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POWER SYSTEM FLEXIBILITY IN A VARIABLE CLIMATE

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Executive summary

Our report “Power system flexibility in a variable climate” assesses the impact of the annual variation of meteorological factors – the climate variability – on the operations of the power systems in 34 European countries that jointly constitute the interconnected European electricity systems. It covers important aspects such as CO_2 emissions and use of freshwater for cooling of power plants, and estimates their sensitivity to the changing climatic conditions.

Changing weather conditions affect the operation of the European power systems. The output of renewable energy sources fluctuates depending on the availability of wind, cloud cover, or water levels in reservoirs, while the output of dispatchable generators, such as gas turbines, must be adapted accordingly to ensure that supply and demand are balanced at all times. The link between meteorology and power systems also manifests itself through other aspects such as the demand for electricity, affecting the operation of power markets, and thus power prices, emissions, and use of resources (fuels, fresh water etc). Today more than 40% of the European electricity generation capacity is heavily dependent on climatic factors. This dependence is expected to increase in the future as Europe transitions to a carbon-neutral economy.

Methodology

This work is based on a set of simulations carried out with the Dispa-SET power system model, developed by the JRC, using hourly datasets for wind and solar capacity factors, electricity demand and hydropower inflows based on actual meteorological conditions. The simulations reproduce the behaviour of all the European power systems, as they operated in 2016, using a set of 26 different climatic conditions as inputs.

Key results

Our analysis shows that:

- In some systems the quantity of electricity that can be generated by renewable sources varies considerably due to climatic conditions: by 57-77% in the Northern countries[1] , or 35-50% in the Iberian peninsula[2].
- the quantity of water available for hydropower generation in Europe varies annually from -19% to +25% with respect to the long-term average
- the season with the biggest capacity factors for wind is the winter; and the highest ones are 39.1% in UK & Ireland for onshore and 49.6% in the Northern countries for offshore
- the region with the highest capacity factor for solar PV is Iberia during summer (24%) followed by Southeast Europe[3] (21%)
- the three regions with the most variable peak load are UK & Ireland, Iberia and Italy.

Impacts of climate variability on the European power systems

On average, renewable power in Europe ranges has an annual share between 29% and 33.5% of the total generation, leading to CO_2 emissions intensity of 291 – 315 g/KWh for the whole power system. In terms of absolute emissions, this range implies that climate variability alone can cause a variation of CO_2 emissions similar to these of a country like Belgium (74 $MtCO_2$ in 2018).

Hydropower exhibits the largest annual variability (Figure 1). The calculated ranges vary by region. In the Northern countries it is 57-77% of the total generation, while in the Central Eastern[4] part of the continent it is 16-19%, due to the lesser installed capacity of renewable energy.

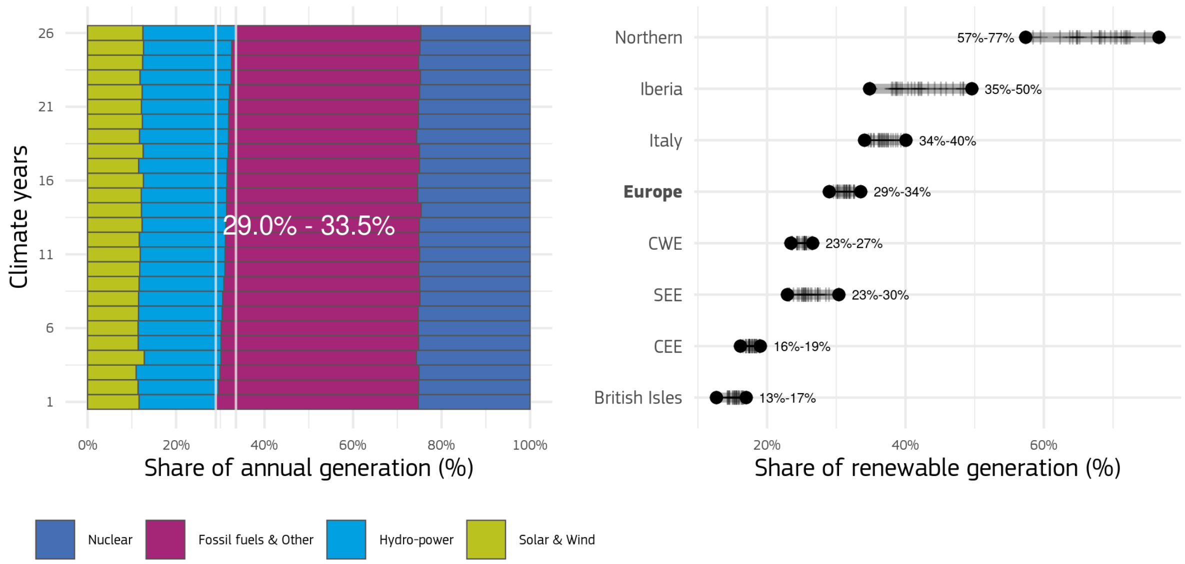
The simulation shows also that renewable generation ranges are generally larger at seasonal level. The Northern and Iberian regions experience the highest variability. Thus, the same regions exhibit the largest climate-induced variability of CO_2 emissions, which in the case of Iberia is 175 – 310 gCO_2/kWh.

[1] Denmark (DK), Estonia (EE), Finland (FI), Latvia (LV), Lithuania (LT), Norway (NO), Sweden (SE)
[2] Spain (ES), Portugal (PT)
[3] Albania (AL), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), Greece (EL), Kosovo[3] (XK), Montenegro (ME), North Macedonia (MK), Serbia (RS)
[4] Czechia (CZ), Hungary (HU), Poland (PL), Romania (RO), Slovakia (SK), Slovenia (SI)

The effect on power prices is similarly important. A year-on-year range of average power market prices exceeding 3 EUR/MWh was calculated. The impact on net cross-border exchanges of power is less evident. Regions do not change their import/export status on an annual basis. This, however, is not true month-on-month: some regions can shift from exporter to importer status within one year.

The current study also identified the presence of positively or negatively correlated weather-driven effects on national power systems (i.e. renewable source availability, demand, etc.). Such patterns exist between the more distant geographical regions: for example, hydropower generation in Northern countries and Iberia shows a negative correlation. This means that when there is a period drier than normal in Scandinavia (i.e. less hydropower generation) the Iberian Peninsula might run into a wetter period than usual. On the other hand, neighbouring countries/zones are typically correlated. For example, conditions inducing very high electricity demand in one country (i.e. a cold wave), will likely also prevail in the neighbouring countries/areas.

Figure 1: Generation mix and share of renewables for the 26 different climatic conditions (climate years from 1990 to 2015)



Conclusions

In Europe, considering a set of different climatic conditions, the electricity generated from renewables is on average 1 047 TWh, i.e. 31% of the total generation. This quantity varies year by year, with the minimum and the maximum from 979 TWh (29%) to 1 116 TWh (33.5%).

The analysis described in the report highlights the potential vulnerabilities arising in specific periods of the year due to climate. The variability of renewable generation and its effect on the power system, is most evident in the Iberian and Northern regions, where hydropower and wind power represent high shares of the total installed capacity. Climate conditions resulting in renewable generation lower than normal might lead, for example, to higher electricity costs or higher use of freshwater for thermal cooling. Cross-border exchanges of electricity through interconnectors can help mitigate the impact of an unexpected decrease in generation by making available the surplus of generation in other inter-connected regions.

The interconnection among the European power systems can be considered either a potential source of vulnerability, for example due to cascade effects, or an opportunity to mitigate the impact of climate-related events. Thanks to electricity interconnections, it is possible to use the eventual surplus of low-carbon electricity in a region to satisfy the needs of another region experiencing reduced renewable generation. This must be taken into account when analysing the potential issues caused by a temporary decrease of renewable power generation due to weather. The contribution of interconnections in integrating more renewable generation can be better understood by analysing and anticipating when possible, the co-variability of sun/wind/water in the European regions.

The methodology used in this report could be seen also as a tool to explore the impact of grid expansion projects (e.g. a proposed Project of Common Interest, PCI) or other energy policy considerations under possible climatic conditions (observed and projected). Furthermore, the present analysis and datasets on climate variability could be useful in the assessment of regional electricity crisis scenarios identified according to Regulation (EU) 2019/941 of the European Parliament and of the Council on risk-preparedness in the electricity sector.

Linking the state of European systems with large-scale weather patterns could also lead to a more effective use of seasonal climate forecasts to predict potential adequacy issues in the next months.

This work is a foundation of necessary analyses of the future decarbonised power system under increased climate change realities, which are needed to assess the possible pathways to deliver the European Green Deal.

Box 1. Future work

Future research could focus on the impacts of long-term climate scenarios on future power systems, in order to enhance our understanding of the following issues:

- The cost of extreme weather events in the future energy scenarios and future climate
- The impact of climate change on the availability and temperature of water (both freshwater and seawater) for thermal cooling
- The difference between current and future weather patterns in terms of frequency and intensity
- How to take into account the information about weather patterns to design resilient 100%-renewables energy systems
- Volatility of prices and its impact on markets caused by future climate
- How to estimate the capacity factor of future wind farms (onshore and offshore) in order to address correctly the uncertainty induced by climate change projections
- How to define patterns of electricity demand according to future energy scenarios linked to climatic conditions
- How to model the impact of the projected changes in water resources over Europe to future hydropower generation (particularly including glacier melting)

1 Introduction

The weather affects the energy sector. Wind, solar and hydropower generation, as well as energy demand (e.g. heating and cooling) depend on weather conditions. Energy infrastructures (e.g. transmission lines) are also exposed to extreme events, such as storms and floods, which may cause damage or alter the normal operating conditions. Some notable examples are the 2012 blackouts in India (more than 600 million people affected due to increased irrigation needs and low hydropower generation caused by late arrival of monsoons) or the 2018 heatwave in central Europe which led to lower hydropower generation in north Europe and in the Balkans, and reduced the generation of many nuclear power plants in France, Germany, Switzerland, Finland and Sweden due to cooling water restrictions[5].

High-impact events are relatively common. According to Munich RE, in the period 1980 – 2018 in Europe there were 2 796 relevant weather-related loss events[6], a definition that includes storms, extreme temperatures, forest fires, floods, and droughts.

In order to examine the link between meteorological events and power systems in Europe, we must consider the following two aspects:

1. Power systems are changing worldwide, becoming more interconnected and impacted by the variability of natural resources (water, wind, sun) due to the increasing penetration of renewable energy

2. The climate is changing and an intensification of extreme events might be expected

If climate variability can be considered a critical factor, climate change[7] is of the utmost importance, when it comes to shaping the power systems of the near and distant future. This is also highlighted, especially for hydropower, in the accompanying analysis for the European Commissions' communication "A Clean Planet for All" (European Commission, 2018) that states:

> *Due to climate change alone, and in the absence of adaptation, annual damage to Europe's critical infrastructure could increase ten-fold by the end of the century under business-as-usual scenarios, from the current EUR 3.4 billion to EUR 34 billion. Losses would be highest for the industry, transport, and energy. One of the greatest challenges is how to assess impacts on energy production which may occur as a consequence of the projected increase in the intensity of extreme weather events, as research gaps include economic modelling of extreme events and vulnerabilities of transmission infrastructure.*
>
> *Impacts on renewable energy sources are of specific concern, given their critical contribution to emissions reduction. There is some evidence on impacts on hydropower production due to water scarcity, but also on wind, solar, biomass. As regards hydropower in particular, the main mechanisms through which climate change can affect hydropower production are changes in river flow, evaporation, and dam safety.*

The high level of relevance of an analysis on the link between energy and meteorology is not only due to climate change, whose effect is year by year more evident, but also due to the ambitious plan of the European Union to reduce drastically the emissions of electricity generation across the EU. The European Commission is setting as priority the European Green Deal that aims to make Europe the first carbon-neutral continent by 2050. Accordingly, it is not a surprise that the first letter from the President of the European Commission sent to the Commissioner for Energy[8] states:

> *To speed up the deployment of clean energy across the economy, you should promote a power system largely based on renewables, with increased interconnectivity and improved energy storage.*

Renewable generation plays a key role in a low-carbon power system but, at the same time, a system based on renewables is a system strongly affected by the variability of climate. As the share of renewables in the generation portfolio increases, the uncertainty of their generation becomes more relevant for the system

[5] A more detailed description of this heatwave can be found in (Magagna et al., 2019). A visual summary is available at the following URL: https://www.plattsinsight.com/insight/commodity/cross-commodity/key-commodity-impacts-of-europes-heat-wave/

[6] Data from the Munich RE NatCatSERVICE: https://natcatservice.munichre.com/

[7] A clear description of the difference between the terms "climate variability" and "climate change" is available in the website of the World Meteorological Organisation (WMO) at the following address: http://www.wmo.int/pages/prog/wcp/ccl/faqs.php

[8] https://ec.europa.eu/commission/sites/beta-political/files/mission-letter-kadri-simson_en.pdf

adequacy. To mitigate the impact of climate variability, it is important to have enough flexibility in the system, in order to accommodate the changes in the generation that often are fast and unpredictable.

What is the definition of flexibility? A power system works properly when there is at any moment a balance between the demand of electricity and its supply from various sources. Nevertheless, both sides can be unpredictable to some extent: for example, there can be anomalous peaks of power demand (for example due to extreme temperatures) or there could be fluctuations in the generation from solar and wind power. The flexibility is the capacity of a power system to cope with unpredictability in order to maintain the supply-demand balance. This flexibility is provided in multiple ways:

1. Modulating the generation, often with generation units that have very fast start-up times and high ramp rates
2. Storing the energy in order to "fill the gaps" and not wasting the excess of electricity
3. Importing or exporting electricity with inter-connections
4. Adapting the demand (for example, through demand response)
5. Forcing a reduction of the load (load shedding) or of the renewable generation (curtailment)

Obviously, the last option is undesired and is generally avoided for its cost for users and electricity providers.

This report analyses the impact of climate variability on the European power systems as of 2016, simulating their behaviour under the climatic conditions observed during the last three decades. Compared to the available scientific literature, the novelty of this study is twofold: a) it simulates 34 power systems under 26 different climatic conditions; b) It includes the impact of variability on wind, solar and hydropower as well as electricity demand.

1.1 Goal and scope of this study

The goal of this report is to shed light on and analyse the flexibility of European power systems to adjust their operational patterns to the long-term variation of climatic conditions. As the power systems are interconnected, this study goes beyond the EU. The report focuses on 34 European countries that jointly constitute the interconnected European electricity systems (with the exception of Malta and Cyprus).

The analysis is carried out by using a power system model representing the current (as of 2016) power systems (see Section 1.2). The model is able to simulate the behaviour of the European power system considering different climate conditions.

Although all results are generated at country level, for the sake of clarity we grouped the countries according to the classification described in Table 1. The classification used is the same applied in the gas and electricity market quarterly reports[9] of the European Commission.

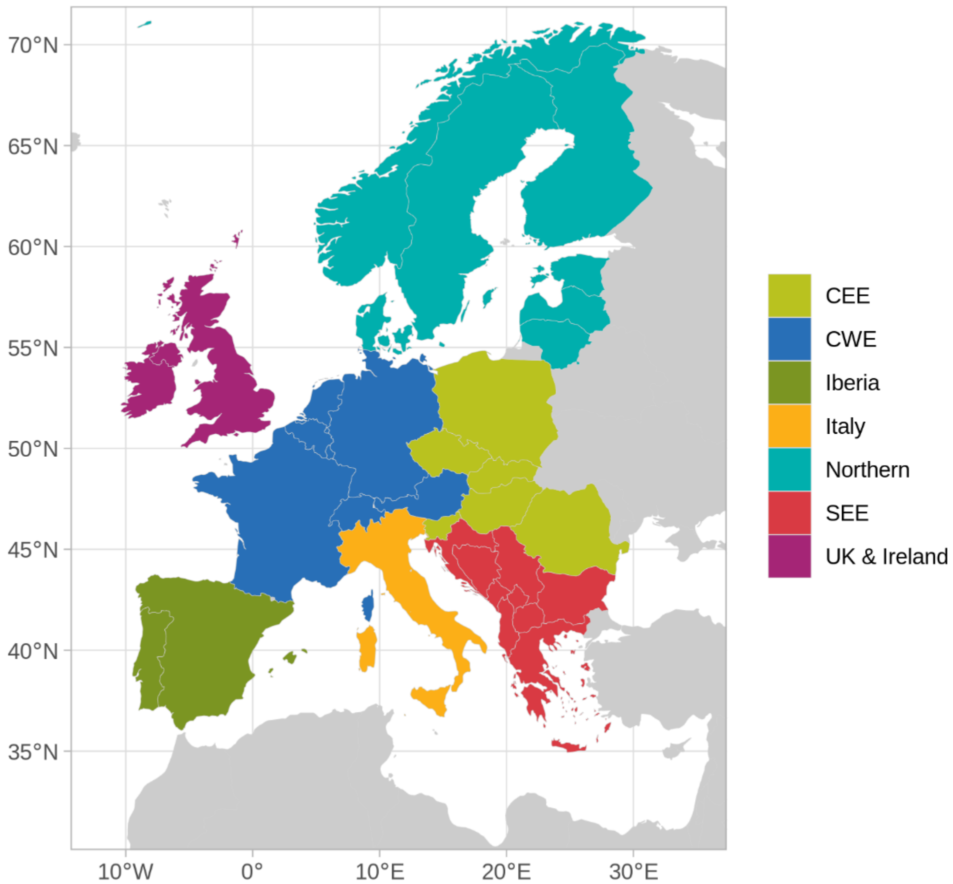
[9] Available here https://ec.europa.eu/energy/en/data-analysis/market-analysis

Table 1: List of the countries analysed and the grouping used in this study

Group name	Countries and country codes[10]
Central Eastern Europe (CEE)	Czechia (CZ), Hungary (HU), Poland (PL), Romania (RO), Slovakia (SK), Slovenia (SI)
Central Western Europe (CWE)	Austria (AT), Belgium (BE), France (FR), Germany (DE), Luxembourg (LU), Netherlands (NL), Switzerland (CH)
Iberian Peninsula	Portugal (PT), Spain (ES)
Italy	Italy (IT)
Northern	Denmark (DK), Estonia (EE), Finland (FI), Latvia (LV), Lithuania (LT), Norway (NO), Sweden (SE)
South Eastern Europe (SEE)	Albania (AL), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), Greece (EL), Kosovo[11] (XK), Montenegro (ME), North Macedonia (MK), Serbia (RS)
UK & Ireland	Ireland (IE), United Kingdom (UK)

The geographical scope of this study as well as the classification used can be seen also in Figure 2.

Figure 2. The countries modelled and analysed in this study and the classification used to group them.



[10] ISO 3166-1 alpha-2

[11] This designation is without prejudice to positions on status, and is in line with UNSCR 1244/1999 and the ICJ Opinion on the Kosovo declaration of independence.

1.2 Our methodology

This work estimates the impact of climate variability on current (as of 2016) European power systems using the Dispa-SET power system model (see Box).

Dispa-SET simulates the behaviour of the current European power systems (briefly described in Section 3.1) with the climate observed in the period 1990-2015 (the longest period available for the input data). For each year in this period, defined "climate year", we build data sets of all the inputs of the power system model that are climate dependant, namely:

1. Wind power (onshore and offshore) capacity factor
2. Solar photovoltaic power capacity factor
3. Hydropower inflow (i.e. the quantity of water that is available for conversion into energy)
4. Electricity demand

Then we simulate, for each climate year, all the European power systems in order to analyse the distribution of the relevant metrics and variables. The model we use is able to simulate many aspects of power systems, producing many variables as output. The variables we use in this report are:

1. Levels of the reservoirs (%)
2. Shed load (MWh)
3. Generated power per fuel/technology (MWh)
4. Commitment of a generating unit (yes/no)
5. Shadow price (EUR/MWh)
6. System cost (EUR)
7. Exchanged electricity on a transmission line (MWh)
8. Lost load (MWh)

The model is described in the Annex 1 while the input we have used and their data source is described in the Annex 2. In the Annex 3 we propose a brief validation of the model accuracy with respect to the data from ENTSO-E (European Network of Transmission System Operators for Electricity).

Box 2. Why using Dispa-SET

Dispa-SET is a unit commitment and optimal dispatch model mainly developed within the Joint Research Centre of the EU Commission, in close collaboration with the University of Liège and the KU Leuven (Belgium) (Hidalgo González, Sylvain, and Zucker, 2014; Kavvadias et al., 2018).

The model has been used for many studies (Fernández-Blanco Carramolino, Kavvadias, and Hidalgo González, 2017; Fernández-Blanco Carramolino et al., 2016; De Felice et al., 2018; Pavičević et al., 2019; Beltramo et al., 2017; Quoilin et al., 2015).

Dispa-SET is able to answer two main questions:

1) What is the optimal mix of hydropower and thermal generation during a long period of time (e.g. one year)?

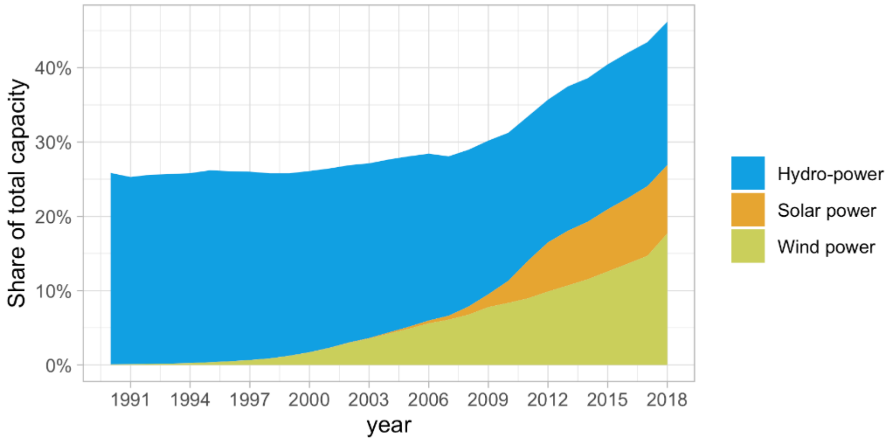
2) How is the power demand allocated each hour during the simulation period to the different power plants in a way that minimises the overall cost of the system and is technically feasible?

The software is available with open source license on the website http://www.dispaset.eu

2 Analysis of climate variability

As mentioned in the introduction, meteorological events have always had an impact on power systems, mainly due to extreme events causing damages and disruptions. When hydropower generation became widespread, new factors, such as precipitation patterns, river flows and snow melting started also to play an important role in influencing power systems.

Figure 3. Fraction of the hydro, solar and wind power capacities with respect to the total electricity generation capacities for the European countries.



Source: EUROSTAT “Electricity production capacities by main fuel groups and operator” (nrg_inf_epc)

In the last 20 years, wind and, more recently, solar power increased their share as shown in Figure 3. Wind and solar power, given the very stochastic nature of their drivers (principally wind and solar radiation), increase dramatically the relationship between weather conditions and power systems, introducing high frequency (from minutes to hours) unpredictable changes in the supply side.

Thus, taking into account wind, solar and hydropower, today more than 40% of the European electricity generation is affected by climatic factors. According to future scenarios, this share will increase with the expected uptake of wind and solar generation in the next decades (this is discussed in Section 4.1).

Also, the demand-side is influenced by climate, in particular by air temperature. Due to the use of electric heating and cooling devices, the electricity demand in many European countries can be very sensitive to the variation of air temperature (for example see (Moral-Carcedo and Vicéns-Otero, 2005; Hekkenberg et al., 2009) for two studies on European countries on the link between meteorology and electricity demand). Not differently from the supply side, in the future an increase of this relationship due to a growth of the electrification of the heating and cooling sector is expected (see (Kavvadias, Jimenez Navarro, and Thomassen, 2019).

In the rest of this section, an analysis on the climate-driven variability of renewable energy sources and electricity demand is presented.

Box 3. The data used in this report

The model used in this report is based on the work described in (Kanellopoulos et al., 2019). For the Balkans power systems we refer to (Pavičević et al., 2019; Stunjek and Krajacic, 2020)

The datasets we analyse in this section and that are used to simulate the impact of the climate variability in the power systems are the following:

— EMHIRES dataset for the onshore/offshore wind and solar power capacity factors

— A dataset of hourly electricity demand corrected with the temperature data in the period 1986-2015

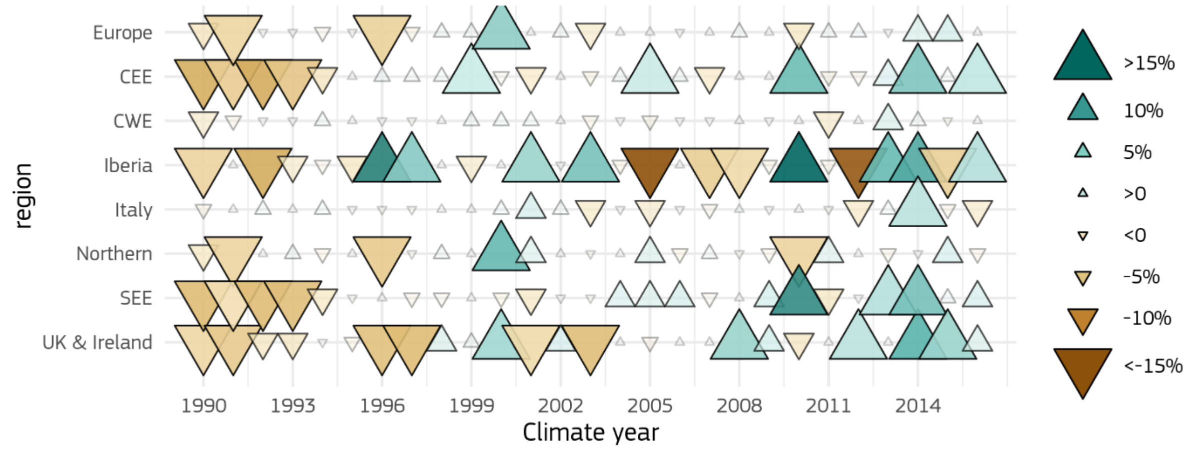
— A new dataset of hydropower inflows based on the runoff calculated by the JRC LISFLOOD model

Further details and references can be found in the Annex 2.

2.1 Water

The availability of water resources used for hydropower generation (i.e. inflow) also shows a strong inter-annual variability, as shown in Figure 4. In addition, considering the speed of the physical processes affecting the water resources, the deviations during the year from the average are more persistent than in the case of wind or solar (see Box 4. for further details).

Figure 4. Annual variability (percentage deviation from the average) of daily inflow in the 26 climate years for the considered regions.



The availability of water to generate electricity is not evenly distributed during the year but it follows a specific pattern for each region. Table 2 shows how the inflow for each region is distributed across the seasons and the minimum/maximum share for each season in the 26 climate years. For some regions, the range of the available water (and then energy) is particularly wide, as for example for Iberia in winter where the share goes from 21% (in 1993) to 50% (in 1995).

Table 2. Seasonal share of inflow with respect to the annual sum computed.

Region	Winter (MIN/**AVG**/MAX)	Spring (MIN/**AVG**/MAX)	Summer (MIN/**AVG**/MAX)	Autumn (MIN/**AVG**/MAX)
Europe	16% / **22%** / 27%	21% / **25%** / 29%	21% / **29%** / 36%	18% / **24%** / 28%
CEE	20% / **23%** / 27%	24% / **29%** / 34%	19% / **25%** / 30%	17% / **23%** / 29%
CWE	17% / **19%** / 22%	23% / **27%** / 31%	27% / **32%** / 37%	17% / **22%** / 24%
Iberia	21% / **37%** / 50%	15% / **32%** / 46%	8% / **11%** / 17%	9% / **19%** / 34%
Italy	16% / **19%** / 22%	23% / **26%** / 31%	27% / **31%** / 38%	18% / **23%** / 28%
Northern	6% / **12%** / 16%	20% / **27%** / 35%	28% / **39%** / 49%	15% / **22%** / 28%
SEE	22% / **26%** / 29%	24% / **30%** / 37%	19% / **22%** / 25%	18% / **22%** / 29%
UK & Ireland	30% / **39%** / 48%	16% / **22%** / 29%	7% / **12%** / 21%	15% / **26%** / 36%

In bold there is the average share and on the left/right-side there are the minimum/maximum computed on all the climate years

Box 4. Persistence and autocorrelation

We use the term “persistence” to define the tendency of a state (e.g. low wind) to last for more than one day. In general, the persistence can be measured with the autocorrelation, basically the correlation of a time-series with its delayed version.

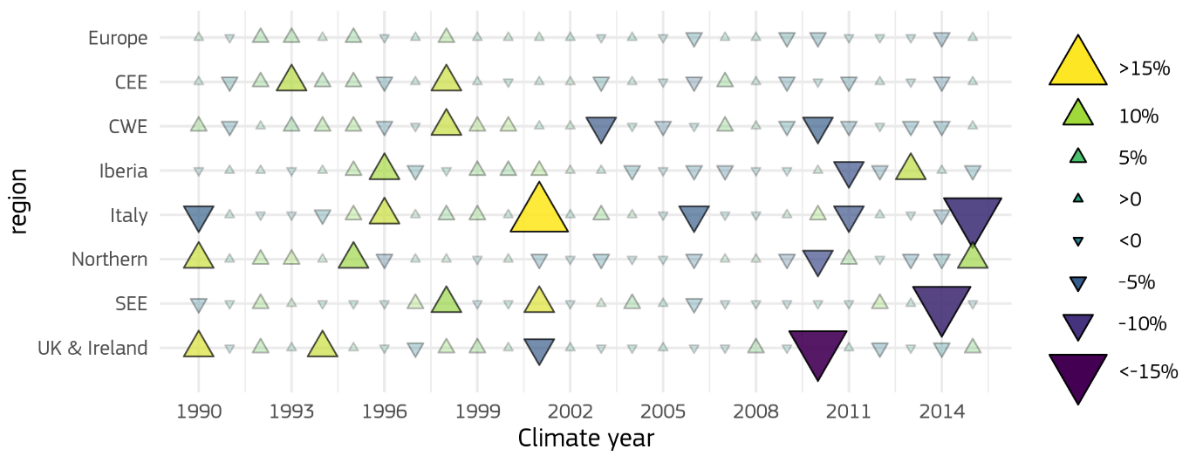
In the case of water inflow, the time-series of the daily deviations from the daily average (i.e. the difference between the value in one specific day and its average across all the available years) shows a high autocorrelation: in average 0.94 with the lag of one day, 0.65 with one week and 0.3 with one month. In the case of the wind resources (analysed in Section 2.2), the autocorrelation is 0.58 with one day, 0.06 in one week and basically zero after one month. The values for solar capacity factors are very similar to the wind case.

This high persistence (implied by the high auto-correlation) can explain the high values shown in Figure 4. Another explanation is a phenomenon called long-term persistence discussed in (Iliopoulou and Koutsoyiannis, 2019). According to this, a dry year is more probable to happen after a dry year, and a wet year is more probable to happen after a wet year. This implies that weather related effects usually persist and do not always average out within a few years.

2.2 Wind

Among the renewable energy sources, wind is definitely the resource with the highest high-frequency fluctuations and variability. Figure 5 shows the deviation of the annual average wind profile (see Annex 2) with respect to the average of the entire period.

Figure 5. Annual variability (percentage deviation from the average) of onshore wind resources in the 26 climate years for the considered regions.



The figure illustrates how the availability of onshore wind varies year by year in the different regions. Although the cases with a large variation (+/- 15%) are few, at a seasonal scale the variability of wind is larger than in the annual average. Table 3 shows the average capacity factors by region for all the years and for each season. The table also indicates the standard deviation of the capacity factor across all the climate years. The peak of generation happens during winter, with UK & Ireland and Iberia the regions with the highest capacity factors.

Table 3. Annual and seasonal average of capacity factors (CF) of onshore wind with the standard deviation for all the climate years.

Region	Annual average CF (st. dev.)	Winter	Spring	Summer	Autumn
Europe	21.7% (+/- 0.9%)	29.6% (2%)	21.4% (1.7%)	14.0% (1.1%)	21.9% (1.5%)
CEE	19.6% (+/- 1.2%)	27.5% (3%)	19.6% (2%)	11.8% (1.4%)	19.6% (2.1%)
CWE	21.8% (+/- 1.5%)	31.2% (4.3%)	20.8% (2.4%)	13.3% (1.6%)	22.2% (2.8%)
Iberia	25.5% (+/- 1.6%)	31.7% (4.9%)	27% (3%)	18.5% (1.6%)	24.9% (2.5%)
Italy	16.9% (+/- 1.4%)	24.1% (5%)	17.8% (2.3%)	9.4 (1.5%)	16.5% (2.9%)
Northern	21.1% (+/- 1.5%)	29.8% (4%)	19.4% (2.8%)	12.9% (1.6%)	22.6% (1.9%)
SEE	17.7% (+/- 1.2%)	24% (2.6%)	17.2% (2.3%)	13.2% (1.7%)	16.5% (1.6%)
UK & Ireland	29.1% (+/-2.2%)	39.1% (5.8%)	27.9% (4.3%)	18.9 (2.3%)	30.7% (3.5%)

Offshore wind shows a similar situation, although with much higher capacity factors. According to Wind Europe (Wind Europe, 2018), the annual capacity factors of the offshore wind farms in Europe is between 29% and 42%, range that is consistent with the figures in Table 4.

Table 4. Annual and seasonal average of capacity factors of offshore wind with the standard deviation for all the climate years

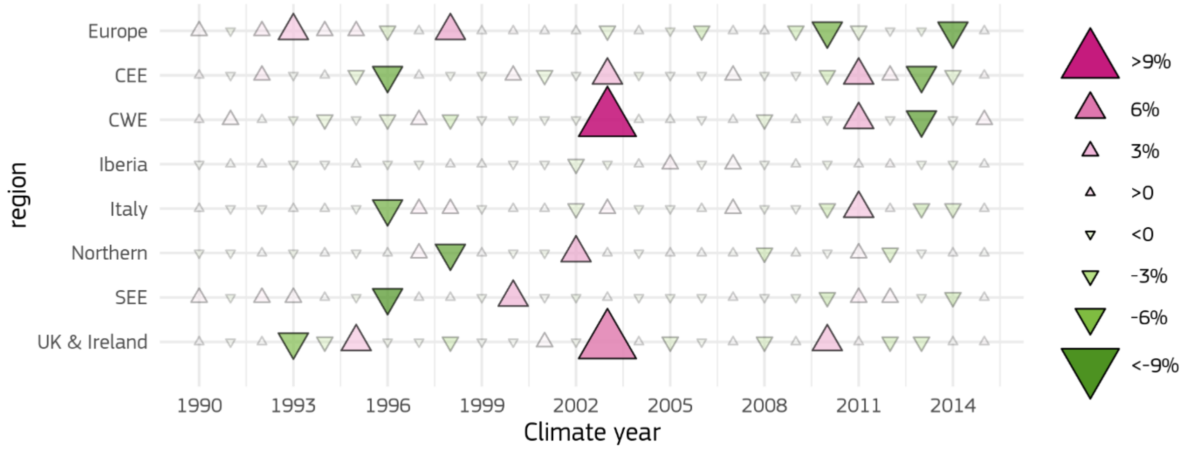
Region	Annual average CF (st. dev)	Winter	Spring	Summer	Autumn
Europe	34.6% (+/-1.9%)	44.3% (5.3%)	32% (3.2%)	24.7% (4.4%)	37.9% (3.4%)
CWE	37.5% (+/-2.2%)	48.3% (5.9%)	34.6 (3.4%)	26.4 (3.4%)	40.7 (3.9%)
Northern	40% (+/-2.2%)	49.6% (5.8%)	36.7% (3.2%)	29.8% (4.4%)	44.1% (3.4%)
UK & Ireland	26.5% (+/- 1.7)	34.8% (4.8%)	24.9% (3.2%)	17.7% (2.4%)	28.8% (2.9%)

In general, looking at seasonal level, a larger variability than in the annual value is observed and, in all the regions, winter is at the same time the season with the largest availability of wind and with the biggest inter-annual fluctuations.

2.3 Solar power

Solar radiation shows a strong seasonality according to the period of the year and the latitude. However, the annual availability of sun, measured with the average annual capacity factor (see Annex 2), can vary year by year, as shown in Figure 6.

Figure 6. Annual variability (percentage deviation from the average) of solar resources in the 26 climate years for the considered regions.



It is evident how, compared to the variability shown in Figure 5 (which uses a different range in the visualisation), the inter-annual variability of the solar resources is much lower than wind. It is worth noting that the two cases with the highest variability happen both with the climate year 2003, the year where a heat wave led to the hottest summer recorded in centuries (Stott, Stone, and Allen, 2004). Table 5 summarises the average capacity factors for each season and their standard deviation. Not surprisingly, summer is the season with the highest capacity factors and with the smallest fluctuations.

Table 5. Annual and seasonal average of capacity factors of PV solar power with the standard deviation for all the climate years

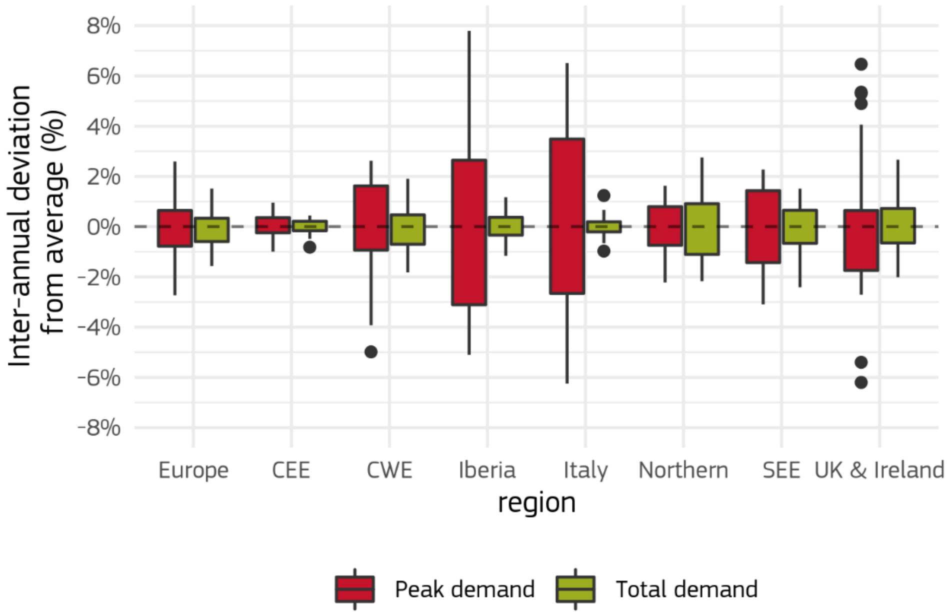
Region	Annual Average CF (st. dev.)	Winter	Spring	Summer	Autumn
Europe	12.8% (+/-0.3%)	7.2% (0.5%)	15.1% (0.7%)	18.0% (0.3%)	10.6% (0.4%)
CEE	12.4% (+/-0.5%)	6.2% (0.6%)	15.1% (1.1%)	17.9% (0.6%)	10.3% (0.9%)
CWE	11.7% (+/-0.5%)	5.8% (0.5%)	14.4% (1.2%)	16.8% (0.7%)	9.6% (0.8%)
Iberia	19.1% (+/-0.4%)	14.2% (1.2%)	20.8% (0.8%)	24.0% (0.4%)	17.2% (0.8%)
Italy	13.9% (+/-0.5%)	9.0% (0.8%)	15.5% (1.0%)	19.1% (0.6%)	12.0% (0.8%)
Northern	8.2% (+/-0.3%)	2.1% (0.2%)	11.4% (0.6%)	14.0% (0.9%)	5.2% (0.4%)
SEE	15.2% (+/-0.6%)	9.2% (1.1%)	16.9% (0.9%)	21.0% (0.7%)	13.5% (0.9%)
UK & Ireland	9.0% (+/-0.4%)	3.8% (0.4%)	11.7% (0.9%)	13.5% (0.8%)	6.9% (0.3%)

2.4 Electricity demand

As mentioned before, electricity demand can be influenced by air temperature. In this work, the electricity demand data are generated correcting the electricity demand of a single year with the air temperature for the period 1986-2015. This means that the variability of the electricity demand that we analyse in this section is caused only by the variability of temperature and not by other factors (e.g. economic growth, demography, etc.).

The year-on-year variability of electricity demand is shown in Figure 7 considering both the total annual demand and the peak hourly load. Three regions show a deviation range (i.e. the difference between maximum and minimum deviation) larger than 10 percentage points: UK & Ireland (14.4 percentage points), Iberia (12.9 percentage points) and Italy (12.7 percentage points). On the other side, CEE exhibits a very low variability for both the total (1.2 percentage points) and peak demand (1.9 percentage points). The variability of the different regions can be explained by the use of electricity for heating and cooling (e.g. heat pumps, air conditioners), which is very sensitive to air temperature. Further analysis and statistics about heating and cooling in Europe can be found in (Connolly, 2017; Kavvadias, Jimenez Navarro, and Thomassen, 2019).

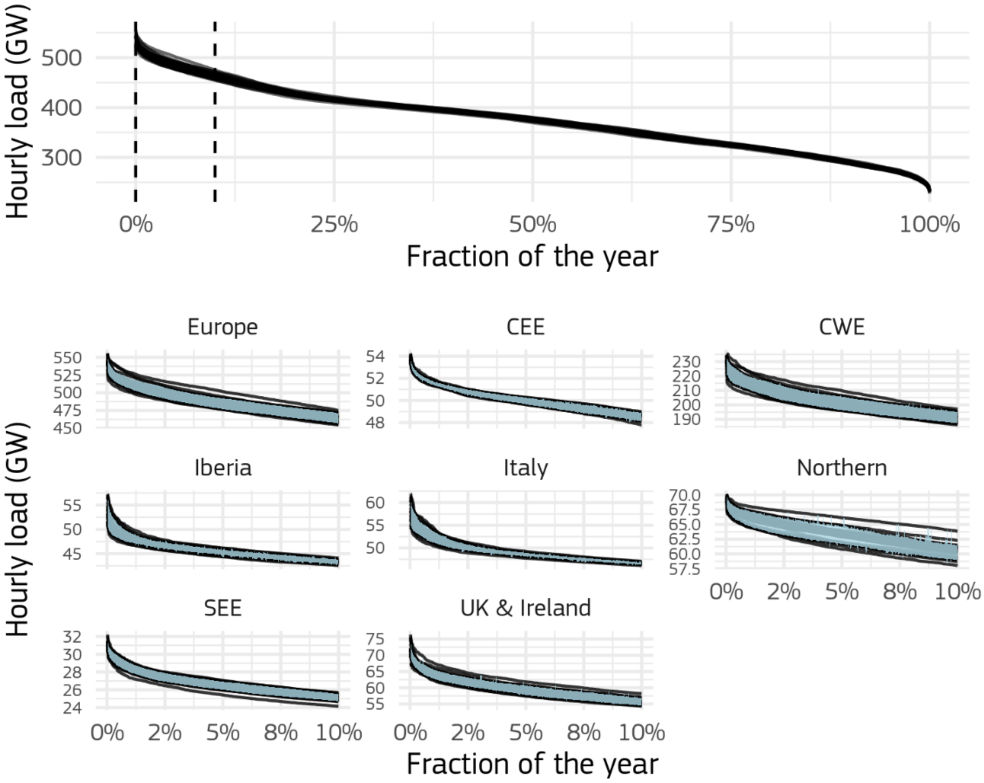
Figure 7. Box-whisker plot of annual percentage deviation of total energy demand and peak demand for the regions on the 26 climate years.



The lower and upper hinges correspond to the 25th and 75th percentiles and the whiskers extend no further than 1.5 times the interquartile range, data samples beyond this range are shown as points.

An effective way to illustrate the variation of load during the year is the load duration curve, which is used in Figure 8 to show the hourly load for Europe and all the regions for all the considered climatic years. Given that the peak load is the most critical aspect of demand, the figure is focused on the first 10% of the curve, in order to show how this can vary on annual basis.

Figure 8. Load duration curves for Europe (top panel) and for all the regions (bottom panel) for the 26 climate years.



In the bottom, it is shown the duration curve only for the range 0-10% (highlighted in the top panel with the two dashed lines) for all the regions including Europe. The light blue represents the range between the 10th and the 90th percentile.

Another climate variability impact can be observed by examining the hourly gradient of the residual demand (i.e. electricity demand minus wind and solar power). Table 6 shows statistics about the gradients of the countries with the highest electricity demand.

Table 6. Statistics about residual demand gradients (in GW/hour) in the ten countries with the highest peak load computed on all the 26 climate years

Country	Average up-gradient	Average down-gradient	99.9th perc. up-gradient	99.9th perc. down-gradient	Peak load (GW)
France (FR)	2.28 - 2.50	1.82 – 1.95	8.35 - 9.27	5.98 - 6.40	96.1
Germany (DE)	2.76 - 3.15	2.22 - 2.46	10.23 - 11.66	7.16 - 9.81	82.7
United Kingdom (UK)	2.23 - 2.30	1.70 - 1.75	8.88 - 9.25	5.84 - 6.15	67.0
Italy (IT)	2.11 - 2.28	1.82 - 1.90	7.37 - 7.77	4.78 - 6.20	58.1
Spain (ES)	1.31 - 1.46	1.11 - 1.19	5.41 - 6.08	3.99 - 4.54	44.4
Sweden (SE)	0.48 - 0.51	0.36 - 0.38	2.25 - 2.40	1.32 - 1.50	24.9
Poland (PL)	0.63 - 0.66	0.53 - 0.56	2.72 - 2.86	1.77 - 1.93	23.2
Norway (NO)	0.39 - 0.41	0.25 - 0.29	1.86 - 1.95	1.09 - 1.55	22.8
Netherlands (NL)	0.49 - 0.50	0.38 - 0.40	2.26 - 2.33	1.20 - 1.44	18.3
Belgium (BE)	0.33 - 0.35	0.29 - 0.31	1.29 - 1.52	0.88 - 1.08	13.9

3 Impact of climate variability on the European power systems

The role of meteorological variables in the European power systems is widely studied and it can be very different due to geographical reasons, availability of renewable resources, characteristics of the power generation, etc.

In the recent years, the European power systems have experienced many events that can be defined as extreme in terms of their impact on adequacy and energy prices. Although these extreme events can be very diverse, as described in the Section 3.2 of (Magagna et al., 2019), many of the most disrupting events (e.g. shut down of nuclear power plants) are connected to the availability of water and its temperature for cooling purposes.

Even if we cannot link all the extreme events to climate change (an activity called "attribution", see (Stott et al., 2016) for a description) it is possible to associate them to "climate variability", in other words the variation of climatic variables (e.g. temperature, wind speed, etc.) over a given period of time.

In this section, we will show how the European power systems, as of 2016, react to a wide range of climatic conditions presenting the results of a set of power system simulations (the methodology we use is described in Section 1.2).

The simulations, driven by 26 different climate years, produce as output hourly variables describing different aspects of the power systems (commitment of units, cost of dispatching, level of storages, etc.).

Thus, the results show how the conditions for wind, solar, demand and water resources we observed in the past would affect current European power systems. In particular, we will analyse:

- Generation mix
- CO_2 emissions and fuel costs
- Use of fresh water for thermal cooling
- Storage levels
- Cross-border electricity exchanges
- Curtailment and load shedding

At the end of this section, we will also describe a set of four case studies country-specific, to investigate more in-depth the influence of climate variability on power systems.

3.1 The European power systems

This study simulates the European power systems as of 2016 under different climate conditions. The total generating capacity of the European power systems considered in this study is 975 GW (details on our approach can be found Section 1.2). This work is based on the capacities of the 2016 power systems, which are been used to develop the model described in (Kanellopoulos et al., 2019) and that has been used as starting point for our implementation. Currently, the latest figures published in the ENTSO-E Statistical Factsheet[12], which cover all the countries scope of this study, are for 2018. Compared to 2016 we can see an increase in the net generating capacity of 15 GW, about the 1.5% of the total. Although the European power systems are changing steadily, we are confident that the results presented on this report can be generalised also to the more recent years.

Although we model explicitly all technologies this study reports power generation in seven categories mainly driven by their fuel input: fossil fuels (including natural gas, hard coal, lignite and oil), hydropower, nuclear power, solar power, wind power, biomass and another category named 'Other' (including geothermal and waste).

The largest share of the installed power generation capacity in the considered geographical scope corresponds to thermal power plants powered with fossil fuels (370 GW). This total capacity breaks down into natural gas (200 GW), hard coal (96 GW), lignite (61 GW) and oil (12 GW). The second fuel type in terms of

[12] ENTSO-E is the European Network of Transmission System Operators for Electricity, representing more than 40 transmission system operators in 36 countries. The statistical factsheets are available at the following URL: https://www.entsoe.eu/publications/statistics-and-data/#statistical-factsheet

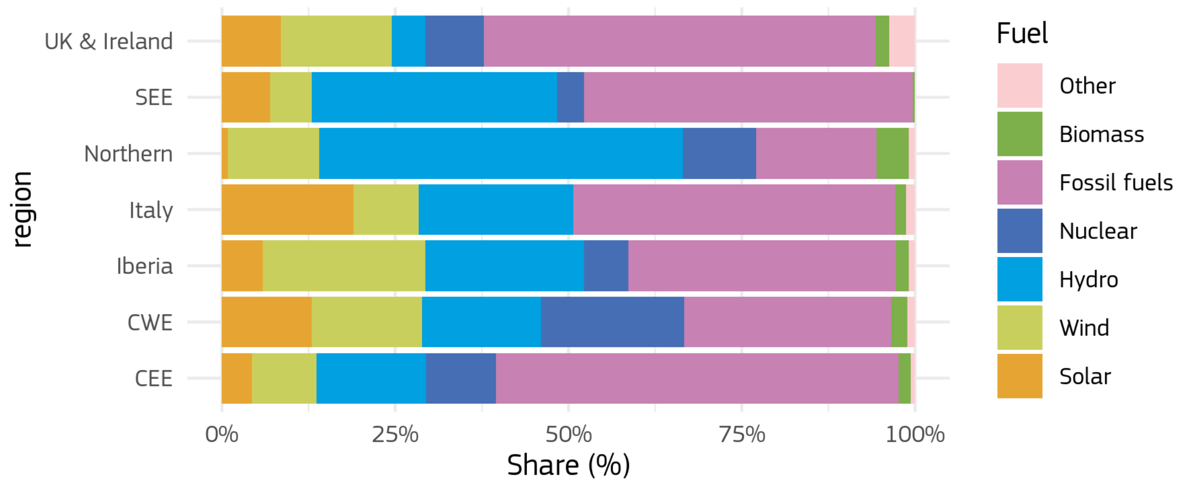
capacity is hydropower with 211 GW, followed by wind power (144 GW of which 133 onshore) and nuclear (121 GW).

Figure 9 summarises the share of generation capacity for each of the seven regions analysed in this report, while the absolute values are in Table 7. CWE is the region which includes countries with a total of 200 million population and thus with the highest installed capacity. The region with the highest share of wind power is Iberia with 24% (27.8 GW) and for solar is Italy with 18.9% (18.9 GW). Regarding hydropower, the highest share appears in the Northern region - 52% (55.5 GW).

Table 7. Installed capacity (in GW) by generation type

region	Total	Nuclear	Fossil fuels	Hydro	Wind	Solar	Biomass	Other
CEE	96.8	9.77	56.19	15.3	9.04	4.18	1.71	0.61
CWE	397	81.9	118.84	68.05	63.3	51.58	9.12	4.57
Iberia	118	7.57	45.68	27.02	27.82	6.93	2.15	1.08
Italy	99.9	0	46.34	22.3	9.42	18.92	1.61	1.29
Northern	106	11.2	18.37	55.55	13.95	0.92	4.83	1.02
SEE	51	2	24.17	18.03	3.1	3.53	0.14	0.04
UK & Ireland	106	8.98	60.16	5.11	16.99	9.06	2.04	3.97

Figure 9. Share of capacity by power generation type in the analysed regions



Hydropower currently accounts for the highest share among renewable energy sources in Europe. This study distinguishes three typologies of hydropower:

1. Reservoir based hydropower (without pumping): 101 GW installed (48.1% of the total hydropower)
2. Pumping hydropower: 53 GW (25.1%)
3. Run-of-river: 57 GW (26.8%)

The first two types are very important because they provide flexibility and storage capacity[13]. Currently, virtually all the utility-scale energy storage capacity in Europe is coming from pumping hydropower. While the

[13] Our model assumes that run-of-river plants do not have any storage capacity although in reality a run-of-river plant can have the possibility to store electricity for hours up to a week (in this case is commonly referred to as pondage). Unfortunately, given the widespread lack of information about the storage size of run-of-river plants, we could not include any run-of-river storage in our

reservoir hydropower plant allows the delay of the use of the water to generate electricity later (from hours to months), pumping hydropower gives the possibility to store the surplus of electricity (generally during low-demand periods) storing it in a reservoir in the form of water. A study presenting the flexibility provided by hydropower and its support to the integration of variable generation sources can be found in (Huertas-Hernando et al., 2017).

The storage capacity of the reservoirs and pumping power plants in Europe is summarised in Figure 10 and Figure 11 respectively.

Figure 10. Maximum capacity (in TWh) of reservoir hydropower

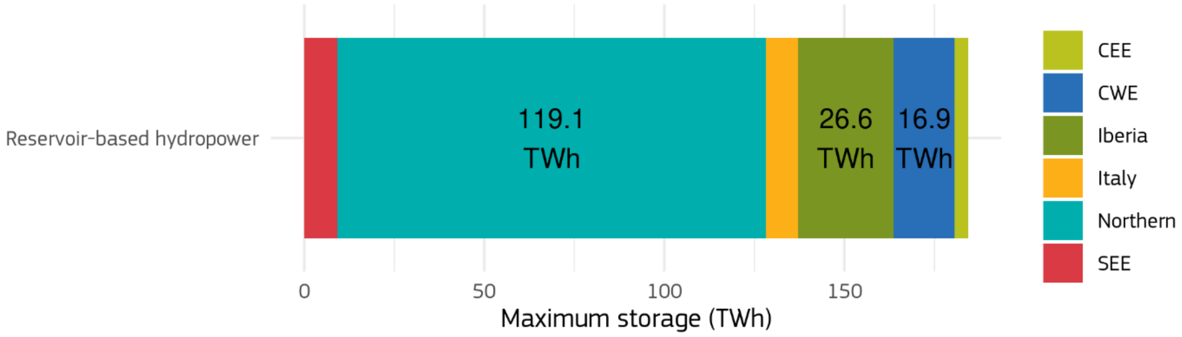
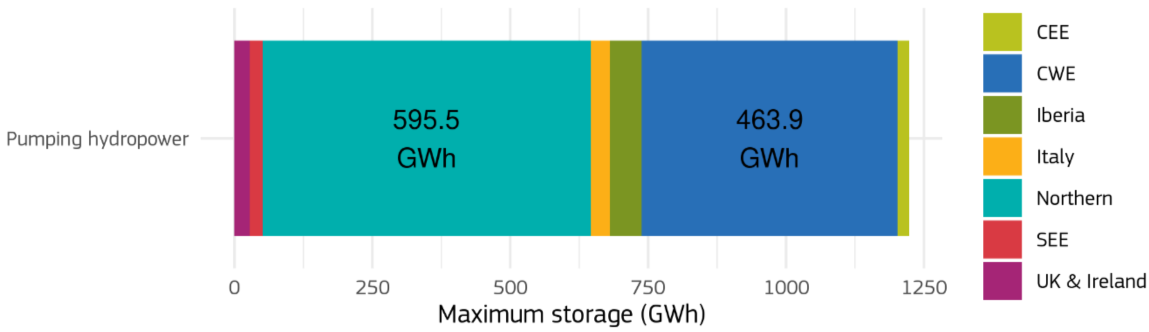


Figure 11. Maximum amount of storable electricity (in GWh) from pumping hydropower plants

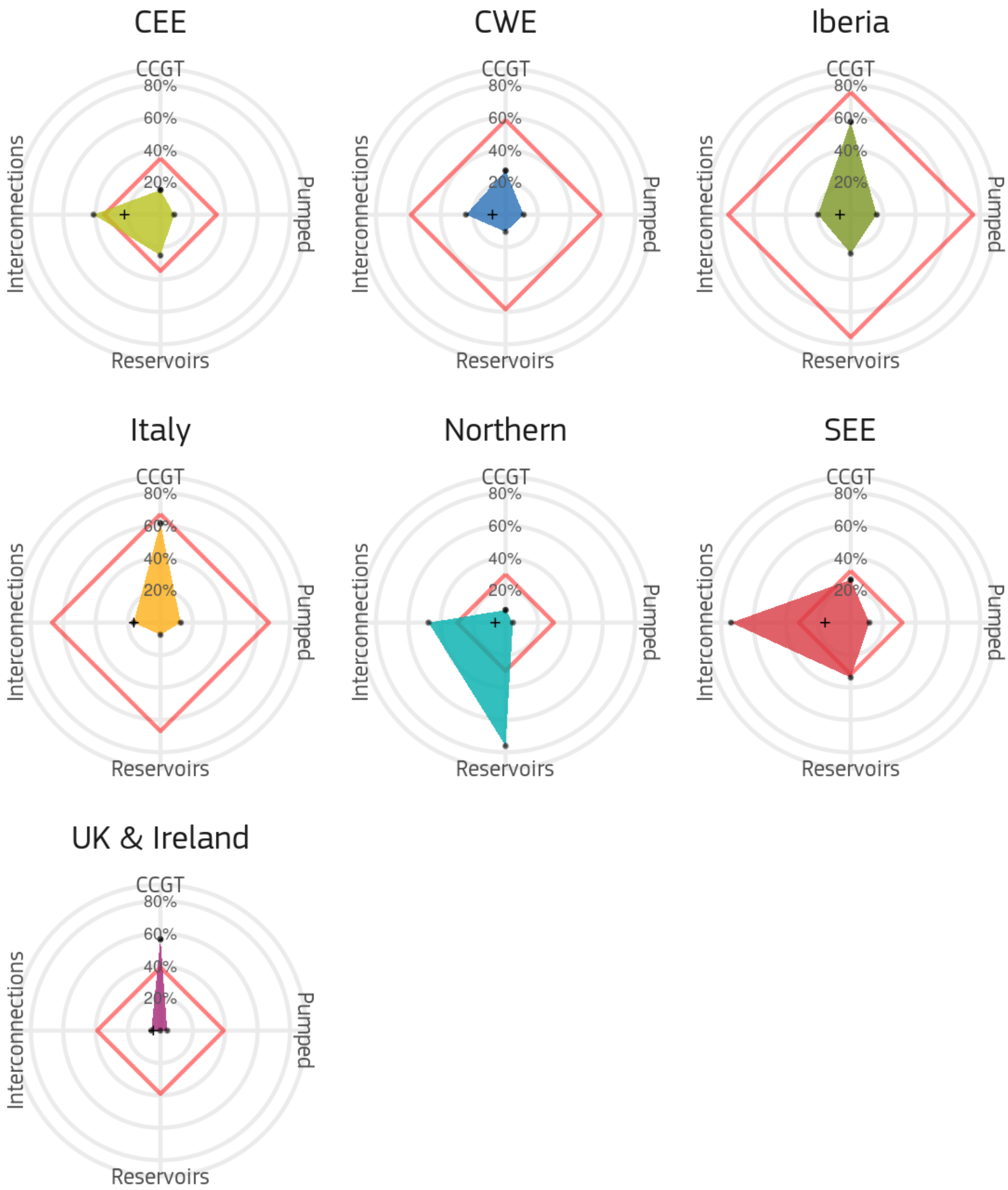


A concise and effective way to illustrate the technologies providing flexibility to the power systems is the flexibility chart shown in Figure 12. This chart categorises four types of flexible resources: combined-cycle gas turbines, electricity interconnections, pumping storage and hydropower reservoirs. Each category is then shown considering the share of its capacity in the region with respect to the peak load. Those are presented together with the penetration rate of wind and solar expressed as ratio of peak load.

As explained in (Yasuda et al., 2013), this chart can show the various sources of flexibility in different regions, also indicating the share of variable generation (namely wind and solar) that must be integrated in the system. At first glance, we can see that the Northern region could get most of its flexibility from water reservoirs and that the most geographically isolated regions (insular or peninsular) rely more on combined-cycle gas turbines.

simulations. For similar reasons, we assume all the pumping hydropower plants as pure (open-loop) plants, thus without natural inflow.

Figure 12. Flexibility charts for the seven regions.



The four vertices of the polygon represent the share of combined-cycle gas turbines (CCGT), reservoir, and pumped capacities compared to the peak load. The red diamond is instead showing the share of renewable generation capacity compared to the peak load. The small cross for the interconnections shows the share without the interconnection among the countries included in the region.

3.2 Generation mix

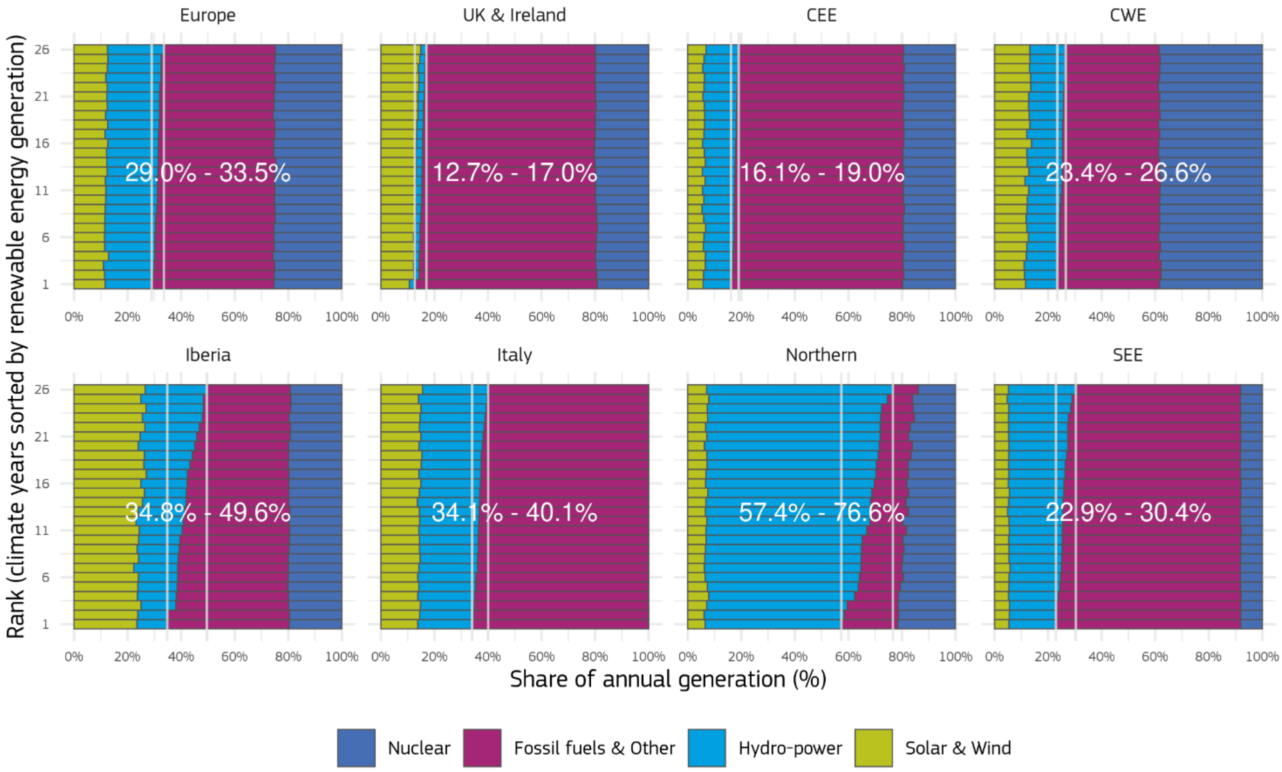
Given that power systems must guarantee at any time the balance between demand of electricity and its supply, any change of the availability of renewable resources leads, at continental level, to a change in the generation from the other sources.

The simulation results show that in Europe the share of renewable energies (wind, solar and hydropower) varies from 29% to 33.5%. In terms of generated electricity, this range translates into 979 – 1 116 TWh, with the minimum and the maximum respectively for the climate years 1991 and 2000. To put this range into perspective, it is in a similar order of magnitude as the electricity consumed in the Netherlands in 2018.

The average amount of electricity generated in one year with renewable sources is 1 047 TWh, and then the deviation range is between 94 and 107%.

Figure 13 displays the energy mix for all the 26 climate years showing clearly the climate-derived variation in renewable generation for all the regions. Among all regions, the Northern area is the one showing the widest range: from 57.4% to 76.6% (from 246 TWh to 336 TWh, respectively in the climate years 1996 and 2000).

Figure 13. Generation mix and share of renewables for the considered climate years.

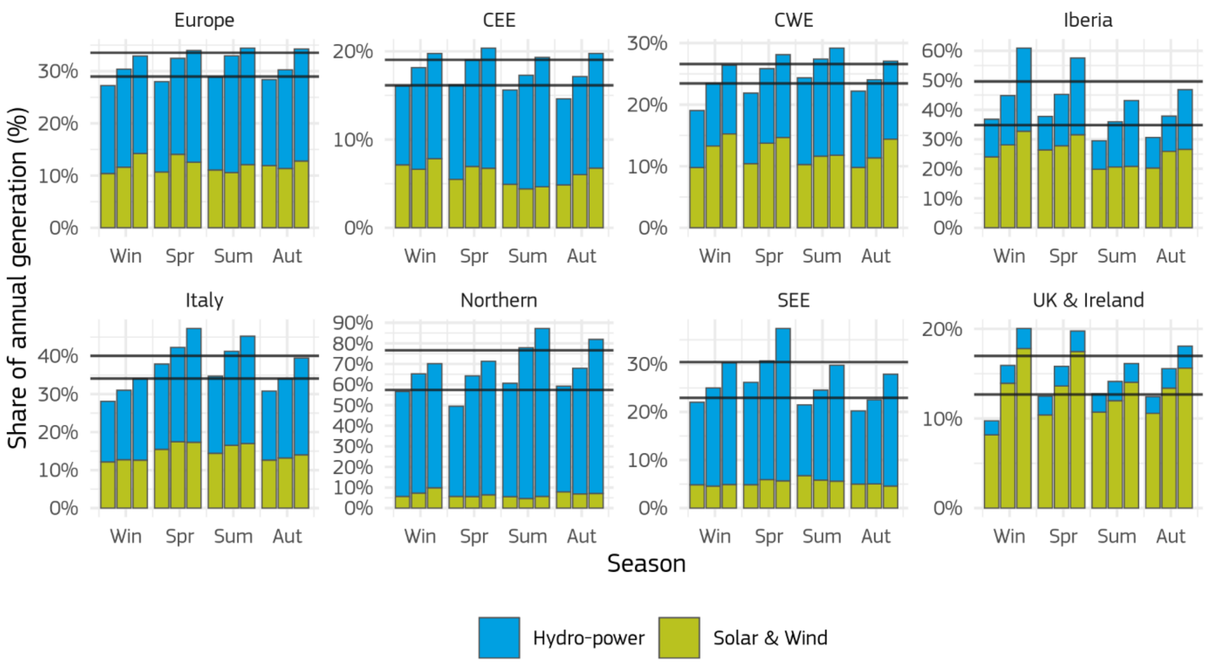


The white lines and the numbers show the fraction of annual generation from renewable energy (wind, solar and hydropower). Climate years are ordered by the share of renewable generation.

The year-on-year variability of renewable generation grouped by season is instead visible in Figure 14. In that figure, we can see that in all the cases the variability of renewables is wider than the range that can be observed at annual level (the white lines in Figure 13). Moreover, the chart gives also an idea of the seasonal variability of wind and solar power that can put power systems under stress in specific periods.

The regions exhibiting the wider difference among the climate years are Northern and Iberia. The former goes from a difference of 13.5% of renewable generation share in winter to 26.6% in summer, while Iberia shows the widest difference during spring (19.8%).

Figure 14. Energy mix for the simulated regions grouped by seasons. The share of generation for each climate year is compared with the range of annual renewable generation shown in Figure 13



For each season, we show the climate year with the lowest share of renewables (first bar), the climate year with the highest share (third bar) and the median year (middle bar). The horizontal black lines represent the same ranges visualised in the Figure 13 in order to show how the seasonal variation is respect to the range of the inter-annual variation.

In most of the regions, except the UK & Ireland, the largest part of the variability is coming from hydropower. To better show this difference, we report in Table 8 the range of the generation each season are for hydropower and solar/wind. The shown ranges clearly depict the importance of the variability of water (for hydropower) and wind and sun for the different European regions. It is notable how the electricity generation mix in the Iberian region is impacted by the natural variability during all seasons.

Table 8. Minimum and maximum energy mix (and generation) per renewable generation type and season.

region	fuel	Winter	Spring	Summer	Autumn
Europe	Hydropower	16.4 - 19.0% (155.5-175.3 TWh)	17.3 - 21.4% (145.3-176.4 TWh)	17.8 - 23.7% (137.2-182.3 TWh)	16.5 - 21.5% (137.2-176.4 TWh)
	Solar & Wind	10.4 - 14.5% (97.5-133.4 TWh)	10.7 - 14.2% (89.6-116.7 TWh)	9.9 - 12.1% (76.4-93.5 TWh)	9.9 - 13.2% (80.7-106.4 TWh)
UK & Ireland	Hydropower	1.6 - 3.1% (1.8-3.2 TWh)	1.7 - 2.6% (1.7-2.3 TWh)	1.9 - 2.6% (1.5-2.1 TWh)	1.8 - 2.9% (1.7-2.7 TWh)
	Solar & Wind	8.2 - 17.8% (9.5-18.6 TWh)	10.4 - 17.5% (9.7-16 TWh)	10.7 - 14.0% (8.6-11.3 TWh)	10.6 - 15.6% (10.5-14.5 TWh)
CEE	Hydropower	8.9 - 12.4% (8.7-12.7 TWh)	10.5 - 14.4% (9.5-13.5 TWh)	10.6 - 14.7% (9.2-12.9 TWh)	9.8 - 13.0% (8.9-12.1 TWh)
	Solar & Wind	4.9 - 8.8% (5.0-8.7 TWh)	5.3 - 7.4% (5-6.9 TWh)	4.4 - 6.1% (3.9-5.3 TWh)	4.9 - 7.2% (4.4-6.6 TWh)
CWE	Hydropower	9.3 - 11.3% (36.5-44.6 TWh)	10.6 - 14.6% (36.4-50.8 TWh)	13.5 - 18.3% (42.9-59.1 TWh)	10.2 - 13.2% (34.8-45.6 TWh)
	Solar & Wind	9.8 - 16.3% (38.6-63.1 TWh)	10.4 - 14.8% (37.4-52.4 TWh)	10.3 - 13.1% (32.9-42.2 TWh)	9.8 - 14.4% (33.0-48.7 TWh)
Iberia	Hydropower	12.1 - 28.2% (10.7-24.3 TWh)	11.4 - 26.6% (8.4-20.4 TWh)	9.6 - 23.0% (7.2-17.1 TWh)	10.3 - 20.3% (7.9-15.6 TWh)
	Solar & Wind	19.8 - 34.0% (17.3-28.2 TWh)	24.2 - 31.6% (18.3-23.5 TWh)	17.2 - 23.5% (13.2-17.7 TWh)	20.3 - 27.3% (15.4-20.8 TWh)
Italy	Hydropower	15.4 - 21.4% (11.0-14.0 TWh)	22.2 - 29.9% (13.2-17.7 TWh)	20.3 - 29.9% (14.1-18.7 TWh)	18.2 - 25.5% (11.7-16.0 TWh)
	Solar & Wind	11.3 - 15.1% (7.9-10.0 TWh)	15.5 - 19.6% (9.4-11.7 TWh)	14.2 - 17.0% (9.3-10.9 TWh)	11.2 - 14.8% (7.3-9.6 TWh)
Northern	Hydropower	50.4 - 61.1% (63.2-76.9 TWh)	43.8 - 64.9% (45.2-69.3 TWh)	55.1 - 81.6% (51.3-77.8 TWh)	51.4 - 74.9% (55.4-82.7 TWh)
	Solar & Wind	5.7 - 10.1% (7.3-12.5 TWh)	5.5 - 8.4% (5.8-8.9 TWh)	3.9 - 6.9% (3.7-6.6 TWh)	5.8 - 8.1% (6.4-8.8 TWh)
SEE	Hydropower	17.2 - 25.3% (9.4-13.9 TWh)	21.1 - 31.7% (10.2-15.4 TWh)	14.7 - 24.1% (7.0-11.1 TWh)	15.0 - 23.3% (7.1-11.0 TWh)
	Solar & Wind	3.9 - 5.2% (2.1-2.9 TWh)	4.7 - 5.9% (2.3-2.8 TWh)	5.5 - 6.9% (2.5-3.2 TWh)	4.3 - 5.7% (2.0-2.7 TWh)

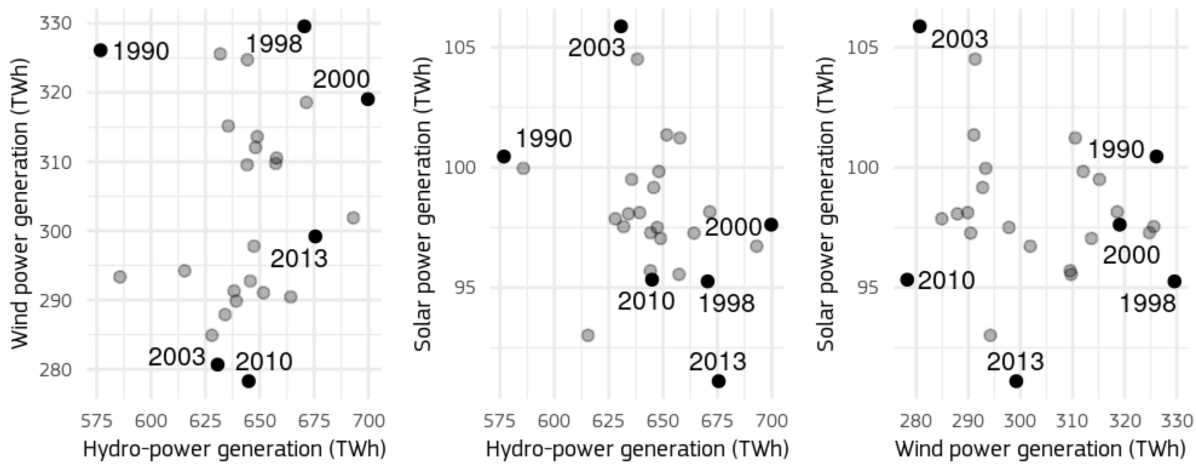
The shades indicate the cases where the range of the generation share is greater than 10% (dark green) and 5% (light green)

Another region showing a high variability of wind and solar is UK & Ireland which shows a deviation range greater than 5% for all the seasons except summer. Hydropower is in general very variable, with three regions having a large variability during all the seasons.

In Figure 15 we can see the covariability of the generation from the three main renewable energy sources for the European continent. In this figure, we have highlighted the climate years that are at the extremes for any of the three categories of generation. The difference between this figure and what we analysed in the Annex 4 is that in the former we analyse the dispatched generation while in the latter the analysis focuses on the resources, then without considering any physical limitation of the systems (e.g. the inability of the power system to use the renewable resource).

It is easy to associate to each of those climate years an extreme weather pattern on the European continent: for example in 1990 there was a prolonged rainfall deficiency that caused many problems across Europe (Bradford, 2000), on the other side during the year 2000 many parts of Europe (including France, England, Norway) experienced record-breaking precipitations (World Meteorological Organization, 2001). It is worth mentioning what happened in 2003, when the continent experienced one of the hottest summers in centuries: the simulations driven by that climate year led to a very low wind generation (-22 TWh from the average) and an extremely high solar generation (+8 TWh from the average).

Figure 15. Covariability of the generation from renewable sources for Europe.



The highlighted points are the climate years that are in the extremes (minimum or maximum) for wind, solar or hydropower generation.

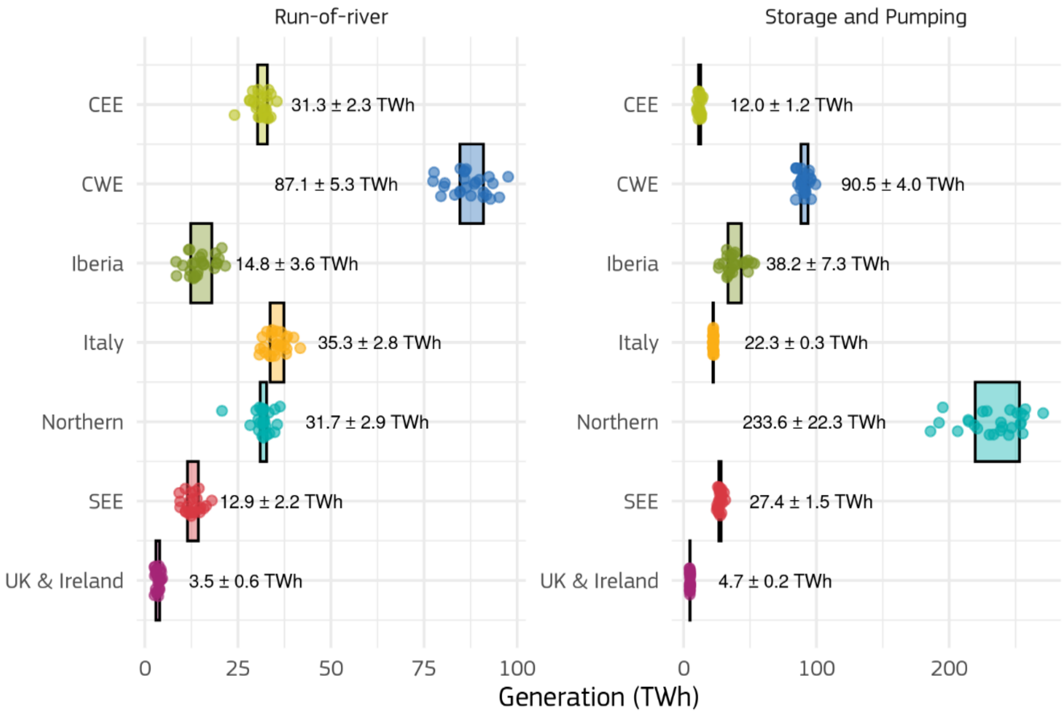
Figure 15 shows that climatic conditions (represented by the climate years) have an impact, at European level, on different renewable sources. However, the aggregation at European level hides the regional differences, which can be very important in a large inter-connected system such as the European grid. While the climate years highlighted in Figure 15 can have a European-wide impact, there are climatic conditions that have an opposite impact on distant, but inter-connected, regions. An example focusing on two specific cases is shown in Figure 16: hydropower in Iberia/Northern regions and wind power in Iberia/UK & Ireland are compared for all the climate years. In the case of hydropower, the shown relationship can also be seen on the daily winter values as depicted by the Figure 41 (Annex 4). It is interesting to see that none of the highlighted years are in the extremes of the total European generation (the highlighted points in Figure 15), demonstrating the importance of analysing this kind of phenomena at regional level.

Figure 16. Simulated generation for hydropower in Northern and Iberia region for all the climate years (left panel). Simulated generation for wind power in UK & Ireland and Iberia for all the climate years (right panel).

The dotted lines represent the 20th and 80th percentiles of generation for the two regions. The highlighted points are the climate years in which the generation of one of the two regions is below the 20th percentile while the in the other region is above the 80th percentile.

Given the importance of hydropower in the European energy mix, it is worth visualising the generation for each climate year and region for run-of-river and for the reservoir-based and pumping plants. Figure 17 illustrates the hydropower generation in all the regions with the different climate years. Again, we can see how the hydropower generation in Iberia shows a large variability due to climate conditions for both the technologies: run-of-river has a normalised standard deviation of 25% while storage/pumping 19%. In general, with run-of-river generation we can observe a larger variability with UK & Ireland and SEE the two regions with the larger values after Iberia, respectively 18% and 17%.

Figure 17. Hydropower generation for run-of-river and storage/pumping for all the regions and the climate years.

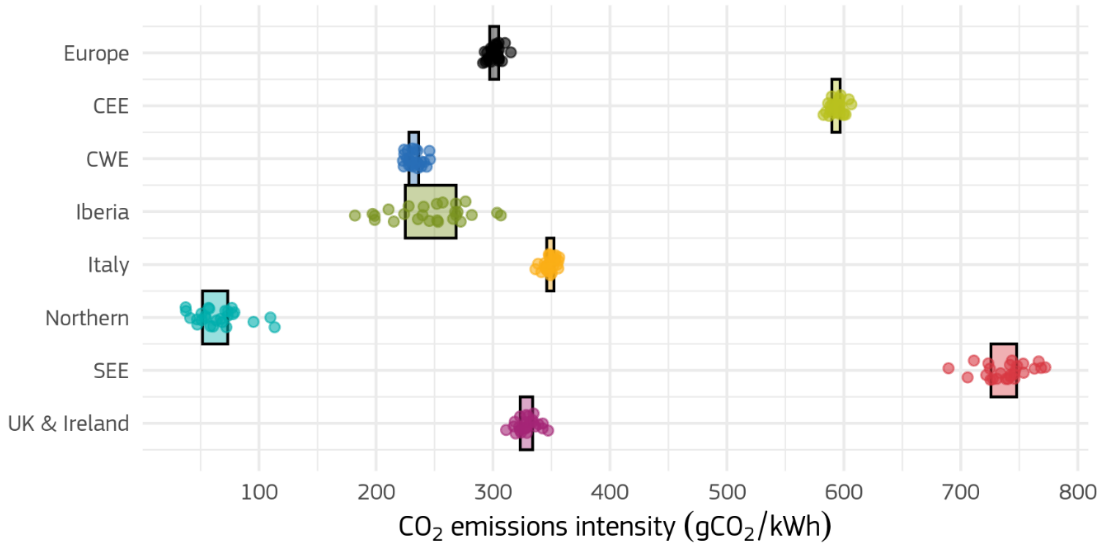


The box shows the range between the 25th and the 75th percentile of the generation for all the climate years considered. Jitter on the y-axis has been added to make the points more visible.

3.3 CO_2 emissions and fuel costs

The variability on the generation mix that we have described in Section 3.2 has also an impact on the CO_2 emissions of the power systems and cost of the fuel. The observed range for the intensity of CO_2 emissions in the entire Europe is between 291 and 315 gCO_2/kWh as illustrated in the first row of Figure 18.

Figure 18. Intensity of the CO_2 emissions of the regional power systems.

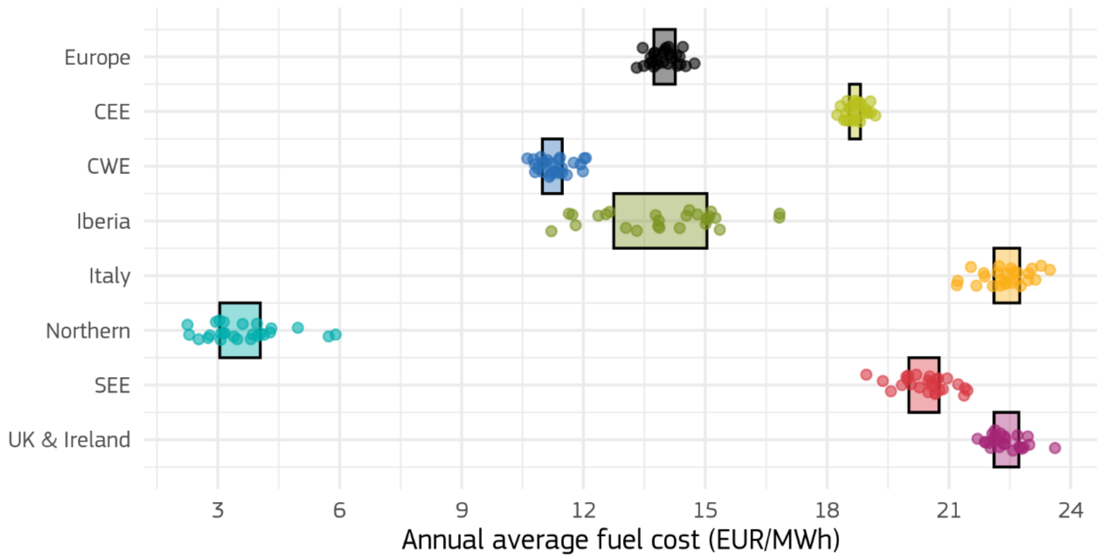


The box shows the range between the 25th and the 75th percentile of the emission intensity for all the climate years considered. Jitter on the y-axis has been added to make the points more visible.

The figure shows that SEE and CEE have the highest emission intensity, due to the large share of fossil fuels as can be seen in Figure 9. Moreover, three regions show a visible large year-on-year variability: SEE with the range 689 – 772, Iberia with 182 – 307 and Northern with 37 – 113 gCO_2/kWh.

The generation cost (based on the fuel costs specified in the Annex 2) is shown in Figure 19 where for the entire Europe we can observe a range between 13.3 and 14.7 EUR/MWh.

Figure 19. Electricity generation cost in the regional power systems.



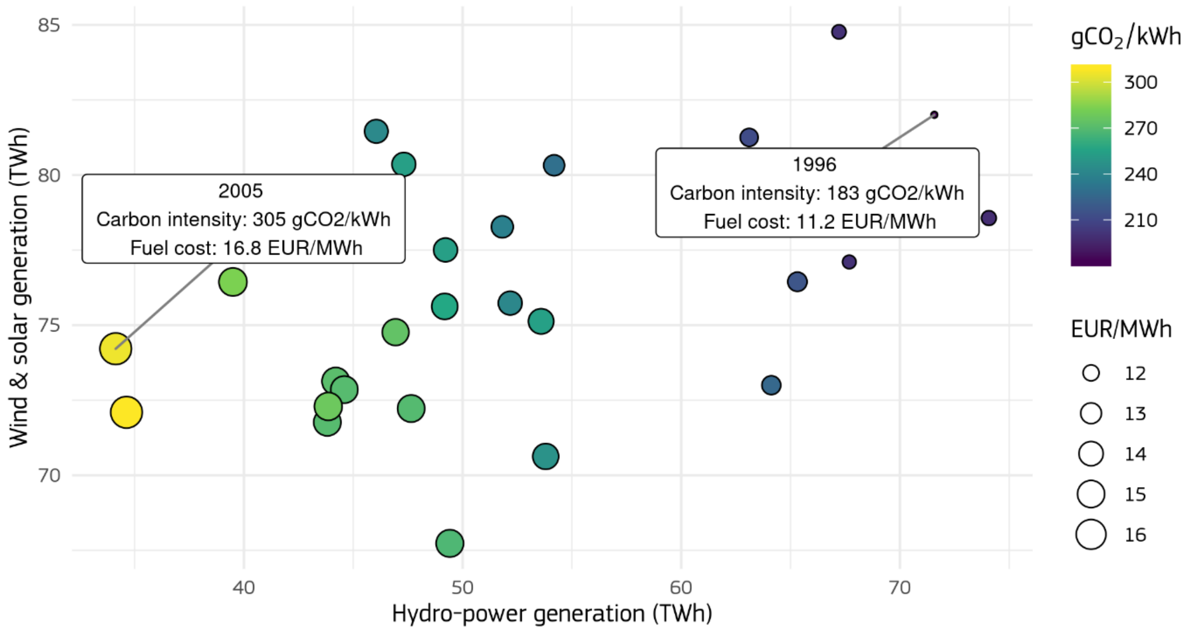
The box shows the range between the 25th and the 75th percentile of the costs for all the climate years considered. Jitter on the y-axis has been added to make the points more visible

In both the figures, we can see that the Northern region is the region with the lowest costs and carbon intensity due to the high share of hydropower capacity (as seen Figure 9) and pumped hydropower storage (Figure 10 and Figure 11). On the other side, the Iberian region is the one experiencing the wider variability in both the variables both for the dispatch of hydropower and a high share of solar and wind power.

The case of the Iberia region deserves to be further analysed because the region appears to be highly affected by climatic conditions, since the installed capacity of hydropower, wind and solar adds up to 52.2%, the second highest among all regions. Figure 20 shows the generation of hydropower and wind & solar in the various climate years used as simulation inputs also displaying their carbon intensity and the cost of the fuels.

In general, we can see that the climatic variability causes a difference of fuel cost in 4.6 EUR/MWh and in carbon intensity of 122 gCO_2/kWh. The highlighted climate years are two extremes for the carbon intensity and the costs: in the 2005, the Iberian Peninsula experienced the driest winter in 60 years with a reduction of 36% of the hydropower in Spain (European Commission, 2007).

Figure 20. Generation from hydropower and solar & wind per climate year for the Iberia region.



The size and the colour of the points show respectively the fuel cost and the carbon intensity for the specific climate year.

3.4 Use of fresh water for thermal cooling

Another important impact of the electricity generation in Europe is the consumption of water for the cooling of thermal power plants. Following the approach used in (Medarac, Magagna, and Hidalgo Gonzalez, 2018), we have estimated the annual need of water for the cooling of thermal power plants (nuclear, gas, coal/lignite, biomass, waste and oil) for the considered climate years excluding seawater cooling. The results of this analysis are visible in Table 9 where we can see the difference among the regions caused by the electricity generation mix. As expected, the regions with the highest variability (i.e. the difference between the maximum and the minimum use of freshwater) are the regions with the highest variability of renewables.

If we look at the average water use intensity (the cubic meters of fresh water per each MWh of generated electricity), we have in the first place the CEE, followed by CWE and then SEE. Those three regions are the ones with a higher share of fossil fuels and nuclear (see Figure 13 for example) and a minor access to seawater for geographical reasons.

Table 9. Usage of freshwater for cooling (absolute values and intensity)

region	Freshwater used for cooling in absolute values (million cubic meters) and percentage (min / **average** / maximum)	Use of freshwater intensity (cubic meters per MWh) (min / **average** / maximum)
CEE	508 / **515** / 525 99% / **100%** / 102%	1.68 / **1.69** / 1.70
CWE	1 435 / **1 468** / 1 508 98% / **100%** / 103%	1.38 / **1.40** / 1.41
Iberia	157 / **182** / 205 86% / **100%** / 113%	0.99 / **1.02** / 1.04
Italy	17 / **19** / 20 89%/ **100%** / 105%	0.11 / **0.12** / 0.12
Northern	38 / **52** / 69 73% / **100%** / 133%	0.34 / **0.37** / 0.43
SEE	173 / **186** / 195 93% / **100%** / 105%	1.27 / **1.28** / 1.29
UK & Ireland	116 / **129** / 143 90% / **100%** / 111%	0.37 / **0.41** / 0.45

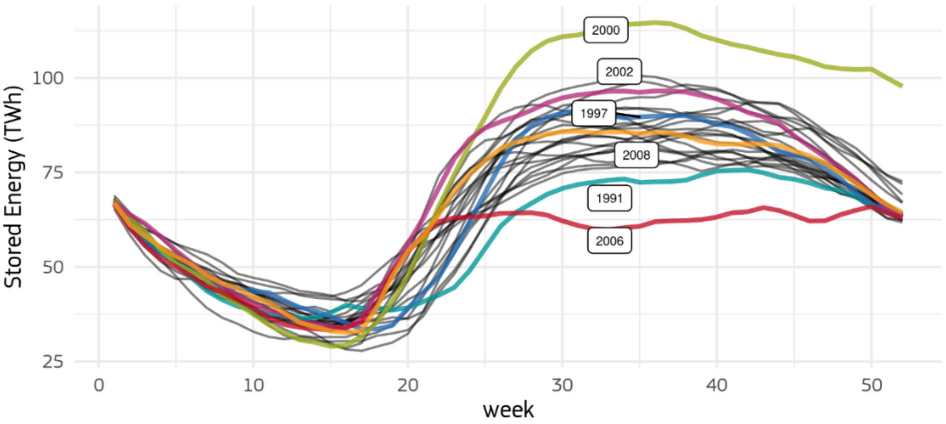
The percentage range is calculated with the respect to the average (100%)

3.5 Reservoir water levels

The availability of water resources due to climatic conditions affects the generation mix of European countries (as shown in Section 3.2) and indirectly the amount of the stored water in European reservoirs.

The total amount of stored energy in the European hydropower reservoirs is shown in Figure 21. In the chart, we have highlighted six out of all the 26 climatic years according to the average annual values. We can see that the maximum difference between the climate years 2006 (the year with the lowest average storage) and 2000 is above 50 TWh (in the week 34). In general, the standard deviation of the stored energy is about 10 TWh during the late summer when the reservoirs in the Scandinavian region tend to be at the maximum levels. However, if we consider the normalised standard deviation (i.e. the standard deviation divided by the average) we have the peak in the weeks 20 – 24 (mid-May to mid-June) where the deviation from the average is about 16%. In the rest of the summer this deviation is instead slightly above the 10%. The high variability in the amount of stored water in the late spring is explained by snow melting, which is caused by temperature rise, increases the runoff and then the inflow into the reservoirs, especially in the Alpine and Scandinavian regions.

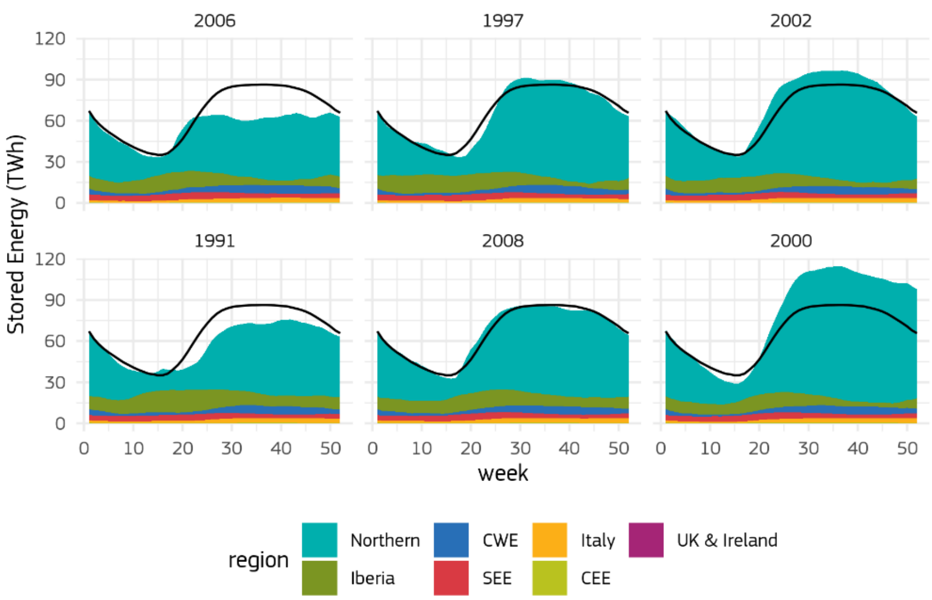
Figure 21. Weekly amount of stored energy for entire Europe.



The highlighted lines represent the storage levels for the two lowest, median and highest climate years according to the average annual level.

The variability of weekly storage levels is shown by regions in Figure 22 where only the six climate years highlighted in Figure 21 are visible. As anticipated in the Figure 10, the majority of hydropower reservoirs are located in the Northern region and, in fact, in that region we can see how during the late spring (around week 16-18) the increased inflow from snow melting causes the increase of water levels in the reservoirs.

Figure 22. Weekly levels of stored energy for the six highlighted climate years in Figure 21.



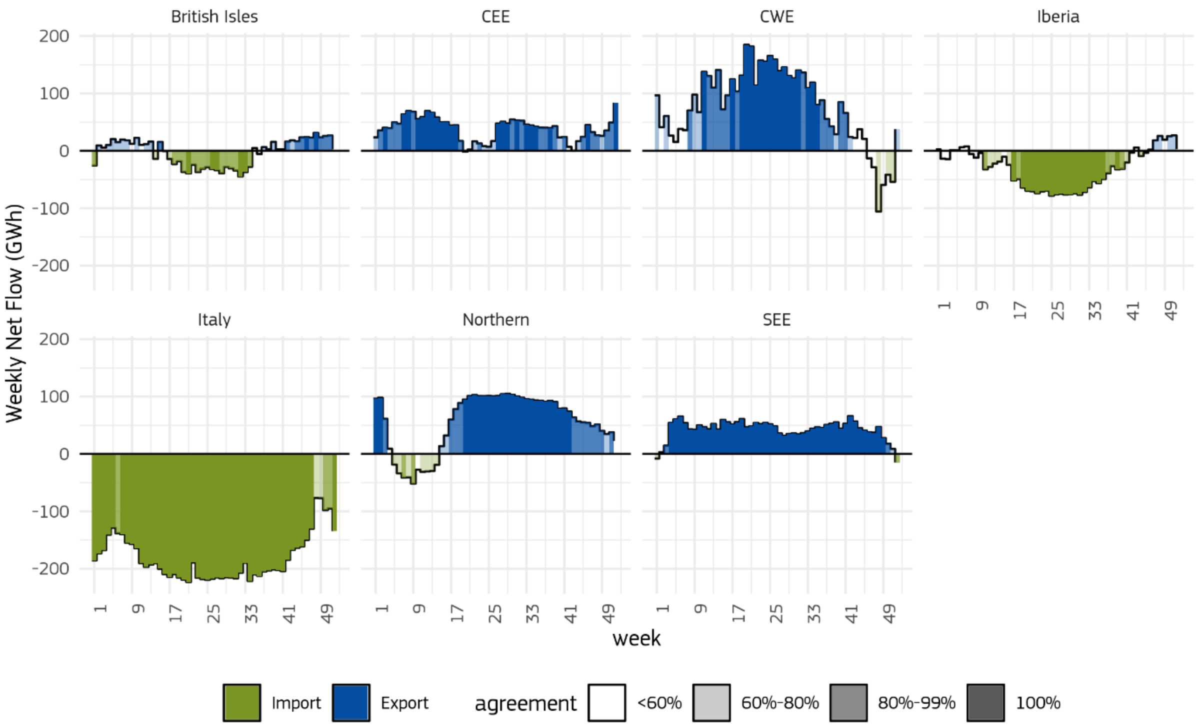
The black line shows the average weekly level for all the climate years.

3.6 Interconnections

In the previous sections, we could see how different climatic conditions could lead to different generation patterns among the European countries.

This difference leads to visible effects to the electricity exchanges among neighbouring countries. Figure 23 depicts the direction of electricity flows between the considered regions (the intra-regional flows have not been considered). The figure shows which regions are mostly importers/exporters and in which part of the year and, furthermore, it gives an idea of the weeks when the direction of the flows (i.e. imports or exports) is more variable due to climatic conditions. For example, in the Northern region we can see how the transition between importing and exporting between the weeks 13 – 17 can vary according to different climatic conditions (i.e. climate years) as also discussed in the Section 3.2. In fact, the climate years when the net import in Northern is higher in the weeks 13 – 17 are 1996 and 2010, as also shown in Figure 16. On the other side, in the simulations, Iberia during those two climate years has the two out of three lowest net imports.

Figure 23. Average weekly electricity net flow between the regions



The exchanges of the countries within the same region is not considered. The transparency shows the agreement of the flow direction (import or export) among the 26 climate years.

The numbers in the Table 10 are instead based on single countries rather than the whole regions. The table shows the range of the annual congestion rate observed in the considered climate years. The congestion rate is defined as the average amount of time that the interconnection use is higher than the 99% of the capacity. The climatic variability is instead represented with the coefficient of variation of the annual congestion rate computed on all the 26 climate years. The left part of the table shows the regions where there is electricity flow constantly and, consistently with Figure 23, 4 out of the top 15 lines include Italy, a net importer of electricity.

Table 10. List of the interconnectors with the highest annual average congestion rate (left) and the highest variability due to climatic condition (right).

	Congestion range (%)	Coefficient of variation (%)
SI → IT	93.1 - 98.4	1.5
AT → IT	90.3 - 95.8	1.3
RS → HR	84.2 - 95.3	2.9
BG → EL	81.9 - 94	3.7
CZ → AT	68.7 - 91	5.2
EL → IT	81.9 - 89.3	2.5
RO → HU	68.2 - 95.7	8.1
IE → UK	78.4 - 84.1	2
MK → EL	67.2 - 89.5	6.2
NO → FI	28.4 - 96.4	22
FR → IT	69 - 86.4	5.8
SE → DE	48.6 – 86.6	13.5
NO → NL	45 – 87.2	15.4
AT → CH	60.2 – 81.5	7.6
SE → PL	48.2 – 85.7	13.2

	Congestion range (%)	Coefficient of variation (%)
DK → NO	2.4 – 41.9	73.4
HR → HU	2.2 - 29.2	72.9
RS → BG	2.7 – 37.1	55.8
IT → FR	1 – 11.7	55.3
RS → ME	2.5 – 16	52.6
MK → BG	4.1 – 36	50.3
LT → SE	2.8 – 47.7	49.6
NL → NO	9.8 – 49.8	48.9
RO → BG	6.7 – 66.1	48.4
DE → DK	7.4 – 38.5	46.1
BG → RO	9.6 – 74	45.8
DK → SE	1.5 – 17.6	45
NO → SE	2.6 – 71.4	44.4
PT → ES	1.6 – 10.8	44.3
DE → SE	10.3 – 47.1	43

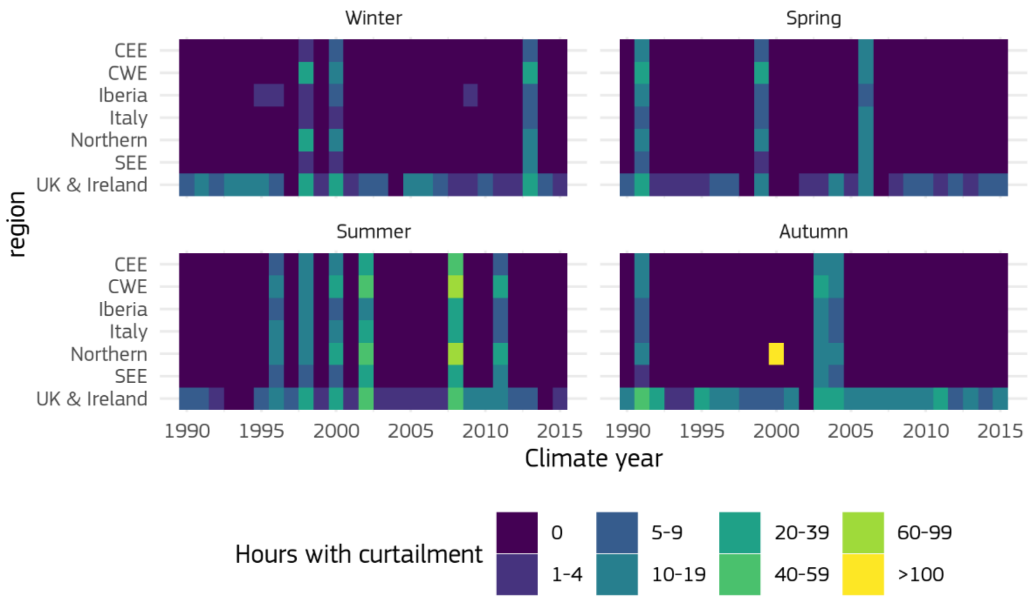
We show only interconnectors with an average congestion greater than 5%. Congestion is defined as the average amount of time that the interconnection use is higher than the 99% of the capacity

3.7 Curtailment and load shedding

As said in the introduction of this report, curtailment may be yet considered a form of flexibility for the power system but is the least desirable option as it results to a wasted resource. In our simulations, the median value of the annual curtailed generation (for wind and solar) in Europe is 2.6 GWh with a median number of 49 hours with curtailment. Figure 24 shows the number of hours of curtailment for each region and season. It is interesting to see how in the UK & Ireland a low number of hours is curtailed uniformly during the year: this can be explained by the fact that Ireland (IE) has both a high installed capacity of wind power (2.7 GW, about half of the peak demand) and an interconnector with the UK that is congested most of the year (in the left part of Table 10). Furthermore, we can see how the curtailment tends to happen in multiple regions in specific climate years. This is an example of how specific climatic conditions affect the entire continent, from Iberia to the Northern region. An outlier in the chart is visible during autumn in the Northern region in the climate year 2000. As visible in the Figure 22, the Northern region experienced an incredibly high availability of water which caused the curtailment of wind and solar[14].

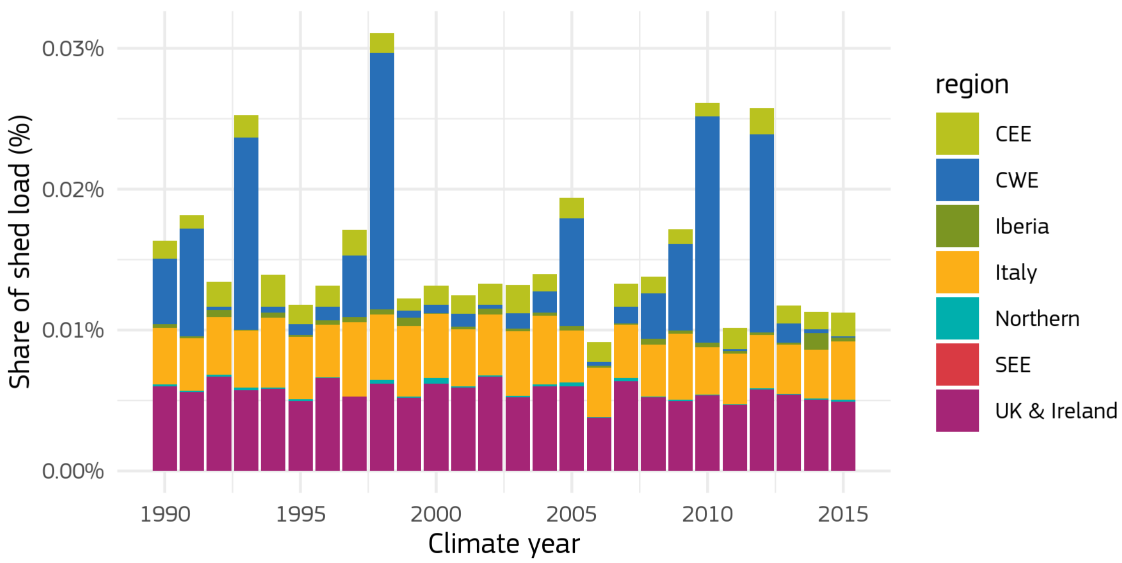
[14] This phenomenon can be explained by the optimisation constraints imposed to the power system simulation. The starting and the ending levels of the storages are fixed in all the climate years, then in case of an extremely high quantity of water in countries with a large share of hydropower and wind/solar, the optimiser, in order to reach the target storage level, gives the priority to hydropower generation potentially leading to a very high curtailment.

Figure 24. Number of hours with curtailment of solar and wind in the European regions.



Another undesired form of flexibility is load shedding, when the consumer reduces its need of electricity, e.g. when an industrial site temporarily stops the production. In our simulations, we have defined the load shedding as 5% of the peak load. The consumer is also compensated with a higher price than usual, in this case 400 EUR/MWh in order to make this option less preferred during the optimisation procedure. In other words, the electricity load is modulated whenever the unsupplied demand is less than the 5% of the peak load and the system does not have access to a more cost-effective source of electricity. This can be considered as a primitive form of a demand response measure. In Figure 25, we show the annual amount of shed load for all the considered regions by climate year. We can see how with some specific climatic conditions the entire continent experiences system adequacy issues. This can be caused both by electricity demand higher than usual (generally for a colder winter) or for a lower availability of renewable sources (for example wind power, which with the climate year 2010 reaches its minimum as, shows in Figure 15).

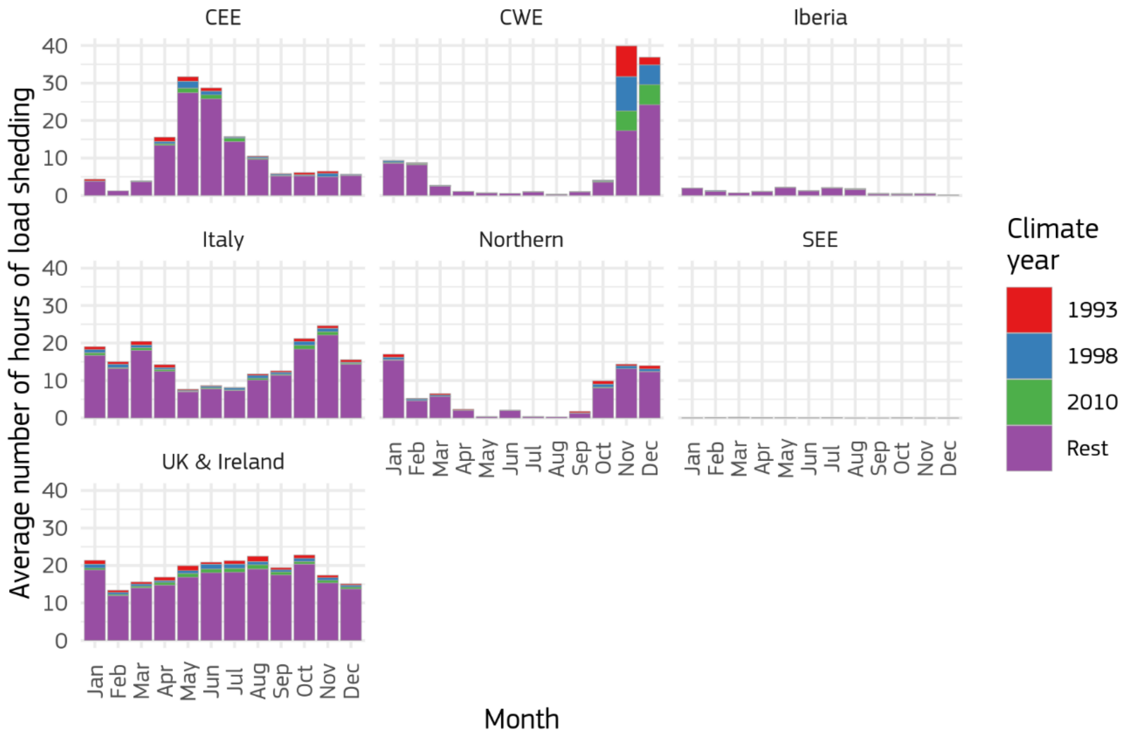
Figure 25. Annual shed load by climate year.



The shed load is shown as percentage of the total demand

From the geographical perspective, we can see that Italy and the UK & Ireland show a relatively uniform value for the shed load while other regions have a higher variability due to climatic conditions (for example CWE which goes from 3.9 GWh to 568 GWh of shed load, respectively with the climate years 2015 and 1998). It is worth investigating which is the country in each region most vulnerable to adequacy issues: in the UK & Ireland region is the United Kingdom (UK), Poland (PL) for the CEE, France (FR) in the CWE, Spain (ES) in Iberia, and Finland (FI) in the Northern region.

Figure 26. Average number of hours with load shedding for each month.



In SEE the average number is less than one in all the months.

Figure 26 illustrates the distribution of the load shedding during the year. It is interesting to see the difference among the regions, the patterns reflect different type of vulnerability of the system in guarantying the supply of electricity. For example, we can see how in CWE and Northern the load shedding tends to happen mostly during winter, while, on the opposite, in CEE we can see a higher vulnerability during the late spring/early summer.

3.8 Observed patterns

An analysis of all the climatic conditions (thus the 26 climate years) for all the considered regions would be too long to be included in this report, although some comments can be found both in the Sections 2 and in this section.

However, we must note that there is a connection between the behaviour of all the national power systems for the following reasons:

1. The systems are inter-connected and they exchange electricity
2. The meteorological drivers can have a geographical scale larger than a single country

The inter-connection means that a surplus or deficit of electricity in a region might lead to a reduction/increase of generation in the neighbouring regions, according to the availability of generation capacity and its costs.

Whenever we analyse the power system operations throughout the 26 climate years, some patterns may emerge. Those patterns play an important role because they can give insights on the co-occurrence of specific events that affect European power systems.

After a statistical analysis of all the climate years, we have chosen four example patterns and presented them in Table 11, showing the impact in terms of resources and power systems' operations.

Although the shown patterns are not sufficient to describe the behaviour of all the European power systems they can however help us to better understand and visualise the "big picture".

Firstly, we can see how some events are negatively correlated: for example, the reservoir inflow between Iberia and SEE (see P2 and P3) or between Northern and CEE/SEE (P1 and P2).

We can also see that the first two patterns appear to be contradictory, with many regions changing sign of the change. This might be explained considering the most important weather phenomenon influencing European weather: the North Atlantic Oscillation (NAO, also mentioned in the Annex 4). In fact, looking at the time-series of the NAO[15], the two climate years we chosen as examples are known to be two peaks: in 2010, the NAO was in a strong negative phase while in 1990 showed instead a marked positive phase.

Finally, it is important to note that our analysis focuses only on the impact of climate on power systems but in reality, other events (e.g. outages) might affect – even drastically – power systems operations. An interesting example can be found in the electricity market report from the European Commission for first quarter of 2010[16]:

> *The Nordic region experienced unusually high prices related to the combination of low hydro reserves, 2 out of 4 nuclear reactors in maintenance, colder-than-normal weather conditions and capacity reduction of major transmission lines. Export from European regions was essential to keep the normal operation of the Nordic region.*

In other words, the climatic conditions per se are not the only cause adequacy issues or disruptions but they can make power systems more vulnerable to events of a different nature (infrastructure failures, planned or unplanned outages, etc.).

[15] Data can be found on the website of the US Climate Prediction Center (CPC): https://www.cpc.ncep.noaa.gov/products/precip/CWlink/pna/nao.shtml

[16] The report can be downloaded at the following URL: https://ec.europa.eu/energy/sites/ener/files/documents/2010_quarterly_eu_electricity_markets.zip

Table 11: Patterns of power systems operation derived by the 26 climate years.

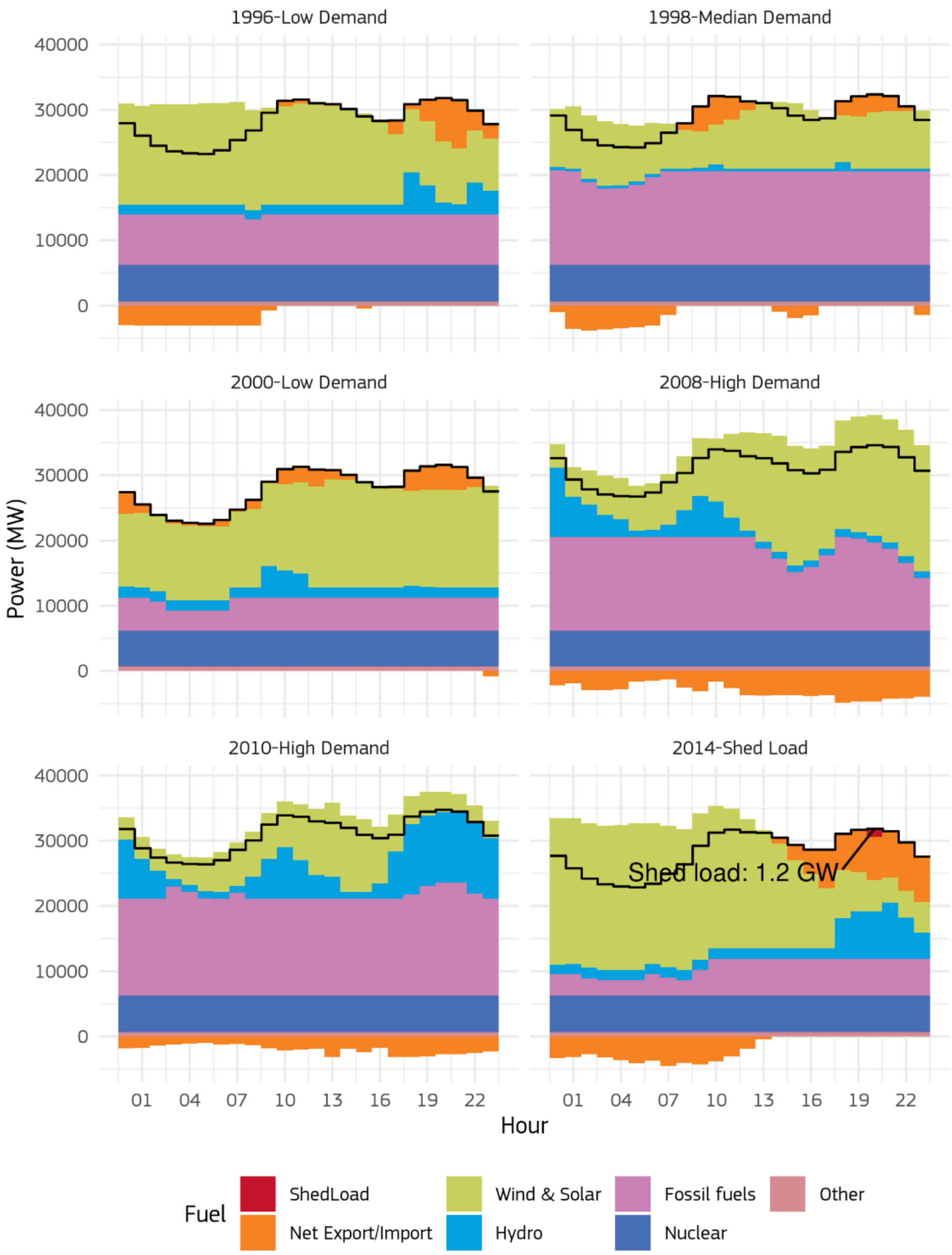
Pattern	Resources	Operation of power systems
P1. Low wind and cold in the North (e.g. 2010 climate year)	**Wind** ↑ Italy, Iberia ↓ Northern, UK & Ireland **Inflow** ↑ CEE, Iberia, SEE ↓ Northern **Sun** ↓ Iberia, SEE, Italy	**Costs** ↑ CWE, Northern, UK & Ireland ↓ Iberia, SEE **Cross-regional exchanges** ↑imports (Northern) ↑exports (Iberia) **Emissions** ↑ Northern **Freshwater use for cooling** ↑ CEE, CWE ↓ SEE, Iberia **Peak load** ↑ CWE, Northern, UK & Ireland
P2. Windy and wet in the North (e.g. 1990 climate year)	**Wind** ↑ CWE, Northern, UK & Ireland **Inflow** ↑ Northern ↓ CEE, SEE **Sun** ↑ CEE, SEE	**Costs** ↑ CEE, Italy, SEE ↓ UK & Ireland **Cross-regional exchanges** +imports (Iberia) **Emissions** ↑ SEE **Freshwater use for cooling** ↑ Iberia, SEE **Peak load** ↓ CWE, Northern
P3. Dry Iberia (e.g. 2005, 2006 climate years)	**Wind** ↓ CWE, Iberia **Inflow** ↑ CEE, SEE ↓ Iberia **Sun** ↑ Iberia	**Emissions** ↑ Iberia, Italy ↓ Northern **Freshwater use for cooling** ↑ Iberia, Italy **Peak load** ↓ UK & Ireland **Shed load** ↓ Italy
P4. Hot & Sunny Europe (e.g. 2003 climate year)	**Wind** ↓ CWE, Italy, UK & Ireland **Inflow** ↓ CEE, CWE, Northern **Sun** ↑ CEE, CWE	**Costs** ↑ all regions **Emissions** ↑ all regions **Freshwater use for cooling** ↑ CEE, Italy **Peak load** ↑ all regions

3.9 Country case studies

Wind and hydropower in Spain

As seen before (especially in Section 3.2), the Iberia region shows a particularly high variability considering its wind, solar and hydropower generation. In this section, we show a case of shed load happening in Spain the 28th November with the simulation using the climate year 2014. That specific day we may observe a large availability of wind and solar power during the first part of the day with a decrease of 1.2 – 2.4 GW per hour from 14:00 to 20:00, in the peak hour when the system experiences an event of load shedding. In other words, within 6 hours about 12 GW of renewables were not available anymore. The simulation shows how the hydropower (pumping and conventional) increased to fill the gap left from the lack of wind and the import from the neighbouring countries. In this case, the interconnector with France reached the full capacity while the one with Portugal was above the 80%.

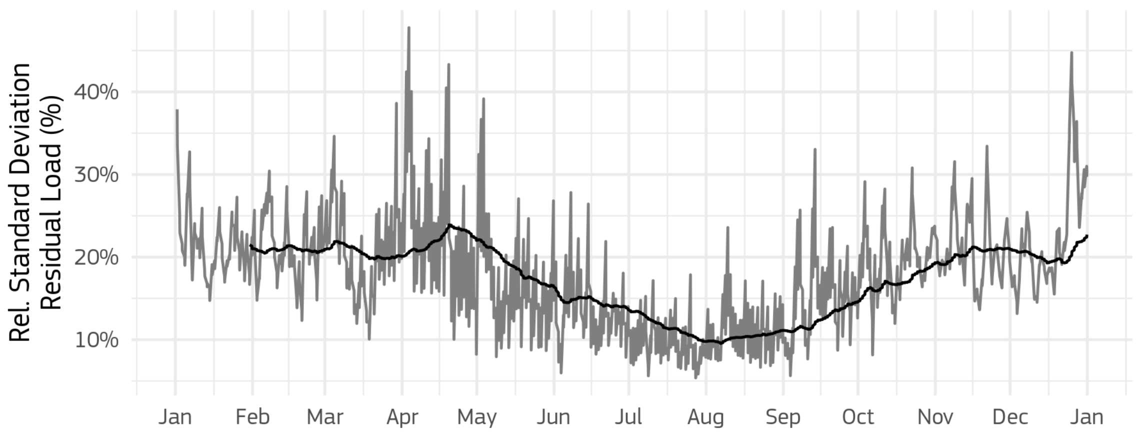
Figure 27. Different dispatch charts for the Spanish system for the 28 November with selected climate years.



We show in Figure 27 the same day with other climate years, choosing the cases where the demand was high, median or low compared to the average in all the 26 climate years.

It is interesting to see how in Spain the residual load (i.e. the electricity demand minus the non-dispatchable renewables) is variable during the year. Figure 28 shows the relative standard deviation of the residual load during the peak hours (18-20) in all the climate years, imposing a rolling average of 30 days. As expected, there is less variability during the summer months, where the weather conditions are generally more stable than in the rest of the year. Two shoulder months, April and November, show a high variability of the residual load. It is worth noting that in November the water stored in the Spanish reservoirs is generally lower than in April making the system less flexible to changes.

Figure 28. Normalised standard deviation of the hourly residual load for Spain during the peak hours (18-20) for all the climate years (grey line).



The black line is a rolling average for 30 days.

Wind power and system adequacy issues in the United Kingdom

As we can see in Section 3.7, with the climatic conditions of 2012 we see many potential adequacy issues in the European power systems. In particular, in our simulation the United Kingdom (UK) experiences a loss of load (unserved demand) during the peak hour of the 30 November. Although the total load in 2010 was not particularly high (it is 20th out of the 26 climatic years), the peak load of that specific day is the highest in the dataset we used for the simulations.

We can see that in five out of the six selected climate years the system experiences issues with the adequacy, with shed load during the peak hours and lost load in the climate year 2012. In many cases, the pumped hydropower (2.7 GW in UK) is used to provide electricity during the peak hours and in many cases, when the power from wind is not enough to cover the demand the system the British system relies on electricity imports.

With climatic conditions of 2012, also Belgium and France experience a loss of load. The latter is particularly important because France is an important exporter of electricity to UK and in the simulations, we can see that the 30th November France exports to UK the 55% of the time during the peak hours.

Figure 29. Different dispatch charts for the United Kingdom for the 30 November with selected climate years.

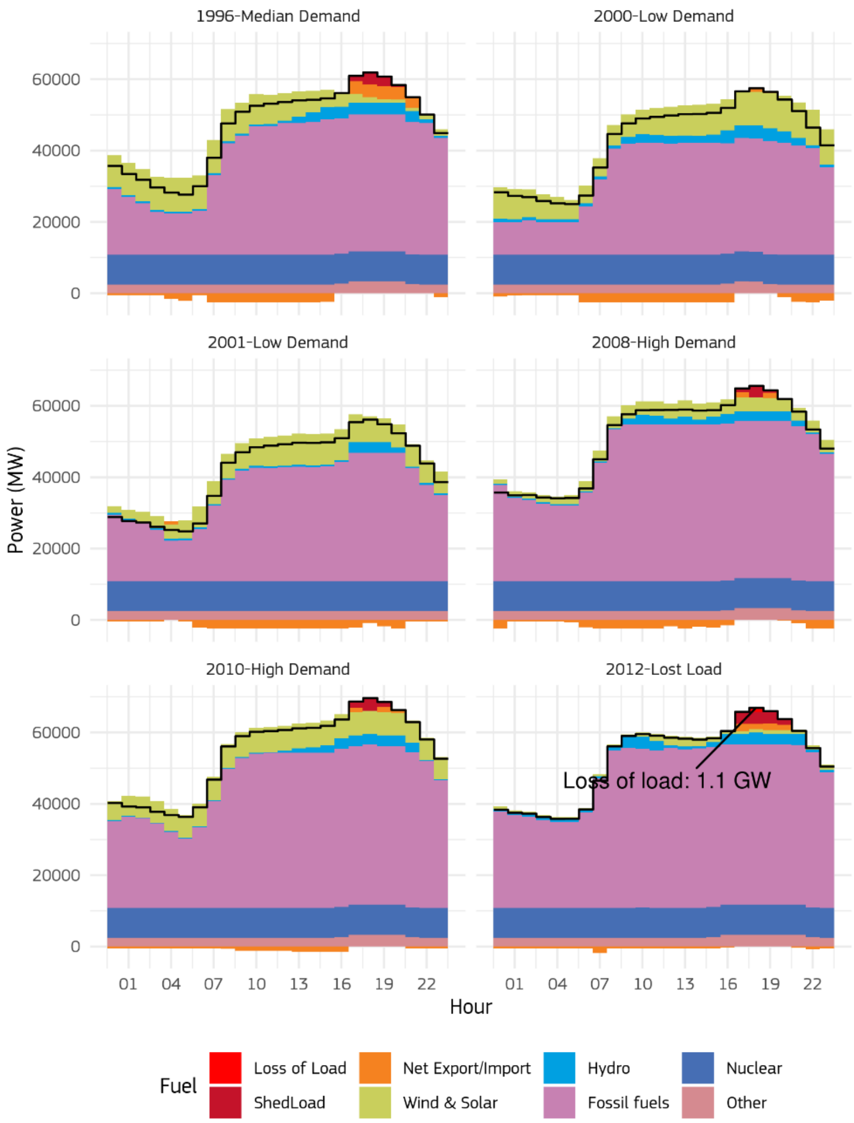
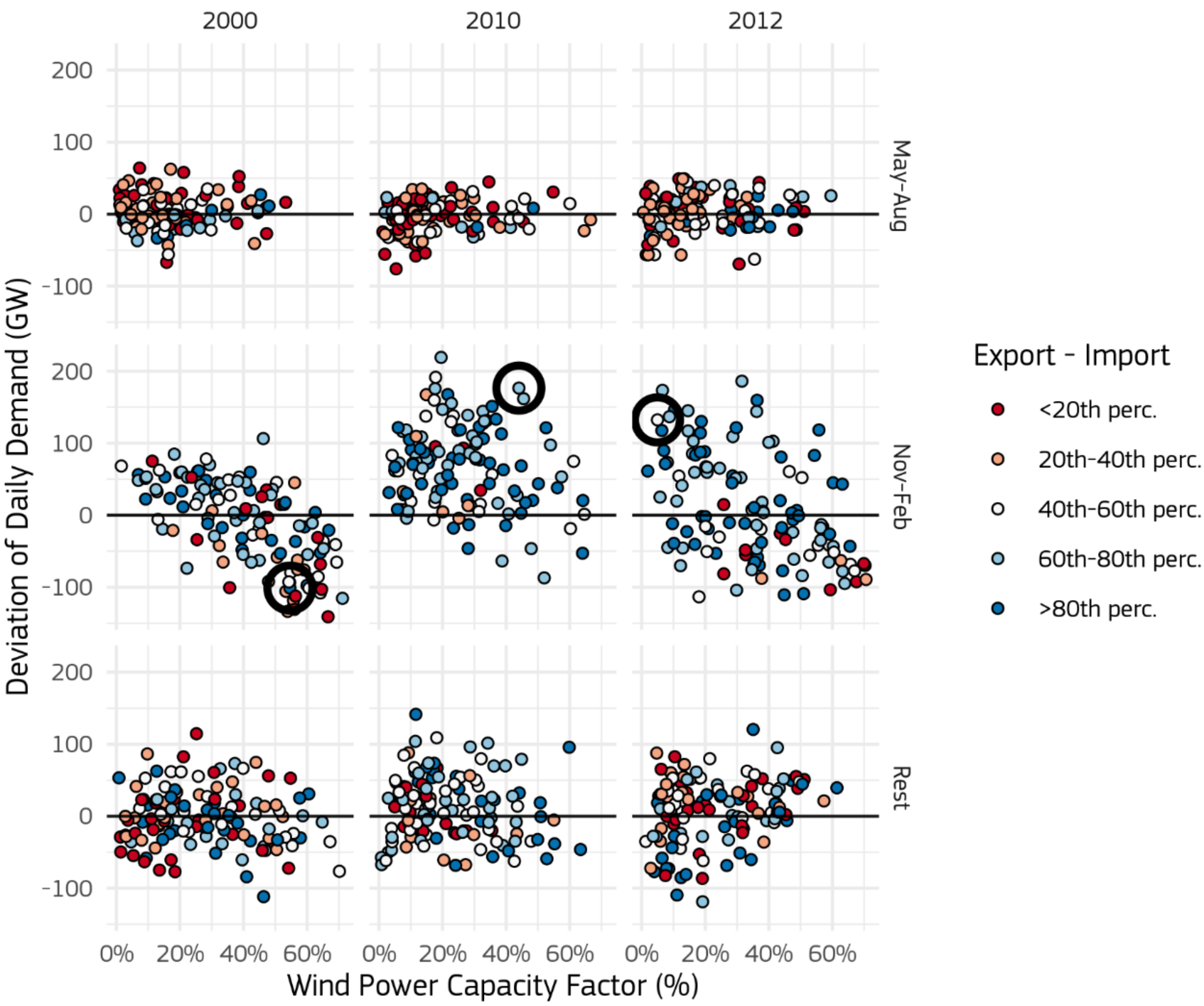


Figure 30 shows the relationship between wind capacity factor, electricity demand and import/export at daily level for the United Kingdom. We can see how the 30 November, analysed in the previous figure, is in the three considered climate years: while in 2010 its demand deviation was higher than in 2012, in the latter climate year the wind capacity factor was very low with an export/import for the whole day around the median values.

Figure 30. Comparison between daily wind capacity factor in the United Kingdom and the deviation of the daily load from the average during the 26 climate years.



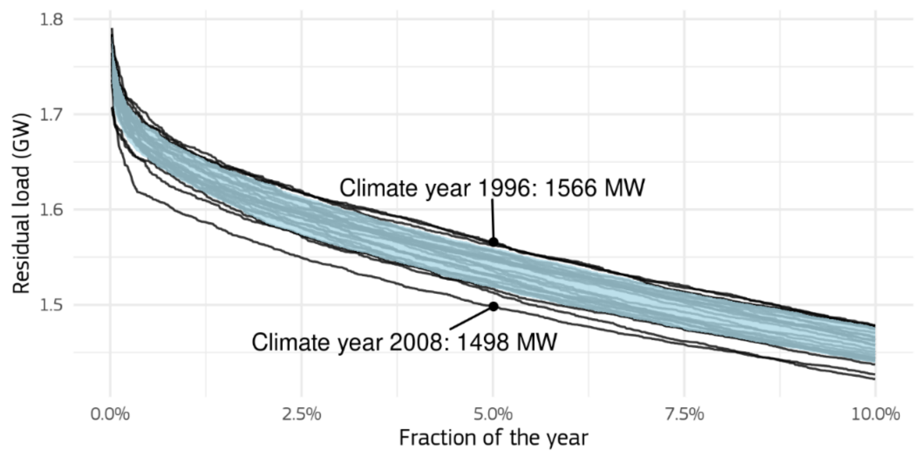
The plot is divided in nine subpanels accordingly to the climate year and the period of the year. The three years, also shown in Figure 21, represents a climate year with low annual demand (2000), a climate year with high annual demand (2010) and a year when a lost load event happened (2012). The colour of the points illustrates the net export/import for that specific day according to the entire distribution for the 26 years. The circled point represents the day analysed in in Figure 29.

Pumped storage and wind power in Lithuania

Lithuania is a country with a high share of both pumped storage (900 MW) and wind onshore (509 MW), in comparison with the peak load (1 794 MW) they are respectively the 50% and the 28%. To this end, it is worth analysing the role of pumped storage in balancing the system with different availabilities of wind. During the climate year 1996 we have the lowest annual generation of wind power in Latvia with 901 GWh while, on the other side, 2008 is the climate year with the 3rd-highest generation: 1 131 GWh (+26%).

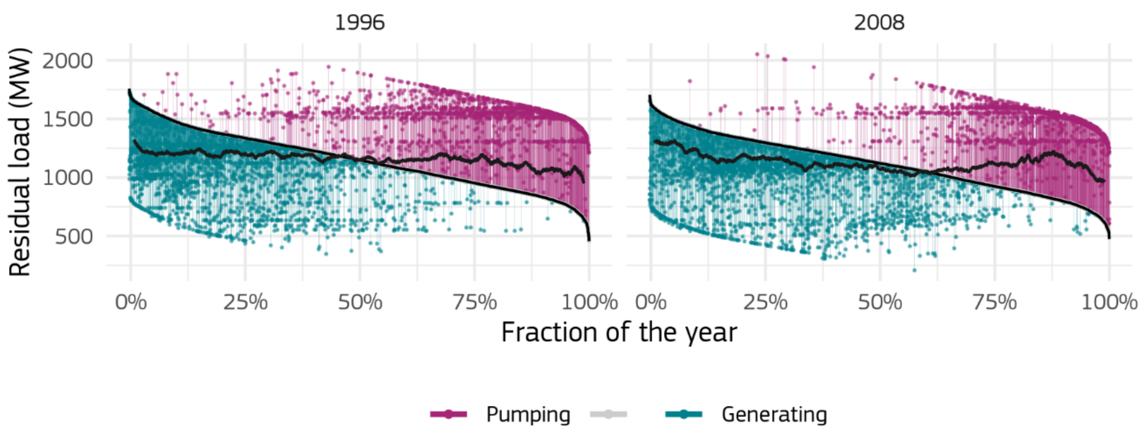
The Figure 31 illustrates the impact of wind variability in the load, we can see highlighted for example two extreme climate years: with the climatic conditions of 2008 we have 440 hours (5% of the time) of residual load above 1 498 MW while with the conditions of 1996 the hours become 768 (8.8%). On the other side, while with the conditions of 2008 we have 440 hours above 1 566 MW, the hours above that load are only 164 (1.9%).

Figure 31. Residual load duration curve in the range 0-10% for Lithuania. The light blue area represents the range between the 10th and the 90th percentile computed on all the climate years.



The difference in the operations of pumping storage is visible in Figure 32 where we can see in the two selected years the operation of the pumped storage power plant in the simulation. The figure gives an idea of the frequency of pumping and generation operations during the different states of the system, in both the cases we can see the capability of pumped storage to mitigate the intensity of high or low load periods respectively. This smoothing effect is shown by the by the dark line which is the residual load duration curve corrected rolling average of the aggregate of pumping and generation in each time interval.

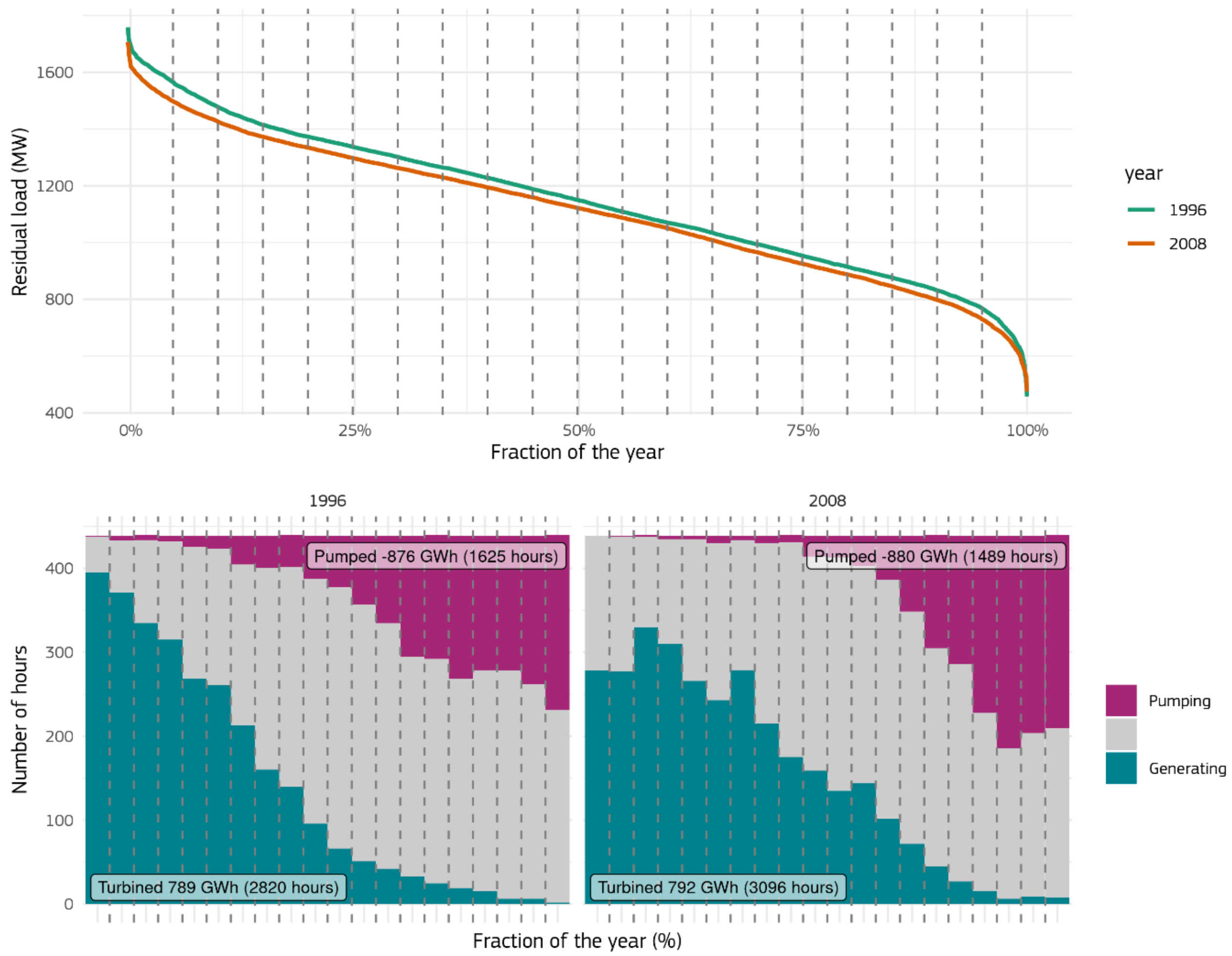
Figure 32. Lithuanian residual load (black line) for two selected climate years: a year with low wind power generation (1996) and one with high wind power generation (2008)



The points show the pumping (purple) or generation (cyan) associated to each hour on the residual load. The dark horizontal line is instead the rolling average with a width of 200 hours of the shown points.

More details are shown in Figure 33 where we can observe the different behaviour of the pumping storage between the two climate years: although the amount of generated/pumped electricity is similar, in the case of low wind (climate year 1996) we can see that the generation is more frequent during the periods of high residual load while in climate year 2008 the generation is more uniformly distributed.

Figure 33. Residual load of Lithuania for the two selected climate years in the top panel. In the bottom, we can see the distribution of the pumping storage activities for each period of the residual load: pumping (purple), generation (cyan) or idle (light grey).

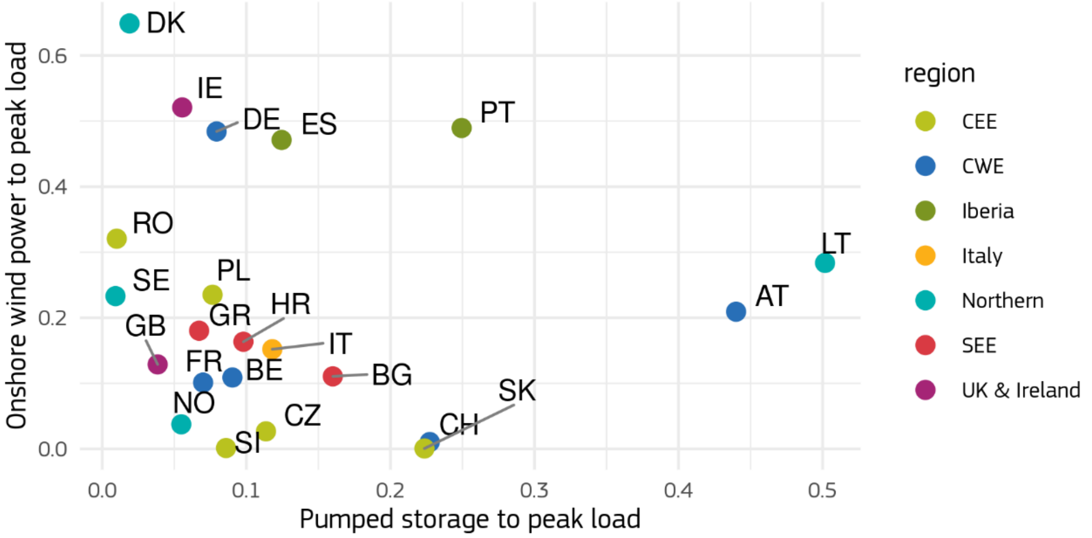


Market values of onshore wind in Austria, Denmark, Germany, Lithuania, Spain and Sweden

This section explores the market values and market value factors of onshore[17] wind generation in the different climate years in selected countries. The market value is defined as the weighted average of the electricity price using generation, that is, it takes into account the specific generation profile of a technology when calculating the value (i.e. the costs displaced), for instance on the electricity spot market. The market value factor is the market value divided by the average electricity price.

Because of the non-controllable generation profile both the market value and the market value factor of wind onshore typically decrease with increasing market share. This is of interest as the market value of onshore wind generation provides a measure of both its competitiveness and its economic value to society, while the market value factor is an economic indicator of how well wind onshore generation integrates with the power system. By looking at a large ensemble of climatic conditions this report provides an estimation of how strong market values and market value factors could vary over a longer time span. Another aspect of interest pertains the question if the flexible ramping capabilities of hydropower plants could be beneficial to integrate wind power generation into the electricity market, which would be indicated by relatively (more) stable levels of market values and/or market value factors. Work conducted by (Hirth, 2016) comparing power systems in Germany and Sweden suggests that this could be the case. To inform the selection of suitable comparison cases Figure 34 displays different countries' power systems by their share of wind onshore power capacity (vertical axis) and pumped-storage power capacity respectively, relative to peak demand.

Figure 34. Ratio of pumped storage capacity (x-axis) and onshore wind power (y-axis) to peak load for all the countries in this study.



Each panel of Figure 35 compares two power systems with somewhat similar variation of wind generation. The systems however differ in terms of the underlying generation portfolio and in particular concerning the amount and type of hydro generation. Each circle displays for each month across all climate years the average share of wind generation in total generation and the average market value. The line shows the fitted linear regression of these points; it is thus a best point approximation for each corresponding share.

The first case compares the power systems of Denmark and Lithuania. Denmark is the country with the highest relative wind capacity installed and consequently shows the highest variation of wind shares reaching up to 80% of total generation. It does not have significant hydro capacity but has interconnections to the other Northern countries. The market values and market value factors show quite some variation for each corresponding wind share, which indicates a fluctuation in the system's ability to absorb similar levels of wind generation feed-in. This could be for instance due to variable Solar PV feed-in and demand, but also due to changes in the status of the interconnectors which is among others determined by the inflows of water in the

[17] We deemed solar PV less suitable to study the impact on market values due to the much smaller variation of output at currently installed capacities.

neighbouring countries. The latter effect can be clearly observed from Table 10 where flows on the Danish interconnectors are among the most impacted in terms of climate variability. Overall, the points however reveal a clear pattern, indicated by the slope of the fitted line, which shows the expected trend of declining market values and market value factors with increasing shares of wind generation. Lithuania also has a significant amount of wind onshore capacity installed and resulting from that, shares of wind onshore generation in the range of 10% to 50%. In contrast to Denmark, it also has significant pumped-hydro capacity installed relative to its peak demand. This could be a plausible explanation why market values are reduced only very little over the range of wind share (slope of the blue line) and why market value factors stay essentially constant at a level of 95% of the average base price. In other words, this means that the high share of pumped-storage capacity helps to integrate variable wind generation into the system by storing it in times of high supply and releasing it when supply is scarce – economically this is reflected by stable market value factors. The mechanics behind this effect are the ones shown in Figure 32.

The second case compares Austria and Sweden. Both countries have a comparable share of installed wind capacity of slightly above 20% and both power systems are dominated by hydropower generation. However, besides run-of-river in the case of Sweden hydro generation stems almost completely from reservoirs whereas in Austria up to 40% of peak-demand can be supplied by pumped storage plants (see Figure 34). For Austria, a similar pattern as for Lithuania is observed where market values and market value factors almost stay stable again suggesting that pumped storage could play an essential role for the economic integration of wind onshore. The results for Sweden at first sight may seem counterintuitive: other than expected the fitted line goes up for increasing shares of wind generation. To provide a better understanding of the underlying effects Figure 36 displays the same data points, but this time split by season of the year. Furthermore, the color-coding denotes the deviation to the average of the share of hydro generation in each month. From this perspective, it becomes evident that the 'tilting' of the fitted line is caused by one season, namely spring. In conjunction with the color-coding, the data show that high shares of hydro generation in spring which cause low market values mostly correlate with low wind shares, which explains the slope of the fitted line. A possible explanation for this is that less windy weather in spring is often sunnier which in turn triggers faster melting of winter ice leading to high water shares in the total generation. This effect is also evident in Figure 22. This result emphasises the relevance of considering the co-variation of hydro output when assessing the impacts of wind variation on market values. If we now tum the focus again on Figure 35 we see that the market value factor is following the expected trend of declining values for higher wind shares. This is the case since the average electricity price is also low when the hydro-generation is high, so that it normalises the results on market values in the panel to the left.

The third case compares Germany and Spain. Both countries take a position close to each other in Figure 35, meaning that they exhibit similar shares of wind and pumped-hydro capacity in their current power systems. However, the share of non-pumped hydro generation is Spain is significantly larger than in Germany. It can be observed that the share of wind generation varies between about 5% and 40% in the case of Germany and 10% and 40% in the case of Spain. These shares correspond to variations in market values in the range of about 30 EUR/MWh to 65 EUR/MWh in Spain and 28 EUR/MWh to 43 EUR/MWh in Germany. This overall higher variation of market values for a given share of wind generation in Spain is explained by the higher co-variation of hydro generation in Spain in particular during the summer months so that the fitted line drops somewhat steeper. The market value factors in both countries change in a very similar fashion for growing wind shares, which suggest similar capabilities to integrate growing shares of wind generation.

Figure 35. Market values (EUR/MWh) and market value factors for variable shares of wind generation across the whole ensemble of climate years. Each circle displays for each month across all climate years the average share of wind generation in total generation and the average market value. The line shows the fitted linear regression of these points.

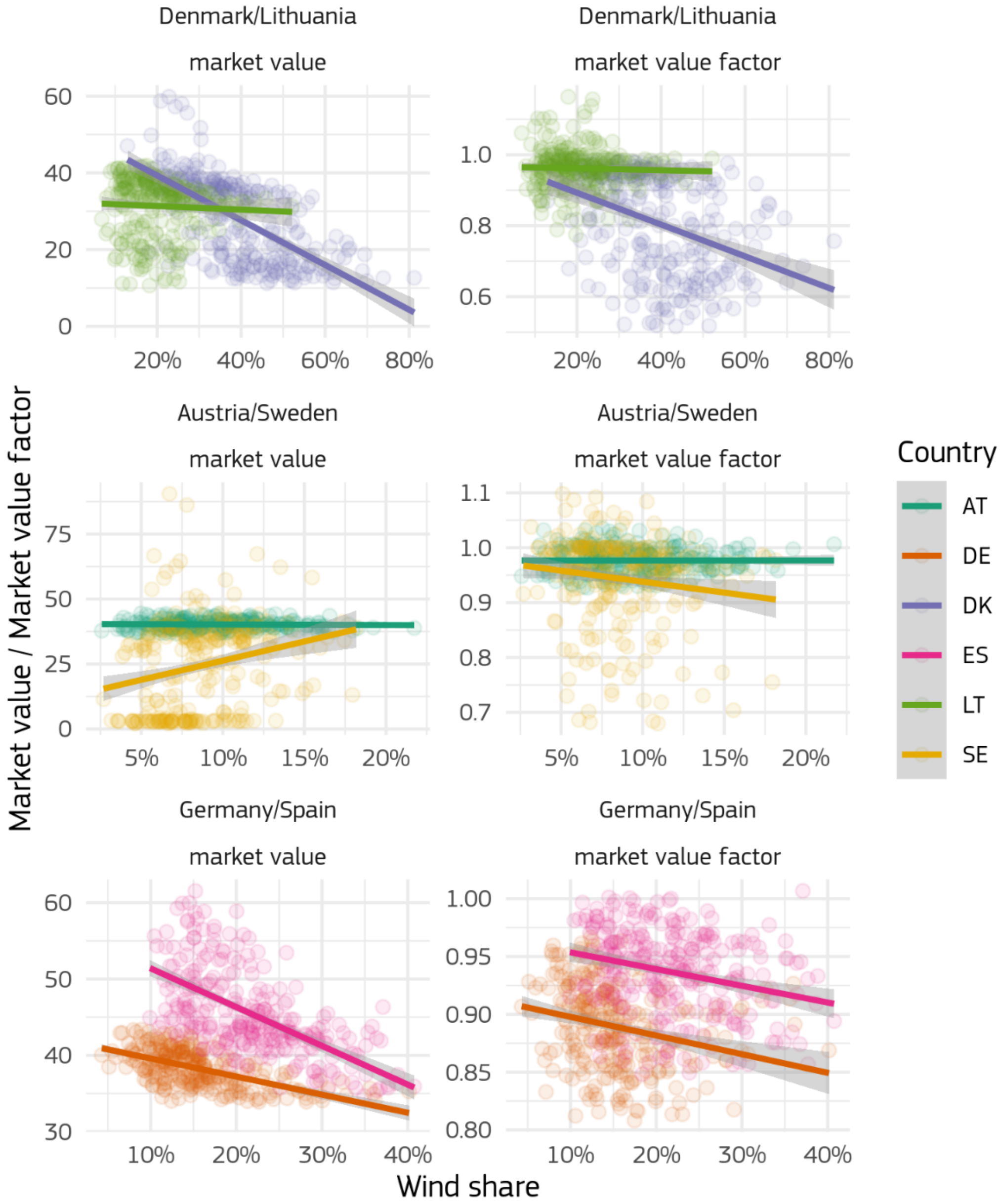
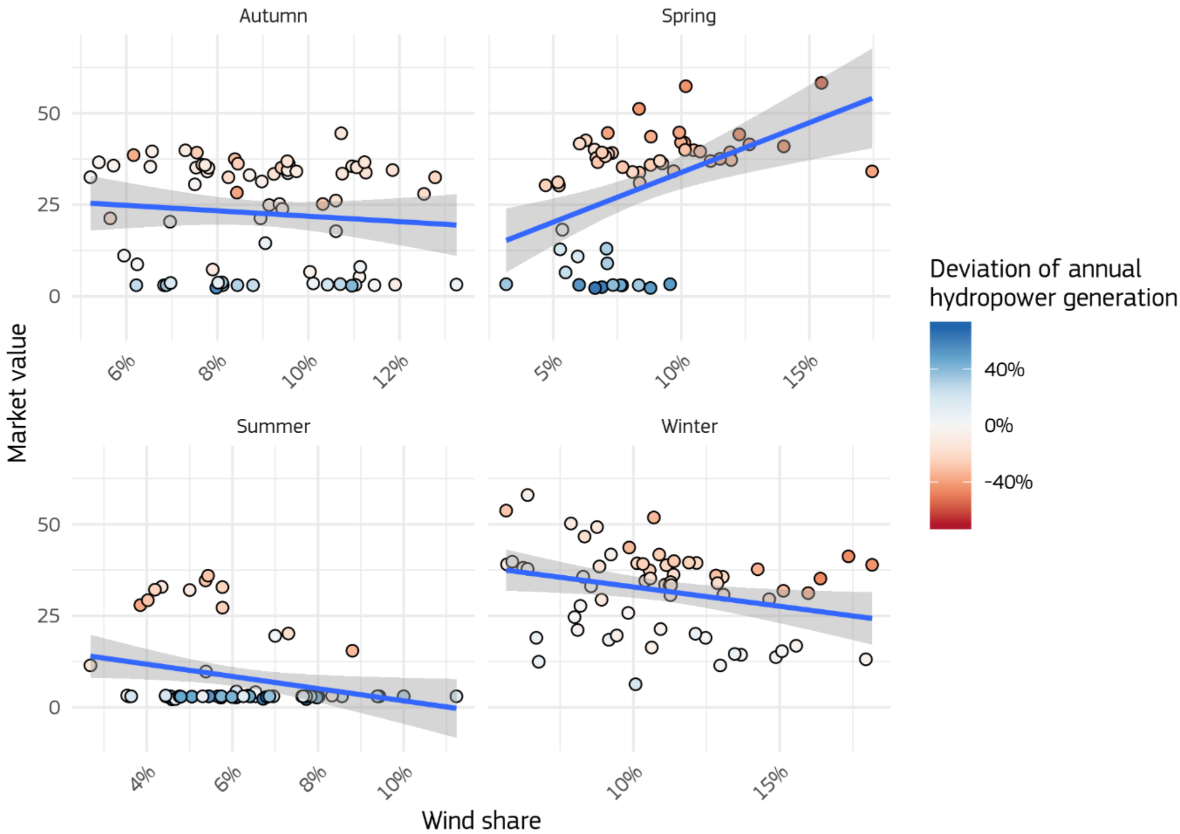


Figure 36. Market values (EUR/MWh) for variable shares of wind generation in Sweden by season.



The following conclusions can be drawn from this section: First of all, the ensemble of climate years at monthly level in most cases reveals a considerable range of market values and market value factors owing to the co-variability of wind and other climate induced generation, in particular hydro. The availability of pumped storage seems to be able to mitigate the variability of market values and market value factors due to the smoothing of the residual load curve. The ability to do so however seems to depend on the size of the pumped-storage capacity relative to the peak demand, which is in Austria and Lithuania in the order of 45% in Figure 34. A word of caution should be added that these modelling results likely over-estimate the flexibility potential due to the simplified representation of technical constraints. It is subject to future work to provide assessments that are more detailed. The findings for Sweden indicate that also reservoir hydropower could play a role in stabilising the market value factor and thus facilitating the integration of variable renewables, which has also been found by (Hirth, 2016). However, the findings also suggest that this impact seems to saturate or could even be reversed for high shares of hydro-generation. An explanation for this could be that in years with very high water availability the dispatch of hydro plants also has to be allocated to hours with high wind shares to make use of all the water so that a trade-off arises between water spillage and curtailment of wind generation. This shows the importance to consider the co-variability of hydro inflows when assessing the market values/market value factors of different wind shares in order to derive indicators that are robust to the range of variations of the inflow profiles.

4 Conclusions

This study presents a model-based approach to investigate the impact of climate variability on current European power systems.

In Europe, considering the climatic conditions in the period 1990-2015, the electricity generated from renewables is on average 1 047 TWh, the 31% of the total generation. This quantity varies year-on-year, with the minimum and the maximum amounting respectively to 979 TWh (29%) and 1 116 TWh (33.5%). The uncertainty posed by the variability of the meteorological factors was estimated by simulating the operating conditions of the current (as of 2016) European power systems – at country level – according to climatic conditions.

The granularity of this analysis allows highlighting the potential vulnerabilities arising in specific areas and periods of the year. The biggest threat posed by climate variability to the European power systems is caused by the variability of renewable generation, in particular in the Iberian and Northern regions, which both have a large share of hydropower and wind power. Climate conditions resulting in a renewable generation lower than normal might lead, for example, to higher electricity costs (see Section 3.3) or higher use of freshwater for thermal cooling (see Section 3.4). Cross-border exchanges of electricity through interconnectors (see Section 3.6) can help mitigate the impact of an unexpected decrease in generation by making available the surplus of generation in neighbouring regions: as shown in the two first case studies in Section 3.9, adequacy issues might be triggered (or amplified) by the reduced availability of imports, caused for example by a meteorological situation affecting more than one country.

The interconnection among the European power systems can be considered either a potential source of vulnerabilities, for example due to cascade effects, or an opportunity to mitigate the impact of climate-related events. In fact, thanks to electricity interconnections, it is possible to use the low-carbon electricity surplus in a region to satisfy the needs of another region experiencing a reduction of renewable resources. This phenomenon has been briefly analysed in a previous report (Kanellopoulus, 2018) and it must be taken into account when analysing the potential issues caused by a drop of renewable generation. However, to integrate more renewable generation it is important to understand better, and anticipate when possible, the covariability of sun/wind/water in the European regions.

In general, some patterns can be observed in relation to renewable shares, electricity costs, import/export levels, etc. The patterns that are shown and briefly analysed in Section 3.8 can give us insights on the co-occurrence of relevant phenomena in the European power systems. For example, the first pattern we have identified (the pattern P1 in Table 11) shows that when wind is abundant in Italy and Iberia it might be less available in Northern region and UK & Ireland. Similarly with water availability for hydropower (i.e. the inflow): when it is higher than average in CEE, SEE and Iberia then it might be lower in the Northern region. This change in the availability of renewable sources inevitably affects also the power systems operations and it can come with a change in solar power availability and peak demands. The second observed pattern instead shows that more water in the Northern region can be associated to more wind in the same area (including also UK & Ireland and CWE) and lower peak loads. At the same time, the southeast of the continent (CEE and SEE) can be drier with a higher use of thermal generation.

However, our analysis also focused on specific countries, illustrating how specific events are driven and caused by specific weather conditions. For example, we have examined a case of unserved demand in the United Kingdom during peak hours comparing the same exact day under different climatic conditions explaining the reasons behind the lack of supply. In this case the contribution of wind power was lower than usual and at the same moment also the countries that usually export electricity to the UK, namely Belgium and France, were experiencing potential adequacy issues caused by the high demand thus reducing the exporting capability.

The methodology used in this report could be seen also as a tool to explore the impact of grid expansion projects (e.g. a proposed Project of Common Interest, PCI) or energy policies under all the possible climatic conditions (observed and projected). Furthermore, the analysis we propose on climate variability might be useful to characterise the regional electricity crisis scenarios identified according to Regulation (EU) 2019/941 of the European Parliament and of the Council on risk-preparedness in the electricity sector[18].

Linking then the state of the European systems with large-scale weather patterns could also lead to a more effective use of seasonal climate forecasts to predict potential adequacy issues in the next months. Seasonal

[18] OJ L 158, 14.6.2019, p. 1–21

prediction systems are a fundamental tool to deliver high-quality and effective climate services in Europe (European Commission, 2015) and currently freely provided operationally by the Copernicus Climate Change Service[19] (C3S) funded by the European Commission.

This work is an unavoidable foundation of the planned analyses of the future power system under climate change, which are needed to assess the possible pathways to achieve the goals of the European Green Deal. The Green Deal is part of the European Commission's strategy to implement the Sustainable Development Goals[20] (SDG), which include the access to sustainable, affordable and reliable energy for all (SDG7). In fact, the EU aims to achieve climate neutrality by 2050 and to effectively take on the challenge we need to gather all the information available on climate and European power systems to produce the needed knowledge.

This report is based on state-of-the-art information on climate and European power systems and fills the knowledge gap we have on the relationship between energy and meteorology. For example, the EEA report on climate change impacts on the European energy system (European Environment Agency, 2019) presents a list of knowledge gaps for climate change impacts on energy. This report contributes to fill the gap on the relationship between water availability and hydropower generation, investigating the influence of climate variability not only on wind and solar but also on the hydropower generation and the reservoir levels. The link between meteorology and hydropower is particularly important in Europe, where water plays a critical role as electricity storage and source of renewable electricity.

This work is based on a set of power system simulations initialised with the best data available for all the European countries. Although the input data used in this work is based on previous JRC studies (see Annex 2 for more details), we have improved the modelling of the climate-derived effects on hydropower creating time-series of hydropower inflow and reservoirs guiding curves for the period 1990-2015. The data generated is openly available and that can be used in other power system models and for additional analyses on the impact of weather/climate on the energy sector.

However, the used data presents some gaps that we aim to fill in the next future to improve the accuracy of the simulations. These gaps include:

1) lack of information at subnational level on electricity demand and transmission capacities;
2) lack of data on the operational constraints of hydro power (e.g. ecological flows and minimum storage levels) and
3) lack of information on single hydro power plants to allow a more granular modelling (for example at hydrological catchment or basin level).

4.1 What about the future?

This report revolves around the question: what is the impact of climate on current power systems? However, we think that the challenge will be to extend this question to the next 50 years: what will be the impact of **future climate** on **future power systems**? To address properly this question, we need firstly to gather the state-of-art knowledge about future climate and then have a look into the future scenarios for European power systems.

Future climate

Anthropogenic climate change has already shown its impact on European climate and its future change is affecting "many aspects of human societies, including energy system" (European Environment Agency, 2019). Although the impact of the projected climate changes on the European energy systems is complex to define, it has been therefore the object of many research initiatives (for example, IMPACT2C[21], EUPORIAS[22], CLIM4ENERGY[23], ECEM[24], CLIM2POWER[25]). The Joint Research Centre also played an important role in defining the climate induced impacts in Europe to support the European policies with the PESETA project studies (Ciscar et al., 2018).

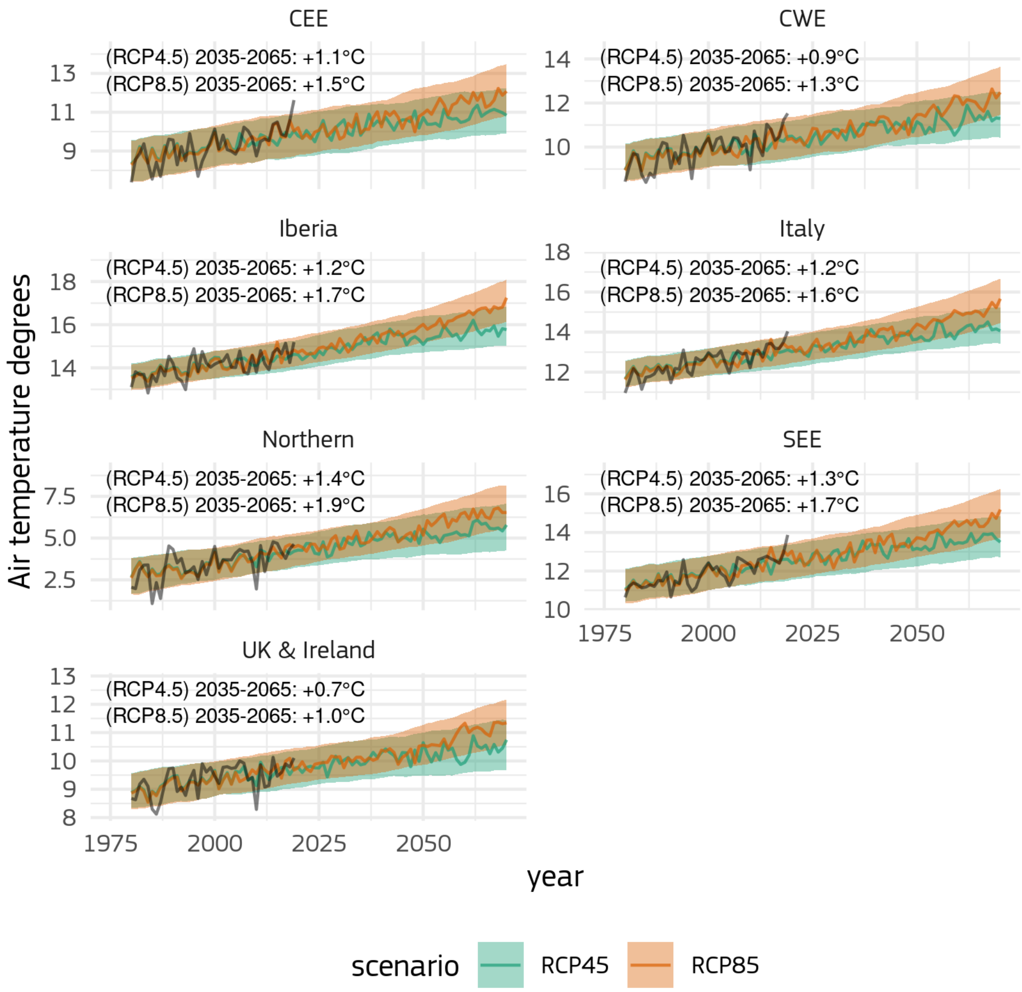
[19] https://climate.copernicus.eu/about-us
[20] https://sustainabledevelopment.un.org/post2015/transformingourworld
[21] https://www.atlas.impact2c.eu/en/about/about-impact2c/
[22] http://www.euporias.eu/
[23] http://clim4energy.climate.copernicus.eu/
[24] https://climate.copernicus.eu/european-climate-energy-mixes
[25] https://clim2power.com/

Temperature Temperature is expected to rise globally in the rest of this century and the AR5 report of the IPCC (Kovats et al., 2014) clearly states that:

> *Climate models show significant agreement for all emission scenarios in warming (magnitude and rate) all over Europe, with strongest warming projected in Southern Europe in summer and in Northern Europe in winter*

Also the results from EURO-CORDEX, the European branch of the CORDEX initiative led by the World Climate Research Programme, show a robust and statistically significant warming for both RCP4.5 and RCP8.5 scenarios (Jacob et al., 2014). We summarise the results for the regions considered in this report in Figure 37, where the projected change in air temperature is shown for both the scenarios.

Figure 37. Average projected air temperature based on the mean of 8 EURO-CORDEX regional climate models for RCP4.5 (light blue) and RCP8.5 (light red).



The filled part of the plot shows the range between the minimum and the maximum among the eight models, smoothed with a rolling average of 20 years. The black line represents the observations until 2019 from the Copernicus Climate Change Service reanalysis ERA5. The numbers summarise the increase of average temperature considering the projections in the period 2035-2065 and the observations (i.e. ERA5) for the last 30 years (1989-2019). Climate projections data have been provided by the Copernicus Climate Change Service operational service for energy.

The projected temperature is expected to rise also in the IPCC WGI AR5 (Christensen et al., 2013) which also states that winter temperature will rise more in northern Europe while, summer warming will be more intense in the Mediterranean regions and in central Europe. Moreover, the length and the intensity of heat waves will increase throughout the entire continent. Also (Jacob et al., 2014) reports a projected increase of heat waves by 2050, particularly evident in the southern Europe

Although the impact of river/sea water temperature for thermal cooling has not been assessed in this report, it cannot be omitted in a list of the potential impacts of global warming on power systems. The temperature of rivers is expected to increase, driven by global temperature rise, in the entire continent (Van Vliet et al., 2013) and this effect will be exacerbated due to the projected reduction of river flows (Van Vliet et al., 2012; Bisselink et al., 2018). The temperature of the sea is also expected to increase, by 1.6 – 2.0 degrees globally in the next 30 years (2031-2050) and by 1.6 – 4.3 degrees by the end of the century (IPCC, 2019)

Solar radiation Climate change projections for solar radiation in Europe do not show a clear signal (Bartók et al., 2017) except for an increase in the Iberian peninsula and a reduction in the northern part of the continent (from Ireland to central eastern Europe).

Wind speed In general, as discussed in (Tobin et al., 2015; Davy et al., 2018; Tobin et al., 2016) and shown in the CLIM4ENERGY portal[26], some parts of northern Europe would expect an increase of wind speed while the rest, particularly the Mediterranean area, would decrease. It is also projected an increment of the inter-annual variability in the Baltic Sea and a decrease in the Mediterranean area (Carvalho et al., 2017). Regarding extremes, it is worth mentioning that the IPCC AR5 describes a small increase (with medium confidence) in projected extreme wind speeds during winter for central and northern Europe (Kovats et al., 2014).

Water availability As summarised in (Magagna et al., 2019) the river flows are projected to decrease in southern and eastern Europe and increase in the other regions, with some seasonal differences. Moreover, with an increase of river and lake temperatures, also the frequency and intensity of droughts is expected to increase.

Glaciers In the last decades we have observed a mass loss of glaciers around Europe and this is expected to continue in the near future with many glaciers projected to disappear regardless of future emissions (IPCC, 2019). Glacier melt will affect the annual streamflow with an impact on seasonal patterns of runoff distribution (Schaefli et al., 2019; Farinotti, Pistocchi, and Huss, 2016).

Future power systems

There are many studies about the impact of climate change on various aspects of the energy systems:

- energy markets (Chandramowli and Felder, 2014; Mideksa and Kallbekken, 2010), electricity demand (Bloomfield et al., 2016; Auffhammer, Baylis, and Hausman, 2017; Wenz, Levermann, and Auffhammer, 2017);
- infrastructures (Cronin, Anandarajah, and Dessens, 2018; Varianou Mikellidou et al., 2018; McColl et al., 2012; Cradden and Harrison, 2013);
- hydropower (Turner, Ng, and Galelli, 2017; Hamududu and Killingtveit, 2012; Lehner, Czisch, and Vassolo, 2005; Van Vliet et al., 2016);
- investments and operating costs (Jaglom et al., 2014)
- cooling systems and thermal efficiency (Ibrahim, Ibrahim, and Attia, 2014; Linnerud, Mideksa, and Eskeland, 2011; Van Vliet et al., 2012)
- renewable systems (Peter, 2019; Karnauskas, Lundquist, and Zhang, 2018; Jerez et al., 2015; Schlott et al., 2018; Tobin et al., 2016; Perera et al., 2020; van der Wiel et al., 2019; Wohland et al., 2017; Kozarcanin, Liu, and Andresen, 2019).

Also, an extensive review can be found in (Bonjean Stanton, Dessai, and Paavola, 2016). However, an incredibly important factor to assess those impacts is the shape of future European power systems.

As stated in the European Commissions' communication "A Clean Planet for All" (European Commission, 2018) the energy system of the future:

> *Relies on a secure and sustainable energy supply underpinned by a market-based and pan-European approach. The future energy system will integrate electricity, gas, heating/cooling and mobility systems and markets, with smart networks placing citizens at the centre.*

[26] Available at http://c4e-visu.ipsl.upmc.fr/ (accessed 15 January 2020)

We can in see in the various scenarios developed by the European Commission what will be the share of the climate-driven electricity sources (hydro, wind and solar power) foresee for the European continent for the year 2050.

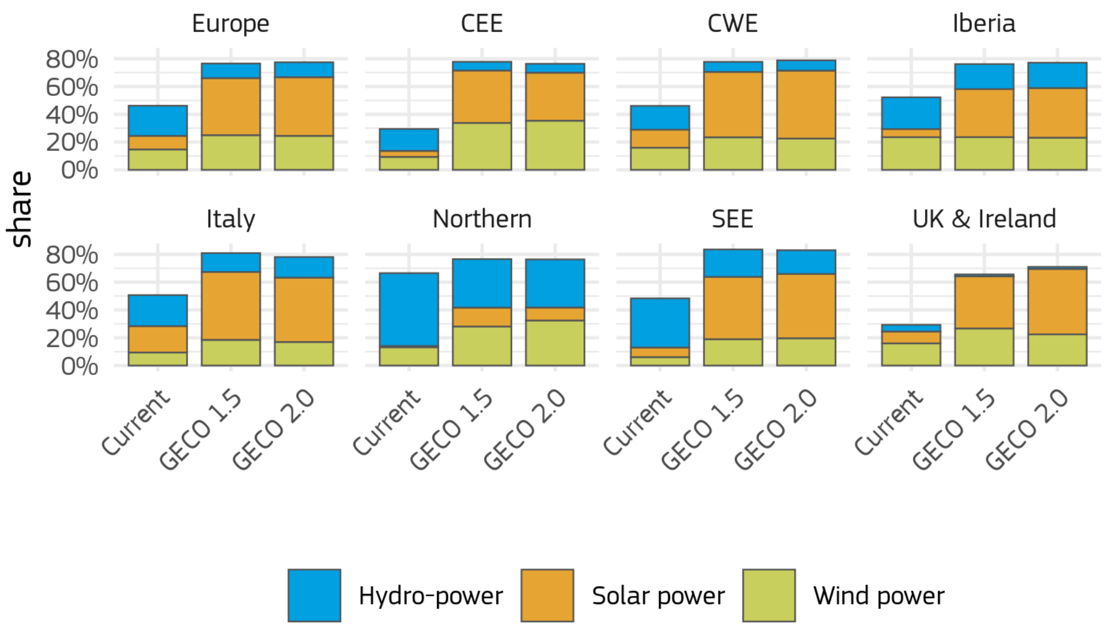
We will look into three scenarios:

1. The EUCO3232.5 scenario, which model the impact of achieving the target of 32% for renewable energy and 32.5% of energy efficiency
2. The POTEnCIA central scenario (Mantzos et al., 2019)
3. The Global Energy and Climate Outlook (GECO) scenarios for the global target emission to reach the 2° degree target (GECO 2.0) and the 1.5° degree target (GECO 1.5) (Keramidas, K., Tchung-Ming et al., 2018)

All the scenarios agree on depicting Europe (in this case EU because both EUCO3232.5 and POTEnCIA cover only the EU area) with more than 70% of the capacity provided by hydro, wind and solar power by 2050.

With the GECO scenarios we can analyse the projections at regional level. Figure 38 summarises the share of renewable energy sources on to the total installed capacity for the two GECO scenarios compared to the current situation (the one on which the simulations in this report are based on). We can see that the GECO scenarios describe a continent where most of the regions, except for Northern, would increase drastically their share of renewables by 2050. This mean that a large fraction of the power generation capacity will be affected, to various extents, to climate variability and, as we have seen previously, to climate change.

Figure 38. Share of installed capacity for renewable energies in European regions for the GECO scenarios in 2050 compared to the situation analysed in this report



4.2 Our roadmap

As said before, this work might be considered a fundamental step for an analysis of the future power system under climate change. To this end, we plan to extend this study considering future power systems, according to one or more European Commission's scenarios, and future climate, taking advantage of the abundant data over Europe on climate change projections.

On the link between climate and power systems still remain many knowledge gaps. We identified a set of gaps that we plan to address in our future works:

1. The cost of extreme weather events in the future energy scenarios and future climate

2. The impact of climate change on the availability and temperature of water (both freshwater and seawater) for thermal cooling
3. The difference between current and future weather patterns in terms of frequency and intensity
4. How to take into account the information about future weather patterns to design resilient 100%-renewables energy systems
5. Volatility of prices and its impact on markets caused by future climate
6. How to estimate the capacity factor of future wind farms (onshore and offshore) in order to address correctly the uncertainty induced by climate change projections
7. How to define patterns of electricity demand according to future energy scenarios and future climatic conditions
8. How to model the impact of the projected changes in water resources over Europe to future hydropower generation (particularly including glacier melting)

We think that a specific focus on extremes, as also suggested by (McCollum et al., 2020), should be given to understand their potential impact on energy scenarios, considering the effect of out of the ordinary, and often high-impact, events on our future power systems. Although some of the climate-induced impacts are already visible nowadays, in the next decades they might become more frequent and ubiquitous. This change is not only due to the changing climate, but as we have discussed in the previous section, also to the high penetration of renewables in the future power systems.

To obtain robust results, the use of multiple climate simulations is fundamental considering the inherent uncertainty of the projection of most of the meteorological variables over the European continent.

Decarbonising of the European energy sector is an ambitious challenge and for a sustainable transition, we should try to deal effectively with the uncertainty posed by the future climatic conditions. To this end, a study assessing all the source of uncertainties and investigating the most critical aspects of our future power systems would be able to support future policies and underpin an effective implementation.

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List of abbreviations and definitions

CEE	Central Eastern Europe
CF	Capacity Factor
CWE	Central Western Europe
EEA	European Environment Agency
ENTSO-E	European Network of Transmission System Operators for Electricity
GECO	Global Energy and Climate Outlook
NAO	North Atlantic Oscillation
PCI	Project of Common Interest
SDG	Sustainable Development Goal
SEE	South Eastern Europe

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Annexes

Annex 1. Modelling approach

This report uses the Dispa-SET[27] power system model (version 2.4) which includes a mid-term hydro-thermal scheduler (MTHS). Dispa-SET solves the unit-commitment and optimal dispatch (UCD) problems for large power systems using a GAMS-based model.

The MTHS implementation, has the objective to calculate the curves of the reservoir levels that will be used by the UCD problem as lower bounds of the reservoirs for the optimisation. In order to generate the curves, the MTHS runs a linear programming (LP) version of the main problem (rather than a mixed-integer) on an entire year using the same input data used by the UCD part. In other words, the MTHS generates the reservoir levels for an entire year used by the UCD, which runs considering a rolling horizon of two days, as guide curves imposing the minimum level of the storage at the end of the horizon.

UCD formulation

The model formulation for Dispa-SET is described on the website (www.dispaset.eu) and in several reports and publications (Fernández-Blanco Carramolino, Kavvadias, and Hidalgo González, 2017; Fernández-Blanco Carramolino et al., 2016; De Felice et al., 2018; Pavičević et al., 2019; Beltramo et al., 2017; Quoilin et al., 2015). We refer the reader to these documents for a detailed model formulation.

Mid-term Hydro-thermal Scheduler (MTHS)

As said before, the MTHS solves a LP version of the UCD problem. The MTHS formulation presents the following differences:

- It lacks all the parameters and constraints related to the start-up and shut-down of the generating units
- It has an additional constraints on the non-pumping reservoirs regarding the minimum level that cannot be lower than the 15% of the total storage size
- It has an additional constraint on the generation of the non-pumping hydro-power units setting the minimum generation at each time step to the 10% of the generating capacity

[27] Version 2.4 is available for download on http://www.dispaset.eu/en/latest/releases.html

Annex 2. Input data: sources and assumptions

The Dispa-SET models use several data inputs to simulate a power system. In this annex, we describe the data source and the assumptions behind each input. The entire dataset is available openly in the JRC Data Catalogue.

Unless differently stated, all the inputs are based on the following sources:

1. The "Current Context" model developed with the METIS model (Kanellopoulos et al., 2019)
2. The studies (Pavičević et al., 2019; Stunjek and Krajacic, 2020) which have been used to add information on the Balkans power systems

Availability factors and outages

This input describes the capacity available of a generating unit as percentage.

For the thermal units we used the values defined in the "Current Context" of METIS as described in the Section 2.2.5 of (Kanellopoulos et al., 2019).

For wind (onshore and offshore), solar and run-of-river we used two sources:

- The EMHIRES dataset (also used in the METIS Current Context) (Gonzalez Aparicio et al., 2016; Gonzalez Aparicio et al., 2017) for wind onshore, offshore and solar
- Inflow from JRC LISFLOOD (described later)

Transmission capacity (NTC)

This input contains the transmission capacity available for each simulation time-step. In our work, we assumed constant values at each time-step, in case the original sources present hourly variations (as explained in the Section 2.1.4 of (Kanellopoulos et al., 2019)), we use as constant value the maximum capacity observed during the year.

Flows

This describes the time-series of imported electricity from regions outside the simulated areas (Russia, Turkey, Ukraine). All the data is from the METIS Current Context using the historical values reported by the ENTSO-E Transparency Platform.

Fuel prices

This input defines the fuel prices of natural gas, oil, lignite and coal. The prices are constant during the year but different per country, as explained in the Section 2.2.6 of (Kanellopoulos et al., 2019).

Electricity demand

The electricity demand hourly time-series used in the METIS "Current Context" are developed by the JRC applying a temperature correction to the actual load time-series for 2015. The description is provided in Section 2.2.1 of (Kanellopoulos et al., 2019). For the countries not in the METIS model, we have used for all the climate years the load time-series from the ENTSO-E Transparency Platform for the year 2015.

Power plants

The power plants dataset from the METIS "Current Context" are based on the JRC Open Power Plants Database[28]. A detailed description is provided in the Section 2.1 of (Kanellopoulos et al., 2019).

Inflows

Inflow time-series have been generated from this report and they are not derived by previous works. This dataset has been created applying a machine-learning system to model the relationship between water

[28] Available with CC-BY-4.0 License at https://data.jrc.ec.europa.eu/dataset/9810feeb-f062-49cd-8e76-8d8cfd488a05

runoff and observed inflows. The water runoff is obtained by the JRC LISFLOOD hydrological model (Burek, van der Knijff, and de Roo, 2013): this variable represents the total amount of water available and is aggregated at catchment[29] level. The time-series of all the catchment runoffs are then used as predictors for a Random Forest (Breiman, 2001) which is trained using observed inflow data for the period 2009-2015. The trained random forest is then used to generate the inflow for the entire JRC LISFLOOD range (1990-2015).

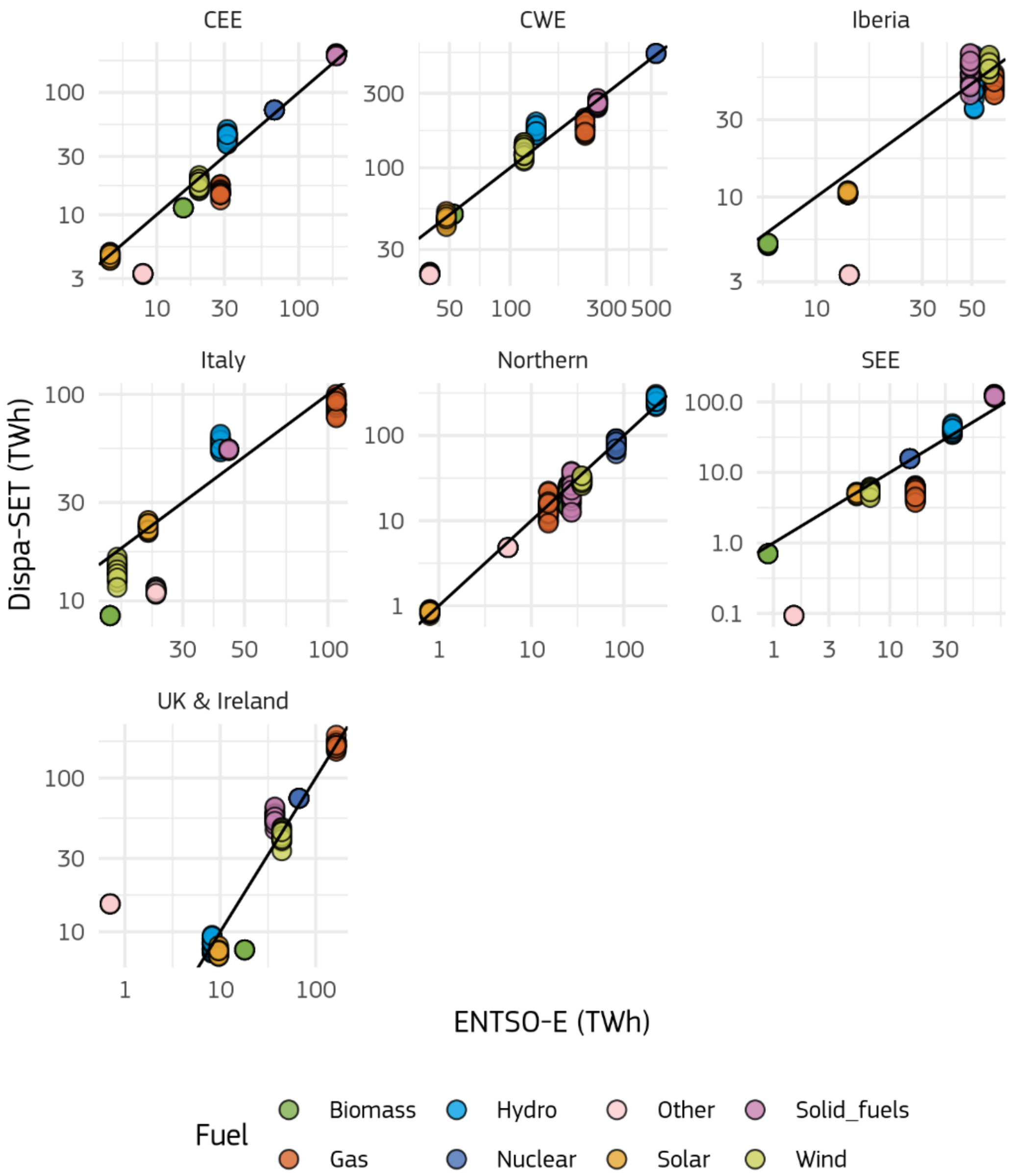
Finally, we rescale the annual inflow for each country obtained with this methodology with the annual inflow from the METIS model described in the Section 2.2.2 of (Kanellopoulos et al., 2019).

[29] A catchment area is defined as the area over which all the precipitation ends up in the same river.

Annex 3. Model validation

The Figure 39 shows in a scatter plot the annual generation reported by ENTSO-E for the year 2016 and the generation simulated with the 26 climate years.

Figure 39. Comparison between the annual generation reported by ENTSO-E for the year 2016 and the simulated generation with the 26 climate years.



ENTSO-E data is from the Statistical Factsheets 2016

Annex 4. Analysis of the spatial covariability

In the Section 2, we have observed how the most important types of input for a power system simulation vary year by year due to climate variability. The next step towards a complete assessment on the impact of climate variability is an analysis on the covariability, thus on how those variables vary together. Covariability of renewable generation in Europe has already been object of many scientific works (Graabak and Korpås, 2016; Monforti, Gaetani, and Vignati, 2016; Malvaldi et al., 2017; Buttler et al., 2016; Thornton et al., 2017). Also, an extensive review on the complementarity of renewable resources can be found in (Jurasz et al., 2020). However, inflow/hydropower generation is rarely taken into account in the studies on covariability.

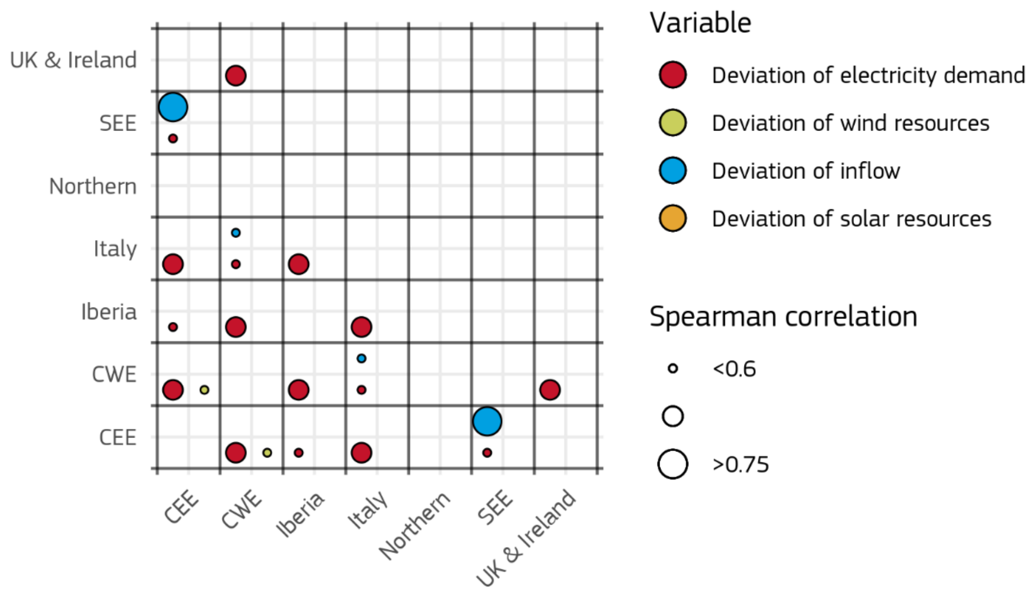
The concept of covariability can be linked to the concept of "compound event", which is considered a very important aspect in relation to the climate derived hazards in (but not only) the energy sector (see for example (Turner et al., 2019; Zscheischler et al., 2018; Zscheischler and Seneviratne, 2017; Leonard et al., 2014)).

Moreover, the impact of spatial and temporal dependency of adequacy of the systems has been investigated in various studies from ENTSO-E (see (ENTSO-E, 2014) and in general the mid-term adequacy forecasts[30]) and from the European Commission (European Commission, 2016)

The first step is the analysis of the spatial covariability: how the same variable changes among the different regions. To this end, Figure 40 shows how the daily values of electricity demand, wind and solar capacity factor, and the inflow are correlated among the regions in the entire year. To avoid to show the correlation of seasonal cycles (particularly evident for solar and demand), the shown correlation is computed using the deviation from the daily averages rather than the absolute values. In other words, for each day we calculate the average for a particular variable on all the climate years and then, for each day and year, we compute the deviation from this average.

All the correlations appear to be positive and the most of them are of the electricity demand, suggesting that air temperature – the main driver of the demand – is a variable with a large geographical scale. As expected, most of the correlations happen between neighbouring regions.

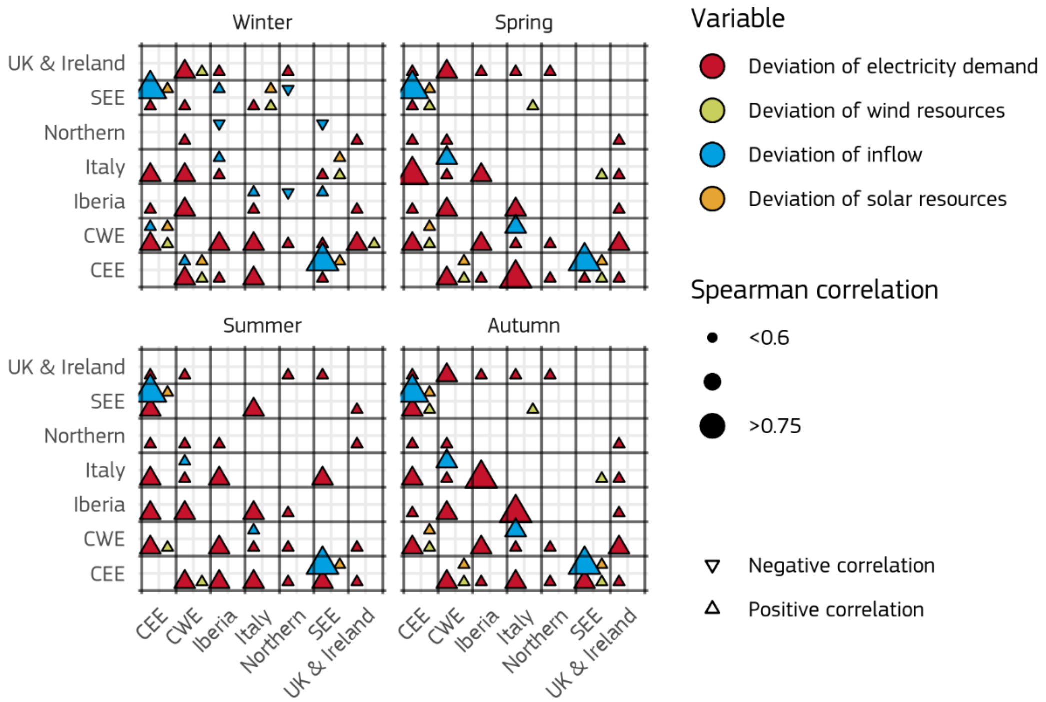
Figure 40. Spearman correlation of daily values of the anomaly (i.e. the deviation from average) of demand, wind, inflow, and solar among the considered regions.



Only the correlations with an absolute value greater than 0.5 are shown. The analysis of the spatial covariability becomes more interesting when considering the correlations for each season, in order to highlight specific phenomena limited only to a part of the year. Figure 41 is similar to Figure 40 but showing a subplot for each season. Some of the correlations appear in all the four seasons and we can observe, differently from the previous figure, also correlations involving solar and wind resources

[30] Available at the following URL: https://docstore.entsoe.eu/outlooks/maf/Pages/default.aspx

Figure 41. Spearman correlation of daily values of the anomaly (i.e. the deviation from average) of demand, wind, solar power and inflow at seasonal level for the regions across the 26 climate years.



Only the correlations with an absolute value greater than 0.5 are shown.

It is worth noting that limiting the analysis to a single season brings to higher correlations and, very important, a few negative ones. The negative correlations are in the winter season and they are between two regions not geographically close: Northern and Iberia and Northern and SEE. The negative correlation suggests a possible role played by the so-called North Atlantic Oscillation (NAO), a large-scale atmospheric pattern affecting the entire Europe and having an impact very different between the northern and the southern part of the continent. An investigation of the impact of the NAO on the renewable generation in Europe can be found in (Jerez et al., 2013; Engström and Uvo, 2016; François, 2016; Grams et al., 2017).

So far, we have analysed the correlation of a single variable among the various regions, in the rest of this section we analyse instead the correlation among different variables. If we look at the correlation of different variables within the same region, we find the values shown in Table 12.

Table 12. The eight correlations with the highest absolute value between two different variables in the same region.

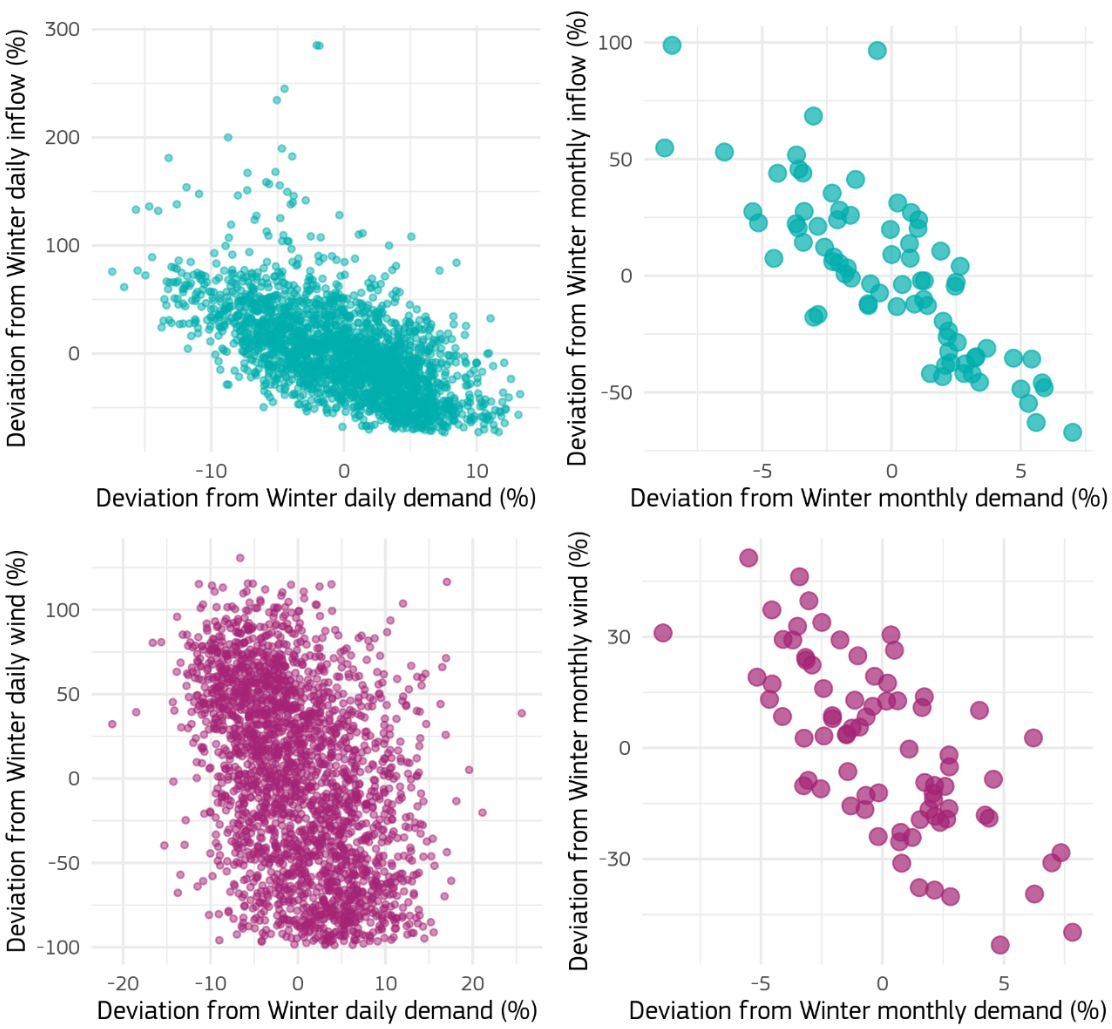
Region	Season	First Variable	Second Variable	Correlation (Spearman)
Northern	Winter	Inflow	Demand	-0.63
Northern	Spring	Inflow	Demand	-0.62
Northern	Winter	Wind	Demand	-0.53
CWE	Winter	Wind	Demand	-0.53
Northern	Autumn	Inflow	Demand	-0.49
Iberia	Autumn	Solar	Inflow	-0.47
UK & Ireland	Winter	Wind	Demand	-0.43
Iberia	Winter	Solar	Inflow	-0.43

The values indicate that the most common relationship between different variables is a negative correlation, for example in the Northern region when the inflow is higher than normal the demand is lower (and vice versa). The highest positive correlation (not shown in the table) is the one between wind and inflow in Iberia during winter, with a correlation of 0.38. Two of the values shown in Table 12 are visualised in Figure 42 as scatter plots, showing both daily (actually used in the table) and monthly percentage deviations of two variables. The daily values of demand and inflow during winter in the Northern region (first two panels) show a Spearman correlation of -0.63 (daily values) and -0.82 (monthly values). For UK & Ireland the correlations are instead -0.43 between the daily values of demand and wind and -0.7 for the monthly values.

It has to be noted that while negative correlation among different resources is desired as they can complement each other, in the case of demand a high positive correlation with a renewable resource is ideal because this reduces the actual residual load, i.e. the part of the electricity demand that must be satisfied with dispatchable generating units.

Both daily and monthly values are important to analyse the covariability. In fact, the higher the temporal resolution the more important is the impact of the compound event (e.g. high demand and low wind) on the power system. On the other side, the monthly value usually shows a clearer relationship highlighting a phenomenon possibly persisting for the entire season.

Figure 42. Two examples of the correlations shown in Table 12: Northern region (first row) and UK & Ireland (second row). Each point is a daily value (left panels) or a monthly value (right panels).



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