailability in Europe decreases towards mid-summer, followed by a minor increase towards the end of summer. Nuclear units show the highest level of unavailability among thermal technologies at the beginning of summer 2025, with gas ranking second, followed by hard coal and lignite.

[7] *Parts of German and Austrian non-market resources have a different primary purpose than coping with resource adequacy risks, such as grid stabilisation. In the event of adequacy issues in Germany and Austria, these might already be partly exhausted for their primary purpose.*

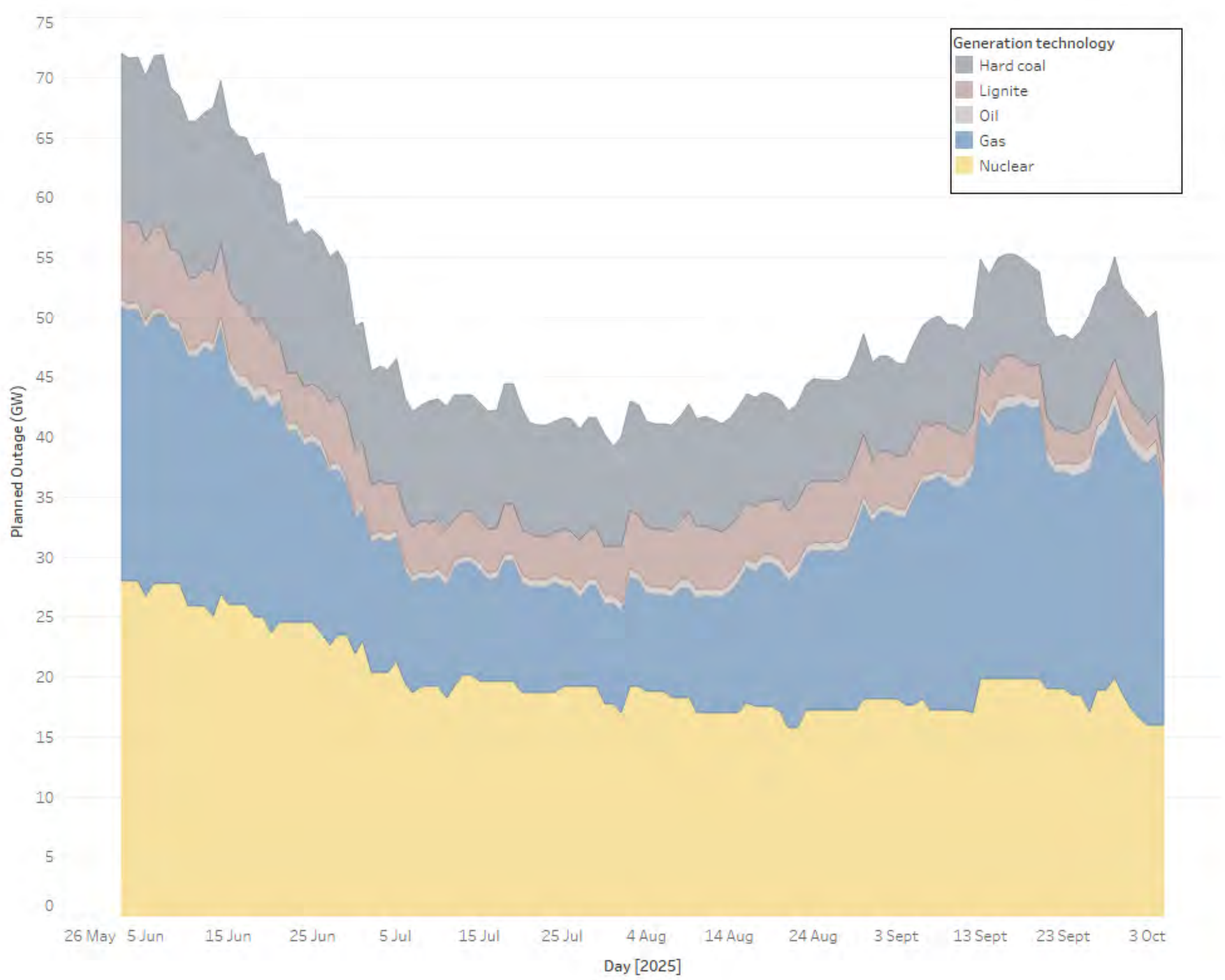

Figure 5: Planned unavailability of thermal units

Planned unavailability in southern countries tends to decrease during the warmest months when the highest demand is expected (i.e., in July and August). This can be observed in the cases of Italy or Greece (GR00), as shown in Figure 6. The figure depicts the weekly ratio of thermal planned unavailability within each study zone with respect to the total thermal NGC of the respective study zone.

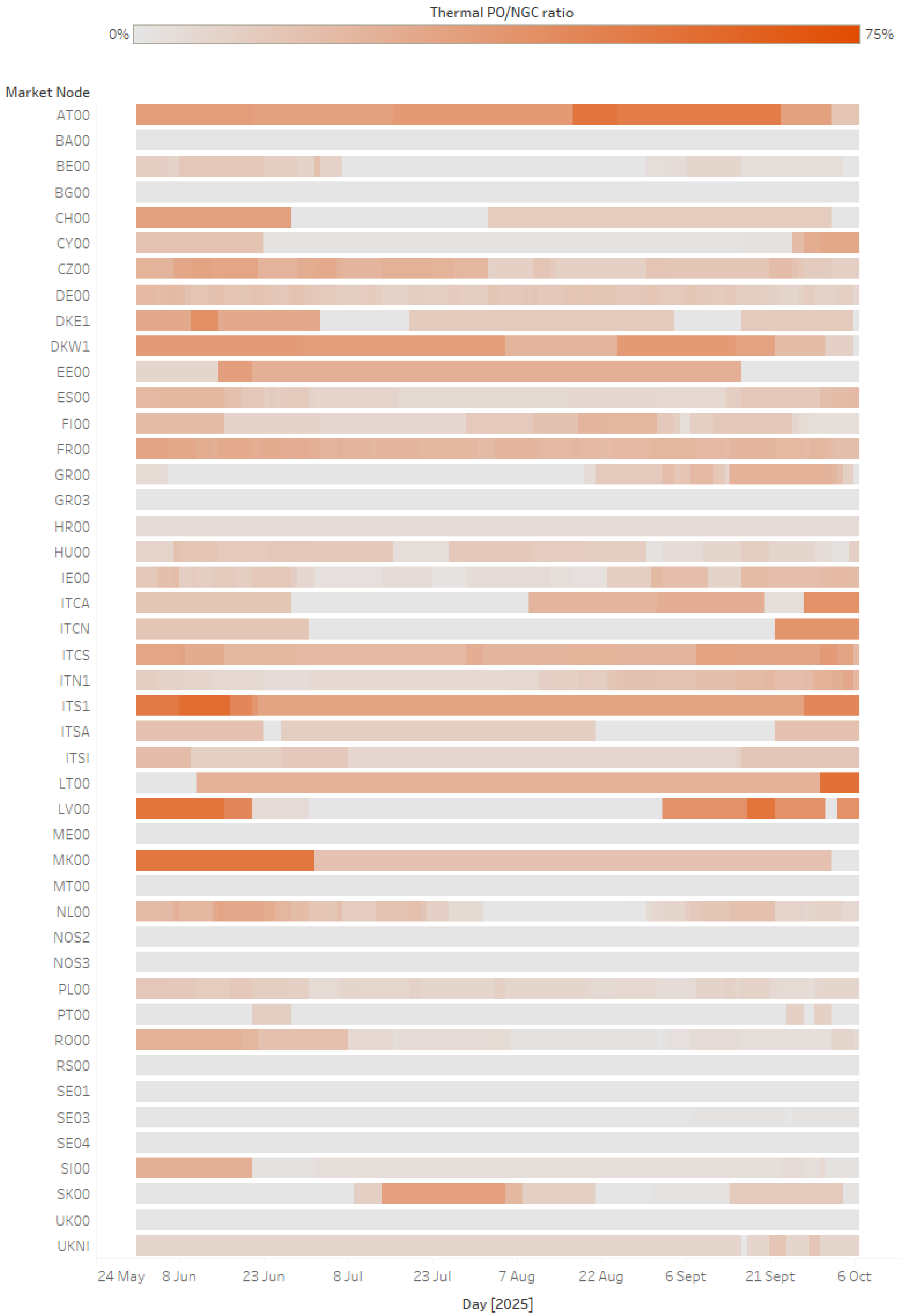

Figure 6: Weekly distribution of thermal planned unavailability relative to thermal NGC

Demand overview

Figure 7 displays a heat map by study zone comparing the expected consumption in each week with the highest expected weekly consumption in summer 2025. The darker shades indicate high expected consumption compared to the highest expected consumption. Demand in continental western Europe (e.g. Austria, Germany, Netherlands) is relatively stable across the summer period. In southern European countries (e.g. Italy, Greece, Malta, Cyprus), there is a trend towards higher demand in the middle of summer linked to air conditioning and tourism, when the temperatures reach yearly peak values.

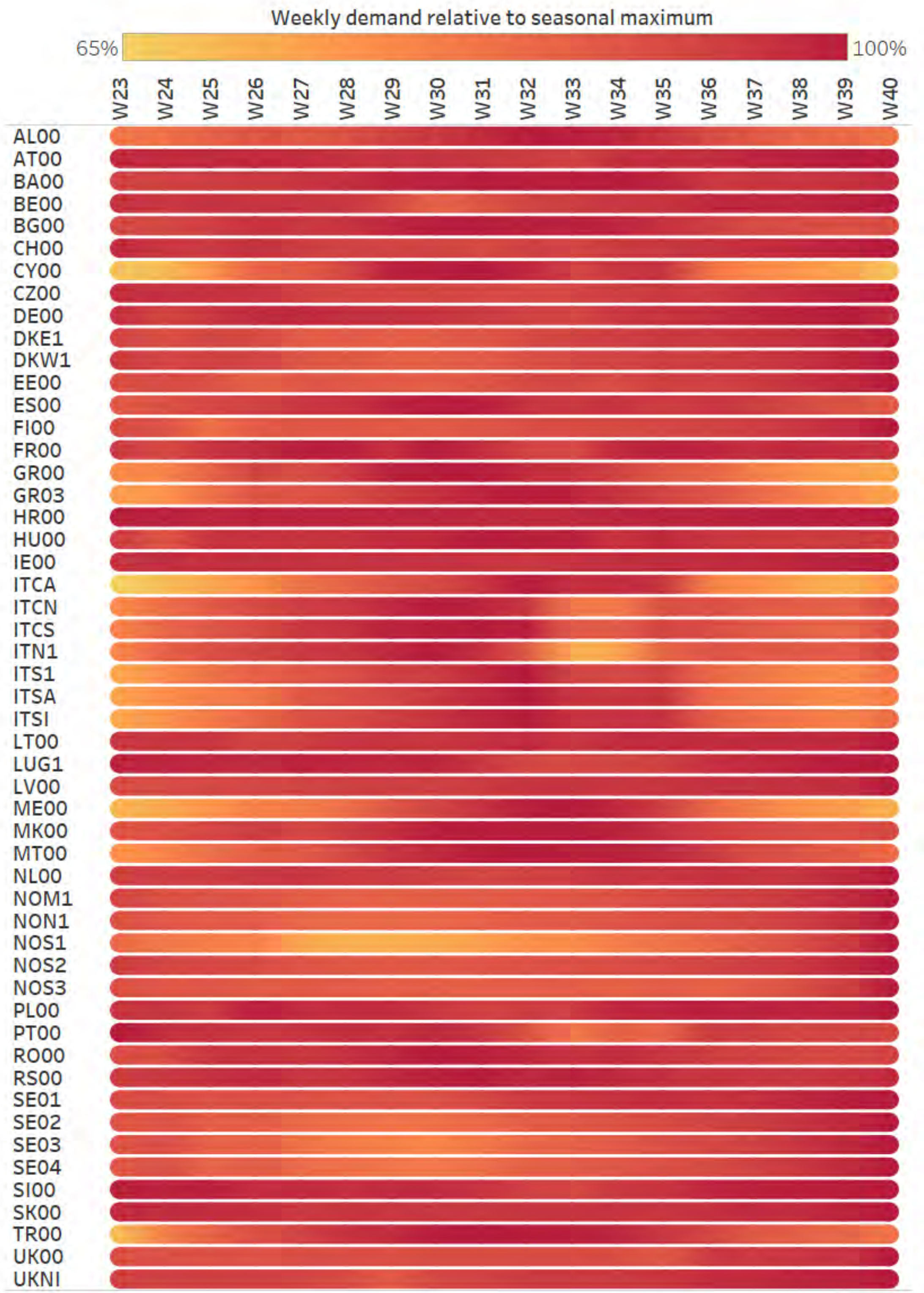

Figure 7: Demand overview: Evolution over summer 2025

Figure 8 shows the workday consumption patterns per study zone by plotting the average demand relative to the highest average demand in summer 2025. The peak demand in Europe is mainly concentrated around noon. Some areas (e.g. Finland, Norway, Northern Sweden) face a relatively stable mean demand during the whole day.

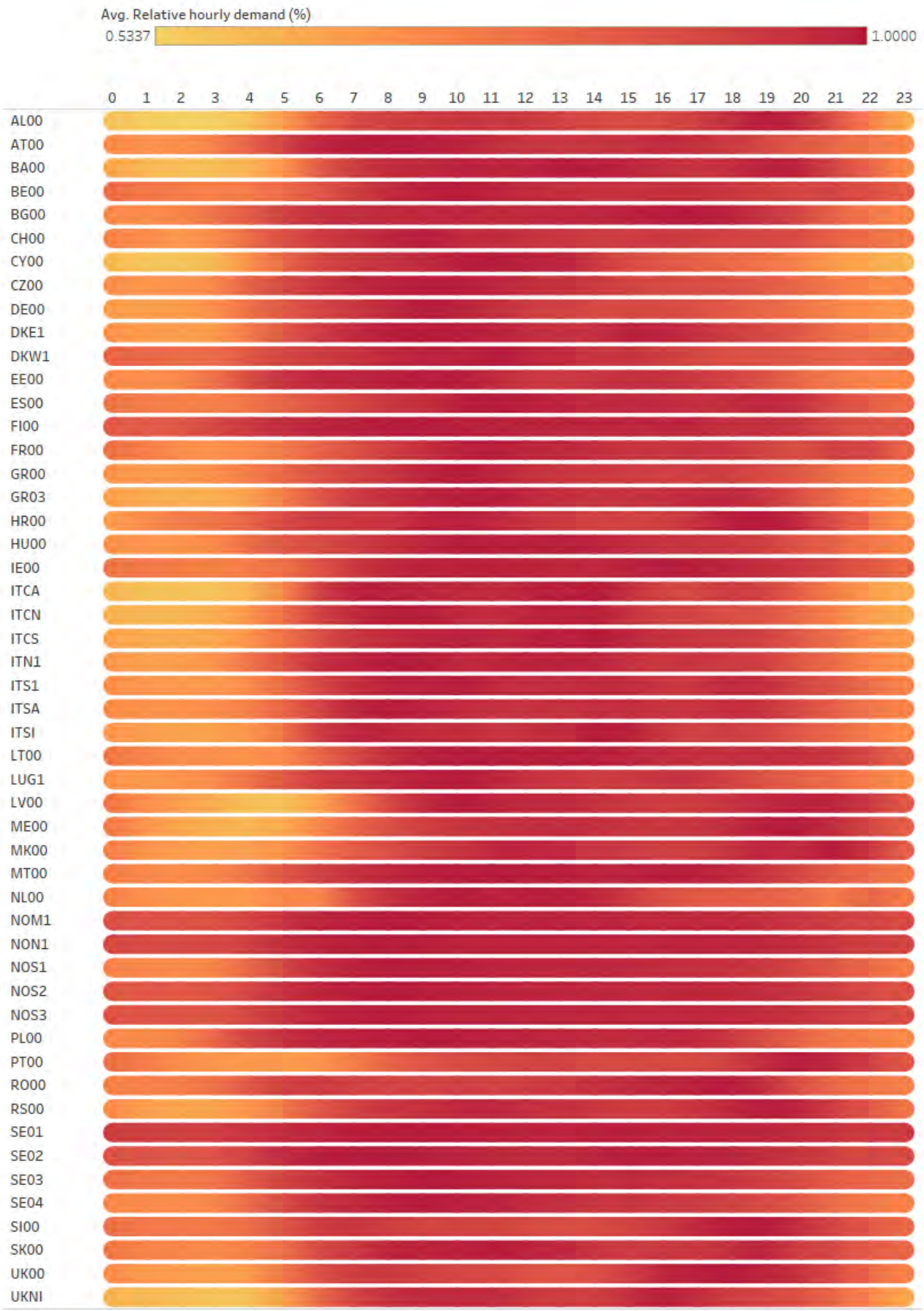

Figure 8: Demand profile overview during Mondays–Fridays in summer 2025[8]

[8] *UTC time convention was used.*

Network overview

Figure 9 shows the ratio of the lowest import capacity to the highest expected demand during the summer, indicating the extent to which systems might be capable of relying on imports from abroad during supply scarcity moments (if generation abroad is available).

A high import capacity to demand ratio cannot predict whether a study zone is dependent on imports for adequacy. For example, Central Italy (ITCN) shows a high import capacity to demand ratio in addition to a low generation capacity to demand ratio (c.f. Figure 2), indicating that this region is dependent on imports. By contrast, a low import capacity to demand ratio does not guarantee that the system is capable of supplying consumers with domestic generation. For example, Northern Italy (ITN1) has a low import capacity to demand ratio but also a rather low generation capacity to demand ratio. Hence, imports to Northern Italy are important for its adequacy, as confirmed by the simulations.

The evaluation of import capacities considers the planned unavailability of grid elements. However, additional unplanned outages might even further constrain import capacities. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, although their contribution is assessed in adequacy simulations.[9]

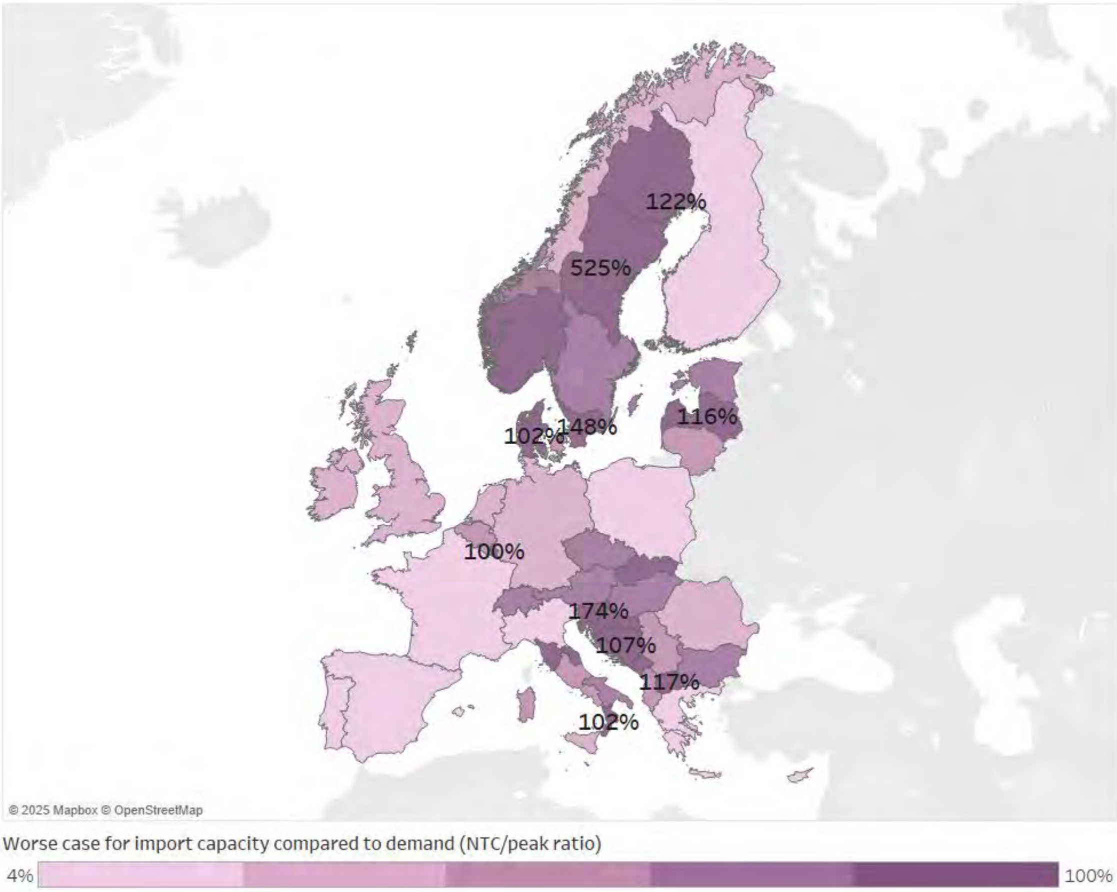

Figure 9: Import capacities per study zone: Ratio between lowest import capacity and highest expected demand (c.f. Figure 20 for details)

[9] *These systems are modelled in a simplified manner by estimating the potential contributions of those systems to the European power system or potentially needed imports from the European power system. Hence, information concerning interconnection capacity and national assets is not used in the adequacy models and not collected.*

Adequacy situation in summer 2025

ENTSO-E assesses the adequacy situation using a two-step approach. In the first step, adequacy under normal market operation conditions is evaluated. In the second step, NMR such as strategic reserves are included to assess their sufficiency for solving the risks identified in the previous step. The NMR can be activated to cope with structural supply shortages in the market.

The adequacy situation in the summer of 2025 (Figure 10) highlights certain adequacy risks—i.e., the risk of having to rely on non-market measures—in Cyprus, Ireland, Malta, and Northern Ireland. NMR significantly mitigate risks in Malta and Ireland, where they are available. However, risks remain largely unchanged in Cyprus as these resources do not exist and the system is not interconnected with the rest of Europe.

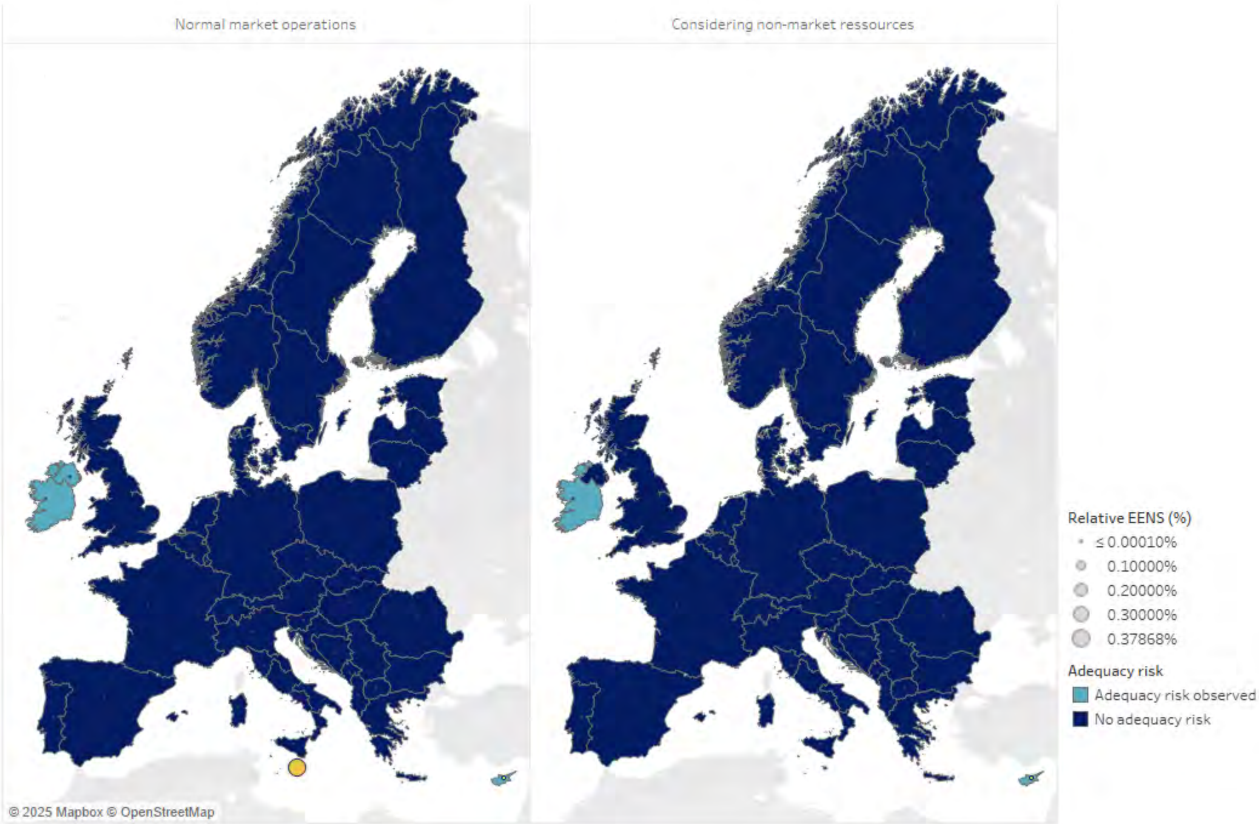

Figure 10: Adequacy overview

The state of the power system is continuously changing and has changed since the data collection (performed in February 2025). For this reason, risks are continuously being monitored by TSOs and Regional Coordination Centres (RCCs).

Focus on adequacy under normal market conditions

Figure 11 presents the adequacy situation under normal market operations. For most countries, no adequacy risks are identified, except for Cyprus (CY00), Ireland (IE00), Malta (MT00), and Northern Ireland (UKNI), which have limited or no interconnection to the European continental network. These risks suggest that systems might need to rely on NMR or operational measures to cope with supply challenges to prevent load shedding.

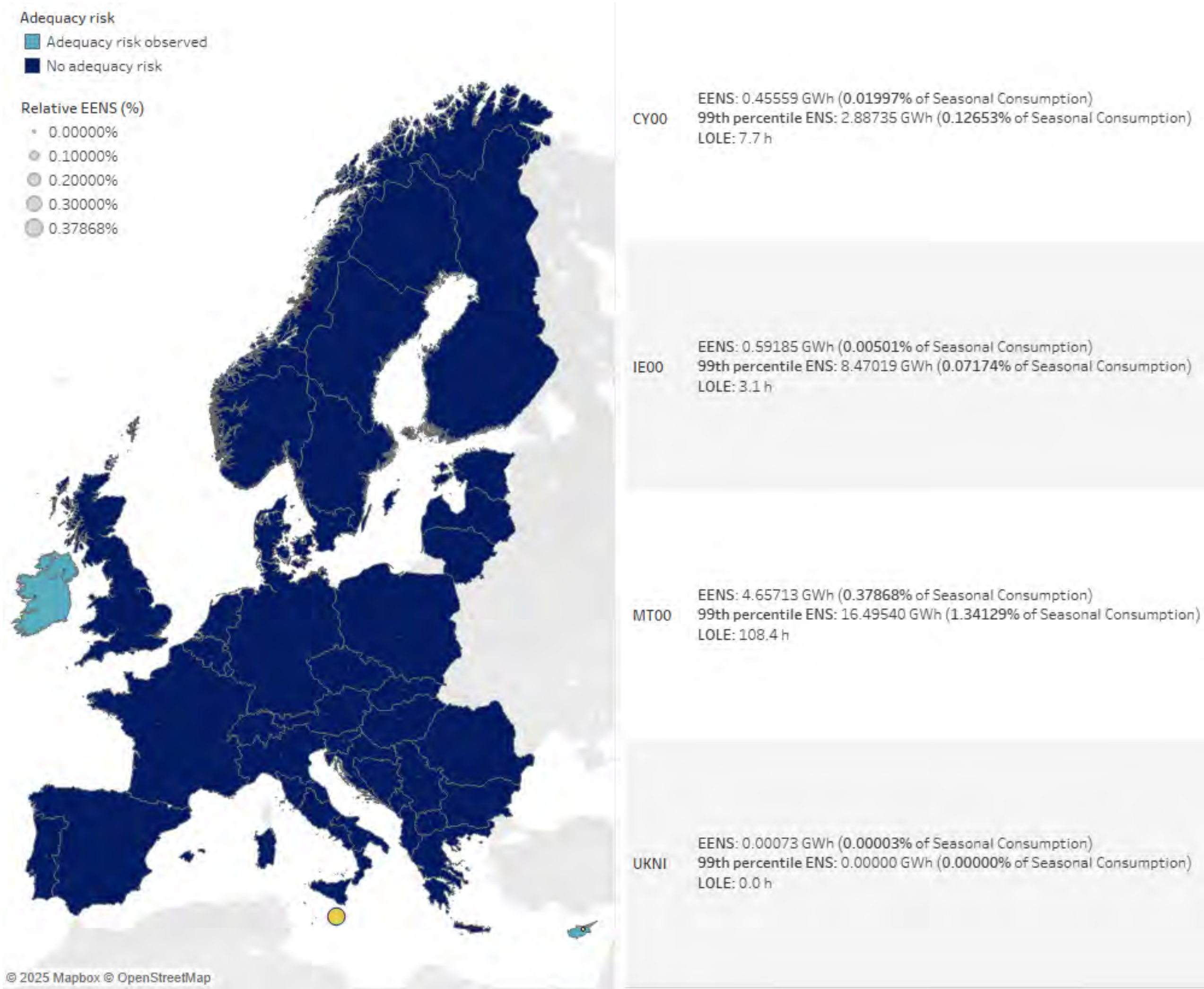

Figure 11: Adequacy risk overview

Figure 12 presents the distribution of risks within the season via the visualisation of Loss Of Load Probability (LOLP). No common pattern could be observed as all systems with risks are rather distant from each other, and system-specific conditions might cause local adequacy issues.

The LOLP shown in Figure 12 is the probability of having loss of load during the week. It is calculated as [LOLE (h)]/168, where 168 is the number of hours in a week. The right part of the figure displays the weekly LOLP relative to the highest weekly LOLP. More specifically, for every study zone and every week, the ratio is the average LOLP over all weather scenarios (WS) and forced outages (FO) divided by the maximum LOLP over all weather scenarios, forced outages, and weeks. The boundaries of the legend are low values (0.00139 – 0.08259), which mean that the average is always much lower than the maximum value. Essentially, in a study zone, for many WS and FO, the number of LOLE hours is much lower than the worst WS/FO combination.

The highest weekly LOLP in CY00 is 1.42%, meaning that the week with the most hours of Loss Of Load Expectation (LOLE) [h] over the entire simulated period has a rate of 1.42% of hours with adequacy issues.

Northern Ireland (UKNI) and Ireland (IE00) show a low probability of adequacy issues distributed over the whole summer. This LOLP arrives in scenarios of high load combined with high unplanned outages of conventional generation. Nonetheless, Ireland (IE00) is marked with adequacy risks in September, where significant planned outages on conventional generation are foreseen (up to 1 GW). These risks are driven by unplanned outages of ageing power plants and will depend on wind generation if such outages occur. The actual adequacy situation in Ireland will depend on operational conditions such as unplanned outages of the ageing generation fleet in Ireland and especially wind generation.

The Cypriot system (CY00) has no interconnection to the other power systems and hence has to rely on domestic supply. There is a possibility of adequacy issues over the summer period in Cyprus if a combination of unfavourable weather conditions and unplanned outages occurs. Higher risks are mostly expected from mid-July to mid-August.

The adequacy situation in Malta (MT00) should be monitored throughout the summer, with special attention in August 2025 as the peak demand period. Adequacy in Malta is typically carefully monitored every summer, which is why Malta has implemented specifically designed NMR to be activated in the event of supply scarcity. The impact of these NMR is presented in the following section.

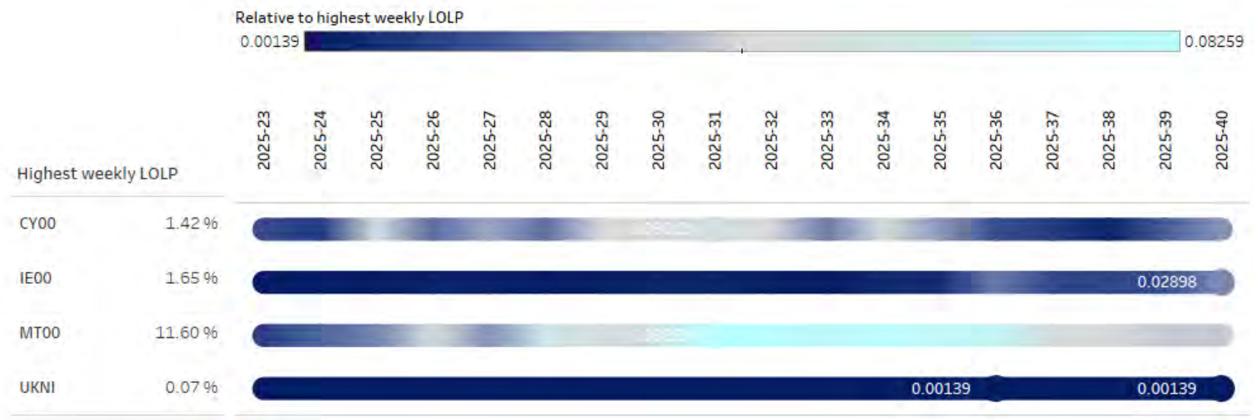

Figure 12: Adequacy weekly insights

Focus on non-market resources

Figure 13 presents the adequacy conditions with NMR. The magnitude of the risks (EENS) significantly decreases for Ireland, Malta, and Northern Ireland[10] compared to the normal market operation as they rely on dedicated NMR (c.f. Figure 4), whereas the magnitude remains the same for Cyprus.

[10] Northern Ireland does not have non-market resources and the decrease in risks comes from using the resources of Ireland. Non-market resources are meant for national use, although in the sensitivity analysis conducted in the Seasonal Outlook sharing of resources is allowed under the assumption that they would be shared to avoid adequacy concerns, where available.

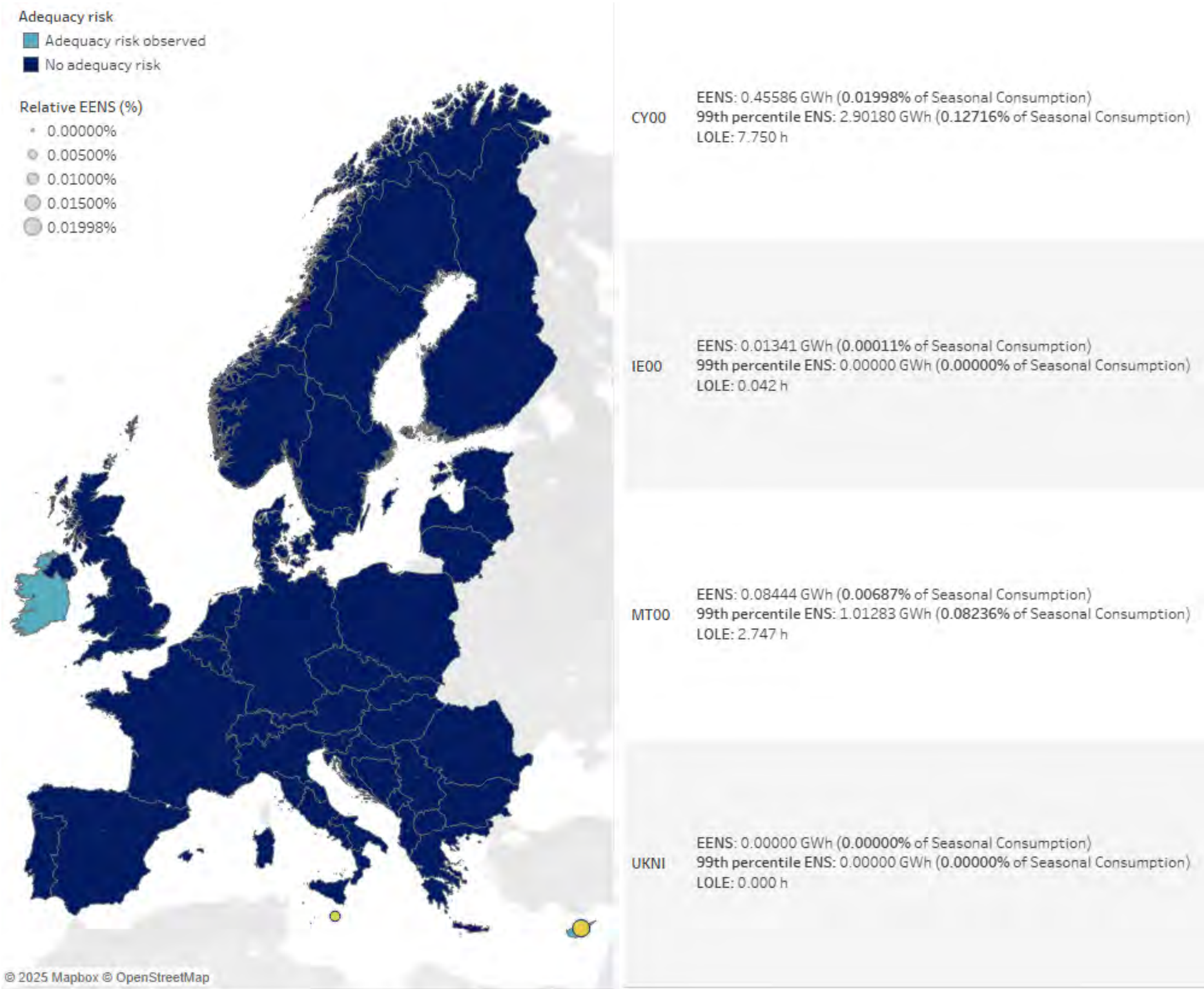

Figure 13: Adequacy risk overview: Considering non-market resources

The LOLP in Malta is significantly lower when NMR are considered (Figure 13) and shows only occasional risks.

The LOLP in Northern Ireland is entirely reduced (Figure 14), implying that there is no adequacy risk when considering NMR. Ireland also sees almost no adequacy issues, with only a handful of very small instances of adequacy concerns remaining.

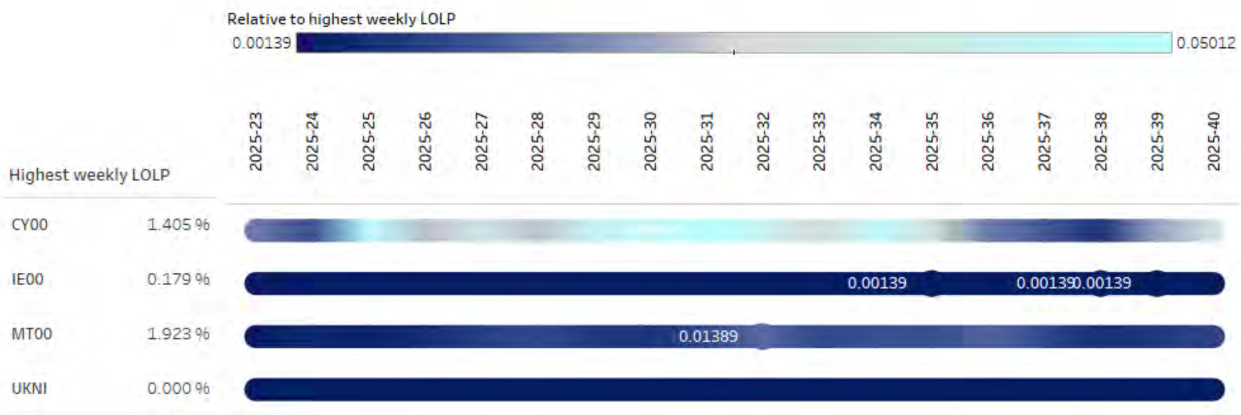

Figure 14: Adequacy weekly insights: Considering non-market resources

Figure 15 represents the impact of NMR, demonstrating that NMR can largely address adequacy concerns in Malta, Ireland, and Northern Ireland.

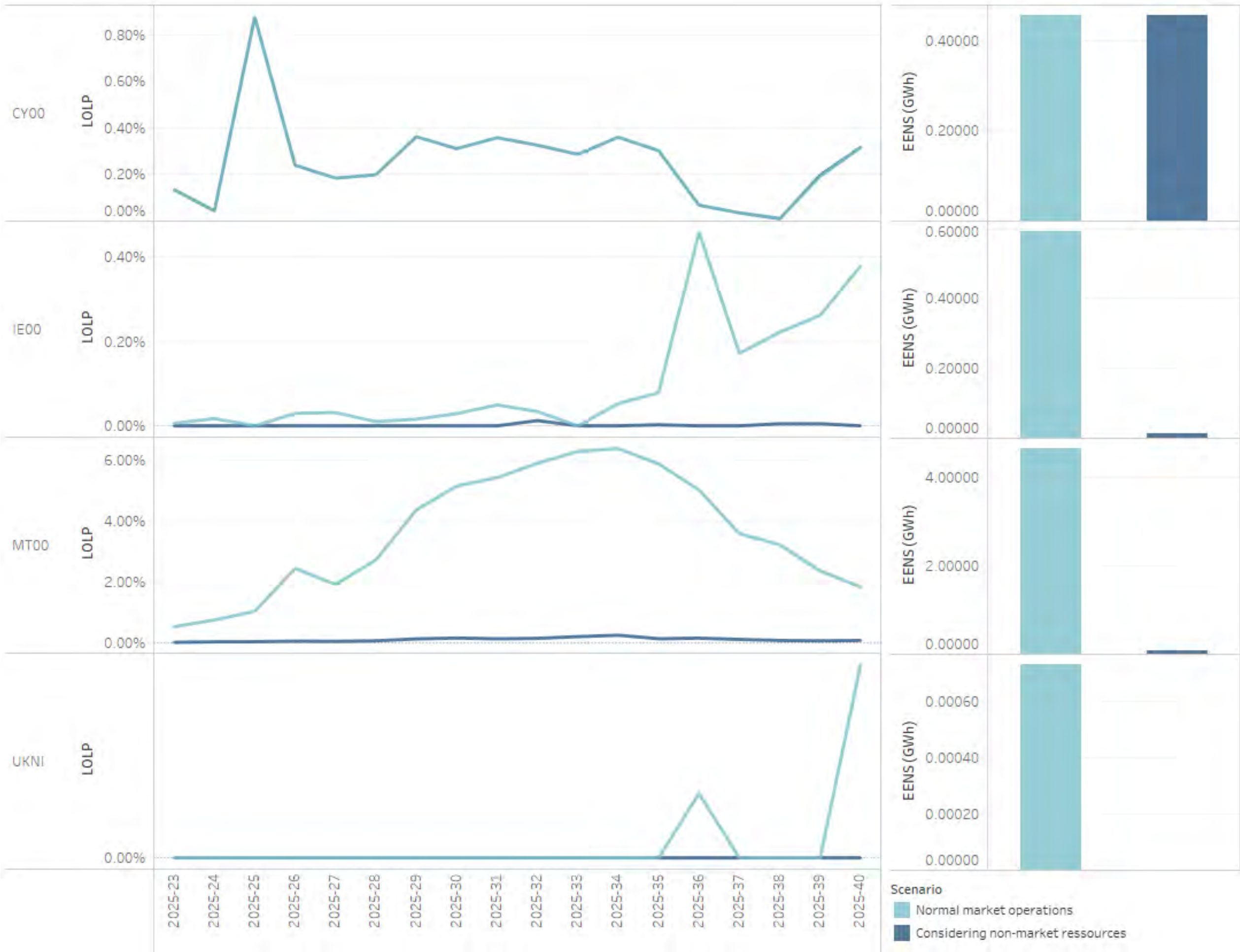

Figure 15: Detailed adequacy overview—weekly LOLP and ENS

Winter 2024-2025 review

Background of the energy sector evolution since early 2022

During 2022, tensions in the European energy sector significantly increased due to the political and economic situation in Europe with the war in Ukraine. In the winter of 2022–2023, a potential gas shortage was identified as one of the most concerning risks for the European power system, together with risks such as coal shortage, low nuclear generation availability, and low hydrological reservoir levels. Many remedial actions and policy decisions have been taken, which have considerably consolidated the European robustness to the gas crisis.

The situation has progressively eased since early 2023, based on the numerous actions and decisions at the European level (e.g. RePowerEU). ENTSO-E used the experiences of 2022–2023 and 2023–2024 to anticipate and address any risk ahead of and during the winter 2024–2025 period.

Preparations for winter 2024–2025

To prepare for winter 2024–2025, ENTSO-E kept a broadened scope of the Seasonal Outlook Adequacy assessment beyond the strict legal mandate, as already performed in 2022 to address the crisis. Moreover, as for the previous winter, an anticipation of the assessment and early release of the report was carried out, in close coordination with the European Commission, ACER and the Member States.

The preparation of winter 2024–2025 was built on the experience from the previous winter preparation, with enhancement compared to the standard seasonal adequacy assessment:

- Early and continuous monitoring starting from early summer 2024 through surveys and quantitative assessments.

- Assessment of Critical Gas Volume (CGV) to ensure adequacy in Europe.

These assessments ensured sufficient preparation for winter 2024–2025, supporting TSOs and all stakeholders with clear risk identification and enabling them to prepare mitigation actions.

Conditions and events during winter 2024–2025

The weather conditions were favourable throughout most of the winter, and hydro stock also improved in some regions, alleviating adequacy concerns for winter 2024–2025. In some countries, the consumption recorded was higher than expected. For instance, Cyprus registered a record high peak winter load of 1,109 MW on 24 February 2025.

Globally, the 2024–2025 winter had above-average temperatures, with January 2025 being the warmest on record (0.79°C warmer than the 1991–2020 average). In Europe, a contrast can be observed between the cardinal directions in the continent: the eastern half of the continent was generally warmer in December 2024 and January 2025, with above 10°C average temperatures in the north-east of the continent. In February 2025, the temperatures vary more in the region, with a freezing spell in the south-east and warmer temperatures concentrated in the north. Temperatures are overall warm in March 2025, apart from the Iberian peninsula. Notably, March 2025 was the warmest March on record in Europe at 2.41°C above the 1991–2020 average. This can be seen in Figure 16, which displays the surface air temperature anomaly observed in winter 2024–2025 (December 2024 to March 2025) from the Copernicus Climate Change Service.

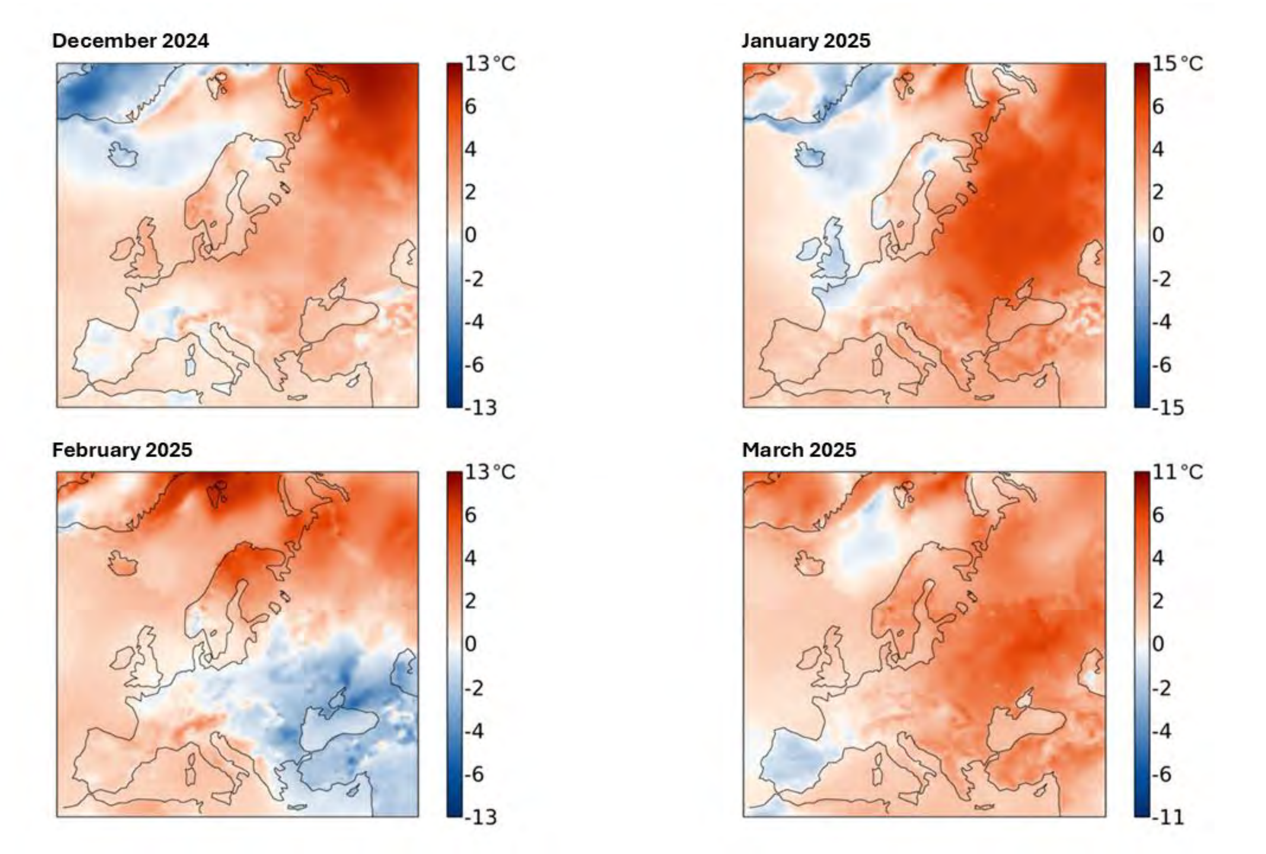

Figure 16: Surface air temperature anomaly in winter 2024–2025 relative to the average for the 1991–2020 period (for December, January, February and March)[11]

Specific comments on winter 2024–2025

In general, no major adequacy issues were observed during the past winter 2024–2025, whereby mild temperatures played a significant role in averting potential shortages. Nevertheless, some countries faced challenges during the past winter:

[11] *Copernicus Climate Change Service: Surface air temperature maps.*

- There were multiple periods with low replacement reserve availability in Cyprus. Furthermore, Cyprus experienced a marginal adequacy situation towards the end of February due to an extreme cold spell that coincided with unplanned outages of old conventional generators.

- Finland's Estlink 2 cable was damaged this winter and could not be repaired, thereby reducing transmission capacity for most of the winter.

- Hungary's system faced the 'alert' and 'emergency' states on a few occasions, albeit being short-lived.

- In Ireland, dispatchable generation margins were insufficient during two cold spells, requiring imports from Great Britain.

- A storm caused damage at a Northern Irish power station, resulting in the loss of conventional generation and forcing generators into extended outage. While several system alerts were issued, demand peaks were lower than expected.

- Spain witnessed near-scarcity situations that required activating the Active Demand Response Service to be activated as a product.

However, despite these situations, no adequacy problems were experienced.

Preparations for winter 2025–2026

ENTSO-E does not foresee any extraordinary risks for winter 2025–2026. It remains vigilant and will continue monitoring how the situation in the energy sector will develop. Extra actions will be taken if deemed necessary on an ad-hoc basis, whether additional adequacy assessments are necessary or mitigating actions are required based on developing circumstances.

The results of the recently released ENTSO-E Summer Outlook[12] show that the storage levels as of 1 April 2025 are lower than in the past two years, although adequate infrastructure is in place to replenish storages ahead of next winter.

The adequacy situation in winter 2025–2026 will depend on how the situation in the energy sector evolves. ENTSO-E will also closely consider specific feedback or requests about the future Winter Outlook from European or National Authorities.

ENTSO-E is striving to release the Winter Outlook 2025–2026 in advance of the legal mandate (mid-November 2025 instead of 1 December).

[12] *OUTLOOKS & REVIEWS | ENTSOG*

Appendix 1: Methodological insights

Since the Summer Outlook 2020, ENTSO-E has significantly upgraded its methodology towards a full probabilistic approach for assessing adequacy on the seasonal time horizon.

This methodology is described in the Methodology for Short-term and Seasonal Adequacy Assessments.[13] It was developed by ENTSO-E in line with the Clean Energy for all Europeans package and especially the Regulation on Risk Preparedness in the Electricity Sector (EU) 2019/941, approved by the ACER.[14]

Most notably, the seasonal adequacy assessment has shifted from a weekly snapshot based on a deterministic approach to the well-proven, state-of-the-art, sequential, hourly Monte Carlo probabilistic approach. In this new approach, a set of possible scenarios for each variable is constructed to assess adequacy risks under various conditions for the analysed timeframe. Figure 17 provides a schematic representation of this scenario construction process.

Figure 17: Scenarios assessed in Seasonal Outlooks

Scenarios are constructed, ensuring that all variables are correlated (interdependent) in time and space. The assessments are prepared by experts working within dedicated teams to ensure the highest data quality. A Pan-European Climate Database maintained by ENTSO-E ensures high data quality and consistency across Europe.

Consequently, ENTSO-E has transitioned from a 'shallow' scenario tree with limited severe and normal conditions samples to a 'deep' scenario tree that incorporates extensive interdependent weather data and random unplanned outages. This generates a wide range of alternative scenarios spanning multiple weather scenarios. Furthermore, an improvement in the methodology also enables considering hydro energy availability. Figure 18 illustrates the difference in the number of scenarios between the two modelling approaches.

[13] Methodology for Short-term and Seasonal Adequacy assessment
[14] ACER decision (No 08/2020) on the methodology for short-term and seasonal adequacy assessments

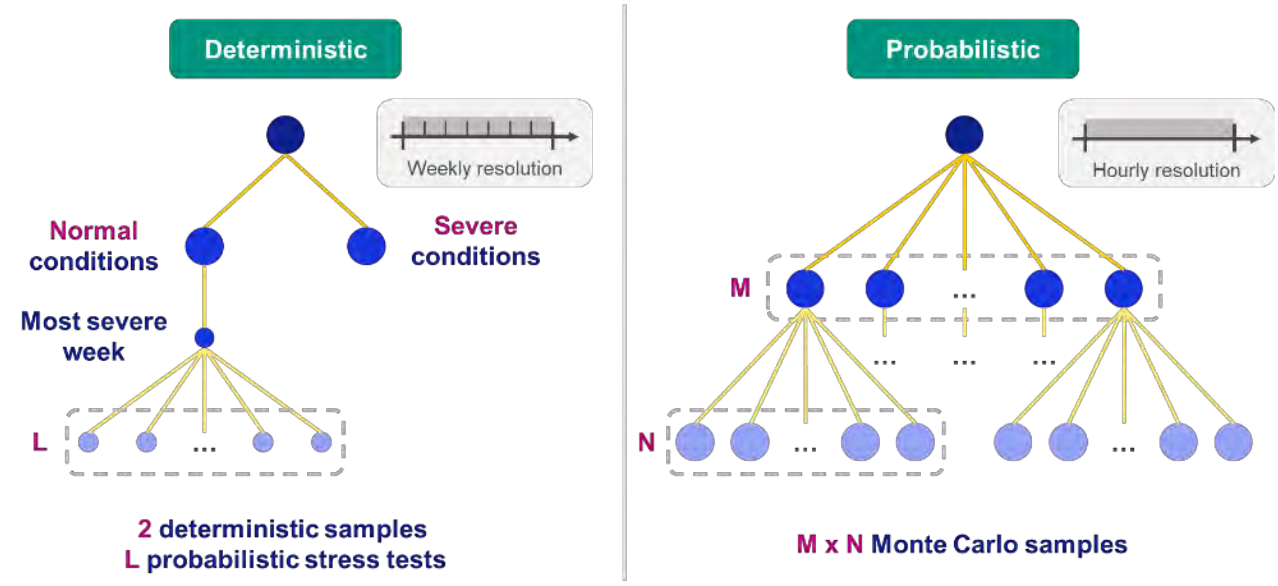

Figure 18: Scenario revolution: From deterministic to probabilistic

An adequacy assessment is conducted for each sample case on the seasonal time horizon, yielding a probabilistic pan-European resource assessment identifying adequacy risks in each deterministic sample and generating numerous consistent pan-European draws while identifying realistic adequacy risks. Further improvements were made after the Winter Outlook 2020–2021, especially in the modelling of exchanges, whereby new constraints on total simultaneous exchanges were implemented. Simultaneous import and simultaneous export limitations were considered in the Summer Outlook 2021, likewise limitations on country position (or net exchange).

Appendix 2: Additional information about the study

Figure 19: Study zones

NTC import table

AL00	ME00 400 MW (400 - 400) MW	RS00 400 MW (400 - 400) MW	GR00 378 MW (0 - 400) MW										
AT00	DE00 4,800 MW (4,800 - 4,800) MW	CH00 1,200 MW (1,200 - 1,200) MW	SI00 950 MW (950 - 950) MW	CZ00 900 MW (900 - 900) MW	HU00 771 MW (0 - 800) MW	ITN1 40 MW (30 - 95) MW							
BA00	HR00 800 MW (800 - 800) MW	RS00 474 MW (474 - 474) MW	ME00 450 MW (450 - 450) MW										
BE00	FR00 2,000 MW (2,000 - 2,000) MW	DE00 1,000 MW (1,000 - 1,000) MW	UK00 1,000 MW (1,000 - 1,000) MW	NL00 950 MW (950 - 950) MW									
BG00	RO00 1,818 MW (1,200 - 1,900) MW	GR00 1,100 MW (1,100 - 1,100) MW	MK00 400 MW (400 - 400) MW	RS00 290 MW (0 - 389) MW									
CH00	FR00 2,918 MW (2,700 - 3,100) MW	DE00 1,988 MW (1,600 - 2,000) MW	ITN1 1,534 MW (1,440 - 1,910) MW	AT00 1,131 MW (736 - 1,200) MW									
CZ00	DE00 2,750 MW (2,750 - 2,750) MW	SK00 1,600 MW (1,600 - 1,600) MW	PLE0 1,000 MW (1,000 - 1,000) MW	AT00 900 MW (900 - 900) MW	PLI0 0 MW (0 - 0) MW								
DE00	AT00 4,800 MW (4,800 - 4,800) MW	NL00 4,400 MW (4,400 - 4,400) MW	CH00 3,968 MW (3,650 - 4,000) MW	FR00 3,000 MW (3,000 - 3,000) MW	PL00 3,000 MW (3,000 - 3,000) MW	CZ00 2,900 MW (2,900 - 2,900) MW	DKW1 2,490 MW (700 - 2,500) MW	NOS2 1,400 MW (1,400 - 1,400) MW	LUV1 1,300 MW (1,300 - 1,300) MW	BE00 1,000 MW (1,000 - 1,000) MW	LUG1 1,000 MW (1,000 - 1,000) MW	SE04 597 MW (350 - 600) MW	DKE1 585 MW (585 - 585) MW
DKE1	DE00 585 MW (585 - 585) MW	DKW1 519 MW (0 - 590) MW	SE04 440 MW (250 - 640) MW										
DKW1	DE00 2,490 MW (700 - 2,500) MW	NOS2 1,628 MW (632 - 1,632) MW	UK00 1,397 MW (700 - 1,400) MW	NL00 690 MW (300 - 700) MW	DKE1 527 MW (0 - 600) MW	SE03 504 MW (0 - 715) MW							
EE00	FI00 703 MW (358 - 1,016) MW	LV00 550 MW (550 - 550) MW											
ES00	PT00 2,483 MW (1,000 - 3,300) MW	FR00 1,526 MW (900 - 2,500) MW											
FI00	SE03 1,055 MW (400 - 1,200) MW	SE01 1,017 MW (400 - 1,300) MW	EE00 703 MW (358 - 1,016) MW	NON1 79 MW (0 - 80) MW									
FR00	UK00 4,000 MW (4,000 - 4,000) MW	DE00 3,000 MW (3,000 - 3,000) MW	ITN1 1,907 MW (1,370 - 2,100) MW	ES00 1,259 MW (400 - 2,300) MW	CH00 1,200 MW (1,200 - 1,200) MW	BE00 650 MW (650 - 650) MW							
GR00	BG00 1,200 MW (1,200 - 1,200) MW	MK00 500 MW (500 - 500) MW	ITS1 418 MW (0 - 500) MW	AL00 378 MW (0 - 400) MW	GR03 150 MW (150 - 150) MW								
GR03	GR00 150 MW (150 - 150) MW												
HR00	SI00 1,500 MW (1,500 - 1,500) MW	HU00 1,000 MW (1,000 - 1,000) MW	BA00 800 MW (800 - 800) MW										
HU00	SK00 2,513 MW (2,513 - 2,513) MW	RO00 1,000 MW (1,000 - 1,000) MW	HR00 800 MW (800 - 800) MW	AT00 771 MW (0 - 800) MW	SI00 687 MW (0 - 700) MW	RS00 642 MW (0 - 800) MW							
IE00	UK00 1,000 MW (1,000 - 1,000) MW	UKNI 400 MW (400 - 400) MW											
ITCA	ITSI 1,269 MW (700 - 1,300) MW	ITS1 980 MW (400 - 1,100) MW											
ITCN	ITN1 3,649 MW (2,800 - 4,450) MW	ITCS 3,045 MW (1,800 - 3,400) MW	ITSA 251 MW (0 - 300) MW										
ITCS	ITS1 3,895 MW (2,600 - 5,200) MW	ITCN 2,506 MW (1,100 - 3,500) MW	ITSA 887 MW (870 - 900) MW	ME00 555 MW (0 - 600) MW									
ITN1	FR00 3,285 MW (2,417 - 3,900) MW	CH00 3,002 MW (413 - 4,036) MW	ITCN 2,600 MW (2,000 - 3,350) MW	SI00 481 MW (0 - 753) MW	AT00 425 MW (415 - 475) MW								
ITS1	ITCS 2,400 MW (2,400 - 2,400) MW	ITCA 2,050 MW (600 - 2,350) MW	GR00 418 MW (0 - 500) MW										
ITSA	ITCS 720 MW (720 - 720) MW	ITCN 220 MW (0 - 300) MW											
ITSI	ITCA 1,504 MW (700 - 1,550) MW	MT00 225 MW (225 - 225) MW											
LT00	LV00 636 MW (594 - 650) MW	SE04 585 MW (0 - 700) MW	PL00 150 MW (150 - 150) MW										
LUG1	DE00 1,000 MW (1,000 - 1,000) MW												
LUV1	DE00 1,300 MW (1,300 - 1,300) MW												
LV00	LT00 700 MW (700 - 700) MW	EE00 450 MW (450 - 450) MW											

ME00	ITCS 555 MW (0 - 600) MW	BA00 500 MW (500 - 500) MW	AL00 400 MW (400 - 400) MW	RS00 286 MW (245 - 300) MW			
MK00	RS00 513 MW (480 - 574) MW	GR00 500 MW (500 - 500) MW	BG00 400 MW (400 - 400) MW				
MT00	ITSI 225 MW (225 - 225) MW						
NL00	DE00 4,400 MW (4,400 - 4,400) MW	BE00 1,400 MW (1,400 - 1,400) MW	UK00 1,000 MW (1,000 - 1,000) MW	DKW1 700 MW (700 - 700) MW	NOS2 700 MW (700 - 700) MW		
NOM1	NON1 1,200 MW (1,200 - 1,200) MW	SE02 827 MW (300 - 1,000) MW	NOS1 500 MW (500 - 500) MW	NOS3 500 MW (500 - 500) MW			
NON1	NOM1 400 MW (400 - 400) MW	SE01 366 MW (0 - 600) MW	SE02 241 MW (0 - 300) MW	FI00 80 MW (80 - 80) MW			
NOS1	NOS3 3,900 MW (3,900 - 3,900) MW	NOS2 3,500 MW (3,500 - 3,500) MW	SE03 1,597 MW (645 - 2,095) MW	NOM1 500 MW (500 - 500) MW			
NOS2	NOS1 2,200 MW (2,200 - 2,200) MW	DKW1 1,628 MW (632 - 1,632) MW	DE00 1,400 MW (1,400 - 1,400) MW	UK00 1,400 MW (1,400 - 1,400) MW	NL00 700 MW (700 - 700) MW	NOS3 600 MW (600 - 600) MW	
NOS3	NOM1 800 MW (800 - 800) MW	NOS1 600 MW (600 - 600) MW	NOS2 500 MW (500 - 500) MW				
PL00	SE04 519 MW (0 - 600) MW	DE00 500 MW (500 - 500) MW	PLI0 183 MW (183 - 183) MW	LT00 150 MW (150 - 150) MW	PLE0 0 MW (0 - 0) MW		
PLE0	PL00 2,140 MW (2,140 - 2,140) MW	CZ00 0 MW (0 - 0) MW					
PLI0	CZ00 1,050 MW (1,050 - 1,050) MW	PL00 0 MW (0 - 0) MW					
PT00	ES00 3,094 MW (1,300 - 4,100) MW						
RO00	BG00 1,818 MW (1,200 - 1,900) MW	HU00 1,000 MW (1,000 - 1,000) MW	RS00 857 MW (800 - 993) MW				
RS00	RO00 887 MW (780 - 1,000) MW	HU00 565 MW (0 - 700) MW	MK00 481 MW (383 - 550) MW	AL00 400 MW (400 - 400) MW	BA00 300 MW (300 - 300) MW	BG00 288 MW (0 - 365) MW	ME00 200 MW (200 - 200) MW
SE01	SE02 3,152 MW (800 - 3,300) MW	FI00 989 MW (200 - 1,100) MW	NON1 389 MW (0 - 700) MW				
SE02	SE03 7,300 MW (7,300 - 7,300) MW	SE01 2,235 MW (2,000 - 3,300) MW	NOM1 572 MW (420 - 600) MW	NON1 185 MW (0 - 250) MW			
SE03	SE02 5,726 MW (5,100 - 7,300) MW	SE04 2,800 MW (2,800 - 2,800) MW	NOS1 1,126 MW (100 - 2,145) MW	DKW1 589 MW (0 - 715) MW	FI00 79 MW (0 - 300) MW		
SE04	SE03 3,747 MW (3,300 - 6,200) MW	DKE1 815 MW (0 - 1,700) MW	LT00 658 MW (0 - 700) MW	DE00 600 MW (600 - 600) MW	PL00 553 MW (0 - 600) MW		
SI00	HR00 1,500 MW (1,500 - 1,500) MW	AT00 950 MW (950 - 950) MW	HU00 687 MW (0 - 700) MW	ITN1 581 MW (0 - 680) MW			
SK00	HU00 1,800 MW (1,800 - 1,800) MW	CZ00 1,700 MW (1,700 - 1,700) MW					
UK00	FR00 4,000 MW (4,000 - 4,000) MW	NOS2 1,400 MW (1,400 - 1,400) MW	DKW1 1,397 MW (700 - 1,400) MW	BE00 1,000 MW (1,000 - 1,000) MW	IE00 1,000 MW (1,000 - 1,000) MW	NL00 1,000 MW (1,000 - 1,000) MW	UKNI 378 MW (0 - 400) MW
UKNI	UK00 423 MW (0 - 450) MW	IE00 400 MW (400 - 400) MW					

Figure 20: Import capacity overview

Appendix 3: Additional information about the results

Loss of Load Expectation and other annual metrics

This appendix presents information about LOLE in the assessed season. LOLE figures can be useful when comparing how adequacy evolved between editions of seasonal adequacy assessments. However, readers are invited to interpret them carefully as LOLE is commonly known as an annual metric, whereas only a specific season (part of the year) is considered in seasonal adequacy assessment.

LOLE analysis might lead to misleading conclusions when compared with Reliability Standards (existing or under development in accordance with Article 26 of Regulation 2019/943). Some examples are given below, assuming that the annual LOLE Reliability Standard[15] is set and compared with seasonal LOLE:

- Seasonal LOLE can be lower than the Reliability Standard, although this does not mean that adequacy within the assessed season complies with the Reliability Standard. For example, even a minor LOLE value can indicate unusual risk in a study zone if the risk is identified in an unusual season (e.g. risk in summer for a northern country).

- Seasonal LOLE can be higher than the Reliability Standard, although this does not necessarily mean that the system design does not comply with the Reliability Standard. The expected situation in the upcoming season could simply be one of the more constraining among a set of possible season scenarios[16] (e.g. if low water availability in hydro reservoirs and high generation unavailability is expected at the beginning of the season).

It is worth considering whether the Reliability Standard is defined as a system design target or as an operational system adequacy metric target. Europe relies initially on market signals (for supply and network investments) to meet the reliability target set for power system design purposes, and market design corrections can be made if they are insufficient (e.g. the establishment of complementary markets such as Capacity Mechanisms). The latter market decisions are based on a several-year-ahead framework,[17] whereas seasonal outlooks relate to an operational timeframe that relies on the market participants taking short-term corrective actions (e.g. change of planned outage schedules), in addition to the TSOs utilising all available resources in the best manner to reduce the risks to the lowest possible level. Therefore, it is important to understand the purpose of any metric against which Seasonal Outlook results might be compared, which is especially important for LOLE.

Considering the background and interpretation limitations, Figure 21 below represents the LOLE results of the Summer Outlook 2025.

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[15] The conclusions made for annual LOLE are also valid for any other annual metric.

[16] The same applies to a particular historical supply scarcity. If hours when demand was shed exceed the LOLE set by the Reliability Standard, this does not mean that the system design does not comply with the Reliability Standard. LOLE set by the Reliability Standard simply indicates in how many hours demand shedding is acceptable (due to supply scarcity) over a long time.

[17] Monitored by the European Resource Adequacy Assessment in line with Article 23 of the Electricity Regulation 2019/943.

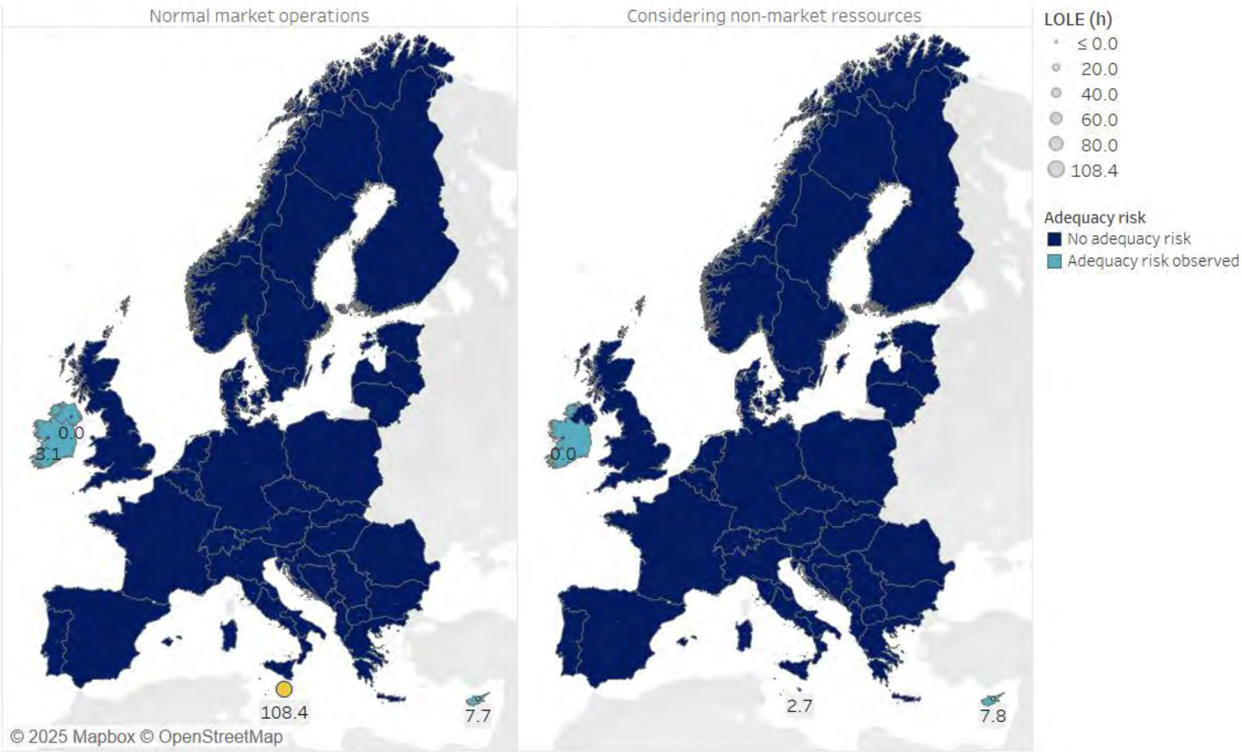

Figure 21: Seasonal LOLE results

Analysis on excess of renewable generation

As an additional insight, this Summer Outlook 2025 introduces an analysis of the excess hourly generation of variable renewable capacity (wind and solar installations) resulting from ENTSO-E's model. Figures 22 and 23 show the average excess of renewable generation from all weather scenarios and forced outage samples. Excess of generation occurs when the total possible generation of wind and solar installations exceeds the total demand of the system in a given hour, taking into account interconnections, as well as must-run or inelastic constraints from conventional power plants modelled.

Several considerations on the assumptions of the model are crucial for interpreting the figures. First, each BZ is considered as a copper plate, and hence **no national transmission or distribution bottlenecks** are considered. Since renewable curtailment in a real-world setting is strongly influenced by grid congestion, the results shown below might show significantly less excess of renewables for specific regions. Second, ramping constraints are not considered in the model, which can have a significant impact on the renewable generation in small isolated systems that rely on a very limited number of power plants for their generation.

Figure 22 summarises the average total unused energy and provides the average excess factor per BZ. Figure 23 illustrates the weekly distribution of the unused energy during the summer for each zone, as well as the average number of hours during which a BZ has excess generation.

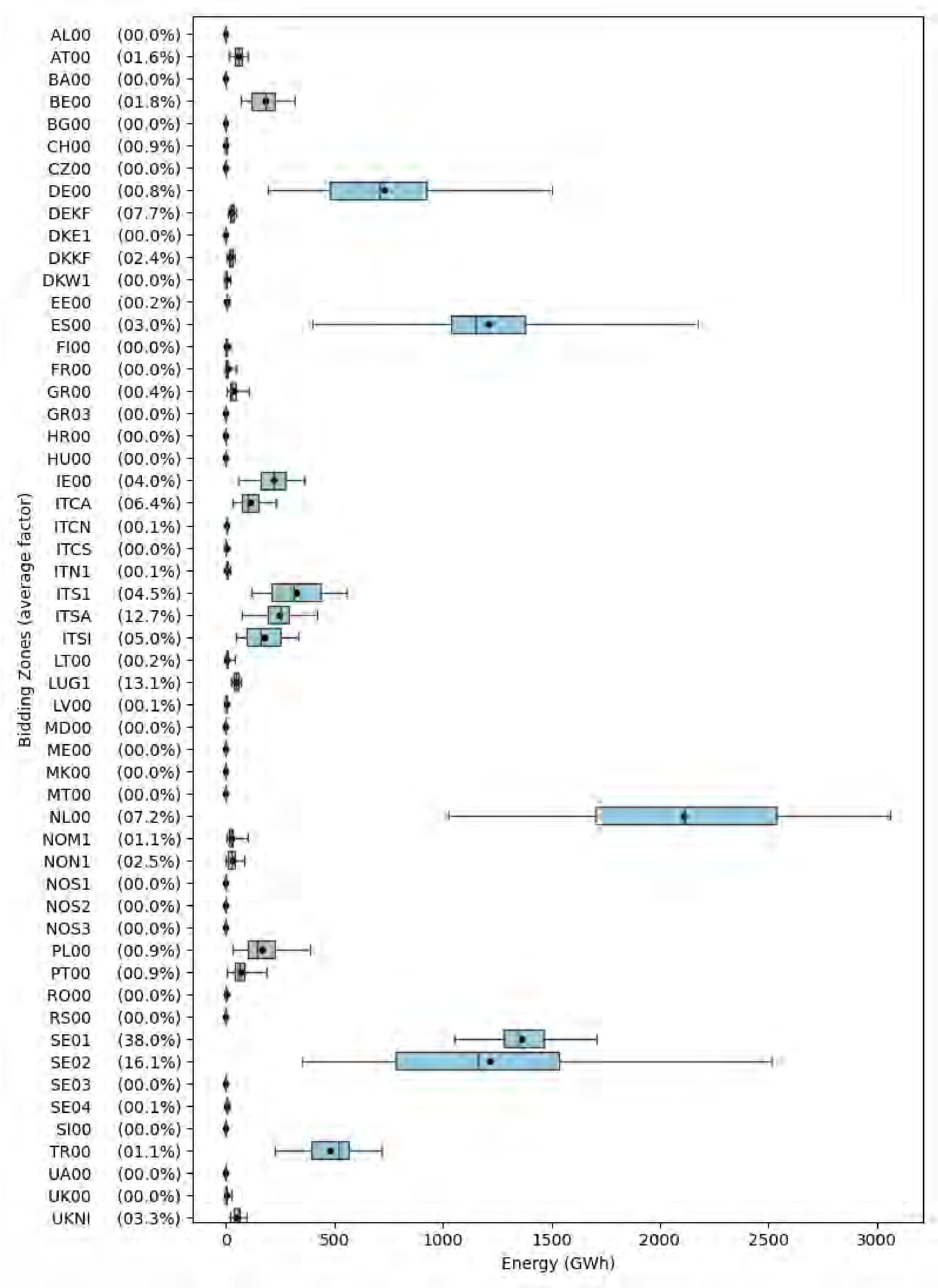

Figure 22: Average total energy not used and average excess factor (per bidding zone)

The boxplot shows the variation of the absolute amount of excess energy over all different weather scenarios, whereby the whiskers should be interpreted as minimum and maximum values, the edges of each box represent the 25th and the 75th percentile, the line inside the box the median, and the black dot depicts the average. The left column shows the average excess production factor over the season (excess energy divided by total produced energy) per zone across all weather scenarios.

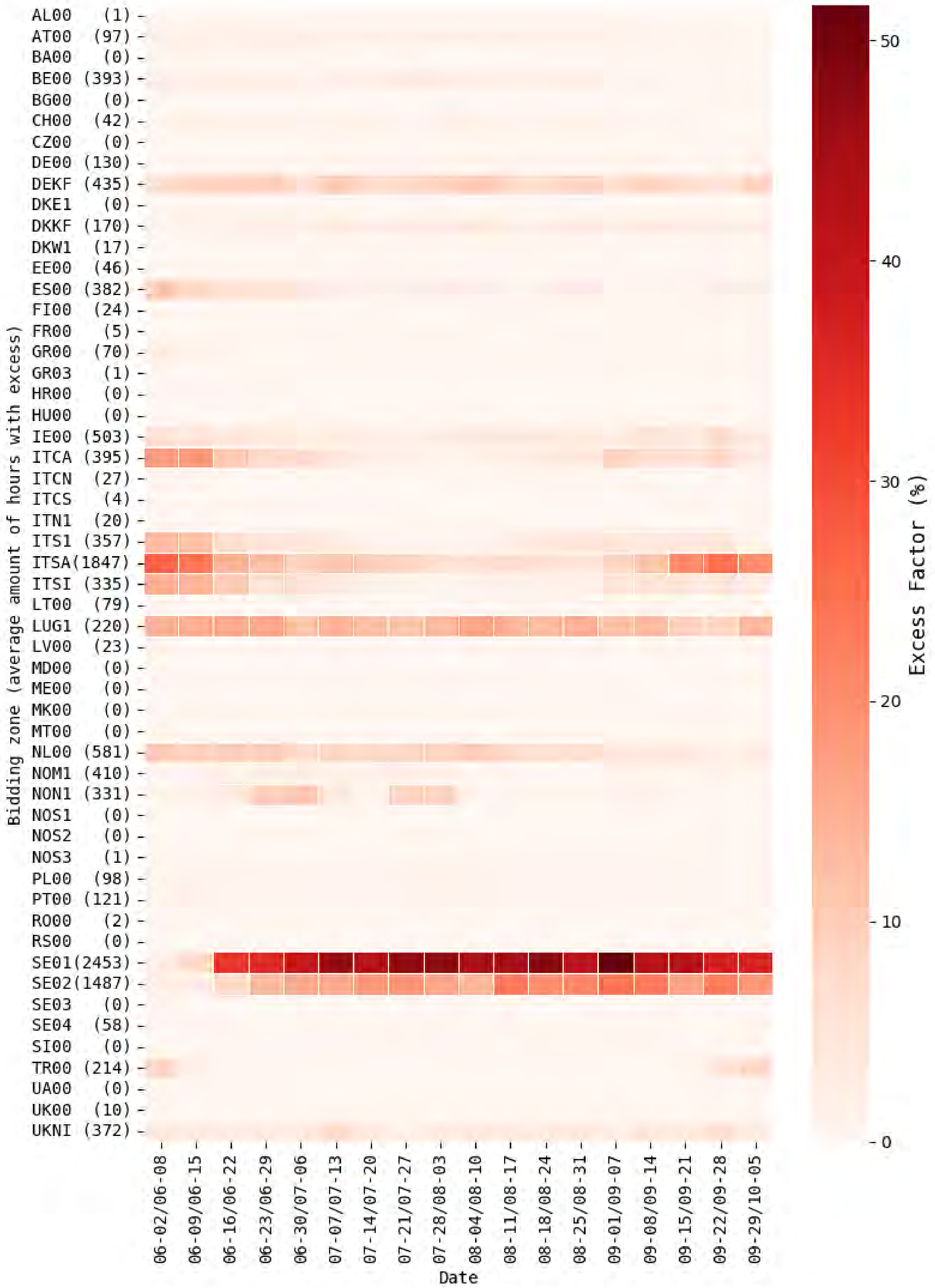

Figure 23: Weekly distribution of the unused energy and average number of hours of excess generation (per bidding zone)

The heatmap shows the renewable excess factor (relative value) in weekly resolution over the summer season and provides insights into the average number of hours where renewable excess occurs across all different weather scenarios.

The boxplot shows that the Netherlands, the northern part of Sweden, Spain, and Germany have the highest absolute renewable excess. However, the amount is only significant in relation to renewable fleet for Sweden (more than 10%). The heatmap shows the distribution over weeks.