Winter Outlook 2022-2023

Summer 2022 Review

Report

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 39 member TSOs, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

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

Our mission

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

Contents

Executive summary

This report provides an assessment of the security of the electricity supply for the upcoming winter season across Europe. It identifies the adequacy risks that are higher compared to previous winters. The main system stresses are identified in the Irish, France, Southern Sweden, Finland, Malta and Cyprus systems where Loss of Load Expectation (LOLE) has risen to higher levels than previous winters and there are simultaneous scarcity situations in various countries. The electricity system remains highly dependent on gas, with minimum gas needs for electricity adequacy equal to approximately one third of total European usable gas storage. Favourable weather conditions may relieve reliance on gas for the power system.

There are some additional risks identified for the winter that may materialise and have a substantial impact on the adequacy situation, especially if they coincide. Close follow-up is needed on the uncertainties around nuclear availability in France, Sweden and Finland, as well as coal supply in Germany and Poland. In the coming months, a continuous monitoring of assumption updates is foreseen, in close alignment with Transmission System Operators (TSOs), ENTSO-E and Regional Coordination Centres (RCCs), in addition to regular exchanges with relevant authorities.

European states have taken specific measures to prepare for winter (gas storage accumulation, extension or returns of some power plants, fuel switching, ambition to reduce electricity consumption). In addition, cutting the electricity demand peaks by 5%, as specified in the Regulation (EU) 2022/1854 as an emergency intervention to address high energy prices, will significantly decrease the adequacy risk.

ENTSO-E and the TSOs have proactively worked intensively since the summer, and this outlook further complements national studies done by TSOs. The report informs on measures ENTSO-E and the TSOs are taking to prepare for the winter and coordinate at all levels to build resilience to the uncertainties/risks for the power system in the current context of energy scarcities. Measures need to be taken by all actors of the system. This is why continuous and close dialogue between TSOs, and with European and national authorities, is ongoing to enable timely coordination and support risk preparedness efforts at all levels.

Summer 2020 Review

The Winter Outlook is accompanied by a retrospect of last summer. In general, no adequacy issues were identified. Adequacy uncertainty for summer 2022 was reflected through soaring electricity prices due to uncertainty of gas and electricity availability. Some countries mention tighter situations due to a relatively dry spring and summer, especially in southern Europe (resulting in low levels in hydro reservoirs); wind generation below average; unplanned outages; and high temperatures affecting the maximum power available from combined cycles gas turbines.

The cuts in electricity exchange with Russia were successfully replaced by domestic generation and imports from Nordics and central Europe.

Introduction

General purpose of the seasonal outlooks

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

The Outlooks are the product of cooperation between 39 European electricity TSOs. Because of their pan-European scope, the Outlooks complement the analysis carried out in national and regional assessments, which provide a more detailed picture of adequacy at the local level. They promote cooperation across Europe and between regional and national stakeholders. The seasonal outlooks model the resource adequacy, not considering specific operational constraints such as grid stability or voltage.

Performing the Seasonal Outlooks (Seasonal Adequacy Assessments) is one of ENTSO-E's legal mandates as specified in the Clean Energy Package and as defined in Article 9 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 the security of electricity supply in the coming season. The Seasonal Outlooks reflect the implementation of the Methodology for Short-term and Seasonal Adequacy Assessments [1] developed by ENTSO-E as per Article 8 of the Risk Preparedness Regulation and as approved by the Agency for the Cooperation of Energy Regulators (ACER) on 6 March 2020. Earlier Seasonal Outlooks (published before 2020) followed a different methodology (deterministic approach).

The interconnected system is a key resource for wider system adequacy. ENTSO-E's Winter Outlook gives results for all ENTSO-E member systems. Data inputs and assumptions from neighbouring interconnected countries are also integrated into the modelling. As in every Outlook, data are collected for Turkey and included in the assessment. The system of Great Britain is strongly interconnected in the North Sea region, and a dedicated collaboration has been set up with National Grid ESO to exchange data. Other neighbouring systems beyond the ENTSO-E perimeter are modelled in a simplified manner by defined hourly exchanges.

Winter 2022–2023 unique context

The 2022—2023 winter outlook is quite different from previous years due to several unique factors, the main one being the war in Ukraine and the subsequent fuel supply uncertainty.

ENTSO-E has been intensively involved in preparing ad hoc analyses about the dependence on Russian fossil fuel in tight coordination with authorities and policy makers. In particular, ENTSO-E has been exchanging with the European Commission (EC) and the Electricity Coordination Group (ECG) on this matter since early March.

In addition to the fuel supply dependency, additional concerns regarding security of supply emerged:

[1] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/seasonal/Methodology%20for%20Short-term%20and%20Seasonal%2D0Adequacy%20Assessment%20-%20ACER%20Decision%2008-2020%20on%20the%20RPR8%20.pdf

- The drought over summer prevented water reservoirs to be filled and also led to a higher electricity consumption for air conditioning. As a result, very low hydro levels were observed until early autumn in Southern Europe and Southern Norway; and

- The low nuclear availability in Europe (especially France) creates increased import needs from neighbouring countries, especially under cold weather conditions.

Europe has stated an ambition to save electricity over the winter 2022–2023, which is presented in the Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices. This ambition is assessed under one of the reference scenarios (c.f. section on scenarios).

Due to the specific context, the winter outlook 2022–2023 has been prepared and anticipated since early spring. First insights were published in the 2022 summer outlook report based on additional analyses from the winter 2021–2022 models. The summer outlook also integrated feedback from TSOs regarding their gas dependency and its reliance on Russian gas supply. During the summer, an early data collection for the winter 2022–2023 period was launched to detect potential adequacy risks at a very early stage. The results of this early assessment are integrated into an Early Insights report published on 20 October. Finally, the present winter 2022/2023 outlook corresponds to the usual seasonal outlook assessment. In addition to the timely anticipation of the winter, the scope of the study was extended with sensitivities as well as analyses of gas volumes needed for electricity generation. Methodological improvements have been integrated at each step, especially to ensure the better representation of gas consumption and of exchange capacities between countries. The table below shows the stepwise approach in publications over the past months.

July	**Summer outlook with winter anticipation**	**Gas dependency qualitative analysis** based on the Winter Outlook 2021–2022 model results: • Calculation of gas volume needed for electricity adequacy; and • Pushing gas to the end of the merit order to save gas. **Sensitivity to Russian gas supply** • TSO survey on gas import dependency from Russia; • Proportion of gas import needed for gas-fired power generation; and • Potential for reduction of gas for power in Europe.

October	**Early insights report**	**2022–2023 winter period from October to March, based on data collected in July**
		• Reference scenario (best estimate projection by TSOs)
		• Multiple sensitivities show additional electricity adequacy risks:
		  Prolonged or increased unavailability of nuclear plants in France, Sweden and Finland
		  • Constraints on the availability of coal/lignite fuel supply in Poland and Germany; and
		  • Increased demand for electricity caused by a switch from gas to electric residential heating.
		• Sensitivities reducing demand for electricity consumption by 10% and peak load by 5%
		For each sensitivity, the critical gas volume (CGV) was assessed on a country and weekly basis

December	**Winter 2022–2023 Outlook**	**2022–2023 winter period from December to March, based on data updates in September** **Three scenarios:** • Reference scenario – Normal demand and additional run with out-of-market resource; • Reference scenario – Low demand: 5% peak power reduction; and • Combined sensitivity – Normal demand with low nuclear and fossil availability. **Update in CGV with respect to must-run plants.**

Coordination at national, regional and European level

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

On the European level

- Exchange on risk preparedness plans via the Electricity Coordination Group and Gas coordination group;
- Winter outlook and updates: If impacting changes in European power system occur this winter, updates to ENTSO-E's winter outlook are possible;
- Following the winter outlook, the Short Term Adequacy (STA) process monitors the coming seven days in rolling-window to detect any adequacy issues on the Cross-Regional (Pan-EU) level;
- The ENTSO-E Assembly made an explicit public statement on 27 October on the crucial importance of exchange capacity for coming winter months; and
- ENTSO-E is ensuring weekly Operational Coordination between all interconnected TSOs and RCCs to enable fast communication and alignment, when necessary, for operational processes.

On the Regional level

- Following the Cross-Regional STA process, in the event of the detection of scarcity situations, a regional STA process exists managed by RCCs with the participation of concerned TSOs to coordinate the proposal of adequacy remedial actions on a regional level; and
- TSOs and RCCs will coordinate during the whole winter to maximise cross-border capacities regionally through an established operational planning coordination (OPC) process.

On the National level

- TSOs conducted national adequacy studies in parallel to the ENTSO-E winter outlook. These national studies may use different sensitivities or focus more on extreme cases, such as the German 'Extraordinary analyses winter 2022/2023', where multiple stress elements coincide. National studies can also consider more detailed constraints, such as internal transmission bottlenecks.
- Each Member State developed a dedicated Risk Preparedness Plan, which includes mitigation measures. The member states set-up coordination with governments, NRAs and key stakeholders to operate these mitigation measures.

Specifically for this Winter Outlook

- The ENTSO-E Winter Outlook regularly reviewed input assumptions to ensure consistent views on demand, plant availabilities and other key parameters such as national mitigation measures for reducing gas dependency. This alignment/coordination ensures results based on which ENTSO-E can draft key messages for all stakeholders;
- Communication between ENTSO-E and ENTSO-G to align assumptions and messages between the gas and electric Winter Outlook

The Winter Outlook's role compared to the ERAA

	Winter Outlook 2022–2023	ERAA
Common principles	The seasonal outlooks and the European Resource Adequacy Assessment (ERAA) aim to model and analyse possible events which can adversely impact the balance between the supply and demand of electric power in different time horizons ahead. Both assessments provide a measure/view of the future power system's ability to maintain the security of supply under a very high number of possible future states depending on various factors that impact adequacy (e.g. weather conditions, outages, generation availability, etc.) and identify potential shortcomings in the system which could be addressed proactively. Both assessments use 34 or 35 weather scenarios compiled from historical data (often referred to as climatic years).	
Timeline	The seasonal adequacy assessments such as the Winter Outlook assess the situation for the forthcoming season.	The ERAA focuses on the horizon 10 years ahead, also including intermediate years.
Methodology	Seasonal Outlooks come with less uncertainty regarding the power system situation as they are based on assumptions which reflect much more closely the real situation a few months ahead. For example, more precise information on planned outages and hydro storage levels is known and is considered in the seasonal outlook studies. Notwithstanding the lower uncertainty, this Winter Outlook still covers various scenarios and sensitivities.	The ERAA mostly indicates the impact on adequacy in the longer run through the economic viability assessment (estimation of resource capacity at risk), which is subject to specific assumptions for the next 10 years. The ERAA also models planned outages but, given the uncertainty in the longer term on the availability of power plants or network elements, the assessment provided spans a wider range of potential possibilities of outcomes for the future. The ERAA takes one central reference scenario as the basis for assessments.
Economic viability	The Seasonal Outlooks provide an insight only into the short-term horizon using predefined unit commitment rules, linked to potential season-specific factors that could create strains on the power system.	The ERAA provides a mid-term view and a risk assessment of which capacities might be lacking revenues to cover their operational costs. This mid-term horizon view is a very important indicator to inform policy-maker decisions on potential incentives to support mid-term adequacy

Scenarios and sensitivities assessed

The Winter Outlook 2022–2023 investigates **two distinct reference scenarios and one combined sensitivity (assessing combined nuclear and coal/gas unavailability in specific countries).** In these scenarios, adequacy and gas needs for European system adequacy (Critical Gas Volume—CGV) are assessed. To estimate CGV, **gas is considered last in the merit order,** meaning gas power plants for electricity generation are started only after all other resource haves been exhausted[2].

ENTSO-E's Winter Outlook does not explicitly model any gas supply disruption scenario. Such assessment would entail too many assumptions, incl. time of disruption, duration, regional coverage, priority use across sectors of gas consumptions, use of storage, etc. This assessment therefore provides for each scenario the reliance on gas for electricity adequacy via the concept of CGVs. These can be monitored on a pan-European basis over a full winter, as well as country/week level. The gas reliance assessment can be read in conjunction with ENTSOG's gas supply outlook under various scenarios. Critical dependency on gas supply is a key constraint factor: there is limited potential for gas saving in the power system in the event of extreme situations (cold spell, other system stress, etc.).

The seasonal outlook considers projected available market resources. Furthermore, it also gives insight into the impact of the integration of **non-market resources for European system adequacy.** It informs TSOs and market participants about adequacy situations and allows them to take further corrective actions (e.g. revising planned outage schemes). After all market and non-market resources are exhausted, TSOs trigger available operational mitigation measures to avoid a controlled demand shedding. One typical operational mitigation measure is voltage reduction, consisting of a light drop in voltage for a few hours, resulting in reduced consumption. Operational mitigation measures are not modelled in resource adequacy simulations.

Reference Scenarios

The **first reference scenario** pictures the 'best estimate' projections from December 2022 to March 2023, based on TSO data updates from late September. This scenario therefore considers the latest best estimate on demand projections, hydro reservoir levels, planned maintenance of power plants and exchange capacities. Confirmed national mitigation measures for winter preparation are also included in this reference scenario.

Notable factors of the reference scenario characterising this Winter Outlook are:

- **Low hydro levels** in Southern Norway and Southern Europe at the start of autumn;
- **Low and uncertain (which is addressed in sensitivity) nuclear availability** over Europe, especially in France.
- **Various national measures** such as a removal of production limits (NL), reopening of coal plants (FR), running of more lignite plants (RO), fuel switching of existing power-plants (IT), return of non-market resources to market (DE).

This reference scenario considers all resources available to supply demand in a market-based approach. As this simulation identifies an adequacy risk in some countries, ENTSO-E carried out an additional simulation

[2] *More information on CGV computation methodology is provided in Appendix 1.*

that also considers the contribution of **non-market resources**. These national defined resources can help mitigate risks at the national level as well as in neighbouring countries[3].

A list of such resource used in simulations is given in Figure

The **second reference scenario** is equivalent in all points to the first scenario except for demand projections. This scenario includes a reduction of demand for electricity by 5% at peak hours, in line with the measures in the Regulation (EU) 2022/1854 for an emergency intervention to address high energy prices[4].

Combined Sensitivity

A combined sensitivity is performed considering several stress factors which coincide this winter. This complements the individual sensitivities assessed in the early insight report[5]. The combination of further reduced nuclear generation availability and fossil fuel supply risks is considered a plausible case of high stress on the system that requires assessment.

This combined sensitivity assesses the impact in case of:

- A **limitation of fossil fuel-based generation** in Germany and Poland:
  - In **Germany**: reduced hard coal (by 4.65 GW on average) and lignite (by 0.27 GW on average) power plant availability; and
  - In **Poland**: limitation on the seasonal generation from hard coal (-7 TWh) and lignite (-2.3 TWh) with respect to historical generation from December until March

- **Prolonged unavailability of nuclear power-plants** in France, Finland and Sweden
  - In **France**: 5 GW lower nuclear availability for the whole winter compared to reference scenario; this is consistent with RTE's lower bound of the 'intermediate scenario'' in the national winter outlook published on 14 September and updated in the RTE mid-November update[6]
  - In **Finland**: 1.6 GW not available through the winter (compared to availability from mid-December in reference scenario) due to the delay in commissioning of Olkiluoto 3. However, import capacity increases by 300 MW if Olkiluoto 3 is not operational.
  - In **Sweden**: 1.1 GW less as of February due to the risks of planned outage extension of Ringhals 4. In addition, internal NTC drops for the second half of March, decreasing by 800 MW from SE02 to SE03 and by 1700 MW from SE03 to SE04.

- Demand profile based on initial projections without reduction, so not accounting for the European emergency measures on total electricity (10%) and peak demand (5%).

[3] *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 may depend on the existing legal framework.*
[4] *More information on peak reduction methodology is provided in Appendix 1.*
[5] *Winter Outlook 2022-2023: Early insight report*
[6] *Actualisation de l'étude Perspectives du système électrique pour l'automne et l'hiver 2022-23 (Novembre) | RTE (rte-france.com)*

Figure 1: Combined sensitivity summary

Overview of the power system in winter 2022–2023

Preparations for Winter 2022–2023

Many Member States took actions to either prepare for the coming winter or mitigate impact (adequacy and gas consumption) during the winter. Preparations include measures such as fuel-switching of some gas power plants, planned outage revisions and stocking gas in storages facilities. Mitigation includes measures such as plans on demand reduction and the revision of response plans[7]. For example, temperature for heating purposes is limited in many public buildings across Europe.

Generation overview

The generation capacity overview in Figure shows 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 may rely more strongly on imports.

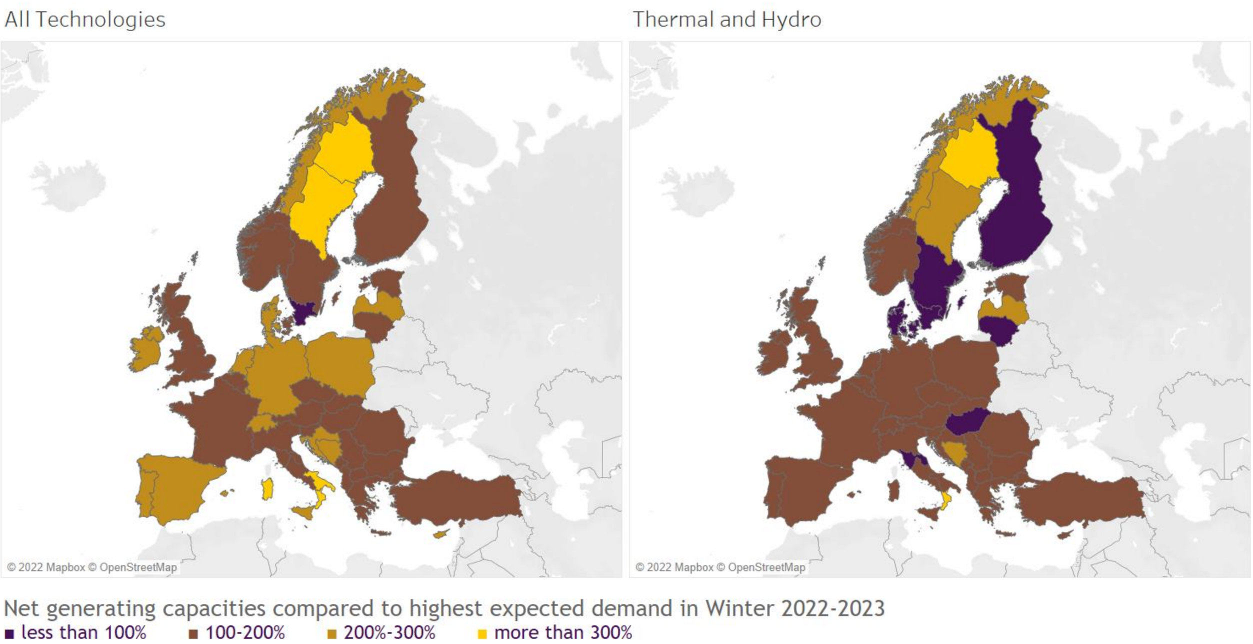


Figure 2: Net generating capacity overview – comparison with highest expected demand

According to Figure 3, thermal net generating capacity (NGC) available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of winter 2022–2023. This is followed by hydro, wind and solar capacities, which constitute the remaining half. In addition, the highest expected demand[8] is depicted with a small black square, and its value as a percentage of each study zone's NGC is given.

In most of the study zones, the thermal NGC share is below 60%. This is especially noticeable in study zones with high hydro capacities. Nevertheless, in some study zones (e.g. Western Denmark [DKW1], Germany

[7] *COUNCIL REGULATION (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas*
[8] *Highest expected demand is computed by taking the highest value of the hourly demand 95th percentiles. Hence, this value is highest expected demand; however, the Seasonal Outlook assessment also considers that demand could even exceed the expected highest value as, occasionally, new peak demand records are registered in Europe.*

[DE00] and southern Sweden [SE04]), the thermal NGC share is low despite insignificant hydro capacities. These systems are characterised by a high share of wind and solar generation.

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

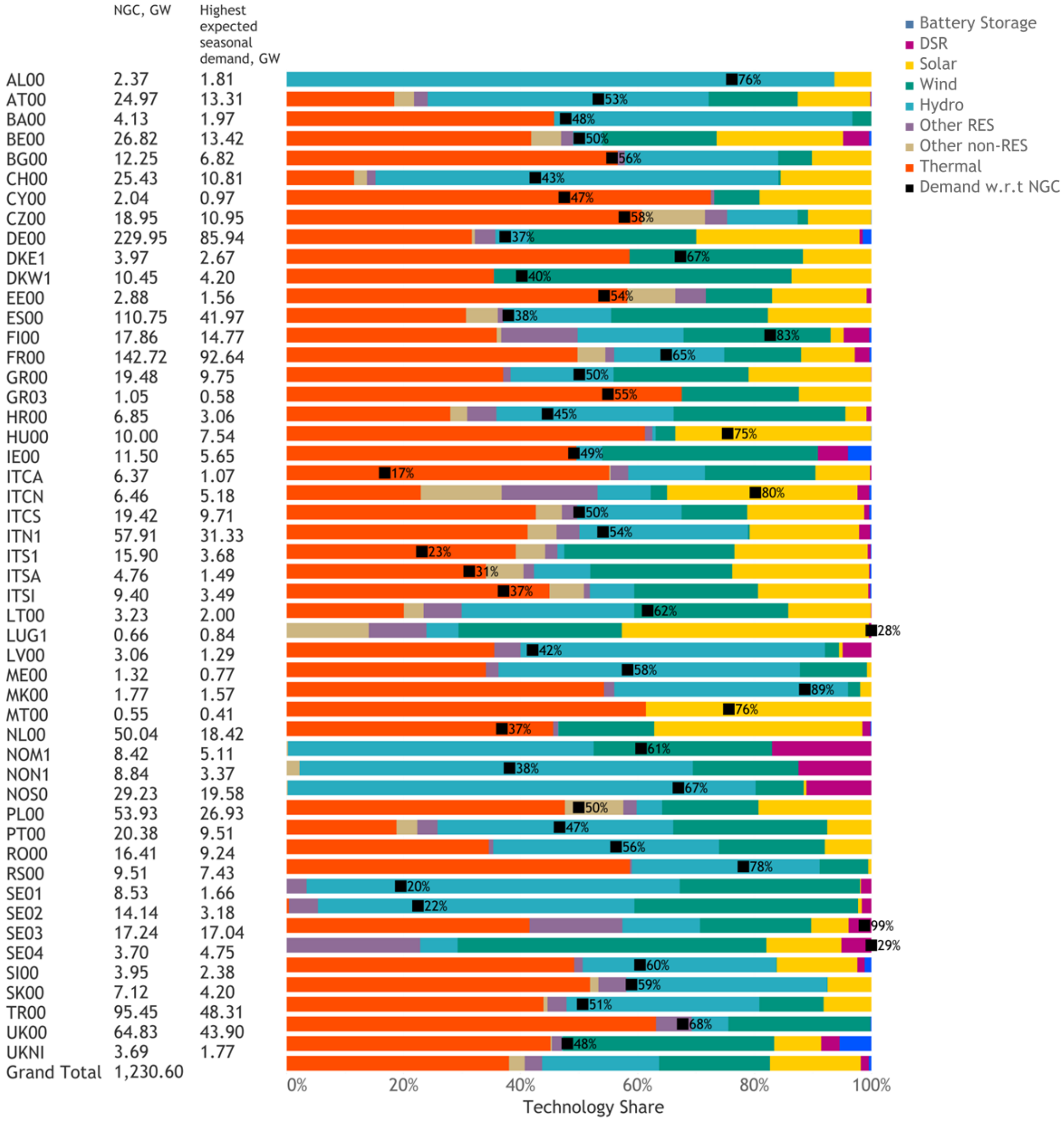


Figure 3: Generation capacity mix at the beginning of winter 2022–2023 per study zone

Figure 4Figure 4: Non-market resources for coping with adequacy challenges in Europeshows which study zones have non-market resources available in addition to the corresponding NGC. In the event of a lack of supply in the market, the activation of dispatchable non-market resources can help address the adequacy challenges. Notable changes compared to the past are:

- Finland did not procure non-market resources for winter 2022–2023. Part of previously contracted capacity is being prepared for commercial use by utilities due to favourable market conditions;

- Germany is marked with the return of some coal-fired power plants to the market which were previously contracted as non-market resources; and

- Poland has been contracting non-market DSR through their capacity markets. These resources can be activated only under very specific conditions and not in a selective manner (i.e. all resources having a capacity market contract must react during the stress events, i.e. both generation and demand side). Hence, this non-market DSR is not represented in seasonal outlook models, but reported here for informational purpose.

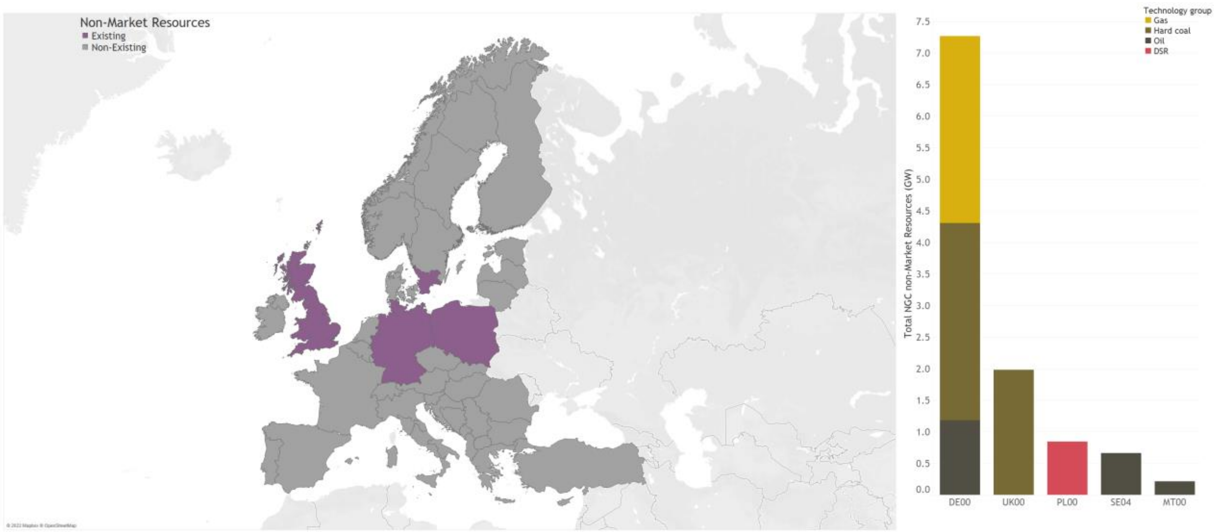


Figure 4: Non-market resources[9] for coping with adequacy challenges in Europe

Capacity evolution

The generation capacity in Europe is growing substantially due to the expansion of renewable generation. Thermal generation is slightly decreasing overall — even though generation capacity of many technologies increases, there is considerable decommissioning of hard coal.

[9] *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 may depend on the existing legal framework.*

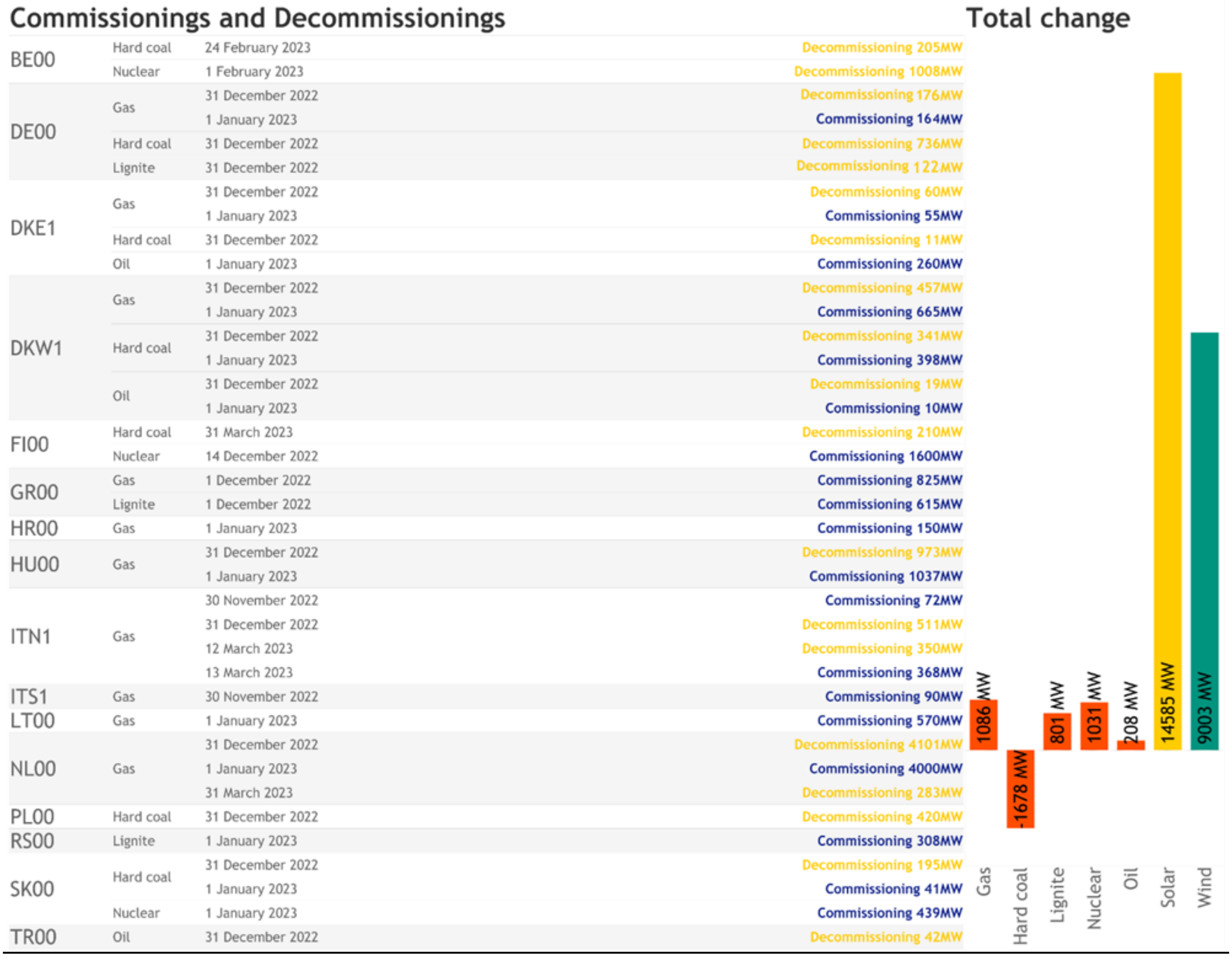


Figure 5: Capacity evolution in winter 2022–2023

Planned unavailability

Figure 6 presents the planned unavailability of units considered in the assessment. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing.

Total planned unavailability steadily decreases towards the end of 2022 and reaches the lowest level in January, when supply margins are tight in Europe (especially in central Europe).

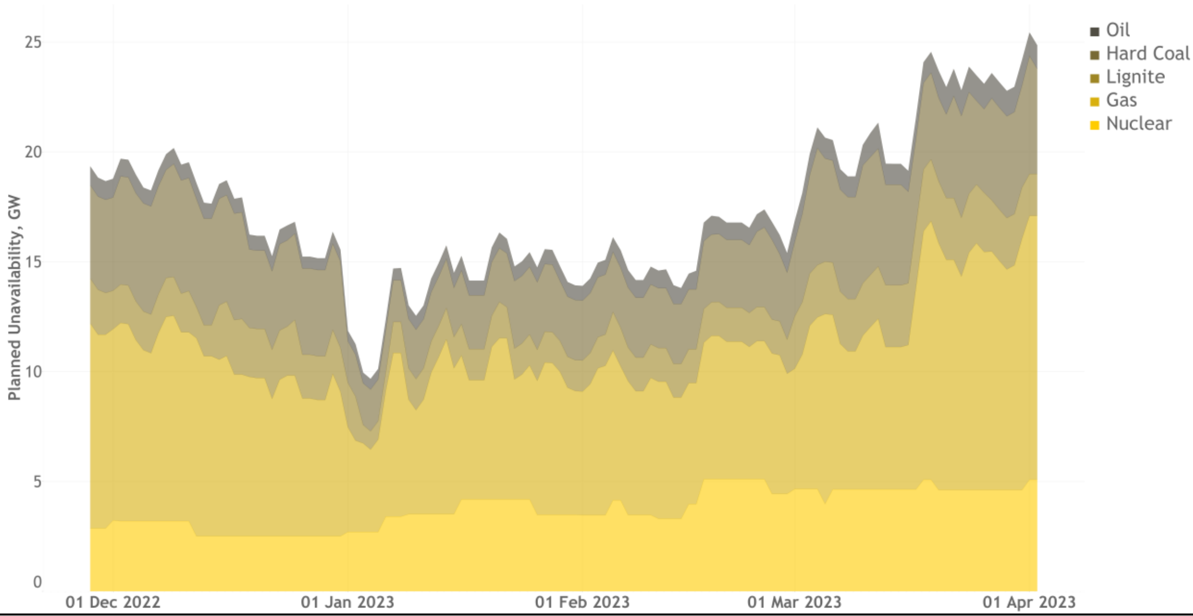


Figure 6: Planned unavailability of thermal units

Planned unavailability in Europe tends to decrease during the coldest months when highest demand is expected. However, planned outages are still notable in some countries (e.g. Portugal and Spain). This can be seen in Figure Figure 7: Weekly distribution of thermal planned unavailability relative to thermal NGC, which depicts the weekly ratio of thermal planned unavailability within each study zone with respect to the total thermal NGC of the respective study zone. In some countries, the planned unavailability varies little throughout the winter or even has an inverse trend (planned unavailability increases towards the mid-winter). This inverse trend can be observed in Greece (GR03), among others.

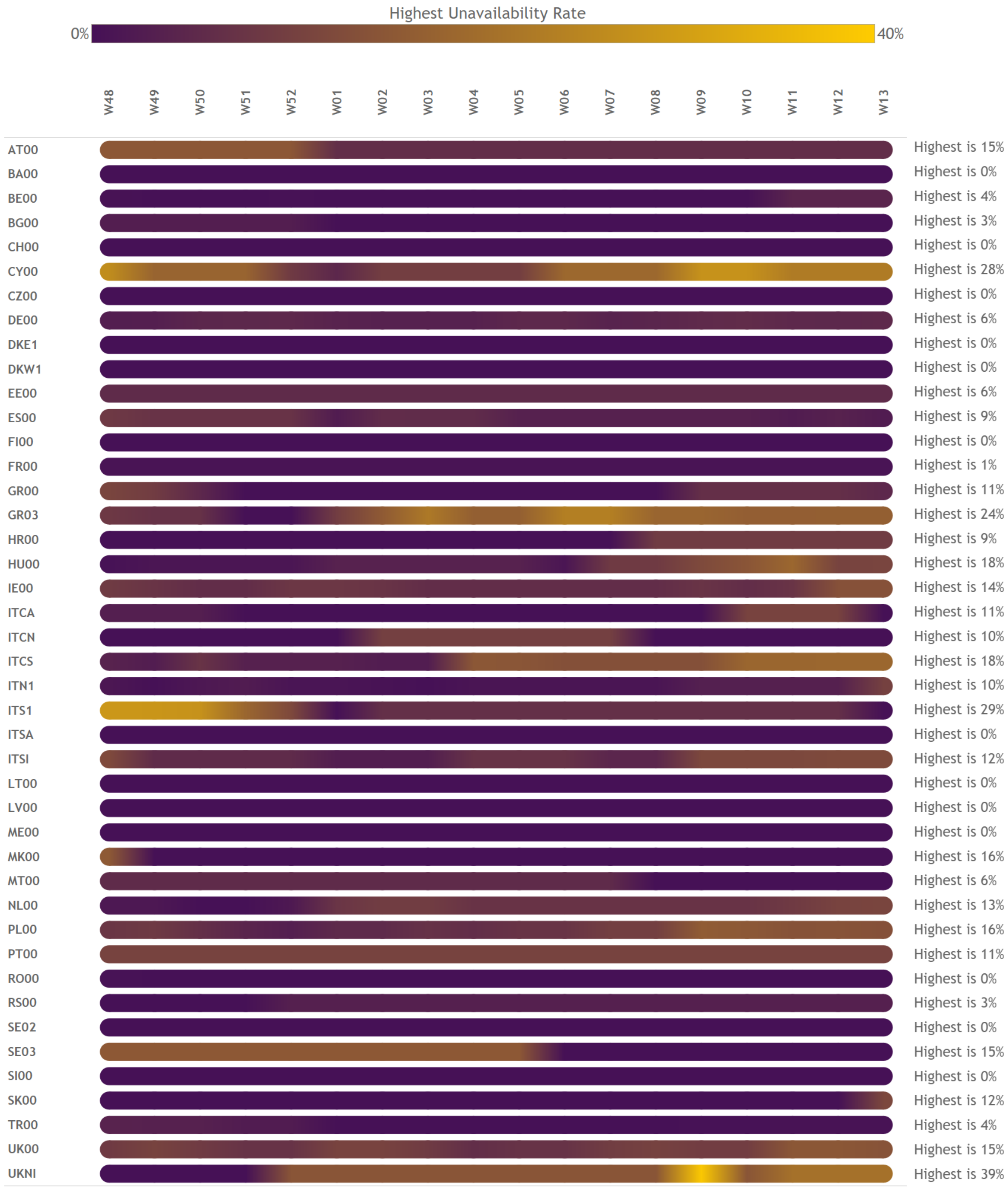


Figure 7: Weekly distribution of thermal planned unavailability relative to thermal NGC

Demand overview

The reference scenario, based on TSO estimates, shows electricity demand with usual variability, comparable with last winter. Furthermore, the highest European demand is expected mid-January to mid-February, although actual weather conditions will have a large impact. At European scale, electricity demand projections are comparable to Winter Outlook 2021/2022, with a post-COVID rebound in demand counterbalanced by a high price effect supressing demand. The impact of EU demand reduction targets is covered in dedicated sensitivity.

The overview of demand (Figure) compares expected consumption in each week with the highest expected weekly consumption in Winter 2022–2023. The darker shades indicate low expected consumption compared to highest expected consumption. This helps to identify holiday periods and other consumption patterns.

The consumption reaches high values in December in most study zones (with typically peaking values in January–February), and does not drop below before March. Meanwhile, noticeable demand drops at the end of the year, suggesting a Christmas break in many countries. A pronounced consumption change in the season is typically present in countries that use electricity for heating (e.g. France in winter) or cooling (e.g. Italy in summer) as this makes electricity consumption very sensitive to outdoor temperatures.

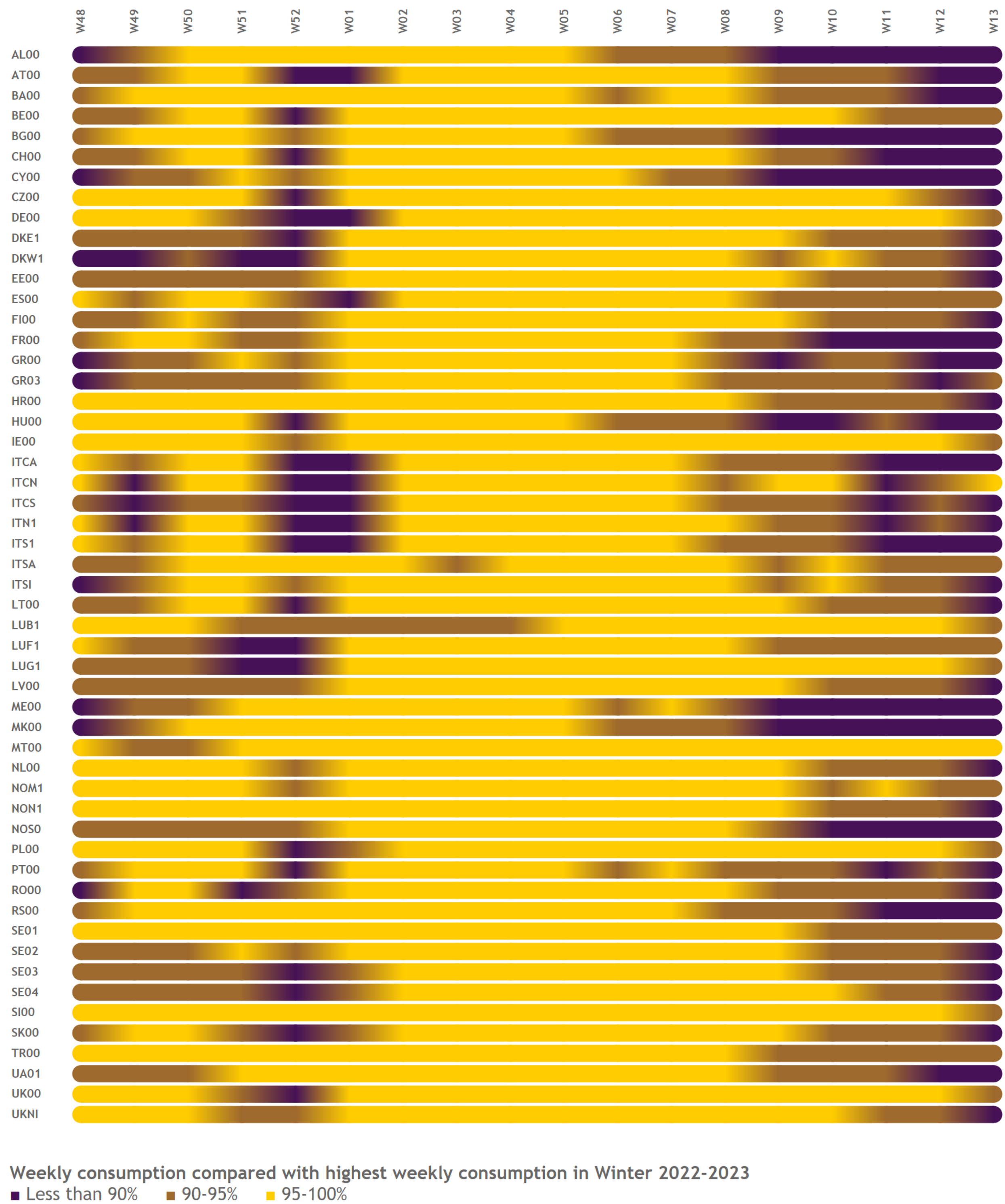


Figure 8: Demand overview – evolution over winter 2022–2023

Figure shows workday consumption patterns per study zone by plotting mean demand compared to the highest mean demand in winter 2022–2023.

Almost all European countries show a clear evening peak. Some countries (e.g. AT00, BE00, CH00, ES00, FR00) typically have distinct morning and evening peaks, with a reduction in demand occurring in the early afternoon. Meanwhile, several Northern and Central European study zones (e.g. CZ00, DE00, EE00, FI00, LT00) display no notable demand variability during daytime.

Figure 9: Demand profile overview during Mondays–Fridays in winter 2022–2023

Level of interconnection

Figure 10 shows the ratio of lowest import capacity in winter 2022–2023 to highest expected demand during the winter. The evaluation of import capacities considers the planned unavailability of grid elements. However, additional unplanned outages may constrain import capacities even further. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, but their contribution is assessed in adequacy simulations[10].

System adequacy relies on all market participants. Efficient market integration and pooling of resources at regional level are key for adequacy support this winter. Cross-border cooperation and close coordination at all levels will be key to ensure that the European power system is adequate. TSOs will coordinate to optimise exchange capacities regionally through close coordination and cooperation within relevant RCCs.

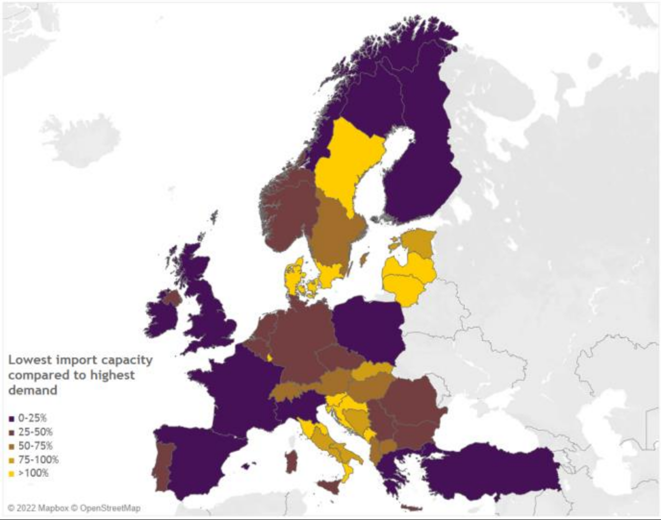


Figure 10: Import capacities per study zone: ratio between lowest import capacity and highest expected demand.

Net exports from Poland may be limited during winter 2022–2023. The adequacy assessment in each scenario considered a lack of net exports from Poland throughout the winter period. The Polish power system is, however, considered fully available for power transit between neighbouring power systems (e.g. between Lithuania/Sweden and Germany/Czech Republic/Slovakia). The underlying reason is that many utilities experience a limited coal stock, often below legally required levels. This results in generation units' unavailability, leading to periods with scarcity risks in the Polish power system, especially during high load and low RES infeed. For these periods, PSE applies allocation constraints to maintain the power system within operational security limits, which is a legally prescribed means defined by CACM Regulation and included in regional capacity calculation methodologies. Allocation constraints are calculated on daily bases, for each hour individually based on the actual adequacy situation. The PSE experience from day-to-day operations, as well as estimates regarding the future situation performed on the basis of information provided by generators, demonstrates that the adequacy situation experienced today will not get better and may even be worse during the coming winter. For this reason, to avoid providing an incorrect picture of the situation, PSE decided to provide the most realistic information for the purpose of the Winter Outlook 2022–2023, i.e. that net exports from Poland will most likely be limited.

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

Adequacy situation and gas need during winter 2022–2023

Adequacy and CGVs are assessed using a two-step approach. In the first step, adequacy under normal market operation conditions is evaluated for the reference and sensitivity scenario. In the second step, non-market resources, such as strategic reserves, are included to assess their sufficiency for mitigating any risks identified in the previous step. This second step is performed for the reference scenario with normal demand. The non-market resources can be activated to cope with structural supply shortages in the market.

The results for winter 2022–2023 (Figure 11) show adequacy risks emerging in a few countries. These risks suggest that there is a likelihood that there will be a need to rely on non-market measures. The CGV for winter 2022–2023 exceeds the records of gas consumption for electricity generation in recent years (winters 2014—2015 to 2018—2019) in all scenarios.

The state of the power system is continuously changing and is different since the data collection (performed in September 2022). For this reason, risks are continuously being monitored by TSOs and RCCs.

Lowering demand (C.f. reference scenario – reduced demand results) can substantially contribute to the mitigation of adequacy risks, though notable risks would still remain in France and Ireland.

Coinciding nuclear availability (France, Finland Sweden) and coal supply disruptions (Germany, Poland) would elevate risks, notably in France and Sweden, and it can raise the risks in Finland and Poland. It would even affect other countries with risks identified in reference scenarios (e.g. Ireland); only Malta and Cyprus would remain unaffected as they have no (Cyprus) or limited (Malta) interconnection with continental Europe.

Non-market resources reduce risks substantially (compared with reference scenario with normal demand) in Malta and Sweden where such resources exist. Non-market resources may support other regions such as Ireland, Northern Ireland and occasionally France, but these systems would rely on non-market resources abroad — especially in Germany — however activation of those may depend on existing legal frameworks[11]. Further non-market measures might be available for TSOs, but their availability is very dependent on the operational situation. Such measures include voltage control, increase of exchange capacities, etc. However, these measures might not always be available (e.g. if some power lines are on outage and the redistribution of power flows is not possible).

[11] 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 may depend on the existing legal framework.

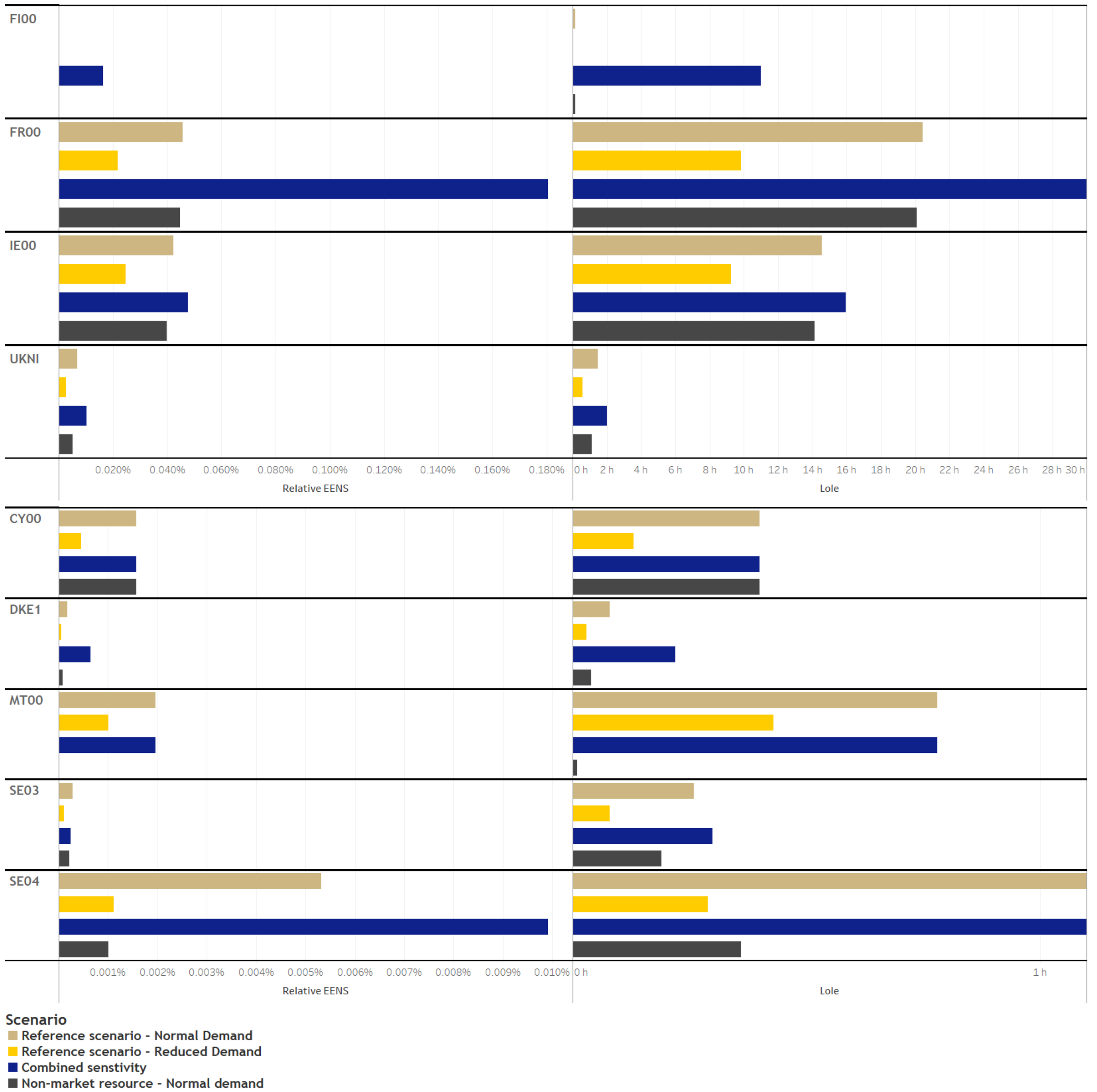


Figure 11: Adequacy overview

Substantial amounts of gas are needed for European system adequacy, which may reach around a third of European Working Gas volume. Approximately a 3% reduction of CGV could be achieved if 5% peak demand reduction was achieved in line with European ambition[12], provided in Council Regulation (EU) 2022/1854 (which is equivalent to ~0.5% of total electricity consumption reduction). On the other hand, the effect of possible issues with nuclear availabilities and/or coal supply issues (c.f. combined sensitivity results) may require almost 12% more gas (Figure 12).

CGV projections consider the worst winter scenarios and inform on electricity system adequacy. Actual volumes may already be higher for certain countries, depending on ancillary service demand, additional new unavailabilities and real market behaviour, with some gas units not being last in the merit order.

[12] *Final value may depend on the actual implementation of regulation by each country. ENTSO-E assumptions may be found in Appendix 1.*

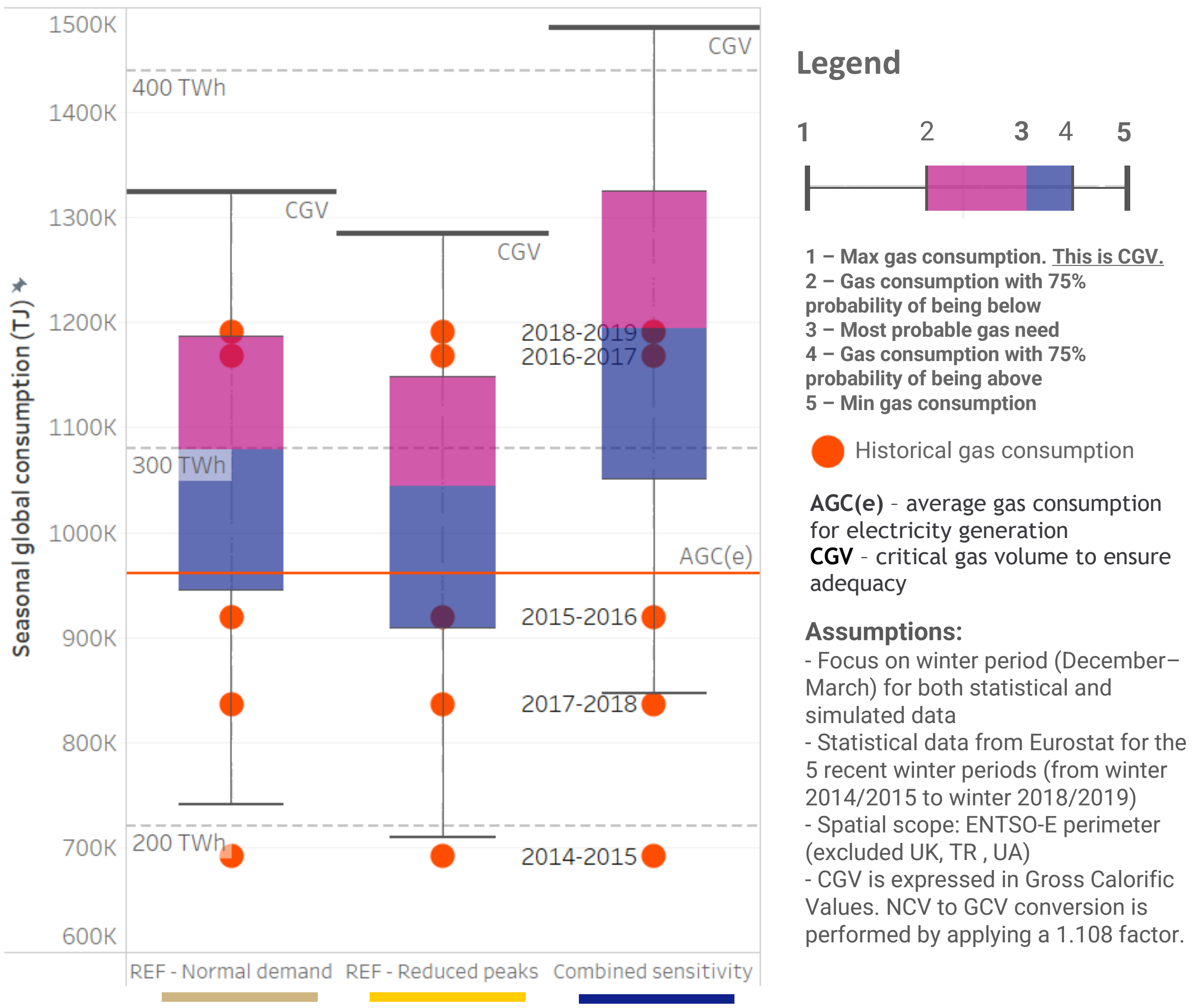


Figure 12: Distribution of European seasonal gas consumption for electricity, all scenarios.

How to interpret the CGV chart

- Each orange 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 AGC(e) (orange line) represents the average gas consumption for electricity generation for the 5 statistical years (orange dots);
- The maximum gas consumption corresponds to the gas volume needed to ensure adequacy in the worst-case simulated weather condition scenario. This maximum is indicated as the CGV to ensure adequacy; and
- The dark and light purple colours represent the range of simulation outcomes of gas volume needed to ensure adequacy for a given year, depending on the climate conditions (the simulation uses 34 climate condition scenarios). There is a 50% probability for a given year to be in this range.

Text box 1: How to interpret CGV charts

Gas consumption for electricity surges as of the beginning of 2023 (Figure 13Figure) with a wider range of possible gas need levels for the 2023 months compared to December 2022. The combination of uncertainty and higher maxima for weekly distributions suggests that particular attention should be paid to January and February.

The gas consumption weekly profile does not vary significantly from one scenario to another.

Figure 13: Distribution of European weekly gas consumption for electricity, Reference Case with normal demand.

Reference scenario with normal demand

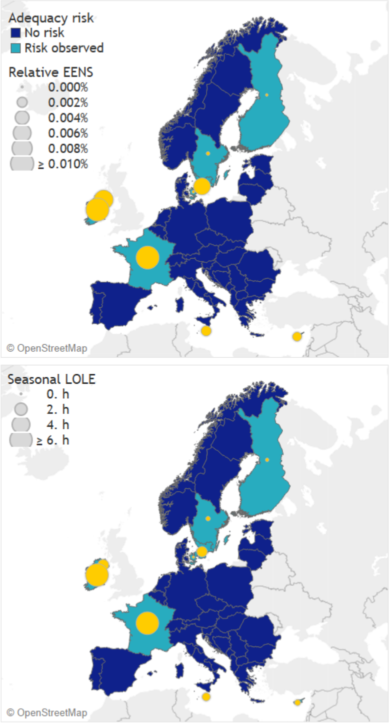
Adequacy risks are identified in Ireland (and to a lesser extent in Northern Ireland), France, Nordics and the Mediterranean islands (c.f. Figure 14). CGV (December – March) reaches ~368 TWh_{GCV} (c.f. Figure 12) with Italy and Germany being major consumers, followed by Spain, France and the Netherlands (c.f. Figure **16**). Adequacy risks and gas consumption increase in January and February especially.

Adequacy in Ireland and Northern Ireland is elevated due to aging gas conventional power plants demonstrating low reliability and often being on unplanned outage. Ireland and Northern Ireland depend on import availability from or through Great Britain, which is notable in most cases. Moments during planned outage of interconnections or any unplanned outages stresses adequacy. Nevertheless, there is considerable wind generation and if wind conditions are good, adequacy issues should be avoided.

The adequacy situation in France is usually dependent on weather condition and nuclear availability. This winter nuclear availability is a key concern for France, especially in light of corrosion inspections being performed since last winter

Risks in Nordics have emerged this winter. The most notable risks are noted in Southern Sweden where there are delays with nuclear planned outages (Ringhal 4). Furthermore, it was rather dry in the Nordics until recent weeks, which suggested low fill rates in reservoirs. No risks are noted in Norway, but reservoir levels may reach low levels.

Risks in Mediterranean islands are also noted. The interconnection planned outage between Malta and Italy was performed earlier this year, hence the likelihood that Malta would need to rely on non-market resources is significantly lower than in previous winters. Nevertheless, in the event of an unplanned interconnection outage they may need to rely on it. Risks in Cyprus are linked to its isolated system.



CY00	**EENS:** 25.00 MWh (**0.00157%** compared to Seasonal Consumption) **99th percentile ENS:** 702.89 MWh (**0.04488%** compared to Seasonal Consumption) **LOLE:** 0.40 h
DKE1	**EENS:** 9.00 MWh (**0.00017%** compared to Seasonal Consumption) **99th percentile ENS:** 262.88 MWh (**0.00469%** compared to Seasonal Consumption) **LOLE:** 0.08 h
FI00	**EENS:** 50.00 MWh (**0.00014%** compared to Seasonal Consumption) **99th percentile ENS:** 1454.35 MWh (**0.00405%** compared to Seasonal Consumption) **LOLE:** 0.16 h
FR00	**EENS:** 88446.00 MWh (**0.04579%** compared to Seasonal Consumption) **99th percentile ENS:** 1462454.90 MWh (**0.75710%** compared to Seasonal Consumption) **LOLE:** 20.43 h
IE00	**EENS:** 5536.00 MWh (**0.04222%** compared to Seasonal Consumption) **99th percentile ENS:** 25667.21 MWh (**0.19572%** compared to Seasonal Consumption) **LOLE:** 14.56 h
MT00	**EENS:** 18.00 MWh (**0.00196%** compared to Seasonal Consumption) **99th percentile ENS:** 352.24 MWh (**0.03763%** compared to Seasonal Consumption) **LOLE:** 0.78 h
SE03	**EENS:** 106.00 MWh (**0.00029%** compared to Seasonal Consumption) **99th percentile ENS:** 1432.35 MWh (**0.00388%** compared to Seasonal Consumption) **LOLE:** 0.26 h
SE04	**EENS:** 553.00 MWh (**0.00533%** compared to Seasonal Consumption) **99th percentile ENS:** 13740.11 MWh (**0.13243%** compared to Seasonal Consumption) **LOLE:** 1.29 h
UKNI	**EENS:** 240.00 MWh (**0.00697%** compared to Seasonal Consumption) **99th percentile ENS:** 3270.02 MWh (**0.09519%** compared to Seasonal Consumption) **LOLE:** 1.46 h

Figure 14: Adequacy risk in EENS and LOLE for reference scenario with normal demand

Most risks emerge in January and February (c.f. Figure 15). Risks in France were detected in December 2022 according to information current to this Winter Outlook; nevertheless it should be noted that according to RTE's national update on 18/11/2022 this risk seems moderate in December 2022 and after February 2023, while it is still high in the first half of January 2023 as a result of lower projections of nuclear production and demand in France having a partially mutual compensating effect. Some risks in other countries appear before 2023, but the majority of risks there are concentrated in January and February.

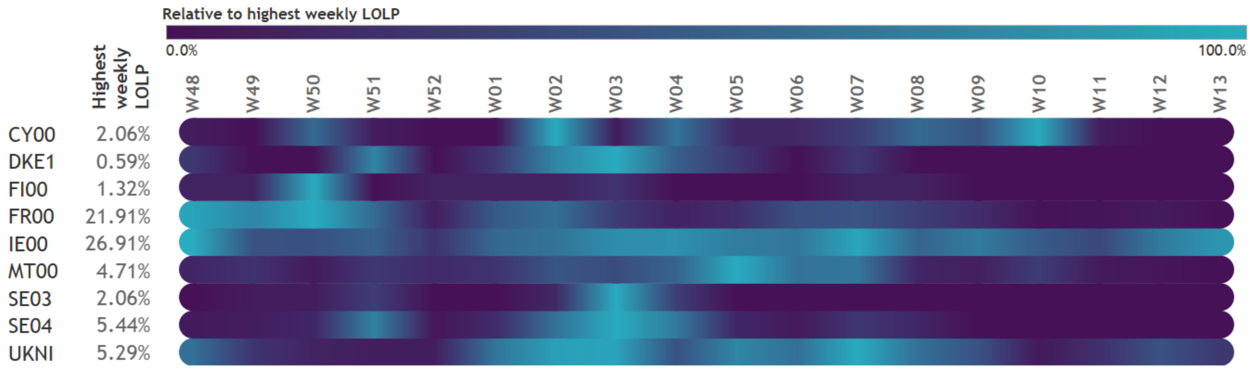


Figure 15: Weekly adequacy insights for reference scenario with normal demand

Seasonal CGV (December – March) reaches ~368 TWh_{GCV} (c.f. Figure 12). Higher fuel requirements for adequacy may be expected for countries which rely heavily on gas in their generation mix (Italy in primis, but also Portugal, Spain, the Netherlands) or countries with a lower dependency on gas but higher power demand (Germany, France). At the same time, distributions of simulation outputs for gas needs for electricity over the coming winter do not follow a clearly defined pattern across countries: the range of gas offtake results, when compared to the average, tends to be the highest in small consumers (Czech Republic, Latvia, Croatia), but bigger consumers such as Spain, France and Portugal are not far behind in terms of probabilistic uncertainty levels (c.f. Figure **16**).

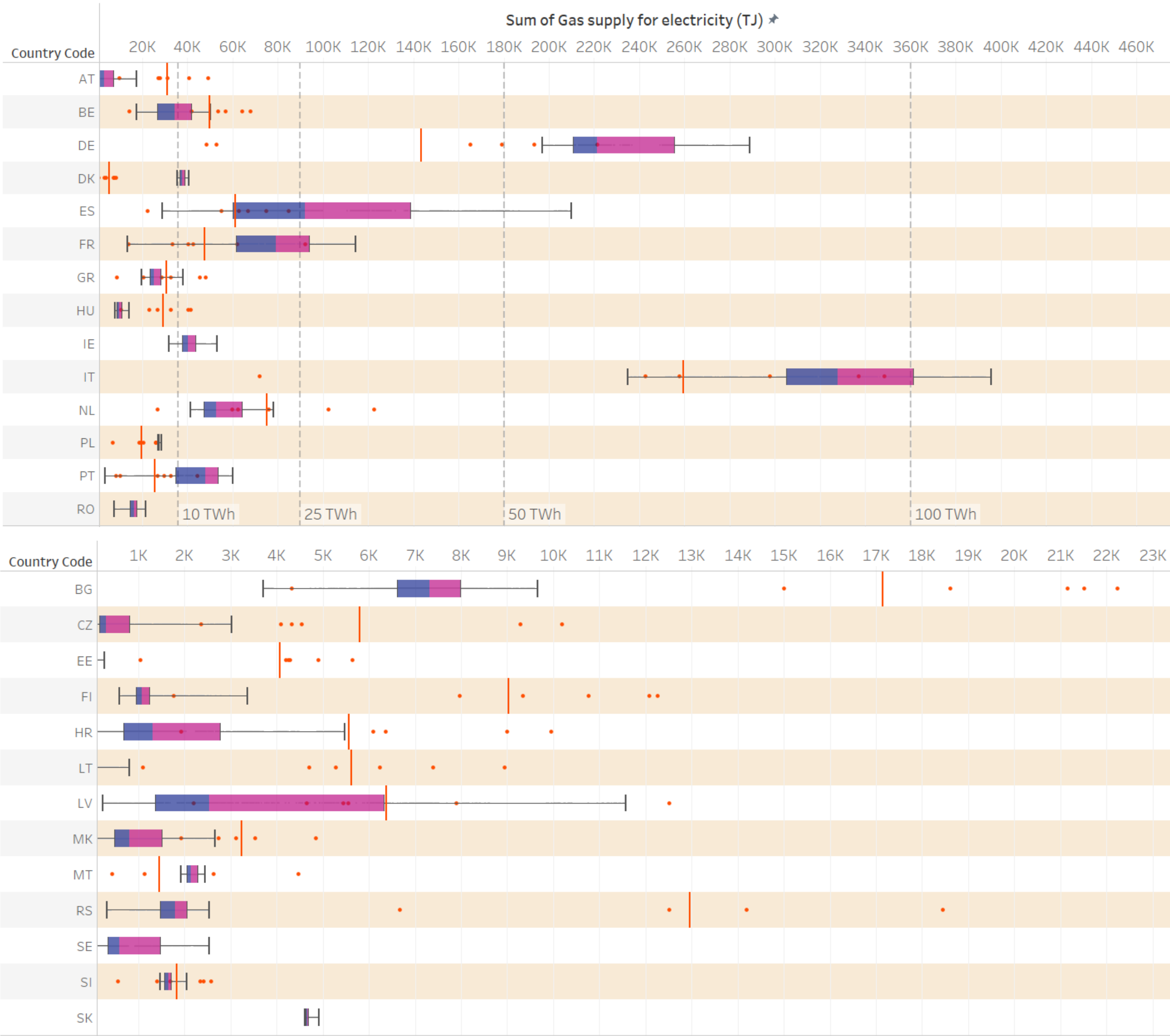


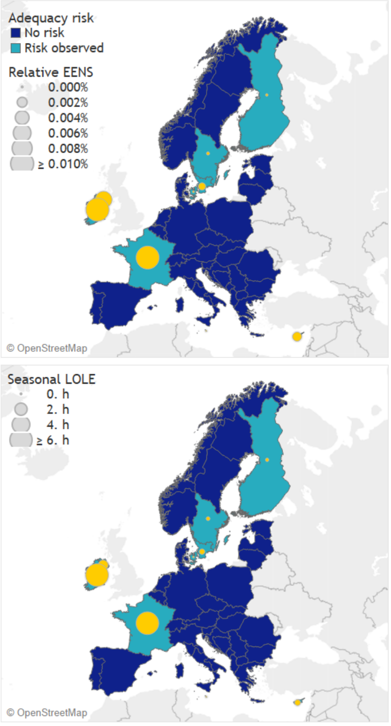
Figure 16: **Seasonal CGV by country, Reference scenario with normal demand**

Impact of non-market resources

Applying non-market resources reduces risks[13] substantially in Malta and Sweden, where such resources exist. Non-market resources may also support other regions such as Ireland, Northern Ireland and occasionally France, but these systems would rely on non-market resources abroad — especially in Germany — however, activation of those resources may depend on existing legal frameworks[14]. Details of residual risks after activation of non-market resources are given in Figure 17, while Polish non-market DSR is excluded due to specific conditions of activation.

[13] Compared with reference scenario with normal demand, on which non-market resources were assessed.

[14] 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 may depend on the existing legal framework.



CY00	EENS: 25.00 MWh (**0.00157%** compared to Seasonal Consumption) **99th percentile ENS:** 702.89 MWh (**0.04488%** compared to Seasonal Consumption) **LOLE:** 0.40 h
DKE1	EENS: 4.00 MWh (**0.00008%** compared to Seasonal Consumption) **99th percentile ENS:** 6.24 MWh (**0.00012%** compared to Seasonal Consumption) **LOLE:** 0.04 h
FI00	EENS: 47.00 MWh (**0.00013%** compared to Seasonal Consumption) **99th percentile ENS:** 1424.94 MWh (**0.00397%** compared to Seasonal Consumption) **LOLE:** 0.15 h
FR00	EENS: 86316.00 MWh (**0.04469%** compared to Seasonal Consumption) **99th percentile ENS:** 1447057.38 MWh (**0.74913%** compared to Seasonal Consumption) **LOLE:** 20.10 h
IE00	EENS: 5223.00 MWh (**0.03983%** compared to Seasonal Consumption) **99th percentile ENS:** 22616.78 MWh (**0.17245%** compared to Seasonal Consumption) **LOLE:** 14.12 h
SE03	EENS: 79.00 MWh (**0.00021%** compared to Seasonal Consumption) **99th percentile ENS:** 1058.69 MWh (**0.00286%** compared to Seasonal Consumption) **LOLE:** 0.19 h
SE04	EENS: 105.00 MWh (**0.00101%** compared to Seasonal Consumption) **99th percentile ENS:** 2711.97 MWh (**0.02614%** compared to Seasonal Consumption) **LOLE:** 0.36 h
UKNI	EENS: 180.00 MWh (**0.00524%** compared to Seasonal Consumption) **99th percentile ENS:** 2604.45 MWh (**0.07582%** compared to Seasonal Consumption) **LOLE:** 1.14 h

Figure 17: Adequacy risk in EENS and LOLE in the reference scenario with normal demand after applying non-market resources

Weekly adequacy (c.f. Figure 18) results suggest that there are residual risks in February for Malta which means that non-market resources may be insufficient there. Swedish results suggest that the majority of risks can be addressed, but special attention should be still paid to week 3 (January).

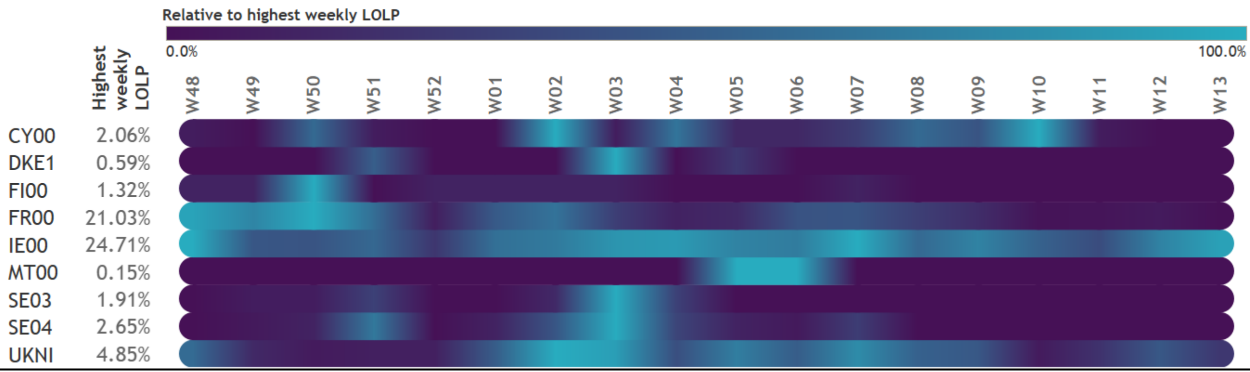
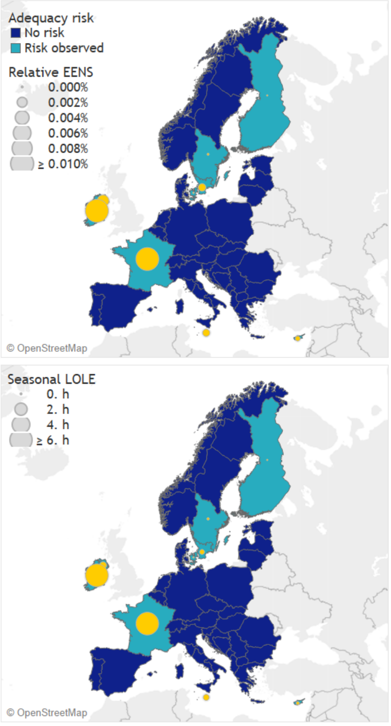


Figure 18: Adequacy insight for the reference scenario and normal demand with non-market resources applied

Reference scenario with 5% peak demand reduction

Adequacy risks decrease notably everywhere if efforts are made to reduce demand peaks (c.f. Appendix 1: for methodological details on demand reduction). Details on residual risks can be seen in Figure 19, where notable risks are only seen in Ireland and France, yet substantially decreased compared with the reference scenario with normal demand. CGV reaches only 357 TWh_{GCV}, which is 3% lower compared with the reference scenario with normal consumption (c.f. Figure 12). All of this can be achieved by reducing peaks, which could affect only around 0.5% of total electricity consumption.



Zone	
CY00	EENS: 7.00 MWh (**0.00046%** compared to Seasonal Consumption) **99th percentile ENS:** 158.32 MWh (**0.01011%** compared to Seasonal Consumption) **LOLE:** 0.130 h
DKE1	EENS: 3.00 MWh (**0.00005%** compared to Seasonal Consumption) **99th percentile ENS:** 0.00 MWh (**0.00000%** compared to Seasonal Consumption) **LOLE:** 0.030 h
FI00	EENS: 5.00 MWh (**0.00001%** compared to Seasonal Consumption) **99th percentile ENS:** 0.00 MWh (**0.00000%** compared to Seasonal Consumption) **LOLE:** 0.020 h
FR00	EENS: 42044.00 MWh (**0.02177%** compared to Seasonal Consumption) **99th percentile ENS:** 1062940.58 MWh (**0.55027%** compared to Seasonal Consumption) **LOLE:** 9.830 h
IE00	EENS: 3247.00 MWh (**0.02475%** compared to Seasonal Consumption) **99th percentile ENS:** 18471.10 MWh (**0.14084%** compared to Seasonal Consumption) **LOLE:** 9.250 h
MT00	EENS: 9.00 MWh (**0.00101%** compared to Seasonal Consumption) **99th percentile ENS:** 215.56 MWh (**0.02302%** compared to Seasonal Consumption) **LOLE:** 0.430 h
SE03	EENS: 37.00 MWh (**0.00010%** compared to Seasonal Consumption) **99th percentile ENS:** 0.00 MWh (**0.00000%** compared to Seasonal Consumption) **LOLE:** 0.080 h
SE04	EENS: 115.00 MWh (**0.00111%** compared to Seasonal Consumption) **99th percentile ENS:** 1968.74 MWh (**0.01897%** compared to Seasonal Consumption) **LOLE:** 0.290 h
UKNI	EENS: 89.00 MWh (**0.00258%** compared to Seasonal Consumption) **99th percentile ENS:** 2471.06 MWh (**0.07193%** compared to Seasonal Consumption) **LOLE:** 0.580 h

Figure 19: Adequacy risk in EENS and LOLE in the reference scenario with demand reduction

The weekly distribution of risks does not change substantially (c.f. Figure 20).

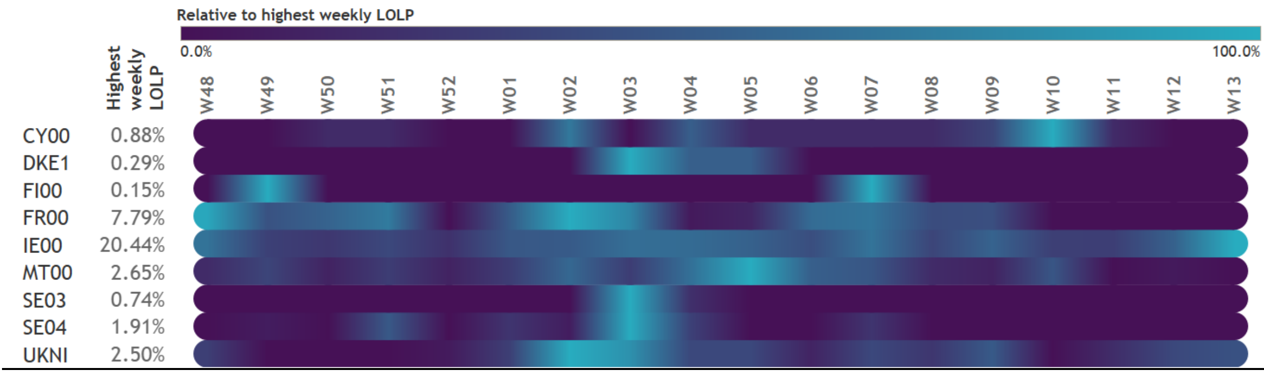


Figure 20: Adequacy insight for the reference scenario and reduced demand

European seasonal CGV reaches only ~357 TWh_{GCV} from December to March, which is 3% below CGV identified in reference scenario with normal demand (c.f. Figure 12). This is no surprise, even considering that only 0.5% of electricity consumption is reduced, because Europe is making an attempt to reduce consumption during peak hours, when gas units may need to be dispatched.

Study zones relying heavily on gas in their generation mix are inevitably driving the decrease in European figures but are not necessarily the most impacted ones, (c.f. Figure 21)[15]: while Italy and Germany present a decrease in their country-specific CGV of around 3%, gas requirements for adequacy in the Netherlands and Greece are reduced by almost 6%. On the other hand, changes in outcomes are barely shown in France, which is also among the major consumers. These differences highlight the varying response to the analysed measure in multiple zones, the ones using gas for peak consumption being affected more than the ones using it for baseload (or under scarcity conditions).

[15] *Please consider that these figures do not forecast gas consumption for coming winter. Some regions expect higher gas consumption — e.g. Spain —because they have access to gas supplies beyond their CGV needs.*

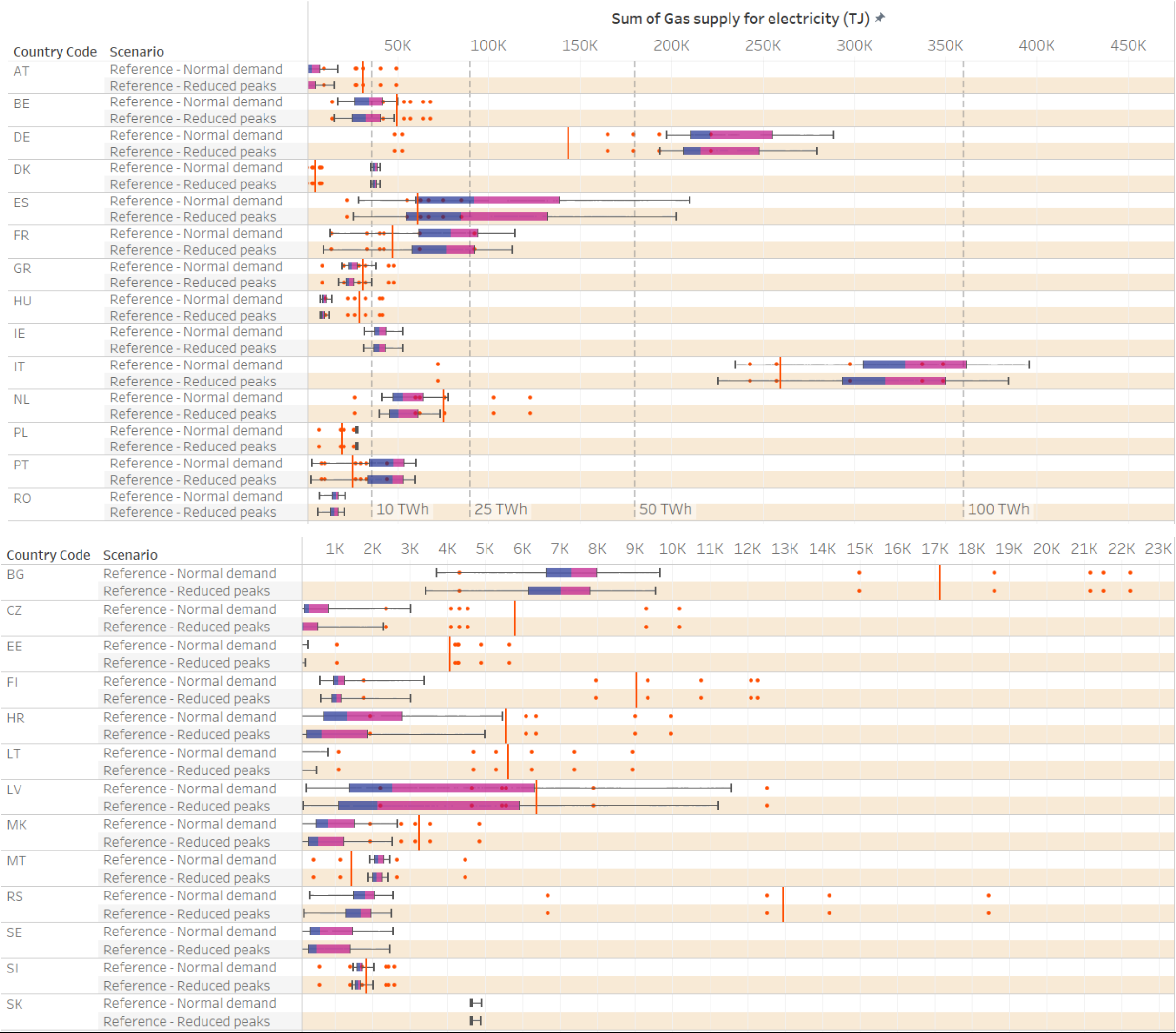


Figure 21: Seasonal CGV by country, Reference Cases

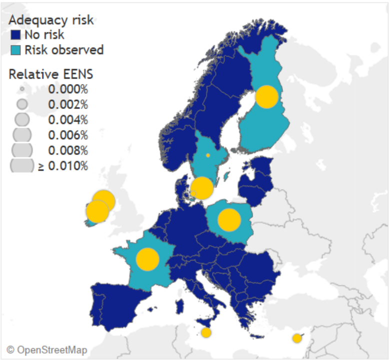
The temporal distribution of gas requirements for adequacy does not change significantly in comparison with the first reference scenario, with the weekly pattern being simply shifted down (check Figure 13).

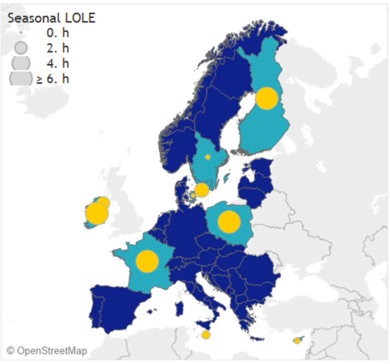
Combined sensitivity

Adequacy risks increase notably if there are coinciding issues with nuclear availability and coal supply in Europe[16]. Risks do appear in Poland, while the reference scenarios show no risks. Furthermore, risks elevate in Finland and France, where there are probabilities of nuclear commissioning and outage delays respectively. Risks in Ireland also increase marginally, suggesting that their system is sensitive to the events on the continent. European seasonal CGV reaches ~411 TWh_{GCV}, which is 12% higher compared with the reference scenario with normal demand (c.f. Figure 12). CGV increases mostly in Finland (nuclear risks), Poland (coal supply risks) and the Czech Republic (to support Poland and other countries).

Details on adequacy risks can be seen in Figure 22, where we see substantial risks in France, Ireland, Poland and Finland.

[16] *Please refer to section on Sensitivities to see details of scenario.*





CY00	EENS: 25.00 MWh (**0.00157%** compared to Seasonal Consumption) **99th percentile ENS:** 702.89 MWh (**0.04488%** compared to Seasonal Consumption) LOLE: 0.40 h
DKE1	EENS: 36.00 MWh (**0.00065%** compared to Seasonal Consumption) **99th percentile ENS:** 945.55 MWh (**0.01688%** compared to Seasonal Consumption) LOLE: 0.22 h
FI00	EENS: 5897.00 MWh (**0.01644%** compared to Seasonal Consumption) **99th percentile ENS:** 58523.24 MWh (**0.16310%** compared to Seasonal Consumption) LOLE: 10.99 h
FR00	EENS: 348693.00 MWh (**0.18052%** compared to Seasonal Consumption) **99th percentile ENS:** 3031604.69 MWh (**1.56944%** compared to Seasonal Consumption) LOLE: 70.64 h
IE00	EENS: 6267.00 MWh (**0.04778%** compared to Seasonal Consumption) **99th percentile ENS:** 26360.10 MWh (**0.20100%** compared to Seasonal Consumption) LOLE: 15.93 h
MT00	EENS: 18.00 MWh (**0.00196%** compared to Seasonal Consumption) **99th percentile ENS:** 352.24 MWh (**0.03763%** compared to Seasonal Consumption) LOLE: 0.78 h
PL00	EENS: 12400.00 MWh (**0.02210%** compared to Seasonal Consumption) **99th percentile ENS:** 158392.67 MWh (**0.28244%** compared to Seasonal Consumption) LOLE: 9.84 h
SE03	EENS: 89.00 MWh (**0.00025%** compared to Seasonal Consumption) **99th percentile ENS:** 2665.81 MWh (**0.00721%** compared to Seasonal Consumption) LOLE: 0.30 h
SE04	EENS: 1029.00 MWh (**0.00992%** compared to Seasonal Consumption) **99th percentile ENS:** 13916.97 MWh (**0.13413%** compared to Seasonal Consumption) LOLE: 2.40 h
UKNI	EENS: 352.00 MWh (**0.01026%** compared to Seasonal Consumption) **99th percentile ENS:** 4022.27 MWh (**0.11708%** compared to Seasonal Consumption) LOLE: 2.02 h

Figure 22: Adequacy risk in EENS and LOLE in the combined sensitivity

Weekly adequacy insights suggest rather even risks in Ireland and Finland throughout winter. Risks in France concentrate in December 2022. Risks in France were detected in December 2022, but as mentioned in the analysis of the reference case, it could be reasonable to anticipate those risks primarily in January 2023. Risks in other countries appear occasionally, and those specific weeks will be monitored with care. The risk in Poland increases towards the end of the season, suggesting that coal stocks should be carefully assessed throughout the winter and not overused to avoid issues towards the end of the winter.

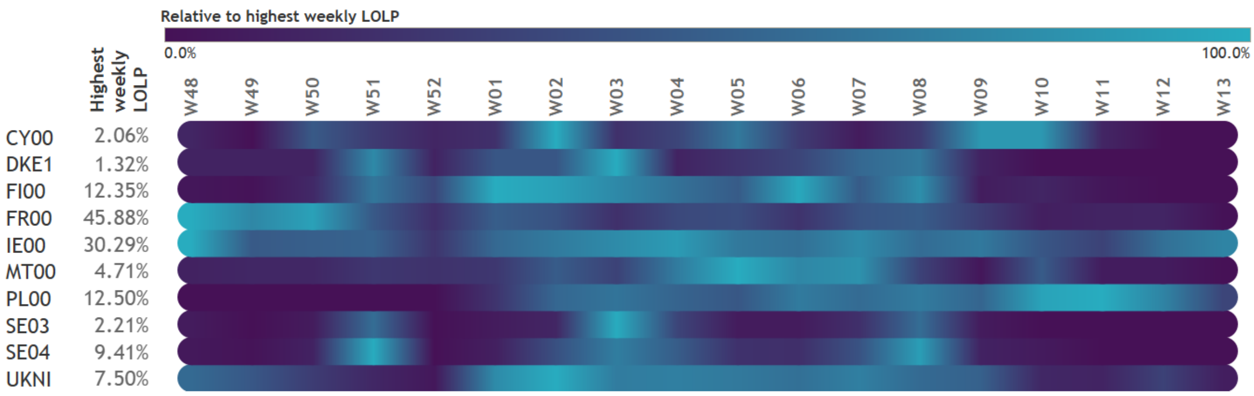


Figure 23: Weekly adequacy insights

Seasonal CGV reaches ~411 TWh_{GCV} in the event of coinciding issues with nuclear availability and coal supply. Trends suggest not only that CGV would increase but also that the lowest amount of gas is needed for adequacy.

CGV increases the most in Poland, Finland, and Czech Republic, with major consumers such as Germany and Italy leading the increase in absolute terms. CGV increases across Europe in different degrees even if most of the countries are not directly affected (c.f. Figure 24).

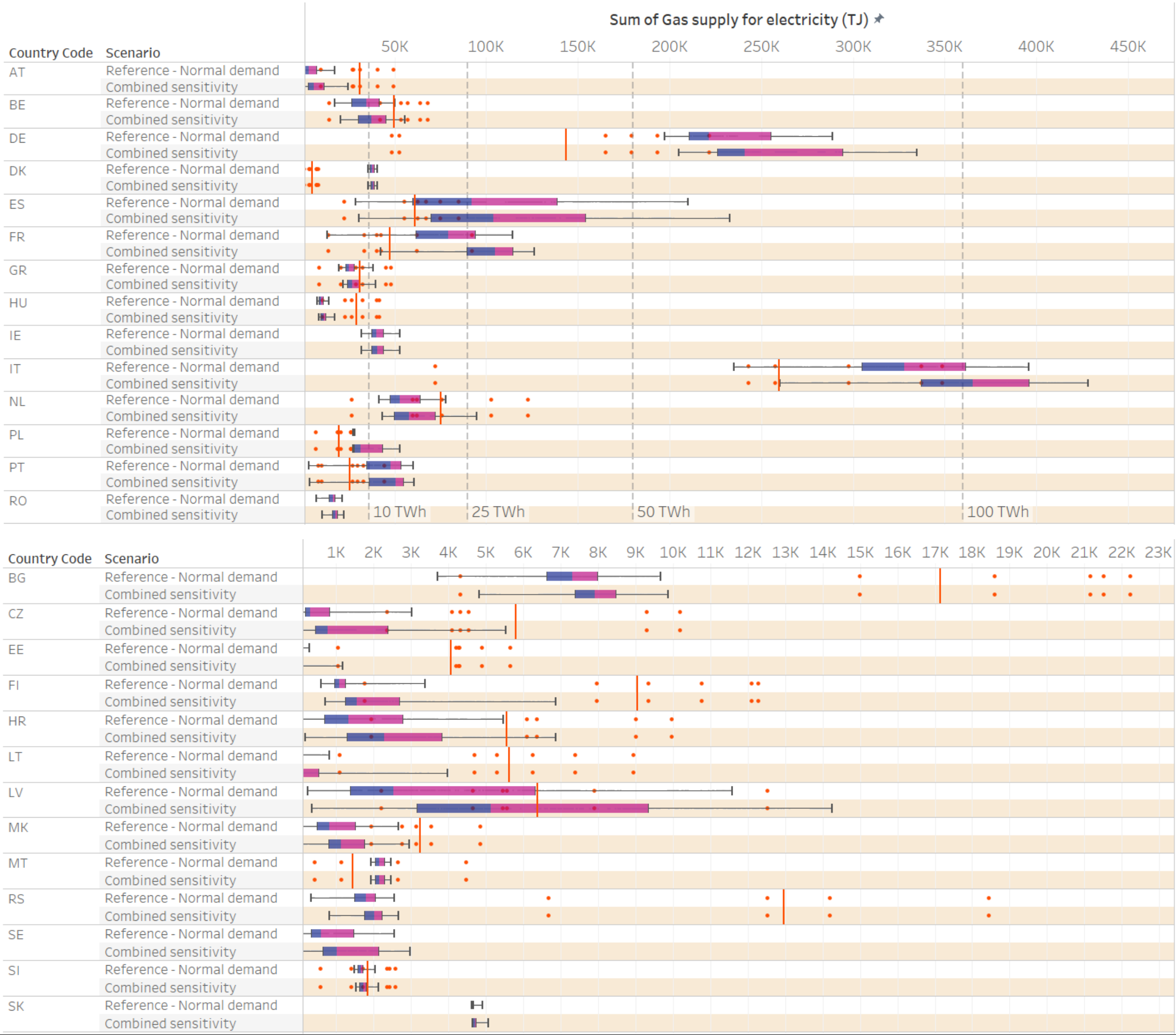


Figure 24: Seasonal CGV by country, Reference Case with normal demand VS Combined Sensitivity

The temporal distribution of gas requirements for adequacy does not change significantly in comparison with the first reference scenario, with the weekly pattern being simply shifted down (see Figure 13).

Summer 2022 review

Temperature overview

Globally, the summer for Europe was almost 0.4°C warmer than the 1991–2020 average, with southern parts of the continent from the Iberian Peninsula across France and into Italy most affected. This can be seen in Figure 25, which displays the surface air temperature anomaly observed in summer 2022 (June to September 2022) from Copernicus Climate Change Service.

In July 2022, temperatures were mostly above average in south-western and western Europe because of an intense, and in some parts prolonged, heatwave around mid-month. Record-breaking maximum temperatures were measured in Portugal, western France and Ireland. The heat travelled further north and east, bringing very high temperatures across other countries, including Germany and parts of Scandinavia. European temperatures were the highest above average in the east of the continent in August; however, temperatures in the south-west were still well above average, and had also been high in June and July. In September, the European-average temperature for September of 2022 was nearly 0.4°C below the 1991–2020 period, with a band of below-average temperatures from central Europe to Russia. Greenland had exceptional temperatures that reached more than 8°C above the monthly average in places, the warmest temperatures for September on record.

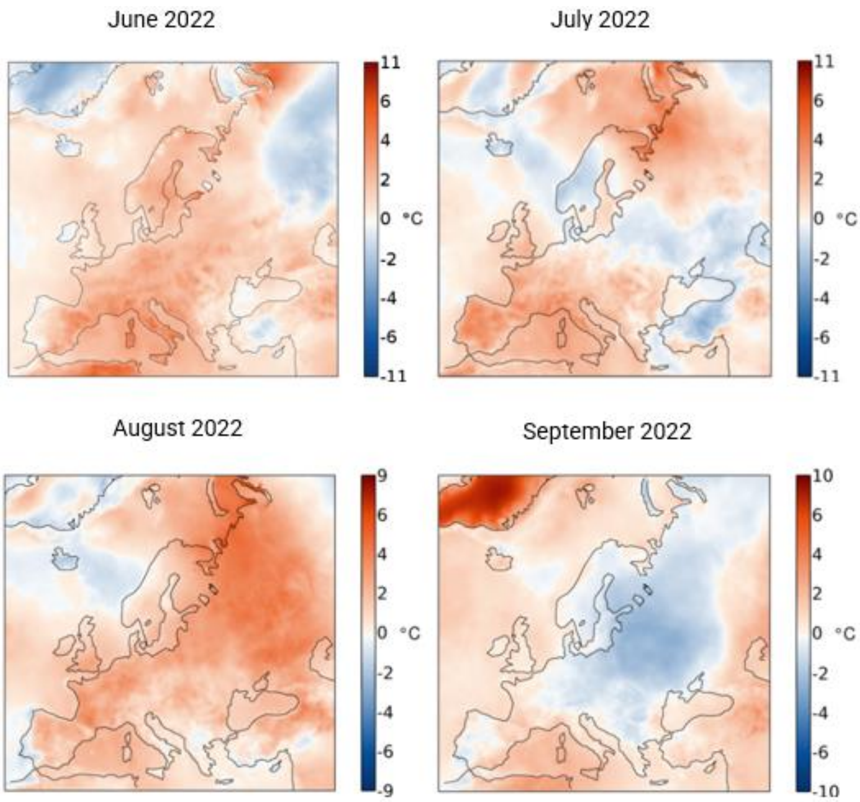


Figure 25: Surface air temperature anomaly in Summer 2022 relative to the average of the periods 1991–2020 (for June, July, August and September)[17]

Adequacy and other relevant events overview

In general, no adequacy issues were identified. Some countries mention tighter situations (Nordics, Ireland).

[17]Copernicus Climate Change Service—Surface air temperature maps

The Nordic countries experienced a relatively dry spring and summer. Wind generation was also below average in Nordics for the period. Nevertheless, this did not have an adverse impact on adequacy in the Nordics.

In Ireland, adequacy risks were linked to planned outages (this often happens during the summer, which leads to lower supply availabilities), high rates of unplanned outages and long periods of low wind generation. The Ireland power system entered the Alert state due to tight generation margins on seven occasions since last winter.

The cuts in electricity exchange with Russia were successfully replaced by domestic generation and imports from Nordics and central Europe.

Appendix 1: Methodological insights

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

It is described in the Methodology for Short-term and Seasonal Adequacy Assessments[18], developed by ENTSO-E in the framework of the Regulation on Risk Preparedness in the Electricity Sector (EU) 2019/941, and is approved by ACER[19]. Although the implementation of this target methodology will still require certain extensions (for instance to include FB modelling), the present Summer Outlook shows a major advancement.

Most notably, the seasonal adequacy assessment uses 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 analysed timeframe. Figure 26 provides a schematic representation of this scenario construction process.

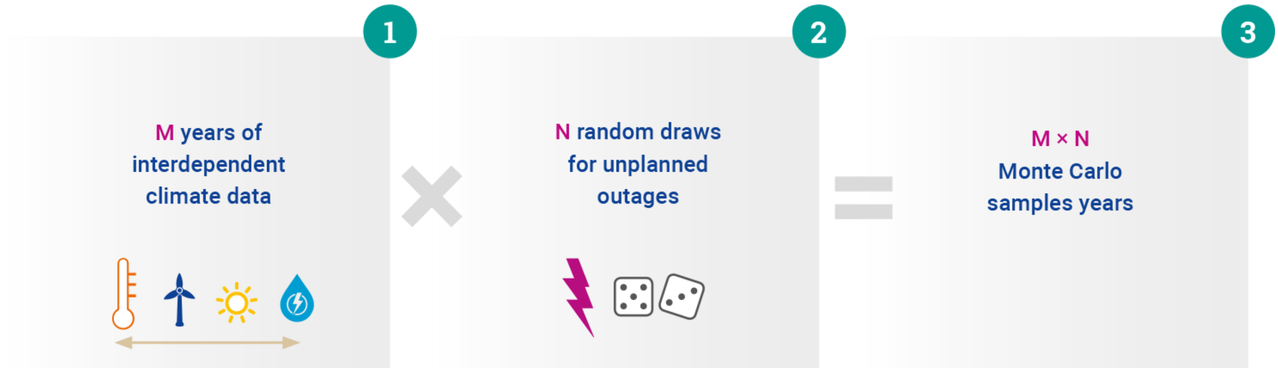


Figure 26 Scenarios assessed in Seasonal Outlooks

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

The Outlook considers multiple possibilities regarding weather and temperature, which can impact generation (e.g. more or less wind) and consumption of electricity (e.g. residential heating). Our simulations are performed for multiple so-called 'climate years'. For the winter outlook, these cover 34 past winter patterns to capture the sufficient spread of possible winter scenarios. In these historical climate data, the temperatures were detrended to account for climate change. This allows us to consider a variety of weather conditions, from a mild winter (less likely to see adequacy risks) to a very cold one (more likely to see adequacy risks). The results presented in the Outlook are an average of many different possible weather conditions.

Consequently, ENTSO-E moved from a 'shallow' scenario tree, containing only a severe conditions sample and a normal conditions sample, to a 'deep' scenario tree that combines dozens of years of interdependent climate data with random draws of unplanned outages to generate a multitude of alternative scenarios.

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

Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 27 illustrates the difference in the number of scenarios between the two modelling approaches.

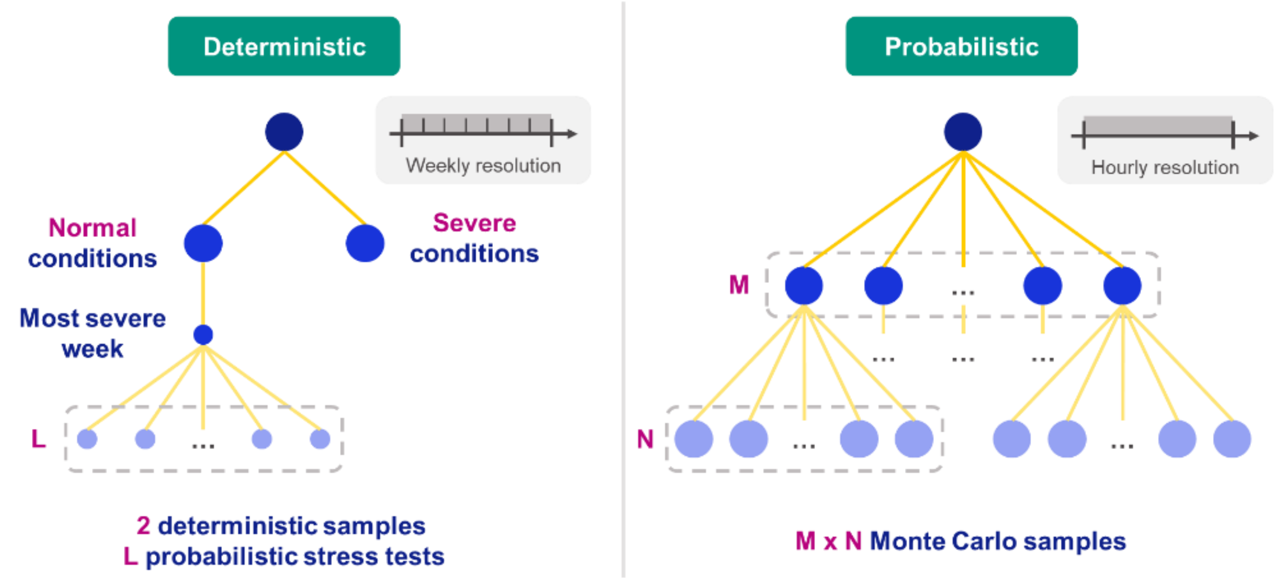


Figure 27: Scenario revolution – from deterministic to probabilistic

The LOLE is an estimate of how many hours supply would not meet demand and can be checked against national reliability standards to confirm whether the adequacy situation is acceptable. It is important to understand that any LOLE value is essentially a risk assessment and an economic trade-off to be evaluated by policy makers and regulators at the national level. A non-zero LOLE value is by no means an actual prediction of outage, because exceptional measures can always be taken.

Loss of load probability (weekly LOLP) represents a probability that lack of supply in a respective scenario could be expected for at least 1 hour and for any amount (even 1 MW). Weekly LOLP under normal market conditions represents the probability that system operators would need to look for non-market resources.

Expected energy not served (EENS) means the expected amount of energy not being served to consumers during the period considered due to system capacity shortages or unexpected outages of assets.

Critical gas volume

CGV refers to the lowest volumes of gas absolutely needed for electricity generation using all market resources even in the most adverse combination of climate conditions and outages. For a typical winter, CGVs are identified by considering gas as the last profitable source in the merit order list; this means that gas units producing electricity are only dispatched last, after all other market resources such as peak units, DSR, storage, etc. are exhausted. ENTSO-E assesses the impacts of the interdependency between the gas and the power system by identifying the CGV in each scenario. With this analysis, ENTSO-E estimates how much gas may be required to maintain electricity adequacy in each country and for each week of the coming winter. Gas is always considered last in the merit order both in the reference scenario and in the sensitivities assessed, with an exception made for plants modelled as must-run under indication of TSOs. In a market context, this means gas generation is the price setter in the wholesale market, but what is most important for an adequacy analysis is that this means the analysis inherently assumes all other resources are deployed first in the market before calling on gas power generation.

Methodology applied for peak demand reduction scenario

The second reference scenario presented in this Outlook differs from the first only in terms of electricity demand timeseries. The aim of this variation is to represent the compulsory measure included in the

Electricity Emergency Tool proposal from the EC, mentioning a 'mandatory target of at least a 5% reduction in gross electricity consumption during selected peak price hours covering at least 10% of the hours of each month where prices are expected to be the highest'.

The new demand timeseries has been computed covering a temporal scope from December to March and a spatial scope, including all countries in the ENTSO-E perimeter.

For each month, climate year and study zone, a partial hourly demand timeseries can be extracted from the reference scenario with normal demand. The reduced demand timeseries is obtained by combining partial hourly demand timeseries from the original dataset after applying the following steps:

1. Computation of the 90th percentile value;
2. Identification of hours in which original demand exceeds the 90th percentile value as peak hours; and
3. Reduction of original demand values by 5% only for hours identified as peak.

Please note that, to identify peak hours, total load and not residual load has been considered. This choice is justified by the intention to better represent operational conditions, in which Member States may be implementing communication strategies to help shave peak demand rather than having TSOs shed consumers according to the hourly combination of demand and RES generation. The actual implementation of demand reduction could be different than that which is modelled.

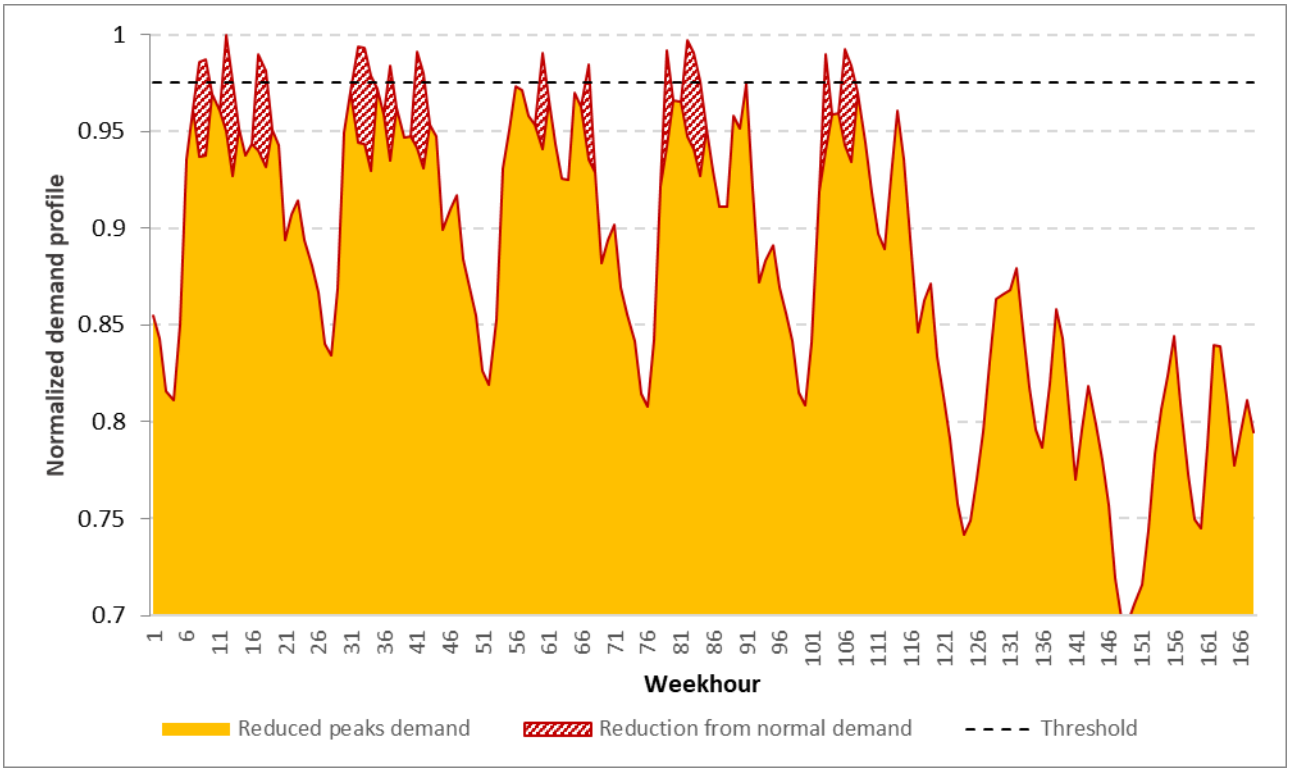


Figure 28: Computation of demand with peak reduction from normal demand, normalised profile.

Due to the typical weekly distribution of demand in the original dataset, peak reduction according to the methodology explained above affects mainly weekdays and not weekends, as shown in Figure 28.

Appendix 2: Geographical perimeter

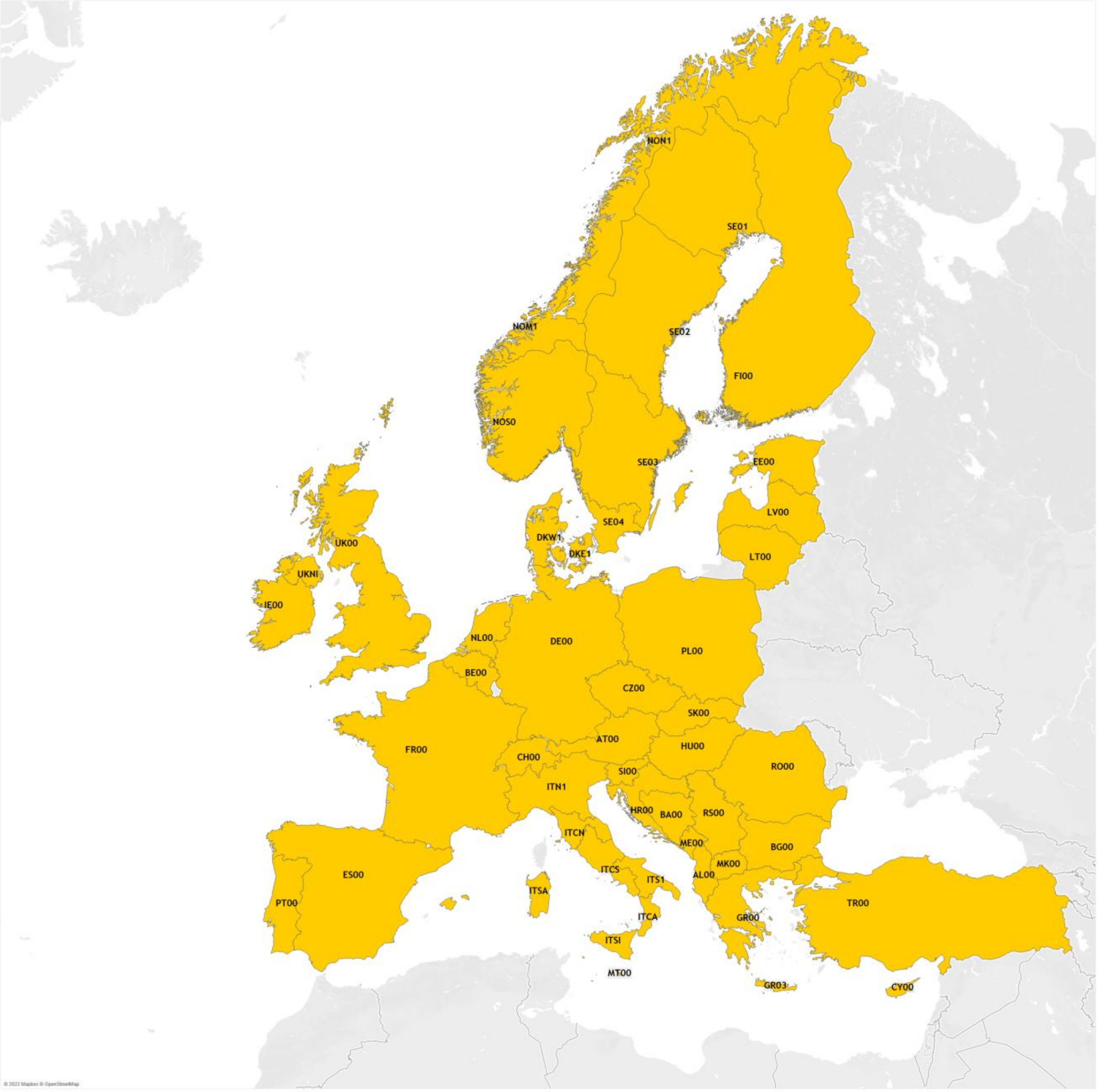


Figure 29: Study zones

Appendix 3: About adequacy metrics and convergence

Loss of Load Expectation and other annual metrics

Information about LOLE in the assessed season is presented in this appendix. LOLE figures can be useful when comparing how adequacy evolved between editions of seasonal adequacy assessments[20]. However, readers are invited to interpret them carefully as LOLE is commonly known as an annual metric, whereas in seasonal adequacy assessment, only a specific season (part of the year) is considered.

LOLE analysis may lead to misleading conclusions when compared with Reliability Standards (existing or under development in accordance with Article 26 of Regulation 2019//943). Some examples are given below, assuming that the annual LOLE Reliability Standard[21] is set and compared with seasonal LOLE:

- Seasonal LOLE can be lower than the Reliability Standard, but 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, but it does not necessarily mean that the system design does not comply with the Reliability Standard. The expected situation in an upcoming season could simply be one of the more constraining from a set of possible season scenarios[22] (e.g. if there is low water availability in hydro reservoirs and high generation unavailability is expected at the beginning of the season).

It could be worth considering whether the Reliability Standard is defined as a system design target or as an operational system adequacy metric target. To meet the Reliability Target set for power system design purposes, Europe relies first on market signals (for supply and network investments) and, if those are insufficient, market design corrections can be made (for example the establishment of complementary markets such as Capacity Mechanisms). The latter market decisions are based on a several-year-ahead framework[23], whereas seasonal outlooks relate to an operational timeframe which 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 to which Seasonal Outlook results may be compared, and this is especially important for LOLE.

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[20] A comparison with past editions is not possible yet because this is the first time this measure has been reported in a seasonal adequacy assessment.
[21] The conclusions made for annual LOLE are also valid for any other annual metric.
[22] The same applies for a particular historical supply scarcity. If hours when demand was shed exceed the LOLE set by the Reliability Standard, it does not mean that system design does not comply with the Reliability Standard. LOLE set by Reliability Standard simply indicates in how many hours demand shedding is acceptable (due to supply scarcity) over a long time.
[23] Monitored by the European Resource Adequacy Assessment in line with Article 23 of the Electricity Regulation 2019/943

Convergence of the results

In addition to seasonal LOLE results, we also publish the convergence overview, which shows that the seasonal assessment has a high accuracy level. The number of analysed Monte Carlo samples was 680.

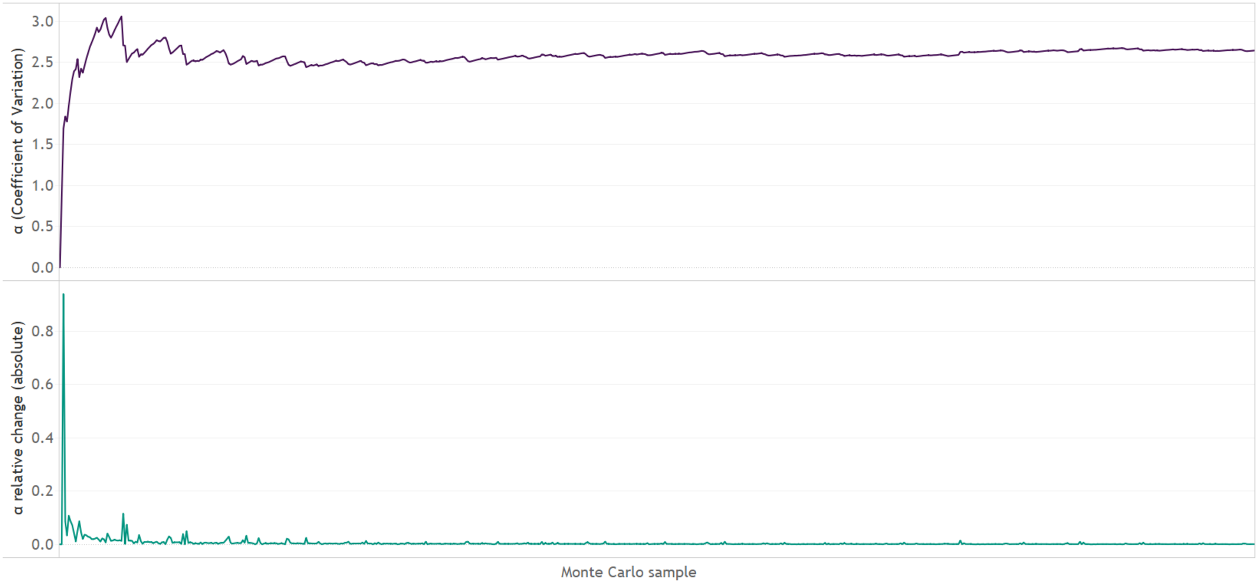

Figure 30: Convergence overview[24]

[24] *The convergence overview shows that the seasonal assessment has a high accuracy level. The number of analysed Monte Carlo samples was 680.*

Appendix 4: Additional detailed results

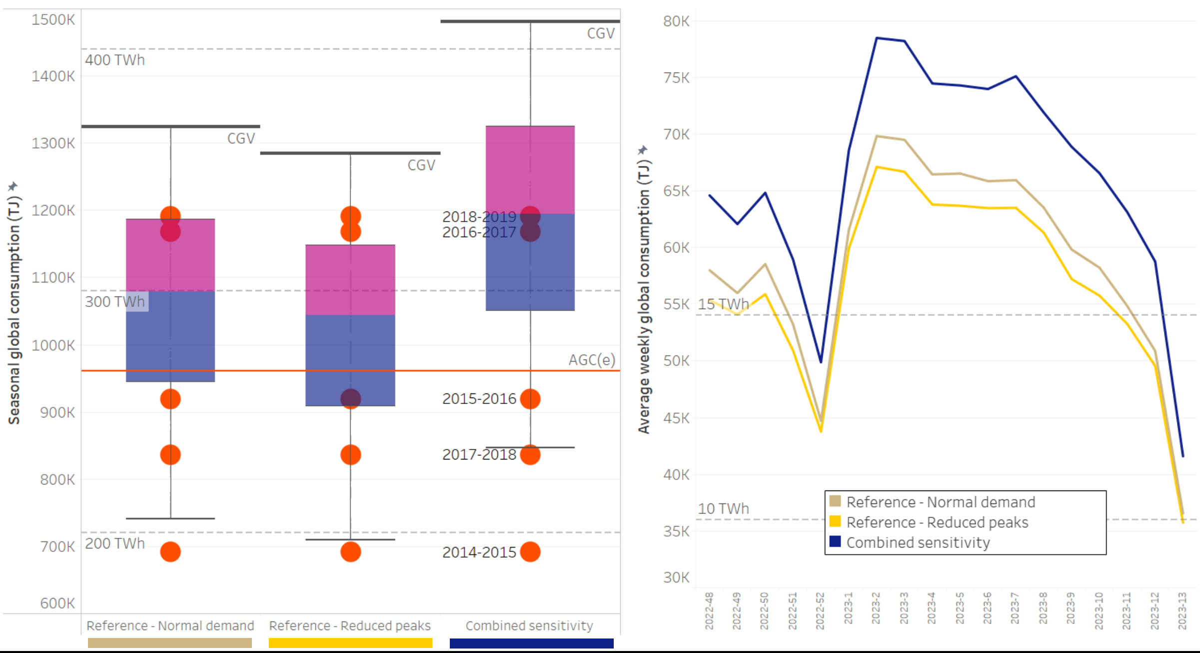

Figure 31: European seasonal CGV (left) and European seasonal average gas consumption for electricity (right) per scenario

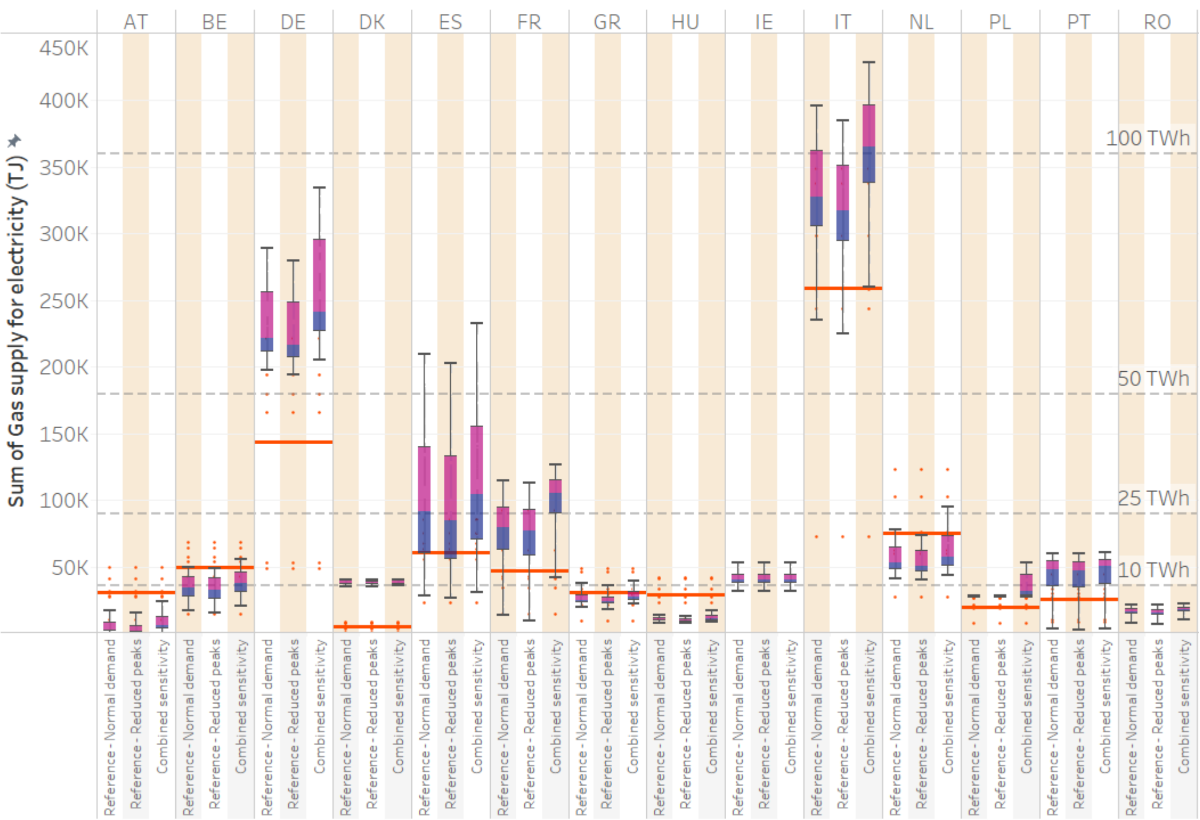

Figure 32: Seasonal CGV by country, all scenarios (big consumers)

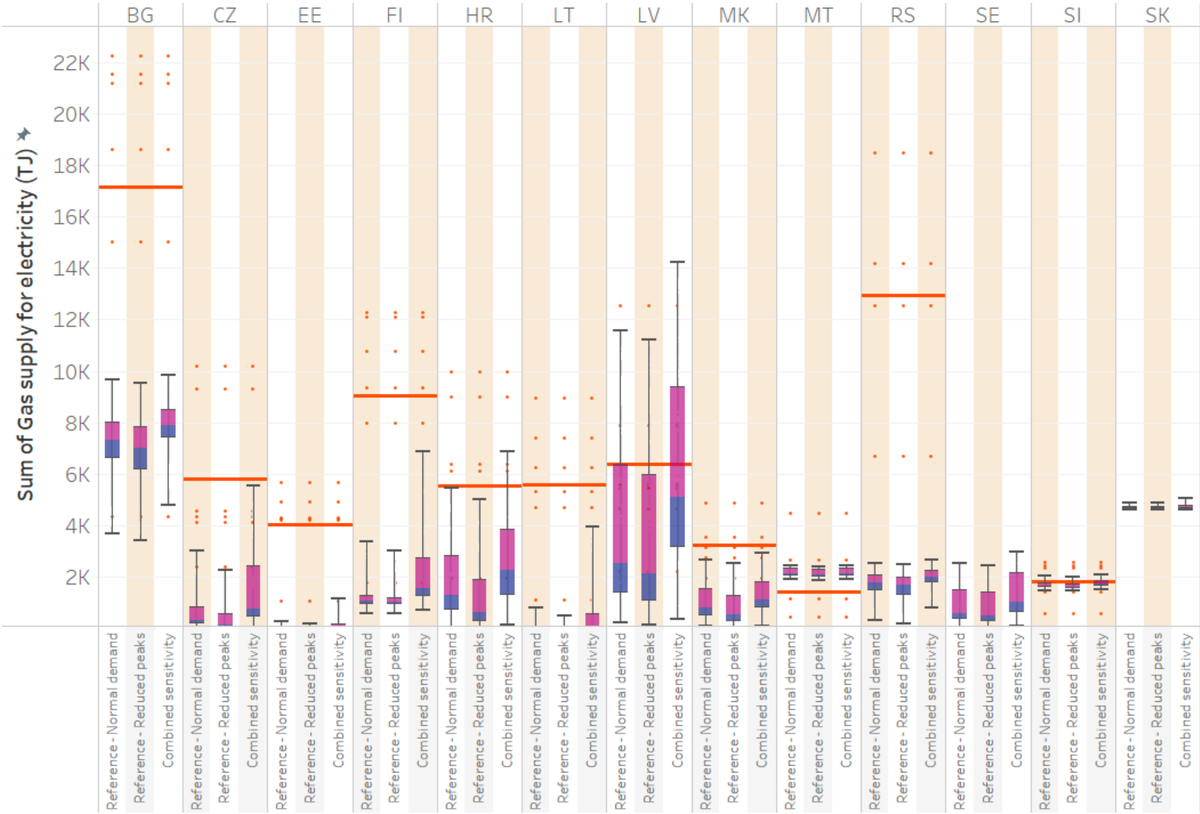

Figure 33: Seasonal CGV by country, all scenarios (small/medium consumers)

Appendix 5: Glossary

AGC(e) refers to average gross gas consumption for the electricity system over recent winters. (Source: Eurostat)

Corrective measures/corrective actions refer to available operational mitigation measures which are triggered by TSOs as a last resort after all market and non-market resources are exhausted, in order to avoid a controlled shedding of demand. The main mitigation measure is voltage reduction as it reduces the consumption by several percent while keeping all consumers supplied.

Critical Gas Volumes (CGV) in each scenario refers to the lowest volumes of gas absolutely needed for electricity generation using all market resources.

Demand – The total instantaneous electricity consumption observed in the transmission system, including transmission network losses.

Demand Response (DSR) – Demand response pursuant to Regulation (EU) 2019/943 of the European Parliament and Council of 5 June 2019 on the internal market for electricity (recast).

Energy Not Served (ENS) [GWh/year] – For a given MTU and modelled zone, the energy which is not supplied due to insufficient capacity resources to meet the demand.

Reference scenario: A reference scenario represents the best estimate projections submitted by the TSOs. This includes confirmed national mitigation measures, gas last in the merit order and an efficient integrated European market system with perfect foresight.

Expected Energy Not Served (EENS) [GWh/year] – In a given modelled zone and in a given time period, the expected ENS.

Explicitly Modelled Systems – Electric systems which are modelled in detail.

Flow-Based (FB) – The flow-based approach pursuant to Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

Flow-Based Market Coupling (FBMC) – Mechanism to couple different electricity markets, increasing the overall economic efficiency, while considering the available transmission capacity between different bidding zones using the FB approach/model.

Forced Outage (also Unplanned Outage) – State of a capacity resource when it is unavailable in the power system and the unavailability was not planned.

Frequency Containment Reserves (FCR) (also primary reserves) – Frequency containment reserves pursuant to Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

Frequency Restoration Reserves (FRR) (also secondary reserves) – Frequency restoration reserves pursuant to Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

Loss of Load Duration (LLD) [h/year] – For a single node, the number of hours during which the node experiences ENS during a single Monte Carlo sample/simulation year. For a geographical area with multiple nodes, LLD is the number of hours during which at least one node of the area experiences ENS during a single Monte Carlo sample/simulation year. A null LLD suggests that there are no adequacy concerns.

Loss of Load Expectation (LOLE) [h/year] – In a given modelled zone and in a given time period, the expected number of hours in which resources are insufficient to meet the demand.

MC – Monte Carlo (i.e. related to the Monte Carlo method);

Modelled zone – Either a bidding zone, a country or another geographic area that is explicitly modelled in the ED. A modelled zone cannot be larger than a bidding zone or a country.

MTU – Market time unit pursuant to Transparency Regulation;

Net Generating Capacity (NGC) of a generation unit – The maximum net active electrical power it can produce continuously throughout a long period of operation in normal conditions, where:

i. 'net' means the difference between, on the one hand, the gross generating capacity of the alternator(s) and, on the other hand, the auxiliary equipment load and the losses in the main transformers of the power station,

ii. for thermal plants, 'normal conditions' means average external conditions (climate etc.) and full availability of fuels; and

iii. for hydro, solar and wind units, 'normal conditions' means the nominal availability of primary energies (i.e. water, solar or wind conditions).

Net Transmission/Transfer Capacity (NTC) approach/model – The coordinated net transmission capacity approach pursuant to Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

Non-explicitly Modelled Systems (also implicitly modelled systems) – Electric systems which are not explicitly represented in the modelling framework in detail, and which are directly interconnected with an explicitly modelled system.

Non-market resources can include generation, demand-side-response and storage resources, among others depending on the country and are resources dedicated to ensuring grid security and stability, as well as transmission reliability margins used for coping with variability of power flow. They are kept outside the market but can be called upon in the event of a supply shortage to ensure security of supply.

Non-renewable Energy Sources – Energy from non-renewable sources, namely oil, natural gas, coal, sewage treatment plant gas and nuclear energy. Inverse of renewable energy sources.

Planned outage – State of a capacity resource when it is not available in the power system and the outage was planned in advance. These outages include maintenance.

Renewable Energy Sources (RES) – Energy from renewable sources pursuant to Directive (EU) 2019/944 of the European Parliament and Council of 5 June 2019 on common rules for the internal market for electricity.

Replacement Reserves (RR) (also tertiary reserves) – replacement reserves pursuant to Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

Reserve Capacity – The frequency containment reserves, frequency restoration reserves or replacement reserves that need to be available to the transmission system operator.

Supply margins (or simply margins) are an indicator of how far away the system is from adequacy issues. They inform how much extra generation could be dispatched or how much extra energy could be imported or the equivalent of how much demand could increase until adequacy issues are observed.

Thermal Generation – Production of electricity from thermal energy obtained from the conversion of primary energy sources, namely oil, natural gas, coal, nuclear energy, solar thermal, geothermal energy, biomass, landfill gas, sewage treatment plant gas, and biogas.

Unplanned Outage – See Forced Outage.

Value of Lost Load (VoLL) [€/MWh] – An estimation of the maximum electricity price that each end user type is willing to pay to avoid an outage.

Working gas volume (WGV) refers to the amount of natural gas that can be injected, stored and withdrawn during the normal commercial operation of a natural gas storage facility