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Simulating the electricity price hike in 2021

A model-based analysis of the European power system with METIS

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Abstract

In 2021, an unprecedented increase in gas spot prices and wholesale electricity prices took place in Europe. Gas spot prices reached a record high day-ahead value of 116.1 EUR/MWh in October 2021. Similarly, the electricity day-ahead prices reached 170 EUR/MWh in October 2021, an increase of 345% compared to October 2020.

This study carries out an analysis on the operation of the European power system in 2021, and with alternative counterfactual settings in order to gain insight into causes and effects of the electricity price spike. The electricity market conditions are analysed using the METIS power system model with particular respect to the impact of weather, renewable capacity additions, and fuel prices. The impact of climatic condition is assessed comparing the modelled 2021 year with a set of climatically-adjusted years, reflecting weather conditions observed in the past 37 years. Furthermore, with the help of counterfactual scenarios, we assess the price mitigation effect of the added renewable capacity fleets within the next three years, and the possible CO_2 emission increase in a year without the gas and CO_2 price spike of the second half of 2021.

Due to the fact that the bulk of this analysis was carried out in the course of October the analysis of the last three months of the year is based on future market commodity prices, and synthetic rather than actual power system parameters (demand, availabilities etc).

1 Introduction

In in the second half of 2021, EU gas spot prices and wholesale electricity prices reached unprecedented levels. Gas spot prices (TTF) increased in the second quarter by 36% with respect to the previous quarter and by 373% on a yearly basis [1], reaching a record high day-ahead value of 116.1 EUR/MWh in October 2021. Similarly, the electricity day-ahead prices in the EU[1] have shown an increase of 110% in the first half of 2021 compared to the same period in the previous year, and the EU average price was 170 EUR/MWh in October 2021, an increase of 345% compared to October 2020.

This price spike triggers a number of questions related to the further development of this situation. We have used the occasion to update our existing 'current METIS context', which was last used for a study to assess the benefits of PCI projects to the European power system, and to conduct a modelling-based assessment of the situation on the electricity and gas markets and of its possible evolution over the next few months.

It is commonly understood that the recent rise in gas prices is driving the parallel increase in electricity wholesale market prices because gas-fired power stations are 'setting the electricity price' for a significant number of hours per year. In the current study we analyse not only how high gas prices translate into electricity price spikes but also to what extent the electricity price spike is exacerbated by the low wind availability observed [1] [2].

This study was launched at the beginning of October 2021, and has a small forward-looking component assessing the possible evolution of gas demand and electricity wholesale prices over the coming months, based on forward prices available at the time.

The abrupt increase in gas prices in the second half of the year means that generating electricity with coal was cheaper during the last quarter of 2021 than generating electricity with natural gas, based on actual European gas hub prices. The extent to which a fuel switch from gas to coal will take place depends upon the actual availability of coal-fired power plants and their readiness to operate at a higher load factor, and on the actual gas procurement costs of gas-fired power plants. The latter may diverge from gas hub prices, depending on the contractual and hedging provisions that individual operators have selected. While these factors are generally not publically available and sometimes impossible to know, it is of interest to assess the extent to which the current very high gas prices will lead to an increase of GHG emissions from the electricity generation sector.

In the coming years, significant renewable capacity will be added to the European power system. Additional renewables reduce the residual load (load served by conventional generation) and thus also the wholesale electricity prices, during periods in which they generate electricity. Therefore it is of interest to assess the extent to which additional renewable generation could contribute to moderating the price spike (and the generation costs).

([1]) Considering the average of all the day-ahead prices (ENTSO-E) of the EU countries weighted by their annual electricity consumption

2 Scenario setup and model benchmarking on available 2021 data

The present analysis uses a 'METIS context'[2] representing the infrastructure present in the European power system in 2021. This was created based on the methodology and assumptions presented in Annex 1. The analysis aims to address the following questions:

1. Is weather (low wind) to blame for the current market situation?
2. What would the situation look like if it had occurred two or three years later? To what extent would additional renewable generation have moderated the price spike?
3. To what extent have the high gas prices increased GHG emissions of the electricity generation sector?
4. What does modelling tell us about how often gas is setting the wholesale electricity price?

Table 1 lists the contexts that were used in the present analysis in order to answer the above questions. Context #1 explores the meteorological factor. It is built on observed demand (and renewable energy production) of 2021 (up to 30 September), which is extended with an 'average year' last quarter as the baseline. This 'historical' baseline is then compared to 37 climatic years (1980-2016).

Context #2 shares the first nine months with the previous context. The last quarter is instead defined by selecting the quarters from the three climatic years (representing the expected climatic range) with a cumulative last quarter demand that is low, average and high.

Context #3 is a counterfactual scenario, derived from context #2, assuming additional renewable capacity.

Context #4 is a counterfactual scenario, derived from context #2, assuming that the gas price in the 2nd half of 2021 replicates the 1st half and thus shows no significant price increase.

Table 1. Scenarios and reported indicators

	Contexts	Output
#1	2021 EU energy system and fuel prices and 1980-2016 climatics	Generation fuel mix Gas demand Marginal cost of electricity CO_2 emissions
#2	2021 EU energy system and fuel prices with last quarter extended with climatic time series corresponding to average, mid and high gas demand	
#3	RES capacity counterfactual of #2	
#4	Price counterfactual (2nd half = 1st half) of #2	

Source: JRC, 2022

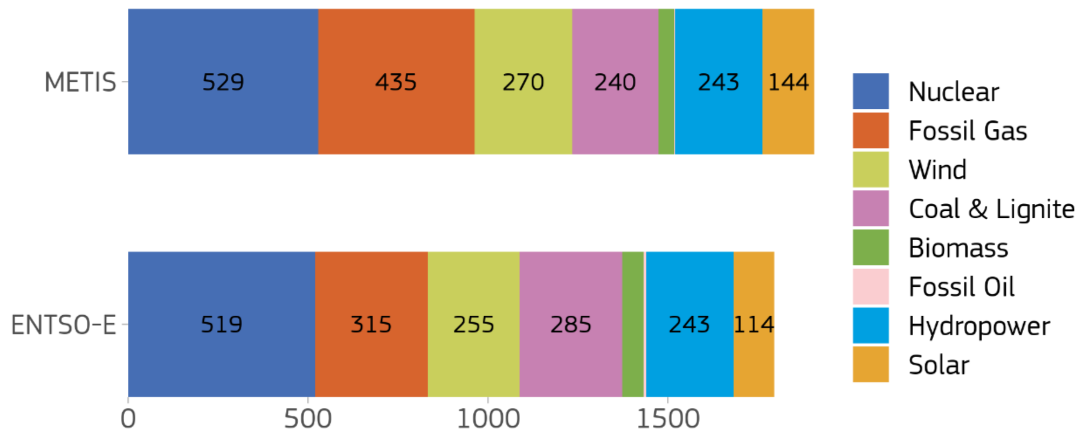
2.1 Benchmarking of 2021 ENTSO-E data (January-September)

The context is a derivative of the JRC's "CURRENT 2016", which was extensively benchmarked with the actual dispatching of the EU power generation fleet observed in 2016 [3]. Figure 1 provides a comparison of the generation fuel mix in the EU during the first nine months of 2021, calculated by the model vs the actual fleet generation reported by ENTSO-E. We observe that the total generation reported in the ENTSO-E transparency platform is approximately 130 TWh lower than the demand reported by the same platform[3].

([2]) A context in METIS is the container of the input dataset and modelling parameters used to define the optimisation problem as well as it's solution and results expressed in the form of annual indicators or time series.

([3]) The demand data used is the 'Actual Total Load' (6.1.A) dataset and the generation data is the 'Aggregated Generation per Type' (16.1.B) from the ENTSO-E Transparency Platform retrieved on 2 November 2021.

Figure 1. EU fuel mix (TWh) in the period January-September 2021 (Model output vs actual fleet generation)



Source: JRC, 2022

The ENTSO-E time series reporting on wind and solar generation is short by 30 TWh and 15 TWh respectively. The remaining 85 TWh are missing from thermal generation (coal, lignite and gas). Previous detailed benchmarking of modelling results with ENTSO-E data [3] identified that gas and coal/lignite generation reporting is incomplete. By extending the results of that analysis to 2021, we conclude that gas-fired generation with METIS is less overestimated than Figure 1 suggests. The opposite is true for coal/lignite-fired generation, which METIS has underestimated more than Figure 1 suggests. **Table 2** provides the observed and estimated[4] deviations between the modelled and historical generation during the first nine months of 2021 for nuclear and thermal fleets respectively.

Table 2. Differences between modelled (METIS) and reported (ENTSO-E) fleet generation

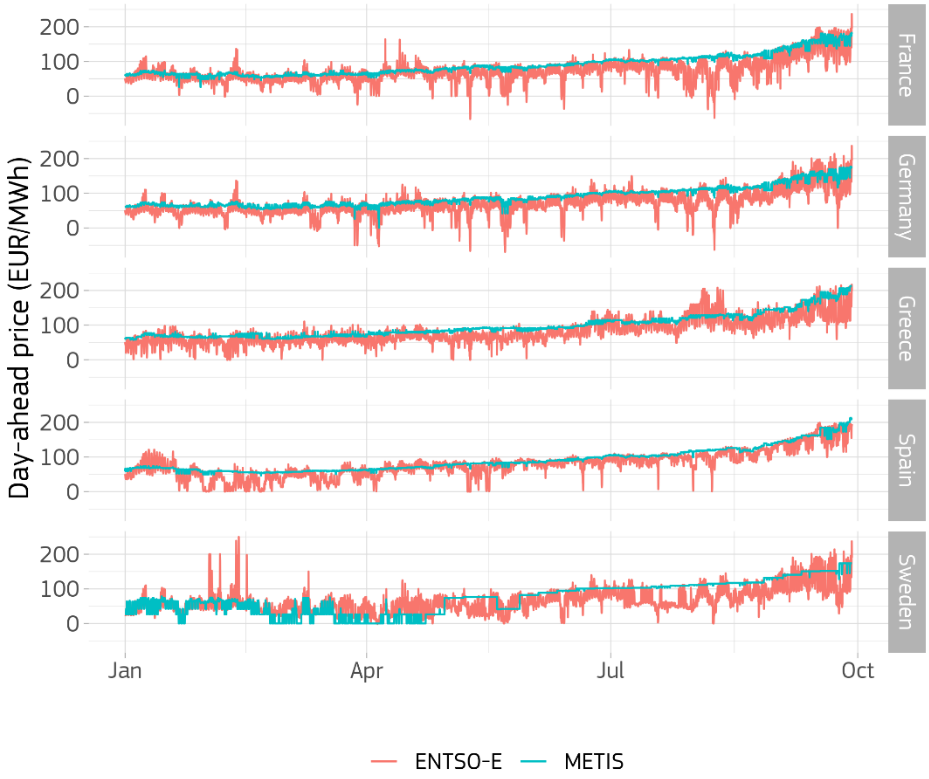
Fuel	METIS vs ENTSO-E Deviation	Possible Explanation
Nuclear	+10 TWh (+2%)	Incomplete outage schedule reported in ENTSO-E TP
Gas	~ +75TWh (+20%)	• Gas-fired are dispatched before coal-fired power stations in the merit order for the majority of hours in January-September 2021. A part of the coal and lignite legacy fleet (possibly cogeneration) were operated more than pure power economics (as currently modelled in METIS) dictate. • Marginal cost used in the model is based on hub daily prices which may not fully reflect the actual total fuel cost of the coal and gas fleets.
Coal & Lignite	~ -85TWh (-26%)	

Source: JRC, 2022.

Figure 2 provides the hourly marginal cost computed by the model for five zones in comparison to the actual 2021 day-ahead market prices (up to September 2021). The results indicate that the model is able to approximate peak prices, but under the assumptions used, cannot predict depressed prices during hours of low residual load. One reason is that METIS does not represent bids submitted by market participants below their variable cost, e.g. resulting from must-run requirements or as trade-off for avoided ramping costs. One further reason for not predicting the low prices is that the model represents each country as one zone and thus cannot capture local intra-zone congestions leading to renewable curtailment and/or thermal generation re-dispatching.

([4]) For this estimate we assume that the missing 85 TWh thermal fleet generation is split in half between gas and coal & lignite.

Figure 2. Day-ahead price: comparison between METIS and ENTSO-E data for five selected countries (France, Germany, Greece, Spain, and Sweden)

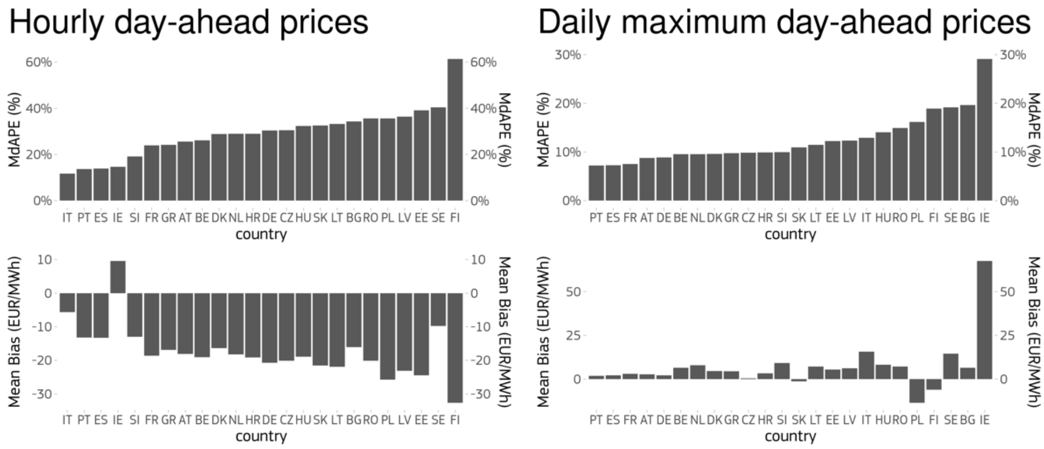


Source: JRC, 2022

Figure 3 shows the difference between the model output and the day-ahead average price (January-September) and, as such, may be seen as an indication of the bias of the model in approximating the day-ahead price. We notice that the median absolute percentage error (MdAPE[5]) ranges from 15% to 60%. This is mainly driven by the errors in simulating the valley (or minimum) daily prices, with the exception of the Nordic Countries (DK, SE, FI), where electricity prices are largely unaffected by the recent rise of gas prices. This is supported by the graph to the right which provides the errors of the daily maximum prices where it's visible, with the exception of Ireland, that the model captures peak prices with a much higher accuracy than the average daily price.

([5]) The Median Absolute Percentage Error between the modelled price at time t ($\widehat{p_t}$) and the observed price (p_t) is defined as: $median(100\left|\frac{p_t - \widehat{p_t}}{p_t}\right|)$. Compared to the MAPE (Mean Absolute Percentage Error), the MdAPE is more robust to outliers. The Mean Bies Error (MBE) represents the average deviation between the two variable and is defined as $\frac{1}{n}\sum_{t=1}^{t=n} p_t - \widehat{p_t}$

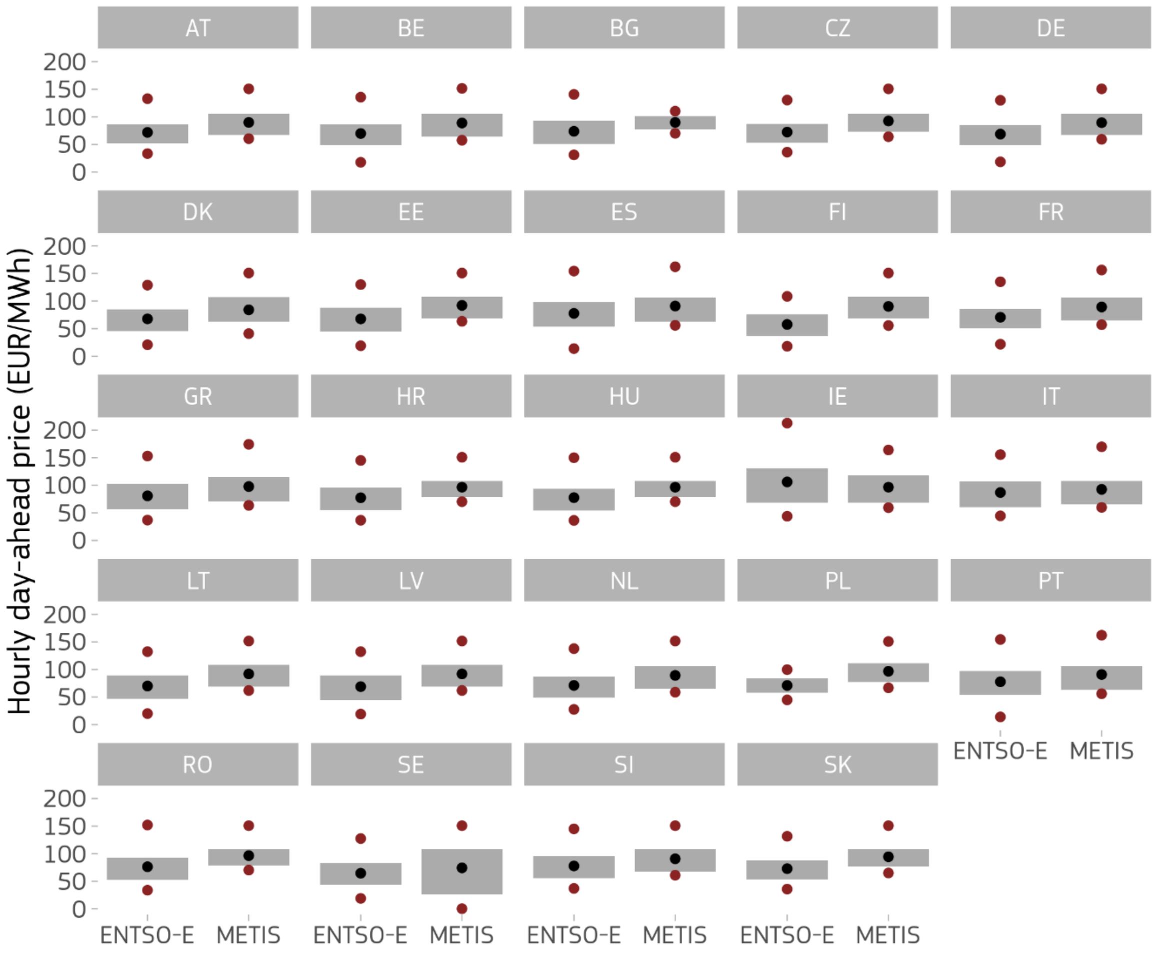
Figure 3. Median Absolute Percentage Error (MdAPE) and Mean Bias Error (MBE) between METIS output and ENTSO-E day-ahead prices (left) and daily max day-ahead prices (right). Errors are computed on the period January – September 2021.



Source: JRC, 2022

In general, the model overestimates the average day-ahead prices with the exception only of Ireland (IE). This bias is visible both on the central part of the distribution (inter-quartile range in Figure 4) and at the extremes (5th and 95th percentiles).

Figure 4: Comparison of the distribution of day-ahead prices between ENTSO-E and METIS outputs. The grey box shows the inter-quartile range of the distribution while the brown points represent the 5Th and the 95th percentiles. The black point shows the average of the distribution.



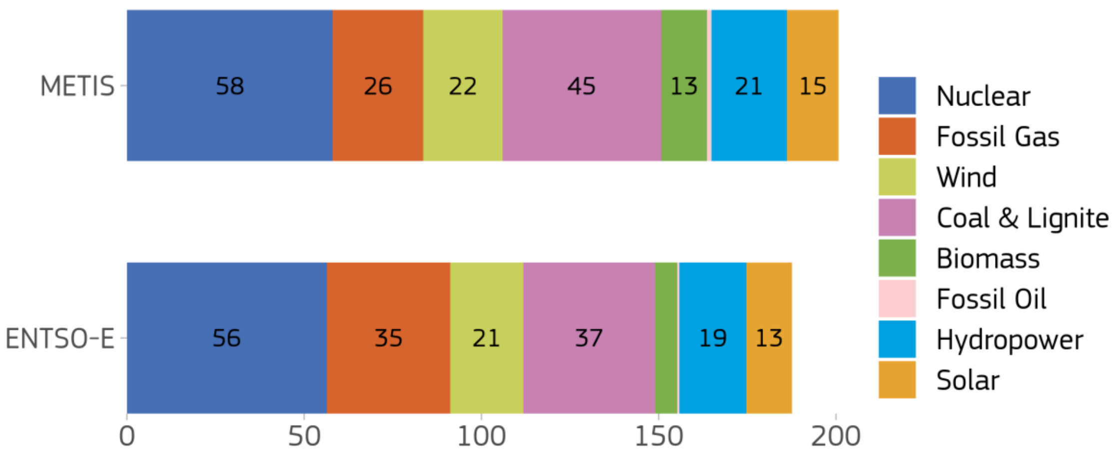
Source: JRC, 2022

2.1.1 Focus on September 2021

By September 2021, the sharp increase in the price of natural gas in European hubs had changed the merit order of the European fleet in favour of coal and lignite. Starting as soon as July, lignite-fired electricity generation picks up first, followed by hard coal-fired generation.

A comparison of the dispatching results until September 30 shows that the model overestimates this fuel switching. This is further evidenced in Figure 5, which provides the dispatching results provided by METIS next to the ENTSO-E transparency platform numbers.

Figure 5: EU fuel mix (TWh) in September 2021 (Model output vs actual fleet generation)

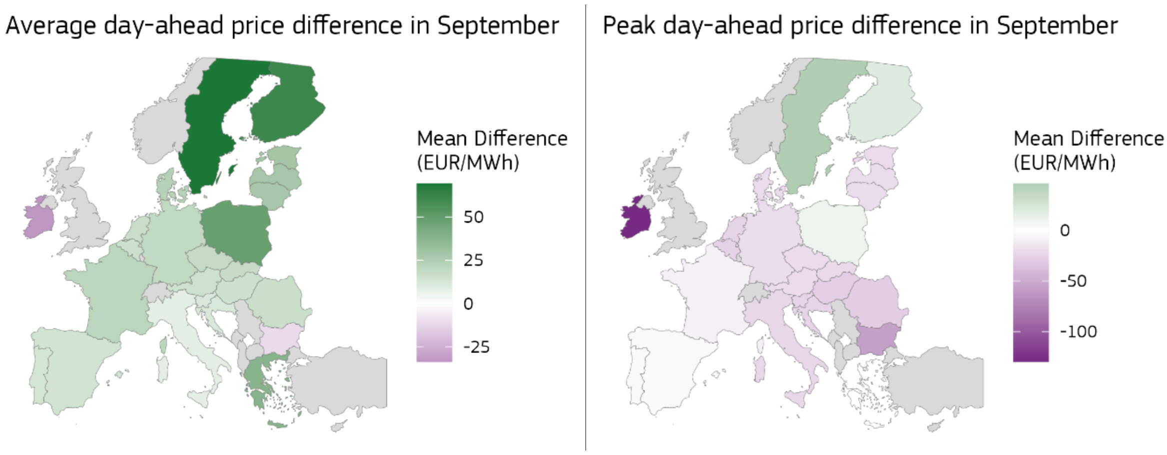


Source: JRC, 2022

We notice that more electricity is generated from coal than from gas, a reversal of the situation during the first nine months as shown in Figure 1. The METIS model selects more coal/lignite than what is observed based on the actual fleet generation data on the ENTSO-E Transparency Platform (TP). This may be either due to coal/lignite units being less available in real life than the outages reported on the TP suggest, or due to the actual cost of fuel procured by power plants being lower than hub-based marginal cost of gas considered in this modelling assessment. Figure 6 provides the difference in the modelled marginal cost and the day-ahead price during September. The map on the left provides the average daily price, while the map on the right provides the difference in the peak daily price. The daily peak electricity price is the maximum hourly value per day and market zone or Member State.

We notice that the difference is significantly lower in the peak daily price. It is possible that this pattern occurs due to more competitive (below hub-priced variable cost) bidding by the gas fleet during low load hours or for part of their offered capacity.

Figure 6: Average and peak day price difference (METIS output minus ENTSO-E day-ahead hourly prices) in September



Source: JRC, 2022

We also notice three distinct clusters of countries where the following patterns are visible:

- Ireland, where peak and average price is underestimated by the model.
- Poland, Sweden and Finland, where both the observed day-ahead average and daily peak price are lower than the modelled price.
- Rest of Europe, where the observed peak day-ahead price appears to be mainly driven by the hub-based gas price and in fair agreement with model results. However as mentioned previously the observed average day-ahead price is lower than the modelled price.

In general, this benchmarking shows that the model is able to reconstruct with sufficient accuracy both the fuel mix and the trend of peak day-ahead prices. The results presented in this section suggest that the implemented modelling framework can be used to gain insights on the operations of EU power systems, as discussed in the rest of this document.

3 Modelling analysis

In this section we present the modelling results that address the questions formulated in section 2. We first compare 2021 with a set of different climatic years to assess the effect of weather variability on gas demand for power. We then compare 2021 results with a year with additional renewable generation, corresponding to 1-3 years ahead to assess the effect of the additional renewable capacity planned to be come online within the next couple of years. Furthermore we compare 2021 results with a "normal" 2021. That is a year where the gas price spikes of the 2nd half never happened, in order to assess the effect of high gas prices on the fuel mix and CO_2 emissions. Finally we conclude with an estimate of the hours that gas and coal fleets are marginal across the EU.

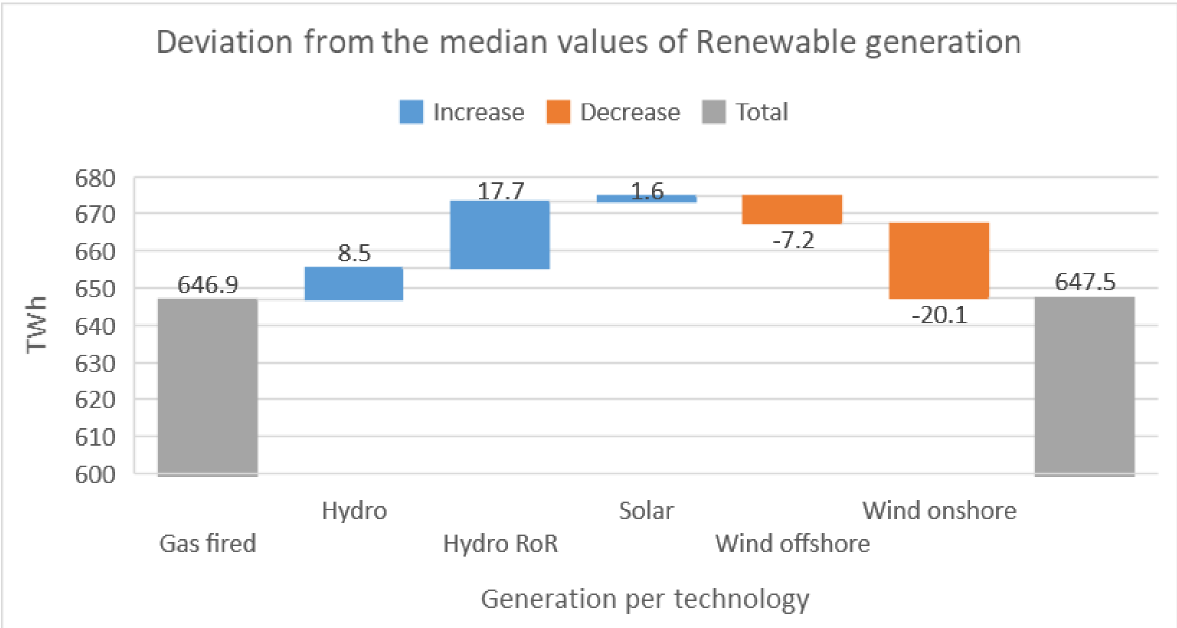
3.1 Comparison of 2021 with climatic years (1980-2016)

In the following paragraphs we seek to assess the extent to which the particular climatic conditions in 2021 have contributed to the current high prices in the European electricity markets. We use the current 'Context-2021' to simulate the partially-historical 2021 alongside 37 climatic years (1980-2016) and compare the model results on factors that affect the estimated yearly gas demand. Detailed information on the methodology used is given in the Annex 2.

3.1.1 Renewable generation in 2021 with respect to the climatic years

Our analysis of the 2021 weather and ENTSO-E data revealed that the observed wind power generation is lower than the 37-year median. For onshore wind the figure is 5.4%, while for offshore wind the value is 5.8%. This deficit is, however, compensated by a notably higher production from hydropower (11% for run-of-river and 2.6% for reservoir hydro). The total renewable electricity production (including hydropower) in the EU during the first nine months of 2021 was thus practically at the level of an average year. This is highlighted in Figure 7.

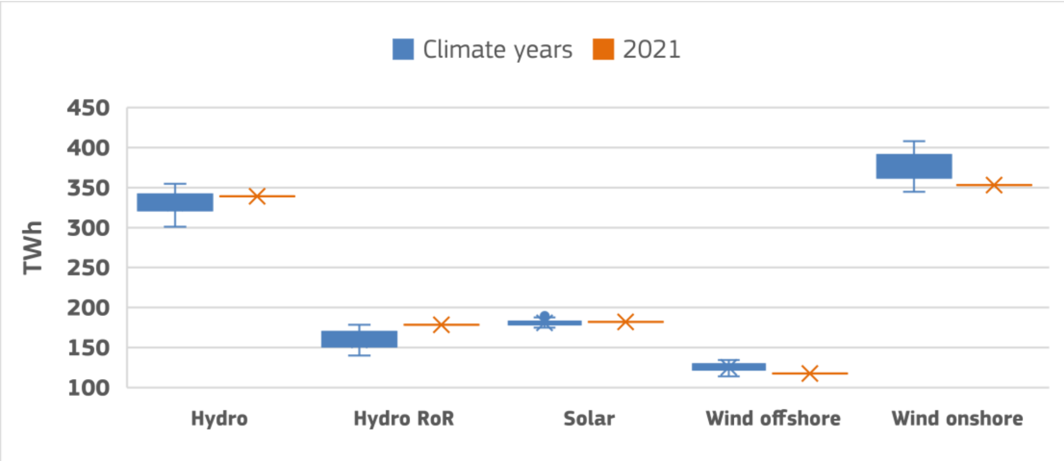
Figure 7. Difference in Renewable generation in 2021 compared to median of 37 climatic years



Source: JRC, 2022

Figure 8 provides the boxplots of the distribution of renewable electricity generation in the 37 climatic years.

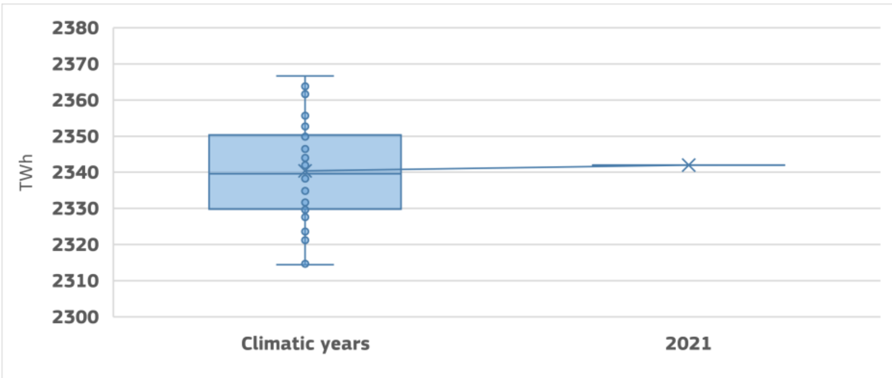
Figure 8. Renewable generation output in 2021 compared to the 1980-2016 range Source: JRC, 2022



Source: JRC, 2022

The following box plot provides a comparison of the overall electricity demand in the modelled area during the first nine months of 2021 with the demand in the 37 climatic years. Power demand is slightly above the average of the 37 climatic years.

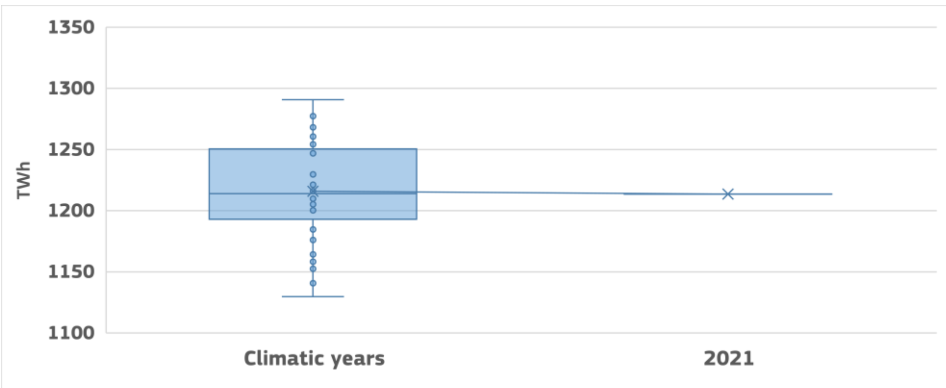
Figure 9. Power demand in 2021 compared to the 1980-2016 range



Source: JRC, 2022

The resulting gas demand for electricity production in 2021 (model result) is slightly below the median value of the 37 climate years (see Figure 10).

Figure 10. Gas demand for power generation in 2021 compared to the 1980-2016 range



Source: JRC, 2022

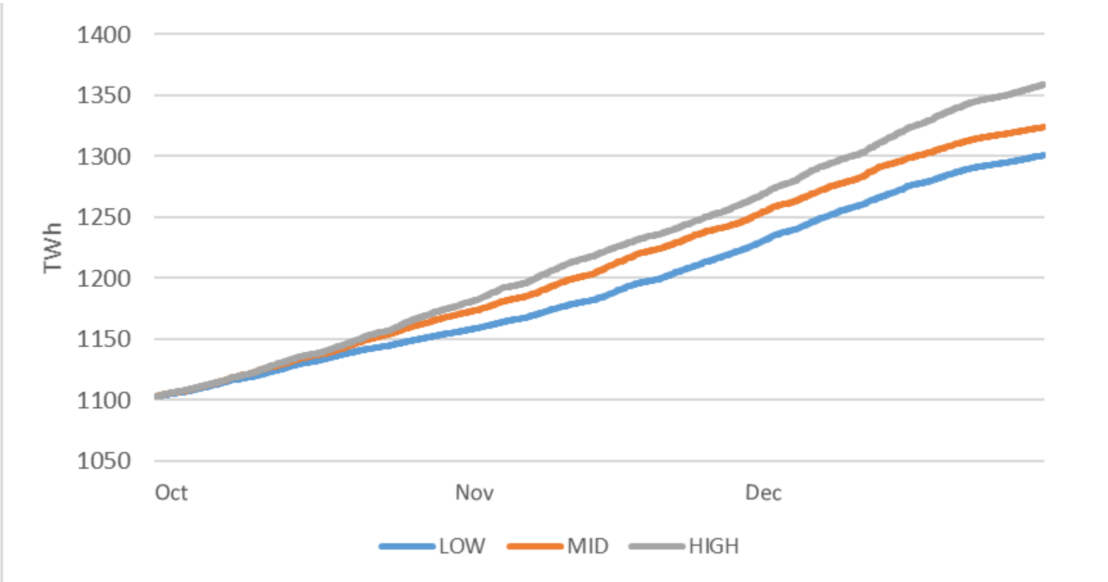
We conclude, based on the results presented in this section, that the weather conditions prevailing in 2021, and in particular the reduced wind availability in the first nine months of 2021, do not appear to have contributed to an increased gas demand for power generation, compared to historical climatic years.

3.1.2 Sensitivity of gas demand for power to climatic variability

The simulation results of the 37 climatic years provide the dispatching of the gas fleets for every zone in the modelled area. By using the range of climatic data we can estimate the possible range of values of gas consumption during the last three months of the year due to weather conditions. We selected the climatic time series from our historical database (wind, solar, water inflows, power demand) of the last three months of the respective year with the highest, average and second lowest gas demand to extend beyond 30 September 2021, up to which point actual time series for the year 2021 were used.

Figure 11 illustrates the cumulative gas consumption by the gas-fired fleet in the EU for the respective three years. We observe that the difference between the high and low consumption year is about 50 TWh, or less than 5% of the total annual gas-to-power consumption.

Figure 11. Cumulative gas demand for power generation high – low and mid gas consumption

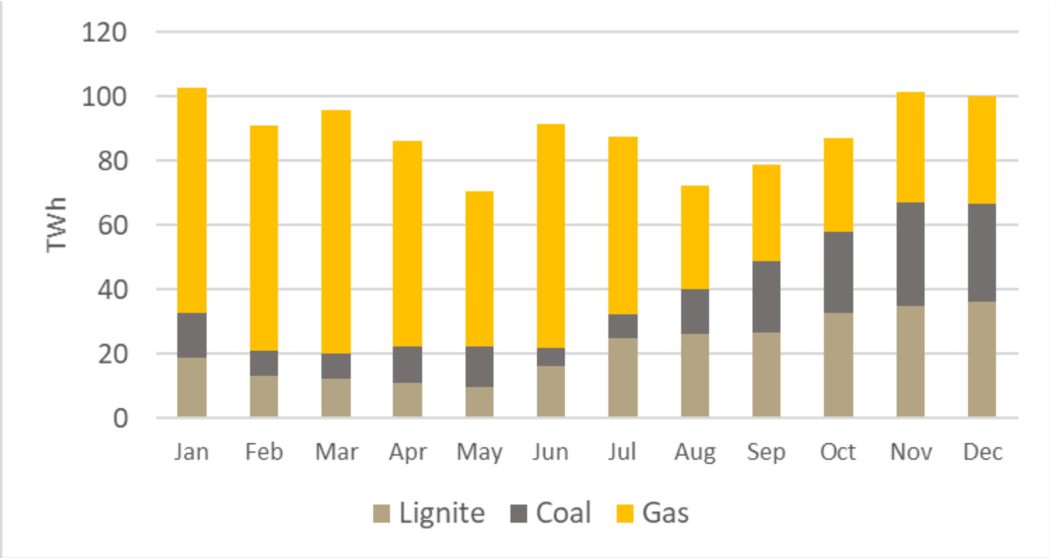


Source: JRC, 2022

Figure 12 illustrates the evolving fuel mix in the EU thermal generation fleet and the rate at which coal replaces gas in the second half of the year for the scenario with average gas demand. In the last two months of the year the model estimates that the generation from the coal and lignite fleets could be two to three times higher than the dispatching calculated during the first months of 2021, therefore potentially contributing to a substantial reduction of gas demand in the last quarter of the year.

The extent of this potential switch from gas to coal and lignite and the resulting effect on CO_2 emissions and gas consumption in the EU is assessed in section 3.3 by means of a counterfactual 'Normal prices 2021'.

Figure 12: Monthly generation from the gas, coal and lignite fleets (EU – model results)



Source: JRC, 2022

3.2 What if we had additional renewables in the system today?

This section looks into a counterfactual setting where additional renewable electricity generation capacities would have been available to the EU electricity system in the year 2021. The scenario is constructed by cumulatively increasing, in annual increments up to 2024, the capacities per country of the solar, wind onshore and wind offshore fleets. The increments are derived from the PRIMES MIX H2 scenario as the yearly average capacity increase in the period 2020-2025 per fleet type and country, projected by the PRIMES model. Where capacities are not increased or reported, the 2021 value is kept constant. Accordingly, in the following, the scenario labelled '2021' presents the reference case and the scenarios labelled '2022', '2023' and '2024' for the increased capacities. On the output side, this section considers how the additional renewable capacities would have changed/alleviated the situation with regard to selected key indicators composed of electricity prices, gas consumption for power generation and CO_2 emissions.

Subsequently, Figure 13 displays the resulting variation of the installed capacities per scenario and fleet. To put these numbers into perspective, the text values indicate the compound annual growth rate (CAGR) between 2021 and 2024. For enhanced clarity in presentation, while preserving regional differences, countries have been mapped to regions according to Table 3, which aligns with some slight adaptations to the conventions applied in the gas and electricity market quarterly reports published by the European Commission.

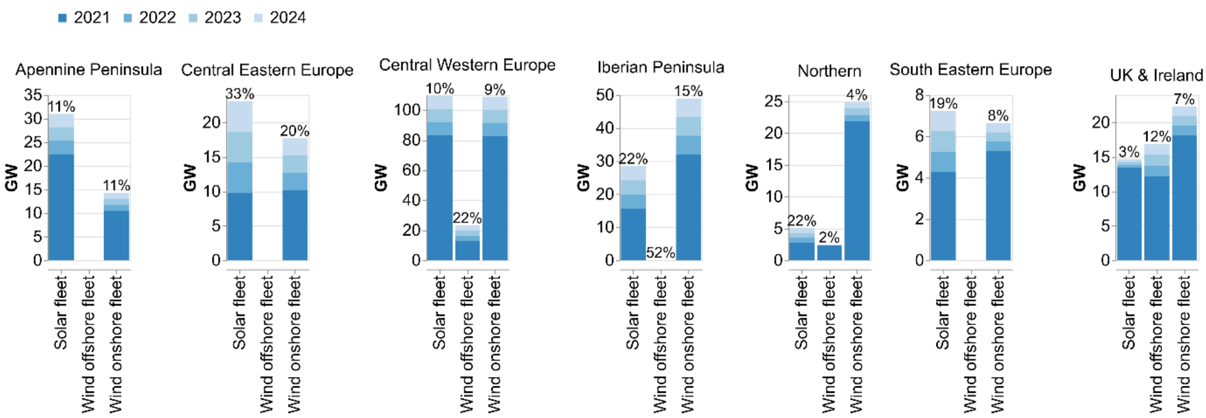
Table 3. Mapping countries to regions.

Region	**Countries and country codes**
Central Eastern Europe (CEE)	Czech Republic (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)
Apennine Peninsula	Cyprus (CY), Italy (IT), Malta (MT)

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[6] (XK), Montenegro (ME), North Macedonia (MK), Serbia (RS)
UK & Ireland	Ireland (IE), United Kingdom (UK)

Source: JRC, 2022

Figure 13. Installed capacities by scenario, region and fleet. Text values indicate the CAGR. Please note the different scales of the vertical axes. A more detailed breakdown by country is provided in Annex 3.



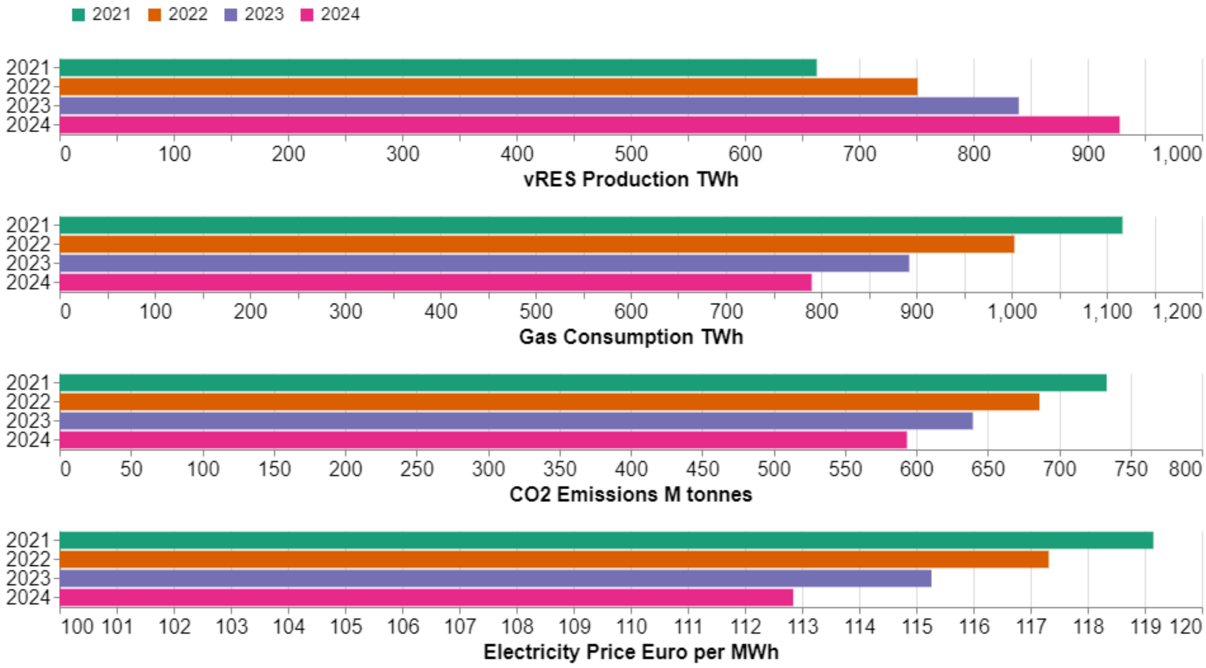
Source: JRC, 2022

Figure 14 provides a compact overview of annual key indicators in the EU. The first panel displays the increase of RES production owing to the higher installed capacities of the solar and wind fleets. Overall, the higher installed capacities would result in a substantial increase of vRES production.

The three subsequent panels, gas consumption of power plants, CO_2 emissions and electricity price, reveal selected impacts that result from displacement of other production assets' generation by the additional vRES production. As could be expected, the additional RES production leads to consistent reduction in the values of all three indicators, whereby a correlation to the incremental levels of vRES production can be observed. It can furthermore be ascertained that the impacts on the decrease of gas consumption and CO_2 emissions – in relative terms – are more pronounced compared to the impacts on electricity price levels, suggesting that the shift in the merit-order induced by the additional vRES capacity over-proportionally displaces energy produced from fossil capacity as compared to fossil fuel capacities setting the price (see also paragraph 3.4).

([6]) 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.

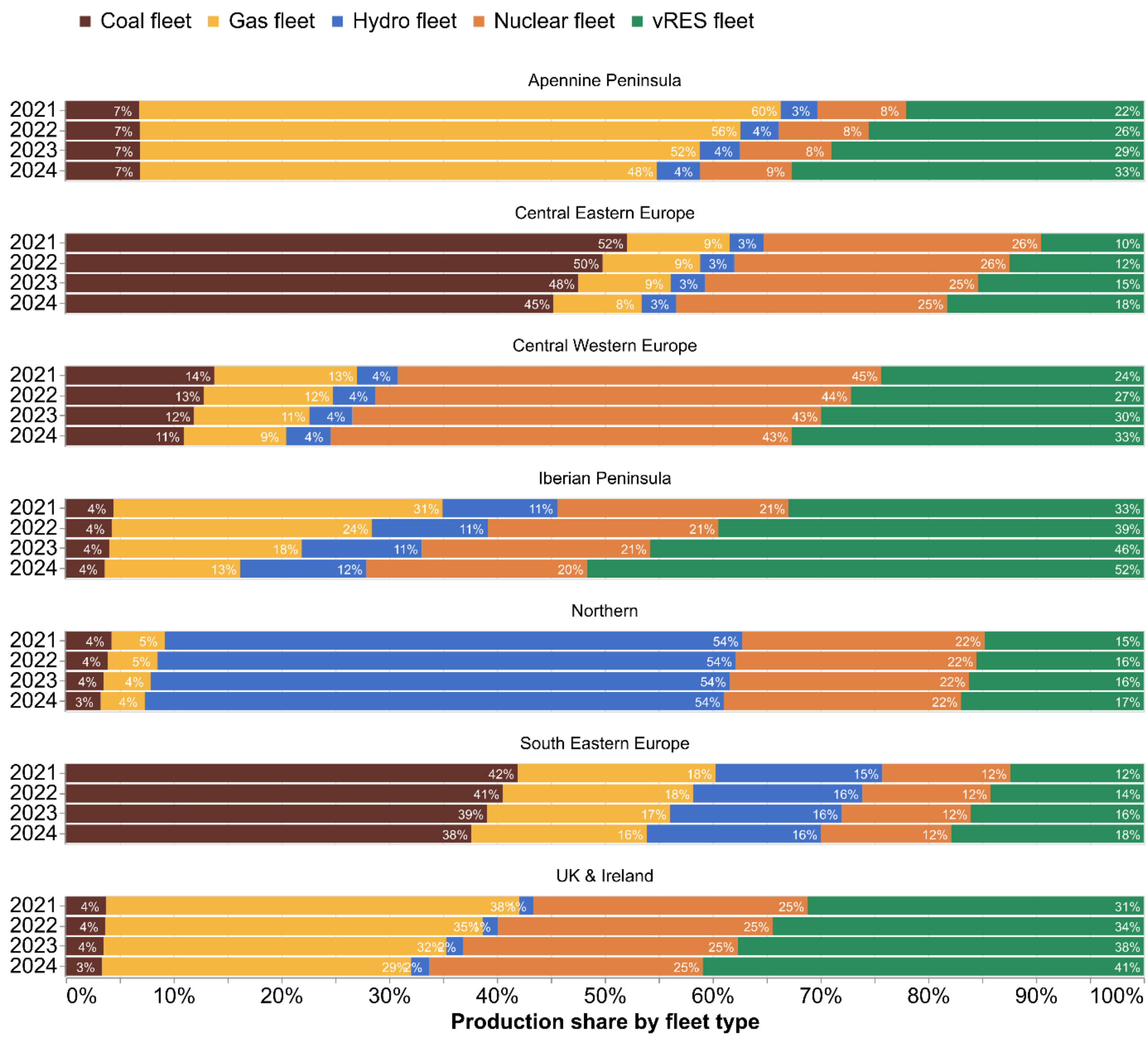
Figure 14. Indicators comparing counterfactual scenarios to 2021 baseline scenario at annual, aggregate EU level. Please note – for better visibility - the different scales, so that the relative magnitude of changes is not comparable across the different indicators.



Source: JRC, 2022

A more detailed depiction of the change in generation mix by market region and scenario is provided in Figure 15. Here it becomes visible that the additional vRES production is substituting in particular gas, and to a lesser extent coal, and only very slightly nuclear production, adding some clarity to the presumption of differentiated substitutional effects in different market regions. The substitutional effect on gas production is particularly noteworthy in the Iberian Peninsula market region.

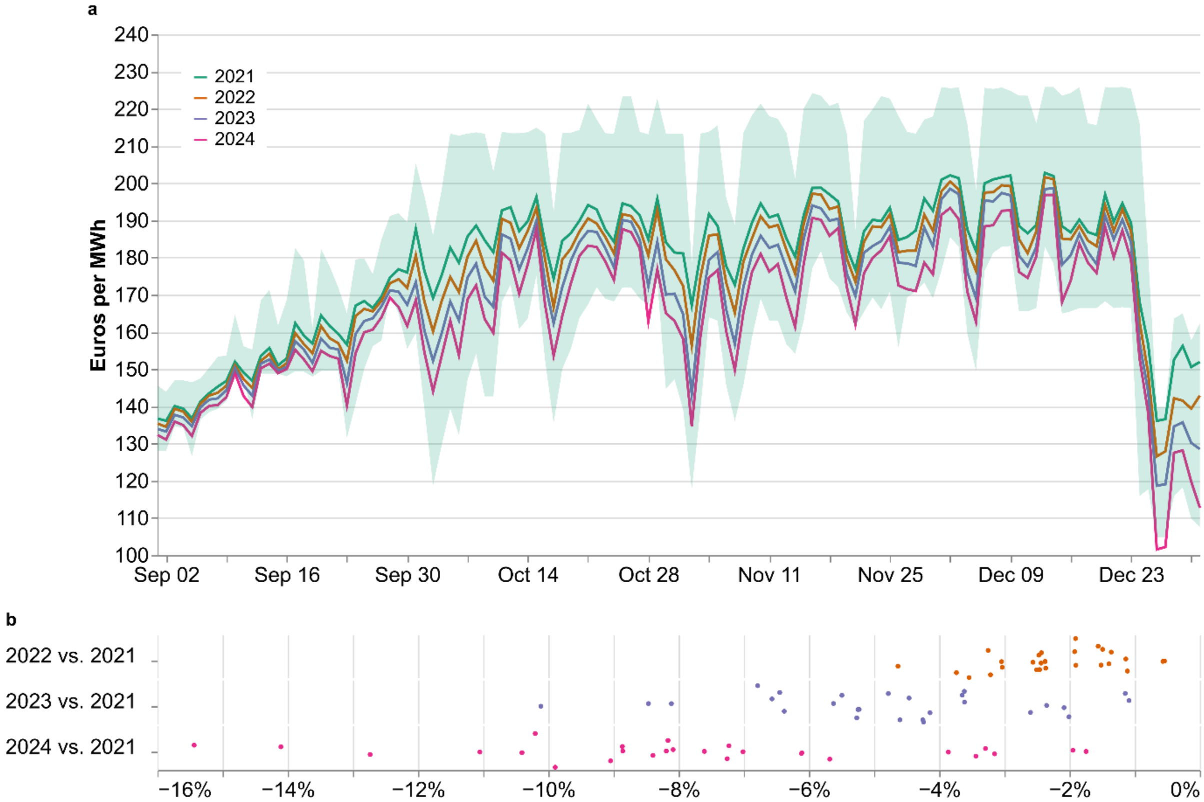
Figure 15. Generation mix for baseline case and counterfactual scenarios.



Source: JRC, 2022

In Figure 16, panel (a) provides a more detailed depiction of modelled electricity prices during the last four months of the year. It can be seen that higher RES shares consistently lead to lower price levels, which is in particular visible during times of high price levels. The bottom panel (b) depicts the relative change compared to the '2021' baseline case of average annual prices at country level. It can be seen that the spread across countries is quite pronounced, i.e. countries benefit to varying extents in terms of lower wholesale electricity prices from the modelled trajectory of additional renewable capacities. Moreover, the reduction of electricity prices consistently increases for higher levels of RES capacity overall, whereby the spread across countries extends further.

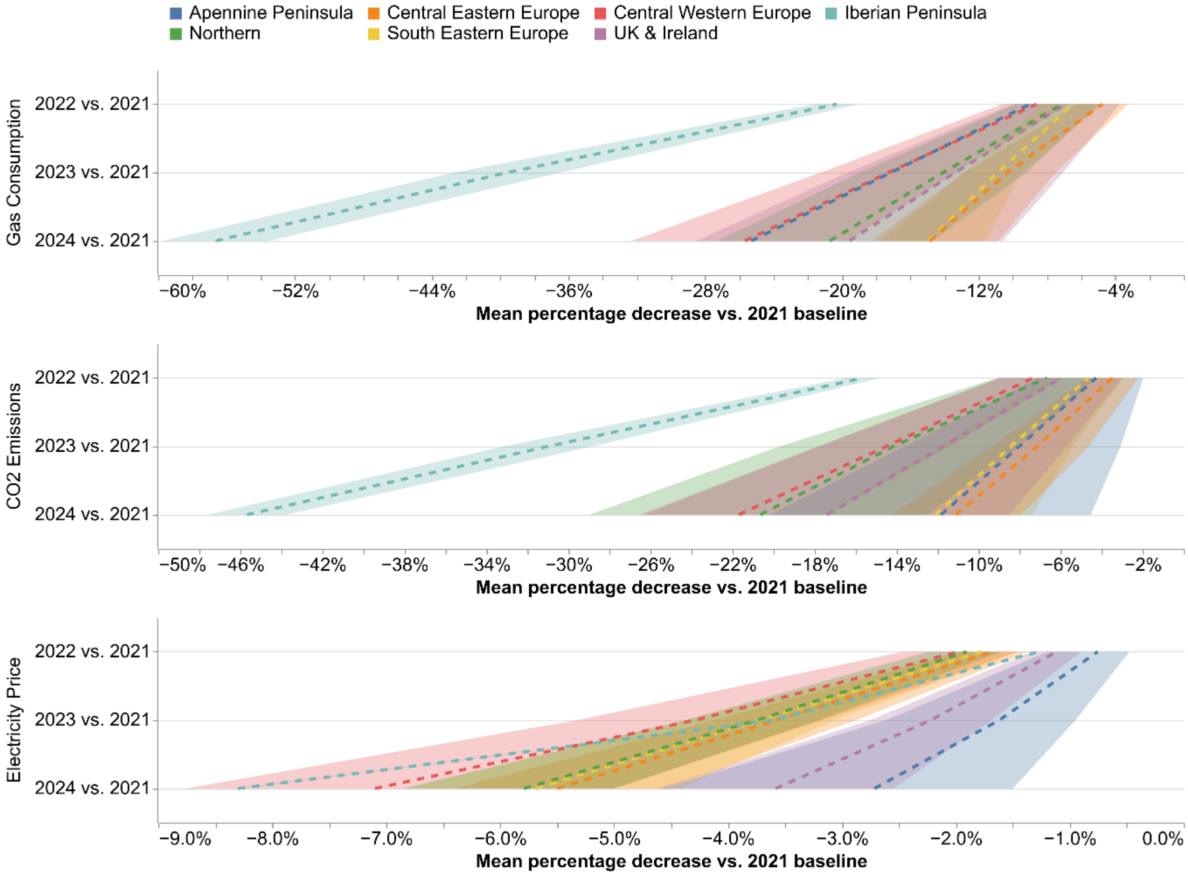
Figure 16. Modelled electricity prices for the September to December range. In top panel (a), lines denote mean EU values; shaded denotes the inter-quartile range for baseline case 2021. In bottom panel (b), circles denote the range of price decreases, relative to 2021 baseline case, across the modelled countries.



Source: JRC, 2022

Figure 17 provides, at regional level, a comparative overview on the annual percentage changes compared to the 2021 baseline case. It becomes further evident that the percentage decreases are highest for the levels of gas consumption, followed by reductions of CO_2 emission and finally by the reduction of electricity price level (note the different scales of horizontal axes), whereby the Iberian Peninsula would clearly stand out compared to other market regions in terms of impacts. By cross-comparison between the trajectories for the different regions across indicators it can also be ascertained that the reduction of gas consumption generally follows a similar pattern to the reduction of CO_2 emissions.

Figure 17. Percentage changes of indicators compared to 2021 baseline case. Dashed lines denote mean values per region and shaded areas the bandwidth per region.

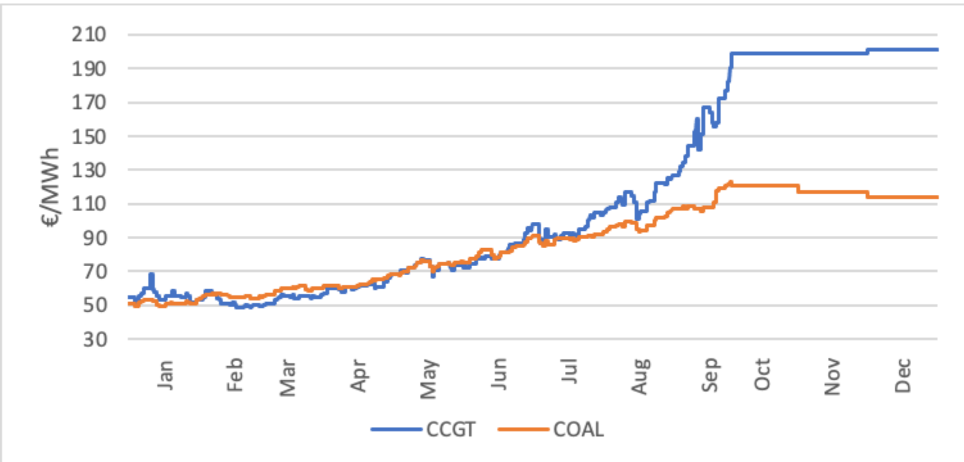


Source: JRC, 2022

3.3 How are high gas prices affecting CO_2 emissions?

In this section, we study the extent to which the current high energy prices may work against EU efforts to cut carbon emissions in the power sector. Commodity prices in the EU mostly floated around their three-year average until early summer of 2021 [4]. Driven by a combination of supply and demand factors, these prices, especially for natural gas, soared in the third quarter of 2021. As Figure 18 illustrates, for the first half of the year, coal and gas marginal generation costs remained within a few euros of difference.

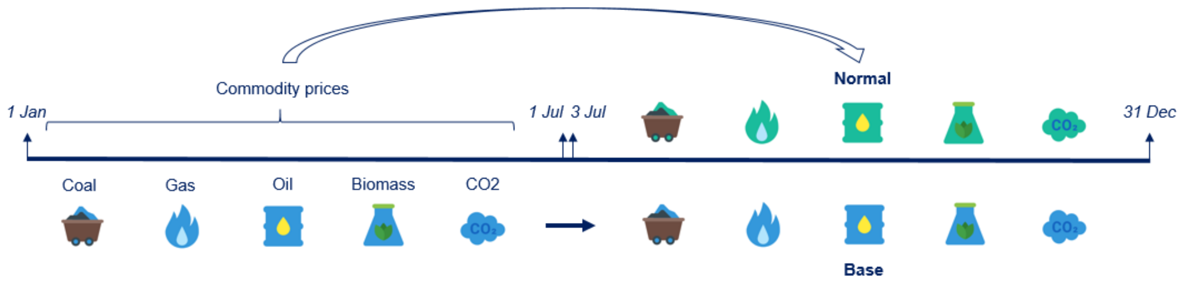
Figure 18. Variable cost gas vs coal-fired generation



Source: JRC, 2022

In the second half of the year, the two costs diverge significantly, with coal-fired generation in October undercutting gas by almost 100 EUR/MWhe. Consequently, the merit order of the generating fleets changes, with coal dispatched first. Concerns about higher carbon emissions therefore seem valid, as high natural gas prices encouraged the use of more emission-intensive substitute fuels for electricity production, like coal, lignite and oil. Note that commodity prices could remain elevated in the course of 2022, before falling again in 2023 [4]. We benchmark the base context to the context 4 counterfactual, representing a scenario where commodity prices stay at regular price levels during the entire year. As indicated in Figure 19, we transpose realised spot prices for the energy commodities coal, gas, oil, biomass and CO_2 from the first half of the year (1 January to 1 July) on the second half of the year (3 July to 31 December).

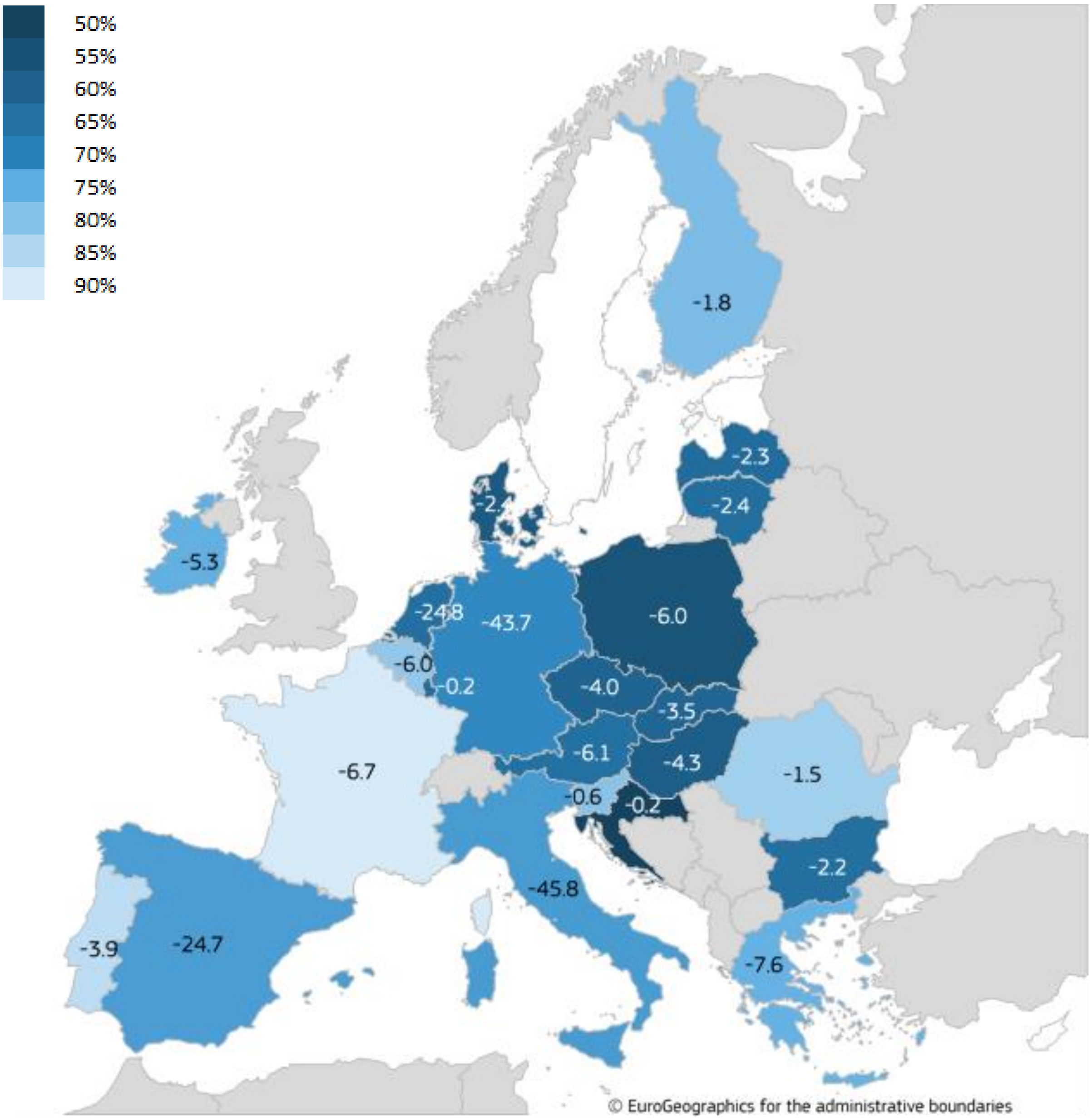
Figure 19. Creation of the context by transposing the commodity prices on the first half of 2021 to the second half.



Source: JRC, 2022

Figure 20 shows the total electricity production of the fleet of combined and open cycle gas turbines (CCGT and OCGT respectively) across the modelled area, where the displayed numbers indicate the difference in production in TWh. The colour scheme indicates the relative drop of power production via the CCGT and OCGT fleet. We find that all countries, except for Estonia where production levels remain equal, experience a decrease in gas-fired electricity production, driven by an extreme increase of natural gas prices that outweighs the parallel increase of coal and CO_2 prices. Within the EU, the effect is the most pronounced for Italy, Germany, the Netherlands and Spain. Croatia experiences the largest drop, with only 48% of gas-fired electricity production in the scenario with current commodity prices compared to the normal scenario. Although Croatia has a relatively small gas-fired fleet, and thus switches relatively easy to alternative fuels to bridge the production gap, other Member States with a larger fleet of gas-fired power production facilities also experience a significant drop, like Germany and the Netherlands, with 68% and 62% respectively. As demand is satisfied by alternative generation facilities, the drop in gas-fired electricity production raises the question of whether it is replaced by more polluting electricity production facilities.

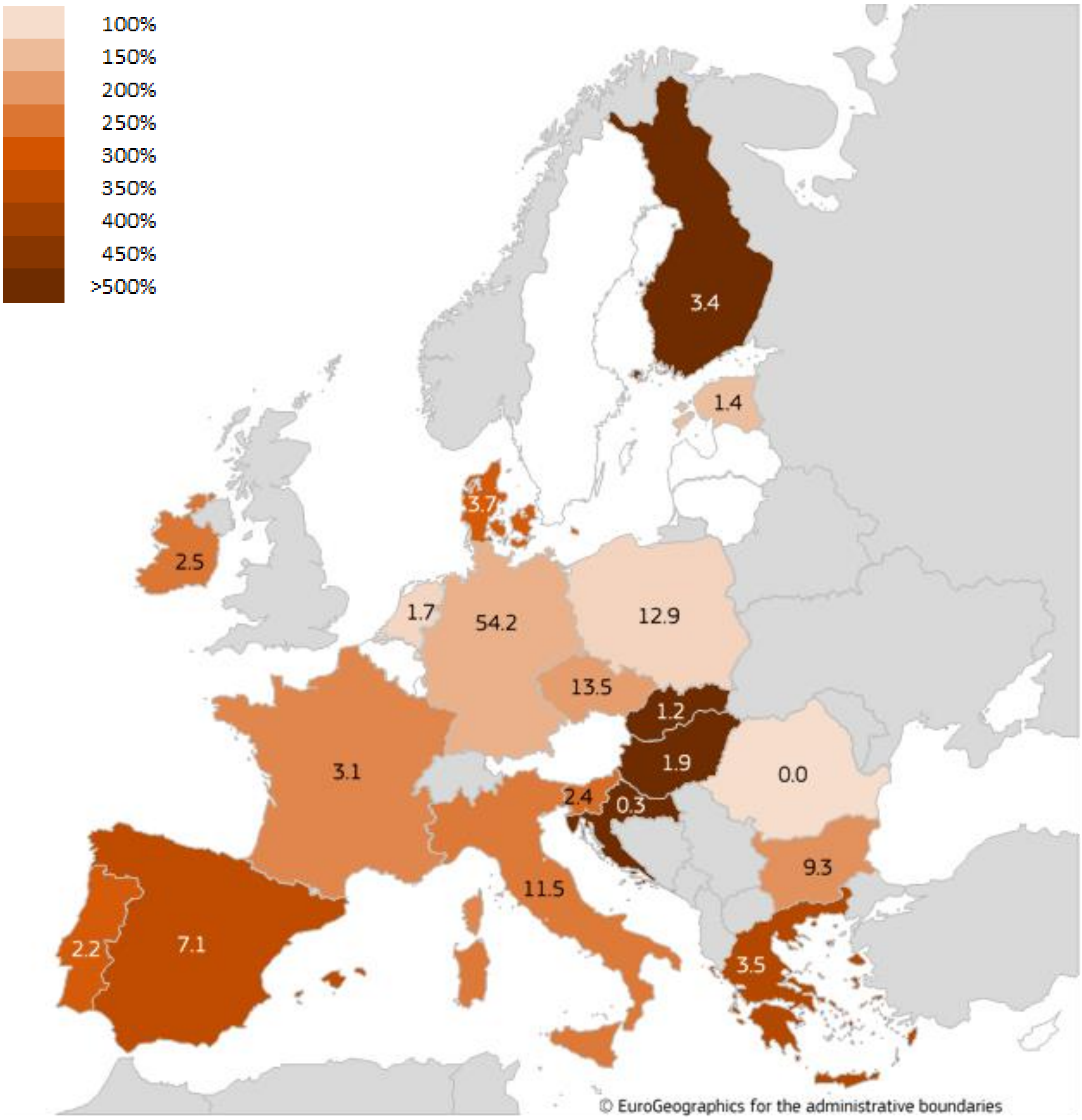
Figure 20. Difference between base and normal scenario for total electricity production of the CCGT and OCGT fleet across the modelled area in 2021. Absolute numerical difference in TWh. Relative difference indicated by colour code.



Source: JRC, 2022

A similar analysis for the coal and lignite-fired fleet is given in Figure 21. Comparing the baseline scenario to the context with 'normal' prices, we find coal-fired electricity production being higher in all Member States with coal-fired power production facilities. The decrease in gas-fired electricity generation is partially substituted by an increased share of coal-fired electricity generation. In absolute numbers, this effect is most pronounced in Member States where there is still significant coal-fired power generation capacity, like Germany, Czech Republic, Poland and Italy. In relative terms, we observe a significant increase of coal and lignite in the power generation mix in the EU for Slovakia, Hungary, Croatia and Finland, with a relative increase of above 500% compared to our scenario defined by normal prices. Slovakia is a notable example, as under normal prices, the entire coal and lignite fleet would have remained idle. Member States with a larger coal-fired power installation fleet also experience large relative increases, like Spain and Italy, with 312% and 218% respectively.

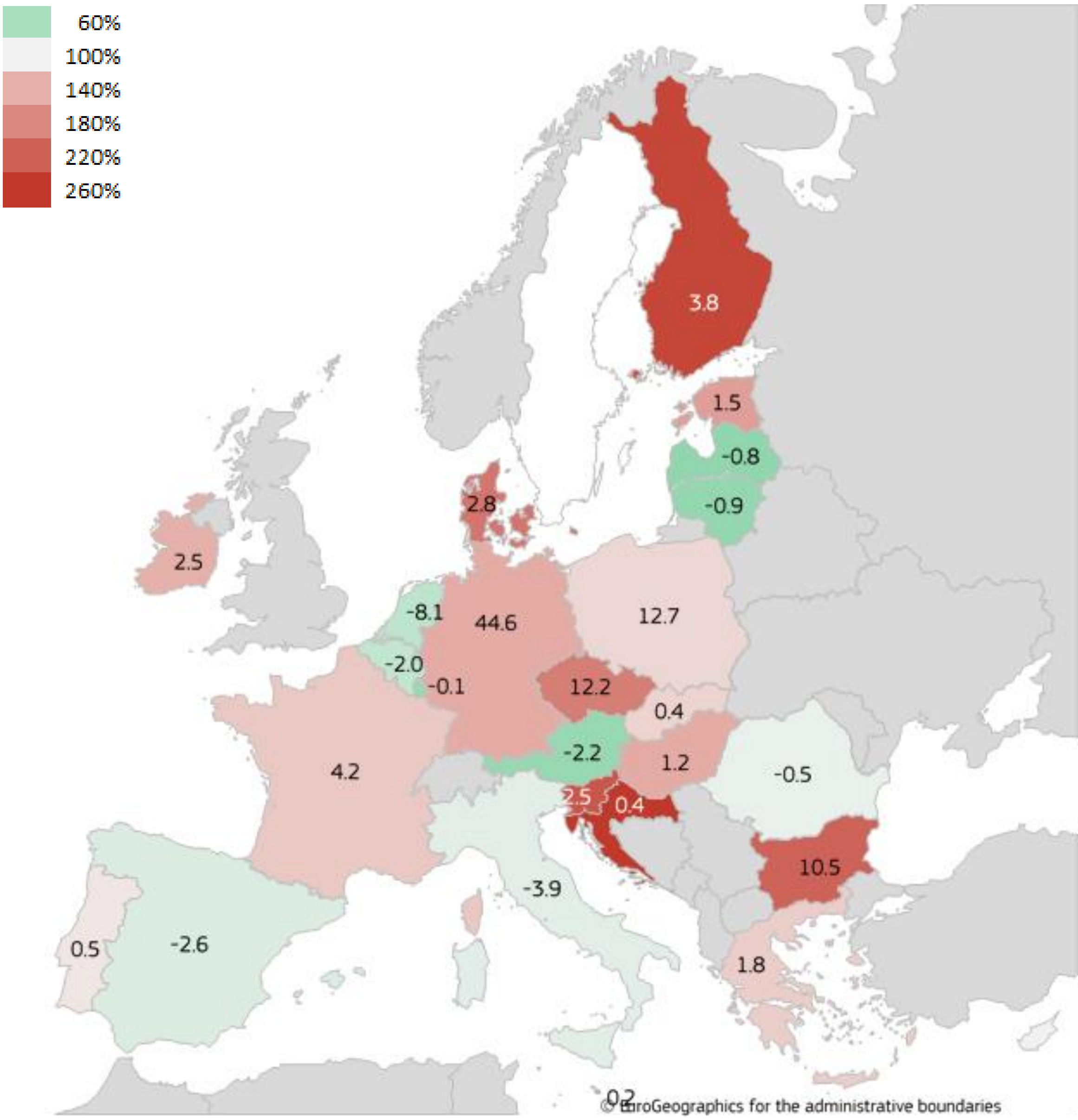
Figure 21. Difference between base and normal scenario for total production of the coal and lignite fleet across the modelled area in 2021. Absolute numerical difference in TWh. Relative difference indicated by colour code.



Source: JRC, 2022

Finally, we compare what the gas to coal fuel switch means in terms of carbon emissions from the power sector. Figure 22 shows the difference in total carbon emissions between the base and normal scenarios. We observe that emissions increase for the majority of Member States. The model results point to an increase of emissions across the modelled area by 80 Mt, primarily driven by significant absolute increases mainly in Germany, Poland, the Czech Republic and Bulgaria. Note that Germany accounts for 55% of the total increase in emissions across the EU. The increase in commodity prices also drives some Member States to less polluting alternatives, most notably in the Netherlands, where emissions drop by 8 Mt. In relative terms, we find that electricity-related emissions mostly increase in Croatia and Finland, with 267% and 191% respectively. In relative terms, emissions drop the most in Latvia, Lithuania and Austria with 61%, 63% and 65%, respectively, of the emissions under the normal scenario. We note that besides fuel switching, a primary driver behind the emissions differences is that some Member States rely increasingly on imports, like the Netherlands, Lithuania and Latvia, where national electricity production decreases by respectively 20%, 17% and 17% of demand. On the other hand, national total electricity production in Germany rises by 8%, the largest in absolute terms, with nearly an additional 40 TWh of electricity produced compared to the scenario with normal prices.

Figure 22. Total carbon emission differences for the power sector between the base and normal scenarios across the modelled area in 2021. Absolute numerical difference in Mt. Relative difference indicated by colour code.



Source: JRC, 2022

3.4 Marginal generating fleets

One last element of our analysis is the estimate of the number of hours during which generating fleets are marginal, therefore having the capacity to set the price in 2021. We clustered EU countries in the following three groups, depending on the hours that gas and coal fleet are marginal in the simulations[7].

([7]) This result is a rough approximation based on post-processing model results and in particular the producer's surplus, identifying fleets with the lowest specific surplus in each zone as "marginal". This is a simplification ignoring the role of interconnectors and the coupling of markets. It however gives an indication of how pivotal national fleets are.

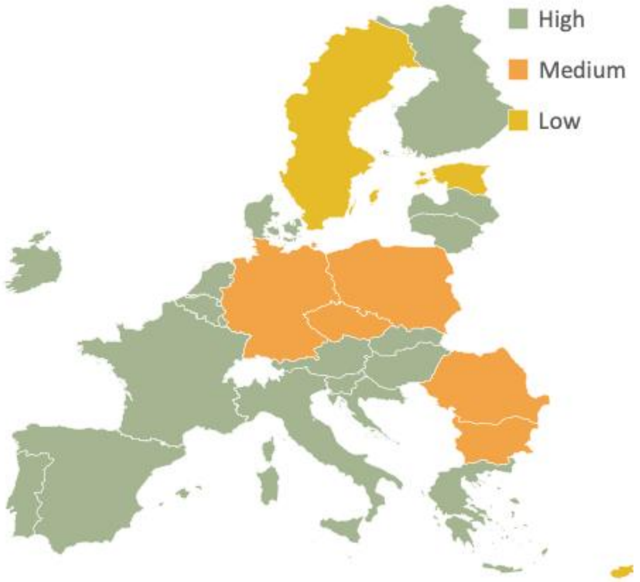
— Low: In this group are countries where gas prices have a minimal effect on the marginal system cost. Price is set either by renewables, nuclear, or oil.

— Medium: countries where gas has a significant presence but in which coal and lignite are the predominant price setters (in 2021).

— High: countries where gas is the predominant marginal technology in 2021. In these countries, coal and lignite may be present to a higher or lower degree however, gas fleets are the most pivotal technology, as they are marginal most of the time in 2021.

Figure 23 illustrates the above clustering of Member States in the three groups described above.

Figure 23. Clustering of countries in groups with high, medium and low gas-fired marginal hours



Source: JRC, 2022

The table below provides the average, minimum and maximum hours (within each group) with marginal gas, coal or nuclear for each group of countries.

Table 4. Marginal price-setting in the three groups.

Group	Hours gas is marginal	Hours coal/shale oil is marginal
Low	7 (0 - 14)	470 (0 - 1 880)
Medium	1 984 (1 254 – 2 931)	4 647(3 614 – 5 625)
High	4936 (3 095 – 7 138)	1 160 (0 – 3 164)

Source: JRC, 2022

In a '2022' scenario the introduction of more renewable capacity (see par.3.2) reduces the hours that gas fleets are marginal by approximately 9% in the 'High' group and by 3% in the Medium group (Table 5). This effect of adding renewable generation on the marginal fleets is expected and in agreement with the findings presented in section 3.2. It should however be noted that this a sensitivity analysis result and not a prediction for 2022, when other factors, most notably Nuclear and Coal plants decommissioning, will come into play and affect the extent to which technologies will be marginal.

Table 5. Hours gas fleets are marginal with 2021 vs a '2022' renewable capacity (additional renewables) scenario

Group	2021	'2022' RES scenario	% change
Medium	1984	1920	-3%
High	4936	4479	-9%

Source: JRC, 2022

4 Summary and Conclusions

In the previous sections, the electricity market conditions affecting the wholesale EU electricity prices in 2021 were analysed with respect to the impact of weather, renewable capacity additions, and fuel prices. Based on the historically available data up to September and the available climatic database, we created a projection into the last three months of 2021 that allowed us to assess the lowest and highest anticipated cumulative gas demand until 31 December. Our results show that this range, exclusively affected by weather, does not exceed 60 TWh of gas (HHV) or less than 4.5% of the modelled annual demand of gas for power generation.

We also simulated the operation of the electricity sector for the year 2021, applying the weather conditions (affecting demand, wind, solar and hydro) observed in 37 past years (1980-2016), and found that weather conditions prevailing in 2021 are not the cause behind an (annual) increased gas demand for power generation. The simulations based on 2021 reveal a marginally lower gas consumption than the median value derived from the simulations based on the 37 past years.

We further investigated the extent to which the planned introduction of new renewable capacity is expected to reduce gas consumption from power plants and the wholesale electricity price. We found that all else being equal, the capacity added in each counterfactual scenario could reduce gas consumption by around 100 TWh of gas, or 10% of baseline gas consumption for power generation. Thus the additional renewable generation expected to be online one year from now can have a stronger effect on gas demand for power than the calculated maximal range of gas demand variation due to weather conditions across the 37 past years mentioned above. In this scenario, the additional renewable generation would result in annual incremental reductions of CO_2 of approximately 50 Mt.

Furthermore, we assessed the economically justifiable fuel switching potential currently available in the EU at the current prices, by means of a counterfactual scenario in which the prevailing commodity prices in the first half of the year are sustained in the second half.

Our modelling results indicate that the fuel switch from gas to coal, lignite and biomass could lead to a reduction of gas demand by as much as 430 MWh (HHV) across the EU, compared to a business as usual normal price scenario (counterfactual scenario). This fuel switch could mean increased CO_2 emissions by as much as 80 million tonnes, compared to a normal year (pricewise).

4.1 Conclusions

The presented analysis allows us to reach the following conclusions:

1. The marginal cost computed by the model is able to replicate the observed electricity market prices to a degree: it predicts peak daily prices with much higher accuracy than the low and average daily prices. However, actual generation data indicate that fuel switching from gas to coal in September was less pronounced than the model predicts, based on marginal costs defined by commodity spot prices and coal fleet availabilities based on outages published in ENTSO-E's transparency platform.

2. The lower than average wind conditions specific to 2021 do not appear to be sufficient to have caused an increase in gas use for power generation. The calculated 2021 gas consumption for electricity generation is very close to the median value of the calculated gas consumption in the 37 climatic variations. Hence, we do not consider climate – and in particular low wind conditions – to be a significant factor behind the gas scarcity.

3. Our analysis shows that the modelled gas demand for electricity production throughout October to December is not significantly affected by climatic variation. The difference between estimated maximum and minimum values, with the prevailing gas prices, does not exceed 5% of the total annual demand for gas to power in 2021.

4. If the present hike in gas prices had occurred a few years ahead (hence with more renewables), gas consumption for power generation could be as much as 25% lower, while the average European price level would be lowered by around 4% or 6 EUR/MWh. This is a model result caused by the re-dispatching of the generating fleets. It therefore ignores the potential price drop in gas prices at European Hubs, due to reduced gas demand. Further insight on this issue will be provided in the next phase of the present study with integrated gas and power markets modelling of 2021-22.

5. CO_2 emissions across the EU could be higher by as much as 80 million tonnes, (a 13% increase) in the second half of 2021, compared to a counterfactual scenario where gas, coal and CO_2 prices were

identical to prices observed in the first half of the year. This is mainly due to significant fuel switching from gas to coal due to the merit order change. It should be noted, however, that this number should be considered an upper bound, as indicated by the benchmarking of modelled dispatching vs actual generation in September.

6. Based on our modelling results of the 2021 electricity systems across the EU, we found that it is possible to identify three groups of countries with similar traits with respect to the frequency that coal and gas-fired generation fleets are marginal. The first group includes outliers such as Sweden, Estonia, Malta and Cyprus and has little or no exposure to gas prices. The second group of countries has significant coal and/or lignite capacity which is marginal a significant amount of time. These countries are Czechia, Germany, Poland, Romania and Bulgaria. The third and largest group includes the remaining EU members states in which gas fleets may be considered the most pivotal technology, as they are the marginal technology most of the time in 2021.

References

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[2] Directorate-General for Energy, “Quarterly report on European Electricity Markets - 2021 Q2,” 2021. [Online]. Available: https://ec.europa.eu/energy/sites/default/files/quarterly_report_on_european_electricity_markets_q2_2021_final.pdf.

[3] K. Kanellopoulos, K. Kavvadias, Carreri F., M. De Felice, S. Busch and I. Hidalgo Gonzalez, “The operation of the European Power System in 2016,” Publications Office of the European Union, Luxembourg, 2019.

[4] World Bank Group, “Commodity Markets Outlook: Urbanization and Commodity Demand, October 2021,” World Bank, Washington, DC, 2021.

List of abbreviations and definitions

CCGT	Combined cycle gas turbine
HHV	Higher heating value
ML	Machine learning
OCGT	Open cycle gas turbine
TP	ENTSO-E's Transparency platform
TTF	Title Transfer Facility. The Dutch gas trading platform.
RES	Renewable energy sources
vRES	Variable renewable energy sources

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Annexes

Annex 1. Methodology for creating the 2021 context

This annex describes the methodology, including data sources and assumptions, applied to build all the components of the METIS contexts used in this study.

Power plants and transmission lines (assets)

The assets dataset has been created starting from the work done for the CURRENT2016 context [3]. ENTSO-E data and data from national TSOs has been used to update the capacities, including new power plants and decommissioning.

Similarly, for cross-border transmission lines ENTSO-E Transparency platform (TP) data and from other sources (national TSOs, TYNDP documents, PCI lists) has been used to check and detect changes. The hourly electricity flows on the TP for all the European interconnectors has been used to check NTCs values.

Outages

The planned and realised outages of generating units for year 2021 reported on the Transparency Platform by ENTSO-E have been used to create time-series of availability. For each asset, METIS model allows to specify an hourly time-series of its availability ranging from 0% (not available) to 100% (entire capacity available). The time-series have been created using the ENTSO-E TP data on the Unavailability of Generation Units (15.1.A_B).

Hydropower inflow

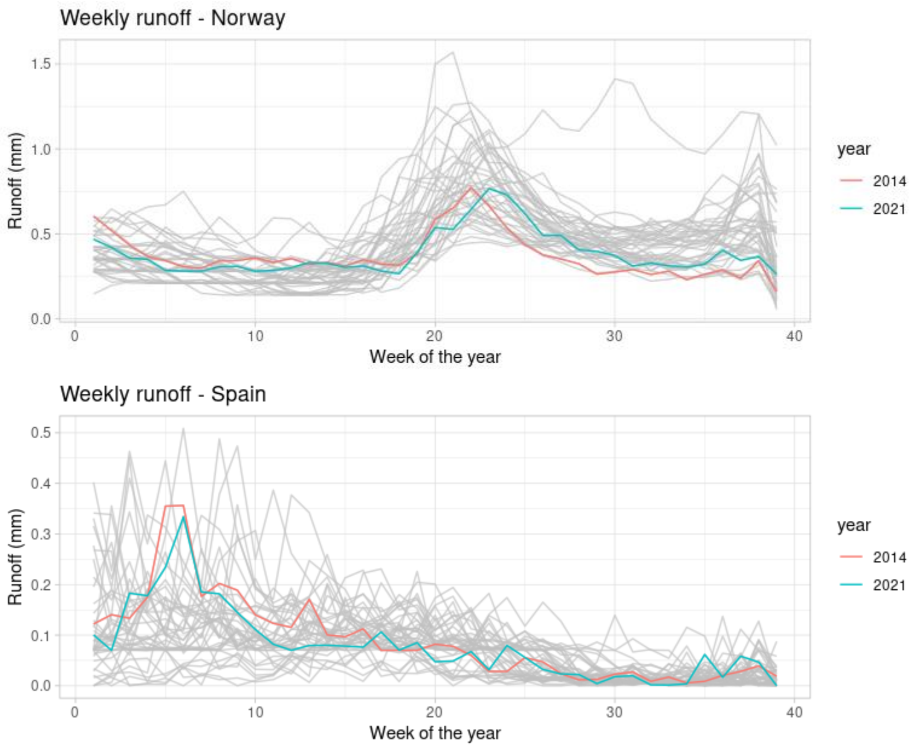
The inflow defines the quantity of energy available to the hydropower stations (both run-of-river and pure reservoirs). Unfortunately, there are no public data on the inflow at European level that could be used to estimate the 2021 time-series.

Then, we opted for using the ENTSO-E Pan-European Climate Database (PECD), which provides weekly inflows for each ENTSO-E zone and technology[8]. The PECD provides a set of weather-based inflows using the climatic information for the years 1982-2017.

Given the lack of any observations, the choice of the year (the climatic year) to use in the 2021 study has been carried out using the weather information from the ERA5 atmospheric reanalysis. The reanalysis provides an estimation of the weather variables at global level in quasi-real time (with 5 days of delay). We chose the ERA5 variable that could convey the most information on hydropower inflows, the run-off rate (a measure of the availability of water in the soil). We analysed the weekly run-off at country-level for the years 1980-2021 only considering the period January to September and we selected the historical year available in the PECD that was similar to the 2021 time-series. We selected the year 2014.

([8]) The latest release of the PECD can be found at the following URL: https://www.entsoe.eu/outlooks/midterm/ (accessed: 22/10/2021)

Figure 24. Weekly runoff patterns across the climate year range for selected countries



Source: JRC, 2022

For each country, the inflow time-series has been calibrated multiplying the original value with a coefficient calculated as the ratio between the observed hydropower generation (from ENTSO-E) and the output from a first run of the model without any inflow correction.

Hydropower storage guiding curve

The hydropower storage levels are defined by the model during the dispatching optimisation. However, the country hydropower storage levels have a lower-bound, in other terms the minimum level of storage that must be followed at every time-step of the simulation.

This guiding curve has been obtained running the METIS model with a daily resolution (to be able to simulate the entire year in a single optimisation run) with all the available inflow time-series. Then, from this set of simulation, for each time-step we calculate the guiding curve as the 15th or 25th percentile of the distribution from all the guiding curves returned by the optimiser. The choice between 15th or 25th percentile has been made ex-post to try to match the characteristics of specific national hydropower systems. The countries using the lower percentile (15th) are Italy, Norway and Portugal.

Solar and wind offshore profiles

The METIS model includes the variability of wind and solar using time-series of capacity factor. Although the ENTSO-E TP provides hourly generation of solar and wind in Europe[9], the use of this data for modelling purpose poses many issues:

- The installed capacity is not consistent with generation because its change during the year is not available (the ENTSO-E TP provides installed capacity once per year). In other words the generation of a specific RES in a time-step cannot be converted to capacity-factor because the actual capacity of that RES source available at the same time-step is not available
- There can be gaps and outliers in the data

(9) During 2021 the UK stopped providing data to the ENTSO-E Transparency Platform. In this study, the rest of the UK data has been retrieved from the Elexon data portal, using their API.

- In some countries (e.g. Italy and Netherlands for solar) the generation does not include all the available generation capacity, leading then to inconsistent and misleading capacity factors

We use the dataset renewables.ninja for an hourly estimate of capacity factors for the past (the dataset version 1.1 covers the years 1980-2016 for wind and 1985-2016 for solar). Although the dataset is an estimate based on atmospheric reanalysis and satellite data, it is considered reliable and it has been used in many modelling activities [REFs].

Then, to avoid using the ENTSO-E TP we opted for a machine-learning (ML) based solution. We used a ML model to learn the relationship between weather variables and capacity factors (provided by renewables.ninja) for each country, and then using the same model to 'extend' the capacity factors time-series to 2021 using the weather variables available in this period.

The weather variables used as predictors are solar radiation for solar power and wind speed at 100m for wind offshore. The variables are provided by JRC ERA-NUTS dataset, using the hourly data aggregated at NUTS2 level.

The ML model used is a Random Forest, trained for each variable (offshore wind and solar generation) and country on 50% of the available data (training dataset). The model is trained on the first 50% of the data and then the rest of the data (testing dataset) has been used to evaluate the model performance and assess its capability of generalise the target variable.

The performance on the testing dataset has been measured using Pearson correlation coefficient, summarised in the following table.

Table 6. ML model performance test results

	Minimum correlation	Mean correlation	Maximum correlation
Solar generation	0.87 (LV)	0.94	0.98 (IT)
Wind offshore generation	0.89 (DE)	0.92	0.96 (UK)

Source: JRC, 2022

Wind onshore

Generation data from the ENTSOE-TP & Elexon Data Portal has been converted to capacity factor dividing the hourly generation by the installed capacity.

In the case of wind onshore, this procedure led to good results – comparing the obtained capacity factors with historical values and reported data where available. In case of missing data points, they have been filled copying the previous value.

A few countries modelled in this study are not available on the TP and their time-series have been created using the data for neighbouring countries: Italy for Cyprus, United Kingdom for Ireland, Estonia for Latvia, Greece for MK and Malta, Croatia for Slovakia, Germany for Luxembourg.

The data for the period October to December 2021 has been defined using the data for the same period in 2020. This choice is based on the similarity of the generation data between the two periods.

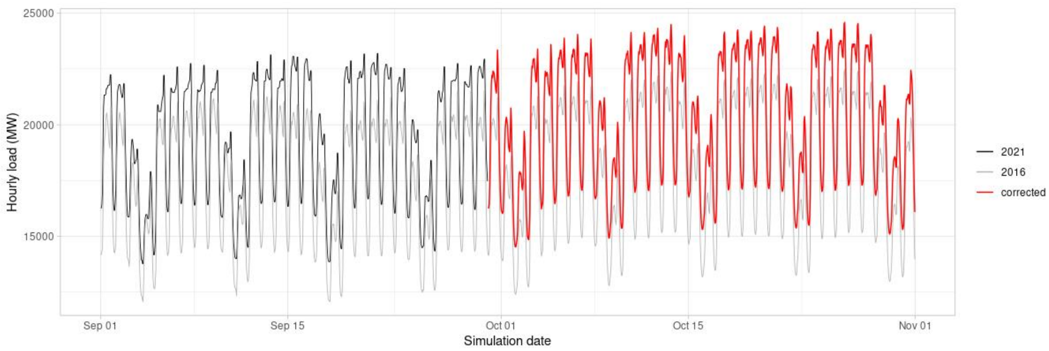
Power demand

The hourly electricity demand has been retrieved from the ENTSO-E Transparency Platform and Elexon Data Portal for the period January to September 2021.

Given that METIS model needs an entire year with 8 760 time-steps, the rest of the year (October – December) has been generated calibrating past ENTSO-E data. We chose the year 2016 in the Transparency Platform because that year has the same calendar of 2021. However, year 2016 and 2021 have substantial differences in electricity demand, then the former has been shifted applying a correction to match the average in the two final weeks of September. In other words, a delta has been applied to the 2016 time-series in order to have the same average demand in the period 15th-30th September.

The following figure shows an example based on Poland: the black line represents the electricity demand from ENTSO-E for year 2021 and the light grey is instead the data for 2016. The red time-series is the load for Oct-Dec 2021 obtained adding a constant value to the 2016 data.

Figure 25. Illustration of synthetic 2021 power demand rescaling



Source: JRC, 2022

Commodities price

The 2021 current context was created using the historical commodity prices up to September 30, and forward contract prices for the next 3 months or quarter (where available). In particular the following table summarises the sources used.

Table 7. Commodity price sources

Commodity	Data source	Comment
Natural gas	Hub prices (NL TTF, BE Zeebrugge, AT Baumgarten, DE GASPOOL, FR TRF, IT PSV, UK NBP, DK Noordpool, ES PVB, PL, CZ,HU, FI, EE, LV,LT,BG Future prices : TTF month-ahead, quarter ahead	1. For zones with no data, closest zone price was used. 2. 2 euros/MWh were added as balancing and transmission tariffs cost. 3. LHV price computed with a factor of 1.11
Coal	Coal CIF ARA spot Future prices : Coal PFC CIF ARA M+1 / Q+1	Single price for a nodes
Lignite	Country specific data for DE, PL, GR	
Oil	Fuel Oil 1 FOB Rdam Barges (PUAAP00)	Single price for a nodes + 13 assumed Euro/ton excise tax
Biomass	European Wood Pellets CIF NEW (Argus)	1. Spot prices are quoted weekly, Future prices are monthly products. 2. Prices in EUR/MWh computed with fixed 4.722 MWh/ton conversion factor and daily USD/EUR exchange rate
CO_2	EUA EEX Spot	

Source: JRC, 2022

Annex 2. Methodology for the climatic analysis

This annex describes how the METIS context for the climatic analysis has been created.

METIS contexts consist of one or more "test cases", in our study each test case is a specific climate year. We decided to associate the first test case (Test Case 00) to the climate year 1980, Test Case 01 to 1981, etc.

In case we do not have data for a specific year (for example because the underlying dataset's coverage), we use instead the first climate year available.

For example, for the inflows (as explained below) the PECD dataset covers the period 1982-2017, then for the first two test cases (Test Case 00 and Test Case 01) we used the climate year 1982.

Power plants and transmission lines (assets)

The climatic analysis used the same assets specified for the 2021 context.

Outages

All the climatic years in the analysis used the same time-series of outages as in the 2021 context.

Hydropower inflow

Here, we used the complete ENTSO-E Pan-European Climate Database (PECD) rather than selecting a single year. For consistency with the 2021 case, we applied the same correction coefficient calculated for the selected year (2014) to all the climate years.

Hydropower storage guiding curve

We used the same minimum storage level used for the 2021 case.

Solar and wind profiles

For solar, wind (on- and off-shore) we used the complete renewables.ninja dataset.

Power demand

To simulate the impact of weather in the electricity demand, we have applied a methodology based on the results of the H2020 project HOTMAPS[10].

For each country, we assume an electric heating & cooling (H&C) capacity based on PRIMES model for year 2020. Then, we create temperature-driven profiles of demand using the curves calculated by HOTMAPS and the temperature time-series from JRC ERA-NUTS dataset.

The synthetic time-series have been calibrated applying a bias-correction to each country using the time-series for year 2021 (based on temperature observed from January to September) and the observed ENTSO-E demand

Commodities price

Same as for the 2021 context.

([10]) https://www.hotmaps-project.eu/hotmaps-project/ [accessed 27-10-2021]

Annex 3. Capacity increases of RES counterfactual scenarios in the EU27.

Table 8. Capacity increases of RES counterfactual scenarios in the EU27

Country Code	Solar PV				Wind Offshore				Wind Onshore			
	2021	2022	2023	2024	2021	2022	2023	2024	2021	2022	2023	2024
AT	1.85	1.90	1.95	2.00	0.00	0.00	0.00	0.00	3.20	3.52	3.84	4.17
BE	4.79	5.31	5.83	6.35	2.26	2.38	2.51	2.63	2.58	3.19	3.81	4.42
BG	1.13	1.67	2.22	2.76	0.00	0.00	0.00	0.00	0.70	0.78	0.85	0.93
CY	0.25	0.32	0.39	0.47	0.00	0.00	0.00	0.00	0.16	0.16	0.17	0.17
CZ	2.05	2.41	2.76	3.12	0.00	0.00	0.00	0.00	0.34	1.17	2.00	2.84
DE	56.00	57.68	59.37	61.05	7.76	9.46	11.16	12.86	55.00	58.73	62.46	66.20
DK	1.30	1.85	2.40	2.95	2.30	2.30	2.30	2.30	4.48	4.98	5.48	5.97
EE	0.21	0.25	0.29	0.33	0.00	0.00	0.00	0.00	0.33	0.37	0.42	0.47
ES	14.60	17.51	20.42	23.32	0.00	0.00	0.00	0.00	26.81	32.13	37.45	42.77
FI	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.14	2.42	2.71	3.00	3.30
FR	10.21	13.71	17.20	20.70	0.01	0.61	1.21	1.81	17.22	19.14	21.07	23.00
GB	13.47	13.87	14.27	14.67	12.16	13.74	15.31	16.89	13.93	15.17	16.40	17.63
GR	3.06	3.40	3.75	4.10	0.00	0.00	0.00	0.00	3.76	3.96	4.17	4.38
HR	0.09	0.18	0.27	0.37	0.00	0.00	0.00	0.00	0.80	0.96	1.13	1.30
HU	1.68	2.21	2.73	3.26	0.00	0.00	0.00	0.00	0.32	0.37	0.42	0.47
IE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.17	4.34	4.52	4.69
IT	22.04	24.81	27.58	30.34	0.00	0.00	0.00	0.00	10.30	11.58	12.86	14.13
LT	0.17	0.23	0.30	0.36	0.00	0.00	0.00	0.00	0.54	0.62	0.71	0.79
LU	0.18	0.42	0.67	0.91	0.00	0.00	0.00	0.00	0.15	0.23	0.32	0.40
LV	0.01	0.02	0.03	0.03	0.00	0.00	0.00	0.00	0.08	0.16	0.23	0.30
MT	0.15	0.16	0.17	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NL	10.21	12.91	15.61	18.31	2.61	3.72	4.83	5.94	4.50	6.44	8.39	10.33
PL	4.09	6.15	8.22	10.29	0.00	0.00	0.00	0.00	6.57	7.63	8.70	9.76
PT	1.03	2.40	3.77	5.14	0.03	0.05	0.07	0.09	5.18	5.52	5.86	6.19
RO	1.15	2.31	3.47	4.63	0.00	0.00	0.00	0.00	2.96	3.52	4.08	4.64
SE	1.09	1.19	1.29	1.39	0.00	0.00	0.00	0.00	10.02	10.04	10.05	10.07

SI	0.28	0.51	0.75	0.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SK	0.53	0.63	0.73	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EU 27	138.1	160.1	182.1	204.2	14.97	18.57	22.16	25.76	162.6	182.3	202	221.7

Source: JRC, 2022

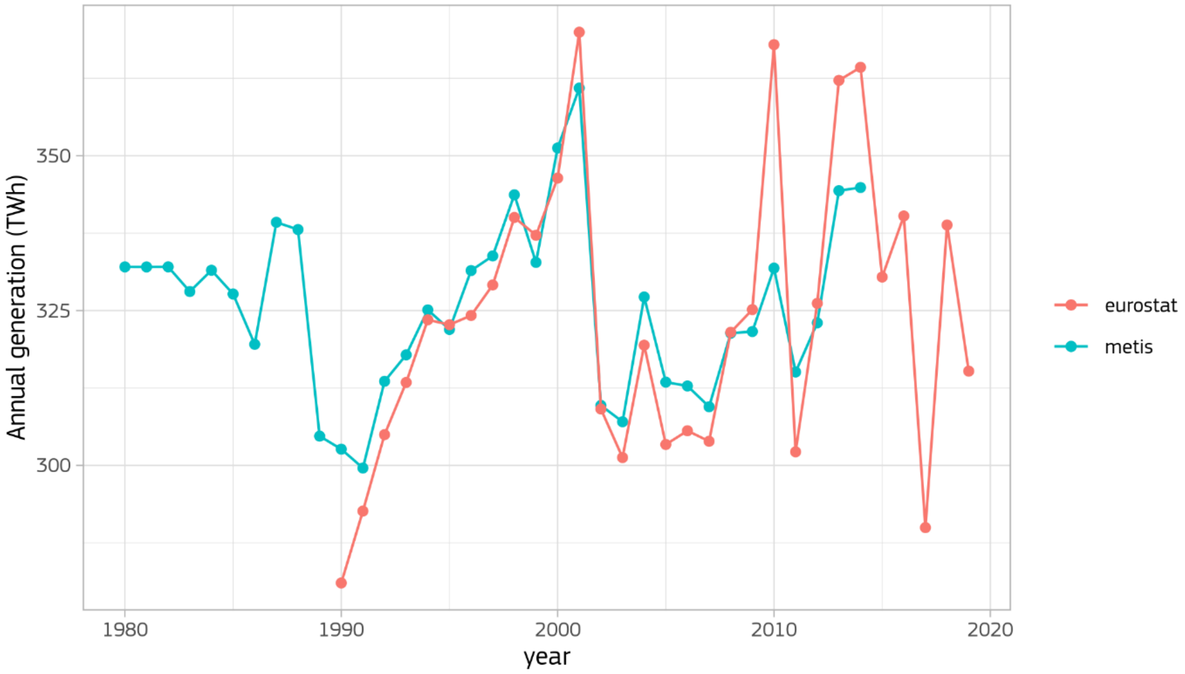
Annex 4. Hydropower calibration of available data for 2021

Annex 1 describes the why we chose 2014 as the best climatic year to represent 2021, where we don't have observed data for the calculation of the inflow.

Given the importance of hydropower in the current EU power system, in this Annex we show a comparison between hydropower generation calculated by METIS and the values reported by EUROSTAT.

Firstly, we compare the annual hydropower generation in METIS (reservoir and run-of-river assets) with the values contained in the EUROSTAT dataset "Gross and net production of electricity and derived heat by type of plant and operator" (*NRG_IND_PEH)*. Given that this EUROSTAT dataset does not differentiate between run-of-river and pure reservoir types, we considered the total hydropower generation (RA100) minus the pumped hydropower (RA130). The following figure shows the comparison of hydropower generation in EU between METIS and EUROSTAT.

Figure 26. Eurostat vs METIS annual generation across the climate years



Source: JRC, 2022

In the figure we can see how the inflow used in METIS are good enough to recreate the year-by-year variability of the hydropower generation reported in the EUROSTAT dataset (which covers the period 1990-2019). It is important to consider that the METIS results are based on the hydropower capacity installed in the year 2021 while the EUROSTAT values report the generation coming from the actual installed capacity in each year: however the change between 1990 and 2019 was minimal, the total hydropower (excluding pumping) went from 98.7 GW in 1990 to 126.5 in 2019 (data from the EUROSTAT dataset "Electricity production capacities by main fuel groups and operator", *NRG_ING_EPC*).

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