Summer Outlook 2026

Winter Outlook 2025-2026 Review

entsoe

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 interconnected power system in all time frames at the 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.

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1. Executive summary

ENTSO-E's Summer Outlook 2026 identifies no substantial immediate adequacy risk in continental Europe, the Nordics, or Great Britain, but notes several important points that require attention. Systems that are isolated or have limited interconnection (Ireland,[1] Malta,[2] and Cyprus) will require close monitoring.

Substantial risks are identified in Moldova due to current limitations in natural gas supply. Ukraine's power system does not show direct adequacy risks based on available projections and the normal seasonal outlook modelling approach. These figures must be considered with care, given the high uncertainty of all projections related to the region's geopolitical context.

The geopolitical situation in the Middle East, including the Strait of Hormuz, has increased uncertainty in global energy markets and supply routes. No significant concern regarding electricity adequacy is currently expected in Europe for the summer period. Further attention is especially needed in preparations for the upcoming winter period. The situation is being closely monitored.

The eventual adequacy situation in Ireland will depend on operational conditions, in particular unplanned outages of conventional generation and especially wind generation. Non-market resources (NMR) are available and will significantly alleviate the risks.

Some residual risks are identified in the more isolated Mediterranean islands of Malta and Cyprus. Issues 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 NMR to ensure security of supply, while Cyprus has no interconnection to other power systems and must rely on domestic supply.

Moldova exhibits a structural adequacy risk for summer 2026. The risk is mainly driven by current limitations in natural gas supply, which affect the availability of thermal generation, including the MGRES power plant. Moldova also remains vulnerable due to its reliance on imports, weak interconnections, dependence on transmission through the Transnistria region, and exposure to disturbances in the Ukrainian power system.

The surplus generation from variable RES is expected to exceed demand during periods of high renewable generation combined with low demand, thus increasing countries' export needs and the need for renewable curtailment in some areas. This Summer Outlook identifies renewable curtailment in several study zones, with the most significant volumes in absolute terms observed in northern Sweden and Germany. These situations will require careful operational management, especially during periods when neighbouring countries may also experience excess renewable generation.

The Summer Outlook is accompanied by a retrospective of the previous winter. In general, no adequacy issues were observed during winter 2025–2026, despite significant variability in weather conditions. December 2025 was predominantly mild, January and February 2026 were colder in several regions, particularly in Northern and Eastern Europe, and March 2026 was markedly warmer than average across almost the entire continent. The system remained resilient overall, and no adequacy issues were reported.

Special notes:

Since March 2022, Ukraine and Moldova have been synchronised with the continental European power system. The situation in Ukraine remains uncertain due to the continuing risk of attacks on power

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[1] *Comprising EIRGRID and SONI.*

[2] *In Malta, adequacy issues identified in the market simulations of Summer Outlook 2026 are covered by the out-of-market capacity on the island.*

generation and grid infrastructure. Since the start of commercial electricity exchanges between Ukraine, Moldova, and their European neighbours in June 2022, TSOs have continuously assessed system conditions and sought to maximise import and export capacity while ensuring system stability and operational security. In July 2025, ENTSO-E transferred responsibility for determining import and export capacity to the Eastern Europe capacity calculation region.

The geopolitical situation in the Middle East, including the Strait of Hormuz, has increased uncertainty in global energy markets and supply routes. No significant concern regarding summer electricity adequacy is currently expected in Europe. The latest supply outlook from the European Network of Transmission System Operators for Gas (ENTSOG) indicates that gas availability, including for power generation, is expected to remain adequate over the summer period. Persistent high gas prices and narrower price spreads may constrain the ability to refill storage, potentially increasing risks for the following winter period, which will be further analysed in the next ENTSOE and ENTSOG Winter Outlook.

In addition to the ENTSO-E seasonal outlook assessments, TSOs continuously monitor external drivers and coordinate at the European level to assess potential risks to electricity security of supply and take appropriate mitigation measures in coordination with authorities.

2. Introduction

General purpose of Seasonal Outlook reports

ENTSO-E's Seasonal Outlook reports investigate the security of electricity supply at the pan-European level before each winter and summer period. They are released twice yearly, with a Summer Outlook in June and a Winter Outlook in December. The role of the Outlook is to identify when and where system adequacy – the balance between electricity supply and demand – is at risk. Outlook reports are not forecasts of the future, but rather identify potential resource adequacy risks at a specific point in time for the upcoming season, which can be proactively addressed with preparation or mitigation measures. The risks identified are based on assessing a reference scenario and various sensitivities, considering uncertainties that could arise.

Outlook reports are the result of cooperation between 40 European electricity TSOs, fostering collaboration across Europe and between regional and national stakeholders. Due to their pan-European scope, Outlook reports complement the analysis carried out in national and regional assessments, which provide a more detailed picture of adequacy at the local level. Seasonal Outlook studies model resource adequacy without considering specific operational constraints, such as grid stability or voltage.

Conducting Seasonal Outlook studies (seasonal adequacy assessments) is one of ENTSO-E's legal mandates as specified in the Clean Energy Package and defined in Article 9(2) of the Risk Preparedness Regulation (Regulation (EU) 2019/941). ENTSO-E performs this assessment to inform national authorities, TSOs, and relevant stakeholders of the potential risks related to electricity supply security in the coming season. Seasonal Outlook studies reflect the implementation of the Methodology for Short-Term and Seasonal Adequacy Assessments[3] developed by ENTSO-E under Article 8 of the Risk Preparedness Regulation and as approved by the Agency for the Cooperation of Energy Regulators (ACER) on 6 March 2020. Seasonal Outlook studies published prior to 2020 followed a different methodology (the deterministic approach).

The interconnected system is a crucial resource for wider system adequacy. ENTSO-E's Summer Outlook provides results for all ENTSO-E member systems. Data inputs and assumptions from neighbouring interconnected countries are also integrated into the modelling.

Coordination at the national, regional, and European levels

Cross-border cooperation and close coordination at all levels will be essential to ensure that the European power system maintains its balance between supply and demand this summer.

European level

- Exchange on risk preparedness plans via the Electricity Coordination Group and Gas Coordination Group;
- Summer Outlook and updates: updates to ENTSO-E's Summer Outlook are possible if significant changes affecting the European power system occur this summer;
- Following the Summer Outlook, the short-term adequacy (STA) process monitors the coming seven days in a rolling window to detect any adequacy issues at the cross-regional (pan-EU) level;

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[3]

- ENTSO-E ensures weekly operational coordination between all interconnected TSOs and regional coordination centres (RCCs) to enable swift communication and alignment – when necessary – for operational processes;
- Communication between ENTSO-E and ENTSOG to align assumptions and messages between the Winter Outlook for gas and electricity.

Regional level

- Following the cross-regional STA process, a regional STA process is implemented if any scarcity situations are detected. This process is managed by RCCs, with the participation of the relevant TSOs, to coordinate the proposal for adequacy remedial actions at the regional level;
- TSOs and RCCs will coordinate throughout the summer to maximise cross-border capacities regionally through an established operational planning coordination (OPC) process.

National level

- TSOs conducted national adequacy studies in parallel with the ENTSO-E Summer Outlook, which may use different sensitivities or focus on extreme cases where multiple stress elements coincide. National studies can also consider more detailed constraints, such as internal transmission bottlenecks.
- Each member state has developed a dedicated Risk Preparedness Plan, which includes mitigation measures. The member states set up coordination with governments, national regulatory authorities (NRAs) and key stakeholders to operate these mitigation measures.

3. Overview of the power system in summer 2026

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 photovoltaic production across Europe, with total installed capacity increasing by 22% over one year.[4]

Battery energy storage system capacity nearly doubled (increased by 107%) compared to the previous summer but remains relatively small in scale, with only 29 GW of installed capacity throughout Europe.

Installed capacity of high carbon-footprint power units, such as hard coal, declined by 6 GW (−11%), gas declined by 6 GW (−3%), while lignite remained stable and oil-fired capacity increased slightly by 1 GW (+11%).

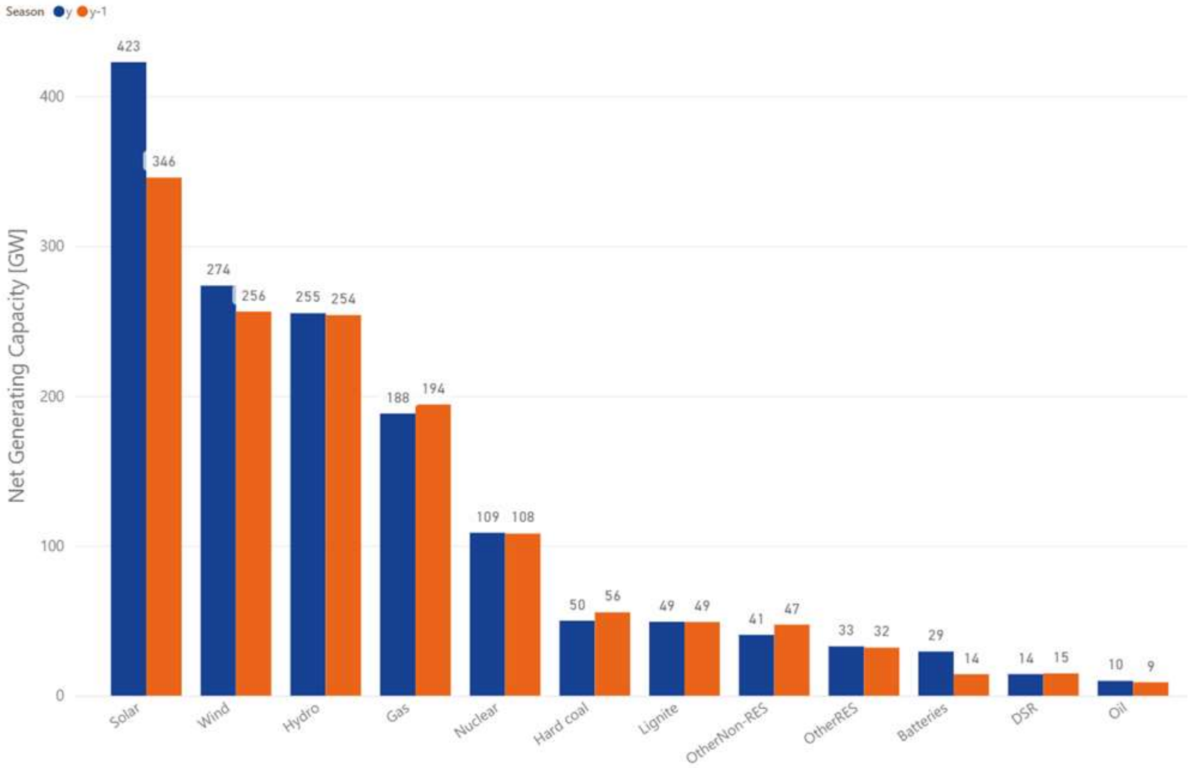

Figure 1: Generation capacity change over one year: Summer Outlook 2026 vs Summer Outlook 2025

Figure 2 shows that generation capacity in Europe is increasing during summer 2026, mainly due to the expansion in renewable capacity generation. Thermal generation is decreasing due to the decommissioning of hard coal plants, which is not balanced by increased gas-fired power plant generation capacity. However, in some exceptional cases, decommissioned units might be contracted as NMR to support adequacy or

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[4] *To ensure a proper comparison with last year, solar data from TR and SK were removed. Data from GB were excluded due to a change in the scope of the analysis.*

under other non-market schemes to provide system services. Figure 2 presents the study zones with sizeable changes in this summer period.

Figure 2. Sizeable capacity evolution in summer 2026

Figure 3 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 Malta (MT) are especially dependent on imports when renewable generation is low.

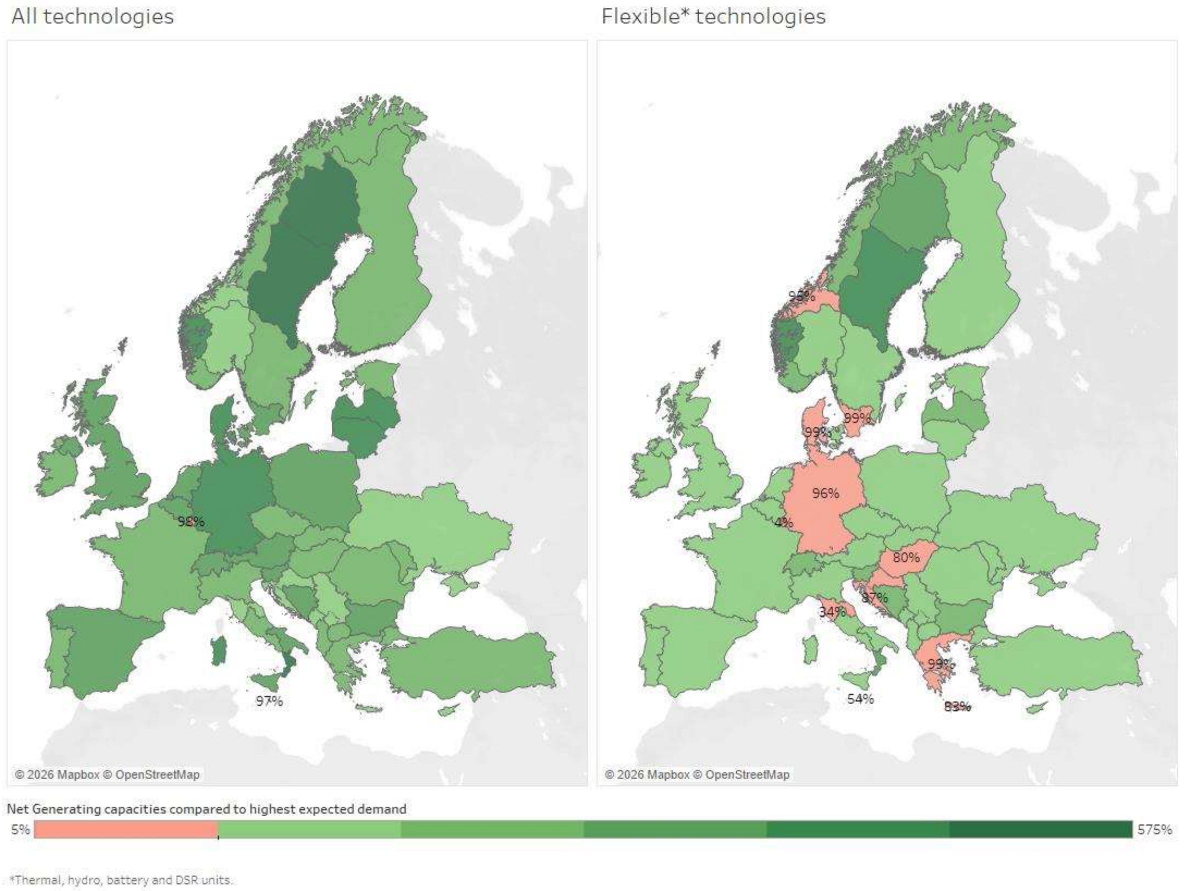

Figure 3: Ratio between net generating capacity and highest expected demand

Figure 4 shows the generation capacity mix for each country. In addition, the highest expected demand[5] 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 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. a few hours in a day) or at varying capacity. More DSR is likely to be available during peak times, although this is not guaranteed.

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[5] *The highest expected demand is computed by taking the highest value of the hourly demand 95th percentiles.*

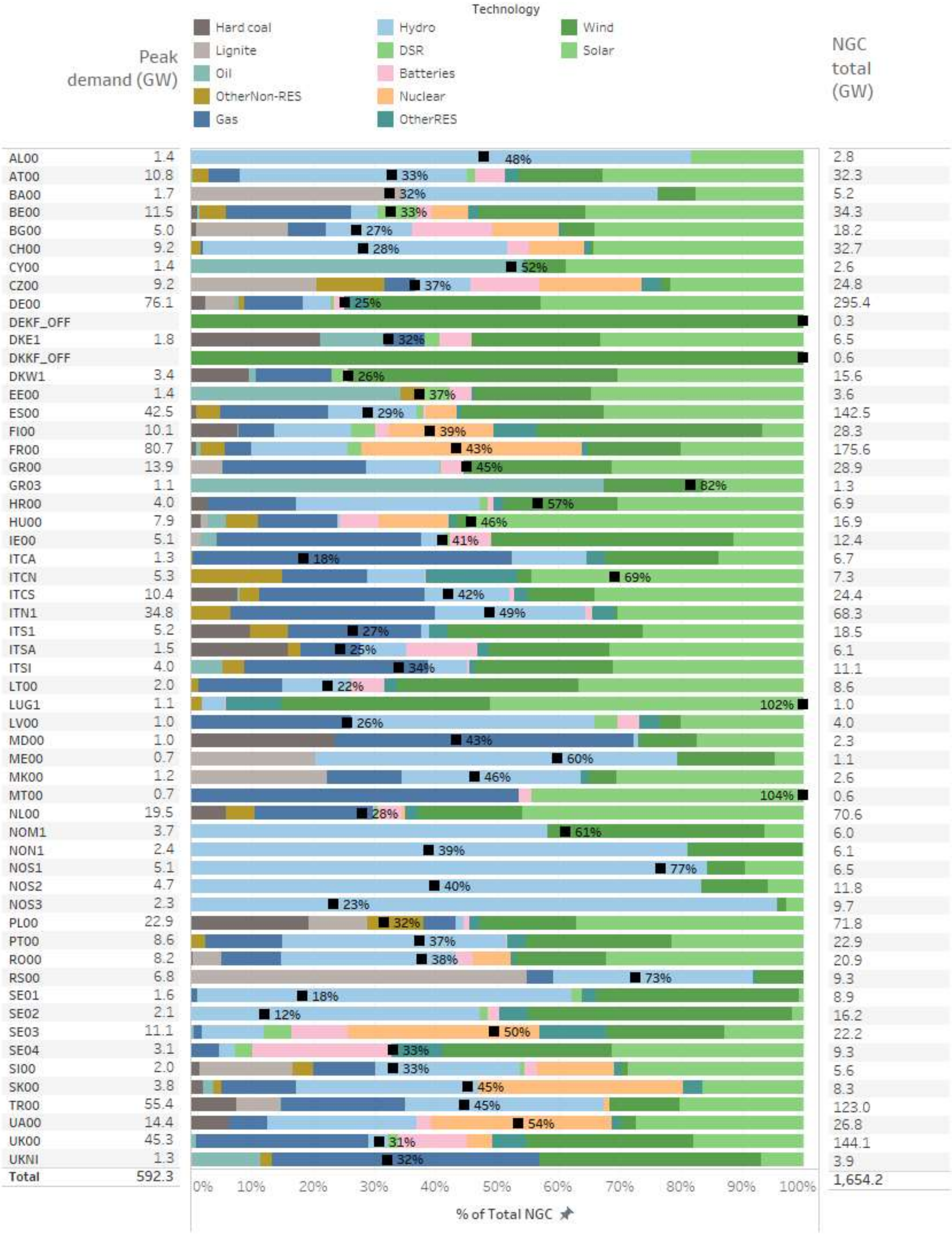

Figure 4: Generation capacity mix at the beginning of summer 2026 per study zone

Figure 5 shows which study zones have 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 address adequacy challenges. Five countries utilise NMR. From largest to smallest NGC, these are Germany, Poland, Ireland, Malta, and Albania. This report also assesses whether these resources are sufficient to address identified adequacy issues (c.f. "Adequacy situation in summer 2026" section).

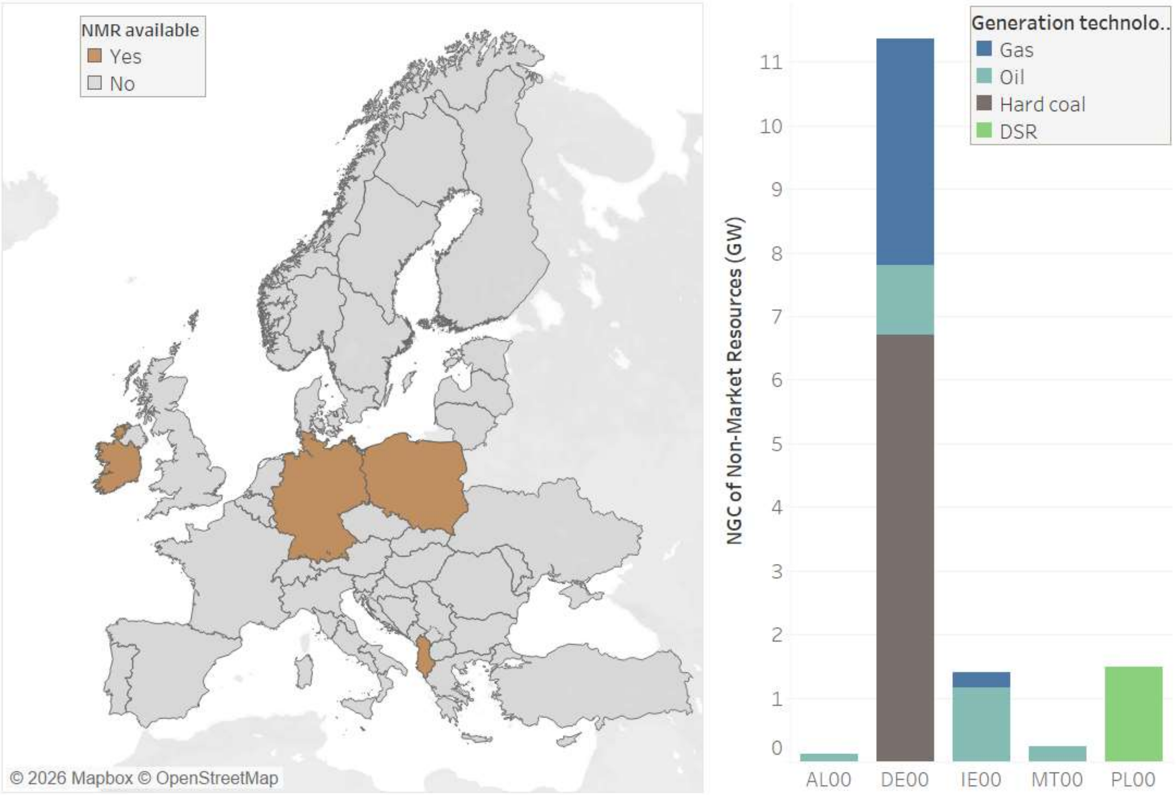

Figure 5: Non-market resources for coping with adequacy challenges in Europe[6] [7]

Planned unavailability of generation

Figure 6 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 2026, with gas ranking second, followed by hard coal and lignite.

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[6] *Parts of German NMR have a different primary purpose than coping with resource adequacy risks, such as grid stabilisation. In the event of adequacy issues in Germany, these might already be partly exhausted for their primary purpose.*

[7] *In Portugal, the CCGT power plant at Tapada do Outeiro (990 MW) is considered an out-of-market resource, with other operational activities serving as its primary purpose; therefore, it was not considered in the simulations.*

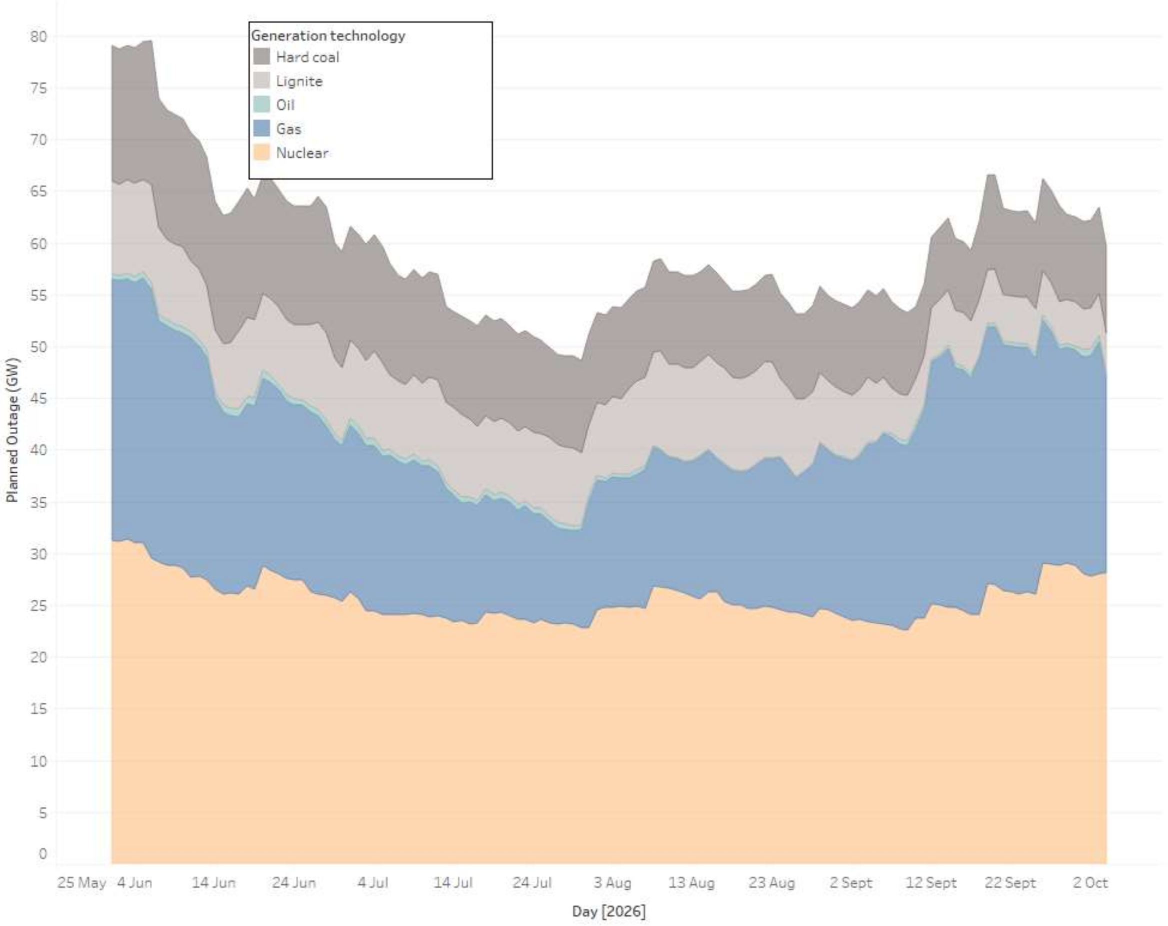

Figure 6: Planned unavailability of thermal units

Planned unavailability in southern countries tends to decrease during the warmest months, when the highest demand is expected (i.e. July and August). This can be observed in the cases of Italy or Greece (GR00), as shown in Figure 7. 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.

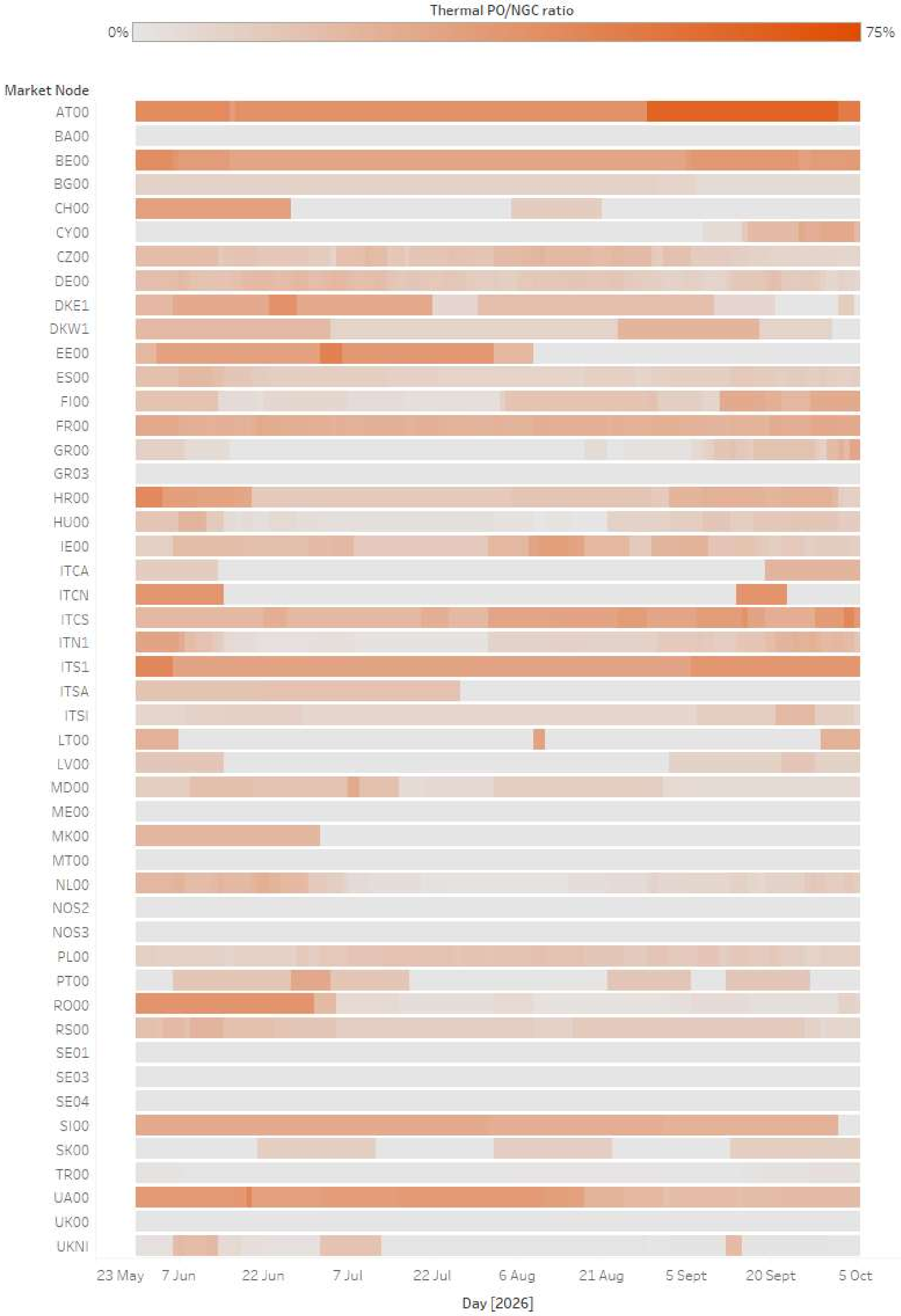

Figure 7: Weekly distribution of thermal planned unavailability relative to thermal NGC

Hydro availability

Figure 8 shows hydro storage level expectations compared to previous summers. Total expected hydro storage levels in June 2026 are above those of June 2024 (+19%) but below those of June 2025 (−18%).

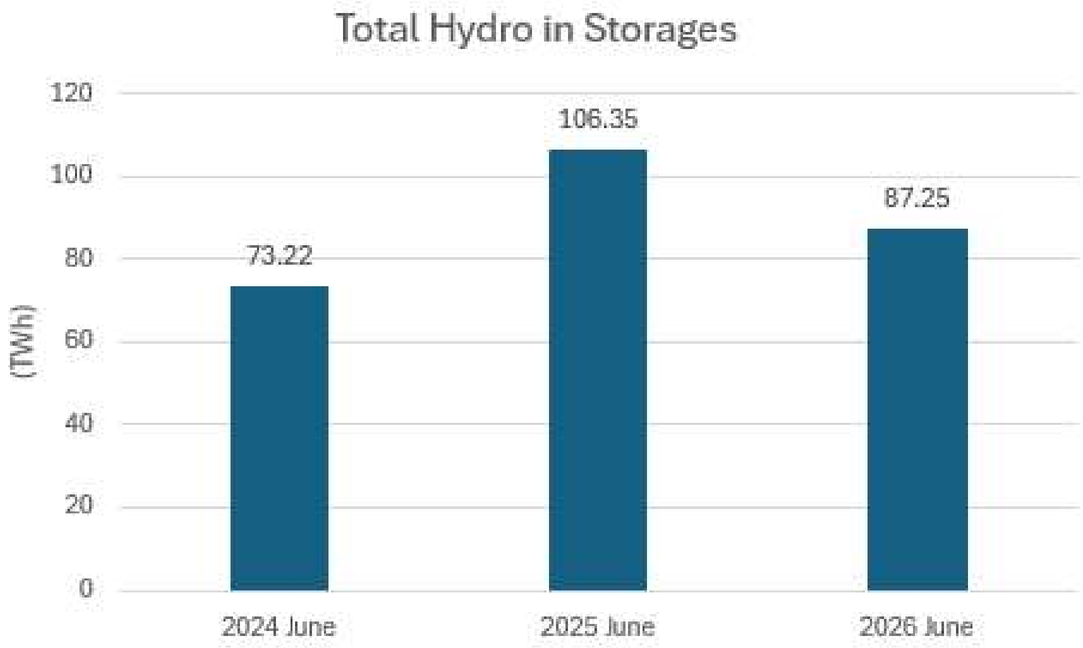

Figure 8: Total hydro storage availability in June in Europe (including GB and excluding UA, TR, and MD)

Demand overview

Overall European electricity demand is expected to be higher (2.5%) than the previous year (Figure 9), but comparable with that of 2024–2025.

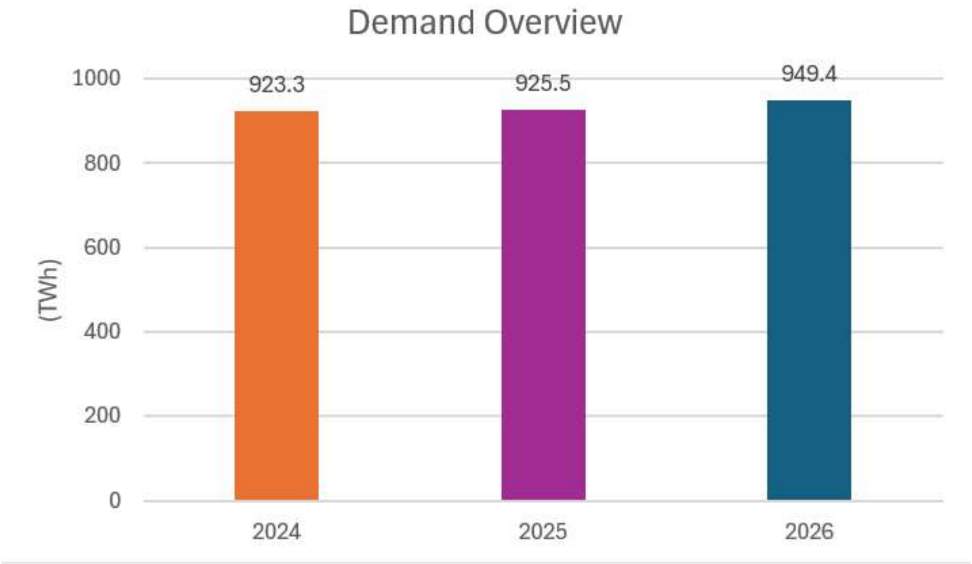

Figure 9: Demand overview: Total demand in summer 2024 (orange), summer 2025 (purple), and summer 2026 (blue). Demand scope includes all of Europe (excluding GB, UA, MD, and TR)

Figure 10 displays a heat map by study zone comparing the expected consumption in each week with the highest expected weekly consumption in summer 2026. 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.

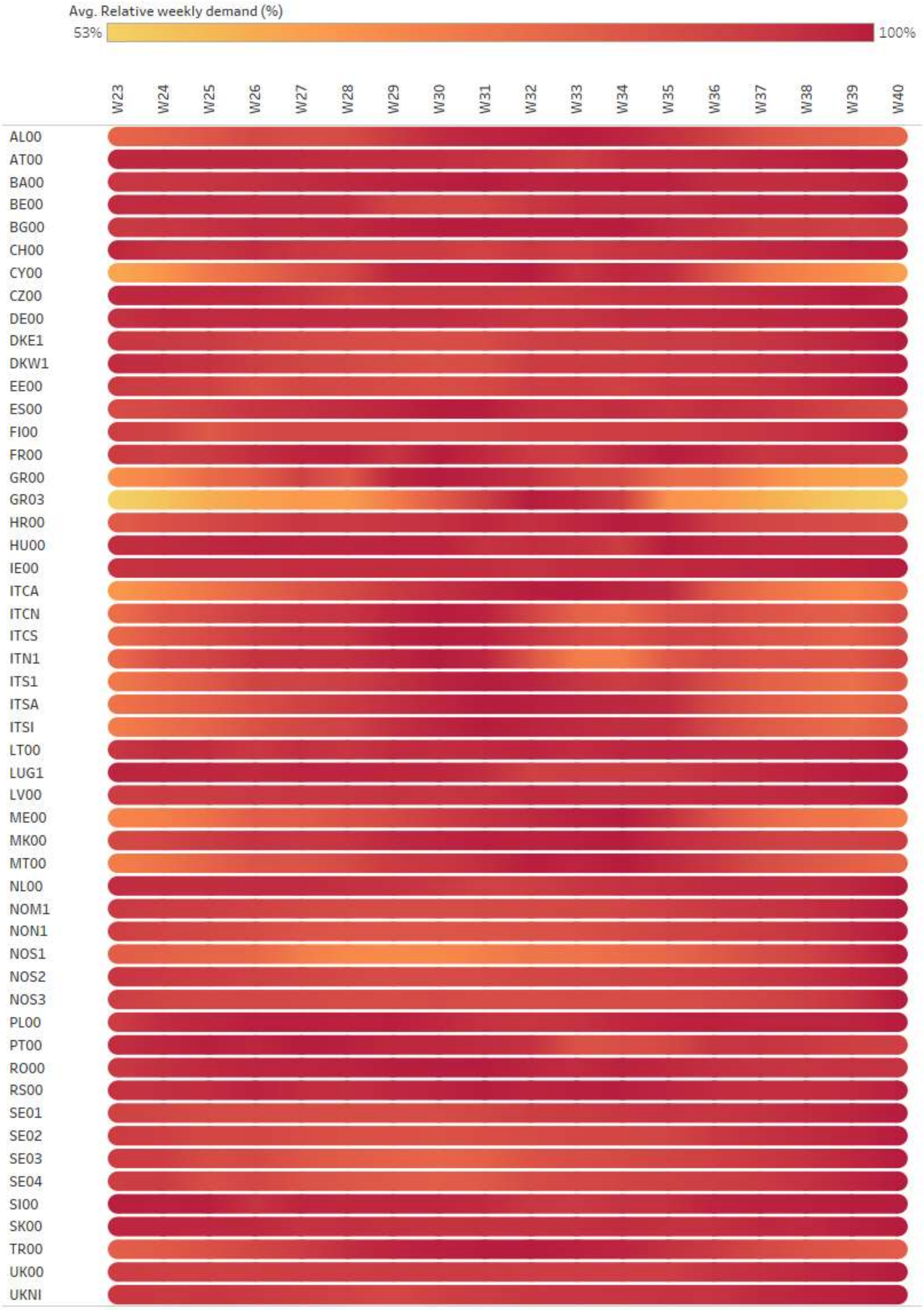

Figure 10: Demand overview: evolution over summer 2026

Figure 11 shows the workday consumption patterns per study zone by plotting the average demand relative to the highest average demand in summer 2026. 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 entire day.

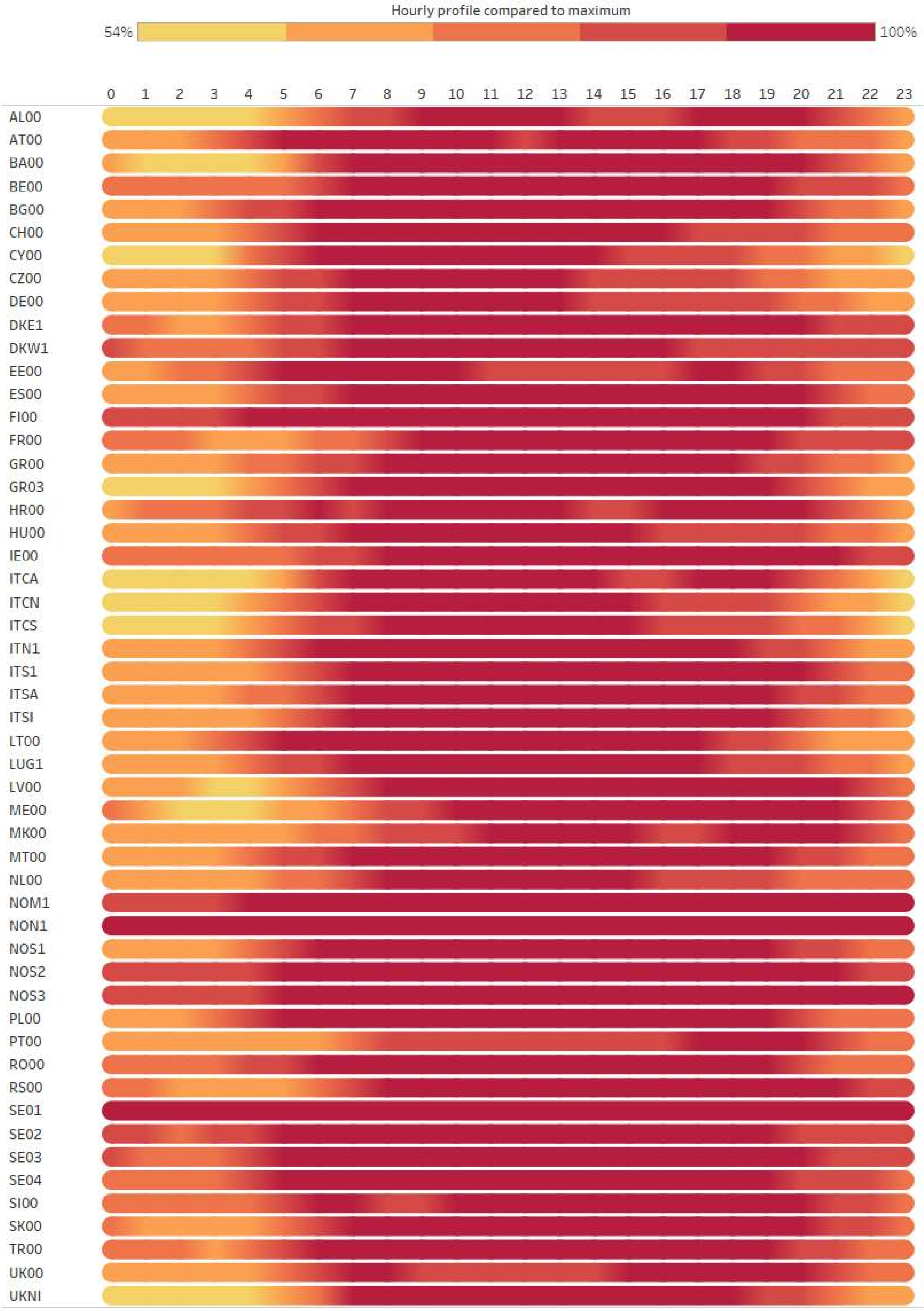

Figure 11: Demand profile overview during Mondays–Fridays in summer 2026[8]

Network overview

Figure 12 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 by itself 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 3), 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 constrain import capacities even further. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, although their contribution is assessed in adequacy simulations.[9]

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[8] UTC time convention was used.

[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 was not collected or used in the adequacy models.

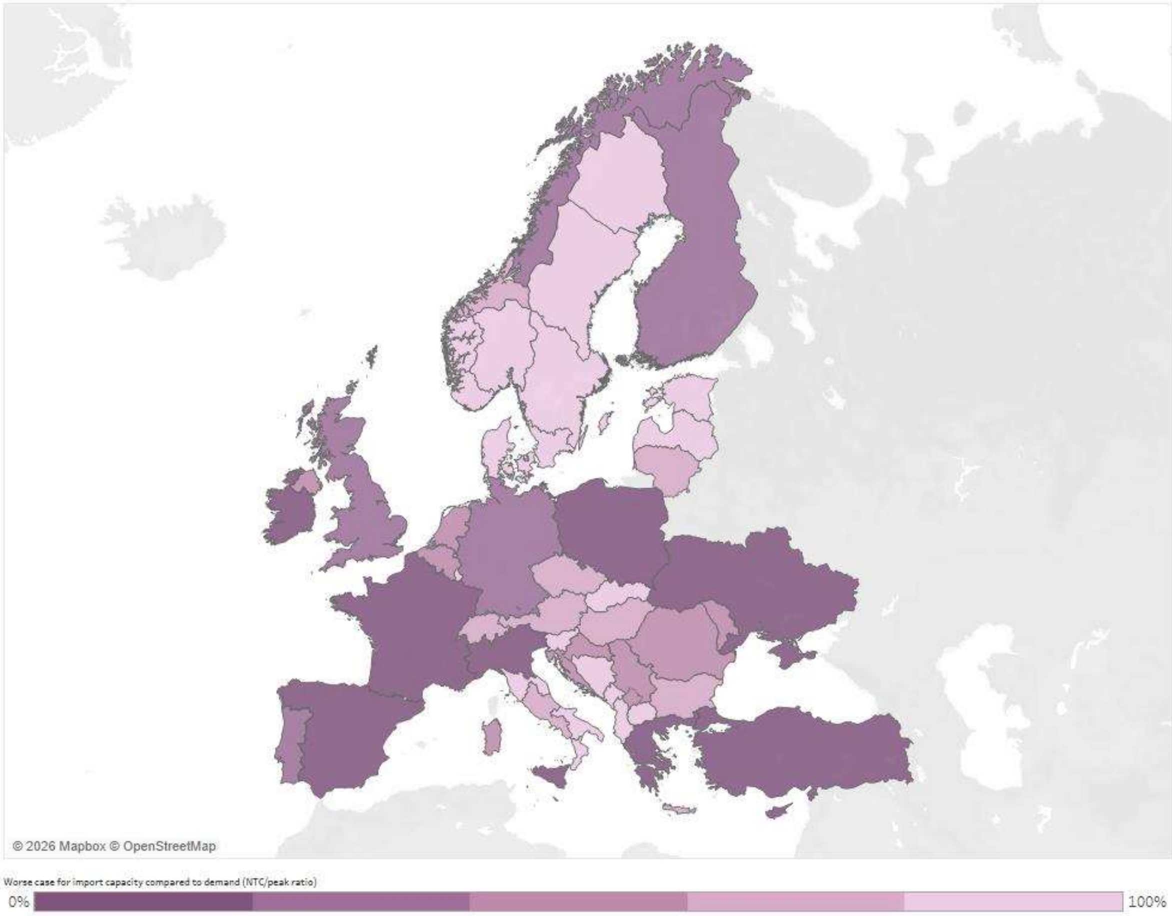


Figure 12: Import capacities per study zone: ratio between lowest import capacity and highest expected demand

Adequacy situation in summer 2026

Reference scenario

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 whether they are sufficient to address 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 2026 (Figure 13) highlights certain adequacy risks in Cyprus, Ireland, Malta, Northern Ireland, and Moldova. NMR significantly mitigate risks in Malta, and in Ireland where they are available. However, risks remain largely unchanged in Cyprus and Moldova, as these resources do not exist and the system is either not interconnected or only weakly interconnected with the rest of Europe. Denmark and Northern Ireland experience low amounts of EENS.

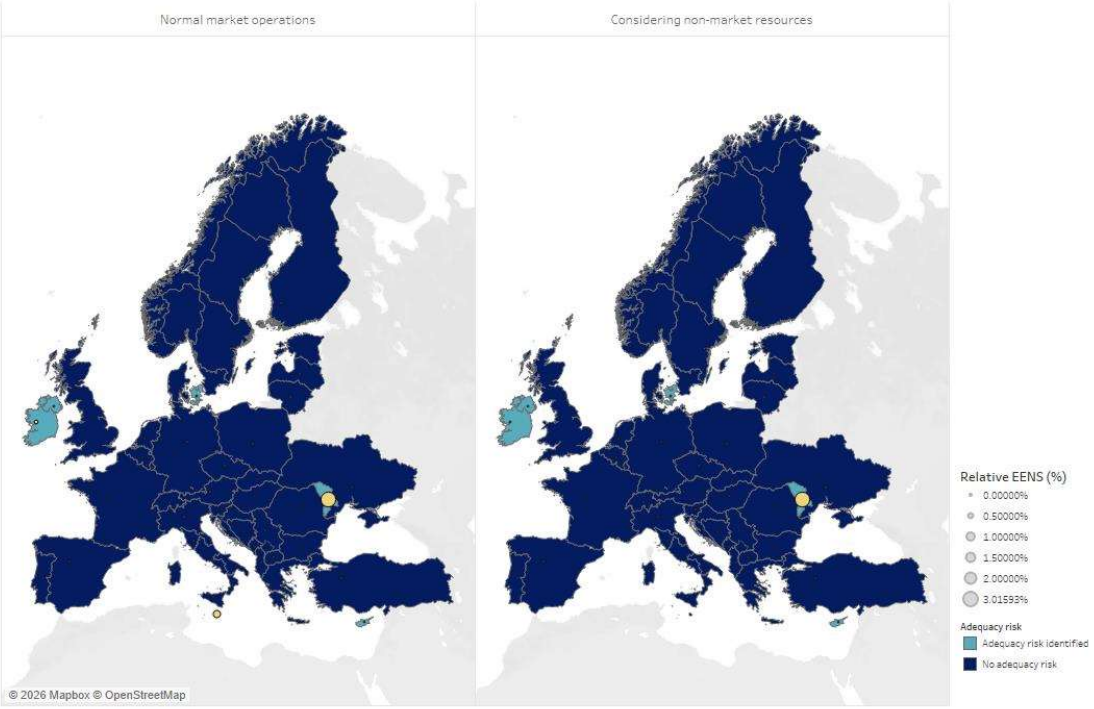


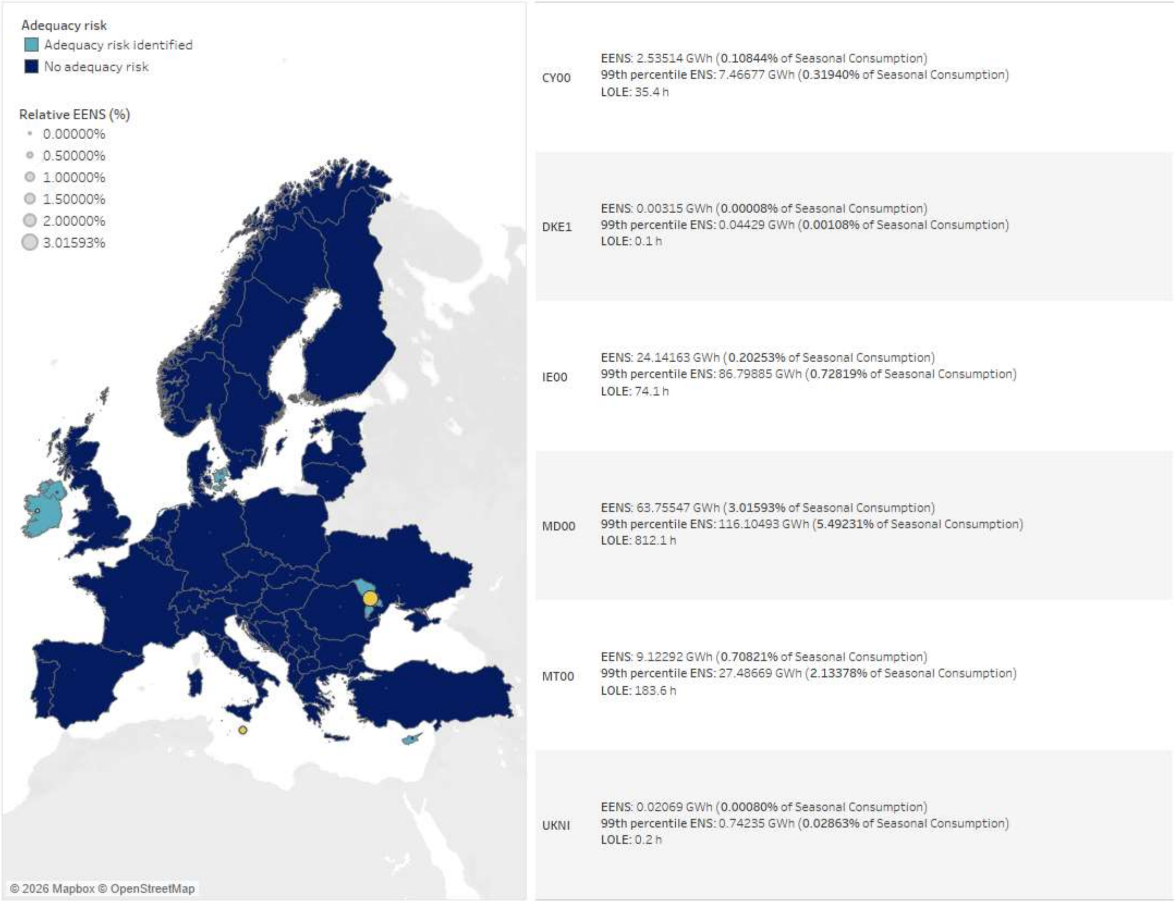
Figure 13: Adequacy overview

The state of the power system is constantly evolving and has changed since the data collection (performed from December 2025 to March 2026). For this reason, risks are continuously being monitored by TSOs and RCCs.

Focus on adequacy under normal market conditions

Figure 14 presents the adequacy situation under normal market operations. For most countries, no adequacy risks are identified, except for Cyprus (CY00), Ireland (IE00), Malta (MT00), Northern Ireland (UKNI), Eastern Denmark (DKE1), and Moldova (MD).

Cyprus has no interconnection to the European continental network, while Ireland, Northern Ireland, Malta, and Moldova have limited ones. These risks suggest that systems may need to rely on NMR or operational measures to cope with supply challenges to prevent load shedding.



CY00	EENS: 2.53514 GWh (**0.10844%** of Seasonal Consumption) **99th percentile ENS:** 7.46677 GWh (**0.31940%** of Seasonal Consumption) LOLE: 35.4 h
DKE1	EENS: 0.00315 GWh (**0.00008%** of Seasonal Consumption) **99th percentile ENS:** 0.04429 GWh (**0.00108%** of Seasonal Consumption) LOLE: 0.1 h
IE00	EENS: 24.14163 GWh (**0.20253%** of Seasonal Consumption) **99th percentile ENS:** 86.79885 GWh (**0.72819%** of Seasonal Consumption) LOLE: 74.1 h
MD00	EENS: 63.75547 GWh (**3.01593%** of Seasonal Consumption) **99th percentile ENS:** 116.10493 GWh (**5.49231%** of Seasonal Consumption) LOLE: 812.1 h
MT00	EENS: 9.12292 GWh (**0.70821%** of Seasonal Consumption) **99th percentile ENS:** 27.48669 GWh (**2.13378%** of Seasonal Consumption) LOLE: 183.6 h
UKNI	EENS: 0.02069 GWh (**0.00080%** of Seasonal Consumption) **99th percentile ENS:** 0.74235 GWh (**0.02863%** of Seasonal Consumption) LOLE: 0.2 h

Figure 14: Adequacy risk overview

Figure 15 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 15 is the probability of having loss of load during the week. It is calculated as [loss of load expectation (LOLE) (h)]/168, where 168 is the number of hours in a week. The highest weekly LOLP in CY00 is 2.089%, meaning that the week with the most hours of LOLE [h] over the entire simulated period has a rate of 2.089% of hours with adequacy issues.

The right part of Figure 15 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 (WSs) and forced outages (FOs) divided by the maximum LOLP over all WSs, FOs, and weeks.

In Ireland (IE00), LOLP arrives in scenarios of high load combined with high unplanned outages of conventional generation and interconnection. Tight generation margins are expected in Ireland (IE00) at times during the summer during periods of low renewables and low interconnector imports, with the highest adequacy risk predicted in mid-August. The actual adequacy situation in Ireland will depend on operational conditions such as unplanned outages and especially renewable generation.

Northern Ireland (UKNI) shows an extremely low probability of adequacy issues distributed over the entire summer, observing LOLP in only the most extreme WS and associated tight margins in Ireland (IE00).

The Cypriot system (CY00) has no interconnection to the other power systems and hence must 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 the end of August.

The adequacy situation in Malta (MT00) should be monitored throughout the summer, with special attention in August 2026 during 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.

Denmark (DKE1) shows low but non-zero LOLP. The scarcity events are not structural but arise under specific combinations of conditions, notably the simultaneous outage of two transmission lines combined with periods of low renewable generation. These situations occur only in a limited number of Monte Carlo samples and WSs, indicating that LOLP is driven by coincidental and adverse configurations rather than by a systematic adequacy issue in the zone. However, it should be noted that the FO rates of those lines are high (≈9%). The risk of two simultaneous line outages is non-negligible.

Moldova (MD) exhibits a high LOLP, with unserved energy occurring frequently across the Summer Outlook simulations. ENS is observed in a large number of hours and across many WSs and Monte Carlo samples, indicating a structural adequacy issue rather than isolated coincidental events. The results are primarily driven by the strong reliance on a limited set of thermal resources, which are significantly affected by derating and fuel constraints. While the connection to Ukraine provides some relief and reduces the severity of ENS, the remaining levels of ENS and LOLP remain substantial, pointing to a persistent vulnerability of the Moldovan system under the simulated conditions.

The adequacy assessment does not identify any ENS in Ukraine. However, given the high level of uncertainty affecting the availability of generation and grid infrastructure, the adequacy outcome for Ukraine must be interpreted with particular caution. The absence of ENS in the simulations reflects the modelled system balance under assumed technical conditions and does not capture external risks that may materialise outside the scope of the adequacy methodology. These risks are not endogenous to system operation but arise from exogenous factors linked to the geopolitical context.

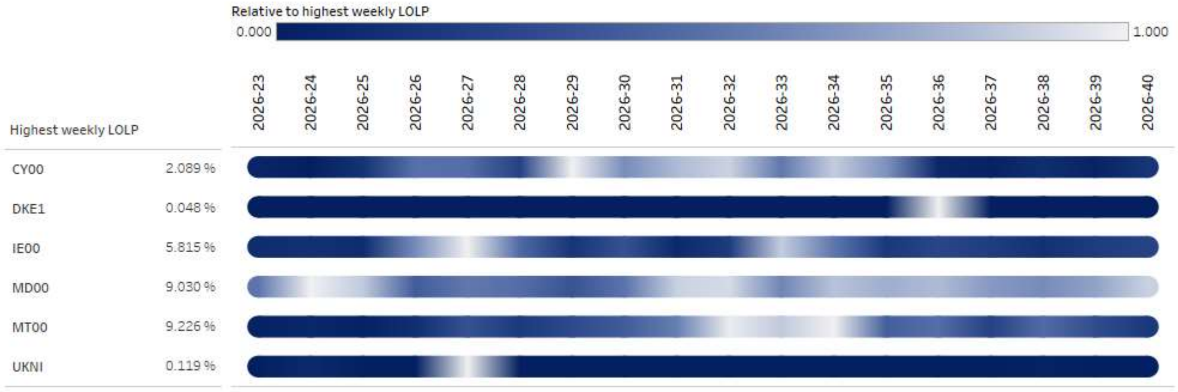
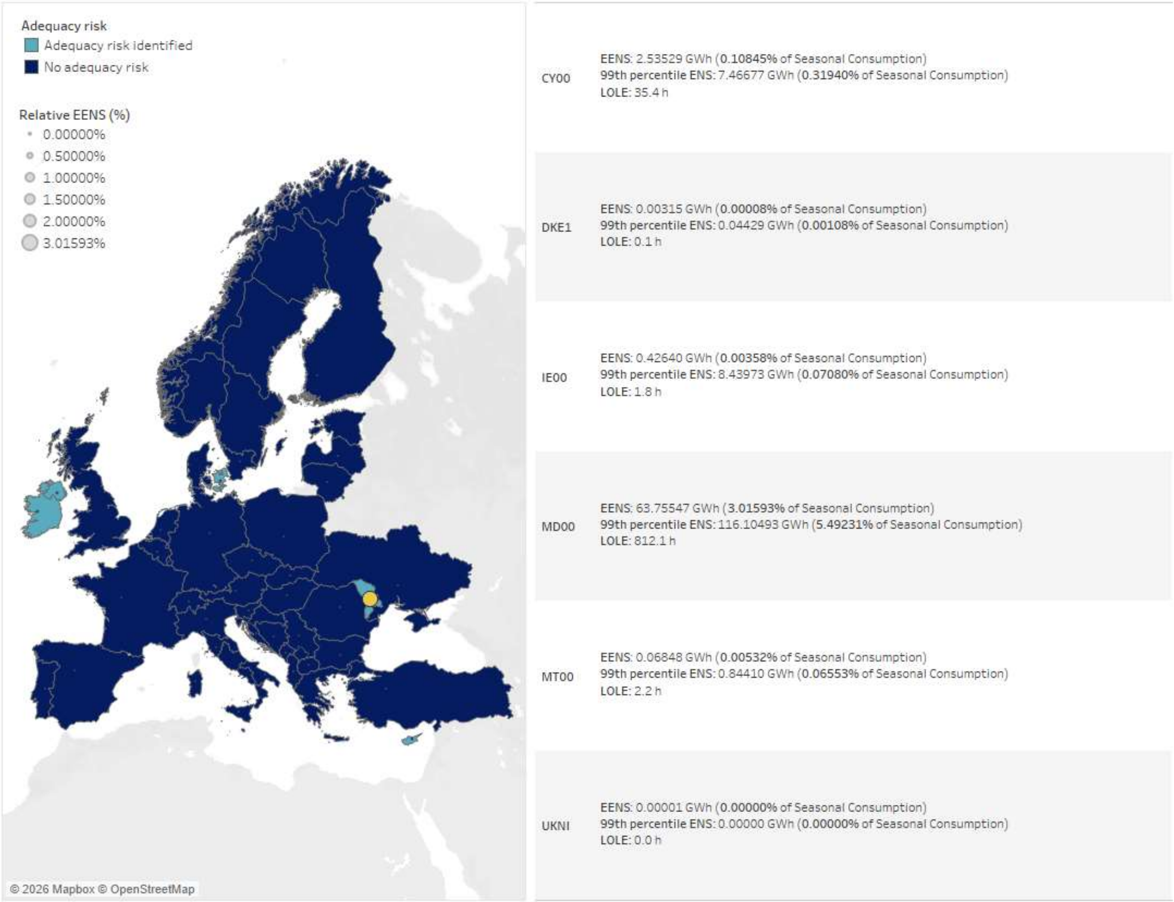


Figure 15: Adequacy weekly insights

Focus on non-market resources

Figure 16 presents the adequacy conditions with NMR. The magnitude of the risks (EENS) significantly decreases for Ireland, Northern Ireland,[10] and Malta compared to normal market operation, as they rely on dedicated NMR (c.f. Figure 5), whereas the magnitude remains the same for Denmark, Cyprus, and Moldova.



CY00	EENS: 2.53529 GWh (**0.10845%** of Seasonal Consumption) **99th percentile ENS:** 7.46677 GWh (**0.31940%** of Seasonal Consumption) LOLE: 35.4 h
DKE1	EENS: 0.00315 GWh (**0.00008%** of Seasonal Consumption) **99th percentile ENS:** 0.04429 GWh (**0.00108%** of Seasonal Consumption) LOLE: 0.1 h
IE00	EENS: 0.42640 GWh (**0.00358%** of Seasonal Consumption) **99th percentile ENS:** 8.43973 GWh (**0.07080%** of Seasonal Consumption) LOLE: 1.8 h
MD00	EENS: 63.75547 GWh (**3.01593%** of Seasonal Consumption) **99th percentile ENS:** 116.10493 GWh (**5.49231%** of Seasonal Consumption) LOLE: 812.1 h
MT00	EENS: 0.06848 GWh (**0.00532%** of Seasonal Consumption) **99th percentile ENS:** 0.84410 GWh (**0.06553%** of Seasonal Consumption) LOLE: 2.2 h
UKNI	EENS: 0.00001 GWh (**0.00000%** of Seasonal Consumption) **99th percentile ENS:** 0.00000 GWh (**0.00000%** of Seasonal Consumption) LOLE: 0.0 h

Figure 16: Adequacy risk overview: considering NMR

The LOLP in Malta is significantly lower when NMR are considered (Figure 17) and shows only occasional risks.

Ireland also sees almost no adequacy issues, with only a handful of very small instances of adequacy concerns remaining.

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[10] *Northern Ireland does not have NMR, and the decrease in risks comes from using the resources of Ireland. NMR are meant for national use. However, the assessment considers pan-European cooperation when activating NMR, which means that NMR in one country are also considered in another during scarcity (but also considering network limitations). The actual activation of NMR abroad might depend on the existing legal framework.*

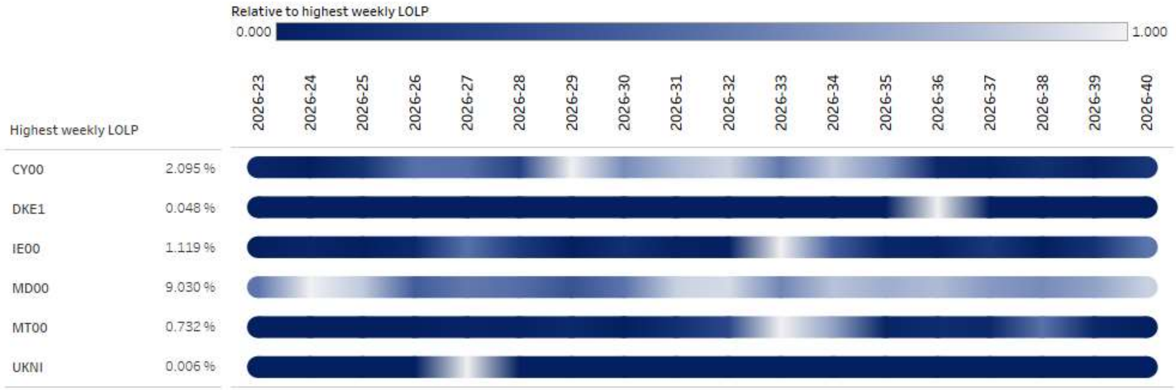

Figure 17: Adequacy weekly insights: considering non-market resources

Figure 18 represents the impact of NMR, demonstrating that NMR can largely address adequacy concerns in Malta and Ireland.

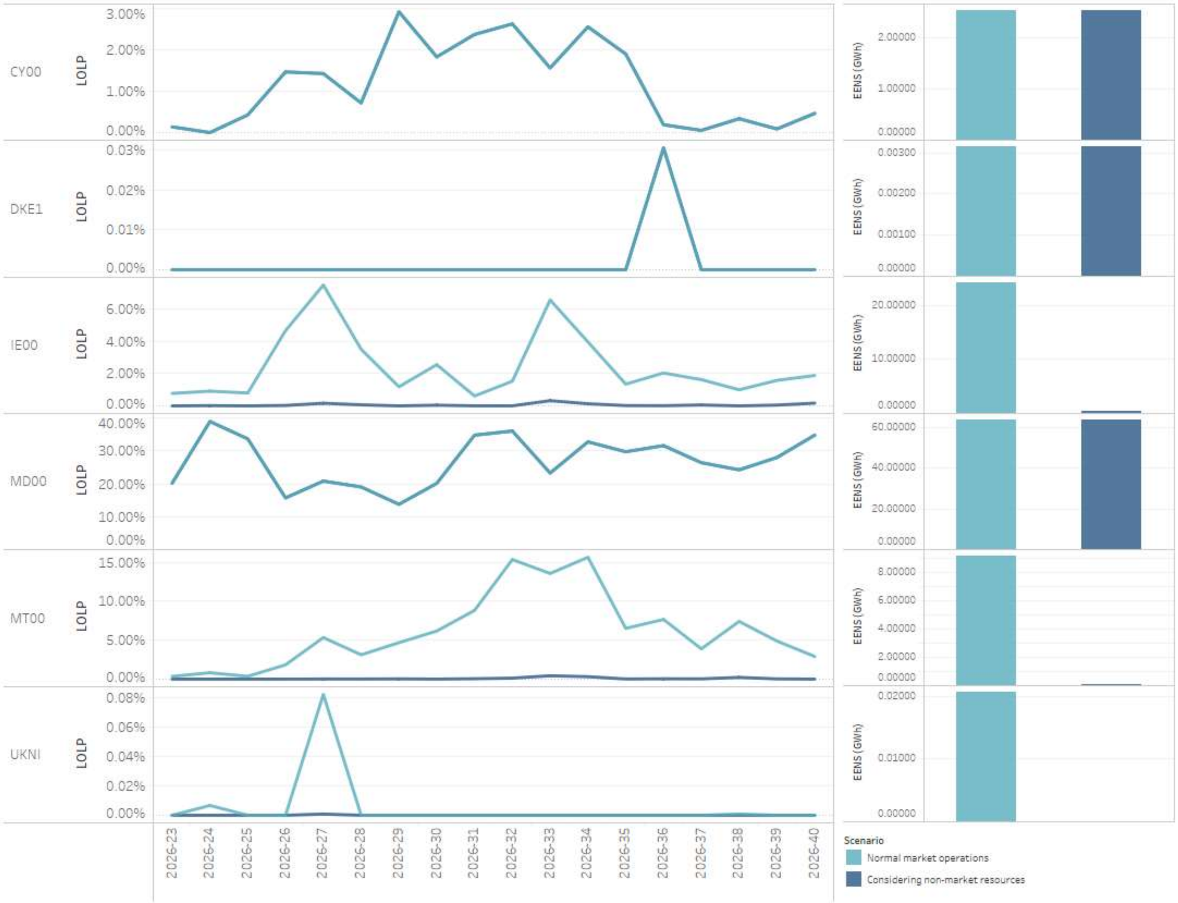

Figure 18: Detailed adequacy overview – weekly LOLP and ENS

Expectations for Ukrainian and Moldovan power systems

The Summer Outlook 2026 includes inputs and outputs for both Moldova and Ukraine. However, these figures are subject to variation and should be considered with the utmost care, considering the high uncertainty related to security of supply evolution. Russia's military aggression against Ukraine, which began in February 2022, continues to create elevated risk and uncertainty in the energy systems of both Ukraine and Moldova. Power generation and grid infrastructure availability in Ukraine are uncertain due to the risk of attacks on infrastructure elements, which may determine the actual situation in Ukraine's power system.

Since June 2022 and the start of the electricity commercial exchanges between Ukraine–Moldova and their European neighbours, the TSOs have continuously assessed the power system conditions and sought ways to maximise export and import capacity, while ensuring power system stability and operational security. Capacity calculation processes were developed and implemented, allowing European TSOs to progressively and regularly increase the export and import capacity limits to/from Ukraine and Moldova. In July 2025, ENTSO-E transferred the responsibility for determining the import and export capacity to the Eastern Europe CCR.

Moldova faces several system adequacy risks for the upcoming summer, including a strong dependence on imports from Romania, weak interconnections at the Romanian border, a strong reliance on power transmission through the unstable Transnistria region, and vulnerability to disturbances in the Ukrainian power system. These adequacy challenges are caused by the current limitations in the natural gas supply. Due to these constraints, the MGRES gas power plant is currently operating with only one unit in service, generating approximately 80–120 MWh on an hourly basis.

Winter 2025-2026 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 implemented, considerably strengthening Europe's resilience to the gas crisis.

The situation has progressively eased since early 2023 due to numerous actions and decisions at the European level (e.g. RePowerEU). ENTSO-E used the experiences of 2023–2024 and 2024–2025 to anticipate and address any risks ahead of and during the winter 2025–2026 period.

Preparations for winter 2025–2026

To prepare for winter 2025–2026, ENTSO-E maintained a broadened scope for the Seasonal Outlook Adequacy assessment beyond the strict legal mandate, as was already done in 2022 to address the crisis. In addition, as in the previous winter, the assessment was conducted earlier and the report was released early, in close coordination with the European Commission, ACER, and Member States.

Preparation for winter 2025–2026 built on the experience gained from the previous winter, with enhancements beyond 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 2025–2026, supporting TSOs and other stakeholders through clear risk identification and enabling the implementation of appropriate mitigation measures.

Conditions and events during winter 2025–2026

The weather conditions during winter 2025–2026 showed strong variability across the season. December 2025 was characterised by generally warmer-than-average temperatures, January and February 2026 experienced colder conditions in several regions, particularly in Northern and Eastern Europe, while March 2026 recorded markedly warmer-than-average temperatures across almost the entire continent.

Globally, December 2025 was the fifth-warmest December on record, with temperatures 0.49°C above the 1991–2020 average, while January, February, and March were among the warmest for their respective months, ranking fifth, fifth, and fourth, respectively. Despite these relatively high global rankings, regional variability was significant. In Europe, December 2025 was notably warm, with an average temperature of 2.68°C, corresponding to 1.99°C above the 1991–2020 average and making it the joint-fourth-warmest December on record. Most of the continent experienced above-average temperatures, particularly across central Norway, Sweden, and Iceland, while only limited areas of the Iberian Peninsula recorded below-average conditions.

In contrast, January 2026 was significantly colder, with an average temperature of −2.34°C, 1.63°C below the 1991–2020 average, making it the coldest January since 2010. Widespread cold conditions affected Fennoscandia, the Baltic States, and Eastern Europe, driven in part by a wavier-than-usual polar jet stream that allowed Arctic air to move into mid-latitudes.

February 2026 continued this pattern of contrasting conditions. The European average temperature was −0.07°C, 0.10°C below the 1991–2020 average. A strong geographical contrast was observed, with above-average temperatures across Western, Southern, and Southeastern Europe, while Fennoscandia, the Baltic States, and northwest Russia experienced continued cold conditions for the second consecutive month.

In March 2026, temperatures in Europe were significantly above average. The average temperature over European land was 5.88°C, corresponding to 2.27°C above the 1991–2020 average, making it the second-warmest March on record. Almost the entire continent experienced warmer-than-average conditions, with the most pronounced anomalies over northwest Russia, northern Fennoscandia, and the Baltic States. Slightly cooler-than-average conditions were observed in parts of Southern Europe, Türkiye, and most of Iceland.

This can be seen in Figure 19, which displays the surface air temperature anomaly observed in winter 2025–2026 (December 2025 to March 2026) from the Copernicus Climate Change Service.

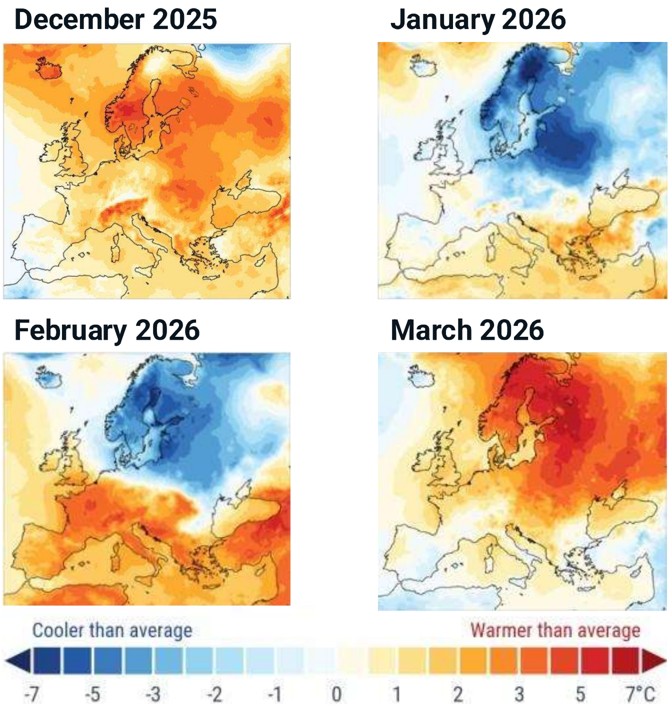

Figure 19: Surface air temperature anomaly in winter 2025–2026 relative to the average for the 1991–2020 period (for December, January, February, and March)[11]

Specific comments on winter 2025–2026

In general, no major adequacy issues were observed during winter 2025–2026, despite significant variability in weather conditions throughout the season. While December was predominantly mild, January and February were characterised by colder conditions, particularly across Northern and Eastern Europe, followed

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

by widespread warmer-than-average conditions in March. Nevertheless, no adequacy problems were reported.

However, several challenging situations were observed during the winter:

- Prolonged and widespread cold conditions in January 2026 affected Fennoscandia, the Baltic States, and Eastern Europe, making it the coldest January since 2010 and increasing heating demand in these regions.
- A severe cold spell during the second half of January impacted large parts of the Northern Hemisphere, including Europe, driven by a wavier-than-usual polar jet stream that allowed Arctic air to spread into mid-latitudes.
- In February 2026, persistent cold conditions continued across Fennoscandia, the Baltic States, and northwest Russia for a second consecutive month.
- In March 2026, almost all of Europe experienced warmer-than-average temperatures, with particularly strong anomalies in regions that had experienced cold conditions in the previous months.

Despite these situations, the system remained resilient overall, and no adequacy issues were experienced.

Preparations for winter 2026–2027

The results of the recently released ENTSOG Summer Outlook[12] show that EU gas storage levels as of 1 April 2026 are lower than in the previous three years and at the same level as pre-energy-crisis averages. The gas infrastructure, including new projects commissioned in recent years, allows for efficient import capacity and system flexibility to support summer storage injections and meet winter supply needs.

However, the escalating conflict in the Persian Gulf, including disruptions to Qatari supply and increased risks of prolonged disruption of navigation in the Strait of Hormuz, is tightening global LNG availability, contributing to higher gas prices in Europe, narrower price spreads, and directly constraining storage injections. Low storage levels and early significant withdrawal from storage facilities will result in low storage levels at the end of the winter season. This could negatively impact the flexibility of the gas system, especially during high-demand events. Overall, the analysis shows that the current system remains sufficiently flexible.

For an order of magnitude and for the sake of comparison, gas consumption for electricity generation in Europe is around 220,000 TJ over the summer period and around 300,000 TJ over the winter period.[13]

ENTSO-E will continue to closely monitor the geopolitical situation and regularly coordinate with ENTSOG to assess any material changes in risks.

ENTSO-E will also closely consider specific feedback or requests about the future Winter Outlook from European or national authorities.

ENTSO-E is preparing for an earlier release of the next Winter Outlook 2026–2027 ahead of the normal 1 December publication date.

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[12] *OUTLOOKS & REVIEWS | ENTSOG*

[13] *Eurostat, data for ENTSOE perimeter*

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.[14] 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 ACER.[15]

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 time frame. Figure 20 provides a schematic representation of this scenario construction process.

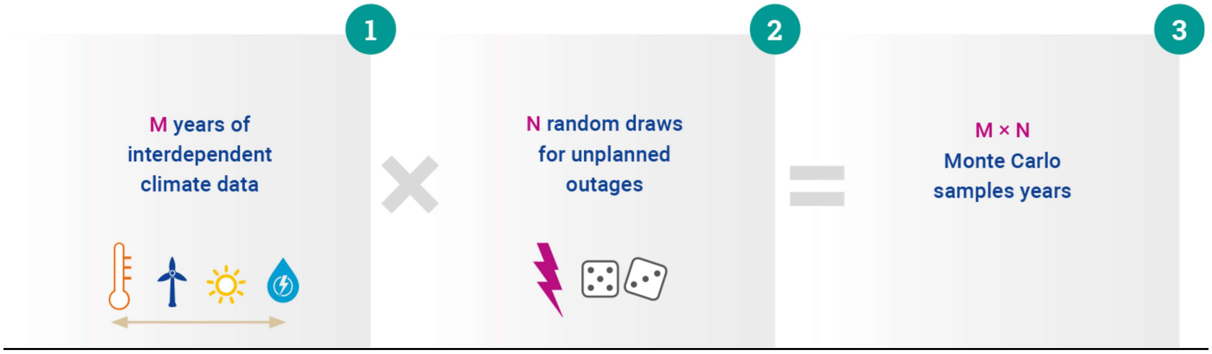

Figure 20: Scenarios assessed in Seasonal Outlooks

Scenarios are constructed, ensuring that all variables are correlated (interdependent) in time and space. The assessments are prepared by experts working in 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 WSs. Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 21 illustrates the difference in the number of scenarios between the two modelling approaches.

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[14] *Methodology for Short-term and Seasonal Adequacy assessment*

[15] *ACER decision (No 08/2020) on the methodology for short-term and seasonal adequacy assessments*

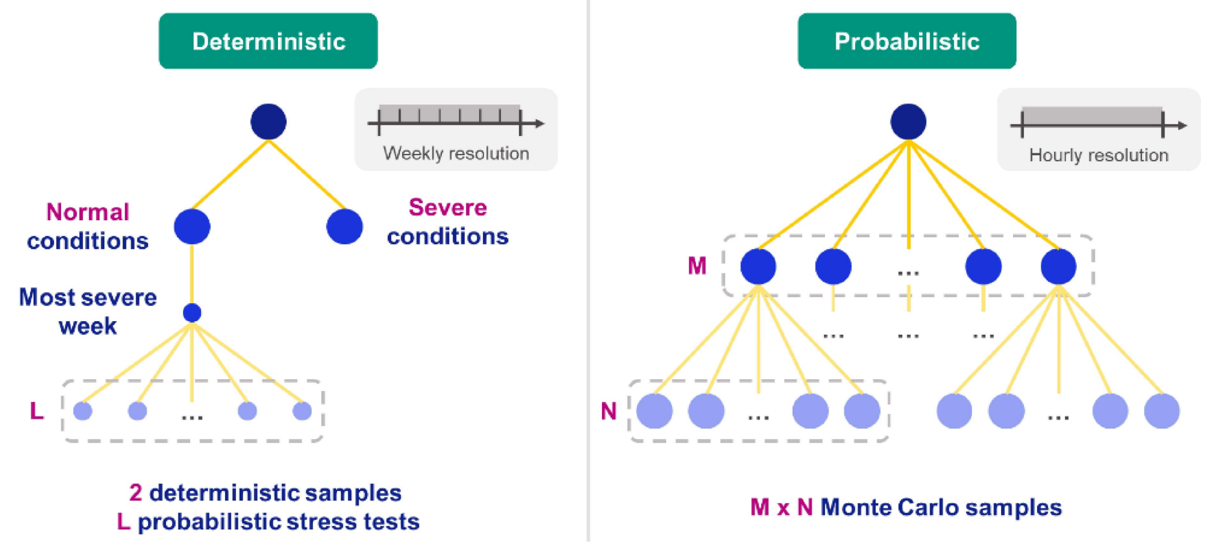

Figure 21: Scenario revolution: from deterministic to probabilistic

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, where 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 22: Study zones

NTC import table

AL00	MK00 500 MW (500 - 500) MW	RS00 400 MW (400 - 400) MW	GR00 394 MW (0 - 400) MW	ME00 300 MW (300 - 300) MW										
AT00	DE00 4,900 MW (4,900 - 4,900) MW	CH00 1,070 MW (436 - 1,200) MW	SI00 950 MW (950 - 950) MW	CZ00 900 MW (900 - 900) MW	HU00 800 MW (800 - 800) MW	ITN1 183 MW (80 - 265) MW								
BA00	HR00 600 MW (600 - 600) MW	RS00 474 MW (474 - 474) MW	ME00 450 MW (450 - 450) MW											
BE00	FR00 1,700 MW (1,700 - 1,700) 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 1,868 MW (1,800 - 1,900) MW	GR00 1,177 MW (700 - 1,200) MW	MK00 400 MW (400 - 400) MW	RS00 356 MW (0 - 400) MW	TR00 321 MW (100 - 334) MW									
CH00	FR00 2,903 MW (2,600 - 3,000) MW	DE00 2,000 MW (2,000 - 2,000) MW	ITN1 1,531 MW (1,440 - 1,910) MW	AT00 1,019 MW (436 - 1,200) MW										
CZ00	DE00 2,800 MW (2,800 - 2,800) 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 4,900 MW (4,900 - 4,900) MW	NL00 4,400 MW (4,400 - 4,400) MW	CH00 3,924 MW (3,700 - 4,000) MW	FR00 3,000 MW (3,000 - 3,000) MW	PL00 3,000 MW (3,000 - 3,000) MW	CZ00 2,800 MW (2,800 - 2,800) MW	DKW1 2,461 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 615 MW (615 - 615) MW	DKE1 585 MW (585 - 585) MW	DEKF OFF 400 MW (400 - 400) MW
DEKF OFF	DE00 400 MW (400 - 400) MW	DKKF OFF 400 MW (400 - 400) MW												
DKE1	DKKF OFF 600 MW (600 - 600) MW	DE00 585 MW (585 - 585) MW	SE04 539 MW (0 - 1,300) MW	DKW1 450 MW (450 - 450) MW										
DKKF OFF	DKE1 600 MW (600 - 600) MW	DEKF OFF 400 MW (400 - 400) MW												
DKW1	DE00 2,463 MW (800 - 2,500) MW	NOS2 1,437 MW (481 - 1,632) MW	UK00 1,384 MW (700 - 1,400) MW	NL00 700 MW (700 - 700) MW	DKE1 600 MW (600 - 600) MW	SE03 382 MW (200 - 715) MW								
EE00	FI00 1,002 MW (658 - 1,016) MW	LV00 852 MW (800 - 864) MW												
ES00	PT00 3,388 MW (1,650 - 4,300) MW	FR00 2,095 MW (1,650 - 2,550) MW												
FI00	SE01 1,783 MW (1,100 - 1,900) MW	SE03 1,198 MW (800 - 1,200) MW	EE00 1,002 MW (658 - 1,016) MW	NON1 80 MW (80 - 80) MW										
FR00	UK00 4,000 MW (4,000 - 4,000) MW	DE00 3,000 MW (3,000 - 3,000) MW	ITN1 1,864 MW (870 - 2,160) MW	ES00 1,329 MW (0 - 1,550) MW	CH00 1,203 MW (1,200 - 1,300) MW	BE00 600 MW (600 - 600) MW								
GR00	BG00 1,177 MW (700 - 1,200) MW	GR03 650 MW (650 - 650) MW	MK00 494 MW (400 - 500) MW	ITS1 468 MW (0 - 500) MW	AL00 443 MW (0 - 450) MW	TR00 161 MW (0 - 166) MW								
GR03	GR00 650 MW (650 - 650) MW													
HR00	SI00 800 MW (800 - 800) MW	BA00 700 MW (700 - 700) MW	HU00 534 MW (500 - 550) MW	RS00 277 MW (150 - 300) MW										
HU00	SK00 2,513 MW (2,513 - 2,513) MW	RO00 988 MW (700 - 1,000) MW	RS00 984 MW (0 - 1,000) MW	AT00 800 MW (800 - 800) MW	SI00 672 MW (0 - 700) MW	HR00 463 MW (400 - 800) MW	UA00 220 MW (220 - 220) MW							
IE00	UK00 868 MW (500 - 1,000) MW	UKNI 400 MW (400 - 400) MW												
ITCA	ITSI 1,317 MW (750 - 1,475) MW	ITS1 1,232 MW (300 - 1,300) MW												
ITCN	ITN1 3,816 MW (3,200 - 4,450) MW	ITCS 3,480 MW (2,000 - 3,500) MW	ITSA 204 MW (0 - 300) MW											
ITCS	ITS1 5,021 MW (3,600 - 5,200) MW	ITCN 2,959 MW (1,100 - 3,600) MW	ITSA 887 MW (870 - 900) MW	ME00 555 MW (0 - 600) MW										
ITN1	FR00 3,009 MW (448 - 4,285) MW	ITCN 2,863 MW (2,250 - 3,350) MW	CH00 2,306 MW (410 - 3,747) MW	AT00 484 MW (69 - 685) MW	SI00 436 MW (0 - 753) MW									
ITS1	ITCA 2,460 MW (1,600 - 2,550) MW	ITCS 2,400 MW (2,400 - 2,400) MW	GR00 468 MW (0 - 500) MW											
ITSA	ITCS 720 MW (720 - 720) MW	ITCN 183 MW (0 - 300) MW												
ITSI	ITCA 1,453 MW (750 - 1,650) MW	MT00 215 MW (0 - 216) MW												
LT00	LV00 1,013 MW (1,013 - 1,013) MW	SE04 597 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 923 MW (923 - 923) MW	EE00 696 MW (696 - 696) MW						
MD00	RO00 255 MW (255 - 255) MW	UA00 173 MW (173 - 173) MW						
ME00	RS00 600 MW (600 - 600) MW	ITCS 555 MW (0 - 600) MW	BA00 500 MW (500 - 500) MW	AL00 300 MW (300 - 300) MW				
MK00	RS00 600 MW (600 - 600) MW	AL00 500 MW (500 - 500) MW	GR00 494 MW (400 - 500) MW	BG00 400 MW (400 - 400) MW				
MT00	ITSI 215 MW (0 - 216) 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	NOS3 800 MW (800 - 800) MW	SE02 758 MW (0 - 1,000) MW	NOS1 500 MW (500 - 500) MW				
NON1	SE01 513 MW (0 - 600) MW	NOM1 400 MW (400 - 400) MW	SE02 281 MW (150 - 300) MW	FI00 80 MW (80 - 80) MW				
NOS1	NOS3 3,900 MW (3,900 - 3,900) MW	NOS2 3,700 MW (3,700 - 3,700) MW	SE03 1,282 MW (150 - 2,095) MW	NOM1 500 MW (500 - 500) MW				
NOS2	NOS1 2,200 MW (2,200 - 2,200) MW	DKW1 1,437 MW (481 - 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	PLI0 1,900 MW (1,900 - 1,900) MW	DE00 1,300 MW (1,300 - 1,300) MW	SE04 516 MW (0 - 600) MW	LT00 150 MW (150 - 150) MW	UA00 80 MW (80 - 80) MW	PLE0 0 MW (0 - 0) MW		
PLE0	PL00 2,500 MW (2,500 - 2,500) MW	CZ00 0 MW (0 - 0) MW	SK00 0 MW (0 - 0) MW					
PLI0	CZ00 1,050 MW (1,050 - 1,050) MW	SK00 818 MW (818 - 818) MW	PL00 0 MW (0 - 0) MW					
PT00	ES00 3,976 MW (3,300 - 5,300) MW							
RO00	BG00 1,783 MW (1,000 - 1,900) MW	RS00 1,000 MW (1,000 - 1,000) MW	HU00 988 MW (700 - 1,000) MW	MD00 120 MW (120 - 120) MW	UA00 120 MW (120 - 120) MW			
RS00	RO00 1,000 MW (1,000 - 1,000) MW	HU00 984 MW (0 - 1,000) MW	MK00 800 MW (800 - 800) MW	AL00 400 MW (400 - 400) MW	ME00 400 MW (400 - 400) MW	BG00 356 MW (0 - 400) MW	BA00 300 MW (300 - 300) MW	HR00 277 MW (150 - 300) MW
SE01	SE02 3,300 MW (3,300 - 3,300) MW	FI00 1,780 MW (200 - 1,900) MW	NON1 616 MW (0 - 700) MW					
SE02	SE03 7,600 MW (7,600 - 7,600) MW	SE01 2,820 MW (2,100 - 3,300) MW	NOM1 578 MW (0 - 600) MW	NON1 225 MW (100 - 250) MW				
SE03	SE02 5,585 MW (5,200 - 7,600) MW	SE04 2,768 MW (2,100 - 2,800) MW	NOS1 1,142 MW (450 - 2,145) MW	DKW1 598 MW (400 - 715) MW	FI00 196 MW (0 - 1,200) MW			
SE04	SE03 3,665 MW (3,300 - 6,200) MW	DKE1 781 MW (0 - 1,700) MW	DE00 600 MW (600 - 600) MW	LT00 533 MW (0 - 700) MW	PL00 501 MW (0 - 600) MW			
SI00	AT00 950 MW (950 - 950) MW	HR00 800 MW (800 - 800) MW	HU00 672 MW (0 - 700) MW	ITN1 622 MW (0 - 680) MW				
SK00	HU00 1,800 MW (1,800 - 1,800) MW	CZ00 1,700 MW (1,700 - 1,700) MW	PLE0 781 MW (781 - 781) MW	UA00 173 MW (173 - 173) MW	PLI0 0 MW (0 - 0) MW			
TR00	BG00 420 MW (216 - 432) MW	GR00 209 MW (0 - 216) MW						
UA00	HU00 680 MW (680 - 680) MW	MD00 257 MW (255 - 315) MW	SK00 257 MW (255 - 315) MW	RO00 255 MW (255 - 255) MW	PL00 140 MW (140 - 140) MW			
UK00	FR00 4,000 MW (4,000 - 4,000) MW	NOS2 1,400 MW (1,400 - 1,400) MW	DKW1 1,384 MW (700 - 1,400) MW	BE00 1,000 MW (1,000 - 1,000) MW	NL00 1,000 MW (1,000 - 1,000) MW	IE00 868 MW (500 - 1,000) MW	UKNI 397 MW (250 - 400) MW	
UKNI	UK00 446 MW (250 - 450) MW	IE00 400 MW (400 - 400) MW						

Node from, average of NTC cross-technology (MW), minimum of NTC cross-technology (MW) and maximum of NTC cross-technology (MW) broken down by Rank of Avg. NTC cross-technology (MW) vs. Node to. The data is filtered on Technology, which keeps HVAC and HVDC.

Figure 23: Import capacity overview (excluding forced outage)

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 advised 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 result in misleading conclusions when compared with reliability standards (existing or under development in accordance with Article 26 of Regulation 2019/943). Some examples are provided below, assuming that the annual LOLE reliability standard[16] 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[17] (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,[18] whereas seasonal outlooks relate to an operational time frame 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 24 below represents the LOLE results of the Summer Outlook 2026.

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

[17] *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 an extended period.*

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

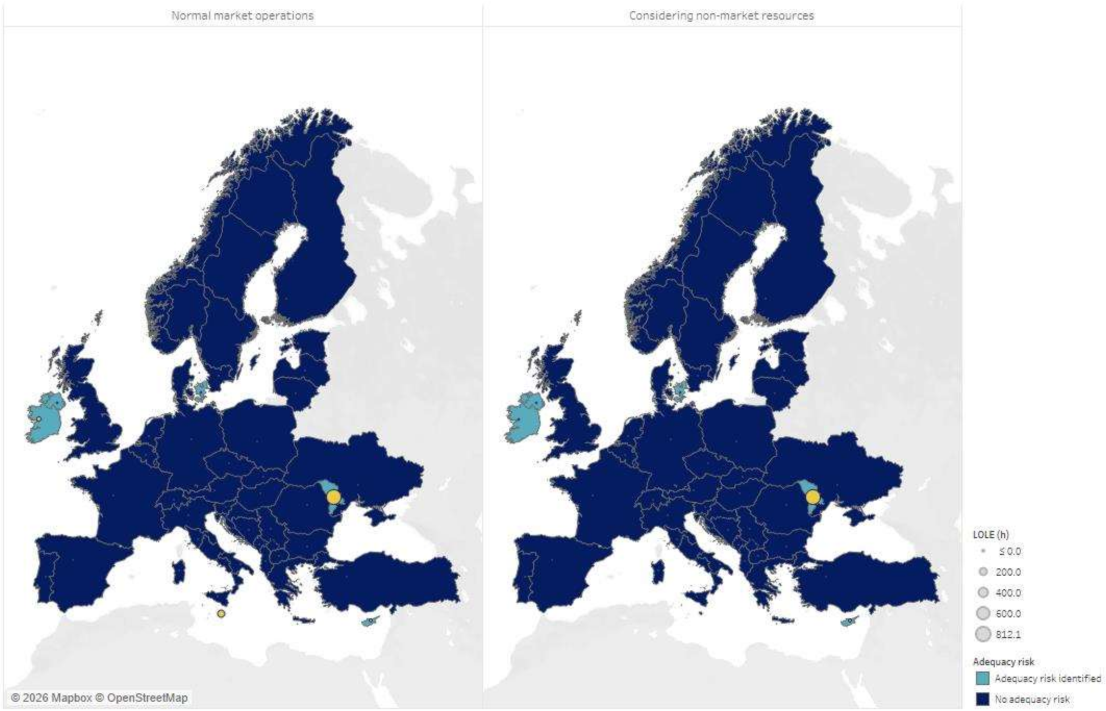

Figure 24: Seasonal LOLE results

Analysis of curtailment of renewable generation

As an additional insight, this Summer Outlook 2026 analyses the curtailment of renewable generation (wind and solar installations) resulting from ENTSO-E's model. Figure 25 and Figure 26 show the average curtailment ratio of renewable generation from all WSs and FO samples. The curtailment ratio is defined as

$$Curtailment\ Ratio = \frac{Energy\ to\ be\ Curtailed}{Energy\ to\ be\ Curtailed + Energy\ Generated} * 100\%.$$

Curtailment 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. Third, it is assumed that all RES plants can be curtailed by 100%. **This means that the results represent the amount of energy that must be curtailed to avoid a situation of excess generation**.

Figure 25 summarises the average total curtailed energy and provides the average curtailment ratio per study zone. Figure 26 illustrates the weekly distribution of the curtailment ratio during the summer for each zone, as well as the average number of hours during which curtailment of generation is needed.

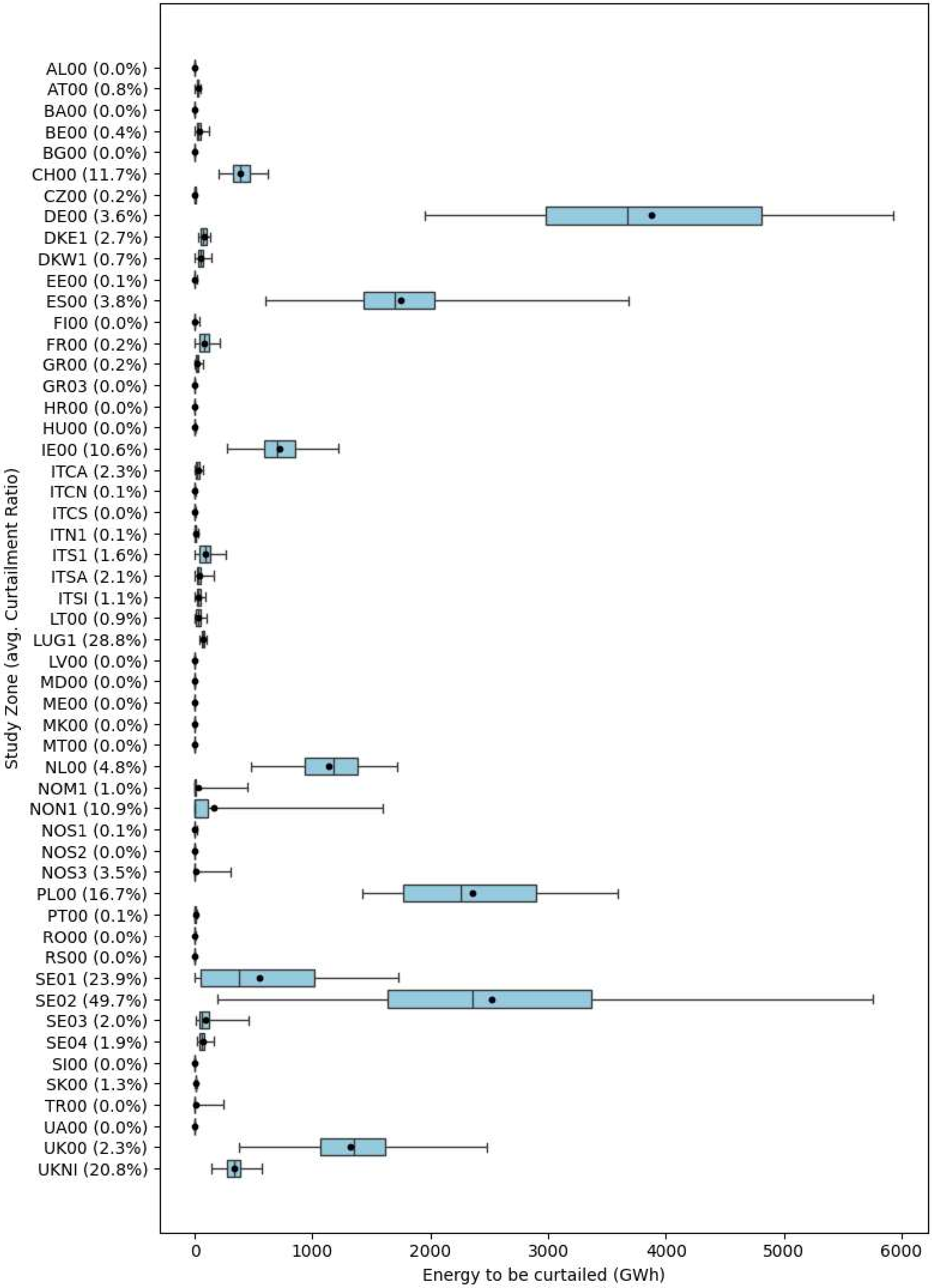

Figure 25: Energy to be curtailed and average curtailment ratio

The boxplot shows the variation of the absolute amount of energy to be curtailed over all different WSs, where 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 represents the median, and the black dot depicts the average. The left column shows the average curtailment ratio over the season per zone across all WSs.

The boxplot shows that, in absolute terms, the northern part of Sweden and Germany must curtail the most energy. However, the amount is only significant in relation to renewable fleet for Sweden (more than 40%).

The heat map in Figure 26 shows the curtailment ratio in weekly resolution over the summer season and provides insights into the average number of hours where renewable curtailment is necessary across all different WSs.

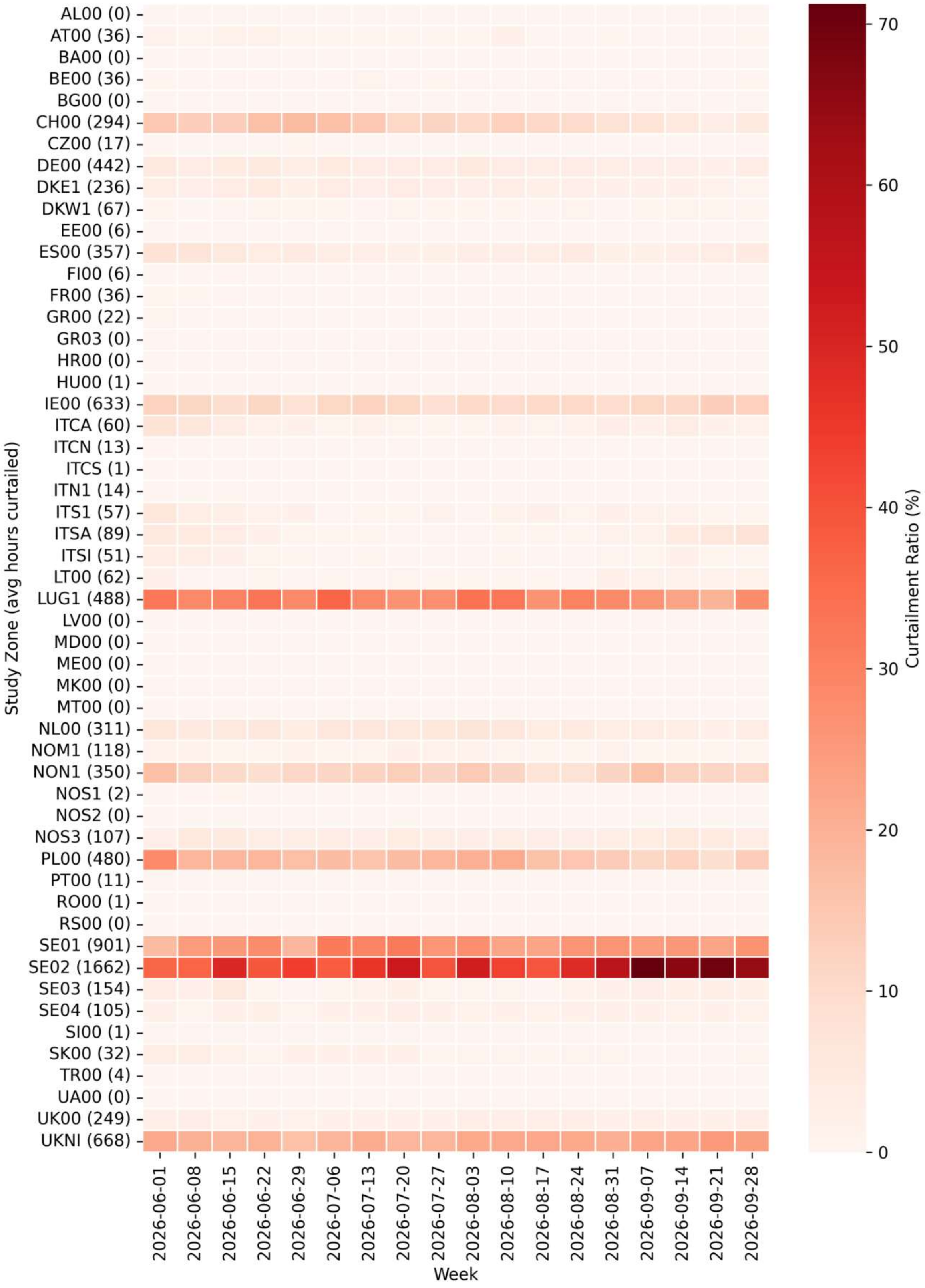

Figure 26: Weekly distribution of the curtailment ratio and average number of hours with curtailment