Winter Outlook 2026–2027

Report



entsoe

Winter Outlook 2026–2027

Report

12 November 2026

ENTSO-E Mission Statement

ENTSO-E – the European Network of Transmission System Operators for Electricity – brings together 40 electricity Transmission System Operators (TSOs) from 36 countries. ENTSO-E members are responsible for the secure and coordinated operation of Europe's electricity - system. Together, they operate a system of around 500,000 km of power lines – the largest interconnected electrical grid in the world – and serve about 520 million citizens.

Electricity is not merely a market commodity, it is an essential service, and TSOs are fully regulated public service entities whose work is essential to powering Europe. The grid is the backbone of the electricity system and has extended over the whole Continent, beyond the borders of the EU. TSOs working together guarantee a functioning infrastructure that makes the trade of electricity possible, contributes to decarbonisation goals, and ensures a reliable and efficient power supply for all members of society.

These shared public service responsibilities need close cooperation beyond national borders, which led to the creation of ENTSO-E. Today, the association serves two main complementary purposes:

1. **Cooperation of European TSOs**

   The foundations of this cooperation date back to the 1950s with the creation of electrical synchronous areas and interconnections, which laid the groundwork for today's interconnected European power system. TSOs established associations to work together on their own mandates and missions, that came together into what today is ENTSO-E. The European electricity system is one of the most stable and reliable grids in the world and is supported by the cooperation and coordination of TSOs both within the European Union and closely interconnected European countries. ENTSO-E strives to build consensus for decision-making amongst its member TSOs as this forms the strongest foundation for cooperation.

2. **Fulfilling EU legal mandates**

   With the adoption of the Third Energy Package in 2009, ENTSO-E's role was formally recognised by European institutions. ENTSO-E was granted legally mandated tasks to further develop the European interconnected grid and to facilitate the integration of European electricity markets. These mandates cover a large spectrum of tasks, including system operation, system development, market integration, information technologies, R&D and innovation.

Contents

1. Executive summary 4

2. Introduction 5

General purpose of Seasonal Outlook reports 5
Coordination at the national, regional, and European levels 5

3. Overview of the power system in winter 2026–2027 7

Generation overview 7
Generation capacity evolution 7
Planned unavailability of generation 13
Hydro availability 15
Demand overview 16
Network overview 19

4. Adequacy situation and gas need during winter 2026–2027 20

Reference scenario 20
Focus on adequacy under normal market conditions 21
Focus on non-market resources 23
Critical gas volume for winter 2026–2027 25
Expectations for the Ukrainian and Moldovan power systems 28

Appendix 1: Methodological insights 29

Appendix 2: Additional information about the study 31

Appendix 3: Additional information about the results 33

Loss of load expectation and other annual metrics 33

1. Executive summary

ENTSO-E Winter Outlook 2026–2027 confirms that the overall favourable adequacy situation in Europe for the coming winter is under control. Some electricity supply risks may occur in Cyprus (CY00), which has no interconnection to the European continental network. While some of these risks are identified under normal market conditions in Malta (MT00) and Ireland (IE00), dedicated non-market resources significantly alleviate these risks. Traces of expected energy not served (EENS) and adequacy risk are also visible for Denmark East (DKE1), Finland (FI00), and Northern Ireland (UKNI). Ukraine (UA00) and Moldova (MD00) face higher risks**.**

European power system trends since winter 2025–2026 show further generation fleet expansion, with considerable increases in renewable energy sources (RES) and subsequent decreases in conventional generation. Planned outages as well as demand are slightly higher than last winter, while hydro reservoir levels are lower than average overall.

Since March 2022, Ukraine and Moldova have been synchronised with the continental European power system. According to national experts, the situation in Ukraine remains uncertain due to potential attacks on energy infrastructure. Until June 2025, European transmission system operators (TSOs) progressively increased export capacity to Ukraine and Moldova. Since July 2025, ENTSO-E has transferred the responsibility for determining the import and export capacity to the Eastern Europe capacity calculation region (CCR).

Moldova faces several system adequacy risks for the upcoming winter, including a strong dependence on imports from Romania through a single Isaccea - Vulcanesti interconnector and insufficient Net Transfer Capacity (NTC) allocated for commercial operation to cover the electricity deficit, and vulnerability to disturbances in the Ukrainian power system caused by Russia's war of aggression. The Winter Outlook is accompanied by an *Extraordinary Review of Summer 2026 Report*. Several countries in South-East Europe, which were particularly affected by the heatwave that hit Europe during summer, activated measures under Article 14 of Regulation (EU) 2019/941 on Risk Preparedness in the Electricity Sector in response to prolonged heatwave conditions and drought. Hungary, Slovenia, Romania, and Bulgaria declared Early Warning situations on 1 August, 2 August, 7 August, and 17 August 2026, respectively, while Romania subsequently declared a Crisis Situation on 10 August 2026. Due to similar unfavourable conditions in Poland, adequacy risks were identified several times during the summer through the short-term adequacy (STA) process. However, the adequacy gap was managed either through high imports or by activating resources under the capacity market, a non-market measure that has been in operation in Poland since 2021. The capacity market was activated on 30 June, 4 August, and 6 August.

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 May and a Winter Outlook in November. 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 an assessment of 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[1] 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 Winter 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 winter.

European level

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

[1] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/seasonal/Methodology%20for%20Short-term%20and%20Seasonal%20Adequacy%20Assessment%20-%20ACER%20Decision%2008-2020%20on%20the%20RPR8%20.pdf.

- 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 the European Network of Transmission System Operators for Gas (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 winter to maximise cross-border capacities regionally through an established outage planning coordination (OPC) process.

National level

- TSOs conducted national adequacy studies in parallel with the ENTSO-E Winter Outlook, which might 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 implement these mitigation measures.

3. Overview of the power system in winter 2026–2027

Generation overview

Generation capacity evolution

Compared to the previous winter (see Figure 1), installed renewable capacity in Europe has increased by roughly 134 GW (+16%). Most of this increase comes from rooftop, industrial and utility-scale photovoltaic panels throughout Europe and the installation of wind turbines, with total installed capacity increasing by 26% (solar) and 13% (wind) over one year. Installed photovoltaic production has increased by 96 GW across Europe, whereas wind capacity has increased by 33 GW.

Battery energy storage system capacity is rapidly increasing (by over 124% compared to the previous winter) but remains small in scale, with 38 GW of installed capacity throughout Europe.

High-carbon-footprint power units such as hard coal and lignite have seen a combined decrease in installed capacity by nearly 6 GW (−9%), while oil remains steady. The more flexible gas power plants also saw a slight decrease of nearly 9 GW (−5%) compared to the previous winter. Nuclear capacity recorded a slight net increase of 1 GW.

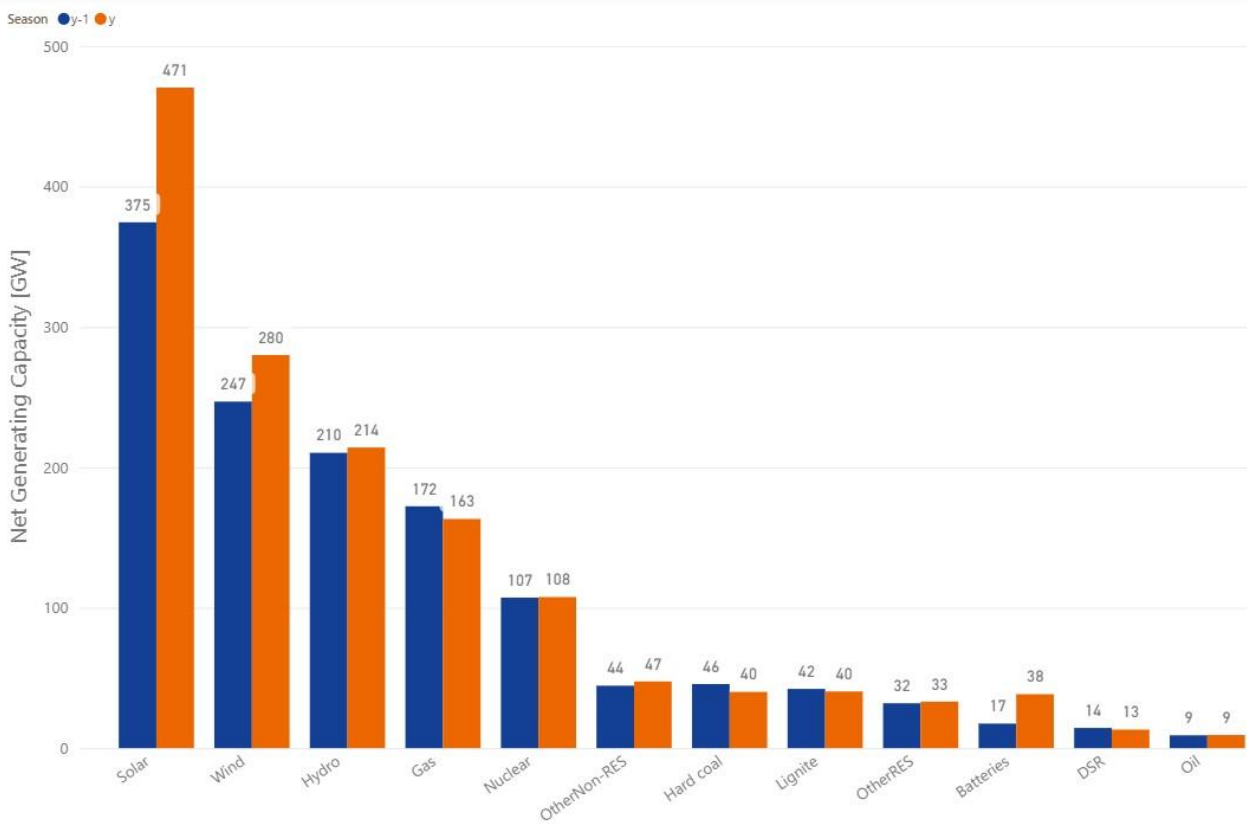


Figure 1. Generation capacity change over one year: Winter Outlook 2026–2027 (orange) vs. Winter Outlook 2025–2026 (blue).[2] [3]

Figure 2 shows that generation capacity in Europe is increasing during winter 2026–2027, mainly due to the expansion in renewable capacity generation. Thermal generation is decreasing due to the decommissioning of hard coal and lignite plants, which is not balanced out by increased gas-fired power plant generation capacity. However, in some exceptional cases, decommissioned units might be contracted as non-market resources to support adequacy or under other non-market schemes to provide system services. Figure 2 presents the study zones with sizeable changes in this winter period.

[2] *UA and MD are included in the data for this visual. TR is not present.*
[3] *Data from GB were excluded due to a change in the scope of the analysis.*

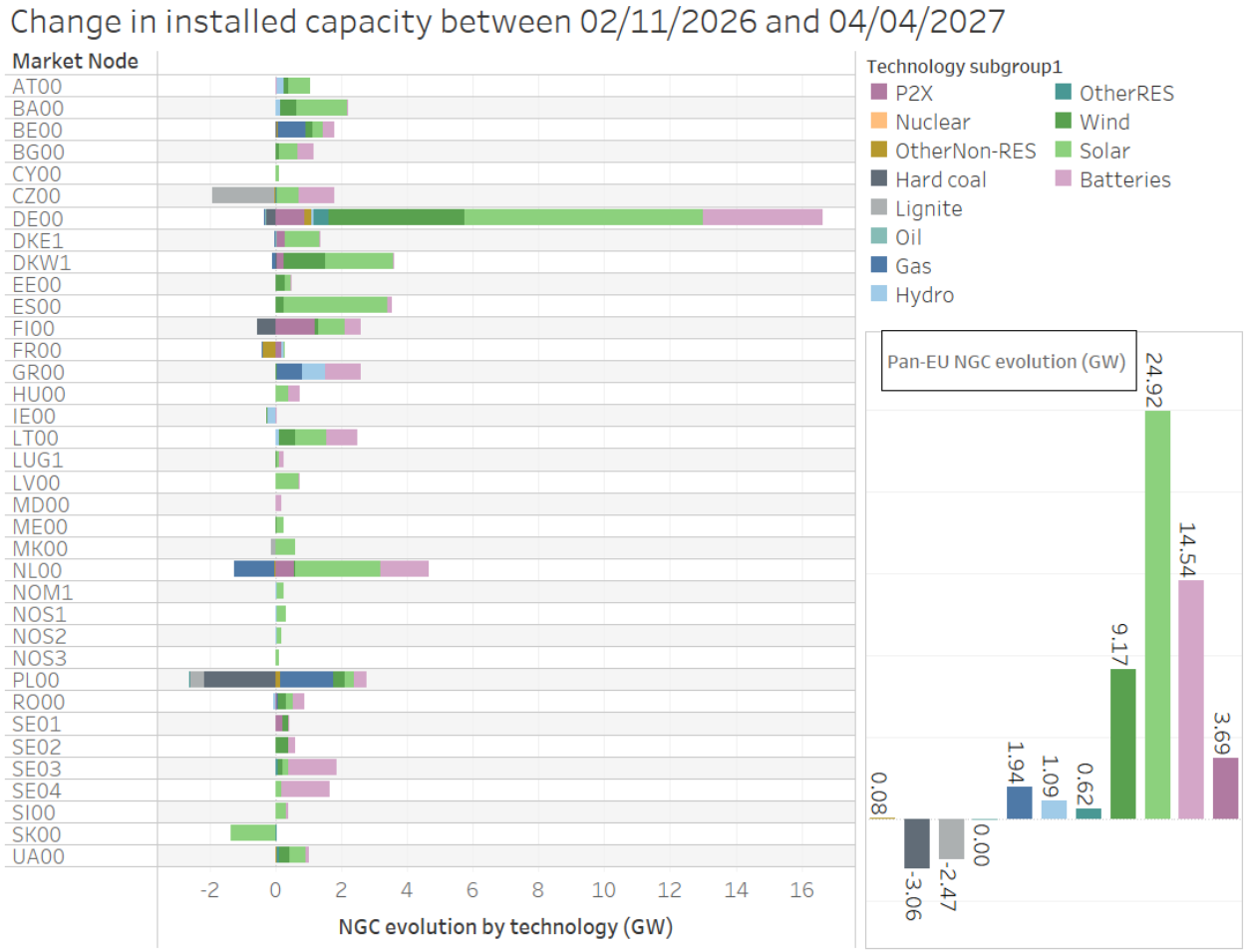


Figure 2. Sizeable capacity evolution in winter 2026–2027. P2X includes both the production of heat (boilers/heat pumps) and H_2 (electrolysers).

Figure 3 shows the net generating capacity (NGC) compared to the highest expected demand for every European study zone. It shows that in high renewable generation scenarios ("all technologies"), most study zones can cover their peak demand without imports, with the exceptions of Luxembourg, Serbia, Crete (GR03) and Norway (NO1). However, considering conventional generation unavailability, such as forced outages and planned unavailability, some zones, such as Belgium, the Netherlands, Denmark, Finland, Germany, Poland, Estonia, Hungary, Ukraine, Malta, and parts of Italy, Sweden, and Norway might rely on imports in low renewable generation scenarios ("flexible technologies").

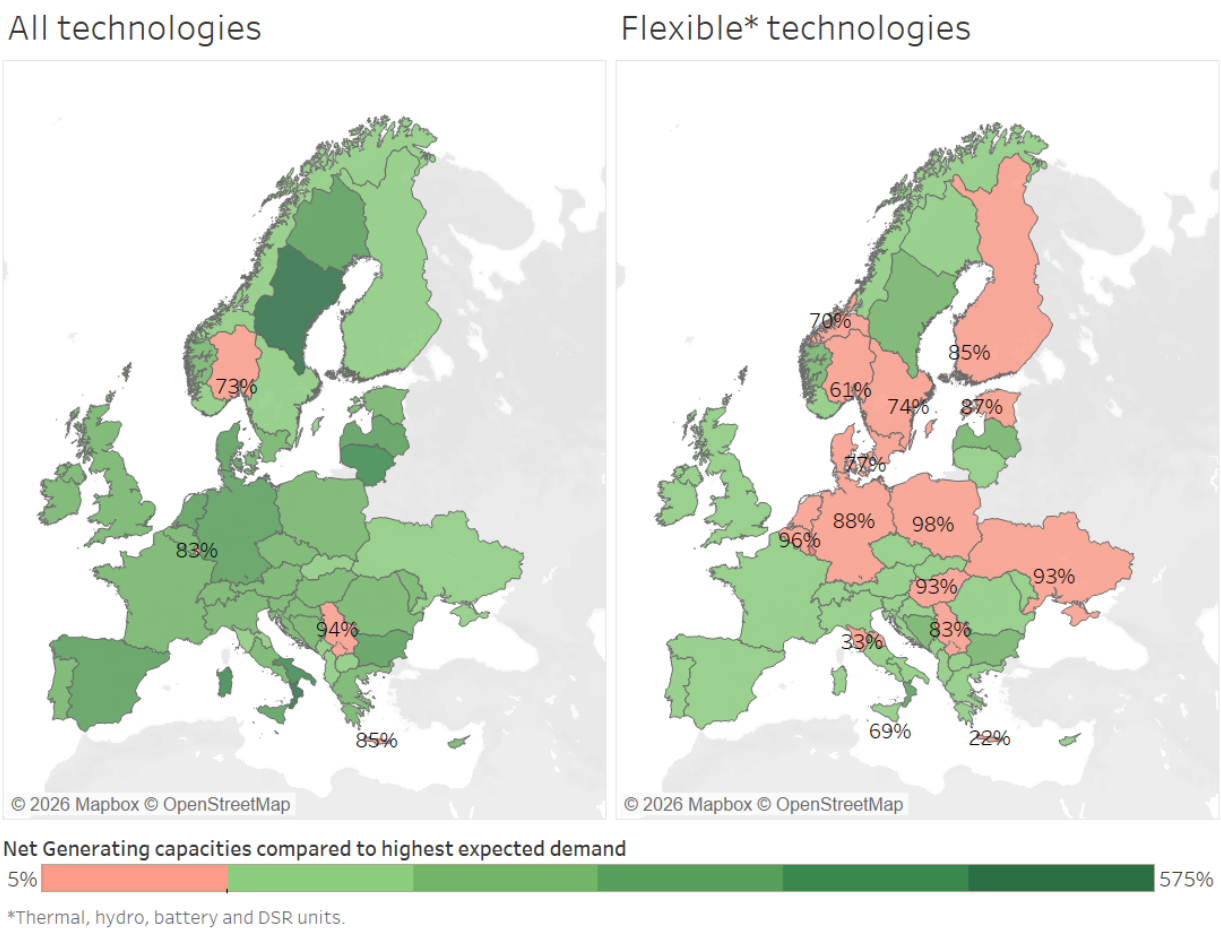


Figure 3. Net generating capacity overview: Comparison with the highest expected demand.[4]

Figure 4 details the generation capacity mix at the beginning of winter 2026–2027 for each study zone for the reference scenario. The date considered in Figure 4 is 2 November 2026, meaning that any unit commissioned beyond that date is not included in the visual (but is still included in the simulation). Similarly, a unit decommissioned after that date is included in the visual.

For each study zone, the small black square indicates the highest expected demand, stated as a percentage of each zone's NGC. For example, in NOS1, peak demand exceeds NGC by 37% and requires interconnections to meet peak demand. While most countries are expected to meet peak demand with their NGC, LUG1, GR03, and RS00 are also expected to see peak demand exceeding NGC.

Some countries or study zones have a high-RES NGC combined with a relatively low thermal NGC (e.g. Luxembourg, Italy, Denmark, Southern Sweden, and Germany). In periods of low RES production, these countries will rely on imports to cover their peak loads.

[4] *The highest expected demand is calculated as the highest 95th percentile based on hourly demand data.*

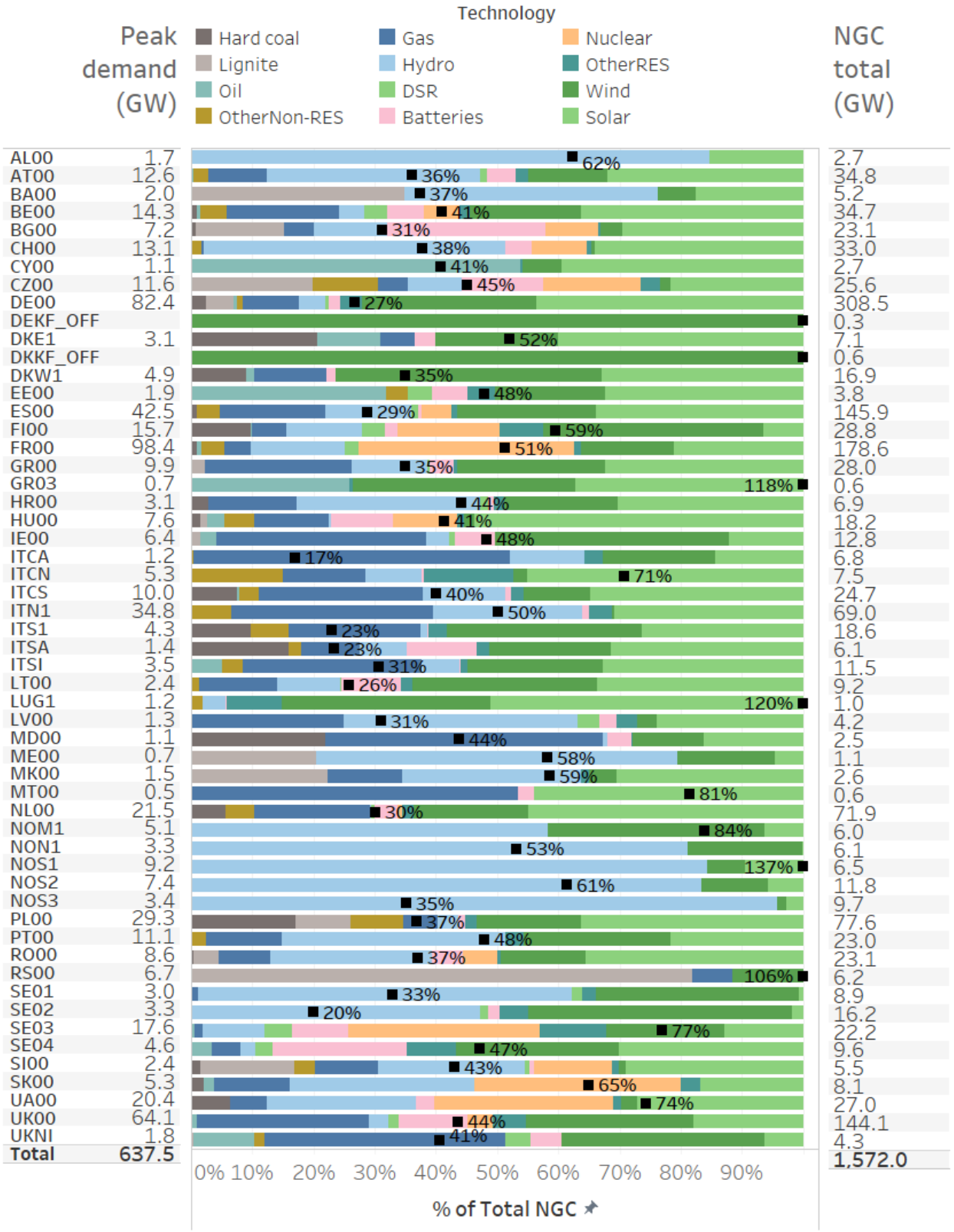


Figure 4. Generation capacity mix at the beginning of winter 2026–2027 for each study zone.

Non-market resources are dispatchable units that can be activated in the event of a lack of supply. They are available in four study zones in the EU (Figure 5). Non-market resources can play a critical role in addressing adequacy challenges, especially in zones with low interconnection capacity, such as Ireland and Malta. Germany has by far the highest share of non-market resource capacity.

This report assesses whether these non-market resources can address identified adequacy issues for the coming winter.

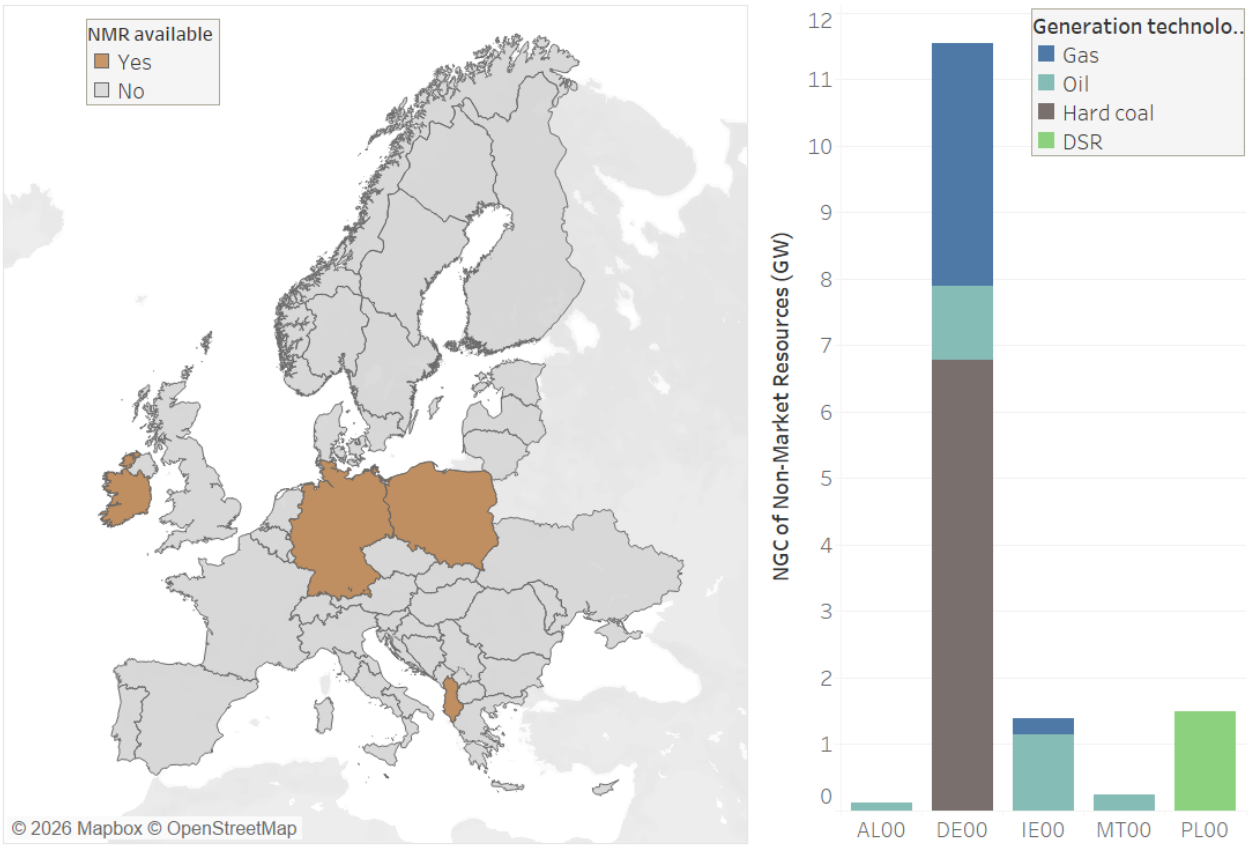


Figure 5. Non-market resources for coping with adequacy challenges in Europe.[5] [6] [7]

[5] *Parts of German 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, these may already be partly exhausted for their primary purpose.*

[6] *CH00: 386 MW of biogas NMRs are missing on NMR summary.png. Their commissioning date is 1 January 2027, so they are deemed available for most of the winter*

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

Planned unavailability of generation

Figure 6 shows the evolution of the planned unavailability of thermal and nuclear generation units throughout winter 2026–2027. The planned unavailability of generation units includes planned outages for maintenance and mothballing. Winter 2026–2027 shows a slightly higher level of planned outages compared to the previous winter, mainly driven by higher French nuclear planned outages.

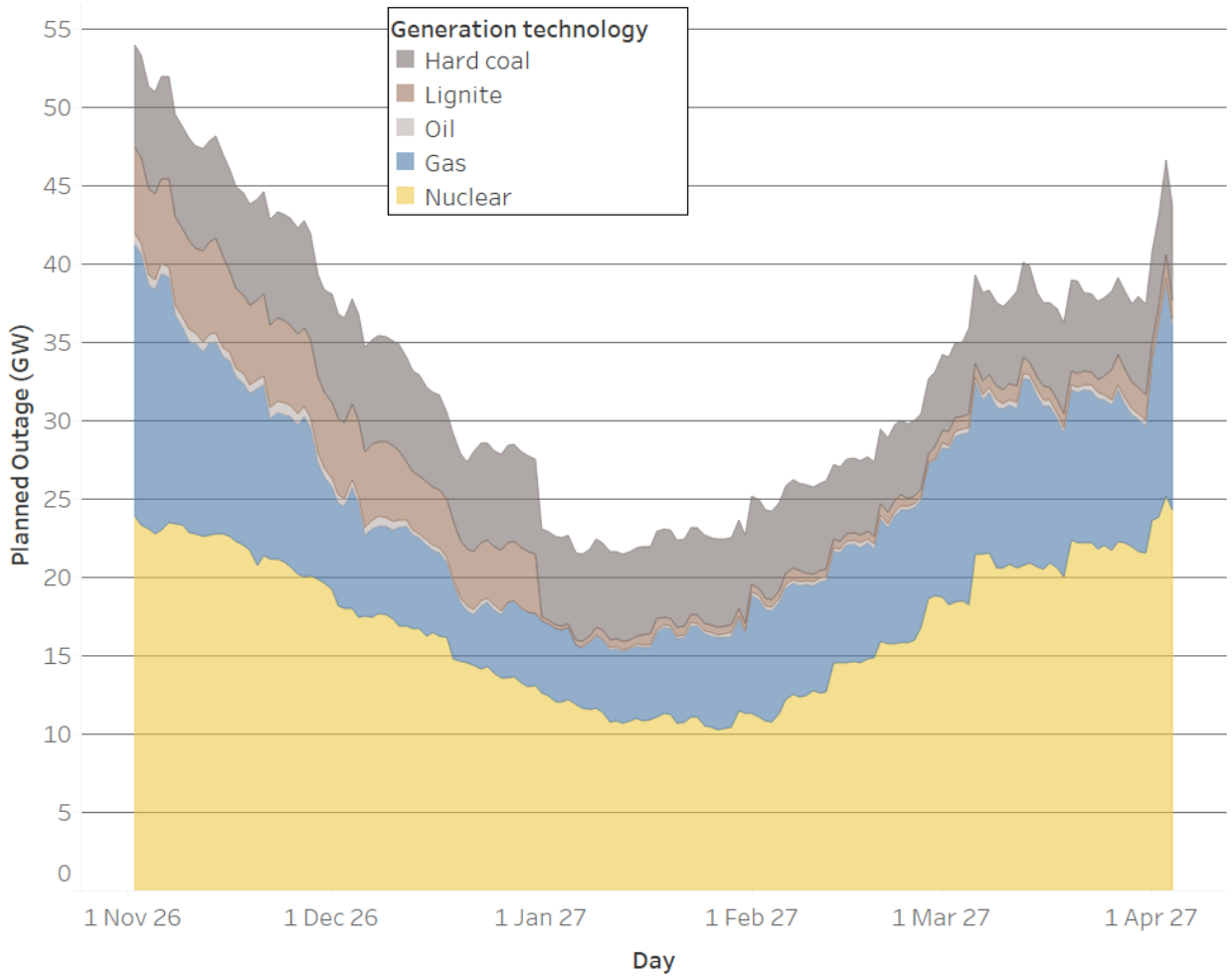


Figure 6. Planned unavailability of thermal generation units 2026–2027.

Figure 7 depicts the weekly share of thermal NGC in planned outages within each study zone. As usual, most countries have minimal maintenance outages planned during the coldest winter period (January and February). However, some countries show a high maintenance ratio compared to the thermal fleet, such as France, Spain, Ukraine, and certain study zones in Italy (e.g. ITCN, ITCS, and ITSI).

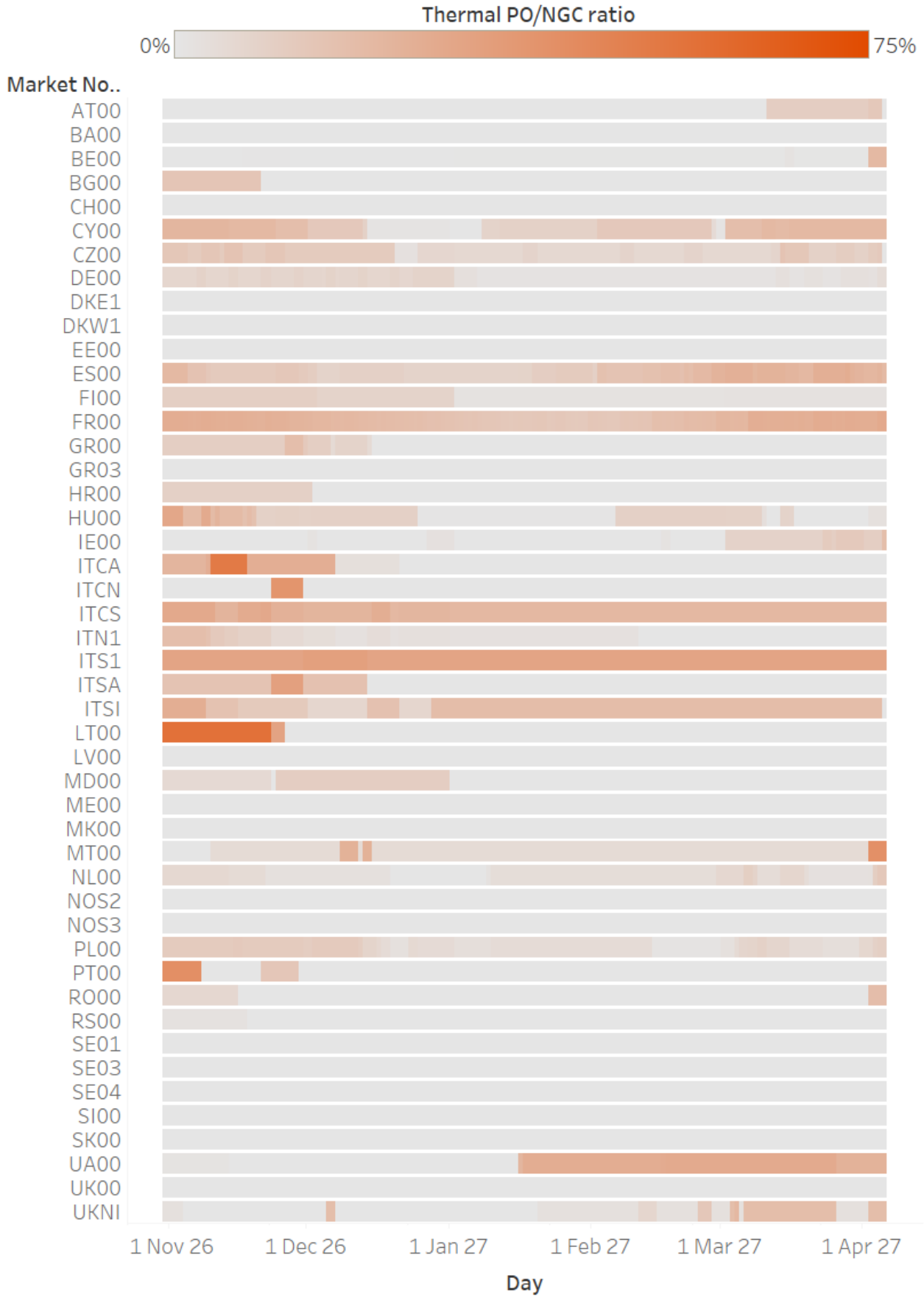


Figure 7. Weekly distribution of thermal planned outage (PO) relative to thermal NGC.

Hydro availability

Figure 8 shows hydro storage level expectations compared to previous winters. Total expected hydro storage levels in November 2026 are well below past levels (2023–2025) and slightly below 2022.

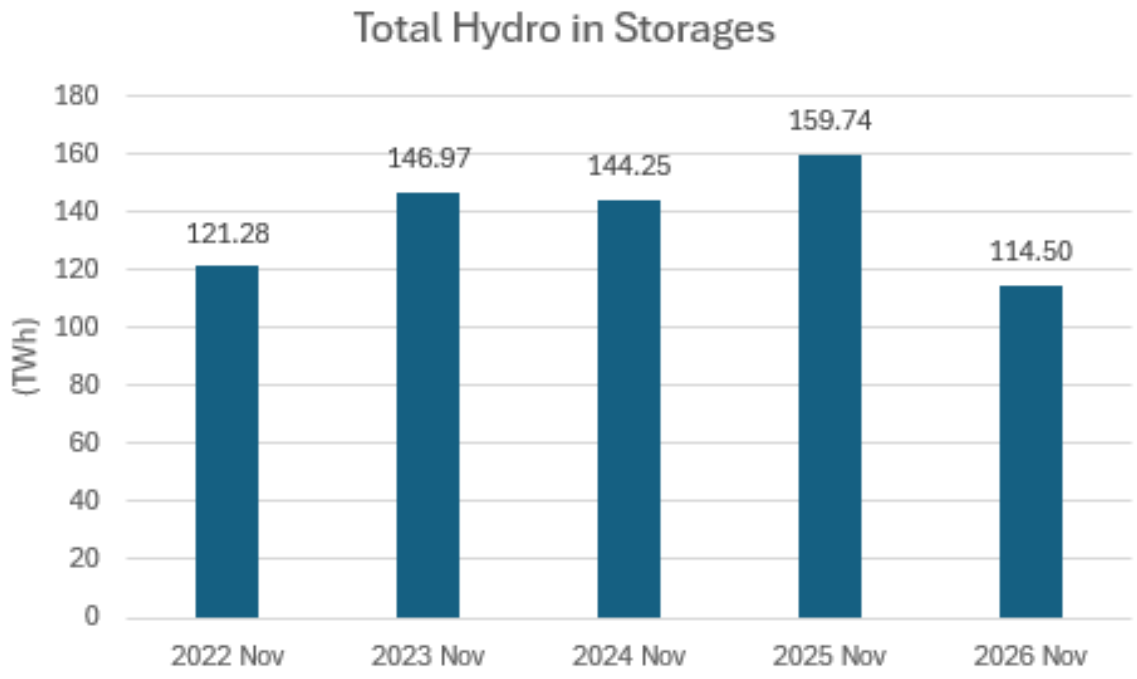


Figure 8. Total hydro storage availability in November in Europe (including the UK and excluding UA, TR, and MD).

Demand overview

Overall EU electricity demand is expected to be slightly higher (0.4%) than the previous year (Figure 9).

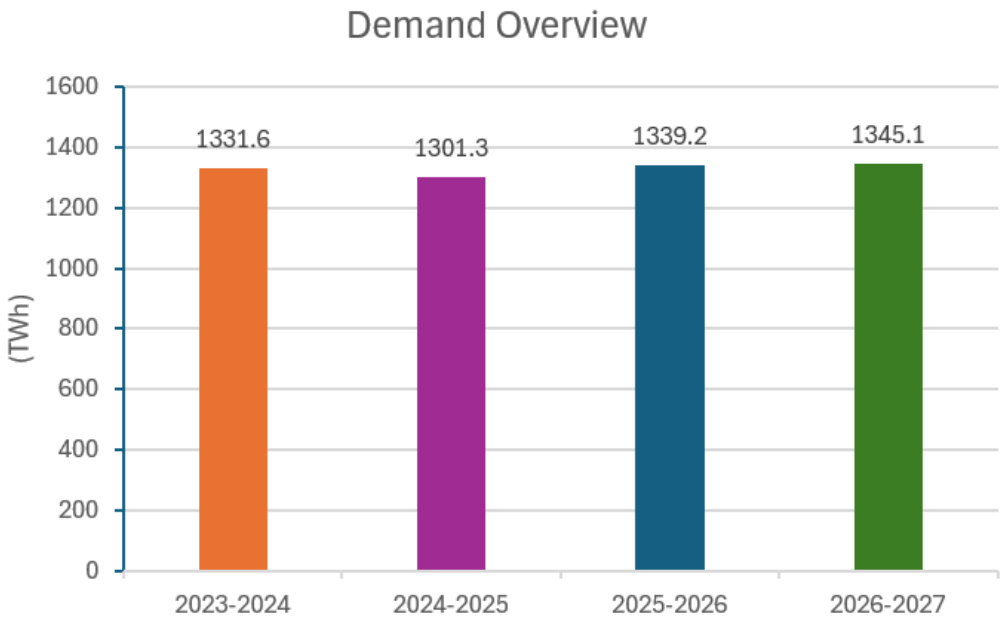


Figure 9. Demand overview: Total demand in winter 2023–2024 (orange), winter 2024–2025 (purple), winter 2025–2026 (blue), and winter 2026–2027 (green). Demand scope includes all of Europe (including the UK and excluding UA, MD, and TR).

Figure 10 shows a heat map by study zone, comparing the expected consumption in each week with the highest expected weekly consumption in winter 2026–2027. The darker shades indicate high expected consumption compared to the highest expected consumption. Typically, January and February show the highest weekly consumption. The workday consumption patterns per study zone are illustrated in Figure 11, where the average demand is plotted relative to the highest average demand in winter 2026–2027. The peak demand in Europe is mostly concentrated during the day.

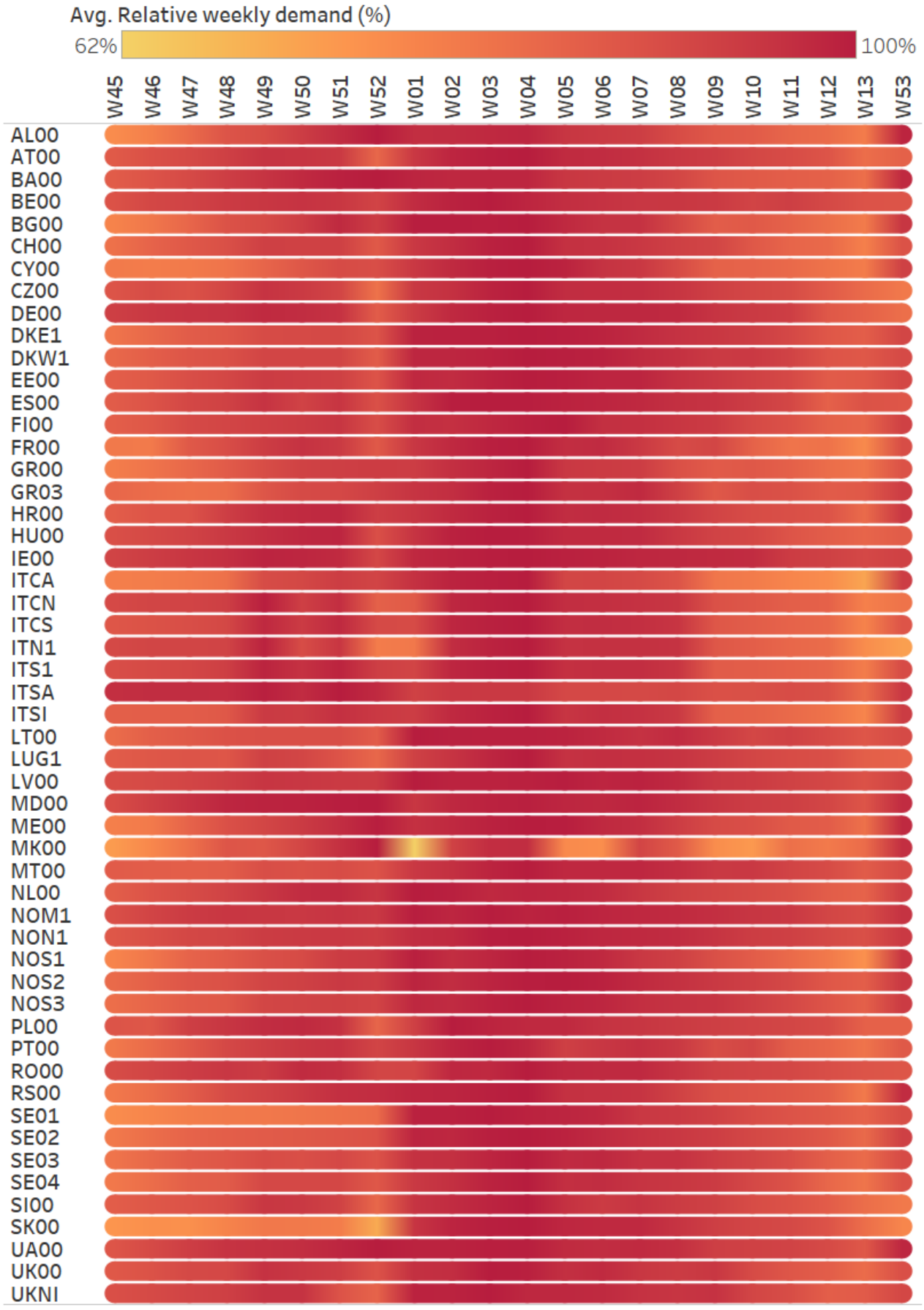


Figure 10. Demand overview: Evolution over winter 2026–2027.

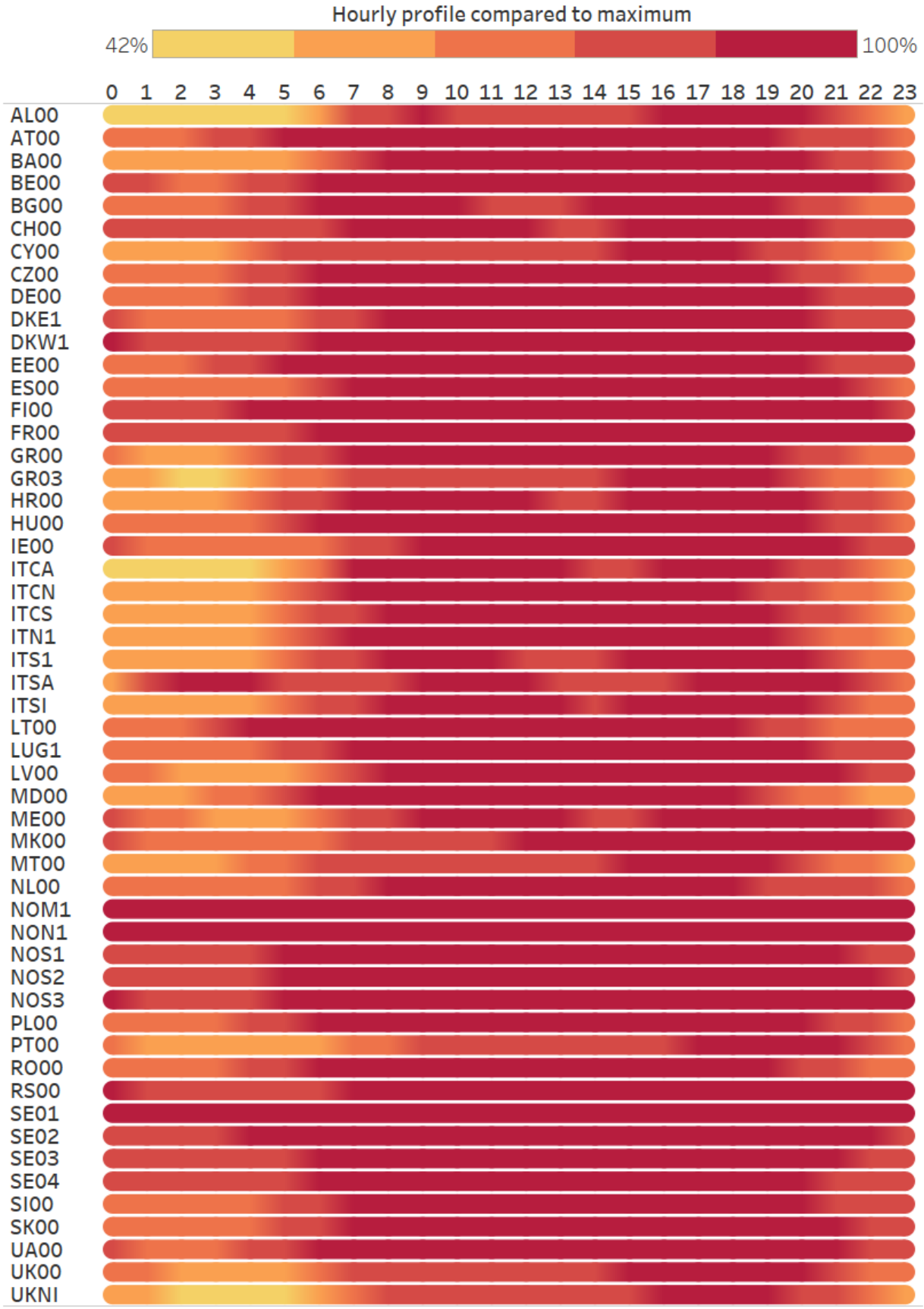


Figure 11. Demand profile overview for Mondays–Fridays in winter 2026–2027.[8]

[8] *The Coordinated Universal Time (UTC) convention was used.*

Network overview

Figure 12 shows the ratio of the lowest import capacity (of the studied period) to the highest expected demand (95th percentile) for the coming winter. It indicates the extent to which systems might be capable of relying on imports from abroad during supply scarcity moments (if generation abroad is available). The lighter the shade of purple, the more interconnection capacity of the market node compared to its own load.

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

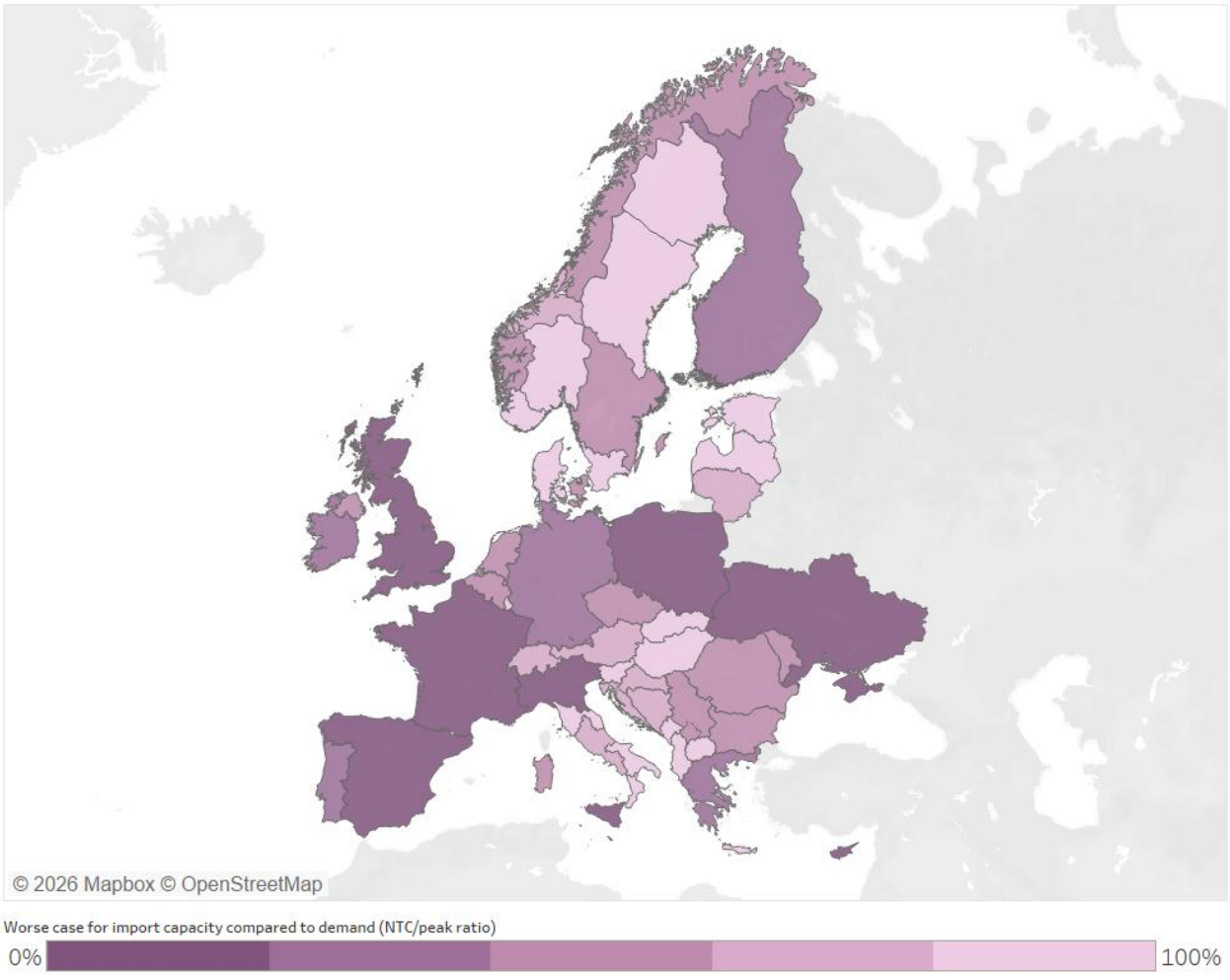


Figure 12. Import capacities per study zone: Ratio between lowest import capacity and highest expected demand.[9]

[9] *Ratios above 100% are also represented in the lightest shade of the scale.*

4. Adequacy situation and gas need during winter 2026–2027

Reference scenario

The adequacy situation during winter 2026–2027 is assessed using a two-step approach. In the first step, adequacy under normal market operation conditions is evaluated. In the second step, non-market resources – such as strategic reserves – are included to assess their sufficiency to solve the risks identified in the previous step. Non-market resources can be activated to address structural supply shortages in the market.

Figure 13 provides an overview of EENS and the presence of adequacy risk for each country for both steps.

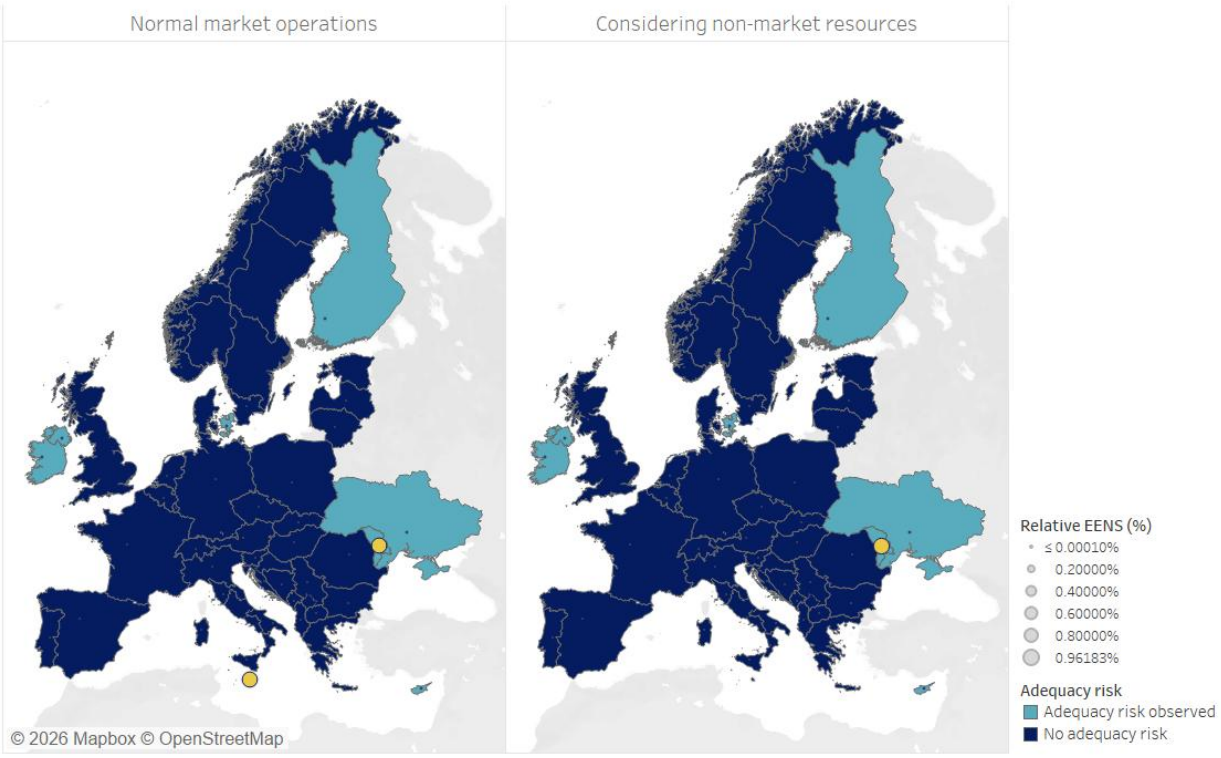


Figure 13. Adequacy overview.

Focus on adequacy under normal market conditions

Under normal market conditions, no adequacy risk is identified for most countries (Figure 14). Risks are present in Cyprus (CY00), Ireland (IE00), and Malta (MT00), which have limited or no interconnection to the European continental network. Traces of EENS and adequacy risk are also visible for Denmark East (DKE1), Finland (FI00), Moldova (MD00), Northern Ireland (UKNI), and Ukraine (UA00).

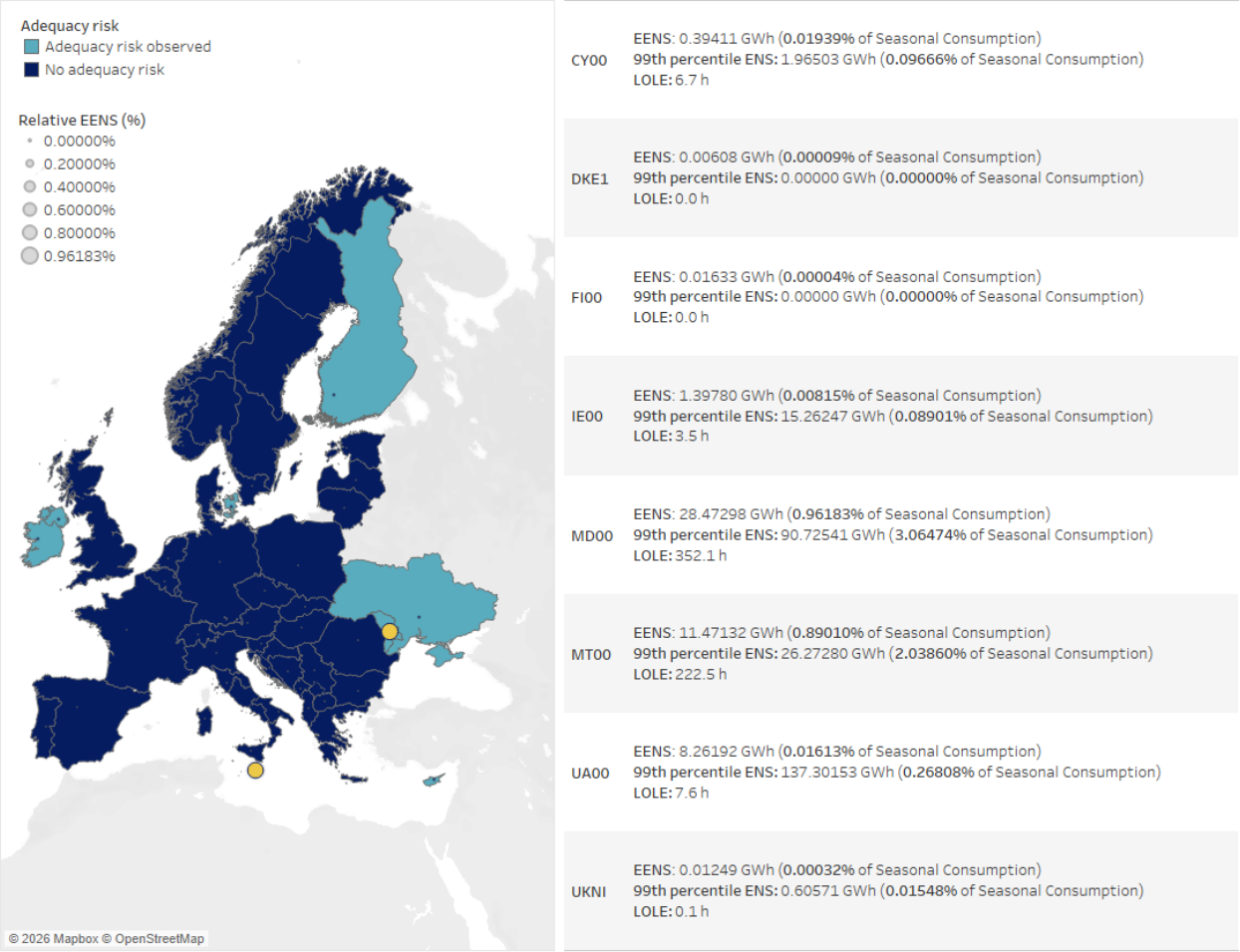


Figure 14. Adequacy risk overview under normal market conditions.

The loss of load probability (LOLP) for winter 2026–2027 at the weekly level is detailed in Figure 15. No common pattern can be observed, as the systems with risks are geographically dispersed, and system-specific conditions may 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 is the maximum across all weeks of the weekly average across all climate years and unplanned outage samples.

Cyprus (CY00) may face risks in the event of adverse weather conditions combined with unplanned outages. The Cypriot system has no interconnection to other power systems and must therefore rely on domestic supply.

Ireland (IE00) has adequacy risks throughout winter 2026–2027, with an expected peak in the first week of March 2027. While generation capacity has increased in the past year, the system may enter an alert state at times, most likely during periods of low wind and low interconnector imports. A similar situation could occur in Northern Ireland (UKNI) at the end of 2026 and in March 2027.

The Maltese (MT00) system may face risks starting in late 2026. Based on careful monitoring of adequacy every winter, Malta has implemented specially designed non-market resources that can be activated in the event of supply scarcity. The impact of these non-market resources is presented in the following section.

The Finnish (FI00) system may face risks at the end of 2026 and the beginning of 2027, while the Danish system could face risks at the end of 2026 in its eastern market node (DKE1), suggesting that supply margins in its system are low. This means that electricity consumers might be affected by a combination of extreme weather conditions and interconnection outages. In Finland, the power system is increasingly dominated by wind power generation, and the reliability of domestic power generation and interconnectors is crucial during cold, calm days.

The forecast for Ukraine (UA00) shows limited adequacy risks this winter. However, it is important to note that this analysis does not cover any disruptive failures of power system elements caused by actions due to the ongoing war. Therefore, the forecasted situation is subject to change at any time.

Moldova (MD00) faces a high risk of supply adequacy throughout the winter due to the significant unavailability of important gas-fired power capacity. As a result, Moldova is highly dependent on other production sources, mainly imports from Ukraine (UA00), which has multiple lines but presents important risks, as noted in the previous paragraph, and Romania (RO00). The exchange capacity between Romania and Moldova is modelled with a single interconnection line.

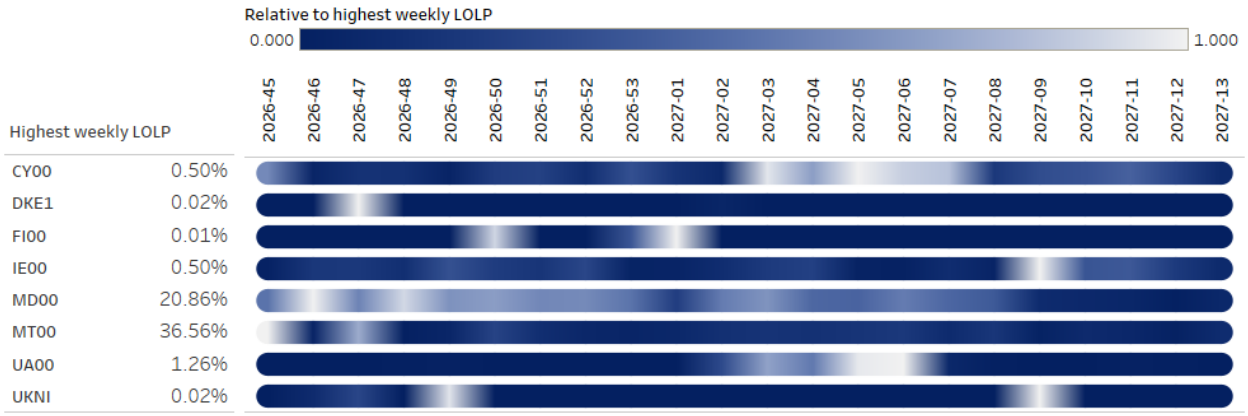


Figure 15. Weekly adequacy insights under normal market conditions.

Focus on non-market resources

Adequacy risks in Malta and Ireland are significantly reduced compared to normal market conditions, with only minimal residual risks remaining due to their reliance on dedicated non-market resources (cf. Figure 18). The activation of these resources can depend on the existing legal frameworks.[10]

Figure 16 presents the adequacy conditions with non-market resources.

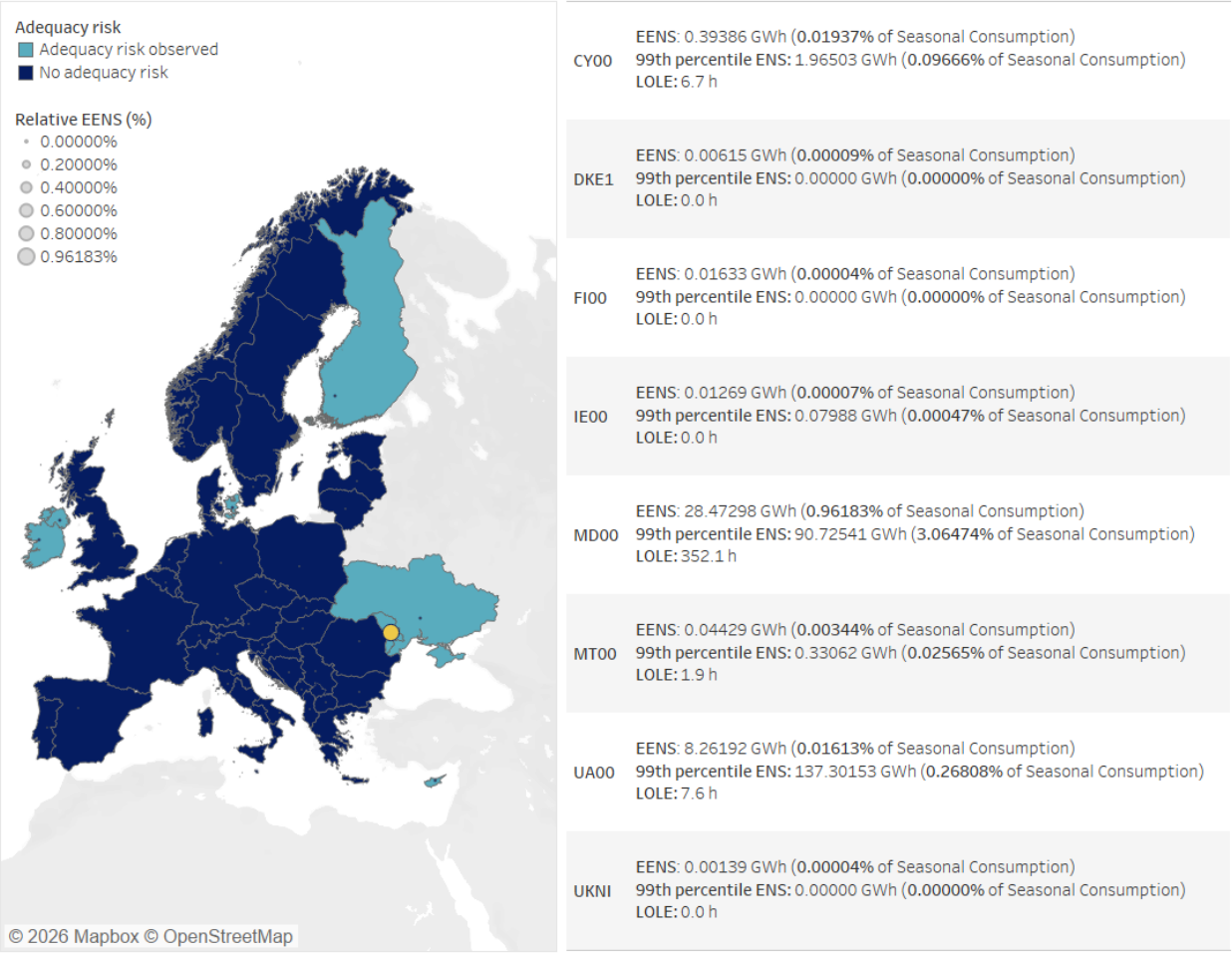


Figure 16. Adequacy risk overview considering non-market resources.

The activation of non-market resources significantly reduces LOLP in Ireland, Northern Ireland, and Malta (Figure 17). The weekly LOLP remains generally elevated in Cyprus in January and February 2027. DKE1 and FI00 present small risks in the event of exceptionally adverse operational conditions combined with low RES production and high unplanned outages. MD00 and UA00 present structural risks.

[10] *The assessment considers pan-European cooperation when activating non-market resources, which means that non-market resources in one country are also considered in another during scarcity (but also considering network limitations). The actual activation of non-market resources abroad might depend on the existing legal framework.*

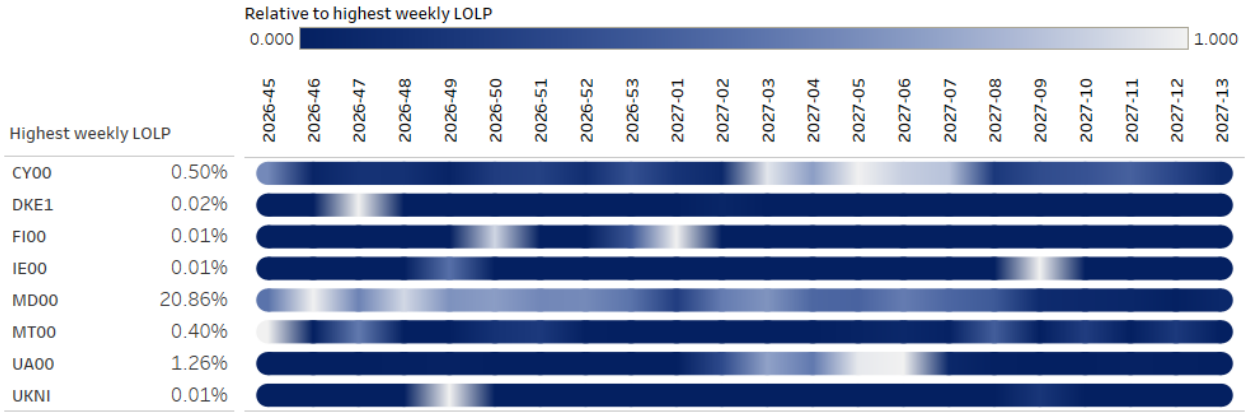


Figure 17. Weekly adequacy insights considering non-market resources.

Figure 18 shows the weekly LOLP and EENS, both under normal market operations (light blue) and considering non-market resources (dark blue). For study zones with higher ENS in normal market operations, spikes are balanced out (less drastic) when non-market resources are considered. As mentioned above, adequacy risks (LOLP and EENS) are significantly reduced in Ireland, Northern Ireland, and Malta when non-market resources are considered.



Figure 18. Detailed adequacy overview of weekly LOLP and EENS.

Critical gas volume for winter 2026–2027

The situation in the European power system for winter 2026–2027 is more uncertain than in recent winters. Geopolitical tensions affecting key maritime routes, notably the Strait of Hormuz and the Bab el-Mandeb Strait, introduce additional uncertainty regarding gas prices and lead to gas storage below historical levels. In addition, hydro reservoir levels are lower than usual due to an exceptionally dry summer in many European countries, reducing the buffer available from hydropower compared with previous winters.

As in previous Winter Outlook assessments, an adequacy and critical gas volume (CGV) analysis was performed to support awareness of potential risks to the European power system. CGV projections consider the most challenging winter scenarios and quantify the minimum gas volume required to ensure electricity system adequacy. Actual gas volumes used for power generation may be higher, depending on ancillary service demand, additional unavailability, and actual market behaviour, including situations where gas-fired units are not the last units in the merit order.

Figure 19 and Figure 20 illustrate the CGV analysis conducted for winter 2026–2027. Peak demand is expected in December and the end of January, with a maximum weekly demand of 105,000 TJ (29 TWh). In total, the CGV need over the studied period accounts for 416 TWh. This represents around one-third of the European working gas volume.[11]

[11] *According to Gas Infrastructure Europe - AGSI on 15 October 2026, including only EU countries for a total of 1,130 TWh Technical Capacity.*

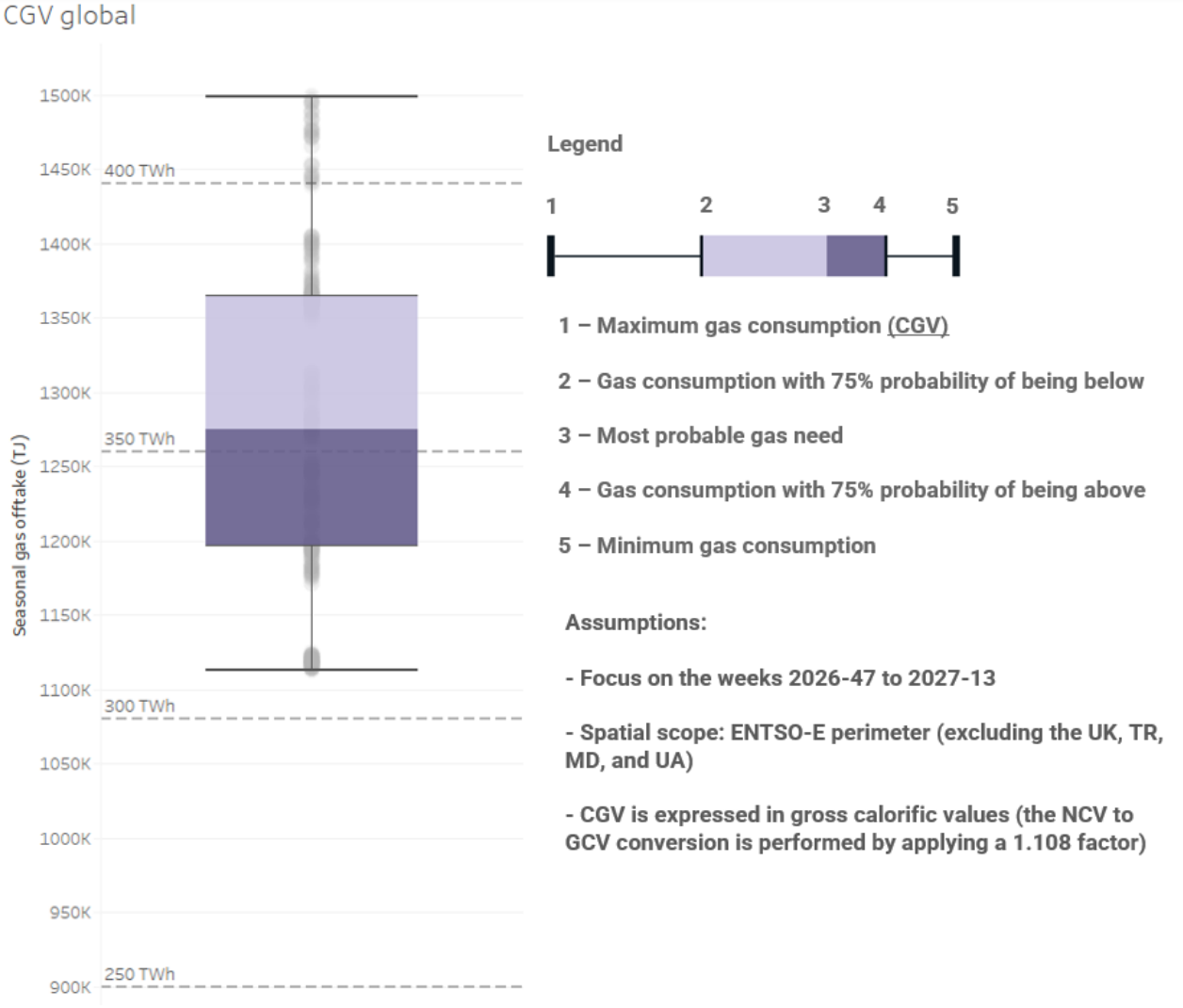


Figure 19. CGV analysis overview.

How to interpret the CGV chart

- Each grey dot represents a historical winter period of gas consumption for electricity generation. The significant differences between periods are primarily related to temperature and climate conditions but can also be influenced by the situation in the electricity market (prices, planned outages, changing generation fleet, etc.).
- The maximum gas consumption corresponds to the necessary gas volume to ensure adequacy in the worst-case simulated weather condition scenario. This maximum is indicated as the CGV to ensure adequacy.
- The dark and light purple colours represent the range of simulation outcomes of gas volume necessary to ensure adequacy for a given year, depending on climate conditions. There is a 50% probability of a given year being in this range.

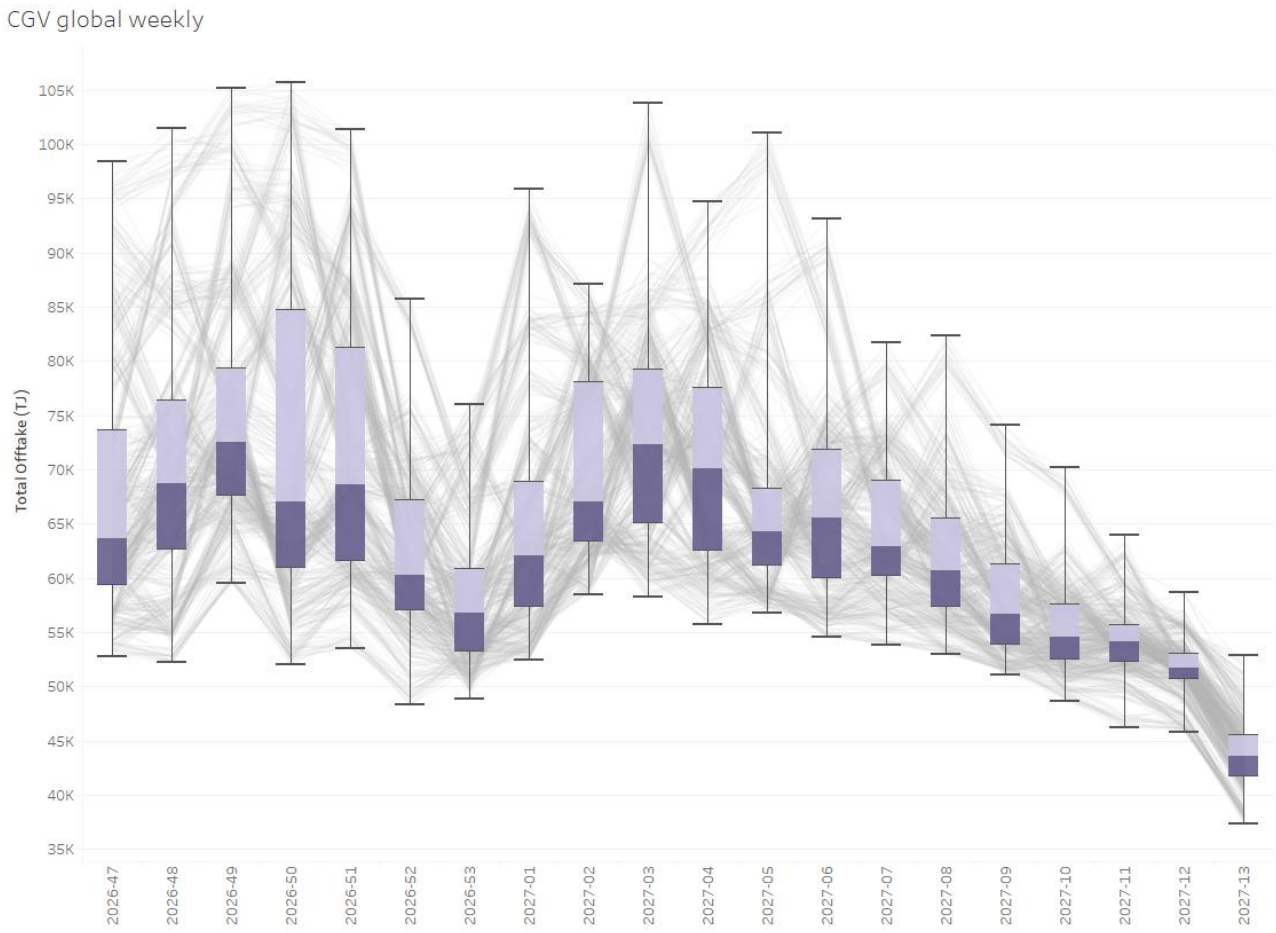


Figure 20. Weekly European gas offtake for the modelled horizon.[12]

[12] *The whiskers of the boxplot indicate the maximum and minimum gas consumption by week.*

Expectations for the Ukrainian and Moldovan power systems

The Winter Outlook 2026–2027 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, TSOs have continuously assessed 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 import and export capacity to the Eastern Europe CCR. ENTSO-E contributes to this calculation by determining the dynamic limits in both directions.

Moldova faces several system adequacy risks for the upcoming winter, including a strong dependence on imports from Romania through a single Isaccea - Vulcanesti interconnector and insufficient Net Transfer Capacity (NTC) allocated for commercial operation to cover the electricity deficit, and vulnerability to disturbances in the Ukrainian power system caused by Russia's war of aggression. Given the insufficient interconnection capacity allocated for commercial operations, the security of supply in Moldova also depends on the reallocation of unused capacity at the borders between Ukraine and European countries, based on a process agreed upon between all relevant TSOs starting from January 2025.

Other concerns include a lack of flexibility in the power system.

Appendix 1: Methodological insights

ENTSO-E has significantly upgraded its methodology for assessing adequacy on the seasonal time horizon since the Summer Outlook 2020 report.

This methodology, described in the Methodology for Short-term and Seasonal Adequacy Assessments,[13] 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, receiving formal approval from 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 the Monte Carlo approach, a set of possible scenarios for each variable is constructed to assess adequacy risks under various conditions for the time frame analysed. Figure 21 provides a schematic representation of this scenario construction process.

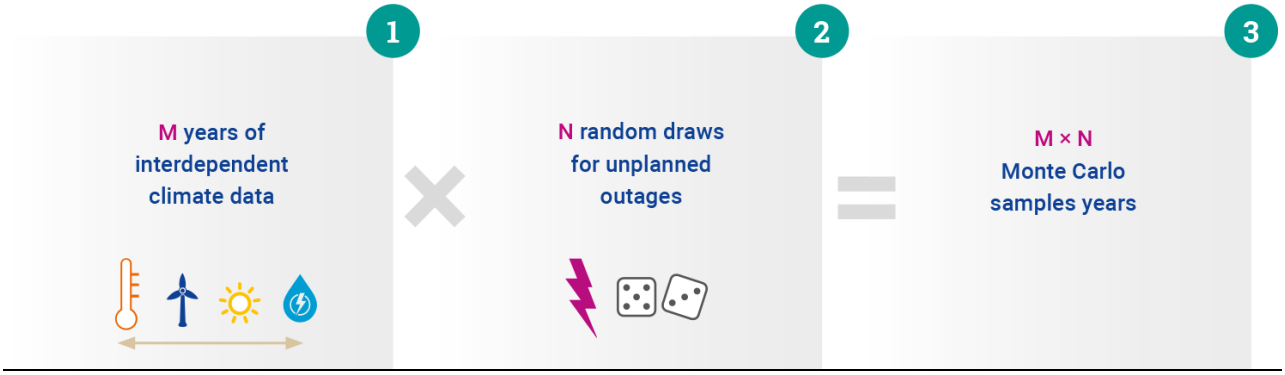


Figure 21. Scenarios assessed in the Seasonal Outlook.

Scenarios are constructed so that all variables are correlated (interdependent) across both time and space. To ensure the highest data quality in the assessments, they are prepared by experts working within dedicated teams. A pan-European climate database (PECD) maintained by Copernicus Climate Change Service (C3S) 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 31 weather scenarios and 20 forced outage patterns. Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 22 illustrates the difference in the number of scenarios between the two modelling approaches.

[13] *Methodology for Short-term and Seasonal Adequacy assessment.*
[14] *https://acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER%20Decision%2008-2020%20on%20the%20short-term%20and%20seasonal%20adequacy%20assessments%20methodology_RPR8_1.pdf*.

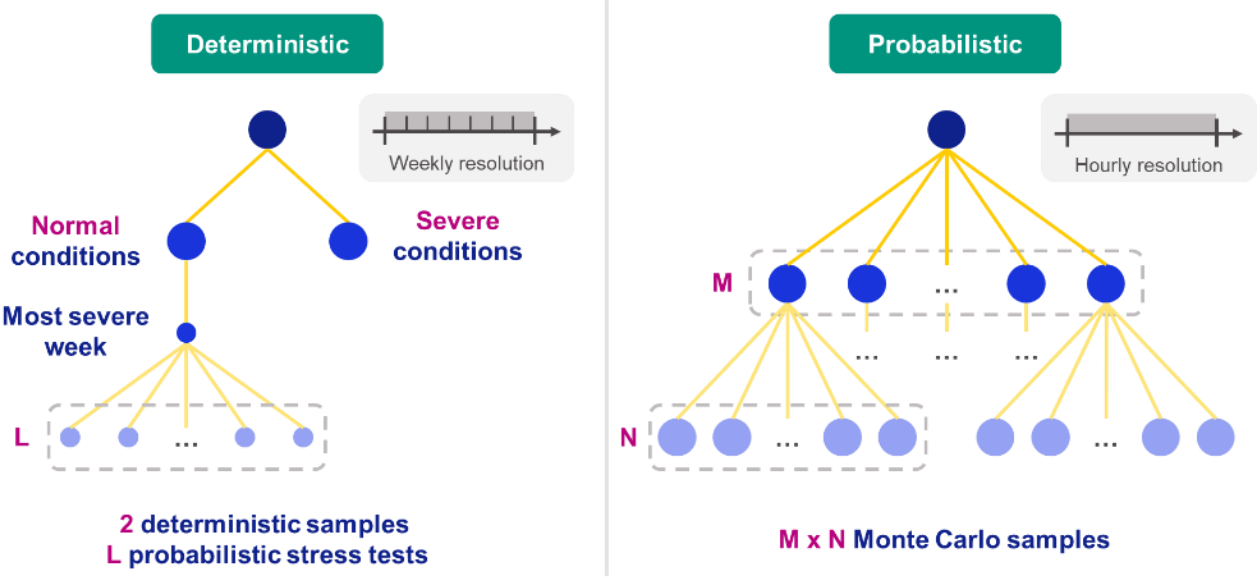


Figure 22. Scenario revolution, from deterministic to probabilistic.

An adequacy assessment is conducted for each sample case on the seasonal time horizon, yielding a probabilistic pan-European resource assessment. It identifies adequacy risks in each deterministic sample and generates numerous consistent pan-European draws while identifying realistic adequacy risk.

Appendix 2: Additional information about the study



Figure 23. Study zones.

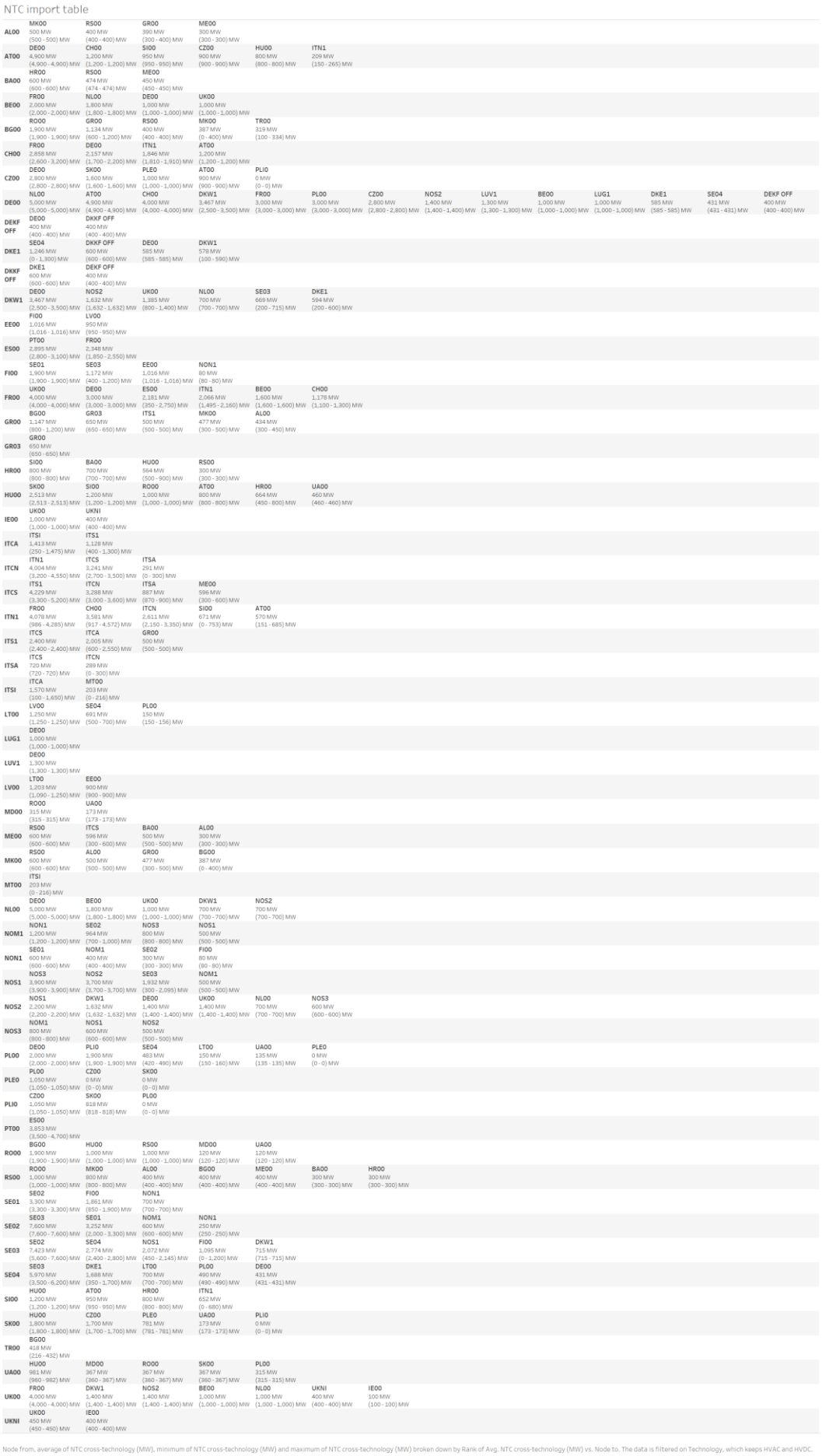


Figure 24. Import capacity overview.

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 has evolved across different seasonal adequacy assessment editions. However, readers are encouraged 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 assessments.

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 provided 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 meets 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, such as 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 meet the reliability standard. The expected situation in an upcoming season could simply be a rather constraining one from a set of possible seasonal scenarios (e.g. low water availability in hydro reservoirs could coincide with a high generation unavailability at the beginning of the season).

It is worth considering whether the reliability standard is defined as a system design target or an operational system adequacy metric target. Europe initially relies on market signals (for supply and network investments) to meet the reliability target set for power system design purposes. If they are insufficient, market design corrections can be made, e.g. by establishing complementary markets, such as capacity mechanisms. The latter market decisions are based on a several-year-ahead framework,[16] whereas Seasonal Outlook reports pertain to an operational time frame that relies on market participants taking short-term corrective actions (e.g. changing planned outage schedules) in addition to TSOs utilising all available resources to minimise risks. Therefore, it is important to understand the purpose of any metric to which Seasonal Outlook results might be compared., This is especially important for LOLE.

Considering the aforementioned background and interpretation limitations, LOLE figures can be found in the main report content (Figure 14 and Figure 16).

---

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

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