Winter Outlook 2020-2021

Summer Review 2020

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Contents

Introductory remarks

The study horizon of Winter Outlook 2020–2021 has, as an exception, included the month of November. Due to the Covid-19 pandemic, several outages planned in the spring and summer of 2020 had to be postponed to the late autumn and winter seasons, and this made adequacy simulations relevant for this month.

The extension of the Winter Outlook 2020–2021 study horizon aimed to capture the possible impact of these postponed planned outages on adequacy and allow TSOs to prepare mitigation measures.

Unfortunately, ENTSO-E had to strike a balance between publication date and the representativeness of the data used in assessment (i.e. earlier publication would have imposed data collection further in advance and hence used data which might change considerably). Therefore, in light of the high uncertainty in consumption and supply forecasts introduced by the pandemic, ENTSO-E has decided to follow the common timeline and use representative data which is expected to change least. This allowed timely results to be delivered to TSOs and stakeholders regarding the situation in November and a whole report to be prepared for publication by December 2020.

Readers should note that the actual situation in November or any other month might be different, as the situation of Europe's power system is continuously changing. Indeed, the pandemic has resulted in a more challenging and volatile adequacy forecast than in previous assessments.

Executive summary

The ENTSO-E Winter Outlook 2020–2021 expects a general balanced adequacy in Europe, with particular attention on France.

Although the Winter Outlook identifies potential risks of supply shortage in Denmark, Finland, France and Malta, most of these risks can be addressed with available non-market resources. However, some risks remain in France, and exceptional operational measures might be necessary in the event of a cold spell combined with low generation availability.

The COVID-19 pandemic is expected to reduce demand throughout Europe, and many countries are already experiencing lower demand for electricity compared to the same period of the previous year, whereas some countries expect demand to potentially decline further during winter. However, considerable uncertainty remains in respect to possible powerplant planned outage rescheduling due to the pandemics in winter, which could in some cases outweigh the demand decrease and then worsen the adequacy.

Many lessons were learned in spring–summer 2020, which suggests that Transmission System Operators (TSOs) and all power system stakeholders are better prepared than they were for the first pandemic wave.

In **France**, adequacy risks are identified in the Winter Outlook from November 2020 until February 2021, with risks peaking in November and February. Since the data collection (in September), planned outage periods of the nuclear plants have been rearranged. The update has led to an important reduction of risks for November, but risks remain for the beginning of 2021, mainly in January and February. Risks are identified under cold weather conditions, as demand in France is very temperature-sensitive.

Some adequacy risk was identified in November in **Denmark**. **The risk in early November** is associated with a planned outage that was prolonged due to an unexpected cable fault on the Kontek interconnection between Denmark East bidding zone (DKE1) and Germany (DE00), and the postponed commissioning of the Kriegers Flak interconnector between Danish (DKKF) and German (DEKF) Kriegers Flak offshore hubs. Energinet, the Danish TSO, rescheduled the planned outage of the Great Belt connection between DKE1 and the Denmark West (DKW1) bidding zone to 2021, which has relieved the situation so that adequacy risks are no longer expected for Denmark (Text Box 1). **The risk in late November** is associated with planned outages on the Great Belt interconnector and a simultaneous decrease of import capacity from southern Sweden (SE04). Energinet has been continuously monitoring the situation, and due to favourable operational conditions, no mitigation measures have been necessary.

Risks are observed in **Malta**, but non-market resources should be sufficient to cope with risks under the majority of scenarios. The need to rely on non-market resources to ensure security of supply in rather isolated systems, such as Malta and Sicily, is common, especially under circumstances of high unplanned outages. The situation will be further monitored in Malta and in Sicily to establish if sufficient imports can be expected.

In **Finland**, some minor risks were identified for January in the event supply gets tighter during the cold weather. However, non-market resources (strategic reserves in Finland) should be ready in January to address these.

Adequacy risks identified in this report are continuously being monitored by the concerned TSOs and Regional Security Coordinators via the short-term adequacy forecast service.

Summer 2020 Review

The Winter Outlook is accompanied by a retrospect of last summer. Europe was generally warmer than average in the past summer (June 2020 to September 2020). The period June–August was 0.9°C above the 1981–2010 norm and witnessed the second-hottest June and hottest September on record. High average temperatures, and especially heat waves, at times negatively impacted generation availability and caused supply margins to reach low levels, although without adequacy issues.

The European power system was especially stressed on 15 September, when high cooling demand in southern Europe, low wind generation and low conventional generation availability due to planned outages caused several TSOs to trigger an alert state in the European Awareness System and deplete all real time measures.

The COVID-19 pandemic had a noticeable impact in many countries, either because of sanitary constraints not allowing for the execution of planned outage activities or because of economic activities being lower overall. Although the former impact reduced the availability of generation capacities in some cases, the latter, even combined with a warm summer, caused a decrease in energy demand between 2% and 10% throughout most of Europe.

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[1]. 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 received formal approval from Agency for the Cooperation of Energy Regulators (ACER)[2]. 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 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.

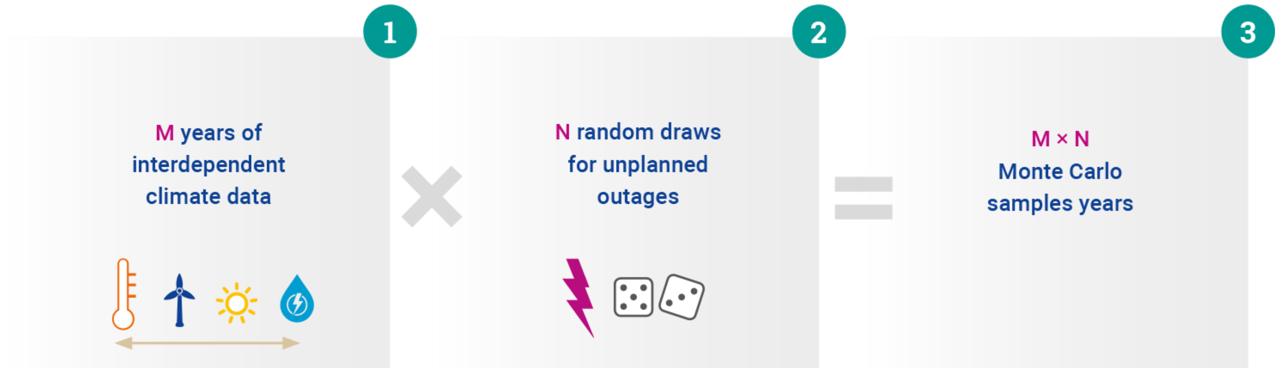

Figure 1 Scenarios assessed in Seasonal Outlooks

Scenarios are constructed ensuring that all variables are correlated (interdependent) in time and space. To ensure the highest quality of data used in 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 the hydro energy availability. Figure 2 illustrates the difference in the number of scenarios between the two modelling approaches.

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

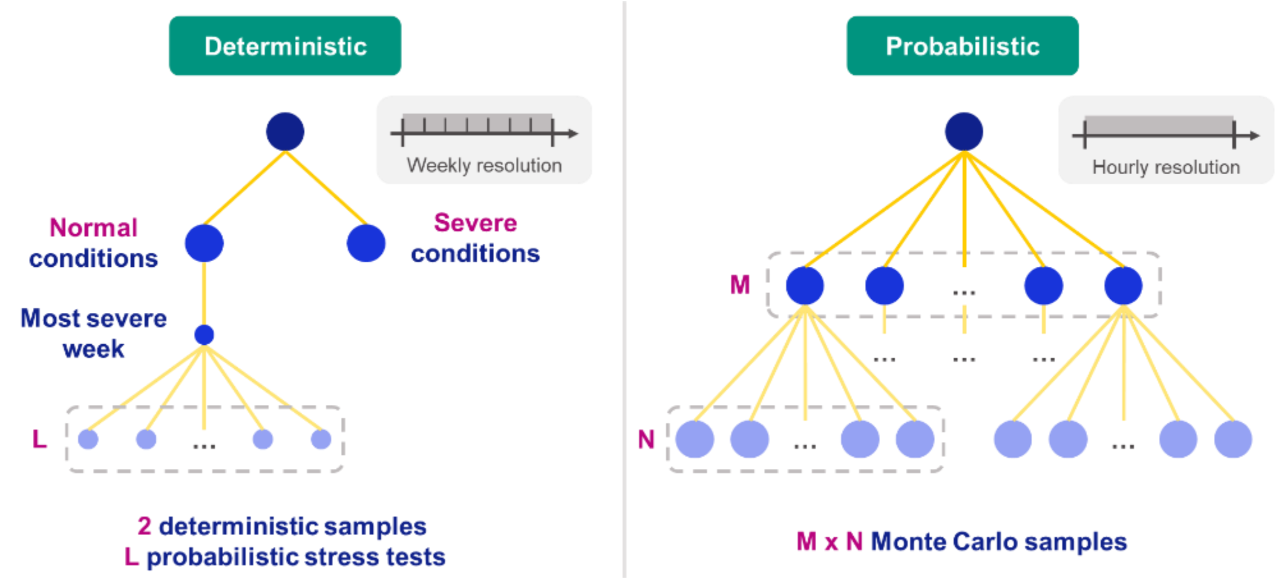

Figure 2 Scenario revolution – from deterministic to probabilistic

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.

In addition to the methodology scope of last Summer Outlook 2020, further improvements have been made, especially with the inclusion of a scenario with non-market resources in the present winter outlook assessment.

Overview of the power system in Winter 2020–2021

Information collected for the Winter Outlook 2020–2021 study represents the best available information in August–September 2020. This was a moment when the COVID-19 pandemic off-peak was recorded and potential pandemic evolution was highly uncertain. Therefore, TSOs did not consider the evolution of the pandemic when delivering data but did account for any known residual consequences from the first pandemic wave (e.g. rescheduled planned outages and decreased consumption due to the slowed economy). 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.

Compared with the Summer Outlook 2020, study zone configuration has been revised to address recent changes. First, in light of Italian bidding zone reconfiguration[3], 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) were reassigned from one bidding zone to other. Second, Crete is planned to be interconnected with mainland Greece (GR00) on 1 January 2021, and hence a study zone has been added (GR03). Any data or result comparison made 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 as 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 resources physically available in the power system.

Vice versa, all figures in this section correspond to resources available in the market. This means that total capacity overview (Figure 4) or generation capacity mix (Figure 5) disregards non-market resources. The non-market resources are presented in a dedicated figure to show how much capacity could be used in the event of a supply shortage in the market.

COVID-19 pandemic context in winter 2020–2021

The COVID-19 pandemic has introduced unprecedented uncertainty into the European power system. Depending on how it evolves, and mitigation measures taken by governments to combat the spread, supply margins may tighten or loosen. Demand may decrease if the pandemic grows; however, sanitary measures can slow maintenance works during planned and unplanned outages, hence decreasing available supply and network capacities. Overall, adverse pandemic effects may outweigh the positive. TSOs remain alert but simultaneously optimistic, as many lessons were learned during the first pandemic wave.

The COVID-19 impact on demand is given in Figure 3. The figure presents the best estimate TSOs had in September 2020 of what was expected for winter 2020–2021.

First, the figure shows the expected demand recovery if there was no second wave (impact of the first wave from spring). Several countries, such as Ireland, the Scandinavian countries, the Baltic countries and several Central European and South-Eastern European countries were expecting demand to be at pre-pandemic

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[3] *Effective from 1 January 2021. Deliberation 103/2019/R/eel of the Italian Authority of 19 March 2019*

levels, whereas others indicate demand levels still being below normal. No regional trends could be marked, and this shows the country-specific impact and the huge uncertainty involved.

Second, the expected impact of the pandemic on demand in the winter season[4] during a pandemic peak shows that many countries indicate that demand could decrease if the pandemic was to increase again. Nevertheless, some TSOs indicated that the situation is so uncertain that no estimates could be made.

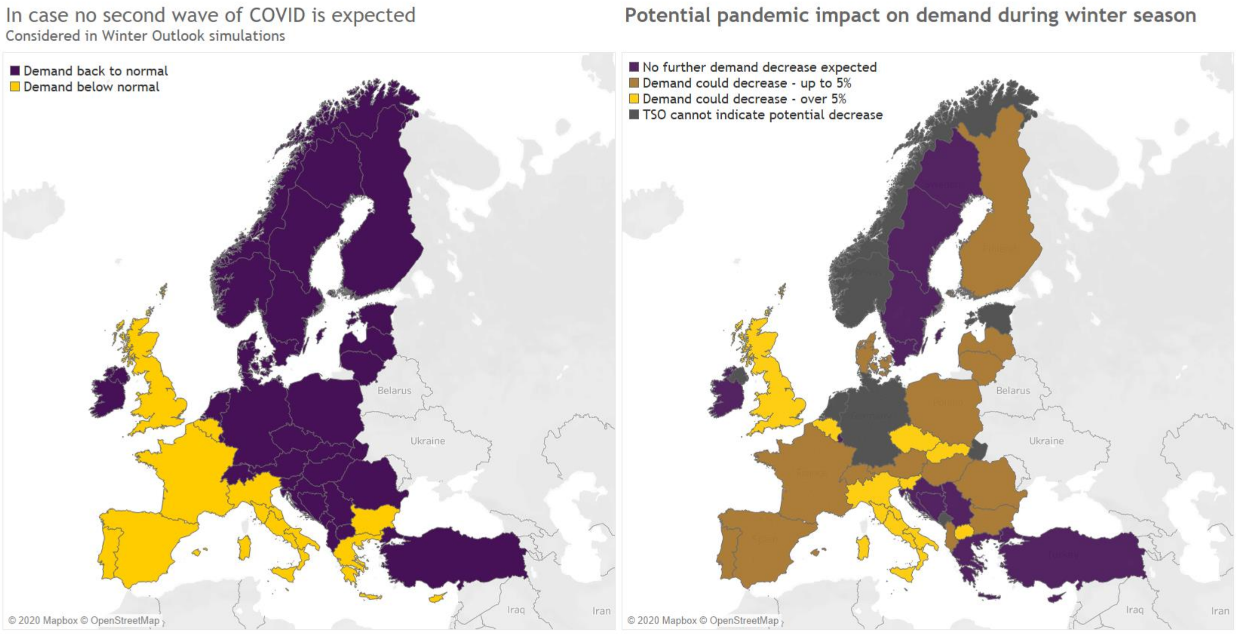


Figure 3 COVID-19 demand impact overview (winter expectations seen from September 2020)

TSOs are confident in their ability to maintain system operations; however, no further insights could be given into the potential impact of the pandemic on supply and network availabilities. Many lessons were learned in spring–summer 2020 (e.g. international provisions for cross-border maintenance crew movement or spare parts; protocols to ensure producers are able to staff and operate power plants) which suggests that Europe is better prepared for the potential second pandemic wave than it was for the first.

Generation overview

The generation capacity overview in Figure 4 shows that all countries except Serbia have sufficient Net Generation Capacity (NGC) to be self-sufficient, but more countries would need to rely on imports if renewable generation is low. NGC available on the market exceeds the highest expected demand in the 2020–2021 winter season in all studied zones except Serbia (where total NGC is very close to highest demand). When only considering thermal and hydro units, in some study zones the NGC falls below expected highest demand in winter 2020–2021. Furthermore, most study zones may need to rely on imports if renewable generation is low and if generation unavailability (e.g. planned and unplanned outages) and further technical constraints are considered. Therefore, this shows the importance of the interconnected European power system and the relevance of pan-European adequacy studies.

[4] *Note that Figure 3 is based on data collected in September and considers the demand recovery and the expected impact of a second wave seen from that time.*

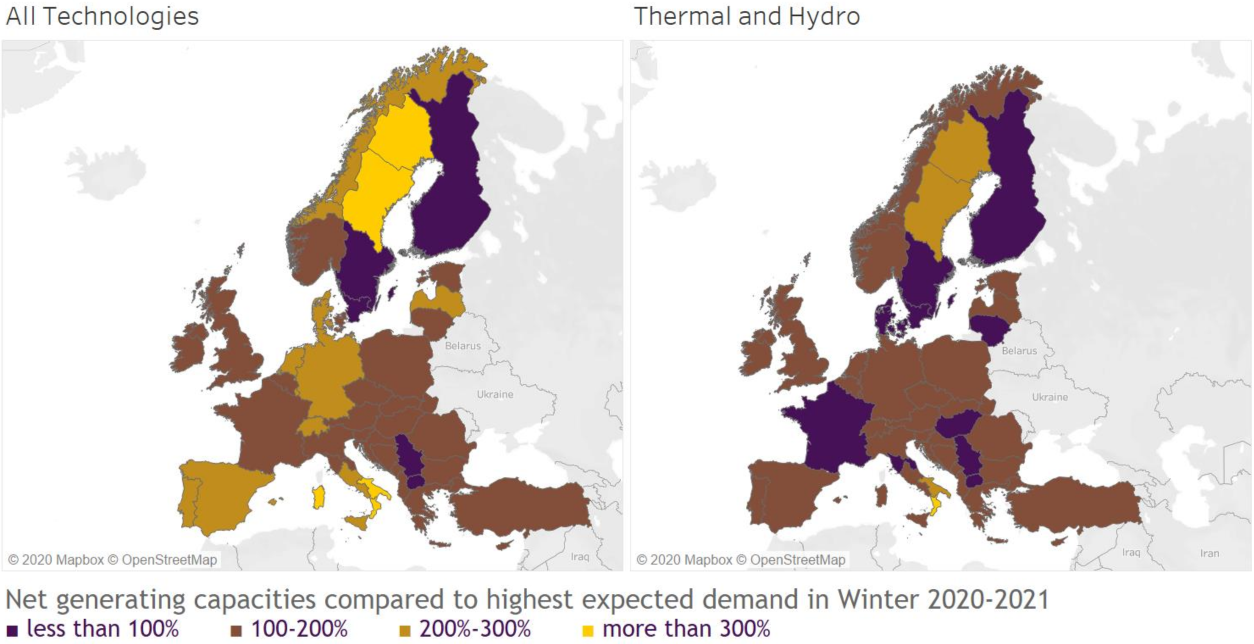


Figure 4 Net generating capacity overview – comparison with highest expected demand

According to Figure 5, thermal NGC which is available on the market accounts for approximately 50% of the total capacity of the European power system at the beginning of winter 2020–2021. This is followed by hydro, wind and solar capacities, which constitute the remaining half.

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 distinguished 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 are available in Error! Reference source not found.

Demand Side Response (DSR) services are gaining popularity in Europe. This, in turn, means the 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.

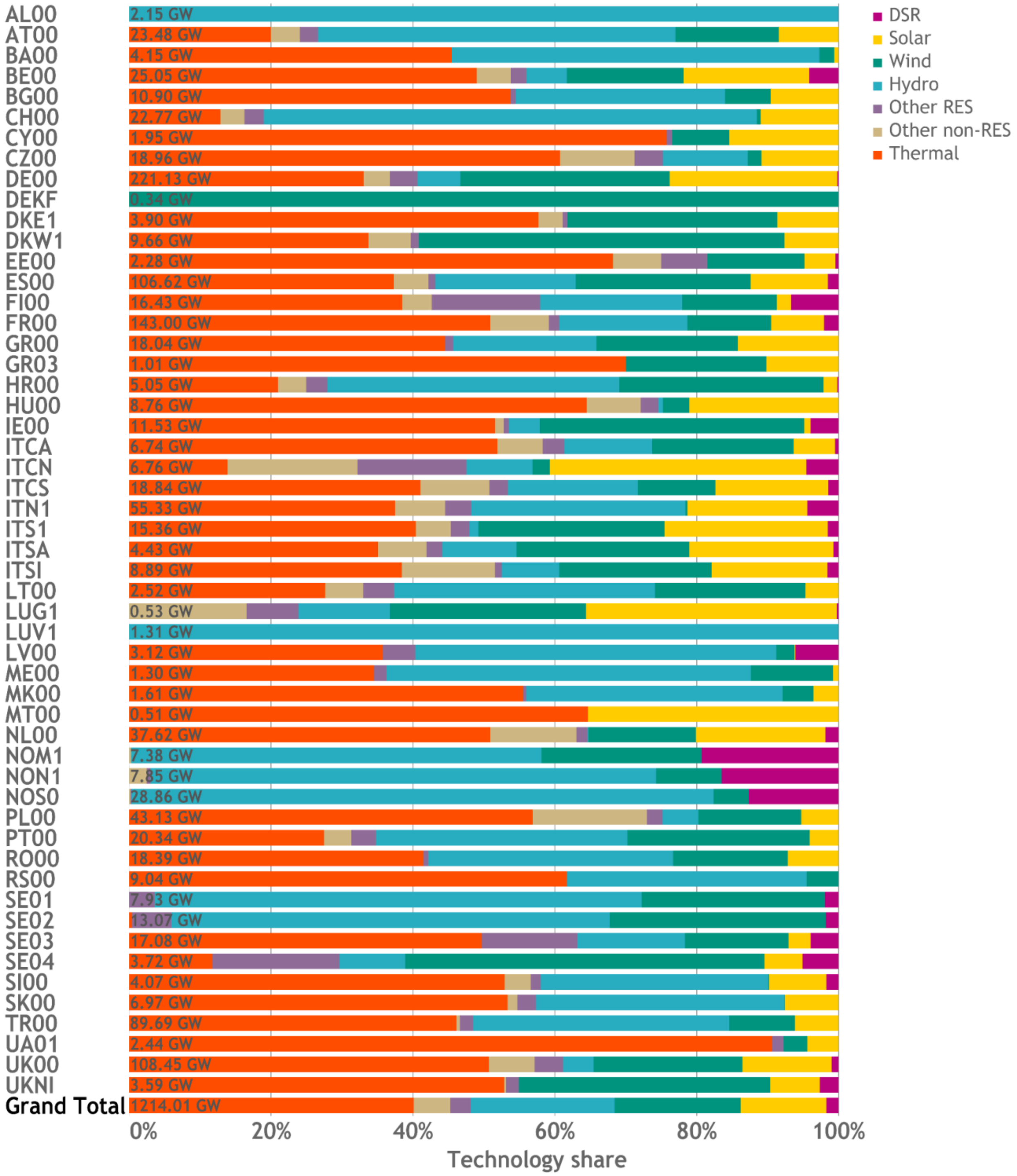


Figure 5 Generation capacity mix at the beginning of winter 2020–2021 per study zones

Figure 6 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.

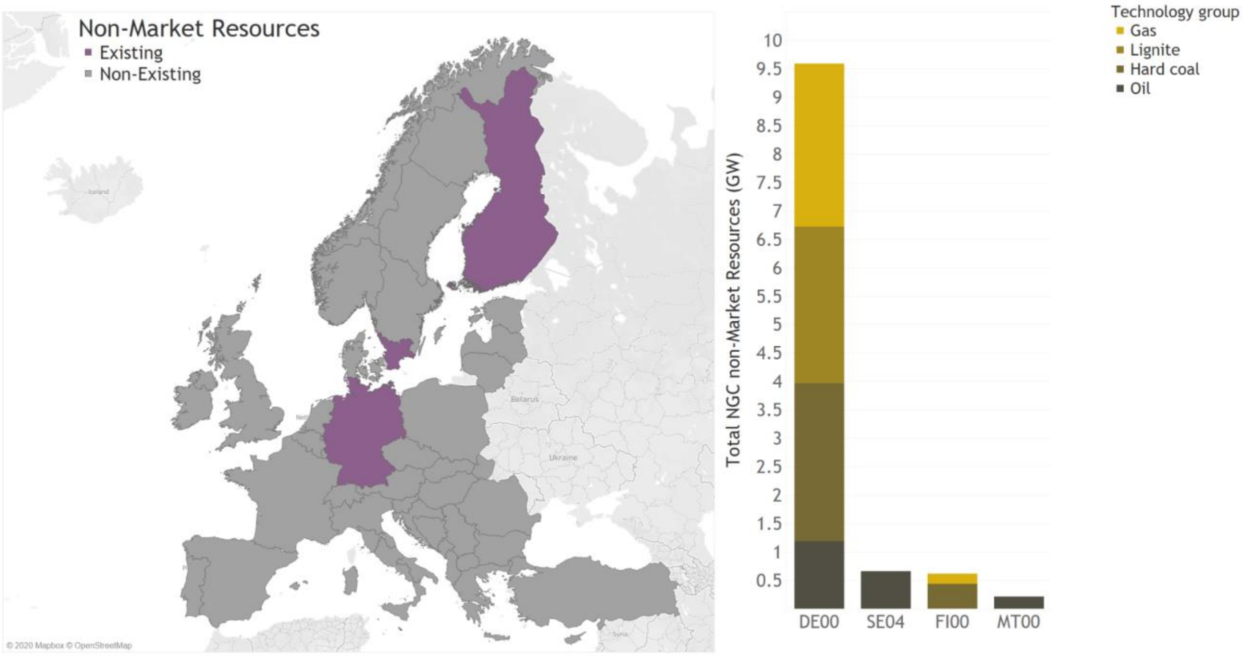


Figure 6 Non-market resources for coping with adequacy challenges in Europe

Capacity evolution

The most relevant thermal capacity evolutions[5] during Winter 2020–2021 are shown in Figure 7 and show a net decrease in Europe of over 6.9 GW. The capacity of all thermal technologies in Europe decreases; however, few thermal powerplants are commissioned, and this partially compensates for the total capacity decrease. Lignite is an exception, which is marked by only decommissioning.

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

Commissionings and Decommissionings

BE00	Gas	1 January 2021	Commissioning 32 MW
BG00	Gas	1 January 2021	Commissioning 25 MW
CZ00	Lignite	31 December 2020	Decommissioning 157 MW
DE00	Gas	1 January 2021	Commissioning 1405 MW
		1 April 2021	Decommissioning 15 MW
	Lignite	31 December 2020	Decommissioning 297 MW
	Oil	31 December 2020	Decommissioning 184 MW
DKE1	Gas	31 December 2020	Decommissioning 5 MW
		1 January 2021	Commissioning 4 MW
	Hard coal	31 December 2020	Decommissioning 10 MW
		1 January 2021	Commissioning 8 MW
DKW1	Gas	31 December 2020	Decommissioning 128 MW
		1 January 2021	Commissioning 92 MW
	Hard coal	31 December 2020	Decommissioning 63 MW
		1 January 2021	Commissioning 45 MW
	Oil	31 December 2020	Decommissioning 16 MW
		1 January 2021	Commissioning 11 MW
HR00	Gas	1 January 2021	Decommissioning 83 MW
HU00	Gas	31 December 2020	Decommissioning 496 MW
	Hard coal	31 December 2020	Decommissioning 28 MW
	Oil	31 December 2020	Decommissioning 170 MW
IE00	Lignite	31 December 2020	Decommissioning 228 MW
ITS1	Hard coal	31 December 2020	Decommissioning 605 MW
NL00	Gas	1 January 2021	Commissioning 5 MW
PL00	Hard coal	15 November 2020	Commissioning 840 MW
		30 November 2020	Decommissioning 651 MW
		31 December 2020	Decommissioning 604 MW
PT00	Hard coal	31 December 2020	Decommissioning 1180 MW
RO00	Gas	1 January 2021	Commissioning 400 MW
SE03	Nuclear	31 December 2020	Decommissioning 880 MW
SK00	Nuclear	1 April 2021	Commissioning 438 MW
TR00	Gas	31 December 2020	Commissioning 393 MW
UK00	Gas	31 December 2020	Decommissioning 4845 MW

Figure 7 Thermal capacity evolution in Winter 2020–2021

Planned unavailability

The planned unavailability of units considered in the assessment is presented in Figure 8. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing.

Total planned unavailability decreases toward the end of 2020 and reaches low levels in January, when supply margins are tight in Europe (especially central Europe). A sharp drop at the end of year indicates that many planned outages are scheduled to be finished by end of year; therefore, any delays should be carefully monitored. Planned outages start ramping up at the end of January and follow a linear trend until the end of winter.

Planned outages of each technology decrease in January in different degrees. Lignite planned outages are low in January and start increasing very late, whereas hard coal planned outages do not change throughout the winter. Nuclear and gas power plant planned outages decrease substantially in January; however, they remain notable.

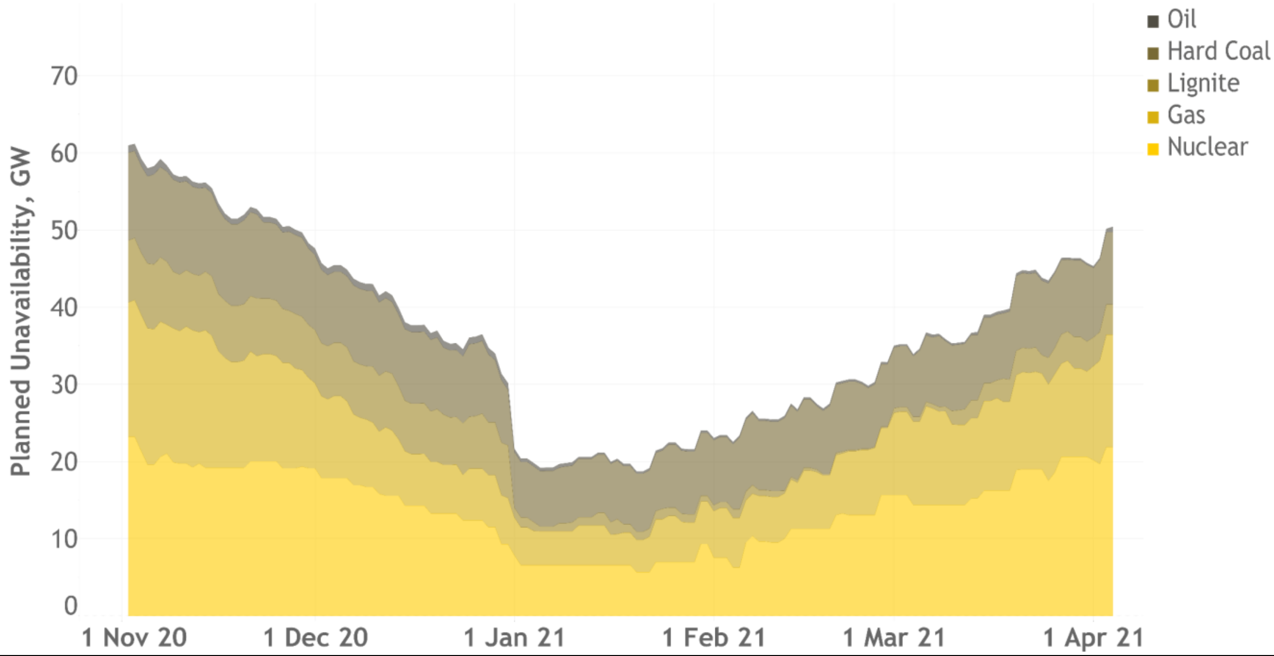


Figure 8 Planned unavailability of thermal units

Figure 9 represents the weekly distribution of thermal planned unavailability within all study zones by depicting the highest ratio of thermal planned unavailability with total thermal NGC[6] in each study zone for all weeks. Planned unavailability rates are remarkably high and exceed half of thermal NGC in southern Sweden (SE04 – all thermal capacity is on planned outage), Estonia (EE00) and Malta (MT00). Planned unavailability rates tend to follow a 'V' shape – they decrease towards the middle of the winter season and then start increasing again. However, in some study zones, planned outages do not follow this pattern and are spotted only in some weeks – Slovenia (SI00), northern–central Italy (ITCN), Sicily (ITSI) and Ireland (IE00).

[6] In the Summer Outlook 2020 report, the ratio to total NGC, which included renewables, was used. Any comparisons of pattern or highest ratios should be made with caution.

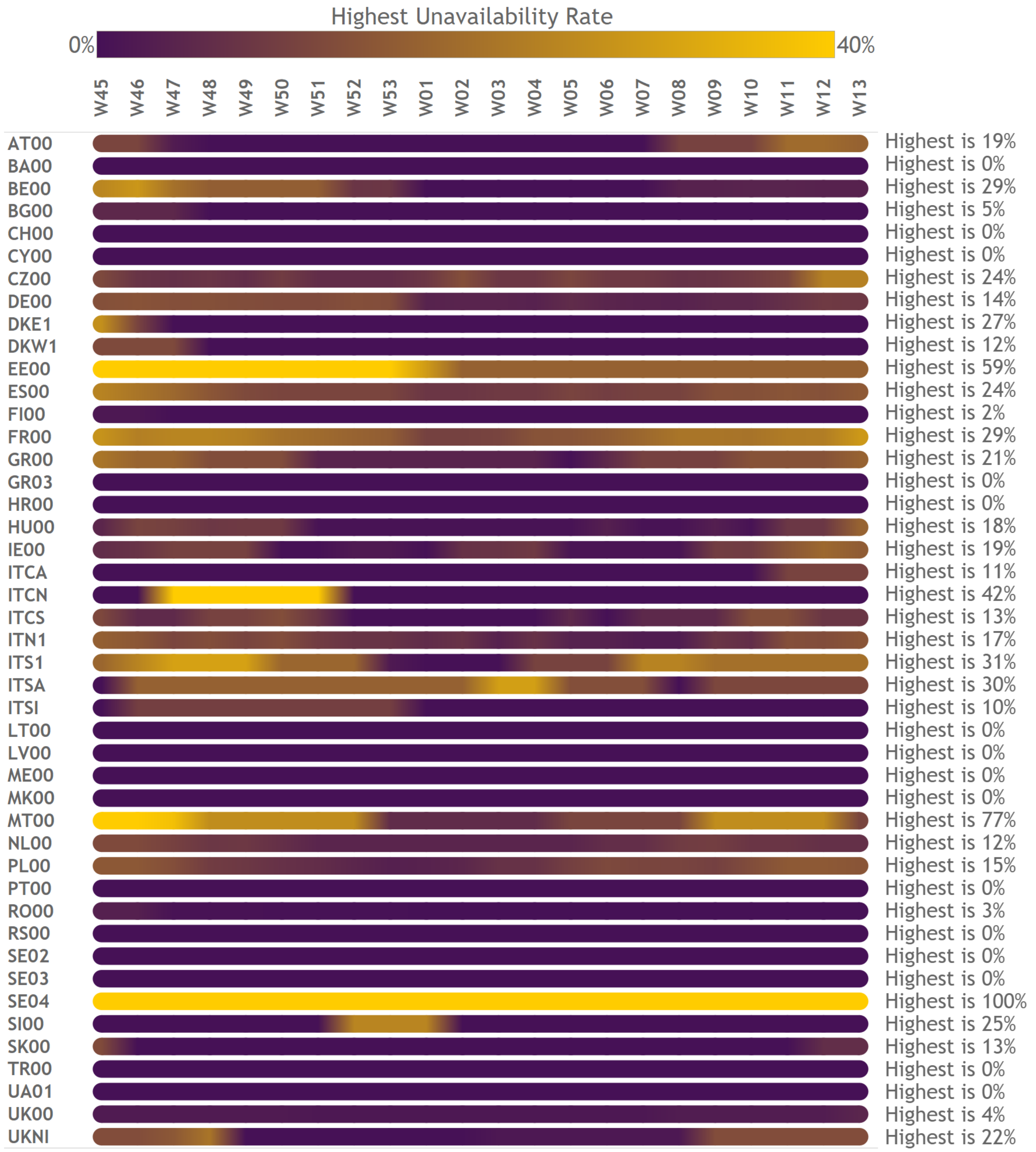


Figure 9 Weekly distribution of thermal planned unavailability relative to thermal NGC

Further availability limitations

The availability reduction overview (Figure 10) shows that resources are further limited by approximately 50 GW in winter 2020–2021. No clear seasonal pattern is recorded; however, pronounced daily changes are observed for DSR.

Generation and DSR availability can be limited by some factors other than planned and unplanned outages, and hence resources might be not available at full capacity. The generation could be impacted by seasonal factors (e.g. due to cooling water temperature changes), whereas DSR availability might depend on demand levels in particular hours of the day. The availability of some other technologies might depend on external factors (e.g. CHP availability for electricity production might depend on heat needs). Other availabilities might be strongly dependent on climate; they are not represented here but are available in the published dataset.

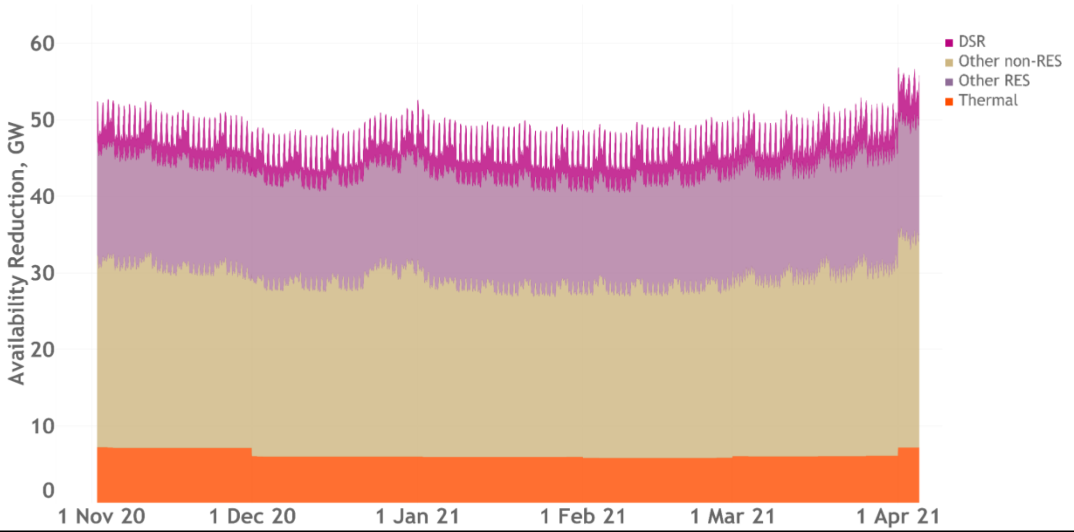


Figure 10 Availability reduction of generation and demand side response

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

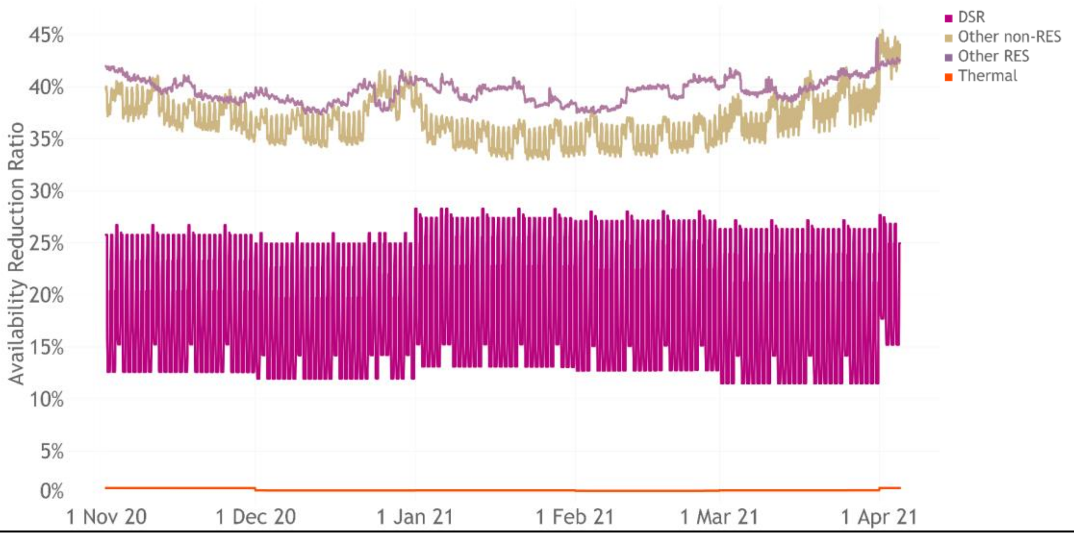


Figure 11 Relative availability reduction – not outage dependent

The availability reduction profile overview shows that DSR availability is least reduced during daytime, whereas other technologies do not show strong variability. Nevertheless, this figure presents a pan-European overview, and patterns that can be observed in some countries are not notable when the data are aggregated on a pan-European level.

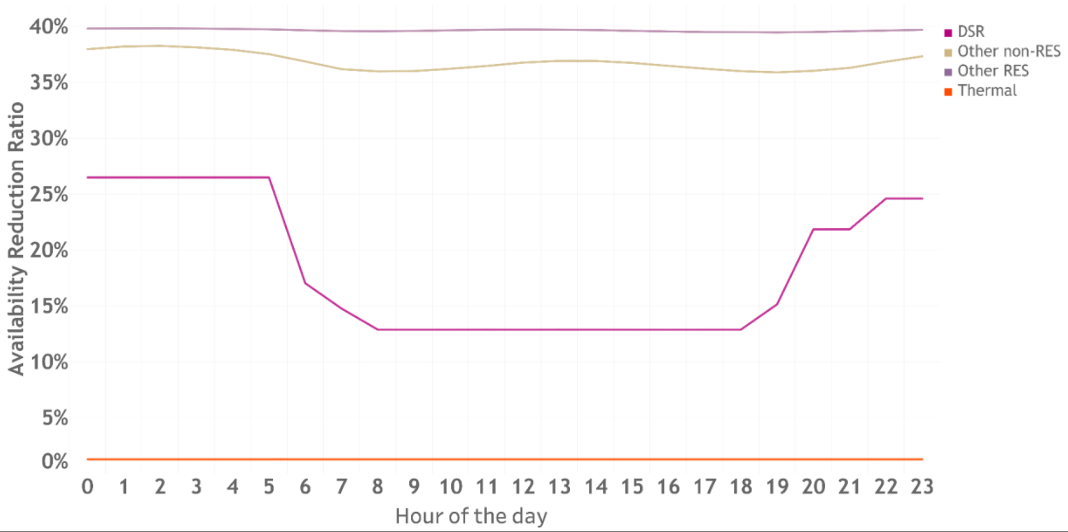


Figure 12 Average availability reduction profile overview

Demand overview

The demand overview in Figure 13 compares expected consumption in each week with the highest expected weekly consumption in winter 2020–2021. The darker shades indicate low expected consumption compared to highest expected consumption. This helps to identify holiday periods (e.g. Belgium and France) and other consumption patterns.

The highest level of consumption is typically reached in November–December and continues into February–March. A pronounced consumption change in season is typically present in countries that use electricity for heating (e.g. France in winter) or cooling (e.g. Italy in summer), as this makes electricity consumption very sensitive to outdoor temperatures. In many countries, a clear demand drop is visible during the winter holiday period, although this is not the case for all studied countries/zones.

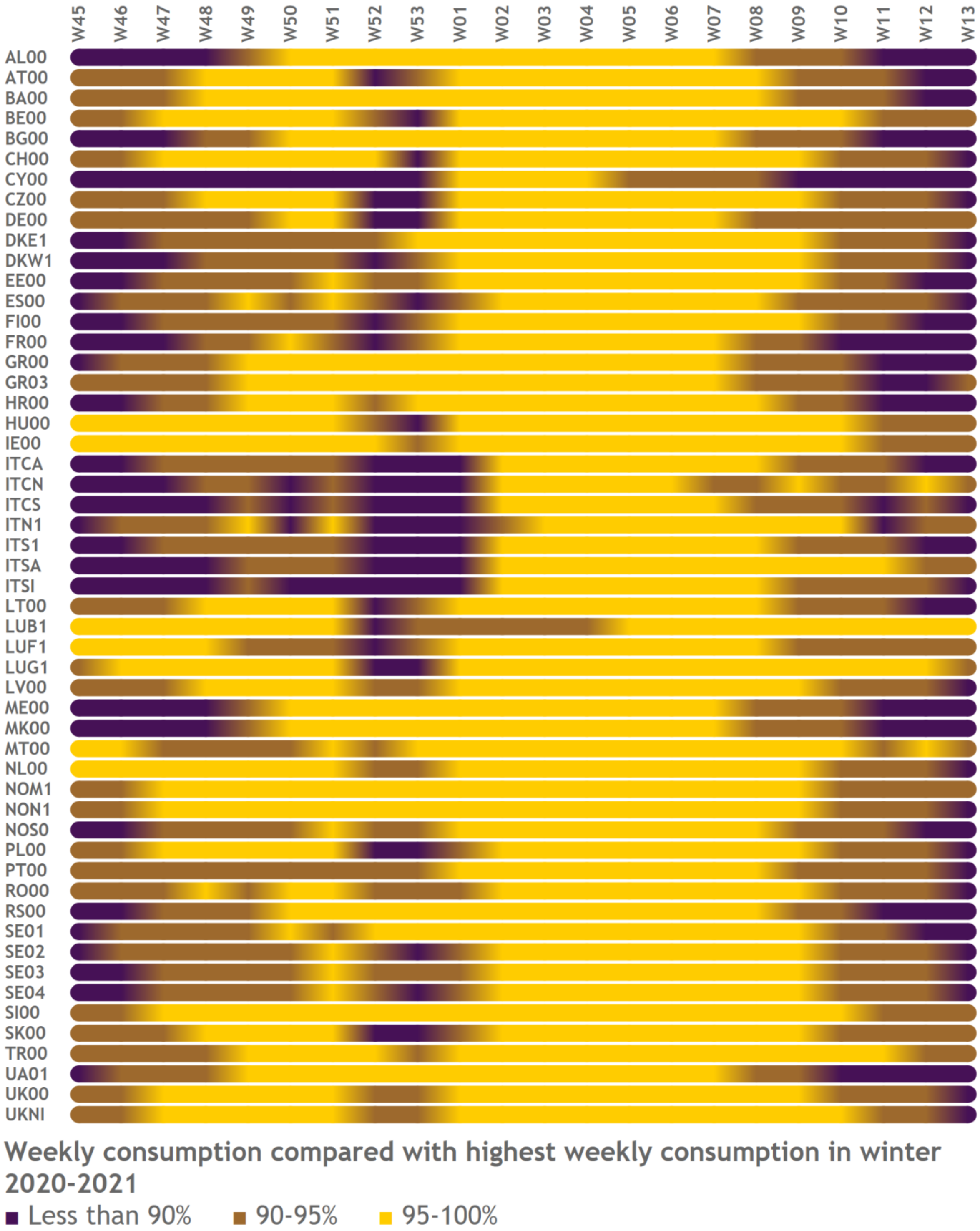


Figure 13 Demand overview – evolution over winter 2020–2021

Figure 14 shows workday consumption patterns per study zone by plotting the mean demand relative to the highest mean demand in winter 2020–2021. Almost all European countries are distinguished by a clear evening peak. More south-western countries (e.g. AT00, BE00, CH00,) typically have distinct morning and evening peaks, with a reduction in demand occurring in the early afternoon. Meanwhile, several Northern and Central European study zones (e.g. CZ00, DE00, EE00) do not mark notable demand variability during daytime.

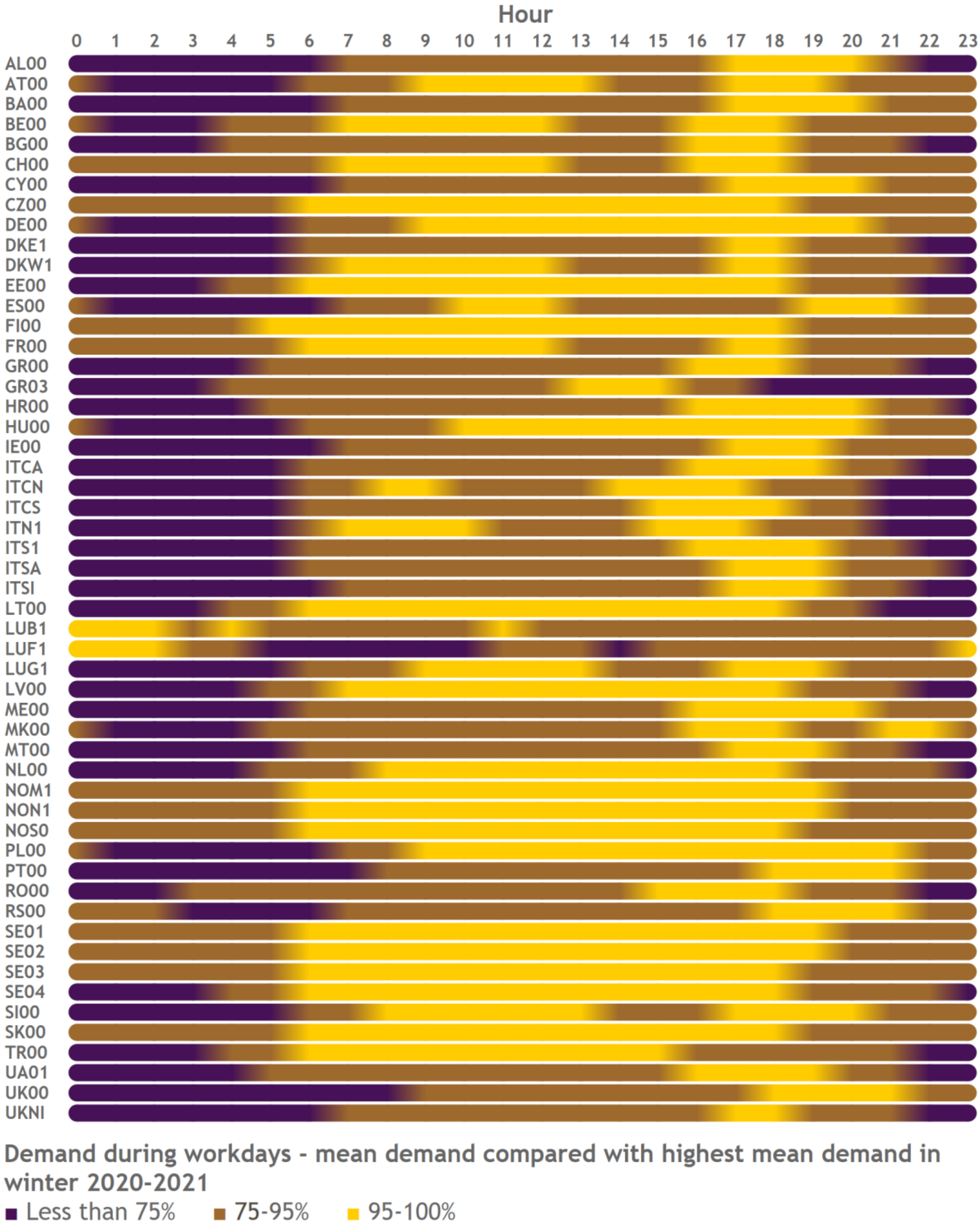


Figure 14 Demand profile overview during Mondays–Fridays in winter 2020–2021[7]

Network overview

The map in Figure 15 shows the ratio of lowest import capacity in Winter 2020–2021 to the highest expected demand during the same period. 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-modelled systems (not coloured in the figure) are not considered.

[7] *UTC time convention was used.*

Sweden, the centre of Norway, the Baltic countries, southern mainland Italy, the south of Central Europe, and the northwest Balkans, present the highest ratio (above 50%). Other regions indicate a lower ratio of available transfer capacities to the highest demand. Therefore, these countries might be highly reliant on locally available resources during demand peaks.

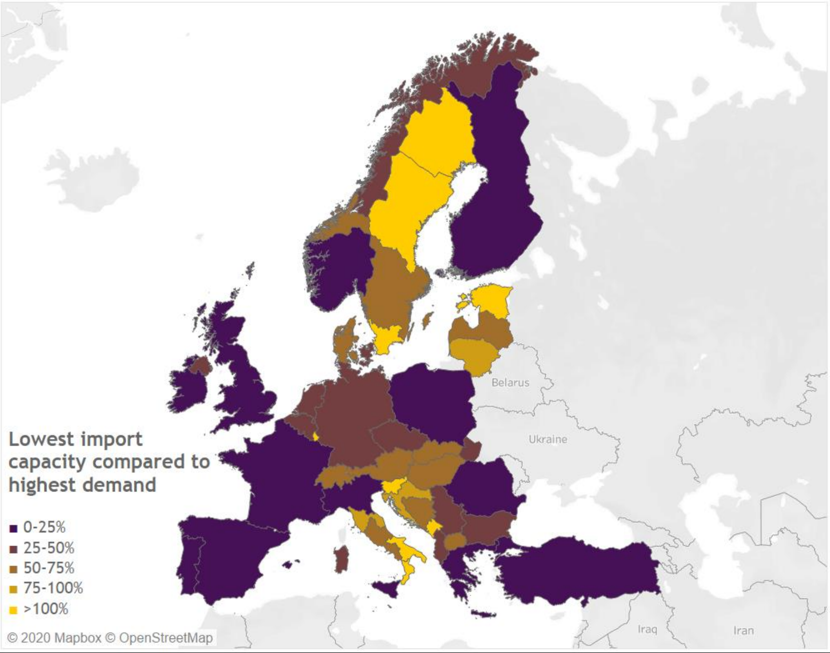


Figure 15 Import capacities per study zone: ratio between lowest import capacity and peak demand. C.f. Figure 24 for details

Adequacy situation

The adequacy situation is assessed using a two-step approach. In a first step, adequacy under normal market operation conditions is evaluated. In a 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 Winter 2020–2021 (Figure 16) shows some adequacy risks – i.e. the risk of relying on non-market measures – in Denmark, Finland, France and Malta. Non-market resources reduce risks substantially in Malta and Finland, where these resources exist, whereas risks do not decrease in France and Denmark, where available non-market resources in neighbouring regions (closest in Germany and Sweden - Figure 6) cannot be reached due to interconnection limitations.

Late editorial update:

Danish TSO (Energinet) updated the planned outages on its network in order to reduce risks identified in early November. This updated outage planning is expected to mitigate the risks considerably but could not be updated in these adequacy results, as a whole rerun of the assessment was not feasible. Risks in late November are carefully monitored closer to real time and actions may be taken according to circumstances.

Text Box 1 Editorial update on adequacy in Denmark

Late editorial update:

Risks in France were managed following an adequacy assessment. Initially, the period at risk is identified in the Winter Outlook from November 2020 until February 2021, with peaking risks in November and February. Since the data collection (in September), planned outage periods of the nuclear plants have been rearranged. The update leads to an important reduction of risks for November, but risks remain for the beginning of 2021, mainly in January and February. Risks are identified under cold weather conditions (as demand in France is very temperature-sensitive) and are continuously monitored. Necessary actions might be taken closer to real time.

Text Box 2 Editorial update on adequacy in France

In the Winter Outlook 2020–2021, the impact of the first wave of the COVID-19 pandemic was considered (postponed planned outages; demand being below normal levels – if not recovered), but no scenarios for the possible evolution of the pandemic were considered for the coming winter. The actual situation might therefore be better or worse depending on the pandemic’s evolution, the national measures taken, and eventually the impact on demand and on availability of supply.

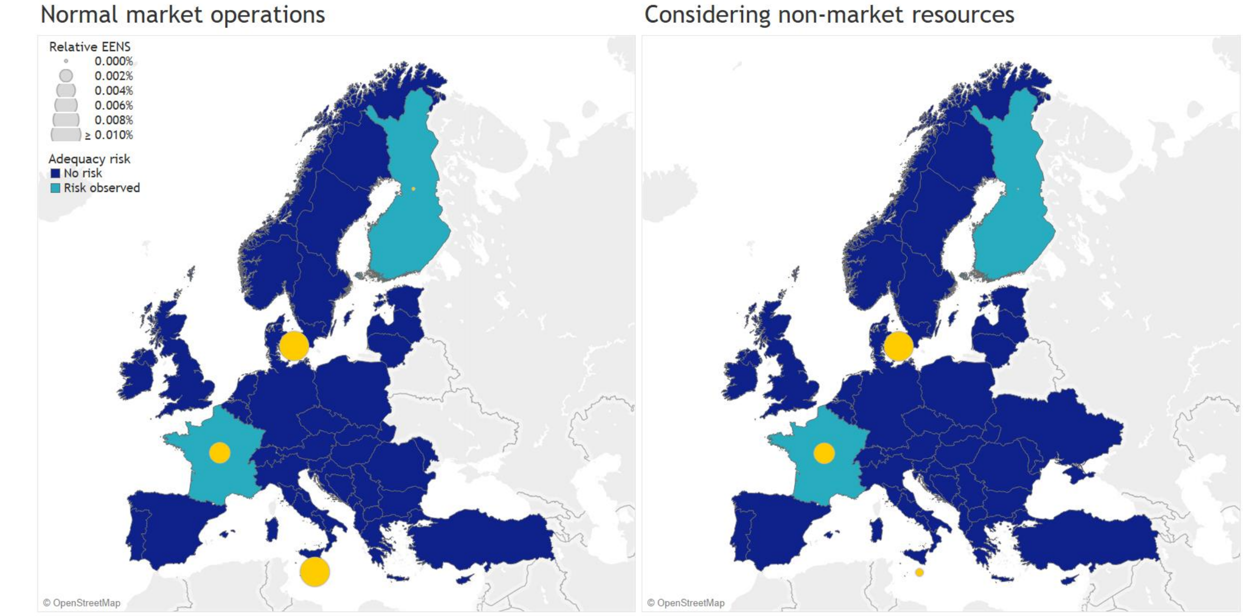


Figure 16 Adequacy overview

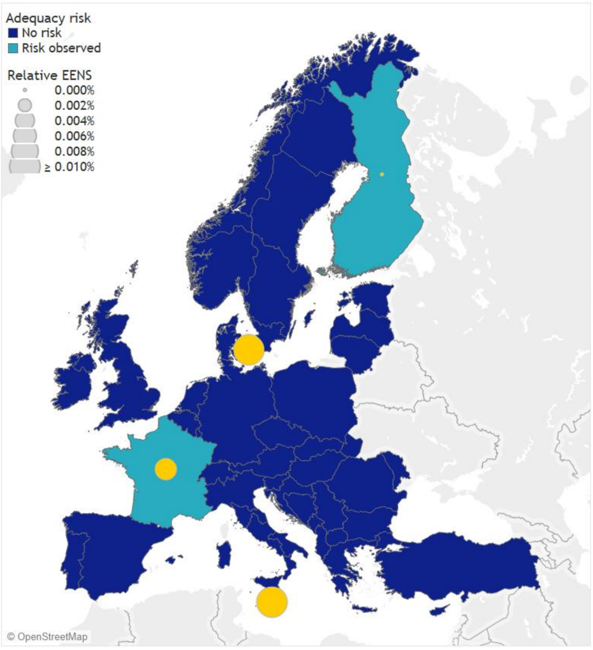
The state of the power system is continuously changing from what was known in late September 2020, and hence the risks are too. The risks are therefore continuously being monitored by TSOs and RSCs.

Focus on adequacy under normal market conditions

Under normal market operation conditions, risks are identified in Denmark[8], Finland, France and Malta (Figure 17). Whereas risk is marginal in Finland, considerable Expected Energy Not Served (EENS)[9] values are identified in the Danish, French and Maltese power systems. When comparing EENS to total seasonal consumption, Malta in particular shows an elevated risk.

[8] The planned outages in Denmark has been updated since data collection. For details, see Text Box 1 and the Denmark country comments in the dedicated document.

[9] EENS (or any other risk indicator) under normal market operations indicates only risk from a market perspective – i.e. the risk that certain energy might be not supplied via the market. After this is identified, non-market resources are exploited when available. If not sufficient, TSOs may take last operational measures, such as voltage control. Only if all these supply scarcity mitigative measures are exhausted and are insufficient does partial and controlled demand shedding occur.



DKE1	**EENS:** 680.66 MWh (**0.00995%** compared to Seasonal Consumption) **99th percentile ENS:** 6729.44 MWh (**0.09842%** compared to Seasonal Consumption)
FI00	**EENS:** 62.03 MWh (**0.00014%** compared to Seasonal Consumption) **99th percentile ENS:** 1346.74 MWh (**0.00312%** compared to Seasonal Consumption)
FR00	**EENS:** 12192.54 MWh (**0.00506%** compared to Seasonal Consumption) **99th percentile ENS:** 159927.79 MWh (**0.06633%** compared to Seasonal Consumption)
MT00	**EENS:** 948.58 MWh (**0.08930%** compared to Seasonal Consumption) **99th percentile ENS:** 4396.92 MWh (**0.41391%** compared to Seasonal Consumption)

Figure 17 Adequacy risk overview

The distribution of risks within season is presented in Figure 18. No pattern could be observed at regional level, suggesting that the risks are of a local nature. However, Finland and France mark risks in January which relate to historically cold weather conditions.

The weekly Loss of Load Probability (LOLP) was especially high in Denmark[8] (DKE1) during winter 2020–2021 (Figure 18). The underlying reason for adequacy risks are low import availability due to a planned outage that was prolonged due to an unexpected cable fault on the Kontek interconnection between the Denmark East bidding zone (DKE1) and Germany (DE00). Furthermore, when the Kontek interconnection outage was planned, it was expected that the Kriegers Flak interconnection would already be operating, however this has been postponed to 2021. The Kriegers Flak interconnector connects Danish and German Kriegers Flak offshore hubs (DKKF, DEKF) and hence also connects DKE1 and DE00 through this hub. After adequacy risks were identified in Denmark, Energinet (Danish TSO) updated the planned outages on its network to mitigate risks in early November and continuously monitored the situation in late November to take timely measures if necessary (Text Box 1).

France[10] (FR00) also shows adequacy stress, in particular weeks in November 2020 and January–February 2021, with a highest weekly LOLP of 11.84%. All risks in France are usually associated with severely cold weather conditions, as demand in France is temperature-sensitive. Some risks in these periods (marginal in November and February; and notable risks in January) are common in France; however, higher nuclear planned outages (postponed from spring–summer) elevate risks from the usual levels in November and February. Risks in January are maintained at a common level, partially because nuclear availability in Belgium is higher than usual. Nevertheless, some planned outages (especially in Belgium and Germany) were scheduled to be finished by end of 2020, so any delays should be carefully monitored. The situation is being continuously monitored for the following months in coordination with other TSOs through RSCs.

Finland presents a risk of supply shortage in the electricity market mostly in the second week of 2021. Risks are associated with severe cold weather conditions, as demand is temperature-sensitive in Finland. Historically, the harshest weather has been recorded in the second week of January. Risks in other weeks should be closely monitored in case of unprecedented cold weather. These risks can be addressed, to a large extent, with the available non-market resources (c.f. following section).

The situation in Malta (MT00) is standard, as every year,[11] and should be closely monitored throughout the winter, with the risk of relying on non-market resources exceeding 6%. Malta has interconnection allowing

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[10] The planned outages in France has been updated since data collection. For details see Text Box 2 and the France country comments in the dedicated document. More insights on adequacy in France can be found in the national adequacy assessment (link).
[11] Statement based on power system overview – supply and interconnection availability is expected to be at normal levels.

import of around half of peak demand needs and also has thermal generation allowing to almost supply peak demand (in addition to notable solar generation). However, many factors (in Malta as well as in Sicily) affect the adequacy situation in Malta, and therefore close monitoring is necessary. Enemalta (the Maltese DSO) will closely monitor the situation in cooperation with Terna (the Italian TSO) and will utilise non-market resources if necessary (c.f. following section).

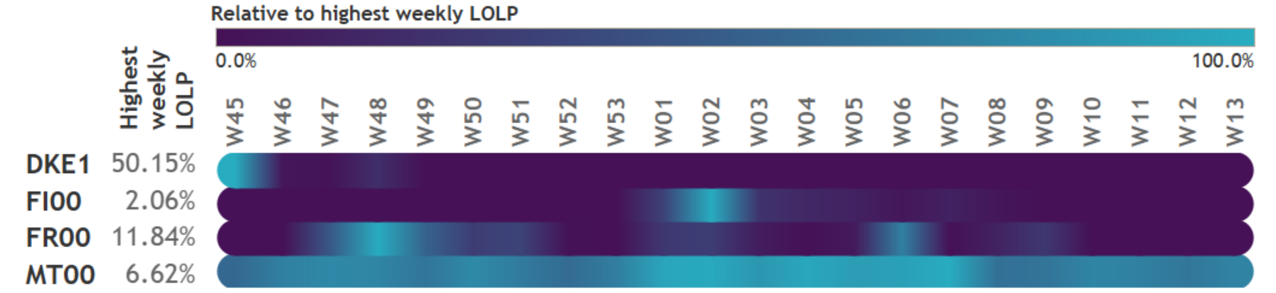

Figure 18 Adequacy weekly insights

Focus on non-market resources

Non-market resources (overview in Figure 6) drastically reduces EENS in Malta and Finland, indicating these measures are sufficient to address most adequacy concerns in winter 2020–2021 (Figure 19). Non-market resources are an integral part of the power system in Malta. Being an island country, the Maltese power system heavily relies on these resources during tighter supply moments and especially during potential outages of its interconnection with Italy. The Finnish power system also has some non-market resources to address the risks of rare but harsh cold spells.

Denmark[12] and France do not have access to non-market resources, which explains why EENS values do not or barely improve for these countries. Identified adequacy concerns are therefore significant and require appropriate preventive action from the TSOs to avoid or minimise ENS.

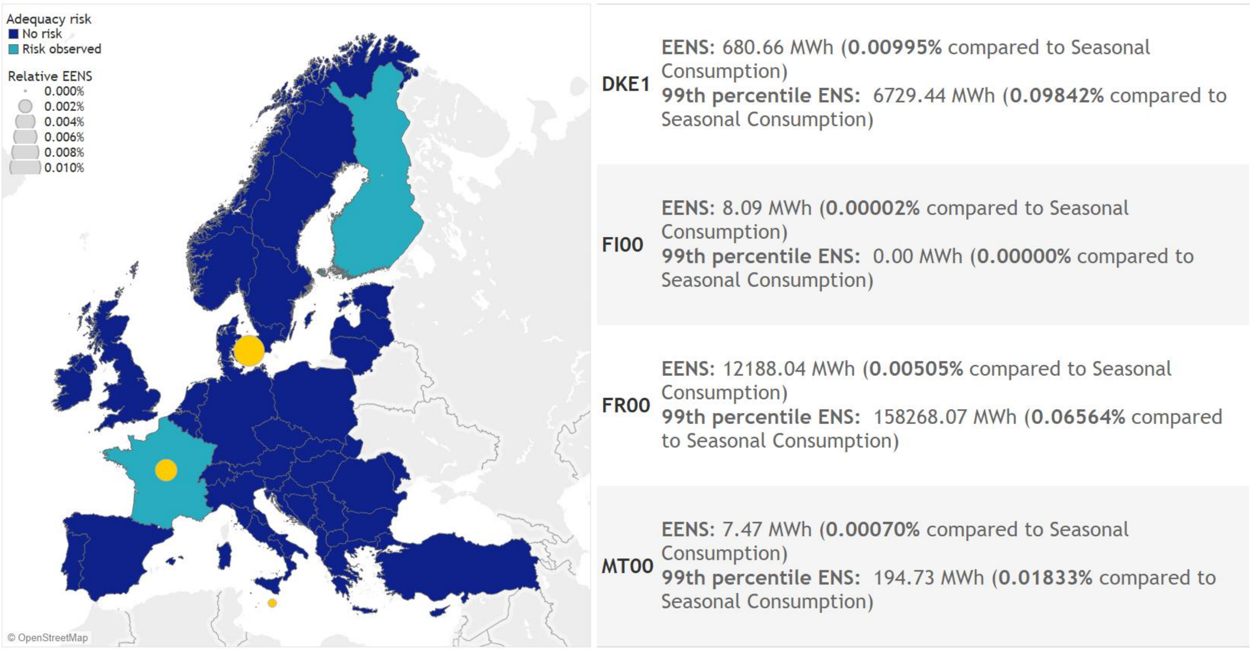

Figure 19 Adequacy risk overview – considering non-market resources

The highest weekly LOLP of Malta has dropped substantially from 6.62% to 1.03% (Figure 20) due to the consideration of non-market resources. The continuous monitoring of adequacy risks is still a necessary

[12] *The planned outages in Denmark has been updated since data collection. For details, see Text Box 1 and the Denmark country comments in the dedicated document.*

precaution. Even if non-market resources do not cover shortage in all hours, the magnitude of potential load-shedding would decrease considerably. Finland's highest LOLP is also reduced, from 2.06% to 0.51%. The LOLPs remain unchanged for France and Denmark, as non-market measures are absent for these countries and are not accessible in neighbouring regions due to congestions in network.

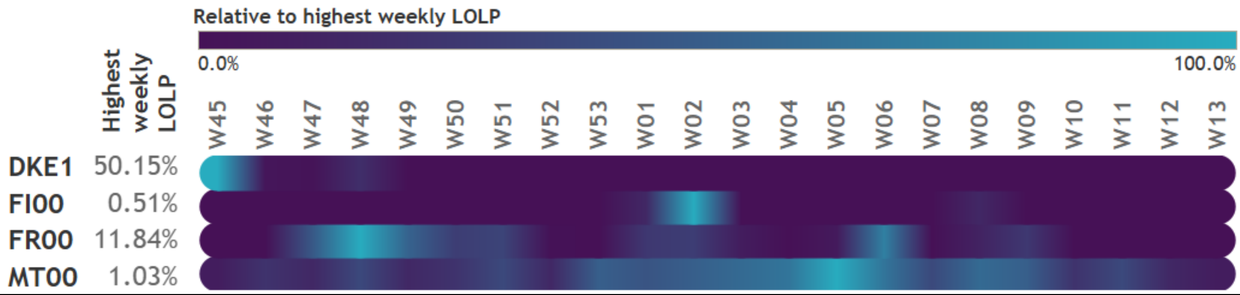

Figure 20 Adequacy weekly insights – considering non-market resources

The impact of non-market resources is represented visually in Figure 21. The LOLP in Finland is reduced considering the contribution of the non-market resources during the first months of 2021. In Malta, the significant impact of non-market resources on adequacy is clearly illustrated, with a constant reduction of approximately 3% to 6% throughout winter 2020–2021.

Malta and Finland are able to reduce EENS by 99% and 87% respectively through the activation of non-market resources. However, total European EENS remains significant, as France clearly represents the biggest share of EENS under normal market operations, followed by Malta, Denmark and Finland.

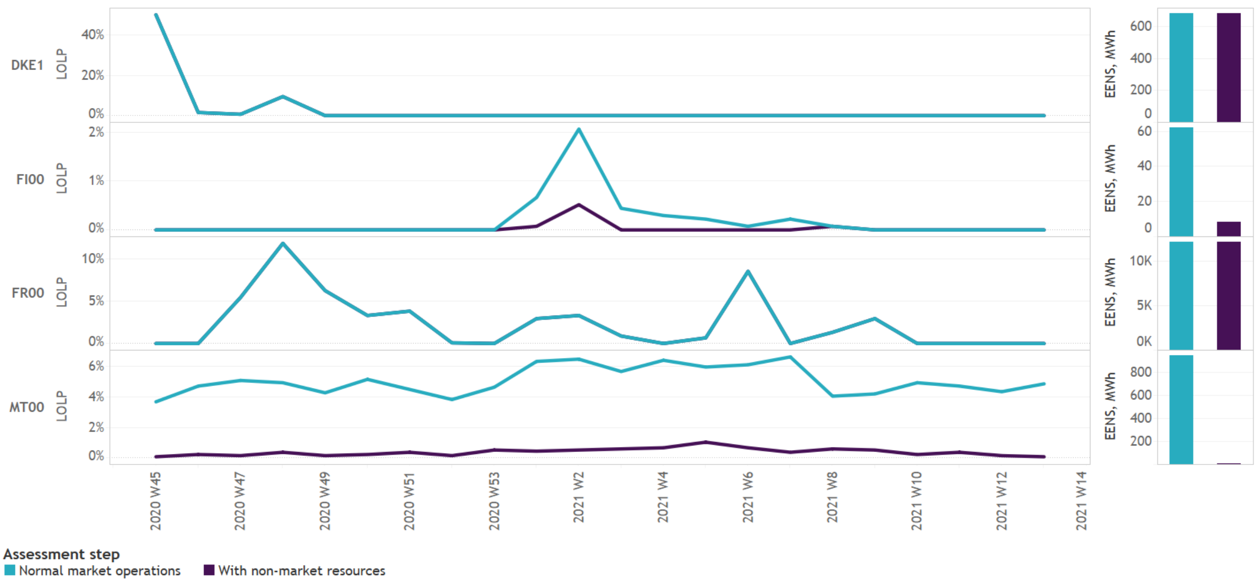

Figure 21 Detailed adequacy overview – weekly LOLP and ENS

Summer 2020 Review

The summer review is based on the qualitative information submitted by ENTSO-E TSOs in October 2020 to represent the most important events that occurred during the summer of 2020 and compare them to the study results reported in the previous Seasonal Outlook. Important or unusual events or conditions in the power system and remedial actions taken by the TSOs are also mentioned. A detailed summer review by country can be found in the separate Country Comments document if TSOs had anything specific to report.

Overview

In the past summer (June 2020 to September 2020), Europe was generally warmer than average, but not remarkably so compared with other recent years. The period June–August was 0.9°C above the 1981–2010 norm. This is distinctly cooler than during the hottest summer, in 2018, when the average temperature was 1.4°C above normal. The summer of 2020 witnessed the second-hottest June and hottest September on record.

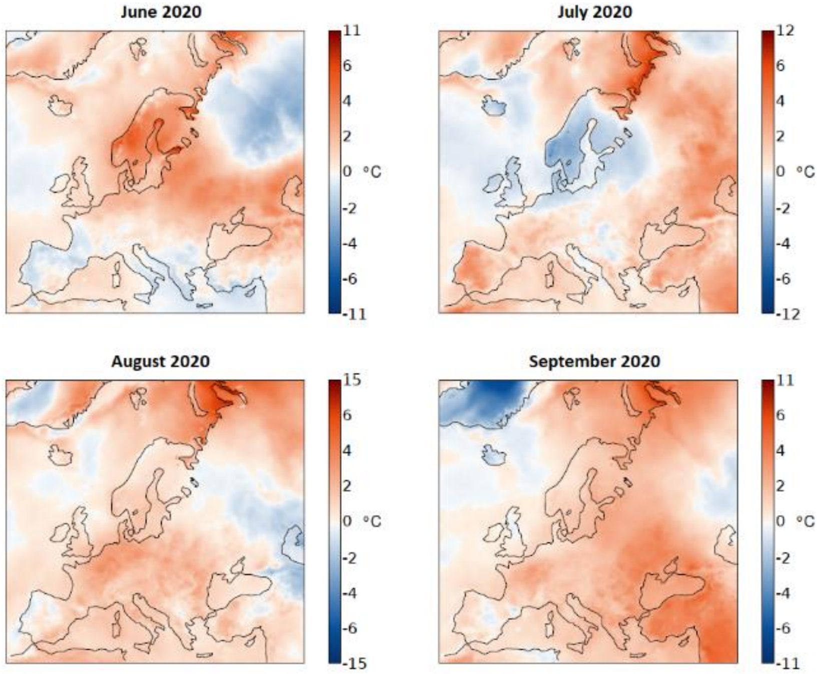

Figure 22 Surface air temperature anomaly in summer 2020 relative to the average of the period 1981‑2010[13]

The COVID-19 pandemic had a noticeable impact in some countries. In several countries, such as in Italy and France, sanitary measures caused a postponement of planned generation outages from spring to summer. Hence, the availability of generation capacities during summer was frequently lower than initially foreseen. However, lower economic activity caused by the COVID-19 pandemic relaxed the adequacy situation, causing a decrease in electricity consumption by several percentage points in many countries.

Voltage regulation issues were recorded due to decreased demand (as a result of COVID-19) and high RES generation in Europe. Challenges were addressed, and no impacts were noticed by consumers.

Specific events

In general terms, the summer of 2020 was favourable for adequacy, except for a number of events discussed below:

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

- On 15 September, supply margins across Europe were tight, and several TSOs where consequently on Alert State in the European Awareness System. Demand increased in Europe due to high temperatures (mainly for cooling), whereas wind production was very low throughout Europe, and the availability of generation capacities was limited due to planned outages. France and Denmark experienced strong tight supply margins and countermeasures had to be taken in real time. No consumers lost electricity supply.

- In France there were many days (including days of heat waves in early August and mid-September) recorded in summer when supply margins hit alarming levels and alert messages were sent to market participants. The COVID-19 crisis led to a demand decrease of approximately 7% on average, but the impact on planned outage schedules was also notable, leading to a total decrease of nuclear power availability by 22% on average compared to previous summers. No consumers lost electricity supply.

Endnote

The Winter Outlook 2020–2021 represents the Seasonal Adequacy Assessments defined in Risk Preparedness Regulation (Regulation (EU) 2019/941). ENTSO-E performs this assessment to alert Member States and TSOs about the risks related to the security of electricity supply that might occur in the coming season.

This is a further step in the implementation of the new methodology approved by ACER on 6 March 2020 (decision No 08/2020). The methodology is supposed to be fully implemented one year after approval, but the present assessment already considers many of the requirements set out in the methodology.

Appendix: Additional material for publication

Figure 23 Study zones

AL00	From: GR00 Avg. 300 MW (300 - 300) MW	From: ME00 Avg. 300 MW (300 - 300) MW	From: RS00 Avg. 250 MW (250 - 250) MW											
AT00	From: DE00 Avg. 4,900 MW (4,900 - 4,900) MW	From: CH00 Avg. 1,200 MW (1,200 - 1,200) MW	From: SI00 Avg. 950 MW (950 - 950) MW	From: CZ00 Avg. 792 MW (700 - 800) MW	From: HU00 Avg. 600 MW (600 - 600) MW	From: ITN1 Avg. 120 MW (100 - 145) MW								
BA00	From: HR00 Avg. 600 MW (600 - 600) MW	From: RS00 Avg. 520 MW (500 - 600) MW	From: ME00 Avg. 500 MW (500 - 500) MW											
BE00	From: FR00 Avg. 1,940 MW (1,940 - 1,940) MW	From: NL00 Avg. 1,020 MW (1,020 - 1,020) MW	From: UK00 Avg. 875 MW (750 - 1,000) MW	From: DE00 Avg. 500 MW (500 - 500) MW	From: LUB1 Avg. 400 MW (400 - 400) MW									
BG00	From: RO00 Avg. 900 MW (900 - 900) MW	From: GR00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 249 MW (150 - 300) MW	From: MK00 Avg. 249 MW (134 - 250) MW	From: TR00 Avg. 234 MW (234 - 234) MW									
CH00	From: FR00 Avg. 3,000 MW (3,000 - 3,000) MW	From: ITN1 Avg. 1,855 MW (1,810 - 1,910) MW	From: AT00 Avg. 1,200 MW (1,200 - 1,200) MW	From: DE00 Avg. 1,200 MW (1,200 - 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: PLE0 Avg. 986 MW (900 - 1,000) MW	From: AT00 Avg. 888 MW (750 - 900) 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: FR00 Avg. 3,000 MW (3,000 - 3,000) MW	From: PLE0 Avg. 3,000 MW (3,000 - 3,000) MW	From: DKW1 Avg. 2,298 MW (200 - 2,500) MW	From: CZ00 Avg. 2,100 MW (2,100 - 2,100) MW	From: LUV1 Avg. 1,300 MW (1,300 - 1,300) MW	From: NOS0 Avg. 1,136 MW (0 - 1,400) MW	From: LUG1 Avg. 1,000 MW (1,000 - 1,000) MW	From: SE04 Avg. 615 MW (615 - 615) MW	From: BE00 Avg. 500 MW (500 - 500) MW	From: DKE1 Avg. 487 MW (0 - 585) MW	From: DEKF Avg. 400 MW (400 - 400) MW
DKE1	From: SE04 Avg. 1,263 MW (750 - 1,300) MW	From: DKW1 Avg. 571 MW (0 - 590) MW	From: DE00 Avg. 500 MW (0 - 600) MW	From: DKKF Avg. 366 MW (0 - 600) MW										
DKW1	From: DE00 Avg. 2,324 MW (500 - 2,500) MW	From: NOS0 Avg. 1,632 MW (1,632 - 1,632) MW	From: SE03 Avg. 655 MW (0 - 715) MW	From: DKE1 Avg. 580 MW (0 - 600) MW	From: NL00 Avg. 455 MW (0 - 700) MW									
EE00	From: FI00 Avg. 1,016 MW (1,016 - 1,016) MW	From: LV00 Avg. 835 MW (750 - 879) MW												
ES00	From: PT00 Avg. 2,537 MW (2,200 - 2,610) MW	From: FR00 Avg. 2,494 MW (2,000 - 2,600) MW												
FI00	From: SE01 Avg. 1,500 MW (1,500 - 1,500) MW	From: SE03 Avg. 1,200 MW (1,200 - 1,200) MW	From: EE00 Avg. 1,014 MW (908 - 1,016) MW											
FR00	From: DE00 Avg. 3,000 MW (3,000 - 3,000) MW	From: UK00 Avg. 2,000 MW (2,000 - 2,000) MW	From: ES00 Avg. 1,946 MW (1,100 - 2,000) MW	From: CH00 Avg. 1,100 MW (1,100 - 1,100) MW	From: ITN1 Avg. 997 MW (995 - 1,000) MW	From: BE00 Avg. 810 MW (810 - 810) MW	From: LUF1 Avg. 400 MW (400 - 400) MW							
GR00	From: BG00 Avg. 700 MW (700 - 700) MW	From: MK00 Avg. 553 MW (345 - 600) MW	From: ITS1 Avg. 500 MW (500 - 500) MW	From: AL00 Avg. 300 MW (300 - 300) MW	From: TR00 Avg. 166 MW (166 - 166) MW	From: GR03 Avg. 92 MW (0 - 150) MW								
GR03	From: GR00 Avg. 92 MW (0 - 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: HR00 Avg. 900 MW (900 - 900) MW	From: SK00 Avg. 800 MW (800 - 800) MW	From: RS00 Avg. 698 MW (610 - 700) MW	From: UA01 Avg. 601 MW (455 - 650) MW	From: AT00 Avg. 600 MW (600 - 600) MW	From: RO00 Avg. 550 MW (550 - 550) MW								
IE00	From: UK00 Avg. 483 MW (0 - 500) MW	From: UKNI Avg. 300 MW (300 - 300) MW												
ITCA	From: ITS1 Avg. 4,567 MW (1,100 - 9,999) MW	From: ITSI Avg. 1,160 MW (100 - 1,200) MW												
ITCN	From: ITN1 Avg. 3,468 MW (2,400 - 4,000) MW	From: ITCS Avg. 2,445 MW (1,200 - 2,700) MW	From: ITSA Avg. 300 MW (300 - 300) MW											
ITCS	From: ITS1 Avg. 3,925 MW (3,200 - 4,600) MW	From: ITCN Avg. 2,041 MW (800 - 2,500) MW	From: ITSA Avg. 881 MW (720 - 900) MW	From: ME00 Avg. 600 MW (600 - 600) MW										
ITN1	From: CH00 Avg. 3,678 MW (2,288 - 3,710) MW	From: FR00 Avg. 2,240 MW (195 - 2,700) MW	From: ITCN Avg. 1,942 MW (800 - 2,700) MW	From: SI00 Avg. 656 MW (81 - 730) MW	From: AT00 Avg. 303 MW (182 - 315) MW									
ITS1	From: ITCS Avg. 5,116 MW (2,000 - 9,999) MW	From: ITCA Avg. 2,139 MW (900 - 2,450) MW	From: GR00 Avg. 500 MW (500 - 500) MW											
ITSA	From: ITCS Avg. 701 MW (210 - 720) MW	From: ITCN Avg. 300 MW (300 - 300) MW												
ITSI	From: ITCA Avg. 1,063 MW (100 - 1,100) MW	From: MT00 Avg. 225 MW (225 - 225) MW												
LT00	From: LV00 Avg. 1,024 MW (752 - 1,202) MW	From: SE04 Avg. 658 MW (350 - 700) MW	From: PL00 Avg. 500 MW (500 - 500) MW											
LUB1	From: BE00 Avg. 400 MW (400 - 400) MW													
LUF1	From: FR00 Avg. 400 MW (400 - 400) MW													
LUG1	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW													
LUV1	From: DE00 Avg. 1,300 MW (1,300 - 1,300) MW													
LV00	From: EE00 Avg. 877 MW (700 - 947) MW	From: LT00 Avg. 427 MW (284 - 684) MW												
ME00	From: RS00 Avg. 604 MW (500 - 700) MW	From: ITCS Avg. 600 MW (600 - 600) MW	From: BA00 Avg. 500 MW (500 - 500) MW	From: AL00 Avg. 300 MW (300 - 300) MW										
MK00	From: RS00 Avg. 620 MW (353 - 700) MW	From: GR00 Avg. 597 MW (350 - 600) MW	From: BG00 Avg. 256 MW (200 - 300) MW											
MT00	From: ITSI Avg. 225 MW (225 - 225) MW													
NL00	From: DE00 Avg. 4,250 MW (4,250 - 4,250) MW	From: BE00 Avg. 1,060 MW (1,060 - 1,060) MW	From: UK00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NOS0 Avg. 695 MW (600 - 700) MW	From: DKW1 Avg. 455 MW (0 - 700) MW									
NOM1	From: SE02 Avg. 965 MW (650 - 1,000) MW	From: NON1 Avg. 925 MW (875 - 945) MW	From: NOS0 Avg. 412 MW (400 - 420) MW											
NON1	From: SE01 Avg. 452 MW (375 - 473) MW	From: SE02 Avg. 255 MW (225 - 263) MW	From: NOM1 Avg. 206 MW (200 - 210) MW											
NOS0	From: SE03 Avg. 2,011 MW (1,323 - 2,095) MW	From: DE00 Avg. 1,136 MW (0 - 1,400) MW	From: DKW1 Avg. 953 MW (953 - 953) MW	From: NL00 Avg. 700 MW (700 - 700) MW	From: NOM1 Avg. 309 MW (300 - 315) MW									
PL00	From: PLI0 Avg. 800 MW (800 - 800) MW	From: SE04 Avg. 600 MW (600 - 600) MW	From: LT00 Avg. 500 MW (500 - 500) MW											
PT00	From: ES00 Avg. 2,682 MW (2,000 - 3,300) MW													
RO00	From: BG00 Avg. 900 MW (900 - 900) MW	From: HU00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 500 MW (500 - 500) MW	From: UA01 Avg. 100 MW (100 - 100) MW										
RS00	From: ME00 Avg. 602 MW (350 - 750) MW	From: BA00 Avg. 561 MW (500 - 600) MW	From: HU00 Avg. 500 MW (500 - 500) MW	From: RO00 Avg. 455 MW (330 - 500) MW	From: MK00 Avg. 372 MW (350 - 400) MW	From: BG00 Avg. 270 MW (150 - 350) MW	From: AL00 Avg. 250 MW (250 - 250) MW	From: HR00 Avg. 150 MW (150 - 150) MW						
SE01	From: SE02 Avg. 3,300 MW (3,300 - 3,300) MW	From: FI00 Avg. 1,100 MW (1,100 - 1,100) MW	From: NON1 Avg. 657 MW (483 - 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. 600 MW (600 - 600) MW	From: NON1 Avg. 144 MW (125 - 158) MW										
SE03	From: SE02 Avg. 7,300 MW (7,300 - 7,300) MW	From: SE04 Avg. 2,556 MW (2,000 - 2,800) MW	From: NOS0 Avg. 2,020 MW (1,323 - 2,145) MW	From: FI00 Avg. 1,200 MW (1,200 - 1,200) MW	From: DKW1 Avg. 693 MW (0 - 715) MW									
SE04	From: SE03 Avg. 5,956 MW (5,400 - 6,200) MW	From: DKE1 Avg. 1,472 MW (400 - 1,700) MW	From: LT00 Avg. 700 MW (700 - 700) MW	From: DE00 Avg. 615 MW (615 - 615) MW	From: PL00 Avg. 600 MW (600 - 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. 668 MW (660 - 680) MW											
SK00	From: CZ00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HU00 Avg. 800 MW (800 - 800) MW	From: PLE0 Avg. 500 MW (500 - 500) MW	From: UA01 Avg. 387 MW (0 - 400) MW										
TR00	From: BG00 Avg. 334 MW (334 - 334) MW	From: GR00 Avg. 216 MW (216 - 216) MW												
UA01	From: HU00 Avg. 450 MW (450 - 450) MW	From: SK00 Avg. 387 MW (0 - 400) MW	From: RO00 Avg. 50 MW (50 - 50) MW											
UK00	From: FR00 Avg. 2,000 MW (2,000 - 2,000) MW	From: NL00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 875 MW (750 - 1,000) MW	From: IE00 Avg. 483 MW (0 - 500) MW	From: UKNI Avg. 381 MW (380 - 500) MW									
UKNI	From: UK00 Avg. 442 MW (442 - 500) MW	From: IE00 Avg. 300 MW (300 - 300) MW												

Figure 24 Import capacity overview

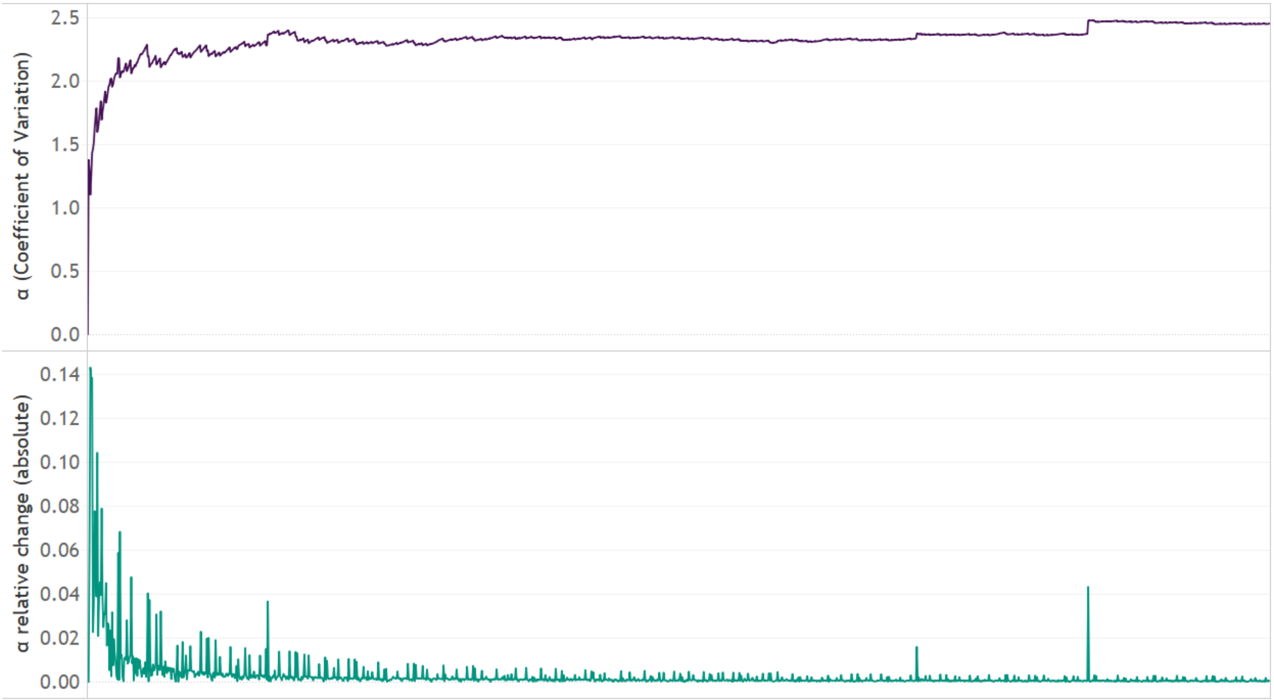

Figure 25 Convergence overview[14]

[14] *The convergence overview shows a high accuracy level of the seasonal assessment. The number of analysed Monte Carlo samples was 1360 (34 Climate Condition scenarios and 40 scenarios of unplanned outages). Details on how this was calculated are presented in the methodology for [Short-term and Seasonal Adequacy assessment methodology](). Convergence of Normal Market Conditions is presented. Convergence of simulations with Non-Market resources shows non-notable differences.*