Summer Outlook 2022

Winter Review 2021-2022

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

No major risk for electricity supply in Europe this summer. Close monitoring and coordination needed for this winter.

Based on the ENTSOG summer outlook[1] and on the results of a survey performed by ENTSO-E TSOs, gas shortage for electricity generation is unlikely during the summer, even in the event of Russian gas disruption. Specific risks are identified in Latvia, Estonia and Finland by ENTSOG under the scenario of no gas supply throughout the summer, but some mitigation measures are available. In addition, the ENTSO-E analysis shows that these systems can rely on generation from other powerplants or that there will be sufficient imports available from neighbouring countries.

The gas and hydro storage accumulation for winter months will be thoroughly monitored during the summer. According to the ENTSOG Summer Outlook 2022, particular attention to the monitoring of gas storage levels is essential to have sufficient levels of storage at the end of the summer and to be prepared for the winter. The hydro accumulation at winter's start will depend on the precipitation amount during the summer.

Risks appear in islands (Creta, Cyprus, Malta) in summer 2022 as the demand expectation increases compared to summer 2021. However, these risks are either minor or else non-market resources are available to address these situations. Traces of risk are noted in mainland Greece but only under extreme adverse conditions (high electricity demand combined with low resource availability). Furthermore, some risks are also noted in Ireland and Eastern Denmark due to planned outages of network and generation, but only in worst-case operational conditions (high electricity consumption combined with low renewable generation and numerous generators being on unplanned outage). In such cases, the TSOs remain vigilant and may adapt planned outage schedules closer to real time operations.

Considering the current European energy situation, it is crucial to anticipate the Winter Outlook 2022/2023

ENTSO-E is continuously working to gain preliminary insights into what the coming winter could look like. A preliminary analysis is being revised according to mitigation actions taken by TSOs and Member State authorities. A current early sensitivity analysis concludes:

- A certain level of gas consumption decrease for electricity production could be anticipated if gas-fired generation is used only as a last fuel after the exhaustion of all other market resources.
- A significant volume of gas is still needed for electricity adequacy. Electricity supply may be impacted if gas supplies are scarce in Europe. The impact depends, among other factors, on how well Europe is prepared for winter (gas storage levels) and how gas is distributed across gas consumers if there is a lack of gas.
- The dependency on Russian gas for power generation varies considerably across European countries. In the event of gas disruption, solidarity among countries will be key in gas and electricity sectors.

TSOs have identified the following topics of utmost importance for the coming winter:

- Continue early winter adequacy assessments and exchanges with relevant stakeholders;
- The inclusion of pre-winter months in the preliminary winter adequacy assessment; and
- Pay special attention to possible gas-fuel supply disruptions (Pan-EU problem) and coal availability (relevant for some countries), and assess the impact of potentially low nuclear generation availability (especially in Central-West Europe).

ENTSO-E will continue refining and improving winter adequacy assessments to gain additional insights about winter 2022–2023. Specifically, ENTSO-E will maintain tight exchanges with the European Commission (EC),

[1] ENTSOG Summer Outlook 2022

the Electricity Coordination Group (ECG), the Agency for the Cooperation of Energy Regulators (ACER), and the European Network of Transmission System Operators for Gas (ENTSOG). Regular interaction with ENTSOG allows both parties to stay up-to-date with changing situations in both energy systems. Exchanges with EC, ECG, ACER and Member States allow decision-makers to be kept aware of latest expectations about the coming winter. The situation is rapidly evolving, with numerous TSOs and Member State authorities taking various preparatory actions for winter 2022–2023 at the national and regional level. A tight coordination over the coming months will allow measure and mitigation adjustment where necessary.

Overview of the power system in summer 2022

Generation overview

The generation capacity overview in Figure 3 shows that installed capacities available on the market cover the highest expected demand in summer 2022. However, in some areas, imports might be necessary in the event of low renewable generation. Net Generating Capacities (NGCs) are larger than the highest expected demand in each study zone, but thermal and hydro units alone do not reach the peak demand in certain zones. This suggests that in the event of low renewable generation, imports might be necessary to ensure security of supply. Furthermore, this increases in importance if we consider generation unavailability (e.g. planned and unplanned outages) and additional technical constraints (e.g. reductions of NGC due to de-rating with high ambient temperature, high cooling water temperatures). This shows the importance of the interconnected European power system and the relevance of pan-European adequacy studies.

No fuel disruptions for electricity generation or interruptions of electricity exchanges with Russia were considered in the summer outlook simulations. ENTSO-E has been intensively involved in preparing ad hoc analyses about dependence on Russian fossil fuel in tight coordination with authorities, policy makers and Oil and Gas associations since the invasion of Ukraine on 24 February 2022 and the escalation of political concerns (see specific chapter below). Based on these exchanges, the short-term impact for the summer of 2022 is considered moderate. Furthermore, electricity exchanges with Russia during summer months has a minor impact on adequacy, but the impact will be carefully monitored for the coming winter. Both these topics—fuel supply disruptions and electricity exchange disruption with Russia—will need to be carefully analysed to anticipate the coming winter period.

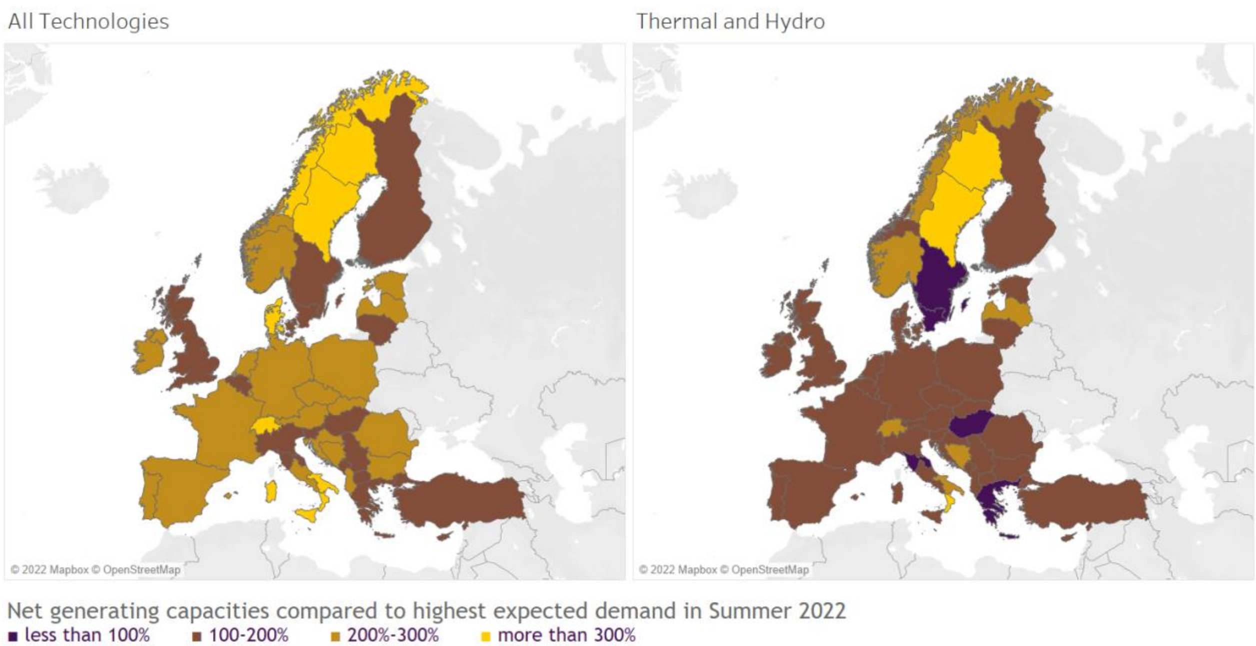

Figure 1: Net generating capacity overview – comparison with highest expected demand

According to Figure 2, thermal NGC available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of summer 2022. This is followed by hydro, wind and solar capacities, which constitute the remaining half. In addition, the highest expected demand[2] 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 [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 popularity in Europe. This, in turn, means a greater participation of electricity consumers in the electricity market. Nevertheless, DSR is not continuously available and may be available only for a limited period of time (e.g. 2 hours in a day) or at varying capacity. More DSR is likely to be available during peak times, but this is not guaranteed.

[2] *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.*

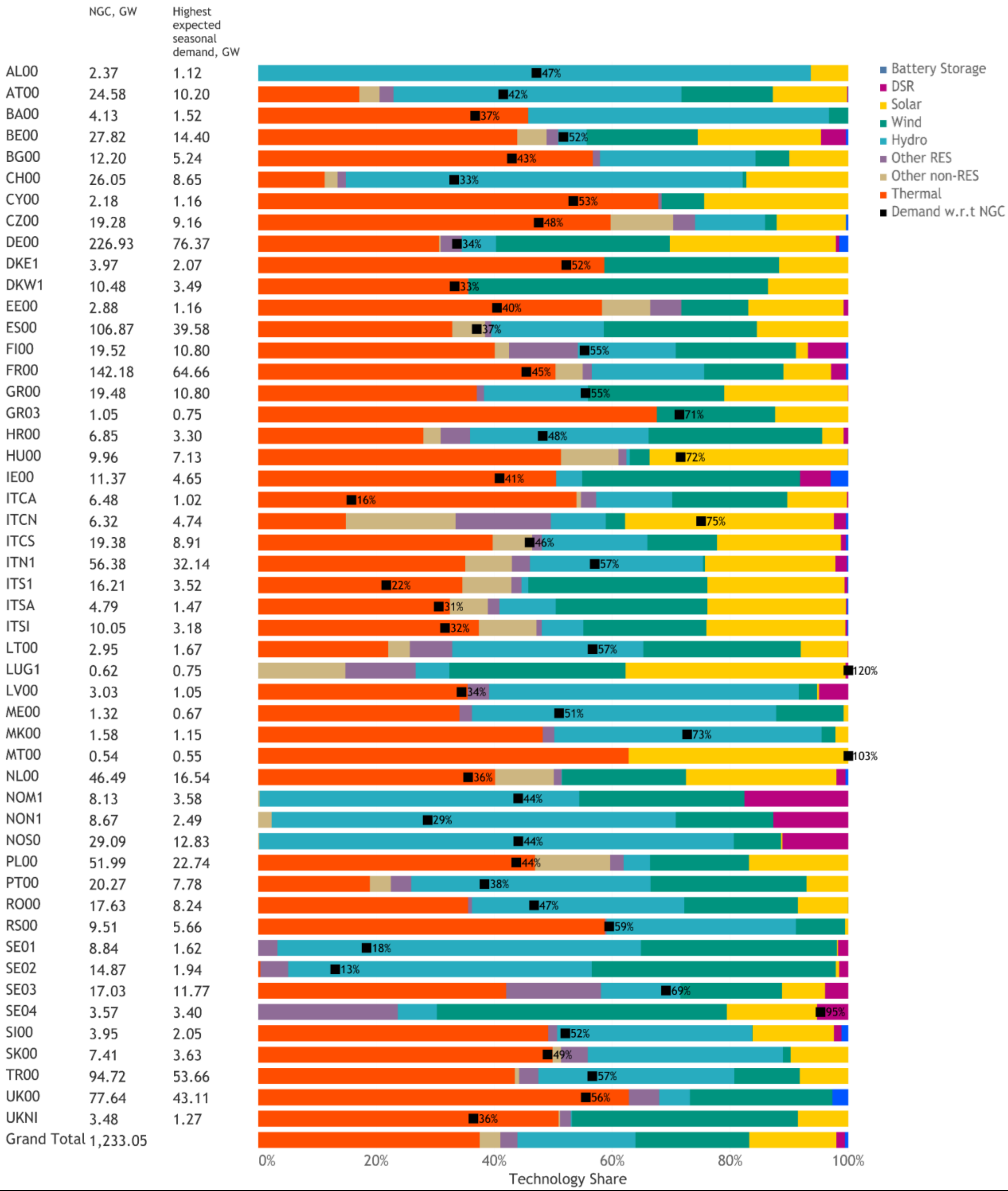

Figure 2: Generation capacity mix at the beginning of summer 2022 per study zones

Info box:
Study zone naming convention

Country code XX YY

ENTSO-E zone index

Map with codes is available in Appendix 2:

Figure 3 shows 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. Only five countries make use of non-market resources. From largest to smallest NGC, these are: Germany, Sweden, Finland, Malta Crete. This report also assesses if these resources are sufficient to address identified adequacy issues.

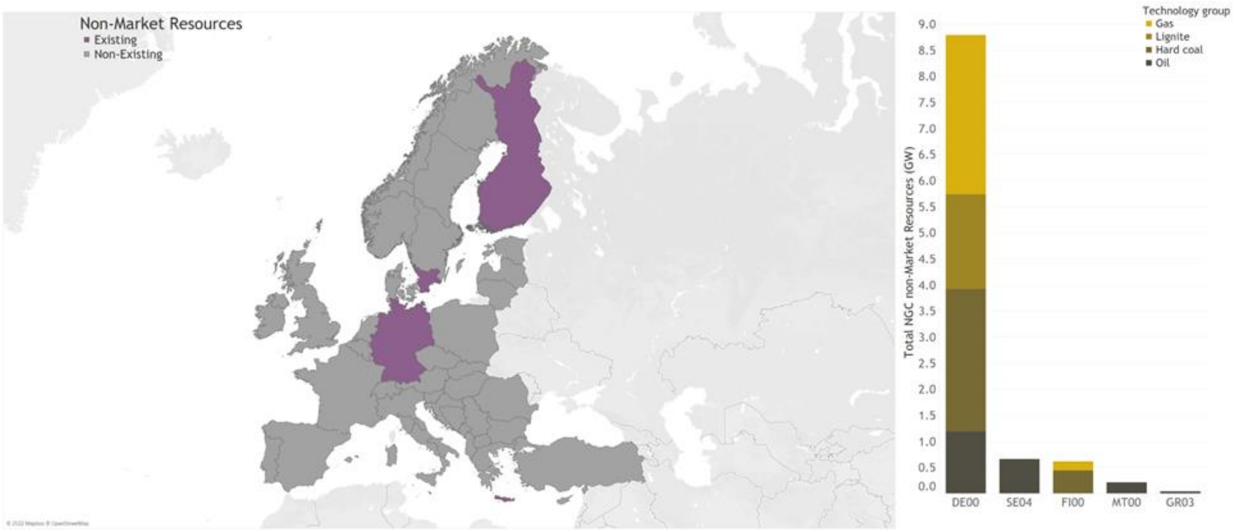

Figure 3: Non-market resources for coping with adequacy challenges in Europe[3,4]

Capacity evolution

The most relevant capacity evolutions[5] during summer 2022 are provided in Figure 4, which shows a net increase in Europe of approximately 7000 MW. The capacity of lignite and nuclear power plants in Europe decreases; this is largely compensated for by the commissioning of gas-fired power plants, solar and wind. In the modelling, the exact dates of commissioning and decommissioning are considered.

[3] 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.

[4] In Finland, the current strategic reserve period ends at the end of June, and it assumed that the resources will not be subsequently available for the market. However, there is an on-going procurement of resources for the upcoming strategic reserve period starting on 1 November 2022.

[5] Some additional commissioning and decommissioning may occur during season.

Commissionings and Decommissionings			
BE00	Nuclear	1 October 2022	Decommissioning 1006MW
CZ00	Lignite	30 June 2022	Decommissioning 97MW
GR00	Gas	1 September 2022	Commissioning 825MW
ITCN	Gas	1 July 2022	Commissioning 54MW
ITCS	Gas	30 June 2022	Commissioning 127MW
ITN1	Gas	30 June 2022	Commissioning 144MW
		1 July 2022	Commissioning 148MW
		1 August 2022	Commissioning 1255MW
ITS1	Gas	30 June 2022	Commissioning 92MW
LT00	Wind	4 September 2022	Commissioning 18MW
MK00	Solar	1 July 2022	Commissioning 50MW
	Wind	1 July 2022	Commissioning 13MW
NL00	Solar	1 June 2022	Commissioning 600MW
		1 July 2022	Commissioning 600MW
		1 August 2022	Commissioning 600MW
		1 September 2022	Commissioning 600MW
		1 October 2022	Commissioning 600MW
NOM1	Wind	1 July 2022	Commissioning 205MW
		1 September 2022	Commissioning 86MW
NON1	Wind	1 July 2022	Commissioning 165MW
NOS0	Solar	1 July 2022	Commissioning 67MW
	Wind	1 July 2022	Commissioning 80MW
PL00	Solar	1 June 2022	Commissioning 1116MW
	Wind	1 June 2022	Commissioning 536MW

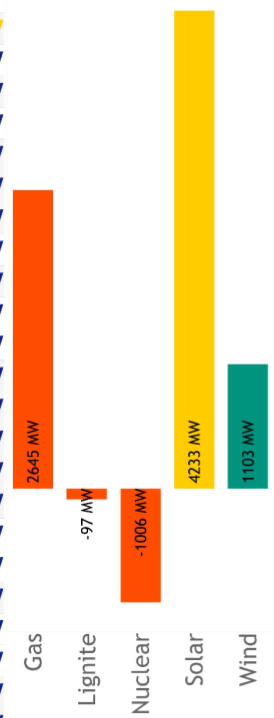

Figure 4: Capacity evolution in summer 2022

Planned unavailability

The planned unavailability of units considered in the assessment is presented in Figure 5. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing.

Total planned unavailability in Europe decreases towards mid-summer and is followed by a minor increase towards the end of summer. Nuclear units show the highest level of unavailability among thermal technologies at the beginning of summer 2022, with gas ranking second, followed by hard coal, lignite and oil.

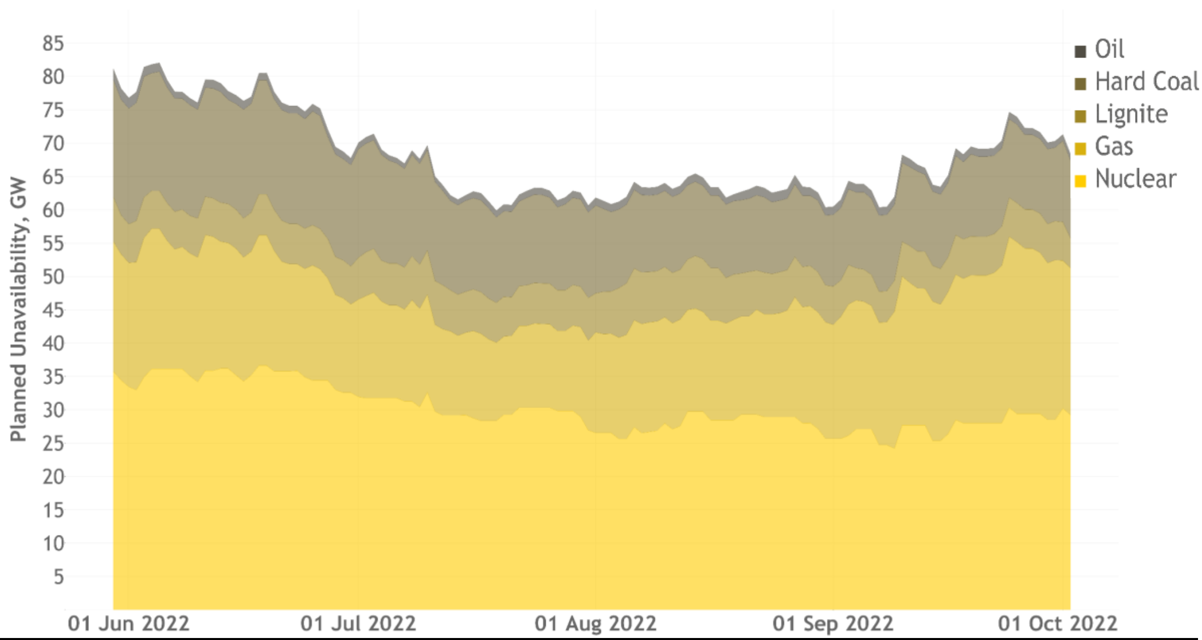

Figure 5: Planned unavailability of thermal units

Planned unavailability in southern countries tends to decrease during the warmest months when highest demand is expected (i.e. in July and August). This can be observed in the cases of Sardinia (ITSA) or Greece (GR00) in Figure 6. The figure depicts the weekly ratio of thermal planned unavailability within each study zone with respect to the total thermal NGC of the respective study zone. In some countries, the planned unavailability varies little throughout the summer or even has an inverse trend (planned unavailability increases towards the mid-summer). This inverse trend can be observed in Hungary (HU00), among others.

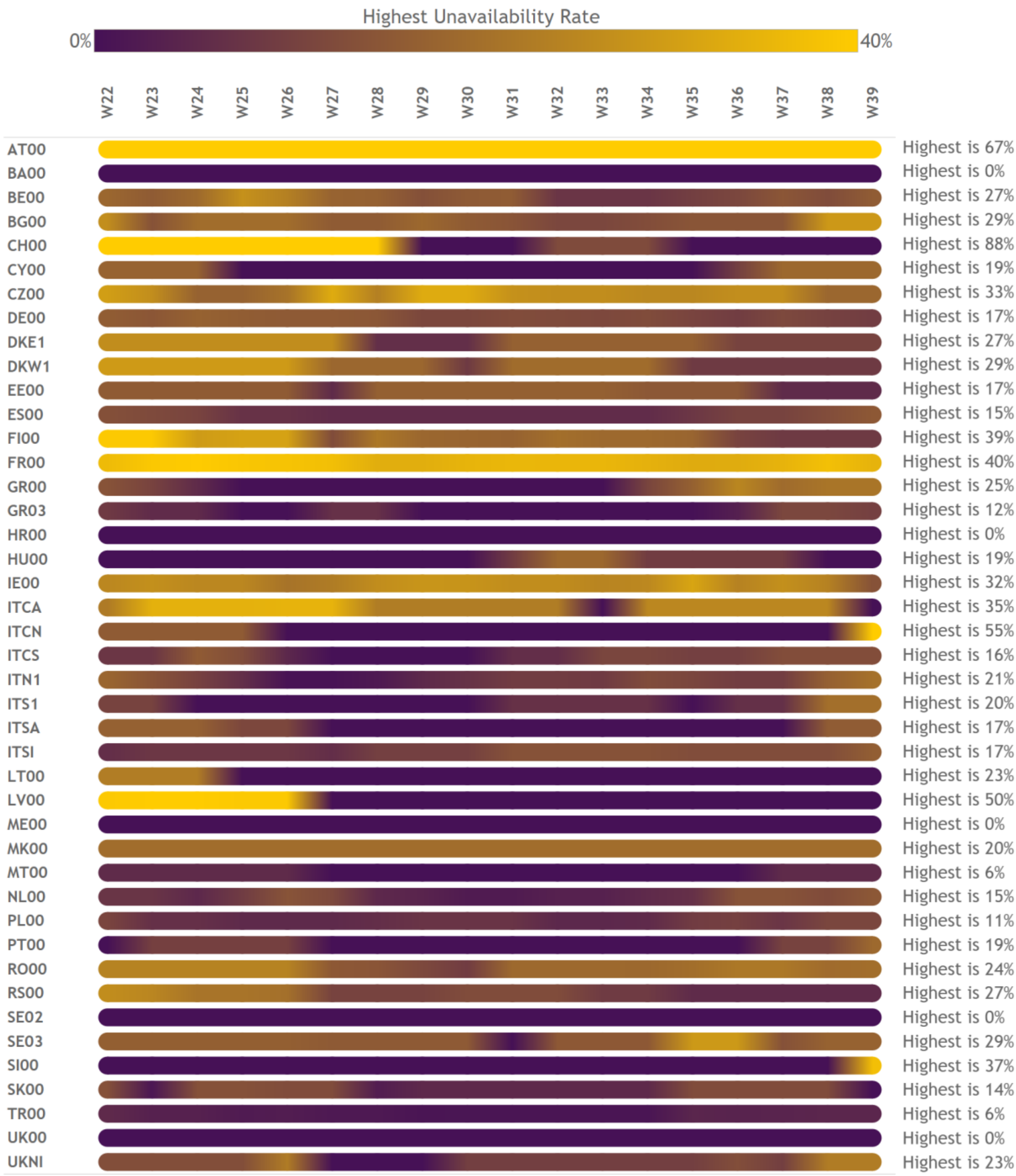

Figure 6: Weekly distribution of thermal planned unavailability relative to thermal NGC

Demand overview

The demand overview in Figure 7 compares expected consumption in each week with the highest expected weekly consumption in summer 2022. The darker shades indicate low expected consumption compared to highest expected consumption. As evident, demand in continental western Europe (e.g. Austria, Germany, Netherlands) is relatively stable across the summer period. In France, demand decreases for a few weeks due to the holiday period. In southern European countries (e.g. Italy, Greece, Spain), there is a trend towards higher demand linked to tourism and air-conditioning in the middle of summer, when the temperatures reach yearly peak values.

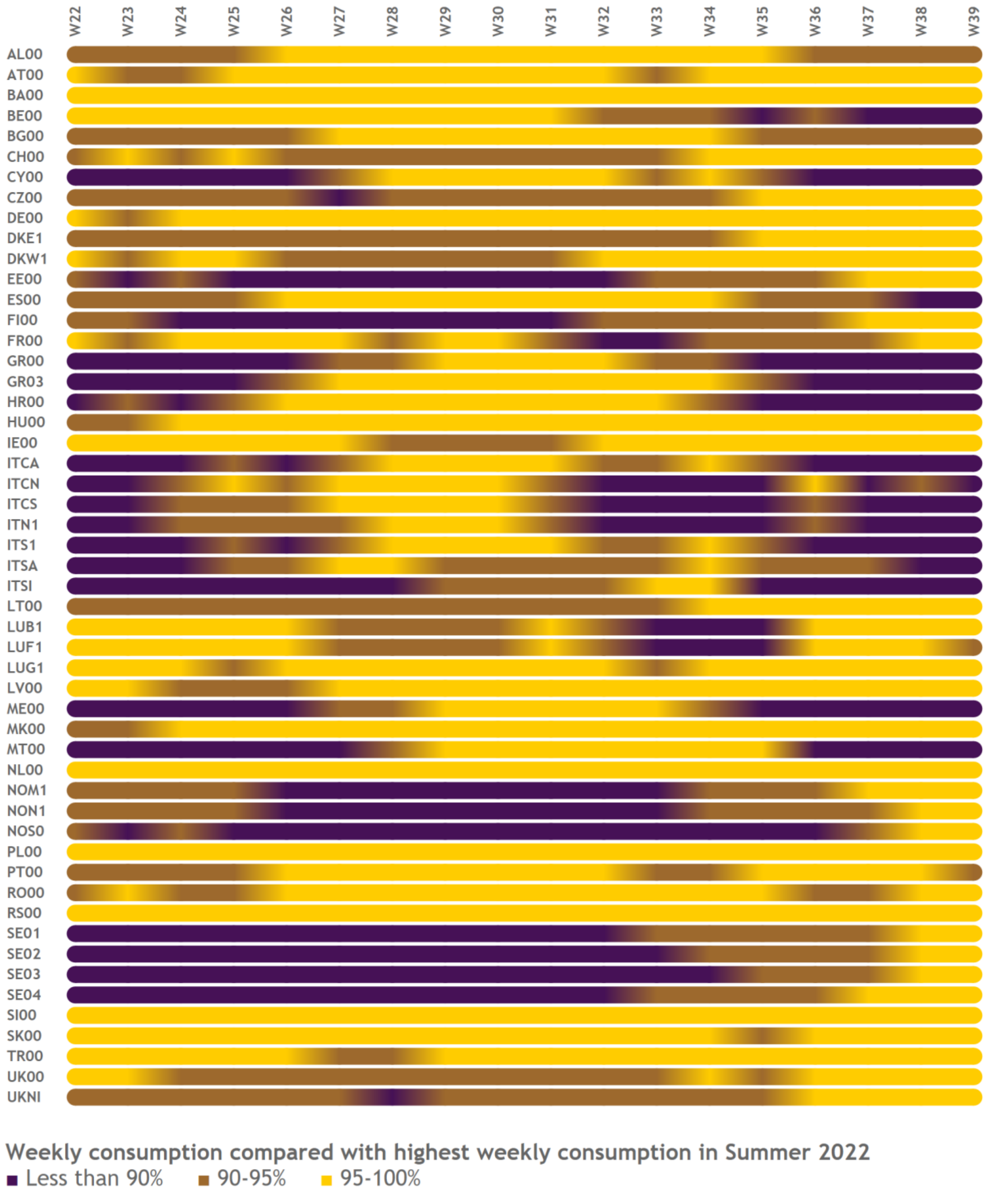

Figure 7: Demand overview – evolution over summer 2022

Figure 8 shows workday consumption patterns per study zone by plotting the mean demand relative to the highest mean demand in summer 2022. The demand peak in Europe is concentrated around noon for most of the study zones. In some study zones (e.g. Albania, Bosnia and Herzegovina), an evening peak similar to the noon demand peak is also observed. In other study zones (e.g. Italy, Montenegro) a demand peak is observed in the evening. In addition, Scandinavian study zones (e.g. Finland, Norway, Sweden) face a relatively stable mean demand during the day. The mean demand for some of these study zones never falls below 75% of the highest mean demand.

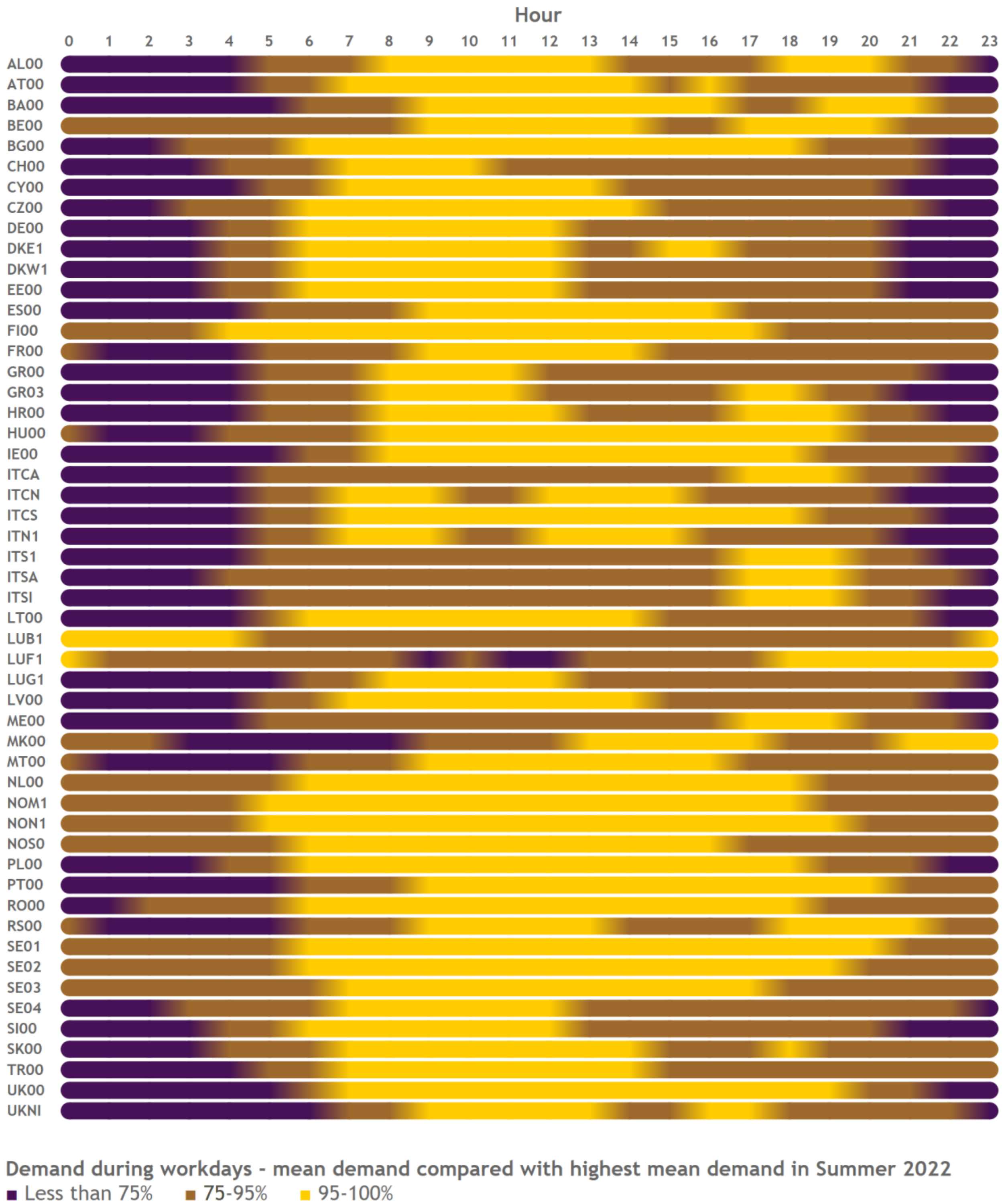

Figure 8: Demand profile overview during Mondays–Fridays in summer 2022[6]

[6] *UTC time convention was used.*

Network overview

Figure 9 shows the ratio of lowest import capacity in summer 2022 to highest expected demand during the summer. 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[7].

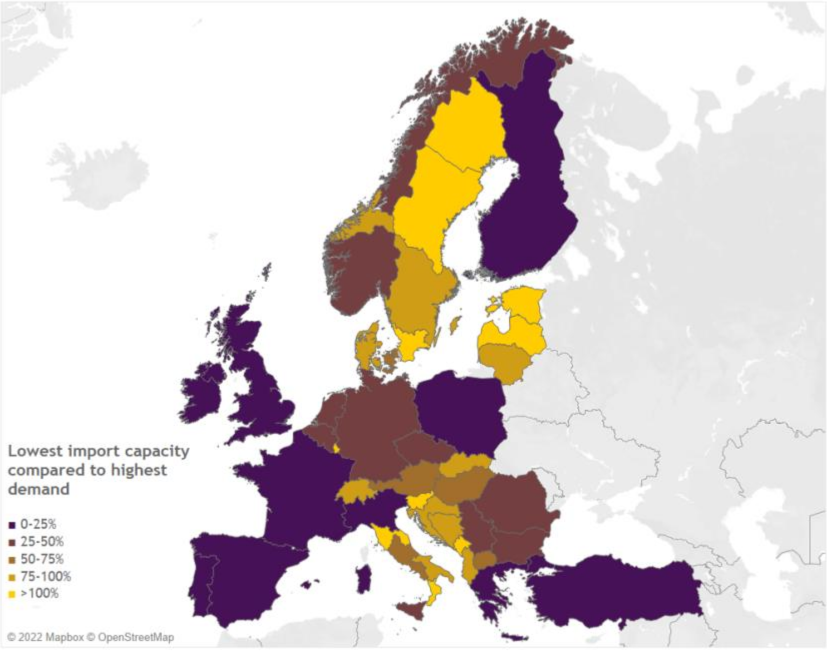

Figure 9: Import capacities per study zone: ratio between lowest import capacity and highest expected demand. C.f. Figure 22 for details

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

Adequacy situation in summer 2022

The adequacy situation 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 for solving the risks identified in the previous step. The non-market resources can be activated to cope with structural supply shortages in the market.

The adequacy situation in summer 2022 (Figure 10) shows some adequacy risks – i.e. the risk of having to rely on non-market measures – in Creta, Cyprus, Denmark, Ireland and Malta. Non-market resources reduce risks substantially in Malta and Creta where such resources exist, whereas risks do not decrease notably in Ireland and Denmark as available non-market resources in neighbouring regions cannot be reached due to interconnection limitations[8]. Risks in Cyprus do not decrease as these resources do not exist and the system is not interconnected with the rest of Europe.

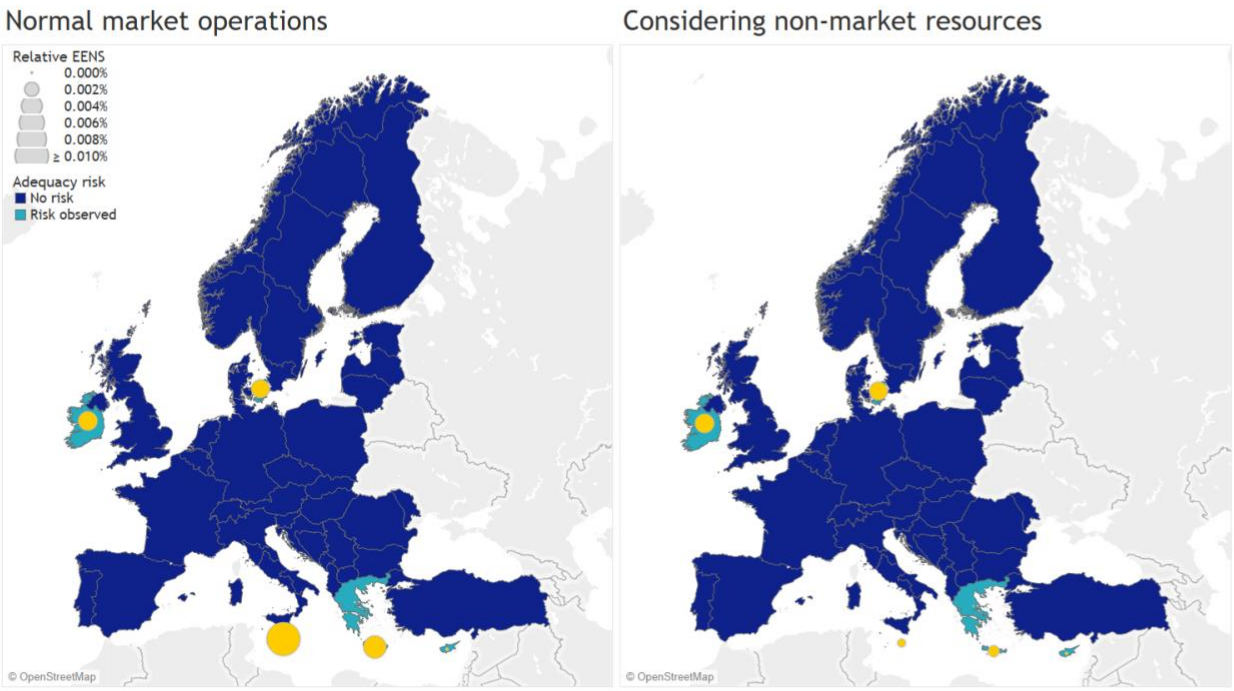

Figure 10: Adequacy overview

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

Focus on adequacy under normal market conditions

Under normal market operation conditions, risks are identified in Ireland (IE00) and Malta (MT00) (c.f. Figure 11). Risks in Creta (GR03), Cyprus (CY00) and Denmark (DKE1) also appear to be notable.

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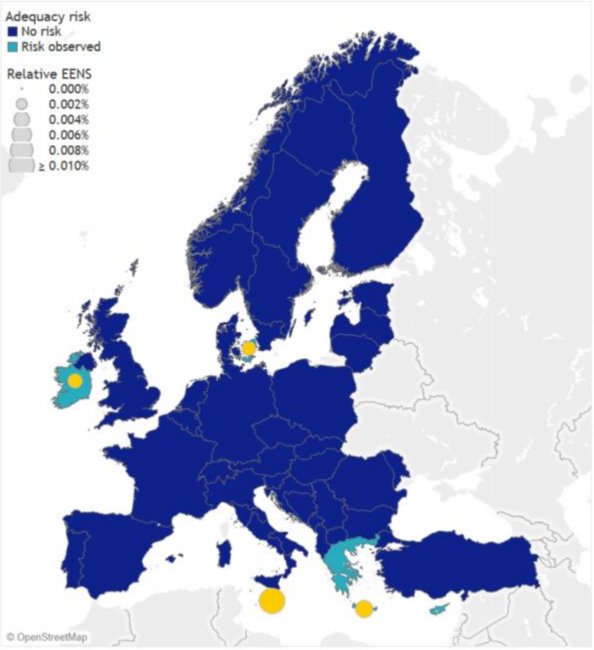
[8] The assessment considers pan-European cooperation when activating non-market resources, which means that non-market resources in one country are also considered in another during scarcity (but also considering network limitations). The actual activation of non-market resources abroad may depend on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



CY00	**EENS:** 2.00 MWh (**0.00010%** compared to Seasonal Consumption) **99th percentile ENS:** 0.00 MWh (**0.00000%** compared to Seasonal Consumption)
DKE1	**EENS:** 130.00 MWh (**0.00291%** compared to Seasonal Consumption) **99th percentile ENS:** 2848.11 MWh (**0.06390%** compared to Seasonal Consumption)
GR00	**EENS:** 6.00 MWh (**0.00003%** compared to Seasonal Consumption) **99th percentile ENS:** 65.19 MWh (**0.00034%** compared to Seasonal Consumption)
GR03	**EENS:** 60.00 MWh (**0.00453%** compared to Seasonal Consumption) **99th percentile ENS:** 1050.31 MWh (**0.07930%** compared to Seasonal Consumption)
IE00	**EENS:** 335.00 MWh (**0.00328%** compared to Seasonal Consumption) **99th percentile ENS:** 5440.86 MWh (**0.05330%** compared to Seasonal Consumption)
MT00	**EENS:** 1568.00 MWh (**0.14354%** compared to Seasonal Consumption) **99th percentile ENS:** 8340.88 MWh (**0.76354%** compared to Seasonal Consumption)

Figure 11: Adequacy risk overview

The distribution of risks within season is presented in Figure 12 via the visualisation of Loss of Load Probability (weekly LOLP[9]). No common pattern could be observed for the six Study Zones, except for mainland Greece (GR00) and Creta (GR03).

Cyprus (CY00) may face adequacy issues in mid-summer when demand may reach the highest values (c.f. Figure 7) and if combined with high unplanned outages of conventional generation. If weather conditions are favourable or at least not combined with high unplanned outages, no adequacy issues should be recorded over summer 2022 in Cyprus.

Eastern Denmark (DKE1) is marked with adequacy risks towards the end of summer 2022, when interconnection outages are planned with southern Sweden (SE04). This interconnection is the largest for Eastern Denmark and accounts for over one third of typical import capacity. The risks are somewhat expected, and the TSO remains vigilant. Planned outages may be rescheduled closer to real-time operations, depending on the situation.

Creta (GR03) is marked by possible adequacy risks, which start increasing towards mid-summer and then decline towards the end of summer. As in Cyprus, it can be explained by a seasonal pattern of demand which may reach its highest value in mid-summer. If weather conditions for renewable generation are favourable, adequacy issues should be avoided. Furthermore, demand expectations for summer 2022 have increased compared with summer 2021, when the COVID-19 effect was anticipated. This is the reason why risks were noted only for summer 2022. Nevertheless, Greece has contracted non-market resources to address these exceptional cases in Creta, which is a rather isolated system. The impact of these non-market resources is presented in the following section.

Mainland Greece (GR00) is marked by only traces of adequacy risks in mid-summer. These risks will materialise only if extreme adverse operational conditions coincide. These operational conditions include a prolonged heat wave driving electricity demand; low renewable generation; a notable unplanned outage of thermal generation; and low import potential from neighbouring power systems. Under these circumstances, close monitoring would be necessary.

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[9] *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). This suggests that weekly LOLP under normal market conditions represents the probability that system operators would need to identify non-market resources, whereas weekly LOLP when considering non-market resources represents the probability that the power system may face a lack of supply and TSOs may need to identify non-market measures and, if none are available, partial and controlled demand shedding for a limited duration will be necessary to restore power balance.*

Ireland (IE00) is marked with adequacy risks in July. As observed in past seasons, risks are driven by unplanned outages of aging powerplants. EirGrid has revised the planned outages throughout the summer months to reduce risks. Furthermore, fewer imports can be expected from Great Britain (UK00) this year. Overall, risks should be moderated by the update of planned outages in Ireland.

The adequacy situation in Malta (MT00) should be monitored throughout summer, with a special focus on the middle of the summer. Adequacy in Malta is typically carefully monitored every summer, and for this reason, Malta implemented specifically designed non-market resources, which could be activated in the event of supply scarcity. The impact of these non-market resources is presented in the following section.

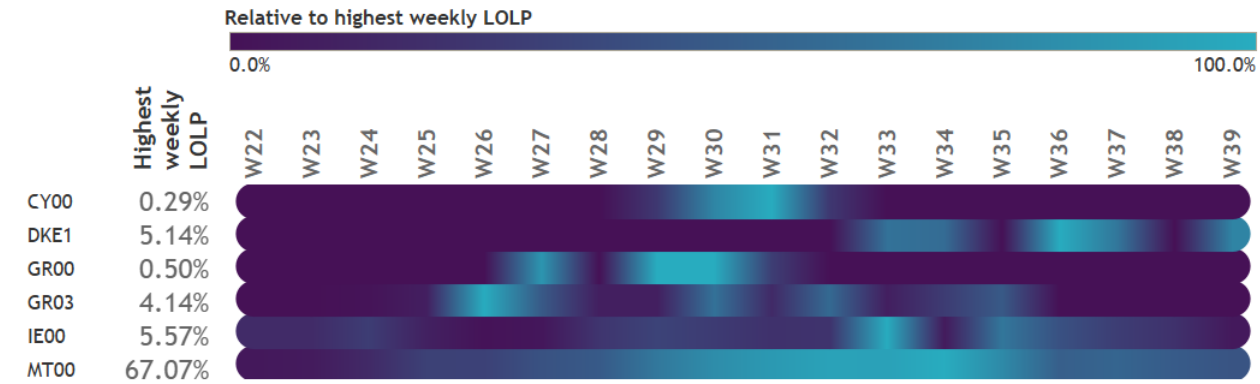
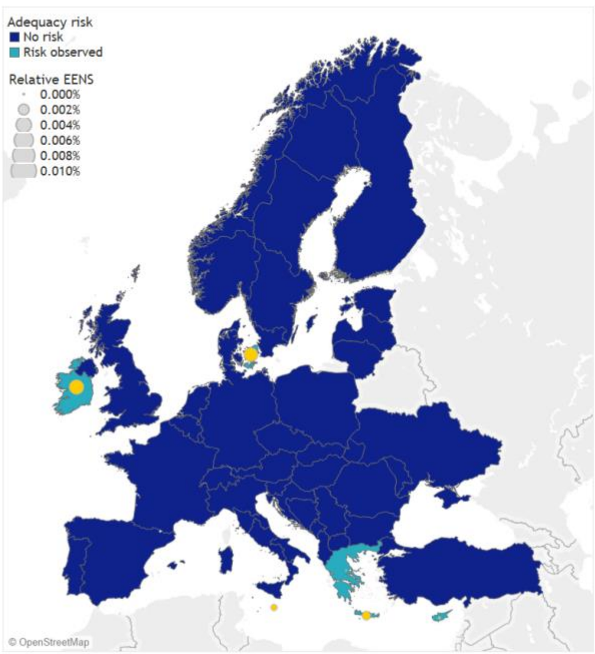


Figure 12: Weekly adequacy insights

Focus on non-market resources

Non-market resources (overview in Figure 3) drastically reduce Expected Energy Not Served (EENS) in Malta and Creta (Figure 13). Non-market resources in Creta also slightly decrease EENS in mainland Greece (GR00). No notable impact in other Study Zones is observed as they do not have dedicated non-market resources available and the resources available abroad are not accessible due to interconnection limitations.



CY00	**EENS:** 2.00 MWh (**0.00010%** compared to Seasonal Consumption) **99th percentile ENS:** 0.00 MWh (**0.00000%** compared to Seasonal Consumption)
DKE1	**EENS:** 130.00 MWh (**0.00291%** compared to Seasonal Consumption) **99th percentile ENS:** 2848.11 MWh (**0.06390%** compared to Seasonal Consumption)
GR00	**EENS:** 5.00 MWh (**0.00003%** compared to Seasonal Consumption) **99th percentile ENS:** 52.72 MWh (**0.00027%** compared to Seasonal Consumption)
GR03	**EENS:** 15.00 MWh (**0.00112%** compared to Seasonal Consumption) **99th percentile ENS:** 470.25 MWh (**0.03550%** compared to Seasonal Consumption)
IE00	**EENS:** 335.00 MWh (**0.00328%** compared to Seasonal Consumption) **99th percentile ENS:** 5362.26 MWh (**0.05253%** compared to Seasonal Consumption)
MT00	**EENS:** 6.00 MWh (**0.00057%** compared to Seasonal Consumption) **99th percentile ENS:** 155.75 MWh (**0.01426%** compared to Seasonal Consumption)

Figure 13: Adequacy risk overview – considering non-market resources

LOLP in Malta is significantly lower when non-market resources are considered and shows only occasional risks (Figure 14). This suggests that partial demand shedding might be required only under exceptional operational conditions and only if these conditions occur in particular weeks with an elevated adequacy risk (especially week 33 to week 36). A similar situation is observed in Creta.

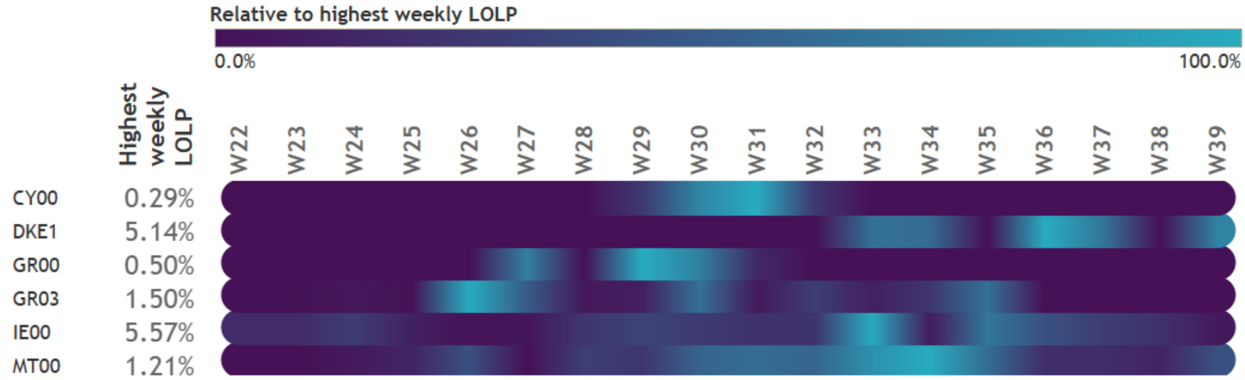


Figure 14: Adequacy weekly insights – considering non-market resources

Figure 15 represents the impact of non-market resources, which demonstrates that non-market resources can, to a large extent, address adequacy concerns in Malta.

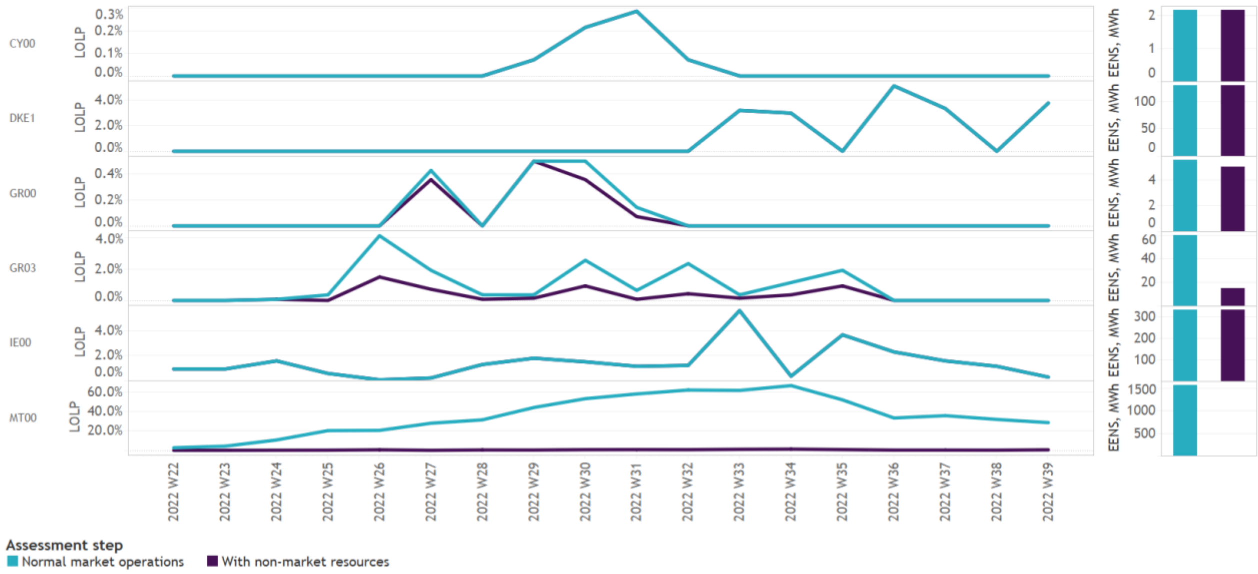


Figure 15: Detailed adequacy overview – weekly LOLP and ENS

Gas dependency and preparation for winter 2022–2023

ENTSO-E has been intensively involved in preparing ad hoc analyses about the dependence on Russian fossil fuel in tight coordination with authorities, policy makers and Oil and Gas associations since the invasion of Ukraine on 24 February 2022 and the escalation of political concerns. In particular, ENTSO-E has been exchanging with the EC and the ECG on this matter since early March.

Member States have a central role in addressing security of supply. They coordinate at European level through the EC, chaired by the EC. Each Member State has been developing a dedicated Risk Preparedness Plan, which includes mitigation measures.

TSOs undertake continuous assessments via the Short-term Adequacy (STA) process, and ENTSO-E is preparing early assessments for the next Winter period in collaboration with all its members, the gas sector and policy makers.

Risks are anticipated for the upcoming winter, with gas supply as the current primary concern. Other potential fuel disruptions will also be investigated in consultation with other organisations, Oil and Gas associations, and key experts.

The present ENTSO-E analysis gives first quantitative insights and qualitative awareness perspectives. Further ad hoc iterations in coordination with policy makers are foreseen in the coming months to more deeply anticipate the 2022–2023 Winter Outlook.

Gas dependency quantitative analysis

This analysis focuses on the European power system's sensitivity to gas supplies from Russia

- by assessing the critical gas volume for electricity generation in Europe; and
- by consolidating statistical information on gas consumption over the last years (using Eurostat data).

Preliminary analysis take-away:

- a significant gas volume is needed for electricity adequacy reasons; and
- by pushing gas to the end of the merit order, some gas demand could be saved while still covering the demand for electricity generation.

The analysis is based on the latest available Winter Outlook 2021–2022 model[10]. Critical gas volumes for a typical winter 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.

The following chart compares historical gas consumption with the critical gas volume required to meet the demand by dispatching gas units only when it is necessary to supply consumers. Due to the probabilistic

[10] The model contains the installed capacity, maintenance and demand as of December 2021. No new data collection for next winter was performed at that stage.

assessment (probabilistic elements are mainly the climatic conditions), a box plot is used to indicate the range of the needed gas volume.

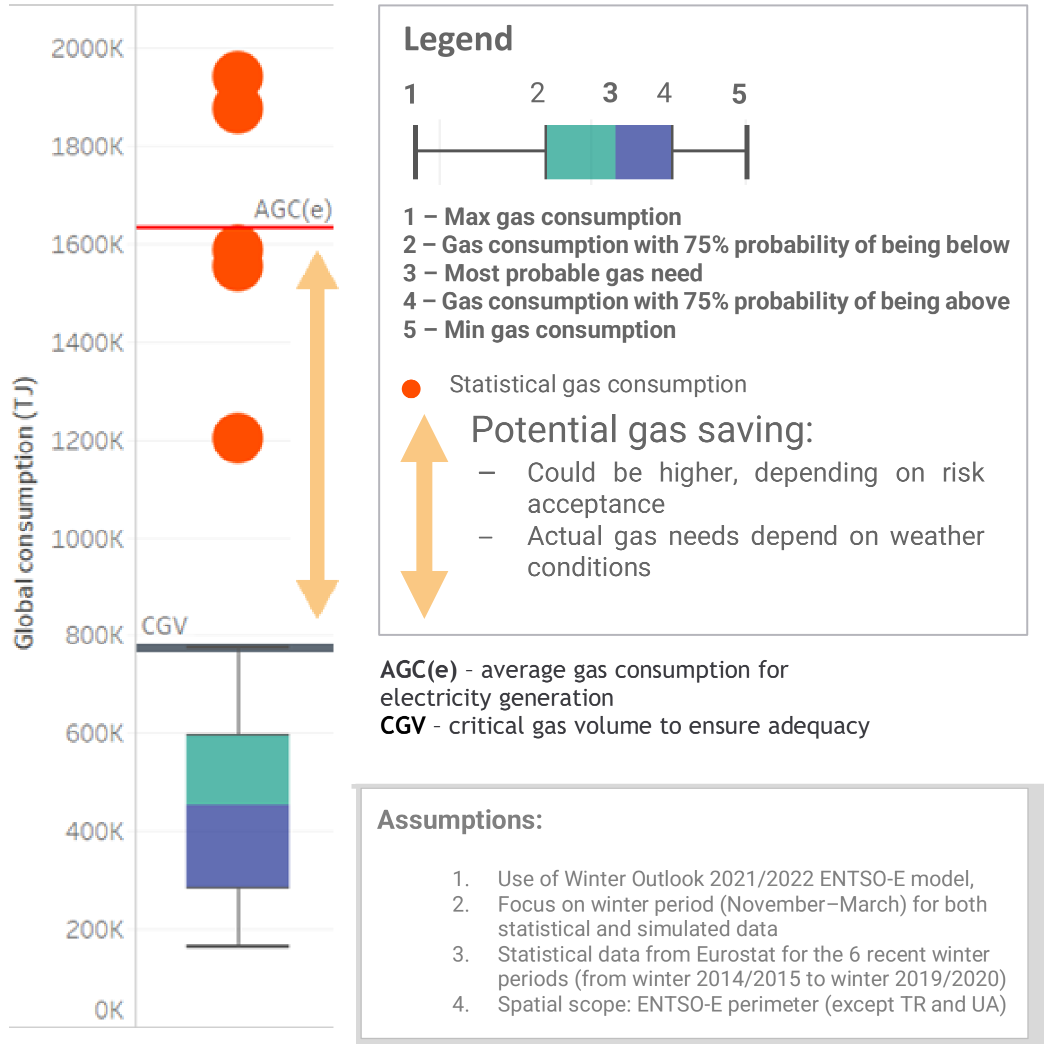


Figure 16: Critical gas volume (CGV) compared with historical average gas consumption in Europe (AGC(e))

How to interpret the CGV chart

- Each orange dot represents a historical year of gas consumption for electricity generation. The significant differences between years are primarily related to temperature and climate conditions, but can also be influenced by the situation in the electricity market (e.g. prices, planned outages; changing generation fleet, etc.).
- The AGC(e) 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 critical gas volume (CGV) to ensure adequacy.
- The blue and cyan 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 35 climate condition scenarios). There is a 50% probability for a given year to be in this range.
- The potential gas saving is the difference between AGC for electricity generation among the statistical years and the critical volume to ensure adequacy.

Text Box 1: How to interpret Critical Gas Volume analysis

The sensitivity to Russian gas supply is also investigated at the country level. The graph below shows three parameters for each country that are interesting to compare:

- The average gas import from Russia (based on Eurostat data);
- The gas share of electricity production in the total gas consumption (based on Eurostat data); and
- The gas consumption decrease potential (based on the simulation as explained above, but now on a country level).

Some refinements are necessary to obtain a more realistic view for next winter (e.g. use of winter 2022/2023 data, improved consideration of gas supply for CHPs providing heat and electricity, improved consideration of the gas supply needed for critical infrastructure providing grid services, etc.). However, the graph already provide some interesting insights:

- 15 countries (13 EU Member States) import more than half of their gas from Russia;
- 8 countries have used in past years at least one third of their gas import for gas-fired power; and
- The potential for reduction of gas for power is heterogenous across Europe.

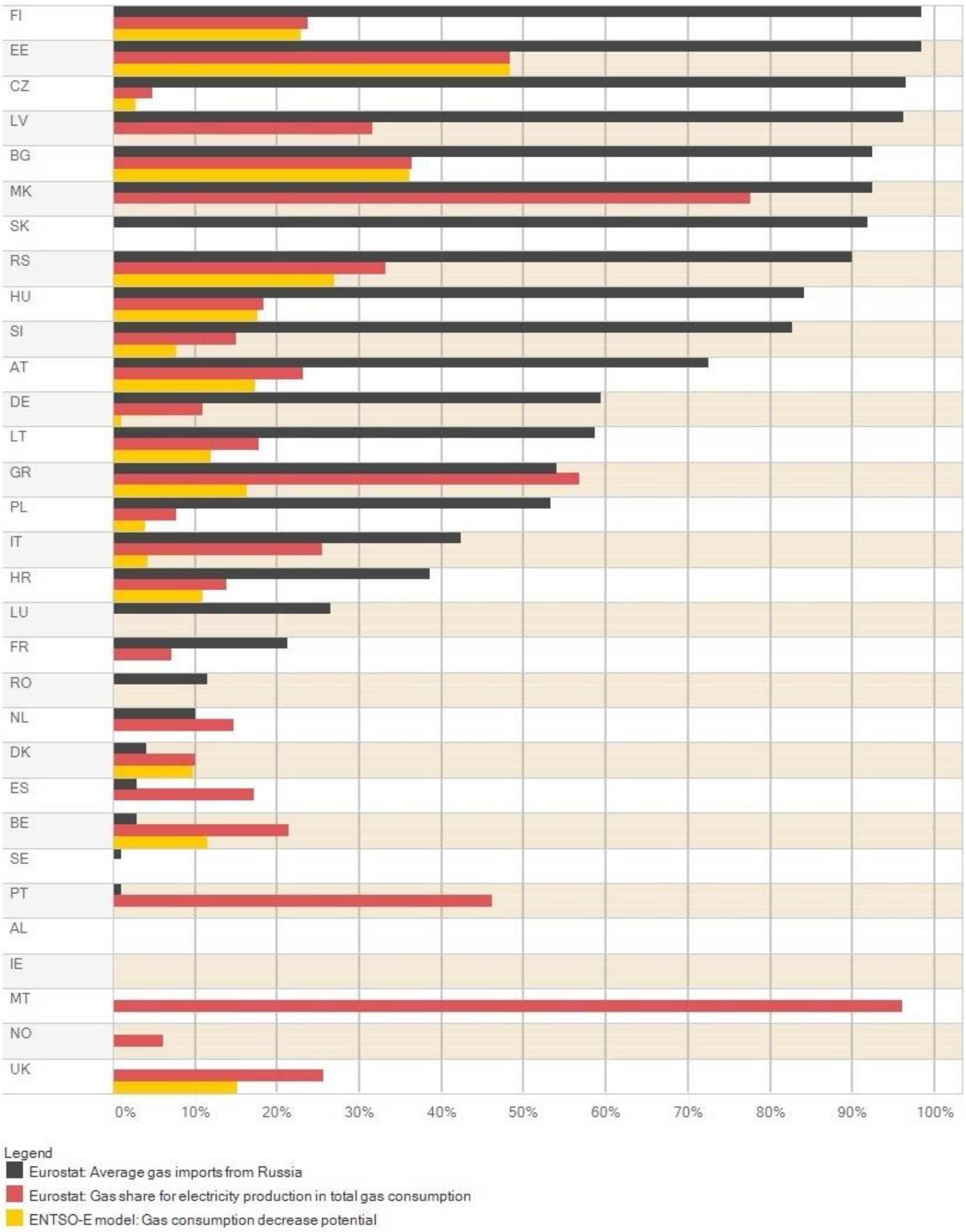


Figure 17: Gas consumption landscape: gas imports from Russia, gas usage in power sector and potential savings in the power sector[11,12]

This assessment will be refined in the coming weeks and months through additional ad hoc sensitivities in addition to an early preparation of next winter outlook, in tight coordination with the policy makers and ENTSOG.

Emphasis on gas storages to prepare for winter 2022–2023

To ensure gas supplies during the winter (for electricity and gas demand), it is important to start the winter with sufficient gas storage. Gas storage will play an essential role for gas supply over the winter months and represents an important factor for gaining confidence in the adequacy situation in the power sector. According to ENTSOG, gas storage serves as seasonal storage, which allows gas to be stored over the summer months to make it available during the winter months, when gas consumption is higher and import

[11] *Gas consumption decrease potential may be overestimated for some countries because the gas consumption of small power plants (especially CHP) was not considered in this analysis*

[12] *For Germany results of a more detailed analysis performed by the four German TSOs are presented in this figure. The German TSO analysis is based on two different simulation runs: A reference simulation with gas prices from end of 2021 and a sensitivity with a significantly higher gas price in order to reflect the current market situation.*

capacities might be insufficient. Gas storage can cover approximately one third of Europe's winter gas consumption in all sectors. ENTSOG has published its summer outlook gas adequacy assessment[13] and is preparing for the Winter Outlook 2022–2023 assessment to provide insights on possible winter gas availability scenarios.

The rules on how gas is distributed over all gas consumers is important for the power system when gas is scarce. Gas storage levels at the beginning of the winter season are key, but they are not the only indicator for assessing the impact on the European power system adequacy. For power systems, gas could be supplied from storages or from direct imports. High gas storage levels are a positive signal for the power system adequacy, and additional direct gas imports will also play a role in ensuring security of the electricity supply during winter.

ENTSOG is continuously assessing gas supply adequacy, publishing reports on its own website, and sharing information with the electricity TSO community.

TSOs' perspectives on winter 2022–2023: beyond gas supply concerns

In addition to the previous quantitative analysis based on Eurostat data, ENTSO-E has performed a qualitative investigation. It builds on a TSO's survey, prepared in tight coordination with the respective Member States. TSOs were invited to fill in the questionnaire until end of April. Anticipated risks and mitigation measures reflect the information available at that stage. Although the study can be completed by further dedicated questionnaires over the coming months, it already contains the following preliminary outcomes:

- The gas supply is a main concern for the electricity security of supply in many countries:
  - Other fuel supplies are seen as less critical by TSOs.
  - There are few national concerns regarding coal supply (e.g. Poland).
- Nuclear availability is a second important concern for several TSOs.
- Mitigation actions are consistent with the REpowerEU package[14], such as:
  - gas storage requirements;
  - alternative fuel supply route arrangement;
  - RES development acceleration;
  - fuel switching; and
  - delay of certain coal or nuclear unit retirements.
- A higher electricity demand due to the lack of gas and/or increasing energy prices can be expected in some countries. However, the sizing of this change is complex to address and ENTSO-E will liaise with policy makers (EC, Members States) on this matter.
- Technology dependence on Russia is low, with only local dependent utilities in the Balkan area (e.g. Serbia and North Macedonia).

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[13] *ENTSOG Summer Outlook 2022*
[14] *RepowerEU Plan*

Additional factors to consider for the coming winter

Several factors may affect the situation over the coming winter. Those could be positive (supporting) and negative (critical) factors. These are, to a large extent, covered within the TSO survey, but some factors can further influence the adequacy situation over the winter:

- Hydrological conditions;
- Electricity consumption; and
- Renewable generation.

Hydrological conditions are very important as they determine how much hydro can be generated over the summer, but they may also influence how much water could be accumulated for winter in countries with large hydro reservoirs. High hydro generation (especially of units which do not have hydro reservoirs) over summer can help to accumulate more gas in storages. Hydro accumulation in reservoirs for winter can help relieve tensions over gas supply. Currently, hydro reservoir accumulations are mainly driven by market participant decisions and their future expectations.

Electricity consumption is temperature-sensitive and is largely driven by weather conditions. Less favourable weather conditions require more electricity generation from gas and/or hydro units, which results in fewer resources made available for the winter. Electricity consumption could be moderated by the consumers to some extent by adapting their heating and cooling systems and other electrical appliances. However, conversely, power consumption could rise in the event of gas shortage for heating if customers heat with other electrical means.

Renewable generation also influences the amount of gas and hydro available over the winter 2022–2023. The more favourable renewable generation allows more gas and hydro resources to be available during winter. RES development acceleration does support power systems, especially if combined with favourable weather conditions.

Although no major risk for adequacy is expected for the summer 2022, the levels of hydro storage at the end of summer will impact the winter outlook assessment. At the date of this report edition, the hydrological conditions in southern Europe are below the average levels; in addition, the hydro reservoir levels and so-called snow water equivalent (SWE) is low compared to historical levels. Beyond that, Copernicus Climate Change service notes that soil humidity and other factors are not the most favourable for the coming months. Furthermore, forecasts over hydrological conditions are not optimistic, which could influence the adequacy situation for winter 2022–2023 in this region. Hence, close monitoring is essential in the coming weeks and months.

Retrospective winter 2021–2022

Surface air temperature maps

Figure 18 displays the surface air temperature anomaly observed in winter 2021–2022 (December 2021 to March 2022) from Copernicus Climate Change Service. Globally, winter for Europe was almost 1°C warmer than the 1991–2020 average. December 2021 showed warm conditions in the west and south, and colder conditions in the northeast. Temperatures in January were above average, with disparities between countries. Warmer conditions were observed in Germany, eastern Europe, Scandinavia, the northern UK and Ireland. Colder conditions were observed in France, northeastern Spain, Greece and Turkey. Temperatures in February were above 2°C warmer than the average of the period 1991–2020. Colder than average conditions were observed in March, again with a contrast between regions. Warmer-than-average conditions were observed in the north of Europe, whereas colder conditions were observed in the south.

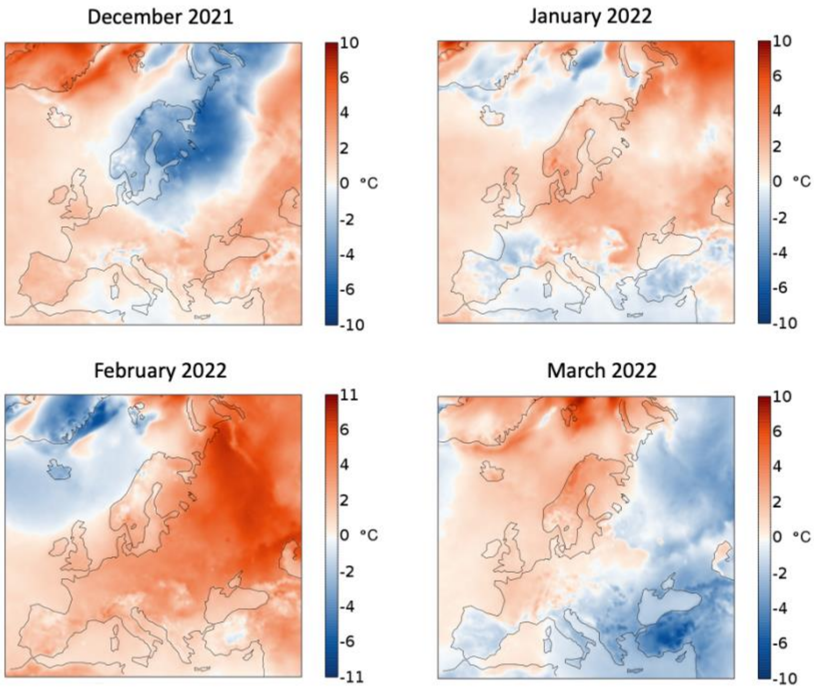

Figure 18: Surface air temperature anomaly in winter 2021–2022 relative to the average of the periods 1991–2020 (for December, January, February and March)[15]

Comments on winter 2021–2022

In general, no adequacy issues were observed due to the mild temperature of the winter 2021–2022. Some countries mention tighter situations (Germany, Ireland, Spain): low coal availability and nuclear/coal phase-out in Germany; unavailable thermal capacity, low wind generation and low hydro reserves in Spain. This situation led to high redispatching amounts in Germany, requiring international redispatching with Switzerland. However, no problems were experienced in Ireland and Spain, despite the tight situation.

[15] *Copernicus Climate Change Service—Surface air temperature maps*

Poland faced multiple difficulties. Regarding adequacy, the worst situation occurred on 5 December for the working day of 6 December. PSE, the Polish TSO, requested a regional STA process during which remedial actions were sought in the region in a coordinated manner. Several options were identified to support the Polish power system, and finally a emergency energy exchange was made, preventing the risk of power shortage. In addition, outages caused by the storm Eunice led to around 37 GWh of energy not served mid-February. A tripping of the Krajnik–Plewiska 400 kV line caused the separation of the Szczecin agglomeration with the Polish synchronous area. The agglomeration remained connected through the distribution network and through one circuit of the 400 kV line Krajnik-Vierraden with 50 Hertz.

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.

This new methodology is described in the Methodology for Short-term and Seasonal Adequacy Assessments[16]. It was developed by ENTSO-E in line with the Clean Energy for all Europeans package and especially the Regulation on Risk Preparedness in the Electricity Sector (EU) 2019/941, and it received formal approval from the Agency for the Cooperation of Energy Regulators (ACER)[17]. Although the implementation of this target methodology will still require certain extensions in the coming year (for instance to include flow-based modelling), the present Summer Outlook shows a major advancement.

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 analysed timeframe. Figure 19 provides a schematic representation of this scenario construction process.

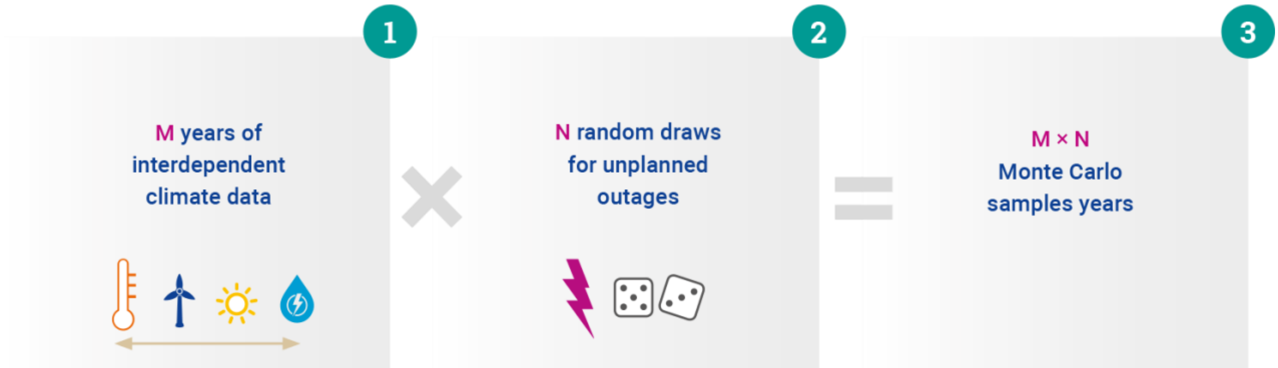

Figure 19: Scenarios assessed in Seasonal Outlooks

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.

Consequently, ENTSO-E has 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. Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 20 illustrates the difference in the number of scenarios between the two modelling approaches.

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

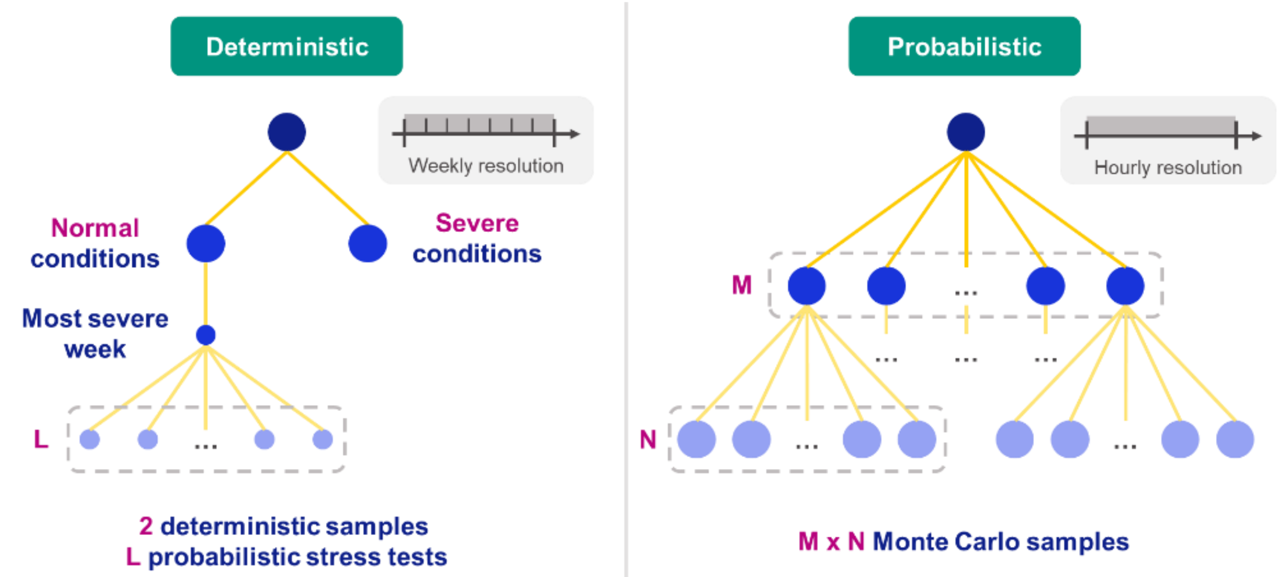

Figure 20: Scenario revolution – from deterministic to probabilistic

For each of the scenarios, an adequacy assessment is performed on the seasonal time horizon, resulting in an overall probabilistic assessment of pan-European resource adequacy that can not only identify whether the adequacy risks exist under various deterministic scenarios but also construct a high number of consistent pan-European scenarios and identify realistic adequacy risk. After the Winter Outlook 2020–2021, further improvements were made, especially in the modelling of exchanges, whereby new constraints on total simultaneous exchanges were implemented. In the Summer Outlook 2021, simultaneous import and simultaneous export limitations were considered, as were limitations on country position (or net exchange).

Appendix 2: Additional information about the study

Figure 21: Study zones

AL00	From: GR00 Avg. 400 MW (400 - 400) MW	From: ME00 Avg. 300 MW (300 - 300) MW	From: RS00 Avg. 200 MW (200 - 200) MW											
AT00	From: DE00 Avg. 4,900 MW (4,900 - 4,900) MW	From: SI00 Avg. 950 MW (950 - 950) MW	From: HU00 Avg. 799 MW (400 - 800) MW	From: CZ00 Avg. 780 MW (650 - 800) MW	From: CH00 Avg. 737 MW (486 - 1,200) MW	From: ITN1 Avg. 81 MW (10 - 100) MW								
BA00	From: HR00 Avg. 600 MW (600 - 600) MW	From: ME00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 492 MW (200 - 600) MW											
BE00	From: FR00 Avg. 1,800 MW (1,800 - 1,800) MW	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NL00 Avg. 950 MW (950 - 950) MW	From: UK00 Avg. 947 MW (0 - 1,000) MW										
BG00	From: RO00 Avg. 1,250 MW (1,250 - 1,250) MW	From: GR00 Avg. 550 MW (550 - 550) MW	From: MK00 Avg. 400 MW (400 - 400) MW	From: RS00 Avg. 283 MW (0 - 300) MW	From: TR00 Avg. 159 MW (100 - 334) MW									
CH00	From: FR00 Avg. 3,000 MW (3,000 - 3,000) MW	From: DE00 Avg. 2,000 MW (2,000 - 2,000) MW	From: ITN1 Avg. 1,541 MW (1,440 - 1,910) MW	From: AT00 Avg. 729 MW (486 - 1,200) MW										
CZ00	From: DE00 Avg. 2,318 MW (1,600 - 2,600) MW	From: SK00 Avg. 1,200 MW (1,200 - 1,200) MW	From: AT00 Avg. 887 MW (800 - 900) MW	From: PLE0 Avg. 781 MW (500 - 800) MW										
DE00	From: AT00 Avg. 4,900 MW (4,900 - 4,900) MW	From: NL00 Avg. 4,250 MW (4,250 - 4,250) MW	From: CH00 Avg. 4,000 MW (4,000 - 4,000) MW	From: PLE0 Avg. 3,000 MW (3,000 - 3,000) MW	From: CZ00 Avg. 2,774 MW (2,300 - 2,800) MW	From: DKW1 Avg. 2,294 MW (1,030 - 2,500) MW	From: FR00 Avg. 1,706 MW (1,350 - 2,950) MW	From: NOS0 Avg. 1,400 MW (1,400 - 1,400) MW	From: LUV1 Avg. 1,300 MW (1,300 - 1,300) MW	From: BE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: LUG1 Avg. 1,000 MW (1,000 - 1,000) MW	From: SE04 Avg. 615 MW (615 - 615) MW	From: DKE1 Avg. 568 MW (400 - 585) MW	From: DEKF Avg. 400 MW (400 - 400) MW
DKE1	From: SE04 Avg. 969 MW (0 - 1,300) MW	From: DE00 Avg. 581 MW (400 - 600) MW	From: DKW1 Avg. 507 MW (0 - 590) MW	From: DKKF Avg. 400 MW (400 - 400) MW										
DKW1	From: DE00 Avg. 2,224 MW (535 - 2,500) MW	From: NOS0 Avg. 785 MW (608 - 1,460) MW	From: NL00 Avg. 700 MW (700 - 700) MW	From: SE03 Avg. 674 MW (0 - 715) MW	From: DKE1 Avg. 516 MW (0 - 600) MW									
EE00	From: FI00 Avg. 1,003 MW (658 - 1,016) MW	From: LV00 Avg. 679 MW (679 - 679) MW												
ES00	From: PT00 Avg. 2,080 MW (1,300 - 3,600) MW	From: FR00 Avg. 1,864 MW (1,300 - 2,200) MW												
FI00	From: SE01 Avg. 1,190 MW (400 - 1,200) MW	From: SE03 Avg. 1,180 MW (800 - 1,200) MW	From: EE00 Avg. 1,003 MW (658 - 1,016) MW											
FR00	From: UK00 Avg. 1,908 MW (1,000 - 2,000) MW	From: DE00 Avg. 1,906 MW (1,450 - 3,000) MW	From: ES00 Avg. 1,361 MW (900 - 2,000) MW	From: CH00 Avg. 1,165 MW (800 - 1,700) MW	From: ITN1 Avg. 947 MW (870 - 1,160) MW	From: BE00 Avg. 600 MW (600 - 600) MW								
GR00	From: BG00 Avg. 650 MW (650 - 650) MW	From: MK00 Avg. 449 MW (396 - 450) MW	From: ITS1 Avg. 405 MW (0 - 500) MW	From: AL00 Avg. 400 MW (400 - 400) MW	From: GR03 Avg. 150 MW (150 - 150) MW	From: TR00 Avg. 61 MW (0 - 100) MW								
GR03	From: GR00 Avg. 150 MW (150 - 150) MW													
HR00	From: HU00 Avg. 1,000 MW (1,000 - 1,000) MW	From: SI00 Avg. 900 MW (900 - 900) MW	From: BA00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 388 MW (200 - 400) MW										
HU00	From: SK00 Avg. 1,500 MW (1,500 - 1,500) MW	From: RS00 Avg. 965 MW (300 - 1,000) MW	From: SI00 Avg. 895 MW (0 - 1,200) MW	From: HR00 Avg. 800 MW (800 - 800) MW	From: RO00 Avg. 800 MW (800 - 800) MW	From: AT00 Avg. 799 MW (400 - 800) MW								
IE00	From: UK00 Avg. 497 MW (0 - 500) MW	From: UKNI Avg. 300 MW (300 - 300) MW												
ITCA	From: ITSI Avg. 1,199 MW (1,100 - 1,200) MW	From: ITS1 Avg. 1,100 MW (1,100 - 1,100) MW												
ITCN	From: ITN1 Avg. 3,784 MW (3,100 - 4,200) MW	From: ITCS Avg. 2,639 MW (1,600 - 2,800) MW	From: ITCO Avg. 251 MW (0 - 300) MW											
ITCS	From: ITS1 Avg. 4,610 MW (3,800 - 5,000) MW	From: ITCN Avg. 2,130 MW (1,700 - 2,900) MW	From: ITSA Avg. 757 MW (0 - 900) MW	From: ME00 Avg. 568 MW (0 - 600) MW										
ITN1	From: ITCN Avg. 2,552 MW (1,900 - 3,100) MW	From: CH00 Avg. 2,298 MW (725 - 3,420) MW	From: FR00 Avg. 1,646 MW (392 - 2,144) MW	From: SI00 Avg. 445 MW (0 - 730) MW	From: AT00 Avg. 240 MW (60 - 270) MW									
ITS1	From: ITCA Avg. 2,231 MW (900 - 2,350) MW	From: ITCS Avg. 2,000 MW (2,000 - 2,000) MW	From: GR00 Avg. 405 MW (0 - 500) MW											
ITSA	From: ITCS Avg. 563 MW (0 - 720) MW	From: ITCO Avg. 247 MW (0 - 300) MW												
ITSI	From: ITCA Avg. 1,495 MW (1,100 - 1,500) MW	From: MT00 Avg. 201 MW (200 - 225) MW												
LT00	From: LV00 Avg. 833 MW (780 - 881) MW	From: SE04 Avg. 656 MW (0 - 700) MW	From: PL00 Avg. 492 MW (492 - 492) MW											
LUB1	From: BE00 Avg. 400 MW (400 - 400) MW													
LUF1	From: FR00 Avg. 380 MW (380 - 380) MW													
LUG1	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW													
LV00	From: LT00 Avg. 903 MW (820 - 904) MW	From: EE00 Avg. 703 MW (580 - 896) MW												
ME00	From: ITCS Avg. 568 MW (0 - 600) MW	From: BA00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 477 MW (0 - 700) MW	From: AL00 Avg. 300 MW (300 - 300) MW										
MK00	From: RS00 Avg. 383 MW (150 - 500) MW	From: BG00 Avg. 370 MW (308 - 400) MW	From: GR00 Avg. 350 MW (350 - 350) MW											
MT00	From: ITSI Avg. 201 MW (200 - 225) MW													
NL00	From: DE00 Avg. 4,250 MW (4,250 - 4,250) MW	From: BE00 Avg. 950 MW (950 - 950) MW	From: UK00 Avg. 891 MW (0 - 1,000) MW	From: DKW1 Avg. 700 MW (700 - 700) MW	From: NOS0 Avg. 700 MW (700 - 700) MW									
NOM1	From: NON1 Avg. 1,300 MW (1,300 - 1,300) MW	From: SE02 Avg. 985 MW (800 - 1,100) MW	From: NOS0 Avg. 600 MW (600 - 600) MW											
NON1	From: SE01 Avg. 565 MW (0 - 700) MW	From: NOM1 Avg. 350 MW (350 - 350) MW	From: SE02 Avg. 256 MW (0 - 300) MW											
NOS0	From: SE03 Avg. 2,138 MW (734 - 2,184) MW	From: DE00 Avg. 1,348 MW (13 - 1,400) MW	From: UK00 Avg. 1,050 MW (1,050 - 1,050) MW	From: DKW1 Avg. 968 MW (802 - 1,632) MW	From: NOM1 Avg. 800 MW (800 - 800) MW	From: NL00 Avg. 700 MW (700 - 700) MW								
PL00	From: PLI0 Avg. 800 MW (800 - 800) MW	From: SE04 Avg. 500 MW (0 - 600) MW	From: LT00 Avg. 485 MW (485 - 485) MW											
PT00	From: ES00 Avg. 2,766 MW (1,000 - 4,300) MW													
RO00	From: BG00 Avg. 1,250 MW (1,250 - 1,250) MW	From: HU00 Avg. 1,000 MW (1,000 - 1,000) MW	From: RS00 Avg. 477 MW (300 - 500) MW	From: UA01 Avg. 300 MW (300 - 300) MW										
RS00	From: HU00 Avg. 988 MW (300 - 1,000) MW	From: ME00 Avg. 605 MW (0 - 700) MW	From: BA00 Avg. 464 MW (150 - 600) MW	From: MK00 Avg. 455 MW (250 - 500) MW	From: RO00 Avg. 373 MW (300 - 450) MW	From: BG00 Avg. 330 MW (0 - 350) MW	From: HR00 Avg. 289 MW (150 - 300) MW	From: AL00 Avg. 200 MW (200 - 200) MW						
SE01	From: SE02 Avg. 3,300 MW (3,300 - 3,300) MW	From: FI00 Avg. 1,059 MW (300 - 1,100) MW	From: NON1 Avg. 700 MW (700 - 700) MW											
SE02	From: SE03 Avg. 7,300 MW (7,300 - 7,300) MW	From: SE01 Avg. 2,856 MW (1,900 - 3,300) MW	From: NOM1 Avg. 700 MW (700 - 700) MW	From: NON1 Avg. 200 MW (200 - 200) MW										
SE03	From: SE02 Avg. 5,610 MW (4,500 - 7,300) MW	From: NOS0 Avg. 2,212 MW (2,014 - 2,214) MW	From: SE04 Avg. 1,400 MW (800 - 2,000) MW	From: DKW1 Avg. 676 MW (0 - 715) MW	From: FI00 Avg. 635 MW (0 - 1,200) MW									
SE04	From: SE03 Avg. 2,437 MW (800 - 5,400) MW	From: DKE1 Avg. 1,353 MW (375 - 1,700) MW	From: DE00 Avg. 615 MW (615 - 615) MW	From: LT00 Avg. 478 MW (0 - 700) MW	From: PL00 Avg. 354 MW (0 - 600) MW									
SI00	From: AT00 Avg. 950 MW (950 - 950) MW	From: HR00 Avg. 900 MW (900 - 900) MW	From: HU00 Avg. 895 MW (0 - 1,200) MW	From: ITN1 Avg. 574 MW (0 - 680) MW										
SK00	From: CZ00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HU00 Avg. 1,500 MW (1,500 - 1,500) MW	From: PLE0 Avg. 576 MW (0 - 600) MW	From: UA01 Avg. 400 MW (400 - 400) MW										
TR00	From: BG00 Avg. 399 MW (216 - 432) MW	From: GR00 Avg. 207 MW (0 - 216) MW												
UA01	From: SK00 Avg. 400 MW (400 - 400) MW	From: RO00 Avg. 200 MW (200 - 200) MW												
UK00	From: FR00 Avg. 2,000 MW (2,000 - 2,000) MW	From: NOS0 Avg. 1,050 MW (1,050 - 1,050) MW	From: BE00 Avg. 947 MW (0 - 1,000) MW	From: NL00 Avg. 891 MW (0 - 1,000) MW	From: IE00 Avg. 497 MW (0 - 500) MW	From: UKNI Avg. 165 MW (0 - 400) MW								
UKNI	From: IE00 Avg. 300 MW (300 - 300) MW	From: UK00 Avg. 166 MW (0 - 450) MW												

Figure 22: Import capacity overview

Appendix 3: Additional information about the results

Loss of Load Expectation and other annual metrics

Information about Loss of Load Expectation (LOLE) in the assessed season is presented in this appendix. LOLE figures could be useful when comparing how adequacy evolved between editions of seasonal adequacy assessments[18]. 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[19] 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 upcoming season could simply be one of the more constraining from a set of possible season scenarios[20] (e.g. if 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[21], 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.

Considering the aforementioned background and interpretation limitations, the Figure 23: Seasonal LOLE results below represents the LOLE results of the Summer Outlook 2022.

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[18] 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.

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

[20] 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.

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

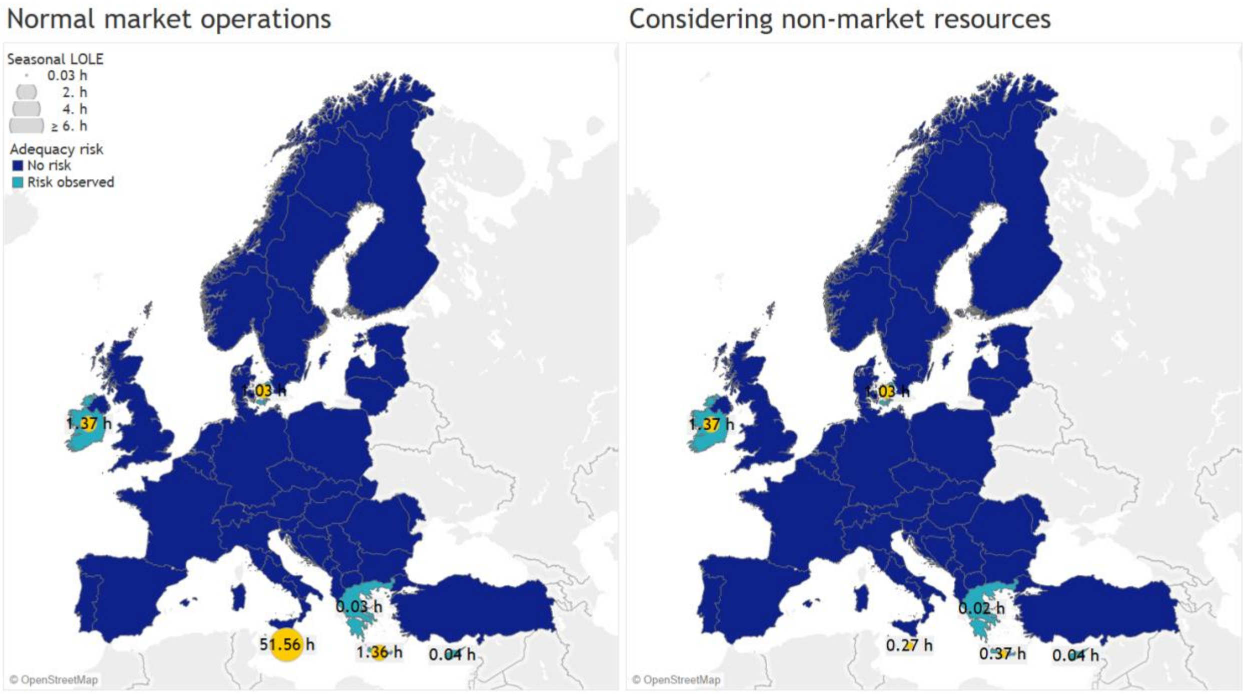

Figure 23: Seasonal LOLE results

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 1400.

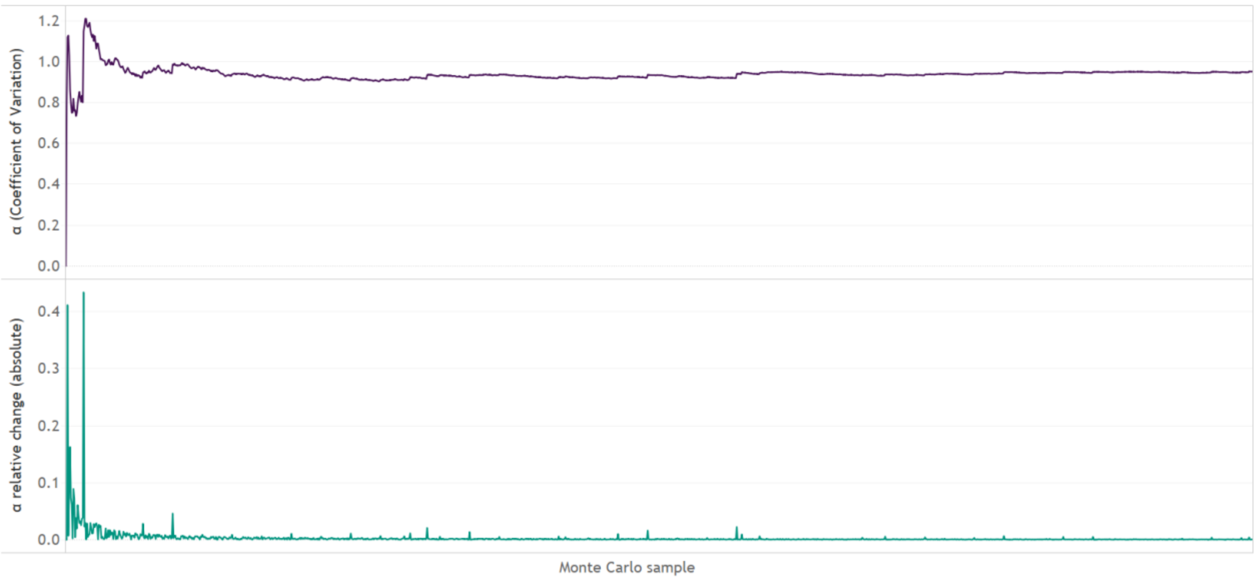

Figure 24: Convergence overview[22]

[22] *The convergence overview shows that the seasonal assessment has a high accuracy level. The number of analysed Monte Carlo samples was 1400.*