Summer Outlook 2021

Winter Review 2020-2021

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 42 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

ENTSO-E Summer Outlook 2021: no adequacy risk is identified except for the close monitoring required in Ireland.

The adequacy risk identified in Ireland at the beginning of summer is driven by generation planned outages, whereas risks at the end of summer season are driven by the planned outage of interconnection with Great Britain. These outages reduce potential supply availability by approximately 450–500 MW compared with normal years. The actual adequacy situation will depend on the operational conditions and especially on wind generation.

The need to rely on non-market resources to ensure security of supply in rather isolated Mediterranean systems such as Malta is common in summer periods. The Summer Outlook 2021 highlights some risks in this respect, but non-market resources should be sufficient to cope with operational challenges and supply shortages.

The Summer Outlook is accompanied by a retrospect of last winter. The weather conditions were rather favourable. Winter 2020–2021 was favourable for adequacy in general as overall temperatures were close to average and supply margins were sufficient to ensure adequacy during cold spells. Cold weather in early January, including cold spells, caused tight supply margins in Western Europe, but no lack of supply was recorded.

System Alerts were issued in Ireland and Northern Ireland on multiple occasions during winter due to tight supply margins. Market participants responded and TSOs countertraded exchanges with Great Britain. Eventually, no lack of supply was recorded.

The Continental Europe electricity system was separated on 8 January 2021[1] due to the cascaded fault protection activation of several transmission network elements. The system was synchronised in one hour and, due to a fast and coordinated approach, no major loss of load or damages were observed in the power system. These risks are out of the scope of adequacy assessments but are being investigated according to the System Operation Guidelines. A dedicated expert team prepared an interim report, published on ENTSO-E's website. This report is being extended and analysed for final publication in the coming months.

[1] *Interim Report on Continental Europe Synchronous Area Separation on 8 January 2021*

Methodological revolution

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[2]. 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)[3]. Although the implementation of this target methodology will still require some 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 1 provides a schematic representation of this scenario construction process.

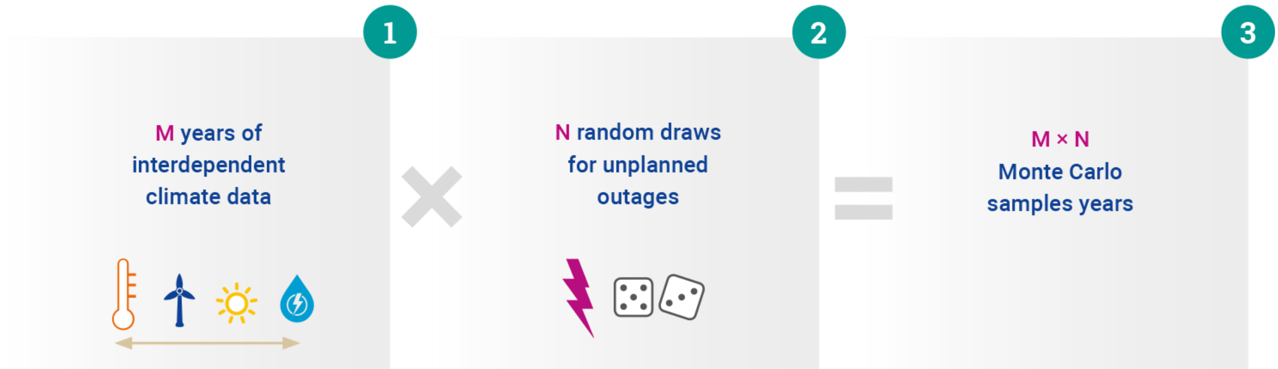

Figure 1: Scenarios assessed in Seasonal Outlooks

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 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 2 illustrates the difference in the number of scenarios between the two modelling approaches.

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

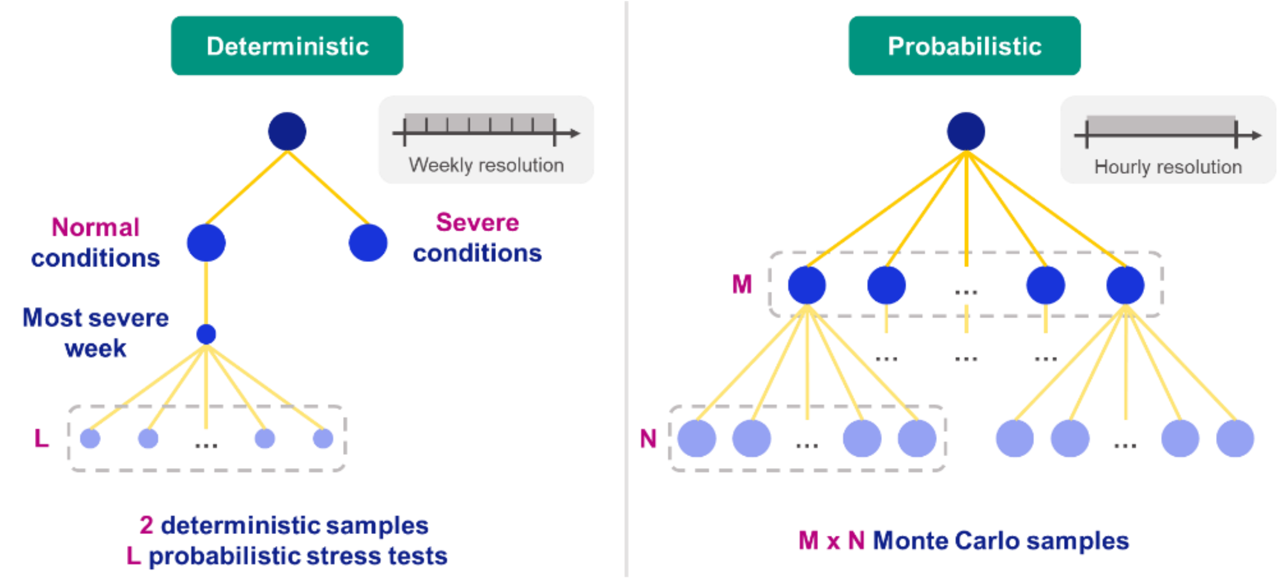

Figure 2: Scenario revolution – from deterministic to probabilistic

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, where 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).

Overview of the power system in Summer 2021

Information collected for the Summer Outlook 2021 study represents the best available information in February–March 2021. TSOs continue to cooperate closely and monitor adequacy closer to real-time through the services of the Regional Security Coordinators (RSCs) to address the always changing situation in the power system.

Since the Summer Outlook 2020, study zone configuration has been revised to address recent changes. First, in light of the Italian bidding zone reconfiguration[4], study zones have been updated accordingly. Southern Italy (ITS1) was split into two study zones – Calabria (ITCA) and the remaining southern Italy (ITS1). In addition, the Umbria region in central Italian bidding zones (study zones ITCN and ITCS) was reassigned from one bidding zone to another. Second, Crete was interconnected with mainland Greece (GR00) in May 2021[5], and hence a study zone has been added (GR03). Any data or result comparison considering previous seasonal outlook editions should take this update into account.

The information about the power system presented in this report considers all the resources available to supply demand in a market-based approach or available resources to supply demand in the event of supply shortage in the market. This means that non-market resources committed to ensuring operational security are not represented. This includes generation, demand-side response and storage resources, which are dedicated to ensuring grid security and stability, as well as transmission reliability margins (by which transfer capacities are being reduced) which are dedicated to coping with power flow variability. Therefore, the figures presented in the report should not be considered representative of all the physically available resources in the power system.

All figures in this section correspond to resources available in the market. This means that the total capacity overview (Figure 3) and generation capacity mix (Figure 4) disregard non-market resources. Non-market resources are presented in a dedicated figure to show the amount of capacity that can be used in the event of a supply shortage in the market.

Generation overview

The generation capacity overview in Figure 3 shows that installed capacities available on the market cover the highest expected demand in Summer 2021. However, in some places, imports might be necessary in the event of low renewable generation. Net Generating Capacities (NGCs) are sufficient to cover the highest expected demand in all study zones, but if only thermal and hydro units are considered, the NGCs in many study zones decrease. In some zones, they even drop below the highest expected demand in Summer 2021. This suggests that in the case 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 high cooling water temperatures). This shows the importance of the interconnected European power system and the relevance of pan-European adequacy studies.

[4] Effective from 1 January 2021. Deliberation 103/2019/R/eel of the Italian Authority of 19 March 2019
[5] Press release: [Crete-Peloponnese: The record-breaking interconnection is completed]

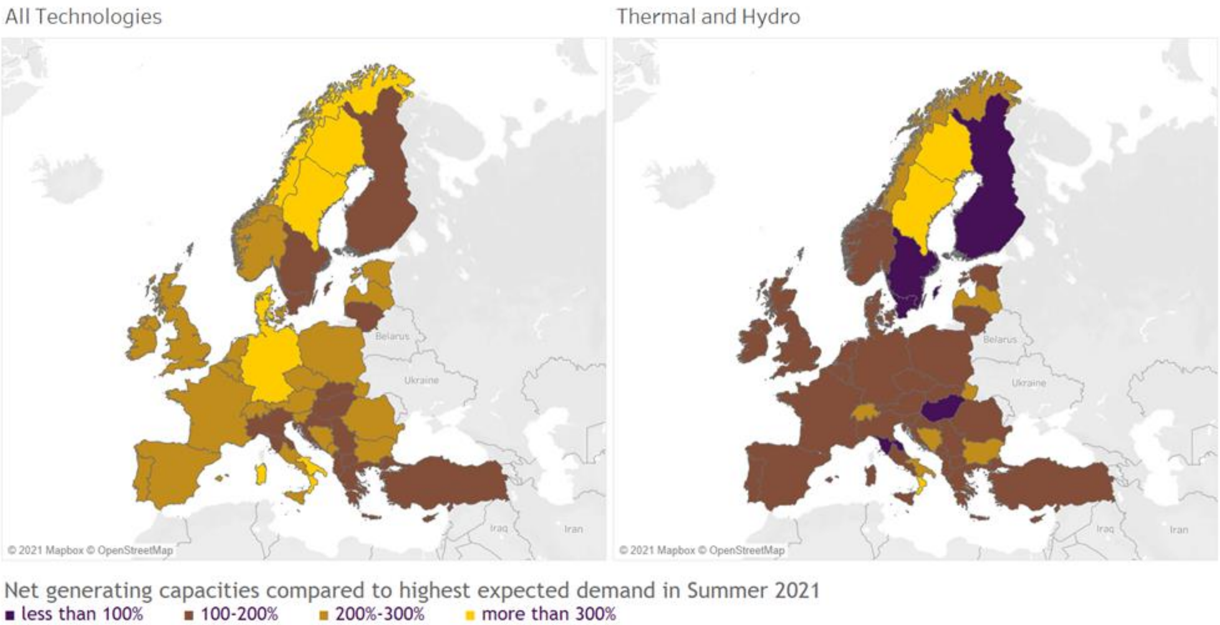

Figure 3: Net generating capacity overview – comparison with highest expected demand

According to Figure 4, thermal NGC available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of Summer 2021. This is followed by hydro, wind and solar capacities, which constitute the remaining half. In addition, the highest expected demand[6] is depicted with a small black square, and its value as a percentage of each node'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]), thermal NGC share is low despite insignificant hydro capacities. These systems are characterised by a high share of wind and solar generation.

Info box:
Study zone naming convention

Country code ← XXYY

ENTSO-E zone index ←

Map with codes is available in Appendix 1:

Demand Side Response (DSR) services 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 (c.f. Figure 10). More DSR is likely to be available during peak times, but this is not guaranteed.

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[6] *Highest expected demand is computed by taking the highest value of the hourly demand 95th percentiles. Hence, this value is highest expected demand; however Seasonal Outlook assessment also considers that demand could even exceed expected highest value as, occasionally, new peak demand records are registered in Europe.*

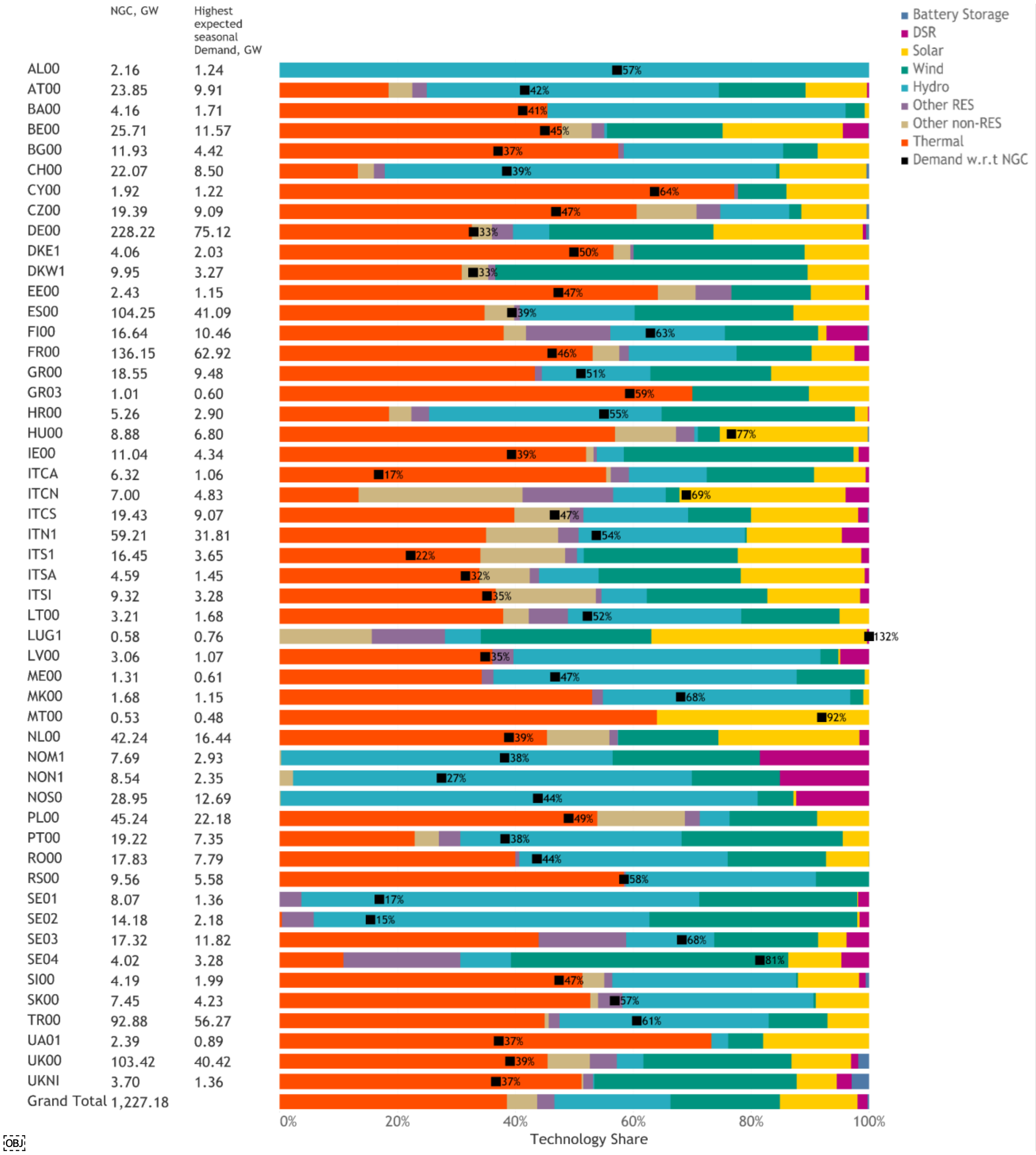


Figure 4: Generation capacity mix at the beginning of summer 2021 per study zones

Figure 5 shows which study zones have non-market resources available along with the corresponding NGC. In the event of a lack of supply in the market, the activation of dispatchable non-market resources can help to cope with adequacy challenges. Only four countries make use of non-market resources. From largest to smallest NGC, these are: Germany, Sweden, Finland and Malta. This report will assess if these resources are sufficient to cope with adequacy issues and by how much.

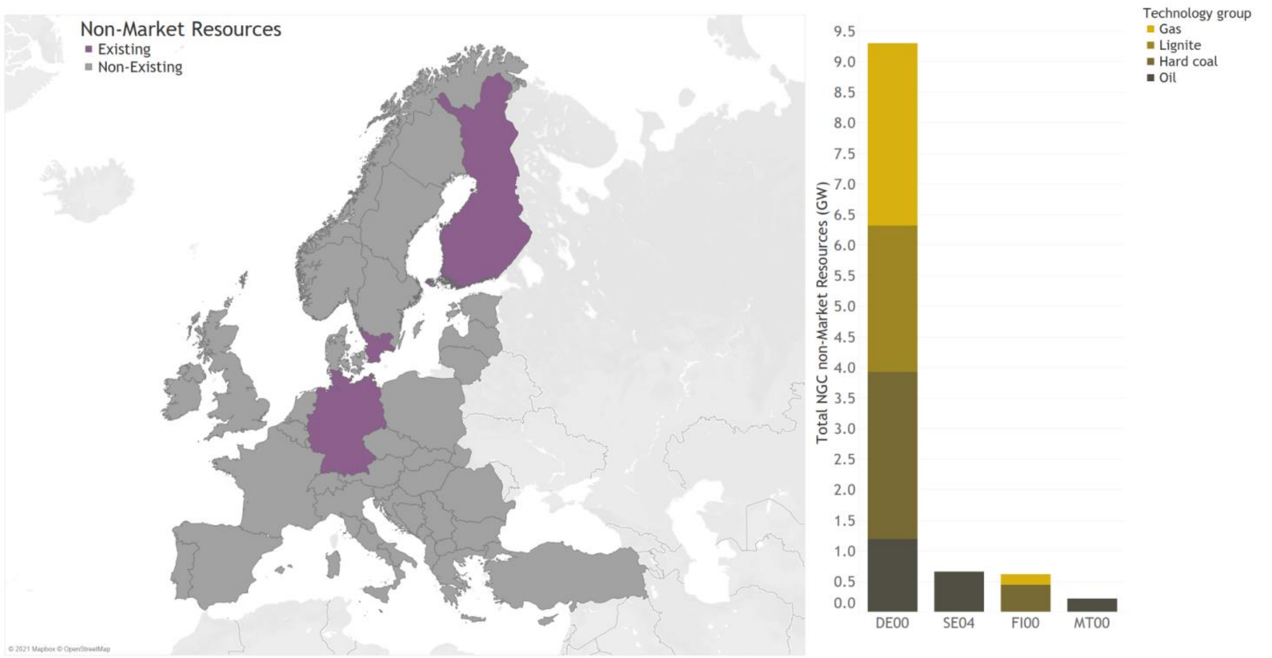


Figure 5: Non-market resources for coping with adequacy challenges in Europe

Capacity evolution

The most relevant thermal capacity evolutions[7] during summer 2021 are shown in Figure 6 and show a net decrease in Europe of approximately 600 MW. The capacity of lignite and hard coal thermal power plants in Europe decreases; this is partially compensated for by the commissioning of gas-fired power plants.

Figure 6: Thermal capacity evolution in Summer 2021

Planned unavailability

The planned unavailability of units considered in the assessment is presented in Figure 7. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing.

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

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 2021, with gas ranking second, followed by hard coal, lignite and oil.

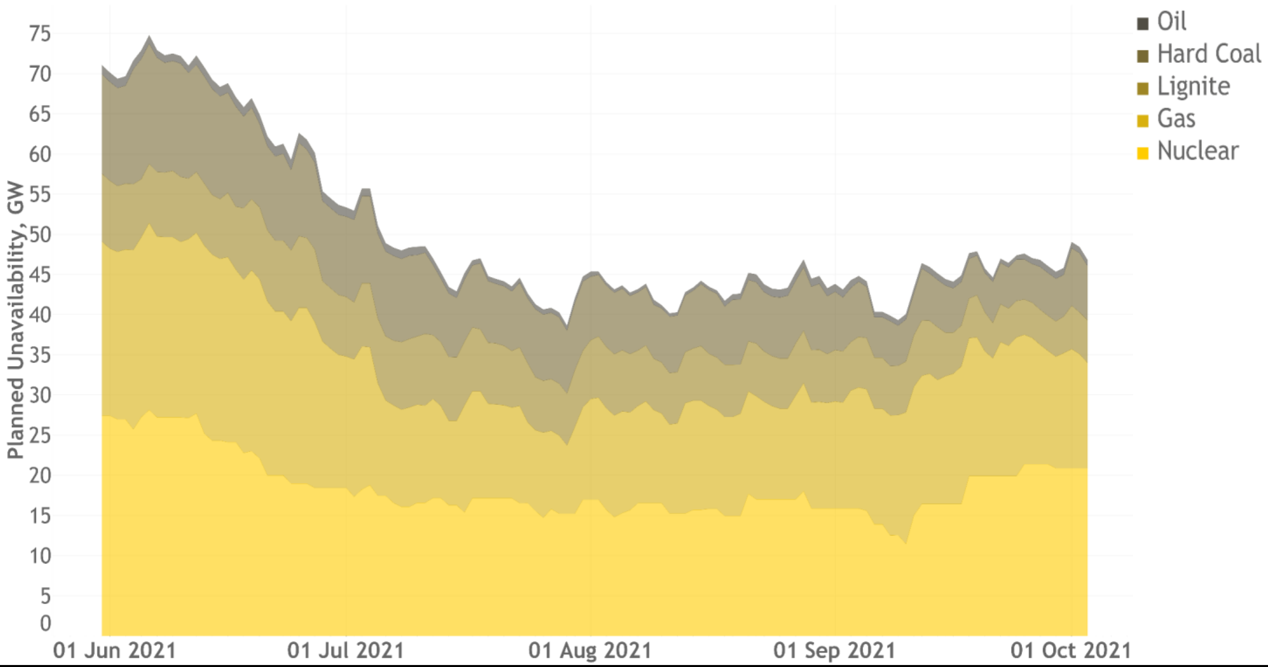


Figure 7: Planned unavailability of thermal units

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 southern Italy (ITS1) or Greece (GR00) in Figure 8. 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 Denmark (DKE1, DKW1) among others.

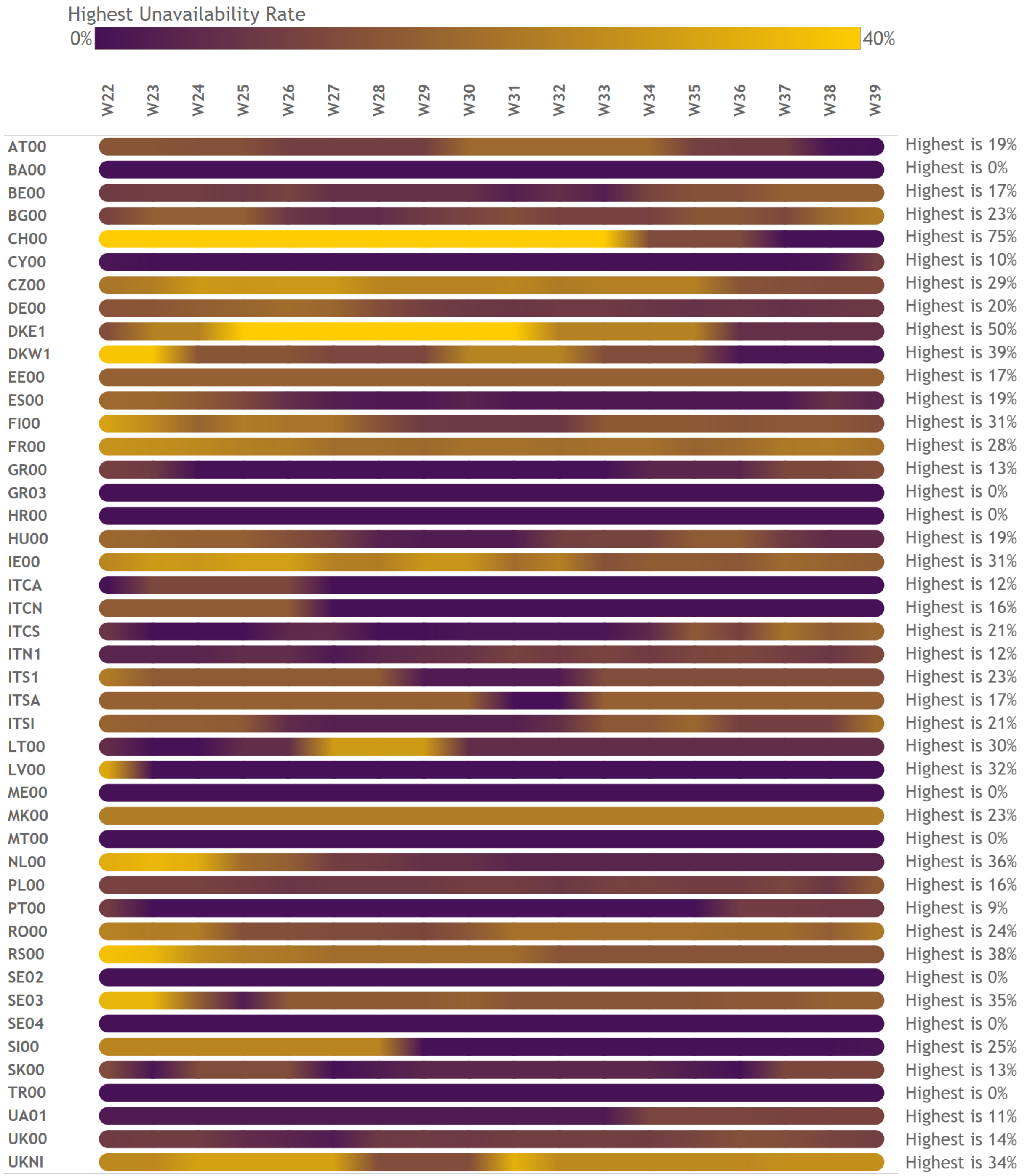


Figure 8: Weekly distribution of thermal planned unavailability relative to thermal NGC

Further availability limitations

The availability reduction overview presented in Figure 9 shows that resources are further limited by approximately 40 GW in summer 2021. Overall, only a minor peak towards mid-summer can be observed, with DSR showing pronounced daily changes.

Generation and DSR availability can be limited by factors other than planned and unplanned outages, and hence resources might not be available at full capacity. The generation could be impacted by seasonal factors (e.g. changes in cooling water temperature), whereas DSR availability might depend on demand levels during particular hours of the day. The availability of other technologies might depend on external factors (e.g. CHP availability for electricity production might depend on heat needs). In some cases, the availabilities of generation (other renewable and non-renewable energy sources) might be strongly dependent on climate; they are, however, not represented in the figure below. This is analogous with wind and solar generation, which are not visualised but are available in the published dataset.

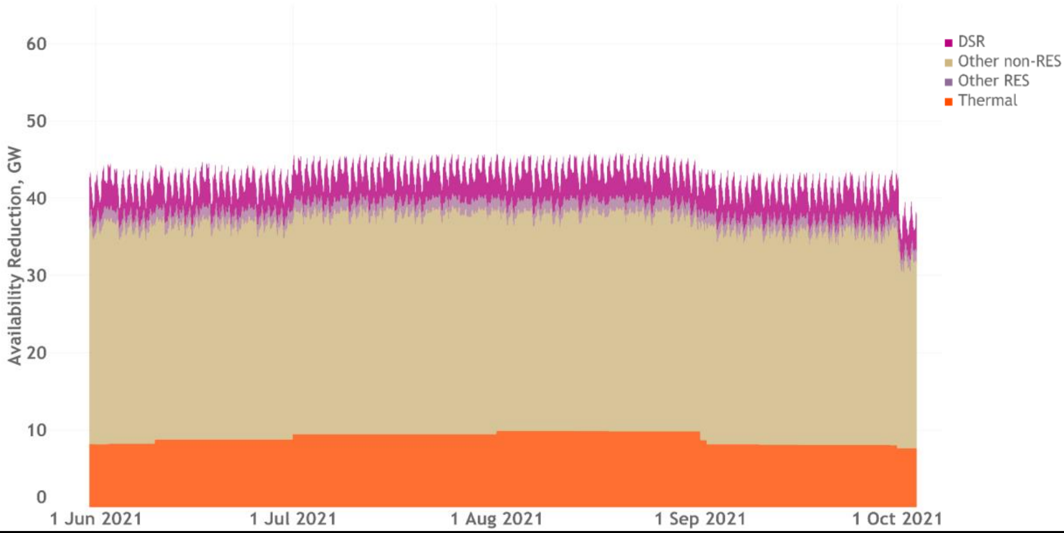


Figure 9: Availability reduction of generation and demand side response

Despite the absolute availability decrease appearing marginal (40 GW) in Europe, the relative availability decrease (showing the ratio of capacity that may not be available due to limitations) is rather notable, as shown in Figure 10. Other non-RES availability may be limited by approximately 40%, whereas DSR varies around 20% depending on the time of the day. This information is especially relevant for study zones with relatively high capacities for these technologies (such as northern–centre Italy [ITCN] and Finland [FI00]).

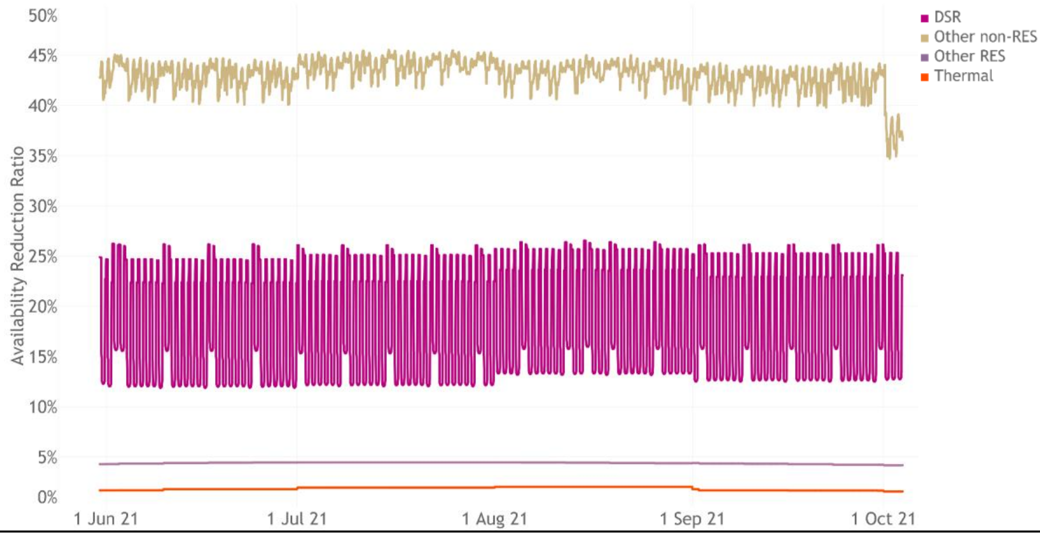


Figure 10: Relative availability reduction – not outage dependent

The availability reduction profile overview in Figure 11 shows that DSR availability is least reduced during daytime, whereas other technologies do not show strong variability throughout the day. However, Figure 11 presents a pan-European overview, and noticeable patterns present in individual countries may not be detectable when examining data aggregated on a pan-European level.

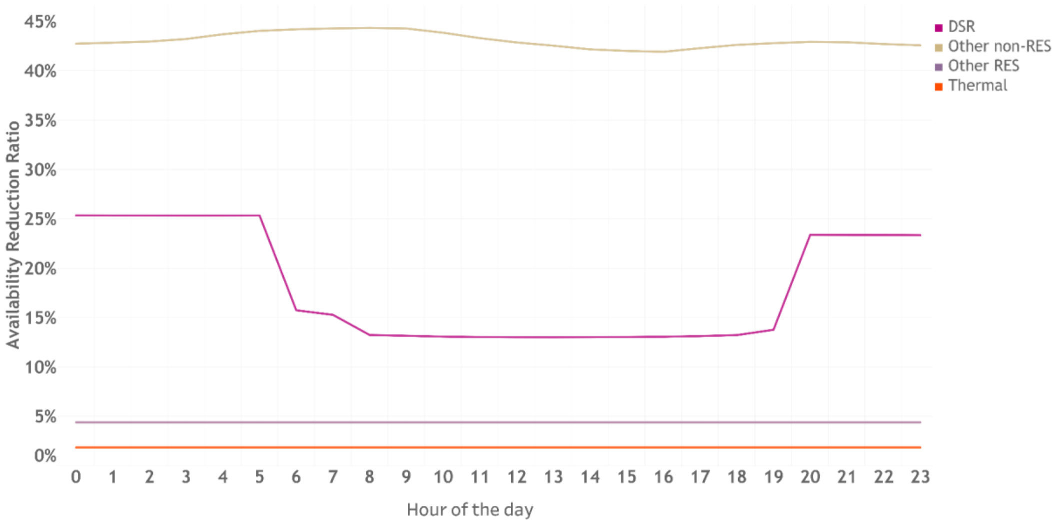


Figure 11: Average daily availability reduction profile overview

Demand overview

The demand overview in Figure 12 compares expected consumption in each week with the highest expected weekly consumption in summer 2021. 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. As for Belgium and France, demand is reduced for a few weeks due to the most favoured holiday period. In southern European countries (e.g. Italy, Greece, Spain), there is a trend towards higher demand in the middle of summer, when the temperature reaches yearly peak values.

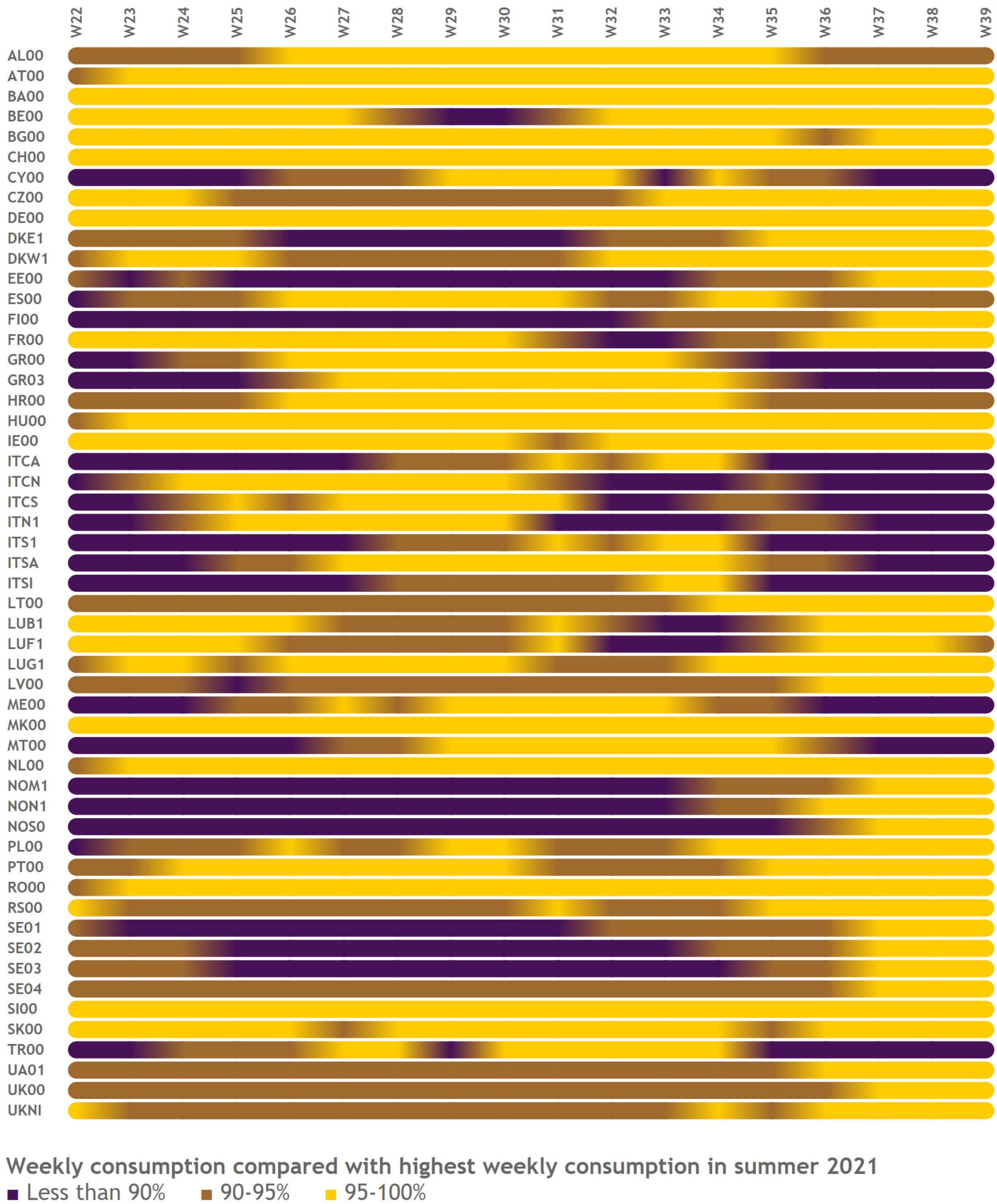


Figure 12: Demand overview – evolution over summer 2021

Figure 13 shows workday consumption patterns per study zone by plotting the mean demand relative to the highest mean demand in summer 2021. The demand peak in Europe is concentrated around noon for most of the study zones. In some study zones (e.g. Denmark East, Bosnia and Herzegovina), an evening peak similar to the noon demand peak is also observed. In other study zones (e.g. Bulgaria, Italy) 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.

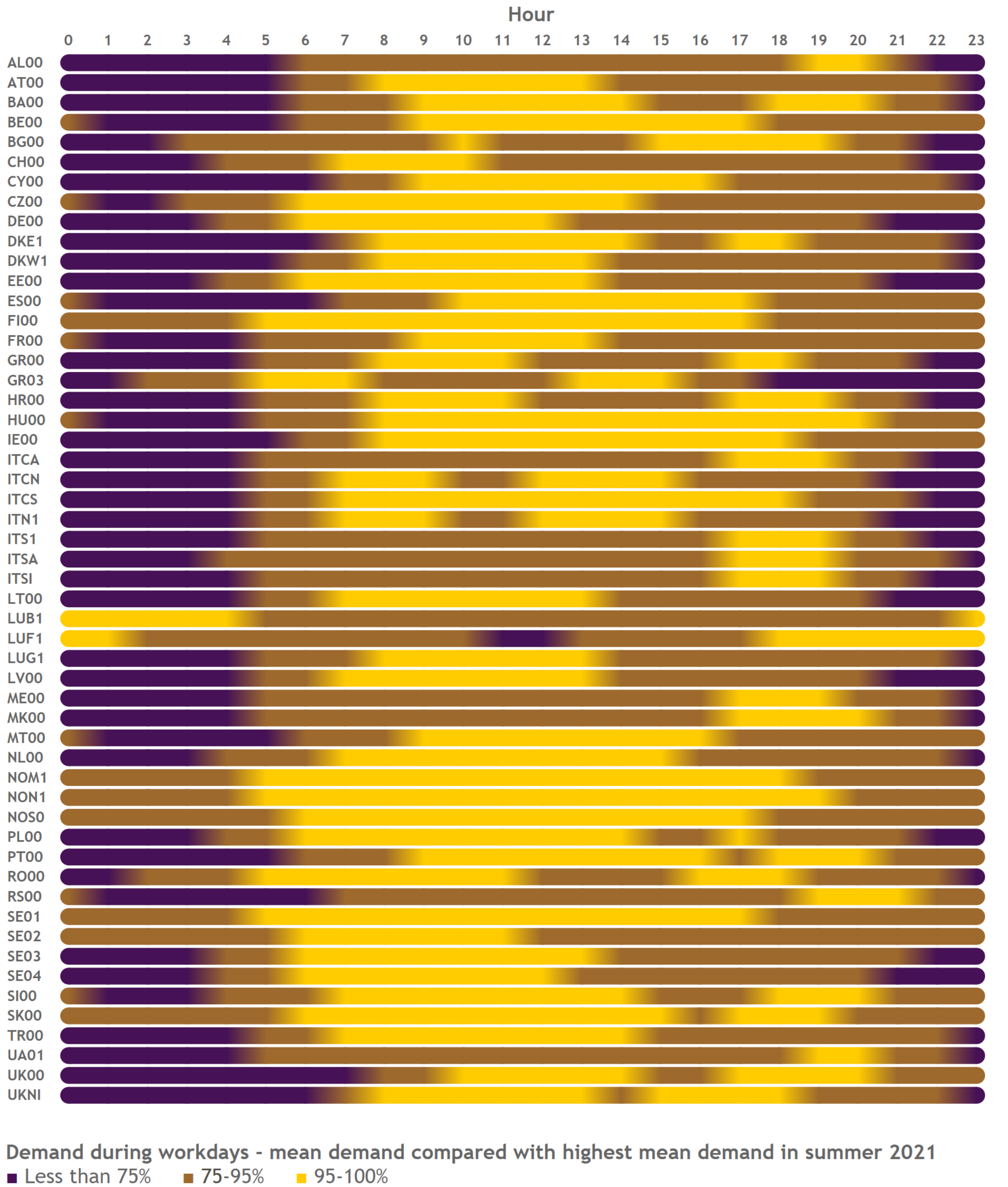


Figure 13: Demand profile overview during Mondays–Fridays in summer 2021[8]

Network overview

The map in Figure 14 shows the ratio of lowest import capacity in Summer 2021 to highest expected demand[6] 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

[8] *UTC time convention was used.*

capacities with non-explicitly modelled systems are not considered in the figure, but their contribution is assessed in adequacy simulations[9] .

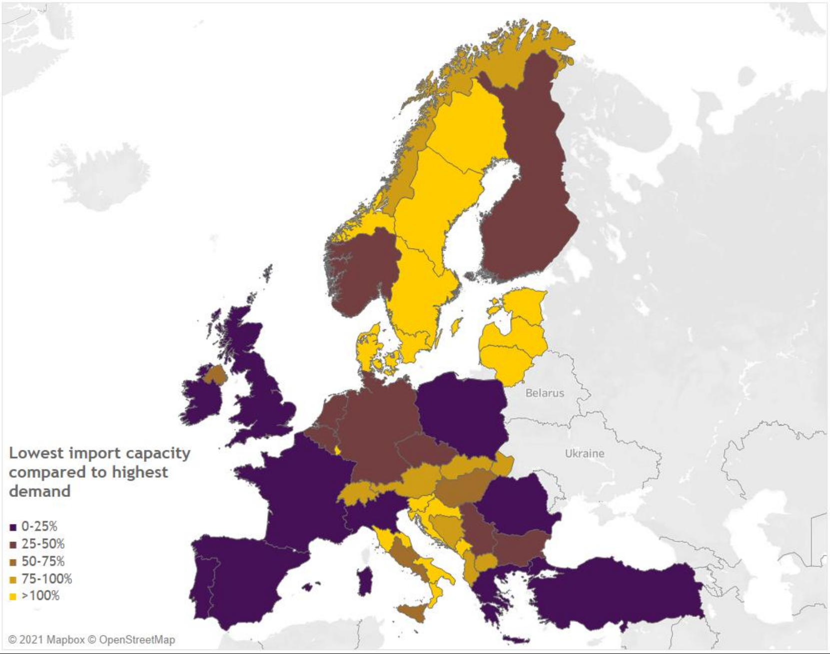


Figure 14: Import capacities per study zone: ratio between lowest import capacity and peak demand. C.f. Figure 24 for details

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

Adequacy situation

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 whether these would be sufficient to solve the risks identified in the previous step. The non-market resources can be activated after a supply shortage in the market.

The adequacy situation in Summer 2021 (Figure 15) shows some adequacy risks – i.e. the risk of having to rely on non-market measures – in Cyprus, Ireland and Malta. Non-market resources reduce risks substantially in Malta where these resources exist, whereas risks do not decrease in Cyprus and Ireland, where available non-market resources in neighbouring regions cannot be reached due to interconnection limitations.

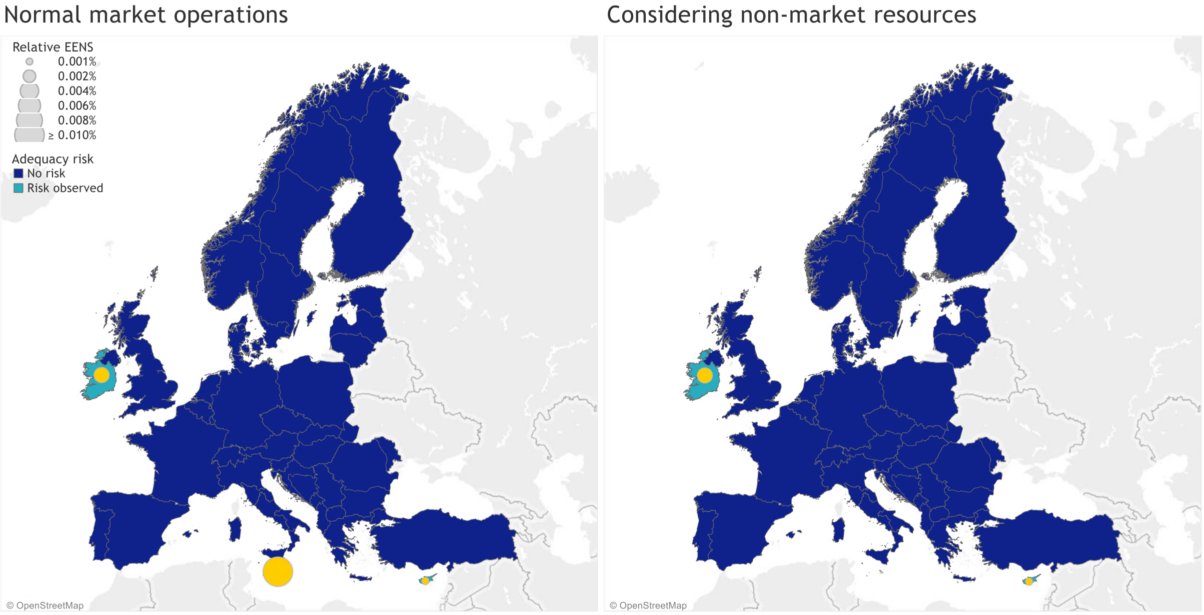
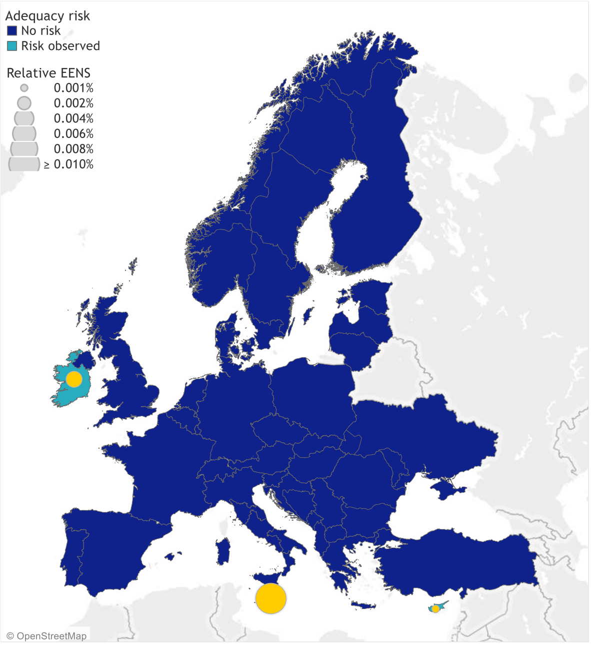


Figure 15: Adequacy overview

The state of the power system is continuously changing and is therefore different from what was known during data collection (performed between late February and early March), and hence the related risks are different too. For this reason, risks are continuously being monitored by TSOs and RSCs.

Focus on adequacy under normal market conditions

Under normal market operation conditions, risks are identified in Cyprus, Ireland, Malta (Figure 16). Risks appear to be marginal in Cyprus, whereas in Ireland and Malta they appear to be more notable.



CY00
EENS: 10.19 MWh (**0.00059%** compared to Seasonal Consumption)
99th percentile ENS: 316.71 MWh (**0.01825%** compared to Seasonal Consumption)

IE00
EENS: 277.50 MWh (**0.00272%** compared to Seasonal Consumption)
99th percentile ENS: 5642.90 MWh (**0.05535%** compared to Seasonal Consumption)

MT00
EENS: 139.88 MWh (**0.01424%** compared to Seasonal Consumption)
99th percentile ENS: 1120.41 MWh (**0.11402%** compared to Seasonal Consumption)

Figure 16 Adequacy risk overview

The distribution of risks within season is presented in Figure 17 by the visualisation of Loss of Load Probability (weekly LOLP[10]). No common pattern could be observed for all Study Zones. In Malta, the probability of having to activate non-market resources appears to be the highest. This is a normal situation, which is why Malta has non-market resources available (c.f. Figure 5).

The weekly LOLP in Cyprus (CY00) shows some minor risk of lack of supply in the middle of the summer season. These risks follow the seasonal demand pattern (Figure 12), and are related to extreme heatwave conditions with a very small likelihood of occurrence. The probability of an extreme heat event combined with unplanned outages is very low; however, the lack of interconnection means that in this case, controlled and partial demand shedding might be inevitable. TSO-Cyprus has a Summer Action Plan in place to manage any emergency situations arising during this period.

Ireland (IE00) indicates some risks which are uncommon in the region. These risks are mainly driven by long-term forced outages of two large CCGT generation units totalling 844 MW, as well as the poor reliability of some older units on the system. Nevertheless, as Ireland is characterised by a large share of wind generation (Figure 4), actual risks are expected only if renewable generation is low and if other non-favourable operational conditions occur simultaneously (high demand or unplanned outages of other generation units or interconnectors). However, if these conditions occur simultaneously, partial and controlled demand shedding may be conceivable because no non-market measures, other than information about low supply margins through market messages (System Alerts), are available 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.

[10] *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). That suggest that weekly LOLP under normal market conditions represents the probability that system operators would need to look for 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 look for non-market measures and, if none are available, partial and controlled demand shedding for a limited duration will be necessary to restore power balance.*

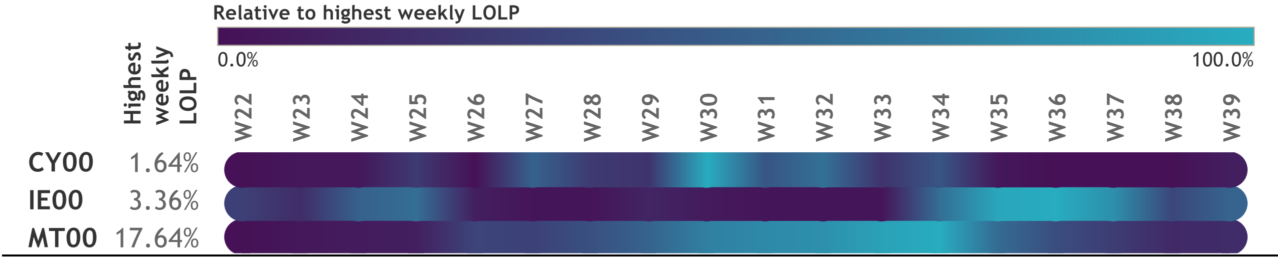


Figure 17: Weekly adequacy insights

Focus on non-market resources

Non-market resources (overview in Figure 5) drastically reduce EENS in Malta (Figure 18). The adequacy situation remains unchanged in other Study Zones as they do not have dedicated non-market resources available and resources that are available abroad are not accessible due to interconnection limitations.

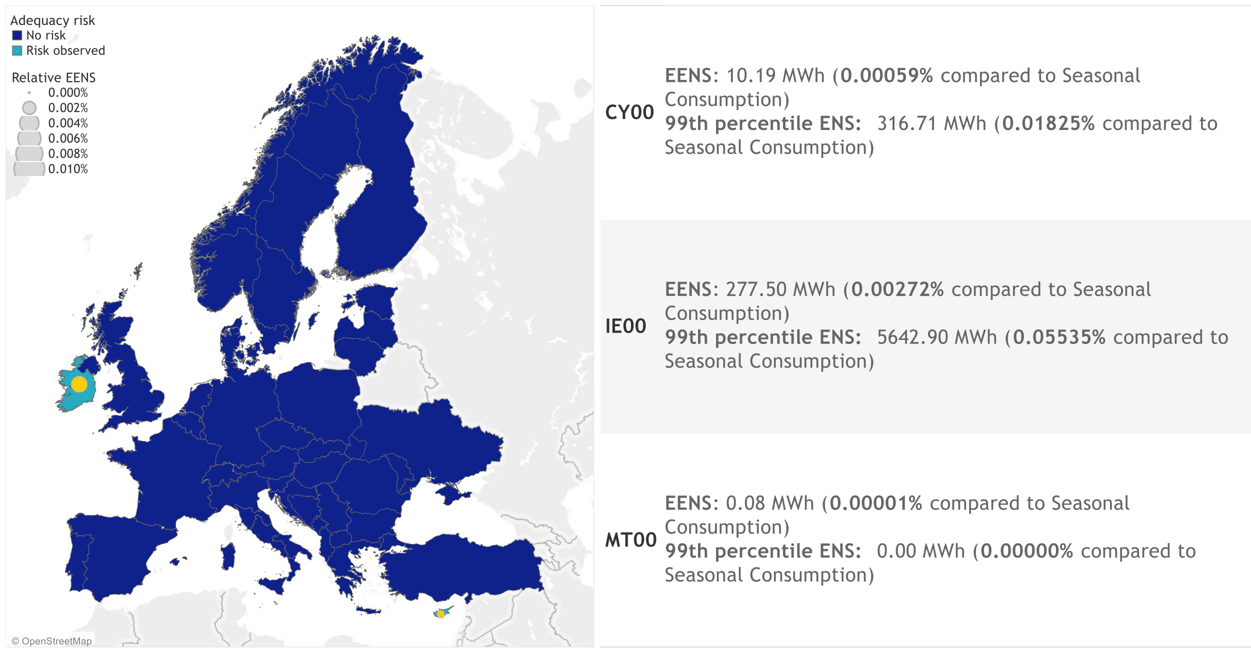


Figure 18: Adequacy risk overview – considering non-market resources

LOLP in Malta is significantly lower when non-market resources are considered and shows only occasional risks (Figure 20). This suggests that partial demand shedding might be required only under exceptional operational conditions and only if these conditions occur in particular weeks with elevated adequacy risk.

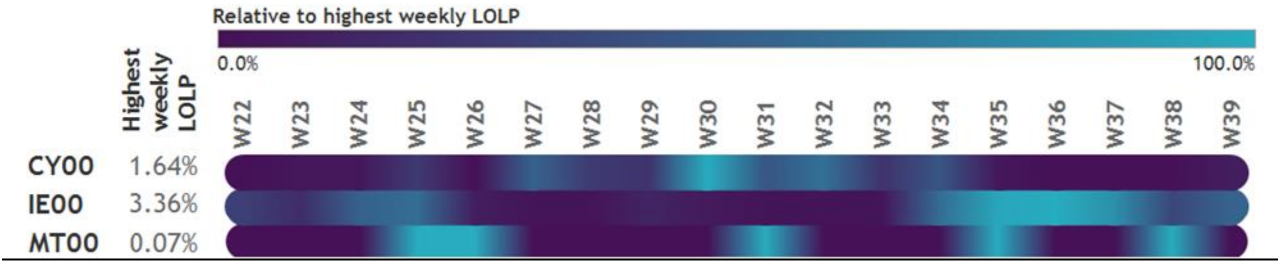


Figure 19: Adequacy weekly insights – considering non-market resources

Figure 20 represents the impact of non-market resources, which demonstrates that non-market resources can, to a large extent, address adequacy concerns in Malta.

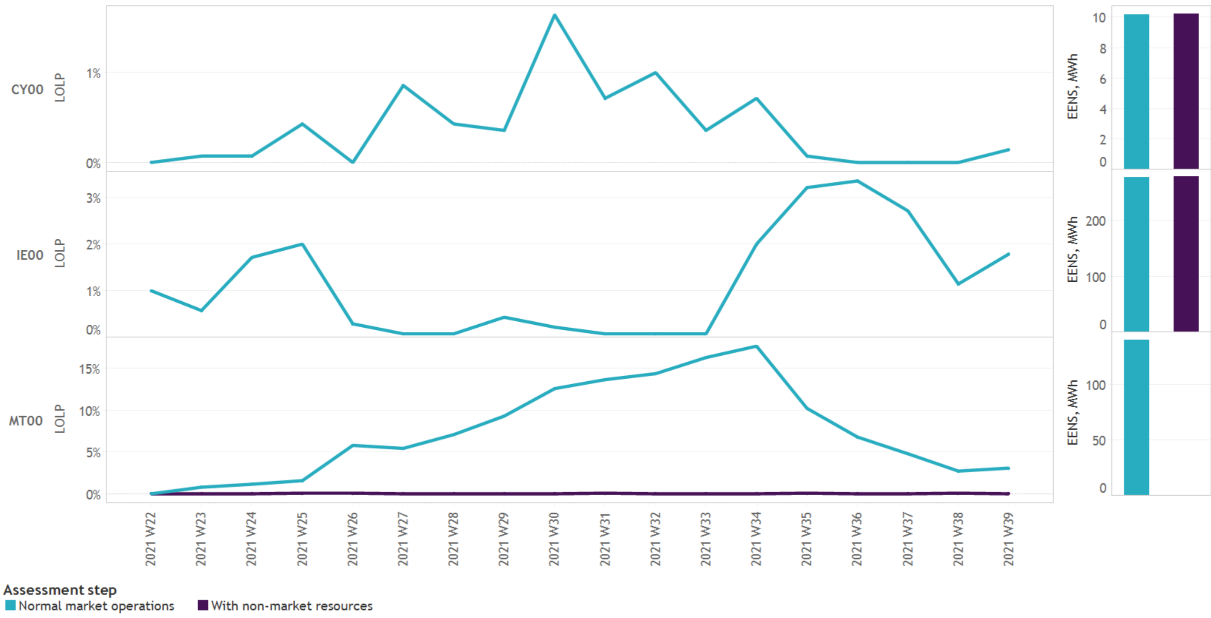


Figure 20: Detailed adequacy overview – weekly LOLP and ENS

Solar eclipse on 10 June

A partial solar eclipse is passing over Europe on 10 June 2021 during noon hours. The impact on European system adequacy is expected to be negligible.

Adequacy risks in Ireland should not be increased because of the solar eclipse as solar generation plays a minor role in supply there and in the neighbouring systems. In southern Europe, Malta and Cyprus do not fall under the path of the solar eclipse so the presented adequacy results in the previous section remain unaltered by it.

A dedicated team was established to prepare for potential operational challenges in Continental Europe. These challenges are expected because solar generation is notable, and the eclipse could cause rapid changes in it. However, adequacy issues are not common in this region during the summer, and the partial solar eclipse should not pose any additional risk for adequacy. The dedicated team in Continental Europe will keep working to prepare adapted mitigations for dealing with the partial solar eclipse.

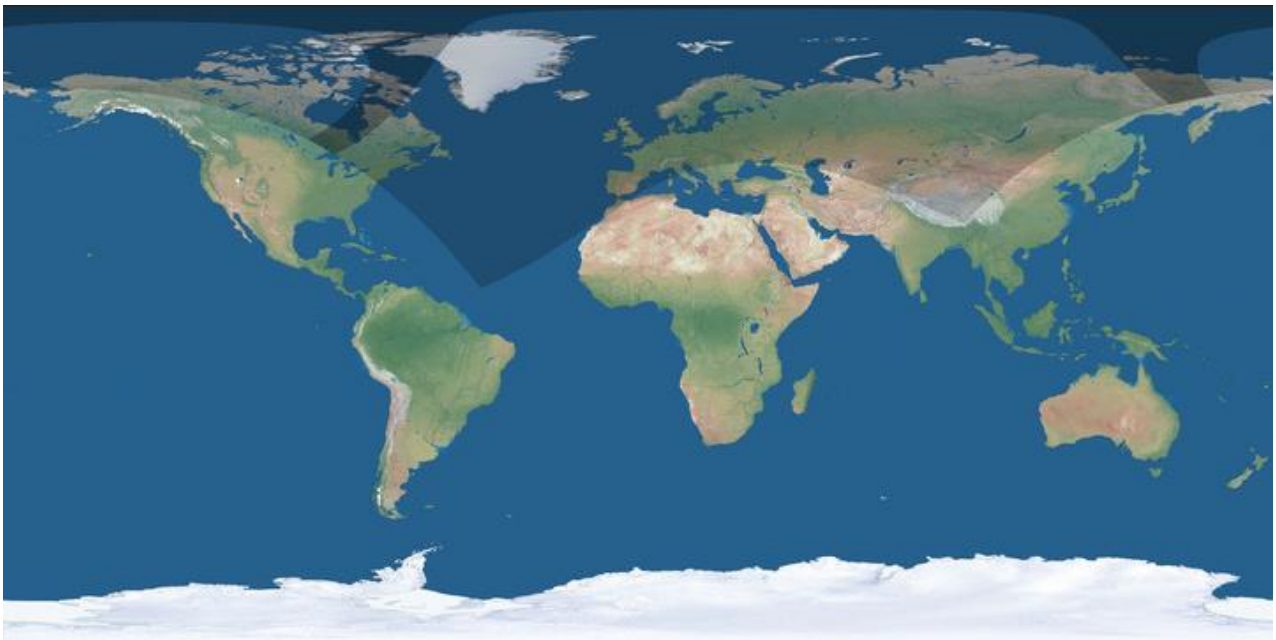


Figure 21: Path of the annular solar eclipse on 10 June 2021[11]

[11] *©Andreas Möller, 2021. Accessible on solar-eclipse website.*

Winter 2020–2021 Review

The winter review is based on qualitative information submitted by ENTSO-E TSOs in April 2021. Its goal is to represent the most important events that occurred during winter 2020–2021 and compare them to the study results reported in the previous Seasonal Outlook. The winter review also mentions important or unusual events or conditions that occurred in the power system, as well as remedial actions taken by the TSOs. A detailed winter review by country can be found in the separate Country Comments document. It contains information for those countries where TSOs had specific events to report.

Temperature overview[12]

Winter 2020–2021 temperatures were average overall, but varied strongly from month to month as well as from one part of Europe to another (see Figure 22). Temperatures in December 2020 were higher than the 1981–2010 average for most of the continent whereas temperatures in January, February and March 2021 were closer to the 1991–2020 average.

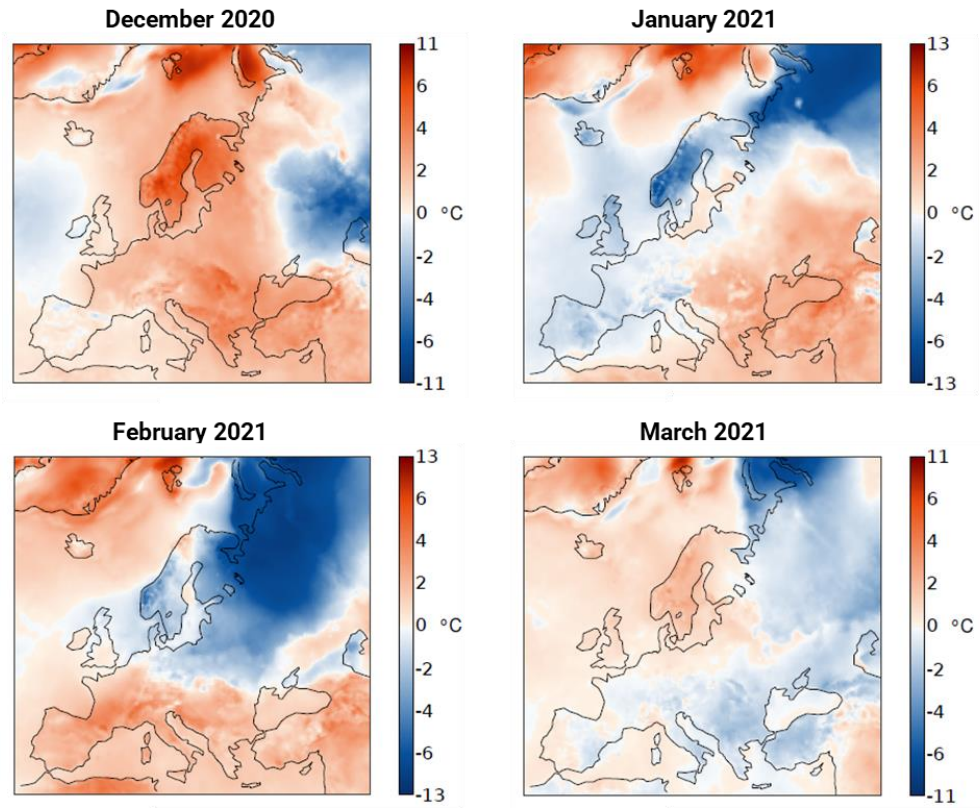


Figure 22: Surface air temperature anomaly in winter 2020–2021 relative to the average of the periods 1981–2010 (for December) and 1991–2020 (for January, February and March)[13]

December temperatures were close to average in Ireland and the Iberian Peninsula but warmer than average in the rest of Europe. Temperatures were considerably higher over the Nordic countries. January was colder than average in the west and most of the north and warmer than average in the east and southeast. Similarly, February was marked by lower-than-average temperatures in the north of Europe and higher-than-average temperatures in the south of Europe. Temperatures in March were slightly warmer than usual in north-western Europe, colder than average in south-eastern Europe and close to average in south-western Europe. Considerable temperature variations occurred both during February and March.

[12] *December 2020 temperatures are compared with the average December temperatures of the period 1981–2010, whereas January, February, and March 2021 temperatures are compared with the average January, February, and March temperatures of the period 1991–2020.*

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

Adequacy overview

Winter 2020–2021 was favourable for adequacy in general as overall temperatures were close to average and supply margins were sufficient to ensure adequacy during cold spells. Cold weather in early January, including cold spells, caused tight supply margins in Western Europe. Timely signals to the electricity market to procure additional generation (e.g. Electricity Market Notices in Great Britain) and international electricity exchanges (e.g. high levels of import in Great Britain and France) were sufficient to ensure adequacy during peak hours in this period. On two separate instances, heavy snow falls caused local disconnections of transmission and distribution system elements in Greece and Western part of North Macedonia. Consumers were affected in those countries: 600 MW of consumers were affected in Greece; and in North Macedonia 100 MWh were not supplied.

System Alerts were issued in Ireland and Northern Ireland on multiple occasions during winter due to tight supply margins. System Alerts were issued on 9 December 2020 and 6 January 2021 due to the combination of multiple unplanned generation outages which combined with high demand and low wind generation. Market participants responded as Kilroot units temporarily switched to oil fuel, which enabled an increase in maximum generation. Furthermore, some countertrading took place on interconnections with Great Britain, especially when the wind generation forecast overestimated generation. Eventually, no supply disruptions were recorded.

The overall impact of the COVID-19 pandemic on adequacy was limited in winter 2020–2021 as planned outage schedule disruptions were manageable whereas demand was marginally depressed. Planned outage schedule disruptions in 2020, which resulted in higher than usual planned outages in winter 2020/2021, increased the number of network operational constraints for several TSOs compared to a typical winter but were seldom problematic. Only in Northern Ireland did these postponed outages, together with simultaneous unplanned outages of a few generation units and low renewable energy production, trigger system alerts on a few occasions. These system alert states never evolved into a lack of supply.

Demand across Europe was either not affected or only marginally depressed during winter 2020–2021 due to decreased economic activity. Exceptions are some southern countries such as Greece and Malta, where demand values were lower, whereas consumption in some other countries (such as Italy and Hungary) even increased. Furthermore, some peak demand records were even registered (Hungary, Ireland, Portugal); however, supply in the market was sufficient to supply those peaks.

Cold spells

A cold spell occurred early in January, impacting large parts of Western Europe. Supply margins were tight in some countries but no severe adequacy issues occurred:

- In **France**, temperatures were 3.7°C below average during the cold spell. The peak demand of 88.4 GW was recorded which was supplied in part by imports of 8.7 GW.

- In **Great Britain**, temperatures measured 5.1°C below average on 7 January. A peak demand of 46.4 GW was consequently reached. Import through interconnectors from France, the Netherlands, and Belgium helped cover demand during peak hours. Electricity Market Notices were sent on 6, 8 and 13 January (as well as on 4 and 5 November, and 6 December) to issue additional generation from market participants for the next day.

- In **Ireland**, a System Alert was issued on 6 January as a demand peak of 5241 MW was reached. Wind generation was low at (approximately 130 MW), and 779 MW (12.5% of a total of 6250 MW) of dispatchable conventional generation was on unplanned outage. In mitigation, System Operator trades took place on the East–West Interconnector between Ireland and Great Britain.

- In **Northern Ireland**, peak demand 6 January 2021 (simultaneously with Ireland) was well below the previous record but coincided with a period of low wind energy generation (below 40 MW) and high scheduled interconnector export to Great Britain (400 MW). This resulted in the Northern Ireland system being in an alert state from 16:00 to 20:00, due to low system margin. As the situation was known ahead of time, both dual-rated Kilroot units were able to be switched over to oil to provide higher generation during the peak. All available units were dispatched, with one gas turbine failing to synchronise. A countertrade with Great Britain was reached to reduce the export on the Moyle interconnector.

- In **Spain**, temperatures dropped to the record low values in the second week of January, and the demand reached a peak value of 42 GW, which had not been reached since 2012, although this value is below the historical peak demand of 45 GW which was reached in 2007. No adequacy issues were recorded.

- In **Portugal**, the cold spell in the first two weeks of 2021 set some record peak values, reaching 9.9 GW, significantly above the previous record of 9.4 GW that occurred in 2010. These situations did not lead to grid operation or generation/demand balance issues.

Cold spells also occurred in Southeastern Europe:

- In **Greece**, cold spells occurred on a number of days, but did not lead to adequacy issues because of their short duration (2–3 days). However, heavy snow falls between 14 and 17 February led to a cut-off of distribution lines in the area of Attica, mainly affecting household customers. The demand that was interrupted is estimated at approximately 600 MW.

- On 10 January 2021, the western part of **North Macedonia** was affected by heavy weather conditions which led to unplanned outages in the local transmission network. Heavy snowfall mixed with freezing rain caused an outage on two local 110 kV overhead lines and a lack of electricity supply in a small city and neighbouring villages (energy not served was 100 MWh). These outages were solved within two days.

Other specific events

In addition to weather impact on adequacy, a number of specific events also impacted adequacy:

Electricity system separation in Continental Europe on 8 January 2021

On 8 January 2021 at 14.05 CET, the synchronous area of Continental Europe was separated into a North-West area and a South-East area due to outages of several transmission network elements in the South-East Europe in a very short time period[14]. European TSOs resynchronised the continental Europe power system at 15.08 CET. Due to the fast and coordinated approach, no major loss of load or damages were observed in the power system.

Earthquakes in Croatia

A series of earthquakes occurred in central Croatia, causing great damage to the transmission and distribution systems. Interruption of supply occurred consequently on 29 December at 12:19 CET, but supply was restored in the afternoon of the same day.

Strikes in France

Several strikes put some adequacy stress on the French system, particularly in December and January. Margins were tight, and RTE had to send alerts to market participants to get more balancing offers and on recover margins. Ultimately, these situations did not lead to adequacy issues in real time.

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[14] *For more information see ENTSO-E's interim report on the Continental Europe synchronous area separation:*

Endnote

The Summer Outlook 2021 represents the Seasonal Adequacy Assessments defined in Article 9 of the Risk Preparedness Regulation (Regulation (EU) 2019/941). ENTSO-E performs this assessment to alert Member States and TSOs of the risks related to the security of electricity supply that might occur in the coming season.

This assessment aims to reflect the implementation of the methodology[15] approved by ACER on 6 March 2020 (decision No 08/2020).

[15] *Short-term and Seasonal Adequacy Assessment methodology*

Appendix 1: Additional information about the study

Figure 23: Study zones

AL00	From: GR00 Avg. 400 MW (400 - 400) MW	From: RS00 Avg. 400 MW (400 - 400) MW	From: ME00 Avg. 300 MW (300 - 300) MW											
AT00	From: DE00 Avg. 4,900 MW (4,900 - 4,900) MW	From: CH00 Avg. 963 MW (486 - 1,200) MW	From: SI00 Avg. 950 MW (950 - 950) MW	From: CZ00 Avg. 784 MW (600 - 900) MW	From: HU00 Avg. 600 MW (600 - 600) MW	From: ITN1 Avg. 89 MW (70 - 145) MW								
BA00	From: HR00 Avg. 600 MW (600 - 600) MW	From: ME00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 494 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. 689 MW (600 - 1,000) MW	From: LUG1 Avg. 500 MW (500 - 500) MW									
BG00	From: RO00 Avg. 917 MW (700 - 1,000) MW	From: GR00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 283 MW (0 - 300) MW	From: MK00 Avg. 253 MW (250 - 300) MW	From: TR00 Avg. 185 MW (100 - 200) MW									
CH00	From: FR00 Avg. 2,840 MW (2,500 - 3,000) MW	From: DE00 Avg. 1,994 MW (1,600 - 2,000) MW	From: ITN1 Avg. 1,527 MW (1,440 - 1,910) MW	From: AT00 Avg. 886 MW (186 - 1,200) MW										
CZ00	From: DE00 Avg. 1,500 MW (1,500 - 1,500) MW	From: SK00 Avg. 1,200 MW (1,200 - 1,200) MW	From: AT00 Avg. 827 MW (700 - 900) MW	From: PLE0 Avg. 785 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. 3,982 MW (3,800 - 4,000) MW	From: FR00 Avg. 3,000 MW (3,000 - 3,000) MW	From: PLE0 Avg. 3,000 MW (3,000 - 3,000) MW	From: DKW1 Avg. 2,500 MW (2,500 - 2,500) MW	From: CZ00 Avg. 2,100 MW (2,100 - 2,100) 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. 532 MW (0 - 585) MW	From: DEKF Avg. 400 MW (400 - 400) MW
DKE1	From: SE04 Avg. 1,300 MW (1,300 - 1,300) MW	From: DKKF Avg. 600 MW (600 - 600) MW	From: DKW1 Avg. 590 MW (590 - 590) MW	From: DE00 Avg. 545 MW (0 - 600) MW										
DKW1	From: DE00 Avg. 2,500 MW (2,500 - 2,500) MW	From: NOS0 Avg. 1,632 MW (1,632 - 1,632) MW	From: NL00 Avg. 700 MW (700 - 700) MW	From: SE03 Avg. 675 MW (0 - 715) MW	From: DKE1 Avg. 600 MW (600 - 600) MW									
EE00	From: FI00 Avg. 1,003 MW (658 - 1,016) MW	From: LV00 Avg. 933 MW (680 - 1,109) MW												
ES00	From: PT00 Avg. 2,340 MW (1,080 - 3,780) MW	From: FR00 Avg. 2,212 MW (1,250 - 2,900) MW												
FI00	From: SE01 Avg. 1,388 MW (400 - 1,500) MW	From: SE03 Avg. 1,200 MW (1,200 - 1,200) MW	From: EE00 Avg. 1,003 MW (658 - 1,016) MW											
FR00	From: DE00 Avg. 3,000 MW (3,000 - 3,000) MW	From: UK00 Avg. 2,921 MW (2,000 - 3,000) MW	From: ES00 Avg. 1,971 MW (1,100 - 2,500) MW	From: CH00 Avg. 1,089 MW (900 - 1,100) MW	From: ITN1 Avg. 940 MW (870 - 1,160) MW	From: BE00 Avg. 600 MW (600 - 600) MW								
GR00	From: BG00 Avg. 700 MW (700 - 700) MW	From: MK00 Avg. 477 MW (300 - 500) MW	From: ITS1 Avg. 417 MW (0 - 500) MW	From: AL00 Avg. 400 MW (400 - 400) MW	From: GR03 Avg. 150 MW (150 - 150) MW	From: TR00 Avg. 94 MW (0 - 100) MW								
GR03	From: GR00 Avg. 150 MW (150 - 150) MW													
HR00	From: SI00 Avg. 1,200 MW (1,200 - 1,200) MW	From: HU00 Avg. 1,100 MW (1,100 - 1,100) MW	From: BA00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 200 MW (200 - 200) MW										
HU00	From: SK00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HR00 Avg. 900 MW (900 - 900) MW	From: RO00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 667 MW (0 - 700) MW	From: AT00 Avg. 600 MW (600 - 600) MW	From: UA01 Avg. 575 MW (455 - 650) MW								
IE00	From: UK00 Avg. 355 MW (0 - 530) MW	From: UKNI Avg. 300 MW (300 - 300) MW												
ITCA	From: ITSI Avg. 1,200 MW (1,200 - 1,200) MW	From: ITS1 Avg. 1,100 MW (1,100 - 1,100) MW												
ITCN	From: ITN1 Avg. 3,680 MW (2,600 - 4,200) MW	From: ITCS Avg. 2,759 MW (1,600 - 2,800) MW	From: ITCO Avg. 251 MW (0 - 300) MW											
ITCS	From: ITS1 Avg. 4,588 MW (2,600 - 5,000) MW	From: ITCN Avg. 2,142 MW (800 - 2,900) MW	From: ITSA Avg. 791 MW (0 - 900) MW	From: ME00 Avg. 600 MW (600 - 600) MW										
ITN1	From: ITCN Avg. 2,554 MW (1,200 - 3,100) MW	From: FR00 Avg. 2,373 MW (392 - 3,150) MW	From: CH00 Avg. 2,190 MW (492 - 3,350) MW	From: SI00 Avg. 429 MW (75 - 730) MW	From: AT00 Avg. 250 MW (40 - 315) MW									
ITS1	From: ITCA Avg. 2,350 MW (2,350 - 2,350) MW	From: ITCS Avg. 2,000 MW (2,000 - 2,000) MW	From: GR00 Avg. 417 MW (0 - 500) MW											
ITSA	From: ITCS Avg. 645 MW (0 - 720) MW	From: ITCO Avg. 230 MW (0 - 300) MW												
ITSI	From: ITCA Avg. 1,500 MW (1,500 - 1,500) MW	From: MT00 Avg. 201 MW (200 - 225) MW												
LT00	From: LV00 Avg. 1,004 MW (752 - 1,052) MW	From: SE04 Avg. 700 MW (700 - 700) MW	From: PL00 Avg. 500 MW (500 - 500) MW											
LUF1	From: FR00 Avg. 380 MW (380 - 380) MW													
LUG1	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 500 MW (500 - 500) MW												
LV00	From: LT00 Avg. 1,139 MW (904 - 1,234) MW	From: EE00 Avg. 813 MW (520 - 1,247) MW												
ME00	From: ITCS Avg. 600 MW (600 - 600) MW	From: BA00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 467 MW (0 - 600) MW	From: AL00 Avg. 300 MW (300 - 300) MW										
MK00	From: GR00 Avg. 478 MW (300 - 500) MW	From: RS00 Avg. 387 MW (150 - 500) MW	From: BG00 Avg. 303 MW (300 - 350) MW											
MT00	From: ITSI Avg. 201 MW (200 - 225) MW													
NL00	From: DE00 Avg. 4,250 MW (4,250 - 4,250) MW	From: UK00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 950 MW (950 - 950) MW	From: DKW1 Avg. 700 MW (700 - 700) MW	From: NOS0 Avg. 634 MW (550 - 670) MW									
NOM1	From: NOS0 Avg. 1,375 MW (1,375 - 1,375) MW	From: NON1 Avg. 1,200 MW (1,200 - 1,200) MW	From: SE02 Avg. 1,000 MW (1,000 - 1,000) MW											
NON1	From: NOM1 Avg. 1,200 MW (1,200 - 1,200) MW	From: SE01 Avg. 600 MW (600 - 600) MW	From: SE02 Avg. 300 MW (300 - 300) MW											
NOS0	From: SE03 Avg. 1,765 MW (1,695 - 1,795) MW	From: DE00 Avg. 1,400 MW (1,400 - 1,400) MW	From: NOM1 Avg. 1,375 MW (1,375 - 1,375) MW	From: DKW1 Avg. 1,110 MW (1,110 - 1,110) MW	From: NL00 Avg. 634 MW (550 - 670) MW	From: UK00 Avg. 35 MW (0 - 1,464) MW								
PL00	From: PLI0 Avg. 800 MW (800 - 800) MW	From: SE04 Avg. 567 MW (0 - 600) MW	From: LT00 Avg. 500 MW (500 - 500) MW											
PLE0	From: PL00 Avg. 435 MW (0 - 700) MW													
PLI0	From: CZ00 Avg. 785 MW (500 - 800) MW	From: DE00 Avg. 500 MW (500 - 500) MW	From: SK00 Avg. 500 MW (500 - 500) MW											
PT00	From: ES00 Avg. 2,615 MW (1,260 - 3,420) MW													
RO00	From: BG00 Avg. 917 MW (700 - 1,000) MW	From: RS00 Avg. 557 MW (300 - 700) MW	From: HU00 Avg. 500 MW (500 - 500) MW	From: UA01 Avg. 193 MW (0 - 200) MW										
RS00	From: ME00 Avg. 605 MW (0 - 700) MW	From: HU00 Avg. 479 MW (0 - 500) MW	From: BA00 Avg. 463 MW (150 - 600) MW	From: MK00 Avg. 456 MW (250 - 500) MW	From: AL00 Avg. 400 MW (400 - 400) MW	From: RO00 Avg. 373 MW (300 - 450) MW	From: BG00 Avg. 331 MW (0 - 350) MW	From: HR00 Avg. 150 MW (150 - 150) MW						
SE01	From: SE02 Avg. 3,300 MW (3,300 - 3,300) MW	From: FI00 Avg. 1,021 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. 3,300 MW (3,300 - 3,300) MW	From: NOM1 Avg. 1,000 MW (1,000 - 1,000) MW	From: NON1 Avg. 250 MW (250 - 250) MW										
SE03	From: SE02 Avg. 7,300 MW (7,300 - 7,300) MW	From: NOS0 Avg. 1,815 MW (1,745 - 1,845) MW	From: SE04 Avg. 1,400 MW (800 - 2,000) MW	From: FI00 Avg. 1,200 MW (1,200 - 1,200) MW	From: DKW1 Avg. 682 MW (0 - 715) MW									
SE04	From: SE03 Avg. 3,100 MW (800 - 5,400) MW	From: DKE1 Avg. 1,700 MW (1,700 - 1,700) MW	From: LT00 Avg. 700 MW (700 - 700) MW	From: DE00 Avg. 615 MW (615 - 615) MW	From: PL00 Avg. 390 MW (0 - 600) MW									
SI00	From: HR00 Avg. 1,000 MW (1,000 - 1,000) MW	From: AT00 Avg. 950 MW (950 - 950) MW	From: ITN1 Avg. 593 MW (250 - 680) MW											
SK00	From: CZ00 Avg. 1,770 MW (1,700 - 2,000) MW	From: HU00 Avg. 1,500 MW (1,500 - 1,500) MW	From: PLE0 Avg. 500 MW (500 - 500) MW	From: UA01 Avg. 400 MW (400 - 400) MW										
TR00	From: BG00 Avg. 398 MW (216 - 430) MW	From: GR00 Avg. 204 MW (0 - 216) MW												
UA01	From: HU00 Avg. 450 MW (450 - 450) MW	From: SK00 Avg. 400 MW (400 - 400) MW	From: RO00 Avg. 97 MW (0 - 150) MW											
UK00	From: FR00 Avg. 2,921 MW (2,000 - 3,000) MW	From: NL00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 689 MW (600 - 1,000) MW	From: IE00 Avg. 335 MW (0 - 500) MW	From: UKNI Avg. 285 MW (250 - 380) MW	From: NOS0 Avg. 35 MW (0 - 1,464) MW								
UKNI	From: UK00 Avg. 447 MW (400 - 450) MW	From: IE00 Avg. 300 MW (300 - 300) MW												

Figure 24: Import capacity overview

Appendix 2: 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, following a request from ACER. LOLE figures could be useful when comparing how adequacy evolved between editions of seasonal adequacy assessments[16]. However, ENTSO-E requests that readers interpret it carefully, because 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 the ones under development in accordance with Article 26 of Regulation 2019//943). Some examples are given below, assuming that the annual LOLE Reliability Standard[17] is set and compared with seasonal LOLE:

- Seasonal LOLE can be lower than the Reliability Standard, but it would not mean that adequacy within the assessed season complies with the Reliability Standard. For example, even minor LOLE value can indicate unusual risk in a Study Zone if risk is identified in an unusual season (e.g. risk during summer season in Northern countries).

- 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 be simply be one of the more constraining ones from a set of possible season scenarios[18] (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 not sufficient, market design corrections could 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[19], 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) as well as on 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, Figure 25 below represents the LOLE results of the Summer Outlook 2021.

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[16] A comparison with past editions is not possible yet, because this is first time this measure has been reported in a seasonal adequacy assessment.
[17] The conclusions made for annual LOLE are also valid for any other annual metric.
[18] 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 just indicates in how many hours demand shedding is acceptable (due to supply scarcity) over a long time.
[19] Monitored by the European Resource Adequacy Assessment in line with Article 23 of the Electricity Regulation 2019/943

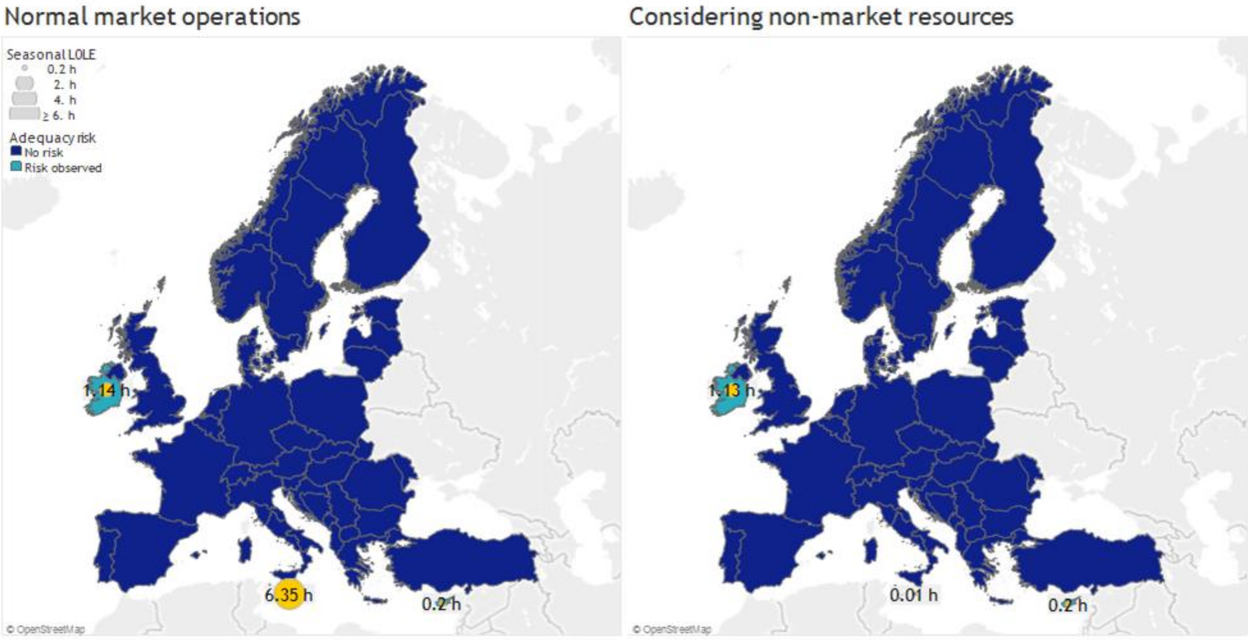

Figure 25: Seasonal LOLE results

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.

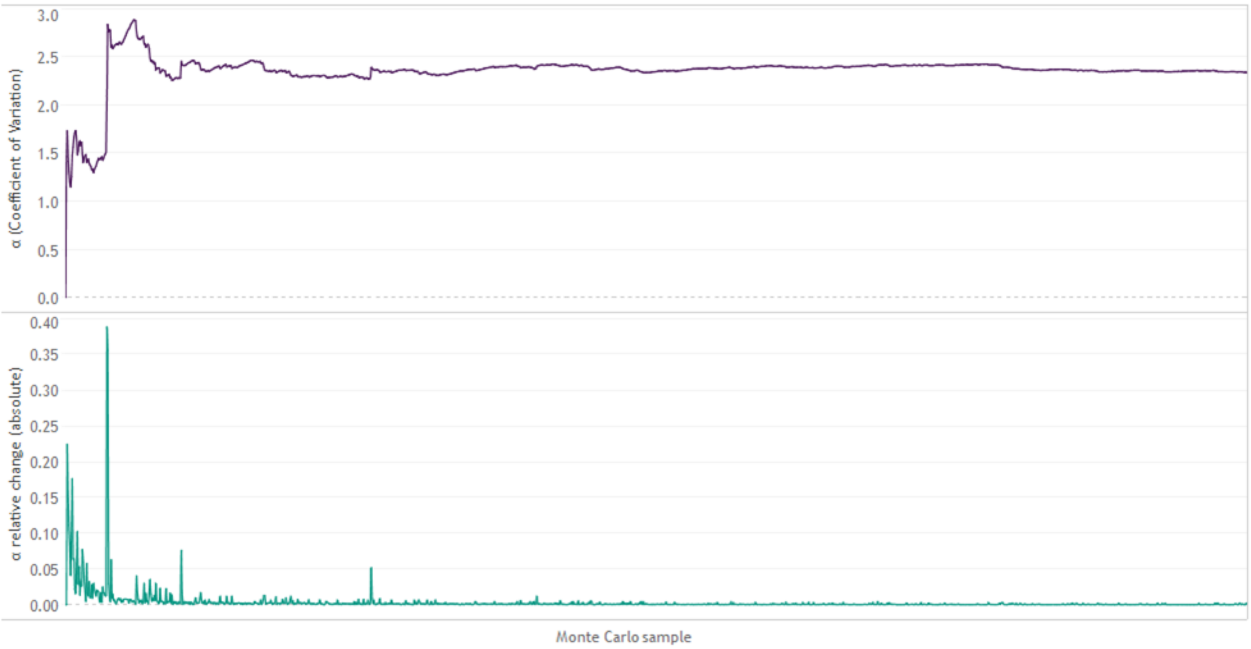

Figure 26: Convergence overview[20]

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